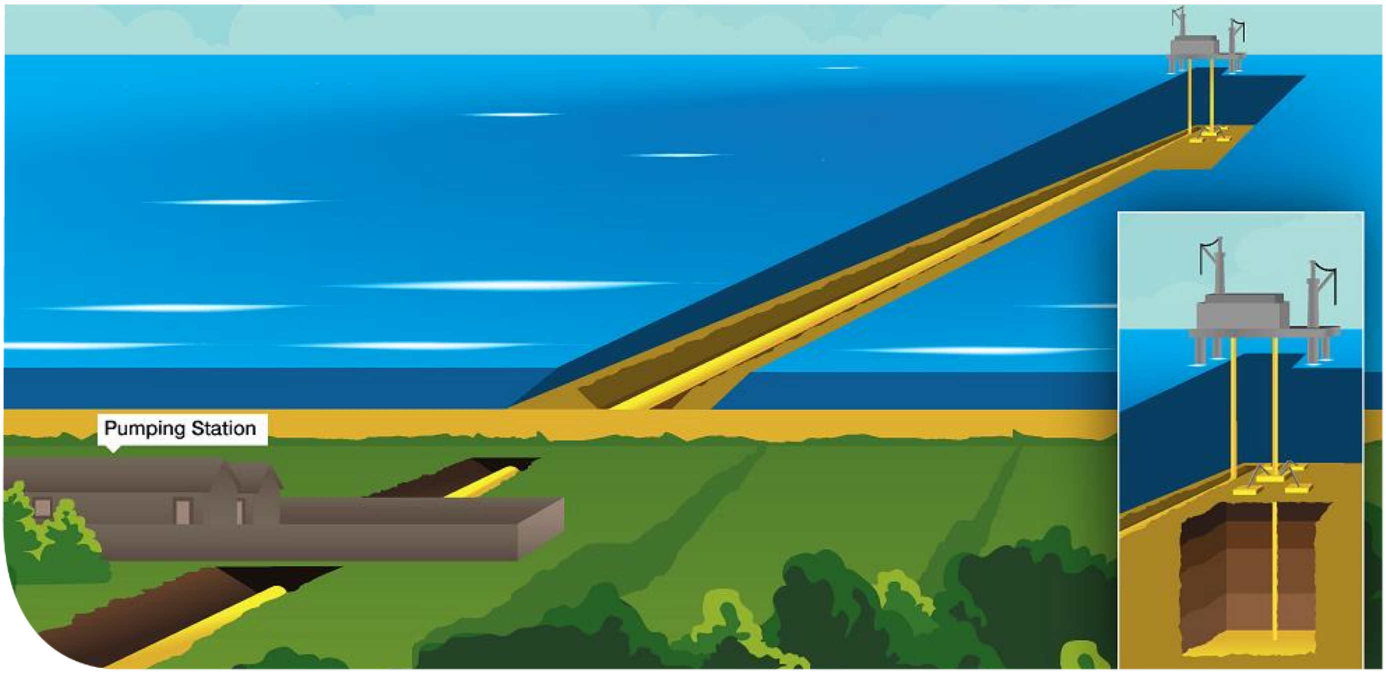
January 2016

K38: Subsurface Well Report

Category: Storage



IMPORTANT NOTICE

Contents

Key Words

Key Word	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.
Key knowledge	Information that may be useful if not vital to understanding how some enterprise may be successfully undertaken
Well	A structure which forms a conduit from surface to a storage reservoir (in the case of CCS). The structure is formed of concentric tubes or pipes, decreasing in diameter from surface to the reservoir depth. The outermost tubes are known as casings and are inserted into drilled holes and cemented in place. The innermost pipe is known as the tubing and conveys the CO_2 transported by pipeline from onshore and into the store.
Storage	The containment of CO_2 in a store for an indefinite period of time. The store is composed of porous rock, with the pores initially containing saline water, but as CO_2 injection commences the pores will contain CO_2 and water. With respect to the White Rose project, the Storage Site comprises the BSF (Bunter Sandstone Formation) within the Endurance structure. The lithologies above and below Bunter sandstone are mainly shales and evaporites, hence they are all envisaged to have a good sealing quality. The areal dimensions of the Storage Site are taken from the most likely Top Bunter depth map which closes at 1460m TVDSS.
Reservoir	A unit or volume of rock which has both porosity and permeability and can store, produce or receive (by injection in the CCS case) fluids. In the context of CCS, the reservoir forms the main storage facility for CO_2 injected into the store.
Subsurface	Pertaining to the rocks below the seabed, for an offshore development. Also, in the context of disciplines, can mean the activities of individuals, such as geologist, geophysicists and petrologists who perform technical work related to defining and analysing the rocks and fluids below the seabed.

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.

The White Rose CCS Project plans to develop an integrated power and Carbon Capture and Storage (CCS) demonstration project with a gross output of 448MW of electricity where over 90% of the plant's carbon dioxide (CO_2) emissions up to 2.68MTPA for a period of twenty years will be transported through a dedicated pipeline offshore for permanent underground storage in the UK Sector of the North Sea, specifically the Endurance Structure located in blocks 42/25 and 43/21.

Delivery of the full-chain project is be provided by National Grid Carbon Limited (NGCL), which is responsible for the T&S network and Capture Power Limited (CPL), which is responsible for the Oxy Power Plant (OPP) and the Gas Processing Unit (GPU).

The Endurance structure is a four-way dip-closure within the Bunter Sandstone Formation of the Southern North Sea. It is a saline formation, 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. A layer of mudstone called the Röt Clay provides the primary seal. This in turn is overlain by more than 90m of a salt layer known as the Röt Halite at the base of the 900m thick Haisborough Group which provide the secondary sealing capability. None of the overburden faults visible on seismic penetrate the Röt Halite.

The proposed OPP will be connected by a short 12in diameter pipeline to a junction manifold, the Camblesforth Multi-Junction, which is provided to allow easy connection of other regional CO_2 emitters. From the Multi-Junction a 60km 24in diameter pipeline buried to at least 1.2m will be connected to the Barmston booster pumping station situated close to the proposed beach crossing. A 90km 24in diameter pipeline will be laid offshore to the platform location in Block 42/25d. The pipeline from Camblesforth to the platform will have a capacity of up to 17MTPA of CO_2 to allow for future expansion.

The platform, a Normally Unmanned Installation (NUI), is designed to have six well slots, filters for the injected CO_2, flow-meters for well allocation measurement, provision for temporary equipment for well maintenance as well as providing control and measurement interfaces.

The injection wells, to be drilled by jack-up rig through the platform, will be moderately deviated to optimise the separation of their bottom hole locations within the Bunter Sandstone reservoir. The CO_2 will be injected into the Bunter Sandstone reservoir through perforation in the lower (deeper) half of the reservoir thickness in order to maximise the residual trapping of CO_2. The CO_2 plume will develop and migrate, initially vertically towards the top of the reservoir, and then laterally towards the crest of the structure in an east-south-easterly direction.

The Storage Complex comprises the Storage Site, its Triassic underburden down to the base of the Zechstein Halite and the overburden up to the top Jurassic Lias. Conformance of the observed and predicted response of the Storage Site to CO_2 injection will be monitored during the injection period under a comprehensive Measurement, Monitoring and Verification Plan (MMV Plan). If the operation of the Storage Site behaves as forecast and the dynamic capacity is confirmed, consideration may be given to increasing the quantity of CO_2 to be stored in the Endurance Structure. After injection ceases, the Storage Site and Storage Complex will be monitored for a number of years after which the platform and wells will be decommissioned before responsibility for the Storage Complex will be transferred to the designated Competent Authority.

This document provides information on the CO_2 injection wells proposed for the White Rose development. It presents information and data, which is provided by a number of subsurface wells report in respect of wells already drilled in the area local to the Endurance site, in support of well drilling work, which will be required to provide the CO_2 injection wells proposed for the White Rose development.

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 CCS Project (the WR Project).

CPL have entered into an agreement (the 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 contents of this K38 report draws on work, which was undertaken by National Grid in support of the Don Valley Power Project, which was partly funded under the European Union's European Energy Programme for Recovery (EEPR). The WR Assets comprise an end-to-end electricity generation and carbon capture and storage (CCS) 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 located in the North Sea blocks 42/25 and 43/21.

CPL and NGC have entered into an agreement (the KSC) pursuant to which NGC will perform a project (the WR T&S FEED Project) which will meet that part of CPL's obligations under the FEED Contract which would be 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 the offshore storage reservoir, which was previously identified as Endurance and is now known as Endurance.

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 (KKDs). This document is one of these KKDs and its specific purpose is summarised below.

The Endurance structure is a four-way dip-closure within the Bunter Sandstone Formation of the Southern North Sea. It is a saline formation, 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.

A number of wells had been drilled in the area of the proposed reservoir in search of these commodities. The information provided by such wells together with one drilled specifically to study the geology with a view to CO_2 storage is reviewed in this report, which goes on to discuss the options and practicalities presented by this section of the WR Project.

2 Purpose

This report presents information and data, which is provided by a number of subsurface wells report in respect of wells already drilled in the area local to the Endurance site, in support of the development well drilling activities work and includes comments on and descriptions of:

- lithology review & drilling hazards review;
- casing review;
- fluids review;
- structural conductor analysis including negative wellhead growth and fatigue assessment;
- fluids concept select;
- casing concept select;
- conductor concept select;
- cement concept select, cement qualification;
- well abandonment concept including possible re-entry of abandoned wells;
- time and cost estimates;
- coring review / programme definition;
- well test / evaluation review;
- anchor handling / Rig mobilisation / demobilisation;
- regulatory consents register management;
- well design rationale document (BOD);
- HSE notification/submission preparation;
- wellheads, trees and overtrawlable structure definition;
- rig specification; and
- drilling optimisation study.

This report includes:

- lower completion review;
- upper completion review;
- component qualification (report & review);
- component selection;
- completion concept select report;
- metallurgy/elastomer studies report;
- well intervention / Workover BOD; and
- well intervention / Workover schedule Optimization.

3 Overview

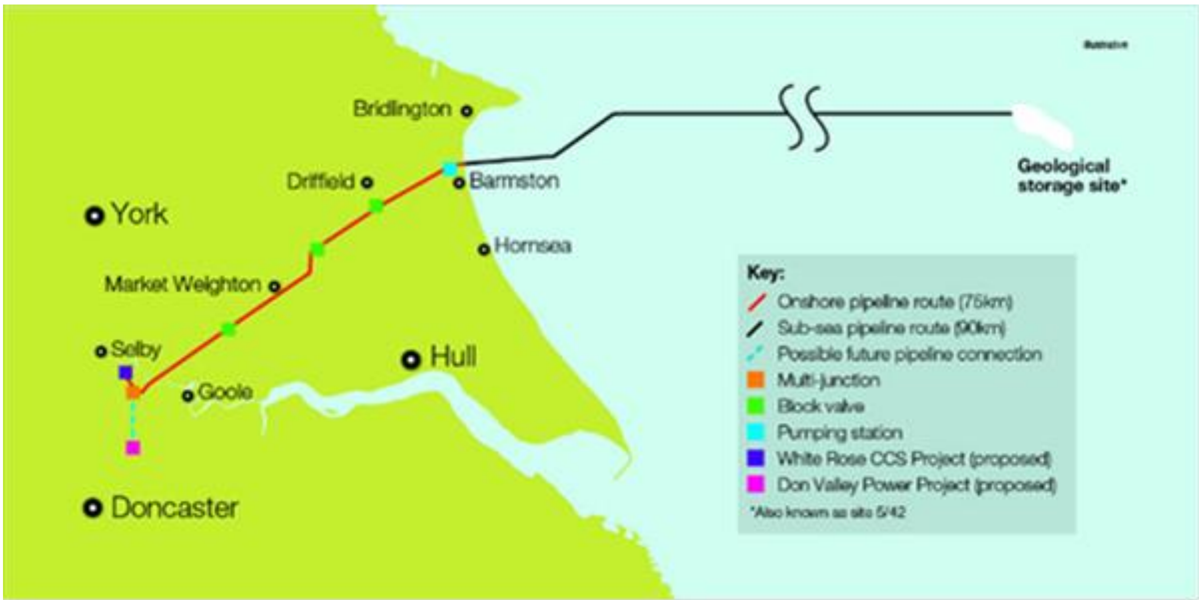
3.1 General Overview

The White Rose CCS Project aims to provide an example of a clean coal-fired power station of up to 450MW 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; where part of the fossil fuel supplied to the plant would be replaced with a 'carbon lean', renewable alternative.

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 carbon dioxide (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

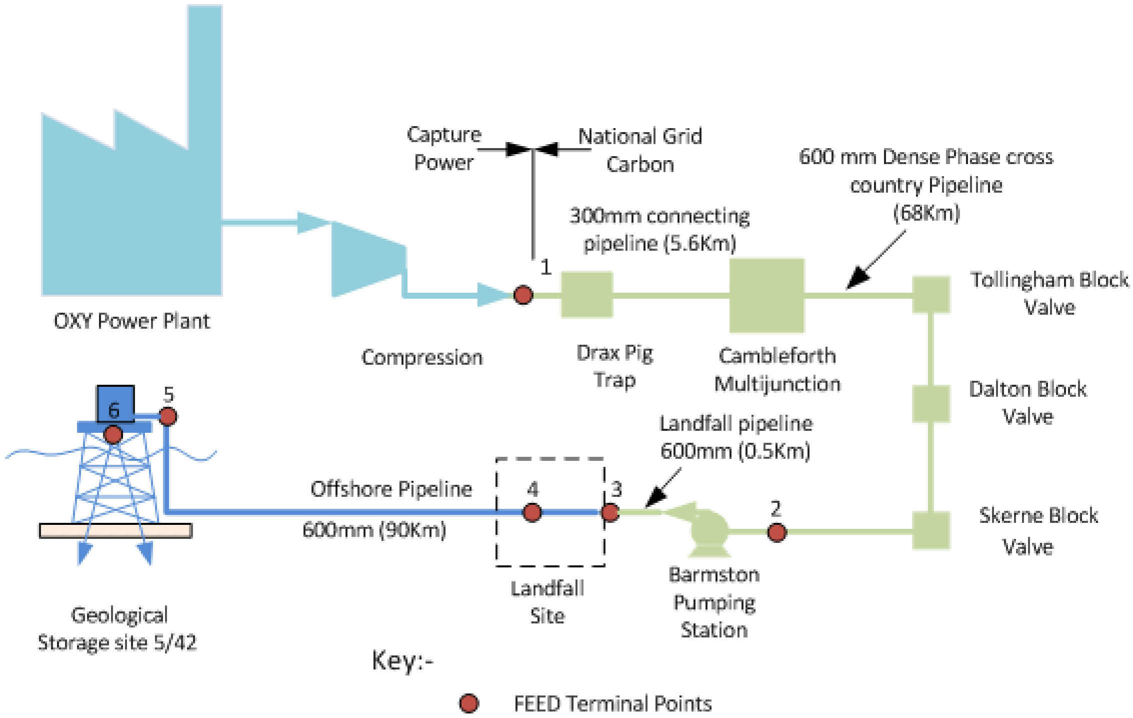


The standalone power plant would be located at the existing Drax Power Station site near Selby, North Yorkshire and generating electricity for export to the Electricity Transmission Network (the Grid) as well as capturing approximately two million tonnes of CO_2 per year, some 90% of all CO_2 emissions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

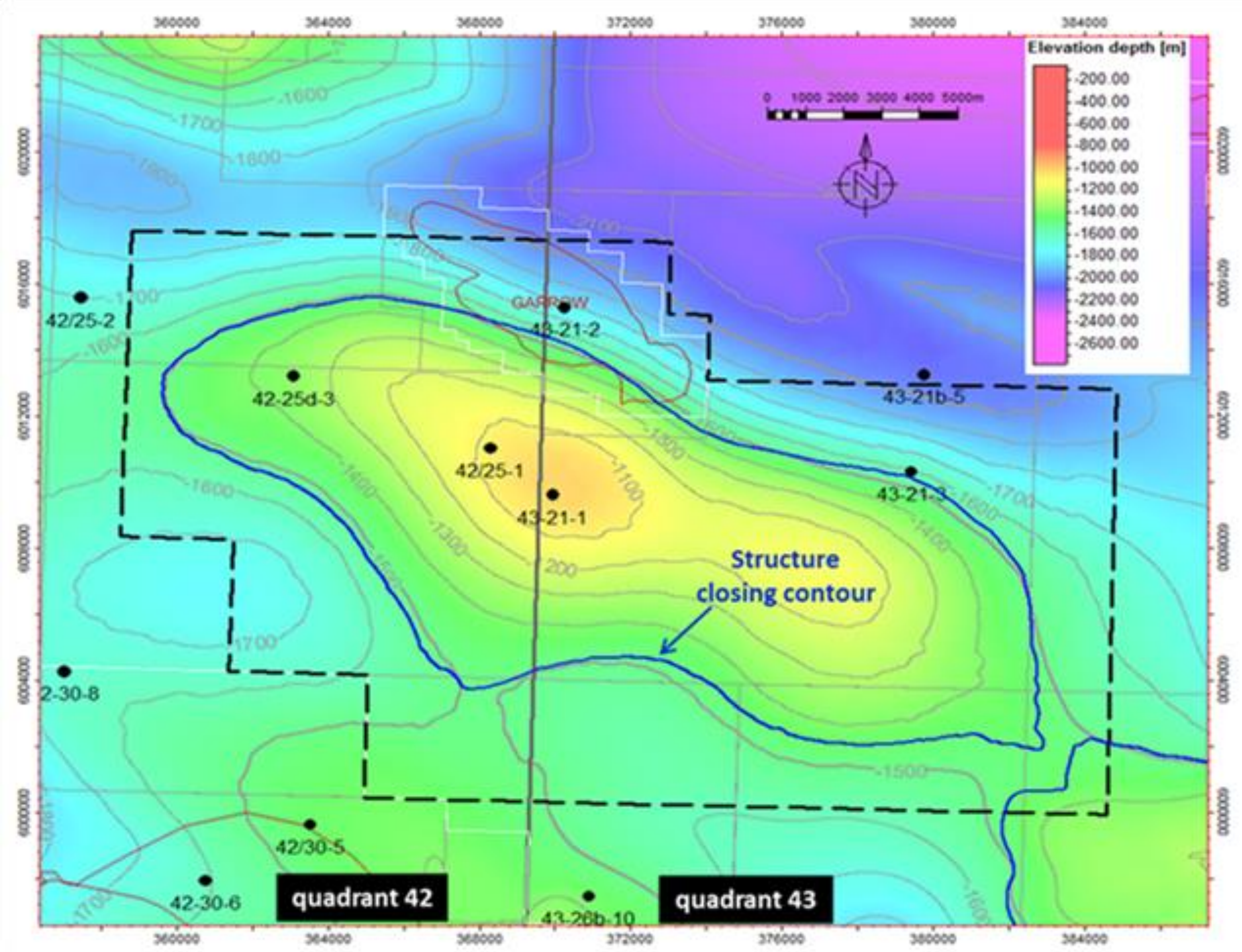
The overall integrated control of the end-to-end CCS chain would have similarities to that of the National Grid natural gas pipeline network. Operation of the transport and storage system would be undertaken by NGC. However, transportation of carbon dioxide presents differing concerns to those of natural 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 Endurance structure is one of several structural closures of the Bunter Sandstone Formation found within the Triassic Southern North Sea (SNS) basin. It has been penetrated by three exploration and appraisal wells drilled between 1970 and 2013. Several other exploration and appraisal wells drilled with various objectives surround the structure as shown in Figure 3.3. This figure shows the Top Bunter depth structure map over Endurance Storage Site showing licence block boundaries (broken black line) as well as exploration and appraisal wells within the Area of Interest (AOI). Note wells 42/25d-3, 42/25-1, and 43/21-1 are the only ones to have penetrated the Endurance structure.

Figure 3.3: Depth Structure Map over Endurance Storage Site



4 Well Reports

4.1 Drilling Hazards and Lithology

The methodology of design of the CO_2 injection wells is the same as applies to the design of hydrocarbon wells. Typically therefore the starting point for the well design is to review offset analogue wells in the nearby area and most useful of these offset wells are wells which penetrate the same or very similar formations in the subsurface. This methodology has been applied to the design of the White Rose CO_2 injection wells. The offset reviews typically look for particular drilling problems and the formation or lithology in which the problems occurred. The following therefore discusses this information which applies to the White Rose wells. Note that in the same way as for drilling hazards are review, previous casing schemes of nearby relevant offset wells are studied, as is noted in Section 4.3 of this document. These casing schemes are selected in part to counteract drilling hazards.

There were two existing wells on the Endurance White Rose structure: 42/25-1 and 43/21-1 located 2.3km and 4.5km respectively, from the proposed development well centre - 42/25d-D location. Another appraisal well 42/25d-3 was drilled, by NGC in 2013, at a distance of 3.7km from 42/25d-D and also properly abandoned.

Due to the limited data available for the 42/25-1 and 43/21-1 wells, further wells were taken into consideration in order to provide a sufficiently detailed offset review. All these wells are referred to here as "offset" from the proposed development well centre.

The following wells have been included in the offset review based on their proximity and lithology:

Wells located on the Endurance structure

- 42/25d-3
- 42/25-1
- 43/21-1

Additional offset wells

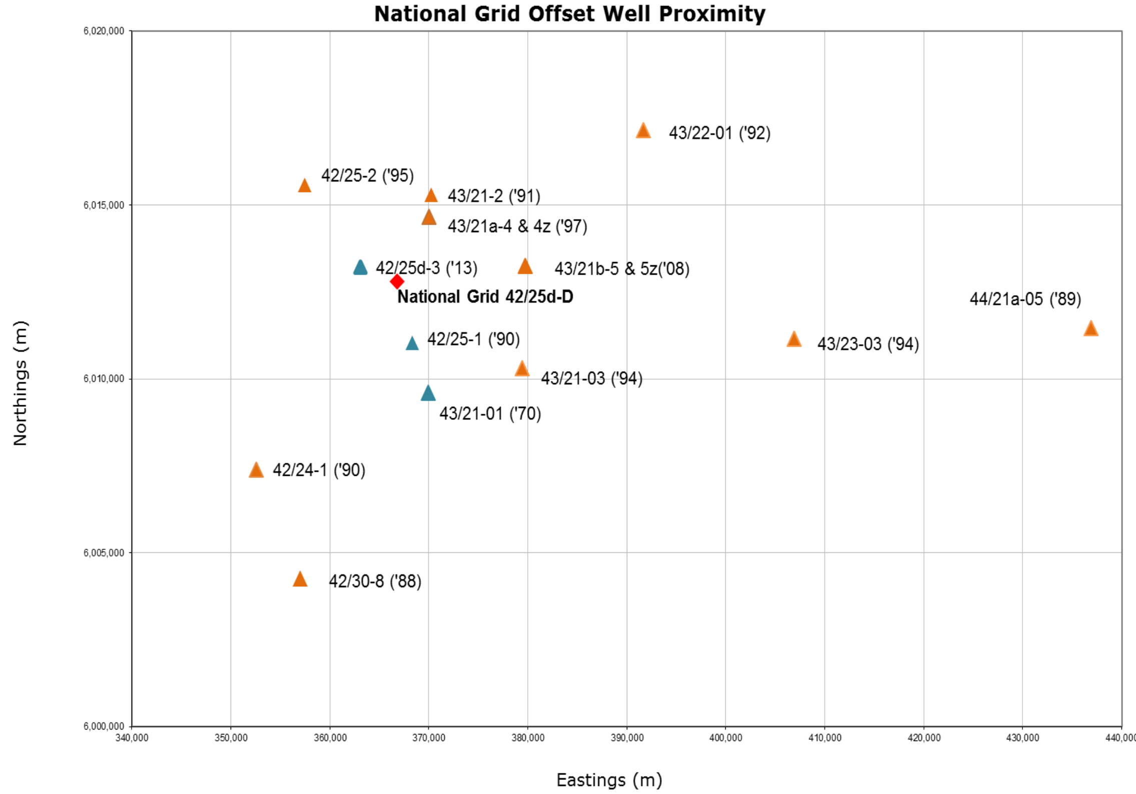
- 42/25-2
- 43/21a-4
- 43/21-2
- 42/24-1
- 43/21b-5

Refer to Figure 4.1 and Figure 4.2, Offset Well Proximity Table and Offset Well Proximity Plan View, respectively.

Figure 4.1: Offset Well Proximity Table

			OFFSET WELL PROXIMITY				
Well	**Name**	**Eastings**	**Northings**	**Proximity km**	**Profile**	**Max Inclination**	**Direction**
			Proposed Well location				
1	National Grid 42/25d-D	366,822	6,012,790	0.0	Directional	55°	0.0
			Offset Well Locations				
2	42/25d-3 ('13)	363,100	6,013,203	3.7	Vertical		-83.7
3	42/25-1 ('90)	368,296	6,011,029	2.3	Vertical		140.1
4	43/21-01 ('70)	369,946	6,009,606	4.5	Vertical		135.5
5	42/25-2 ('95)	357,479	6,015,579	9.8	Vertical		-73.4
6	43/21a-4 & 4z ('97)	370,010	6,014,666	3.7	Vert + sidetrack		59.5
7	43/21-2 ('91)	370,254	6,015,289	4.2	Directional	35.5°	53.9
8	42/30-8 ('88)	357,030	6,004,254	13.0	Unknown		228.9
9	42/24-1 ('90)	352,555	6,007,392	15.3	Vertical		249.3
10	43/21b-5 & 5z('08)	379,750	6,013,255	12.9	Vertical +sidetrack	17.5°	87.9
11	43/21-03 ('94)	379,418	6,010,309	12.8	Vertical	6.3°	101.1
12	43/22-01 ('92)	391,697	6,017,151	25.3	Vertical		80.1
13	43/23-03 ('94)	406,902	6,011,164	40.1	Vertical	0.96°	92.3
14	44/21a-05 ('89)	436,895	6,011,465	70.1	Vertical	6.09°	91.1

Figure 4.2: Offset Well Proximity Plan View



4.1.1 Shallow Gas

A site survey has not yet been conducted, but it has been assumed that there is no shallow gas (any hydrocarbon-bearing zone at a depth close to the surface) at the location. None of the offset wells had issues with shallow gas.

4.1.2 Shallow Formations

Resistance to the drilling was experienced at the 42/24-1 well in the top hole section. This was possibly due to the presence of glacial pebbles or boulder beds and the conductor had to be washed to bottom.

Issues were also encountered on the 42/25d-3 well, where resistance to drilling was encountered at 557ft (170m) MDBRT. The conductor became stuck and was recovered to surface and wiper trip performed with no obstructions observed. The back-up conductor was Run-In-Hole (RIH) and due to a restriction the conductor was set shallower (further from the vertical) than planned.

4.1.3 Limestone in Lias

Within the Lias, limestone stringers have been encountered which reduced the Rate Of Penetration (ROP). There is also the potential for mud losses by seepage into the fractured limestone within the Lias formation.

4.1.4 Reactive Claystones

Offset wells have experienced considerable bit balling due to the reactive clays in both the Lias and the Haisborough group. On two occasions at the start of the 26in section in the 43/21a-4 well, problems were experienced with gumbo whilst drilling with seawater. In the 42/24-1 well the 20in casing string would not pass 770ft (235m) and the casing was pulled out of hole to ream the hole clear. On the second attempt to run the 20in casing, tight spots were encountered from 770ft to 1227ft (235m to 374m) with a maximum of 210klb (934 kN) overpull required to free the string. Tight spots were also encountered on the 42/25d-3 well while Pulling Out Of hole (POOH).

4.1.5 Mobile Salts

The salts in the Haisborough group can be mobile although stuck pipe whilst drilling would be more of a concern than opposed to casing collapse due to corrosion. A few of the offset wells have experienced tight spots during wiper trips with overpulls of 140klb (622 kN) being recorded to free the string.

4.1.6 Dolomite/Anhydrite Stringer

Stringers have been encountered in the offset wells resulting in ledges and tight tripping along with a reduction in ROP.

4.1.7 Losses in Bunter Sandstone

The 42/25-2 and 43/21-2 wells both experienced small mud losses in the Bunter sandstone.

4.1.8 Differential Sticking in Bunter Sandstone

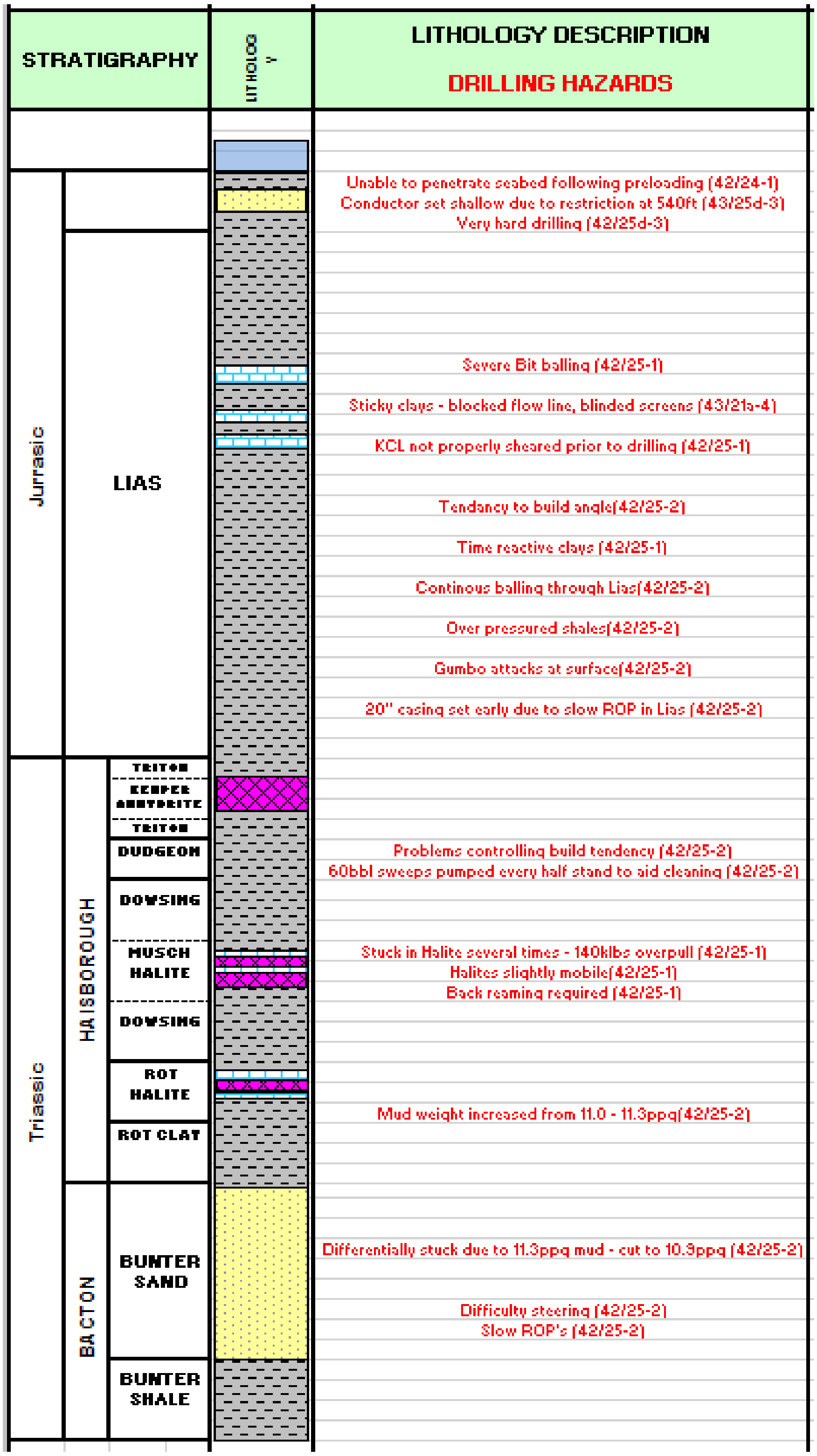
The Bunter sand could have a permeability of up to 5000mD with an expected pore pressure of 9.26ppge (1.11 SG) and as a result the possibility of differential sticking is reasonable within the sandstone as seen in the 42/25-2 well where 210klb (934 kN) overpull was required to free the string and the mud weight was reduced from 11.3ppg (1.35 SG) to 11.0ppg (1.32 SG). However, on the 42/25-1 well the Bunter Sands (RFT 9.08ppg (1.09 SG) EMW) was drilled with 11.8ppg (1.41 SG) and there were no problems.

MDT (Modular Dynamics Tester) data acquired in the Bunter sandstone on the 42/25d-3 well recorded a pore pressure of 9.2ppg (1.10 SG) EMW.

4.1.9 Well Inclination - Hole Angle 55° to 60°

All offset wells are vertical to the expected 42/25d-D wells TD. On offset well 42/25-2, a 26in rotary Bottom Hole Assembly (BHA) had a build tendency while drilling the Lias. Initial White Rose wellpaths have been developed for the purpose of the FEED limiting build rate to 3°/100ft to a tangent of 55°. The build is located in the Lias and Haisbourgh; therefore the reactive clays must be taken into consideration. Figure 4.3 is a summary of offset well drilling hazards.

Figure 4.3: Summary of Drilling Hazards



4.1.10 Lithology

Table 4.1 below outlines the expected formation depths and formation names at the 42/25d-D wells (Well W1, W2 and W3) locations.

Table 4.1: Expected Formation Tops

	W1		W2		W3	
Formation Tops	MDBRT (ft)	TVDSS (ft)	MDBRT (ft)	TVDSS (ft)	MDBRT (ft)	TVDSS (ft)
Seabed	308	193	308	193	308	193
Lias	419	305	419	305	419	305
Rhaetic Winterton	2237	1955	2178	1922	2178	1932
Haisborough – Triton	2420	2073	2331	2027	2333	2040
Keuper Anhydrite Member	2527	2135	2424	2086	2423	2099
Base Keuper Anhydrite Member	2796	2290	2677	2235	2668	2244
Dudgeon	3110	2470	2980	2408	2971	2417
Dowsing	3711	2814	3564	2742	3543	2746
Muschelkalk Halite Member	3991	2975	3833	2896	3806	2896
Base Muschelkalk Halite Member	4351	3182	4204	3110	4155	3097
Rot Halite Member	5072	3595	4937	3530	4858	3500
Rot Clay Member	5684	3946	5577	3897	5482	3858
Bunter Sandstone	5747	3982	5640	3933	5545	3894
Bunter Shale	7314	4881	7319	4896	7312	4908
Well TD	7526	5003	7556	5032	7593	5068

4.2 Reservoir Data

Table 4.2: Reservoir Base Data

Parameters	Input Data	Units
Reservoir Temperature	135 / 57.2	°F / °C
Reservoir Pressure	2313 / 159.5 (@ 4736.7ft TVDSS)	psi / barg
Reservoir Thickness	(656 to 820) / (200 to250)	ft / m
Porosity	10 to 30 (average 25)	%
Permeability	50 to1000 (average 260)	mD
Min & Max Arrival Pressure	(1305 & 2639) / (90 & 182)	psi / barg
Min & Max Arrival Temperature	(19.4 & 75.2) / (-7 & 24)	°F / °C
Design Arrival Rate	(31 to 138) / (0.564 to 2.65)	MMSCFD /MTPA
CO_2 Purity	96 to 99.7	%
Maximum H_2S	0	ppm

4.3 Well Fluids

During the drilling of a well, holes of various sizes, starting large and becoming smaller, are drilled into the formations with the use of a bit on the bottom of a drilling ‘string’. The drilling string consists of lengths of pipe connected together with threaded connections. In order for the drilling string to progress deeper, the cuttings of rock, produced by the bits drilling action must be removed from the bottom of the hole and back to the surface, where the cuttings are removed. The method by which the cuttings are removed is by the use of a ‘thickened’ liquid, referred to as a drilling fluid or mud, which is pumped down the well on the inside of the drillstring and returns up the well in the gap between the drillstring and the sides of the new hole that has been drilled. Note that the gap between the drillstring and the hole is referred to as the annulus. The velocity of the drilling fluid in the annulus (determined by the pump rate) and the rheological properties of the mud are the method by which the cuttings are removed from the well. The section below describes the well fluids or drilling fluids that have been used previously on offset wells and how this information is used in the selection of drilling fluids to be used for drilling the proposed new CO_2 injection wells.

The drilling fluids and cements used on offset wells are shown in the following montages Figure 4.4 to Figure 4.11.

Generally, it can be seen that water based muds were used to drill the upper hole sections (represented by 17-1/2in diameter hole but sometimes drilled in 26in and then 16in) and although historically sea water and sweeps has been used, this proved problematic and the use of inhibitive mud formulations such as Glydrill and KCl polymer were used latterly.

In the lower hole sections, represented by 12¼in diameter hole and 8½in sections both Oil Based Mud (OBM) and salt saturated muds have been used, but due to improved hole properties and more efficient drilling, the OBMs have prevailed more recently.

Figure 4.4: Well Montage 42/25d-3

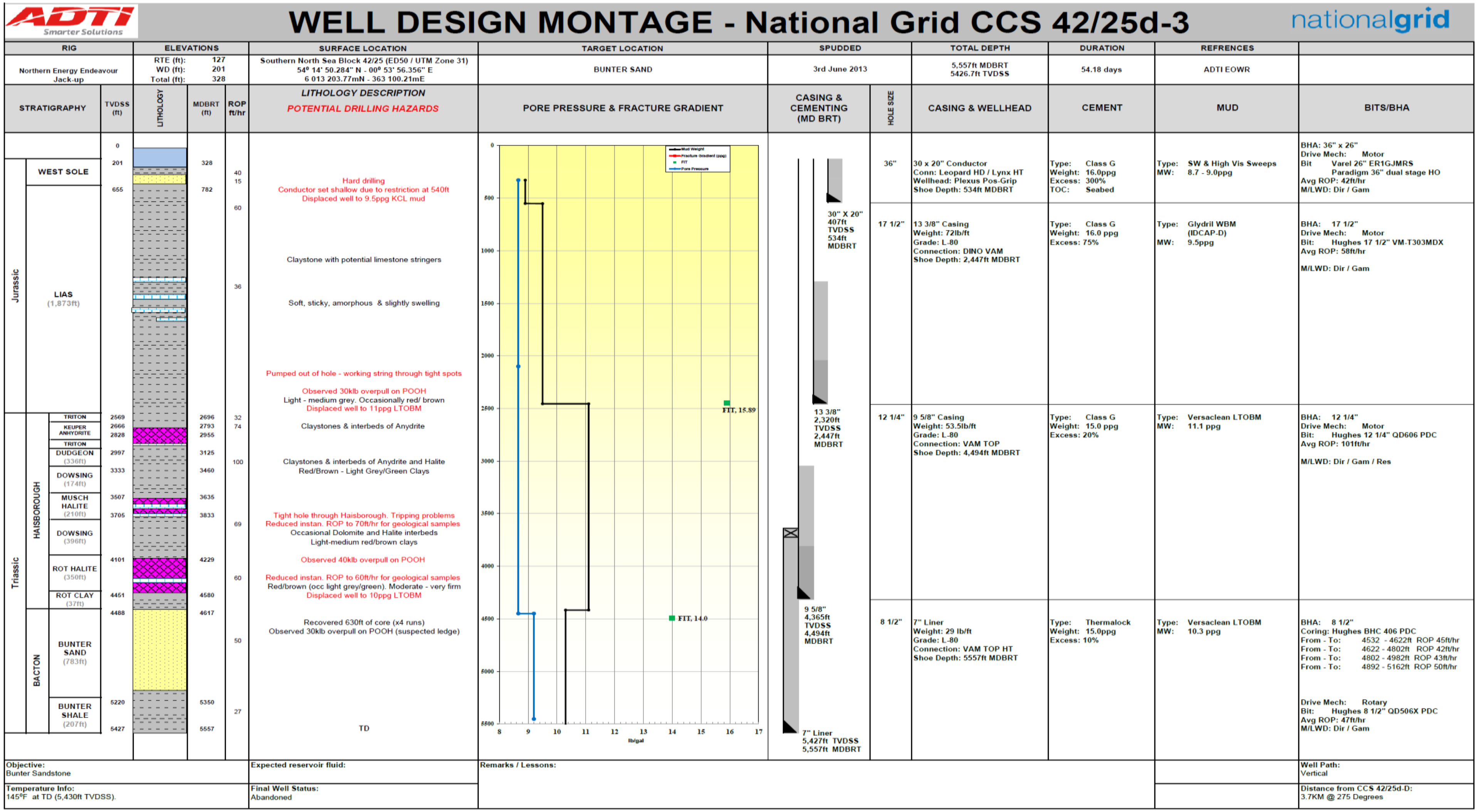


Figure 4.5: Well Montage 42/25-1

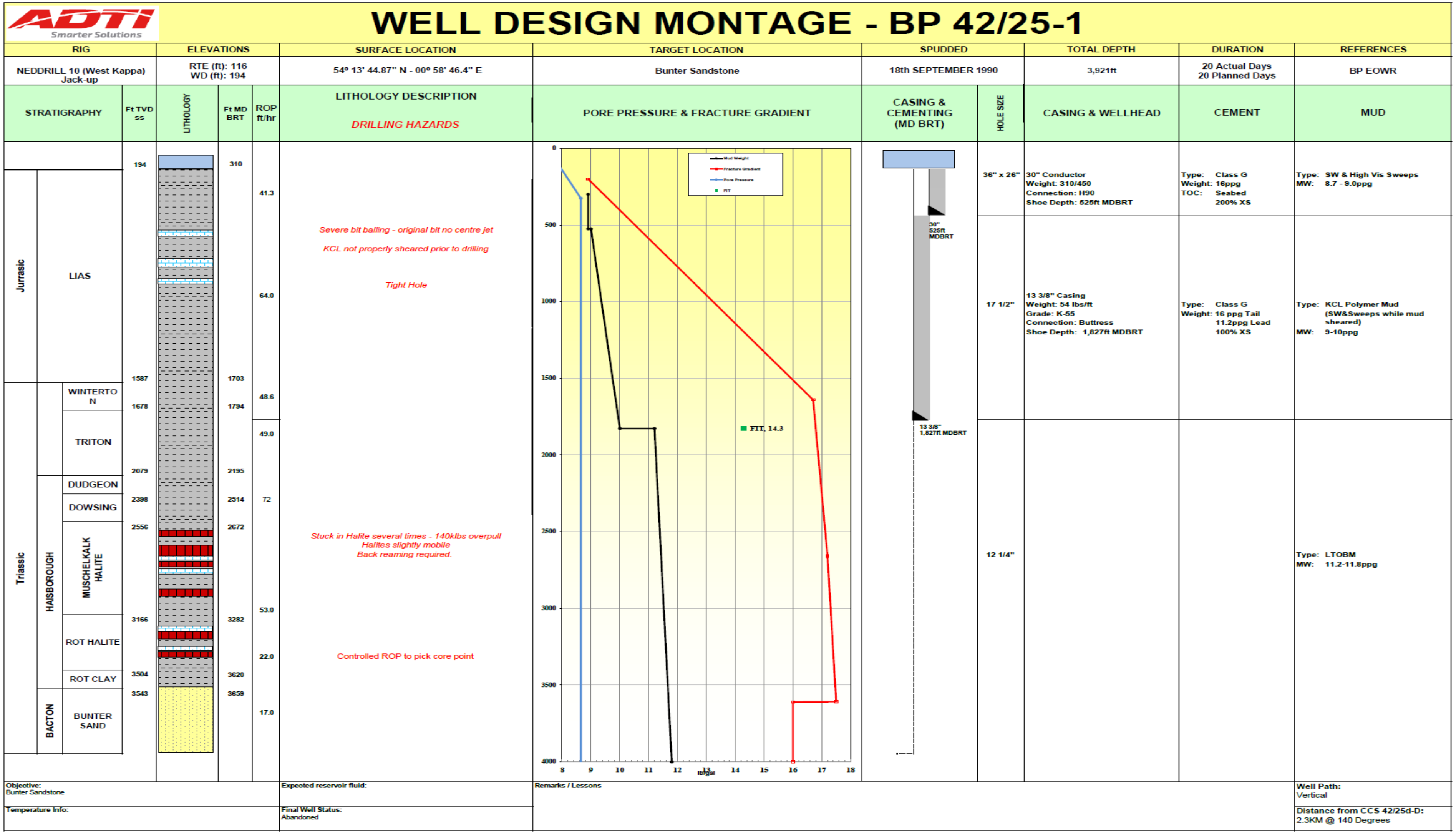


Figure 4.6: Well Montage 43/21-1

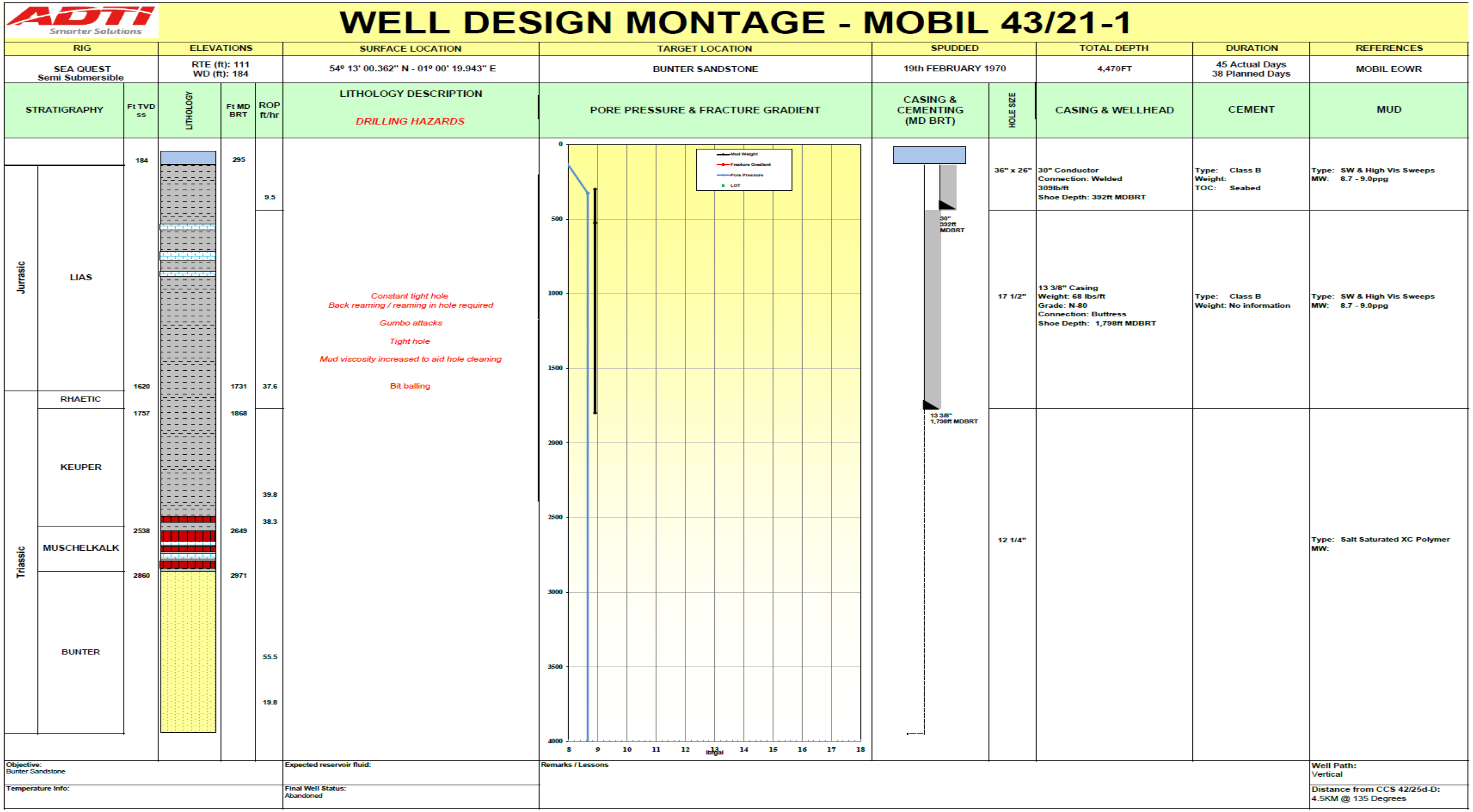


Figure 4.7: Well Montage 43/21a-4

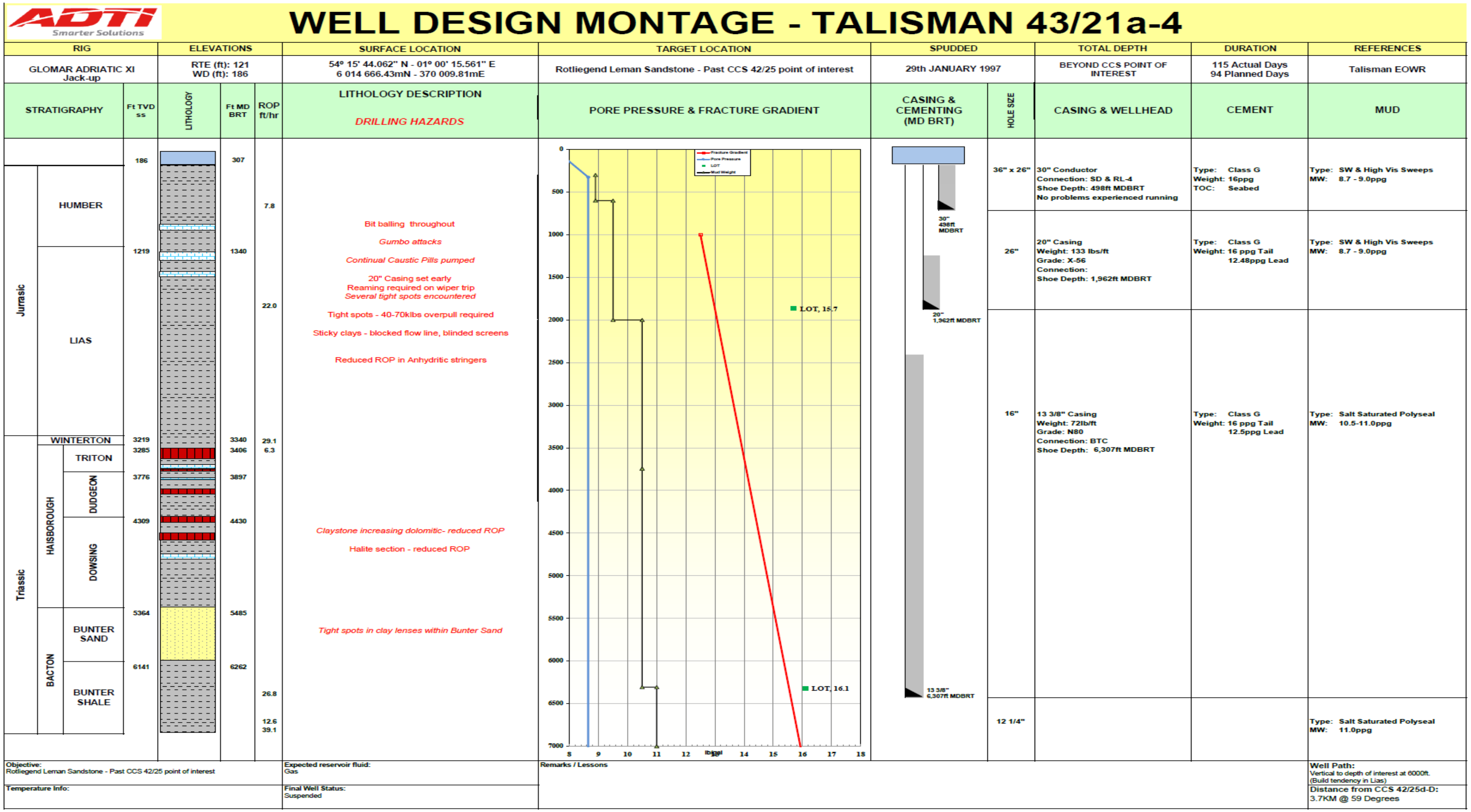
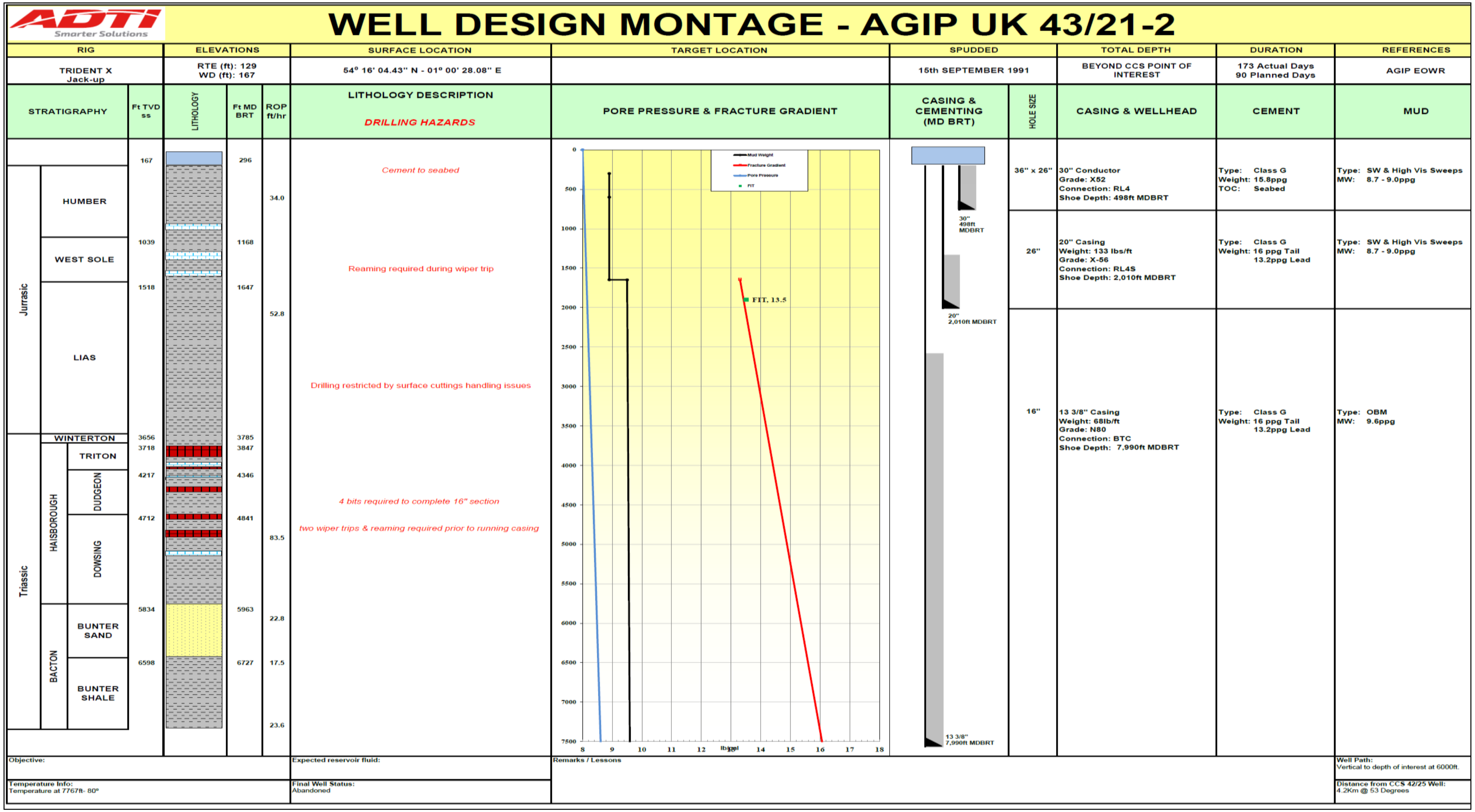


Figure 4.8: Well Montage 43/21-2



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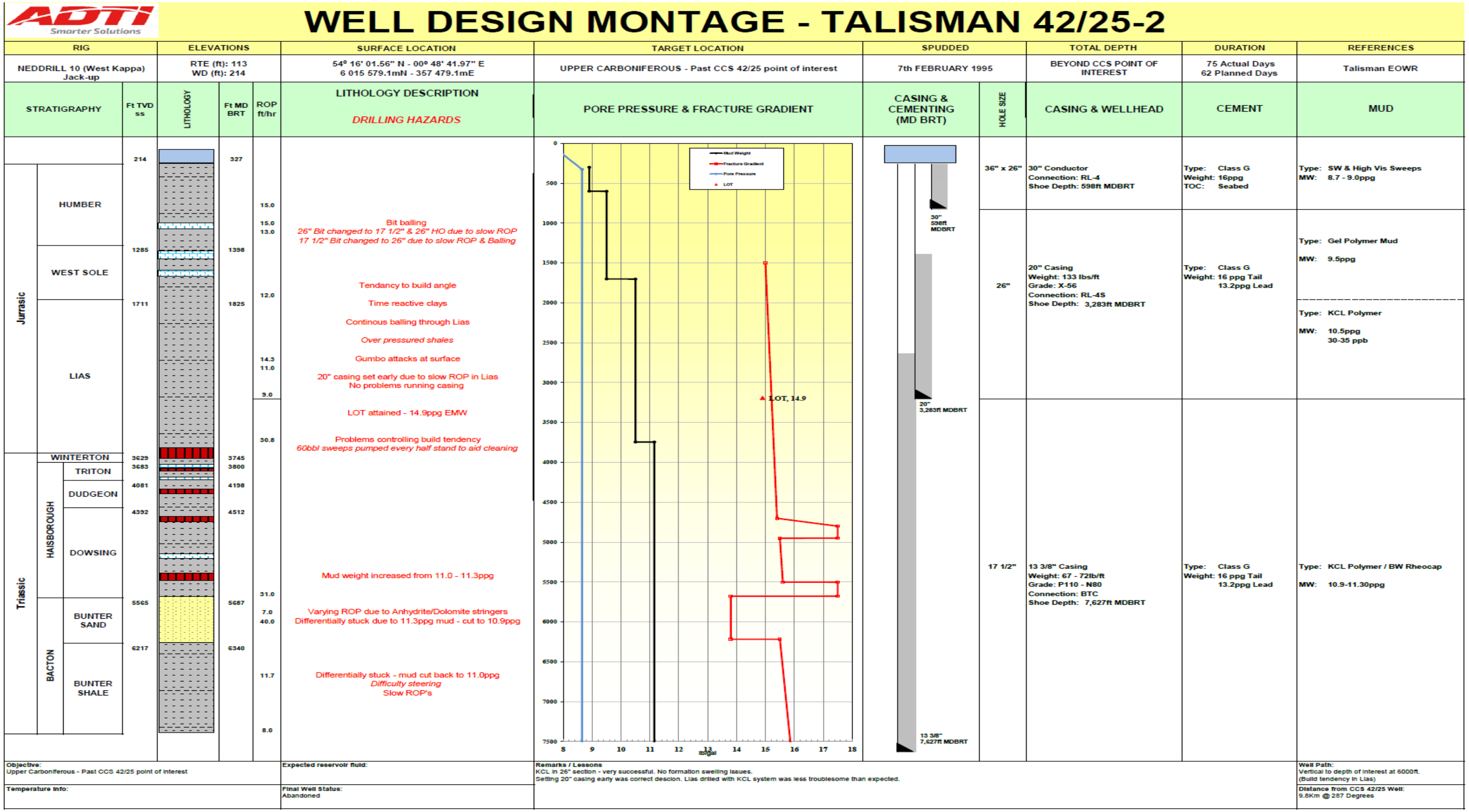


Figure 4.10: Well Montage 42/24-1

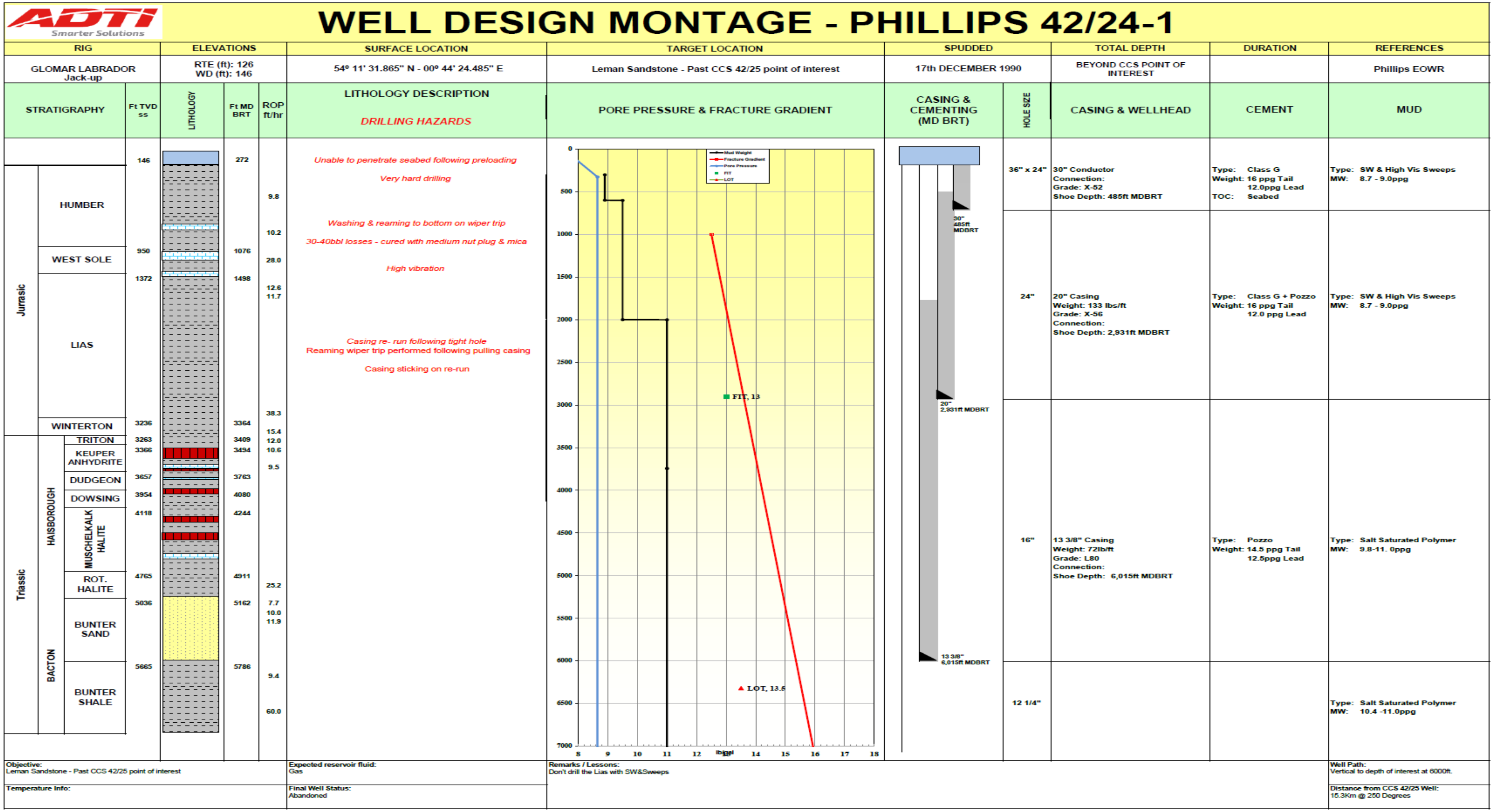
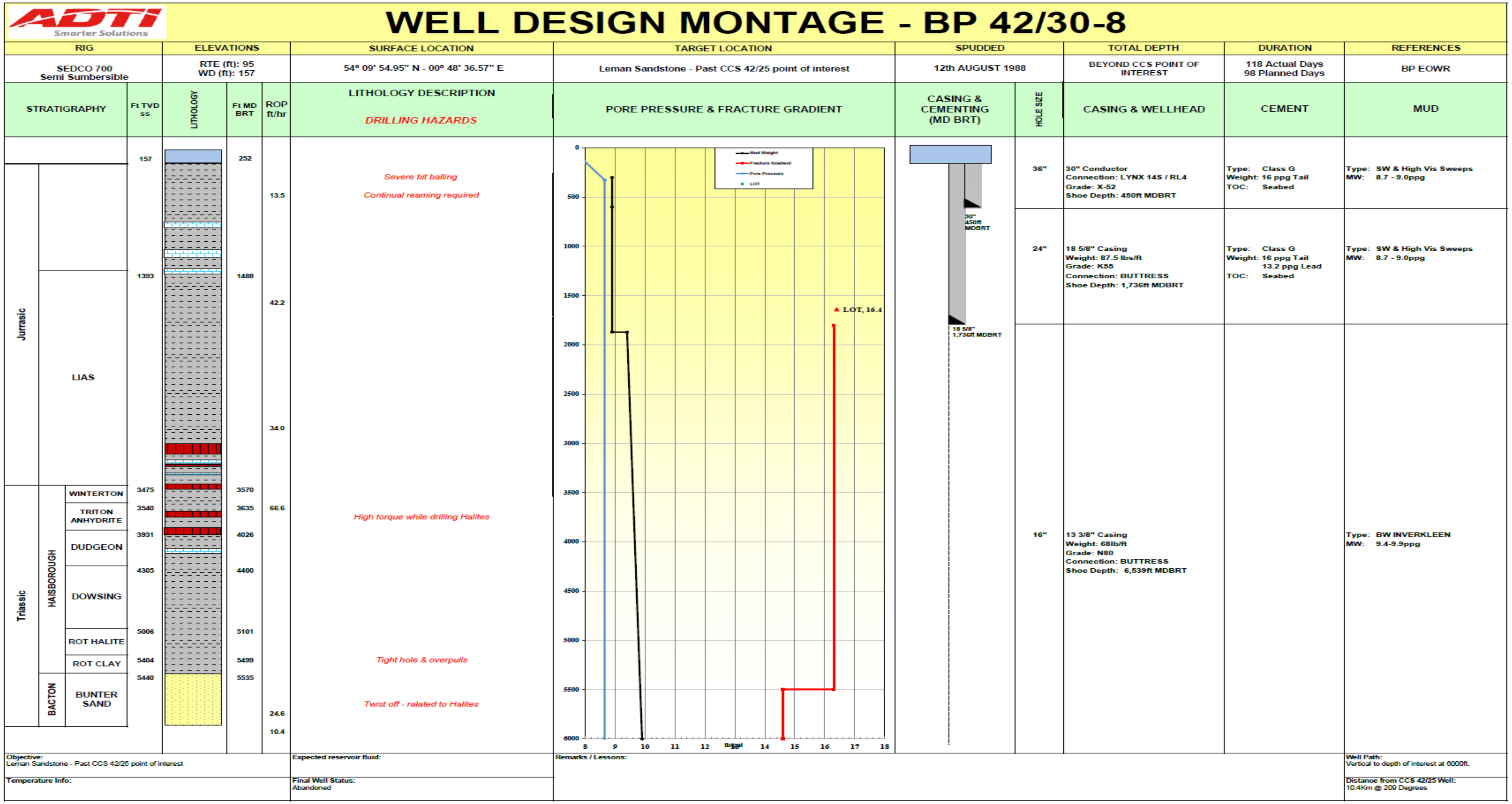


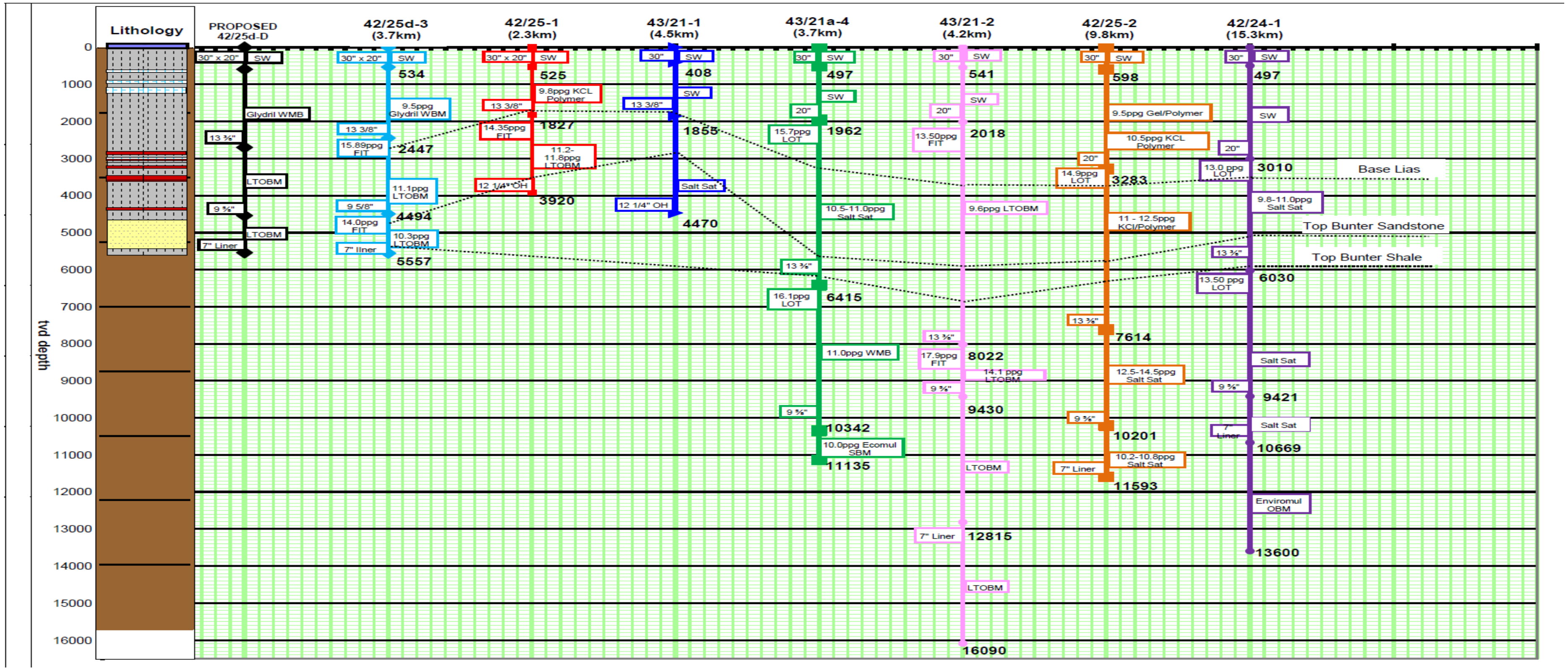
Figure 4.11: Well Montage 42/30-8



4.4 Casing Programme

The casing programmes for the offset wells in the area are shown in Figure 4.12, below.

Figure 4.12: Casing Programmes



4.5 Structural Conductor Analysis Including Negative Wellhead Growth and Fatigue Assessment

The conductor analysis was performed by comparison with existing conductors in similar developments in similar water depths, as specific analysis is not possible until the White Rose location site survey geotechnical borings have been conducted. The conductor proposed is adequate for the design, proposed details of which are provided in Section 4.15 (Well Design Rational) below. Fatigue calculations for this analysis would be conducted in detailed design, once the wellhead system had been specified. As the White Rose location may have rock rather than soft sediments at a very shallow depth, it may not be possible to start the well by pile-driving the conductor into the seabed; it is likely that the conductor would be drilled and cemented into the rock.

When CO_2 is injected into the well it will produce a cooling effect on the casings. The anticipated contraction of the casing stringers, “negative wellhead growth”, has been assessed by the use of WELLCAT (casing design software) multi-string analysis to demonstrate feasibility of the design. The worst conditions of flow rate and temperature were used in this assessment. The negative wellhead growth was assessed from commencing injection and increasing injection rate to 138MMSCFD CO_2 injection rate at minus 20°C. These transient and temporary conditions induce a negative wellhead movement of 0.76in (less than 25mm). Negative growth indicates that the load is imposed downward from the well inner casings and tubing onto the load shoulder below the wellhead and onto the conductor. The relatively small movement is due to the stiffness of the conductor and combined strings of casings. The compressive loads imparted on the well casing strings where analysed. The result showed that none of the elements of the design (including connections) were compromised. Note that the minus 20°C condition (due to the expansion of the CO_2 across the injection choke) is actually a worst case condition since thermal heating from the environment was not accounted for, therefore actual wellhead movement should be less than 0.76in.

4.6 Mud Concept Selection

The fluids selected at the FEED stage are described below.

4.6.1 36in x 26in Diameter Hole Section

The 36in x 26in diameter hole section would be drilled with seawater pumped at maximum pump rate. Pre-hydrated bentonite sweeps would be pumped at each connection and mid-stand, or as hole conditions dictate to TD at ±565ft MDBRT. At section TD, the hole would be circulated clean with a 100bbl pill and displaced to a 10.0ppg bentonite mud prior to carrying out a wiper trip and then re-displacing prior to pulling out of hole to run the conductor. The 10.0ppg mud would aid wellbore stability while running the conductor. Refer to Table 4.3, showing the Hi-Vis (high viscosity) Sweep and Displacement mud formulations.

Table 4.3: Hi-Visc Sweep and Displacement Mud Formulations

Hi-Vis Sweep Formulation		Displacement Mud Formulation	
Drill Water	0.966bbl	Drill Water	0.923bbl
Bentonite	25ppb	Bentonite	20ppb
Caustic Soda	0.125ppb	Caustic Soda	0.125ppb

Hi-Vis Sweep Formulation		Displacement Mud Formulation	
Soda ash	0.125ppb	Soda ash	0.125ppb
DUOVIS	As required	Barite	73.7ppb

4.6.2 17½in Diameter Hole Section

The 17 ½in diameter hole section would be drilled with a 9.5-10.0ppg KCL GLYDRIL Water Based Mud (WBM) system. Additions of shale inhibitor would be added to reduce bit balling potential and provide enhanced cuttings encapsulation for the potentially troublesome Lias formation. Bit balling has been a major issue on offset wells therefore sufficient pills / sweeps would be available and should be pumped frequently while drilling the build section. This system provided the required inhibition to successfully drill the section and run 13 ⅜in casing to TD on the 42/25d-3 appraisal well. Refer to Table 4.4, Gydrill mud formulation.

Table 4.4: Gydrill mud formulation

Gydril Formulation				
Products	**Function**	**Concentration**	**Fluid Properties**	
Water	Volume	0.510bbl	Mud Weight (ppg)	*9.5*
KCl Brine	Inhibition	0.417bbl	PV (120 F)	ALAP
Soda Ash	Calcium remover	0.125ppb	YP (120 F)	25 – 30
Caustic Soda	pH	0.125ppb	Fann 6 (120 F)	10 – 16
DUOVIS	Viscosifer	1.000ppb	pH	9 – 10
POLYPAC UL	Fluid Loss Control	1.500ppb	MBT	< 15.0
Drilling Starch	Fluid Loss Control	2.000ppb	API Fluid Loss (mls)	< 5.0 ml
SAFE-CIDE	Biocide	0.001ppb	KCl (ppb)	> 30
M-I BAR	Weighting Agent	35.588ppb	Total hardness (mg/l)	< 400
GLYDRIL MC	Inhibition	13.900ppb	Glycol (%)	> 3
IDCAP D	Incapsulator	1.500ppb		

4.6.3 12¼in Diameter Hole Section

The 12 ¼in section is planned to be drilled through the Haisborough group to ±65ft (±19.8m) from the base of the Rot Halite formation. A Versaclean Low Toxic Oil Based Mud would be utilised to provide inhibition while drilling through the shale formations and also help to maintain wellbore stability. Although normally pressured the mud system would be 11.0-11.5ppg in order to prevent any potential salt mobility in the salts. Refer to Table 4.5, Versaclean mud formulation

Table 4.5: 12-1/4in Diameter Hole Versaclean mud formulation

VERSACLEAN Formulation				
Products	**Function**	**Concentration**	**Drilling Fluid Properties**	
Drill Water	Discontinuous Phase	0.191bbl	Mud Weight (ppg)	11.0
Base Fluid	Continuous Phase	0.591bbl	PV (120 F)	ALAP

VERSACLEAN Formulation				
Calcium Chloride	Water Phase Salinity	29.62ppb	YP (120 F)	20 - 35
VERSAGEL HT/TRUVIS	Viscosifier	5.0ppb	Fann 6 (120 F)	10 – 15
VERSACLEAN VB	Primary Emulsifier	6.0ppb	Gels (10s/10m)	10 – 20 / 15 – 25
VERSACLEAN FL	Secondary Emulsifier	6.0ppb	HTHP Fluid Loss (250 F)	< 5.0 ml
Ecotrol RD	Fluid Loss Control	1.50ppb	Electrical Stability (Volts)	> 400
Lime	Alkalinity	8.0ppb	WPS Chloride (g/l)	210 – 240
M-I BAR UFG	Weighting Agent	143.61ppb	Excess Lime (ppb)	> 1.0
SAFE-CARB 40	Bridging	15ppb	O/W Ratio	73/27 - 77/23

4.6.4 8½in Diameter Hole Section

An extensive coring and logging programme is planned for the 8 ½in section including coring the Bunter Sand formation. A new LTOBM mud system would be used for the 8 ½in section to increase the likelihood of attaining the full data acquisition programme. A mud weight of 10.0-10.5ppg would be used and calcium carbonate added to the system in order to prevent losses to the Bunter Sand and mitigate the risk of differential sticking. Given that the evaluation period could potentially last up to 1 week, the use of LTOBM would aid in maintaining a good hole condition. Refer to Table 4.6, 8-1/2in diameter hole Versaclean mud formulation.

Table 4.6: 8-1/2in Diameter Hole Versaclean mud formulation

VERSACLEAN Formulation				
Products	**Function**	**Concentration**	**Drilling Fluid Properties**	
Drill Water	Discontinuous Phase	0.194bbl	Mud Weight (ppg)	10.0
Base Fluid	Continuous Phase	0.599bbl	PV (120 F)	ALAP
Calcium Chloride	Water Phase Salinity	30.056ppb	YP (120 F)	15 – 25
VERSAGEL HT/TRUVIS	Viscosifier	5.0ppb	Fann 6 (120 F)	8 – 15
VERSACLEAN VB	Primary Emulsifier	6.0ppb	Gels (10s/10m)	10 – 20 / 15 – 25
VERSACLEAN FL	Secondary Emulsifier	6.0ppb	HTHP Fluid Loss (250 F)	< 3.0 ml
Ecotrol RD	Fluid Loss Control	1.50ppb	Electrical Stability (Volts)	> 600
Lime	Alkalinity	8.0ppb	WPS Chloride (g/l)	210 – 240
M-I BAR UFG	Weighting Agent	114.06ppb	Excess Lime (ppb)	> 1.0
SAFE-CARB 40	Bridging	30.0ppb	O/W Ratio	73/27 - 77/23

4.7 Casing Concept Selection

A well consists of an initial large hole drilled into the formations. At a certain depth, the hole requires support, otherwise it may collapse. The support is provided in the first hole size by what is called a conductor. A conductor is the first pipe lowered into the well (or driven using a large hammer) and forms the support for this hole section. Once in place, with the lower part of the conductor at what is referred to as the casing point, cement is pumped down the conductor with the objective of placing it (whilst still in a liquid form) in the annulus around the conductor, where the cement will set. The conductor then forms a structural foundation for the rest of the well. When the second and subsequent hole sizes are drilled deeper, the same process of lowering a pipe into the hole and cementing it is used to construct the well. These pipes are referred to as casing. The casing points (at which the lowest part of the casing is positioned) are selected not only to avoid collapse of the hole, but also to ensure that the drilling is performed safely and that there is no uncontrolled release of formation fluids from the well. There are many other factors which determine when a casing should be run, but a primary reason is in order that the formation fluid pressures (in porous rock, which can contain hydrocarbons at high pressure) are contain in the well by the hydrostatic pressure imposed by the drilling fluid, due to the drilling fluids density. In order that the formation fluids are contained in the well, the casing has to be specified and designed in order that it has the material strength to hold back the formation pressure if unplanned flow from the well (referred to as a kick) and the casing scheme discussed below addresses this and other issues. Note also that the casing comes in standard lengths that require connecting together. These connections are also referred to below (e.g. DINO VAM, VAM TOP HT, which are proprietary designs of connection from particular manufacturers).

The casing scheme selected during the FEED stage is outlined below.

4.7.1 30in x 20in Conductor

The conductor string with 6 joints below the seabed would be set on depth, based on the length of conductor joints, at 564ft (±172m) MDBRT. The bottom of the conductor would be swaged to 20in OD, in line with the slim design of this well. It is planned to cement the conductor back to the mudline with 300% excess cement. A riser analysis would be carried out on the 310 lb/ft 30in OD conductor during detailed design to check the suitability of the planned conductor string design.

4.7.2 13⅜in Surface Casing

The 13⅜in, 68lb/ft, L80 DINO VAM surface casing is planned to be set at 1949ft (±594m) TVDSS (2201ft or ±671m MDBRT) in the Lias formation; this would isolate most of the reactive Lias formation. The casing setting point would be set on depth. The 13⅝in BOP stack would be installed after running the casing, allowing the mud system to be swapped to LTOBM and the mud weight to be increased to drill the deeper formations.

4.7.3 9⅝in Intermediate/Injection Casing

A 9⅝in, 53.5lb/ft, L80, VAM TOP injection (production) casing string would be run and set +/- 66ft (20m) above the Rot Clay cap rock in the Rot Halite formation at 3848ft (±1173m) TVDSS (5400ft ±1646m MDBRT). The 9⅝in would cover most of the potential mobile salt sections allowing the Rot Halite, Rot Clay and Bunter Sandstone to be cored. It would also provide an injection (production) conduit with sufficient burst, collapse and tensional strength to withstand the loads from any injection scenario. The casing setting depth could be moved higher up the well, in the Rot Halite should future abandonment requirements (for improved store integrity to CO_2 leakage) dictate the need for a larger cement ‘pancake’ plug above the Rot Clay cap rock.

4.7.4 7in Injection Casing

A 7in, 29lb/ft, SM25CRW-125, Super Duplex VAM TOP HT production liner would be run and set off bottom at 5151ft (±1570m) TVDSS (7549ft ±2301m MDBRT). A liner to overlap of +/- 492ft (150m) would be incorporated and the string cemented to top liner hanger with CO_2 resistant cement. The VAM TOP HT connection would be specified so that the liner can be rotated during the cement job whilst the 25 Chrome Super Duplex liner would be specified for its inert nature and CO_2 resistant properties. Further work in the detail design phase would be required to select the ideal metallurgy.

4.8 Conductor Concept Selection

The conductor scheme selected during the FEED stage would be adequate for the design; it is detailed in the Well design rational.

30in x 1in API 5L X52/X56 conductor pipe has been used in many of the deep water platforms with more highly preloaded connectors such as GE/Vetco SR-20 and Oilstates Merlin. These are metal to metal sealing connectors and are more suited to long term fatigue applications.

In common with other suppliers, Oilstates offer a range with various ODs and IDs to be compatible with API pipe, plus versions designed to be driven. These would have an even higher rating in compression.

Since these wells would be slim hole, it may be possible to use 26inOD x 1.25inw.t. X52/X56 pipe with suitable fatigue resistant connections. The 26in conductor can be configured at the cellar deck to allow use of the same diverter and wellhead running sequence as the 30in pipe. At the bottom end, the conductor shoe joint would be swaged to 20ft of 20in casing with a 20in float shoe to allow clean drill out at the start of the 17½in diameter hole section.

For long term use, it would be advisable to have the joints from just below the seabed to the cellar deck coated in either Thermal Sprayed Aluminium (TSA) or epoxy coated. The joints below seabed need not be coated. Heat shrink sleeves are available to mould around made up connectors, but these tend not to be used. This is mainly due the probability that they would get damaged running through the conductor guides and also due to the problems removing the sleeves should the conductor need to be pulled and re-run.

It would be beneficial to incorporate a small funnel on the bottom side of the conductor guides as well as a larger funnel on the upper side. This would allow cleaner passage of any drift or drilling assemblies and, if necessary, the recovery of conductor through the guides.

Although the wells are fairly shallow, the downward load on the conductor due to casing strings, the upper completion, wellhead and Christmas tree may cause the conductor to elastically buckle into the guides.

Any fatigue study of the conductor and connections would be likely to recommend that the pipe is well centralized in the conductor guides. However if close fit centralizers are fitted to the pipe during running then there may be enough built-in interference between the centralizers and the platform guides to prevent the conductor being run to depth. Should excessive vibration occur after the conductor is installed, it may be that centralizers are required to be fitted in the guides. These would be split centralizers which could be fitted by an engineering contractor in any accessible guides above the water line. Retrofitting centralizers below water line may be more problematic. Provided the guide IDs were made to a fairly tight drift tolerance, then the running clearance between the conductor and the guides may be small enough to negate the need for retrofit centralizers. If this is the case then an under reamer would need to be used to open out the top hole for running conductor. Any buckling due to top weight could close any clearance at the guides and be beneficial to fatigue life.

It would also be sensible to try and avoid placing a connector at the splash zone and to ensure that any long term annulus fluid within the conductor are dosed with inhibitor to limit the risk of corrosion at the connectors from the inside.

Risks:

- platform guide drift diameters and alignment would be well defined in order to allow trouble free top hole drilling and conductor installation whilst minimizing clearances;
- long term fatigue life and long term corrosion, although existing standard equipment would be deemed adequate;
- impact damage at guides due to wave action and large a clearances; and
- increased hydrodynamic drag over time due to marine growth.

4.8.1 Conductor Analysis

In order for a meaningful analysis to be carried out it, inside diameters, tolerances and elevations of the conductor guides would be required. These details are not yet available; typically conductor analysis would take in the region of two months once all such information had been provided.

None the less, existing analysis carried out on a similar platform not far away from block 42 and in similar water depth could be used as a reference. The conductor used was 26in x 1.25inw.t c/w Merlin connections.

There are two aspect of a typical analysis, “Strength and Stability” and “Fatigue Assessment”.

4.8.1.1 Strength and Stability

The comparable analysis indicates that “strength and stability” is not a problem with the conductor suitable for 100 year environmental conditions. Since the carbon capture wells are shallower than the reference wells then the compression on the conductor due to tubing and casing string weights would be less, although the conductor would still tend to buckle into the guides.

The usual area of concern is the bending moment and pressure containment at the wellhead, when drilling the well, due to possible jack up movement relative to the jacket during extreme conditions.

Negative wellhead growth would compress the casing strings. Cyclic loading would exist due to wave action and possibly due to vortex shedding in periods of high current. It may be possible to observe wellhead movement due to these effects at certain times.

The existence of cyclic stresses is unavoidable, but their magnitude could be limited by restricting the movement of the conductor within the guides. There would be adequate clearance within the guides to allow the conductor to be run through, but once the conductor was installed then this clearance would need to be reduced as much as possible. Retrofit centralizers / wedges may be required to restrain the conductor fully at the guides.

There would be a risk in not getting the conductor to bottom if tight clearance centralizers were fitted to the conductor to coincide with the guides. Jacket fabrication tolerances and conductor connector alignment may be such that the conductor may bind in the guides during the last few feet of installation.

Stress concentration factors and fatigue curves (S/N curves) are well documented for conductor pipe body, machined connectors and pipe to connector welds. These could be used with the cyclic loading to determine the likely fatigue life of the conductor.

Conductor analysts emphasise the need to centralize the conductor within the guides as much as possible in order to extend fatigue life.

Any bucking of the conductor into the guides due to top loading would also reduce the clearance between the conductor pipe body and the guides and hence improve the fatigue life. There may also be a small benefit in the slightly increased compressive stress in the pipe body.

4.9 Cement Concept Selection and Cement Verification

As previously mentioned, cement is used to bond the casing to the formation. Cement performs various task, such as zonal isolation, supporting the casing mechanically and other functions. The cement is mixed at surface and pumped down the well, but with the objective that the cement ends up in the annulus between the casing and the previously drilled open hole. The mixed cement is referred to as slurry, which has various properties (such as thickening time and compressive strength) which are reported in the following discussion. Typically the cement is pumped into the casing with a wiper bottom plug ahead of the slurry and a wiper top plug behind the slurry, after which displacement fluid is pumped to place the cement where it is required. The wiper plugs literally wipe the inside of the casing but also separate the displacement fluid from the cement in order that contamination of the cement is avoided.

The cementing scheme selected and the method by which cement would be verified for zonal isolation is described below.

4.9.1 30in x 20in Conductor Cement

For structural support, the 30in x 20in conductor would be cemented to the mudline with 16.0ppg Class G cement. This would be an inner string job with an open hole excess of 300%. A 20bbl seawater / dye spacer would be pumped ahead of the cement to detect returns at the seabed. Refer to Figure 4.13, below.

Figure 4.13: Conductor Cement Slurry Formulation

30"x 20" CONDUCTOR			
Composition		**Properties**	
Lafarge Class G		Surface density:	16.00 ppg
Calcium Chloride Liquid	0.54 gal/sk	Surface yield:	1.17 ft³/sk
Seawater	4.65 gal/sk	Total mixing fluid:	5.21 gal/sk
NF-6	10.00 pts/10bblMF	Thickening time (70 Bc):	5:00 +
		Free water vert at 48°F:	0.0 %
		Pv/Yp at 48°F:	30/64 (cP/lbs/100ft²)
		Comp strength at 46°F	50 psi in 8 hrs
		Comp strength at 46°F	500 psi in 12 hrs
		Lab report no:	UK-219486

4.9.2 13⅜in Surface Casing Cement

The 13⅜in casing would be cemented, starting with a 13.5ppg lead and finishing with a 16.0ppg tail. Both slurries would be Class G cement and would be displaced by means of a single wiper plug. A 75% open hole excess is planned to be pumped with top of cement at +/- 1,500ft (+/-457m). Refer to Figure 4.14, 13⅜in, below.

Figure 4.14: 13⅜in Cement Slurry Formulation

13 3/8" CASING			
Composition		**Properties**	
Lafarge Class G		Surface density:	16.00 ppg
Silicalite Liquid	1.00 gal/sk	Surface yield:	1.20 ft³/sk
CFR-8L	0.50 gal/sk	Total mixing fluid:	5.43 gal/sk
HR-4L	0.15 gal/sk	Thickening time (70 Bc):	4:00
Freshwater	3.77 gal/sk	Free water vert at 73°F:	0.0 %
NF-6	10.00 pts/10bblMF	Pv/Yp at 73°F:	53/82 (cP/lbs/100ft²)
		Comp strength at 80°F	50 psi in 12 hrs
		Comp strength at 80°F	500 psi in 16 hrs
		Lab report no:	UK-219490

4.9.3 9⅝in Production Casing Cement

The 9⅝in casing would be cemented to ±3,000ft (±914m) MDBRT with Class G 13.5ppg lead and 16.0ppg tail cement. This would seal off the majority of the mobile salt sections drilled in the 12¼in section. An open hole excess of 50% is planned to be pumped as part of a dual plug cement job. Refer to Figure 4.15, below.

Figure 4.15: 9⅝in Casing Cement Slurry Formulation

9 5/8" CASING			
Composition		**Properties**	
Lafarge Class G		Surface density:	15.00 ppg
Halad-300L NS	0.60 gal/sk	Surface yield:	1.37 ft³/sk
HR-4L	0.08 gal/sk	Total mixing fluid:	6.69 gal/sk
Silicalite Liquid	1.00 gal/sk	Thickening time (70 Bc):	4:00
Freshwater	4.99 gal/sk	Free water vert at 102°F:	< 1 % %
NF-6	10.00 pts/10bblMF	Pv/Yp at 102°F:	135/45 (cP/lbs/100ft²)
		Comp strength at 115°F	50 psi in 8 hrs
		Comp strength at 115°F	500 psi in 14 hrs

Cement placement would be strictly controlled with monitoring of displacement rates and monitoring of the slurry density in order that zonal isolation is achieved.

Verification of the placement and zonal isolation effectiveness of the 9-5/8in casing primary cementation would be performed with the use of azimuthal cement bond logging.

4.9.4 7in Production Liner

The 7in casing would be cemented back to the liner hanger at ±4,900ft MDBRT with 14.5ppg CO_2 resistant cement. This would aid in the longevity of the well integrity as part of the CO_2 store to assure leakage does not occur.

The 42/25d-3 appraisal well utilised the Halliburton CorossaCem NP (Thermalock) slurry to cement the 7in liner in place. This slurry ensures that zero carbonation takes place when the cement is exposed to CO_2. However, the expected temperature fluctuations in the 42/25d-D injection wells may require addition of fibres to the cement recipe for elasticity. Thermalock cement cannot be mixed with Portland cement and therefore has to be stored in clean tanks and pumped through clean lines to avoid contamination.

Schlumberger utilise EverCRETE CO_2 resistant cement. EverCRETE retains its integrity under exposure to the most critical CO_2 conditions, having predictable mechanical properties on its full range of density. EverCRETE is compatible with Portland based systems, therefore eliminates any associated risk of contamination when handling and storing offshore. EverCRETE has also been used and tested by other oil companies and would be selected for the 7in production liner for this project.

Cement placement would be strictly controlled with monitoring of displacement rates, monitoring of the slurry density in order to avoid micro-annuli. Additionally, the liner would be rotated during placement of the primary cementation.

Verification of the placement and zonal isolation effectiveness of the 7in liner primary cementation would be performed with the use of azimuthal cement bond logging. Refer to Figure 4.16, below.

Figure 4.16: 7in liner cement slurry formulation

7" LINER			
Composition		**Properties**	
EverCRETE		Surface density:	15.00 ppg
Fe-2	0.70 %BWOC	Surface yield:	1.21 ft³/sk
Latex 2000	2.00 gal/sk	Total mixing fluid:	4.96 gal/sk
SA-1015	0.10 %BWOC	Thickening time (70 Bc):	7:00
Freshwater	2.89 gal/sk	Free water vert at 111°F:	0.0 %
NF-6	10.00 pts/10bblMF	Fluid loss at 111°F:	20 cc/30min
		Pv/Yp at mix:	60/30 (cP/lbs/100ft²)
		Pv/Yp at 111°F:	60/30 (cP/lbs/100ft²)
		Comp strength at 134°F	50 psi in 10 hrs
		Comp strength at 134°F	500 psi in 16 hrs

Note that %BWOC are based on a 94 lb sack

4.10 Time and cost estimates

Detailed time and cost estimates of the White Rose wells were performed during FEED. Timings were derived from offset well Time vs. Depth information.

The cost estimates were for the life cycle of the first load, so include for drilling, completing and also interventions. The intervention philosophy and frequency was determined during a Reliability, Availability and Maintainability (RAM) study.

The cost estimates were based upon material, equipment, personnel and services costs that were based upon service agreements held by ADTI at the time and are therefore current and accurate. Figure 4.17 below shows the most relevant offset well Days vs. Depth information. Figure 4.18 shows the generic days vs depth plot for the White Rose CO_2 injection wells planned during FEED, from which the timings were derived in order to estimate the costs in this document.

Figure 4.17: Offset Wells - Days vs Depth plot

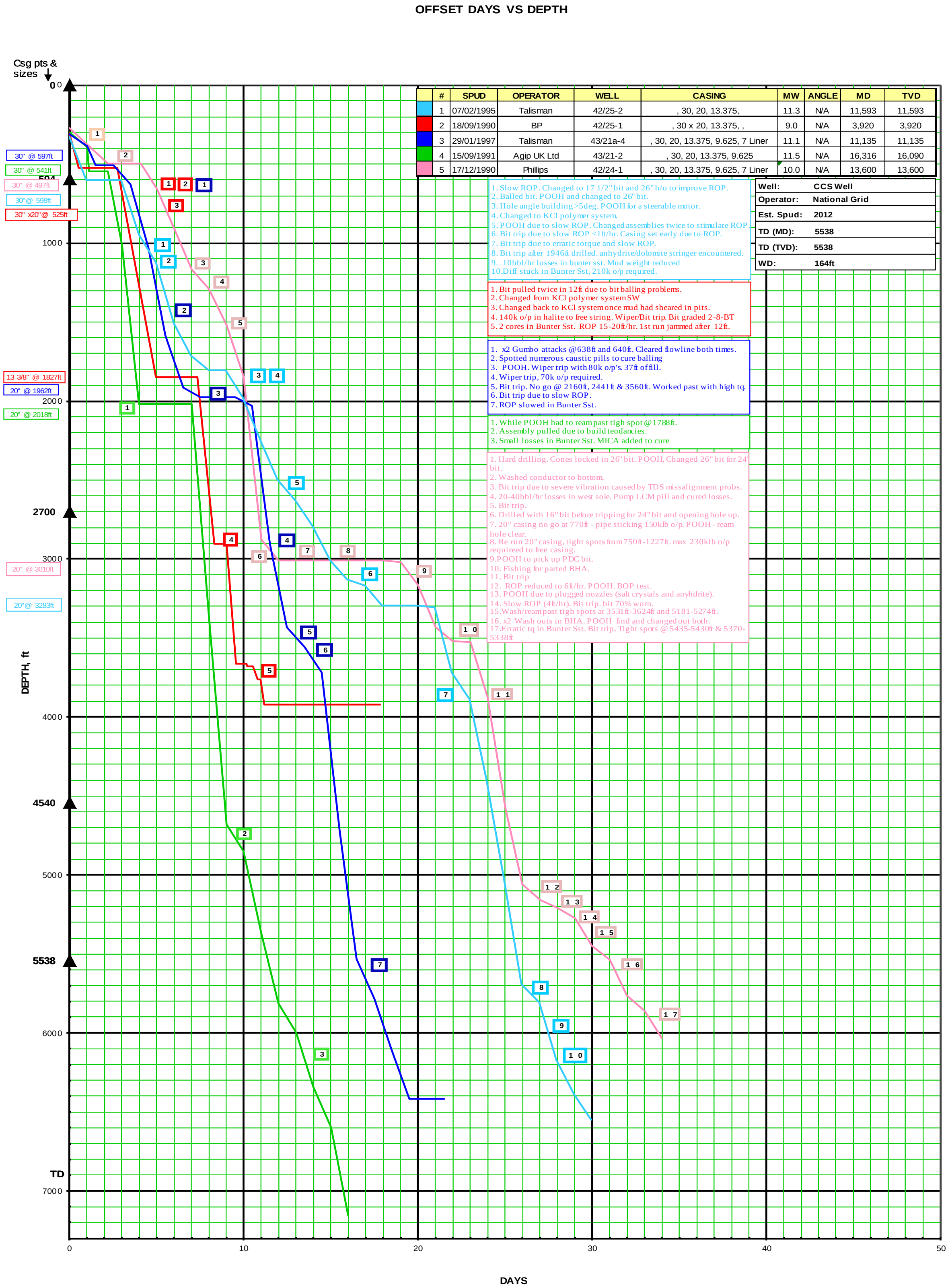
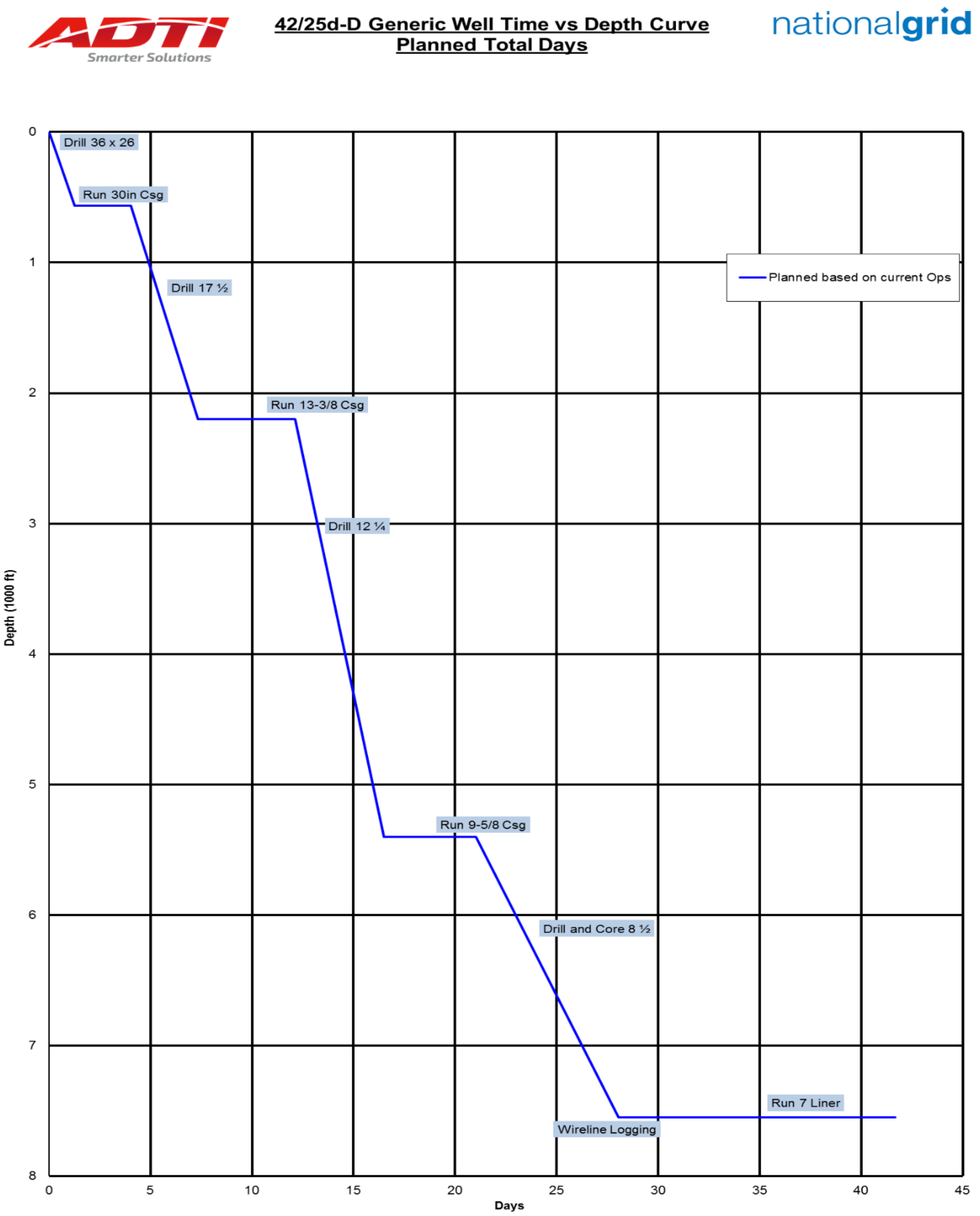


Figure 4.18: Generic CO_2 well Days vs Depth plot



The following programme generic steps were used to build up the time/depth estimate:

- mobilise rig to 42/25d-D surface location and interface with the White Rose platform;
- Spud Well and drill 36in x 26in section with sea water and sweeps to ±570ft MDBRT; displace section to 10.0ppg bentonite mud (to spud a well is to make the first penetration into the seabed so essentially to start the drilling phase);
- run conductor to ±565ft MDBRT and cement to seabed (the conductor is the first pipe placed into the well);
- nipple up overshot and diverter (to nipple up is to attach something to the top of the pipe – in this case the conductor and an overshot is a temporary attachment device and a diverter is equipment to divert flow from the well in the case that uncontrolled flow emanates from the well);
- drill 17 ½in section with 9.5ppg KCL Polymer Mud to ±2,175ft MDBRT;
- run 13 ⅜in casing to ±2,170ft MDBRT and cement to ±1,500ft;
- pressure test 13 ⅜in casing to 1,700psi on cementing wiper plug bump (bumping the plug means pumping the wiper plug until it stops at the bottom of the casing and the pressure test confirms there are no leaks in the casing);
- install surface wellhead & 13 ⅝in BOPs. Pressure test BOPs and wellhead connection;
- drill out 13 ⅜in casing shoe and perform FIT, which confirms the strength of the rock and also the integrity of the cement previously pumped into the annulus (the space between the outside diameter of the casing and in diameter of the drilled hole within which the casing was run);
- drill 12 ¼in diameter hole to ±5,405ft MDBRT with 11.0ppg LTOBM;
- run wireline logs (PEX – AIT – Sonic Scanner – CBL). The wireline logs make physical property measurements of the formation in order to evaluate the formation;
- 12 ¼in Contingency wiper trip, which involves running drilling tools into and back out of the hole to confirm that the hole has not deteriorated in condition and is performed prior to running the 9 ⅝in casing to improve the chances of a trouble free casing run and cementation;
- run 9 ⅝in casing to ±5,400ft MDBRT and cement back to ±3,000ft MDBRT;
- pressure test 9 ⅝in casing on plug bump;
- drill out 9 ⅝in casing shoe and perform FIT. Drill ahead to core point;
- two independent core runs across the cap rock and Bunter Sandstone. Coring involves cutting and removal of a cylindrical sample of the rock, known as a core, which can be evaluated for physical properties of the formation cored;
- drill remainder of 8 ½in section to TD (±7,526ft MDBRT) with 10.0-10.5ppg LTOBM;
- run wireline logs;
  - (PEX – AIT - CMR+ - ECS);
  - (Sonic Scanner - HNGS - OBMI2 - CBL);
  - (MDT - Quicksilver Pressures & samples);
  - (MDT Micro Frac + Vertical Interference Tests);
- 8 ½in Contingency wiper trip;
- run 7in liner to ±7,526ft MDBRT and cement back to TOL ±4,900ft MDBRT;
- pressure test 7in liner to 5,000psi (subject to completion requirements);
- Wellbore Clean Out run (displace well to inhibited brine);
- Shoot & Pull;
- run 4 ½in x 5 ½in Upper Completion;
- recover 7'' Landing String, BOP & 13 ⅝'' HP Riser;
- install Christmas Tree. Rig Up STT. Recover TH Plug & Prong; and
- perform Injection test with filtered inhibited seawater.

4.10.1 Summary Timings Table - Drill & Complete Three Platform Wells

The following summary Table 4.7 identifies the step-by-step breakdown of operational timings for drilling and completing 3 wells with a jack up rig.

Subsequent Tables identify the costs for drilling 3 wells. The cost categories are summaries of highly detailed cost estimates (which are not shown in this report). It will be noted that reference is made to Standard and Heavy Duty jack up rigs. For the purposes of this report, the standard jack up rig was estimated to cost US$ 155,000 per day to hire and operate and the Heavy Duty jack up was estimated to cost US$ 255,000 per day to hire and operate.

Table 4.7: Summary Timing Table Drill and Complete 3 Wells

Scenario # 2 - Drill 3 Wells			
Step	Operation	Days	Scenario
1	Mobilise rig to 42/25d-D location	7.35	#2
2	14 Days WOW to locate over platform	14.00	
2	Drill 36" hole to ±570ft MDBRT	1.18	
3	Run & Cement 26" x 20" Conductor	2.57	
4	Drill 17 1/2" hole to ±2,175ft MDBRT	3.54	
5	Run and cement 13 3/8" casing and perform FIT	4.94	
6	Drill 12 1/4" hole to ±5,405ft MDBRT	4.41	
7	Logging (PEX – AIT – Sonic Scanner – CBL)	0.53	
8	12 1/4" Contingency wiper trip	0.75	
9	Run and cement 9 5/8 casing and perform FIT	4.54	
10	Core 8 1/2" (Two independent core runs)	3.60	
11	Drill 8 1/2" to TD at ±7,526ft MDBRT	3.91	
12	Logging (8-1/2" PEX – AIT - CMR+ - ECS)	0.57	
13	Logging (Sonic Scanner - HNGS - OBMI2 - CBL)	0.52	
14	Logging (MDT - Quicksilver Pressures & samples)	2.03	
15	Logging (MDT Micro Frac + Vertical Interference Tests)	2.03	
16	8 1/2" Contingency wiper trip	1.00	
17	Run & Cement 7" Liner, TOL ±4,900ft MDBRT	2.36	
18	Well Bore Clean Up (displace well to inhibited brine)	3.50	
19	TCP Shoot & Pull	3.07	
20	Run 4-1/2" x 5-1/2" Upper Completion	2.42	
21	Recover BOP and Install Xmas Tree	2.81	W1 Sub Total
22	Injection Testing with filtered inhibited seawater	0.38	50.66 days
23	Skid Drilling Package	0.26	
24	Drill 36" hole to ±570ft MDBRT	1.18	
25	Run & Cement 26" x 20" Conductor	2.57	
26	Drill 17 1/2" hole to ±2,175ft MDBRT	3.43	
27	Run and cement 13 3/8" casing and perform FIT	4.92	
28	Drill 12 1/4" hole to ±5,405ft MDBRT	4.50	
29	Logging (PEX – AIT – Sonic Scanner – CBL)	0.53	
30	12 1/4" Contingency wiper trip	0.75	
31	Run and cement 9 5/8 casing and perform FIT	4.53	
32	Core 8 1/2" (Two independent core runs)	3.60	
33	Drill 8 1/2" to TD at ±7,526ft MDBRT	3.98	
34	Logging (8-1/2" PEX – AIT - CMR+ - ECS)	0.57	
35	Logging (Sonic Scanner - HNGS - OBMI2 - CBL)	0.52	
36	Logging (MDT - Quicksilver Pressures & samples)	2.03	
37	Logging (MDT Micro Frac + Vertical Interference Tests)	2.03	
38	8 1/2" Contingency wiper trip	1.00	
39	Run & Cement 7" Liner, TOL ±4,900ft MDBRT	2.37	
40	Well Bore Clean Up (displace well to inhibited brine)	3.50	
41	TCP Shoot & Pull	3.07	
42	Run 4-1/2" x 5-1/2" Upper Completion	2.42	
43	Recover BOP and Install Xmas Tree	2.81	W2 Sub Total
44	Injection Testing with filtered inhibited seawater	0.38	50.95 days

Table 4.8 continued: Summary Timing Table Drill and Complete 3 Wells

45	Skid Drilling Package	0.26	
46	Drill 36" hole to ±570ft MDBRT	1.18	
47	Run & Cement 26" x 20" Conductor	2.57	
48	Drill 17 1/2" hole to ±2,175ft MDBRT	3.43	
49	Run and cement 13 3/8" casing and perform FIT	4.92	
50	Drill 12 1/4" hole to ±5,405ft MDBRT	4.52	
51	Logging (PEX – AIT – Sonic Scanner – CBL)	0.53	
52	12 1/4" Contingency wiper trip	0.75	
53	Run and cement 9 5/8 casing and perform FIT	4.53	
54	Core 8 1/2" (Two independent core runs)	3.60	
55	Drill 8 1/2" to TD at ±7,526ft MDBRT	4.07	
56	Logging (8-1/2" PEX – AIT - CMR+ - ECS)	0.57	
57	Logging (Sonic Scanner - HNGS - OBMI2 - CBL)	0.52	
58	Logging (MDT - Quicksilver Pressures & samples)	2.03	
59	Logging (MDT Micro Frac + Vertical Interference Tests)	2.03	
60	8 1/2" Contingency wiper trip	1.00	
61	Run & Cement 7" Liner, TOL ±4,900ft MDBRT	2.37	
62	Well Bore Clean Up (displace well to inhibited brine)	3.50	
63	TCP Shoot & Pull	3.07	
64	Run 4-1/2” x 5-1/2” Upper Completion	2.42	
65	Recover BOP and Install Xmas Tree	2.81	W3 Sub Total
66	Injection Testing with filtered inhibited seawater	0.38	51.06 days
67	De-mobilise rig to 500m zone	2.45	
	Cumulative Time	176.47	

4.10.2 Summary Costs Table - Drill & Complete Three Platform Wells with Standard Jack Up Rig

Table 4.8: Drill and Complete 3 wells with a Standard Jack Up rig

SCENARIO #2 TOTAL COST	£68,391,391
GENERAL	
Location Survey/Preparation	£61,900.00
Direct / Other Labour / Fringe (Staff)	£6,092,448.36
Wells Personnel Travel	£113,264.00
Miscellaneous Services	£71,886.63
Casual / Contract Labour	£10,692.00
LOGISTICS	
Supply Vessel (No fuel)	£4,463,040.00
Anchor Handling Vessels	£1,290,000.00
Physical Location Preparation	£45,325.00
Standby Vessel Only (No Fuel)	£1,337,400.00
All Fuel (Rig / PSV's / AHV's)	£1,777,552.42
Transportation Costs	£1,108,763.75
Customs Duties / Admin charges	£3,526.40
Marine Agents/Port Services	£787,990.00
Waste Disposal	£121,205.84
DRILLING	
Drilling Rig Hire	£18,958,898.33
Rig Inspection	£36,000.00
Weather Service	£11,325.20
Permitting - 3rd Party Charges	£17,493.00
BHA/Drilling Tools Rental	£217,040.71
Directional Drilling	£552,937.14
Casing Service	£342,623.54
Liner Running - Service charges	£71,158.47
Fishing Service	£112,707.87
Mud Engineer & Contractors	£354,457.07
Cuttings Containment	£775,260.72
Cementing Service	£484,029.73
Drillstring & Handling Tools Rental	£128,003.19
Other Rentals & Leases	£144,704.15
Drilling Fluids	£1,290,184.23
Cement & Additives	£618,000.00
Casing / Liner Hangers / Tubulars	£4,606,599.51
Bits	£457,500.00
Miscellaneous Materials/ Equipment	£27,882.00
Mud Logging	£245,731.62
Coring Services	£293,436.00
Elec Logging & Eval	£5,169,620.93
LWD	£444,984.61
SUBSEA	
ROV Service	£419,938.13
Xmas Tree Installation & Tangibles	£1,488,105.31
Wellhead / MLS Services	£667,900.00
Wellhead/MLS Costs	£76,026.00
WELL SERVICES	
Completion Running Services	£1,226,281.35
Completion Equipment	£10,755,644.00
Filtration Service	£254,494.80
Well Testing Services	£567,999.63
Well Intervention Services	£289,428.90

4.10.3 3 Platform Wells Life Cycle Cost estimate (Standard Jack Up)

The life cycle cost estimates noted in Table 4.9 and Table 4.10 document the drilling costs but also the costs associated with performing other work on the wells which is envisaged to be required throughout the life of the development. This other work incudes interventions into the wells which do not require a drilling rig (boat based) and interventions which require a drilling rig to perform the work at the platform location, which include P&A (Plug and abandon) work. P&A work is the work required to permanently seal the wells off, once the injection of CO_2 has finished and the wells have been monitored for an extended period to ensure no leaks of CO_2 from the wells is occurring.

Table 4.9: 3 Platform wells life cycle cost estimate (Standard Jack Up)

Scenario #	LIFECYCLE COSTS - 3 PLATFORM WELLS	Option Cost	Occurrence Project Lifecycle	Lifecycle Cost
2	Drill & Complete Three Platform Wells	£68,391,391	1.00	£68,391,391
4	P&A Two Platform Wells	£15,284,680	1.00	£15,284,680
6	Boat Based Intervention 1 - E-line PLT	£546,437	60.00	£32,786,237
7	Boat Based Intervention 2 - E-line Perforate additional 40 ft	£506,439	0.30	£151,932
8	Boat Based Intervention 3 - Insert Wireline SSSV valve	£352,235	2.25	£792,529
9	Boat Based Intervention 4 - Water wash (Bullhead - rate diversion)	£434,423	58.80	£25,544,086
10	Boat Based Intervention 5 - Install Temp Memory gauges	£352,019	15.00	£5,280,278
11	Rig Based Intervention 1 - Water wash (Coil Tubing)	£11,495,274	1.20	£13,794,329
12	Rig Based Intervention 2 - Coil Tubing Sand Clean Out	£8,834,227	0.12	£1,060,107
13	Rig Based Workover 1 - Recover tubing string / packer	£14,209,147	3.84	£54,563,126
14	Rig Based Workover 2 – Recover tubing and run Sand Screens	£16,070,472	0.09	£1,446,342
15	Drill & Complete One Subsea Monitoring Well	£15,218,378	1.00	£15,218,378
16	P&A One Subsea Monitoring Well	£6,937,142	1.00	£6,937,142
17	P&A One Platform Well and install a wireless plug integrity monitoring	£8,693,484	1.00	£8,693,484
	Total Lifecycle Costs for 3 Platform Wells			£249,944,042

4.10.4 3 Platform Wells Life Cycle Cost estimate (Heavy Duty Jack Up)

Table 4.10: Platform wells life cycle cost estimate (Heavy Duty Jack Up)

Scenario #	LIFECYCLE COSTS - 3 PLATFORM WELLS	Option Cost	Occurrence Project Lifecycle	Lifecycle Cost
2	Drill & Complete Three Platform Wells	£80,146,057	1.00	£80,146,057
4	P&A Two Platform Wells	£19,249,347	1.00	£19,249,347
6	Boat Based Intervention 1 - E-line PLT	£546,437	60.00	£32,786,237
7	Boat Based Intervention 2 - E-line Perforate additional 40 ft	£506,439	0.30	£151,932
8	Boat Based Intervention 3 - Insert Wireline SSSV valve	£352,235	2.25	£792,529
9	Boat Based Intervention 4 - Water wash (Bullhead - rate diversion)	£434,423	58.80	£25,544,086
10	Boat Based Intervention 5 - Install Temp Memory gauges	£352,019	15.00	£5,280,278
11	Rig Based Intervention 1 - Water wash (Coil Tubing)	£14,757,941	1.20	£17,709,529
12	Rig Based Intervention 2 - Coil Tubing Sand Clean Out	£11,066,893	0.12	£1,328,027
13	Rig Based Workover 1 - Recover tubing string / packer	£16,941,147	3.84	£65,054,006
14	Rig Based Workover 2 – Recover tubing and run Sand Screens	£18,951,139	0.09	£1,705,602
15	Drill & Complete One Subsea Monitoring Well	£17,822,397	1.00	£17,822,397
16	P&A One Subsea Monitoring Well	£8,595,142	1.00	£8,595,142
17	P&A One Platform Well and install a wireless plug integrity monitoring	£10,573,484	1.00	£10,573,484
	Total Lifecycle Costs for 3 Platform Wells			£286,738,654

4.10.5 Cost Estimate Phase Timing and assumptions

Phase times were generated for each phase of the drilling, completion and abandonment operations, with each phase broken down into the operational steps required to complete each phase. A risk allowance was added to each phase time to produce a Most Likely Time. As there is no finalised design and the rig is not known, the risk allowance used was ADTI's historic P50 NPT figure of 25% (NPT and WOW). Note that NPT means Non-Productive Time and WOW is Waiting on Weather time. NPT occurs during operations when the planned operations do not progress according to plan, which may occur due to equipment failure on the rig, well equipment failure, problems related to well drilling and other issues. WOW time may be incurred for example when sea states are prohibitively adverse for logistics movements from a supply vessel to the rig or possibly due to high winds impeding operation of the rigs cranes.

Table 4.11: Risk allowances

Risk Allowances (NPT & WOW)	Risk %
Phase Times	0%
Low Case (NPT rate for all wells 2005-2014)	17%
Most Likely (NPT rate for all wells 2005-2014)	25%
High Case (NPT rate for all wells 2005-2014)	33%

WOW during Platform Interfacing

To account for WOW to move from the standby location to interface with the platform, 14 days delay has been assumed for each rig visit to allow for WOW while approaching or departing the platform.

Learning Curve

Due to the budgetary nature of the cost estimates in this document, no allowance has been made for any 'learning curve' improvement during drilling or completions. This can be added in future estimates which have better definition with respect to costs.

No allowance has been made for potential SIMOPS with the platform commissioning team during drilling or completions operations.

4.10.6 Intervention Frequency Assumptions for Life Cycle Cost Estimates

The Intervention Frequency has been taken from the wells RAM study. The RAM study assessed the Reliability, Availability and Maintainability of the wells as a statistical occurrence of failures in the wells that would require intervention. The occurrence of failures was documented as various scenarios (assigned a scenario # or scenario number, which are shown in the Tables below). The occurrence of these failures was then assigned a number (as noted in Table 4.12) and this was used to estimate the cost of the required interventions throughout the life cycle of the development.

Table 4.12: Intervention Frequency Assumptions

Scenario #	INTERVENTIONS & WORKOVERS OPERATIONS	Frequency Well Lifecycle	Occurrence Well Lifecycle
8	Insert Wireline SSSV valve	75%	0.75
13	Tubing workover to replace SSSV valve	25%	0.25
13	Tubing workover to fix a tubing leak	100%	1.00
13	Tubing workover to fix a tubing Hanger leak	1%	0.01
13	Tubing workover to fix a production packer leak	1%	0.01

Scenario #	INTERVENTIONS & WORKOVERS OPERATIONS	Frequency Well Lifecycle	Occurrence Well Lifecycle
NA	Tree Valve Replacement	No cost to wells	0.00
NA	Tree Replacement	No cost to wells	0.00
13	Tubing workover to replace a Gauge Mandrel Seal	1%	0.01
NA	Surface Leaks (to Christmas tree and wellhead)	No cost to wells	0.00
7	Wireline perforation an additional 40ft	10%	0.10
12	Coil tubing sand clean out run to remove sand fill	4%	0.04
14	Recover tubing to run sand screens	3%	0.03
9 &11	Waterwash Operations	Annually	1.00
9	Platform based bullhead waterwash	98%	19.60
11	Rig Based coil tubing waterwash	2%	0.40
6	Annual wireline PLT and calliper logging	100%	20.00
NA	Integrity Testing Tree	No cost to wells	0.00
NA	Integrity Testing SSSV	No cost to wells	0.00
10	Wireline intervention to installing temporary memory gauges	20%	5.00

4.10.7 Cost Assumptions – General

Table 4.13: (below) shows all the general assumptions applied to the production of the FEED cost estimates.

Table 4.13: General Cost Assumptions

#	ASSUMPTIONS	Cost
1	All costs are based on January 2015 costs, no allowance has been made for inflation	
2	No overhead costs for NGC have been assumed.	
3	No allowance has been made for cost uncertainty of the Rig, Vessels and fuel rates	
4	The times and costs quoted are budgetary	
5	Personnel costs are based on a design team for 18 months	
6	Times used are trouble free + 25% NPT risk allowance (including WOW)	
7	For each rig visit to the platform 14 days WOW is assumed	
8	Exchange Rate US $1.50/£	£1.50
9	Current average Standard Jack up rig rate $155,000/Day	$155,000
10	Fuel rate £331/MT assumed (average rate for Jan 2015)	£331
11	Supply Vessel £22,000/day (Excluding Fuel)	£22,000
12	Standby Vessel £7,500/day (Excluding Fuel)	£7,500
13	Ad Hoc Supply Vessels £30,000/day (Excluding fuel)	£30,000
14	One AHV at £30,000/day (Excluding Fuel & Mob/ De-Mob charges)	£30,000
15	Two tugs at £10,000/day (Excluding Fuel & Mob/ De-Mob charges)	£10,000
16	£/flying hour based on 4 flights/week & 2hr round trip (£3,879/hr)	£3,879
17	7in liner (SM125 25CR 29ppf Vam Top HT) assumed to be $394.98/ft	£263
18	5 ½in 17# 25% Chrome Super Duplex (PREN>40) JFE Bear R3 ($700/ft)	£467
19	4 1½in 12.6# 25% Chrome Super Duplex (PREN>40) JFE Bear R3 ($600/ft)	£400
20	Service company prices are based on January 2015 rates	

#	ASSUMPTIONS	Cost
21	Assumed equipment turnaround - 7 days, personnel turnaround - 4 days	
22	Assumes supply base is Great Yarmouth	
23	Assumes well is as per the basis of design	
24	No loss circulation materials have been included in mud costs	
25	No H_2S equipment has been included	
26	No offshore geologist costs have been included; it is assumed that this is included in the NGC overhead.	
27	Time estimate assumed that all sections are drilled in one bit trip.	
28	Two independent 90ft cores cut across the cap rock & Bunter Sandstone in each injection well have been assumed.	
29	No allowance for sidetracks has been made	
30	Mobilisation estimates assume 24hr tow to location and 48hour interface required at platform	
31	De-Mobilisation assumes rig is off hire upon Exit from 500m zone	

The rate for a 'Heavy Duty' Jack Up has been at a premium over the standard Jack-up day rate. A 'Standard' jack up has been used for costing purposes.

4.10.8 Cost Assumptions – Well Design

The following is a summary of the proposed sequence of events for a generic 42/25d-D well which is based upon the Drilling Plan and Completion design as noted in this document.

1. mobilise rig to 42/25d-D surface location and interface with the White Rose platform;
2. spud Well and drill 36in x 26in section with sea water and sweeps to ±570ft MDBRT; displace section to 10.0ppg bentonite mud;
3. run conductor to ±565ft MDBRT and cement to seabed;
4. nipple up overshot and diverter;
5. drill 17 ½in section with 9.5ppg KCL Polymer Mud to ±2,175ft MDBRT;
6. run 13 ⅜in casing to ±2,170ft MDBRT and cement to ±1,500ft;
7. pressure test 13 ⅜in casing to 1,700psi on plug bump;
8. install surface wellhead & 13 ⅝in BOP. Pressure test BOP and wellhead connector;
9. drill out 13 ⅜in casing shoe and perform FIT.;
10. drill 12 ¼in diameter hole to ±5,405ft MDBRT with 11.0ppg LTOBM;
11. run wireline logs (PEX – AIT – Sonic Scanner – CBL);
12. 12 ¼in Contingency wiper trip;
13. run 9 ⅝in casing to ±5,400ft MDBRT and cement back to ±3,000ft MDBRT;
14. pressure test 9 ⅝in casing on plug bump;
15. drill out 9 ⅝in casing shoe and perform FIT. Drill ahead to core point;
16. two independent core runs across the cap rock and Bunter Sandstone;
17. drill remainder of 8 ½in section to TD (±7,526ft MDBRT) with 10.0-10.5ppg LTOBM;
18. run wireline logs;
19. (PEX – AIT - CMR+ - ECS);
20. (Sonic Scanner - HNGS - OBMI2 - CBL);
21. (MDT - Quicksilver Pressures & samples);
22. (MDT Micro Frac + Vertical Interference Tests);
23. 8½in Contingency wiper trip;

24. run 7in liner to ±7,526ft MDBRT and cement back to TOL ±4,900ft MDBRT;
25. pressure test 7in liner to 5,000psi (subject to completion requirements);
26. wellbore Clean Out run (displace well to inhibited brine);
27. shoot & Pull;
28. run 4 ½in x 5 ½in Upper Completion;
29. recover 7'' Landing String, BOP & 13 ⅝in HP Riser;
30. install Christmas Tree. Rig Up STT. Recover TH Plug & Prong; then
31. perform Injection test with filtered inhibited seawater.

4.10.9 Cost Assumptions – Formation Evaluation

The following formation evaluation work has been assumed for each well in Table 4.14.

Table 4.14: Formation evaluation assumptions

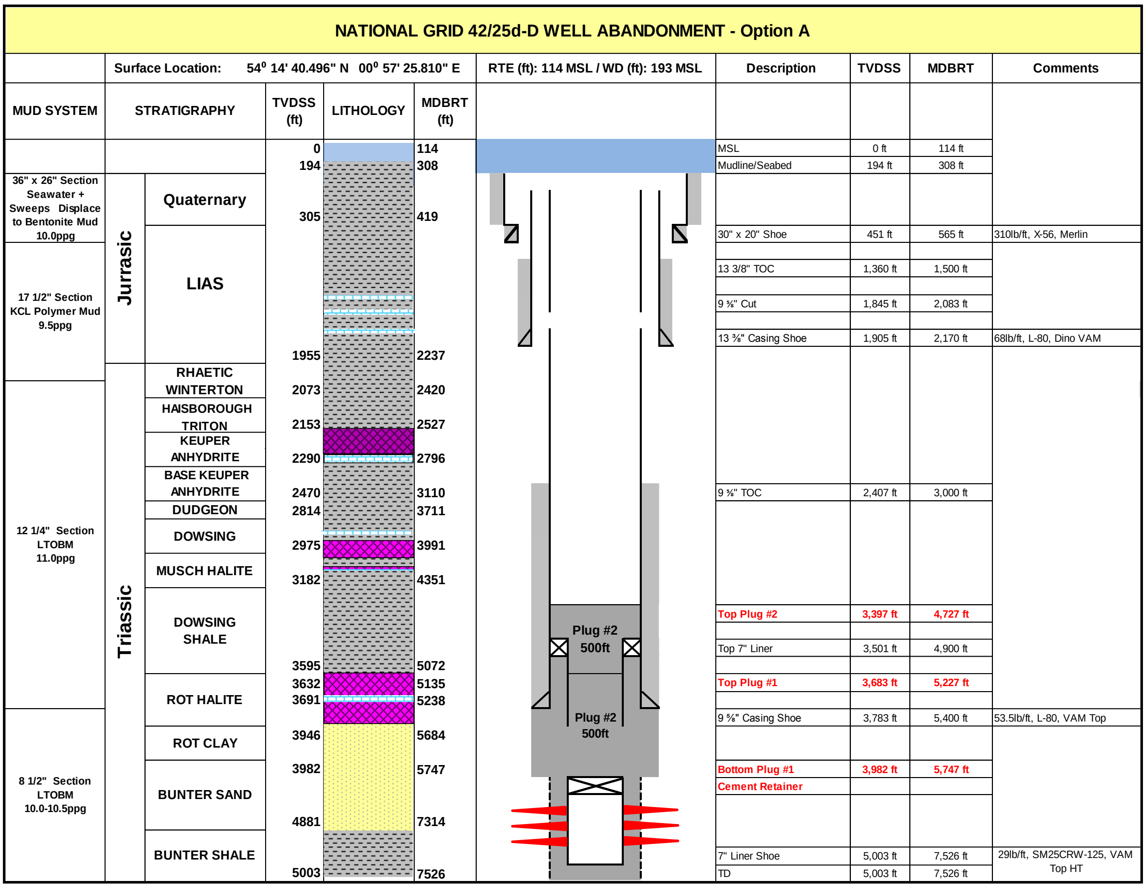
Hole Section	Formation Evaluation
36in x 26in	M/LWD Only
17 ½in	M/LWD Only
12 ¼in	PEX – AIT – Sonic Scanner – CBL
8 ½in	PEX – AIT - CMR+ - ECS
	Sonic Scanner - HNGS - OBMI2 - CBL
	MDT - Quicksilver Pressures & samples
	MDT -Micro Frac + Vertical Interference Tests

It has been assumed that two independent 90ft cores shall be cut on each injection well, across the cap rock and through the bunter sandstone.

4.10.10 Cost Assumptions – Plug & Abandonment

The time and cost estimates have assumed the wells have been Plugged and Abandoned as per Option – A, detailed in this report. Refer to Figure 4.19, below.

Figure 4.19: Plug and abandonment – Option A



4.10.11 Cost Assumptions – Platform Based Interventions

For life cycle interventions the following assumptions are made:

- intervention personnel and equipment will be mobilised to the platform by 'Walk To Work Vessel'. i.e. no helicopter flights. It has been assumed that 24hr working with 2 shifts will be used;
- no allowance is made for wait on weather time when the vessel cannot dock with the platform due to weather conditions being above specification, or when the vessel is docked but during times when the bridge cannot be used due to bad weather;
- it is assumed that the vessel is permanently on hire to NGC and no costs are assigned to Wells for the use of the vessel. i.e. charter costs, fuels/lubes and all costs are attributed to the asset (production) rather than wells;
- it is assumed that there is no restriction on wells personnel count on the platform for performing well related work;
- it is assumed that all shore base costs (tonnage across the quay, carnage, stevedoring etc.) are borne by the asset (production) rather than wells;
- the cost of wash water chemicals is not included and assumed supplied by the asset;
- it has been assumed that there is no Supply Vessel, Standby Vessel, as these function are performed by the walk to work vessel;
- mobilisation assumes 3 days to load, sail, establish on location, hook up to platform, etc.; and

- de-mobilisation assumes 2 days to de-establish from platform, sail, offload equipment, etc.

4.10.12 Cost Assumptions – Rig Based Interventions & Workovers

For rig based workover options the following assumptions are made:

- workover options required a Jack-up rig;
- NPT risk allowance used is 25% NPT (including WOW);
- assumes use of rig pits & pumps for wash water storage;
- assumes wash water chemicals dosing in pits (no injection pumps);
- the cost of wash water chemicals, assumed supplied by the storage system operator; and
- costs for one set of completion equipment purchased, no back-up equipment available.

4.10.13 Cost Assumptions - Subsea Monitoring Well

Subsea monitoring wells were envisaged as being required during the pre-FEED work. In the case where this type of well is required to monitor the behaviour of CO_2 in the store at a position remote to the platform location, cost assumptions for these types of wells are as follows:

- subsea well drilled using a Jack-up;
- well follows the slim hole architecture of the injections wells, but with TD in 12 ¼in to remove the 8 ½in section;
- it is assumed there is no coring requirement of the cap rock;
- £100,000 of modifications required to the Jack-up to run subsea tree;
- 13.2ppg brine used at £340/bbl;
- 4 ½in, 12.6lb/ft, 13%Cr material used for completion;
- well assumed to be vertical and formation tops based of W1 well;
- well TD assumed to be 4,386ft TVDSS;
- no wireline logging required;
- GE 13⅝in Subsea Tree System cost £2,000,000, plus £250,000 Engineering & Project Management;
- no costs associated with powering or providing a data link to the subsea tree have been included;
- no interventions required during life of subsea monitoring well have been assumed; and
- subsea well Plugged and Abandoned using a Jack-up rig at a cost of around one hundred-thousand Pounds Sterling per day (year 2015 prices).

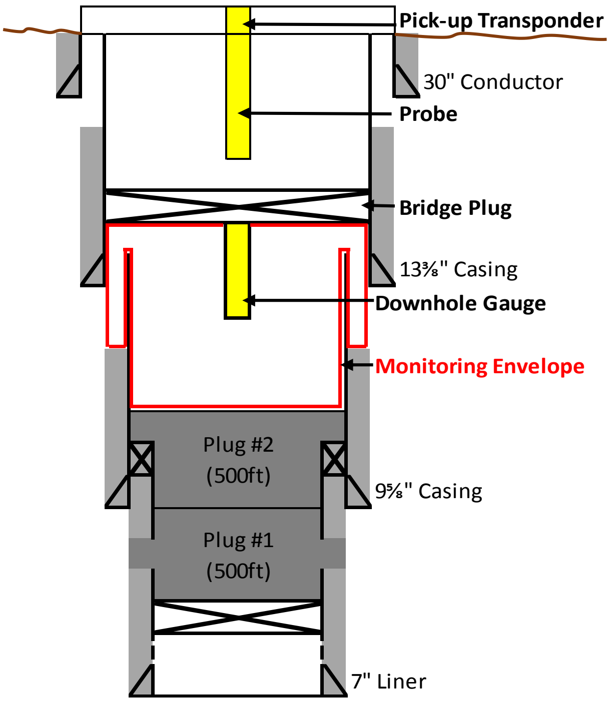
4.10.14 Cost Assumptions – Platform Well Abandonment Plug Integrity Monitoring

For this option the following assumptions have been made:

- the reservoir is abandoned as per well abandonment – Option A;
- the monitoring option is as per Figure 4.20, below.
- mobilisation and de-mobilisation time and costs accounted for in the Platform Plug and Abandonment option;
- the conductor is cut 10ft above the mudline during reservoir abandonment;
- the costs associated with platform topsides and jacket decommissioned are not borne by wells;
- a jack-up is mobilised to cut the conductor 10ft below the mudline and install the gauge monitoring telemetry system (CaTs) mudline equipment and an overtrawlable structure is installed;
- the gauge monitoring system costs £506,509;
- Overtrawlable Structure £89,000;

- it is assumed that at 2,000ft TVDSS the gauge monitoring system will transmit data for 8 years, without requiring intervention work;
- a standby vessel is used yearly to perform a data pick-up using subsea acoustic modem installed in the overtrawlable structure at £50,000 per well visit plus £20,000 for Expro Data upload Service;
- at end of life a DSV is used to recover the overtrawlable structure assumed to take 1 day;
- DSV Vessel day rate of £150,000; and
- DSV Mobilisation costs £100,000.

Figure 4.20: Abandonment integrity monitoring – Wireless Gauges



4.11 Coring Review and Programme Definition

The method by which coring may be accomplished was reviewed during FEED. The coring evaluation programme will include core being taken from the base Rot Halite, Rot Claystone cap rock and a section of the Bunter Sandstone. Notionally, two (2) 120ft long cores will be taken on the first of the development wells. Subsequent coring requirements on the second and third wells will be dependent upon the results of the first well coring.

In order to ensure the carbon capping / storage capacity of the Rot Clay caprock, it is required to recover the entire Rot Clay formation. The 12 ¼in section TD has been chosen to allow the 9 ⅝in casing shoe to be set in the Rot Halite formation at ±5,400ft, ±550ft below the top Rot Halite marker. This should be clear on LWD logs (low GR deflection and high Resistivity deflection) and correspond to halite cuttings. This will allow for a 15ft rathole beneath the 9 ⅝in shoe and a 50ft Rot Halite core to be cut prior to coring the complete Rot Clay caprock.

Previously, successful coring accomplished whilst drilling offset wells in the area of White Rose has been conducted using standard core barrels and a coring system (such as BHI's Jambuster system) to avoid jamming.

4.12 Well Test and Evaluation Review

The requirements for Well Testing and evaluation were reviewed in FEED and are described below. The evaluation requirements are based upon taking measurements of physical properties of the well in order to evaluate the integrity of the well. For example, cement bond logging uses sonic/ultrasonic measurements to detect how well the cement bonds to the casings and liner in the well in order to avoid CO_2 leakage up the sides of the well. Other evaluation measurements include downhole pressure and temperature measurements, as a leakage of CO_2 from the well will become apparent by irregular trends and readings from those established during CO_2 injection without leakage. These latter measurements form part of the MMV plan for well operation, which is referred to below.

The evaluation of the wells for integrity during life cycle service includes initial cement bond logs of the injection liner and the injection (production) casing to confirm zonal isolation and MMV such as downhole Pressure and Temperature. Additionally through lifecycle logging for the detection of corrosion (via multi-finger callipers and sonic wall thickness logs) will be performed during well interventions.

The main MMV equipment in the wells is downhole pressure and temperature monitoring and surface mounted 'A' and 'B' annulus pressure monitoring. The methodology of monitoring the MMV information and what happens in the case where potential problems are detected (such as leaks) will be scoped out in the Wells Operation and Maintenance philosophy (O&MP). The O&MP will be produced during detailed design along with a Well Operation and Maintenance detailed plan.

4.13 Anchor Handling/Rig Mobilisation/Rig Demobilisation

This section describes the relevant parts of the anchor handling, rig mobilisation and rig demobilisation considered in FEED.

A semi-submersible rig was considered in pre-FEED to pre-drill wells with mudline suspension, which would then be tied back after platform installation and therefore anchor handling in the White Rose development area was relevant. During FEED the pre-drilled wells option was discounted due to the extra complexity and cost of the option as compared to drilling after the platform was installed and to that end anchor handling became irrelevant.

In detailed design the wells contractor will select a suitable jack up rig for the drilling and completion of the White Rose wells. The contractor will also arrange for the planning of the rig move to mobilise to the White Rose location.

Rig mobilisation and demobilisation planning will include the selection and contracting of rig move vessels and the services of a rig mover, the planning of rig movements (via a formal rig move plan). The rig move plans will include subsidiary service contracts, such as rig positioning. Once the rig move plans are created, the wells contractor will arrange a rig move meeting with all the key personnel from the rig contractor and all the relevant service companies. The rig move plans will be risk assessed and approved by NGC and its EPCm contractor(s).

On arrival at the White Rose location the rig will be positioned, the legs pinned and pre-loaded to a load value in excess of the maximum bearing capacity which will be seen when operating the rig at the location. Once the pre-loading is complete the rig will be jacked up to drilling elevation and interfaced to the White Rose platform in order to commence well related work. Note that pre-loading a rig involves pumping seawater into tanks on the rig to simulate the loads imposed by the rig on its spud cans. The spud cans are 18m (approx.) diameter 'plates' on the bottom of the legs of the jack up. The spud cans spread the load of the rig across a large area in order to avoid excessive leg penetration during pre-loading and in normal rig operations.

Upon completion of the wells work at the White Rose platform, the rig will be de-interfaced, jacked down and the legs raised ready for demobilisation, with the appropriate rig movement plans as previously noted above.

4.14 Regulatory Consents Register Management

The regulator requires that certain consents are applied for in order to complete certain well related activities, such as permissions to drill, consent to locate a drilling rig and consent to perform site survey activities. The consents requirements for the development well related activities for White Rose will be managed by the contractor selected for detailed design. All drilling and completion activity consent requirements by the UKCS regulatory regime will be adhered to by the detailed design wells contractor, as per the NGC contractual requirements which are within the current tendering package for the White Rose wells design and construction requirements.

The wells contractor will draft and submit the consent applications according to the company's own consents management system, with a register of the required consents (including a time line for their due consideration by the regulator) timeously such that activities are not delayed due to a lack of consent for the activities.

4.15 Well Design Rational

The basis upon which the White Rose CO_2 wells were designed at the FEED stage is described below.

The design basis has considered the following:

- the requirements of CO_2 injection;
- the robustness of the well design for injection and for its isolation in the event of leakage during injection; and
- the ability to install multiple independent abandonment seals for permanent secure storage of CO_2.

4.15.1 Pore / Fracture Pressure Information

The following describes the Pore pressure and Fracture pressure regime in the White Rose store area. Pore pressure is literally the pressure of the liquids or gases resident within the pore spaces of the rock. They are expressed either as absolute pressures or gradients or as equivalent mud weights. Normally pressured rocks typically in the offshore environment have and 8.6ppg equivalent mud weight. This occurs when the liquid (seawater) column is uninterrupted from sea level down to any depth below the seabed. When interruptions to pressure communication exist, greater than 'normal' pressures can exist in the pore spaces of rock, which is typical the deeper a hole is. Mud weights slightly higher than ‘normal’ are typically used in shallow drilling, but as the hole gets deeper, mud weights typically increase to balance (and slightly exceed) the pore pressure of the rock. This concept is known as ‘primary well control’ and means that the hydrostatic pressure in the well is kept greater than the pore pressure in order that the pore fluids do not flow back up the well. The latter circumstance is referred to as a kick or a well control incident. Other reasons for making the mud weight higher include stabilisation of the wellbore. For example in the White Rose area, salts exist. Salts can flow in a ductile or plastic way unless the mud weight is maintained. Flowing salts can lead to pipe becoming stuck in the hole.

The Fracture pressure is a measure of the physical strength of a rock, but expressed either as a pressure or as with pore pressure, as a gradient or an equivalent mud weight. As mud weight is increased the pressure it imposes on the rocks being drilled increases and in some cases the pressure imposed by the mud can approach or even exceed the fracture pressure of the rocks. It is therefore a requirement in planning for and drilling a well to ensure that both the pore pressure is slightly exceeded by the mud weight and also that the mud weight does not exceed the fracture gradient of the rocks.

The following section discusses the requirements of mud weight to address the pore pressure and estimated fracture pressure of the rocks to be drilled by wells in the White Rose area.

The majority of the well is projected to be normally pressured however many offset wells have drilled through the Haisborough Group with mud weights up to 11.8ppg in order to reduce salt mobility. The most common mud weight through the section however was 11.0-11.2ppg.

Information from the 42/25d-3 well provided a pore pressure of 9.2ppg in the Bunter Sandstone. RFT pressures from the 42/25-1 indicate normal formation pressure although a maximum pore pressure of 9.8ppg (equivalent of salt saturated water at reservoir pressure & temperature) was stated in the 42/25d-C Appraisal Well PDDP. A 9.8ppg pore pressure in the Bunter sandstone will be used for worst case design purposes. The pressure of the Bunter shale below the Bunter sand is thought to be normally pressured.

The majority of offset wells in the area provide fracture data from the Lias formation with one well setting casing in the Triton. The Lias offset shows FITs were achieved from 14.9ppg to 16.4ppg EMW. The 42/25d-3 appraisal well was the only offset well to perform an FIT in the Rot Halite, achieving a 14.0ppg EMW.

Table 4.15 below shows the leak off test and formation integrity data with depths and formations.

Table 4.15: Offset LOT/FIT Data

Formation	*Fracture Pressure (ppg)*	*Depth TVDSS (ft)*	*LOT / FIT*	*Well*
Lias	16.4	1640	LOT	42/30-8
Triton	14.3	1712	FIT	42/25-1
Lias	15.7	1866	LOT	43/21a-4
Lias	13.5	1899	FIT	43/21-2
Lias	15.89	2346	FIT	42/25d-3
Lias	14.4	2851	FIT	43/21b-5

Formation	Fracture Pressure (ppg)	Depth TVDSS (ft)	LOT / FIT	Well
Lias	13.0	2904	FIT	42-24-1
Lias	14.9	3192	LOT	42/25-2
Rot Halite	14.0	4403	FIT	42/25d-3

4.15.2 Maximum Predicted Surface Pressure

The 42/25d-D wells are targeting a saline formation, which offset wells have proven that no hydrocarbons are present. The convention to calculate maximum predicted surface pressure for a well is using a gas gradient to surface. Using this methodology the potential surface pressure calculated using a gas gradient from the Bunter Sandstone @ 3,982ft TVDSS (W1 well) is as follows:

Formation Pressure = 9.80ppg x 3,982ft x 0.052

= 2,030psi

Gas gradient of 0.1psi/ft x 3,982ft = 398psi

Surface Pressure = 2,030psi – 398psi

= 1,632psi

The production casing would be designed for pressure of up to 5,500psi to allow the operation of annulus pressure operated tools in the completion. Therefore, the casing is designed far in excess of any formation pressure to surface.

4.15.3 Temperature Information

The bottom hole temperature at 4,501ft TVDSS is estimated to be 131.5ºF. This equates to a temperature gradient of 40°F at seabed + 2°F/100ft.

4.15.4 Well Design

After review of offset well data and extensive experience and knowledge of Southern North Sea drilling the proposed casing scheme for the 42/25d-D wells is based on a slim hole well design. The well design must be functional, feasible and in compliance with corporate policy, customer requirements and relevant statutory procedures. A detailed casing design has been carried out in StressCheck (a Halliburton software programme), the results of which along with all other relevant casing information can be seen in the sections below.

4.15.5 Well Summary

The following is a summary of the proposed sequence of events for a generic 42/25d-D well:

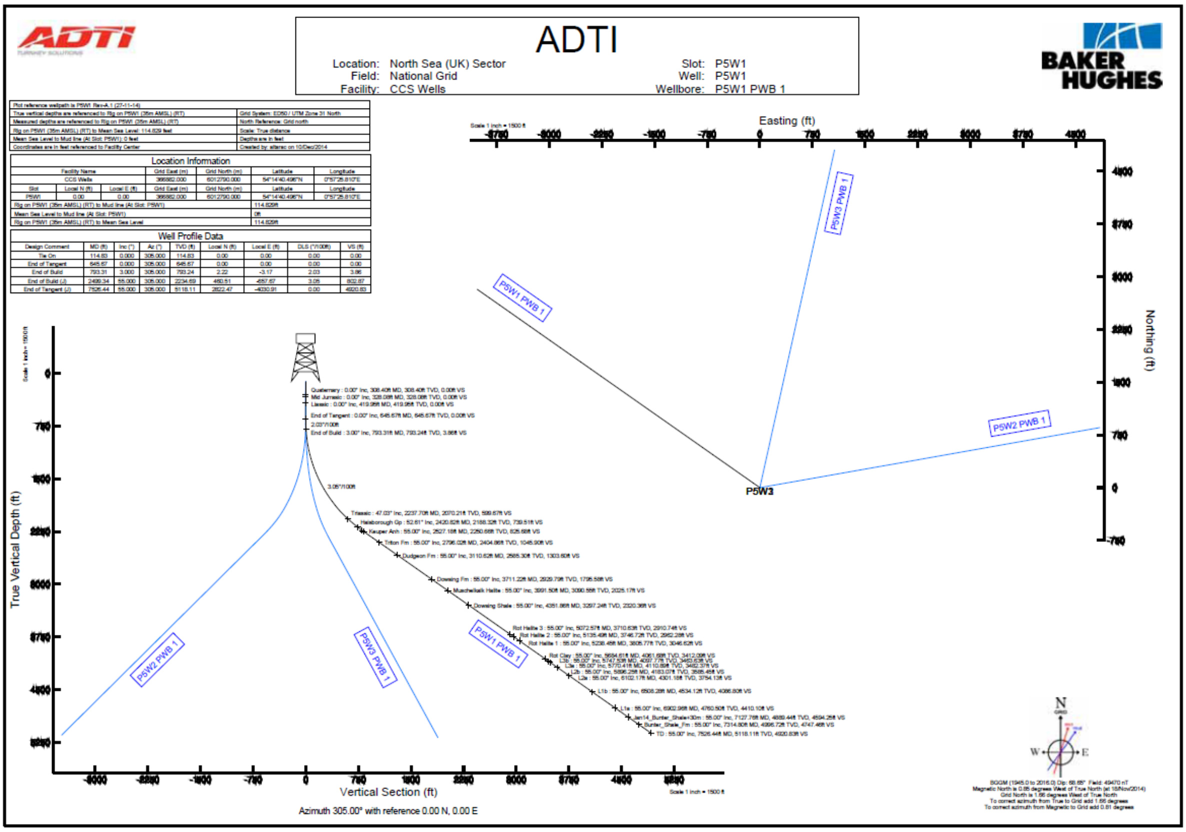
- mobilise rig to 42/25d-D surface location and interface with the White Rose platform;

- skid drilling package over selected slot;
- Spud Well and drill 36in x 26in section with sea water and sweeps to ±565ft MDBRT; displace section to 10.0ppg bentonite mud;
- run 30in x 20in conductor to ±565ft MDBRT and cement to seabed;
- nipple up overshot and diverter;
- drill 17 ½in section with 9.5ppg KCL Polymer Mud to ±2,200ft MDBRT;
- run 13 ⅜in casing to ±2,200ft MDBRT and cement to ±1,500ft;
- pressure test 13 ⅜in casing to 1,700psi on plug bump;
- install surface wellhead & 13 ⅝in BOP. Pressure test BOP and wellhead connector;
- drill out 13 ⅜in casing shoe and perform FIT;
- drill 12 ¼in diameter hole to ±5,400ft MDBRT with 11.0ppg LTOBM;
- run wireline logs;
- run 9 ⅝in casing to ±5,400ft MDBRT and cement back to ±3,000ft MDBRT;
- pressure test 9 ⅝in casing to 5,000psi (subject to completion requirements) on plug bump;
- drill out 9 ⅝in casing shoe and perform FIT. Drill ahead to core point;
- core the Rot Halite, Rot Claystone and the Bunter Sandstone;
- drill remainder of 8 ½in section to TD (±7,500ft MDBRT) with 10.0-10.5ppg LTOBM
- run wireline logs;
- run 7in liner to ±7,500ft MDBRT and cement back to TOL ±4,900ft MDBRT; and
- pressure test 7in liner to 5,500psi (based on completion requirements).

4.15.6 Well Profile

The 3 injection wells will be drilled directionally to a 55° tangent angle in the 17 ½in diameter section of the borehole. This angle will be held through the 12 ¼in and 8 ½in diameter sections onto TD at ±7,550ft MDBRT in the Bunter Shale.

Figure 4.21: Well Profiles



4.15.7 Casing Seat Selection and Casing Design

The casing seat depths below detail a generic injection well design. Casing seat depths for each well can be found in the well montages in this section of the report for each of well W1, W2 and W3.

4.15.8 30in x 20in Conductor

The conductor string with 6 joints below the seabed will be set on depth, based on the length of conductor joints, at ±565ft (172m) MDBRT. It is planned to cement the conductor back to the mudline with 300% excess cement. A riser analysis will be carried out during the detailed design phase to ensure the suitability of the planned conductor string; this may result in a reduction to the OD of the conductor to 26in.

4.15.9 13 3/8in Surface Casing

The 13 ⅜in, 68lb/ft, L80 DINO VAM surface casing is planned to be set at ±1,950ft (594m) TVDSS (±2,200ft (670m) MDBRT) in the Lias formation. L80 in this context refers to the material property and yield strength of the pipe body material. DINO VAM refers to the type of connector used to join pipes together. In this case the connector is a threaded type. This casing string will isolate most of the reactive Lias formation, the casing setting point will be confirmed by depth. The 13 ⅝in BOP stack will be installed after running the casing, allowing the mud system to be swapped to LTOBM and the mud weight to be increased to drill the deeper formations.

4.15.10 9 5/8in Intermediate Casing

A 9 ⅝in, 53.5lb/ft, L80, VAM TOP production casing string will be run and set +/- 65ft above the Rot Clay cap rock in the Rot Halite formation at ±3,850ft (1173m) TVDSS (±5,400ft (1645m) MDBRT). The 9 ⅝in will cover most of the potential mobile salt sections allowing the Rot Halite, Rot Clay and Bunter Sandstone to be cored. It will also provide a production conduit with sufficient burst, collapse and tensional strength to withstand the loads from an injection scenario. The casing setting depth can be moved higher up the well, in the Rot Hailite, should future abandonment requirements dictate the need for a larger cement plug above the Rot Clay cap rock.

4.15.11 7in Production Liner

A 7in, 29lb/ft, SM25CRW-125, Super Duplex VAM TOP HT production liner will be run and set off bottom at ±5,150ft (1570m) TVDSS (±7,550ft (2301m) MDBRT). A liner lap of +/- 500ft will be incorporated and the string cemented to top liner hanger with CO_2 resistant cement. The VAM TOP HT connection is being specified so that the liner can be rotated during the cement job and the 25% Chrome Super Duplex liner is being specified for its inert nature and CO_2 resistant properties. The liner specification selected was chosen after discussions with Sumitomo consultancy and is the highest specification they provide. Through the detailed design phase, once all flow assurance reports have been gathered, further discussion can take place with Sumitomo to select the ideal metallurgy. Issues will arise however in the future abandonment of the wells, chrome liner is renowned for milling problems and a more detailed look into abandonment, with the selected fishing company, will have to take place. Refer to Table 4.16, Casing Schedule.

4.15.12 Casing Schedule

Table 4.16: Casing Schedule

Casing Function	Casing OD (in)	Casing ID (in)	Casing Grade	Casing Weight (lb/ft)	Conn Type	Burst (psi)	Collapse (psi)	Tensile (klb)
Conductor	30	28	X-56	310	Merlin	3267	1681	5102
	20	18.75	X-56	133		3060	1450	2130
Surface / Int.	13 ⅜	12.415	L80	68	DINO VAM	5024	2263	1555
Production	9 ⅝	8.535	L80	53.5	VAM TOP	7930	6620	1244
Production	7	6.184	SM25CR W-125	29	VAM TOP HT	13,110	9,110	1,056

4.15.13 Minimum Casing Design Safety Factors

Table 4.17 below is a summary of the casing design results. It highlights the minimum safety factors for the anticipated load cases during the life cycle of the well. The generic load cases adopted by ADTI often represent the most extreme conditions anticipated in the well.

Table 4.17: Casing Design Safety Factors

Casing	Size (in)	Minimum Design Factors			
		Burst	Collapse	Axial	Triaxial
Conductor	30 x 20	N/A	3.81	N/A	2.58
Surface	13 ⅜	2.89	2.25	3.26	2.69
Production	9 ⅝	1.33	2.97	2.29	1.39
Production	7	2.13	3.25	5.48	2.27
ADTI Minimum Design Factors		**1.2**	**1.0**	**1.5 (Premium Conns) 1.8 (Non-premium Conns)**	**1.25**

The selected casings satisfy the generic load case scenarios outlined in the ADTI casing design guideline document. Buckling and compression loading have been run in StressCheck with no problems noted.

Note that casing mechanical design matches the physical properties of the casing against the load cases it will be exposed to during its service life. For example, the 9-5/8" production casing burst minimum design factor is noted as 1.33 in Table 4.17 above. The lowest acceptable minimum design factor is noted at the bottom of the Table 4.17 in bold text and in the case of the burst load, the minimum acceptable design factor is 1.2. As 1.33 is greater than 1.2, it means this design factor is acceptable.

4.15.14 Casing Wear

Casing wear can be caused while drilling the hole section below the casing section under consideration. The wear removes a certain amount of metal and leads to a loss of material strength, which must be considered during the mechanical design of the casing. Casing wear will generally be greatest at the wells shallowest kick off point, therefore the 13 3/8in casing and 9 5/8in casing will be subject to the greatest forces. StressCheck has been used to measure the 13 3/8in and 9 5/8in casing maximum allowable wear. Casing wear was taken into account in the design safety factors and is not a problem.

4.15.15 Kick Tolerance Methodology

Kick tolerance is an expression of the maximum amount of fluid (a kick) that can enter into the well and yet still be safely controlled within the well without causing the well to fracture at its weakest point (usually thought to be immediately below the last casing point that has been set). Kick tolerance only applies once the secondary well control equipment (the BOPs) has been installed on the well. Although kick tolerance is calculated using mud weights, expected pore pressures and the expected fracture pressure, it is typically expressed as a volume. As such the kick tolerance is the maximum volume of influx (kick) fluid that can be taken into the well and the BOPs having been shut-in (to stop the influx); the influx can be circulated out of the well without fracturing the rock. Kick tolerance is constantly calculated during the drilling process as it changes as the well depth increases and on changes in mud weight.

The kick tolerance calculations below are based on ADTI Minimum Standards for well operations.

Table 4.18: Kick Tolerance Level

Hole Size (for next section)	Required Kick Tolerance Level
16in or greater	100barrels
Less Than 16in	50barrels
6in or less	25 barrels

4.15.16 13 3/8in Shoe Kick Tolerance

A Formation Integrity Test (FIT) will be conducted at the 13 ⅜in casing shoe. After drilling out the shoe, the 12 ¼in section is planned to be drilled to ± 3,850ft (1173m) TVDSS with 11.0ppg LTOBM. National Grid have estimated that the majority of the well will be normally pressured therefore kick tolerance calculations have been calculated based on this. Note that the FIT is a test performed prior to commencing drilling a new hole section, after the setting of a casing string. The test is performed on a short section of new open hole. Pressure is increased in the well to a set pressure, which is determined by the requirements of drilling to the next casing point. Essentially, the FIT value is predicted based upon the expected pore pressure in the next hole section and the test ensures that both the fracture pressure value at the casing shoe is strong enough not to be exceeded due to a kick in the next hole section and also that the cement bond on the outside of the previously set casing will not leak.

A minimum FIT value of 13.5ppge is required to satisfy the ADTI 50bbl kick tolerance requirement. With 11.0ppg mud this provides a kick tolerance of 154bbl, this allows for the planned mud weight to be increased if necessary and still allow a suitable margin for drilling ECD. This is based on a swabbed kick of 8.9ppg at 3,850ft TVDSS from TD of the 12 ¼in section with 11.0ppg mud and 5in drill pipe in the hole.

4.15.17 9 5/8in Shoe Kick Tolerance

A FIT is planned to be conducted at the 9 ⅝in shoe. After drilling out of the shoe, the 8 ½in section will be drilled to well TD at ±5,150ft (±1569m) TVDSS with 10.0ppg to 10.5ppg LTOBM. On the offset wells, the pore pressure of the Bunter Sand has been found to be between 8.79ppg to 9.2ppg EMW. National Grid however has stated in their PDDP that the Saline water is expected to be slightly over pressured at 9.8ppg.

A FIT value of 13.0ppge is planned to satisfy the ADTI 50bbl kick tolerance requirement. In the worst case a 10.0ppg mud will be utilised which provides a 59bbl kick tolerance. This is based on a swabbed kick of 9.8ppg at 5,150ft TVDSS.

4.15.18 Casing Pressure Test Values

Table 4.19: Casing Pressure Test Values

Casing Size (in)	Depth (MDBRT)	Pressure Test Value	Philosophy
30 x 20	565ft	No Test	N/A
13 ⅜	2,200ft	1,700psi	Based on the maximum anticipated surface pressure of 1,468psi from gas to surface from an estimated fracture pressure of 16.4ppg from the shoe.
9 ⅝	5,400ft	5,000psi	Based on the estimated required surface pressure range for well testing and subject to completions requirements.

Casing Size (in)	Depth (MDBRT)	Pressure Test Value	Philosophy
7	7,550ft	5,500psi	Based on the estimated required surface pressure range for well completion.

4.15.19 Bit & Drive Strategy

This section describes the bit and drive strategy assumed for drilling this well. This is subject to further optimisation following a detailed design review. Hydraulics and torque and drag worksheets can be found in a later Section 4.15.29.

The bit is the tool which actually performs the cutting action at the bottom of the drill string. It typical consists of three rotating cones with 'teeth' which chip, crush and scrape rock until the rock fails and forms 'cuttings' in the hole. The method by which the rotation of the string is imparted to the bit is in this case referred to as the 'drive strategy'. Note that rotation is nearly always imparted from the rig's drill string rotating device (the Top Drive) but additionally rotation of the bit can be supplemented by down hole drives, such as mud motors and turbines. The following describes the strategy for the different hole section sizes.

With reference to Hydraulics, this describes the requirements of the circulation of the mud (drilling fluid). Circulation of mud performs many critical tasks, such as removal of the cuttings from the hole. If cuttings were not removed from the hole whilst drilling, the drill string would become stuck. The hydraulics calculations confirm that the pump capacity of the rig is adequate to circulate the mud at an adequate velocity to remove cuttings back to surface, where the cuttings are separated from the mud, before the mud is recirculated.

With reference to torque and drag (calculations), rotation and reciprocation of the drill string inside the well is subject to friction between the drill string and the inside of the well, which influences measured string weight at surface. Drag is the measured difference between the static drill string weight and the dynamic measured weight at surface. Knowledge of the drag is useful in planning the well and feeds into such parameters as the rigs required pulling capacity. Torque is the measured resistance to rotation due to friction but also to the reactive torque from mud motors and also the resistance to rotation due to the action of the bit whilst it is cutting the rock. Torque and drag information can be found in Section 4.15.29 below.

The following sections describe the tools required to perform the drilling.

4.15.20 36in Diameter Hole Section

Bit – 1 x 26in Mill Tooth bit (IADC 115) with 36in diameter hole opener. On the 42/25d-3 well, hang up problems were seen whilst running the conductor. Utilising a 36in bit to drill the top hole section should be looked into during the detailed design phase.

Drive – A motor assembly will be utilised in this section to enhance ROP and also reduce the effects of vibration and shock.

4.15.21 17 ½in Diameter Hole Section

Bit – 1 x 17 ½in Mill Tooth bit (IADC 115).

Drive – The Lias formation will be drilled with a 17 ½in MT bit and bent motor or Rotary Steerable System (RSS) assembly to complete the planned directional work. A rotary steerable system is a tool located at the bottom of the drill string which enables the bit to be tilted or pointed away from the axis of rotation of the drilling assembly (called the BHA or Bottom Hole Assembly) such that controlled directional changes can be imparted on the wellpath and thereby change the inclination or azimuth of the well such that the well progresses in the direction required to hit the ultimate target co-ordinates when the well reaches its planned depth. Note that in section 4.15.24, tables showing BHAs are included. The items within the tables are all essentially either thick walled tubes (called collars or shorter tubes called ponys) or tools such as motors, RSS or stabilisers, all of which are required to control the drilling of the hole. The tables also show drilling parameters, which include RPM (revs per minute at which the bit will be rotated), gpm (gallons per minute at which the drilling fluid will be pumped) and WOB (weight on bit, which is the force intended to be applied to the bit in order to drill efficiently - usually quoted in Klbs or thousands of pounds).

4.15.22 12 ¼in Diameter Hole Section

Bit – 1 x 12 ¼in PDC (IADC M223) bit.

Drive – A RSS will be utilised in this section to hold the tangent angle.

4.15.23 8 ½in Diameter Hole Section

Bit – 1 x 8 ½in PDC bit (IADC M223) to drill through the Bunter Sand.

Drive – A RSS will be utilised in this section to hold the tangent angle through the reservoir.

4.15.24 BHA and Drilling Parameters

4.15.24.1 36in Section

Figure 4.22: 36in BHA

National Grid 42/25d-D									
Mud Weight	8.65	36" Section		11 1/4" Motor + 26" bit + 36" Hole opener + NaviGamma					
Bouyancy Factor is Calculated	0.868	308' - 565'							
Description	O.D.	I.D.	Connections	Length	Accum. Length	Weight In Air	Bouyed Weight	Weight lbs/ft	
26" Bit	26.00		7 5/8" Reg Pin	2.0	2.0	1300	1128	650	
9½" Pony NMDC Inverted	9.50	3.00	7 5/8" Reg Pin x 7 5/8" Reg Box	7.5	9.5	1620	1406	216	
36" Hole opener 6 point	9.50	3.00	7 5/8" Reg Pin x 7 5/8" Reg Box	7.0	16.5	1512	1312	216	
11¼" Ultra X Motor (0°) - 17 1/4" UBHS	11.25	n/a	7 5/8" Reg Box x 7 5/8" Reg Box	32.0	48.5	8000	6944	250	
17 3/8" Non Mag String stabiliser	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	6.0	54.5	1296	1125	216	
9½" Pony NMDC (15')	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	15.0	69.5	3240	2812	216	
Navigamma	9.50	n/a	7 5/8" Reg Box x 7 5/8" Reg Pin	30.0	99.5	6480	5624	216	
17 3/8" Non mag stabiliser	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	6.0	105.5	1296	1125	216	
9 1/2" Non mag filter Sub	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	6.0	115.5	1296	1125	216	
Crossover	9.50	3.00	6 5/8" Reg Box x 7 5/8" Reg Pin	4.0	115.5	864	750	216	
8" Float Sub With Non Ported Float	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	4.0	119.5	600	521	150	
4 x 8" Drill Collars	8.00	2.81	6 5/8" Reg Box x 6 5/8" Reg Pin	120.0	239.5	18000	15623	150	
Crossover	8.00	3.00	NC50 Box x 6 5/8" Reg Pin	4.0	243.5	600	521	150	
9 x 5" HWDP	5.00		NC50 Box x Pin	270.0	513.5	12960	11248	48	
5 " Drill Pipe To Surface	5.00		NC50 Box x Pin					20	
Drilling Parameters									
85-165 rpm									
530-1060 gpm									
WOB 10 -30 Klbs									
Weight Below Jars						**N/A**	**N/A**		
Total BHA Weight						**59,064**	**51,264**		

4.15.24.2 17½in Section

Figure 4.23: 17 1/2in BHA

National Grid 42/25d-D								
Mud Weight	10.00	17½" Section		9½" AutoTrak with CoPilot				
Bouyancy Factor is Calculated	0.847	565' - 2200'						
Description	O.D.	I.D.	Connections	Length	Accum. Length	Weight In Air	Bouyed Weight	Weight lbs/ft
17½" MT Bit	17.50	N/A	7 5/8" Reg Pin	2.0	2.0	200	169	100
9½" AutoTrak Steering head	9.50	N/A	T2 x 7 5/8" Reg Box	8.0	10.0	1728	1464	216
9½" CoPilot	9.50	3.00	T2	9.0	19.0	1944	1647	216
17 3/8" Flex Stab	9.50	3.00	T2	12.0	31.0	2592	2196	216
9½" OnTrak II	9.50	3.00	T2	23.0	54.0	4968	4210	216
17⅜" Mod stab	9.50	3.00	T2	5.0	59.0	1080	915	216
9½" BCPM	9.50	3.00	T2	12.0	71.0	2592	2196	216
Stop sub	9.50	3.00	7 5/8" Reg Box x T2	2.0	73.0	432	366	216
15⅞" Non mag stabiliser	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	6.0	79.0	1296	1098	216
Pony NMDC	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	12.0	97.0	2592	2196	216
14½" Non mag stabiliser	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	6.0	97.0	1296	1098	216
9½" Non mag filter Sub	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	6.0	103.0	1296	1098	216
9½" Float Sub with Ported Float	9.50	3.00	7 5/8" Reg Box x 7 5/8" Reg Pin	4.0	107.0	864	732	216
XO	9.50	3.00	6 5/8" Reg Box x 7 5/8" Reg Pin	4.0	111.0	864	732	216
8" Pony DC	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	15.0	126.0	2250	1906	150
8" NMDC	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	30.0	156.0	4500	3813	150
4 x 8¼" Drill Collars	8.00	2.81	6 5/8" Reg Box x 6 5/8" Reg Pin	120.0	276.0	19800	16777	165
Jar	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	30.0	306.0	4500	3813	150
5 x 8¼" Drill Collar	8.00	2.81	6 5/8" Reg Box x 6 5/8" Reg Pin	150.0	456.0	24750	20971	165
8" Accelerator	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	30.0	486.0	4500	3813	150
1 x 8¼" Drill Collar	8.00	2.81	6 5/8" Reg Box x 6 5/8" Reg Pin	30.0	516.0	4950	4194	165
XO	8.00	2.75	NC50 Box x 6 5/8" Reg Pin	4.0	520.0	600	508	150
3 x 5" HWDP	5.00		NC50 Box x Pin	90.0	610.0	4950	4194	55
5" Drill Pipe To Surface	5.00		NC50 Box x Pin					25
Drilling Parameters								
80-120 rpm								
750-1200 gpm								
WOB 10 - 40 Klbs								
Weight Below Jars						**50,294**	**42,616**	
Total BHA Weight						**88,994**	**75,407**	

4.15.24.312 ¼in Section

Figure 4.24: 12 1/4in BHA

National Grid 42/25d-D								
Mud Weight	**11.50**		**12 1/4" Section**	**9½" AutoTrak with CoPilot**				
Bouyancy Factor is Calculated	**0.824**		**2200' - 5400'**					
Description	**O.D.**	**I.D.**	**Connections**	**Length**	**Accum. Length**	**Weight In Air**	**Bouyed Weight**	**Weight lbs/ft**
12¼" PDC Bit	12.25		6 5/8" Reg Pin	1.0	1.0	100	82	100
9½" AutoTrak Steering head	9.50		T2 x 6 5/8" Reg Box	8.0	9.0	1728	1425	216
12 1/8" Flex Stab	9.50	3.00	T2	11.0	20.0	2376	1959	216
9½" OnTrak II Sensor Sub (with 11 3/4" stab)	9.50	3.00	T2	23.0	43.0	4968	4096	216
12 1/8" Mod Stab	9.50	3.00	T2	6.0	49.0	1296	1068	216
9½" BCPM	9.50	3.00	T2	14.0	63.0	3024	2493	216
Stop sub	9.50	3.00	6 5/8" Reg Box x 9 1/2"T2	3.0	66.0	450	371	150
8" NM Pony	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	10.0	76.0	1500	1237	150
12 1/8" Non mag stab	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	6.0	82.0	900	742	150
Non mag filter Sub	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	5.0	87.0	1080	890	216
Float Sub With Non Ported Float	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	4.0	91.0	864	712	216
4x 8" Drill Collars	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	120.0	211.0	18000	14840	150
Jar	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	30.0	241.0	4500	3710	150
4 x 8" Drill Collar	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	120.0	361.0	18000	14840	150
8" Accelerator	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	30.0	391.0	4500	3710	150
1 x 8" Drill Collar	8.00	3.00	6 5/8" Reg Box x 6 5/8" Reg Pin	30.0	421.0	4500	3710	150
Crossover	8.00	3.00	NC 50 Box x 6 5/8" Reg Pin	4.0	425.0	600	495	150
3 x 5" HWDP	6.63	3.00	NC 50 Box x Pin	90.0	515.0	4320	3562	48
Dart Sub	6.75	2.94	NC50 Box x Pin	5.0	520.0	250	206	50
5 " Drill Pipe	5.00		NC50 Box x Pin	1000.0	1520.0	19500	16076	20
Drilling Parameters 80-120 rpm 550-1000 gpm WOB 20 - 40 Klbs								
Weight Below Jars						**36,286**	**29,915**	
Total BHA Weight						**68,386**	**55,885**	

4.15.24.48 ½in Section

Figure 4.25: 8 1/2in BHA

National Grid 42/25d-D								
Mud Weight Bouyancy Factor is Calculated	10.50 0.840	8½" Section 5400' - 7550'		6¾" AutoTrak with CoPilot				
Description	O.D.	I.D.	Connections	Length	Accum. Length	Weight In Air	Bouyed Weight	Weight lbs/ft
8½" PDC Bit	8.50		4½" Reg Pin	1.0	1.0	0	0	
6¾" Autotrak steering head	8.38		T2 x 4 1/2" Reg Box	6.0	7.0	600	504	100
6¾" CoPilot	6.75		T2 Box X Pin	9.0	16.0	900	756	100
8⅜" Flex Stab	8.38	3.00	T2 Box X Pin	11.0	27.0	1188	998	108
6¾" OnTrak c/w 8¼" stab	6.75		T2 Box X Pin	17.0	44.0	1700	1427	100
6¾" BCPM	6.75		T2 Box X Pin	12.0	56.0	1200	1008	100
Stop Sub	6.75	3.00	NC50 Box x T2 Pin	2.0	58.0	200	168	100
Pony NMDC	6.75	3.00	NC50 Box x Pin	10.0	68.0	1000	840	100
Filter Sub	6.75	3.00	NC50 Box x Pin	6.0	74.0	600	504	100
Float sub with ported float	6.75	3.00	NC50 Box x Pin	4.0	78.0	400	336	100
Circ Sub	6.75	1.55	NC50 Box x Pin	9.0	87.0	900	756	100
8 x 5" HWDP	5.00	3.30	NC50 Box x Pin	240.0	327.0	13200	11084	55
Jars	6.50	2.75	NC50 Box x Pin	30.0	356.0	3000	2519	100
2 x 5" HWDP	5.00	3.30	NC50 Box x Pin	60.0	417.0	3300	2771	55
Accelerator	6.50	2.75	NC50 Box x Pin	30.0	446.0	3000	2519	100
3 x 5" HWDP	5.00	3.30	NC50 Box x Pin	90.0	537.0	4950	4156	55
Dart Sub	7.125	2.11	NC50 Box x Pin	3.0	540.0	165	139	55
5" Drill Pipe to surface	5.00		NC50 Box x Pin					22
Drilling Parameters								
80-120 rpm								
250-600 gpm								
WOB 15 - 30 Klbs								
Weight Below Jars						**21,888**	**18,379**	
Total BHA Weight						**36,303**	**30,483**	

4.15.25 Wellhead and BOP configuration

The 42/25d-D wells will utilise a platform surface wellhead system. The wellhead will consist of the following parts:

- 30in Integral Landing Ring;
- 13 ⅝in Surface Wellhead Assembly;
- 9 ⅝in Surface Casing Hanger; and
- 13 ⅝in Annular Seal.

The 30in conductor will be tied back into the rig diverter system to allow full returns to surface for the 17 ½in diameter hole section.

The 13 ⅜in casing will be landed on the 30in landing ring. The string will also be spaced out to allow for installation of the 13 ⅝in wellhead at the correct elevation. The diverter joint will then be removed and the 13 ⅝in BOP will be installed on to the wellhead for the 12 ¼in section onwards.

The BOP will be stump tested before being run after the 13 ⅜in casing has been cemented. Following this the BOP will be retested in accordance with the rig contractor's policy.

The 9 ⅝in will be landed in the 13 ⅝in wellhead. The string will be spaced out to allow the 9 ⅝in casing hanger to be positioned at the correct elevation within the 13 ⅝in wellhead housing. With the 9 ⅝in casing hanger in the correct position the 13 ⅝in annular seal will be installed.

4.15.26 BOP Pressure Testing Summary

The BOP testing summary will be dependent on the rig selection. The more onerous of the drilling contractor's or the Well construction contractor's procedures will be followed. Typically, a 14 day period between BOPs testing is adopted.

4.15.27 Formation evaluation

4.15.27.1 Cuttings Sampling Intervals

Based on a generic sample collecting programme, this will be finalised during the detailed planning phase.

Table 4.20: Cutting Sampling Intervals

Hole Section	Interval (ft MDBRT)	Sample Interval	Washed & Dried
36in x 26in	300 - 565	Returns to seabed	N/A
17 ½in	565 – 2,200	50ft	3
12¼in	2,200 – 5,400	20ft	3
8 ½in	5,400 – 7,500	20ft	3

Mud samples may also be taken at each of the following points:

- entering Bunter Sandstone;
- drilling Bunter Sandstone; and
- TD prior to logging.

4.15.27.2 Data Acquisition Programme

Table 4.21: Data Acquisition Programme

Hole Section (in)	MWD/LWD	Wireline (Schlumberger)	Coring
36in x 26in	DIR	None	None
17 ½in	GR, DIR/Gyro	PEX – HRLA – Sonic Scanner (Optional LWD available)	None
12¼in	GR, RES, DIR	PEX – AIT – Sonic Scanner (Optional LWD available)	None
8 ½in	GR, RES, DIR	PEX – AIT – Sonic Scanner HNGS – ECS - CMR+ UBI / OBMI2 (optional) MDT - Quicksilver Pressures & samples (optional) MDT -Micro Frac + Vertical Interference Tests (optional)	Rot Halite, Rot Clay & Bunter Sandstone

4.15.28 Coring Programme

The coring evaluation programme will include core being taken from the base Rot Halite, Rot Claystone cap rock and a section of the Bunter Sandstone. An estimated 180ft of formation will be cored.

In order to ensure the carbon capping / storage capacity of the Rot Clay caprock it is required to recover the entire Rot Clay formation. The 12 ¼in section TD has been chosen to allow the 9 ⅝in casing shoe to be set in the Rot Halite formation at ±5,400ft, ±550ft below the top Rot Halite marker which should be clear on LWD logs (low GR deflection and high Resistivity deflection) and correspond to halite cuttings. This will allow for a 15ft rathole beneath the 9 ⅝in shoe and a 50ft Rot Halite core to be cut prior to coring the complete Rot Clay caprock.

WHITE ROSE CARBON CAPTURE & STORAGE PROJECT

Figure 4.26: W1 Well Montage

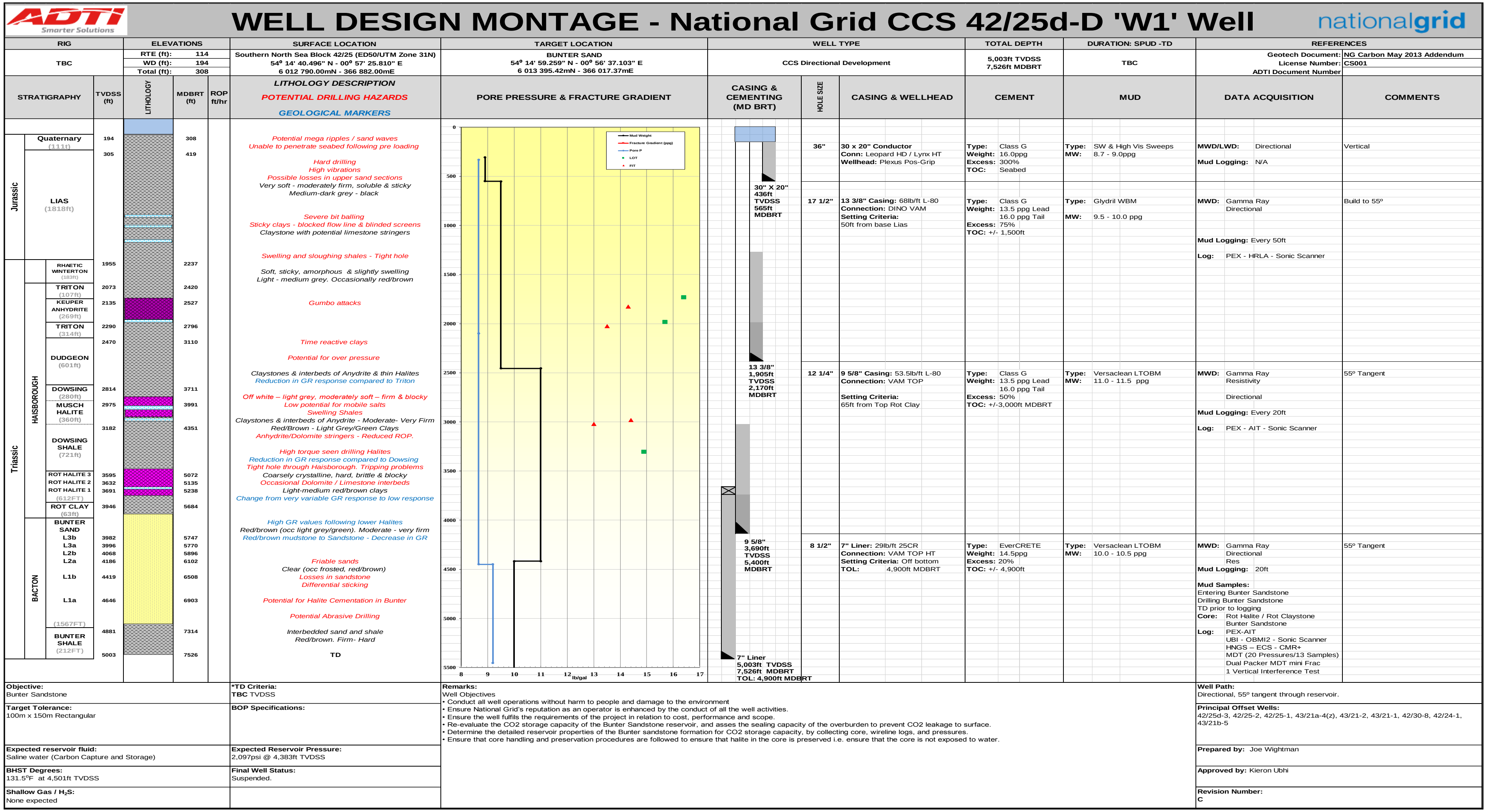


Figure 4.27: W2 Well Montage

WELL DESIGN MONTAGE - National Grid CCS 42/25d-D 'W2' Well

ADTI Smarter Solutions

RIG	ELEVATIONS	SURFACE LOCATION	TARGET LOCATION	WELL TYPE	TOTAL DEPTH	DURATION: SPUD -TD
TBC	RTE (ft): 114 WD (ft): 194 Total (ft): 308	Southern North Sea Block 42/25 (ED50/UTM Zone 31N) 54° 14' 40.496" N - 00° 57' 25.810" E 6 012 790.00mN - 366 882.00mE	BUNTER SAND 54° 14' 47.170" N - 00° 58' 21.078" E 6 012 967.42mN - 367 888.19mE	CCS Directional Development	5,033ft TVDSS 7,557ft MDBRT	TBC

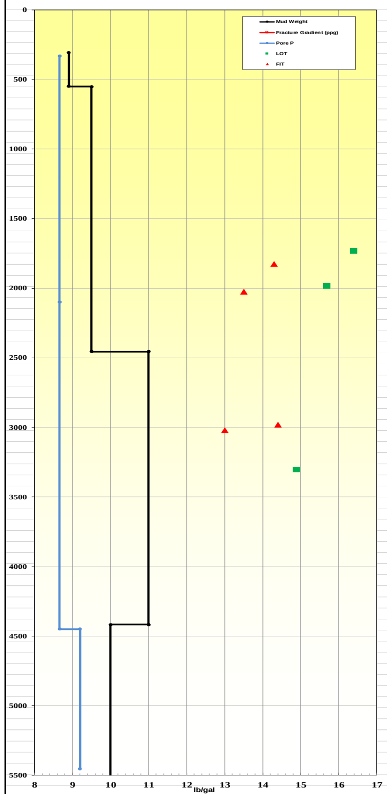
G

ADTI

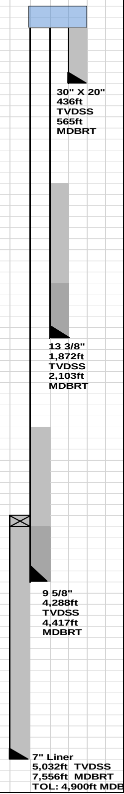
STRATIGRAPHY			TVDSS (ft)	MDBRT (ft)	LITHOLOGY DESCRIPTION / *POTENTIAL DRILLING HAZARDS* / GEOLOGICAL MARKERS
		Quaternary (111ft)	194	308	*Potential mega ripples / sand waves* *Unable to penetrate seabed following pre loading*
Jurassic		LIAS (1759ft)	305	419	*Hard drilling* *High vibrations* *Possible losses in upper sand sections* *Very soft - moderately firm, soluble & sticky* *Medium-dark grey - black* *Severe bit balling* *Sticky clays - blocked flow line & blinded screens* *Claystone with potential limestone stringers* *Swelling and sloughing shales - Tight hole*
Triassic		RHAETIC WINTERTON (153)	1922	2178	*Soft, sticky, amorphous & slightly swelling* *Light - medium grey. Occasionally red/brown*
Triassic	HAISBOROUGH	TRITON (93ft)	2027	2331	
Triassic	HAISBOROUGH	KEUPER ANHYDRITE (253)	2086	2424	*Gumbo attacks*
Triassic	HAISBOROUGH	TRITON (303ft)	2235	2677	
Triassic	HAISBOROUGH	DUDGEON (584ft)	2408	2980	*Time reactive clays* *Potential for over pressure* *Claystones & interbeds of Anydrite & thin Halites* *Reduction in GR response compared to Triton*
Triassic	HAISBOROUGH	DOWSING (269ft)	2742	3564	*Off white – light grey, moderately soft – firm & blocky* *Low potential for mobile salts*
Triassic	HAISBOROUGH	MUSCH HALITE (371ft)	2896	3833	*Swelling Shales* *Claystones & interbeds of Anydrite - Moderate- Very Firm* *Red/Brown - Light Grey/Green Clays*
Triassic	HAISBOROUGH	DOWSING SHALE (733ft)	3110	4204	*Anhydrite/Dolomite stringers - Reduced ROP.* *High torque seen drilling Halites* *Reduction in GR response compared to Dowsing* *Tight hole through Haisborough. Tripping problems*
Triassic	HAISBOROUGH	ROT HALITE 3	3530	4937	*Coarsely crystalline, hard, brittle & blocky*
Triassic	HAISBOROUGH	ROT HALITE 2	3570	5006	*Occasional Dolomite / Limestone interbeds*
Triassic	HAISBOROUGH	ROT HALITE 1 (640ft)	3632	5114	*Light-medium red/brown clays* *Change from very variable GR response to low response*
Triassic	HAISBOROUGH	ROT CLAY (63ft)	3897	5577	
Triassic	BACTON	BUNTER SAND			*High GR values following lower Halites* *Red/brown (occ light grey/green). Moderate - very firm* *Red/brown mudstone to Sandstone - Decrease in GR*
Triassic	BACTON	L3b	3933	5640	
Triassic	BACTON	L3a	3980	5721	
Triassic	BACTON	L2b	4052	5846	
Triassic	BACTON	L2a	4147	6012	*Friable sands* *Clear (occ frosted, red/brown)*
Triassic	BACTON	L1b	4367	6396	*Losses in sandstone* *Differential sticking*
Triassic	BACTON	L1a (1679ft)	4646	6882	*Potential for Halite Cementation in Bunter* *Potential Abrasive Drilling*
Triassic	BACTON	BUNTER SHALE (237ft)	4896	7319	*Interbedded sand and shale* *Red/brown. Firm- Hard*
			5032	7556	TD

LITHOLOGY | ROP ft/hr

PORE PRESSURE & FRACTURE GRADIENT



CASING & CEMENTING (MD BRT)



HOLE SIZE	CASING & WELLHEAD	CEMENT	MUD	DATA ACQ
36"	**30 x 20" Conductor** **Conn:** Leopard HD / Lynx HT **Wellhead:** Plexus Pos-Grip	**Type:** Class G **Weight:** 16.0ppg **Excess:** 300% **TOC:** Seabed	**Type:** SW & High Vis Sweeps **MW:** 8.7 - 9.0ppg	**MWD/LWD:** Direc **Mud Logging:** N/A
17 1/2"	**13 3/8" Casing:** 68lb/ft L-80 **Connection:** DINO VAM **Setting Criteria:** 50ft from base Lias	**Type:** Class G **Weight:** 13.5 ppg Lead 16.0 ppg Tail **Excess:** 75% **TOC:** +/- 1,500ft	**Type:** Glydril WBM **MW:** 9.5 - 10.0 ppg	**MWD:** Gamma Ray Directional **Mud Logging:** Every **Log:** PEX - HRLA -
12 1/4"	**9 5/8" Casing:** 53.5lb/ft L-80 **Connection:** VAM TOP **Setting Criteria:** 65ft from Top Rot Clay	**Type:** Class G **Weight:** 13.5 ppg Lead 16.0 ppg Tail **Excess:** 50% **TOC:** +/-3,000ft MDBRT	**Type:** Versaclean LTOBM **MW:** 11.0 - 11.5 ppg	**MWD:** Gamma Ray Resistivity Directional **Mud Logging:** Every **Log:** PEX - AIT - S
8 1/2"	**7" Liner:** 29lb/ft 25CR **Connection:** VAM TOP HT **Setting Criteria:** Off bottom	**Type:** EverCRETE **Weight:** 14.5ppg **Excess:** 20% **TOC:** +/- 4,900ft	**Type:** Versaclean LTOBM **MW:** 10.0 - 10.5 ppg	**MWD:** Gamma Ray Directional Res **Mud Logging:** 20ft **Mud Samples:** Entering Bunter Sands Drilling Bunter Sandsto TD prior to logging **Core:** Rot Halite / Ro Bunter Sandst **Log:** PEX-AIT UBI - OBMI2 HNGS – ECS MDT (20 Pres Dual Packer M 1 Vertical Inte

Objective: Bunter Sandstone	***TD Criteria:** **TBC** TVDSS
Target Tolerance: 100m x 150m Rectangular	**BOP Specifications:**
Expected reservoir fluid: Saline water (Carbon Capture and Storage)	**Expected Reservoir Pressure:** 2,097psi @ 4,383ft TVDSS
BHST Degrees: 131.5°F at 4,501ft TVDSS	**Final Well Status:** Suspended.
Shallow Gas / H_2S: None expected	

Remarks:
Well Objectives
- Conduct all well operations without harm to people and damage to the environment
- Ensure National Grid's reputation as an operator is enhanced by the conduct of all the well activities.
- Ensure the well fulfils the requirements of the project in relation to cost, performance and scope.
- Re-evaluate the CO2 storage capacity of the Bunter Sandstone reservoir, and asses the sealing capacity of the overburden to prevent CO2 leakage to surface.
- Determine the detailed reservoir properties of the Bunter sandstone formation for CO2 storage capacity, by collecting core, wireline logs, and pressures.
- Ensure that core handling and preservation procedures are followed to ensure that halite in the core is preserved i.e. ensure that the core is not exposed to water.

Well Path:
Directional, 55° tanger

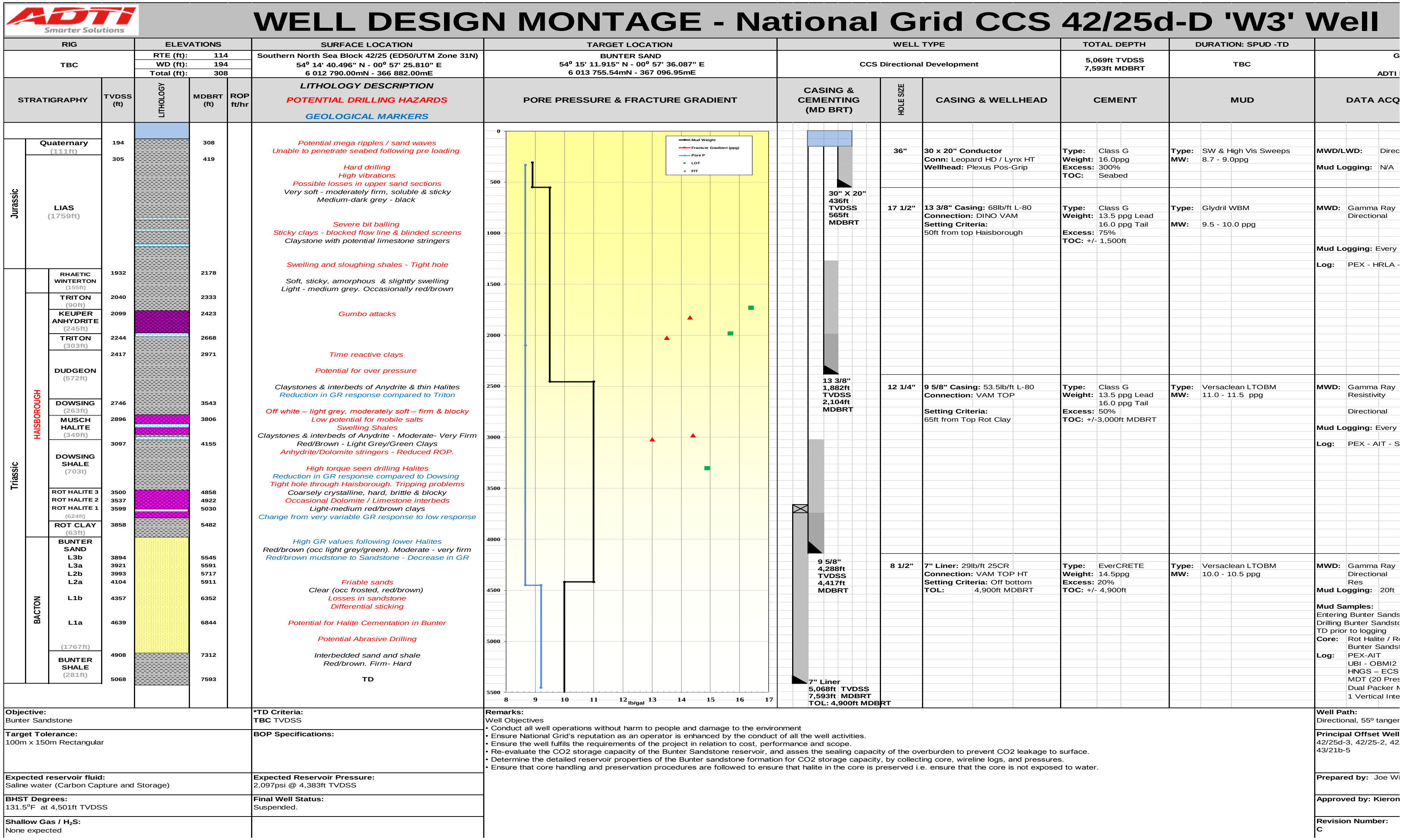
Principal Offset Well
42/25d-3, 42/25-2, 42
43/21b-5

Prepared by: Joe Wi

Approved by: Kieron

Revision Number:
C

Figure 4.28: W3 Well Montage



4.15.29 Hydraulics and Torque/Drag calculations

In order to demonstrate feasibility, hydraulics and Torque/Drag calculations were performed during FEED, as follows.

BHAs used in the Hydraulics report have also been used in the T&D calculation report.

Premium pipe used for calculations: Drill pipe 5in S135 19.5lbs NC50, HWDP 5in HW55 49.77lbs NC50.

Friction factors used for calculations: Cased hole 0.16, Open hole 0.2.

Figure 4.29: 17-1/2in Diameter Hole Hydraulics

ADVANTAGE Hydraulics Spreadsheet Report Including Cuttings Transport

BAKER HUGHES

Case - ADTI P5W1 17 1/2"_Motor

Operator	ADTI / National Grid	**Facility**	
Well	P5W1	**Field**	

General

Max Allw.SPP	6000 psi		
Surface Equip.	Type 4		
Bit Depth	2460.0	**Bit TVD**	2257.2 ft
Bit Nozzles in/32	16\ 5x15	**TFA**	1.0592 in^2
ROP	15.24 m/hr	**RPM**	60 RPM

Drilling Fluid

Mud System	Water Based
Mud Weight	1.1384 sg
PV \ YP	32.00 cP \ 25.00 lbf/100ft^2
Gel Strength, 10s\10min	10 \ 15 lbf/100ft^2
Rheological Model	Herschel-Bulkley
	k 2.830[P] N 0.720[-] YP 8.000[lbf/100ft^2]

Casing / Open Hole

Type	OD in	ID in	Bottom MD ft
Casing	30	28	550.0
Openhole		17 1/2	2460.0

Volumes bbl

Annulus Volume	904.921	**Hole Volume**	987.103
String Displacement	41.790	**String Volume**	40.392

Drill String

Type	Length ft	OD in	ID in	TJ in \ in	Weight lb/ft
DP - NC50 (IF) /S-1...	1933.0	5	4.276	6 5/8 \ 2 3/4	19.50
HWDP-HT50 /HW-100	90.0	5	3	6 5/8 \ 3	50.38
Sub - X/O	3.0	8	3		149.92
DC - API N.C. 56	30.0	8	3		150.00
Accelerator	30.0	8	3		224.65
DC - API N.C. 56	120.0	8	3		150.00
Jar	30.0	8	2.810		223.17
DC - API N.C. 56	120.0	8	3		150.00
NM Sub - float	3.0	8	3		150.00
Sub - X/O	4.0	9 1/2	3		149.92
NM Sub - filter	6.0	9 1/2	3		150.00
NM Stab - string	6.0	9.524	3.118		216.00
MWD - NaviGamma	30.0	9 1/2	3		216.00
DC - 7 5/8 API REG....	15.0	9 1/2	3		217.00
NM Stab - string	6.0	9.524	3.118		216.00
PDM - Ultra X /	32.0	11 1/4	9.173		248.10
INTE... Bit - MT - roll...	2.0	17 1/2			200.00

Flowrate	**USgal/min**	**1200**	**1150**	**1100**	**1050**	**1000**	**950**	**900**	**850**	**800**	**750**
Bit Hydraulics											
SPP	**psi**	3411	3182	2959	2744	2536	2335	2141	1955	1776	1604
Surface HP	**HP**	2385.955	2132.687	1897.339	1679.319	1478.030	1292.872	1123.241	968.529	828.124	701.407
Bit DeltaP	**psi**	974	894	818	746	676	610	548	489	433	380
%SPP	**fraction**	0.2855	0.2811	0.2765	0.2717	0.2667	0.2614	0.2559	0.2500	0.2437	0.2371
Jet Velocity	**m/s**	110.79	106.17	101.56	96.94	92.32	87.71	83.09	78.47	73.86	69.24
Impact Force	**lbf/in^2**	8.924	8.196	7.499	6.832	6.197	5.593	5.020	4.477	3.966	3.486
HSI	**HP/in^2**	2.8736	2.5292	2.2134	1.9251	1.6630	1.4258	1.2123	1.0213	0.8514	0.7016
System Pressure Loss - W/ Cutting Effect											
Surf Equip	**psi**	176	163	150	138	127	115	105	95	85	75
DP,CSG,LNR,TBG	**psi**	678	632	587	544	502	461	422	384	348	313
HWDP/CSDP	**psi**	142	133	123	114	105	97	89	81	73	66
DC/CT	**psi**	450	420	390	362	334	307	281	256	232	209
MWD	**psi**	445	417	390	363	337	311	286	261	237	214
Motor (Op ΔP 74 psi)		382	370	357	344	331	318	305	293	280	267
Additional Tools	**psi**	152	142	132	122	113	104	95	86	78	70
Annulus	**psi**	12	11	11	11	11	11	10	10	10	10
ECD w/ Cut- CSG Shoe	**sg**	1.1426	1.1426	1.1425	1.1425	1.1425	1.1424	1.1424	1.1423	1.1423	1.1422
ECD w/ Cut - BH	**sg**	1.1502	1.1500	1.1498	1.1496	1.1494	1.1492	1.1490	1.1488	1.1486	1.1484
Annular Velocities m/s Flow Regime											
Hole ID in	**String OD in**										
28	5	0.1969 L	0.1887 L	0.1804 L	0.1722 L	0.1640 L	0.1558 L	0.1476 L	0.1394 L	0.1312 L	0.1312 L
17 1/2	5	0.5312 L	0.5091 L	0.4870 L	0.4648 L	0.4427 L	0.4206 L	0.3984 L	0.3763 L	0.3542 L	0.3542 L
17 1/2	8	0.6168 L	0.5911 L	0.5654 L	0.5397 L	0.5140 L	0.4883 L	0.4626 L	0.4369 L	0.4112 L	0.4112 L
17 1/2	9 1/2	0.6917 L	0.6629 L	0.6341 L	0.6053 L	0.5764 L	0.5476 L	0.5188 L	0.4900 L	0.4611 L	0.4611 L
Fluid Circulation Times											
Surface to Bit	**min**	1.45	1.51	1.58	1.66	1.74	1.83	1.93	2.05	2.17	2.32
Bottom Up	**min**	31.75	33.13	34.63	36.28	38.10	40.10	42.33	44.82	47.62	50.79

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Comment 17 1/2" Section - Motor BHA Wellpath: P5W1 Rev-A.1 (27-11-14)

Date 04/Dec/2014 08:09:32
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Figure 4.30: 17-1/2in Diameter Hole Torque and Drag calculations

ADVANTAGE T&D Calculation - Summary Report

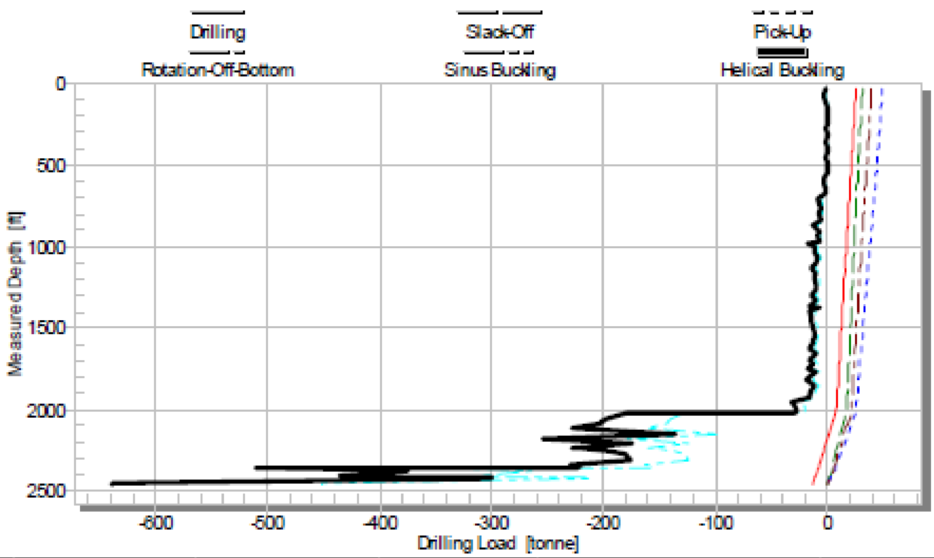
BAKER HUGHES

Case - ADTI P5W1 17 1/2"_Motor

Operator	ADTI / National Grid	**Facility**	
Well	P5W1	**Field**	

Drilling Parameter			Analysis Setup	
Bit Depth	2460	ft	**Calculate Indicated Hook Loads**	Yes
Weight on Bit	14	tonne	**Travelling Assembly Weight**	68 tonne
Torque on Bit	1.823	kft.lb	**Block Efficiency**	1.0000 fraction
Bit Drag Force	-	tonne		
Overpull Force	-	tonne	**Include Bending Influence**	Yes
ROB Torque Resistance	-	kft.lb	**Buckling Criterion**	Conservative - (Unloading)

Calculated Loads along String vs. Measured Depth



	Hook Load @ 0.0 MD tonne	Indicated Hook Load tonne	Rotary Torque kft.lb		Axial Velocity m/hr	Rotary Speed RPM
Drilling	26	94	7.422	**ROP**	15.24	60
Slack-Off	31	100	0.000	**RIH**	304.80	0
Pick-Up	50	118	0.000	**POOH**	304.80	0
Rot off Btm	40	108	6.409	**Rotational Discontinuity**	No	

Drag tonne					Stretch m	
Drilling	0	**Drill String Twist**	0 rev	373 grad	**Drilling**	0.14
Slack-Off	8	**Max Allowable HookLoad (@min. Yield)**	323 tonne		**Slack-Off**	0.20
Pick-Up	10	**DrillString Weight in Air**	58 tonne		**Pick-Up**	0.32
		Bit To Neutral Point (Drilling)	280.3 ft		**Rot off Btm**	0.26
		Sin. Buckling WOB	31 tonne			

	Drawwork HP	at Fastline Load tonne	Rotary HP	Mud Pumps HP	Max Flowrate USgal/min	Max SPP psi
Power	131.033 P	118 P	84.727 D	5595.734	1600	6000

	O.Mode	Stress MPa	at MD ft		O.Mode	Safety Factor	at MD ft
Max Axial	P	142.447	0.0	**Min Yield Safety Factor**	P	4.50	967.8
Max Torsional	D	53.796	0.0	**Min Fatigue Safety Factor**	D	1.81	967.8
Max Bending	P	97.208	967.8				
Max Combined	P	206.704	967.8				
D Drilling	S Slack-Off	P Pick-Up	R Rot off Btm		i input	c calculated	

Comment 17 1/2" Section - Motor BHA Wellpath: P5W1 Rev-A.1 (27-11-14)

Date 04/Dec/2014 08:10:14
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Figure 4.31: 12-1/4in Diameter Hole Hydraulics

ADVANTAGE Hydraulics Spreadsheet Report Including Cuttings Transport

BAKER HUGHES

Case - ADTI P5W1 12 1/4"

Operator	ADTI / National Grid	**Facility**	
Well	P5W1	**Field**	

General

Max Allw.SPP			6000	**psi**
Surface Equip.			Type 4	
Bit Depth	4420.0	**Bit TVD**	3530.4	**ft**
Bit Nozzles in/32	6x16	**TFA**	1.1781	**in^2**
ROP	45.72 **m/hr**	**RPM**	150	**RPM**

Drilling Fluid

Mud System	Oil Based	
Mud Weight	1.3181	**sg**
PV \ YP	30.00 **cP** \ 15.00	**lbf/100ft^2**
Gel Strength, 10s\10min	15 \ 20	**lbf/100ft^2**
Rheological Model	Robertson-Stiff	
	k 0.450[P] **N** 0.948[-] **sri** 191.387[1/s]	

Casing / Open Hole

Type	OD in	ID in	Bottom MD ft
Riser		27	320.0
Casing	13 3/8	12.350	2455.0
Openhole		12 1/4	4420.0

Volumes bbl

Annulus Volume	698.742	**Hole Volume**	829.392
String Displacement	57.352	**String Volume**	73.298

Drill String

Type	Length ft	OD in	ID in	TJ in \ in	Weight lb/ft
DP - NC50 (IF) /S-1...	3881.3	5	4.276	6 5/8 \ 2 3/4	19.50
HWDP-NC50 /HW-55	90.0	5	3	6 5/8 \ 3 1/16	50.10
Sub - X/O	3.0	8	2.810		149.92
DC - API N.C. 56	30.0	8	3		150.00
Accelerator	30.0	8	3		224.65
DC - API N.C. 56	120.0	8	3		150.00
Jar	30.0	8	2.810		223.17
DC - API N.C. 56	120.0	8	3		150.00
NM Sub - float	3.0	8	3		150.00
NM Sub - filter	6.0	8	3		150.00
NM Stab - string	6.0	8	2 13/16		216.00
Sub - stop	3.0	9 1/2	3		216.00
BCPM Std 57mm /INTE...	12.7	9 1/2	3		329.98
MWD - stab - mod	6.0	9 1/2	2 13/16		216.00
ONTRAK II /INTEQ	23.0	9 1/2	2.810		329.76
Sub - stop	3.0	9 1/2	3		216.00
DC - 7 5/8 API REG....	10.0	9 1/2	3		217.00
NM Stab - string	6.0	8	2 13/16		216.00
PDM - Ultra XL /INT...	36.1	9 1/2	7.600		164.93
Bit - PDC - fixed c...	1.0	12 1/4			200.00

Flowrate	**USgal/min**	**1000**	**950**	**900**	**850**	**800**	**750**	**700**	**650**	**600**	**550**
Bit Hydraulics											
SPP	**psi**	4084	3765	3460	3168	2889	2623	2372	2127	1892	1672
Surface HP	**HP**	2380.707	2084.898	1815.066	1569.442	1347.088	1146.877	967.770	806.061	661.842	535.992
Bit DeltaP	**psi**	730	659	591	527	467	410	358	308	263	221
%SPP	**fraction**	0.1787	0.1749	0.1708	0.1664	0.1617	0.1565	0.1508	0.1449	0.1388	0.1320
Jet Velocity	**m/s**	83.01	78.86	74.71	70.56	66.41	62.26	58.10	53.95	49.80	45.65
Impact Force	**lbf/in^2**	13.167	11.883	10.665	9.513	8.427	7.406	6.452	5.563	4.740	3.983
HSI	**HP/in^2**	3.6620	3.1397	2.6696	2.2489	1.8749	1.5449	1.2560	1.0057	0.7910	0.6093
System Pressure Loss - W/ Cutting Effect											
Surf Equip	**psi**	141	128	116	105	94	84	74	65	56	48
DP,CSG,LNR,TBG	**psi**	1302	1195	1092	992	897	806	719	636	558	484
HWDP/CSDP	**psi**	150	138	126	114	103	92	82	72	63	54
DC/CT	**psi**	443	406	370	336	303	272	242	214	187	161
MWD	**psi**	574	525	479	435	394	355	319	280	238	200
Motor (Op ΔP 250 psi)		499	487	475	462	450	437	425	412	400	387
Additional Tools	**psi**	180	165	150	137	123	110	98	87	76	65
Annulus	**psi**	66	63	62	60	58	56	55	54	52	51
ECD w/ Cut- CSG Shoe	**sg**	1.3482	1.3474	1.3467	1.3460	1.3454	1.3447	1.3441	1.3434	1.3428	1.3422
ECD w/ Cut - BH	**sg**	1.3611	1.3595	1.3584	1.3572	1.3560	1.3549	1.3540	1.3531	1.3522	1.3514
Annular Velocities m/s Flow Regime											
Hole ID in	**String OD in**										
27	5	0.1769 L	0.1680 L	0.1592 L	0.1503 L	0.1415 L	0.1326 L	0.1238 L	0.1150 L	0.1061 L	0.1061 L
12.350	5	0.9764 L	0.9276 L	0.8787 L	0.8299 L	0.7811 L	0.7323 L	0.6835 L	0.6346 L	0.5858 L	0.5858 L
12 1/4	5	0.9956 L	0.9458 L	0.8960 L	0.8462 L	0.7965 L	0.7467 L	0.6969 L	0.6471 L	0.5973 L	0.5973 L
12 1/4	8	1.4467 T	1.3744 T	1.3021 L	1.2297 L	1.1574 L	1.0851 L	1.0127 L	0.9404 L	0.8680 L	0.8680 L
12 1/4	9 1/2	2.0817 T	1.9776 T	1.8735 T	1.7694 T	1.6653 T	1.5613 T	1.4572 L	1.3531 L	1.2490 L	1.2490 L
Fluid Circulation Times											
Surface to Bit	**min**	3.16	3.33	3.52	3.72	3.95	4.22	4.52	4.87	5.27	5.75
Bottom Up	**min**	29.51	31.06	32.79	34.72	36.89	39.35	42.16	45.40	49.18	53.66

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Comment 12¼" Section - BHA Wellpath: P5W1 Rev-A.1 (27-11-14)

Date 04/Dec/2014 08:15:42
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Figure 4.32: 12-1/4in Diameter Hole Torque and Drag calculations

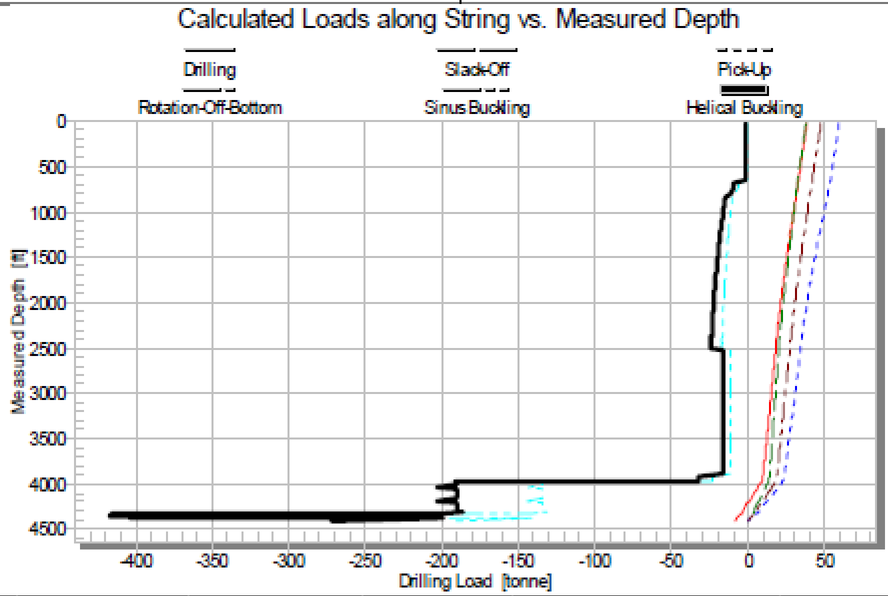
ADVANTAGE T&D Calculation - Summary Report

BAKER HUGHES

Case - ADTI P5W1 12 1/4"

Operator	ADTI / National Grid	**Facility**	
Well	P5W1	**Field**	

Drilling Parameter			Analysis Setup	
Bit Depth	4420	ft	**Calculate Indicated Hook Loads**	Yes
Weight on Bit	9	tonne	**Travelling Assembly Weight**	68 tonne
Torque on Bit	6.000	kft.lb	**Block Efficiency**	1.0000 fraction
Bit Drag Force	-	tonne		
Overpull Force	-	tonne	**Include Bending Influence**	Yes
ROB Torque Resistance	-	kft.lb	**Buckling Criterion**	Conservative - (Unloading)



	Hook Load @ 0.0 MD tonne	Indicated Hook Load tonne	Rotary Torque kft.lb		Axial Velocity m/hr	Rotary Speed RPM
Drilling	39	107	12.502	**ROP**	45.72	150
Slack-Off	38	106	0.000	**RIH**	304.80	0
Pick-Up	60	128	0.000	**POOH**	304.80	0
Rot off Btm	48	116	7.278	**Rotational Discontinuity**	No	

	Drag tonne	Drill String Twist	3 rev	43 grad		Stretch m
Drilling	0	**Max Allowable HookLoad (@min. Yield)**	323 tonne		**Drilling**	0.38
Slack-Off	10	**DrillString Weight in Air**	81 tonne		**Slack-Off**	0.41
Pick-Up	12	**Bit To Neutral Point (Drilling)**	210.5 ft		**Pick-Up**	0.67
		Sin. Buckling WOB	31 tonne		**Rot off Btm**	0.53

	Drawwork HP	at Fastline Load tonne	Rotary HP	Mud Pumps HP	Max Flowrate USgal/min	Max SPP psi
Power	142.332 P	128 P	356.772 D	4196.800	1200	6000

	O.Mode	Stress MPa	at MD ft		O.Mode	Safety Factor	at MD ft
Max Axial	P	171.735	0.0	**Min Yield Safety Factor**	D	4.58	803.8
Max Torsional	D	90.610	0.0	**Min Fatigue Safety Factor**	D	2.76	803.8
Max Bending	P	53.053	803.8				
Max Combined	P	203.125	803.8				
D Drilling	**S Slack-Off**	**P Pick-Up**	**R Rot off Btm**		**i input**	**c calculated**	

Comment 12¼" Section - Motor BHA Wellpath: P5W1 Rev-A.1 (27-11-14)

Date 04/Dec/2014 08:14:55
Prepared by altarac

Figure 4.33: 8-1/2in Diameter Hole Hydraulics

ADVANTAGE Hydraulics Spreadsheet Report Including Cuttings Transport

BAKER HUGHES

Case - ADTI P5W1 8 1/2"_NaviTrak

Operator	ADTI / National Grid	**Facility**	
Well	P5W1	**Field**	

General

Max Allw.SPP		6000 **psi**	
Surface Equip.			Type 4
Bit Depth	5559.0	**Bit TVD**	4270.2 **ft**
Bit Nozzles in/32	3x12\ 3x14	**TFA**	0.7823 **in^2**
ROP	45.72 **m/hr**	**RPM**	150 **RPM**

Drilling Fluid

Mud System	Oil Based
Mud Weight	1.3181 **sg**
PV \ YP	30.00 **cP** \ 15.00 **lbf/100ft^2**
Gel Strength, 10s\10min	15 \ 20 **lbf/100ft^2**
Rheological Model	Herschel-Bulkley
	k 0.380[P] **N** 0.969[-] **YP** 15.000[lbf/100ft^2]

Casing / Open Hole

Type	OD in	ID in	Bottom MD ft
Casing	9 5/8	8.535	4417.0
Openhole		8 1/2	5559.0

Volumes bbl

Annulus Volume	248.682	**Hole Volume**	392.720
String Displacement	55.555	**String Volume**	88.483

Drill String

Type	Length ft	OD in	ID in	TJ in \ in	Weight lb/ft
DP - NC50 (IF) /S-1...	4717.6	5	4.276	6 5/8 \ 2 3/4	19.50
HWDP-HT50 /HW-100	180.0	5	3	6 5/8 \ 3	50.38
Accelerator	30.0	6 1/2	3		100.00
HWDP-HT50 /HW-100	90.0	5	3	6 5/8 \ 3	50.38
Jar	30.0	6 3/4	3		100.00
HWDP-HT50 /HW-100	360.0	5	3	6 5/8 \ 3	50.38
DC - API N.C. 50	30.0	6 3/4	2.810		108.50
NM DC - API N.C. 50	60.0	6 3/4	2.810		108.50
NM Stab - string	5.5	6 3/4	2 1/4		216.00
MWD - NaviTrak	32.0	6 3/4	3		100.00
NM Stab - string	5.5	6 3/4	2 1/4		216.00
DC - API N.C. 50	12.0	6 3/4	2 1/4		108.50
Stab - NB	5.5	6 3/4	2 1/4		100.00
Bit - PDC - fixed c...	1.0	8 1/2			200.00

Flowrate	**USgal/min**	**600**	**550**	**500**	**450**	**400**	**350**	**300**	**250**	**200**	**150**
Bit Hydraulics											
SPP	**psi**	2503	2152	1839	1548	1283	1042	827	637	473	350
Surface HP	**HP**	875.283	689.758	535.975	406.114	299.022	212.675	144.644	92.846	55.132	30.631
Bit DeltaP	**psi**	596	501	414	335	265	203	149	103	66	37
%SPP	**fraction**	0.2380	0.2327	0.2250	0.2164	0.2065	0.1945	0.1801	0.1623	0.1400	0.1063
Jet Velocity	**m/s**	75.00	68.75	62.50	56.25	50.00	43.75	37.50	31.25	25.00	18.75
Impact Force	**lbf/in^2**	14.825	12.457	10.295	8.339	6.589	5.045	3.706	2.574	1.647	0.927
HSI	**HP/in^2**	3.7255	2.8696	2.1560	1.5717	1.1038	0.7395	0.4657	0.2695	0.1380	0.0582
System Pressure Loss - W/ Cutting Effect											
Surf Equip	**psi**	56	48	40	33	27	21	16	12	8	5
DP,CSG,LNR,TBG	**psi**	687	595	509	428	353	284	222	165	116	88
HWDP/CSDP	**psi**	427	369	315	264	217	174	135	100	69	43
DC/CT	**psi**	113	97	83	69	57	45	35	26	18	11
MWD	**psi**	251	214	180	149	120	92	68	47	30	17
Additional Tools	**psi**	82	71	61	51	42	33	26	19	13	8
Annulus	**psi**	291	256	238	219	202	190	178	165	153	140
ECD w/ Cut- CSG Shoe	**sg**	1.4553	1.4397	1.4320	1.4240	1.4170	1.4111	1.4053	1.3995	1.3936	1.3877
ECD w/ Cut - BH	**sg**	1.4752	1.4564	1.4466	1.4363	1.4272	1.4206	1.4139	1.4073	1.4007	1.3939
Annular Velocities m/s Flow Regime											
Hole ID in	**String OD in**										
8.535	5	1.5614 T	1.4313 L	1.3011 L	1.1710 L	1.0409 L	0.9108 L	0.7807 L	0.6506 L	0.5205 L	0.5205 L
8 1/2	5	1.5811 T	1.4493 T	1.3176 L	1.1858 L	1.0541 L	0.9223 L	0.7905 L	0.6588 L	0.5270 L	0.5270 L
8 1/2	6 3/4	2.7993 T	2.5660 T	2.3327 T	2.0995 T	1.8662 T	1.6329 L	1.3996 L	1.1664 L	0.9331 L	0.9331 L
Fluid Circulation Times											
Surface to Bit	**min**	6.37	6.94	7.64	8.49	9.55	10.91	12.73	15.28	19.10	25.46
Bottom Up	**min**	17.75	19.36	21.30	23.67	26.63	30.43	35.50	42.60	53.25	71.00

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Comment 8 1/2" Section - NaviTrak BHA Wellpath: P5W1 Rev-A.1 (27-11-14)

Date 04/Dec/2014 08:22:52
Prepared by altarac

Figure 4.34: 8-1/2in Diameter Hole Torque and Drag calculations

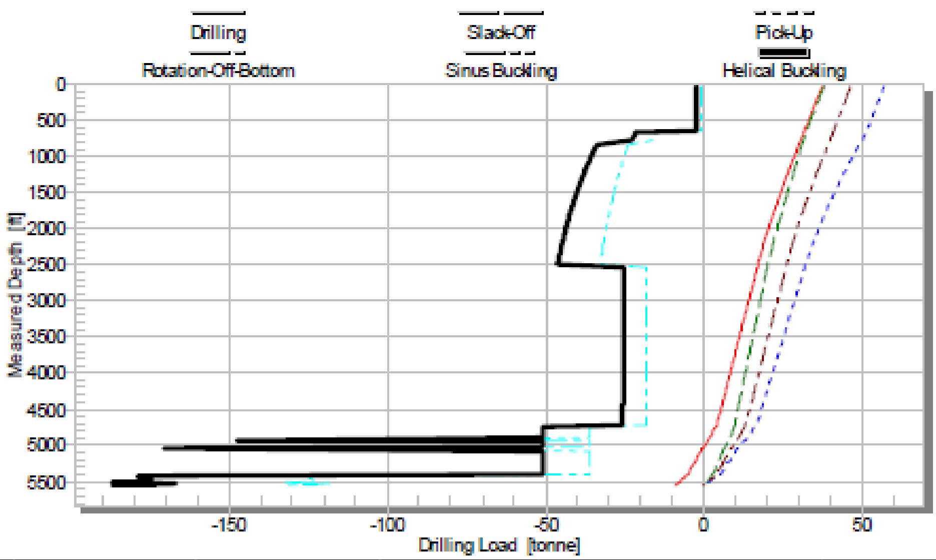
ADVANTAGE T&D Calculation - Summary Report

BAKER HUGHES

Case - ADTI P5W1 8 1/2"_NaviTrak

Operator	ADTI / National Grid	**Facility**	
Well	P5W1	**Field**	

Drilling Parameter			Analysis Setup	
Bit Depth	5559	ft	**Calculate Indicated Hook Loads**	Yes
Weight on Bit	9	tonne	**Travelling Assembly Weight**	68 tonne
Torque on Bit	6.000	kft.lb	**Block Efficiency**	1.0000 fraction
Bit Drag Force	-	tonne		
Overpull Force	-	tonne	**Include Bending Influence**	Yes
ROB Torque Resistance	-	kft.lb	**Buckling Criterion**	Conservative - (Unloading)



	Hook Load @ 0.0 MD tonne	Indicated Hook Load tonne	Rotary Torque kft.lb		Axial Velocity m/hr	Rotary Speed RPM
Drilling	38	106	11.005	**ROP**	45.72	150
Slack-Off	38	106	0.000	**RIH**	304.80	0
Pick-Up	57	125	0.000	**POOH**	304.80	0
Rot off Btm	47	115	5.773	**Rotational Discontinuity**	No	

	Drag tonne				Stretch m
		Drill String Twist	3 rev 144 grad		
Drilling	0	**Max Allowable HookLoad (@min. Yield)**	323 tonne	**Drilling**	0.38
Slack-Off	9	**DrillString Weight in Air**	76 tonne	**Slack-Off**	0.45
Pick-Up	11	**Bit To Neutral Point (Drilling)**	537.8 ft	**Pick-Up**	0.71
		Sin. Buckling WOB	31 tonne	**Rot off Btm**	0.58

	Drawwork HP	at Fastline Load tonne	Rotary HP	Mud Pumps HP	Max Flowrate USgal/min	Max SPP psi
Power	139.527 P	125 P	314.051 D	2273.267	650	6000

	O.Mode	Stress MPa	at MD ft		O.Mode	Safety Factor	at MD ft
Max Axial	P	164.469	0.0	**Min Yield Safety Factor**	P	4.80	803.8
Max Torsional	D	79.760	0.0	**Min Fatigue Safety Factor**	D	2.85	803.8
Max Bending	P	51.819	803.8				
Max Combined	P	193.861	803.8				
D Drilling	**S Slack-Off**	**P Pick-Up**	**R Rot off Btm**		**i input**	**c calculated**	

Comment 8 1/2" Section - NaviTrak BHA Wellpath: P5W1 Rev-A.1 (27-11-14)

Date 04/Dec/2014 08:23:28
Prepared by altarac

4.16 Notification and submission preparation

The HSE notification and submission preparation requirements for the development well related activities for White Rose will be managed by the contractor selected for detailed design phase of the project.

The notifications and submission will include all those required to comply with the UKCS regulatory regime.

4.17 Wellheads, Trees and Overtrawlable Structure Definition

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

A wellhead essentially forms the top of the well. The well is formed of casings and in order to form a pressure seal at the top of each of the casings, a wellhead is required. The wellhead has valves which can be used to access the annuli between each of the casings.

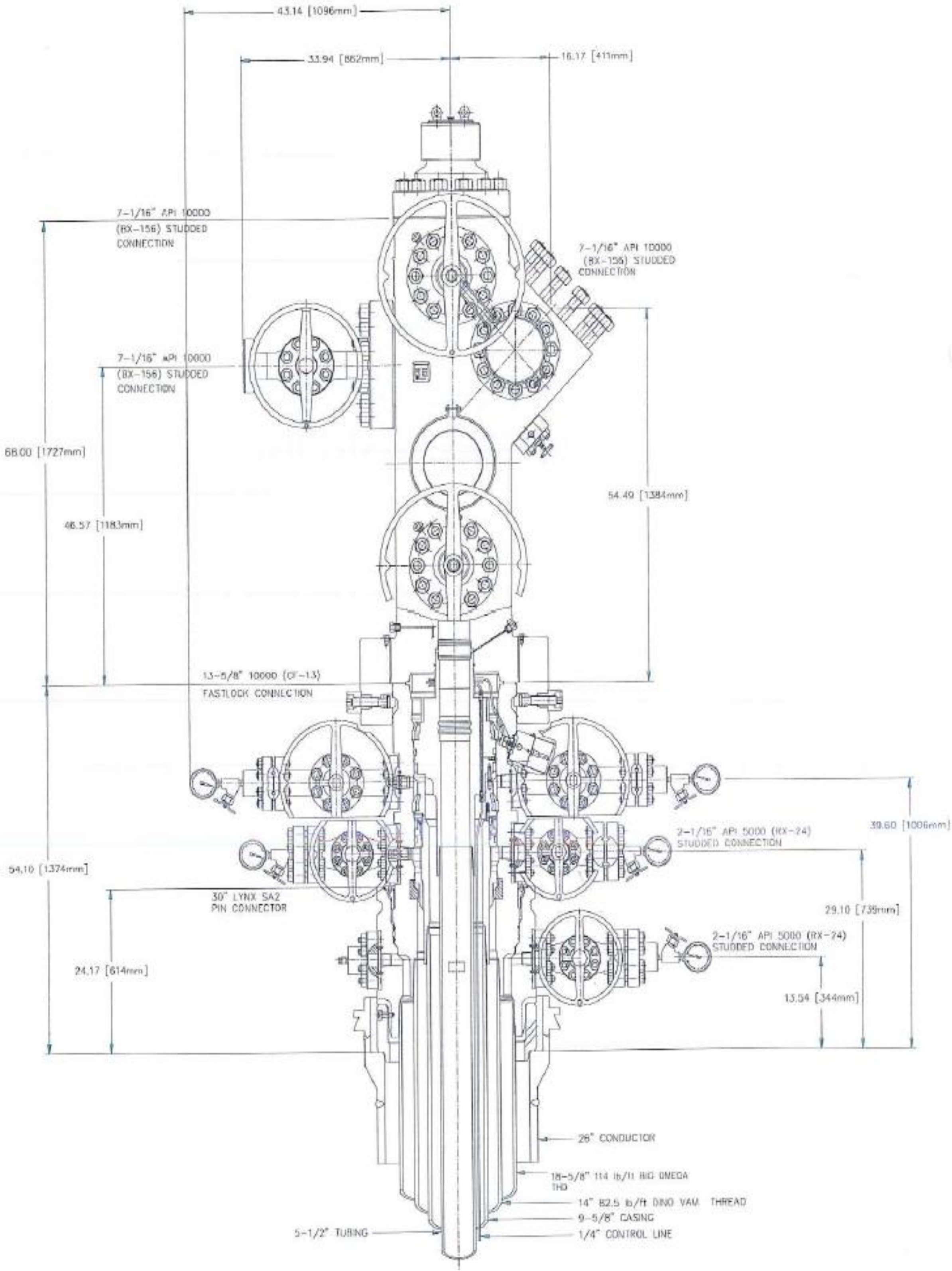
A tree (or Christmas tree) is located on top of the wellhead and forms the access to the CO_2 injection tubing. The tree is only located onto the top of the wellhead prior to the operation of the well as a CO_2 injection conduit. The tree is linked to the CO_2 import manifold by way of a metrology spool (a piece of flanged piping connected on one end to the injection wing valve and on the other end to the CO_2 import manifold).

Where reference is made to cladding below, it refers to corrosion resistant material added to the metal forming the inside surfaces of a wellhead or tree component. This material is added to the tree in order that the body material of the tree is protected for CO_2 corrosion.

4.17.1 Wellhead

It is envisaged that a standard design compact wellhead in slim hole configuration could be used for the 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.

Figure 4.35: Wellhead System



A number of wellhead companies could supply such a wellhead. A version of the Cameron SSMC design is in Figure 4.35 above as reference. Dependant on the pressure test requirement for the completion, a 10,000psi system may be required, (although a 5,000psi system is illustrated). For this wellhead, the installation sequence would be:

1. run conductor, hang off in rigs tension ring, cement and then nipple up diverter joint;
2. drill 17 ½in diameter hole and run 13 3/8in casing with 13 5/8in compact wellhead and land on integral landing shoulder in pin at conductor top;
3. cement 13 3/8in;
4. nipple down diverter joint and any space out joints;
5. nipple up 13 5/8in BOP;
6. drill 12 ¼in diameter hole and run 9 5/8in casing. Land off 9 5/8in in compact wellhead;
7. cement 9 5/8in casing, set and test 9 5/8in seal assembly;
8. drill 8 ½in diameter hole and set liner downhole;
9. run lower completion;
10. run upper completion, land tubing hanger in wellhead and test;
11. nipple up and test Christmas Tree; and then
12. perform downhole work and suspend well.

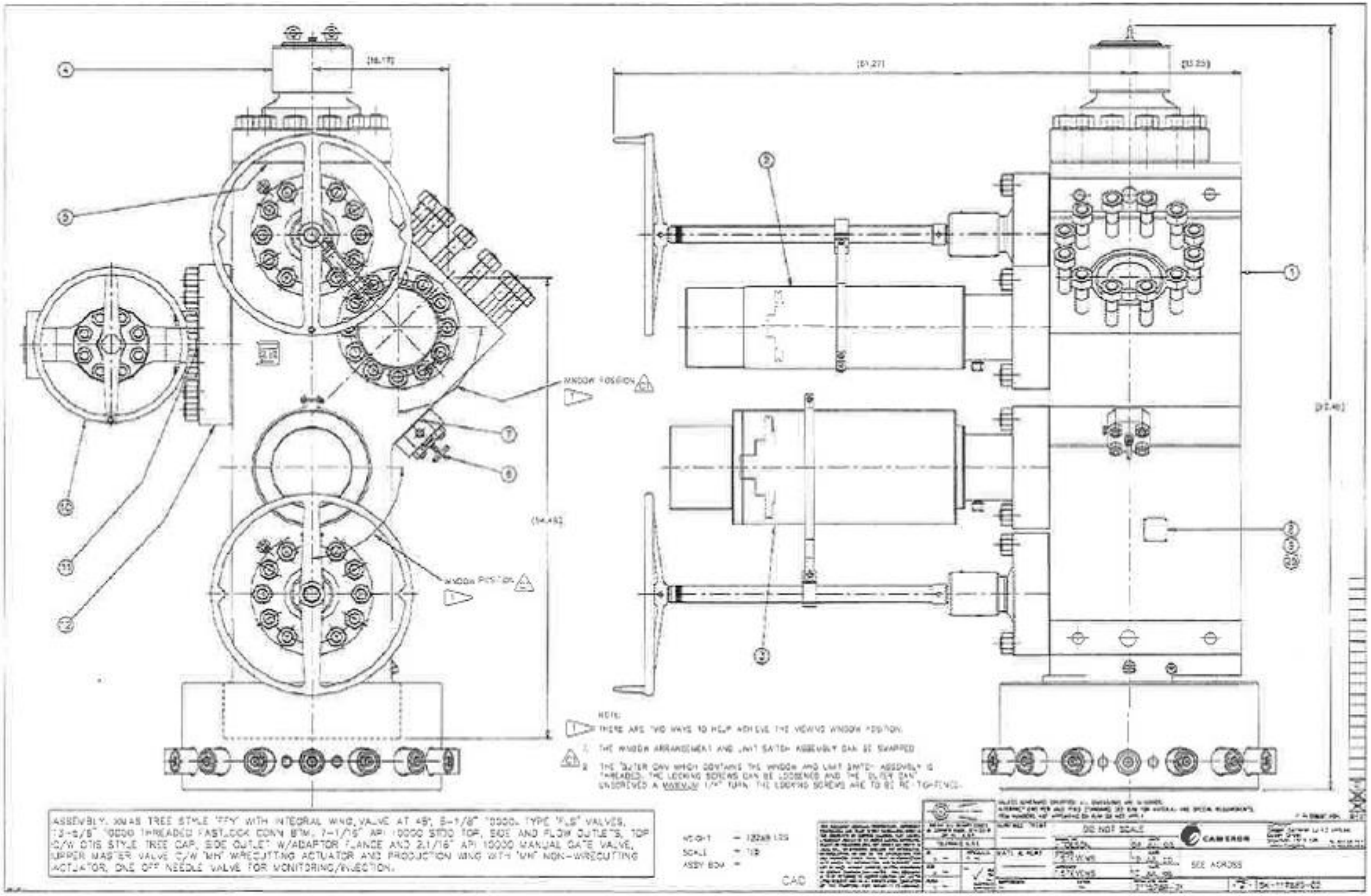
Should there be congestion of downhole function hydraulic lines, electric cables or fibre optic cables passing the body of the downhole safety valve, or just below the tubing hanger, it may be advantageous to use 10 ¾in casing below the surface wellhead down to safety valve depth.

Risks: little new risk; standard equipment and running procedures would be used.

4.17.2 Christmas Trees

It is envisaged that a 5 1/8in 5,000psi working pressure conventional surface tree with standard valve configuration would suit this application. See the example in Figure 4.36 below.

Figure 4.36: Christmas Tree



The proposed conventional tree is installed after the upper completion is installed. The 5 1/8in bore would be compatible with 5 ½in tubing.

The tubing hanger and wellhead would be ported for between 4 to 6 downhole ports whether they are for hydraulic, electrical or fibre optic functions. These may be manufactured with the full complement of ports and the redundant ports blanked off if not required. A conventional wireline plug profile would be machined into the tubing hanger bore and the premium tubing connection below. It is anticipated that the tubing hanger bore wetted surfaces would be clad in CRA and any other external seal surfaces would also be similarly clad.

A standard valve configuration of tree would be used with manual lower master valve, actuated upper master, manual swab, actuated production wing and manual kill valve. The manual kill valve could be used for water flush. It would be possible to have a port for injection of Nitrogen inboard of the kill valve and a port for instrumentation inboard of the wing valve. Both ports would be equipped with double block and bleed valves. It is assumed that the Nitrogen supply line would be though relatively small bore tubing with an injection point through double block and bleed valves just inboard of the kill wing valve.

As insurance against CO_2 corrosion for full design life, it is anticipated that manufacturers will offer solid low allow tree blocks (F22) with the wetted surfaces fully clad in CRA (Inconel 625) and valve trim to suit API HH rating. Standardization initiatives have been implemented in the equipment supply industry in order to reduce lead times and costs, thus it could well be more practical to offer this solution. This would greatly reduce uncertainties associated with corrosion and fulfil the need for an extended design life.

Although corrosion studies may indicate that basic low alloy steel may suffice for the tree, the least that would be acceptable, even for a normal tree production tree annulus bore, would be to clad the gasket and seal surfaces with CRA. This would be for practical purposes when parts are being stored and may deteriorate during storage. Hence the fully clad version may not be too excessive.

The temperature rating would either 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 primarily metal to metal seals (M to M) whereas the L tree and tubing hanger may use M to M in certain areas but may revert to non-elastomeric as primary or back up as required in other parts.

Previous studies have indicated that the likely minimum wellhead temperature would be -20°C.

It is thought that if the choke was mounted on a remote manifold some distance from the tree, then the temperature at the tree will not dip below -40°C and therefore allow the use of an API inLin tree with metal to metal seals and back up non elastomers.

API K trees with pure metal to metal seals could be considered as insurance in the same manner as the fully clad HH tree however they should not automatically be considered as the panacea for all sealing problems.

True zero leakage metal to metal gas seals can be obtained in test conditions with new components and also during factory testing with new assemblies. The reality is that surfaces can get contaminated and possibly slightly damaged during installation of wellhead equipment offshore. All precautions would obviously be taken to ensure that risks are minimized, but the conditions for installation may be far from ideal workshop conditions.

Typical risks to metal to metal sealing would be:

- the tubing hanger seals in the wellhead will probably be set in clean completion brine, but there is always the risk of contaminants from the BOP cavities getting into the seal area;
- installation of the tree over the tubing hanger neck. The tree will not be balanced from one centre lift point. A special sling set will have to be arranged to allow the tree to hang vertically and be slipped over the tubing hanger neck seals in order to make up to the wellhead. There could be slight misalignment on making up the tree; and
- although any completion risers will be checked internally for cleanliness, there is the possibility of scale or rust getting into the tree valve grease.

Standard API connections such as at the valve bonnets and proprietary main wellhead connections are well proven to be gas tight, however moving seal surfaces that would lead to a leak from the tree to the environment (such as the valve stem seals) would be more difficult to make truly metal to metal for the duration of the service life.

Provided any metal to metal seal or non-elastomeric seal has been tested independently in the anticipated service conditions, then it may be beneficial to have one of each type of seal to avoid common mode failure.

Published data suggests that new petroflouroelastomer seals are rated from -40°C to 230°C and have good rapid gas decompression characteristics.

Individual manufacturers may have subtly different tubing hanger neck/tree, seat/ body, stem and bonnet seals to suit K or L temperature ratings. These arrangements would have to be looked at in the detail design phase to check there suitability for low and high pressure sealing over the duration of the well life.

Care should be taken with valve grease packed into the valve cavity will not thicken at low temperatures and hinder the valves from operating correctly. It is likely that any qualification testing of valves would likely have been carried out with internal parts only lightly oiled. Any valve grease should also be assessed to ensure that both liquid and gas CO_2 will not displace the grease and remove the lubrication from the valve.

Although supercritical CO_2 is used for its solvent properties and indeed on occasions to flush out grease from bearings, the CO_2 conditions at the tree should never be in this regime.

Displaced grease from the valve cavities should not be allowed downhole to affect the CO_2 injection into the reservoir.

Typical aerospace grease is available with a temperature range from -73°C to 120°C but may not be compatible with CO_2.

Any grease selection to suit low temperatures and CO_2 in liquid and gas phases will also have to be compatible with any non-elastomeric seals. This may also have an influence on whether a purely metal to metal seal is the optimum solution.

It is not envisaged that CO_2 flashing should affect the tree valves, provided pressure fluctuations are not excessively violent. In the open position the valves may have a tendency to seal on both upstream and downstream gates and seats. To avoid this, a feature such as bleed port is usually drilled through the thickness of the slab gate to allow the cavity and bore pressures to equalize. This should still be effective during any pressure fluctuations to avoid pressure being trapped in the valve cavity.

Fluid for interspace tests on wellhead / tree cavity and other test cavities should be suitable for low temperature service.

As part of any equipment tender it may be worth considering a specific qualification program with liquid CO_2 on a test valve to ensure that there are no unforeseen effects with grease, cavity pressure equalization through gate bleed holes, grease retainer plates, low temperature / low pressure sealing etc.

Although the tree will have a 5 1/8in bore, the studded wing valve inlet may be 7 1/16in API in order to provide structural strength at the flow spool connection. The bending capacity at 5,000psi internal pressure for a 7 1/16in 5k connection is approx. 100,000ftlbs and a for a 7 1/16in 10k at 5,000psi internal pressure it is about 180,000ftlbs. It would be possible to machine a larger studded outlet than is strictly necessary for flow purposes in order to give a higher bending capacity.

Similarly the connection between the tree and wellhead is likely to be a proprietary 13 5/8in connector with bending strength at least equivalent to a 13 5/8in flange. The bending capacities at 5,000psi internal pressure for 5k and 10k flanges are 200,000ftlbs and 800,000ftlbs respectively.

Should temporary pipe hammer occur in the flow loop between the choke and the tree, then it is likely that the connection to the tree will be adequate to tolerate any vibration. The studs and bolts should have sufficient preload to avoid seeing any alternating stress which in turn could cause fatigue failure.

The mass of the tree itself will be in the order of 13,000lbs and the wellhead about 4,000lbs. This weight will be landed on the conductor along with approximately 160,000lbs of 13 3/8in casing weight and 230,000lbs of 9 5/8in casing weight. It is likely then, that any vibration through the tree will be largely transmitted through the stiffest member, namely the conductor rather than into the casing and tubing strings.

Given that the choke to tree flowloops will be supported to allow flexibility but avoid excessive vibration, it is thought likely that any cyclic loads imposed by the vibrating flowline will be very much attenuated before they reached any tubing or casing connections. None the less, it is anticipated that the design of the flow loop supports would be such that they can be varied in location and stiffness to dampen any flowloop vibration and thus minimise the risk of failure of any welds or flanges in the flowloops themselves.

Risks:

- a mixture of CO_2 and fluid being trapped in stagnant cavities such as between the tree, tubing hanger and wellhead and between the swab valve and cap. In theory no CO_2 should be in these cavities, but there is potential for seepage to occur over time. Swab valve gates can "float" when subjected to repeated low pressure cycling which may lead to some pressure build up between the swab valve and the cap. If inhibited test water is used and the surfaces are clad, then no corrosion risk should exist;

- any cavity pressure tests on the wellhead during installation will be performed with inhibited water for a relatively short period of time. This may not be a true indication of seal integrity when exposed to CO_2 liquid or gas at varying pressures over a long duration. It may be necessary to conduct low volume interspace tests such as that between seals on the tubing hanger neck to tree interface with Nitrogen. Voids could be monitored during initial CO_2 injection to ensure pressure integrity before being plugged;
- there will be safety implication with the well in operation when dealing with CO_2 rather than oil or gas. The behaviour of CO_2 needs to be well understood when bleeding off a trapped pressure to be sure that any bleed port is not blocked by dry ice and that indeed the cavity is vented. As is usual practice, the arrangement should be that there should be two ports into any cavity and the cavity pumped through to ensure there is no trapped pressure;
- positioning and orientation of any chemical injection points to pressure/ temperature sensors to minimise the risk of blockage over time; and
- low temperature effects on SCSSV control line fluid in the control line coiled around the tubing hanger neck between the wellhead and tree.

4.17.3 Subsea Trees (and associated overtrawlable structures)

Should vertical subsea wells be required in later years for pressure reduction or reservoir monitoring, then suitable wellheads and trees can be supplied for installation by a jack up drilling rig. Standard 13 5/8in drill through wellheads and trees such as the GE (Vetco) SVXT and FMC JXT-3 would easily fulfil any requirements. The standard specifications of such trees are likely to be higher than required, but there would be cost and delivery benefits in using such a tree rather than a bespoke solution.

Fishing friendly structures (overtrawlable structures) are supplied with these trees. These are principally designed to deflect a trawl net over the tree, but will protect the vulnerable tree parts in the event of being snagged. They typically have a snag resistance of 65 tonnes and a canopy to absorb impact loads due to dropped objects.

This 65 tonne snag load is taken through the well conductor, therefore heavy wall conductor joints with heavy duty connections have to be run below the wellhead housing. These have to take the potential bending moment and possible torsion loads that would be imposed as a result of the structure being snagged.

A standard control module will be fitted on a pressure reduction tree to provide the usual valve functions and means of processing pressure sensor and downhole data prior to be sent by hard wire to the host platform. There would be the option to use the same equipment on a monitoring well if an umbilical is to be laid. Alternatively, transponders could be fitted to the three canopies to allow transmission of pressure data from Metrol or similar gauges.

4.18 Rig specification

The specification of the drilling rig at FEED definition is described below.

The rig will interface with a platform to drill the 3 wells through the allocated slots. The rig will be required to be jacked up to a suitable air gap to allow sufficient space between the platform weather deck and the rigs cantilever deck and the drilling package will be skidded out to an appropriate distance over the platform. These interface requirements will have an impact on the rig selection process as the dimensions and operating air gap of the rig chosen may limit the selection of rigs that allow interface with the proposed platform. There are numerous other factors for consideration such as deck space, personnel, pit space requirements and a rigs recent safety and environmental track record which will be described below.

4.18.1 Technical specification for first load

The selection of a drilling rig for drilling operations will be based on key features, one of which is the rigs drilling depth rating. The rig depth rating is influenced by its derrick load capacity, crown block and travelling block capacity, drilling line size and pulling force. These considerations and others are discussed below.

4.18.2 Type of Drilling Unit

The drilling unit selected needs to be able to operate in the expected water depth with the expected metocean conditions. In the NUI (Normally Unmanned Installation) scenario, a jack-up rig capable of safely operating over a platform in the expected water depth of 193ft is required. The primary advantage of the jackup rig is that it offers a steady and relatively motion-free platform in the drilling position and mobilizes relatively quickly and easily. Jack up rigs are upgradeable from a technical and commercial standpoint and so although a jack up which fully reaches the requirements of the FEED should be sought, it may be possible to make upgrades dependent on costs in the event of an abnormally tight rig market although it is considered unlikely. Drilling units normally specify their total drill depths based on their standard/assumed drillpipe weights/grades.

4.18.3 Hoisting Equipment

Essentially, at drilling rig derrick is a vertically oriented crane for lifting and lowering tubulars into a well. The hoisting equipment made up of the draw works (a powered drum with drilling line spooled on it), crown block (the stationary section of a block and tackle with a set of sheaves to accommodate the drilling line) and the travelling block (the moving part of a block and tackle) and drilling line assemblies will need to be sized based on the depth of hole to be drilled and the worst expected drilling, casing, running completion loads to be expected. Drilling line size and pulling force will determine how much force can be pulled in the event that the drillstring becomes stuck while drilling, tripping pipe or running casing and completions. How much force can be pulled is the lesser of the derrick static hookload, fastline breaking strength and draw works pulling capacities. Bearing in mind that the first load wells are relatively shallow at +/-7,500ft, these loads are expected to be accommodated by a wide variety of jack up rigs of all types and sizes. Table 4.22 summarises the maximum anticipated hoisting equipment loads.

Table 4.22: Maximum hoisting equipment loads

Rig Selection Load Estimates for NGC CCS Wells

Maximum String Weights

Est. Drill Pipe Adjusted Weight	22.93 lb/ft	Max Well TD	7,600ft
Est. Block Weight	85,000lb		
Margin of Overpull	100,000lb		

Drillstring Sizes	Weight (lb/ft)	Length (ft)	Unbuoyed Weight (lb)	MW (ppg)	Buoyancy Factor	Total Hook Load (lb)
Drill Strings						
36" BHA	-	500	59,064	8.7	0.8678	237,550
Drillpipe	22.93	65	1,490			
17-1/2" BHA	-	730	88,994	10.0	0.8472	288,951
5" DP	22.93	1470	33,707			
12-1/4" BHA	-	550	68,386	11.5	0.8243	333,035
5" DP	22.93	4850	111,211			
8-1/2" BHA	-	800	36,303	10.5	0.8395	345,421
5" DP	22.93	6750	154,778			
Estimated Max Drilling Hookload						**345,421**

Casing Size	Weight (lb/ft)	Length (ft)	Unbuoyed Weight (lb)	MW (ppg)	Buoyancy Factor	Total Hook Load (lb)
Casing Strings						
30" x 20"	310	565	175,150	8.65	0.8678	336,998
13-3/8"	72	2200	158,400	10	0.8472	319,195
9-5/8"	53.5	5400	288,900	11.5	0.8243	423,131
7"	29	3650	105,850	10.5	0.8395	273,866
Estmated Max Casing Hook Load						**423,131**
Max Hook Load						**423,131**

Min Pit Volume Required

12-1/4" OH vol	466 bbl	9-5/8" casing vol	390 bbl	Top hole 50bbl sweep	628 bbl
13.375 casing vol	329 bbl	8-1/2" OH vol	151 bbl	100bbl Sweep at TD	100 bbl
Surface vol	600 bbl	Surface vol	650 bbl	10ppg displacem	674 bbl
Total Volume	**1,395 bbl**		1,190 bbl		774 bbl

Derrick Load Calculations

Assumed Number lines strung	12	# lines strung	12
Number of Sheaves	11	# of Sheaves	11
Efficiency factor =	0.782	EF =	0.813
		K - 1.04 (Refer to API RP9B)	

For 6 lines, efficiency factor = 0.874
For 8 lines, efficiency factor = 0.842
For 10 lines, efficiency factor = 0.811
For 12 lines, efficiency factor = 0.782

- Shell Drilling Engineers Notebook May 1992

4.18.4 Derrick Capacity

The derrick or mast should be of sufficient height and be able to withstand the anticipated loads for drilling and running casing. This includes the number of stands that can be stood on the floor dependent on the size of the drillpipe, geometry of the monkey board and racking floor and the maximum uniform weight of tubulars that can be supported by the racking floor. For the purposes of this feed, 5in DP has been assumed for drilling.

It is also advantageous to have a rig which is able to mobilise with drillpipe racked in the derrick to minimise preparation for spud /requirement to pick up pipe once the rig is on location. It is expected that a wide variety of rigs will have a derrick design capable of supporting the loads expected to be seen during the first load wells.

4.18.5 Mud pump capacity

A standard Southern North Sea Jack Up will in general have three triplex pumps with a maximum output of >1200gpm, which will be easily sufficient for drilling the top-hole sections of the planned wells. Most will be rated to ˜4,500psi with 6in liners and with two pumps running capable of pumping at >900gpm at 80% output, giving redundancy if one pump is down at any time. The Energy Endeavour which was used previously to drill the appraisal well was equipped with three National type 12-P-160, 7¼in x 12in triplex pumps. The maximum expected mud pump pressure for the NGC CCS wells is expected to be 4,100psi based on hydraulic modelling.

4.18.6 Mud Pits/Fluid Storage

The rig selected will be required to carry sufficient stocks of bulk fluid for drilling and completions. Complicated mud programs requiring changing of mud systems will necessitate more volume and space. Consideration to not only the capacity but also the quantity of storage tanks/pits on board the rig is also important, as different fluids are required while transitioning from one section or phase of the well operation to another. The first load wells design basis is to use a combination of Water Based Mud (WBM) and Synthetic Oil Based Mud (SOBM) for well drilling operations. Other fluids will also be required during the wellbore clean-up phases. Storage facilitates must be appropriate for fluid segregation of these fluids. Most drilling rigs are equipped with minimum bulk mud storage of 1600bbls.

4.18.7 Power Units/Engines

Provision of power on the chosen rig is required to be sufficient for using the prime movers such as the draw works, mud pumps and rotary system for drilling operations in addition to auxiliary power requirements and life support system requirements. Although the total power may be required in intermittent mode rather than continuous mode, the actual power required at any point in time will depend on the specific operation being carried out. The power estimation for keeping all the prime movers going while drilling is estimated to be around 4,500KW.

4.18.8 Well Control Equipment Pressure Ratings

Well control equipment is selected based on the maximum expected wellbore pressures. BOPs are rated by API as 3M (3,000psi), 5M (5,000psi) 10M (10,000psi) or 15M (15,000psi). The maximum anticipated pressure from a gas leak to surface from the reservoir is 1,632psi (This is a typical design load case rather than a likely outcome in the case of these wells), this is well within the standard BOP pressure rating for Jack Ups drilling in the North Sea, which is typically 10,000psi or 15,000psi. The maximum pressure that will be used for planning purposes at this stage is 5,000psi based on testing the completion equipment. This requires the cement unit and cement manifold also to be rated to 5,000psi. This pressure will be revised down during the detailed planning phase once completion packer inflation pressures and injection test pressures have been confirmed. Some examples of typical Southern North Sea jackup rigs and their BOP equipment ratings are stated in Table 4.23 below.

Table 4.23: Rig BOP size and rating

Rig Name	BOP Size (inches)	BOP Rating (psi)
Energy Endeavour	13 5/8	10,000
Ensco 100	13 5/8	10,000
Ensco 80	13 5/8	10,000
Ensco 70	13 5/8	10,000
Ensco 92	13 5/8	10,000
Energy Enhancer	13 5/8	10,000
Galaxy II	18 3/4	15,000

4.18.9 Drilling Unit Specification Summary

The maximum planned depth of the wells is 7,593ft MDBRT with an expected maximum inclination of 60°. As calculated in the attached Table, a summary of the minimum rig requirements are shown below in Table 4.24. To demonstrate that these minimum requirements should be easily met by most jackup rigs the specifications of the Energy Endeavour (used to drill the 2013 appraisal well) are also given for comparison.

Table 4.24: Drilling unit specification summary

Criteria	Minimum Technical Requirements	Energy Endeavour Specifications
Water Depth	200ft	300ft
Drilling Depth	7,600ft	25,000ft
Cantilever Load	692,605 lbs	900,000lbs 600,000 lbs set back
Hookload	423,131 lbs	1,000,000 lbs
Drillpipe Length	+_7,600ft	12,000ft 5in S-135
Mud Pit Volume	1,395bbls	1,635bbls
Power Capacity	4,937 KW	4 X 1,825kW generator
Well Control Pressure Ratings	10,000psi	15,000psi stack

Note: These minimum requirements are estimates calculated from numbers based on the prognosed well design along with previous experience from similar well designs.

4.18.10 Interfacing with the Platform

To interface successfully with the White Rose platform, a rig will be required to have sufficient cantilever envelope to drill the first load wells within the specified slots of the platform and allow access to additional slots for contingency for any re-spud requirements. Note that the ‘cantilever’ is the moving part of the rig which carries the drilling package (including the derrick). The cantilever can be positioned accurately over any point required within the 'envelope' of positions required without moving the entire rig from the position it was jack up in.

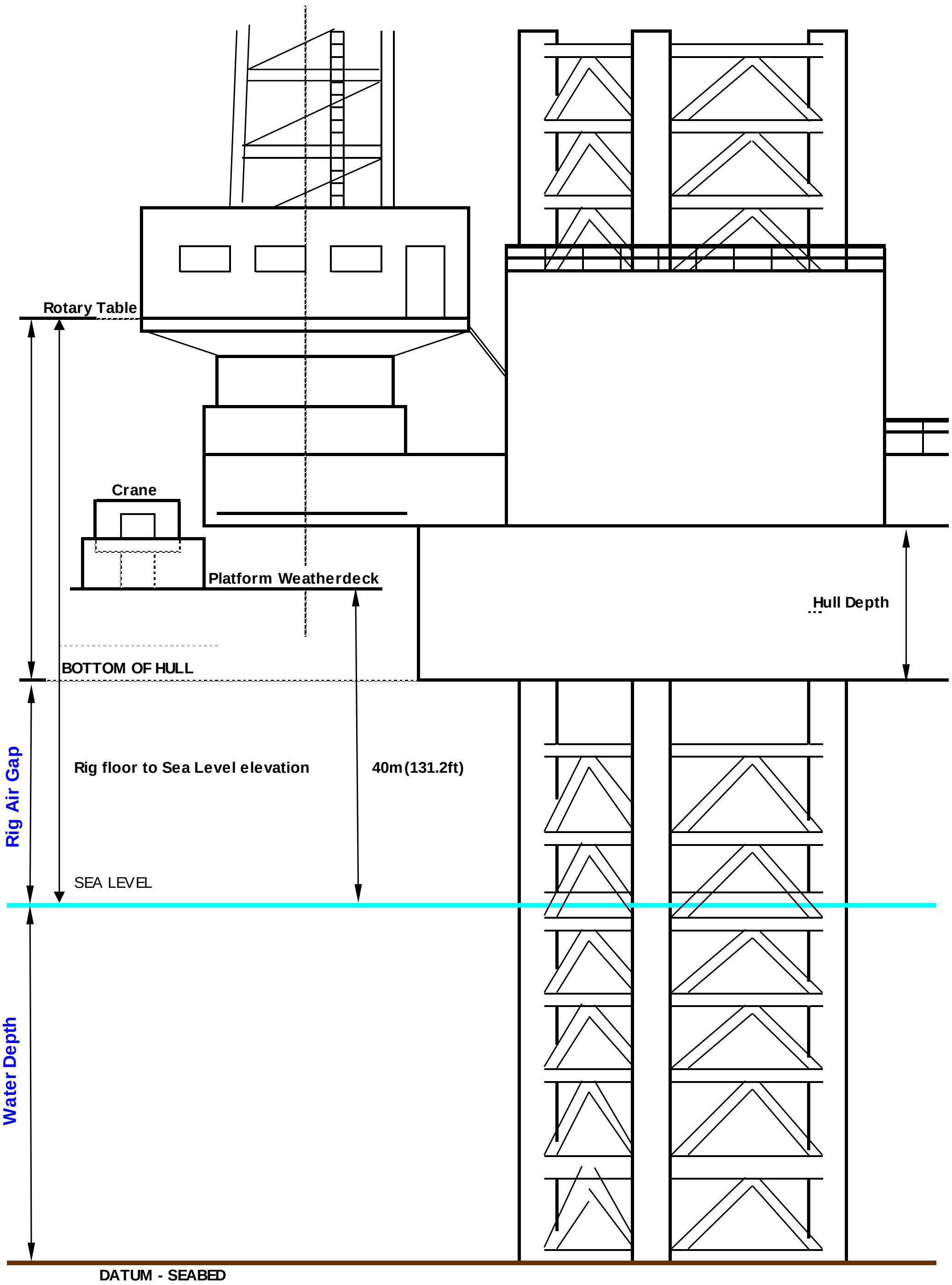
It is not known at this time the minimum distance of the rig from the platform. This will be dependent upon the dimensions of the platform jacket, the cantilever operating envelope, the dimensions of the rig spud cans and the condition of the seabed. The cantilever must be capable of skidding far enough aft to cover this distance and position the rotary table over the specified slots. As several wells will be drilled at a single visit then the rig positioning is critical to ensure that sufficient cantilever loading is available for each of the slots. The slots have been designed to be <7m from the edge of the platform with a 2.5m slot spacing, allowing any standard jack up rig to successfully access the drilling slots. It is anticipated that the well loads should be well within the cantilever load capabilities the vast majority of the jackup rigs used in the Southern North Sea, but must be considered and verified during the selection process.

The dimensions provided for the proposed platform specify a weather deck elevation of 40m (131.2ft) above sea level (Lowest Astronomical Tide). The rig used must be capable of operating with sufficient air gap to accommodate the bottom of the cantilever above any equipment located on the weather deck and allow enough clearance below the rotary table for BOP equipment. Because the air gap of a jack up rig is based on the distance from hull to sea level, the height difference between the hull base, the cantilever base and the rotary table is also important. Therefore the ability of a rig to successfully interface with the proposed platform will depend on the following: The maximum operating air gap; the BOP dimensions; the height difference between the hull and cantilever; the height difference between the hull and rotary table and the required clearance between the base of the cantilever and the platform weather deck. It is likely that smaller jack up rigs may not meet the requirement and for this reason a larger rig may be necessary. It is essential that the ability of potential rigs to operate over the platform be considered in detail during the rig selection process and platform information should be provided during the invitation to tender process. Diagram 1 overleaf is a very basic interface schematic to help visualise the discussion above.

The Energy Endeavour used to drill the 2013 well for example, can operate with a maximum air gap of 100ft. The height difference between the bottom of the hull and the bottom of the cantilever is 27ft, so even jacked up to maximum documented air gap the cantilever would not be high enough to interface with the proposed platform.

Crane access over the platform must also be considered during the rig selection process. The proposed platform has a crane located on the East side; the rig will interface with the platform's South side. From the dimensions provided, the centre of the crane cab is 13m (42.7ft) from the platform's South edge with an expected operating radius of 3m (9.8ft) to 33.5m (109.9ft). When the cantilever is in position over the platform, it is possible that operation of this crane will be impeded. If this is the case, the position and range of the rig cranes should be considered during the rig selection process to assess if these cranes will be capable of accessing those parts of the platform that are out of range of the platform crane. Figure 4.37 below is an interface schematic to help visualise the discussion above.

Figure 4.37: Basis Interface Schematic



4.18.11 Requirement to Install Surface Christmas Trees

A means of installing surface Christmas trees should to be considered when selecting a suitable drilling rig. The most likely solution is to station the tree(s) onto the platform weather deck before the rig positioned on location. When the time comes to install the tree onto the wellhead, it can be lowered on slings through the hatches to the cellar deck. If the rig had the capability to lower the tree onto the platform once on location this would provide another option and more flexibility but is not an essential requirement of the selected rig. If the rig is not capable of this and all the trees for the programme are not available at the commencement of operations, a means of deploying trees on the subsequent slots must also be identified. This would preferably be done by either using the rig or platform crane to land the tree in an accessible area of the platform weather deck for the rig to pick up and deploy.

4.18.12 Review of Key Performance Indicators

A review of each of the key performance indicators will be done for each rig to analyse operational efficiency and rig operability. Information on standard operations (BOP running and retrieval, casing running, slip and cut operations etc.) will be analysed along with rig downtime and safety statistics to help analyse the most efficient and suitable rig. This will be carried out as part of the technical evaluation section of the rig tendering process.

4.18.13 Deck space

Criticality of deck space during a drilling and completion campaign is generally during large casing running sections, drilling with SOBM in intermediate casing section, where a large number of skips are required to be stored on the deck (for ‘skip and ship’ operations to transport Synthetic Oil Based Mud cuttings onshore for disposal) and during well testing operations, where the well test spread needs to be spotted on the main deck.

The planned wells to be drilled by NGC are a maximum depth of ±7,550ft (±2301m) which in terms of the average depth of wells drilled in the North Sea is relatively shallow and no long casing strings are required. The 12¼in section will be drilled with Synthetic Oil based Mud, though this is a short section in a relatively small hole size which will not require large number of skips or space for the 150 joints of 9 5/8in casing.

The Energy Endeavour rig used for drilling the appraisal well in 2013 was a relatively small rig with limited deck space this caused logistical challenges during the phase prior to spud.

4.18.14 Variable Deck Load (VDL)

The VDL generally encompasses any weight added to the MODU that is in addition to its basic design. The VDL determines what the rig can safely carry under the conditions it is subject to at any point in time. Included is all installed equipment such as top drive systems and mud pumps, to fuel, pot water, spare parts and all drilling equipment. In general, jackup rigs have lower VDLs than other types of rigs (semi-submersibles and drillships). The general range of VDLs for jackups are between 2000T to 5000T, however newer generation jackup rigs can have greater VDLs than this. As discussed, the well depth for the first load wells are relatively shallow at 7,550ft in comparison with typical North Sea wells drilled, however the VDL will still need to be assessed during the rig selection process and managed during operations.

4.18.15 Personnel on Board Capacity

The maximum berths available on the rig must be sufficient to accommodate the personnel required throughout the different stages of the project. The 2013 well averaged number of People On Board (POB) is of around 88 for most of the drilling operations; increasing during well testing to a maximum of 96. The POB throughout the testing and completion phase of previous projects is high due to the large numbers of specialists required during these operations and so it is anticipated that this stage of the project will put the most demand on bed space. Recent SNS platform projects have carried high POBs during both the drilling phase and the testing/completions phase, however these high POBs (sometimes up to 110 persons) can often be attributed to the presence of platform maintenance personnel on the rig and so may not be applicable to this project. Sometimes room for regulatory personnel may be a requirement for new and sensitive UK North Sea projects. It should also be noted that if POB space is limited, very careful management of crew changes and flights can reduce the personnel on board, but ideally there should be sufficient space on the rig to allow some flexibility. It is therefore recommended that as a minimum requirement the rig should be capable of accommodating 95 persons, although a jack up with as much space as possible, ideally for over 100 persons, should be sought if there is a requirement for additional platform personnel.

4.19 Drilling Optimisation Study

From the offset wells review, where possible the method used to drill was considered and used to form the basis of the Well Design rational in this document, where particular types of bit, motors and RSS (Rotary Steerable Systems) have been proposed along with cements and muds etc.

However, in Detailed Design the main optimisation will take place to drill and complete the wells in the most efficient and safe way. The optimisation will consist of selecting the most appropriate contractors to provide the most appropriate equipment necessary to do the well work.

Additionally, when detailed design considers each well individually, specific optimisations will be performed of the mechanical design of the well, such as specific cement top depths and specific depths to drill each section to. These latter are well design optimisations. An example will be the trajectory, which will be optimised to avoid sub-surface risk, such as faults but also perform directional work in the most suitable formations (and avoid such directional work where formations are not as suitable).

4.20 Lower Completion Review

The various factors which influenced the lower completion design during FEED are described below. Note that in the context of this document, the lower completion is the part of the well cemented into place and covering the hole section within the bunter sandstone store. It mainly consists of the CO_2 injection liner and how it is prepared for injection.

4.20.1 Lower Completion

In order to select an appropriate lower completion design a number of issues were addressed. Each is discussed in turn below.

4.20.2 Sanding Risk / Sand Control

Sanding is the process resulting in reservoir sand ingression into the well. Sanding is an undesirable outcome and must be avoided. Should it happen, it may result in reduced CO_2 injection rates and other undesirable outcomes. The sanding study discussed in section 4.24 of this document has indicated that sand production is not a concern for the CO_2 injector wells hence downhole sand control is not required.

4.20.3 Stand Off And Reservoir Quality

The well objective is to meet CO_2 target injection rates into a Bunter Sandstone section interval with the base 100ft (30m) away from the Bunter Shale. This stand-off from the Bunter shale ensures the injection targets a section of the reservoir of adequate quality to meet injection requirements and is in acknowledgement of the observed poorer quality reservoir seen at the base of the Bunter in the recent appraisal well 42/25d-3.

4.20.4 Injection Interval Length

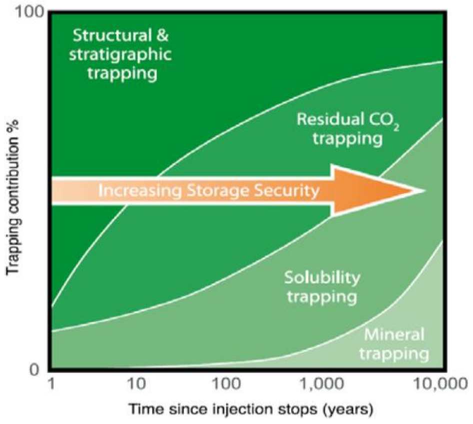
Injection modelling discussed in Section 4.24 of this report suggests an injection interval of circa 200ft will be required. The required injection interval length determines the amount of perforation required in the 7in injection liner.

Note that the 7in injection liner is just a section of pipe run into the well, cemented and then perforated such that CO_2 can be injected through the liner and into the Bunter sandstone store.

4.20.5 CO_2 Injection Plume Transit Time

CO_2 injected into the store migrates into the store in the form of a plume of CO_2. Reservoir modelling has indicated a preference that CO_2 injection should be zonally restricted at the well to reservoir interface to the lower section of the reservoir. The approach maximises the transit time between injection, local contact with the reservoir seal and subsequent migration to highest accessible crestal reservoir point in the structure. There are several potential CO_2 trapping mechanisms in saline reservoirs; structural trapping, residual gas trapping (gas or liquid immobilised in the porous media by capillary or wettability effects), solubility trapping and mineral trapping.

Figure 4.38: CO_2 trapping Mechanisms vs Time



It can be seen the first three mechanisms are applicable during the early stages of injection and storage. Thus the increase in transit time by injecting toward the base of the reservoir is considered beneficial to promote local and improved CO_2 formation capture and storage. This reduces the aggregation or extent of the continuous less dense CO_2 phase at the crest and thus plays a role in reducing the overall reservoir pressure increase at the reservoir seal.

4.20.6 Hydraulic / Thermal Fracture Propagation Risk

It would be an undesirable outcome that CO_2 injection would initiate fracturing in the store. Fracturing of the store will be avoided by limiting injection pressure.

CO_2 injection pressure will be maintained at a safe margin below expected reservoir fracture pressure (230bar) to mitigate the risk of an un-planned hydraulic fracture being propagated upward adjacent to the wellbore.

The benefit of injection being targeted at the base rather than the top of the reservoir means reservoir thickness provides a greater margin of security with respect any risk of an un-planned hydraulic fracture approaching the seal.

A similar point can be made for any potential risks posed by thermal fracturing that might be associated with either CO_2 or water wash operations. Note that thermal fracturing results from the temperature change associated with injection, as the temperature change can change the near wellbore stress field due to contraction etc.

4.20.7 Cement Integrity and Effective Zonal Isolation

A benefit of injecting into the lower half of the reservoir is that in the case of a cemented liner a significant continuous column of cement is present between the top perforation and the reservoir seal. This can ensure that even with some variability locally in cement bond quality with depth, the effective well integrity is good with no CO_2 migration up the back of the liner or casing.

As a zonal isolation choice cement provides maximised footage of sealing area and is also tolerable of variable gauge hole when compared with discrete packer units.

4.20.8 Deployment

A key consideration in any lower completion choice is deployment risk. In this case the combination of a 55° tangent hole angle and character of the 8-1/2in diameter hole reservoir in terms of pressure, temperature, wellbore stability and fracture gradient is considered relatively benign. Hence the operational lower completion deployment risk is considered low.

However, the use of a cemented liner represents a robust conservative proven mature technology. This choice provides a means to both circulate, rotate at maximised torque and to apply optimal set down and pick up weights as required to help get the liner to bottom if hole conditions were found to be more problematic than expected. The torque and tensile ratings of alternate materials such as fibreglass are considerably less than the proposed conventional steel liner choice.

4.20.9 Recommendation

Cementing and perforating the 7in liner as a lower completion strategy is recommended given that sand control is not required and this is the most cost effective and robust means to provide adequate zonal isolation and injection performance. See the material selection section of this report (within Section 4.24) for further material recommendation details.

4.21 Upper Completion Review

4.21.1 Completion Configuration Option Screening

The upper completion is the part of the completion which is not cemented into the well and is formed of the completion tubing and other downhole tools that are deployed on the tubing. The upper completion of the part of the completion that can be removed from the well, should a failure occur in the upper completion. Such an upper completion removal and replacement is normally referred to as a work over.

The upper completion options considered in FEED engineering are described below, along with the rational for selecting the FEED upper completion design.

4.21.2 Single vs Two Phase CO_2 Requirement Background

Pre-FEED it was considered a preference to ensure that CO_2 be maintained in the well and pipeline as a single phase liquid (super critical/dense phase) at all times.

The perception was that damage might occur to the completion equipment through shock, vibration or fatigue associated with transitions between single and multiphase CO_2 states. Note that this transition from a dense phase to a vapour or gas phase is accompanied by significant expansion and a localised drop in temperature, which will occur initially in the wells as the ‘supply’ pressure of the CO_2 to the well is significantly higher than the pressure in the well. Note that after injection operations have be running for some time, pressure in the store will rise and this phase change will no longer occur. The discussion below looks at various options to manage this situation, including not allowing this phase change to occur until near the bottom of the well.

A two fold approach was developed with respect to this issue as described below:

- a series of conceptual completion options have been identified and screened to consider how single phase might be feasible or best maintained in the wellbore and have been compared to a multiphase completion configuration approach;
- a flow assurance study was carried out by Genesis on behalf of NGC to examine pipeline and well CO_2 injection performance across a wide range of conditions including transient start up, steady state injection and transient shut-down operations using Hysys Olga modelling software. The study aim was to substantiate or discount any of the listed concerns with respect multiphase flow.

4.21.3 Conceptual Single Phase Completion Options Screened

4.21.3.1 Single Phase – Remote Upper Completion Choke Sleeve and Bullnose Configuration

Table 4.25: Remote Choke Sleeve Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
Maintain CITHP by closing downhole choke	Maintain Injection THP using downhole choke	Maintain Injection THP using downhole choke	Maintain CITHP by closing downhole choke	Maintain CITHP by closing downhole choke	Maintain CITHP by closing downhole choke

In this configuration the base of the upper completion terminates below the production packer with a tailpipe complete with bullnose at the base and a hydraulic remotely actuated sliding choke sleeve immediately above. This allows the reservoir to be either partially choked or fully isolated by closing the sleeve such that tubing pressure can be managed and maintained during shut-in periods. As a result the CO_2 in the tubing can be maintained in a liquid (super critical/dense phase) state.

Table 4.26: Remote Choke Sleeve Injection Performance and Well Intervention

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No issue to phase as THP rises, but Q.inj. Falls. Remediation needed	Maintain Injection THP using downhole choke	bullhead or chemical injection	No Reservoir access	No Reservoir access	No Reservoir access	Procedural / Nitrogen / MEG / Methanol	Downhole valve & no reservoir access increases workover risk

In a positive sense this option can cope with changes in the injectivity index of the sand face either positive or negative as the choke sleeve provides independent control. In terms of injection performance and intervention, an issue with a bullnose present in the string is that this prevents physical access to the reservoir for MMV or for remedial intervention operations such as further or repeat perforating. This could be addressed if instead of a bullnose a wireline retrievable plug was installed however this adds some risk in terms of the ability to successfully recover the plug for intervention access. The main concern with this approach is that the mechanism to control the pressure in the well adds complexity and risk as it is dependent on a downhole hydraulic sleeve which in a worse case may fail closed and require an operation to either cut and drop or perforate the tailpipe to re-establish flow. To fully re-instate the choke sleeve functionality however a tubing workover would likely be required.

4.21.3.2 Single Phase – Remote Upper Completion Bi-Directional Ball Valve.

Table 4.27: Remote Bi-Directional Ball Valve Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
Maintain CITHP by closing downhole choke	Maintain Injection THP using downhole choke	Maintain Injection THP using downhole choke	Maintain CITHP by closing downhole choke	Maintain CITHP by closing downhole choke	Maintain CITHP by closing downhole choke

In this configuration the base of the upper completion terminates below the production packer with a tailpipe complete with a hydraulic remotely actuated bi-directional ball valve. This allows the reservoir to be fully isolated by closing the valve such that tubing pressure can be maintained during shut-in periods. As a result the CO_2 in the tubing can be maintained in a liquid (super critical/dense phase) state.

Table 4.28: Remote Bi-Directional Ball Valve Injection Performance and Well Intervention

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No issue to phase as THP rises, but Q.inj. Falls. Remediation needed	Maintain Injection THP using downhole choke	bullhead or chemical injection	Full reservoir access	Full reservoir access	Full reservoir access	Procedural / Nitrogen / MEG / Methanol	Downhole valve increases workover risk

In a positive sense this option can cope with changes in the injectivity index of the sand face either positive or negative as the bi-directional ball valve provides independent control. In terms of injection performance and intervention access the valve is fullbore and access is unrestricted. The main concern with this approach is that the mechanism to control the pressure in the well adds complexity and risk as it is dependent on a downhole valve which in a worse case may fail closed and require an operation to either cut and drop or perforate the tailpipe to re-establish flow. To fully re-instate the valve functionality however a tubing workover would likely be required.

4.21.3.3 Single Phase – Limited Entry Perforations

Table 4.29: Limited Entry Perforations Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
No ability to maintain static THP	Fixed sandface dp, rate constraint may promote ppts	Fixed sandface dp, rate constraint may promote ppts	No ability to maintain static THP	No ability to maintain static THP	No ability to maintain static THP

In this configuration the lower completion perforation interval is reduced to increase the partial penetration skin effect and thus this results in a larger flowing bottom hole and surface injection pressure to achieve a given target injection rate. In this way tubing head injection pressure can be maintained above the critical point pressure and the CO_2 maintained in a single phase liquid state. This solution however does not address static shut-in conditions and only aids start up and steady state injection within a relatively narrow parameter range as discussed below.

Table 4.30: Limited Entry Perforations Injection Performance and Well Intervention

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No issue to phase as THP rises, but Q.inj. Falls. Remediation needed	Some benefit within limited range.	bullhead or chemical injection	Full reservoir access	Full reservoir access	Full reservoir access	Procedural / Nitrogen / MEG / Methanol	Potential increased dp skin intervention risk

In a positive sense this option supports physical access to the reservoir for MMV or for remedial intervention operations such as further or repeat perforating.

In the event that the reservoir injectivity index rises (e.g. due to thermal fracturing) then a reduction of the existing perforated interval is not practical. At best this might be achieved if the well was initially perforated over a series of separate intervals separated with circa 20-30ft unperforated intervals. This would then allow liner set wireline plugs to be used to between to reduce the effective perforated interval length as required. This approach however increases the height of the top perforation shot and thus reduces the CO_2 plume transit time. Further such wireline activity increases well intervention activity and associated risks.

The restricted or limited length of the perforation interval may mean a greater risk of the injectivity index falling. To maintain rate the injection pressure would be increased to overcome the increased back pressure until the maximum allowable injection pressure as governed by expected fracture gradient had been reached. The limited entry perforation interval may be more prone to impairment because any solids entrained in the injected fluids are injected in a more concentrated fashion and similarly associated pressure drops, injection and cyclic flux rates will likely be increased and this may promote increased salt precipitation.

A reduction in the injectivity index should it occur would need to be addressed with a water wash treatment or a wireline intervention to either perforate new intervals or to re-perforate existing impaired intervals.

4.21.3.4 Single Phase – Sandface with Inflow Control Devices (ICDs)

Table 4.31: Sandface with Inflow Control Devices Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
No ability to maintain static THP	Fixed sandface dp, rate constraint may promote ppts	Fixed sandface dp, rate constraint may promote ppts	No ability to maintain static THP	No ability to maintain static THP	No ability to maintain static THP

In this configuration the lower completion is combination of sand screens, annular and swell packers. Each sand control screen incorporates a sized choke or other flow control device. The result is to increase the pressure drop across the sandface completion and a larger flowing bottom hole and surface injection pressure is required to achieve a given target injection rate. In this way, tubing head injection pressure can be maintained above the critical point pressure and the CO_2 maintained in a single phase liquid state. This solution however does not address static shut-in conditions and only aids start up and steady state injection within a narrow relatively inflexible parameter range as discussed below.

Table 4.32: Sandface with Inflow Control Devices Injection Performance and Well Intervention

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No issue to phase as THP rises, but Q.inj. Falls. Remediation needed	Some benefit within limited range.	bullhead or chemical injection	Full reservoir access	Full reservoir access	Full reservoir access but loose ICD choke if re-perf	Procedural / Nitrogen / MEG / Methanol	Potential increased dp skin intervention risk

In a positive sense this option supports physical access to the reservoir for MMV.

In the event that the reservoir injectivity index rises (e.g. due to thermal fracturing) then a reduction of injection intervals could at best be achieved using liner set wireline plugs or actuated ICDs that can be closed, adjusted, or opened by either intervention or remotely, or react autonomously. Use of wireline plugs and blank liner however increases the height of the top perforation shot and thus reduces the CO_2 plume transit time. Further, any wireline activity increases well intervention activity and associated risks.

The restricted injection pathway through the ICDs may mean a greater risk of the injectivity index falling. To maintain rate the injection pressure would be increased to overcome the increased back pressure until the maximum allowable injection pressure as governed by expected fracture gradient had been reached. To increase above this level without certainty that the increased back pressure was due to the ICD plugging impairment rather than the formation, would risk fracturing the formation. The ICD solution may be more prone to impairment because any solids entrained in the injected fluids are injected in a more concentrated fashion through the ICD and similarly associated pressure drops, injection and cyclic flux rates will likely be increased and this may promote increased salt precipitation. Check valves could be used to prevent backflow through the ICD but may be considered a further increase in plugging impairment risk as they create a further convolution in the injected flow path.

A reduction in the injectivity index should it occur could be addressed with a water wash treatment initially. If unsuccessful however the use of sand control with ICDs in this configuration means remedial or additional perforating would not be compatible with this solution.

4.21.3.5 Single Phase – Upper Completion with Downhole Electrical Heating System

Table 4.33: Downhole Electrical Heating System Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
No ability to maintain stable full fluid column. If resultant gas cap heated beyond critical point, would require similarly heated surface CO2 inventory.	No ability to maintain stable full fluid column. If resultant gas cap heated beyond critical point, would require similarly heated surface CO2 inventory.	No issues expected for base case injection performance	No ability to maintain stable full fluid column. If resultant gas cap heated beyond critical point, would require similarly heated surface CO2 inventory.	No ability to maintain stable full fluid column. If resultant gas cap heated beyond critical point, would require similarly heated surface CO2 inventory.	No ability to maintain stable full fluid column. If resultant gas cap heated beyond critical point, would require similarly heated surface CO2 inventory.

In this configuration single phase is maintained by elevating the temperature of the fluid in the wellbore and the surface inventory. This is achieved through use of a downhole and surface heating system. It can be seen however that in the event of a platform outage a gas cap will still develop as the well cools down.

Table 4.34: Downhole Electrical Heating System Injection Performance and Well Intervention

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No advantage	No advantage	bullhead or chemical injection	Full reservoir access	Full reservoir access	Full reservoir access	Procedural / Nitrogen / MEG / Methanol	Increased workover risk, adds well complexity, limited track record.

In a positive sense this option supports physical access to the reservoir for MMV, or remedial intervention operations such as further or repeat perforating.

Whilst both surface and downhole heating systems exist in the market place they are not a standard solution. Downhole systems have very limited track record and would not be considered reliable for even a few months. The use of such systems would require significant power to support several wells and the associated equipment footprint would present a further challenge to the already congested NUI. In the event that the downhole system failed, a tubing workover would be required.

4.21.3.6 Single Phase – Circulation of Heated Fluids

Table 4.35: Circulation of Heated Fluids Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
No ability to inject N2 and maintain THP. Gas cap forms	Gradual re-intro of liquid CO2 across equalised choke into the well above high pressure N2 gas / base tubing / reservoir liquid CO2	No issues expected for base case injection performance	No ability to maintain static THP	N2 injection used to CO2 purge and then maintain Inj.THP.	N2 injection used to CO2 purge and then maintain Inj.THP.

In this configuration single phase is maintained by elevating the temperature of the fluid in the wellbore and the surface inventory. This is achieved through use of a heated fluid circulating system to treat both downhole and the surface system. It can be seen however that in the event of a well shut-in or platform outage a gas cap will still develop as the well cools down.

Table 4.36: Circulation of Heating Fluid Injection Performance and Well Intervention

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No issue to phase as THP rises, but Q.inj. Falls. Remediation needed	Increased N2 rate required to support / maintain THP	bullhead or chemical injection	Full reservoir access	Full reservoir access	Full reservoir access	Procedural / Nitrogen / MEG / Methanol	Increased topside scope / impact. N2 interaction wrt hydrates / reservoir drying TBA

In a positive sense this option supports physical access to the reservoir for MMV, or remedial intervention operations such as further or repeat perforating.

A downhole heating system could be achieved by use of a dual completion comprising a 4-1/2in and a 2-7/8in diameter string inside 9-5/8in / 10-3/4in casing. The heated fluid would be pumped down the 2-7/8in tubing and return up the annulus. The CO_2 would be injected down the 4-1/2in tubing. This configuration faces a number of issues. The injection tubing size is constrained which imposes an injection rate restriction. Even using a 4-1/2in tubing size, the effective outer diameter, once cables, clamps and the downhole safety valve are considered would need an increase in casing size from 9-5/8in to 10-3/4in. Further, the completion string is more complex with a greater risk of problems during installation and lifecycle.

Alternatively a system could be considered that provides a flow path of heated fluid down to the mudline only via a subsea riser / hose external to the wellbore with entry at this level into the well annulus via a subsea manifold arrangement. This method introduces modified long lead none standard subsea architecture / wellhead design and adds riser stress complexity. By creating a connection to the well annulus at the mudline this increases integrity risk.

In the event that the downhole system failed, a tubing workover would be required.

The most obvious choice of circulated fluid would be seawater based on ready availability and the low HS&E impact in the event of an external leak. It should be noted however introducing a circulated water system into a well with pressured CO_2 can be seen as an increase in hydrate risk in the event of any leaks across interfaces such as tubing hangers and wellheads.

Both downhole and surface system would require considerable deck space to filter, add corrosion and scale inhibitors and biocides, then heat and pump the fluid. The system would require manifold control valves and an integrated control and emergency shutdown system. This solution would be a bespoke solution with no known current example in the North Sea. An expectation at this stage is that the system of this type would be a manned not remotely actuated system.

In conclusion the use of such a system would require significant power to support several wells and when considered along with the associated pumping and treatment packages, the total equipment footprint and manpower requirement would not be compatible with the constraints of the already congested NUI.

4.21.3.7 Single Phase – Local Nitrogen Supply

Table 4.37: Local Nitrogen Supply Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
No ability to inject N2 and maintain THP. Gas cap forms	Gradual re-intro of liquid CO2 across equalised choke into the well above high pressure N2 gas / base tubing / reservoir liquid CO2	No issues expected for base case injection performance	No ability to maintain static THP	N2 injection used to CO2 purge and then maintain Inj.THP.	N2 injection used to CO2 purge and then maintain Inj.THP.

In this configuration nitrogen is used to maintain tubing head pressure in the well to ensure a single phase CO_2 state is sustained.

It can be seen however that in the event of a well shut-in or platform outage a gas cap will still develop as the tubing and bottom hole pressure bleeds off to the reservoir.

Table 4.38: Local Nitrogen Supply Injection Performance and Well Intervention

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No issue to phase as THP rises, but Q.inj. Falls. Remediation needed	Increased N2 rate required to support / maintain THP	bullhead or chemical injection	Full reservoir access	Full reservoir access	Full reservoir access	Procedural / Nitrogen / MEG / Methanol	Increased topside scope / impact. N2 interaction wrt hydrates / reservoir drying TBA

The method has merit in that this option supports physical access to the reservoir for MMV, or remedial intervention operations such as further or repeat perforating.

Further use of nitrogen achieves separation between water wash or formation water and the injected CO_2 stream which has benefit in terms of hydrate management and corrosion risk mitigation.

This method does not rely on downhole equipment and tools and is therefore inherently more reliable. In the event of any surface equipment failing it can be readily accessed and quickly replaced at a fractional cost compared to that of a completion tubing workover operation.

The challenge for this method is the logistics of supplying adequate nitrogen and whether the system can be remotely operated or not.

The provision of nitrogen equipment is discussed in detail in the workover and intervention section of this report. It considers atmospheric, tanked and bottled N_2 supply systems. The first two options require manned systems. The bottled system is likely remotely operable.

However, the large number of bottles required to create an adequately pressured N_2 column per shut down mean that the method looks best suited for occasional intervention activities such as water wash rather than daily or weekly unplanned platform / pipeline shut-ins.

4.21.3.8 Single Phase – Pipeline Inventory Bleed

Table 4.39: Pipeline Inventory Bleed Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
No ability to inject and maintain THP. Gas cap forms	Gas cap in well, phase transition as CO2 introduced to depleted shut in THP	No issues expected for base case injection performance	No ability to inject and maintain THP. Gas cap forms	No ability to inject and maintain THP. Gas cap forms	Bleed off pipeline inventory at Qmin required to maintain THP / liquid phase.

This method relies on pressure within the well being maintained by bleeding off pressure from the pipeline inventory. The method is constrained by the available volume that can be delivered from the pipeline whilst still maintaining the pipeline in a liquid state condition.

It can be seen however that in the event of a well shut-in or platform outage a gas cap will still develop as the tubing and bottom hole pressure bleeds off to the reservoir.

Table 4.40: Pipeline Inventory Bleed Phase Management

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No issue to phase as THP rises, but Q.inj. Falls. Remediation needed	Need increased pipeline bleed rate to maintain THP.	bullhead or chemical injection	Full reservoir access	Full reservoir access	Full reservoir access	Procedural / Nitrogen / MEG / Methanol	Minimal gains

The method has merit in that this option supports physical access to the reservoir for MMV, or remedial intervention operations such as further or repeat perforating.

This method does not rely on downhole equipment and tools and is therefore inherently more reliable than some of the other methods. In the event of any associated surface equipment failing it can be readily accessed and quickly replaced at a fractional cost compared to that of a completion tubing workover operation. The amount of additional surface equipment to adopt this approach is minimal.

4.21.3.9 Single Phase – Concentric or Dual String Upper Completion

In this completion configuration the CO_2 can be injected into the well by more than one flow path. Geometrically a concentric string could be achieved with a 2-7/8in tubing inside a 6-5/8in tubing string. A dual string could be achieved using a 2-3/8in tubing string adjacent to a 4-1/2in tubing string. At high injection rates CO_2 is injected down both available flow paths. During periods of reduced CO_2 supply, CO_2 is injected down only one flow path which has the result that dynamic injection pressure is maintained due to the reduced effective internal diameter.

It can be seen however that in the event of a well shut-in or platform outage a gas cap will still develop as the tubing and bottom hole pressure bleeds off to the reservoir. This solution then does not address static shut-in conditions and only aids start up and steady state injection within a narrow relatively inflexible parameter range.

Table 4.41: Concentric / Dual String Phase Management

Well Shut In	Transient Start Up	Steady Injection	Platform shut down / outage	Onshore Pipeline Shut In	Offshore Pipeline Shut In
No ability to inject and maintain THP. Gas cap forms	Gas cap in well, phase transition as CO2 introduced to depleted shut in THP	No issues expected for base case injection performance	No ability to inject and maintain THP. Gas cap forms	No ability to inject and maintain THP. Gas cap forms	No ability to inject and maintain THP. Gas cap forms

Table 4.42: Concentric / Dual String Injection Performance and Well Intervention

↓ Injectivity Index (Skin e.g salt)	↑ Injectivity Index (e.g. thermal frac)	Surface Water Wash	CT Water Wash	PLT Logging	Re-Perf	Hydrate Mangt	Workover
No issue to phase as THP rises, but Q.inj. Falls. Remediation needed	Varying combos of annulus and tubing inj. Allows > range of inj.BHPs to	bullhead or chemical injection	Full reservoir access	Full reservoir access	Full reservoir access	Procedural / Nitrogen / MEG / Methanol	Adds well complexity, greater no. penetrations > integrity risk.

The method has some merit in that this option supports physical access to the reservoir for MMV or access for remedial intervention operations such as further or repeat perforating. It should be noted however that both configurations add complexity and risk to well construction. The concentric string or dual string solution would require longer lead time particularly for Christmas tree, wellhead, tubing hanger and packer components. Well intervention access would be constrained to internal diameters of either the concentric 2-7/8in string, or the dual 4-1/2in string. Two rather than one downhole safety valve would be required which also increases reliability risk. Dual string packers are also considered less reliable than single string packer types.

4.21.4 Single vs Two Phase Conclusions

The following conclusions are drawn from the option screening process above:

- tt is clear from the options screened above that maintaining the CO_2 stream in a single phase does not appear practical without an increase in risk in terms of cost and system reliability;
- during steady state injection single liquid phase CO_2 conditions are expected;
- two phase conditions that arise during transient periods such as shut and start up and water wash are best managed procedurally through a combination of hydrate inhibition, nitrogen purging and pressure equalisation management;
- the concern that damage might occur to the completion equipment through shock, vibration or fatigue associated with transitions between single and multiphase CO_2 states was considered as part of the scope of a flow assurance study (see the K34 Report); this has examined pipeline and well CO_2 injection performance across a wide of conditions including transient start up, steady state injection and transient shut down operations using Hysys Olga modelling software;
- the flow assurance study work has been unable to substantiate any of the concerns of shock, vibration, or fatigue with respect multiphase flow; and
- it is concluded that multi-phase flow during short periods of transient flow in the well is acceptable and the upper completion design basis for FEED was based upon this premise.

4.22 Component Qualification

For the purposes of this document, components are considered to be critical components to assure the integrity of the well system for CO_2 service. At FEED level definition, component qualification cannot be accomplished, as this requires detailed design to specify exactly the components.

The main integrity critical components that will be qualified are tubing material and the cement and this will be performed in detailed design. Additionally the Wellhead and tree will be qualified for CO_2 service, along with their sealing elements (metal or elastomer).

4.23 Component Selection

For the purposes of this document, components are considered to be critical components to assure the integrity of the well system for CO_2 service. At FEED level definition, component selection cannot be accomplished, as this requires detailed design.

The main integrity critical components (tubing, cement, wellhead and tree, as above) will be selected according to those which have qualified and are best suited to CO_2 service.

4.24 Completion Concept Selection

4.24.1 Well Objectives

The objective of the first phase CO_2 injection wells are to facilitate safe, reliable and efficient construction and subsequent use for the injection of CO_2 into the storage reservoir over a period of 20 years.

The wells are expected to cater for a range of injection rates ranging (30MMSCFD to 138MMSCFD, (0.564MTPA to 2.65MTPA).

The well must be designed with due consideration with respect to well operation, well abandonment and post abandonment long term CO_2 well / store integrity and the need to monitor and verify the well integrity and mitigate risk.

The reliability of the system from power station to reservoir as a whole is expected to be 85%, with a requirement for the wells to operate at a target rate of 99%.

The work undertaken has sought to ensure that:

- design considers the requirements of CO_2 injection;
- design has considered the robustness of the well design for injection and for its isolation in the event of deakage during injection; and
- Design has considered the ability to install multiple independent abandonment seals for permanent secure storage of CO_2.

The work outlined in Section 4.21 of this report (Upper completion review) documents the decision not to include downhole choking to assist in maintaining the CO_2 in dense phase.

The perforation interval is based on 100ft (30m) stand off from the base of the reservoir. The stand-off is based on avoiding the poor quality lower permeability that was observed at the base of the reservoir section in the 42/25-d3 appraisal well.

The nominal 200ft (61m), (114ft TVD) length of perforated interval is based on injection modelling performance discussed later in this report.

4.24.2 Sand Character and sanding Risk

In March 2012, prior to the appraisal well 42/25d-3 being drilled, a sanding study was carried out on the Endurance area target Bunter sandstone using offset well (incl. 42/25-1 and 43/21-1 5/42 crestal wells) log derived rock strength data that was calibrated using 42/25-1 core derived Uniaxial Compressive Strength (UCS) and Thick Wall Cylinder (TWC) rock mechanic test results. An in-situ stress model was developed based on offset and field wells to date including LOT and FIT data sets. The sanding model was developed to consider a range of drawdown, depletion and injection conditions to consider both lifecycle injector and producer well sanding risks.

The study indicated in that in general terms rock mechanical strength increases with depth. This is matched by the inverse trend of reservoir quality decreasing with depth. In a drawdown scenario of up to 69bar sand production risk was considered low. If the drawdown was increased to 138bar then some sand production from the weakest interval was expected.

The study also indicated that for a CO_2 injection well completed with a cemented and perforated sand face solution there would be minimal risk of sanding given a rising lifecycle reservoir pressure where matrix stress is reduced over time as pore pressure rises.

Additionally, given a base case to perforate in the lower half of the reservoir where strengths are highest then sanding risk can be reduced still further. At this depth with TWC strengths of 600bar to 700bar expected then, even without a reservoir pressure increase, no drawdown case poses a threat with respect formation failure and wellbore sanding. Sanding risk however can be seen to increase toward the top of the middle Bunter where some weaker intervals are present and consideration should be given to such intervals if future shallower perforation operations out with the base case are considered at these depths.

Following the drilling of the 42/25d-3 appraisal well further significant high quality test and log data and fresh core was acquired. A further programme of rock mechanics and formation damage study was undertaken that concluded that sand production would not be produced in any of these cases during the CO_2 injection phase.

4.24.3 Lifecycle Pressure and Temperature

4.24.3.1 Geothermal and Ambient Temperature

The geothermal gradient for Endurance storage system has been defined as 3.16°C/100m, anchored to a bottom hole datum temperature of 68.0°C at 1654.1m TVDSS based on offset and most recent data acquired from the 42/25-3 well.

Table 4.43: Geothermal Gradient

Temperature	Depth (m) TVD(SS)	Depth (ft) TVD(SS)	Temp (°C)	Temp (°F)
Rig Floor (RTE-MSL 35m)	-35.0	114.0	8.5	47.3
MSL	0.0	0.0	10.0	50.0
Seabed (61.2 m)	61.2	200.8	4.0	39.2
Top Reservoir (W3)	1,186.8	3,894.0	53.2	127.8
Top Perfs (W3)	1,404.4	4,608.0	60.1	140.2
Reservoir Pr. Datum (42/25d-3)	1,405.3	4,610.8	60.1	140.2
Btm Perfs (W3)	1,465.4	4,808.0	62.0	143.7
Base Reservoir (W3)	1,495.9	4,908.0	63.0	145.4
TD (W3)	1,544.7	5,068.0	64.5	148.2
Reservoir Datum (3.16°C/100m)	1,654.1	5,427.1	68.0	154.4

Ambient seabed and surface temperatures will vary seasonally as below.

Table 4.44: Sea and Air Temperature

Air and Sea Temperature	Surface Air (°C)	Surface Air (°F)	Sea (°C)	Sea (°F)
Minimum	-7	19.4	3	37.4
Average	8.5	47.3	10	49
Maximum	24	75.2	16	60.8

4.24.3.2 CO_2 Pipeline Arrival Pressure and Temperatures

Table 4.45: Pipeline Operating Parameters

Pipeline Operating Parameters	bar / °C		psi / °F	
Design Pressure (bar /psi)	200		2900	
Maximum Normal Operating Pressure (bar /psi)	182		2639	
Minimum Normal Operating Pressure	90		1305	
Max/Min Design Temperature	40	0	104	32
Maximum Normal Operating Temperature	16*	24**	60.8	75.2
Minimum Normal Operating Temperature	3*	-7**	37.4	19.4

Note: range values a function of continuous injection* (summer / winter sea temperature driven) and short term start up using summer / winter surface CO_2 process inventory for initial injection** (air temperature driven).

4.24.3.3 Choke Pressure and Temperature Drops

The choke is a flow and pressure control device. When fully closed the choke does not allow CO_2 into the well. When the choke is opened, it allows CO_2 at a controlled rate into the well. The choke can be set at a totally variable range of percentage open. Each well will have a choke which controls CO_2 access to each well. A choke pressure drop induced downstream minimum potential temperature of -20°C is proposed as the design basis for this report based upon a high differential between pipeline arrival and downstream well shut-in pressures of a seawater column at 10barg. The need to manage or mitigate this potential is discussed in more detail in the Hydrate and Material Selection sections of this report.

4.24.4 Static Shut-In Well pressures

The static shut-in well pressure profile is the depth against pressure profile resulting from the content of the well at the time, the prevailing reservoir pressure in the store and does not reflect the pressures associated injection of CO_2 into the well. The 'shut-in' refers to the fact that at the surface, valves are closed at the tree and/or the choke and that pressure from the pipeline does not influence the pressure in the well. A series of static shut-in pressure profiles have been generated based on expected bottom hole pressure for a series of potential fluid/gas columns in the well (formation brine, seawater, methane, nitrogen and CO_2). For simplicity these have been approximated using an average gradient and serve to indicate the maximum shut-in pressures expected in relation to each fluid type. The purpose in this context is to consider the maximum load and equipment rating requirements.

The pressures have been considered using both initial reservoir pressure, 151.8bar (2201psi) at 1405.3m TVDSS (4610.8ft TVDSS) and final reservoir pressure, 200bar (2900psi) expected after 20 years first phase CO_2 injection.

Initial Reservoir Pressure

Table 4.46: Shut-In Pressure at Initial Reservoir Pressure

Wellbore Static Column Pressures (psi)	Depth TVDSS (m)	Depth TVDSS (ft)	Formation Brine (9.77 ppg)	Seawater (8.54 ppg)	Methane Gas	Nitrogen Gas	CO2
Gradient (psi/ft)			0.50804	0.44408	0.1	0.067	0.314
Rig Floor (RTE-MSL 35m)	-35.0	-114.0	-199.3	62.5	1,845.5	2,016.5	736.6
MSL	0.0	0.0	-141.4	113.1	1,856.9	2,024.2	772.4
Seabed (61.2 m)	61.2	200.8	-39.4	202.3	1,877.0	2,037.6	835.4
Top Reservoir (W3)	1,186.8	3,894.0	1,836.9	1,842.4	2,246.3	2,285.1	1,995.1
Top Perfs (W3)	1,404.4	4,608.0	2,199.7	2,159.5	2,317.7	2,332.9	2,219.3
Reservoir Pr.Datum (42/25d-3)	1,405.3	4,610.8	2201.1	2,160.7	2,318.0	2,333.1	2,220.2
Btm Perfs (W3)	1,465.4	4,808.0	2,231.6	2,248.3	2,337.7	2,346.3	2,282.1
Base Reservoir (W3)	1,495.9	4,908.0	2,282.4	2,292.7	2,347.7	2,353.0	2,313.5
TD (W3)	1,544.7	5,068.0	2,363.7	2,363.7	2,363.7	2,363.7	2,363.7

Wellbore Static Column Pressures (bar)	Depth TVDSS (m)	Depth TVDSS (ft)	Formation Brine (9.77 ppg)	Seawater (8.54 ppg)	Methane Gas	Nitrogen Gas	CO2
Gradient (bar/m)			0.1149572	0.1004846	0.022628	0.01516	0.071051
Rig Floor (RTE-MSL 35m)	-35.0	-114.0	-13.8	9.1	132.1	143.9	55.6
MSL	0.0	0.0	-9.7	12.6	132.9	144.4	58.1
Seabed (61.2 m)	61.2	200.8	-2.7	18.8	134.3	145.3	62.4
Top Reservoir (W3)	1,186.8	3,894.0	126.7	131.9	159.7	162.4	142.4
Top Perfs (W3)	1,404.4	4,608.0	151.7	153.7	164.6	165.7	157.9
Reservoir Pr.Datum (42/25d-3)	1,405.3	4,610.8	151.8	153.8	164.7	165.7	157.9
Btm Perfs (W3)	1,465.4	4,808.0	158.7	159.9	166.0	166.6	162.2
Base Reservoir (W3)	1,495.9	4,908.0	162.2	162.9	166.7	167.1	164.4
TD (W3)	1,544.7	5,068.0	167.8	167.8	167.8	167.8	167.8

Final Reservoir Pressure

Although prior wells to date have established no hydrocarbons to be present in the saline formation within the Endurance structure a methane gradient has been included as a nominal relative reference for the other fluid shut-in pressures.

The highest maximum shut-in pressures of 180bar / 192bar (2544psi / 2715psi) are generated when methane and nitrogen gas columns respectively are considered at final reservoir pressure conditions. At initial conditions the equivalent values are 132bar / 144bar (1846/2017psi).

Table 4.47: Shut-In Pressures at Final Reservoir Pressure

Wellbore Static Column Pressures (psi)	Depth TVDSS (m)	Depth TVDSS (ft)	Formation Brine (9.77 ppg)	Seawater (8.54 ppg)	Methane Gas	Nitrogen Gas	CO2
Gradient (psi/ft)			0.50804	0.44408	0.1	0.067	0.314
Rig Floor (RTE-MSL 35m)	-35.0	-114.0	499.6	761.4	2,544.4	2,715.4	1,435.5
MSL	0.0	0.0	557.5	812.0	2,555.8	2,723.1	1,471.3
Seabed (61.2 m)	61.2	200.8	659.5	901.2	2,575.9	2,736.5	1,534.3
Top Reservoir (W3)	1,186.8	3,894.0	2,535.8	2,541.3	2,945.2	2,984.0	2,694.0
Top Perfs (W3)	1,404.4	4,608.0	2,898.6	2,858.4	3,016.6	3,031.8	2,918.2
Reservoir Pr.Datum (42/25d-3)	1,405.3	4,610.8	2900	2,859.6	3,016.9	3,032.0	2,919.1
Btm Perfs (W3)	1,465.4	4,808.0	2,930.5	2,947.2	3,036.6	3,045.2	2,981.0
Base Reservoir (W3)	1,495.9	4,908.0	2,981.3	2,991.6	3,046.6	3,051.9	3,012.4
TD (W3)	1,544.7	5,068.0	3,062.6	3,062.6	3,062.6	3,062.6	3,062.6

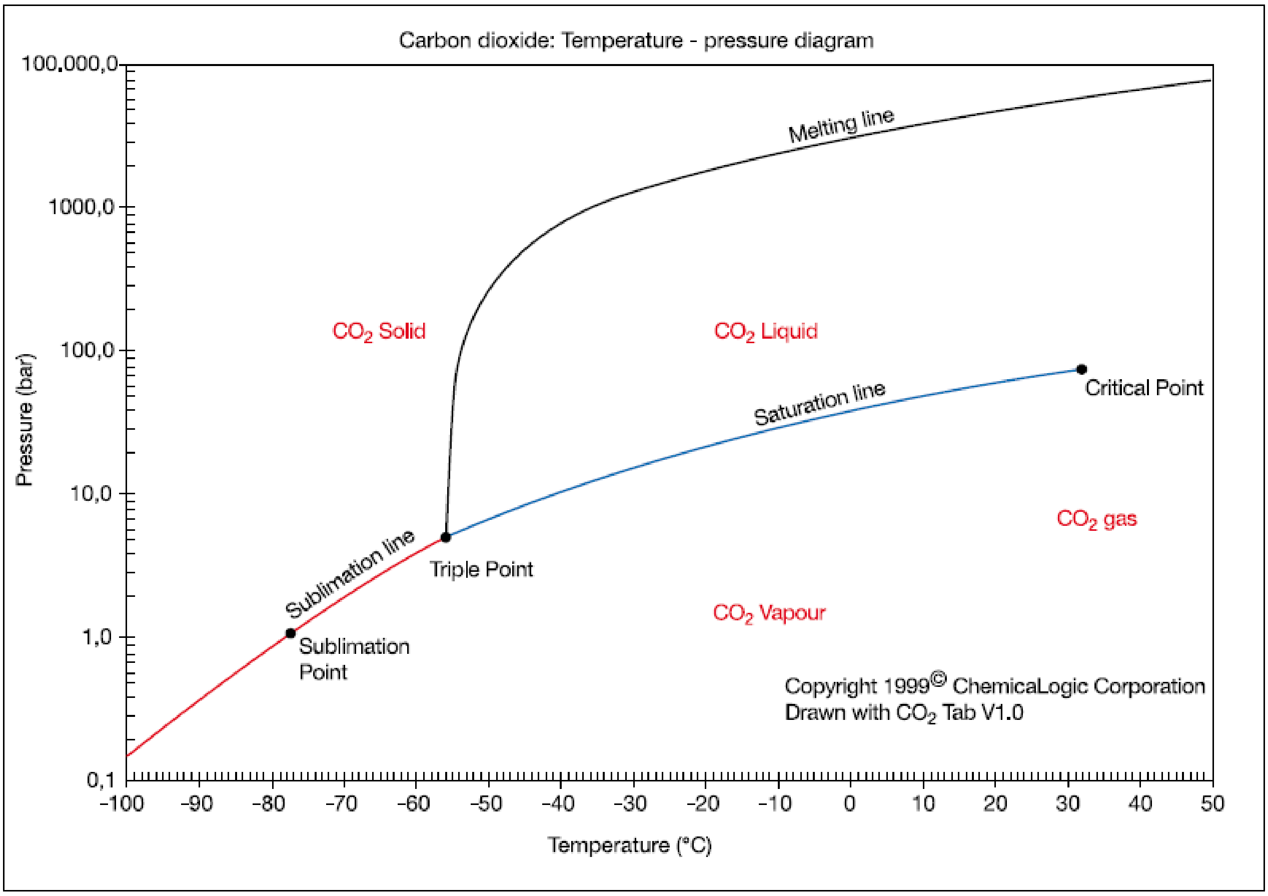
Wellbore Static Column Pressures (bar)	Depth TVDSS (m)	Depth TVDSS (ft)	Formation Brine (9.77 ppg)	Seawater (8.54 ppg)	Methane Gas	Nitrogen Gas	CO2
Gradient (bar/m)			0.1149572	0.1004846	0.022628	0.01516	0.071051
Rig Floor (RTE-MSL 35m)	-35.0	-114.0	34.4	57.3	180.3	192.1	103.8
MSL	0.0	0.0	38.5	60.8	181.1	192.6	106.3
Seabed (61.2 m)	61.2	200.8	45.5	67.0	182.5	193.5	110.6
Top Reservoir (W3)	1,186.8	3,894.0	174.9	180.1	207.9	210.6	190.6
Top Perfs (W3)	1,404.4	4,608.0	199.9	201.9	212.8	213.9	206.1
Reservoir Pr.Datum (42/25d-3)	1,405.3	4,610.8	200.0	202.0	212.9	213.9	206.1
Btm Perfs (W3)	1,465.4	4,808.0	206.9	208.1	214.2	214.8	210.4
Base Reservoir (W3)	1,495.9	4,908.0	210.4	211.1	214.9	215.3	212.6
TD (W3)	1,544.7	5,068.0	216.0	216.0	216.0	216.0	216.0

The highest maximum shut-in pressures of 180bar / 192bar (2544psi / 2715psi) are generated when methane and nitrogen gas columns respectively are considered at final reservoir pressure conditions. At initial conditions the equivalent values are 132bar / 144bar (1846psi / 2017psi).

The highest maximum CO_2 shut-in pressure of 104bar (1436psi) is generated at final reservoir pressure conditions. At initial conditions the equivalent value 56bar (737psi). Note - the CO_2 values are highly subject to temperature which in turn impacts phase and density.

The static CO_2 column is a mixture of a liquid (super critical/dense phase) column with a gas cap as illustrated in the phase diagram and with the Prosper Petex modelled gradient profile figures below. Note the phase diagram below relates to pure CO_2, the actual CO_2 stream composition contains a number of impurities causing variation. At reservoir depth under the conditions of 151bar and 60°C the CO_2 is liquid.

Figure 4.39: CO_2 Phase Diagram



Reservoir pressure will increase over the 25 yr. injection lifecycle period to between 200bar and an upper 230bar limit based on fracture gradient risk. This will result in an entirely liquid CO_2 column being supported in due course.

4.24.5 Water Wash Injection Pressure and Temperature Injection Profiles

Injection modelling has carried out with respect periodic water wash treatments. This has established maximum expected surface pressure 68bar / 103bar, (1000psi / 1500psi), at initial / final reservoir conditions respectively. Further well performance modelling details are provided later in this report.

4.24.6 Well Kill

It is recommended that a 300psi bullhead well kill margin is added to the maximum shut-in pressures generated above.

4.24.7 Drill String Packer Setting and Tubing and Annulus Pressure Tests

Multiple strings will be potentially run in hole including those to support the following operations: wellbore clean-up, perforating, upper completion packer setting. All need to be considered with respect to operational and integrity pressure test requirements.

A maximum upper completion production packer / perforation gun initiation set pressure of 5500psi is considered appropriate for planning purposes at this time. Use of hydrostatic packers may allow this number to be reduced as detailed planning progresses.

4.24.8 Pressure Test Requirement Summary

In conclusion, the maximum tubing and casing pressure test requirement for planning purposes at this stage is 5500psi (379bar).

4.24.9 Upper Completion Option Screening

The main driver for the upper completion is simplicity, reliability and integrity in terms of construction and meeting the required injection and MMV storage lifecycle needs.

A base case 5-1/2in tubing and an alternate 7in tubing option are presented and discussed below.

For outline completion installation programme see Outline Programme section of this report.

Table 4.48: 5-1/2in & 7in Upper Completion Configurations

Base Case 5-1/2in Upper Completion	Alternate Case 7in Upper Completion
Tubing hanger	Tubing hanger
5-1/2in completion Tubing	7in completion Tubing
5-1/2in TRSSSV	7in TRSSSV
5-1/2in completion tubing	7in completion tubing
5-1/2in Permanent downhole gauge	7in Permanent downhole gauge
5-1/2in x 4-1/2in Crossover	9-5/8in Production Packer
7in Production Packer	7in Liner Top Male Seal Mandrel
4-1/2in completion tubing tailpipe	
Wireline Nipple (3.688in)	
Self-Aligning Muleshoe	

Use is made of some vendor specific material is made throughout this section to illustrate generic architecture and functionality of these systems; however, these are just examples and should not be interpreted as an endorsement for a particular system type.

4.24.10 Base Case 5-1/2in Upper Completion Equipment

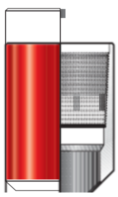
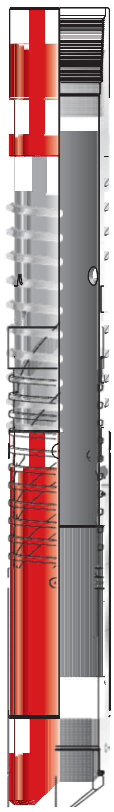
Self-Aligning Muleshoe Guide.

The base of upper completion tailpipe terminates in a self-aligning muleshoe (“mule shoe”, see Figure 4.40). A muleshoe provides a means to guide the end of the tubing away from the casing wall, then enter the liner top or packer bore. The length of the muleshoe varies with the application from centralisation, to seal guide and protection, to flow isolation sleeve.

Collet muleshoe guides combine the features of a muleshoe with an indicator collet to provide a surface indication of the packer seals entering or leaving a packer bore. Push-through and no-go type collets are available for indications on the packer or a special ID sub below the packer.

Self-aligning muleshoe guides, (Halliburton patent) allow the end of the guide to rotate and orient with the liner top without rotation of the tubing. The tool is especially useful in dual wellbore or horizontal completions where control of tubing rotation downhole is difficult.

Figure 4.40: Muleshoe

		
Muleshoe	Collet Muleshoe	Self-Aligning Muleshoe

Wireline nipples

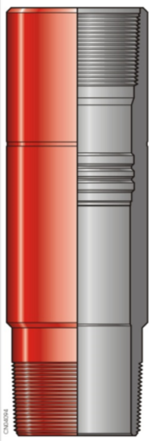
The following wireline completion nipples are proposed:

- a Halliburton 4.562in RPT nipple profile in the tubing hanger, which would allow the second of the shallow set wireline plugs to be set to allow a drilling BOP change out and the installation or future replacement of the dry Christmas tree;

- a Halliburton 4.313in RPT nipple in the TRSSSV, which would allow the first of the shallow set wireline plugs to be set to allow a drilling BOP change out and allow the installation or future replacement of the dry Christmas tree and which would allow a means to lock in place a wireline insert replacement downhole safety valve in the event of failure of the tubing retrievable down hole safety valve; and
- a Halliburton 3.688in RPT nipple (see Figure 4.41) will be located in the tailpipe to allow the production packer to be hydraulically set and the upper completion to be pressure tested.

Figure 4.41: Example Landing Nipple Specification

3.688" RPT Landing Nipple



Design Specification	
Lock Profile	RPT
Size	3.688"
Max OD	5.61"
Length	22.89"
Material	Nickel Alloy 925
Material Yield Strength	110ksi
Threads	4 ½" 12.6lb/ft Premium thread
Pressure Rating	10,600psi

Production packer

The production packer provides a means to isolate the casing annulus above from exposure to reservoir fluids.

Two generic types can be considered as discussed below.

Hydraulically Set Packer

A permanent hydraulic set packer is set by applying differential tubing to annulus pressure. This is typically achieved by setting a plug in the tailpipe, but could be set without a nipple, i.e. a slick plug. The purpose of the packer is:

- to provide a sealing barrier from the tubing to annulus, which would allow the 9 5/8in and part of the 7in liner to be protected from the corrosive elements of the reservoir fluid and any high pressures that may be experienced during stimulation operations; and
- to provide a tubing anchor point to avoid tubing movement.

Hydrostatically Set packer

An increasingly commonly used alternate to a hydraulic set packer is that of a hydrostatically set packer. These normally require an initiation pressure applied from surface to release a setting mechanism based on a stroked closure of an atmospheric chamber. The initiation pressure is normally achieved by pressuring against a cased and lined well bore or a lower completion isolation valve in order to burst a rupture disc. This method removes the wireline trips involved with hydraulically set packers and also the related risks and time. It also permits setting the packer at depths and inclinations that are not accessible by conventional slickline methods. Note that slickline is a wireline which can be used to place and remove items inside the completion at any depth required. The wireline is spooled onto a powered drum which, with sufficient line to reach the required placement depths of tools in the completion.

Given a base case 5-1/2in upper completion with the 7in liner perforated prior to the upper completion being run then a hydrostatic packer is not an option in this case. Further the maximum well angle is 55° and thus the tailpipe is readily accessible by wireline without any tractor assistance. Therefore the recommended packer setting type is a hydraulic set packer.

Packer Setting Depth Considerations

Annular fluid column casing support: conventionally locally high differential collapse loads on the casing induced by troublesome salt zones may be countered or reduced by ensuring the production packer is set below such formations. This then ensures the inside of the casing is supported by an annulus brine hydrostatic column, as opposed to exposed to a lesser bottom hole flowing pressure associated with production.

In this injection case however, assuming a normal annular fluid column gradient, then flowing bottom hole pressure is similar or higher due to the nature of injection operations and further the static reservoir pressure will rise with time.

In addition, based on offset wells, mobile salts and high pressure zones are not a high risk for this well.

Flow Wetting / Corrosion / Material Selection: setting the packer deep protects a greater portion of the 9-5/8in / 7in liner from flow wetting by produced or injected fluids and thereby reduces corrosion/erosion risk. This in turn drives choices in terms of material selection as discussed later in the Material Selection of this report. Given the long length of the 7in liner, very long well life, the inherent inability to workover and replace a section of cemented liner as opposed to recovering an upper completion tubing and the high cost of high chrome nickel alloys material then an argument for a deep set packer is attractive if loss of ready access to perforate the mid / upper reservoir is accepted.

Seal Integrity - The packer provides a sealing barrier with all points of the well above the packer served by both a primary well integrity envelope (tubing, packer, tubing hanger) and a secondary well integrity envelope (production casing, wellhead, casing hangers). Below the packer the well is served by a single well integrity envelope in terms of the production liner. The packer should be set deep enough such that any failure in the 7in production liner beneath the packer is contained due to the inherent fracture gradient strength of the seal formation present above the reservoir. Given fracture gradient in generic terms generally increases with depth then the packer is normally set as close to top reservoir as possible.

Flow Assurance: the packer / tailpipe typically represents a transition in geometry between the internal diameter of the tubing and that of the production liner. The associated changes in flow performance with respect velocity, flow regime and any impacts with respect such as water hold up, scale, wax, asphaltene and sand / solids transport need to be considered.

In this injection case there are no major concerns given the injected nature and fluid characteristics at the 4-1/2in tailpipe tubing and 7in liner transition.

Contingent Packer Setting Depth: in the event the primary packer fails then a further packer may have to be set above the primary packer. As a result the setting depth of the packer needs to consider ensuring that any contingent packer setting can also be set adequately deep enough. If not achievable then the primary packer must be milled and recovered.

Wireline Access: the wellbore maximum inclination is less than 65° therefore packer setting depth with regard to slickline access (in terms of inclination) is not a constraint in this case.

Note – above 65° wellbore inclination is generally considered a deviation at which wireline access requires additional tools either 'a roller bogey' to reduce toolstring friction can be added or an electrically powered tractor system is used.

Cement Support – a good cement job is desirable to provide support at the packer setting depth to reduce the risk of tubing to packer to casing forces damaging the casing. As a general rule the presence of cement is more likely closer to the shoe.

The quality of the cement job post execution should be addressed before finalizing packer setting depth.

Reservoir / Perforation Access: formations below the packer and any associated tailpipe can be readily accessed with the upper completion in place by through tubing wireline or coil tubing operations. In this scenario the proposed 200ft perforation interval is toward the base of the reservoir section. This still leaves circa 1300ft (400m) along hole of reservoir section between top shot and the top of the Bunter Sandstone reservoir that has not been perforated in each of the proposed injection wells (W1,W2,W3, Fig.4).

If the packer is set across the seal just above top reservoir then this allows full reservoir access to be retained to add further perforations as required without a workover to replace the upper completion.

MMV Monitoring – Wireline: formations beneath the packer / tailpipe can be more directly accessed for wireline deployed MMV surveys as only a single barrier of the liner is present between the tool and the formation.

MMV Monitoring – Upper Completion Deployed Permanent Systems: the deeper the packer the closer any upper completion deployed MMV monitoring systems such as Distributive Temperature Sensing (DTS) / Distributive Acoustic Sensing (DAS) can be placed to the point of injection. If DTS / DAS are deployed on an upper completion with a packer set 1300ft above top shot then it is difficult to envisage a clear added value. Conventional permanent downhole and surface pressure and temperature gauges systems will readily detect any tubing to annulus leak characterized by an increase in annular pressure. Conventional wireline well intervention techniques such as a PLT / caliper run combined with annulus tubing circulation, or sequential plug setting and pressure testing would readily confirm the depth of any leak. In any event if a leak occurred the corrosive nature of the CO_2 stream would mean that injection operations would be immediately stopped to protect the production casing and preparations made to work the well over.

The case for DAS or DTS as a technology adding value in an upper completion deployed configuration rests on its ability to detect change in the formation outside the well annuli since as discussed already any change in the well annuli are already adequately addressed by pressure and temperature gauges.

If the injected CO_2 were to track alongside the casing exploiting a cement channel weakness, then this would need to run for 1300ft up the 55° inclined wellbore before the CO_2 stream reached the proximity of the upper completion tubing mounted DTS / DAS system. The process of injecting CO_2 will significantly cool the base of the upper completion tubing and production annulus fluid and production casing / liner. A channel leak would represent a small fraction of the overall injected stream given the annular clearance between the liner outer diameter and the open hole mean that the diameter of any channel through the cement is very limited. If the cement was breached then injection into the highly permeable formation would occur and the minor plume would track vertically away from the 55° inclined wellbore. As the cool minor channel tracking stream rose it would continue to equilibrate with the warmer formation temperature out with the main plume zone of cooling. It can be seen that such a 1300ft channel leak through cement is highly unlikely and that the ability of a DTS system inside the casing to detect this event against a backdrop of cooling due to the internal injected CO_2 stream is highly questionable.

A DAS system faces a similar challenge in detecting CO_2 induced formation changes such as hydraulic fracturing or thermal fracturing. Hydraulic fracturing would occur close to the point of injection with a near vertical orientation to track away from the 55° inclined wellbore and rapidly loose energy in such as highly permeable formation. Operating procedures and management systems in the first instance should be in place to ensure injection pressure is maintained well below expected fracture pressure. Thermal fracturing will be only associated with large volume injection to induce adequate thermal change and would dissipate quickly with distance away from the point of injection.

It can be seen therefore that, as discussed above, a 1300ft channel leak through cement is highly unlikely and that the ability of a DAS system inside the casing to detect change at the considerable vertical, horizontal and 1300ft along hole distance to top perforations against a backdrop of ambient internal injected CO_2 stream noise is highly questionable.

On a positive note a tubing deployed DTS / DAS system with packer set at top reservoir would be proximal to the reservoir seal and provide an ongoing indication of 'no detectable change' at the well / reservoir seal interface.

It should also be noted that in the event that further perforations are added closer to top reservoir then DTS / DAS detection capabilities of any top perforation environment changes may improve and thus potentially aid in qualifying any rise of concern with respect seal risk.

If earlier intelligence is needed in the event of injected CO_2 tracking up the outside of the liner along the 'cemented' annulus then a deeper set packer close to top perforations would have an improved chance of providing this.

Packer Setting Depth Conclusions

- A hydraulic set packer should be set within the 7in liner.
- Further work is required to confirm the well specific relevant performance capabilities of potential MMV DTS and DAS systems operating at either top reservoir or top perforation depths. Note that DTS and DAS are not envisaged to be required in the CO_2 injection wells, but detailed design work will confirm this assumption.
- The current base case assumes that reservoir access to tubing perforate any part of the reservoir is prioritized and thus that the packer / tailpipe is set at top reservoir. If sufficient confidence is expressed in long term injection performance that such access is not required then a deep-set packer can provide corrosion protection to a greater portion of the 7in liner above the top perforation interval.

Packer Specifications

An example packer specification outline of a suitable hydraulic set packer is provided below. Material selection is discussed in more detail in the relevant subsequent section.

Figure 4.42: Example Hydraulic Set Permanent Packer

Hydraulic Set Permanent Packer

Design Specification	
Casing Size	7”
Weight Range	23 – 32 lb/ft
Max OD	5.875”
Min ID	3.800”
Length	67.51”
Material	Nickel Alloy 925, 110ksi
Element	Nitrile
O-Ring	Nitrile
Threads	4 ½” Premium Box x Pin
Pressure Rating	5,000 psi in 23lb/ft, 9,880psi in 32lb/ft

PERMA-SERIES® PACKERS are advanced permanent production packers ideal for single or multizone completions and feature a contoured slip design to maximize casing contact.

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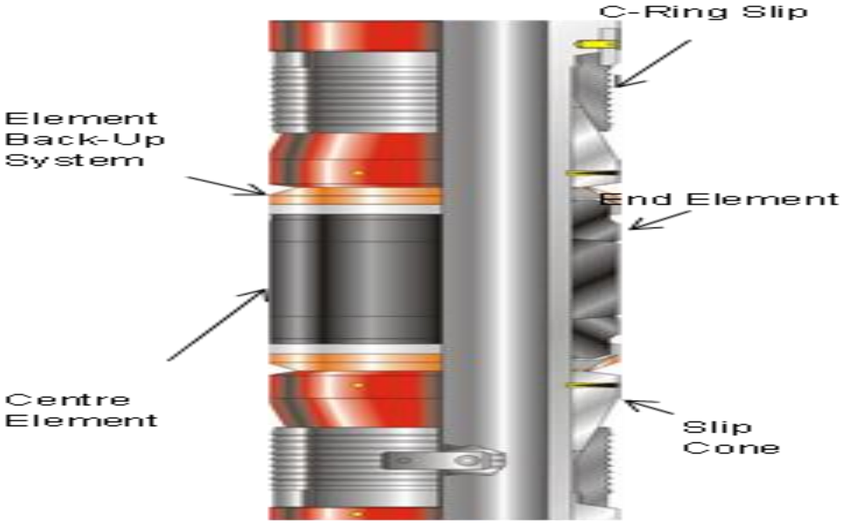
Performance requirements in terms of pressure (<5000psi) and temperature (<250^{0}F) are not considered onerous in this application and well within equipment design limits.

Figure 4.43: Example Packer Components



Tubing to packer and packer to casing forces in response to various load cases are evaluated in detail as part of the tubing stress analysis process reported separately. Results indicate all loads to be manageable and that tubing movement device above the packer such as a polished bore receptacle (PBR) is not required.

Permanent Downhole Gauge Systems

This topic is discussed in more detail in the MMV section of this report.

Use is made of some vendor specific material below to illustrate generic architecture and functionality of these systems; however, this is just an example and should not be interpreted as an endorsement for a particular system type.

The Halliburton ROC System is a conventional tubing deployed permanent downhole gauge system. The systems incorporate a Quartz based sensor with the ability to use a dual sensor or fully redundant sensor gauge package. The ROC gauges have been installed in over 1,800 wells and the Quartz based system is the newest tool available from Halliburton. The tables below provide pressure and temperature performance for the ROC gauges as a whole.

Table 4.49: ROC Gauges- Pressure Performance

Pressure Range (psi / bar)	0 to 10,000 / 0 to 690	0 to 16,000 / 0 to 1,100	0 to 20,000 / 0 to 1,380	0 to 25,000 / 0 to 1,725
Accuracy (% FS)	0.015	0.02	0.02	0.02
Typical Accuracy (% FS)	0.012	0.015	0.015	0.015
Achievable Resolution (psi/sec)	<0.006	<0.008	<0.008	<0.010
Repeatability (% FS)	<0.01	<0.01	<0.01	<0.01
Response Time to FS Step (for 99.5% FS)	<1 sec	<1 sec	<1 sec	<1 sec
Acceleration Sensitivity (psi/g – any axis)	<0.02	<0.02	<0.02	<0.02
Drift at 14 psi and 25°C (%FS/year)	Negligible	Negligible	Negligible	Negligible
Drift at Max. Pressure and Temperature (%FS/year)	0.02	0.02	0.02	0.02

Table 4.50: ROC Gauges- Temperature Performance

Accuracy (°C)	0.5
Typical Accuracy (°C)	0.15
Achievable Resolution (°C/sec)	<0.005
Repeatability (°C)	<0.01
Drift at 177°C (°C/year)	<0.1

The closer the downhole temperature gets to the maximum rating of the tool, the shorter the life expectancy of the electronic components. Since the maximum anticipated temperature (and pressure) of the injection wells for Endurance is much lower than the tool is rated for, this reduces the stress on the electronics and increases the reliability and expected life span.

Although maximum operating pressure and temperatures are expected to be considerably less, a pressure of 5kpsi and temperature of 250°F (120°C) has been assumed for planning and design purposes.

The ROC gauge system, if selected, would be deployed on the upper completion tubing.

Based on the specifications provided, the ROC-S model would be an appropriate potential choice for use with the Endurance injection wells and an overview of this specific gauge's reliability is presented below.

Table 4.51: ROC S Gauge specification

Gauge Type - ROC-S, S/DF		
Systems Installed		155
Gauges Installed		266
PM Reliability	PM Failures	3
	Duration (years)	895
	MTTF (years)	298
Gauge Reliability	PM Failures	1
	Duration (years)	895
	MTTF (years)	895

As the gauges are permanently mounted on tubing as is the case with the system configuration considered here, then this requires the completion to be recovered in order to replace any failed gauges.

A workover can be a complex and costly operation therefore, it is necessary to consider what the monitoring objective is. If memory data is acceptable, then a downhole memory gauge that is run and pulled on a rotational basis might be an alternative in meeting the objective.

Production tubing

The production tubing required for the 5-1/2in Base Case Upper Completion configuration is a combination of 5-1/2in outer diameter tubing to circa 150ft above the 7in liner and 4-1/2in outer diameter tubing to the base of the upper completion. The minimum yield strength is 80ksi material. Premium gas tight connections will be required.

Table 4.52: Completion Tubing Specification

From	To	Description	Yield Strength	Connection
Surface	Tubing Cross Over above 7in Liner Top	5-1/2in 17 lb/ft	Minimum 80 ksi	Premium Connection
Tubing Cross Over above 7in Liner Top	Base of Tailpipe	4-1/2 12.6 lb/ft	Minimum 80 ksi	Premium Connection

The grade of material is discussed in detail in the later Material Selection section of this report.

This includes discussion of the relative requirements with respect high chrome and use of none metallic materials such as glass re-enforced epoxy (GRE) or fibreglass.

High 25Cr alloys are considered as a base case at this stage subject to appropriate further detailed design materials studies and testing.

Downhole Safety Valve

In the event that the wellhead integrity is compromised, downhole shut-in will be achieved by a 5 ½in tubing retrievable surface controlled subsurface safety valve (TRSCSSSV). The valve will be a self-equalising tubing retrievable curved flapper type with a pump through capability to inject into the well in the event that control of the valve is lost.

If a curved flapper type valve is selected this provides a greater internal diameter (ID) than a non-curved type.

Downhole Safety Valve Setting Depth Considerations

The valve should be set deep enough such that ambient temperature is high enough to minimize hydrate risk during any shut-in periods.

A setting depth of circa 2000ft is proposed in order to minimize hydrate risk.

This proposed 2000ft setting depth is also deeper that the 30 x 20in conductor shoe which is being set at 436ft (132 m) TVDSS and thus should a catastrophic event at surface disturb the casing and interfere with the production tubing, containment of the reservoir fluid is still likely with the TRSCSSSV.

The valve should not be set unnecessarily deep in order to keep the inventory above the valve to a minimum. A self-equalising type is recommended to avoid complicated equalising and opening procedures. A non-elastomeric valve is preferred and removes the risk of elastomeric incompatibility with completion fluids.

As setting depth is increased then the static control line head exerted on the valve actuator pistons increases such that valve closure force must be confirmed adequate to ensure the valve will close reliably when control line pressure is bled off.

An adequate stock of wireline retrievable replacement valves and associated sets of lock out tools should be either purchased or confirmed as available for the full 20 year well lifecycle period.

Lifecycle servicing and replacement stock equipment should be carefully considered for all well components given the expected 20 year well lifecycle.

Example tubing retrievable and wireline retrievable replacement downhole safety valve specifications are provided below.

Halliburton SP Tubing Retrievable Downhole Safety Valve (TR-SCSSSV)

The valve has the option of accepting a wireline retrievable valve in the event of the primary valve failure. As the platform is unmanned the valve can be supplied self-equalising or none equalising. The valve has a 4.562in wireline RPT lock profile to accommodate a wireline insert valve, or to set a tubing isolation plug.

SP Safety Valve Design Criteria

- Fail safe – close.
- Flapper valve.
- Accommodate a wire line insert valve.
- Remote hydraulic control.

Example Valve Specification

Table 4.53: Downhole Safety Valve Specification 1/2

Features/Parameter	Value/Description
Valve Manufacturer	Halliburton
Valve Model	SP-2e Tubing Retrievable Valve
Closure Type	Curved Flapper
Size	5 ½in

Features/Parameter	Value/Description
Service	CO_2 & H_2S
Meets requirements of NACE MR-0175	Yes
Pressure Rating	12,500psi
Equalising Feature	If Required
Maximum OD	8.09in
Minimum Inside Diameter without packing bore	4.58in
Top Seal Bore ID-Minimum	4.562in
Bottom Seal Bore ID-Minimum	4.562in
Length	122.5in
Lock Profile	RPT
Temperature Rating	40 to 400ºF
Top Thread	5 ½in Premium threaded as per tubing thread
Bottom Thread	5 ½in Premium threaded as per tubing thread
Connection Type	Box (top) – Pin (bottom)
Tubing Thread Make-up Torque	15,200ft-lb
Maximum Full Open Pressure	3,400psi
Minimum Closing Pressure	1,500psi
Control Line Pressure to Equalise	4,400psi
Maximum Pressure Differential at Valve Opening	0psi
Piston Displacement Volume	2.250 cubic-inch (36.872cc)
Burst Pressure	20,544psi
Collapse Pressure	16,732psi (at ambient)

Table 4.54: Downhole Safety Valve Specification 2/2

Features/Parameter	Value/Description
Tensile with Work Pressure, without Tubing Thread	613,000
Tensile without Work Pressure, without Tubing Thread	870,000
Control Line Connection	7/16in-20 HIF
Control Line Male Nut	101009039 (78Q3402)
Control Line Ferrule, Back	101085851 (93F1497)
Control Line Ferrule, Front	101085850 (93F1496)
Technology Bulletin for HIF Fitting Installation	CPS 014-B
Material	Incoloy 718/ Incoloy 925
Check Lockout Tool	101228079 (42LO44303)
Pressure to Lockout	1300psi
Check Open Tool	101228064 (42OO203)
Exercise Tool	101060099 (42TL552)
Wireline Replacement Valve	102039957
Running/Pulling Prong Extension	49P2101
Isolation Assembly Lock Mandrel Type	4.562in RPV
Isolation Assembly Extension Mandrel	22D5577
Isolation Assembly Extension Mandrel O-Ring	100090693 (91QV1043-H)

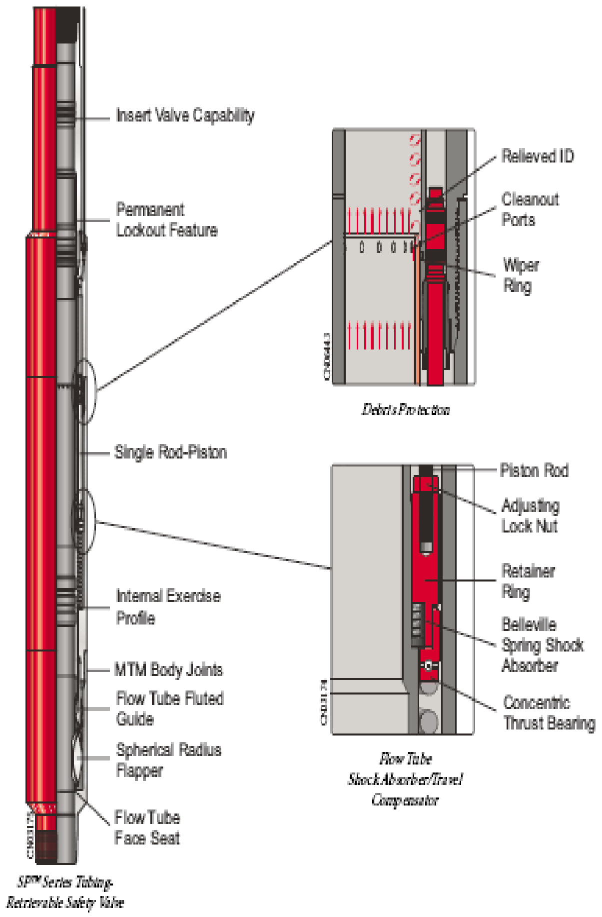
Features/Parameter	Value/Description
Drift Bar	81R237
Drift Bar Outside Diameter	4.490in
Drift Bar Length	24.0in
Meets Requirements of	API-Q1/ISO 9001
API Specification	14A/ISO 10432
API Class	1,2,3S
Edition of API Specification Qualified to	Eleventh

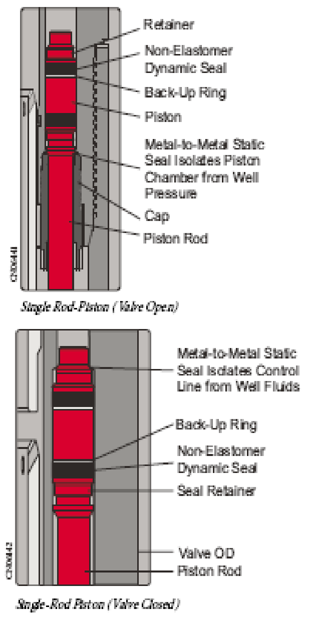
TR-SCSSSV Schematic

Figure 4.44: Halliburton SP Downhole Safety Valve Schematic

5 ½in Tubing retrievable safety valve showing expanded views of the expander rod piston assembly to open and close the flapper valve.

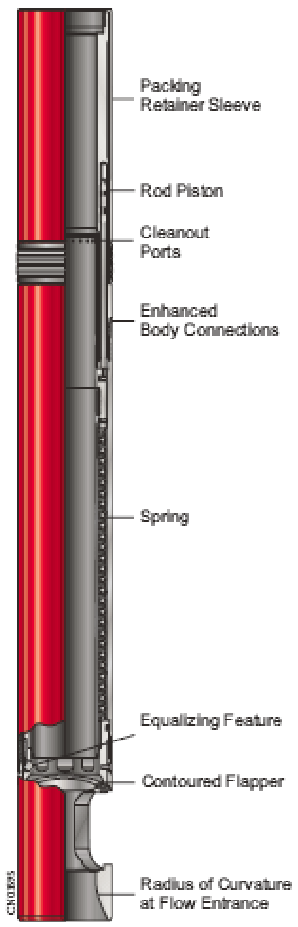
Safety valve operating piston, controlled by surface activated hydraulics.

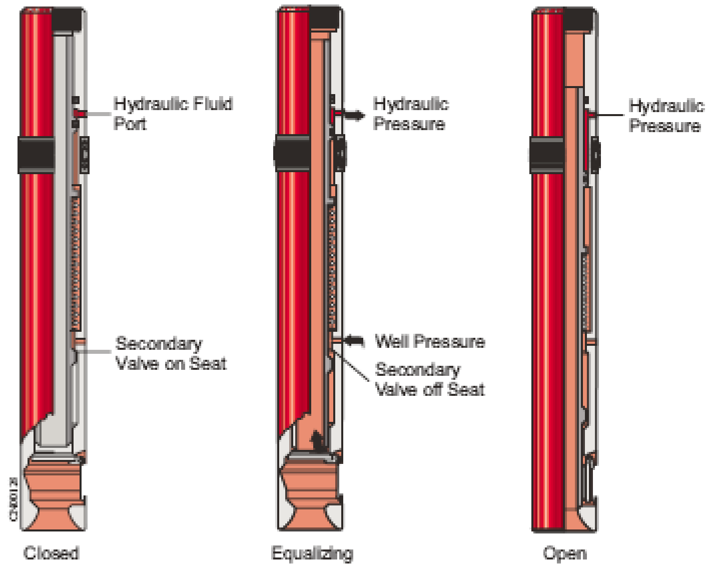




Wireline Insert Valve and Lock Mandrel Schematic

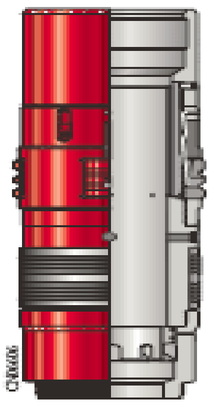
Figure 4.45: Halliburton Wireline Replacement Valve Schematic

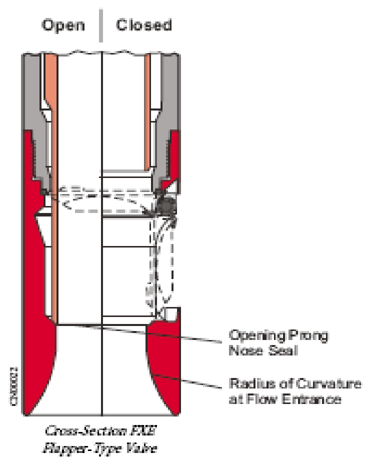




RPT Lock Mandrel connects to top of valve assembly

Shows the valve flapper in the open and closed position





Control Line

A ¼in Inconel 625 encapsulated control line will be used to convey hydraulic fluid to the TR-SCSSSV and attached with compression type of tube fittings.

The control line will be filled with filtered hydraulic fluid to National Aerospace Standards (NAS) specification NAS-CLASS 6 and circulated through the control line until the NAS-CLASS 6 specification is achieved. The control line will be clamped to the tubing at every tubing connection.

Measuring Hydraulic Fluid Cleanliness

The ISO Cleanliness Code, ISO 4406, 1987 is perhaps the most widely used International standard for representing the contamination level of industrial fluid power systems. Under ISO 4406 cleanliness is classified by a two number code, e.g. 16/13, based on the number of particles greater than 5 µm and 15 µm respectively in a known volume of fluid. However some manufacturers have expanded the code to three numbers by the addition of a code number representing the number of particles greater than 2 µm, e.g. 18/16/13. Using Table 4.55 below, we can see a cleanliness rating of 18/16/13 would mean that there were 1300 to 2500 particles greater than 2 micron in size 320 to 640 particles greater than 5 micron in size and 40 to 80 particles greater than 15 microns in size. The full table of ranges for ISO 4406 is shown below.

The NAS 1638 cleanliness standard was originally developed for aerospace components in the US, but is still widely used for industrial and aerospace fluid power applications. It is used widely in the UK North Sea industries. NAS 1638 is comprised of fluid cleanliness classes, each class defined in terms of maximum allowed particle counts for designated particle size ranges. See below.

Table 4.55: National Aerospace Standards (NAS) Cleanliness

Table 1. NAS 1638 Cleanliness Classes

Particle Size, µm		Maximum Contamination Limits (particles/ 100 mL)				
		5 - 15	15 - 25	25 - 50	50 – 100	> 100
Classes	00	125	22	4	1	0
	0	250	44	8	2	0
	1	500	89	16	3	1
	2	1,000	178	32	6	1
	3	2,000	356	63	11	2
	4	4,000	712	126	22	4
	5	8,000	1,425	253	45	8
	6	16,000	2,850	506	90	16
	7	32,000	5,700	1,012	180	32
	8	64,000	11,400	2,025	360	64
	9	128,000	22,800	4,050	720	128
	10	256,000	45,600	8,100	1,440	256
	11	512,000	91,200	16,200	2,880	512
	12	1,024,000	182,400	32,400	5,760	1,024

Valve Equalisation

Most downhole safety valves can be supplied with a self-equalising feature. This is initiated by applying hydraulic pressure through the control line. The pressure across the valve needs to fully equalise before the flapper valve will open.

In a producer well this feature is useful to avoid the time and effort to introduce additional fluids (glycol, water or hydrocarbons from an adjacent producer well) into the top of the well to equalise the lower pressure above the closed valve with any higher pressure trapped beneath the valve. In an injector well however fluid is introduced to the top of the well above the closed valve as a matter of course and the need for an equalising feature on this basis is therefore not present.

A further reason for a self-equalising feature is to mitigate the risks of the valve becoming damaged by attempts to open the downhole safety valve with a high differential in place. In some circumstances, inexperienced operators may seek to excessively increase control line actuation pressure rather than lining up to introduce fluid equalising pressure above the valve. A self-equalising functionality on the valve can be seen to offer some element to mitigate this risk provided adequate time is allowed for the valve to self-equalise.

A considered potential weakness of a self-equalising valve historically was that it offered an additional leak path and therefore greater risk of the valve failing to seal. Valve design improvements are generally considered to have addressed this issue.

Cross Coupling Control Line Protectors

Cross coupling control line protectors will be fitted at every tubing joint connection. An early integrated approach is required to ensure all potential control lines, power, gauge, fibre cables are considered within the constraints of tubing, casing, wellhead, tubing hanger and completion assembly geometries.

Further Components

At this stage an MMV plan has not been finalised. It is clear further iterative cross discipline discussion will be required in the detailed planning phase.

The most likely further downhole equipment that may need to be incorporated into the completion is DAS / DTS fibre optic systems. These are discussed in more detail in the MMV section of this report.

It is understood that a series of feasibility / sensitivity studies specific to Endurance are underway for a number of MMV technologies including micro seismic and gravity. It is assumed once complete this information can be provided as input to the Wells Detailed design stage.

4.24.11 Alternative Case 7in Upper Completion Equipment

In the detailed design stage an Alternate Case 7in Upper Completion can be considered.

The use of a 7in upper completion offers a number of advantages:

- increased injection rates;

- increased redundancy and thus improved system uptime;
- reduced corrosion / erosion risk – lower fluid velocities;
- reduced perforation costs (Electric line perforating through tubing, rather than a dedicated shoot and pull perforation run on tubing)
- larger gun size can be used for through tubing perforating / re-perforating; and
- monobore design with upper completion male seal stabbed into liner top sealbore reduces corrosion risk behind tailpipe.

The use of a 7in upper completion carries some potential constraints:

- 7in Downhole safety valve clearance inside 9-5/8in constrained may need 10-3/4in casing at top of the well. Clearance check required inclusive all clamps / cables / lines;
- 7in Permanent Downhole Pressure and Temperature gauge system inside 9-5/8in. Clearance check required inclusive all clamps / cables / lines;
- given a 7in liner top at top reservoir / seal depth, then the 7in monobore configuration means that compared with a 5-1/2in / 4-1/2in upper completion configuration with the option of a deep set packer inside the 7in, more of the liner is exposed to flow wetted corrosion. However if a deep set packer is not acceptable based on a need for ready access to perforate mid / upper reservoir without pulling the upper completion tubing then 7in monobore and 5-1/2in are similar with respect flow wetted liner length that is exposed;
- DTS / DAS equipment will be constrained within annulus space. A clearance check is required inclusive of all clamps, cables, lines;
- monobore design with upper completion male seal stabbed into liner top sealbore creates a trapped annulus. Potential thermal annular contraction risk has been qualified with Wellcat Multistring as not an issue.

Seal Mandrel

The base of the alternate Case 7in Upper Completion would terminate with a male mandrel that would land out a polished bore in the top of the 7in Liner.

Wireline Nipple

A wireline nipple would be required in the tailpipe of the 7in completion as the packer would be set hydrostatically.

Production Packer

For the alternate case of a 7in upper completion with perforating being carried out subsequent to the upper completion being run a hydro set packer could be used with the following benefits

- it reduces risk associated with slickline intervention;
- it reduces cost due to reduced rig time from having fewer slickline runs; and
- it is field proven reliable equipment.

Permanent Downhole Gauge and Downhole Safety Valve

Suitable 7in Permanent Downhole Gauges and TRSCSSSVs are available but would be subject to geometry clearance check including all proposed cables / clamps / control lines. The top 9-5/8in casing string might require a section of 10-3/8in casing to accommodate the Permanent Downhole gauge and TRSCSSSV.

4.24.12 Material Selection

4.24.12.1 Introduction

The selection of well construction materials that will be exposed to the CO_2 injection stream is an important factor, as the injection stream is potentially highly corrosive. The following material selection section discusses this issue.

Material selection is a key challenge for the design of the proposed CO_2 injection wells given the potential presence in the well environment of multiple high corrosive potential components, including carbon dioxide, oxygen and high salinity water.

A key report on material selection, "Materials Study for CO_2 Storage Wells" was produced to date for the project by Billingham, M., 05/11/13.

It should be recognised that whilst a general practitioner approach is suited for many projects, material selection is also a highly specialised area. The role of experienced general practitioners is to screen and address the majority of material selection challenges and to recognise the atypical where appropriate. This may mean organising project specific material testing programmes where a gap in industry or available knowledge exists and / or accessing a specialist with the specific theoretical knowledge, or empirical data / experience.

The worldwide industry experience of designing and operating CO_2 rich oil and gas producing wells and employing CO_2 injection for enhanced oil recovery provides a valuable body of knowledge with which to address the design and operation of CCS wells. A number of ongoing CCS projects also further add to this knowledge base. It needs to be remembered however that each project is different and needs to be fully qualified in its own right in line with current industry best practices such as API RP5801, API5812, Institute of Petroleum IP123 and IP134, ISO 92235, ISO 92246, Norsok M-5067 and ISO 15156-1 / NACE MR01758, NACE MR0175, HSE report OTO449.

The proposed Endurance project CCS project whilst perhaps an apparent analogue for Sleiper Norway is significantly different in material section terms given the presence in Endurance of significantly greater oxygen (up to 0.8% vs 50ppb), the absence of significant hydrogen sulphide (Sleipner 150 ppm H_2S) in the injected CO_2 stream and an order of magnitude of greater salinity (304k mg/l v circa 30k mg/l) of the Endurance formation water.

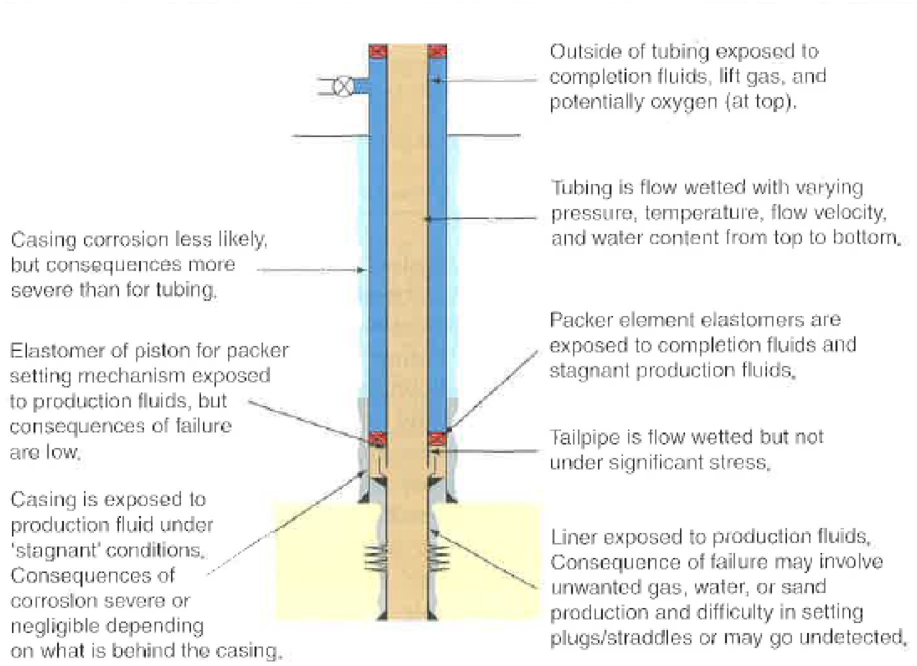
Corrosive Well Environment Types

Corrosion in the well can occur under various conditions as illustrated in Figure 4.46 and characterised below:

- flow wetted - areas that are exposed to produced or injected flow streams;

- stagnant – areas that are exposed to produced or injected fluids that are not replaced and are not flowing;
- completion fluid exposure – areas exposed to completion brines which may contain oxygen or other potentially corrosive contaminants (not produced or injected fluids); and
- stressed components – pressure and temperature induced bust / collapse / tensile loads can lead to stress corrosion cracking.

Figure 4.46: Material Selection Well Environments



4.24.12.2 Well Conditions and Fluids

For corrosion to occur water must be present in the well. Water may occur in proposed injector wells in one of the following ways:

1. water introduced within the CO_2 stream (in vapour form or condensed) <50 ppmv;
2. weawater used for periodic water wash operations using seawater (Salinity TDS 35,000 mg/L);
3. completion brine; and
4. saline formation water which may enter the well during shut-in periods. The column of fluid that will be supported will increase with time in line with rising reservoir pressure due to CO_2 injection operations. (Salinty TDS circa 306,000 mg/L).

4.24.12.3 Steady State CO_2 Injection

During steady state injection, CO_2 with <50 ppmv water content is injected into the well. The CO_2 is expected to have displaced any free water from the completion tubing and injected same into the reservoir.

Modelling indicates that water in the injected CO_2 stream at <50 ppmv will remain in vapour conditions for all well conditions scenarios of pressure and temperature. Hence given an absence of free water during steady state CO_2 injection operations then no corrosion is expected in this scenario. The exceptions to this are where the injected CO_2 stream meets residual free water present in the following areas:

1. in the Christmas tree valve cavities;
2. present at the upper completion to liner interface either between liner top and casing or behind upper completion tailpipe;
3. in the liner sump below the deepest point of injection; and
4. on the outside of the liner / casing.

In the first two cases then it can be seen a relatively small finite volume will be present and over an extended steady state injection period the ‘dry’ CO_2 stream could be expected to absorb the residual water. At this point with water removed the corrosion would cease and not recommence unless the water was replaced.

In the liner sump and external to the perforations larger, volumes mean an increased risk of protracted corrosion damage.

In the ‘A’ annulus (between injection tubing and 9-5/8in production casing), given the environment is one filled with a suitably filtered completion brine treated with corrosion inhibitors and biocide and isolated by the upper completion production packer and tubing hanger then corrosion would not occur, or be short lived once the initial finite background active agents ($H_2S/O_2/CO_2$) had been consumed.

4.24.12.4 Shut-In / Start Up

In the event of a CO_2 injection shut then the change from dynamic to static conditions would result in bottom hole pressure declining a few hundred psi.

Under initial reservoir conditions a largely liquid column of CO_2 would be present in the wellbore with a potential minor CO_2 gas cap in the upper few hundred feet of the tubing. In later time as reservoir pressure rises, an entirely liquid CO_2 column is expected.

Post shut-in the relative buoyancy of the injected CO_2 compared to formation water and the 55° inclination of the wellbore would promote a change out of CO_2 to formation brine inside the liner from the depth of the top perforation to the base of the sump. A similar process would occur in the near wellbore area external to the liner from the deepest point of perforation injection upward. During and post the change out, a significant corrosion risk would be posed through the combination of high salinity formation brine and the injected CO_2 stream mixed in various proportions. The corrosion risk to the back of the liner above the top perforation would depend on the quality of the cement isolation and the extent to which the plume above the top perforation either tracked directly upward or partially tracked along the back of the liner.

On start-up of injection, replenished residual water volumes would be present again in the liner sump and in any potential sump / dead leg at the upper completion to liner top interface ready to combine for some time with injected CO_2 stream until is depleted.

In the event of a CO_2 injection shut-in, the potential exists through diffusivity and convection for water to move upward from the base of the well through the initially ‘dry’ <50ppmv CO_2 liquid / gas column. In time this can result in a sufficient concentration of water for condensed free water to occur shallow in the well.

4.24.12.5 CO_2 Stream Specification

CO_2 Export System Entry Requirements

Table 4.56: CO_2 Export System Entry Requirements

Component	Limiting Criterion % Volume		
	Safety Max.	Integrity Max	Hydraulic Efficiency
CO_2	100	100	96
H_2S	0	0.002 (Note1)	0
CO	0.2	0	0
NOx	0.01	0	0
SOx	0.01	0	0
N_2	0	0	(Note 4)
O_2	0	0.001 (Note 3)	(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 2)	0

Notes:

(1) NACE limit for dense phase CO_2 at a total pressure of 150barg (specified to avoid requirement for sour service materials)

(2) Maximum water content (50 ppmv). Specified to ensure no free water occurs during normal or transient operations.

(3) Maximum oxygen content (10 ppmv). Specified to avoid material selection issues in the well tubing where the dry CO_2 contacts saline formation water

(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%

4.24.12.6 Operational Conditions

The tables below outlines the expected well operating conditions in terms of key parameters with respect to corrosion.

Surface Shut-In Pressure (40bar)

Table 4.57: Surface Shut-In Pressure (40bar)

Component	Case	Max. ppmv	Mol %	Pressure	Pressure	Partial P	Partial P	Partial P	Partial P
				psi	bara	bara	psia	Atma	mbar
CO2			96	580	40.00	38.400	556.800	37.878	38400.00
H20		50	0.005	580	40.00	0.002	0.029	0.002	2.00
H2S	Low Case	20	0.002	580	40.00	0.001	0.012	0.001	0.80
	High Case	80	0.008	580	40.00	0.003	0.046	0.003	3.20
CO		2000	0.2	580	40.00	0.080	1.160	0.079	80.00
NOx		100	0.01	580	40.00	0.004	0.058	0.004	4.00
SOx		100	0.01	580	40.00	0.004	0.058	0.004	4.00
Oxygen	Low Case	10	0.001	580	40.00	0.000	0.006	0.000	0.40
	High Case	8000	0.8	580	40.00	0.320	4.640	0.316	320.00
H2		20000	2	580	40.00	0.800	11.600	0.789	800.00

Downhole Initial Top Reservoir Pressure / Surface Injection Pressure (118bar)

Table 4.58: Downhole Initial Res. / Surface Injection Pressure (118bar)

Component	Case	Max. ppmv	Mol %	Pressure	Pressure	Partial P	Partial P	Partial P	Partial P
				psi	bara	bara	psia	Atma	mbar
CO2			96	1711	118.00	113.280	1642.560	111.739	113280
H20		50	0.005	1711	118.00	0.006	0.086	0.006	5.9
H2S	Low Case	20	0.002	1711	118.00	0.002	0.034	0.002	2.36
	High Case	80	0.008	1711	118.00	0.009	0.137	0.009	9.44
CO		2000	0.2	1711	118.00	0.236	3.422	0.233	236
NOx		100	0.01	1711	118.00	0.012	0.171	0.012	11.8
SOx		100	0.01	1711	118.00	0.012	0.171	0.012	11.8
Oxygen	Low Case	10	0.001	1711	118.00	0.001	0.017	0.001	1.18
	High Case	8000	0.8	1711	118.00	0.944	13.688	0.931	944
H2		20000	2	1711	118.00	2.360	34.220	2.328	2360

Downhole Initial Reservoir Pressure (151bar) (Top Perfs W3)

Table 4.59: Downhole Initial Reservoir Pressure (151bar) (Top Perfs W3)

Component	Case	Max. ppmv	Mol %	Pressure	Pressure	Partial P	Partial P	Partial P	Partial P
				psi	bara	bara	psia	Atma	mbar
CO2			96	2044	140.97	135.327	1962.240	133.486	135326.90
H20		50	0.005	2044	140.97	0.007	0.102	0.007	7.05
H2S	Low Case	20	0.002	2044	140.97	0.003	0.041	0.003	2.82
	High Case	80	0.008	2044	140.97	0.011	0.164	0.011	11.28
CO		2000	0.2	2044	140.97	0.282	4.088	0.278	281.93
NOx		100	0.01	2044	140.97	0.014	0.204	0.014	14.10
SOx		100	0.01	2044	140.97	0.014	0.204	0.014	14.10
Oxygen	Low Case	10	0.001	2044	140.97	0.001	0.020	0.001	1.41
	High Case	8000	0.8	2044	140.97	1.128	16.352	1.112	1127.72
H2		20000	2	2044	140.97	2.819	40.880	2.781	2819.31

Downhole Final Reservoir Pressure (200bar) (Top Perfs. W3)

Table 4.60: Downhole Final Reservoir Pressure (200bar) (Top Perfs. W3)

Component	Case	Max. ppmv	Mol %	Pressure	Pressure	Partial P	Partial P	Partial P	Partial P
				psi	bara	bara	psia	Atma	mbar
CO2			96	2900	200.00	192.000	2784.000	189.388	192000.00
H20		50	0.005	2900	200.00	0.010	0.145	0.010	10.00
H2S	Low Case	20	0.002	2900	200.00	0.004	0.058	0.004	4.00
	High Case	80	0.008	2900	200.00	0.016	0.232	0.016	16.00
CO		2000	0.2	2900	200.00	0.400	5.800	0.395	400.00
NOx		100	0.01	2900	200.00	0.020	0.290	0.020	20.00
SOx		100	0.01	2900	200.00	0.020	0.290	0.020	20.00
Oxygen	Low Case	10	0.001	2900	200.00	0.002	0.029	0.002	2.00
	High Case	8000	0.8	2900	200.00	1.600	23.200	1.578	1600.00
H2		20000	2	2900	200.00	4.000	58.000	3.946	4000.00

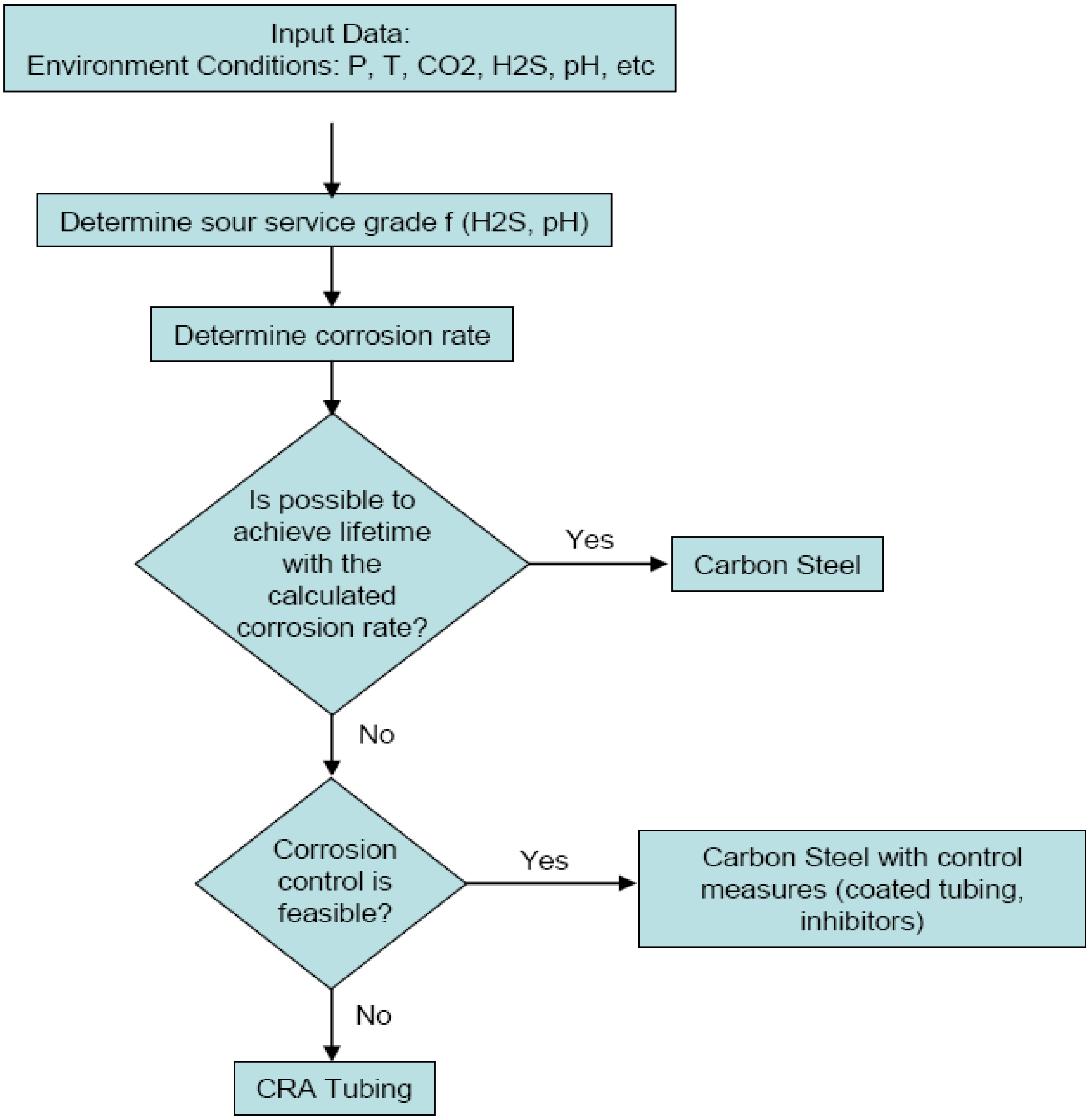
Downhole Final Reservoir Pressure (230bar)

Table 4.61: Downhole Final Reservoir Pressure (230bar)

Component	Case	Max. ppmv	Mol %	Pressure	Pressure	Partial P	Partial P	Partial P	Partial P
				psi	bara	bara	psia	Atma	mbar
CO2			96	3335	230.00	220.800	3201.600	217.796	220800
H20		50	0.005	3335	230.00	0.012	0.167	0.011	11.5
H2S	Low Case	20	0.002	3335	230.00	0.005	0.067	0.005	4.6
	High Case	80	0.008	3335	230.00	0.018	0.267	0.018	18.4
CO		2000	0.2	3335	230.00	0.460	6.670	0.454	460
NOx		100	0.01	3335	230.00	0.023	0.334	0.023	23
SOx		100	0.01	3335	230.00	0.023	0.334	0.023	23
Oxygen	Low Case	10	0.001	3335	230.00	0.002	0.033	0.002	2.3
	High Case	8000	0.8	3335	230.00	1.840	26.680	1.815	1840
H2		20000	2	3335	230.00	4.600	66.700	4.537	4600

4.24.12.7 Tubing Material Selection Flow Chart

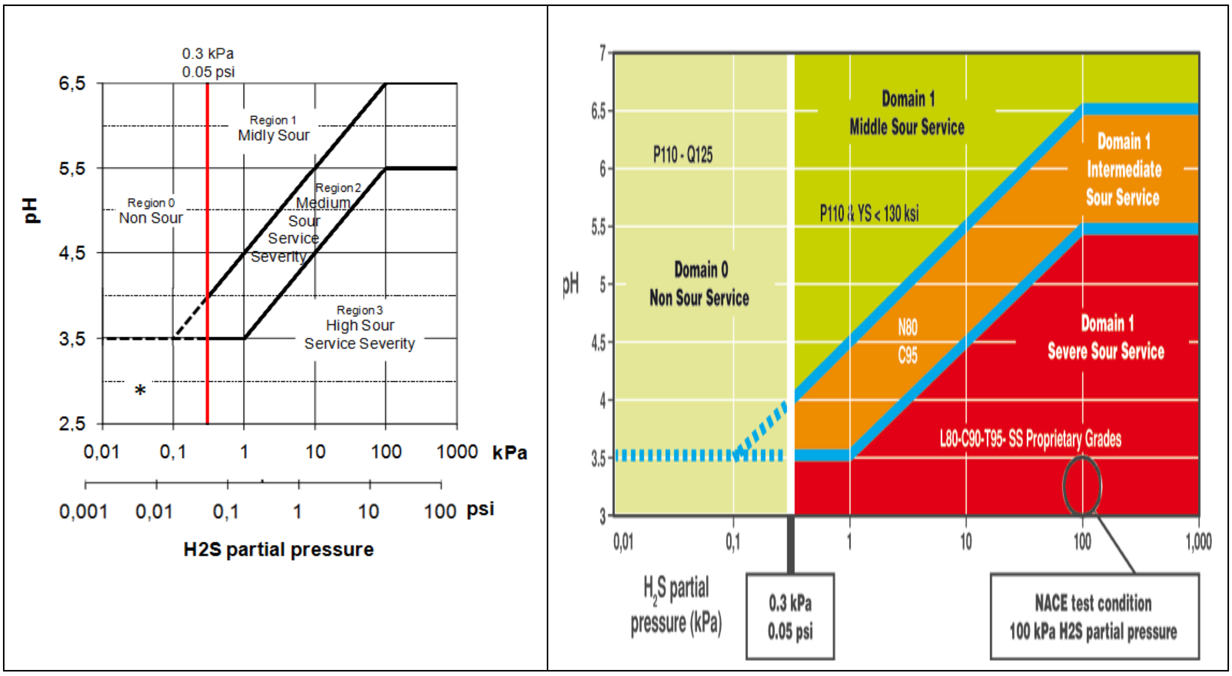
Figure 4.47: Material Selection Flowchart



The flowchart above has been used to consider the proposed CO_2 Injector wells. The sour service grade in terms of H_2S partial pressure and pH was determined using the graph in Figure 4.48. Sour service grade is defined as an H_2S partial pressures of >=0.05psia according to NACE MR0175.

A pH of 3.2 has been estimated for pure CO_2 at a pressure of 230bar, at 65°C. The presence of SOx has the potential to reduce this further.

Figure 4.48: Sour Condition Domains according to EFC16



This initial process indicates that sour service material provision is not required for up to 151bar initial reservoir conditions at top Perforation level resulting in a pH_2S of 0.041psia. At a final reservoir pressure of 200bar then this 0.05psia limit is marginally exceeded with a pH_2S or 0.058psia as tabulated above.

In terms of CO_2 sweet corrosion then given the 96-99% mol content and associated partial pressure it is clear in the event of an aqueous environment to support the process, L80 and 13 CR materials would be inadequate as the charts in Figure 4.48 illustrate.

Figure 4.49: 13 Cr and 22 CR Material Performance

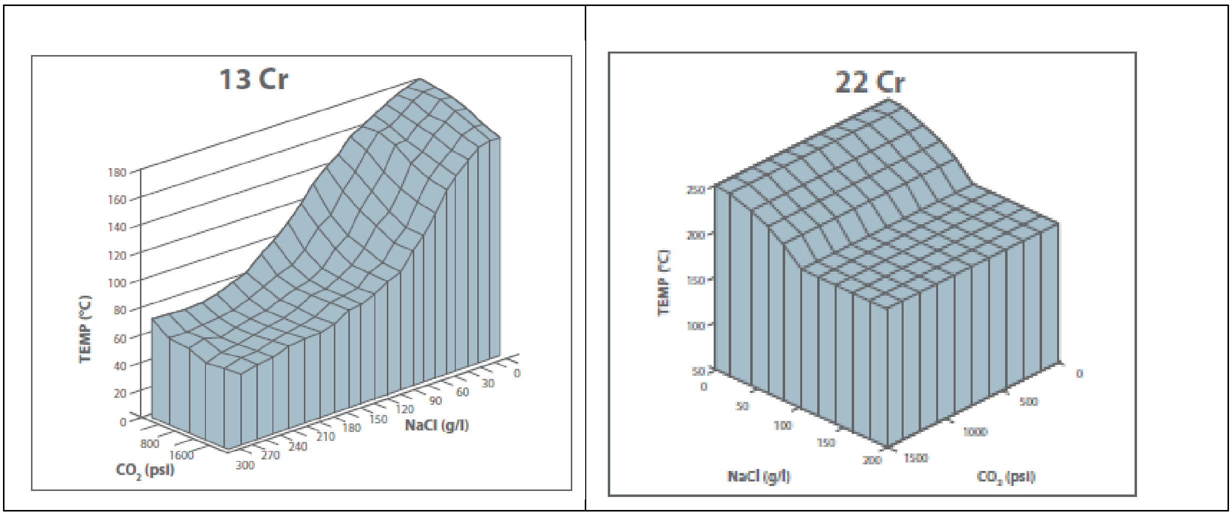


Figure 4.50: Sumitomo Metals Material Selection Chart 1

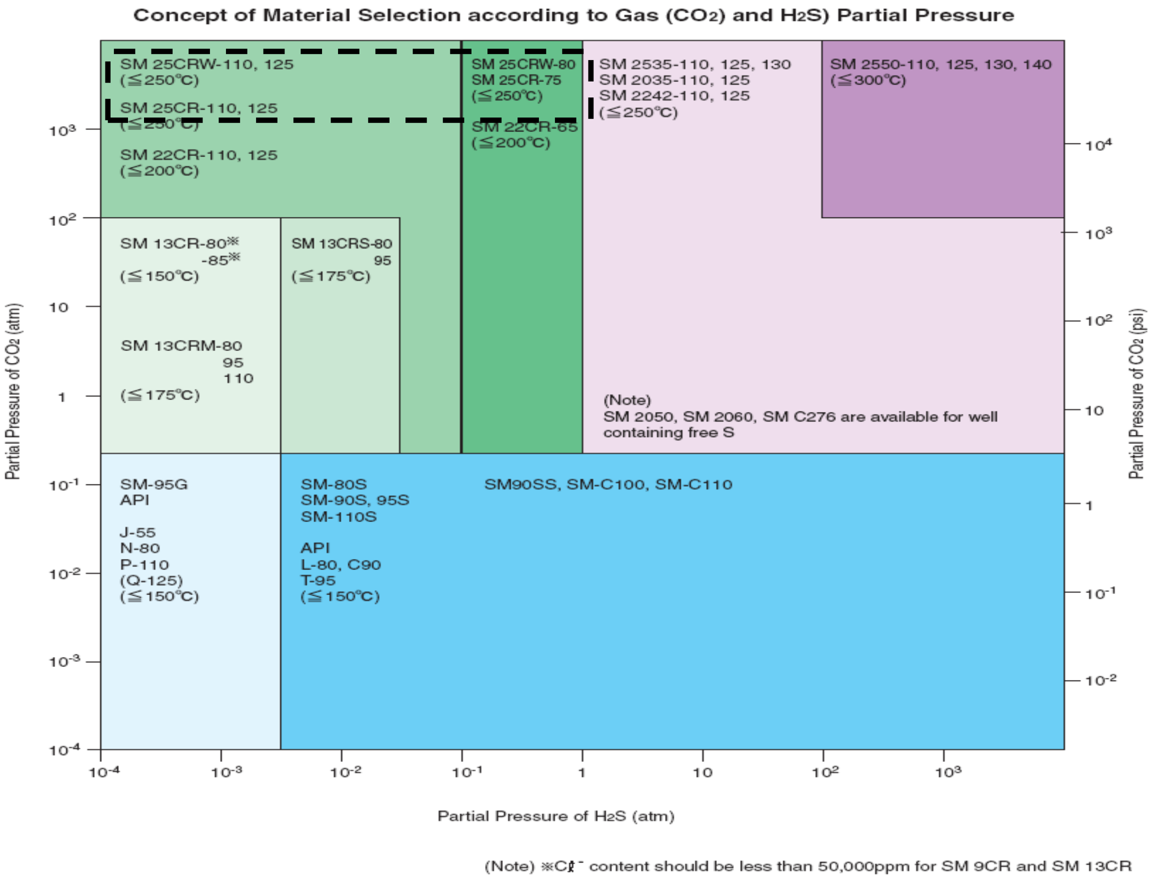


Table 4.62: Sumitomo Metals Material Selection Table 1

Special Applications for Corrosive Well Environments

Special Application	Special Application	Special Application	Special Application
Mild Environment	API Specification	J-55 M-65 N-80 P-110 (Q-125) SM-95G (SM-125G)	
Sulfide Stress Corrosion Cracking (Medium Pressure and Medium Temperature)	Cr or Cr-Mo Steel	L-80 C-90 T-95 SM-80S SM-90S SM-95S SM-110S	SM110S $H_2S \leqq 0.1$atm
Sulfide Stress Corrosion Cracking (High Pressure and High Temperature)	Cr or Cr-Mo Steel	SM90SS SM-C100 SM-C110	Higher Yield Strength for Sour Service
Wet CO_2 Corrosion	13Cr (Mod. AISI 420)	SM13CR-80 SM13CR-85 SM13CR-95※1	Quench and Tempered
	13Cr-5Ni-2Mo	SM13CRS-80 SM13CRS-90 SM13CRS-95 SM13CRS-110	Quench and Tempered
	13Cr- 5Ni- 1Mo	SM13CRM-80※1 SM13CRM-95※1 SM13CRM-110※1	Quench and Tempered
Wet CO_2 with a little H_2S Corrosion	22Cr-5Ni-3Mo	SM22CR-65※2 SM22CR-110, -125※3	Duplex Phase Stainless Steel
	25Cr-7Ni-3Mo	SM25CR-75※2 SM25CR-110, -125※3	※2 Solution Treated ※3 As Cold Drawn
	25Cr-7Ni-3Mo-2W	SM25CRW-80※2 SM25CRW-110, -125※3	
Wet CO_2 and H_2S Corrosion	25Cr-35Ni-3Mo	SM2535-110, -125, -130	As Cold Drawn
	22Cr-42Ni-3Mo	SM2242-110, -125	
	20Cr-35Ni-4Mo	SM2035-110, -125	
Most Corrosive Environment	25Cr-50Ni-6Mo	SM2550-110, -125, -130, -140	As Cold Drawn
	20Cr-50Ni-11Mo	SM2050-110, -125, -130, -140※4	※4 Environment with Free Sulphur
	20Cr-58Ni-13Mo	SM2060-110, -125, -130, -140, -150, -155※4	
	16Cr-54Ni-16Mo-W	SMC276-110, -125, -130, -140, -150※4	

※1 These materials are not suitable for H_2S containing environments.

Two generic selection tables for water injection tubing are included below given some commonality with CCS component issues i.e. oxygen, chloride content.

Table 4.63: Material Selection for Injection Well Tubulars

Option	Advantages	Disadvantages	Comments
Carbon Steel	Low Capex Widely Available	Poor lifetime Requires deaeration and possibly corrosion inhibition (high OPEX)	Can increase life by specifying >0.5% Cr
Coated Carbon Steel	Low Capex	Coating damage unavoidable and resulting life similar to carbon steel / lower due to more concentrated corrosion	
13Cr Steel		Highly susceptible to pitting even at low oxygen levels	Moderate Capex
High Alloy CRA	Most Reliable Option Good corrosion resistance and life Deaeration and corrosion inhibition not required	High Capex Cost of Material may be prohibitive	
GRE / Plastic Coated carbon steel	Good corrosion resistance and life Deaeration and corrosion inhibition not required	Some concerns with damage during installation and wirelining	Moderate Capex
Cement lined carbon steel	Good corrosion resistance and life Deaeration and corrosion inhibition not required	Note widely available and heavy for shipping Problems with damage during installation	Little operational experience outside U.S.A.

Table 4.64: Norsok M-001 Materials Selection for Wells

Well type	Tubing and liner	Completion equipment (Where different from tubing/liner)	NOTES
Production	13Cr is base case. See Table 6 for design limitations.		1
	Low alloy steel. (Option for systems with low corrosivity/short lifetime.)	13Cr	1, 2
	13 % Cr and 15 % Cr alloys modified with Mo/Ni (S13Cr), duplex and austenitic stainless steels and nickel alloys are options for high corrosivity		3
Aquifer water production	13Cr is base case		
Deaerated seawater injection	Low alloy steel	UNS N09925, Alloy 718 22Cr or 25Cr duplex	2, 4, 7
Raw seawater	Low alloy steel with GRP or other lining	Titanium. See also Table 6.	5, 8, 9
injection	Low alloy steel for short design life	Titanium. See also Table 6.	8, 9
	Titanium. See Table 6 for design limitations.		9
Produced water and aquifer water injection.	Low alloy steel	13Cr (limitations as for tubing for this service).	1, 2, 6
	Low alloy steel with GRP or other lining	13Cr (limitations as for tubing for this service).	1, 5
	13Cr. Provided oxygen < 10 mg/m^3, see also Table 6.		1
	22Cr duplex, Alloy 718, N09925. Provided oxygen < 20 mg/m^3.		
Gas injection	Materials selection shall be as for production wells and shall follow the guidelines in 4.3.2.		
Alternating injection and combination wells	Materials selection shall take into account that the corrosion resistance of different material alternatives will differ for various media.		

NOTES

1 For fluids with a partial pressure of H_2S above 0,1 bar, or pH below 3,5, 13Cr shall have a maximum SMYS of 560 MPa (80 ksi). Limiting the strength is generally recommended to avoid hydrogen stress cracking caused by hydrogen formed by galvanic corrosion of the casing.
2 Low alloy steel with corrosion allowance for tubing. Use of same CRA as for completion equipment shall be evaluated for liners.
3 Cold worked grades of duplex stainless steel shall be limited to 862 MPa (125 ksi) SMYS and maximum 966 MPa (140 ksi) actual yield strength in longitudinal and tangential direction.
4 Detailed materials selection for completion equipment to be based upon design requirements and supplier experience.
5 For GRP lining, qualification is required unless field experience can be provided. If GRP solid pipe is evaluated as an alternative for downhole tubing, see 6.3.3.
6 Corrosion inhibitors can be used in oxygen free systems provided acceptable from reservoir considerations.
7 Low alloy steel can be used in components located in lower sections of the well if strict dimensional tolerances in service are not required.
8 For short design lives and low temperatures, stainless steels or Ni-based alloys may be considered for completion equipment.
9 Raw seawater contains oxygen and may or may not contain chlorine.

The source of water for the proposed CCS wells as discussed will be a combination of condensed, seawater and formation water.

Critical to the seawater preparation for water wash is adequate quality control with respect filtration, oxygen scavenging and corrosion inhibition.

If tight control can be achieved on the residual oxygen concentration (<20ppb) and residual chlorine (<0.3 ppm) then the use of low alloy 1% Cr carbon steel can be considered.

If reliable stringent quality control of treated injection water to the required standard from the seawater source cannot be achieved it should be recognised that whilst the general corrosion rate of 13 Cr steel is lower than that of carbon steel in seawater, 13 Cr steels have a high susceptibility to pitting and crevice corrosion in this environment. Even if seawater is de-aerated, localised corrosion can be initiated during any breakdown in de-aeration and the levels of residual oxygen present with de-aeration can then be sufficient to propagate this corrosion mechanism.

In terms of the CO_2 injected stream quality, a similar level of oxygen to that applied historically to water injectors fluids is the basis behind the proposed target of <10 ppmv. This is estimated to result in a concentration of 20ppb in the formation brine at reservoir conditions based on 230bar and 60°C.

4.24.12.8 Summary of Material Selection Discussion

Common tubular material options for CO_2 injection wells are:

- carbon steel;
- Glass Reinforced Epoxy (GRE) lined carbon steel;
- 13Cr stainless steel; and
- Corrosion Resistant Alloy (CRA) e.g. Duplex.

CO_2 & General Corrosion

The corrosion resistant alloys provide corrosion protection as a result of their chromium content. The chromium creates a protective layer, the effectiveness of which depends upon the chromium content. Under mild conditions the martensitic stainless steels containing 13% chromium may be adequate however if the pH falls below 3.5, higher alloys such as a duplex stainless steels are recommended. 13% chromium steels should not be used for water injection wells without careful modelling of pH for both current and future well conditions. 13Cr tubulars are often predicted to have a low general corrosion rate (<0.1mm/y) in a CO_2 injection system. However, the presence of oxygen in the injected CO_2 can cause severe pitting corrosion on 13Cr tubulars where liquid water is present. Duplex (25% Cr) is an option to mitigate this and has been used by Statoil in the Sleipner field. In that case, CO_2 was injected into an aquifer and therefore, the tubulars in the CO_2 injection wells were in contact with formation water during shut-in, similar to the proposed White Rose project.

Cl-, O_2 & Pitting Corrosion

The presence of Chlorides or Oxygen can compromise the protective chromium oxide layer, resulting in pitting or crevice corrosion. These forms of corrosion may occur rapidly, they are difficult to detect and often catastrophic. In addition to the chloride and oxygen content, the rate of pitting corrosion depends upon temperature, pH and velocities. If the chloride content exceeds 1,000 ppm or oxygen content exceeds 10ppb, corrosion resistant alloys with a high Pitting Resistance Equivalent Number (PREN) should be used. The martensitic stainless steels will not provide sufficient protection. To prevent localised corrosion in seawater or where there is a potential for oxygen contamination, an alloy with PREN>40 is recommended, such as 25Cr Super Duplex or CRA 2550E.

Chlorides in the presence of tensile stresses may also lead to Stress Corrosion Cracking (SCC) at elevated temperatures. Alloys with higher nickel content are more resistant to SCC. Alloys with nickel content greater than 42%, such as CRA 2550E are considered immune to SCC from chlorides.

H_2S, H & Environmentally Assisted Cracking

H_2S corrosion in the presence of tensile stress may result in catastrophic failure as a results of hydrogen embrittlement by mechanisms such as Sulphide Stress Cracking (SSC) and Stress Corrosion Cracking (SCC). Hydrogen embrittlement may also result from other sources of hydrogen such as cathodic protection commonly used in seawater. These failures are often delayed, but happen abruptly with no visible warning and may happen at stresses well below the yield strength. Factors contributing to Environmentally Assisted Cracking (EAC) include partial pressures of H_2S and CO_2, temperature, pH, chlorides and stress. Environments with partial pressure of H_2S greater than 0.05psi are considered "sour" and cracking can only be avoided through the proper selection of materials. The potential for an increase in H_2S content over the life of the well should considered. NACE MR0175/ISO 15156 serves as the industry guideline for selection of materials for sour service.

Material properties contributing to EAC resistance include composition, microstructure, processing history and hardness. The martensitic stainless steels may be adequate where the partial pressure of H_2S is below 1.5psi and the pH is greater than 3.5 while 25Cr Super Duplex Stainless Steel is acceptable up to 3.0psi H_2S. Above that, nickel base alloys such as CRA 2550E are required. CRA 2550E can be used up to 300F with no restriction to H_2S content; in addition its high PREN prevents pitting corrosion.

GRE (Glass Reinforced Epoxy)

Given the potential shortcomings of carbon steel and 13Cr, when in contact with combinations of CO_2, O_2 and high salinity brines an alternative material, GRE could be considered.

GRE can be used either as an internal lining providing corrosion protection to the inside of a steel tubular or it can be used as a standalone tubular product. The use of GRE as an internal lining of steel tubing is far more common that the GRE standalone approach which is rare. Both approaches have been used in CO_2 wells where GRE has been used in elements of the flow wetted casing / liner scheme or upper completion tubing with varying degrees of success.

GRE as an internal lining of steel tubulars reduces the pipe internal diameter. The increase in frictional injection pressure losses that might be expected however are typically offset due to the significantly reduced friction co-efficient or 'pipe roughness' of GRE compared to steel. Modelling is needed on a case by case basis to confirm the variance that can be expected. Provisional sensitivities on injection performance with respect pipe roughness have been included in this report.

GRE as an internal lining of steel tubulars is the most commonly used GRE throughout the industry, however with this approach the outside of the pipe is unprotected, if exposed to the environment. If GRE lined pipe is used as an upper completion tubing then this is not an issue given that the A annulus is normally isolated by a production packer at the base of the upper completion. However, if this is used as a cemented and perforated production liner then the backside of the liner across the perforations will be exposed. A solution for this can be to cover the OD in GRE also.

GRE Issues

In the event that a GRE lining or GRE outer coating becomes damaged either during installation or at any other time over the course of the well lifecycle then the steel tubular becomes exposed to the concentrated efforts of the corrosive agents in the well flow stream.

An issue noted with GRE lined pipe historically has been damage at tubular connections which led to a re-design in this area by suppliers.

A main drawback of GRE material relates to its mechanical properties. GRE as a standalone tubular solution has very limited strength and low stiffness compared with metallic tubing. Compatibility with metallic downhole equipment can be a problem, for example the local sealing forces developed by conventional packers. At high pressures, GRE tubing is prone to creep to a much greater extent than metallic materials. This is especially true in high temperature fluctuation applications.

Solid GRE is a potential solution for two-sided CO_2 exposure and where GRE lined pipe is not feasible. This again has issues with mechanical properties and handling when running in hole during installation.

Not enough information and data is available on solid GRE casing however, it would be prudent to assess what is available in more detail during the detailed design phase.

NOV (National Oilwell Varco, Inc.) which are the only solid GRE liner/casing supplier in the world have stated that they have operated with supercritical CO_2 up to 2100psi roughly, mostly without issues. It is known that CO_2 permeates GRE very slowly and if rapidly decompressed it can blister the GRE, in the case of liners they predict that the rapid decompression would collapse the liner. If there are operations at pressures higher than 2000psi, they would expect this to magnify the explosive decompression issues. Rapid changes in temperature can also simulate higher pressures and force the same phenomenon.

The conventional method to install a production liner is to run the liner in the well bore with a liner hanger. Generally, installed on the bottom of the liner is a float shoe and float collar; the liner is attached to the liner hanger and is carried into the hole on a setting tool attached to the work string. At setting depth, the liner hanger is engaged and rotation is put into the string to aide cement placement. Cement is pumped down the work string, down the liner and circulated around the outside of the liner. After the cement has been placed around the liner, the float collar and float shoe close and act as back pressure valves to prevent the cement migrating back into the liner. The setting tool is retrieved from the liner hanger and pulled out of the hole. Any cement left in the liner is drilled out. This leaves a ‘clean’, open bore from the liner hanger at the top of the liner, to the float equipment at the base of the liner.

This conventional method is unacceptable with fibreglass liner for several reasons. First, it is required that no cement be inside the fibreglass liner. To drill out cement inside the fibreglass may result in damaging or destroying the fibreglass. Second, the buoyancy of the fibreglass in the cement requires that the work string be left in the well to hold the fibreglass liner in place until the cement sets up, or that a hold-down slip system be used on the liner hanger. Third, the liner rotation to aide cement placement will not be able to take place due to the brittle nature of fibreglass and the lack of torsional strength.

The liner hanger would have to include a hold-down system. Because of the corrosiveness of the CO_2 injection, this system of tools would have to be made of corrosion resistant alloy such as 25 Chrome. To have a mass of such steel on the top of the fibreglass liner negated one of the reasons for using the fibreglass – its drillability.

A drillable permanent packer could be substituted for the liner hanger system in this installation. The liner would be run to depth and cemented in place. The permanent packer would then be set, sealing off the cement and locking the fibreglass liner in place. To overcome the requirement that no cement be allowed inside the fibreglass liner during cementing operations, an inner cementing string could be incorporated into the mechanical packer setting tool. This will allow the liner to be run and cemented without cement contamination inside the fibreglass.

Due to the brittle nature of the fibreglass, the type and quantity of workovers will have to be assessed. For example; upper completion packer setting and retrieval will damage the integrity of the fibreglass liner. Speciality packers would have to be sourced and they bring their own problems with running and setting.

The most common application of GRE as an upper completion lining has been in water injectors. This has been based on a driver to reduce friction to optimise high rate injection rates, lesser cost compared to high grade alloys and importantly an expectation of zero / minimal wireline or coil tubing through tubing well intervention requirements which would risk damaging the protective GRE lining.

Offset CCS Material Feed Specifications

Table 4.65: Metallurgy Offset Selection Choices

Project	Completion Metallurgy
Chevron Gorgon (proposed)	Production liner and lower production casing: Super duplex (25% Cr with tungsten) Tubing: GRE lined carbon steel
Sleipner	Upper and lower completion: Duplex
BP In-Salah	Carbon steel throughout
Sumitomo initial recommendations for Browse	Production liner and lower completion: S725CrW Tubing Carbon steel or GRE lined carbon steel

4.24.12.9 Recommendation

Table 4.66: Material recommendation

Equipment Type	Selected Material
Tubing	1% Cr steel with GRE Internal Lining or 25 Cr SDSS*
Equipment with dynamic seal surfaces (DHSVs etc.)	25 Cr SDSS*
Packer	25 Cr SDSS*
Liner	25 Cr SDSS*
Wellhead, Christmas Tree, Tubing Hanger	25 Cr SDSS*
	Low alloy steel with UNS NO6625 weld overlay

*If pH_2S is less than 20 mbar / 3psi

25 Cr Super Duplex SS L80 material with a PREN number >40 should be used for the completion jewellery, assembly pups and in order to simplify rig time handling also the tailpipe and the tubing section between the hanger and safety valve.

Given that the machining ability for 25 Cr is limited then alternately for some components Alloy 925 or Alloy 718 is the recommended choice.

4.24.13 CO_2 Injection Modelling

A single bore CO_2 Injector has been modelled from sand face to surface with Prosper software (IPM 9.0 Build #152) for well path P5W3 Rev A.1 G&G R Report.

A Petroleum Experts (PE) reservoir model has been considered for inflow performance along with Wong-Clifford selected to account deviation and partial penetration skin. Petroleum Experts 5 was selected for the vertical flow correlation. This correlation includes the features of the earlier PE correlations plus original work on predicting low-rate Vertical Lift Performances (VLPs) and well stability. PE5 is capable of modelling any fluid type over any well or pipe trajectory. This correlation accounts for fluid density changes for incline and decline trajectories. Currently no ongoing Endurance CO_2 injection field data is yet available to match / refined the model.

Prosper modelling was run to optimise injectivity profile for Endurance well for different injection rates for a specific wellhead pressure.

Tubing size sensitivities were run for 7in, 5 ½in and 4-1/2in upper completion tubing string / completion configurations. Sensitivities were run on permeability, perforated interval, reservoir thickness and skin.

The wellhead pressure ranges considered were from 750psig to 1000psig, permeability from 50mm to 800mD, Skin assumed from 2 to 20 and perforated interval considered from 100ft to 500ft. In all cases, the bottom perforations depths are considered 100ft above from the bottom of the reservoir at 7313ft MDBRT. Reservoir thickness varies from 899ft to 1014ft TVD. A reservoir thickness of 1014ft TVD was used for analysis, based on P5W3 formation tops. A radial flow model with a drainage area of 1311 acres (1300m radial) and Dietz shape factor of 31.6 has been assumed for calculation purposes.

A fracture gradient of 13.4ppg has been assumed from the Initial Well Test Evaluation Report on Well 42/25d- 3. Maximum static wellhead pressure using seawater and without fracturing the formation has been calculated as approx. 1086psi. Injected temperature assumed as 60°F.

CO_2 Injection Model

For inflow performance a single layer Petroleum Expert model with Wong-Clifford has been chosen and sensitivities has been run based on the following parameters:

- permeability; 50,100,260,500 & 800md;
- reservoir thickness; 1014ft TVD (from P5W3 formation tops);
- rerforated Interval; 100,200,300,400 & 500ft (assumed);
- reservoir pressure; 2313psi at top perf at 7013ftMDBRT/4851ftTVD (extrapolated from datum); and
- wellhead pressures; 750, 1000psig.

Completion Schematic/Flow Path

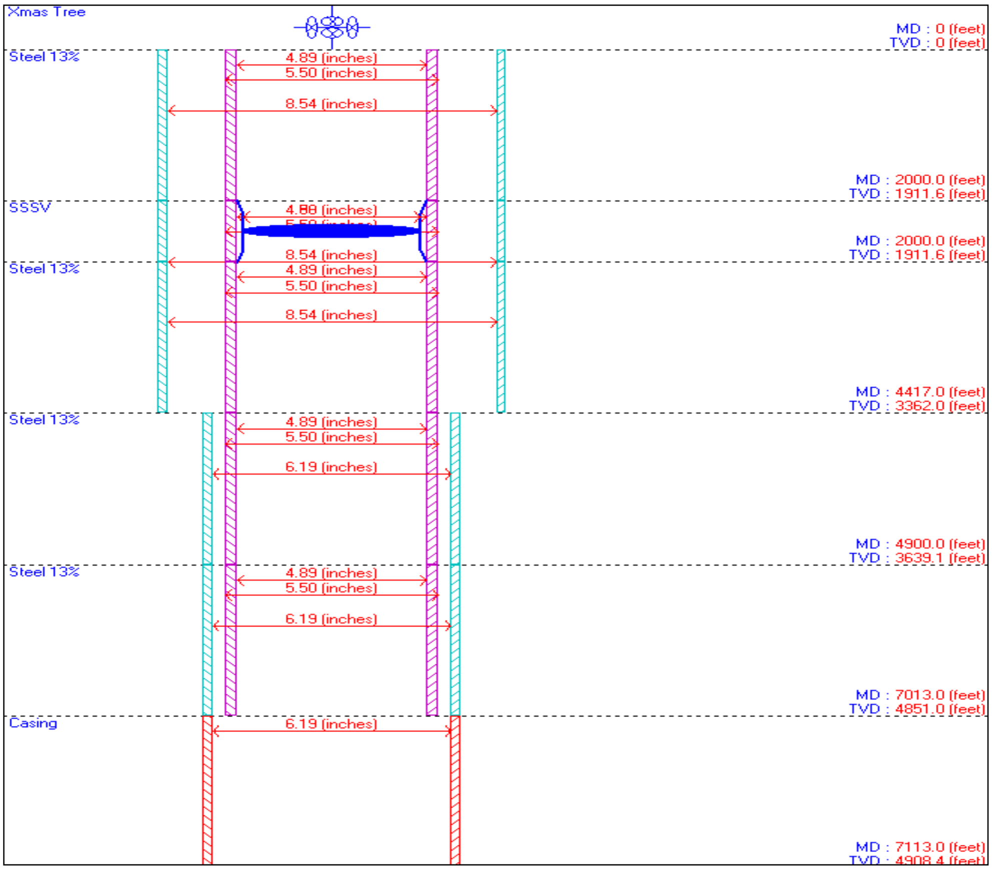
The model downhole configuration based on a 5 ½in / 7in upper completion tubing is tabulated in Table 4.67 below.

Table 4.67: Downhole Configuration

Parameters	To Surface / Configuration
Riser (in)	20
Casing (in)	13-3/8
Casing (in)	9-5/8
Liner (in)	7
Wellbore Diameter (in)	8-1/2
Tubing Diameter (in)	5-1/2, 7
Reservoir Formation	Bunter Sandstone L1b, L1a

A flow path and downhole equipment diagram is shown in Figure 4.51 for 5 ½in tubing configuration.

Figure 4.51: Downhole Configurations

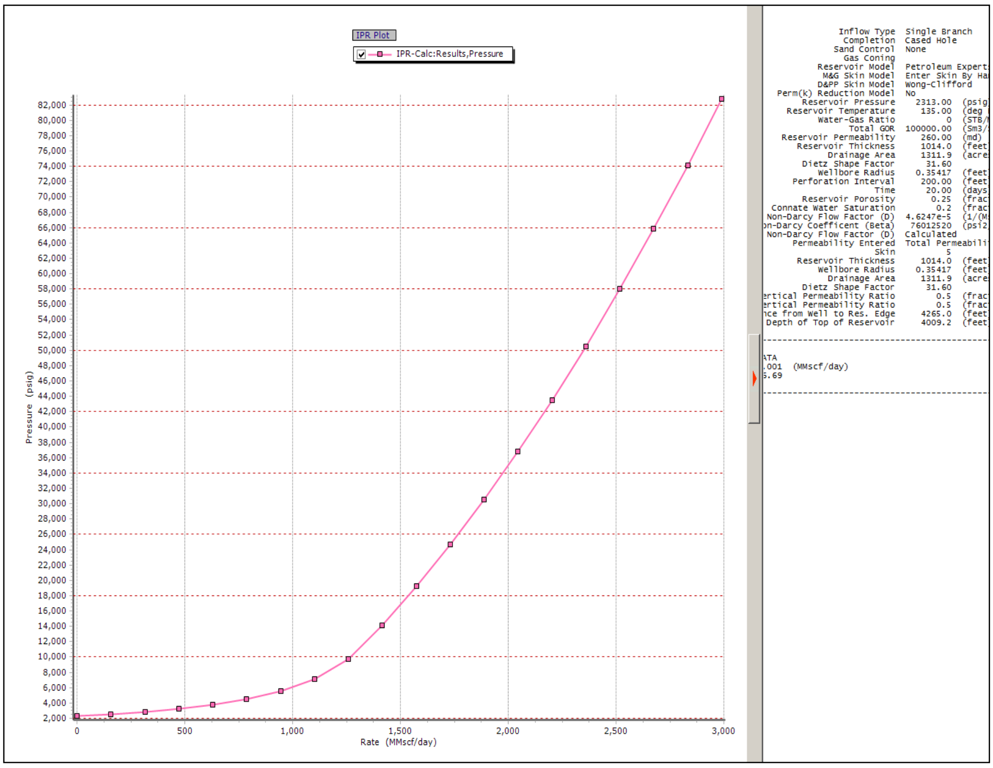


CO_2 Injection Plots 5-1/2in Tubing

The inflow performance of the CO_2 injector well is shown below. The plot shows an Absolute Open Flow (AOF) of 2,991MMSCFD. However, as this is an injector well, the principle of the AOF no longer has a physical meaning as there is no limit to what the BHP can be (unlike a production well which is limited by

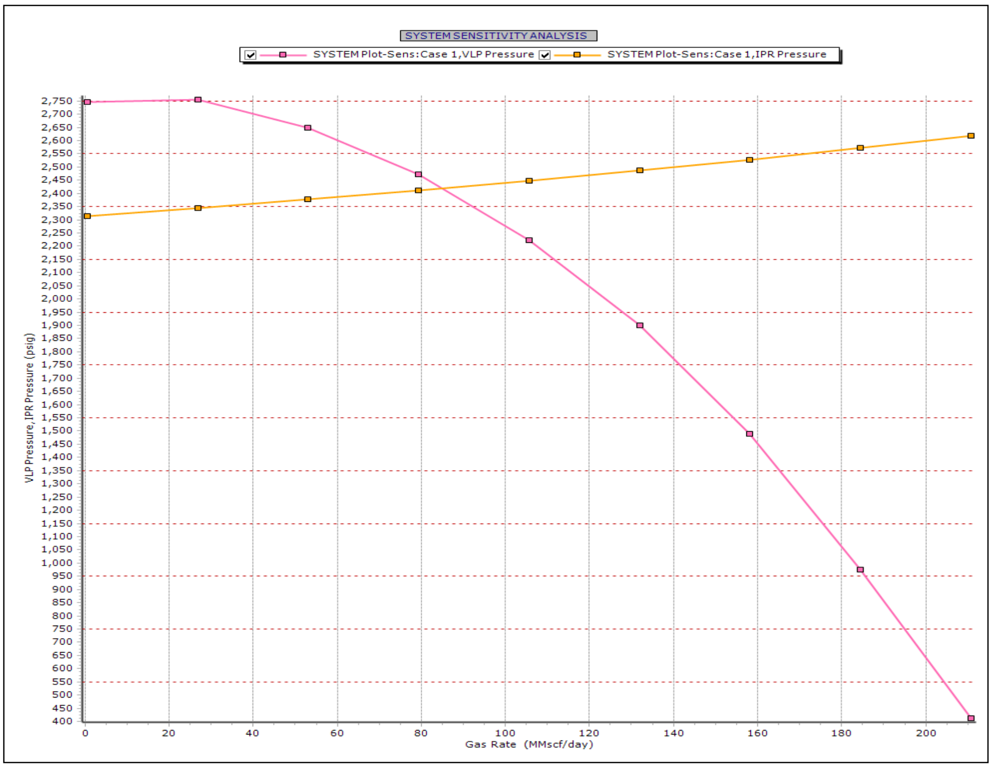
0psig). As the range of the value used is so wide, the curve shown may not be representative of the actual injectivity at lower rates.

Figure 4.52: IPR Plot



The System plot in figure 62 below for 5 ½in tubing string, show that if a WHP of 1000psig, a skin of 5 and reservoir permeability of 260mD, the model predicts that the well can inject CO_2 at approximately 84.8MMSCFD and that the corresponding bottom hole flowing pressure will be 2419psig.

Figure 4.53: System Sensitivity Analysis Plot



4.24.14 CO_2 Injection Rate Unit Comparison

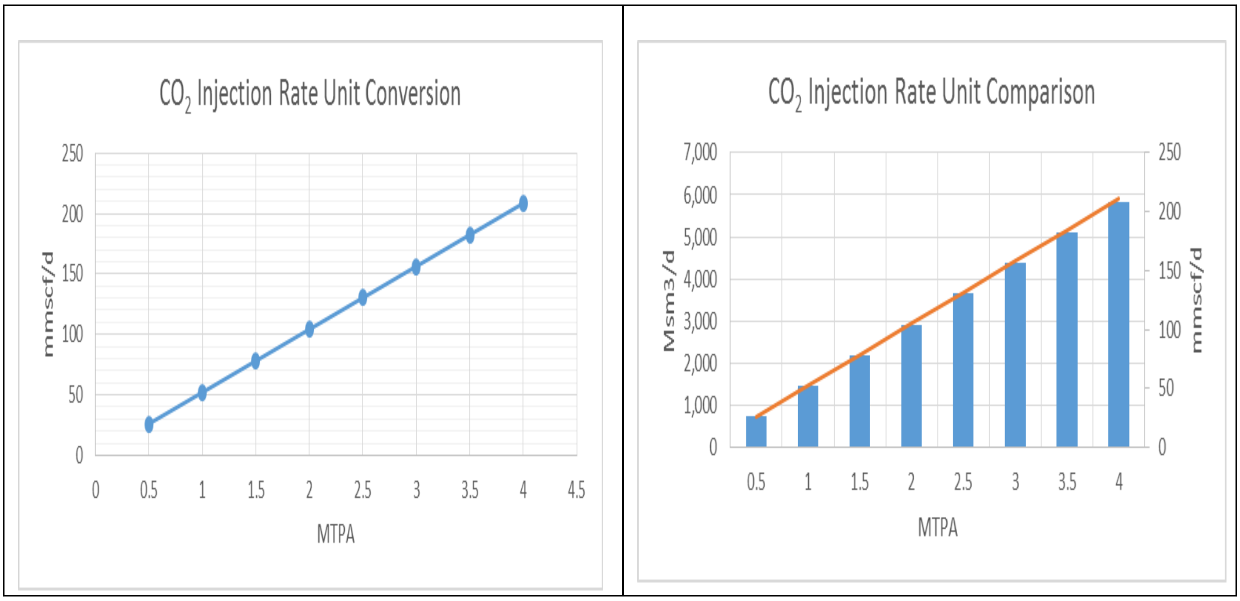
CO_2 injection rates are expressed in million metric tonnes per year (MTPA) by the onshore power station network that feeds the pipeline. Offshore, units of gas at standard conditions are more commonly (15.6°C / 1 atmos.) expressed in either thousands of cubic metres per day (Msm^3/d), or millions of cubic ft per day (MMSCFD). 1 Metric Tonne is 2205 lbs or 50.113 lb moles which occupies 19,029scf or 538.8Sm^3. Table 4.68 and plots in Figure 4.54 below are provided for a means of convenient comparison between these units. 1MTPA is equivalent to 52.135MMSCFD.

Table 4.68: Rate Unit Conversion Comparison

MTPA	MMSCF/yr	mmsm^3/yr	MMSCFD	msm^3/d
0.1	1,903	54	5	148
0.2	3,806	108	10	295
0.4	7,612	216	21	591
0.564	10,733	304	29	833
0.6	11,418	323	31	886
0.8	15,224	431	42	1,181
1	19,029	539	52	1,476
1.5	28,544	808	78	2,214
2	38,059	1,078	104	2,953
2.5	47,574	1,347	130	3,691
2.65	50,428	1,428	138	3,912

MTPA	MMSCF/yr	mmsm^3/yr	MMSCFD	msm^3/d
3	57,088	1,617	156	4,429
3.5	66,603	1,886	182	5,167
4	76,118	2,155	209	5,905

Figure 4.54: Rate Unit Conversion Comparison



4.24.15 CO_2 Injection 4-1/2in Tubing Tabulated Results

The results for all 4-1/2in tubing sensitivities run have been shown below:

Table 4.69: Permeability Sensitivity Results

CO2 Injection Rate, MMScf/d:

Permeability, K mD			WHP, psig 750	850	1000
50	None	None	None	28.52	38.78
100	None	None	None	33.89	46.54
260	None	None	None	38.36	52.99
500	None	None	None	39.95	54.39
800	None	None	None	40.63	54.97

Bottm Hole Pressure (BHP), psig:

Permeability, K mD			WHP, psig 750	850	1000
50	None	None	None	2477	2544
100	None	None	None	2411	2450
260	None	None	None	2355	2372
500	None	None	None	2336	2344
800	None	None	None	2327	2333

Nb: Skin = 2
Perf Interval = 200 ft, MD

Table 4.70: Skin Sensitivity Results

CO_2 Injection Rate, MMScf/d:

	WHP, psig				
Skin			750	850	1000
2	None	None	None	40.23	52.99
5	None	None	None	40.02	52.69
10	None	None	None	39.68	52.24
15	None	None	None	39.31	51.85
20	None	None	None	38.91	51.46

Bottm Hole Pressure (BHP), psig:

	WHP, psig				
Skin			750	850	1000
2	None	None	None	2357	2372
5	None	None	None	2360	2376
10	None	None	None	2365	2382
15	None	None	None	2369	2388
20	None	None	None	2373	2394

Nb: Permeability = 260 mD
Perf Interval = 200 ft, MD

Table 4.71: Perforated Interval Sensitivity

CO_2 Injection Rate, MMScf/d:

	WHP, psig				
Perforated Interval, ft MD			750	850	1000
100	None	None	None	37.73	50.31
200	None	None	None	40.02	52.69
300	None	None	None	40.83	53.57
400	None	None	None	41.27	54.08
500	None	None	None	41.56	54.41

Bottm Hole Pressure (BHP), psig:

	WHP, psig				
Perforated Interval, ft MD			750	850	1000
100	None	None	None	2386	2412
200	None	None	None	2360	2376
300	None	None	None	2349	2362
400	None	None	None	2343	2354
500	None	None	None	2339	2349

Nb: Skin = 5
Permeability = 260 mD

Table 4.72: Tubing Roughness Sensitivity

CO2 Injection Rate, MMScf/d:

Tubing Roughness	WHP, psig				1000
0.006	None	None	None	None	42.00
0.007	None	None	None	None	41.25
0.008	None	None	None	None	40.61
0.009	None	None	None	None	40.04
0.010	None	None	None	None	39.53

Bottm Hole Pressure (BHP), psig:

Tubing Roughness	WHP, psig				1000
0.006	None	None	None	None	2363
0.007	None	None	None	None	2362
0.008	None	None	None	None	2361
0.009	None	None	None	None	2360
0.010	None	None	None	None	2359

Nb: Skin = 5
Permeability = 260 mD

4.24.16 CO_2 Injection 5-1/2in Tubing Tabulated Results (sensitive runs)

Table 4.73: Permeability Sensitivity Results

CO2 Injection Rate, MMScf/d:

Permeability, K mD	WHP, psig			750	1000
50	None	None	None	4.46	52.6
100	None	None	None	4.97	68.66
260	None	None	None	5.34	81.85
500	None	None	None	5.47	86.43
800	None	None	None	5.25	88.28

Bottm Hole Pressure (BHP), psig:

Permeability, K mD	WHP, psig			750	1000
50	None	None	None	2337	2633
100	None	None	None	2326	2522
260	None	None	None	2318	2408
500	None	None	None	2316	2365
800	None	None	None	2314	2346

Nb: Skin = 2
Perf Interval = 200 ft, MD

Table 4.74: Skin Sensitivity Results

CO2 Injection Rate, MMScf/d:

		WHP, psig				
					750	1000
Skin	2	None	None	None	5.34	81.85
	5	None	None	None	5.32	81.27
	10	None	None	None	5.3	80.33
	15	None	None	None	5.27	79.4
	20	None	None	None	5.24	78.44

Bottm Hole Pressure (BHP), psig:

		WHP, psig				
					750	1000
Skin	2	None	None	None	2318	2408
	5	None	None	None	2319	2414
	10	None	None	None	2319	2423
	15	None	None	None	2320	2432
	20	None	None	None	2321	2440

Nb: Permeability = 260 mD
Perf Interval = 200 ft, MD

Table 4.75: Perforated Interval Sensitivity

CO2 Injection Rate, MMScf/d:

		WHP, psig				
					750	1000
Perforated Interval, ft MD	100	None	None	None	5.15	75.5
	200	None	None	None	5.32	81.27
	300	None	None	None	5.39	83.53
	400	None	None	None	5.43	84.8
	500	None	None	None	5.46	85.6

Bottm Hole Pressure (BHP), psig:

		WHP, psig				
				500	750	1000
Perforated Interval, ft MD	100	None	None	None	2322	2466
	200	None	None	None	2319	2414
	300	None	None	None	2317	2392
	400	None	None	None	2316	2380
	500	None	None	None	2316	2372

Nb: Skin = 5
Permeability = 260 mD

Table 4.76: Tubing Roughness Sensitivity

CO2 Injection Rate, MMScf/d:

Tubing Roughness	WHP, psig				1000
0.006	None	None	None	None	68.4
0.007	None	None	None	None	66.78
0.008	None	None	None	None	65.87
0.009	None	None	None	None	65.07
0.010	None	None	None	None	64.34

Bottm Hole Pressure (BHP), psig:

Tubing Roughness	WHP, psig				1000
0.006	None	None	None	None	2397
0.007	None	None	None	None	2395
0.008	None	None	None	None	2393
0.009	None	None	None	None	2392
0.010	None	None	None	None	2391

Nb: Skin = 5
Permeability = 260 mD

4.24.17 CO_2 Injection 7in Tubing Tabulated Results (sensitive runs)

Table 4.77: Permeability Sensitivity Results

CO2 Injection Rate, MMScf/d:

Permeability, K mD	WHP, psig			750	1000
50	None	None	None	55.57	87.81
100	None	None	None	86.85	130.22
260	None	None	None	123.31	173.66
500	None	None	None	138.41	190.52
800	None	None	None	144.93	197.61

Bottm Hole Pressure (BHP), psig:

Permeability, K mD	WHP, psig			750	1000
50	None	None	None	2628	2846
100	None	None	None	2564	2712
260	None	None	None	2451	2517
500	None	None	None	2393	2428
800	None	None	None	2365	2387

Nb: Skin = 2
Perf Interval = 200 ft, MD

Table 4.78: Skin Sensitivity Results

CO2 Injection Rate, MMScf/d:

		WHP, psig				
					750	1000
Skin	2	None	None	None	123.31	173.66
	5	None	None	None	121.31	171.51
	10	None	None	None	118.12	168.02
	15	None	None	None	115.09	164.69
	20	None	None	None	112.23	161.46

Bottm Hole Pressure (BHP), psig:

		WHP, psig				
					750	1000
Skin	2	None	None	None	2451	2517
	5	None	None	None	2458	2528
	10	None	None	None	2470	2546
	15	None	None	None	2480	2562
	20	None	None	None	2490	2579

Nb: Permeability = 260 mD
Perf Interval = 200 ft, MD

Table 4.79: Perforated Interval Sensitivity

CO2 Injection Rate, MMScf/d:

		WHP, psig				
					750	1000
Perforated Interval, ft MD	100	None	None	None	105.19	152.87
	200	None	None	None	121.31	171.51
	300	None	None	None	128.79	179.47
	400	None	None	None	132.97	184.01
	500	None	None	None	135.41	186.71

Bottm Hole Pressure (BHP), psig:

		WHP, psig				
					750	1000
Perforated Interval, ft MD	100	None	None	None	2515	2618
	200	None	None	None	2458	2528
	300	None	None	None	2432	2488
	400	None	None	None	2417	2465
	500	None	None	None	2406	2450

Nb: Skin = 5
Permeability = 260 mD

Table 4.80: Tubing Roughness Sensitivity

CO2 Injection Rate, MMScf/d:

Tubing Roughness	WHP, psig			750	1000
0.006	None	None	None	112.05	153.51
0.007	None	None	None	110.34	150.85
0.008	None	None	None	108.87	148.56
0.009	None	None	None	107.58	146.55
0.010	None	None	None	106.43	144.77

Bottm Hole Pressure (BHP), psig:

Tubing Roughness	WHP, psig			750	1000
0.006	None	None	None	2388	2421
0.007	None	None	None	2386	2419
0.008	None	None	None	2385	2417
0.009	None	None	None	2384	2415
0.010	None	None	None	2383	2414

Nb: Skin = 5
Permeability = 260 mD

4.24.18 Erosion Velocity Constraints

CO_2 injection erosional velocity limits have been examined within Prosper for 4-1/2, 5-1/2 and 7in upper completion tubing sizes. The results illustrate how at higher rates larger tubing sizes result in lower flow velocities and allow the adoption of more conservative erosional 'C' factor value choices whilst still meeting target injection rates.

Table 4.81: Erosional Velocity and C Factor Sensitivity on 4 ½in Tubing

C Factor	Flow Rate, MMScf/d	Wellhead Pressure, Psig	Erosional Velocity, ft/sec	Erosional Velocity Flag
250	55.35	750	52.3	No
	79.01	750	63.5	Yes
	110.55	1000	35.06	No
	118.44	1000	35.16	Yes
450	86.89	750	100.43	No
	94.78	750	213.07	Yes
	142.1	1000	63.98	No
	149.98	1000	63.88	No

Table 4.82: Erosional Velocity and C Factor Sensitivity on 5 ½in Tubing

C Factor	Flow Rate, MMScf/d	Wellhead Pressure, Psig	Erosional Velocity, ft/sec	Erosional Velocity Flag
250	79.3	750	61.7	No
	131.9	750	63.3	Yes
	158.2	1000	34.8	No
	184.5	1000	35	Yes
450	131.9	750	114	No
	158.2	750	144	Yes
	263.4	1000	384	No
	289.6	1000	556	Yes

Table 4.83: Erosional Velocity and C Factor Sensitivity on 7in Tubing

C Factor	Flow Rate, MMScf/d	Wellhead Pressure, Psig	Erosional Velocity, ft/sec	Erosional Velocity Flag
250	131.9	750	61.9	No
	158.2	750	61.3	Yes
	263.3	1000	34.8	No
	289.6	1000	34.9	Yes
450	263.3	750	100	No
	289.6	750	144	Yes
	473.6	1000	63.8	No
	499.9	1000	63.9	Yes

The reported flow rate values relate to tubing performance only not system (inflow / outflow) but serve to indicate the threshold rates at which velocity erosional limits are reached or “flagged”.

Detailed design should consider how further an appropriate C factor might be qualified through either empirical data research or testing specific to the proposed CO_2 injected stream.

In a positive sense the following points can be made in terms of lower erosion / corrosion risk with regard to the CO_2 injected stream:

- expected to be ‘dry’ with respect water content;
- will be filtered at surface to a circa sub 10 micron solid level; and
- will exist entirely as a liquid under steady state injection conditions.

In a negative sense the following points can be made in terms of increased erosion / corrosion risk with regard the CO_2 injected stream:

- the well life is very long at 20 years; and
- Corrosion potential is high given potential combined presence of (CO_2, O_2, Cl and H_2O).

A 5-1/2in tubing choice is considered to provide an acceptable choice with respect to the erosion velocity limit risk, with a 7in tubing choice providing a high level of conservatism for maximum rates. Further a 7in monobore style tubing choice can be a means to reduce turbulence at the upper completion / liner interface which in turn may reduce erosion / corrosion risk.

4.24.19 Injection Choke Temperature Modelling

An area of key project concern has been to qualify the risk with respect low temperature as a result of CO_2 phase changes associated with the injection of CO_2 across the surface injection chokes. Prosper software has been used for the study of choke performance for a range of relevant pressure drops for minimum and maximum injection rates of 30MMSCFD and 138MMSCFD respectively.

Table 4.84: Pressure & Temperature

Inlet Pressure barg	Inlet Temperature, ℃	Outlet Pressure, barg	Gas Rate, MMScf/d	Predict Choke Setting, in	Outlet Temperature, ℃	Critical Pressure, barg	Critical Rate, MMScf/d	Critical Temperature, ℃
182	16	10	30	0.58	-28.88	68.01	30.05	11.2
		80	30	0.58	12	68.01	30.07	11.2
	3	10	30	0.57	-28.88	67.66	30.05	0.68
		80	30	0.57	1.09	67.67	30.07	0.68
90	16	10	30	0.71	-28.88	36.17	30.05	0.69
		80	30	0.94	15.29	42.77	53.65	6.46
	3	10	30	0.69	-28.88	35.78	30.05	-12.36
		80	30	0.93	2.67	42.18	53.9	1.06

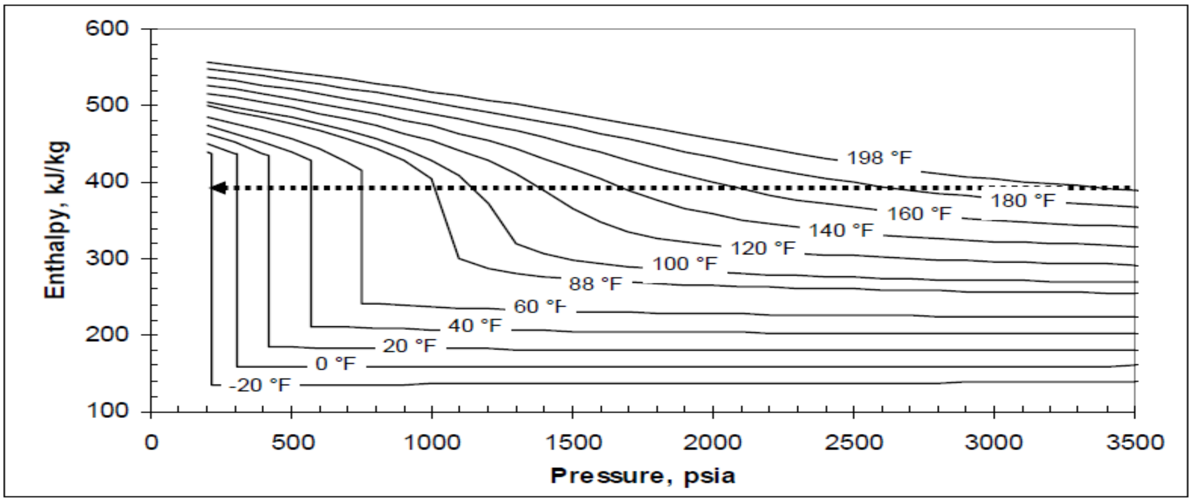
Table 4.85: Pressure & Temperature

Inlet Pressure barg	Inlet Temperature, ℃	Outlet Pressure, barg	Gas Rate, MMScf/d	Predict Choke Setting, in	Outlet Temperature, ℃	Critical Pressure, barg	Critical Rate, MMScf/d	Critical Temperature, ℃
182	16	10	138	1.24	-28.88	108.21	138.13	13.51
		80	138	1.25	12	108.26	138.27	13.51
	3	10	138	1.23	-28.88	106.77	138.13	1.82
		80	138	1.23	1.09	106.82	138.28	1.82
90	16	10	138	1.52	-28.88	64.97	137.98	14.05
		80	138	1.63	15.29	70.45	159.57	14.53
	3	10	138	1.48	-28.88	63.38	138.03	2.05
		80	138	1.61	2.67	69.51	163.25	2.29

On review it was established that at the highest pressure drop values there was an inconsistency in the calculated results with Prosper generating a constant minimum downstream temperature value of -28.88°C / -19.98^{0}F once a certain magnitude of pressure drop had been reached. Whilst this provides some guide to an upper minimum value further review was considered to qualify this outcome.

To this end, an approach was taken to simply consider the maximum pressure drop, the upstream temperature, constant enthalpy (no transfer of external heat to the system) and on this basis determine the outcome to represent the downstream temperature that could be expected as per the Figure 4.55 below.

Figure 4.55: CO_2 Enthalpy vs Pressure and Temperature



Based on the Figure 4.55 it can be seen given an upstream pressure of 2639psi (182bar) and a downstream pressure of 200psi (14bar) then a downstream temperature of -20^{0}F / -28°C is predicted.

Given a minimum surface pressure of a seawater column of 145psi (10bar) then a minimum temperature immediately downstream of the injection choke slightly colder than -20^{0}F / -28°C must be considered.

The injection choke itself however is some distance from the well and ambient surface temperature will contribute to increase the temperature of the flow stream entering the well. Further the cooling effect will rapidly reduce as pressure is equalised. Operating procedures will also be used to seek to minimise the risk of hydrates by using hydrate inhibitor pills.

Further operating procedures will seek means to equalise or reduce the initial pressure differential using water / glycol / nitrogen purging techniques prior to opening the injection choke after shut-in. These approaches are discussed later in the hydrate / operating procedure sections of this report.

A choke pressure drop induced downstream minimum potential temperature of -30°C is proposed as the design basis for this report based a high differential between pipeline arrival and downstream well shut-in pressures of a seawater column at 10barg.

The injection choke pressure drop induced temperature modelling discussion has highlighted the potential for large temperature drops associated with well start up with a high differential between pipeline arrival and well shut-in pressures. A further extrapolation of this logic is to consider line, well tubular rupture and subsequent line or well uncontrolled atmospheric (1bar) venting. This in theory would potentially result in temperatures as low as -70°C. This issue of extreme low temperature theoretically as low as -70°C, due to unplanned or planned atmospheric venting of CO_2 for each section of the system, (subsea pipeline, topsides process pipework upstream and downstream of the injection choke and well tubulars) needs to properly qualified and assessed with an integrated discussion in the detailed planning phase. A similar approach was reported with regard the Sleipner CCS project.

4.24.20 CO_2 Injection Modelling Conclusions

The wells are expected to cater for a range of injection rates ranging from 30MMSCFD to 138MMSCFD, (0.564MTPA to 2.65MTPA). Consideration has been given to accommodating the entire expected pipeline first load rate range within one well. This serves to increase system uptime / redundancy provided that the erosional flow velocity risks are not unacceptably increased.

A wide range of sensitivities with regards to perforated interval, permeability, wellhead pressure, skin and tubing roughness have been run on 4-1/2in, 5-1/2in and 7in tubing in order to optimize the required CO_2 injection in the well.

A relative measure of the impact of tubing size is seen by comparing injection rates achieved for a 1000psi surface injection pressure given an expected base case of 2048psi (141bar) reservoir pressure, 10,14ftTVD (309m) reservoir thickness, 200ft (60.95m) of perforated interval, skin of 5 and average reservoir permeability of 260mD. The predicted CO_2 gas injection rates for 4-1/2in, 5-1/2in and 7in upper completion tubing under these conditions are 52.9MMSCFD, 84.8MMSCFD, 171.5MMSCFD (1.01MTPA, 1.62MTPA, 3.28MTPA) respectively.

The 1000psi (69bar) surface injection pressure sensitivity used above is considered robust given an expected normal pipeline arrival operating pressure of 1305psi (90bar).

The reservoir inflow model indicates 200ft of perforations to be more than adequate for the maximum 138MMSCFD (2.65MTPA) required rate with flowing bottom hole injection pressures, 2200-2800psi, (151-193bar), well within acceptable limits with respect expected fracture pressure, 3335psi (230bar) given a base case permeability level of 260mD.

A 4½in upper completion tubing selection is considered to be an unacceptable choice with respect to erosional velocity limit risk, deliverability of maximum injection rates, system redundancy and reliability.

A 5½in in upper completion tubing selection is considered to provide an acceptable choice with respect to erosion velocity limit risk and injection rate delivery. However in terms of available injection pressure, fracture pressure and permeability it is tubing size that is the most likely operating constraint with respect to rate which can be improved with larger tubing.

A 7in tubing choice is considered to provide further conservatism with respect erosional velocity limit risks for the highest injection rate delivery and this in turn offers improved redundancy and system reliability although at some marginal incremental cost.

A choke pressure drop induced downstream minimum potential temperature of -30°C is proposed as the design basis for this report based a high differential between pipeline arrival and downstream well shut-in pressures of a seawater column at 10barg. The need to manage or mitigate this with respect potential hydrates is discussed in hydrate management section of this report.

4.24.21 Perforation System Design

The following section discusses options by which hole can be produced in the 7” injection liner, in order that CO_2 injection can be accomplished into the Bunter sandstone store. Perforation is achieved by multiple small shaped explosive charges. The perforating charges, referred to as guns, can be deployed into the well by various methods, such as on a wireline or conveyed on tubing. Different methods and perforating systems are available, with some advantages and disadvantages. The following discusses the perforating options.

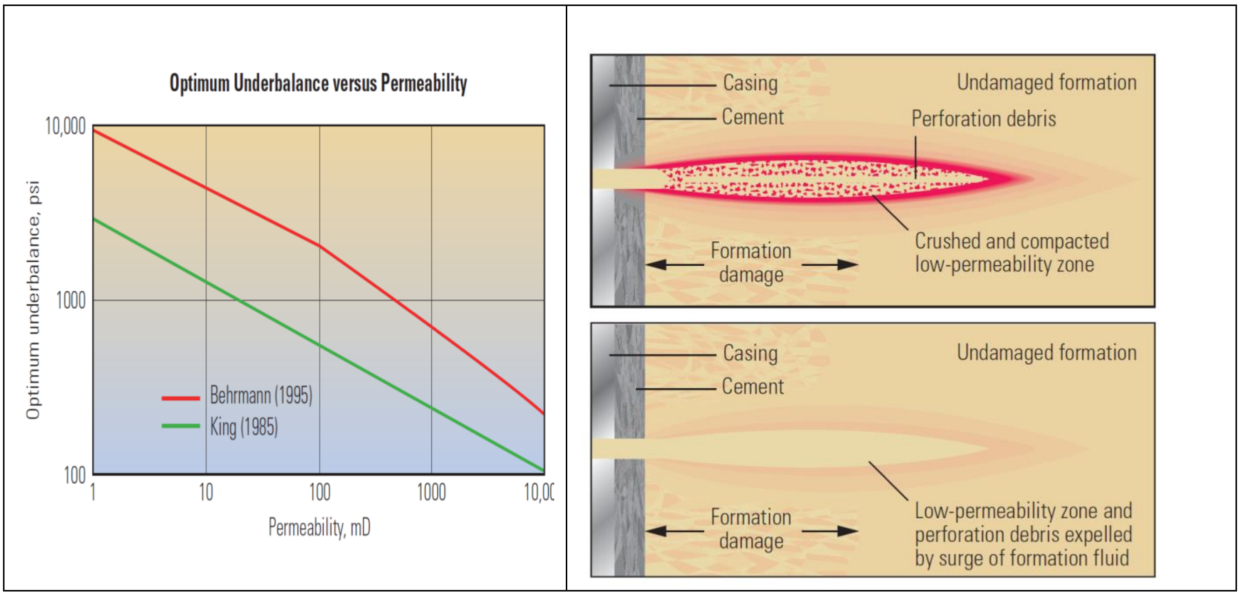
4.24.21.1 Perforating Objectives

- Optimally formed, clean and debris free tunnels to minimize skin and improve flow efficiency. In this context, the tunnels are the conduits produced by the perforating charge which allow CO_2 injection into the store.
- Optimised dynamic / static underbalance system design.
- Cost effective deployment and execution

4.24.21.2 Perforating Underbalance (dynamic / static) / Tunnel Clean Up

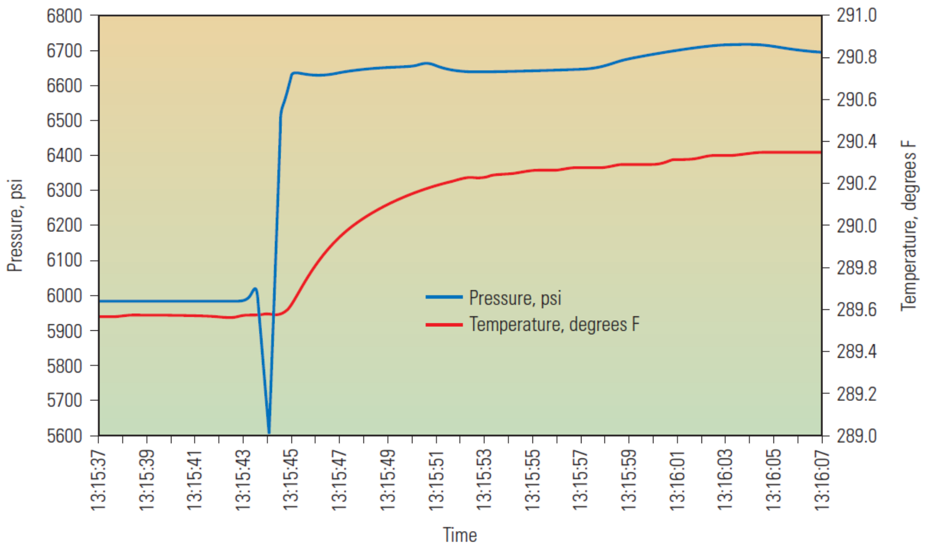
The general merit of underbalanced perforating is well documented with the industry as a means to promote optimal perforation tunnel clean up and removal or break up of the perforation crushed zone associated with perforation formation. Reference to quick look guidance charts as provided below would suggest a static underbalance of circa 1000psi would typically offer a reasonable balance between aiding the clean-up of the crushed zone and not applying excessive drawdown to risk failing the sandface.

Figure 4.56: Optimum Underbalance b) Perforation Tunnel Crush Zone Clean Up



In addition to static underbalance the role and optimised use of dynamic underbalance needs to be also considered. As the perforation jet collapses and the void space in the hollow carrier guns is exposed to the wellbore then wellbore pressure falls rapidly such that a positive differential formation to wellbore gradient develops. This phenomenon referred to as 'dynamic underbalance' induces fluid flow across the perforations which can assist in the clean-up and removal or break up of the crushed zone.

Figure 4.57: Dynamic Underbalance Response



^ North Sea gas-well completion. During completion of a NAM well in the gas-bearing Rotliegend sandstone of the southern North Sea, pressure data from gauges in the gun string confirmed that the PURE perforating design achieved the required dynamic underbalance.

Software modelling programmes such as SPAN by Schlumberger allow multiple parameter sensitivities such as rock strength, permeability, fluid type, crush zone thickness and static and dynamic underbalance to be considered as well as gun system charges sizes and types to be compared as discussed further below.

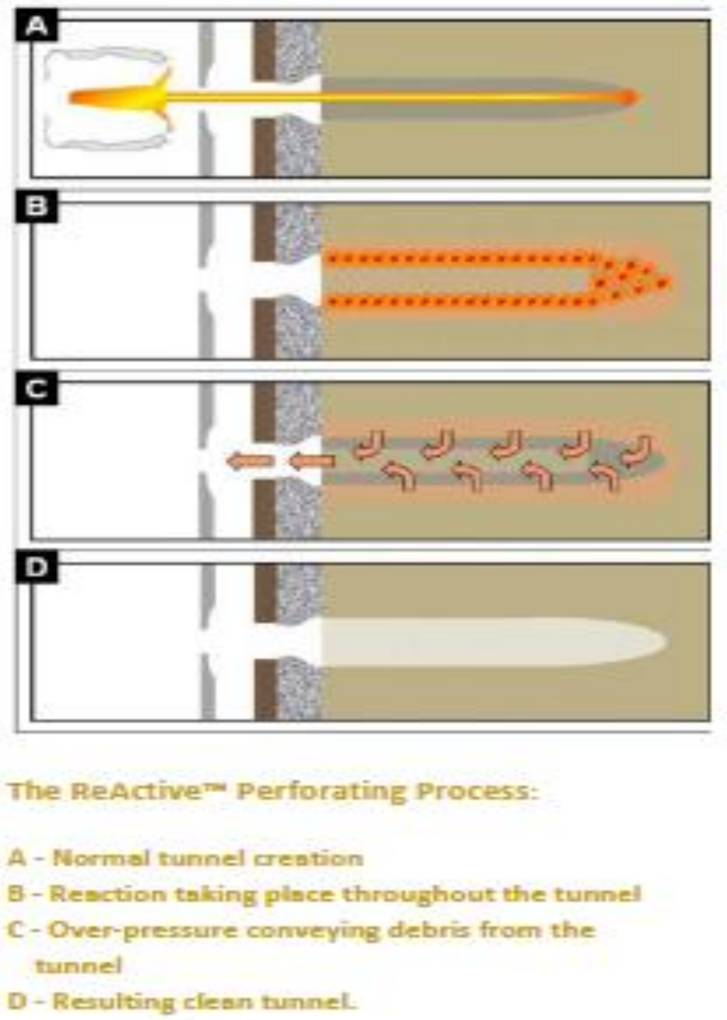
4.24.21.3Reactive Metal Liner Charges

In recent years reactive metal liner technology as a means to enhance perforation tunnel clean-up has found favour in the market. It has been provided in the UK by Geokey under license from Geodynamics. It is understood Schlumberger also plans to offer a version of this technology in the near future although with a view that it has only very limited niche suitability and compared to the widespread applicability of the dynamic underbalance technique. This technology is described by the extract from Geokey literature below.

‘When a ConneX® Perforating charge is fired, it initially behaves in the same manner as a conventional shaped charge as illustrated below in Figure 4.58. The main explosive load detonates, evolving a large volume of gas and generating tremendous pressure. As the detonation wave advances through the main body of the charge it collapses the conical metal liner toward its axis, producing a high velocity jet of particles moving at over 20,000 feet per second. Along the axis of the cone, particle collision pressures as high as 15 millionpsi are generated. The particle jet pushes aside and plastically deforms the gun body, wellbore casing, cement and formation. Rock grains are pulverized and displaced radially, forming the perforation tunnel. Finely crushed rock together with mud, cement and charge debris is forced into the pore throats of the surrounding rock, leading to a ‘crushed’ or ‘altered’ zone of reduced permeability. Whereas perforation with conventional charges depends on flow from the undamaged matrix to the wellbore to remove the crushed zone and any debris that may be obstructing the tunnel, ConneX® Perforating introduces a secondary ReActive™ effect that makes flow unnecessary.

A carefully controlled bimetallic combination within the powdered metal liner reacts under the tremendous pressures of detonation and liner collapse. This Hume-Rothery reaction is highly exothermic and takes place in the perforation tunnel microseconds after it has formed [B]. The energy released supercharges the near-tunnel region, creating a surge of flow into the wellbore [C]. This flow removes material from the entire tunnel length, including the impermeable but relatively weak crushed zone, leaving an ideal, undamaged connection to the reservoir [D]. Since every tunnel is subjected to this secondary reaction they are all cleaned out, irrespective of differences in rock quality or local pressure conditions.

Figure 4.58: Reactive Metal Liner Perforating Process



ADTI experience with this technology has been successful but it is considered still arguably niche, best suited to a high formation strength, low porosity, low permeability, depleted gas reservoir where other techniques such as dynamic underbalance are significantly constrained.

4.24.22 Artificially Lifted Clean Up

A specific challenge for injector wells compared with producer wells, whether water or CO_2, is how to ensure perforation tunnels are adequately cleaned up without a costly dedicated production clean up flow prior to starting injection operations.

In this scenario the dense saline formation water cannot sustain natural flow to surface. In the recent Endurance appraisal well, the well was first perforated with a dedicated shoot and pull string. Next an Electrical Submersible Pump (ESP) was used in the DST string to initially perform a production test. This ensured a sustained flow to surface was achieved to aid the removal of perforation gun debris and crushed zone material from the perforations.

The reason a dedicated perforation run was carried out first was in part because ESP systems and perforation charges are not compatible due to the risk of perforation shock induced ESP damage.

In the case of the proposed CO_2 injectors the incorporation of an artificial lift system in the upper completion string is not appropriate since it adds unacceptable complexity. An ESP system even with a pump bypass for wireline access would restrict perforation gun access and would not be compatible to long term high rate injection through the pump. If other artificial lift systems such as gas lift, hydraulic submersible pumps, or jet pumps, are considered then it is recognised that by nature they require tubing to annulus communication pathways, therefore increase the potential for well integrity leaks.

In conclusion use of artificial lift can be considered a potential contingency solution in the event that optimised perforating techniques alone prove inadequate. Incorporating artificial lift as a base case at this stage adds complexity that is unlikely to be necessary.

4.24.23 Limited Tubing Inflow / Solids Free Pill

Whilst artificial lift is necessary to ensure sustained flow to surface it should also be recognised that the well will support formation brine influx to deliver a formation brine column to within approximately 80ft of the mudline. Thus a limited tubing inflow could be considered as a means to encourage debris / crushed zone disturbance and removal from the perforations. It should be noted that the formation brine influx would have to be subsequently re-injected before seawater injection commissioning and CO_2 injections operations started, but some of the produced crushed zone material may settle past the perforations and even returned crushed zone material once initially disturbed is likely to have higher permeability than that of the undisturbed crush zone, ignoring any negative impact of additional gun debris material.

A risk associated with this approach however would be salt being precipitated as the saturated formation brine column rises and cools. The precipitated material may not dissolve quickly and causing plugging / injectivity impairment when re-injected.

If reactive charges, artificial lift and limited tubing inflow approaches are ruled out with respect an initial base case approach then this leaves the focus on use of a combination of static and dynamic underbalance with either a shoot and pull or wireline through tubing deployment method and these are discussed in turn below.

Use of a shoot and pull technique would require a fluid loss control pill spotted on bottom prior to perforating. This is to ensures any fluid losses are immediately stemmed post perforating so that a stable overbalance fluid column can be confirmed before the shoot and pull string is recovered and the upper completion installed.

A solids free self-breaking pill such as K-Max (cross-linkable HEC or hydroxyethyl cellulose), a Halliburton product, would be used so that injection can be achieved without need to backflow the well first. The first well could be drilled and completed and a tubing surface signature pressure applied offline as a means to monitor the breakdown of the pill as subsequent wells were drilled. Once the surface pressure had bled off then a filtered inhibited seawater injection commissioning test could be carried out before the well was handed over to the process team for subsequent CO_2 injection operation commissioning.

4.24.24 Perforation Interval

The primary target interval for the proposed injection well is the Bunter Sandstone formation. It is proposed to perforate the proposed injection wells over an estimated circa 200 foot interval. It is expected that a single sand package will be present. The base case targets an interval 100ft above the base of the reservoir as discussed earlier avoiding lesser quality pay at the base of the reservoir. Final perforation intervals will be confirmed once the reservoir section has been drilled and logged in each well.

Table 4.86: Nominal Bunter Sandstone Perforated Interval (W3)

Unit	Depth (TVDSS m)	Depth (TVDSS ft)
Top Perforation (Well W3)	1404.4	4608.0
Base Perforation (Well W3)	1465.4	4808.0

4.24.25 Perforating Options

Generic deployment options include:

- Tubing Conveyed Perforation (TCP) on the end of the upper completion tubing string with the guns dropped upon firing into a sump (redundant firing and nitrogen cushion);
- TCP on the end of a dedicated shoot and pull string run prior and recovered prior to the running of the upper completion; and
- wireline perforating through upper completion tubing.

TCP on Upper Completion String

In this option the tubing conveyed perforation guns (TCP guns) are run on the base of the upper completion tailpipe and auto-dropped after firing. This method is not suitable in this case because of the need to be able to contingently access and perforate the middle and upper sections of the Bunter Sandstone. To achieve this, the upper completion packer and auto-drop mechanism must be positioned above the top of the reservoir so on firing the lower half of the auto-drop sub and all the tubing and guns across the reservoir drop clear of the reservoir. In practical terms this requires too great a sump beneath the bottom shot to accommodate circa 600ft of dropped tubing and guns, plus the conventional shoetrack circa 120ft and production logging sump circa 40ft. A sump of this size adds drilling cost and liner deployment and cement loss risk.

TCP on Dedicated Shoot and Pull String

In this option the TCP guns are run and recovered on the base of a temporary tubing string before the upper completion is run. The recovery of the guns means that an extended sump as discussed above is not required and full subsequent reservoir access is enabled as required for future MMV or remedial well intervention operations.

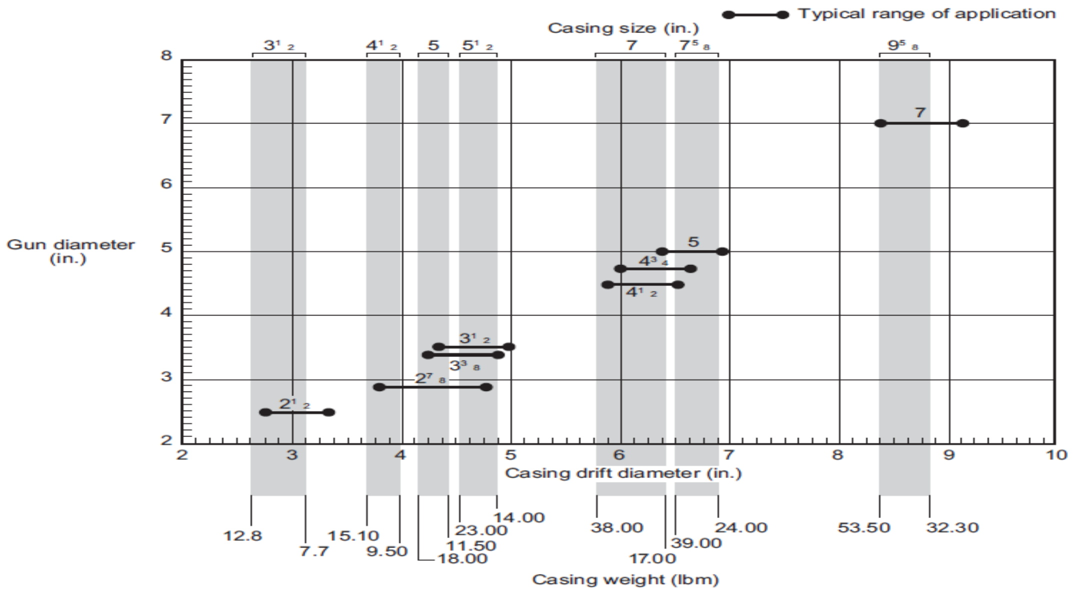
Use of a dedicated tubing deployed perforating gun run before the upper completion is installed means that the size of the perforating guns is not constrained by minimum internal diameter of the base case 5-1/2in upper completion, allowing the optimal 4-1/2in gun size for the 7in cemented liner to be run. Further unlike wireline, string weight is not an issue and a 200ft interval can be perforated with the largest guns in one run. A drawback to this option is that a stable overbalance kill fluid column must be applied to the formation before the gun string is recovered and the upper completion run. This adds some risk in terms of formation damage and skin but is considered manageable with appropriate integration of fluids, solids free fluid loss pill technology and perforating system design. Perforation was carried out successfully with a similar approach on the appraisal well

Wireline Perforating through the Upper Completion

In this option guns are deployed on wireline through the upper completion. This option may present a time saving of 12hr to16hr per well compared to the dedicated tubing gun deployed option. This will vary subject to gun size and associated string weight.

However if the base case of a 5-1/2in upper completion tubing size is considered then gun size would be constrained to 2-7/8in or 3-1/8inguns. This is based on the minimum completion restriction of a 3.688in wireline nipple in the tailpipe and a post perforating in liquid gun swell sizes of 2.96-3.16 and 3.5-3.57in respectively. In principal this represents an increase in skin risk because of the reduced charge size and thus perforation tunnel size and the greater offset or gun stand-off with smaller 2-7/8in or 3-1/8in guns within the 7in liner. If 7in upper completion tubing is considered then the larger optimal 4-1/2in could be deployed on wire through the completion. This is based on a gun swell size in liquid of 4.74-4.91in for a 4-1/2in gun.

Figure 4.59: Gun Size vs Casing Drift Diameter



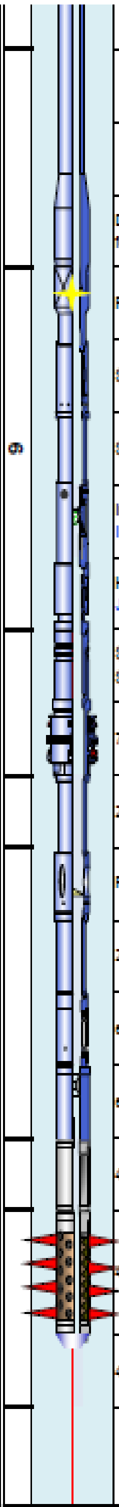
An advantage of this method is that well does not have to be killed post perforating. The initial gun run can be performed under balance with the subsequent gun runs performed on balance. The wireline operation from a drilling rig is expected to require 4 gun runs assuming a 50ft length of guns can be run deployed on each run.

4.24.26 Base Case 5-1/2in Upper Completion - Schlumberger TCP Shoot and Pull Equipment

The recommended perforating option for the base case 5-1/2in upper completion is the use of a TCP shoot and pull technique.

The main perforating system components are summarised below illustrated using a Schlumberger equipment example.

Figure 4.60: Schlumberger TCP Shoot and Pull Perforating String



					0.00	0.00		
					0.00	0.00		
Drillpipe and/or heavy weight sufficient for packer			TBC	6045.00	0.00	6045.00	Schlumberger	
RA Marker Sub	5.000	2.200	3 1/2" PH6 Box 3 1/2" PH6 Pin	2.00	6045.00	6047.00	Schlumberger	
SHRV single shot reversing valve	5.000	2.200	3 1/2" PH6 Box 3 1/2" PH6 Pin	4.00	6047.00	6051.00	Schlumberger	
Stand 4 3/4" Drill Collar 47#/ft or similar	4.750	2.200	3 1/2" PH6 Box 3 1/2" PH6 Pin	90.00	6051.00	6141.00	Schlumberger	
Iris Dual Valve IRDV-AB	5.000	2.200	3 1/2" PH6 Box 3 1/2" PH6 Pin	20.00	6141.00	6161.00	Schlumberger	
Hydraulic Jar Open JAR	5.000	2.200	3 1/2" PH6 Box 3 1/2" PH6 Pin	8.00	6161.00	6169.00	Schlumberger	
Safety Joint SJB	5.000	2.200	3 1/2" PH6 Box 3 1/2" PH6 Pin	2.00	6169.00	6171.00	Schlumberger	
7" Retrievable packer		2.200	3 1/2" PH6 Box 2 7/8" EUE Pin	8.00	6171.00	6179.00	Schlumberger	
2 7/8" EUE Tubing joint	3.680	2.400	2 7/8" EUE Box 2 7/8" EUE Pin	30.00	6179.00	6209.00	Schlumberger	
Ported Debris Sub	3.680	2.400	2 7/8" EUE Box 2 7/8" EUE Pin	2.00	6209.00	6211.00	Schlumberger	
2 7/8" EUE Tubing joint	3.680	2.400	2 7/8" EUE Box 2 7/8" EUE Pin	30.00	6211.00	6241.00	Schlumberger	
eFire 240hr Firing head	3.680	N.A	2 7/8" EUE Box	16.00	6241.00	6257.00	Schlumberger	
eFire 240hr Firing head	3.680	N.A		16.00	6257.00	6273.00	Schlumberger	
4.5" HSD Gun Safety Spacer	4.500	N.A		10.00	6273.00	6283.00	Schlumberger	
4 1/2" HMX PURE perforating gun	4.500	N.A		200.00	6283.00	6483.00	Schlumberger	
4 1/2" Bullnose	4.500	N.A		1.00	6483.00	6484.00	Schlumberger	

Updated By:	G.Rogers	Date:	21/12/2014	Reviewed By		Date	

Ported Bullnose

The ported bullnose contains four 1in ports, allowing well fluids to enter through and act upon the bottom mounted firing head. Pressure can then be transmitted to the firing head through these ports.

Perforating Guns

Hollow Carrier Guns

Hollow carrier guns are pressure-tight steel tubes in which the shaped charges are positioned. For gun ODs of 2 7/8in and larger, Hollow carrier guns perform better than exposed guns because they use larger charges with optimized phasing and increased shot density. Hollow carrier guns are also used when debris is unacceptable and in hostile conditions that preclude using exposed guns.

It provides maximum perforating performance because carrier guns are designed as systems, comprising carriers, charges, detonating cords and boosters. Gun systems are customized by optimizing their configuration to the wellbore environment and reservoir conditions using software such as the Schlumberger SPAN Rock rock-based penetration model.

High Shot Density (HSD) high Shot Density Guns

The pressure-tight steel tubes of High Shot Density (HSD) perforating guns enable combining the best-performing charges with optimal phasing patterns in a high shot density to produce the ideal perforations for the well. The carrier tubes themselves are expendable and retrievable, which means that once the gun system has been used, it is retrieved and disposed of.

Safety Spacer

The safety spacer is used for added safety at surface.

Hydraulic Delay Firing Head / Schlumberger E-Fire

If overbalanced perforating combined with or without a Schlumberger PURE type dynamic underbalance is considered acceptable then a standard hydraulic firing head for initiating the gun firing sequence can be used. This incorporates independent and sequentially operated shear pins and hydraulic sections and provides an adjustable hydraulic delay to enable sufficient time to shear the actuation shear pins and bleed off tubing pressure to the desired pressure before detonation occurs.

In this case use of a column of seawater in the well at initial reservoir pressure would provide a marginal or negligible underbalance of circa 50psi.

If a greater underbalance is required then this could be achieved using an E-Fire type intelligent firing head system combined with a DST packer. In this option DST circulating tools (IRDV) are included in the string to allow nitrogen gas to be circulated into the tubing string to increase the underbalance. The Efire firing system which relies on intelligent signalling based on specific ranges and durations of applied tubing to initiate the guns is able to communicate through mixed fluid / gas columns.

Ported Debris Sub / Slotted pipe

This provides a flow path directly below the packer, which helps remove gas during the well kill process.

TCP / Deployment Tubing and Packer Interface

The TCP BHA incorporates commonly used connections to crossover to the tubing string and HPPK or PosiTest retrievable packer.

4.24.27 Alternate Case 7in Upper Completion - Schlumberger Wireline perforating

If an alternate case 7in upper completion is considered for the injection wells, then a similar base case shoot and pull approach is recommended. The use of wireline gun length for stand-alone platform operations using a readily available MAST on the Weather Deck intervention is constrained to 50ft (15.24m). This means that after the first 50ft interval subsequent intervals can only be perforated at static balance relying solely on dynamic underbalance. Thus in order to achieve static and dynamic underbalance across the entire interval then a single shoot and pull 200ft (60.96m) perforation operation is preferred. In the case of initial perforating operations however then nominally up to 90ft (27.4m) derrick height would be available within which to work to support additional lubricator riser sections. The limit in this scenario is likely to be wireline yield strength for the larger 4-1/2in guns.

However it should be noted that the 7in tubing size has an advantage in allowing the use of larger 4-1/2in guns for contingent through tubing wireline operations to add further perforation intervals or to re-perforating existing intervals.

Gun system performance for both the 5-1/2in tubing and alternate case in terms of tunnel geometry and injectivity are discussed further below.

4.24.28 Gun Specification & Charge Performance

If a Schlumberger 2-7/8in, 3-1/8in or 4-1/2in high shot density perforating system is considered then the expected relative perforating gun and charge performance details based on API RP 19B surface tests are as tabulated below.

Table 4.87: Schlumberger High Shot Density Guns

High Shot Density Perforating Systems Performance and Mechanical Data Summary									
Gun Size, in	Shot Density, spf	Phasing, °	Charge	API RP 19B Section 1			Weight of Loaded 20-ft Gun in Air (without adapters), lbm	Maximum Diameter Including Burrs, Shot in Liquid, in	Maximum Diameter Including Burrs, Shot in Gas, in
				Penetration, in	Entrance Hole, in	Maximum Explosive Load, g			
Deep Penetration Shaped Charges									
1.56-in HSD*	6	60	PowerJet* 1606, HMX	11.3	0.17	3.5	76	1.72	1.75
2-in HSD	6	60	PowerJet Omega* 2006, HMX	21.8	0.22	7.3	123	2.29	2.31
2-in HSD	6	60	PowerJet 2006, HNS	15.3	0.22	8	123	2.16	2.21
2-in HSD	6	60	PowerJet 2006, HMX	18.7	0.23	6.5	123	2.16	2.21
2¼-in HSD	6	60	PowerJet 2306, HMX	17.7	0.3	8.7	155	2.46	2.48
2¼-in HSD	6	60	PowerJet 2306, HNS	15.7	0.27	9.5	155	2.46	2.48
2½-in HSD	6	60	PowerJet Omega 2506, HMX	30.6	0.32	12	171	2.78	–
2½-in HSD	6	60	PowerJet 2506, HNS	16.7	0.3	13.5	174	2.66	2.75
2½-in HSD	6	60	PowerJet 2506, HMX	24.4	0.31	10.5	176	2.66	2.75
2⅞-in HSD	6	60	PowerJet Omega 2906, HMX	36.0	0.34	16	246	3.16	3.32
2⅞-in HSD	6	60	PowerJet Omega 2906, HNS	24.3	0.31	17.6	249	3.16	3.32
2⅞-in HSD	6	60	PowerJet 2906, HMX	25.3	0.38	15	245	2.98	3.08
2⅞-in HSD	6	60	PowerJet 2906, HNS	21.0	0.31	19.5	239	2.96	3.08
3⅛-in HSD	6	60	PowerJet Omega 3106, HMX	36.9	0.34	20	301	3.57	–
3⅛-in Frac Gun*	6	60	PowerJet Omega 3104, HMX	37.5	0.38	17.9	280	3.50	–
3⅜-in HSD†	6	60	PowerJet 3406, HMX	36.5	0.37	22.7	334	3.66	–
3⅜-in HSD†	6	60	PowerJet 3406, HNS	28.8	0.31	25	335	3.66	–
3⅜-in OrientXact*‡	5	±10	PowerJet OX 3505, HMX	37.7	0.34	22.5	564	na	3.78
3½-in HSD	6	72	PowerJet Omega 3506, HMX	44.2	0.44	27	370	3.72	–
3½-in HSD	6	72	PowerJet Omega 3506, HNS	33.7	0.32	28	374	3.72	–
4-in HSD	5	72	PowerJet Omega 4005, HMX	51.7	0.48	38.8	496	4.44	–
4-in HSD	5	0/180	PowerJet 4006, HMX	36.5	0.46	26.0	425	na	4.37
4½-in HSD§	5	72	PowerJet Omega 4505, HMX	65.2	0.43	38.8	504	4.74	–
4½-in HSD§	5	72	PowerJet 4505, HMX	46.4	0.47	38.6	504	4.74	–
4½-in HSD§	12	135/45	PowerJet Omega 4512, HMX	34.0	0.35	22	495	4.91	–
4½-in HSD§	12	135/45	PowerJet 4512, HMX	30.2	0.34	22	495	4.91	–
4½-in OrientXact††	4	±10	PowerJet OX 4504, HMX	43.8	0.29	38.8	568	4.74	4.77
4.72-in HSD	5	72	PowerJet Omega 4705, HNS	44.4	0.36	38.8	606	4.95	5.16
4.72-in HSD	5	72	PowerJet 4505, HMX	48.3	0.51	38.6	606	4.95	5.16
4.72-in HSD	5	72	PowerJet 4505, HNS	34.4	0.4	38	623	4.95	5.16
4.72-in HSD	12	135/45	PowerJet 4512, HNS	22.8	0.31	22.5	610	4.99	5.16
4.72-in HSD	21	120/60	PowerJet 4521, HMX	21.0	0.32	15	665	4.93	–
7-in HSD	12	135/45	PowerJet Omega 4505, HMX	62.0	0.46	38.8	1,168	7.28	–
7-in HSD	12	135/45	PowerJet 4505, HMX	43.6	0.44	38.6	1,169	7.05	–
7-in HSD	27	120/60	PowerJet Omega 7027, HMX	35.5	0.29	20	1,110	7.05	–

Notes: Every attempt has been made to verify the accuracy of the data tabulated; contact your Schlumberger representative for further information. Other shot densities and phasings are available; Schlumberger also custom designs perforation systems to meet specific needs.

na = not available

Blue type identifies API 19B Registered Perforation Systems; unofficial API data is listed for the other systems.

† Available in 3⅜-, 3½-, and 3.67-in perforating systems

‡ Available in 3⅛-in perforating systems

§ Available in 4½-, 4⅝-, 4.72-, and 5-in perforating systems

†† Available in 4.72-in perforating systems rated for high pressure

In order to consider the relative performance of various configurations in terms of both tunnel geometry and productivity under downhole conditions, a first pass analysis was carried out by Schlumberger using SPAN software for various 4-1/2in gun systems inside 7in cemented liner.

- Overbalanced (300psi) open ended pipe (Table 4.88)
- Overbalanced (300psi) PURE design with open ended pipe (Table 4.89)

- Closed chamber with DST Tools and PURE design (Table 4.90)

Further analysis has also considered PURE dynamic underbalance supplemented with 1500psi static underbalance and PURE dynamic underbalance applied as a separate post perforation clean up run.

Analysis Results

Table 4.88: Perforation Geometry

Formation

Rock Type:	Sandstone		Rock Strength (UCS):	2900	psi
Porosity:	22.5	%	Vertical Stress:	5807	psi
Bulk Density:	2.28	g/cm3	Pore Pressure:	2048	psi
Temperature:	135	deg F	Wellbore Damage:	6	in
Formation Fluid:	Water				

Perforating System(s)

Perf #	Phasing Angle (deg)	Shot Density (spf)	PURE Density (spf)	Gun Position	Stand Off (in)	Total Pen Average (in)	Form Pen Average (in)	Form Dia Average (in)	EH Dia Average (in)	AOF (in2/ft)
1	72	5.00	0.00	Eccentered	0	26.33 *	25.12 *	1.23	0.47	0.87
2	135/45	12.00	0.00	Eccentered	0	20.00 *	18.79 *	0.91	0.35	1.18
3	72	2.50	0.50	Eccentered	0	26.33 *	25.12 *	1.23	0.47	0.43
4	135/45	5.00	0.50	Eccentered	0	20.00 *	18.79 *	0.91	0.35	0.49
5	72	2.50	0.50	Eccentered	0	26.33 *	25.12 *	1.23	0.47	0.43
6	135/45	5.00	0.50	Eccentered	0	20.00 *	18.79 *	0.91	0.35	0.49

* Rock-based Model: Based on lab experiments in rocks with UCS up to 18k psi under downhole conditions

Gun System(s)

#	Name	Chg Wt (g)	Gun OD (in)	API Pen (in)	API EH (in)	Comment
1	4-1/2" HSD, PowerJet Omega 4505, HMX	38.8	4.5	65.20	0.45	19B 1st Ed
2	4-1/2" HSD, PowerJet Omega 4512, HMX	22.0	4.5	34.00	0.35	19B 1st Ed
3	4-1/2" PURE, PowerJet Omega 4505, HMX	38.8	4.5	65.20	0.45	Based on 19B 1st Ed
4	4-1/2" PURE, PowerJet Omega 4512, HMX	22.0	4.5	34.00	0.35	Based on 19B 1st Ed
5	4-1/2" PURE, PJO4505, Closed Chamber	38.8	4.5	65.20	0.45	Based on 19B 1st Ed
6	4-1/2" PURE, PJO4512, HMX Closed Chamber	22.0	4.5	34.00	0.35	Based on 19B 1st Ed

Table 4.89: Productivity Performance

Perforating System(s)

Perf #	Loaded Length (ft)	Phasing Angle (deg)	Shot Density /Open Perfs (spf/%)	Eff Shot Density (spf)	PURE Density (spf)	Crush Zone kc/k	Crush Zone (in)	Form Pen Avg (in)	Form Dia Avg (in)	EH Dia Avg (in)
1	200.0	72	5.00/100	5.00	0.00	0.03	0.50	25.12 *	1.23	0.47
2	200.0	135/45	12.00/100	12.00	0.00	0.08	0.50	18.79 *	0.91	0.35
3	200.0	72	2.50/100	2.50	0.50	0.65	0.50	25.12 *	1.23	0.47
4	200.0	135/45	5.00/100	5.00	0.50	0.58	0.50	18.79 *	0.91	0.35
5	200.0	72	2.50/100	2.50	0.50	0.50	0.50	25.12 *	1.23	0.47
6	200.0	135/45	5.00/100	5.00	0.50	0.56	0.50	18.79 *	0.91	0.35

* Rock-based Model: Based on lab experiments in rocks with UCS up to 18k psi under downhole conditions

Perf #	Eff Skin	Darcy Skin	Perf Skin	Crush Zone Skin	Deviation Skin	Partially Open Skin	Non-Darcy Coeff (1/STB/day)	Non-Darcy Skin	IR	II (STB/day /psi)
1	0.37	0.25	0.41	1.59	-0.16	0.00	1.248e-5	0.1229	0.97	90.17
2	-0.93	-1.02	-0.85	0.45	-0.16	0.00	9.114e-6	0.08974	1.18	110.12
3	-1.17	-1.25	-1.09	0.06	-0.16	0.00	8.129e-6	0.08004	1.23	114.97
4	-1.10	-1.18	-1.02	0.07	-0.16	0.00	8.754e-6	0.08619	1.21	113.41
5	-1.11	-1.19	-1.03	0.11	-0.16	0.00	8.339e-6	0.08211	1.21	113.65
6	-1.09	-1.18	-1.01	0.07	-0.16	0.00	8.769e-6	0.08634	1.21	113.29

1. 4-1/2" HSD, PowerJet Omega 4505, HMX
2. 4-1/2" HSD, PowerJet Omega 4512, HMX
3. 4-1/2" PURE, PowerJet Omega 4505, HMX
4. 4-1/2" PURE, PowerJet Omega 4512, HMX
5. 4-1/2" PURE, PJO4505, Closed Chamber
6. 4-1/2" PURE, PJO4512, HMX Closed Chamber

Perforating System(s)

Perf #	Gun Length (ft)	Loaded Length (ft)	Shot Density (spf)	PURE Density (spf)	Static UB/OB (psi)	DUB (psi)	Duration (sec)	kc/k	Perf Skin
1	200.0	200.0	5.00	0.00	300	---	---	0.03	0.41
2	200.0	200.0	12.00	0.00	300	---	---	0.08	-0.85
3	200.0	200.0	2.50	0.50	300	-483	2.050	0.65	-1.09
4	200.0	200.0	5.00	0.50	300	-420	1.970	0.58	-1.02
5	200.0	200.0	2.50	0.50	300	-411	2.250	0.50	-1.03
6	200.0	200.0	5.00	0.50	300	-412	2.170	0.56	-1.01

1. 4-1/2" HSD, PowerJet Omega 4505, HMX
2. 4-1/2" HSD, PowerJet Omega 4512, HMX
3. 4-1/2" PURE, PowerJet Omega 4505, HMX
4. 4-1/2" PURE, PowerJet Omega 4512, HMX
5. 4-1/2" PURE, PJO4505, Closed Chamber
6. 4-1/2" PURE, PJO4512, HMX Closed Chamber

The results indicate all options considered achieve adequate tunnel geometry in terms of length and diameter with marginally negative Darcy skin (circa -1). Average formation penetration length ranges from 18.79 to 25.12in while entrance hole diameters range from 0.35 to 0.47in as would be expected with 4½in guns used in 7in liner in a Bunter Sandstone. The analysis indicates improved tunnel clean up using the PURE dynamic underbalance approach in the 300psi overbalance condition scenario considered. A dynamic underbalance of circa 400psi to 500psi is predicted.

Further Analysis was carried to consider 2⅞in perforating guns deployed by wireline through the Base Case 5½in Upper Completion tubing to perforate the 7in cemented liner.

Analysis Results

Table 4.90: Perforation Geometry & Performance Results

Formation

Rock Type:	Sandstone		Rock Strength (UCS):	2900	psi
Porosity:	22.5	%	Vertical Stress:	5807	psi
Bulk Density:	2.28	g/cm3	Pore Pressure:	2048	psi
Temperature:	135	deg F	Wellbore Damage:	6	in
Formation Fluid:	Water				

Perforating System(s)

Perf #	Phasing Angle (deg)	Shot Density (spf)	PURE Density (spf)	Gun Position	Stand Off (in)	Total Pen Average (in)	Form Pen Average (in)	Form Dia Average (in)	EH Dia Average (in)	AOF (in2/ft)
1	60	6.00	0.00	Eccentered	0	17.89 *	16.69 *	0.77	0.29	0.44

* Rock-based Model: Based on lab experiments in rocks with UCS up to 18k psi under downhole conditions

Gun System(s)

#	Name	Chg Wt (g)	Gun OD (in)	API Pen (in)	API EH (in)	Comment
1	2-7/8" P3 PURE, PJO2906 Post Perf Pulse	16.0	2.802	36.00	0.34	Based on 19B 1st Ed

Perforating System(s)

Perf #	Loaded Length (ft)	Phasing Angle (deg)	Shot Density /Open Perfs (spf/%)	Eff Shot Density (spf)	PURE Density (spf)	Crush Zone kc/k	Crush Zone (in)	Form Pen Avg (in)	Form Dia Avg (in)	EH Dia Avg (in)
1	200.0	60	6.00/100	6.00	0.00	1.00	0.50	16.69 *	0.77	0.29

* Rock-based Model: Based on lab experiments in rocks with UCS up to 18k psi under downhole conditions

Perf #	Eff Skin	Darcy Skin	Perf Skin	Crush Zone Skin	Deviation Skin	Partially Open Skin	Non-Darcy Coeff (1/STB/day)	Non-Darcy Skin	IR	II (STB/day /psi)
1	-1.13	-1.22	-1.06	0.00	-0.16	0.00	8.973e-6	0.08834	1.22	114.11

1. 2-7/8" P3 PURE, PJO2906 Post Perf Pulse

Perforating System(s)

Perf #	Gun Length (ft)	Loaded Length (ft)	Shot Density (spf)	PURE Density (spf)	Static UB/OB (psi)	DUB (psi)	Duration (sec)	kc/k	Perf Skin
1	200.0	200.0	6.00	0.00	300	-1474	1.500	1.00	-1.06

1. 2-7/8" P3 PURE, PJO2906 Post Perf Pulse

The results indicate adequate tunnel geometry in terms of length and diameter with marginally negative Darcy skin (-1.06) reported. Average formation penetration length of 16.69in and entrance hole diameter 0.29in is estimated. The 2⅞in gun performance showing a marginal reduction in tunnel length compared to 4½in guns used in 7in liner in a Bunter Sandstone.

The analysis includes a dedicated dynamic underbalance PURE PS3 run post the perforating run. PURE being used to provide improved tunnel clean up in the 300psi overbalance condition scenario considered. A dynamic underbalance of circa 1400psi to 1500psi is predicted.

4.24.29 Perforating Recommendation

The Bunter sandstone is generally not considered a major perforation challenge given the general qualities of moderate rock strength, high porosity and high permeability. The constraint for an injection well is the cost driver to proceed from perforation operations straight to injection without having to initially flow the well to clean up.

In this scenario the high permeability, extensive sandstone interval available with respect target injection rates and contingent ability to wireline re-perforate through tubing, is considered to offer adequate robustness for a base case without a sustained dedicated clean up flow to surface prior to injection. Clean up is considered manageable through best optimisation of static and dynamic underbalance.

Base Case 5-1/2in Upper Completion

For the base case 5-1/2in upper completion and 7in cemented liner the recommendation is either; a Schlumberger 4½in x 2.5 spf, 72 deg phasing gun system, with 38.8g Powerjet Omega 4505 or a Schlumberger 4½in x 5 spf, 135/45 deg phasing gun system, with 22.0g Powerjet Omega 4512; for either, HMX charge type is recommended.

These should be deployed on a shoot and pull basis prior to the upper completion being run with a combination of a PURE dynamic underbalance design and a 1500psi static underbalance applied. Wireline deployed 2⅞ or 3⅛in perforating guns could be used for contingent re-perforation or the addition of further perforations.

Alternate Case 7in Upper Completion

For the Alternate case 7in upper completion and 7in cemented liner the recommendation is either; a Schlumberger 4½in x 2.5 spf, 72 deg phasing gun system, with 38.8g Powerjet Omega 4505 or a Schlumberger 4½in x 5 spf, 135/45 deg phasing gun system, with 22.0g Powerjet Omega 4512; for either, HMX charge type is recommended.

These should be deployed on a shoot and pull basis prior to the upper completion being run with a combination of a PURE dynamic underbalance design and a 1500psi static underbalance applied.

The larger through bore of the Base case 7in upper completion means larger through tubing perforating guns can be used. Detailed design planning should consider whether initial perforating might be achieved as a through tubing process rather than shoot and pull. Wireline deployed perforating guns can be used for contingent re-perforation or the addition of further perforations.

4.24.30 Tubing Stress Analysis

The following describes the tubing stress analysis performed during FEED. Tubing stress analysis is used to confirm that the mechanical design of the well system is strong enough to take the loads imposed on the well by the load cases which are generated by the CO_2 injection service. The software used in this analysis is provided by a company called Landmark (part of Halliburton) and the particular software package name is called WELLCAT, an industry accepted package. The following discusses the software, the analysis and the results of the analysis.

4.24.30.1 Introduction to Tubing Stress Analysis

Landmark WellCat Software version (EDM 5000.1.9.0 (09.03.06.067)) was used to model the well using Prod, Tube and Multistring modules. This report presents the results for the Base Case 5 ½in Upper Completion String stress analysis and associated multistring wellhead movement.

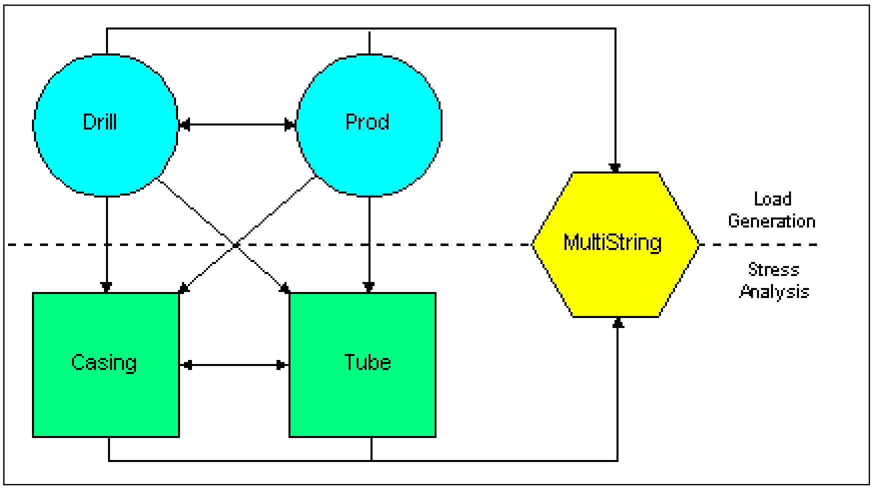
The WELLCAT (Well Casing and Tubing) software is an integrated suite of programs that predicts temperatures and pressures in the wellbore and analyses stresses and deformation (including buckling) in tubing and casing.

The WELLCAT software can perform the following modelling or essential tasks required:

- accurate temperature modelling;
- reliable service life analysis;
- critical well design;
- complex tubular stress and movement analysis; and
- MultiString analysis.

The Figure 4.61 below shows the interrelationship between the applications making up the WELLCAT software package. The arrows indicate the results from one program that can be input into another.

Figure 4.61: WellCat Interrelationship between Applications



Prod (Production module) is used to simulate fluid flow and heat transfer during completion, production, simulation, testing and well-servicing operations. It has full transient (or steady-state) analysis with Tube and Casing and is an advanced Windows-environment engineering tool for predicting:

- temperatures and pressures for flowing and shut-in well-streams;
- conditions for tubing analysis based on service loads;

- temperatures and pressures during forward and reverse circulation;
- thermo-setting resin and gel treatment behaviour; and
- permafrost thaw radius.

WellStress-Tube (Tube) is used to analyse tubing loads, design integrity and buckling behaviour under complex mechanical, fluid pressure and thermal loading conditions. It has standard and automatic load-case generation and is linked to Prod thermal analysis and is an advanced Windows-environment engineering tool for:

- comprehensive tubing design and analysis;
- installation and service loads;
- tubing movement;
- complex completions;
- buckling; and
- CRA tubulars with yield anisotropy.

WELLCAT's MultiString is used to conduct a total well system analysis. It can also be used to analyse the influence of the thermal expansion of annulus fluids and/or the influence of loads imparted on the wellhead during the life of the well and on the integrity of a well's tubulars. The single-string analyses performed in Tube and Casing evaluates the effects of these loading conditions on one string only. MultiString evaluates the effects of these loading conditions on the entire load bearing strings in the well system. Either effect can be modelled independently or the combined effects of both can be modelled.

MultiString engineering code determines the pressures due to the expansion of annular fluids and the position (displacement) of the wellhead over the life of the well. These pressure loads and wellhead displacement values are used to determine the integrity of a well's tubulars.

Both single string tubing stress analysis and multistring analysis were performed on the injections wells during FEED and the results of this analysis are described below.

4.24.30.2 Gas Composition

The range of CO_2 properties as tabulated below in Table 4.91 have been considered for this tubing stress analysis.

Initial production modelling indicated a marginally greater cooling impact was observed when injecting the purer CO_2 Case 1 mixture. Since the greater cooling generates a larger thermally induced load then it is the Case 1 mixture CO_2 results that have been presented within the report.

Table 4.91: CO_2 Composition

Name	Case 1 Mole Percent (Purity 99%)	Case 2 Mole Percent (Purity 96%)
CO_2	99.05	95.973
N_2	0.722	3.782
H_2S	0.002	0.002
CO	0.200	0.206
NO	0.005	0.001

Name	Case 1 Mole Percent (Purity 99%)	Case 2 Mole Percent (Purity 96%)
NO_2	0.005	0.001
SO	0.005	0.010
SO_2	0.005	0.010
O_2	0.001	0.010

4.24.30.3 Tubing Stress Analysis Design factors

The analysis has been completed for all tubing string (pipe body and connections) based on ADTI Guidance Document and the minimum acceptable design criteria for the following test elements in Table 4.92 below:

Table 4.92: TSA Design Factors

Component	Load	Safety Factor
Pipe Body	Tri-axial	1.25
	Burst	1.1
	Collapse	1.0
	Axial (Tension & Compression)	1.3
Connection	Burst / Leak	1.1
	Compression	1.3
	Tension	1.3

4.24.30.4 Connection Rating

The tubing connections have been de-rated to a percentage of the tensile load capacity for compression loading, in accordance with the manufacturer's recommendations in Table 4.93 below.

Table 4.93: TSA Compression Efficiency

Tubing Connection	Compression Efficiency
4 1/2in 12.6 lb/ft L-80 JFE Bear	80%
5-1/2in 17.0 lb/ft L-80 JFE Bear	80%
7in 29 lb/ft L-80 VAM Top Casing	80%

4.24.30.5 Tubing String

A 5 1/2in 17# L80 JFE Bear upper completion tubing string has been evaluated with respect to a 30MMSCFD to 138MMSCFD injection rate and other associated lifecycle loads. The mechanical 80 ksi material yield strength properties of this string relevant for tubing stress analysis purposes match those of the recommended base case more corrosion resistant Super Duplex 25CR material. The packer has been assumed to be set in the 7in liner at 5100ft MDBRT.

4.24.30.6 Tubular Temperature Deration

De-rating of the steel through temperature (temperature deration) has been selected as a default in the analysis programme to ensure that realistic downhole material strengths will be utilised.

4.24.30.7 Survey and Dog Leg Severity

The deviation survey used for this tubing stress analysis is P5W3 Rev-A1 G&G Report (27_11_14). The significant survey doglegs are highlighted below in Table 4.94 . No further account for unplanned doglegs has been added.

Table 4.94: Deviation Survey

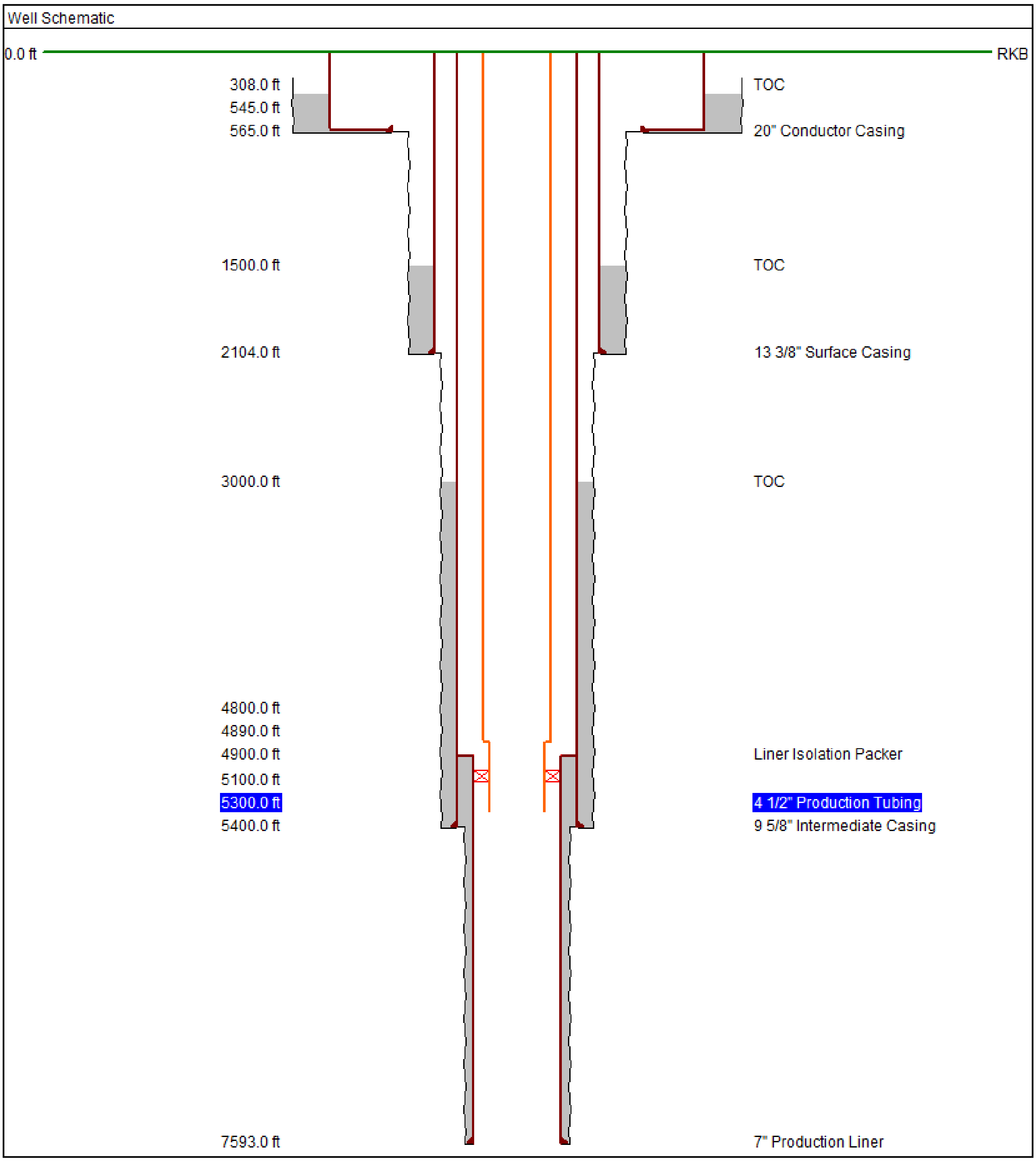
MD (ft)	Inclination (°degrees)	Azimuth (°degrees)	TVD (ft)	DLS (°/(30m) 100ft)	Comments
114.82	0.000	12.500	0.00	0.00	Tie On
709.96	0.000	12.500	595.13	0.00	Tangent
857.60	3.000	12.500	742.71	2.00	Build
2563.62	55.000	12.500	2135.66	3.00	Build (J)
7591.18	55.000	12.500	4955.36	0.00	Tangent (J)

4.24.30.8 Wellbore Schematic

Completion String

Figure 4.62 below illustrates the modelled tapered 5-1/2in x 4-1/2in upper completion string, with a packer set inside the 7in liner.

Figure 4.62: Wellbore Schematic



4.24.30.9 Casing and Tubing Configuration

Casing and tubing mechanical properties are listed in Table 4.95 below.

Table 4.95: Casing and Tubing Mechanical Properties

Casing Function	Casing OD (in)	Casing ID (in)	Casing Grade	Casing Weight (lb/ft)	Conn Type	Burst (psi)	Collapse (psi)	Tensile (lb)
Conductor	30	28	X-56	309.72	Merlin	3270	1680	5102
	20	18.75	X-56	129.33	Merlin	3060	1450	2130
Surface / Int.	13 ⅜	12.415	L80	68	DINO VAM	5024	2263	1555
Production	9 ⅝	8.535	L80	53.5	VAM TOP	7930	6620	1244
Production Liner	7	6.184	L80-25CR	29	VAM TOP HT	8,160	7,030	676
Tubing	5 1/2	4.892	L80	17.0	JFEbear	7740	6290	397
Tubing	4 1/2	3.958	L80	12.6	JFEbear	8430	7500	288

Table 4.96 below shows the casing and tubing configuration summary;

Table 4.96: Casing and Tubing Configuration

Casing and Tubing Configuration

	Name	Type	OD (in)	MD (ft) Hanger	MD (ft) TOC	MD (ft) Base	Hole Size (in)	Annulus Fluid
1	Conductor	Casing	30.000	0.0	308.0	565.0	36.000	Seawater
2	Surface	Casing	13 3/8	0.0	1500.0	2104.0	17 1/2	Gydril WBM 10 ppg
3	Intermediate	Casing	9 5/8	0.0	3000.0	5400.0	12 1/4	Versa CI LTOBM 11.5 ppg
4	Production	Liner	7.000	4900.0	4900.0	7593.0	8 1/2	Versa CI LTOBM 10.5 ppg
5	Production	Tubing	5 1/2	0.0		5300.0		Brine KCl/NaCl 9.98ppg
6								

String Sections - 5 1/2" Production Tubing

	MD (ft) Top	MD (ft) Base	Pipe Type	Pipe OD (in)	Pipe Weight (ppf)	Pipe Grade	Connection Pipe	Connection Name	Connection Grade	Connection OD (in)	Pipe Insulation Material	Pipe Insulation Thickness
1	0.0	4800.0		5 1/2	17.000	L-80		JFE Bear	L-80	6.050	None	0.000
2	4800.0	5300.0		4 1/2	12.600	L-80		4.5" JFE Bear	L-80	5.000	None	0.000
3												

4.24.30.10 Model A Tubing Stress Analysis (single string model)

In Model A, Tubing Stresses Analysis (TSA) has been carried out for 5 ½in completion string. In Model B, both Annular Fluid Expansion (AFE) and Wellhead Movement Analysis (WHM) have been carried out (multi-string analysis).

Initial conditions:

In order to carry out different loads sensitivities on the 5 ½in tubing string, the initial well condition has been described. The initial conditions are the conditions after the production packer is set and setting pressure has been released. Pressure and temperature has been defined for both tubing and annulus side of the well. Fluids present in the well are of significant importance as they will influence pressure and temperature profiles during different sensitivities run.

Pressure Testing:

To confirm the integrity of the tubing and the well, a pressure test has to be performed. The pressure test is based on a consideration of the various planned and potential lifecycle pressure loads with the addition of a safety factor to derive a final test pressure. The maximum pressure load may be driven by the maximum shut-in well head pressure based on the reservoir pressure and a fluid column above, or it may be based on an operational pressure load such as applied surface pressure to set a packer or fire guns.

In this proposed injector well case with only modest injection pressures the maximum expected tubing pressure has been assumed to be associated with packer setting or perforation gun initiation. A 5500psi tubing pressure test value with a plug installed in the tail pipe has been assumed.

An annulus pressure test will also be performed in order to experience a differential pressure on the packer (similar to what it will see during injection). An annulus test value of 5500psi has been modelled.

Tubing Leak:

Tubing leak during injection case has been modelled to see the effect of pressure in the A annulus due to a tubing leak.

Production/Injection:

A sensitivity has been performed on the both Model A&B using one year of CO_2 production and injection for 70 & 138MMSCFD rate respectively for analysis purposes.

Shut-In:

A CO_2 injection shut-in load case has also been run to see the pressure build up and temperature profile with time.

Overpull:

A 100k lbs overpull sensitivity has been performed to check the tubing integrity should it be stuck.

Initial and Final Kill:

Initial and final well kill sensitivities runs have been performed.

Prod Module:

The following are the load cases run in Prod Module of the WellCat software:

Table 4.97: Operations Load Cases

		Tubing Pressure (psi)	Annulus Pressure (psi)	Tubing Fluid
1	Displace to brine at 300gpm	-	0	9.98ppg KCl / NaCl Brine
2	Run completion	2313 at Perfs @ 7012ft dbrt	0	9.98ppg KCl / NaCl Brine

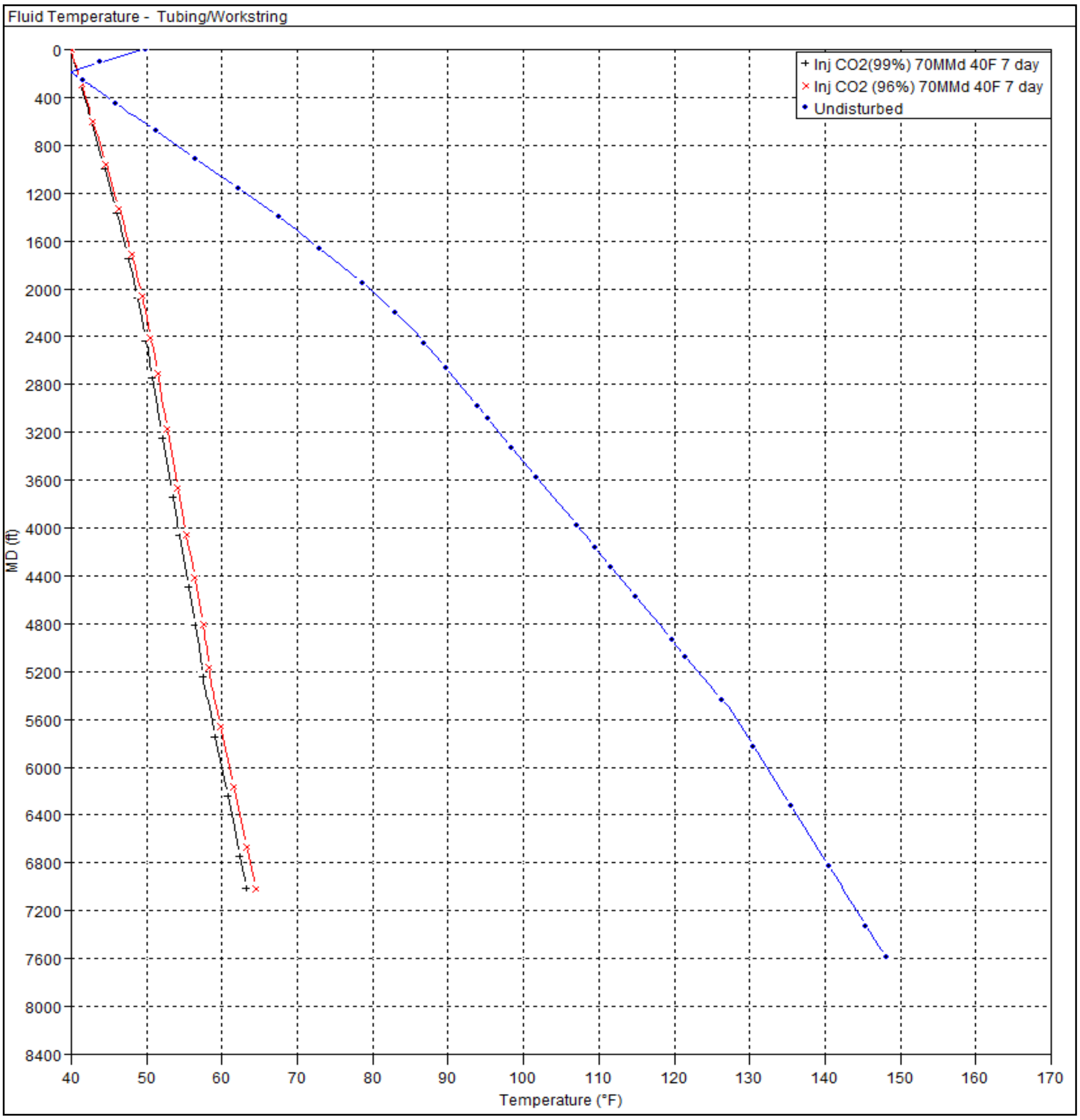
		Tubing Pressure (psi)	Annulus Pressure (psi)	Tubing Fluid
3	Wellbore clean-up / production Form brine 5000bpd	2313 at Perfs @ 7012ft dbrt	0	Seawater/ Formation brine
4	Produce CO_2 at 70MMSCFD	2313 at Perfs @ 7012ft dbrt	0	CO_2/CH_4
5	Inject Water 6000bpd at 40°F (4°C) for 7 day	2400 at surface	0	
6	Inject CO_2 138MMSCFD at 40°F(4°C) for 7 day	2313 at Perfs @ 7012ft dbrt	0	CO_2
7	Shut-In CO_2 Inj 138MMSCFD at 40°F (4°C) for 1 min	2313 at Perfs @ 7012ft dbrt	0	CO_2
8	Initial Well kill	2313 at Perfs @ 7012ft dbrt	0	CO_2
9	Final Well kill	2313 at Perfs @ 7012ft dbrt	0	9.98ppg KCl / NaCl Brine
10	Inject CO_2 138MMSCFD at -20°C/ -4°F for 1 day	2313 at Perfs @ 7012ft dbrt	0	CO_2
11	Inject CO_2 138MMSCFD at -20°C/ -4°F for 47 min	2313 at Perfs @ 7012ft dbrt	0	CO_2
12	Inject CO_2 138MMSCFD at -60°C/ -76°F for 1 day	2313 at Perfs @ 7012ft dbrt	0	CO_2
13	Shut-In CO_2 when Inj 138MMSCFD 40°F (4°C) for 1 hr	2313 at Perfs @ 7012ft dbrt	0	CO_2
14	Shut-In CO_2 when Inj 138MMSCFD 40°F (4°C) for 1 day	2313 at Perfs @ 7012ft dbrt	0	CO_2
15	Shut-In CO_2 when Inj 138MMSCFD 40°F f(4°C) or 1 month	2313 at Perfs @ 7012ft dbrt	0	CO_2
16	Inject CO_2 70MMSCFD at 40°F (4°C) Prosper BHP for 7 day	2399 at Perfs @ 7012ft MDBRT	0	CO_2
17	Inject CO_2 138MMSCFD 40°F (4°C) Prosper BHP for 1 hr	2498 at Perfs @ 7012ft MDBRT	0	CO_2
18	Inject CO_2 138MMSCFD 40°F (4°C) Prosper BHP for 1 day	2498 at Perfs @ 7012ft MDBRT	0	CO_2
19	Inject CO_2 138MMSCFD 40°F (4°C) Prosper BHP for 7 day	2498 at Perfs @ 7012ft MDBRT	0	CO_2
20	Inject CO_2 138MMSCFD 40°F (4°C) Prosper BHP for 1 month	2498 at Perfs @ 7012ft MDBRT	0	CO_2
21	Inject CO_2 138MMSCFD 40°F (4°C) Prosper BHP for 1 year	2498 at Perfs @ 7012ft MDBRT	0	CO_2
22	Inject N_2 30MMSCFD 40°F (4°C) for 1 day	2413 at Perfs @ 7012ft MDBRT	0	CO_2

4.24.30.11 Analysis Results Prod Module

The Production Module calculations were run on the loads cases given above in Table 4.97. The temperature and pressure profile against depth results for the different load case are shown below in Figure 4.63 to Figure 4.73.

Temperature Profile

Figure 4.63: Fluid Temperatures (99.9% CO_2 Vs 96% CO_2 Injection Cases)



The above Figure 4.63 shows the fluid temperature for the injection of both "pure" 99.9% CO_2 and 96% CO_2 with impurities. It can be seen from the Figure that injecting pure CO_2 results in a marginally greater wellbore cooling (1.2°F) as compared to use of a 96% CO_2 injection mixture. Hence the 99.9% CO_2 composition analysis results have been used and presented in this report.

Figure 4.64: Fluid Temperatures (Injection Cases)

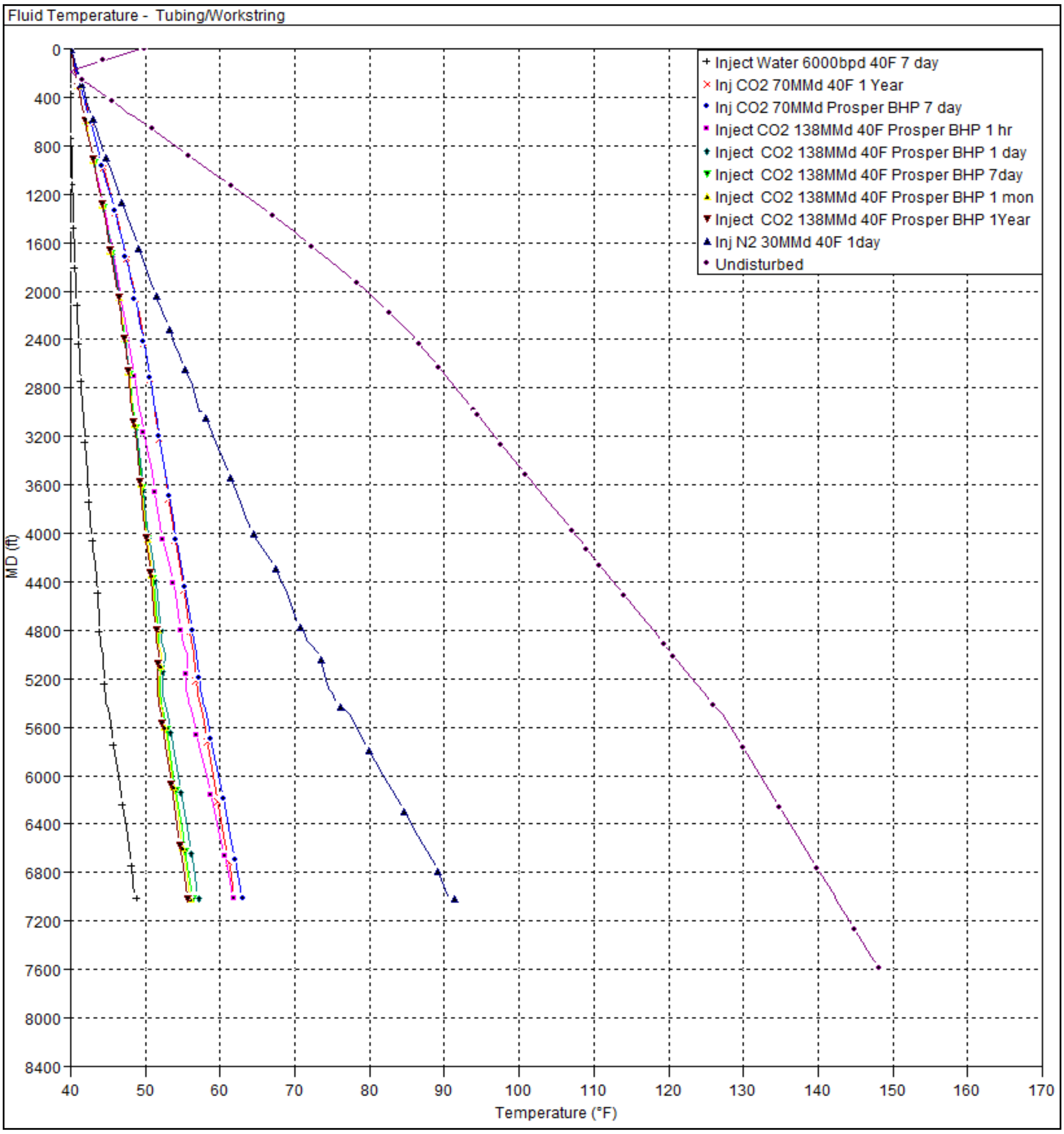


Figure 4.65: Fluid Temperatures (Injection cases at extreme cold)

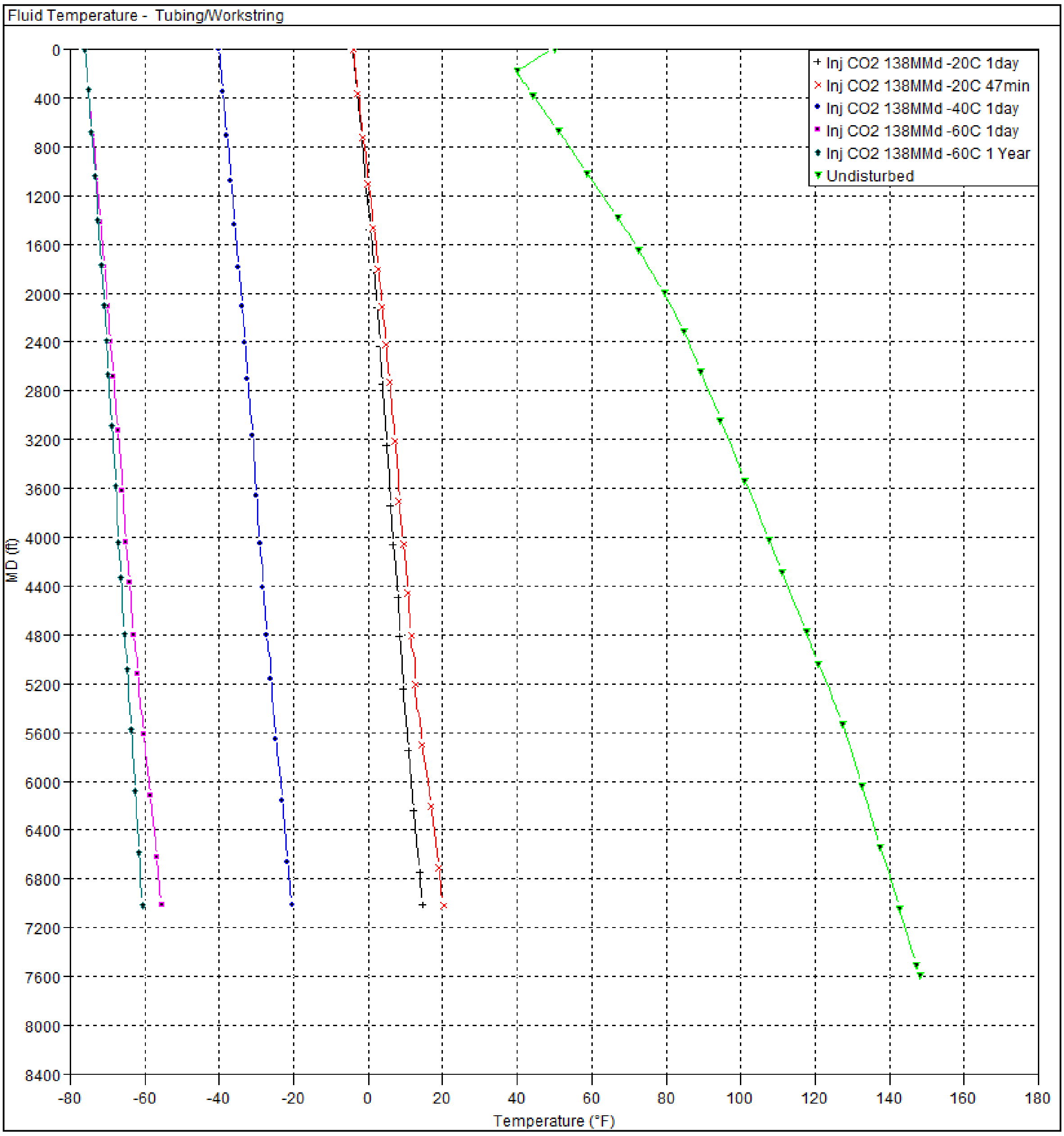


Figure 4.66: Fluid Temperatures (Production Cases)

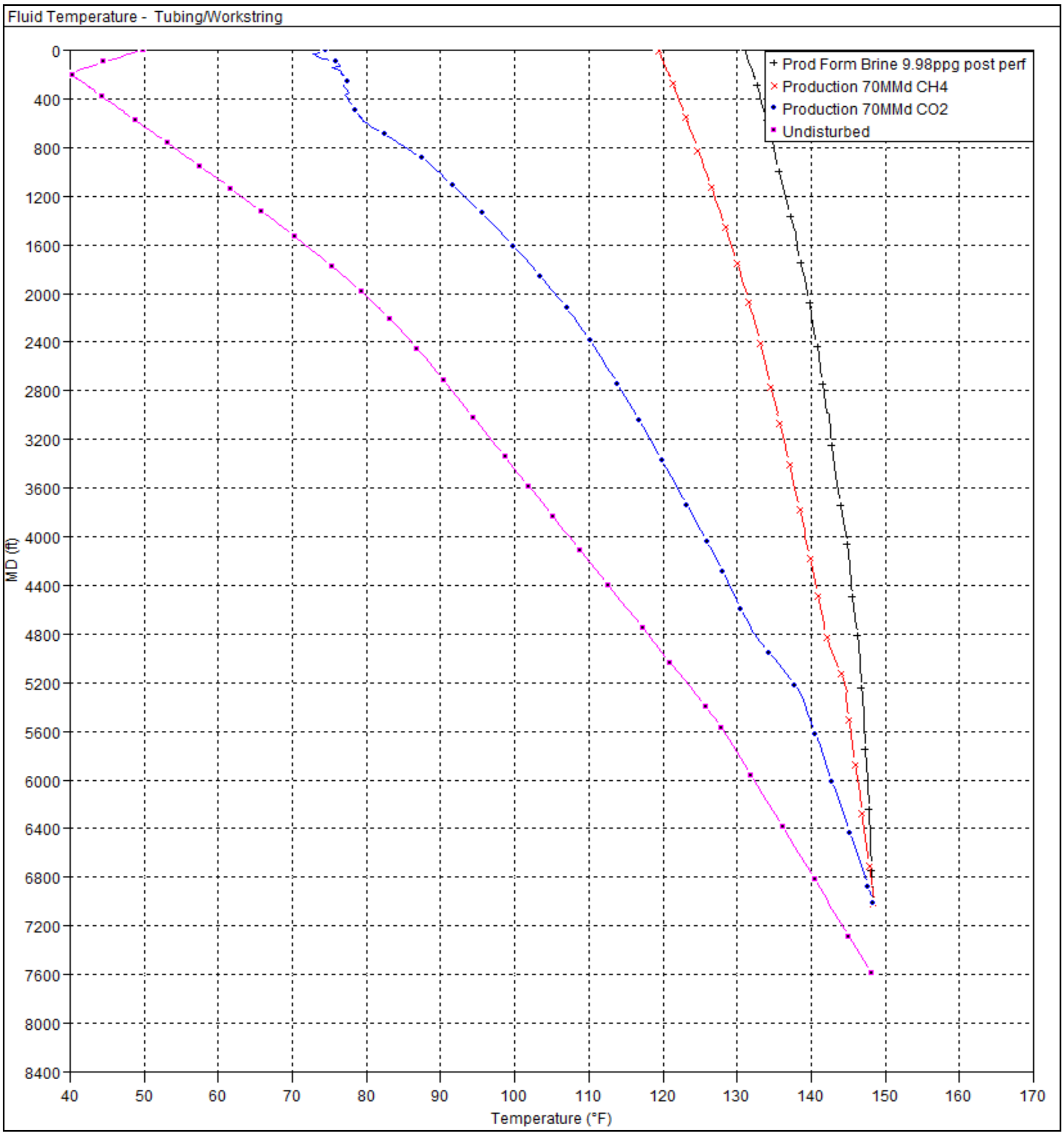
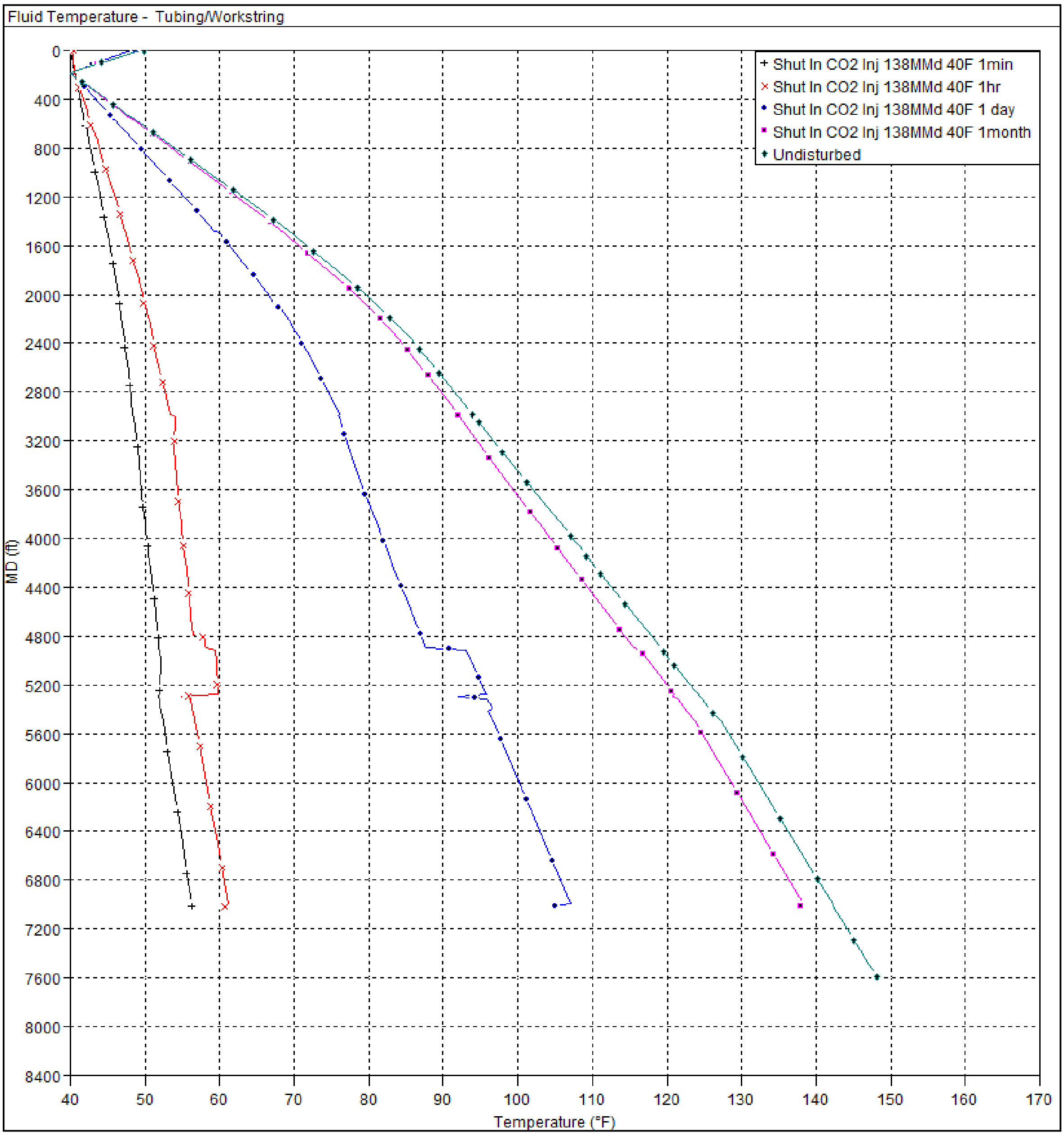


Figure 4.67: Fluid Temperatures (Shut-In Cases)



The Figure 4.67 above shows the fluid temperatures 1min, 1hr, 1day and 1 month after shutting in the well. After a month the temperature of the well will be approx. 4°F less than the undisturbed temperature base tubing / reservoir depth.

Figure 4.68: Temperatures Vs Time (Injection Cases)

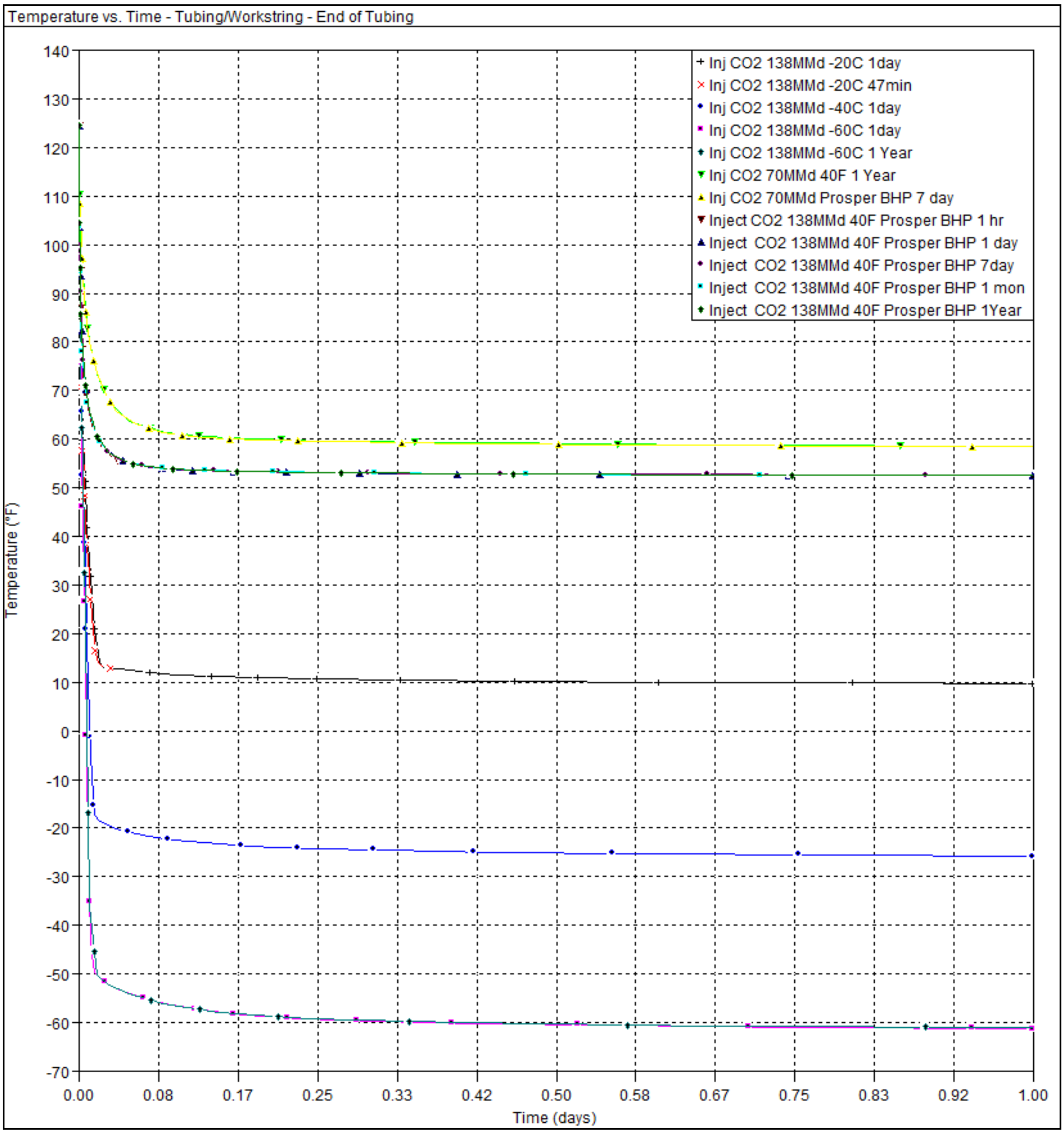


Figure 4.68 above shows the temperature at the base of the upper completion tubing against time for various CO_2 injection cases. It can be seen that the temperature initially drops rapidly before 'essentially' stabilising within 8 hours.

The injection of low temperature CO_2 into the well as a result of a large initial pressure drop across the injection choke has been discussed and qualified in this report. This is expected to result in CO_2 entering the well at a temperature of -10°C to 20°C. The equalisation process or opening of the choke is expected to take minutes rather than hours. A potential concern whilst injecting cold CO_2 is that the annular fluid might freeze. Further it was recognised Wellcat software is not designed to cater for annular freezing scenarios. Various injection stream temperatures and time periods were modelled to examine the temperature impact on each annuli.

Figure 4.69: Temperatures profile of Different annuli (for -20°C Injection Case)

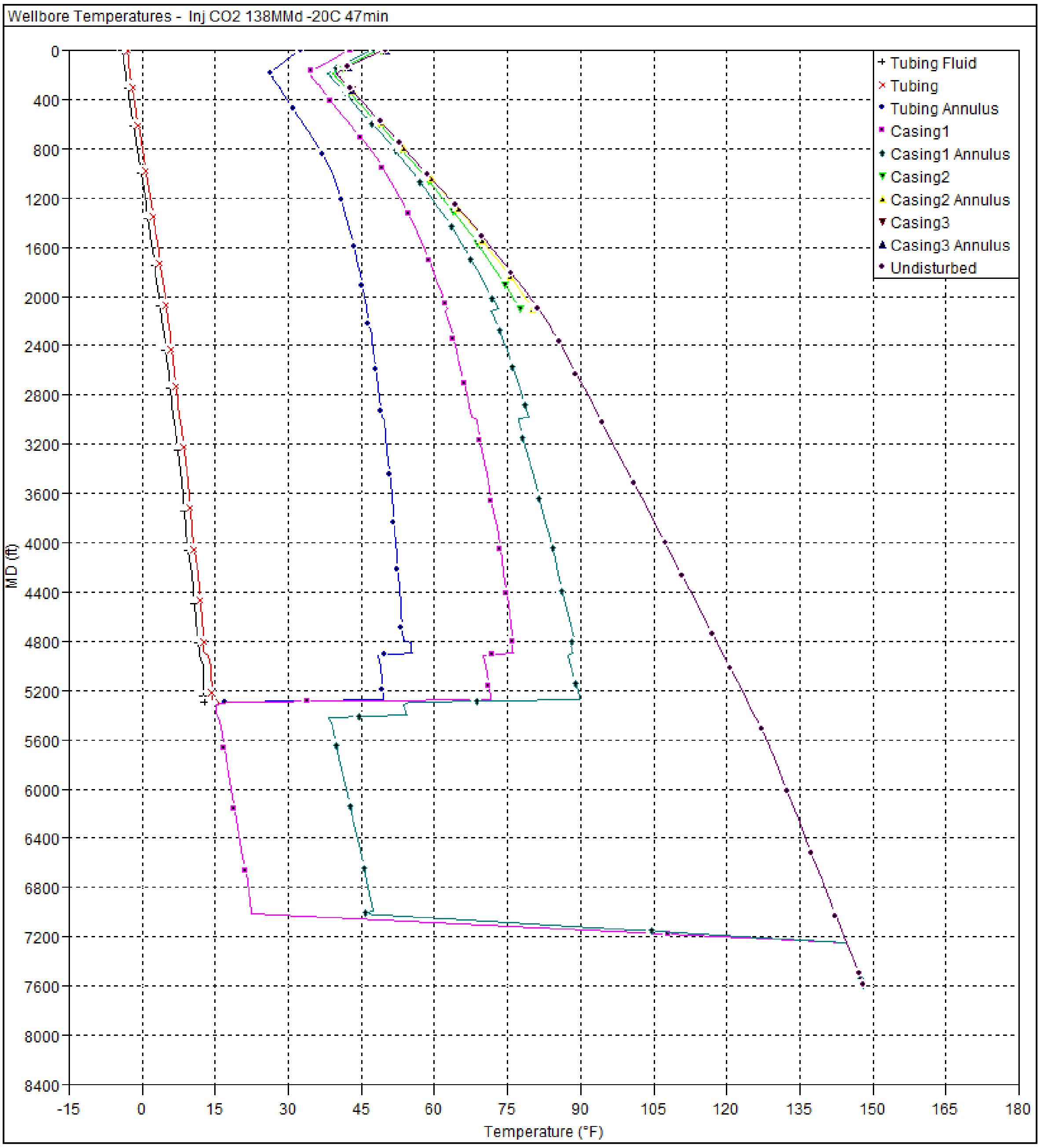


Figure 4.69 above shows that CO_2 can be injected into the completion tubing at 138MMSCFD at a temperature of -20°C (4°F) for 47 minutes before the A annulus surface temperature is cooled to 32°F/0°C the freezing point of freshwater (Note the mudline temperature is actually slightly lower than freezing). These points support the validity of the -20°C (4°F) model being run based on the assumption that the annular fluids will not freeze within this timeframe and that Wellcat software is being applied within

acceptable boundaries in terms of functional capability. The -20°C (4°F) CO_2 injection model was also run for a 1 day duration case and the calculated surface A annulus temperature was -12°C (9.87 F). For this case to be valid it should be recognised it is based on an assumption that adequate salinity is present to reduce the freezing point of the A annulus fluid. In reality however there is no expectation as stated earlier that such low temperature injection will be maintained for greater than an hour. In addition on further review is was recognised that the proposed A annulus 9.98ppg NaCl brine freezes at -22°C providing considerable further tolerance with respect freezing issues.

The 4°C (40°F) CO_2 injection cases are the steady state cases and thus these have been run for the longer term 1 day, month and year with no concerns with respect of low temperature annular freezing issues.

Pressures Profiles

Figure 4.70: Pressure vs Depth 5 1/2in Tubing String (Injection Cases)

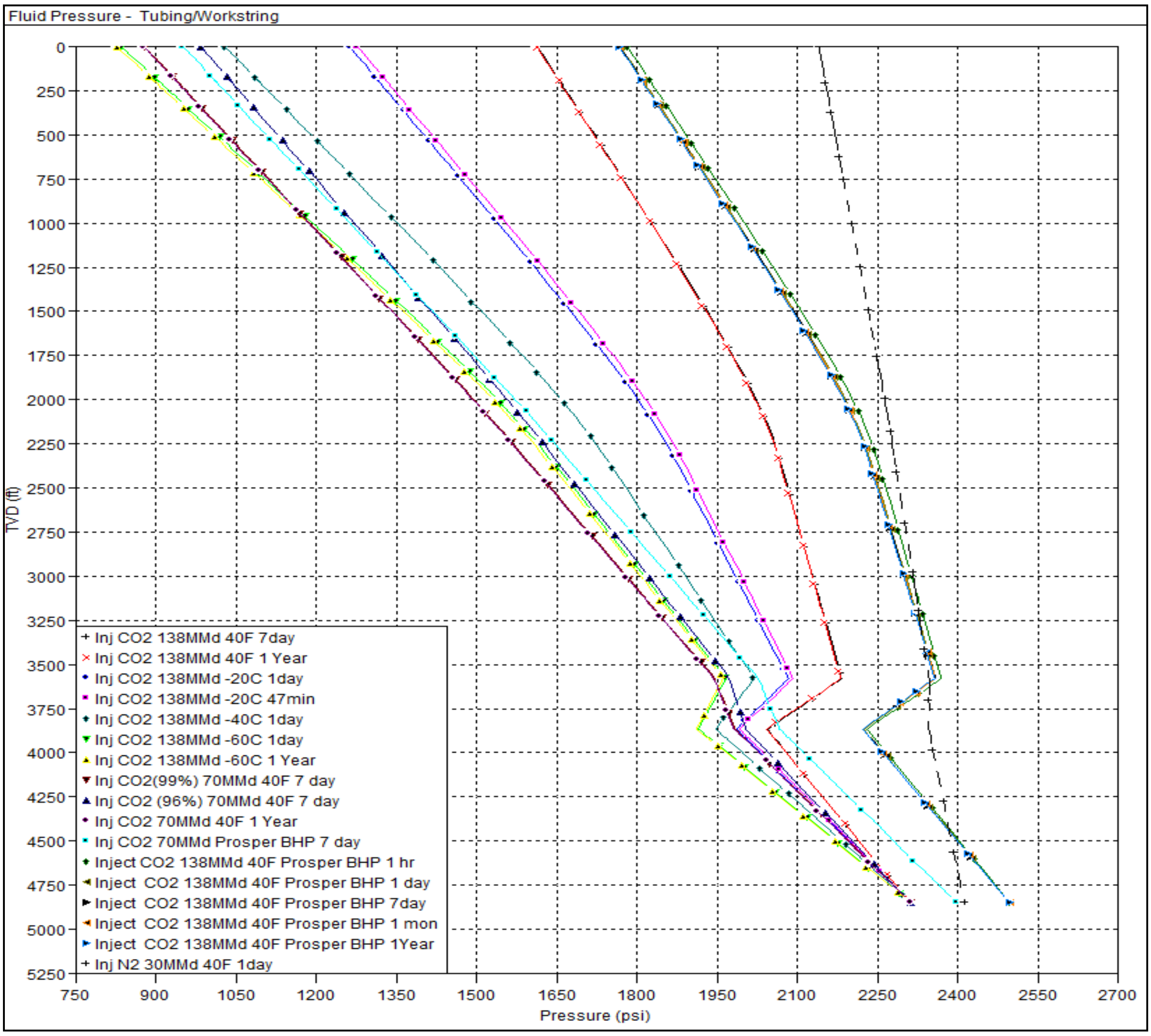


Figure 4.71: Pressure vs Depth 5 1/2in Tubing String. (Production Cases)

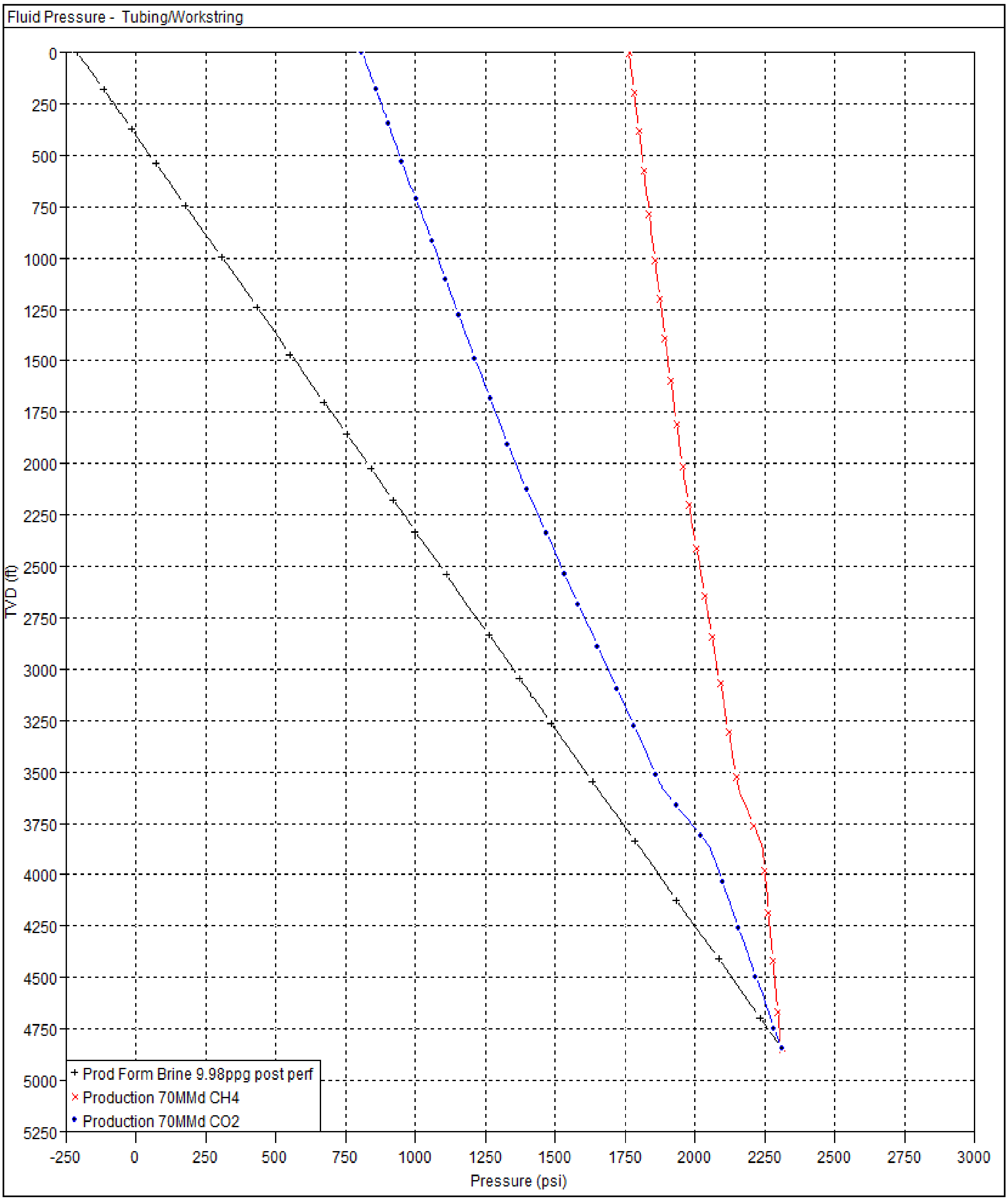


Figure 4.72: Pressure vs Depth 5 1/2in Tubing String (Shut-In Cases)

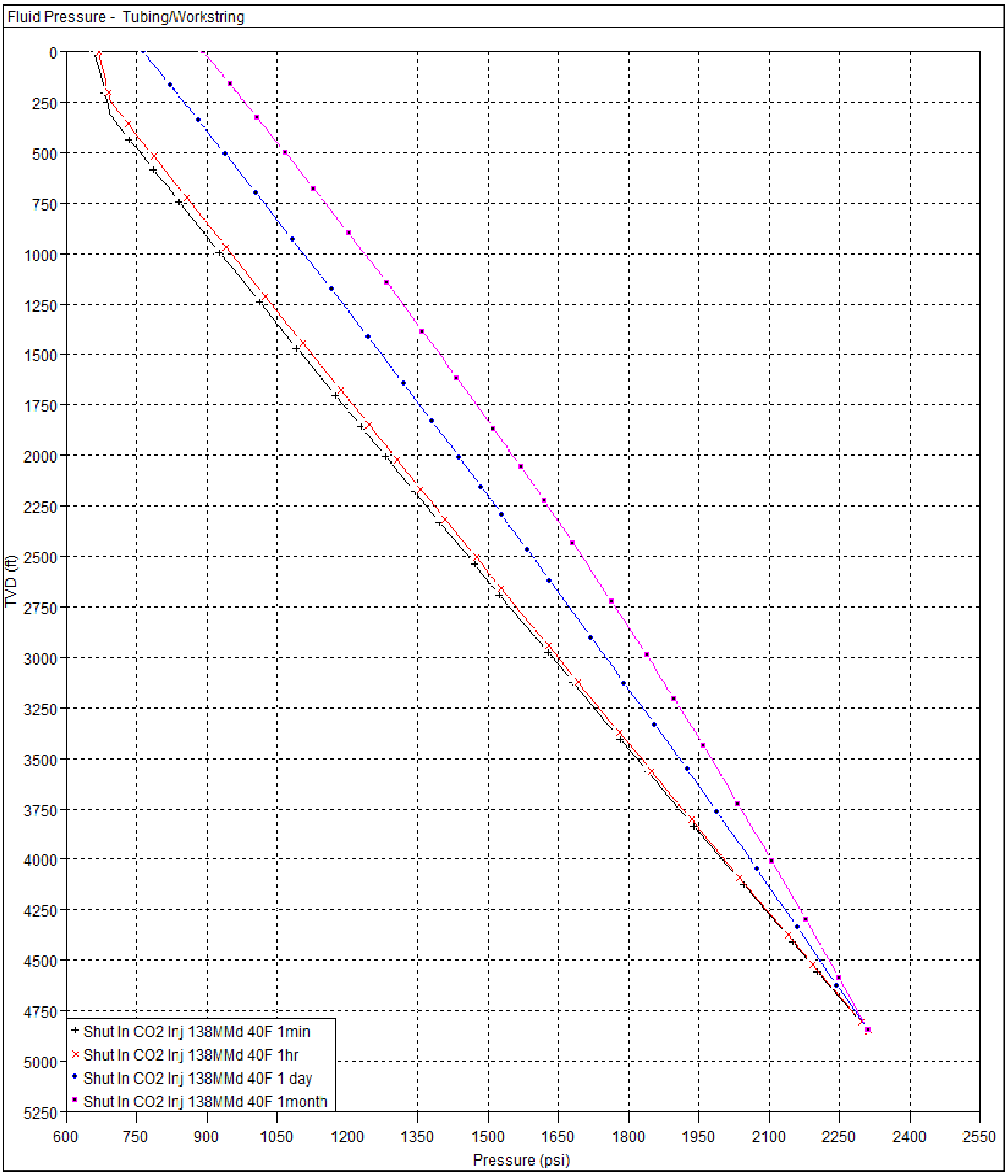
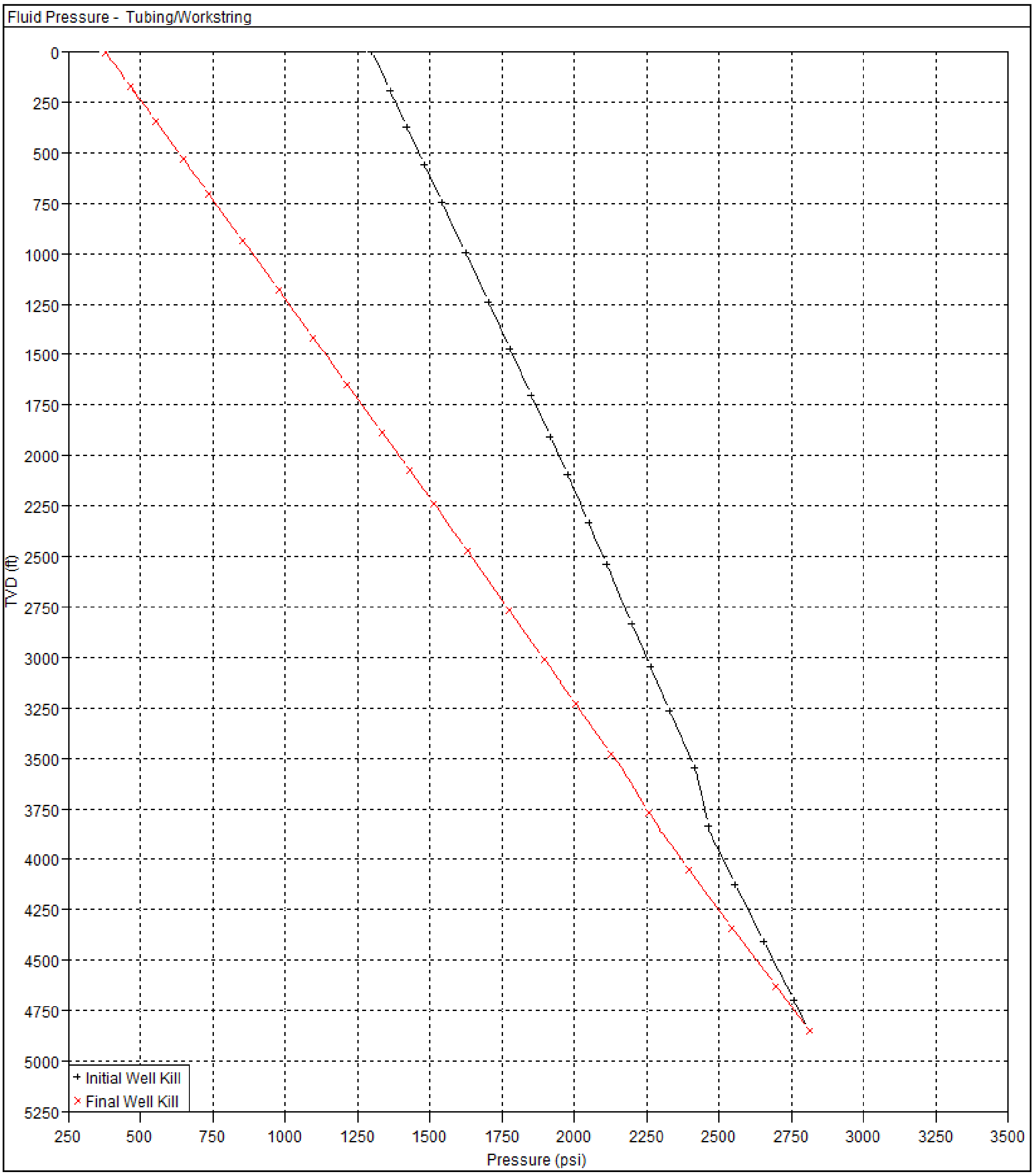


Figure 4.73: Pressure vs Depth 5 1/2in Tubing String (Well Kill Cases)



Tube Module:

The following are the load cases run in Tube Module of the WellCat software in Table 4.98:

Table 4.98: Completion String Load Cases

Load Conditions		Tubing Pressure (psi)	Annulus Pressure (psi)	Tubing Fluid
1	Pressure test tubing plug at 5280ft	5500 @ surface	0 @ surface	9.98ppg KCl/NaCl Brine
2	Pressure test annulus	0 @ surface	5500 @ surface	9.98ppg KCl/NaCl Brine
3	Inject water at 6000bpd	2400 @perfs @ 7012ft MDBRT	0 @ surface	Seawater
4	Produce CO_2 at 70MMSCFD	2313 @perfs @ 7012ft MDBRT	0 @ surface	CO_2
5	Tubing leak during production CO_2	2313 @perfs @ 7012ft MDBRT	0 rising with leak to 810psi @ surface	CO_2
6	Tubing leak during CO_2 injection	2313@Perfs @ 7012ft MDBRT	0 rising with leak to 1610psi @ surface	CO_2
7	Overpull 100k	0 @ surface	0 @ surface	9.98ppg KCl/NaCl Brine
8	Initial Well kill	2813@Perfs @7012ft MDBRT	0 @ surface	9.98ppg KCl/NaCl Brine
9	Final well kill	500psi above 2313psi reservoir pressure at Perfs @ 7012ft MDBRT	0 @ surface	9.98ppg KCl/NaCl Brine
10	Inject CO_2 at 138MMSCFD -20 C for 47min	2313@Perfs @ 7012ft MDBRT	0 @ surface	CO_2
11	Inject CO_2 at 138MMSCFD -20 C for 1 day	2313@Perfs @ 7012ft MDBRT	0 @ surface	CO_2
11	Inject CO_2 at 138MMSCFD 40°F for 1 year	2313@Perfs @ 7012ft MDBRT	0 @ surface	CO_2
12	Inject CO_2 at 70MMSCFD 40°F for 1 year	2313@Perfs @ 7012ft MDBRT	0 @ surface	CO_2
13	Shut-In CO_2 after Inj 138MMSCFD for 1 min	2313@Perfs @ 7012ft MDBRT	0 @ surface	CO_2
14	Shut-In CO_2 after Inj 138MMSCFD for 1 month	2313@Perfs @ 7012ft MDBRT	0 @ surface	CO_2
15	Inject N_2 30MMSCFD 40°F for 1 day	2413 @Perfs @ 7012ft MDBRT	0 @ surface	N2

Note: the highest maximum shut-in pressures of (2544psi / 2715psi) are generated when methane and nitrogen gas columns considered respectively at final reservoir pressure conditions. At initial conditions the equivalent values are 132bar / 144bar (1846psi / 2017psi).

The highest maximum CO_2 shut-in pressure of 104bar (1436psi) is generated at final reservoir pressure conditions. At initial conditions the equivalent value is 56bar (737psi).

4.24.30.12 *Analysis Results Tube Module*

The results from the 5-1/2in x 4-1/2in tapered upper completion tubing stress analysis are presented below. The results are presented as absolute safety factors for burst, collapse axial and tri-axial.

Absolute Minimum Safety Factors

Table 4.99 below shows the minimum safety factors for all load cases considered.

Table 4.99: 5 1/2in 17# L8013Cr JFE bear Completion String

Load Conditions		Burst Design Factor (min)	Depth ft (MD)	Collapse Design Factor (min)	Depth ft (MD)	Axial Design Factor (min)	Depth ft (MD)	Tri-axial Design Factor (min)	Depth ft (MD)
Design Factors		**1.1**		**1.0**		**1.3**		**1.25**	
1	Pressure test tubing plug at 5280ft	1.386	4800	100+	-	2.842	858	1.508	4800
2	Pressure test annulus	100+	-	1.092	4800	CM4.635	4800	1.346	858
3	Inject water at 6000bpd	36.212	0.1	22.132	4800	3.311	858	D3.332	858
4	Produce CO_2 at 70MMSCFD	9.534	0.1	32.473	4800	7.034	858	7.675	858
5	Tubing leak during production CO_2	100+	-	6.238	4800	8.883	858	D70.49	858
6	Tubing leak during CO_2 injection	100+	-	30.055	4800	5.185	858	D5.037	858
7	Overpull 100k	100+	-	26.074	5300	2.509	858	D2.473	858
8	Initial Well kill	5.563	0.1	2.040	5300	3.196	858	3.505	858
9	Final well kill	20.169	4800	25.639	5300	3.182	858	D3.319	858
10	Inject CO_2 at 138MMSCFD, -20 C for 47min	6.059	0.1	31.271	5300	2.436	858	2.672	858
11	Inject CO_2 at 138MMSCFD, -20 C for 1 day	6.132	0.1	31.361	5300	2.405	858	2.637	858
12	Inject CO_2 at 138MMSCFD 40°F for 1 year	4.798	0.1	30.494	5300	3.201	858	3.493	858
13	Shut-In CO_2 after Inj 138MMSCFD for 1 month	9.084	0.1	29.873	5300	4.773	858	5.258	858
14	Inject N_2 30MMSCFD 40°F for 1 day	3.614	0.1	26.502	5300	3.357	858	3.289	0.1
	C = Connection, D = Outer Wall Safety Factor, N = Negative Bending, M = Compression								

Design Limit Plots

Figure 4.74: Design Limit Plot Section 1

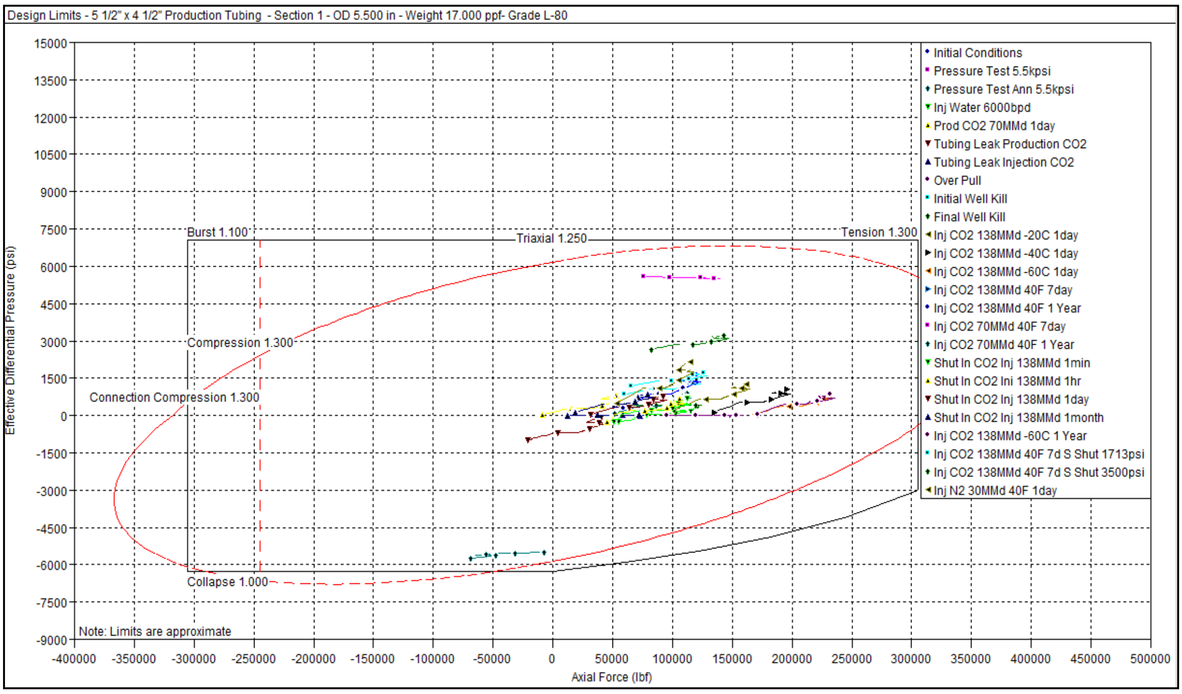
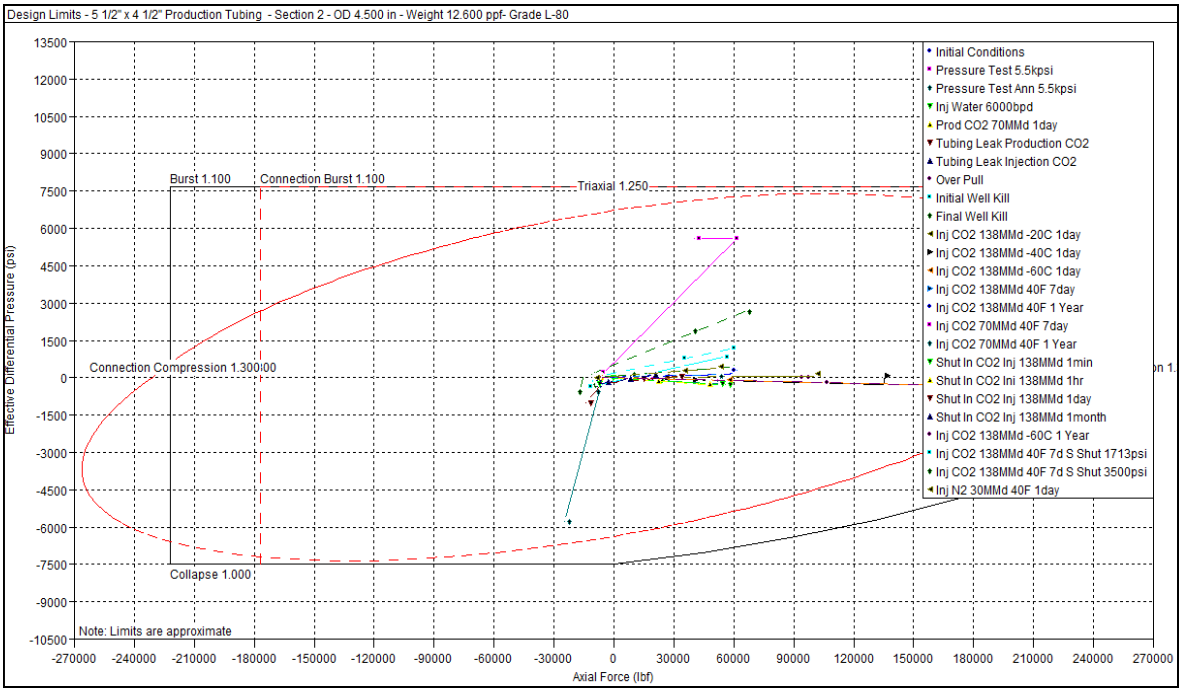


Figure 4.75: Design Limit Plot Section 2



Safety Factors

Figure 4.76: Burst Safety Factors

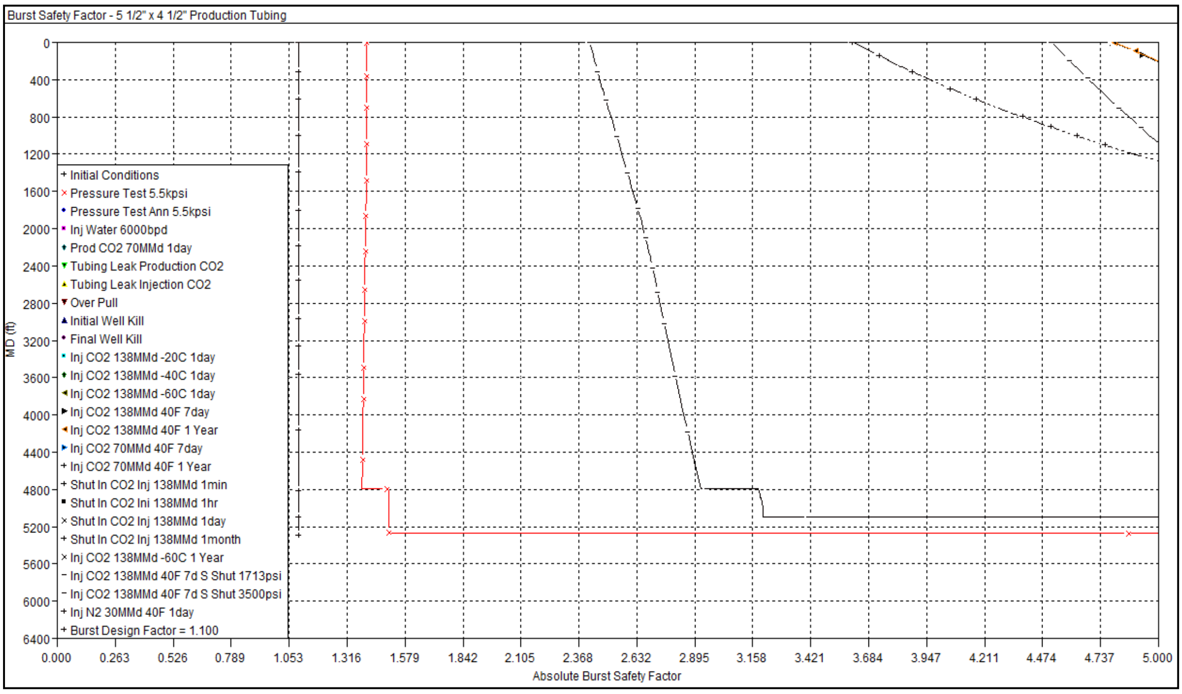


Figure 4.77: Collapse Safety Factors

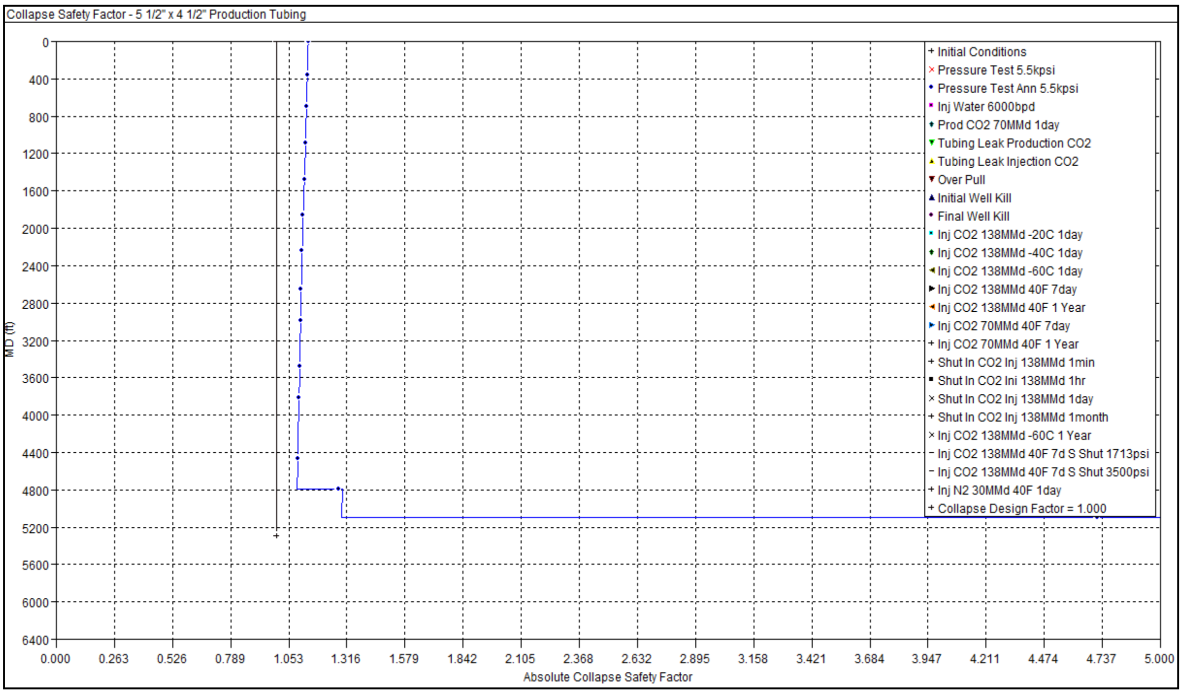


Figure 4.78: Axial Safety Factors

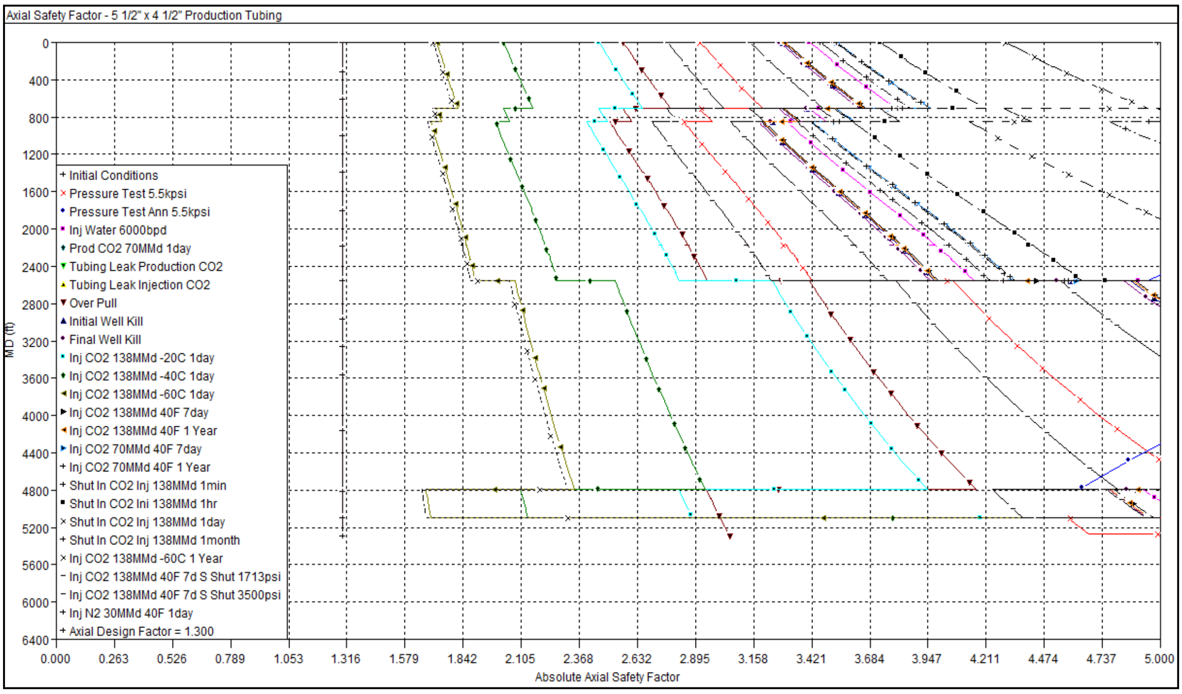
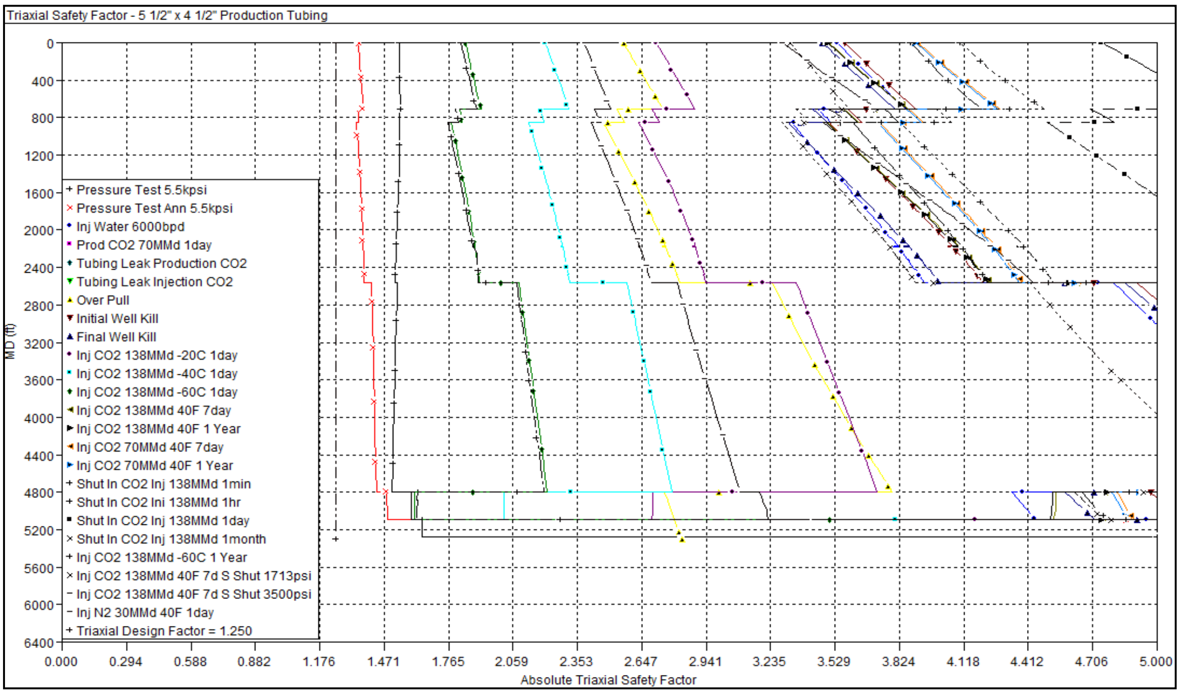


Figure 4.79: Triaxial Safety Factors



Tubing Movement Bar-Chart

Figure 4.80: Tubing Movement

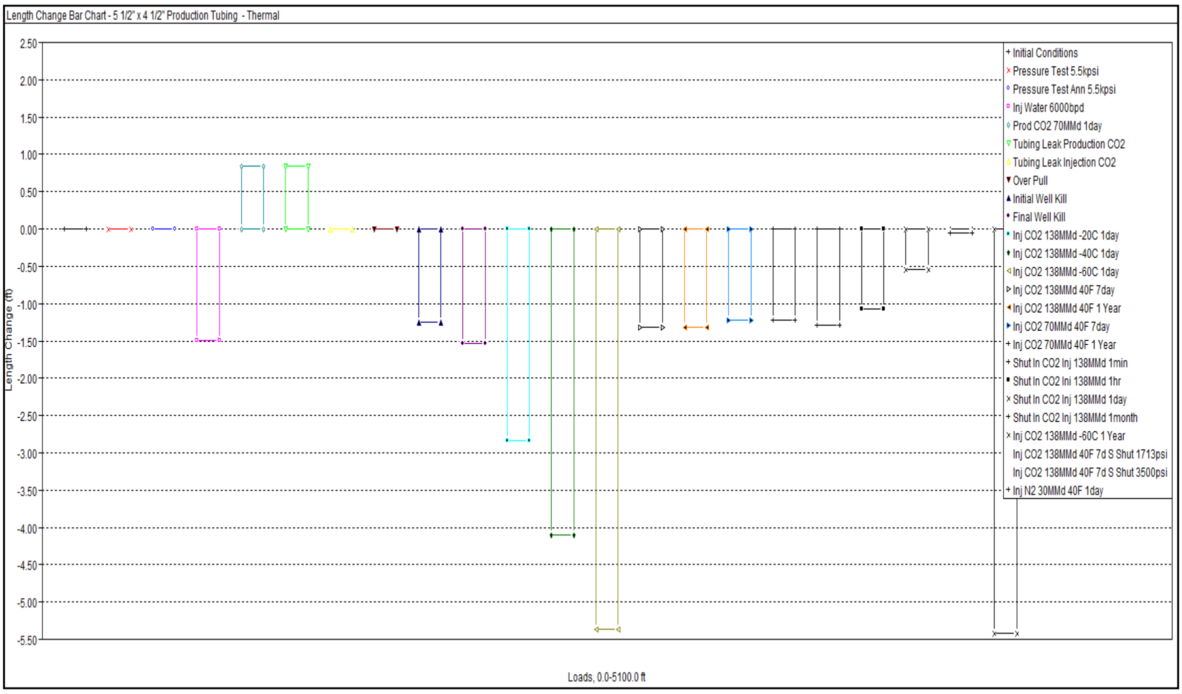


Figure 4.80 shows that during the 70MMSCFD CO_2 production and tubing leak cases, the maximum tubing expansion is 0.84ft while for injection case of 138MMSCFD at -60°C/-76°F the maximum contraction in the tubing is -5.37ft.

Packers Loads

The packer loads during injecting CO_2 at 138MMSCFD and -20°C (4°F) temperature are shown below in Table 4.100.

Table 4.100: Packer Loads (Injection Case)

Packer Load Summary - Inj CO2 138MMd -20C 1day - 5 1/2" x 4 1/2" Production Tubing

	Name	Packer MD (ft)	Setting Sequence #	Tubing-to-Packer Force (lbf)	Axial Load Above (lbf)	Axial Load Below (lbf)	Annulus Pressure Above (psi)	Annulus Pressure Below (psi)	Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force (lbf)
1	Fixed Packer (Packer)	5100.0	1	-105673	99964	-5709	2001.20	2017.50	10.38	--	-105903
2											
3	Negative forces are in the upward direction.										

Table 4.101: Fixed Packer Loads Summary

Packer Loads - 5 1/2" x 4 1/2" Production Tubing - Fixed Packer (Packer @ 5100.0 ft MD)

	Load	Tubing-to-Packer Force (lbf)	Axial Load		Annulus Pressure		Temperature (°F)	Latching Force (lbf)	Packer-to-Casing Force (lbf)
			Above (lbf)	Below (lbf)	Above (psi)	Below (psi)			
1	Initial Conditions	-18280	12505	-5776	1946.07	1946.13	121.94	---	-18280
2	Pressure Test 5.5kpsi	21926	39969	61894	1946.07	1946.16	121.94	---	21926
3	Pressure Test Ann 5.5kpsi	18291	-24067	-5776	7446.07	1946.16	121.94	---	96009
4	Inj Water 6000bpd	-61976	56386	-5590	1986.50	1903.49	45.07	---	-60803
5	Prod CO2 70MMd 1day	2090	-8049	-5959	1958.30	1992.96	136.20	---	1600
6	Tubing Leak Production CO2	7457	-13416	-5959	2745.26	2031.94	136.20	---	17537
7	Tubing Leak Injection CO2	-18280	12505	-5776	1946.07	1946.16	121.94	---	-18280
8	Over Pull	N/A	94224	94224	1946.07	1946.13	121.94	---	N/A
9	Initial Well Kill	-63593	54860	-8733	1974.47	2784.24	56.68	---	-75036
10	Final Well Kill	-65587	58283	-7305	1985.50	2369.30	42.63	---	-71011
11	Inj CO2 138MMd -20C 1day	-105675	99966	-5709	2001.20	2017.50	10.38	---	-105905
12	Inj CO2 138MMd 40F 7day	-63931	58015	-5916	1984.90	2090.54	52.58	---	-65424
13	Inj CO2 138MMd 40F 1 Year	-64097	58184	-5913	1985.50	2089.54	52.10	---	-65567
14	Inj CO2 70MMd 40F 7day	-57231	51531	-5700	1984.20	1966.69	57.78	---	-56983
15	Inj CO2 70MMd 40F 1 Year	-57497	51802	-5695	1984.80	1965.18	56.98	---	-57220
16	Shut In CO2 Inj 138MMd 1min	-57789	52201	-5588	1974.60	1911.45	53.83	---	-56897
17	Shut In CO2 Ini 138MMd 1hr	-51733	46131	-5602	1972.18	1916.61	64.70	---	-50947
18	Shut In CO2 Inj 138MMd 1day	-37455	31657	-5798	1960.14	1977.21	94.77	---	-37696
19	Shut In CO2 Inj 138MMd 1month	-24381	18400	-5982	1948.38	2033.61	118.85	---	-25586
20	Inj N2 30MMd 40F 1day	-58313	51307	-7006	1982.00	2346.62	74.54	---	-63465
21									
22	Negative forces are in the upward direction.								

A description of the tubing to packer loads considered most representative was achieved by first modelling a cool down tension scenario (-4°F to 40°F) at the planned 70-138MMSCFD CO_2 injection rate and then modelling shut-in scenarios. A water injection rate of 6000bpd was also modelled. The results are shown above in Table 4.101 and indicate the different tension loads for the different conditions.

4.24.31 Wellhead Movement Analysis

4.24.31.1 Model B

Multi String Module

The WellCat software multistring module has been used to perform AFE and WHM. Based on the combined interaction of all the casing and tubing strings inside the wellbore, the model allows an evaluation of the integrity of the casing and tubing under AFE and WHM conditions. The AFE computes stresses that act on the selected casing for user defined custom loads taking into account the annular pressure build up. The landing data, initial conditions, design parameters are specified in the model for each of the respective casing, liners and tubing strings. The cementing and landing data is also used in the wellhead movement analysis to compute the weight of a string as it is landed in the wellhead. This weight acts as a downward axial force and causes the wellhead to move downward. Further, the temperature cool down or rise also have an impact on wellhead movement.

For AFE modelling purposes, 13 3/8in and 9 5/8in casing annuli have been conservatively assumed to be none vented annuli. Since the 13 3/8in & 9 5/8in casing TOC is well below 20in & 13 3/8in casing shoe respectively, any pressure build up above the fracture gradient will leaked off into the formation. Stresses acting on the 13 3/8in and 20in casing due to annular pressure have been analysed. The 7in liner has been considered as cemented to TOL hence is assumed not an AFE issue.

For WHM analysis a chronological load history has been defined for the well based on the order that each piece of equipment (e.g. casing, Christmas tree, BOP) is landed in place. The movement of the wellhead has been computed and the load distribution between all the casings analysed.

The AFE computes stresses that act on the casing / tubing strings for predefined custom loads, taking into account the annular pressure build up. The packer, initial conditions and design parameters have been used for stress calculation. The landing condition of the tubing has also been used in the wellhead movement analysis.

The WHM analysis requires the specification of the outermost string to which the wellhead will be attached. The wellhead will be installed on 13 3/8in surface casing.

The string to which the wellhead is attached is defined in the model as the outermost string. The wellhead will be installed on 13 3/8in surface casing. This string and those within are considered as a system. The outermost string bears the hang off weight of the inner hanging strings secured from the wellhead. In Wellcat terms the point of fixity is the point where movement of the outer string is considered arrested by full formation or cement bonding.

Each internal string is constrained in terms of movement defined individually by hanger, specific tops of cements and for tubing by any packers. These various other 'points of fixity' are considered fully in thermal load case / movement terms.

AFE Custom Load

The stress analysis has been performed on the custom load described below. The loads for each string are defined as Max Burst, Max collapse and AFE.

Table 4.102: – AFE Custom Loads

Strings		Custom Loads
1	30 x 20in Conductor Casing	Max Burst
2	13 3/8in Surface Casing 9 5/8in Intermediate Casing	AFE, Max Burst, Max Collapse
3	7in Production Liner	Max Burst
4	5 1/2in Production Tubing	AFE, Max Burst, Max Collapse

Installation and Static Load Definition

The following installation and static load cases have been considered in the MultiString analysis:

Table 4.103: Installation and Static load definition

Load Conditions		Installed Wellhead (lbf)	Point of Fixity (ft)	String Dependent Static Loads			
				Hang off Drillstring in BOP (lbf)	Nipple Up BOP (lbf)	Nipple Down BOP (lbf)	Nipple Up Tree (lbf)
1	30x20in Conductor Casing	14,000	308	Undefined	Undefined	Undefined	Undefined
2	13 3/8in Surface Casing	14,000	-	Undefined	100,000	Undefined	Undefined
3	9 5/8in Intermediate Casing	14,000	-	Undefined	Undefined	Undefined	Undefined
4	5 1/2in Production Tubing	14,000	-	Undefined	Undefined	100,000	14,000

Load History Definition:

The load history considered is described below in Table 4.104:

Table 4.104: Load History Definition

Load Condition		Load History
1	30 x 20in Conductor Casing	
2	13 3/8in Surface Casing	Installed Wellhead Nipple up BOP
3	5 1/2in Production Tubing	Nipple down BOP Nipple up Tree Case 1: Produce CO_2 at 70MMSCFD, 40°F (4°C.) for 7 days Case 2: Inject CO_2 at 138MMSCFD, 40°F (4°C.)for 7 days Case 3: Inject CO_2 at 138MMSCFD, -20°C (4°F) for 47min Nipple down Tree

4.24.31.2 Model B Analysis Results

AFE Sensitivity Analysis

The AFE sensitivity has been run on customs loads for three cases as given below:

- Case 1:

Produce CO_2 at 70MMSCFD, 40°F for 7 days

- Case 2:

Inject CO_2 at 138MMSCFD, 40°F for 7 days

- Case 3:

Inject CO_2 at 138MMSCFD, -20°C for 47min.

The results are presented below from Tables 4.107 to Table 4.107 for all three cases. The multistring AFE summary shows surface pressure induced from annular fluid expansion simulation for each region outside of each string. It also contains the annulus fluids expansion volume for each of those regions.

Table 4.105: AFE Summary Case 1

MultiString Annular Fluid Expansion Summary

	String Annulus	Region	Incremental AFE Pressure (1) (psi)	Incremental AFE Volume (2) (bbl)
1	13 3/8" Surface Casing	Region 1	0.00	1.7
2	9 5/8" Intermediate Casing	Region 1	170.00	2.0
3	5 1/2" x 4 1/2" Production Tubing	Region 1	1977.00	1.2
4				
5	(1) Pressure change caused solely by the Annular Fluid Expansion (AFE) phenomenon.			
6	(2) Volume change caused solely by the Annular Fluid Expansion (AFE) effect.			

Table 4.106: AFE Summary Case 2

MultiString Annular Fluid Expansion Summary

	String Annulus	Region	Incremental AFE Pressure (1) (psi)	Incremental AFE Volume (2) (bbl)
1	13 3/8" Surface Casing	Region 1	-15.00	-0.6
2	9 5/8" Intermediate Casing	Region 1	-15.00	-2.0
3	5 1/2" x 4 1/2" Production Tubing	Region 1	-15.00	-1.6
4				
5	(1) Pressure change caused solely by the Annular Fluid Expansion (AFE) phenomenon.			
6	(2) Volume change caused solely by the Annular Fluid Expansion (AFE) effect.			

Table 4.107: AFE Summary Case 3

MultiString Annular Fluid Expansion Summary

	String Annulus	Region	Incremental AFE Pressure (1) (psi)	Incremental AFE Volume (2) (bbl)
1	13 3/8" Surface Casing	Region 1	0.00	0.0
2	9 5/8" Intermediate Casing	Region 1	-15.00	-0.9
3	5 1/2" x 4 1/2" Production Tubing	Region 1	-15.00	-2.1
4				
5	(1) Pressure change caused solely by the Annular Fluid Expansion (AFE) phenomenon.			
6	(2) Volume change caused solely by the Annular Fluid Expansion (AFE) effect.			

AFE can induce collapse or burst forces. To consider the range of extremes the programme allows the user to consider AFE temperature / pressure build up change on one side only of a string (one side might not heat up / cool down or fluid may leak off). This is thus captured / described as max burst / max collapse end cases for each string.

- **AFE Axial Load Summary Case 1:** the axial load summary in Table 4.108 below shows the Case 1 axial load profile as a function of depth.
- **AFE Axial Load Summary Case 2:** the annulus fluid expansion axial load summary in Table 4.109 below shows the Case 2 axial load profile as a function of depth.
- **AFE Axial Load Summary Case 3:** the axial load summary in Table 4.110 below shows the Case 3 axial load profile as a function of depth.

Table 4.108: AFE Axial Load Summary Case 1

MD (ft) (ft)	Axial Load (lbf) Initial Conditions	5 1/2" x 4 1/2" Production Tubing -	5 1/2" x 4 1/2" Production Tubing -	5 1/2" x 4 1/2" Production Tubing -AFE
0.1	73031	23923	52569	23923
10.9	72848	23740	52385	23740
19.9	72695	23587	52232	23587
20.1	72691	23583	52229	23583
500.0	64533	15425	44071	15425
508.4	64390	15282	43928	15282
508.5	64388	15280	43926	15280
612.5	62626	13518	42164	13518
709.9	60976	11868	40513	11868
710.1	60972	11864	40510	11864
803.7	59386	10278	38924	10278
803.9	59383	10275	38920	10275
857.5	58475	9366	38012	9366
857.7	58471	9363	38009	9363
902.1	57719	8611	37256	8611
902.3	57715	8607	37253	8607
1000.0	56060	6952	35597	6952
1000.6	56050	6942	35587	6942
1000.8	56046	6938	35584	6938
1099.0	54382	5274	33920	5274
1099.2	54379	5271	33917	5271
1197.4	52780	3672	32318	3672
1197.6	52777	3669	32314	3669
1295.8	51178	2070	30715	2070
1296.0	51174	2066	30712	2066
1394.3	49574	466	29111	466
1394.5	49570	462	29108	462
1492.7	47971	-1137	27509	-1137
1492.9	47968	-1140	27506	-1140
1500.0	47862	-1246	27400	-1246
1591.1	46502	-2606	26040	-2606
1591.3	46499	-2609	26037	-2609
1689.5	45033	-4075	24570	-4075
1689.7	45030	-4078	24567	-4078
1788.0	43562	-5546	23100	-5546
1788.2	43559	-5549	23097	-5549
1886.4	42093	-7015	21630	-7015
1886.6	42090	-7018	21628	-7018
1984.8	40791	-8317	20329	-8317
1985.0	40789	-8319	20326	-8319
2000.0	40590	-8518	20128	-8518
2083.2	39490	-9618	19028	-9618
2083.4	39488	-9621	19025	-9621
2178.2	38234	-10874	17772	-10874
2178.4	38231	-10877	17769	-10877
2181.7	38188	-10920	17725	-10920
2181.9	38185	-10923	17723	-10923
2280.1	37048	-12060	16586	-12060
2280.3	37046	-12062	16584	-12062
2333.0	36436	-12672	15974	-12672
2333.2	36434	-12674	15971	-12674
2378.5	35909	-13199	15447	-13199
2378.7	35907	-13201	15444	-13201
2423.7	35386	-13722	14924	-13722
2423.9	35384	-13724	14921	-13724
2476.9	34852	-14257	14389	-14257
2477.1	34850	-14259	14387	-14259
2500.0	34620	-14488	14157	-14488
2563.6	33981	-15127	13519	-15127
2563.8	33979	-15129	13517	-15129
2668.0	32933	-16175	12470	-16175
2668.1	32932	-16176	12469	-16176
2969.1	29997	-19111	9534	-19111
2969.2	29996	-19112	9533	-19112
3000.0	29695	-19413	9233	-19413
3264.3	27117	-21991	6655	-21991
3264.4	27116	-21992	6654	-21992
3500.0	24820	-24288	4357	-24288
3559.6	24239	-24869	3776	-24869
3559.7	24238	-24870	3775	-24870
3854.9	21359	-27749	897	-27749
3855.0	21358	-27750	896	-27750
4000.0	19945	-29164	-518	-29164
4155.2	18432	-30676	-2031	-30676
4155.3	18431	-30677	-2032	-30677
4500.0	15069	-34039	-5394	-34039
4543.9	14641	-34467	-5822	-34467
4544.0	14640	-34468	-5823	-34468
4799.9	12145	-36963	-8318	-36963
4800.1	14672	-19020	-5886	-19020
4858.8	14248	-19444	-6310	-19444
4858.9	14247	-19445	-6311	-19445
4889.9	14023	-19669	-6535	-19669
4890.1	14021	-19670	-6536	-19670
4899.9	13951	-19741	-6607	-19741
4900.1	13949	-19743	-6609	-19743
5000.0	13228	-20464	-7330	-20464
5036.0	12967	-20725	-7591	-20725
5036.1	12967	-20725	-7591	-20725
5099.9	12505	-21187	-8053	-21187
5100.1	-5776	-5959	-5959	-5959
5299.9	-7221	-7405	-7405	-7405

Table 4.109: AFE Axial Load Summary Case 2

MD (ft)	Axial Load (lbf)			
	Initial Conditions	5 1/2" x 4 1/2" Production Tubing - MaxCo	5 1/2" x 4 1/2" Production Tubing - MaxBu	5 1/2" x 4 1/2" Production Tubing -AFE
(ft)				
0.1	73031	120590	120374	120590
10.9	72848	120407	120190	120407
19.9	72695	120254	120037	120254
20.1	72691	120250	120034	120250
500.0	64533	112092	111875	112092
508.4	64390	111949	111733	111949
508.5	64388	111948	111731	111948
709.9	60976	108535	108318	108535
710.1	60972	108531	108315	108531
803.7	59386	106945	106729	106945
803.9	59383	106942	106725	106942
857.5	58475	106034	105817	106034
857.7	58471	106030	105814	106030
902.1	57719	105278	105061	105278
902.3	57715	105275	105058	105275
1000.0	56060	103619	103402	103619
1000.6	56050	103609	103392	103609
1000.8	56046	103605	103389	103605
1099.0	54382	101941	101725	101941
1099.2	54379	101938	101721	101938
1197.4	52780	100339	100122	100339
1197.6	52777	100336	100119	100336
1295.8	51178	98737	98520	98737
1296.0	51174	98734	98517	98734
1394.3	49574	97133	96916	97133
1394.5	49570	97130	96913	97130
1492.7	47971	95531	95314	95531
1492.9	47968	95528	95311	95528
1500.0	47862	95422	95205	95422
1510.0	47713	95272	95055	95272
1591.1	46502	94061	93844	94061
1591.3	46499	94058	93842	94058
1689.5	45033	92592	92375	92592
1689.7	45030	92589	92372	92589
1788.0	43562	91121	90904	91121
1788.2	43559	91118	90901	91118
1812.5	43196	90755	90539	90755
1886.4	42093	89652	89435	89652
1886.6	42090	89649	89432	89649
1984.8	40791	88351	88134	88351
1985.0	40789	88348	88131	88348
2000.0	40590	88150	87933	88150
2042.0	40035	87594	87377	87594
2083.2	39490	87049	86833	87049
2083.4	39488	87047	86830	87047
2178.2	38234	85793	85576	85793
2178.4	38231	85790	85574	85790
2181.7	38188	85747	85530	85747
2181.9	38185	85744	85528	85744
2250.0	37397	84956	84739	84956
2280.1	37048	84608	84391	84608
2280.3	37046	84605	84388	84605
2333.0	36436	83995	83778	83995
2333.2	36434	83993	83776	83993
2378.5	35909	83468	83252	83468
2378.7	35907	83466	83249	83466
2423.7	35386	82945	82728	82945
2423.9	35384	82943	82726	82943
2437.5	35247	82806	82590	82806
2476.9	34852	82411	82194	82411
2477.1	34850	82409	82192	82409
2500.0	34620	82179	81962	82179
2563.6	33981	81540	81323	81540
2563.8	33979	81538	81321	81538
2668.0	32933	80492	80275	80492
2668.1	32932	80491	80274	80491
2969.1	29997	77556	77339	77556
2969.2	29996	77555	77338	77555
3000.0	29695	77254	77038	77254
3264.3	27117	74676	74459	74676
3264.4	27116	74675	74458	74675
3500.0	24820	72379	72162	72379
3559.6	24239	71798	71581	71798
3559.7	24238	71797	71580	71797
3854.9	21359	68918	68701	68918
3855.0	21358	68917	68700	68917
4000.0	19945	67504	67287	67504
4155.2	18432	65991	65774	65991
4155.3	18431	65990	65773	65990
4500.0	15069	62628	62411	62628
4543.9	14641	62200	61983	62200
4544.0	14640	62199	61982	62199
4799.9	12145	59704	59487	59704
4800.1	14672	60285	60186	60285
4858.8	14248	59860	59761	59860
4858.9	14247	59860	59761	59860
4889.9	14023	59636	59537	59636
4890.1	14021	59634	59535	59634
4899.9	13951	59563	59465	59563
4900.1	13949	59562	59463	59562
5000.0	13228	58840	58741	58840
5036.0	12967	58580	58481	58580
5036.1	12967	58580	58481	58580
5099.9	12505	58118	58019	58118
5100.1	-5776	-5916	-5916	-5916
5299.9	-7221	-7361	-7361	-7361

Table 4.110: AFE Axial Load Summary Case 3

MD (ft)	Axial Load (lbf)			
(ft)	Initial Conditions	5 1/2" x 4 1/2" Production Tubing -	5 1/2" x 4 1/2" Production Tubing -	5 1/2" x 4 1/2" Production Tubing -AFE
0.1	73031	159710	159493	159710
10.9	72848	159526	159310	159526
19.9	72695	159373	159157	159373
20.1	72691	159370	159153	159370
500.0	64533	151212	150995	151212
508.4	64390	151069	150852	151069
508.5	64388	151067	150850	151067
709.9	60976	147654	147438	147654
710.1	60972	147651	147434	147651
803.7	59386	146065	145848	146065
803.9	59383	146061	145845	146061
857.5	58475	145153	144936	145153
857.7	58471	145150	144933	145150
902.1	57719	144397	144181	144397
902.3	57715	144394	144177	144394
1000.0	56060	142738	142522	142738
1000.6	56050	142728	142512	142728
1000.8	56046	142725	142508	142725
1099.0	54382	141061	140844	141061
1099.2	54379	141058	140841	141058
1197.4	52780	139459	139242	139459
1197.6	52777	139455	139239	139455
1295.8	51178	137856	137640	137856
1296.0	51174	137853	137636	137853
1394.3	49574	136252	136036	136252
1394.5	49570	136249	136032	136249
1490.0	48015	134694	134477	134694
1492.7	47971	134650	134433	134650
1492.9	47968	134647	134430	134647
1500.0	47862	134541	134324	134541
1591.1	46502	133181	132964	133181
1591.3	46499	133178	132961	133178
1689.5	45033	131711	131495	131711
1689.7	45030	131708	131492	131708
1750.0	44129	130808	130591	130808
1788.0	43562	130241	130024	130241
1788.2	43559	130238	130021	130238
1886.4	42093	128771	128555	128771
1886.6	42090	128769	128552	128769
1937.5	41417	128095	127879	128095
1984.8	40791	127470	127253	127470
1985.0	40789	127467	127251	127467
2000.0	40590	127269	127052	127269
2083.2	39490	126169	125952	126169
2083.4	39488	126166	125949	126166
2155.5	38534	125213	124996	125213
2178.2	38234	124913	124696	124913
2178.4	38231	124910	124693	124910
2181.7	38188	124866	124650	124866
2181.9	38185	124864	124647	124864
2280.1	37048	123727	123510	123727
2280.3	37046	123725	123508	123725
2312.5	36673	123352	123135	123352
2333.0	36436	123115	122898	123115
2333.2	36434	123112	122895	123112
2378.5	35909	122588	122371	122588
2378.7	35907	122585	122369	122585
2423.7	35386	122065	121848	122065
2423.9	35384	122062	121846	122062
2476.9	34852	121530	121313	121530
2477.1	34850	121528	121311	121528
2500.0	34620	121298	121081	121298
2563.6	33981	120660	120443	120660
2563.8	33979	120658	120441	120658
2668.0	32933	119611	119395	119611
2668.1	32932	119610	119394	119610
2969.1	29997	116675	116459	116675
2969.2	29996	116674	116458	116674
3000.0	29695	116374	116157	116374
3264.3	27117	113796	113579	113796
3264.4	27116	113795	113578	113795
3500.0	24820	111498	111282	111498
3559.6	24239	110917	110701	110917
3559.7	24238	110916	110700	110916
3854.9	21359	108038	107821	108038
3855.0	21358	108037	107820	108037
4000.0	19945	106623	106406	106623
4155.2	18432	105110	104894	105110
4155.3	18431	105109	104893	105109
4500.0	15069	101747	101531	101747
4543.9	14641	101319	101103	101319
4544.0	14640	101318	101102	101318
4799.9	12145	98823	98607	98823
4800.1	14672	100023	99924	100023
4858.8	14248	99599	99500	99599
4858.9	14247	99598	99499	99598
4889.9	14023	99374	99275	99374
4890.1	14021	99373	99274	99373
4899.9	13951	99302	99203	99302
4900.1	13949	99300	99201	99300
5000.0	13228	98579	98480	98579
5036.0	12967	98318	98219	98318
5036.1	12967	98318	98219	98318
5099.9	12505	97856	97757	97856
5100.1	-5776	-5730	-5730	-5730
5299.9	-7221	-7175	-7175	-7175

Given the focus of the study to consider negative wellhead growth during steady state CO_2 injection then further Case 2 multistring results detail is provided with respect minimum absolute safety factors in Table 4.111 below.

Table 4.111: Safety Factors

String Section	MD (ft)	Minimum Absolute Safety Factor Triaxial	Burst	Collapse	Axial
1	0.1	3.493 L2	4.793 L2	100+ L1	3.294 L2
1	10.9	3.496 L2	4.786 L2	100+ L1	3.299 L2
1	19.9	3.498 L2	4.780 L2	100+ L1	3.303 L2
1	20.1	3.498 L2	4.780 L2	100+ L1	3.303 L2
1	500.0	3.739 L2	5.259 L2	100+ L1	3.544 L2
1	508.4	3.743 L2	5.269 L2	100+ L1	3.548 L2
1	508.5	3.743 L2	5.269 L2	100+ L1	3.548 L2
1	709.9	3.854 L2	5.507 L2	100+ L1	3.660 L2
1	710.1	3.560 L2	5.507 L2	100+ L1	3.293 L2
1	803.7	3.604 L2	5.626 L2	100+ L1	3.336 L2
1	803.9	3.605 L2	5.626 L2	100+ L1	3.338 L2
1	857.5	3.631 L2	5.696 L2	100+ L1	3.364 L2
1	857.7	3.489 L2	5.696 L2	100+ L1	3.199 L2
1	902.1	3.509 L2	5.755 L2	100+ L1	3.218 L2
1	902.3	3.509 L2	5.756 L2	100+ L1	3.219 L2
1	1000.0	3.553 L2	5.891 L2	100+ L1	3.262 L2
1	1000.6	3.553 L2	5.892 L2	100+ L1	3.263 L2
1	1000.8	3.553 L2	5.892 L2	100+ L1	3.263 L2
1	1099.0	3.598 L2	6.033 L2	95.280 L1	3.308 L2
1	1099.2	3.598 L2	6.033 L2	95.263 L1	3.308 L2
1	1197.4	3.642 L2	6.181 L2	87.884 L1	3.353 L2
1	1197.6	3.642 L2	6.181 L2	87.871 L1	3.353 L2
1	1295.8	3.687 L2	6.337 L2	81.573 L1	3.399 L2
1	1296.0	3.688 L2	6.337 L2	81.561 L1	3.399 L2
1	1394.3	3.734 L2	6.497 L2	76.118 L1	3.446 L2
1	1394.5	3.734 L2	6.498 L2	76.108 L1	3.446 L2
1	1492.7	3.781 L2	6.664 L2	71.343 L1	3.494 L2
1	1492.9	3.781 L2	6.664 L2	71.334 L1	3.495 L2
1	1500.0	3.784 L2	6.676 L2	71.039 L1	3.498 L2
1	1510.0	3.788 L2	6.692 L2	70.628 L1	3.502 L2
1	1591.1	3.825 L2	6.839 L2	67.462 L1	3.540 L2
1	1591.3	3.825 L2	6.840 L2	67.455 L1	3.540 L2
1	1689.5	3.870 L2	7.022 L2	63.987 L1	3.587 L2
1	1689.7	3.870 L2	7.022 L2	63.981 L1	3.587 L2
1	1788.0	3.916 L2	7.206 L2	60.858 L1	3.635 L2
1	1788.2	3.916 L2	7.207 L2	60.852 L1	3.636 L2
1	1812.5	3.927 L2	7.252 L2	60.127 L1	3.648 L2
1	1886.4	3.962 L2	7.404 L2	58.028 L1	3.685 L2
1	1886.6	3.962 L2	7.404 L2	58.023 L1	3.685 L2
1	1984.8	4.004 L2	7.607 L2	55.735 L1	3.730 L2
1	1985.0	4.004 L2	7.608 L2	55.730 L1	3.730 L2
1	2000.0	4.011 L2	7.640 L2	55.397 L1	3.737 L2
1	2042.0	4.029 L2	7.726 L2	54.486 L1	3.757 L2
1	2083.2	4.047 L2	7.817 L2	53.621 L1	3.776 L2
1	2083.4	4.048 L2	7.818 L2	53.617 L1	3.777 L2
1	2178.2	4.090 L2	8.038 L2	51.731 L1	3.823 L2
1	2178.4	4.068 L2	8.039 L2	51.727 L1	3.799 L2
1	2181.7	4.070 L2	8.047 L2	51.663 L1	3.801 L2
1	2181.9	4.090 L2	8.047 L2	51.660 L1	3.824 L2
1	2250.0	4.117 L2	8.194 L2	50.544 L1	3.853 L2
1	2280.1	4.129 L2	8.265 L2	50.066 L1	3.866 L2
1	2280.3	4.130 L2	8.265 L2	50.063 L1	3.867 L2
1	2333.0	4.151 L2	8.392 L2	49.249 L1	3.890 L2
1	2333.2	4.149 L2	8.392 L2	49.246 L1	3.888 L2
1	2378.5	4.167 L2	8.504 L2	48.567 L1	3.908 L2
1	2378.7	4.166 L2	8.505 L2	48.564 L1	3.908 L2
1	2423.7	4.184 L2	8.615 L2	47.909 L1	3.928 L2
1	2423.9	4.187 L2	8.616 L2	47.906 L1	3.931 L2
1	2437.5	4.192 L2	8.645 L2	47.737 L1	3.937 L2
1	2476.9	4.206 L2	8.747 L2	47.255 L1	3.952 L2
1	2477.1	4.204 L2	8.747 L2	47.252 L1	3.950 L2
1	2500.0	4.212 L2	8.807 L2	46.977 L1	3.960 L2

Table of Safety Factors continued

1	2563.6	4.234 L2	8.971 L2	46.229 L1	3.985 L2
1	2563.8	4.995 L2	8.971 L2	46.226 L1	4.872 L2
1	2668.0	5.051 L2	9.252 L2	45.052 L1	4.935 L2
1	2668.1	5.051 L2	9.253 L2	45.050 L1	4.935 L2
1	2969.1	5.211 L2	10.152 L2	42.059 L1	5.122 L2
1	2969.2	5.211 L2	10.153 L2	42.058 L1	5.122 L2
1	3000.0	5.228 L2	10.255 L2	41.774 L1	5.142 L2
1	3264.3	5.372 L2	11.240 L2	39.494 L1	5.319 L2
1	3264.4	5.372 L2	11.241 L2	39.493 L1	5.319 L2
1	3500.0	5.502 L2	12.292 L2	37.667 L1	5.488 L2
1	3559.6	5.535 L2	12.590 L2	37.232 L1	5.533 L2
1	3559.7	5.535 L2	12.591 L2	37.231 L1	5.533 L2
1	3854.9	5.699 L2	14.309 L2	35.220 L1	5.764 L2
1	3855.0	5.699 L2	14.310 L2	35.219 L1	5.764 L2
1	4000.0	5.779 L2	15.338 L2	34.311 L1	5.885 L2
1	4155.2	5.865 L2	16.616 L2	33.391 L1	6.019 L2
1	4155.3	5.865 L2	16.616 L2	33.391 L1	6.020 L2
1	4500.0	6.052 L2	20.391 L2	31.517 L1	6.343 L2
1	4543.9	6.076 L3	20.999 L2	31.294 L1	6.386 L2
1	4544.0	6.076 L3	21.000 L2	31.293 L1	6.386 L2
1	4799.9	6.207 L3	25.412 L2	30.055 L1	6.653 L2
2	4800.1	4.538 L3	C 27.691 L2	32.587 L1	4.781 L2
2	4858.8	4.539 L3	C 31.186 L2	32.298 L1	4.815 L2
2	4858.9	4.539 L3	C 31.193 L2	32.297 L1	4.815 L2
2	4889.9	4.539 L3	C 33.420 L2	32.146 L1	4.833 L2
2	4890.1	4.539 L3	C 33.435 L2	32.145 L1	4.833 L2
2	4899.9	4.538 L3	C 34.208 L2	32.097 L1	4.839 L2
2	4900.1	4.538 L3	C 34.224 L2	32.096 L1	4.839 L2
2	5000.0	4.535 L3	C 44.773 L2	31.620 L1	4.898 L2
2	5036.0	4.533 L3	C 50.368 L2	31.452 L1	4.920 L2
2	5036.1	4.533 L3	C 50.386 L2	31.452 L1	4.920 L2
2	5099.9	4.529 L3	C 64.730 L2	31.159 L1	4.959 L2
2	5100.1	D 100+ L1	100+ L1	29.669 L2	CM 38.902 L2
2	5299.9	100+ L1	100+ L1	30.475 L2	CM 31.264 L2

L1 = Initial Conditions
L2 = 5 1/2" x 4 1/2" Production Tubing -MaxCo
L3 = 5 1/2" x 4 1/2" Production Tubing -MaxBu
Burst and Axial Flags
Default = Pipe Body, L = Connection Leak, B = Connection Burst, F = Connection Fracture, J = Connection Jump-out, Y = Connection Yield, C = Connection
Axial Flags
Default = Tension, M = Compression
Triaxial Flags
Default = Inner Wall and Positive Bending OR No Bending, D = Outer wall safety factor, N = Negative Bending, C = ISO Connection

WHM Sensitivity Analysis

The displacement result below shows the wellhead movement as each successive load is applied to the wellhead during the life of the well or during considered loads conditions.

Table 4.112: Wellhead Displacement Summary (Case 1)

MultiString Wellhead Movement Displacement Summary			
	Load	Displacement	
		Incremental (ft)	Cumulative (ft)
1	Install Wellhead - 30in x 20" Conductor Casing	0.00	0.00
2	Primary Cementing - 13 3/8in Surface Casing	-0.01	-0.01
3	Nipple-Up BOP - 13 3/8in Surface Casing	-0.01	-0.02
4	Primary Cementing - 9 5/8in Intermediate Casing	-0.02	-0.04
5	Primary Cementing - 7in Production Liner	0.00	-0.04
6	Primary Cementing - 5 1/2in x 4 1/2" Production Tubing	-0.01	-0.05
7	Nipple-down BOP - 5 1/2in x 4 1/2" Production Tubing	0.01	-0.03
8	Nipple-Up Tree - 5 1/2in x 4 1/2" Production Tubing	0.00	-0.05
9	Production 70MMd CO2 - 5 1/2in x 4 1/2" Production Tubing	0.02	-0.02

Table 4.113: Wellhead Displacement Summary (Case 2)

MultiString Wellhead Movement Displacement Summary			
	Load	Displacement	
		Incremental (ft)	Cumulative (ft)
1	Install Wellhead - 30in x 20" Conductor Casing	0.00	0.00
2	Primary Cementing - 13 3/8in Surface Casing	-0.01	-0.01
3	Nipple-Up BOP - 13 3/8in Surface Casing	-0.01	-0.02
4	Primary Cementing - 9 5/8in Intermediate Casing	-0.02	-0.04
5	Primary Cementing - 7in Production Liner	0.00	-0.04
6	Primary Cementing - 5 1/2in x 4 1/2" Production Tubing	-0.01	-0.05
7	Nipple-down BOP - 5 1/2in x 4 1/2" Production Tubing	0.01	-0.03
8	Nipple-Up Tree - 5 1/2in x 4 1/2" Production Tubing	0.00	-0.05
9	Inj CO2 138MMd 40F 7day - 5 1/2in x 4 1/2" Production T	-0.01	-0.06

Table 4.114: Wellhead Displacement Summary (Case 3)

MultiString Wellhead Movement Displacement Summary			
	Load	Displacement	
		Incremental (ft)	Cumulative (ft)
1	Install Wellhead - 30in x 20" Conductor Casing	0.00	0.00
2	Primary Cementing - 13 3/8in Surface Casing	-0.01	-0.01
3	Nipple-Up BOP - 13 3/8in Surface Casing	-0.01	-0.02
4	Primary Cementing - 9 5/8in Intermediate Casing	-0.02	-0.04
5	Primary Cementing - 7in Production Liner	0.00	-0.04
6	Primary Cementing - 5 1/2in x 4 1/2" Production Tubing	-0.01	-0.05
7	Nipple-down BOP - 5 1/2in x 4 1/2" Production Tubing	0.01	-0.03
8	Nipple-Up Tree - 5 1/2in x 4 1/2" Production Tubing	0.00	-0.05
9	Inj CO2 138MMd -20C 47min - 5 1/2in x 4 1/2" Production Tubing	-0.01	-0.06

The incremental displacement represents the movement of the wellhead due to a specific load. This movement represent the applied force from that load divided by the current system stiffness.

Column 4 in Table 4.112 shows the wellhead has moved down 0.24inch (-0.02ft) after the heavy 13 3/8in casing was landed in the wellhead. It should be noted that the positive increment represent the upward movement and negative increment represent downward movement. The well stiffness changes as successive casing are landed in the well. The wellhead is installed on 13 3/8in casing and sits on the outermost 30x20in conductor which takes all casing loads. The effect of static loads and also thermal loads is distributed between all the strings that are landed in the wellhead at the time event occurs. As shown above the wellhead cumulative displacement is 0.72in (-0.06ft) during CO_2 injection for 7 days as shown above. The displacement for production load case 3 is shown above in Table 4.114.

The multistring wellhead movement shows the axial loads at the wellhead for all the strings as a particular wellhead movement load is applied. The load column shows the list of all installation, static and thermal loads that were modelled in the wellhead movement analysis. For every string in the wellbore, the axil loads column display the axial force acting at the hanger depth for that string.

For those strings that were not landed in the wellhead when a particular load event occurs, NA (Not Applicable) is displayed as the axial force at the hanger depth. Results are tabulated below in Table 4.115 to Table 4.117.

Table 4.115: Wellhead Forces Summary (Case 1)

MultiString Wellhead Movement Load Summary

	Load	Axial Load (lbf)				
		30" x 20" Conductor Casin	13 3/8" Surface Casing	9 5/8" Intermediate Casing	7" Production Liner	5 1/2" x 4 1/2" Production Tu
1	Install Wellhead - 30in x 20" Conductor Casing	-14000	NA	NA	NA	NA
2	Primary Cementing - 13 3/8in Surface Casing	-113398	99398	NA	NA	NA
3	Nipple-Up BOP - 13 3/8in Surface Casing	-209166	95166	NA	NA	NA
4	Primary Cementing - 9 5/8in Intermediate Casing	-358228	85398	158829	NA	NA
5	Primary Cementing - 7in Production Liner	-358228	85398	158829	8552	NA
6	Primary Cementing - 5 1/2in x 4 1/2" Production Tubing	-407097	83239	155050	8552	54808
7	Nipple-down BOP - 5 1/2in x 4 1/2" Production Tubing	-313173	87326	156700	8552	55115
8	Nipple-Up Tree - 5 1/2in x 4 1/2" Production Tubing	-420248	82663	154820	8552	54765
9	Production 70MMd CO2 - 5 1/2in x 4 1/2" Production Tubing	-223212	31836	140475	8552	11214

Table 4.116: Wellhead Forces Summary (Case 2)

MultiString Wellhead Movement Load Summary

	Load	Axial Load (lbf)				
		30" x 20" Conductor Casin	13 3/8" Surface Casing	9 5/8" Intermediate Casing	7" Production Liner	5 1/2" x 4 1/2" Production Tu
1	Install Wellhead - 30in x 20" Conductor Casing	-14000	NA	NA	NA	NA
2	Primary Cementing - 13 3/8in Surface Casing	-113398	99398	NA	NA	NA
3	Nipple-Up BOP - 13 3/8in Surface Casing	-209166	95166	NA	NA	NA
4	Primary Cementing - 9 5/8in Intermediate Casing	-358228	85398	158829	NA	NA
5	Primary Cementing - 7in Production Liner	-358228	85398	158829	8552	NA
6	Primary Cementing - 5 1/2in x 4 1/2" Production Tubing	-407097	83239	155050	8552	54808
7	Nipple-down BOP - 5 1/2in x 4 1/2" Production Tubing	-313173	87326	156700	8552	55115
8	Nipple-Up Tree - 5 1/2in x 4 1/2" Production Tubing	-420248	82663	154820	8552	54765
9	Inj CO2 138MMd 40F 7day - 5 1/2in x 4 1/2" Production Tubing	-534228	102439	206972	8552	102722

Table 4.117: Wellhead Forces Summary (Case 3)

MultiString Wellhead Movement Load Summary

	Load	Axial Load (lbf)				
		30" x 20" Conductor Casin	13 3/8" Surface Casing	9 5/8" Intermediate Casing	7" Production Liner	5 1/2" x 4 1/2" Production Tu
1	Install Wellhead - 30in x 20" Conductor Casing	-14000	NA	NA	NA	NA
2	Primary Cementing - 13 3/8in Surface Casing	-113398	99398	NA	NA	NA
3	Nipple-Up BOP - 13 3/8in Surface Casing	-209166	95166	NA	NA	NA
4	Primary Cementing - 9 5/8in Intermediate Casing	-358228	85398	158829	NA	NA
5	Primary Cementing - 7in Production Liner	-358228	85398	158829	8552	NA
6	Primary Cementing - 5 1/2in x 4 1/2" Production Tubing	-407097	83239	155050	8552	54808
7	Nipple-down BOP - 5 1/2in x 4 1/2" Production Tubing	-313173	87326	156700	8552	55115
8	Nipple-Up Tree - 5 1/2in x 4 1/2" Production Tubing	-420248	82663	154820	8552	54765
9	Inj CO2 138MMd -20C 47min - 5 1/2in x 4 1/2" Production Tub	-533137	80632	196641	8552	140674

The tables below, Table 4.118 (Case1) Table 4.119 (case 2) and Table 4.120 (Case 3) shows the contact loads between strings that are associates with the wellhead: Case 1 for production load results, and Cases 2 and 3 for injection load results. These results show the strings that are present in the well and loads that each string exerts on the outer string because of being part of one combined wellhead system.

Table 4.118: Wellhead Contact Loads (Case 1)

Wellhead Contact Loads - Production 70MMd CO2 - 5 1/2in x 4 1/2" Production Tubing - Wellhead Movement			
	Wellhead @ 0.0 ft		
	String1	String2	Contact Load (lbf)
1	5 1/2" x 4 1/2" Production Tubing	9 5/8" Intermediate Casing	11214
2	9 5/8" Intermediate Casing	13 3/8" Surface Casing	151689
3	13 3/8" Surface Casing	30" x 20" Conductor Casing	183525

Table 4.119: Wellhead Contact Loads (Case 2)

Wellhead Contact Loads - Inj CO2 138MMd 40F 7day - 5 1/2in x 4 1/2" Production Tubing - Wellhead Movement			
	Wellhead @ 0.0 ft		
	String1	String2	Contact Load (lbf)
1	5 1/2" x 4 1/2" Production Tubing	9 5/8" Intermediate Casing	102722
2	9 5/8" Intermediate Casing	13 3/8" Surface Casing	309694
3	13 3/8" Surface Casing	30" x 20" Conductor Casing	412133

Table 4.120: Wellhead Contact Loads (Case 3)

Wellhead Contact Loads - Inj CO2 138MMd -20C 47min - 5 1/2in x 4 1/2" Production Tubing - Wellhead Movement			
	Wellhead @ 0.0 ft		
	String1	String2	Contact Load (lbf)
1	5 1/2" x 4 1/2" Production Tubing	9 5/8" Intermediate Casing	140674
2	9 5/8" Intermediate Casing	13 3/8" Surface Casing	337315
3	13 3/8" Surface Casing	30" x 20" Conductor Casing	417946

Length Change Bar:

The length change bar-chart due to multiple loads for production Case 1, injection Case 2 & 3 are shown below from Figure 4.81 to Figure 4.83.

Figure 4.81: Tubing Movement Case 1

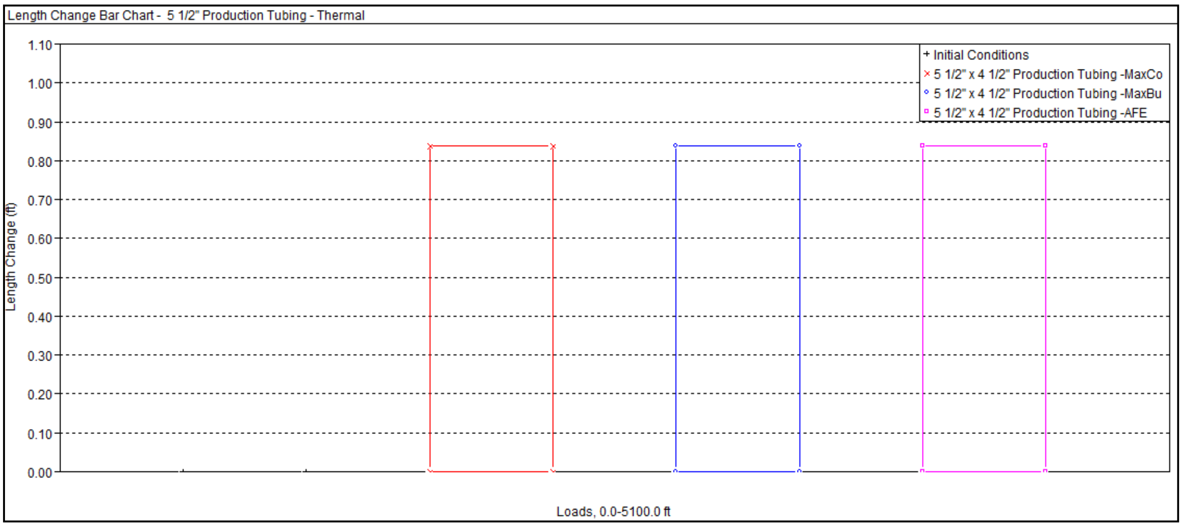


Figure 4.82: Tubing Movement Case 2

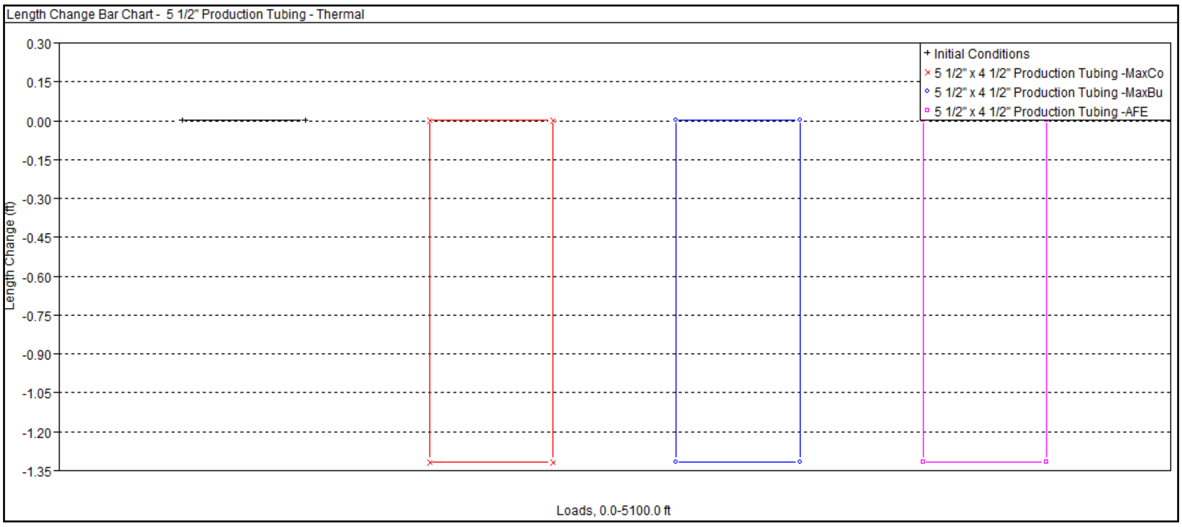
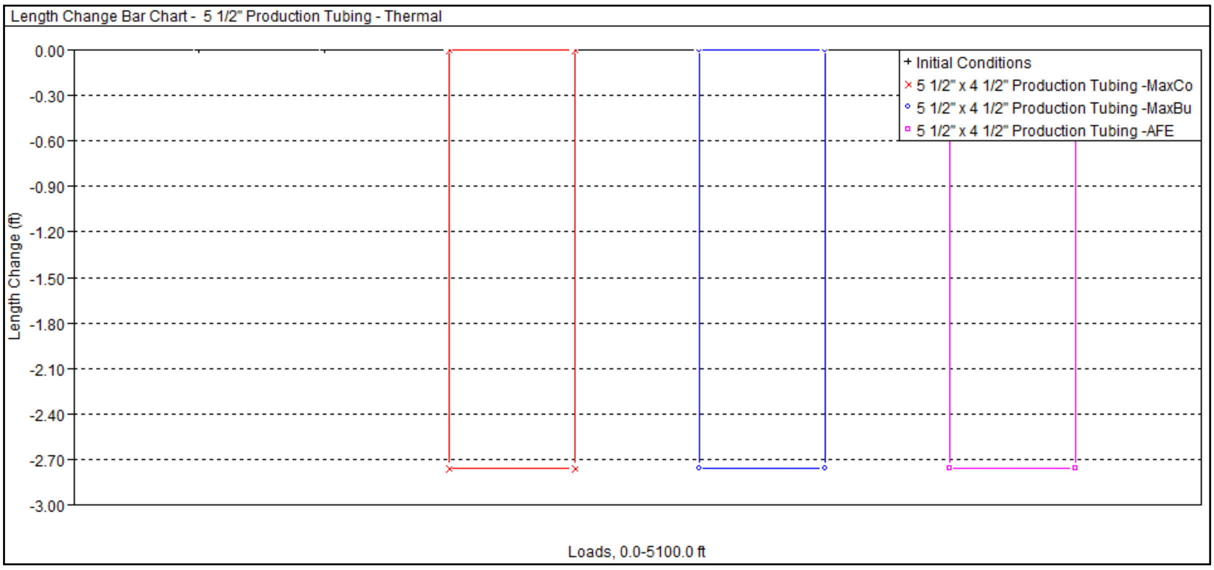


Figure 4.83: Tubing Movement Case 3



4.24.31.3 Tubing Stress and Multi-String analysis Conclusions & Recommendations

1. A proposed CO_2 injector well Base Case 5 ½in 17# 80 ksi yield strength upper completion tubing string has been subjected to a tubing stress analysis.
2. The 5 1/2in 17# 80ksi yield strength tubing string satisfies all loads considered with respect burst, collapse, axial and triaxial design safety factors.
3. A multi-string annular fluid expansion and wellhead movement analysis has been carried out on the proposed Base Case Injector well design. No issues have been identified of concern with respect all load cases considered. Injection rates of 138MMSCFD of CO_2 into the modelled well resulted in 0.72in (0.06ft) of cumulative downward wellhead movement. Annular pressure change due to annular fluid cooling and contraction was a maximum of 15psi.

4.24.32 Summary of Conclusions & Recommendations for the Completion concept selection

Sand Character and Sanding Risk

1. Initial sanding study undertaken in March 2012 on target bunter sandstone using offset well (42/25-1, 43/21-1 and Endurance)log derived rock strength data was calibrated using 42/25-1 UCS and TWC rock mechanics test results. Study indicated in general terms that rock mechanical strength increases with depth.
2. The sanding risk can be reduced further given a base case to perforate the lower ½ of the reservoir, where strengths are highest.
3. Further rock mechanic and formation damage study undertaken following the drilling of well 42/25d-3, shows that the impact of reservoir pressure rising as a result of CO_2 injection will not have an impact on sand production. Sand production will not be produced during the injection phase.
4. The impact of start-up and shut-in with respect to water hammer effect creating a pressure cycle sufficient to induce wellbore failure has also been considered. The bottomhole pressure pulse generated will not present a significant issue with respect to completion and sand face integrity.

5. Geochemical impact of CO_2 injection studies carried out on core samples and samples of overlying Rot clay show little reduction in rock strength after 30 day exposure to super critical CO_2 injection.
6. Core studies based on potential wellbore stress changes incurred during CO_2 stop/restart show no failure of the cores after repeated shut-in cycles.
7. The conclusion based on current CO_2 injection test data at this time, is that CO_2 injection is unlikely to have a negative impact on rock strength and the expectation that sanding is not an issue during CO_2 injection remains.

Lifecycle Pressure and Temperature

8. The geothermal temperature gradient for 5 /42 storage system is defined as 3.16°C/100m, anchored to bottom hole datum temperature of 68.0°C at 1654.1m TVDSS.
9. The maximum pipeline arrival operating temperature and pressure is 24°C/75.2°F and 60.8psi/16bar.
10. A choke pressure drop induced downstream minimum potential temperature of -30^{0} C is proposed as the design basis for this report based a high differential between pipeline arrival and downstream well shut-in pressures of a seawater column at 10barg.
11. The injection choke pressure drop induced temperature modelling discussion has highlighted the potential for large temperature drops associated with well start up with a high differential between pipeline arrival and well shut-in pressures. A further extrapolation of this logic is to consider line, well tubular rupture and subsequent line or well uncontrolled atmospheric (1bar) venting. This in theory would potentially result in temperatures as low as -70°C.
12. This issue of extreme low temperature due to unplanned or planned atmospheric venting of CO_2 for each section of the system, (subsea pipeline, topsides process pipework upstream and downstream of the injection choke and well tubulars) needs to properly qualified and assessed with an integrated discussion in the detailed planning phase. A similar approach was reported with regard the Sleipner CCS project.
13. Static shut-in well pressure profiles were generated for a series of potential fluid/gas columns in the well. The maximum shut-in pressure of 180bar /192bar (2544psi / 2717psi) is generated when methane and nitrogen gas columns are respectively considered at final reservoir conditions. At initial reservoir conditions the equivalent maximum shut-in pressure values are 132/144bar (1846/2017psi) respectively.
14. It is recommended that a 300psi bullhead well kill margin is added to the maximum shut-in pressure.
15. A maximum upper completion production packer/perforation gun initiation set pressure of 5000psi is considered appropriate for planning purposes at this time.
16. The maximum tubing and casing pressure test requirement for planning purposes at this stage is 5000psi (344bar), although 5500psi has been assumed in the design for calculation of stresses.
17. A series of conceptual completion options have been identified and screened to consider how single phase CO_2 injection might be feasible or best maintained in the wellbore compared to a multiphase completion approach. The limitations of each method identified is outlined below;

Table 4.121: Conceptual completion options

Method	Limitations
Remote choke sleeve management	Prevents access to the reservoir when interventions are needed.
Remote bidirectional valve	Introduces increased complexity and risk should the valve fail
Limited entry perforation phase management	Does not address static shut-in conditions and there is also a risk of reduction of injectivity index
Sandface with inflow control devices	Solution does not address static shut-in conditions and only aids start up and steady state injection. Not compatible with remedial or additional perforations should they be required
Downhole electrical heating system	In the event of platform outage, a gas cap will develop as well cools down. This solution has a limited track record. A work over is required if the system fails
Circulation of heated fluids	In the event of platform outage, a gas cap will develop as well cools down. Significant power is needed to support several wells. Total equipment footprint is not compatible with NUI constraints.
Local Nitrogen Supply	In the event of a well shut-in or platform outage, a gas cap will develop as the tubing and bottomhole pressure bleed off into the reservoir.

- Of these single phase CO_2 injection options, local Nitrogen supply phase management is the most reliable and least complex method that fulfils the requirements. Additionally, the use of Nitrogen achieves separation between water wash and the injected CO_2 stream which as benefit in terms of hydrate management and corrosion risk management.
- Two phase conditions that arise during transient periods such as shut-in and start up and water wash are best managed procedurally through a combination of hydrate inhibition, nitrogen purging and pressure equalisation management.

Lower Completion

- The use of a 7in cemented and perforated liner as a lower completion strategy is recommended given that sand control is not required and this is the most cost effective and robust means to provide zonal isolation and injection performance.

Drill in Fluid

- An extensive coring and logging programme is planned for the 8 ½in Section. A new LTOBM mud system will be used for this section to increase the likelihood of a successful programme. A mud weight of 10.0 – 10.5ppg will be used and calcium carbonate added to prevent losses to the bunter sand and mitigate the risk of differential sticking.

Completion Brine

- Once the production liner is set and cemented in place the hole will be displaced to kill weight 9.2 ppg NaCL/KCL brine. This will provide adequate inhibition with regard reservoir matrix clay swelling to mitigate any risk of formation damage.
- In the event that the liner is perforated before the upper completion is run, a solids free perforating 9.2ppg fluid loss pill will also be spotted across the perforating interval in readiness for perforating operations.

Upper Completion

- The upper completion equipment for the base case of 5½in tubing and alternate 7in tubing option are presented below:

Table 4.122: Completion equipment options

Base Case 5-1/2in Upper Completion	Alternate Case 7in Upper Completion
Tubing hanger	Tubing hanger
5-1/2in completion Tubing	7in completion Tubing
5-1/2in TRSSSV	7in TRSSSV
5-1/2in completion tubing	7in completion tubing
5-1/2in Permanent downhole gauge	7in Permanent downhole gauge
5-1/2in x 4-1/2in Crossover	9-5/8in Production Packer
7in Production Packer	7in Liner Top Male Seal Mandrel
4-1/2in completion tubing tailpipe	
Wireline Nipple (3.688in)	
Self-Aligning Muleshoe	

- The production tubing required for the 5½in base case upper completion configuration is a combination of 5½in outer diameter tubing to circa 150ft above the 7in liner and 4½in outer diameter tubing to the base of the upper completion.
- High 25Cr alloys are considered as a base case at this stage subject to appropriate further detailed design materials studies and testing.
- The recommended packer setting type is a hydraulic set packer (set by applying differential tubing to annulus pressure).
- A permanent down hole gauge with a quartz based sensor is recommended for this application. This is to be deployed on the upper completion tubing. Should any gauges fail, the completion needs to be recovered to replace any failed gauges. Memory data from a downhole memory gauge that is run and pulled on a rational basis maybe an acceptable alternative.
- Further work is required to confirm the well specific relevant performance capabilities of potential MMV DTS and DAS systems operating at either top reservoir or top perforation depths.
- The safety valve should be set deep enough such that ambient temperature at the valve setting depth is high enough to minimize hydrate risk during any shut-in periods. A setting depth of circa 2000ft is proposed in order to minimize hydrate risk. A self-equalising type is recommended to avoid complicated equalising and opening procedures.
- A ¼in Inconel 625 encapsulated control line is recommended to convey hydraulic fluid to the TR-SCSSSV and attached with compression type of tube fittings.
- A summary of alternative 7in completion advantages and disadvantages is detailed below:

Table 4.123: 7in Completion advantages and disadvantages

Advantage	Disadvantage
Increased injection rates	7in Downhole safety valve clearance inside 9-5/8in constrained may need 10-3/4in casing of the well. Clearance check required inclusive all clamps / cables / lines.
Increased redundancy and thus improved system uptime.	7in Permanent Downhole Pressure and Temperature gauge system inside 9-5/8in. Clearance check required inclusive all clamps / cables / lines.
Reduced corrosion / erosion risk – lower fluid velocities	DTS / DAS / and particularly equipment such as microseismic geophones will be constrained within annulus space. Clearance check required inclusive of all clamps, cables, lines.
Reduced perforation costs (Eline through tubing, rather than dedicated shoot and pull	Monobore design with upper completion male seal stabbed into liner top sealbore creates trapped annuli. Potential thermal annular contraction (TAC) risk qualified with Wellcat Multistring as not an issue. Reported in separate Multistring Study Report WFS6.
Larger gun size can be used for through tubing perforating / re-perforating	Given a 7in liner top at top reservoir / seal depth then the 7in monobore configuration means compared with a 5-1/2in / 4-1/2in upper completion configuration with the option of a deepset packer inside the 7in, more of the liner is exposed to flow wetted corrosion. If a deepset packer is not acceptable based on a need for ready access to perforate mid / upper reservoir without pulling the upper completion tubing.
Monobore design with upper completion male seal stabbed into liner top sealbore reduces corrosion risk behind tailpipe.	

- A conventional dry Christmas tree is proposed.

Material Selection

- 25 Cr Super Duplex SS L80 material with a PREN number >40 should be used for the completion jewellery, assembly pups and in order to simplify rig time handling also the tailpipe and the tubing section between the hanger and safety valve.
- Given that the machining ability for 25 Cr is limited then alternately for some components Alloy 925 or Alloy 718 is the recommended choice.
- Use of GRE coated liner was rejected. Use of GRE in liners is rare (<2% GRE job histories), due to the risk that if a cement / liner clean-up is required the coating is likely to become damaged by drillstring wear as experienced in prior UK SNS project. Further GRE may become damaged by packer setting and perforating operations.
- If considered in the tubing then a similar concern exists that repeated wireline runs associated with MMV periodic survey commitments may damage GRE lined tubing.
- Free hydrogen remains a residual concern to be qualified following NGC raised concerns that under some pipeline shut-in scenarios free hydrogen gas may develop. Work is ongoing to determine whether the potential of this scenario and any impact in terms of free hydrogen gas being present in the CO_2 stream when it reaches the well.
- The material specifications are provisional and further vendor and material selection specialist dialogue is needed during the detailed phase with a well specific material testing programme likely.

- Transient flow assurance study work is ongoing to determine a final project agreed worst case minimum downstream choke temperature and resultant associated minimum downstream choke well temperature.
- This issue of extreme low temperature in theory as low as-70°C due to unplanned or planned atmospheric venting of CO_2 for each section of the system, (subsea pipeline, topsides process pipework upstream and downstream of the injection choke and well tubulars) needs to properly qualified and assessed with an integrated discussion in the detailed planning phase. A similar approach was reported with regard the Sleipner CCS project.
- Specific additional material toughness testing at low temperature may be required to ensure tree, wellhead, casing and tubulars selected are fit for purpose.

Well Performance/Flow assurance

CO_2 Injection

- A wide range of sensitivities with regards to perforated interval, permeability, wellhead pressure, skin and tubing roughness have been run on 4-1/2in, 5-1/2in and 7in tubing in order to optimize the required CO_2 injection in the well.
- A relative measure of the impact of tubing size can be seen by comparing injection rates achieved for a 1000psi surface injection pressure given an expected base case of 2048psi (141bar) reservoir pressure, 10,14ftTVD (309m) reservoir thickness, 200ft (60.95m) of perforated interval, skin of 5 and average reservoir permeability of 260mD.

Table 4.124: Tubing size injection rates

Tubing Size	Injection Rate (MMSCFD)
4 ½in	52.9 (1.01MTPA) (1.49 MM m^3/d)
5 ½in	84.8 (1.62MTPA) (2.40 MM m^3/d)
7in	171.5 (3.27MTPA) (4.85 MM m^3/d)

- A 4½in upper completion tubing selection is considered to be less than an acceptable choice with respect erosional velocity limit risk, deliverability of maximum injection rates, system redundancy and reliability.
- A 5½in upper completion tubing selection is considered to provide an acceptable choice with respect erosion velocity limit risk and injection rate delivery.
- In comparison between 4½in and 5½in tubing string, the larger tubular are considered more operationally robust with regard to rig site handling.
- A 7in tubing choice is considered to provide further conservatism with respect erosional velocity limit risks for the highest injection rate delivery and this in turn offers improved redundancy and system reliability although at some marginal incremental cost.
- The reservoir inflow model indicates 200ft of perforations to be more than adequate for the maximum 138MMSCFD (2.65MTPA) required rate with flowing bottom hole injection pressures, 2200psi to 2800psi, (151-193bar),
- A choke pressure drop induced downstream minimum potential temperature of -30°C is proposed as the design basis for this report based a high differential between pipeline arrival and downstream well shut-in pressures of a seawater column at 10barg.
- The injection choke pressure drop induced temperature modelling discussion has highlighted the potential for large temperature drops associated with well start up with a high differential between

pipeline arrival and well shut-in pressures. A further extrapolation of this logic is to consider line, well tubular rupture and subsequent line or well uncontrolled atmospheric (1bar) venting. This in theory would potentially result in temperatures as low as -70°C.

- This issue of extreme low temperature due to unplanned or planned atmospheric venting of CO_2 for each section of the system, (subsea pipeline, topsides process pipework upstream and downstream of the injection choke and well tubulars) needs to properly qualified and assessed with an integrated discussion in the detailed planning phase. A similar approach was reported with regard the Sleipner CCS project.

Water injection

- A wide range of sensitivities with regards to perforated interval, permeability, wellhead pressure, skin have been run in order to optimize the required injectivity profile for water injection in the well using 5½in tubing string.
- Given a base case of 2048psi reservoir pressure, 1014ftTVD reservoir thickness, 200ft of perforated interval, skin of 5 and 260mD permeability, a water injection rate of 6366stb/day is obtained while keeping a wellhead pressure of 300psig. While increasing the wellhead pressure to 1000psig, a water injection rate of 29,131stb/day is possible.
- Initial water injection for 100% seawater has been considered in conjunction with low end sensitivities of permeability and perforated interval and high skin and once again found to be robust and stable given initial reservoir pressure with 5 1/2in tubing.
- In comparison between 4 1/2in and 5 1/2in tubing string, the larger tubular are considered more operationally robust with regard to rig site handling.
- Multi-layer modelling has demonstrated that self-diversion provides a simple and robust means to uniformly water wash the proposed 200ft perforated interval. Diversion is readily achievable whilst operating comfortably within acceptable limits with respect expected fracture pressure, 3335psi (230bar).
- The base case tubing size of 5½in is more than adequate for the water wash target injection rate of 1000m3/d (6290bbl/d).

Perforation System Design

- Underbalanced perforating is a well-documented technique within the industry that promotes optimal perforation tunnel clean up and removal or break up of the perforation crushed zone. Reactive metal liner charges are a relatively new method used to enhance perforation tunnel clean up. This method is best suited to high formation strength, low porosity, low permeability depleted gas reservoir, where dynamic underbalance techniques are constrained and is therefore discounted for this application.
- The use of artificial lift to aid a production clean up flow can be considered as a potential contingency solution in the event that optimised perforating techniques prove inadequate in cleaning the perforation tunnels. Incorporating artificial lift as a base case at this stage adds unnecessary complexity.
- Dynamic/Static underbalance perforating using a shoot and pull technique would require the use of a fluid loss pill to ensure any fluid losses are stemmed post perforating so that a stable over balance fluid column can be confirmed before the shoot and pull string can be recovered.
- The proposed perforation interval of circa 200ft based on there being a single sand package in the reservoir.
- TCP on a dedicated shoot and pull string has been identified as the preferred method for perforating the interval. As there are no constraints on internal diameter, the optimal gun size for the 7in liner can

be run in a single run. The need for an overbalance kill fluid column can be carefully managed with the appropriate integration of fluids, solids free fluid loss technology and perforating system design.

- If an alternative base case 7in completion is considered then a similar base case shoot and pull approach is recommended.
- Based on a preliminary analysis using Schlumberger SPAN software to determine optimal gun size and charge type, the recommendation for the base case 5½in upper completions is either;
  - A Schlumberger 4½in x 2.5 spf, 72° phasing gun system, with 38.8g Powerjet Omega 4505, HMX charge type is recommended; or
  - A Schlumberger 4½in x 5 spf, 135°/45° phasing gun system, with 22.0g Powerjet Omega 4512, HMX charge type is recommended.
- For the Base case 7in upper completion and 7in cemented liner the recommendation is either;
  - A Schlumberger 4½in x 2.5 spf, 72° phasing gun system, with 38.8g Powerjet Omega 4505, HMX charge type is recommended; or
  - A Schlumberger 4½in x 5 spf, 135°/45° phasing gun system, with 22.0g Powerjet Omega 4512, HMX charge type is recommended.
- For both scenarios wireline deployed 2⅞in or 3⅞in perforating guns can be used for contingent re-perforation or the addition of further perforations.
- Tubing Stress Analysis – reported in separate document.

Lifecycle Intervention/Workovers

- Enough space is available on the platform weather deck to accommodate either wireline or slickline equipment, assuming no other operations are taking place. Use of a multiline unit is recommended should both types of well servicing be required.
- Deck loading requirements can be met, with the exception of the cable winch which could exceed capacity depending on the type and length of cable required. This could be readily addressed with the use of temporary spreader beams.
- As no tool string greater than 90ft in length is anticipated being used, a 60ft mast is deemed sufficient for this application. A larger mast might be considered however to reduce the number of runs if intervals longer than 200ft are to be perforated.
- The use of slickline and wireline on the NUI to carry out the following operations is considered reasonable and achievable:
  - downhole gauge failures;
  - injectivity reduction requiring additional perforations;
  - TRSSSV failure requiring repair using and insert WRSSV; and
  - Additional ad hoc logging or data gathering that may be required.
- The residual challenges for use of wireline / slickline from the platform relate to the logistics of travel, accommodation, SIMOPS with other well work as well as platform maintenance operations. The mobilisation and demobilisation of people and equipment is most difficult in winter for unplanned work. A walk to work system based on a vessel and walkway system has been proposed in platform project planning documents to date. The impact on wireline work may mean either delayed operations, limited day shift working or summer only planned campaigns.
- In practical terms a coiled tubing spread can be installed and rigged up on the NUI on the weather deck subject to final crane performance confirmations and use of spreader beams as required.
- However use of coil combined with the proposed surface water wash equipment package does not appear achievable without further work / detailed planning given the limited size of the weather deck

area. At this time coiled tubing from a rig should be assumed as the proven base case requiring simultaneous operations (SIMOPS) combining coil, water wash and or wireline elements.

- Coiled tubing is a viable method of jetting the perforations and clearing obstructions. A jetting approach however is not considered viable to injecting controlled volumes on a layer by layer basis required to remove halite out to a radius of up to 10m.
- The use of tandem packers on coil tubing to provide layer specific injection carries additional complexity, time, risk and cost. The option of re-perforating or perforating a fresh interval is recommended as a first measure before this option is at all considered.
- Residual challenges for use of coil from the NUI relate to the logistics of travel, accommodation, SIMOPS with other well work as well as platform maintenance operations. The mobilisation and demobilisation of people and equipment is most difficult in winter for unplanned work. A walk to work system based on a vessel and walkway system has been proposed in platform project planning documents to date. The impact on coil tubing work may mean either delayed operations, limited day shift working or summer only planned campaigns.
- Bottled, liquid and membrane nitrogen options each represent different considerations logistically. In considering these, it should be highlighted that nitrogen in liquid form irrespective of the means used to convey it into the well is not a process which can be automated at least one human operator will need to be present to oversee displacement. The required Nitrogen quantities needed for a full and a partial purge of the well have been calculated below.

Table 4.125: Nitrogen quantities required for a full and partial purge per well

Nitrogen Purge method	Minimum quantity required per full purge – 7600ftMD	Minimum quantity required per partial purge – 500ftMD	Minimum quantity required per partial purge – 1000ftMD	Minimum quantity required per partial purge – 1500ftMD	Minimum quantity required per partial purge – 2000ftMD
Nitrogen bottles	11 Racks	0.11 rack	0.31 racks	0.6 racks	1.02 racks
Nitrogen bottles with booster pump	6 Racks	0.1 rack	0.25 rack	0.45 rack	0.72 racks
Liquid Nitrogen (THP 2250psi)	1.24 tanks	0.2 tanks	0.06 tanks	0.11 tanks	0.17tanks

- Due to its simplicity, the use of nitrogen bottles is seen to be the most suitable option for partially purging the well. The use of a booster pump may be beneficial but adds a slight increase in complexity.
- The use of liquid nitrogen is seen to be the most suitable option for fully displacing the well.
- The potential use of N_2 with respect unplanned shut downs and start-ups needs further discussion given the current understanding that the platform proposed bottled N_2 system is manually operated only at present. Whether this can be automated to support unplanned start up is not clear at this stage.
- The proposed water wash set up provides the necessary equipment to undertake water wash operations on the platform. The current platform layout provides adequate space and interfaces to accommodate the modular water wash set up but consideration should be given to the additional foot print needed for the chemicals required. Potential chemical injection points have been identified and additional laboratory testing to assess the compatibility of the chemicals needs to be undertaken to determine the suitability of each of these. Any modular equipment will need to be subjected to HAZID integration with platform ESD management system.
- The required injectivity is achievable with the specified equipment and the final filtration requirements will need to be finalised as and when core testing results become available. PROSPER modelling on

rate diversion suggests that relying upon rate diversion as opposed to mechanical or chemical diversion would appear to be acceptable in this scenario.

Platform Interface

- A review of the interface between the well and the platform facility (section of the well between the mudline and outboard flanges of the Christmas tree), has been undertaken and the following observations noted.
- Detailed design should include consideration of not just the ‘A’ or completion tubing / production casing annulus pressure monitoring, but the further external B and C annuli if established prudent for MMV integrity management purposes.
- The proposed NUI environment means a clear definition is required in the detailed design phase of remote data reporting and remote operability with respect the well and platform.
- Platform lifting operation planning should consider platform crane performance and reach with respect the water wash modular package and electric line equipment. Nominally the platform crane capacity is assumed to be of the order of 50 MT with the proposed intervention packages (water / eline) maximum weights circa 25 MT.
- Deck loading for the proposed Weather Deck intervention packages need to be confirmed as adequate and is nominally assumed as to be provided > 2000 kg /M2.
- Detailed planning should also confirm through platform capability for workover including lifting management for tree recovery and re-deployment.
- At this stage the proposed method or standards to be used with respect platform hazardous area zoning has not been clearly stated. This needs to be resolved to allow the appropriate specifications of equipment to be confirmed.
- The injection of CO_2 into the well will result in thermal induced loads with temperature drops associated with both a potential phase changes across flow restriction such as production) and steady state injection potentially cooling the average well temperature with respect the ambient geothermal gradient. The impact of these loads needs to be considered amongst other things in relation to tree height negative growth as the well tubulars cool.
- The use of Landmark Wellcat multi-string modelling software in conjunction with a review of offset empirical data is recommended to qualify the extent of any such tree height movement. Platform bulkheads and flowline design needs to flexibility cater for such movement in terms of clearance or adjustable support tolerances.

MMV

- The provision of conventional pressure and temperature surface gauges for monitoring the tubing, ‘A’ and ‘B’ annuli is recommended. Monitoring of the other annuli should be considered in the detailed phase and formally closed out with the project team as appropriate.
- The provision of a conventional permanent downhole gauge system with an electrical cable for power and real time data surface read out would also be of benefit. These two elements are considered the primary MMV recommended in well tools.
- The surface gauge equipment can be readily replaced and maintained, as required. The initial downhole equipment can be expected to have a run life of 5 to 10 years, which is likely to be increased if additional gauge and cables are installed with the initial equipment.
- In considering the scenario of the failure of the initial downhole system, the MMV plan must consider the value of the data going forward at the point of failure compared to the risked cost of the re-instatement of the system.

- Detailed planning should consider the merits and risks of wireline recoverable gauge components of downhole pressure and temperature systems. These may provide a means to avoiding a tubing workover in the event of a gauge as the point of failure.
- When using a downhole memory gauge system for pressure and temperature measurements, these are battery powered and wireline deployed and recovered; meaning data is not real time but historic. If they are considered an acceptable substitute when combined with use of surface data, downhole memory gauges may provide a role in offering periodic data after the initial system described above has failed.
- Alternative pressure and temperature downhole gauge system types that might provide battery powered, wireline replacement options after failure of the primary system do exist. The Expro CaTS system provides real time gauge data on a wireless basis using electromagnetic telemetry. Nominal expectation subject to detailed planning is that this system is fit for purpose as a retro-fitted wireline replacement solution and can achieve telemetry to surface. Although real time, it should be recognised the telemetry technology is less proven than the conventional memory gauge technology. A combination of both can be used to address this concern. Once again the wireline risks need to be weighed up.
- The Metrol acoustic system provides real time gauge data based on a battery powered, wireless basis using acoustic telemetry. Again, although real time, it should be recognised the telemetry technology is less proven than the conventional memory gauge technology. The system needs to be subject to detailed design review to confirm architecture and performance. As discussed with the CaTS system, the wireline risks need to be weighed up.
- Further MMV tools and techniques relevant to the well are considered to be periodic well intervention with wireline logging tools using a combination of PLT and multi-finger calliper / wall thickness, CBL and USIT tools. These tools offer the opportunity to trend and capture any changes to initially established pre and initial injection baselines and additional logging surveys. In the absence of other documented stipulation, these are considered prudent as performed at 0, 2, 5, 10, 15 and 20 years of well injection life. The value of these operations must be offset with an assessment of operational risk that would be associated with multiple wireline interventions such ‘stuck wire / tools’ and the potential risk of protracted fishing operations.
- At this time, fibre optic DTS / DAS systems are considered secondary / marginal with respect MMV tools and techniques based on cost, reliability limitations, data management and interpretation difficulties.
- An initial feasibility study on the use of an in well geophone system to complement the proposed seabed array has been recently shared by NGC with ADTI. On brief review it appears to show merit with respect plume or fracture tracking. However, the longevity of the initial well system must be recognised as likely short term (0 to 5 years) and integration into the well and completion design in terms of wellhead / tubing hanger feed through requirements and tubing / casing annular mechanical clearances needs focus in the detailed design stage before a final project view on inclusion in the well design can be developed.

Outline Programme

- A base case outline programme and costing has been developed and is covered in full in this document.

Hydrates

- During expected steady state CO_2 injection operations CO_2-water hydrates are not a concern given the proposed maintenance of the water fraction at sub-hydrate forming levels (50 ppmv).
- The risk of hydrates is present for transient events where water enters the well environment as either a standing column of formation water during shut-ins or where seawater is used for washwater operations.
- Ongoing transient flow assurance studies that accurately describe the extent of the impact of temperature drops across the production choke and the resultant pressure and temperature gradient down the well are key to determining the extent of hydrate risk at for various CO_2 to water interfaces depths and water salinities in more detail.
- Mono Ethylene Glycol (MEG) is recommended as the primary chemical inhibition treatment.
- A MEG concentration of 50% by volume is recommended. In an operational context a 70% concentration by volume is recommended to cater for any dilution effects in the event of dilution by any free water that may be present in the well.
- The use of methanol is constrained due to the risk of promoting salt precipitation in the reservoir. Methanol use if applied to a plug in the well from above would be unsuccessful due to positive buoyancy with respect any water column, or initial MEG pill sitting above the plug. Methanol might only be considered as a contingency to MEG if injected direct into the Christmas tree via a suitable chemical injection line.
- A complete hydrate control and management strategy for all operating conditions should be developed in the detailed planning phase.
- A multi-discipline a hydrate HAZID / Risk Assessment for the project should be performed in the detailed planning phase.
- Ensure all test fluids incorporate hydrate inhibitors.
- Inhibited displacement spacers or pills should be spotted between any CO_2 / water phases, supplemented by nitrogen purging as nitrogen capacity allows.
- A deep set safety valve circa 2000ft will minimise risk of hydrates occurring across same.
- Flush all any surface lines to remove potential water / CO_2 traces as appropriate.
- Be aware of all potential pressure drops in the system and the temperature cooling impact of the Joules Thompson effect. Start-up procedures should consider staged approach to equalisation across valves and choke to allow equilibration to ambient temperature to minimise hydrate risk.
- Ensure inhibitor injection lines are properly sized and located to meet current and future requirements for future inhibition goals.
- Ensure inhibition provision addresses both the prevention and remediation of hydrates. This should consider the inclusion of pipework / pumps / seals / bunding for methanol is in place for use if required.
- Ensure tubing sizing and flow assurance studies involves consideration of hydrates.

4.25 Metallurgy/Elastomers Studies

At FEED definition, the requirement for qualifying metallurgy and elastomers for CO_2 service for critical components is recognised as a detailed design phase requirement, since the specific equipment has not as yet been identified. As noted above the, this work is specified within the EPC Wells contractor Scope of Work and will be performed once the project has been approved via a Financial Investment Decision (FID) and a contractor nominated to perform the work.

The FEED definition Metallurgy and Elastomers can be found above in Section 4.24 (Completion Concept selection) within the Materials Selection section and in the Wellhead and Tree Section 4.17.2.

4.26 Well Intervention/Workover

The following describes the Lifecycle interventions and workovers considered during FEED.

4.26.1 Expected Intervention and Workover Operations

It is expected that interventions, both planned and unplanned will take place during the life of the wells. Due to the nature of the platform, any well modifications which may require to be performed will need to be kept as simple and as flexible as possible.

The final number and type of planned well interventions are in part subject to the requirements of the final NG MMV plan, which will be completed in Detailed Design. The following Table 4.126 is a summary of the lifecycle interventions and workovers considered in FEED.

Table 4.126: Summary of Lifecycle Well Intervention Workover Operations Wireline/Slickline operations

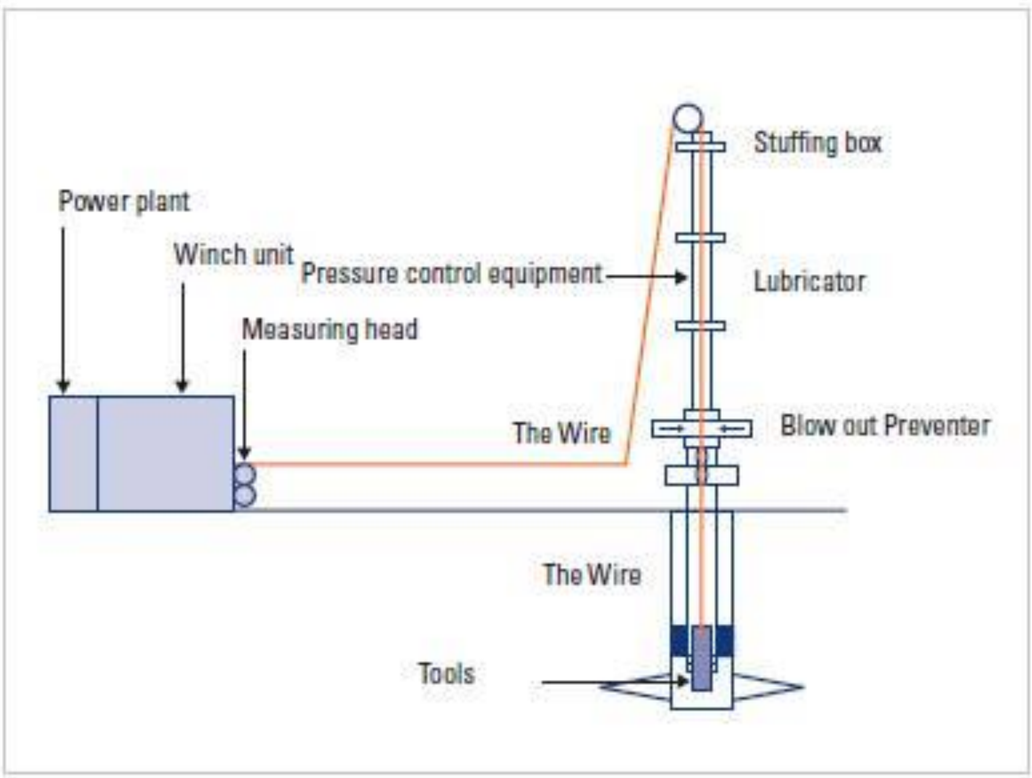
Operation	Type	Planned /Unplanned	Frequency	Location	Challenges
Water wash treatment	Bullhead	Planned	6 monthly	Platform	Treatment placement, Logistics of travel, accommodation
Wireline logs	Wireline	Planned	Yearly	Platform	Logistics of travel, accommodation, SIMOPS with other well work as well as platform maintenance operations.
Downhole Gauge failures	Slickline	Unplanned	Unplanned	Platform	Logistics of travel, accommodation, SIMOPS with other well work as well as platform maintenance operations.
TRSSSV failure	Slickline	Unplanned	Unplanned	Platform	Logistics of travel, accommodation, SIMOPS with other well work as well as platform maintenance operations.
Insert screen placement	Inner work string	Unplanned	Unplanned	Rig	Long lead time, planning, cost
TRSSSV failure where WRSSV repair is unsuccessful	Workover	Unplanned	Unplanned	Rig	Long Lead time, planning, cost
Coil tubing clean out of obstruction	Coil tubing	Unplanned	Unplanned	Rig base case	Limited weather deck space on NUI, unable to perform SIMOPS if used.
Coil tubing to perform water wash if bull head is unsuccessful	Coil tubing	Unplanned	Unplanned	Rig base case	Limited weather deck space on NUI, unable to perform SIMOPS if used.
Completion tubing replacement	Work over	Unplanned	Unplanned	Rig	Long lead time, planning, cost
Production packer failure requiring a work over	Work over	Unplanned	Unplanned	Rig	Long lead time, planning, cost

Operation	Type	Planned /Unplanned	Frequency	Location	Challenges
Nitrogen purge well displacement	Bullhead	Unplanned	Unplanned	Platform base case	Limited weather deck space on platform, hazards associated with liquid nitrogen

Wireline and slickline tools are tools that are inserted into the well for both workover and logging activities. Whilst slickline is a thin cable introduced into a well to deliver and retrieve tools downhole, wireline is an electrical cable used to lower tools into and transmit data about the conditions of the wellbore. Wireline usually consists of braided lines. Braided line can contain an inner core of insulated wires which provide power to equipment located at the end of the cable, normally referred to as electric line and provides a pathway for electrical telemetry for communication between the surface and equipment at the end of the cable. Consisting of single strands or multi-strands, wireline is used for both well intervention and formation evaluation operations.

Slickline is used to place and recover wellbore equipment, such as plugs, gauges and valves. Slickline is a single-strand non-electric cable lowered into wells from the surface. Slickline can also be used to repair tubing within the wellbore. Wrapped around a drum, slickline is raised and lowered in the well by reeling in and out the wire hydraulically.

Figure 4.84: Standard wireline equipment set up



The main components of a wireline or slickline spread are the following: a diesel power pack, a slickline or wireline unit, a mast and pressure control equipment as illustrated above. In addition to the above, the platform weather deck would also need to be able accommodate a mast, workshop containers (the final quantity is dependent on job type) and a tool rack.

Masts are available in both 60ft and 90ft configurations. The proposed mast for this application is 60ft. This, along with the height available from the top of the Christmas tree to the weather deck (30ft) gives a total of 90ft as maximum toolstring length.

Table 4.127: Wireline logging tool lengths

Tools	Toolstring length
Production logging string (PLT)	70ft
Multifingered calliper tool (MFCT)	40ft
Perforation String (guns)	90ft (70ft)

Elevation drawings of the weather deck and cellar deck indicate that enough space is available to accommodate all the equipment required.

Should slickline and wireline be required consecutively, a solution to minimise deck space is available. A multiline unit allows logging operations and slickline operations using a single unit to be performed. The standard configuration for this unit is with a self-contained power pack and either with a single or dual drum. This enables operations to switch between various well servicing activities without needing an extra winch, operator or engineer on the rig. The combined system reduces the need for equipment and people in delivering slickline and wireline operations.

Personnel required: a total of 6 people for either a slickline or wireline crew would be needed for 24 hour coverage.

4.26.1.1 Conclusions

Enough space is available on the platform weather deck to accommodate either wireline or slickline equipment, assuming no other operations are taking place. Use of a multiline unit is recommended should both types of well servicing be required.

Deck loading requirements can be met with the exception of the cable winch which could exceed capacity depending on the type and length of cable required. This could be readily addressed with the use of temporary spreader beams.

As no tool string greater than 90ft in length is anticipated being used, a 60ft mast is deemed sufficient for this application. A larger mast might be considered however to reduce the number of runs if intervals longer than 200ft are to be perforated.

The use of slickline and wireline on the NUI to carry out the following operations is considered reasonable and achievable:

- downhole gauge failures;
- injectivity reduction requiring additional perforations;
- TRSSSV failure requiring repair using and insert WRSSV; and
- additional ad hoc logging or data gathering that may be required.

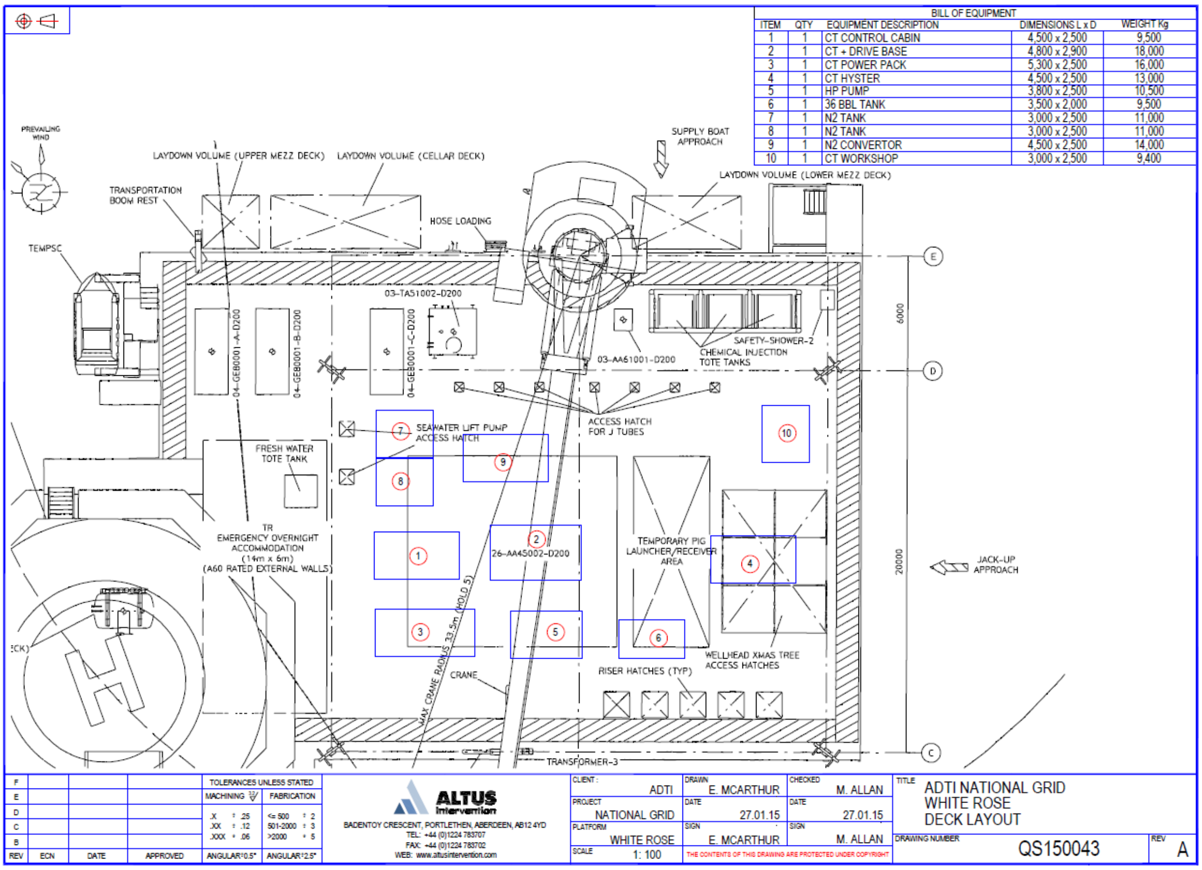
The residual challenges for use of wireline / slickline from the platform relate to the logistics of travel, accommodation, SIMOPS with other well work as well as platform maintenance operations. The mobilisation and demobilisation of people and equipment is most difficult in winter for unplanned work. A "walk to work" system based on a vessel and walkway system has been proposed in platform project planning documents to date. The impact on wireline work may mean either delayed operations, limited day shift working or summer only planned campaigns.

4.26.2 Coil Tubing Operations

In the event that surface bullhead water washing is ineffective then the use of coil maybe considered as a contingent method. The technique involves introducing a continuous flexible metallic tube into the well, which is transported to and from the platform on a large reel. Tubing is run to the desired location in the well and fluids may be pumped through the tubing to allow for placement in the well.

A coiled tubing equipment spread is transported to and from the platform or rig in modules. Modules are designed to be of suitable size and weight to be lifted and spotted in position using rig cranes. However for any job actual current crane performance including reach constraints need to be confirmed. This is particularly so for NUI style platforms where lower capacity cranes may be installed to save cost or older platforms where down rated equipment may be a constraint.

Figure 4.85: Coil tubing equipment modules shown on platform weather deck



With the specified equipment, deck loading is anticipated to be less than the maximum specified weather deck capacity of 1.5MT/m^2 in all areas. The exception to this is the coiled tubing drive frame and the support platform positioned above the wellhead. A reduction in cool tubing equipment deck loading to within manageable levels can be readily achieved with the use of spreader beams which are regularly used to spread the load of equipment and allow for heavy loads to be supported on decks.

There are two options which can be considered when using coiled tubing for facilitating water wash treatments: a jetting toolstring or a straddle packer toolstring.

4.26.2.1 Jetting Toolstring

This can be used for jetting the perforations to clean up blocked or plugged perforation tunnels. It can be also be used to remove any loose sand fill or debris that might be causing an obstruction in the well.

The challenge of using this assembly to effectively water wash on a layer by layer basis is that the bulk of the fluid will follow the path of least resistance rather than enter the formation at the depth of the jetting nozzles. Thus given halite is expected to potentially occur out to a radius of up to 10m then this approach is unlikely to succeed as a contingent solution where the water wash surface bullhead approach has already failed. The exception to this would be if only a very shallow salt seal within the perforations is present.

4.26.2.2 Straddle Packer Toolstring

The second option is using the coiled tubing with 20ft length spaced inflatable straddle packers. Treatment fluid (wash water) is injected between the packers through a nozzle in the coil and sections of the perforated interval are treated progressively on a 20ft layer by layer basis. The packers are inflated and the water is injected and squeezed into the relevant layer. The packer is then deflated and the tool string moved to the next layer and the process is repeated. The benefit of this method is that known volumes of wash water are positively injected into each target layer.

The operation does not come without its risks however. There is a risk the packer elements become damaged on the perforations. The operation requires that the inflate packers are reliably inflated and deflated 10 times to cover a 200ft perforation interval. In the event that the packers do not fully deflate, there is a risk of a partially deflated packer becoming stuck as the assembly is pulled back into the base of the tubing. This method also requires considerable time because the injection treatment is less efficient in batches of circa 4,200bbls per 20ft zone. Time is required to move the string between each interval and set and unset the inflate packers and treatment rate is lower, hydraulically constrained by the lesser internal diameter of the coil tubing string as compared to the completion when surface bullheading.

Coiled tubing equipment must be specified for use typically some months before the operational commencement date. The key limiting factor is the availability of the specified tubing, but given the relatively shallow depth and simple geometry of the proposed wells tubing availability is not anticipated to present undue logistical issues.

The equipment is typically operated by a crew of seven. Three of these on day shift and three on night shift, the seventh crew member is a supervisor who splits his or her time between the two shifts as required.

4.26.2.3 Conclusion

In practical terms, a coiled tubing spread can be installed and rigged up on the NUI on the weather deck subject to final crane performance confirmations and use of spreader beams as required.

However use of coil combined with the proposed surface water wash equipment package does not appear achievable without further work / detailed planning given the limited size of the weather deck area. At this time coiled tubing from a rig should be assumed as the proven base case requiring simultaneous operations (SIMOPS) combining coil, water wash and or wireline elements.

Coiled tubing is a viable method of jetting the perforations and clearing obstructions. A jetting approach however is not considered viable to injecting controlled volumes on a layer by layer basis required to remove halite out to a radius of up to 10m.

The use of tandem packers on coil tubing to provide layer specific injection carries additional complexity, time, risk and cost. The option of re-perforating or perforating a fresh interval is recommended as a first measure before this option is at all considered.

Residual challenges for use of coil from the NUI relate to the logistics of travel, accommodation, SIMOPS with other well work as well as platform maintenance operations. The mobilisation and demobilisation of people and equipment is most difficult in winter for unplanned work. A "walk to work" system based on a vessel and walkway system has been proposed in platform project planning documents to date. The impact on coil tubing work may mean either delayed operations, limited day shift working or summer only planned campaigns.

4.26.3 Nitrogen Operations

Nitrogen injection may be necessary in order to purge the wells of CO_2 prior to and after water washing to prevent the formation of hydrates and minimise corrosive risks posed by CO_2 and seawater phase mixing within the wellbore. Three specific means of nitrogen injection have been identified and are discussed in turn below.

4.26.3.1 Platform Based Bottled Nitrogen

Bottled nitrogen is transported to and from the platform in bottle racks. Nitrogen bottles may be stored on the platform and used when required. The key limiting factor of bottled nitrogen is the volume of nitrogen available. A typical nitrogen bottle rack may contain up to 64 bottles each containing up to 200m^3 of nitrogen. = 450,000scf. This method of purging the well can also be used with the addition of a booster pump to reach the required THP whilst reducing the overall amount of N2 bottles needed. Bottled nitrogen is supplied at a high level of purity, typically in the order of 99.9% pure. Provision for bottled nitrogen has been made on Weather Deck of the platform) and piping is in place for injection into the wellhead. However, it is not known from the drawings what quantities have been accounted for. Available platform documentation suggests this Nitrogen may be for purging surface lines only.

4.26.3.2 Liquid Nitrogen Tanks

Liquid nitrogen can be transported to the platform in large tanks. Once on the platform, the liquid nitrogen is expanded to a gas and pumped downhole. The use of liquid nitrogen has the benefits of offering large volumes of nitrogen compressed into (relatively) small and easy to handle tanks, but at the cost of additional hazards associated with spillage of liquid nitrogen and the extremely low temperature of liquid nitrogen. The system also requires cryogenic equipment. Liquid nitrogen will naturally evaporate over time so there is a time limit on rig-based storage before a top-up is required. Liquid nitrogen is supplied at a high level of purity, typically in the order of 99.9%.

4.26.3.3 Membrane Nitrogen Generation

Nitrogen can be generated from the air in a process called membrane nitrogen generation. The process involves passing air through membranes and bleeding off the constituent gases (H_2O, CO_2, O_2 and Ar) based on their relative permeation rates. Membrane nitrogen generation has the benefit of not requiring a supply of nitrogen bottles or tanks. It his however an expensive means of acquiring nitrogen for purging and cannot achieve purity rates as high as bottled or tank nitrogen. For the proposed application, a membrane system would be able to produce 95-96% pure nitrogen, the main contaminant being oxygen. This and its potential impact on completion integrity remains the biggest residual concern for this method.

4.26.3.4 Conclusion

Bottled, liquid and membrane nitrogen options each represent different considerations logistically. In considering these, it should be highlighted that nitrogen in liquid form irrespective of the means used to convey it into the well is not a process which can be automated at least one human operator will need to be present to oversee displacement. The required Nitrogen quantities needed for a full and a partial purge of the well have been noted below.

Table 4.128: Nitrogen quantities required for a full and partial purge per well

Nitrogen Purge method	Minimum quantity required per full purge – 7600ftMD	Minimum quantity required per partial purge – 500ftMD	Minimum quantity required per partial purge – 1000ftMD	Minimum quantity required per partial purge – 1500ftMD	Minimum quantity required per partial purge – 2000ftMD
Nitrogen bottles	11 Racks	0.11 rack	0.31 racks	0.6 racks	1.02 racks
Nitrogen bottles with booster pump	6 Racks	0.1 rack	0.25 rack	0.45 rack	0.72 racks
Liquid Nitrogen (THP 2250psi)	1.24 tanks	0.2 tanks	0.06 tanks	0.11 tanks	0.17tanks

Due to its simplicity, the use of nitrogen bottles is seen to be the most suitable option for partially purging the well. The use of a booster pump may be beneficial but adds a slight increase in complexity.

The use of liquid nitrogen is seen to be the most suitable option for fully displacing the well.

The potential use of N_2 with respect unplanned shut downs and start-ups needs further discussion given the current understanding that the platform proposed bottled N_2 system is manually operated only at present. Whether this can be automated to support unplanned start up is not clear at this stage.

4.26.4 Workover operations

A workover generally refers to the process of pulling and replacing a completion. These can be the most complex, difficult and expensive types of well work. If well integrity is threatened, either by corroded tubing or failure of any of the critical downhole components, then a workover needs to be carried out.

Workovers require the capability of a drilling rig and as such must be planned months in advance. A typical work over will include work such as removing the Christmas tree and recovering the tubing hanger and tubing string. If the production packer is not a retrievable type then the tubing needs to be cut so that the completion tubing can be pulled from the well. The packer is subsequently milled out.

A jack up rig would be positioned over the platform and the well accessed vertically from above by temporarily extending the well envelope using riser sections through the platform.

Detailed planning including safety case, bridging documents and appropriate HAZID and SIMOP processes should address workover operations. It should be recognised that mobilising a jack up rig over the NUI would require a platform shut-in of all wells until the rig move is completed. In terms of downtime all lifecycle well intervention and workover activities need to be considered to understand associated down time.

Tubing replacement work overs are estimated to take in the order of one month to complete. This includes mobilizing the rig, equipment and crew, performing the work and demobilizing both crew and equipment.

4.26.5 Water Wash Operations

Previous work done by the NGC sub-surface team, shows that the injection of CO_2 into Endurance can cause removal of all the water in the near wellbore region, (so-called drying-out) leading to halite precipitation in the pore spaces. Due to the relative buoyancy of CO_2 to the formation brine, fresh formation brine flows into the near wellbore region when injection ceases. This provides the source for additional drying-out and subsequent halite precipitation. This can lead to a reduction of porosity which can reduce the permeability and therefore the injectivity. This in turn leads to a build-up in pressure and the risk of hydraulic fracturing which can compromise reservoir and cap-rock integrity. As discussed previously, this problem can be remedied by using a water wash system.

The water wash treatment parameters are subject to ongoing subsurface modelling and core analysis. In the interim' the provisional water wash rate, duration and frequencies used for FEED design are as follows:

Table 4.129: Water wash rate, duration and frequencies

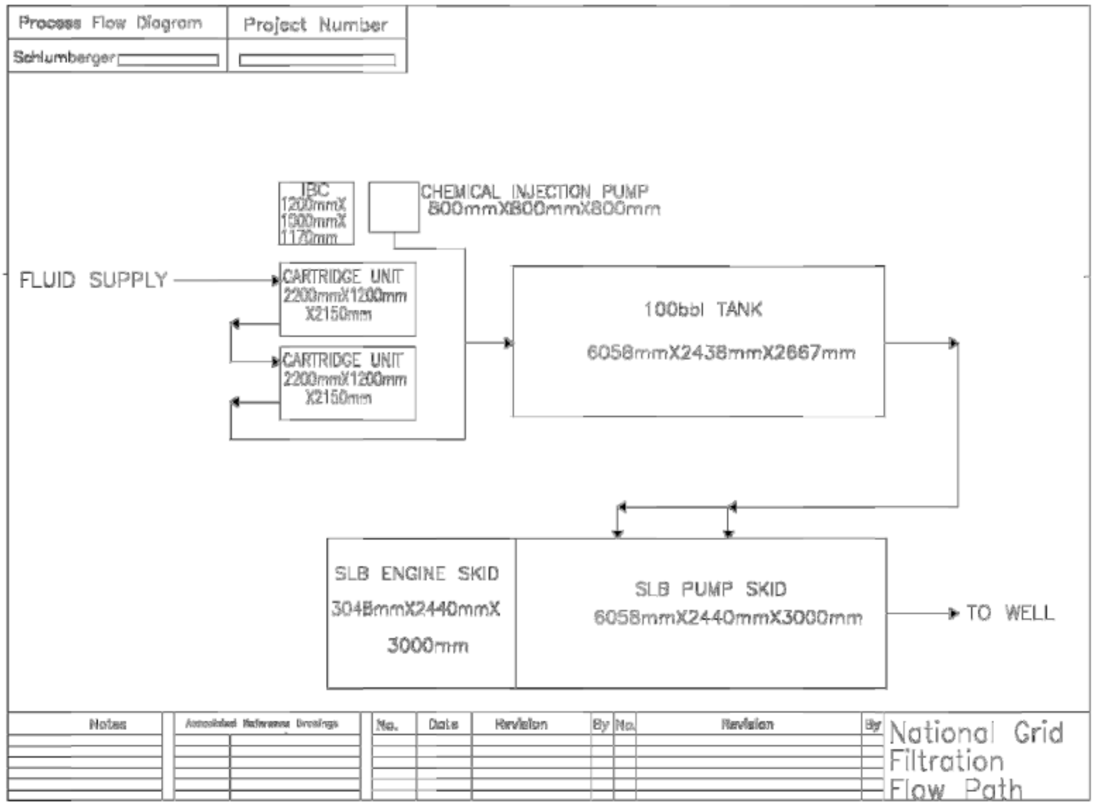
Water Wash Data	
Water wash rate	175gpm (954m^3/day)
Water wash duration	7 days per well
Water wash frequency	1 – 2 per year

To assess the feasibility and effectiveness of this operation, various parameters are considered including the equipment set up, filtration requirements, chemicals required, manpower requirements and water wash treatment placement.

4.26.5.1 Equipment set up

The proposed skid illustrated in Figure 4.86 below consists of a pumping unit, chemical injection pump and two filtration cartridge units should satisfy the requirements set out above in respect of equipment details for a modular water wash skid.

Figure 4.86: Proposed water wash equipment layout



4.26.5.2 Filtration

As sea water typically poses no problems with respect to filtering, two twin vessel cartridge filter units are proposed. The first unit would be dressed with 10µm nominal filters to provide the initial filtration phase and to protect the second unit. The second unit would be dressed with 2µm absolute filter elements providing the polish to ensure that the filtered fluid meets the cleanliness specification for pumping downhole. The flexibility of these units means that final micron ratings for the filtration can easily be adjusted pending final core analysis results.

4.26.5.3 Chemical Requirements

A chemical injection precision pump package is required in the set up to allow biocide, oxygen scavenger, scale inhibitor and hydrate inhibitor to be injected in to the fluid stream at the correct dosage. Although the preferred injection points have been outlined in Table 4.130 below, provision for chemical injection has been made on the upper mezzanine deck (White Rose CCS Project Feed Piping and Instrumentation Diagram Offshore Storage Facility Upper Mezzanine Deck.). Further detailed design will have to be undertaken to assess the suitability of these points. Chemical injection pumps can be provided as part of the modular water wash package if required. OR-11 (Oxygen scavenger provided by MI Swaco, similar products are also provided by other companies) is expected to be injected @ 100 ppm between the filter skid and the stock tank, with MB-5919 (Biocide provided by MI Swaco, similar products are also provided by other companies) injected @ 500 ppm between the stock tank and the HP pump. Scale inhibitor SI-414N (provided by MI Swaco, similar products are also provided by other companies) is expected to be injected prior to or upstream of the Oxygen scavenger (OR-11). These recommendations would require further laboratory testing to confirm their effectiveness and to be further optimised.

Table 4.130: Estimation of chemical dosage and quantities required per water wash treatment

Chemical	Dosage	Quantity Required per water wash treatment (4200bbls)	Recommended Injection Point	Quantity of IBC (Intermediate bulk container)needed per water wash treatment
OR-11 Oxygen Scavenger	100ppm	1000 Litres	Between the filter skid and stock tank	1
MB 5919	500ppm	3500 Litres	Between the stock tank and HP pump	4 -5
Scale Inhibitor SI-414N	50ppm to100 ppm	Up to 1000 litres	Upstream of OR-11 injection in the sea water	1
Hydrate Inhibition	To be specified in WFS 4 Hydrate Inhibition Requirements	To be specified in WFS 4 Hydrate Inhibition Requirements	To be specified in WFS 4 Hydrate Inhibition Requirements	To be specified in WFS 4 Hydrate Inhibition Requirements

4.26.5.4 Manpower

In order to minimise downtime and provide continuous service, 24 hour cover during water wash operations is recommended. To achieve this, the following manpower will be required:

- 1 x Filtration Supervisor on dayshift;
- 1 x Filtration Engineer on nightshift;
- 1 x Cementer / Pump operator on dayshift; and
- 1 x Cementer / Pump operator on nightshift.

Consideration should be given to available accommodation on the platform, especially if SIMOPS are taking place. Personnel will also be necessary to service the water wash system at predetermined intervals.

4.26.5.5 Water wash treatment placement

Consideration should also be given to the effectiveness of the water wash placement when injecting from surface. There is always the risk that the water wash fluid will only enter the top perforations, limiting the effectiveness of the treatment. Should additional diversion be needed to provide adequate treatment placement, then the standard approaches to address this issue are discussed below.

4.26.5.6 Rate Diversion

This method relies upon increasing rate and relying upon increasing formation back pressure to force the treatment fluid into other zones of either lesser permeability or greater depth. The attractions of this method are simplicity and low cost and risk and no additional equipment, chemicals or people. Real time control and exact confidence in rate diversion is limited however and you are relying on calculated numbers for results. The uncertainty with this method increases as the length of the of perforated interval increases, therefore its use is typically constrained to a limited or finite perforation interval length. PROSPER well performance software has been used to consider suitability of this method to this particular treatment scenario. Five separate 40ft layers were considered within the perforated interval, each with increasing levels of skin from 2 to 20. The first model looks at the injectivity rates achieved per layer with steady WHP but increasing treatment flow rate. The second model looks at the injectivity per layer with steady treatment flow rates and increasing WHP.

The multi-layer modelling results as discussed and presented earlier in the Well Performance / Flow Assurance section of this report indicate that self-diversion provides a simple and robust means to uniformly water wash the proposed 200ft perforated interval. Diversion is readily achievable whilst operating comfortably within acceptable limits with respect expected fracture pressure, 3335psi (230bar).

4.26.5.7 Chemical Diversion

Chemical diversion typically includes the use of viscous pills to divert the fluid to the required zones. The solution would require alternating between pumping wash water and viscous pill until progressively deeper zones had been treated. One of the challenges of this approach is the lack of confirmation as to the exact level of diversion being achieved, either real time or post treatment. This method requires additional time for the subsequent breakdown of the diversion chemicals and an increase in water wash time is also needed to allow all the perforations to receive the correct amount of fluid. Increased cost, complexity, man power and chemical footprint must also be taken into consideration with this method. Post treatment, there needs to be confirmation that there are no indications of formation damage.

4.26.5.8 Mechanical Diversion

Mechanical diversion methods can include setting a mechanical barrier on electric line or using coiled tubing to jet the perforations with the water wash treatment. Mechanical barriers can include equipment such as ball sealers, however these are not recommended for this application as they need to be flowed back out of the well. Soluble balls are available but additional time is needed for these to dissolve. Plugs can be set on e-line, but these can pose a fishing risk. Mechanical diversion operations can be quite complex. Attention should be given to the amount of available deck space and accommodation available as these operations would likely occur in conjunction with the water wash treatment. Detailed planning would have to be undertaken for this diversion option in order to overcome the operational and logistical challenges this would pose.

4.26.5.9 Conclusions

The proposed water wash set up provides the necessary equipment to undertake water wash operations on the platform. The current platform layout provides adequate space and interfaces to accommodate the modular water wash set up but consideration should be given to the additional foot print needed for the chemicals required. Potential chemical injection points have been identified and additional laboratory testing to assess the compatibility of the chemicals needs to be undertaken to determine the suitability of each of these. Any modular equipment will need to be subjected to HAZID integration with platform ESD management system.

The required injectivity is achievable with the specified equipment and the final filtration requirements will need to be finalised as and when core testing results become available. PROSPER modelling on rate diversion suggests that relying upon rate diversion as opposed to mechanical or chemical diversion would appear to be acceptable in this scenario.

4.27 Well Intervention/Workover Schedule Optimisation

The well interventions and workovers schedule was only considered at high level in the FEED work. This scheduling will be optimised during detailed design and will form a part of the Operation and Maintenance philosophy and Operation and Maintenance detailed plan for White Rose.

Interventions and workovers will however be scheduled according to the most appropriate times available, according to how the power station plans to work, such as during periods of planned shut downs for maintenance.

Interventions and workovers will also be performed when an urgent need for these operations exists, such as when wells require corrective actions to repair malfunctions. In the case where heavy workovers (requiring tubing removal for example, using a rig) are required, a lengthy period of time will be required for planning the remedial actions, contracting a rig to perform the work and acquiring the equipment needed for the remedial work. In these cases, a campaign of work will be scheduled which will likely involve the replacement of all wells tubings and downhole equipment.

5 Well Abandonment Concept Including Possible Re-Entry of Abandoned Wells

The method selected for CO_2 injection well abandonment, including possible re-entry of previously abandoned wells, is described below. Note that the re-entry of previously abandoned wells was considered in FEED but subsequent to a detailed risk analysis by Quintessa, there is no requirement to perform such re-entries, however this information is kept in the document for information.

5.1.1 CO_2 Injection Well Abandonment

The following diagrams illustrate the options available in order to reinstate the long term integrity of the injection wells. Two options are given below for the abandonment.

The following assumptions have been made for the injection wells:

- completion string has been removed from the well;
- surface wellheads have been utilised;
- monitoring system has not been installed in the well;
- no temporary suspension in the wellbore;
- formations tops as per Table 4.1; and
- casing integrity proven.

5.1.1.1 Injection Well Abandonment Philosophy - Option A

Refer to Figure 5.1 (Injection Well Abandonment – Option A), below. The following programme steps would be executed.

Mill Section #1

Milling is the process of cutting into and removing a section of casing in order that a cement plug can be placed into the removed section of casing. A length of 200ft (60.9m) of the 7in liner would be milled, from ± 5,747ft (± 1751m) to 5,547ft (± 1690m) MDBRT. It would be critical that the section located at the primary seal Rot Clay from 5,747ft (± 1751m) to 5,684ft (± 1732m) is milled. Due to CO_2 resistant cement having been placed behind the 7in liner, it would be unlikely that this cement would require milling, but in the event that there is an insufficient bond between plug #1 and formation wall, it would be advised to mill the cement.

There are several methods which could be used as a base for plug #1, for example a cement retainer or a Viscous Reactive Pill (VRP). The base for plug #1 will either be set inside the 7in liner or in the open hole depending on the method selected. The base for plug #1 would not be considered a barrier to the well.

Plug #1 5,747ft – 5,227ft

A 16.0ppg CO_2 resistant cement plug would be set from 5,747ft (1751m) to 5,227ft (1593m) (length 500ft) to act as the primary barrier to the Bunter sand. This plug would restore the cap rock and seal across the naturally sealing formations in the Rot Clay and Rot Halite.

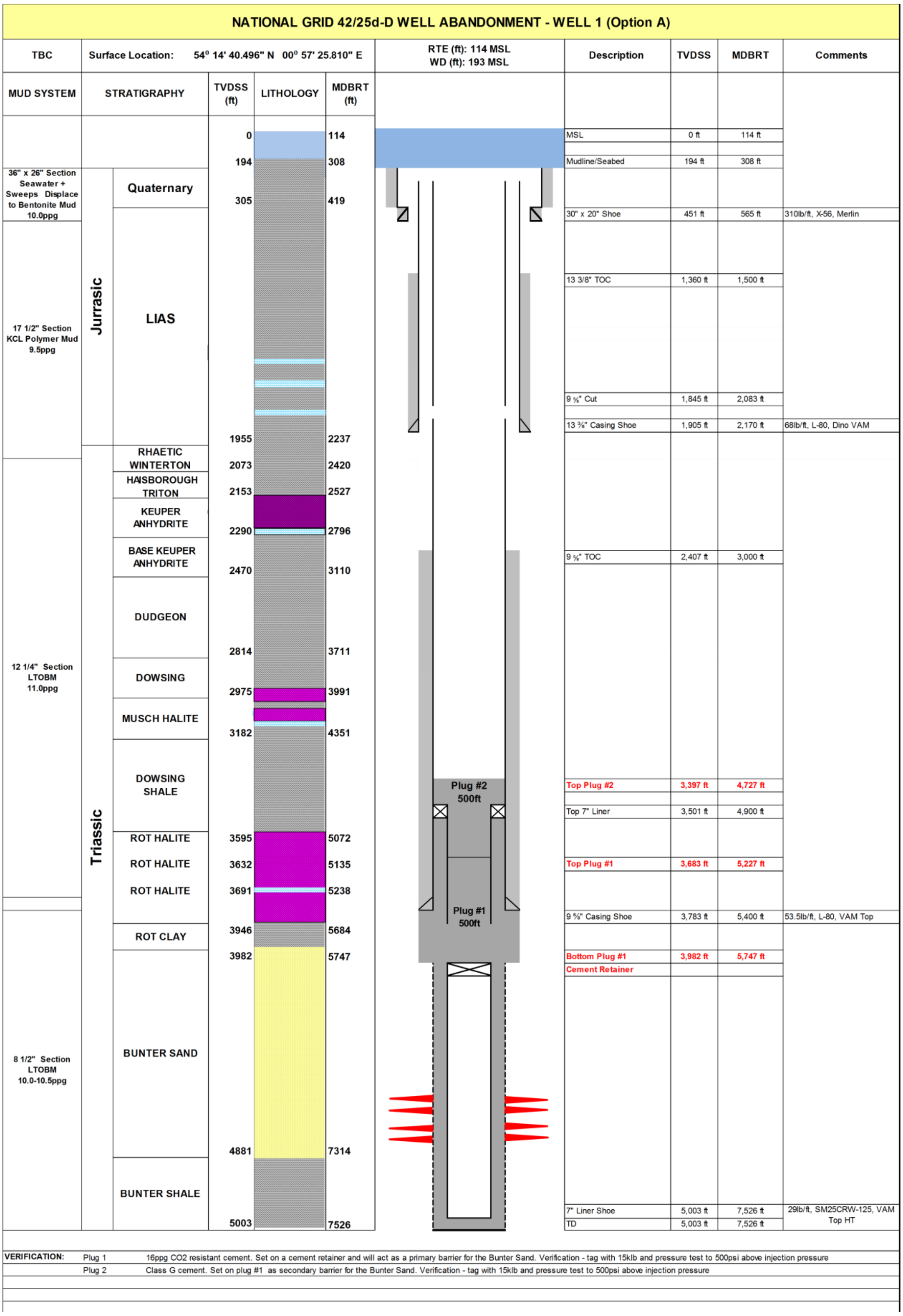
The plug would be verified with a 15klb tag, pressure test to 500psi above injection pressure.

Plug #2 5,227ft – 4,727ft

A 500ft, 16.0ppg Class G cement plug would be set on plug #1, to act as a secondary barrier to the Bunter sand. The plug would have to be verified with a 10-15klb tag.

The hazards stated above do not take into account the specific methods required in order to re-enter the crestal wells. It can be noted from the hazards stated that there is a huge amount of operational risk which could prevent all the re-abandonment objectives being successfully achieved. There are several key milestones that need to be achieved, such as re-establishment on the well, achieving pressure containment, attempting to access deep plugs before abandonment cement plugs can be set in order to achieve well objectives. It should also be noted that where operational difficulties / existing status of the wells, prevent any further progress being made, significant expenditure could already have been committed at the point where operations are curtailed.

Figure 5.1: Injection Well Abandonment – Option A



5.1.1.2 Injection Well Abandonment Philosophy – Option B

Refer to Figure 5.2 (Injection Well Abandonment – Option B), below. The following programme steps would be executed.

Mill Section #2

Mill 200ft of 9 5/8in casing from ± 4,351ft (1326m) to 4,151ft (1265m) MDBRT. The section milled would be across a naturally sealing formation in the Muschelkalk Halite (4351ft to 3991ft) - this may be altered in order to optimise the well abandonment. CO_2 resistant cement would not be planned to go behind the 9⅝in casing therefore the cement would have to be milled back to formation wall.

There are several methods that could be used as a base for plug #2, for example a cement retainer or a VRP. The base for plug #2 will either be set inside the 9⅝in casing or in the open hole depending on the method selected. The base for plug #2 would not be considered a barrier to the well.

Plug #2 4,351ft – 3,851ft

A 16.0ppg CO_2 resistant cement plug would be set from 4,351ft to 3,851ft (1173m) (length 500ft) to act as the secondary barrier to the Bunter sand. The casing is milled in order to remove the potential of casing corrosion and cement plug #2 set in the event of possible CO_2 migration through cement plug #1. Plug #2 is located across the naturally sealing formation in Muschelkalk Halite.

The plug would be verified with a 15klb tag, pressure test to 500psi above injection pressure.

5.1.2 Re-entry of Previously Abandoned Wells

If remediation work would be required on the pre-existing wells then the flow diagram shown a Figure 5.3 below, provides a possible three phased approached to re-enter and re-abandon the wells. The phases are detailed at a high level, with each phase presenting many risks and hazards, which could halt the re-entry and re-abandonment. The three phases are:

First Phase – Locating & Survey Phase: Involves mobilising a survey vessel, physically locating the wells, performing a geotechnical investigation and thereby determining an appropriate method of excavation.

Second Phase – Evaluation Phase: Involves exposing the 30in conductor (current status: approximately 10ft below seabed in both wells) and dressing it, as well as investigating the status of the 13⅜in string and the relevant annuli. The inclination of the conductor from vertical should also be checked. Additionally, if possible then the installation of a cofferdam/retaining system and protective structure around the 30in pipe should be considered at this stage to reduce the risks at phase 3 of the process.

Third Phase – Rig Phase: Selection of an appropriate method of re-entering the well - the two main options being either a mudline re-entry whereby an environmental and pressure containment envelope to surface would be re-established, or an intersection well, making use of relief well techniques, to intersect the existing wellbores at the 13⅜in surface casing.

Figure 5.2: Injection Well Abandonment - Option B

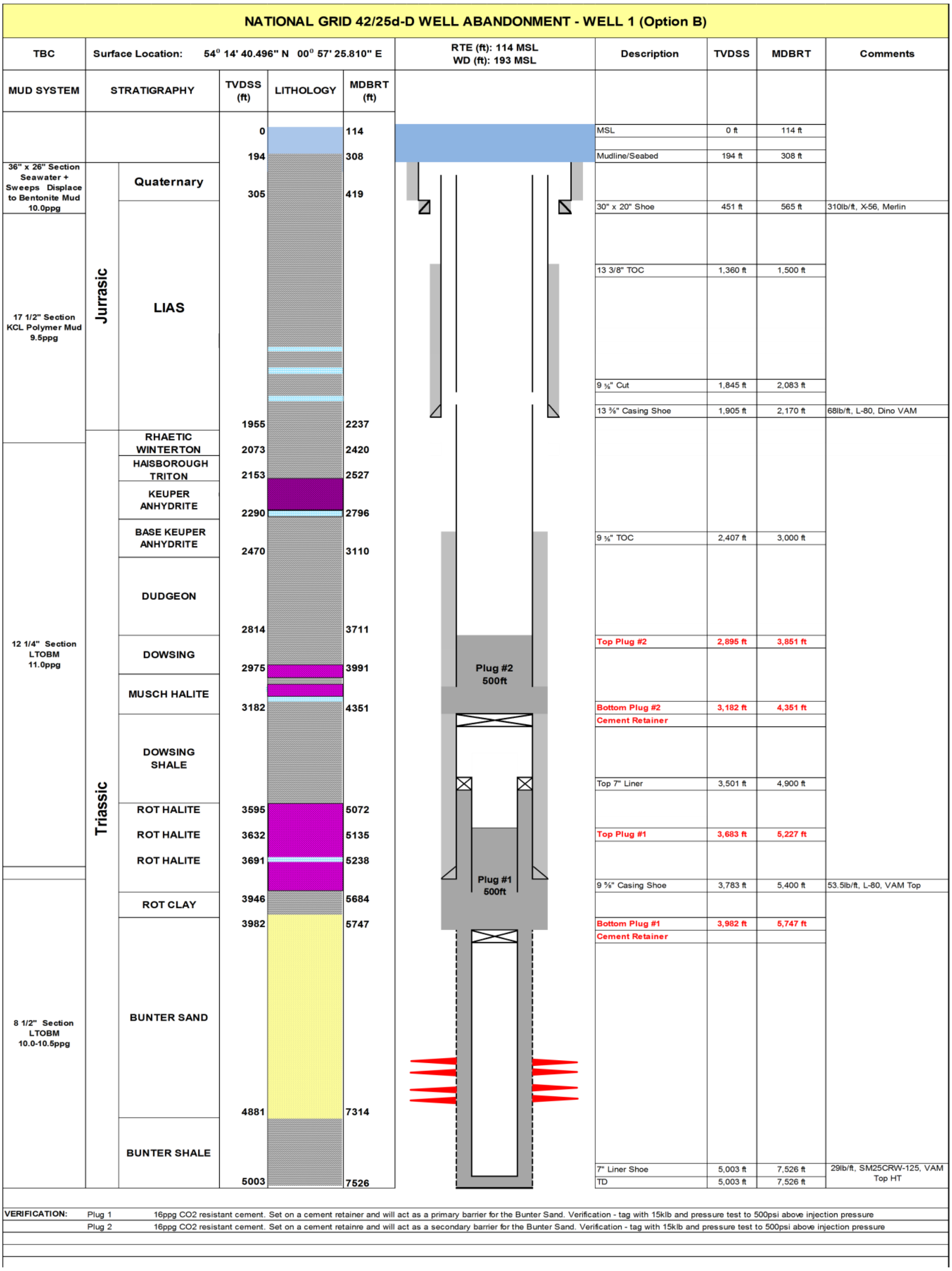
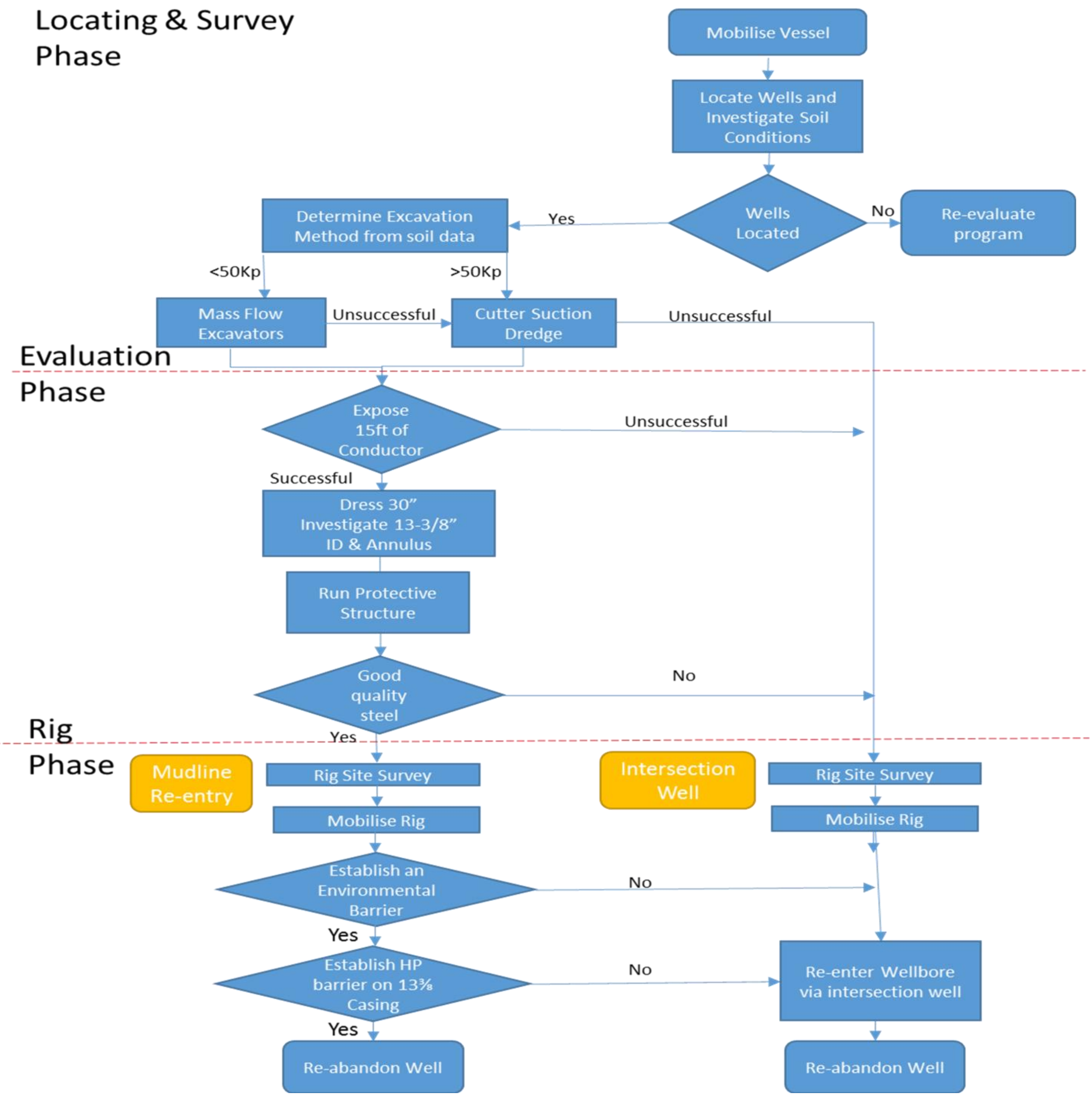


Figure 5.3: Re-entry and Re-abandonment Flow Diagram



5.1.2.1 Potential Re-entry and Re-abandonment Hazards

Many hazards have been identified with the re-entry and re-abandonment of the pre-existing wells. A detailed risk assessment would have to be conducted, ensuring that well specific risks were considered for each individual well.

The hazards have been categorised as Environmental, Pressure Containment and Open Hole Hazards.

5.1.2.2 Environmental Hazards

Shallow gas – has not been noted in the end of well reports for the pre-existing wells and none of the close offsets have encountered shallow gas.

Seabed conditions – would have to be considered when selecting and positioning the rig on location and the excavation method required.

Sediment and cement – conditions are unknown at each well location, therefore the excavation method maybe insufficient for the shear strength of the sediment/cement lenses.

Sand waves – were observed on the 42/25-3 well, therefore sand waves may have to be excavated in addition to the excavation required to expose the conductor.

Currents /tides – in the southern North Sea may affect the visibility while conducting ROV / diving operations and stabbing into the well. They could also impact the excavation and maybe cause the hole to re-fill.

Excavation refill – may occur naturally if the sediment around the conductor is soft.

Verticality of 30in conductor – is unknown and in the period during which the wells were drilled the criteria applied to the wells may not have been specified to vary by less than 1° (one degree) from vertical. The 43/21-1 well was also drilled from a Semi-submersible therefore the verticality could be worse than the 42/25-1 well drilled with a jack-up. This in turn may cause issues centralising over the 30in conductor and greater loads on it may be encountered.

Condition of 30in conductor – highlights several concerns such as the quality of the cut, corrosion / wall thickness, the shape (oval/circular) and if there are holes, scars, welds and couplings therefore limiting the capabilities to seal on to the 30in conductor and also to support an environmental barrier to surface.

Cement sheath – around the 30in conductor may limit the sealing capabilities and if present then it may be difficult to remove the cement from the conductor.

Environmental barrier – would have to pass analysis with environmental conditions applied and ensure environmental loads would not be encountered on the internal re-connect method if utilised.

5.1.2.3 Pressure Containment Hazards

Condition of 13⅜in casing – is unknown and corrosion is likely. In order to re-enter and re-abandon the wells, a pressure test of approximately 1,500psi would have to be applied to the 13⅜in casing depending on the re-entry method selected. It is also possible that the 13⅜in casing may have collapsed.

Casing tallies – are not available therefore casing connections must be taken into consideration if selecting external reconnection methods on the 13⅜in casing.

Plug placement – is only known for plug #2 on both wells as they were the only plugs tagged. There is no guarantee that the other plugs are placed as stated in the well abandonment diagrams therefore care should be taken if remediation work is required with the requirement to drill out the cement plugs.

Pressure containment / well control – to surface would have to be established prior to drilling into a potentially over pressured area, for example below plug #3.

Reservoir conditions – at present are normally pressured. If remediation were required, it would be preferable to complete this prior to injection to ensure a secure store.

OBM - is recorded as being beneath the plug #3 and #2 on the 42/25-1 well and therefore containment would be required to prevent environmental damage. The drilling contractor may have concerns if pressure containment has not been confirmed.

Internal excavation – of the 30in and 13⅜in strings may be required to expose the cut in order to assess what remedial work is necessary.

13⅜in annular cement - is stated as being to surface on 43/21-1 well, therefore depending on the re-connect method, an attempt to remove the annular cement maybe required.

13⅜in casing cut – is recorded as being cut 21ft (6.4m) and 11ft (3.3m) below seabed on the 43/21-1 well. This may present an issue due to the requirement to have pressure containment and the potential re-connection method.

5.1.2.4 Open Hole Hazards

Open hole collapse – would be expected due to the formation overburden pressure and formations type, for example mobile salts (Rot Halite and Muschelkalk).

Open hole mud – conditions are likely to have deteriorated due to the wells being drilled 25 and 45years ago and being located in open hole. The OBM 11.8ppg would have separated into each phase: base oil, water and barite.

Over pressure below plug – could be present due to the degradation of the mud system and therefore potentially resulting in the presence of gas, causing over pressure, although it is noted that no hydrocarbon gas is expected to be present at the crest of the structure.

Plug #2 – is set in cased and open hole and if attempting to drill the open hole section in order to re-enter the existing open hole then the drill out assembly may kick off prior to drilling out plug #2, therefore, re-entry in to the existing hole would be unlikely.

Plug #1 – is set in 12¼in open hole therefore the probability of tagging the existing plug is unlikely in the event that the hole has collapsed, due to the requirement to follow the original wellpath.

In addition to the above mentioned hazards there may be operational risks associated with the specific methods which may be employed.

5.1.3 Re-entry Pressure Test Requirements

Information from the 42/25d-3 well provided a pore pressure of 9.2ppg in the Bunter Sandstone. RFT pressures from the 42/25-1 indicate normal formation pressure although a maximum pore pressure of 9.8ppg (equivalent of salt saturated water at reservoir pressure & temperature) was stated in the 42/25d-C Appraisal Well PDDP. A 9.8ppg pore pressure in the Bunter sandstone will be used for worst case scenario. The pressure of the Bunter shale below the Bunter sand is thought to be normally pressured.

The majority of offset wells in the area provide fracture pressure data from the Lias formation with one well setting casing in the Triton. The Lias offset shows FITs were achieved from 14.9ppg to 16.4ppg EMW. The 42/25d-3 appraisal well was the only offset well to perform an FIT in the Rot Halite, achieving a 14.0ppg EMW.

The 42/25d-3 well targeted a saline aquifer, which offsets wells have proven that no hydrocarbons are present. The convention to calculate maximum predicted surface pressure for a well is using a gas gradient to surface. Using this methodology the potential surface pressure calculated using a gas gradient from the Bunter Sandstone @ 3,659ft MDBRT (42/25-1) is as follows:

Formation Pressure	= 9.80ppg x 3,659ft x 0.052
	= 1,864psi
Gas gradient of 0.1psi/ft x 3,659ft	= 366psi
Surface Pressure	= 1,864psi – 366psi
	= 1,498psi

If remediation work was conducted and cased hole plugs set, the following assumptions have been made in order to calculate the maximum pressure test:

- 42/25-1 Casing shoe at 1827ft MDBRT (1711ft TVDSS) FIT to 14.3ppg;
- no FIT / LOT data available for the 43/21-1 well;
- maximum injection pressure, 42/30-8 well: 16.4ppg at 1,640ft TVDSS in Lias formation.;
- wellbore fluid: seawater 8.6ppg (maximum pressure differential);
- assumed top of plug 170ft inside the 13 3/8in; and
- mud degradation pressure has not been considered.

Maximum Injection pressure + 500psi	= (16.4ppg x 1,827ft x 0.052) + 500psi
	= 1558psi + 500psi
	= 2,058psi
Internal pressure with sea water	= 8.6ppg x (1,827ft-170ft) x 0.052
	= 821psi

Pressure Test = 2,058psi – 821psi

= 1,237psi

Therefore the maximum pressure test required on the 13 3/8in casing is ± 1,500psi, with gas gradient to surface from the Bunter Sandstone at 3,659ft (1115m) MDBRT. This should be reviewed during detailed design to identify if there is any scope for reduction in the pressure, to reduce the load on the re-establishment equipment.

5.1.4 Locating Wells

The 43/21-1 and 42/25-1 well locations were detailed in the historical information as per the European Datum 1950 International Ellipsoid and UTM Grid Zone 31N (3° East). Refer to Table 5.1, Pre-existing well location.

The well positions are known but due to the technology used, the accuracy of the original well positions are less than GPS radial uncertainty of 1.5-3m (95% confidence levels) used today. It is likely the 1970 well would have used a Hi-fix and sextant and at 95% confidence levels which puts the radial uncertainty at 50-300m (164ft – 984ft). The 1990 well would have probably used Syledis radio navigation, at 95% confidence levels the radial uncertainty is 15-30m (49ft – 98ft).

Table 5.1: Pre-existing Well Location - Historical Data

Historical data		
43/21-1		
UTM Coordinates:	6 009 594.7mN	369 928.7mE
Latitude / Longitude:	54^0 13' 00.000in N	001^0 00' 18.998in E
Water Depth	191ft MSL	
42/25-1		
UTM Coordinates:	6 011 028.9mN	368 296.4mE
Latitude / Longitude:	54^0 13' 44.869in N	000^0 58' 46.679in E
Water Depth	202ft MSL	

Although the conductor and casing (310lb.ft conductor and 68lb.ft casing) have been cut below the mudline it is possible to detect all sizes of ferrous objects and any other object with magnetic expression using magnetometers. A magnetometer investigation was undertaken by Gardline Geosurvey, in 2012 which successfully located the wells with the following well co-ordinates recorded. Refer to Table 5.2.

Table 5.2: Pre-existing Well Location - Magnetometer Survey 2012

Gardline, Magnetometer Survey		
43/21-1		
UTM Coordinates:	6 009 623mN	369 963mE
Latitude / Longitude:	54^0 13' 00.943in N	001^0 00' 20.846in E
Water Depth	189ft MSL	
Distance and direction from UKDeal position	44m (144ft) NE	
The interpreted position of the abandoned 43/21-1 well has been derived using magnetometer data only; the well was not		

Gardline, Magnetometer Survey		
observed on bathymetry, sidescan sonar or pinger data.		
42/25-1		
UTM Coordinates:	6 011 024mN	368 306mE
Latitude / Longitude:	54^0 13' 44.720in N	000^0 58' 47.216in E
Water Depth	202ft MSL	
Distance and direction from UKDeal position	11m (36ft) ESE	
The interpreted position of the abandoned 42/25-1 well has been derived using magnetometer data only; the well was not observed on bathymetry, sidescan sonar or pinger data.		

Although the wells have been located and the accuracy on the wells is potentially within 1.5-3m of the stated location, the wells are still situated approximately 10ft (3m) below the mudline.

In order to gain information about the well locations, it would be prudent to mobilise a vessel to conducted investigation work at the locations. When the well is detected an intrusive geotechnical site investigation (e.g. bore hole combined with sampling, cone penetrometer testing and rock coring) will determine methods that can be used for future excavation and re-entry. Specific hazards and risk can also be determined and the potential impact it may have on future remediation work. For example Bathymetry charts Figure 5.4 and Figure 5.5 are available below which may highlight potential rig positioning issues.

Figure 5.4: 43/21-1 Bathymetry Chart

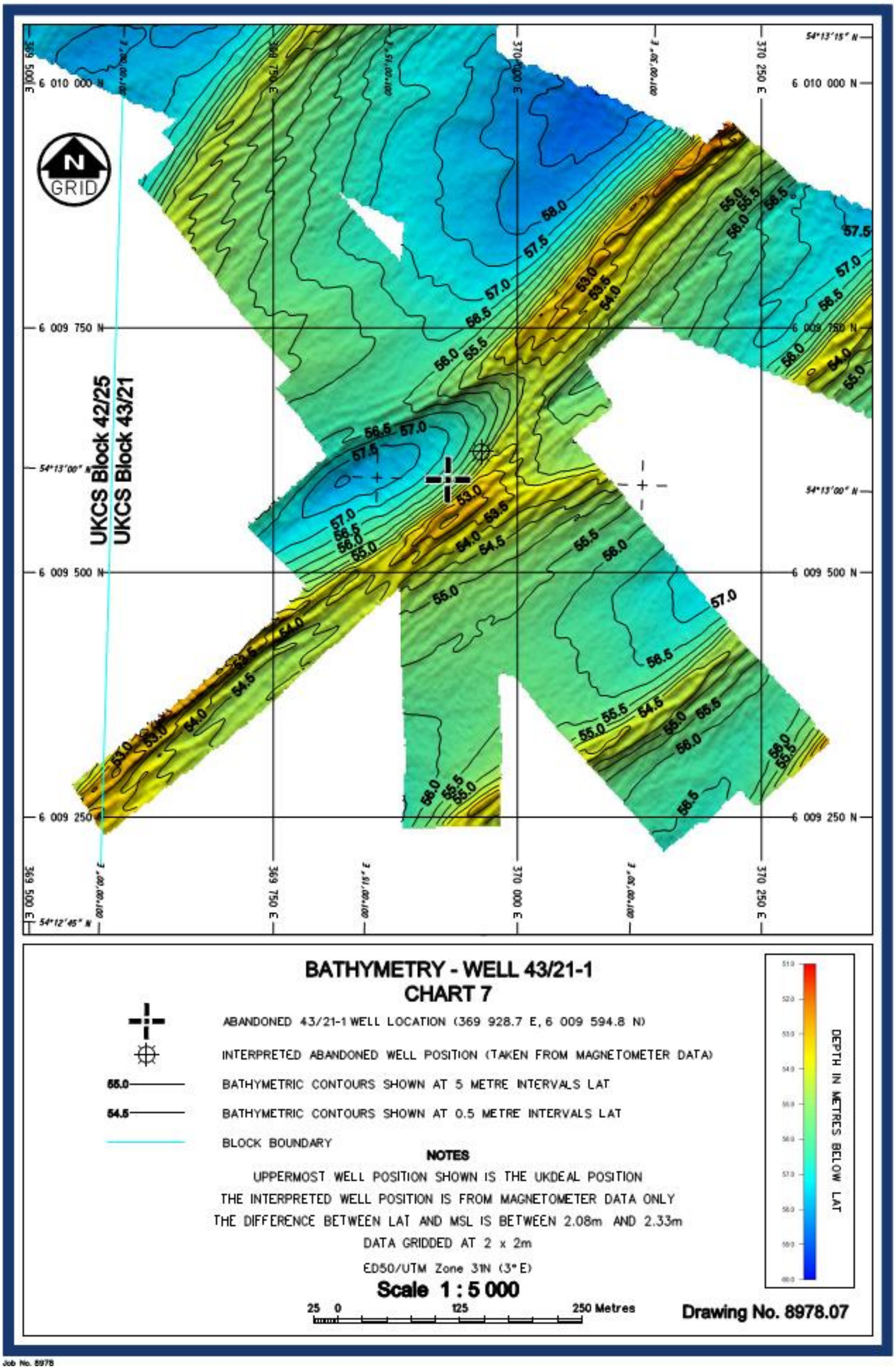
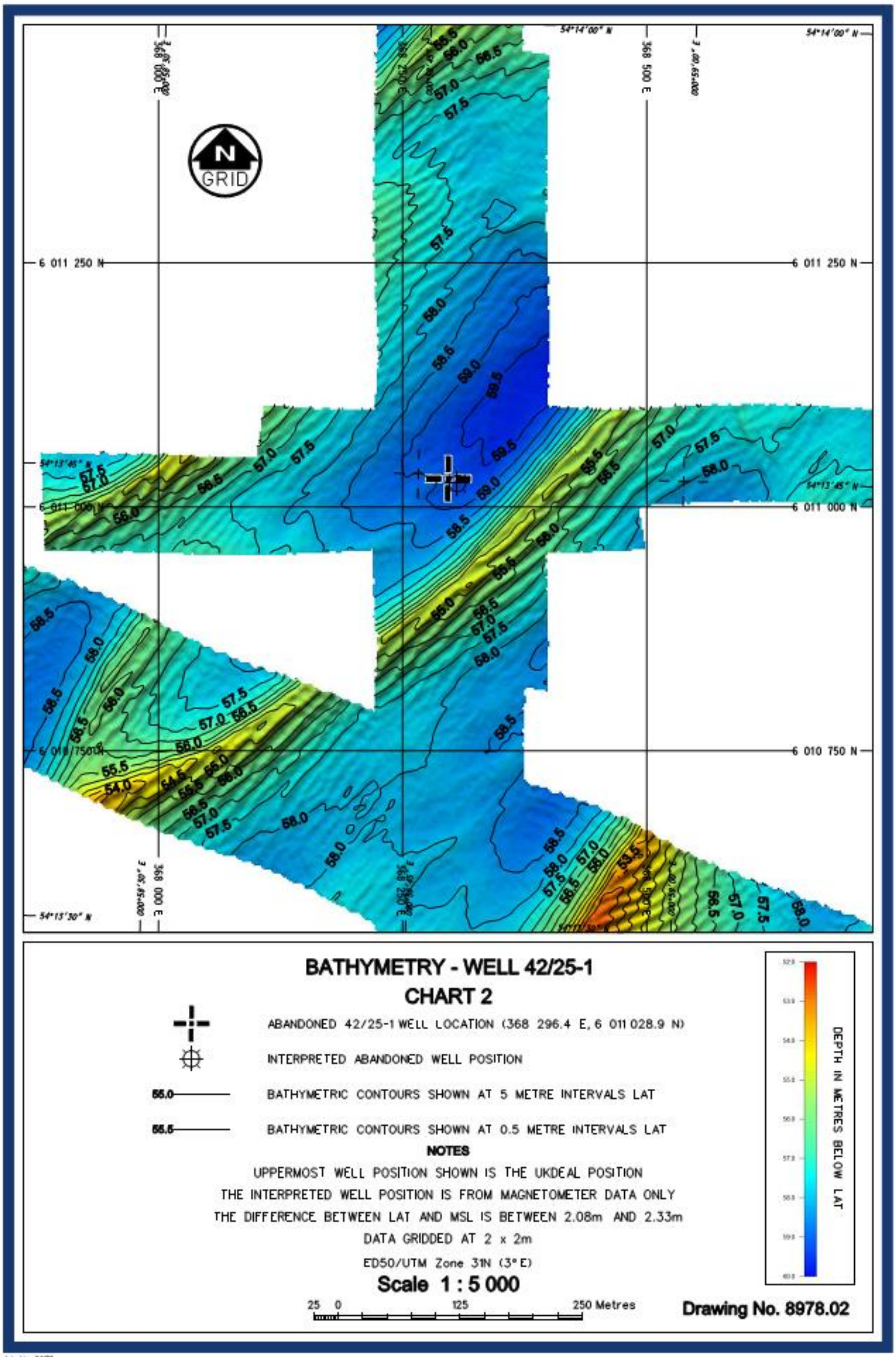


Figure 5.5: 42/25-1 Bathymetry Chart



5.1.5 Remediation Methods

The phased approach as stated above would be advisable in order to establish the most suitable options available. Many options presented below are conceptual and further detailed design would be required.

5.1.6 Excavation methods

At present the only soil data available is that from the 2013 site survey. The site survey was conducted for the 42/25d-3 well located approximately 6.6km and 8.7km from the 42/25-1 and 43/21-1 wells respectively.

The 2013 site survey detailed shear strength around 100kPA to a maximum of 400kPA, this gives an indication of soil strength but is not a true representation of the near soil data around the 30in conductor. Consideration must be given to the fact that drilling activity (weakens the natural formation strength) has been conducted previously and 30in cemented in place (extrusion of cement creating cement lenses is possible).

The depth and diameter of excavation has not been established at this stage due to the uncertainty of soil conditions and the method to reconnect to the existing well, therefore the methods stated below may only be suitable for aspects of the excavation.

The methods which have been considered are Mass Flow Excavators (MFE) and cutter suction dredges. MFE are limited to soils with shear strength less than 50kPa but if jetting nozzles are added they can cut up to around 120kPa clays. However to evacuate these soils from a hole for example 25ft would be challenging using MFE.

A cutter suction dredge is recommended for clay up to 110kPa -200kPa although in the event of the potential maximum shear strength stated in the 2013 survey this would be challenging. The soil removal rates for MFE and suction dredging would depend on the soil strength and area therefore no time estimates can be provided at this time.

Both systems may be utilised during the project phases although care must be taken when selecting the size of unit due to the method it can be mobilised whether from a DP vessel or rig.

During the evaluation phase of the well, after the 30in conductor has been exposed it would be recommend to install a retaining structure in order to minimise the requirement to re-excavate the location and if necessary an overtrawlable structure may be required to deflect any fishing nets to prevent snag loading.

5.1.7 External Sealing Methods

The methods described below have the potential to provide means to seal externally on the 30in conductor or utilise the seabed to provide structural integrity which would enable a riser to be run from seabed to surface absorbing the environmental loads. This would enable a suitable internal pressure containment string to be run prior to drilling out the cement plugs.

5.1.7.1 30in Hydraulic / Mechanical Overshot - Claxton

At present Claxton have utilised a 20in Hydraulic / Mechanical Overshot which as a self-centralising mechanism using weight activated collets and hydraulically operated slips to enable the connector to grip the conductor/pipe and lock onto it.

Unfortunately a Functional Design Specification (FDS) is only available for a 30 inch Hydraulic / Mechanical Overshot which was designed to lock onto a Lynx HD connection shoulder. An overshot system would enable an environmental conduit to surface and could be swedged to 20in riser which would minimise the loads transferred to the 30in conductor rather than a 30in riser to surface.

The 43/21-1 and 42/25-1 conductors and connections are 30in 309lb/ft, B, 1inWT welded and 30in 310 / 451lb/ft, X52, H-90 respectively.

Figure 5.6: Claxton Conceptual 30in Overshot

If the overshot (Figure 5.6) was utilised, the welded pipe connections may be able to withstand tensile loads, but not bending or fatigue loads. Dril-Quip H90 connection on the 42/25-1 well is likely to be box up therefore it may be possible to lock onto the connection shoulder. This connection uses an anti-rotation device which prevents the connection backing out or over torqueing when subjected to torsional forces or impact loads. The conductor tally is unavailable therefore the connection/weld depths are unknown and quality of the welded connection on the 43/21-1 well cannot be verified.

Cement sheath on the 30in may also hamper the attempt to connect to the 30in although there is uncertainty about the cement bond on the 30in conductor.

Claxton were confident that an overshot design with a suitable locking mechanism could be created in order to meet the project requirements. It was highlighted that the condition of the existing 30in conductor would be detrimental to the loads that could be applied to the environmental riser and overshot along with the surface condition may also affect sealing.

Environmental data would determine the minimum requirements applied to the riser and the overshot. In order to minimise the load conditions it would be recommended to conduct remediation work in the summer months and a limited duration for example 2 months.

5.1.7.2 Inflatable Design – Sudelac

Sudelac are working in conjunction with Inflatable Packers International (IPI) to investigate inflatable packer design concepts. The following concepts have been investigated:

- 23 7/8in inflatable packer (internal to 30in);
- 23 7/8in packer (internal to 30in) with a 13 3/8in overshot (external to 13 3/8in); and
- 23 7/8in packer (internal to 30in) with a 13 3/8in external packer.

Control lines would be utilised to inflate the packers with fluid and in order that the packers can be removed from the well it is also possible to deflate the packers. The packers are not off the shelf items and can be designed to suit a specific application.

IPI's inflatable packer technology has many advantages for the rapid development of custom made applications. Packers:

- can have several layers of reinforcement;
- can have a customised ID and OD;
- can use a variety of elastomers;
- can be readily modified for specific inflation formats (e.g. to a physical OD limit) and/or include inserts for injection or sampling;
- can be inward inflating, suitable for applications such as inflatable seals; and
- are designed by experienced and qualified engineers using IPI proprietary CAD software, which accurately defines the pressure / expansion envelope for that design.

5.1.7.3 Driving Conductor – Conductor Installation Services Ltd (CIS)

If the structural integrity of the 30in was considered to be doubtful after investigation one of the methods considered was to drive a larger conductor over the pre-existing 30in conductor. This could potentially remove the requirement to latch onto the 30in therefore eliminating the requirement for the pre-existing 30in conductor to withstand the environmental loads.

While discussing this possible option with CIS several concerns were raised such as the centralisation over the original conductor and the potential damage which may be incurred. The other main concern was that the original conductor was drilled and cemented therefore it would not be possible to conduct a drive study which would provide a depth penetration. If depth penetration is not guaranteed it may not be possible to drive the conductor to a sufficient depth in order to provide structural support to surface taking the environmental loads into consideration.

CIS also have experience with subsea piling for example, pipeline initiation piles (30-36in) and mooring piles. If a large pile was required it would not be viable to run it through the rotary on a drilling rig therefore a vessel would be required. A piling frame (24in-48in) can be mobilised from a vessel in order to provide support while piling but a similar concern was raised due to the uncertainty of shallow cement lenses and the success of piling to a sufficient depth in order to gain structural integrity.

Unfortunately due to the information available at present CIS advised that they were unable to provide a viable solution that could work safely.

5.1.7.4 Conductor Anchor Node (CAN) – NeoDrill

The CAN technology was stated as being the most promising means to re-connect to the wells. For conventional applications (CAN installed prior to well spud) a standardised 6m diameter is used with a varying length, typically between 8 and 12m depending on the soil conditions.

A specialised CAN, called a Wellhead Support Structure (WSS) is used for installation over an existing wellhead, with the dimensions of this structure highly dependent on:

- the required load capacity (axial, lateral and overturning);
- a drilled and cemented conductor installation the diameter may need to be increased in order so that there is no conflict with the cement around the conductor (from mudline down to the WSS skirt tip); and
- for specialised cases the diameter can be increased to 8m and more if necessary.

The WSS has similar limitations to driving conductor with regard to soil conditions and mobilisation techniques. Generally suction anchors are suitable for use in clay formations, but installation is also possible in sandy seabed conditions. It is more complicated when mixed layers are encountered for the WSS penetration depth.

A WSS would require installation by a vessel due to the drilling rig being unable to handle and run a structure as large as the WSS.

Centralisation and verticality may also be an issue due to shallow soils, but the existing conductor is also not guaranteed to be vertical therefore potentially emphasising misalignment when connecting the riser and also re-entering the 13 3/8in casing. In order to align the WSS a stabbing guide could be jetted into the 13 3/8in casing but this would restrict the options available in order to establish a pressure containing barrier to surface.

There are several other issues that need to be considered such as the method to connect the WSS to surface ensuring integrity and environmental seal. If the WSS is placed over the 30in it will remove the visibility to the 30in and 13 3/8in casing. In the event that there is pressure within the WSS it is likely to pump out. Therefore due to the points above and in particular the soil strength, it may be unlikely that this method can be used.

5.1.7.5 Riser

Riser analysis would normally be conducted to confirm suitability of the riser from seabed to surface. It would also provide an estimate of the loadings in the existing conductor below the seabed.

A smaller outside diameter riser would likely minimise the loads on the existing 30in conductor but still allow adequate access into the well. A 20in riser could potentially be used and swaged at the bottom in the event that a 30in external method is used to obtain an environmental barrier.

If smaller OD risers are to be utilised, consideration must be given to the strength of the connection when environmental loads are applied. Many casing connections are not designed to withstand these loads although a VAM TOP FE (Fatigue Enhanced) is available in typical sizes 9 5/8in, 13 3/8in and 16in and grades L-80 and P-110. Specific analysis would be required in order to establish the life of connection on the pre-existing wells.

At this time no analysis has been undertaken due to the limited input data. Due to the uncertainty of the condition of the 30in conductor pipe body and welds below seabed it may be difficult to quantify the risk of failure of the old conductor. It is likely that any analysis company would not accept any liability for results relating to the existing conductor. To this end, it may be advisable to devise another means of taking the riser structural loads.

5.1.8 Internal Sealing Method

The methods described below rely on a riser from seabed to surface absorbing the environmental loads in order to run an internal pressure containing string prior to drilling out plug #3 entirely on both wells. This will enable a secondary barrier to be utilised in the event of encountering overpressure below the plug. The method selected to reconnect to the existing casing will only be required to support the tension from reconnect at mudline to surface (based on a jack-up).

5.1.8.1 13 3/8in casing overshot – META

The META casing re-connect uses metalmorphology technology which morphs the metal to conform to the casing. This solution would be external to the 13 3/8in casing and can be conducted in one trip. The connection provides a gas tight seal and has axial loading capabilities. The 13 3/8in casing would be dressed prior to running the re-connect which has approximately 13ft swallow. There are no ID restrictions using the casing reconnect although there are several factors which could restrict the use of this method such as:

- the presence of cement in the 30in x 13 3/8in annulus;
- the tolerances and quality (corrosion) of existing 13 3/8in casing; and
- casing connections.

Figure 5.7: Casing Re-connect Operational Sequence

Casing cut and dressed. Casing Reconnect spaced out with new casing which is set in surface hanger	Setting tool positioned on depth (integrated latch mechanism)	Hydraulic pressure supplied, monitored and controlled from surface	Setting tool recovered to surface, leaving a metal-to-metal, gas tight connection

5.1.8.2 Internal Clad - META

The internal clad is based on a similar principle as the casing re-connect utilising the metalmorphology technology. The clad is run inside the existing 13 3/8in casing and provides a gas tight seal and supports bi–directional loading. The clad length is typically 8-16ft although longer clads can be provided. As per the Table 5.3 below the clad ensures a minimal loss of ID (approximately 0.54-0.6in) therefore allowing the maximum through bore to be achieved. The internal clad can be run on drill pipe, wireline and coil tubing.

Table 5.3: Technical Data Summary

Technical data summary

Casing Size	Tubing Weight	OD Pre-Morph	ID Pre-Morph	ID Post-Morph	Internal Pressure	External Pressure
4 1/2"	9.5 11.6 12.6	3.740"	3.150"	3.500" 3.410" 3.368"	5500	3000
5"	15 18 21.4 23.2 24.1	3.740"	3.150"	3.810" 3.680" 3.540" 3.450" 3.410"	5500	3000
5 1/2"	14 15.5 17 20 23	4.256"	3.822"	4.594" 4.515" 4.458" 4.436" 4.235"	4500	2000
7"	29 32	5.827"	5.118"	5.475" 5.585"	5000	2000
9 5/8"	40 47 53.5	8.250"	7.560"	8.135" 7.991" 7.845"	2500	2000
9 7/8"	62.8 66.4	8.250"	7.560"	7.935" 7.863"	2500	2000
13 3/8"	68 72	12.106" 12.106"	11.256" 11.256"	11.565" 11.497"	3500	1500
13 5/8"	88.2	12.106"	11.256"	11.493"	3500	1500

Additional base casing sizing and weights, as well as a combination of casing weights, may be accommodated on a case by case basis. Please contact your Meta representative for more information.

The casing could be calipered to establish the ID of the 13 3/8in casing prior to running any internal re-connect. The condition of the casing will determine the sealing properties of connection. The top of plug #3 has been stated in the information provided and the 13 3/8in casing has been cut above plug#3 in both wells, The distance between top of plug #3 and cut in the 43/21-1 well is approximately 65ft (19.8m) and the 42/25-1 30ft (9.1m). If required plug #3 could be partially drilled to establish a deeper re-connect prior to drilling out the remainder of plug #3.

5.1.8.3 Internal Casing Running

A string of casing could be run inside the 13 3/8in existing string and cemented in place. This would require sufficient casing to be cemented inside the 13 3/8in in order to provide structural support. To provide a larger sealing surface it may be possible to partially drill out plug #3 prior to establishing pressure containment.

A smaller string of casing would be required to be run inside the 13 3/8in 68lb/ft (ID 12.415in) and 13 3/8in 54.5lb/ft (ID 12.615in). The diameter of the drill out assembly would be restricted and if essential an under reamer would be required to drill the necessary hole diameter.

Consideration would have to be given to internal casing OD to ensure sufficient clearance to provide an effective cement bond.

5.1.8.4 External Casing Packer – Baker

An External Casing Packer (ECP) is run externally on an inner string for example 9 5/8in with the packer OD of 11.25in and utilises cement as the inflation method. The string would be run inside the existing 13 3/8in casing therefore restricting the ID of the top section of the well. There are two seal length options, 20ft and 40ft, although there is no anchor to the 13 3/8in. This option would restrict the ID of the top section of the well.

This method is not considered to be favourable due to the requirement to pull tension on the packer; therefore it should be negated from any potential remedial action.

5.1.8.5 Bowen Packer Type Casing Patch - NOV

The NOV Bowen Packer type casing patch could also be utilised. It is an external casing patch which would be run over the 13 3/8in casing and uses an engagement method which provides a positive engagement and positive seal-off in both directions. The casing patch relies on free casing in order to apply tension to ensure the grapple sets. This method ensures there is no ID restriction although annular cement may be an issue due to the requirement to the casing patch externally.

Figure 5.8: NOV Casing Patch

6 Glossary

Abbreviation	Meaning or Explanation
ADTI	Applied Drilling Technology International Ltd. Well Engineering Project Management Sub-Contractor
AIT	Array Induction Imager Tool - provides formation resistivities at multiple depths of investigation in freshwater and oil-based drilling mud systems. It gives detailed analysis of formation resistivity (Rt), flushed zone resistivity (Rxo) and depth of invasion.
ALTUS	Liquid Nitrogen Vendor
API	American Petroleum Institute
Ar	Argon
Baker Hughes	Oilfield services vendor
Bar	Metric unit of pressure
barg	Unit of pressure. The g denotes gauge pressure.
bbl	Barrel (oilfield unit of volume measurement).
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
°C	Temperature in degrees Celsius
CA	Competent Authority
CAN	Conductor Anchor Node
CaTS	Cableless Telemetry System
CBL	Cement Bond Log
'C' factor	An indication of erosion potential (inside the completion)
CCS	Carbon Capture and Storage
CIS	Conductor Installation Services
CMR	Combinable Magnetic Resonance Tool - enables the measurement of important reservoir parameters not measured by conventional logs: permeability, producible fluid type and irreducible water saturation.
CNL	Compensated Neutron Log - makes thermal and epithermal neutron measurements to calculate porosity and identify lithology and the presence of gas.
CO_2	Carbon Dioxide
CPL	Capture Power Limited
CRA	Corrosion Resistant Alloy
CRT	Critical
CST	Cement Support Tool
CT	Coiled Tubing
DAS	Distributed Acoustic Sensing
dbrt	depth blow rotary table
DECC	the UK Government's Department of Energy and Climate Change
DHPG	Downhole Permanent Gauge

Abbreviation	Meaning or Explanation
DHPT	Downhole pressure and temperature gauge
DHSV	Down Hole Safety Valve
DNV	Det Norske Veritas
DRACAS	Data Recording and Corrective Action System
DRAX	National Grid's planned CO_2 emitting power station.
DST	Drillstem Test
DTS	Distributed Temperature Sensing
EBD	National Grid's European Business Development group.
EC GD	European Commission Guidance Document
ECD	Equivalent Circulating Density
ECP	External Casing Packer
ECS	Elemental Capture Spectroscopy - provides volume measurements of carbonate, quartz, feldspar, mica and clay volume.
EM	Electromagnetic
EMW	Equivalent Mud Weight
EOR	Enhanced Oil Recovery
EOWR	End of Well Report
EPC	Engineer, Procure and Construct
EPCm	EPC management
ERT	Electrical Resistivity Tomography
ESP	Electric Submersible Pump
°F	Fahrenheit
F6NM	American Society for Testing and Materials classification for a specific grade of stainless steel
FDS	Functional Design Specification
FEED Contract	Front End Engineering Design Contract made between DECC and CPL pursuant to which WR Project FEED (as defined) will be performed.
FIT	Formation Integrity Test
FLS	F type Cameron gate valve
FPSO	Floating Production Storage and Offloading
FS	Full Scale
ft	Feet (Imperial unit of length, height and depth).
GPS	Global Positioning System
GWD	Gyro While Drilling
H_2O	Water
H_2S	Hydrogen Sulphide.
HNGS	Highly-integrated Neutron Gamma-ray Sonde – Measures natural gamma-ray activity in the borehole. Can assist in locating fracture zones, identifying the lithology of subsurface formations, measuring bed thickness, correlating zones of

Abbreviation	Meaning or Explanation
	interest between wells and making qualitative estimates of formation permeability.
HPU	High Power Unit
HRLA	High Resolution Laterolog Array Tool - provides formation resistivities at multiple depths of investigation in conductive, water-based drilling mud systems. It gives detailed analysis of formation resistivity (Rt), flushed zone resistivity (Rxo) and depth of invasion.
IBC	Intermediate bulk container
ICD	Inflow Control Devices
ID	Internal Diameter
in	Inch (Imperial unit) sometimes shown as **”.**
IPI	Inflatable Packer International
IR	Infrared
KG/M^2	Unit Of Mass per unit area. Kilogrammes per square metre.
KCl	Potassium Chloride
kips	Pounds Force (thousands)
km	Kilometres
kN	Kilonewton – measure of force
ksi	As kps (thousand pounds per square inch), but used when referring to material properties.
LAT	Lowest Astronomical Tide or Latitude
lbs	Pounds Force
Lbs/ft	Pounds per foot
LCM	Lost Circulation Material
LONG	Longitude
LOT	Leak Off Test
LPU	Low Pressure Unit
LTOBM	Low Toxicity Oil-based Mud
LWD	Logging While Drilling
M to M	Metal to metal. As in sealing
m^3/d	Cubic metres per day.
mD	Millidarcy, units of permeability (not SI units)
MD	Measured depth
MD (RT)	Measured Depth (from Rotary Table)
MDBRT	Measured Depth Below Rotary Table
MDT	Schlumberger Modular (Formation) Dynamics Tester wireline tool.
MFCT	Multifingered calliper tool
MFE	Mass Flow Excavator
Micron	Unit of length. 1×10^{-6} of a metre

Abbreviation	Meaning or Explanation
MLS	Mud Line Suspension (wellhead) system
MMSCF	Million (metric) standard cubic feet
MMSCFD	million (metric) standard cubic feet per day
MMV	Measurement, Monitoring and Verification
MNU	Membrane Nitrogen Unit
MODU	Mobile Offshore Drilling Unit
MRT	Mean Repair Time
MSL	Mean Sea Level
MT	Metric Tonnes
MT/m^2	Metric tonne per meter squared
MTPA	Million Ton Per Annum
MTTF	Mean Time To Failure
MTTR	Mean Time To Repair (equal to MRT plus critical path lead time)
MWD	Measurement While Drilling
N_2	Nitrogen
NAS	National Aerospace Standards
NDIR	Non-Dispersive Infrared
NGC	National Grid Carbon Limited
NGC EPC Sub-contractors	Contractors providing an offer to develop a part of the WR T&S Assets in pursuance of the WR Development Project.
NGC FEED Sub-contractors	Contractors entering into a contract with NGC to carry out a part of the obligations under the KSC.
NGC KSC	Contract made between CPL and NGC pursuant to which that part of the WR Project FEED (as defined) which appertains to the WR T&S assets will be performed.
NGC KSC Deliverables	A number of documents and services, the delivery of which is a contractual obligation under the KSC.
NGC Technical Assurance Team	EBD team responsible for providing independent technical auditing and peer review services to the WR T&S FEED Project.
NGC WR Team	The NGC team established to meet the obligations in the KSC.
NPT	Non-Productive Time
NUI	Normally Unmanned Installation
O_2	Oxygen
OBM	Oil Based Mud
OBMI	Oil-Base Microimager – Provides detailed structural, sedimentological and petrophysical analysis using image data in wells drilled with oil-based mud.
P & IDs	Piping and Instrument Diagrams
PCE	Pressure control equipment
PDDP	Pre-Drill Data Package

Abbreviation	Meaning or Explanation
PDG	Permanent Downhole Gauge
perfs	
PEX	Platform Express – The logging system consists of the four standard major open hole measurements (resistivity, density, neutron, acoustic), plus auxiliary services.
PLT	Production Logging Tools
PM	Permanent Monitoring
POB	Personnel on-board (the number of people on-board a drilling rig in particular)
POOH	Pull Out Of Hole
PPC	Powered Positioning Calliper
Ppb	Part per billion
ppf	Pounds per foot (relating to tubing and casing weight)
ppge	(“mud weight equivalent” pressure unit)
ppg	Pounds per gallon (EMW)
ppm	Parts per million
PREN	Pitting Resistance Equivalent Number (corrosion resistance measure of a material)
PROSPER	A well performance, design and optimisation program for modelling most types of well configurations
psi	Pounds per square inch (Pressure)
RAM	Reliability, Availability and Maintainability
RFT	Repeat Formation Tester
RIH	Run in Hole
ROP	Rate of Penetration
ROV	Remote Operated Vehicle (referring to an unmanned submarine)
rpm	Revolutions Per Minute (rotational speed)
RPT	An industry accepted identifier for the internal profile of a ‘nipple’ (which is a short piece of pipe into which a plug can be located - usually by mechanical means, from a slick line)
RSS	Rotary Steerable System
RT	Running Tool
SACROC	Scurry Area Canyon Reef Operations Committee
SCC	Stress Corrosion Cracking
scf	Standard cubic feet
SCSSV	Surface Controlled Subsurface Safety Valve
Shallow gas	Any hydrocarbon gas bearing zone which may be encountered at a depth close to the surface.
SIMOPS	Simultaneous operations
SOBM	Synthetic Oil Based Mud

Abbreviation	Meaning or Explanation
SRO	Surface Read-Out
SSC	Sulphide Stress Cracking
SSSV	Sub Surface Safety Valve
stb	Stop Tank Barrel a volume as measured at normal temperature and pressure.
STP	Standard temperature and pressure
t	(tonne) metric unit of mass equivalent to 1000kg
TBC	To Be Confirmed
TCP	Tubing Conveyed Perforation
TD	Total Depth (referring to the ultimate depth of the well)
TDS	Top Drive System
TEC	Tubing Encased Conductor
THP	Tubing head pressure
TLD	Three-Detector Lithology Density
TOC	Top of Cement
TOL	Top of Liner
TRSSSV	Tubing Retrievable Sub Surface Safety Valve
TVD(SS)	True Vertical Depth of a point in a well, referenced to the seabed
TWC	Thick Wall Cylinder
UCS	Uniaxial Compressive Strength
UKCS	United Kingdom Continental Shelf
UMV	Christmas Tree Upper Master Valve
UTM	Universal Transverse Mercator
VDL	Variable Deck Load (of a drilling rig)
VR Plug	Valve Removal Plug. Threaded plug used to isolate valve for removal.
VRP	Viscous Reactive Pill
WBM	Water Based Mud
WOC	Wait on Cement
WOW	Wait On Weather
WR Assets	All those assets that would be developed pursuant to the WR Project
WR Development Project	A project to develop, operate and decommission the WR Assets which may transpire following the completion of the WR FEED Project.
WR FEED Project	Project to carry out a FEED (as defined in the FEED Contract) with regard to the WR Assets.
WR Project	White Rose CCS Project
WR T&S Assets	That part of the WR Assets which would carry out the carbon dioxide transportation and storage functions of the WR Project and to which the KSC Contract relates.
WR T&S FEED Project	The project to be pursued by NGC in order to meet its obligations under the NGC KSC.

Abbreviation	Meaning or Explanation
WRSSSV	Wireline Retrievable Sub Surface Safety Valve
WSS	Wellhead Support Structure
WV	Christmas Tree Wing Valve
“HH” trim	American Petroleum Institute rating for material service conditions
“K” Rated	American Petroleum Institute temperature rating for well equipment
“L” Rated	American Petroleum Institute temperature rating for well equipment
“M” Rated	American Petroleum Institute temperature rating for well equipment

7 Nomenclature and Jargon

term	meaning
bit balling	The fouling of a rotary drilling bit in sticky, gumbo-like shale which reduces the bits drilling efficiency
Christmas tree	This is the main assembly of valves that controls flow to the well and allows access for well interventions.
completion	Completion is the process of making a well ready for production (or injection). This principally involves preparing the bottom of the hole to the required specifications, running in the production tubing and its associated down hole tools as well as perforating and stimulating as required. Sometimes, the process of running in and cementing the casing is also included.
conductor	The Conductor Pipe is a large diameter pipe that is set into the ground to provide the initial stable structural foundation for a borehole or well
gumbo	Any of various fine-grained clays or silts which hydrate to form a firm clay/silt mass of material which may block flow lines and cause surface mud losses
well intervention	A well intervention is any operation carried out on the well during or at the end of its productive life, which alters the state of the well and/or well geometry, provides well diagnostics, or manages the production of the well.
ledges in drill holes	Ledges occur while drilling in formations which have sequential soft then hard layers and naturally fractured formations.
lithology	The description of the physical character of a rock as determined by eye or with a low-power magnifier and based on colour, structures, mineralogical components and grain size.
mud	A water or oil based suspension of chemicals pumped into a well during drilling in order to seal off porous rock layers, slightly overbalance formation pressure (maintain well control), cool the drill bit and flush out the cuttings.
overpull	Overpull is additional tension applied at surface to the drill string when attempting to free a stuck drill string.
Perfs	Perferations: in the context of oil wells refers to a hole punched in the casing or liner of an oil well to connect it to the reservoir. In cased hole completions, the well will be drilled down past the section of the formation desired for production and will have casing or a liner run in separating the formation from the well bore. The final stage of the completion will involve running in perforating guns, a string of shaped charges, down to the desired depth and firing them to perforate the casing or liner. A typical perforating gun can carry many dozens of charges.
pre-hydrated	Concentrated slurry of bentonite (an absorbent aluminium phyllosilicate) clay mixed in fresh water.
pill	A relatively small volume of specially prepared drilling or completion fluid placed or circulated in the wellbore for various reasons
properly abandoned	Abandoned in such a way to ensure that as far as is reasonably practicable, there can be no unplanned escape of fluids from the well.
wiper trip	This is where the bit is pulled back to the top of the open hole section and then ran back to TD to ensure the hole condition is stable.
reactive clay	In the drilling industry, clay is commonly referred to as reactive because, when hydrated, clay will swell, get sticky and potentially ball up around drill bits.
tagging	Lowering the drill bit and contacting the bottom of a well bore or a cement plug