Programme Area: Carbon Capture and Storage

Project: DECC Storage Appraisal

# Title: WP5D – Captain X Site Storage Development Plan


## Abstract:

Storage in the Captain Sandstone aquifer in UKCS quadrants 13 and 14 in the Central North Sea. 3 well, single stage development of Captain X Site from an unmanned platform, supplied with CO2 from St. Fergus via an existing 78km 16” pipeline. Ambitious programme to Final Investment Decision in 2018 and first injection in 2022. Capital investment of £152 million (PV10, 2015), equating to £2.5 for each tonne stored. The store can contain 60Mt from the 20 year CO2 supply profile at 3Mt/y. There is good subsurface data but further seismic investigation is required to understand plume development and shape the development plan.


## Context:

This project, funded with up to £2.5m from the UK Department of Energy and Climate Change (DECC - now the Department of Business, Energy and Industrial Strategy), was led by Aberdeen-based consultancy Pale Blue Dot Energy supported by Axis Well Technology and Costain. The project appraised five selected CO2 storage sites towards readiness for Final Investment Decisions. The sites were selected from a short-list of 20 (drawn from a long-list of 579 potential sites), representing the tip of a very large strategic national CO2 storage resource potential (estimated as 78,000 million tonnes). The sites were selected based on their potential to mobilise commercial-scale carbon, capture and storage projects for the UK. Outline development plans and budgets were prepared, confirming no major technical hurdles to storing industrial scale CO2 offshore in the UK with sites able to service both mainland Europe and the UK. The project built on data from CO2 Stored - the UK’s CO2 storage atlas - a database which was created from the ETI’s UK Storage Appraisal Project. This is now publically available and being further developed by The Crown Estate and the British Geological Survey. Information on CO2Stored is available at www.co2stored.com.

2016

# D13: WP5D – Captain X Site Storage Development Plan

10113ETIS-Rep-19-03

March 2016

www.pale-blu.com

www.axis-wt.com

# Contents

| Document Summary | | | |
|---|---|---|---|
| **Client** | The Energy Technologies Institute | | |
| **Project Title** | DECC Strategic UK CCS Storage Appraisal Project | | |
| **Title:** | D13: Wp5d – Captain X Site Storage Development Plan | | |
| **Distribution:** | A Green, D Gammer | **Classification:** | Client Confidential |
| **Date of Issue:** | Click here to enter text. | | |
| | **Name** | **Role** | **Signature** |
| **Prepared by:** | A James, S Baines & S McCollough | Chief Technologist, Scientific Advisor & Subsurface Lead | |
| **Approved by:** | S J Murphy | Project Manager | |

| Amendment Record | | | | | | |
|---|---|---|---|---|---|---|
| **Rev** | **Date** | **Description** | **Issued By** | **Checked By** | **Approved By** | **Client Approval** |
| V01 | 26/2/16 | Draft | D Pilbeam | A James | S Murphy | |
| V02 | 18/3/16 | Final | D Pilbeam | A James | S Murphy | A Green |
| V03 | 20/04/16 | Final (added PV10 Real values) | D Pilbeam | A James | S Murphy | A Green |

**Disclaimer:**

While the authors consider that the data and opinions contained in this report are sound, all parties must rely upon their own skill and judgement when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. There is considerable uncertainty around the development of $CO_2$ stores and the available data are extremely limited. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report. The views and judgements expressed here are the opinions of the authors and do not reflect those of the ETI or any of the stakeholders consulted during the course of this project. The figures, charts and tables contained in this report comply with the intellectual property and copyright constraints of this project and in some cases this has meant that they have been simplified or their number limited.

# Table of Contents

## Detailed Table of Contents

## Figures

## Tables

# 1.0 Executive Summary

*Storage in the Captain Sandstone aquifer in UKCS quadrants 13 and 14 in the Central North Sea.*

*3 well, single stage development of Captain X Site from an unmanned platform, supplied with $CO_2$ from St. Fergus via an existing 78km 16" pipeline.*

*Ambitious programme to Final Investment Decision in 2018 and first injection in 2022.*

*Capital investment of £152 million ($PV_{10}$, 2015), equating to £2.5 for each tonne stored.*

*The store can contain 60Mt from the 20 year $CO_2$ supply profile at 3Mt/y.*

*There is good subsurface data but further seismic investigation is required to understand plume development and shape the development plan.*

This Energy Technologies Institute (ETI) Strategic UK CCS Storage Appraisal project has been commissioned on behalf of the Department of Energy and Climate Change. The project brings together existing storage appraisal initiatives, accelerates the development of strategically important storage capacity and leverages further investment in building this capacity to meet UK needs.

The primary objective of the overall project is to down-select and materially progress the appraisal of five potential $CO_2$ storage sites on their path towards final investment decision (FID) readiness from an initial site inventory of over 500. The desired outcome is the delivery of a mature set of high quality $CO_2$ storage options for the developers of major power and industrial CCS project developers to access in the future. The work will add significantly to the de-risking of these stores and be transferable to storage developers to complete the more capital intensive parts of storage development.

The Captain aquifer was selected as one of five target storage sites as part of a portfolio selection process. The full rationale behind the screening and selection is fully documented in the following reports:

- D04: Initial Screening & Down-Select (Pale Blue Dot Energy; Axis Well Technology, 2015).
- D05: Due Diligence and Portfolio Selection (Pale Blue Dot Energy; Axis Well Technology, 2015).

The whole Captain aquifer covers an area of approximately 3438km$^2$ (Scottish Carbon Capture and Storage, 2011) in the Central North Sea and could potentially accommodate multiple $CO_2$ storage sites. These studies have concluded that the Captain Aquifer system could hold in excess of 360MT of injected $CO_2$ from a range of injection sites. Here, a site selection process considered several potential sites and identified Site X as the most suitable for this study.

Site X covers an area of 344 km$^2$ or about 10% of the entire fairway and is located in UKCS quadrants 13 and 14 between the Atlantic and Blake hydrocarbon fields. The proposed injection site is approximately 80 km from St Fergus as illustrated in Figure 1-1.

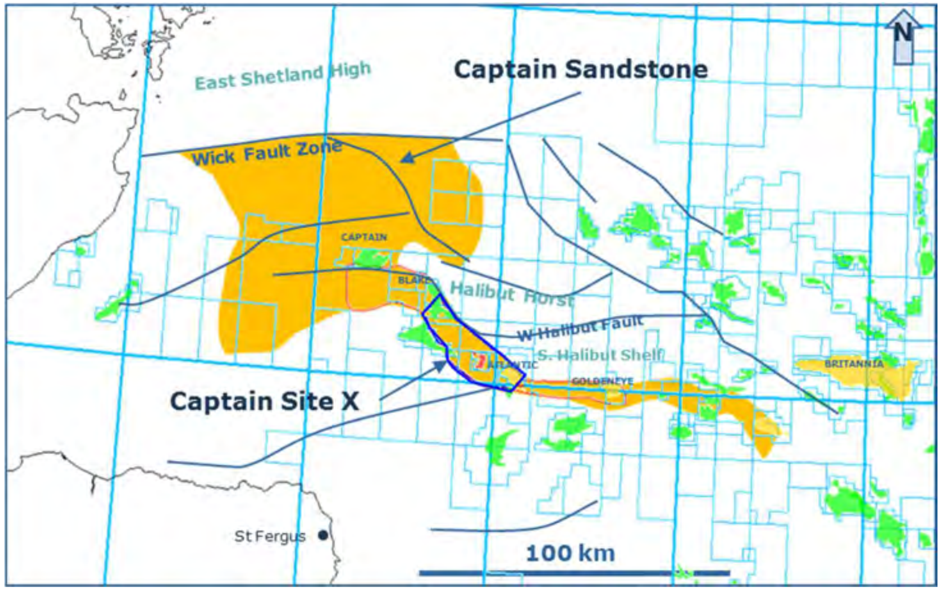



*Figure 1-1 Location Map of Captain Aquifer Site X*

The primary storage unit is the Captain Sandstone within the Lower Cretaceous Cromer Knoll Group. The primary seal is provided by the mudstones within the Rodby and Carrick Formations (Figure 1-2).

The Captain Sandstone consists of channel-dominated turbidite deposits of generally excellent reservoir quality, with an average porosity of 25%. Whilst the Upper Captain Sandstone is laterally extensive, the Lower Captain Sandstone, which is partially isolated from the Upper Sandstone by a Mid Captain Shale, is not laterally extensive across the site.

Secure vertical containment is provided by laterally extensive mudstones and shale of the Rodby and Carrick Formations which are a proven seal for multiple hydrocarbon fields in the Central North Sea and provides an excellent caprock for the storage complex.

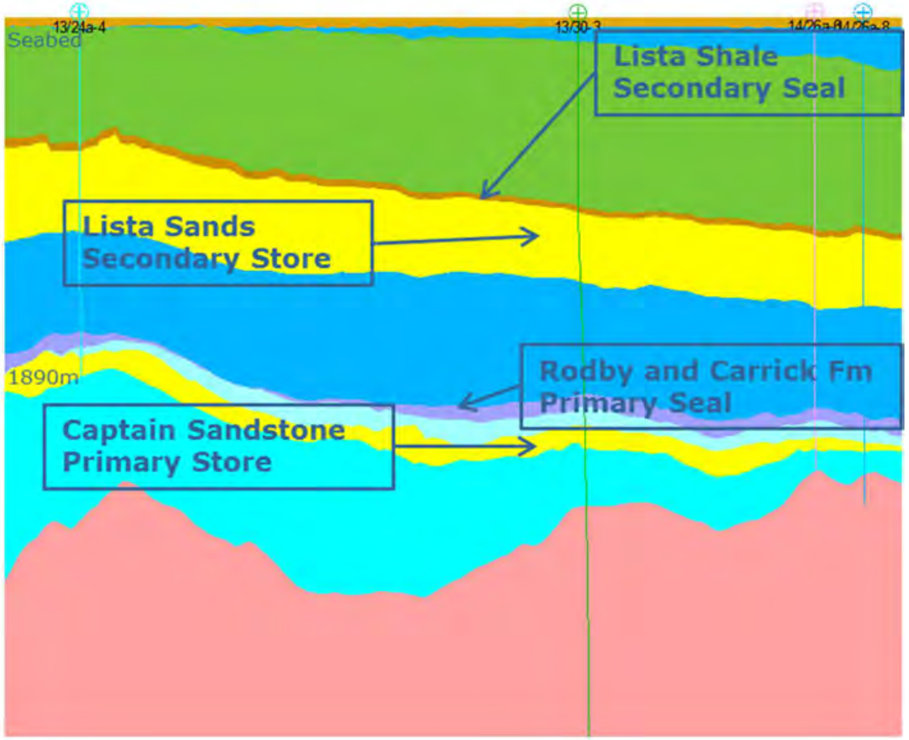



*Figure 1-2 Stores and Seals of the Captain X Site*

A seismic interpretation was carried out on the PGS Central North Sea MegaSurvey. The seismic data quality is generally very good, but at Captain Sandstone level it is poor because the Top Captain Sandstone is seismically transparent. This limits confidence in the depth definition at the Top Captain Sandstone which has implications for $CO_2$ plume modelling. There is significant high quality well data available in the area. 16 wells within the site have been used to build the geological model. 7 of these have also been cored. The static model has been upscaled and used in dynamic simulation modelling. This was used to generate the injection profile and assess $CO_2$ plume migration for the store development plan.

Geological and reservoir engineering work has concluded that the Captain X Site is laterally well connected hydraulically with excellent reservoir quality. It is the combination of the low dip environment at the Captain X site coupled with the exceptional reservoir quality and high vertical permeability that makes the $CO_2$ plume very mobile and its development very sensitive to small structural features. As a result, injected $CO_2$ moves quickly to the "roof" of the reservoir and then along the highest structural path that it can find. This makes the storage capacity very sensitive to small structural features which control plume migration within the storage complex. Injection wells are postioned in the deeper parts of the structure in the Upper Captain Sandstone to maximise the sites' storage efficiency by creating a tortuous path to the crest of the reservoir. Injectivity is expected to be good and high angle wells are required in the reservoir section to achieve the target injection rates of 1 - 2Mt/y per well.

The key results of the dynamic modelling work suggest that injecting CO2 into the Captain Sandstone reservoir is very straightforward due to its excellent quality and connectivity. The main challenge at Site X is controlling the plume development so that it sweeps through a large reservoir volume and achieves a high storage efficiency. Sensitivities indicated an ability to inject up to 180MT of $CO_2$ into the site, but the plume is very mobile and could not be retained within the proposed storage complex boundary. As a result the injected inventory was limited to 60MT. Modelling has show that this can be contained within the storage complex for at least 1000 years after injection stops.

The basis for the development plan is an assumed $CO_2$ supply of 3Mt/y to be provided from the shore terminal at St. Fergus commencing in 2022. $CO_2$ will be transported offshore in liquid-phase via an existing 78km 16" pipeline from St. Fergus to the area of the depleted Atlantic gas field and then via a new 8km 16" pipeline to a newly installed Normally Unmanned Installation (NUI), minimum facilities platform on a 4 legged steel jacket standing in 115m of water. During the main operational period, two of the wells are expected to be injecting at any point in time with the third as backup in the event of an unforeseen well problem. In this manner, the facilities will maintain a robust injection capacity and inject 3Mt/y of $CO_2$ for the 20 year project life without breaching the safe operating envelope.

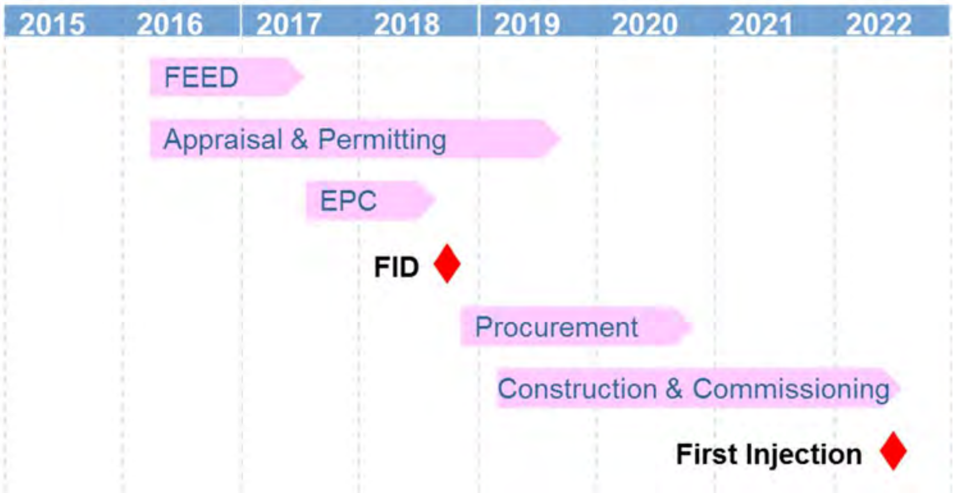



*Figure 1-3 Captain X Project Schedule*

The development schedule has 5 main phases of activity and is anticipated to require 6 years to complete, as illustrated in Figure 1-3. The schedule indicates that FEED, appraisal and contracting activities will commence 2-3 years prior to the final investment decision (FID) in 2018. The capital intensive activities of procurement and construction follow FID and take place over a 3-4 year period.

First injection is forecast to be in mid-late 2022. This is a very ambitious timetable.

The development of the offshore transportation and injection infrastructure is estimated to require a capital investment of £152 million (in present value terms discounted at 10% to 2015), equating to £2.5/t, or £11.6/T on a levelised basis. The life-cycle levelised costs are estimated to be £283 million (PV10), equating to £21.6/T on a levelised cost basis, as summarised in Table 1-1.

| £million ($PV_{10}$, 2015) | Total |
|---|---|
| **Transportation** | 22 |
| **Facilities** | 72 |
| **Wells** | 59 |
| **Opex** | 115 |
| **Decommissioning & MMV** | 15 |
| **Total** | 283 |

*Table 1-1 Life Cycle Costs (PV10, 2015)*

A series of recommendations for further work are provided towards the end of this report. The principal ones being:

- Access improved 3-D seismic data and use it to improve the characterisation of reservoir quality and architecture. This controls $CO_2$ plume dynamics and capacity and will strongly influence the final selected development plan.

- Identify opportunities for cost and risk reduction across the whole development and in particular consider the potential for subsea development.
- Gain more access to data from nearby hydrocarbon fields to improve the regional pressure situation and the status of abandoned wells and ensure planned abandonments do not jeopardise containment of a future $CO_2$ storage development.

# 2.0 Objectives

The Strategic UK CCS Storage Appraisal Project has five objectives, as illustrated in Figure 2-1.


*Figure 2-1 The five project objectives*

The Captain X site is one of the five $CO_2$ storage targets evaluated as part of Work Pack 5 (WP5). The primary objective of this element of the project is to advance understanding of the nature, potential, costs and risks associated with developing the site, with the data currently available to the project and within normal budget and schedule constraints. The output fits within the broader purpose of the project to "facilitate the future commercial development of UK $CO_2$ storage capacity".

This report documents the current appraisal status of the site and recommends further appraisal and development options within the framework of a $CO_2$ storage development plan. An additional objective of this phase of the project is to provide a repository for the seismic and geological interpretations, subsurface and reservoir simulation models. These items have been supplied separately.

WP5 has seven principal components:

1. Data collection & maintenance.
2. Seismic interpretation and structural modelling.
3. Containment.
4. Well design and modelling.
5. Site performance modelling.
6. Development planning.
7. Documentation and library.

These components and their contribution to the storage development plan are illustrated in Figure 2-2.

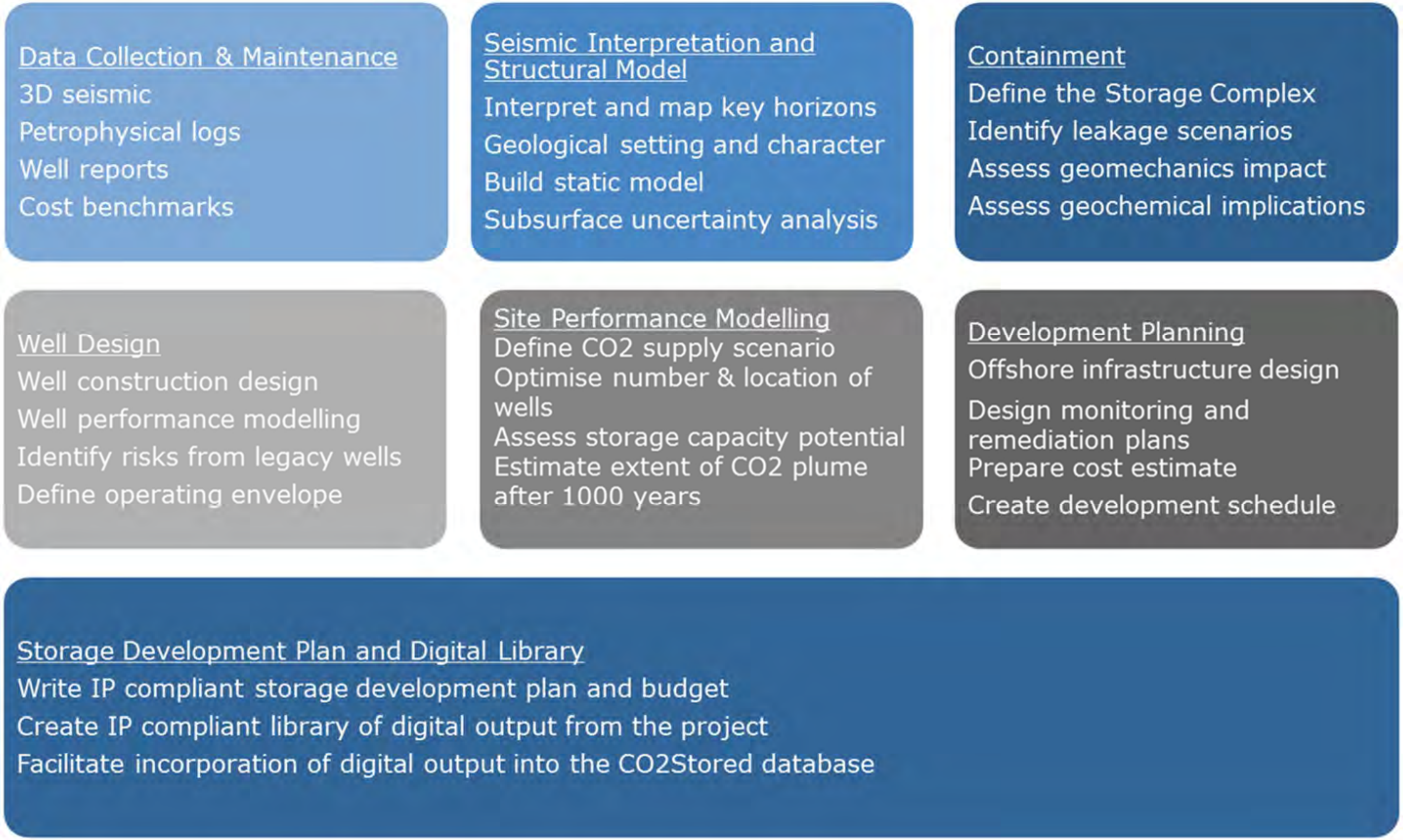



*Figure 2-2 Seven components of Workpack 5*

# 3.0 Site Characterisation

## 3.1 Geological Setting

The Captain open aquifer system was selected as part of a portfolio of five target storage sites in the Strategic UK CCS Storage Appraisal Project. The pan shaped fairway stretches for almost 200km from its shallowest part in the north west where it has its widest extent and is found to sub-crop at the seabed, to its deepest extent in the far south east where it exceeds depths of 3660m (12,000ft). To the east the fairway is a confined corridor representing the "pan handle". The fairway has been the subject of significant petroleum activity over the years and hosts producing fields, Captain, Blake, Cromarty, Atlantic, Goldeneye and Hannay. The Britannia condensate reservoir in the far east is also an equivalent of the Captain sandstone. Also, since 2010, the Captain sandstone within the depleted Goldeneye gas field has been the location of a proposed $CO_2$ storage development, initially for Longannet and then for Peterhead CCS project.

Several previous studies have considered the Captain sandstone as a potential $CO_2$ storage site. This includes the 2015 $CO_2$Multistore joint industry project led by SCCS which concluded that "Stakeholders can have increased confidence that at least 360 million tonnes of $CO_2$ captured over the coming 35 years could be permanently injected, at a rate of between 6 and 12 million tonnes per year, using two injection sites." (Scottish Power CCS Consortium, 2015).

Whilst it would be possible to engineer a $CO_2$ storage development plan in many parts of the Captain fairway it was decided to focus upon that part of the "pan handle" between Atlantic and Blake. The reasons for this were:

1. Whilst the western area represents a large potential target, it is very shallow, often less than 800m and also contains the Captain oilfield which is estimated to continue operations until 2030. Furthermore, the 3D seismic coverage available to this project was incomplete over the area of the "pan" itself. For these reasons the western area was not selected as a potential storage site.
2. Any practical progression of $CO_2$ storage site in the Captain sandstone for development before 2030 must ensure that there is significant separation between that site and any development at Goldeneye which has already been issued an agreement for lease by the Crowne Estate. This is in order to minimise the effects of site interference. Unfortunately, whilst this study was being completed, UK government announced the cancelation of the CCS commercialisation programme. This resulted in the cancelation of the Goldeneye development project.
3. The easternmost part of the "pan handle" is at a greater depth and poorer reservoir quality than areas to the west.

There have been several $CO_2$ storage studies completed on different aspects of the Captain Sandstone. These include:

2011 - Goldeneye FEED with injection at the Goldeneye platform

2015 - $CO_2$ Multistore JIP with injection at Sites "A" and "B"

2012 Jin, Mackay, Quinn et al with injection sites 1 through 12.

As this study is focussed upon the commercial development of a part of the fairway only, and to minimise any confusion with other Captain sandstone $CO_2$

injection studies or even the Chevron Operated Captain oilfield, the conceptual development here is referred to as Captain X.

The full rationale and process behind the screening and selection is fully documented in the following reports:

- D04: Initial Screening & Down-Select (Pale Blue Dot Energy; Axis Well Technology, 2015)
- D05: Due Diligence and Portfolio (Pale Blue Dot Energy; Axis Well Technology, 2015)

The primary storage unit for Captain X is the Captain Sandstone Member of the Lower Cretaceous Cromer Knoll Group.

The Captain Sandstone Member is an extensive sandy turbidite system, with mass flow sediments deposited in a long, confined north west to south east fairway.

As the licensing of this very large site is unlikely to be a practical way forward, a smaller initial development area within the Captain fairway was selected. This development area (Captain X) covers 344 $km^2$ and is located in the centre of the Captain fairway, between the Blake and Atlantic Fields, approximately 60km from the Aberdeen coast in UKCS blocks 13/30 and 14/26.

The development area includes parts of the Blake oilfield and Atlantic gas field and the whole of the Cromarty gas field. These fields all have the Captain Sandstone as their primary reservoir.

The distribution of the Captain Sandstone in the UK sector of the CNS, and the injection site location, is shown in Figure 3-1

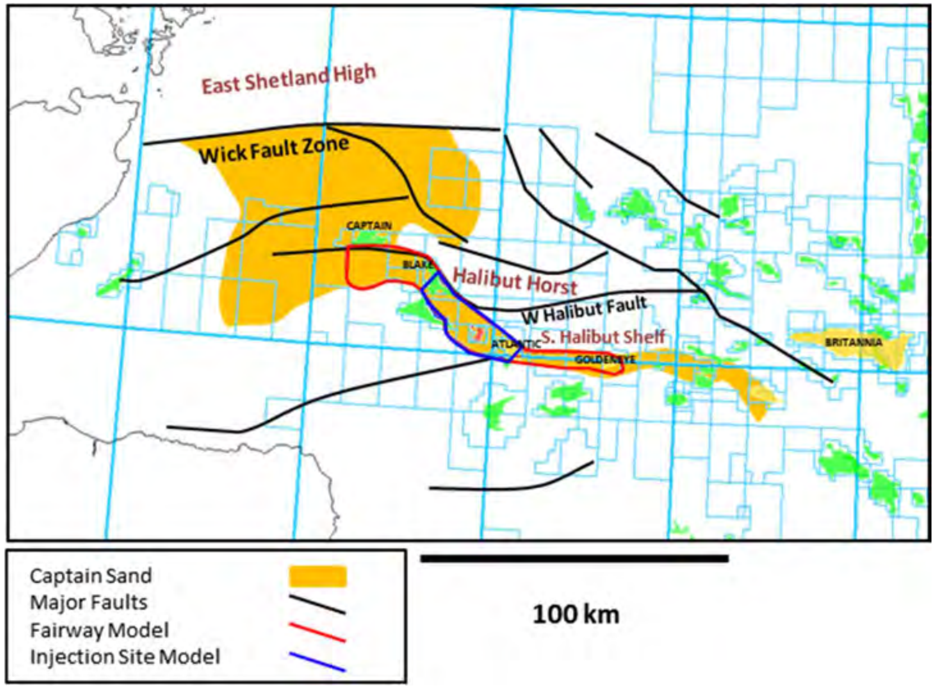



*Figure 3-1 Captain sandstone fairway*

## 3.2 Site History and Database

### 3.2.1 History

The Captain X development area comprises an open, saline aquifer system which dips to the SE at approximately 1 to 2 degrees, with a steep ramp of up to 20 degrees close to the Halibut Horst fault at the north western end.

During the Jurassic and Lower Cretaceous the main structural element in the area was the east-west trending Halibut Horst directly to the north. Parts of this remained above sea level through most of the Jurassic and Lower Cretaceous, contributing significantly to the deposition of turbidites during the Lower Cretaceous.

The Captain Sand fairway is a 5-10 km wide ribbon of sand deposited along the long southern edge of the Halibut Horst and South Halibut Shelf extending east across the South Halibut Basin towards the Britannia Field. The sands were deposited as deep water marine turbidites, controlled by the existing basin topography, and were triggered in response to a major fall in sea level.

### 3.2.2 Hydrocarbon Exploration

Within the Central North Sea (CNS) the Captain Sandstone is a prolific hydrocarbon reservoir with many hydrocarbon fields such as Captain, Blake, Cromarty, Atlantic, Goldeneye and Hannay. The effective top seal for these is provided by mudstones of the Carrack (Sola) and Rodby Formations (Pinnock & Clitheroe, 2003).

The underlying Lower Cretaceous sands of the Punt and Coracle are also prospective for hydrocarbons, with Punt being an oil bearing reservoir in Golden Eagle, Peregrine, Hobby and Solitaire fields nearby.

The deeper Burns and Piper Sandstones of the Upper Jurassic (below the Lower Cretaceous) are also well-documented hydrocarbon reservoirs within the CNS.

Solitaire is a single well oilfield in an Upper Jurassic Burns Sandstone reservoir which lies directly underneath the Atlantic gas condensate field, and the geography of the main Captain Sandstone fairway. First oil from Solitaire was in 2015, with end of production forecast in 2028 coinciding with that of the Golden Eagle development to which it is tied back. Further west, the Upper Jurassic Ross oil field also partially lies below the geography of the Captain Sand fairway. Neither are considered to be hydraulically connected to the Captain sandstone. In the case of Ross, none of the wells targeting this deeper interval penetrate the Captain Sandstone as mapped.

The reservoirs of the Cromarty (gas), Blake (oil) and Atlantic (condensate) fields are part of the Captain Sandstone fairway itself. Both Atlantic and Cromarty are undergoing decommissioning. First production and expected Cessation of Production dates are shown below:

- Blake: First oil 2001 CoP 2026
- Cromarty: First gas 2006 CoP 2012
- Atlantic: First oil 2006 CoP 2012

The late Jurassic Kimmeridge Clay Formation provides the source rock for the hydrocarbons, which have migrated into the Cretaceous Captain reservoir from the West Halibut Basin and Smith Bank Graben (Pinnock & Clitheroe, 2003).

### 3.2.3 Seismic

The seismic data set used for the Captain X site and fairway interpretation was the PGS Central North Sea MegaSurvey (PGS, 2015). These data were loaded to Schlumberger's proprietary PETREL software where the seismic interpretation was undertaken. Figure 3-2 shows the extent of seismic available together with the area of the fairway interpretation and the Captain X $CO_2$ storage site model. Seismic coverage over the fairway is nearly complete apart from data gaps to the South West of Cromarty Field and to the North West of the Blake Field. Interpreted surfaces were interpolated across areas with no seismic data coverage. The seismic volume is made up of several different surveys that have been merged post stack (Figure 3-2). These were acquired between 1990 and 2003. Additional more modern surveys and re-processed data sets are also available in the area, but were not available to this project.

Seismic data SEGY summary is provided in Appendix 3.

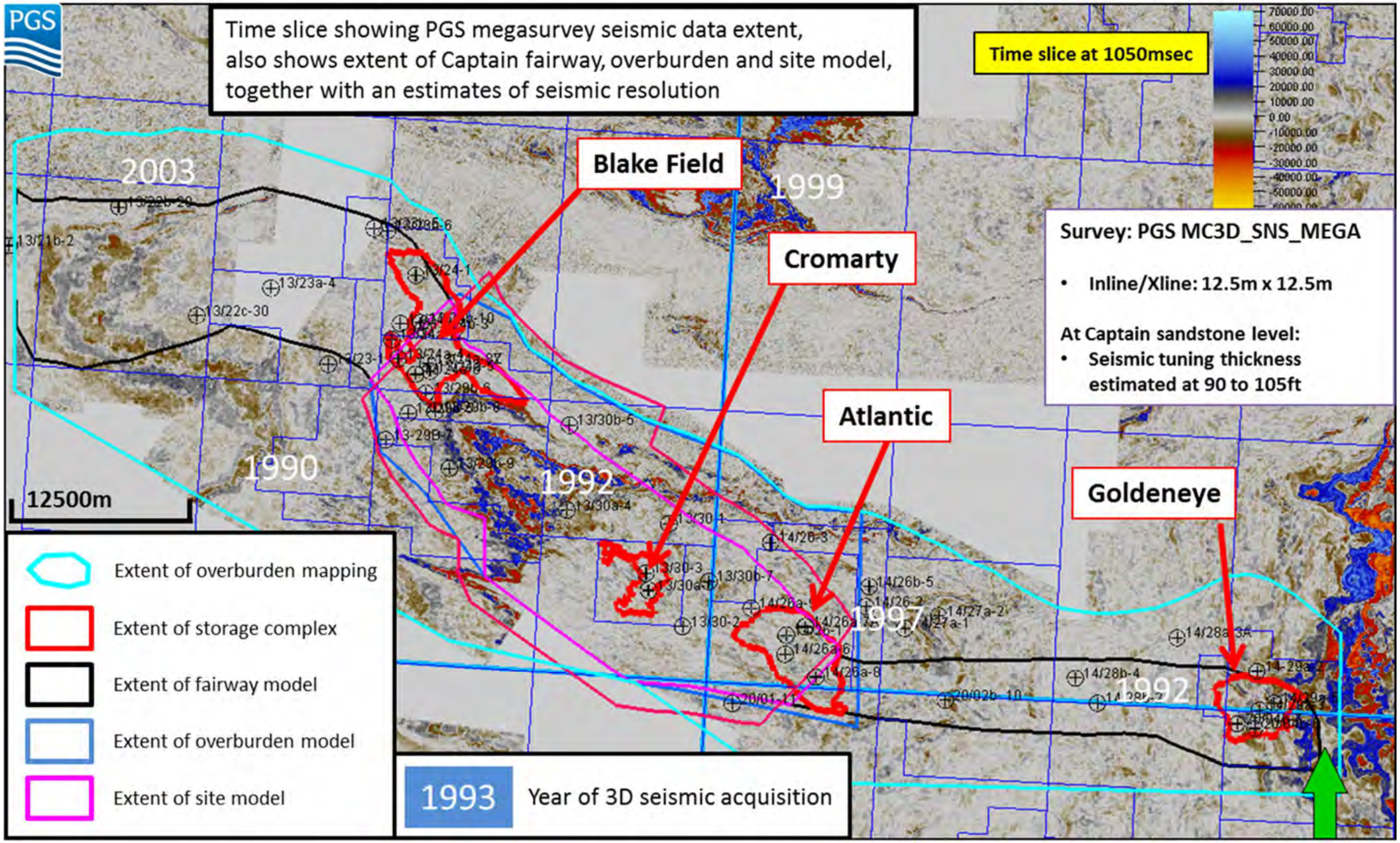



*Figure 3-2 Seismic database*

### 3.2.4 Wells

Well log data for released wells was sourced from the publically available CDA database. The regulations for well release depend upon the license that the well was drilled under, however for guidance the January 2016 well release was for wells drilled between 2010 and 2012. The data from CDA are varied in range and quality, but generally include LIS or DLIS formatted digital log data, field reports, end of well reports, composite logs and core reports. 57 wells were selected from the CDA database and used for a range of activities. These included wells from the Blake, Cromarty and Atlantic Fields.

A total of 16 wells across the Captain fairway were selected that have suitable data for petrophysical evaluation over the Captain Sandstone interval (Table 3-1). Conventional wireline data were used in preference to Measurement While Drilling (MWD) data in all cases. Seven of the wells in the study area were cored, the core coverage is extensive for all the Captain sands in these wells with a total of some 2400 conventional core measurements.

The well data quality is generally very good, no major issues were identified and little manipulation was required to prepare the data for interpretation. The hole condition at the time of logging, interpreted from the calliper and DRHO curves over the zones of interest, was generally good with only a few exceptions. Data were checked against the operator's composite logs to ensure consistency between the digital data and the operator's reports.

Figure 3-3 shows the wells used for the seismic interpretation. 12 wells have time depth information with 9 of those wells having sonic logs.

An inventory of well data accessed for the final study is included in Appendix 3.

| Well | Wireline | MWD | Core | Mud Type |
|---|---|---|---|---|
| 13/23b- 5 | ✓ | ✓ | ✓ | KCL/ Glycol |
| 13/24a- 4 | ✓ | ✓ | ✓ | Bentonite (WBM) |
| 13/24a- 5 | ✓ | ✓ | ✓ | Bentonite (WBM) |
| 13/24a- 6 | ✓ | ✓ | ✓ | Bentonite (WBM) |
| 13/24b- 3 | ✓ | | ✓ | Bentonite (WBM) |
| 13/29b- 6 | ✓ | ✓ | ✓ | WBM |
| 13/30 - 3 | ✓ | | ✓ | OBM |
| 13/30a- 4 | ✓ | ✓ | ✓ | Bentonite (WBM) |
| 14/26a- 6 | ✓ | ✓ | ✓ | KCL/CBW Brine |
| 14/26a- 7A | ✓ | ✓ | ✓ | KCL Polymer |
| 14/26a- 8 | ✓ | ✓ | ✓ | OBM |
| 14/28b- 2 | | ✓ | ✓ | KCL/Silicate (WBM) |
| 14/29a- 3 | ✓ | ✓ | ✓ | OBM |
| 14/29a- 5 | ✓ | ✓ | ✓ | OBM |
| 20/04b- 6 | ✓ | ✓ | ✓ | WBM |
| 20/04b- 7 | ✓ | ✓ | ✓ | OBM |

*Table 3-1 Captain X Site available well data*

### 3.2.5 Other

Other information used in this characterisation of the Captain X $CO_2$ injection site includes:

- DECC sourced production data
- Wood Mackenzie sourced COP dates

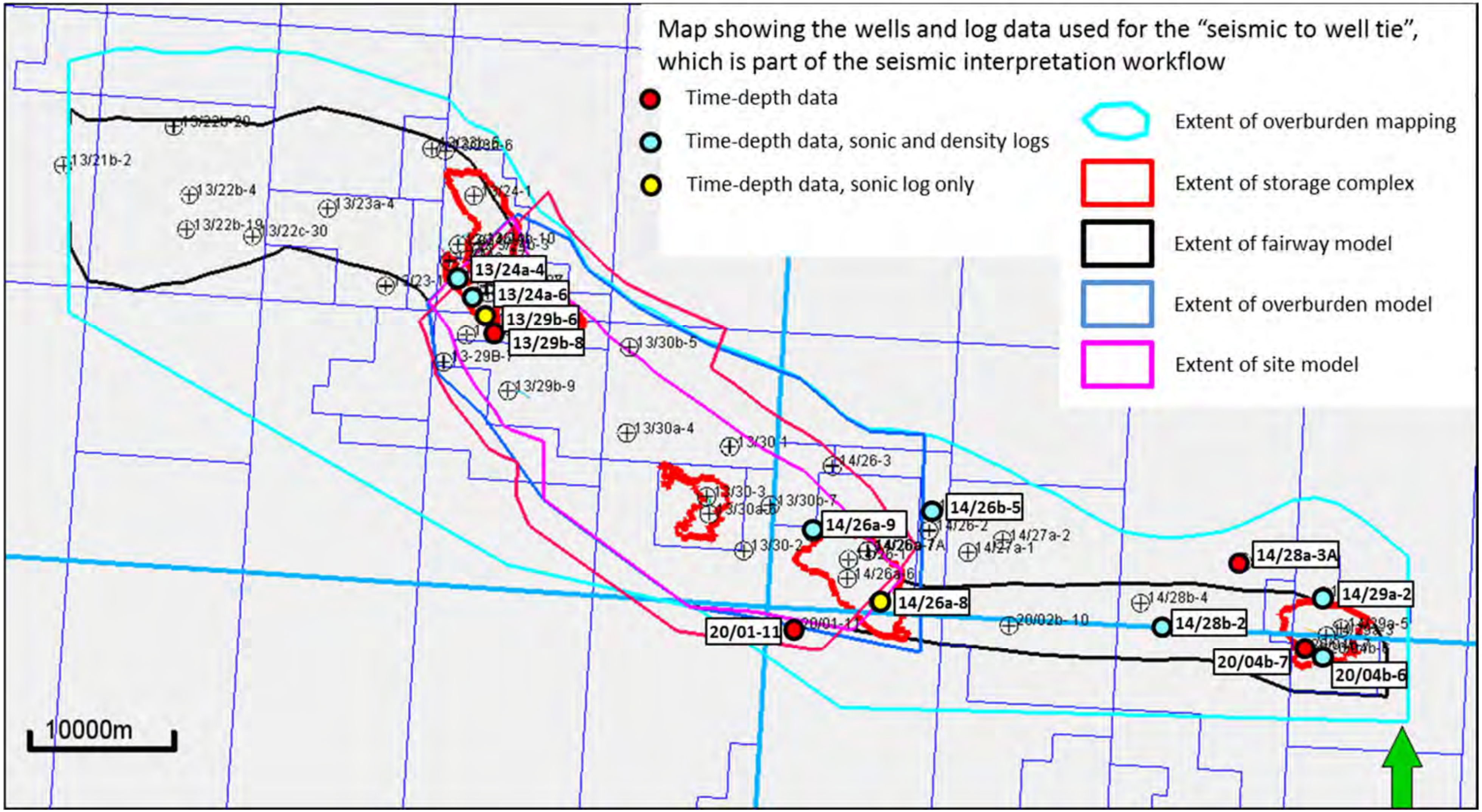



*Figure 3-3 Geophysical wells and log database*

## 3.3 Storage Stratigraphy

A stratigraphic column of the site is shown in Figure 3-4.

**Upper Jurassic**

The top of the Upper Jurassic is comprised of marine hemipelagic claystones of the Kimmeridge Clay Formation with locally developed deep-water mass flow sediments of the Burns and Ettrick Sand Members. These sands are the reservoir unit for some deeper hydrocarbon fields in the area, and a number of wells within the Captain fairway have targeted prospects within them. The claystones and shales of the Kimmeridge Clay Formation are high in organic content, making them an extremely important regional hydrocarbon source rock.

Below the Kimmeridge Clay Formation, shore-face sands of the Piper and Heather Formation are also an important reservoir target regionally, with the Ross Field (Piper/Sgiath Sands) partially lying below the Captain fairway.

**Lower Cretaceous - Cromer Knoll Group**

The Lower Cretaceous covers the interval from the Top to the Base of the Cromer Knoll Group.

The Early Cretaceous saw the periodic deposition of deep-water turbidite sands, into the background hemipelagic shales and marls of the Valhall Formation (Copestake, et al., 2003). These shales form the top, base and lateral seal for many of the turbidite sand units. These comprise the Punt, Coracle and Captain sandstones, which whilst classified as a part of the Valhall Formation, are also commonly collectively referred to as the Wick Sandstone Formation.

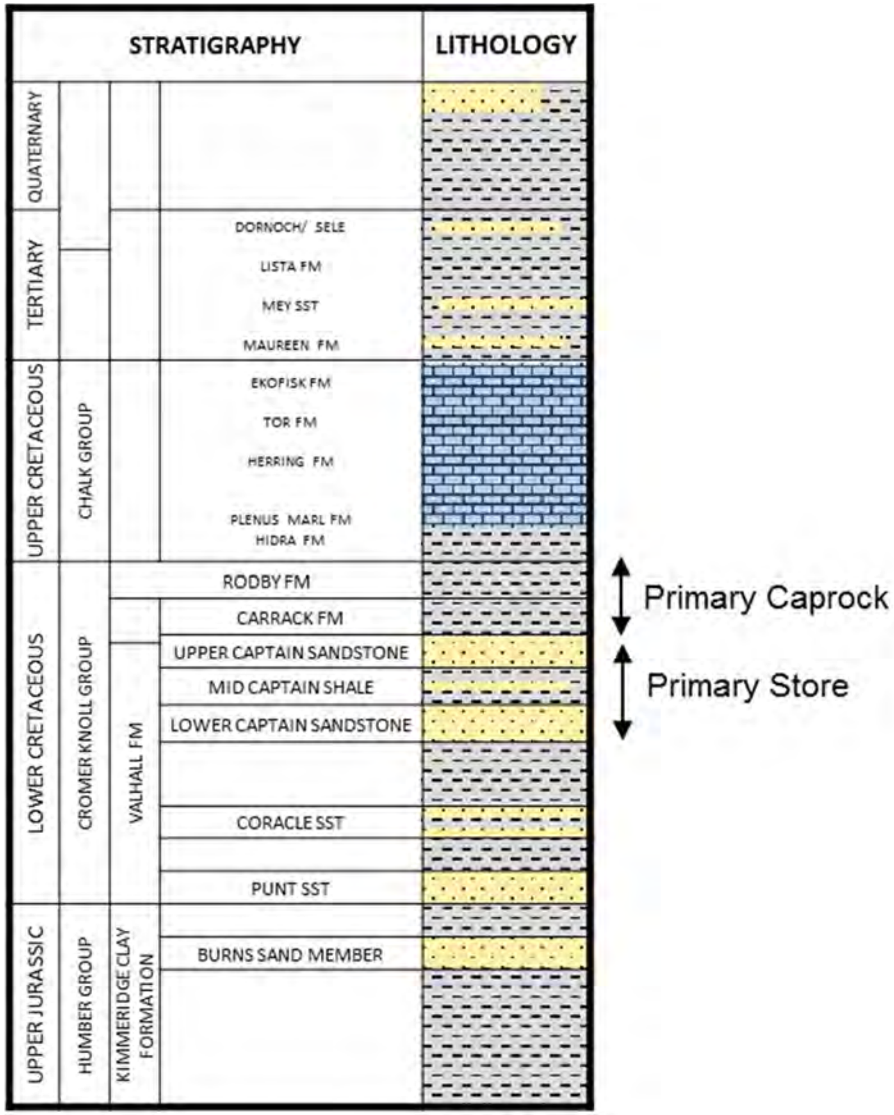



*Figure 3-4 Stratigraphic Column*

*Captain Sandstone Member* – The Captain Sandstone is the primary storage target and in this area has been deposited as an elongate ribbon of sand deposited NW – SE along the southern edge of the Halibut Horst. It is split into Upper and Lower Captain Sandstones separated by the mid-Captain shale. The Upper Captain Sandstone is a thick massive sand deposited along the length of the fairway with pinch out to both north and south. The Lower Captain Sandstone is more laterally restricted deposited as a number of more locally sourced fans.

The thickness of the full unit averages 54m (180ft) but is up to 143 m (470 ft) thick in the centre of the fairway within the site area. The mid-Captain shale between the upper and lower sands averages 15m (50ft) thick.

Across the site area shales of the Carrack Formation overlie the Captain Sandstones, immediately below the Rodby formation, providing an additional seal interval.

*Rodby Formation* – The Rodby Formation is a proven hydrocarbon seal for the fields within the Captain Sandstones fairway. It consists of marls, mudstones with occasional thin argillaceous limestone beds. Across the Captain X area the Top Rodby to Top Captain shale interval has an average thickness of 90m (300ft) and can be confidently mapped across the Captain Sandstone fairway.

**Upper Cretaceous - Chalk Group**

*Plenus Marl and Hidra Formations* – The Hidra Formation (argillaceous limestones, marls and mudstones) and Plenus Marl Formation (black anoxic calcareous mudstones) directly overlie the Rodby Formation at the base of the Chalk Group. Both are considered to be impermeable. Across the Captain X area the Top Plenus Marl to Top Rodby interval has an average thickness of 70m (230ft).

*Ekofisk, Tor, Hod and Herring Formations* – Above the Hidra is a thick sequence (450 – 600 m; 1500 – 2000ft) of limestone deposited as pelagic chalks. These are interbedded with occasional claystone and marl beds, particularly within the lower formations.

**Tertiary**

*Maureen Formation (Montrose Group)* – The Maureen Formation typically overlies the Chalk Group and is widely distributed in the Central Graben. It is comprised predominantly of amalgamated gravity flow sands interbedded with siltstones and reworked basinal carbonates (chalk). The base of the Maureen is marked by a thin but extensive marl layer above the Ekofisk.

*Lista Formation (Montrose Group)* – Regionally the Lista Formation is composed largely of grey mudstone deposited in a marine basin or outer shelf environment, interbedded with sandstones deposited as submarine gravity flows. These sandstones are extensively developed across the Outer Moray Firth and Central Graben where they are assigned to the Mey Sandstone Member, locally named Andrew and Balmoral members.

At the top of the Lista Formation, the Lista shale is widely present within the Halibut Trough area. The Lista Shale is a proven caprock for several Palaeocene fields, the closest being the Rubie and MacCulloch Fields (Shell, 2015).

**Quaternary – Nordland Group**

At the Captain X saline aquifer site location, the upper part of the stratigraphic sequence is thick accumulation of undifferentiated mudstones, claystones and occasionally marls. The thickness of the Nordland Group within the area is over 640 m (2100 ft).

## 3.4 Seismic Characterisation

### 3.4.1 Database

Many 2D and 3D seismic surveys are available across the Captain fairway area. Of these, the PGS Central North Sea MegaSurvey (PGS, 2015) is the most comprehensive in terms of its areal coverage. The seismic volume is made up of several different surveys that have been merged post stack (Figure 3-2) and were acquired between 1990 and 2003. More modern surveys are available including re-processed datasets, but were not available to this project. Seismic coverage over the fairway is good, except for in the north west region of the fairway where there is missing seismic data. Interpreted surfaces were interpolated across areas with no seismic data coverage.

Wavelet extraction confirms the key seismic volume over the Captain X site to be SEG normal polarity with a peak (blue on seismic sections) representing an increase in acoustic impedance and a trough (red on seismic sections) representing a decrease in acoustic impedance. It also shows the seismic volume is close to zero phase with a change in acoustic impedance at a formation interface being represented by either a peak or a trough.

To aid fault identification, semblance volumes were generated using the OpendTect open source software then exported and loaded into the Petrel project. A non-dip adapted semblance volume was generated over the entire fairway. Due to the relatively shallow dip over most of the Captain Sandstone fairway it was not necessary to generate a dip adapted semblance volume.

Figure 3-3 shows the wells used for the calibration of the seismic interpretation. 12 wells have time vs depth information with 9 of those wells having the sonic logs required for synthetic seismic trace calibration.

### 3.4.2 Horizon Identification

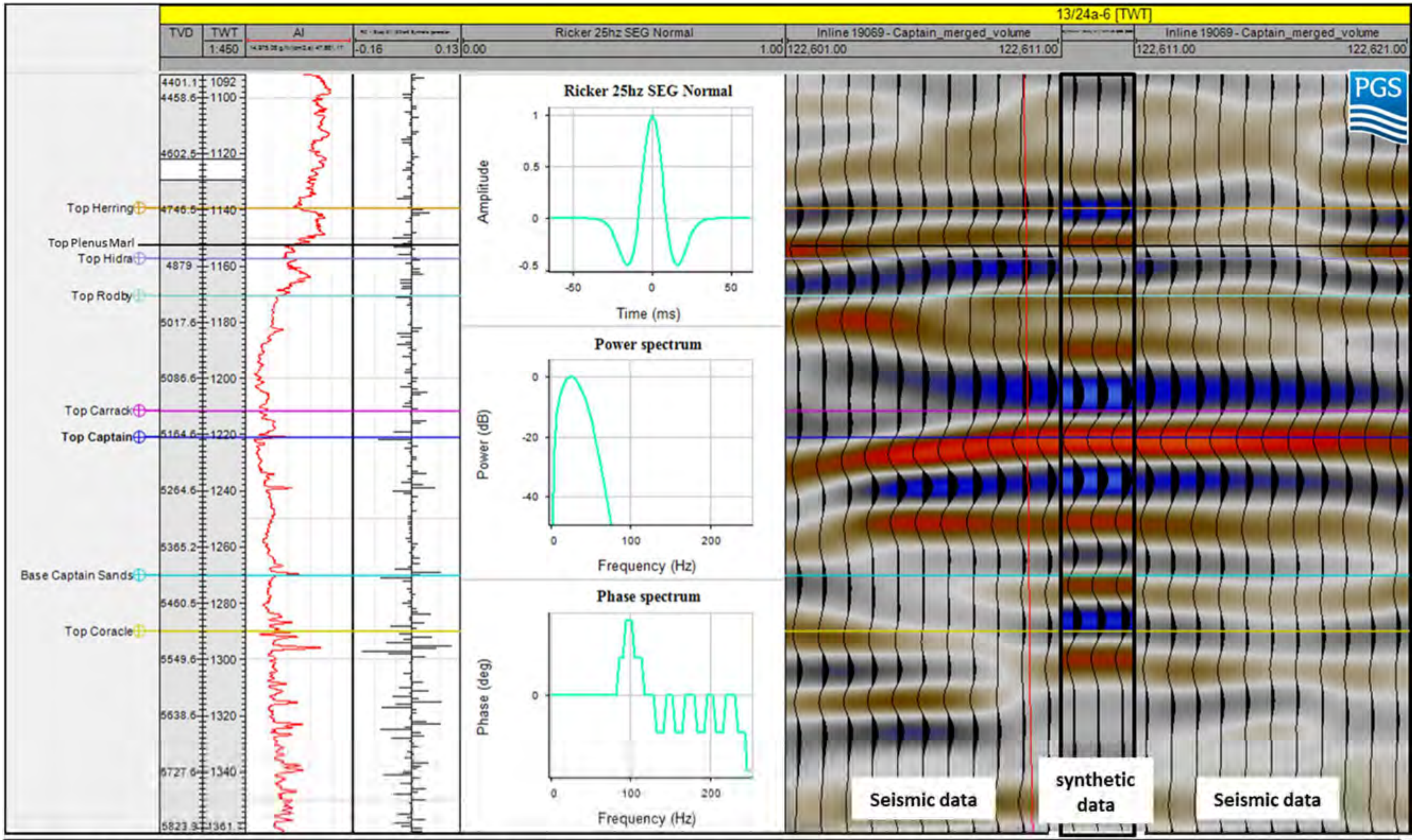
Whilst the seismic volume is recorded in terms of two-way travel time for a seismic wave to travel from the surface to the subsurface reflector and back again, well data are recorded in depth (ft or m). The well data are used to identify the seismic events within the 3D volume. Using checkshots, recorded in the well, a time vs depth relationship for the well is established. This time-depth relationship together with sonic and density logs are used to generate synthetic seismograms. The purpose of a synthetic seismogram is to forward model the seismic response of rock properties in the well bore to a seismic pulse at the well location, convolving the reflection coefficient log with the seismic pulse wavelet. This enables the interpreter to accurately match the position of certain seismic reflectors with respect to the known subsurface geology of an area.

9 synthetic well ties (13/24a-4, 13/24a-6, 13/29b-8, 14/26a-8, 14/26a-9, 14/26b-5, 14-29a-2, 14/29a-5, 20/04b-6, Figure 3-3) were produced using available sonic and density logs in each well.

To generate the synthetic seismograms a theoretical Ricker wavelet was used with an appropriate frequency applied to each well (range 25-30Hz). Seven wells contained both sonic and density logs with an additional two wells containing only sonic logs. For those wells with missing density logs a constant density value was used in the synthetic generation. An example of a synthetic for well 13/24a-6 is shown in Figure 3-5. Well 13/24a-6 has sonic and density log runs which extend over the Captain Sandstone interval. The synthetic has been time shifted up by 10msec in order to provide the best tie to the seismic section. The synthetic seismogram and actual seismic data display a good match. The identified horizons, their pick criteria and general pick quality are listed below in Table 3-2 and illustrated on a seismic line in Figure 3-6.

The Top Plenus Marl and Top Rodby (just above Top Captain) are consistent strong amplitude events on both the seismic and the synthetics. All synthetics were bulk shifted to provide a good tie at these events.

Synthetic seismograms show that the Top and Base Captain Sandstone have variable seismic responses. This makes it very difficult to produce a consistent Top and Base Captain Sandstone seismic interpretation because the seismic event can vary from being a peak to a trough.




13/24a-6 Synthetic well tie with actual seismic data. Generated using just the sonic log. 25Hz zero phase, SEG normal wavelet is convolved with the AI (acoustic impedance) generated reflection coefficients to create the synthetic seismic trace

*Figure 3-5 13/24a- 6 Synthetic seismogram*

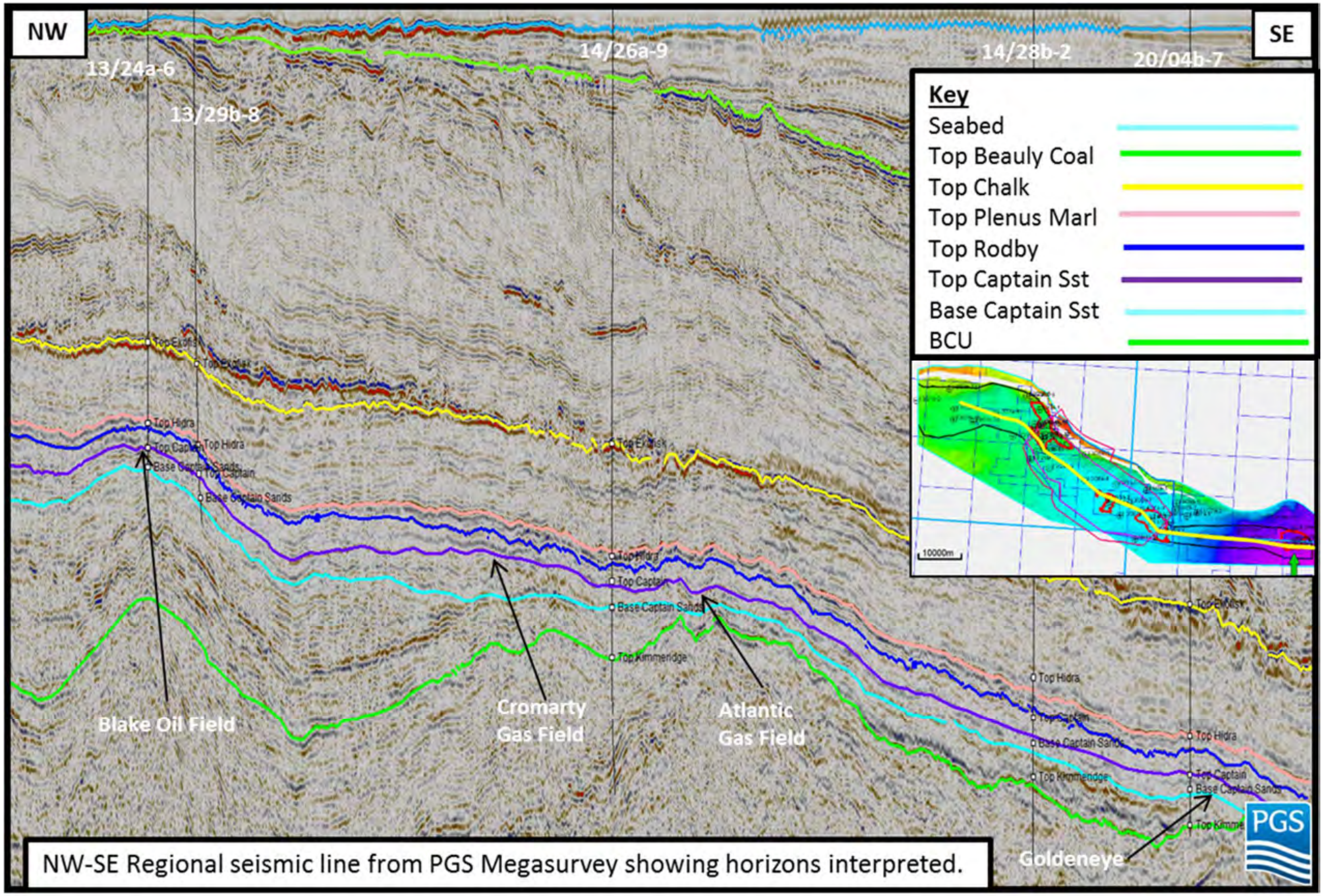



*Figure 3-6 SW NE Captain fairway seismic profile*

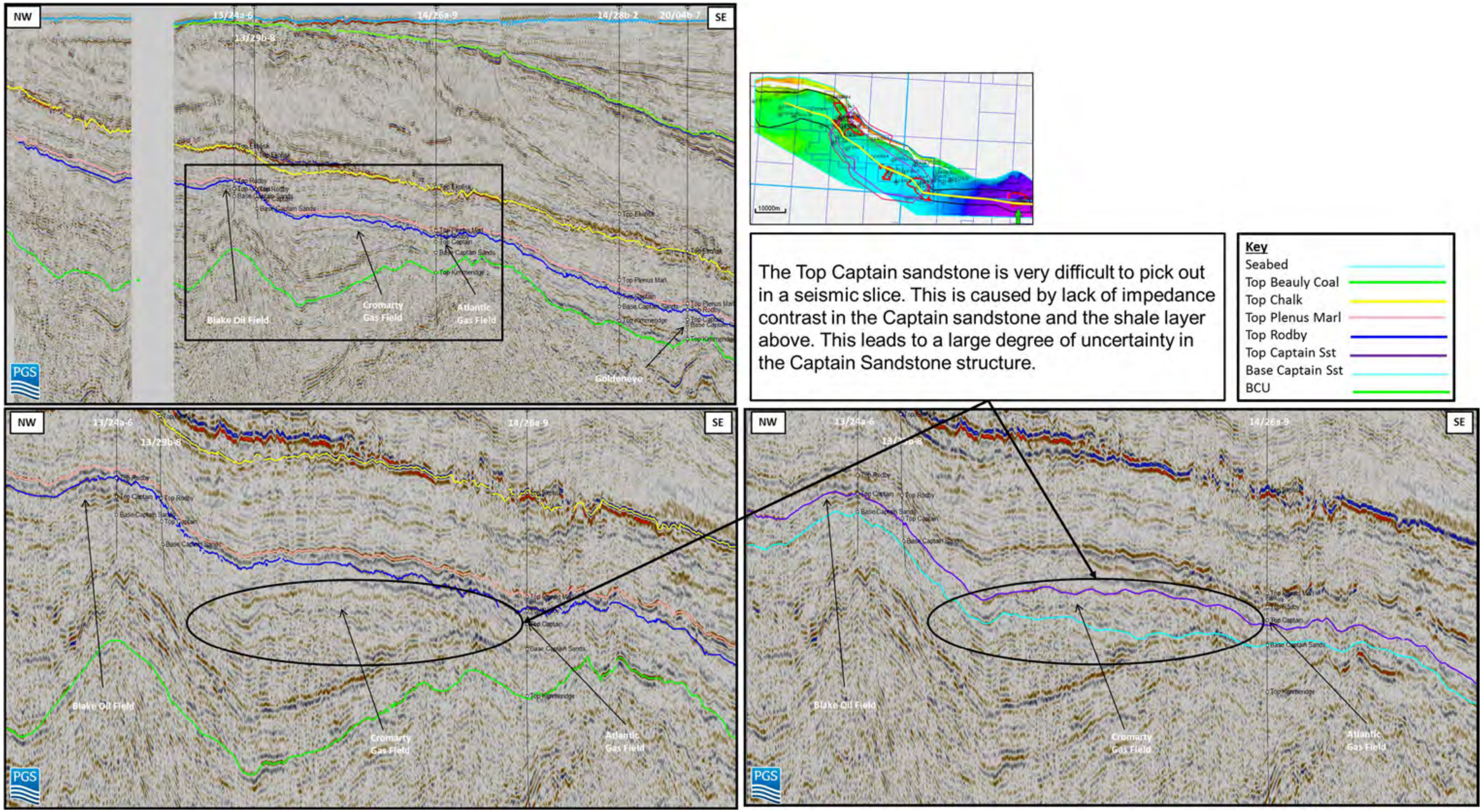



*Figure 3-7 Seismic profile highlighting difficulty interpreting Top and Base Captain Sandstone*

There were four wells that contained only checkshot data, allowing a well tie to be produced, but not a synthetic tie (which needs at least a sonic log). Several wells required an additional time shift in order to tie the seismic. If wells have no time depth data then it is shared from nearby wells that contain time depth information.

| Horizon | Display Response | Pick Quality |
|---|---|---|
| **Seabed** | Peak | Very Good |
| **Top Beauly Coal** | Trough | Good |
| **Top Chalk** | Peak | Very Good |
| **Top Plenus Marl** | Trough | Fair - Good |
| **Top Rodby** | Trough | Fair - Good |
| **Top Captain** | Peak/Trough/Zero Crossing | Very Poor |
| **Base Captain** | Peak/Trough | Very Poor |
| **Base Cretaceous U/C** | Trough | Good |

*Table 3-2 Interpreted horizons*

### 3.4.3 Horizon Interpretation

A detailed seismic interpretation was carried out using a combination of seismic reflectivity and semblance volumes to provide input surfaces to the Captain X site, Fairway and Overburden Static Models.

In total eight horizons from the Seabed down to the Base Cretaceous Unconformity were interpreted across the 3D seismic data set (see Table 3-2 and Figure 3-6 and Figure 3-8). Six events were picked on a seed grid and then autotracked. The Top and Base Captain Sandstone could not be autotracked because of their variable and poor seismic response.

The area of missing seismic to the north west edge of the Captain fairway has been interpolated using interpreted data around the edges to extrapolate over the area of missing seismic. A polygon has been used to define the area of each surface (Figure 3-2 light blue polygon) except for:

- Top Beauly Coal which out crops at the seabed and is only present in the eastern half of the area
- Top and Base Captain Sandstone which is limited to a narrow fairway (Figure 3-2 black polygon)

The horizon values were then gridded at 50x50m grid increment and the resultant time maps are shown in Figure 3-9 to Figure 3-20. The interpreted seismic horizons are described below.

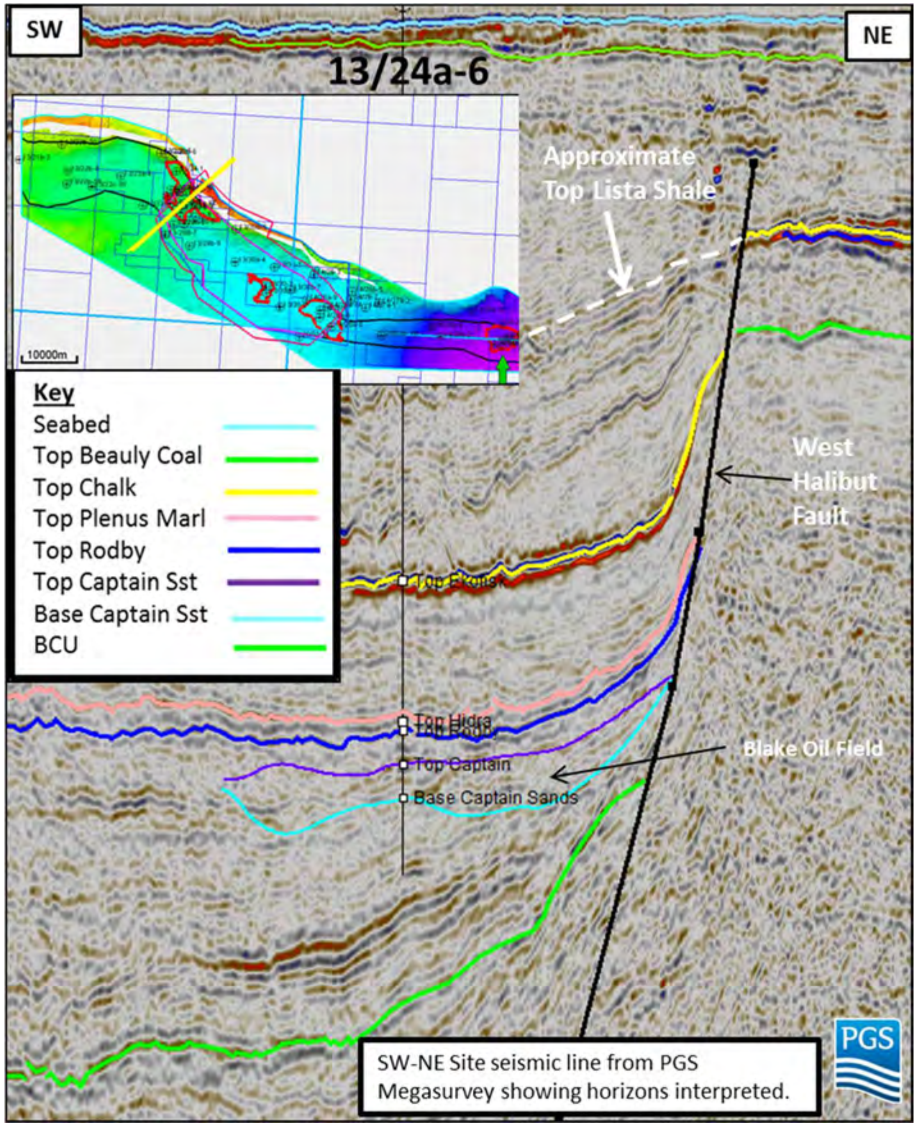



Figure 3-8 SW NE Captain fairway seismic profile

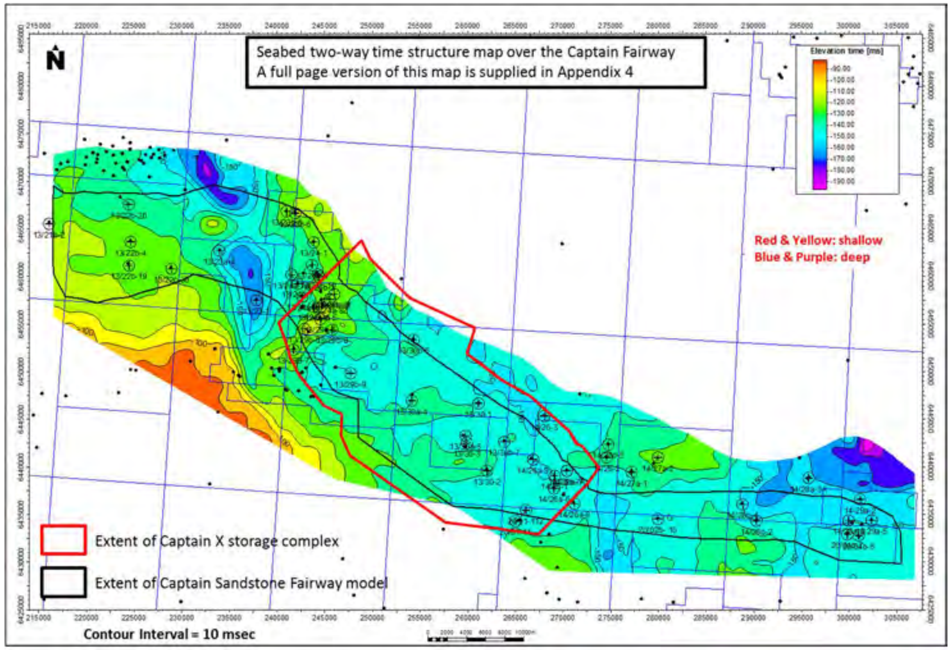



*Figure 3-9 Seabed two-way time map over the Captain fairway*

Seabed – This event is a high-amplitude continuous peak, representing an increase in acoustic impedance at the seabed. The horizon was manually picked at a seed increment inline/crossline spacing of 128 enabling the event to be accurately autotracked with a high level of confidence (Figure 3-9). There is a prominent acquisition footprint to the south east of the Captain fairway causing distinctive north-south lineaments which has affected the geometry of the sea bed pick in areas. Smoothing of the final time grid has removed these seismic acquisition artefacts.

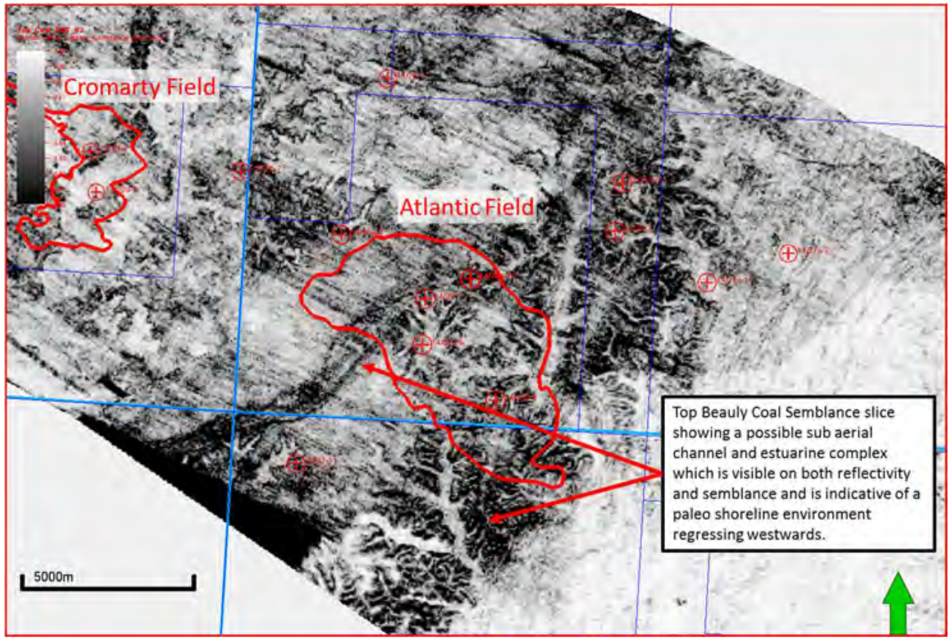



*Figure 3-10 Semblance horizon at Top Beauly Coal*

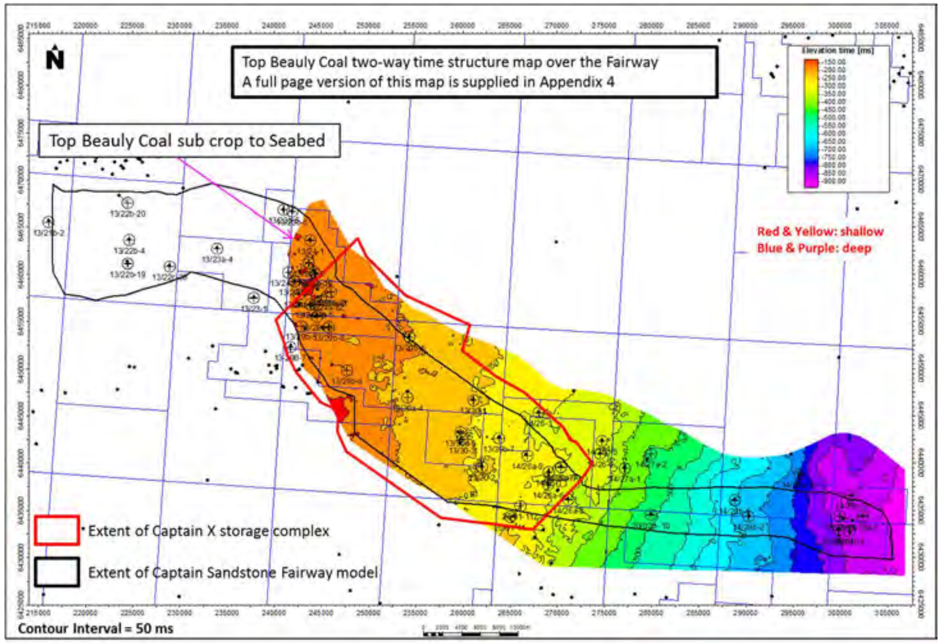



*Figure 3-11 Top Beauly Coal two-way time structure map over the Captain fairway*

Top Beauly Coal – The Top Beauly Coal is a high-amplitude trough representing a decrease in acoustic impedance. The event marks the top of a package of very bright high amplitude reflectors. This package varies in thickness laterally displaying a general thickening from west to east. A series of distinct channel incisions can be identified trending in a north west to south east orientation, south east of the Cromarty field. This proposed sub aerial channel and estuarine complex which is visible on both reflectivity and semblance volumes at Top Beauly Coal level (Figure 3-10), is indicative of a paleo shoreline environment regressing westwards (Shell, 2015). The coal package is present over the Captain X site area but outcrops at the seabed to the north west of the Blake oil field. The horizon was manually picked at a seed increment inline/crossline spacing of 128 enabling the event to be accurately autotracked with a high level of confidence (Figure 3-11).

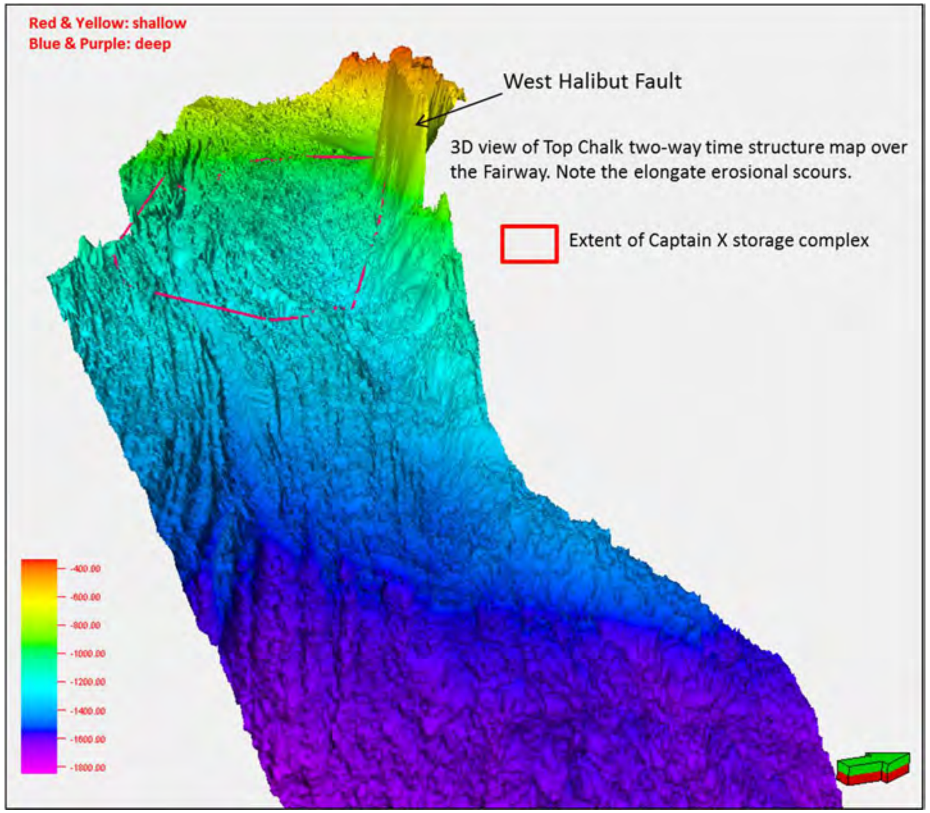



*Figure 3-12 3D view of Top Chalk two-way time map*

Top Chalk (Top Ekofisk) – The Top Chalk (Top Ekofisk) is a high amplitude peak at the base of the Tertiary section representing an increase in acoustic impedance. This strong reflector is continuous across the entire fairway area and is highly rugose in nature mainly due to erosion and minor faulting (Figure 3-12). The rugosity also contributes to degradation of data quality of the reflectors below due to scattering of the seismic energy.

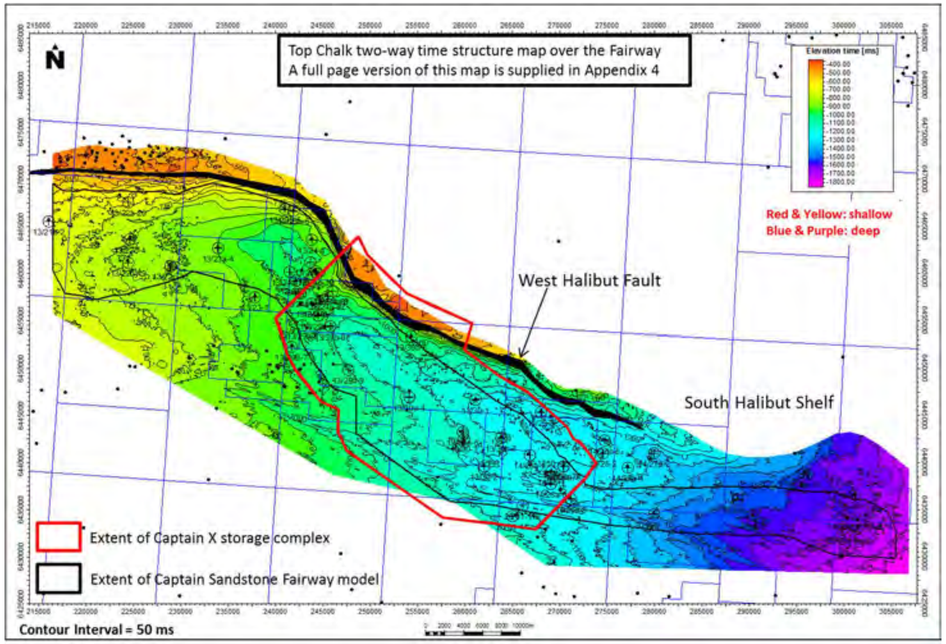



*Figure 3-13 Top Chalk two-way time structure map over the Fairway*

Due to erosion the horizon is lithologically variable and in the Goldeneye area the event merges with the underlying Top Tor event (intra Chalk). Along the northern edge of the fairway, the Top Chalk is significantly offset across the West Halibut Fault (Figure 3-8). The throw of this fault decreases to the south east and eventually the fault dies out. At this point the chalk is no longer offset by the fault and onlaps onto the South Halibut Shelf instead. The Top Chalk horizon has been manually picked at a seed increment inline/crossline spacing of 128 enabling the event to be accurately autotracked with a high level of confidence (Figure 3-13).

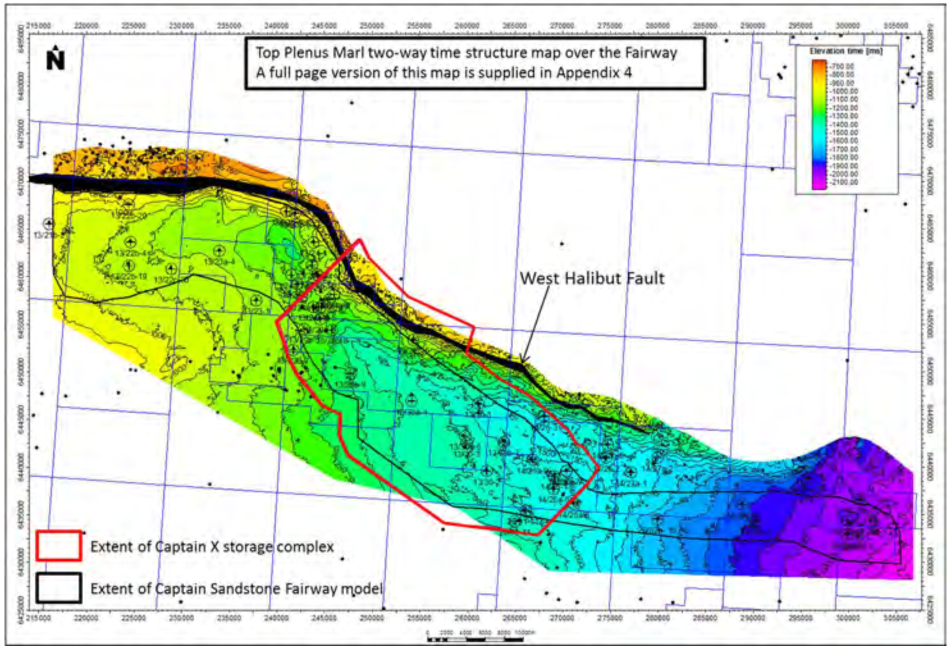



*Figure 3-14 Top Plenus Marl two-way time map over the Captain fairway*

<u>Top Plenus Marl</u> – The seismic response of the Top Plenus Marl is predominately a moderately high amplitude trough, representing a decrease in acoustic impedance. The event is continuous regionally across the entire Captain fairway. The Top Plenus Marl acts as a reliable marker to hang the synthetic seismograms from in the seismic to well tie process. The Plenus Marl and Hidra Formation intervals are thinnest over the Blake Field area and thicken towards the south east and north west (Figure 3-6). Like the Chalk above, the Plenus Marl and Hidra Formations are also offset by the West Halibut Fault and limited well control shows that it is absent across some areas of the Halibut Horst.

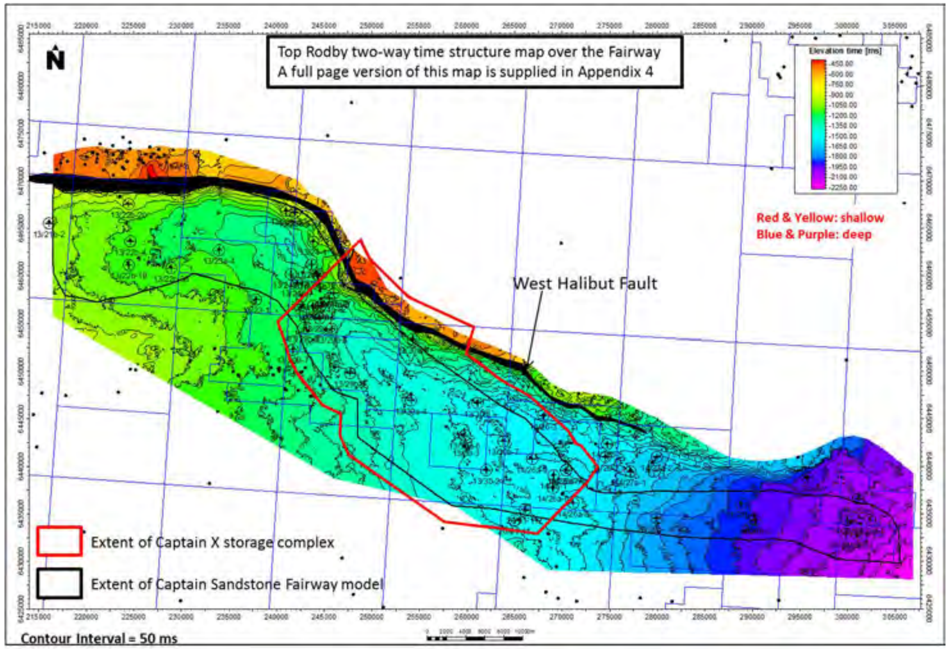



*Figure 3-15 Top Rodby two-way time structure map over the Captain fairway*

The horizon was manually picked at a seed increment inline/crossline spacing of 128 enabling the event to be accurately autotracked with a fair to good level of confidence (Figure 3-14).

<u>Top Rodby</u> – The Top Rodby is a medium to high amplitude trough, representing a decrease in acoustic impedance. The event is one full seismic loop below the Top Plenus Marl and conforms to the same topography. The event is continuous regionally across the entire fairway. The Top Rodby acts as a reliable marker to hang the synthetic seismograms from in the seismic to well tie process. The Top Rodby is a key event due to the high confidence of the pick and is used to help constrain the Top Captain Sandstone interpretation. Limited well control

shows that the Rodby interval is probably absent to the north of the West Halibut fault on the Halibut horst.

The horizon was manually picked at a seed increment inline/crossline spacing of 128 enabling the event to be accurately autotracked with a medium to high level of confidence (Figure 3-15). The long wavelet period of the event does cause horizon interpretation timing uncertainties when autotracking which results in a noisy surface (Figure 3-15) when compared with the overlying Top Plenus Marl (Figure 3-14).

<u>Top Captain Sandstone</u> – The Captain Sandstone fairway lies within the hanging wall of the half graben (downfaulted) created by the West Halibut Fault. The top of the Captain Sandstone has a variable seismic response and poor seismic resolution making accurate interpretation of the event extremely difficult. The seismic imaging of the reservoir is hindered by a lack of acoustic impedance contrast across the interface between the Rodby/Carrack Shale and the Captain Sandstone making delineation of the top sandstone very uncertain using conventional seismic interpretation techniques (Argent, et al., 2005). To make matters worse, there is peg leg multiple (a secondary seismic echo created between two interfaces) caused by the overlying Chalk interval which often arrives at a similar travel time to the Top Captain Sandstone, making interpretation more prone to error (Law, et al., 2000).

Shell, as part of the Longannet CCS Project, document that a considerable amount of time and effort was expended in interpreting Top and Base Captain Sandstone events on reprocessed 3D seismic volumes. From published maps (Shell, 2015), it is possible to define a polygon in Petrel to limit the lateral extent of the north west-to south east trending Captain Sandstone fairway in the “pan handle” area. In the same report Shell also notes that the position of the northward pinchout of the Captain Sandstone could be recognised with some confidence, however the delineation of the southward shale-out/pinchout is less reliable, especially in Blocks 13/29 and 20/3b, even with re-processed data.

The north west extent of the Captain Sandstone Fairway is not covered by the Shell polygon (Figure 3-16). In this area the West Halibut Fault intersects the east-west trending Captain Field main boundary fault. North of this fault, Captain Sandstone is present in numerous wells, but because only 25% of the area is covered by the PGS 3D seismic, this large northern part of the Captain fairway has not been specifically mapped in this study. It is however represented in the dynamic modelling work by a representative numerical aquifer to account for this extra brine filled pore space. To the south of the Captain and West Halibut Faults there is considerable uncertainty on the exact location where the Captain Sandstone pinches-out along the edge of the fairway. In the hanging wall (the down faulted side) the Captain Sandstone probably extends up to the Captain Field main boundary fault. In the middle section of the fairway (at the Blake oil field and Tain oil discovery) the Captain Sandstone probably extends north-eastwards up to the West Halibut Fault in places (Figure 3-17). To the south west, drilling has confirmed that the sand is absent and must pinch-out before reaching this fault (Figure 3-17). Captain Sandstone is not present on the Halibut Horst. On the southern side of the fairway, away from well control, the Captain Sandstone pinch-out edge is very uncertain and in this interpretation it is controlled exclusively by the Shell fairway polygon and well control. Due to the uncertainty in the pinch-out out the storage complex south west boundary has been extended some 2 km beyond the currently mapped sandstone limit.

Well ties show that the seismic response of the Top Captain Sandstone varies between a peak, trough and zero crossing. Due to this, the horizon has not been interpreted on a specific event and a more model based approach has been taken using the Top Rodby horizon pick, Top Captain Sandstone well picks, seismic character and Shell's sand pinch out edge polygon to help guide the interpretation. The horizon was manually interpreted at a seed increment of inline/crossline spacing of 128. The resultant surface can be seen in Figure 3-16. The variable nature of the seismic response meant that the horizon could not be autotracked and the resultant time mapping is low confidence.

The north west extent of the Captain Sandstone Fairway is not covered by the Shell polygon (Figure 3-16). In this area the West Halibut fault intersects the east-west trending Captain Field main boundary fault. North of this fault, Captain Sandstone is present in numerous wells, but because only 25% of the area is covered by the PGS 3D seismic, this large northern part of the Captain fairway has not been specifically mapped in this study. It is however represented in the dynamic modelling work with a representative numerical aquifer to account for this extra brine filled pore space. In the hanging wall (the down faulted side) the Captain Sandstone probably extends up to the Captain Field main boundary fault. In the middle section of the fairway (at the Blake oil field) it is possible that the Captain Sandstone extends north-eastwards up to the West Halibut Fault (Figure 3-17). To the south west, drilling has confirmed that the sand is absent and must pinchout before reaching this fault (Figure 3-17). Captain Sandstone is not present on the Halibut Horst.

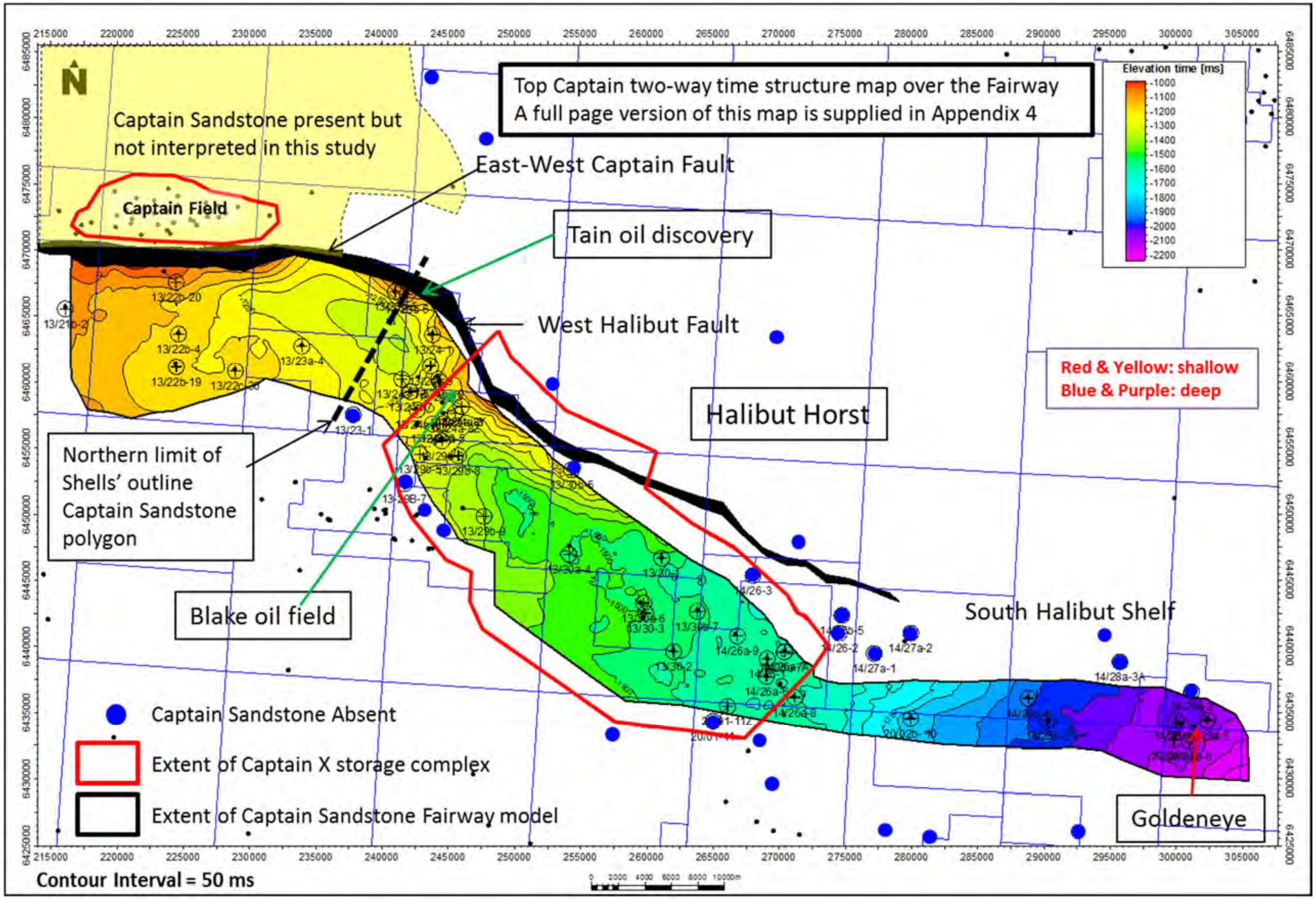



*Figure 3-16 Top Captain sandstone two-way time map*

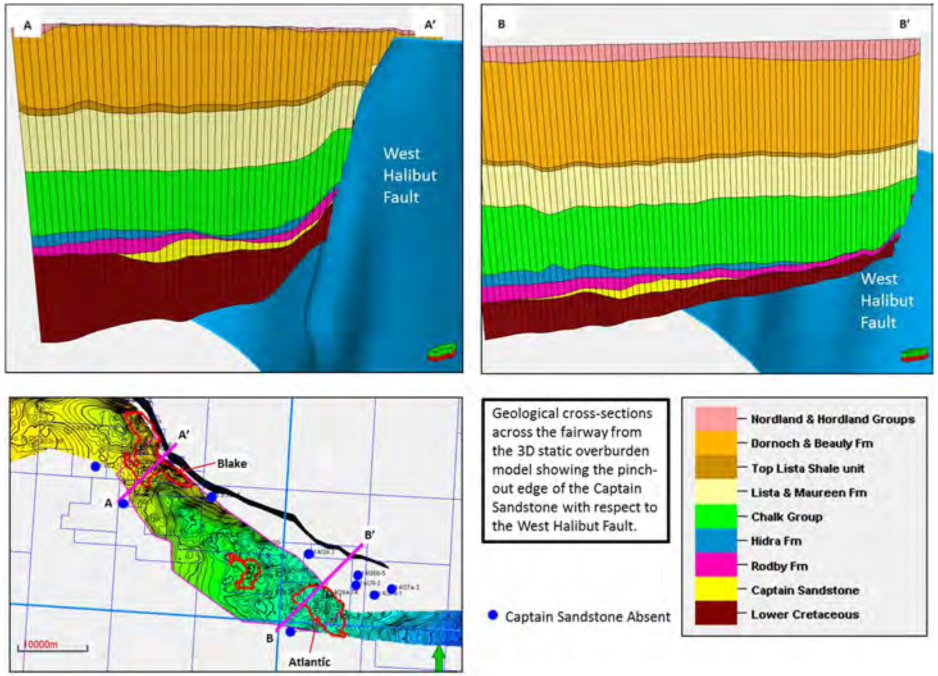



*Figure 3-17 Fairway cross sections from the 3D static overburden model*

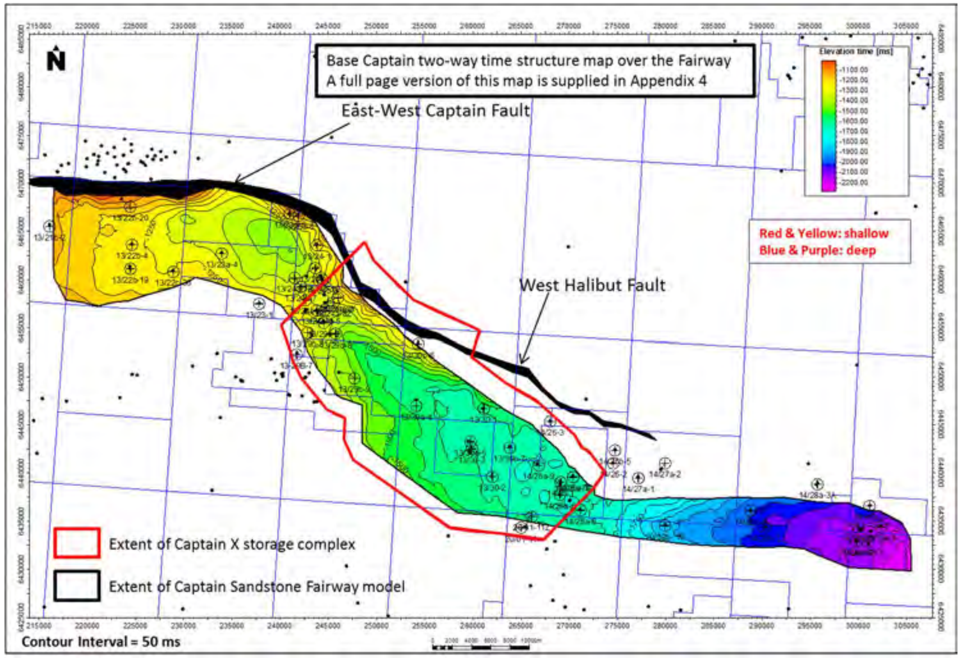



*Figure 3-18 Base Captain sandstone two-way time map*

Base Captain Sandstone – The Base Captain Sandstone event is an erosive surface and, like the Top Captain, has a highly variable seismic response. The pick is predominantly a peak but can also be a trough or zero-crossing and this together with poor seismic resolution makes reliable interpretation of the event very difficult. The key purpose of interpreting this event was to attempt to define the pinch-out edges of the Captain Sandstone fairway. A Captain Sandstone isochore (depth thickness map) generated from well picks was converted from depth to time to create a Captain Sandstone isochron (time thickness map). This isochron was added to the Top Captain Sandstone time surface and the resultant approximate Base Captain time surface was used to help guide the interpretation. The Base Captain Sandstone was manually interpreted at a seed increment of inline/crossline spacing of 128. The resultant surface can be seen in Figure 3-18. The variable nature of the seismic response meant that the horizon could not be autotracked and is mapped with low confidence.

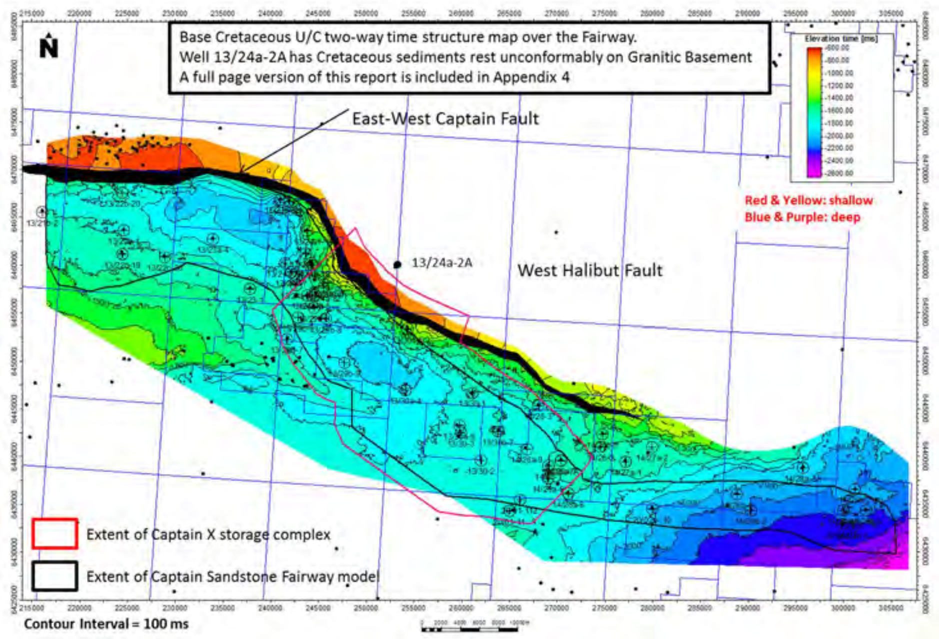



*Figure 3-19 Base Cretaceous unconformity two-way time structure*

Base Cretaceous Unconformity – The seismic response of the Base Cretaceous Unconformity is a moderate to high amplitude trough, representing a decrease in acoustic impedance. This pick defines the top of the Kimmeridge Clay formation and also is the base of the Static Models. The Base Cretaceous Unconformity is offset by the West Halibut and Captain Field Boundary Faults and limited well control shows that in places Cretaceous sediments rest unconformably on Granitic Basement (well 13/24a-2A in Figure 3-19). The horizon was manually interpreted at a seed increment of inline/crossline spacing of 128. Due the strong amplitude response of the event it was autotracked with a medium to high level of confidence (Figure 3-19).

Figure 3-20 shows a 3D view of Top Captain Sandstone two-way time structure (yellow surface) sitting above the Base Cretaceous Unconformity two-way time surface.

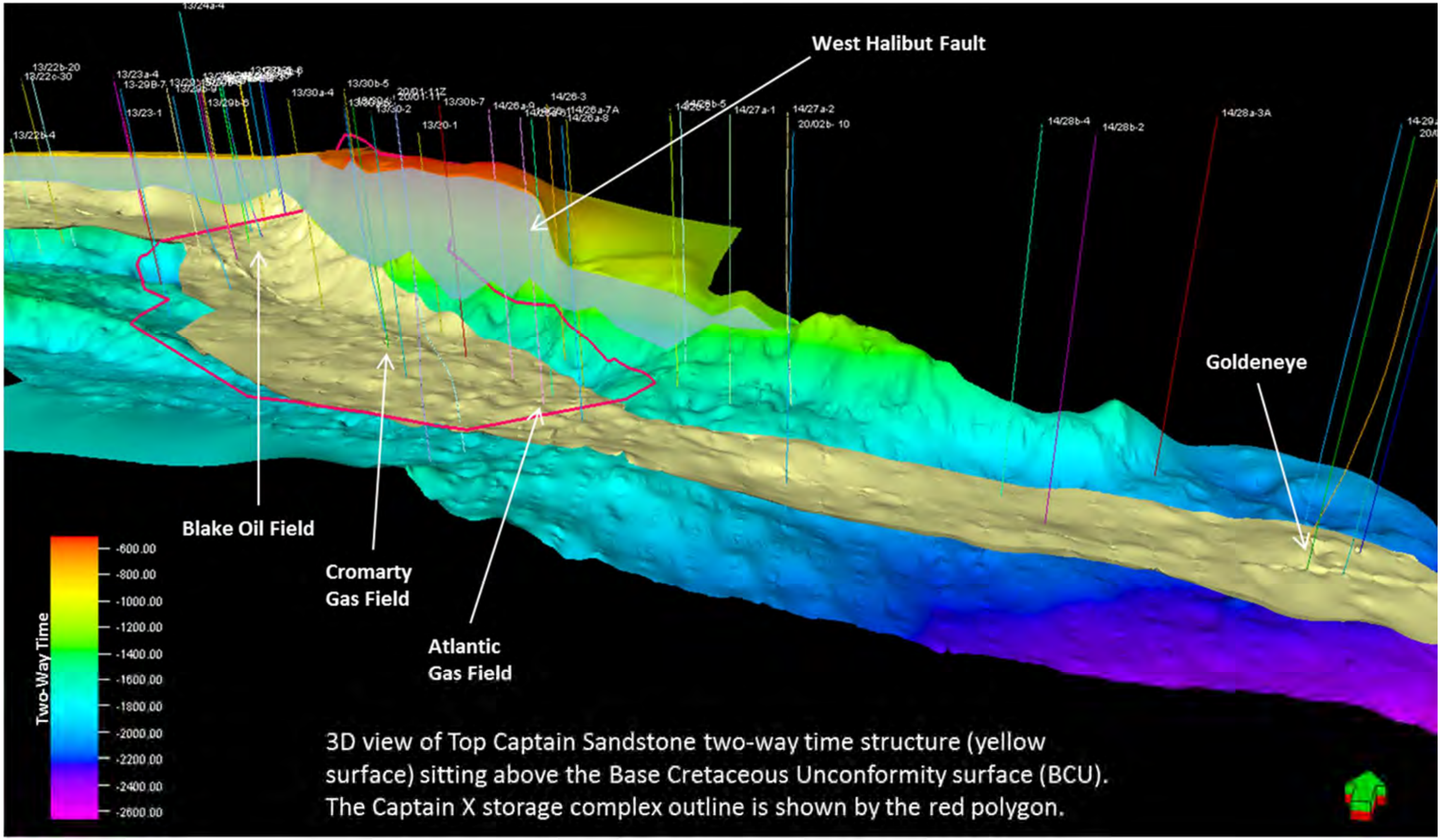



*Figure 3-20 3D view of Top Captain sandstone time interpretation*

### 3.4.4 Faulting

At the northern end of the Captain Sandstone fairway, The west to east trending Captain Fault separates the “pan-handle” from the “pan” with the Captain Sandstone extending across the fault to provide the reservoir for the Captain oil field to the north of it. The West Halibut Fault appears to extend this to the south east with the Captain Sandstone fairway lying to the downthrown south of the fault ( Figure 3-16).

Due to the poor seismic imaging of the Captain Sandstone (section 3.4.3) there is uncertainty on whether the Captain Sandstone extends right up to the West Halibut Fault or pinches-out before it reaches it. Where the Captain and West Halibut Faults meet there is a small oil discovery (Tain) in Captain Sandstones in the hanging wall of the faults. To the south east of Tain the oil in the Blake field is trapped in the Captain Sandstones which the operator believes extends up to the West Halibut Fault. At Blake and probably at Tain, well control to the north suggests that the Captain Sandstones are juxtaposed across the fault against either granitic basement or Devonian claystone (with occasional very tight sandstone) and at these two locations the fault is probably sealing as shown by the presence of trapped oil. To the west of Tain the amount of offset on the Captain Fault decreases and across the fault the Captain Sandstone is probably juxtaposed against Triassic and Jurassic units which do contain sandstones and there is an increased lateral containment risk across this fault.

Elsewhere, to the south east, the fairway contains a number of 4-way dip closed and 3 way dip plus stratigraphic pinch out structures which provide the trapping mechanisms for four significant Captain Sandstone hydrocarbon accumulations, Blake, Cromarty, Atlantic and Goldeneye.

The West Halibut Fault extends upwards into the shallow Tertiary section but not to the seabed. Between Atlantic and Tain the Lista secondary cap-rock is offset by this fault (Figure 3-8). Further to the west it is not clear if the Captain Fault extends to the seabed. Shallow seismic data quality is very poor due to seismic noise at the join of two 3D surveys and a strong seabed multiple. This seismic noise also masks the Lista event and it is not clear if there is any offset of the Lista across the fault.

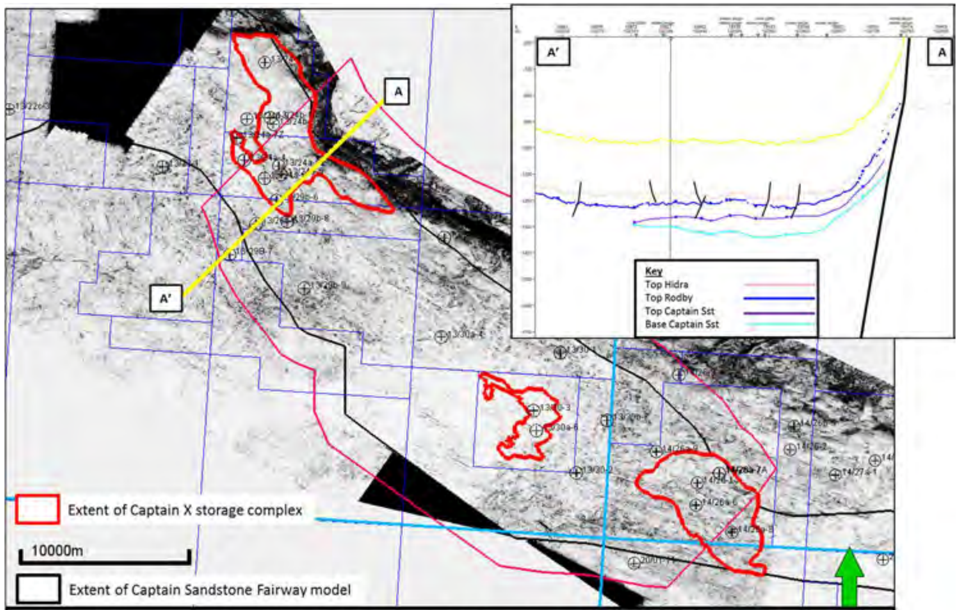
To the south east of Blake the offset on the West Halibut Fault decrease and the fault ends some 20km from the Goldeneye field. Between Blake and Goldeneye there are 9 wells on the southern side of the fault with no Captain Sandstone which confirms that the sandstone is absent and must pinch-out before reaching this fault Figure 3-17. Captain Sandstone is not present on the Halibut Horst.

Within the “pan-handle” part of the Captain Sandstone fairway, no other significant faults have been identified at the Top Captain Sandstone using the available seismic data. Due to the poor seismic imaging of the Captain Sandstone (section 3.4.3) faulting may be more significant than currently identified. However, the Top Rodby is a reliable seismic marker and this is the top of the primary seal. A semblance horizon slice at Top Rodby (Figure 3-21) reveals potential small scale features, running in a north west to south east orientation. Some of these features may be seismic artefacts caused by the merging of seismic volumes but several of these features do appear to be real faults when displayed in seismic section. These are very minor faults and do not breach the Rodby/Carrack primary seal.

There is some evidence of seismically resolvable small scale faulting within the Captain Sandstone, particularly in the region of the Goldeneye field. Shell document that the greatest fault density can be identified around the vicinity of the Goldeneye14/29a-3 well (Shell, 2015). The faults extend in an approximately East to West orientation, which is consistent with the regional trend of the Halibut Horst and regional structural framework. Seismic resolution of the faulting is poor making interpretation difficult. The faults are limited in vertical extent and do not offset the overlying Rodby/Carrack sealing shale formation. Within the Captain Sandstone fault throw appears to be small and are not expected to create any significant barrier or baffle to the flow of $CO_2$. This conclusion is supported by the pressure depletion record of post production RFTs which suggest excellent lateral hydraulic connectivity. As the minor faulting within the Top Rodby does not breach the top seal or provide a barrier to $CO_2$ within the

Captain Sandstone it was not deemed necessary to include them when building the Static Models.

Figure 3-22 shows the Top Chalk semblance horizon slice and numerous lineaments can be seen, mainly orientated north west to south east. The majority of the lineaments appear to be erosional in nature although some are probably due to faulting. This faulting does not extend far into the overburden and they do not appear to be connected with the small scale deeper faulting within the Captain Sandstone and Top Rodby shale. In the shallower Tertiary section there is little evidence of significant faulting. The subsurface formations are poorly imaged with the seismic data due to seismic energy absorption within the thick, laterally variable shallower coal layers. Shallower discontinuities visible in the Tertiary section are not interpreted as faulting, and are more likely to be a seismic artefact caused by “edge effects” due to velocity contrasts from the overlying coals and shales (Shell, 2015). No faults have been included in the Captain Fairway or Captain X site static models. The overburden model does include the West Halibut Fault.




Top Rodby Semblance slice. The North West to South East trending black lines potentially show small scale faulting at the Top Rodby. Some of these features may be as a result of seismic artefacts, such as merging of seismic volume, however a cross section, based on a seismic line, does show that some of these features are probably small faults.

*Figure 3-21 Top Rodby semblance slice*

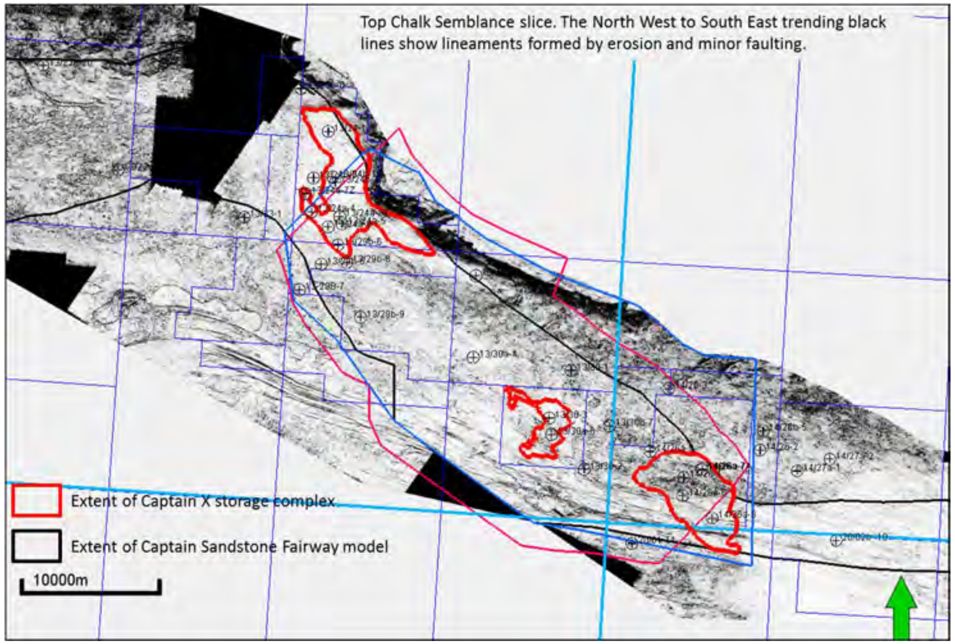


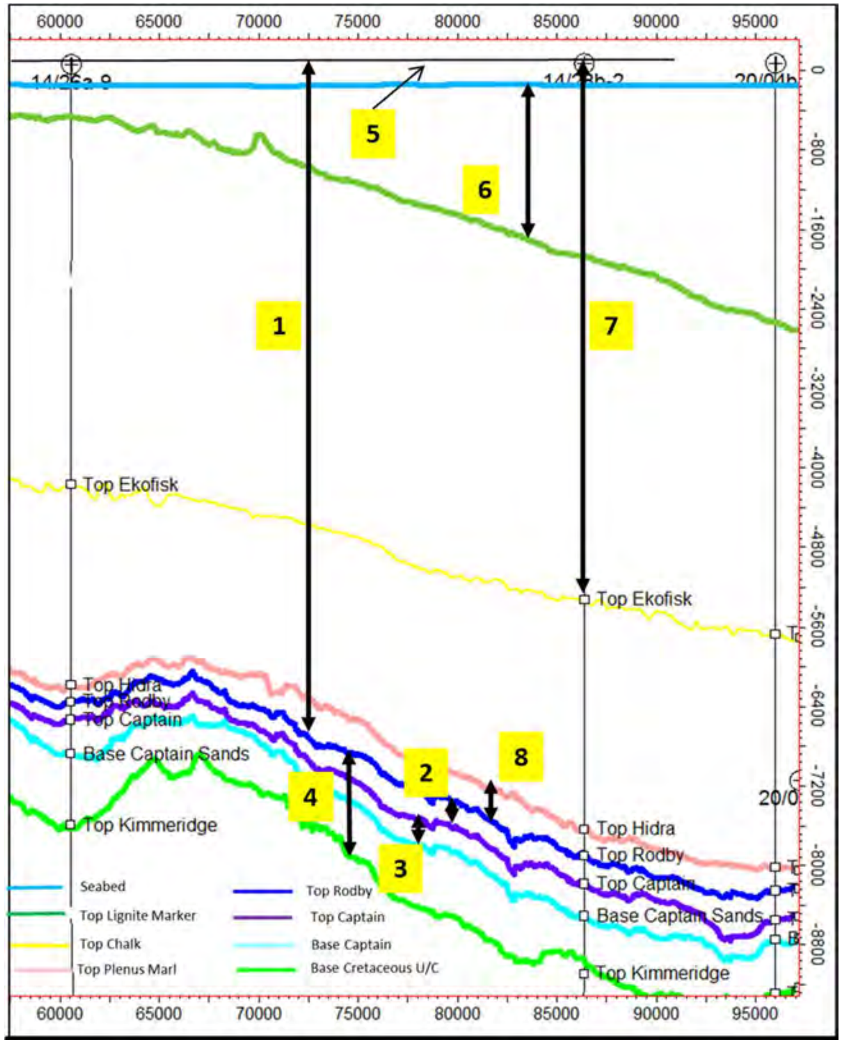

*Figure 3-22 Top Chalk semblance slice*

### 3.4.5 Depth Conversion

Whilst the time interpretation of the Top and Base Captain sandstone has proved challenging because of variable acoustic impedance, depth conversion of these events has also been historically problematic. This challenge arises due to the effect of rapid lateral velocity changes in the overburden, particularly related to lithology variations within the Tertiary section and rugosity of the Top Chalk surface (which is the top of a high velocity interval). Traditionally multi-layer depth conversions have been used for hydrocarbon field development projects (Shell, 2015). However, a multi-layer depth conversion was not considered feasible to apply across the entire Captain Fairway for this project.

In this study a single layer depth conversion method has been used from Mean Sea Level (MSL) down to Top Rodby using an average velocity map. This is similar to the method Shell used for their Captain Sandstone fairway depth conversion (Shell, 2015). The Top Rodby depth surface was then used as a depth reference surface and the Rodby/Carrack isochore hung from this to derive the Top Captain Sandstone depth surface. As a regional depth conversion this somewhat simplified method was considered fit for purpose and has the added advantage of not having a strong imprint of the heavily eroded Top Chalk surface embedded in the Top Captain depth surface potentially adding rugosity to the Top Captain surface where it in fact probably did not exist.

The depth conversion was undertaken in the industry standard interpretation software PETREL. The depth conversion method for each interval or surface is outlined below and the depth conversion steps are summarised in Figure 3-23;




Cross section based on a seismic line illustrating the depth conversion method used for each surface. The numbers refer to the depth conversion step (see text)

*Figure 3-23 Depth conversion summary*

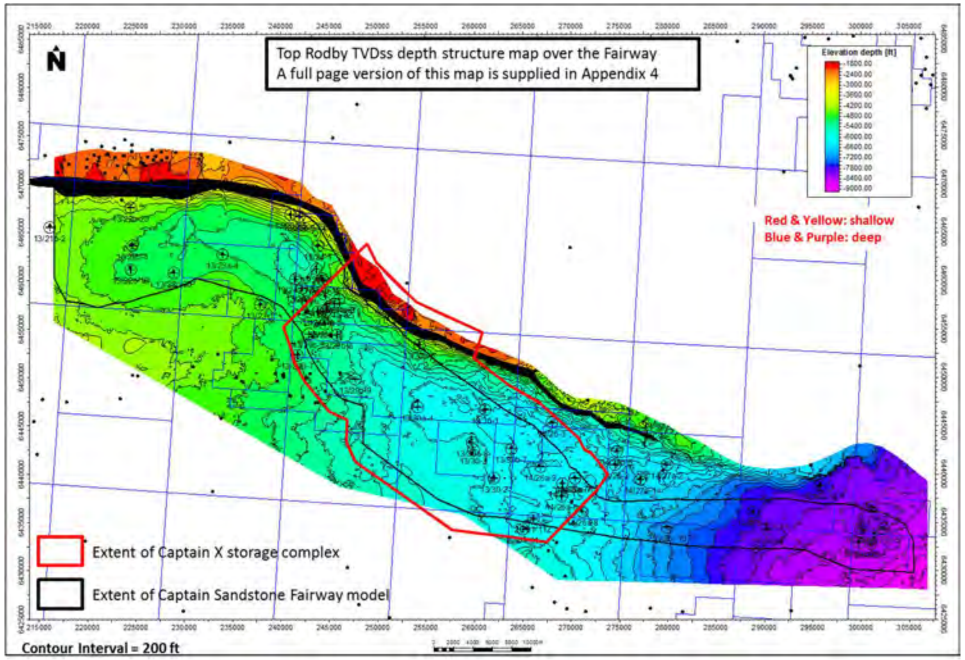



*Figure 3-24 Top Rodby TVDSS depth structure map over the Captain fairway*

1. <u>Mean Sea Level (MSL) to Top Rodby Interval</u> – This interval was depth converted using an average "pseudo-velocity" map. At the well locations the Top Rodby two-way time values from the gridded time surface were extracted along with the drilled depths. These were combined to create the average "pseudo velocity" at each well. The average velocity map was then generated by gridding and contouring the data points. The Top Rodby time surface was then multiplied by the average velocity map in order to generate the Top Rodby depth surface (Figure 3-24).

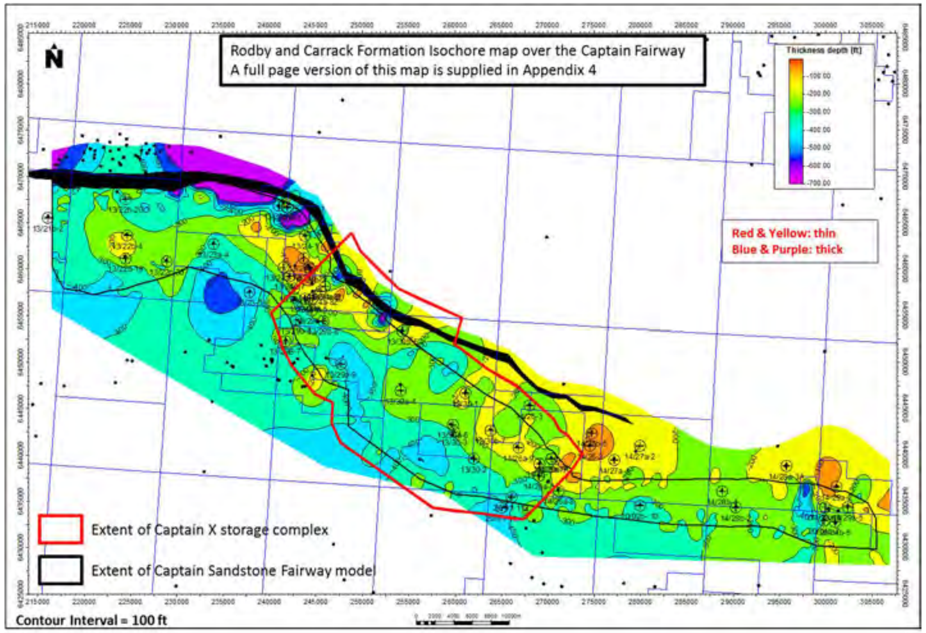



*Figure 3-25 Rodby and Carrack formation isochore map over the Captain fairway*

2. <u>Top Rodby to Top Captain Sandstone Interval</u> – The seismic interpretation of the Top Captain Sandstone is uncertain, therefore in the centre of the fairway an isochore based on gridded and contoured well thicknesses has been used to define the Rodby/Carrack isochore and this is added to the Top Rodby depth surface to give the Top Captain Sandstone depth surface. However, due to lack of well control around the fairway limits, this gave unrealistic results at the fairway edges and an alternative approach was needed.

   In these problematic areas at the edge of the fairway, an isochron between the Top Rodby and Top Captain Sandstone seismic interpretation was generated. The isochron was then depth converted to an isochore using a constant velocity of 9510 feet per second (derived from the time and depth values from available well data). This isochore (derived from the seismic interpretation) was blanked so that the surface was only present at the pinchout edges of the fairway. It was then merged with the isochore that had been calculated from the well tops to produce a final isochore (Figure 3-25). This was added to the Top Rodby depth surface to give the Top Captain Sandstone depth surface. The depth converted Top Captain surface required some hand editing, in order to ensure the closures of the Blake, Cromarty, Atlantic and Goldeneye fields match the Operator inferred size and spill point locations. The final depth surface is shown in Figure 3-26 and as a 3D image in Figure 3-27. The depth surface dips down to the south east with dips varying between 0.5 and 6 degrees.

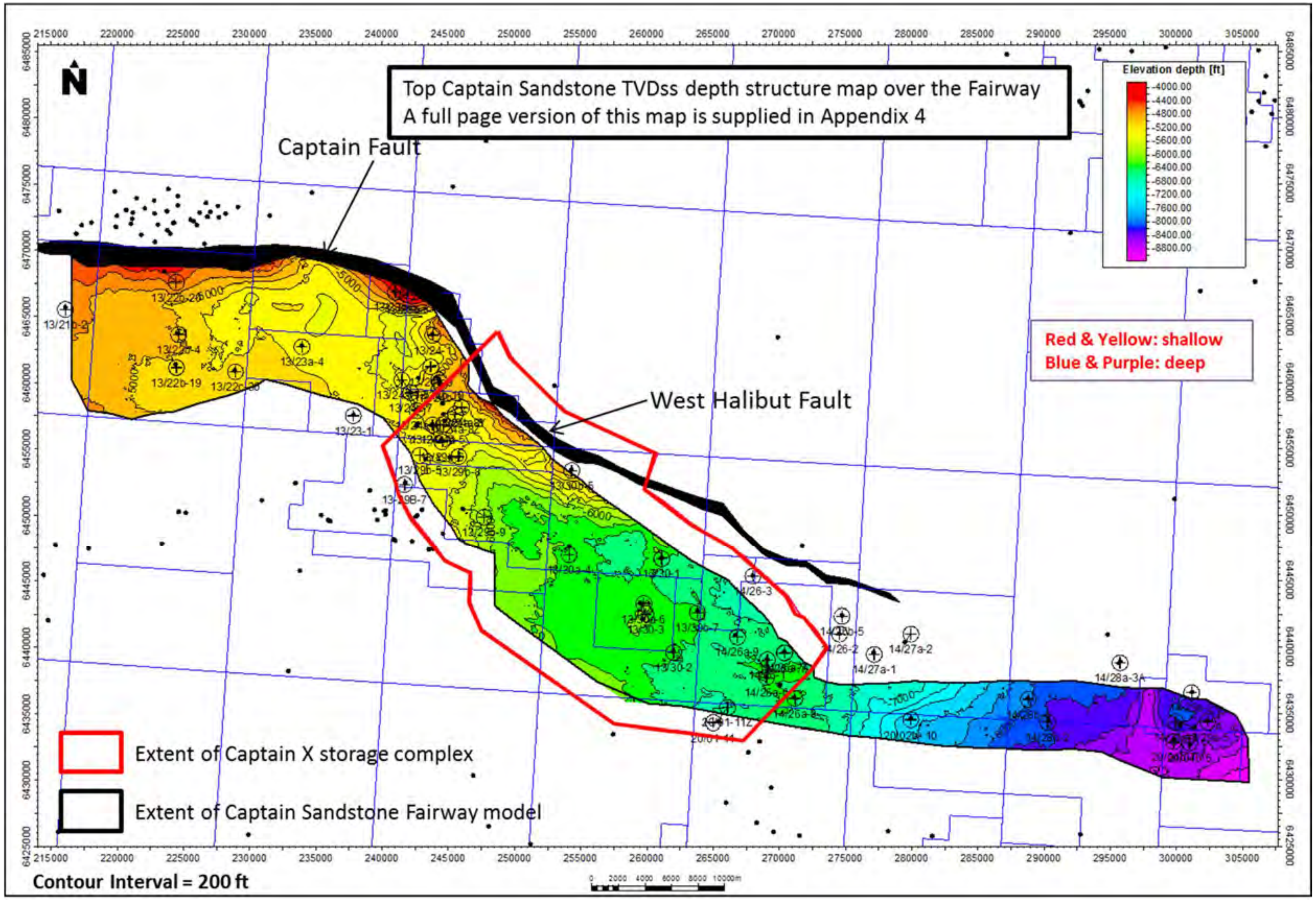



*Figure 3-26 Top Captain sandstone depth stucture map*

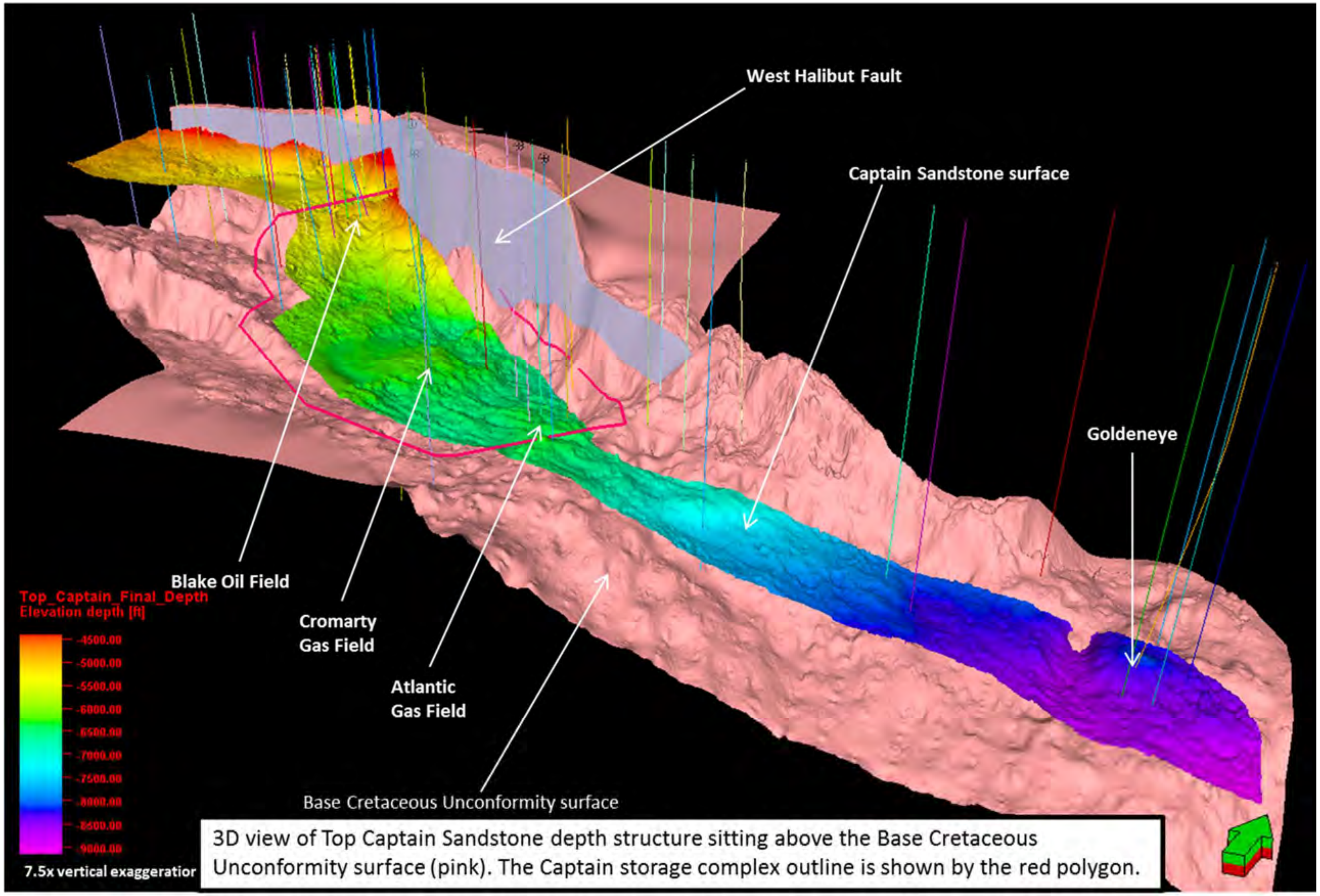



*Figure 3-27 Top Captain sandstone depth structure surface 3D view*

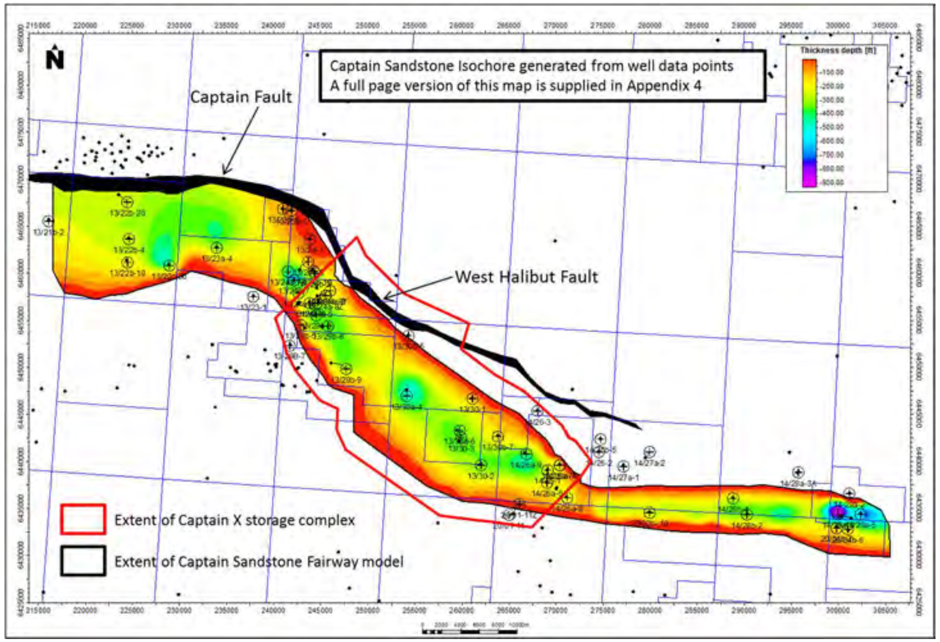



*Figure 3-28 Captain sandstone isochore*

3. Top Captain to Base Captain Sandstone Interval – The Top and Base Captain Sandstone seismic interpretation is very uncertain. The distribution and thickness of the Captain Sandstone is therefore only poorly defined by seismic data. It is however reasonably well defined by extensive well penetrations across the area. The isochore is probably influenced by the structural framework and position of the West Halibut Fault. A Lower Cretaceous isochron was produced from the seismic interpretation (Figure 3-28) but was of only limited use. The isochron does show the existence of a thicker section up against the Captain Fault in the northern part of the fairway and another thick between Atlantic and Blake. This thickening indicates there has been more accommodation space for sediment to collect and could indicate where the Captain Sandstones are present. However, south east of Atlantic the isochron shows just a gradual thickening to the south and gives no clue to where the Captain Sandstone might be present. Therefore, a Top Captain to Base Captain Sandstone isochore was generated by gridding well data points (Figure 3-28). This isochore map was added to the Top Captain Sandstone depth surface to a produce final Base Captain Sandstone depth surface (Figure 3-29) .

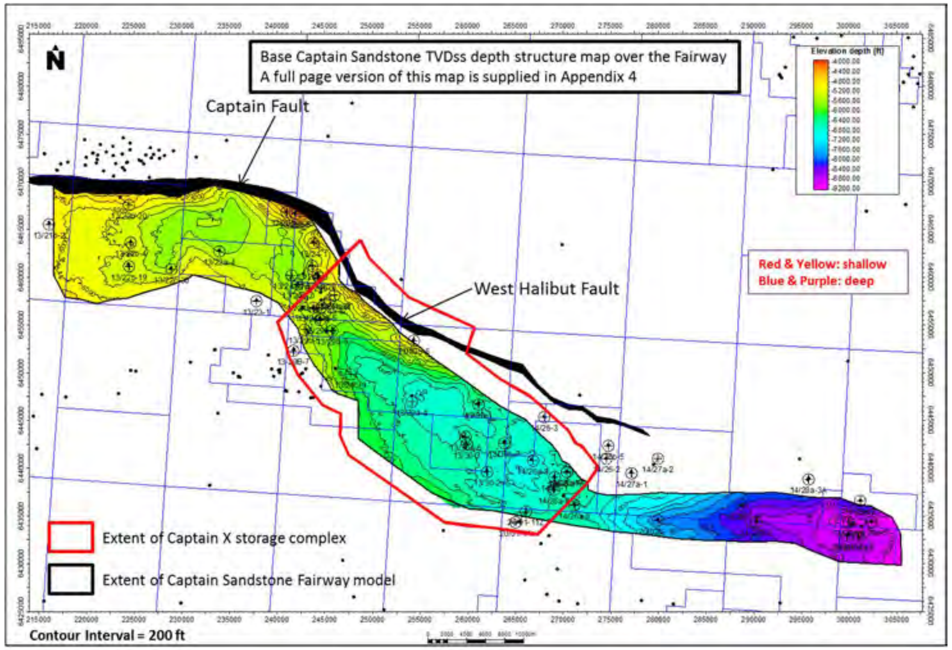



*Figure 3-29 Base Captain sandstone depth structure map*

4. Base Cretaceous Unconformity – As the Captain Sandstone is not present over the entire mapped area, to depth convert the Base Cretaceous Unconformity, which is present throughout the area, required the Top Rodby to Base Cretaceous Unconformity interval to be converted as a single unit. This was accomplished by creating an isochron of the Top Rodby to Base Cretaceous Unconformity time interpretation (Figure 3-30) and multiplying it by a constant velocity of 10450 feet per second to produce an isochore. The constant velocity of 10450 feet per second was derived by using time and depth values taken from several wells across the fairway area and calculating the velocity of the interval at each well and then combining all of the values to give an overall average constant velocity for the layer. This isochore was then added to the Top Rodby depth interval to produce a Base Cretaceous Unconformity depth surface (Figure 3-31).

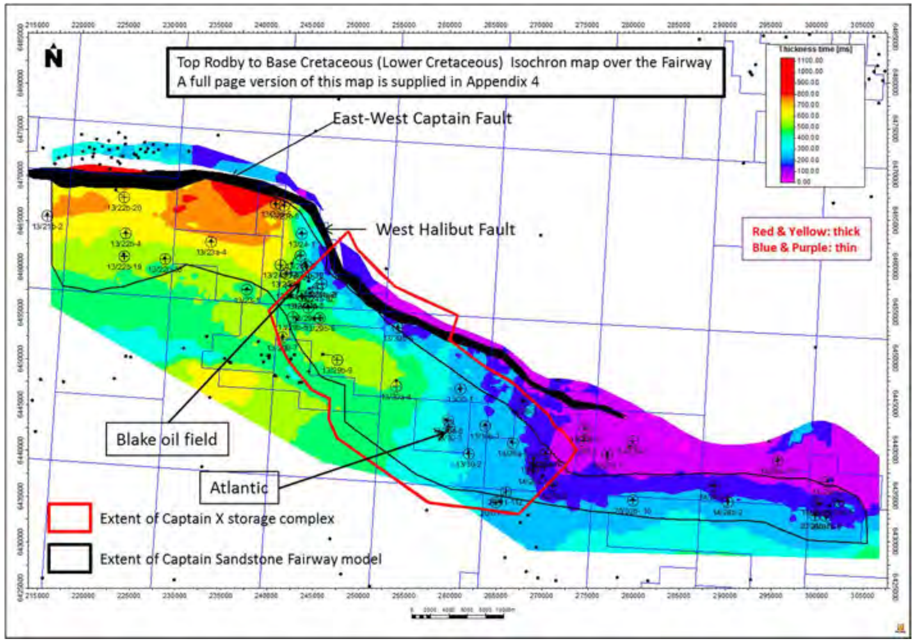



Figure 3-30 Top Rodby to Base Cretaceous isochron

The remaining interpreted time surfaces were depth converted to provide surfaces for the overburden 3D Static Model. The depth conversion method for each interval or surface is outlined below and the depth conversion steps are summarised in Figure 3-23;

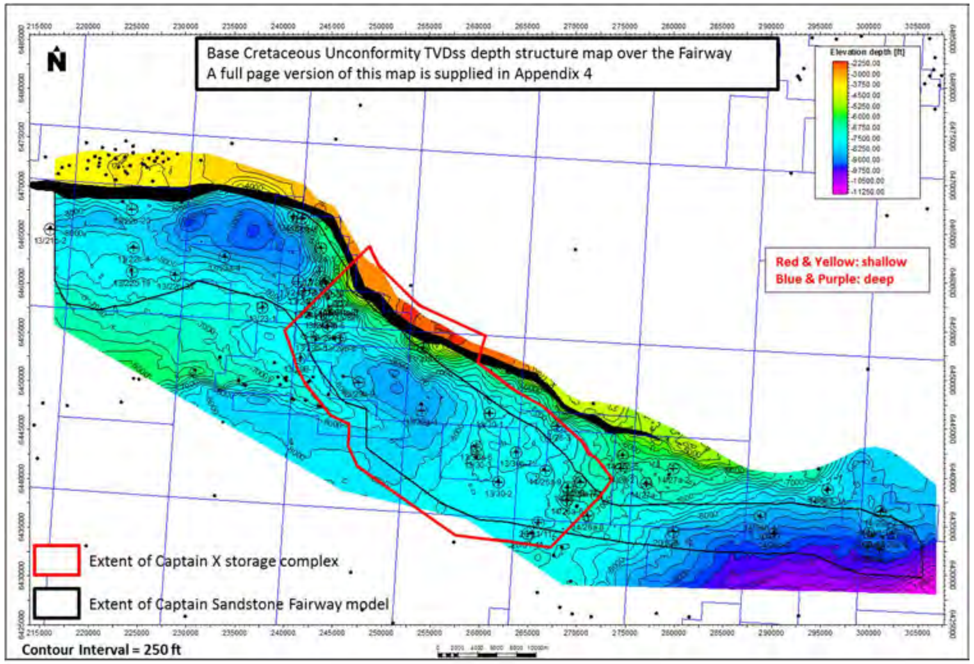



Figure 3-31 Base Cretaceous unconformity depth structure map

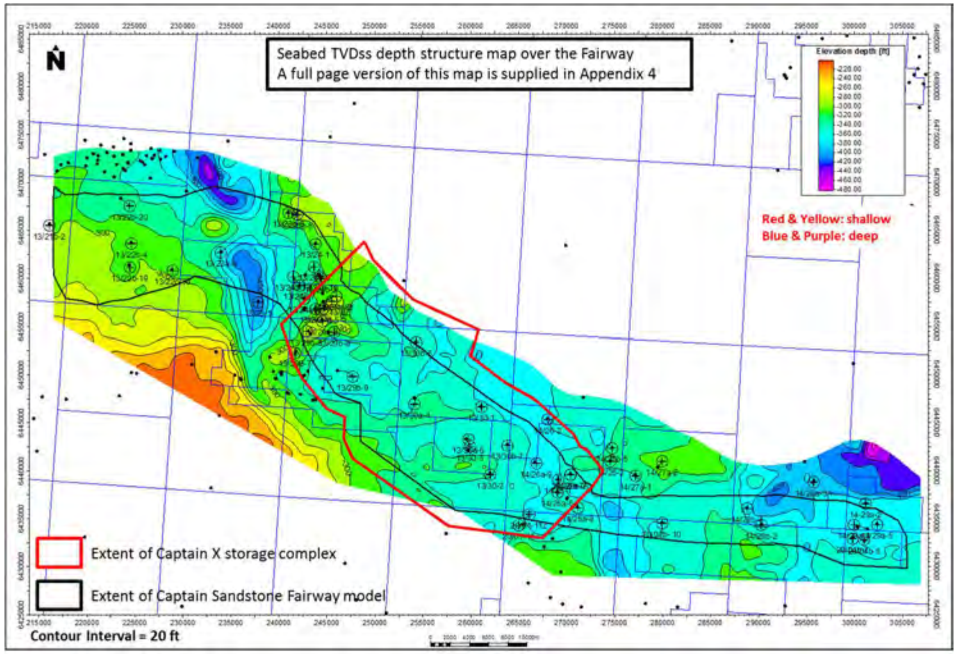



*Figure 3-32 Seabed depth structure map*

5. Sea Bed – The Seabed depth surface was generated by multiplying the Seabed time surface by a velocity of 4900 feet per second (speed of sound through the water column). The resulting depth surface is shown in Figure 3-32.

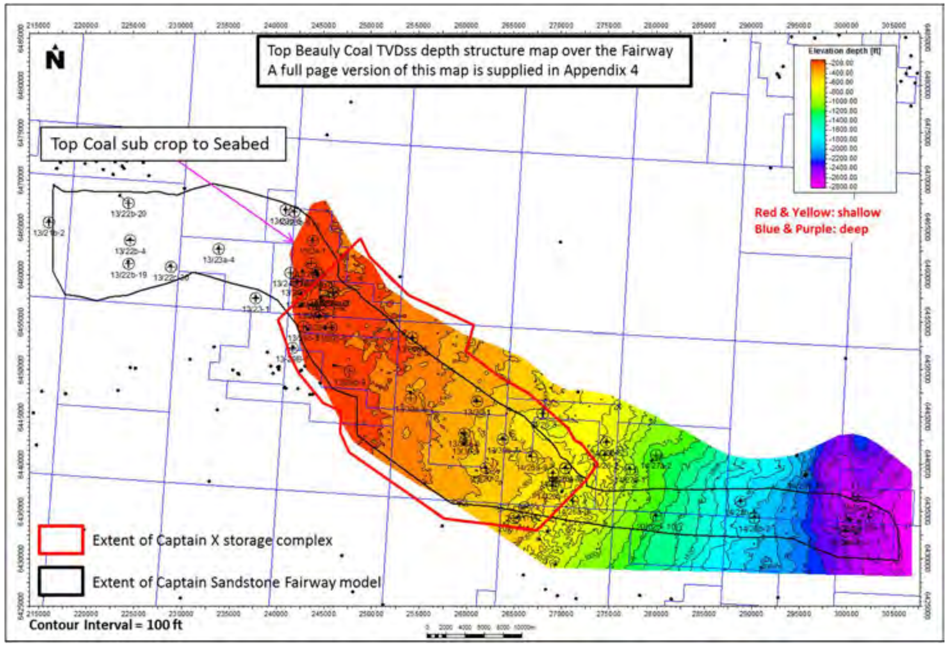



*Figure 3-33 Top Beauly Coal depth structure map*

6. Top Beauly Coal – This event was depth converted by multiplying the isochron (Top Beauly Coal time surface minus Seabed time surface) by a constant velocity. The constant velocity of 6200 feet per second was derived by using time and depth values taken from several wells across the fairway area and calculating the velocity of the interval at each well and then combining all of the values to give an overall average constant velocity for the layer. The resultant isochore was added to the Seabed depth map to give the Top Beauly Coal depth surface. This surface was blanked at the point the Top Beauly Coal out crops at the seabed. The resulting surface is shown in Figure 3-33.

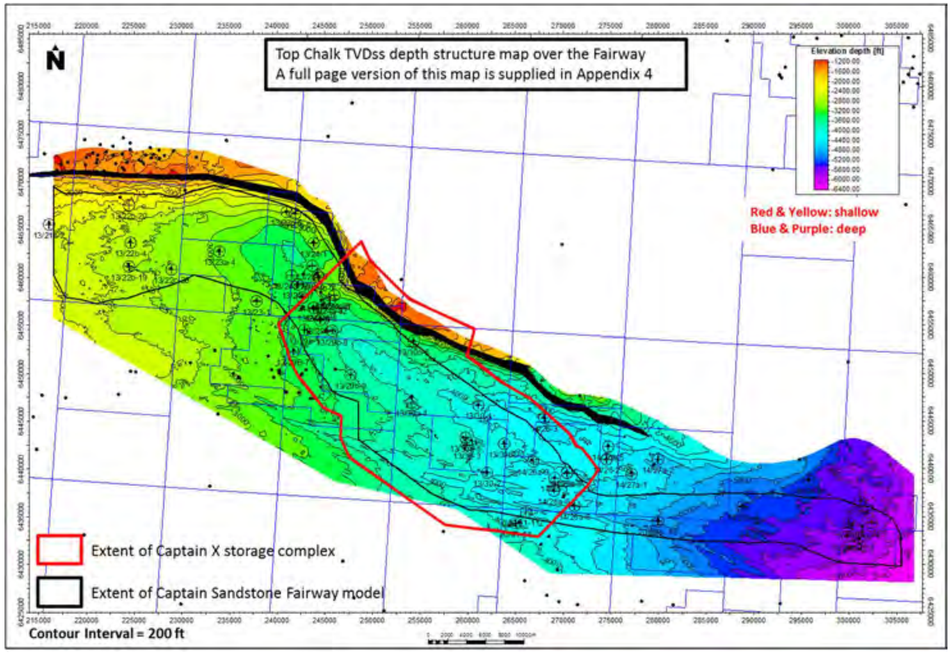



*Figure 3-34 Top Chalk depth structure map*

7. Top Chalk – Top Chalk event was depth converted by applying a linear time-depth function derived from back interpolated time values at the wells:
   Depth = (3.5311*T) + 119.08 where T is the Top Chalk time surface.
   The resulting depth surface is shown in Figure 3-34.

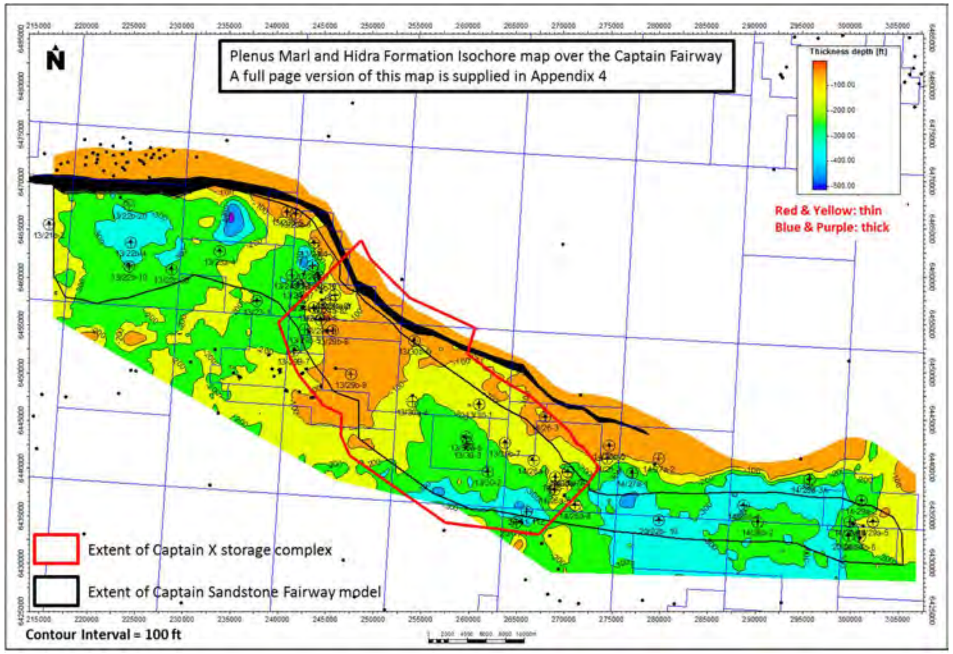



*Figure 3-35 Plenus Marl and Hidra formation isochore map*

8. Top Plenus Marl Formation – This event was depth converted by using an interval velocity map calculated from back interpolated time values and depth values between the Top Plenus Marl and Top Rodby at each well. The resulting velocity data points were gridded to create an interval velocity map across the area of interest. The Plenus Marl and Hidra isochron (Top Rodby time surface minus Top Plenus Marl time surface) was then multiplied by the interval velocity map in order to generate the Top Rodby to Top Plenus Marl isochore. This isochore (Figure 3-35) was subtracted from the Top Rodby depth interval to produce the Top Plenus Marl depth surface (Figure 3-36).

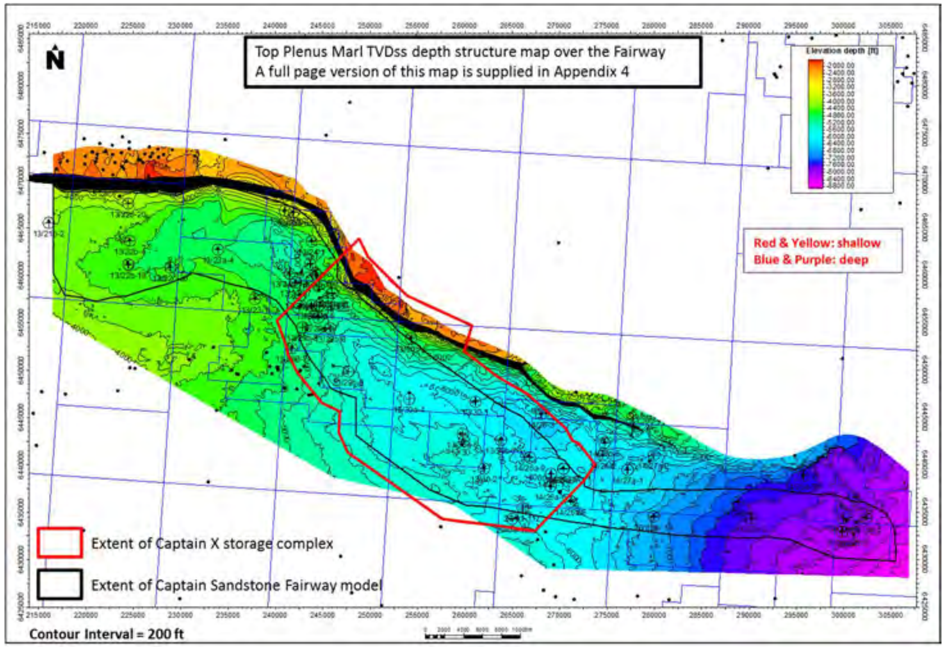



*Figure 3-36 Top Plenus Marl depth structure map*

### 3.4.6 Depth Conversion Uncertainty

Depth conversion uncertainty to the Lower Cretaceous target storage reservoir is significant. Published literature relating to hydrocarbon exploration and development in the Captain fairway shows that depth conversion is complex and uncertain and was not resolved even during field development. Petroleum FIDs having to be robust to the volumetric variance that depth conversion uncertainty contributes. Unlike in petroleum development where depth conversion directly influences the oil or gas volumetrics and therefore reserves, in $CO_2$ storage in an open aquifer system, depth conversion is a second order control on pore volume. Accurate depth definition is important to understanding the detailed migration pathways of injected $CO_2$ away from the injection site. Improved seismic data which enables the Top Captain sandstone in particular to be imaged and mapped with confidence is however a pre-requisite. Once in place, further detailed work on depth conversion is recommended. However, in order to understand the influence of the Top Captain depth surface on the $CO_2$ migration over time, the base-case depth surface was edited manually in the area to the west of the two $CO_2$ injection wells (Figure 3-37) and a new realisation of this depth map was developed which is also fully consistent with the available data. A new 3D static and dynamic model was made from this modified surface and deployed as a sensitivity within the dynamic reservoir modelling work to understand its relative importance (Section 3.6).

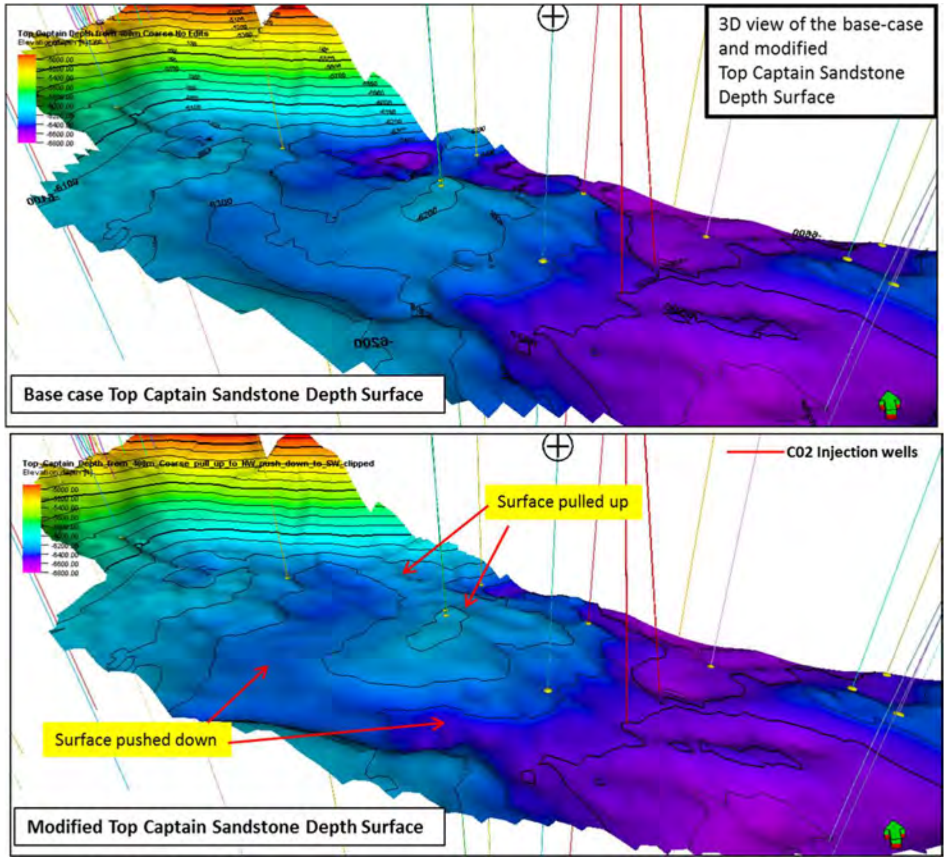



*Figure 3-37 Top Captain sandstone depth stucture surface 3D view*

### 3.4.7 Seismic Attributes

Seismic attribute displays have been generated and used for a range of applications in this characterisation of Captain Fairway. The attributes fall into two primary application groups:

**Supporting structural definition -** these include semblance attributes which describe the degree to which a trace in the 3D volume resembles its adjacent neighbouring traces. Where there is a strong and laterally continuous seismic reflection across an area then the semblance measure will be high. Where such a seismic reflection is broken or discontinuous then the semblance will be low. Semblance can be calculated relative to a constant time value or it can be dip adapted so that continuous, but sloping reflectors will also display high semblance. Semblance can be used to quickly identify faults and structural features in the subsurface detected by the seismic data as an important aid to interpretation. Under certain circumstances the Semblance can also identify stratigraphic features such as channel margins etc. Semblance has a similar function to other attributes like Similarity, Continuity, Coherency. At the Captain X site this attribute has been used to characterise structural detail at each interpreted horizon, including the key search for small faults in the primary cap rock (Rodby and Carrack Formations).

**Supporting interval characterisation -** these include seismic amplitude which describe the magnitude of the signal peak or trough of the reflected seismic wave. This is related to the acoustic impedance contrast between the layers in the earth and can be used to infer some information about the properties of one layer relative to an adjacent layer. In ideal conditions this can be used to quantify lateral variation in overall reservoir quality.

As already discussed in section 3.4.3 seismic imaging of the Captain Sandstone is hindered by a lack of impedance contrast at the Top and Base of the Captain Sandstone. Seismic attributes extracted from the full stack 3D seismic volume, available to this project, produced no useful results.

### 3.4.8 Conclusions

The PGS Central North Sea MegaSurvey seismic volume (PGS, 2015) which extends over the Captain Sandstone Fairway, has been interpreted. The key horizons have been identified, interpreted and mapped. The "pan-handle" part of the Captain Sandstone fairway is bounded along its northern and north eastern edge by the Captain and West Halibut Faults respectively. Seismic data quality is considered adequate for structural interpretation of the overburden interval to the target reservoir of the Captain X site, but is not sufficient to confidently map the depth of the target storage reservoir at Top or Base Captain sandstone. The lack of acoustic impedance contrast for the interpretation of the Top Captain Sandstone, coupled with an important, but second order depth conversion challenge means that there is considerable pick and therefore depth uncertainty away from well control. This challenge has been one of the primary issues for the petroleum developments such as Cromarty, Atlantic and Goldeneye. Even with an improved reprocessed seismic data set, Shell concluded that "the Captain Sandstone cannot unambiguously be mapped along the fairway due to its weak expression on the seismic data as a result of the poor impedance contrast at top reservoir between the Captain Sandstones and the overlying Rodby shales" (Shell, 2015).

The Base Captain seismic interpretation is considered very uncertain. Therefore, a Top Captain to Base Captain Sandstone isochore map was generated from well data points (independent of seismic data) and added to the Top Captain Sandstone depth surface to a produce final Base Captain Sandstone depth surface. A Lower Cretaceous isochron, generated to aid isochore construction, was of only limited use.

Due to this poor seismic imaging there is uncertainty on whether the Captain Sandstone extends up to the Captain and West Halibut Faults or pinches-out before them. Along the fairway's northern edge it appears likely that the sandstone extends up to the Captain Fault. At Tain and Blake the sandstone probably extends up to the West Halibut Fault. To the south east of Blake well control confirms that there is an area on the downthrown side of the West Halibut Fault where the Captain Sandstone is absent. It must therefore pinch-out before reaching this fault. Captain Sandstone is not present on the Halibut Horst itself. On the southern side of the fairway, away from well control, the Captain Sandstone pinch-out edge is more uncertain and in this interpretation it is controlled exclusively by the Shell fairway polygon.

At Blake and Tain the West Halibut Fault is probably sealing as evidenced by the presence of trapped oil. However, there is an increased lateral containment risk across the Captain fault with Captain Sandstone probably juxtaposed against Triassic and Jurassic units which do contain sandstones. Small scale faulting within the Top Rodby Shale and the Captain Sandstone are not anticipated to provide a potential breach to the primary seal or a significant barrier or baffle to flow of $CO_2$. Therefore, it was not deemed necessary to include this small scale internal faulting when building the static models.

The West Halibut Fault extends upwards into the shallow Tertiary section but not to the seabed. Between Atlantic and Tain the Lista secondary cap-rock is offset by this fault. However, due to seismic noise it is unclear if the Captain Fault extends to the seabed and whether the Lista is offset by this fault.

Due to the variable overburden geology and the pick uncertainty at Top and Base Captain level, a complex multi-layer depth conversion could not be justified across the entire Captain fairway. At Goldeneye, the Operator completed a 10 layer depth conversion and still experienced depth mapping residuals at the Top of the Captain in the development wells of +/- 60ft. An alternative single layer depth conversion method based upon other fairway work (Shell, 2015) was adopted. This involved using an average velocity map from MSL down to Top Rodby. The Top Rodby depth surface was then used as a depth reference surface and a modified Rodby - Carrack isochore hung from this to derive the Top Captain depth surface. As a regional depth conversion this somewhat simplified depth conversion method was considered fit for purpose for $CO_2$ dynamic modelling.

Seismic imaging of the Captain Sandstone is hindered by a lack of impedance contrast at the top and base of the Captain Sandstone reservoir. Seismic attributes extracted from the full stack 3D seismic volume, available to this project, produced no useful results.

Depth converted structure grids have been taken forward and used as input data for fairway, site and overburden 3D static models. The West Halibut Fault has been used only in the overburden 3D static model as it is considered to be the edge of the Captain Sandstone fairway with no Captain sandstone present on the Halibut Horst.

## 3.5 Geological Characterisation

### 3.5.1 Primary Store

#### *3.5.1.1 Depositional Model*

The primary storage unit is the Captain Sandstone Member of the Lower Cretaceous Cromer Knoll Group. At the Captain X site the top of the sandstone ranges from 1485 m tvdss (4870 ft tvdss) at the crest of the Blake oilfield down to approximately 1980 m tvdss (6500 ft tvdss) at the target injection site between Atlantic and Cromarty. The average Captain Sandstone thickness for the Captain X site is approximately 54 m (178 ft) but can reach up to 143 m (470 ft) thick in the central axis of the fairway.

The Captain Sandstone fairway is a sand rich deep water marine turbidite system deposited as a 5-10 km wide ribbon of sand along the southern edge of the Halibut Horst. Deposition occurred in response to a major fall in relative sea level which resulted in large volumes of shelf sands being moved into deeper water by submarine mass flow events. There are up to three phases of deposition identified from biostratigraphy (Law, et al., 2000). Typically, these were deposited as stacked amalgamated turbidite sandstones, 60 – 120 m (200 – 400 ft) thick in the centre of the fairway. Sands are generally clean, massive and structureless. The rock quality is excellent with the net to gross ratio from wells in excess of 75%, average porosity of 25 % (max 30%) and average permeability of approximately 1400 mD with measured core permeability often exceeding 2000 mD.

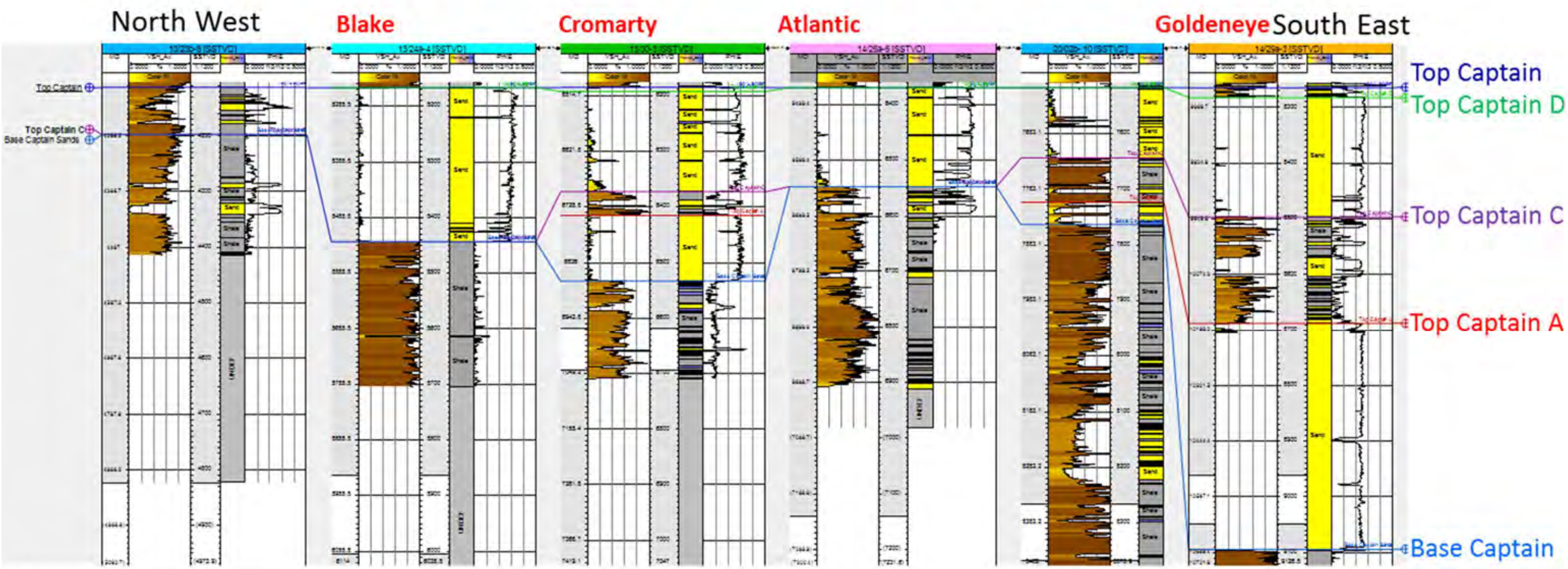
Deposition was controlled by the existing sea floor topography and two depositional models have been proposed (Shell, 2015). Sands deposited axially, from the emergent East Shetland High, along the northwest to southeast fairway appear dominant in the north-western part of the fairway (around Blake). In the southeast (around Goldeneye), more locally sourced sand prone turbidite fans, feeding directly from the Halibut Horst, appear to dominate.

The Captain Sands have been subdivided into 4 lithostratigraphic zones A – E (Shell, 2015). These zones have been correlated across the Captain Sand fairway using the available well data. A well correlation section across the Captain Fairway with cored wells is shown in Figure 3-38.

The basal Captain A is a massive medium grained sandstone, it is laterally restricted and discontinuous across the full fairway. The depositional model suggests localised deposition directly from the Halibut Horst. Captain A is present at the Captain X injection site although well data interpretation shows that it pinches out to the North before reaching the Blake Field, and to the South at the Grampian arch.

The Captain C, often referred to as the mid-Captain shale, is a heterogeneous sequence with significant mudstone and shale deposits. Thin interbedded sandstones appear, but are discontinuous and chaotic. The top of the interval is shaley and includes several shales, which appear to be laterally extensive and can be correlated across the fairway. Based on the available well log data these may prove to be significant horizontal barriers to vertical flow between the upper (E & D) and lower sands (A). However, RFT pressure data from wells drilled after production started from the fairway indicates that this interval is not completely sealing everywhere, although the communication pathway is uncertain. Nevertheless, the impact of a fully sealing Captain C is anticipated to be minimal on the proposed development.

Captain D is the main reservoir unit for the hydrocarbon fields within the Captain Sand Fairway. It is a massive sandstone unit, which is laterally extensive and present across the full length of the fairway.



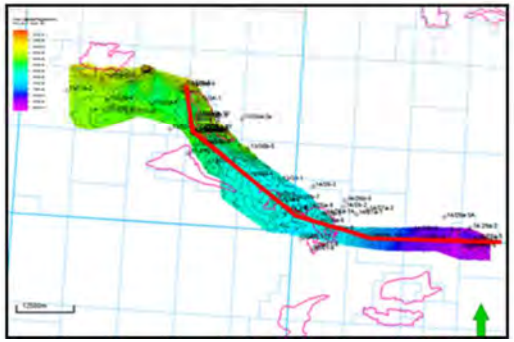



*Figure 3-38 Fairway correlation*

Captain E is a thin discontinuous (intermittent over the fairway) heterolithic zone, which forms the top most interval within the Captain Sands. It is shale dominated, typically marked by a thin shale at its base.

#### *3.5.1.2 Rock and Fluid Properties*

The petrophysical database was outlined in Section 3.2.4 and was sourced from the publically available CDA database. The data quality is very good.

Conventional core data were available for seven wells for which petrophysical analysis was carried out. These core data include Grain Density, Helium Porosity, Horizontal and Vertical Permeability.

A comprehensive petrophysics report for the Blake Field (Colley, 1999) was available and provided a valuable reference in defining the petrophysical parameters for the interpretation. The report focuses on 5 wells that are within the Captain fairway: 13/24a-4, 13/24b-3, 13/29b-6, 13/24a-5, 13/24a6

Archie saturation exponents (a = 1.0, m = 1.8, n = 2.0) were estimated from the limited SCAL data, cross referenced to the recommendations in the ‘Blake Field Petrophysical Report’ and validated in the water zones with Pickett plots.

Rwa is calibrated in all the water zones from core and gives a fairly consistent estimate of formation water resistivity (Rw). Based on measured core data Rw is assumed to be 0.160 at 60°F. This is consistent with the values reported in the *Blake Field Petrophysics report* .

For the purposes of quantitative evaluation of rock properties from wireline logs, a standard oilfield approach has been adopted. This is outlined in Appendix 8 and Figure 3-39.

The results of the petrophysical analysis are summarised below across the wells reviewed. Computer Processed Interpretation (CPI) plots for each analysed well showing derived calculated information are also provided in Appendix 4. Note that the input curves have been provided under CDA license and are not reproduced in this report.

Table 3-3 is a summary of the Net Reservoir properties for the Captain Sandstone fairway.

Permeability has not been estimated based on wireline data, but was computed within the Primary static model using core based porosity versus permeability relationships (Section 3.5.4).

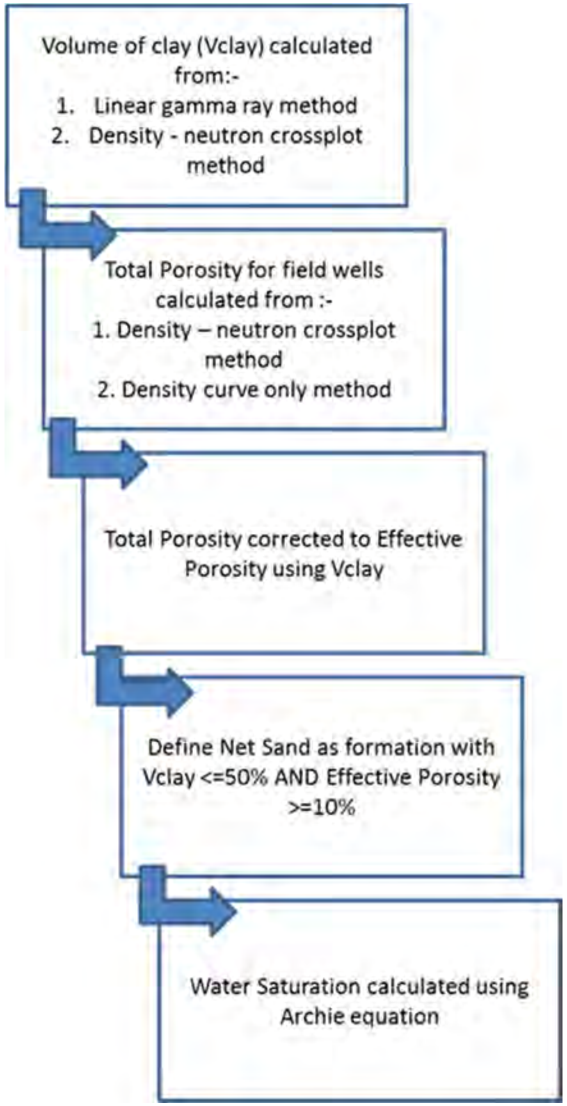



*Figure 3-39 Summary of petrophysical workflow*

| Well | Zone Name | Gross [ft] | Net [ft] | NTG | Porosity | Av Vcl |
|---|---|---|---|---|---|---|
| All Wells | All Zones | 327.1 | 249.0 | 0.76 | 0.26 | 0.06 |
| All Wells | Captain E | 15.2 | 11.0 | 0.73 | 0.23 | 0.10 |
| All Wells | Captain D | 166.6 | 142.9 | 0.86 | 0.27 | 0.05 |
| All Wells | Captain C | 94.3 | 36.9 | 0.39 | 0.23 | 0.16 |
| All Wells | Captain A | 159.8 | 136.3 | 0.85 | 0.25 | 0.05 |
| 13/30-3 | Captain E | 7.6 | 7.6 | 1.00 | 0.23 | 0.02 |
| 13/30a-4 | Captain E | 11.3 | 10.6 | 0.93 | 0.28 | 0.13 |
| 14/26a-8 | Captain E | 5.8 | 5.8 | 1.00 | 0.25 | 0.00 |
| 14/29a-3 | Captain E | 22.0 | 12.8 | 0.58 | 0.18 | 0.17 |
| 14/29a-5 | Captain E | 22.4 | 19.8 | 0.89 | 0.25 | 0.02 |
| 20/04b-6 | Captain E | 21.8 | 9.6 | 0.44 | 0.17 | 0.27 |
| 13/23b-5 | Captain D | 85.0 | 16.0 | 0.19 | 0.23 | 0.33 |
| 13/24a-4 | Captain D | 277.0 | 273.0 | 0.99 | 0.29 | 0.01 |
| 13/24a-5 | Captain D | 208.5 | 32.0 | 0.15 | 0.20 | 0.14 |
| 13/24a-6 | Captain D | 246.5 | 237.8 | 0.97 | 0.30 | 0.03 |
| 13/24b-3 | Captain D | 70.0 | 18.5 | 0.26 | 0.27 | 0.27 |
| 13/29b-6 | Captain D | 193.0 | 188.3 | 0.98 | 0.28 | 0.06 |
| 13/30-3 | Captain D | 192.7 | 187.7 | 0.97 | 0.28 | 0.05 |
| 13/30a-4 | Captain D | 150.7 | 144.7 | 0.96 | 0.28 | 0.08 |
| 14/26a-6 | Captain D | 177.8 | 168.8 | 0.95 | 0.28 | 0.01 |
| 14/26a-8 | Captain D | 166.6 | 161.1 | 0.97 | 0.28 | 0.00 |
| 14/26a-A7 | Captain D | 48.3 | 45.6 | 0.94 | 0.29 | 0.05 |
| 14/28b-2 | Captain D | 232.0 | 231.8 | 1.00 | 0.25 | 0.12 |
| 14/29a-3 | Captain D | 268.7 | 263.8 | 0.98 | 0.25 | 0.00 |
| 14/29a-5 | Captain D | 82.6 | 81.2 | 0.98 | 0.24 | 0.00 |
| 20/04b-6 | Captain D | 139.6 | 122.1 | 0.88 | 0.23 | 0.09 |

| Well | Zone Name | Gross [ft] | Net [ft] | NTG | Porosity | Av Vcl |
|---|---|---|---|---|---|---|
| 20/04b-7 | Captain D | 127.0 | 113.8 | 0.90 | 0.25 | 0.04 |
| 13/24b-3 | Captain C | 42.0 | 4.5 | 0.11 | 0.19 | 0.38 |
| 13/29b-6 | Captain C | 180.0 | 93.3 | 0.52 | 0.23 | 0.22 |
| 13/30-3 | Captain C | 46.1 | 21.6 | 0.47 | 0.22 | 0.19 |
| 13/30a-4 | Captain C | 53.3 | 38.8 | 0.73 | 0.24 | 0.19 |
| 14/26a-8 | Captain C | 57.1 | 51.1 | 0.90 | 0.31 | 0.12 |
| 14/26a-A7 | Captain C | 96.4 | 19.0 | 0.20 | 0.16 | 0.36 |
| 14/28b-2 | Captain C | 30.9 | 2.7 | 0.09 | 0.13 | 0.46 |
| 14/29a-3 | Captain C | 237.4 | 75.9 | 0.32 | 0.21 | 0.10 |
| 14/29a-5 | Captain C | 203.9 | 71.4 | 0.35 | 0.21 | 0.11 |
| 20/04b-6 | Captain C | 48.6 | 17.6 | 0.36 | 0.22 | 0.13 |
| 20/04b-7 | Captain C | 42.0 | 10.0 | 0.24 | 0.17 | 0.16 |
| 13/24b-3 | Captain A | 97.0 | 47.8 | 0.49 | 0.22 | 0.27 |
| 13/30-3 | Captain A | 125.8 | 125.6 | 1.00 | 0.29 | 0.04 |
| 13/30a-4 | Captain A | 252.8 | 210.8 | 0.83 | 0.26 | 0.11 |
| 14/26a-A7 | Captain A | 42.9 | 42.0 | 0.98 | 0.28 | 0.03 |
| 14/28b-2 | Captain A | 63.4 | 50.9 | 0.80 | 0.24 | 0.19 |
| 14/29a-3 | Captain A | 499.2 | 487.2 | 0.98 | 0.24 | 0.00 |
| 14/29a-5 | Captain A | 315.1 | 225.9 | 0.72 | 0.23 | 0.05 |
| 20/04b-6 | Captain A | 19.0 | 16.3 | 0.86 | 0.23 | 0.03 |
| 20/04b-7 | Captain A | 23.0 | 20.0 | 0.87 | 0.24 | 0.01 |

*Table 3-3 Captain sand fairway net reservoir summary*

#### 3.5.1.3 Relative Permeability and Capillary Pressure

There is no specific SCAL available from the Captain X storage site data set within CDA. This is discussed further in Section 3.6.

#### 3.5.1.4 Geomechanics

Geomechanical modelling of the primary store was conducted to clarify the strength of the storage formation and its ability to withstand injection operations without suffering mechanical failure at any point during those operations. No significant issues of drillability, fracturing risk or sand failure risk were identified. Further details are included in Section 3.6.6.

#### 3.5.1.5 Geochemistry

Geochemical modelling of the subsurface materials is reported in Section 3.5.2.5 and 3.7. Modelling has been primarily focussed upon the caprock reactivity and its potential degradation. Injection of $CO_2$ into the Captain X storage site is not expected to lead to any significant risk of loss of strength or significant change in reservoir quality.

### 3.5.2 Primary Caprock

#### 3.5.2.1 Depositional Model

The top of the Captain Sandstone Member is recognised by the rapid transition to the overlying shale of the Carrick and Rodby Formations (Law, et al., 2000). These calcareous mudstones, and the Hidra of the Chalk Group above, provide the Primary top seal for the Captain Sandstone.

The shale above the Captain reservoir from Top Rodby down to Top Captain is laterally extensive and has an average thickness of 90 m (~290 ft) within the site area. These formations represent the abandonment and burial of the Captain turbidite fan system by basin shales.

The shales and mudstones of the Valhalll and Carrack Formations also provide an effective seal along the sand fairway pinch-out edges to the North and South.

#### 3.5.2.2 Rock and Fluid Properties

Core measurements are not typically acquired in non-reservoir lithologies, there are therefore no measured core data available for the Carrack, Rodby or Hidra intervals at the site location. These intervals are effective seals in nearby hydrocarbon fields and the effective permeability can reasonably assumed to be exceptionally low or zero, and therefore impermeable.

#### 3.5.2.3 Relative Permeability and Capillary Pressure

There are no direct capillary pressure measurements available for the cap rock formations of the Captain Sandstone.

#### 3.5.2.4 Geomechanics

No significant issues of drillability, or fracturing risk were identified. Further details are included in Section 3.6.6.

#### 3.5.2.5 Geochemistry

Geochemical modelling of the primary caprock for the Captain sandstone aquifer was carried out to evaluate the likely impact of $CO_2$ injection on the rock fabric and mineralogy following the injection period and the long term post-closure phase. The main objective was to gain a better understanding of the key geochemical risks to injection site operation and security of storage.

The approach, methodology used and the results are described in more detail in Appendix 8 but were focussed on one key question:

- Will increasing the amount (partial pressure) of $CO_2$ in the Captain sandstone aquifer lead to mineral reactions which result in either increase or decrease of porosity and permeability of the Rodby Formation aquiclude overlying the aquifer?

A dataset of water and gas compositional data for the Captain sandstone and the Rodby Formation and its mineralogy was compiled from both published data and technical reports available in the CDA and the public domain. These data were then used to establish the pre-$CO_2$ geochemical conditions in the primary reservoir and the assumption was then made that similar conditions existed in the caprock.

A kinetic study of geochemical reactions in the caprock was then undertaken with appropriate estimates of rock fabric and the selection of appropriate kinetic constants for the identified reactants to evaluate the realistic impact of $CO_2$ injection with regard to time, using 10,000 years as the target timeframe. No equilibrium modelling was undertaken due to the pre-$CO_2$ mineral composition of the Rodby Formation which has a high proportion of metastable smectite clay mineral.

*Summary of Geochemical Impact of $CO_2$ Injection*

The main changes modelled in the Rodby Formation caprock are the major dissolution of smectite due to $CO_2$ influx and the relatively minor loss of calcite over 10,000 years of addition of $CO_2$. The products of these changes are an increase in volume of the carbonate minerals (dawsonite, dolomite and siderite), sequestering the $CO_2$ into the carbonate mineral phase, and additional sulphate mineral precipitation, such as anhydrite. In addition, the Fe, Mg, Si and Al-bearing smectite is replaced by illite, kaolinite, quartz and dawsonite. Overall, there is a solid mineral volume increase due to $CO_2$ interaction with the Rodby Formation meaning that there is no increase in porosity and thus no increase in permeability.

In summary, by flooding the Captain sandstone with $CO_2$, the overlying calcareous, clay-rich Rodby Formation and equivalent caprocks are unlikely to be affected in a way that increases permeability:

- The fastest reactions that occur lead to a very small net solid volume increase due to the new replacement minerals having relatively lower density and reaction with the fluxing $CO_2$.
- Smectite is the most reactive mineral present but it is likely, upon contact with the acid water induced by $CO_2$ influx, to be replaced by quartz, illite and kaolinite.
- Sodium, iron and magnesium are also released from smectite thus leading to the growth of the carbonate minerals: dawsonite, siderite and dolomite.
- Calcite undergoes partial replacement by dolomite instead of wholesale dissolution.
- Overall, the injection of $CO_2$ will probably lead to a solid volume increase of 3% in 10,000 years. This will lead to lower porosity and lower permeability.

Rodby Formation seal failure is, therefore, unlikely to be induced by mineral reactions with the $CO_2$.

### 3.5.3 Secondary Store

The reservoir quality sands of the Maureen and Mey Formations provide the most likely secondary store above the injection site location. These are widely distributed over the Moray Firth to Central Graben region. These are developed as sand prone shelf and slope area within the Inner Moray Forth Basin, and in the Outer Moray Firth and Central Graben as deep water turbidite fans systems. Paleocene sandstones typically have excellent reservoir quality and good regional connectivity with porosities up to 35% and Darcy permeabilities.

The overlying Lista Formation provides the secondary seal, this is a proven seal for several Paleocene reservoirs (Andrew/ Mey Sandstone) in the CNS, and is approximately 30 m (100 ft) thick over the site location.

#### 3.5.3.1 Depositional Model

The heterogeneous Andrew Sand is laterally extensive and well known within this part of the CNS. A full characterisation of the secondary store potential would require further work.

### 3.5.4 Static Modelling

Three static models have been built as part of the characterisation effort of Captain X $CO_2$ storage site:

- Fairway Model - The primary static model is semi-regional in nature and covers a large area (>800 $km^2$) across the Captain Sand Fairway. This model was built with the purpose of selecting the final site and understanding connectivity to nearby hydrocarbon fields and $CO_2$ storage sites.
- Injection Site Model - As the static model covered the full Captain Sand Fairway, it was not required to build a specific site model. The site model cut from primary fairway model as a reduced section. The purpose of this model is to serve as a basis for building an effective reservoir simulation model over the Captain X site.
- Overburden Model - The third static model builds upon the footprint of the Primary static model, but extends to describe the

overburden geology all the way to the seafloor. This model was primarily used for consideration of containment issues which are detailed in Section 3.7.

#### *3.5.4.1 Primary Static Model (Fairway)*

**Grid Definition**

The static model described in this section focuses on the fairway geological model for the Captain Sandstone. Maps of the input horizons for Top Captain and Base Captain Sandstone within the site area are shown in Section 3.4.

The area selected for the site model covers a large area of approximately 808 km$^2$ (~95 km x ~10 km), the coordinates of the site model boundary are

X Min 216547.60 X Max 305442.48

Y Min 6429685.08 Y Max 6471727.75

Reservoir modelling has been carried out using Petrel v2014.

Reference system used ED50 (UTM31).

The stratigraphic interval for the site model is from the Top Rodby Formation down to 30m (100 ft) below the Base Captain. The primary seal for this interval is the overlying Carrack/ Rodby shale formations.

The model stratigraphy is shown in Table 3-4, and is based upon the zonation scheme defined during the well correlation.

| Horizon | Zone | Source | Number of Layers |
|---|---|---|---|
| **Top Rodby** | Carrack and Rodby | Direct seismic interpretation and depth conversion | 1 |
| **Top Captain** | Top Captain E | Built down from Top Rodby using well derived isochore | 5 |
| **Top Captain D** | Top Captain D | Built down from Top Captain using well derived isochore | 50 |
| **Top Captain C** | Top Captain C | Built down from Top Captain D using well derived isochore | 50 |
| **Top Captain A** | Top Captain A | Built down from Top Captain C using well derived isochore | 50 |
| **Base Captain** | Lwr Valhall Fm | Built down from Top Captain using well derived isochore | 1 |
| **Base Captain +100** | | | |

*Table 3-4 Stratigraphy, zonation and layering for site model*

The Top Rodby depth horizon within the fairway model was created from the depth surfaces interpreted from the seismic and time to depth converted (Section 3.4).

The Top Captain was generated by building down from the Top Rodby using a well derived isochore map, at the edge of the fairway where it pinches out the seismic was used to help improve and control the pinch out edge and thickness. (Section 3.4.5).

The Base Captain was created by building down from the Top Captain using well derived isochore map, the isochore map was edited to better control the pinch out edge.

The remaining internal Captain horizons were generated by building down from the Top Captain using well derived isochore maps.

The top of the model is the Top Rodby, as the interval above the Top Captain is an impermeable zone it is represented in the model by a single layer.

The base of the model has been generated by adding 30m (100ft) to the Base Captain, this represents the top of the underlying (Lower) Valhall Formation. The Lower Valhall includes Punt or Burns Member sands, however these are not connected to the overlying Captain sands. These sands are separated from the Captain Sandstone by shale intervals of varying thicknesses, but it is interpreted that they are not connected to the overlying Captain Sandstone Fairway. In previous work ($CO_2$Multistore) reference was made to the hydraulic significance of the "underburden" as a means of dissipating injection pressure away from $CO_2$ injection sites and enable sustainable periods of high injection rates without over pressuring the reservoir. Given the nature of the underlying shales and their proven ability to be an effective seal for a range of deeper Jurassic oil and gas fields, no evidence has been found to suggest that such an "underburden" interval would provide an effective pressure dissipation mechanism.

One main major fault has been incorporated into the fairway model – the Halibut Horst to the north of the Captain fairway. This may form the boundary of the storage site along the north-west edge of the fairway in the region of the Blake field.

A cross section through the structure showing the different zones and layering within the model is shown in Figure 3-40.

The fairway model 3D grid was built with a rotation of 135° and grid cells of 200m x 200m in the X, Y direction.

Proportional layering has been used for all zones. The number of layers has been selected in order to effectively model the geological heterogeneity, specifically capturing the thin shales and cemented layers observed in the well data.

The resulting grid has approximately 16.1 million grid cells.

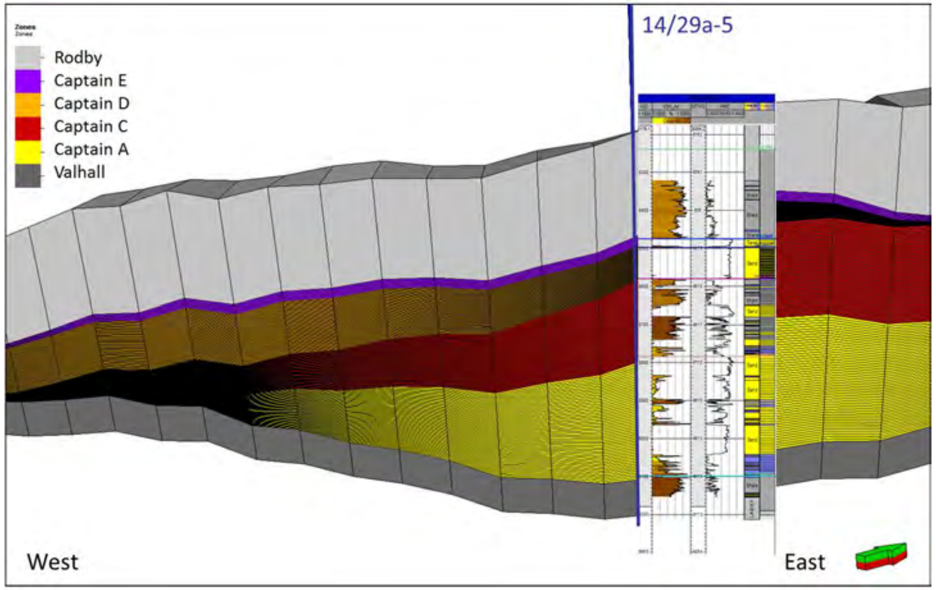



*Figure 3-40 Cross section through the 3D grid at well*

#### 3.5.4.2 Property Modelling

The Captain Sandstone Fairway is a high quality, commonly massive sandstone, deposited as stacked turbidite sands primarily from the northwest.

The formation rock quality is excellent within the main Captain Sand with net to gross ratio from wells in excess of 75%, average porosity of 25 % (max 30 %) and average permeability of approximately 1400 mD.

*Captain Sandstone*

The deeper and younger Captain (A) mass flow deposits infilled a deep channel incision, and the upper Captain sandstone (D) are the result of overlapping lobes of sandstone sheets (Copestake, et al., 2003).

Within the site model the Captain D sands are thick and massive with little or no shales or cemented sand layers which could act as barriers and baffles. The lower Captain A sands are considerably more heterogeneous and are not laterally extensive across the entire fairway. To allow for these shales and cements to be explicitly captured within the static model a facies model has been built.

The mid Captain shale (Zone C) varies in thickness across the fairway area, containing thin sands, shales and tuffs representing a sub-sequence boundary (Copestake, et al., 2003). This layer possibly represents a significant barrier to flow between the Upper (D and E) and Lower Captain (A) reservoir zones in some places, but does not represent a fully, hydraulically sealing layer.

Porosity within the Captain Sandstone has been modelled within the facies model using the available interpreted PHIE log. Permeability has been modelled within the 3D grid using the available measured core data and correlated to the modelled porosity.

#### 3.5.4.3 Facies Log Interpretation

A lithology log at the wells has been generated using a combination of wireline cut-offs and manual interpretation.

Three Facies have been interpreted using Vshale, Density and Sonic logs: sand, shale and calcite cemented sands. Full petrophysical analysis has been carried out for 16 representative wells; however Vshale has been calculated for additional 16 wells to help improve the facies modelling. This has been done using a simple linear Gamma Ray method (VSh= (GR- GRlow)/(GRhigh-GRlow)).

The cut-offs used are shown in Table 3-5.

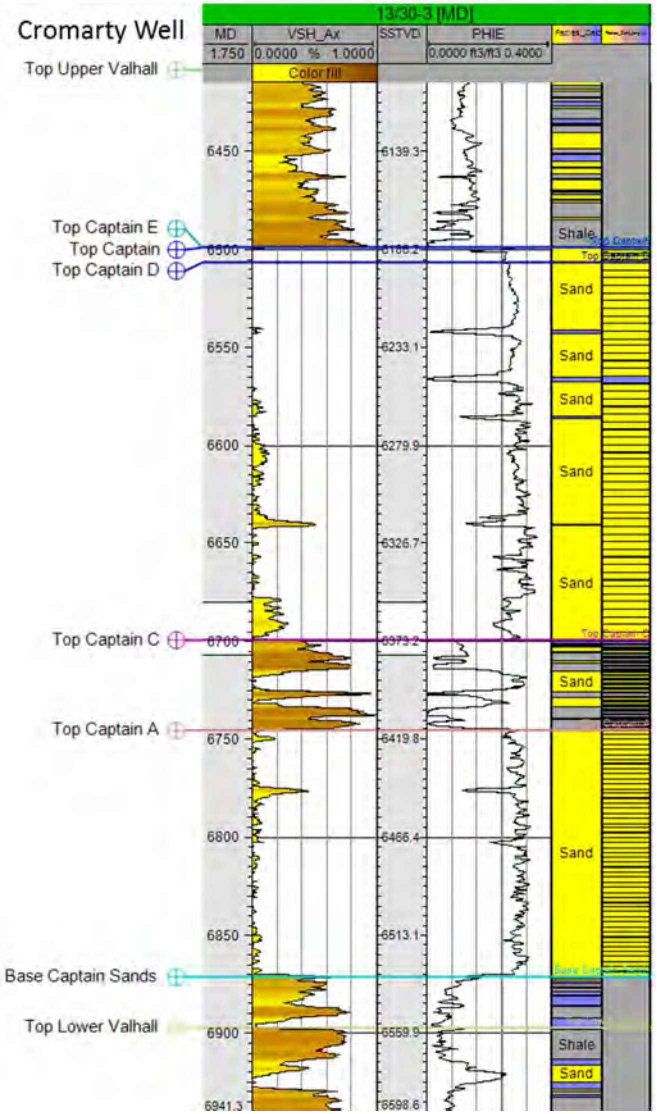
| Facies | Cut off |
|---|---|
| **Sand** | Vsh<=0.5 |
| **Shales** | Vsh>0.5 |
| **Cemented Sands** | Clean sand (Vsh<=0.5) with density and/or sonic spike<br>RHOB>2.4 and sonic <=70 |

*Table 3-5 Cut offs used to determine lithology based facies log*

Facies logs have been calculated for 32 wells, and these have been used to control the facies modelling:

13/22b-19, 13/22b-20, 13/22b-4, 13/22c-30, 13/23a-4, 13/23b-5, 13/23b-6, 13/24a-4, 13/24a-5, 13/24a-6, 13/24b-3, 13/24b-9, 13/29b-5, 13/29b-6, 13/29b-8, 13/29b-9, 13/30-1, 13/30-3, 13/30a-4, 13/30b-7, 14/26-1, 14/26a-6, 14/26a-7A, 14/26a-8, 14/26a-9, 14/28b-2, 14/28b-4, 14/29a-3, 14/29a-5, 20/02b-10, 20/04b-6, 20/04b-7.

An example of the lithology facies log and final upscaled lithology log is shown in Figure 3-41.




Raw log data were used to assist with the lithology interpretation but cannot be included in this report.

*Figure 3-41 Example of lithology log and final upscaled lithology log*

### 3.5.4.4 Facies Modelling

Facies modelling was completed in all Captain zones using the facies log as input. This was carried out using Sequential Indicator Simulation (SIS) across the entire fairway (Figure 3-42). This is a standard oil industry modelling technique. Sand, shale and cement proportions have been calculated from well data. The orientation has been aligned with the depositional direction, approximately NW – SE. Variogram ranges and settings are shown in Table 3-6.

| Zone | Facies | Major | Minor | Vertical | Azimuth |
|---|---|---|---|---|---|
| E | Sand and Shale | 10,000 | 1,000 | 3 | Trend |
| | Calcite | 500 | 250 | 3 | |
| D | Sand and Shale | 10,000 | 1,000 | 10 | Trend |
| | Calcite | 500 | 250 | 3 | |
| C | Sand | 5,000 | 2,000 | 10 | 0 |
| | Shale | 5,000 | 1,000 | 10 | |
| | Calcite | 500 | 250 | 3 | |
| A | Sand and Shale | 10,000 | 1,000 | 10 | Trend |
| | Calcite | 500 | 250 | 3 | |

*Table 3-6 Input properties used for SIS modelling in Captain facies model*

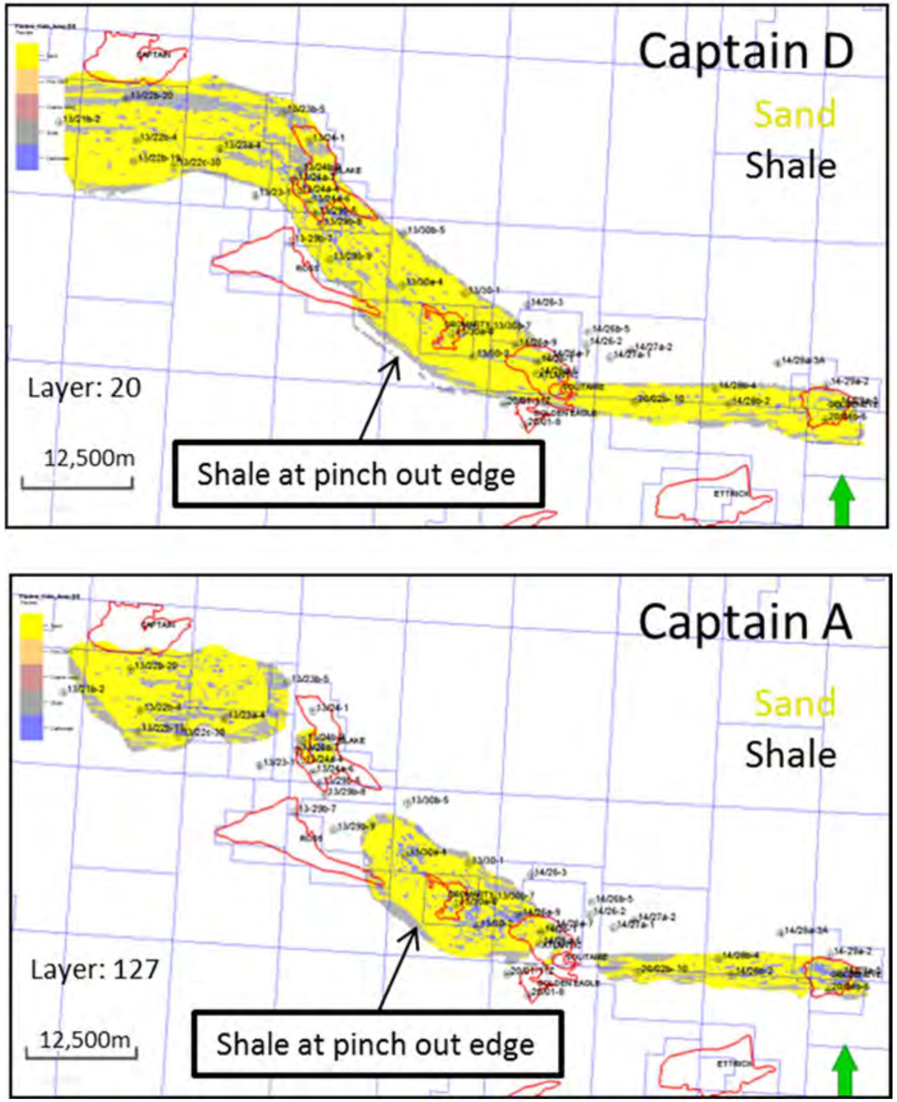



*Figure 3-42 Facies modelling slice through each Captain D and Captain A*

Net to gross trend maps, derived from well data, have been used to control the lateral proportion of sands and shales within the model for Captain D and A (Figure 3-44). Vertical proportion curves have also been used but as there are no strong vertical trends within the regional well dataset, these have little impact.

A local varying azimuth trend map is used to orientate the Captain E, D and A sands along the channel fairway and resulting modelled grid.

Well data suggests that the edges of the Captain fairway can sometimes be areas of lower net to gross. This is not expected to have any material impact on either the capacity or containment due to the thin nature of these sections.

The final modelled facies proportions are shown in Table 3-7.

| Model Results | Sand (%) | Shale (%) | Cement (%) |
|---|---|---|---|
| **Captain E** | 52.8 | 42.8 | 4.4 |
| **Captain D** | 82.4 | 15.9 | 1.7 |
| **Captain C** | 28 | 68.18 | 3.83 |
| **Captain A** | 76.8 | 18.5 | 4.7 |

*Table 3-7 Modelled facies proportions for depositional model and final facies model*

A cross section through the Final Facies model is shown in Figure 3-44.

No facies modelling has been done within the Rodby or Lower Valhall zones.

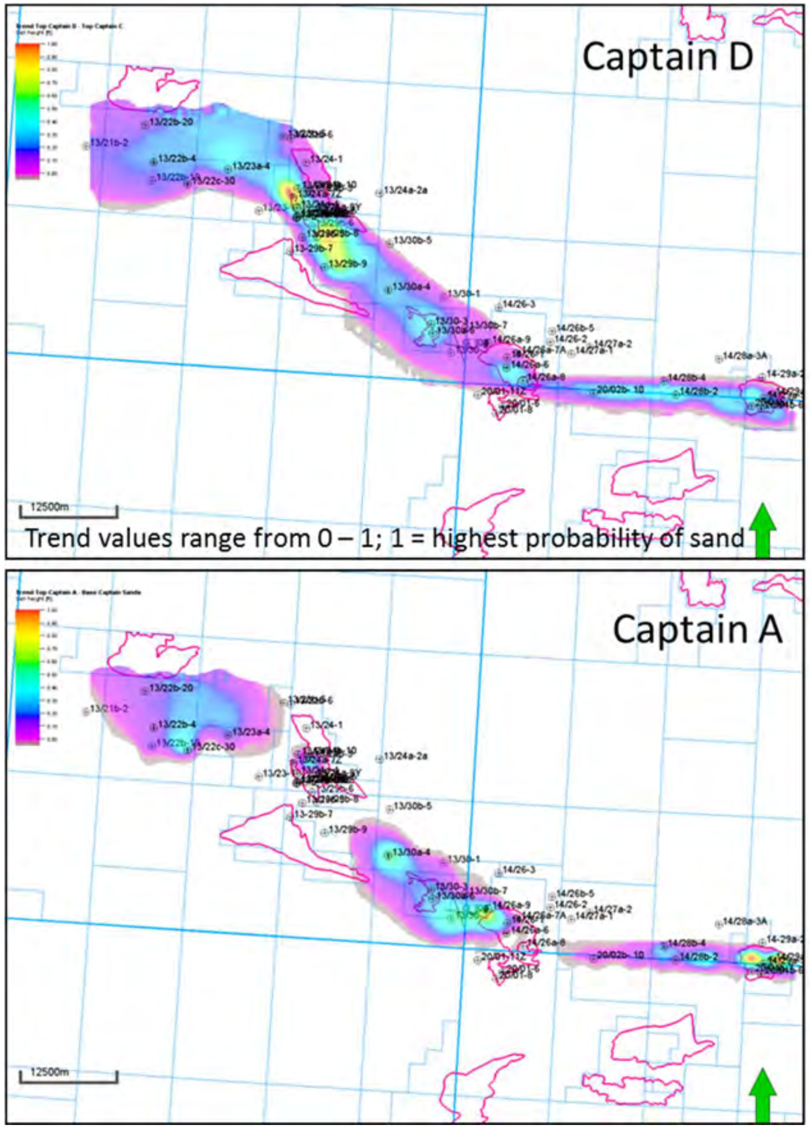



*Figure 3-43 Trend maps used to control facies modelling and distribution*

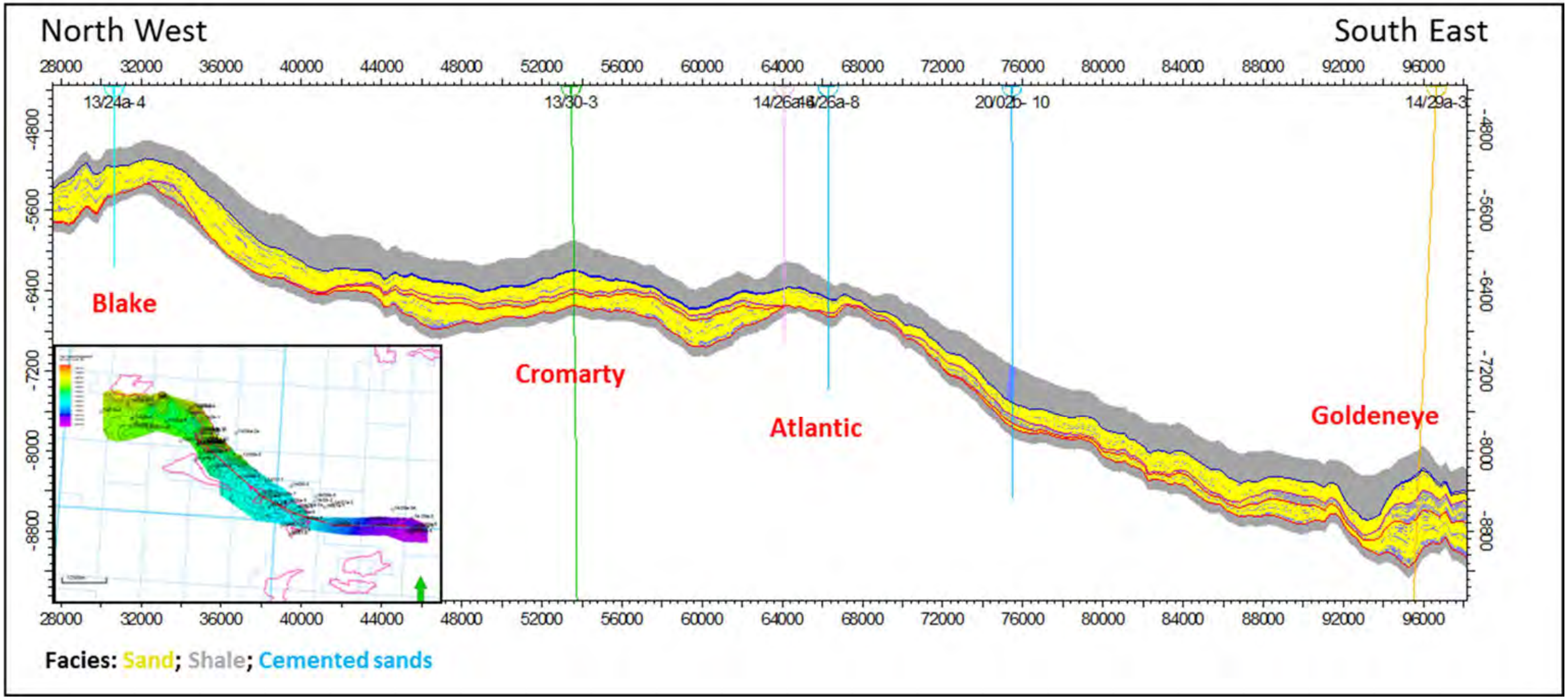



*Figure 3-44 Facies cross section through model*

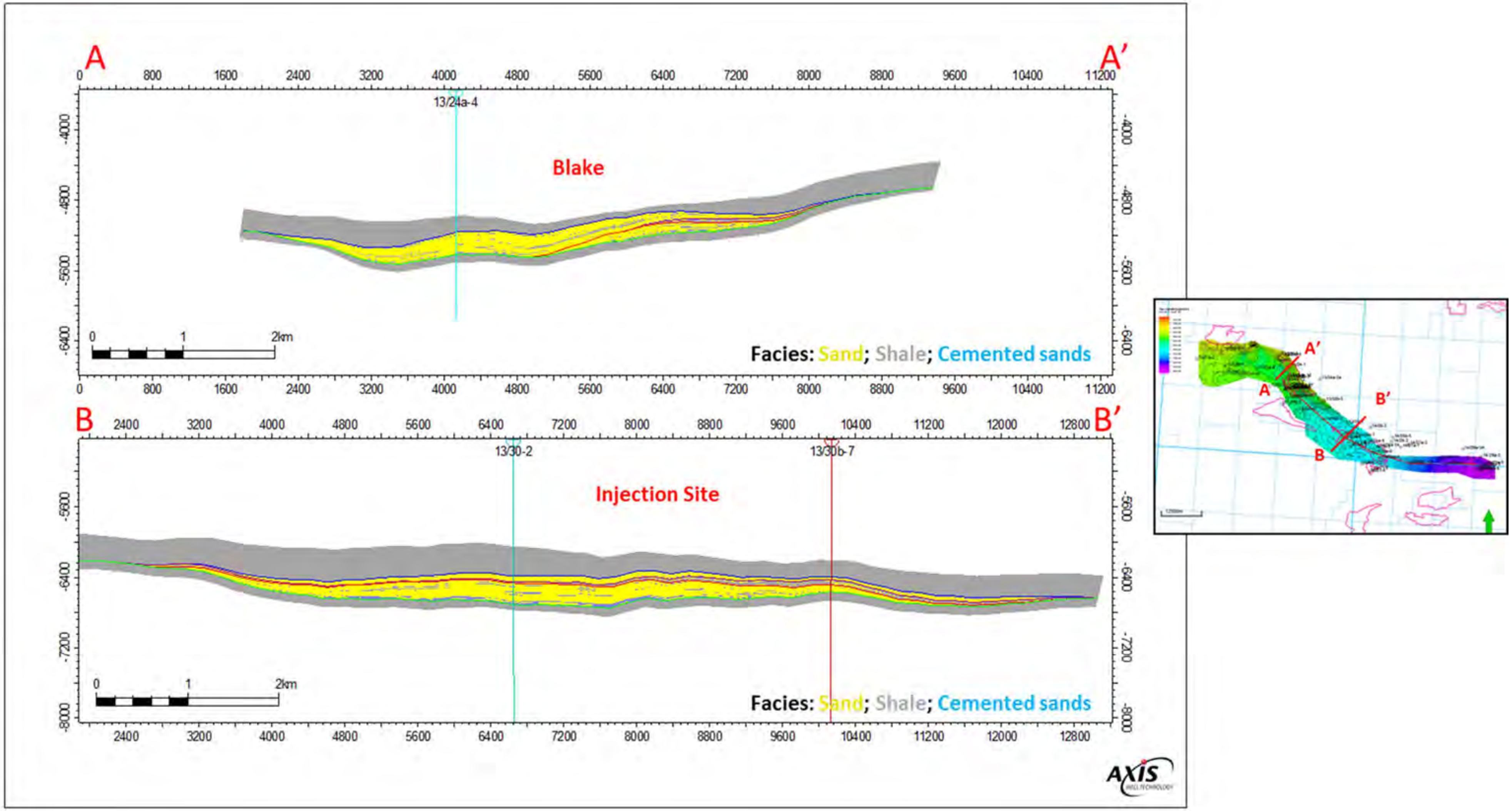



*Figure 3-45 Facies cross section through model*

#### 3.5.4.5 Porosity Modelling

A total of 16 wells had porosity logs interpreted, which were used within the site model for the modelling of porosity: 13/23b-5, 13/24a-4, 13/24a-5, 13/24a-6, 13/24b-3, 13/29b-6, 13/30-3, 13/30a-4, 14/26a-6, 14/26a-7A, 14/26a-8, 14/28b-2, 14/29a-3, 14/29a-5, 20/04b-6, 20/04b-7.

The interpreted PHIE log was upscaled to the grid scale using arithmetic averages, biased to the final facies logs. This ensures that the porosity distribution (mean and standard deviation) for each facies is correct.

Porosity modelling is performed for each zone using Sequential Gaussian Simulation, constrained to the wells and the facies model. This ensures that the property distributions (mean and standard deviation) in the original log porosity data are maintained in the final model. Cemented sands and shales are assigned porosity values of 0%.

Settings for the modelling are shown in Table 3-8.

| Zone | Type | Major Axis [m] | Minor Axis [m] | Vertical [m] | Azimuth [deg] |
|---|---|---|---|---|---|
| E | Spherical | 10,000 | 1000 | 3 | Trend |
| D | Spherical | 10,000 | 1000 | 10 | Trend |
| C | Spherical | 10,000 | 1000 | 3 | 0 |
| A | Spherical | 10,000 | 1000 | 10 | Trend |

*Table 3-8 Input setting for porosity and permeability SGS modelling*

A reduction in porosity with increasing depth, west to east along the fairway, is evident in the log data. To account for this a trend map was created from well data for the Captain D and A zones. The trend is better constrained within the Captain D due to more well data being available; the Captain A has less well penetrations due to it not being as laterally extensive. These trend maps were used to ensure the depth trends were incorporated into the final porosity model, and are shown in Figure 3-46.

The average modelled porosity within the main Captain D sand is 27%, the same as the average from well logs for the Captain D. The average modelled within the Captain A is 24%.

A histogram showing a comparison of the porosity well log input versus the modelled porosity for the sand facies is shown in Figure 3-47.

Average modelled sand porosity values by zone are shown in Table 3-9.

| Zone | Average porosity (%) |
|---|---|
| E | 21.9 |
| D | 26.6 |
| C | 21.4 |
| A | 24.1 |

*Table 3-9 Average modelled porosity values by zone (sand facies only)*

The porosity within the mudstone caprock (Rodby) is assumed to be zero and has not been modelled further.

Whilst there are sands within the underlying Valhall formation, well data across the fairway shows that these are separated from the Captain Sandstone by thicknesses of claystones and mudstones significant enough to form barriers to vertical flow. The layer below the Captain Sand within the model is therefore assumed to have zero porosity and are not modelled further.

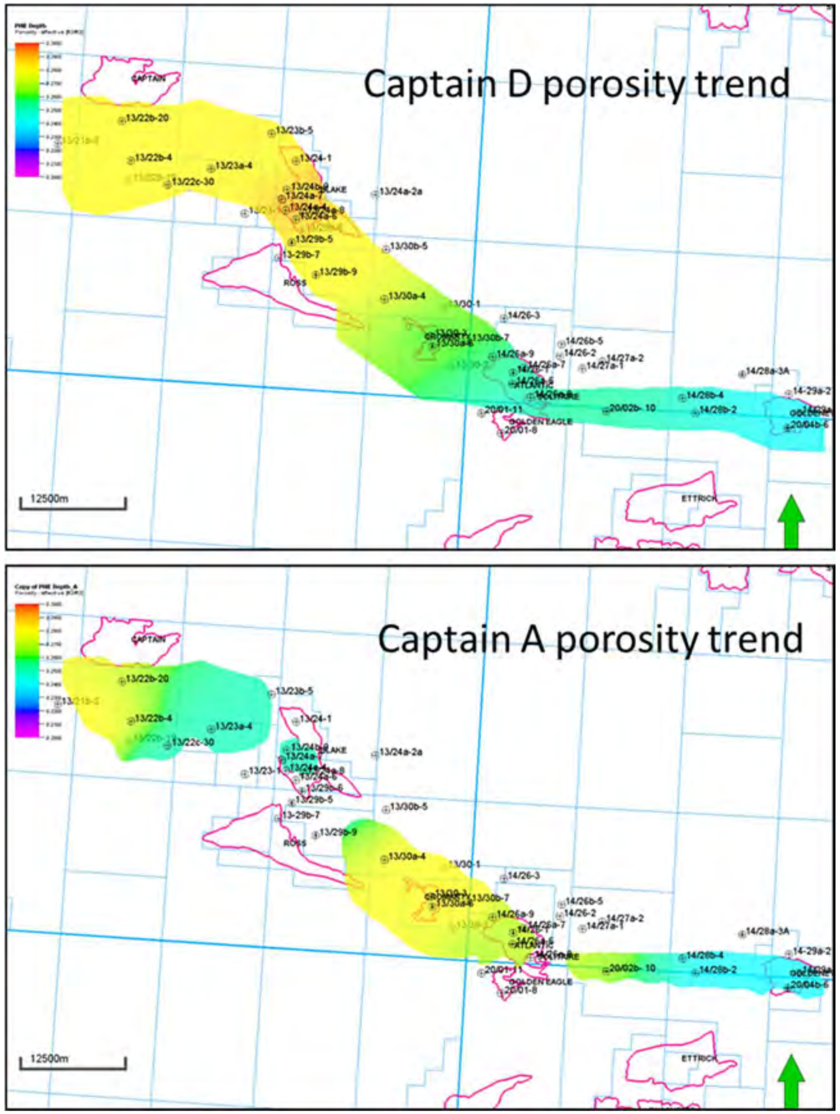
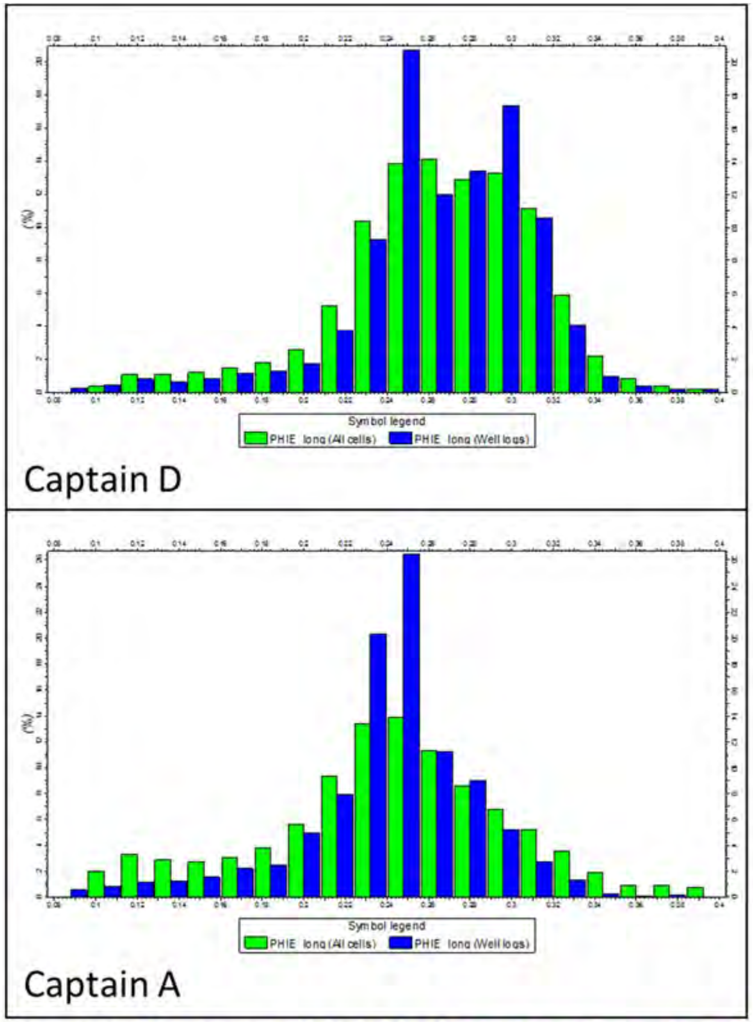



Figure 3-46 Porosity trend maps




Interpreted log porosity (dark blue); Modelled porosity, all zones (green)

Figure 3-47 Histogram of porosity within sand facies

### 3.5.4.6 Permeability Modelling

As observed in core data, there is a strong positive correlation between the measured core porosity and core permeability. A cross plot of porosity versus permeability for the measure core data shown in Figure 3-49.

Within the Captain D zone horizontal permeability in the sand facies has been modelled using a bivariate distribution method, allowing for this correlation and distribution to be used directly and ensure that the final permeability distribution matches that of the measured core data. The modelled porosity is used as a secondary property input, ensuring that the resulting permeability model also remains correlated with the modelled porosity, i.e. a cell with a high porosity will have a high permeability.

Within the other zones, whilst there are core data available, there are not sufficient samples to carry out bivariate modelling. Permeability modelling has therefore been carried out by co-simulating the available core data with the modelled porosity. This is a common oil industry approach and ensures that the porosity and permeability correlations are captured.

The variogram settings used are the same as those used for the porosity modelling. Shale and cemented sands are assigned permeability values of 0 mD.

A histogram showing the horizontal permeability for the sand facies is shown in Figure 3-48. Average horizontal permeability values for the modelled sand facies, by zone are shown in Table 3-10. The core measured Kv /Kh from wells is high, with values in clean sands approaching 1 and an average Kv /Kh ratio of 0.8. This has been used directly in the model to calculate the vertical permeability within the sands. The permeability in the overlying Rodby Formation and the Valhall Formation underlying the Captain Sands are assumed to be zero, and are not modelled further.

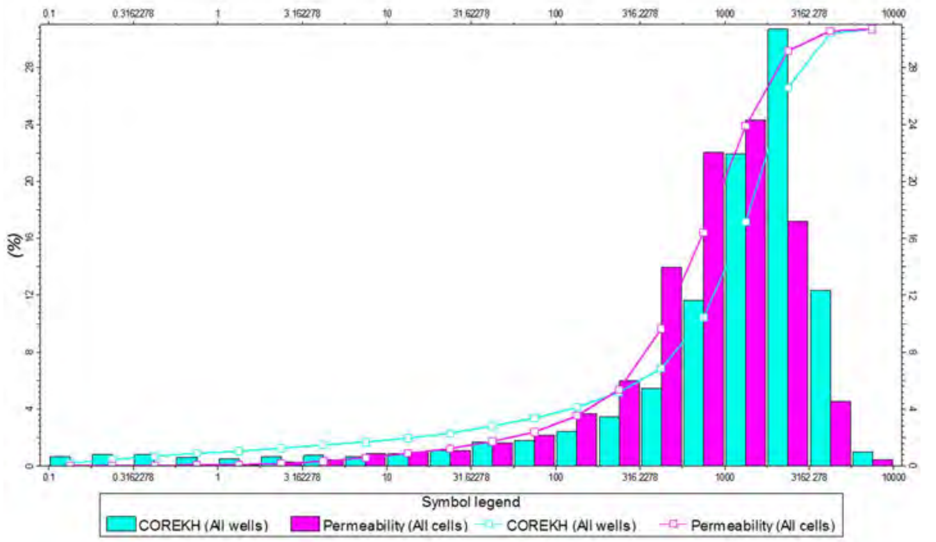



*Figure 3-48 Histogram comparison of core versus modelled permeability (horizontal) - all zones*

| Zone | Average Horizontal permeability (mD) | Average Vertical permeability (mD) |
|---|---|---|
| E | 274 | 219 |
| D | 1753 | 1402 |
| C | 634 | 507 |
| A | 704 | 563 |

*Table 3-10 Average modelled permeability values by zone (sand facies only)*

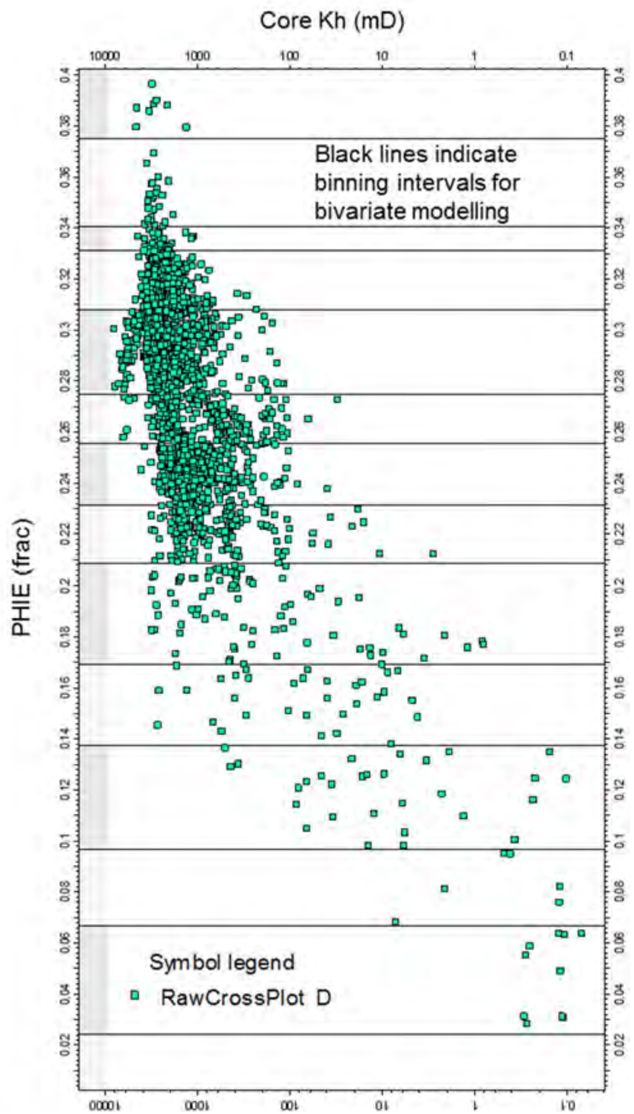



*Figure 3-49 Cross plot of core porosity versus permeability - Captain D*

### *3.5.4.7 Rock and Pore Volumetrics*

Volumes in the static model have been calculated for the entire Captain fairway model and are shown in Table 3-11.

| Zones | Bulk volume [*10^6 m3] | Pore volume [*10^6 m3] |
|---|---|---|
| **Captain E** | 2,081 | 295 |
| **Captain D** | 24,458 | 5,935 |
| **Captain A** | 12,204 | 2,527 |
| **Total** | 38,743 | 8,757 |

*Table 3-11 Gross rock and pore volumes for Captain fairway model*

### *3.5.4.8 Simulation Model Gridding and Upscaling*

To enable dynamic simulation models to run within a reasonable time frame several coarser simulation grids and models have been generated, and used within the dynamic modelling for different purposes.

**Model 1: Site Upscaled Model**

The model area was reduced to the Captain X injection site area only, covering the area between the Blake and Atlantic Fields. Figure 3-50 shows the Model 1 area.

The grid was vertically coarsened from 157 layers in the fairway model, to 58 layers in the dynamic model. The structure, zonation, X and Y cell increment and grid orientation remain the same as the fairway model. This reduced the number of defined cells from approximately 16.1 million to approximately 400,000.

A comparison of the layering between the static and Model 1 3D grid is shown in Figure 3-51. The layering scheme is summarised in Table 3-12.

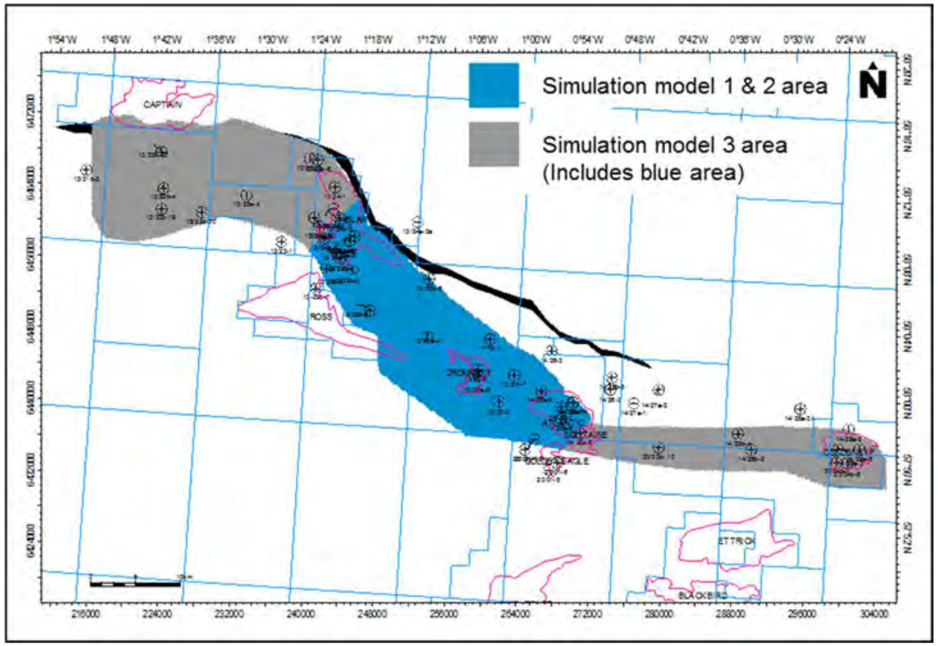



*Figure 3-50 Map showing site model area*

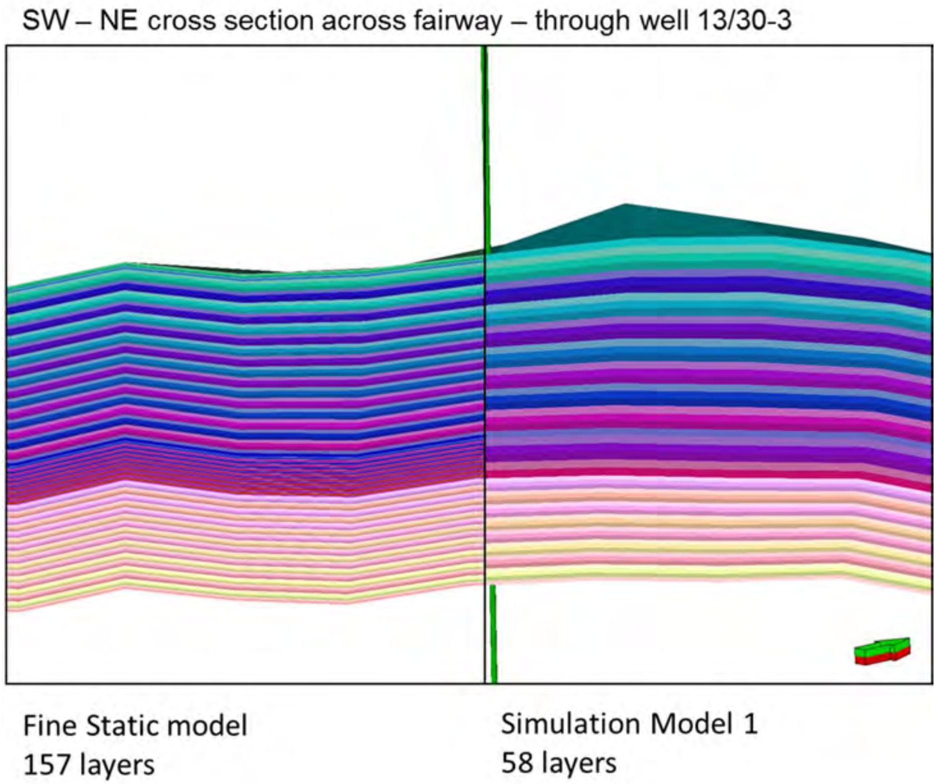



*Figure 3-51 Model 1: Comparison between static and simulation model vertical 3D grid resolution*

| Zone | Static Model Layers | Dynamic Model Layers |
|---|---|---|
| **Rodby** | 1 | 1 |
| **Captain E** | 5 | 1 |
| **Captain D** | 50 | 25 |
| **Captain C** | 50 | 5 |
| **Captain A** | 50 | 25 |
| **Lower Valhall** | 1 | 1 |

*Table 3-12 Summary of static and dynamic model layer equivalences*

This model was used for initial sensitivities and model calibration; however as the runs times were significant a coarser site model was required and used for subsequent simulation runs (Section 3.6.7).

**Model 2: Site Coarse Upscaled Model**

The grid covered the same area as Model 1, however both horizontal and vertical upscaling of the grid has been carried out.

The 3D grid has been coarsened horizontally to 400m x 400m cells. It has also been vertically coarsened from 157 layers in the fairway model, to 30 layers in the coarse dynamic model.  The structure, zonation, and grid orientation remain the same as the Fairway model. This reduced the number of defined cells from approximately 16.1 million to approximately 53,000.

A comparison of the layering between static and Model 2 3D grid is shown in Figure 3-52. The layering scheme is summarised in Table 3-13.

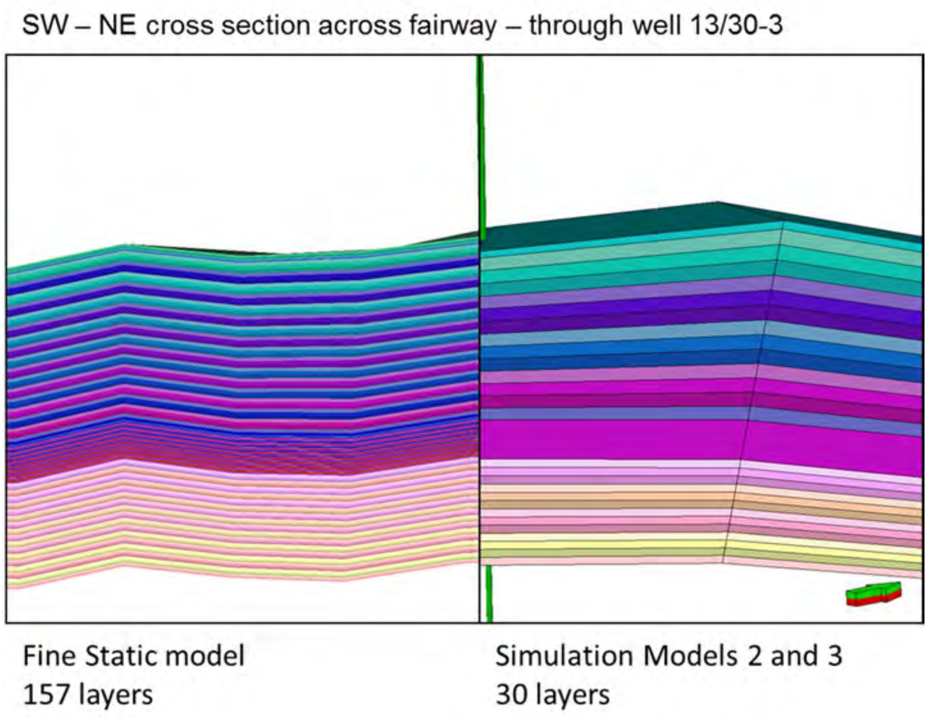



*Figure 3-52 Models 2&3: Comparison of static and simulation model vertical 3D grid resolution*

| Zone | Static Model Layers | Dynamic Model Layers |
|---|---|---|
| **Rodby** | 1 | 1 |
| **Captain E** | 5 | 1 |
| **Captain D** | 50 | 13 |
| **Captain C** | 50 | 1 |
| **Captain A** | 50 | 13 |
| **Lower Valhall** | 1 | 1 |

*Table 3-13 Summary of static and dynamic model layer equivalences*

This model has been used as the primary tool for dynamic sensitivity analysis and development planning (Section 3.6.7).

**Model 3: Fairway Coarse Upscaled Model**

The grid covered the same area as the Fairway Static Model, however both horizontal and vertical upscaling of the grid has been carried out.

The 3D grid has been coarsened horizontally to 400m x 400m cells. It has also been vertically coarsened from 157 layers in the fairway model, to 30 layers in the coarse dynamic model. The Structure, zonation, and grid orientation remain the same as the Fairway model. This reduced the number of defined cells from approximately 16.1 million to approximately 131,000.

A comparison of the layering between static and Model 3 3D grid is shown in Figure 3-52. The layering scheme is summarised in Table 3-14.

| Zone | Static Model Layers | Dynamic Model Layers |
|---|---|---|
| **Rodby** | 1 | 1 |
| **Captain E** | 5 | 1 |
| **Captain D** | 50 | 13 |
| **Captain C** | 50 | 1 |
| **Captain A** | 50 | 13 |
| **Lower Valhall** | 1 | 1 |

*Table 3-14 Summary of static and dynamic model 3 layer equivalences*

This model has been used to test the 1000 year plume migration and containment which otherwise would require impractically long run times. (Section 3.6.7).

Porosity, horizontal permeability and vertical permeability have been upscaled (averaged) from the fine scale grid into the coarser scale simulation grids using standard hydrocarbon industry upscaling methods.

A similar upscaling methodology has been applied for each of the different upscaled grids.

**Model 1**

- Porosity: Volume weighted arithmetic average
- Horizontal Permeability: Volume weighted arithmetic average
- Vertical Permeability: Volume weighted harmonic average

**Models 2 and 3**

- Porosity: Volume weighted arithmetic average
- Horizontal and Vertical Permeability: Cardwell Parsons directional averaging

Checks of static model versus dynamic model pore volumes were carried out for each of the upscaled grids and the differences confirmed as less than 1%.

#### *3.5.4.9 Primary Static Model Sensitivity Cases*

**Structural Uncertainty**

There is poor seismic imaging of the Top Captain sandstone. Whilst there are a large number of wells along the Captain Fairway these tend to be focussed in and around existing hydrocarbon fields, several areas of the fairway have little or no well control. These factors combine to give a large uncertainty associated with the Top Captain Depth structure.

Due to the very high permeability within the Captain Sandstone, the dip and relief of the Top Captain Depth structure has a big impact on the migration pathway of the $CO_2$. An alternative Top Captain Structure has been generated and used to update the reference case model, in order to test the sensitivity of $CO_2$ migration to small changes in the structure.

**Permeable Lower Valhall**

Whist this study was unable to conclude that there was a porous and permeable underburden of any significance, a sensitivity was carried out to test the impact of a such a permeable Valhall "underburden". To achieve this, a single average porosity of 7% and a permeability of 33mD, was applied to the Lower Valhall underlying the Captain Sandstone.

**Captain C Transmissibility**

Whilst well data, and published literature, suggest that the Captain C is an effective horizontal barrier to vertical flow between the Captain D and Captain C zones, RFT data indicates that there is some limited communication between these zones. The reference case has been calibrated to this RFT data by applying a low average porosity and permeability within the Captain C Shale across the full extent of the site model.

A sensitivity has also been run which assumes that the Captain C is completely sealing.

### 3.5.5 Fairway Static Model

The purpose of a fairway static model is to provide a characterisation which could be used to track movement of $CO_2$ from the injection site across the fairway area towards and potentially into other nearby subsurface sites such as oil and gas fields or other $CO_2$ storage sites.

A separate fairway model was not constructed, instead the primary static model was built at the fairway level.

### 3.5.6 Probabilistic Volumetrics

The combination of static and dynamic modelling have through uncertainty and sensitivity analysis provided a range of estimates of rock volume, pore volume and dynamic $CO_2$ storage capacity. Whilst a wide range of scenarios are explored in the dynamic modelling characterisation, a full exploration of this uncertainty space using reservoir simulation impractical. A simple probabilistic approach to estimation has been adopted to provide a context within which the specific runs from the static and dynamic models can be considered.

The approach used has been adopted from oil and gas industry practice for the estimation of oil and gas volume estimates where:

$$STOIIP = GRV \times NGR \times PHI \times (1 - SW) \times Bo$$

Where:

STOIIP – Stock tank oil initially in place

GRV – Gross rock volume – the geometric volume of the gross reservoir internal from its top surface to the deepest level that contains hydrocarbons

NGR – Net to gross ratio – The average vertical proportion of the gross reservoir interval that can be considered to be effective (net) reservoir

PHI – Porosity – The average effective porosity of the net reservoir volume

SW – The average proportion of the net reservoir volume pore space that is saturated with water

Bo – The shrinkage (oil)or expansion (gas) factor to convert the hydrocarbon volumes from reservoir conditions to surface conditions

This equation has been modified to be:

$$Dynamic\ Capacity = GRV \times NGR \times PHI \times CO_2\ Density \times E$$

Where:

$CO_2$ Density – The average density of $CO_2$ in the store at the end of injection period.

E – The dynamic storage efficiency – the volume proportion of pore space within the target storage reservoir volume that can be filled with $CO_2$ given the development options considered.

To consider probabilistic estimates of capacity, a Monte Carlo model has been developed around this equation. Each input parameter is described by a simple probability distribution function and then each of these is sampled many times to calculate a large range of possible dynamic capacity estimates.

The input to the calculation and the results are outlined below.

#### 3.5.6.1 Gross Rock Volume

One key uncertainty in the Captain X rock volume is the inability to clearly interpret the top and bottom of the Captain sandstone. The rock volume has been determined using well data and available seismic and accounts for the uncertainty in both structure mapping and reservoir thickness. The volume used in the probabilistic analysis was 18724 MMCUM with high and low values of 14979 and 22469 MMCUM respectively. A relatively wide uncertainty range of +/- 20% has been adopted to account for this.

#### 3.5.6.2 Net to Gross Ratio

An average net to gross ratio of 76% for the aquifer was extracted from the static model. This is derived from an interpolation of the petrophysics from well control throughout the model and appropriately weighted to the aquifer. An upper and lower value of 86% and 73% have been assigned from consideration of the well data in the area and the well density.

#### 3.5.6.3 Porosity

An average porosity of 26% has been extracted from the static model. This is derived from an interpolation of the petrophysics from well control and appropriately weighted to the aquifer. Triangular distribution has been assumed with a small variance from 23% to 26.6% to reflect well observations.

#### 3.5.6.4 $CO_2$ Density

A range of 0.61 to 0.69 and 0.75 was established after consideration of low and high ranges of final temperature at the end of the injection cycle for the midpoint of the storage reservoir using an equation of state to compute the $CO_2$ density. A simple triangular distribution had been used.

#### 3.5.6.5 Dynamic Storage Efficiency

Since each dynamic model run is based upon the same model volume, the results can be used to extract the estimates of E, the dynamic storage efficiency factor. This accounts for the average $CO_2$ saturation achieved in each dynamic simulation together with the vertical and aerial sweep efficiency. It also fully accounts for limiting factors such as the fracture pressure limit. In the Captain X aquifer the storage efficiency is quite low with values between 1 and 5% with the mid case being 2.5% in a triangular distribution. The low storage efficiency is a result of the high mobility of $CO_2$ in the Captain sandstone and the scarcity of laterally persistent barriers to vertical flow across the Upper sand injection target. A long thin plume can be observed moving towards the north west (see section 3.7) and as a result the sweep efficiency of the $CO_2$ flood in the aquifer is very low.

#### 3.5.6.6 Probabilistic Volumetric Results

Figure 3-53 captures the input and outputs of the Monte Carlo assessment of dynamic $CO_2$ storage capacity for the specified development plan of the Captain X storage site. The P90 value (i.e. 90% chance of exceeding) is 43 MT, with P50 (50% chance of exceeding) of 69 MT and a P10 (10% chance of exceeding) of 102 MT. These numbers provide context for the “deterministic” estimates from the dynamic modelling work for the “development of the base case” of 60 MT.

The results also show that upside and downside potential of the storage capacity are fairly equally weighted due to the uncertainties in how values change across the aquifer.

Since there is no formalised resource classification system currently in use by the CCS industry for $CO_2$ storage resources, a scheme has been adopted from the SPE petroleum resource world (Society of Petroleum Engineers, 2000) and is outlined in Figure 3-54.

There are no $CO_2$ storage reserves currently assessed for the Captain X storage site. The resource base cannot be considered to be commercial at this time as FID has not been concluded and there is no commercial contract in place for its development with an emitter. As a result, the assessed volumes all fall within the sub-commercial contingent resources category. The pore space within the storage site is of course proven and there is excellent evidence from wells and seismic that the site could be developed. The key issue is the degree of control regarding plume dispersal with higher injected inventories. This factor has limited the capacity estimate for this specific development plan at this time. Without a matched emissions point the resource has been characterised on the basis of this probabilistic assessment as:

“Contingent Resources – Development unclarified”

1C – 43 MT – P90

2C – 69 MT – P50

3C – 102 MT – P10

The full scope of the probabilistic dynamic $CO_2$ storage capacity ranges from a P100 of 23 MT to a P0 of 147 MT.

Pale Blue Dot.
AXIS WELL TECHNOLOGY

**CO2 Capacity of Captain X**

Run - 1

| Parameter | Inputs | | Comments | Distribution |
|---|---|---|---|---|
| Gross Rock Volume MMCUM | Low | 14979 | | |
| | Mid | 18724 | | |
| | High | 22469 | | |
| Net to Gross Ratio | Low | 0.73 | Based on well and model averages | |
| | Mid | 0.76 | | |
| | High | 0.86 | | |
| Porosity | Low | 0.23 | Based on well and model averages | |
| | Mid | 0.26 | | |
| | High | 0.27 | | |
| $CO_2$ Density T/M$^3$ | Low | 0.61 | $CO_2$ density calculation | |
| | Mid | 0.69 | | |
| | High | 0.75 | | |
| $CO_2$ Storage Efficien | Low | 0.010 | | |
| | Mid | 0.025 | | |
| | High | 0.050 | | |
| Dynamic Storage Capacity MT | P90 | 43 | | |
| | P50 | 69 | | |
| | P10 | 102 | | |

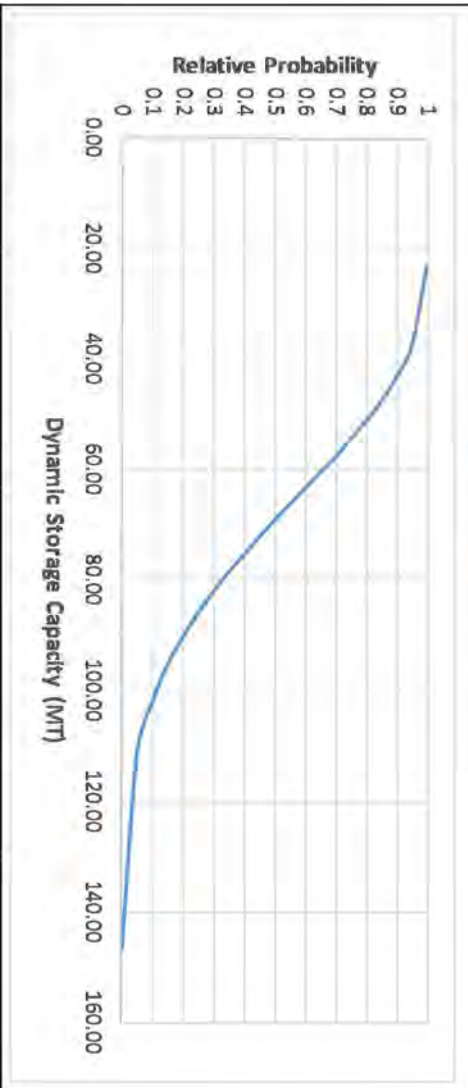




*Figure 3-53 Captain X probalistic volume capacity*

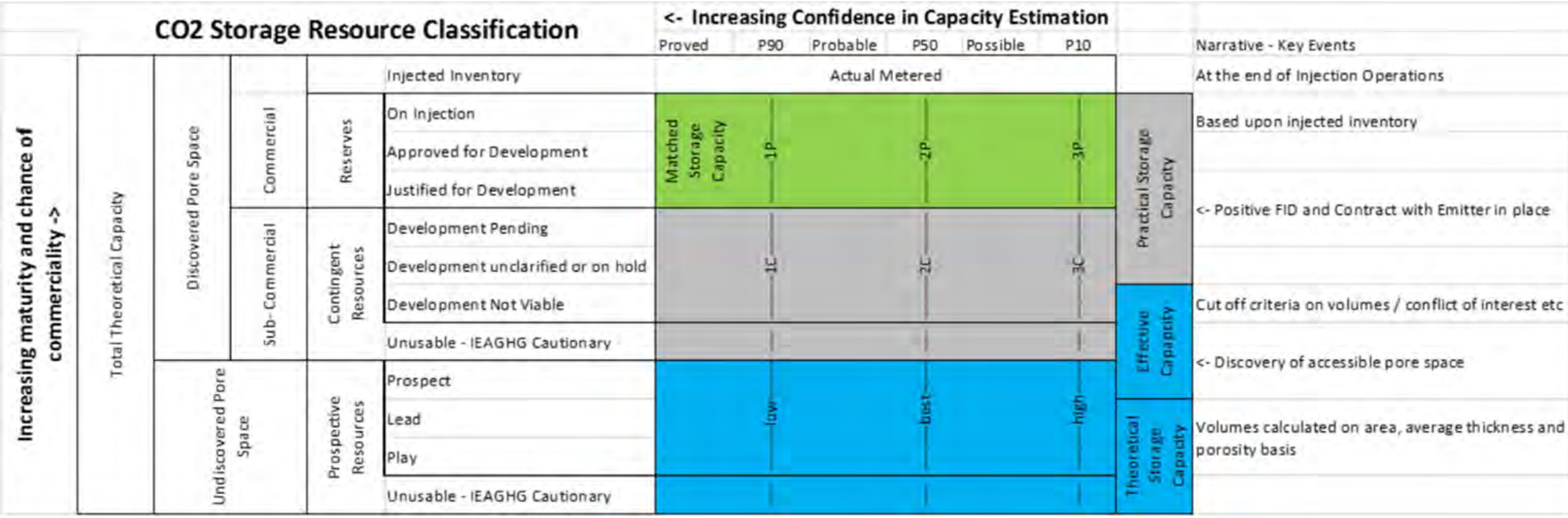



*Figure 3-54 Adopted $CO_2$ storage resource classification*

## 3.6 Injection Performance Characterisation

### 3.6.1 PVT Characteristics

This study has deployed the Peng Robinson model as the equation of state. For modelling $CO_2$ injection, the $CO_2$ density correction implemented by Petroleum Experts was used. The injection fluid was modelled as 100% $CO_2$ in compliance with project $CO_2$ composition limits (Scottish Power CCS Consortium, 2011). The PVT description used is shown in Table 3-15 below.

| Property | Units | Value |
|---|---|---|
| **Critical Temperature** | °C | 30.98 |
| **Critical Pressure** | bara | 73.77 |
| **Critical Volume** | $M^3$/kg.mole | 0.0939 |
| **Acentric Factor** | None | 0.239 |
| **Molecular Weight** | None | 44.01 |
| **Specific Gravity** | None | 1.53 |
| **Boiling Point** | °C | -78.45 |

*Table 3-15 PVT Definition*

The $CO_2$ physical properties that strongly affect tubing flow and hence transport are density (ρ) and viscosity (μ). To test the validity of the Prosper PVT model, predicted in-situ $CO_2$ densities and viscosities were compared with pure component $CO_2$ properties calculated using the Thermophysical Properties of Fluid Systems (National Institute of Standards and Technology, n.d.). Comparisons were carried out for a range of temperatures and pressures (temperatures of 4 °C to 100 °C and pressures of 5 bara to 450 bara), with the following results:

- Density differs from the NIST calculated value by a maximum of 1.1% with an average of 0.3%.
- Viscosity differs from the NIST calculated value by a maximum of 14.3% with an average of 7.3%.

These results were considered adequate for the purposes of this study.

#### *3.6.1.1 $CO_2$ Impurity Sensitivity*

The well and tubing design work has been carried out assuming that the $CO_2$ is contaminant free. In practice, however, a small amount of other gases may be present in the injection gas. The main effect of this is that the phase envelope, which simplifies to a line in the case of pure $CO_2$, has a two phase region and the minimum injection pressures required to ensure single phase liquid injection have to be raised (see the figure below). For small amounts of impurities this shift is minor, but in order to simulate the effect of possible contamination a 10% safety region has been defined around the pure $CO_2$ phase envelope and this region has been avoided during the well design work.

A further effect of the presence of contaminants is that the fluid viscosity and density will change, which has an effect on the flow behaviour, which should be minor if contaminant content is insignificant.

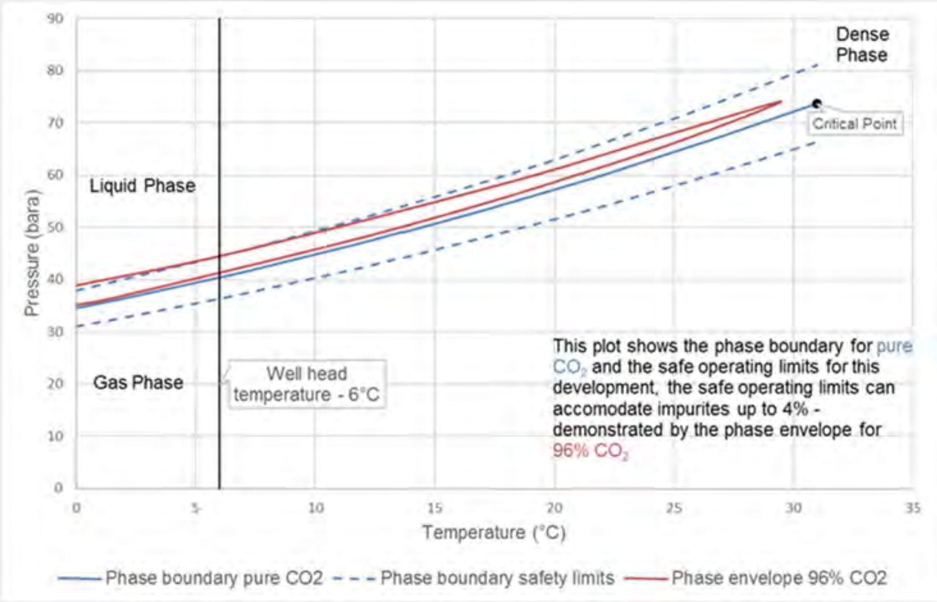



*Figure 3-55 Effect of impurities on the phase envelope*

## 3.6.2 Well Placement Strategy

In order to model well injection performance, the well deviation profiles (route from surface to reservoir) were determined following a well placement strategy review.

The Captain well placement strategy has been driven by development strategy (platform structure required for filtering and control) as well as reservoir geometry, geology, reservoir engineering modelling and the economics of development.

First pass reservoir engineering suggests that 2 wells (plus 1 well for back-up / redundancy) are required over field life to inject target $CO_2$ volumes. Furthermore because of the exceptional quality of the reservoir, well spacing to prevent well to well interference does not appear to be a critical factor. As a result, and for the design rate, the injection wells can be drilled from the same surface location.

For standard oil and gas developments, the most economical development strategy for such a low well count is often a sub-sea development. However, in any reservoir injection project, the removal of fine particulates from the injection stream is considered critical. If this is not done, then it can lead to a rapid degeneration of injectivity as the rock pore throats are plugged with fines. As the Captain X site is a large distance from any $CO_2$ source, pipeline lengths are considerable and the potential for particulate debris is high. Furthermore, subsea wells need to be controlled, and the cost of conventional control umbilicals from shore would be high. Whilst such a subsea development is possible, a lower risk, conventional development using a single 3 well slot platform (hosting filtering facilities and well controls) was selected as a base case. As this study considers stand-alone development only, options to supply any future subsea developments from existing (or future) third party platform facilities has not been considered.

The platform development option dictates a single development centre for the development wells. Reservoir engineering suggests that two injection wells will be adequate to achieve target injection rates. A third well would be drilled to provide redundancy should a well fall out of service. In common with the operational injection wells, this additional well would also be used for routine reservoir monitoring.

In order to maximise reservoir coverage and well separation, deviated wells are proposed. The wells will kick-off at about 550ft TVD and have a sail angle of around 60° all the way to the reservoir. The 60° angle through the reservoir should provide sufficient sand face to allow high injection rates in what is expected to be a high permeability reservoir.

The base case development scenario suggests that the primary $CO_2$ storage target is the Upper Captain sand. As a result, there is an opportunity to consider horizontal wells if more sandface is required for enhancing injectivity. Should the Lower Captain sand (more limited in extent and potentially only limited connectivity to the upper sand) be considered for future development, a dedicated well to target this sand may be preferred, again opening the possibility of a horizontal well profile, should it be required. Injecting into both sands from the same wellbore, while simple to accomplish with a 60° deviated well, may prove problematic due to:

- Potential for different 'pressure charging' rates, creating significant crossflows during well shut-in periods. This could in turn lead to significant sanding and corrosion issues.
- Charging of the lower sands to fracture pressure well before the upper sand reaches this limit. In practice, this may not be an issue, as fractures from the lower sand through the inter-sand shale would not result in containment loss. However, the strategy adopted in this work is to remain below fracture pressures at every point in the reservoir in case of uncontrolled propagation.

#### *3.6.2.1 Injection Well Spacing*

Well spacing was initially limited to a minimum 1,000m in order to prevent temperature interference and minimise pressure interference. Subsequent work (near wellbore study from Bunter 36 and reservoir engineering study) have suggested that this is a conservative limit with respect to temperature, but is reasonable for pressure interference effects. Applying this limit to the Captain X site with a single drill centre, results in a simple radial well pattern (see section 5.3).

#### *3.6.2.2 Monitoring Well*

A dedicated monitoring (observation) well is not thought necessary, or valuable, for the Captain X injection site. As the plume migration area is large, choosing a single relevant observation point would be challenging. As the injection site is an open aquifer system and not structurally contained, injection pressure (pressure above reservoir pressure) is expected to dissipate away from the wells shortly after shut-in. This means that pressure observations at the injection wells should be representative of the injection site as a whole. It is therefore recommended that all injection wells are equipped with pressure and temperature gauges (and DTS if possible) in order to observe injection behaviour. Changes in $CO_2$ / brine saturation can be observed at the 'back-up' well until such times as it is required as an injector well. Plume migration away from the injector wells will be monitored by 4D seismic.

### 3.6.3 Well Performance Modelling

The purpose of the well performance modelling is to assist in the selection of a suitable injection tubing size and to evaluate some of the factors that may limit injection performance. The results of this modelling exercise are then made available to reservoir engineering in the form of Vertical Lift Performance tables (VLP), that are used to predict well performance in the reservoir simulation models.

All modelling needs to respect the safe operating limits described in section 3.6.6.

#### 3.6.3.1 Methodology

Well modelling was carried out using Petroleum Experts' Prosper software, which is a leading software for this type of application. The field development plan stipulates three $CO_2$ injection wells (two operational and one spare) for Captain X with a single platform based injection facility. The primary injection target is the Upper Captain Sandstone. Tubing selection, which uses the base case, therefore only considers injection into this upper layer.

Well performance was investigated using a single prototype well, GI01. The well model input data are described in the following sections.

#### 3.6.3.2 Downhole Equipment

Since part of the purpose of this study was to determine the optimal tubing size for the Captain X Site wells a set of sensitivity cases was defined on downhole equipment (discussed later on in this section).

#### 3.6.3.3 Wellbore Trajectory

The wellbore trajectory used for the Captain X Site well models were simplified from the deviation surveys provided by the well design study (see section 5.3).

#### 3.6.3.4 Temperature Model

Prosper offers three heat transfer models; rough approximation, improved approximation and enthalpy balance.

The rough approximation model estimates heat transfer and hence fluid temperatures from background temperature information, an overall heat transfer coefficient and user-supplied values for the average heat capacity (Cp value) for oil, gas and water. In an application in which accurate temperature prediction is vital this model is considered too inaccurate, especially since it neglects Joule-Thomson effects, which can be vital in predicting the behaviour of a $CO_2$ injector. For this reason, this model was not considered.

The full enthalpy balance model performs more rigorous heat transfer calculations (Petroleum Experts Ltd., 2015) (including capturing Joule-Thomson effects) and estimates the heat transfer coefficients as a function of depth from a full specification of drilling information, completion details and lithology. However, at the current stage in the design cycle many of the input parameters are still unknown (e.g. mud densities). For this reason, the improved approximation model was chosen for this work. The sole difference between this model and the full enthalpy balance model is that the user supplies reasonable values for the heat transfer coefficient rather than having them estimated from the completion information and lithology. In line with Petroleum Experts recommendations, a uniform heat transfer coefficient of 3 BTU/h/ft2/F (17.04 W/m2/K) was chosen.

For the modelling a delivery and seabed temperature of 6°C (ICES; EuroGOOS, 2007) was assumed and the required background temperature gradient was defined as 6°C at the seabed and reservoir temperature at top perforation depth. Note that some slight seasonal variation in temperature may occur, but it is not thought to be significant at this location.

#### 3.6.3.5 Reservoir Data and Inflow Performance Relationship (IPR)

A full review of likely reservoir and field parameters was carried out and estimates on which the IPR modelling was based are summarised in Table 3-16 and Table 3-17 below:

| Parameter | Unit | Low | Best Estimate | High |
|---|---|---|---|---|
| **Formation Top Depth (Datum)** | *ft (m) TVDSS* | | 6200 (1890) | |
| **Formation NTG** | - | 0.73 | 0.76 | 0.86 |
| **Reservoir Pressure at start of injection (@ Datum)** | *bara (psia)* | | 193 (2799) | |
| **Reservoir Temperature** | *°F (°C)* | | 149 (65) | |
| **Permeability Anisotropy ($K_v/K_h$)** | - | 0.40 | 0.65 | 0.90 |
| **Formation Water Salinity** | *ppm* | | 56,600 | |

*Table 3-16 Captain X site reservoir data*

| Parameter | Unit | Low | Best Estimate | High |
|---|---|---|---|---|
| **Water Depth** | *m (ft)* | | 115 (377) | |
| **Pressure Gradient** | *psi /ft* | | 0.451 | |
| **Geothermal Gradient** | *°F/100ft* | | 1.87 | |

*Table 3-17 Captain X site field and well data*

These parameters were derived primarily from well data from within the storage site. The formation water salinity estimate comes from the Captain sand aquifer at Blake, as per samples obtained from well 13/29b-8. A low case of 12,000ppm could be derived from Pinnock & Clitheroe, updated by Rose (2003). However, well data from well 13/30a-4 gives a high case of 62,730ppm.

Using these data three IPR models were defined in Prosper to represent high, medium and low reservoir performance. These are summarised in Table 3 4 below.

| Parameter | Unit | Low | Medium | High |
|---|---|---|---|---|
| **IPR Model** | *n/a* | Jones | | |
| **Permeability** | *mD* | 700 | 1350 | 2500 |
| **Reservoir Thickness** | *ft* | 60 | 70 | 85 |
| **Drainage Area per well** | *acres* | 1213 | | |
| **Dietz Shape Factor** | *(-)* | 31.6 | | |
| **Perforation Interval** | *ft* | 60 | 70 | 85 |
| **Skin** | *(-)* | +20 | +10 | 0 |

*Table 3-18 Captain X site IPR input data*

#### *3.6.3.6 Tubing Selection*

*Injection Limits*

Some pressure and temperature limits on injection operations have been defined and have been summarised in Table 3-19 below.

| Parameter | Unit | Value |
|---|---|---|
| **Fracture Limit at Top Perforation Depth** | *bara (psia)* | 257.4 (3733) |
| **Minimum Fluid Temperature at Perforation Depth** | *°C* | 0 |
| **Maximum Pipeline delivery pressure at wellhead** | *bara (psia)* | 160 (2321) |

*Table 3-19 Injection pressure limits*

Please note:

- The fracture limit at top perforation depth has been derived using a fracture gradient of 0.69 psi/ft and a top perforation depth of 6011 ft TVDSS. An uncertainty factor of 0.9 was applied to the calculated fracture pressure giving a limit of 0.62 psi/ft. (Appendix 9)
- A maximum THP for fracture prevention can be derived to ensure that pressure at top perforation depth stays below the fracture pressure even if a rapid loss of injection occurs. This value is calculated as the fracture limit at top perforation depth minus the hydrostatic head imposed by a column of (liquid phase) $CO_2$ in the wellbore. The hydrostatic head has been estimated in Prosper for this well as 2342 psi. This estimate has been calculated at the lowest pressure and rate at which no phase change occurs and liquid injection is maintained throughout the wellbore. Liquid compressibility is low but to allow for increases in density due to operation at higher pressure a 5% safety margin has been added giving a hydrostatic head of 2459 psi. This gives a maximum THP of 1274 psia (87.8 bara). The limit is, in effect, based on the assumption that at the point of well shut-in, all frictional pressure is lost and the full injection pressure is applied to the hydrostatic column. This is a highly conservative assumption as, when a well is shut-in at surface, the liquid column remains in motion and frictional pressure losses continue until the hydrostatic balance is achieved. For the tubing design the more generous limit imposed by the maximum pipeline delivery pressure has been used and this fracture prevention THP limit has been ignored.
- The minimum fluid temperature at perforation depth exists to prevent formation water from freezing during injection.

### *Sensitivity Cases*

The sensitivity cases considered for maximum injection pressure are summarised in Table 3-20 below. The injection temperature at the well head is 6°C for all cases.

The high, medium and low reservoir cases are as described earlier. The minimum tubing head pressure (44.5 bara) is the minimum pressure required to ensure single phase liquid injection throughout the tubing. The maximum tubing head pressure (160 bara) represents the maximum pipeline delivery pressure.

### *Results*

Table 3-20 summarises the rates achievable for the various sensitivity cases and Figure 3-56 provides a graphical representation. Prosper uses volumetric flow rates and the conversion to mass flowrate is based on a density of 1.8714 kg/m3 at standard conditions.

| Case | Reservoir Case | Tubing Size | Max and Min THP (bara) | Rate (MMscf/d) | Rate (MMte/yr) |
|---|---|---|---|---|---|
| 1 | High | 4.5'' (12.6 ppf) | 160 | 114.2 | 2.208 |
| | | | 44.5 | 38.6 | 0.747 |
| 2 | Medium | 4.5'' (12.6 ppf) | 160 | 112.5 | 2.175 |
| | | | 44.5 | 37.0 | 0.716 |
| 3 | Low | 4.5'' (12.6 ppf) | 160 | 106.5 | 2.060 |
| | | | 44.5 | 32.9 | 0.636 |
| 4 | High | 5.5'' (17 ppf) | 160 | 197.7 | 3.823 |
| | | | 44.5 | 69.5 | 1.344 |
| 5 | Medium | 5.5'' (17 ppf) | 160 | 191.9 | 3.712 |
| | | | 44.5 | 64.0 | 1.237 |
| 6 | Low | 5.5'' (17 ppf) | 160 | 175.2 | 3.389 |
| | | | 44.5 | 51.4 | 0.995 |
| 7 | High | 7'' (29 ppf) | 160 | 360.6 | 6.975 |
| | | | 44.5 | 127.0 | 2.456 |
| 8 | Medium | 7'' (29 ppf) | 160 | 340.0 | 6.577 |
| | | | 44.5 | 110.6 | 2.140 |
| 9 | Low | 7'' (29 ppf) | 160 | 284.5 | 5.503 |
| | | | 44.5 | 74.1 | 1.433 |

*Table 3-20 Rates achievable by case for minimum and maximum tubing head pressure*

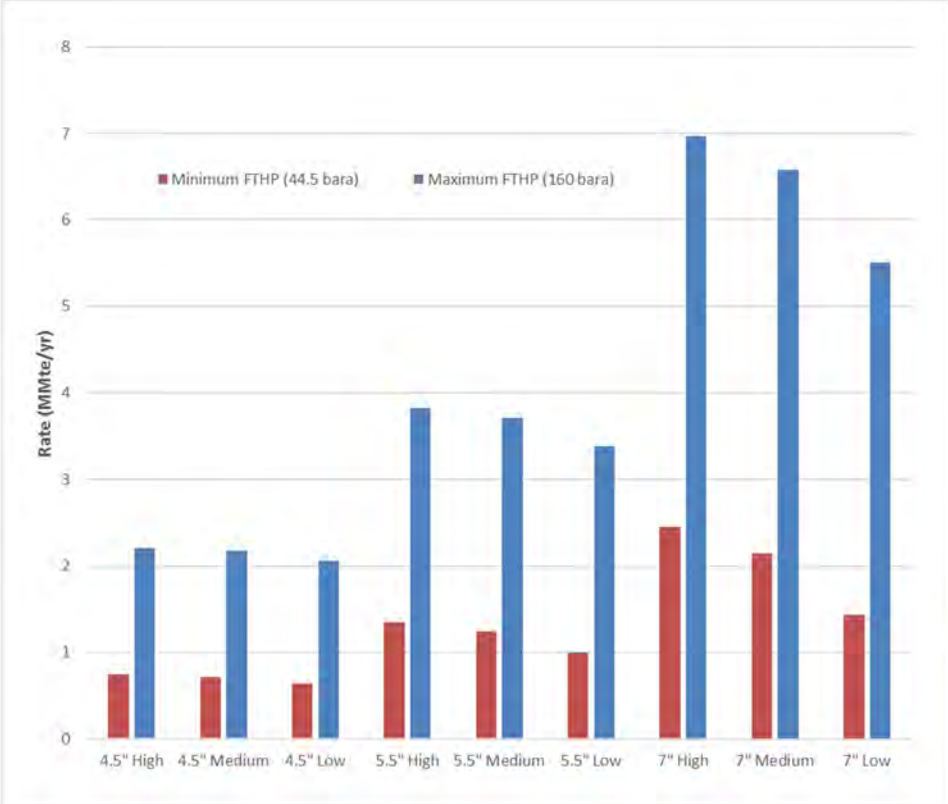



*Figure 3-56 Rates achievable by case for minimum and maximum tubing head pressure*

Figure 3-57 shows the pressure and temperature behaviour along the tubing plotted as pressure versus temperature for the various tubing sizes and well head injection pressures. The graphs also show the phase boundary with an upper and lower safety limit and the various pressure and temperature limits.

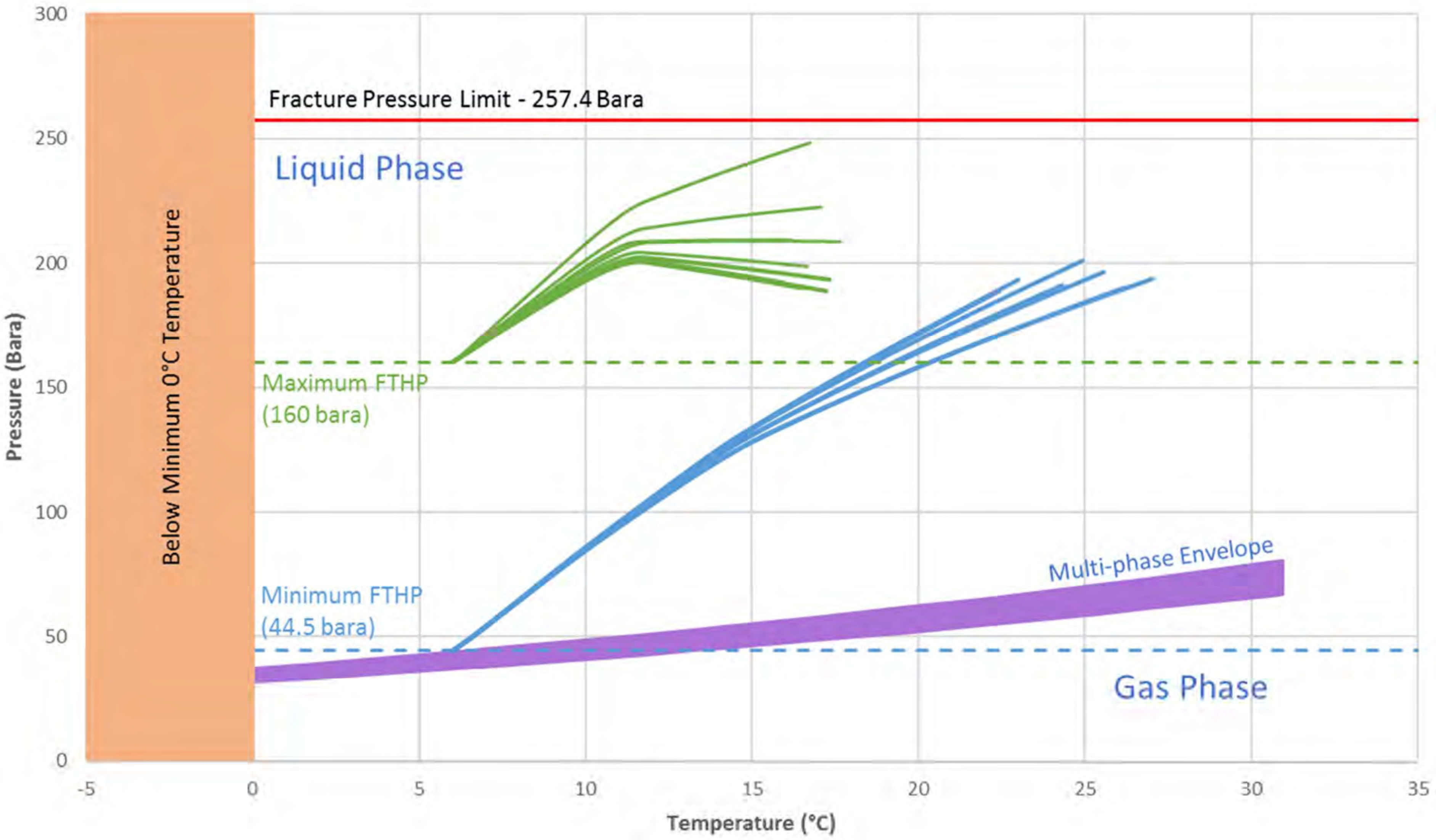



*Figure 3-57 Temperature and pressure completion modelling results*

The results can be summarised as follows:

- Acceptable injection rates can be achieved for all reservoir cases and all tubing sizes considered.
- Fracture pressure limits are not approached in the near wellbore, other than for a low reservoir property, high injection rate case.
- Within the operating envelope no issues with phase changes in the tubing should be encountered and the bottom hole temperature limit should not be breached.
- Choice of tubing size will depend on economic (number of wells) and contractual (maximum and minimum delivery range) considerations. Larger tubing gives a much higher maximum injection rate, but the corresponding high minimum rate reduces operational flexibility (for example, supply rates must be maintained at a minimum of 2.14 MMte/yr for the mid case 7" tubing).
- Based on a field injection target of about 3 MMte/yr, 5.5'' tubing is the most suitable choice as target can be achieved by two wells (optimum development case) while reducing THP requirements and reducing minimum injection rates to 1.237 MMte/yr in the mid reservoir case. 5.5" has therefore been adopted as base case.
- Should greater flexibility in operating range be required, a mixture of 4.5" and 5.5" wells could be considered. Given that full redundancy is required, this would increase well count to 4 (2 x 5.5" and 2 x 4.5") as opposed to the base case 3 (2 x 5.5" plus 1 x 5.5" spare).

The minimum wellhead injection pressure is dictated by the phase envelope as 44.5 bara; the maximum THP is given by the assumed pipeline delivery limit of 160 bara. For reduced individual well target rates, there is an opportunity to reduce pipeline delivery specifications.

Figure 3-58 shows a typical plot of pressure and temperature versus depth, plotted for the maximum injection rate in 5.5" tubing (mid reservoir properties case).

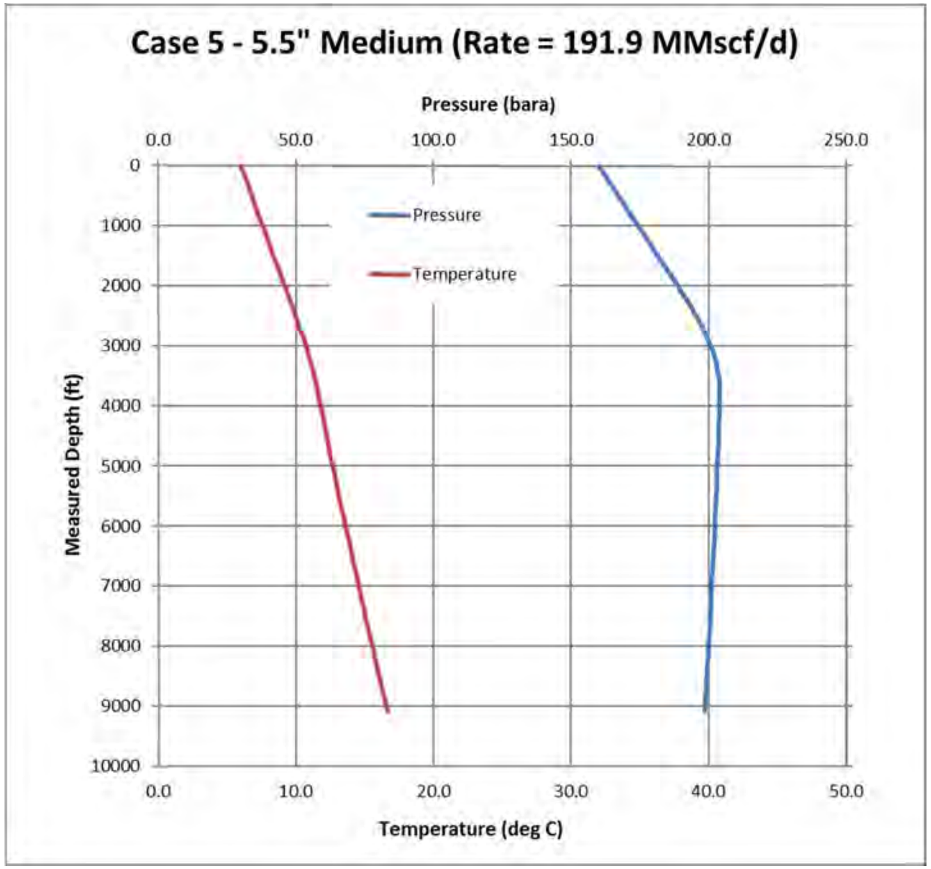



*Figure 3-58 Case 5 (Maximum THP) - Pressure and Temerature v Depth Plot*

#### 3.6.3.7 Vertical Lift Performance Curve Generation

Vertical lift performance (VLP) curves were generated for the Captain X injection wells. To allow sensitivities to injection pressure limits and other quantities to be run in Eclipse without extrapolation, the curves were generated for pressures and rates that were adjusted to Eclipse requirements rather than reflecting limits to these values discussed above.

Input parameters were as follows:

- Tubing Head Pressures: 645 psia (44.5 bara) to 2500 psia (172.4 bara) in 10 steps
- Gas Rates: 16 MMscf/d to 280 MMscf/d in 20 steps

The performance envelope of the well is shown in Figure 3-59. It was ensured that for all points shown on the curves dense phase injection was maintained throughout the tubing and that the temperature limit of 0°C was not broken.

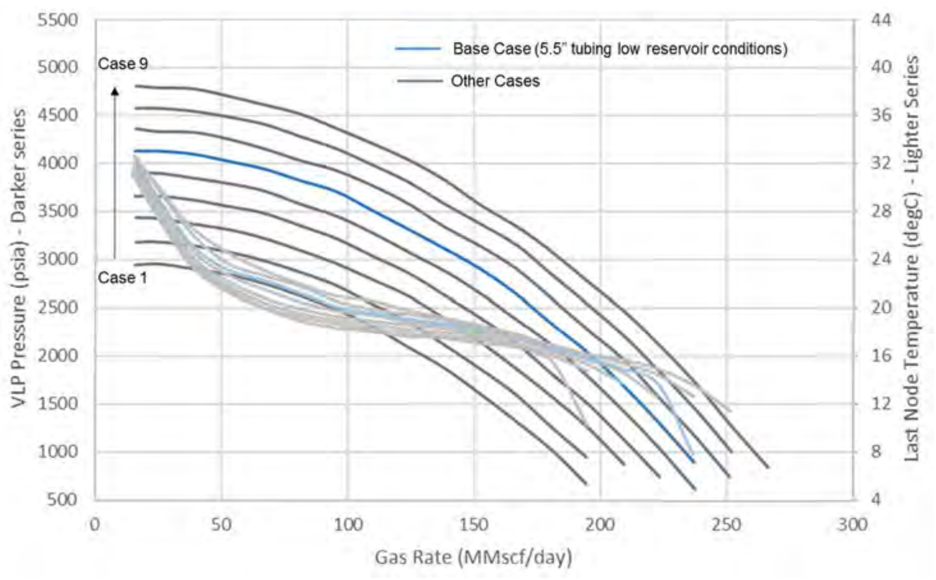



*Figure 3-59 Performance envelope - 5 1/2" tubing*

### 3.6.4 Injectivity and Near Wellbore Issues

The effects of long term $CO_2$ injection into a sandstone reservoir are not yet fully defined. Despite some experience of the process gained in the industry, each reservoir rock, each injection profile and each development scenario is different. The reservoir rock is subject to pressure and thermally induced stresses, applied in sometimes random patterns (cyclic stressing from variations in supply conditions). These stresses can lead to rock failure or damage to the rock fabric and therefore permeability changes. Interaction of $CO_2$ with in-place reservoir rock and fluids may also alter the ability of the rock to conduct fluids.

Some of the more recognised issues are discussed below, along with their effect on the Captain X site storage potential.

#### 3.6.4.1 Halite

When $CO_2$ is injected into formations containing saline brine, the majority of the brine will be pushed away from the wellbore by the injected $CO_2$. However, some brine will remain in pores and adhering to rock matrix. As $CO_2$ and water are miscible, $CO_2$ will absorb the water. However, the salt in the brine is not soluble in $CO_2$, thus precipitating the salt out of solution as halite. In other words, the near wellbore is dehydrated (water removed), leaving the salts behind. If this effect is significant, it can reduce both porosity and permeability over time (Mathias, Gluyas, & Gonzalez, 2011) .

The Captain Sandstone formation water is a saline brine. There is some uncertainty in the composition of this brine, but a nearby well (13/29b-8) reported salinity measurements of 56,600ppm, and this has been taken to be the best estimate. A lower estimate of 12,000ppm was suggested by Pinnock & Clitheroe, updated by Rose (2003), while a high estimate of 62,730ppm was obtained from sampling in well 13/30a-4. While higher than seawater salinity, these values are still considered to be relatively low. The range of available data would appear to indicate some variability across the Captain fairway, possibly where variations in local diagenesis has occurred. This creates a moderate uncertainty with respect to the actual brine salinity, and this should be investigated further.

However, on the assumption that the Captain brine is relatively low salinity, there is a possibility that near wellbore permeability will remain unchanged by dehydration, or possibly enhanced. Even if all halite (salt) was precipitated, less than 2% of the pore volume would be occupied with halite.

The effect of halite precipitation can be mitigated by 'washing' the near wellbore with fresh water. The wash water dissolves the salt and carries it away from the near wellbore region, where the effects of permeability reduction have most impact. However, as the halite risk for Captain X is currently considered to be low, the addition of wash water facilities for these operations is not considered cost effective. Should problems arise, temporary well intervention operations can be planned and implemented on the platform.

#### 3.6.4.2 Thermal Fracturing

The $CO_2$ stream injected into the Captain Sandstone member is colder than the modelled ambient reservoir temperature (around 20°C vs 62°C). This reduction in temperature will be limited to a region close to the wellbore (thermal modelling in Eclipse 100 for on other reservoirs (Bunter Sandstone from Southern North Sea) have suggested a cooling radius of 12m before geothermal gradient was re-established. As Captain Sandstone is hotter, a smaller effect is expected. A drop in temperature will have an effect on the near wellbore stresses, and will make rock more liable to fracture through tensile failure. The effect of this thermal effect on the fracture pressure has not been investigated in this report. However, as the magnitude of temperature drop is low and restricted in extent, it is not expected to be problematic in the Captain Sandstone. The applied safety margin (10%) on fracture pressure and the 20ft stand-off from injection point to cap rock provides some security with respect to cap rock fracturing and containment issues. Furthermore, the effect of increasing fracture pressure with increased pore pressure (pore pressure increases throughout the injection period) has not been taken into consideration when defining fracture limits, and this is likely to have a countering effect to the potential for thermal effects on fracture pressure. It is recommended that these issues be reconciled in the FEED stage.

#### 3.6.4.3 Sand Failure

As with water injection wells, there is a potential for sand failure in $CO_2$ injection wells. The principal causes of this are similar:

- Flow back (unlikely to occur in $CO_2$ injection wells without some form of pre-flow pad)
- Hammer effects during shut-in
- Downhole crossflow during shut-in (from and to formation zones with different charging profiles)
- Well to well crossflow during shut-in (if individual wells are charged to different pressures and surface vales are left open, allowing cross-flow via injection manifold)

The effects of sand failure are that near wellbore injectivity can be reduced (failed sand packs the perforation tunnels or plugs the formation) or the well can be filled with sand (reducing injectivity and potentially plugging the well completely).

The pre-requisite for sand failure is that the effective near wellbore stresses, as a result of depletion and drawdown, exceed the strength of the formation.

The in-situ stresses at the wellbore wall, while predominantly a function of the overburden and tectonic forces, will vary dependent on the trajectory (deviation and azimuth) of the proposed wellbore. So, while field wide values can be generalised, the specifics of the well can impact on the required conditions for failure of the formation.

These notes apply a generic critical drawdown process to selected well strength logs to provide a guide for the pressure drops required for failure in a $CO_2$ injector. More detailed work would be required once the well trajectory and injection scheme parameters are better defined.

$$p_{w(crit)} = \frac{3\sigma_1 - \sigma_2 - \sigma_{yield} - p_t A}{2 - A}$$

Where:

$$A = \frac{(1 - 2\mu)}{(1 - \mu)} \alpha$$

The cumulative uncalibrated rock strength (UCS) in the Captain Sandstone as calculated from logs for the wells 13/29b-6, 13/30-3, 13/30a-4 and 13/30b-7 are shown in Figure 3-60, where the average range is between 2800 psi to 3300 psi.

Two cases were considered in this analysis of the critical total drawdown (CTD) for sanding: a) at original reservoir pressure condition; and b) at depleted reservoir conditions. The following figures indicate the CTD for the four wells evaluated in the Captain Sandstone, including original and depleted reservoir pressure conditions.

As can be seen, the CTD at original and depleted reservoir condition for wells 13/29b-6, 13/30-3, 13/30a-4 and 13/30b-7 are all above 2000 psi, indicating a low risk for sanding. However, it is worth mentioning that this is based on an uncalibrated rock strength so uncertainty remains.

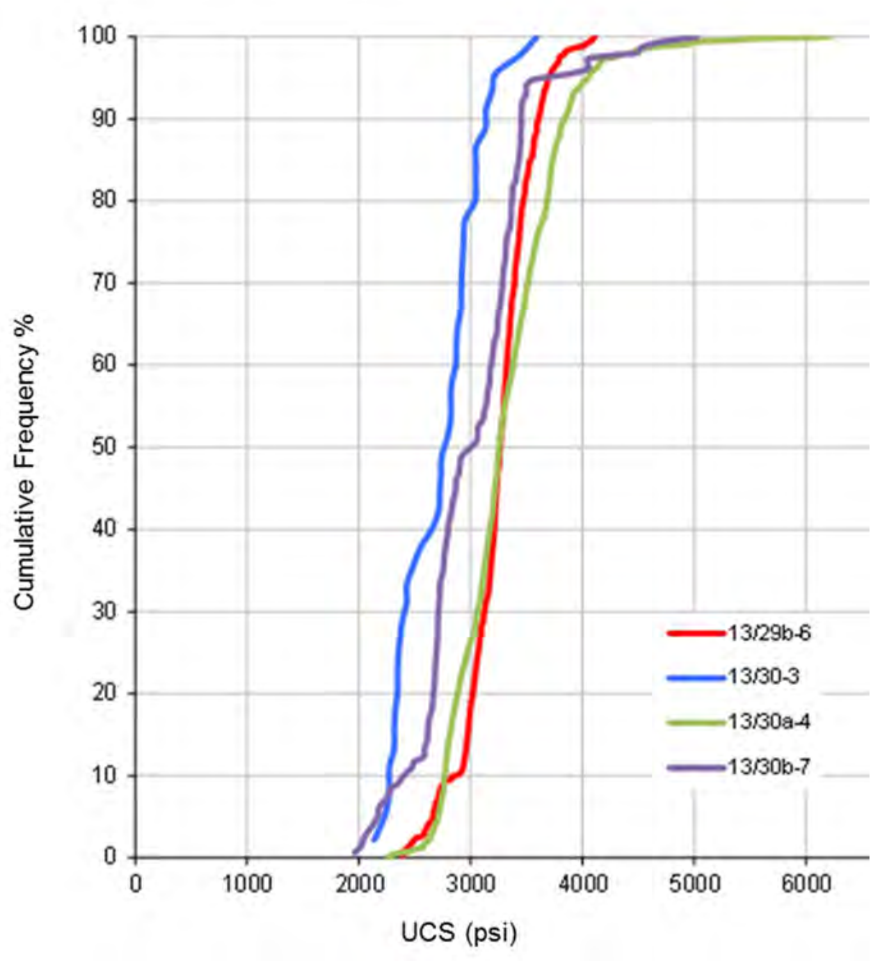



*Figure 3-60 Captain Sandstone UCS cumulative distributions*

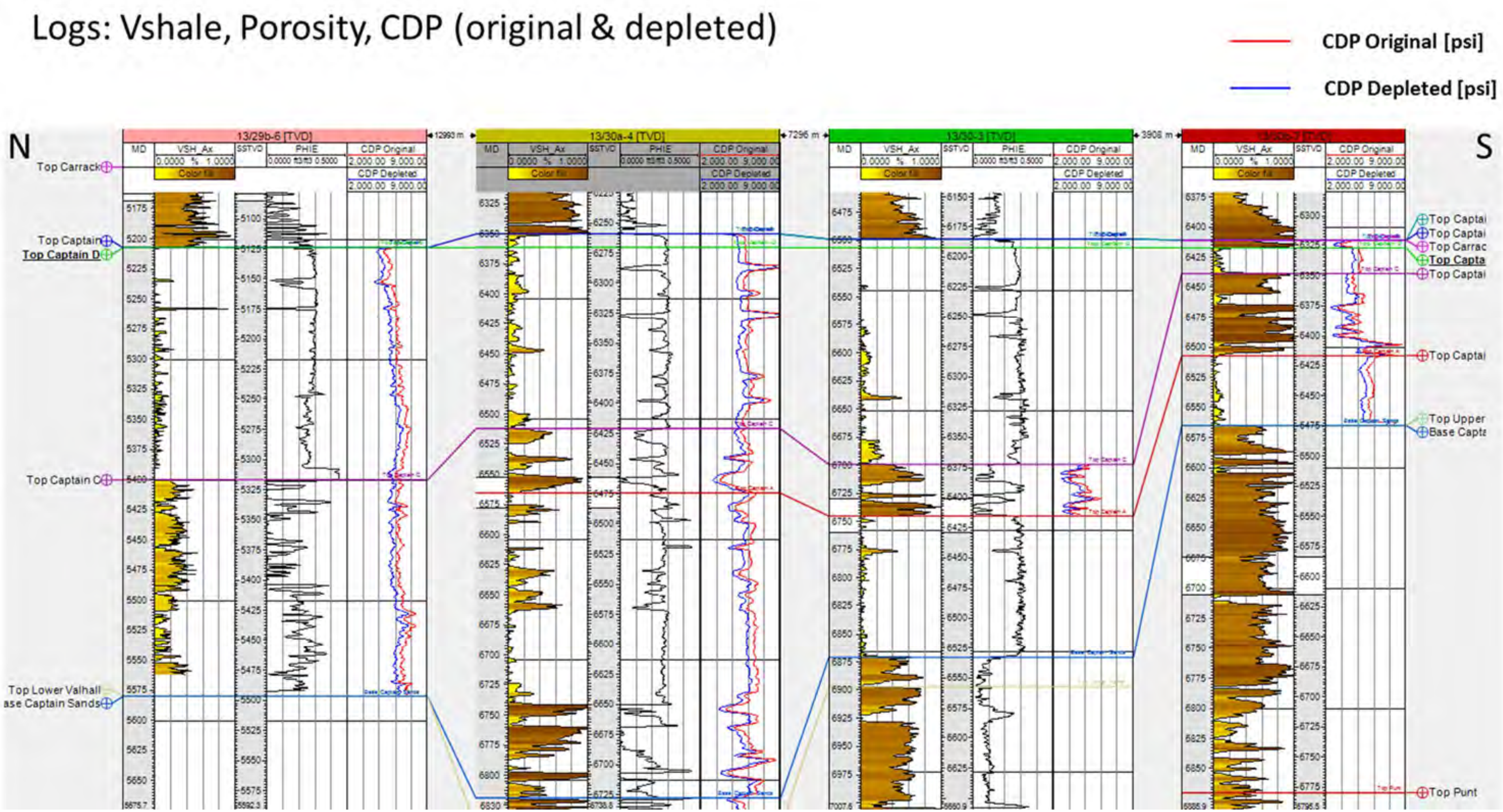



*Figure 3-61 Critical drawdown pressure for the Captain Sandstone*

*Impact on Well Completion*

Following the guidelines from SPE 39436 (Morita, E, & Whitebay, 1998), the Captain Sandstone could be considered as a Case D, a consolidated formation but with limited weak zones. (due to uncertainty in rock strength calibration). However, given that the Captain oil field has suffered sand production (albeit from shallower and weaker sands) and that Goldeneye has recommended sand control, the base case development will be stand-alone sand screens (SAS). Selective perforating, by its very nature, avoids the weakest (generally the most permeable) sands and reduces the overall sandface flow area. An objective of any injection well is to maximise this sandface flow area (this reduces the effects of injection debris plugging in the wells), and an 'open hole' completion such as SAS is the most effective completion for this purpose, short of hydraulic fracturing.

## 3.6.5 Transient Well Behaviour

In the Captain X injection site, $CO_2$ remains in liquid or dense phase in all injection scenarios within the wells, providing minimum rates of injection are achieved. However, if the wells are shut-in at surface, the tubing head pressure (THP) will drop below critical pressure and $CO_2$ will boil off into the gas phase. This will generate significant temperature drops and create two phases in the tubing when the well is re-started. There effects are transient, but have significant impact on well design (temperature resistance) and operations planning and are discussed further below.

### 3.6.5.1 Shut-in at Surface with a Full Column of $CO_2$ in the Well

With a surface shut-in, the pressure at the top of the well, below the shut-in point, falls to below the phase boundary, so gas will evolve, leading to significant cooling (and gas slugging when injection starts up again). When injection starts again, the pressure will be low at the wellhead at the top of the $CO_2$ column and there will be a short transitional period of high pressure liquid entering a low pressure gas environment, leading to further cooling effects.

The transient pressure effects of a surface shut-in could be modelled using a simulator such as OLGA, for example. This would give a better prediction of the maximum and minimum pressures in the wellbore and highlight if the pressure variations (for example, the 'water hammer' effect) cause problems at the sandface.

### 3.6.5.2 Alternative Solution to Transient Effects

There is a possible alternative solution to these transitional effects which involves adding a deep-set shut-in valve to the completion. The deep-set valve would act as the primary shut-in.

Shut-in closer to the formation reduces the hydrostatic head of $CO_2$ acting on the formation and removes the risk of damaging pressure pulses ('water hammer' effect) affecting the sandface integrity. After shut-in the well could be left with the $CO_2$ supply pressure applied and therefore mitigate cooling effects at the wellhead on restart. The pressure differential across the downhole valve will be minimal and cause no problematic transitional effects. Some OLGA modelling would be required to determine the minimum depth of shut-in and a suitable valve specified.

A similar approach could be taken for a water wash: the system left pressured above the deep set valve at the end of the treatment (or re-pressured before restarting $CO_2$ injection). The higher pressure mitigates the cooling at the $CO_2$ / water interface when injection restarts.

The oil and gas industry offers a range of subsurface isolation valves that could be evaluated. Preferred features would be:

- Surface controlled – hydraulic control lines
- Ball valve
- Metal-to-metal sealing
- Bi-directional sealing
- Deep set functioning
- Wireline retrievable
- Reliable

Potential candidate valves are currently available on the market. These are surface-controlled, tubing-retrievable isolation barrier valves. Open/close is achieved by applying hydraulic pressure to the tool via dual control lines. They have metal-to-metal sealing body joints, full bore internal diameter, bi-directional sealing and a deep-set capability (the actuation mechanisms in these valves mean that the setting depth is unrestricted). Some have a contingency mechanical shifting capability.

The one preferred feature not available is the ability to retrieve/set the valves on wireline, which means a workover is required to retrieve it in case of failure. Including these valves in the completion adds some complexity and slows the completion running/pulling time because of the need to run dual control lines. However, if they can be operated reliably, they considerably simplify the well shut-in and start-up procedure and would be beneficial over the project life.

These valves are tested to ISO 28781 Barrier Valve Certification. However, before incorporating them into a completion for $CO_2$ injection there should be a comprehensive evaluation of the historic reliability of these valves under similar operating conditions to give confidence that their inclusion does not compromise the efficient operation of the injection program.

For the purposes of this work, it is assumed that a suitable mechanism is available to perform the downhole shut-in function. Transient effects are therefore mitigated. However, further work is required in the FEED stage to substantiate this approach, or to provide alternate solutions. In all cases, well design should reflect the potential for very low temperatures should these mitigations fail.

### 3.6.6 Safe Operating Envelope Definition

With respect to $CO_2$ injection, safe operating limits are those that allow the continuous injection of $CO_2$ without compromising the integrity of the well or the geological store. Since wells are designed to cope with the expected injection pressures and temperatures, the primary risk to integrity is uncontrolled fracturing of the formation rock, leading to an escape of $CO_2$ through the caprock (adjacent to the wellbore or at a point anywhere in the storage complex). The pressure at which fractures can propagate through formation rock is called the fracture pressure and is usually defined as a gradient, as it varies with true vertical depth.

In order to prevent fracturing of the caprock, it is essential to limit the pressure to which the caprock is exposed, in both the near wellbore and the storage site as a whole. The pressure limit at any one point depends on the caprock properties, including strength, elasticity and thickness. Given that there is always uncertainty in rock properties as you move away from ‘control’ wells, and that caprock properties are generally not measured and documented to the same degree as permeable formation rock, there is a high degree of uncertainty surrounding caprock fracture initiation pressures and the vertical extent of any resulting fracture (fully penetrating or partially penetrating). For this reason, this study has used the permeable formation fracture pressure as the pressure limit (which, in the overwhelming majority of cases considered for $CO_2$ storage, is lower than the caprock fracture pressure) rather than that of the caprock itself. This provides a conservative approach, and also allays concerns over the concentration of cold $CO_2$ at high pressure that might be delivered to the caprock boundary through fracture propagation in the target formation. A further safety margin of 10% is taken from the estimated formation fracture pressure in order to allow for variations (and unknowns) within the formation rock properties.

A further risk to well integrity and the well injection performance is the poor understanding of operating a $CO_2$ injection well close to the gas / liquid phase boundary. Due to the characteristics of $CO_2$, changes in phase can be accompanied by significant changes in temperature as well as flow performance (pressure drops due to friction within the wellbore). Across the phase boundary, $CO_2$ is boiling and condensing, making it an extremely complex system to model, from both a temperature and flow perspective. This complexity introduces significant uncertainty.

#### *3.6.6.1 Fracture Pressures*

In order to determine the fracture pressure for Captain, to be used as an upper injection pressure constraint, a geomechanical review was performed on the available well data (Appendix 1). Some key data requirements for this study were not available, including rock strength data from core and actual in-situ stress orientation. Regional stress maps were used in the assumption of a NW-SE maximum stress orientation. Correlations from well log data were used to determine rock strength. Different geomechanical correlations use different measured parameters from logs to estimate rock strength and these often result in a range of fracture pressure estimates, some more conservative than others. Field data are normally used to determine which of these correlations might be more representative of the in situ rock.

The geomechanics review was performed on well data from within the Captain X injection site. Using the best fit correlation, and calibrated by LOT data (where available), an initial fracture gradient (from literature) of 0.165 bar/m (0.73psi/ft) was supported. Using Drillworks 5000 software, and applying the Mathews and Kelly correlation, this fracture pressure was corrected for reservoir depletion of 27.6 bara (400 psi) to give a safe working assumption of 0.145 bar/m (0.69 psi/ft) for this study. A safety margin of 10% is applied to this figure to account for local variations and uncertainties, resulting in a limiting injection pressure gradient of 0.14 bar/m (0.62 psi/ft).

#### *3.6.6.2 Phase Envelope*

In order to minimise the risk associated with the uncertainty introduced by operating wells across a phase boundary, all injection will be limited to single phase. With the reservoir pressure of Captain aquifer (187 bara) being above the critical point for $CO_2$ (74 bara) at all times, injection will be limited to liquid (below critical temperature) or dense phase (above critical temperature). $CO_2$ will be delivered to the injections sites in liquid phase, with pipeline operating pressures of up to 160 bara (see Section 3.6.3).

### 3.6.7 Dynamic Modelling

#### *3.6.7.1 Model Inputs*

Schlumberger's Eclipse 100™ 'Black Oil' simulator was used for the dynamic modelling. Although there are some limitations in using Eclipse100™ previous studies have shown that there is no significant loss of accuracy in using the 'Black Oil' simulator for modelling $CO_2$ storage in saline aquifers (Hassanzadeh, Pooladi - Darvish, Elsharkawy, Keith, & Leonenko, 2008).

*Structural Grid and Reservoir Modelling*

The structural grid and static property modelling has been discussed in detail in section 3.5.4.

The Captain X injection site is located within the panhandle area of the Captain aquifer. The narrow Captain aquifer fairway does not behave like a fully open aquifer system as no flow boundaries exist above and below the primary store sandstones in addition to the no flow boundaries at the sand pinch out edges to the NE and SW of the fairway, as shown in Figure 3-62.

However, the Captain X site is connected to the more extensive Captain aquifer system at the NW and SE edges of the model. The size of the connected aquifer significantly impacts the storage capacity for the Captain X site itself as it allows for the dissipation of pressure as that pressure builds up during injection. Active pressure dissipation results in a slower pressure build up rate. This means that injection can be sustained for a longer period and injection of a greater volume of $CO_2$ achieved before the fracture pressure constraint is reached. The reference case connected aquifer size was determined as part of the model calibration process and is shown in Table 3-21 below. However, there is significant uncertainty in the size and connectivity of the aquifer volumes. The impact of the size of the connected aquifer has been evaluated as part of the sensitivity analysis which is discussed in section 3.6.3.

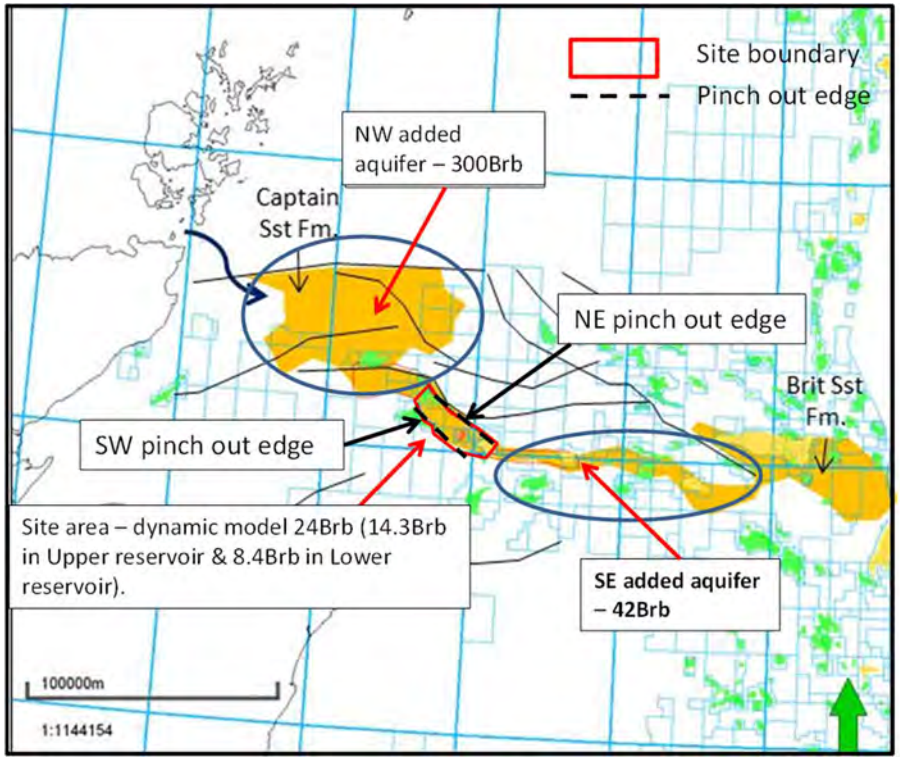



*Figure 3-62 Extent of Captain sandstone, showing site location and connected sand volumes*

| Area | Volume ($m^3$) |
|---|---|
| Captain X Site | $3.7x10^9$ |
| Northern aquifer | $48.6x10^9$ |
| Southern aquifer | $6.7x10^9$ |
| Total | $59x10^9$ |

*Table 3-21 Dynamic model reservoir volume initially in place*

Within the Captain X site model the Captain Sandstone is divided into the Upper Captain Sandstone and the Lower Captain Sandstone by the Mid- Captain shale. The lower sand does not extend over the entire site model. The main lower sand body within the Captain X site model pinches out to the NW and SE and is therefore probably not directly connected to the more extensive aquifers beyond the site model boundaries. The lower reservoir contains 35% of the Captain X site pore volume. The pore volume split between the Upper and Lower reservoirs being $2.4x10^9$ $m^3$ and $1.3x10^9$ $m^3$ respectively. The extent of the Lower reservoir within the Captain X site model is shown in Figure 3-63.

If the Mid-Captain shale acts as a perfect seal across the entire site model the lower sand unit would behave as a pressure isolated sand body. Production data suggests that there has been no production from this unit within the Captain X site area that might have caused pressure depletion to occurr. However, post production (2011) RFT data are available for well 14/26a-9 and this clearly shows that, although there is a strong pressure discontinuity between the Upper and Lower sandstones, both sand units show depletion from the original pressure as a result of production from the upper sandstone only.

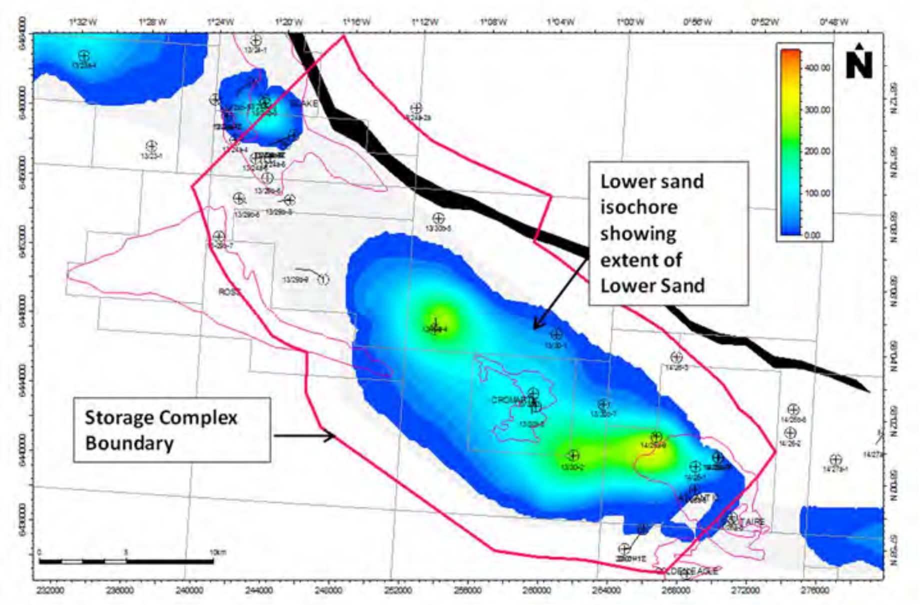



*Figure 3-63 Extent of lower Captain sand within the Captain X site model*

It has been assumed that the pressure depletion seen in the Lower sands is due to a connection to the Upper sand unit. As the Mid shale is present in all of the wells that contain both the upper and lower sand, the mechanism for this hydraulic connectivity is unclear. As a result, a simple approach has been adopted in the Captain X dynamic model in which a transmissibility through the Mid Captain shale layer is included and its value changed until a match to the 14/26a-9 RFT response was achieved. The match to the RFT data is discussed later in this section.

The dynamic model was built over the Captain X site area, a segment of the full Captain fairway. Two dynamic models were built and used for the evaluation of the Captain X injection site. Model 1, a relatively fine scale grid that was upscaled from the static model, was used for the initial screening of the site performance. Model 2, a coarser, further upscaled version of Model 1 with a significantly reduced run time, was used to finalise the development scenario and run the many sensitivity analyses. Model 2 was calibrated to the available measured data and the injection performance and plume migration match the prediction from Model 1. This provided a tool which allowed for reasonable run times and also captured the reservoir characterisation effectively in both a static and dynamic sense. The dimensions and properties for both dynamic models are tabulated in Table 3-22.

Connected aquifer size and the transmissibility across the Mid Captain shale were identified as key subsurface uncertainties. The impact of a range of values for each parameter on injectivity and $CO_2$ plume migration was evaluated in the sensitivity analyses and is detailed in section 3.6.3.

| Dynamic model parameters | Model 1: Fine Scaled | Model 2: Upscaled |
|---|---|---|
| **Dimensions (NX x NY x NZ)** | 179x69x58 | 89x34x30 |
| **Cell Size – X x Y (m)** | 200x200 | 400x400 |
| **Cell thickness range / average (m)** | 1.1 | 2.1 |
| **Number of cells** | 716358 | 90780 |
| **Number of active cells** | 304128 | 47081 |
| **Site WIIP ($m^3$^9)** | 3.6 | 3.7 |
| **Added NW aquifer volume ($m^3$^9)** | 64.6 | 48.6 |
| **Added SE aquifer volume ($m^3$^9)** | 6.7 | 6.7 |
| **Total model volume ($m^3$^9)** | 75.3 | 59.0 |
| **Permeability (horizontal) average (mD)** | 941 | 836 |
| **Permeability (vertical) average (mD)** | 674 | 445 |

*Table 3-22 Dimensions and properties for the dynamic models*

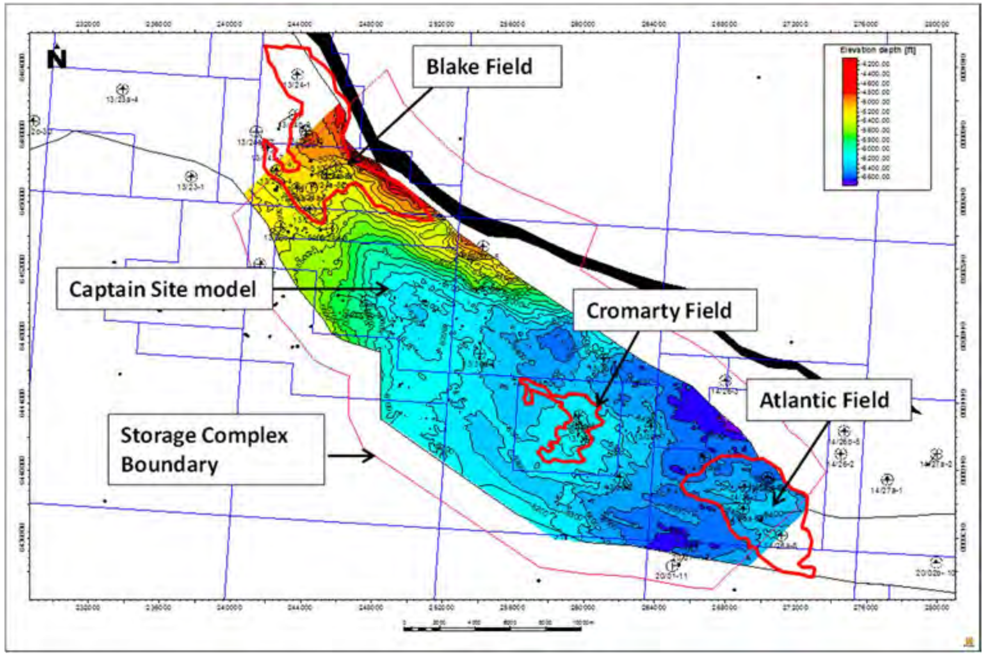



*Figure 3-64 Hydrocarbon fields within the Captain X site shown on the Top Captain sand depth map*

### *Equilibration and Volumes in Place*

Three hydrocarbon fields are located within the modelled area for the injection site, the Blake oil and gas field, the Cromarty gas field and the Atlantic gas field. The locations of the fields are shown in Figure 3-64.

Production and reservoir pressure data were provided by the operator for the Blake field but only limited field data were available for Cromarty and Atlantic. Some post production RFT pressure data are available for exploration wells near Cromarty and Atlantic from the CDA database. A more confident model calibration would have resulted had well by well production, pressure and fluid properties been available for these fields. It is recommended that these data are accessed before any further evaluation of this Captain X site area.

The Blake field commenced production in 2001 and the current estimate of the end of commercial production (CoP) is in 2026. Cromarty and Atlantic are already produced out and are under decommissioning. A high level model calibration was performed using the available pressure depletion data from the Blake field in addition to the pressure depletion observed from RFT data (2011) near Cromarty and Atlantic. In addition, hydrocarbon gas was modelled in Cromarty and Atlantic to capture the impact of the remaining unrecovered gas and its relatively high compressibility on the injected $CO_2$ plume migration. The model was initialised at 2011 when pressure match points in Blake and in the SE of the model close to Atlantic and Cromarty were available.

The model was initialised with six equilibration regions as shown in Figure 3-65 and the initialisation pressure (at 2011), at a datum depth of 1890m TVDSS (6200ft TVDSS) is tabulated in Table 3-23.

| Region | Pressure (bara (psia)) |
|---|---|
| **North Boundary** | 190 (2750) |
| **Blake Field** | 190 (2750) |
| **Cromarty Field** | 160 (2325) |
| **Atlantic Field** | 156 (2265) |
| **Captain Aquifer** | 193 (2800) |
| **South Boundary** | 156 (2265) |

*Table 3-23 Initialisation pressure for the dynamic model equilibrium regions*

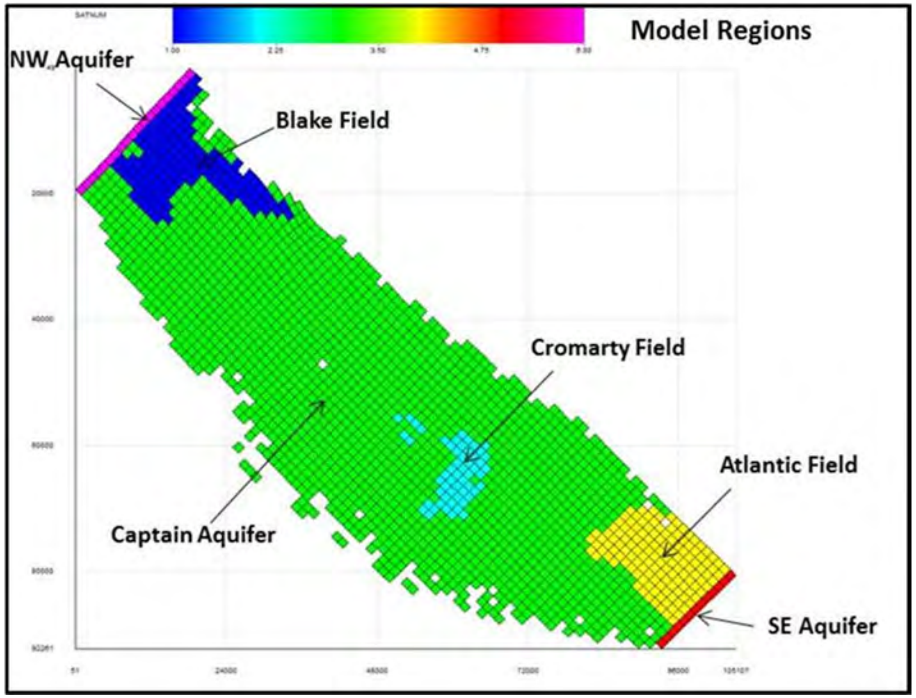



*Figure 3-65 Equilibriation regions within the Captain X site model*

## PVT Management within Eclipse

Commercial Black Oil reservoir simulators (e.g. Eclipse™) are used widely throughout the petroleum industry to model oil, water and/or gas as separate and immiscible phases whose properties and inter-phase mass transfer are averaged functions of pressure and temperature, where in reality the fluids have complex molecular compositions. This treatment involves the use of published "Black Oil" correlations and other physical relationships. Previous studies, such as those of Gammer et al. (2011) and Goater et al. (2013), have shown that this same approach can be applied for $CO_2$ storage in saline aquifers by adapting the Black Oil fluid model to the PVT behaviour of $CO_2$-brine mixtures. In this way, $CO_2$ properties are described using the gas-phase, whereas the brine is designated as the oil-phase. This allows for mass transfer between the two phases; dissolution of $CO_2$ into brine using solution gas-oil ratio (Rs), and vaporisation of water into the free $CO_2$ phase using the solution oil-gas ratio (Rv). This approach represents the mutual solubility between the two phases and demonstrates acceptable accuracy with improved computational efficiency, as compared to the alternative compositional simulation, which requires complex equations of state describing molecular component interactions.

Eclipse100™ can only model isothermal systems with uniform salinity. The Captain reservoir temperature is 65°C and the salinity is 56600 ppm. For this study the fluid description has been further simplified and the vaporisation of water into the free $CO_2$ phase has not been included as the value of Rv for this system is so small, with an equilibrium mole fraction of less than 1%.

### *Relative Permeability*

Relative permeability is a key parameter that influences injectivity performance and $CO_2$ plume migration. However, there is very limited data available for North Sea formations. The impact of alternative functions has been evaluated within the uncertainty analysis and is discussed in section 3.6.3. The reference case drainage and imbibition curves are illustrated in Figure 3-66 below.

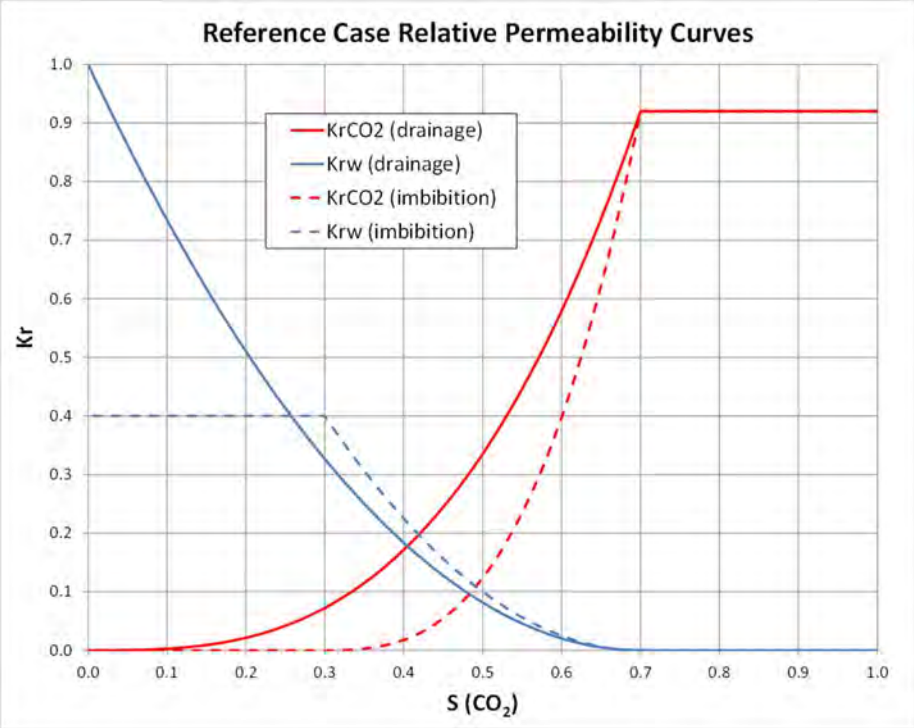



*Figure 3-66 Reference case relative permeability functions*

The functions were generated using Corey functions. End points were based on the published results from (Shell UK ltd., 2011) for the Captain Sandstone member within the Goldeneye field, North Sea (Shell UK ltd., 2011). Drainage and imbibition curves are included allowing for the residual trapping of $CO_2$ to be modelled. The residual saturation is 0.29.

### *Pressure Constraints*

The Captain sandstone member is hydrostatically pressured resulting in an initial (pre-production) reservoir pressure of 197bar (2857 psi) at a datum depth of 1890m TVDSS. There are three hydrocarbon fields within the site model area that have or are still producing from the Captain sands, Blake, Cromarty and Atlantic. Cromarty and Atlantic stopped production in 2009 but Blake will continue to produce until an estimated date of 2026. The production has resulted in pressure depletion throughout the site. Without detailed well by well production and pressure data a full model calibration was not possible. This creates some uncertainty in the pressure depletion over time which could be refined in the future once the missing data are accessed. The RFT data from well 14/26a-9 is available from CDA and the data show a depletion of 27.6 bar (400psi) in 2011, in the south east area of the Captain X site.

To avoid any chance of fracturing the reservoir the maximum pressure will be limited to 90% of the estimated fracture pressure. The determination of the fracture pressure for the Captain sands is discussed in Appendix 9 and has been estimated for pre-production and depleted conditions. The fracture pressure gradient at pre-production conditions is 0.165bar/m (0.73 psi/ft). Under depleted conditions (depletion of 27.6 bar or 400psi) the fracture pressure is estimated to be 0.156bar/m (0.69 psi/ft).

During the $CO_2$ injection phase the reservoir pressure will increase and the fracture pressure will also increase but the rate at which it increases is uncertain. The reference case assumes that the fracture pressure will return to the pre-production value with increasing pressure and in this case the pressure constraint in the model was set at 90% of the pre-production fracture pressure gradient, 0.149bar/m (0.657psi/ft). The worst case scenario is that the fracture pressure does not increase with increasing pressure. A low fracture pressure case has been evaluated in the sensitivity analysis and is discussed in section 3.6.3.

The dynamic model is set up so that if the pressure in any cell in the model reaches the pressure limit at any time step, injection will be stopped. This is important as the fracture pressure limit is often reached in locations away from injection wells. In all sensitivities it was found that the pressure limit was reached in the shallowest area of the Captain X site, in the north east within the Blake field area. The area where the pressure limit is first met in the reference case model is shown in Figure 3-67.

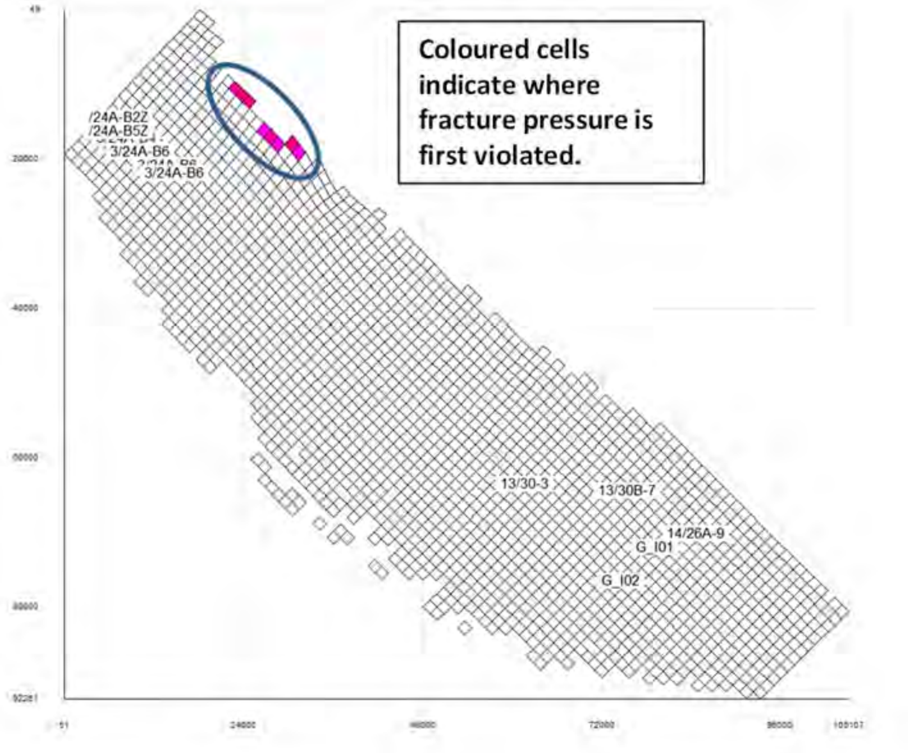



*Figure 3-67 Location in reference case model where pressure limit is first violated*

*Well Modelling*

The required injection rate per well for the proposed development is 1.5Mt/y. It is understood that injection operations will not be stable and part of the purpose of the well modelling analysis is to determine the safe operating range for a selection of tubing sizes so that a suitable well size can be selected that can handle injection at lower and higher rates for a short time. The operating range for the 5.5" tubing (with a maximum THP of 130bar) is 1.1 to 3.4 Mt/y. Vertical Lift Performance tables were generated for 4.5", 5.5" and 7" tubing sizes and used in the dynamic modelling to evaluate the impact of tubing size on site performance. The well modelling is discussed in detail in section 3.6.3.

As the risk of sand failure is considered to be high for the Captain sands, the completion strategy for the injection wells is an open hole completion with stand-alone sand screens. An objective of any injection well is to maximise this sandface flow area (this reduces the effects of injection debris plugging in the wells), and an 'open hole' completion such as SAS is the most effective completion for this purpose.

### *3.6.7.2 Model Calibration*

Data available for the model calibration were limited to well level production, injection and pressure data for the Blake field plus a single reported post production RFT pressure measurement from CDA from the area near Atlantic and Cromarty. Pressure is the main match parameter used for this study. As a result, the intention was to capture the impact of the oil and gas fields on the site performance rather than achieve a fully detailed history matched model. It is recommended that the model calibration is reviewed, to achieve a more rigorous history match, should additional pressure and production data become available.

*Northern Pressure Match*

The initial pressure in the Blake region and north west aquifer region was set at the measured pressure data available from the Blake field at 2011, 190 bar at a datum depth of 1890m TVDSS. The model was matched to the pressure decline seen from the Blake measured data by adjusting the size of the connected aquifer in the north west. The final match was achieved using a north west aquifer volume of 48.6x10$^9$ m$^3$. There is uncertainty in the net production from 2011 to 2015 from the modelled area as the model does not extend over the entire Blake field and there is also uncertainty in the connected aquifer volume. The impact of the uncertainty on the site performance was evaluated in the uncertainty analysis discussed in section 3.6.3. The pressure match at the four production wells in Blake is shown in Figure 3-68. Whilst the match is not perfect, it does a reasonably effective job of characterising and predicting the Blake well pressures over time.

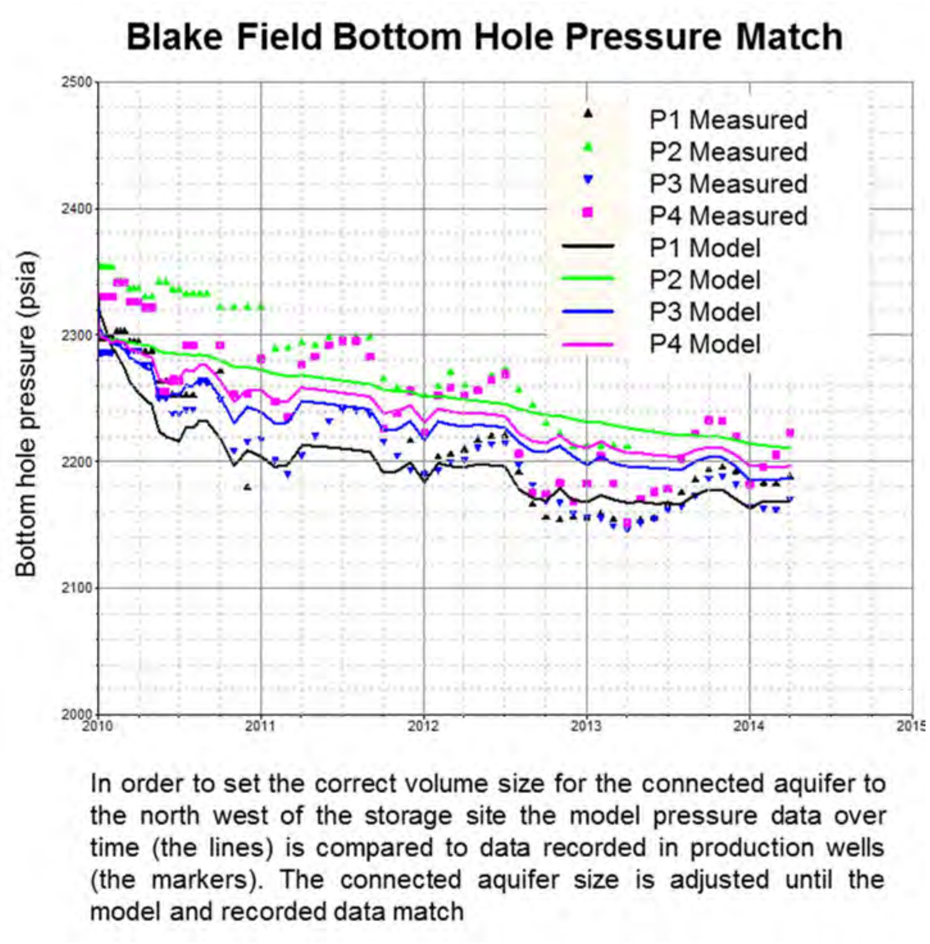



*Figure 3-68 Blake field bottom hole pressure match*

*Southern Pressure Match*

The initial pressure in the southern regions was matched to the post production RFT data available for well 14/26a-9. The well location is highlighted in Figure 3-69.

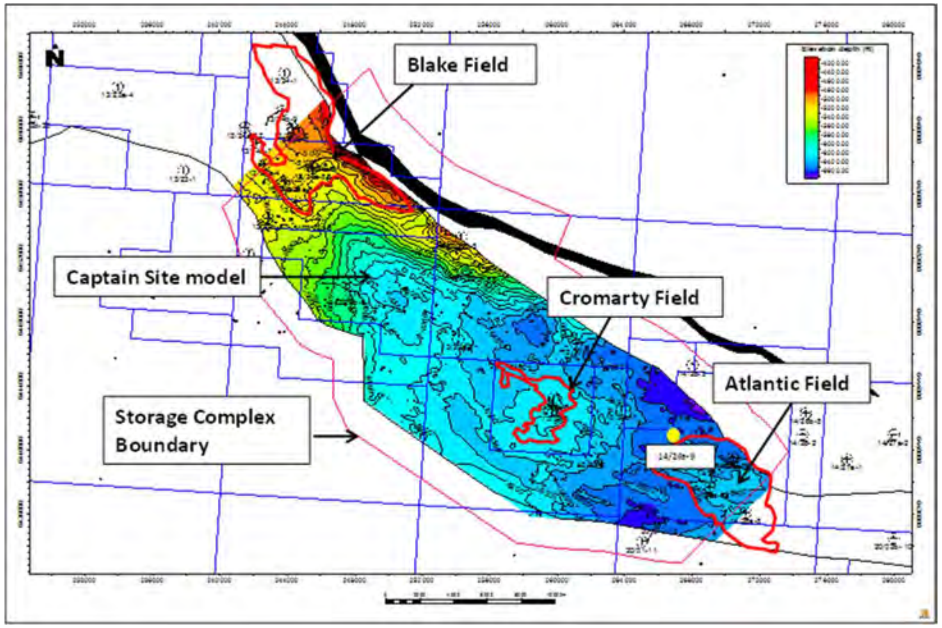



*Figure 3-69 14/26a-9 well location highlighted on Top Captain depth map*

Post production RFT data are an important calibration points as they provide an indication of the pressure change due to production from or injection into connected sands. However, it only represents the pressure at a single point in time. The RFT data from 14/26a-9 show the Upper sands to be depleted by approximately 34.5 bar (500psi) in 2011. This will be mainly due to production from Cromarty and Atlantic and could potentially be influenced by the Goldeneye field, which is connected through the SE aquifer. Goldeneye is not specifically included in the Captain X site model. The pressure match to the 2011, 14/26a-9 Upper Sandstone data was achieved by adjusting the initial pressure in the Cromarty, Atlantic and south east aquifer regions (which includes Goldeneye).

An important observation from the RFT data is that, although there is a pressure discontinuity between the Upper and Lower Sandstones , the Lower sand has been depleted by approximately 30.3 bar (440psi) as of 2011, 4.1 bar (60psi) less than the depletion observed in the Upper sand. The depletion in the Lower sands has been assumed to be due to a connection to the depleted Upper sands as there has been no production from the Lower Sandstone in the Captain X site area. The Mid Captain shale is therefore acting as a significant baffle to vertical flow but does not hydraulically isolate the Lower Sandstones . Based on the well log analysis for this study, none of the available and examined wells show a sand on sand connection between the Upper and Lower sands (i.e. a missing Mid Shale). Additional data and further analysis is required to understand where the connection through the shale could occur. For the purposes of this study a transmissibility has been introduced between the Upper and Lower sand across the entire site model. The transmissibility was used as a match parameter to calibrate the model to the RFT data. A very low transmissibility (equivalent to a vertical permeability of 0.001mD) is required to achieve the RFT match, which is shown in Figure 3-70 below.

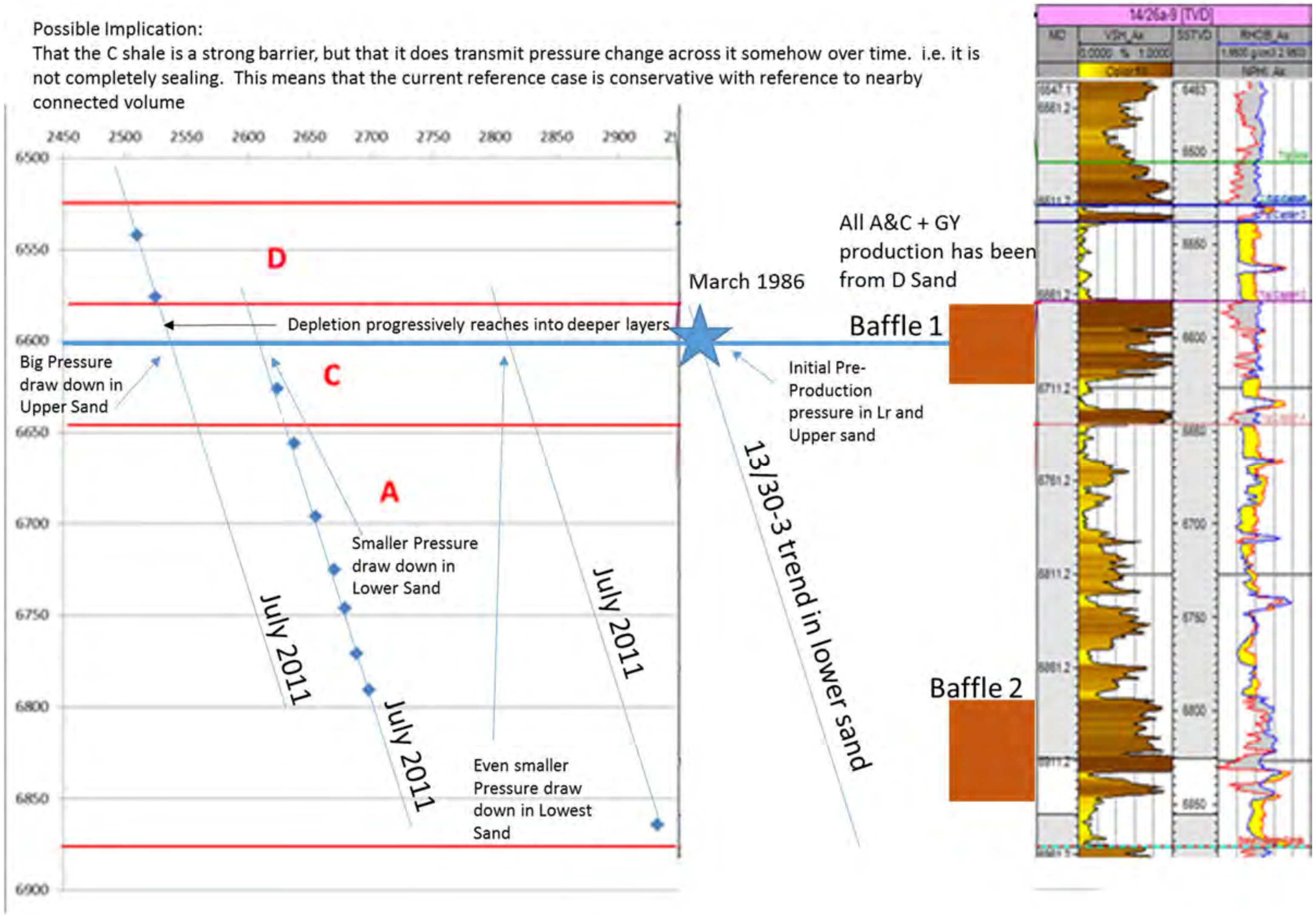



*Figure 3-70 14/26a-9 RFT data and calibrated model prediction*

#### 3.6.7.3 Modelling Results

*Development Strategy*

The proposed target development plan for the Captain X storage site was to inject 3Mt/y for 40 years using two 5.5" injection wells (and one spare well), with injection commencing in 2022. In this case 120 Mt of $CO_2$ would be injected and stored. It should be noted that the Blake field, which is located within the storage complex, is expected to be on production until 2026. As the injection site is located to the south east of the model, furthest from the Blake field, the $CO_2$ is still a considerable distance (greater than 20kms) from the Blake field in 2026 and should not create any production related issues for the Blake field operator other than perhaps some additional pressure support.

*Well Placement*

A number of well locations were tested during the initial screening stage. The Captain sands are excellent quality sands, highly permeable and well connected laterally throughout the Captain X site model. Target injection rates can be met in all areas tested and as the Upper sands are continuous, pressure build up is relatively uniform throughout the Captain X site model. This excellent pressure dissipation results in the fracture pressure limit being reached in the shallowest area of the structure rather than near to injection wells themselves. As injectivity potential and capacity were similar for the tested well locations, the well locations were selected with the objective of maximising the storage efficiency. As $CO_2$ is less dense than the brine within the saline aquifer, buoyancy forces significantly impact $CO_2$ migration. The wells were placed in the deeper areas of the site model, furthest from the north east high where the pressure limit is first met.

As the risk of sand failure is considered to be high for the Captain sands, the completion strategy for the injection wells is an open hole completion with stand-alone sand screens. An objective of any injection well is to maximise this sandface flow area (this reduces the effects of injection debris plugging in the wells), and an 'open hole' completion with sand screens is the most effective completion for this purpose.

Sensitivities were run to evaluate the completion strategy for the Upper and Lower sands. Three scenarios were tested, wells completed in the Upper sands, wells completed in both the Upper and Lower sands and dedicated injectors for the Upper and Lower sands. The results indicated that for all cases the overall capacity is similar with a reduction in injected volume into the Upper sands as the injected volume into the Lower sands is increased. The Lower sands are less extensive than the Upper sands resulting in a more rapid pressure build up during injection. This introduces a risk of cross flow from the Lower sands to the Upper sands that cannot be controlled. Due to the uncertainty in connection between the Upper and Lower sands and to avoid the risk of cross flow, the reference case development scenario had wells completed in the Upper sands only. An additional well targeting the Lower sands doesn't materially increase the capacity for the site and is difficult to justify at this stage. Therefore, a two well development scenario, with both wells completed in the Upper sands, was selected as the reference case development scenario.

*Well Injectivity Potential*

The well injectivity potential is discussed in detail in section 3.6.4. Lift curves were generated for 4.5", 5.5" and 7" tubing sizes and these were incorporated into the dynamic model. Injection rate sensitivities were carried out to determine the impact on capacity and site performance. The results are discussed in section 3.6.3.

5.5” wells were selected with an injection rate of 1.5Mt/y each. Additionally, the wells were subject to a minimum injection rate of 1.1 MT/y (60 MMscf/d) due to inversion of the lift curve at rates below this cut off, a condition that is not supported in Eclipse™. Although this is a modelling limitation, it is nevertheless satisfactory to our work since the flow would otherwise be unstable below the given cut-off due to two phase effects along the tubing and potential slugging behaviour, which would be undesirable.

Pressure dissipation in the reservoir allows this rate to be sustained for the targeted 40 year injection life, with a maximum THP of 130 bar reached at the end of injection. The well performance curves are shown in section 3.6.3.

*Well Number*

The Captain sands are very permeable and the injectivity potential is high. However, the injection rate needs to be limited to optimise the storage capacity whist injecting at a plateau rate for an extended period of time. The minimum number of wells for the development is two, to allow for continued injection if one well is shut-in for a short time. Based on the well modelling two 5.5” wells have been selected for this development. A spare well will also be drilled as a replacement well should there be any need to shut-in a development well long term.

*Sensitivity Analysis*

A number of subsurface and development uncertainties were identified through the course of the project and assessed for their impact on $CO_2$ injectivity and site performance across the design life of the proposed development, to 2062, and beyond until the fracture pressure limit was reached.

The Reference Case is described with respect to the sensitivity parameters in Table 3-25. Moreover, its development is extensively discussed in previous sections, but for clarity the main input parameters presented throughout the body of this report are consolidated in Table 3-24, provided as a summary.

| Input Parameter | Value / Description |
|---|---|
| Datum depth (mTVDSS) | 1890 |
| Initial Pressure at datum (bar) | 197 |
| Temperature at datum (°C) | 65 |
| Rock compressibility | 3.5E-007 @2500 psi |
| $CO_2$ density at datum (kg/m3) | 673 |
| $CO_2$ viscosity at datum (cp) | 0.054 |
| Brine Salinity (NaCl eq.) (ppm) | 56600 |
| Porosity (mean) (fraction) | 0.185 |
| Permeability (mean / range) mD | 836 (0 - 5871) |
| Aquifer Volume (m3) | $59 \times 10^9$ |
| Well Number | 2 |
| Injection Rate per well (Mt/y) | 1.5 |
| Tubing Size (“) | 5.5 |

*Table 3-24 Key input parameters to the reference case dynamic model*

The uncertainty parameters and the associated range of values is summarised in the sensitivity matrix in Table 3-25 and the results are summarised in Figure 3-71 a bar chart showing the injected mass at 40 years and the injected mass from 40 years until the fracture pressure limit is reached and in Figure 3-72. a line plot of the comparative site injection profiles.

| Sensitivity | Unit | Input Values | | |
|---|---|---|---|---|
| | | Low | Reference | High |
| NW Aquifer size | $m^3$ | $15.9x10^9$ | $48.6x10^9$ | $63.6x10^9$ |
| SE Aquifer size | $^{m3}$ | $3.2x10^9$ | $6.8x10^9$ | $9.5x10^9$ |
| Fracture pressure limit | bar/m | 0.14 | 0.165 | 0.18 |
| Injection rate | Mt/y | 1 | 3 | 5 |
| | | | Reference | Alternative |
| Lower Valhall sand connection | | | None | 7% Poro; 33mD permx |
| Captain C transmissibility | | | 1% poro; 0.001mD | 0 |
| Relative permeability | | | Set 2 | Sets 1 and 3 |
| Structural uncertainty | | | - | Northern lows removed |
| Brine Production | | | None | Brine producer close to Blake |

*Table 3-25 Subsurface uncertainty parameters and associated range of values*

The parameters with the greatest impact on the total injected mass are the fracture pressure limit and those that control the size of the connected aquifer volume. The Captain X injection site behaves as a relatively well confined structure as it is bounded to the north east and south west by sand pinch-outs and above and below by clearly defined no flow boundaries. In every sensitivity that was run the fracture pressure limit was eventually reached, at which point $CO_2$ injection is stopped in the model. For the range of sensitivities tested, the injected inventory ranged from 78MT to 180MT.

Confidence in fracture gradient is reasonably high and the Reference Case uses a best estimate determined through geomechanical assessment of well data from the area.

In most cases 120 MT can be injected in close to 40 years as indicated by the blue bars in Figure 3-71. This is not achieved in the small aquifer cases where pressure build up is more rapid and the fracture pressure is reached earlier or the lower fracture pressure limit case, which is representative of the unlikely scenario in which the fracture pressure remains at a lower value corresponding to the depleted aquifer case. The lower injection rate also fails to inject 120MT. Although in this case the injection profile is extended from 40 years to 78 years, the pressure constraint is reached at the shallowest point of the structure when less $CO_2$ has been injected.

The injected mass can be increased beyond the 120MT for cases in which the connected aquifer size is increased or the fracture pressure limit is higher, with the maximum increase within the tested range being +29% (+47MT). There is significant uncertainty in the size and connectivity of the aquifer and it is recommended that further work is carried out to more fully understand the range in connected aquifer size.

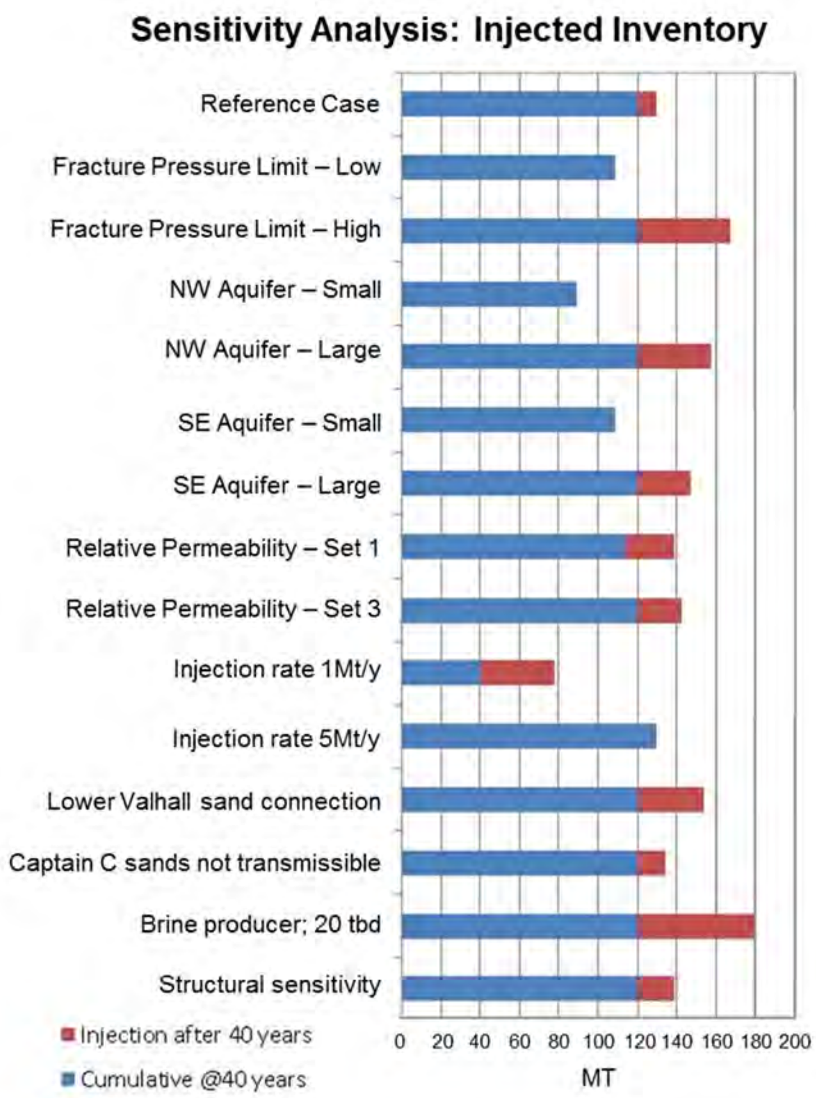



*Figure 3-71 Sensitivity analysis: comparison of capacity per case*

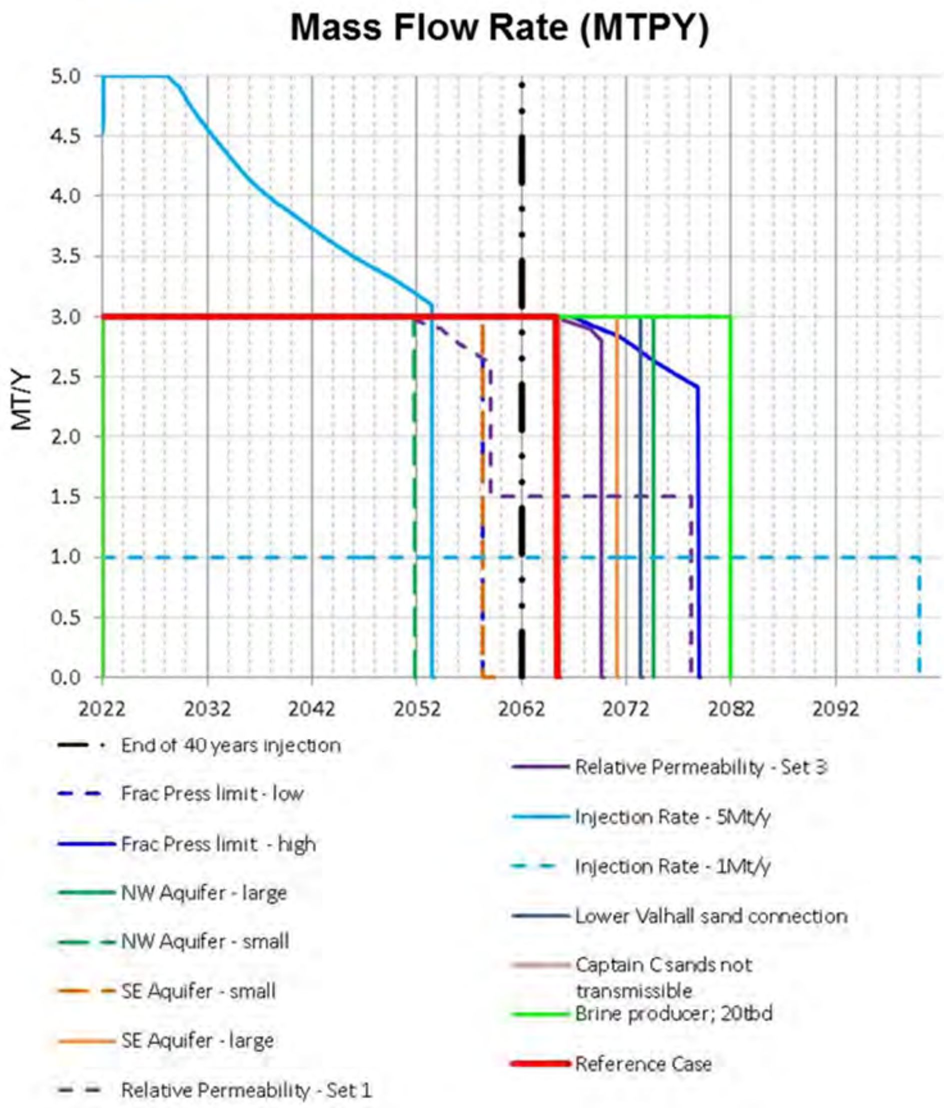



*Figure 3-72 Sensitivity analysis: injection forecast comparison per case*

The impact of the uncertainties on the Captain X storage site performance is discussed in more detail in Appendix 9.

*Brine Production*

An additional sensitivity was carried out to evaluate the benefit of brine production from Captain X. As the total injected mass is dependent on the rate of pressure build up, managing the pressure using a brine production well could allow for an increased mass to be injected. This was tested with a production well added in the NW of the model, just south of the Blake field. Brine was produced at a rate of 3200 m$^3$/d (20mbd) from the Upper Sand. This allowed the injection period to be extended by 20 years which increased the injected inventory by 39%. At the end of the 40 year injection period the $CO_2$ was more than 6kms from the brine production well.

*Structural Uncertainty*

There is significant uncertainty in the Top Captain sand location within the site model due to a combination of both seismic pick and depth conversion issues. The top of the Captain Sandstone has a variable seismic response and poor seismic resolution which makes accurate and confident interpretation impossible. The imaging of the reservoir is hindered by a lack of impedance contrast across the interface between the Rodby/Carrack Shale and the Captain Sandstone making delineation of the Top Captain sandstone very uncertain from 3D seismic data (section 3.4.3). As well as the uncertainty in the seismic picking of the Top Captain Sandstone there are also depth conversion uncertainties due to the effect of lateral velocity changes in the overburden, particularly related to lithology variations within the Tertiary section and rugosity of the Top Chalk surface (section 3.4.5).

As $CO_2$ is less dense than the brine within the saline aquifer, buoyancy forces significantly impact $CO_2$ migration. The wells were placed in the deeper areas of the site model, furthest from the north east high where the pressure limit is first met. The migration pathway for the $CO_2$ is towards structural highs whilst lower structural areas serve to divert the $CO_2$ around them. In the reference case model, the Top Sand structure routes the $CO_2$ towards Cromarty and then along the south west edge of the model, following the thinner and shallower reservoir. Two minor structural low areas to the north east, outside well control, were identified and manually modified in an alternative structural interpretation, to test the impact of the structural uncertainty on the site performance. These modifications were all consistent with the seismic interpretation. The results showed that the impact on the total injected mass was relatively small, +7%, but there was a significant impact on the direction of plume migration. The alternative structure introduces an alternative migration pathway to the north east of the model and most of the $CO_2$ migrates to the north east as opposed to the north west. A comparison of the $CO_2$ plume migration at the end of the 1000 year shut-in period is shown in Figure 3-73.

The structural interpretation is therefore a critical factor in the storage site evaluation as it directly impacts injection well locations and the $CO_2$ plume migration. As a result, any development seeking to inject more than 20 -30 Mt through its life will require much improved structure definition. It is recommended therefore that additional seismic data are acquired and further structural and modelling analysis performed prior to progressing the development of Captain X to ensure that the $CO_2$ plume migration can be confidently predicted. The Reference Case structure was used as the basis for the storage development evaluation.

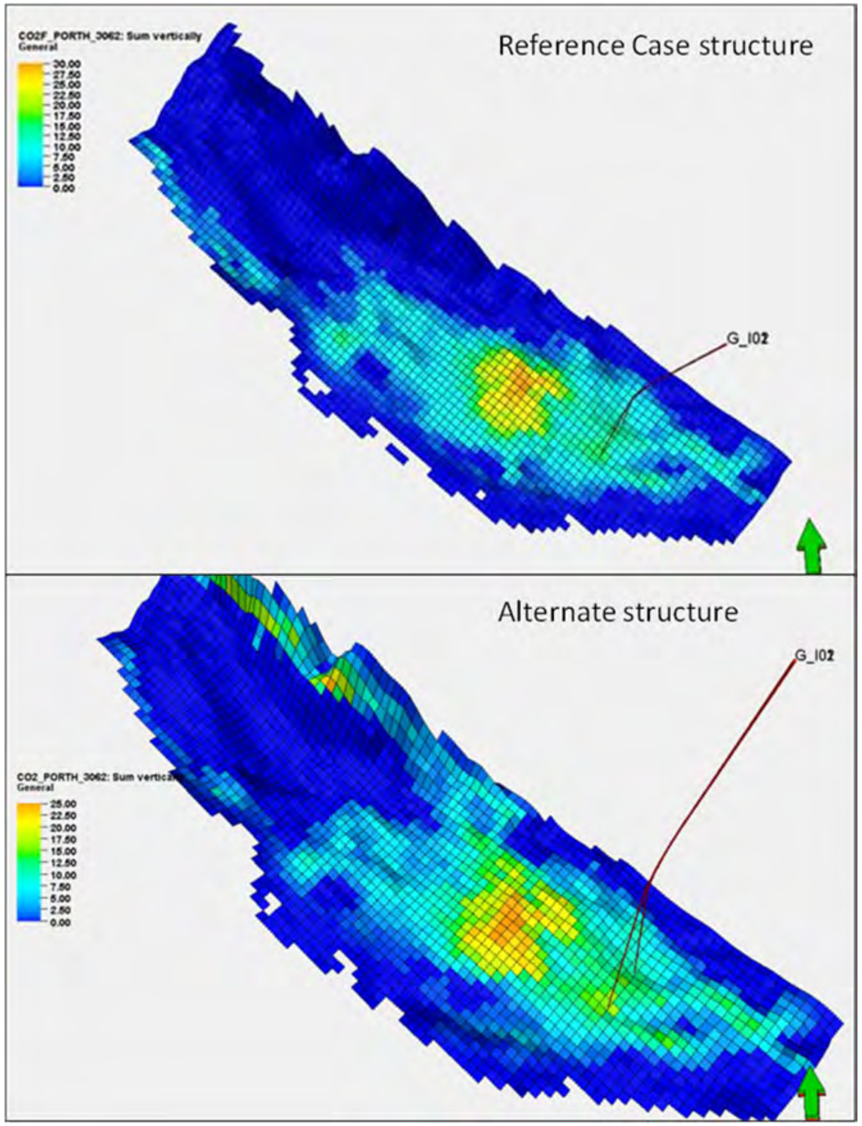



*Figure 3-73 $CO_2$ plume migration after 1000 year shut in*

#### 3.6.7.4 $CO_2$ Plume Migration

The dynamic modelling has shown, within the range of sensitivities carried out, that 180MT of $CO_2$ can be injected into Captain X. For Captain X to be a viable storage site the $CO_2$ must be contained within the storage complex boundary, 1000 years after injection ceases. The reference case model was run with injection of 120MT of $CO_2$ over a 40 year period, after which injection was stopped and the model was then run for a further 1000 years.

As $CO_2$ is less dense than the brine within the saline aquifer, buoyancy forces significantly impact $CO_2$ migration. Post injection, the $CO_2$ migrates from Cromarty, a structural high, to the south west pinch out edge of the model after which it continues to migrate along the model boundary which rises to the north west boundary. It reaches the north west boundary of the model within 200 years. There is no physical boundary to contain the $CO_2$ within the storage complex in this area and after 1000years, the plume migration has extended beyond the Storage Complex boundary as shown in the top map in Figure 3-73.

It was decided to use the fairway model to investigate the extent of the plume migration. The fairway model was upscaled and calibrated to the available dynamic data. After 1000 years the $CO_2$ plume has migrated a significant distance beyond the complex boundary and, although the velocities are less than 10m/y, it is expected that, in time, the $CO_2$ plume will migrate to the fairway model boundary. The $CO_2$ plume migration is shown in Figure 3-74.

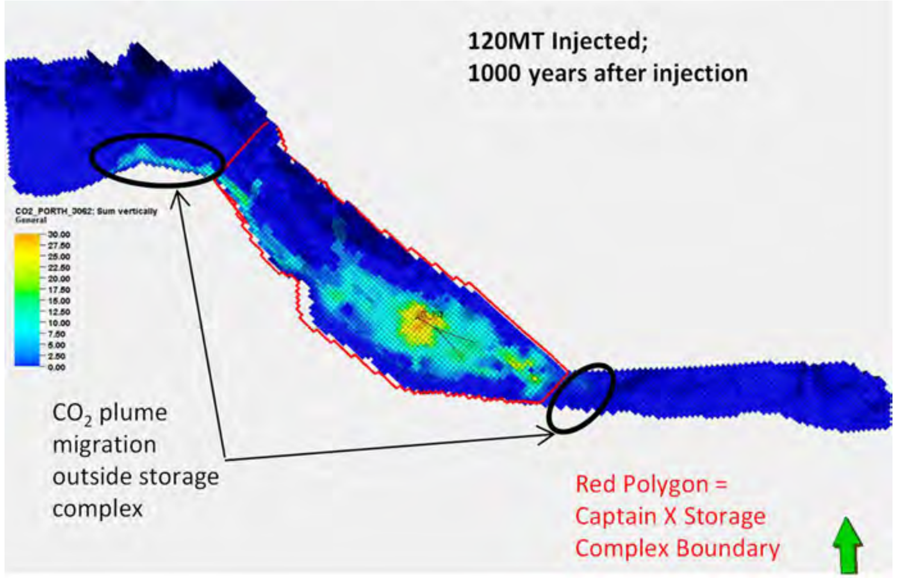



*Figure 3-74 Captain X Fairway model: $CO_2$ plume migration after 1000 years shut in - Reference Model*

Clearly, without an ability to confidently predict the long term migration of $CO_2$ and confirm its retention within the storage complex boundary, a viable development plan cannot be concluded at this time. There are three options to resolve this:

1. **Extend the Storage Complex boundary**. If the prediction of the plume migration pattern was confidently resolved, then this would have been a simple way forward. Unfortunately given the uncertainties in the structural definition outlined above, this is not a practical option for either a developer or regulator.
2. **$CO_2$ mobility engineering**. It is possible to influence the direction of plume migration through deliberate engineering of either or both of the pressure distribution in the reservoir (by water injection or production) and permeability modification through addition of mobility modifiers such as polymers. Such technologies are routinely deployed within enhanced oil recovery projects to encourage maximum sweep and therefore oil recovery. Here they would be used to encourage maximum sweep and therefore storage efficiency. Realistically such work would require a much improved understanding of the structure before it could be usefully considered.
3. **Reduce the injected inventory**. Reducing the injected inventory until the whole injected mass can be confidently retained within the storage complex is a viable option and will limit the extent of plume migration at the site.

Option 3 was deployed here and a series of further runs was developed to assess how much injected $CO_2$ the Reference Case model could receive and contain within the defined Storage Complex Boundary for at least 1000 years. As a result of this, the total injected inventory was limited to 60MT, injected at 1.5Mt/yr per well (2 wells) over 20 years.

#### *3.6.7.5 Storage Site Development Plan*

The proposed development for Captain X is a platform development with three 5.5” deviated wells, 2 injectors and one spare well. Injection is planned to commence in 2022 at 3MT/y and will continue for 20 years, resulting in 60MT stored in the site. Although much more $CO_2$ can be injected into the site, the limiting factor for this development is the containment of $CO_2$ within the storage complex. The well locations are shown on the Top Captain sandstone structure map in Figure 3-75.

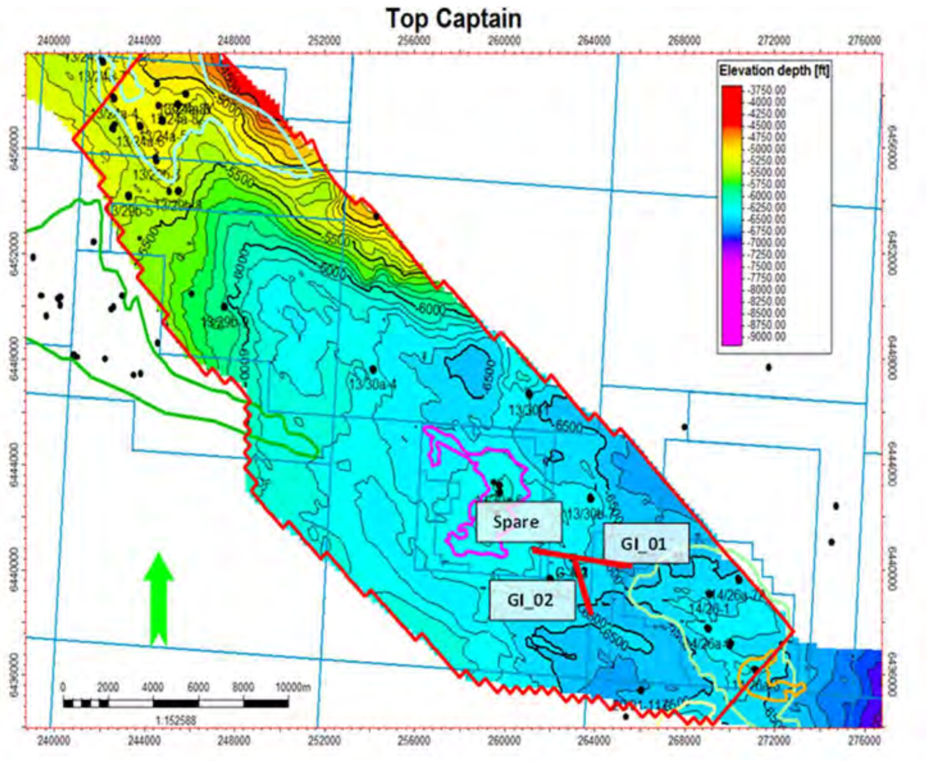



*Figure 3-75 Development well locations on Captain Top structure map*

The field injection profile is 3MT/y for 20 years, 1.5Mt/y per well. The tubing head pressure per well is shown in Figure 3-76.

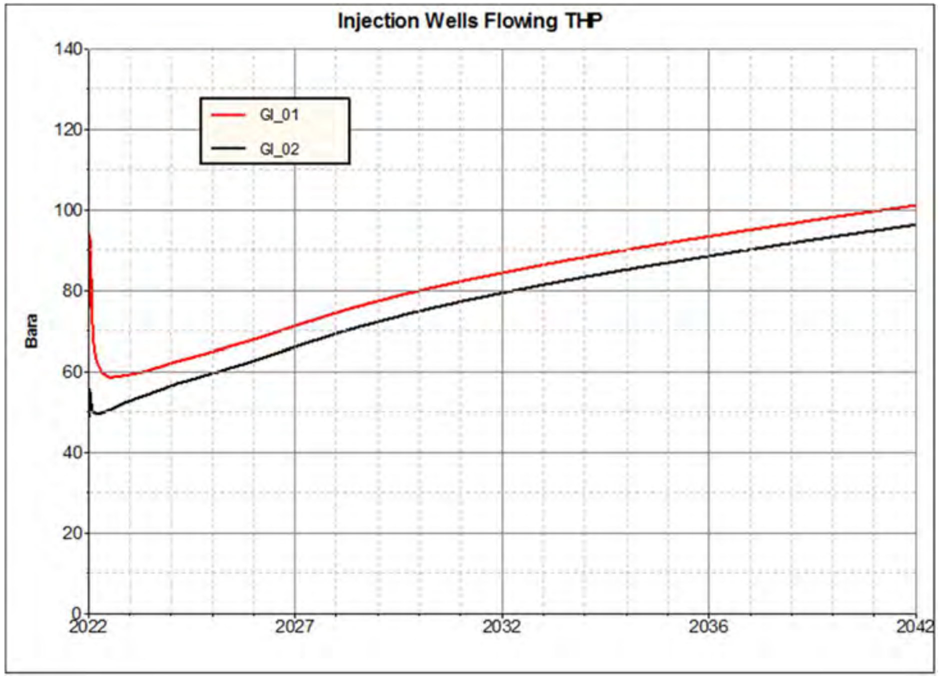



*Figure 3-76 Flowing tubing head pressure for injection wells*

#### 3.6.7.6 $CO_2$ Migration

Buoyancy forces significantly impact $CO_2$ migration in saline aquifers. During injection the $CO_2$ is driven from the injectors into the full sand thickness near the wells and as it migrates from the wells it tends to move upwards, into and along structural highs. In Captain X, $CO_2$ migrates towards and around the Cromarty gas field and also towards the Atlantic field. The remaining hydrocarbon gas in these fields is less dense than the injected $CO_2$ and also influences the $CO_2$ migration pathway.

In the Reference Case Model, after injection ends, the $CO_2$ migrates from Cromarty, a structural high, towards the south west pinch out edge of the model after which it continues to migrate along the model boundary which rises to the north west boundary. For the proposed development plan, of 60MT injected, the $CO_2$ migrates to within 1.2kms from the north west boundary in 1000 years and the velocity is less than 10m/y at this time.

The $CO_2$ migration after 1000 years shut-in are shown in Figure 3-77.

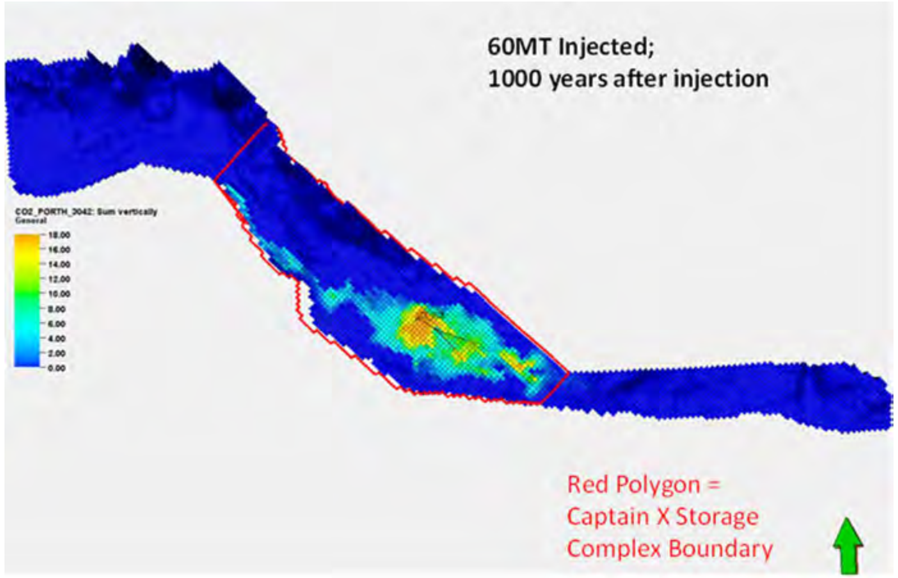



*Figure 3-77 $CO_2$ migration 1000 years after injection ceased for proposed development case*

### 3.6.7.7 Trapping Mechanism

As free $CO_2$ migrates through the subsurface, over time, it becomes ever increasingly trapped when encountering new formation and under-saturated pore fluids. There are several types of trapping, the most important of which are structural trapping, solution trapping and residual trapping, all of which are quantifiable. Additionally, we define a low migration velocity trapping for any remaining $CO_2$ that is moving with a total velocity of less than 10m per year. The balance of any free $CO_2$ that is not structurally, residually or velocity trapped is classified as untrapped and will have the potential to escape the area in time; however, it is important to remember that this too will be converted by the other mechanisms into trapped volumes as its migration proceeds.

For Captain X few significant structural traps exist other than Cromarty and Atlantic. In detail the Top Captain depth map has considerable rugosity, but it is likely that much of this surface roughness is a function of overburden complexity rather than genuine structure. The proportion of structurally trapped $CO_2$ is therefore not expected to be significantly higher than that outlined here, especially with high injected inventories.

The very high vertical permeability means that the $CO_2$ rises to the top of the sandstone very quickly which limits the effective volume that $CO_2$ sweeps through which limits the proportion of residually trapped $CO_2$. 74% is classed as low velocity trapping. The allocation of the stored $CO_2$ per trapping mechanism is shown in Figure 3-79.

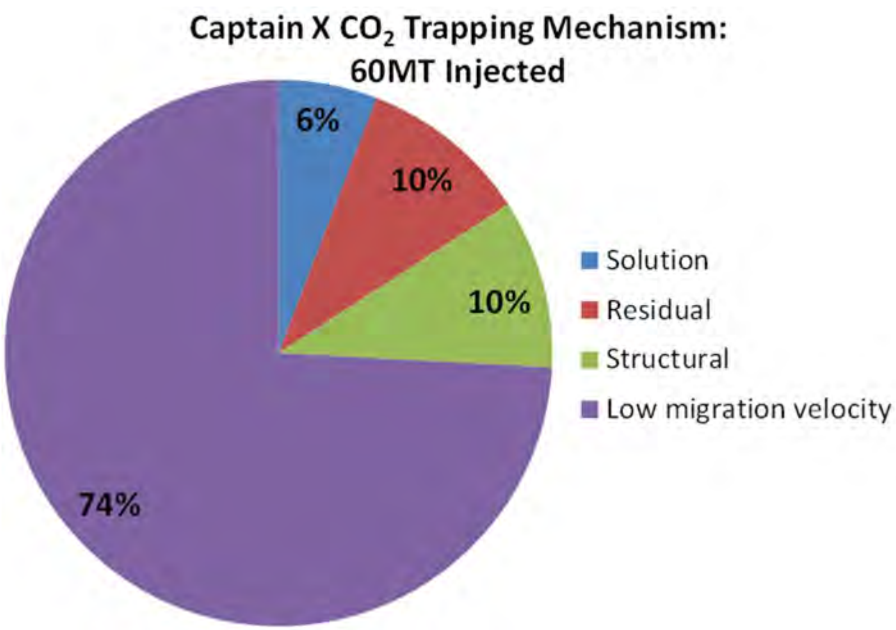



*Figure 3-78 Captain X $CO_2$ trapping mechanisms for 60MT injected*

### 3.6.7.8 Dynamic Storage Capacity

It is important to differentiate between the amount of $CO_2$ that can be injected into a site and the amount of $CO_2$ that can be successfully contained within a site. At Captain X, these figures are significantly different, and it is only that mass that can be both injected and confidently retained within the defined storage complex boundary that can be referred to as "Capacity".

The storage capacity for Captain X is primarily dependent on containment of the injected $CO_2$ within the storage complex 1000 years after injection has ceased. The storage complex for the site was defined at the start of the project to accommodate the presence of ongoing petroleum extraction operations at Blake, and also accommodate a separate $CO_2$ injection project anticipated at Goldeneye. The complex therefore stretches from the "Grampian Arch" in the south east where the Captain Sandstone member thins and narrows to the Blake field in the north west. This study has shown that no more than 60MT can be injected and contained within the storage complex boundary, for the reference case modelling assumptions. For this case, the fracture pressure limit is not reached anywhere in the model.

### 3.6.7.9 Impact of $CO_2$ Injection into Goldeneye

Goldeneye, a potential $CO_2$ injection site in its own right, is located to the south east of Captain X. The impact of injection into Goldeneye upon the injection at Captain X was evaluated using the calibrated fairway model, as the field is located within this. The tested case included injection into Goldeneye at 2MT/y for 10 years, commencing in 2026. Goldeneye was the subject of a detailed FEED study during the Longannet CCS project which demonstrated, that the structural closure alone could accommodate and retain such an injected inventory. Injection into Goldeneye results in an increased pressure at the south east boundary. This impacts the pressure build up rate in Captain X resulting in the fracture pressure limit being reached 4.5 years earlier than in the reference case, 38.5 years as opposed to 43 years, reducing the total injected mass by approximately 10%. However, the injection duration for the proposed development scenario is 20 years and injection into Goldeneye does not impact the injection profile over this time. The $CO_2$ plume migration, with injection into Goldeneye, is shown in Figure 3-79.

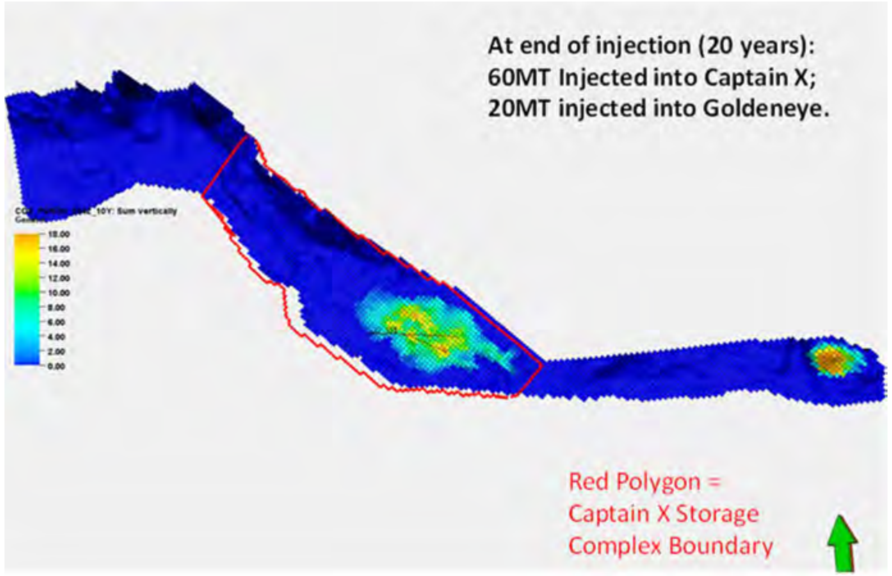



*Figure 3-79 $CO_2$ plume migration at the end of injection for case with Goldeneye injection included*

## 3.7 Containment Characterisation

### 3.7.1 Storage Complex Definition

The "pan-handle" part of the Captain Sandstone fairway is bounded along its northern and north eastern edge by the Captain and West Halibut Faults respectively. The Captain Sand is a depositionally extensive turbidite system and reservoir quality is excellent. The fairway is over 100 km long and covers an area of over 800 km$^2$. Within this fairway, apart from the Captain and West Halibut Faults, no other significant faults have been identified.

After careful review of the available subsurface data, the Captain X site storage complex has been defined as the subsurface volume whose upper and lower boundaries are the Top Lista Shale Formation and Base Cretaceous depth surfaces. The lateral limits of the site were guided by the injection site selection, within which the $CO_2$ inventory is designed to remain indefinitely with the proposed development plan. The south eastern boundary is located close to the narrowest part of the fairway above the Grampian arch, the north western boundary is located at the Blake oilfield, which itself serves as a backup structural closure to trap any long distance $CO_2$ migration. In the proposed development, there is no intention to charge the Blake field with CO2 and so the proposed storage complex boundary has been drawn midway through the field at this time forcing any development to monitor the plume migration carefully. Options exist to define a much bigger storage complex area subject to avoiding conflict with other subsurface use. Due to poor seismic imaging there is uncertainty in the Captain Sandstone pinch-out out edge and the storage complex south west boundary has been extended some 2 km beyond the currently mapped sandstone limit to capture this uncertainty. There is also uncertainty on the exact location of the West Halibut Fault which is why the storage complex north east boundary has been extended some 2 km beyond the currently mapped West Halibut Fault. There is no Captain Sandstone present on the Halibut Horst.

This storage complex definition includes the storage reservoir and its primary and secondary caprock together with the overlying Maureen and Mey Sandstones which may act as a secondary store or provide additional upside potential.

The proposed storage complex is illustrated in Figure 3-80.

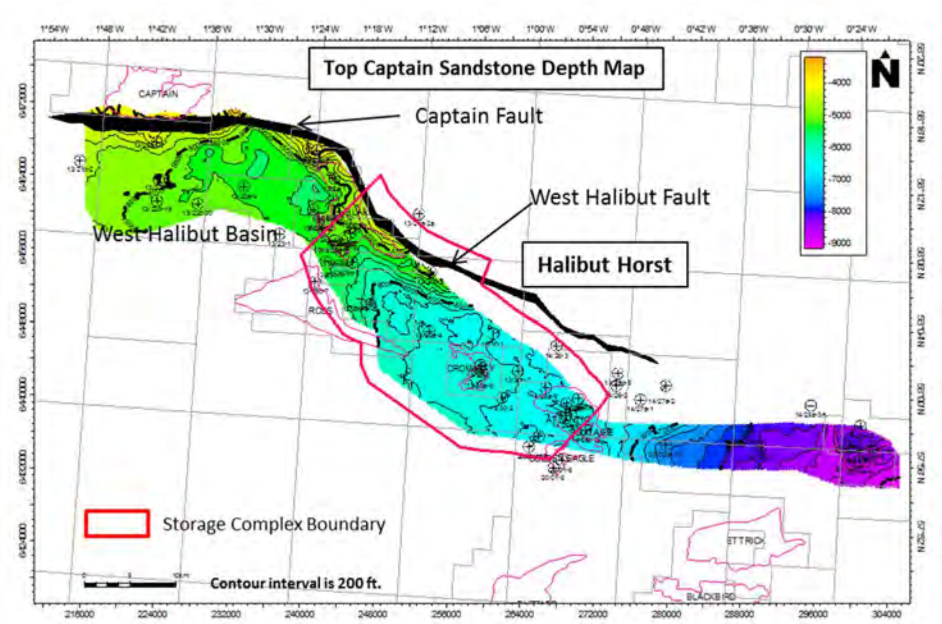



*Figure 3-80 Map of storage complex outline*

#### 3.7.1.1 Hydraulic Communication between Geological Units

The top seal for the Captain Sand is provided by the overlying, laterally extensive shales and mudstones of the Carrick and Rodby Formations which provide proven seals for hydrocarbon fields within the main Captain Sand Fairway. This provides an effective seal and eliminates the possibility of hydraulic communication into shallower formations. There are no hydrocarbon accumulations in any shallower formations in this area, primarily as a result of the top seal effectiveness.

The base seal is provided by mudstones of the Valhall Formation. The Valhall contains occasional thin sand interbeds observed in some wells. These cannot be correlated between wells and are unlikely to be laterally extensive. Well data also indicates that these thin sands are isolated from the main Captain Sand by an average of over 25 m (80ft) of mudstones. Thicker reservoir quality sands of the Coracle and Punt are generally 60m (200 ft) or more below the base Captain Sand and appear not to be in hydraulic communication with the Captain Sand. The deeper Burns sand intervals within the underlying Upper Jurassic also appear to be hydraulically isolated from the Captain sands. Oil and gas are being produced from this interval from a single well solitaire development located directly below the southern part of the Atlantic field. Specific focus is required to ensure the continued integrity of isolation in this area.

The Upper Captain D Sand interval is laterally extensive across the full fairway and lateral connectivity across the fairway within this zone is expected to be good. The lower Captain A sand, which may be partially isolated for the overlying Captain D sand, is more restricted in its distribution with consequently poorer lateral connectivity.

Within the storage complex the north east limit of the Captain Sandstones is either the West Halibut Fault or a pinch-out prior to the fault. This uncertainty in the area between Blake and Atlantic is due to the poor seismic imaging of the Captain Sandstone (section 3.4.3). At Blake well control to the north suggests that the Captain Sandstones are juxtaposed across the West Halibut Fault against either granitic basement or Devonian claystone (with occasional very tight sandstone) and at this location if the sands extend up to the fault then the fault is sealing as shown by the presence of trapped oil. To the south east of Blake the offset on the West Halibut Fault decrease and the fault ends some 20km from the Goldeneye field. Between Blake and Goldeneye there are 9 wells on the southern side of the fault with no Captain Sandstone which confirms that the sandstone is absent and must pinch-out before reaching this fault (Figure 3-16). Captain Sandstone is not present on the Halibut Horst. Between Atlantic and Tain the West Halibut Fault extends upwards into the shallow Tertiary section but not to the seabed. Therefore the potential for $CO_2$ to flow across the West Halibut fault is considered to be limited. The Lista secondary cap-rock is offset by this fault (Figure 3-8) and there is an increased lateral containment risk in the secondary storage unit across the fault as a result.

Outside of the storage complex, but within the fairway, it appears likely that the Captain Sandstone extends up to the Captain Fault as it is present across the fault to the north in the Captain Field. The amount of offset on the Captain Fault decreases westward and across this fault the Captain Sandstone is probably juxtaposed against Triassic and Jurassic units which do contain sandstones and there is an increased lateral containment risk across the fault. Geochemistry analysis of the oil in the Captain Field suggests that it was sourced from both the West Halibut Basin (i.e. beneath the “pan-handle” part of the Captain Sandstone fairway) and Smith Bank Graben, with the primary phase of charging to have occurred during the early Tertiary (Pinnock & Clitheroe, 2003). However, it is not clear if the oil migrated through the Captain Fault or around its western edge where the fault offset decreases to zero.

Due to seismic noise at the join of two 3D surveys and a strong seabed multiple still present in the dataset it is not clear if the Captain Fault extends to the seabed This seismic noise also masks the Lista event and it is not clear if there is any offset of the Lista across the fault.

#### *3.7.1.2 Top, Base and Lateral Seal*

Sitting immediately above the Top Captain Sandstone is a thick interval of Carrick and Rodby Formation mudstone and shales which have been chosen as the primary caprock interval (Figure 3-82). The thickness varies across the storage site from approximately 30 m to over 120 m (approx. 90 – > 400 ft). A total thickness map of these intervals is shown in Section 3.4. These are a proven effective seal for many hydrocarbon fields within the main Captain Fairway. There is some evidence of seismically visible small scale faulting within the Captain Sandstone. These faults are limited in vertical extent and do not offset the overlying Rodby/Carrack formation. Within the Captain Sandstone fault throws appear to be small and due to sand on sand contact on either side of the faults it is not expected that they will provide a significant barrier or baffle to the flow of $CO_2$. The calcareous marls of the overlying Hidra Formation provide additional primary store containment.

Where the Captain Sandstone pinches/ shales out on the southern and northern margins of the fairway, the lateral seal is also provided by the mudstones of the Valhall Formation as proven by the Goldeneye Field. Due to poor seismic quality there is uncertainty associated with the exact location of this pinch out edge, however there is good well control in places which demonstrate that this pinch out can be very rapid. An example of this is the 20/01-11 well which contained no Captain Sand, whilst the sidetrack less than 1km to the North contained over 20 m (60 ft) of net sand.

The Captain fairway is open at both ends, to the north west the sands open out into the pan handle, and to the south east the sand fairway continues towards the Hannay oilfield.

The base seal is provided by the underlying mudstones of the Valhall Formation.

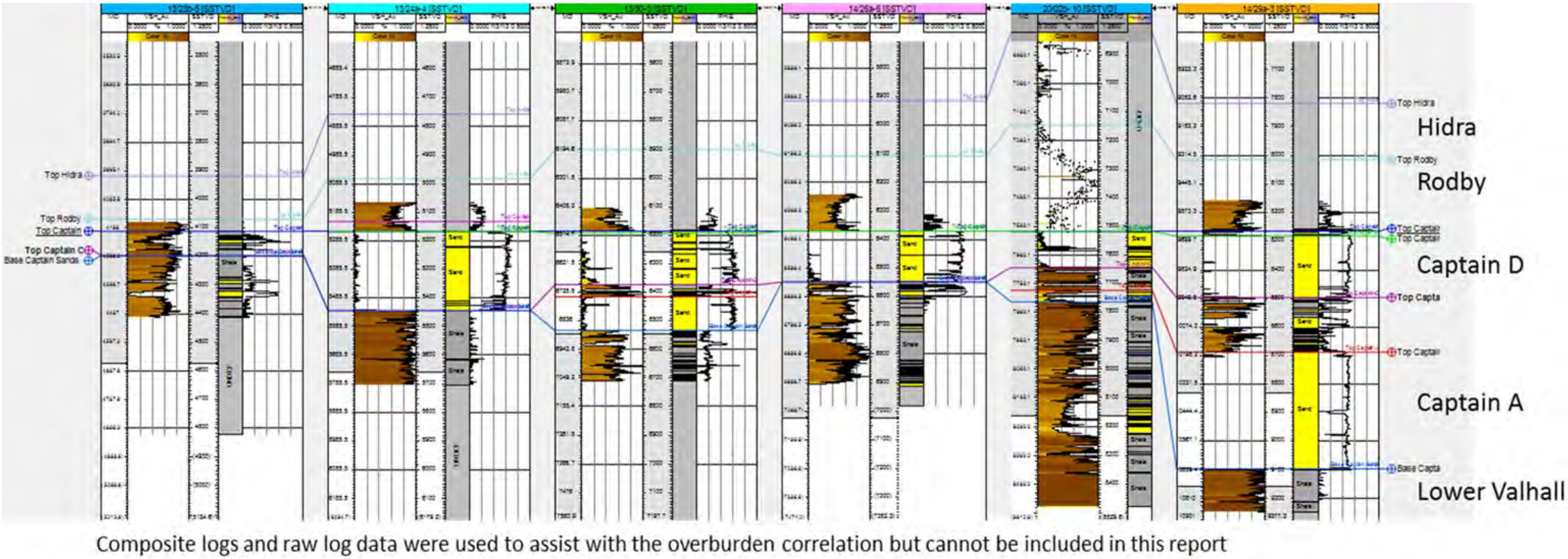



*Figure 3-81 Primary top seal*

### 3.7.1.3 Overburden Model

A simple overburden model was built covering the same area of interest as the site static model (Table 3-26).

As the purpose of the overburden model was to help and inform the discussion on geological containment, no petrophysical analysis or property modelling have been carried out within the overburden.

| Formation | Source |
|---|---|
| **Seabed** | Mapped from seismic data and depth conversion |
| **Top Beauly Coals** | Direct seismic interpretation and depth conversion |
| **Top Lista Shale** | Calculated from well tops, conformable to overlying and underlying formations |
| **Top Lista Sandstone** | Calculated from well tops, conformable to overlying and underlying formations |
| **Top Ekofisk** | Direct seismic interpretation and depth conversion |
| **Top Hidra** | Direct seismic interpretation and depth conversion |
| **Top Rodby** | Direct seismic interpretation and depth conversion |
| **Top Captain Sand** | Built down from the Top Rodby using well derived isochore |
| **Base Captain Sand** | Built down from the Top Captain using well derived isochore. |
| **Base Cretaceous** | Direct seismic interpretation and depth conversion |

*Table 3-26 Summary of horizons in the overburden model*

A cross section through the overburden model is shown in Figure 3-82.

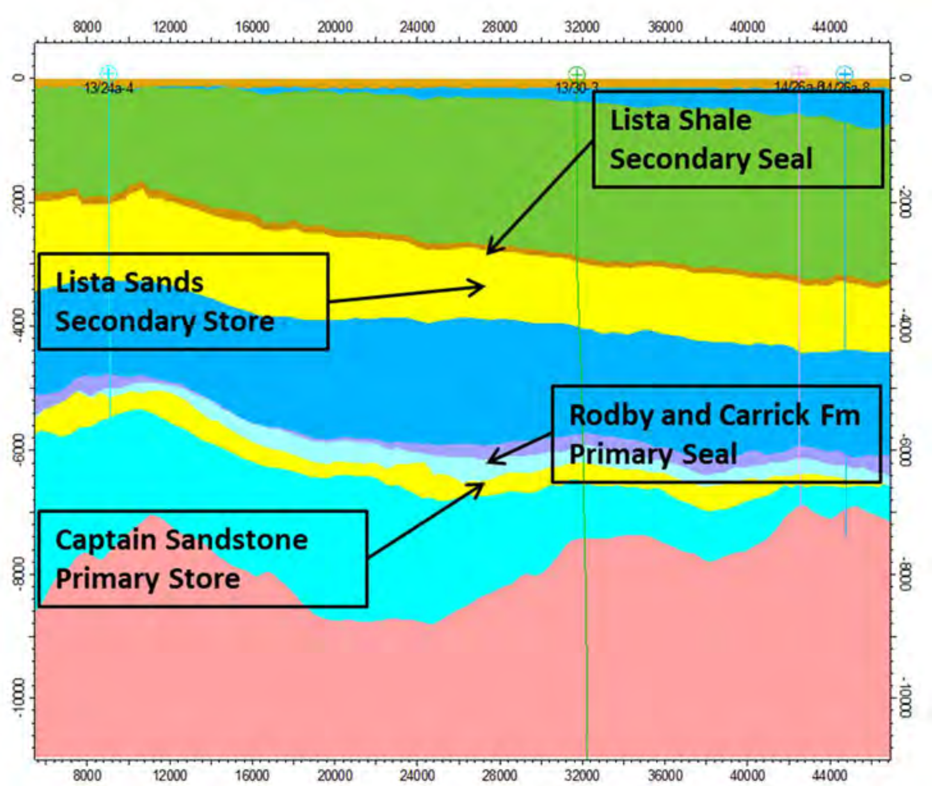



*Figure 3-82 NW - SE Cross section through the overburden model*

#### *3.7.1.4 Geomechanical Analysis and Results*

Geomechanical modelling of the primary store was conducted to clarify the strength of the storage formation and its ability to withstand injection operations without suffering mechanical failure at any point during those operations. No significant issues of drillability, fracturing risk or sand failure risk were identified. Further details are included in Section 3.6.6.

The $CO_2$ injection is into a large, laterally extensive open aquifer system, it is therefore expected that pressure will dissipate rapidly. This is supported by dynamic modelling.

#### *3.7.1.5 Geochemical Degradation Analysis and Results*

A detailed account of the results of the geochemical modelling of the potential degradation of the cap rock lithologies when exposed to $CO_2$ for long periods of time is presented in section 3.5.2.5. The conclusion of this work suggests that the fastest reactions that occur lead to very small changes in net solid volume changes and that Rodby Formation seal failure is unlikely to be induced by mineral reactions with the $CO_2$.

### 3.7.2 Engineering Containment Integrity Characterisation

In order to contain the $CO_2$ injected into the Captain reservoir, the integrity of the caprock must be maintained. The ‘man made’ (or engineered) risks to this containment are damage through the application of excessive pressure (fracturing) or the failure to maintain an effective seal in the wells that penetrate the caprock. The following section explores the engineered containment risk for the Captain storage site.

#### *3.7.2.1 Leak Risk*

Engineered containment risk (the risk that man-made reservoir penetrations may leak, resulting in a loss of $CO_2$ to the environment) depends on several factors, most of which are well specific.

Risk, in this case, is considered to be the probability of a leak occurring. The quantification of the leakage (volume of $CO_2$ likely to be released) is not considered at this stage, but has been fully described in AGR’s report for DECC (AGR, 2012).

Two main conclusions from this paper have been used as input assumptions to the current risk review, as follows:

- The range of leak risk from abandoned wells is 0.0012 to 0.005 depending on age / type of abandonment
- The risk of leakage is higher for abandoned wells where the storage target is above the original well target (hydrocarbon reservoir) due to less attention being paid to non-hydrocarbon bearing formations

The number of wells in each category of abandoned wells (time period of abandonment and the location of the well target depth) was determined by a review of the CDA database. Wells were selected from this database by field names.

#### *3.7.2.2 Abandonment Practices and Guidelines*

Well abandonment practices have improved (become more rigorous) over time, resulting in the current practices for wells abandoned in the reservoir having the lowest risk (0.0012). All earlier abandonment practices, and those where wells have been completed below the storage reservoir target, have relatively less rigorous practices, so that a well abandoned prior to 1986 (when API guidelines were first published) where the well is targeted at a reservoir below the storage reservoir has the highest risk (0.005).

| Guideline | API RP 57 | UKOOA | UKOOA | UKOOA | UKOOA | UKOOA |
|---|---|---|---|---|---|---|
| **Year** | 1986 - 1994 | 1994 - 2001 | 2001 - 2005 | 2005 - 2009 | 2009 - 2012 | Post 2012 |
| **Issue/Rev** | n/a | Issue 0 | Issue 1 | Issue 2 | Issue 3 | Issue 4 |

*Table 3-27 Guidelines for the suspension and abandonment of wells*

A brief summary of the main oil and gas abandonment guidelines relating to exploration/appraisal wells are detailed below with reference to major changes over the years:

1. Permanent barrier material – cement. Not specifically detailed until Issue 4 when a separate guideline was introduced for cement materials.
2. Bridge plug or viscous pill to support cement plug introduced in Issue 3 (2009) but mentioned in API RP 57.
3. Two permanent barriers for hydrocarbon zones. One permanent barrier for water bearing zones.
4. One permanent barrier to isolate distinct permeable zones.
5. Cement plug to be set across or above the highest point of potential inflow.
6. Position of cement plug to be placed adjacent to the cap rock introduced in Issue 4.
7. Length of cement plug typically 500 ft thick to assure a minimum of 100 ft of good cement.
8. Internal cement plugs are placed inside a previously cemented casing (lapped) with a 100ft minimum annulus cement for good annulus bond or 1000 ft annulus cement if TOC estimated.
9. Plug verification – cement plug tagged/weight tested and/or pressure tested.
10. All casing strings retrieved to a minimum of 10 ft below the seabed.

For the Captain X site, a total of 59 wells were plugged and abandoned. A total of 8 legacy wells were reviewed from the details in the CDA database. Using these details, the actual well abandonment practises were compared to the assumed abandonment practises at that time. The risk scoring is verified if the abandonment has been performed as per the guidelines at that time and as per the assumptions. Any significant departure (better or worse) is documented and highlighted with the legacy wells. The risk assessment is categorised as low/medium/high and defined as follows:

- Low – does not meet the guidelines at that time
- Medium – meets the guidelines at that time
- High – exceeds the guidelines at that time

#### *3.7.2.3 Benchmark Abandonment Practices*

As a benchmark for $CO_2$ storage, the Goldeneye abandonment proposal could be considered. This has a critical seal across the caprock and milled window providing plug#1 with a rock-to-rock seal. Shallow cement plugs provide a barrier for the water bearing zone. Cement retainer or inflatable plug provides support for the cement plug and prevents slumping. This exceeds current guidelines, UKOOA Issue 4, as no milled window is required if the casing cement is considered good but does provide a good benchmark example of an abandoned well.

#### *3.7.2.4 Review of Legacy Wells*

*Initial Risk Assessment (Due Diligence)*

The initial risk assessment of the Captain (see Table 3-28 below) considered the Captain entire sand body. This was an extensive area (2,905km$^2$) and contained over two hundred and seventy wells. The assessed containment risk was unacceptably high, with a 33% probability of a leak within 100yrs if the whole store was exposed to $CO_2$. However, it was recognised that the whole complex would not be exposed to $CO_2$, and that the risk was dependant on the chosen injection site.

A reduced area of the Captain sand (the Captain 'panhandle') was then considered in the due diligence work. This site had considerably fewer wells, but the reduced area slightly increased the well density. Overall leakage risk was reduced, with a 21% probability of a leak in 100 years.

| | Initial Risk Review | 'Panhandle' Risk Review | Revised Risk Review |
|---|---|---|---|
| **Total Number of Wells** | 273 | 108 | 59 |
| **Total Number of Abandoned Wells** | 169 | 74 | 41 |
| **Total Number Abandoned Before 1986** | 16 | 5 | 2 |
| **Total Number of at Risk Wells** | 169 | 74 | 38 |
| **% Probability of a Well Leak in 100yrs** | 32.76 | 21.52 | 13.29 |
| **Storage Area (km$^2$)** | 2905 | 885 | 344 |
| **Well Density (wells/km$^2$)** | 0.06 | 0.08 | 0.11 |
| **Leakage Risk Assessment (Well Density x Leak probability)** | 0.019 | 0.018 | 0.015 |

*Table 3-28 Risk review over the Captain Aquifer*

A subsequent screening exercise was undertaken in order to identify a suitable storage site within the Captain 'Panhandle' sand unit. The boundaries of the selected site are described in the Containment Characterisation section of the

FDP (section 3.7). The risk assessment was repeated for this reduced area, and is summarised in Table 3-28.

The engineering containment risk has been reduced to moderate, with 59 wells in total and 38 considered to be at risk of leakage, 23 of which were sidetracks within the store depth. 41 wells were plugged and abandoned (3 of these wells above store depth and therefore not considered at risk), 2 of which were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is 13% and the well density factor is a moderate 0.11 wells/km$^2$. The resulting risk assessment score of 0.015 is moderately low. It should be noted that the site complex has been defined as a regular polygon, and incorporates part of the Blake field and Atlantic fields and the entire Cromarty field, all with relatively high well densities. The predicted plume migration affects a much smaller area, with fewer wells likely to be contacted (Table 3-29).

It is important however to remember that the plume migration itself is very uncertain due to the accuracy of the Top Captain Sandstone depth map. Further work would be required during FEED in order to refine the leak risk model, and define what risk to assign wells that are likely to be close to the plume migration front (modelling uncertainty).

| Well | $CO_2$ Contact during injection | $CO_2$ Contact during storage | Close to plume but not contacted |
|---|---|---|---|
| **13/24b-9** | | | x |
| **13/29b-9** | | | x |
| **13/30a-6** | x | | |
| **14/26a-8** | x | | |
| **13/29b-5** | | x | |
| **13/29b-6** | | x | |
| **13/29b-8** | | x | |
| **13/30-2** | x | | |
| **13/30-3** | x | | |
| **13/30b-5** | | x | |
| **13/30b-7** | x | | |
| **14/26-1** | x | | |
| **14/26a-6** | x | | |
| **13/30-1** | | | x |
| **13/30a-4** | x | | |
| **14/26a-7A** | | | x |
| **13/22c-30** | | | x |
| **13/24a-4** | | | x |
| **13/24a-5** | | | x |
| **13/24a-6** | | | x |
| **13/24a-7** | | | x |
| **13/24a-7Z** | | | x |
| **13/24a-8Z** | | | x |
| **13/24b-10** | | | x |
| **13/24b-3** | | | x |
| **14/26a-9** | x | | |
| **20/01-11Z** | | | x |
| **Blake producing wells** | | | |
| **13/24a-B1Z** | | | x |
| **13/24a-B2Z** | | | x |
| **13/24a-B3Z** | | | x |
| **13/24a-B4** | | | x |
| **13/24a-B5Z** | | | x |
| **13/24a-6** | | | x |
| **Total** | 9 | 4 | 20 |

*Table 3-29 Predicted exposure of Captain wells*

*Detailed Risk Assessment*

The detailed risk assessment was performed using the historical well data in the CDA data base. These data include the Final Well Reports or Abandonment Reports for the legacy wells. A total of 41 wells in the Captain X site were plugged and abandoned, of which 3 were above the store depth.

A selection of 8 representative legacy wells was chosen for this review, some from within the plume affected areas and some from the wider complex area. The review is summarised in Table 3-30.

The 8 legacy wells range from 1979 to 2007 (over 25 years) and cover the specification, i.e. API RP 57, UKOOA Issue 0 and 2.

Well 13/24b-3 (1997) is an example of an abandoned well that meets the specification. The target sands are the same as the store depth at 4,987 ft MDBRT in the 9 5/8" casing and are isolated with 3 cement plugs. The first plug is across the perforation and supported with viscous pill. The 2nd cement plug is in the 9 5/8" casing immediately above the first plug. The 9 5/8" casing is cut at 1369 ft and the shallow set cement T-plug is set inside both the 13 3/8" and 9 5/8" casings and supported with a bridge plug. All cement plugs are lapped with annular cement. The 2nd and 3rd cement plugs have been tagged and tested.

However, well 13/30-1 and 13/30b-7 are examined in more detail below. Well 13/30-1 failed to meet the spec and is reliant on only one barrier as the shallow set cement plug is not lapped with annulus cement. Well 13/30b-7 was found to be water wet and meet the spec at that time. However, for a $CO_2$ store site, it is reliant on only one barrier and would require further remedial work.

| Well | UKOOA or API | Target Above/Below/In Primary Store | Specification | Comments |
|---|---|---|---|---|
| **13/24b-3 1997** | Issue 0 – 1994 | In store depth | Meets | Cased hole well with 3 cement plugs. Lower plug across perforations in 9 5/8” casing. Second plug immediately above and lapped with annulus cement. 9 5/8” casing cut at 1369 ft and shallow set cement T-plug set inside both 9 5/8” casing and 13 3/8” casing. Shallow set plug lapped with annulus cement. Plugs supported with either viscous pill or bridge plug. Store depth at reservoir target and isolated 2 cement plugs. Meets spec – with 2 cement plugs above store. |
| **13/30-1 1981** | API RP 57 | Below | Fails | Openhole well with 3 cement plugs. Lower plug in openhole section across reservoir. Two cement plugs in 9 5/8” casing but not lapped with annulus cement. Both casing cement plugs not supported with bridge plugs. Hydrocarbon sands. Store depth above reservoir target and isolated with plugs #2, #3. Does not meet spec – no annulus cement. |
| **13/30-2 1984** | API RP 57 | Below | Fails | Cased hole well with 3 cement plugs. Lower plug filled bottom of well and across perfs, Middle plug supported with bridge plug and lapped annulus cement. Cement plug #3 not supported with bridge plug and no annular cement. Hydrocarbon sands. Store depth above reservoir target and isolated with 2 cement plugs. Does not meet spec – shallow set cement plug not lapped with annulus cement. |
| **13/30a-4 1998** | Issue 0 – 1994 | Below | Meets | Openhole well with 4 cement plugs; 3 plugs in openhole section and one cement plug at 13 3/8” casing shoe. Casing cement plug lapped with annulus cement. All plugs supported with viscous pill. Water wet sands. Store depth above reservoir target and isolated with plugs #3, #4. Meets spec with two permanent barriers above store depth. |
| **13/30b-7 2007** | Issue 2 – 2005 | Below | Meets | Openhole well with one cement plug placed across 13 3/8” shoe and lapped with annulus cement. Water wet sands. Store depth above reservoir target and isolated with one cement plug. Meets spec with one barrier for isolation of water zone. |
| **14/26-1 1979** | API RP 57 | Below | Meets | Openhole well with 3 cement plugs and additional bridge plug. Shallow set cement plug lapped with annulus cement. Oil and water bearing zones. Store depth above reservoir target and isolated with cement plugs #2, #3. Meets spec with 2 cement plugs above store depth. |
| **14/26a-6 1997** | Issue 0 – 1994 | In store depth | Meets | Cased hole well with 3 cement plugs. Lower plug set across perforation in 7” liner and to 800 ft above. Second plug in 9 5/8” casing and lapped with annulus cement. Shallow set cement plug in 9 5/8” casing and lapped with annulus cement. Meets spec with 2 cement plugs above store depth. |
| **14/26a-7A 1999** | Issue 0 – 1994 | Below | Meets | Openhole well with 4 cement plugs. Lower 2 cement plugs in open hole section. 3rd cement plug at 13 3/8” casing shoe. 13 3/8” casing cut at 676 ft and shallow set cement T-plug set in 20” casing. Store depth above reservoir target and isolated with 2 cement plugs both lapped with annulus cement. Meets spec with 2 cement plugs above store depth. |

*Table 3-30 Captain legacy wells*

*Well 13/30-1*

There is annular cement in the 9 5/8” across the Captain sands. If there is a leak path through the annular cement, (or at the interfaces) the $CO_2$ leak in the annulus will corrode the 9 5/8” and 13 3/8” casings. The leak path is through the 9 5/8” casing and directly to surface via the unsupported cement plug, bypassing the shallow set cement plug through the 9 5/8” & 13 3/8” casings into the A and/or B annulus to surface. The well integrity relies on the cement column above the Captain sands as the shallow cement plug is not lapped with annulus cement. In summary there is only one barrier and the shallow cement plug is not lapped with annulus cement to provide a secondary barrier for a leak up the A or B annulus.

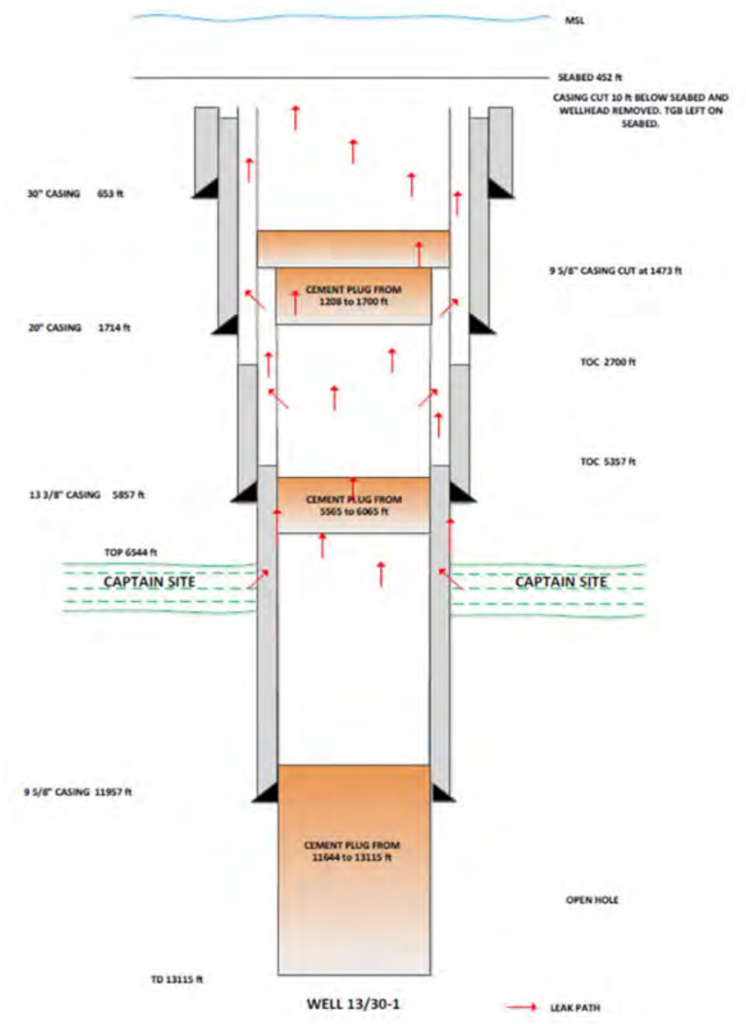



*Figure 3-83 Schematic of well 13/30-1 with potential leak paths indicated*

*Well 13/30b-7*

The exploration well is open hole and there is no annular cement across the Captain sands. The plan was to prove up the existence of hydrocarbons in the Captain and Ettrick sands, but both sands were found to be water wet and abandoned with one cement plug across the casing shoe as per the specs at that time. A hi-vis pill was used to spot the cement plug at the casing shoe.

For $CO_2$ store site, if there is a leak path through the single cement plug (or at the interfaces), the $CO_2$ leaks directly up the wellbore to surface. The well integrity relies on the single cement plug at the 13 3/8" casing shoe. In summary, there is only one barrier to surface which was adequate for a water bearing zone at the time of abandonment but is insufficient for a $CO_2$ store.

Also of considerable concern is that the sands below the storage site (including the Ettrick or Burns sands) may not be isolated and that a leak path currently exists through the wellbore. Although the well diagram shows total connectivity through the open hole, there may be some barriers to flow. These are the mud cake from the in-place Oil Based Mud which would prevent leak-off to the lower sands and the potential for hole collapse over time due to creep from the large shale sections below the Captain sands. While both of these mechanisms for isolation are possible, neither is (nor can be) proven. Mud cake can break down or regain some permeability over time (it is rarely totally impermeable), or even be lifted off due to short term cross-flow. Collapsing shales may leave tortuous flow paths through the 'rubble' or may take longer than the project life span to seal completely.

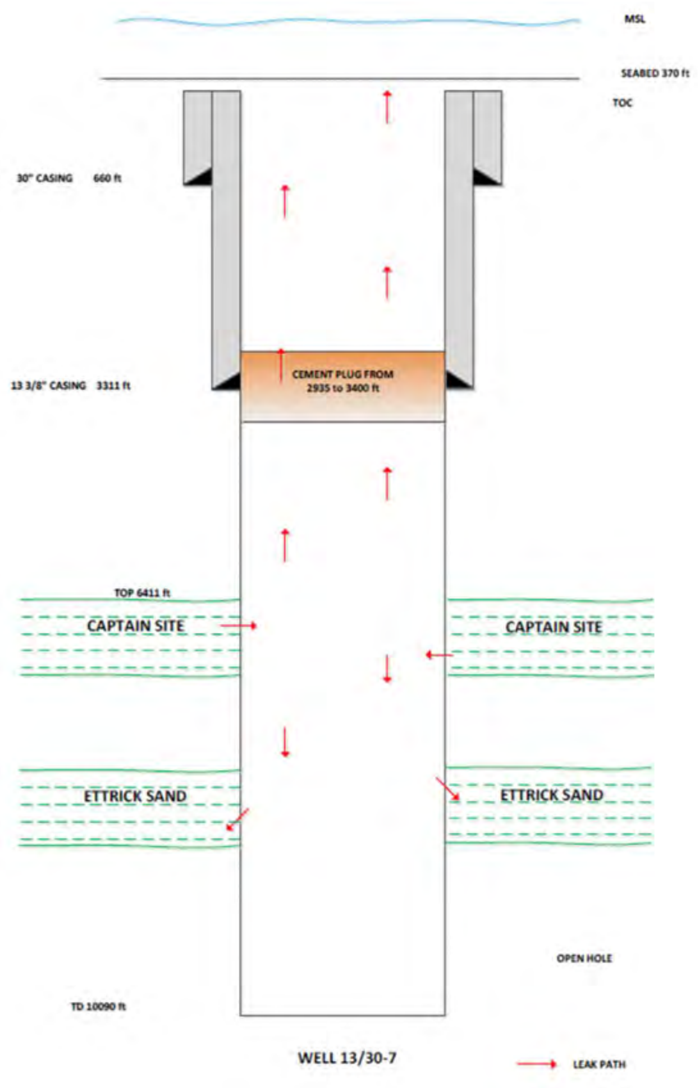



*Figure 3-84 Schematic of well 13/30b-7 with potential leak paths indicated*

This well is a therefore a considerable risk to storage site integrity, although the consequences of a leak to the lower sands is likely to be negligible, depending on leak rate. Given the buoyancy of $CO_2$ when compared to brine, a considerable overpressure would be required to inject $CO_2$ downwards. This may be possible later in project life (as pressures increase above hydrostatic and $CO_2$ saturation increases) or earlier if any of the lower sands are depleted (or below hydrostatic). Should this site be selected to store $CO_2$, it is therefore recommended in FEED to incorporate the lower sands in the dynamic simulation model and establish if injection to them is likely to occur through an open wellbore. If this leak path is confirmed, then the impact of the leak should be assessed, and the project proceeds if the impact is negligible and containment is proven. This may necessitate the extension of the storage complex to incorporate these lower sands.

Should modelling fail to prove containment, conventional procedure is to consider re-entering the well to abandon it to $CO_2$ specifications. As the well has been fully abandoned, the wellhead and surface casing has been cut and removed to 10ft below the seabed. Re-entering this well to perform any testing or remediation will be technically challenging and is currently beyond the expertise and technology that is available to the industry. There is a high risk associated with working on an offshore well that has no wellhead due to the lack of mechanical seal when re-entering the well. This is mitigated by the fact that only water was found in the well (no hydrocarbons) although it cannot be proven that gas (hydrocarbon / $CO_2$ etc.) in small volumes has not migrated to the well where it might accumulate.

A safer re-entry technique is to drill a 'relief' well from a new site adjacent to the old well. This new well would attempt to target the old wellbore, below the old cement plug, and inject cement into the old wellbore (cement squeeze) thus eliminating any permeability. This cement plug would then be pressure tested from above. The assumption would be that if nothing can be injected, then nothing will be produced. This is a common assumption, but is not always correct, and cannot be verified. Furthermore, the ability of the new wellbore to hit the old wellbore may be questionable, as without a metal casing, locating the wellbore in the subsurface will be difficult. A certain amount of trial and error might be expected, and this would add to the cost of the relief well.

For the purposes of this study, the cost of a relief well has been incorporated into the project costs. This money may be used for a re-entry instead, should the technology and processes to allow safe re-entry be developed and proven in the meantime. The best outcome is that remediating this well is not required, following further extensive study work in the FEED stage.

Given that this well raises such concerns; it is recommended that all legacy wells are studied in detail in FEED work for all proposed $CO_2$ storage sites.

#### *3.7.2.5 Degradation*

It has been shown that long term exposure of well construction materials to $CO_2$ (and its by-product when combined with water – carbonic acid) leads to a process of degradation. Cement used to seal the well casing annuli (and for creating barrier plugs) can degrade over time, with chemical reactions creating an increase in porosity and permeability of the cement and decreasing its compressive strength. However, cement has a 'self-healing' mechanism (carbonate precipitation) that reduces the rate of this degradation in the short term. If a cement is fully integral at the outset of exposure to $CO_2$, degradation is likely to be an infinitely slow process. However, if a weakness (fracture, micro-annulus or flow path) exists in the cement, the subsequent degradation process may be accelerated. Further work is required to identify the rate of cement degradation under all conditions in order to establish a minimum height of integral cement to prevent leakage in the storage time frame and to produce a range of potential leak rates. This should then be applied to all legacy wells.

Carbon steel casing (as used in legacy wells) is also subject to degradation through exposure to $CO_2$. Corrosion rates are more predictable (up to and around 3.7mm/yr in carbon steel for Captain conditions, when exposed to the flow of $CO_2$ / water). Under static conditions, the corrosion rate reduces significantly. A leak path (or constant flux) adjacent to the casing is therefore required to cause degradation concern. Note that, for the new injector wells, the corrosion rate for 13%Cr material is considerably lower. As the legacy wells are likely to be exposed to a flux of $CO_2$ during the 20 year injection period, it can be assumed that all casing strings in the reservoir section that are not protected by cement will be subject to significant corrosion. Casing strings above the reservoir will only be affected if a leak path is initiated.

#### 3.7.2.6 Engineering Containment Risk Summary

The high level risk review (discussed earlier in this section) determined that the risk of $CO_2$ leakage in selected Captain X site was moderate. Following the more detailed risk review, where 2 wells of the 8 reviewed showed higher risk than initially assumed, the overall risk is increased. The risk score, however, remains the same, as these wells already hold the highest risk score, as they were abandoned prior to 1986. However, the actual risk of loss of containment in wells 13/30-1 and 13/30-2 is considered low to moderate, as at least 2 barriers to flow (annular cement and casing) would need to fail before a leak occurred. Nonetheless, a suitable monitoring programme would be required for these wells.

However, the potential failure modes of well 13/30b-7 (leak to surface through a single cement plug or leak to lower sands through open wellbore) are far more significant, and only one can be monitored from surface. As this well has been abandoned 'to spec', the inherent problems of high level probability based risk reviews are exposed. A detailed review of each and every legacy well is recommended prior to site investment decision.

In light of the status of well 13/30b-7, the current risk of leakage from the Captain X site must be considered to be high. Further work is recommended to investigate the impact of such a leakage.

#### 3.7.2.7 Well Remediation Options

Appendix 5 includes a catalogue of the well containment failure modes and the associated effect, remediation and estimated cost. The remediation options available will be specific to the well and depend on:

- The type of well failure
- The location of the failure
- The overall design of the well

It is recommended that a detailed well integrity management system is adopted to ensure well integrity is optimised throughout the life of the project (Smith, Billingham, Lee, & Milanovic, 2010).

### 3.7.3 Containment Risk Assessment

A subsurface and wells containment risk assessment was completed and the results are detailed in Appendix 2. The workflow considered ten specific failure modes or pathways for $CO_2$ to move out of the primary store and/or storage complex in a manner contrary to the development plan. Each failure mode might be caused by a range of failure mechanisms. Ultimately, pathways that could potentially lead to $CO_2$ moving out with the Storage Complex were mapped out from combinations of failure modes. The pathways were then grouped into more general leakage scenarios. These are outlined in Table 3-31 and displayed in a risk matrix plot in Figure 3-85.

The key containment risks perceived at the present time involve existing legacy wells:

- Vertical movement of $CO_2$ downwards in subsurface via legacy wells into deeper sands, e.g. through well 13/30b-7, where there is total communication between Captain sand and Burns sand below. Well was abandoned in 2007, with wellhead & surface casing cut 10ft below seabed and removed.
- Escape of $CO_2$ from existing legacy wells leading to seabed release of $CO_2$.
- Lateral movement of $CO_2$ from the Primary store out with the storage complex boundary (due to uncertainties in Top Captain pick and challenges with depth conversion)

The first key containment risk can be mitigated by a more comprehensive risk assessment, in extremis it may be necessary to re-enter the well and isolate the relevant horizons.

The second key containment risk can be mitigated by careful monitoring of abandoned well heads, as laid out in the monitoring plan.

The third key containment risk may be reduced by acquiring additional high resolution 3D seismic. The Top Captain is challenging to pick on seismic due to the low acoustic impedance contrast between the sand and overlying shale and its variability across the fairway; new seismic may help with this mapping.

| Leakage scenario | Likelihood | Impact | Matrix Position |
|---|---|---|---|
| Vertical movement of $CO_2$ from Primary store to overburden through caprock | 1 | 3 | |
| Vertical movement of $CO_2$ from Primary store to overburden via existing wells | 1 | 3 | |
| Vertical movement of $CO_2$ from Primary store to overburden via injection wells | 1 | 3 | |
| Vertical movement of $CO_2$ from Primary store to overburden via caprock & wells | 1 | 3 | |
| Vertical movement of $CO_2$ from Primary store to upper well/ seabed via P&A wells | 3 | 4 | |
| Vertical movement of $CO_2$ from Primary store to upper well/ seabed via suspended wells | 2 | 4 | |
| Vertical movement of $CO_2$ from Primary store to upper well/ seabed via injection wells | 2 | 4 | |
| Vertical movement of $CO_2$ from Primary store to upper well/ seabed via caprock & wells | 1 | 4 | |
| Lateral movement of $CO_2$ from Primary store out with storage complex w/in Captain | 3 | 3 | |
| Vertical movement of $CO_2$ from Primary store to underburden via existing wells (e.g. 13/30b-7) | 5 | 3 | |
| Vertical movement of $CO_2$ from Primary store to underburden via store floor (out with storage complex) | 1 | 3 | |

*Table 3-31 Captain X Leakage Scenarios*

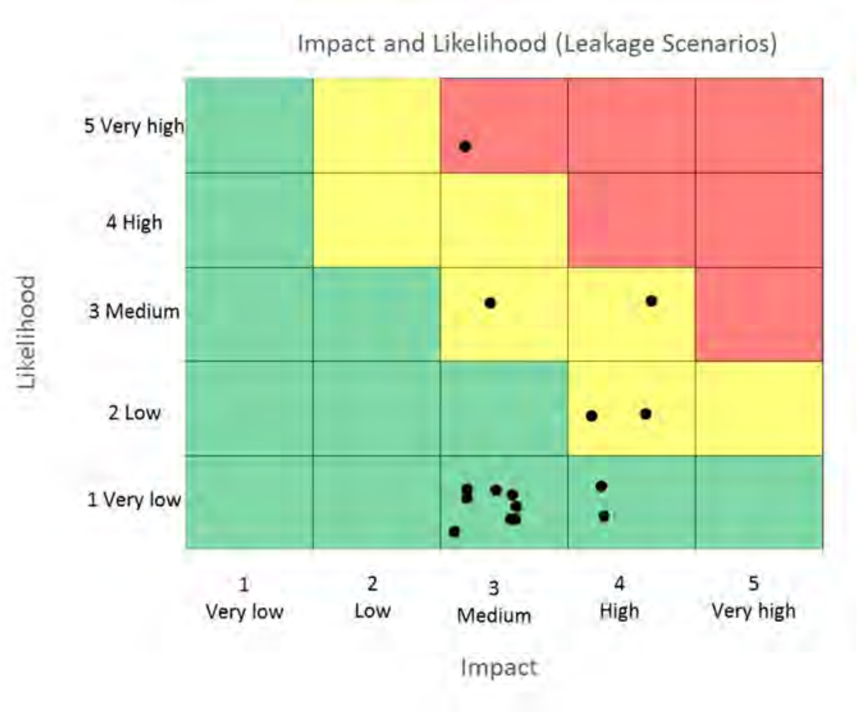



*Figure 3-85 Captain X Risk matrix of leakage scenarios*

## 3.7.4 MMV Plan

Monitoring, measurement and verification (MMV) of any $CO_2$ storage site in the United Kingdom Continental Shelf (UKCS) is required under the EU CCS Directive (The European Parliament And The Council Of The European Union, 2009) and its transposition into UK Law through the Energy Act 2008 (Energy Act, Chapter 32, 2008). A comprehensive monitoring plan is an essential part of the $CO_2$ Storage Permit.

For more information about the purposes of monitoring and the different monitoring phases and domains, please see Appendix 7 MMV Technologies.

### *3.7.4.1 Monitoring Technologies*

Many technologies which can be used for offshore $CO_2$ storage monitoring are well established in the oil and gas industry.

Monitoring of offshore $CO_2$ storage reservoirs has been carried out for many years at Sleipner and Snohvit in Norway and at the K12-B pilot project in the Netherlands. Onshore, Ketzin in Germany has a significant focus on developing MMV research and best practice.

A comprehensive list of existing technologies has been pulled together from (National Energy Technology Laboratory, US Department of Energy, 2012) and (IEAGHG, 2015). This list of monitoring technologies and how they were screened is provided in Appendix 7.

### *3.7.4.2 Captain Sandstone seismic response of $CO_2$*

With the significant cost of seismic surveys, it is essential to understand if they can detect and delineate $CO_2$ in the storage site. During injection, the $CO_2$ replaces and mixes with in-situ pore fluid, changing the density and compressibility of the fluid in the pore space, which may change the seismic response enough to be detected.

This can be modelled prior to injection using a technique known as 1D forward modelling. A 1D model of the subsurface is built from well-log data and fluid substitution is carried out over the injection interval, substituting $CO_2$ for brine. The seismic response of this new fluid mixture is modelled via a synthetic seismogram and any visible changes give an indication that seismic will be able to detect the stored $CO_2$ at the site.

*Modelling Inputs*

The Captain D and C sands of well 13/30a-4 were modelled with a bulk mineral density of 2.65g/cc (from petrophysics), brine density of 1.042g/cc, Vp and density from well logs and Vs derived from Vp. The fluid substitution case modelled 60% $CO_2$ saturation with a density of 0.8g/cc. 60% saturation is broadly in line with the saturations modelled for buoyant trapping or fully mobile $CO_2$. A 25Hz North Sea (reverse SEG) polarity Ricker wavelet was used to generate the synthetic seismogram.

The software uses low-frequency Gassmann equations, which relate the saturated bulk modulus of the rock (Ksat) to its porosity, the bulk modulus of the porous rock frame, the bulk modulus of the mineral matrix and the bulk modulus of the pore-filling fluids. The saturated bulk modulus can also be related to P-wave velocity (Vp), S-wave velocity (Vs) and density (rho) and so these data can be taken from well logs.

The software takes Vp, Vs and rho from well logs (either directly or derived) to determine the bulk modulus of the saturated rock over the modelled interval and then determines the mineral matrix and bulk modulus of the pore fluid from specified user inputs. It then essentially "removes" the in-situ fluid to calculate the bulk modulus of the rock matrix only and substitutes the pore fluid with the desired fluid to be modelled (in this case $CO_2$). Once the desired fluid is substituted it calculates the bulk modulus of the rock saturated with the new fluid and, as mentioned above, a new Vp, Vs and density can be determined from the saturated bulk modulus. This new Vp, Vs and density is then used with the synthetic wavelet to generate a synthetic seismogram.

*Results*

Figure 3-86 shows the results with 0% $CO_2$/ 100% brine and 60% $CO_2$/ 40% brine on the seismic response within the Captain D and C sands in well 13/30a-4, which is within the Captain X Site.

A slight dimming of the Top Captain trough in this well can be seen as the acoustic impedance contrast between the Rodby and Captain is reduced by the presence of $CO_2$.

This result is different from that seen from the results of the 1D forward modelling in the Goldeneye 14/29a-3 well (Shell, 2015), where a polarity reversal was seen with the presence of $CO_2$; the Top Captain trough becoming a peak with higher $CO_2$ saturations.

The Goldeneye 14/29a-3 results were recreated in the Kingdom software using a different wavelet and it was noted that the results of the modelling are sensitive to the type of wavelet used.

Comparing the two wells, the change in seismic response at the deeper Goldeneye 14/29a-3 well (~8000ft tvdss) was more significant than at the shallower 13/30a-4 well (complete polarity reversal versus slight amplitude dimming, respectively). This may be due to the burial depth, but more study is required. There is also considerable variability of the Captain Sandstone across the fairway.

From the results at well 13/30a-4, $CO_2$ may be detectable using 4D seismic, with the Top Captain seismic response dimming due to the presence of $CO_2$ and will certainly need a good baseline. OBC or OBN should be considered during FEED to ensure repeatability of the survey which could help maximise detection of small amplitude changes from the presence of $CO_2$.

Modelling at Goldeneye indicates that 4D seismic may also detect the presence of $CO_2$ in the shallower Mey Sandstone (Shell, 2015), which is a secondary store within the Captain X storage complex.

During FEED, a fluid substitution should be carried out for several wells across the fairway and with a range of $CO_2$ saturations to understand the detectability threshold for 4D seismic over the Captain fairway. In addition, modelling of the AVO (amplitude versus offset) response of the $CO_2$ in the Captain Sandstone would be useful to understand if there is an AVO response which could help with detection.

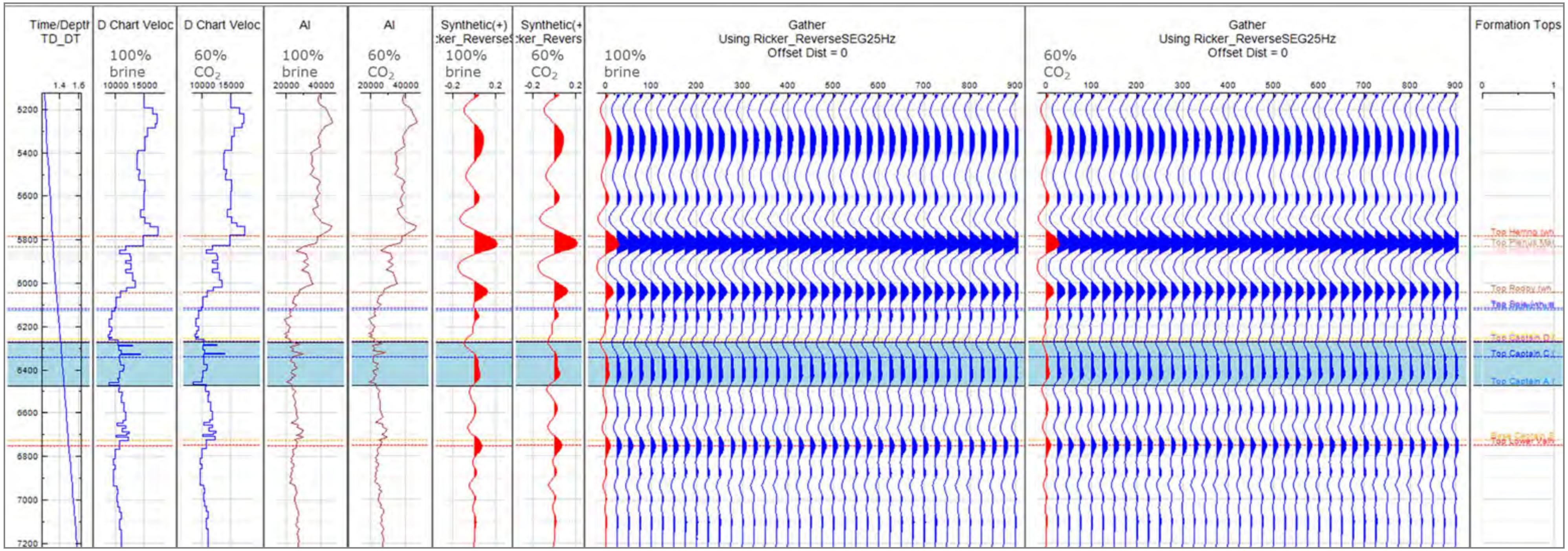



*Figure 3-86 Results of 1D forward modelling for Captain X site*

#### 3.7.4.3 Outline Base Case Monitoring Plan

The outline monitoring plan has been developed to focus on the leakage scenarios as identified in Appendix 2, with the most applicable technologies at the time of writing.

49 technologies that are used in the hydrocarbon industry and existing $CO_2$ storage projects were reviewed and 35 were found to be suitable for $CO_2$ storage offshore. A list and description of the offshore technologies is in Appendix 5.

The monitoring plans for the Captain X storage site is shown in Figure 3-87, with the rationale and timing for each technology contained in tables in Appendix 5. The plans are based on using technologies from a general offshore UKCS Boston Square (see Appendix 5), which plots technology cost against value of information, and are from either the "just do it" (low cost, high benefit) or "focussed application" (high cost, high benefit) categories.

Other technologies that are in the "consider" (low cost, low benefit) category require additional work during FEED to more fully assess the value for the Captain Aquifer storage site. Note that some of the "consider" technologies are less commercially mature, but may move to the "just do it" category over time.

Before the site can be handed over to the Regulator, confidence that the plume has stabilised must be demonstrated. Due to the uncertainties that exist over plume migration (please see Section 3.6.7.4 for a discussion on $CO_2$ Plume Migration), it may be that the post closure injection phase is extended beyond 20 years, with more extensive monitoring during this time. The post-closure monitoring period has been kept at 20 years for Captain X Site to ensure consistency between sites, but noting that this could be extended. Annual MMV reporting to DECC will include information about site performance and may include commentary around any site-specific monitoring challenges that have occurred, which could include uncertainties over plume stabilisation. An on-going dialogue with the Regulator will be key to managing this uncertainty.

Figure 3-88 maps the selected technologies to the leakage scenarios discussed in Appendix 2.

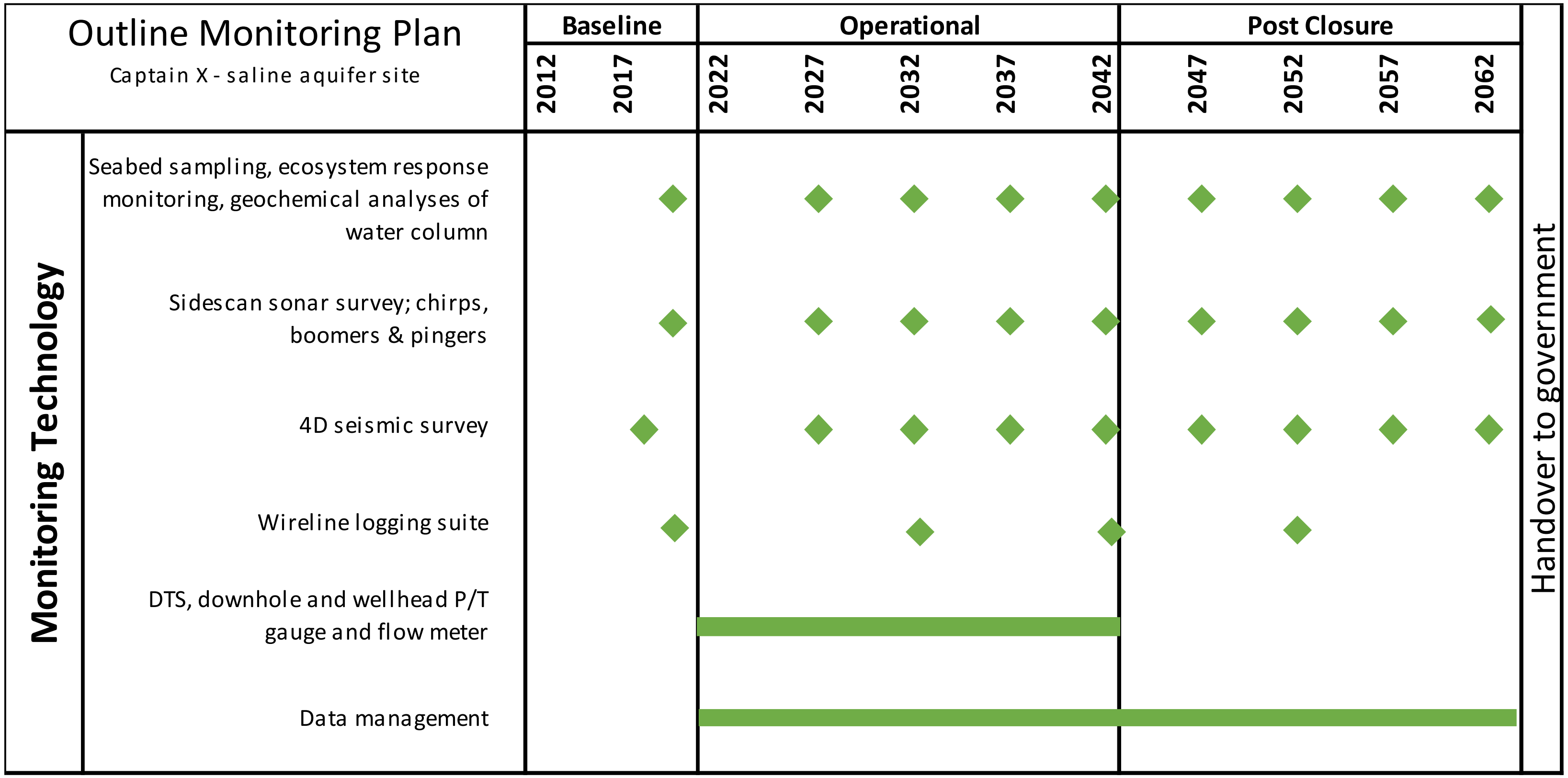



*Figure 3-87 Outline monitoring plan for Captain X Aquifer storage site*

● Critical

● Serious

● Moderate

● Minor

| Leakage Scenario | | | Risk ranking | | | Monitoring Technology | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Likelihood | Impact | Ranking | Seabed sampling, ecosystem response monitoring, geochemical analyses of water column | Sidescan sonar survey, chirps, boomers & pingers | 4D Seismic | Wireline logging | Permanently installed wellbore tools (DTS), downhole and wellhead P/T gauge and flow meter |
| Leakage Scenario | Overburden | Vertical movement of CO2 from Primary store to overburden through caprock | 1 | 3 | Minor | | | X | | X |
| | Overburden | Vertical movement of CO2 from Primary store to overburden via pre-existing wells | 1 | 3 | Minor | | | X | | |
| | Overburden | Vertical movement of CO2 from Primary store to overburden via injection wells | 1 | 3 | Minor | | | X | | X |
| | Overburden | Vertical movement of CO2 from Primary store to overburden via both caprock & wells | 1 | 3 | Minor | | | X | | X |
| | Seabed | Vertical movement of CO2 from Primary store to seabed via P&A wells | 3 | 4 | Moderate | X | X | | | |
| | Seabed | Vertical movement of CO2 from Primary store to seabed via suspended wells | 2 | 4 | Moderate | X | X | | | |
| | Seabed | Vertical movement of CO2 from Primary store to seabed via injection wells | 2 | 4 | Moderate | X | X | | X | X |
| | Seabed | Vertical movement of CO2 from Primary store to seabed via both caprock & wells | 1 | 4 | Minor | X | X | X | X | X |
| | Lateral | Lateral movement of CO2 from Primary store out with storage complex w/in Captain | 3 | 3 | Moderate | | | X | | |
| | Underburden | Vertical movement of CO2 from Primary store to underburden via existing wells (e.g. 13/30b-7) | 5 | 3 | Serious | | | X | | |
| | Underburden | Vertical movement of CO2 from Primary store to underburden via store floor (out with storage complex) | 1 | 3 | Minor | | | X | | |

*Figure 3-88 Captain X storage site - Leakage scenario mapping to MMV technology*

#### 3.7.4.4 Outline Corrective Measures Plan

The corrective measures plan will be deployed if either leakage or significant irregularities are detected from the monitoring, measurement and verification plan above.

Some examples of significant irregularities and their implications are shown in Table 3-32.

Once a significant irregularity has been detected, additional monitoring may be carried out to gather data which can be used to more fully understand the irregularity. A risk assessment should then be carried out to decide on the appropriate corrective measures to deploy, if any. It may be that only further monitoring is required.

Depending on the implication of the significant irregularity, some measures may be needed to control or prevent escalation and remediation options may be required.

The Appendix 1 Risk Matrix contains examples of mitigation actions (controls) and potential remediation options. For the leakage scenarios discussed in Appendix 2 and mapped to MMV technologies in Figure 3-88, some examples of control actions and remediation options are shown in Figure 3-89.

| Monitoring technology | Example of significant irregularity | Implication |
|---|---|---|
| **Wireline logging suite (incl well bore integrity)** | Indication that wellbore integrity compromised | Injection process at risk |
| **4D seismic survey** | $CO_2$ plume detected out with the storage site or complex (e.g. laterally or vertically) | Potential $CO_2$ leakage or unexpected migration |
| **Sidescan sonar survey**<br>**Chirps, boomers & pingers** | Bubble stream detected near P&A wellbore | Potential $CO_2$ leakage to seabed via P&A wells |
| **Seabed sampling, ecosystem response monitoring, geochemical analyses of water column** | Elevated $CO_2$ concentrations above background levels detected in seabed | Potential $CO_2$ leakage to seabed |
| **DTS, downhole and wellhead P/T gauge and flow meter readings** | Sudden temperature drop along tubing<br>Sudden pressure or temperature drop in reservoir | Potential $CO_2$ leakage from injection wellbore<br>Storage site integrity compromised (e.g. caprock fractured) - $CO_2$ potentially |

*Table 3-32 Examples of irergularities and possible implications*

| | | | Outline Corrective Measures | |
|---|---|---|---|---|
| | | | **Control/ mitigation actions** | **Potential Remediation Options** |
| Leakage Scenario | Overburden | Vertical movement of CO2 from Primary store to overburden through caprock | Invesitgate irregularity, assess risk, update models if required, increased monitoring to ensure under control | Increased monitoring to ensure under control (CO2 should be trapped by additional geological barriers in the overburden) |
| | | Vertical movement of CO2 from Primary store to overburden via pre-existing wells | Invesitgate irregularity, assess risk, update models if required, increased monitoring to ensure under control | Increased monitoring to ensure under control. Consider adjusting injection pattern if can limit plume interaction with pre-existing wellbore. Worst case scenario would require a relief well (re-entry into an abandoned well is complex, difficult and has a very low chance of success) |
| | | Vertical movement of CO2 from Primary store to overburden via injection wells | Stop injection, investigate irregularity, acquire additional shut-in reservoir data, update models | Replacement of damaged well parts (e.g. tubing or packer) by workover. Worst case scenario would be to abandon the injection well. |
| | | Vertical movement of CO2 from Primary store to overburden via both caprock & wells | Invesitgate irregularity, assess risk, update models if required, increased monitoring to ensure under control | Increased monitoring to ensure under control (CO2 should be trapped by additional geological barriers in the overburden) |
| | Seabed | Vertical movement of CO2 from Primary store to seabed via P&A wells | Stop injection, investigate irregularity via additional monitoring at seabed and acquisition of shut-in reservoir data, assess risk, update models | Re-entry into an abandoned well is complex, difficult and has a very low chance of success. A relief well is required. |
| | | Vertical movement of CO2 from Primary store to seabed via suspended wells | Stop injection, investigate irregularity via additional monitoring at seabed and acquisition of shut-in reservoir data, assess risk, update models | Re-entry into a suspended well may be easier than an abandoned well. Engage Operator. |
| | | Vertical movement of CO2 from Primary store to seabed via injection wells | Stop injection, shut in the well and initiate well control procedures, investigate irregularity via additional monitoring at seabed and acquisition of shut-in reservoir data, assess risk, update models | Replacement of damaged well parts (e.g. tubing or packer) by workover. Worst case scenario would be to abandon the injection well. |
| | | Vertical movement of CO2 from Primary store to seabed via both caprock & wells | Stop injection, investigate irregularity via additional monitoring at seabed, assess risk | If injection well - replacement of damaged well parts (e.g. tubing or packer) by workover. Worst case scenario would be to abandon the injection well. If P&A well - a relief well may be required. |
| | Lateral | Lateral movement of CO2 from Primary store out with storage complex w/in Captain | Invesitgate irregularity, assess risk, update models if required, increased monitoring to ensure under control | Continue to monitor, licence additional area as part of Storage Complex. |
| | Underburden | Primary store to underburden via existing wells (e.g. 13/30b-7) | Invesitgate irregularity, assess risk, update models if required, increased monitoring to ensure under control | Continue to monitor, licence additional area as part of Storage Complex. Worst case scenario: a relief well may be required (re-entry into an abandoned well is complex, difficult and has a very low chance of success) |
| | | Primary store to underburden via store floor (out with storage complex) | Invesitgate irregularity, assess risk, update models if required, increased monitoring to ensure under control | Continue to monitor, licence additional area as part of Storage Complex. |

*Figure 3-89 Outline Corrective Measures Plan*

# 4.0 Appraisal Planning

## 4.1 Discussion of Key Uncertainties

The Captain Sandstone member has been the subject of petroleum activity since the mid 1970's. During that time almost 100 wells have been drilled, logged, cored, tested and in some circumstances produced over extended periods of time. The area as a whole has therefore been the subject of extensive drilling and data acquisition with good quality data from both the hydrocarbon and water bearing reservoir intervals. The injection site is located in between the Atlantic and Cromarty gas fields. The reservoir quality is excellent with proven extensive lateral connectivity across the fairway for 100 km or so from Blake to Goldeneye. Whilst the Captain Sandstone aquifer system is exceptionally well appraised, there are several key remaining uncertainties which remain. Most of these are associated with the pattern of $CO_2$ plume migration and most cannot be resolved by drilling.

After careful consideration, it has been concluded that additional drilling for appraisal purposes will do little to further derisk the storage site. Specifically, it is felt that the released data from CDA used in this project can be significantly supplemented through appropriate agreements with petroleum operators to include important well by well pressure and flow rate information and key well abandonment records. Furthermore, it is understood that there is considerable core material available including in some cases, caprock and preserved samples from the water bearing intervals. These are key resources for any project hoping to achieve FID.

The imperative requirement which will enable the progression of the Captain Sandstone aquifer within the fairway to be developed as an effective $CO_2$ storage site is improved seismic data. It has already been described how the Top and Base Captain represent very poor quality seismic reflectors due to the lack of a consistent and significant acoustic impedance across them. This issue has been a major challenge to the hydrocarbon developments in the area and continues to be a challenge for $CO_2$ storage.

In their work on Goldeneye some 35km to the east of Captain X, Shell used significantly improved 2001 re-processing of a 1997 3D seismic survey. This Pre-Stack Depth Migration processing was used in the 2011 FEED seismic interpretation where it was reported that:

*"Seismic interpretation of the Captain Sandstone is generally difficult due to problems in imaging the reservoir itself, because of the poor impedance contrast at top reservoir between the Captain Sandstones and the overlying Rodby shales. The seismic image quality at reservoir level is also reduced due to the effect of the overlying lithology. In addition, the seismic data are contaminated with water-bottom multiples and strong long-period multiples generated by the coal and chalk interfaces".*

Whilst these data were used to plan the Goldeneye development, the development well depth forecasting was only accurate to +/- 60ft. In very low dip areas such as the Captain X site, this kind of depth precision also results in challenges to structural definition, but outside of a large closure such as Goldeneye, the consequences of this depth uncertainty on plume migration and lateral containment are considerable. This is why new improved 3D seismic data are essential to progress the deployment of the Captain aquifer store at any point in the fairway.

## 4.2 Proposed Appraisal Plan

**Appraisal Drilling:** Whilst some uncertainties do remain regarding the subsurface reservoir and caprock properties, they do not currently justify the expense of an additional appraisal well.

**Seismic Acquisition:** A new 3D seismic survey capable of imaging the Top Captain Sandstone more effectively is essential for progressing the Captain aquifer as a significant $CO_2$ storage site. The identified structures such as Goldeneye, Atlantic and Cromarty are helpful but represent rather minor contributions to storage capacity. Unfortunately, the PGS MegaSurvey does not include "offset or angle stacks". Such volumes can support significantly improved data quality in challenging areas. There are other 3D surveys available over the Captain X area which do offer these "angle stacks" including one from TGS- Nopec. New Broadband seismic acquisition may be preferable. This retains more of the lower frequencies which helps in inversions. Before making any procurement decision, it is recommended that a modern rock physics study and seismic acquisition modelling is completed to confirm whether the imaging at Top Captain can be improved upon before a decision is taken to acquire new seismic. This should also be revisited to check the performance of a new survey in tracking plume migration.

**Other Appraisal Activity:** Once an improved depth map at the Top Captain is in place, then further modelling work is recommended which is fully calibrated to well by well production and pressure data from the operators of Blake, Atlantic, Cromarty and Goldeneye. It is also important to work closely with all petroleum operators in the area to ensure that wells are abandoned to maintain maximum subsurface integrity in the light of a potential future $CO_2$ storage development. This is required in order to eliminate any further degradation of engineered containment risk introduced through well abandonment operations.

# 5.0 Development Planning

## 5.1 Description of Development

The Captain aquifer site X is located in the outer Moray Firth and has an estimated capacity in the region of 60 MT. Figure 5-1 shows the extents of the aquifer, and its location relative to nearby oil and gas infrastructure.


*Figure 5-1 Captain aquifer location*

The current base case for the Captain X CO2 storage development consist of utilising the existing 16" Atlantic and Cromarty pipeline from St Fergus to Atlantic (via an acquisition from BG International). A newly installed Normally Unmanned Installation (NUI) will be located at the Captain aquifer, approximately midway between the Atlantic and Cromarty developments. A new 8km 16" pipeline will be installed to connect the 16" Atlantic pipeline and the NUI. The new 16" pipeline will be surface laid (laid on the seabed) and stabilised/protected with concrete weight coating.

The Captain X NUI will take the form of a conventional 4-legged steel jacket standing in 115m water depth and supporting a multi-deck minimum facilities topsides. The steel jacket will be piled to the seabed and provide conductor guides which in conjunction with a 4 slot well bay will enable cantilevered jack-up drilling operations for the injection wells. It is anticipated that $CO_2$ will be injected into the Captain aquifer via two platform wells (plus a monitoring well) over the 20 year design life.

The installation will be controlled from shore via dual redundant satellite links with system and operational procedures designed to minimise offshore visits. The installation will be capable of operating in unattended mode for up to 90 days with routine maintenance visits scheduled approximately every six weeks to replenish consumables (fuel, chemicals, etc.), and carry out essential maintenance and inspection activities.

## 5.2 $CO_2$ Supply Profile

The assumed supply profile for the reference case is for 3 Mt/y to be provided for the shore terminal at St Fergus for the duration of the 20 year injection period, this is illustrated in Figure 5-2.

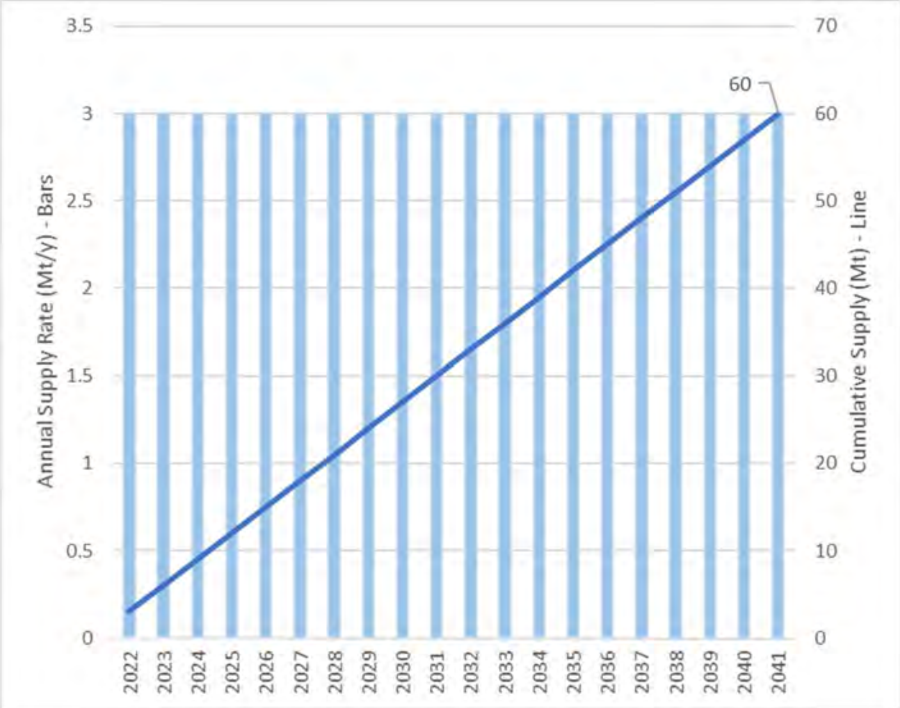



*Figure 5-2 $CO_2$ supply profile*

## 5.3 Well Development Plan

The Captain X well placement strategy has been driven by development strategy (platform structure required for filtering and control) as well as reservoir geometry, geology, reservoir engineering modelling and the economics of development.

First pass reservoir engineering suggests that 2 wells (plus 1 well for back-up / redundancy) are required over field life to inject target $CO_2$ volumes. Furthermore because of the exceptional quality of the reservoir, well spacing to prevent well to well interference does not appear to be a critical factor. As a result, and for the design rate, the injection wells can be drilled from the same surface location.

For standard oil and gas developments, the most economical development strategy for such a low well count is often a sub-sea development. However, in any reservoir injection project, the removal of fine particulates from the injection stream is considered critical. If this is not done, then it can lead to a rapid degeneration of injectivity as the rock pore throats are plugged with fines. As the Captain X site is a large distance from any $CO_2$ source, pipeline lengths are considerable and the potential for particulate debris is high. Furthermore, subsea wells need to be controlled, and the cost of conventional control umbilicals from shore would be high. Whilst such a subsea development is possible, a lower risk, conventional development using a single 3 well slot platform (hosting filtering facilities and well controls) was selected as a base case. As this study considers stand-alone development only, options to supply any future subsea developments from existing (or future) third party platform facilities has not been considered.

The platform development option dictates a single development centre for the development wells. Reservoir engineering suggests that two injection wells will be adequate to achieve target injection rates. A third well would be drilled to provide redundancy should a well fall out of service. In common with the operational injection wells, this additional well would also be used for routine reservoir monitoring.

In order to maximise reservoir coverage and well separation, deviated wells are proposed. The wells will kick-off at about 550ft TVD and have a sail angle of around 60° all the way to the reservoir. The 60° angle through the reservoir should provide sufficient sand face to allow high injection rates in what is expected to be a high permeability reservoir.

In the base case development scenario, the primary $CO_2$ storage target is the Upper Captain sand. As a result, there is an opportunity to consider horizontal wells if more sandface is required for enhancing injectivity. Should the Lower Captain sand (more limited in extent and potentially only limited connectivity to the upper sand) be considered for future development, a dedicated well to target this sand may be preferred, again opening the possibility of a horizontal well profile, should it be required. Injecting into both sands from the same wellbore, while simple to accomplish with a 60deg deviated well, may prove problematic due to:

- Potential for different 'pressure charging' rates, creating significant crossflows during well shut-in periods. This could in turn lead to significant sanding and corrosion issues.
- Charging of the lower sands to fracture pressure well before the upper sand reaches this limit. In practice, this may not be an issue, as fractures from the lower sand through the inter-sand shale would not result in containment loss. However, the strategy adopted in this work is to remain below fracture pressures at every point in the reservoir in case of uncontrolled propagation.

### 5.3.1 Well Design

The key design criteria for the injection wells is that they must be capable of injecting 1.5 Mt/y $CO_2$ in liquid phase throughout the project life and require minimal intervention during that time.

The Captain X Site Injector Well Basis of Design can be summarised as follows:

1. The injector wells will be drilled from a stand alone NUI platform by heavy duty jack-up rig
2. The wells will be a deviated (up to 60°) in the target formation
3. The platform wells will consist of 26" conductor, 20"x13-3/8" surface casing and 9-5/8" production casing, with 5-1/2" stand alone sand screens.
4. The wells will be completed with 5-1/2" production tubulars
5. All flow wetted surfaces will be 13%Cr material
6. Maximum injection rates in the platform wells will be 3.823 Mte/yr (197.7 mmscf/day)
7. Minimum FTHP will be 44.5 bara
8. Maximum FTHP will be 160 bar or lower pipeline spec limit
9. Maximum SITHP will be 100 bar
10. Maximum WHT will be 6°C during injection
11. Minimum Design Temperature (to be confirmed by transient modelling)

#### 5.3.1.1 *Well Construction*

The following reservoir targets have been identified for the Captain reservoir:

| Target Name | TVDSS (m) | UTM North (m) | UTM East (m) |
|---|---|---|---|
| GI-01 Top Captain | 2,014.9 | 6,440,148.6 | 265,001.2 |
| GI-01 TD | 2,135.3 | 6,440,112.4 | 265,206.6 |
| GI-02 Top Captain | 1,981.3 | 6,438,715.4 | 263,621.5 |
| GI-02 TD | 2,071.2 | 6,438,565.0 | 263,661.8 |
| GI-03 Top Captain | 1,924.9 | 6,440,774.4 | 261,452.2 |
| GI-03 TD | 2,025.5 | 6,440,804.6 | 261,280.6 |

*Table 5-1 Captain X well locations*

Note: Well GI-03 is currently defined as the spare injector and/or monitoring well. However, the reservoir location of this well may be modified following further detailed analysis during the FEED stage.

The conceptual directional plans for the $CO_2$ injectors have been designed on the following basis:

1. All wells will be drilled as slant wells, including the spare well which will also act as monitoring well.
2. All wells will be drilled vertically to 550m TVDSS (i.e. to below the surface casing shoe).
3. All wells will be kicked off below 550m MD, with a planned dogleg severity of 3.0° per 30m. The wells will be built to the required tangent angle, while turning the wellpath onto the required azimuth.
4. A build section will be drilled from the surface shoe to the depth at which inclination is sufficient to reach the identified reservoir target.
5. A turn and build / drop section will be drilled in the 12 ¼" hole section to deliver an inclination of 60° at the top of the Captain Sand while turning the well path onto the desired azimuth.
6. The reservoir section will be drilled as a tangent section, holding inclination at 60° to TD below the base of the targeted Captain Sand.

A directional well spider plot is provided in Figure 5-3. The directional profile for platform injector GI-01 is provided in Figure 5-4. Full details for all wells are provided in Appendix 6.

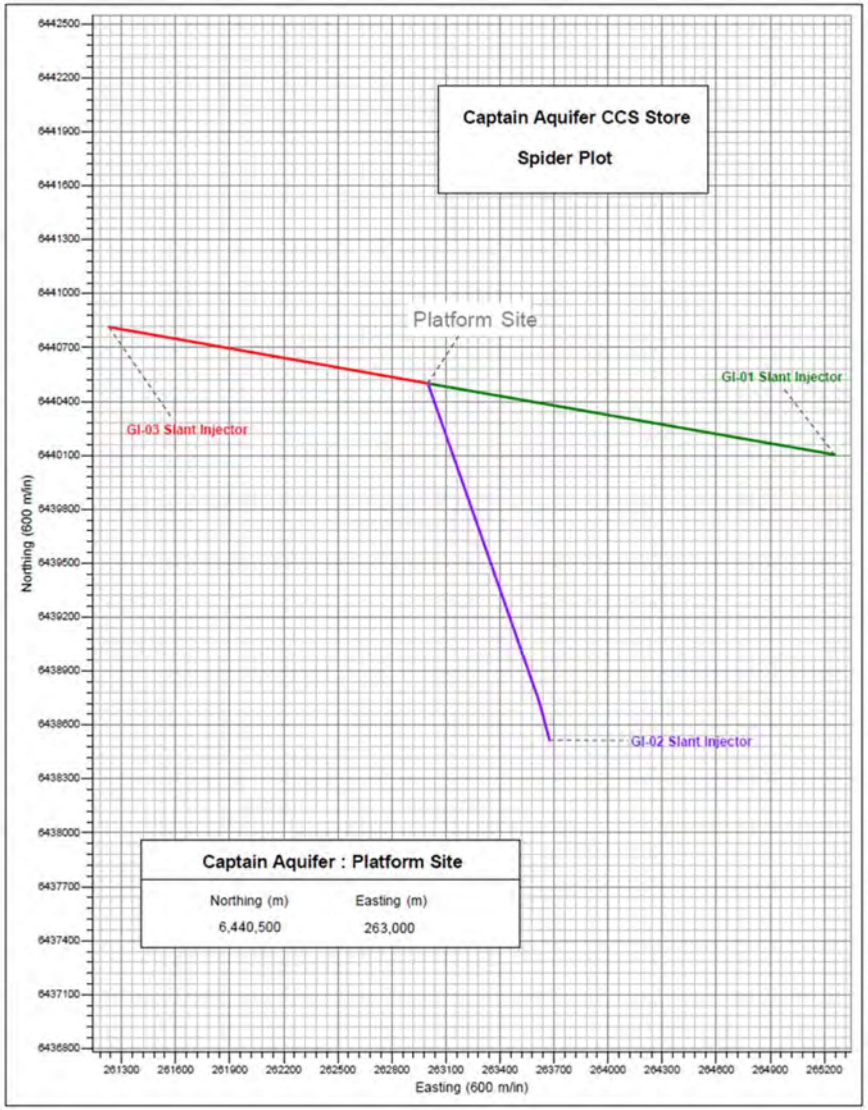
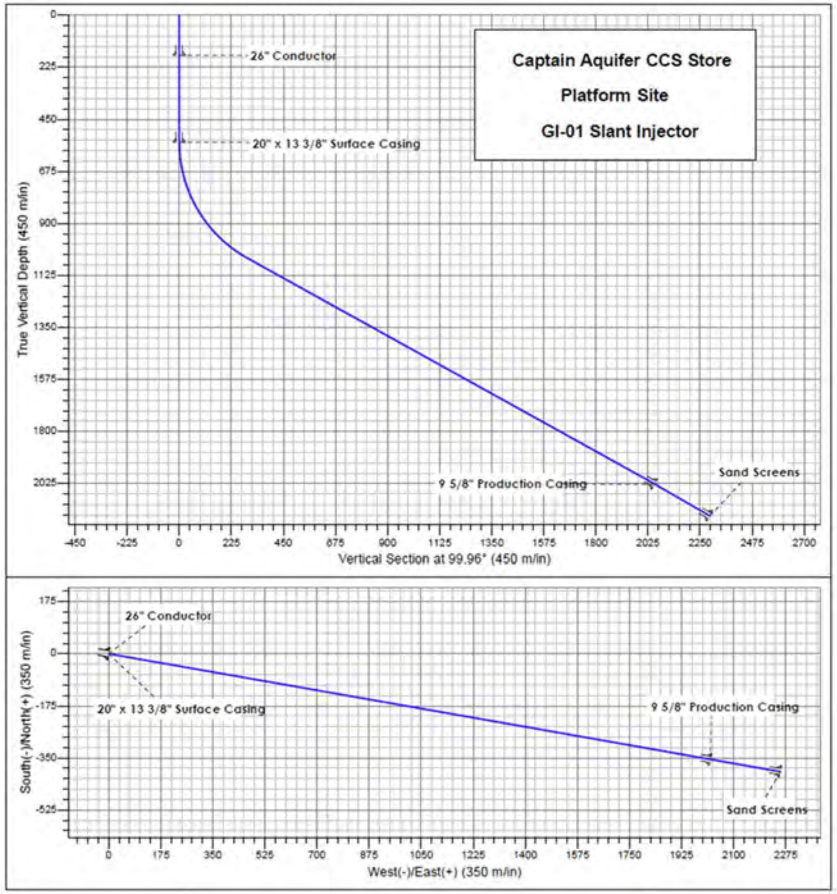



*Figure 5-3 Platform directional spider plot*




SECTION DETAILS

| MD | Inc | Azi | TVD | +N/-S | +E/-W | Dleg | TFace | VSect |
|---|---|---|---|---|---|---|---|---|
| 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.000 | 0.00 | 0.00 |
| 550.00 | 0.00 | 0.00 | 550.00 | 0.00 | 0.00 | 0.000 | 0.00 | 0.00 |
| 1159.73 | 60.97 | 99.96 | 1050.99 | -51.01 | 290.50 | 3.000 | 99.96 | 294.95 |
| 3136.38 | 60.97 | 99.96 | 2010.10 | -349.93 | 1992.82 | 0.000 | 0.00 | 2023.31 |
| 3146.11 | 60.00 | 100.00 | 2014.90 | -351.40 | 2001.16 | 3.000 | 177.93 | 2031.78 |
| 3146.18 | 60.01 | 100.00 | 2014.93 | -351.41 | 2001.22 | 3.000 | 18.80 | 2031.83 |
| 3386.89 | 60.01 | 100.00 | 2135.27 | -387.62 | 2206.52 | 0.000 | 0.00 | 2240.31 |
| 3386.96 | 60.00 | 100.00 | 2135.30 | -387.63 | 2206.58 | 3.000 | -161.20 | 2240.37 |
| 3446.96 | 60.00 | 100.00 | 2165.30 | -396.65 | 2257.75 | 0.000 | 0.00 | 2292.33 |

*Figure 5-4 Platform injector GI-01 directional profile*

##### 5.3.1.2 Well Completion

The upper completion consists of a 5.5" tubing string, anchored at depth by a production packer in the 9-5/8" production casing, just above the 5.5" lower completion hanger. Components include:

1. 5-1/2" 13Cr tubing (weight to be confirmed with tubing stress analysis work)
2. Tubing Retrievable Sub Surface Safety Valve (TRSSSV)
3. Deep Set Surface-controlled Tubing-Retrievable Isolation Barrier Valve (wireline retrievable, if available)
4. Permanent Downhole Gauge (PDHG) for pressure and temperature above the production packer
5. Optional DTS (Distributed Temperature Sensing) installation
6. 9-5/8" Production Packer

The DTS installation will give a detailed temperature profile along the injection tubulars and can enhance integrity monitoring (leak detection) and give some confidence in injected fluid phase behaviour. The value of this information should be further assessed, if confidence has been gained in other projects (tubing leaks can be monitored through annular pressure measurements at surface, leaks detected by wireline temperature logs and phase behaviour modelled with appropriate software).

### 5.3.2 Number of Wells

The Captain sands are very permeable and the injectivity potential is high. However, the injection rate needs to be limited to optimise the storage capacity whist injecting at a plateau rate for an extended period of time. The minimum number of wells for the development is two, to allow for continued injection if one well is shut-in for a short time. Based on the well modelling two 5.5" wells have been selected for this development. A spare well will also be drilled as a replacement well should there be any need to shut-in a development well long term.

### 5.3.3 Drilling Programme

The summary well drilling and completion schedule for the life of the project is illustrated in Table 5-2.

| | Year | | | | |
|---|---|---|---|---|---|
| **Well Activity** | 0 | 5 | 10 | 15 | 20 |
| **Drill and complete new injection well** | 2 | | | | |
| **Drill and complete new monitoring well / spare injector** | 1 | | | | |
| **Local Sidetrack** | | | 2 | | |
| **Abandonment** | | | | | 3 |

*Table 5-2 Summary well activity schedule*

##### 5.3.3.1 Well Construction Programme

The outline drilling, casing and mud programmes for platform wells are provided in Table 5-3.

| Section | Casing | Comments |
|---|---|---|
| **Surface (Driven)** | 26", 60m below mudline | |
| **Surface (20") Water based Mud** | 13 3/8", 550m<br>Carbon steel<br>Cemented to the mudline | |
| **Intermediate (12 ¼") Oil based mud** | 9 5/8", 1975m<br>Carbon steel<br>Cemented to 1000m below the 13 3/8" shoe | Isolate the Chalk, Rodby and Sola formations |
| **Injection (8 ½") Oil based mud** | 5.5", 2050m<br>13 Cr below packer<br>Cemented to inside of liner | |

*Table 5-3 Outline well construction programme*

### 5.3.4 Injection Forecast

Injection commences in 2022 and continues for approximately 20 years, the final year of injection is 2041. The injection forecast for the reference case is for 3 Mt/y for the 20 year store life. This forecast results in a cumulative injection of 60 Mt of $CO_2$. This will be delivered by two injection wells and one spare well.

| Year | Rate (Mt/y) | Total (Mt) | Year | Rate (Mt/y) | Total (Mt) |
|---|---|---|---|---|---|
| **2022** | 3 | 3 | **2032** | 3 | 33 |
| **2023** | 3 | 6 | **2033** | 3 | 36 |
| **2024** | 3 | 9 | **2034** | 3 | 39 |
| **2025** | 3 | 12 | **2035** | 3 | 42 |
| **2026** | 3 | 15 | **2036** | 3 | 45 |
| **2027** | 3 | 18 | **2037** | 3 | 48 |
| **2028** | 3 | 21 | **2038** | 3 | 51 |
| **2029** | 3 | 24 | **2039** | 3 | 54 |
| **2030** | 3 | 27 | **2040** | 3 | 57 |
| **2031** | 3 | 30 | **2041** | 3 | 60 |

*Table 5-4 Injection profile*

### 5.3.5 Movement of the $CO_2$ Plume

The dynamic modelling has shown, within the range of sensitivities carried out, that 180MT of $CO_2$ can be injected into Captain X. For Captain X to be a viable storage site the $CO_2$ must be contained within the storage complex boundary, 1000 years after injection ceases. The preliminary reference case model was run with injection of 120MT of $CO_2$ over a 40 year period, after which injection was stopped and the model was then run for a further 1000 years.

As $CO_2$ is less dense than the brine within the saline aquifer, buoyancy forces significantly impact $CO_2$ migration. Post injection, the $CO_2$ migrates from Cromarty, a structural high, to the south west pinch out edge of the model after which it continues to migrate along the model boundary which rises to the north west boundary. It reaches the north west boundary of the model within 1000 years. There is no physical boundary to contain the $CO_2$ within the storage complex in this area. The plume migration at the end of injection and after 1000 years shut-in are shown in Figure 5-6.

It was decided to use the fairway model to investigate the extent of the plume migration. The fairway model was upscaled and calibrated to the available dynamic data. After 1000 years the $CO_2$ plume has migrated a significant distance beyond the complex boundary and, although the velocities are less than 10m/y, it is expected that, in time, the $CO_2$ plume will migrate to the fairway model boundary. The $CO_2$ plume migration is shown in Figure 5-5.

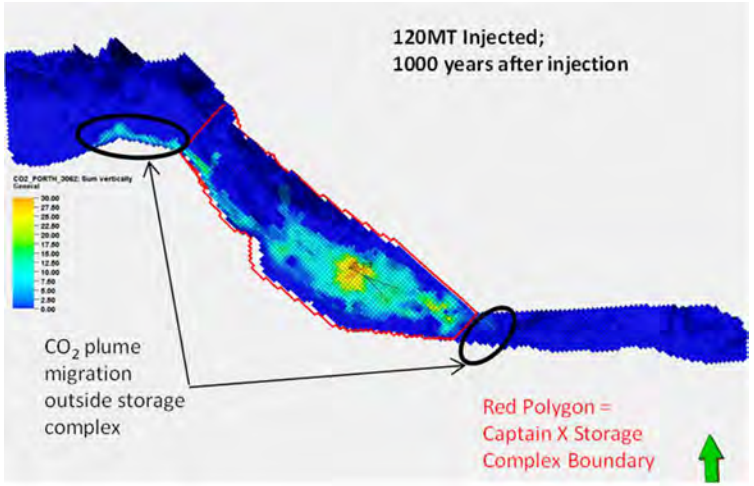



*Figure 5-5 Fairway model: $CO_2$ plume migration after 1000 years shut-in*

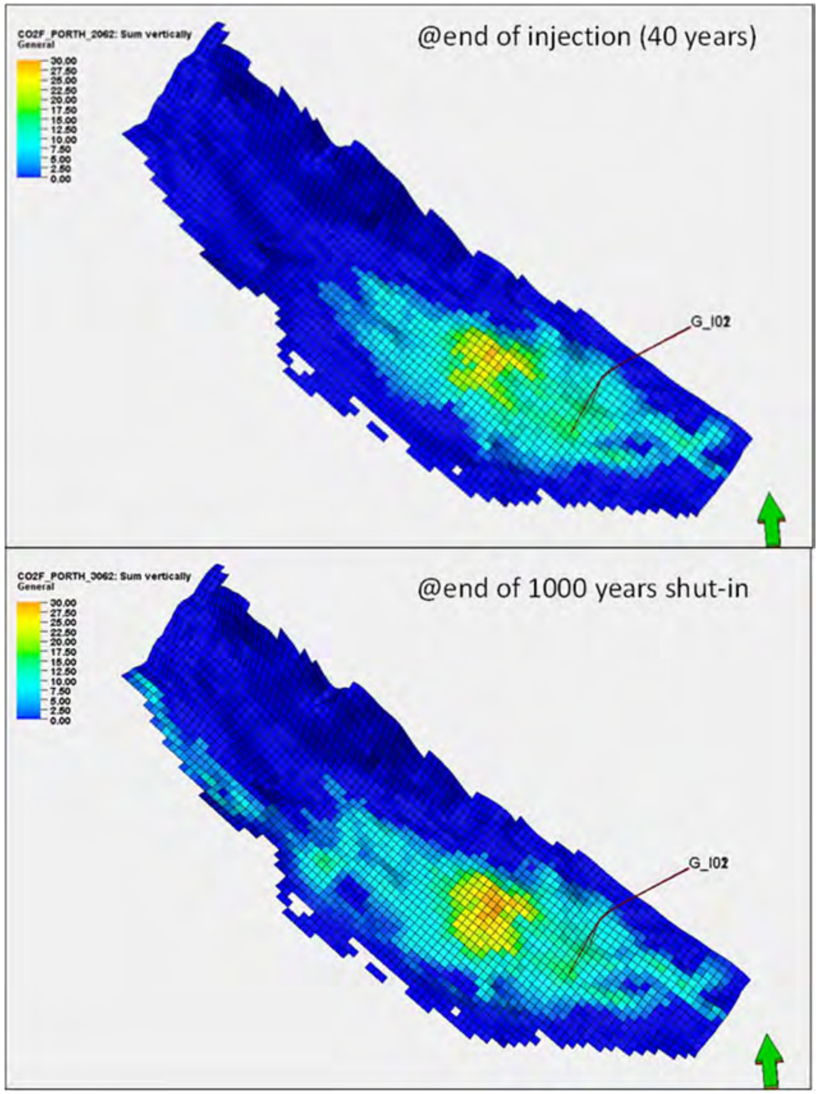



*Figure 5-6 $CO_2$ Plume migration at the end of injection and after 1000 years shut-in for the preliminary storage complex reference case model*

## 5.4 Offshore Infrastructure Development Plan

The optimum platform location for the Captain X NUI has been determined through drilling studies, UTM coordinates are presented in the table below.

| Platform | UTM Coordinates | |
|---|---|---|
| | Eastings (m) | Northings (m) |
| **Captain X NUI** | 6,440,500 | 263,000 |

*Table 5-5 Platform location (Captain NUI)*

### 5.4.1 $CO_2$ Transportation Facilities

This section provides an overview of the Captain X $CO_2$ transportation facilities. $CO_2$ will be transported in the liquid (dense) phase.

#### *5.4.1.1 Overview*

The base case for transporting $CO_2$ from St Fergus to the Captain NUI is to utilise the existing 16” pipeline from St Fergus to Atlantic (COP 2011), with a new 16” pipeline installed to connect the existing pipeline to the Captain NUI (via tie-in spools). Acquisition of the 16” Atlantic pipeline from BG is discussed in the following section.

Note that there is a 12km 12” export pipeline from Cromarty to Atlantic that passes in the vicinity of the Captain X NUI location, however it has been assumed that a new pipeline will be required for the following reasons:

- Smaller diameter/reduced ullage (12” versus 16”);
- The 12” Cromarty pipeline was specified for a design life of 10 years (2016) whilst the 16” Atlantic pipeline was specified for a design life of 20 years (2026). Extending the design life until 2056 years may not be feasible;
- Trenched and buried therefore it would require excavation and cutting at the NUI location to facilitate tie-in;
- It will not be possible to inspect the line via intelligent pig due to large internal diameter changes (18”/16”/12”).

Consideration was initially also given to utilising the existing 20” Goldeneye pipeline. The Goldeneye field is located approximately 100km north east of Aberdeen, and approximately 30km west of the existing Atlantic facilities. The selected location for the Captain X NUI is approximately 8km west of the Atlantic development and as such the existing Atlantic pipeline is the preferred choice (8km new pipeline versus a 38km new pipeline) provided its integrity can be confirmed. Furthermore the original design pressure of the 20” Goldeneye pipeline is 132 barg, which would likely lead to operability issues given the required tubing head pressures for $CO_2$ injection in the Captain aquifer (further discussion is included in Section 3.6.3). The Goldeneye pipeline has therefore not been considered further herein. Costs for a new pipeline have also been considered and included for comparison.

#### *5.4.1.2 Acquisition of 16” Atlantic Pipeline from BG*

As discussed, the base case for the Captain X CO2 storage development assumes acquisition of BG International’s 16” Atlantic pipeline. The original pipeline design parameters are included in Section 5.4.1.4. The Atlantic and Cromarty development was commissioned in 2006. The 16” pipeline was specified for a 20 year design life based on transporting hydrocarbons (and water) at relatively high pressure, however production ceased in 2009 (after less than 4 years) and formal Cessation Of Production (COP) was granted by DECC in 2011; at which point the pipeline was filled with a mixture of produced water, MEG (mono ethylene glycol), corrosion inhibitor and hydrocarbons, before the pipeline was cleaned and rendered hydrocarbon free in 2012.

The DECC decommissioning portal (itportal.decc.gov.uk) states that a decommissioning programme for the Atlantic manifold, related facilities and pipelines is currently in preparation. The decommissioning of the pipeline will involve flushing operations, cutting and burying the end sections of the pipeline. Adoption of the pipeline following decommissioning may still be possible, however, the pipeline integrity would be compromised and would require extensive inspection, reconnection and testing and likely become commercially unfeasible.

The commercial considerations are not discussed herein however it is recommended that discussions with BG are progressed at the earliest opportunity in order to establish their willingness to transfer ownership, and to confirm the assumptions made herein. It is worth noting that any acquisition will also take on liability for decommissioning some, or all, of the Atlantic and Cromarty facilities. Royal Dutch Shell plc is currently in negotiations to take over BG Group plc (of which BG International is a subsidiary) which also needs to be considered as they would become a stakeholder.

Preliminary design calculations (line sizing, wall thickness) for the Captain X $CO_2$ storage development pipeline system are included in Section 5.4.1.4. Given that the Atlantic pipeline was originally designed for 20 years hydrocarbon service, requiring a 3mm corrosion allowance, and provided that prior to suspension it was sufficiently cleaned by pigging/flushing to ensure residual concentrations of hydrocarbons were as low as reasonably practicable (ALARP), it can reasonably be assumed that the pipeline will not have degraded sufficiently in the 3-4 years of operation, or in its subsequent state, as to be deemed unfit for future $CO_2$ service. It is also worth noting that the pipeline has an internal epoxy coating that will also protect the internal pipe surfaces from corrosion and erosion (as well as reducing friction).

A full pipeline integrity and life extension study will be required to confirm suitability. This will involve detailed internal and external inspection in order to re-qualify the pipeline and verify that it is suitable for re-use to transport $CO_2$ for up to 20 years. Re-qualification shall comply with the same requirements as for a pipeline designed specifically for transportation of $CO_2$. Figure 5-7 has been extracted from DNV RP J202 ‘Design and Operation of $CO_2$ Pipelines’ and demonstrates the recommended requalification process. Further information is included in the recommended practice.

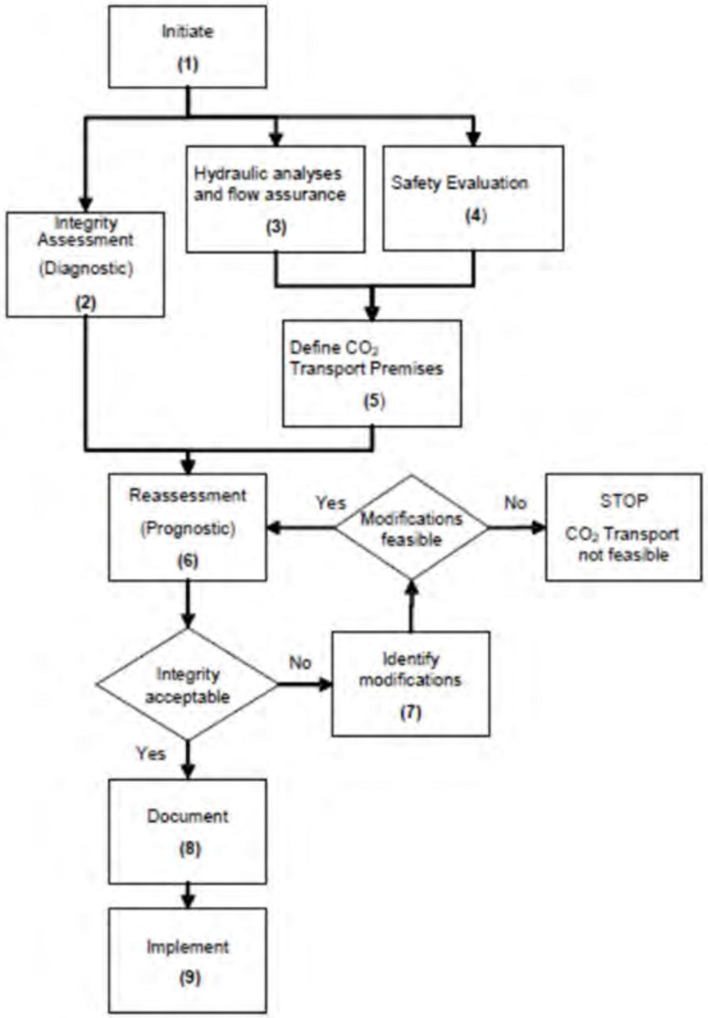



*Figure 5-7 DNV RP J202 Requalification of existing pipeline for $CO_2$ service*

A detailed external inspection will be required by Remotely Operated Vehicle (ROV) to detect any unsupported spans where the pipeline isn't trenched and buried/rockdumped, and any boulders or debris in the vicinity of the pipeline, as well as to inspect, where possible, the pipeline anodes in order to determine the number of anode skids required to protect the pipeline for a further 20 years. It would also be prudent to survey the pipeline route from Atlantic to the Captain X NUI at this time.

Internal inspection will be achieved via an intelligent pigging campaign. Intelligent pigs will be utilised to determine the remaining thickness of the pipeline wall and internal epoxy coating, any internal corrosion and any wall defects/deformation that may require repair/modification. Note that this may require the use of a temporary pig launcher receiver (PLR) at the Atlantic (offshore) end of the pipeline.

Note that the cost estimates included in Section 6 include a nominal sum for acquisition of this pipeline, and for pipeline preparation (inspection, intelligent pigging etc.). It has also been assumed that a new anode skid will be required every 2.5 km to ensure the pipeline is cathodically protected to prevent external corrosion.

#### *5.4.1.3 Pipeline Routing*

**Existing 16" Atlantic and Cromarty Pipeline**

The 16" diameter 78km pipeline was installed in 2006 and has a piggybacked 4" diameter MEG pipeline. The pipelines connect the Atlantic manifold to the onshore gas terminal at St Fergus. Figure 5-8 shows the pipeline route.

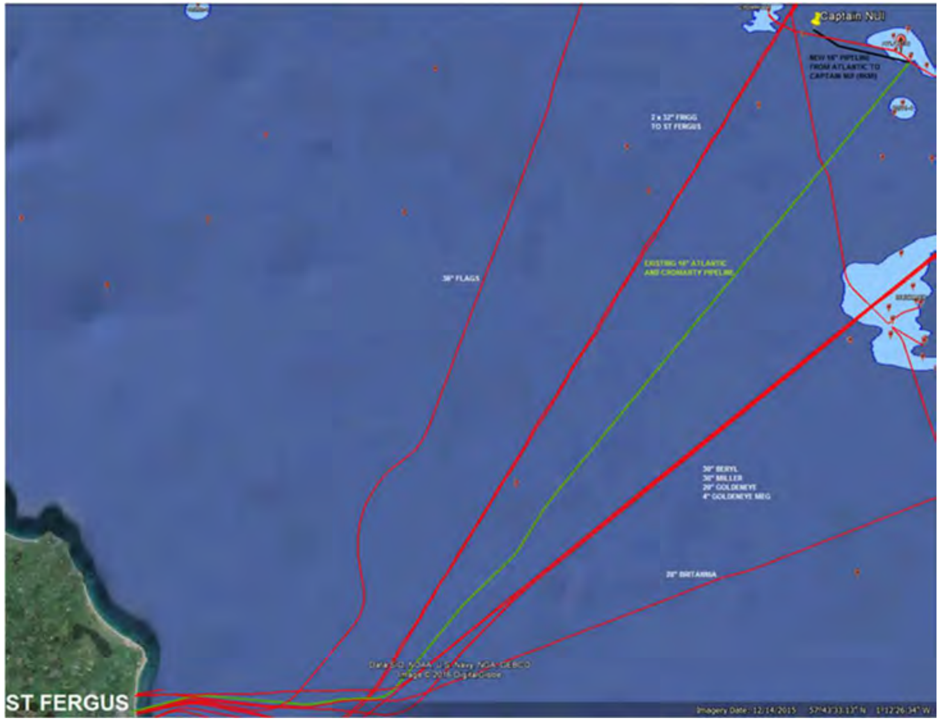



*Figure 5-8 Pipeline route (Captain X $CO_2$ storage development)*

The pipeline landfall at St Fergus extends out to 1.2km and was installed by open cut trenching and utilised the installation of a temporary sheetpile cofferdam in the tidal zone. Once the trench was pre-cut the lay vessel dropped anchor at the end of the trench and the pipeline was pulled ashore using a shorebased winch. With the pipeline pulled ashore, the vessel then commenced lay of the subsea pipelines along the pre-defined route. Between KP 0 and 1.2, the pipelines were installed into the pre-cut trench and were stabilised by backfilling the trench and ultimately removing the cofferdam and returning the beach zone to its natural state. Note that this 1.2km landfall section has an increased diameter of 18” (457mm), beyond KP1.2 the diameter reduces to 16” and the pipelines are stabilised/protected with concrete weight coating (CWC) 40-60mm thick, giving an overall diameter of up to 532mm. Out to KP 1.2 the piggybacked pipelines are trenched to 1000mm depth of lowering (DOL). Beyond this point, the burial depth of the pipeline is 600mm DOL although there are some sections where this could not be achieved due to shallow rock outcrops and regions with a high density of boulders. These regions are protected with rock dump.

There are six pipeline crossings along the existing pipeline route from St Fergus to the Atlantic manifold, summarised in the table below.

| Pipeline | Surface Laid / Trenched | Operator |
|---|---|---|
| **28-inch Britannia** | Surface Laid | Britannia |
| **36-inch FLAGS** | Surface Laid | Shell UK |
| **32-inch Frigg Vesterled** | Surface Laid | Total |
| **32-inch Frigg Fuka** | Surface Laid | PX/Total |
| **30-inch SAGE** | Surface Laid | Exxon Mobil |
| **10” Buzzard Gas Export** | Trenched and Buried | Nexen |

*Table 5-6 Pipeline Crossings (Existing 16" Atlantic and Cromarty pipeline)*

**New 16" Infield Pipeline to Captain X NUI**

The existing 16" Atlantic pipeline connected the St Fergus terminal to the Atlantic manifold. A new 16" pipeline will therefore be required to connect this pipeline to the Captain X NUI (via tie-in spools).

The optimum location for the Captain X NUI has been determined through drilling studies, and is approximately 8km north west of the Atlantic manifold location.

The infield pipeline route is shown in Figure 1 4. It can be seen that the 8km 16" pipeline route has been selected to minimise route length while avoiding existing facilities. There are two pipeline crossings, where it crosses the existing Cromarty pipeline and umbilical, as summarised in the table below.


*Figure 5-9 Infield pipeline route (Captain X $CO_2$ storage development)*

| Pipeline | Surface Laid / Trenched | Operator |
|---|---|---|
| **12" Atlantic and Cromarty** | Trenched and Buried | BG (COP 2011) |
| **Umbilical (Goldeneye – Cromarty)** | Trenched and Buried | BG (COP 2011) |

*Table 5-7 Pipeline crossing (Atlantic to Captain X NUI)*

A full desktop study will be required to confirm the pipeline route and ensure that all seabed obstructions (wells, platforms, pipelines, umbilicals and cables etc.) and seabed features (rocks, sandwaves, pockmarks, mud slides etc.) are identified and accounted for appropriately.

### 5.4.1.4 Preliminary Pipeline Sizing

Preliminary line sizing calculations have been performed to determine the pipeline outer diameter and wall thickness requirements for the Captain X pipeline system. The pipeline route lengths are summarised in the table below.

| Pipeline | Route Length | Status |
|---|---|---|
| **16" St Fergus to Atlantic** | 78km | Existing |
| **16" Atlantic to Captain X NUI** | 8 km | New |

*Table 5-8 Pipeline route lengths*

The original design parameters of the 16" Atlantic pipeline are summarised in the table below. The pipeline was installed & commissioned in 2006, and was designed to transport gas and gas condensate production from the Atlantic manifold (which comingles flow from the three Atlantic and Cromarty wells) to the Scottish Area Gas Evacuation (SAGE) terminal at the St Fergus gas plant.

Note that prior to re-use for $CO_2$ transportation a full pipeline integrity and life extension study will be required to confirm suitability. The contents of the (currently suspended) pipeline will need to be discharged to sea. The pipeline will require further cleaning, intelligent pigging to confirm integrity, end to end testing, hydrostatic pressure testing and drying to enable future $CO_2$ transport.

| Parameter | Value |
|---|---|
| **PL ID (DECC)** | PL2029 |
| **Design Life** | 20 Year |
| **Outer Diameter** | 406.4 [1] |
| **Wall Thickness** | 15.5 [1] |
| **Material** | X65 Carbon Steel HFW (high frequency welded) |
| **Corrosion Allowance** | 3mm |
| **External Coating** | Concrete weight coating 40-60mm thick |
| **Internal Coating** | 0.075mm internal thin film epoxy coating |
| **Cathodic Protection** | Coatings and cathodic protection (CP) anodes |
| **Design Pressure** | 170 barg |
| **MAOP (max allowable operating pressure)** | 170 barg |
| **Operating Pressure** | 82 barg |
| **Design Temperature** | 60 / -10 °C |
| **Operating Temperature** | 50 °C |

*Table 5-9 Existing pipeline design parameters (Atlantic and Cromarty)*

Notes:

1. The landfall comprises 1.2 km of 18" pipeline (17.5 mm wall thickness)

The total pipeline route lengths are summarised in Table 5-8 above, the existing 16" Atlantic pipeline route length is 78km and the new 16" infield pipeline route is 8km, giving a total route length of 86km.

The 16" Atlantic pipeline was designed for a pressure of 170 bar. The 15.5mm wall thickness was calculated based on a mill tolerance of -5% (HFW), and included a 3mm corrosion allowance (for a 20 year design life). Some of this corrosion allowance may have been used during the 4 years in operation and subsequent suspension period. A minimum arrival pressure of 55 – 130 bar has been calculated for the Captain X $CO_2$ injection wells (giving an allowable pressure drop of 40 bar without any margins based on the original design).

It can be seen from Figure 1 5 that a 16" pipeline is sufficient to meet the predicted Captain X $CO_2$ supply profile (3 MTPA via 2 wells, see Section 5.2).

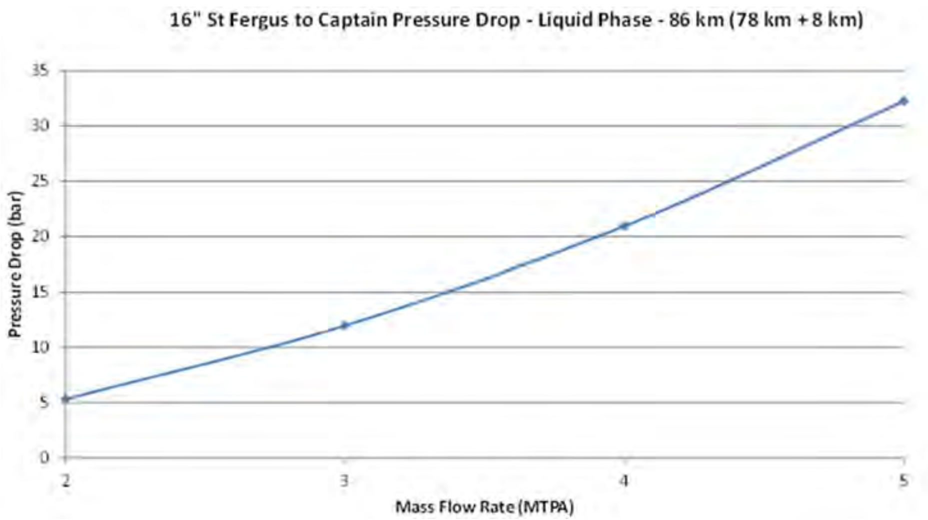



*Figure 5-10 Pipeline pressure drop - 16" 86 km (St Fergus to Captain)*

The pipeline Maximum Operating Pressure (MOP) for Captain X $CO_2$ service has been calculated based on the maximum Tubing Head Pressure (THP) of 130 bar (see Section 3.6.3), plus the pipeline pressure drops as per Figure 5-10, and incorporating a safety factor of 1.1 to account for uncertainties in the modelling. This pressure was then used to calculate the minimum required wall thickness as per PD8010 part 2 and confirm the existing pipeline capacity for an increased ullage.

The pipeline pressure drops over the full 86km route for a range of mass flow rates have been extracted from the graph above and are tabulated below, alongside the resultant MOP and the required minimum PD8010 Part 2 pipeline wall thickness. The MOP will in turn become the compressor rating at the beach. Note that the minimum wall thickness requirements include a mill tolerance of

12.5% and a nominal corrosion allowance of 1mm (deemed suitable for dry $CO_2$ service).

| Mass Flow Rate | Pressure Drop (86km) | MOP[1] | PD8010 Part 2 Wall Thickness[2] |
|---|---|---|---|
| **2 MTPA** | 5.3 bar | 148.9 bar | 11.10 mm |
| **3 MTPA** | 12.0 bar | 156.2 bar | 11.63 mm |
| **4 MTPA** | 20.9 bar | 166.0 bar | 12.34 mm |
| **5 MTPA** | 32.3 bar | 178.5 bar | 13.23 mm |

*Table 5-10 Pipeline requirements (Total 86 km pipeline route length)*

Notes:

1. Max Operating Pressure (MOP) = (Max THP (130 bar) + Pressure Drop) x 1.1
2. Minimum wall thickness required considering pressure containment (hoop stress), hydrostatic collapse, propagation buckling and equivalent stress, plus a nominal 1mm corrosion allowance and 12.5% fabrication tolerance

For a mass flow rate of 3 MTPA (reference case) the pressure drop for a 16" pipeline over the full pipeline route length of 86km (78km + 8km) is approximately 12 bar.

For an increased mass flow rate of 5 MTPA (i.e. an increase of 66% in ullage) the pressure drop increases to approximately 32 bar, with MOP in the region of 180 bar. This exceeds the original Atlantic design pressure however, as summarised above in Table 5-9, the 16" Atlantic pipeline was designed with a 3mm corrosion allowance, which was deemed sufficient for hydrocarbon service over a 20 year design life. For dry $CO_2$ service it is likely the corrosion allowance could be reduced to 1mm, and the minimum required wall thickness (PD8010) reduces to approximately 13.2 mm.

As discussed in Section 5.4.1.2 the 16" pipeline was in service for less than 4 years before being suspended, therefore, provided it was sufficiently cleaned by pigging/flushing to ensure residual concentrations of hydrocarbons were as low as reasonably practicable (ALARP), it is likely that the pipeline could be re-rated for $CO_2$ service at this higher pressure (circa 180 bar). It is also worth noting that the pipeline has an internal epoxy coating that will also protect the internal pipe surfaces from corrosion and erosion, reducing the risk of a significantly corroded wall thickness further.

A full pipeline integrity and life extension study will be required to confirm suitability.

Therefore, provided the pipeline integrity is deemed acceptable, there is sufficient ullage in the 16" pipeline for an additional Captain X injection well (1.5 MTPA) before potentially exceeding the limits of the existing pipeline and beyond which a new pipeline, and additional pumping, may be required. Future build out of $CO_2$ storage (or EOR) could be achieved via an additional platform well, a tie-back via the spare riser, or via an in-line tee structure that is installed at KP42 of the Atlantic pipeline. Further discussion is included in Section 5.6.

The new 8km 16" pipeline to Captain X is sufficiently large (OD ≥ 16") that it does not require burial or rockdumping for protection purposes. Instead it is proposed the pipeline be surface laid and protected/stabilised with concrete weight coating, which necessitates installation by S-lay. Pipeline protection and stability requirements should be fully assessed during FEED.

#### 5.4.1.5 Subsea Isolation Valve (SSIV)

For conservatism, development costs include for an actuated piggable ball valve SSIV structure being installed on the 16” pipeline adjacent to the Captain X NUI Jacket. The requirement for SSIVs to be installed on $CO_2$ service pipelines feeding a normally unmanned installation (NUI) is not clear-cut. The Peterhead CCS Project Offshore Environmental statement (Shell, 2014) states that a new SSIV will be put in place to support the proposed project and provide a means of isolation in the event of loss of containment close to the platform. The Offshore Environmental Statement for the White Rose CCS project (National Grid Carbon Ltd; Carbon Sentinel Ltd; Hartley Anderson Ltd, 2015) states that the White Rose 4/52 pipeline will not have a subsea isolation valve (SSIV). Comparatively the inventory of the proposed White Rose pipeline is greater than that of Goldeneye. The requirement for an SSIV for the Captain X pipeline system should be fully appraised in FEED. The Captain X platform import riser will be fitted with an emergency shutdown valve (ESDV) and the riser located so as to mitigate risk of collision damage by support vessels. Full dispersion modelling will be required in order to position the ESDV and Riser and any temporary refuge facilities specified accordingly in compliance with PFEER regulations. If an SSIV is deemed necessary for the Captain X pipeline then consideration must be given to the pressure rating of the piping, spools and riser to allow for thermal expansion of any potential trapped $CO_2$ inventory.

### 5.4.2 Offshore $CO_2$ Injection Facilities

It is proposed that $CO_2$ is injected into the Captain aquifer from a single Normally Unmanned Installation (Platform) with a 6 slot wellbay that will enable heavy duty Jack Up drilling and completion of dry injection trees. A NUI platform is considered as both the most economical and technically suited development concept for Captain X.

The key input parameters used to size and cost the NUI platform for Captain X are listed below, and a master equipment list is provided in Table 5-5:

NUI Jacket:

- 115m water depth
- 20 year design life
- 10,000 year return wave air gap
- Jacket supported conductor guide frames
- J-tube and Riser to facilitate future tie back

NUI Topsides:

- Minimum Facilities Topsides
- Diesel driven generator package
- Well and valve controls HPU and MCS package
- HVAC package
- Low temperature valving and manifolding pipework package
- Sampling and Metering package
- No compression / pumping
- Consumable tanks sized for 90 days self-sustained operations

| Requirement | Quantity/Value | Comment |
|---|---|---|
| **Design Life** | 20 Years | 2 wells plus a spare injector plus a spare slot. |
| **Platform Well Slots** | 3 | |
| **Platform Wells** | 3 | |
| **Trees (XT)** | 3 | - |
| **Diesel Generator** | 3 | 1 to run full time, 2nd when manned, 3rd as standby |
| **Satellite Communications** | 2 x 100% | Dual redundant VSAT systems |
| **Risers** | 2 | 1 spare for future tie-back/expansion |
| **J-Tube** | 2 | For future tie-back/expansion |
| **Subsea Isolation Valve (SSIV)** | 1 | SSIV at Captain X NUI |
| **Temporary Refuge** | 1 | 4 Man |
| **Lifeboat** | 1 | TEMPSC and Life rafts |
| **Helideck** | 1 | - |
| **Pig Launcher Receiver** | Permanent | - |
| **$CO_2$ Filters** | Yes | Bypassable |
| **Crane** | 1 | Electric crane |
| **Vent Stack** | 1 | Low Volume |
| **Leak detection and monitoring** | 1 | |
| **Chemical Injection** | MEG | MEG for start-ups/restarts c/w storage, injection pumps and ports. |
| **General Utilities** | Yes | Open hazardous drains etc. |

*Table 5-11 Master equipment list - Captain X NUI*

A process flow diagram of the Captain X development is presented in Figure 5-11

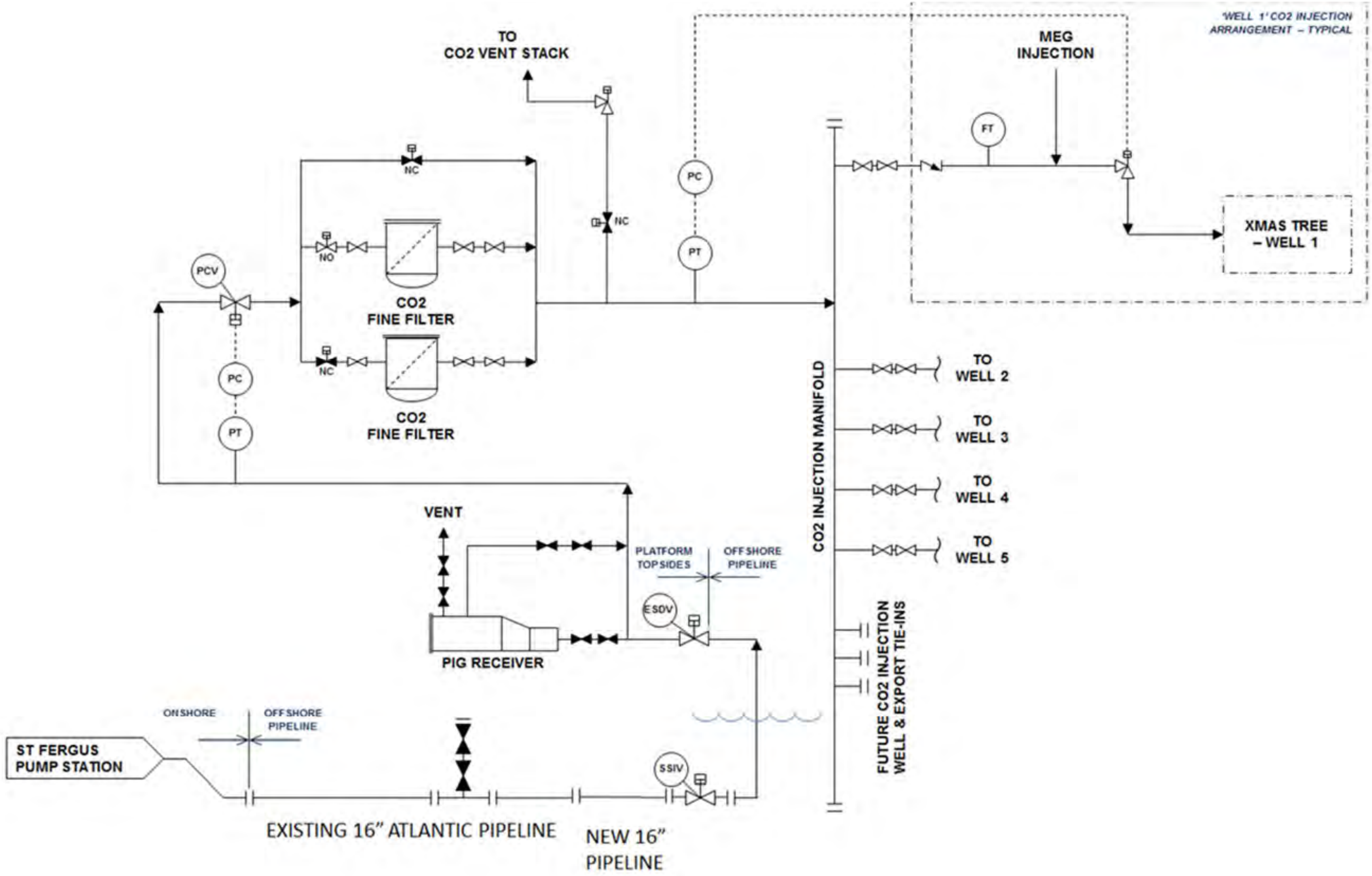



*Figure 5-11 Captain X Process flow diagram*

##### 5.4.2.1 Platform Infrastructure

**Jacket Design:**

A conventional 4-legged Steel Jacket has been assumed. The jacket will be piled to the seabed and will be sufficiently tall to ensure an air gap is maintained between the topsides structure and the 10,000 year return period wave crest height. The Jacket would be protected by sacrificial anodes and marine grade anti-corrosion coat paint.

**Jacket Installation:**

The Jacket will be fabricated onshore, skid loaded onto an installation barge, towed to site, and launched. Mudmats will provide temporary stability once the jacket has been upended and positioned; with driven piles installed and grouted to provide load transfer to the piled foundations.

**Topsides Design:**

The Installation topsides are proposed to be constructed as a single lift topsides module. A multi-level topsides module consisting of a Weather Deck, a Mid Level, a lower Cellar Deck and a cantilevered Helideck has been assumed.

The Weather deck will be of solid construction to act as a roof for the lower decks, it will provide a laydown area for the crane and house the HVAC package and VSAT domes. A Helideck will be cantilevered out over the Weather Deck.

The Mid Level deck will only partially cover the topsides footprint and will serve to house the Manifolding pipework, and Pig Receiver.

The Cellar Deck will house the Wellhead Xmas Trees and associated piping, a Master Control Station (MCS), Hydraulic Power Unit (HPU), power generation package, chemical and diesel tanks, Control and Equipment Room and Short Stay accommodation unit.

The Jacket and topsides will be sized and arranged so as to enable Jack-Up set up on two faces, in order to access the 4 well slots.

**Platform Power:**

Platform power will be provided by diesel-fuelled generators. Under normal unmanned operations a single generator will power the platform. When manned the electrical load increases (crane operations, HVAC etc) and two generators will provide the power with the third acting as a spare. Diesel storage will be sized to permit 90 days unmanned operation.

**Topsides Process:**

The primary Platform Injection facilities will consist of a topsides Emergency Shutdown Valve (ESDV), a pressure control valve (PSV) which will serve to safeguard the pipeline pressure and maintain the $CO_2$ in the pipeline in liquid phase, Fines Filters that will prevent solid contaminates entering the injection well bores, a vent stack to enable blowdown of the topsides pipework for maintenance, and an injection manifold which will facilitate injection of the $CO_2$ to the respective wells.

Topsides pig receiving facilities will also be provided to enable periodic pipeline integrity monitoring, there is no foreseen requirement for operational pigging. All the topsides process pipework will use low temperature stainless steel materials in the event that a low pressure event occurs (i.e. venting).

**Drains:**

An open hazardous drains system will exist to drain the drip trays from equipment in Environmental Pollutant service i.e. the fuel and chemical tanks, power generation package, and HPU. These drain sources shall be positioned below the weather deck to minimise rainwater runoff from the equipment into the hazardous open drain system. The hazardous open drains tank shall be emptied during routine maintenance. There is no foreseen requirement for a closed drains system.

**Closed Loop Hydraulic system:**

Topsides and tree valves will be hydraulically actuated and will utilise a water based hydraulic fluid. Dual redundant (2x100%) Hydraulic Power Units (HPUs) will be provided to allow offline maintenance.

**Crane:**

An electric crane will enable load transfer between vessel and NUI, and enable load transfer between the working decks of the installation.

#### *5.4.2.2 Rationale for Development Concept*

The following provides a brief overview of why a NUI Platform comprising a steel jacket and topsides has specifically been selected as the reference case for the Captain X development.

The Captain X development requires 2 injection wells (plus a monitoring well) over the 20 year field life. The proposed trajectories of the slant injector wells are such that they can be drilled from a single drill centre. The water depth at the proposed drilling location of Captain X is 115m. This is sufficiently shallow to enable the wells to be drilled by a Jack Up drill rig (heavy duty) cantilevered over a platform with 4 well slots (2 injectors + spare injector + spare slot).

From a commercial viewpoint the design, build and installation of a NUI platform will exceed the CAPEX of an entirely subsea development however this will be eroded by the increased CAPEX of drilling subsea wells (approximately 25% more expensive to drill and complete than dry wells) and the provision of power and control/chemical supplies from a suitable nearby host facility or from shore.

Platform based wells will also improve the availability of the injection wells due to more readily achievable and inexpensive maintenance and well intervention. The OPEX for intervening on subsea wells will typically exceed that of dry wells by an order of magnitude. A platform also enables the provision of enhanced process capabilities, including (where required) the provision of the following which are not readily achievable with subsea wells:

- Pre-injection filtering (filters pipeline corrosion / scaling products), which becomes more critical for a long pipeline and is especially critical when planning matrix (as opposed to fracture) injection.
- Choke heating.
- Physical sampling facilities to ensure $CO_2$ injection quality.
- Pressure monitoring of all well casing annuli for integrity monitoring.
- Future connections are easier as the connections are above water thereby avoiding water ingress into existing systems and it's easier to dry any future pipelines.

Providing the following process facilities to subsea wells is possible but will be more costly than for platform based wells:

- Process monitoring, and well allocation metering for reservoir management.
- Process chemical injection of MEG, and N2 for transient well conditions
- Pig receiver.

Due to the requirement of a heavy lift vessel to remove the platform and topsides at the end of field life the ABEX costs associated with decommissioning a NUI platform is likely to exceed that of a subsea development, however the P&A

(plug and abandonment) of subsea wells will be approximately 25% more costly than the P&A of platform wells

## 5.5 Other Activities in this Area

In addition to Atlantic and Cromarty there are a number of hydrocarbon fields in the vicinity of Captain X site, and along the pipeline route. These include Golden Eagle and Solitaire as shown in the figure below.


*Figure 5-12 Hydrocarbon fields in the vicinity of the Captain aquifer*

Other activities in the area that are pertinent to the Captain X development are fishing and shipping.

A protection philosophy should be produced for the Captain X development, the results of which should be adopted to ensure all risks are identified and mitigated/minimized. To ensure the risks of any interaction with dropped anchors or fishing gear are minimized it is also recommended that any new infrastructure associated with the Captain X development is entered into fishing and marine charting systems to notify other marine users.

## 5.6 Options for Expansion

The information available at the time of writing indicates that the Atlantic and Cromarty development included for pre-investment in a future tie-in structure at KP42 of the 16" Atlantic pipeline. This would facilitate future connections without the need for purging and flooding the existing pipeline. An alternative to tie-ing in via the tee structure is to perform a hot-tap operation. This is a considerably more expensive operation however it allows for flexibility for selection of the connection location. There is also a spare riser and J-tube included as part of the NUI (see Table 5-11).

There are a number of other potential storage sites and oil/gas developments that are located along the pipeline route and in the vicinity of Captain X which could be utilised for future build out of $CO_2$ storage / EOR.

The potential for EOR in the UK Sector of the Central North Sea is detailed in Energy Research Partnership's "Prospects for $CO_2$-EOR in the UKCS" report published in October 2015. Whilst potential $CO_2$-EOR candidate fields exist that could be serviced as a step out or from the tie-in point on the in-line tee (KP42), the publically available cessation of production date for these fields is typically 2028 or earlier. The potential fields that could benefit from EOR as detailed by Energy Research Partnership and which are within reasonable distance of the in-line tee structure or proposed NUI are Forties, Buzzard, Nelson, and Alba. As stated the cessation of production dates for these fields may predate 2022 and potential suitability for EOR has been appraised based only upon publically available data.

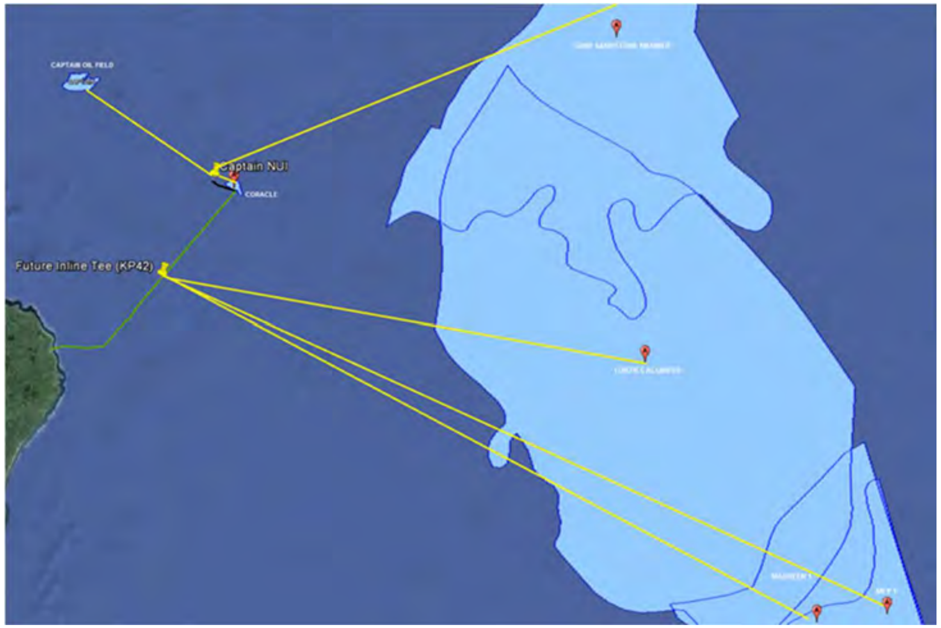



*Figure 5-13 Options for expanding the development*

So whilst a credible consideration, $CO_2$ supply for EOR purposes design consideration within the Captain proposed $CO_2$ storage development proposal is limited to the utilisation of the tie-in structure at KP42, or the spare riser on the Captain X NUI, to potentially service Buzzard. However, given the proposed time frame of this development (2022 to 2042) further feasible EOR prospects could be found in this area.

It can be seen from the figure below that there are a large number of potential further $CO_2$ storage sites surrounding the Captain aquifer. These have been checked against the WP3 rankings, and those in the top 20 list have been extracted from $CO_2$Stored and are summarised in the table below. These sites could be developed as step outs from the Captain X NUI or tied in via the future tie-in structure at KP42.

| Site | WP3 Ranking | Tie-in Distance (Centre of Site) [1] | Tee / Tie-Back |
|---|---|---|---|
| **Forties 5** | 3 | 140km | Either |
| **Grid Sandstone Member** | 9 | 212km | Tie-Back |
| **Mey 1** | 10 | 234km | Tee (KP42) |
| **Maureen 1** | 11 | 224km | Tee (KP42) |
| **Coracle Aquifer** | 15 | 8km | Tie-Back |
| **Captain Oil Field** | 16 | 48km | Tie-Back |

*Table 5-12 Options for expansion (Top 20 WP3 sites)*

Notes:

1. This is the distance to the centre of the site and therefore there is scope to optimise the drill centre location for the Captain X NUI

The figure below shows the oil/gas developments located along the pipeline route and in the vicinity of the chosen location for the Captain X NUI.


*Table 5-13 Options for expanding the development - hydrocarbon fields*

## 5.7 Operations

The Captain X development will inject $CO_2$ at a constant injection rate of 3 MTPA, via 2 platform based injector wells plus a monitoring well throughout the 20 year field life.

The Captain X platform will be a Normally Unmanned Installation (NUI), and will be capable of operating unattended for approximately 3 months (90 days). The NUI will be controlled from the beach, utilizing dual redundant satellite links.

The NUI will require regular IMR (Inspection, Maintenance and Repair), and it is envisaged that visits will typically be required every six weeks. Routine maintenance activities will include the following:

- Replenishing chemicals;
- Replenishing fuel (for emergency back-up generator, as required);
- IMR of diesel generators;
- IMR of emergency power generation system;
- IMR of lifeboats;
- IMR of telecommunications system (satellite comms);
- IMR of mechanical handling (crane);
- IMR of HVAC system;
- IMR of venting system;
- IMR and certification of metering system for $CO_2$ injection;
- IMR of chemical injection system including pumps, tanks and associated equipment;
- IMR of $CO_2$ filters;
- IMR of hazardous open drains (drain tanks, heaters and pumps);
- IMR of non-hazardous open and closed drains (drain tanks, heaters and pumps);
- IMR of fire and gas detection systems, fire pumps and firewater systems;
- IMR of nitrogen system;
- IMR of emergency power generation system;
- Painting (fabric maintenance);
- Cleaning.

The pipelines will also require regular IMR. This will include regular (typically bi-annual) surveys (ROV) to confirm integrity. Although pigging facilities are available, the frequency will be minimal subject to an integrity management risk assessment of the control of the $CO_2$ quality.

## 5.8 Decommissioning

The decommissioning philosophy assumed for the Captain X facilities is as follows:

Note that this philosophy is subject to the outcome of the comparative assessment process and subsequent approval by DECC.

- Wells plugged and abandoned.
- Topsides facilities are cleaned, prepared and disconnected.
- Removal of Topsides (reverse installation).
- Steel jacket completely removed and taken ashore for dismantling and recycling.
- Pipelines are cleaned and left in place, part end recovery and ends protected by burial/rockdump.
- 16” pipelines are assumed to be covered by the UK fisheries offshore oil and gas legacy trust fund.
- Pipeline spools to be recovered.
- Subsea structures to be recovered (SSIV and anode skids).
- Subsea concrete mattresses and grout bags recovered.

## 5.9 Post Closure Plan

The aim of post-injection/closure monitoring is to show that all available evidence indicates that the stored $CO_2$ will be completely and permanently contained. Once this has been shown the site can be transferred to the UK Competent Authority.

In the Captain aquifer, this translates into the following performance criteria:

1. The $CO_2$ has not migrated laterally or vertically from the storage site. (This is not necessarily the original site, if $CO_2$ has migrated then the site will have been extended and a new volume licensed.)
2. The $CO_2$ within the structural containment storage site has reached a gravity stable equilibrium. Any $CO_2$ in an aquifer storage containment site is conforming to dynamic modelling assumptions – i.e. its size and rate of motion match the modelling results.
3. The above are proven by two separate post closure surveys – with a minimum separation of five years.

The post closure period is assumed to last for a minimum of 20 years after the cessation of injection. During this time monitoring will be required, as detailed in Appendix 5.

## 5.10 Handover to Authority

Immediately following the completion of the post closure period the responsibility for the Captain X $CO_2$ storage site will be handed over to the UK Competent Authority. It is anticipated that a fee, estimated at ten times the annual cost of post closure monitoring will accompany the handover.

## 5.11 Development Risk Assessment

The following development risks have been identified:

Pipeline Acquisition: It is recommended that discussions with BG (and possibly Shell) are progressed at the earliest opportunity in order to establish the feasibility acquiring the 16” Atlantic pipeline.

Pipeline Integrity: A full pipeline integrity and life extension study will be required to confirm the suitability of the 16” Atlantic pipeline for $CO_2$ service over 20 years.

Survey data: A full pipeline route survey is required. There is a risk that this may identify unknown seabed obstructions or features that will necessitate route deviations.

$CO_2$ composition/chemistry: This is unknown and therefore there is a risk of it being significantly different than that assumed throughout this study, with unforeseen consequences. There are going to be challenges operating the system in an operating pressure window that is affected by impurities, temperature fluctuations and well performance. Thorough steady state and transient modelling of these effects is required and may require strict control during operations.

The water depth of the proposed location enables drilling to be performed by a Jack-Up drill rig.  However it should be noted that local geotechnics may dictate that a semi-submersible drill rig may be required.

The following opportunities have been identified and should be considered as part of further work:

- Value Engineering: A value engineering exercise should be carried out to assess all equipment to ensure all specified equipment is technically justified in its application and not included on the basis of accepted oil and gas practice. Some examples are provided below.$CO_2$ Screens: A reduction in CAPEX and OPEX could be realized by removing the requirement for $CO_2$ screens.
- Venting: Opportunity to remove the requirement for venting, with all venting performed from the beach.
- Pig Receiver: Temporary v Permanent. Should permanent facilities not be required this will result in a reduction in topsides weight and the associated savings in CAPEX/OPEX.
- SSIV: Requirement for an SSIV can be challenged during FEED and potentially omitted which would reduce the requirement for increased pressure rating of the riser and associated piping between SSIV and ESDV, to account for thermal expansion of riser inventory during shut in.
- SSIV Location: If it is not possible to remove the requirement for an SSIV the location should be optimized with consideration to the impact of the riser volume on temporary refuge specification.
- Helideck:  A significant reduction in cost may be realised by removing the Helideck and relying on Walk to Work vessels for platform visits. Helidecks have typically been specified for hydrocarbon producing NUI's due to the requirement for personnel to be on the facility to restart production following a shutdown, and the associated cost of deferred production until the restart can be enacted.  Removing this requirement by enabling remote restart of $CO_2$ injection will improve uptime and negate the requirement for a Helideck for platform visits.
- Pipeline design to be progressed to confirm wall thickness and remove uncertainties in mechanical design. Pipeline design to be performed to either PD8010 Part 2 or DNV OS F101, and should follow the requirements of DNV RP J202.  A reduction in pipe wall thickness may be possible by increasing the grade of steel or use of non-standard thicknesses.
- Geotechnical data – a lack of site specific geotechnical data can lead to foundation redesign with significant cost impact.  Geotechnical risk should be mitigated by early development of desktop study and geotechnical testing programme performed/supervised by experienced geotechnical specialists.

- Risk of pipeline leak/rupture – ensure pipeline is designed in accordance with DNV RP J202 Design and Operation of $CO_2$ pipelines, for the full range of design conditions, with an appropriate corrosion and fishing protection measures, integrity management plans and operating procedures.
- There may be a limited number of vendors globally capable of producing valves suitable for $CO_2$ service of the required bore and specification. Design and prequalification by vendors may incur additional cost and time.
- Legislation – development of UK legislation could result in modifications to facilities requirements (e.g. emissions, safety case requirements, MMV).
- Seabed conditions may require expensive seabed intervention to avoid pipeline instability and free-spanning. Metocean and geophysical surveys are required to confirm seabed conditions.

# 6.0 Budget & Schedule

## 6.1 Schedule of Development

A level 1 schedule (up to first $CO_2$ injection) has been produced and is included in Figure 6-1. The schedule is built up using the same breakdown structure as the cost estimate to allow for cost scheduling and is based on the following assumptions:

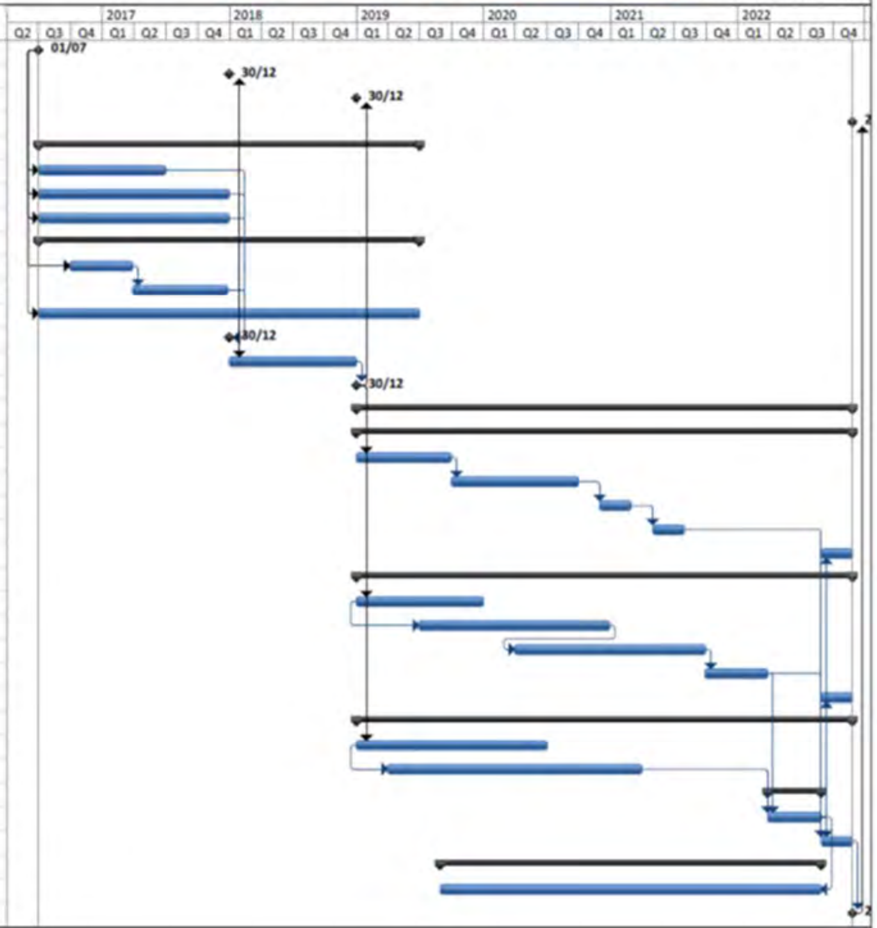
- Project kick off summer 2016.
- 12 months of EPC ITTs, contract and financing negotiation prior to FID.
- Project sanction / FID end of the year 2018.
- Detailed design commences immediately following sanction.
- Captain X NUI jacket and topsides installed prior to drilling (facilities on critical path).
- The pipeline and facilities are pre-commissioned following completion of construction.
- Drilling and completing of the two platform injector wells commencing 2022.
- The pipeline, facilities and wells are commissioned in a continuous sequence of events.
- First $CO_2$ injection Q4 2022 which coincides with the projected supply profile

Total project duration from pre-FEED to first injection is projected to be just over 6 years.

WP5 Captain Schedule

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

| ID | Project Phase ID | Task Name | Duration | Start | Finish |
|---|---|---|---|---|---|
| 1 | MS0 | Start of Project | 0 days | Fri 01/07/16 | Fri 01/07/16 |
| 2 | MS1 | End of FEED | 0 days | Sat 30/12/17 | Sat 30/12/17 |
| 3 | MS2 | Final Investment Decision | 0 days | Sun 30/12/18 | Sun 30/12/18 |
| 4 | MS3 | First Injection | 0 days | Fri 25/11/22 | Fri 25/11/22 |
| 5 | **A** | **A. Pre-Final Investment Decision (Pre-FID)** | **1095 days** | **Fri 01/07/16** | **Sun 30/06/19** |
| 6 | A1.1 | Transportation | 365 days | Fri 01/07/16 | Fri 30/06/17 |
| 7 | A1.2 | Facilities | 548 days | Fri 01/07/16 | Sat 30/12/17 |
| 8 | A1.3 | Wells | 548 days | Fri 01/07/16 | Sat 30/12/17 |
| 9 | **A1.4** | **Other** | **1095 days** | **Fri 01/07/16** | **Sun 30/06/19** |
| 10 | A1.4.2 | Seismic and Baseline Survey | 180 days | Thu 29/09/16 | Mon 27/03/17 |
| 11 | A1.4.3 | Engineering and Analysis | 273 days | Tue 28/03/17 | Mon 25/12/17 |
| 12 | A1.4.4 | Licencing and Permits | 1095 days | Fri 01/07/16 | Sun 30/06/19 |
| 13 | MS1 | End of FEED | 0 days | Sat 30/12/17 | Sat 30/12/17 |
| 14 | | EPC Contract and Financing Period | 365 days | Sun 31/12/17 | Sun 30/12/18 |
| 15 | MS2 | FID | 0 days | Sun 30/12/18 | Sun 30/12/18 |
| 16 | **B** | **B. Post-Final Investment Decision (Post-FID)** | **1426 days** | **Mon 31/12/18** | **Fri 25/11/22** |
| 17 | **B1.1** | **Transportation** | **1426 days** | **Mon 31/12/18** | **Fri 25/11/22** |
| 18 | B1.1.1 | Detailed Design | 273 days | Mon 31/12/18 | Sun 29/09/19 |
| 19 | B1.1.2 | Procurement | 365 days | Mon 30/09/19 | Mon 28/09/20 |
| 20 | B1.1.3 | Fabrication | 90 days | Sun 29/11/20 | Fri 26/02/21 |
| 21 | B1.1.4 | Construction and Pre-Commissioning | 90 days | Sat 01/05/21 | Thu 29/07/21 |
| 22 | B1.1.4.1 | Pipeline Commissioning | 90 days | Sun 28/08/22 | Fri 25/11/22 |
| 23 | **B1.2** | **Facilities** | **1426 days** | **Mon 31/12/18** | **Fri 25/11/22** |
| 24 | B1.2.1 | Detailed Design | 365 days | Mon 31/12/18 | Mon 30/12/19 |
| 25 | B1.2.2 | Procurement | 548 days | Sat 29/06/19 | Sun 27/12/20 |
| 26 | B1.2.3 | Fabrication | 548 days | Mon 30/03/20 | Tue 28/09/21 |
| 27 | B1.2.4 | Construction and Commissioning | 180 days | Tue 28/09/21 | Sat 26/03/22 |
| 28 | B1.2.4.1 | Platform Commissioning | 90 days | Sun 28/08/22 | Fri 25/11/22 |
| 29 | **B1.3** | **Wells** | **1426 days** | **Mon 31/12/18** | **Fri 25/11/22** |
| 30 | B1.3.1 | Detailed Design | 548 days | Mon 31/12/18 | Tue 30/06/20 |
| 31 | B1.3.2 | Procurement | 730 days | Sun 31/03/19 | Mon 29/03/21 |
| 32 | **B1.3.4** | **Construction and Commissioning** | **154 days** | **Sun 27/03/22** | **Sat 27/08/22** |
| 33 | B1.3.4.1 | Injectors 1 and 2 + Spare Well | 154 days | Sun 27/03/22 | Sat 27/08/22 |
| 34 | B1.3.4.3 | Wells Commississioning / First Injection | 90 days | Sun 28/08/22 | Fri 25/11/22 |
| 35 | **B1.4** | **Other** | **1095 days** | **Thu 29/08/19** | **Sat 27/08/22** |
| 36 | B1.4.1 | Approvals and Consents | 1095 days | Thu 29/08/19 | Sat 27/08/22 |
| 37 | **MS3** | **First Injection** | 0 days | Fri 25/11/22 | Fri 25/11/22 |




Date: 11/02/2016

*Figure 6-1 Summary level project schedule*

## 6.2 Budget

The costs associated with the capital (CAPEX), operating (OPEX) and abandonment (ABEX) phase expenditures have been calculated for the engineering, procurement, construction, installation, commissioning, operation and decommissioning of the Captain X facilities. The OPEX has been calculated based on a 20 year design life. A 30% contingency has been included throughout.

An overview of the Captain X development (transportation, facilities, wells) is given in Section 5. The cost estimate is made up of the following components:

- Utilise the existing 16" Atlantic and Cromarty pipeline from St Fergus to Atlantic (via an acquisition from BG International);
- Captain X NUI (jacket and topsides);
- Two platform wells, plus a spare injector for field life of 20 years.

### 6.2.1 Cost Estimate Summary

The cost estimate summary for the Captain X development is outlined in Table 6-1. These numbers are current day estimates for the base case development. Details are provided in Appendix 8.

In the tables that follow estimates are provided in Real, 2015 terms and Nominal, 2015 PV10 terms.

- Real, 2015. These values represent current-day estimates and exclude the effects of cost escalation, inflation and discounting.
- Nominal, 2015 PV10. These values incorporate the time value of money into the estimates (i.e. including the effects of cost escalation and inflation (2%) that are then discounted back to a common base year of 2015 using an annual discount rate of 10%).

Unless specified otherwise, costs are presented in real, 2015 terms.

| Category | Total Captain X Development (£ MM) |
|---|---|
| **CAPEX** | 231.8 |
| **OPEX** | 384.6 |
| **ABEX** | 187.2 |
| **Total Cost** | 803.6 |
| **Cost $CO_2$ Injected (£ per Tonne)** | 13.39 |

*Table 6-1 Captain X development cost estimate summary*

It should be noted that the cost estimates in Table 6-1 are 2015 estimates for 2015 activity and the present value estimates are provided in Table 6-2.

| Category | £millions ($PV_{10}$, Nominal 2015) |
|---|---|
| **Capex** | 152 |
| **Opex** | 110 |
| **Abex** | 11 |
| **Total Cost** | 278 |
| **Injected Volume (PV10 Mt)** | 13 |
| **Cost $CO_2$ Injected (£/T, PV10)** | 21.2 |

*Table 6-2 Project cost estimate summary ($PV_{10}$, Nominal 2015)*

The cost over time is illustrated in Figure 6-2 (values are not inflated or discounted).

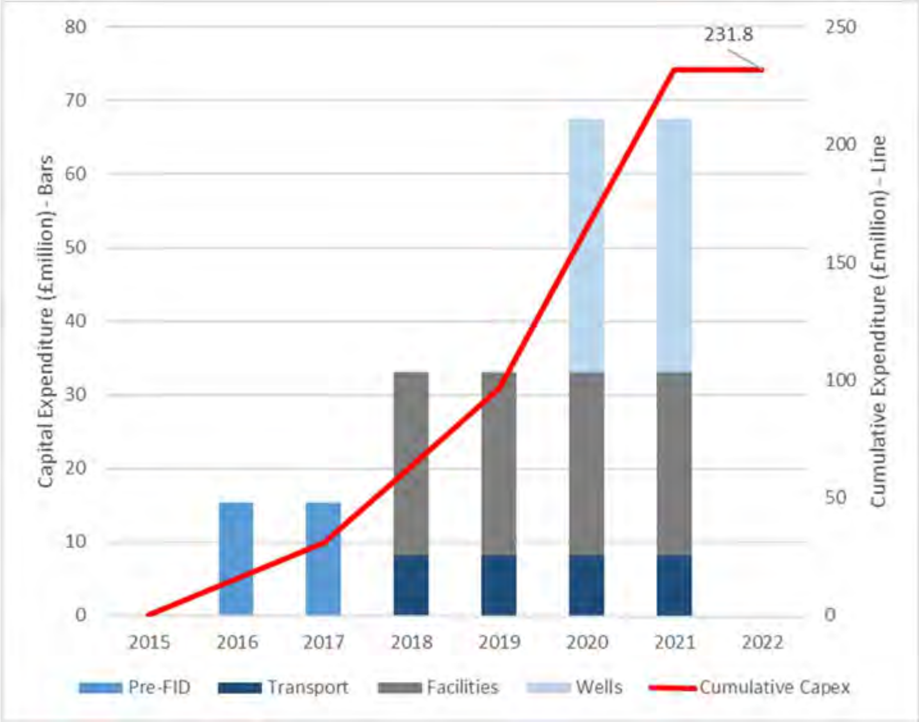



*Figure 6-2 Captain X Phasing of capital spend*

### 6.2.2 Life Cycle Costs

The total project costs, inflated at 2% p.a. with a discount factor of 10% p.a., are summarised in Table 6-3.

| Category | £millions (PV10, 2015 Nominal) |
|---|---|
| Transportation | 22 |
| Facilities | 72 |
| Wells | 59 |
| Opex | 110 |
| Decommissioning & Post Closure Activity | 15 |
| Total | 278 |

*Table 6-3 Project cost estimate by component*

Details of when these costs are incurred based on 2015 spending activity are shown in Figure 6-3.

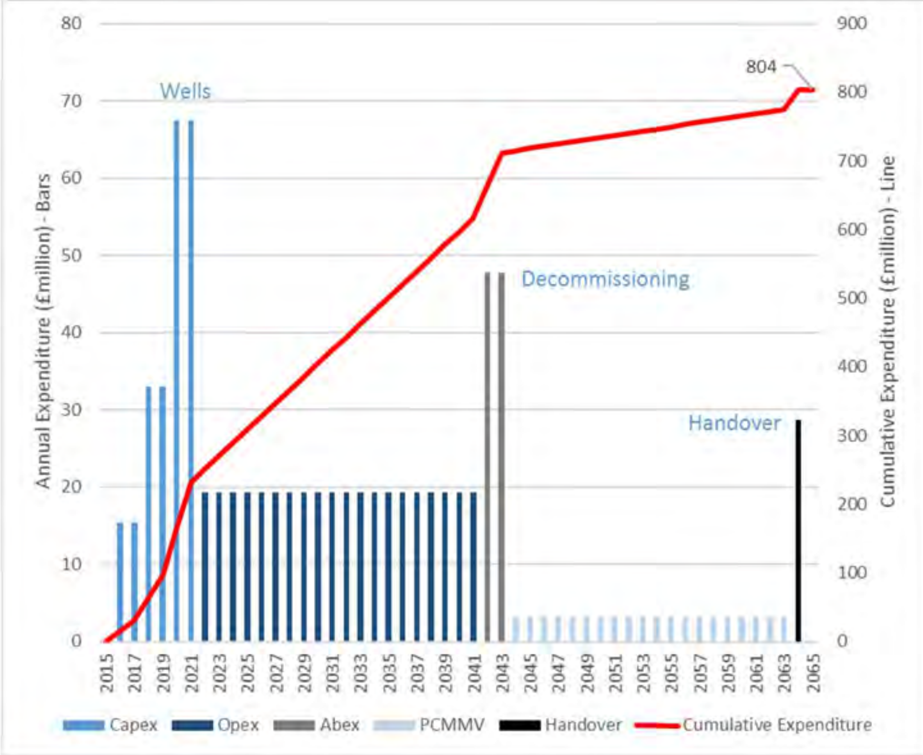



*Figure 6-3 Elements of cost over project lifetime*

#### *6.2.2.1 Capital Expenditure*

The CAPEX estimates for the Captain development are summarised in the following tables. The costs are split up into transportation, facilities, wells and "other". The cost estimates in these tables are in 2015 Real terms.

| Phase | Category | Total Captain X Development (£ MM) |
|---|---|---|
| Pre-FID | Pre-FEED | 0.4 |
| | FEED | 0.6 |
| Post-FID | Detailed Design | 0.7 |
| | Procurement | 5.1 |
| | Fabrication | 4.9 |
| | Construction & Commissioning | 22.0 |
| **Total CAPEX – Transportation (£MM)** | | 33.7 |

*Table 6-4 Captain X development - transport CAPEX (Base case)*

The current base case for the Captain X $CO_2$ storage development consist of utilising the existing 16" Atlantic and Cromarty pipeline from St Fergus to Atlantic (via an acquisition from BG International) under a leasing arrangement. Purchase alternatives are an alternative which should be considered in further work. If it were not possible to acquire this pipeline, due to integrity issues or an unwillingness within BG (or Shell) to transfer ownership, then a new pipeline from St Fergus to the Captain X NUI will be required. The transportation CAPEX for this scenario is summarised in the table below. It can be seen that the CAPEX associated with a new pipeline is approximately £100 MM.

| Phase | Category | Total Captain X Development (£ MM) |
|---|---|---|
| Pre-FID | Pre-FEED | 0.4 |
| | FEED | 0.6 |
| Post-FID | Detailed Design | 0.7 |
| | Procurement | 30.7 |
| | Fabrication | 8.5 |
| | Construction & Commissioning | 60.0 |
| **Total CAPEX – Transportation (£MM)** | | 101.7 |

*Table 6-5 Captain X development - transport CAPEX (New pipeline system)*

The CAPEX for the Captain X NUI (jacket + topsides) was generated using the Que$tor cost estimating software, and benchmarked using Costain Norms.

| Phase | Category | Total Captain X Development (£ MM) |
|---|---|---|
| Pre-FID | Pre-FEED | 2.8 |
| | FEED | 5.7 |
| Post-FID | Detailed Design | 16.9 |
| | Procurement | 28.1 |
| | Fabrication | 25.4 |
| | Construction & Commissioning | 29.1 |
| **Total CAPEX – Facilities (£MM)** | | 108.0 |

*Table 6-6 Captain X development - Facilities CAPEX*

The well expenditure (CAPEX) for the Captain X development is summarised in the following table.

| Phase | Category | Total Captain X Development (£ MM) |
|---|---|---|
| Pre-FID | Pre-FEED / FEED PM&E | 2.9 |
| Post-FID | Detailed Design | 2.9 |
| | Procurement | 14.1 |
| | Construction and Commissioning (Drilling) | 49.3 |
| **Total CAPEX – Wells (£MM)** | | 69.2 |

*Table 6-7 Captain X development - Wells CAPEX*

| Phase | Category | Total Captain X Development (£ MM) |
|---|---|---|
| Pre-FID | Seismic and Baseline Survey | 12.9 |
| | Appraisal Well | - |
| | Engineering and Analysis | 2.9 |
| | Licencing and Permits | 2.6 |
| Post-FID | Licencing and Permits | 2.6 |
| **Total CAPEX – Other Costs (£MM)** | | 21.0 |

*Table 6-8 Captain X development - Other CAPEX*

#### 6.2.2.2 Operating Expenditure

The 20 year OPEX for the Captain X development has been estimated to be £384.6 million based on the following:

- Transportation at 1% of pipeline CAPEX per year
- Offshore facilities at 6% of facilities CAPEX per year
- Wells based on requiring workovers and local sidetracks as described in Section 3 of the report.
- Other, as summarised in Table 6-9.

A breakdown of the OPEX associated with "Other" costs is presented below.

| OPEX Estimate | Total Captain X Development (£ MM) |
|---|---|
| **Measurement, Monitoring and Verification** | 51.1 |
| **Financial Securities** | 60.6 |
| **Ongoing Tariffs and Agreements[1]** | 52.0 |
| **Total** | 163.7 |

*Table 6-9 Captain X development - Other OPEX*

Notes:

1. It is assumed that the supplier covers 3rd party tariffs

#### 6.2.2.3 Abandonment Expenditure

Abandonment costs for the Captain X $CO_2$ transportation (pipeline) system has been estimated at 10% of transportation CAPEX.

The decommissioning costs for the offshore facilities are summarised in the table below, these costs were also generated using Que$tor.

| ABEX Decommissioning | Total Captain X Development (£ MM) |
|---|---|
| **Transportation** | 4.8 |
| **Facilities** | 65.3 |
| **Wells** | 25.5 |
| **Total** | 95.6 |

*Table 6-10 Captain X development - facilities ABEX*

A breakdown of the ABEX associated with other is presented below.

| Other | Total Captain X Development (£ MM) |
|---|---|
| **Post Closure Monitoring** | 63.0 |
| **Handover** | 28.6 |
| **Total** | 91.6 |

*Table 6-11 Captain X development - Other ABEX*

## 6.3 Economics

This section summarises the cost based economic metrics for the proposed development.

The contribution of each major element of the development to the overall cost is summarised in the following sections.

### 6.3.1 Project Component Costs

| £million | Real (2015) | Nominal (MOTD) | $PV_{10}$ (Nominal, 2015) |
|---|---|---|---|
| **Transport** | 34 | 37 | 22 |
| **Facilities** | 108 | 118 | 72 |
| **Wells** | 90 | 99 | 59 |
| **Opex** | 385 | 537 | 110 |
| **Decommissioning & Post Closure Activity** | 187 | 372 | 15 |
| **Total** | 804 | 1162 | 278 |

*Table 6-12 Captain X development cost in real and nominal terms*

### 6.3.2 Transportation and Storage Costs

The contribution of each major element of the development to the overall cost is summarised below.

| £million | Real (2015) | Nominal (MOTD) | $PV_{10}$ (Nominal, 2015) |
|---|---|---|---|
| **Transportation** | 48 | 57 | 25 |
| **Injection** | 756 | 1105 | 253 |
| **Total** | 804 | 1162 | 278 |

*Table 6-13 Captain X total transportation and storage costs*

### 6.3.3 Unit Costs

The unit costs of the development are summarised in the tables below.

| £/T | Real (2015) | Levelised ($PV_{10}$, Real, 2015) | Nominal (MOTD) | Levelised ($PV_{10}$, Nominal, 2015) |
|---|---|---|---|---|
| **Transportation** | 1 | 2 | 1 | 2 |
| **Injection** | 12 | 16 | 18 | 19 |
| **Total** | 13 | 18 | 19 | 21 |

*Table 6-14 Captain X transport and storage costs per tonne of $CO_2$*

Note: The levelised cost includes the discounted value of the $CO_2$ stored (13MT rather than the undiscounted value of 60MT).

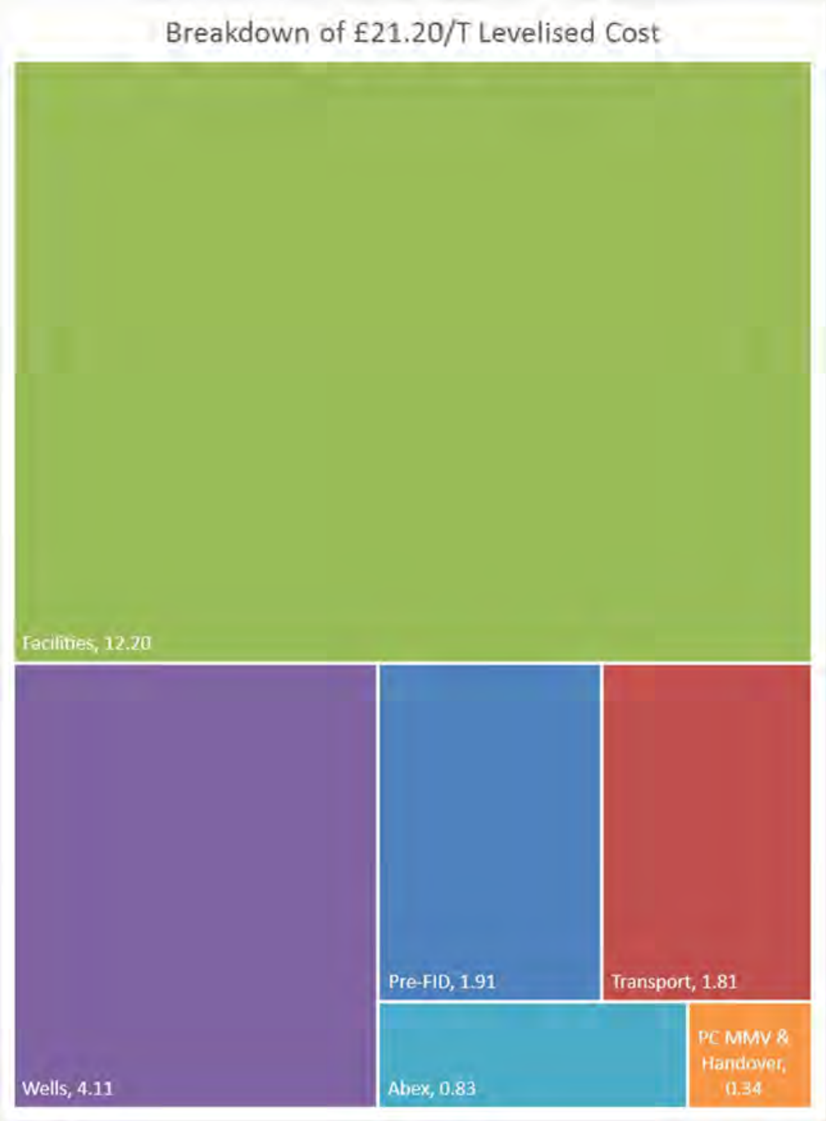



*Figure 6-4 Breakdown of Levelised Costs*

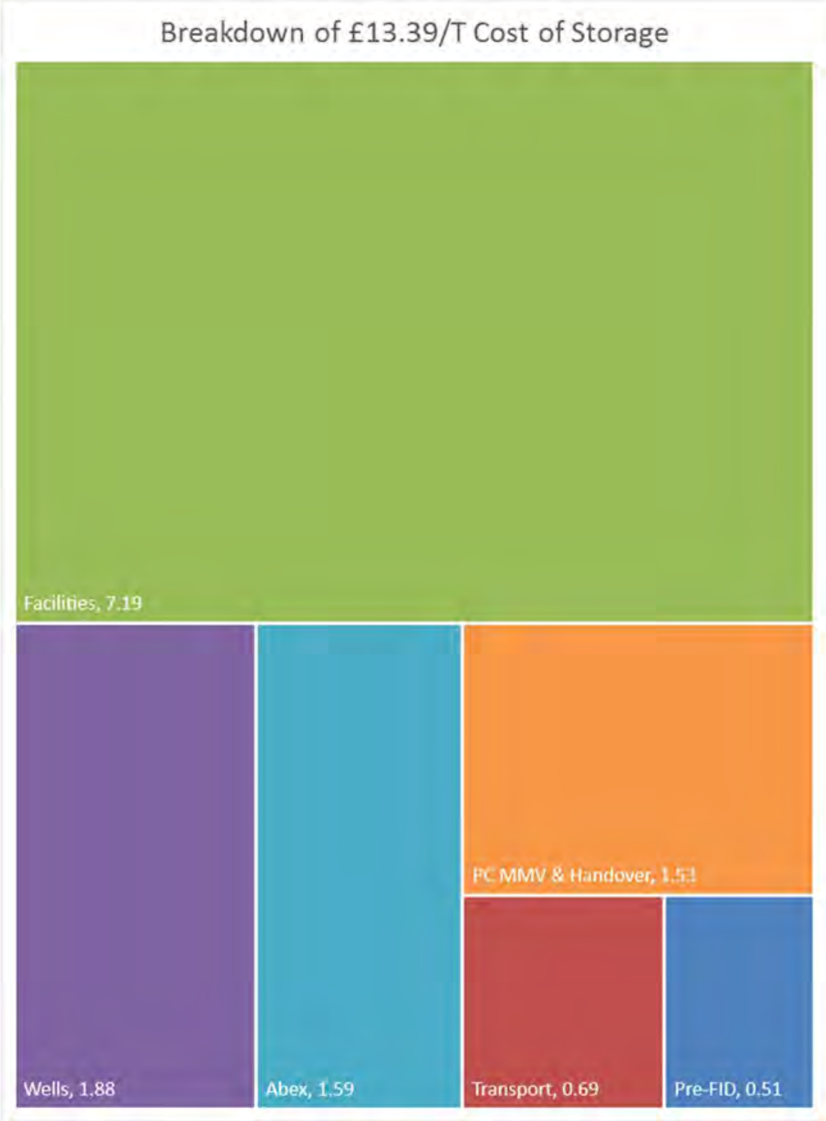



*Figure 6-5 Breakdown of Life-cycle Cost*

The charts shown in Figure 6-4 and Figure 6-5 show the components of unit cost on a levelised and real basis and illustrate the relative rank of each component for the two calculations. The levelised cost calculation (DECC, 2013) includes both inflation and discounting and therefore shows the impact of the timing of the timing of expenditure and injection. Thus expenditure far in the future such as MMV and handover (dark blue rectangles) appear smaller than on an undiscounted basis, as shown in Figure 6-5.

The variation between the Levelised and Real cost is due to both the timing of the expenditures as well as the rate at which the expenditure takes place.

| £/T | Real (2015) | Levelised ($PV_{10}$, Real, 2015) | Nominal (MOTD) | Levelised ($PV_{10}$, Nominal, 2015) |
|---|---|---|---|---|
| **Pre-FID** | 0.51 | 1.85 | 0.53 | 1.91 |
| **Transport** | 0.69 | 1.63 | 0.80 | 1.81 |
| **Facilities** | 7.19 | 10.06 | 9.54 | 12.20 |
| **Power** | 0.00 | 0.00 | 0.00 | 0.00 |
| **Wells** | 1.88 | 3.56 | 2.30 | 4.11 |
| **Abex** | 1.59 | 0.48 | 2.75 | 0.83 |
| **PC MMV & Handover** | 1.53 | 0.16 | 3.46 | 0.34 |
| **Total** | 13.39 | 17.74 | 19.36 | 21.20 |

*Table 6-15 Unit Costs in Detail*

# 7.0 Conclusions & Recommendations

## 7.1 Conclusions

**Data**

- The PGS Central North Sea Megasurvey volume covers approximately >95% of Site X and has been interpreted. In this area the dataset comprises multiple seismic volumes that are 1990 – 2003 vintage.
- There is good regional well coverage and good well data available within the storage complex, including modern logs and core data.

**Containment**

- The primary seal is provided by the marls and mudstones of the Rodby Formation which is 90 – 100m thick over the site and its distribution can be confidently mapped across the fairway where it is a proven seal for hydrocarbon fields.
- The storage complex has been defined as the subsurface volume between the Top Lista Formation and Base Cretaceous, and between the Grampian Arch to the south east and the Blake oilfield in the north west.
- There is a reasonable degree of confidence that around 60Mt of $CO_2$ can be contained within the Captain Sandstone in Site X of the Captain aquifer unit.
- 1000 years after the cessation of injection the $CO_2$ plume is still contained within the Storage Complex.
- Plume migration pattern is very sensitive to the Top Captain structure depth map. This in turn carries significant uncertainty due to the poor seismic imaging of the Top Captain event and the complex velocity field in the overburden.
- The initial Storage Complex boundary could be adjusted in subsequent studies to provide additional certainty around containment within the planned lease area.
- Underlying the Captain Sandstone are the shales and marls of the Valhall Formation which form an effective base seal.
- Site X also encompasses the Atlantic, Cromarty and Blake hydrocarbon fields which may provide a degree of structural containment.
- Reservoir quality is excellent and the nature and continuity of the high permeability intervals are likely to have a significant influence on the evolution of the $CO_2$ plume.

**Site Characterisation**

- Site X covers an area of 344 $km^2$ towards the east of the Captain aquifer in UKCS quadrants 13 & 14, approximately 100 km from Aberdeen.
- The Captain Sandstone is a sand-rich turbidite fan system deposited as a 5-10km wide ribbon of sand along the southern edge of the Halibut Horst in the Central North Sea.

- Reservoir properties are excellent: net-to-gross is typically >75%, average porosity is 25% and the average permeability is over 1400mD.
- The key horizons have been identified, interpreted and mapped. Seismic data quality is considered adequate for structural interpretation of the overburden but inadequate for accurate depth mapping of the Top or Base Captain Sandstone.
- Seismic imaging of the Captain Sandstone is hindered by a lack of impedance contrast at the top and base of the Captain Sandstone reservoir. Seismic attributes extracted from the full stack 3D seismic volume available to this project, within the Captain Sandstone produced no useful results.
- The main reservoir event is a difficult and incoherent pick over the whole site. The lack of acoustic impedance contrast for the interpretation of the Top Captain Sandstone, coupled with an important, but second order depth conversion challenge means that there is considerable pick and therefore depth uncertainty away from well control. This challenge has been one of the primary issues for petroleum developments in the area.
- There is no clear evidence of any significant faulting in the reservoir or primary cap rock of the Captain storage site X that is considered likely to breach the primary cap rock.
- Generally, the Top Captain Sandstone dips gently at 1 to 2 degrees to the south-east but is up to 15 degrees in the area to the west of the injection site.
- Well density is relatively high within the site and consequently there is a high degree of confidence about the reservoir quality across the site.

**Capacity**

- The primary storage unit is the Captain Sandstone of the Cromer Knoll Group.
- Significant volumes of $CO_2$ can be injected into the Captain X site, however no more than 60MT can be contained within the defined storage complex.
- 1000 years after injection stops, 10% of the injected inventory is structurally trapped, 10% residually trapped, 6% in solution and the remaining 74% continues to be mobile, travelling at less than 10m/year.
- Dynamic storage efficiency is limited at 1-2% and predominantly controlled by the high vertical permeability and structure mapping.

**Appraisal**

- The Captain aquifer system has had almost 100 wells drilled through it and can be considered to be well appraised.
- The remaining key uncertainties relating to $CO_2$ storage are structural mapping and plume migration, neither of these can be resolved by an appraisal drilling programme.
- Significant production or pressure exists and would be useful in building a more comprehensive understanding of the regional connectivity, only limited amounts of these data were available to this study.

- The seismic interpretation challenges experienced on this project have also been reported by others (Shell, 2015).

**Development**

- Final Investment Decision needs to be in 2018 in order to achieve the first injection data of 2022.
- The planning work indicates that approximately 6 years are required to appraise and develop the store.
- A single-phase development is proposed, comprising a platform in the southern part of the site, two active injection wells and a back-up well.
- The 20 year, 3-well development is designed to accommodate the Reference Case supply profile of 3Mt $CO_2$/year from 2022 and terminating in 2041.
- It is considered feasible to reuse the 16" pipeline between St. Fergus and the depleted Atlantic field. It was installed in 2006 and ceased production in 2009 and so has been active for only a small proportion of its 20-year design life.
- A £152 million capital investment (in present value terms discounted at 10% to 2015) is required to design, build, install and commission the pipeline, platform and wells. This represents £2.53/t for the 60Mt Reference Case. The levelised cost of ownership is £21.2/t.
- The Reference Case development includes a combination of reused and new infrastructure: a new minimum facilities platform, 78 km of reused 16" pipeline from St Fergus, a 16", 8km step out to the platform, 2 active injection wells and a back-up injection well.
- The main opportunities for potential cost reductions are: price reduction due to quantity of pipeline materials, commercial optimisation of pipeline size (i.e. standard versus non-standard sizes), well intervention frequency and cost. Subsea development may also offer some cost savings.
- The ability to monitor the extent and development of the plume is limited by the seismic interpretation challenges.
- The risk associated with the uncertainty in plume development could be managed to some extent by reducing the injection inventory.

**Operations**

- The safe operating envelope for the wells is based on a fracture pressure gradient of 0.156bar/m determined by geomechanical analysis. At the top perforation depth of 1,832m (tvdss) the fracture pressure is 302 bar.
- The maximum allowable reservoir pressure within the simulation model has been constrained to 90% of the fracture pressure. This is depth-dependent and at the top perforation depth equates to 257 bar.
- The design accommodates up to 130 bar arrival pressure of the $CO_2$ supply at the platform to enable injection through the life of the project. This would require a discharge pressure of approximately 156 bar from the pump station at St Fergus.

## 7.2 Recommendations

### Appraisal Programme

- Procure a modern 3D seismic volume capable of imaging the Top Captain Sandstone.
- Complete a detailed rock physics study and seismic acquisition analysis to confirm whether imaging at the Top Captain event might be improved with new seismic data.
- Evaluate the TGS-Nopec seismic volume over the Captain X area. This dataset includes offset (angle) stacks that are often useful in creating improved data quality in challenging areas.
- Consider acquiring a new broadband seismic survey, these typically retain more of the lower frequency signals which may assist in improving imaging.
- Plan to have interpreted the new seismic data and incorporated this into a revised development plan before the final investment decision is taken.
- Obtain well by well production and pressure data from the operators of Blake, Atlantic, Cromarty and Goldeneye. Use these data to fully calibrate the reservoir simulation model, once the top structure is more robustly defined.
- Conduct a more comprehensive study and risk assessment of the wells in the planned storage complex to inform the decisions around the store development plan. This future work should investigate, in particular the 13/30b-7 well, which this study identified as being problematic potentially requiring remedial action.
- Further work on understanding the plume stabilisation issues should be commissioned to enable a developer to demonstrate to the Regulator that the plume is stable and safe. Key questions to be addressed include:
  - Can the modelling be used to show how plume trapping stabilises in early decades after injections?
  - How long does that take?
  - What commercial risks does this uncertainty result in?

### Operational Planning

- Gain more detailed access to the field data set so that well status and abandonment status can be fully understood. Work to ensure that Operators of nearby hydrocarbon fields are familiar with the potential for $CO_2$ storage in the area and seek collaboration to leverage cost reductions from potential synergies that this might present.
- Identify and quantify opportunities for cost and risk reduction across the whole development.
- Identify synergies with other offshore operations.
- Further investigation into the range of operational issues identified in Section 5.

### Development Planning

- Incorporate the regulatory licensing and permitting requirements into the development plan.
- Work with the petroleum operators of nearby hydrocarbon fields and the Regulator to ensure that the wells are abandoned using all best practice to secure the $CO_2$ integrity of the site.

- Examine options for extending storage development to other injection sites within the Captain fairway and in particular how a more easterly injection site may help to manage plume migration and containment.
- Challenge the assumption that containment must be demonstrated by plume containment within the Storage Complex over 1000 years. This very long time period introduces some potentially large commercial uncertainties and open-ended obligations for project developers.
- Investigate what degree of plume stabilisation must be demonstrated to satisfy the Regulator. This is a key consideration for a commercial $CO_2$ store developer who will be seeking to complete their Transfer of Responsibility to the Regulator as soon as possible after injection and ideally within 20 years. Consequently, they are likely to be more interested in demonstrating plume stabilisation on a shorter timeframe than the 1000 years used in this study.

# 8.0 References

AGR. (2012). *CO2 Storage Liabilities in the North Sea: An Assessment of the Risks and Financial Consequences; Summary Report (including Annexes) for DECC.*

Argent, J., Blight, R., Cox, P., Hardy, R., Law, A., Smallwood, J., & Walter, D. (2005). The technical challenges to exploration and development of the Kopervik fairway, Outer Moray Firth. *Petroleum Geology: North-West Europe and Global Perspectives - Proceedings of the 6th Petroleum Geology Conference*, (pp. 217-229).

Colley, N. M. (1999). *Blake Field Petrophysics Report.* BG International.

Copestake, P., Sms, A. P., Crittenden, S., Hamar, G. P., Ineson, J. R., Rose, P. T., & and Tringham, M. E. (2003). Lower Cretaceous. *Evans, D; Graham, C; Armour, A and Bathurst, P (eds.) The Millenium Atlas: Petroleum Geology of the Central and Northern North Sea*, pp. 191-211.

DECC. (2013). *Electricity Generation Costs 2013.* HMG.

(2008). *Energy Act, Chapter 32.* Retrieved from http://www.legislation.gov.uk/ukpga/2008/32/pdfs/ukpga_20080032_en.pdf

Hassanzadeh, H., Pooladi - Darvish, M., Elsharkawy, A. M., Keith, D. W., & Leonenko, Y. (2008). Predicting PVT data for CO2-brine mixtures for black oil simulation of CO2 geological storage. *International Journal of Greenhouse Gas Control, 6*, 5-77.

ICES; EuroGOOS. (2007). *North Sea Pilot Project - NORSEPP ICES/EuroGOOS Planning Group for NORSEPP (PGNSP) Update report on North Sea Conditions - 2nd Quarter 2007.* Institute of Marine Research.

IEAGHG. (2015). *CCS Deployment in the Context of Regional Development in Meeting Long-Term Climate Change Objectives.*

Law, A., Raymond, R., White, G., Atkinson, A., Clifton, M., Atherton, T., . . . Brawley, S. (2000). The Kopervik Fairway, Moray Firth, UK. *Petroleum Geoscience*, 265-274.

Mathias, S. A., Gluyas, J. G., & Gonzalez, G. J. (2011). Role of partial miscibility on pressure buildup due to constant rate injection of CO2 into closed and open brine aquifers. *Water Resources Reseach*.

Morita, N., E, D., & Whitebay, L. (1998). *Guidelines foe Solving Sand Problems in Water Injection Wells. SPE Paper 39436.*

National Energy Technology Laboratory, US Department of Energy. (2012). *Best Practices for Monitoring, Verfication and Accounting of CO2 Stored in Deep Geologic Formations.*

National Grid Carbon Ltd; Carbon Sentinel Ltd; Hartley Anderson Ltd. (2015). *Yorkshire and Humber CCS Offshore Pipeline and Storage Project: Offshore Environmental Statement.* Retrieved from http://nationalgrid.opendebate.co.uk/files/nationalgrid/ccshumber/Pages_from_D41752015_-_Yorkshire_and_Humber_CCS_Offshore_Pipeline_and_Storage_Project_ES-_main_report.pdf

National Institute of Standards and Technology. (n.d.). *Thermophysical Properties of Fluid Systems* . Retrieved from https://webbook.nist.gov/chemistry/fluid

Pale Blue Dot Energy; Axis Well Technology. (2015). *D04: Initial Screening and Downselect - Strategic UK CCS Storage Project.* The Energy Technologies Institute.

Pale Blue Dot Energy; Axis Well Technology. (2015). *D04: Initial Screening and Downselect - Strategic UK CCS Storage Project.* The Energy Technologies Institute.

Pale Blue Dot Energy; Axis Well Technology. (2015). *D05: Due Diligence and Portfolio Selection - Strategic UK CCS Storage Project.* The Energy Technologies Institute.

Pale Blue Dot Energy; Axis Well Technology. (2015). *D05: Due Diligence and Portfolio Selection - Strategic UK CCS Storage Project.* The Energy Technologies Institute.

Petroleum Experts Ltd. (2015). *User Manual IPM Prosper Version 13.*

PGS. (2015). *The PGS Mega surveys*. Retrieved from http://www.pgs.com/upload/31007/MegaSurvey%20(1366Kb).pdf

Pinnock, S., & Clitheroe, A. (2003). The Captain Field, Block 13/22a, UK North Sea. *Gluyas, JG & Hichens, HM (eds.) United Kingdom Oil and Gas Fields, Commemorative Millenium Volume. Geological Society, London, Memoir, 20*, pp. 431-441.

Scottish Carbon Capture and Storage. (2011). *Progressing Scotland's CO2 Storage Opportunities.* Edinburgh: SCCS.

Scottish Power CCS Consortium. (2011). *UK Carbon Capture and Storage Demonstration Competition; Post Feed End-to-End Basis of Design.*

Scottish Power CCS Consortium. (2015). *CO2Multistore: Optimising CO2 storage in geological formations; a case study offshore Scotland.*

Shell. (2014). *Offshore Environmental Statement .*

Shell. (2015). *Peterhead CCS Project Doc no PCCS-05-PTD-ZG-0580-00001 Date 19/03-2015.*

Shell. (2015). *Seismic Interpretation Report Doc no PCCS-05-PT-ZG-0580-00002.*

Shell UK ltd. (2011). *UK CCS Knowledge Transfer S7.19 SCALL Report.*

Smith, L., Billingham, M. A., Lee, C.-H., & Milanovic, D. (2010). *SPE-13660 CO2 Sequestration Wells - the Lifetime Integrity Challenge.* Society of Petroluem Engineers.

Society of Petroleum Engineers. (2000). *Petroleum Resources Classification System and Definitions*. Retrieved from Petroleum Resources Classification System and Definitions

The European Parliament And The Council Of The European Union. (2009). Directive 2009/31/Ec Of The European Parliament And Of The Council On The Geological Storage Of Carbon Dioxide. *Official Journal of the European Union*, 114-135.

# 9.0 Contributing Authors

| First Name | Last Name | Company |
|---|---|---|
| Shelagh | Baines | Pale Blue Dot Energy |
| Andrew | Clark | Axis Well Technology |
| Hazel | Clyne | Pale Blue Dot Energy |
| Sybille | Handley – Schachler | Axis Well Technology |
| Dave | Hardy | Axis Well Technology |
| Charlie | Hartley-Sewel | Pale Blue Dot Energy |
| Jen | Hickling | Pale Blue Dot Energy |
| Alan | James | Pale Blue Dot Energy |
| Ken | Johnson | Axis Well Technology |
| Doug | Maxwell | Axis Well Technology |
| Sharon | McCollough | Axis Well Technology |
| Jacqueline | McSorely | Axis Well Technology |
| Steve | Murphy | Pale Blue Dot Energy |
| David | Pilbeam | Pale Blue Dot Energy |
| Angus | Reid | Costain |

| First Name | Last Name | Company |
|---|---|---|
| Ryan | Robbins | Costain |
| Farzaneh | Sedighi | Axis Well Technology |
| David | Sweeney | Axis Well Technology |
| Jamie | Telford | Costain |
| Tim | Wynn | Axis Well Technology |

# 10.0 Glossary

| Defined Term | Definition |
|---|---|
| **Aeolian** | Pertaining to material transported and deposited (aeolian deposit) by the wind. Includes clastic materials such as dune sands, sand sheets, loess deposits, and clay |
| **Alluvial Plain** | General term for the accumulation of fluvial sediments (including floodplains, fan and braided stream deposits) that form low gradient and low relief areas, often on the flanks of mountains. |
| **Basin** | A low lying area, of tectonic origin, in which sediments have accumulated. |
| **Bottom Hole Pressure (BHP)** | This the pressure at the midpoint of the open perforations in a well connected to a reservoir system |
| **Clastic** | Pertaining to rock or sediment composed mainly of fragments derived from pre-existing rocks or minerals and moved from their place of origin. Often used to denote sandstones and siltstones. |
| **Closure** | A configuration of a storage formation and overlying cap rock formation which enables the buoyant trapping of $CO_2$ in the storage formation. |
| **$CO_2$ Plume** | The dispersing volume of $CO_2$ in a geological storage formation |
| **Containment Failure Mechanism** | The geological or engineering feature or event which could cause $CO_2$ to leave the primary store and/or storage complex |
| **Containment Failure Modes** | Pathways for $CO_2$ to move out of the primary store and/or storage complex which are contrary to the storage development plan |
| **Containment Risk Scenario** | A specific scenario comprising a Containment Failure Mechanism and Containment Failure Mode which might result in the movement of $CO_2$ out of the primary store and/or storage complex |
| **Evaporite** | Sediments chemically precipitated due to evaporation of water. Common evaporates can be dominated by halite (salt), anhydrite and gypsum. Evaporites may be marine formed by the evaporation within an oceanic basin, or non-marine typically formed in arid environments. |

| Defined Term | Definition |
|---|---|
| **Facies (Sedimentary)** | A volume of rock that can be defined and recognised by a particular set of characteristics (physical, compositional, chemical) often reflecting its environment of deposition |
| **Fault** | Fracture discontinuity in a volume of rock, across which there has been significant displacement as a result of rock movement |
| **Fluvial** | Pertaining to or produced by streams or rivers |
| **Formation** | A formation is a geological rock unit that is distinctive enough in appearance and properties to distinguish it from surrounding rock units. It must also be thick enough and extensive enough to capture in a map or model. Formations are given names that include the geographic name of a permanent feature near the location where the rocks are well exposed. If the formation consists of a single or dominant rock type, such as shale or sandstone, then the rock type is included in the name. |
| **Gardener's Equation** | A relationship between seismic velocity V in ft/s (ie. The inverse of the sonic log measured in μs/ft) and density ρ in g/cm³ for saturated sedimentary rocks. The equation was proposed by Gardener et al (1974) based on lab experiments and is of the form $\rho = aV^b$. Typically a = 0.23 and b = 0.25 but these values should be refined if measured V and ρ are available for calculation. |
| **Geological Formation** | Lithostratigraphical subdivision within which distinct rock layers can be found and mapped [CCS Directive] |
| **Halokinesis** | The study of salt tectonics, which includes the mobilization and flow of subsurface salt, and the subsequent emplacement and resulting structure of salt bodies |
| **Hydraulic Unit** | A Hydraulic Unit is a hydraulically connected pore space where pressure communication can be measured by technical means and which is bordered by flow barriers, such as faults, salt domes, lithological boundaries, or by the wedging out or outcropping of the formation (EU CCS Directive); |
| **Leak** | The movement of $CO_2$ from the Storage Complex |
| **Levelised Cost** | The levelised cost of transportation and storage for a development is the ratio of the discounted life cycle cost to the discounted injection profile. Both items discounted at the same discount rate and to the same base year. |
| **Maximum Flooding Surface (MFS)** | This is a geological surface which represents the deepest water facies within any particular sequence. It makes the change from a period of relative sea level rise to a period of relative sea level fall. An MFS commonly displays evidence of condensed or slow deposition. Such surfaces are key aids to understanding the stratigraphic evolution of a geological sequence. |

| Defined Term | Definition |
|---|---|
| **Outline Storage Development Plan (OSDP)** | The Outline Storage Development Plan defines the scope of the application process for a storage permit, including identification of required documents. These documents, include a Characterization Report (CR), an Injection and Operating Plan (IOP) (including a tentative site closure plan), a Storage Performance Forecast (SPF), an Impact Hypothesis (IH), a Contingency Plan (CP), and a Monitoring, Measurement and Verification, (MMV) plan. |
| **Playa Lake** | A shallow, intermittent lake in a arid or semiarid region, covering or occupying a playa in the wet season but drying up in summer; an ephemeral lake that upon evaporation leaves or forms a playa. |
| **Primary Migration** | The movement of $CO_2$ within the injection system and primary reservoir according to and in line with the Storage Development Plan |
| **Risk** | Concept that denotes the product of the probability (likelihood) of a hazard and the subsequent consequence (impact) of the associated event [$CO_2$QUALSTORE] |
| **Sabkha** | A flat area of sedimentation and erosion formed under semiarid or arid conditions commonly along coastal areas but can also be deposited in interior areas (basin floors slightly above playa lake beds). |
| **Secondary Migration** | The movement of $CO_2$ within subsurface or wells environment beyond the scope of the Storage Development Plan |
| **Silver Pit Basin** | Located in the northern part of the Southern North Sea. Over much of the basin up to 400 m of Silverpit Formation interbedded shales and evaporites are present. The absence of the Leman Sandstone reservoir over much of the basin has meant that gas fields predominate in the Carboniferous rather than in the Permian, as is the case in the Sole Pit Basin to the South. |
| **Site Closure** | The definitive cessation of $CO_2$ injection into a Storage Site |
| **Storage Complex** | The Storage Complex is a storage site and surrounding geological domain which can have an effect on overall storage integrity and security; that is, secondary containment formations (EU CCS Directive). |
| **Storage Site** | Storage Site is a defined volume within a geological formation that is or could be used for the geological storage of CO2. The Storage Site includes its associated surface and injection facilities (EU CCS Directive); |
| **Storage Unit** | A Storage Unit is a mappable subsurface body of reservoir rock that is at depths greater than 800 m below sea level, has similar geological characteristics and which has the potential to retain $CO_2$ (UKSAP) |

| Defined Term | Definition |
|---|---|
| **Stratigraphic Column** | A diagram that shows the vertical sequence of rock units present beneath a given location with the oldest at the bottom and youngest at the top. |
| **Stratigraphy** | The study of sedimentary rock units, including their geographic extent, age, classification, characteristics and formation. |
| **Tectonic** | Relating to the structure of the Earth's crust, the forces or conditions causing movements of the crust and the resulting features. |
| **Tubing Head Pressure (THP)** | The pressure at the top of the injection tubing in a well downstream of any choke valve |

# 11.0 Appendices

The following appendices have been provided separately:

## 11.1 Appendix 1 – Risk Matrix

## 11.2 Appendix 2 – Leakage Workshop Report

## 11.3 Appendix 3 – Database

## 11.4 Appendix 4 – Geological Information

## 11.5 Appendix 5 – MMV Technologies

## 11.6 Appendix 6 – Well Basis of Design

## 11.7 Appendix 7 – Cost Estimate

## 11.8 Appendix 8 – Methodologies

## 11.9 Appendix 9 – Fracture Pressure Gradient

## 11.10 Appendix 10 – Subsurface Uncertainty Analysis

## 11.11 Appendix 11 – Comparison with CO2MultiStore Analysis

2016

# D13: WP5D – Captain X Storage Development Plan

## 10113ETIS-Rep-19-02 Appendices

March 2016

www.pale-blu.com

www.axis-wt.com

# Contents

| Document Summary | | | |
|---|---|---|---|
| **Client** | The Energy Technologies Institute | | |
| **Project Title** | DECC Strategic UK CCS Storage Appraisal Project | | |
| **Title:** | D13: Wp5d – Captain X Storage Development Plan | | |
| **Distribution:** | A Green, D Gammer | **Classification:** | Client Confidential |
| **Date of Issue:** | 21/03/16 | | |
| | **Name** | **Role** | **Signature** |
| **Prepared by:** | A James, S Baines & S McCollough | Chief Technologist, Scientific Advisor & Subsurface Lead | |
| **Approved by:** | S J Murphy | Project Manager | |

| Amendment Record | | | | | | |
|---|---|---|---|---|---|---|
| **Rev** | **Date** | **Description** | **Issued By** | **Checked By** | **Approved By** | **Client Approval** |
| V01 | 26/02/16 | Draft | D Pilbeam | A James | S Murphy | |
| V02 | 21/03/16 | Final | D Pilbeam | A James | S Murphy | A Green |

**Disclaimer:**

While the authors consider that the data and opinions contained in this report are sound, all parties must rely upon their own skill and judgement when using it. The authors do not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the report. There is considerable uncertainty around the development of $CO_2$ stores and the available data are extremely limited. The authors assume no liability for any loss or damage arising from decisions made on the basis of this report. The views and judgements expressed here are the opinions of the authors and do not reflect those of the ETI or any of the stakeholders consulted during the course of this project. The figures, charts and tables contained in this report comply with the intellectual property and copyright constraints of this project and in some cases this has meant that they have been simplified or their number limited.

# Table of Contents

## Figures

## Tables

# 11.0 Appendices

## 11.1 Appendix 1 – Risk Register

Provided separately in Excel.

## 11.2 Appendix 2 – Leakage Workshop

### 11.2.1 Objectives

The objectives for this workshop were to discuss and capture the leakage scenarios for the Captain storage site & their risk (likelihood & impact).

### 11.2.2 Methodology

The Leakage Scenario Definition Workshop (WP5D.T23) covered all aspects of natural and engineering integrity. The project team of subsurface experts came together to brainstorm an inventory of potential leak paths (both geological and engineered) for the Captain site X. These potential leak paths were then assessed for their likelihood and impact, based on all the available evidence.

The scope of the workshop was for the Captain site X only, from the subsurface to the wellhead and did not include offshore facilities or pipeline transportation.

The roles in the room included:

- Facilitator, timekeeper, note-taker
- Geophysics expert
- Geology expert
- Reservoir Engineering expert
- Wells expert
- $CO_2$ Storage expert

The workshop focussed one at a time on each of the following 10 containment failure modes (pathways for $CO_2$ to move out of the primary store and/or storage complex which are contrary to the storage development plan):

1. Flow through Primary Caprock
2. Lateral Exit from Primary Store
3. Lateral Exit from Secondary Store
4. Flow through Secondary Caprock
5. $CO_2$ entry into a post operational or legacy well
6. $CO_2$ flow upwards in wellbore zone within Storage Complex
7. $CO_2$ exit from welbore zone outside Primary Store
8. $CO_2$ flow upwards in wellbore zone beyond Storage Complex boundary
9. $CO_2$ flow through Store floor and beyond storage complex boundary
10. $CO_2$ flow downwards in wellbore zone beyond Storage Complex boundary

These are summarised in the following diagram:

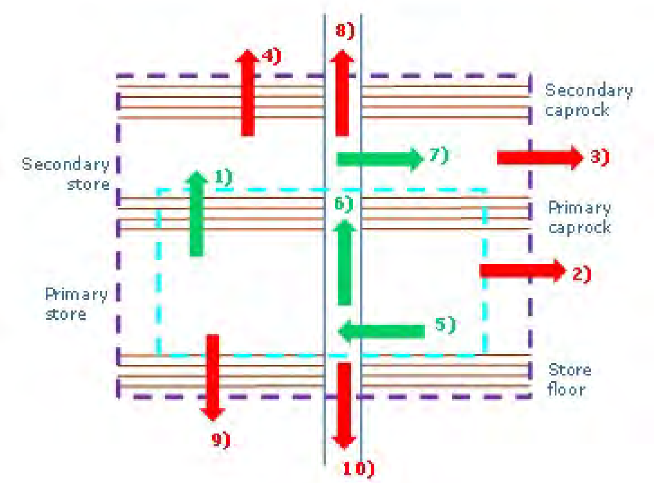



*Figure 11-1 Containment failure modes*

For each failure mode, a number of containment failure mechanisms were discussed. A containment failure mechanism is a geological or engineering feature, event or process which could cause $CO_2$ to move out of the primary store and/or storage complex (contrary to the storage development plan). An example is: fault reactivation in primary caprock.

The likelihood and impact of each containment failure mechanism was discussed, based on the $CO_2$QUALSTORE (DNV, 2009) (DNV, 2010) framework shown in Table 11-2 and Table 11-3.

The failure mechanisms were then cross-checked with the Quintessa $CO_2$ FEP (feature, event, process) database (Quintessa, 2014) to ensure all possibilities were considered.

Pathways that could potentially lead to $CO_2$ moving out with the Storage Complex were mapped out from combinations of failure modes. For each pathway, the likelihood was taken as the lowest from likelihood of any of the failure modes that made it up and the impact was take as the highest. The pathways were then grouped into more general leakage scenarios.

### 11.2.3 Results

| Leakage scenario | Likelihood | Impact | |
|---|---|---|---|
| Vertical movement of $CO_2$ from Primary store to overburden through caprock | 1 | 3 | |
| Vertical movement of $CO_2$ from Primary store to overburden via existing wells | 1 | 3 | |
| Vertical movement of $CO_2$ from Primary store to overburden via injection wells | 1 | 3 | |
| Vertical movement of $CO_2$ from Primary store to overburden via caprock & wells | 1 | 3 | |
| Vertical movement of $CO_2$ from Primary store to upper well/ seabed via P&A wells | 3 | 4 | |
| Vertical movement of $CO_2$ from Primary store to upper well/ seabed via suspended wells | 2 | 4 | |
| Vertical movement of $CO_2$ from Primary store to upper well/ seabed via injection wells | 2 | 4 | |
| Vertical movement of $CO_2$ from Primary store to upper well/ seabed via caprock & wells | 1 | 4 | |
| Lateral movement of $CO_2$ from Primary store out with storage complex w/in Captain | 3 | 3 | |
| Vertical movement of $CO_2$ from Primary store to underburden via existing wells (13/30b-7) | 5 | 3 | |
| Vertical movement of $CO_2$ from Primary store to underburden via store floor (out with storage complex) | 1 | 3 | |

*Table 11-1- Leakage Scenarios*

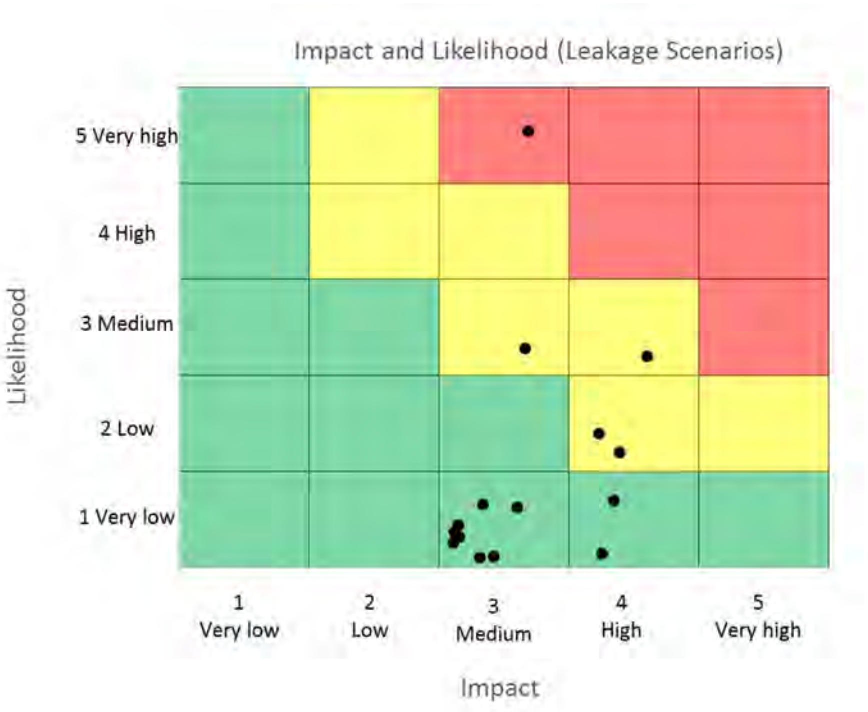



*Figure 11-2 Risk matrix of leakage scenarios*

The scenarios with the highest risk relate to existing (P&A and development) and injection wells as they provide a potential leakage pathway directly from the storage site to seabed, and lateral movement of $CO_2$ out with the storage complex, due to the uncertainty in Top Captain seismic pick.

In particular, P&A well 13/30b-7 is seen as a potential risk as it provides total communication between the Captain sand and deeper Burns sand. The well was abandoned in 2007, with wellhead & surface casing cut 10ft below seabed and removed.

Due to the uncertainties associated with the challenging Top Captain seismic pick and depth conversion, there is a risk of lateral movement of $CO_2$ out with the Storage Complex boundary.

| Score | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Name** | Very Low | Low | Medium | High | Very High |
| **Impact on storage integrity** | None | Unexpected migration of $CO_2$ inside the defined storage complex | Unexpected migration of $CO_2$ outside the defined storage complex | Leakage to seabed or water column over small area (<100m2) | Leakage seabed water column over large area (>100m2) |
| **Impact on local environment** | Minor environmental damage | Local environmental damage of short duration | Time for restitution of ecological resource <2 years | Time for restitution of ecological resource 2-5 years | Time for restitution of ecological resource such as marine Biosystems, groundwater >5 years |
| **Impact on reputation** | Slight or no impact | Limited impact | Considerable impact | National impact | International impact |
| **Consequence for Permit to operate** | None | Small fine | Large fine | Temporary withdrawal of permit | Permanent loss of permit |

*Table 11-2 - Impact Categories*

| Score | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Name** | Very Low | Low | Medium | High | Very High |
| **Description** | Improbable, negligible | Remotely probably, hardly likely | Occasional, likely | Probable, very likely | Frequent, to be expected |
| **Event (E)** | Very unlikely to occur during the next 5000 years | Very unlikely to occur during injection operations | Likely to occur during injection operations | May occur several times during injection operations | Will occur several times during injection operations |
| **Frequency** | About 1 per 5000 years | About 1 per 500 years | About 1 per 50 years | About 1 per 5 years | About 1 per year or more |
| **Feature (F)/ Process (P)** | Disregarded | Not expected | 50/50 chance | Expected | Sure |

*Table 11-3 - Likelihood Categories*

## 11.3 Appendix 3 – Database

### 11.3.1 Captain Aquifer: SEG-Y data summary

The seismic 3D survey used for the evaluation of Captain Aquifer came from PGS UK CNS Mega Survey:

- **Survey: MC3D_NSEA (CNS)_MEGA (UK Sector)**
    - **Final Merged Migration (53 Tiles)**

These data were supply as SEG-Y on a USB hard drive and have the following survey datum and map projections:

| **Survey Datum** | **Name:** | **ED50** |
|---|---|---|
| Ellipsoid: | INTERNATIONAL 1924 | |
| Semi Major Axis | 6378388 | |
| 1/Flattening | 297 | |
| **Map Projection** | **Projection** | **UTM 31N** |
| Central Meridian | 3 EAST | |
| Scale Factor on Central Meridian | 0.9996 | |
| Latitude of Origin | 0.00N | |
| False Northing | 0 | |
| False Easting | 500000 | |

*Table 11-4 SEG-Y survey datum and map projections*

The following tiles of SEG-Y data were used for the Captain site selection and evaluation:

| File Name | Format | Tile | Media | IL Range | XL Range |
|---|---|---|---|---|---|
| **OS0445_MC3D_NSEA_MEGA_F04_MAR2014** | SEG-Y | F04 | 27395002 | 15001-20000 | 120001-124000 |
| **MC3D_NSEA_MEGA_F05** | SEG-Y | F05 | 27395002 | 20001-25000 | 120001-124000 |

*Table 11-5 SEG-Y tiles for Captain Aquifer evaluation*

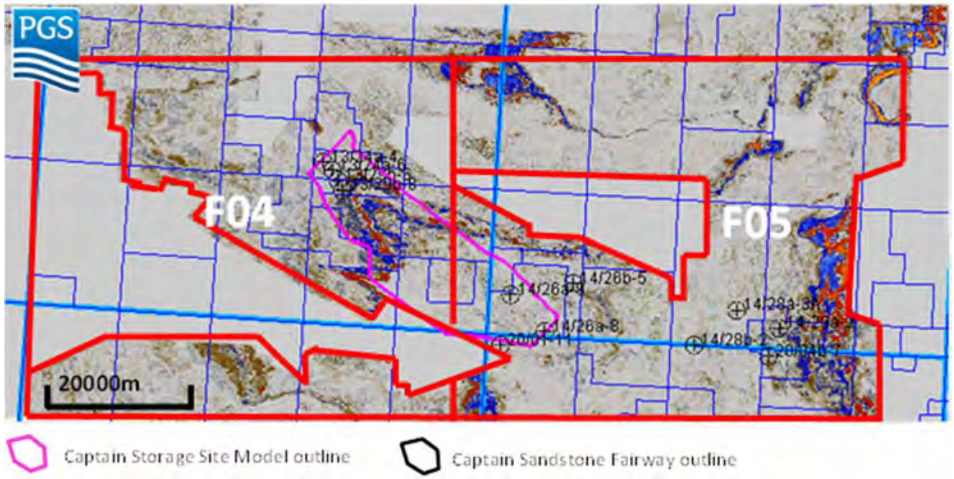



*Figure 11-3 PGS SNS Mega survey time slice showing the SEG-Y data extent and tiles*

### 11.3.2 Captain Site X: Well log data summary

The table below shows a summary of the well log data for Captain Site X, downloaded from CDA.

| Well | Date | E/A/D | DLIS or las? | GR | Neutron | Density | DT/ Sonic | SP | Comp Log | Geol Report/Final Well Report | Digital Checkshots | Deviation Data | Well Tops | Core Data over Captain |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **13/21b- 2** | 1990 | E | | y | n | n | y | n | n | y | n | y | y | n |
| **13/22b- 19** | 1993 | A | | y | n | n | y | y | y | y | n | y | y | n |
| **13/22b- 20** | 1993 | E | | y | n | n | y | y | y | y | n | y | y | n |
| **13/22b- 4** | 1990 | E | | y | n | n | y | y | n | y | n | y | y | n |
| **13/22c- 30** | 2006 | E | | y | y | y | n | n | y | y | n | y | y | n |
| **13/23- 1** | 1991 | E | | y | n | y | n | n | n | y | n | y | y | n |
| **13/23a- 4** | 1999 | E | | y | y | y | n | n | y | y | n | y | y | n |
| **13/23b- 5** | 2005 | E | DLIS | y | y | n | n | y | y | y | n | y | y | y |
| **13/23b- 6** | 2008 | A | LAS | y | n | n | n | n | y | y | n | y | y | n |
| **13/24- 1** | 1974 | E | | y | n | y | y | n | y | y | n | n | n | n |
| **13/24a- 4** | 1997 | A | | y | y | y | y | y | y | y | y | y | y | y |
| **13/24a- 5** | 1998 | A | | y | | y | y | | y | y | y | y | y | y |
| **13/24a- 6** | 1998 | A | | y | n | y | y | n | y | y | y | y | y | y |
| **13/24a-7** | 2000 | D | | n | n | n | n | n | y | y | n | y | y | n |
| **13/24a- 7Z** | 2000 | D | | n | n | n | n | n | y | y | n | y | y | n |
| **13/24A-8** | 2001 | A | | n | n | n | n | n | y | y | n | y | y | n |
| **13/24A-8Y** | 2001 | A | | n | n | n | n | n | y | y | n | y | y | n |
| **13/24a- 8Z** | 2001 | A | | n | n | n | n | n | y | y | n | y | y | n |
| **13/24b- 10** | 2010 | D | | n | n | n | n | n | y | y | n | y | y | n |
| **13/24b- 3** | 1997 | E | | y | n | y | n | n | y | y | n | y | y | y |
| **13/24b- 9** | 2003 | D | DLIS | y | n | n | n | n | y | y | n | y | y | n |

| Well | Date | E/A/D | DLIS or las? | GR | Neutron | Density | DT/ Sonic | SP | Comp Log | Geol Report/Final Well Report | Digital Checkshots | Deviation Data | Well Tops | Core Data over Captain |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **13/29b- 5** | 1995 | E | | y | n | n | n | n | y | y | n | y | y | n |
| **13/29b- 6** | 1999 | A | | y | y | n | y | n | y | y | n | y | y | y |
| **13/29b- 7** | 2001 | E | LAS | n | n | n | n | n | y | y | n | y | y | n |
| **13/29b- 8** | 2001 | D | | y | n | n | n | n | y | y | y | y | y | n |
| **13/29b- 9** | 2004 | E | DLIS | n | n | n | n | n | y | n | n | y | y | n |
| **13/30- 1** | 1981 | E | | y | y | y | y | y | y | y | n | y | y | n |
| **13/30- 2** | 1984 | E | | n | n | n | n | n | n | y | n | y | y | n |
| **13/30- 3** | 1986 | E | | y | y | y | y | y | n | y | n | y | y | y |
| **13/30a- 4** | 1998 | E | LAS | y | n | y | y | y | y | y | n | y | y | y |
| **13/30a- 6** | 2005 | D | DLIS | n | n | n | n | n | y | y | n | y | y | n |
| **13/30b- 5** | 1999 | E | | n | n | n | n | n | y | y | n | y | y | n |
| **13/30b- 7** | 2007 | E | | y | y | n | y | n | y | y | n | y | y | n |
| **14/26- 1** | 1979 | E | | y | y | y | y | y | n | y | n | y | n | n |
| **14/26- 2** | 1982 | E | | y | y | y | y | y | n | y | n | y | n | n |
| **14/26- 3** | 1983 | E | | y | y | y | y | y | n | y | n | y | n | n |
| **14/26a- 6** | 1997 | E | | y | y | y | y | y | y | y | n | y | y | y |
| **14/26a- 7** | 1999 | A | | n | n | n | n | n | n | n | n | n | n | n |
| **14/26a- 7A** | 1999 | A | | y | y | y | n | n | y | y | n | y | y | y |
| **14/26a- 8** | 2000 | A | DLIS | y | y | n | y | y | y | y | y | y | y | y |
| **14/26a- 9** | 2011 | A | | n | y | y | n | n | y | y | y | y | y | n |
| **14/26b- 5** | 1997 | E | | y | y | y | y | y | y | y | y | y | y | n |

| Well | Date | E/A/D | DLIS or las? | GR | Neutron | Density | DT/ Sonic | SP | Comp Log | Geol Report/Final Well Report | Digital Checkshots | Deviation Data | Well Tops | Core Data over Captain |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **14/27a- 1** | 1990 | E | | y | n | y | n | y | n | y | n | y | y | n |
| **14/27a- 2** | 2006 | E | | n | n | n | n | n | y | y | n | y | y | n |
| **14/28a- 3A** | 2000 | E | | y | n | n | n | n | y | y | y | y | y | n |
| **14/28b- 2** | 1997 | E | | y | y | y | y | y | y | y | y | y | y | y |
| **14/28b- 4** | 2006 | E | DLIS | y | y | y | y | y | y | y | n | y | y | n |
| **14/29a- 2** | 1980 | E | | y | y | y | y | y | y | y | y | y | y | n |
| **14/29a- 3** | 1996 | E | DLIS | y | n | y | y | n | y | y | n | y | y | y |
| **14/29a- 5** | 1999 | E | DLIS | y | y | y | y | n | y | y | n | y | y | y |
| **20/02b- 10** | 2010 | E | DLIS | y | y | y | n | n | y | y | n | y | y | n |
| **20/04b- 6** | 1997 | E | | y | y | y | y | y | y | y | n | y | y | y |
| **20/04b- 7** | 1999 | E | | y | n | n | n | n | y | y | y | y | y | y |
| **20/01-11** | 2009 | A | | n | y | y | n | n | y | y | y | y | y | n |
| **20/01-11Z** | 2009 | A | | y | n | y | n | n | y | y | y | y | y | n |
| **20/01-6** | 2006 | D | | y | y | y | n | n | y | y | n | y | y | n |
| **20/01-8** | 2009 | E | | y | y | y | n | n | y | y | n | y | y | n |

*Table 11-6 Well log data summary*

### 11.3.3 Captain Site X: Core data summary

The table below show a summary of the core data available over the Captain Site X.

| Field | Well | Core Depth (MD) |
|---|---|---|
| | 13/23b- 5 | 4240.3-4261.2 |
| **BLAKE** | 13/24a- 4 | 5295.1-5450.1 |
| **BLAKE** | 13/24a- 5 | 5207.2-5400.6 |
| **BLAKE** | 13/24a- 6 | 5177.4-5409.1 |
| **BLAKE** | 13/24b- 3 | 4990.0-5302.0 |
| **BLAKE** | 13/29b- 6 | 5203.85-5375.0 |
| **CROMARTY** | 13/30- 3 | 6577.0-6702.85 |
| | 13/30a- 4 | 6364.2-6461.0 |
| **ATLANTIC** | 14/26a- 6 | 6467.1-6541.9 |
| **ATLANTIC** | 14/26a- 7A | 6540.1-6577.8 |
| **SOLITAIRE** | 14/26a- 8 | 6428.9-6658.9 |
| | 14/28b- 2 | 8248.0-8331.0 |
| **GOLDENEYE** | 14/29a- 3 | 9727.0-10188.9 |
| **GOLDENEYE** | 14/29a- 5 | 8473.1-8680.0 |
| **GOLDENEYE** | 20/04b- 6 | 8644.2-8777.9 |
| **GOLDENEYE** | 20/04b- 7 | 8639.2-8812.0 |

*Table 11-7 Core data summary*

### 11.3.4 Data from Operators

Limited pressure data from Operators in the area were provided as input to the Captain Site X work.

## 11.4 Appendix 4 – Geological Information

### 11.4.1 Maps

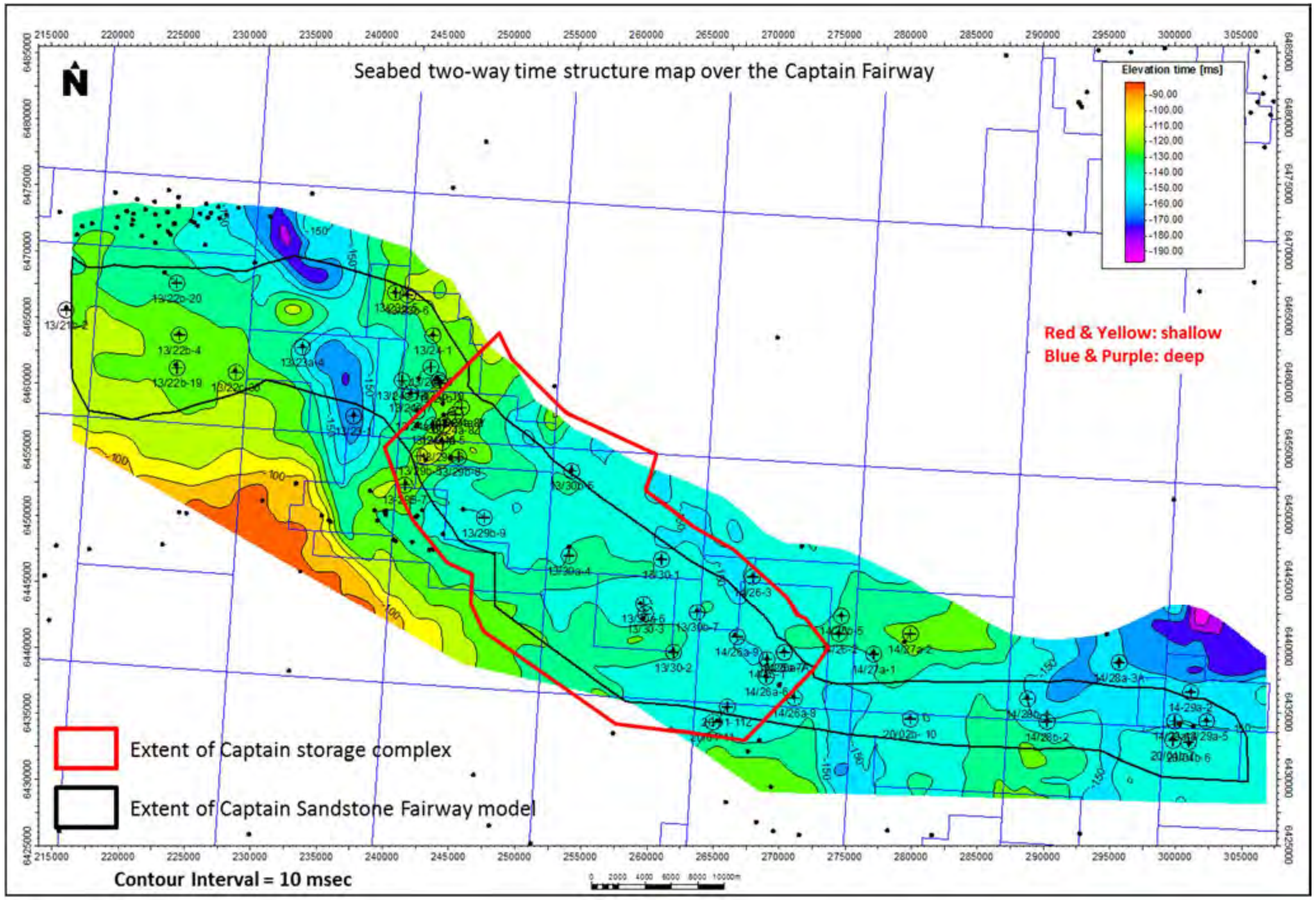



*Figure 11-4 Seabed Two-Way Time Map*

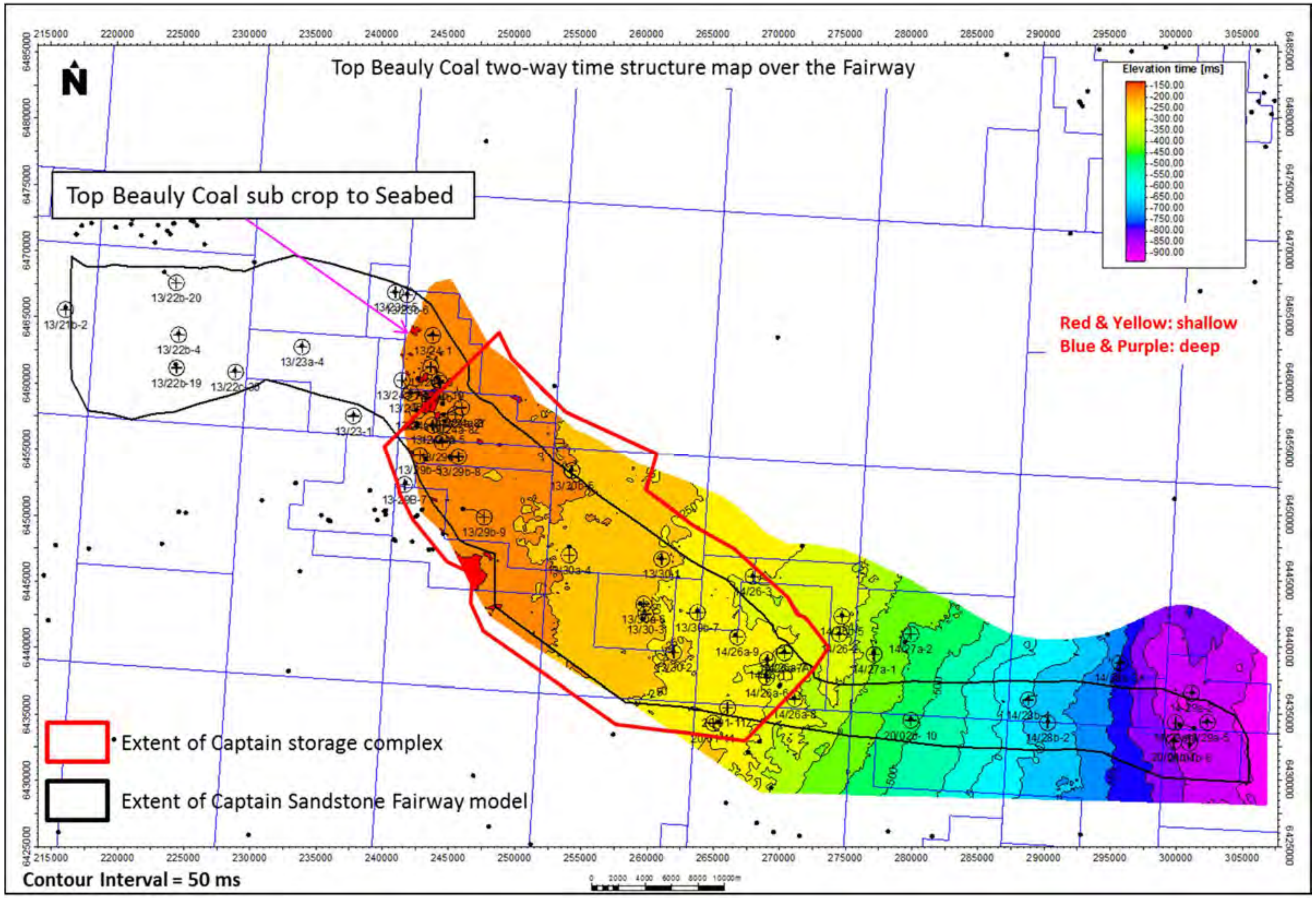



*Figure 11-5 Top Beauly Coal Two-Way Time Map*

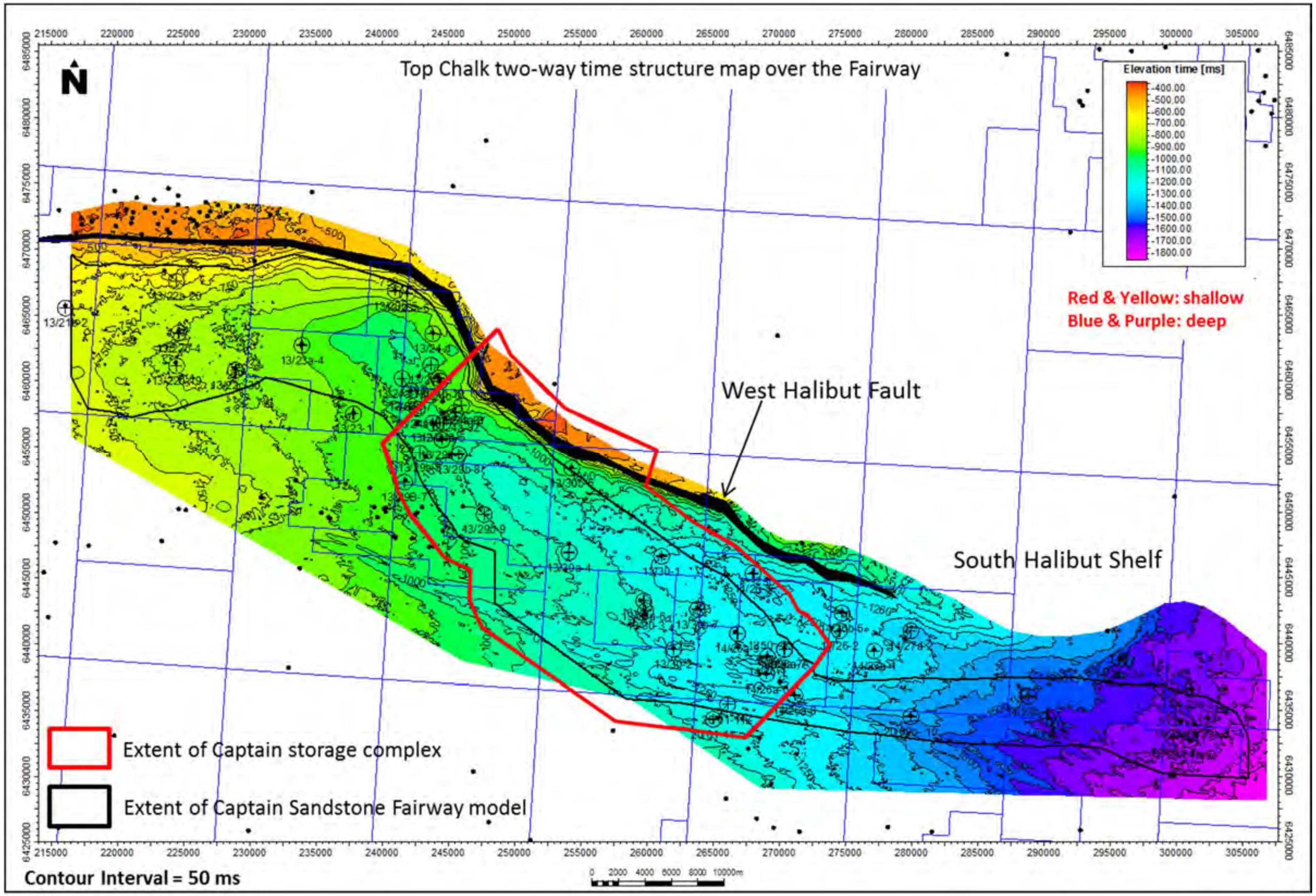



*Figure 11-6 Top Chalk Two-Way Time Map*

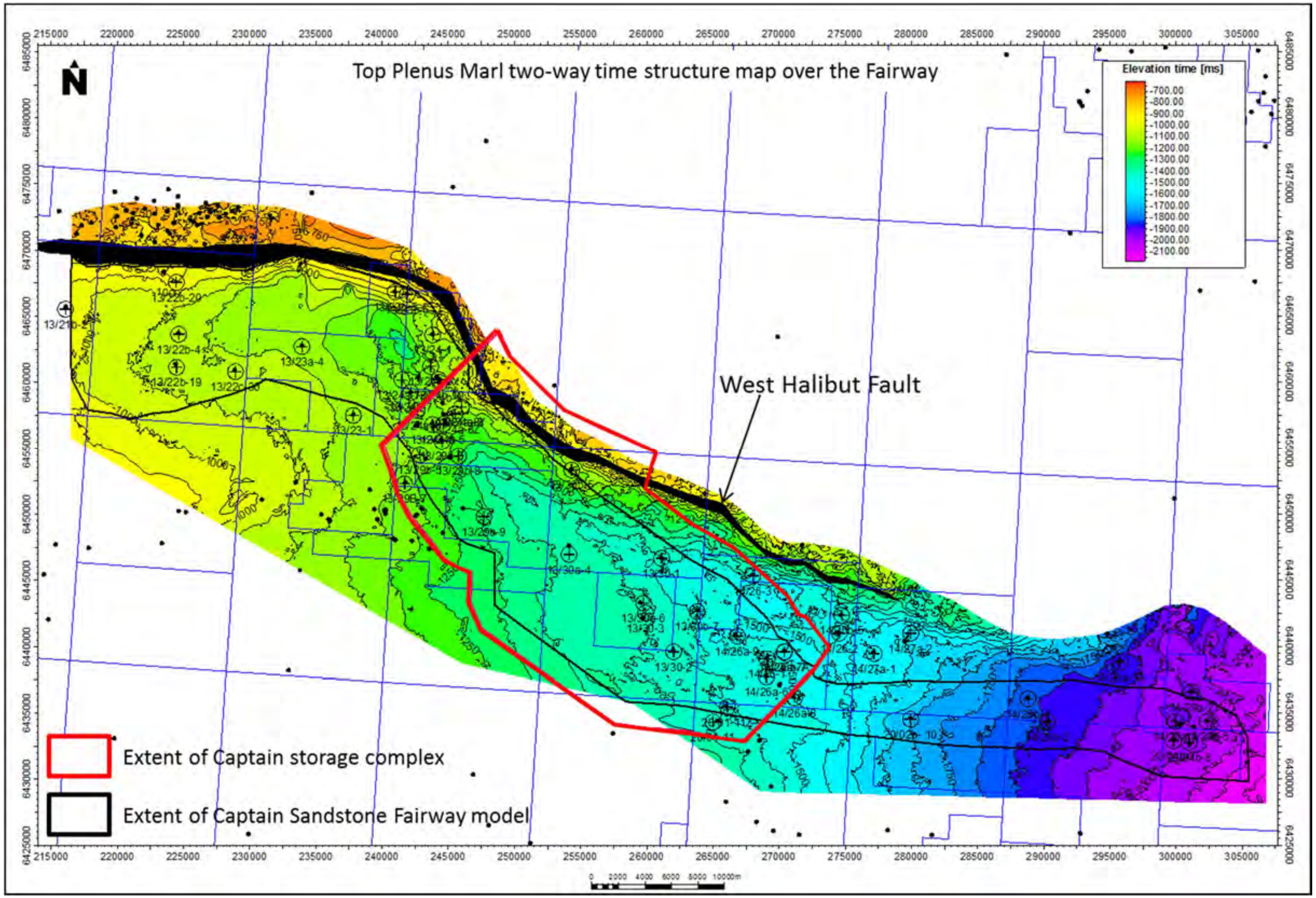



*Figure 11-7 Top Plenus Marl Two-Way Time Map*

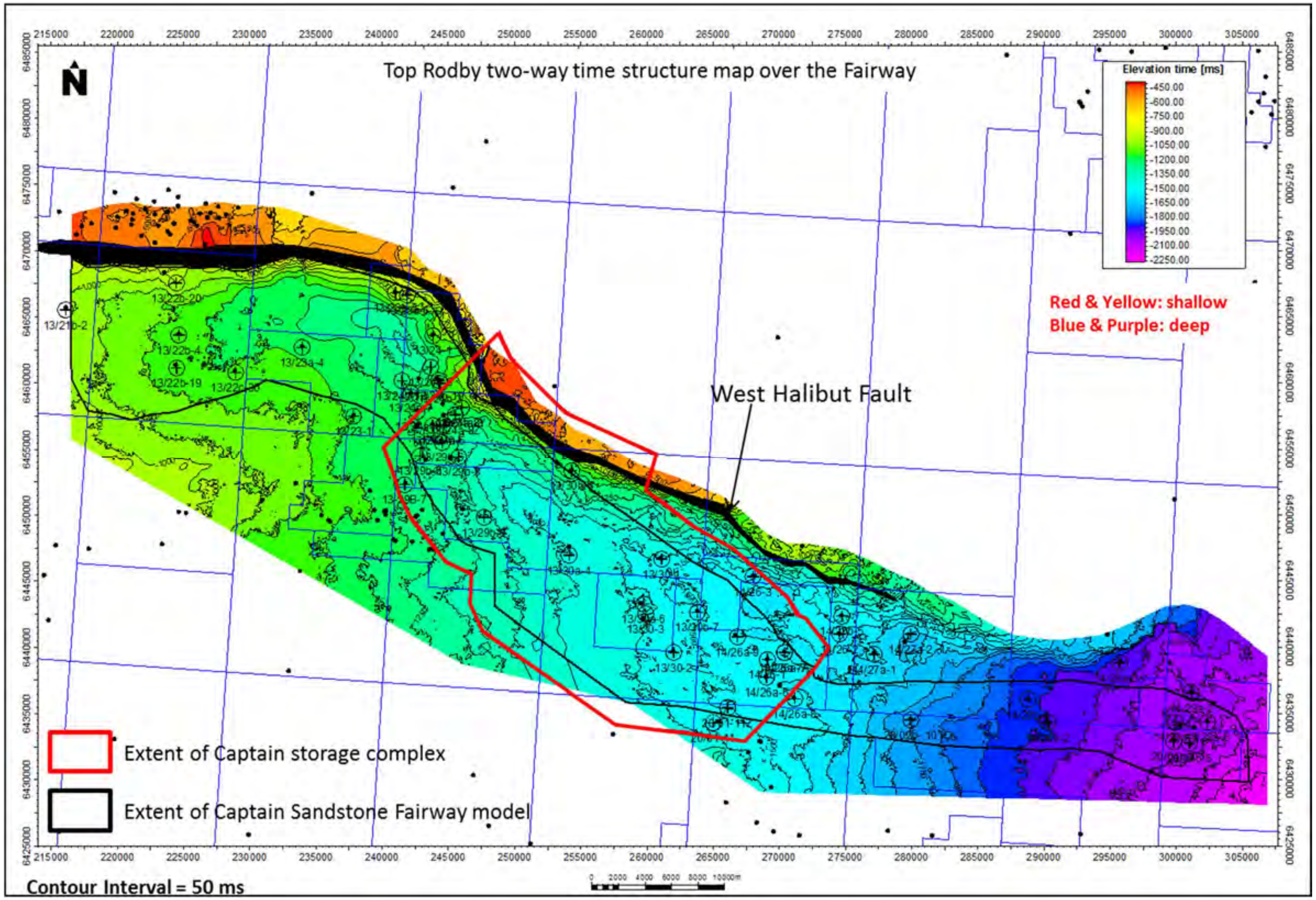



*Figure 11-8 Top Rodby Two-Way Time Map*

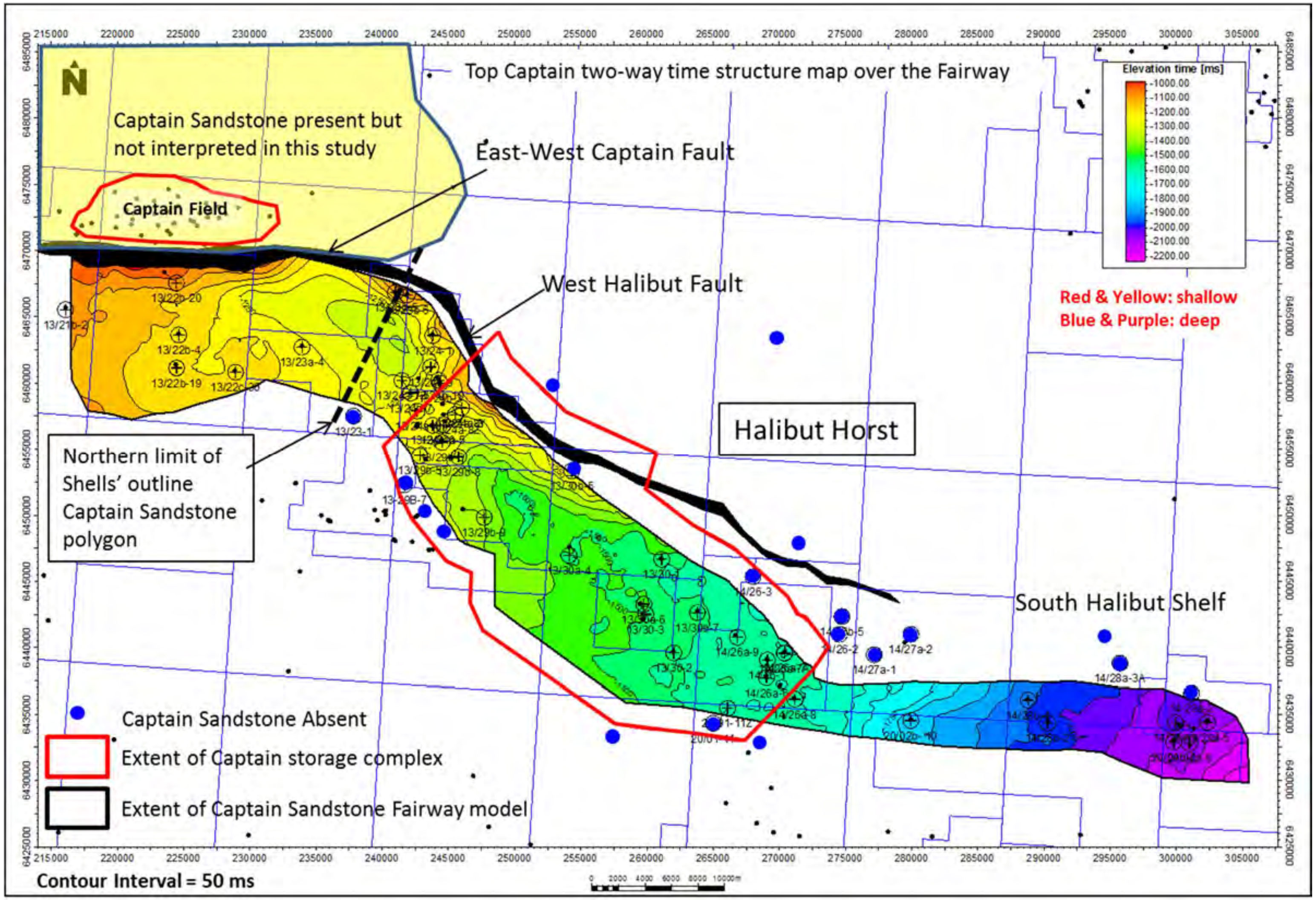



*Figure 11-9 Top Captain Sandstone Two-Way Time Map*

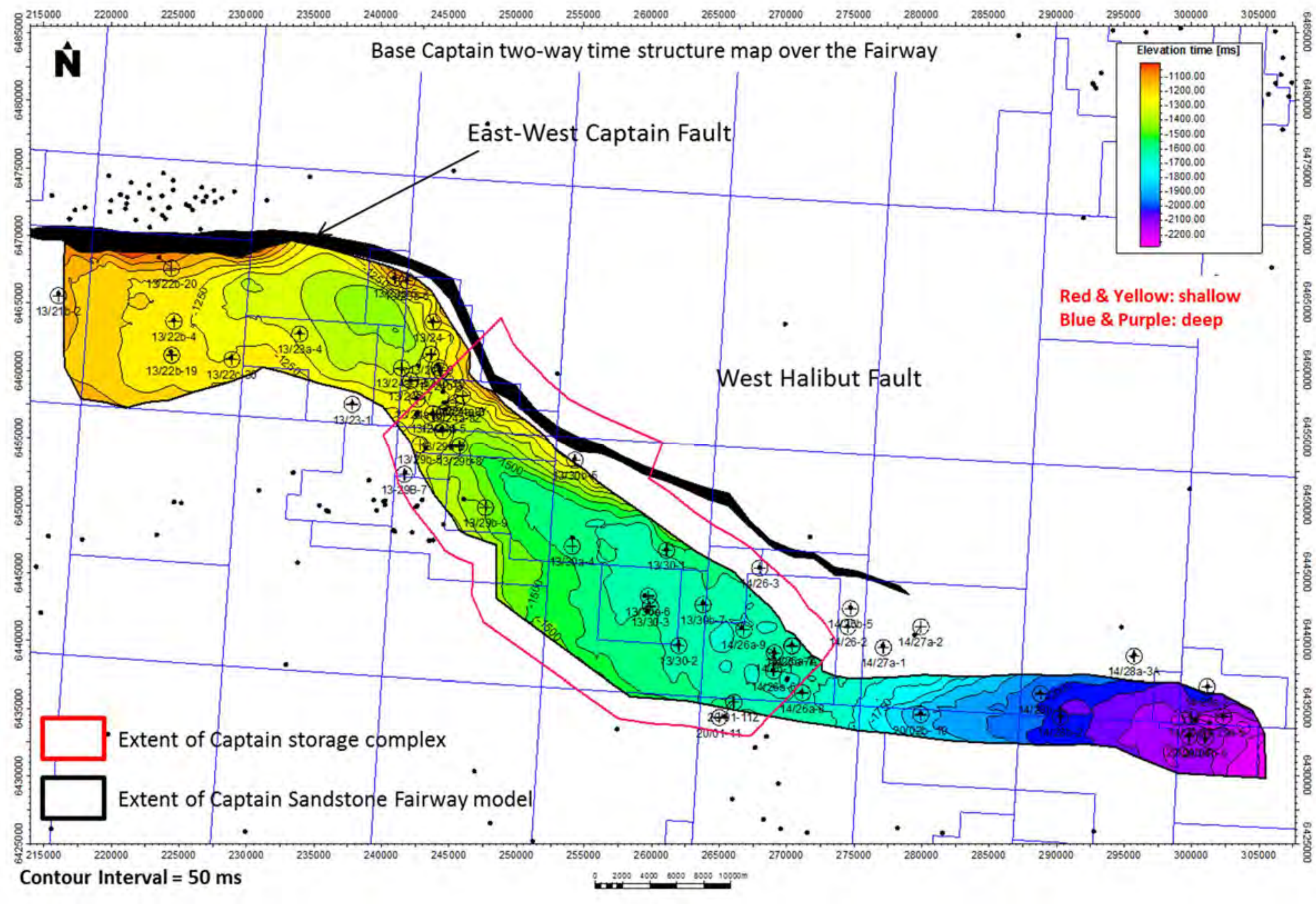



*Figure 11-10 Base Captain Sandstone Two-Way Time Map*

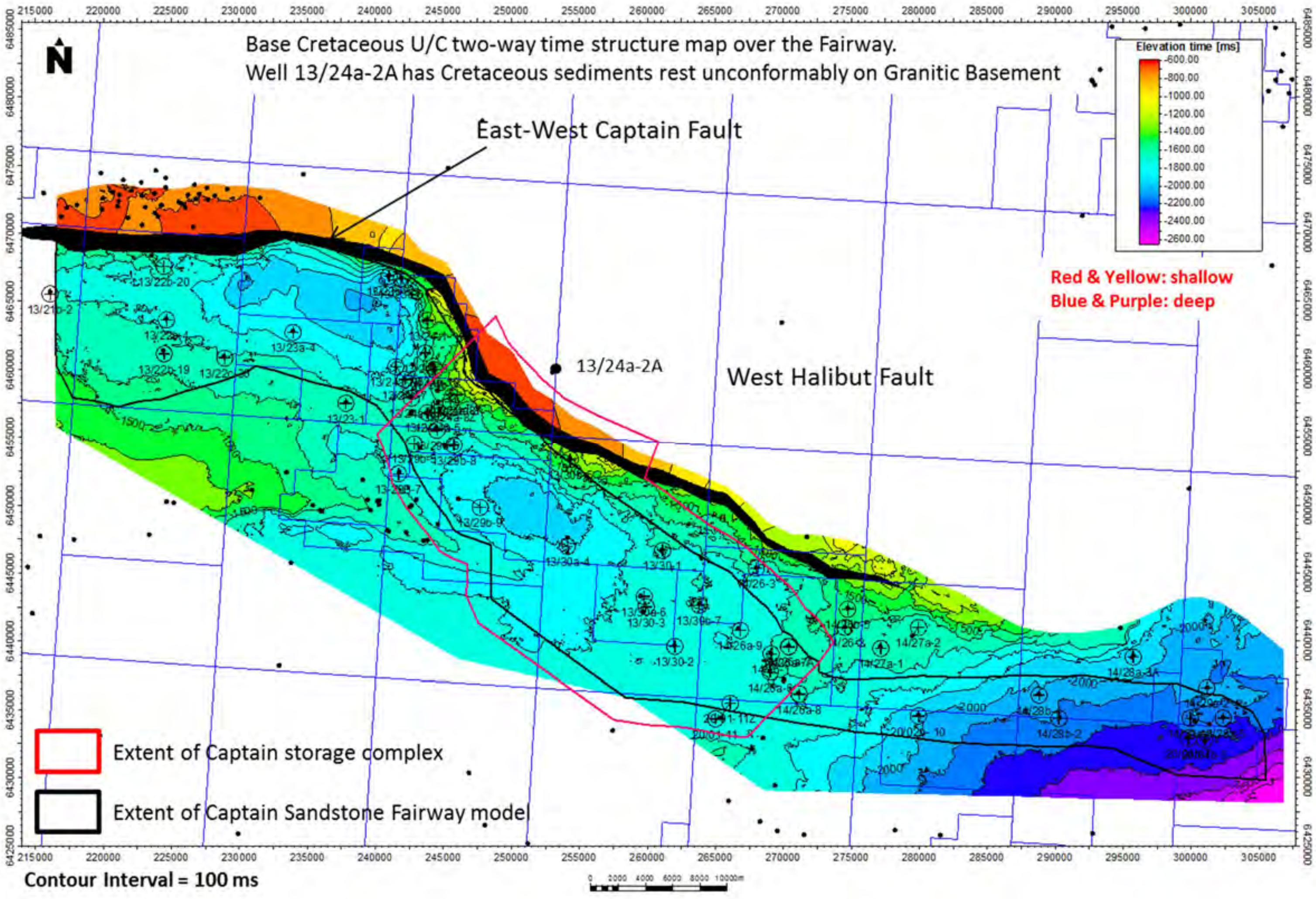



*Figure 11-11 Base Cretaceous Unconformity Two-Way Time Map*

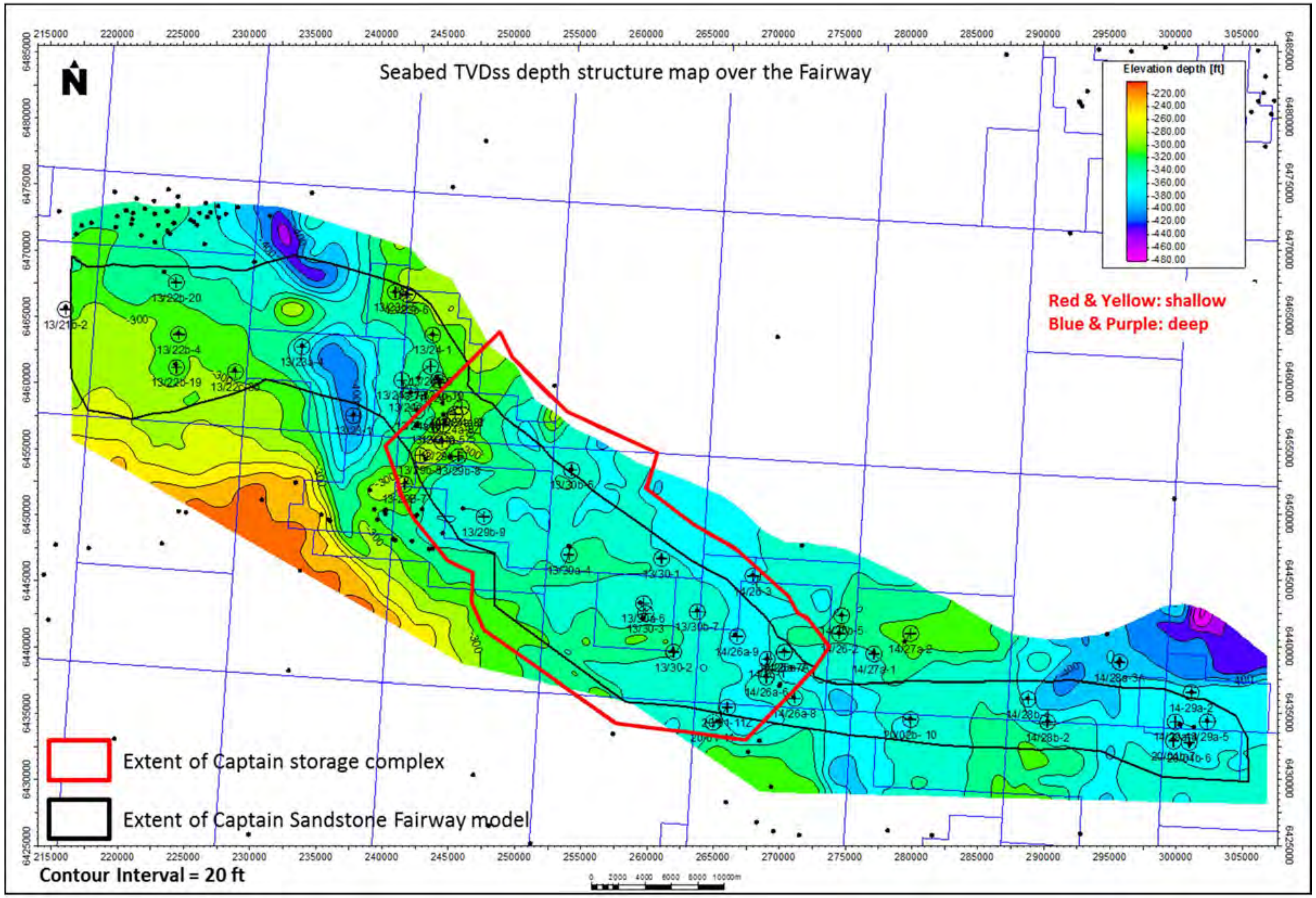



*Figure 11-12 Seabed Depth Structure Map*

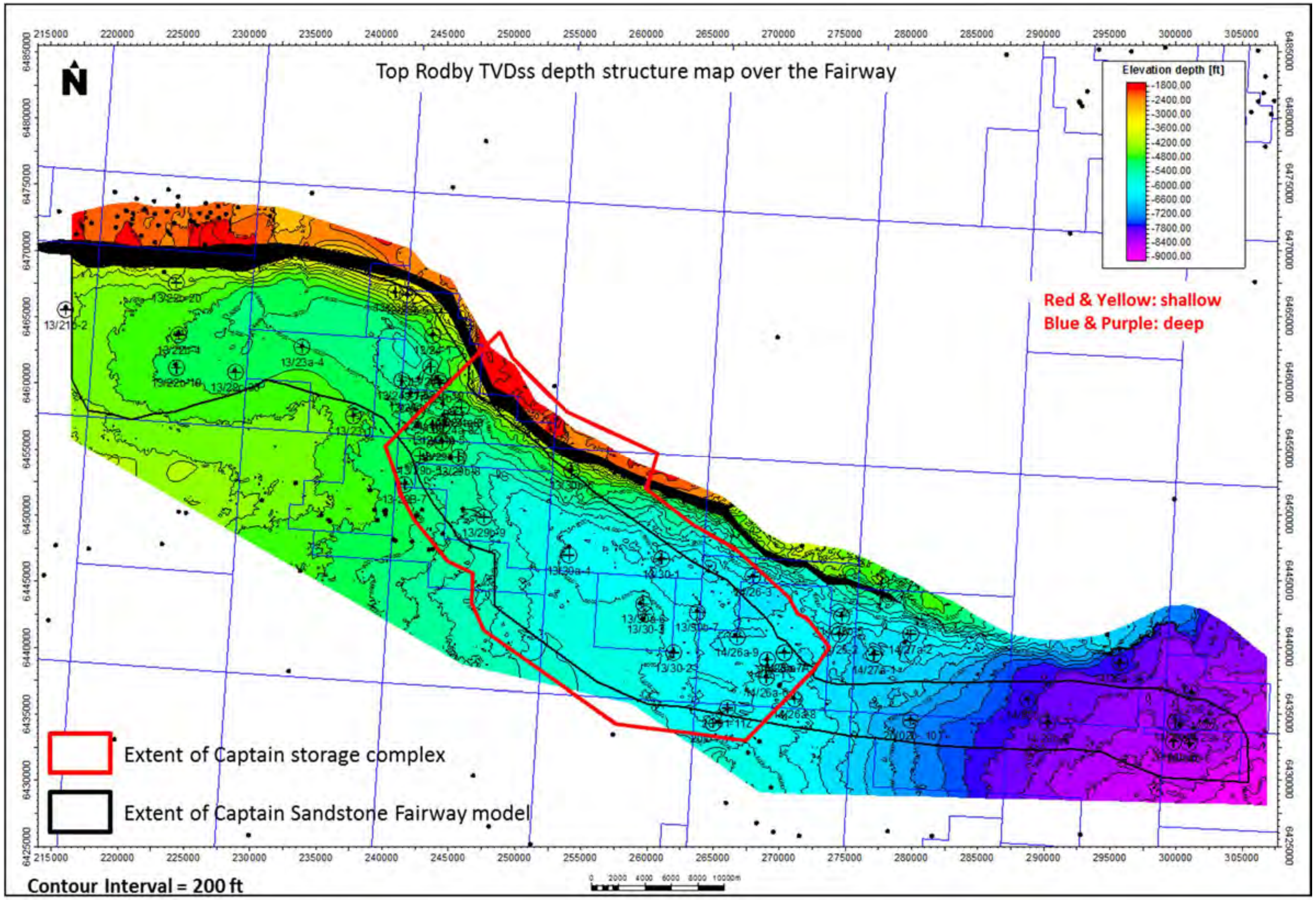



*Figure 11-13 Top Rodby Depth Structure Map*

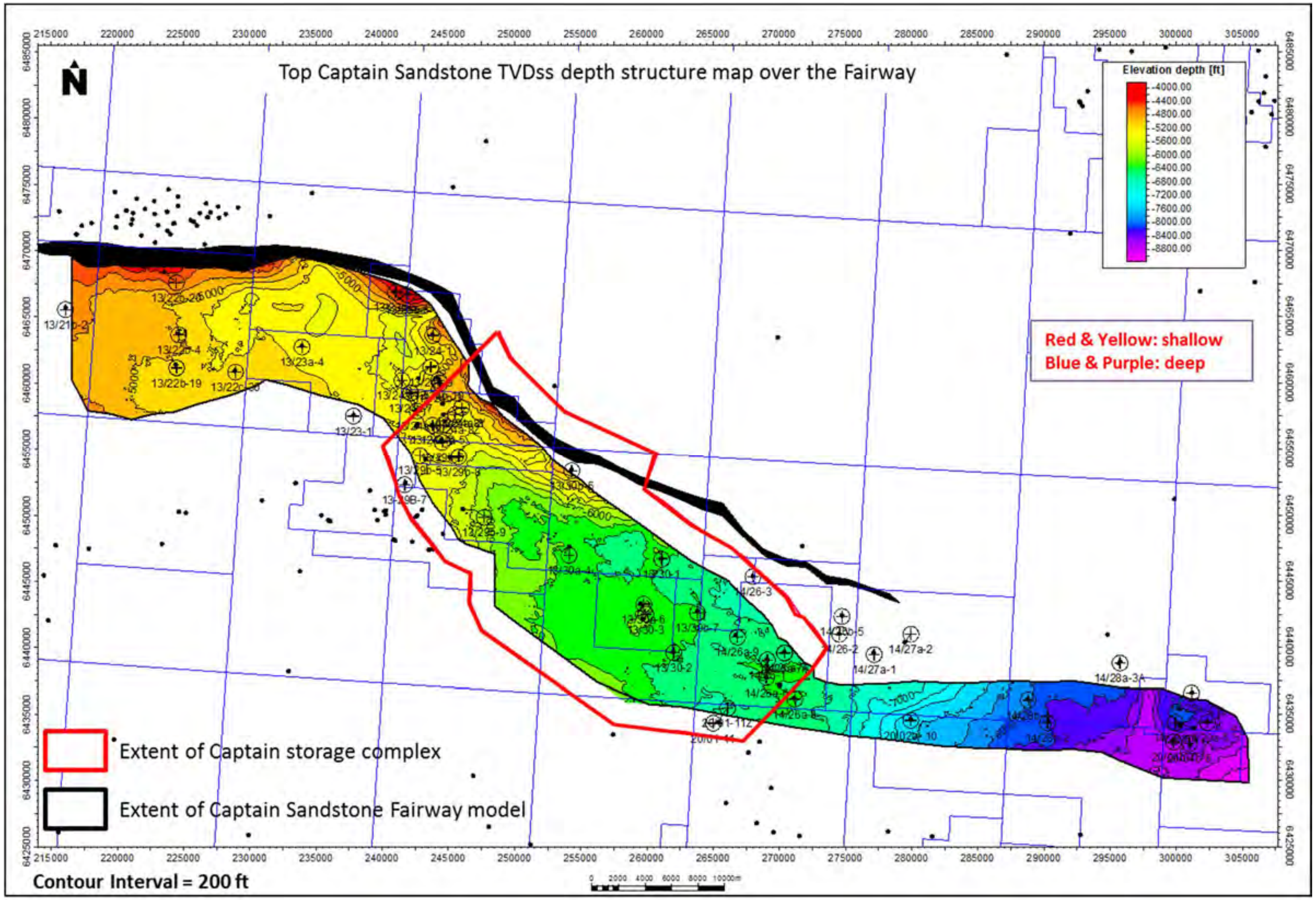



Figure 11-14 Top Captain Depth Structure Map

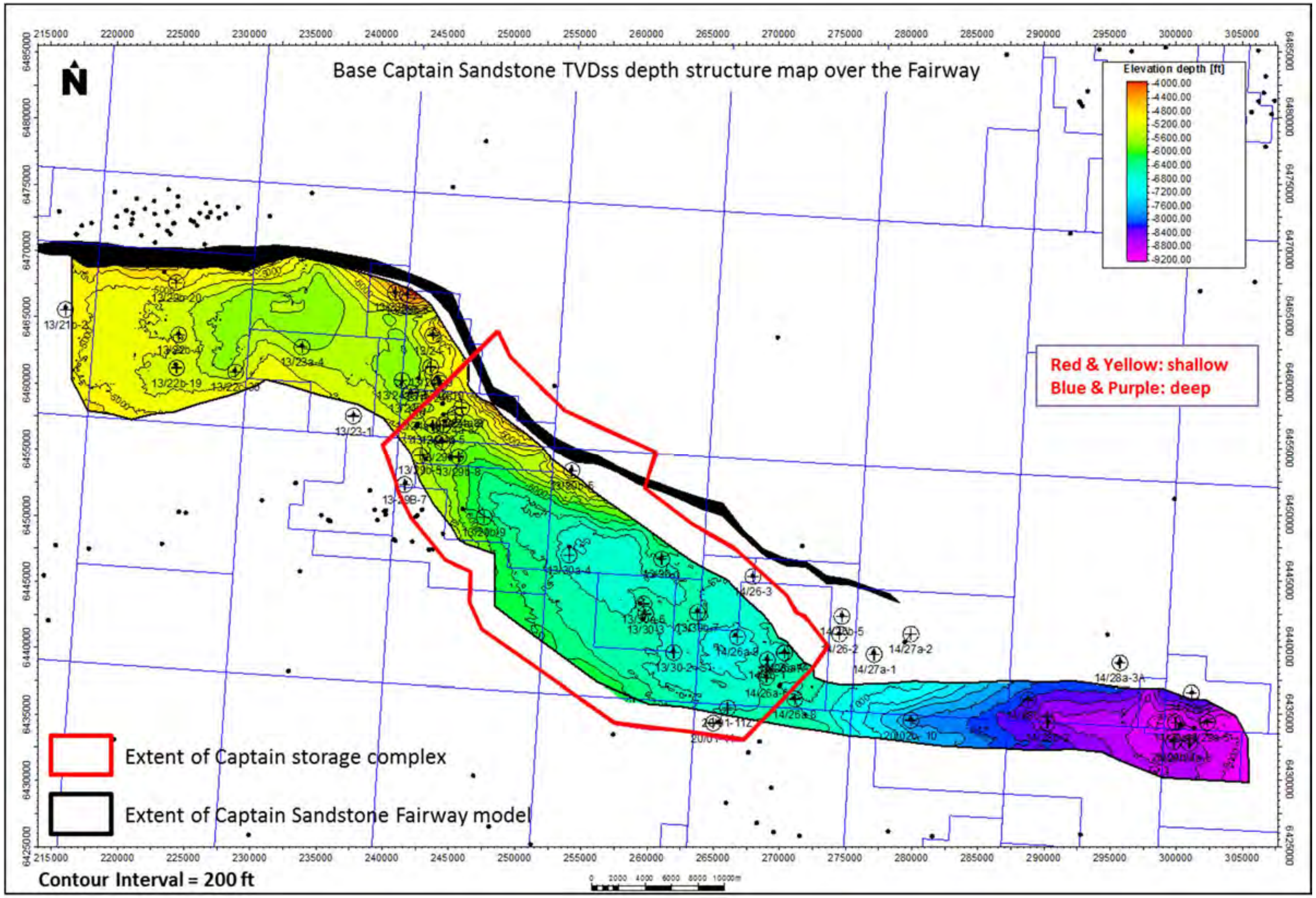



*Figure 11-15 Base Captain Sandstone Depth Structure Map*

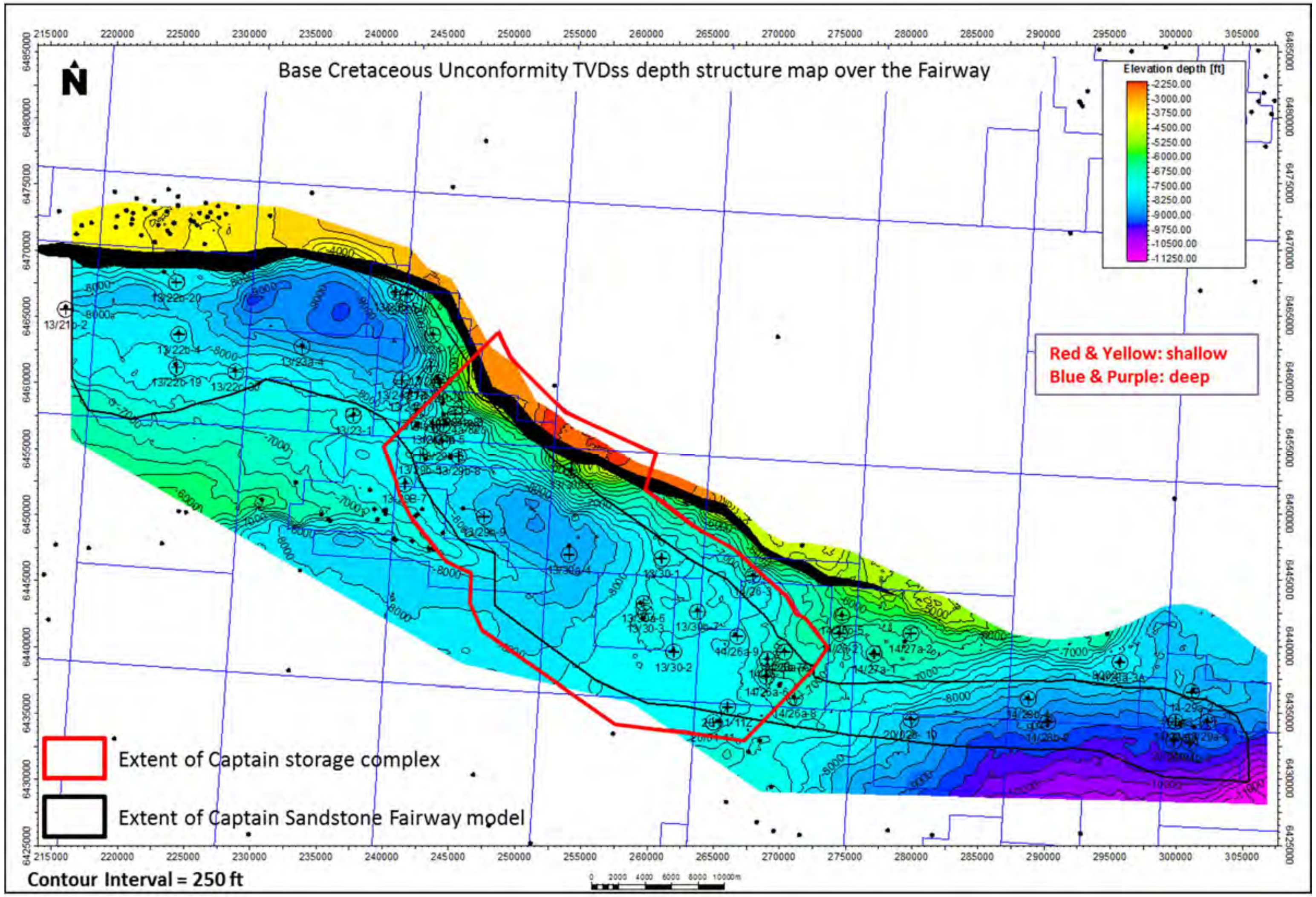



*Figure 11-16 Base Cretaceous Unconformity Depth Structure Map*

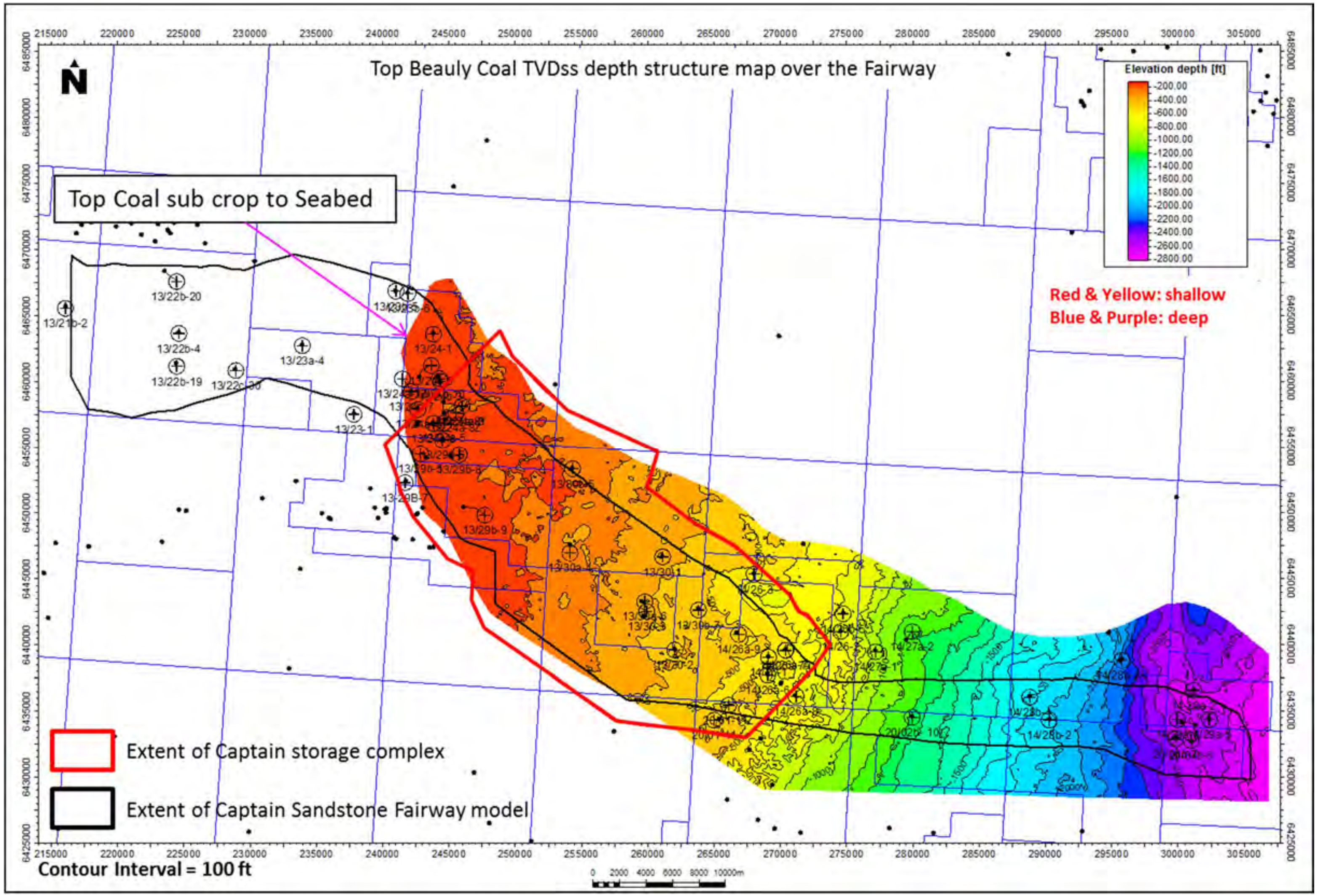



*Figure 11-17 Top Beauly Coal Depth Structure Map*

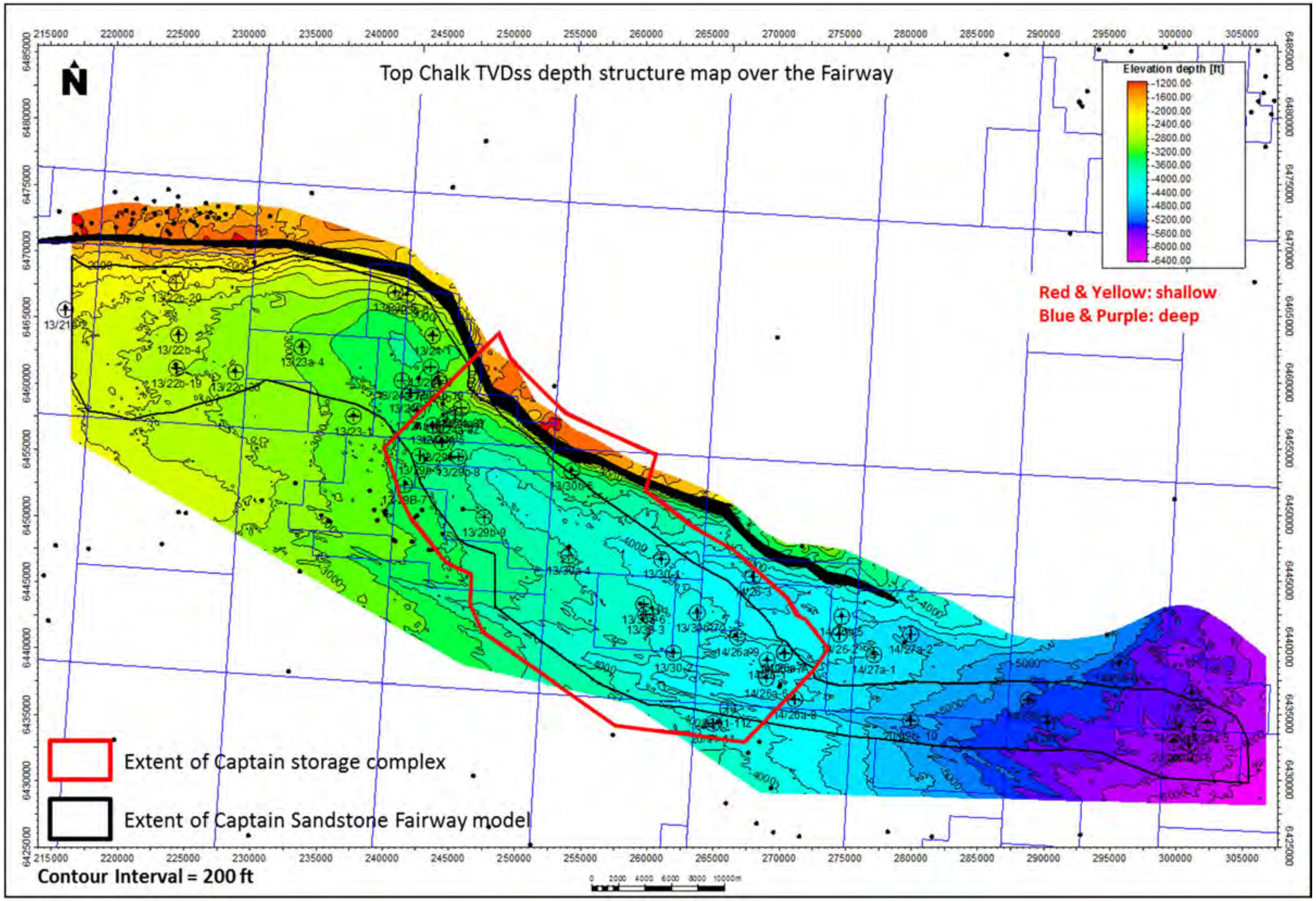



*Figure 11-18 Top Chalk Depth Structure Map*

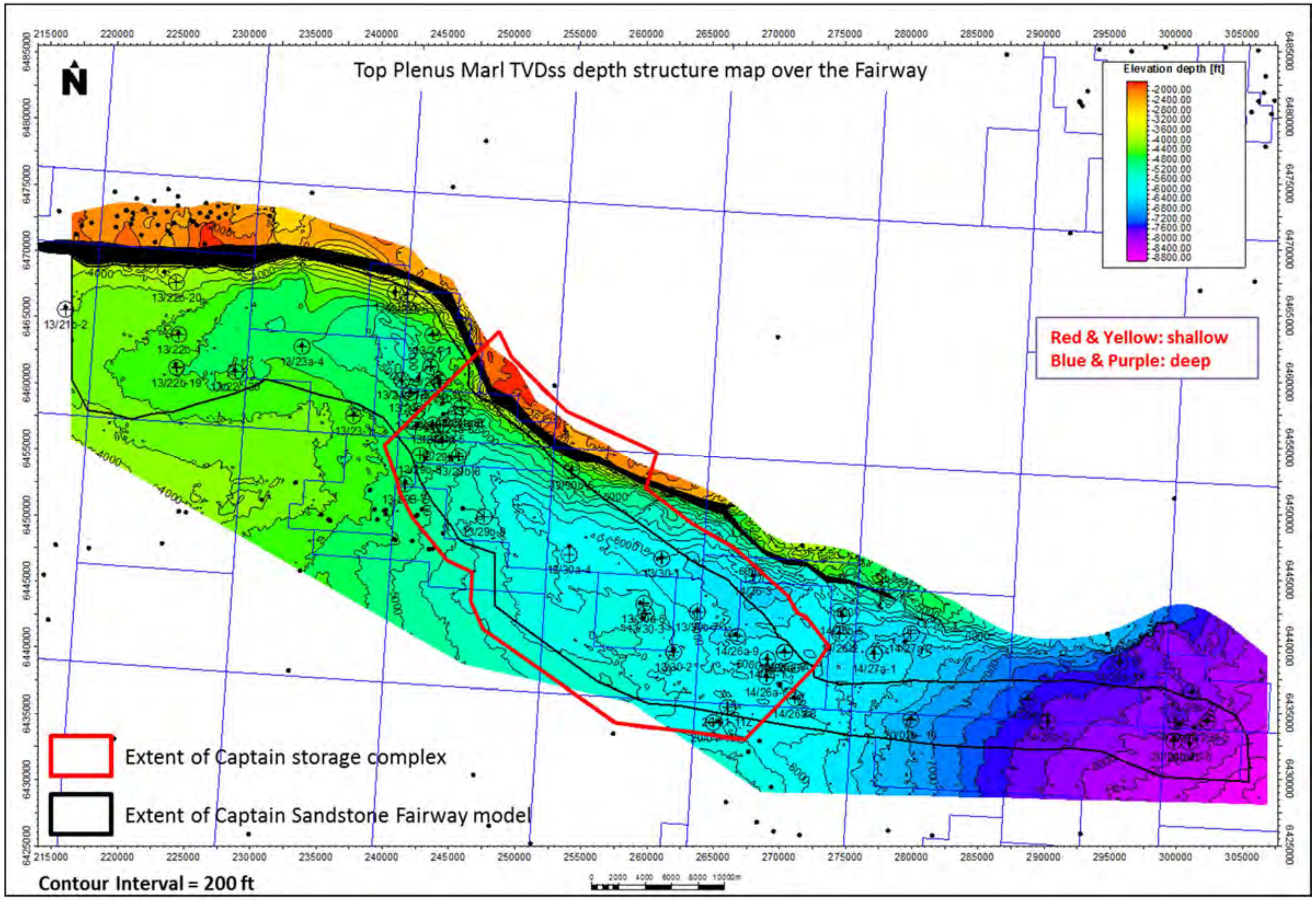



*Figure 11-19 Top Plenus Marl Depth Structure Map*

### 11.4.2 CPI logs

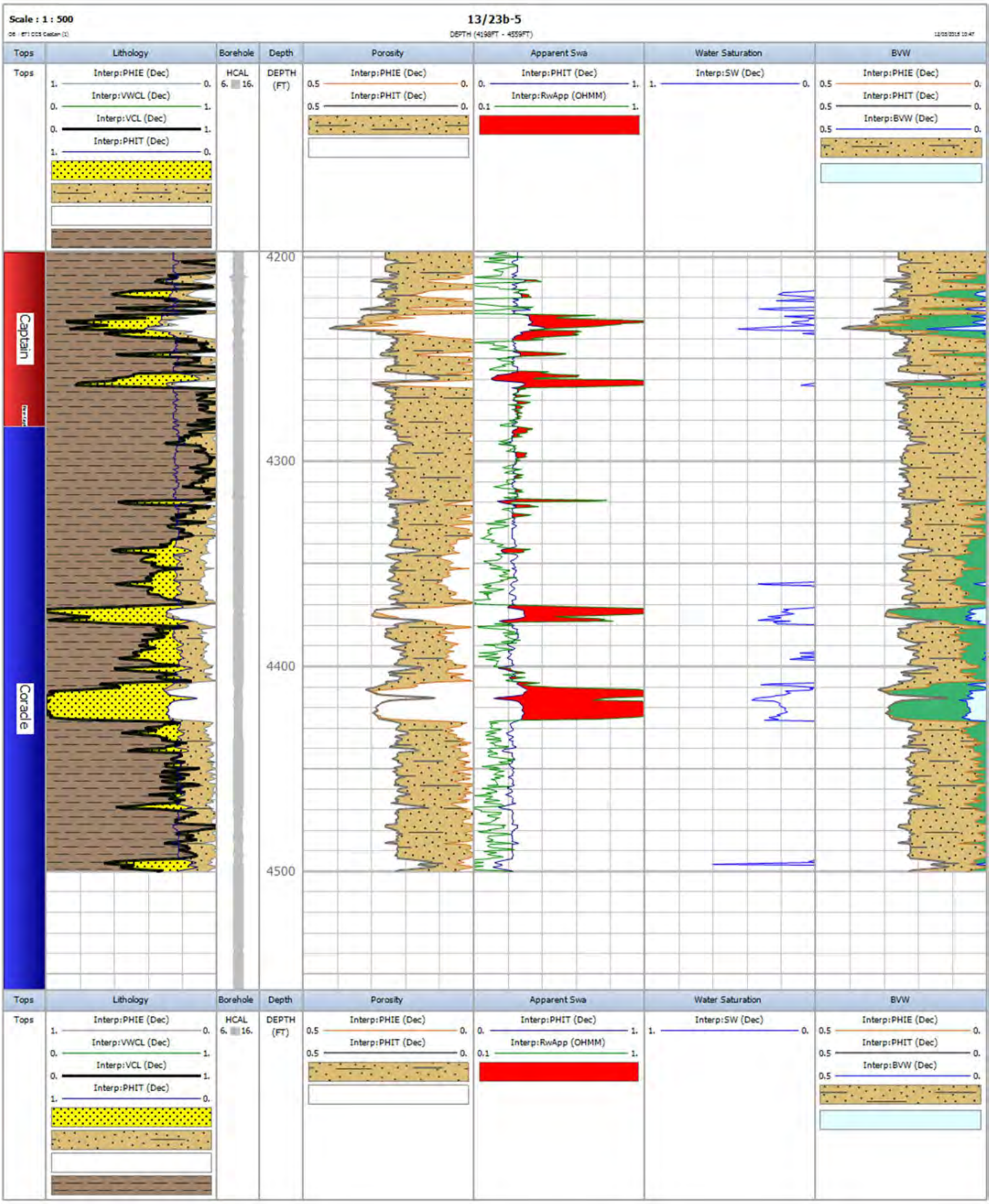



*Figure 11-20 13/23-5 CPI*

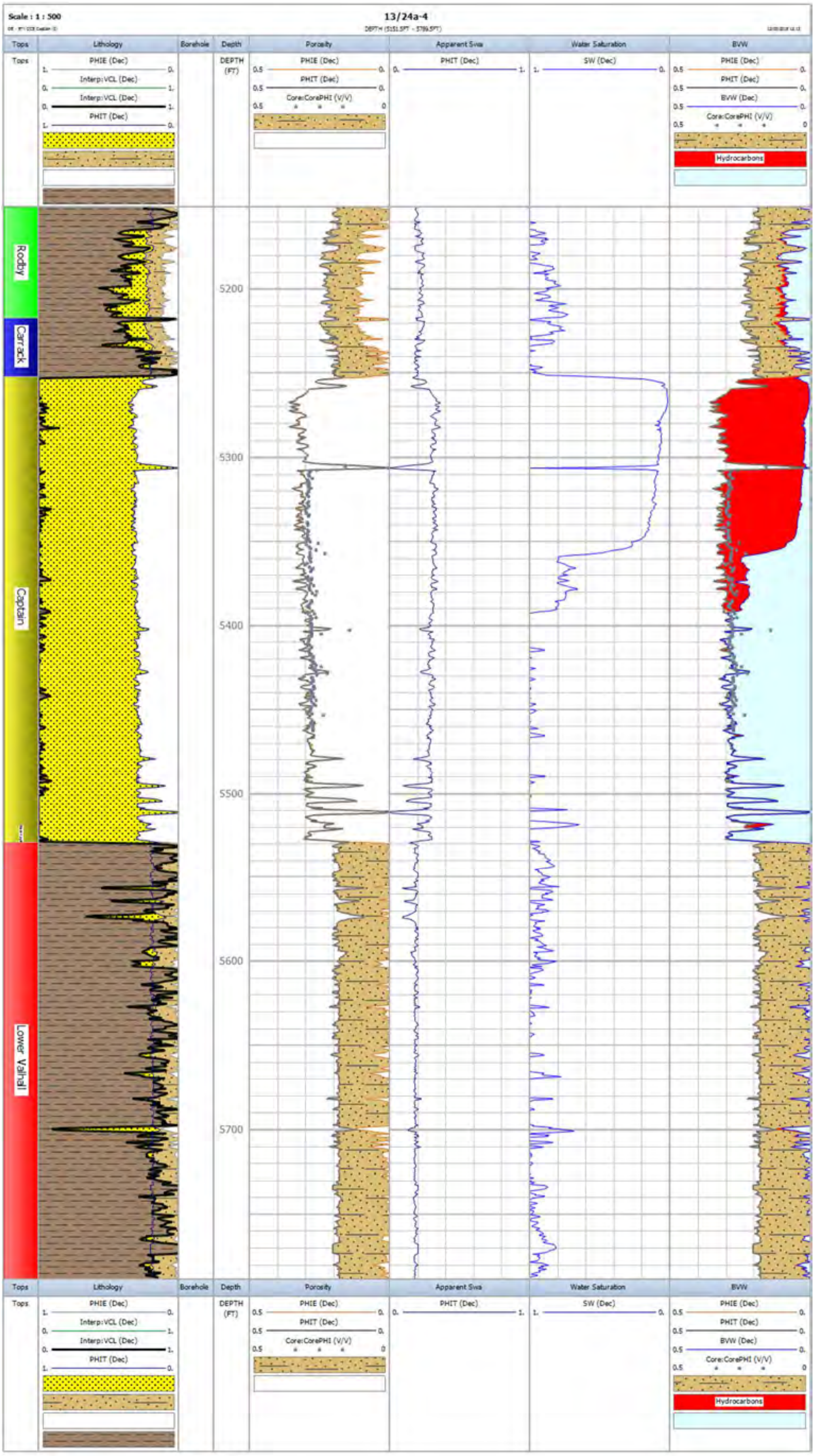



*Figure 11-21 13/24a-4 CPI*

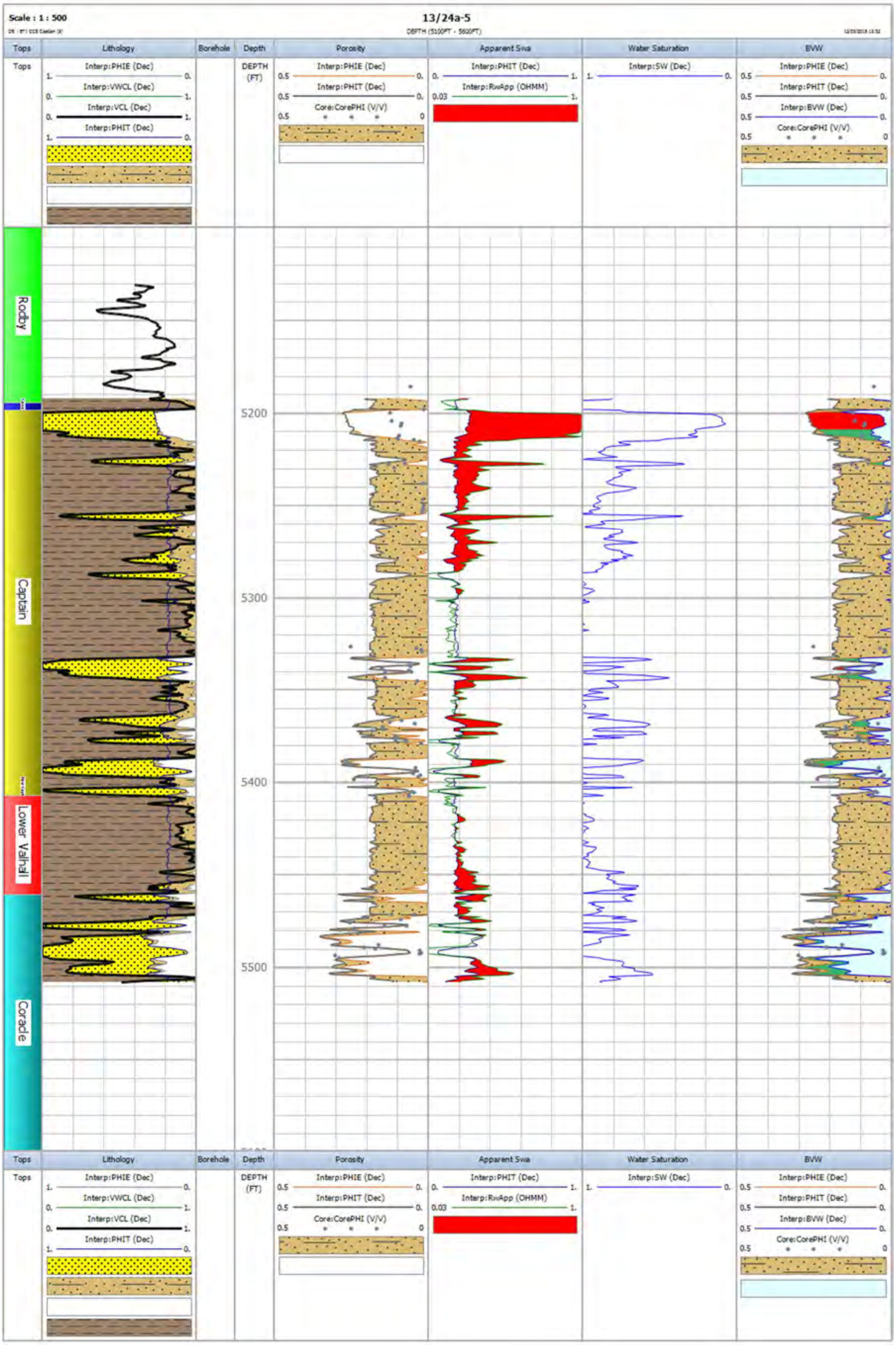



*Figure 11-22 13/24a-5 CPI*

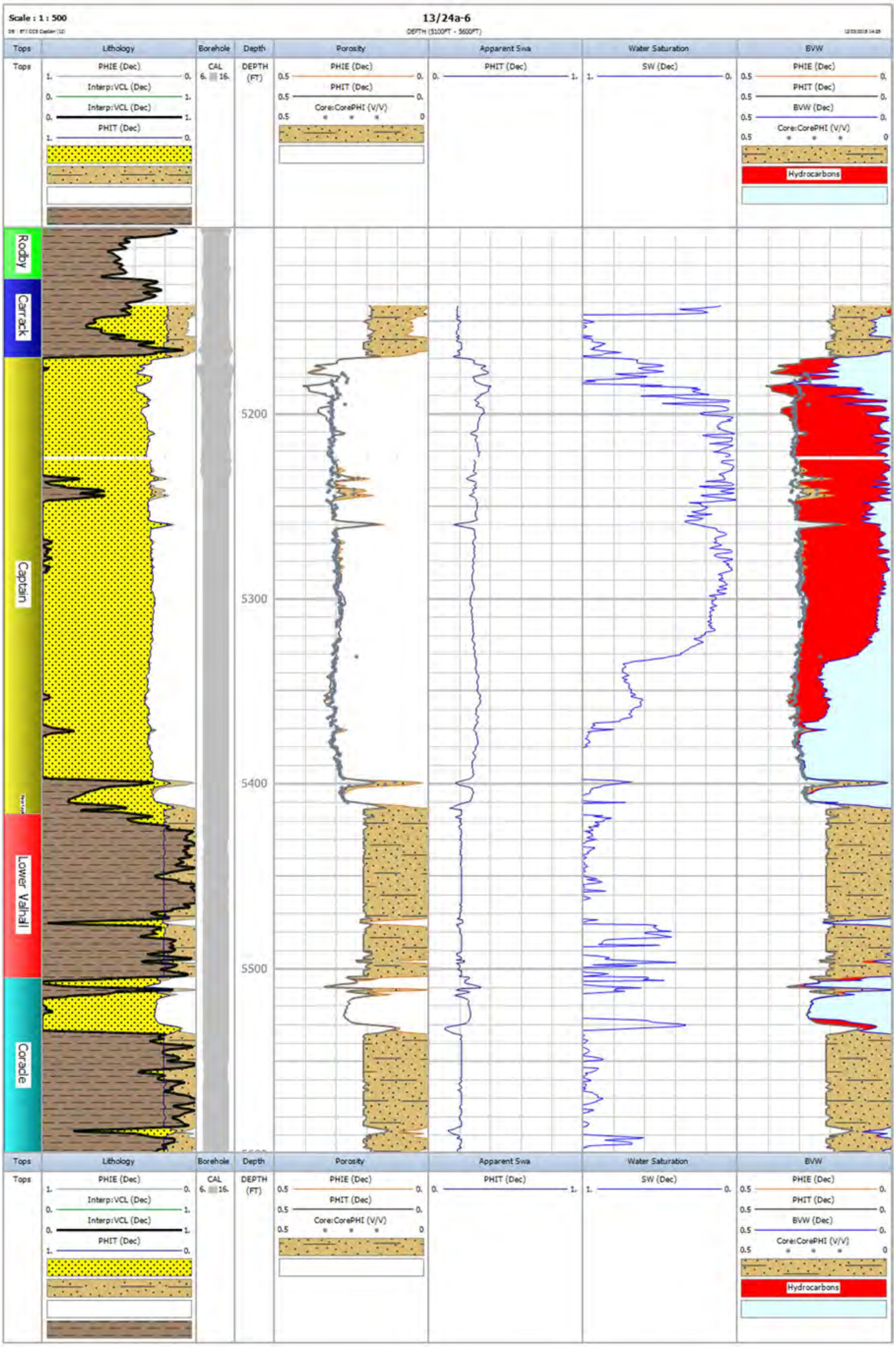



*Figure 11-23 13/24a-6 CPI*

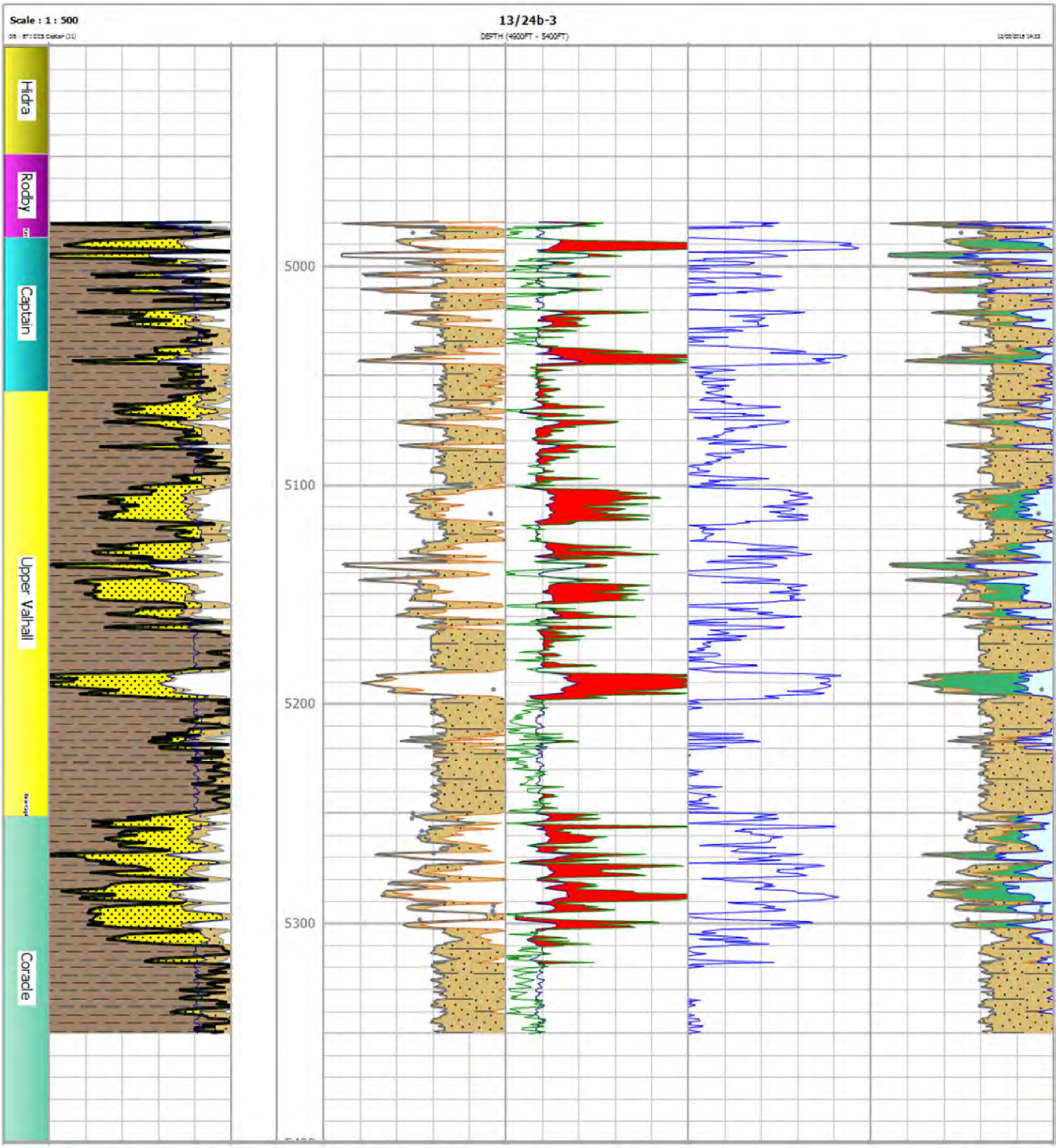



*Figure 11-24 13/24b-3 CPI*

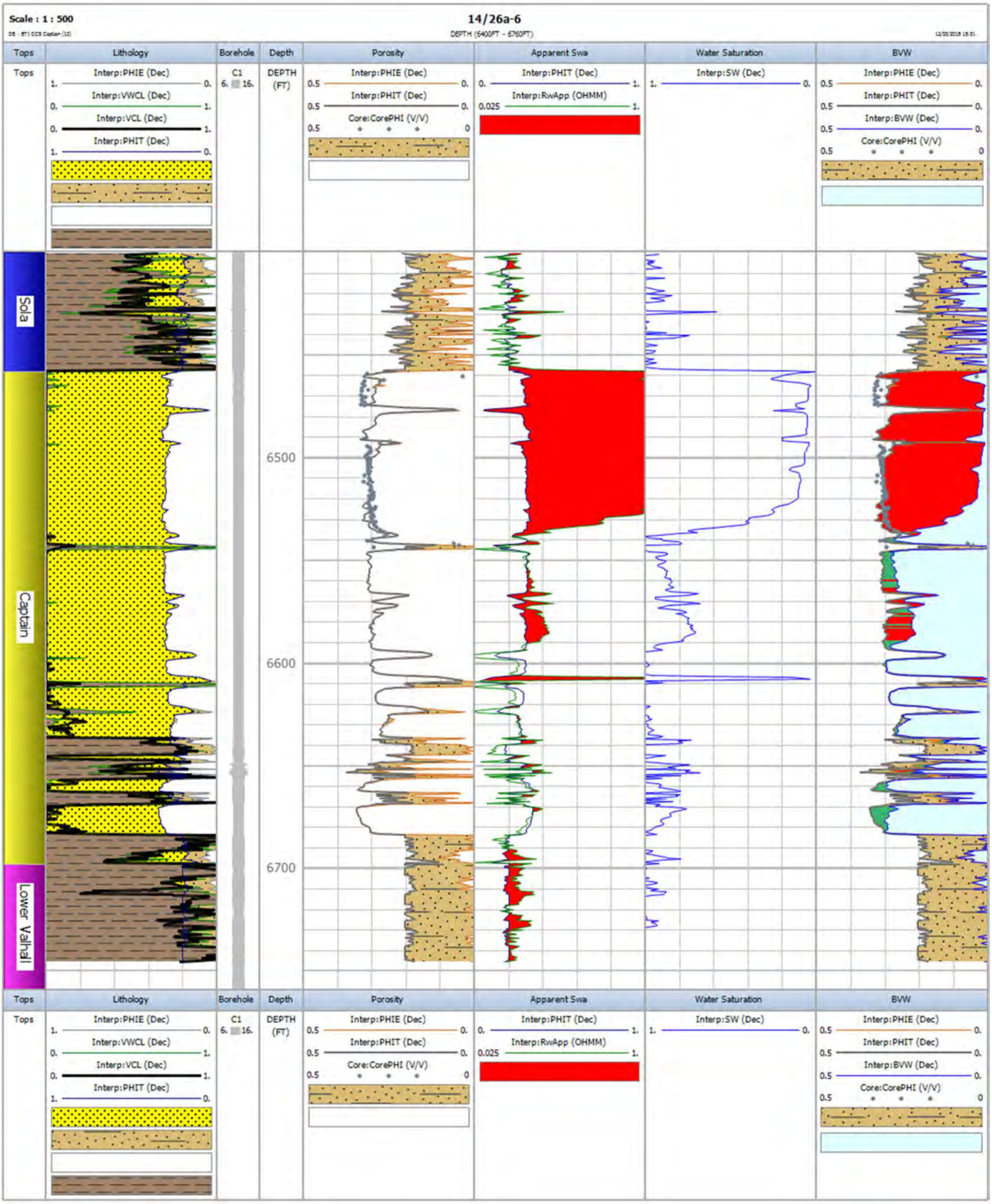



*Figure 11-25 13/26a-6 CPI*

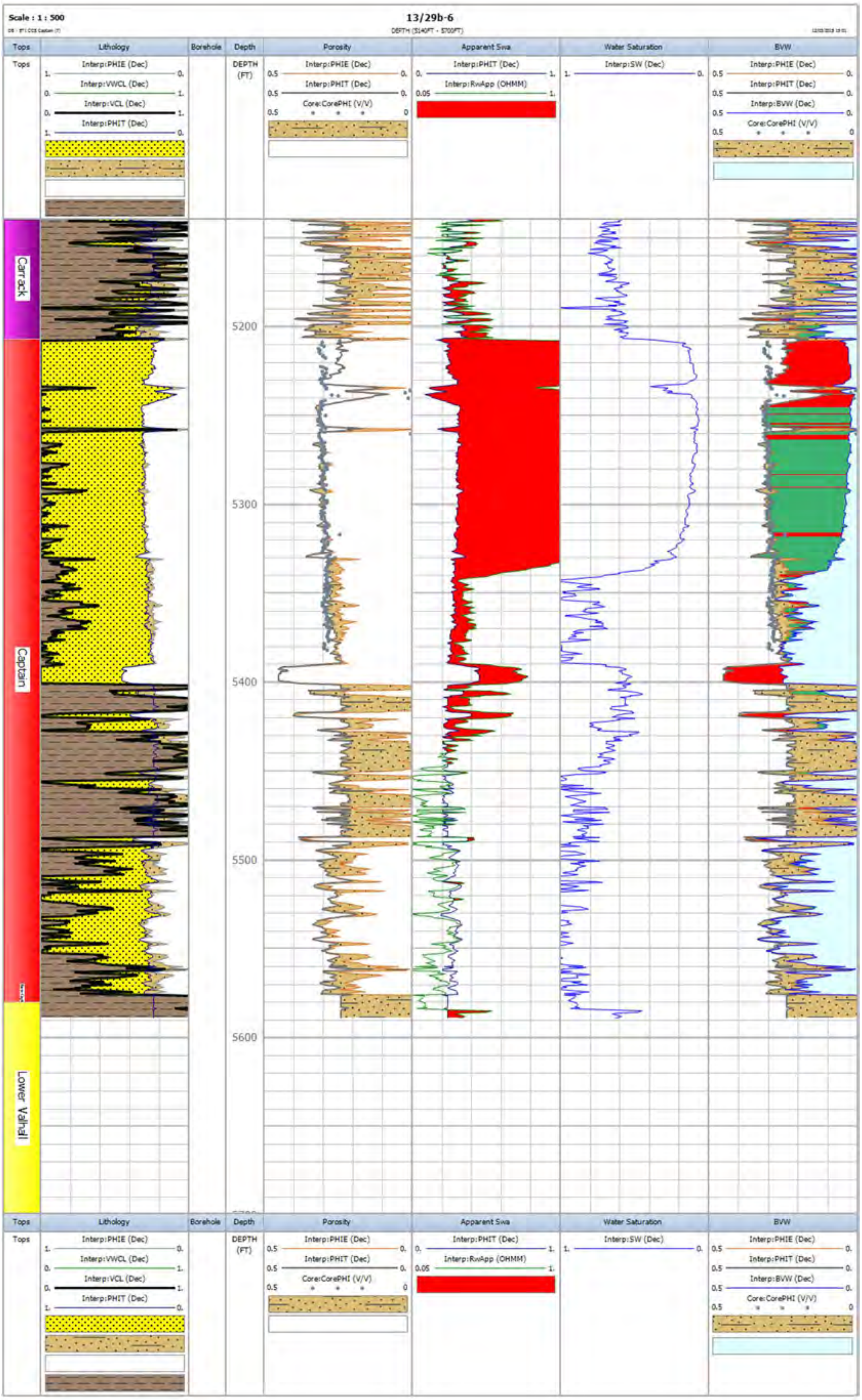



*Figure 11-26 13/29b-6 CPI*

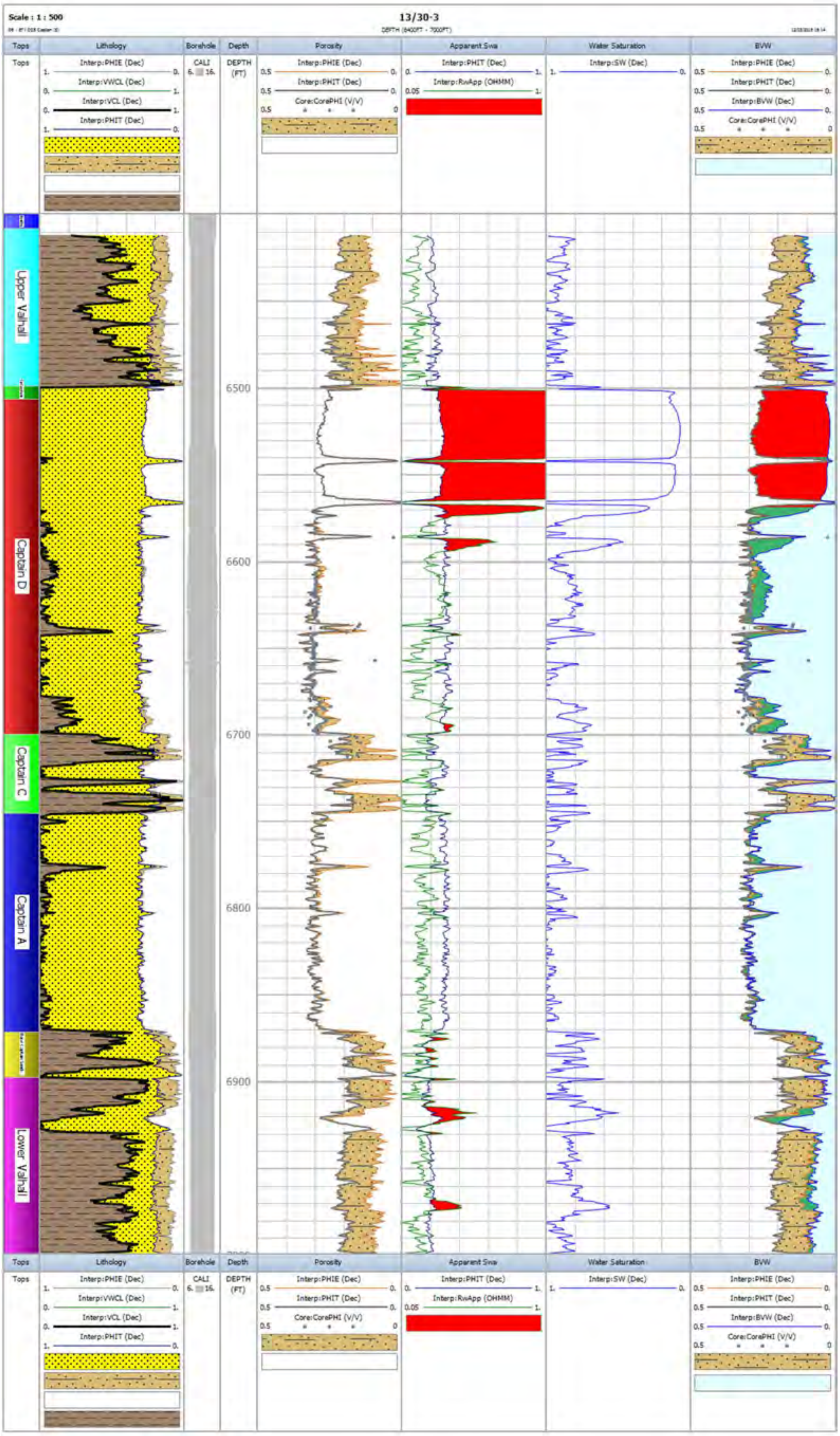



*Figure 11-27 13/30-3 CPI*

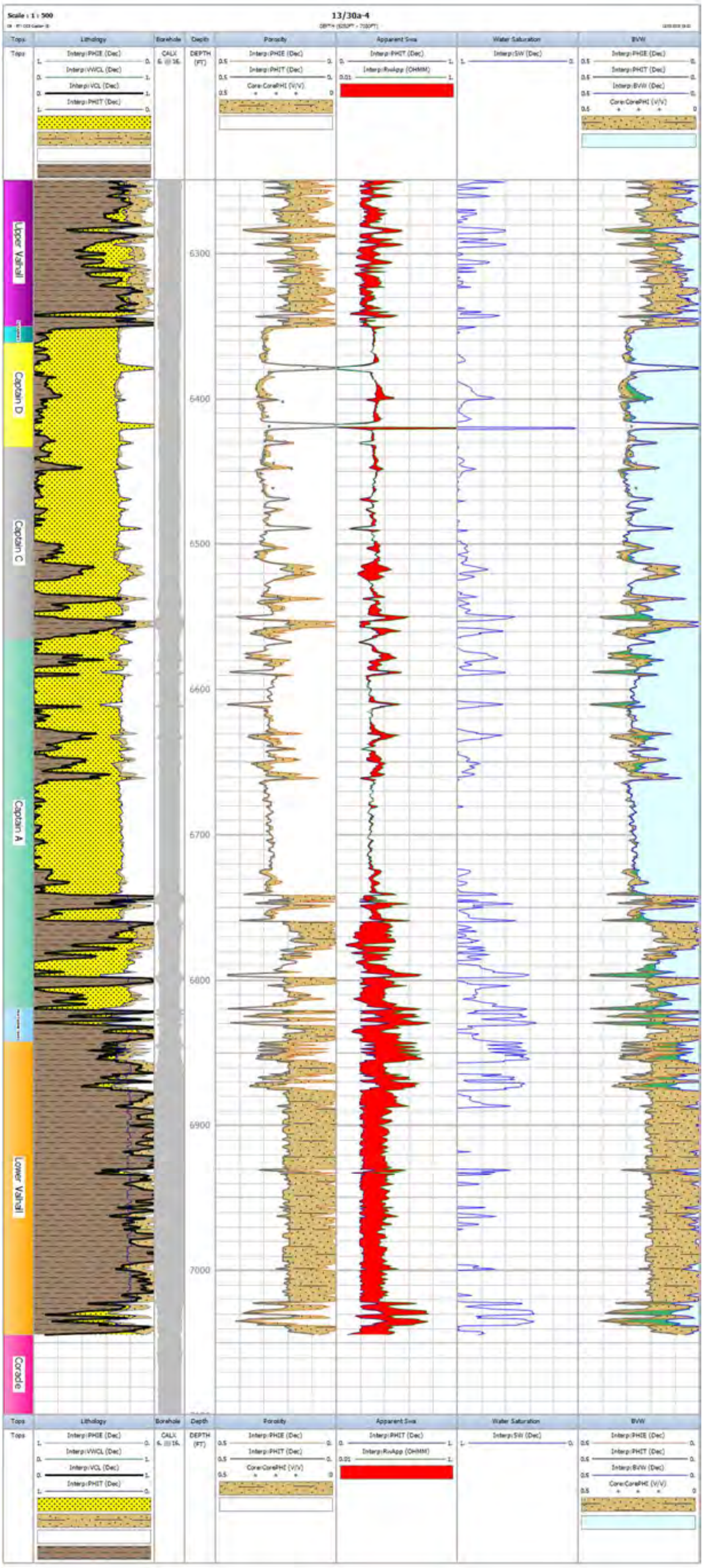



*Figure 11-28 13/30a-4 CPI*

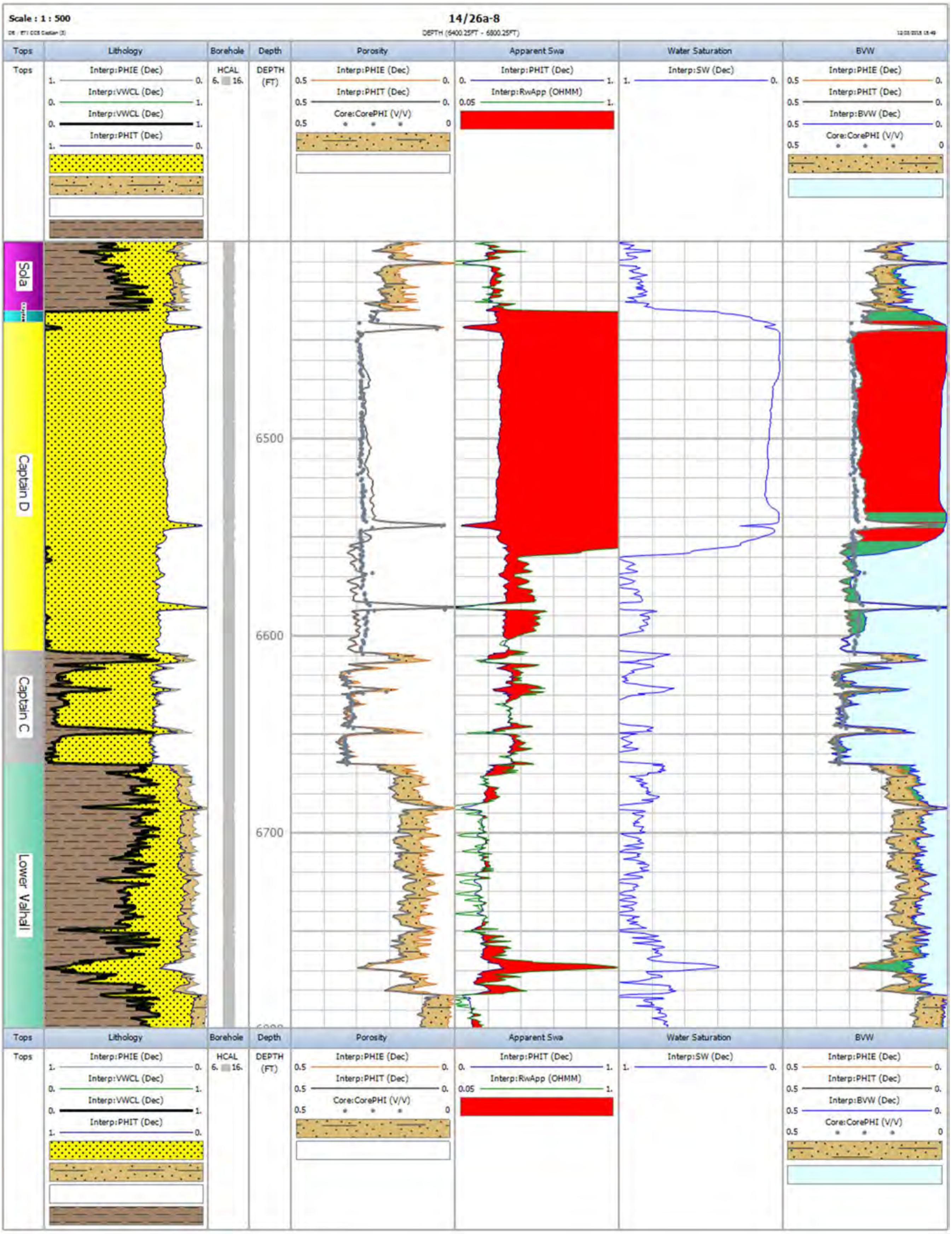



*Figure 11-29 14/26a-8 CPI*

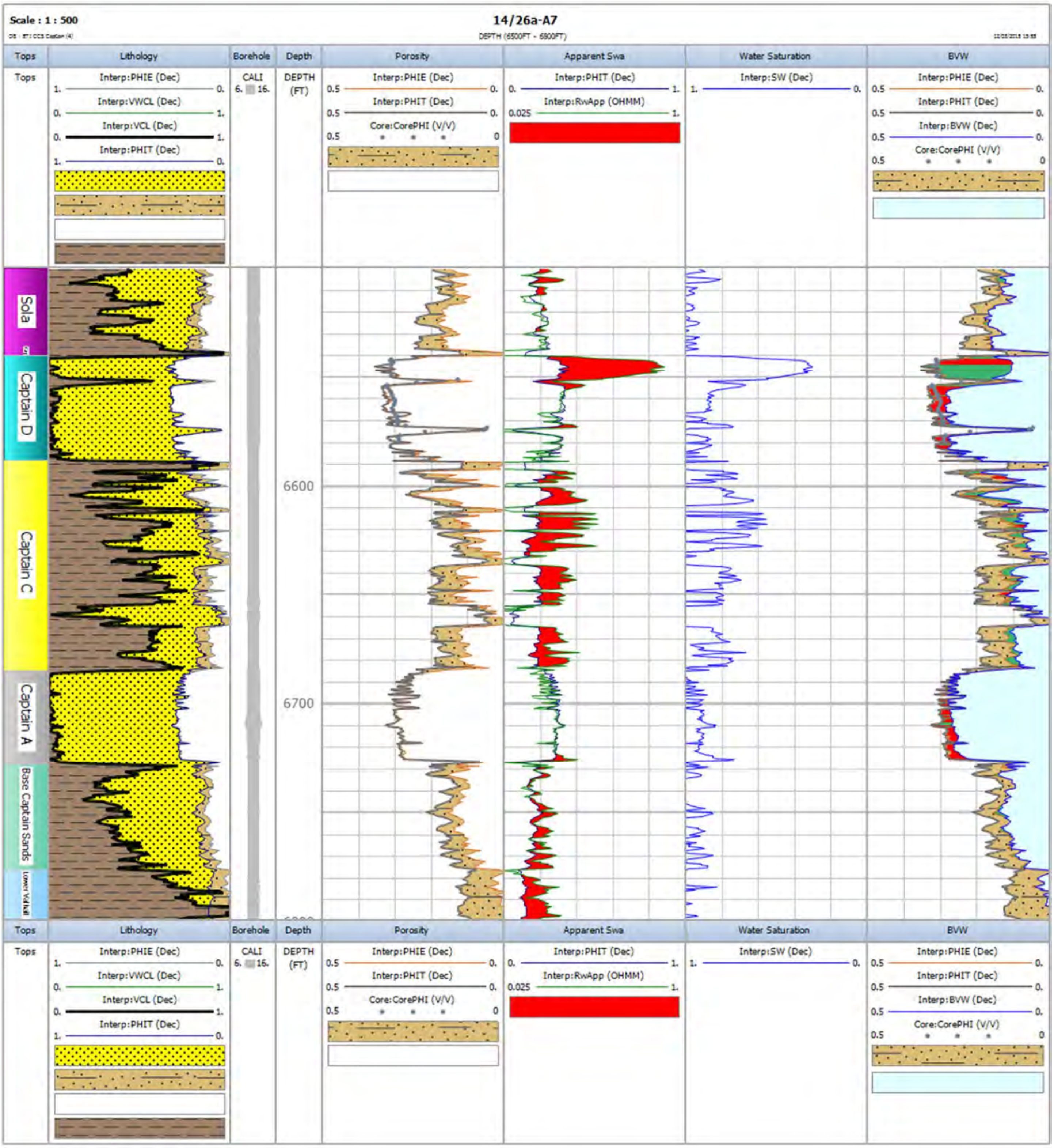



Figure 11-30 14/26a-A7 CPI

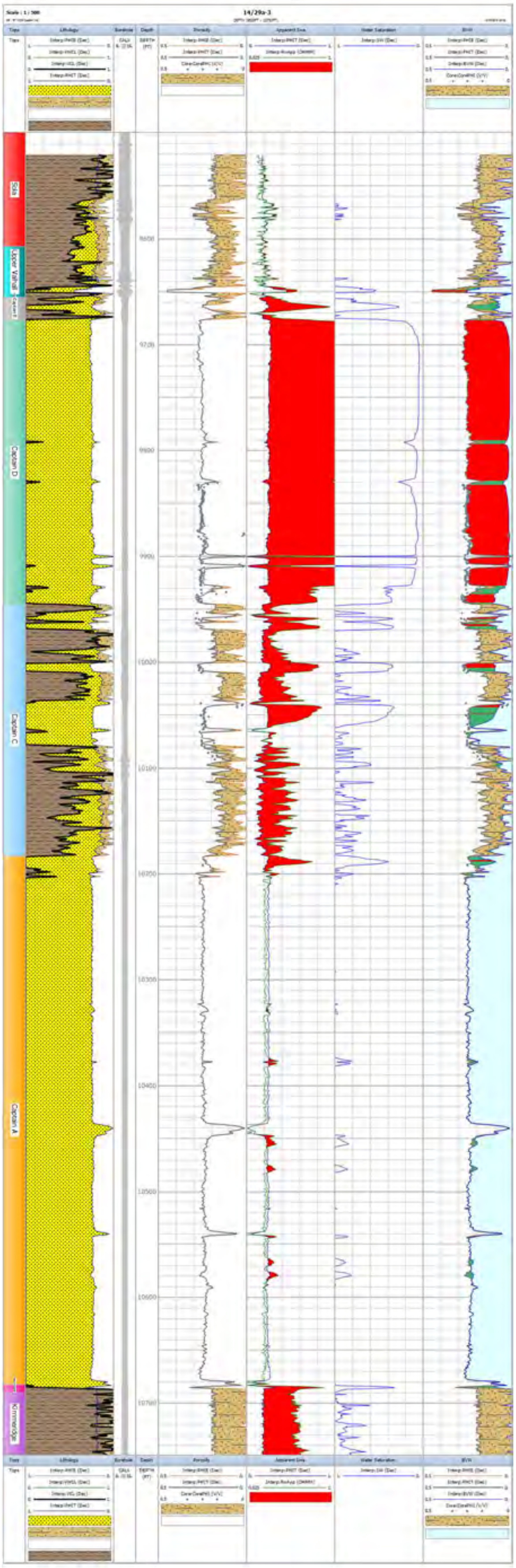



*Figure 11-31 14/29a-3 CPI*

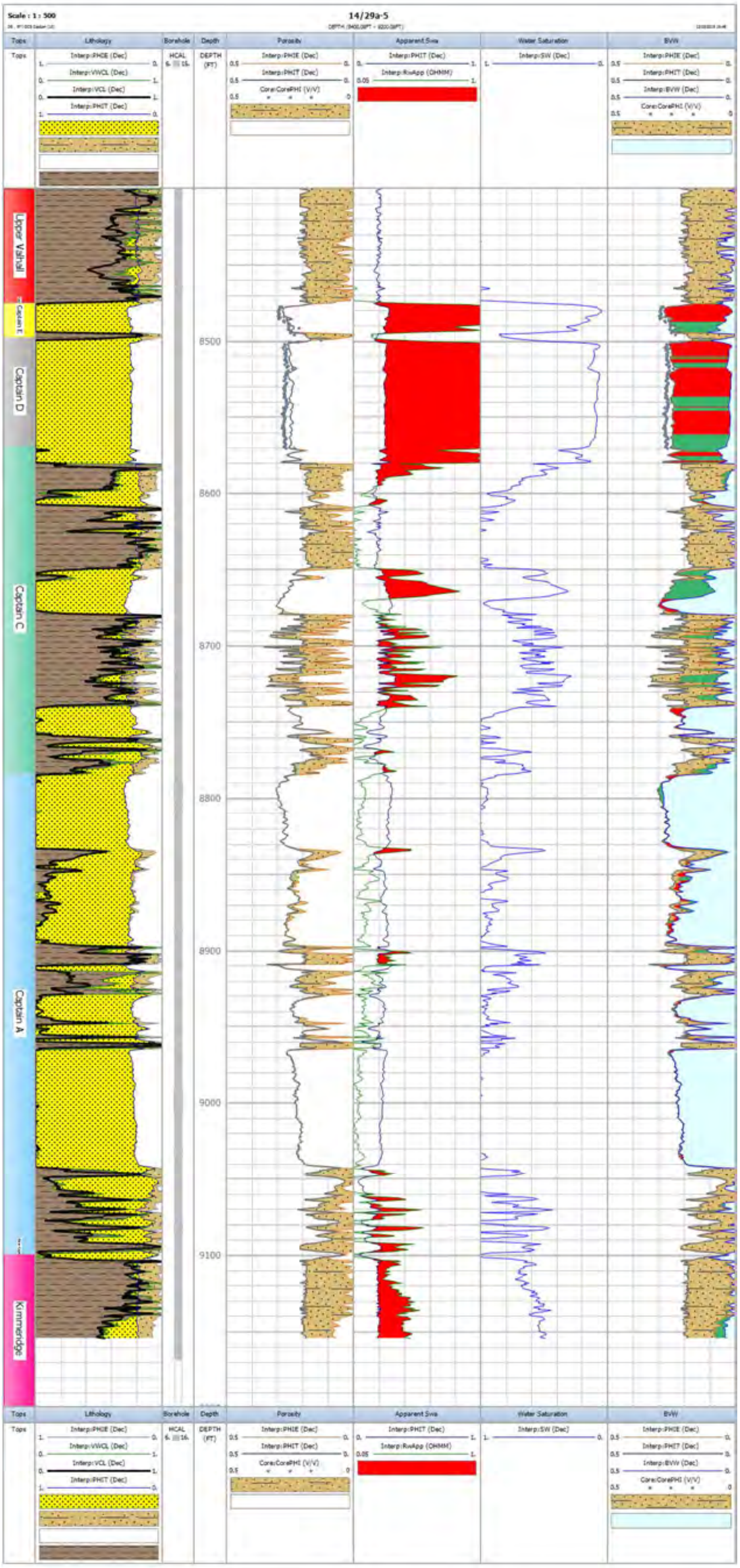



*Figure 11-32 14/29a-5 CPI*

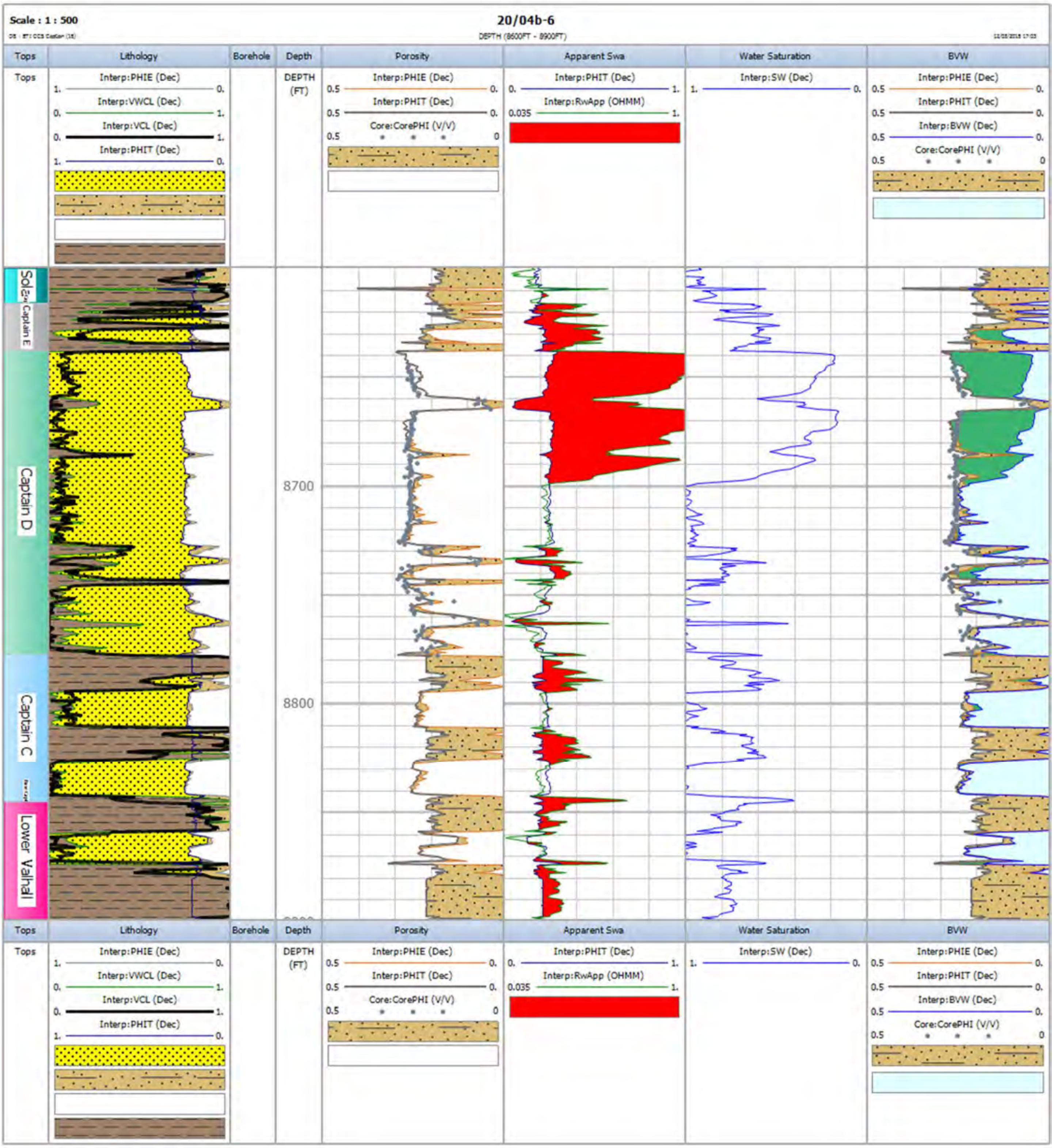



*Figure 11-33 20/04b-6 CPI*

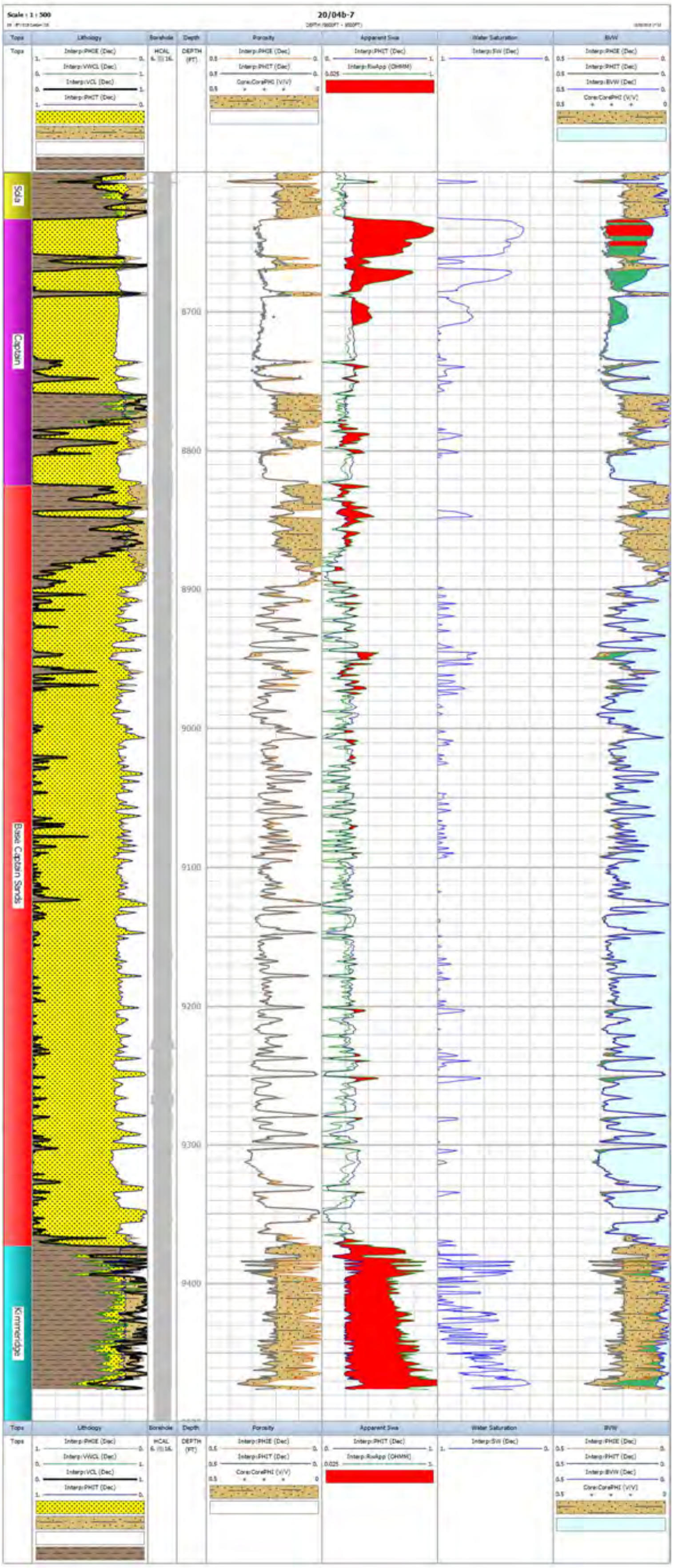



*Figure 11-34 20/04b-7 CPI*

## 11.5 Appendix 5 – MMV Technologies

Monitoring, measurement and verification (MMV) of any $CO_2$ storage site in the United Kingdom Continental Shelf (UKCS) is required under the EU CCS Directive (The European Parliament And The Council Of The European Union, 2009) and its transposition into UK Law through the Energy Act 2008 (Energy Act, Chapter 32, 2008). A comprehensive monitoring plan is an essential part of the $CO_2$ Storage Permit.

The four main purposes of monitoring a $CO_2$ storage site are to:

- Confirm that the actual behaviour of the injected $CO_2$ conforms with the modelled behaviour.
- Confirm that there is no detectable leakage from the storage reservoir and defined storage complex.
- Confirm that the storage site will permanently contain the injected $CO_2$.
- Acquire data to update reservoir models to refine future $CO_2$ behaviour predictions.

The storage site has been carefully selected to ensure secure containment of the $CO_2$ and so loss of containment is not expected. A site monitoring plan needs to prove that the integrity of the store has not been compromised and build confidence that the store is behaving as predicted.

The monitoring plan is based on a risk assessment of the storage site and is designed to prevent risks, or mitigate them, should they occur. The plan is also dynamic, meaning that it will be updated throughout the life of the projected as new data are acquired, or perhaps as new technologies become commercial.

The two elements of the monitoring plan are discussed in the following sections:

- Base Case monitoring plan.
- Corrective measures plan.

#### 11.5.1.1 Base Case Monitoring Plan

The base case plan is one that is scheduled and consists of baseline, operational and post-closure monitoring activity.

**Baseline monitoring** is carried out prior to injection and provides a baseline against which to compare all future results to. Since all future results will be compared to these pre-injection data, it is very important to ensure a thorough understanding of what the baseline is so that any possible deviations from it can be detected with greater confidence.

**Operational monitoring** is carried out during injection and to ensure that the $CO_2$ is contained and that the injection process and performance of the store is as expected. Data acquired from this monitoring phase will be used to update and history match existing reservoir models. The data will also be used to revise and update the risk assessment. Data such as flow, pressure and temperature at injection wellheads will be used for quantification of the injected $CO_2$ for accounting and reporting under the EU Emissions Trading Scheme (The European Parliament and the Council of the European Union, 2012).

As part of the Storage Permit application, the monitoring plan should include surface facilities and equipment process monitoring to demonstrate that the pipeline and facilities are operating as designed.

**Post-closure monitoring** takes place after cessation of injection with the primary purpose to confirm that the storage site is behaving as expected. Within the UK the anticipated requirement is for 20 years of post-closure monitoring, after which time the Department of Energy and Climate Change (DECC), or their successor will take on the storage liabilities, assuming the site shows conformance. A post-closure baseline will be carried out prior to post-closure monitoring for all future results to be compared against.

Post-handover monitoring may be required in the UK by DECC following handover of the storage liabilities. This would likely be negotiated between the $CO_2$ Storage Operator and DECC during the post-closure monitoring phase.

As discussed above, the monitoring plan is dynamic and will be updated and revised with data collected and interpreted from the monitoring activities. The plan will also be updated if new $CO_2$ sources are to be injected into the storage site or if there are significant deviations from previous modelling as a result of history matching.

Annual reporting to DECC will include information about site performance and may include commentary around any site-specific monitoring challenges that have occurred.

#### *11.5.1.2 Corrective Measures Plan*

The Corrective Measures Plan is deployed in case of detection of a 'significant irregularity' in the monitoring data, or leakage, and includes additional monitoring to further identify the irregularity and remediation options should they be required.

A 'significant irregularity' is defined in the CCS Directive as: *any irregularity in the injection or storage operations or in the condition of the storage complex itself, which implies the risk of a leakage or risk to the environment or human health.*

Corrective measures are defined in the CCS Directive as: *any measures taken to correct significant irregularities or to close leakages in order to prevent or stop the release of $CO_2$ from the storage complex.*

The four main parts to the Corrective Measures Plan are:

- Additional monitoring to understand the irregularity and gather additional data;
- Risk assessment to understand the potential implications of the irregularity;
- Measures to control or prevent the irregularities and;
- Potential remediation options (if required)

If any corrective measures are taken, their effectiveness must be assessed.

### 11.5.2 Monitoring Domains

Within the storage site and complex there are several monitoring domains, which have different monitoring purposes Table 11-8.

| Monitoring domain | Monitoring purpose |
|---|---|
| **Storage reservoir** | Confirm that the $CO_2$ is behaving as predicted |
| **Injection wells** | Ensure safe injection process, collect data to update reservoir models for $CO_2$ prediction and detect any early signs of loss of containment |
| **Storage complex (including P&A wells)** | Detection of $CO_2$ |
| **Seabed/ atmosphere** | Detection of $CO_2$<br>Quantification of $CO_2$ leakage |

*Table 11-8 Monitoring domains*

### 11.5.3 Monitoring Technologies

Many technologies which can be used for offshore $CO_2$ storage monitoring are well established in the oil and gas industry.

Monitoring of offshore $CO_2$ storage reservoirs has been carried out for many years at Sleipner and Snohvit in Norway and at the K12-B pilot project in the Netherlands. Onshore, Ketzin in Germany has a significant focus on developing MMV research and best practice.

A comprehensive list of existing technologies has been pulled together from NETL (2012) and IEAGHG (2015).

NETL (2012) references a "field readiness stage" for each technology, based on its maturity:

- Commercial
- Early demonstration
- Development

IEAGHG (2015) included an estimate of the cost of some offshore technology.

To help map each monitoring technology's relevance and applicability to a generic Storage site in the North Sea site, a Boston Square plot was used. This is a useful tool, which has been used on previous $CO_2$ storage projects such as In Salah (operational) and Longannet (FEED study).

Along the x-axis of the plot is the relative cost (low to high) and along the y-axis is the relative value of information (VOI) benefit (high to low) and so each monitoring technology is plotted according to these parameters. The Boston Square can then be divided into four quadrants, which help to refine the choice of monitoring technologies:

"Just do it" - technologies with low cost and high VOI - these should be included as standard in the monitoring plan

"Park" - technologies with high cost and low VOI- these should be excluded from the plan

"Consider" - technologies with low cost but also a low VOI - these should not be ruled out due to their low cost

"Focussed application" - technologies with a high cost but a high VOI- these may be deployed less frequently, over a specific area or included in the corrective measures plan

Note that this Boston Square is for this stage in the project and would likely be modified following additional work to refine costs and benefits of the technologies for this site.

The Boston Square for a generic North Sea storage site is shown in Figure 11-35 and Table 11-9 provides additional information about each technology and the rationale for technologies in each quadrant.

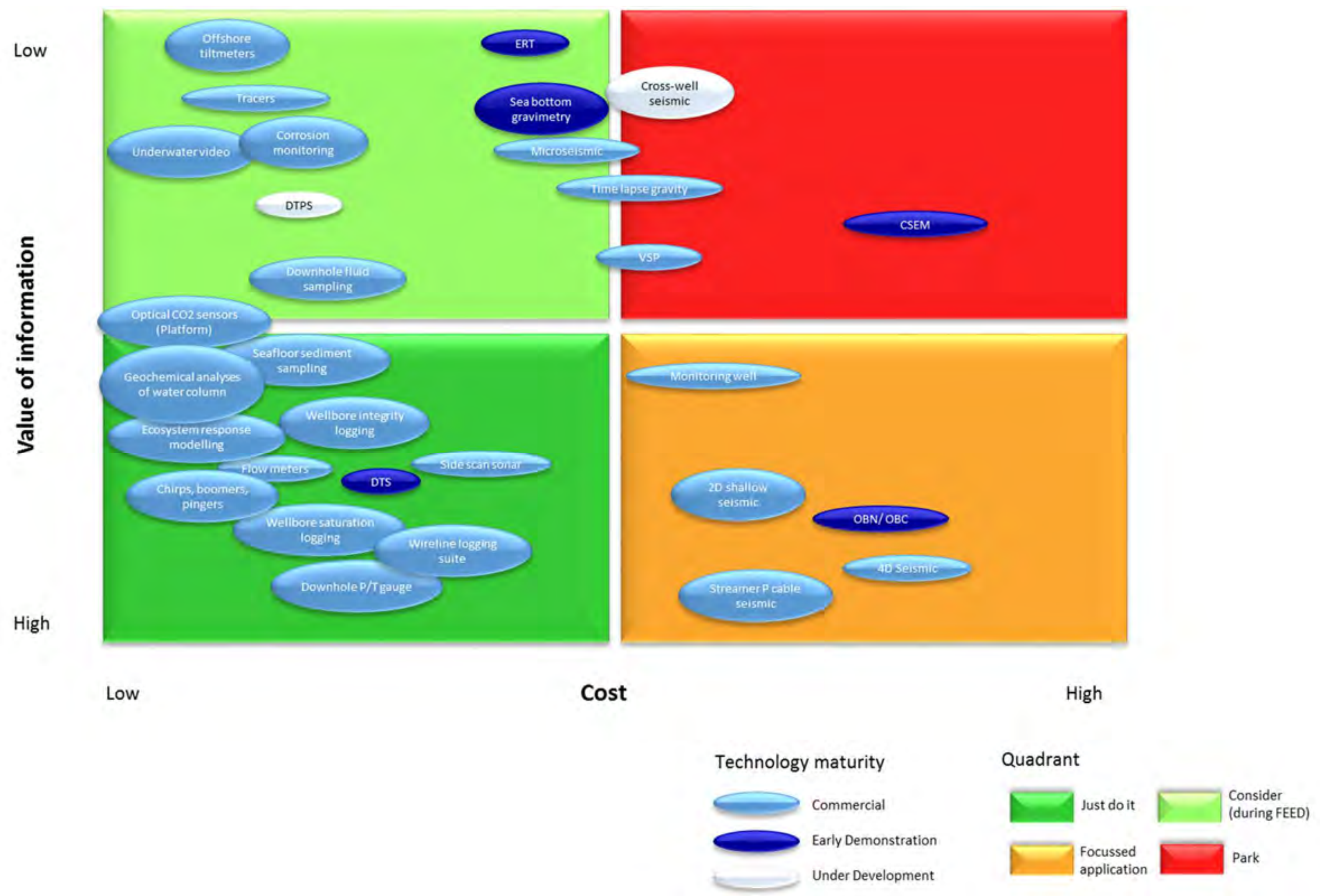



*Figure 11-35 Boston square plot of monitoring technologies applicable offshore*

### 11.5.4 Technologies for monitoring offshore

The table in the following pages contains technologies suitable for monitoring offshore.

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Subsurface** | Wireline Logging Tool | Commercial | Density logging | Platform and subsea | Standard wireline tool that provides information about a formation's bulk density along borehole length. Bulk density relates to the rock matrix and pore fluid so can be used to infer pore fluid and characterise reservoir models. Uses gamma rays (radioactive source) and detector that detects their scatter, which is related to the formation's electron density. | Just do it | Used for formation characterisation in reservoir models |
| **Subsurface** | Wireline Logging Tool | Commercial | Sonic logging | Platform and subsea | Standard wireline tool in the oil and gas industry. Measures velocity of both compressional and shear waves in the subsurface and transit times of acoustic wave. Could detect changes in pore fluid from $CO_2$ due to velocity contrasts between $CO_2$ and brine. | Just do it | Used for formation characterisation in reservoir models |
| **Subsurface** | Wireline Logging Tool | Commercial | Dual-induction logging | Platform and subsea | Resistivity logging - detects resistivity contrast between $CO_2$ (resistive) and water (conductive). | Just do it | Used for formation characterisation in reservoir models |
| **Subsurface** | Wireline Logging Tool | Commercial | Wellbore integrity logging | Platform and subsea | Well integrity logging focusses on determining the integrity of the wellbore (and its cement, casing etc.) and is important for safe injection operations and reduces leakage risk. i.e. Cement bond logging (CBL) and formation bond logging (VDL) | Just do it | Well integrity logging is considered essential for determining injection well integrity during operations. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Subsurface** | Wireline Logging Tool | Commercial | Pulsed neutron tool (PNT) | Platform and subsea | A standard wireline tool using pulsed neutron techniques to measure $CO_2$ saturation. Sensitive to changes in reservoir fluids and can distinguish between brine, oil and $CO_2$. PNT will not detect $CO_2$ dissolved in brine. | Just do it | Used for formation characterisation in reservoir models |
| **Subsurface** | Permanent Downhole Tool | Early Demonstration Stage | Distributed temperature sensor (DTS) | Platform and subsea | Permanent down-hole optical fibre tools which can detect temperature at ~1m intervals along the wellbore. Can measure in real time and may be able to detect $CO_2$ migration from reservoir with associated temperature drop or any fluid temperature fluctuations which could indicate a poorly sealed wellbore. | Just do it | Considered essential to ensure integrity of injection operations. Also used to update reservoir models. |
| **Subsurface** | Permanent Downhole Tool | Development Stage | Distributed thermal pertubation sensor (DTPS) | Platform and subsea | DTPS measures the thermal conductivity of the formation and can estimate $CO_2$ saturation within the zone of injection (decrease in bulk thermal conductivity indicates an increase in $CO_2$ saturation). Equipment includes an electrical heater with DTS. | Consider | The technology is at development stage so monitor its maturation and consider inclusion in FEED. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Subsurface** | Permanent Downhole Tool | Commercial | Corrosion monitoring | Platform and subsea | $CO_2$ with brine can be corrosive and so corrosion monitoring can be used to prevent potential failures within the injection system. Two techniques: (i) expose a removable piece of casing to the corrosive fluid for a set amount of time, remove it and analyse it (ii) install a corrosion loop with the injection system which can be removed and examined for signs of corrosion | Consider | Wellbores will designed to minimise corrosion and injection $CO_2$ will be dehydrated to minimise corrosion. Therefore uncertainty over benefit. To consider further in FEED. |
| **Subsurface** | Permanent Downhole Tool | Commercial | Downhole & wellhead Pressure/ Temperature gauges | Platform and subsea | Located in the storage reservoir and can give continuous reservoir pressure and temperature throughout field life. The injected $CO_2$ will be at a lower temperature than reservoir temperature so can differentiate between $CO_2$ and brine. Pressure and Temperature data can be used as input to reservoir models. Pressure can be used to confirm mechanical integrity of wellbore. Can be used at monitoring wells to aid in detection of $CO_2$ arrival ($CO_2$ may be at lower temperature and higher pressure than fluids in the formation). Deployment required under the EU Storage Directive | Just do it | Required under the EU Storage Directive and considered essential to ensure integrity of injection operations and to update reservoir models. |
| **Subsurface** | Permanent Downhole Tool | Commercial | Flow meters | Platform and subsea | Directly measure rate and volume of injected $CO_2$. Different types: differential pressure meters, velocity meters, mass meters. Used for reporting of injected volumes of $CO_2$. | Just do it | Essential for reporting on injected volumes of $CO_2$. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Subsurface** | Permanent Downhole Tool | | Subsurface Fluid Sampling and Tracer Analysis | Platform and subsea | Collection of liquid or gas samples via wells (from either reservoir or overlying formation) for geochemical analysis of changes in reservoir due to $CO_2$ or identify any tracers. Data can be used to constrain reservoir simulation modelling (e.g. fluid chemistry, $CO_2$ saturation etc). Challenges with additional reservoir fluids of hydrocarbon and brine and preserving samples at reservoir temperature and pressure. | Consider | Moderate cost and can be conducted during wireline runs. To be more fully considered during FEED |
| **Subsurface** | Seismic Method | Early Demonstration | Microseismic/ passive seismic | Platform and subsea | Microseismic/ passive seismic monitoring includes installation of geophones down the wellbore when the wells are drilled and may provide real-time information on hydraulic and geomechanical processes taking place within the reservoir. This may give useful insight into reservoir and caprock integrity during the injection process. Challenges with reliability of sensors. | Consider | Moderately high cost and uncertainty over reliability of sensors and of information benefit (since caprocks in five storage sites are excellent). To be more fully considered during FEED. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Subsurface** | Seismic Method | Commercial | 4D/time-lapse 3D seismic | Platform and subsea | Reflection 3D seismic uses the acoustic properties of geological formations and pore fluid to image the subsurface in a 3D volume. 4D seismic involves repeating the 3D survey over time to detect any changes. Each $CO_2$ storage site is unique and site-specific modelling is required to understand if reflection seismic will detect $CO_2$ at that specific site | Focussed application | High cost, but it may provide extremely useful insight into plume extent for certain sites in the North Sea. Can also be used in corrective measures plan if loss of containment to overburden is suspected. |
| **Subsurface** | Seismic Method | Commercial | 2D seismic | | A seismic survey with closely spaced geophones along a 2D seismic line to give greater resolution at shallower depths. | Focussed application | This may be usefully deployed in a corrective measures plan seeking to detect $CO_2$ in the shallow overburden. |
| **Subsurface** | Seismic Method | | Streamer - P Cable seismic | Platform and subsea | High resolution 3D seismic system for shallow sections (<1000m) so could be used for imaging the overburden | Focussed application | This may be usefully deployed in a corrective measures plan seeking to detect $CO_2$ in the shallow overburden. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Subsurface** | Seismic Method | Development | Ocean bottom nodes (OBN) and cables (OBC) | Platform and subsea | Multicomponent (p and s-wave recording) geophones placed on the seabed and can provide full azimuth coverage. Can provide data near platforms (unlike towed streamers which have an exclusion radius) | Focussed application | Multicomponent seismic may provide greater cost-benefit analysis over field life. Analysis to be carried out for specific sites during FEED. |
| **Subsurface** | Gravity | Early Demonstration | Time lapse seabottom gravimetry | Platform and subsea | Use of gravity to monitor changes in density of fluid resulting from $CO_2$ due to the fact that $CO_2$ is less dense than the formation water. Resolution of gravity surveys is much lower than seismic surveys. Time-lapse could track migration and distribution of $CO_2$ in the subsurface. Deeper reservoirs are also less suitable for gravity monitoring. Technology example: remotely-operated vehicle-deployable-deep-ocean gravimeters (ROVDOG) | Consider | Relatively low cost, but often requires a larger $CO_2$ plume before detection. Technology sensitivity modelling to be done during FEED to understand minimum plume detection limits. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Subsurface** | Electrical Techniques | Development | Controlled-source Electomagnetic (CSEM) survey | Platform and subsea | Seabottom CSEM (Controlled Source Electro Magnetic) surveying is a novel application of a longstanding technique, currently at a quite early stage of development. It involves a towed electromagnetic source and a series of seabed receivers that measure induced electrical and magnetic fields. These can be used to determine subsurface electrical profiles that may be influenced by the presence of highly resistive $CO_2$. Challenges of technique in shallow water (<300m) and offshore deployment is logistically complex. | Park | Costly and challenging to deploy, still in early stages of development. However, modelling during FEED will determine whether this is likely to provide any benefit. |
| **Subsurface** | Electrical Techniques | Early Demonstration | Electrical resistivity tomography (ERT) | | Electrodes used to measure pattern of resistivity in the subsurface and can be mounted on outside of non-conductive well casing. Can have Cross-well ERT or surface-downhole ERT configurations, depending on scale of imaging | Consider | Modelling during FEED to understand the benefit of this technology |
| **Subsurface** | | | Monitoring well | | An additional well drilled for the purpose of monitoring, with no intent to inject $CO_2$ into it. $CO_2$ breakthrough at the monitoring well can give insight into plume movement (rates, extent, etc) through the reservoir and pressure and temperature measurements can provide information on aquifer connectivity. The draw-back is that monitoring wells can be expensive and only give one point source measurement. | Focussed application | A redundancy well is currently considered, which will monitor when not injecting. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Subsurface** | Seismic Method | Commercial | Vertical Seismic Profiling (VSP) | Platform and subsea | VSPs have seismic source in water column (offshore) or at surface (onshore) and geophones at regular intervals down the wellbore to produce a high-resolution near-wellbore image (300 to 600m away). Time-lapse VSPs are repeated over time to understand any changes. May be challenges with repeatability as reliability of sensors is a key issue | Park | Moderately expensive offshore and value of information uncertain compared with other technologies of similar or less cost - modelling during FEED. |
| **Subsurface** | Seismic Method | Early Demonstration | Cross-well seismic | Platform and subsea | Borehole seismic using seismic source in one well and receiver array in nearby well to build up a velocity map between the wells. Requires wellbore access and good coordination with other monitoring acitivies. | Park | Challenging regarding wellbore access and uncertainty over value of information. |
| **Seabed/ water column** | Seismic method | Commercial | Chirps, boomers & pingers | Platform and subsea | Very high resolution surface seismic surveys which may detect bubble streams. AUV systems have chirp transducers. | Just do it | Relatively low cost and can be used to rule out bubble streams at seabed and around abandoned/injection wellheads which may indicate loss of containment. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Seabed/ water column** | Seabed Method | Commercial | Side scan sonar | Platform and subsea | Sidescan sonar, a towed echo sounding system, is one of the most accurate tools for imaging large areas of the seabed. Sidescan sonar transmits a specially shaped acoustic beam perpendicular to the path of the support craft (which could included AUV or ROV), and out to each side. It can detect streams any bubbles, for example around abandoned or injection wellheads which penetrate the storage complex. | Just do it | Can be used to rule out bubble streams at seabed and around abandoned/injection wellheads which may indicate loss of containment. |
| **Seabed/ water column** | Seabed Method | Commercial | Underwater Video | Platform and subsea | Recording and high definition images of bubbles and other features which could indicate $CO_2$ at seabed/ water column. Qualitative - cannot resolve size or shape of bubbles. | Consider | Consider inclusion as additional monitoring in corrective measures plan. |
| **Seabed/ water column** | Surface displacement monitoring | Development | Offshore tiltmeters | Platform and subsea | Reservoir pressure changes from $CO_2$ injection can cause surface deformation and so vertical displacement of seabed may indicate that this has occurred. GPS system may be able to measure this to 5mm accuracy. Measuring subsistence or uplift may provide evidence of containment and conformance. | Consider | Moderate cost but modelling required to understand detectability limit for store depth and injected $CO_2$ volumes and therefore information benefit. |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Seabed/ water column** | Geochemical Monitoring of water column | Commercial | Geochemical analyses of water column | Platform and subsea | CTD (conductivity, temperature and depth) probes from survey ships or platforms (for continuous measurement) can measure water column conductivity, used in addition to pH $pCO_2$, dissolved O2 and other chemical components, any anomalous chemistry can be detected. Requires good baseline measurements and may have challenges detecting small quantities of $CO_2$ due to dispersion. | Just do it | Relatively cheap and can be used to rule out loss of containment of $CO_2$ to seabed over a large area and also around wellheads. Carry out survey at same time as side-scan sonar |
| **Seabed/ water column** | Tracer | | Tracers | | $CO_2$ soluble compounds injected along with the $CO_2$ into the target formation. Act as a "fingerprint" for the $CO_2$ in case of any leakage. | Consider | Tracers are in the "Consider" box as they are of moderate cost, but low benefit as containment loss at the storage sites is not expected. To explore further during FEED. |
| **Seabed/ water column** | Seabed Method | | Seafloor sediment samples | Platform and subsea | Sediment samples are extracted from the seabed (for example using a Van Veen Grab, vibro corer, CPT+BAT probe, hydrostatically sealed corer) and analysed for $CO_2$ content. The $CO_2$ content may give insight into $CO_2$ flux (if any) above abandoned wellbores which penetrate the storage complex. Requires a good baseline to detect $CO_2$ above background levels. | Just do it | Relatively cheap and can be used to rule out loss of containment of $CO_2$ to seabed over a large area and also around wellheads. Carry out survey at same time as side-scan sonar |

| Monitoring Domain | Type | Field Readiness | Technology | Applicability to Offshore | Description | Boston Square Box | Comments/ rationale |
|---|---|---|---|---|---|---|---|
| **Seabed/ water column** | Seabed Method | | Ecosystem response monitoring | Platform and subsea | Time-lapse sediment sampling may detect changes in seabed flora and fauna from $CO_2$. Baseline survey key to determine normal behaviour and $CO_2$ concentrations | Just do it | Relatively cheap and can be used to rule out loss of containment of $CO_2$ to seabed over a large area and also around wellheads. Carry out survey at same time as side-scan sonar |
| **Atmospheric** | Optical $CO_2$ Sensors | Commercial | e.g. CRDS, NDIR-based $CO_2$ sensors, DIAL/ LIDAR | Platform only | All sensors optical $CO_2$ sensors measure absorption of infrared radiation (IR) along the path of a laser beam<br><br>Cavity ring-down spectroscopy (CRDS): Sensors to measure continuous or intermittent $CO_2$ in air. Works better over smaller areas and may be difficult to detect any $CO_2$ release from background $CO_2$ emissions. Relatively cheap and portable.<br><br>Non-dispersive infrared (NDIR) spectroscopy. $CO_2$ detectors for health and safety monitoring.<br><br>Light detection and ranging (LIDAR). | Just do it | Atmospheric $CO_2$ sensors will be essential if platform (including unmanned) injection facilities. For health and safety of personnel inspecting or maintaining platform. Modelling required during FEED to understand which atmospheric $CO_2$ sensors should be installed. |

*Table 11-9 Offshore technologies for monitoring*

### 11.5.5 Outline Base Case Monitoring Plan

For the monitoring schedule, please see section on Containment Characterisation.

A dedicated monitoring well has not been included in the plan, but instead a redundancy injection well, which will monitor when not in use.

The surface facilities include an unmanned platform with occasional personnel carrying out inspections and maintenance. There will be a requirement for some atmospheric $CO_2$ monitoring, perhaps using optical $CO_2$ sensors, to ensure the safety of these personnel.

Monitoring of pipeline wall thickness and valve seal performance will be carried out as part of routine maintenance and the pipeline has been designed to receive pigs.

| Monitoring technology/ workscope | Rationale | Timing |
|---|---|---|
| **Seabed sampling, ecosystem response monitoring, geochemical analyses of water column** | Baseline sampling to understand background $CO_2$ concentrations in the sediment and water column to benchmark any future surveys against. | 1-2 years prior to injection |
| **Sidescan sonar survey**<br>**Chirps, boomers & pingers** | Baseline sidescan sonar survey to benchmark future surveys. Looking to detect any pre-existing bubble streams on seabed or around abandoned wellheads and map pock-marks. | 1-2 years prior to injection |
| **Seismic survey** | Baseline survey required for 4D seismic. | 1-2 years prior to injection |
| **Wireline logging suite (incl well bore integrity)** | Part of the drilling programme to gather data on the reservoir, overburden and wellbore for baseline update to reservoir models. | During drilling programme |
| **Installation of Distributed Temperature Sensor (DTS), downhole and wellhead P/T gauge and flow meter** | DTS for real-time monitoring of temperature along the length of the wellbore, which can indicate $CO_2$ leakage through tubing. Downhole pressure and temperature monitoring is considered essential to ensure injection integrity & required under EU Storage Directive; flow meter for reporting. | Permanent installation once wells drilled |

*All surveys to be carried out over the storage complex*

*Table 11-10 Baseline monitoring plan*

### 11.5.6 Operational Monitoring Plan

| Monitoring technology/ workscope | Rationale | Timing |
|---|---|---|
| **Wireline logging suite (incl well bore integrity)** | Gather data on the reservoir, overburden and wellbore integrity to ensure injection integrity and update reservoir models. | Every 10 years |
| **4D seismic survey** | Used to detect plume extent and update geological and dynamic models. Also looking for any early-warning signs of loss of containment, such as unexpected lateral or vertical migration of $CO_2$ within the storage complex. | Every 5 years |
| **Sidescan sonar survey**<br>**Chirps, boomers & pingers** | Used to detect any bubble streams around abandoned wellheads, on the seabed or around pock-marks, which could indicate loss of containment to seabed. | Every 5 years |
| **Seabed sampling, ecosystem response monitoring, geochemical analyses of water column** | Used to detect any evidence of elevated $CO_2$ concentrations in sediment or water column which may indicate loss of containment. | Every 5 years |
| **DTS, downhole and wellhead P/T gauge and flow meter readings** | DTS for real-time monitoring of temperature along the length of the wellbore, which can indicate $CO_2$ leakage through tubing. Downhole pressure and temperature monitoring is required under EU Storage Directive, can be used to update models and is considered essential to ensure injection integrity. Flow meter for reporting. | Continuous |
| **Data management** | To collate, manage, interpret and report on monitoring data. | Continuous |

*All surveys to be carried out over the storage complex*

*Table 11-11 Operational monitoring plan*

### 11.5.7 Post-Closure Monitoring Plan

| Monitoring technology/ workscope | Rationale | Timing |
|---|---|---|
| **4D seismic survey** | Detect plume extent at end of injection operations and monitor to show site conformance prior to handover. | 1 year post injection, then every 5 years |
| **Seabed sampling, ecosystem response monitoring, geochemical analyses of water column** | Used to detect any evidence of elevated $CO_2$ concentrations in sediment or water column which may indicate loss of containment | 1 year post injection, then every 5 years |
| **Sidescan sonar survey**<br>**Chirps, boomers & pingers** | Looking to detect any bubble streams around abandoned wellheads, seabed or pock-marks and set a baseline for post-closure and post-handover monitoring. | 1 year post injection, then every 5 years |
| **Data interpretation, management and reporting** | To collate, manage, interpret and report on monitoring data. | Continuous |

*All surveys to be carried out over the storage complex*

*Table 11-12 Post closure monitoring plan*

### 11.5.8 Corrective Measures – Remediation Options

For each key risk event a remediation option (or options) is defined and an associated high level cost is associated. Options to improve the integrity status are identified.

#### 11.5.8.1 Well Containment Risks

This section examines the containment risks from wells in the Captain field. The following well types are (or will be) present in the reservoir if it is developed for $CO_2$ storage:

- Previously abandoned wells.
- Pre-existing wells that are operational, shut-in or suspended (to be abandoned).
- $CO_2$ injection wells.
- Observation wells for data gathering (optional).
- Wells drilled for $CO_2$ storage that are abandoned during the storage project's lifetime.

The assumption is that pre-existing wells were not designed for $CO_2$ injection or any other role in a $CO_2$ storage project and will be unsuitable for conversion to that purpose and will, therefore, be abandoned.

All wells present a $CO_2$ containment risk: migration past the designed pressure containment barriers of the well to the biosphere (atmosphere or ocean). The possible well containment failures are:

- Flow through paths in poor casing cement sheaths or cement plugs.
- Flow through paths in casing cement sheaths created by pressure cycling.
- Flow through a cement sheaths or plugs degraded by contact with $CO_2$ or carbonic acid.
- Corrosion of tubulars, metallic well components or wellhead by carbonic acid.
- Degradation of elastomers by contact with $CO_2$ or carbonic acid.
- Blowout whilst drilling an injection/observation well.
- Blowout whilst conducting a well intervention on an injection/observation well.

Several studies in recent years have comprehensively assessed containment risk. The following analysis of the containment risks is a summary of these reports (Jewell & Senior, 2012) (DNV, 2011) (Decision Gate Approach to Storage Site Appraisal, Mott MacDonald Report C12MMD002B, 2012).

All active wells that are part of the $CO_2$ injection system (injectors, observation, pressure maintenance) should be designed and constructed not to leak in service and will satisfy the well integrity requirements set out in the governing legislation and guidance (Offshore Installation & Wells (Design and Construction etc.) Regulations 1996) (Oil and Gas UK , 2012). Wells will also be designed to facilitate the most secure abandonment when they are taken out of service.

Abandoned wells that penetrate the storage reservoir pose a leak risk because they provide a direct pathway to the surface. There are three abandoned well types to consider:

- Pre-existing wells that are operational, shut-in or suspended and were abandoned as part of the development of the storage field.
- Wells drilled for $CO_2$ storage that are abandoned during the storage project's lifetime.
- Previously abandoned wells.

Pre-existing, still operational, wells in the field will be abandoned before injection starts, using the latest standards and practices to make them safe in a $CO_2$ storage environment. The well construction itself may not be suitable for a $CO_2$ environment (e.g. material selection for corrosion resistance).

$CO_2$ injection wells (or related observation or water abstraction wells), which are decommissioned during the life of the storage facility, will be designed to be abandoned using the latest standards and practices. Both well types that provides confidence in the long-term containment.

Previously abandoned wells (exploration and appraisal wells from earlier hydrocarbon development) may have been abandoned in a way that is inadequate for a $CO_2$ storage environment because of their outdated construction design and abandonment practices (see section 6). In addition, record keeping for abandoned wells is not always complete and it may not be possible to determine how a particular well was abandoned. Crucially, these wells will have been cleared to approximately 15ft below the seabed; the wellhead and all casing strings close to the seabed will have been cut and recovered, access into an abandoned well is very complex and expensive. It is unlikely that this would be attempted to remediate a perceived risk, but only in the event of a major loss of containment.

#### 11.5.8.2 Well Containment Envelope

All wells in the field (including abandoned wells) will have a defined pressure containment envelope: the barriers that prevent an unplanned escape of fluids from the well. There must be suitable barriers in place that isolate the hazard from the surface throughout the well life.

Barriers that form the well pressure containment envelope must be monitored and maintained for the life of the well (not normally applied to abandoned wells).

If a barrier is found to be not fully functional then the well monitoring and management processes identify this and initiate appropriate remediation.

#### 11.5.8.3 Containment Risks and Remediation Options

The following tables catalogue the well containment failure mode and the associated effect, remediation and estimated cost (it is assumed that the wells are offshore). The remediation options available will be specific to the well and depend on:

- The type of failure.
- The location of the failure.
- The overall design of the well.

| ACTIVE WELL | | | |
|---|---|---|---|
| **Risk Event** | **Effect** | **Remediation** | **Cost** |
| **Blowout during drilling** | Possible escape of $CO_2$ to the biosphere. | Standard procedures: shut-in the well and initiate well control procedures. | \$3-5 million (5 days & tangibles). |
| **Blowout during well intervention** | Possible escape of $CO_2$ to the biosphere. | Standard procedures: shut-in the well and initiate well control procedures. | \$2-3 million (3 days & tangibles). |
| **Tubing leak** | Pressured $CO_2$ in the A-annulus.<br>Sustained $CO_2$ annulus pressure will be an unsustainable well integrity state and require remediation. | Tubing replacement by workover. | \$15 -20 million (16 days & tangibles). |
| **Packer leak** | Pressured $CO_2$ in the A-annulus.<br>Sustained $CO_2$ annulus pressure will be an unsustainable well integrity state and require remediation. | Packer replacement by workover. | \$15 -20 million (16 days & tangibles). |
| **Cement sheath failure (Production Liner)** | Requires:<br>a failure of the liner packer or<br>failure of the liner above the production packer<br>before there is pressured $CO_2$ in the A-annulus.<br>Sustained $CO_2$ annulus pressure will be an unsustainable well integrity state and require remediation. | Repair by cement squeeze (possible chance of failure).<br>Requires the completion to be retrieved and rerun (if installed). | \$3-5 million (5 days & tangibles).<br>\$18-25 million (if a workover required). |

| ACTIVE WELL | | | |
|---|---|---|---|
| **Risk Event** | **Effect** | **Remediation** | **Cost** |
| **Production Liner failure** | Requires:<br>a failure of the liner above the production packer and<br>a failure of the cement sheath<br>before there is pressured $CO_2$ in the A-annulus.<br>Sustained $CO_2$ annulus pressure will be an unsustainable well integrity state and require remediation. | Repair by patching (possible chance of failure) or running a smaller diameter contingency liner.<br>Requires the completion to be retrieved and rerun (if installed).<br>Will change the casing internal diameter and may have an impact on the completion design and placement.<br>Repair by side-track. | \$3-5 million (3 days & tangibles).<br>\$18-25 million (if a workover required).<br>Side-track estimated to be equal to the cost of a new well - \$55 million (60 days & tangibles). |
| **Cement sheath failure (Production Casing)** | Requires:<br>a failure of the Production Liner cement sheath or<br>a pressurised A-annulus and<br>failure of the production casing<br>before there is pressured $CO_2$ in the B-annulus.<br>Sustained $CO_2$ annulus pressure will be an unsustainable well integrity state and require remediation. | Repair by cement squeeze (possible chance of failure).<br>Requires the completion to be retrieved and rerun (if installed). | \$3-5 million (5 days & tangibles).<br>\$18-25 million (if a workover required). |

| ACTIVE WELL | | | |
|---|---|---|---|
| **Risk Event** | **Effect** | **Remediation** | **Cost** |
| **Production Casing Failure** | Requires:<br>a pressurised A-annulus and<br>a failure of the Production Casing cement sheath<br>before there is pressure $CO_2$ in the B-annulus.<br>Sustained $CO_2$ annulus pressure will be an unsustainable well integrity state and require remediation. | Repair by patching (possible chance of failure).<br>Requires the completion to be retrieved (if installed).<br>Will change the casing internal diameter and may have an impact on the completion design and placement. | \$3-5 million (3 days & tangibles).<br>\$18-25 million (if a workover required).<br>Side-track estimated to be equal to the cost of a new well - \$55 million (60 days & tangibles). |
| **Safety critical valve failure – tubing safety valve** | Inability to remotely shut-in the well below surface. Unsustainable well integrity state. | Repair by:<br>installation of insert back-up by intervention or<br>replacement by workover | £1 million to run insert (1 day & tangibles).<br>\$18-25 million (if a workover required). |
| **Safety critical valve failure – Xmas Tree valve** | Inability to remotely shut-in the well at the Xmas Tree. Unsustainable well integrity state. | Repair by valve replacement. | Dry Tree: < \$1 million (costs associated with 5 days loss of injection, tangibles and man days).<br>Subsea: \$5-7 million (vessels, ROV, dive support & tangibles). |

| ACTIVE WELL | | | |
|---|---|---|---|
| **Risk Event** | **Effect** | **Remediation** | **Cost** |
| **Wellhead seal leak** | Requires:<br><br>a pressurised annulus and<br>multiple seal failures<br><br>before there is a release to the biosphere.<br><br>Seal failure will be an unsustainable well integrity state and require remediation. | Possible repair by treatment with a replacement sealant or repair components that are part of the wellhead design. Highly dependent on the design and ease of access (dry tree or subsea).<br><br>May mean the well has insufficient integrity and would be abandoned. | Dry Tree: <$3 million (costs associated with 7 days loss of injection, tangibles and man days).<br><br>Abandonment $15-25 (21 days & tangibles). |
| **Xmas Tree seal leak** | Requires multiple seal failures before there is a release to the biosphere.<br><br>Seal failure will be an unsustainable well integrity state and require remediation. | Possible repair by specific back-up components that are part of the wellhead design. Highly dependent on the design and ease of access.<br><br>May mean the Xmas Tree need to be removed/recovered to be repaired. This is a time consuming process for a subsea tree. | Dry Tree: <$3 million (costs associated with 7 days loss of injection, tangibles and man days).<br><br>Subsea: $12-15 million (12 days & tangibles). |

*Table 11-13 Active well containment failure modes and associated effects and remediation options*

| ABANDONED WELL | | | |
|---|---|---|---|
| **Risk Event** | **Effect** | **Remediation** | **Cost** |
| **Well Leak** | Escape of $CO_2$ to the biosphere.<br><br>Only the final event – leak to the biosphere – will be detected. | Re-entry into an abandoned well is complex, difficult and has a very low chance of success.<br><br>A relief well is required. | Relief well: $55 million (60 days & tangibles). |

*Table 11-14 Abandoned well containment failure modes and associated effects and remediation options*

## 11.6 Appendix 6 Well Basis of Design

### 11.6.1 Wellbore Stability

In order to drill a well in the subsurface it is essential to understand the safe operating window (the wellbore pressure required to prevent ingress of formation fluids and to prevent hole collapse, while avoiding the fracturing of the formation, which could lead to loss of well fluids (mud) and thus loss of well pressure control). In order to define this window, a 1D analytical wellbore stability analysis of key wells on the structure was performed in order to determine fracture gradient, breakout line and the mud window to drill hole with no breakouts or losses. The fracture gradient and stress analysis work is described in section 3.1.1. The basic work flow in Drillworks 5000 was supplemented with safe mud weight windows and optimal wellbore trajectory analysis. Note, the safe mud weight ranges are for zero losses and zero breakouts so they may be somewhat conservative.

#### 11.6.1.1 Safe Mud Weight Windows -Original Reservoir Pressure Condition

**Well 13/29b-6**

- The MW used in this well varies from 9.5 to 10 ppg (purple diamonds in the plot)
- No drilling issues reported after 3000 ftMD (only tight spots and reaming at 2960 ft)
- A safe MW would vary in the layers between 9 to 13 ppg (for a vertical well) as specified in the safe mud windows plot.
- A safe MW for the Captain Sandstone would be between 10 to 13 ppg (for a vertical well)

**Well 13/30-3**

- The MW used in this well varies from 9.1 to 10 ppg (purple diamonds in the plot)
- A safe MW would be between 9.5 to 13.5 ppg (for a vertical well) as specified in the safe mud windows plot.

**Well 13/30a-4**

- The MW used in this well varies from 9.1 to 10 ppg (purple diamonds in the plot)
- A safe MW would vary in the layers between 9 to 14 ppg (for a vertical well) as specified in the safe mud windows plot.
- A safe MW for the Captain Sandstone would be between 9.5 to 14 ppg (for a vertical well)

**Well 13/30b-7**

- The MW used in this well varies from 10 to 12 ppg (purple diamonds in the plot)
- No drilling issues reported in this well.
- A safe MW would vary in the layers between 9 to 14 ppg (for a vertical well) as specified in the safe mud windows plot.
- A safe MW for the Captain Sandstone would be between 10 to 14 ppg (for a vertical well)

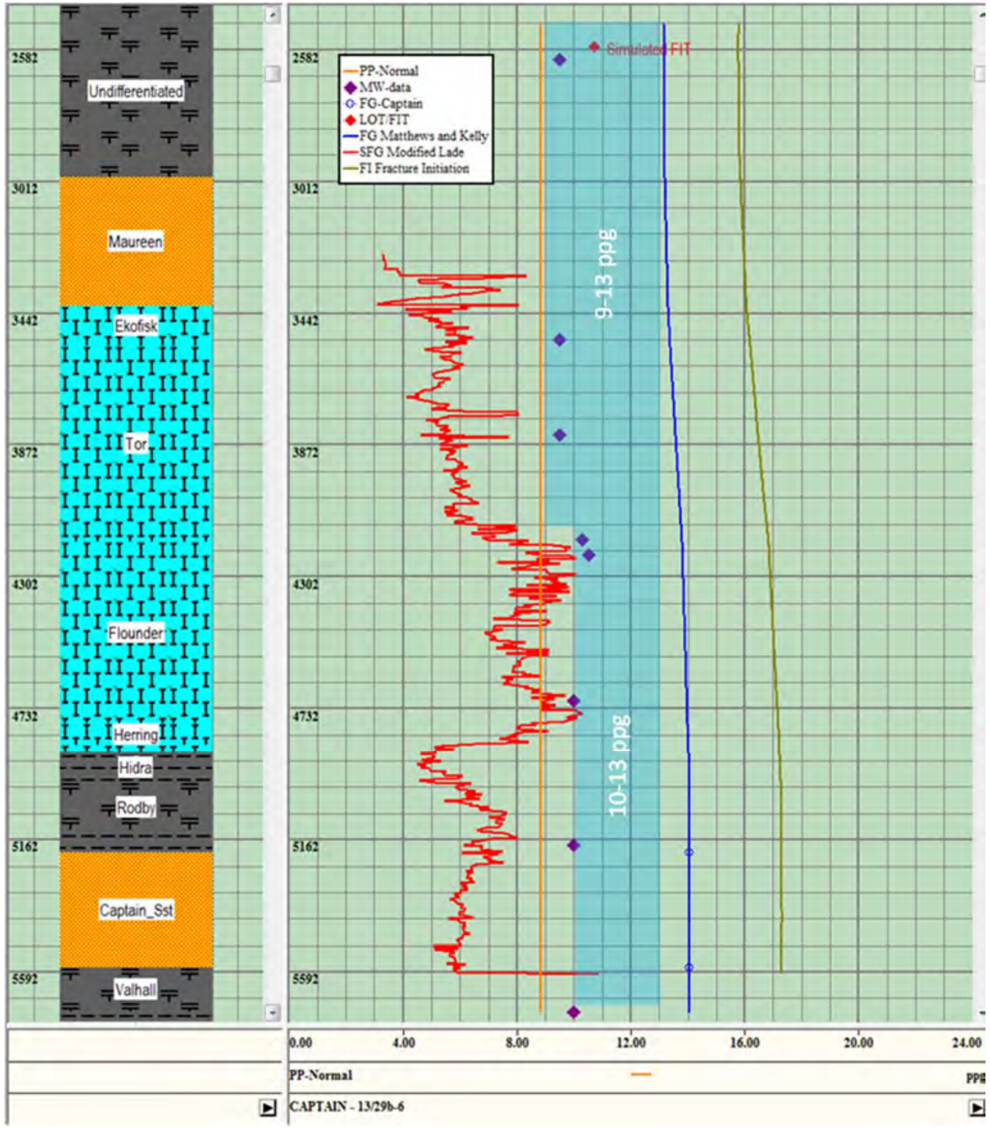



*Figure 11-36 Safe mud weight analysis: well 13/29b-6 (original conditions)*

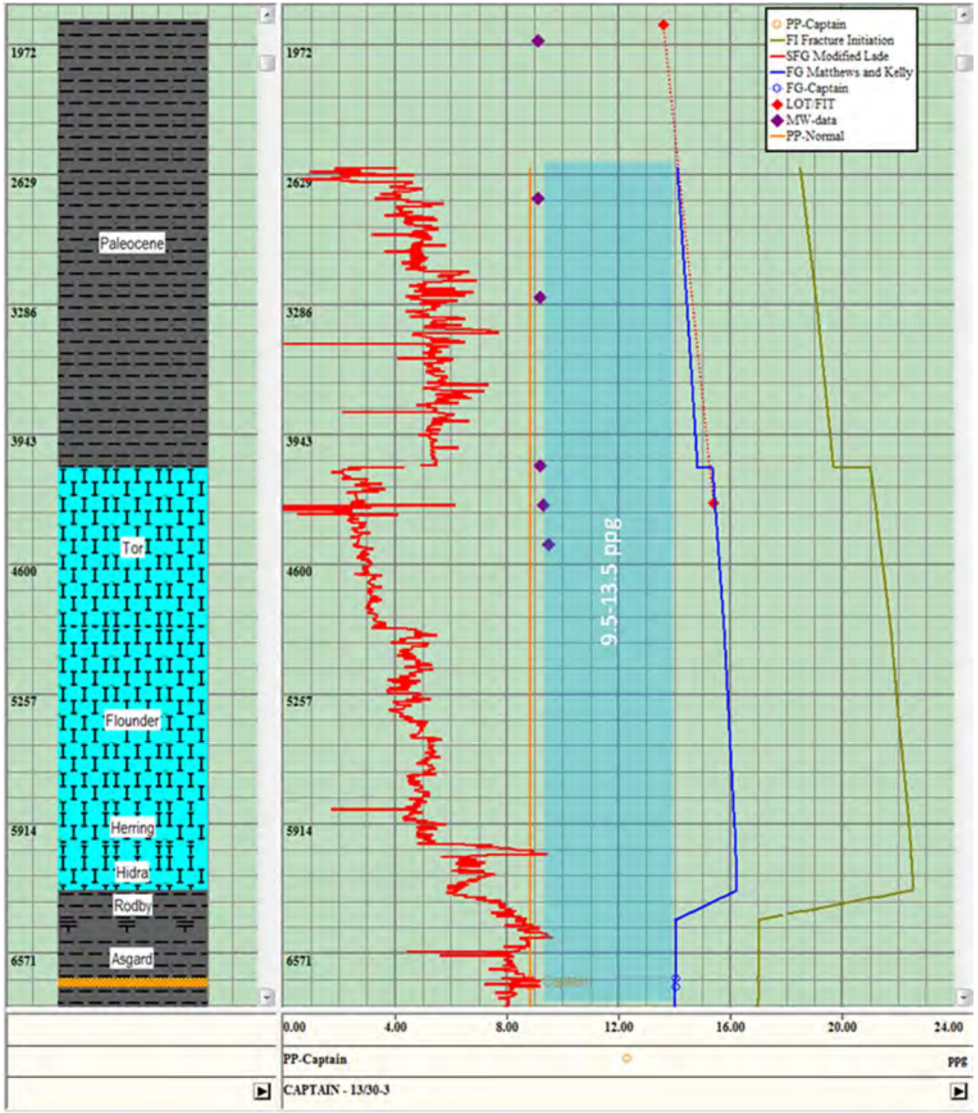



*Figure 11-37 Safe mud weight analysis: well 13/30 (original conditions)*

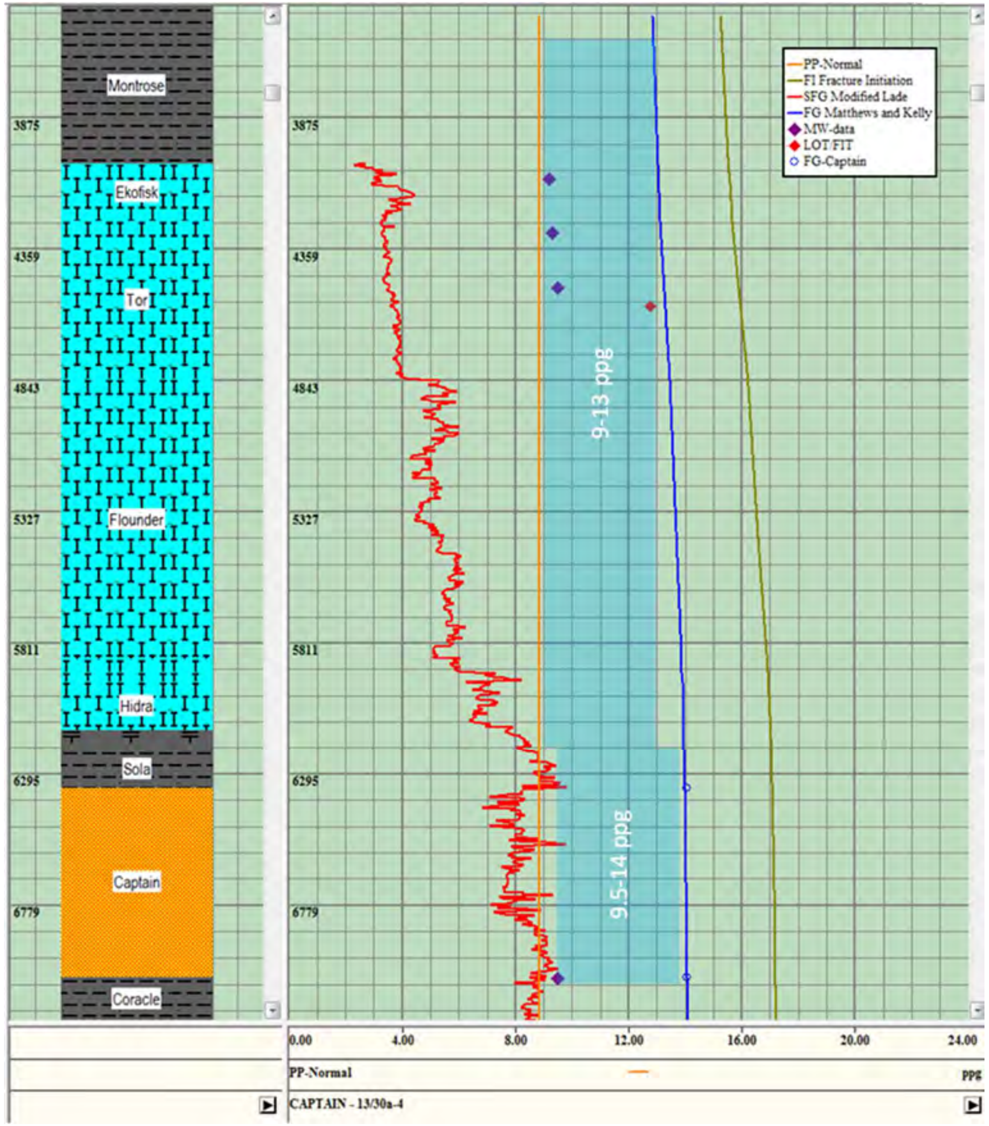



Figure 11-38 Safe mud weight analysis: well 13/30a-4 (original conditions)

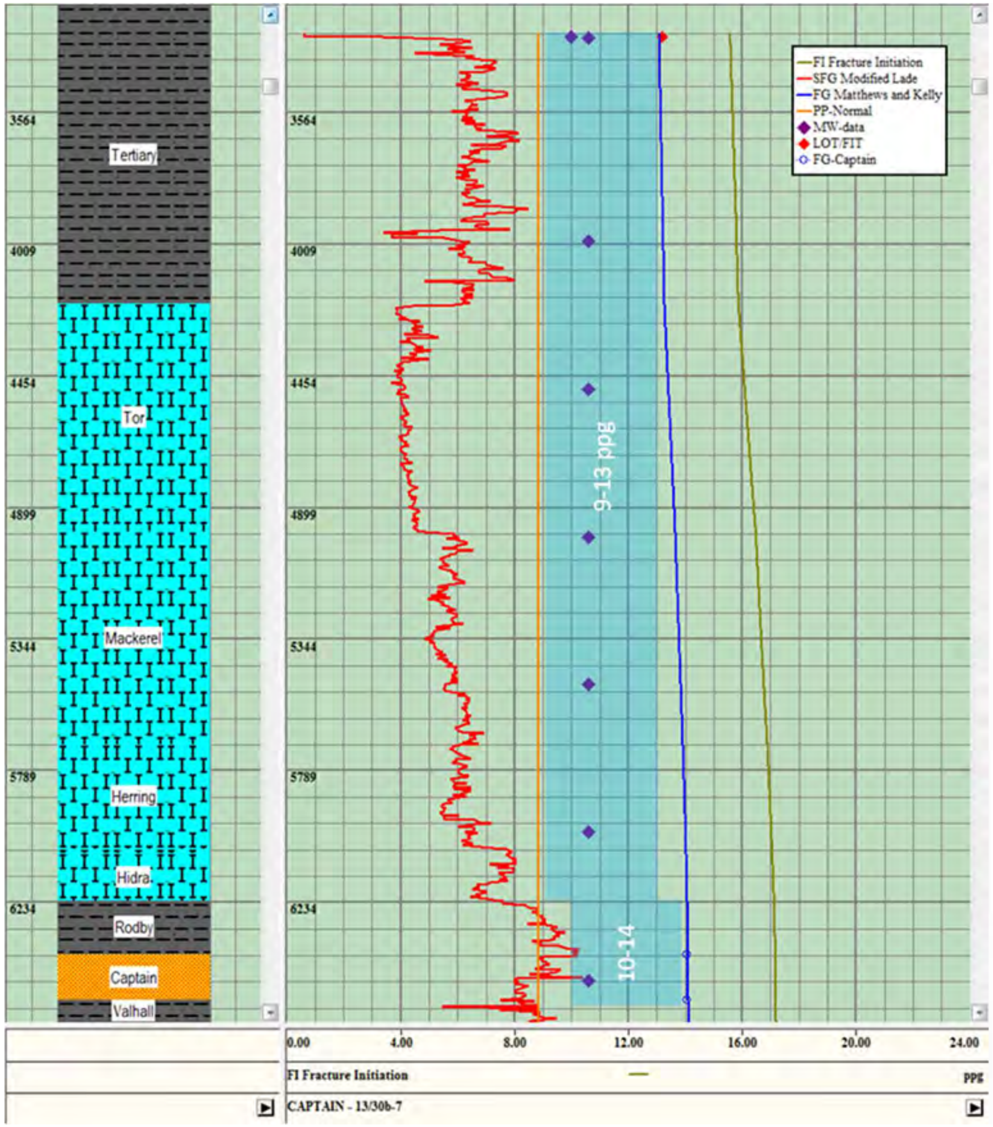



Figure 11-39 Safe mud weight analysis: well 13/30b-7 (original conditions)

### *11.6.1.2 Wellbore Trajectory Analysis*

The figures below indicate the variation of the minimum mud weight to prevent any breakout with changes in wellbore inclination and orientation.

Figure 11-40 shows the Captain sandstone at 5201 ft TVD in the well 13/29b-6, where a horizontal well with NW-SE orientation would increase the MW by up to 1.6 ppg (11.6 ppg).

Figure 11-41 shows the Captain sandstone at 6715 ft TVD in the well 13/30-3, where a horizontal well with NW-SE orientation would increase the MW by up to 2 ppg (11.5 ppg).

Figure 11-42 shows the Captain sandstone at 6746 ft TVD in the well 13/30a-4, where a horizontal well with NW-SE orientation would increase the MW by up to 1.7 ppg (11.7 ppg).

Figure 11-43 shows the Captain sandstone at 6485 ft TVD in the well 13/30b-7, where a horizontal well with NW-SE orientation would increase the MW by up to 1.7 ppg (11.7 ppg).

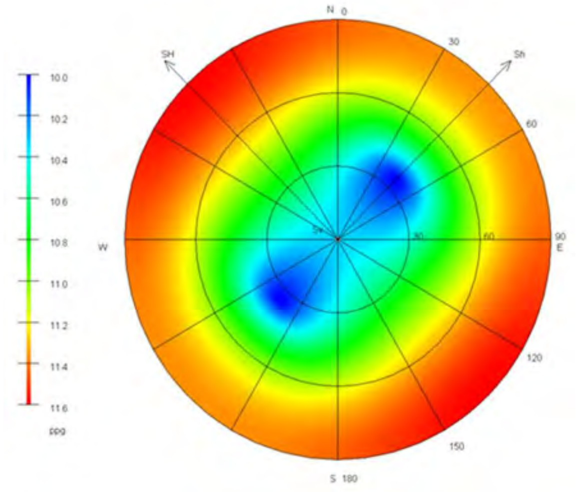



*Figure 11-40 Well trajectory analysis: well 13-29b-6 (original condition)*

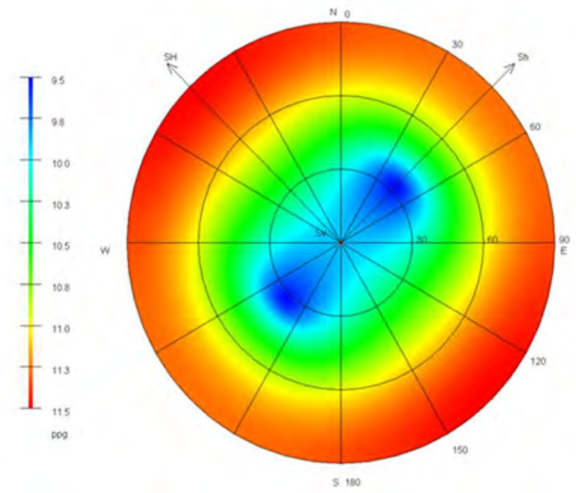



*Figure 11-41 Well trajectory analysis: well 13/30-3 (original condition)*

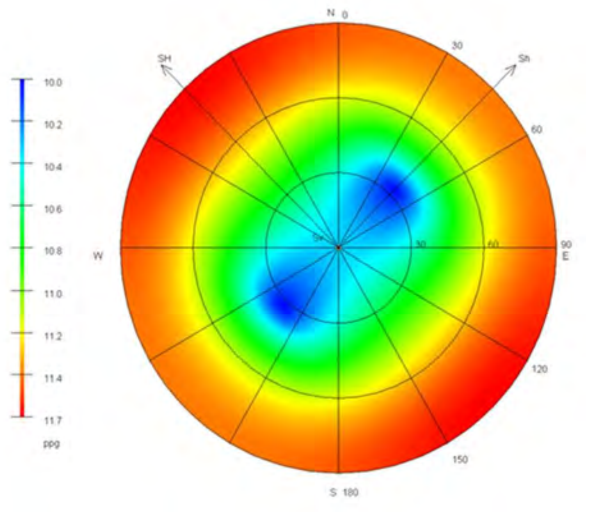



*Figure 11-42 Well trajectory analysis: well 13/30a-4 (original condition)*

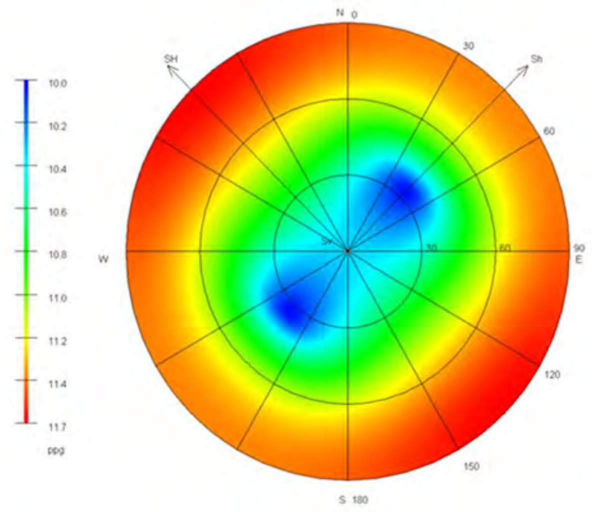



*Figure 11-43 Well trajectory analysis: well 13/30b-7 (original conditon)*

#### *11.6.1.3 Safe Mud Weight Windows – Depleted Reservoir Pressure Conditions*

For the Captain Sandstone, the changes in the safe MW due to depletion would be as follows:

**Well 13/29b-6**

- Original Conditions: between 10 to 14 ppg (for a vertical well)
- Depleted Conditions: between 7.5 to 13 ppg (for a vertical well)

**Well 13/30-3**

- Original Conditions: between 9.5 to 14 ppg (for a vertical well)
- Depleted Conditions: between 8.5 to 13 ppg (for a vertical well)

**Well 13/30a-4**

- Original Conditions: between 9.5 to 14 ppg (for a vertical well)
- Depleted Conditions: between 8.5 to 13 ppg (for a vertical well)

**Well 13/30b-7**

- Original Conditions: between 10 to 14 ppg (for a vertical well)
- Depleted Conditions: between 9 to 13 ppg (for a vertical well)

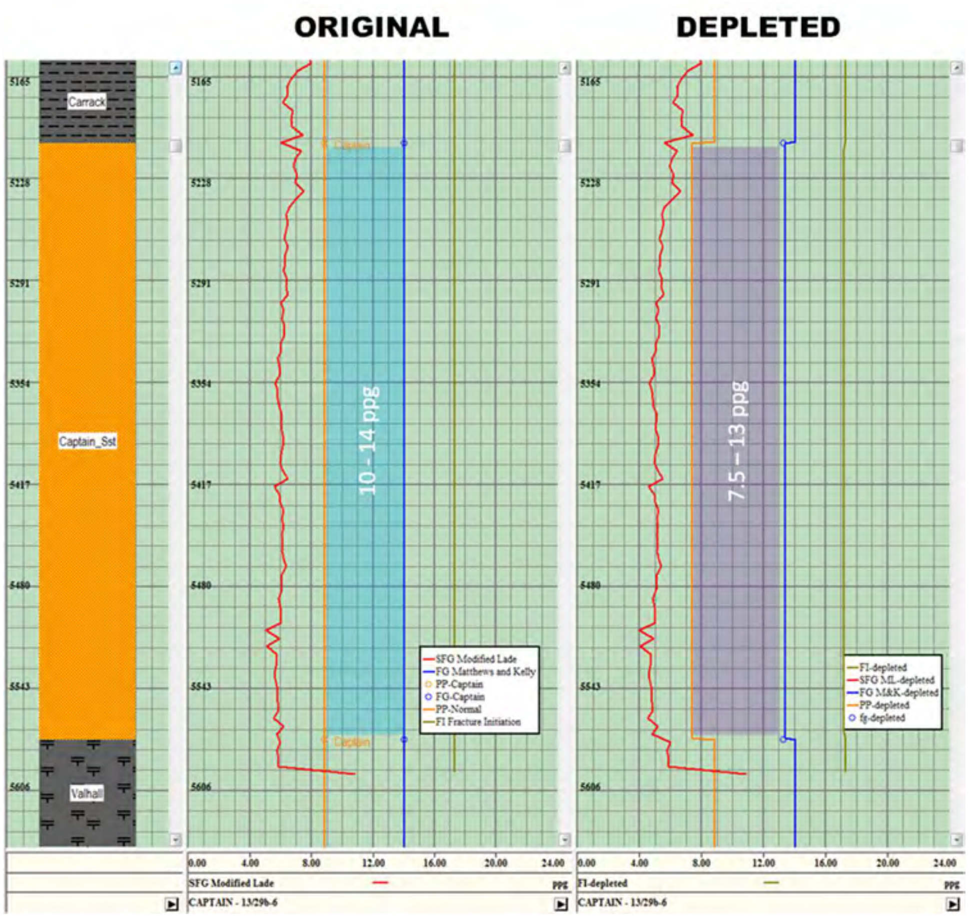



*Figure 11-44 Safe mud weight analysis: well 13/29b-6 (original/depleted)*

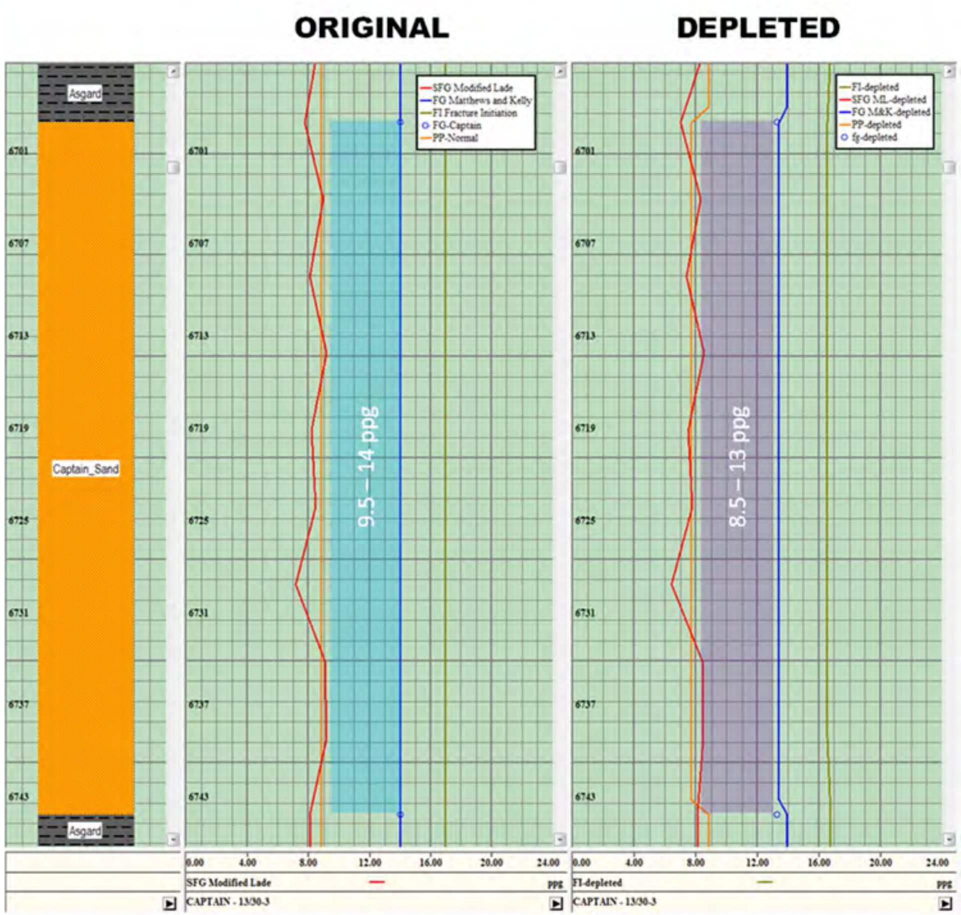



*Figure 11-45 Safe mud weight analysis: well 13/30-3 (orignal/depleted)*

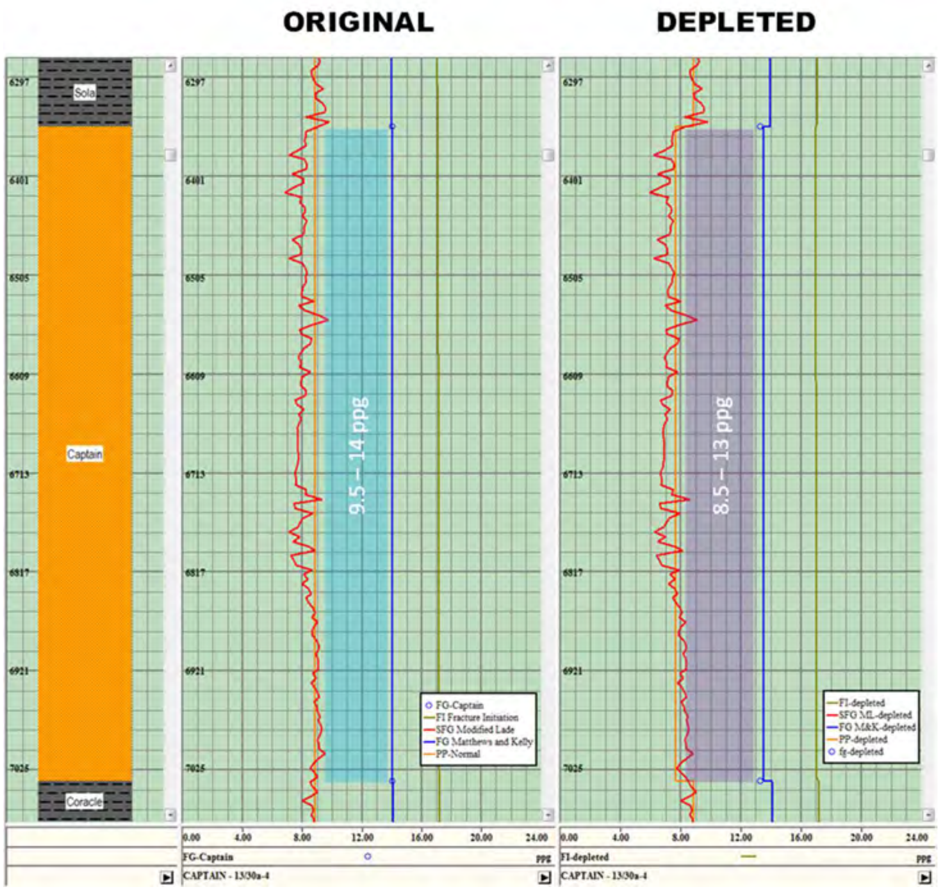



*Figure 11-46 Safe mud weight analysis: well 13/30a-4 (original/depleted)*

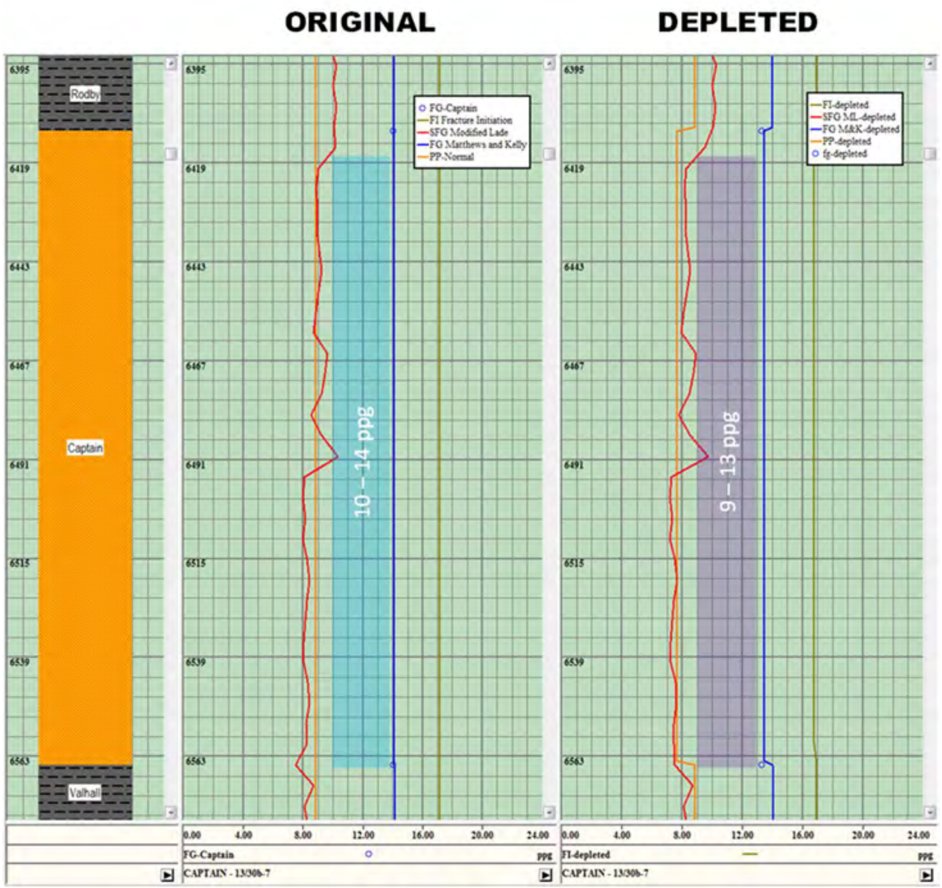



*Figure 11-47 Safe mud weight analysis: well 13/30b-7 (original/depleted)*

#### 11.6.1.4 Wellbore Trajectory Analysis – Depleted Reservoir Condition

The figures below indicate the variation of the minimum mud weight to prevent any breakout with wellbore inclination and orientation taking into account a depleted reservoir pressure in the Captain Sandstone.

Figure 11-48 shows a depleted Captain sandstone at 5201 ft TVD in the well 13/29b-6, where a horizontal well with NW-SE orientation would increase the MW by up to 1.6 ppg (9.1 ppg).

Figure 11-49 shows a depleted Captain sandstone at 6715 ft TVD in the well 13/30-3, where a horizontal well with NW-SE orientation would increase the MW by up to 2.2 ppg (10.7 ppg).

Figure 11-50 shows a depleted Captain sandstone at 6746 ft TVD in the well 13/30a-4, where a horizontal well with NW-SE orientation would increase the MW by up to 1.8 ppg (10.3 ppg).

Figure 11-51 shows a depleted Captain sandstone at 6485 ft TVD in the well 13/30b-7, where a horizontal well with NW-SE orientation would increase the MW by up to 1.9 ppg (10.9 ppg).

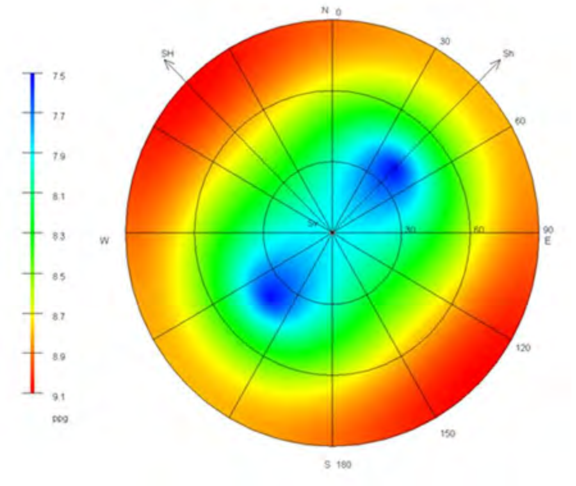


*Figure 11-48 Well trajectory analysis: well 13/29b-6 (depleted condition)*

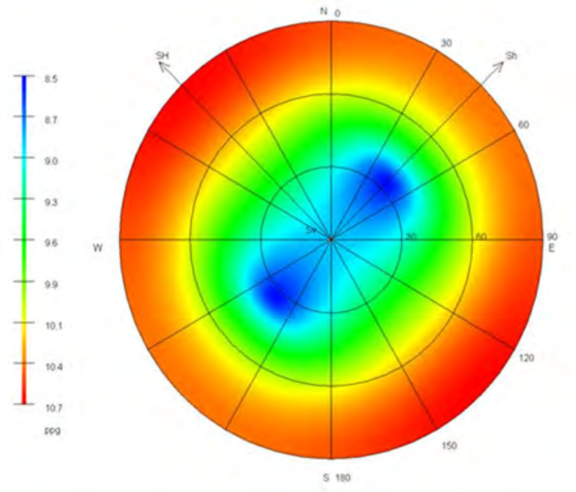


*Figure 11-49 Well trajectory analysis: well 13/30-3 (depleted condition)*

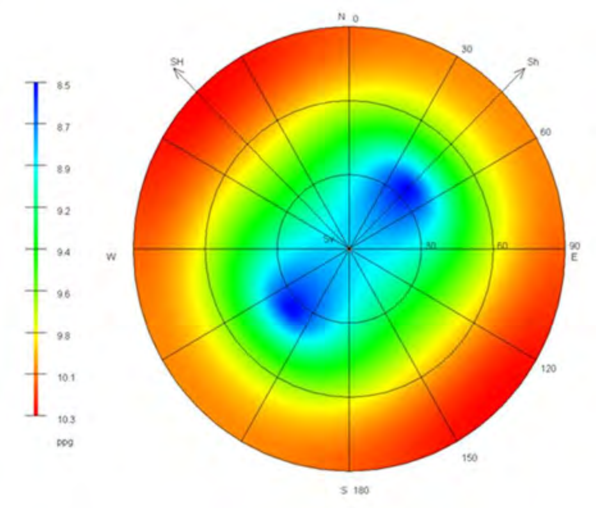



*Figure 11-50 Well trajectory analysis: well 13/30a-4 (depleted condition)*

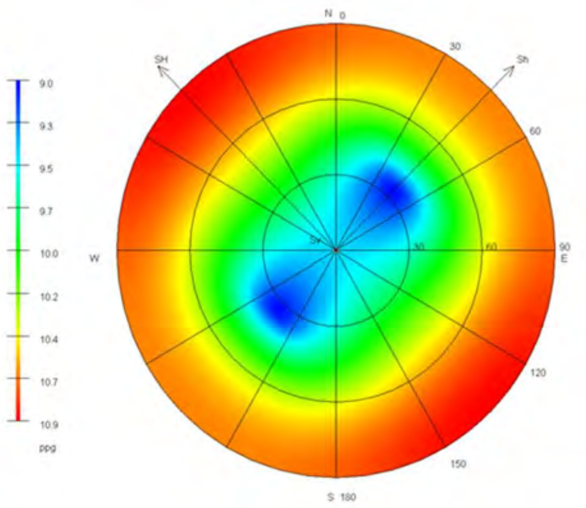



*Figure 11-51 Well trajectory analysis: well 13/30b-7 (depleted condition)*

#### *11.6.1.5 Conclusions*

- 1D geomechanical analysis of existing wells and pore pressure depletion estimation indicates that a potential depleted SHmin gradient could be around 0.69 psi/ft in the Captain Sandstone and that vertical wells can be drilled through the overburden and Captain Sandstone with 13 ppg as a maximum mud weight. The actual depleted conditions in the Captain sandstone have not been confirmed with field data.
- For vertical wells in the Captain sandstone, the recommended mud weight is around 10 – 14 ppg for virgin conditions and 9 – 13 ppg for depleted conditions. Some basic analysis on required mud weights at different injector orientations has been performed within the Captain Sandstone. In general, mud weight increases of 1.6 to 2.2 ppg are sufficient to prevent breakouts for the worst orientation (horizontal wells parallel to SHmax).
- Assumptions are made that the regional NW-SE in-situ Shmax stress orientation is relevant to the Captain Sandstone area. Real Shmax azimuth may be different (e.g. oriented parallel to local structure).
- Note the reported static mud weight windows are for drilling 'gun barrel' hole with no losses. If some breakout is tolerated and or losses can be managed with LCM then the real mud window could be larger.
- No core has been available to calibrate the strength (breakout) information. This would need optimising for any planned wells.
- The wellbore trajectory analysis has been made on Captain Sandstone levels only. For any planned wells a predicted MW

window would need to be generated based on expected lithologies vs planned trajectory. This could indicate different mud weights are required to maintain stability in some of the shallower units drilled at a higher angle than existing vertical wells.

### 11.6.2 Well Design

In order to develop the Captain aquifer for carbon capture and storage, $CO_2$ injection wells will be required. The $CO_2$ injectors will be J-shaped, high angle wells in order to optimise dense phase $CO_2$ injection performance. A spare injector, also used for monitoring, will also be J-shaped.

The purpose of this section of the report is to:

- Identify well design risks and drilling hazards based on the available offset well data.
- Generate a preliminary well design for the identified injection and monitoring wells.
- Provide high level time and cost estimates for each well type.

This report proposes a conceptual well design that could form the basis of a detailed well design. It should be stressed that the well design suggested herein is not fully developed and may be subject to change following detailed engineering analysis.

#### *11.6.2.1 Offset Review*

Well data from available sources has been analysed in order to identify inputs for designing the Captain aquifer $CO_2$ injection and monitoring wells. The key findings are as follows:

*Surface Hole and Conductor*

The surface hole sections were drilled through the shallow marine clays with surface casing being set directly below the top of the Chalk formation. This setting depth was selected to provide sufficient formation strength to drill the next hole section into the top of the Captain reservoir.

All surface hole sections were drilled using seawater, with bentonite sweeps being used to assist with hole cleaning.

Some surface hole sections were directionally drilled in order to allow the wells to reach horizontal in the shallow Captain reservoir. There were no reported issues associated with nudging the surface hole sections, making this a viable option for reservoir placement of $CO_2$ injectors from a single drill centre.

*Surface Hole Section and Casing*

The surface hole sections were drilled through the shallow marine clays with surface casing being set directly below the top of the Chalk formation. This setting depth was selected to provide sufficient formation strength to drill the next hole section into the top of the Captain reservoir.

All surface hole sections were drilled using seawater, with bentonite sweeps being used to assist with hole cleaning.

Some surface hole sections were directionally drilled in order to allow the wells to reach horizontal in the shallow Captain reservoir. There were no reported issues associated with nudging the surface hole sections, making this a viable option for reservoir placement of $CO_2$ injectors from a single drill centre.

*Intermediate Hole Section and Production Casing*

The intermediate hole sections were drilled through the Chalk, Rodby and Sola Shales, with the production casing shoe being set directly below the top of the Upper Captain Sands. This casing setting depth performed two functions, these being:

- The overlying shales were cased off, thereby reducing the risk of wellbore instability when drilling the reservoir sections.
- The reservoir mud system could be designed to minimise formation damage, and reduce the risk of sand screen blockage.

The intermediate hole section was used to build the well to horizontal, with the production casing shoe being set at, or close to 90o on many occasions. No directional drilling problems occurred in the Chalk, and the directional drilling objectives were normally met, even when relying on high dog-leg severities to achieve the required build and turn.

No problems occurred drilling through the top of the Captain reservoir, indicating that the sand formation strength is sufficient to hold the mud weight required to maintain wellbore stability in the Rodby and Sola Shales.

Oil based mud was used to drilling the intermediate hole section in order to:

- Reduce the friction factors for sliding the directional drilling assemblies.
- Reduce the risk of wellbore instability in the Rodby and Sola Shales.
- Maintain gauge hole for hole cleaning at high angle.

*Production Hole Section and Sand Screens*

Long horizontal sections of up to 1,800m (6,000ft) were drilled through either the Upper or Lower Captain Sands, depending upon the reservoir target. These were positioned approximately 20ft below top reservoir in order to minimise the volumes of stranded attic oil, while also ensuring that the hole section remained in the reservoir sands.

Due to the unconsolidated nature of the sands, high ROPs were experienced, with hole cleaning being problematic on occasion.

The reservoir sections were drilled with water based mud, designed specifically to minimise formation damage. For example, the weighting agent used was $CaCO_3$ instead of barite, to allow filter cake to be acidised in the event that high skins occurred or the sand screens became blocked. In addition, by keeping the wellbore positioned in reservoir sand and avoiding exposure to the overlying shale, the mud weight didn't have to be selected based on shale wellbore stability concerns. This meant that the reservoir mud weight could be reduced to 9.5 ppg, when compared with the 11.5 ppg required to drill the intermediate hole section. The advantages arising from this mud weight reduction include:

- By minimising the differential pressure between the mud weight and reservoir pressure, mud filtrate invasion is reduced, thereby reducing the impact of formation damage.
- The risk of differential sticking is reduced.
- The risk of formation breakdown and subsequent losses is reduced.

#### 11.6.2.2 Drilling Risks and Hazards

The following drilling risks and hazards have been identified from the available offset data:

*Shallow Gas*

At present, it is assumed that shallow gas will not be present below the platform location. However, this will be confirmed when the results of the shallow gas survey are available. In the event that shallow gas is identified at the selected platform site, the location should be moved.

*Shallow Swelling Clays*

The shallow clays overlying the Chalk formation swell when exposed to seawater or water based drilling fluids. Therefore, the length of time in which they are left open should be minimised. This situation has been managed in the offset wells by setting surface casing upon positive identification of top Chalk.

*Hole Cleaning*

High rates of penetration (ROP) have been experienced in the shallow formations, which have led to hole cleaning problems at high angle. In order to manage this issue, frequent wiper trips may be required to clean-up formed cuttings beds.

*Low Formation Strength Sand*

The Captain reservoir sand is known to be unconsolidated with low formation strength. As such, the risk of losses exists if the equivalent circulating density (ECD) is too high. However, high circulating rates are required to minimise the risk of hole cleaning problems occurring. Therefore, a balance must be maintained between flow rate and ECD. In order to manage this issue the well design should consider:

- Using as low a reservoir mud weight as possible, in order to minimise ECD.
- Modelling the minimum flow rate required to deliver effective hole cleaning.
- Sizing the $CaCO_3$ weighting agent to allow it to bridge across the sand pore throats and act as a lost circulation material.

*Differential Sticking*

The Captain Sand is highly permeable; therefore, the risk of differential sticking exists when drilling with an overbalance. In order to reduce the risk of differential sticking, the following factors should be considered when designing the reservoir hole section:

- Use as low a mud weight as possible, in order to minimise the differential pressure between hydrostatic head and pore pressure.
- Design the BHA to minimise stationary time (i.e. directionally drill using rotary steerable tools instead of mud motors and bent housings).
- Design the mud system to build a tight filter cake, with minimal fluid loss.

#### *11.6.2.3 Directional Profiles*

*Reservoir Targets*

The following reservoir targets have been identified for the Captain reservoir.

The coordinate system in use is UTM, ED50 Common Offshore, Zone 31N (0° to 6°East)

| Target Name | TVDSS (m) | UTM North (m) | UTM East (m) |
|---|---|---|---|
| GI-01 Top Captain | 2,014.9 | 6,440,148.6 | 265,001.2 |
| GI-02 Top Captain | 1,981.3 | 6,438,715.4 | 263,621.5 |
| GI-03 Top Captain | 1,924.9 | 6,440,774.4 | 261,452.2 |

*Figure 11-52 Captain aquifer reservoir targets*

Note:

Well GI-03 is currently defined as the spare injector and/or monitoring well. However, the reservoir location of this well may be modified following further detailed analysis during the FEED stage.

*Surface Location*

A central surface location for the platform has been selected with the coordinates being as follows:

- 6,440,500m North
- 263,000m East

The surface location and well position is shown in the spider plot:

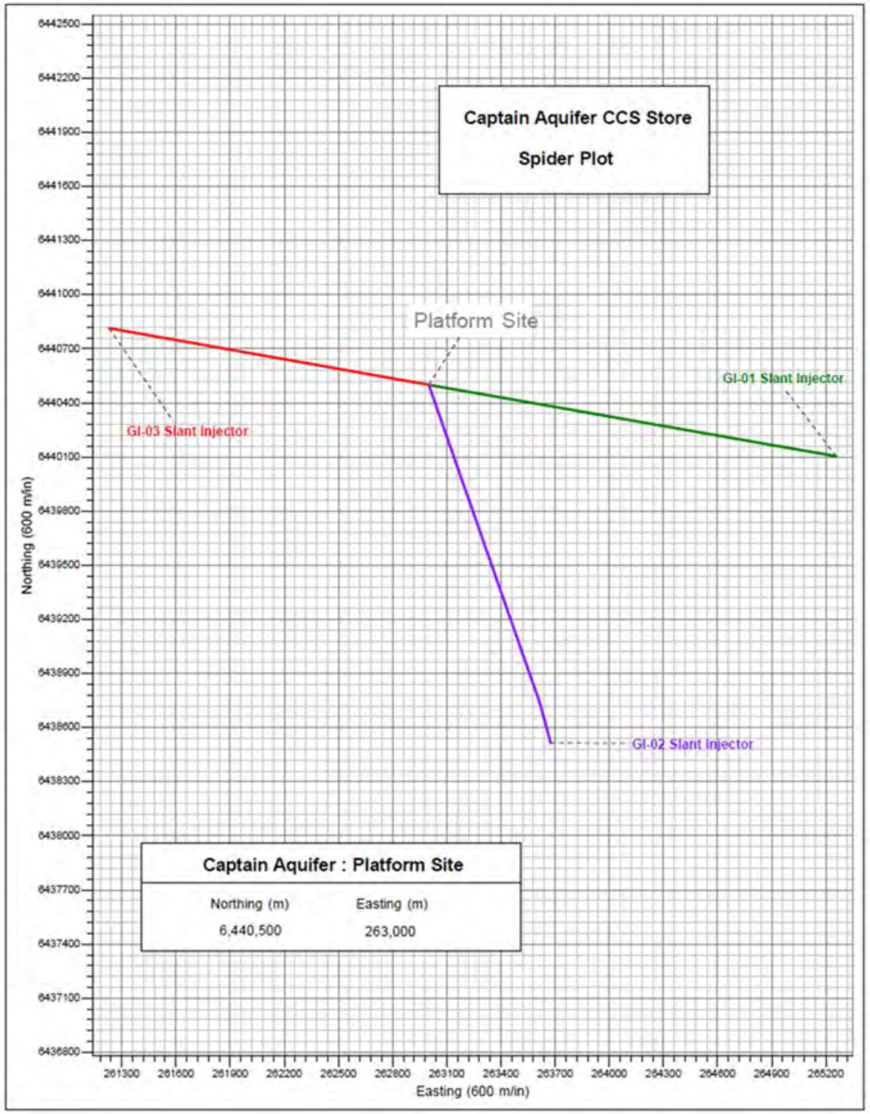



*Figure 11-53 Platform directional spider plot*

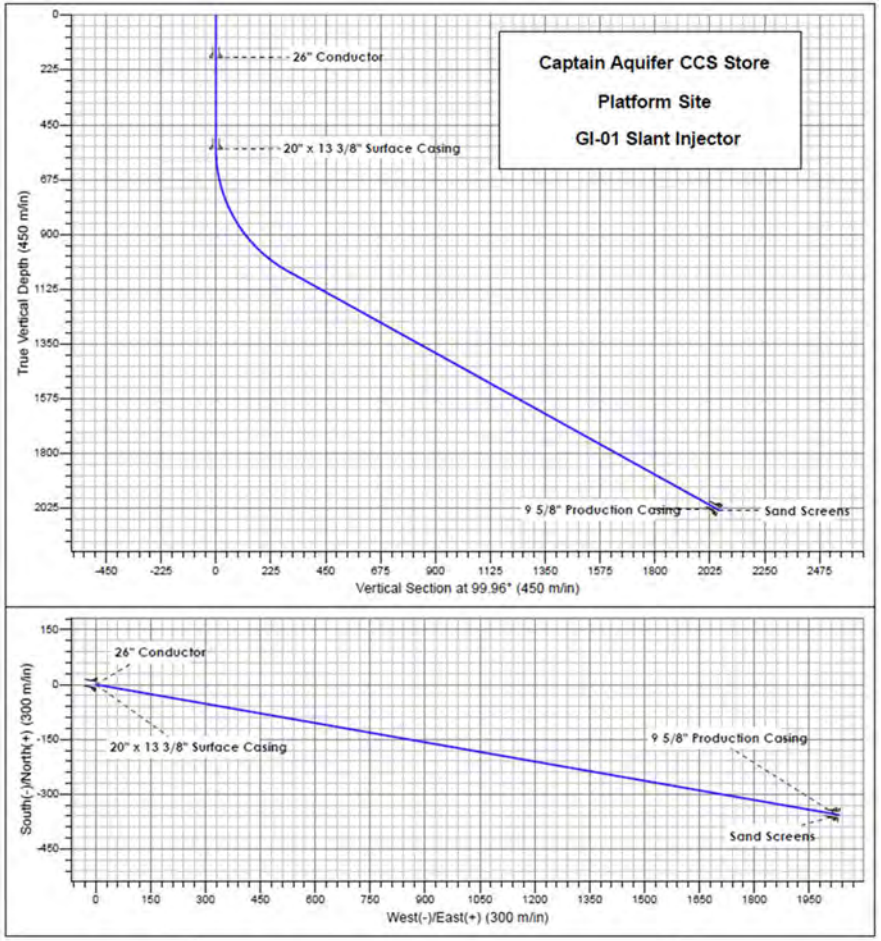
*Directional Design*

The surface and well reservoir locations have been selected for conceptual well design purposes; however, it should be noted that these locations have not been optimised for reservoir management or directional drilling purposes. Therefore, it is recommended that the wells are re-planned and anti-collision scans conducted during the FEED stage when the target locations have been finalised.

The conceptual directional plans for the $CO_2$ injectors have been designed on the following basis:

- All wells will be drilled as slant wells, including the spare well which will also act as monitoring well.
- All wells will be drilled vertically to 550m TVDSS (i.e. to below the surface casing shoe).
- All wells will be kicked off below 550m MD, with a planned dogleg severity of 3.0° per 30m. The wells will be built to the required tangent angle, while turning the wellpath onto the required azimuth.
- A build section will be drilled from the surface shoe to the depth at which inclination is sufficient to reach the identified reservoir target.
- A turn and build / drop section will be drilled in the 12 ¼" hole section to deliver an inclination of 60° at the top of the Captain Sand while turning the well path onto the desired azimuth.
- The reservoir section will be drilled as a tangent section, holding inclination at 60° to TD below the base of the targeted Captain Sand.

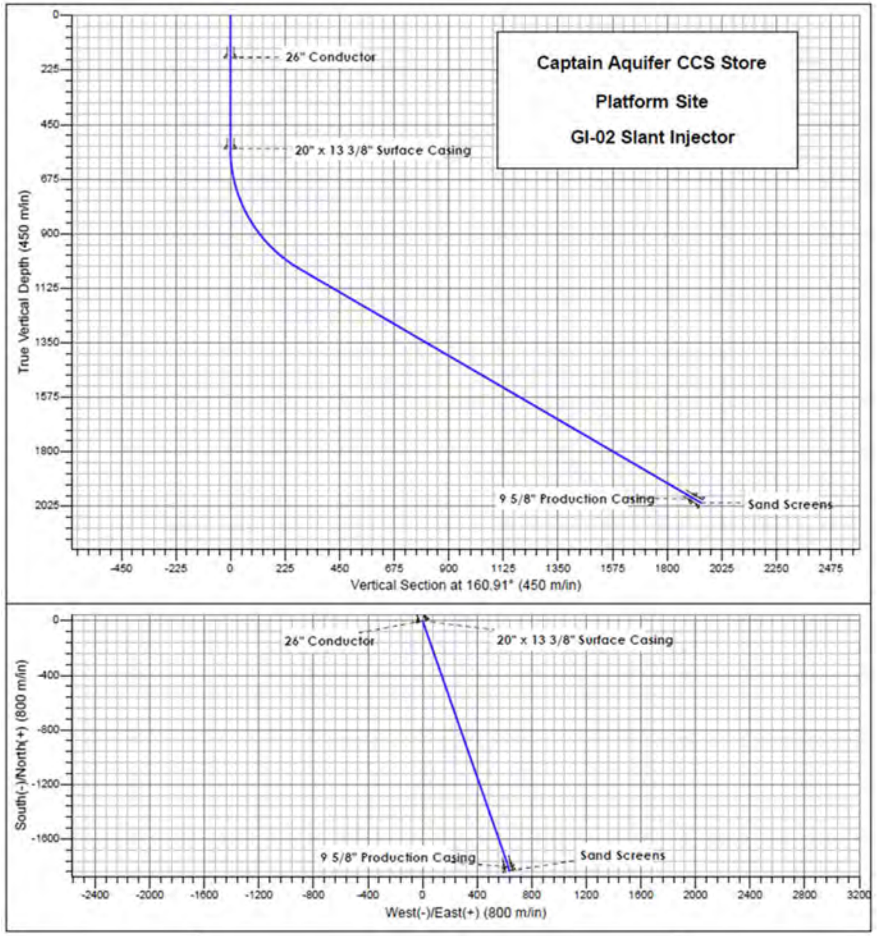
Directional profiles have been prepared for each well based on the reservoir targets and directional drilling limitations, as follows:




SECTION DETAILS

| MD | Inc | Azi | TVD | +N/-S | +E/-W | Dleg | TFace | VSect |
|---|---|---|---|---|---|---|---|---|
| 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.000 | 0.00 | 0.00 |
| 550.00 | 0.00 | 0.00 | 550.00 | 0.00 | 0.00 | 0.000 | 0.00 | 0.00 |
| 1159.73 | 60.97 | 99.96 | 1050.99 | -51.01 | 290.50 | 3.000 | 99.96 | 294.95 |
| 3136.38 | 60.97 | 99.96 | 2010.10 | -349.93 | 1992.82 | 0.000 | 0.00 | 2023.31 |
| 3146.11 | 60.00 | 100.00 | 2014.90 | -351.40 | 2001.16 | 3.000 | 177.93 | 2031.78 |
| 3172.91 | 60.00 | 100.00 | 2028.30 | -355.43 | 2024.02 | 0.000 | 0.00 | 2054.99 |
| 3182.91 | 60.00 | 100.00 | 2033.30 | -356.93 | 2032.55 | 0.000 | 0.00 | 2063.65 |

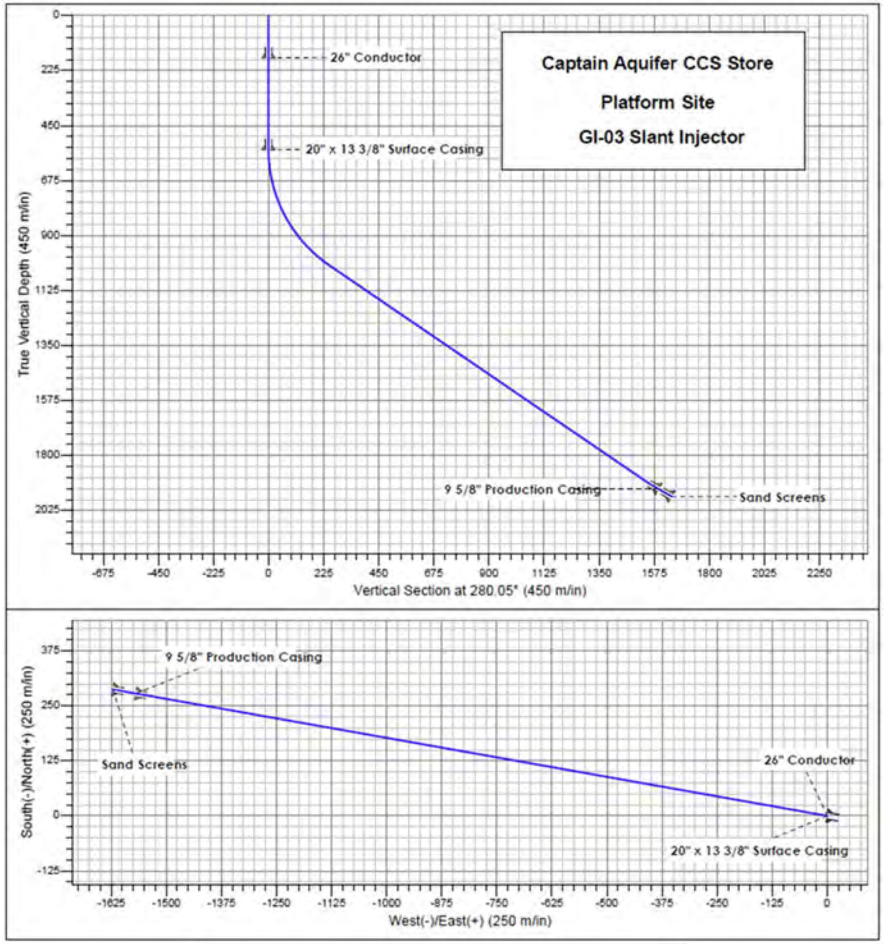
*Figure 11-54 Platform injector GI-01 directional profile*




SECTION DETAILS

| MD | Inc | Azi | TVD | +N/-S | +E/-W | Dleg | TFace | VSect |
|---|---|---|---|---|---|---|---|---|
| 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.000 | 0.00 | 0.00 |
| 550.00 | 0.00 | 0.00 | 550.00 | 0.00 | 0.00 | 0.000 | 0.00 | 0.00 |
| 1147.45 | 59.74 | 160.76 | 1044.91 | -268.40 | 93.66 | 3.000 | 160.76 | 284.27 |
| 2969.29 | 59.74 | 160.76 | 1962.86 | -1754.22 | 612.13 | 0.000 | 0.00 | 1857.95 |
| 3006.02 | 60.00 | 165.00 | 1981.30 | -1784.57 | 621.48 | 3.000 | 87.08 | 1889.69 |
| 3055.62 | 60.00 | 165.00 | 2006.10 | -1826.06 | 632.60 | 0.000 | 0.00 | 1932.53 |
| 3065.62 | 60.00 | 165.00 | 2011.10 | -1834.43 | 634.84 | 0.000 | 0.00 | 1941.17 |

*Figure 11-55 Platform injector GI-02 directional profile*




SECTION DETAILS

| MD | Inc | Azi | TVD | +N/-S | +E/-W | Dleg | TFace | VSect |
|---|---|---|---|---|---|---|---|---|
| 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.000 | 0.00 | 0.00 |
| 550.00 | 0.00 | 0.00 | 550.00 | 0.00 | 0.00 | 0.000 | 0.00 | 0.00 |
| 1106.44 | 55.64 | 280.05 | 1023.00 | 43.57 | -245.78 | 3.000 | 280.05 | 249.62 |
| 2663.49 | 55.64 | 280.05 | 1901.71 | 267.94 | -1511.47 | 0.000 | 0.00 | 1535.03 |
| 2707.06 | 60.00 | 280.00 | 1924.90 | 274.36 | -1547.77 | 3.000 | -0.60 | 1571.90 |
| 2783.46 | 60.00 | 280.00 | 1963.10 | 285.85 | -1612.93 | 0.000 | 0.00 | 1638.06 |
| 2793.46 | 60.00 | 280.00 | 1968.10 | 287.35 | -1621.46 | 0.000 | 0.00 | 1646.72 |

*Figure 11-56 Spare injector / monitoring well GI-03 directional profile*

#### 11.6.2.4 Detailed Well Design

*$CO_2$ Injector – Platform Well*

The conceptual well design for the $CO_2$ injectors and spare injector (monitoring well) is as follows:

*26” Conductor*

The conductor string will be driven to depth during platform installation, with the setting depth having been specified as 60m below the mudline for the following reasons:

- Conductors have been successfully driven to this depth regionally.
- The formation strength at this depth should be sufficient to hold a mud weight of 10.0 ppg (recommended spud mud weight prior to running surface casing), and allow returns to be taken to the rig floor elevation.

The selected conductor size is 26” which is compatible with the selected well design, while minimising the tubular diameter for driving efficiency

*17 ½” Surface Hole and 20” x 13 3/8” Casing Setting Depth*

The surface casing setting depth should be set directly below the top of the Chalk formation, which is predicted to be at approximately 550m TVDSS. This setting depth has been selected to case off the swelling clays above the Chalk formation and provide sufficient formation strength to drill the intermediate hole section to the top of the Captain reservoir. This is considered to be advantageous for the following reasons:

- Time Related Instability: The length of time to which the shallow clays are exposed to seawater should be minimised to reduce the impact of gumbo type problems.
- Formation Strength: The Chalk formation will provide sufficient formation strength to allow the 12¼” hole section to be drilled with 11.5 ppg mud weight.
- Directional Drilling: By setting the surface casing at 550m TVDSS, the surface hole section can be drilled vertically.

20” casing should be used from the 26” conductor shoe to surface in order to provide structural stability in the uncemented section of the well. Below the mudline, 13 ⅜” casing should be used to reduce cost, and assist 12 ¼” hole cleaning.

*12 ¼” Intermediate Hole and 9 5/8” Production Casing Setting Depth*

The 12 ¼” intermediate hole section will be drilled through the Chalk, Rodby and Sola formations, and these will be cased off prior to drilling the reservoir section. The 9 ⅝” production casing setting depth has been selected as 12 to 25m MD below the top of the Captain Sand for the following reasons:

- Cement Quality: By setting the 9 ⅝” casing shoe below the top of the Captain Sandstone, the production casing can be cemented across the Rodby and Sola shales. This provides the following advantages:
    - The $CO_2$ injection point will be below top reservoir, ensuring that injection pressure is not applied close to the cap rock.
    - The cement design can be optimised to provide isolation from the reservoir, thereby minimising the risk of $CO_2$ leakage from the reservoir.

    - The probability of delivering a good cement job for end of life abandonment purposes is increased.
- Mud Weight: By casing off the overlying shales, the mud weight used for the reservoir section could be reduced from 11.5 ppg to 9.5 ppg. The advantages associated with this weight reduction include:
    - A lower mud weight reduces the differential pressure. This in turn reduces mud filtrate invasion, thereby minimising the impact of formation damage.
    - The risk of differential sticking is reduced.
    - The risk of formation breakdown and subsequent losses is reduced.
- Sandface Completion: By drilling the reservoir in a dedicated hole section, the sandface completion can be designed to:
    - Optimise sand control.
    - Allow well intervention access to conduct remedial stimulation work should formation damage impact on injectivity performance.
    - Provide limited zonal isolation and reservoir management options.

*8 ½" Production Hole and Sand Screen Setting Depth*

The 8 ½" hole section will be drilled through the Upper Captain Sand only in order to limit the cross-flow potential between the two sands.

Sand screens will be set across the reservoir section in order to:

- Manage sand production when the well is flowed back to clean up.
- Minimise the risk of sand collapse into the wellbore when the well is shut-in (i.e. during well intervention, periods of platform maintenance or unplanned shutdowns).

*End of Life Well Abandonment*

The casing sizes and setting depths have been selected to ensure that the well can be abandoned at the end of field life by placing cement plugs inside cemented 9 ⅝" production casing and opposite the Rodby and Sola shales. These formations have sufficient strength to contain reservoir pressure; therefore, by placing the abandonment plugs opposite these formations, store integrity will be assured.

*Casing Metallurgy*

When selecting the casing materials for the $CO_2$ injectors and monitoring well (spare injector), the following issues should be taken into consideration:

- Corrosion caused by exposure to dense phase $CO_2$.
- Material selection for low temperature.

For casing strings with no direct exposure to the $CO_2$ injection stream, $CO_2$ corrosion resistant materials are not required. Therefore, the following casings strings may be specified using conventional carbon steel grades:

- 26" conductor
- 20" x 13 ⅜" surface casing
- 9 ⅝" production casing above the production packer

However, below the production packer, the casing and sand screen components will be exposed to injected $CO_2$. The corrosion potential will be dependent upon the water content of the injected $CO_2$, and/or latent water in the wellbore;

however, some form of corrosion resistant alloy (CRA) will be required. The most commonly used CRA for $CO_2$ corrosion resistance is 13Cr and this would probably be suitable for the casing strings exposed to the injection stream below the production packer. However, it is recommended that detailed design work is conducted during the FEED stage to confirm that this material is suitable for the injection stream specification. The casing strings to be designed using CRA materials are:

- 9 ⅝" production casing below the production packer
- Sand screens

When selecting the casing materials, it should also be noted that all casing strings could be exposed to low temperatures. The worst case happens during transient conditions which occur when wellbore pressure is released. A reduction in wellbore pressure can occur due to planned operations (i.e. when pressure is bled off to test a downhole safety valve or during well servicing activities), or when an unplanned event occurs (i.e. there is a leak at the wellhead). When wellbore pressure is released either by design or unexpectedly, the dense phase (liquid) $CO_2$ will revert to its gaseous phase. At the liquid / gas interface, temperatures can be as low as -78oC, and heat transfer will lead to the near wellbore casing materials being exposed to low temperatures. In order to determine the minimum temperature that each casing string could be exposed to, modelling will be required, and this should be conducted during the detailed design phase.

When metals cool they lose toughness, which could become an issue when subjected to mechanical load. Therefore, in order to demonstrate that the selected casing grades are suitable for the modelled temperatures, low temperature impact toughness testing should be conducted by the steel suppliers, to confirm that the selected tubular is suitable for a low temperature application

*Wellhead Design*

As with the casing materials, the wellhead components must also be designed to provide suitable low temperature performance and corrosion resistance. Wellhead component temperature rating is specified in API 6A with a class being assigned to reflect the temperature range to which the components are rated. For $CO_2$ injection wells, API 6A class K materials may be suitable, as the low temperature rating of these materials is -60oC. This should be acceptable for $CO_2$ injection purposes; however, it is recommended that detailed modelling is conducted for each wellhead component to confirm the lowest temperature to which they may be exposed, and that suitable materials are being selected.

In addition, the wellhead components which are directly exposed to the $CO_2$ injection stream should be specified from $CO_2$ resistant alloys.

*Drilling Fluids Selection*

*17 ½" Hole Section*

This hole section should be drilled with seawater and viscous sweeps, taking returns to the rig. At section TD, the hole should be displaced to 10.0 ppg spud mud, to maintain wellbore stability prior to running the surface casing string.

*12 ¼" Hole Section*

This hole section should be drilled with 11.5 ppg oil based mud, taking returns to the rig. Oil based mud has been selected to:

- Maintain wellbore instability in the Rodby and Sola Shales.
- Reduce the friction factors for running drillstrings and casing.

- Maintain gauge hole in order to reduce the risk of hole cleaning problems and increase the probability of obtaining a good cement bond.

It should be recognised that cuttings collection and management will be an important issue when using oil based mud. Therefore, this factor should be addressed early in the planning process, when selecting the rig.

*8 ½" Hole Section*

The 8 ½" hole section should be drilled with a 9.5 ppg oil based mud. Oil-based mud has been selected to minimise the risk of wellbore instability from the intra-reservoir shales while also minimising the impact of formation damage by being designed to:

- Build a tight filter cake.
- Have as low a fluid loss as is possible.
- Using as low a mud weight as possible, and thereby reducing the differential pressure. This in turn reduces mud filtrate invasion, thereby minimising the impact of formation damage.

The 9.5 ppg mud weight has been selected in order to maintain primary well control and wellbore stability in the shales and unconsolidated sands, while also keeping the weight as low as possible. A low mud weight minimises the differential pressure between hydrostatic head and pore pressure, thereby reducing the risk of differential sticking. In addition, using a low mud weight reduces the risk of losses due to ECD induced formation breakdown

It is recommended that the weighting agent used is $CaCO_3$ instead of barite. Use of $CaCO_3$ provides the option to remove the filter cake via acid treatment should high skins occur or the sand screens become blocked. In addition, the $CaCO_3$ weighting agent can be sized to allow it to bridge across the sand pore throats and act as a lost circulation material.

*Cement Programme*

20" x 13 3/8" Surface Casing

The purpose of the 20" x 13 ⅜" cement job is primarily to provide a strong shoe prior to drilling the intermediate hole section into the top of the Captain reservoir, and a tail slurry should be used to generate the compressive strength required to meet this objective.

The 20" x 13 ⅜" casing should be cemented back to the mudline in order to provide structural stability, and minimise abandonment costs.

Conventional lead and tail slurries should be selected for this cement job.

*9 5/8" Production Casing*

The purpose of the 9 ⅝" cement job is to provide a strong shoe and prevent $CO_2$ leakage from the reservoir. A tail slurry should be used to generate the compressive strength required to meet this objective.

The 9 ⅝" casing should be cemented back to 1,000m below the 13 ⅜" shoe in order to:

- Cement off all open formations, and minimise leak paths from the Captain Sand.
- Optimise the end of field life abandonment design.

It should be noted that the Captain Sand formation strength is insufficient to allow the top of the 9 ⅝" cement to be placed inside the 13 ⅜" casing shoe. Therefore, at the end of field life, an additional abandonment cement plug will be required to isolate the open formations below the 13 ⅜" casing shoe.

*Sand Screens*

The reservoir section will be completed using sand screens for sand control purposes, and will not be cemented. If zonal isolation in the reservoir is required, this will be provided using swellable packers positioned at suitable intervals.

*Production Casing Cementing Design*

At present, it is planned to cement the production casing using conventional Portland Class G cement. The interaction between Portland cement and $CO_2$ is as follows:

- Carbonic acid will form when water and $CO_2$ are present:

$$CO_2 + H_2O \rightleftharpoons HCO_3^- + H^+ \rightleftharpoons CO_3^{2-} + 2H^+$$

- When cement and carbonic acid are in contact, cement dissolution and carbonate precipitation (also called cement carbonation) occurs. This process forms an insoluble precipitate and leads to lower porosity because calcium carbonate has a higher molar volume than Ca(OH)2 (i.e. cement ). This reduces the $CO_2$ diffusion rate into the cement and is therefore a self-healing mechanism (Shen & Pye, 1989). The precipitation mechanism is:

$$Ca(OH)_2 + CO_3^{2-} + 2H^+ \rightleftharpoons CaCO_3 + 2H_2O$$

$$3H_2CO_3 + Ca_3Si_2O_7 \cdot 4H_2O \rightleftharpoons 3CaCO_3 + 2SiO_2 \cdot H_2O + 3H_2O$$

Due to the carbonation effect, cement degradation is a very slow process. Lab testing has been conducted by various parties in order to determine the rate of degradation, with a summary of the test results shown below.

| Test Reference | Cement Class | Test Pressure (bar) | Test Temperature (°C) | Cement degradation per 1,000 years (mm) | Cement degradation per 10,000 years (mm) |
|---|---|---|---|---|---|
| Bartlet-Gouedard | G | 280 | 90 | 776 | 2,454 |
| Bartlet-Gouedard | G | 280 | 90 | 646 | 2,042 |
| Duguid et al | H | 1 | 23 | 29 | 92 |
| Duguid et al | H | 1 | 23 | 16 | 50 |
| Duguid et al | H | 1 | 23 / 50 | 99 | 314 |
| Duguid et al | H | 1 | 23 / 50 | 74 | 234 |
| Lecolier et al | Conventional | 150 | 120 | 1,648 | 5,211 |
| Shen & Pye | G | 69 | 204 | 3,907 | 12,354 |
| Bruckdorfer | A | 207 | 79 | 184 | 583 |
| Bruckdorfer | C | 207 | 79 | 152 | 480 |
| Bruckdorfer | H | 207 | 79 | 228 | 721 |
| Bruckdorfer | H + flyash | 207 | 79 | 250 | 789 |

*Table 11-15 Cement degradation rates in $CO_2$ - Laboratory test results*

For comparison purposes, the Captain reservoir pressure is predicted to be approximately 83 bar. As such, the rate of cement degradation predicted by Shen and Pye may be the most appropriate measurement to use. This suggests that cement would degrade at a rate of 12.3m per 10,000 years. Given that the length of cement behind the 9 ⅝" production casing is designed to cover approximately 1,000m, it may be concluded that the rate of conventional class G cement degradation makes the selection of this cementing material suitable for use.

However, the loss of integrity due to degradation is not the only factor to be considered when selecting the cement type. The creation of micro-annuli due to thermal cycling should also be taken into consideration, as the wellbore could be exposed to low temperatures at certain stages of the $CO_2$ management process.

$CO_2$ resistant cements are available from the main cementing service providers, with the chemistry being well understood. These specialist cements have been used in $CO_2$ environments, however, they can be problematic to handle as they are incompatible with conventional cementing products. Therefore, when selecting the preferred cement type it is recommended that conventional cements are compared with $CO_2$ resistant systems, and that the selection is based on best practices and standards in place at the time of drilling.

Consideration should also be given to annular packers (casing deployed). These can have elastomer or metal seals, and reduce the risk of an annular leak path (micro-annulus) through the expansion and contraction of the casing during cementing operations.

## 11.6.3 Completion Design

### *11.6.3.1 Lower Completion*

The lower completion consists of 5-1/2" stand alone sand screens, following the recommendations of the sanding risk review (section 3.6.3). Shale sections can be isolated by blank pipe (with or without external isolation packers). This will allow the formation sands to 'relax' and form a pack around the screens. Open hole gravel pack could be considered, but as it is a more expensive and technically complex installation operation, it is felt that the risk of poor clean-up or inefficient installation outweighs the benefits. Note that reactive shales are unlikely to be a risk in $CO_2$ injection wells.

The 9-5/8" shoe would be set around 40ft to 80ft into the Captain sandstone formation at an angle of 60 degrees, thereby providing some offset from the top injection point through the screens to the penetration point. This also provides a vertical stand-off of 20 to 40ft TVD between the top injection depth and the caprock for thermal and fracture initiation moderation.

### *11.6.3.2 Upper Completion*

The upper completion consists of a 5.5" tubing string, anchored at depth by a production packer in the 9-5/8" production casing, just above the 5.5" lower completion hanger. Components include:

- 5-1/2" 13Cr tubing (weight to be confirmed with tubing stress analysis work)
- Tubing Retrievable Sub Surface Safety Valve (TRSSSV)
- Deep Set Surface-controlled Tubing-Retrievable Isolation Barrier Valve (wireline retrievable, if available)
- Permanent Downhole Gauge (PDHG) for pressure and temperature above the production packer

- Optional DTS (Distributed Temperature Sensing) installation
- 9-5/8" Production Packer

The DTS installation will give a detailed temperature profile along the injection tubulars and can enhance integrity monitoring (leak detection) and give some confidence in injected fluid phase behaviour. The value of this information should be further assessed, if confidence has been gained in other projects (tubing leaks can be monitored through annular pressure measurements at surface, leaks detected by wireline temperature logs and phase behaviour modelled with appropriate software).

#### 11.6.3.3 Completion Metallurgy

*Initial Assumptions*

It is assumed that the injected gas will be predominantly $CO_2$ with small concentrations of water, oxygen and nitrogen. Other minor impurities may exist however it will not be present in high enough concentrations to cause corrosion/cracking issues.

*Metallurgy Selection*

The selection of the metallurgy for flow wetted components of the $CO_2$ injection wells depends on the final composition of the supply stream. For pure $CO_2$, with negligible water content (<300ppmv), carbon steel is suitable. As contaminants increase, metallurgy specifications change and a higher spec is normally required. The table below indicates the impact of various contaminants.

While nitrogen, methane and some other gases may also be present in the injected fluid, they do not react with the injection tubulars and therefore have no significance with regards to material selection.

| Contaminants | Selectable materials |
|---|---|
| | |
| **$CO_2$ only** | Carbon steel |
| **$CO_2$ + H2O / O2** | 13Cr |
| **$CO_2$ + H2S** | 25Cr |
| **$CO_2$ + H2S + O2** | Nickel Alloy |
| **$CO_2$ + NO2/SO2** | GRE |

*Table 11-16 Material selection for a range of contaminants*

While it is expected that the supply stream will have negligible H2S content, some hydrocarbon reservoirs may contain high H2S levels. In the case of Captain (saline aquifer), H2S can be ignored.

NO2 and SO2 can increase corrosion rates in 13%Cr, but only when present in significant quantities or at high temperatures (>140°C for NO2 and >70°C for SO2). Captain reservoir temperature is low (~ 62°C) and therefore the impact of these impurities should be insignificant, However, these should be re-assessed once the final composition of the injected fluids is known.

Given that liquid water may be present in the system (out of spec conditions or following water wash operations), a minimum spec of 13%Cr is recommended for all flow wetted components, including production tubulars and tubing hangers.

Material grade is limited to 80ksi (L-80) due to the potential for low temperatures.

#### 11.6.3.4 Elastomers

NBR nitrile elastomer can be used within the temperature range of -30 to 120°C [S13] and is therefore suitable for $CO_2$ injection wells. This elastomer gives the lowest operating temperature among the typical downhole elastomers.

The major issue associated with elastomers and $CO_2$ is the loss of integrity due to explosive decompression. This occurs due to the diffusion of $CO_2$ into the elastomer and the rapid expansion of absorbed $CO_2$ during rapid decompression (or blow down). While blow down is not planned to occur in the Captain wells under normal operation conditions, unexpected / unplanned events may occur. An elastomer that is more tolerant of rapid gas decompression with the same low temperature capability is recommended, such as specially formulated HNBR elastomers.

#### 11.6.3.5 Flow Assurance

*Hydrates*

Hydrates may be an issue at very low temperatures, providing water is present and $CO_2$ gas phase. The injection of MEG (glycol) where low temperature events occur may help mitigate this issue (see discussion of ice below). In the liquid / dense phase injection system for Captain, the primary risk of hydrate formation is following any wash water injection operations (see section 3.6.4). Further work on this area is recommended in FEED.

*Ice*

Ice will be expected to form if fresh water (e.g. condensed water or halite wash water) is present and temperatures drop to below 0°C. Saline brines (60,000ppm), such as is present in the reservoir, may freeze if temperatures drop below -8°C.

$CO_2$ injection is unlikely to reduce temperature to this low temperature in the well (injection pressures and rates have been limited so as not to drop temperature below 0°C). However, unplanned blowdowns or local pressure drops may drop temperatures to these levels through Joules-Thomson effects. Intervention operations, where $CO_2$ may be vented in the presence of water, should carry the contingency of inhibitors such as MEG. Detailed operation planning is required in order to confirm requirements and concentrations.

A flow control choke is required in order to control the distribution of flow to individual wells and in some circumstances, such as start-up, to provide some back pressure for the delivery system. Pressure drops across the choke may result in significant temperature drops. This is only problematic in a flow assurance context if free water is continuously present in the delivery system upstream of the choke. Choke modelling will be required in order to determine the extent of this issue, and the knock on effect in downhole temperature. Mitigations include the addition of heating upstream of the choke and / or the continuous injection of ice inhibitors (e.g. MEG). Heating is the more appealing solution, as the effect of continuous MEG injection on the reservoir is unknown. System design, where the well is operating with the choke mostly open is the preferred solution. Heating and / or insulation of the subsea well chokes requires further pre-FEED study.

### 11.6.4 Intervention Programme

Intervention requirements for the $CO_2$ injection wells are not well defined at present due to lack of analogue experience. It is expected that some well performance logging will be required (production logging or PLT) in order to monitor injection profile. Well drifting may also be required from time to time in order to monitor the build-up of sand or other solids in the bottom hole.

## 11.7 Appendix 7 – Cost Estimate

Provided separately as a PDF.

# 11.8 Appendix 8 – Methodologies

## 11.8.1 Offshore Infrastructure Sizing

Methodology:

The preliminary calculations are based on fluid flow equations as given in Crane Corporation (1988) and were performed to provide a high level estimate of pressure drop along the pipeline routes.

Erosional Velocity: $V_e = c/\sqrt{\rho}$

Where;

$V_e$ = Erosional Velocity (m/s)

c = factor (see below)

$\rho$ = Density (kg/m3)

Industry experience to date shows that for solids-free fluids, values of c =100 for continuous service and c = 125 for intermittent service are conservative. For solids-free fluids where corrosion is not anticipated or when corrosion is controlled by inhibition or by employing corrosion resistant alloys, values of c = 150 to 200 may be used for continuous service; while values of up to 250 may be used for intermittent service. (American Petroleum Institute, 1991)

Velocity: $V = 4Q/\pi d^2$

Where,

V = Velocity (m/s)

Q = Mass flow rate (MTPa)

Reynolds Number: $Re = \frac{\rho V d}{\mu}$

Darcy Friction Factor: The friction factor is obtained from the Serghides' solution of the Colebrook-White equation.

$$A = -2\log_{10}\left(\frac{\varepsilon/D}{3.7} + \frac{12}{Re}\right),\ B = -2\log_{10}\left(\frac{\varepsilon/D}{3.7} + \frac{2.51}{Re}\right),\ C = -2\log_{10}\left(\frac{\varepsilon/D}{3.7} + \frac{2.51}{Re}\right),\ f = \left(\frac{A-(B-A)^2}{C-2B+A}\right)^{-2}$$

Pressure drop for single phase fluid flow: $\Delta P = \frac{fL\rho V^2}{\mu}$

| Pipeline | Pipeline OD | Mass Flow Rate | Route Length | Pipe Roughness | Fluid Phase | Pressure Drop per km | Pressure Drop |
|---|---|---|---|---|---|---|---|
| **St Fergus to Captain NUI** | 16” (406.4mm) | 2MTPa | 86km (78+8) | 0.045 | Liquid/Dense [1] | 0.062bar | 5.3bar |
| | | 3MTPa | | | | 0.139bar | 12.0bar |
| | | 4MTPa | | | | 0.244bar | 20.9bar |
| | | 5MTPa | | | | 0.375bar | 32.3bar |

*Table 11-17 St Fergus to Captain NUI pipeline pressure drop*

1. Density of 980.3 kg/m$^3$ and viscosity 0.1016 kgs/m

Preliminary wall thickness calculations to PD8010 Part 2 (British Standards Institution, 2015) have also been performed. As the product is dry CO2 composition, carbon steel is sufficient for the pipeline however the material specification will require particular fracture toughness properties to avoid ductile fracture propagation. The resulting pipeline configurations are summarized in the table below.

| Parameter | St Fergus to Atlantic | Atlantic to Captain NUI |
|---|---|---|
| **Status** | Existing (Acquisition) | New |
| **Outer Diameter** | 406.4 [1] | 406.4 |
| **Wall Thickness** | 15.5 [1] | 14.3 |
| **Corrosion Allowance** | 1mm | 1mm |
| **Material** | Carbon Steel | Carbon Steel |
| **Corrosion Coating** | 3 Layer PP | 3 Layer PP |
| **Weight Coating** | Concrete Weight Coating | Concrete Weight Coating |
| **Pipeline Route Length** | 78km | 8km |
| **Installation** | S-Lay (Trenched and Buried / Rockdump) [2] | S-Lay (Surface Laid) |
| **Crossings** | 7 | 1 |

*Table 11-18 Captain development pipeline specifications*

Notes:

1. The landfall comprises of 1.2km of 18" pipeline (17.5mm wall thickness).
2. Trenched and buried for protection and stability (piggybacked 4" MEG pipeline).

### 11.8.2 Cost Estimation

The CAPEX, OPEX and ABEX have been calculated for the engineering, procurement, construction, installation, commissioning, operation and decommissioning of the Captain facilities. The OPEX has been calculated based on a 20 year design life.

An overview of the Captain development (transportation, facilities, wells) is given in Section 5. The cost estimate is made up of the following components:

- Transportation: Pipeline, landfall and structures along the pipeline
- Facilities: NUI – Jacket / Topsides
- Wells: Drilling and the well materials and subsurface materials
- Other: Anything not covered under transportation, facilities or wells.

The cost estimate WBS adopted throughout is shown in Table 11-19. A 30% contingency has been included throughout.

| CAPEX (Transport, Facilities, Wells, Other) | |
|---|---|
| **Pre-FID** | Pre-FEED |
| | FEED |
| **Post FID** | Detailed Design |
| | Procurement |
| | Fabrication |
| | Construction and Commissioning |
| **OPEX (Transportation, Facilities, Wells, Other)** | |
| **Operating Expenditure (34 year design life)** | |
| **ABEX (Transportation, Facilities, Wells, Other)** | |
| **Decommissioning, Post Closure Monitoring, Handover** | |

*Table 11-19 Cost Estimate WBS*

### 11.8.3 Petrophysics

For the purposes of quantitative evaluation of reservoir rock properties from wireline logs, a standard oilfield approach to formation evaluation has been adopted. This is outlined and illustrated in Figure 11-57.

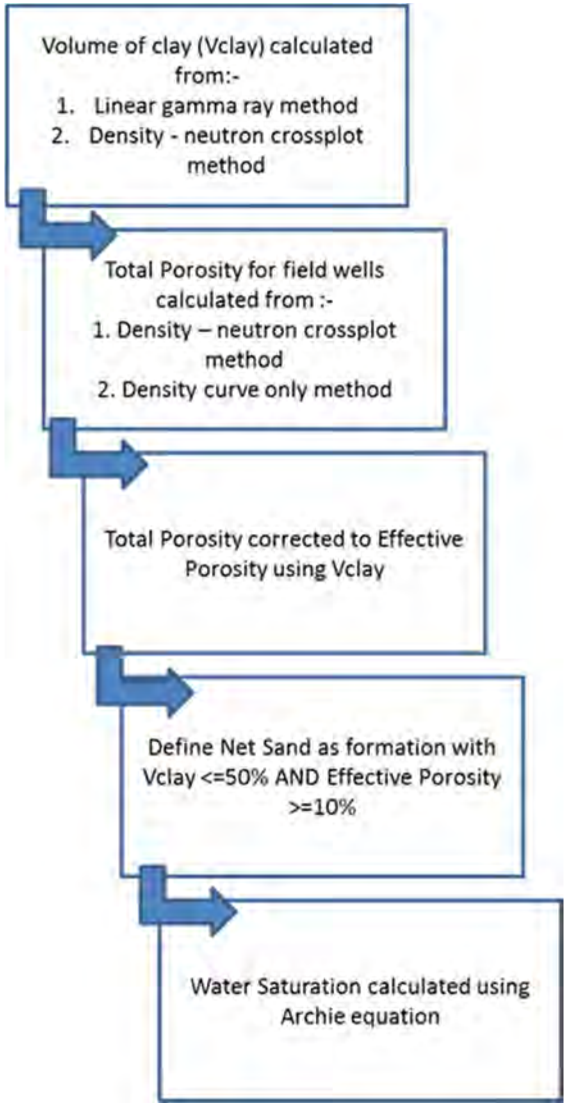



*Figure 11-57 Summary of petrophysical workflow*

#### 11.8.3.1 Parameter Definition

*Blake Field Petrophysics Report*

The Blake Field Petrophysics Report is a comprehensive reference describing the petrophysical model developed for the Cretaceous Captain Sands by BG International. The report focuses on 5 wells that are also included in this study:

13/24a-4, 13/24a-5, 13/24a-6, 13/24b-3, 13/29b-6

The report supports the same petrophysical approach as described in this report. There is a slightly different 'average' Rw reported of 0.172 ohm m at 60°F

| Resistivity of Connate Water | | | | |
|---|---|---|---|---|
| | Water Sample | | | Rw at 60 DegF |
| | Rw Sample | Depth | Pickett | |
| **13/24b-3** | | 5910 | 0.083 | 0.180 |
| **13/24a-4** | 0.070 | 5410 | 0.071 | 0.148 |
| **13/24a-5** | 0.074 | 5389 | | 0.176 |
| **13/24a-6** | 0.082 | 5300 | 0.089 | 0.183 |
| | | | | **0.172** |

*Table 11-20 Rwa summary from Blake Petrophysics Report*

This is slightly less saline than 0.160 ohm.m at 60°F recommended in this report, but both values fall within acceptable measurement uncertainty of the methods used to estimate Rw.

The Blake Field model notes that the formation factor 'm' ranges between 1.72 to 2.09 in core measurements and has opted for a mid-point of m=1.8 and a=1. This is consistent with the fixed point regression of the available SCAL data (Figure 11-60) and results in the same parameter selection as used in this report.

*Formation Temperature Gradient*

Formation temperatures were taken from the maximum reported bottom hole temperature on the field wireline prints or composite logs from TD and intermediate logging runs. These data were plotted and a regression line fitted to estimate temperature over the intervals of interest.

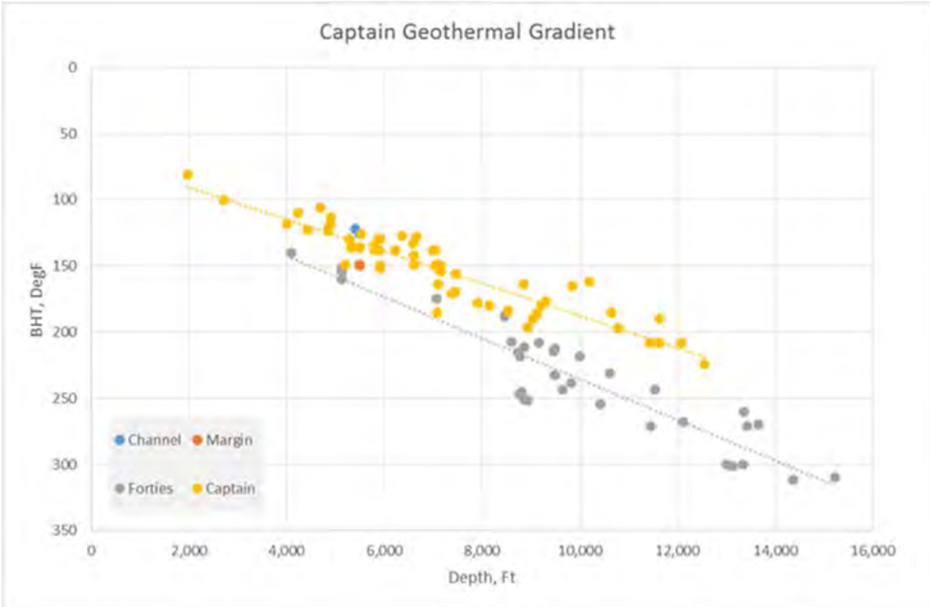



*Figure 11-58 Recorded bottom hole pressure from wirleine data*

Figure 11-58 is a comparison of the Forties Fairway and Captain Sands geothermal gradient; these data suggests that the Captain sands are slightly cooler than the Forties sands. Furthermore, there is the suggestion in the Blake Petrophysical Report that variation exists between different facies in the Captain sands, however the scatter observed in these data is greater than the described variance by facies type.

For this study a single geothermal gradient is assumed; assuming a linear free regression model through these data, the temperature gradient, in degrees Fahrenheit, is estimated using the following equation:

$$BHT = 0.0122 \times TVD + 66.0$$

This results in a formation temperature between 135°F and 150°F over the zone of interest.

*Formation Water Resistivity*

Rwa is calibrated in all the water zones and gives a fairly consistent estimate of formation water resistivity. Figure 11-59 shows Rwa estimates from the aquifer from various wells, it is clear that that well 20/04b-7 is a single outlier to these data, however it is not understood why the aquifer in this location is much fresher water.

Formation water resistivity (Rw) is assumed to be 0.160 at 60°F for the core area of this study.

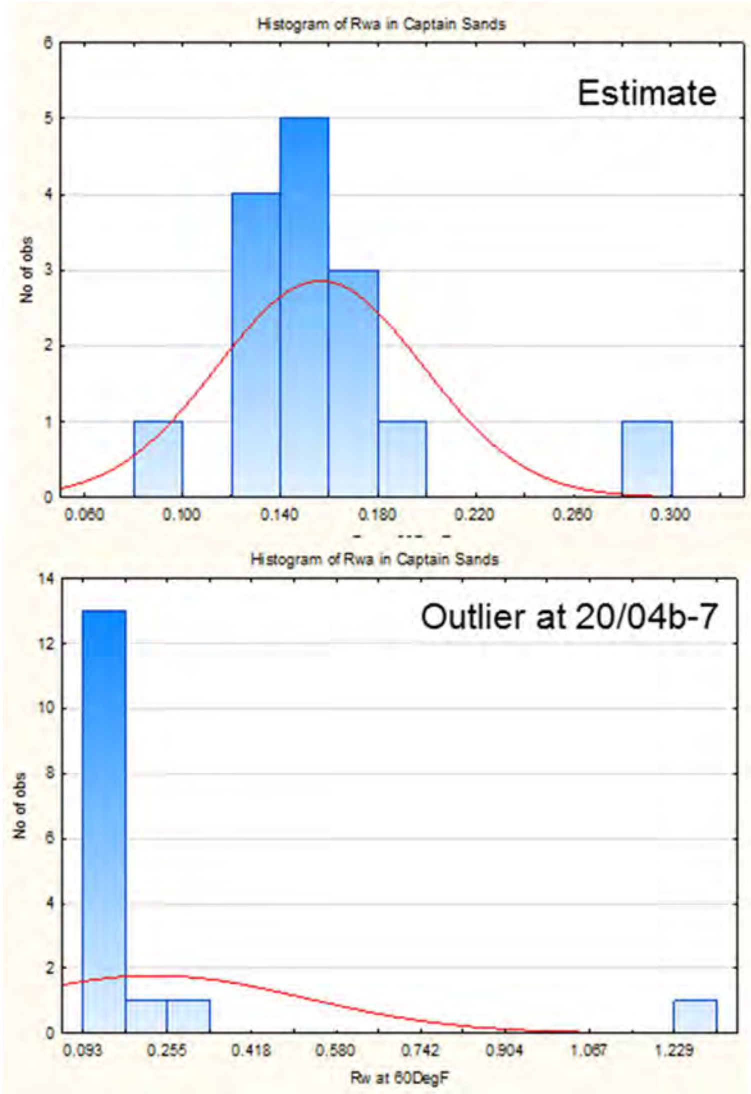



*Figure 11-59 Rwa estimates*

*Electrical Resistivity Properties*

Well 14/29a-3 and 20/04b-6 had a number of formation resistivity factor measurements that were consistent with the petrophysical model published in the Blake Field petrophysical report. Figure 11-60 is a crossplot of porosity vs. measured formation resistivity factor.

The forced regression fit of these data supports the use of parameters a=1, m=1.8, and n = 2.0

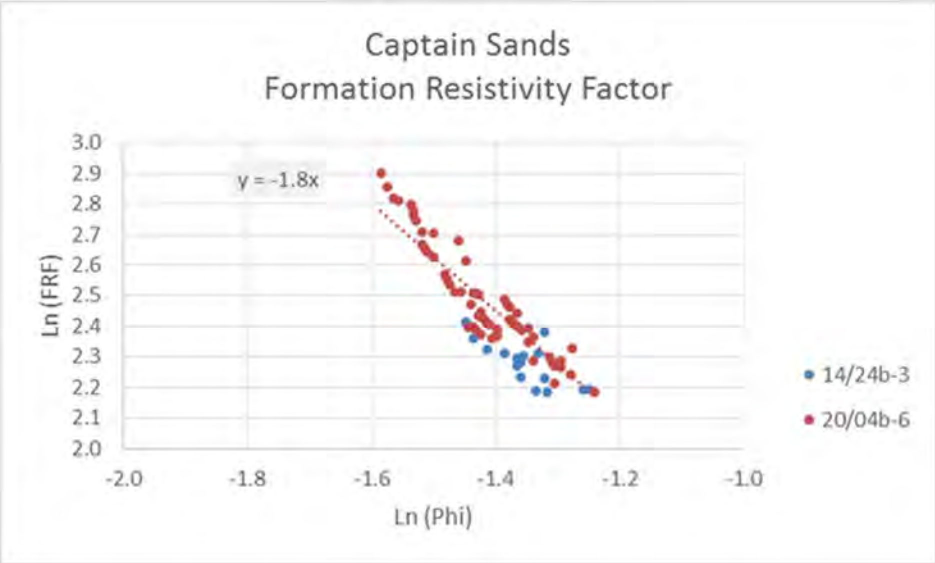



*Figure 11-60 Formation resitivity factor*

*Formation Resistivity*

The deepest penetrating resistivity curve is always used as the measurement of true formation resistivity. No additional environmental corrections are applied to these curves as the data archived by CDA does not give a detailed history of any resistivity post-processing.

### *11.8.3.2 Clay and Shale Volume Estimates*

The volume of clay in the reservoir is estimated by two independent deterministic methods.

*Gamma Ray*

The simplest model, for quartz sandstone, is to assume a linear relationship between clean and clay end-points. This assumes that a clean, clay free sand is represented by the minimum gamma count within the interval and that the shales and clays are represented by the highest gamma count.

The linear model gamma ray Vclay equation is shown below:

VClay = (GRlog-GRmin)/(GRmax-GRmin)

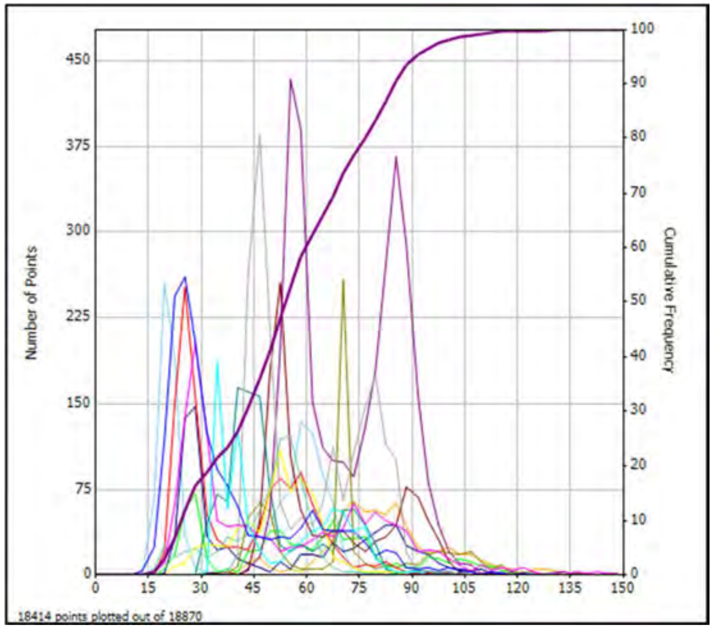



*Figure 11-61 Multi well gamma ray over zone of interest*

Figure 11-61 is a multi-well gamma ray plot for the Captain sands; these data show a good multi-modal response with a confident definition of both the clean sand and shale response from all wells.

The average clean sand and shale points used are 36 and 87 API respectively, for each well these may be slightly shifted on a zone by zone basis.

*Neutron – Density Crossplot.*

A double clay indicator method. This method uses a Neutron- Density cross-plot method that defines a clean sand line and a clay point. The volume of clay is then estimated as the distance the data falls between the clay point and the clean sand line.

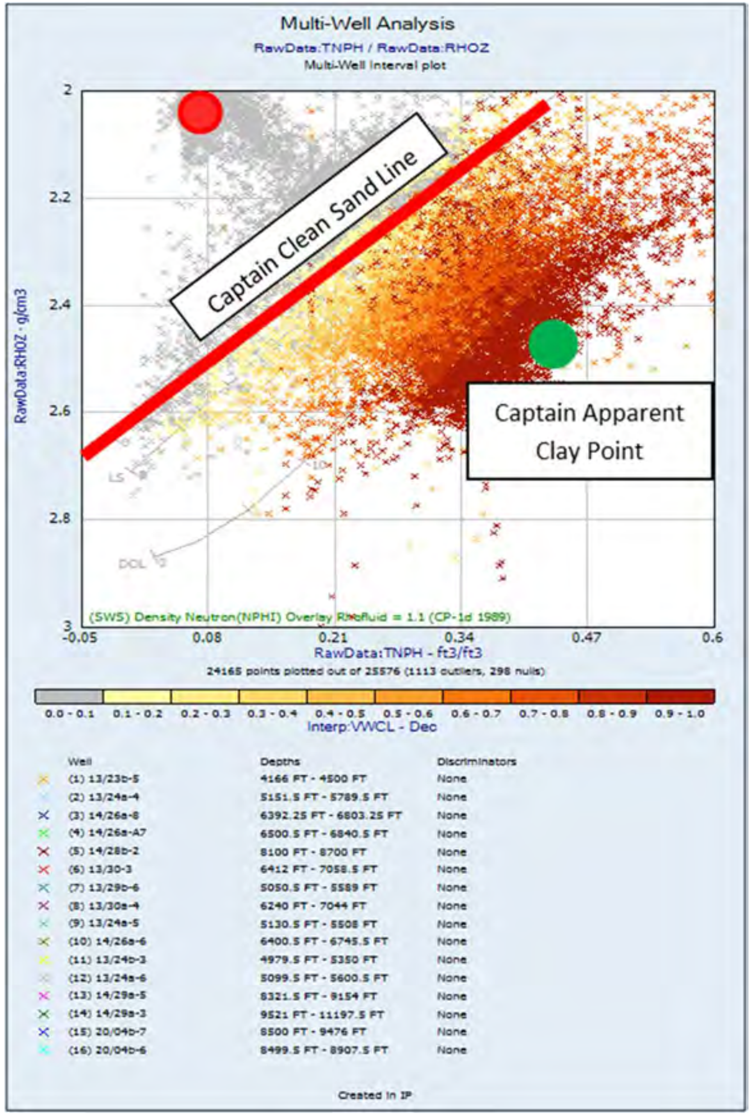



*Figure 11-62 Multi well neutron density crossplot over the zone of interest*

Figure 11-62 is a multi-well crossplot of the Neutron-Density over the Captain zone of interest. These data fall on a consistent 'clean' sand line with an expected global 'clay-point' falling at approximately 0.38 p.u. and 2.43 g/cc respectively for the Neutron and Density.

#### *11.8.3.3 Porosity and Water Saturation*

The estimation of Porosity and Water Saturation are coupled as an iterative process such that any parameter update during the calculation of porosity or water saturation will result in porosity and water saturation being recalculated; furthermore, if it becomes necessary to fine-tune the clay model this will cycle back to update the volume clay models for the same interval.

This linkage of parameters ensures consistency throughout all aspects of the interpretation and preserves the necessary dependency between all the variables in the analysis.

*Porosity Model*

Porosity is calculated using either the single curve Density model or Density – Neutron crossplot method with option to calculate sonic porosity if the condition of the borehole is too poor to acquire accurate density data.

Borehole conditions are estimated from limits set for the calliper and the density DRHO curves, if these limits are exceeded sonic is substituted as the most appropriate porosity method.

A clay volume fraction correction is made to estimate 'effective' porosity from the 'total' porosity calculation.

A total of 1,293 core grain measurements were available (Table 11-21, Figure 11-63), the data plots with a mean grain density of 2.65g/cc, and this is consistent with the expected value for the quartz dominated matrix of the Captain sandstone.

| | Summary Statistics for Core Grain Density | | | | |
|---|---|---|---|---|---|
| | Valid N | Mean | Minimum | Maximum | Std. Dev. |
| Core GRD | 1293 | 2.650 | 2.490 | 3.170 | 0.039 |

*Table 11-21 Core grain denstiy*

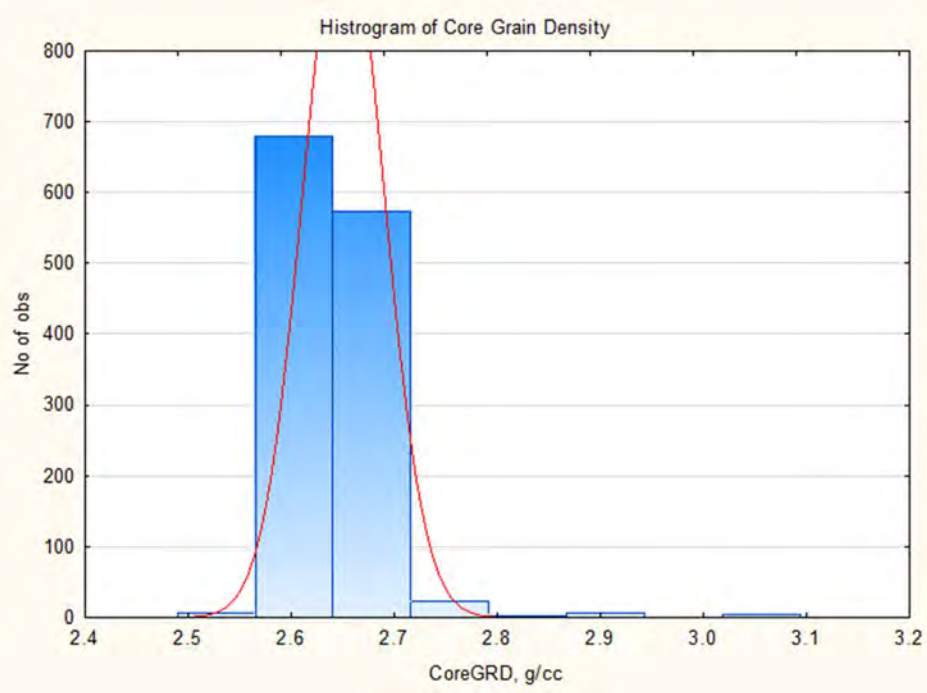



*Figure 11-63 Measured core grain density*

Where core porosity data is available, the best fit porosity model to the core data is noted and then preferentially selected for un-cored intervals and wells. Table 11-22 and Figure 11-64 summarize the distribution of the core porosity data, the plot has 2,429 validated data points, the plot suggests there is very little variance in the data set with a modal and mean porosity of 25.8%.

This compares closely to the 25.1% mean porosity generated from the wireline analysis.

| | Core Porosity Summary Statistics | | | | |
|---|---|---|---|---|---|
| | Valid N | Mean | Minimum | Maximum | Std. Dev. |
| Core PHI | 2429 | 0.258 | 0.005 | 0.344 | 0.064 |

*Table 11-22 Core porosity summary statistics*

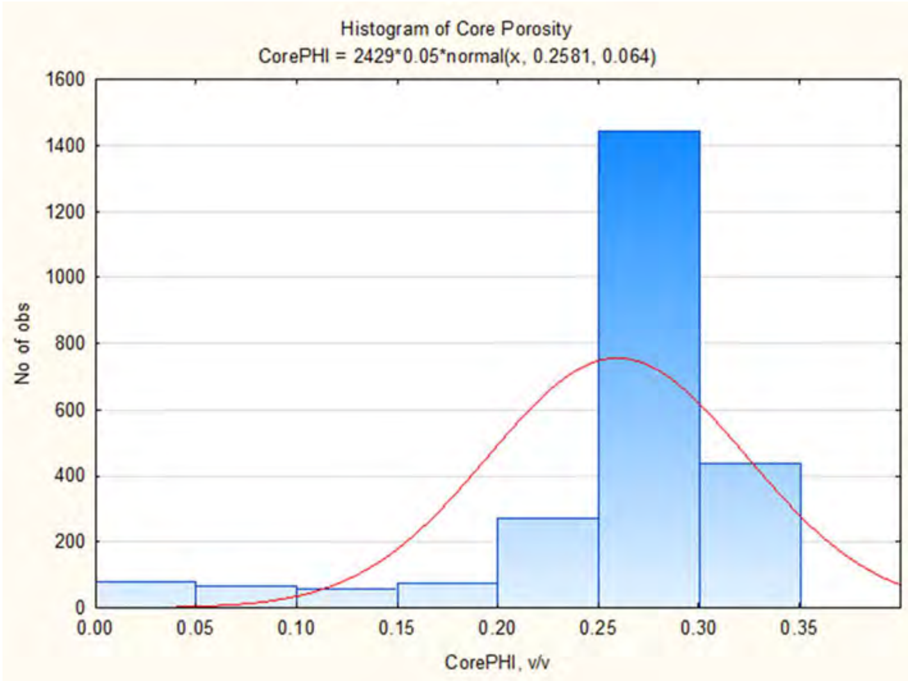



*Figure 11-64 Measured core density*

### *Water Saturation*

Water Saturation is calculated in the deep zone of the reservoir (Sw) and the invaded zone (Sxo) using deep and shallow resistivity respectively; where oil based mud is used as the drilling fluid an approximation of the invaded zone saturation is made with defined limits using an Sxo ratio factor.

Archie saturation exponents, were estimated from the limited SCAL data, cross referenced to the recommendations in the 'Blake Field Petrophysical Report' and validated in the water zones with Pickett plots.

### 11.8.3.4 Petrophysical Parameter Selection

Table 11-23 details parameters used to estimate shale and clay volume:

| Petrophysical Parameter Selection for Clays and Shale Models | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Well** | $GR_{Clean}$ | $GR_{Shale}$ | $RHOB_{Clay}$ | $NPHI_{Clay}$ | $PEF_{Clay}$ | $Rt_{Clay}$ | $DT_{Clay}$ |
| **13/23b-5** | 46 | 87 | 2.338 | 0.399 | 4.0 | 2.2 | 134 |
| **13/24a-4** | 20 | 63 | 2.424 | 0.371 | 2.5 | 1.1 | 115 |
| **13/24a-5** | 21 | 57 | 2.449 | 0.405 | 3.0 | 1.3 | 121 |
| **13/24a-6** | 47 | 85 | 2.418 | 0.385 | 3.0 | 1.4 | |
| **13/24b-3** | 36 | 61 | 2.423 | 0.386 | 4.1 | 1.4 | 110 |
| **13/29b-6** | 40 | 97 | 2.364 | 0.290 | 1.0 | 0.7 | 119 |
| **13/30-3** | 24 | 81 | 2.446 | 0.409 | 3.0 | 1.1 | |
| **13/30a-4** | 55 | 88 | 2.399 | 0.476 | 3.0 | 1.2 | 130 |
| **14/26a-6** | 63 | 103 | 2.426 | 0.353 | 3.4 | 1.8 | 110 |
| **14/26a-A7** | 28 | 112 | 2.563 | 0.289 | 3.0 | 3.0 | |
| **14/26a-8** | 28 | 89 | 2.550 | 0.510 | 3.0 | 1.1 | 112 |
| **14/28b-2** | 45 | 112 | 2.510 | 0.383 | 4.2 | 1.4 | 91 |
| **14/29a-3** | 32 | 85 | 2.431 | 0.410 | 3.7 | 3.3 | 116 |
| **14/29a-5** | 25 | 87 | 2.411 | 0.392 | 3.5 | 1.0 | 113 |
| **20/04b-6** | 41 | 90 | 2.405 | 0.389 | 3.0 | 0.9 | 108 |
| **20/04b-7** | 23 | 89 | 2.350 | 0.340 | 3.1 | 4.5 | 109 |
| | | | | | | | |
| **Averages** | **36** | **87** | **2.432** | **0.387** | **3.1** | **1.7** | **114** |

*Table 11-23 Clay parameter selection*

Table 11-24 details parameters used to estimate porosity and water saturation using the 'Indonesian' shaley sand saturation model.

| Petrophysical Parameter Selection for Porosity and Saturation Model | | | |
|---|---|---|---|
| **Well** | Phi Model | Rw at 60 DEGF | Sw Model |
| **13/23b-5** | Density | 0.150 | Indo |
| **13/24a-4** | ND Xplot | 0.184 | Indo |
| **13/24a-5** | ND Xplot | 0.154 | Indo |
| **13/24a-6** | ND Xplot | 0.170 | Indo |
| **13/24b-3** | Density | 0.154 | Indo |
| **13/29b-6** | ND Xplot | 0.285 | Indo |
| **13/30-3** | ND Xplot | 0.167 | Indo |
| **13/30a-4** | Density | 0.093 | Indo |
| **14/26a-6** | ND Xplot | 0.143 | Indo |
| **14/26a-A7** | ND Xplot | 0.138 | Indo |
| **14/26a-8** | ND Xplot | 0.154 | Indo |
| **14/28b-2** | ND Xplot | 0.121 | Indo |
| **14/29a-3** | ND Xplot | 0.135 | Indo |
| **14/29a-5** | ND Xplot | 0.130 | Indo |
| **20/04b-6** | ND Xplot | 0.163 | Indo |
| **20/04b-7** | ND Xplot | 1.310 | Indo |

*Table 11-24 Porosity and water saturation parameter selection*

#### 11.8.3.5 Cut off and Summation Definitions

A cut-off of less than 50% clay content has been selected to define sandstone, 10% porosity as the minimum for the sands to be considered of net reservoir quality however, most of the net sand is greater than 10% so this is a fairly insensitive cut-off until the porosity cut-off is increased to greater than 15%.

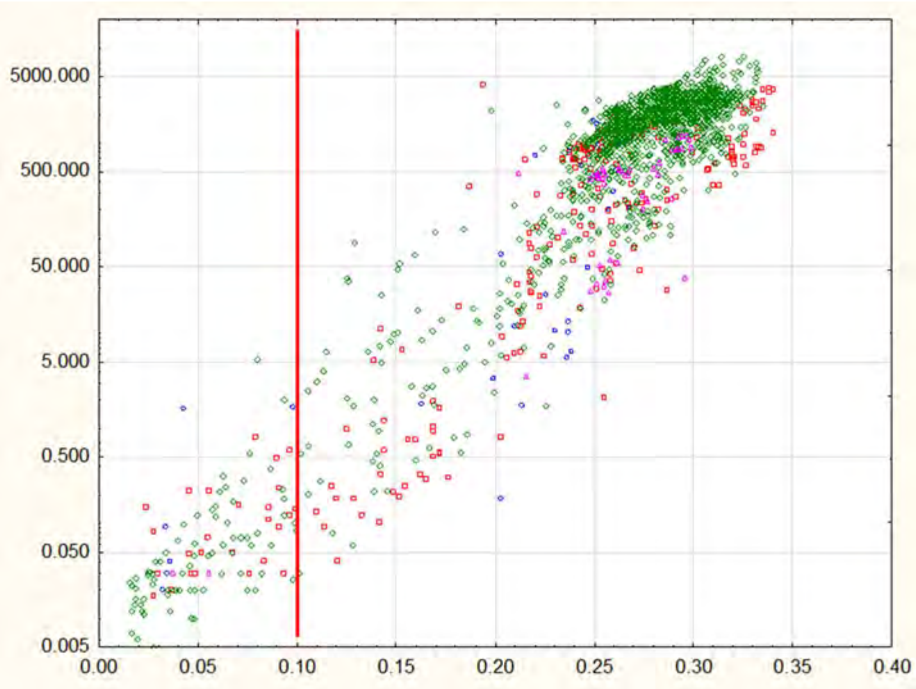



*Figure 11-65 Core porosity-permeability crossplot*

Figure 11-65 is a crossplot of all the available Captain porosity and permeability core data, there is clearly at least two ‘populations’ of data and no effective reservoir is excluded using 10% porosity given the bulk of the effective reservoir is clustered at 25% porosity.

### 11.8.4 Geochemistry

#### 11.8.4.1 Objective

Geochemical modelling of the primary caprock for the Captain X aquifer storage site, UKCS was carried out to evaluate the likely impact of CO2 injection on the rock fabric and mineralogy following the injection period and the long term post-closure phase. The main objective was to gain a better understanding of the key geochemical risks to injection site operation and security of storage. Specifically, the main objective in this study was to assess if, increasing the volume (partial pressure) of CO2 in the Captain reservoir sands leads to mineral reactions which result in either an increase or decrease of the porosity and permeability of the overlying Carrack and Rodby Formation caprocks.

#### 11.8.4.2 Methodology

A study methodology was developed to answer a key question:

- Will increasing the amount (partial pressure) of CO2 in the Captain sandstones lead to mineral reactions which result in either increase or decrease of porosity and permeability of the Rodby Formation primary caprock overlying the aquifer?

The work flow followed is shown in Figure 11-66. Water and any gas geochemical data, and mineral proportion data from the reservoir and the caprock (representing the pre-CO2 injection conditions) were collected from published analogue data.

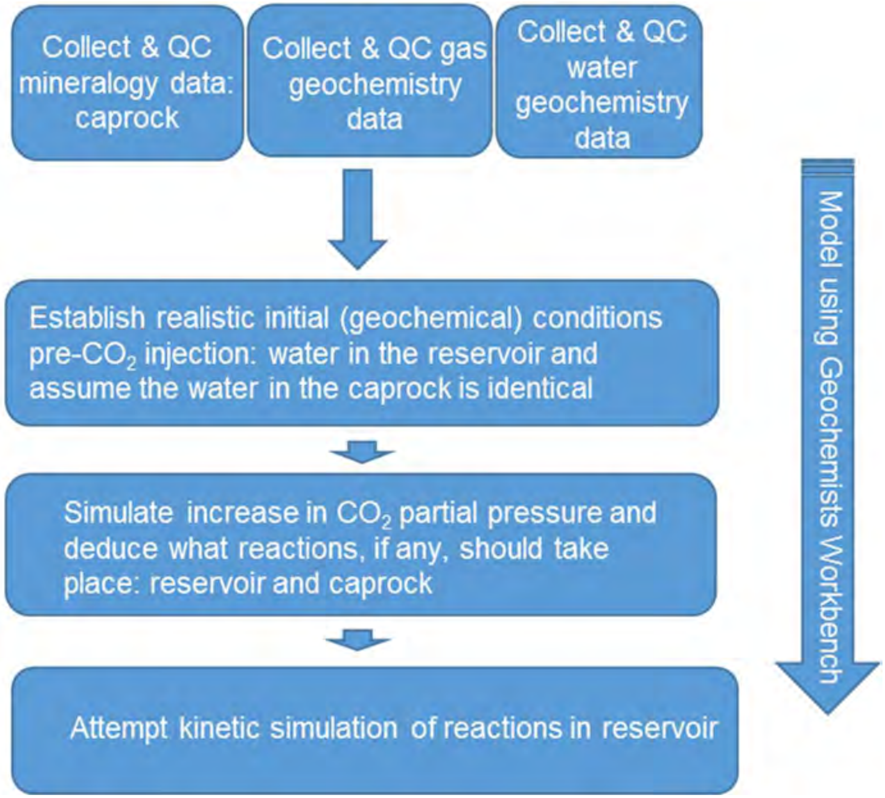



*Figure 11-66 Geochemical modelling workflow*

Following data QC, the initial gas-water-rock compositions were modelled, using a range of CO2 partial pressures and temperatures, using two approaches:

- The first, and most simple, modelling approach is to assume that there is instant equilibrium between minerals, aqueous solution and changing gas composition. The extent of this type of reaction is thus simply a function of the amount of CO2 that has arrived at the reaction site (as reflected in the fugacity [as stated approximately the partial pressure] of CO2]).
- A more subtle approach involves a kinetic approach that requires a range of further inputs including rate of reaction (e.g., dissolution), and textural controls on dissolution such as grain size (which is reflected in the specific surface area per unit mass or unit volume.

All modelling was undertaken using Geochemists Workbench.

#### 11.8.4.3 Data Availability

Some water compositional data were available from wells 13/30-1 (RFT samples) and 13/24a-8y but these analyses have some unusual data (i.e. less than fully credible – see details below). Instead, an average water composition from the Shell Goldeneye report (Shell UK ltd., 2011) was employed.

Gas compositional data were taken from a CDA PVT report for a sample from 13/24a-8y.

Caprock mineralogy data from the Rodby Formation from the Captain field (or the blocks under consideration) were not available so equivalent data were taken from the available Shell report for Goldeneye (Shell UK ltd., 2011).

#### 11.8.4.4 Water Geochemistry

The water compositional data used are shown in Table 11-25.

| ppm | K+ | Na+ | Mg++ | Ca++ | Sr++ | Ba++ | Fe++ | Cl- | SO4- | HCO3- | pH | % Charge Difference |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **13/30-1 (sample 389)** | 359 | 15000 | 15 | 755 | 2.3 | 2.2 | 4.1 | 16500 | 108700 | 415 | 9.1 | -59.21 |
| **13/30-1 (sample 390)** | 454 | 20100 | 405 | 2540 | 256 | 2.4 | 1.4 | 36300 | 1320 | 230 | 7.28 | -0.16 |
| **13/24a-8y** | 7056 | 15800 | 407 | 1018 | 332 | 152 | 23 | 33500 | 27 | 1102 | 6.8 | -0.05 |
| **Goldeneye 1** | 225 | 19180 | 230 | 1020 | 245 | 79 | 3.3 | 33420 | 15 | 710 | 7 | -2.03 |
| **Goldeneye 2** | 225 | 19990 | 235 | 1050 | 250 | 83 | 0.72 | 33680 | 13 | 805 | 7 | -0.46 |
| **Goldeneye 3** | 260 | 20370 | 245 | 1060 | 250 | 83 | 0.05 | 33470 | 28 | 1010 | 7 | 0.59 |
| **Goldeneye 4** | 253.5 | 20751 | 243.5 | 1309 | 314.5 | 52 | 0 | 33448 | 11.6 | 738.5 | 7 | 2.38 |
| **Goldeneye 5** | 210 | 19885 | 264.5 | 1372 | 264 | 50.12 | 1.58 | 32920 | 15.35 | 0 | 7 | 2.02 |
| **Average** | 241 | 20035 | 244 | 1162 | 265 | 69 | 1 | 33388 | 17 | 653 | 7 | 0.52 |

*Table 11-25 Water geochemical composition data used in modelling*

As mentioned above, although RFT samples were available in the CDA, the data are considered unreliable as representative water compositional data.

- One RFT sample from 13/30-1 (sample 389) had an unfeasibly high sulphate concentration that led to a poor charge balance which invalidates the data.
- Another RFT sample from 13/30-1 (sample 390) had unusually high calcium and sulphate concentrations.
- The analysis reported for 13/24a-8y has an unusually high potassium concentration rendering the result less than credible.
- The data reported for Goldeneye is believable (within expected values for North Sea Mid to Upper Mesozoic formation water in this sub-basin). The average Goldeneye water composition has, therefore, been employed in the subsequent modelling

#### *11.8.4.5 Gas Geochemistry*

Gas geochemical data for the Captain sandstone were taken from a single well (13/24a-8y).

| 13/24a-8y | Monophasic fluid composition |
|---|---|
| N2 | 0.07 |
| CO2 | 0.3 |
| H2S | 0 |
| CH4 | 38.22 |
| C2H6 | 3.69 |
| C3H8 | 0.15 |
| C4H10 | 0.33 |
| C5H12 | 0.24 |
| C6+ | 57 |

*Table 11-26 Gas geochemical composition data used in modelling*

- The reservoir contains a very small proportion of $CO_2$ that is in equilibrium with the minerals in the reservoir (and possibly lowermost caprock)
- Adding more $CO_2$ (increasing the fugacity of the $CO_2$) will likely lead to mineral reactions.

#### 11.8.4.6 Caprock Mineralogy

An extensive search of the available literature failed to find any usable mineralogy data for the Carrack or Rodby Formation caprocks sitting on top of the Captain sandstone reservoir. The mineralogy reported for the Rodby Fm in the Goldeneye field (where is also acts as the primary caprock) have been used instead as a geologically-reasonable analogue (Table 11-27).

- The Rodby Formation contains a highly varied collection of minerals including Fe-bearing smectite, chamosite and pyrite.
- The clay mineralogy of the caprock is also highly complex containing illite, two types of smectite and chamosite.
- The relative proportions of the clay minerals have been converted (for use in the geochemical modelling; Table 11-27) into absolute volumes ($cm^3$) that react with 1 kg of water assuming the caprock has a fairly typical 10% porosity.

| Top seal mineral | XRD and petrographically determined relative volume % |
|---|---|
| **Quartz** | 7.58 |
| **Albite** | 1.82 |
| **K-feldspar** | 1.12 |
| **Kaolinite** | 2.41 |
| **Illite** | 16.7 |
| **Smectite-low-Fe-Mg** | 7.79 |
| **Smectite-Ca** | 7.79 |
| **Chamosite-7A** | 3.37 |
| **Calcite** | 50.2 |
| **Pyrite** | 0.48 |
| **Top seal mineral** | **Absolute volume (cm3) reacting with 1kg water at 10% porosity** |
| **Quartz** | 171 |
| **Albite** | 41 |
| **K-feldspar** | 25 |
| **Kaolinite** | 54 |
| **Illite** | 376 |
| **Smectite-low-Fe-Mg** | 175 |
| **Smectite-Ca** | 175 |
| **Chamosite-7A** | 76 |
| **Calcite** | 1130 |
| **Pyrite** | 11 |

*Table 11-27 Primary caprock (Rodby Formation) mineralogy*

##### 11.8.4.7 Modelling Approach: Types of Reaction Schemes Due to CO2 Injection into the Reservoir

Equilibrium modelling was not undertaken for the primary caprock at eh Captain X site. The presence of metastable minerals such as smectite (which, under equilibrium conditions would instantly transform to muscovite and chlorite in the models) indicates equilibrium modelling will not offer useful information.

If reactions are **kinetically** influenced, e.g. by slow dissolution rates, then the rate of interaction with CO2 is limited by dissolution rate and not the rate of influx of CO2. Carbonate and sulphate dissolution and growth kinetics are 6 to 10 orders of magnitude faster than silicate dissolution rates. Clay mineral and feldspar dissolution rates are thus the most likely rate controlling steps. The kinetics of carbonate and sulphate dissolution and growth have been excluded since they will add nothing to the computation of the rate controlling steps. The kinetics of the silicate dissolution reactions have been taken from Xu et al. (Xu, Sonnethal, Spycher, & Pruess, 2006).

##### 11.8.4.8 Results

*Mineral Reactions in the Rodby Formation*

The key mineral reactants and products likely in the Rodby formation (I the presence of injected $CO_2$) are shown in Table 11-28.

An important process is the reaction of (Na-, K-, Mg- and Fe-bearing) smectite with acidity ($H^+$) induced by the influx of $CO_2$:

$$Smectite + H^+ + K^+ \rightarrow Illite + Kaolinite + Quartz + Na^+ + Fe^{2+} + Mg^{2+}$$

In addition, calcite reacts with released Mg and Fe from smectite breakdown to create dolomite and siderite:

$$Calcite + Mg^{2+} + CO_2 \rightarrow Dolomite$$

$$Calcite + Fe^{2+} \rightarrow Siderite + Ca^{2+}$$

| | Mineral | Alternative name | Formula | Mineral type |
|---|---|---|---|---|
| Reactants | K-feldspar | Maximum Microcline | $KAl_3Si_3O_8$ | Silicate |
| | Quartz | | $SiO_2$ | Silicate |
| | Illite | Muscovite | $KAl_3Si_3O_{10}(OH)_2$ | Clay |
| | Muscovite | | $KAl_3Si_3O_{10}(OH)_2$ | Clay |
| | Smectite | low Fe-Mg smectite | $Na_{0.15}Ca_{0.2}K_{0.2}Mg_{0.9}Fe_{0.45}Al_{1.25}Si_{3.75}O_{10}(OH)_2$ | Clay |
| | Kaolinite | | $Al_2Si_2O_5(OH)_4$ | Clay |
| | Dolomite | | $CaMg(CO_3)_2$ | Carbonate |
| | Calcite | | $CaCO_3$ | Carbonate |
| | Pyrite | | $FeS_2$ | Sulphide |
| | Anhydrite | | $CaSO_4$ | Sulphate |
| Products | Dawsonite | | $NaAl(CO_3)OH$ | Carbonate |
| | Alunite | Alum | $KAl_3(SO_4)_2(OH)_6$ | Sulphate |
| | Siderite | | $FeCO_3$ | Carbonate |
| | Chamosite | | $Fe_2Al_2SiO_5(OH)_4$ | Clay |
| | Hematite | | $Fe_2O_3$ | Oxide |

*Table 11-28 Key mineral reactants and products in the Rodby formation in the presence of $CO_2$*

*Kinetic Modelling: Caprock*

In order to evaluate the kinetic effects on the caprock, models reacting 10 mol CO2(g) over 10000 years at 50°C for the Rodby Formation caprock composition were run for the following conditions:

Kinetic constraints were placed as follows

- K-feldspar dissolution kinetics: pre-exponential rate constant 8.71x10-11 mol/m2.s, activation energy 51.7 kJ/mol, 500 cm2/g surface area.
- Smectite dissolution kinetics: pre-exponential rate constant 1.047x10-11 mol/m2.s, activation energy 23.6 kJ/mol, 2000 cm2/g surface area.

The key results derived from the kinetic modelling are shown in Table 11-29 below and in Figure 11-67Figure 11-68. Table 11-29 shows the modelled relative mineral volume change in the Rodby Formation caprock after CO2 has been injected into the underlying reservoir.

The main changes modelled in the Rodby Formation caprock are the major dissolution of smectite due to CO2 influx and the relatively minor loss of calcite over 10,000 years of addition of CO2. The products of these changes are shown in the right hand graph, showing the increase in volume of the carbonate minerals (dawsonite, dolomite and siderite), sequestering the CO2 into the mineral phase, and additional sulphate minerals such as anhydrite. These processes can be observed in the plots of CO2 fugacity (partial pressure, or 'volume of CO2') and pH below. In addition, the Fe, Mg, Si and Al-bearing smectite is replaced by illite, kaolinite, quartz and dawsonite.

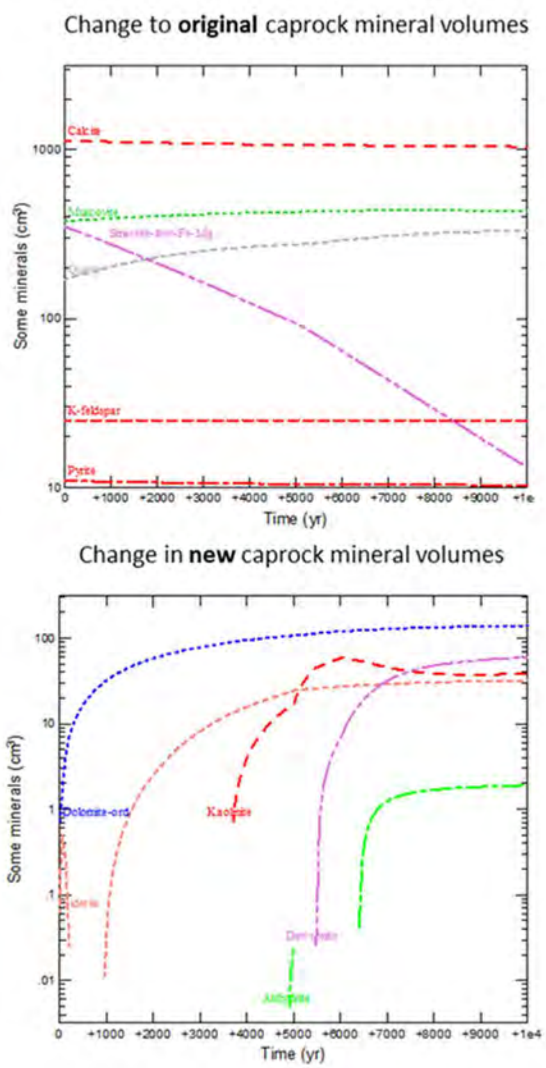



*Figure 11-67 Kinetic modelling results: mineral dissolution and growth (note change in Y-axis scale between graphs)*

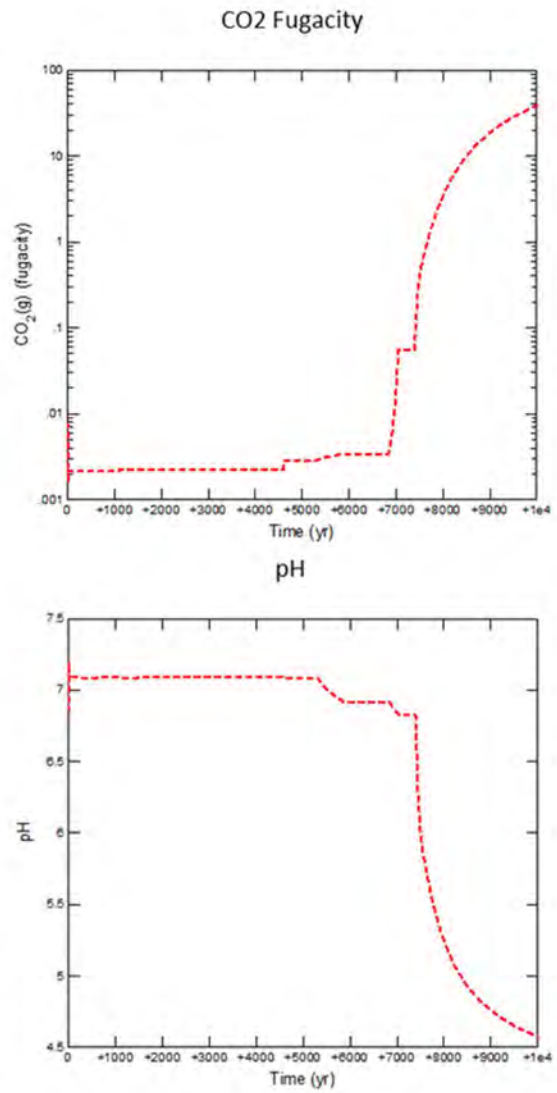



*Figure 11-68 Kinetic modelling results: $CO_2$ Fugacity and pH trends*

- Initial buffering of the fugacity (partial pressure) of CO2 due to reaction with smectite and growth of new carbonate minerals (siderite, dolomite and dawsonite).
- Initial buffering of the pH due to the acidity being mopped up by reaction with smectite and growth of new carbonate minerals (siderite, dolomite and dawsonite).

Overall, there is a solid volume **increase** (Table 11-29) due to the $CO_2$ flooding of the Rodby formation meaning that there is no increase in porosity and thus no increase in permeability.

| Top seal mineral | At equilibration | 5,000 years | 10,000 years |
|---|---|---|---|
| **Quartz** | 171 | 275.7 | 331 |
| **Albite** | 1 | 0 | 0 |
| **K-feldspar** | 25 | 24.97 | 24.95 |
| **Kaolinite** | 0 | 17.05 | 38.3 |
| **Illite** | 376 | 429 | 434.8 |
| **Paragonite** | 0 | 36.74 | 0 |
| **Smectite-low-Fe-Mg** | 350 | 93.55 | 13.18 |
| **Chamosite-7A** | 0 | 0.18 | 0 |
| **Calcite** | 1129 | 1068 | 1038 |
| **Pyrite** | 11 | 10.5 | 10.34 |
| **Dawsonite** | 0 | 0 | 59.63 |
| **Anhydrite** | 0 | 0 | 1.91 |
| **Siderite** | 0 | 24.37 | 31.96 |
| **Dolomite** | 0 | 107.4 | 140 |
| **Total** | 2062 | 2087.47 | 2124.07 |
| **Fractional volume change** | | 1.01 | 1.03 |

*Table 11-29 Kinetic modelling mineral volume results for the Rodby formation*

#### 11.8.4.9 Conclusions

On flooding the Captain sandstone with $CO_2$, the calcareous, clay-rich Rodby Formation and equivalent caprocks are unlikely to be affected in a way that increases permeability:

- The fastest reactions that occur lead to a very small net solid volume increase due to the new replacement minerals having relatively lower density and reaction with the fluxing $CO_2$.
- Smectite is the most reactive mineral present but it is likely, upon contact with the acid water induced by $CO_2$ influx, to be replaced by quartz, illite and kaolinite.
- Sodium, iron and magnesium are also released from smectite thus leading to the growth of the carbonate minerals: dawsonite, siderite and dolomite.
- Calcite undergoes partial replacement by dolomite instead of wholesale dissolution.
- Overall, the injection of $CO_2$ will probably lead to a solid volume increase of 3% in 10,000 years. This will lead to lower porosity and lower permeability.

Rodby Formation seal failure is, therefore, unlikely to be induced by mineral reactions with the $CO_2$.

## 11.9 Appendix 9: Fracture Pressure Gradient Calculation

In order to determine fracture (and pore) pressure in the Captain sandstone, an analysis of available log data was carried out using DrillWorks 5000. The following tasks were performed for selected wells in each field (basic workflow):

- Overburden or Vertical stress (SV): based on bulk density log
- Normal pore pressure assumed based on the well data review
- Fracture Gradient or minimum horizontal stress (Shmin): Matthews and Kelly method calibrated with reference fracture gradient (0.73 psi/ft)
- Poisson's ratio: based on GR/vshale log
- UCS: Lal's law correlation applied to the sonic log
- Stress regime: normal assumed (SV>SH>Shmin)
- Maximum horizontal stress (SH) calculated from SV and Shmin
- Stress orientation from the World Stress map

This process utilises log derived geomechanical properties combined with elastic stress calculations. The modified Lade shear failure criterion was applied. This utilises all three principal stresses and is generally less conservative than the Mohr-Coulomb failure criterion.

Public domain data suggests a virgin pore pressure fracture gradient of 0.73 psi/ft in the Captain sandstone, therefore the calculated fracture gradient is calibrated to this reference fracture gradient and compared with any specific FIT or LOT data, where available. The calculated breakout criterion and fracture gradient lines are combined with information on drilled mud weights and any drilling issues (tight hole, losses) to provide a qualitative calibration on the rock property / stress system.

### 11.9.1 Stress Orientation

The World Stress Map is a global reference for tectonic stress data when there is no any other data available (e.g. reliable dual arm calliper or image log data). The web link is in the References section.

The regional maximum horizontal stress (SH) is aligned NW-SE, and therefore the Shmin is aligned NE-SW.

The Captain Sandstone structural alignment is also NW-SE, Shmax is often parallel to the main structural grain in the North Sea

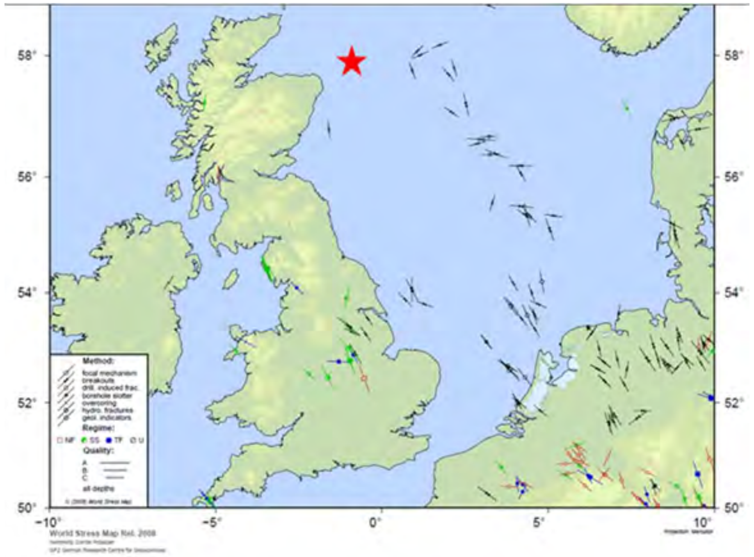


*Figure 11-69 Captain sandstone stress orientation*

### 11.9.2 Wells Evaluated

Logs available were obtained from the CDA website. The analysis was focused on four wells to cover the Captain Sandstone area: 13/29b-6, 13/30-3, 13/30a-4 and 13/30b-7.

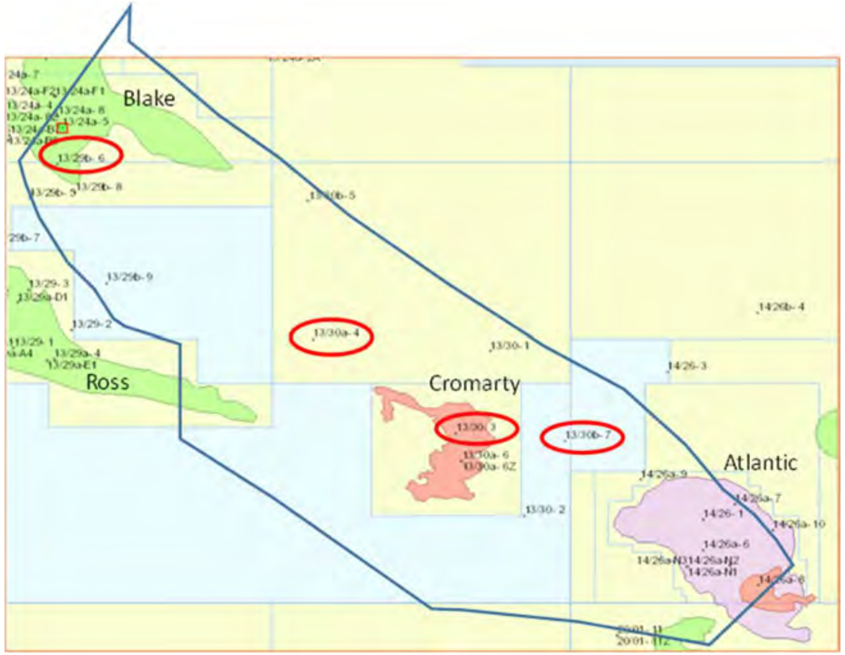



*Figure 11-70 Captain sandstone area*

### 11.9.3 Stress Path and Rock Mechanical Properties

The following figures describe the calculated stress curves and log derived rock mechanical properties in each well.

The calculated stress curves figures show pore pressure (orange line), minimum horizontal stress (red line), maximum horizontal stress (black line) and overburden (magenta line). The following considerations were used to calculate the stress path:

- Normal pore pressure assumed based on the well data review.
- Minimum horizontal stress (Shmin) calculated by Matthews and Kelly and calibrated with reference fracture gradient (0.657 psi/ft) in Captain sandstone
- Normal stress regime assumed. Maximum horizontal stress calculated from average of Shmin and overburden (Sv)

The minimum horizontal stress curves were compared with LOT/FITs available as follows:

**Wells 13/29b-6:**

- Various attempt to perform LOTs without success, however a “simulated” FIT was reported at 2571 ft (10.7 ppg)

**Well 13/30-3**

- LOT available at 1870 ft (13.6 ppg)
- LOT available at 4293 ft (15.4 ppg)

**Well 13/30a-4**

- LOT available at 4570 ft (12.75 ppg)

**Well 13/30b-7**

- LOT available at 3311 ft (13.19 ppg)

The rock mechanical properties figures depict the following rock mechanical properties derived from logs:

- Poisson's ratio (black line)
- Friction angle (blue line)
- Rock strength (UCS) (purple line)

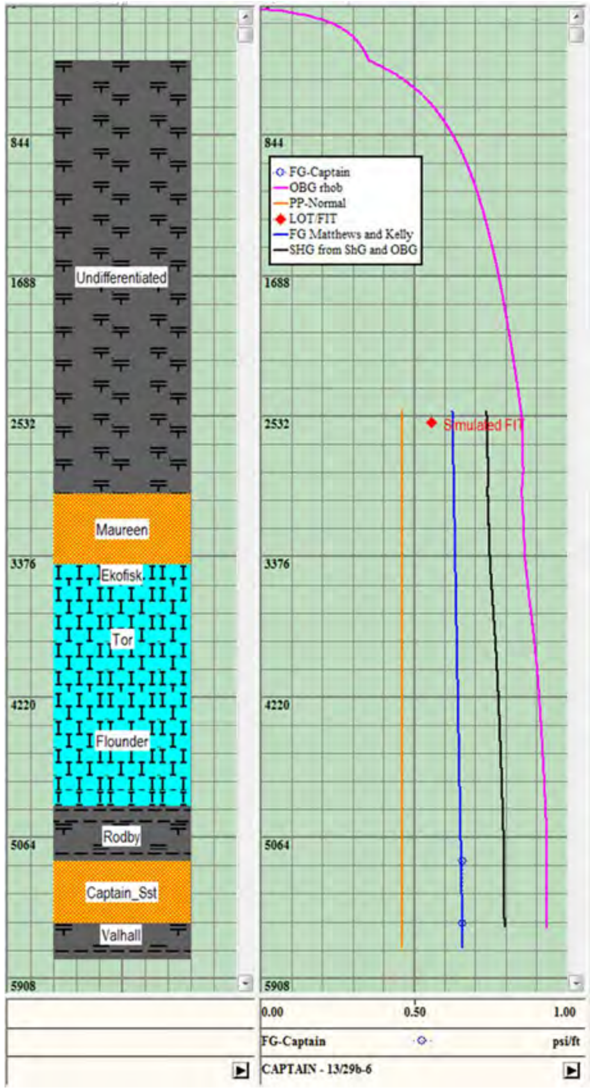



*Figure 11-71 Calculated stress curves - well 12/29b-6*

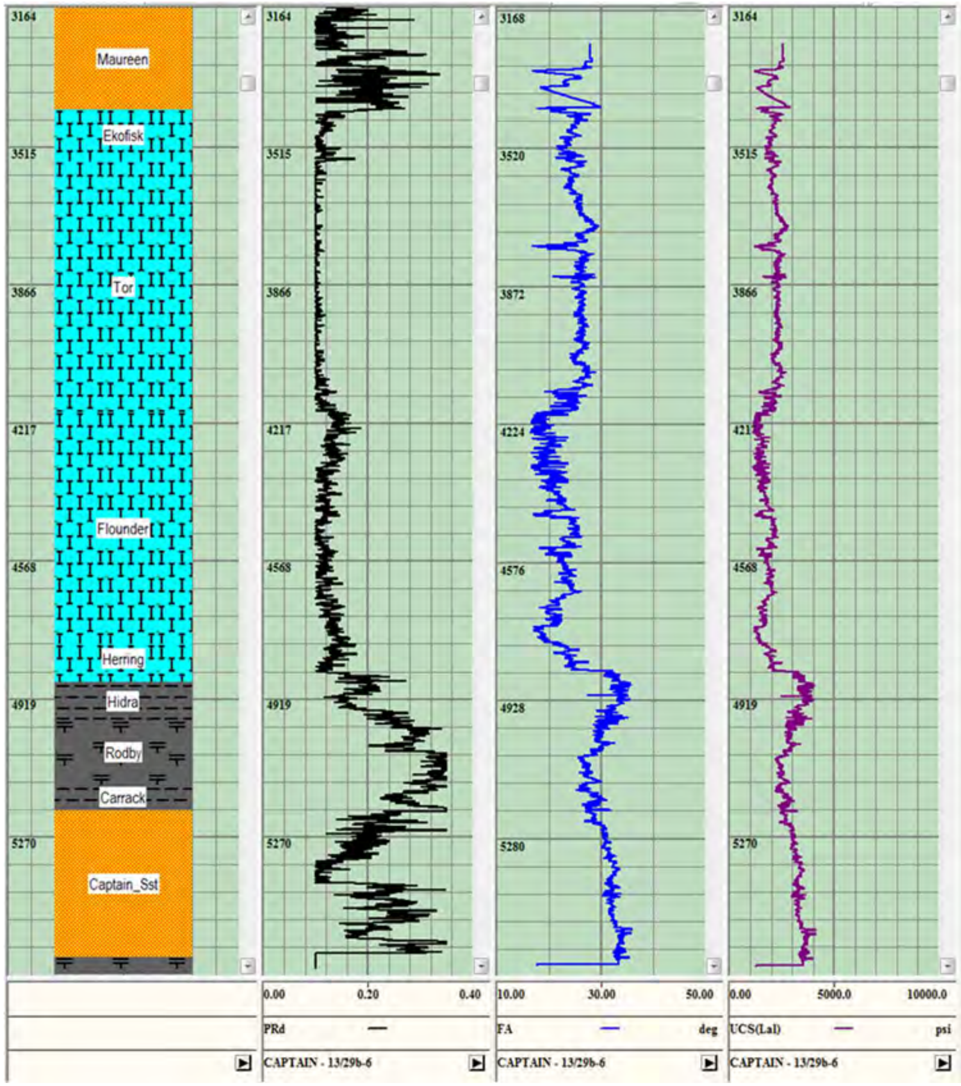



*Figure 11-72 Rock mechanical properties - well 13/29-6*

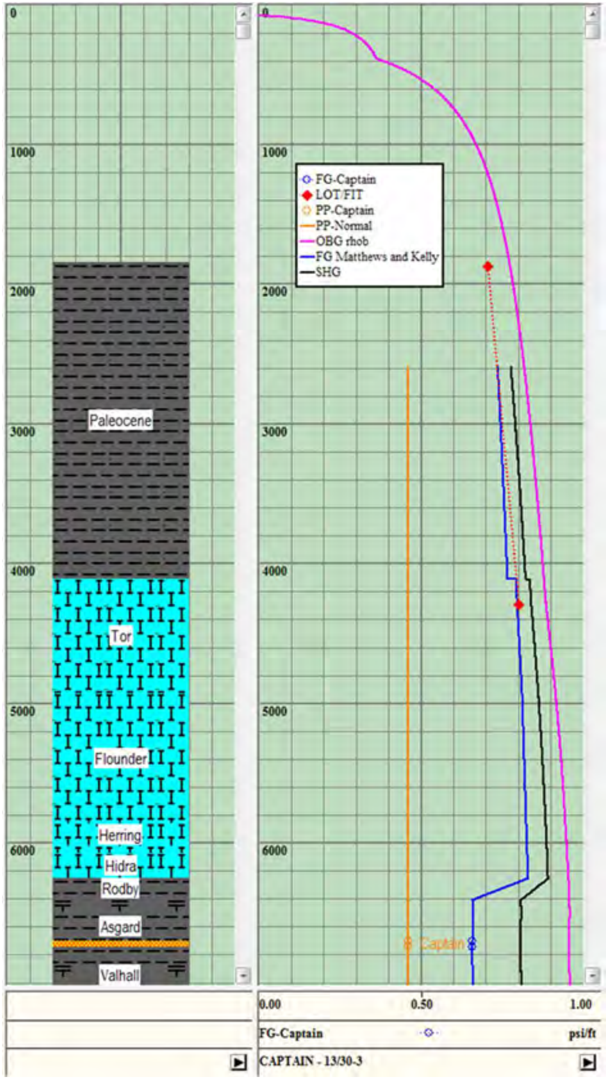



*Figure 11-73 Calculated stress curves - well 13/30-3*

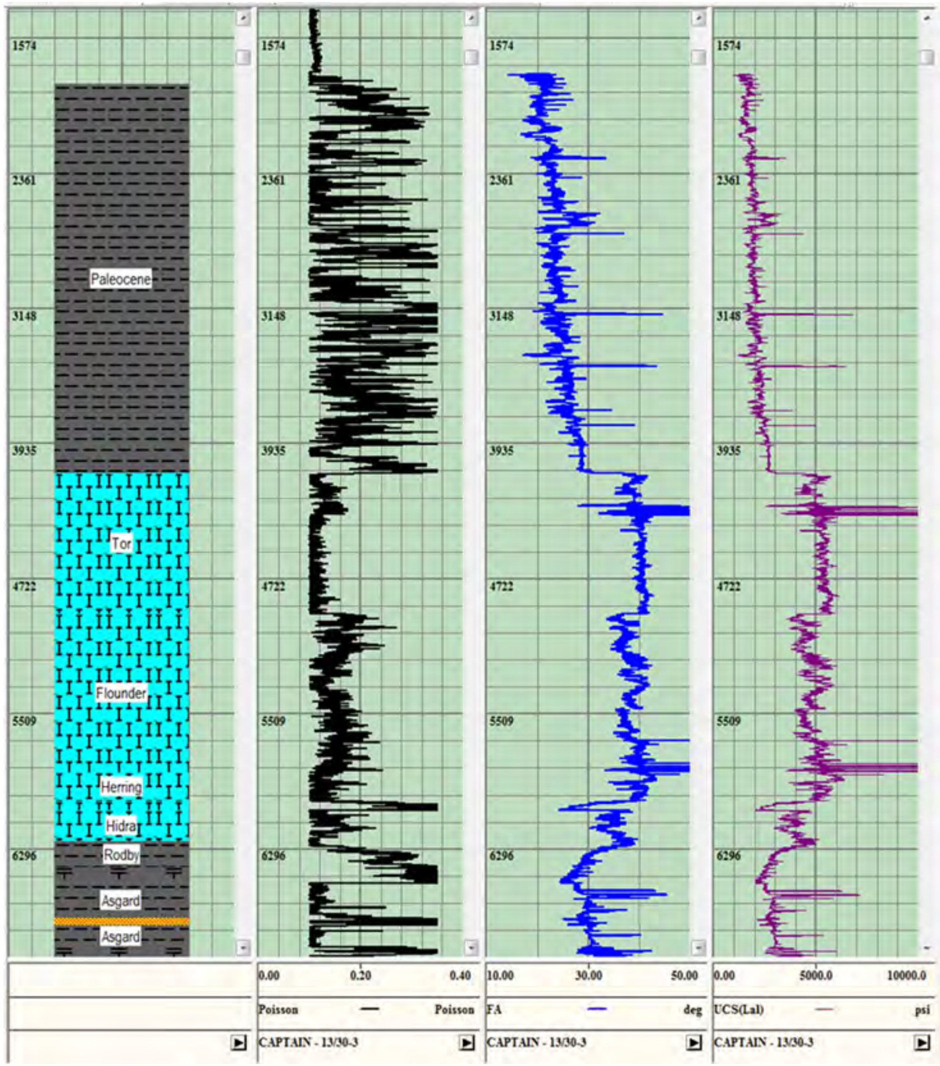



*Figure 11-74 Rock mechanical properties - well 13/30-3*

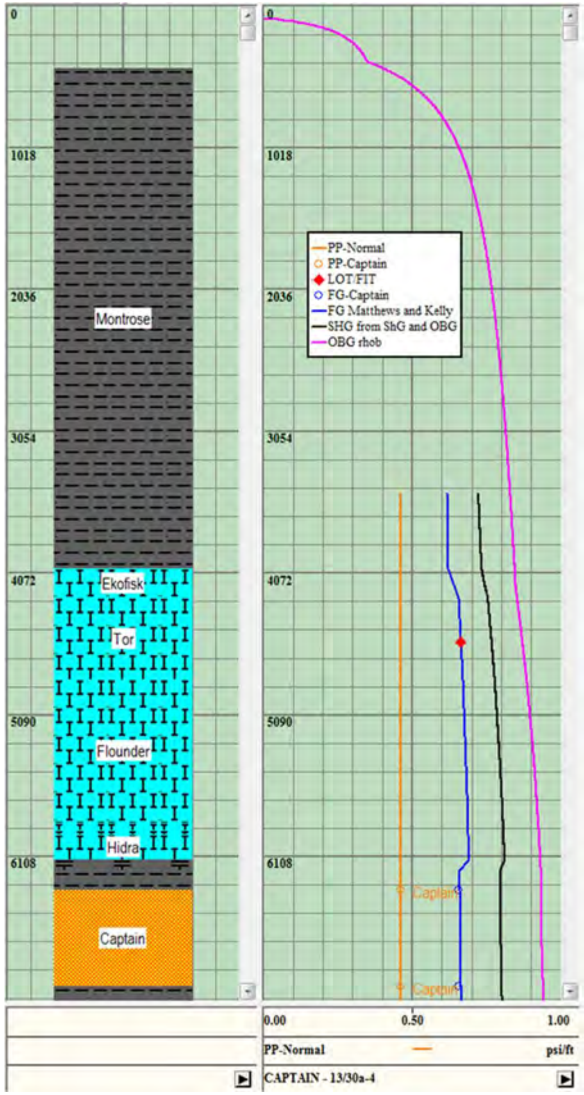



*Figure 11-75 Calculated stress curves - well 13/30a-4*

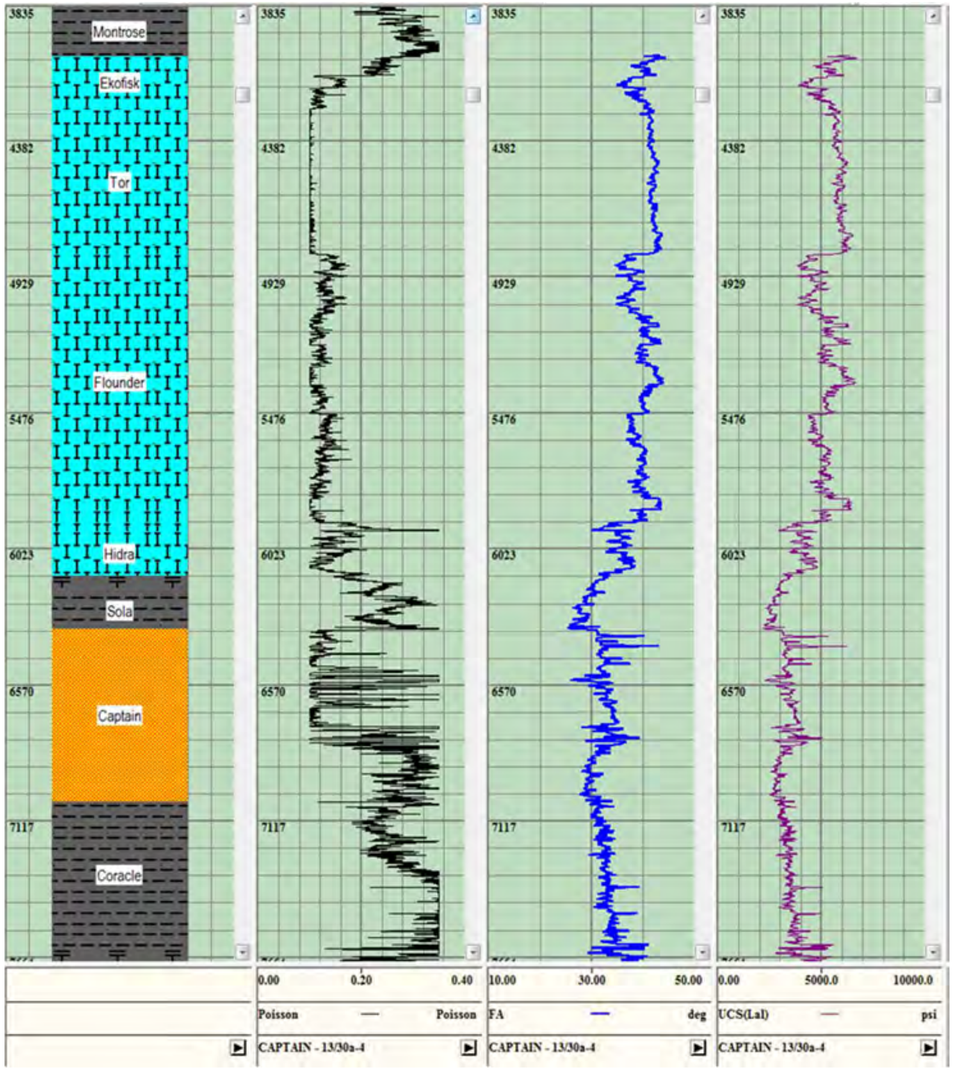



Figure 11-76 Rock mechanical properties - well 13/30a-4

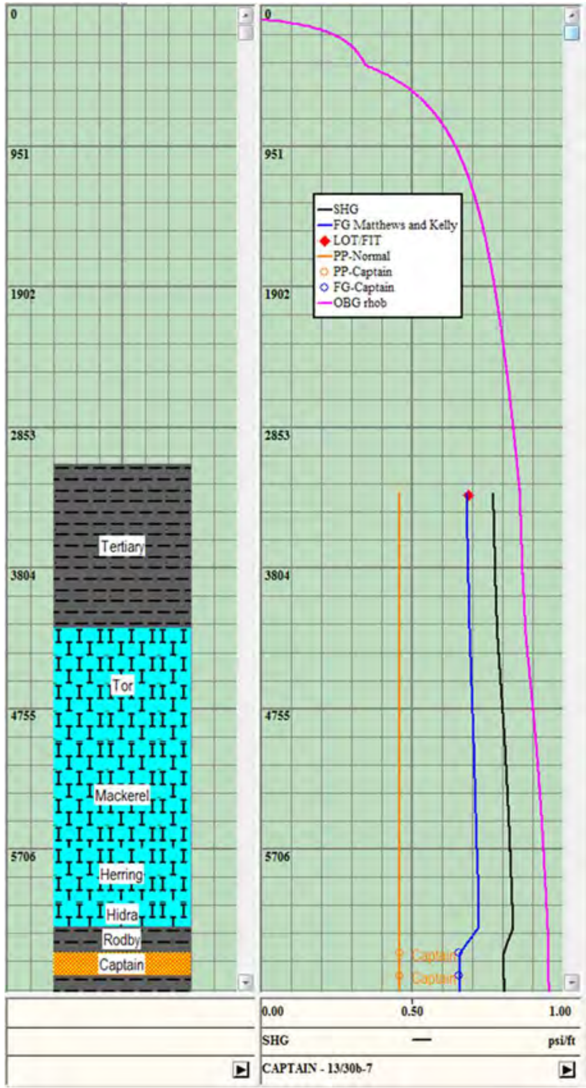



Figure 11-77 Calculated stress curves - well 13/30b-7

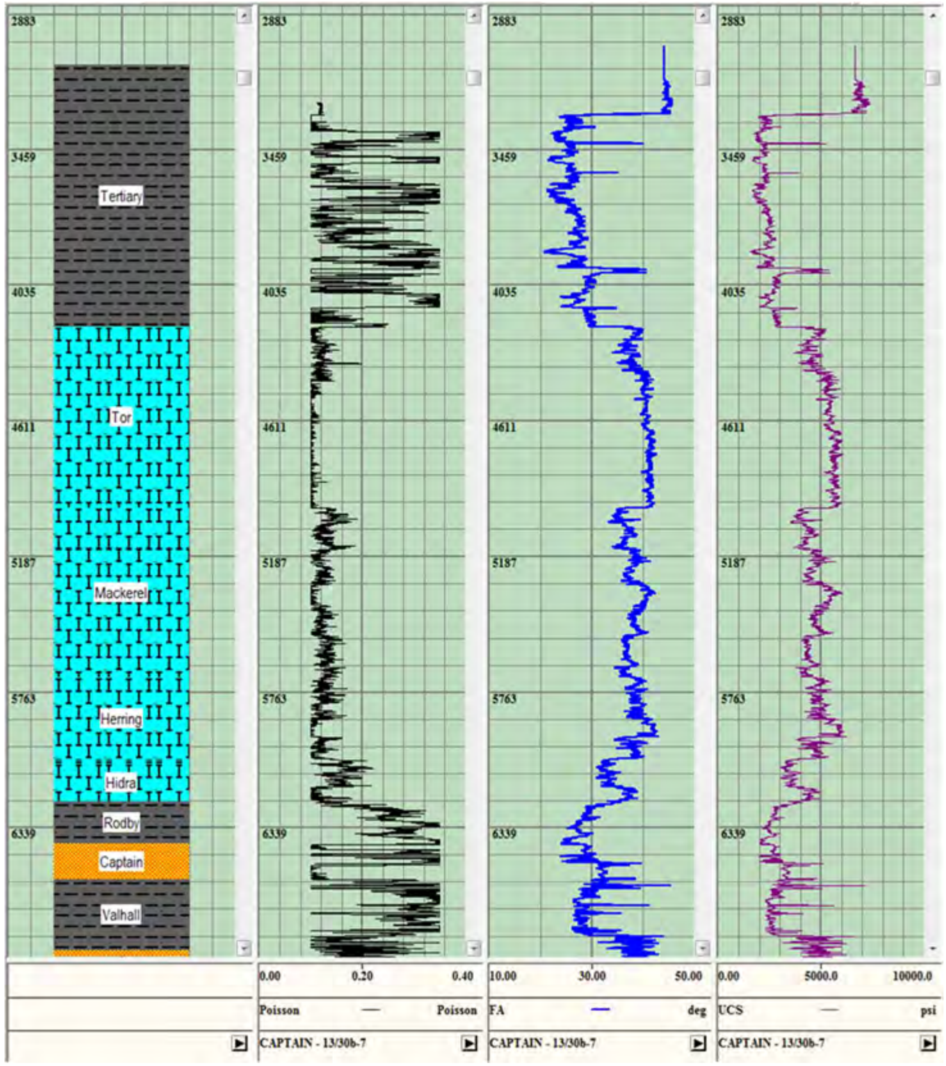



*Figure 11-78 Rock mechanical properties - well 13/30b-7*

### 11.9.4 Depletion Analysis – Poroelasticity

Depletion in a reservoir can lower the fracture gradient due to a combination of Biot's factor (pore pressure effectiveness) and Poisson's ratio (lateral strain/vertical strain). During depletion the total stress stays the same (weight of rock doesn't change) but the effective vertical stress (σv) increases as;

$$\sigma_v = S_v - \alpha P_p$$

Where:

α = Biot's factor.

The effective horizontal stresses also increase with depletion but the increasing vertical strain causes an increase in lateral strain that counteracts the horizontal stress increase. This means the net result is a total horizontal stress decrease during depletion. The equation for the change in total horizontal stress with pore pressure change (stress path or λ) is shown below:

λ = α((1-2v)/(1-v)) = ΔSh/ΔPp e.g. Zoback (2007)

Where:

α = Biot's factor

v = Poisson's ratio.

This formula is valid where the reservoir width is equal or higher than ten times (10x) the reservoir height (to prevent stress arching).

For the Captain sandstone, this translates to a depleted fracture gradient range of 0.69 psi/ft. However, this simple relationship can only be used as a rough guide to the potential change in fracture gradient as it assumes a vertical stress with elastic response control on the horizontal stress system with depletion. The actual stress path may be affected by local variations in far field tectonic stresses, depletion variability, lithological changes or the local structure (folds and faults).

Even if this relationship is broadly correct, there is the potential for hysteresis if the reservoir pressure is increased from the depleted state. The worst case scenario for fracturing the reservoir is that during injection, the fracture gradient stays similar to the depleted fracture gradient.

The impact of the changes in reservoir pressure on the overburden units will be much less, meaning the seals should still have fracture gradients close to original conditions. If there is any stress arching effects then the horizontal stresses may increase slightly.

The following considerations were taken to calculate the fracture gradient at depleted condition in DrillWorks 5000:

- The depletion condition was applied only to the Captain Sandstone.
- A depletion of 400 psi to the original pore pressure was used in the Captain Sandstone
- The Matthews & Kelly correlation was used to identify the depleted fracture gradient condition

### 11.9.5 Conclusions

- Assumptions are made that the regional NW-SE in-situ maximum horizontal stress orientation is relevant to the Captain Sandstone area. Real maximum horizontal stress azimuth may be different.
- The actual depleted stress conditions in the Captain sandstone are not confirmed with field data, at the moment the estimation is based on the correlation used (Matthews and Kelly).
- No core has been available to calibrate the strength (breakout) information.
- The average pore pressure gradient in the wells analysed were 0.46 psi/ft. The assumed average depleted pore pressure gradient in the Captain Sandstone was 0.395 psi/ft (based on assumed 400 psi depletion).
- Based on the analyses presented here, a valid working assumption for a depleted fracture gradient in Captain Sandstone is 0.69 psi/ft. Note this is likely to increase back towards the undepleted value of 0.73psi/ft as the reservoir is pressurised although that is not guaranteed. Applying a 10% safety margin gives an initial fracture pressure limit of 0.62 psi/ft.

## 11.10 Appendix 10 – Subsurface Sensitivity Analysis

A number of subsurface and development uncertainties were identified through the course of the project and assessed for their impact on CO2 injectivity and site performance across the design life of the proposed development, to 2062, and beyond until the fracture pressure limit was reached.

The uncertainty parameters and the associated range of values is summarised in the sensitivity matrix in Table 11-30 and the results are tabulated in Table 11-31. In addition, the results are summarised in Figure 11-79, a bar chart showing the injected mass at 40 years and the injected mass from 40 years until the fracture pressure limit is reached and in Figure 11-80, a line plot of the comparative site injection profiles.

| Sensitivity | Unit | Input Values | | |
|---|---|---|---|---|
| | | Low | Reference | High |
| **NW Aquifer size** | $m^3$ | $15.9 \times 10^9$ | $48.6 \times 10^9$ | $63.6 \times 10^9$ |
| **SE Aquifer size** | $M^3$ | $3.2 \times 10^9$ | $6.8 \times 10^9$ | $9.5 \times 10^9$ |
| **Fracture pressure limit** | bar/m | 0.14 | 0.165 | 0.18 |
| **Injection rate** | Mt/y | 1 | 3 | 5 |
| | | | Reference | Alternative |
| **Lower Valhall sand connection** | | | None | 7% Poro; 33mD permx |
| **Captain C transmissibility** | | | 1% poro; 0.001mD | None |
| **Relative permeability** | | | Set 2 | Sets 1 and 3 |
| **Structural uncertainty** | | | - | Northern lows removed |

*Table 11-30 Subsurface uncertainty parameters and associated range of values*

| | Target Rate (MT/Y) | Cumulative at 40 years (MT) | Plateau Duration (Years) | Profile Length (Years) | Total Injected Mass (MT) |
|---|---|---|---|---|---|
| **Reference Case** | 3 | 120 | 43 | 43 | 129 |
| **Frac Pressure Limit - Low** | 3 | 109 | 36 | 36 | 109 |
| **Frac Pressure Limit - High** | 3 | 120 | 45 | 45 | 167 |
| **NW Aquifer - Small** | 3 | 89 | 30 | 30 | 89 |
| **NW Aquifer - Large** | 3 | 120 | 53 | 53 | 158 |
| **SE Aquifer - Small** | 3 | 109 | 36 | 36 | 109 |
| **SE Aquifer - Large** | 3 | 120 | 49 | 49 | 147 |
| **Relative Permeability - Set 1** | 3 | 114 | 29 | 56 | 138 |
| **Relative Permeability - Set 3** | 3 | 120 | 43 | 48 | 142 |
| **Injection Rate - 1MT/Y** | 3 | 40 | 78 | 78 | 78 |
| **Injection Rate - 5MT/Y** | 3 | 129 | 6 | 31 | 130 |
| **Lower Valhall Sand Connection** | 3 | 120 | 51 | 51 | 154 |
| **Captain C Sands Not Transmissible** | 3 | 120 | 44 | 44 | 131 |
| **Brine Producer; 20tbd** | 3 | 120 | 63 | 63 | 188 |
| **Structural Sensitivity** | 3 | 120 | 46 | 46 | 139 |

*Table 11-31 Subsurface uncertainty results: profile length and total injected mass per case*

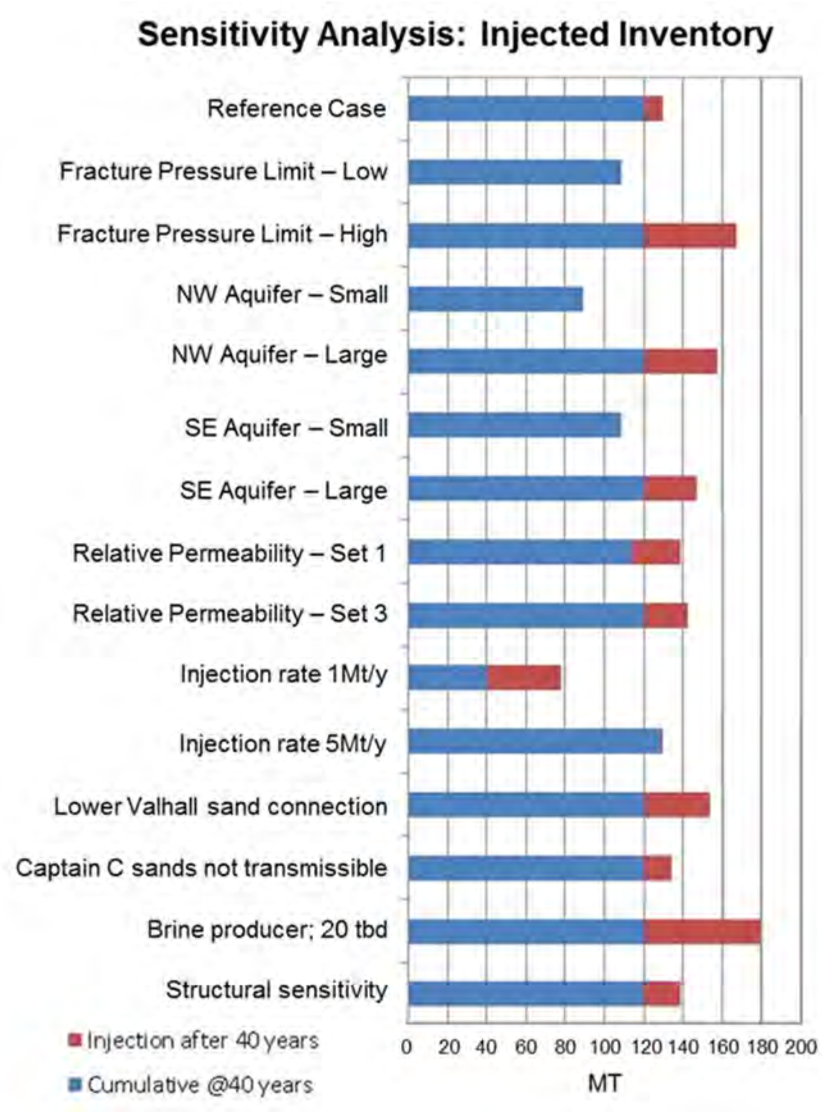



*Figure 11-79 Sensitivity analysis: comparison of cumulative injected mass per case*

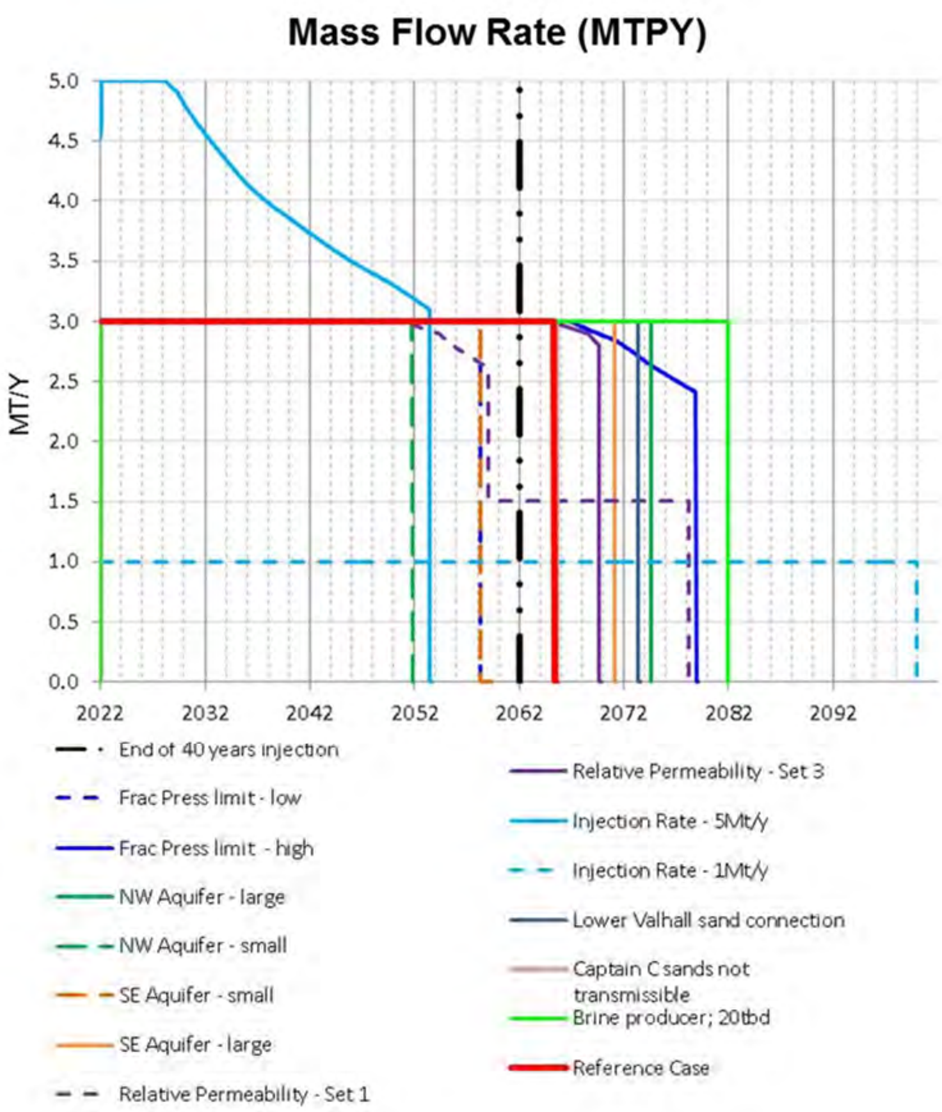



*Figure 11-80 Sensitivity analysis: injection forecast comparison per case*

The parameters with the greatest impact on the cumulative injected mass are the fracture pressure limit and those that control the size of the connected aquifer volume. The Captain injection site behaves as a relative well confined structure as it is bounded to the north east and south west by sand pinch-outs and above and below by clearly defined no flow boundaries. In every sensitivity that was run the fracture pressure limit was eventually reached, at which point CO2 injection is stopped in the model. For the range of sensitivities tested, the injected inventory ranged from 78MT to 180MT.

Confidence in fracture gradient is reasonably high and the Reference Case uses a best estimate determined through geomechanical assessment of well data from the area.

### 11.10.1 Boundary Conditions: Aquifer Size

The north west and south east boundary definitions are discussed previously in section 1. An additional sensitivity was run to test the potential for Lower Valhall interval to provide pressure dissipation through some kind of hydraulic connection to additional pore space. This is thought to be unlikely but, as it has been evaluated in other studies (Reference CO2 multistore project September 2015) it was considered to be important to evaluate the impact in this study. Adding the connection to the Lower Valhall extends the reference case injection profile by 8 years resulting in a 19% increase in the injected inventory. Larger aquifers connected to the north and south had a similar impact, increasing the profile length by 10 years and 6 years respectively, and increasing the injected inventory by 22% and 14% respectively.

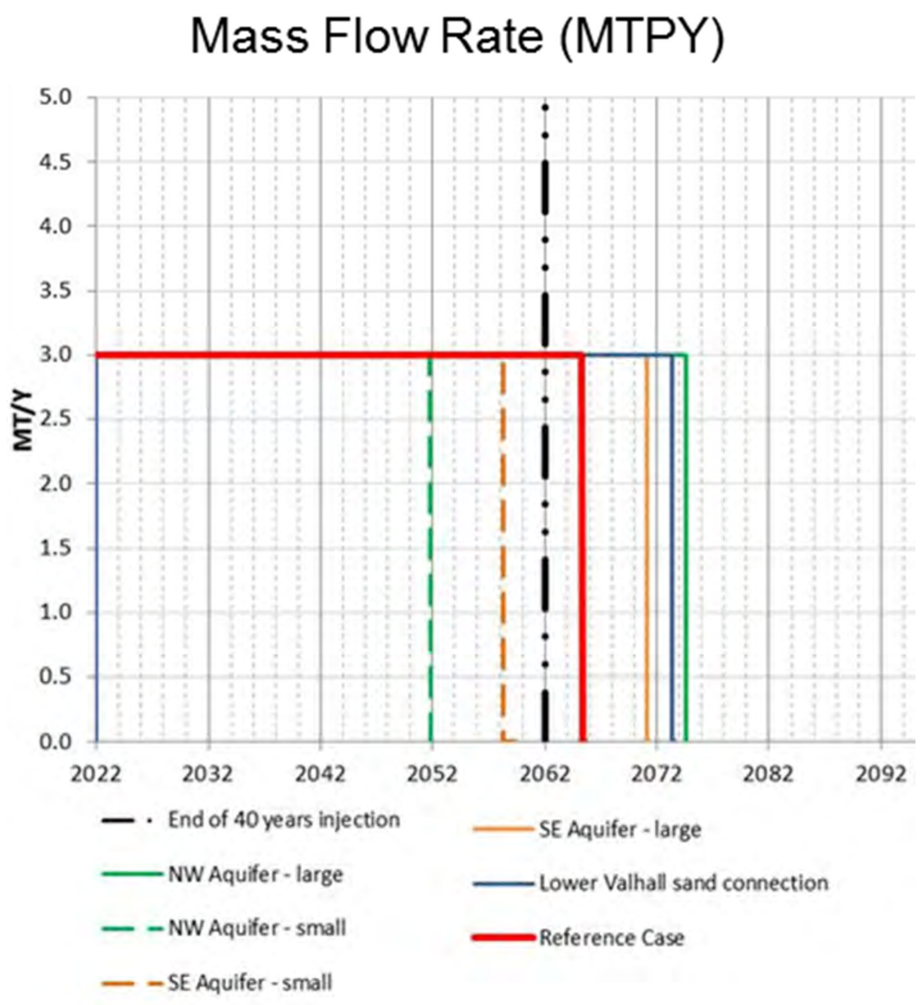



*Figure 11-81 Field mass injection forecasts for aquifer size sensitivities*

### 11.10.2 Relative Permeability

Significant uncertainty exists in the relative permeability functions. Three relative permeability sets were tested as part of the uncertainty analysis to evaluate the impact on injectivity and CO2 plume migration. Endpoint inputs were based on available published experimental values for Set 1 and Set 2. A third set was generated to capture the guidance provided by NGC (National Grid Carbon, 2015). Drainage curves for the three sets are compared in Figure 11-82 and the Corey exponents and end points used to generate the curves are shown in Table 3 12.

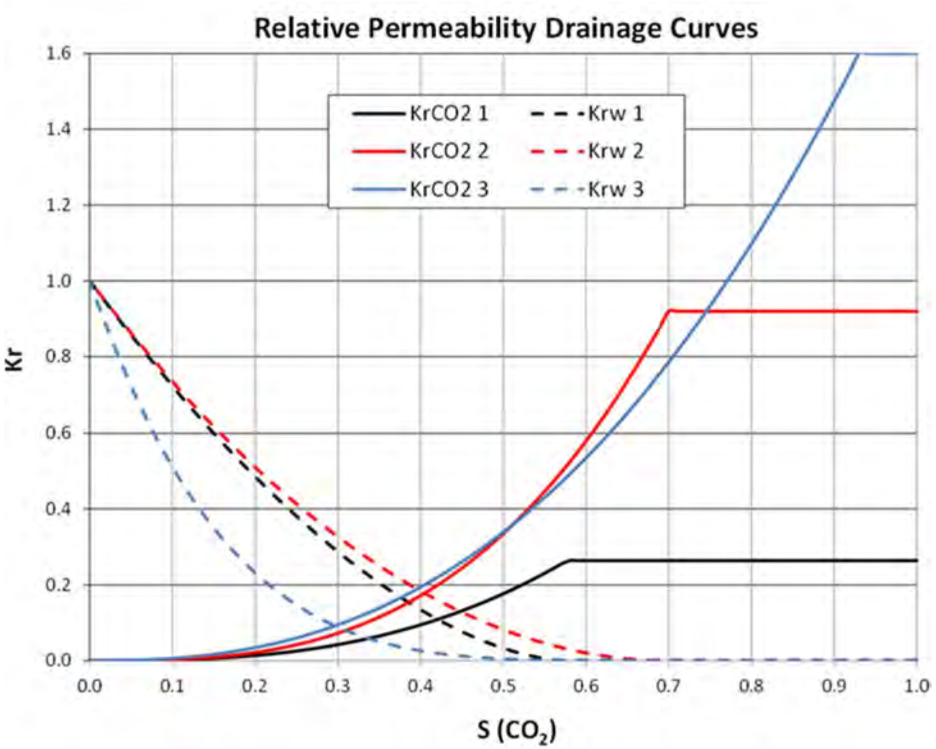



*Figure 11-82 Range of relative permeability drainage curves*

| | Drainage | | | Imbibition | | |
|---|---|---|---|---|---|---|
| **Relative Permeability Set** | Set 1 | Set 2 | Set 3 | Set 1 | Set 2 | Set 3 |
| **Ng** | 2.8 | 3 | 2.5 | 4 | 3 | 2.5 |
| **Nw** | 1.7 | 2 | 4.5 | 2.1 | 2 | 4.5 |
| **Krw @ SGWCR** | 1.000 | 1.000 | 1.000 | 0.365 | 0.400 | 0.400 |
| **Krg @ SWCR** | 0.2638 | 0.920 | 1.600 | 0.2638 | 0.920 | 1.600 |
| **SWL** | 0.423 | 0.300 | 0.070 | 0.423 | 0.300 | 0.070 |
| **SWCR** | 0.423 | 0.300 | 0.280 | 0.423 | 0.300 | 0.280 |
| **SGWCR** | 0.000 | 0.000 | 0.000 | 0.297 | 0.290 | 0.300 |
| **SWU** | 1.000 | 1.000 | 1.000 | 0.703 | 0.710 | 0.720 |

*Table 11-32 Corey exponents and end point inputs for the relative permeability curves*

The maximum Krg value is an indication of CO2 mobility in the system, the higher the value the more mobile CO2 will be. The values range from 0.26 in Set 1 to 1.6 in Set 3. The low mobility case is representative of relatively low permeability system, ~20mD. This is based on the published results from the Bachu (2013) study for the Viking#2 formation, Alberta Canada (Bachu, et al., 2013). Set 2 includes a maximum Krg value of 0.92. This is based on the published results from Shell (2011) for the Captain formation within the Goldeneye field, North Sea (Shell UK ltd., 2011). Guidance from NGC indicated that the CO2 is much more mobile than previous experiments have indicated and that maximum Krg values of 1.6 are possible. This has been incorporated into Set 3.

The impact of increasing the maximum Krg value is to increase the CO2 mobility. The mobility of water is also an important factor of injectivity potential. Sets 1 and 2 have similar water relative permeability trends. However, Set 3, based on guidance from NGC, has significantly reduced water mobility. As CO2 injection into the saline aquifer relies on water displacement, reduced water mobility also restricts the mobility of CO2.

The three alternative relative permeability sets were evaluated using the reference case model and the impact on the injection forecast is shown in Figure 11-83.

The reduced mobility of CO2, using Set 1, highlights the interference between the injection wells. The more northerly injection well, GI02, shuts in early as the CO2 from GI02 migrates either into the path of the GI01 CO2 plume, which in this case is less mobile. The alternative migration pathway is downdip, against the natural buoyancy force of the less dense CO2 in the brine system.

Set 2 will be applied in the reference case as it is considered to be the best analogue for the Captain storage site sands.

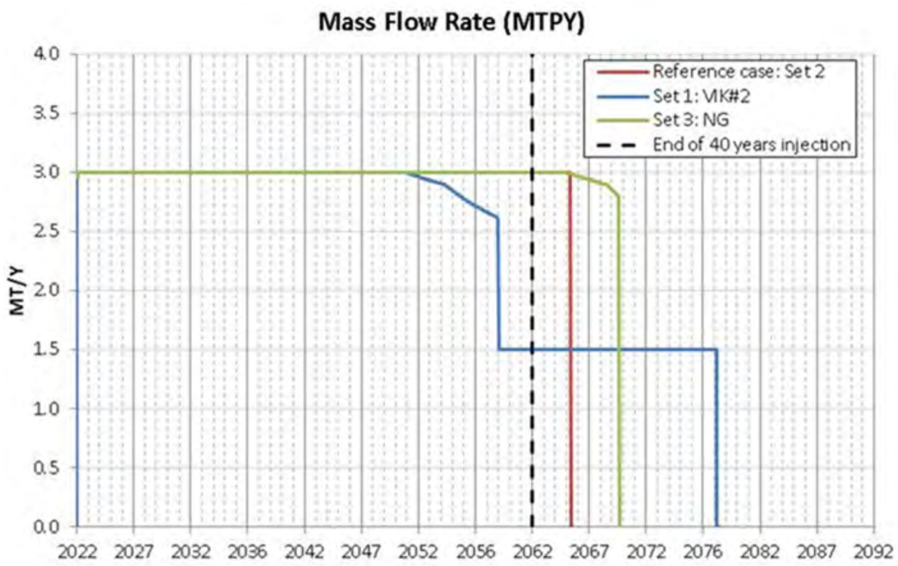



*Figure 11-83 Field mass injection forecasts for relative permeability sensitivity*

## 11.10.3 Fracture Gradient

The Captain sandstone formation is hydrostatically pressured resulting in an initial (pre-production) reservoir pressure of 197bar (2857 psi) at a datum depth of 1890m TVDSS. There are three hydrocarbon fields within the site model area that have or are still producing from the Captain sands, Blake, Cromarty and Atlantic. Cromarty and Atlantic stopped production in 2009 but Blake will continue to produce until an estimated date of 2026. The production has resulted in pressure depletion throughout the site. There is some uncertainty in the pressure depletion over time which could be refined in the future once the missing data is accessed. The RFT data from well 14/26a-9 is available from

CDA and the data show a depletion of 27.6 bar (400psi) in 2011, in the south east area of the Captain X site.

To avoid any chance of fracturing the reservoir the maximum pressure will be limited to 90% of the estimated fracture pressure. The determination of the fracture pressure for the Captain sands is discussed in Appendix 9 and has been estimated for pre-production and depleted conditions. The fracture pressure gradient at pre-production conditions is 0.165bar/m (0.73 psi/ft). Under depleted conditions (27.6 bar - 400psi) the fracture pressure is estimated to be 0.14bar/m (0.62 psi/ft). During the CO2 injection phase the reservoir pressure will increase and the fracture pressure will also increase but the rate at which it increases is uncertain. The reference case assumes that the fracture pressure will return to the pre-production value with increasing pressure and in this case the pressure constraint in the model was set at 90% of the fracture pressure gradient, 0.149bar/m (0.657psi/ft). The worst case scenario is that the fracture pressure does not increase with increasing pressure. A low fracture pressure case has been evaluated and in this case the total injected mass, when the pressure limit is reached, is reduced by 16% to 109MT. A high fracture pressure case was run to capture the impact of any upside potential. In this case the fracture pressure limit of 0.18bar/m (0.80 psi/ft) was used and the total injected mass, when the pressure limit is reached, is increased by 29% to 167MT. In this case the THP limit of 120bara is reached after 42 years. The mass injected forecasts for the fracture pressure limit sensitivity are shown in Figure 11-84.

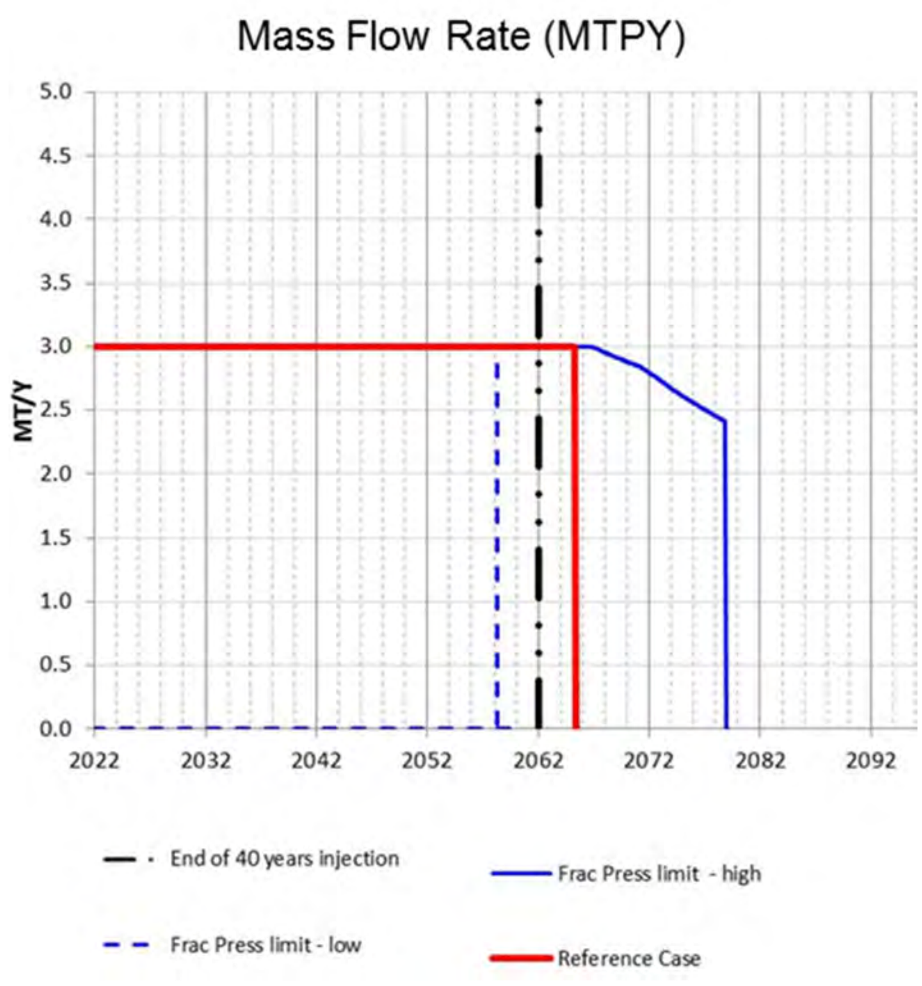



*Figure 11-84 Field mass injection forecasts for fracture pressure limit sensitivity*

### 11.10.4 Injection Rate

The injection rate can impact the storage site capacity as higher rates usually result in a more rapid pressure build-up and a reduced injected mass before the fracture pressure is reached. Rate sensitivities are run to evaluate the injectivity potential but also to determine a suitable plateau rate and plateau duration for the injection site. Injection rates of 5MT/y and 1MT/y were evaluated and compared to the reference case of 3MT/y, for the selected 5.5" tubing. A rate of 5MT/y cannot be sustained beyond 6 years but the total mass injected in this case is similar to the reference case. A low rate of 1MT/y can be sustained until the fracture pressure limit is reached but in this case the total injected mass is reduced considerably from the reference case by 40 %, to 78MT. The mass injected forecasts for the rate sensitivity are shown in Figure 11-85.

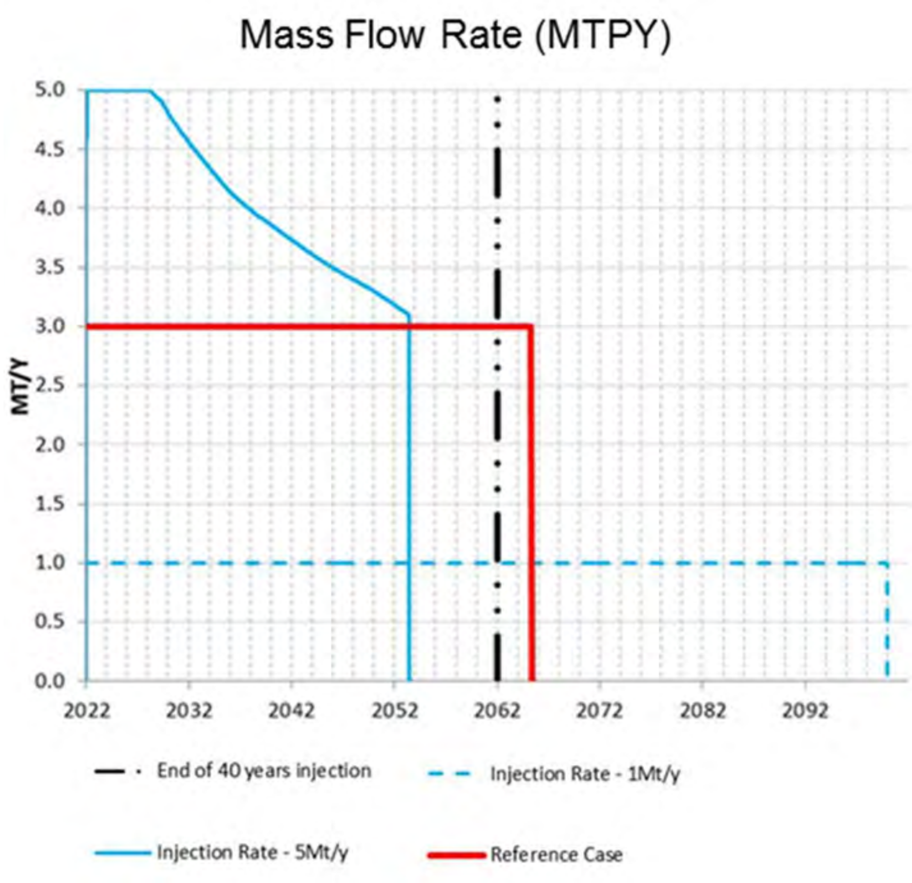



*Figure 11-85 Field mass injection forecasts for injection rate sensitivity*

### 11.10.5 Captain C Transmissibility

As discussed in the main report, the Mid Captain Shale is acting as a significant baffle to vertical flow but does not hydraulically isolate the Lower Sand. Based on the well log analysis for this study, none of the available and examined wells show as and on sand connection between the Upper and Lower sands (i.e. a missing Mid Shale). Additional data and further analysis is required to understand where the connection through the shale could occur. For the purposes of this study a transmissibility has been introduced between the Upper and Lower sand across the entire site model. The transmissibility was used as a match parameter to calibrate the model to the RFT data. A very low transmissibility (equivalent to a vertical permeability of 0.001mD) is required to achieve the RFT match. The impact of introducing a transmissibility through the Mid Captain Shale on the injection forecast is small. The plateau is extended by 7 months and the injected mass is increased from 129MT to 131MT.

### 11.10.6 Structural Sensitivity

There is significant uncertainty in the Top Captain sand location within the site model due to a combination of both seismic pick and depth conversion issues. The top of the Captain Sandstone has a variable seismic response and poor seismic resolution which makes accurate interpretation of the event extremely difficult. The imaging of the reservoir is hindered by a lack of impedance contrast across the interface between the Rodby/Carrack Shale and the Captain Sandstone making delineation of the top sandstone very uncertain from 3D seismic data (section 3.4.3). As well as uncertainty in the seismic picking of the Top Captain Sandstone there are also depth conversion uncertainties due to the effect of lateral velocity changes in the overburden, particularly related to lithology variations within the Tertiary section and rugosity of the Top Chalk surface (section 3.4.5).

As CO2 is less dense than the brine within the saline aquifer, buoyancy forces significantly impact CO2 migration. The wells were placed in the deeper areas of the site model, furthest from the north east high where the pressure limit is first met. The migration pathway for the CO2 is towards structural highs whilst lower structural areas act as baffles resulting in the CO2 moving either around or away from these areas. In the reference case structure, the CO2 migrates towards Cromarty and then travels along the south west edge of the model, following the thinner, higher structure. The CO2 migration is for the reference case structure, at the end of 1000 years shut-in, is shown in Figure 11-86.

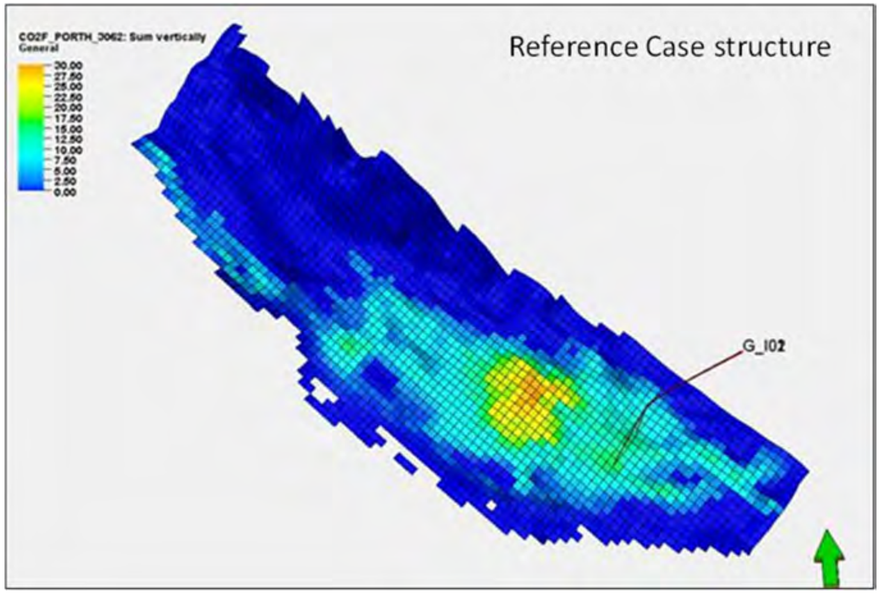



*Figure 11-86 $CO_2$ migration for the reference case structure, at the end of 1000 year shut in*

Two lower areas to the north east, with limited well control, were identified as potential baffles. The model was modified to captures an alternative structural interpretation, within the limits of the seismic interpretation, to test the impact of the structural uncertainty on the site performance. The structural modifications are shown in Figure 11-87.

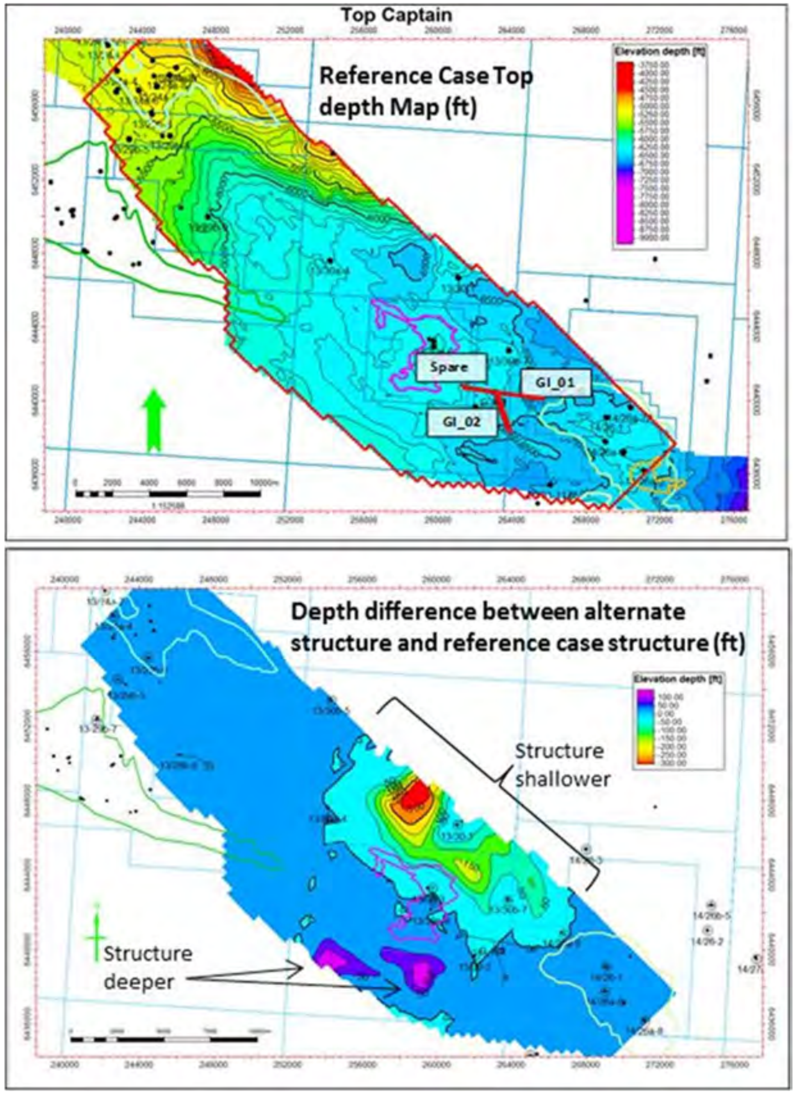



*Figure 11-87 Maps highlighting structural differences between the reference case and the alternative structure*

The impact on the total injected mass was relatively small, +7%, but there was a significant impact on plume migration, as the alternative structure introduces a migration pathway to the north east of the model and most of the CO2 migrates to the north east as opposed to the north west. The CO2 plume migration at the end of the 1000 year shut-in period for the alternative structure case is shown in Figure 11-88

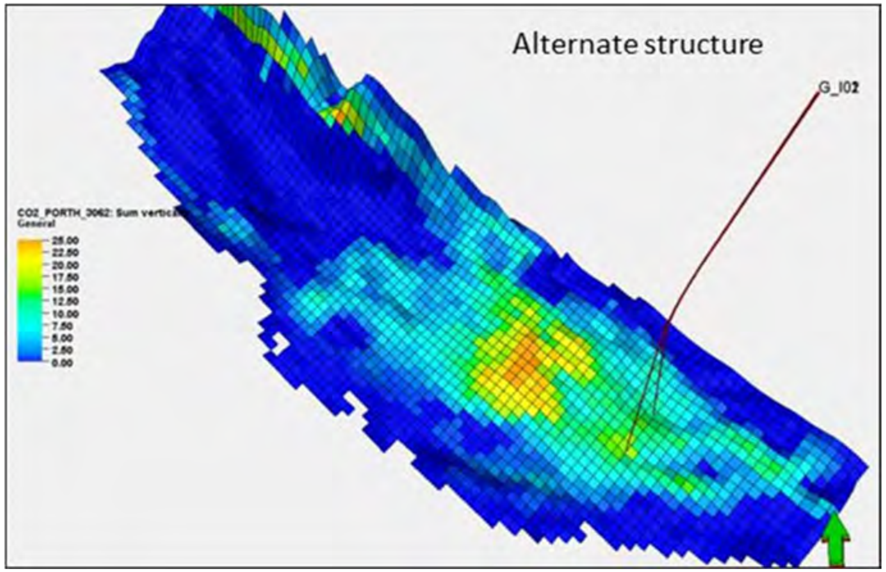



*Figure 11-88 $CO_2$ plume migration after 1000 years shut in for the alternate structural interpretation*

The structural interpretation is a key factor in the storage site evaluation as it directly impacts injection well locations and the CO2 plume migration. It is recommended that additional data and further analysis is carried out prior to progressing the development of Captain X.

## 11.11 Appendix 11 – Comparison with $CO_2$MutliStore

In September 2015 the SCCS published the results of CO2MultiStore, a research project to investigate a case study of injection sites within a single, multi-user, storage formation. The project team consulted with SCCS during the course of this project and SCCS confirmed that our findings are in line with those of CO2MultiStore. A brief comparison of the two projects is presented in the following table.

| Aspect | $CO_2$MultiStore | CAPTAIN X |
|---|---|---|
| Purpose | Investigate the operation of multiple $CO_2$ injection sites within a single storage formation (Captain Sandstone) | To define a storage development plan for CO2 storage in the Captain aquifer, including technical, commercial and outline regulatory considerations |
| Seismic Interpretation | None performed. | Specific seismic interpretation completed for the project across the full area of interest. |
| Road to Consenting | "The model does not support the level of accurate predictions needed for characterisation of a planned injection site and as underlying technical work for a $CO_2$ storage permit" | Project focussed to deliver a specific outline storage development plan which can be progressed by a developer to a full permit application |
| Reservoir Correlation | No detailed reservoir correlation across the full area of the study. – constant 45m Upper Captain across the SCCS model | Consistent correlation across the full area of the study. |
| Model gridding | 400m x 400m – potentially smoothing out key surface rugosity | 200m * 200m for Primary model & 400m * 400m for upscaled model |
| Cap rock modelling | Primary cap rock modelled as a single layer | Carry the Rodby, Carrack, Hidra and Plenus Marl unit as component layers. (A suggestion from $CO_2$Multistore) |
| Modelling Approach | Splice of two models developed for two different reasons. | Single coherent model built across the full area of interest with specific objective of site characterisation |
| Timeframe | GY injecting 6MT from 2016 and Site B injecting 6MT from 2021 – operations active early whilst adjacent hydrocarbon fields in operation | GY injecting 1MT/yr from 2021 to 2031 in sensitivity<br>Site injecting 3MT/yr from 2022 in reference case |
| Well schematic | Uses all five existing Goldeneye Wells | Designed wells for the specific circumstances at Site X |
| Response | Required the assignment of the underlying Valhall Formation (350m) with both porosity and permeability to keep the Captain operating at below fracture pressure | No evidence found for hydraulically active underburden |

| Aspect | $CO_2$MultiStore | CAPTAIN X |
|---|---|---|
| Production Rates | 7 wells used to calibrate – 5 on GY and 2 on Hannay together with field rates on other areas. | 6 wells used to calibrate – 5 on GY, 1 on Cromarty together with field rates for other areas. |
| Hydrocarbon field fluid properties | Used GY properties for all fields | Used published properties for each field as appropriate |
| $CO_2$ Plume Movement | Noted wide and rapid dispersal of plume but its full control was not required by the purpose of the study | Injection inventory constrained to limit dispersal of plume within the defined storage complex |

# RISK REGISTER

**Captain - saline aquifer site**

Document: D13 10113ETIS WP5D Report - Appendix 01 Risk Register

| Risk ID | Risk description/ event | Consequence of risk/ impact on project | Likelihood | Impact | Likelihood x impact | Comments (if applicable) | Controls (mitigation actions) | Potential remediation options | High level cost |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Storage and injectivity of Captain different (poorer) than forecast | Significant uncertainty over final cost of project, potential to reduce timescale of injection operations, reputational impact and fines | 2 | 4 | 8 | | Appraisal well and well test to understand injectivity | Work-over/ stimulate wells. Drill additional wells | |
| 2 | Inability to demonstrate plume stabilisation to Regulator after 20 years | Extended monitoring costs, reputation damage, temporary withdrawal of storage permit | 2 | 3 | 6 | Modelling indicates possiblity of faster than expected migration to NW or NNE | Monitoring of site to understand dynamic behaviour of plume; regular dialogue with Regulator via updated monitoring plan | | |
| 3 | Drilling activities near the storage site (either for O&G or CO2 storage) | Potential to compromise caprocks of storage site and provide an additional migration pathway to the near-surface/surface | 1 | 4 | 4 | | Work closely with DECC to understand future drilling activities in the area and then work closely with Operators to ensure their drilling operations do not compromise storage integrity | | |
| 4 | Future O&G extraction operations hindered by presence of CO2 in storage site | Presence of injected CO2 may hinder extractive operations near the storage site by obscuring seismic traces (eg in prospective formations below the storage site) or making drilling process more difficult. Drilling through formation with supercritical CO2 might cause blow out or loss of containment. May be requirement to pay compensation | 1 | 4 | 4 | | Work closely with DECC to understand future drilling activities in the area and then work closely with Operators to ensure their drilling operations do not compromise storage integrity | | |
| 5 | Accidental or intentional damage to injection process or storage site that disrupts storage site | Depending on scale of damage, could result in release of CO2 to seabed via well bores, injection being stopped, reputational and financial implications | 1 | 4 | 4 | Very low probability event but could have significant impact on storage system by disrupting expected evolution of the system | Monitoring of site to ensure operations are as expected | Shut in wells, further work to understand the scale of the damage, potentially require new injection site. | |
| 6 | Seismic event compromises store integrity | | 1 | 1 | 1 | The North Sea is a fairly quiescent area and far from plate boundaries so likelihood of large-scale seismicity is very low | Monitoring of site to ensure operations are as expected | Shut in wells, further work to understand the scale of the damage, potentially require new injection site. | |
| 7 | Loss of containment of CO2 from primary store to overburden through caprock | | 1 | 3 | 3 | | | | |
| 8 | Loss of containment from primary store to overburden through caprock & P&A wells | Unexpected movement of CO2 outwith the storage site, but within the storage complex in the overburden, considerable reputational impact, large fine likely | 1 | 3 | 3 | Only a leak to the biosphere will be detected. | | Re-entry into an abandoned well is complex, difficult and has a very low chance of success.<br><br>A relief well is required. | Relief well: $55 million (60 days & tangibles). |
| 9 | Loss of containment from primary store to overburden through caprock & inj wells | Unexpected movement of CO2 outwith the defined storage complex in the overburden, considerable reputational impact, large fine likely | 1 | 3 | 3 | | | | |
| 10 | Loss of containment from primary store to overburden through caprock & suspended wells | Unexpected movement of CO2 outwith the defined storage complex in the overburden, considerable reputational impact, large fine likely | 1 | 3 | 3 | | | | |
| 11 | Loss of containment from primary store to overburden via P&A wells | Unexpected movement of CO2 outwith the defined storage complex in the overburden, considerable reputational impact, large fine likely | 1 | 3 | 3 | Only a leak to the biosphere will be detected. | | Re-entry into an abandoned well is complex, difficult and has a very low chance of success.<br><br>A relief well is required. | Relief well: $55 million (60 days & tangibles). |
| 12 | Loss of containment from primary store to overburden via injection wells | Unexpected movement of CO2 outwith the defined storage complex in the overburden, considerable reputational impact, large fine likely | 1 | 3 | 3 | Only a leak to the biosphere will be detected. | Injection wells designed to have low risk of loss of containment; downhole P/T gauges and DTS along the wellbore as part of monitoring plan to detect first signs of loss of integrity. | | |
| 13 | Loss of containment from primary store to overburden via suspended wells | Unexpected movement of CO2 outwith the defined storage complex in the overburden, considerable reputational impact, large fine likely | 1 | 3 | 3 | Only a leak to the biosphere will be detected. | | | |
| 14 | Loss of containment from primary store to upper well/ seabed via P&A wells | CO2 to seabed. Environmental, national reputation and cost implications | 3 | 4 | 12 | | | Re-entry into an abandoned well is complex, difficult and has a very low chance of success.<br><br>A relief well is required. | Relief well: $55 million (60 days & tangibles). |
| 15 | Loss of containment from primary store to upper well/ seabed via injection wells | CO2 to seabed. Environmental, national reputation and cost implications | 2 | 4 | 8 | | Injection wells designed to have low risk of loss of containment; downhole P/T gauges and DTS along the wellbore as part of monitoring plan to detect first signs of loss of integrity. | | |
| 16 | Loss of containment of CO2 from primary store to seabed via combination of both caprock and wells | | 1 | 4 | 4 | | | | |
| 17 | Lateral movement of CO2 from Primary store out with storage complex w/in Captain | Considerable reputational impact, large fine likely. May affect other subsurface users within Captain fairway. | 3 | 3 | 9 | Modelling results have shown higher or faster than expected migration to NW or NNE. | | Stop injection; corrective measures plan | |
| 18 | Loss of containment from primary store to underburden (e.g. via 13/30b-7 well) | | 5 | 3 | 15 | 13/30b-7 total communication between captain and burns below - right in middle of the site. Abandoned in 2007. Data from CDA. Wellhead & surface casing cut 10ft below seabed & removed | | Stop injection; corrective measures plan | |
| 19 | Primary store to underburden via store floor (out with storage compelx) | | 1 | 3 | 3 | Thick formations underlying Captain formation so v low likelihood | | | |
| 20 | Fault reactivation through primary caprock | | 1 | 2 | 2 | The "pan-handle" part of the Captain Sandstone fairway is bounded along its northern and north eastern edge by the Captain and West Halibut Faults respectively. There is uncertainty on the exact location of the West Halibut Fault which is why the storage complex north east boundary has been extended some 2 km beyond the currently mapped West Halibut Fault. Within this fairway, apart from the Captain and West Halibut Faults, no other significant faults have been identified. There is some evidence of seismically visible small scale faulting within the Captain Sandstone. These faults are limited in vertical extent and do not offset the overlying Rodby/Carrack formation | Maximum reservoir pressure during injection set to 90% of reservoir fracture pressure | Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes | |
| 21 | CO2 flow through unreactivated, permeable fault in primary caprock | | 1 | 2 | 2 | Have not mapped any faults (apart from Captain and West Halibut faults - see Risk ID 20 Comments), but some small faults seen at top Captain. There is some evidence of seismically visible small scale faulting within the Captain Sandstone. These faults are limited in vertical extent and do not offset the overlying Rodby/Carrack formation | n/a | | |
| 22 | Thermal fracturing of primary caprock from injection of cold CO2 into a warm reservoir | | 1 | 2 | 2 | No phase change of injecting CO2, decent thickness of caprock & taking conservative approach - 90% of reservoir frac pressure (rather than cap rock frac pressure); Injection wells will not be at Top Captain(40ft below top reservoir) and so CO2 will migrate through warm reservoir before hitting caprock | | Stop injection, corrective measures plan, limit injection volumes/rate | |
| 23 | Mechanical fracturing of primary caprock from injection pressure of CO2 exceeding the fracture pressure of the caprock | | 2 | 2 | 4 | No phase change of injecting CO2, decent thickness of caprock & taking conservative approach - 90% of reservoir frac pressure (rather than cap rock frac pressure); Injection wells will not be at Top Captain(40ft below top reservoir); Formation has quite high frac pressure (0.8psi/ft) | | | |
| 24 | CO2 and brine react with minerals in caprock and create permeability pathway | | 1 | 2 | 2 | CO2 plume & caprock - 50-75m over 10m000 years, low risk of induced leakage. Dissolved CO2/Caprock - some dissolution possible in calcute-rich features but onlyover small dist at base - low risk of induced leakage (http://webarchive.nationalarchives.gov.uk/20120803125817/http://decc.gov.uk/assets/decc/11/ccs/sp-chapter3/ukccs-kt-s7.19-shell-003-grr.pdf) | None required | | |
| 25 | Buoyant CO2 exposes caprock to pressures beyond the capillary entry pressure enabling it to flow through primary caprock | | 1 | 2 | 2 | No O&G fields above in this area; accumulations at GY, Blake, A&G, big col gas at GY - indicates v low | | Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes to reduce column height of CO2, | |
| 26 | Geology of caprock lithology is variable and lacks continuity such that its presence cannot be assured across the whole site | | 2 | 2 | 4 | Continuous - no wells showing evidence of missing caprock | | Stop injection, corrective measures plan | |
| 27 | Relative permeability curves in the model move the CO2 too slowly within the primary store relative to reality | In the unlikely event that CO2 did migrate faster than expected and laterally exited the primary store, this would be unexpected migration but at reservoir level. Considerable impact on reputation and large fine likely. | 2 | 3 | 6 | Injection programme designed for injected inventory to stay within the storage complex boundaries and reduce migration risk. Some uncertainty remains over CO2 rel perm curves due to a lack of CO2-specific data for this site. Have used a range. | Site specific relative permeability study from core in appraisal well to constrain curves | Stop injection, corrective measures plan, re-model expected CO2 plume movement with new data and re-assess injection volumes to ensure containment integrity | |
| 28 | Permeability anisotropy (e.g. channels) causes the CO2 to move more quickly than expected | | 2 | 3 | 6 | Due to pinchout of Captain (confined turbidite sytsem), CO2 will not migrate to the NE or SW. The CO2 could migrate out the E or W side of the Storage complex, but the injection programme is designed to ensure that it doesn't. | | | |
| 29 | Depth conversion uncertainty | In the unlikely event that the depth conversion uncertainty caused CO2 to laterally exit the primary store, this would be unexpected migration but at reservoir level. Considerable impact on reputation and large fine likely. | 2 | 3 | 6 | Good well control & extensive area so any uncertainty from depth conversion should not lead to lateral migration of CO2 out with storage complex, however modelling results have shown higher or faster than expected migration to NW or NNE. | | | |
| 30 | Depletion or pressure gradient from nearby fields | In the unlikely event that depletion or pressure gradient from nearby fields caused CO2 to laterally exit the primary store, this would be unexpected migration but at reservoir level. Considerable impact on reputation and large fine likely. | 2 | 3 | 6 | Not expecting large pressure sink at Blake (some pressure support due to injection into Blake) - 60% voidage replacement; manageable and not big issue | Model impacts; good engagement with other operators in the area to understand impact | Stop injection until situation understood; further detailed work | |
| 31 | Impact of injection and CO2 storage on nearby fields is greater than expected | Pressure build up quicker than expected so reduces storage capacity, potential loss of credibility of CCS project | 2 | 2 | 4 | | Draft process for dispute resolution with nearby subsurface users | Stop injection until situation understood; further detailed work | |
| 32 | Well placement error | In the unlikely event that the well was drilled at the edge of the storage complex and caused CO2 to laterally exit the primary store, this would be unexpected migration but at reservoir level. Considerable impact on reputation and large fine likely. | 1 | 1 | 1 | Targeting a central area for drilling so not an issue at this storage site | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 33 | Inject in wrong zone of reservoir or damage reservoir | In the unlikely event that CO2 was injected into the wrong zone or the reservoir was damaged and caused CO2 to laterally exit the primary store, this would be unexpected migration but at reservoir level. Considerable impact on reputation and large fine likely. | 2 | 1 | 2 | Even if injected complete inventory into lower sand instead of upper sand - could fracture into the upper sand and not a significant risk | Downhole P/T gauges and DTS along the wellbore as part of monitoring plan to detect first signs of loss of integrity. | | |
| 34 | CO2 becomes dissolved in water and laterally exits the primary store | Even if it exits the primary store laterally, the impact would be limited as will be gravitationally stable. | 1 | 1 | 1 | CO2 cannot move laterally so no increase in risk. Water mobility less than CO2 mobility. | | | |
| 35 | CO2 bubble expands beyond spill point and laterally exits the primary store | | 1 | 1 | 1 | No spill point - negligible | | | |
| 36 | CO2 laterally exits the secondary store | | 1 | 1 | 1 | Either via moving faster than rel-perm curves; | | | |
| 37 | Fault reactivation through secondary primary caprock | | 1 | 3 | 3 | Lista shales - can be under 100ft - quite thin - not mapped | | Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes | |
| 38 | CO2 flow through unreactivated, permeable fault in primary caprock | | 1 | 3 | 3 | | | | |
| 39 | Thermal fracturing of primary caprock from injection of cold CO2 into a warm reservoir | | 1 | 3 | 3 | | | Stop injection, corrective measures plan, limit injection volumes/rate | |
| 40 | Mechanical fracturing of primary caprock from injection pressure of CO2 exceeding the fracture pressure of the caprock | | 1 | 3 | 3 | | | | |
| 41 | CO2 and brine react with minerals in caprock and create permeability pathway | | 1 | 3 | 3 | Note: no GY work on secondary caprock reactibvity | | | |
| 42 | Buoyant CO2 exposes caprock to pressures beyond the capillary entry pressure enabling it to flow through primary caprock | | 1 | 3 | 3 | Note: no GY work on secondary caprock reactivity | | Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes to reduce column height of CO2, | |
| 43 | Geology of caprock lithology is variable and lacks continuity such that its presence cannot be assured across the whole site | | 1 | 3 | 3 | From looking at wells - seems continuous (could be some faults breaking it but not mapped these) | | Stop injection, corrective measures plan | |
| 37 | Blowout during drilling | Possible escape of CO2 to the biosphere. | | | | | Mapping of shallow gas, understanding subsurface pressure regime for appropriate mud weight, drilling procedures | Standard procedures: shut-in the well and initiate well control procedures. | \$3-5 million (5 days & tangibles). |
| 38 | Blowout during well intervention | Possible escape of CO2 to the biosphere. | | | | | Mapping of shallow gas, understanding subsurface pressure regime for appropriate mud weight, drilling procedures | Standard procedures: shut-in the well and initiate well control procedures. | \$2-3 million (3 days & tangibles). |
| 39 | Tubing leak | Pressured CO2 in the A-annulus. Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation. | | | | | Downhole P/T gauges and DTS along the wellbore as part of monitoring plan to detect first signs of loss of integrity. | Tubing replacement by workover. | \$15 -20 million (16 days & tangibles). |
| 40 | Packer leak | Pressured CO2 in the A-annulus. Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation. | | | | | | Packer replacement by workover. | \$15 -20 million (16 days & tangibles). |
| 41 | Cement sheath failure (Production Liner) | Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation. | | | | Requires:<br>- a failure of the liner packer or<br>- failure of the liner above the production packer<br>before there is pressured CO2 in the A-annulus. | | Repair by cement squeeze (possible chance of failure).<br><br>Requires the completion to be retrieved and rerun (if installed). | \$3-5 million (5 days & tangibles).<br><br>\$18-25 million (if a workover required). |
| 42 | Production Liner failure | Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation. | | | | Requires:<br>- a failure of the liner above the production packer and<br>- a failure of the cement sheath<br>before there is pressured CO2 in the A-annulus. | | Repair by patching (possible chance of failure) or running a smaller diameter contingency liner.<br><br>Requires the completion to be retrieved and rerun (if installed).<br><br>Will change the casing internal diameter and may have an impact on the completion design and placement.<br><br>Repair by side-track. | \$3-5 million (3 days & tangibles).<br><br>\$18-25 million (if a workover required).<br><br>Side-track estimated to be equal to the cost of a new well - \$55 million (60 days & tangibles). |
| 43 | Cement sheath failure (Production Casing) | Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation. | | | | Requires:<br>- a failure of the Production Liner cement sheath or<br>- a pressurised A-annulus and<br>- failure of the production casing<br>before there is pressured CO2 in the B-annulus. | | Repair by cement squeeze (possible chance of failure).<br><br>Requires the completion to be retrieved and rerun (if installed). | \$3-5 million (5 days & tangibles).<br><br>\$18-25 million (if a workover required). |
| 44 | Production Casing Failure | Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation. | | | | Requires:<br>- a pressurised A-annulus and<br>- a failure of the Production Casing cement sheath<br>before there is pressure CO2 in the B-annulus. | | Repair by patching (possible chance of failure).<br><br>Requires the completion to be retrieved (if installed).<br><br>Will change the casing internal diameter and may have an impact on the completion design and placement. | \$3-5 million (3 days & tangibles).<br><br>\$18-25 million (if a workover required).<br><br>Side-track estimated to be equal to the cost of a new well - \$55 million (60 days & tangibles). |
| 45 | Safety critical valve failure – tubing safety valve | Inability to remotely shut-in the well below surface. Unsustainable well integrity state. | | | | | | Repair by:<br><br>- installation of insert back-up by intervention or<br>- replacement by workover | £1 million to run insert (1 day & tangibles).<br><br>\$18-25 million (if a workover required). |
| 46 | Safety critical valve failure – Xmas Tree valve | Inability to remotely shut-in the well at the Xmas Tree. Unsustainable well integrity state. | | | | | | Repair by valve replacement. | Dry Tree: < \$1 million (costs associated with 5 days loss of injection, tangibles and man days).<br><br>Subsea: \$5-7 million (vessels, ROV, dive support & tangibles). |
| 47 | Wellhead seal leak | Seal failure will be an unsustainable well integrity state and require remediation. | | | | Requires:<br>- a pressurised annulus and<br>- multiple seal failures<br>before there is a release to the biosphere. | | Possible repair by treatment with a replacement sealant or repair components that are part of the wellhead design. Highly dependent on the design and ease of access (dry tree or subsea).<br><br>May mean the well has insufficient integrity and would be abandoned. | Dry Tree: <\$3 million (costs associated with 7 days loss of injection, tangibles and man days).<br><br>Abandonment \$15-25 (21 days & tangibles). |
| 48 | Xmas Tree seal leak | Seal failure will be an unsustainable well integrity state and require remediation. | | | | Requires multiple seal failures before there is a release to the biosphere. | | Possible repair by specific back-up components that are part of the wellhead design. Highly dependent on the design and ease of access.<br><br>May mean the Xmas Tree need to be removed/recovered to be repaired. This is a time consuming process for a subsea tree. | Dry Tree: <\$3 million (costs associated with 7 days loss of injection, tangibles and man days).<br><br>Subsea: \$12-15 million (12 days & tangibles). |

**Impact categories (CO2QUALSTORE)**

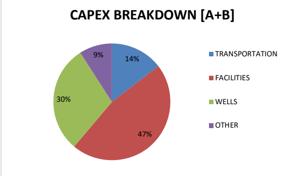
| **No.** | **1** | **2** | **3** | **4** | **5** |
|---|---|---|---|---|---|
| **Name** | Very Low | Low | Medium | High | Very High |
| **Impact on storage integrity** | None | Unexpected migration of $CO_2$ inside the defined storage complex | Unexpected migration of $CO_2$ outside the defined storage complex | Leakage to seabed or water column over small area (<100m2) | Leakage seabed water column over large area (>100m2) |
| **Impact on local environment** | Minor environmental damage | Local environmental damage of short duration | Time for restitution of ecological resource <2 years | Time for restitution of ecological resource 2-5 years | Time for restitution of ecological resource such as marine Biosystems, ground water >5 years |
| **Impact on reputation** | Slight or no impact | Limited impact | Considerable impact | National impact | International impact |
| **Consequence for Permit to operate** | None | Small fine | Large fine | Temporary withdrawal of permit | Permanent loss of permit |

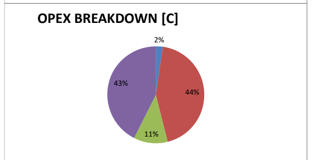
**Likelihood categories (CO2QUALSTORE)**

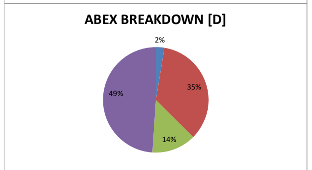
| **No.** | **1** | **2** | **3** | **4** | **5** |
|---|---|---|---|---|---|
| **Name** | Very Low | Low | Medium | High | Very High |
| **Description** | Improbable, negligible | Remotely probably, hardly likely | Occasional, likely | Probable, very likely | Frequent, to be expected |
| **Event (E)** | Very unlikely to occur during the next 5000 years | Very unlikely to occur during injection operations | Likely to occur during injection operations | May occur several times during injection operations | Will occur several times during injection operations |
| **Frequency** | About 1 per 5000 years | About 1 per 500 years | About 1 per 50 years | About 1 per 5 years | About 1 per year or more |
| **Feature (F)/ Process (P)** | Disregarded | Not expected | 50/50 chance | Expected | Sure |

| | | | |
|---|---|---|---|
| PROJECT | Strategic UK Storage Appraisal Project | | |
| TITLE | SITE 14: CAPTAIN AQUIFER | LEVEL 2 COST ESTIMATE | Pale Blue Dot. COSTAIN AXIS |
| CLIENT | ETI | | |
| REVISION | A1 | | |
| DATE | 21/03/2016 | | |

| | Category | Comment | Primary Cost (£ MM) | Overheads (£ MM) | Total Cost excl. Contingency (£ MM) | Contingency (%) | Total Cost inc. Contingency (£ MM) |
|---|---|---|---|---|---|---|---|
| ***A. Pre-Final Investment Decision (Pre-FID)*** | | including Pre-FEED / FEED Design and Engineering | **19.1** | **4.6** | **23.7** | | **30.8** |
| **A1.1** | **Transportation** | CO2 Pipeline System Pre-FEED/FEED Design | 0.6 | 0.2 | 0.8 | | 1.0 |
| **A1.2** | **Facilities** | Design of Platforms, Subsea Structures, Umbilicals, Power Cables | 4.5 | 2.0 | 6.5 | | 8.5 |
| **A1.3** | **Wells** | Pre-Feed / FEED Wells Engineering Design | 2.0 | 0.2 | 2.2 | | 2.9 |
| **A1.4** | **Other** | | 12.0 | 2.1 | 14.1 | 30% | 18.4 |
| **A1.4.1** | Seismic and Baseline Survey | Data Acquisition & Interpretation | 9.0 | 0.9 | 9.9 | | 12.9 |
| **A1.4.2** | Appraisal Well | Procurement for, and Drilling of, Appraisal Well(s) | 0.0 | 0.0 | 0.0 | | 0.0 |
| **A1.4.3** | Engineering and Analysis | Additional subsurface analysis and re-engineering if required | 2.0 | 0.2 | 2.2 | | 2.9 |
| **A1.4.4** | Licencing and Permits | Licenses, Permissions Permit, PLANC | 1.0 | 1.0 | 2.0 | | 2.6 |
| ***B. Post-Final Investment Decision (Post-FID)*** | | | **140.4** | **15.3** | **155.7** | **-** | **201.0** |
| **B1.1** | **Transportation** | | 24.1 | 1.0 | 25.1 | - | 32.7 |
| **B1.1.1** | Detailed Design | Detailed Design of CO2 Pipeline System | 0.4 | 0.1 | 0.5 | | 0.7 |
| **B1.1.2** | Procurement | Long lead items (linepipe, coatings etc) | 3.2 | 0.7 | 3.9 | 30% | 5.1 |
| **B1.1.3** | Fabrication | Spoolbase Fabrication and Coating etc | 3.6 | 0.2 | 3.8 | | 4.9 |
| **B1.1.4** | Construction and Commissioning | Logistics, Installation, WX, Function Testing and Commissioning | 17.0 | 0.0 | 17.0 | | 22.0 |
| **B1.2** | **Facilities** | | 68.0 | 8.6 | 76.5 | - | 99.5 |
| **B1.2.1** | Detailed Design | Design of Platforms, Subsea Structures, Umbilicals, Power Cables | 10.0 | 3.0 | 13.0 | | 16.9 |
| **B1.2.2** | Procurement | Jacket, Topsides, Templates, Umbilicals, Power Cables, etc | 17.1 | 4.5 | 21.6 | 30% | 28.1 |
| **B1.2.3** | Fabrication | Platform/NUI and Subsea Structures Fabrication | 18.4 | 1.1 | 19.5 | | 25.4 |
| **B1.2.4** | Construction and Commissioning | Logistics, Transportation, Installation, HUC | 22.4 | 0.0 | 22.4 | | 29.1 |
| **B1.3** | **Wells** | | 47.3 | 4.7 | 52.0 | - | 66.3 |
| **B1.3.1** | Detailed Design | including submission of OPEP (or CO2 equivalent) | 2.0 | 0.2 | 2.2 | | 2.9 |
| **B1.3.2** | Procurement | Wells long lead items - Trees, Tubing Hangers, etc | 9.3 | 0.9 | 10.2 | | 14.1 |
| **B1.3.3** | Fabrication | - | 0.0 | 0.0 | 0.0 | 30% | 0.0 |
| **B1.3.4** | Construction and Commissioning | Drilling/Intervention, WX | 36.0 | 3.6 | 39.6 | | 49.3 |
| | | Platform Injector 1-2 + MW | 36.0 | 3.6 | 39.6 | | 49.3 |
| | | Platform Injector 3-4 + MW2 | 0.0 | 0.0 | 0.0 | | 0.0 |
| **B1.4** | **Other** | | 1.0 | 1.0 | 2.0 | - | 2.6 |
| **B1.4.1** | Licencing and Permits | Licenses, Permissions Permit, PLANC | 1.0 | 1.0 | 2.0 | 30% | 2.6 |
| ***C. Total Operating Expenditure (OPEX)*** | | | **274.7** | **21.5** | **296.2** | **-** | **384.6** |
| **C1.1** | **OPEX - Transportation** | Inspections, Maintenance, Repair (IMR) | 6.4 | 0.3 | 6.7 | | 8.8 |
| **C1.2** | **OPEX - Facilities** | Manning, Power, IMR, Chemicals | 118.8 | 10.8 | 129.6 | | 168.4 |
| **C1.3** | **OPEX - Wells** | Workovers, Sidetracks, Power, Chemicals | 31.4 | 2.6 | 34.0 | | 43.7 |
| **C1.3.1** | **Well Sidetracks and Workovers** | Local Platform Sidetrack 1 | 15.6 | 1.5 | 17.1 | 30% | 22.0 |
| | | Local Platform Sidetrack 2 | 15.8 | 1.1 | 16.9 | | 21.7 |
| | | Local Platform Sidetrack 3 | 0.0 | 0.0 | 0.0 | | 0.0 |
| | | Local Platform Sidetrack 4 | 0.0 | 0.0 | 0.0 | | 0.0 |
| **C1.4** | **Other** | | 118.1 | 7.8 | 125.9 | - | 163.7 |
| **C1.4.1** | Measurement, Monitoring and Verification | includes data management and interpretation | 35.7 | 3.6 | 39.3 | | 51.1 |
| **C1.4.2** | Financial Securities | | 42.4 | 4.2 | 46.64 | 30% | 60.6 |
| **C1.4.3** | Ongoing Tariffs and Agreements | assume supplier covers 3rd party tariffs | 40.0 | 0.0 | 40 | | 52.0 |
| ***D. Abandonment (ABEX)*** | | | **133.8** | **11.1** | **144.9** | **-** | **187.2** |
| **D1.1** | **Decommissioning - Transportation** | 10% Transportation CAPEX | 3.4 | 0.3 | 3.7 | | 4.8 |
| **D1.2** | **Decommissioning - Facilities** | Que$tor | 45.6 | 4.6 | 50.2 | 30% | 65.3 |
| **D1.3** | **Decommissioning - Wells** | | 18.7 | 1.8 | 20.5 | | 25.5 |
| **D1.4** | **Other** | | 66.1 | 4.4 | 70.5 | - | 91.6 |
| **D1.4.1** | Post Closure Monitoring | includes data management and interpretation | 44.1 | 4.4 | 48.5 | 30% | 63.0 |
| **D1.4.2** | Handover | additional 10 years of coverage | 22.0 | 0.0 | 22.0 | | 28.6 |

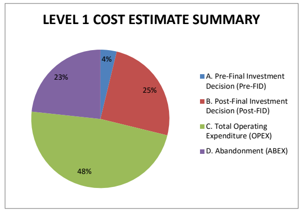



| | |
|---|---|
| FIELD LIFE (YEARS) | 20 |
| CO2 STORED (MT) | 60 |

| **DEFINITIONS** | |
|---|---|
| TRANSPORTATION | CO2 PIPELINE SYSTEM (LANDFALL & OFFSHORE PIPELINE) |
| FACILITIES | NUI's, SUBSEA STRUCTURES, UMBILICALS, POWER CABLES |
| WELLS | ALL COSTS ASSOCIATED WITH CO2 INJECTION WELLS |
| OTHER | ANY AND ALL COSTS NOT COVERED WITHIN ABOVE |
| PRIMARY COST | PRIMARY CONTRACT COSTS |
| OVERHEAD | ADDITIONAL OWNER'S COSTS COVERING OWNER'S PROJECT MANAGEMENT, VERIFICATION, ETC |




**CAPEX / OPEX / ABEX BREAKDOWN SUMMARY**

| COST | TOTAL COST (£ MM) | CATEGORY | COST (£ MM) |
|---|---|---|---|
| CAPEX [A + B] | 231.8 | TRANSPORTATION | 33.7 |
| | | FACILITIES | 108.0 |
| | | WELLS | 69.2 |
| | | OTHER | 21.0 |
| OPEX [C] | 384.6 | TRANSPORTATION | 8.8 |
| | | FACILITIES | 168.4 |
| | | WELLS | 43.7 |
| | | OTHER | 163.7 |
| ABEX [D] | 187.2 | TRANSPORTATION | 4.8 |
| | | FACILITIES | 65.3 |
| | | WELLS | 25.5 |
| | | OTHER | 91.6 |
| TOTAL | 803.6 | - | 803.6 |

**LEVEL 1 COST ESTIMATE SUMMARY**

| Category | Primary Cost (£ MM) | Overheads (£ MM) | Total Cost excluding Contingency (£ MM) | Total Cost inc. Contingency (£ MM) |
|---|---|---|---|---|
| A. Pre-Final Investment Decision (Pre-FID) | 19.1 | 4.6 | 23.7 | 30.8 |
| B. Post-Final Investment Decision (Post-FID) | 140.4 | 15.3 | 155.7 | 201.0 |
| C. Total Operating Expenditure (OPEX) | 274.7 | 21.5 | 296.2 | 384.6 |
| D. Abandonment (ABEX) | 133.8 | 11.1 | 144.9 | 187.2 |
| ***TOTAL COST (CAPEX, OPEX, ABEX)*** | | | 620.4 | **803.6** |
| ***COST CO2 INJECTED (£ PER TONNE)*** | | | £10.34 | **£13.39** |

| | | |
|---|---|---|
| **PROJECT** | Strategic UK Storage Appraisal Project | **TRANSPORTATION: PROCUREMENT & FABRICATION** |
| **TITLE** | SITE 14: CAPTAIN AQUIFER | |
| **CLIENT** | ETI | |
| **REVISION** | A1 | |
| **DATE** | 21/03/2016 | |

Pale Blue Dot. COSTAIN AXIS

| **Pipeline** | **Trunk Pipeline(s)** | **Infield Pipeline(s)** |
|---|---|---|
| **Number** | **ACQUISITION OF A&C PIPELINE** | 1 |
| **Route Length (km)** | | 8 |
| **Route Length Factor** | | 1.05 |
| **Pipeline Crossings** | | 1 |
| **Tee Structures** | | 0 |
| **Outer Diameter (mm)** | | 406.4 |
| **Wall Thickness (mm)** | | 14.3 |
| **Anode Spacing (m)** | | 300 |

| **No.** | **Item** | **Description** | **Unit Cost (£)** | **Unit** | **Qty** | **Total (£MM)** | **Overhead (£)** | **Description (Overheads)** | **Total Cost (£)** |
|---|---|---|---|---|---|---|---|---|---|
| **A. Pre-FID** | | | | | | | | | |
| **A1.1** | **Transportation - Pre FID** | | | | | | | | **£697.500** |
| A1.1.1 | Pre-FEED | Lump Sum | £200,000 | LS | 1.00 | £200,000 | £90,000 | *Company Time Writing, Contractor Surveillance* | £290,000 |
| A1.1.2 | FEED | Lump Sum | £350,000 | LS | 1.00 | £250,000 | £157,500 | *Company Time Writing, Contractor Surveillance* | £407,500 |
| **B. Post FID** | | | | | | | | | |
| **B1.1** | **Transportation - Post FID** | | | | | | | | **£8.158.916** |
| B1.1.1 | Detailed Design | Lump Sum | £400,000 | LS | 1.00 | £400,000 | £100,000 | *Company Time Writing, IVB, SIT, Insurance etc* | £500,000 |
| B1.1.2 | Procurement | | - | - | - | - | - | | **£3.888.916** |
| B1.1.2.1 | Acquisition of Atlantic & Cromarty pipeline | 16" St Fergus - Atlantic | £1,000,000 | LS | 1.00 | £1,000,000 | £50,000 | Cost of new pipeline = £100M | **£1.050.000** |
| B1.1.2.2 | Insurance and Certification | Infield pipeline | - | - | - | | £500,000 | *Insurance and Certification* | £500,000 |
| B1.1.2.3 | Geotechnical Testing | Infield pipeline | £2,000 | km | 8 | £16,800 | £28,000 | *Documentation etc* | £44,800 |
| B1.1.2.4 | *Procurement - Linepipe (Trunk)* | *API 5L X65, OD 406.4mm, WT 14.3mm* | £1,500 | Te | 1,162 | £1,743,000 | £104,580 | *Logistics/Freight @ 6%* | £1,847,580 |
| B1.1.2.5 | *Procurement - Coating (Trunk)* | *Corrosion Coating* | £20 | m | 8,400 | £168,000 | £10,080 | | £178,080 |
| B1.1.2.6 | *Procurement - Coating (Trunk)* | *Concrete Coating* | £30 | m | 8,400 | £252,000 | £15,120 | | £267,120 |
| B1.1.2.7 | *Procurement - Anodes (Trunk)* | *CP Protection* | £45 | Each | 28 | £1,260 | £76 | | £1,336 |
| B1.1.3 | Fabrication | | - | - | - | - | - | | **£3.770.000** |
| B1.1.3.1 | SSIV | Subsea Isolation Valve Structure | £1,500,000 | LS | 1 | £1,500,000 | £100,000 | *Contractor Surveillance* | £1,600,000 |
| B1.1.3.2 | *Spoolbase Fabrication* | *Coating Only (S Lay)* | £50 | m | 8,400 | £420,000 | £50,000 | *Contractor Surveillance* | £470,000 |
| B1.1.3.3 | *Crossing Supports* | *Concrete Crossing Plinth/Supports* | £100,000 | Per Crossing | 1 | £100,000 | £20,000 | *Contractor Surveillance* | £120,000 |
| B1.1.3.4 | *Anode Skid Structure (every 2.5km)* | *For existing 78km pipeline* | £50,000 | Each | 31 | £1,560,000 | £20,000 | *Contractor Surveillance* | £1,580,000 |
| | | | | | | **Total (Excluding Contingency)** | | | **£8,856,416** |
| | | | | | | **Pre-FID Contingency (%)** | | **30%** | **£209,250** |
| | | | | | | **Post-FID Contingency (%)** | | **30%** | **£2,447,675** |
| | | | | | | **Total (Including Contingency)** | | | **£11,513,340** |

| | | |
|---|---|---|
| **PROJECT** | Strategic UK Storage Appraisal Project | **TRANSPORTATION: CONSTRUCTION AND COMMISSIONING** |
| **TITLE** | SITE 14: CAPTAIN AQUIFER | |
| **CLIENT** | ETI | |
| **REVISION** | A1 | |
| **DATE** | 21/03/2016 | |

Pale Blue Dot. COSTAIN AXIS

| Pipeline | Trunk Pipeline(s) | Infield Pipeline(s) |
|---|---|---|
| Number | | 1 |
| Route Length (km) | | 8 |
| Route Length Factor | | 1.05 |
| Pipeline Crossings | | 1 |
| Outer Diameter (mm) | | 406.4 |
| Wall Thickness (mm) | | 14.3 |
| Anode Spacing (m) | | 300 |
| Landfall Required? | NO | - |

| Activity | Vessel | Dayrate (£) | Working Rate (m/hr) |
|---|---|---|---|
| Pipeline Route Survey | Survey Vessel | £100,000 | 750 |
| Pipelay (Reel) | Reel Lay Vessel | £150,000 | 500 |
| Pipelay (S-Lay) | S-Lay Vessel (14000Te) | £350,000 | 100 |
| Trenching and Backfill | Ploughing Vessel | £100,000 | 400 |
| Crossing Installation | Survey Vessel | £100,000 | - |
| Spoolpiece Tie-ins | DSV | £150,000 | - |
| Commissioning | Survey Vessel | £100,000 | - |
| Pipelay (Carrier) | Pipe Carrier (1600Te) | £50,000 | - |
| Structure Installation | DSV | £150,000 | - |

| | |
|---|---|
| **Landfall Cost** | |

| No. | Activity | Breakdown | Vessel | Day Rate (£) | Days | Sub-Total (£) | Total Cost (£) |
|---|---|---|---|---|---|---|---|
| **B. Post FID** | | | | | | | |
| **B1.1** | **Transportation - Post FID** | | | | | | |
| B1.1.4 | **Construction and Commissioning** | | | | | | |
| B1.1.4.1 | Pipeline Route Survey | Mobilisation | Survey Vessel | £100,000 | 2 | £200,000 | £500,000 |
| | | Infield Operations | | | 1 | £100,000 | |
| | | Demobilisation | | | 2 | £200,000 | |
| B1.1.4.2 | Pipelay (S-Lay) | Mobilisation | S-Lay Vessel (14000Te) | £350,000 | 2 | £700,000 | £2,800,000 |
| | | Infield Operations | | | 4 | £1,400,000 | |
| | | Demobilisation | | | 2 | £700,000 | |
| B1.1.4.3 | Crossing Installation | Mobilisation | Survey Vessel | £100,000 | 2 | £200,000 | £700,000 |
| | | Infield Operations - 3 day per Crossing | | | 3 | £300,000 | |
| | | Demobilisation | | | 2 | £200,000 | |
| B1.1.4.4 | Spoolpiece Tie-ins | Mobilisation | DSV | £150,000 | 2 | £200,000 | £1,400,000 |
| | | Infield Operations | | | 10 | £1,000,000 | |
| | | Demobilisation | | | 2 | £200,000 | |
| B1.1.4.5 | Commissioning | Mobilisation | Survey Vessel | £100,000 | 2 | £200,000 | £600,000 |
| | | Infield Operations | | | 2 | £200,000 | |
| | | Demobilisation | | | 2 | £200,000 | |
| B1.1.4.6 | Structure Installation | Mobilisation | DSV | £150,000 | 12 | £1,800,000 | £6,000,000 |
| | | Infield Operations -SSIV and Anode Skids | | | 16 | £2,400,000 | |
| | | Demobilisation | | | 12 | £1,800,000 | |
| B1.1.4.7 | Mattress Installation (Anode Skid Protection) | Mobilisation | Survey Vessel | £100,000 | 4 | £400,000 | £1,600,000 |
| | | Infield Operations | | | 8 | £800,000 | |
| | | Demobilisation | | | 4 | £400,000 | |
| B1.1.4.8 | Construction Project Management and Engineering | | - | Lump Sum (10%) | - | £1,360,000 | £1,360,000 |
| B1.1.4.9 | A&C pipeline prep - inspection, intelligent pigging etc. | | - | Lump Sum | - | £2,000,000 | £2,000,000 |
| | | | | | **Total (Excluding Contingency)** | | **£16,960,000** |
| | | | | | **Contingency** | **30%** | **£5,088,000** |
| | | | | | **Total (Including Contingency)** | | **£22,048,000** |

| | | |
|---|---|---|
| PROJECT | Strategic UK Storage Appraisal Project | Facilities: PROCUREMENT & FABRICATION |
| TITLE | SITE 14: CAPTAIN AQUIFER | |
| CLIENT | ETI | |
| REVISION | A1 | |
| DATE | 21/03/2016 | |

**COSTS EXTRACTED FROM QUE$TOR**

| Exchange Rate (£:$) | 1.50 |
|---|---|

| No. | Item | Description | Unit Cost (£) | Unit | Qty | Total (£MM) | Overhead (£) | Description (Overheads) | Total Cost (£) |
|---|---|---|---|---|---|---|---|---|---|
| **A. Pre-FID** | | | | | | | | | |
| **A1.2** | **Facilities - Pre FID** | | | | | | | | **£6,525,000** |
| A1.2.1 | Pre-FEED | 4 Legged Jacket, Topsides | £1,500,000 | LS | 1 | £1,500,000 | £675,000 | *Company Time Writing, Contractor Surveillance* | £2,175,000 |
| A1.2.2 | FEED | 4 Legged Jacket, Topsides | £3,000,000 | LS | 1 | £3,000,000 | £1,350,000 | *Company Time Writing, Contractor Surveillance* | £4,350,000 |
| **B. Post FID** | | | | | | | | | |
| **B1.2** | **Facilities - Post FID** | | | | | | | | **£76,532,309** |
| B1.2.1 | Detailed Design | 4 Legged Jacket, Topsides | £10,000,000 | LS | 1 | £10,000,000 | £3,000,000 | *Company Time Writing, IVB, SIT etc* | **£13,000,000** |
| B1.2.2 | Procurement | | - | - | - | | - | - | **£21,603,707** |
| | Jacket | 4 Legged Jacket | - | - | - | | - | - | ***£11,428,935*** |
| B1.2.2.1.1 | Insurance and Certification | | - | - | - | | £2,351,333 | *Insurance and Certification* | £2,351,333 |
| B1.2.2.1.2 | *Jacket Steel* | | £1,333 | Te | 3,831 | £5,108,000 | £306,480 | | £5,414,480 |
| B1.2.2.1.3 | *Piles* | | £1,301 | Te | 2,057 | £2,675,471 | £160,528 | *Logistics/Freight @ 6%* | £2,836,000 |
| B1.2.2.1.4 | *Anodes* | | £3,685 | Te | 153 | £563,856 | £33,831 | | £597,687 |
| B1.2.2.1.5 | *Installation Aids* | | £1,127 | Te | 192 | £216,448 | £12,987 | | £229,435 |
| | Topsides | | - | - | - | | - | - | ***£10,174,772*** |
| B1.2.2.2.1 | Insurance and Certification | | - | - | - | | £1,086,000 | *Insurance and Certification* | £1,086,000 |
| B1.2.2.2.2 | *Primary Steel* | | £1,087 | Te | 179 | £194,513 | £11,671 | | £206,184.13 |
| B1.2.2.2.3 | *Secondary Steel* | | £900 | Te | 110 | £99,000 | £5,940 | | £104,940.00 |
| B1.2.2.2.4 | *Piping* | | £10,733 | Te | 30 | £322,000 | £19,320 | | £341,320.00 |
| B1.2.2.2.5 | *Electrical* | | £19,200 | Te | 15 | £288,000 | £17,280 | | £305,280.00 |
| B1.2.2.2.6 | *Instrumentation* | | £36,333 | Te | 13 | £472,333 | £28,340 | | £500,673.33 |
| B1.2.2.2.7 | *Miscellaneous* | | £8,800 | Te | 20 | £176,000 | £10,560 | | £186,560.00 |
| B1.2.2.2.8 | *Manifolding* | | £14,733 | Te | 15 | £221,000 | £13,260 | | £234,260.00 |
| B1.2.2.2.9 | *Control and Communications* | *Sat Comms* | £460,733 | Te | 5 | £2,303,667 | £138,220 | | £2,441,886.67 |
| B1.2.2.2.10 | *General Utilities* | *Drainage, Diesel Storage etc* | £50,000 | Te | 4 | £200,000 | £12,000 | *Logistics/Freight @ 6%* | £212,000.00 |
| B1.2.2.2.11 | *Vent Stack* | *Low Volume (venting done at beach)* | £6,933 | Te | 35 | £242,667 | £14,560 | | £257,226.67 |
| B1.2.2.2.12 | *Diesel Generators* | *Power Generation* | £52,067 | Te | 18 | £937,200 | £56,232 | | £993,432.00 |
| B1.2.2.2.13 | *Power Distribution* | | £36,067 | Te | 5 | £180,333 | £10,820 | | £191,153.33 |
| B1.2.2.2.14 | *Emergency Power* | | £34,733 | Te | 2 | £69,467 | £4,168 | | £73,634.67 |
| B1.2.2.2.15 | *Quarters and Helideck* | *50 Te Helideck plus TR* | £23,333 | Te | 70 | £1,633,333 | £98,000 | | £1,731,333.33 |
| B1.2.2.2.16 | *Crane* | *Mechanical Handling* | £19,267 | Te | 30 | £578,000 | £34,680 | | £612,680.00 |
| B1.2.2.2.17 | *Lifeboats* | *Freefall Lifeboats* | £24,400 | Te | 7 | £170,800 | £10,248 | | £181,048.00 |
| B1.2.2.2.18 | *Chemical Injection* | *Chemicals, Pumps, Storage* | £46,600 | Te | 10 | £466,000 | £27,960 | | £493,960.00 |
| B1.2.2.2.19 | *PLR* | *Pig Reciever* | £10,000 | Te | 2 | £20,000 | £1,200 | | £21,200.00 |
| B1.2.3 | Fabrication | | - | - | | | - | | **£19,506,044** |
| | Jacket | | - | - | | | - | | ***£16,332,016*** |
| B1.2.3.1 | *Jacket Steel* | | £3,245 | m | 3,831 | £12,430,318 | £745,819 | | £13,176,137 |
| B1.2.3.2 | *Piles* | | £1,022 | m | 2,057 | £2,102,254 | £126,135 | *Logistics/Freight @ 6%* | £2,228,389 |
| B1.2.3.3 | *Anodes* | | £755 | Each | 153 | £115,566 | £6,934 | | £122,500 |
| B1.2.3.4 | *Installation Aids* | | £3,955 | | 192 | £759,424 | £45,565 | | £804,989 |
| | Topsides | | - | | - | | - | - | ***£3,174,029*** |
| B1.2.3.2.1 | *Primary Steel* | | £5,467 | Te | 179 | £978,533 | £58,712 | | £1,037,245 |
| B1.2.3.2.2 | *Secondary Steel* | | £7,200 | Te | 110 | £792,000 | £47,520 | | £839,520 |
| B1.2.3.2.3 | *Equipment* | | £1,513 | Te | 75 | £113,500 | £6,810 | | £120,310 |
| B1.2.3.2.4 | *Piping* | | £14,867 | Te | 30 | £446,000 | £26,760 | *Logistics/Freight @ 6%* | £472,760 |
| B1.2.3.2.5 | *Electrical* | | £26,467 | Te | 15 | £397,000 | £23,820 | | £420,820 |
| B1.2.3.2.6 | *PLR* | *Pig Reciever* | £25,000 | Te | 2 | £50,000 | £3,000 | | £53,000 |
| B1.2.3.2.7 | *Miscellaneous* | | £10,867 | Te | 20 | £217,333 | £13,040 | | £230,373 |
| B1.2.4 | Construction and Commissioning | | - | - | - | | - | - | **£22,422,557** |
| *B1.2.4.1* | Installation Spread | Jacket Installation | £596,206 | Days | 28 | £16,693,768 | £0 | - | £16,693,768 |
| *B1.2.4.2* | Installation Spread | Topsides Installation | £135,533 | Days | 7 | £948,733 | £0 | - | £948,733 |
| *B1.2.4.3* | *Tug Transport - Jacket* | *Mobilisation* | £57,236 | Days | 4 | £228,944 | £0 | - | £228,944 |
| | | *Infield Operations* | £57,236 | Days | 16 | £915,776 | £0 | - | £915,776 |
| | | *Demobilisation* | £57,236 | Days | 4 | £228,944 | £0 | - | £228,944 |
| *B1.2.4.4* | *Barge Transport - Jacket* | *Mobilisation* | £8,672 | Days | 4 | £34,688 | £0 | - | £34,688 |
| | | *Infield Operations* | £8,672 | Days | 56 | £485,632 | £0 | - | £485,632 |
| | | *Demobilisation* | £8,672 | Days | 4 | £34,688 | £0 | - | £34,688 |
| *B1.2.4.5* | *Tug Transport - Topsides* | *Mobilisation* | £57,236 | Days | 4 | £228,944 | £0 | - | £228,944 |
| | | *Infield Operations* | £57,236 | Days | 30 | £1,717,080 | £0 | - | £1,717,080 |
| | | *Demobilisation* | £57,236 | Days | 4 | £228,944 | £0 | - | £228,944 |
| *B1.2.4.6* | *Barge Transport - Topsides* | *Mobilisation* | £8,672 | Days | 4 | £34,688 | £0 | - | £34,688 |
| | | *Infield Operations* | £8,672 | Days | 70 | £607,040 | £0 | - | £607,040 |
| | | *Demobilisation* | £8,672 | Days | 4 | £34,688 | £0 | - | £34,688 |
| | | | | **Total (Excluding Contingency)** | | | | | **£83,057,309** |
| | | | | **Pre-FID Contingency (%)** | | | | **30%** | **£1,957,500** |
| | | | | **Post-FID Contingency (%)** | | | | **30%** | **£22,959,693** |
| | | | | **Total (Including Contingency)** | | | | | **£107,974,502** |

| | | |
|---|---|---|
| **PROJECT** | Strategic UK Storage Appraisal Project | **WELLS: COST SUMMARY** |
| **TITLE** | SITE 2: FORTIES 5 - NORTH SITE | |
| **CLIENT** | ETI | |
| **REVISION** | DRAFT | |
| **DATE** | 42382 | |

Pale Blue Dot. COSTAIN AXIS

**Well Cost Summary (including 30% Contingency)**

| Well Name | Days | Well Cost (£,000) |
|---|---|---|
| **Year 0** | | |
| **Platform Injector 1** | 54.0 | 21897.9 |
| **Platform Injector 2** | 47.5 | 19473.4 |
| **Monitoring Well 1 / Spare Injector** | 52.5 | 21138.4 |
| **Year 10** | | |
| **Local Platform Sidetrack 1** | 58.5 | 22015.5 |
| **Local Platform Sidetrack 2** | 58.5 | 21680.5 |
| **Year 20** | | |
| **Platform Injector 3** | | |
| **Platform Injector 4** | | |
| **Monitoring Well 1 / Spare Injector** | | |
| **Year 30** | | |
| **Local Platform Sidetrack 3** | | |
| **Local Platform Sidetrack 4** | | |
| **Year 40** | | |
| **Abandonment Platform Injector 1** | 27.3 | 9178.9 |
| **Abandonment Platform Injector 2** | 20.8 | 8169.4 |
| **Abandonment Monitoring Well 1** | 20.8 | 8169.4 |
| **Abandonment Platform Injector 4** | | |
| **Abandonment Platform Injector 5** | | |
| **Abandonment Monitoring Well 2** | | |
| **TOTAL** | 339.8 | 131723.3 |

Note: This figure does not include the PM & Eng costs.

**Drilling Overhead Cost Summary**

| Drilling Campaign | Overhead (£MM) |
|---|---|
| Platform Injector 1-2 + MW | 3.60 |
| Platform Injector 3-4 + MW2 | |
| Abandonment | 1.80 |

**OPEX Overhead Cost Summary**

| OPEX Campaign | Overhead (£MM) |
|---|---|
| Local Platform Sidetrack 1 | 1.50 |
| Local Platform Sidetrack 2 | 1.05 |
| Local Platform Sidetrack 3 | |
| Local Platform Sidetrack 4 | |

**Wells Cost Estimate - Primary Cost Summary**

| Activity | Drilling Costs | | | Procurement Costs (£,000) | | Total Cost (£,000) |
|---|---|---|---|---|---|---|
| | Phase Rig Cost (£,000) | Phase Spread Cost (£,000) | Contingency (£,000) | Procurement (£,000) | Contingency (£,000) | |
| **Development Wells - CAPEX Breakdown** | | | | | | |
| Platform Injector 1 | 5,520 | 6,875 | 3,523 | 4,600 | 1,380 | 21,898 |
| Platform Injector 2 | 4,855 | 6,125 | 3,099 | 4,150 | 1,245 | 19,473 |
| Monitoring Well 1 / Spare Injector | 5,520 | 7,125 | 3,099 | 4,150 | 1,245 | 21,138 |
| Platform Injector 3 | | | | | | |
| Platform Injector 4 | | | | | | |
| Monitoring Well 1 / Spare Injector | | | | | | |
| **Wells - OPEX Breakdown** | | | | | | |
| Local Platform Sidetrack 1 | 5,985 | 7,400 | 3,821 | 3,700 | 1,110 | 22,016 |
| Local Platform Sidetrack 2 | 5,985 | 7,650 | 3,821 | 3,250 | 975 | 21,681 |
| Local Platform Sidetrack 3 | | | | | | |
| Local Platform Sidetrack 4 | | | | | | |
| **Wells - ABEX Breakdown** | | | | | | |
| Abandonment Platform Injector 1 | 2,926 | 3,300 | 1,783 | 900 | 270 | 9,179 |
| Abandonment Platform Injector 2 | 2926 | 3300 | 1358.4 | 450 | 135 | 8169.4 |
| Abandonment Monitoring Well 1 | 2926 | 3300 | 1358.4 | 450 | 135 | 8169.4 |
| Abandonment Platform Injector 4 | | | | | | |
| Abandonment Platform Injector 5 | | | | | | |
| Abandonment Monitoring Well 2 | | | | | | |

| CAPEX Summary | Excluding Contingency (£MM) | Overhead (£MM) | Overhead Description | Sub-Total (£MM) | Contingency | | Total Cost (£MM) |
|---|---|---|---|---|---|---|---|
| | | | | | % | £MM | |
| Pre-FEED / FEED PM & E | 2.0 | 0.2 | Company Time Writing, IVB, SIT, Insurance etc | 2.2 | 30% | 0.7 | **2.9** |
| Detailed Design PM & E | 2.0 | 0.2 | | 2.2 | 30% | 0.7 | **2.9** |
| Procurement | 9.3 | 0.9 | | 10.2 | 30% | 3.9 | **14.1** |
| Construction and Commissioning (Drilling) | 36.0 | 3.60 | Well Management Fees, Insurance, Site Survey, Studies etc. | 39.6 | 30% | 9.7 | **49.3** |
| **Total** | **258.6** | **16.6** | | **275.2** | **-** | **43.6** | **69.2** |

| OPEX Summary | Excluding Contingency (£MM) | Overhead (£MM) | Overhead Description | Sub-Total (£MM) | Contingency | | Total Cost (£MM) |
|---|---|---|---|---|---|---|---|
| | | | | | % | £MM | |
| OPEX | 31.4 | 2.55 | Well Management Fees, Insurance, Site Survey, Studies etc. | 34.0 | 30% | 9.7 | **43.7** |

| ABEX Summary | Excluding Contingency (£MM) | Overhead (£MM) | Overhead Description | Sub-Total (£MM) | Contingency | | Total Cost (£MM) |
|---|---|---|---|---|---|---|---|
| | | | | | % | £MM | |
| ABEX | 18.7 | 1.80 | Well Management Fees, Insurance, Site Survey, Studies etc. | 20.5 | 30% | 5.0 | **25.5** |

**Level 1 Cost Estimate Summary - Wells**

| | |
|---|---|
| Total CAPEX (£MM) | 69.2 |
| Total OPEX (£MM) | 43.7 |
| Total ABEX (£MM) | 25.5 |
| **TOTAL (£MM)** | **138.4** |