Programme Area: Carbon Capture and Storage

Project: DECC Storage Appraisal

Title: WP5B – Forties 5 Site 1 Storage Development Plan

Abstract:

Storage in the Forties Sandstone in the Forties 5 aquifer in UKCS quadrant 22 in the Central North Sea. 9 well, phased development of Forties 5 Site 1 from an unmanned platform and subsea tie-back, supplied with CO2 from St. Fergus via a 24” 217km pipeline. Final investment decision in 2025 and first injection in 2030. Capital investment of £284 million (PV10, 2015), equating to £0.9 for each tonne stored. The store can contain the 300Mt from the CO2 supply profile of up to 8Mt/y over a 40 year period. Good subsurface data but further appraisal drilling required.

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.

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AXIS WELL TECHNOLOGY

D11: WP5B – Forties 5 Site 1 Storage Development Plan

10113ETIS-Rep-18-03

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Document Summary			
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Disclaimer:

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9 well, phased development of Forties 5 Site 1 from an unmanned platform and subsea tie-back, supplied with CO_2 from St. Fergus via a 24" 217km pipeline.

Final investment decision in 2025 and first injection in 2030.

Capital investment of £284 million (PV_{10}, 2015), equating to £0.9 for each tonne stored.

The store can contain the 300Mt from the CO_2 supply profile of up to 8Mt/y over a 40 year period.

Good subsurface data but further appraisal drilling required.

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 the 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 Forties 5 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 Forties 5 aquifer covers a huge area and could potentially accommodate multiple CO_2 stores. A site selection process considered 5 potential sites and identified Site 1 as the most suitable for this study (Pale Blue Dot Energy; Axis Well Technology, 2015).

Site 1 covers an area of 1634 km^2 towards the east of the Forties 5 aquifer in UKCS quadrant 22, approximately 190 km from Aberdeen as illustrated in Figure 1-1. The primary storage unit is the Forties Sandstone Member within the Sele Formation of the Eocene/Palaeocene Moray Group. The primary seal are the mudstones within the Sele Formation (Figure 1-2).

The Forties Sandstone consists of channel-dominated turbidite deposits of generally moderate to good reservoir quality, with porosity ranging between 16 - 18%. Shales are not believed to be laterally extensive in the site model, baffling rather than impeding fluid flow.

Secure containment is provided by laterally extensive mudstones and shale of the Sele Formation which are a proven seal for multiple hydrocarbon fields in the Central North Sea and provides an excellent caprock for the storage complex described in Section 3.7.

A seismic interpretation was carried out on the PGS Central North Sea MegaSurvey. The geological model is based on this interpretation and the petrophysical evaluation of 45 regional wells, 16 of which are within the site and also have core data. 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. Within the predicted plume area there are two legacy wells which represent a specific containment concern. These are 22/8a-3 and 22/15-1 and will require further assessment.

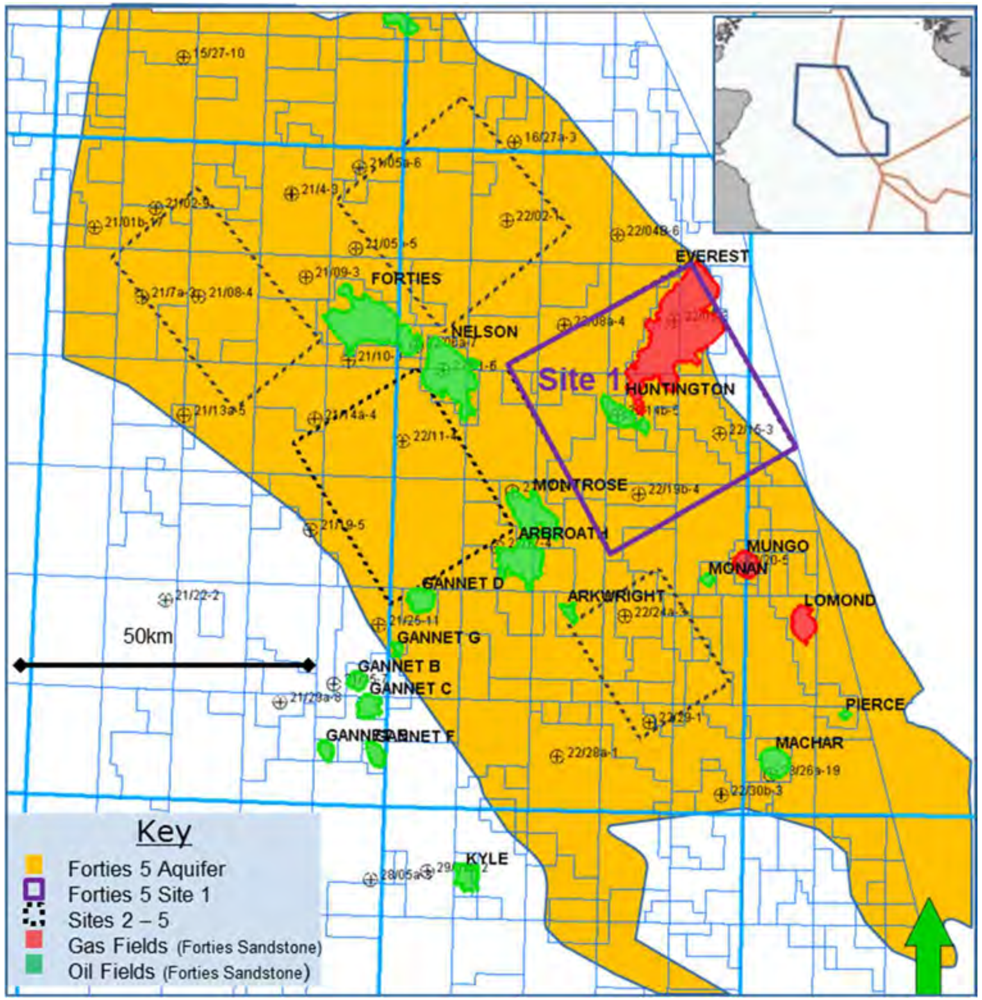


Figure 1-1 Forties 5 Site 1 Location Map

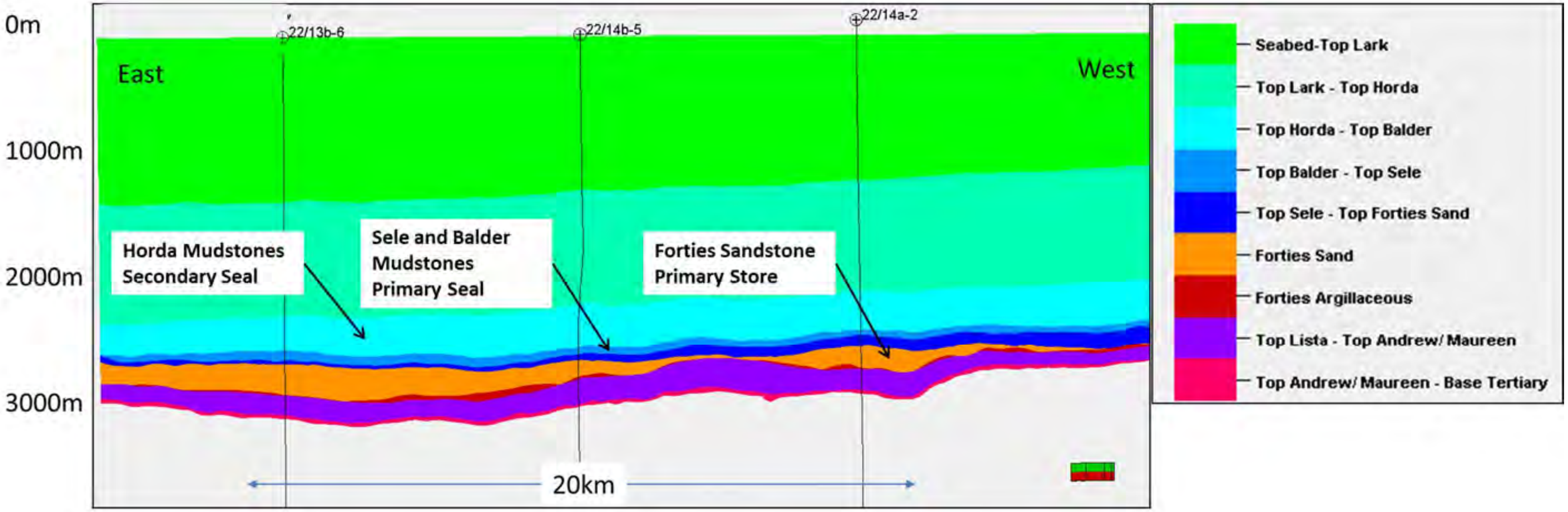


Figure 1-2 Forties 5 Site 1 Store and Seals

The basis for the development plan is an assumed CO_2 supply of 6Mt/y to be provided from the shore terminal at St. Fergus commencing in 2030 and increasing to 8Mt/y from 2040. CO_2 will be transported offshore in liquid-phase via a new 217km 24" pipeline from St. Fergus to a newly installed Normally Unmanned Installation (NUI), minimum facilities platform on a 4 legged steel jacket standing in 85m of water. During the operational period nine wells are required to accommodate the supply profile.

Geological and reservoir engineering work has concluded that the Forties 5 Site 1 is well connected hydraulically but with variable reservoir quality so that storage capacity is sensitive to well placement. Injection wells are postioned in the lower layers of reservoir to maximise the site's storage efficiency by creating a tortuous path to the crest of the reservoir. Injectivity is expected to be fair and horizontal wells are required in the reservoir section to achieve the target injection rates of 1 - 2Mt/y per well.

During the main operational period, 8 of the wells are expected to be injecting at any point in time with the 9th as backup in the event of an unforeseen well problem. In this manner, the facilities will maintain a robust injection capacity and inject 6-8Mt/y of CO_2 for the 40 year project life without breaching the safe operating envelope. Over the period, a total of 300Mt CO_2 will have been contained within the storage complex.

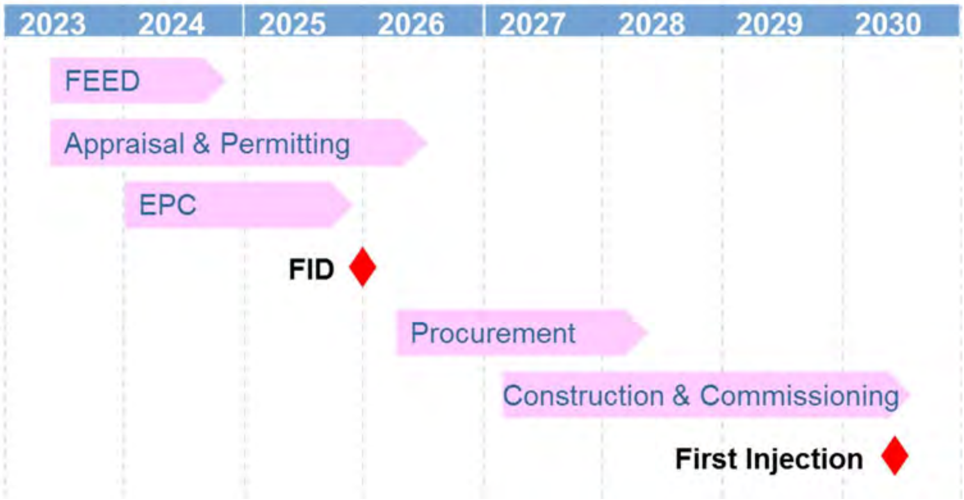


Figure 1-3 Summary Development Schedule

The development schedule has 5 main phases of activity and is anticipated to require 7 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 2025. The capital intensive activities of procurement and construction follow FID and take place over a 4-5 year period. First injection is forecast to be in mid-2030, several years after hydrocarbon fields in the area are expected to have ceased producing.

The development of the offshore transportation and injection infrastructure is estimated to require a capital investment of £284 million (in present value terms discounted at 10% to 2015), equating to £0.7/t. The life-cycle levelised costs are estimated to be £410 million (PV10), equating to £26.0/t, as summarised in Table 1-1.

£million (PV_{10}, 2015)	Phase I	Phase II	Total
Transportation	122	5	127
Facilities	36	4	40
Wells	87	30	117
Opex	97	25	121
Decommissioning & MMV	3	2	5
Total	344	66	410

Table 1-1 Project Cost Estimate (PV10, 2015)

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

- Acquire a new 3-D seismic survey and use it to improve the characterisation of reservoir quality and architecture.
- Identify opportunities for cost and risk reduction across the whole 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

Forties 5 Site 1 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 and are listed in Appendix 11.

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.

Data Collection & Maintenance
3D seismic
Petrophysical logs
Well reports
Cost benchmarks

Seismic Interpretation and Structural Model
Interpret and map key horizons
Geological setting and character
Build static model
Subsurface uncertainty analysis

Containment
Define the Storage Complex
Identify leakage scenarios
Assess geomechanics impact
Assess geochemical implications

Well Design
Well construction design
Well performance modelling
Identify risks from legacy wells
Define operating envelope

Site Performance Modelling
Define CO2 supply scenario
Optimise number & location of wells
Assess storage capacity potential
Estimate extent of CO2 plume after 1000 years

Development Planning
Offshore infrastructure design
Design monitoring and remediation plans
Prepare cost estimate
Create development schedule

Storage Development Plan and Digital Library
Write IP compliant storage development plan and budget
Create IP compliant library of digital output from the project
Facilitate incorporation of digital output into the CO2Stored database

Figure 2-2 Seven components of Workpack 5

3.0 Site Characterisation

3.1 Geological Setting

The Forties 5 open aquifer system was selected as part of a portfolio of five target storage sites in the Strategic UK CCS Storage Appraisal Project. The 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 Selection (Pale Blue Dot Energy; Axis Well Technology, 2015)

The primary storage unit is the Forties Sandstone Member of the Palaeocene age Sele Formation.

The Forties Sand Member is an elongate (NW-SE) sand rich turbidite fan system which is present across a large area of the Central North Sea, extending to an area of over 20,000km^2. It is a prolific hydrocarbon reservoir with many producing fields such as Forties, Nelson, Montrose-Arbroath, Everest, Pierce, the Gannet cluster and Guillemot A.

The sheer size of the unit meant that it was not sensible to consider the development of the whole aquifer in a single phase. A supplementary work scope was carried out to identify an appropriate site to initiate CO_2 injection within the Forties 5 unit such that the potential of open aquifer systems can be developed and matured. This is fully documented in the following report:

- D07: WP5 Report – Forties 5 Aquifer Storage Site Selection Study (10113ETIS-Rep-08-1.4 September 2015)

The selected site (Forties 5 Site 1) covers an area of 1634 km^2 and is located in the east of the Forties sandstone aquifer, approximately 190km from the Aberdeen coast in Quadrants 22 and 23. Site 1 was selected because it has a good combination of substantial capacity and low containment risk and this combination probably offers the best opportunity for the first development of CO_2 storage within the Forties aquifer system.

The Site 1 area includes the Everest (gas) and Huntington (oil) fields, both of which have Forties Sandstone reservoirs. Everest also contains gas in the underlying Andrew and Maureen Formations. At the western boundary of the site there are two deeper Upper Jurassic sand oil fields; Howe and Bardolino. These deeper reservoirs are not connected to the Forties 5 aquifer.

The distribution of the Forties Sandstone Member in the UK sector of the CNS, and the Site 1 location, is shown in Figure 3-1.

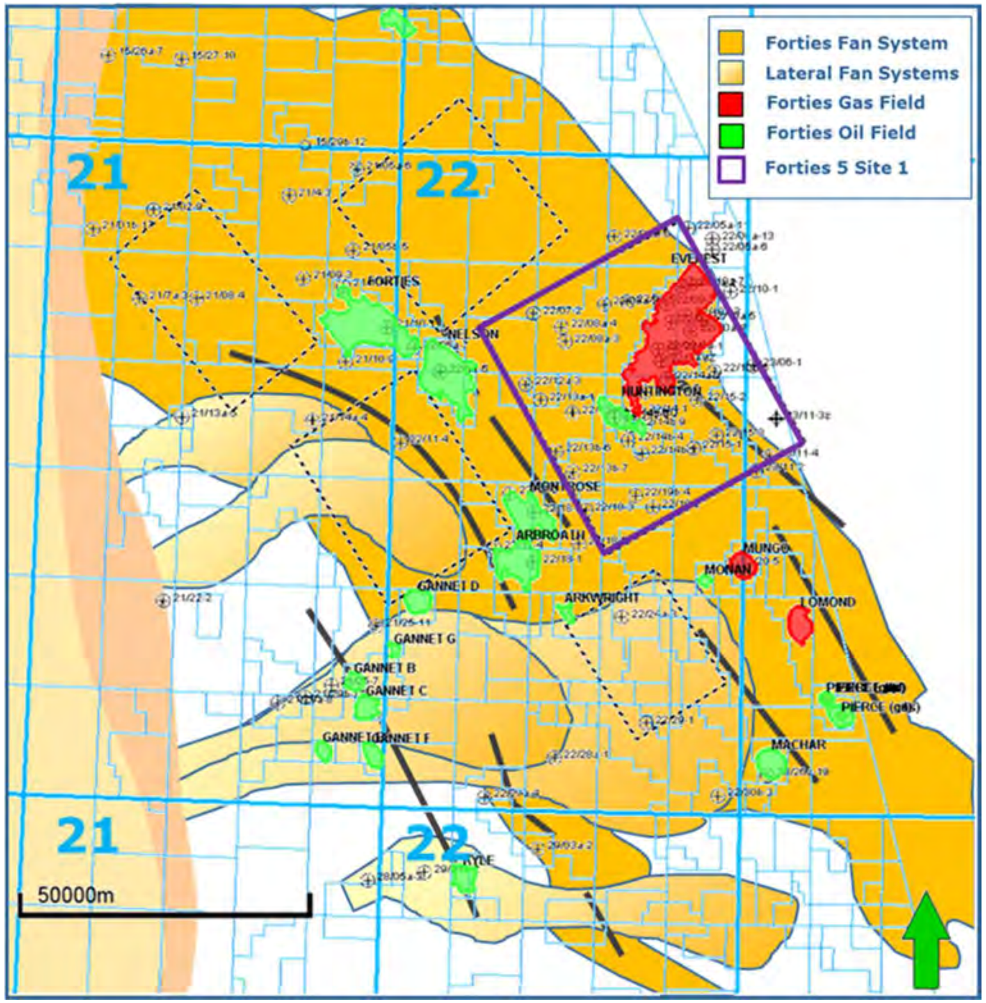


Figure 3-1 Map of site location and Forties fan extent

3.2 Site History and Database

3.2.1 History

Forties 5 Site 1 is part of a large open aquifer system which dips gently to the south and southeast at approximately 1 – 2 degrees, although local dips can be up to 5 degrees. Within the site are two hydrocarbon fields which rely on a combination of pinch out or shale out and dip closure related to sediment drape over older structural highs, for trapping.

During the early Tertiary thermal uplift of Scotland and the East Shetland platform, associated with the opening of the Atlantic, large volumes of clastic sediment were shed into the North Sea Basin from the North. These were deposited as extensive submarine fans in the Central Graben.

Early Tertiary sedimentation was controlled by Pre-Tertiary structures, with clastic sediments accumulating in the axial regions of grabens formed during Late Jurassic rifting, with little or no sedimentation over previous highs. By late Palaeocene these topographic highs had been buried and the distribution of later submarine fan lobes and associated channels systems were controlled by differential subsidence over the underlying palaeo-highs.

There is no evidence of significant faulting in the Forties within the site area. There are a small number of small faults that have been interpreted, but none of these compromise the integrity of the top seal.

3.2.2 Hydrocarbon Exploration

Within the Central North Sea (CNS) the Forties Sandstone is a prolific hydrocarbon reservoir with many producing fields such as Forties, Nelson, Arbroath - Montrose, Pierce, the Gannet cluster and Guillemot A. The top seal for these is provided by the overlying mudstones of the Sele Formation.

The Everest (gas) and Huntington (oil) fields are both within the site area and have Forties Sandstone reservoirs. First production and expected Cessation of Production dates are shown below:

Everest: First gas 1993 CoP 2026

Huntington: First oil 2013 CoP expected prior to 2020

Everest is a 3-way dip closure with sand pinch-out to the NE. Huntington Forties oil is probably trapped in a combined dip and stratigraphic trap. There is a good chance that there are small, and sub commercial hydrocarbon accumulations in the Forties, e.g. 22/15-3 (Banks) as well as water bearing 4-way dip closures. It is possible that hydrocarbon filled closures in the Forties Sandstone will have a direct hydrocarbon indicator on seismic data. Modelling would be required to understand the minimum accumulation that could be seen on the seismic. Small hydrocarbon accumulations would be largely bypassed by injected CO_2 and as a result, plume migration velocity may not be slowed. It is expected that this would have a minor impact upon CO_2 storage efficiency and capacity due to the size of the site.

The Late Jurassic age Kimmeridge Clay Formation is the source rock for the hydrocarbons, which have migrated into the Palaeocene Forties Sandstone via the extensional faults running N-S at the margin of the Forties-Montrose High (Hogg, 2003).

3.2.3 Seismic

There are many 2D and 3D seismic data sets available over and around the area of the Forties 5 Site 1 which have resulted from years of hydrocarbon exploration and development activity. The seismic data set used for the Forties 5 site 1 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 site model. Interpreted surfaces were interpolated across areas not covered by the seismic data. There is almost (95%) complete seismic coverage over the area of the Forties 5 Site 1 with just a very small data gap in at the northern edge. However, for the larger fairway area there are some larger gaps especially in the north. The seismic volume is made up of several different volumes that have been merged post stack (Figure 3-3) and were acquired between 1990 and 1994.

Seismic data SEGY summary is provided in Appendix 3.

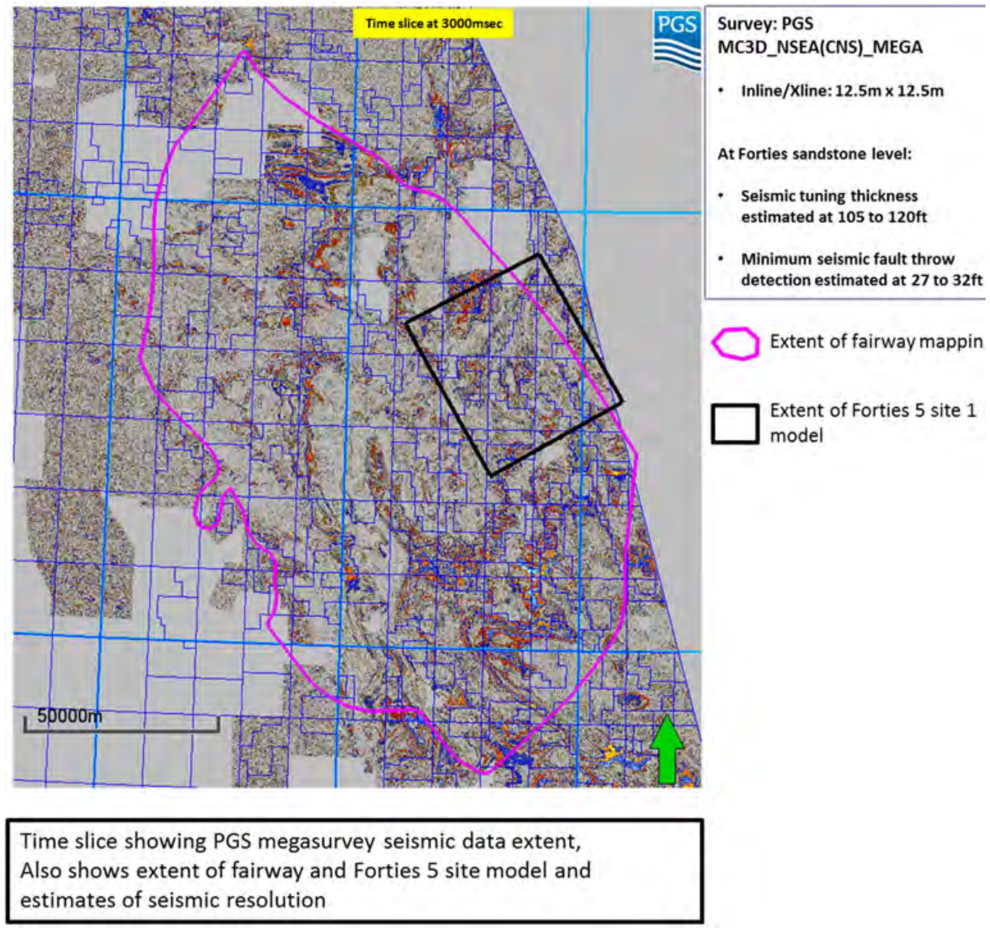


Figure 3-2 Seismic database

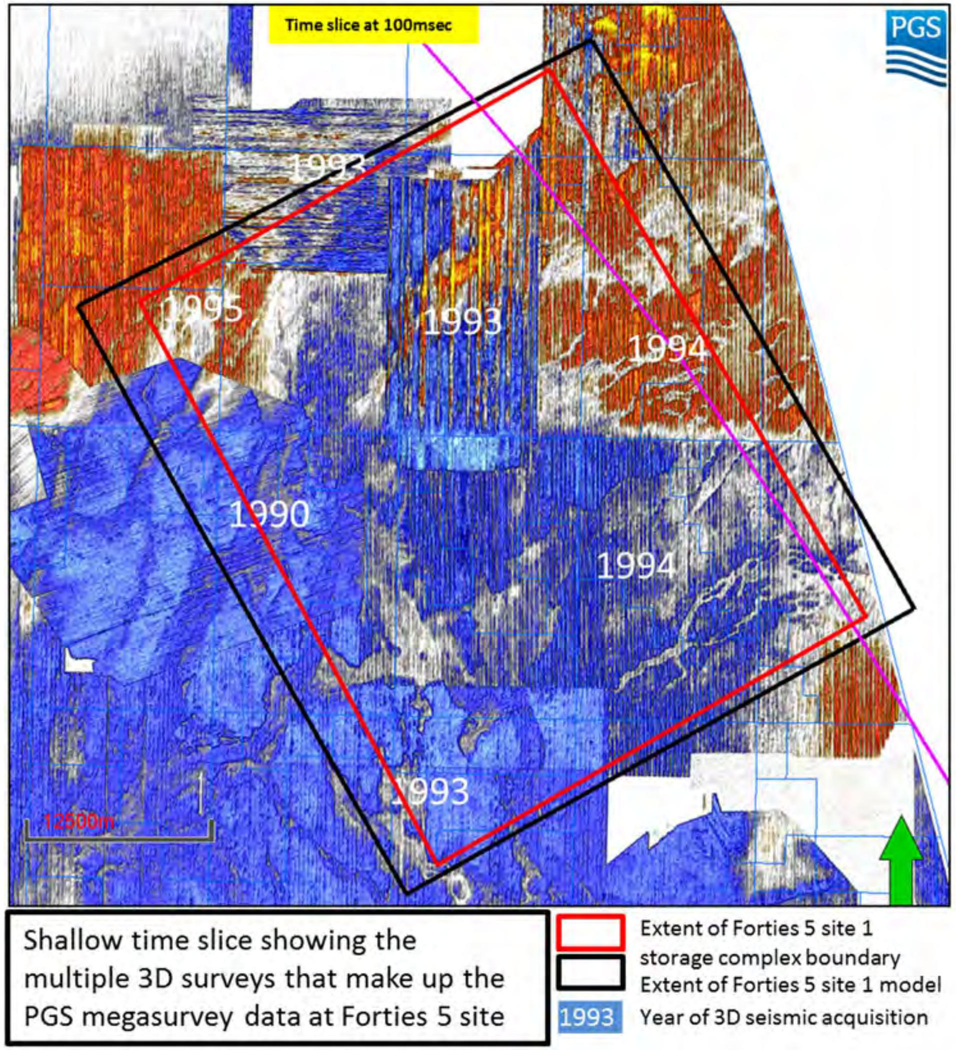


Figure 3-3 Seismic database, merged surveys

3.2.4 Wells

All well log data was sourced from the publically available CDA database. These data 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. 45 wells were selected from the CDA database and used for a range of activities. These included wells from the nearby Everest and Huntington Fields.

A total of 16 wells across the site were selected that have suitable data for petrophysical evaluation over the Forties Sandstone interval (Table 3-1). Of the selected wells all have conventional core analysis, although some have very limited amounts. Some SCAL data was also identified from the CDA database including capillary pressure and relative permeability data for the Everest area.

The quality of the log data was generally good. Where there was any uncertainty in log quality it was possible to reference back to the composite log or final well reports for guidance.

Section 3.4.1 describes the wells used for the Forties 5 site 1 seismic interpretation. 14 wells contain Time-Depth data, Sonic and density logs.

An inventory of well data is included in Appendix 3.

Well	Wireline	MWD	Core	Mud Type
22/08a-3	✓		✓	OBM
22/09-2	✓		✓	OBM
22/09-3	✓		✓	OBM
22/09-4	✓		✓	OBM
22/10a-4	✓		✓	OBM
22/10b-6	✓		✓	OBM
22/14-1	✓		✓	OBM
22/14a-2	✓		✓	OBM
22/14b-5	✓		✓	OBM
22/14b-6Q		✓	✓	OBM
22/14b-8		✓	✓	OBM
22/15-2	✓		✓	OBM
22/15-3	✓		✓	OBM
22/18-3	✓		✓	OBM
22/18-5	✓		✓	OBM
23/11/2	✓		✓	OBM

Table 3-1 Wells included in petrophysical analysis

3.2.5 Other

Other information used in this characterisation of the Forties 5 Site 1 is:

- DECC production data
- Wood Mackenzie COP dates
- Published papers

3.3 Storage Stratigraphy

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

Palaeocene

The Palaeocene of the Northern North Sea is dominated by a series of submarine fan systems deposited into basin of background clay and mudstones. Several pulses of fan deposition have been identified and include sediments of the Maureen, Mey and Forties Members.

Ekofisk Formation

At the base of the Tertiary is the Chalk Group Ekofisk Formation. Over the Central North Sea this comprises a thickness of up to 200 m (650ft) of Chalk deposited in a deep water, pelagic environment.

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.

Maureen sands within the site area provide a deeper secondary hydrocarbon reservoir in the Everest field (O'Connor & Walker, 1993).

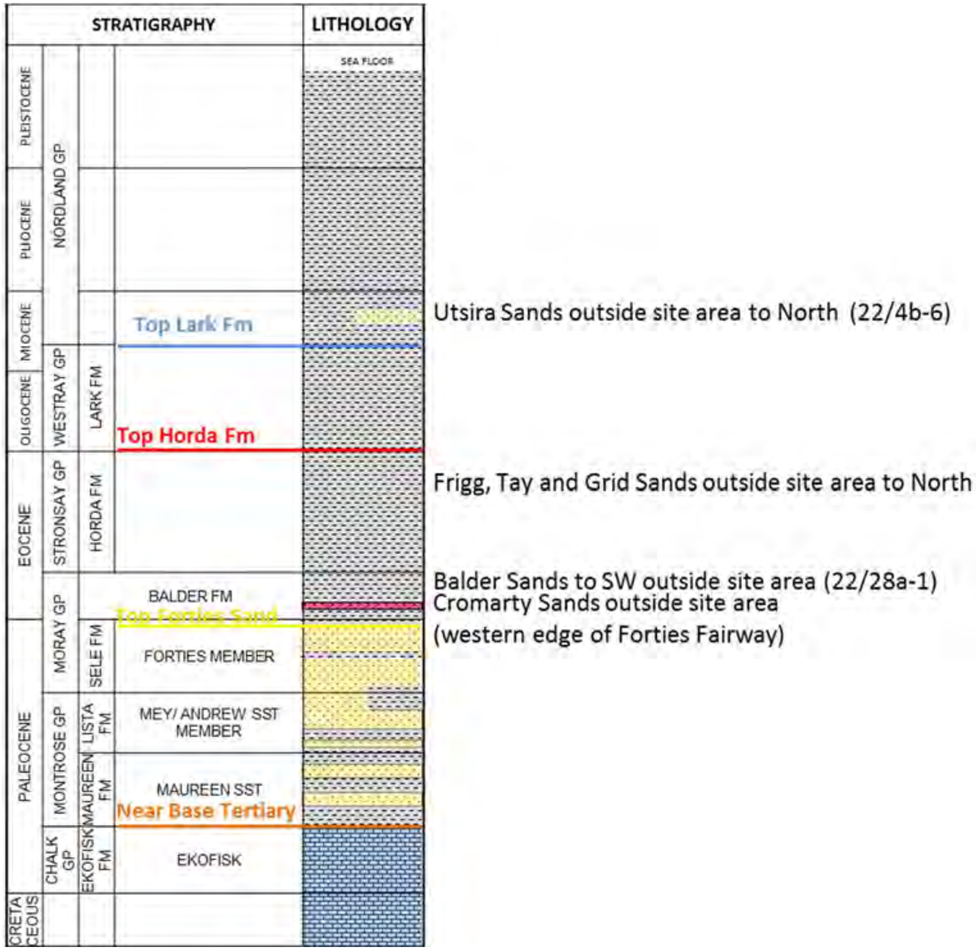


Figure 3-4 Stratigraphic column at Forties 5 Site 1, showing the overlying and underlying geological formations

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 in the Central Graben and Forties 5 site area where they are assigned to the Mey Sandstone Member, locally named Andrew, Glamis and Balmoral members. The Andrew sand is capped by a claystone that is believed to be regionally extensive (O'Connor & Walker, 1993).

Andrew sands within the site area provide a deeper secondary hydrocarbon reservoir in the Everest field (O'Connor and Walker, 1993).

Sele Formation

The Forties Sandstone Member is an elongate (NW-SE) sand rich turbidite fan system deposited into the Central Graben primarily from the northwest (O'Connor & Walker, 1993). Within the site area the fan lobes are overlapping in the Everest field with a channel from the Northwest through the Huntington field (Hollywood & Olson, 2010). Forties sand thickness within the site area is up to approximately 245 m (800 ft), with an average thickness of 115m (380ft).

The basal part of the Forties Member, between the top Lista Formation and the bottom Forties sand bed, is dominated by laminated shales, these have historically been informally described as the Forties Argillaceous Unit, the Lower Forties Shale or the Forties Mudstone. This interval is not seen in all wells in the site area, in some wells Lista Formation sits directly below the Forties sands.

The overlying Sele shales are sufficiently widespread to provide a thick, proven top seal to the Forties Sandstone Member. These shales represent the abandonment and covering of the Forties turbidite fans system by basin shales. Within the site boundary the Sele shales above the Forties Sand are up to 145 m (480 ft) thick with an average in thickness of over 65 m (220 ft).

Eocene

Balder Formation

The tuffaceous mudstones of the Balder Formation straddle the Palaeocene-Eocene boundary, representing a major transgression that resulted in widespread shale deposition. Within the site area the Balder Formation is up to 150 m (500 ft) thick with an average thickness over 60 m (200 ft).

Horda Formation

Claystone and mudstones, occasionally calcareous, with rare limestone beds. Within the site area they have a thickness of over 230 m (755 ft).

Oligocene - Seabed

Nordland Group

At the Forties 5 Site 1 location, the upper part of the stratigraphic sequence from the Top Horda to Seabed is a thick accumulation of undifferentiated mudstones, claystones and occasionally marl. The total average thickness of the Nordland Group within Site 1 area is over 2100 m (6890 ft).

3.4 Seismic Characterisation

3.4.1 Database

The seismic data set used for the Forties 5 Site 1 interpretation was the PGS Central North Sea MegaSurvey (PGS, 2015) and is described in Section 3.2.

Wavelet extraction confirms the seismic volume to be SEG Reverse polarity (North Sea normal) with a trough representing an increase in acoustic impedance and a peak representing a decrease in acoustic impedance. It also shows the seismic volume is close to zero phase with a change in acoustic impedance (AI) being represented by either a peak or a trough.

To aid fault identification, a semblance volume was generated using the OpendTect open source software then exported and loaded into the Petrel project. A non-dip adapted semblance volume over the entire fairway was generated (Figure 3-5). A dip adapted semblance volume was not generated due to time constraints as this process is computationally very intense.

Figure 3-6 shows the wells used for the Forties 5 site 1 seismic interpretation:

- 14 wells contain Time-Depth data, Sonic and density logs
- 1 well contains Time-Depth data and Sonic log only
- 30 wells contain only Time – Depth data

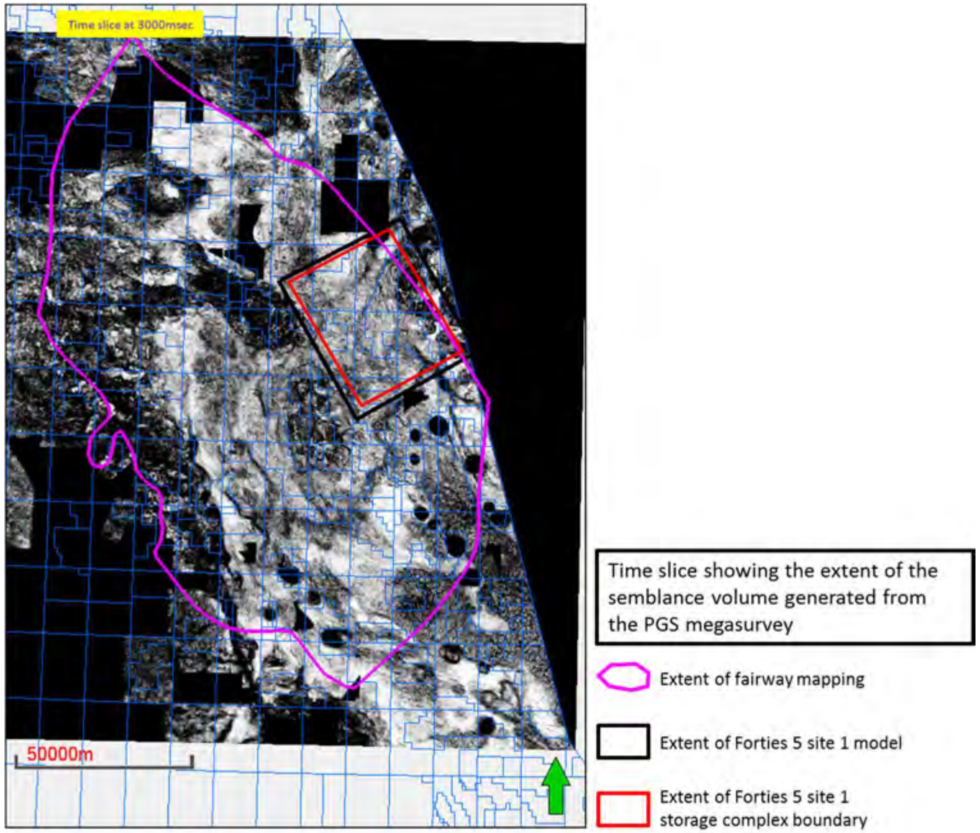


Figure 3-5 Non dip adapted semblance volumes

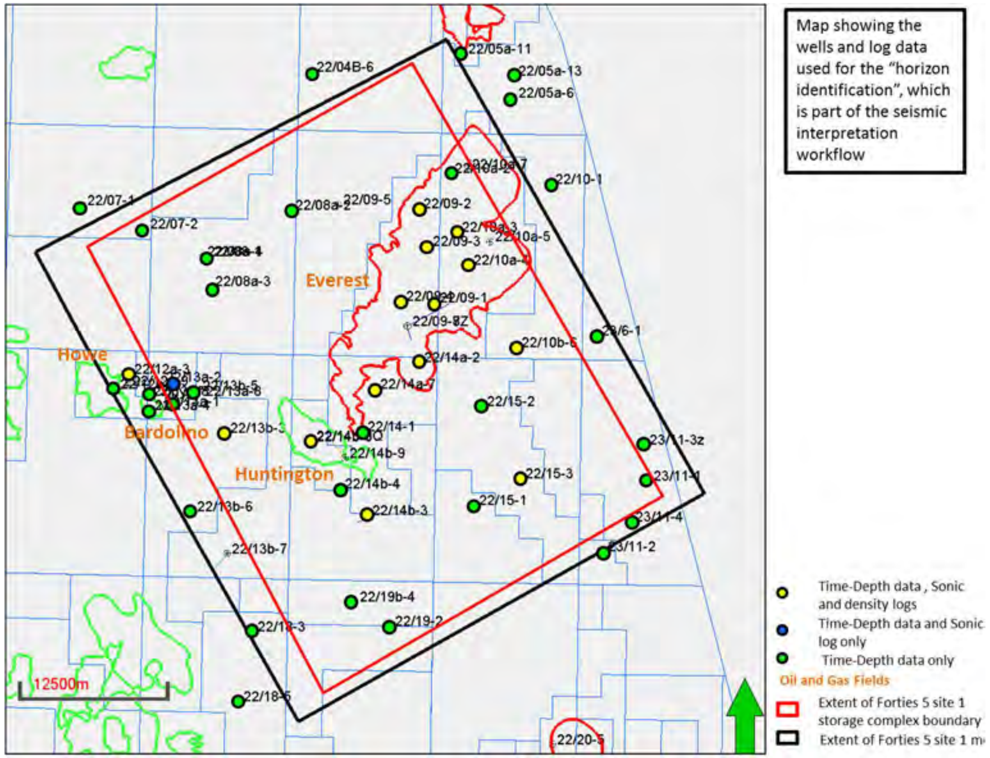


Figure 3-6 Geophysical wells and log database

3.4.2 Horizon Identification

The well data are in depth and the seismic volume in two-way time. The well data is used to identify the seismic events within the 3D volume. Using checkshots, recorded in the well, a time-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 with a seismic signal at the well location, convolving the reflection coefficient log with the seismic wavelet. This enables the interpreter to more accurately match the position of certain seismic reflectors with respect to the subsurface geology of an area.

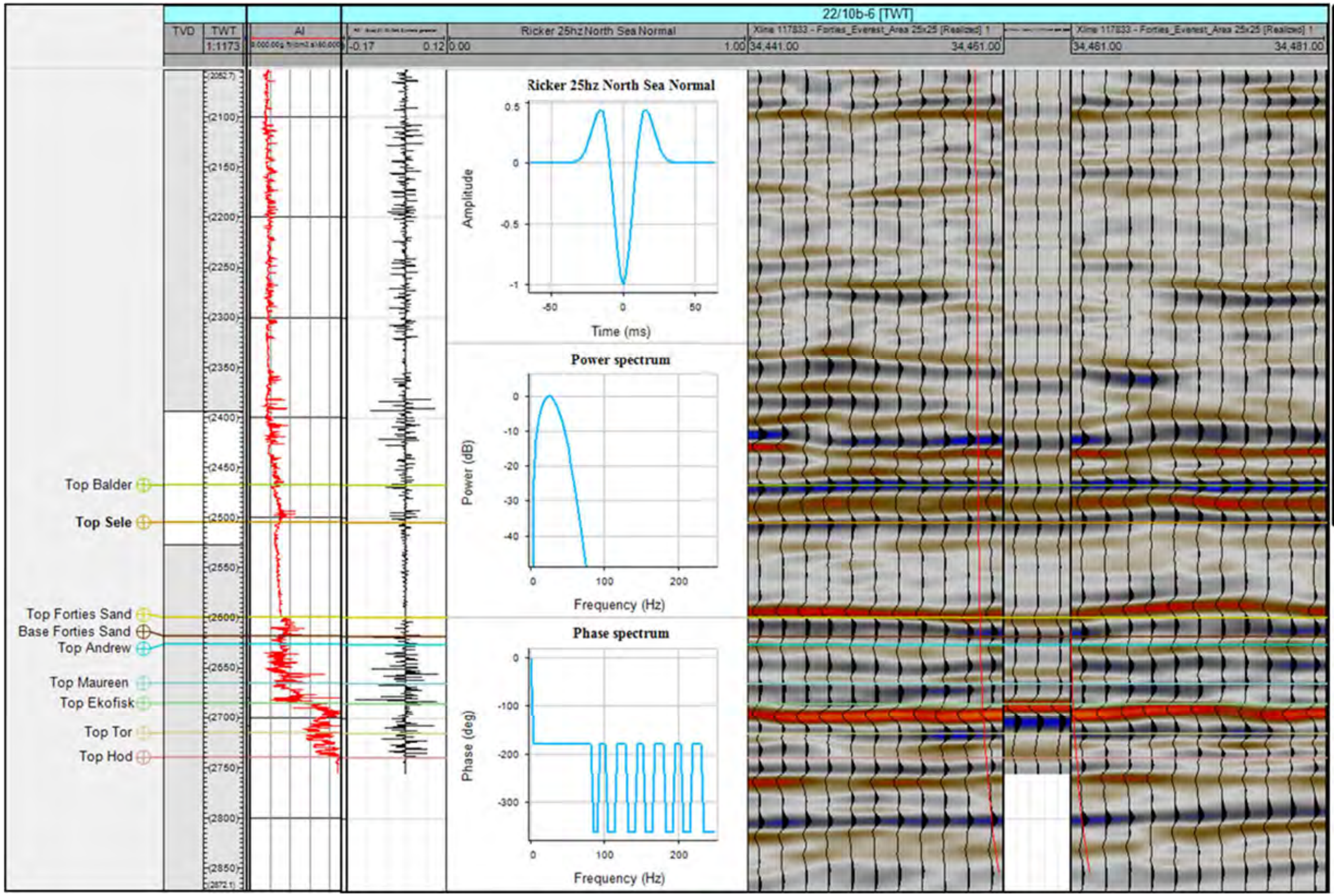
15 synthetic well ties were produced using available sonic and density logs in each well (22/09-1, 22/09-2, 22/09-3, 22/09-4, 22/10a-3, 22/10a-4, 22/10b-6, 22/12a-3, 22/13a-2, 22/13b-3, 22/14a-2, 22/14b-3, 22/14a-5, 22/14a-7, 22/15-3).

To generate the synthetic seismograms a theoretical Ricker wavelet was used with an appropriate frequency applied to each well (range 25-30Hz). One well (22/13a-2) only contains a sonic log and a constant density was used in the synthetic generation. An example synthetic for well 22/10b-6 is shown in Figure 3-7. The synthetic seismogram and the actual seismic 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 3-8.

There were thirty wells that contained only checkshot data (Figure 3-6), allowing a well tie to be produced, but not a synthetic tie. Several wells required an additional time shift in order to tie the seismic.

Horizon	Display Response	Pick Quality
Near Top Lark	Trough	Very Good
Near Top Horda	Peak	Fair - Good
Top Balder	Peak	Very Good
Top Sele	Peak	Very Good
Top Forties Sandstone	Trough	Very Good
Base Forties Sandstone	Variable	Poor - Fair
Base Tertiary	Trough	Fair - Good

Table 3-2 Interpreted Horizons



22/10b-6 Synthetic well tie with actual seismic data. Generated using the sonic log and density log.

25Hz Zero Phase wavelet is convolved with the AI (acoustic impedance) generated reflection coefficients to create the synthetic seismic trace

Figure 3-7 22/10b-6 Synthetic seismogram

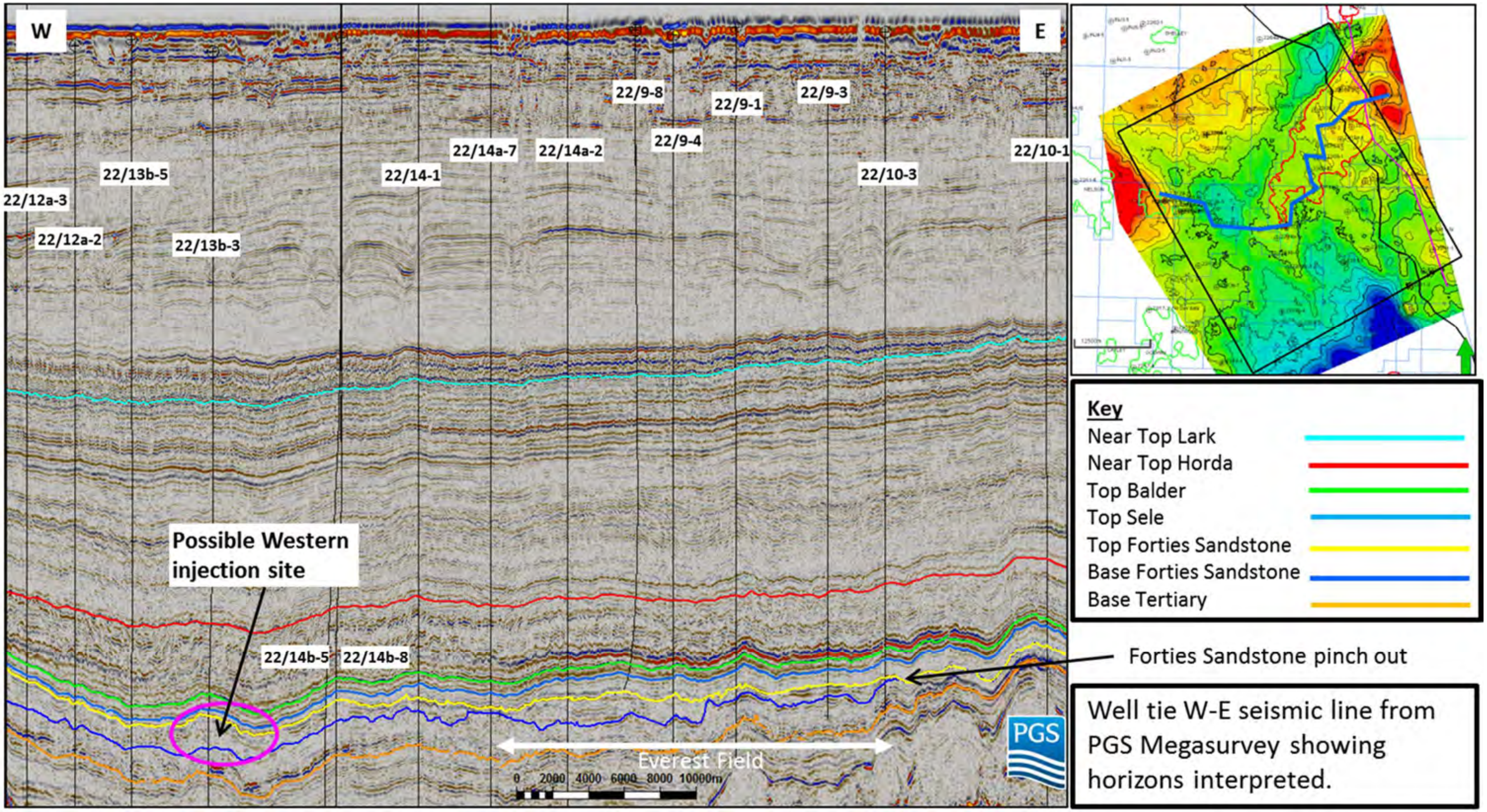


Figure 3-8 W-E Regional seismic profile

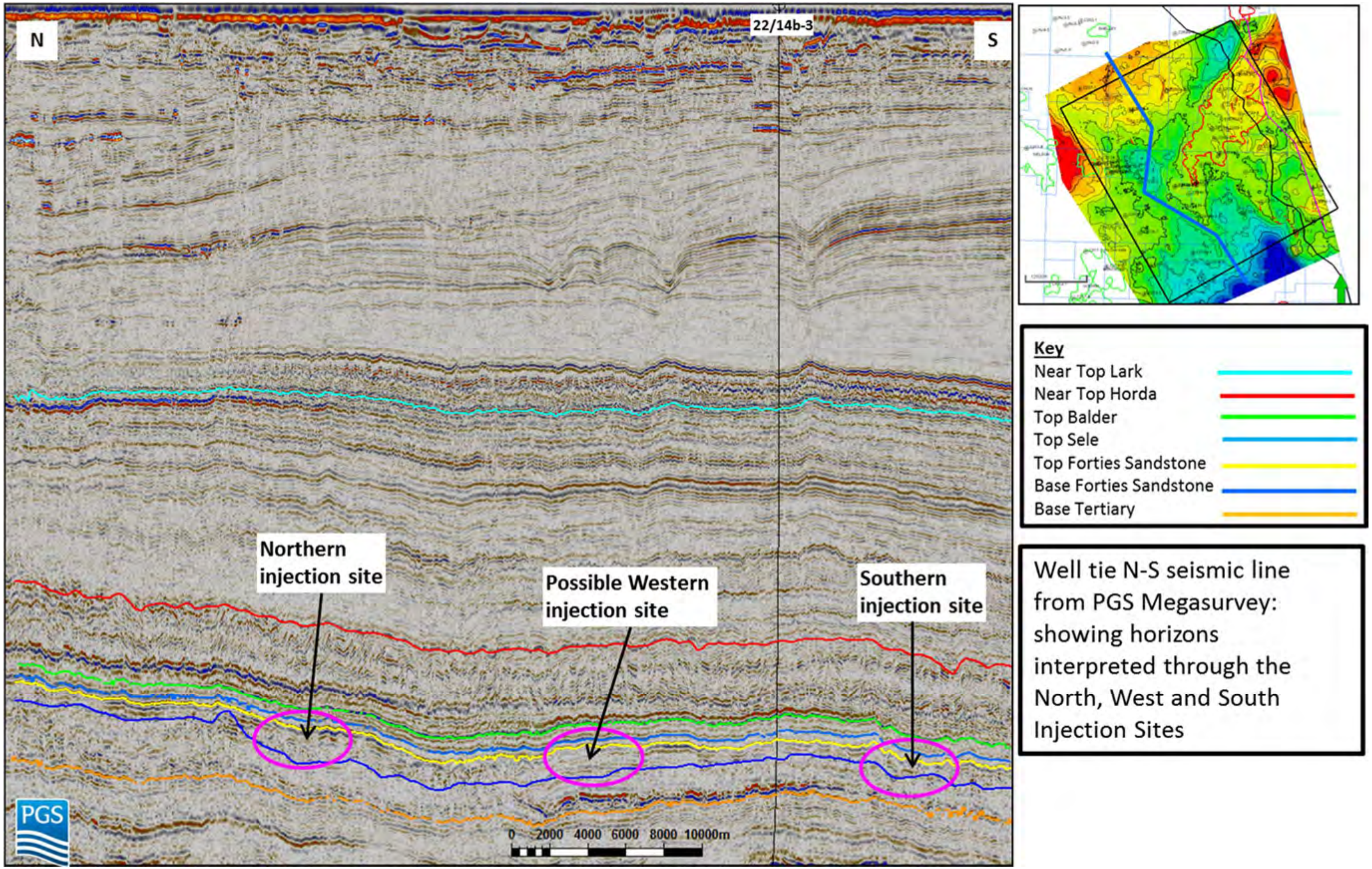


Figure 3-9 N-S Regional seismic profile

3.4.3 Horizon Interpretation

A detailed seismic interpretation was carried out using reflectivity and semblance volumes to provide input horizons to the Forties 5 site 1 Static Model and Overburden Static Model. The seismic interpretation for the fairway model had previously been undertaken as part of the Forties 5 screening study and this is documented in Forties 5 Aquifer Site Selection Study (Pale Blue Dot Energy; Axis Well Technology, 2015). The Base Tertiary (below the Base Forties Sandstone) has also been included to allow full evaluation of the containment potential of the site.

In total seven horizons from the seabed down to the Base Tertiary were interpreted across the 3D seismic data (Table 3-2, Figure 3-8 and Figure 3-9). All events were manually picked on a seed grid and then autotracked with the exception of Base Forties, which due to its variable nature, could not be autotracked.

The 7 key seismic horizons were interpreted over an area slightly larger than the Forties 5 site 1 (Figure 3-8 & Figure 3-9). The small area of missing seismic within the site has been interpolated using interpreted data around the edges to extrapolate over the region of missing seismic. The autotracked horizons were gridded at 100x100m grid increment with the exception of the Top Forties sandstone which was gridded at 50x50m to preserve its complexity. The resultant time maps are shown in Figure 3-10 to Figure 3-18. The interpreted seismic horizons are described below from the youngest to the oldest;

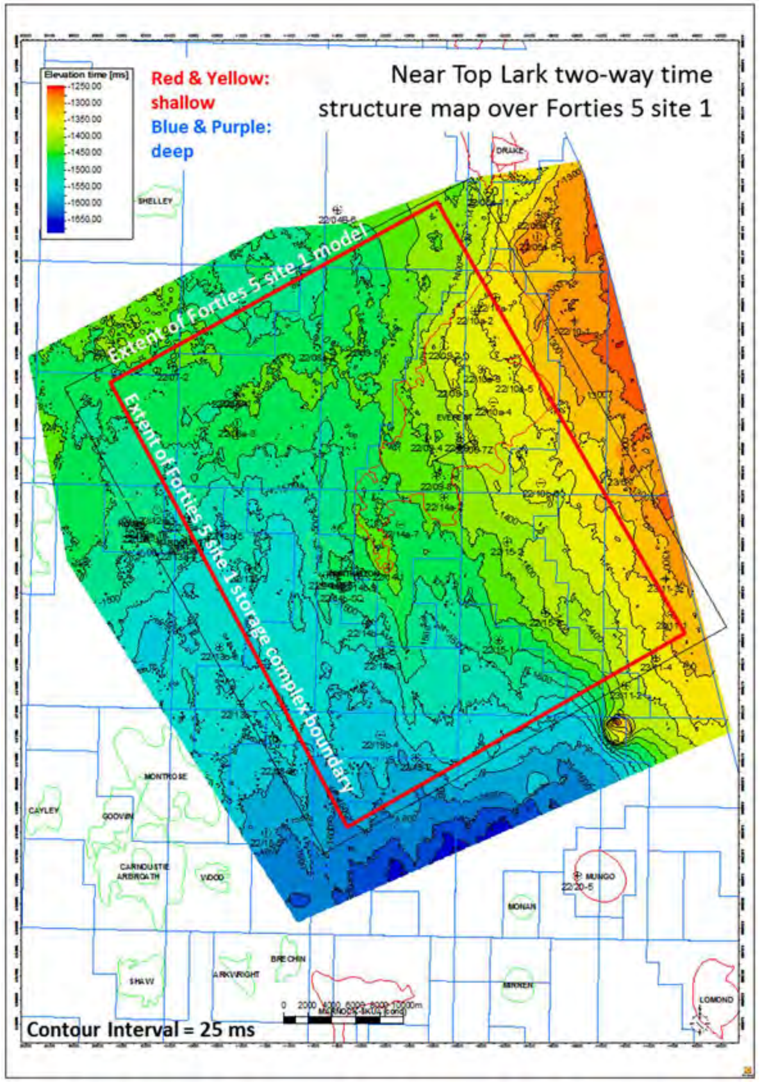


Figure 3-10 Near Top Lark two-way-time structure

Near Top Lark – The top of this formation has only been picked in 12 wells and the tie to the seismic is poor due to the lack of checkshots at this shallow depth (approximately 1070-1370m (3500-4500ft)). The Top Lark has been interpreted on a high-amplitude continuous trough; however, it is not clear if this is the actual top of the Lark which is why the surface has been called Near Top Lark. Due to its high amplitude the horizon was only manually picked as a seed on a couple of well tie lines. This was enough to enable the event to be accurately autotracked with a high level of confidence (Figure 3-10).

Near Top Horda – The top of the Horda Formation has only been picked in 13 wells and the tie to the seismic is poor due to the lack of acoustic contrast. The Top Horda has been interpreted on a moderate-amplitude discontinuous peak which approximately corresponds to Top Horda in the wells, which is why it is called Near Top Horda. Due to the moderate amplitude and discontinuous nature the horizon was manually picked at a seed increment inline/crossline spacing of 64 enabling the event to be accurately autotracked with a moderate to high level of confidence (Figure 3-11).

Top Balder – The seismic response of the event is predominately a high amplitude continuous peak, representing a soft kick at the base of the higher velocity lower Eocene. The horizon was manually picked at a seed increment inline/crossline spacing of 256 enabling the event to be accurately autotracked with a high level of confidence (Figure 3-12).

Top Sele – The seismic response of the event is predominately a high amplitude continuous peak, representing a soft kick at the base of the high velocity Balder tuffaceous mudstone. The horizon was manually picked at a seed increment inline/crossline spacing of 256 enabling the event to be accurately autotracked with a high level of confidence (Figure 3-13).

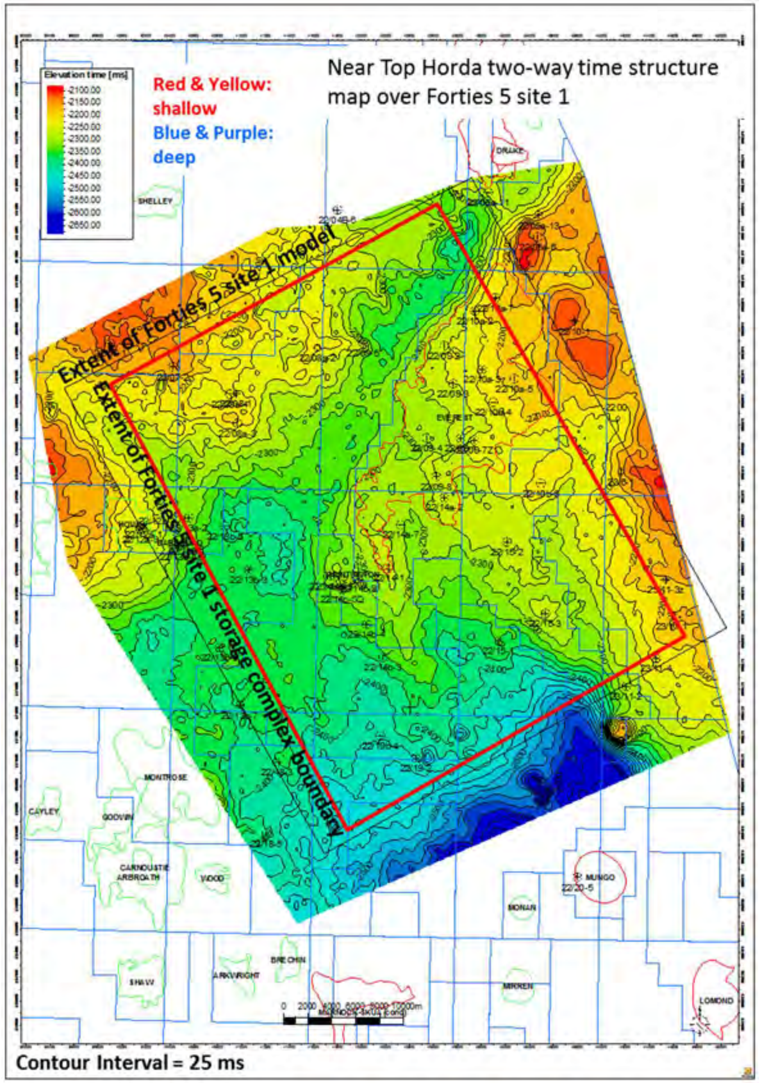


Figure 3-11 Near Top Horda two-way-time structure

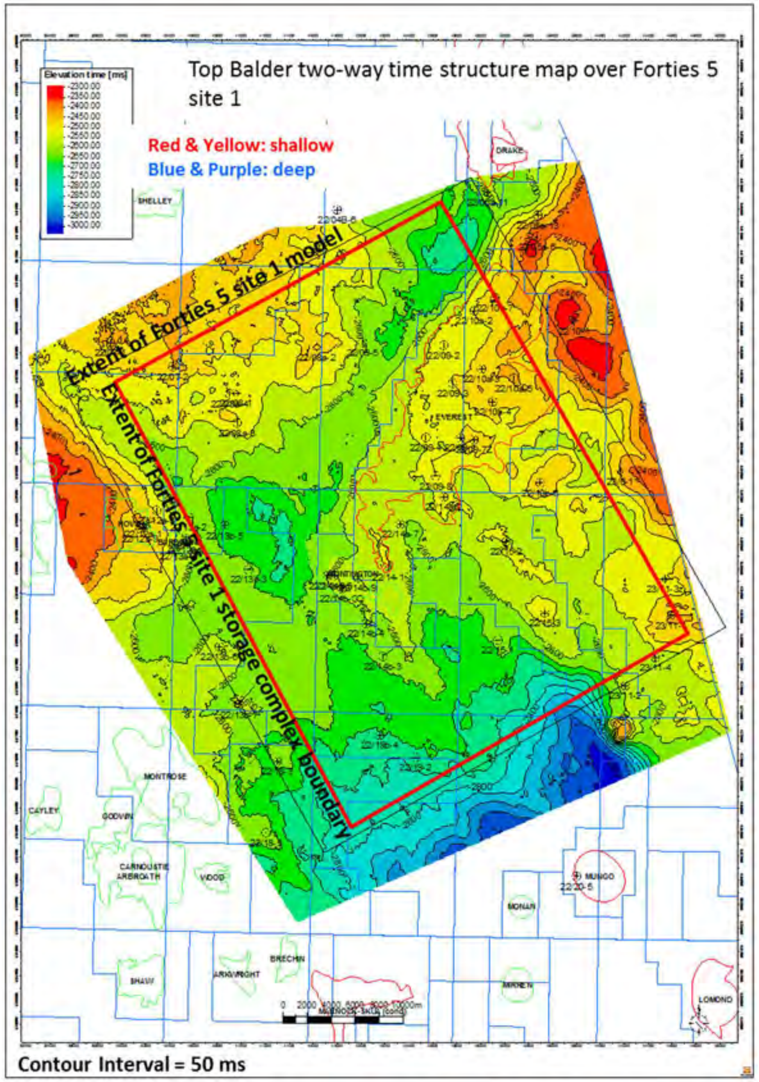


Figure 3-12 Top Balder two-way-time structure

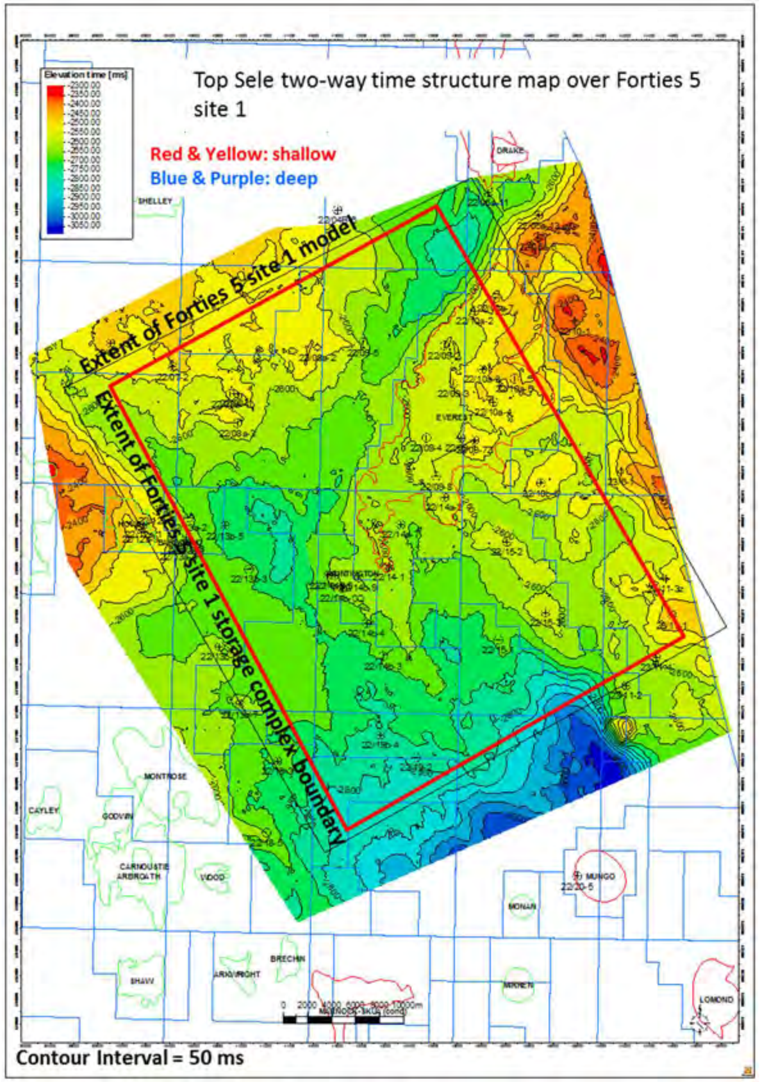


Figure 3-13 Top Sele two-way-time structure

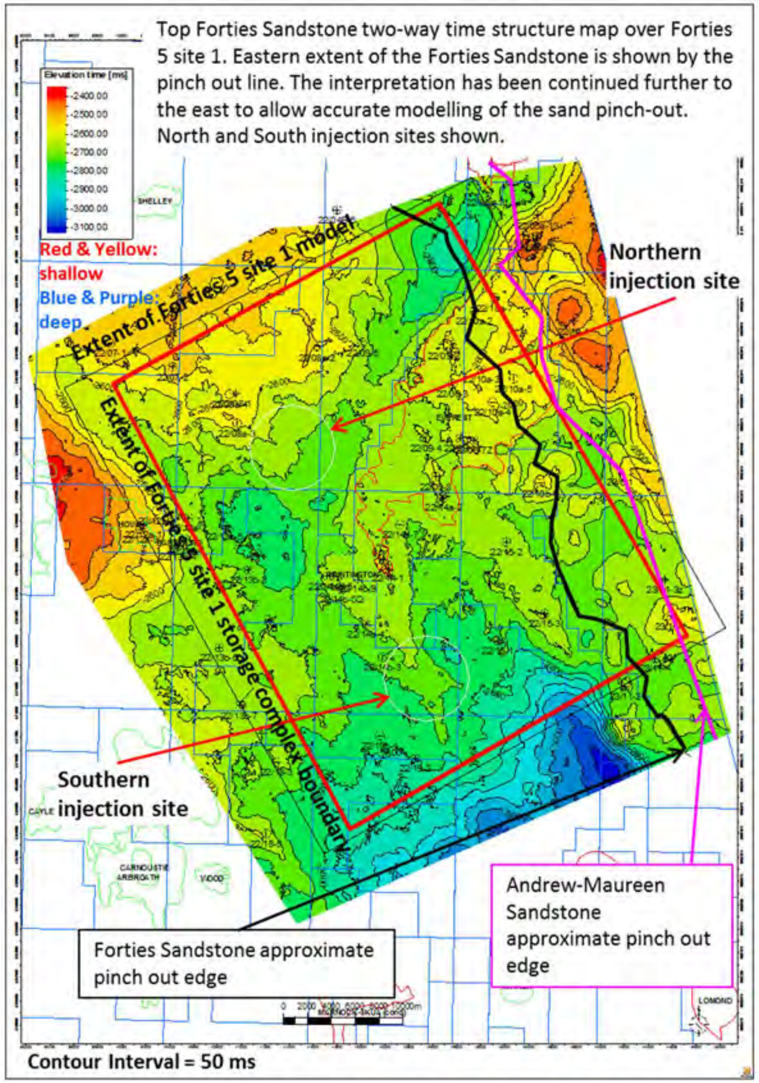
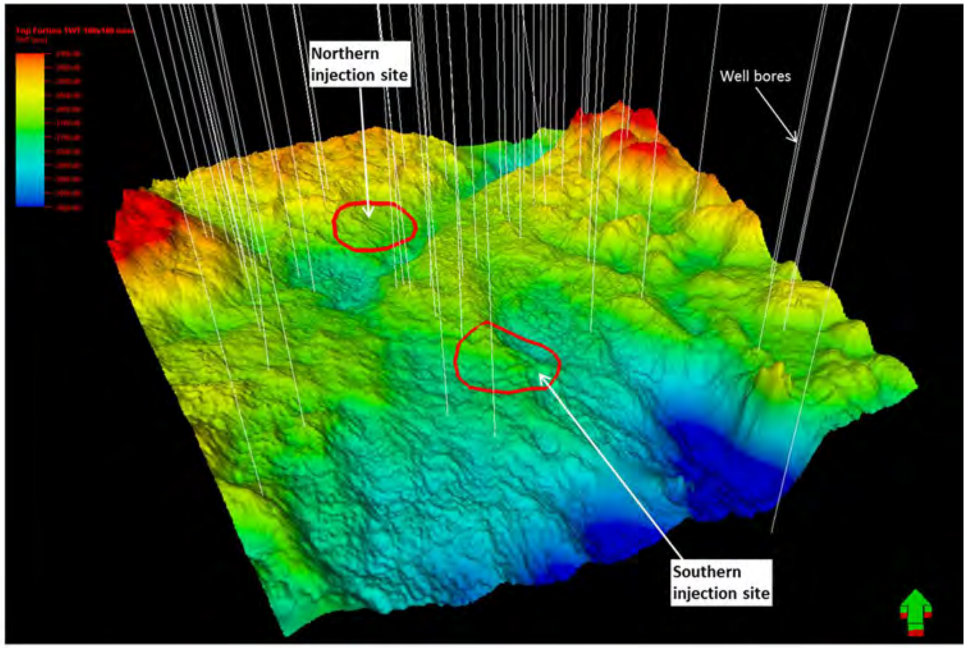


Figure 3-14 Top Forties Sandstone two-way-time structure

Top Forties Sandstone – The seismic response of the event is predominately a high amplitude continuous trough, representing a hard kick at the base of the low velocity Sele shale. The Forties sandstones are generally high velocity (11000ft/sec), however as noted in the Forties 5 Site Selection Study (Pale Blue Dot Energy; Axis Well Technology, 2015), hydrocarbons within the oil and gas fields cause a dimming of the seismic amplitudes (Figure 3-36). In the eastern part of the site the event significantly dims in amplitude and this is caused by a lack of acoustic contrast as the Forties sandstone is absent due to a pinch out (Figure 3-36). However, the horizon interpretation has been continued further to the east to allow accurate modelling of the sand pinch-out. The horizon was manually picked at a varying seed increment inline/crossline spacing of 16 to 256 enabling the event to be accurately autotracked with a high level of confidence (Figure 3-14). This figure also shows the pinch out edge of the Forties Sandstone. A 3D view of the Top Forties Sandstone time surface is shown in Figure 3-21.



3D view of Top Forties Sandstone two-way time structure over the Forties 5 site 1. North and South injection sites shown.

Figure 3-15 3D view of Top Forties Sandstone TWT interpretation

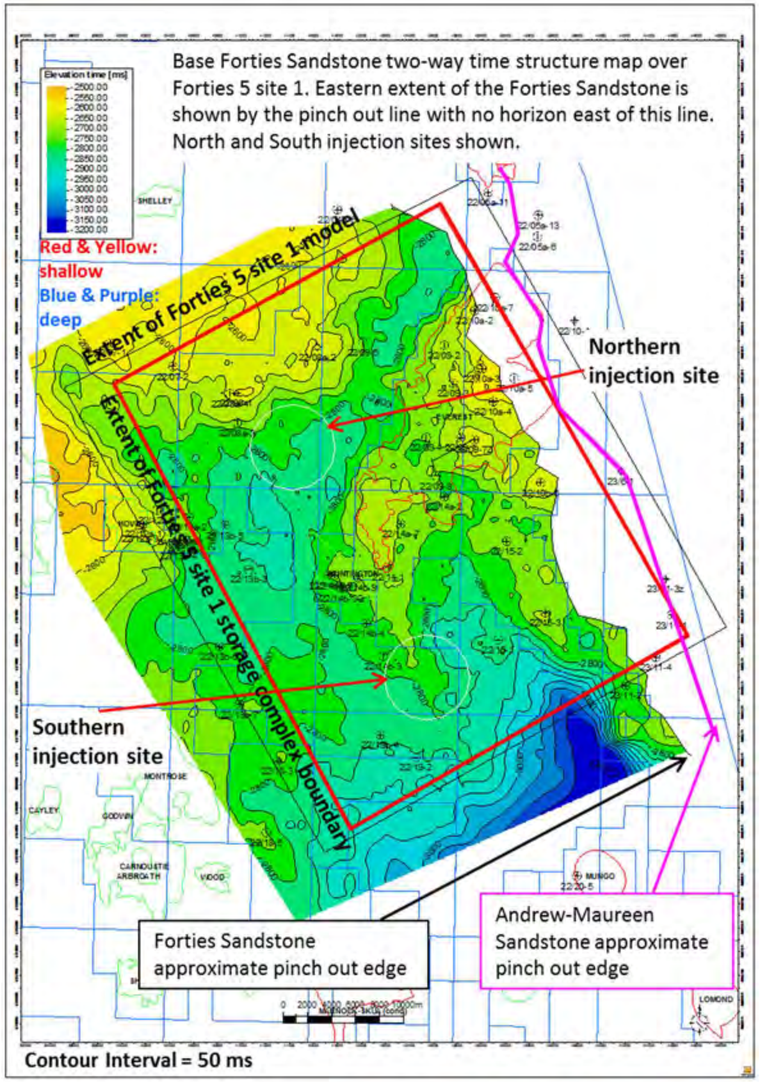


Figure 3-16 Base Forties Sandstone two-way-time structure

Base Forties Sandstone – The Base Forties is an erosive event cutting down into the underlying Lista interval. This is the most difficult event to pick both on seismic and in the wells (where it is not always clear which sand belongs to the Lista and which belongs to the Forties, see section 3.5). To help guide the interpretation a Forties isochron was generated from well data and added to the Top Forties time surface Figure 3-17. The horizon was manually picked at a seed increment inline/crossline spacing of 64. The event is too variable to auto track and the seed pick was gridded to generate the Base Forties time surface (Figure 3-16). Figure 3-17 shows a comparison of the Forties isochron derived from well data only and one from the seismic interpretation.

The deeper Andrew and Maureen sandstones have not been interpreted. However well control shows that they also pinch out to the east and an approximate pinch out line is shown on the maps.

Base Tertiary – The Base Tertiary is picked on a moderate to high amplitude trough. The event is continuous across the Forties 5 site 1 and varies laterally in amplitude, generally decreasing to the west. The event corresponds to the top of the high velocity Ekofisk Chalk group. The event has been manually picked at a seed increment inline/crossline spacing of 256 and autotracked with a high level of confidence (Figure 3-18).

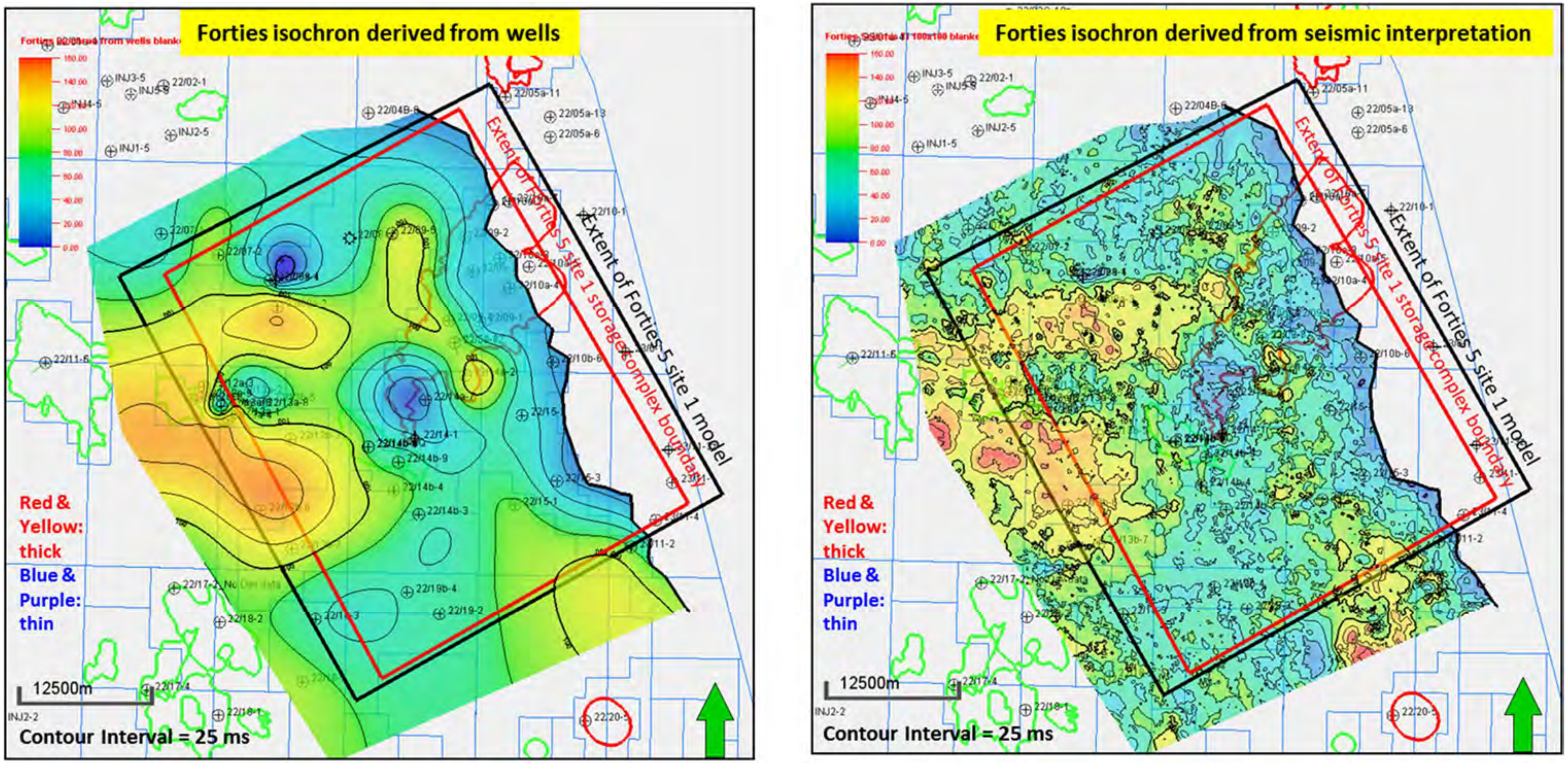


Figure 3-17 Comparison of Forties Sandstone isochrons

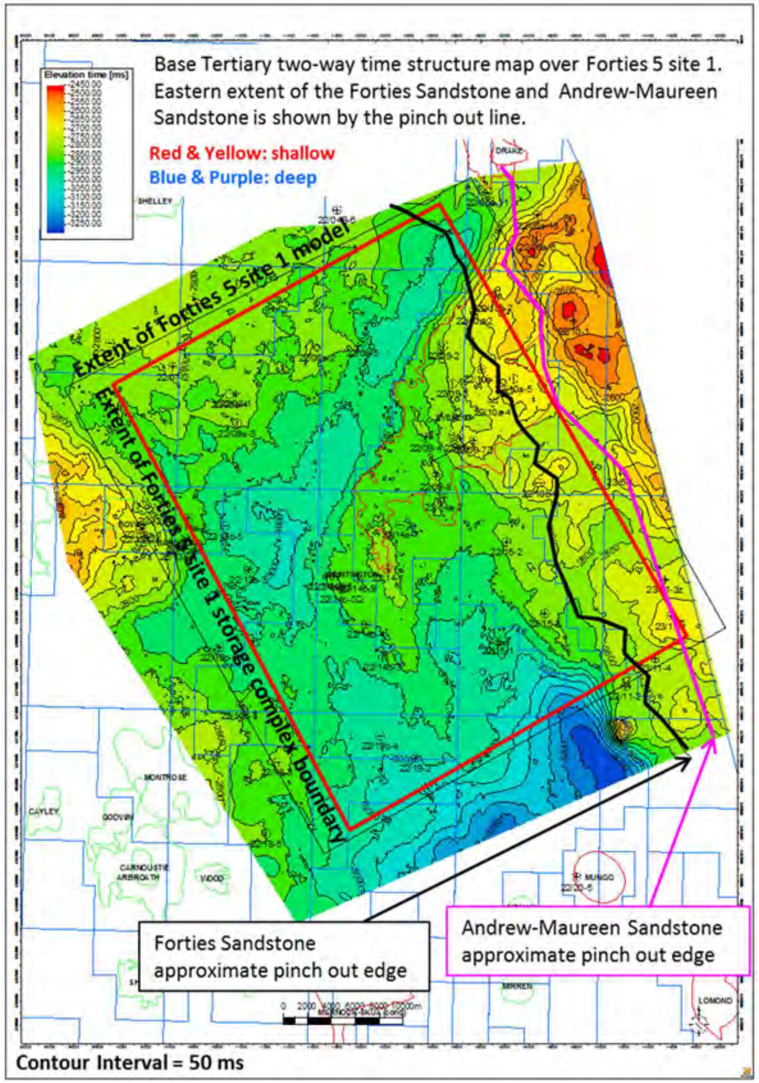


Figure 3-18 Base Tertiary two-way-time structure

3.4.4 Faulting

The Top Forties semblance horizon slice shows little or no evidence of any significant faulting (Figure 3-19). There are some small faults in the SE corner of the site, also around the salt diaper just outside of the site southern boundary and within the Everest Field. A small fault in the Sele shale is clearly seen on seismic over the Everest field but the top seal has not been compromised by this fault.

The largest fault (Fault-1) identified on seismic is close to well 22/08a-2 and Figure 3-20 shows a cross section based on a seismic line across this fault. Forties sandstone is juxtaposed against the Sele shale which is the proven top seal of the Everest and Huntington hydrocarbon fields. The fault extends up into the Lark Formation. All the other faults interpreted within the storage site have less throw than Fault-1 and tend to die out within the Horda Formation. A 3D image of the Base Forties depth surface together with the faults included in the Static Model, is shown in Figure 3-21.

Overall faulting is very limited in the over burden and reservoir level both regionally and specifically over the two injection sites, posing little risk to containment.

Large scale sand injection features are present in some parts of the Central North Sea which impacts the Palaeocene / Eocene stratigraphy. During the interpretation a careful search for such features in the area of interest has revealed no obvious sand injection structures that may complicate containment.

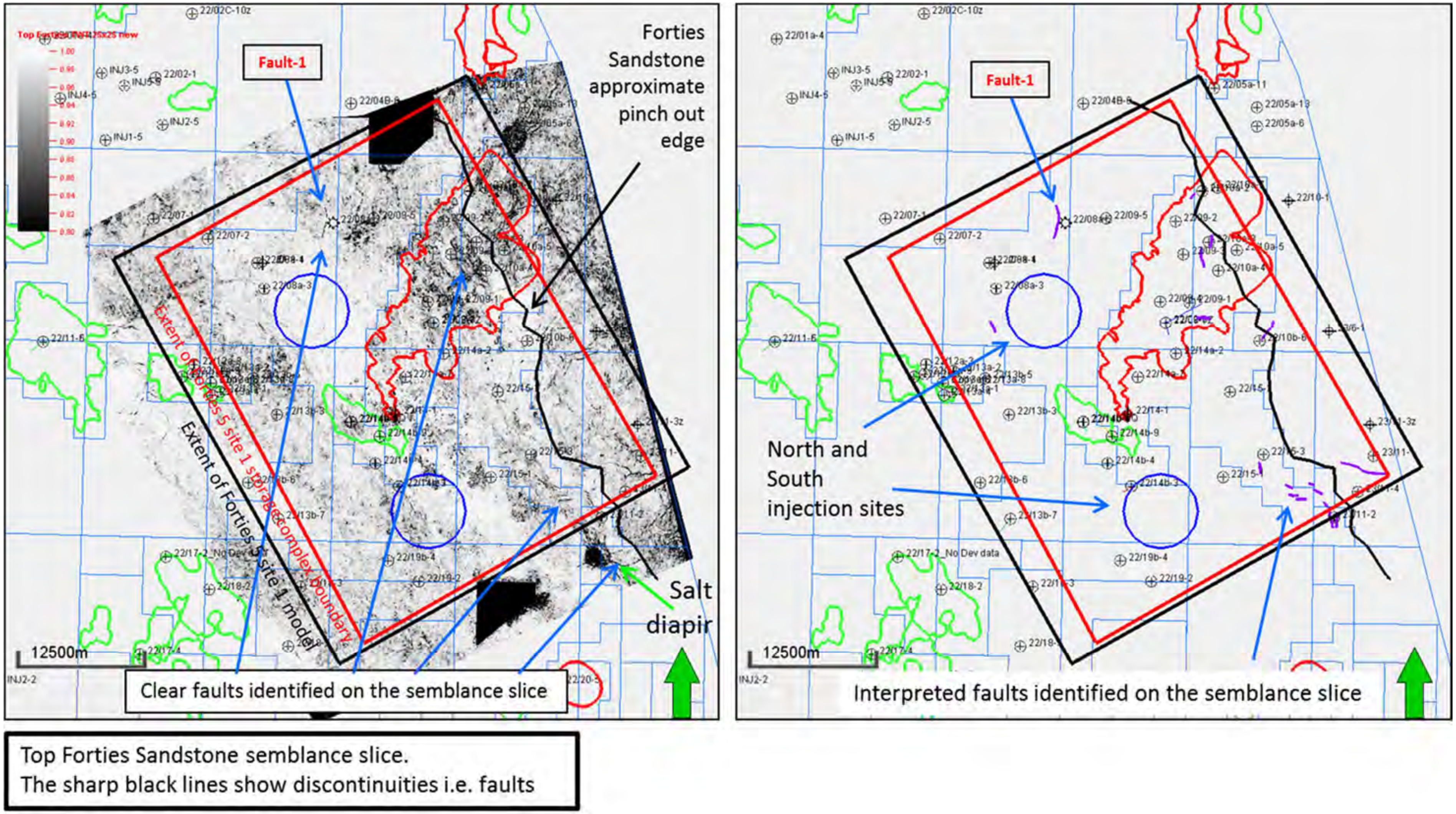


Figure 3-19 Forties Sandstone faulting

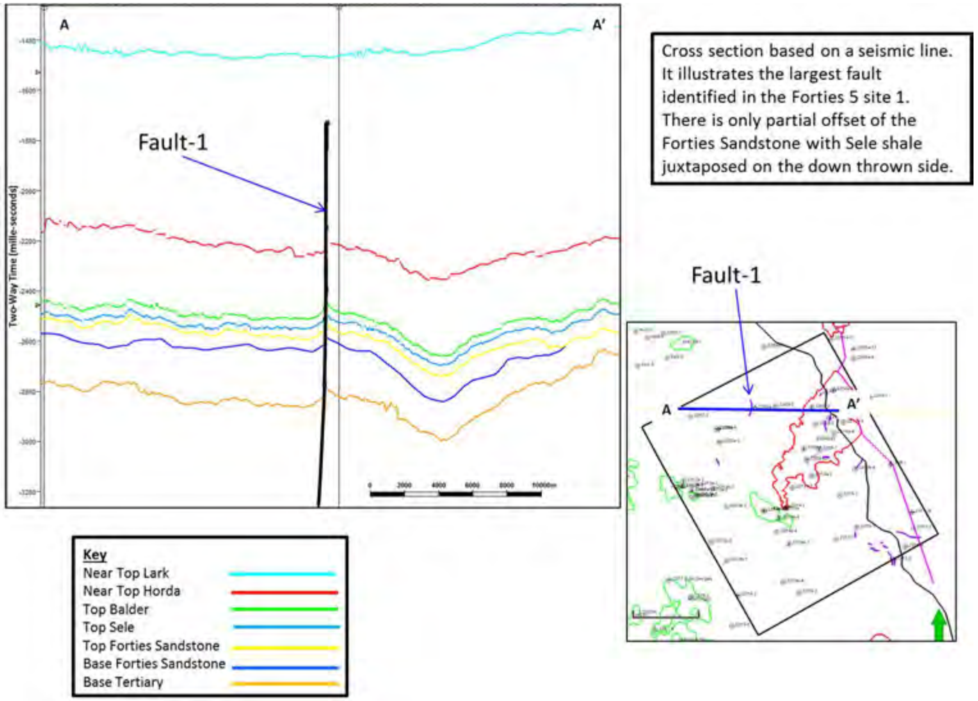


Figure 3-20 Forties 5 Site 1 example of faulting

3.4.5 Depth Conversion

Relatively small and gradual thickness variations in the overburden Tertiary units (Figure 3-22) indicate that a single layer depth conversion down to Top Forties Sandstone is an appropriate method to use. Below Top Forties Sandstone an additional layer was required to depth convert the Base Forties Sandstone and the Base Tertiary. Each interval was depth converted using oil industry standard depth conversion techniques and these are summarised in Figure 3-23. The depth conversion was undertaken in the Petrel software using the velocity modelling plug-in. Near Top Lark, Near Top Horda, Top and Base Forties Sandstone and Base Tertiary were depth converted directly using the Petrel generated velocity model. Two additional units (Sele and Balder) were depth converted using the Petrel calculator tool to create isochores which were then subtracted from surfaces generated in the Petrel velocity model to generate the Top Sele and Top Balder depth surfaces.

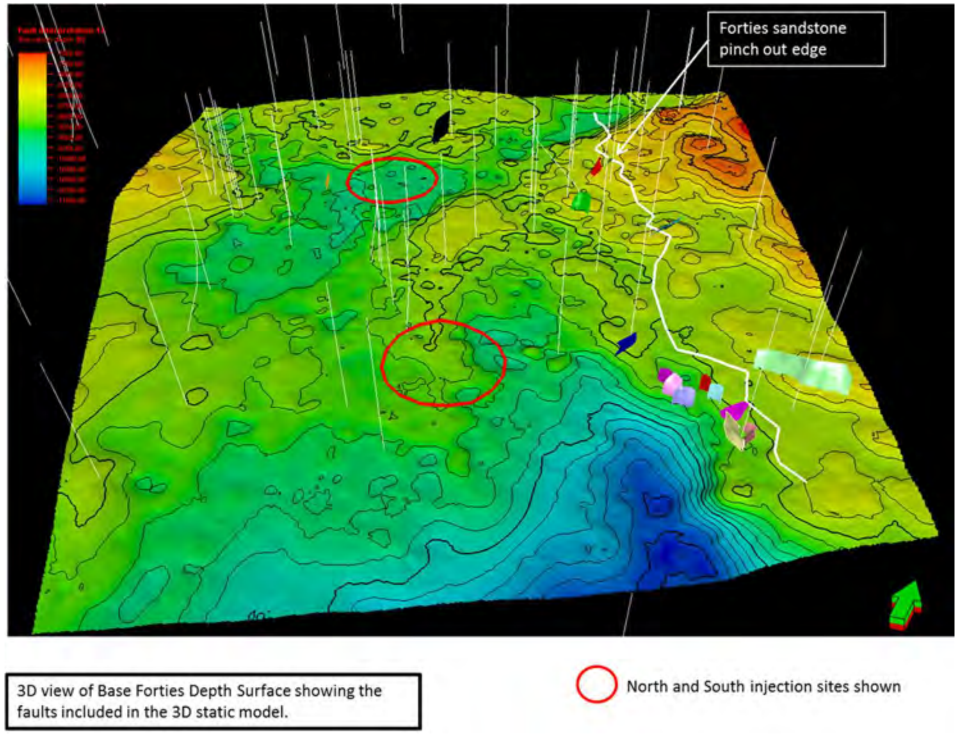


Figure 3-21 Forties Sandstone faulting included in the 3D static model

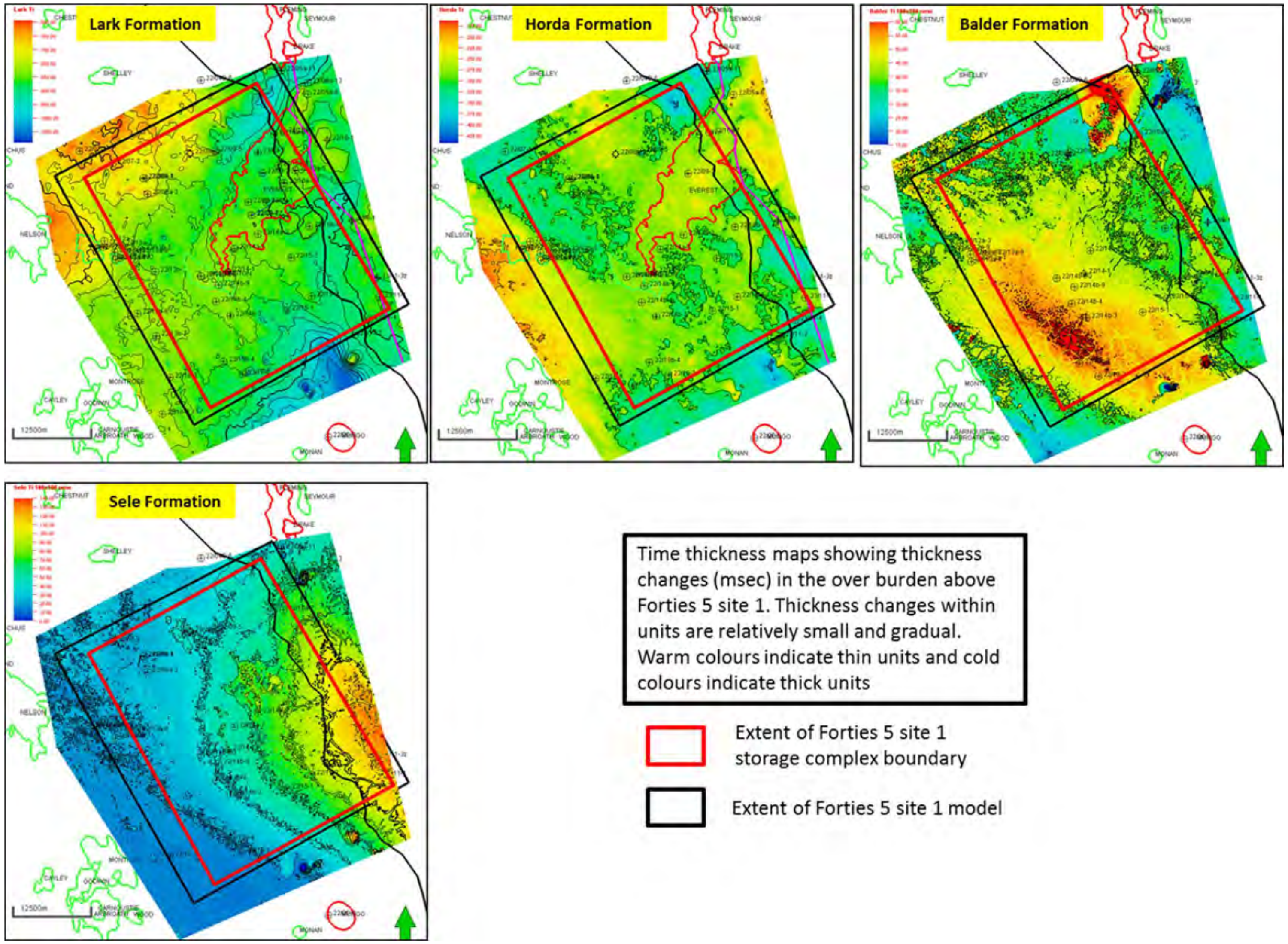


Figure 3-22 Overburden velocity units thickness change

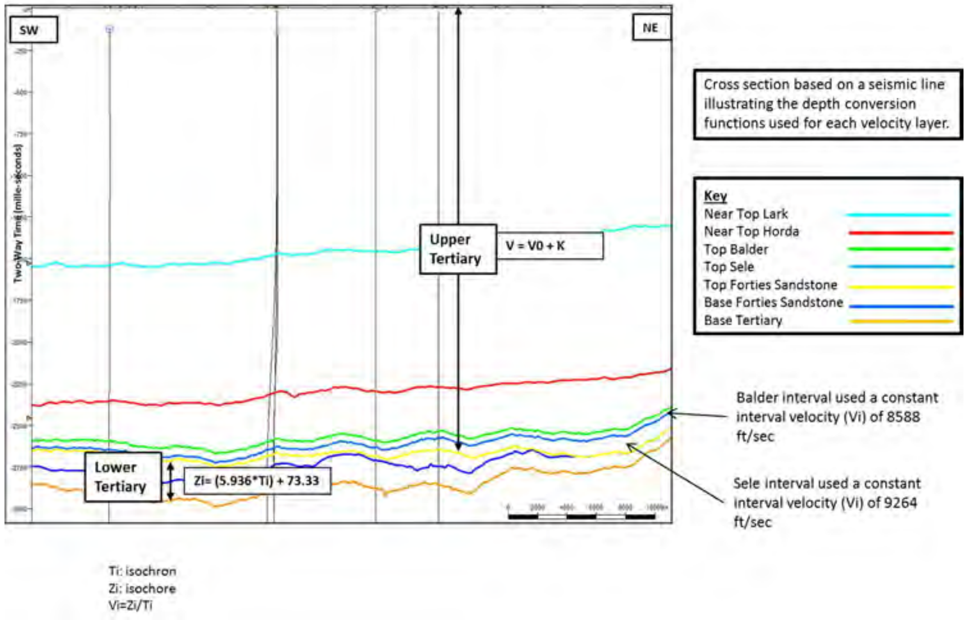


Figure 3-23 Layer cake depth conversion summary

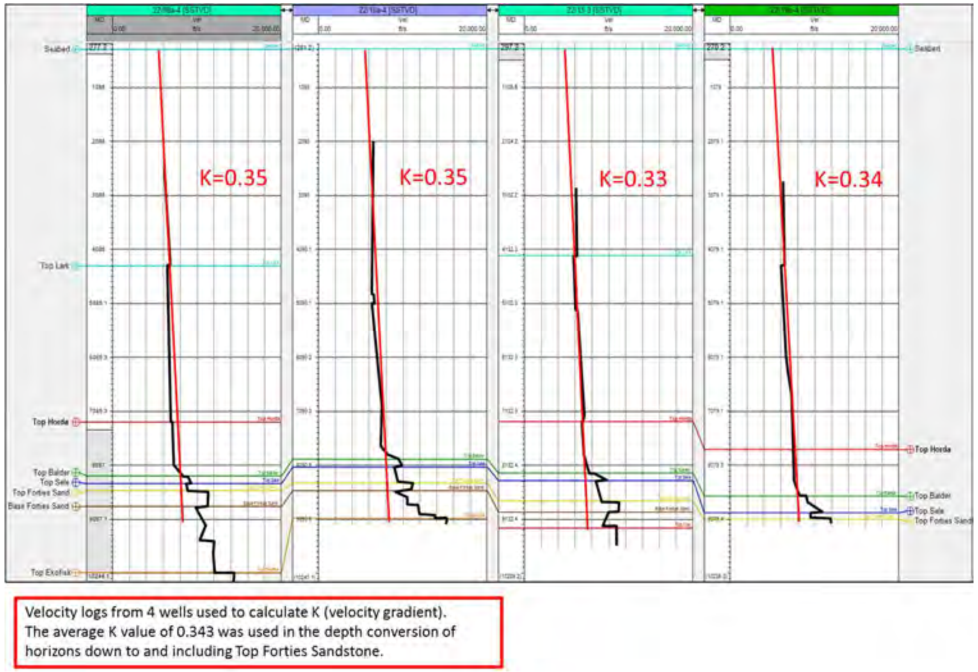


Figure 3-24 Upper tertiary K gradient calculations

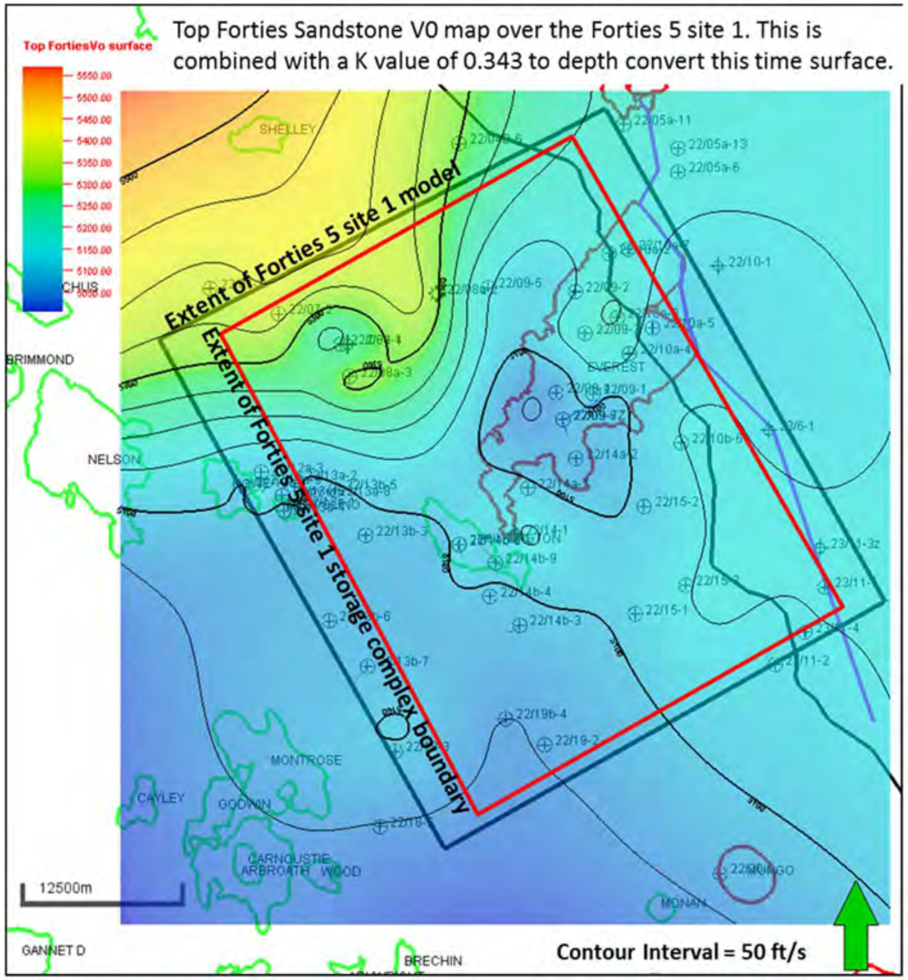


Figure 3-25 Top Forties Sandstone V0 map

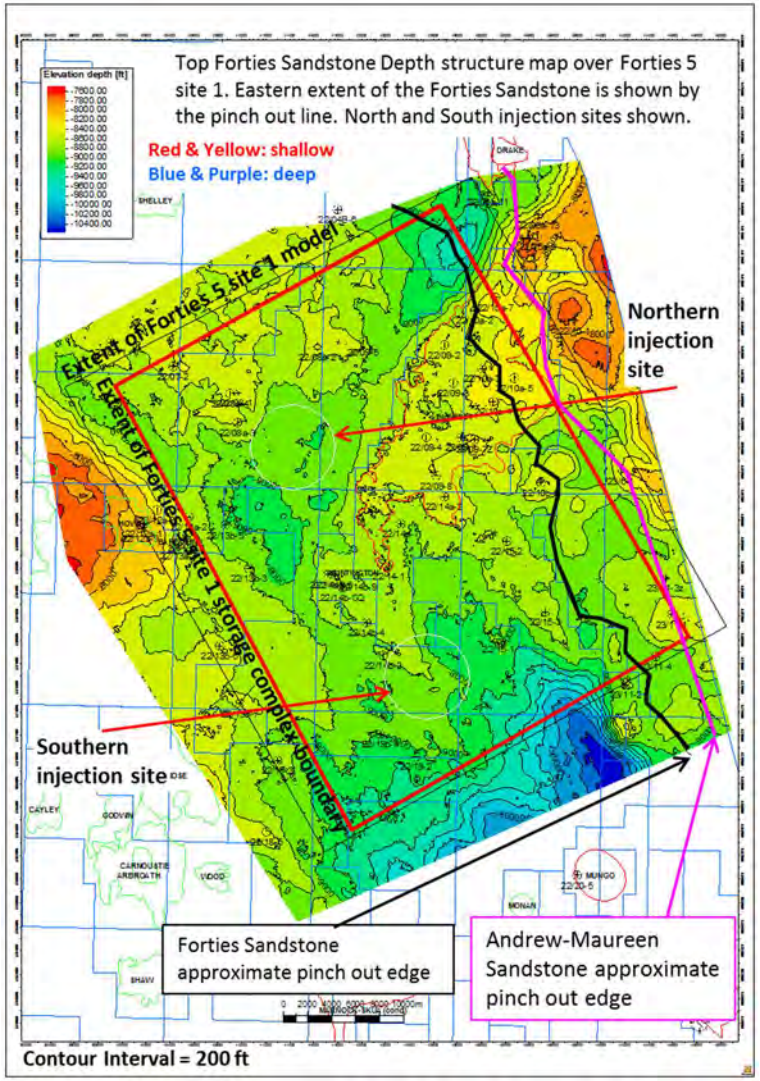


Figure 3-26 Top Forties Sandstone depth structure map

The depth conversion method for each interval or surface is outlined below:

Mean Sea Level to Top Forties Sandstone Interval – This interval was generated using a V0+K function (constant K and a mapped V0 surface). The defined K value (0.343) was derived from 4 velocity logs calculated from the sonic logs in wells 22/08a-4, 22/10a-4, 22/15-3, 22/19b-4 (Figure 3-24). The V0 surface was generated by gridding V0 values derived at all the wells within the site (Figure 3-25). The derived V0s ensure that the depth surface ties at the wells. The resulting Top Forties Sandstone depth surface is shown in Figure 3-26. Typical dips of the Top Forties Sandstone are 1 to 2 degrees however there are dips of 5 to 7 degrees in places.

Top Forties Sandstone to Base Tertiary Interval – This layer was depth converted by using an interval velocity map derived from a linear function (Zi=(5.936*Ti)+73.33)) calculated from well depth picks and back interpolated seismic time values at each well. The interval velocity map (Figure 3-27) was inserted into the Petrel Velocity model described above. The Base Tertiary surface was depth converted directly using the Petrel Velocity model with a final correction to the well tops using a 2000m influence radius. The resulting depth surface is shown in Figure 3-28.

Base Forties Sandstone Surface – The Base Forties Sandstone time surface was depth converted directly using the Petrel velocity model with a final correction to the well tops using a 2000m influence radius. The resulting depth surface is shown in Figure 3-29.

Near Top Lark Surface – The Near Top Lark time surface was depth converted directly using the Petrel velocity model and the resulting depth surface is shown in Figure 3-30.

Near Top Horda Surface – The Near Top Horda time surface was depth converted directly using the Petrel velocity model and the resulting depth surface is shown in Figure 3-31.

Top Sele Surface – The Top Sele time surface was depth converted using a constant velocity of 2824m/s (9264ft/s) (derived from well checkshot data) which was multiplied with the Sele isochron to generate an isochore. The isochore was subtracted from the Top Forties Sandstone depth surface to generate a Top Sele depth surface which was corrected to the well tops using a 2000m influence radius. The resulting depth surface is shown in Figure 3-32 and the Sele isochore in Figure 3-33.

Top Balder Surface – The Top Balder surface was depth converted using a constant velocity of 2618m/s (8588ft/s) (derived from well checkshot data) which was multiplied with the Balder isochron to generate an isochore. The isochore was subtracted from the Top Sele depth surface to generate a Top Balder depth surface which was corrected to the well tops using a 2000m influence radius. The resulting depth surface is shown in Figure 3-34 and the Balder isochore in Figure 3-35.

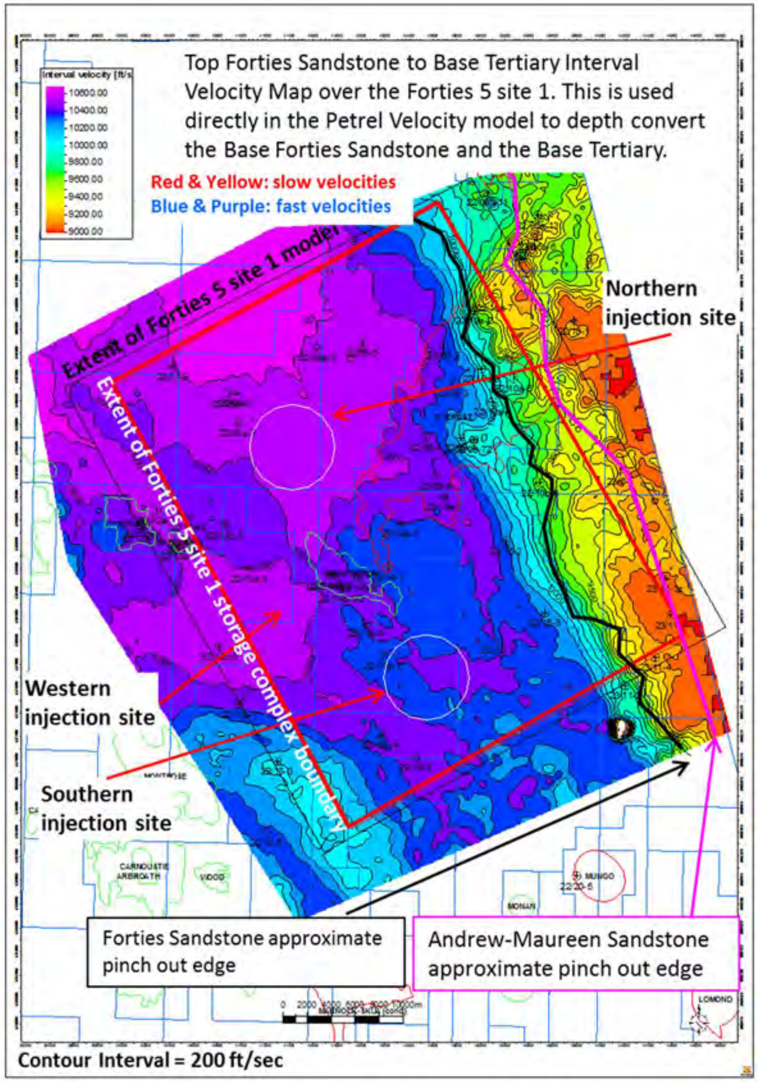


Figure 3-27 Top Forties Sandstone to base tertiary interval velocity map

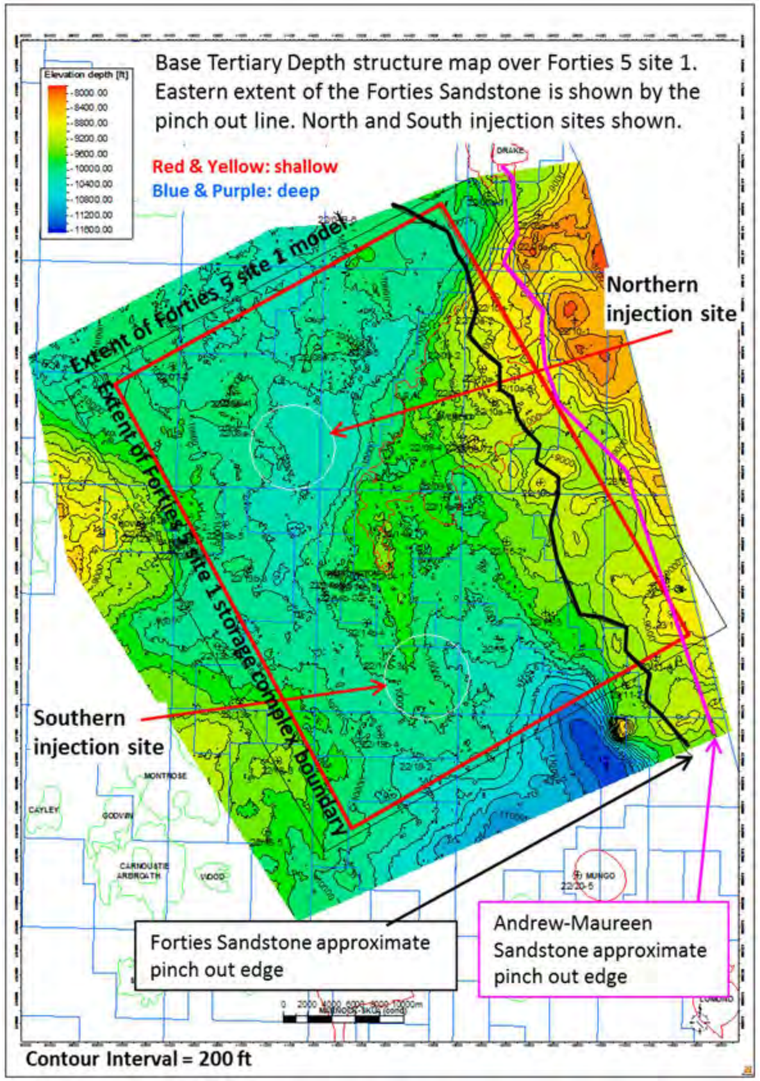


Figure 3-28 Base Tertiary depth structure map

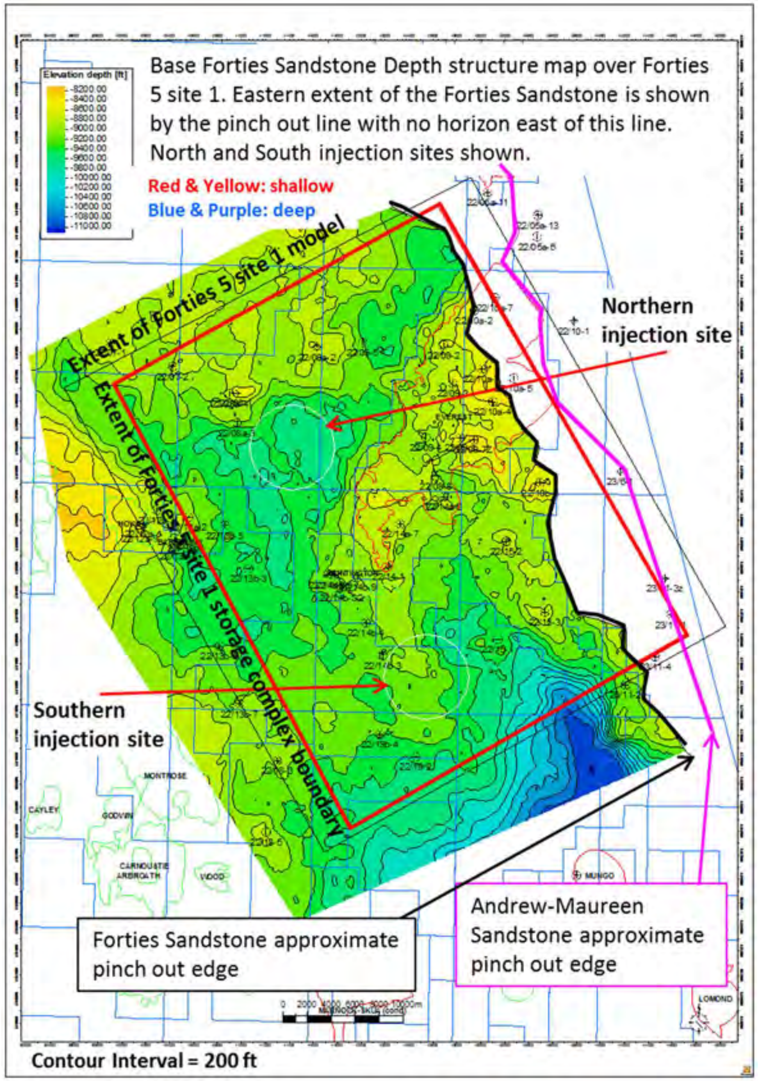


Figure 3-29 Base Forties Sandstone depth structure map

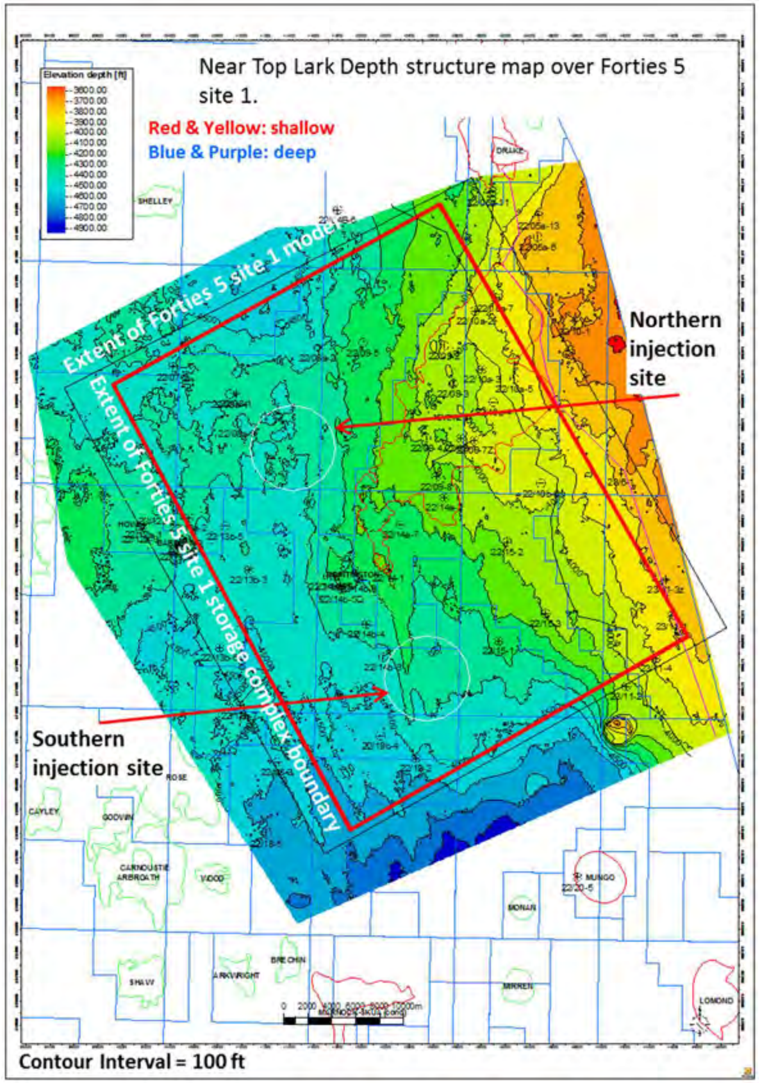


Figure 3-30 Near Top Lark depth structure map

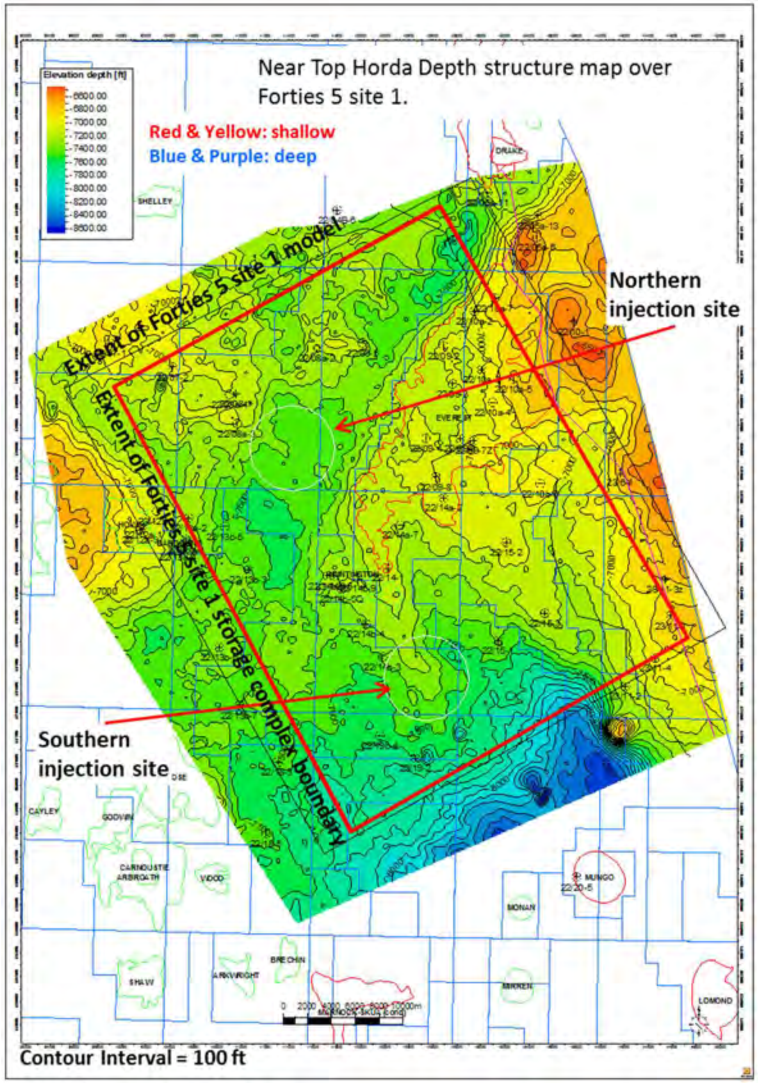


Figure 3-31 Near Top Horda depth structure map over Forties 5 Site 1

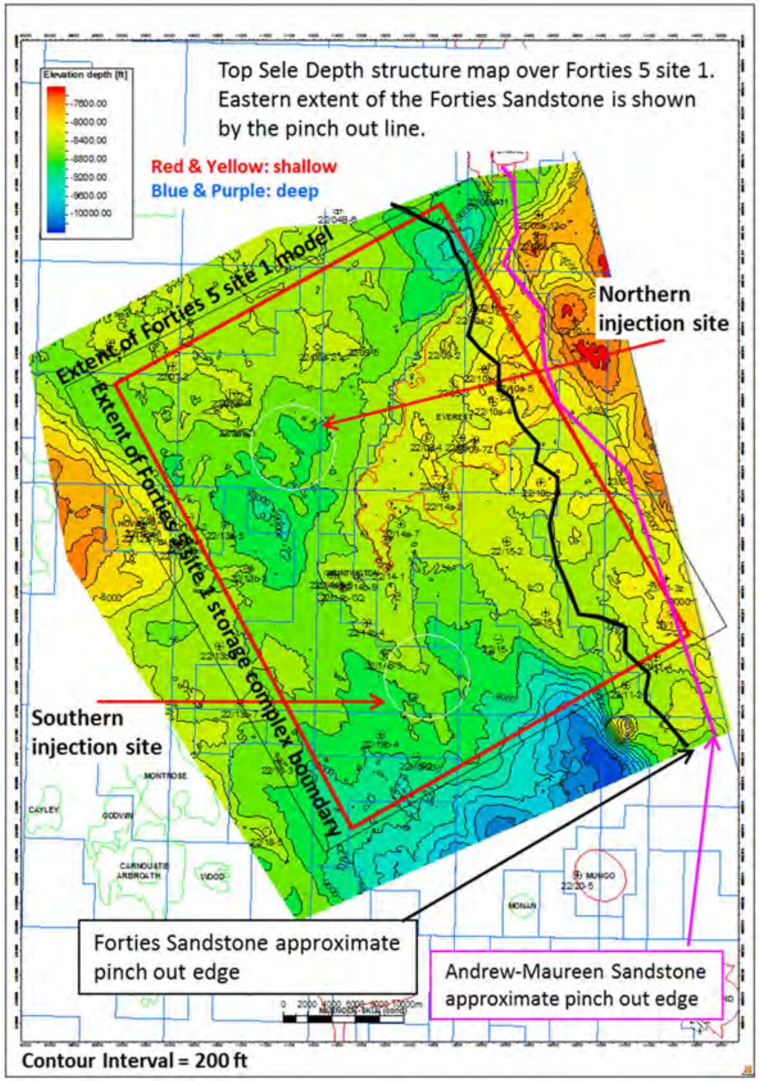


Figure 3-32 Top Sele depth structure map

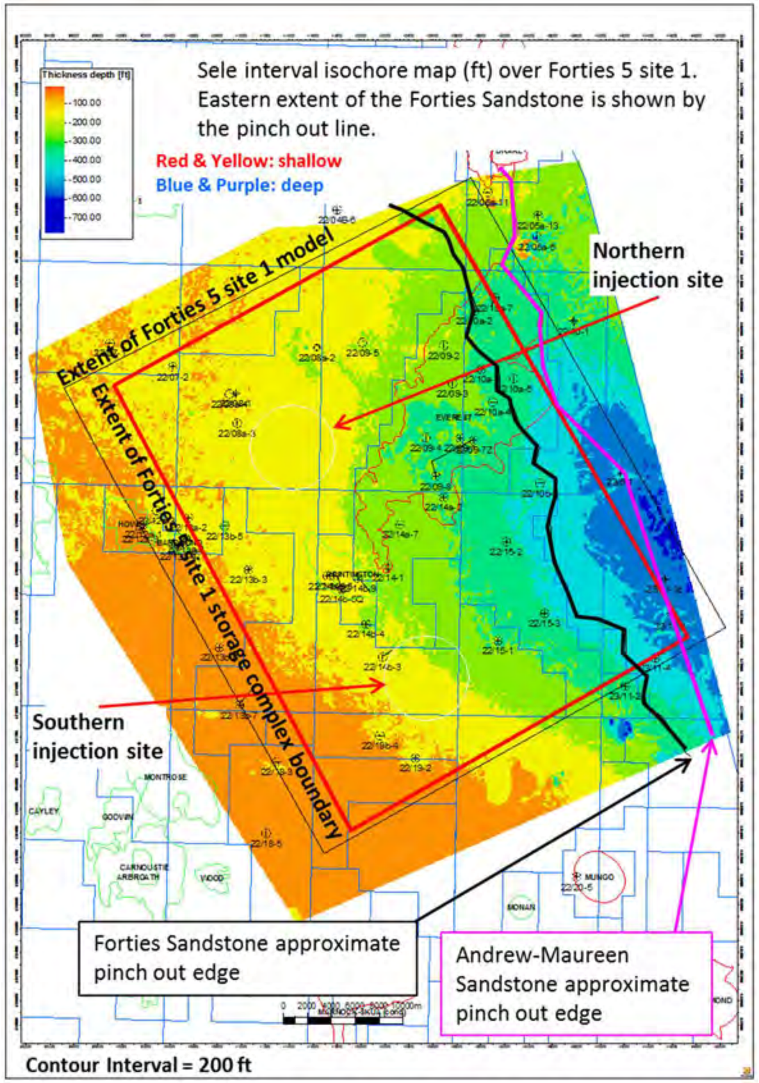


Figure 3-33 Sele isochore map

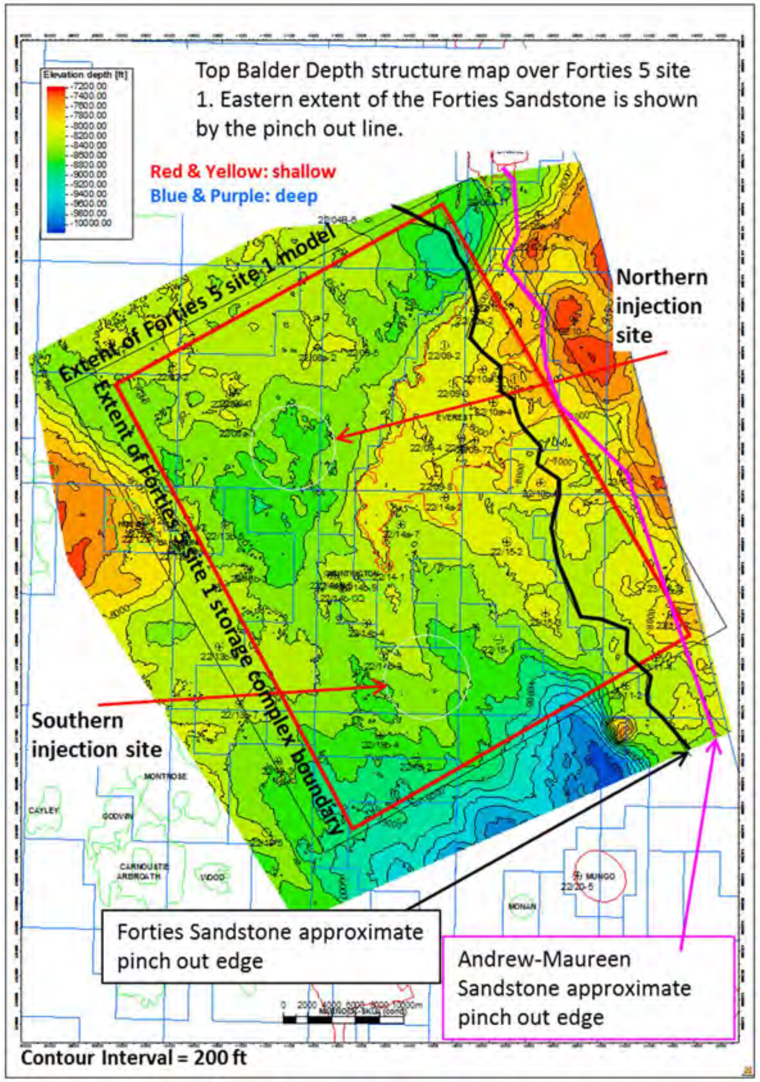


Figure 3-34 Top Balder depth structure map

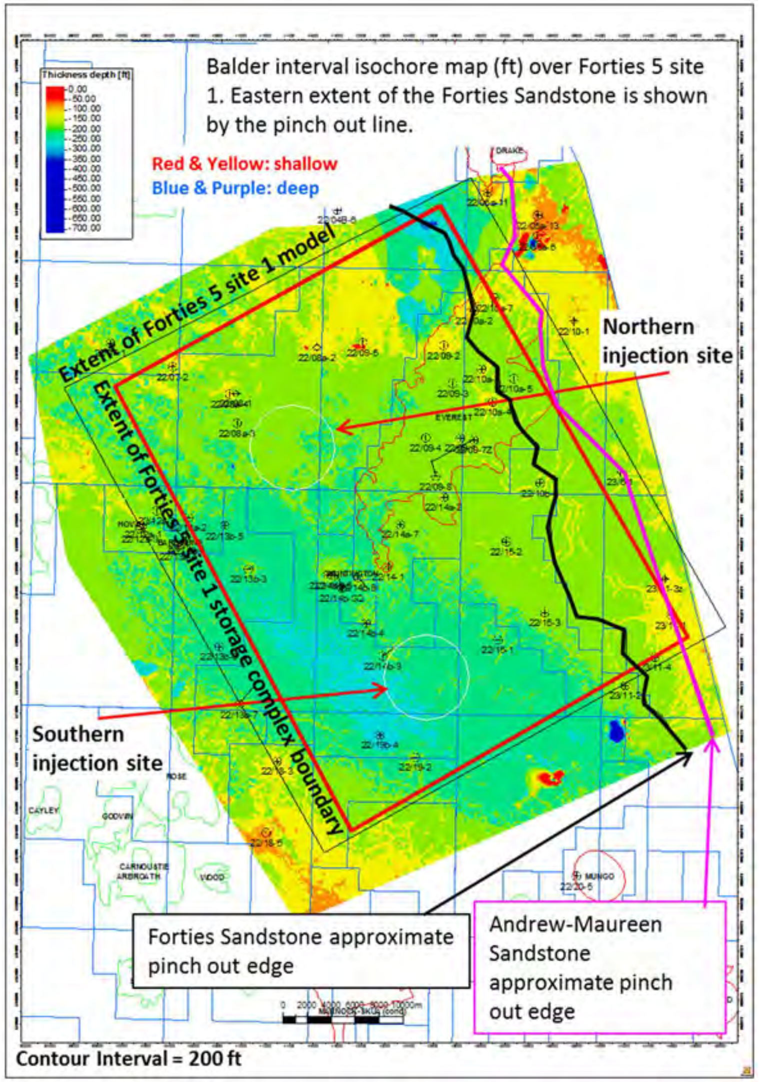


Figure 3-35 Balder isochore map

3.4.6 Depth Conversion Uncertainty

With a simple over burden and numerous well ties within Forties 5 site 1, depth conversion uncertainty was considered unnecessary for this level of study.

3.4.7 Seismic Attributes

Seismic attribute displays have been generated and used for a range of applications in this characterisation of Forties 5 site 1. 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 Forties 5 site 1, 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.

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 especially when pre stack AVO (amplitude versus offset) products are used.

As already discussed in the Forties screening study (Pale Blue Dot Energy; Axis Well Technology, 2015) amplitude extractions from the seismic volume show the approximate distribution of the sand fairways (red, yellow and greens) with the main sand input from the NW and this forms a large elongate NW-SE trending dispersal system. There is also minor lateral input from the west which forms smaller E-W trending fans. Hydrocarbons within the oil and gas fields cause a dimming of the seismic amplitudes.

Figure 3-36 shows the minimum seismic amplitude extracted from a window around the Top Forties seismic horizon (+/-8msec) over the Forties 5 storage site. A qualitative assessment between the well and seismic data shows that in general the more negative the amplitudes the better the sand quality. A clear NW-SE trend can be seen with a dimming of the seismic amplitudes over the Everest and Huntington hydrocarbon fields. Figure 3-37 shows a 3D view of the Top Forties depth surface with the minimum seismic amplitudes draped over the surface. A detailed rock physics study is required to calibrate this such that seismic attributes can be used in a quantitative manner to predict reservoir quality directly.

Both of these attribute groups are affected by the patchwork nature of the PGS 3D mega survey used for this project. The post stack splicing of different 3D seismic surveys with different acquisition and processing parameters makes the quantitative deployment of amplitude challenging and can result in linear artefacts in the attributes along the joins between the surveys. This is one of the motivations behind a recommendation to acquire new purpose designed 3D seismic data for the area ahead of any development.

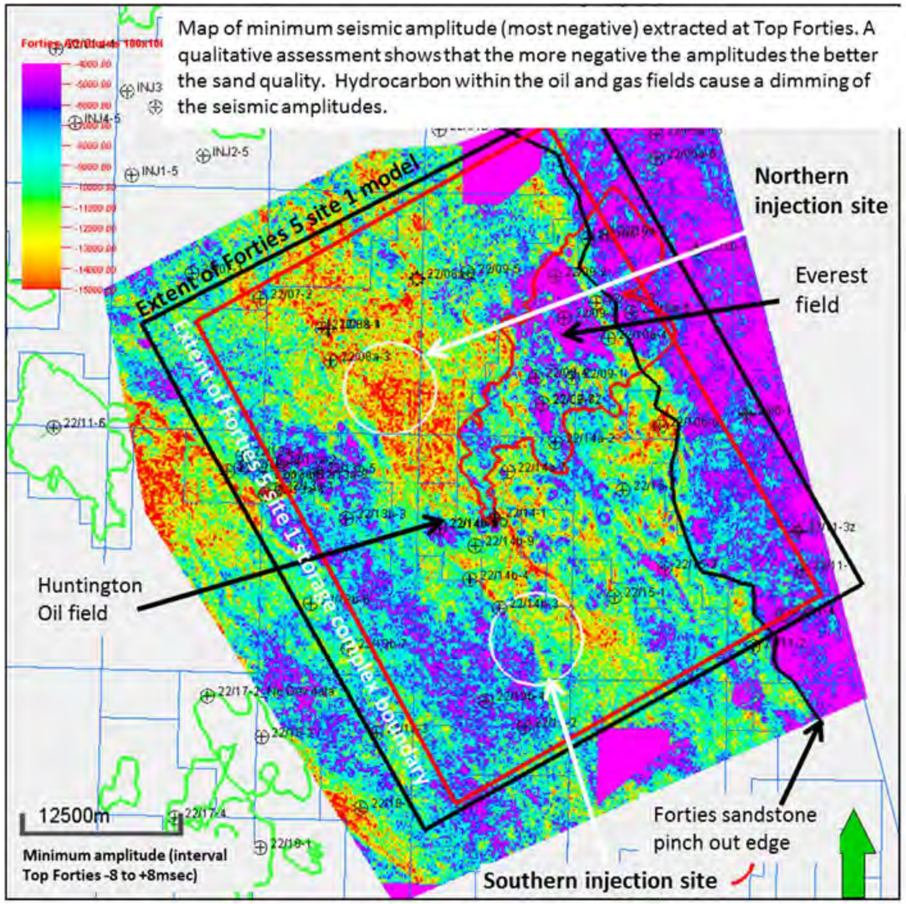


Figure 3-36 Top Forties seismic attribute map

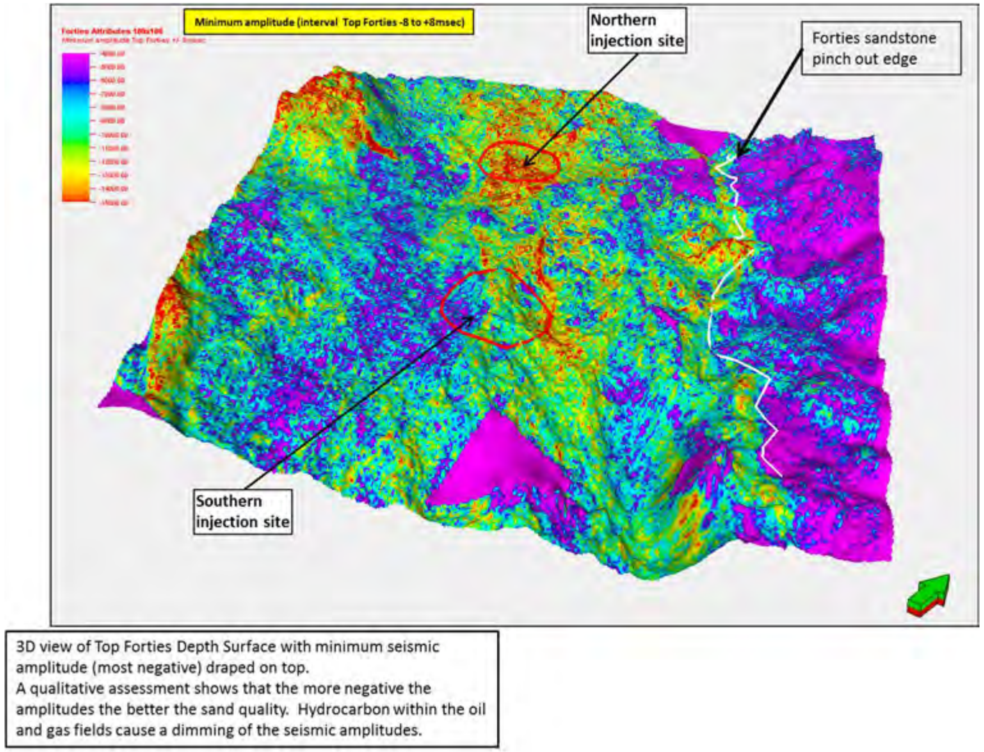


Figure 3-37 3D view of top Forties depth surface with seismic amplitude drape

3.4.8 Conclusions

The PGS Central North Sea MegaSurvey seismic volume which extends over the Forties 5 fairway and site 1 has been interpreted. The key horizons have been identified, interpreted and mapped. Seismic data quality is considered adequate for structural interpretation.

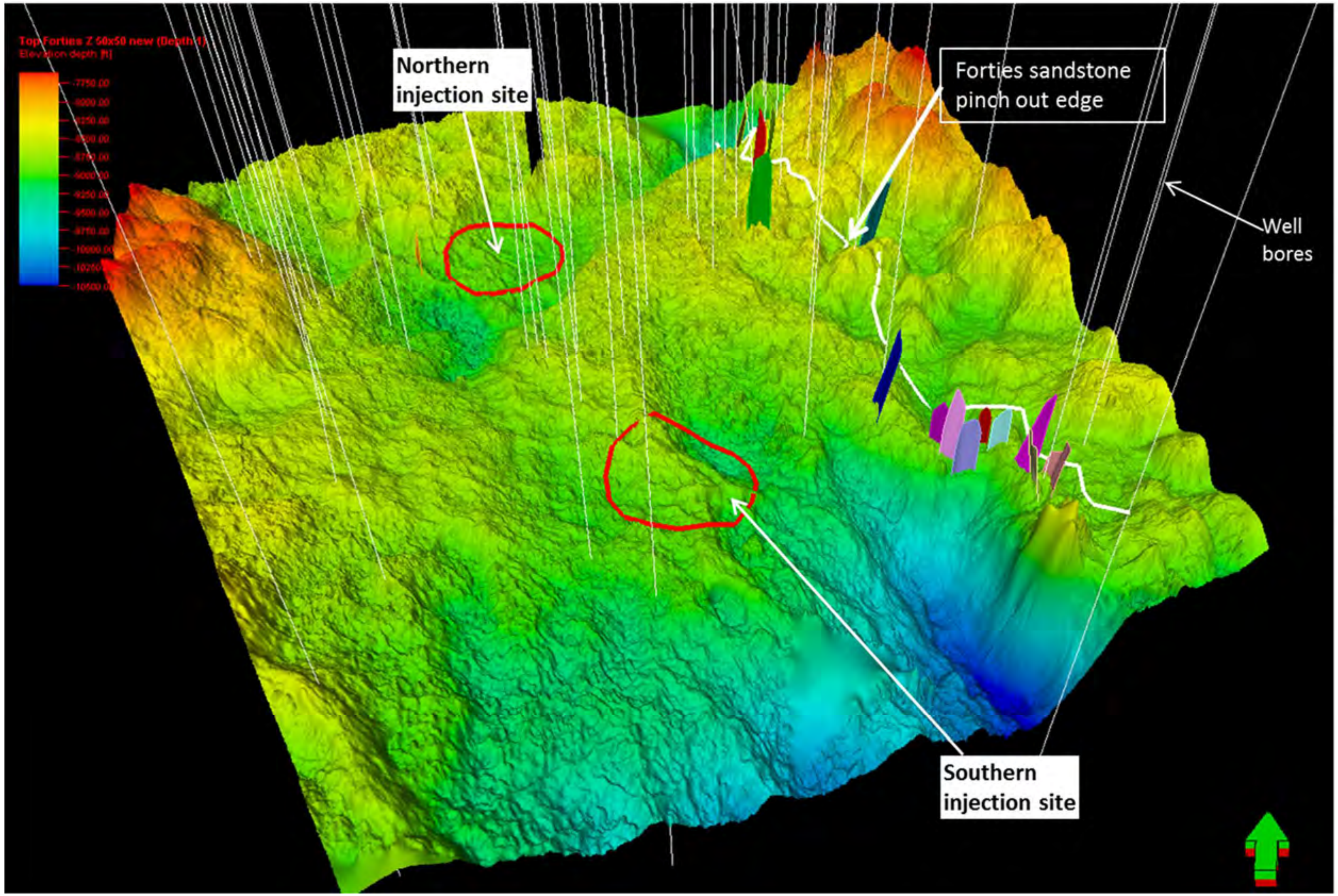
There is no clear evidence of any significant faulting in the reservoir or primary cap rock of the Forties 5 storage site 1 that is considered likely to breach the primary cap rock (Balder and Sele). A small fault in the Sele shale is clearly seen on seismic over the Everest field but the top seal has not been compromised by this fault.

The mapped time surfaces have been depth converted using a combination of a V0+k and interval velocity layer cake depth conversion method. A single layer depth conversion is considered technically the best approach down to Top Forties Sandstone due to relatively small and gradual thickness variations in the overburden Tertiary units.

Generally, the Top Forties Sandstone dips gently at 1 to 2 degrees however locally there are dips of 5 to 7 degrees in places. The irregular surface has many small crests and troughs which can be seen on the seismic lines in Figure 3-8 and as well as in the 3D view of the time surface in Figure 3-15.

Seismic amplitudes appear to show qualitatively reservoir changes. However, an in-depth rock physics study is required to show that seismic attributes can be used in a quantitative prediction of reservoir quality. It is recommended that modern 3D seismic is either purchased (2005 and 2009 CGG multi-client 3D volumes are available) or a new survey is acquired. This would allow pre stack AVO products to be generated to aid quantitative prediction of reservoir quality from seismic data.

Faulted depth structure grids have been taken forward and used as input data for the site and overburden 3D static models (Figure 3-38).



3D view of Top Forties Sandstone Depth structure over the Forties 5 site 1. North and South injection sites shown.
This is the faulted surface that is taken forward to 3D static modelling.

Figure 3-38 3D view of Top Forties Sandstone depth structure

3.5 Geological Characterisation

3.5.1 Primary Store

3.5.1.1 Depositional Model

The primary storage is the Forties Member of the Sele Formation of Palaeocene age.

The depth to the crest of the Everest field is 2530 m tvdss (8300 ft tvdss), although the depth at the planned injection sites is approximately 2745 m tvdss (9000 ft tvdss). The average Forties Sandstone thickness at the site is approximately 115m (380ft). A Top Forties Sandstone depth map for the site is shown Figure 3-39.

The formation rock quality is within the Forties Sandstone is good with a net to gross ratio from wells exceeding 70%, average porosity of approximately 18% (max 35%) and average permeability of approximately 50 mD (max 765 mD)

The Forties Sandstone was deposited in a submarine fan system with turbidites sourced from the northwest and west. The depositional model consists of channel dominated turbidites, with inter-channel facies and shales Figure 3-40 (Hempton, et al., 2005), and (Hollywood & Olson, 2010).

Generally, shales are not considered to be laterally extensive in the site model, and would serve to baffle rather than prevent fluid flow at the scales of the site. Laterally extensive shales related to Maximum Flooding Surfaces (MFS) are interpreted in some hydrocarbon fields within the Forties Sandstone, however further detailed biostratigraphic data would be required to confidently correlate any MFS events within the site area.

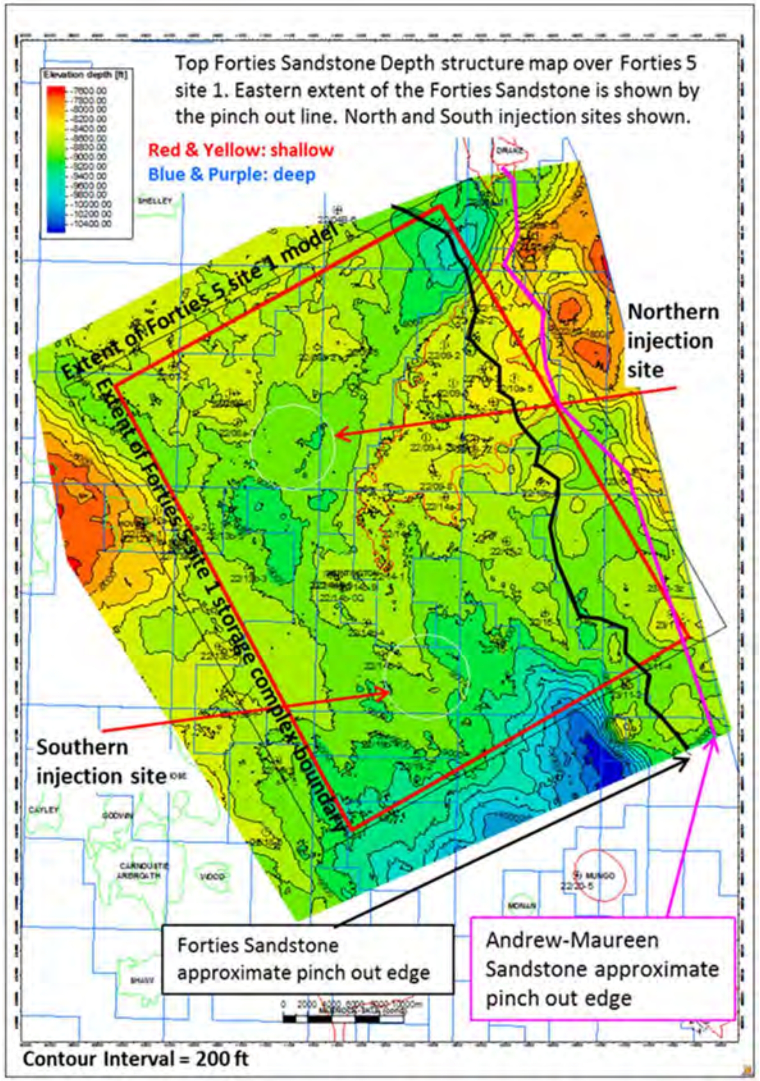
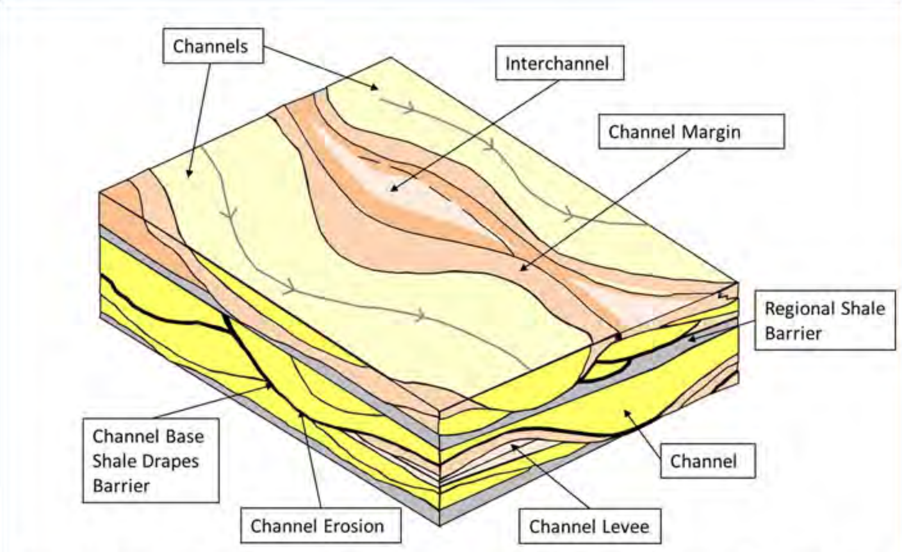


Figure 3-39 Top Forties Sandstone depth map



Schematic diagram representing the reservoir architecture of Forties Sandstone turbidite intervals. The channel facies have the best reservoir characteristics. Channels are approximately 500 -1500m wide

Figure 3-40 Depositional model – Forties Sandstone (Hempton, et al., 2005)

The Forties Argillaceous Unit is the basal unit of the Forties Member, between the oldest Forties sand bed and the top Lista Formation. It is dominated by laminated shales with a low net to gross (NTG) (less than 25%) and easily identified on due to the high gamma ray response seen in wireline log data. It is also informally described as the Lower Forties Shale or the Forties Mudstone.

The Forties Sandstone and the underlying Maureen and Andrew sands pinch out or shale out to the east, this can be interpreted on seismic and validated with data from wells 22/05a-6, 22/05-11, 22/05a-13, 22/10-1, 22/10a-5, 22/10a-7, 23/6-1, 23/11-1, 23/11-3z and 23/11-4.

A well correlation across Forties 5 Site 1 with cored wells is shown in Figure 3-41.

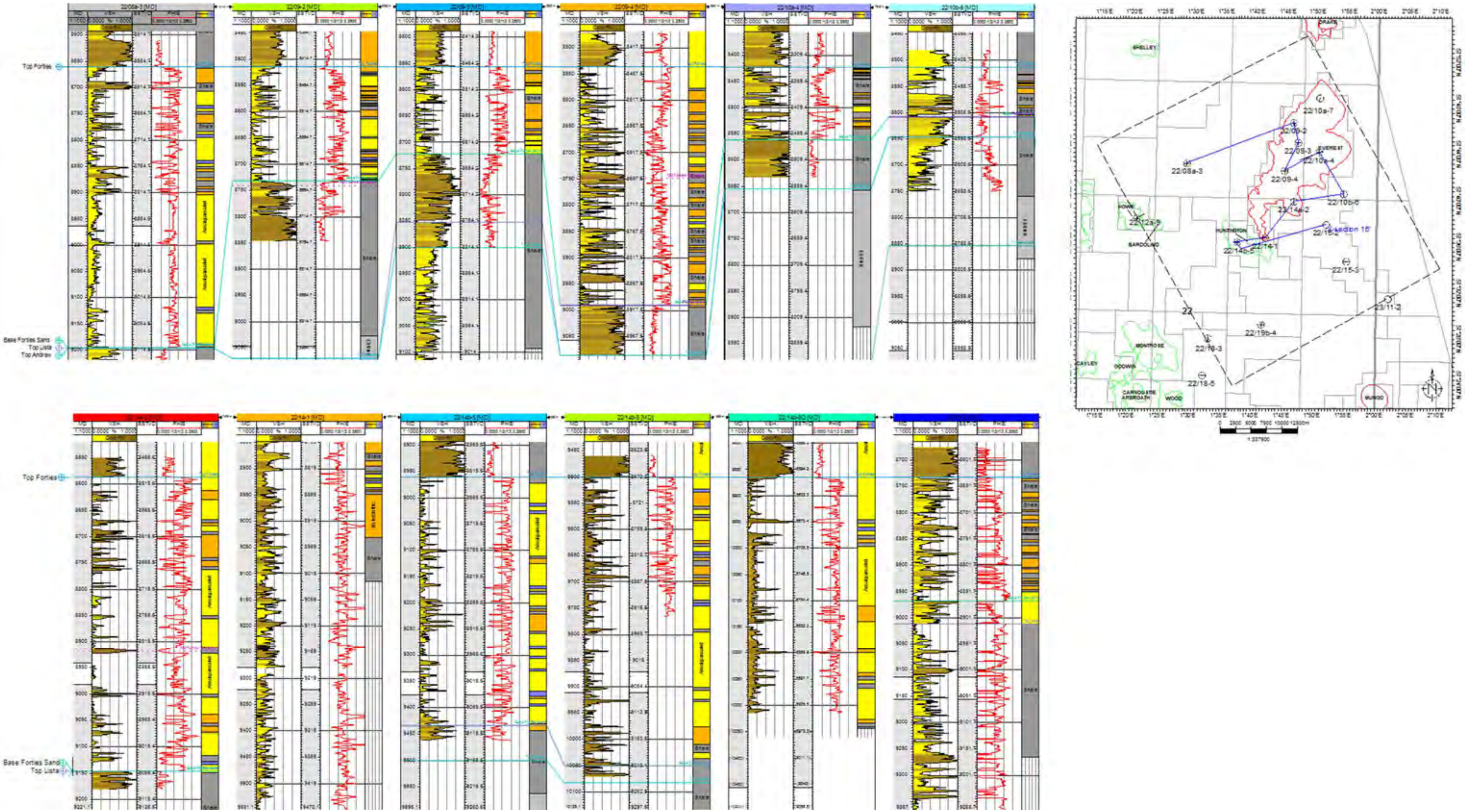


Figure 3-41 Well correlation across Forties 5 Site 1

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 quality of the data is generally good.

Well 22/14b-5 required approximately 15 ft depth shift to match the resistivity and gamma ray curves to the neutron density log, the density log was assumed to be the depth reference in this case.

Conventional core data was available for all the 16 wells for which petrophysical analysis was carried out, although in some wells the core coverage was very limited. These core data include grain density, helium porosity, horizontal and occasionally vertical permeability.

No data was identified to validate the electric properties used for the porosity and saturation exponents. Standard values have been assumed with a=0.62, m=2.15 and n=2.0.

The Forties Area Aquifer is assumed to have an Rw of 0.100 at 60 °F, based on published data for a selection of Forties Fields in the Water Resistivity Atlas (Society of Petroleum Well Log Analysts, 1994).

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 summarised in Figure 3-42.

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 3. 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 Forties Sandstone. The mean zone wireline estimated porosity is slightly lower than the porosity measurement made of the core data of 18.5%. The cause of the apparent discrepancy is unknown without further investigation, but is most likely due to core porosity measurements at ambient conditions not being corrected for overburden. With a typical overburden correction of 0.96 the log versus core porosity are in agreement.

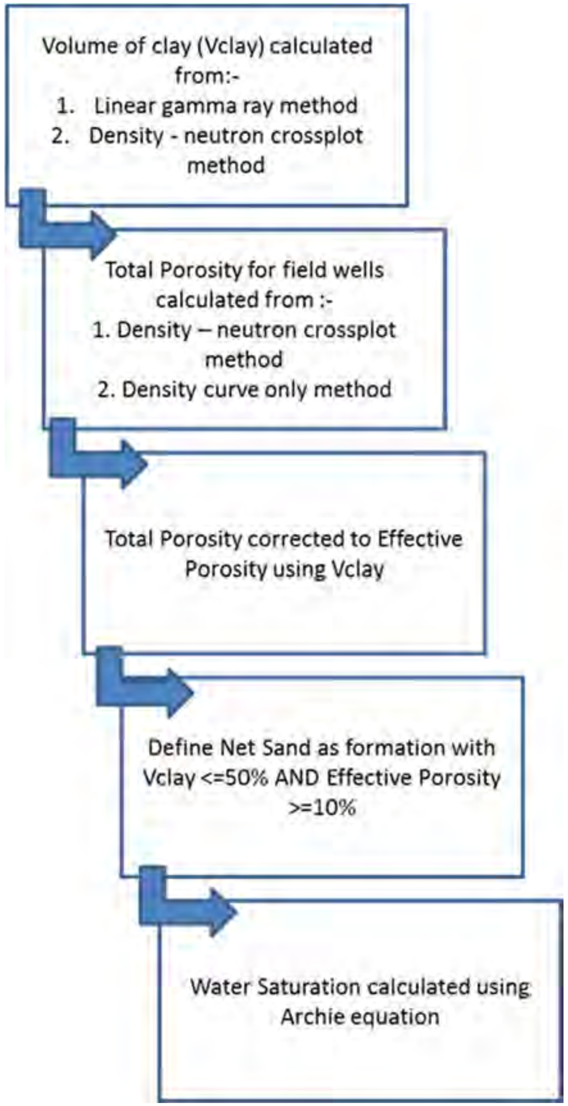


Figure 3-42 Summary of petrophysical workflow

Well	Gross[ft]	Net [ft]	NTG	Porosity	Av Vcl
22/08a-3	535.0	495.50	0.93	0.18	0.13
22/09-2	217.4	191.65	0.80	0.16	0.19
22/09-3	166.0	144.25	0.59	0.17	0.14
22/09-4	454.0	321.25	0.71	0.16	0.14
22/10a-4	138.0	68.50	0.42	0.16	0.16
22/10b-6	94.8	46.25	0.41	0.15	0.22
22/14-1	138.0	64.25	0.72	0.18	0.16
22/14a-2	560.0	475.00	0.85	0.19	0.23
22/14b-5	474.0	390.25	0.82	0.18	0.07
22/14b-6Q	449.0	407.25	0.91	0.18	0.11
22/14b-8	550.0	221.00	0.83	0.17	0.12
22/15-2	229.9	169.13	0.75	0.18	0.18
22/15-3	213.0	149.00	0.56	0.19	0.15
22/18-3	85.9	82.91	0.84	0.17	0.24
22/18-5	333.0	296.75	0.89	0.20	0.14
23/11-2	392.0	139.00	0.36	0.16	0.17
All Wells	**314.4**	**228.87**	**0.74**	**0.18**	**0.15**

Table 3-3 Forties Sandstone net reservoir summary

There is a lot of core permeability data available within the site area, however the majority of this core is from the hydrocarbon interval of fields or discoveries.

Whilst there is no direct evidence that the aquifer permeability at the Forties 5 Site 1 location will be degraded by diagenesis, and studies on some Forties Sandstone fields have shown that there is no reduction in permeability

(Hempton, et al., 2005), uncertainty with regards to permeability within the aquifer remains. Further work to understand the permeability relationship within the Forties aquifer is recommended.

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).

3.5.1.3 Relative Permeability and Capillary Pressure

There is specific SCAL available from the Forties 5 Site 1 data set within CDA. This has been a source of useful capillary pressure and relative permeability information for a number of Everest wells. 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 and 3.7.

3.5.1.5 Geochemistry

Geochemical modelling of the subsurface materials is reported in section 3.5.2.5 and 3.7. Modelling has primarily focussed upon the cap rock reactivity and its potential degradation. The Forties sandstone is typically dominated by quartz with some illite and feldspar. Injection of CO_2 into the Forties Aquifer 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 Forties Sandstone Member is recognised by the rapid transition to the overlying Sele Formation Mudstones. These thick mudstones, and the tuffaceous mudstones of the Balder Formation above, provide the primary top seal for the Forties Sandstone. The same formations also provide an effective seal along the eastern pinch-out edge in fields such as Everest.

The shales and mudstones of the Sele and Balder are laterally extensive and have a combined average thickness of 130 m (430 ft) within the site area.

The Sele shales represent the abandonment and covering of the Forties turbidite fans system by basin shales. The shales of the Balder mark a major transgression, and are interbedded with subaqueous air-fall volcanic ash or tuffs. It is recommended that a full audit is performed of the mud gas logs in the overburden of all wells within the storage complex during FEED.

3.5.2.2 Rock and Fluid Properties

There are no measured core data available for the Sele or Balder intervals at the site location. These intervals are effective seals in nearby hydrocarbon fields and the effective porosity and permeability can be 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 Forties 5 Site 1. Capillary entry pressures are high enough to have successfully trapped a significant gas column of approximately 100m at the Everest Gas field. No production history or GWC movement data from Everest were available to this project.

3.5.2.4 Geomechanics

No significant issues of drillability, or fracturing risk were identified. Further details are included in Section 3.6 and 3.7.

3.5.2.5 Geochemistry

Geochemical modelling of the primary caprock for the Forties Eocene 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. Specifically, the main objective in this study was to assess if, increasing the volume (partial pressure) of CO_2 in the Forties Eocene reservoir sands leads to mineral reactions which result in either an increase or decrease of the porosity and permeability of the overlying Sele Formation caprock.

The approach and methodology used 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 Forties Eocene aquifer lead to mineral reactions which result in either increase or decrease of porosity and permeability of the Sele Formation aquiclude overlying the aquifer?

A dataset of water and gas compositional data for the Forties aquifer and caprock mineralogy was compiled from both published data and technical reports available in the CDA. 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 5000 years and 20000 years as the target timeframes. No equilibrium modelling was undertaken as, due to the metastable smectite content of the Sele Formation, the results are non-representative of reality (under equilibrium modelling, smectite immediately transforms to muscovite and chlorite).

If reactions are kinetically influenced, e.g. by slow dissolution rates, then the rate of interaction with CO_2 is limited by dissolution rate and not the rate of influx of CO_2. 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, Sonnethal, Spycher, & Pruess, 2006)

Rate of Reaction: Kinetic Controls on the Geochemical Impact of CO_2 Injection

Three caprock lithologies, Types 1 to 3 based on a low, intermediate or high smectite content, were modelled were modelled. The main changes modelled in all three Sele Formation caprock types are that: illite is partly replaced by dawsonite (and muscovite), smectite is partly replaced by kaolinite, and calcite is partly replaced by dolomite. Precipitation of siderite, dolomite and dawsonite represent the sequestration of the fluxed CO_2 in the mineral phase. The growth of kaolinite and quartz represent the acidity-induced breakdown of smectite and illite.

Overall, there is a solid volume increase due to CO_2 flooding of the Sele Formation meaning that there is no increase in porosity and thus no increase in permeability.

The same reactions will happen in all three caprock types, but to different degrees of intensity as a function of the initial amount of smectite. The difference between the smectite-poor and smectite-rich lithologies is, however, less than 0.2%, even after 20,000 years.

Summary of Geochemical Impact of CO_2 Injection

Injection of CO_2 into the Forties Aquifer is not expected to lead to any significant risk of loss of containment, either on the injection timescale or in the long term, post-injection. The clay-rich Sele Formation, and younger overburden lithologies, are considered unlikely to be geochemically affected in a way that increases permeability:

1. Mineral reactions are slow, and effectively negligible on the 5,000 year timescale.
2. The reactions that do occur lead to a very small net solid volume increase due to the replacement minerals having low density and reaction with the fluxing CO_2.
3. 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 kaolinite and quartz, releasing the cations: sodium, iron and magnesium, which leads to the growth of the carbonate minerals: dawsonite, siderite and dolomite.
4. Calcite undergoes replacement by dolomite instead of wholesale dissolution.
5. Overall, the most likely mineralogy is represented by caprock-3 (smectite-rich) leading to a miniscule solid volume increase of 0.15% in 5,000 years and 0.86% in 20,000 years.

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

3.5.3 Secondary Store

Forties 5 Site 1 was selected as a preferred location from which to commence a Forties aquifer storage development because of the secure containment and mud dominated overburden. As a result, no secondary store exists above the Forties formation, however the Andrew Sands (Mey Sandstone Member) in the underlying Lista Formation could potentially provide some future upside secondary storage if there is communication between it and the overlying Forties. No communication has been assumed in the reference case model, as the claystone at the top of the Andrew is believed to be regionally extensive. Migration of CO_2 within the aquifer is also assumed to be upwards, with little or no migration into deeper intervals.

The Mey Sandstone Member occurs over most of the Outer Moray Firth and extends into the Central Graben and was deposited as one of a series of Palaeocene submarine, turbidite fans. Within the site area it is present as the Andrew Sand which over the area is characterised as quite heterogeneous in nature, although the sands are laterally extensive with sand body dimensions in the region of 8 – 12 Km.

The Andrew Sand (and deeper Maureen Sands) are secondary hydrocarbon reservoirs at the Everest Field, where it has a thickness of 90 – 120 m (300 –

400 ft). At the Everest Field these deeper reservoirs are believed to be isolated from the shallower Forties Sandstone reservoir.

Detailed study of the Andrew Sands has not been completed here, but is recommended ahead of any development. Based on the work carried out the reservoir quality of the Andrew sands within the site area is good, with a NTG in the region of 50% and average porosity from log interpretation of 17%. No core permeability data were available for the Andrew Sands in the data reviewed. It has been assumed that the permeability range will be similar to that seen in the overlying Forties Sandstone, however there is uncertainty associated with this assumption. Further work would need to be carried out to identify and review any available Andrew Sand core or core analysis data that may be publically available from CDA.

3.5.4 Static Modelling

Three static models have been built as part of the characterisation effort of Forties 5 Site 1:

- Primary Static Model- this has been developed over an area which includes the Forties 5 Site 1 area. The purpose of this model is to serve as a basis for building an effective reservoir simulation model over the site.
- Fairway Model- The second model is semi-regional in nature and covers a very large area (approximately 14,000 km^2) across the Forties 5 aquifer. This model was built during the screening with the purpose of selecting the final site and understanding connectivity to nearby hydrocarbon fields and CO_2 storage sites.
- 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

Grid Definition

The static model described in this section focuses on the site geological model for the Palaeocene Forties 5 Site 1. Maps of the input horizons for Top Forties and Base Forties Sandstone within the site area are shown in Figure 3-43.

The area selected for the site model covers a large area of approximately 1634 km^2 (43km x 38km), the coordinates of the site model boundary are

X Min 395157.98 X Max 449737.81

Y Min 6362344.30 Y Max 6418659.98

Reservoir modelling has been carried out using Petrel v2014.

Reference system used ED50 (UTM31).

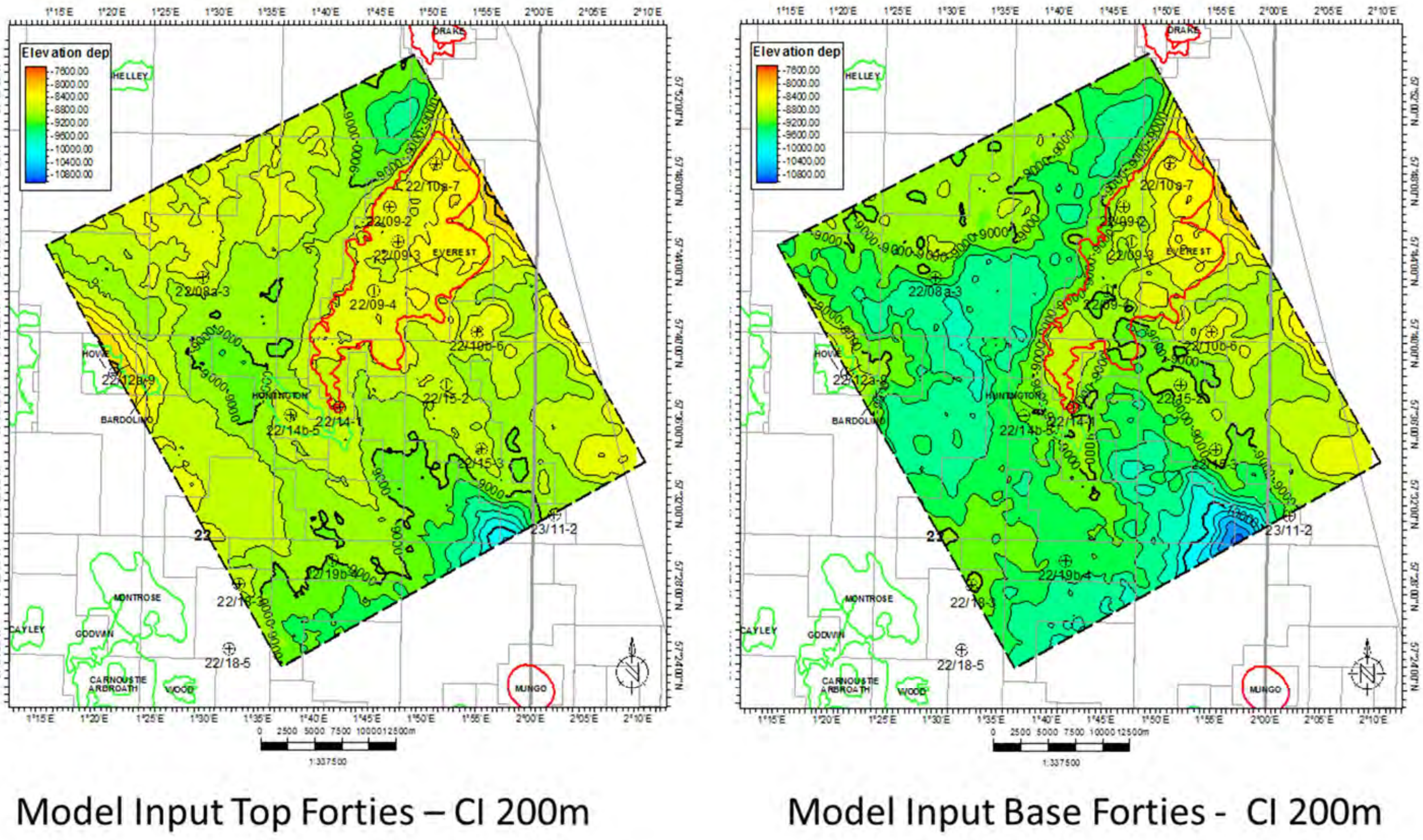


Figure 3-43 Modelled depth maps

The stratigraphic interval for the primary site model extends from the Top Sele Formation down to 76m (250 ft) below the Top Lista. The primary seal for this interval is the overlying Sele Formation.

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 Sele	Sele	Direct seismic interpretation and depth conversion	1
Top Forties Sand	Forties	Direct seismic interpretation and depth conversion	100
Base Forties Sand	Forties Argillaceous	Direct seismic interpretation and depth conversion	1
Top Lista	Lista	Built down from the Top Forties Sand using well derived isochore	2
Top Lista +250			

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

The Top Sele, Top Forties Sand and Base Forties Sand depth horizons within the static model were created from the depth surfaces interpreted from the seismic and time to depth converted (this is discussed and illustrated in Section 3.4.5). The Top Lista was generated by building down from the Top Forties Sand using an isochore map derived from well data.

The top of the model is the Top Sele, this is impermeable and is represented in the model by a single layer.

The base of the model been generated by adding 76 m (250ft) to the Top Lista. The Lista has Andrew sands, which may be connected to the overlying Forties Sand, where the Forties Argillaceous unit is absent. These deeper sands may provide both additional aquifer volume (providing pressure dissipation under injection) and future potential upside secondary storage. The reference case assumes that the Andrew Sands are not connected to the overlying Forties Sand.

No faults have been incorporated into the model as only small minor faults have been interpreted within the primary site model area.

A cross section through the structure showing the different zones and layering within the model is shown in Figure 3-44.

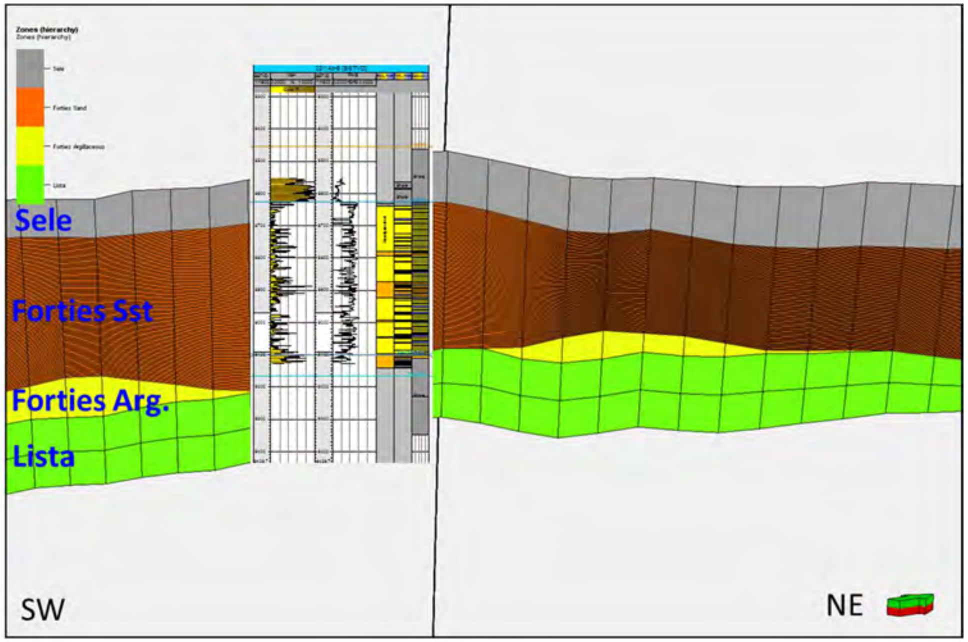


Figure 3-44 Cross section through the 3D grid at well 22/14b-5 (Huntington field)

The site model 3D grid was built with a rotation of 35° 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 layering per zone is shown in Table 3-4.

The resulting grid has approximately 5.6 million grid cells.

3.5.4.2 Property Modelling

The Forties Sandstone Member was deposited as turbidites from the northwest and west (Hempton, et al., 2005).

The Forties Sandstone interval has a high average net to gross of over 70%, whereas the underlying Forties Argillaceous interval has a low net to gross of approximately 20%. The primary storage reservoir and focus of the static modelling is the main Forties Sandstone interval.

Forties Sandstone

In a sandy system such as the Forties Sandstone, one of the key controls on CO_2 plume migration will be thin shales and cemented sand layers which act as barriers and baffles to vertical flow. To allow for these to be explicitly captured within the static model a facies model has been built.

Porosity within the Forties 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.

Forties Argillaceous and Lista (Andrew) Sandstone

These have been modelled with well based interpolation of zone average properties (NTG, Porosity, Permeability).

3.5.4.3 Facies Log Interpretation

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

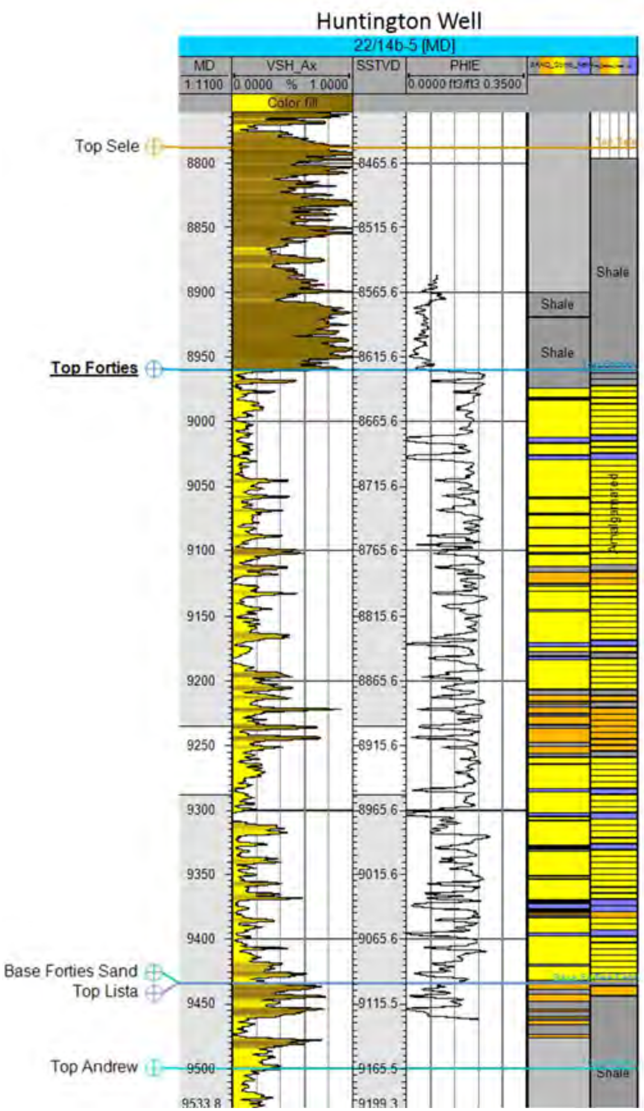
1. Three depositional facies associations have been interpreted using a combination of average Vshale and sandstone bed thickness:

- Amalgamated – Highest quality reservoir consisting intervals of stacked and amalgamated thick bedded sands. This sand rich association is likely to be the product of high density turbidity currents representing lobe axis or depositional channel.
- Heterolithic – Dominated by heterogeneous facies deposited in low density turbidite currents. This association represents several different sub-environments including both lobe margin on the flanks and more distal lobe margins.
- Shales/ silts – These represent lobe fringe and interlobe/ lobe abandonment shales which are considered to be non-reservoir facies.

2. The final facies model is lithology based. This step adds the detailed heterogeneity within the depositional facies associations. Thin shale and calcite cemented beds are interpreted within the existing amalgamated and heterolithic depositional associations using log cut-offs. The cut-offs used are shown in Table 3-5.
3. Facies logs have been calculated for 28 wells, and these have been used to control the facies modelling: 22/07-2, 22/08a-2, 22/08a-3, 22/08a-4, 22/09-1, 22/09-2, 22/09-3, 22/09-4, 22/09-5, 22/10a-4, 22/10b-6, 22/12a-3, 22/13a-4, 22/13b-3, 22/13b-6, 22/14-1, 22/14a-2, 22/14a-7, 22/14b-4, 22/14b-5, 22/14b-6Q, 22/14b-8, 22/15-2, 22/15-3, 22/18-3, 22/18-5, 22/19b-4 and 23/11-2.
4. An example of the depositional facies log, lithology facies log and final upscaled lithology log is shown in Figure 3-45.

Amalgamated Sand	**Depositional Facies = Amalgamated** **Vsh:<=0.35**
Heterolithic Sand	Depositional Facies = Heterolithic Vsh:<=0.35
Shales/ silts	Depositional Facies = Amalgamated or Heterolithic Vsh > 0.35
Cemented Sands	Clean sand (Vsh <=0.35) with density and/ or sonic spike: RHOB > 2.4 and sonic <=80

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



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

Figure 3-45 Example of facies interpretation at 22/14b-5

3.5.4.4 Facies Modelling

The facies modelling was only done in the Forties Sandstone interval, and was carried out in two stages (Figure 3-46):

1. Depositional Facies

Three depositional facies associations have been modelled, as interpreted within the wells: amalgamated, heterolithic and shales/ silts.

Amalgamated facies and shales have been modelled as objects within a background of heterolithic facies. This fits with the conceptual model of lobe and channel sands with decreasing reservoir quality towards the margins.

The proportion of shales and sands is calculated based on well data within the site area. The vertical and horizontal distribution of these is controlled by a 3D trend based on average net to gross values for the Forties Sandstone (Figure 3-47).

2. Lithology Facies Model

In the second step detailed heterogeneity is modelled within the depositional facies associations. This allows for heterogeneity within the amalgamated and heterolithic depositional facies associations to be fully captured.

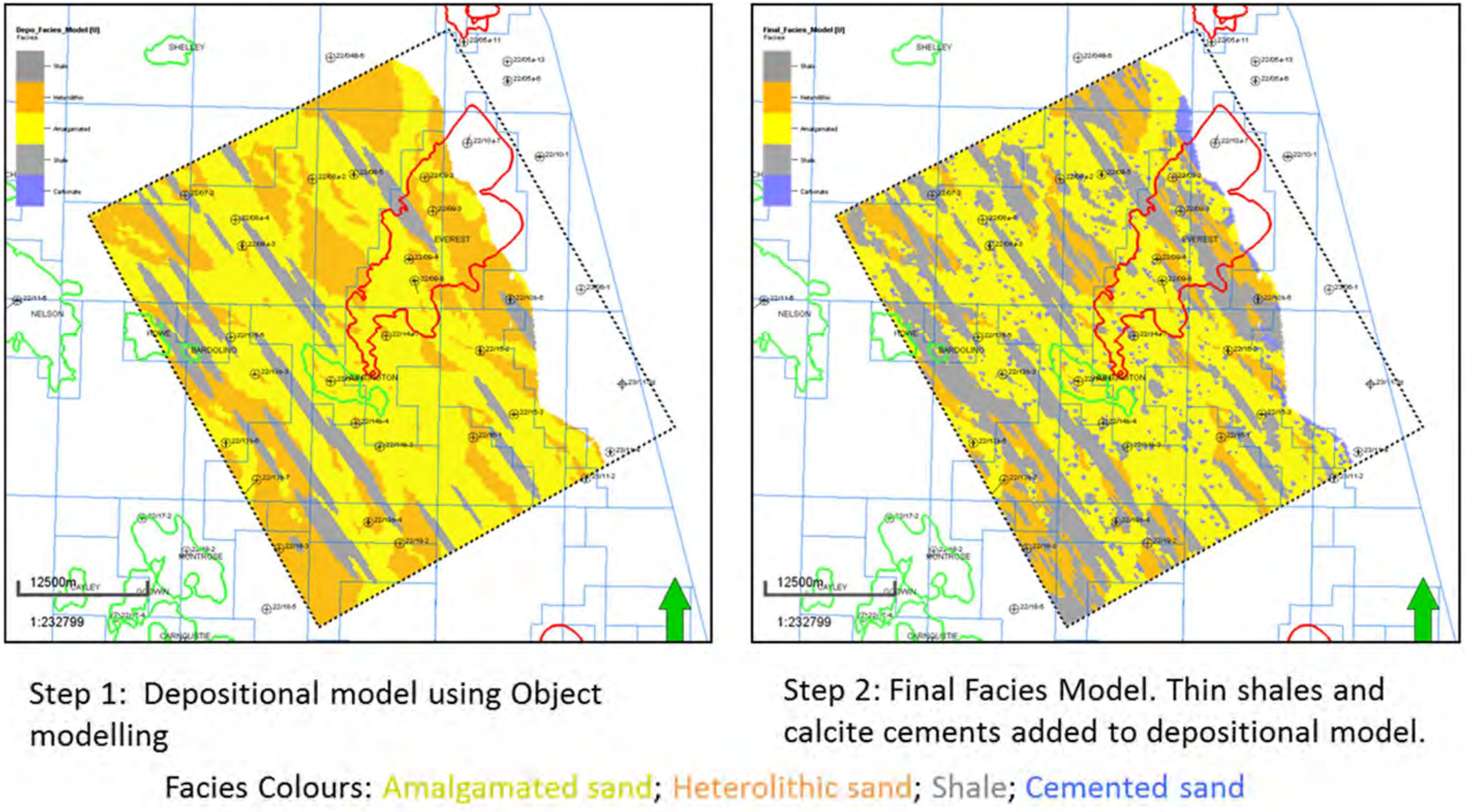


Figure 3-46 Depositional and final facies modelling results - single layer

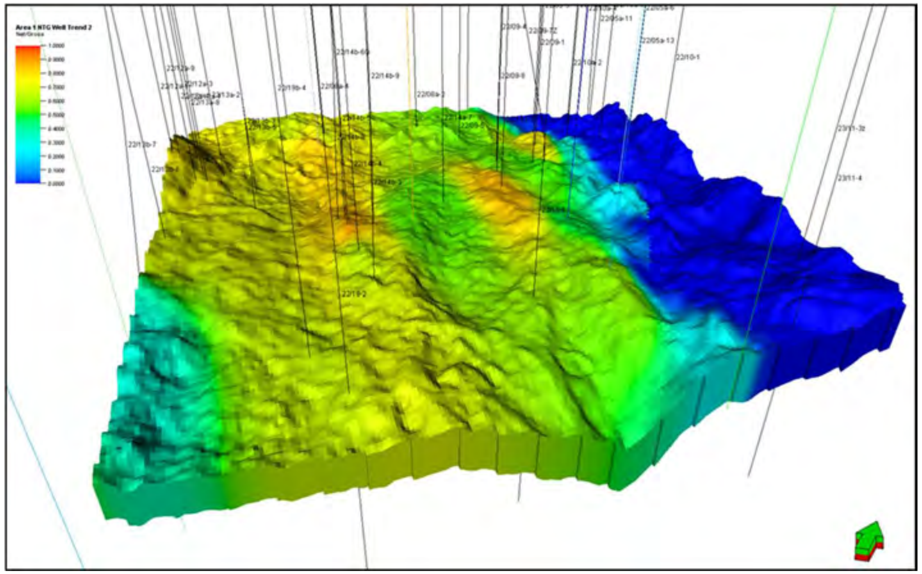


Figure 3-47 3D View of facies model trend derived from well NTG mapping

The type and sizes of the objects used in the modelling are shown in Table 3-6 and Table 3-7 below.

The orientation of the axis of the amalgamated sands and shale objects has been aligned with the depositional direction, approximately NW – SE.

Facies	Object shape	Orientation [Degrees]	Amplitude [m]	Wavelength [m]	Width [m]	Thickness [m]
Amalgamated	Channel	-40 to -35	(Triangular) 200-400-500	(Triangular) 1000-1500-2000	(Triangular) 1000-1500-5000	(Triangular) 10-20-30

Table 3-6 Input properties used for object modelling of Amalgamated depositional facies

Facies	Object shape	Orientation [Degrees]	Width [m]	Length/ Width ratio	Thickness [m]
Shale	Ellipse	-35	(Triangular) 750-1000-1500	(Triangular) 2-10-15	(Normal) 12 (SD=5)

Table 3-7 Input properties used for object modelling within the depositional facies of Shale depositional facies

Deposition Facies Association	Facies	Method	Orientation [Degrees]	Variogram Length [m]	Variogram Width [m]	Variogram Thickness [m]
Heterolithic	Heterolithic Sand	SIS	-35	5000	1000	3
	Silt/shale	SIS	-35	5000	1000	3
	Cements	SIS	-35	5000	1000	3

Table 3-8 Input properties used for SIS modelling in Forties final facies model, which uses the initial depositional Heterolithic sands as input

Deposition Facies Association	Facies	Method	Object shape	Orientation [Degrees]	Minor width [m]	Maj/ Min ratio	Thickness [m]
Amalgamated	Shale	Object	Ellipse	-35	(Triangular) 500-1500	(Triangular) 1-2.5	(Uniform) 1-5
	Cement	Object	Ellipse	-35	(Triangular) 200-500	(Triangular) 0.75-1.5	(Normal) 1-3

Table 3-9 Input properties used for object modelling in Forties final facies model, which uses the initial depositional amalgamated sands as input

Shales/ Silts

Within the shale/ silt depositional facies association no additional facies modelling has been carried out. They are assumed to be non-reservoir facies.

Heterolithic

Within the heterolithic depositional facies association, heterolithic sands, shales and cements are modelled using sequential indicator simulation (SIS).

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 3-8. A 3D NTG trend volume derived from well data has been used to control the proportion deposition of sands and shales.

Amalgamated

Within the amalgamated depositional facies association, shales and cements are modelled using object modelling with the initial amalgamated facies assigned as the background sand facies.

Sand, shale and cement proportions have been calculated from well data. Vertical proportion curves have been used to control the vertical distribution of the modelled shale facies (Figure 14). The orientation has been aligned with the depositional direction, approximately NW – SE. Variogram ranges and settings are shown in Table 3-9.

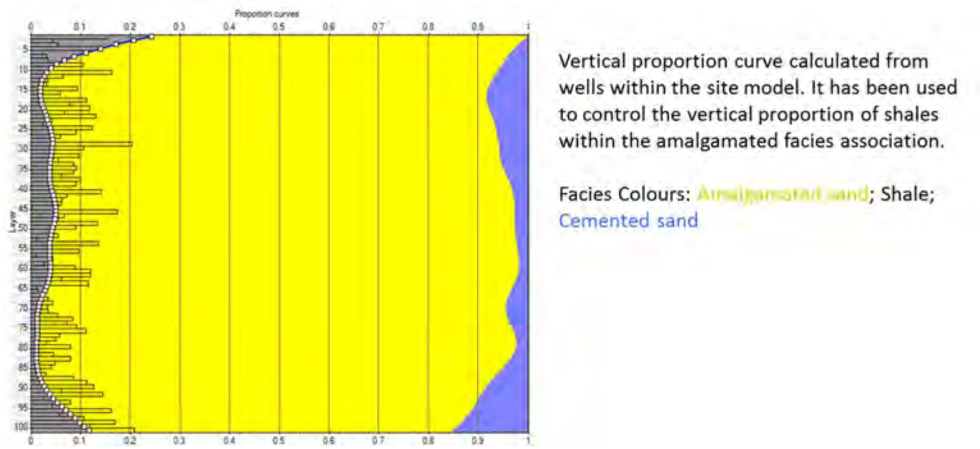


Figure 3-48 Vertical proportion curves

Modelled facies proportions are shown in Table 3-10

Model Results	Amalgamated (Sand)	Heterolithic (Sand)	Shale	Cement
Depositional Facies Model	52%	37%	11%	N/A
Final Facies Model	43%	19%	34%	4%

Table 3-10 Modelled facies proportions for depositional model and final facies model

A cross section through the final facies model is shown in Figure 3-49.

No facies modelling has been done within the Sele, Forties Argillaceous and Lista intervals.

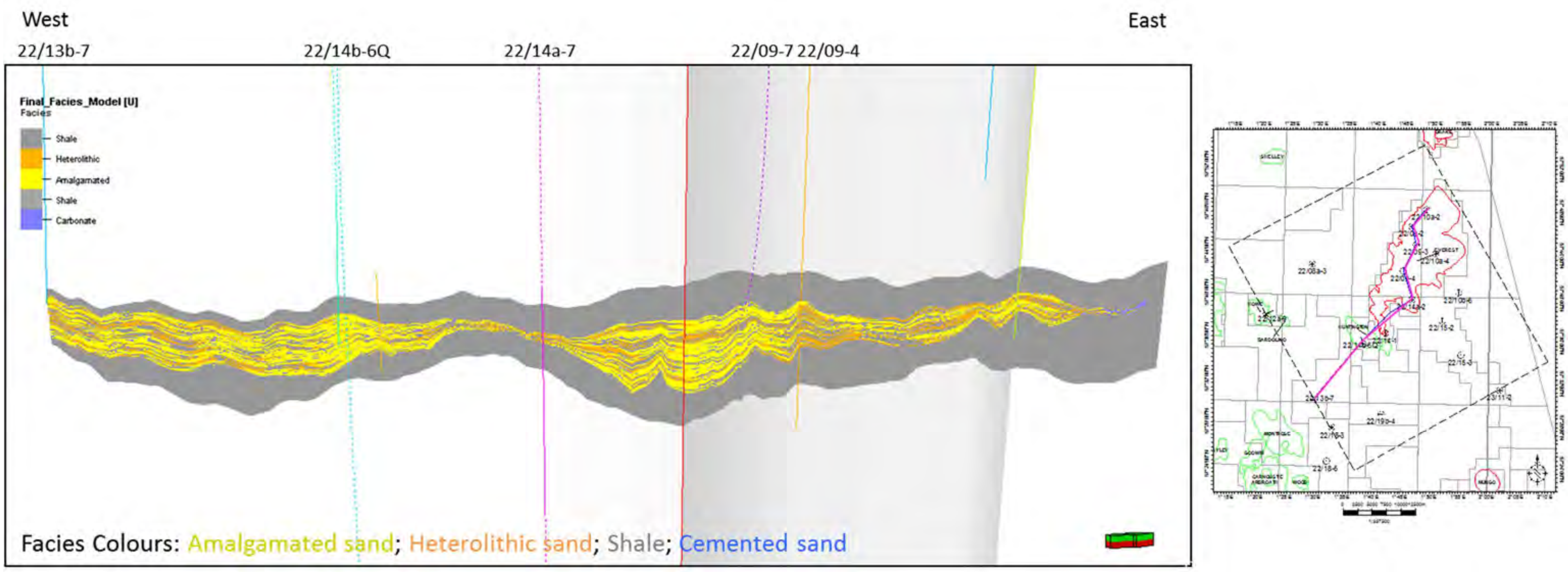


Figure 3-49 West to East cross section through site showing final facies model

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: 22/08a-3, 22/09-2, 22/09-3, 22/09-4, 22/10a-4, 22/10b-6, 22/14-1, 22/14a-2, 22/14b-5, 22/14b-6Q, 22/14b-8, 22/15-2, 22/15-3, 22/18-5, 22/18-3, 23/11-2.

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. Properties within each sand facies (Heterolithic and Amalgamated) were distributed separately within the model using a Gaussian random function simulation method, 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 3-11.

Sands	Type	Major Axis [m]	Minor Axis [m]	Vertical [m]	Azimuth [deg]
Heterolithic	Spherical	5000	1000	3	-35
Amalgamated	Spherical	5000	1000	10	-35

Table 3-11 Input setting for porosity and permeability SGS modelling

A histogram showing a comparison of the porosity well log input versus the modelled porosity for the sand facies is shown in Figure 3-50.

Average modelled porosity values by zone are shown in Table 3-12.

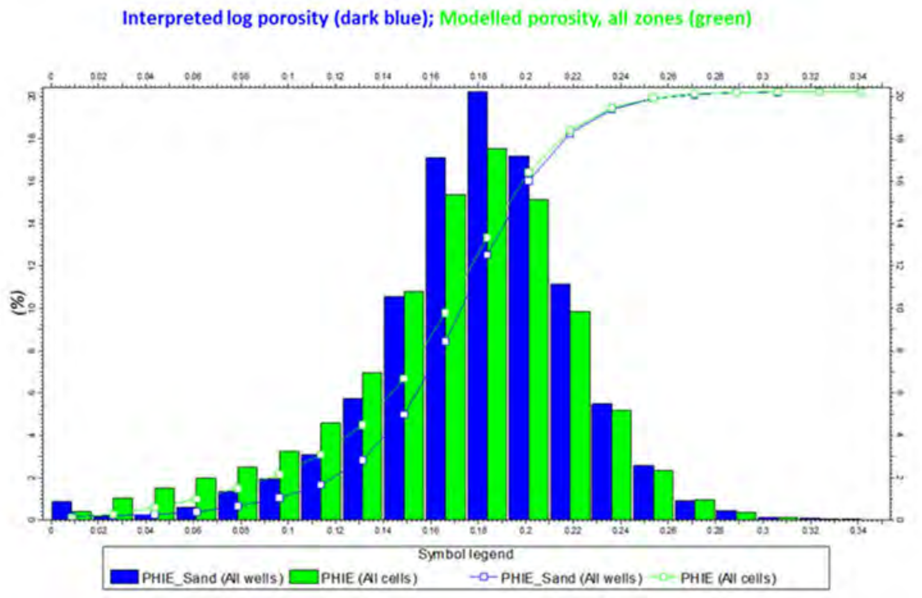


Figure 3-50 Histogram of porosity within sand facies

Facies	Average porosity (%)
Heterolithic Sand	15.8
Amalgamated Sand	17.5
All sands	17.0

Table 3-12 Average modelled porosity values for sand facies

3.5.4.6 Forties Argillaceous and Lista porosity

The porosity PHIE raw log extends down through the Forties Argillaceous and into the top of the Lista zones. The interpreted PHIE log is upscaled as per the Forties zone with the properties within the Forties Argillaceous and Lista zones distributed in the model, between wells, using a moving average method.

Settings for the modelling are shown in Table 3-13.

Zones	Major/Minor Ratio [m]	Vertical [m]	Orientation [deg]	Weighting
Argillaceous and Lista	3	200	-35	Inverse distance quadrupled

Table 3-13 Input setting for porosity and permeability

3.5.4.7 Permeability Modelling

As observed in core data, there is a strong positive correlation between the measured core porosity and core permeability. Horizontal permeability within the sand facies is 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.

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 cross plot of porosity versus permeability for both the measured core data and final modelled data are shown in Figure 3-51 and Figure 3-52.

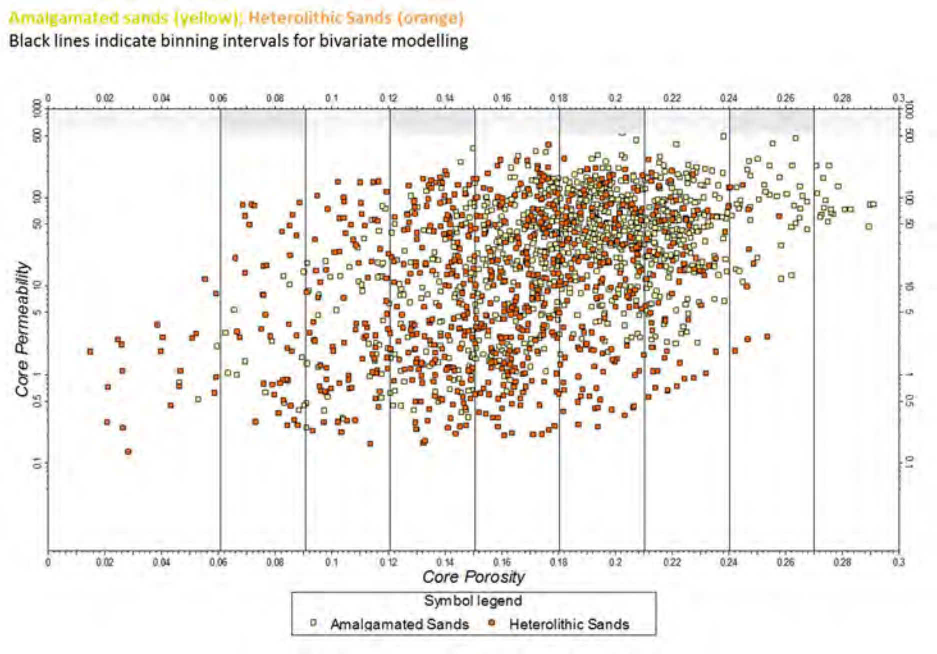


Figure 3-51 Cross plot of core porosity versus permeability

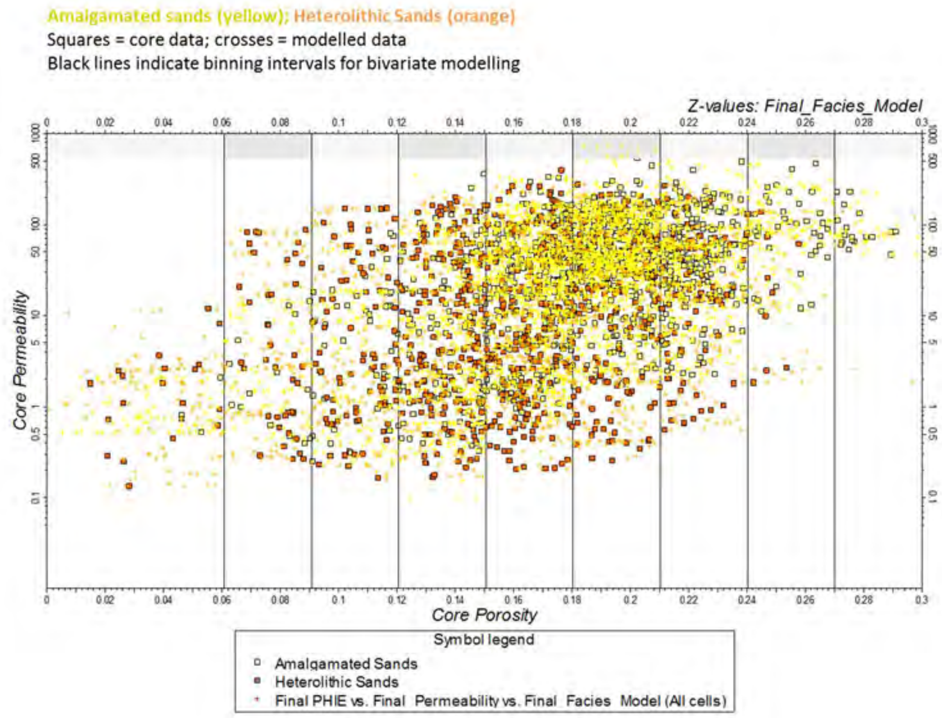


Figure 3-52 Cross plot of core porosity versus permeability modelling results

The average horizontal permeability from core is 48 mD which compares to the average modelled horizontal permeability of 47.5 mD. A histogram showing the horizontal permeability for the sand facies is shown in Figure 3-53 .

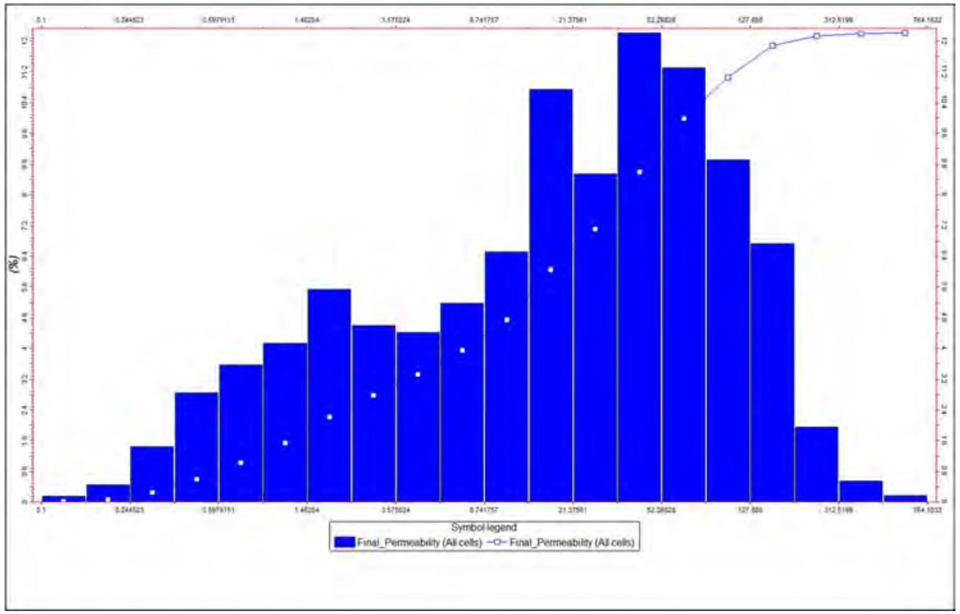


Figure 3-53 Histogram of modelled horizontal permeability

Average horizontal permeability values by Facies are shown in Table 3-14.

Sand	Average Kh in sand facies
Heterolithic Sand	33 mD
Amalgamated Sand	54 mD
All sands	47mD

Table 3-14 Average modelled horizontal permeability values for facies

Limited vertical permeability data were available in the core data set. A strong correlation between horizontal and vertical permeability is observed in the available core, this has been used to generate a function which has been used to calculate vertical permeability within the static model (Figure 3-54).

Derived function: log(kv) = 1.11093 * log(kh) - 0.332788

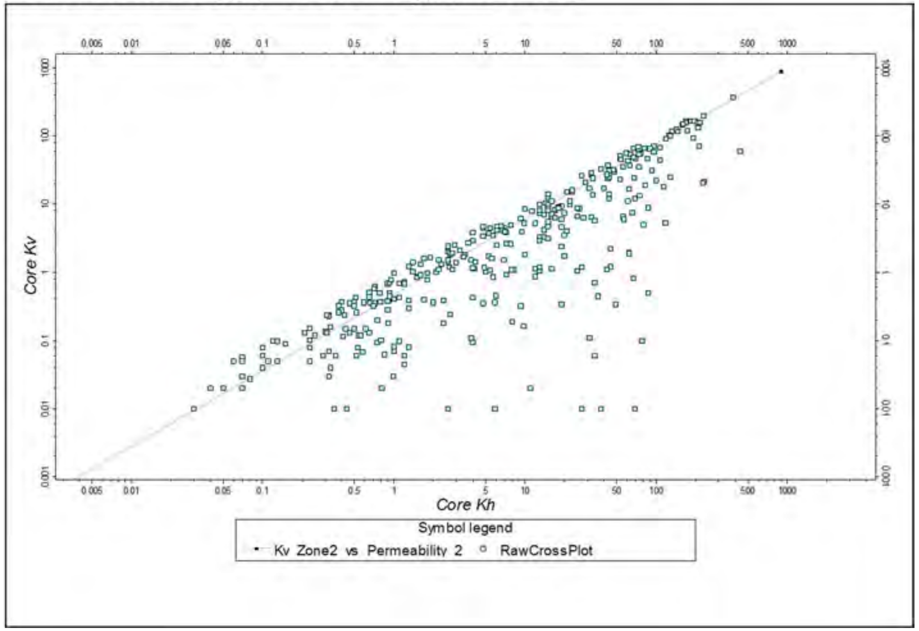


Figure 3-54 Cross plot of horizontal versus vertical core permeability (log scales)

The average modelled vertical permeability is 37 mD, the average Kv /Kh ratio is 0.65.

Forties Argillaceous and Lista permeability

The core plot used to create a bivariate split by sand facies (heterolithic and amalgamated) were also used as functions for the zones below the Forties Sandstone. The heterolithic function was used for Forties Argillaceous, and the amalgamated function was used for Lista (Top 250ft). This results in the Lista having a higher permeability than the Forties Argillaceous which is consistent with core data and literature.

The average horizontal permeability for the Forties Argillaceous is 5.9 mD, with the Lista higher at 21.4 mD.

3.5.4.8 Rock and Pore Volumetrics

Volumes in the static model have been calculated for the entire Forties 5 Site 1 model and are shown in Table 3-15.

Zones	Bulk volume [*10^6 m^3]	Pore volume [*10^6 m^3]
Sele	118,278	0
Forties	167,654	18,882
Forties Argillaceous	57,618	2,231
Lista (Top 250ft)	118,872	10,164
Total	462,422	31,278

Table 3-15 Gross rock and pore volumes for entire Forties 5 site model

3.5.4.9 Simulation Model Gridding and Upscaling

To enable dynamic simulation models to run within a reasonable time frame, a coarser simulation grid and model was generated. Horizontal and vertical coarsening from 200m x 200m with 104 layers in the static model, to 400m x400m with 44 layers in the dynamic model has been used to reduce the number of cells from approximately 5.7 million to 768,600. The model area (~44km x 38km), zonation, and grid orientation (-35°) remain the same as the static model.

A fractional layering scheme has been used for the simulation grid, this allows for the cells at the top of each zone to retain the same vertical resolution, with thicker cell thicknesses in the deeper layers only. This ensures that the heterogeneity is retained at the top of each zone where it is expected the majority of the CO_2 plume migration will take place.

A comparison of the layering between static and dynamic models is shown in Figure 3-55. The layering scheme is summarised in Table 3-16.

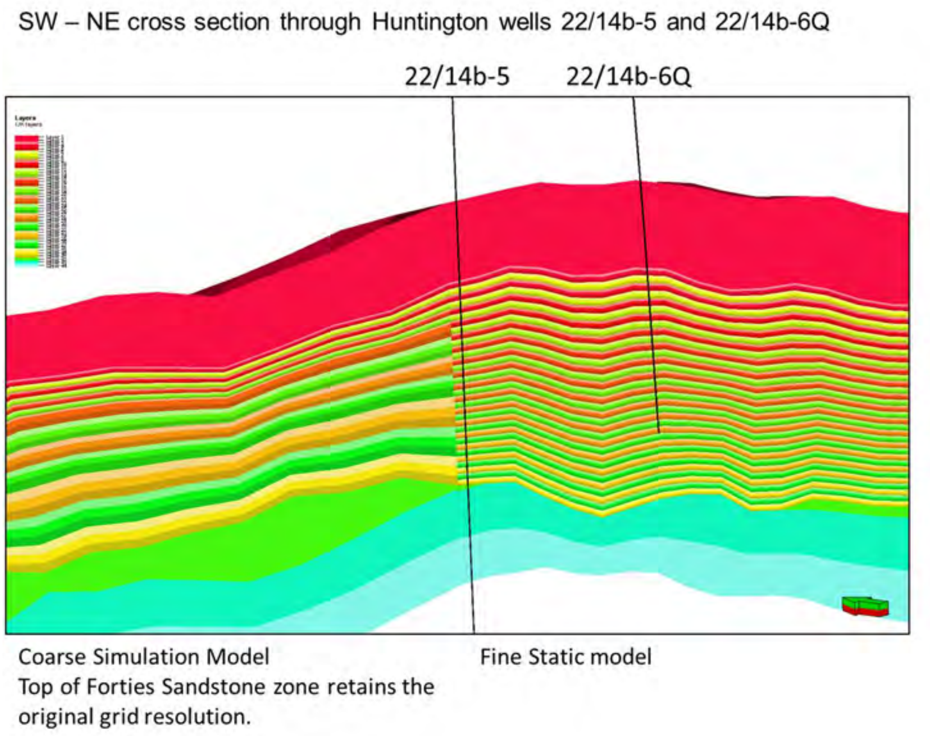


Figure 3-55 Comparison of coarse and fine scaled models

Zone	Static Model Layers	Dynamic Model Layers
Sele	1	1
Forties	2-101	2-41
Forties Argillaceous	102	42
Lista (Top 250ft)	103-104	43-44

Table 3-16 Summary of static and dynamic model layer equivalencies

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

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

A check of static model versus dynamic model pore volumes was carried out and the difference was less than 2%.

3.5.4.10 Primary Static Model Sensitivity Cases

A range of sensitivity cases have been run in the dynamic modelling. As part of these sensitivities, three additional deterministic static model cases have been generated capturing key static uncertainties.

Forties Mid-Shale Zone

Within the reference case, no barriers to flow and pressure are present. In some fields within the Forties Sandstone fairway there is evidence for a laterally extensive shale caused by a Maximum Flooding Surface event. To quantify the impact of such a barrier across the Forties 5 Site 1 area, a sensitivity has been run in the dynamic modelling which includes a single impermeable layer (layer 20). The selection of this layer is based on a review of the well data and analogue field data.

Low Permeability Case

With limited core measurement within the Forties Sandstone aquifer outside the main fields (Everest and Huntington) there are uncertainties related to rock quality within the aquifer. A case has been generated which captures a low case permeability scenario.

For the horizontal permeability this has been done by removing the field wells in Everest and Huntington and 22/15-3 (gas discovery). The modelled horizontal permeability average is approximately 29 mD, the modelled horizontal permeability distribution is shown in Figure 3-56.

A Low Kv was created using the same function as for the reference case.

This case was upscaled for the dynamic model using the same methodology as the reference case.

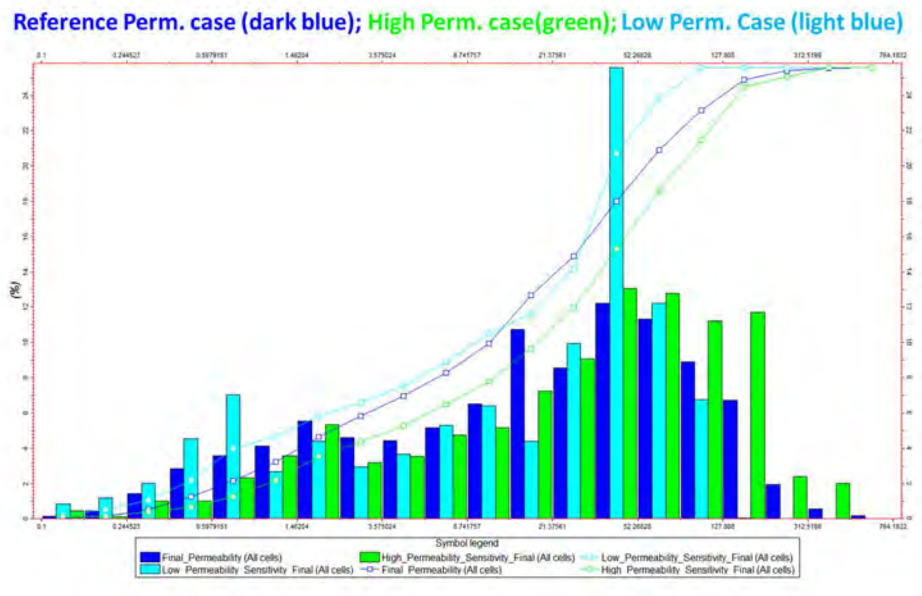


Figure 3-56 Histogram comparison of permeability sensitivity

High Permeability Case

A high permeability case has been generated by using only the higher measured permeability values from core in the Everest and Huntington field wells (22/09-2, 22/09-3, 22/09-4, 22/14b-5, 22/14b-6Q and 22/15-3). The modelled horizontal permeability average is approximately 64 mD, the modelled horizontal permeability distribution is shown in Figure 3-56.

A High Kv was created using the same function as for the reference case.

This case was upscaled for the dynamic model using the same methodology as the reference case.

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. The Forties 5 Site 1 model is already very extensive taking in the major part of the Everest gas field and extending westwards towards the Montrose and Arbroath area. Along the pathway to selecting this site as the preferred location to commence a Forties aquifer CO_2 injection project, a very large Fairway static and dynamic model was developed. Full details of this work and the resulting models are included in (Pale Blue Dot Energy; Axis Well Technology, 2015).

3.5.5.1 Static Model – Uncertainty Statement

Whilst both the seismic and well data used in the construction of the static model are considered to be of both good quantity and sufficient quality, as with all subsurface characterisation, some important uncertainties remain unresolved and should be the focus of any future appraisal activity. These include:

Reservoir Quality - whilst there are reasonably good quality logs available over the area together with some core material, they have all been acquired for the purposes of hydrocarbon exploration and not for CO_2 storage. In particular, there remains an uncertainty regarding the potential for reservoir quality degradation within the aquifer intervals of wells where diagenetic processes have not been halted by hydrocarbon fill. Furthermore, it is the huge scale of this storage site that presents challenges, since despite the high number of wells available, well density is still low in the targeted injection areas. It is recommended that more quantitative reservoir quality determination from the existing seismic data set is completed with carefully calibrated rock physics to assist in managing this uncertainty.

Hydraulic Architecture of the Reservoir - the nature and continuity of both the high permeability and low permeability intervals have a significant influence on how an injected CO_2 inventory might move in the subsurface. In particular the detailed mapping and distribution of reservoir facies will strongly influence the plume development in this open system. It is recommended that more detailed work be completed on this including the clarification of detailed biostratigraphy correlations through the maximum flooding surfaces. This could be achieved through core and cuttings samples and quality biostratigraphic analysis under access agreements with petroleum operators.

Structural Depth Model – Although the Forties 5 Site 1 location is not dependent upon buoyant trapping, depth structure is still a very strong influence on how the CO_2 plume develops across the area. Continued monitoring of depth uncertainty and potential buoyant migration pathways should be maintained in any future development to support the design of containment confidence.

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 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

A key issue for this Forties 5 Site 1 is the decision regarding the area of the aquifer which should be considered as the target CO_2 storage site. With a complex reservoir architecture and a finite development plan, it is not possible to maximise the capacity that the full storage complex presents. Instead a practical, but material development plan with a step out (growth model) has been defined. For the purposes of this calculation, the gross rock volume has been calculated over the area occupied by the maximum CO_2 plume extend after 1000 years multiplied by the reservoir thickness. To account for uncertainty in the depth map for the top depth map to the top reservoir across the aquifer a high and low value for the gross rock volume was generated by increasing and decreasing the reservoir thickness by 30%. This represents a +/- range of 10% for length, width and thickness. This presents a high case of 78,600 MMCUM, a mid case of 60,400 MMCUM and a low case of 46,500 MMCUM.

3.5.6.2 Net to Gross Ratio

An average net to gross ratio of 67% 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 80% and 50% have been assigned from consideration of the well data in the area and the uncertainty presented by relatively low well density.

3.5.6.3 Porosity

An average porosity of 17.1% 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 15% to 20% to reflect well observations.

3.5.6.4 CO_2 Density

A range of 0.64 to 0.72 and 0.78 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 Forties 5 Site 1 aquifer the storage efficiency is quite low with values of 0.053 to 0.067 due to the challenge of placing CO_2 into the deep parts of the formation away from injection wells. To this end, a refined development plan with higher well count would be expected to increase this factor.

3.5.6.6 Probabilistic Volumetric Results

Figure 3-57 captures the input and outputs of the Monte Carlo assessment of dynamic CO_2 storage capacity for the specified development plan Forties storage site. The P90 value (i.e. 90% chance of exceeding) is 238 MT, with P50 (50% chance of exceeding) of 297 MT and a P10 (10% chance of exceeding) of

367 MT. These numbers provide context for the “deterministic” estimates from the dynamic modelling work for the “development of the base case” of 300 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 3-58.

There are no CO_2 storage reserves currently assessed for the Forties 5 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 storage site is of course proven and there is excellent evidence from wells and seismic that the site could be developed. Without a matched emissions point the resource has been characterised on the basis of this probabilistic assessment as:

“Contingent Resources – Development unclarified”

1C – 238 MT – P90

2C – 297 MT – P50

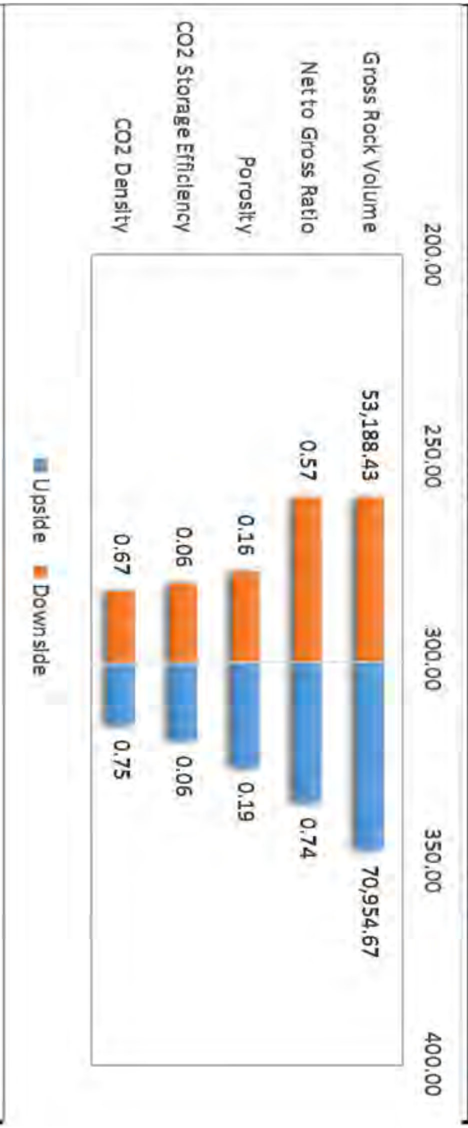
3C – 367 MT – P10

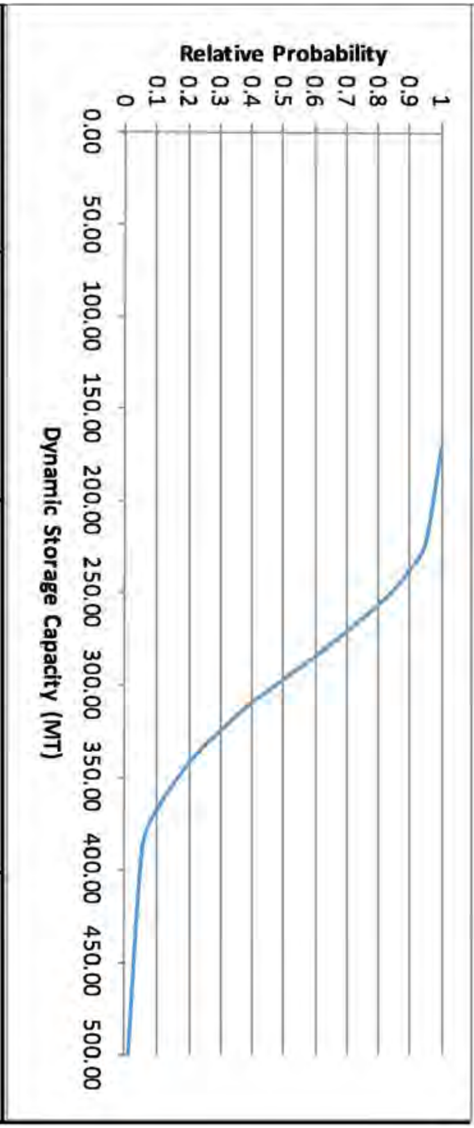
The full scope of the probabilistic dynamic CO_2 storage capacity ranges from a P100 of 172 MT to a P0 of 511 MT.

CO2 Capacity of Forties 5 Site 1

Run - 1

Parameter	Inputs		Comments	Distribution
Gross Rock Volume MMCUM	Low Mid High	46500 60400 78600	Mid case is the maximum plume area after 1000 years multiplied by reservoir thickness, low and high cases from increasing/decreasing thickness by 30%	
Net to Gross Ratio	Low Mid High	0.500 0.676 0.800	Mid case based on reservoir model averages in the area of plume extent	
Porosity	Low Mid High	0.150 0.171 0.200	Mid case based on reservoir model averages in the area of plume extent	
CO_2 Density T/M^3	Low Mid High	0.635 0.716 0.776	CO_2 density calculation	
CO_2 Storage Efficien	Low Mid High	0.053 0.060 0.067	Extracted from simulation runs over a 40 year injection period	





Dynamic Storage Capacity MT	P90 P50 P10	238 297 367		

Figure 3-57 Forties 5 Site 1 – probabilistic volume capacity

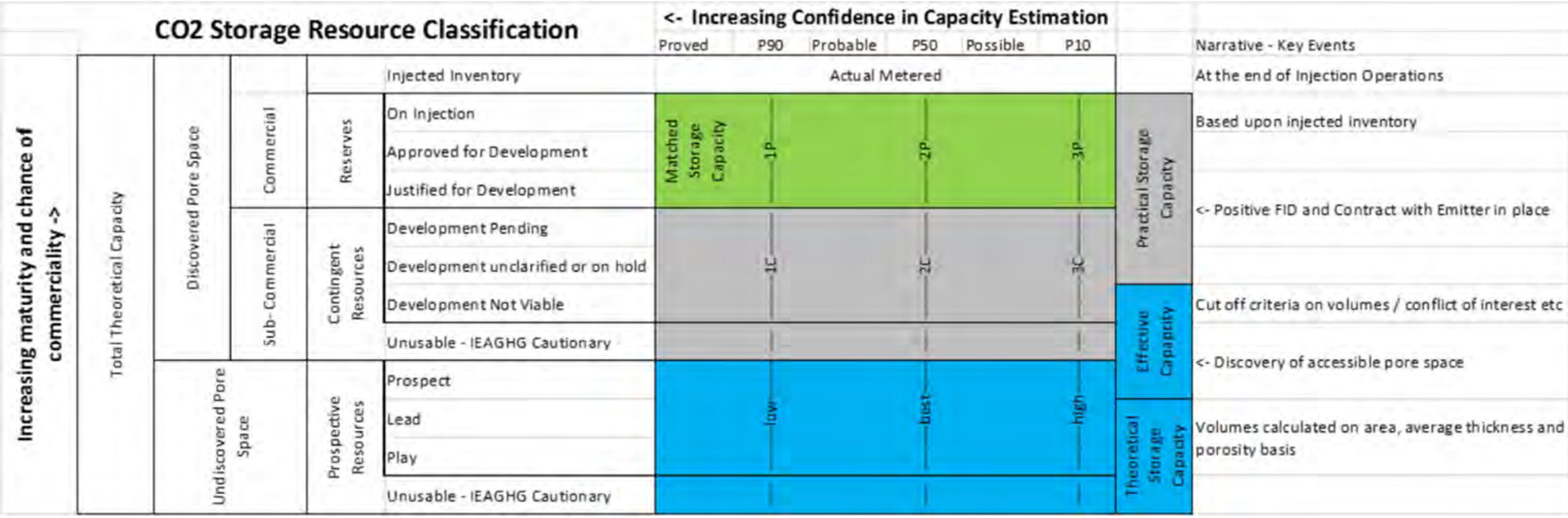


Figure 3-58 Adopted CO_2 storage resource classification

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 3-17 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 3-17 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, 2016). 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 fluid. 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 (Figure 3-59). 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.

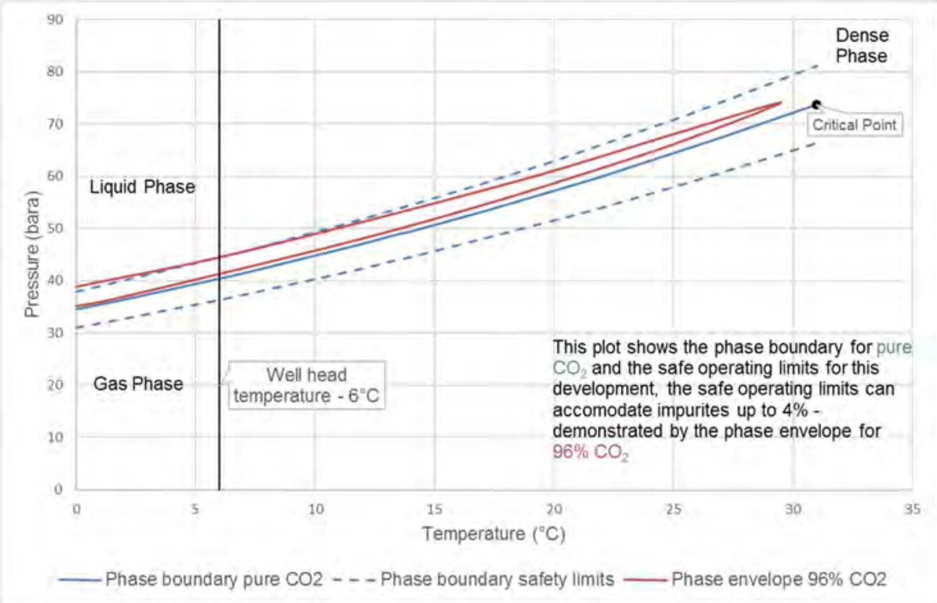


Figure 3-59 Effect of Impurities on the phase envelope

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 Forties 5 Site 1 well placement strategy has been driven by an overall development strategy (platform structure required for filtering and control) as well as reservoir characteristics (geometry, geology, reservoir engineering modelling) and the economics of development.

First pass reservoir engineering suggests that several wells are required over field life to inject target CO_2 volumes. Given the large extent of the storage site, the requirement for multiple injection sites to access the pore space and enable a logical expansion were acknowledged. As a result, an early 'Southern' injection site was augmented with a subsequent 'Northern' injection site in the initial plan.

Whilst a fully subsea development strategy would be an ideal outcome in many ways, a phased development comprising a single platform hosting multiple wells and at least one subsea tie back is considered optimal at this early stage in the CCS role out. In any reservoir injection project, the removal of fine particulates from the injection stream is critical (otherwise rapid degeneration of injectivity can occur due to the plugging of rock pores). As the Forties 5 Site 1 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 long distance control umbilicals from shore would be high. A fixed unmanned platform provides cost effective filtering and control to support the step out subsea development. More work is required to investigate, cost and de-risk leading edge subsea technologies currently being rolled out in the oil and gas sector. As this technology matures rapidly it is anticipated that this may quickly evolve into a preferred development solution for this project.

The platform location (south site), presents a single top hole well location cluster for all the southern development wells. Reservoir modelling suggests that 4 wells, evenly distributed in a radial pattern, will result in the highest storage capacity being realised while achieving target injection rates. A fifth well would be drilled to provide redundancy and robustness against an injection well failure of any kind. This spare well would also be used as an additional reservoir monitoring point.

There are a number of options for the northern site, including 'daisy chained' single wells or connected multi-well templates. As a practical limit to the number of wells that can be drilled from a single template is 4 to 6 (depending on rig type and whether all slots can be reached without a rig move). In this case, a single 4 slot template was chosen as the most likely initial solution. After a period of initial injection at the south site, both injection sites will operate concurrently and share the single back up well at the southern site. Should additional wells be required, single subsea well tiebacks would be appropriate, with the subsea template designed to accommodate them.

In order to maximise reservoir coverage and well separation, long step out wells (~3,500m (11480 ft) radius reach) are proposed. Depending on target location, the wells will have a sail angle of around 60deg before turning to the horizontal through the lower part of the Forties Sandstone reservoir. A 300m (~1,000ft) horizontal section will be drilled towards in the lower part of the reservoir, but only the lower-most 150m will be perforated initially. This allows for redundancy should reservoir properties deteriorate during the injection phase, minimising the requirement for local sidetracks. This well profile also has the benefit of removing the injection point laterally from the cap rock penetration point in order to reduce the direct impact of the CO_2 plume (which will rise vertically) at this location. Horizontal wells allow for additional "sand face" to be drilled should reservoir quality prove to be lower than expected. As no laterally extensive barriers to horizontal or vertical flow are expected in the Forties sandstone, CO_2 will propagate throughout the reservoir, in both the vertical and horizontal directions.

3.6.2.1 Injection Well Spacing

Well spacing is initially limited to a minimum 1,000m to prevent temperature interference and minimise pressure interference. A near wellbore study from Bunter 36 (Pale Blue Dot Energy; Axis Well Technology, 2015) has suggested that this is a conservative limit with respect to temperature, but is reasonable for pressure interference effects. Applying this limit to the Forties structure (and the predicted distribution of high net sands), using a single point surface location, results in an irregular radial well pattern (see section 5.3).

3.6.2.2 Monitoring Well

A dedicated monitoring well is not necessary, for the Forties 5 Site 1 development plan. As the injection site is 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 wells are equipped with pressure and temperature gauges including DTS in order to monitor reservoir and injection performance. Changes in CO_2 / brine saturation can be observed at all wells using DTS or standard cased hole wireline logging. 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 below.

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 phased development plan involves two injection sites. With wells at each injection site expected to be similar and it was decided to evaluate well performance using a single prototype well for each site, INJ01S for the South site and INJ03N for the North site. The input data for the well models is described in the following sections. PVT is described in Section 3.6.1.

3.6.3.2 Downhole Equipment

Since part of the purpose of this study was to determine the optimal tubing size for the Forties 5 Site 1 wells, a set of sensitivity cases was defined on downhole equipment (detailed towards the end of this section).

3.6.3.3 Wellbore Trajectory

The wellbore trajectory used for the Forties Site 1 well models were simplified from the deviation surveys provided by the well design study (Appendix 6).

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/ft^2/F (17.04 W/m^2/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 (1 – 3ºC) seasonal variation in temperature may occur, but it is not thought to be significant enough at this location to have a material impact on the CO_2 density or tubing design.

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 3-18 and Table 3-19 below.

Parameter	Unit	Low	Best Estimate	High
Formation Top Depth (Datum)	*ft TVDSS*		8900	
Formation Gross Thickness	*ft*	85	450	600
Formation NTG	-	0.25	0.60	0.85
Reservoir Pressure	*bara (psia)*		281 (4078)	
Reservoir Temperature	*°F*		218	
Permeability	*mD*	14	33	44
Permeability Anisotropy (K_v/K_h)	-	0.15	0.31	0.44
Porosity	*fraction*		0.185	
Connate Water Saturation	*fraction*		0.31	
Formation Water Salinity	*ppm*		94000	

Table 3-18 Forties 5 Site 1 Reservoir data

Parameter	Unit	Low	Best Estimate	High
Water Depth	*ft*		295	
Pressure Gradient	*psi /ft*		0.458	
Geothermal Gradient	*°F/100ft*		2.03	
Drainage Area	*acres*		3090	

Table 3-19 Forties 5 Site 1 Field and well data

This data was derived primarily from well data within the storage site. Formation water salinity measurements ranged from 62,000ppm to 94,000ppm within the storage site, but a single measurement from an Everest field well measured 212,320ppm. 94,000ppm was chosen as representative.

Using this data three IPR models were defined in Prosper to represent high, medium and low reservoir performance. These are summarised in Table 3-20 below.

Parameter	Unit	Low	Medium	High
Reservoir Pressure @ top perforation depth (INJ01S)	*bara (psia)*	298 (4319)	298 (4319)	298 (4319)
Reservoir Temperature @ top perforation depth (INJ01S)	*°C (°F)*	109.0 (228.2)	109.0 (228.2)	109.0 (228.2)
Reservoir Pressure @ top perforation depth (INJ03N)	*bara (psia)*	286 (4154)	28 (4154)	286 (4154)
Reservoir Temperature @ top perforation depth (INJ03N)	*°C (°F)*	104.9 (220.8)	104.9 (220.8)	104.9 (220.8)
IPR Model	*n/a*	Horizontal Well	Horizontal Well	Horizontal Well
Permeability	*mD*	14	33	44
Reservoir Thickness	*ft*	21	270	510
Vertical Anisotropy	*n/a*	0.15	0.31	0.44
Reservoir Length	*ft*	11602	11602	11602
Reservoir Width	*ft*	11602	11602	11602
Well Length	*m (ft)*	152 (500)	152 (500)	152 (500)
Porosity	*fraction*	0.185	0.185	0.185
Connate Water Saturation	*fraction*	0.31	0.31	0.31
Skin	*n/a*	20	10	0

Table 3-20 Forties 5 site 1 IPR definitions

3.6.3.6 Tubing Selection

Tubing selection was carried out for dense phase injection in both the subsea and platform well groups.

Injection Limits – Platform Wells (South)

Some pressure and temperature limits on injection operations have been defined and are summarised in Table 3-21 below.

Parameter	Unit	Value
Fracture Limit at Top Perforation Depth	bara (psia)	438.7 (6362)
Maximum THP for Fracture Prevention	bara (psia)	170.1 (2466)
Maximum Delivery Pressure	bara (psia)	160 (2321)
Minimum Fluid Temperature at Perforation Depth	°C	0

Table 3-21 Injection pressure and temperature limits - Platform wells

Notes:

- The fracture limit at top perforation depth has been derived using a fracture gradient of 0.75 psi/ft and a top perforation depth of 2873 m (9426 ft) TVDSS. An uncertainty factor of 0.9 was applied to the calculated fracture pressure.
- For the purposes of this work, the maximum THP for fracture prevention is the maximum THP that can be applied to ensure that the pressure at top perforation depth stays below the fracture pressure even if a rapid loss of injection occurs. This value has been

calculated as the fracture limit at top perforation depth minus the hydrostatic head imposed by a column of (dense phase) CO_2 in the wellbore. The hydrostatic head has been estimated in Prosper for this well as 256 bara (3711 psi). This estimate has been calculated using a typical injection rate and the lowest safe tubing head injection pressure at which no phase change occurs - 44.5 bara (660 psia). 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 3896 psi. This limit in effect reflects 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.

- The minimum fluid temperature at perforation depth exists to prevent formation water from freezing during injection.

Sensitivity Cases – Platform Wells (South)

The sensitivity cases considered for the south site platform wells are summarised in Table 3-22 below.

The high, medium and low reservoir cases are as described in section 3.6.3.6 above. The tubing head pressure has been chosen to comply with the maximum delivery pressure limit. Table 3-22 summarises the rates achievable for the various sensitivity cases and Figure 3-60 provides a graphical representation. Prosper uses volumetric flow rates and the conversion to mass flowrate is based on a density of 1.8714 kg/m^3 at standard conditions

Case	IPR Case	Tubing Size	THP (bara)	THT (°C)	Rate (MMscf/d)	Rate (MMte/yr)
Case 1	High	4-½ (12.6 ppf)			81.6	1.578
Case 2	Medium	4-½ (12.6 ppf)			72.8	1.408
Case 3	Low	4-½ (12.6 ppf)			22.7	0.438
Case 4	High	5-½ (17 ppf)			137.5	2.659
Case 5	Medium	5-½ (17 ppf)	160	6	112.0	2.167
Case 6	Low	5-½ (17 ppf)			23.7	0.459
Case 7	High	7'' (29 ppf)			232.6	4.500
Case 8	Medium	7'' (29 ppf)			162.3	3.139
Case 9	Low	7'' (29 ppf)			23.9	0.462

Table 3-22 Rates achievable by case - Platform wells

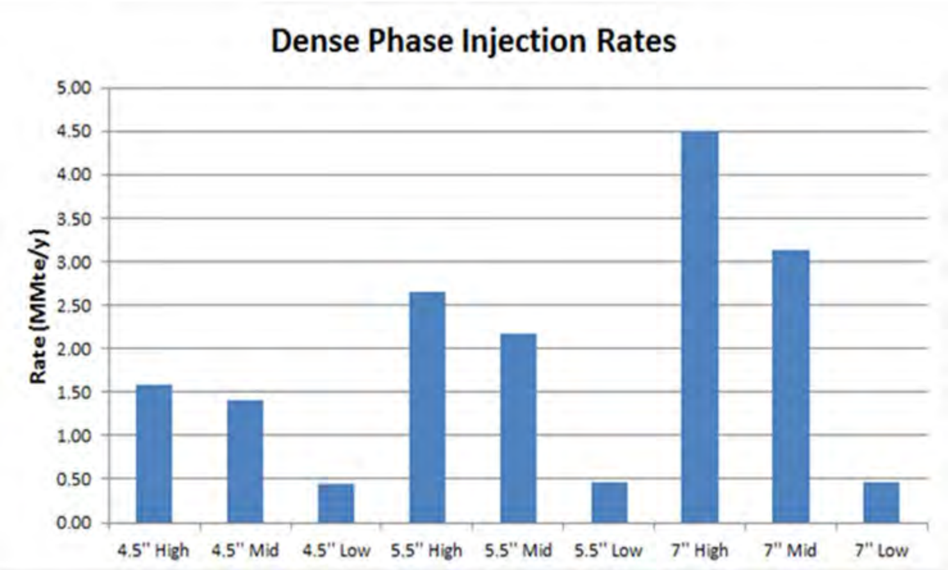


Figure 3-60 Rates achievable by case - Platform wells

Figure 3-61 shows the pressure and temperature behaviour along the tubing plotted as pressure versus temperature for the various tubing sizes and injection temperatures. The graphs also show the phase boundary with an upper and lower safety limit and the temperature and fracture limits.

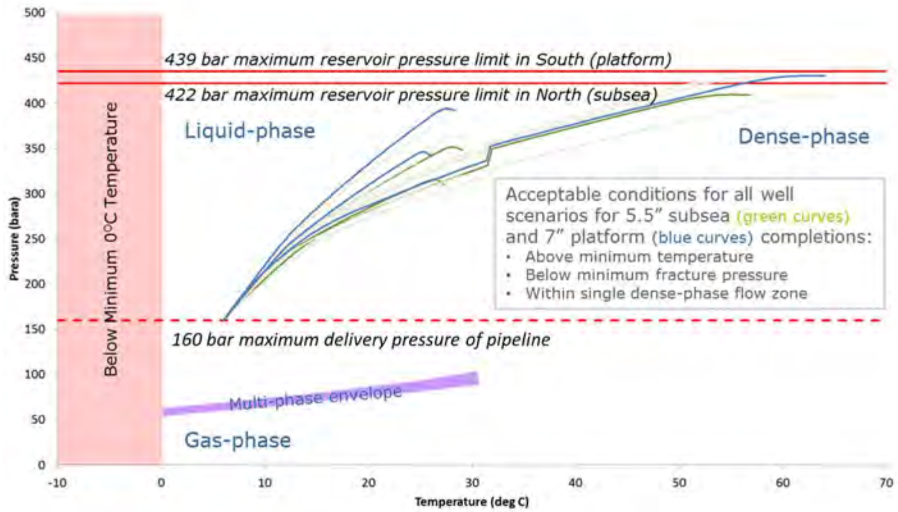


Figure 3-61 Temperature and Pressure Completion Modelling Results

For the low reservoir case the predicted injection rates are low and may not reach target rates with any completion type. This risk has been managed by defining a suitable well placement strategy (Section 3.6.2).

- The injection target for the south site platform wells is approximately 2.0 MMte/yr per well during the first ten years of injection. Based on this injection target,
  - Both the 5½'' and the 7'' tubing are predicted to achieve the injection target for the remaining reservoir cases and can therefore be considered.
  - The simulated rate for the 5½'' tubing only just exceeds the required rate for the mid (best estimate) reservoir case. Since the simulations use initial reservoir pressure and the

Prosper inflow model cannot fully capture the (considerable) heterogeneity of the Forties reservoir the margin of safety is considered insufficient for practical purposes and the 7'' tubing is therefore the preferred choice.

- The maximum wellhead injection pressure is the maximum delivery pressure.
- If the maximum injection pressure is maintained, the injection fluid is predicted to stay in dense phase throughout the tubing and the bottom hole temperature and fracture limits should not be breached.

Injection Limits – Subsea Wells (North)

Some pressure and temperature limits on injection operations have been defined and are summarised in Table 3-23 below.

Parameter	Unit	Value
Fracture Limit at Top Perforation Depth	bara (psia)	421.9 (6119)
Maximum THP for Fracture Prevention	bara (psia)	163.5 (2372)
Maximum Delivery Pressure	bara (psia)	160 (2321)
Minimum Fluid Temperature at Perforation Depth	°C	0

Table 3-23 Injection pressure and temperature limits – subsea wells

The limits have been derived in the same manner described for the southern platform wells.

Sensitivity Cases – Subsea Wells (North)

The sensitivity cases considered for the northern subsea wells are summarised in Table 3-24. The high, medium and low reservoir cases are as described in section 3.6.3.6 above. The tubing head pressure is the maximum delivery pressure. Table 3-10 summarises the rates predicted for the various sensitivity cases and Figure 3-62 provides a graphical representation.

Case	IPR Case	Tubing Size	THP (bara)	THT (°C)	Rate (MMscf/d)	Rate (MMte/yr)
Case 1	High	4-½ (12.6 ppf)	160	6	79.4	1.536
Case 2	Medium	4-½ (12.6 ppf)			70.5	1.364
Case 3	Low	4-½ (12.6 ppf)			21.3	0.412
Case 4	High	5-½ (17 ppf)			133.9	2.589
Case 5	Medium	5-½ (17 ppf)			107.8	2.086
Case 6	Low	5-½ (17 ppf)			22.2	0.429
Case 7	High	7'' (29 ppf)			225.5	4.362
Case 8	Medium	7'' (29 ppf)			155.6	3.009
Case 9	Low	7'' (29 ppf)			22.3	0.431

Table 3-24 Rates achievable by case - subsea wells

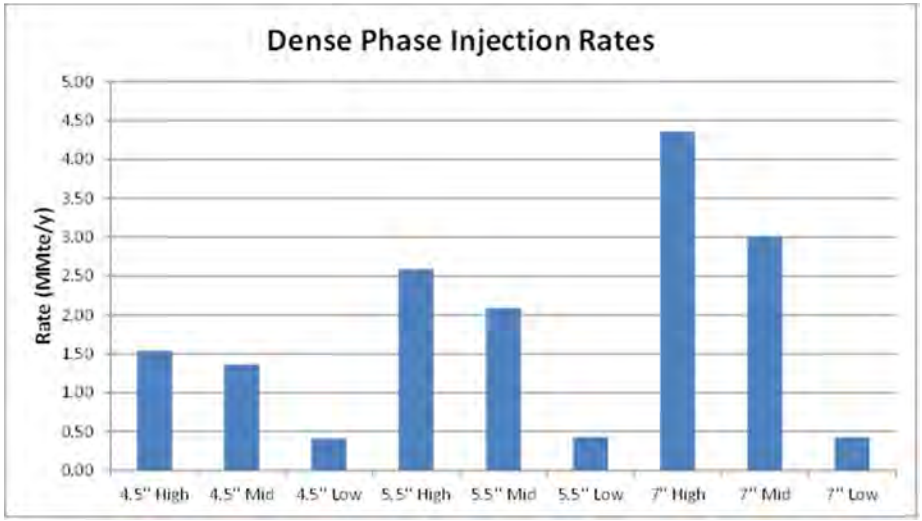


Figure 3-62 Rates predicted by case - subsea wells

Figure 3-61 shows the pressure and temperature behaviour along the tubing plotted as pressure versus temperature for the various tubing sizes. The graph also shows the phase boundary with an upper and lower safety limit and the temperature and fracture limits.

The results can be summarised as follows:

- As was the case for the platform wells, for the low reservoir case the predicted injection rates do not meet the desired targets, independent of tubing choice. This risk has been managed by defining a suitable well placement strategy (see 3.6.7).
- The injection target for the North Subsea wells is approximately 1.25 Mt/yr per well. Based on this injection target,
  - All tubing choices are predicted to achieve the injection target for the remaining reservoir cases.
  - The simulated rate for the 4½'' only just exceeds the required rate for the mid (best estimate) reservoir case, while the 5½'' and 7'' tubing rates do so comfortably and may be considered, with the less expensive 5½'' tubing being the preferred choice in this case.
- The maximum wellhead injection pressure is the maximum delivery pressure.
- If the maximum injection pressure is maintained the injection fluid is predicted to stay in dense phase throughout the tubing and the bottom hole temperature and fracture limits should not be breached.

3.6.3.7 Minimum Injection Pressure

For both the platform and subsea well cases and their respective chosen tubing sizes a minimum tubing head injection pressure to ensure injection stays in single phase was determined and the corresponding rates calculated.

Assuming a tubing head injection temperature of 6 °C the minimum safe injection pressure just outside the safety region defined around the phase envelope is 44.5 bara for both cases. Since no injection is possible at any of the wells considered for the Forties 5 Site 1 development at this pressure, this limit is of theoretical interest only.

The minimum rates and pressures achievable depend on the details of the inflow and vertical lift performance. For the mid (best estimate) reservoir case the results are as follows:

- Platform Injectors – South (INJ01S)
  - The minimum injection rate is 19.9 MMscf/d (0.385 MMte/yr) at a tubing head pressure of 61.5 bara.

- The minimum stable injection rate is approximately 40 MMscf/d (0.774 MMte/yr) at a tubing head pressure of 66.2 bara.
- The results are illustrated in Figure 3-63 below. Note that the inflow curves for the two cases are identical and therefore overlay on the graph. The minimum stable injection rate corresponds to the maximum on the VLP curve.

- Subsea Injectors – North (INJ03N)
    - The minimum injection rate is 18.6 MMscf/d (0.360 MMte/yr) at a tubing head pressure of 65.5 bara.
    - The minimum stable injection rate is approximately 25 MMscf/d (0.484 MMte/yr) at a tubing head pressure of 67.3 bara.
    - The results are illustrated in Figure 3-63 below.

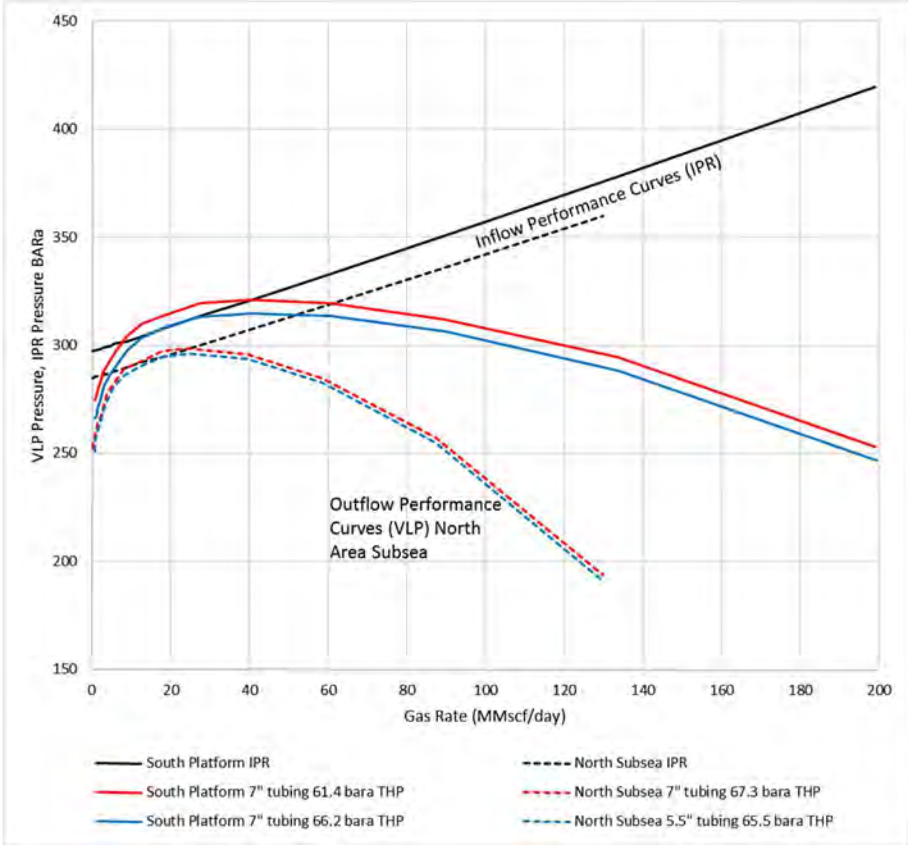


Figure 3-63 Inflow / Outflow curves - mid reservoir case

3.6.3.8 Vertical Lift Performance Curve Generation

Vertical lift performance (VLP) curves were generated for the Forties 5 Site 1 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.

Platform Wells (South)

Input parameters were as follows:

- Tubing Head Pressures: 645 psia (44.5 bara) to 3481 psia (240 bara) in 10 steps
- Gas Rates: 40 MMscf/d to 200 MMscf/d in 20 steps

The performance envelope of the well is shown in Figure 3-64 below. 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. The instability in temperature occurs around the critical point.

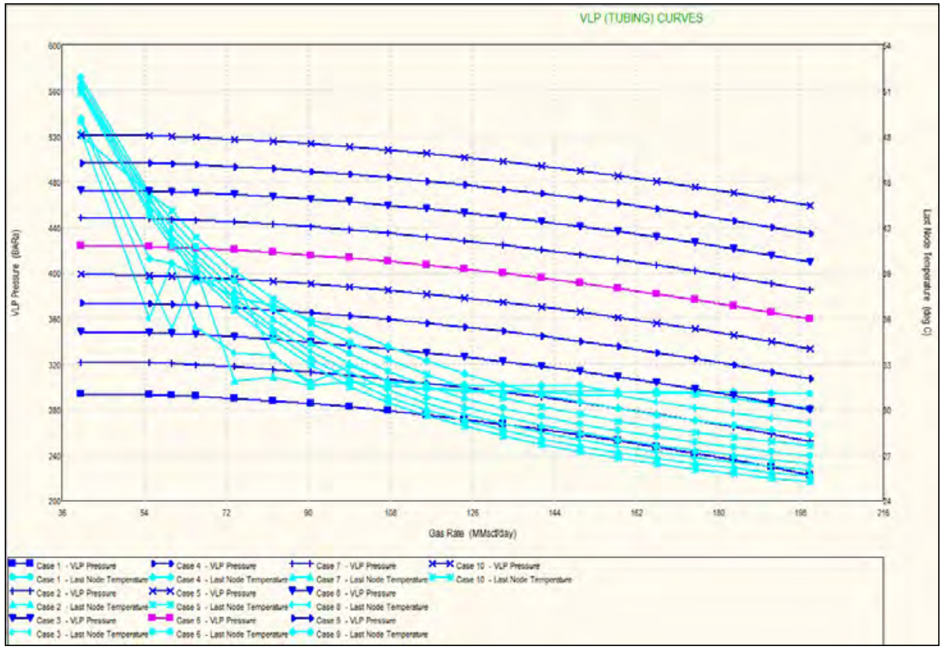


Figure 3-64 Performance envelope (platform wells) - 7" tubing

Subsea Wells (North)

Input parameters were as follows:

- Tubing Head Pressures: 645 psia (44.5 bara) to 3481 psia (240 bara) in 10 steps
- Gas Rates: 25 MMscf/d to 190 MMscf/d in 20 steps

The performance envelope of the well is shown in Figure 3-65 below. 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. Again, the instability in temperature occurs around the critical point.

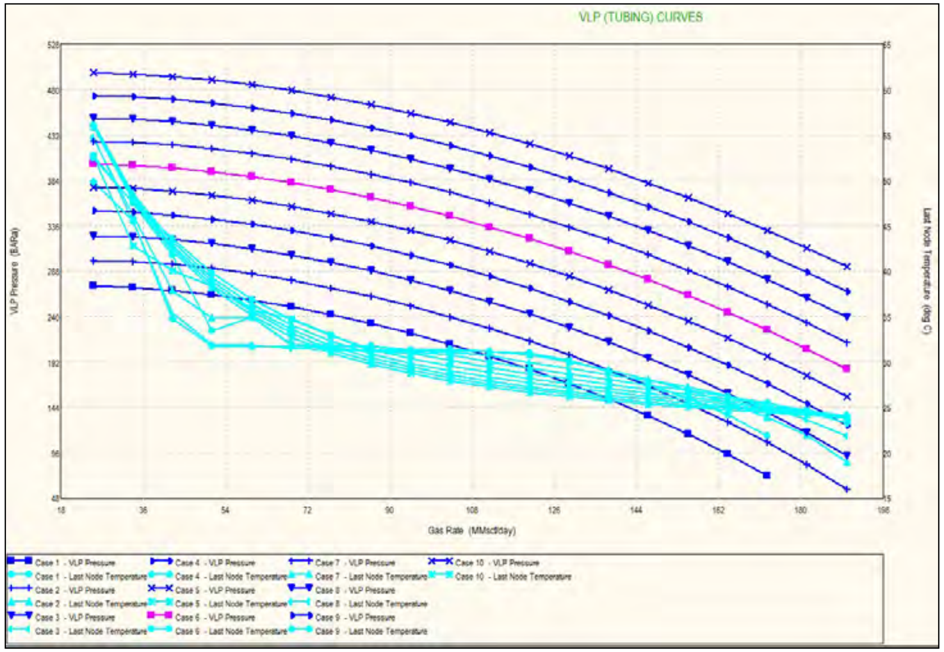


Figure 3-65 Performance envelope (subsea wells) - 5 1/2" tubing

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 Forties site storage potential.

3.6.4.1 Halite

The Forties formation water is a saline brine. There is some uncertainty in the composition of this brine, but nearby wells (22/15-3, 22/10b-6 and 22/14b-5) reported salinity measurements of 94,000ppm, 62,000ppm and 75,560ppm respectively. While higher than seawater salinity, these values are considered to be relatively low. A sample from the nearby Everest field (22/14a-2) had a much higher value of 212,320ppm, which would appear to indicate some variability across the Forties system, possibly where structural trapping (and variations in local diagenesis) has occurred. However, this creates a moderate uncertainty with respect to the actual brine salinity, and this should be investigated during site appraisal.

As the near wellbore is dehydrated through CO_2 injection, the insoluble content of the brine will be precipitated as this is not soluble in CO_2. The volume of solid salt crystals produced depends on brine salinity, residual brine volume (left after the 'sweep'' of CO_2), interactions at the CO_2 flood front and the propensity of the brine to re-saturate the near wellbore during shut-in periods. Capillary pressure also plays a part in re-saturation, but is likely to be masked by CO_2 buoyancy effects (CO_2 rising in the fluid column, allowing brine to recharge from below) in this scenario. As the re-saturation will depend on the number and length of shut-ins, predictions of actual salt precipitation volumes are not possible at this stage.

Since the Forties brine is relatively low salinity, there is a possibility that near wellbore permeability will remain largely unchanged by dehydration since even if all halite (salt) was precipitated, less than 5% of the pore volume would be occupied with halite.

Halite will only become an issue if the halite crystals are mobilised and form bridges / plugs in the matrix rock pore throats. Given the large injection area (sand face) planned in the wells, fluid velocity through the matrix will be low and mobilisation may not occur. Alternatively, if the halite concentration is small and the crystals are small with respect to pore throat size, salt crystals may be mobilised away from the wellbore and deposited in low velocity zones. At a distance from the wellbore they no longer pose a significant risk to injectivity (diffusion effect).

Considerable uncertainty remains surrounding the actual halite risk to injectivity in a low saline system such as this, although lessons could be learned from Statoil's Snohvit project (Grude, Landro, Dvorkin, Clark, & Vanorio). Injectivity in Snohvit was lower than expected, with pressure building up earlier. Salt precipitation was suspected, but lab tests suggested that the effect was relatively minor in horizontal cores, with a conclusion that limited reservoir heterogeneities and limited volume were the primary culprits. Halite and pore filling fines may have resulted in some injection efficiency reductions (Salinity was higher than Forties, at ~ 168,000ppm).

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 Forties 5 Site 1 is currently considered to be low, the addition of wash water facilities for these operations is probably not justified. Should problems arise, temporary well intervention operations can be planned and implemented on both platform and subsea sites. Alternatively, a longer section of wellbore could be perforated in order to reduce CO_2 flux velocities (less likely to mobilise salt crystals) and to increase total sand face flow area (reducing the effect of near wellbore permeability impairment).

3.6.4.2 Thermal Fracturing

The CO_2 stream injected into the Forties Sandstone is colder (less than 30°C depending on input assumptions) than the modelled ambient reservoir temperature (105 to 109°C). This reduction in temperature is limited to a region close to the wellbore (thermal modelling in Eclipse 100 for the Bunter reservoir suggested a radius of 12m before geothermal gradient was re-established, but Forties is much hotter, suggesting a smaller effect). A drop in temperature will have an effect on the near wellbore stresses, and will make rock more liable to fracture (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 Forties Sandstone. The applied safety margin (10%) on fracture pressure and the 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.

$$p_{w(cri} = \frac{3\sigma_1 - \sigma_2 - \sigma_{yield} - p_r A}{2 - A}$$

Where:

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

The cumulative rock strength (UCS) in the Forties Sandstone, as calculated from logs, for the 3 analysed wells is shown in Figure 3-66, where the average is around ~3600 psi.

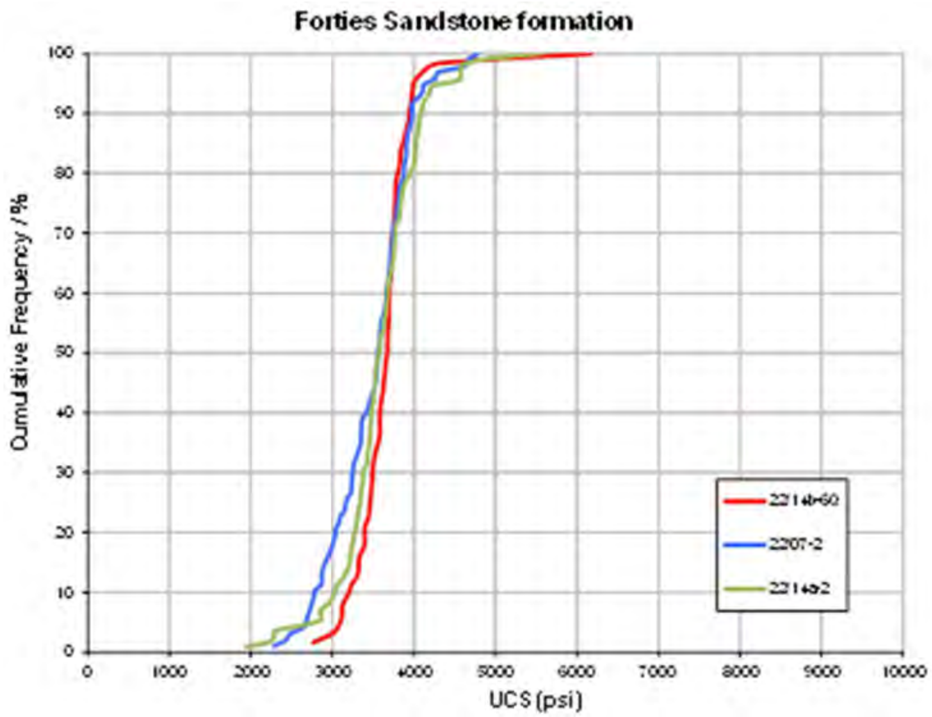


Figure 3-66 Forties sandstone UCS cumulative distributions

Figure 3-67 indicates the critical total drawdown (CTD) for the 3 wells evaluated only for the Forties Sandstone. As can be seen, the CTD for the wells is above 3000 psi, indicating that the Forties Sandstone is competent and there is low risk for sanding during injection operations. However, it is worth mentioning that this is based on an uncalibrated rock strength so uncertainty remains.

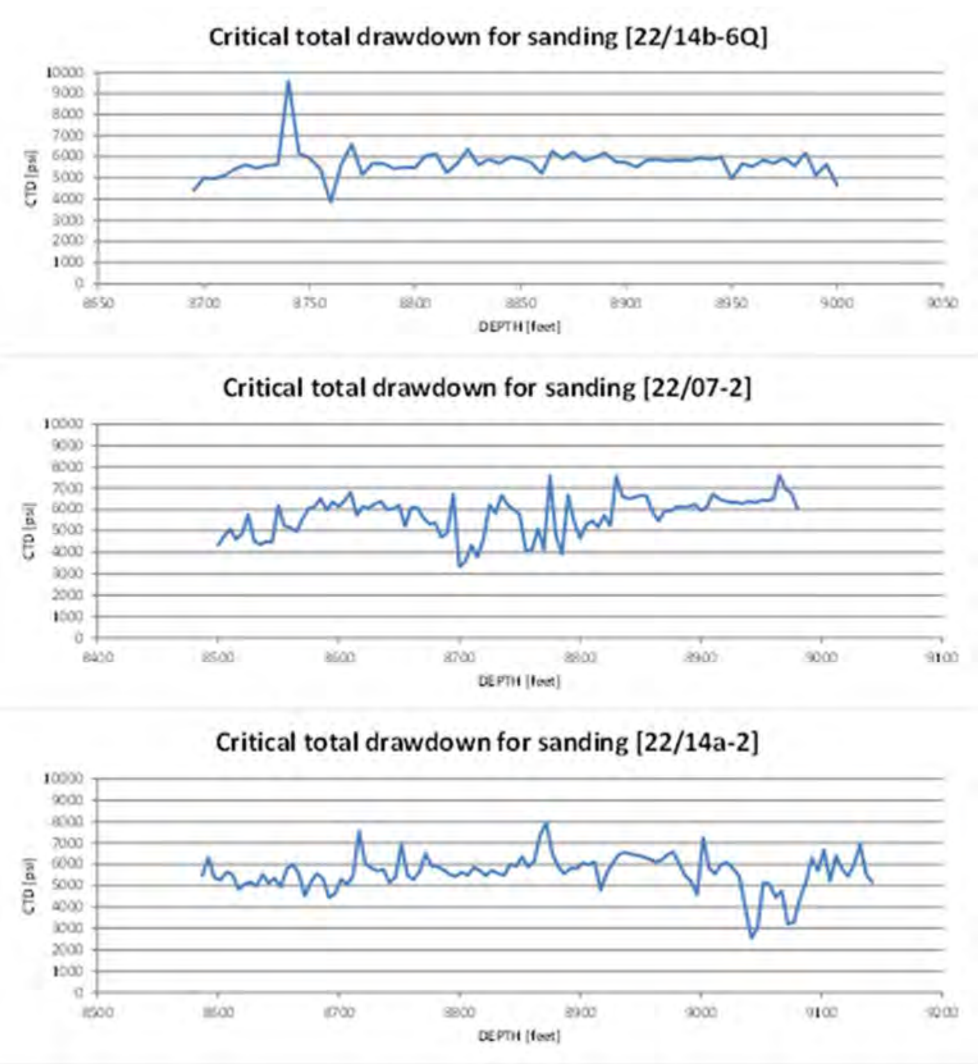


Figure 3-67 Critical drawdown pressure for the Forties Sandstone

Impact on Well Completion

Following the guidelines from SPE 39436 (Morita, E, & Whitebay, 1998), the cases listed below are selected depending on the critical drawdown criteria.

Case A: Very weak or unconsolidated formation from top to bottom

- Gravel pack
- Openhole with prepacked screen – if zone isolation is not required and there is a narrow grain size distribution

Case B: Weakly consolidated formation, low injection pressure

- Selective perforation with a propped hydraulic fracture
- Selective perforation with a fracture pack, without a screen

Case C: Weakly consolidated formation, high injection pressure

- Selective perforation with a high injection pressure. Injectivity enhanced by thermal cracking

Case D: Consolidated formation with limited weak zones

- Selective perforation

Case E: Uniformly strong formation

- Openhole completion, no screen

Following the guidelines from SPE 39436 (Morita, E, & Whitebay, 1998), the Forties 5 Site 1 injection site could be considered as a Case D, suggesting that perforated cemented liner is suitable.

3.6.5 Transient Well Behaviour

In the Forties 5 Site 1 development plan, CO_2 remains in liquid or dense phase in all injection scenarios, 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 a two phase scenario when the well is re-started. These effects are transient, but have significant impact on well design (temperature resistance) and operations planning.

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.

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 mitigating 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.

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 to be used as an upper injection pressure constraint in the Forties 5 Site 1 development, a geomechanical review was performed on the available well data (Appendix 6). 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 is 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 extensive Forties storage site. Using the best fit correlation, and calibrated by LOT data where available, a fracture gradient of 0.75psi/ft (0.17 bar/m) was confirmed. This figure is thought to be a reasonable estimate for use in this study, and fits within the range of published data. 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 0.675 psi/ft (0.153 bar/m). As planned injection will be towards the bottom of the forties sand unit, the large stand-off from injection point to the caprock will provide additional safety margin.

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 the Forties Sandstone reservoir (281 bara) being above the critical point for CO_2 (74 bara), injection will be limited to liquid (below critical temperature) or dense phase (above critical temperature).

3.6.7 Dynamic Modelling

3.6.7.1 Model Inputs

Structural Grid and Reservoir Modelling

The simulation grid comprises 768,000 cells, out of which 331,180 are active in the dynamic model. The grid has dimension 105 x 120 x 61 cells (or 54.7 x 56.3 x 1.1 km), each being approximately square with a side-length of circa 400m. The grid has an average dip of 2.7 degrees, with topography conforming to several seismic horizons that define model zonation; (a) top Sele Formation, (b) top Forties Sandstone, (c) base Forties Sandstone, and (d) top Lista Formation. Accordingly, the model is given the following zonation:

- Sele Formation – between top Sele and top Forties, a single layer of up to 193m thickness (70m on average), which is deactivated in the dynamic model due to its sealing shale character.
- Forties Sandstone – between top Forties and base Forties and comprising 40 layers with thickness of up to 279m in total (108m on average). The upper layers, 2 to 21, are of similar dimension having an average thickness of 1.05m. Similarly, the lower layers, 22 to 41 have an average thickness of 4.57m. Notably, the Forties Sandstone pinches out to the east along a NW-SE line running approximately parallel to and 7.5km in from the Eastern boundary of the grid. The Forties Sandstone is the target storage unit in the dynamic model.
- Forties Argillaceous – between base Forties Sandstone and top Lista. A single layer with variable thickness of up to 238m (42m on average), which is discontinuous across the site due to the depositional process.
- Lista – extended in the model up to 102m (71m on average) below the top Lista, thus covering the top portion of the Lista Formation only. Modelled with two layers of approximately equal dimension.

The reservoir is not faulted, and thus structure is controlled primarily by local topography within the defined strata. Figure 3-68 illustrates the structural character of the dynamic model. (The sealing Sele Formation is not displayed in the top right image which also has a vertical exaggeration of 30).

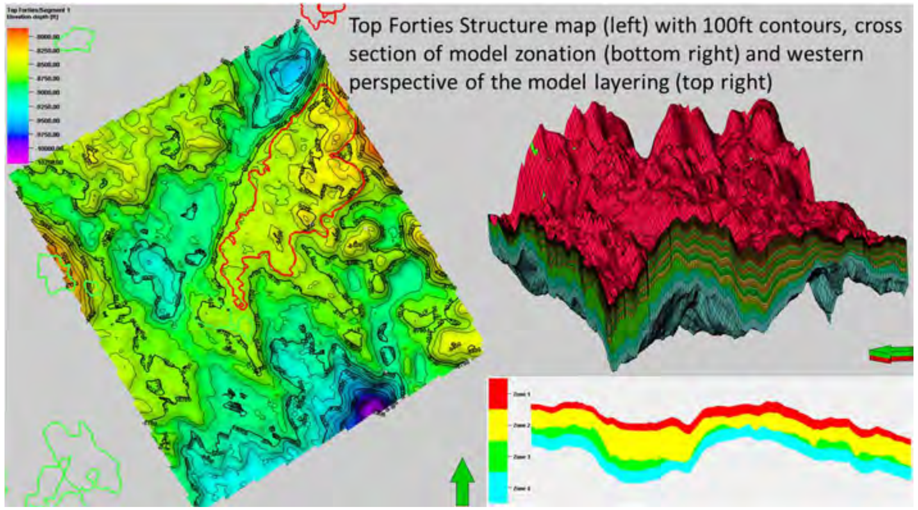


Figure 3-68 Model Structure Illustrated By Top Forties Topography

Static properties for the dynamic model are summarised in Table 3-25. Porosity and Net-to-Gross (NTG) are taken as the volumetric weighted average. The average porosity is determined for net-sand, using a NTG cut-off of 0.01 (to eliminate shales). The property modelling is described in detail in section 3.5.4.

Formation	Porosity	NTG	Grid Bulk Volume	Grid Pore Volume
Sele	Non-net	Non-net	1.183×10^{11} m^3	0.000 m^3
Forties Sand	17.0%	66.2%	1.677×10^{11} m^3	1.889×10^{10} m^3
Forties Argillaceous	13.1%	28.6%	5.763×10^{10} m^3	2.234×10^{9} m^3
Lista	16.8%	57.9%	1.188×10^{11} m^3	1.153×10^{10} m^3

Table 3-25 Static properties, by formation, as given in the dynamic model

The model dynamic properties are summarised in Table 3-26. Permeability is taken as the volumetric weighted average, determined for net sand, using a NTG cut-off of 0.01 (to eliminate shales).

Formation	K_h	K_v
Sele	Non-net	Non-net
Forties Sand	47 mD	14 mD
Forties Argillaceous	6.3 mD	3.6 mD
Lista	21 mD	12 mD

Table 3-26 Dynamic properties, by formation, as given in the dynamic model

The dynamic model assumes a rock compressibility of 4.89 x10-5 MPa^{-1}, as defined for the Forties aquifer in the recent study of Goater et al (Goater, Bijeljic, & Blunt, 2011).

Equilibration and Volumes in Place

The dynamic model is initialised with two distinct equilibration regions in the Forties Sandstone, necessary to represent the hydrocarbon gas in the Everest field, as well as the corresponding reservoir depletion (following production from the field during its commercial lifetime). Additionally, this was also necessary in order to model the contrasting fluid properties, PVT behaviour and saturation functions of the Everest field with that of the surrounding saline aquifer assessed for CO_2 injection and long-term geological storage.

According to the information (i.e. field shape files) obtained from DECC, there are several other fields either wholly or partially within the modelled area that required some consideration. The Shell operated Howe and Bardolino oilfields lie mainly to the West of the area, but are partially overlapping with the modelled area, however it was determined that these fields drain the much deeper Jurassic interval – namely the Hugin, Fulmar and Pentland sands – thus can be ignored in terms of their pressure response in the Forties sandstone.

More importantly, the Huntington oilfield is fully within the modelled area, downdip and to the SW of Everest, and within the Forties sandstone. After inspection of the (limited) production data available and careful consideration, it was deemed acceptable to ignore the pressure response from Huntington in the dynamic model. This decision was based on several factors; firstly, that oil compressibility is not so markedly different to water compressibility (as compared to the gas contained in Everest). Secondly, although no pressure history was available for the wells of Huntington, according to normal oil field management practice in the North Sea an assumption that Huntington is operated with water injection for pressure maintenance was considered fair, and consequently we would not expect any significant pressure depletion due to the withdrawn production volumes. This assumption was tested using the data available, which showed that while the voidage replacement ratio (VRR) could be estimated at 0.63 we would also expect there to be additional pressure support from the wider Forties aquifer that would likely contribute to an overall VRR of unity. This is possibly supported by the field GOR, which has remained constant throughout the field's available production history. Data available for Huntington (Oil and Gas UK, 2016) indicates an initial reservoir pressure of 269.0 bar (3900 psi), while PVT data from suggests a fluid bubble point of 135.7 bar (1968 psi). Finally, the limits of the “Black-Oil” simulation software are already stretched by the incorporation of a hydrocarbon gas region (Everest) where water is modelled as an oil-phase to satisfy the mutual solubility requirements of CO_2 storage in a saline aquifer. The incorporation of a hydrocarbon oil region would mean an additional workaround, which was thought to be overly complex and, additionally time-consuming, for little added value to the project objectives at this time.

The Everest field meanwhile is comprised of two independent accumulations; Everest and Everest East. The first is known to consist of two sub-reservoirs, North Everest and South Everest, contained within separate sand lobes of the Forties Formation and separated by an intermediate sand-poor zone. (O'Connor & Walker, 1993). These reservoirs contain gas only, although there is condensate associated with gas production. Everest East contains wet-gas, and includes an oil-rim. This accumulation is within the underlying Andrew and Maureen members of the Lista Formation, thus is not a Forties reservoir. The literature suggests that the Everest Complex contained reserves amounting to 1.0 TCF of gas and 40 MMbbl of condensate, estimated pre-development (O'Connor & Walker, 1993). Current volumes recovered from the Everest fields total 908 BCF gas and 35 MMbbl condensate. For the purpose of this study, the dynamic model is initialised with gas in Everest only, without the volumes in Everest East. This is rationalised by the fact that these gas volumes in the Maureen and Andrew sands of the Lista Formation would have little bearing on the performance and capacity of the Forties sandstone, while from the current study it is thought that there is most likely no (or perhaps only very little) pressure communication between the two.

Therefore, while the modelling choices justified above are appropriate to this study, the dynamic model is initialised with 10 equilibration regions to allow additional flexibility either for sensitivity analysis and/or future study work. The equilibration regions are given below in Table 3-27. The Everest and Huntington regions are defined by their respective boundaries, obtained from DECC. Each equilibration region requires specific PVT inputs, which are further discussed in the next section.

	Equilibration Region Number		
Formation	**Aquifer**	**Everest**	**Huntington**
Sele		4	
Forties Sandstone	1	2	3
Forties Argillaceous	5	6	7
Lista	8	9	10

Table 3-27 Dynamic model equilibration regions

The local pressure in the Forties aquifer has been established from wells in the area. In particular, from review of formation tester (RFT) pressures taken in the water leg of wells 22/15-2, 22/15-3, 22/10b-6 and 22/14a-2, which gave a range in possible pressure gradient of between 0.100 bar/m (0.443 psi/ft) to 0.112 bar/m (0.493 psi/ft) and is broadly consistent with the literature on the area. The reference case pressure is taken as average of all RFT points obtained, which was 0.104 bar/m (0.458 psi/ft), resulting in a pressure at the modelled datum (2652m / 8700ft TVDSS) of 274.8 bar (3985 psi). The relevant data is given in Figure 3-69.

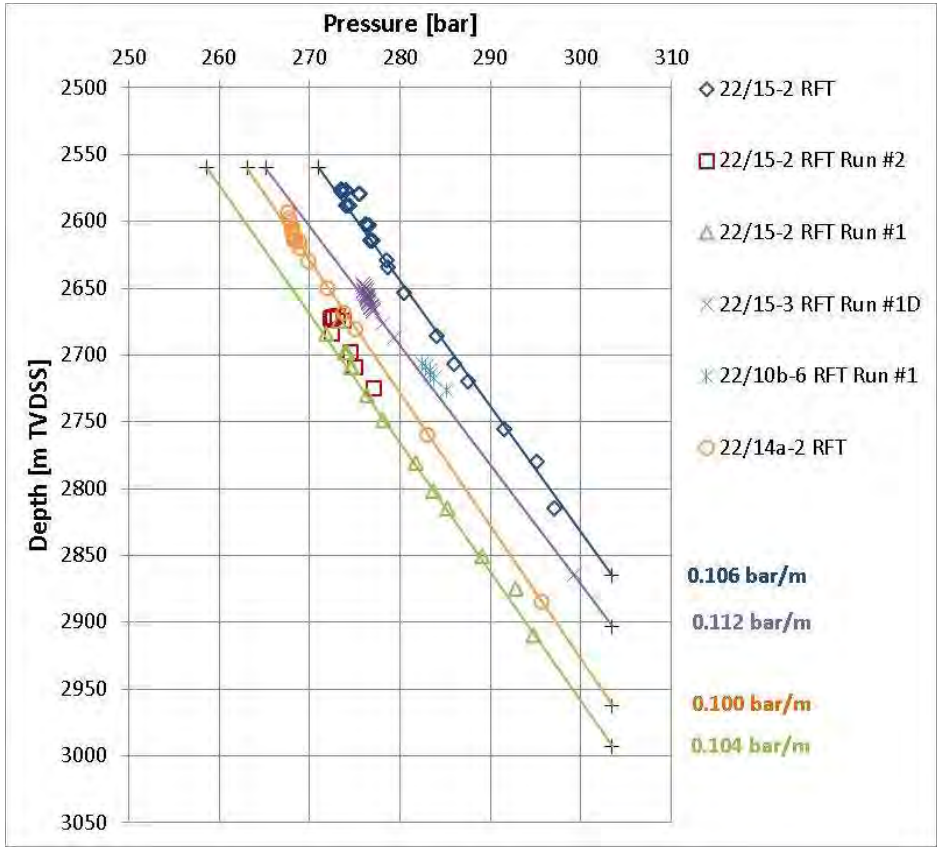


Figure 3-69 RFT pressure data obtained from the water leg of wells within the modelled area

The gas-water contact (GWC) in Everest has been established using the RFT data from wells 22/14a-2, 22/09-2 and 22/09-4 and is picked graphically as an average through the given data points. As illustrated in Figure 3-70, the GWC is taken as 2624.2m (8610ft) TVDSS, at the intersection of the of gradient lines for the gas and water columns. The dynamic model is initialised with a capillary pressure of zero at the contact meaning that the contact also represents the free-water level in the reservoir. Although there is a small discrepancy, 2.8 bar (40.6 psi) in the pressure determined at the contact, comparing RFT pressures from wells within Everest to those in the nearby aquifer, the latter is applied throughout the model to avoid any hydrostatic instability and since the discrepancy is well within the measured uncertainty.

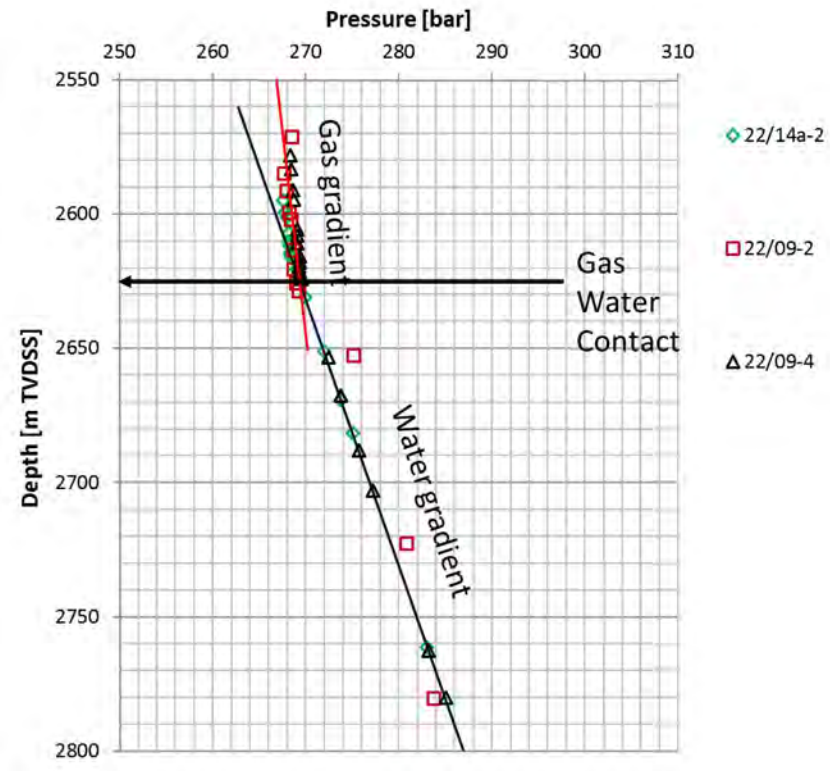
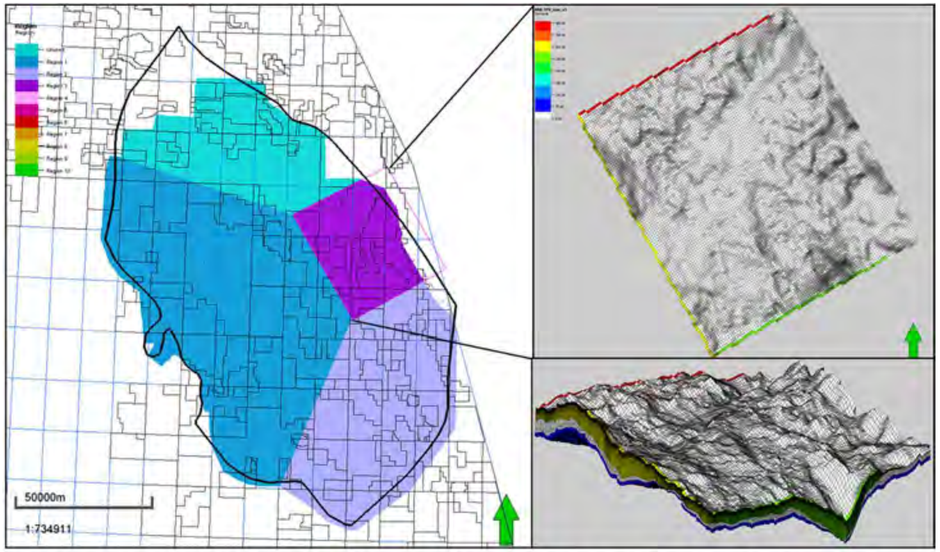


Figure 3-70 RFT pressure data obtained from Everest wells used to determine the GWC

The dynamic model incorporates two aquifers; Forties and Lista, both of which are regionally extensive and with the capability of delivering significant pressure support (or sink in the case of CO_2 injection). The aquifer modelling has appropriately defined representative volumes and the limits of uncertainty. The Forties aquifer extends to the North, West and South of the storage site and its connection to the dynamic model is facilitated by pore volume multipliers along the respective edges of the grid. The apportioning of these volumes along each edge is illustrated in Figure 3-71, with the respective volumes set out in Table 3-28. By contrast, the Lista aquifer volume has been modelled by way of pore volume multipliers along the entire bottom layer of the grid, although it is important to note that the hydraulic connectivity between the Forties and Lista formations within the modelled area is not considered likely and therefore does not form part of the reference case. There remains a high degree of uncertainty in the connected aquifer volumes, the impact of which is necessarily assessed via the sensitivity analysis.

Table 3-28 provides the reference case volumes in place for Everest, Forties and Lista aquifers, after initialisation of the model and prior to any depletion of the Everest Field (under production since 1993). It was not possible to independently verify the gas initially in place (GIIP) for Everest, since the operator data (well by well pressures and flow rates) were not available, but in the absence of any better information the GIIP was sense checked against the DECC cumulative field production of 25.7 billion m^3 (908 Bscf to May 2015 (DECC - UK Government, 2015)) to ensure that the recovery factor is within a sensible range of 0.7-0.9, as might reasonably be expected from a Central North Sea gas field. It should be noted that the field production data, obtained from DECC, is thought to relate to the Everest Complex as a whole (i.e. includes Everest East), whereas the modelled volumes relate only to North and South

Everest. While there is subsequently uncertainty over the volumetrics, these are accepted here in the absence of the definitive data, and are deemed sufficient for the purposes of this study.



Regional extent of the Forties system aquifer and the delineation used to apportion volumes along the corresponding edges of the dynamic model grid also shown is the connection of the Lista aquifer to the bottom layer of the simulation grid.

Figure 3-71 Regional Forties 5 Aquifer Connections to Site 1 Model

Formation	PORV (m^3/Brb)	WIIP (m^3/Bstb)	GIIP (m^3/Tscf)	RF (%)
Sele	-	-	-	-
Forties Sand	2.245 $x10^{11}$ / 1412	2.172 $x10^{11}$ / 1366	3.398 $x10^{10}$ / 1.200	76
Forties Argillaceous	2.234 $x10^{9}$ / 14.1	2.164 $x10^{9}$ / 13.6	-	-
Lista	1.737 $x10^{11}$ / 1093	1.683 $x10^{11}$ / 1059	-	-
TOTAL	4.004 $x10^{11}$ / 2519	3.877 $x10^{11}$ / 2439	3.398 $x10^{10}$ / 1.200	76

Table 3-28 Dynamic model volumetircs for Forties 5 Site 1

The model initialisation is represented below; Figure 3-72, in terms of hydrocarbon pore thickness (HCPT) in the Forties Sandstone and illustrating gas and water saturations in Everest and across the storage site, used as the reference case for this work. Please note that the absence of any hydrocarbon in the north eastern portion of the Everest Field is beyond the pinch out of the Forties Sandstone and reflects the location of the Everest East accumulation in the deeper Lista Formation which was not modelled in this study.

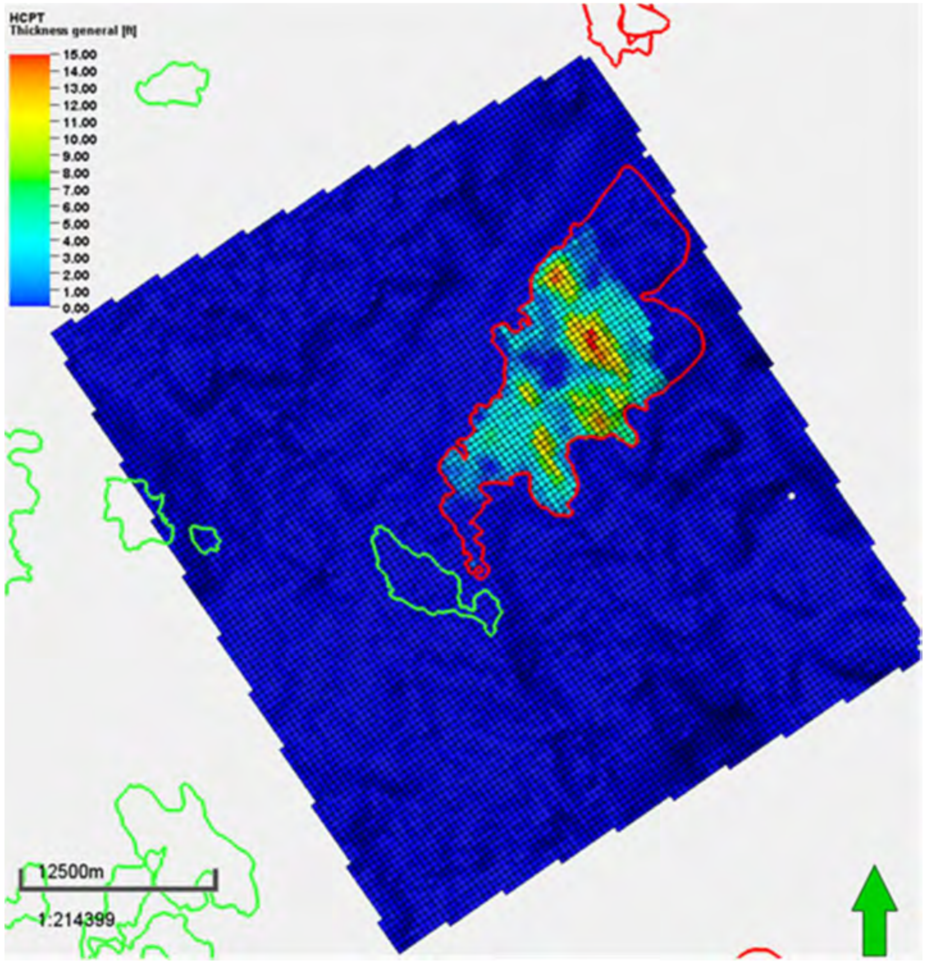


Figure 3-72 Initialisation of the reference case illustrating fluid saturations in terms of HCPT

PVT Management within Eclipse

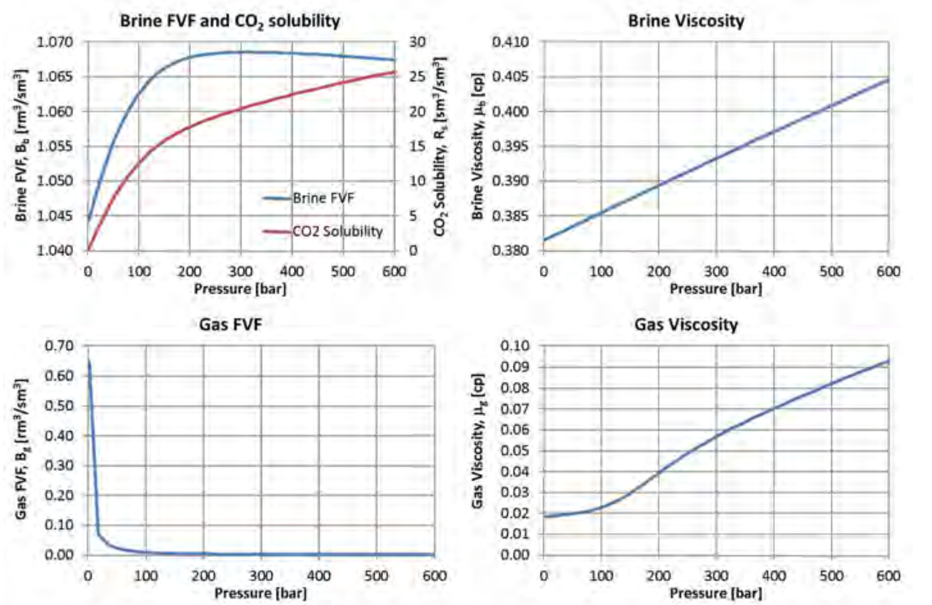
In the particular case of CO_2 sequestration into saline aquifers, such as Forties 5 Site 1, the dynamic model can be developed using commercial "Black Oil" reservoir simulators (e.g. Eclipse™), used widely throughout the petroleum industry, and so called for their treatment of oil, water and/or gas 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 (Energy Technologies Institue, 2011) and (Goater, Bijeljic, & Blunt, 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.

For the purpose of this work, a CO_2-Brine PVT model was developed from the literature and coded in Excel™ to facilitate the generation of "Black-Oil" PVT tables taken as inputs to the dynamic model. The theoretical and procedural basis of this approach is described in detail by (Hassanzadeh, Pooladi - Darvish, Elsharkawy, Keith, & Leonenko, 2008), requiring only reservoir temperature and brine salinity as inputs.

The Forties 5 Site 1 aquifer PVT is generated for a temperature of 100 °C (212 °F), determined at the modelled datum of 2652m (8700ft), assuming a seabed temperature of 6 °C (43 °F) with a water depth of 90m (295ft) and a temperature gradient of 37 °C/km (2.03 °F/100ft), which was obtained from the data set of Huntington well 22/14b-8 located within the storage site (Oil and Gas UK, 2016). Formation brine salinity is taken as 94,000 ppm NaCl equivalent, obtained from the data set of well 22/15-3, located within the storage site, approximately 13 km SE of the Everest field (Oil and Gas UK, 2016). Both the temperature and salinity assumptions used herein have been checked for consistency with the literature on this area.

In this study, the solution water-gas ratio (Rv), representing water vapour in free CO_2 phase, is neglected. Instead the CO_2 phase is modelled as a dry gas, which is a common simplifying assumption used in the petroleum industry where, for example, the solution oil-gas ratio is very small. This is analogous to modelling a lean wet gas carrying small condensate volumes, where in our case we have a gas phase expected to be composed of circa 0.02 mole fraction of water at in-situ aquifer conditions, which is therefore relatively insignificant.

As described in the previous section, the dynamic model employs 10 independent equilibration regions, each requiring specific PVT inputs. Amongst other things, this is necessary to account for the differing fluid properties and PVT behaviours of the hydrocarbon gas-water and CO_2 gas-water systems of the Everest field and surrounding saline aquifer, respectively. The former is applied within the Everest region, whilst the latter applies throughout the rest of the model. The CO_2-brine PVT inputs are as described above, further illustrated in Figure 3-73, below.



Clockwise from top left; brine formation volume factor (B_b) and CO_2 solubility in brine (R_s), brine viscosity (μ_s), CO_2 viscosity (μ_g) and CO_2 formation volume factor (B_g)

Figure 3-73 The reference case PVT properties for the CO_2 brine system applied to the Forties aquifer

For the purposes of this study, the Everest fluid may also be modelled as a dry hydrocarbon gas. In fact, the selection of gas model is in part dictated by the choice of input for CO_2 gas (and vice versa), since Eclipse™ requires consistency. Hydrocarbon sampling, fluid properties and laboratory data has been obtained for Everest from the 22/09-3 well (Oil and Gas UK, 2016) and the model PVT inputs determined in Petrel™ RE, using the available fluids module. Verification of the fluid properties generated was possible using the simulation study reported by Amerada Hess for well 22/14a-2 (Oil and Gas UK, 2016). Figure 3-74 illustrates the Everest gas PVT properties and their validation against those from the earlier study of Amerada Hess (Oil and Gas UK, 2016). Identical PVT inputs for formation brine were adopted in Everest, as were used for the surrounding Forties aquifer.

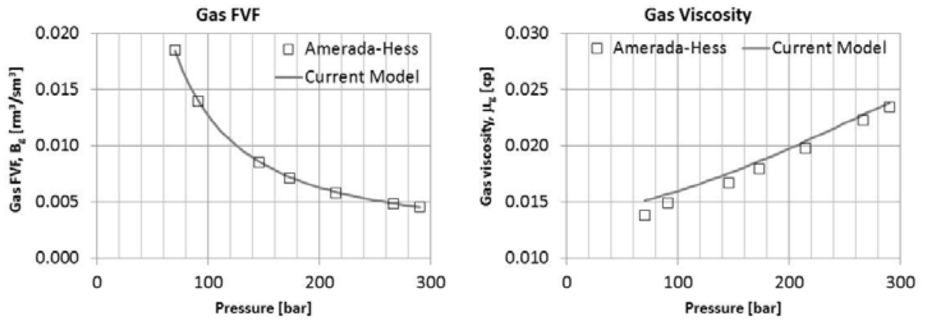


Figure 3-74 Dry gas PVT properties applied to the Everest field and validation of same using the earlier work of Amerada Hess

Formation brine density at the reference conditions is taken as 1068 kg/m^3, determined from salinity, while reference CO_2 density is taken as 1.872 kg/m^3 (Lemmon, E.W., McLinden, M.O., and Friend D.G., 2015) and the hydrocarbon gas of Everest is given a density 0.846 kg/m^3, as determined in Petrel^{TM} RE's fluid PVT module using the field data described above.

Relative Permeability

The dynamic model uses two distinct saturation function regions to distinguish between the behaviours of hydrocarbon gas-water and CO_2 gas-water systems. The former is applied within the region of the Everest field, while the latter is defined within the surrounding Forties aquifer.

Relative permeability and capillary pressure functions for Everest have been obtained from the Special Core Analysis (SCAL) data obtained by Amerada-Hess from the well 22/14a-2 in 1985 (Oil and Gas UK, 2016). Amerada-Hess reported the laboratory analysis of 10 core samples, which ranged in porosity from 10.5% to 24.2% with permeability from 2.1mD to 346mD. Both capillary pressure and air-brine relative permeability test data were available for all 10 samples. For the purpose of this study, a single set of saturation functions was obtained, based on the sample having porosity and permeability most similar to the modelled average permeability in the Forties Sandstone. That is, a sample was selected with porosity of 19.5% (as opposed to an average of 17% in the model) and a permeability of 43 mD (as opposed to an average of 47mD). The available data set included only the drainage saturation functions, thus the imbibition process was estimated. In contrast to relative permeability functions, no hysteresis is considered for capillary pressure in the model. The imbibition relative permeability of water was used as a variable during the model calibration process to help approximate field water production, whereas the remaining saturation functions were held constant. Figure 3-75 gives illustration of the Reference Case Everest saturation functions.

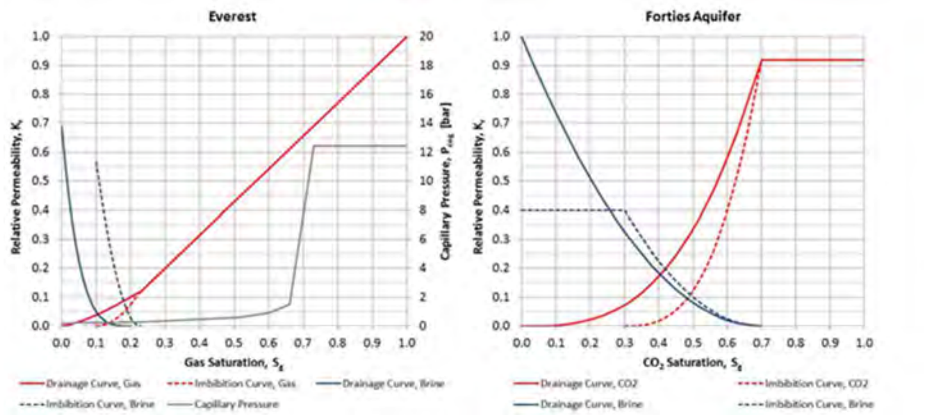


Figure 3-75 Reference case relative permeability curves for Everest (left) and the Forties aquifer (right)

Significant uncertainty exists in the relative permeability functions for CO_2 injection. The maximum $KrCO_2$ value is an indication of CO_2 mobility in the system, the higher the value the more mobile CO_2 will be. There is limited data available, but from published experimental values (Burnside & Naylor, 2014) the best analogue for the Forties aquifer is the Captain formation within the Goldeneye field in the North Sea with a $KrCO_2$ value of 0.92. Drainage and imbibition curves are included allowing for the residual trapping of CO_2 to be modelled. The residual saturation (i.e. trapped gas) from the same analogue is 0.29. The saturation functions were generated using Corey functions from the input relative permeability end-points. The impact of alternative rock physics was evaluated within the uncertainty analysis and is discussed in Section 3.6.6.3. The Reference Case drainage and imbibition curves are illustrated in Figure 3-75 and the input assumptions are detailed in Table 3-29.

Parameter	Drainage	Imbibition
N_g	3	3
N_w	2	2
K_{rw} @ S_{gcr}	1.00	0.40
K_{rg} @ S_{wcr}	0.92	0.92
Sgcr	0.00	0.29
Swcr	0.30	0.30

Table 3-29 End-points and Corey exponents defining the CO_2-brine relative permeability functions

Pressure Constraint

The process of CO_2 injection causes an increase in formation pore pressure. By the same token, the migration of CO_2 into structural and/or stratigraphic traps has the potential to create an increasing localised pressure. It is important that the pore pressure is maintained below the fracture pressure to avoid uncontrolled fracturing and potentially loss of containment through the overlying seal.

The local fracture pressure gradient of the Forties Sandstone is estimated to be 0.170 bar/m (0.75 psi/ft) and is discussed in more detail in Appendix 9. This recommendation is adopted in the reference case dynamic model, applying an additional safety margin of 10%, and implemented as a local pressure constraint over the entire simulation grid, as well as a bottom hole pressure constraint in each of the injection wells.

The model is set-up to stop all injection, in the event that the fracture pressure is exceeded anywhere in the modelled formation. This is expected to be somewhat conservative. The impact of a lower fracture pressure gradient has been assessed in the sensitivity analysis discussed in Section 3. Note that in the reference case, the fracture pressure constraint is never met.

Well Modelling

The target CO_2 injection rate for the Forties 5 Site 1 development is initially 6 Mt/y, increasing to 8 Mt/y after 10 years and continuing for a further 30 years. The number of development wells increases in line with the target profile. Furthermore, the development of the Forties 5 Site 1 as a storage site involves two drilling locations, each with four operational wells, in the south and the north of the modelled area. The southern location is developed first, and is responsible for the first 10 years of CO_2 injection, whilst a satellite location (in the north) comes online to share the higher loading of the latter 30 year injection period. The proposed development is discussed in greater detail in Section 3.6.6.4, but this provides some context for the well modelling requirements. Wells in the south are required to have a greater potential injectivity, each up to 2.00 MT/y, whereas those in the north have less stringent performance requirements, of just 1.35 MT/y, in order to deliver the injection targets. In accordance with the Forties pressure and temperature regime, the CO_2 will be injected in dense (i.e. supercritical) phase.

All wells were assumed to have the same general trajectory and more importantly to terminate in a 305m (1000 ft) horizontal section, cased and perforated for 152 m (500 ft) at the toe. The additional horizontal section was essentially “spare”, available for future re-perforation in the case of degrading injectivity or other performance issues. As per the well performance modelling conducted separately, and reported in Section 3.6.3, several tubing sizes were assessed for their impact on injectivity. This work showed that the selection of tubing size is marginal – either 5-1/2” or 7” in the south and either 4-1/2” or 5-1/2” for the wells of the north – however it was reasoned that given some reservoir uncertainty and the low tolerance on the target injection rates, that the larger of the tubing sizes should be selected, respectively (i.e. 7” in the south and 5-1/2” in the north). This was confirmed through simulation, since equipping the wells in the south with 5-1/2” tubing was insufficient to deliver the target profile during the first 10 years of injection.

Each well was modelled with a dedicated lift curve (i.e. VLP table) and controlled at a target injection rate developed with consideration to total volumes injected in each location and the subsequent long term migration of CO_2 within the area. For the purposes of this study it was imperative that the CO_2 plume was confined to the modelled area after 1000 years from the end of injection. The wells were also constrained in terms of tubing head pressure (THP), based on a maximum delivery pressure of 160 bar, which was also confirmed to be within the maximum THP for fracture prevention under hydrostatic conditions (since frictional pressure loss limits bottom hole pressure during injection). The maximum THP is attained at the end of injection and was calculated to be 152 bar (2200 psi). The Reference Case THP profiles are shown in Figure 3-76 for the wells of both the northern and southern injection sites.

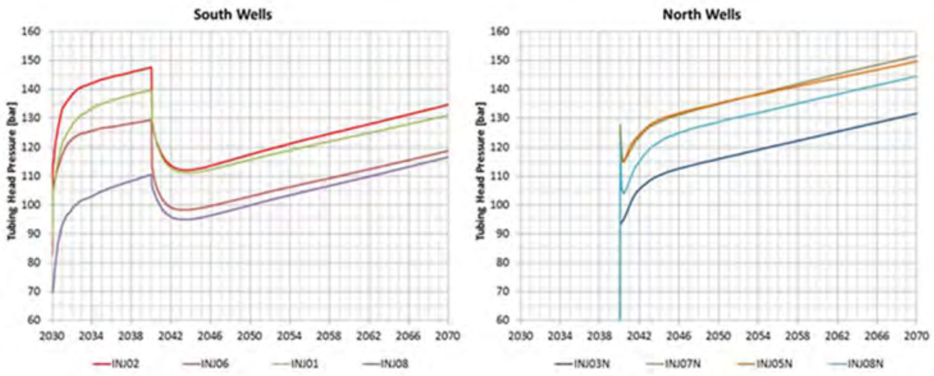


Figure 3-76 Reference case THP forecasts

3.6.7.2 Model Calibration

Although the primary storage target within Site 1 is the saline aquifer, the Everest gas field, a proven structural trap, provides additional storage potential. As part of the model calibration process it was considered to be important to include hydrocarbon gas in the Everest field to capture the higher compressibility system and also include the pressure depletion observed in the Everest field, as both these parameters are expected to impact injectivity and the storage potential within the aquifer.

Data available for the model calibration were limited to field level production data from DECC and a single reported pressure measurement from the field (Rattan, Stevens, & Nguyen, 2011). No additional data were available from the Operator. The intention was not to generate a fully history matched model but to capture the impact of the depleted gas field on the site performance. It would be recommended to revisit the model calibration, to achieve a more rigorous history match, when detailed data from the operator is available.

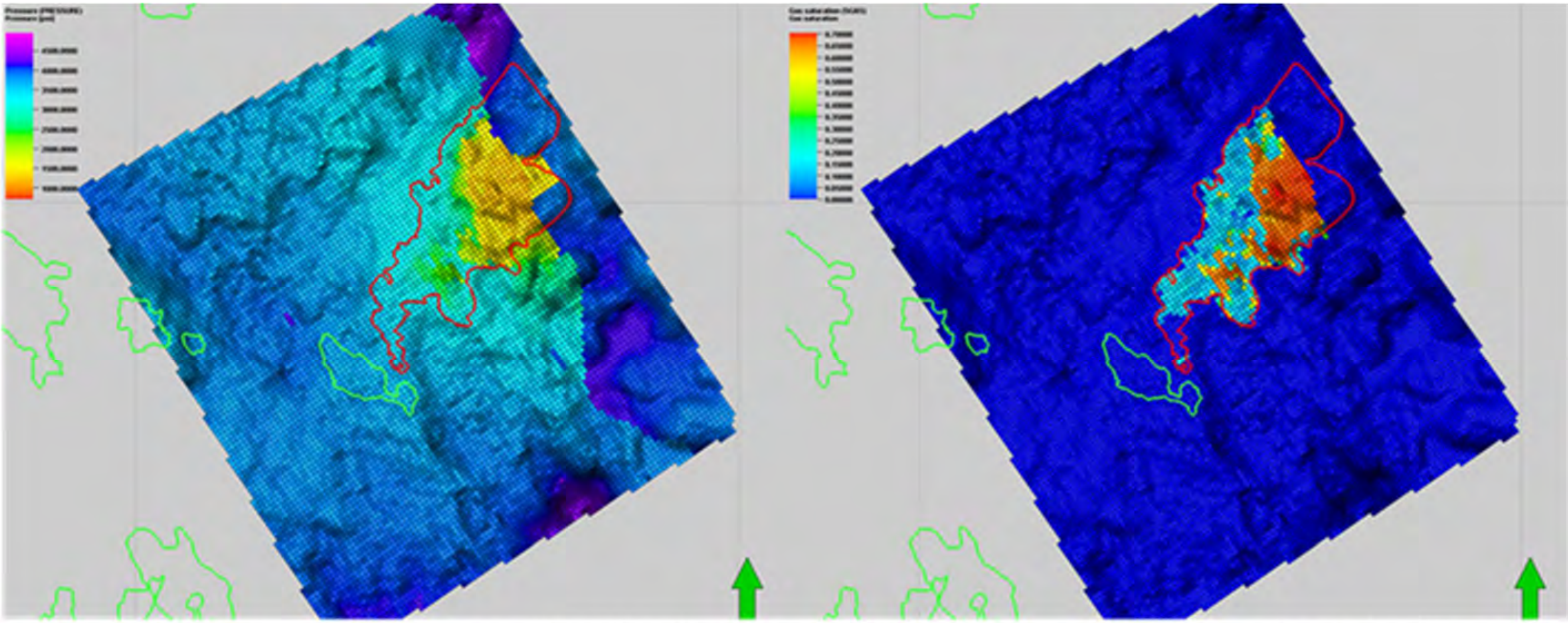
Everest has been on production since May 1993. As of May 2015, the Everest field had produced 25.7 billion m^3 (908 Bscf) of gas, 5.51 million m^3 (35 MMstb) condensate and 0.61 million m^3 (3.8 MMstb) water. The produced condensate, being equivalent to an overall condensate gas ratio of 38 stb/MMscf, represents a relatively lean gas and in the absence of any other data can be considered an associated liquid production, allowing the assumption of a dry gas in Everest for the purposes of numerical simulation.

This study therefore attempted to produce the entire Everest gas and water volume (including Everest East) from the modelled Everest gas accumulation (Everest North and South), neglecting condensate production (as above). In the absence of individual well data, the total rate was apportioned amongst 8 synthetic wells, positioned in accordance with the HCPT map to drain the largest gas accumulations within the field. The apportioning of gas was not straight-forward, but was achieved through trial and error in order to obtain the best overall match at the field level. Wells were rate controlled, by gas production, to conform to their synthetic rate histories while attempting to match the water production and a single known pressure point.

The model calibration indicated that the inclusion of both Forties and Lista aquifers provided too much energy to the system, which compromised the match to the known pressure and water rates. The Lista volume was removed, as a lack of hydraulic communication might be supported and was more plausible than a lack of communication through the Forties. Vertical permeability was also refined through the model calibration, since a vertical permeability upscaled from the static model using harmonic averaging gave a more favourable result. The imbibition relative permeability for water was also used as a history match parameter within Everest in an attempt to restrict the water mobility. This was done with some (limited) success, in that a match was achieved for the total volume of water produced at the end of the available history, although the water rates did not. It is probable that in reality, water is actively managed through shut-off, well shut-ins and infill drilling, which could not be reproduced without an appropriate data set.

Reservoir Pressure Match

The current reservoir pressure in Everest is not known with any certainty, since the data is not available to this project. A single pressure point (65.5 bar) was obtained from the literature, quoted by BG (the operator) during a Gas Well Deliquification Workshop in Denver, Colorado, during March 2011 (Rattan, Stevens, & Nguyen, 2011) and was used as the match point for the model. This value in itself carries considerable uncertainty since neither the date nor depth of measurement is referenced in the workshop proceedings. Figure 3-77 illustrates the pressure and saturation maps corresponding to the model calibration and representing the reservoir conditions at top Forties in 2030, following partial recharge of the area, and just prior to injection. This reflects the restart data adopted in the CCS evaluation.



Pressure (left) and gas saturation maps (right) for the top Forties following Everest depletion and partial recharge, shown just prior to CO_2 injection, in 2030

Figure 3-77 Pressure and gas saturation maps in 2030 just prior to CO_2 injection

Production Rate Match

The resulting simulated gas and water rates for the Everest field are compared to the observed data in Figure 3-78. The predicted future production is also shown.

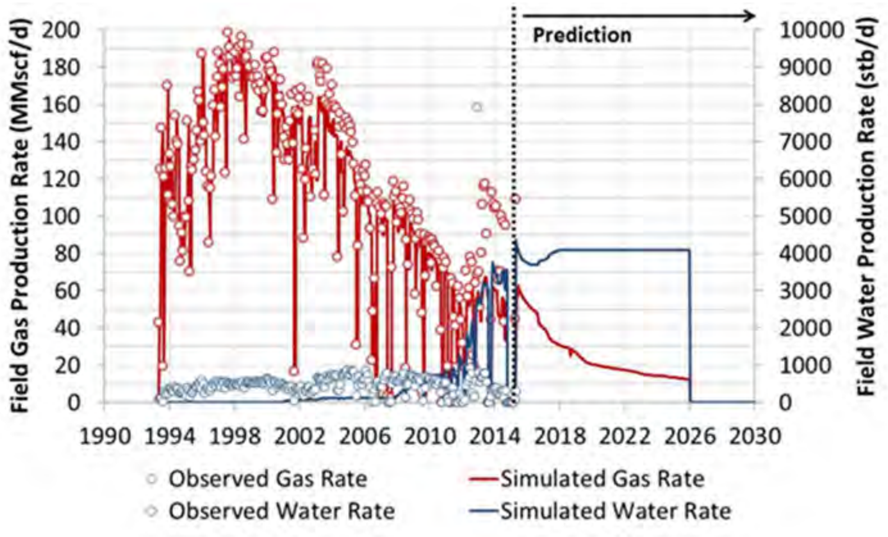


Figure 3-78 Comparison of simulated and observed data for the Everest field

The match quality is reasonable for gas, with the exception of certain peaks in field gas rate, particularly during the interval between 2012 and 2015, which might have been attributed to infill drilling, or the additional potential of Everest East. The fact that these peak rates overcome the natural declining trend in gas production is indicative of field management activity, which is not incorporated to this study. By the same token, the match quality is poor in terms of the water rate, which will at least partly be due to active management of water production by the operator. In this study, water production escalates after breakthrough since there is no management in place. The imbibition water relative permeability has been adjusted to give a match on the field cumulative water volume at the end of the production history, near-to the point at which the pressure comparison has been made.

A prediction was run to the projected CoP date, using gas rates as the control by setting the target to the final historical value for each well. A constraint was also applied on water production, limiting it to its final simulated value. This was intended to prevent water rates, which were already exaggerated, from increasing uncontrollably and created a natural decline in the gas rates that appeared to be reasonable. As at the forecast Everest CoP date, the estimated remaining volume of free gas in place was 6.129 x10^9 m^3 (216 Bscf) and the final recovery factor estimated to be 82%.

3.6.7.3 Modelling Results

Development Strategy

The Forties 5 Site 1 storage complex includes both the Huntington and Everest fields, both currently in operation. Of these two fields, Everest has the later cessation of production date (CoP), currently scheduled for 2026 (Pale Blue Dot Energy; Axis Well Technology, 2015). Subsequent CO_2 injection and storage in the Forties sandstone is proposed to commence in 2030; for the purpose of this work. It is assumed that injection commences on the 1st of January and extends for 40 years through to 2070. The proposed development is phased, in line with a target injection profile of 6Mt/y during the initial 10 years, using 4 horizontal wells drilled and completed (7” tubing) from a platform in the south of the area. Thereafter it includes the build-out and tie-back of a further 4 horizontal wells (5.5” tubing) from a subsea tie back location in the north, at which time the injection target is increased to 8 MT/y, using all 8 wells (i.e. north and south), for the remaining 30 years. Naturally, in addition to the initial development wells, the strategy includes replacement wells, workovers and a contingency well to preserve site performance and guarantee its longevity. Full details are provided in the Drilling Schedule, Section 3.6.3.

For the proposed development scenario, 300 Mt of CO_2 is injected and stored during the course of the site's initial design lifetime. That said, it is important to note that this is significantly below the ultimate potential storage capacity of the whole storage complex. There is significant additional build-out potential within the site (not to mention the wider Forties system and deeper reservoir intervals). Furthermore, as the objective for this study was to develop a site plan for the Forties 5 Site 1 aquifer, injectors are not placed inside the Everest gas field, although it recognises the value of the Everest structure as a proven structural trap for migrating CO_2. The selected injection forecast allows for maximum injection into the 2 selected injection sites whilst ensuring that the injected CO_2 remains within the designated storage complex boundary for a minimum of 1000 years after injection ceases.

Well Placement

A number of target well locations were identified across the entire Forties 5 Site 1 aquifer region, with targets selected to optimise the trapping opportunities afforded by the available structural features. This quickly focussed interest on the areas to the south and down-dip of the Everest Field, which is itself the largest structural trap in the area. Wells were placed to inject in the lower layers of the Forties Sandstone to optimise residual trapping as upward migration of CO_2 under buoyant forces occurred.

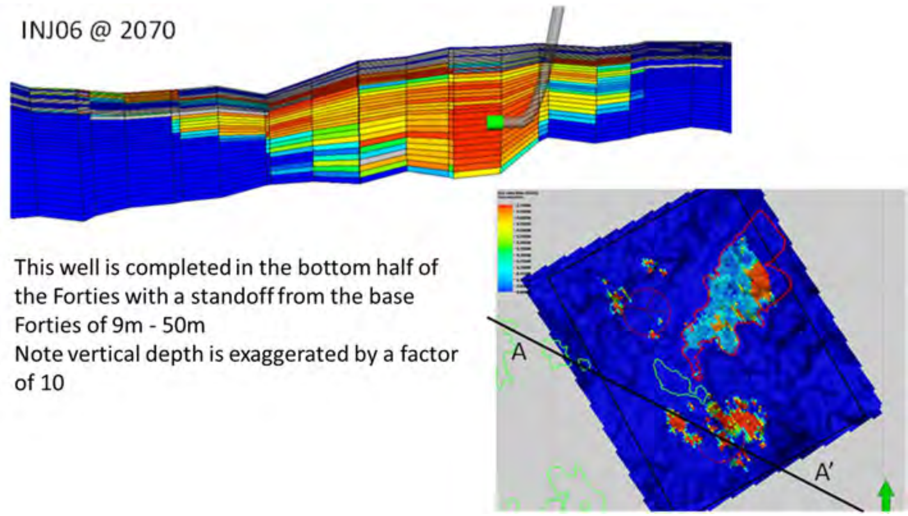


Figure 3-79 Illustration of Injector well placement within the Forties Sandstone

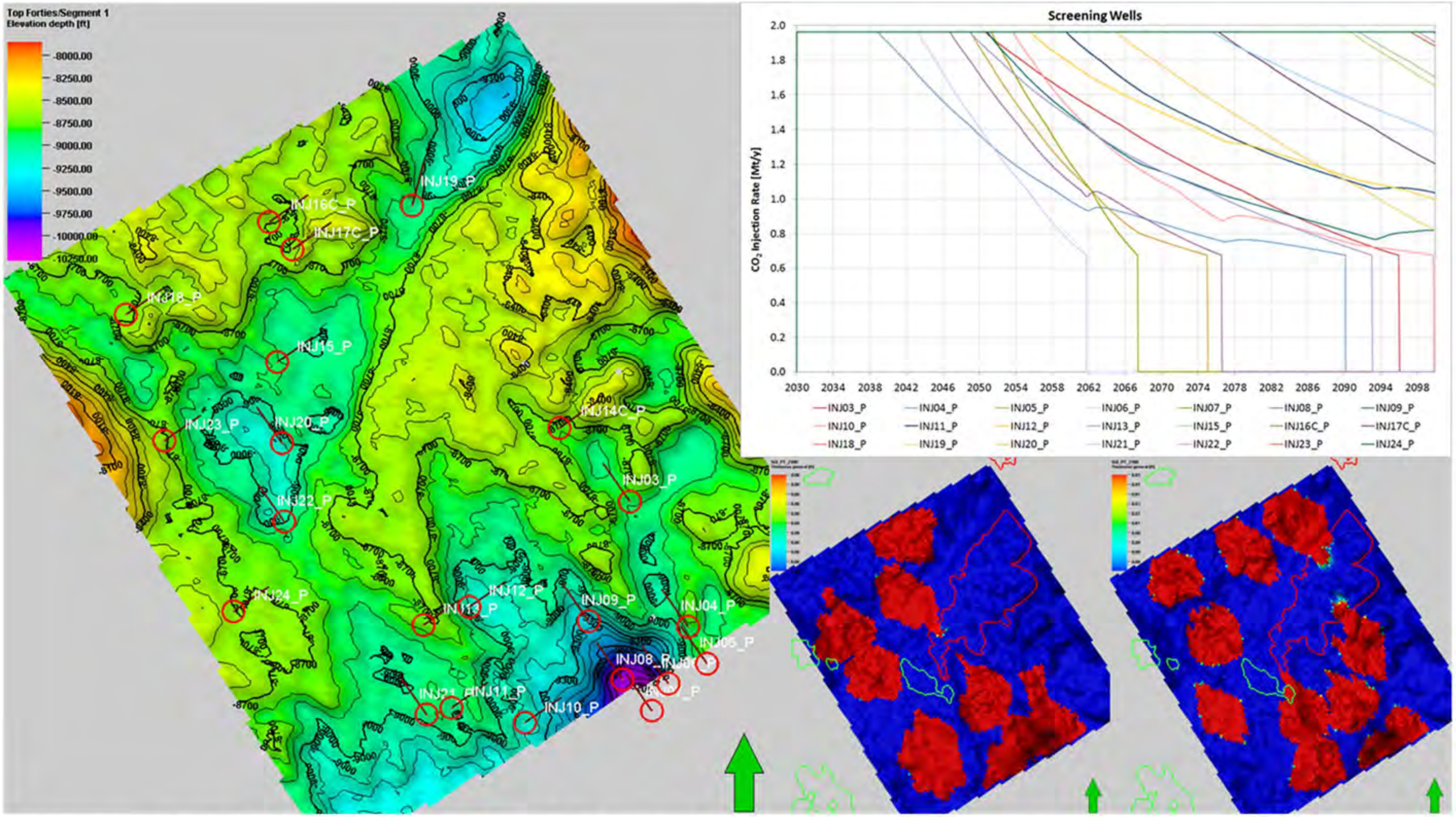
This facilitates a larger contact with the reservoir by encountering shale barriers and baffles within the Forties sand. By forcing the CO_2 along a more tortuous path, the site's storage efficiency would be improved by promoting a larger fraction of the CO_2 to be stored by the dissolution and residual trapping mechanisms. With the exception of wells placed specifically in some of the smaller structural features along the top of the Forties, specifically tested for their ability to structurally trap injected volumes, the wells were completed in one of the 10 lower layers selected independently at each location to include the best quality sands in that interval (typically based on a maximum permeability of between 50 and 200 mD). This naturally resulted in a wide variability in well injectivity performance.

Figure 3-80 indicates the well locations initially screened within the defined storage complex area. Wells were tested via a set of two simulation runs, to better resolve the migration and performance of each well by attempting, within reason, to limit interference. Wells were rate controlled at 2MT/y, but were subject to the usual bottom hole pressure constraint of 90% fracture gradient and a maximum tubing head pressure of 157 bar. The wells were set up with a preliminary type well VFP table (7”), which was identical for all. Wells targeted 70 years of injection between 2030 and 2100.

Based on the initial screening, three potential drilling locations were selected for further assessment in the South, West and North. In addition, the following factors were taken into consideration:

- Drilling radius –a practical drilling radius of 3570m (11712 ft) was established for the given formation depth from a single drilling location (i.e. platform or subsea template) to constrain well trajectory and ensure drillability.
- Reservoir quality risk –the area directly to the south of Everest (in the SE quadrant of the grid) carries a greater risk of poorer reservoir quality. For this reason it was decided to omit this part of the grid from further consideration, focussing instead on the areas most likely aligned with the Forties sandstone channel features extending through the area from the north.
- Migration risk – while there is almost no risk of migration out of the area to the east, due to the Everest stratigraphic trap and the Forties pinch out feature, migration of the CO_2 plume to the north and west presents a finite risk in this open aquifer system since the sand geometry dips upward and the reservoir quality improves. By contrast the risk of migration to the south is tempered by a combination of southerly dipping geometry and degrading reservoir quality. The development should therefore mitigate against migration toward the north and west, whilst adopting the Everest closure as a backup trapping mechanism should the CO_2 plume move faster than modelling predicts.

With these factors in mind, a Level 2 screening exercise was carried out involving a total of 8 potential development well locations that were identified and tested in the South, 2 in the West and 9 in the North, as shown in Figure 3-81. Wells in the north were tested independently of those in the south, in each instance incorporating the wells in the west as a potential (later) tie-in. The wells exhibited a range of injectivity performance, and CO_2 migration paths, also shown in Figure 3-81. This process also allowed for the optimum number of wells to be established for each location. Wells were individually tested to 3MT/y, although rates/volumes were later reduced to satisfy the containment criteria.



The range of well performance is illustrated in terms of injection rate (top right) and free CO_2 migration during 70 years of injection for the corresponding set of two case runs (bottom right)

Figure 3-80 Initial well screening locations (Forties top structure map)

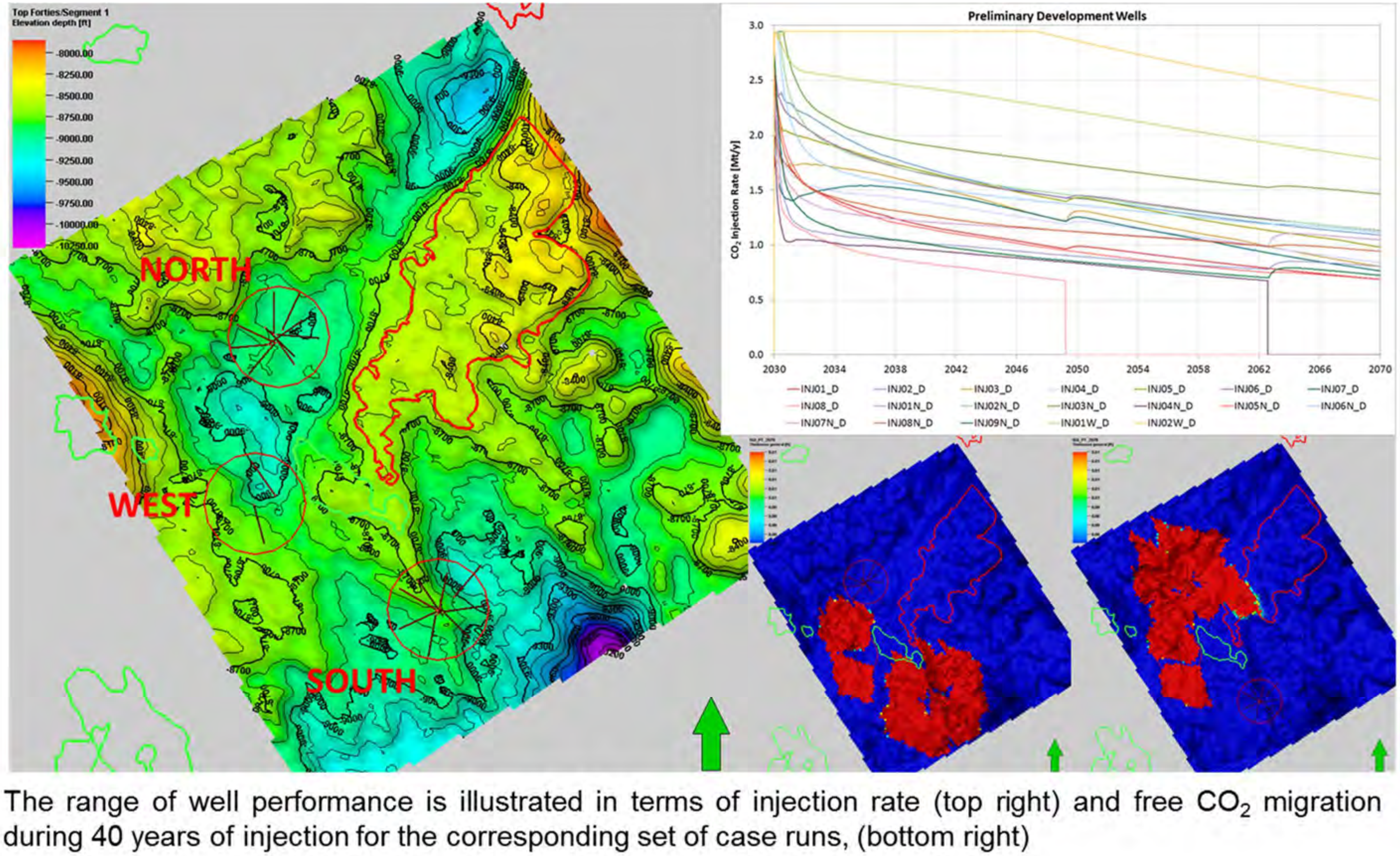


Figure 3-81 Targeted drilling locations over the Forties top structure map

Despite relatively low reservoir quality in this part of the Forties 5 Site 1 aquifer, it was determined that injectivity was not a constraining factor for the development, since well potential and storage capacity were observed to far exceed the volume that can be contained within the model. One of the key challenges being mitigating migration beyond the storage complex boundary. For the three potential drilling sites assessed, the final well placement was therefore largely dictated by migration risk. Moreover, the target injection profile was also scaled back to a maximum of 8Mt/y, shared between two sites, and controlled at the well level to limit injected volumes along the most susceptible migration pathways. The drilling site in the West was not considered further due to the higher potential for migration of injected CO_2 up-dip towards the many well penetrations in and around the Howe and Bardolino oilfields. The reference case was further optimised through some 27 case runs, until there was confidence in the containment of injected CO_2 volumes after 1000 years of storage and migration. The optimisation runs were configured with reference case grid properties and well pressure constraints. Best estimate aquifer volumes and Everest depletion were also included. Well selection and rates were varied with injection strategy and the wells in the north and south each used VLP tables from type wells (7” and 5-1/2”) to more accurately represent outflow performance. In selected cases, the simulations were run to 1000 years to assess longer term containment.

8 wells were selected for the development with an additional contingency or back up well in the South. The final well locations are shown in Figure 3-82. Further information on well injectivity performance and well number is provided in 3.6.3.

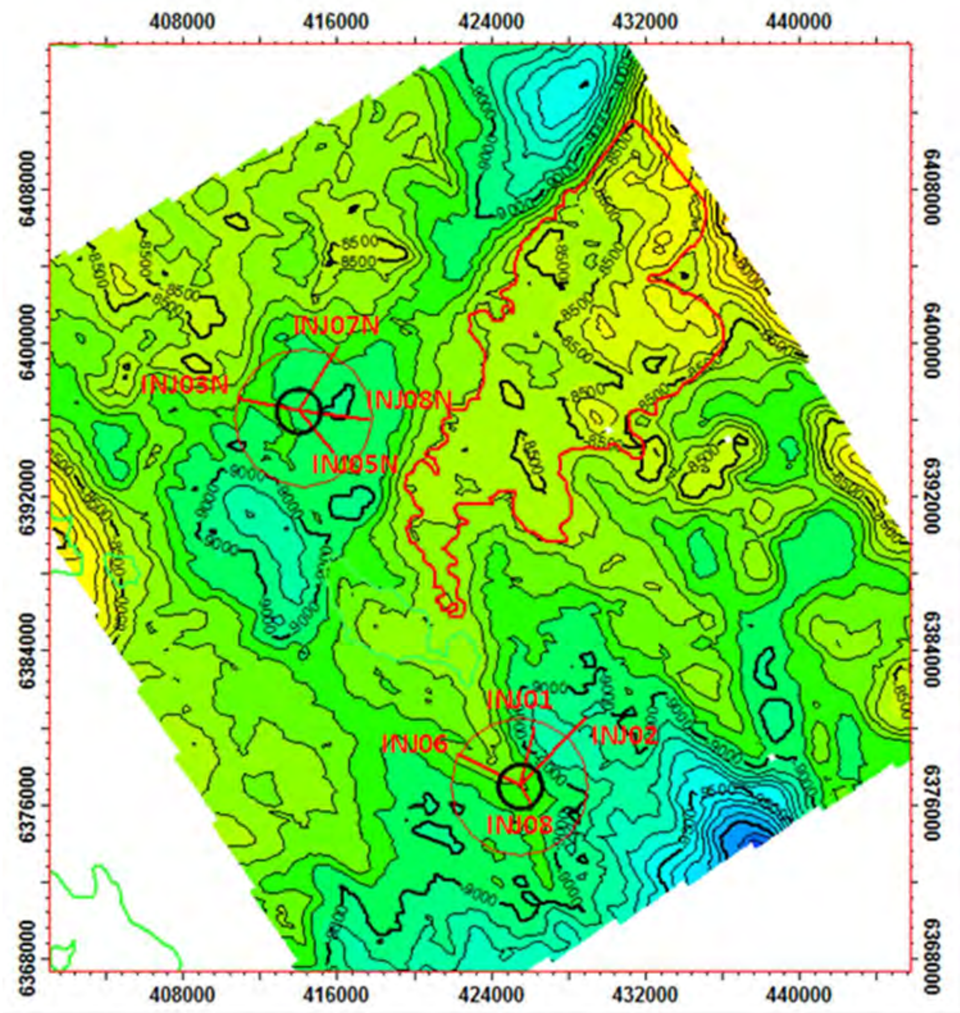


Figure 3-82 Final well locations over the Forties top structure map

Well Injectivity Potential

Several preliminary runs were carried out to establish the injectivity potential of candidate development wells and rank them accordingly. As presented here, wells were simulated with an injection rate control of 3Mt/y out to 2070, as described by the Level 2 screening process in the previous section, which provided a clear discrimination between wells and demonstrated their wide ranging potentials. Generally speaking, the wells in the west stood out as having the greatest potential injectivity, followed by the wells in the north and then those in the south; however the north and south sites were less dissimilar having a relatively large range with significant overlap. All wells were observed to switch on at the target rate of 3Mt/y, however in many cases the decline was rapid and the target rate was maintained for several days only. Therefore, taking the initial injection rate at July 2030 as a guide, the well injectivity potential within the site can be seen to range between 1.16 MT/y (60 MMscf/d) to in excess of 3 MT/y (155 MMscf/d). The lowest injectivity was observed in well INJ04N (in the north), while the best injectivity was observed in well INJ01W (in the west). The results are shown in Figure 3-83.

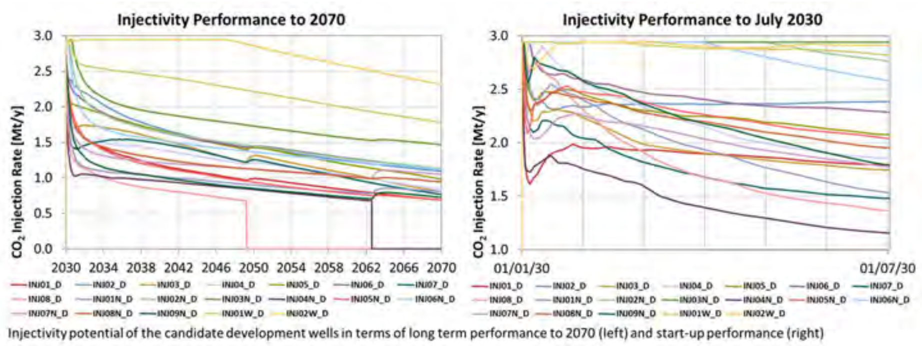


Figure 3-83 Start up and long term injectivity potential of the candidate development wells

Sensitivity Analysis

As outlined in the previous section, injectivity was not a constraining factor for the development, since containment risk dictated lower injection volumes, thus a lower well count and lesser injection rates, but also careful well placement with consideration to migration pathways. For this reason, some of the lower injectivity wells were later used in the reference case. Based on this same simulation result, the well injectivity potential is compared for the selected development wells, in Figure 3-84.

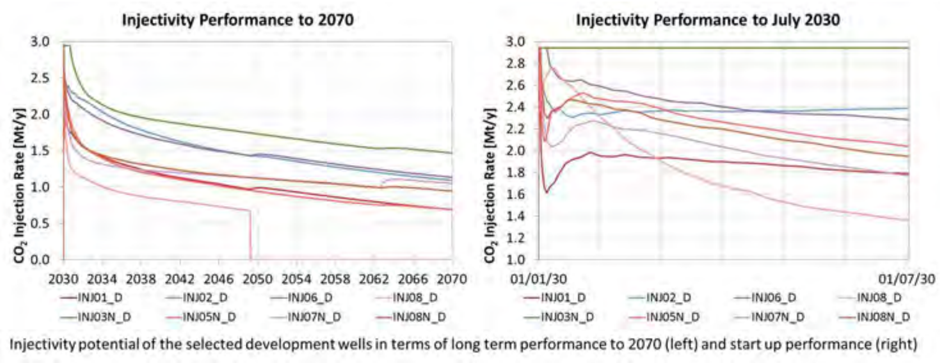


Figure 3-84 Start up and long term injectivity potential of the selected development wells

There is good pressure communication throughout the Forties aquifer system resulting in some pressure interference between injected sites. The impact on each site performance depends on the injection rate targets, with lower injection rates resulting in less of an impact. A sensitivity was run to quantify the impact on the case in which a target rate of 6Mt/y was set for both the southern and northern sites. Neither site can sustain this rate with 4 injection wells but the impact on the southern site performance when injection is included in the northern site is:

- the duration of the 6Mt/y rate plateau is reduced from 22 years to 10 years and
- the cumulative injected volume after 40 years of injection is reduced by 9%.

Although the injectivity into each site is better without additional sites the injection rate into each site is limited by the CO_2 migration constraint and the pore volume utilisation is improved by employing multiple injection sites within such an extensive storage complex.

Well Number

In terms of maximising the total injection to the site, the optimum number of wells was determined by a series of simulation runs, each adding a well (either in the north or the south) in succession. The wells in the west were added in the same way to both of these primary drilling sites. It was subsequently determined that the optimum number of wells in the south was 7, since the addition of the 8th well brought little value. Similarly, in the north, the optimum number of wells was 8. In both cases the addition of either one or two wells in the west had significant value in terms of total injectivity, however as has already been discussed the western drilling site was later omitted due to concerns over the CO_2 migration path from these wells. The results are provided in Figure 3-85.

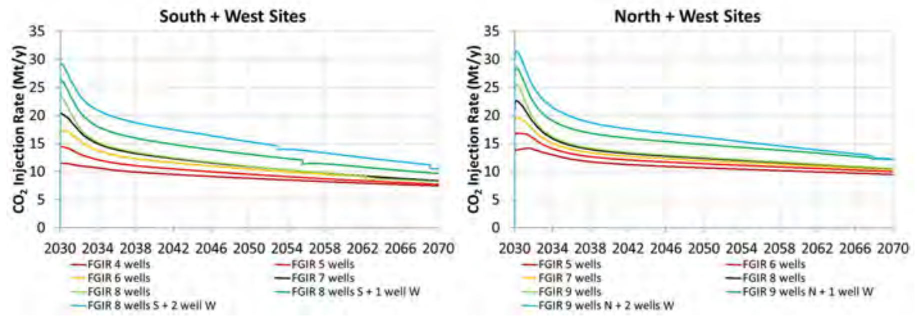


Figure 3-85 Sensitivity of injection potential to well number at key injection sites

With reference to Figure 3-84, although it was established that the potential long-term injection performance of the primary drilling locations could readily be sustained in excess of 10 MT/y, the further evaluation of the site at these volumes indicated the increased risk of CO_2 migrating beyond the defined storage complex boundary. It was therefore decided to omit the site in the west and evaluate a phased development, with the primary drilling site in the south and a secondary site in the north, with the respective start dates staggered by 10 years, in 2030 and 2040. This decision was based on evidence that containment risk was lower in the south due to structural dip and degrading reservoir quality down-dip, supported by the migration patterns observed from the preliminary simulation work. This meant that greater volumes could be injected in the south. After optimisation of the development scenario, for well number, well location and site injection targets it was concluded that 4 wells were required at each site, which was surplus to requirements but meant that there was sufficient confidence that the injection target could be maintained out to 2070 and beyond. Importantly there would be excess well potential to accommodate any short-term loss of injectivity at any particular well, or other process interruption.

Containment and Storage Complex Boundary

It is important to emphasise that the Storage Complex Boundary was defined early in the process of exploring the potential of the storage site. This boundary has been fixed and the development plan has been subsequently engineered to limit the CO_2 plume within the boundary. In a real development, there may be an opportunity to re-define this storage complex boundary to help optimise the dynamic storage efficiency and perhaps extend the life of the injection project still further.

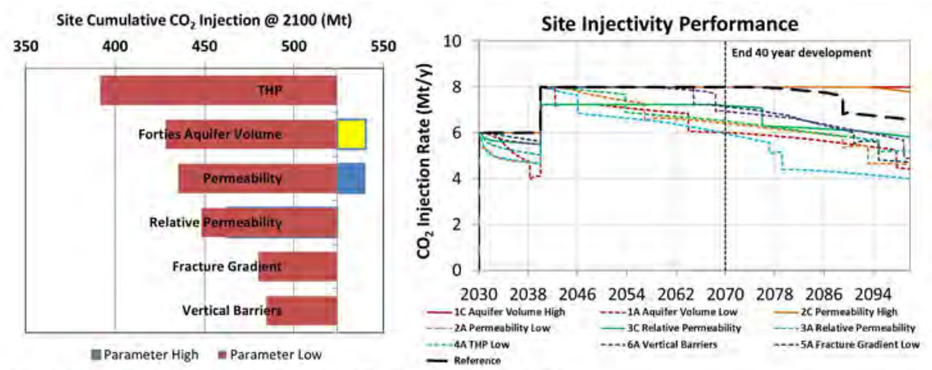
Sensitivity Analysis

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 2070, and beyond out to 2100.

In summary, the sensitivity matrix is outlined below in Table 3-30 and the results are summarised in Figure 3-86, which includes a tornado plot comparing cumulative injected CO_2 alongside a line plot of the comparative site injection profiles. It is observed that the greatest sensitivity is attributable to tubing head pressure – although fortunately this can be controlled. Meanwhile, of the subsurface uncertainties, aquifer volume has the largest impact, closely followed by permeability. Each of these inputs and their corresponding results are discussed further within the subsequent sections of this report.

	Parameter	Units	Low	Reference	High
No.			A	B	C
1	Forties aquifer pore volume	km^3	1.7 $x10^2$	2.2E $x10^2$	4.4 $x10^2$
2	Permeability (avg. k_h / k_v)	mD	26 / 9	47 / 14	64 / 21
3	Relative permeability set	-	Set 2	Set 1	Set 3
4	THP limit	bar	120	157	-
5	Fracture pressure gradient	bar/m	0.158	0.170	0.172
6	Vertical barriers (shale)	-	Layer 20	Nil	-

Table 3-30 The uncertainty matrix assessed through sensitivity analysis for the Forties aquifer

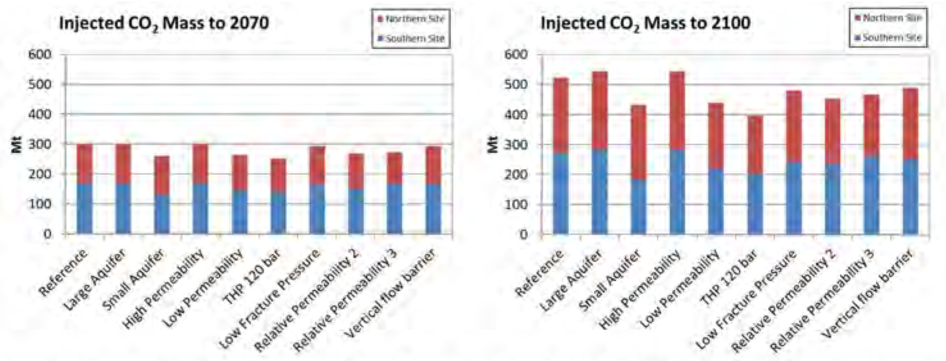


Tornado plot of cumulative injection (left) and site CO_2 injection rate (right) to 2100

Figure 3-86 Results of the sensitivity analysis for key subsurface and development uncertainties

The simulation sensitivity results demonstrate a number of downside risks, but also with some upside (Further upside is of course available in the case of exploitation of the pore volume in the Everest gas field and the deeper Maureen and Andrew sandstone aquifers – all of which were excluded from this simulation review). The results shown in the Tornado Plot are centred on the reference case mass of 524 Mt injected out to 2100. Whereas in the case of the Forties Aquifer Volume, the upside is indicated in bright yellow, the result is constrained by the given development strategy and the upside is potentially much greater. Tubing head pressure (THP), although having a large impact, is within the control of engineering/budget, thus can be controlled and is not a particular risk to the project. Permeability and relative permeability remain significant uncertainties, carrying considerable downside, although the reference case incorporates a best estimate based on available information. 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 and validated in the literature. The presence of barriers to vertical flow (i.e. intermediate shale within the Forties) is considered a possibility; however lateral extent is uncertain and probably unlikely to be regionally extensive (even within the locale of the model). It has been included for completeness.

These results may also be presented in terms of total injected CO_2 mass, by case, and the split between sites in the north and south, compared for the planned 40 year development life-cycle (to 2070) and an extended 70 year injection period (to 2100). The results are presented in Figure 3-87.



Sensitivity results compared in terms of injected CO_2 mass volumes for north and south sites during 40 year injection to 2070 (left) and 70 year injection (right)

Figure 3-87 Dynamic Model Sensitivity results

Based on the data available for this study, the reference case is considered to be the most representative model for Forties 5 Site 1 and is the basis for the storage development plan.

Reference Case

The reference case is described with respect to the sensitivity parameters in Table 3-30, presented above. Moreover, its development is extensively discussed in Section 3.6.6, but for clarity the main input parameters presented throughout the body of this report are consolidated in Table 3-31, provided as a summary.

Input Parameter	Value / Description
Datum depth	2651.6 m (8700 ft)
Initial Pressure at datum (mean)	273.6 bar (3967 psi)
Depletion Pressure (mean)	249.2 bar (3613 psi)
Temperature at datum	100 degC (212 degF)
Rock compressibility (at 320 bar)	4.89 x10^{-6} bar^{-1} (3.37 x10^{-7} psi^{-1})
CO_2 density at datum	617.1 kg/m^3 (38.44 lb/ft^3)
CO_2 viscosity at datum	0.053 cp
Brine Salinity (NaCl eq.)	94000 ppm wt.
Brine density at datum	1070 kg/m^3 (66.65 lb/ft^3)
Porosity (mean)	17%
NTG (mean)	66.2%
Permeability (mean/range)	47 mD / 0 – 764 mD
Permeability anisotropy (mean)	0.24
Pore Volume	2.267 x10^{11} m^3 (1426 Brb)
Aquifer Volume	2.194 x10^{11} m^3 (1380 Bstb)
Well Models	North: type well (INJ02) VLP table
	South: type well (INJ03N) VLP table
Well Control	Individual rate control BHP constraint: 405 bar (5873 psi) THP constraint: 157 bar (2276 psi)
Completion Type	152m (500ft) horizontal
Well Number	8 (total); 4 (south) + 4 (north)
Injection Rate	10 years @ 6MT + 30 years @ 8 MT
Tubing Size	7” (south), 5-1/2” (north)

Table 3-31 Key input parameters to the reference case dynamic model

Additionally, the wells were subject to a minimum injection rate of 0.77 MT/y (40 MMscf/d) in the south (7" tubing) and 0.48 MT/y (25 MMscf/d) in the north (5-1/2" tubing), due to inversion of the lift curve at rates below this cut-off, a condition which is not easy to model 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 statistics given in Table 3-31 are obtained from the grid by filtering cells at the reference depth, in the aquifer, and obtaining the corresponding mean value. Depletion pressure refers to the mean pressure at datum after depletion of the Everest field (to 2026) and the subsequent period of natural recharge ending in 2030. This is estimated to be close to the initial field pressure at the start of CO_2 injection.

Tubing Head Pressure

The delivery pressure of CO_2 to the tubing head has a direct impact on cost of the development; principally, the cost of compression and transmission (pipelines, risers, etc.). This development is designed with a CO_2 delivery pressure of 160 bar, while tubing head pressure is limited to 157 bar in the dynamic model, just below the delivery pressure. It was determined by the well performance modelling that there should be a maximum tubing head pressure constraint, necessary as a precaution in the case of unplanned failure/shut-in of the wells, since such an event may result in a loss of the frictional pressure head between surface and bottom hole, changes in phase properties and consequently a risk of exceeding the fracture pressure. The delivery pressure in this development is specified below, but close to, this maximum tubing head pressure and was fixed during the reference case optimisation. Consequently, any reduction in this pressure would compromise the target injection profile and would lead to a differing result. It was important to quantify this as a sensitivity, by comparison to a typically lower delivery pressure of 120 bar (1740 psi). By constraining tubing head pressure accordingly, we observe failure to meet the target injection rates and an injected volume reduced from 300 Mt to 252 Mt (-16%) during a 40 year development lifespan, and from 524Mt to 397 Mt (-24%) during a 70 year injection period. Figure 3-88 provides illustration of the results.

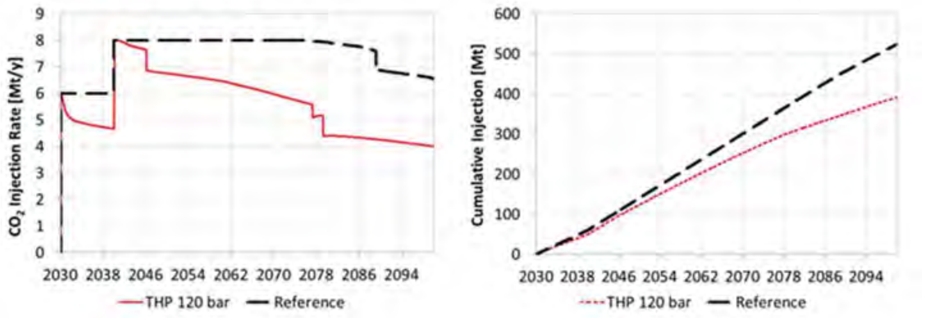


Figure 3-88 Low THP pressure sensitivity coparing injection results for 160 bar delivery pressure with 120 bar delivery pressure to 2100

Forties Aquifer Volume

There is significant uncertainty associated with the size of the aquifer that is connected through the Forties sandstone (and possibly the Lista Formation below) to the modelled area. The connected aquifer volume, beyond the site model, was incorporated using pore volume modifiers in the outer cells of the grid and is further discussed in Section 3.6.6.1. As per Table 3-31, the connected aquifer volume in the reference case is 2.194 x10^{11} m^3 (1380 Bstb). This primarily represents a best estimate of the Forties 5 aquifer, but as modelled also includes the pore volume of the Forties Argillaceous within the simulation grid. The Lista aquifer was also modelled, but has not been assigned any connectivity to either of the Forties intervals, in line with the model calibration. Irrespective of this, the large range tested for aquifer size uncertainty is believed to adequately account for the possibility of some connectivity to the Lista, which may be an alternative realization.

To assess the impact of connected aquifer volume on CO_2 injectivity and mass stored for the given development scenario, a range in aquifer size was assumed; from 1.7 x10^{11} m^3 on the low side to a high case of 4.4 x10^{11} m^3. The low estimate was achieved practically, by assuming no connection to the aquifer in the south and resulted in 23% reduction in injected volume. By contrast, it was felt that doubling the connected volume would be an appropriate upside.

As presented in Figure 3-89, the results show that a smaller connected aquifer results in a faster pressure build up, which leads to wells being rapidly constrained by pressure, and an inability to maintain the target injection profile. The smaller aquifer volume resulted in injected CO_2 mass reduced to 261 Mt (-13%) during a 40 year development lifespan, and down to 433 Mt (-17%) during the 70 year injection period. It is evident from Figure 3-87, that the low aquifer volume is likely to have a greater impact on the southern site, as could be expected since it is the aquifer volume to the south which is most likely disconnected, although this may vary depending on the actual aquifer distribution. On the other hand, a larger connected aquifer, having the opposite effect, results in increased CO_2 injected, up to 545 Mt (+4%) over the extended 70 year injection. It is important to recognise that this figure is constrained by the development plan (i.e. injection profile and storage complex boundary definition) and is not therefore entirely representative. Needless to say, the large aquifer case has an equivalent mass of CO_2 injected to the Reference Case during the 40 year development lifespan.

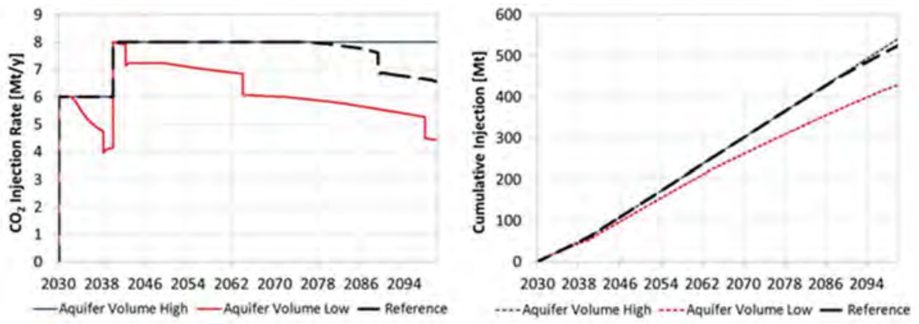


Figure 3-89 Aquifer size sensitivity comparing results for small and large aquifer sizes to the reference case for injection to 2100

Permeability

Permeability within the aquifer region of the modelled Forties 5 Site 1 area suffers significant uncertainty. In particular, while there is offset well data within the area, it comes primarily from the hydrocarbon fields and consequently data over the aquifer itself is sparse. To evaluate the impact of varying rock quality, high and low case permeability arrays have been incorporated to the sensitivity analysis. Both horizontal and vertical permeabilities have been reworked independently for this study and the results are presented in Figure 3-90.

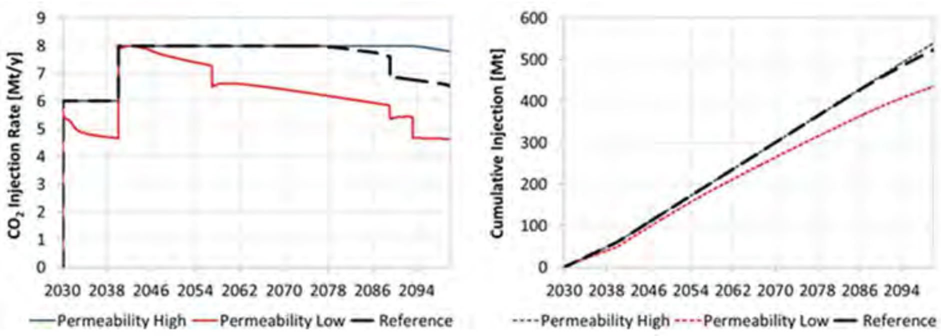


Figure 3-90 Permeability sensitivity comparing results for low and high permeability grids to the reference case for injection to 2100

Evidently a low permeability restricts inflow performance, resulting in wells being rapidly constrained by pressure at the given rates and subsequently entering decline until, in some cases, they reach their minimum rate limit and are shut-in. The impact of low permeability is estimated to reduce injected CO_2 mass to 264 Mt (-12%) during a 40 year development lifespan, and to 440 Mt (-16%) during the extended 70 year injection period. By contrast, the high permeability case comfortably meets with the injection demand of the 40 year development and reaches an injection total of 544 Mt (+3.8%) over the 70 year injection to 2100, being largely constrained by the development strategy until circa 2094.

Relative Permeability

The relative permeability behaviour of a CO_2-brine system in the Forties Sandstone is highly uncertain. For this reason it was imperative that a range of possible behaviours be assessed. Three relative permeability data sets were tested as part of the uncertainty analysis to evaluate the impact on injectivity and CO_2 plume migration. Endpoint inputs and Corey exponents were based on available published experimental values; Set 2, representing the Viking #2 formation in Alberta, Canada (Bachu, et al., 2013), and Set 1, representing the Goldeneye data set, from the Captain formation in the Central North Sea within the UKCS (Burnside & Naylor, 2014). A third set was generated to capture the guidance provided by NGC (National Grid Carbon, 2015), which relates to the Bunter Sandstone formation in the Southern North Sea, UKCS. As previously explained, the reference case was configured with Set 1. Drainage and imbibition curves for the three data sets are compared Figure 3-91, while the Corey exponents and end points used to generate the curves are shown in Table 3-32 below.

	Set 1 (Reference)		Set 2		Set 3	
Parameter	Drainage	Imbibition	Drainage	Imbibition	Drainage	Imbibition
N_g	3	3	2.8	4	2.5	2.5
N_w	2	2	1.7	2.1	4.5	4.5
K_{rw} @ S_{gcr}	1.00	0.40	1.00	0.365	1.00	0.40
K_{rg} @ S_{wcr}	0.92	0.92	0.2638	0.2638	1.60	1.60
Sgcr	0.00	0.29	0.00	0.297	0.00	0.30
Swcr	0.30	0.30	0.423	0.423	0.28	0.28

Table 3-32 Relative permeability end-points and Corey expoents used for the saturation function sensitivities

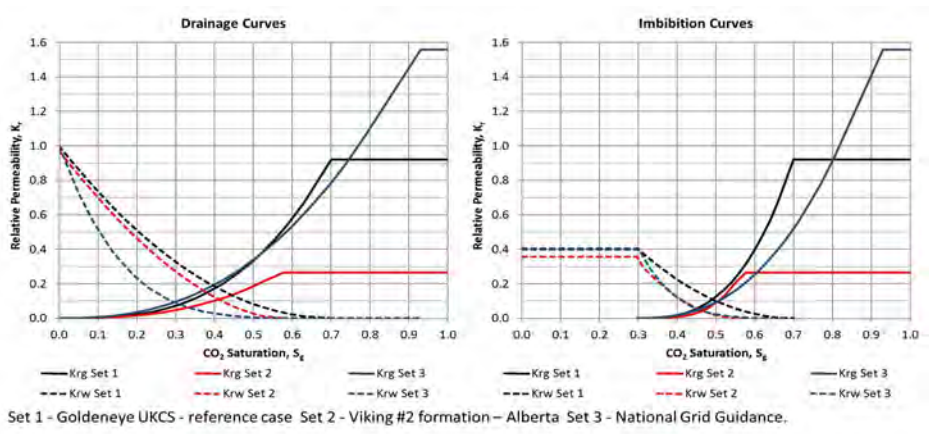


Figure 3-91 Comparison of relative permeability curves used in the sensitivity analysis

The maximum Krg value is an indication of CO_2 mobility in the system; the higher the value the more mobile CO_2 will be. The values range from 0.26 in Set 2 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 study for the Viking#2 formation, Alberta Canada (Bachu, et al., 2013). This is considered to be too low for the Forties system. Set 1 includes a maximum Krg value of 0.92. This is based on the published results (Shell UK ltd., 2011) for the Captain Sandstone Member within the Goldeneye field, North Sea. Guidance from NGC indicated that the CO_2 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 expected impact of increasing the maximum Krg value is to increase the CO_2 mobility resulting in increased injection rates; however, the mobility of water is also an important factor for injectivity potential. Sets 1 and 2 have similar water relative permeability trends, whereas Set 3, based on guidance from NGC, has significantly reduced water mobility. As CO_2 injection into the saline aquifer relies on water displacement, reduced water mobility subsequently restricts the mobility of CO_2. The three alternative relative permeability sets were evaluated using the reference case model, and the impact on the injection forecast is shown in Figure 3-92.

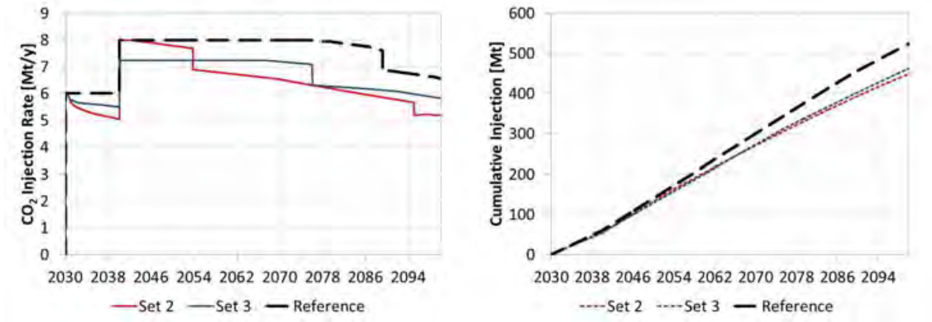


Figure 3-92 Relative permeability sensitivity comparing results for Sets 1 (Reference), 2 and 3 for injection to 2100

The forecasts show a reduced injection rate resulting from using Set 2 relative permeability input compared to Set 1. This is mainly attributable to a reduction in the Krg end-point from 0.26 to 0.92, where water mobility behaves comparatively. The Set 3 forecast also shows a reduced injectivity rate compared to Set 1; in this case, although the maximum Krg is increased significantly, the mobility of CO_2 during drainage (i.e. injection phase) is adversely affected by the lower water mobility, meaning that the displacement of water is a more difficult process.

The impact of saturation data Set 2 is estimated to reduce injected CO_2 mass to 270 Mt (-10%) during a 40 year development lifespan, and to 453 Mt (-14%)

during the extended 70 year injection period. Similarly, the saturation data Set 3 also reduces the injection CO_2 mass to 273 Mt (-9%) over the 40 year development and to 467 Mt (-11%) over the 70 year injection to 2100. Notably, there is the rapid loss of injection well INJ08N within days of commencing injection from the northern site, due to effective PI reduction and an inability to sustain injection above the minimum threshold.

Set 1 is applied in the reference case as Set 2 is considered to be too low in terms of CO_2 mobility and Set 3 data has not yet been validated.

Fracture Gradient

Geomechanical assessment of the fracture pressure gradient within the modelled Forties area, referenced to top Forties, provides a range of 0.158-0.172 bar/m (0.698-0.760 psi/ft), which has been obtained from review of wells 22/07-2, 22/12a-3 and 22/13b-3. The reference case fracture pressure gradient, of 0.170 bar/m was selected as the best-fit to the data from these wells. Primarily, the risk of fracturing the formation must be avoided for the secure long-term containment of injected CO_2 and is therefore an important uncertainty to assess. In particular, for the given development strategy, where a lower fracture pressure is encountered, the field operating pressure constraints must be adjusted to ensure formation integrity.

The impact of the lower fracture gradient is estimated to marginally reduce injected CO_2 mass to just under 300 Mt (-0.1%) for the 40 year development, but results in a reduction to 480 Mt (-8%) over the extended 70 year injection period to 2100. In this case some of the wells are constrained by bottom hole pressure, which is limited to 90% of the fracture gradient at the well datum, to ensure integrity of the near-well formation. There is no impact of a higher fracture gradient, for the given development strategy, since the bottom hole pressure limit is not encountered in the reference case and will not therefore be a limiting factor when fracture pressure is increased further. It follows that the mass injected remains the same (or less), as too is reservoir pressure, and consequently the fracture pressure is never encountered within the reservoir for any of these cases. The results are illustrated in Figure 3-93.

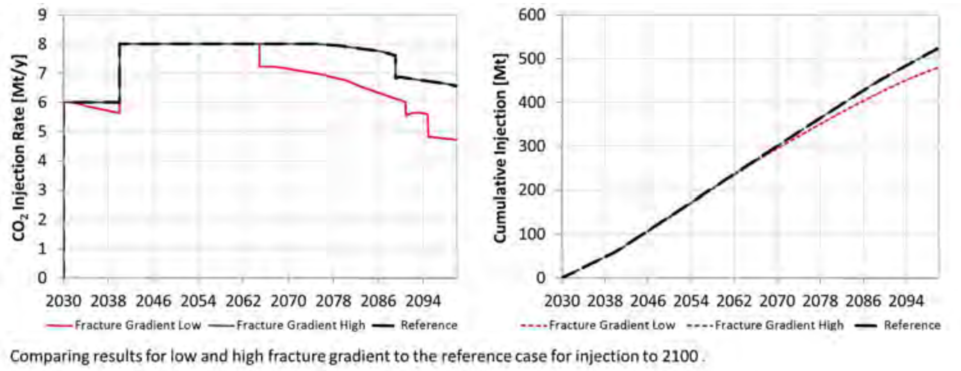


Figure 3-93 Dynamic model fracture pressure sensitivity

Barriers to Vertical Flow

The reference case Forties sandstone includes many minor shale and/or low permeability baffles within the sand that provide limited obstacles to vertical communication. In general these are discontinuous and there is reasonable vertical communication throughout. There is however the possibility that a laterally extensive shale exists, which for the given development plan, might impact site injection performance by restricting the pore volume in communication with the injection wells and leading to an accelerated pressure build-up. This scenario was evaluated by imposing shale properties (i.e. zero permeability) on layer 20 within the dynamic model, which was deemed the most likely location of such a barrier based on the available well data and field analogues. Figure 3-94 illustrates the location of the layer within the Forties Sandstone for a cross-section through the north and south injection sites. The results of the simulation are given in Figure 3-95.

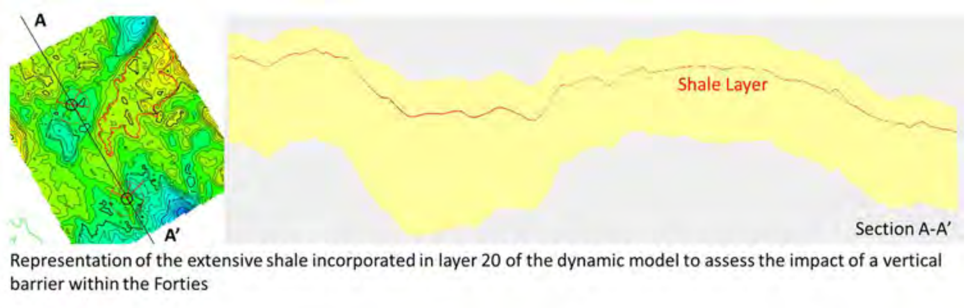


Figure 3-94 Illustration of the potential extensive shale sensitivity in the dynamic model

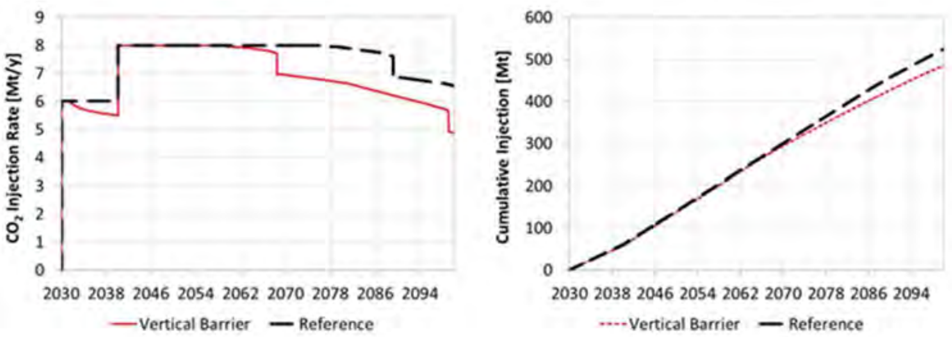


Figure 3-95 Sensitivity results of considering the potential for laterally extensive barriers to vertical flow in the Forties sandstone

The results demonstrate that an extensive vertical barrier could have a small impact on the development strategy, reducing the total mass injected to 294 Mt (-2%) during the planned 40 year development lifecycle (to 2070), or to 489 Mt (-7%) for an extended 70 year injection period out to 2100. In reality, it may be possible to mitigate this scenario by drilling and completing additional wells at a shallower depth (i.e. above the shale), or similarly, by reviewing the existing wells with a view to relocating several of them to the upper section of the Forties. By the same token, it may be appropriate to revisit the basis of well design to understand whether vertical and/or deviated wells perforated through the entire Forties Sandstone could overcome any limits imposed by vertical barriers.

3.6.7.4 Storage Site Development Plan

For most all intents and purposes, the base case (for development) is identical to the reference case already described, which was worked up through model calibration (for key subsurface uncertainties and depletion), optimisation of the development strategy (for well placement, well number, well design and well control) and uncertainty analysis (to confirm model behaviour and key dependencies). The principle difference is that the base case incorporates dedicated well models (i.e. VLP tables) for each well to capture the differences in well path and tubing size, as per the final well design, whereas the reference case used a type well in each of the drilling locations for simplicity. Furthermore, the base case involves injection terminating in 2070, according to the development strategy, and is thereafter run out to 3070 (i.e. 1000 years from the end of injection) to assess the long-term migration of CO_2, the trapping mechanisms and to confirm the containment of injected within the storage site.

Development Forecast Injection Rate Selection

The CO_2 injection rates selected for the Forties 5 Site 1 CO_2 storage development have been determined as described previously. In brief, the development strategy has been driven primarily by containment, rather than optimising injectivity or capacity. It has been shown that the major limiting factor is the containment of CO_2 within the defined storage complex due to its tendency to migrate over large distances. The challenge then became to inject an optimum CO_2 mass, for the selected development, that would be contained within the site after 1000 years. In this case, the development involved two injection sites, located in the north and the south of the modelled area, with a phased start-up staggered 10 years apart and an injection profile that increased from 6Mt/y to 8Mt/y accordingly. Figure 3-96 provides illustration of the selected site injection profile, including the respective share of the sub-site injection targets apportioned to wells in the north and south. The given forecast results in a total CO_2 mass injection of 300 Mt, with 170 Mt injected in the south and 130 Mt injected in the north.

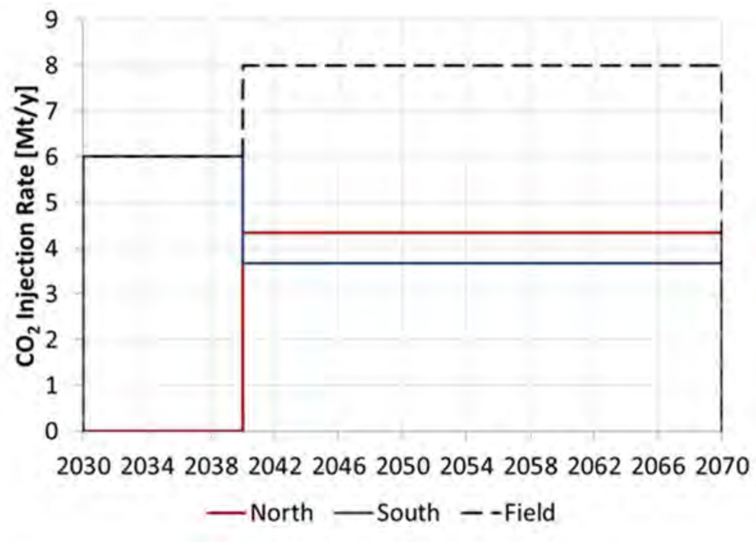


Figure 3-96 Base Case Development Forecast

Well Forecasts

Well level forecasts are in accordance with the individual rate controls applied. Accordingly, the well pressures necessarily had to remain within the applied pressure constraints to avoid the onset of decline. There is additional potential in most wells, for the majority of field life, as demonstrated by the forecast bottom-hole and tubing head pressure plots overlain with the relevant pressure constraint, although the potential diminishes with time (and increasing formation pressure). The well injection forecasts are given in Figure 3-97, and the pressure profiles are represented in Figure 3-98.

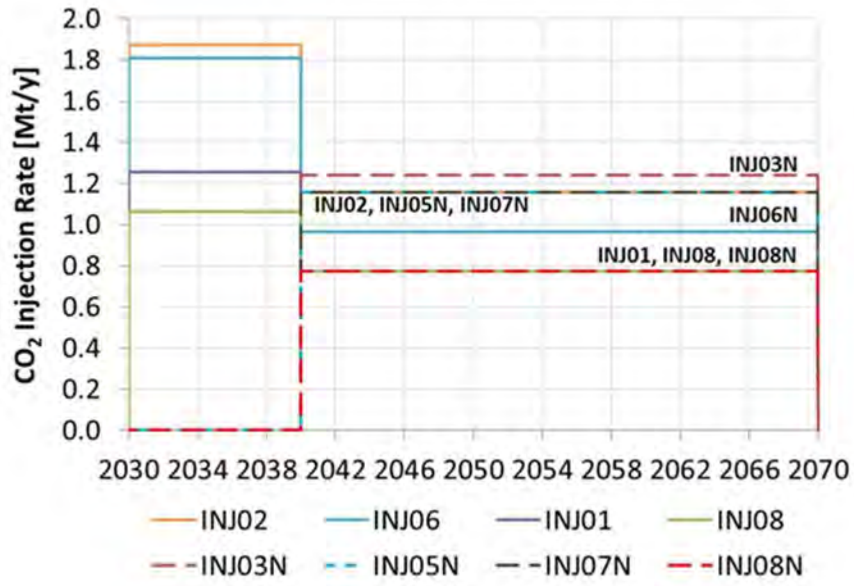


Figure 3-97 Base Case Well Forecasts

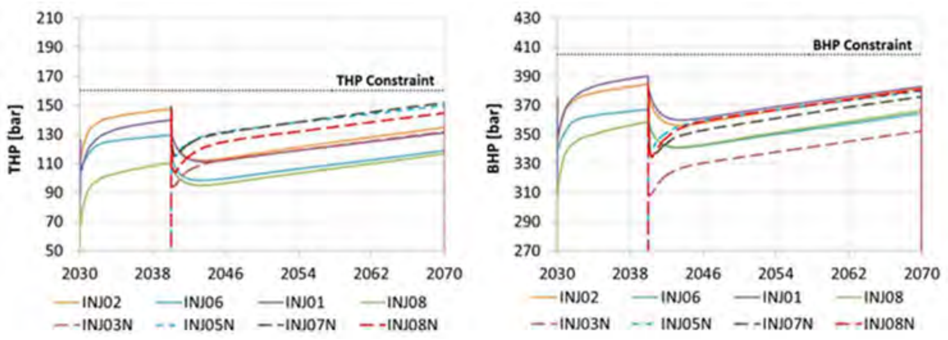
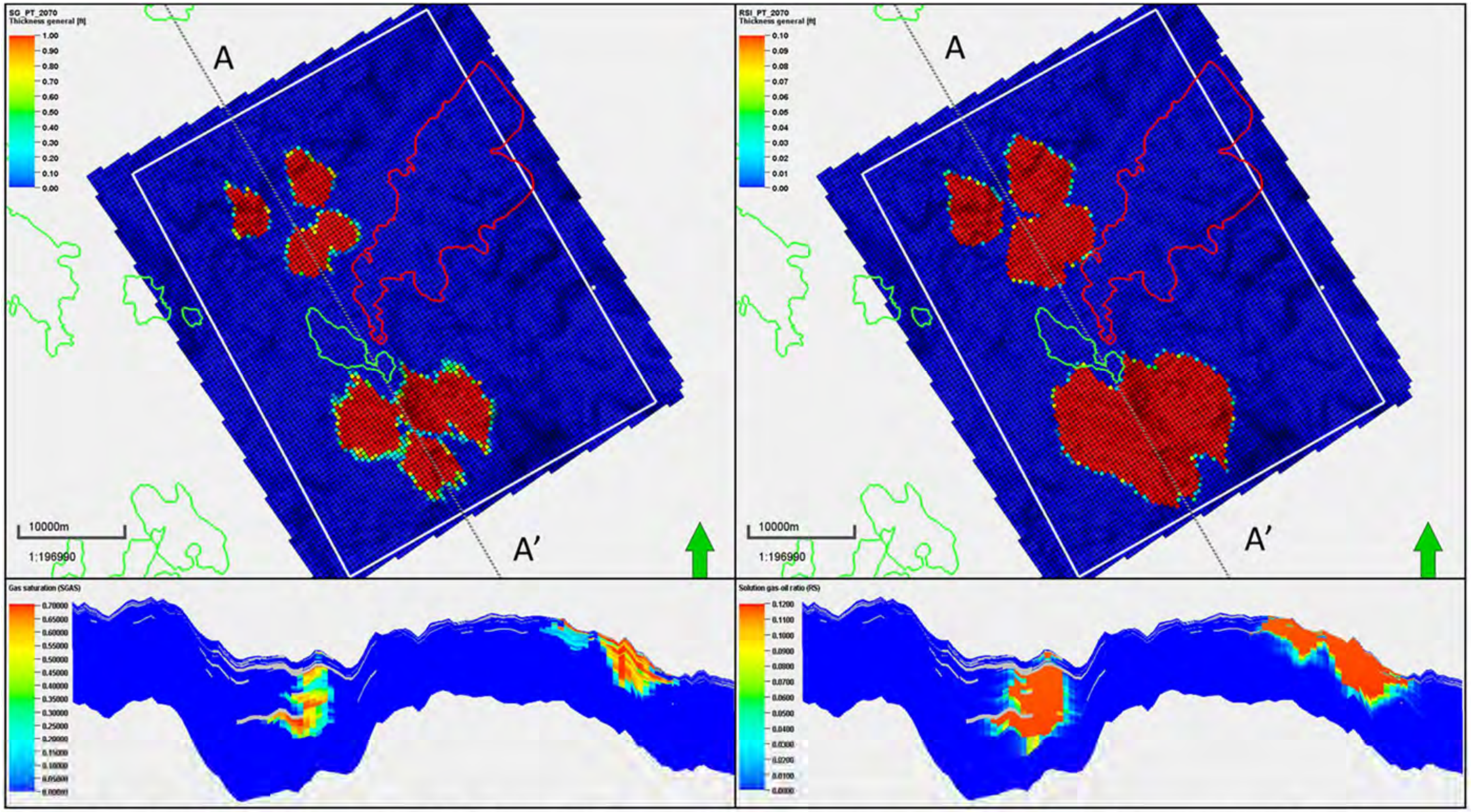


Figure 3-98 Base case THP and BHP forecasts with respect to the applied pressure constraints

3.6.7.5 CO_2 Migration

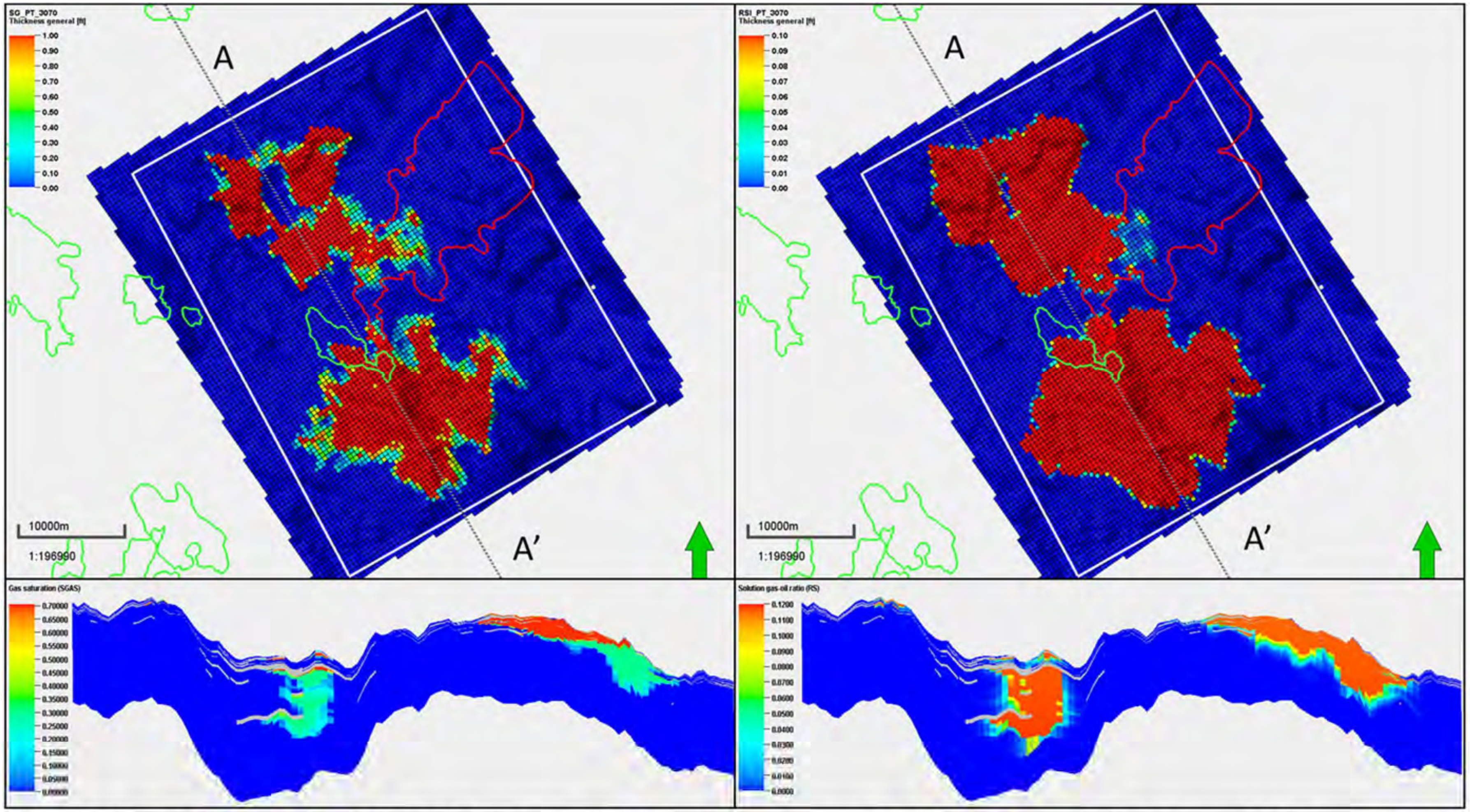
The Forties is an open aquifer system and there is considerable potential for injected CO_2 to migrate beyond the boundary of the storage complex which must be avoided. This study defines a storage complex boundary, within which the CO_2 must remain at all times during injection and thereafter. Here we simulate the migration of CO_2 for 1000 years, following the end of injection, to verify that containment is achieved. As 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. Mineral trapping is also important, but generally on timescales beyond the interest of this study; moreover, due to software limitations it cannot be modelled with the "Black-Oil" simulator and is therefore not considered. 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 cross the storage complex boundary 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.

The containment of CO_2 within the designated boundary is demonstrated at the end of injection (i.e. after 40 years) and after 1000 years from the end of injection (i.e. at 1040 years). The containment boundary, as shown, defines the areal limits of the site storage complex. The results are shown in Figure 3-99 and Figure 3-100, respectively.



Free CO_2 (top left) and solution CO_2 (top right) pore thickness maps, complete with the corresponding free gas and solution gas sections through 'A-A' as shown (bottom) after 40 years injection, the complex boundary is overlain in white

Figure 3-99 Free and Dissolved CO_2 distribtion after 40 years of injection



Free CO_2 (top left) and solution CO_2 (top right) pore thickness maps, complete with the corresponding free gas and solution gas sections through 'A-A' as shown (bottom) after 1040 years, the containment boundary is overlain in white

Figure 3-100 Free and Dissolved CO_2 distribution after 1,000 years after end of injection

3.6.7.6 Trapping Mechanism

The various trapping mechanisms are quantified for injected CO_2 geologically stored as the result of the proposed development; Figure 3-101 provides details.

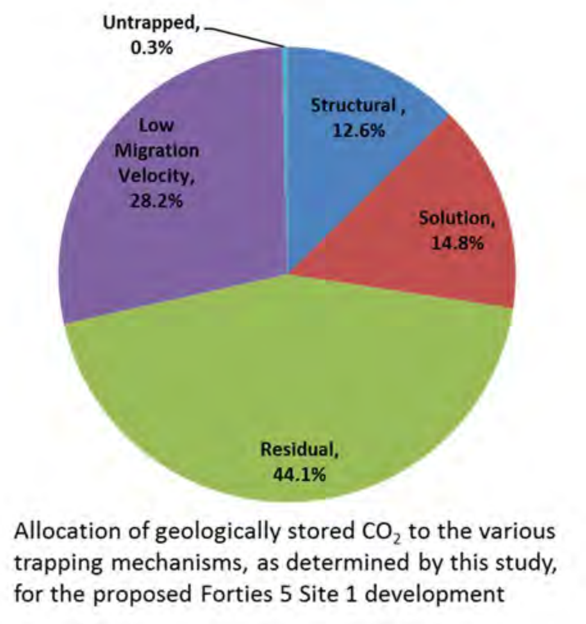


Figure 3-101 Forties 5 Site 1 - Summary of Trapping Mechanism for Injected Inventory

3.6.7.7 Dynamic Storage Capacity

The ultimate storage capacity of Forties 5 Site 1 is not determined by this work but the capacity of the proposed development is confirmed to be in excess of 300 Mt CO_2. Significant additional upside capacity exists both within Everest and within other parts of the modelled area. Complete assessment of the capacity of the site should include additional build-out capacity, perhaps with some extension of the existing boundaries to take in other structural trapping features proximal to the site. Any such work focussing on, or including Everest as a dedicated carbon store, would require compositional simulation. The workaround utilised for this study (i.e. “Black-Oil” simulation) is applicable only to saline aquifer injection and storage.

3.7 Containment Characterisation

3.7.1 Storage Complex Definition

The Forties 5 Site 1 storage complex is a subsurface volume, whose upper and base boundaries are the Top Balder and Base Tertiary depth surfaces. The lateral limits of the site were guided by the Forties 5 Site 1 selection, within which the CO_2 inventory is designed to remain indefinitely with the proposed development plan. This storage complex definition included the storage reservoir and its primary and secondary caprock together with the underlying Lista which may act as a secondary store, if there is communication between these deeper sands and the Forties Sandstone.

The proposed storage complex is illustrated in Figure 3-102.

It should be noted that the storage complex boundaries were defined before the exploration of injection performance had been completed within the dynamic modelling. As such the dynamic modelling and therefore the resulting base case development plan have been engineered to achieve containment within the defined storage complex boundary. An alternative available at this stage would be to optimise the development for capacity and then refine the position of the boundary to accommodate all the possible plume mobility outcomes from the dynamic modelling sensitivities.

Whilst the storage complex presented here is considered appropriate for the project stage, further optimisation and refinement is recommended during FEED.

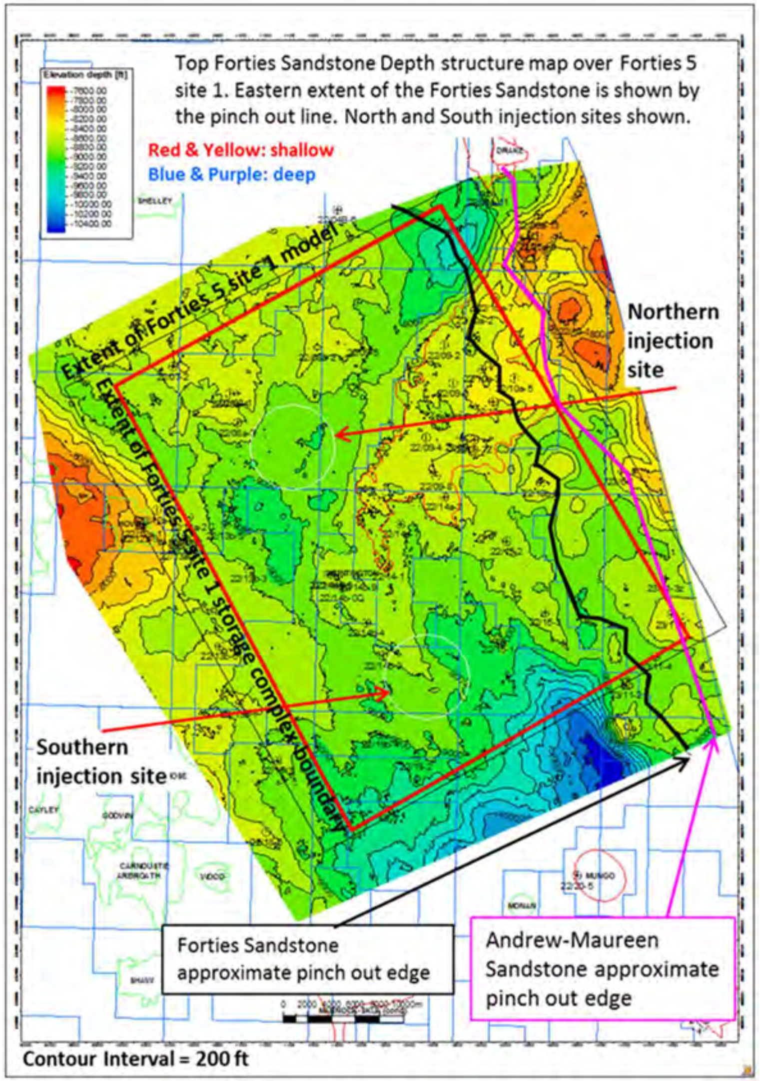


Figure 3-102 Map of the storage complex, top Forties Sandstone depth map, contour interval is 200ft

3.7.2 Geological Containment Integrity Characterisation

3.7.2.1 Hydraulic Communication between Geological Units

The top seal for the Forties Sandstone is provided by the overlying, laterally extensive mudstones of the Sele and Balder Formations which provide proven seals for hydrocarbon fields within the main Forties fan. This provides an effective seal and eliminates the possibility of hydraulic communication into shallower formations.

The Forties Argillaceous unit is a poor quality unit (often shale), at the base of the Forties Member and is prevalent across the Forties 5 Site 1 area but is absent in some wells. The claystones and mudstones at the top of the underlying Lista Formation are believed to be mappable across the area and would provide an effective seal against hydraulic communication into deeper formations. However, there is uncertainty associated with this which may allow for some limited hydraulic communication into the deeper sands of the Lista (Andrew Sands) and Maureen Formations.

The Forties Sandstone is a depositionally extensive fan system covering over 20,000km^2, reservoir quality for the most part is good and oil and gas production experience from the area suggests that lateral connectivity across the region can be expected to be good.

3.7.2.2 Top and Base Seal

Sitting immediately above the Forties Sandstone is a thick interval of Sele and Balder Mudstones which have been chosen as the primary caprock interval (Figure 3-103). The thickness varies across the storage site from 90m to over 180m (approx. 300 – 600 ft). Thickness maps of these intervals are shown in section 3.4. These are a proven effective seal for many hydrocarbon fields within the main Forties fan.

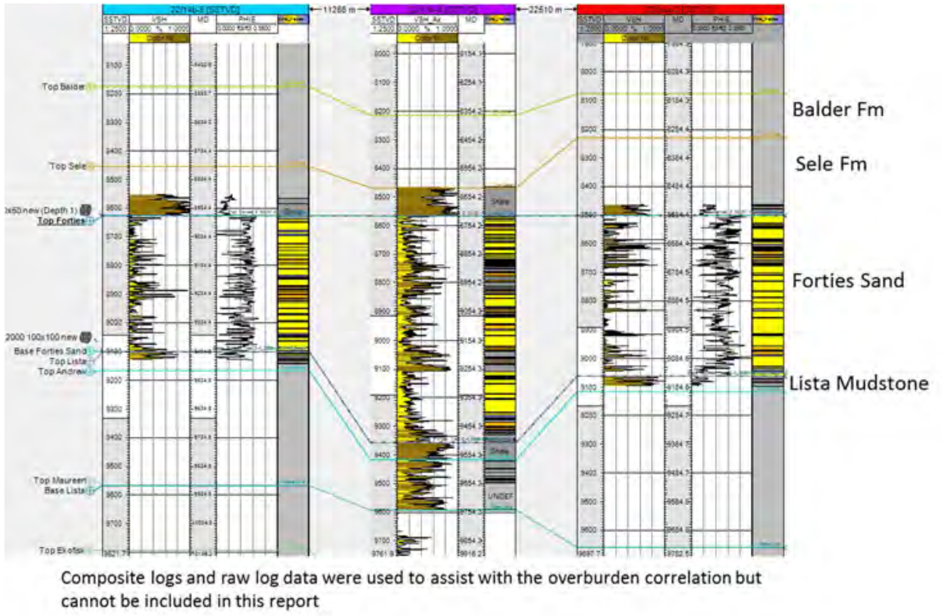


Figure 3-103 Primary Top Seal

The secondary seal is provided by claystones and mudstones of the overlying Horda Formation, within the site area these have a thickness of over 230m (755ft).

Containment along the edges of the main fan is provided by the sands thinning or pinching out, stratigraphically trapped by the surrounding mudstones of the Sele Formation.

Analysis of the seismic identifies some small areas of high amplitudes around 500 msec in the north which may be shallow biogenic generated gas. There is however no evidence of any gas escaping (e.g. pock marks, gas chimneys etc.) from the existing hydrocarbon fields that may indicated seal failure.

Interpretation of seismic and semblance volumes show there is no evidence of significant faulting or major sand injection in the Forties within the site area. There are a small number of small faults that have been interpreted with none compromising the integrity of the top seal.

The Forties Argillaceous unit, at the base of the Forties Member, is prevalent across the Forties 5 Site 1 area and may seal locally, however is absent in some wells. The claystone and mudstones at the top of the underlying Lista Formation and top of the Andrew Sands are believed to be mappable across the area and would provide an effective base seal against hydraulic communication into deeper formations. Within the Everest Field, the deeper Andrew and Maureen reservoir intervals are isolated from the shallower Forties Sandstone reservoir by claystones and mudstones at the top of the Lista Formation.

There is however uncertainty associated with this, and if absent it would allow for some limited hydraulic communication into the deeper sands of the Lista (Andrew Sand) and Maureen Formations. Even if there is hydraulic communication into these deeper sands, loss of containment through significant downward migration of CO_2 within the aquifer is not expected due to the buoyancy of the injected CO_2.

3.7.2.3 Overburden Model

A simple overburden model was built covering the same area of interest as the site static model (Table 3-33).

Formation	Source
Seabed	Mapped from well data
Near Top Lark	Direct seismic interpretation and depth conversion.
Near Top Horda	Direct seismic interpretation and depth conversion.
Top Balder	Direct seismic interpretation and depth conversion.
Top Sele	Direct seismic interpretation and depth conversion.
Top Forties Sand	Direct seismic interpretation and depth conversion.
Base Forties Sand	Direct seismic interpretation and depth conversion.
Top Lista	Built down from the Top Forties Sand using well derived isochore.
Approximate Top Andrew- Maureen Depth	Built up from the Base Tertiary using an average well thickness
Base Tertiary	Direct seismic interpretation and depth conversion.

Table 3-33 Summary of horizons in the overburden model

The minor faults interpreted during the site interpretation have been included.

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.

A cross section through the overburden model is shown in Figure 3-104.

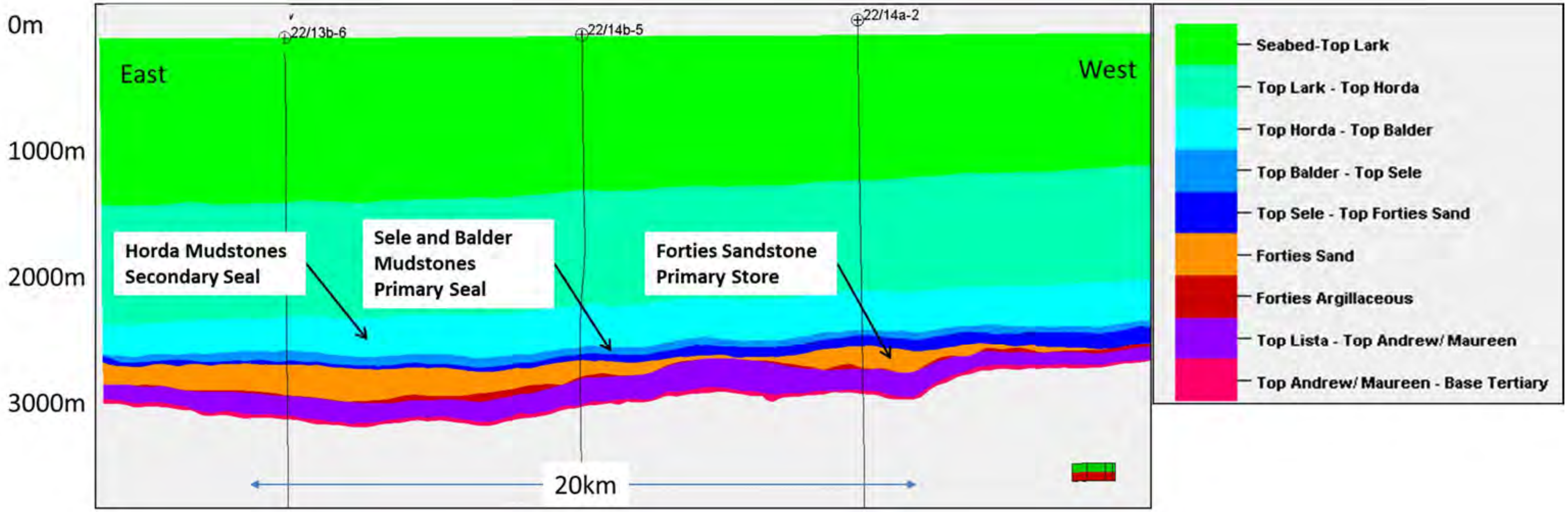


Figure 3-104 SW-NE cross section through the overburden model

3.7.2.4 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.

3.7.2.5 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 reactions are slow and effectively negligible over a 5000 year timescale. Seal failure is unlikely to be induced by mineral reactions with CO_2.

3.7.3 Engineering Containment Integrity Characterisation

Existing, legacy and new wells into the Forties Sandstone reservoir all penetrate the primary caprock. As a result they each present a risk to successful containment of injected CO_2. This engineering containment risk is variable and depends on several factors, most of which are well specific. Here, “Risk” is considered to be the probability of an unplanned loss of containment of CO_2 from either the primary reservoir or Storage Complex occurring. In the case of an unplanned migration out of the Storage Complex then this is referred to as a “leak”. The quantification of any volume of CO_2 subject to containment loss is not considered at this stage, but typical values have been assessed in AGR’s report for DECC (Jewell & Senior, 2012).

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

- The risk of loss of containment from abandoned wells ranges from 0.0012 to 0.005 depending on age / type of abandonment
- The risk of loss of containment 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. Well abandonment practices have improved becoming more rigorous over time. This results in wells abandoned using current standards 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 3-34 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 Forties 5 Site 1 area, a total of 55 wells have been plugged and abandoned, although 9 of these were above store depth. A total of 9 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

Current best practice benchmark for well abandonment is considered to be well represented by the Goldeneye DEMO1 FEED knowledge transfer where a well abandonment proposal is included (Scottish Power CCS Consortium, 2011). Critically this involves establishing a robust seal across the caprock with a milled window and cement plug providing a rock-to-rock seal. Shallow cement plugs provide further barriers for the water bearing zones. 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.

3.7.3.1 Review of Legacy Wells

Initial Risk Assessment (Due Diligence)

A previous screening exercise identified Forties 5 Site 1 as a suitable site within the Forties 5 aquifer region, where well density (and therefore containment risk) was considered acceptable. The risk assessment for this Forties 5 Site 1 area is summarised in Table 3-35.

The engineering containment risk was assessed as low, with 86 wells in total and 77 considered to be at risk, 15 of which were sidetracks within the store depth. 46 wells were plugged and abandoned, 9 of which were before 1986, representing the highest risk. The 100yr probability of a leakage on the field is 0.16 and the well density factor is a low 0.06 wells/km^2. The resulting risk assessment score of 0.009 is low. It should be noted that the site complex has been defined as a regular polygon, and therefore incorporates the Everest and Huntington fields, both with relatively high well densities. The actual predicted plume migration has been modelled and affects a much smaller area, with considerably fewer wells (15 in total see Table 3-36).

Integrity Attribute	
Total Number of Wells	86
Total Number of Abandoned Wells	55
Total number abandoned before 1986	9
Total Number of at Risk Wells	77
Probability of a Well Leak in 100yrs	0.16
Storage Area km2	1325
Well Density (wells /km2)	0.06
Leakage Risk Assessment (Well Density x Leak Probability)	0.009

Table 3-35 Forties 5 Site 1 Engineering Containment Risk Review

South Site	North Site
22/14b-5	22/07-2
22/14b-6Q	22/08a-4
22/14b-8	22/08a-3
22/14b-9	22/13b-5
22/14-1	22/13b-3
22/14b-4	
22/14b-3	
22/15-1	
22/19b-4	
22/19-2	

Table 3-36 Well affected by predicted plume area

Detailed Risk Assessment

The detailed risk assessment was performed using the historical well data in the CDA data base. This data included the Final Well Reports or Abandonment Reports for the legacy wells.

A selection of 9 representative legacy wells were chosen for this review, some from within the plume affected areas and some from the wider complex area. The review is summarised below.

Well	UKOOA or API	Target Above/Below/In Primary Store	Specification	Comments
22/07-2 **1990**	API RP 57	Below	Exceeds	Openhole well with 5 cement plugs. One plug in open hole and 4 plug in 9 5/8” casing supported with retainer. Perforated 9 5/8” casing and squeezed cement behind casing. Casing cement plug lapped with annulus cement. Hydrocarbon zones. Store depth above reservoir target and isolated with 2 cement plugs. Exceeds spec with two permanent barriers for water bearing permeable zone.
22/08a-3 **1984**	API RP 57	Below	Fails	Openhole well with 3 cement plugs. Lower plug in openhole section. Plug #2 in 9 5/8” casing supported with bridge plug and lapped with annulus cement. Shallow set plug set in 9 5/8” casing and not lapped with annulus cement. Hydrocarbon sands. Store depth above reservoir target and isolated with one cement plug. Does not meet spec – no annulus cement at shallow set 9 5/8” cement plug.
22/12a-1 **2005**	Issue 2	Below	Exceeds	Cased hole well suspended in 1987 after DST. Returned in 2005 for permanent abandonment with 5 cement plugs. Lower plug set above existing suspended cement plugs. Casing cut and upper cement plug supported with bridge plug and set in 20” casing lapped with cement. Store depth above reservoir target and isolated with 2 cement plugs. Exceeds spec with two permanent barriers for water bearing permeable zone.
22/13a-2 **2004**	Issue 1	Below	Meets	Cased hole well. Suspended in 1989 after DST. Returned in 2004 for permanent abandonment with 2 cement plugs. Lower plug set above existing suspended cement plugs. Casings cut and upper plug set in 20” casing. Both casing plugs lapped with annulus cement. Hydrocarbon zones. Store depth above reservoir target and isolated with one cement plug.
22/13b-6 **1997**	Issue 0	Below	Meets	Openhole well with two cement plugs supported with viscous pill/bridge plug. Both plugs lapped with annulus cement. Casings cut for 9 5/8” upper plug to lap 20” annulus cement. Dry hole. Store depth above reservoir target and isolated with 20” cement plug.
22/14a-7 **2007**	Issue 2	Below	Meets	Openhole well with 5 cement plug. 4 in openhole section and covering linertop and 1 shallow set plug in 20” casing. Casings cut for 20” cement plug. Waterwet sands. Store depth above reservoir target and isolated with 20” cement plug.
22/14b-3	API RP 57	Below	Meets	Cased hole well. Three cement plugs in 7” liner and across perfs. Additional cement plug in 9 5/8” casing across liner top. 9 5/8” Casing cut and cement plug in 13 3/8” casing. All plugs lapped with annulus cement. Store depth above reservoir target and isolated with one cement plug lapped with annulus cement.
22/14b-8 **2008**	Issue 2	Below	Exceeds	Openhole well with 6 cement plugs; 1 in open hole section and 5 in 9 5/8” casing lapped with cement. Waterwet sands. Store depth above reservoir target and isolated with 2 cement plugs. Exceeds spec with two permanent barriers for water bearing permeable zone.
22/15-1 **1983**	API RP 57	Below	Fails	Openhole well with 7 cement plugs. 2 plugs in open section, 3 plug in liner and 2 plug in 9 5/8” casing. Casing cement plug not lapped with cement and casing perforated. Store depth above reservoir target and isolated with one cement plug. Does not meet spec - no annulus cement at casing cement plugs. Casing perforated above TOC.

Table 3-37 Forties legacy wells

The abandonment dates of the 9 legacy wells range from 1983 to 2008 (25 years) and cover all of the specification, i.e. API RP 57, UKOOA Issue 0,1 and 2. The more recent wells meet or exceed the current specifications but the older wells do not.

Well 22/7-2 (1990) is an example of an abandoned well that exceeds the specification. The target sands (deep hydrocarbon targets) were in the open hole section at 13,800 ft MDBRT. The store depth (8,528 ft MDBRT) is above the target sands and isolated with two shallow permanent barriers lapped with annulus cement. The 9 5/8” cement retainers provide support for the cement and prevents slumping.

However, wells 22/8a-3 and 22/15-1 fail to meet spec and are examined in more detail below. Both wells are reliant on unknown Top of Cement (TOC) levels and cement plugs which are not lapped with annular cement to provide a secondary barrier for a leak up the A annulus. 22/15-1 lies at the eastern edge of the projected CO_2 plume extent in the reference case development plan. 22/8a-3 lies near to one of the northern site injection locations and will likely be exposed to CO_2 from very early injection operations (Figure 3-105). It may be possible through injector placement optimisation to reduce the risk of the CO_2 plume reaching these wells. Nevertheless, any final development plan must seek to further mitigate the containment risk that these wells present.

In 22/8a-3 there is annular cement in the 9 5/8” across the Forties Sandstone. If there is a leak path through this annular cement, (or at the interfaces) the CO_2 leaks directly up the 9 5/8” annulus to surface. The well integrity relies on the cement column above the Forties sand which was never verified. The Final Well Report indicated the 9 5/8” casing was cemented in two stages and to fill the annulus to 1,000 ft into the 13 3/8” casing. First stage went well with no losses, but

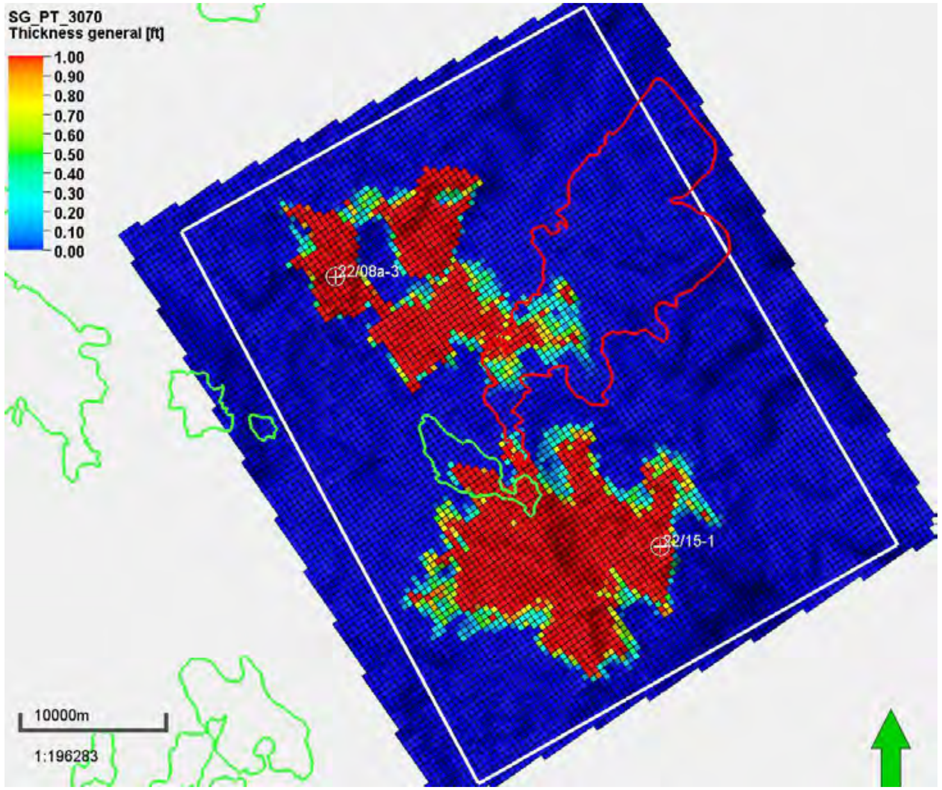


Figure 3-105 Forties 5 Site 1 - Location of higher risk legacy wells within context of free CO_2 plume extent

in the second stage, the stage collar had to be opened with the drill pipe and the top plug did not bump. It was later found in the cement head. The second stage tail pumped and displaced with no returns. Also, a shallow cement plug is placed inside the 9 5/8” casing at 469 ft but this was never tested or supported with hivis pill or bridge plug. Furthermore, the shallow cement plug is not lapped with annulus cement. In summary there is only one barrier, with unknown TOC, and the shallow cement plug is not lapped with cement to provide a secondary barrier for a leak up the A annulus.

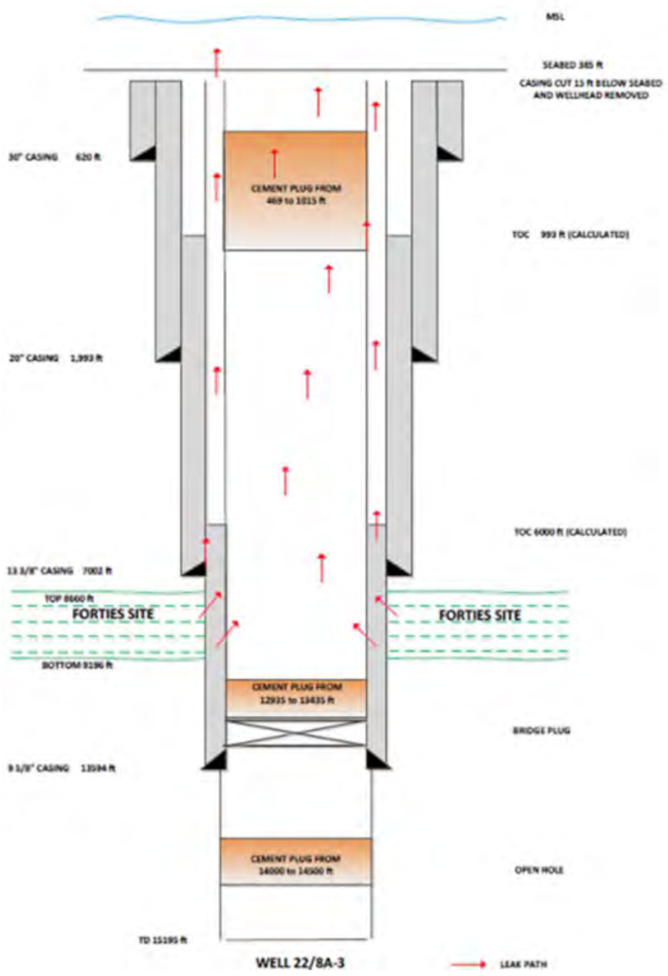


Figure 3-106 Schematic of well 22/8a-3 with potential leak paths indicated

For 22/15-1, there is annular cement in the 9 5/8” across the Forties sand. If there is a leak path through this annular cement, (or at the interfaces) the CO_2 leaks directly up the 9 5/8” annulus to surface. Again, the well integrity relies on the cement column above the Forties sand which is this case is unknown and was never verified. The 9 5/8” casing above the TOC is perforated allowing CO_2 to leak from the wellbore into the annulus and directly up to the surface. Also cement plugs in the 9 5/8” casing were never tested.

In summary there is only one barrier, with unknown TOC, and the shallow cement plugs are not lapped with cement to provide a secondary barrier for a leak up the A annulus.

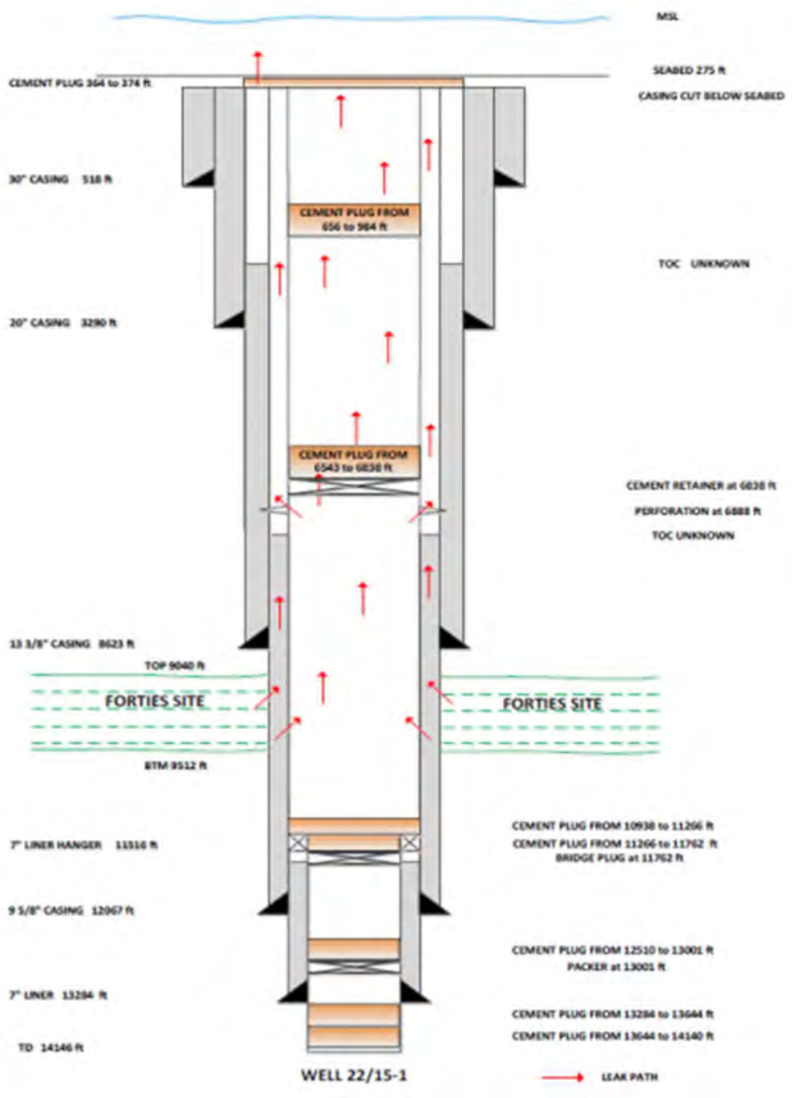


Figure 3-107 Schematic of well 22/15-1 with potential leak paths indicated

3.7.3.2 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 negligible. 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 3.68/yr in carbon steel for Forties 5 Site 1 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 considerable lower. As the legacy wells are likely to be exposed to a flux of CO_2 during the 40 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.

3.7.3.3 Engineering Containment Risk Summary

The high level risk review determined that the risk of CO_2 leakage in selected Forties 5 Site 1 was low. Following the more detailed risk review, where 2 wells of the 9 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 well 22/15-1 and 22/8a-3 is considered high, taking into account cement degradation. Whether this loss of containment results in a leak to surface is difficult to determine. The status of the two abandoned wells not covered in this review is not known. Specific monitoring and contingency plans should be considered for these wells as part of the FEED study.

3.7.3.4 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 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).

3.7.4 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 3-38 and displayed in a risk matrix plot in Figure 3-108.

The key containment risks perceived at the present time involved escape of CO_2 from existing legacy wells leading to seabed release of CO_2. This risk can be mitigated by careful monitoring of abandoned well heads, as laid out in the monitoring plan.

There is also some risk of lateral movement of CO_2 out with the storage complex, with channel permeability anisotropy considered the main cause. This risk can be mitigated by acquiring new 3D seismic before appraisal drilling, and using attributes and Amplitude Versus Offset (AVO) during the interpretation workflow, which have given promising results of channel delineation in nearby fields. Regular Plume monitoring through repeat 4D seismic acquisition should also enable the dynamic models to be calibrated to the observed plume movement.

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 fault (Northern injection site)	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 existing wells	3	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 within Forties due to permeability anisotropy (e.g. channels)	3	3	
Vertical movement of CO_2 from Primary store down to underburden via existing wells (e.g. via Everest well to Andrew Fm)	2	2	
Vertical movement of CO_2 from Primary store to underburden via store floor (out with storage complex)	1	3	

Table 3-38 Forties 5 Site 1 - Leakage Scenarios

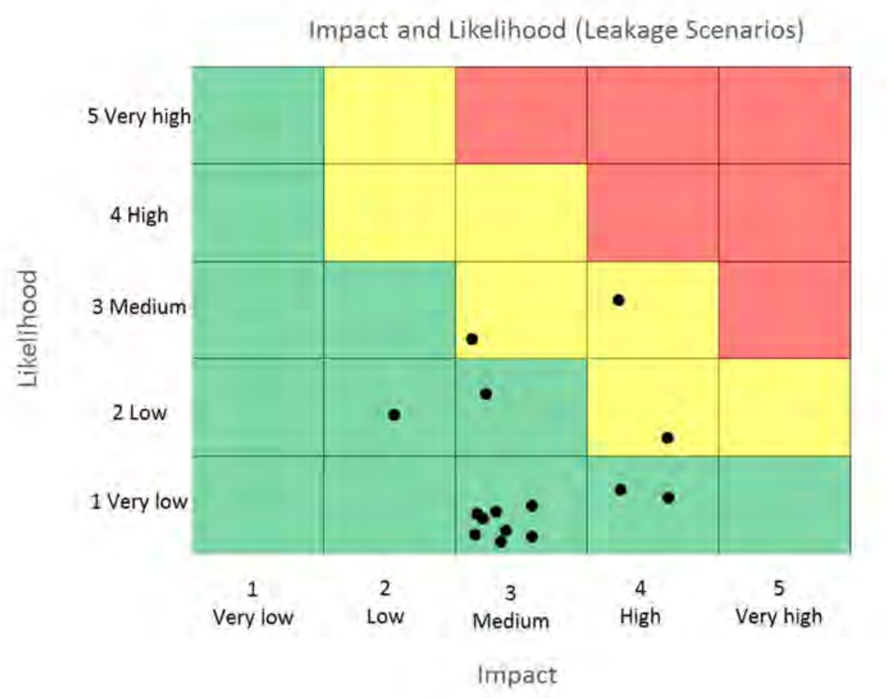


Figure 3-108 Forties 5 Site 1- Risk matrix of leakage scenarios

3.7.5 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 5.

3.7.5.1 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 5.

3.7.5.2 Forties: 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 Forties Sandstone was modelled with a bulk mineral density of 2.666g/cc (from petrophysics), brine density of 1.1g/cc, Vp and density from well logs and Vs derived from Vp. The fluid substitution case modelled 70% CO_2 saturation with a density of 0.8g/cc. The assumed density of CO_2 for a reservoir temperature of 100^{o}C and a reservoir pressure of 4000psi is 0.63g/cc. 70% 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 this 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 3-109 shows the results with 0% CO_2/ 100% water and 70% CO_2/ 30% water on the seismic response within the Forties Sandstone.

There is a general decrease in acoustic impedance over the Forties Sandstone due to the presence of CO_2, which results in a dimming of the top Forties trough. This is a similar response to the amplitude dimming seen elsewhere in the Forties due to the presence of gas, e.g. in the Everest field.

From this quick-look modelling carried out, this dimming of seismic amplitude at Top Forties with 70% CO_2 saturation gives an indication that CO_2 is likely to be detectable within the Forties 5 Site 1 storage site and therefore seismic surveying should be considered as part of the base case monitoring plan.

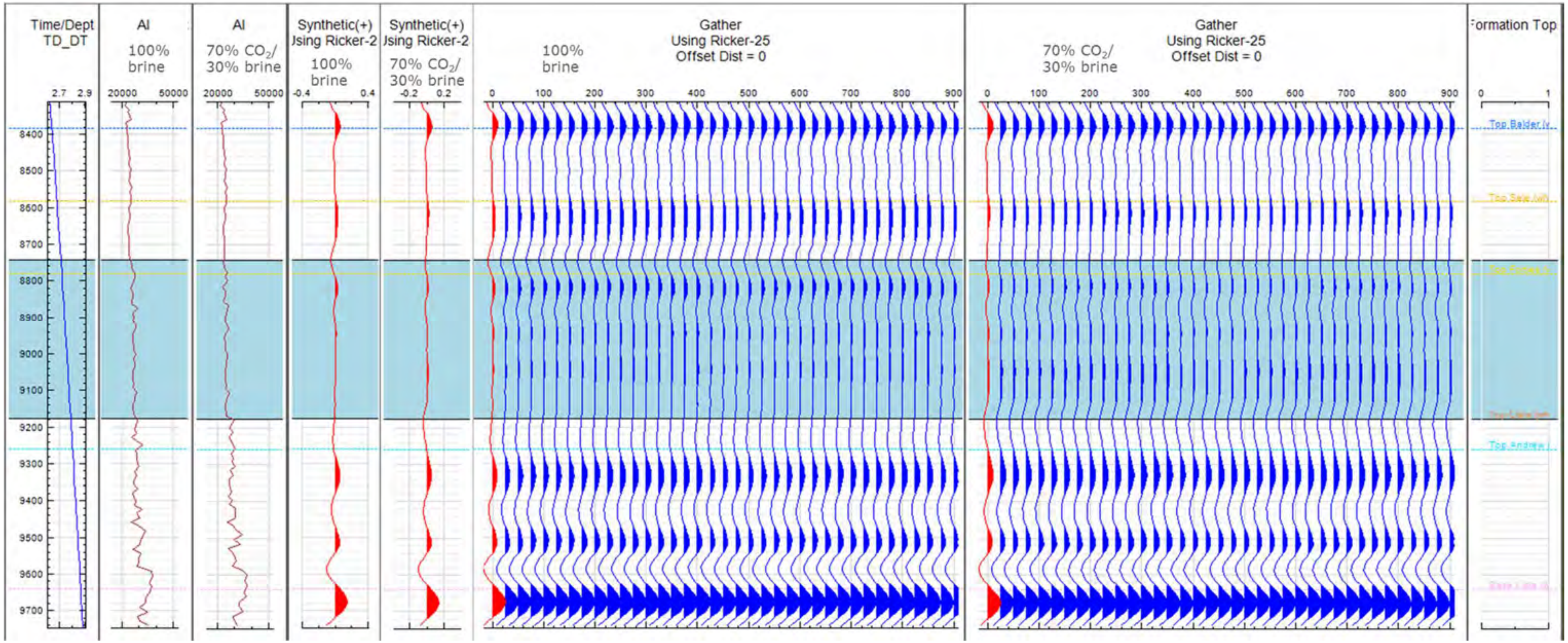


Figure 3-109 Forties 5 Site 1 Potential 4D Seismic Response. Modelled Forties indicated in blue

3.7.5.3 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 plans for the Southern and Northern injection sites are shown in Figure 3-110 and Figure 3-111, 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 a technology's cost against its value of information, and are from either the "just do it" (low cost, high benefit) or "focused 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 Forties 5 Site 1. Note that some of the "consider" technologies are less commercially mature, but may move to the "just do it" category over time.

Figure 3-112 maps the selected technologies to the leakage scenarios discussed in Appendix 2.

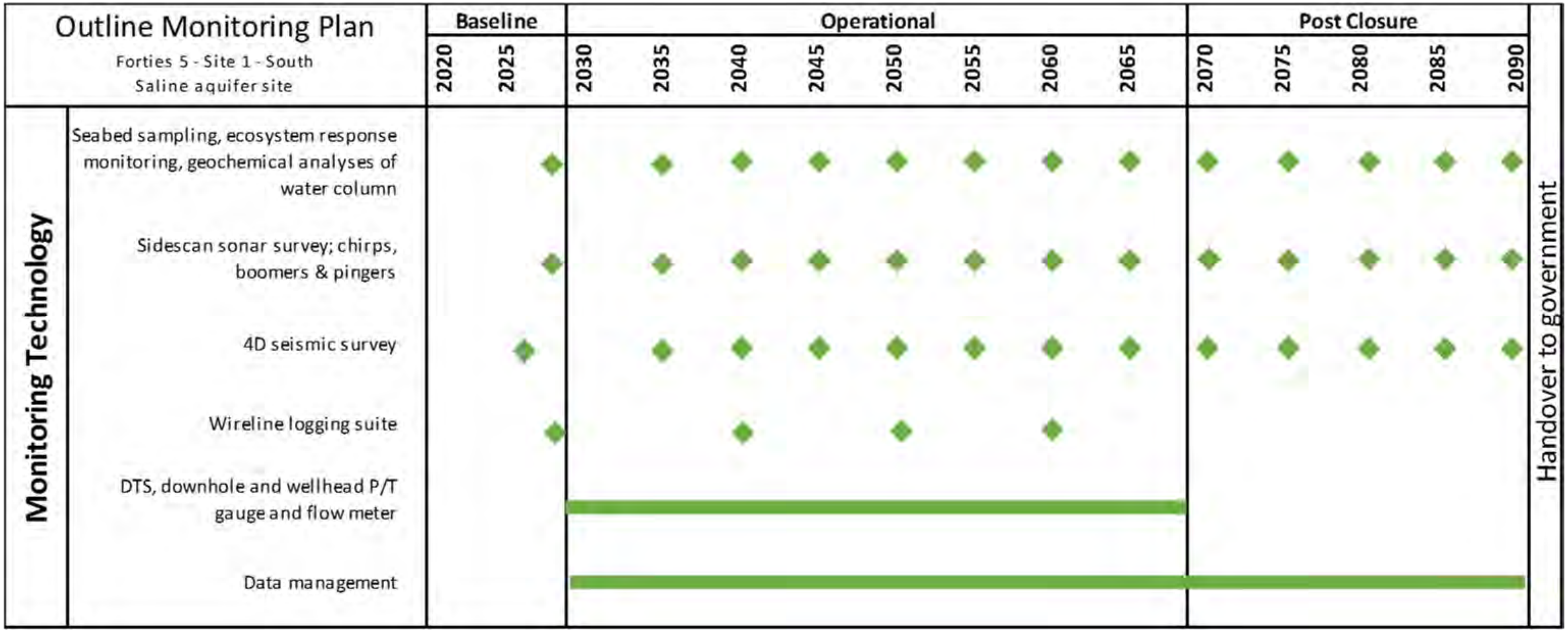


Figure 3-110 Outline monitoring plan for southern injection site

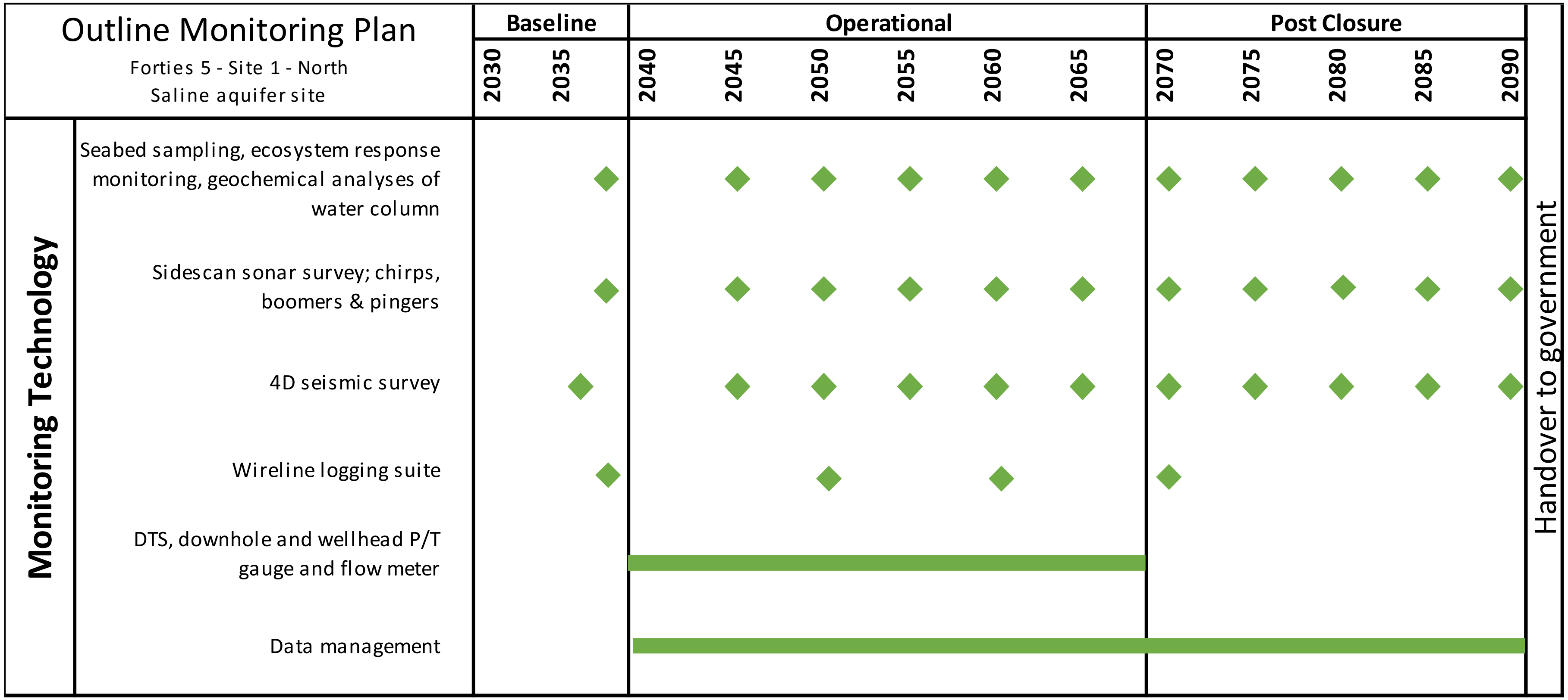


Figure 3-111 Outline Monitoring Plan for Northern injection site

- 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
		Vertical movement of CO2 from Primary store to overburden via fault (Northern injection site)	1	3	Minor			X		
		Vertical movement of CO2 from Primary store to overburden via pre-existing wells	1	3	Minor			X		
		Vertical movement of CO2 from Primary store to overburden via injection wells	1	3	Minor			X		X
		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 pre-existing wells	3	4	Moderate	X	X			
		Vertical movement of CO2 from Primary store to seabed via injection wells	2	4	Moderate	X	X		X	X
		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 Forties due to permeability anisotropy (e.g. channels)	3	3	Moderate			X		
	Underburden	Primary store to underburden (e.g. via Everest well to Andrew Fm)	2	2	Minor			X		
		Primary store to underburden via store floor (out with storage complex)	1	3	Minor			X		

Figure 3-112 Forties 5 - Site 1 Leakage scenario mapping to MMV technology

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3.7.5.4 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 3-39.

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 3-112, some examples of control actions and remediation options are shown in Figure 3-113.

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 **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 Sudden pressure or temperature drop in reservoir	Potential CO_2 leakage from injection wellbore Storage site integrity compromised (e.g. caprock fractured) - CO_2 potentially

Table 3-39 Examples of irregularities and possible implications

			Outline Corrective Measures	
			Control/ mitigation actions	**Potential Remediation Options**
Leakage Scenario	**Overburden**	Vertical movement of CO_2 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 (CO_2 should be trapped by additional geological barriers in the overburden)
		Vertical movement of CO_2 from Primary store to overburden via fault (Northern injection site)	Invesitgate irregularity, assess risk, update models if required, increased monitoring to ensure under control	Increased monitoring to ensure under control (CO_2 should be trapped by additional geological barriers in the overburden)
		Vertical movement of CO_2 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 CO_2 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 CO_2 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 (CO_2 should be trapped by additional geological barriers in the overburden)
	Seabed	Vertical movement of CO_2 from Primary store to seabed via pre-existing 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 CO_2 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 CO_2 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 CO_2 from Primary store out with storage complex w/in Forties	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.
		Lateral movement of CO_2 from Primary store out with storage complex w/in Forties due to permeability anisotropy (e.g. channels)	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 (e.g. via Everest well to Andrew Fm)	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 3-113 Outline Corrective Measures Plan

4.0 Appraisal Planning

4.1 Discussion of Key Uncertainties

The Forties 5 Site 1 enjoys a large well data set (45 regional with 16 within the storage complex) and good quality 3D seismic. Furthermore there is also good quality core coverage available complete with conventional and even some special core analysis. This site is a great example of a common situation in the UKCS where potential aquifer storage sites do have remarkably good data sets which can be used to characterise the site ahead of any development decision. Despite this volume of data, it is easy to forget that the Forties 5 Site 1 is a huge area of some 1634km^2 approximately 100 time larger than the Goldeneye storage site. As such further appraisal drilling is recommended to improve confidence regarding some key aspects of the characterisation. Specifically further confidence is required in the following areas:

1. Caprock core material to assure integrity.
2. Reservoir core material to confirm reservoir quality and flow properties in the water bearing section of the aquifer.
3. Data mining, sampling and analysis of existing core and cuttings materials for biostratigraphic analysis to enhance the characterisation of reservoir correlation and vertical and lateral connectivity across the site.
4. Detailed rock physics study and calibration of well data to seismic in a quantitative fashion to improve the reservoir characterisation from seismic attributes in between the well data points.
5. Consideration of specific well by well pressure and production data from all adjacent sites to support an improved characterisation of the Forties aquifer size and activity.
6. Finally, further refined consideration of CO_2 plume development is warranted once more detailed data is available upon the reservoir architecture and hydraulics including new and specific CO_2 brine relative permeability SCAL data from the Forties Sandstone itself.

4.2 Information Value

The work conducted to date has highlighted that some significant remaining uncertainties exist. Whilst uncertainty cannot be eliminated, there are some key uncertainties that can be significantly reduced through further data acquisition and appraisal activity. This additional appraisal effort will improve the confidence and robustness of any final investment decision. Specifically, high value information can be acquired in the following areas:

- Reservoir quality and architecture across the site. This will impact the injection centre and well placements and the ultimate storage efficiency which are key attributes to capacity estimation.
- The large scale pressure interaction between the local injection site and the regional aquifer. This will impact the longer term injectivity and the capacity estimation.
- CO_2 plume mobility, with the Forties 5 Site 1 location being specifically selected for its “Open aquifer” aspect, it is anticipated that only 12% of the injected inventory is structurally trapped. As

such there is an enhanced focus upon the lateral mobility of CO_2 from the injected wells out into the site.

4.3 Proposed Appraisal Plan

The forward minimum appraisal philosophy and recommended plan therefore involves three main components:

Further data mining from existing wells and adjacent hydrocarbon field developments. The nature of this project and in particular the requirement to publish as much of the analysis as possible has placed some constraints on data access where such data has been deemed of a confidential nature by the holder. Access to specific well data from operators under appropriate confidentiality agreements will help to infill some key local and regional data gaps. This is important for both reservoir characterisation and an improved understanding of well status and abandonment records.

3D Seismic Acquisition. Whilst the 3D seismic data from the PGS MegaSurvey is a high quality product, it represents a complex merge of more than one survey over the Forties 5 Site 1 area. The joins between the surveys can introduce anomalies between which makes quantitative work difficult. A new 3D acquisition across the broader storage complex would enable the following to be achieved:

- High resolution detailed imaging of the overburden interval to characterise small discontinuous faults and layers to support confidence around the high quality containment properties of the area.
- New 3D acquisition could also be processed to reveal more quantitative information regarding the porosity and reservoir quality of the storage site away from existing well information to enable wells to be placed optimally. Elsewhere in the Forties fairway, this technique has delivered excellent results which have enhanced the development of oil and gas fields. Whilst more can be achieved with the existing seismic data, a new survey is a key step to improving confidence around reservoir quality characterisation and long term performance.
- Finally, a new modern 3D seismic would provide a key high resolution reference survey against which to compare any future post injection surveys and perform fluid tracking analysis. This 4D seismic approach is limited by the lowest resolution survey over the area and a new survey would enhance the value of the MMV programme.

Appraisal Drilling. A new appraisal well is a key requirement ahead of any FEED or investment decision. In addition to providing key samples of reservoir and cap rock core for analysis, it will also serve to provide a key test and further calibration of the ability of 3D seismic to support the detailed quantitative reservoir characterisation required so that injection wells can be confidently placed in the best reservoir quality areas using 3D seismic. The detailed location and trajectory of this well require further work, but a location in the vicinity of the southern injection site is envisaged. The initial outline objectives of the well will include:

1. Simple vertical well located within Forties 5 Site 1 southern location. The well should TD at the top of the Cretaceous.
2. The well should be cored through the lower 50ft of the caprock and also throughout the full Forties Sandstone interval to provide reservoir quality information and rock samples for further analysis.

3. Conventional wireline logging targeted at lithology, reservoir quality, mineralogy and geomechanics (Gamma Ray, Resistivity, Neutron, Density and Sonic).
4. Specialize wireline logging will include image logging across the caprock and reservoir interval will support search for small scale fracturing and also the interpretation of future development wells whilst minimising future coring, Dipole sonic and potentially NMR to measure permeability.
5. Pressure profiling through the reservoir will be required to try to identify any small levels of pressure depletion associated with production at nearby fields such as Everest since this would confirm regional connectivity.
6. Mini-fracture testing to calibrate the geomechanical models further and vertical interference testing to check the significance of any shale baffles.
7. Formation water salinity samples will be taken in the Forties Sandstone interval to confirm the value and variability of salinity to refine the view of near wellbore dehydration halite risk during CO_2 injection.
8. Finally - a significant water production and/or injection test will be completed to confirm initial injectivity and minimum connected volume.

In order to minimise the pre-FID costs, this well would be planned as a vertical appraisal that would be subsequently plugged and abandoned. Again, an option to incorporate it as an injector well exists (appraisal / keeper), but this would increase the upfront cost, given that a deviated well would need to be drilled.

5.0 Development Planning

5.1 Description of Development

The Forties 5 aquifer is located in the Central North Sea. Figure 5-1 shows the extents of the aquifer, and its location relative to nearby oil and gas infrastructure.

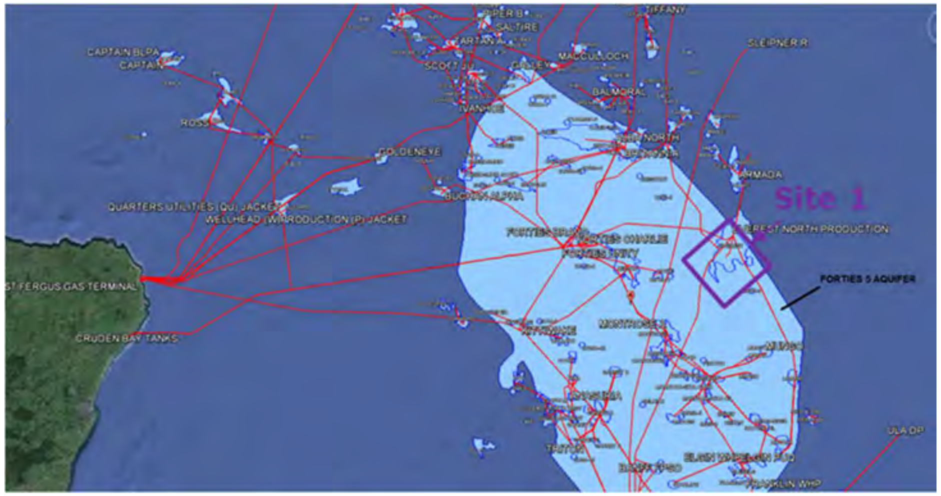


Figure 5-1 Forties aquifer location

Due to the extent of the Forties 5 aquifer, a suitable sub-site, known as Site 1, has been selected for the development (Pale Blue Dot Energy; Axis Well Technology, 2015). It is anticipated that CO_2 will be injected in two phases.

Phase 1 - 6Mt/y for 10 years via a NUI in the south of Site 1 (4 platform wells);

Phase 2 - 8Mt/y for 30 years; via the 4 platform wells plus 4 additional subsea wells via a subsea tie-back to the north of the NUI.

The current base case for the Forties 5 Site 1 development consist of a new 217 km 24” pipeline from St Fergus to a newly installed Normally Unmanned Installation (NUI), approximately 210km East of Peterhead. After 10 years operation, injecting 6 Mt/y via 4 platform wells (60 MT), the second phase will involve the drilling of 4 additional subsea wells (via a 4 slot template) to increase the total injection rate from 6 Mt/y to 8 Mt/y, for a further 30 years. The northern site will be a 26km step out from the NUI and will transport 4.3 Mt/y CO_2 via a 12” pipeline.

The table below summarises the injection plan for Forties 5 Site 1.

	Years	NUI – 4 wells (MT/Yr)	Subsea Template- 4 wells (MT/Yr)	Total Injection Rate (MT/Yr)	Total Stored (MT)
Phase 1	0 - 10	6	0	6	60
Phase 2	10 - 40	3.7	4.3	8	240
Total Stored (MT)	-	170	130	-	300

Table 5-1 Forties 5 Site 1 Development Basis

The 24” pipeline from St Fergus will be surface laid (laid on the seabed) and stabilised with concrete weight coating (the proposed landfall method is discussed in Section 5.5). The 12” pipeline from the Forties 5 Site 1 NUI to the template at the northern site will be trenched and buried throughout for stabilisation and protection.

The Forties 5 Site 1 NUI will take the form of a conventional 4-legged steel jacket standing in 85m 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 6 slot well bay will enable cantilevered jack-up drilling operations for the injection wells.

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.

The Forties 5 Site 1 north subsea template will be a 4 slot piled structure; the cost estimate presented herein assumes drilling with a standard semi-submersible, however drilling by a Jack-Up rig would in theory also be feasible.

5.2 CO_2 Supply Profile

The assumed supply profile for the reference case is for 6 Mt/y to be provided from the shore terminal at St Fergus up until 2039 when the supply will increase to 8 Mt/y for the remainder of the project life, this is illustrated in Figure 5-2.

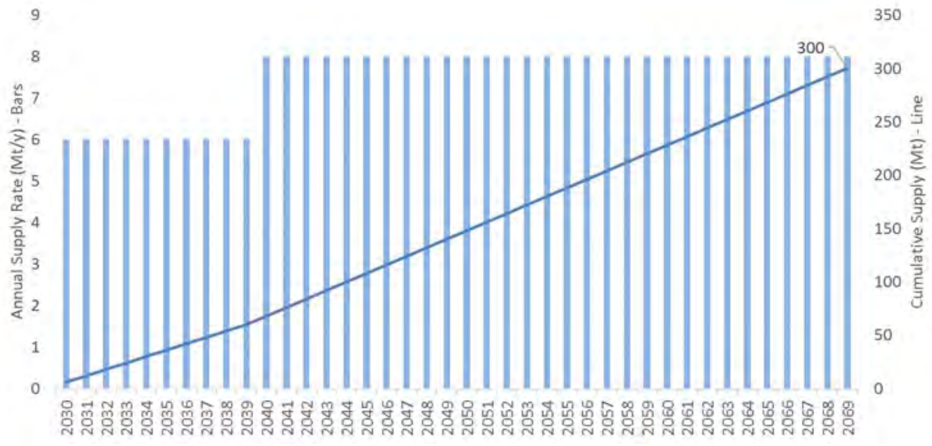


Figure 5-2 CO_2 Supply profile

5.3 Well Development Plan

The well placement strategy has been informed by considerations of geology, reservoir architecture and structural geometry, reservoir engineering modelling and the economics of development. Reservoir engineering results indicate that eight (plus one back-up) wells are required over field life to inject the target CO_2 volumes. The large area extent of Site 1 requires two injection sites to access the pore space and develop the site effectively, as illustrated in Figure 5-3. The southern site will be developed as the initial development phase followed 10 years later by a site 25km to the north.

In order to maximise reservoir coverage and well separation, long reach wells (~3,500m drilling radius) are proposed from each injection centre. Wells are planned to have a 300m horizontal section in the lower part of the Forties reservoir, but initially only the last 150m will be perforated. This provides optionality in case reservoir properties deteriorate during the injection phase and so minimises the requirement for local side-tracks. This well profile also has the benefit of removing the injection point laterally from the cap rock penetration point in order to reduce the direct impact of the CO_2 plume (which will rise vertically) at this location. Horizontal wells allow for additional reservoir section to be available should reservoir quality prove to be lower than expected.

Platform wells are expected to have a useful life of approximately 20 years and consequently the current plan is to re-drill all wells around this time. The subsea wells are assumed to be able to be designed to have a useful life of 30 years.

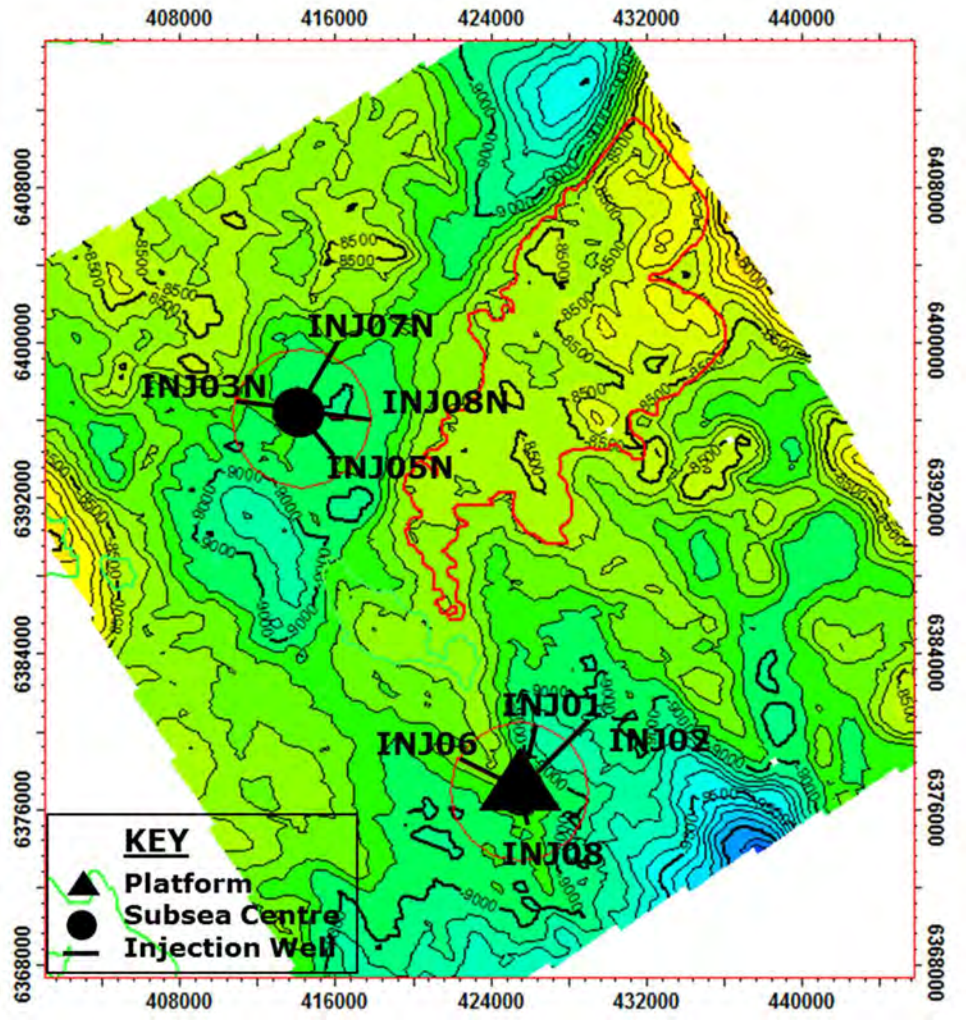


Figure 5-3 Provisional Development Well Locations

5.3.1 Well Design

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

The main features of the injection wells are summarised below:

1. Drillable from a NUI platform by heavy duty North Sea jack-up (not applicable to northern site).
2. Deviated up to 60 degrees in the tangent section and horizontal through the reservoir.
3. Platform well casing programme consisting of 26" conductor, 18-5/8" surface casing, 10-3/4" intermediate casing and 7" production liner.
4. Subsea well casing programme consisting of 30" conductor, 13-3/8" surface casing, 9-5/8" intermediate casing and 7" production liner.
5. Platform wells completed with 7" tubulars subsea wells with 5-1/2" tubulars.
6. All flow wetted surfaces will be 13%Cr material.
7. Maximum FTHP will be 160 bar.
8. Maximum SITHP will be 117 bar.
9. Maximum WHT will be 6°C.

5.3.1.1 Well Construction

For the southern area development, a platform surface location and well locations in the reservoir have been selected for conceptual well design purposes. The platform location has been selected to enable each well to be reached from a single platform. Table 5-2 details the reservoir targets for the toe of the horizontal wells.

Target Name	TVDSS (m)	UTM North (m)	UTM East (m)
INJ-01S Toe	2,873	6,380,084.0	426,220.0
INJ-02S Toe	2,883	6,380,538.1	428,897.5
INJ-04S Toe	2,835	6,375,289.5	422,160.6
INJ-06S Toe	2,737	6,378,687.2	422,252.6
INJ-08S Toe	2,739	6,376,072.1	426,092.0

Table 5-2 Southern Area Well Locations

For the northern area development, a subsea surface location and well locations in the reservoir have been selected for conceptual well design purposes. The subsea location has been selected to enable each well to be reached from a single drilling rig. Table 5-3 details the reservoir targets for the toe of the horizontal wells.

Target Name	TVDSS (m)	UTM North (m)	UTM East (m)
INJ-03N Toe	2,763	6,397,202.0	410,812.0
INJ-05N Toe	2,865	6,394,272.6	415,827.4
INJ-07N Toe	2,781	6,399,839.4	416,010.6
INJ-08N Toe	2,822	6,395,988.5	417,660.7

Table 5-3 Northern Area Well Locations

The conceptual directional plans for the horizontal CO_2 injection wells have been designed on the following basis:

1. Wells to be drilled vertically to 700m (unless a nudge is required to enable the tangent section angle to be less than 60º).
2. All wells will be kicked off below 700m MD and built to the tangent angle using a planned dogleg severity of 3.0º per 30m, while turning to the required azimuth.
3. After drilling a tangent section through the overburden formations, a second directional section will be drilled directly above the reservoir targets, building inclination to horizontal while turning the well path onto the required azimuth through the reservoir.
4. A horizontal section will then be drilled through the reservoir, holding inclination at 90º and maintaining azimuth.

Directional well spider plots are provided in Figure 5-4 and Figure 5-5. The directional profile for Southern Injector 01 is shown in Figure 5-6. Full details for all wells are provided in Appendix 6.

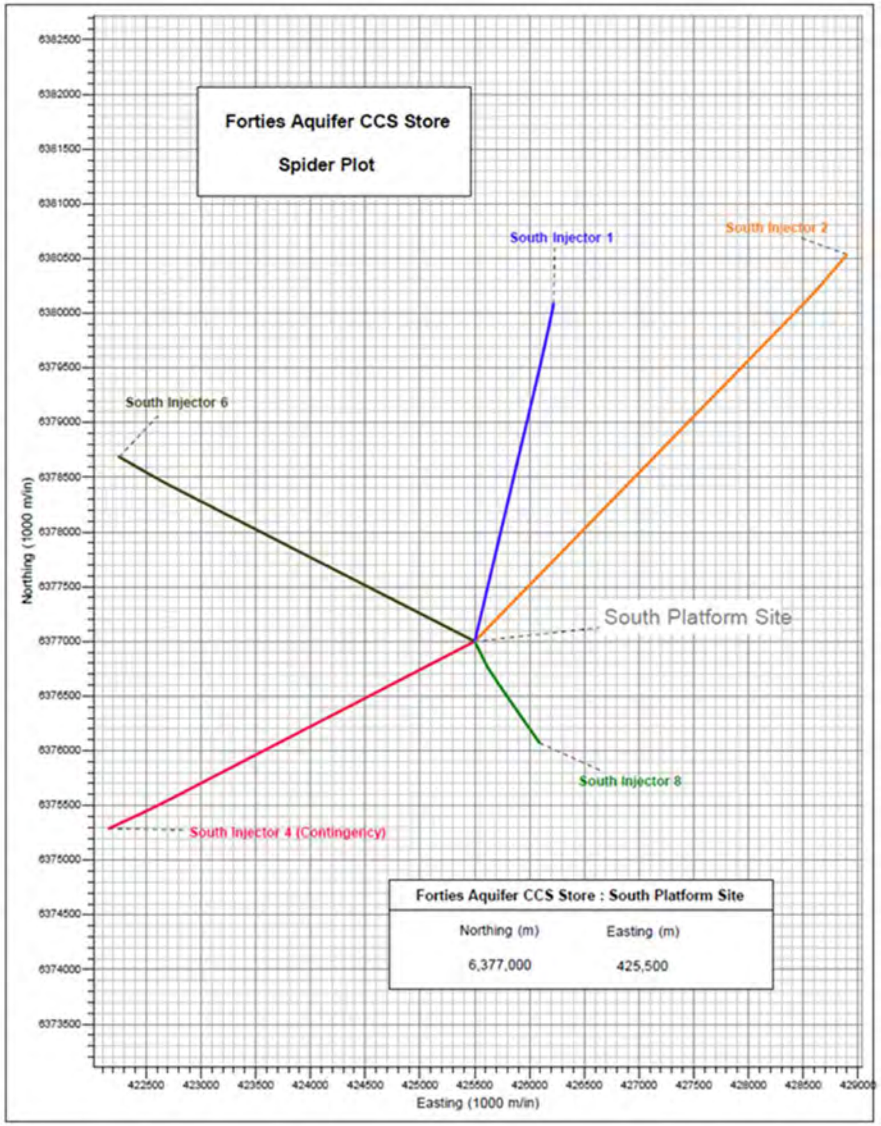


Figure 5-4 Southern Area Well Spider Plot

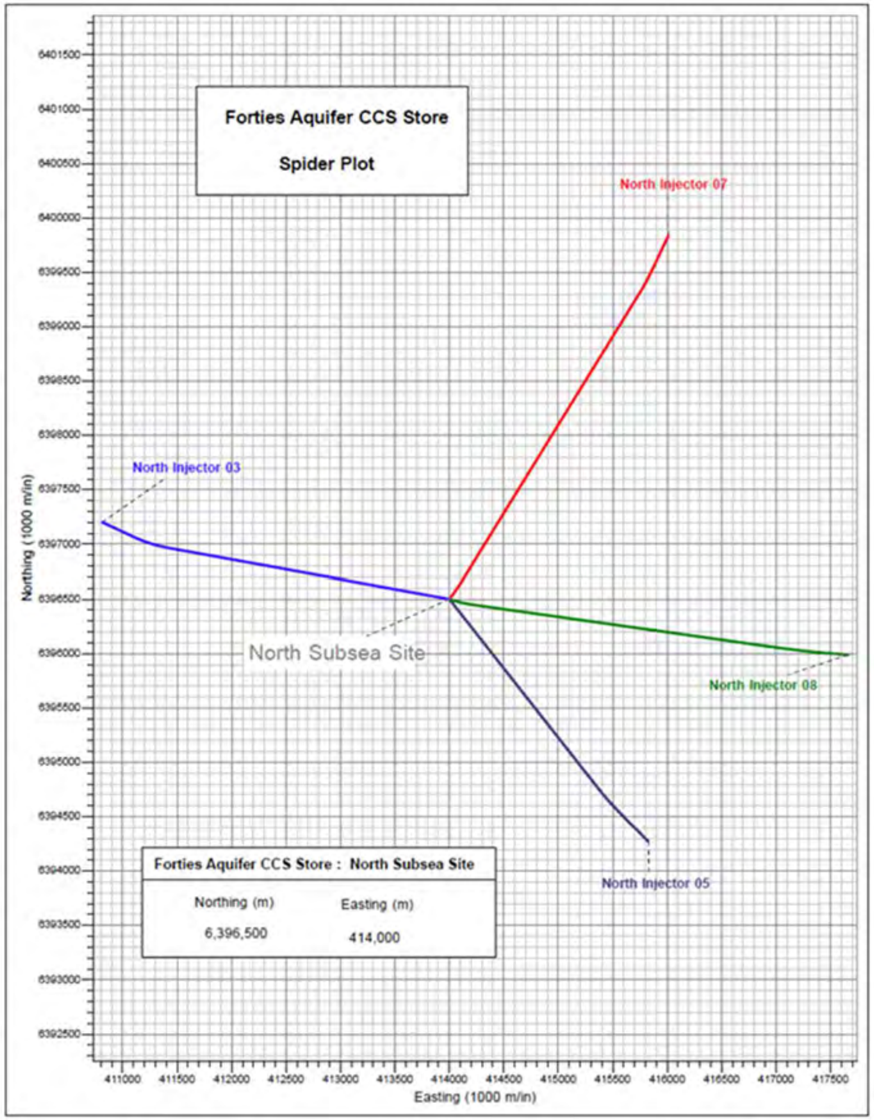


Figure 5-5 Northern Area Well Spider Plot

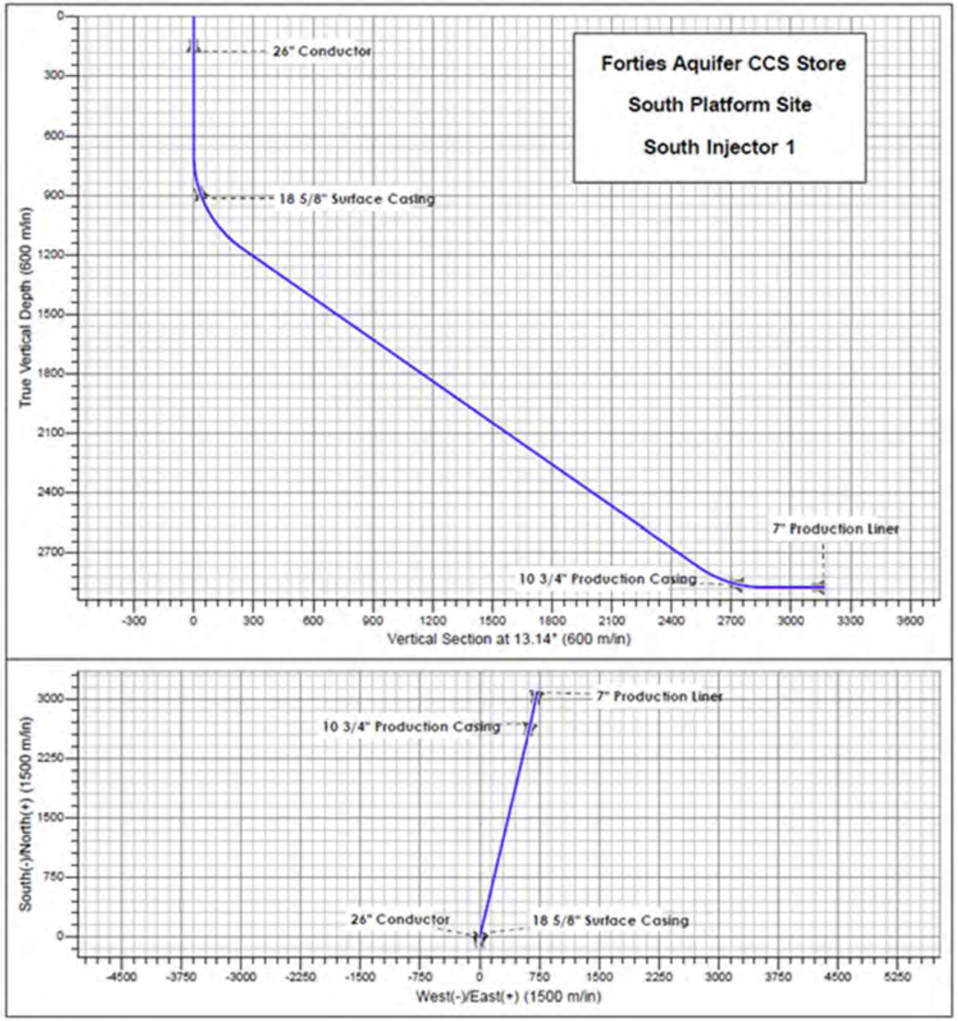


Figure 5-6 Direction Profile for Southern Injector 01

5.3.1.2 Well Completion

The upper completion consists of a 7” tubing string in the southern platform wells and a 5-1/2” tubing string in the northern subsea wells, anchored at depth by a production packer in the 9-5/8” production casing, just above the 7” liner hanger. Components include:

1. 7” / 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

Nine operational wells are required (five in the south and 4 in the north) to inject the anticipated maximum of 8Mt/y of supplied CO_2. A back-up well is included within the plan to provide a degree of redundancy. This is in the anticipation that the store operator will have a “take or pay” style contract with the CO_2 supplier and therefore likely to face significant penalties if unable to inject the contract amount.

The number of operational wells was identified following extensive reservoir simulation work, and this work is discussed in Section 3 of this report.

5.3.3 Drilling Programme

The summary well drilling and completion schedule for the life of the project is illustrated in Table 5-4.

Well Activity	-2	0	5	10	15	20	25	30	35	40
Appraisal Well	1									
Platform Wells (South)		5								
Subsea Wells (North)				4						
Replacement Platform Wells (South)						5				
Local Side-tracks			1		2		2		2	
Workovers							3			
Abandonment										9

Table 5-4 Summary Well Activity Schedule

5.3.3.1 Well Construction Programme

The outline drilling, casing and mud programmes for platform and subsea wells are provided in Table 5-5 and Table 5-6.

Section	Casing	Comments
Surface (Driven)	26”, 75m below mudline	
Surface (22”) **Water Based Mud**	18⅝”, 915m Carbon steel Cemented to the mudline	
Intermediate 1 (14¾”,”) **Oil Based Mud**	10¾”, 2722m Carbon steel Cemented to 100m inside previous casing shoe	Isolate the Eocene, Balder & Sele formations
Injection (8½”) **Oil Based Mud**	7”, 2750m 13Cr below packer Demented to inside the liner	

Table 5-5 Outline Platform Well Construction Programme

Section	Casing	Comments
Surface (36”) **Water Based Mud**	30”, 75m below mudline	
Surface (17½”) **Water Based Mud**	13⅜”, 915m Carbon steel Cemented to the mudline	
Intermediate 1 (12½”) **Oil Based Mud**	9⅝”, 2722m Carbon steel Cemented to 100m inside previous casing shoe	Isolate the Eocene, Balder & Sele formations
Injection (8½”) **Oil Based Mud**	7”, 2750m 13Cr below packer Cemented to inside the liner	

Table 5-6 Outline Subsea Well Construction Programme

5.3.4 Injection Forecast

Injection commences in 2030 and continues for approximately 40 years, the final year of injection is 2069. The injection forecast for the reference case is for 6 Mt/y for 10 years, until 2040, increasing to 8 Mt/y for the remainder of the store life. This forecast results in a cumulative injection of 300 Mt CO_2. This will be delivered by four injection wells in the first phase of operation and eight injection wells during the second phase of operation with one spare well.

Year	Rate (Mt/y)	Total (Mt)	Year	Rate (Mt/y)	Total (Mt)	Year (Mt/y)	Rate (MT/y)	Total (Mt)
2030	6	6	**2044**	8	100	**2058**	8	212
2031	6	12	**2045**	8	108	**2059**	8	220
2032	6	18	**2046**	8	116	**2060**	8	228
2033	6	24	**2047**	8	124	**2061**	8	236
2034	6	30	**2048**	8	132	**2062**	8	244
2035	6	36	**2049**	8	140	**2063**	8	252
2036	6	42	**2050**	8	148	**2064**	8	260
2037	6	48	**2051**	8	156	**2065**	8	268
2038	6	54	**2052**	8	164	**2066**	8	276
2039	6	60	**2053**	8	172	**2067**	8	284
2040	8	68	**2054**	8	180	**2068**	8	292
2041	8	76	**2055**	8	188	**2069**	8	300
2042	8	84	**2056**	8	196			
2043	8	92	**2057**	8	204			

Table 5-7 Injection profile

5.3.5 Movement of the CO_2 Plume

CO_2 is injected into the lowermost part of the Forties Sandstone. Migration is dominated by buoyancy so that CO_2 moves upwards until it reaches the primary caprock or local flow barrier which is essentially impermeable. With continued injection the area of the plume footprint increases until it threatens the integrity of the storage complex boundary at which point injection ceases (see Section 3.6.7).

CO_2 concentration does equilibrate over the 1000 year modelled period across the field but does not move outside the storage complex.

5.4 Offshore Infrastructure Development Plan

The optimum platform location for the NUI and the subsea template have been determined through drilling studies, UTM coordinates are presented in the table below.

Platform	UTM Coordinates	
	Eastings (m)	Northings (m)
NUI (South)	6,377,000	414,000
Subsea Template (North)	6,396,500	414,000

Table 5-8 Platform location

5.4.1 CO_2 Transportation Facilities

This section provides an overview of the transportation facilities required to develop the Forties 5 Site 1 CO_2 store.

5.4.1.1 Pipeline Routing

It is proposed that the new CO_2 pipeline will be installed from the nominated St Fergus beachhead to the proposed offshore injection site.

Landfall at St Fergus can be done by either open cut trenching or Horizontal Directional Drilling (HDD). The selected base case for St Fergus is open cut trenching which will entail installation of a temporary sheet-pile cofferdam in the tidal zone to enable pre-cutting of a trench, the trench will extend out to a distance of approximately 1km. The lay vessel will anchor at the end of the trench and pipeline pulled ashore in the pre-cut trench from the lay vessel using a shore-based winch. With the pipeline pulled ashore, the vessel will commence lay of the subsea pipeline along the pre-defined route. Between KP 0 and 1 the pipeline installed into the pre-cut trench will be stabilised by backfilling the trench and ultimately removing the cofferdam and returning the beach zone to its natural state. Between KP 1 and KP 20 the pipeline will be post lay trenched and buried for stabilisation as is common practise in the area due to high currents. From KP 20 to KP 217 the pipeline will be surface laid. The pipeline will be concrete weight coated for protection and stability.

Landfall by HDD involves a land based drill rig predrilling a pilot hole along a predefined trajectory; the borehole is then reamed to the necessary diameter using a reaming head, potentially using multiple passes. The borehole is stabilised against collapse with engineered drilling mud, and typically exits to the natural seabed via a purpose dug transition trench offshore. The pipeline is pulled through the borehole from the offshore lay barge, before the vessel commences the offshore lay.

Figure 5-7 Pipeline route

There are seven pipeline crossings along the pipeline route from St Fergus to the Forties 5 Site 1 NUI, summarised in the table below.

Pipeline	Surface Laid / Trenched	Operator
36” Forties – Cruden Bay	Surface Laid	BP Exploration
10” Kittiwake - Forties	Trenched & Buried	Venture
10” Nelson – Fulmar	Trenched & Buried	Shell UK
24” ETAP – Forties Unity	Surface Laid	BP Exploration
14” Montrose – Forties	Trenched & Buried	Talisman
44” Langeled	Surface Laid	GASSCO
36” CATS Trunkline	Surface Laid	BP Exploration

Table 5-9 Pipeline crossings (St. Fergus to Forties 5 Stie 1 NUI)

There is a single pipeline crossing along the pipeline route from the Forties 5 Site 1 NUI to the northern template, summarised in the table below.

Pipeline	Surface Laid / Trenched	Operator
36” CATS Trunkline	Surface Laid	BP Exploration

Table 5-10 Pipeline crossing (Forties NUI to Forties 5 North (template))

5.4.1.2 Preliminary Pipeline Sizing

At the time of development opportunity may exist to utilise a decommissioned existing oil pipeline for part or a substantial length of the route to the Forties field. Given the high level of uncertainty surrounding the potential availability and integrity of such pipelines for reallocation to CO_2 for an extended service life the development plan detailed herein assumes a newly installed purpose built pipeline.

Preliminary line sizing calculations have been performed to determine the pipeline’s outer diameters. The pipeline route lengths are summarised in the table below.

Pipeline	Route Length
St Fergus – Forties 5 Site 1 NUI	217 km
Forties 5 Site 1 NUI – Subsea Template (North)	24 km

Table 5-11 Pipeline route lengths

A minimum arrival pressure of 70 – 148 bar has been calculated for the platform wells. A minimum arrival pressure of 92 – 152 bar has been calculated for the subsea wells. For the purposes of line sizing calculations the required delivery pressure at the tubing head has been assumed to be 160 bar for both the NUI platform wells and the subsea wells at the northern template.

It has been assumed that the St Fergus pump station delivers up to 230 bar in pressure, therefore the maximum pressure drop is in the region of 70 bar (St Fergus to the subsea template).

The main pipeline route length from St Fergus to the Forties 5 Site 1 NUI is 217 km, and passes by several other potential storage sites and oil/gas developments which may present opportunities for future build out of CO_2 storage or EOR. The merit in pre-investing in a larger capacity pipeline from St Fergus with future tie-In structures (valved tees) at set locations along the route to facilitate future expansion / EOR (discussed further in Section 5.7) should be fully appraised during FEED.

It can be seen from Figure 5-8 and Figure 5-9 that a 24” pipeline from St Fergus to the NUI and a 12” pipeline from the NUI to the northern template are sufficient to meet the CO_2 supply profile whilst still providing a level of spare capacity. Further results are included in Appendix 9.

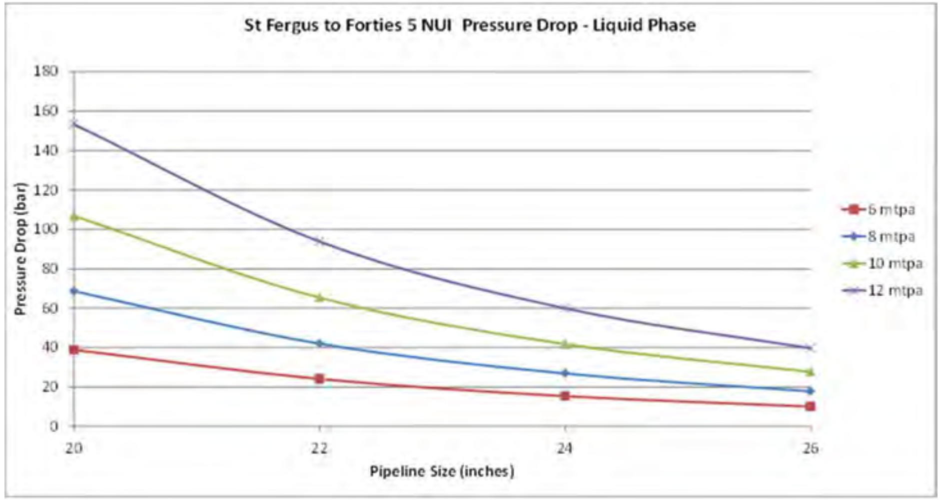


Figure 5-8 Pipeline pressure drops - St Fergus to Forteis 5 Site 1 NUI

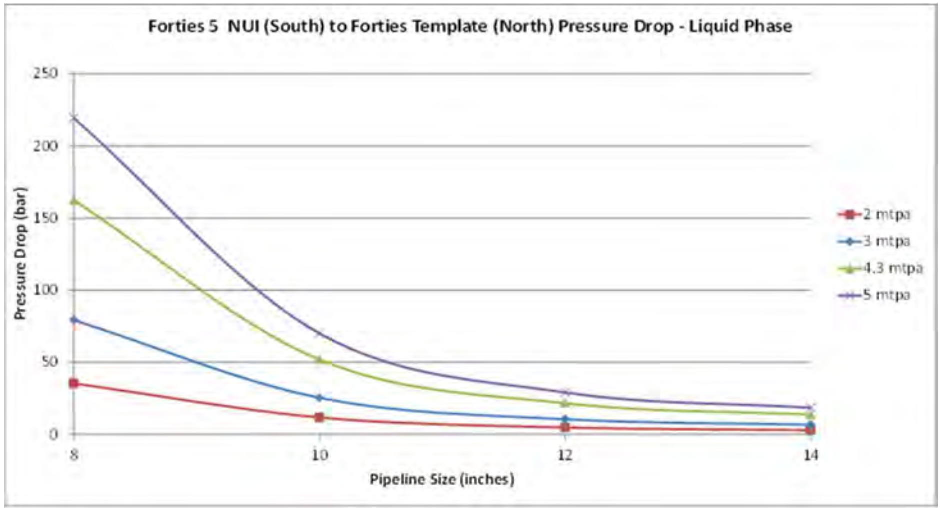


Figure 5-9 Pipeline pressure drops - NUI to Northern template

A flow rate of 8 Mt/y through the 24" pipeline from St Fergus results in a pressure drop of approximately 27 bar. The mass flow rate through the 12" pipeline to the northern site is estimated to be approximately 4.3 Mt/y, which results in a pressure drop of 21.5 bar. Assuming a pressure drop of approximately 5 bar across the Forties 5 Site 1 NUI results in a total pressure drop of approximately 53.5 bar. This increases to approximately 68 bar if the mass flow rate through the 24" pipeline from St Fergus is increased to 10 Mt/a, therefore there is sufficient ullage for an additional step out similar to the northern site before approaching the limit of a 24" pipeline and additional pumping is required.

The trunkline 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. The nearshore section of pipeline to approximately KP 20 is assumed to be trenched and buried due to the high currents in the area, consistent with existing pipelines. The 12" pipeline to the northern template will be installed by reel lay, followed by trenching and burial throughout for protection and stability. Pipeline protection and stability requirements should be fully assessed during FEED.

5.4.1.3 Subsea Isolation Valve (SSIV)

Development costs include for an actuated piggable ball valve SSIV structure being installed on the 24" pipeline adjacent to the NUI jacket.

For conservatism an actuated piggable ball valve SSIV structure has also been included at the base of the NUI for the 12" pipeline feeding CO_2 to the northern injection wells. The requirement for an SSIV to be installed on the 12" CO_2 step-out pipeline feeding the northern wells may be challenged in FEED due to the limited inventory of the pipeline and the NUI status of the platform it is protecting.

All risers on the Forties 5 Site 1 platform will be fitted with an emergency shutdown valve (ESDV) and the risers 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. Where both SSIV and ESDV valves exist on a pipeline and riser 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 between the two valves.

5.4.2 Offshore CO_2 Injection Facilities

Overview

It is anticipated that CO_2 will be injected in two phases.

Phase 1 - 6Mt/y for 10 years via a NUI (4 platform wells);

Phase 2 - 8Mt/y for 30 years; via the 4 platform wells plus 4 additional subsea wells via a subsea tie-back to the north of the NUI.

Forties 5 Site 1 – Southern Area

It is proposed that CO_2 is initially injected into the store from a single Normally Unmanned Installation (NUI) 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 the first phase of the Forties 5 Site 1 store.

The key input parameters used to size and cost the NUI platform are listed below, and a master equipment list is provided in Table 5-12.

NUI Jacket:

- 85m water depth
- 40 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	40 Years	4 wells, plus a spare injector and a spare slot with full replacement after 20 years.
Platform Well Slots	6	
Platform Wells	5	
Trees (XT)	5	-
Diesel Generator	3	1 to run full time, 2nd when manned, 3rd as standby
Satellite Communications	2 x 100%	Dual redundant VSAT systems
Risers	3	1 spare for future tie-back/expansion
J-Tube	3	For future tie-back/expansion
Subsea Isolation Valve (SSIV)	2	SSIV at Forties 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. Temporary Water Wash Facilities with Inert Gas for pressurisation
General Utilities	Yes	Open hazardous drains etc.

Table 5-12 Master Equipment List – Forties 5 Site 1 NUI

Forties 5 Site 1 – Northern Area

In addition to the platform wells, the second phase will involve the drilling of 4 additional subsea wells located 25 km to the north. The subsea wells will be drilled via a 4 slot template by a semi-sub drill rig. A subsea template is considered as both the most economical and technically suited development concept for the second phase of Forties 5 Site 1 store.

The key input parameters used to size and cost the northern site are listed below:

- 91m water depth
- 30 year design life
- 4 slot template
- Piled fishing friendly structure (shaped to minimise damage to and from fishing gear)
- Low temperature valving and manifolding pipework package
- No spare slot but header to incorporate valving to facilitate daisy chain
- Power, Hydraulics and Chemicals supplied by an umbilical from the Forties 5 Site 1 NUI

A process flow diagram of the Forties 5 Site 1 development is presented in Figure 5-10.

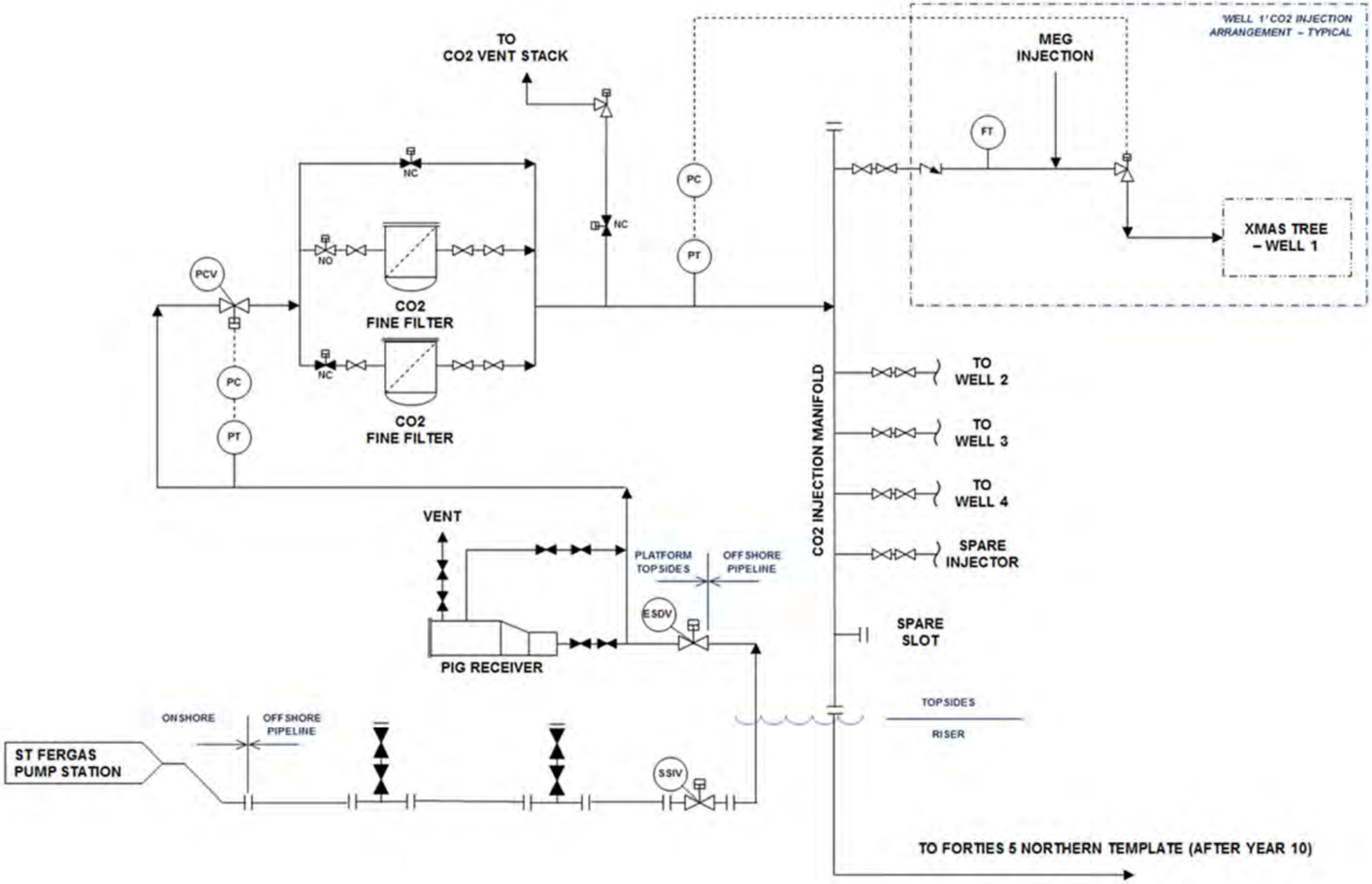


Figure 5-10 Process flow diagram

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 6 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, fine 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 the Forties 5 Site 1 development concept comprises a NUI Platform (a steel jacket and topsides) for the first phase and a subsea tie-back (template) for the second phase.

The first phase of the development (southern site) requires 4 injection wells over the first 10 years of the 40 year field life. The proposed trajectories of the injector wells are such that they can be drilled from a single drill centre. The water depth at the proposed drilling location of Forties 5 is 85m. This is sufficiently shallow to enable the wells to be drilled by a heavy duty Jack Up drill rig cantilevered over a platform with 6 well slots (4 + 1 spare injector + 1 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.

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

- Process monitoring, and well allocation metering for reservoir management.
- Process chemical injection of MEG, and N_2 for transient well conditions and wash water for halite control.
- Pig receiver.

- 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.

These facilities (where required) will be incorporated into the NUI, and as such the second phase of injection can comprise a subsea step out, utilising an EHC umbilical to supply power, hydraulics and chemicals from the NUI. In addition to the first phase platform injector wells the second phase of the Forties 5 development (northern site) requires 4 injection wells for the remaining 30 years of the 40 year field life. The subsea step out is located approximately 25km north of the NUI, and the proposed trajectories of the injector wells is such that they can be drilled from a single drill centre utilising a 4 slot subsea drilling template. The water depth at the proposed drilling location of the subsea template is 91m. Due to greater rig availability it has been assumed that the subsea wells will be drilled utilising a standard semi-sub drilling rig; however drilling by a Jack-Up rig (heavy duty) would in theory also be feasible. Note that no spare well is included at the northern template. Section 3 highlights that there may be sufficient capacity to meet the CO_2 injection profile via 3 of the 4 wells. In the event of an issue with one of the subsea injector wells that results in downtime, the spare platform well can be used for short periods during subsea injector well downtime. Should a permanent replacement well be required at the northern site then the production header on the template will incorporate valving (double block and bleed) to facilitate a daisy chain tie-back.

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 the NUI platform will likely exceed that of an entirely subsea development, however the P&A (plug and abandonment) of subsea wells will be approximately 25% more costly than the P&A of the platform wells.

5.4.3 Umbilical

An umbilical from the NUI will be required to provide power, hydraulics and chemicals to the subsea template. The umbilical will be installed by construction vessel complete with carousel, and will be trenched and buried throughout for protection.

5.5 Other Activities in this Area

There are a number of hydrocarbon fields in the vicinity of Forties 5 Site 1, and along the pipeline route. The nearest of these are shown in the figures in Section 5.6. The pipeline is routed to avoid the existing facilities associated with Kittiwake, Forties, Nelson and Montrose developments (and associated tie-backs).

A protection philosophy should be produced for the Forties 5 Site 1 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 development is entered into fishing and marine charting systems to notify other marine users.

5.6 Options for Expansion

A future tie-in could be facilitated via pre-investment in future tie-In structures (valved tees) at set locations.

Valved tees are recommended as this will allow future connections without the need for purging and flooding the existing pipeline. The structures will consist of a bar tee, dual valve arrangement for isolation and will likely be piled with structural protection for any fishing gear interaction. An alternative to providing tee structures is to perform a hot-tap operation. This is a considerably more expensive operation however it does limit pre-investment and allows for flexibility for selection of the connection location.

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 Forties 5 Site 1 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 the "Prospects for CO_2-EOR in the UKCS" report (Energy Research Partnership, 2015). Whilst potential CO_2-EOR candidate fields exist that could be serviced from suitable tie in points along the Forties 5 Site 1 trunkline, the publically available cessation of production date for these fields is typically 2030 or earlier. The potential hydrocarbon fields that could benefit from EOR as detailed by Energy Research Partnership and which are within reasonable distance of the Forties 5 Site 1 trunkline or proposed NUI are Forties, Buzzard, Nelson, and Alba. As stated the cessation of production dates for these fields may predate 2030 and potential suitability for EOR has been appraised based only upon publically available data.

To provide some optionality for potential EOR projects within the area, provision has been made for a tie in structure along the trunkline to potentially service Buzzard. However, given the proposed time frame of this development (2030 to 2070) further feasible EOR prospects could be found in this area. Also given the proximity of this site to the Norwegian border, expansion possibilities should be investigated to assess EOR sites on the Norwegian Continental Shelf.

Note that the cost estimates in Section 6 includes for the procurement, fabrication and installation of two future tie-in structures (valved tees) at set locations along the pipeline route as part of the base case development.

It can be seen from the figure below that there are a large number of potential further CO_2 storage sites surrounding the Forties 5 aquifer. These have been checked against the WP3 rankings, and those in the top 20 or in the reserve list have been extracted from CO_2Stored data loaded into Google Earth and are summarised in the table below. These sites could be developed as step outs from the Forties 5 NUI or tied in via a future tie-in structure.

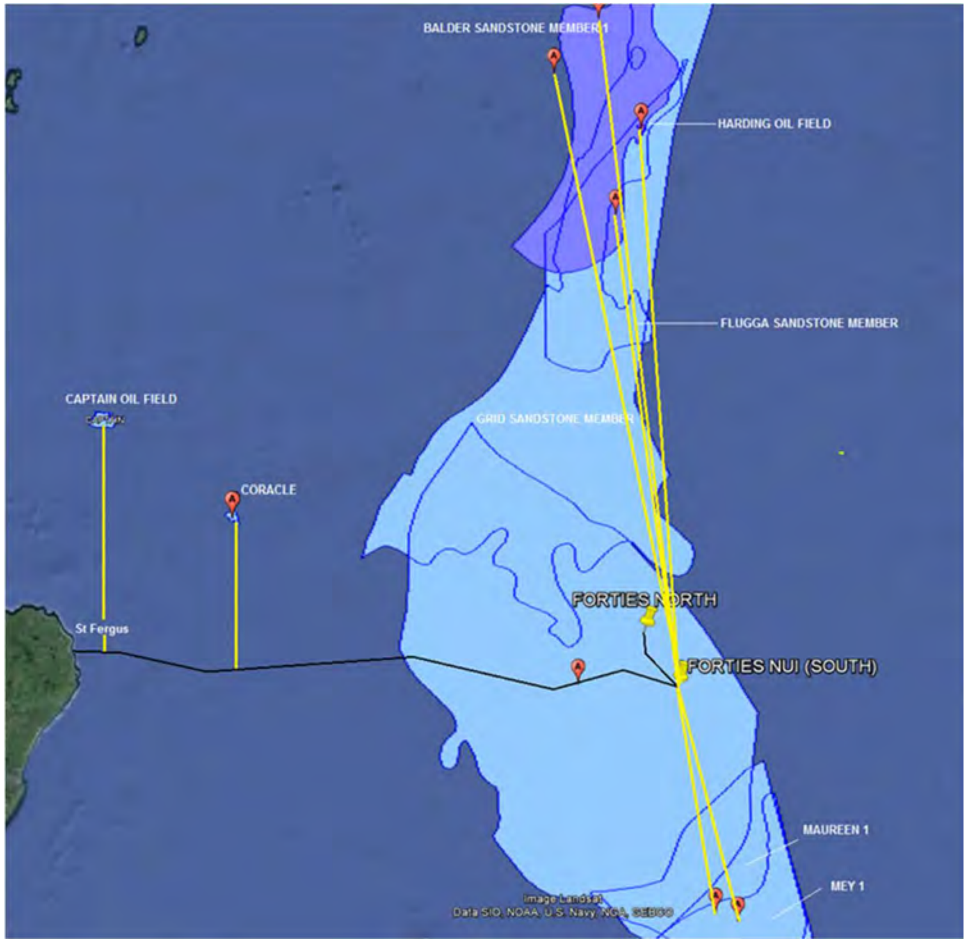


Figure 5-11 Options for expanding the development

Site	WP3 Ranking	Tie-in Distance (Centre of Site) [1]	Tee / Tie-Back
Grid Sandstone Member	9	220km	Tie-Back
Mey 1	10	85km	Tie-Back
Maureen 1	11	81km	Tie-Back
Coracle Aquifer	15	52km	Tie-Back
Captain Oil Field	16	80km	Tee
Harding Oil Field	20	195km	Tie-Back
Balder Sandstone	Reserve	225km	Tie-Back
Flugga Sandstone	Reserve	165km	Tie-Back

Table 5-13 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 locations and reduce these distances significantly.

The figures below show the oil/gas developments located along the pipeline route and in the vicinity of the chosen location for the Forties 5 Site 1 NUI and the subsea template.

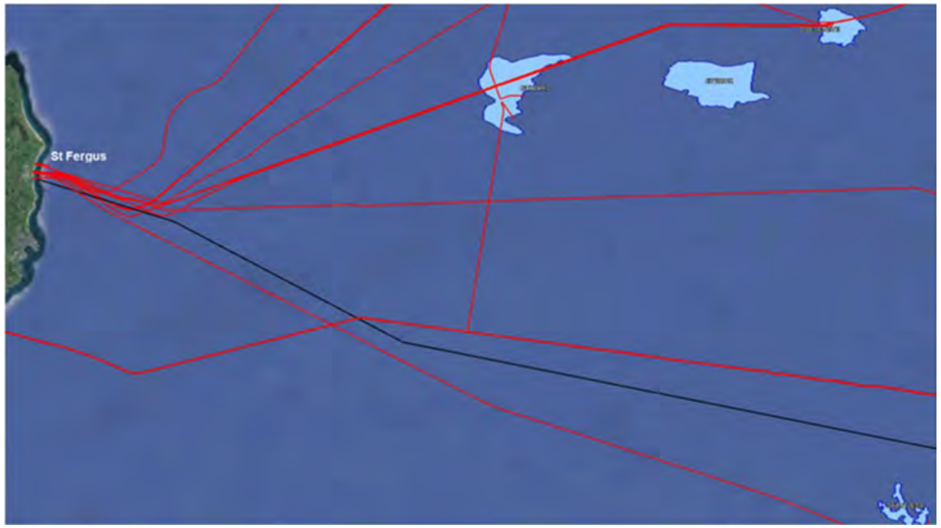


Figure 5-12 Options for expanding the development - hydrocarbon fields near beachhead

Figure 5-13 Options for expanding the development - hydrocarbon fields near installation

While performing this study several drill centre / injection sites were considered across the Forties 5 aquifer area, these are shown on the figure below and also offer several possibilities for future build out of CO_2 storage. Note that the base case Forties 5 CO_2 storage development described herein is located within site 1.

The current base case Transportation CAPEX for the 24" pipeline capable of delivering up to 10 Mt/y is £343 MM (see Section 6). Increasing the ullage capacity requires either an increase in operator pressures (and associated wall thickness) and/or an increase in the pipeline diameter. These will require large CAPEX pre-investment. An outline of the cost differential is presented in the table below.

OD	MASS FLOW RATE = 15 Mt/y				MASS FLOW RATE = 20 Mt/y			
	DP (bar)	MAOP (bar) [1]	WT (mm)	CAPEX (£ MM)	DP (bar)	MAOP (bar)[1]	WT (mm)	CAPEX (£ MM)
24"	93.3	280.3	33	383.3	165.2	352.2	40	430.9
26"	61.8	248.8	32	397.4	109.3	296.3	38	441.8
28"	42.2	229.2	32	417.9	74.6	261.6	36	450.2
30"	29.6	216.6	32	438.1	52.3	239.3	35	464.5
32"	21.3	208.3	32	458.6	37.5	224.5	35	486.8

Table 5-14 CAPEX associated with a larger diameter pipeline from St Fergus to NUI

Note:

1. No consideration has been given to any additional CAPEX associated with procuring such large diameter pipelines in non-

standard wall thicknesses, or any modifications to the St Fergus pump station that may be required to give the required compression.

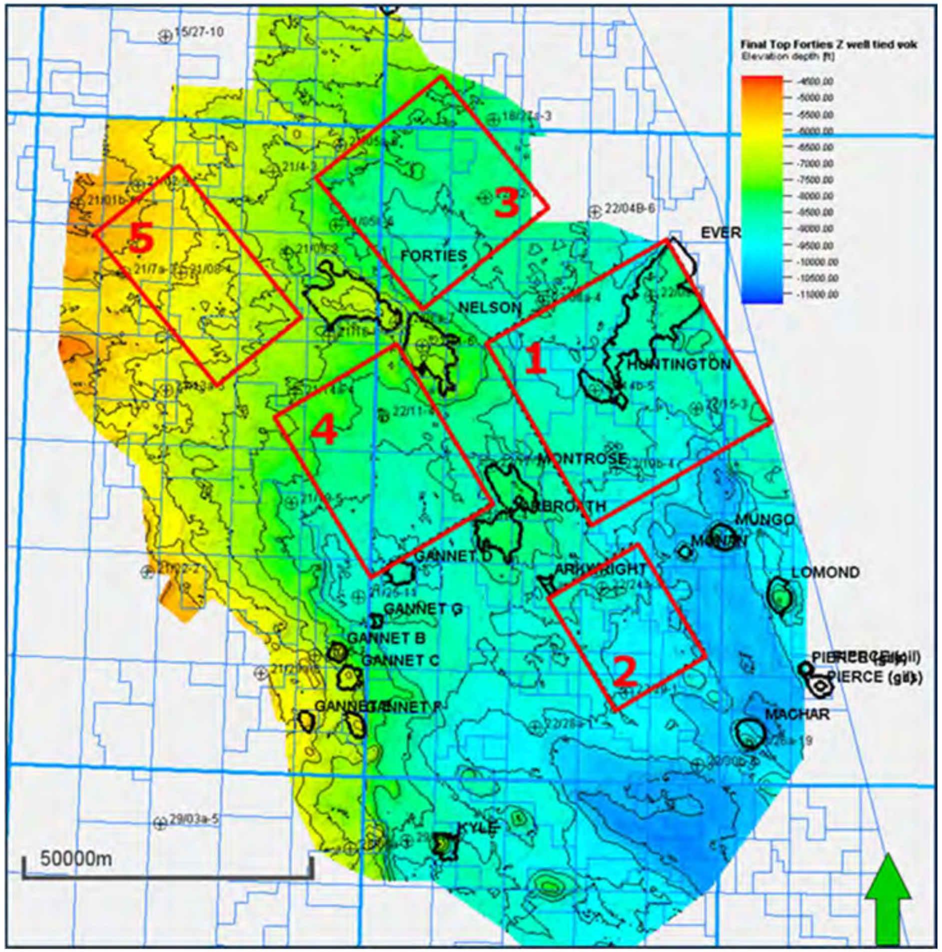


Figure 5-14 Options for expanding the development - Forties 5 Sites

5.7 Operations

The Forties 5 Site 1 development will inject CO_2 at a constant injection rate of 6 Mt/y, via 4 platform based injector wells over 10 years (phase 1), followed by the drilling of 4 subsea wells at the northern site and a further 30 years of injection at 8 Mt/y (phase 2). Phase 2 comprises an injection rate of 3.7 Mt/y at the platform and 4.3 Mt/y at the northern site.

The Forties 5 Site 1 NUI also includes a spare injector (drilled with phase 1 wells) and a spare slot.

The platform will be a Normally Unmanned Installation (NUI), and will be capable of operating unattended for approximately 3 months (90 days). An umbilical will provide power, hydraulics and chemicals to the northern template from the NUI. 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 lifeboats;
- IMR of telecommunications system (satellite communications);
- 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 and umbilical will also require regular IMR. This will include regular (typically biannual) 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 Forties 5 Site 1 facilities is as follows:

- 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;
- 24” pipeline (surface laid) and 12” pipeline (trenched and buried) are assumed to be covered by the UK fisheries offshore oil and gas legacy trust fund;
- Umbilical is cut and left in place;
- Pipeline spools to be recovered;
- Subsea structures to be recovered (SSIV and northern template);
- 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 Forties 5 Site 1, 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 Forties 5 Site 1 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:

The transportation costs form a high overall proportion of the total Forties 5 Site 1 development costs. Due to the magnitude of the procurement of the pipeline materials and its construction, there are opportunities for significant cost savings however there is also a risk of significant cost growth which will have a large impact on the overall cost of the development. Detailed line sizing assessment is required and should include steady state flow assurance accounting for the full range of operating conditions, future developments, available compression at the shore pump station and the CO_2 composition. Material assessment to accurately determine corrosion allowance, line pipe type, and a detailed wall thickness assessment which investigates a range in operating pressures, steel mill capacity and use of non-standard sizes, ease of installation and overall installed cost will then allow a more accurate assessment of the cost benefit and therefore optimise the line pipe selection.

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. Precedent exists in the area for semi-sub drilled wells (Forties Echo) nonetheless siting of the Southern jacket should be done with consideration to Jack-Up operations.

The following opportunities have been identified and should be considered as part of further work:

The selected landfall methodology for the proposed pipeline entails open cut trenching reduced environmental disturbance during construction may be achieved by opting for Horizontal Directional Drilling (HDD).

Further assessment into possible Norwegian CO_2 storage sites and EOR prospects should be included to determine whether it is feasible to include the additional ullage in the pipeline.

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 on the 12” infield line 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. Given the inventory it is assumed an SSIV will be necessary on the main trunkline.
- 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.

Decommissioning – to ensure a conservative approach the transportation ABEX has been calculated as 10% of the CAPEX. Given that the 24” pipeline is 217 km long, and it is likely that the pipeline will be cleaned and left in place, with part end recovery and ends protected by burial/rockdump, there is scope to reduce these costs significantly.

Use of existing infrastructure – given the amount of existing infrastructure in the region there is an opportunity to utilise decommissioned pipelines to transport the CO_2 part, or all, of the way offshore, provided the integrity can be proven. This should be considered during the next phase of the work.

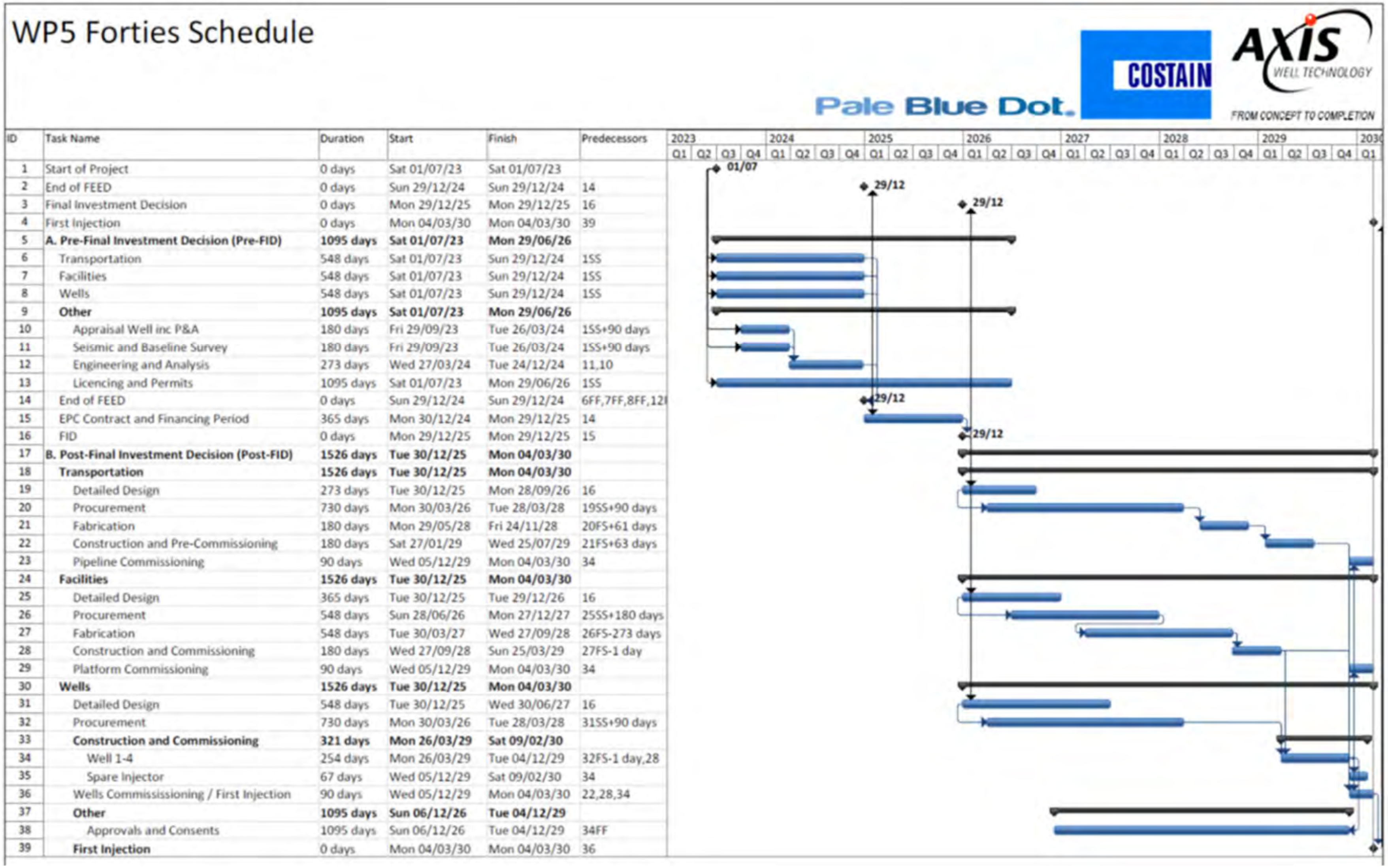
6.0 Budget & Schedule

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 2023.
- 12 months of EPC ITTs, contract and financing negotiation prior to FID.
- Project sanction / FID end of the year 2025.
- Detailed design commences immediately following sanction.
- Forties 5 Site 1 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 four platform injector wells commencing 2029.
- The pipeline, facilities and wells are commissioned in a continuous sequence of events.
- First CO_2 injection Q1 2030 which coincides with the projected supply profile.

Total project duration from pre-FEED to first injection is projected to be just under 7 years.



ID	Task Name	Duration	Start	Finish	Predecessors
1	Start of Project	0 days	Sat 01/07/23	Sat 01/07/23	
2	End of FEED	0 days	Sun 29/12/24	Sun 29/12/24	14
3	Final Investment Decision	0 days	Mon 29/12/25	Mon 29/12/25	16
4	First Injection	0 days	Mon 04/03/30	Mon 04/03/30	39
5	**A. Pre-Final Investment Decision (Pre-FID)**	**1095 days**	**Sat 01/07/23**	**Mon 29/06/26**	
6	Transportation	548 days	Sat 01/07/23	Sun 29/12/24	1SS
7	Facilities	548 days	Sat 01/07/23	Sun 29/12/24	1SS
8	Wells	548 days	Sat 01/07/23	Sun 29/12/24	1SS
9	**Other**	**1095 days**	**Sat 01/07/23**	**Mon 29/06/26**	
10	Appraisal Well inc P&A	180 days	Fri 29/09/23	Tue 26/03/24	1SS+90 days
11	Seismic and Baseline Survey	180 days	Fri 29/09/23	Tue 26/03/24	1SS+90 days
12	Engineering and Analysis	273 days	Wed 27/03/24	Tue 24/12/24	11,10
13	Licencing and Permits	1095 days	Sat 01/07/23	Mon 29/06/26	1SS
14	End of FEED	0 days	Sun 29/12/24	Sun 29/12/24	6FF,7FF,8FF,12I
15	EPC Contract and Financing Period	365 days	Mon 30/12/24	Mon 29/12/25	14
16	FID	0 days	Mon 29/12/25	Mon 29/12/25	15
17	**B. Post-Final Investment Decision (Post-FID)**	**1526 days**	**Tue 30/12/25**	**Mon 04/03/30**	
18	**Transportation**	**1526 days**	**Tue 30/12/25**	**Mon 04/03/30**	
19	Detailed Design	273 days	Tue 30/12/25	Mon 28/09/26	16
20	Procurement	730 days	Mon 30/03/26	Tue 28/03/28	19SS+90 days
21	Fabrication	180 days	Mon 29/05/28	Fri 24/11/28	20FS+61 days
22	Construction and Pre-Commissioning	180 days	Sat 27/01/29	Wed 25/07/29	21FS+63 days
23	Pipeline Commissioning	90 days	Wed 05/12/29	Mon 04/03/30	34
24	**Facilities**	**1526 days**	**Tue 30/12/25**	**Mon 04/03/30**	
25	Detailed Design	365 days	Tue 30/12/25	Tue 29/12/26	16
26	Procurement	548 days	Sun 28/06/26	Mon 27/12/27	25SS+180 days
27	Fabrication	548 days	Tue 30/03/27	Wed 27/09/28	26FS-273 days
28	Construction and Commissioning	180 days	Wed 27/09/28	Sun 25/03/29	27FS-1 day
29	Platform Commissioning	90 days	Wed 05/12/29	Mon 04/03/30	34
30	**Wells**	**1526 days**	**Tue 30/12/25**	**Mon 04/03/30**	
31	Detailed Design	548 days	Tue 30/12/25	Wed 30/06/27	16
32	Procurement	730 days	Mon 30/03/26	Tue 28/03/28	31SS+90 days
33	**Construction and Commissioning**	**321 days**	**Mon 26/03/29**	**Sat 09/02/30**	
34	Well 1-4	254 days	Mon 26/03/29	Tue 04/12/29	32FS-1 day,28
35	Spare Injector	67 days	Wed 05/12/29	Sat 09/02/30	34
36	Wells Commississioning / First Injection	90 days	Wed 05/12/29	Mon 04/03/30	22,28,34
37	**Other**	**1095 days**	**Sun 06/12/26**	**Tue 04/12/29**	
38	Approvals and Consents	1095 days	Sun 06/12/26	Tue 04/12/29	34FF
39	**First Injection**	0 days	Mon 04/03/30	Mon 04/03/30	36

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 Forties facilities. The Opex has been calculated based on a 40 year design life. A 30% contingency has been included.

It is anticipated that CO_2 will be injected in two phases.

Phase 1 - 6Mt/y for 10 years via a Forties NUI (4 platform wells);

Phase 2 - 8Mt/y for 30 years; via the 4 platform wells plus 4 additional subsea wells via a subsea tie-back to the North of the NUI.

Cost estimates are calculated for the base case development:

- Direct pipeline from St Fergus to the Forties 5 Site 1 NUI;
- Forties 5 Site 1 NUI (jacket and topsides);
- Four platform wells, plus a spare injector and a spare slot with full replacement after 20 years;
- Four slot subsea template at Forties 5 Site 1 North c/w four subsea injector wells;
- Umbilical from the NUI to the north template to provide power, hydraulics and chemicals.

6.2.1 Cost Estimate Summary

The cost estimate summary for the Forties 5 Site 1 development is outlined in Table 6-1. These numbers are current day estimates for the base case development. The estimate is provided in present value terms to a base year of 2015 in Table 6-2. 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	South (£ MM)	North (£ MM)	Total (£ MM)
Capex	787.2	237.6	1024.8
Opex	1010.4	435.3	1445.7
Abex	287.6	210.0	497.5
Total Cost	2085.3	882.9	2968.2
Injected Volume (Mt)	171	129	300
Cost CO_2 Injected (£/T)	12.19	6.84	9.89

Table 6-1 Project Cost Estimate Summary (Real, 2015)

Category	South (£ MM)	North (£ MM)	Total (£ MM)
Capex	245	39	284
Opex	97	25	122
Abex	3	2	5
Total Cost	344	66	410
Injected Volume (PV10 Mt)	12.0	3.7	15.7
Cost CO_2 Injected (£/T, PV10)	28.7	17.8	26.1

Table 6-2 Project Cost Estimate Summary (PV10, Nominal 2015)

The cost over time is illustrated in Figure 6-2 (values are not inflated or discounted).

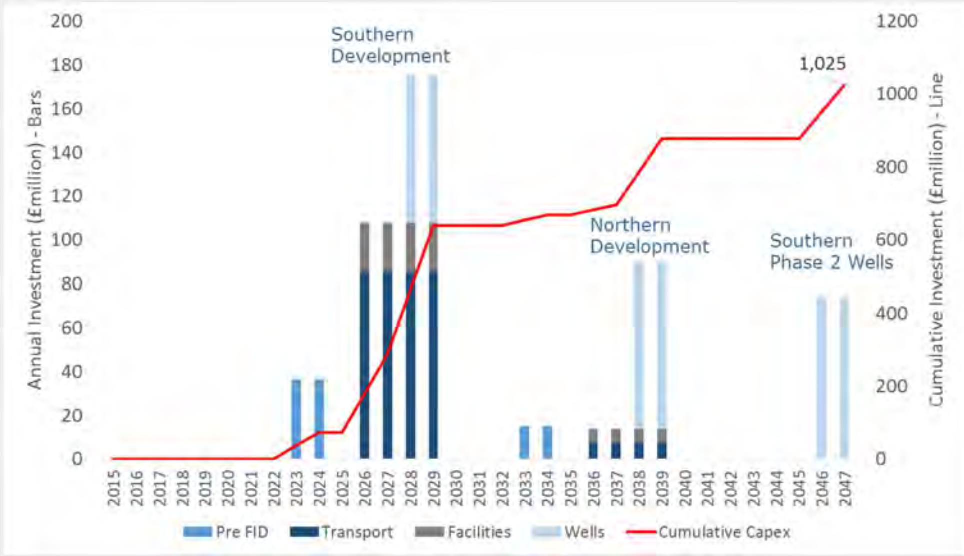


Figure 6-2 Phasing of capital spend

6.2.2 Life Cycle Costs

The total project costs by major element inflated at 2% p.a. with a discount factor of 10% p.a., are summarised in Table 6-3.

Category	South (£ MM)	North (£ MM)	Total (£ MM)
Transportation	122	5	127
Facilities	36	4	40
Wells	87	30	117
Opex	97	25	122
Decommissioning & MMV	3	2	5
Total	344	66	410

Table 6-3 Costs of Major Project Component (PV10, Nominal 2015)

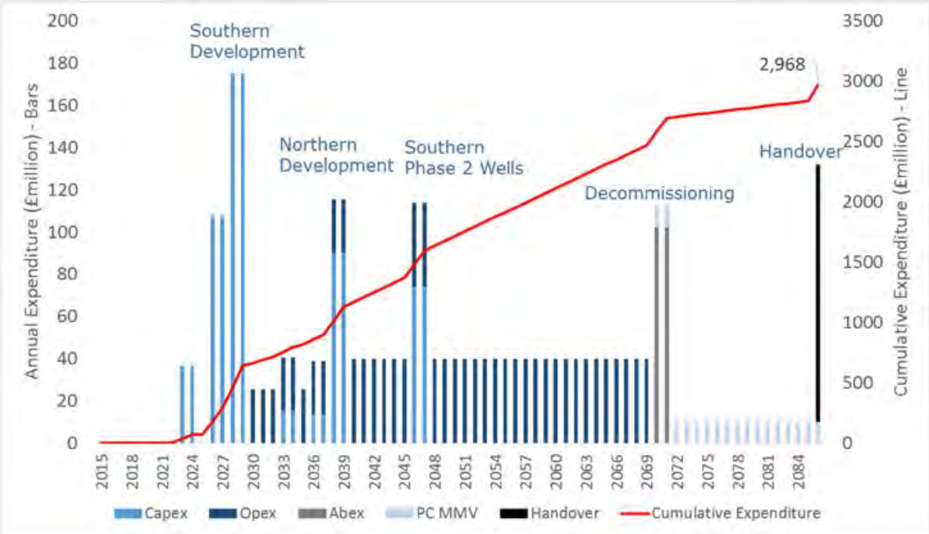


Figure 6-3 Elements of cost over project lifetime (nominal)

6.2.2.1 Capital Expenditure

The Capex estimates for the Forties 5 Site 1 development are summarised in the following tables. The costs are split up into transportation, facilities, wells and “other”. The power system is included in the facilities. The cost estimates in these tables are in 2015 real (uninflated) terms.

Phase	Category	South (£ MM)	North (£ MM)	Total (£ MM)
Pre-FID	Pre-FEED	0.4	0.4	0.8
	FEED	0.6	0.5	1.1
Post-FID	Detailed Design	1.6	1.6	3.2
	Procurement	200.1	8.1	208.2
	Fabrication	30.9	3.9	34.8
	Construction & Commissioning	109.3	16.2	125.5
Total Capex – Transportation (£MM)		342.9	30.7	373.6

Table 6-4 Transportation Capex

Notes:

1. This figure also includes the installation of the facilities (template and umbilical)

The Capex for the Forties 5 NUI (jacket + topsides) was generated using the Que$tor cost estimating software, and benchmarked using Costain Norms.

Phase	Category	South (£ MM)	North (£ MM)	Total (£ MM)
Pre-FID	Pre-FEED	2.8	0.3	3.1
	FEED	5.7	0.6	6.3
Post-FID	Detailed Design	16.9	1.7	18.6
	Procurement	23.3	21.7	45.0
	Fabrication	19.5	1.4	20.9
	Construction & Commissioning	29.1	0 [1]	29.1
Total Capex – Facilities (£MM)		97.3	25.7	123.0

Table 6-5 Offshore Facilities Capex

Notes:

1. Included within the costs for transport construction and commissioning

The well expenditure (Capex) for the Forties 5 Site 1 development is summarised in the following table.

Phase	Category	South (£ MM)	North (£ MM)	Total (£ MM)
Pre-FID	Pre-FEED / FEED PM&E	2.9	2.9	5.8
Post-FID	Detailed Design	2.9	2.9	5.8
	Procurement	57.7	31.1	88.8
	Construction and Commissioning (Drilling)	220.6	116.3	336.9
Total Capex – Wells (£MM)		284.1	153.2	437.3

Table 6-6 Wells Capex

Phase	Category	South (£ MM)	North (£ MM)	Total (£ MM)
Pre-FID	Seismic and Baseline Survey	20.1	20.1	40.2
	Appraisal Well	34.7	0.0	34.7
	Engineering and Analysis	2.9	2.9	5.8
	Licencing and Permits	2.6	2.6	5.2
Post-FID	Licencing and Permits	2.6	2.6	5.2
Total Capex – Other Costs (£MM)		62.9	28.2	91.1

Table 6-7 Other Capex

6.2.2.2 Operating Expenditure

The 40 year Opex for the Forties development has been estimated to be £1445.7 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 5 of the report
- Other, as summarised in Table 6-8

A breakdown of the Opex associated with "Other" costs is presented below.

Opex Estimate	South (£ MM)	North (£ MM)	Total (£ MM)
Measurement, Monitoring and Verification	141.2	100.9	242.1
Financial Securities	263.8	103.4	367.2
Ongoing Tariffs and Agreements [1]	0.0	0.0	0.0
Total	405.0	204.3	609.3

Table 6-8 Other Opex

Notes

1. It is assumed that the supplier will cover 3rd party costs and tariffs

6.2.2.3 Abandonment Expenditure

Abandonment costs for the Forties 5 Site 1 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	South (£ MM)	North (£ MM)	Total (£ MM)
Transportation	49.0	4.4	53.4
Facilities	52.8	1.4	54.2
Wells	39.3	57.7	97.0
Total	141.1	63.5	204.6

Table 6-9 Facilities Abex

A breakdown of the Abex associated with other is presented below.

Other	South (£ MM)	North (£ MM)	Total (£ MM)
Post Closure Monitoring	100.7	100.7	201.4
Handover	45.8	45.8	91.6
Total	146.5	146.5	293.0

Table 6-10 Other Abex

6.3 Economics

This section summarises the cost based economic metrics for the proposed development in a Real, Nominal and Present Value terms.

6.3.1 Project Component Costs

£million	Real (2015)	Nominal (Money of the Day)	PV_{10} (Nominal, 2015)
Transport	343	439	122
Facilities	97	124	36
Wells	347	529	87
Opex	1010	2054	97
Decommissioning & Post Closure Activity	288	971	3
Total	2085	4117	344

Table 6-11 Forties 5-South development cost in real and nominal terms

£million	Real (2015)	Nominal (Money of the Day)	PV_{10} (Nominal, 2015)
Transport	31	48	5
Facilities	26	40	4
Wells	181	284	30
Opex	435	966	25
Decommissioning & Post Closure Activity	210	739	2
Total	883	2076	66

Table 6-12 Forties 5-North development cost in real and nominal terms

£million	Real (2015)	Nominal (Money of the Day)	PV_{10} (Nominal, 2015)
Transport	374	487	127
Facilities	123	164	40
Wells	528	813	117
Opex	1446	3019	121
Decommissioning & Post Closure Activity	498	1710	5
Total	2968	6193	410

Table 6-13 Forties 5 total 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	570	949	140
Injection	1515	3168	205
Total	2085	4117	344

Table 6-14 Forties 5 Site 1- South transportation and storage costs

£million	Real (2015)	Nominal (MOTD)	PV_{10} (Nominal, 2015)
Transportation	47	88	6
Injection	836	1989	60
Total	883	2076	66

Table 6-15 Forties 5 Site 1 - North transportation and storage costs

£million	Real (2015)	Nominal (MOTD)	PV_{10} (Nominal, 2015)
Transportation	617	1036	146
Injection	2351	5157	265
Total	2968	6193	410

Table 6-16 Forties 5 Site 1 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	3.3	8.8	5.5	11.6
Injection	8.9	11.9	18.5	17.0
Total	12.2	20.7	24.1	28.6

Table 6-17 Forties 5 Site 1- South transport and storage costs per tonne of CO_2

£/T	Real (2015)	Levelised (PV_{10} Real 2015)	Nominal (MOTD)	Levelised ($PV_{10,}$ Nominal, 2015)
Transportation	0.4	1.0	0.7	1.6
Injection	6.5	9.3	15.4	16.0
Total	6.8	10.3	16.1	17.6

Table 6-18 Forties 5 Site 1 - North transportation and storge costs per tonne of CO_2

£/T	Real (2015)	Levelised (PV_{10} Real 2015)	Nominal (MOTD)	Levelised ($PV_{10,}$ Nominal, 2015)
Transportation	2.1	7.0	3.5	9.2
Injection	7.8	11.3	17.2	16.8
Total	9.9	18.3	20.6	26.0

Table 6-19 Forties 5 Site 1 total transport and storage costs per tonne of CO_2

Note: The levelised cost includes the discounted value of the CO_2 stored (16MT rather than the undiscounted value of 300 MT).

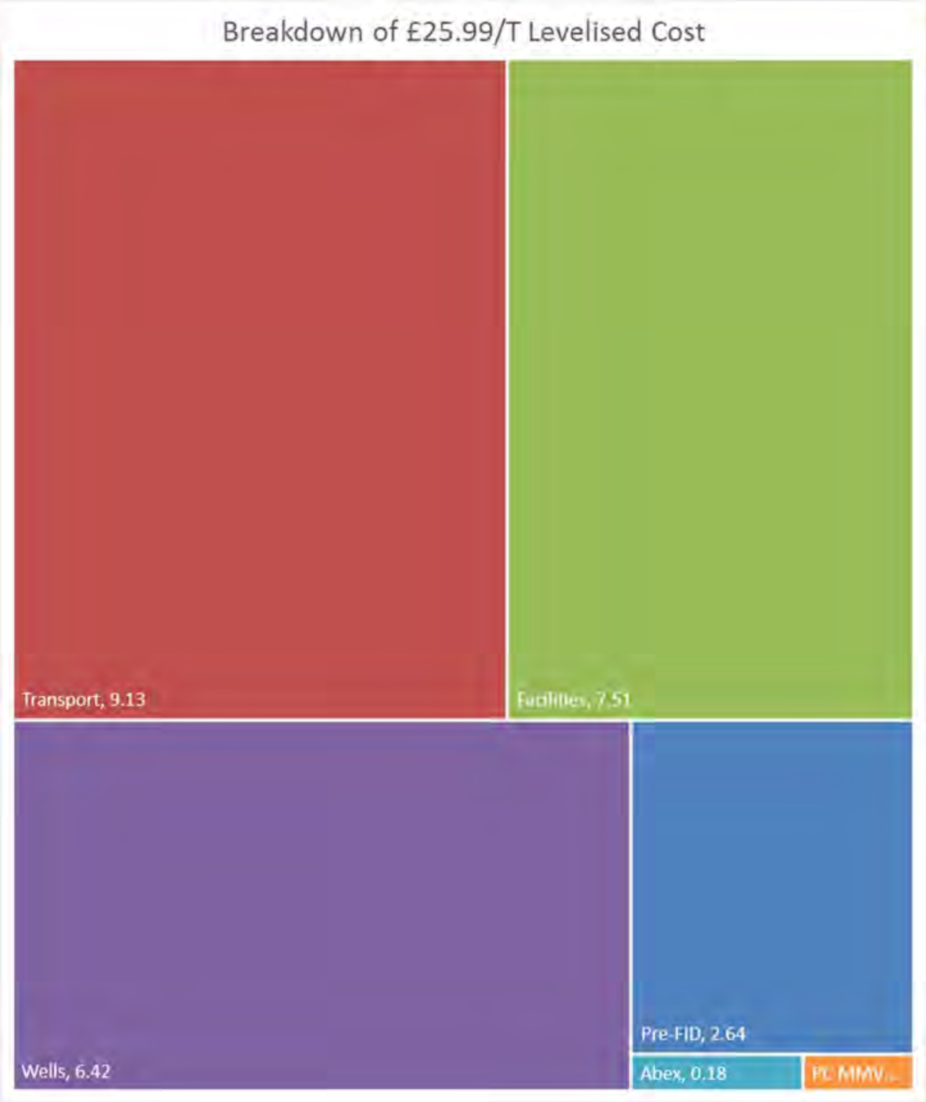


Figure 6-4 Breakdown of Levelised Costs

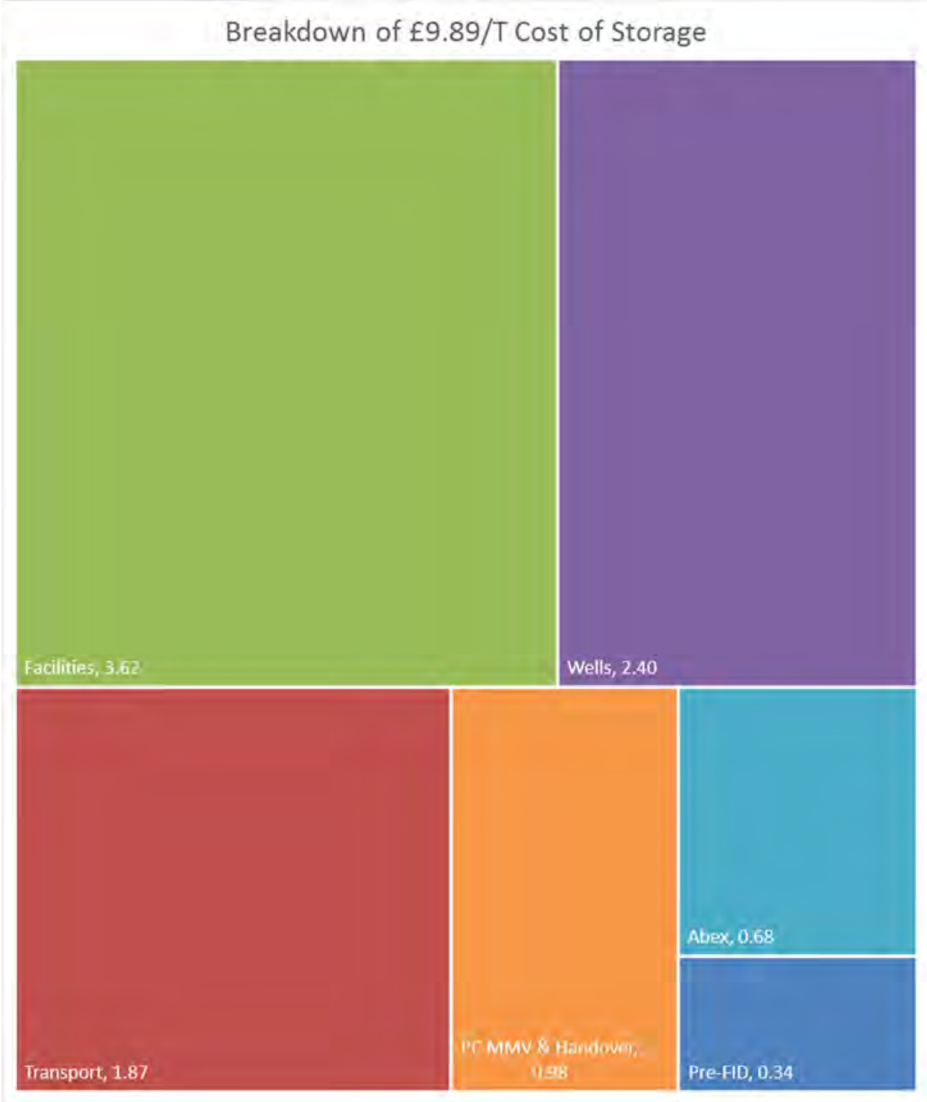


Figure 6-5 Breakdown of Life-cycle Cost

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	0.34	2.17	0.43	2.64
Transport	1.87	6.90	2.91	9.13
Facilities	3.62	4.85	7.27	7.51
Power	0.00	0.00	0.00	0.00
Wells	2.40	4.27	4.33	6.42
Abex	0.68	0.06	2.05	0.18
PC MMV & Handover	0.98	0.03	3.77	0.12
Total	9.89	18.27	20.76	25.99

Table 6-20 Unit Costs in Detail

7.0 Conclusions & Recommendations

7.1 Conclusions

Data

- The PGS Central North Sea Megasurvey volume covers approximately 95% of Site 1 and has been interpreted. In this area the dataset comprises multiple seismic volumes that are 1990 – 1994 vintage.
- There is quite good regional well coverage and reasonable well data available within the storage complex, including modern logs and core data.

Containment

- The primary seal is provided by the mudstones of the Sele Formation which is 90 – 100m thick over the site.
- There is a high degree of confidence that over 300Mt of CO_2 can be contained within the Forties Sandstone in Site 1 of the Forties 5 aquifer unit.
- 1000 years after the cessation of injection the CO_2 plume is still contained within the Storage Complex.
- The initial Storage Complex boundary could be adjusted in subsequent studies to provide additional certainty around containment within the planned lease area.
- Underlying the Forties Sandstone are the claystones and mudstones of the Lista Formation.
- Site 1 also encompasses the Huntington and Everest hydrocarbon fields provide secondary containment.
- The nature and continuity of the high and low permeability intervals are likely to have a significant influence on the evolution of the CO_2 plume.
- Wells 22/15-1 and 22/8a-3 present specific well integrity concerns and represent the highest risk to containment failure.

Site Characterisation

- This study evaluated Site 1 within the Forties 5 aquifer storage unit, as recommended in Deliverable 07 (Forties Site Selection Study).
- Site 1 covers an area of 1634 km^2 towards the east of the Forties 5 aquifer in UKCS quadrant 22, approximately 190 km from Aberdeen.
- The Forties Sandstone is a sand-rich turbidite fan system covering an area of 20,000 km^2 in the Central North Sea.
- The key horizons have been identified, interpreted and mapped. Seismic data quality is considered adequate for structural interpretation.
- The main reservoir event is a clear pick over the whole site.
- There is no clear evidence of any significant faulting in the reservoir or primary cap rock of the Forties 5 storage site 1 that is considered likely to breach the primary cap rock (Balder and Sele). A small fault in the Sele shale is clearly seen on seismic over the Everest field but the top seal has not been compromised by this fault.

- A single layer depth conversion is considered technically the best approach down to Top Forties Sandstone due to relatively small and gradual thickness variations in the overburden Tertiary units.
- Generally the Top Forties Sandstone dips gently at 1 to 2 degrees to the south-east.
- Reservoir quality distribution and reservoir architecture are remaining uncertainties.
- Well density is relatively low within the site and consequently there is a degree of uncertainty about the variation of reservoir quality across the site.
- Seismic amplitudes appear to show qualitatively reservoir changes.

Capacity

- The primary storage unit is the Forties Sandstone Member of the Sele Formation.
- Capacity estimates for the proposed development range from 238MT (P90) to 367MT (P10) with a reference case of 300Mt.
- 1000 years after injection stops, 12% of the injected inventory is structurally trapped, 44% residually trapped, 15% in solution and the remaining 29% travelling at less than 10m/year towards the storage complex boundary.
- The ultimate storage capacity of Forties 5 Site 1 is expected to be significantly more than 300Mt, but this would require much more development activity.
- Dynamic storage efficiency is limited at 5% and predominantly controlled by injection well count.

Appraisal

- A new appraisal well coupled with new 3D will test and prove the value of quantitative analysis of the 3D to refine the reservoir quality characterisation.
- An appraisal well will also collect key rock samples and conduct a series of injection and production tests to confirm injectivity.

Development

- Final investment decision needs to be in 2025 in order to achieve the first injection data of 2030.
- The planning work indicates that approximately 7 years are required to appraise and develop the store.
- A two-phase development is proposed, comprising a platform in the southern part of the store followed 10 years later by a subsea tie-back to the north.
- The 40 year, 9-well development is designed to accommodate the reference case supply profile of 6Mt CO_2/year from 2030 increasing to 8Mt CO_2/year from 2040 and terminating in 2069.
- A £284 million capital investment (in present value terms discounted at 10% to 2015) is required to design, build, install and commission the pipeline, platform, subsea infrastructure and wells. This equates to £0.7/t for the 300Mt reference case.
- The reference case development includes all new infrastructure: a minimum facilities platform in the south, a template in the north, 217 km of 24” pipeline from St Fergus, a 12”, 24km step out to the northern template, 26km subsea tie-back, 8 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.

Operations

- The safe operating envelope for the wells is based on a fracture pressure gradient of 0.17bar/m determined by geomechanical analysis. At the top perforation depth of 2,873m (tvdss) the fracture pressure is 488 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 438 bar.
- The design accommodates up to 160 bar arrival pressure of the CO_2 supply at the platform (phase 1) and northern template (phase 2) to enable injection through the life of the project. This would require a discharge pressure of approximately 230bar from the pump station at St Fergus.

Workflow

- The site location screening study, completed earlier in the project, was a useful step in identifying and ranking potential storage sites within the Forties 5 aquifer storage unit. This approach has wide applicability to other large storage units.

7.2 Recommendations

Appraisal Programme

- Procure a modern 3D seismic volume (2005 and 2009 CGG multi-client 3D volumes are available) or acquire a new survey.
- Conduct high resolution detailed imaging of the overburden interval to characterise small discontinuous faults and layers to support confidence around the high quality containment properties of the area.
- Process the new 3D survey to reveal more quantitative information regarding the porosity and reservoir quality of the storage site away from existing well information to enable wells to be placed optimally. Elsewhere in the Forties fairway, this technique has delivered excellent results which have enhanced the development of oil and gas fields. Whilst more can be achieved with the existing seismic data, a new survey is a key step to improving confidence around reservoir quality characterisation and long term performance.
- Plan to acquire the seismic survey after the final investment decision is taken.
- Gain more detailed access to the field data set so that production history, 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.
- Complete a detailed rock physics study to confirm that seismic attributes can be used in a quantitative prediction of reservoir quality.
- Identify additional studies that could confirm the design and specification of 4D seismic to ensure maximum effectiveness as a monitoring tool.
- Drill an appraisal well to provide key samples of reservoir and cap rock core for analysis, it will also serve to provide a key test and further calibration of the ability of 3D seismic to support the detailed quantitative reservoir characterisation required so that injection wells can be confidently placed in the best reservoir quality areas using 3D seismic. The detailed location and trajectory of this well require further work, but a location in the vicinity of the southern injection site is envisaged.
- Consider a study to examine the long distance interaction between producing regional hydrocarbon fields and the Forties 5 aquifer.

Operational Planning

- 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 sites.

- Explore options for reducing the MMV costs through improved synergies between the two development areas.
- Work with the Regulator to identify which hydrocarbon field data should be transferred to them following cessation of production.
- Conduct a thorough analysis of legacy wells and develop a comprehensive assessment of the risk that they may pose to a CO_2 storage development in this area. This should specifically include 22/15-1 and 22/8a-3.

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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.
Base Year	The common year (2015) to which discounted quantities are referenced for all stores
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
Darcy	Industry unit of permeability equal to 10^{-12} m^2

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.
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/cm^3 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.
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_2QUALSTORE]
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)

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

11.1 Appendix 1 – Risk Matrix

11.2 Appendix 2 – Leakage Workshop Report

11.3 Appendix 3 – Database

11.4 Appendix 4 – Geological Information

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D11: WP5B – Forties 5 Site 1 Storage Development Plan

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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 scenario definitions for Forties 5 Site 1 & their risk (likelihood & impact).

11.2.2 Methodology

The Leakage Scenario Definition Workshop (WP5A.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 Forties site. 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 Forties 5 Site 1 site 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:

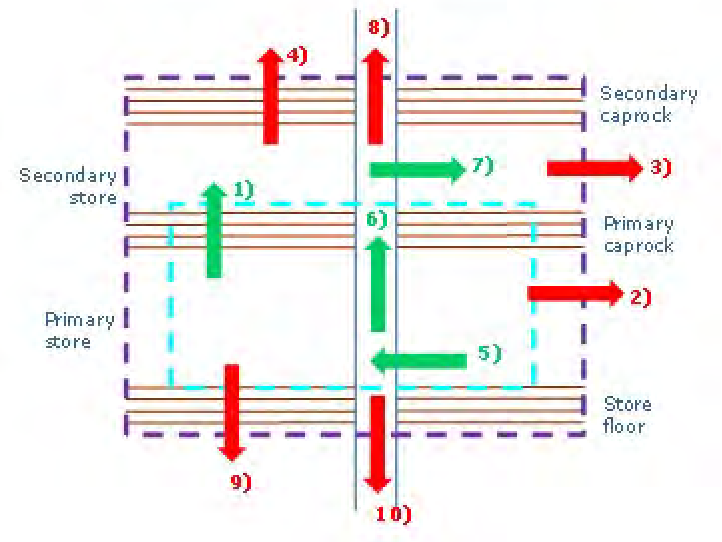


Figure 11-1 Containment failure modes

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_2QUALSTORE (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 fault (Northern Injection site)	1	3	
Vertical movement of CO_2 from Primary store to overburden via pre-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 both caprock & wells	1	3	
Vertical movement of CO_2 from Primary store to seabed via pre-existing wells	3	4	
Vertical movement of CO_2 from Primary store to seabed via injection wells	2	4	
Vertical movement of CO_2 from Primary store to seabed via both caprock & wells	1	4	
Lateral movement of CO_2 from Primary store out with storage complex w/in Forties due to permeability anisotropy (e.g. channels)	3	3	
Primary store to underburden (e.g. via Everest well to Andrew Fm)	2	2	
Primary store to underburden via store floor (out with storage complex)	1	3	

Table 11-1- Leakage Scenarios

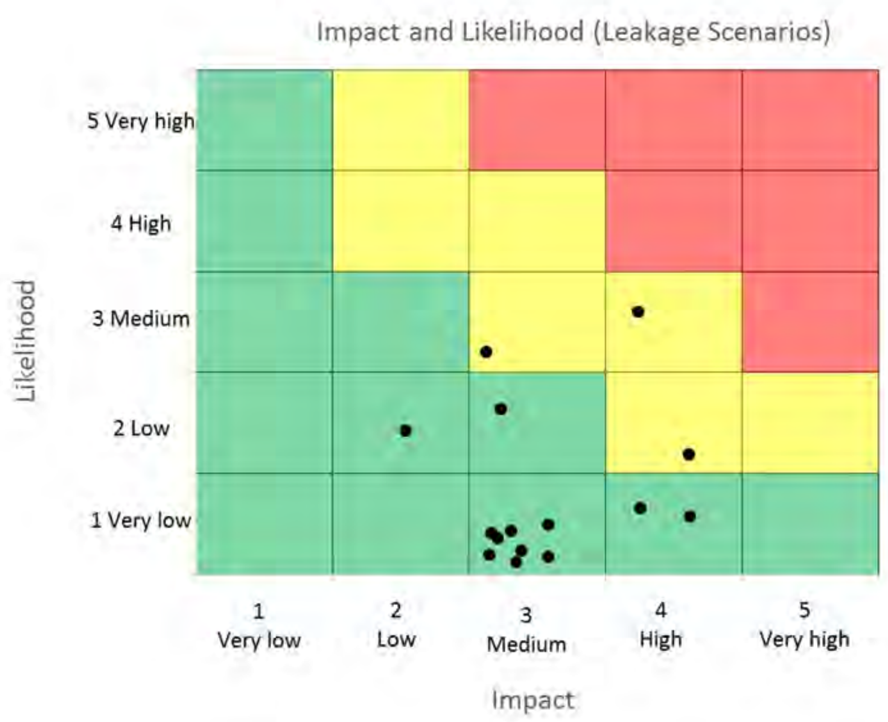


Figure 11-2 Risk matrix of leakage scenarios

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.

Lateral movement of CO_2 within the Forties sandstone was also considered to be a risk due to permeability anisotropy from Forties channels.

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, grounds 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

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 Forties 5 Site 1: SEG-Y data summary

The seismic 3D survey used for the evaluation of Forties 5 Aquifer site selection and Forties 5 Site 1 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 Forties 5 Aquifer site selection and Forties 5 Site 1 evaluation:

File Name	Format	Tile	Media	IL Range	XL Range
OS0423_MC3D_NSEA_MEGA_C06_MAR2014	SEG-Y	C06	27395002	27917-30000	108001-112000
OS0424_MC3D_NSEA_MEGA_C07_MAR2014	SEG-Y	C07	27395002	30001-35000	108001-112000
OS0425_MC3D_NSEA_MEGA_C08_MAR2014	SEG-Y	C08	27395002	35001-38138	108001-112000
OS0429_MC3D_NSEA_MEGA_D06_MAR2014	SEG-Y	D06	27395002	25001-30000	112001-116000
OS0430_MC3D_NSEA_MEGA_D07_MAR2014	SEG-Y	D07	27395002	30001-35000	112001-116000
OS0431_MC3D_NSEA_MEGA_D08_MAR2014	SEG-Y	D08	27395002	35001-36889	112001-116000
MC3D_NSEA_MEGA_E06	SEG-Y	E06	27395002	25001-30000	116001-120000
MC3D_NSEA_MEGA_E07	SEG-Y	E07	27395002	30001-35000	116001-120000
OS0439_MC3D_NSEA_MEGA_E08_MAR2014	SEG-Y	E08	27395002	35001-35773	116001-118826
MC3D_NSEA_MEGA_F06	SEG-Y	F06	27395002	25001-30000	120001-124000
MC3D_NSEA_MEGA_F07	SEG-Y	F07	27395002	30001-34657	120001-124000

Table 11-5 SEG-Y tiles for Forties 5 Site 1 evaluation

Figure 11-3 PGS SNS Mega survey time slice showing the SEG-Y data extent and tiles

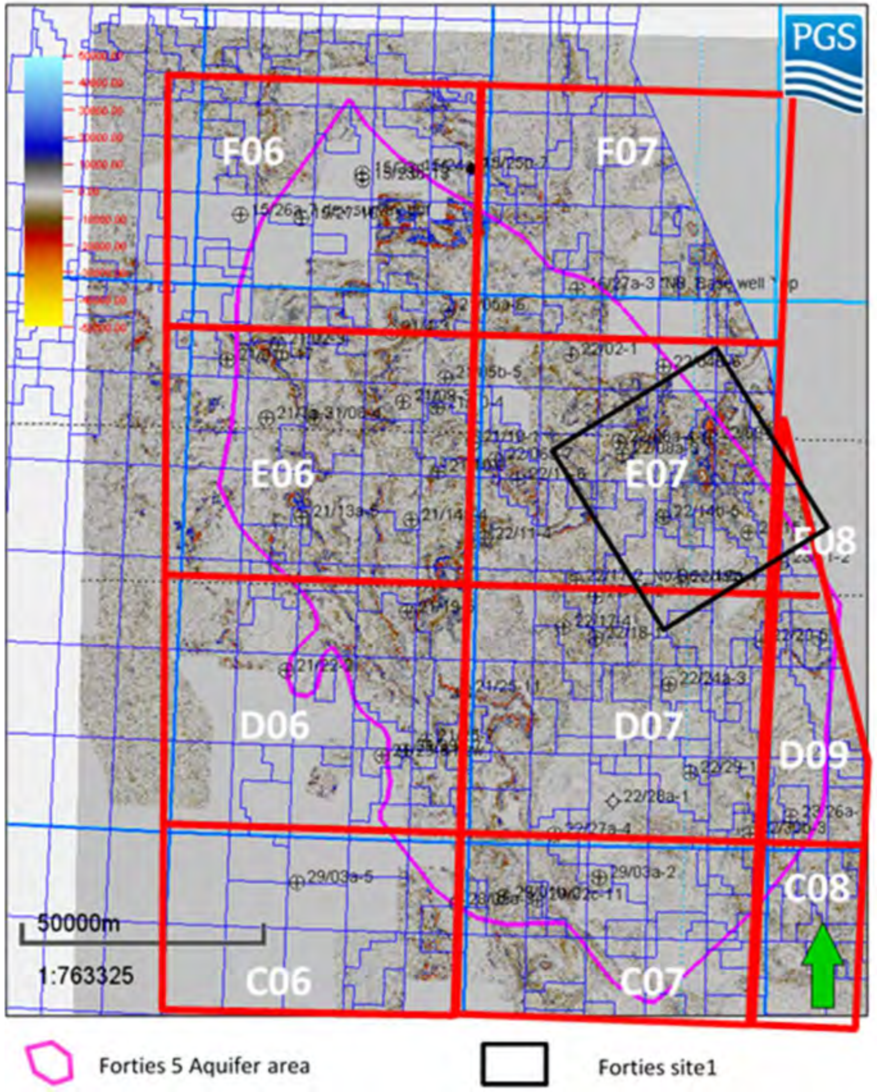


Figure 11-4 PGS CNS Mega Survey time slice showing the SEG-Y data extent (C07 Tile Number)

11.3.2 Forties 5 Site 1: Well log data summary

The table below shows a summary of the well log data for Forties 5 Site 1, downloaded from CDA.

Well	Date	E/A/D	GR	Neutron	Density	DT/ Sonic	SP	Comp Log	Geol Report/Final Well Report	Digital Checkshots	Deviation Data	Well Tops	Core Data over Forties
22/05a-11	1988	A	n	n	n	n	n	y	y	n	y	y	n
22/05a-13	1990	E	y	y	y	y	n	y	y	y	y	y	n
22/05a-6	1983	E	y	y	y	y	n	y	y	n	y	y	n
22/07-2	1989	E	y	y	y	y	y	y	y	y	y	y	n
22/08a-4	1990	E	y	n	n	y	y	y	n	n	y	y	n
22/08a-2	1981	E	y	y	y	y	y	y	y	y	n	y	n
22/08a-3	1985	E	y	y	y	n	n	y	n	y	y	y	y
22/09-1	1975	E	y	n	y	y	y	y	y	n	y	n	n
22/09-2	1985	E	y	y	y	y	n	y	y	n	y	y	y
22/09-3	1985	A	y	y	y	y	n	n	y	n	y	y	y
22/09-4	1986	A	y	y	y	y	y	y	n	n	y	y	y

Well	Date	E/A/D	GR	Neutron	Density	DT/ Sonic	SP	Comp Log	Geol Report/Final Well Report	Digital Checkshots	Deviation Data	Well Tops	Core Data over Forties
22/09-5	1997	E	y	y	y	y	y	y	y	n	y	y	n
22/09-7Z	2000	D	y	n	n	n	n	y	y	n	y	y	n
22/09-8	2000	D	y	n	n	n	n	y	y	n	y	y	n
22/10-1	1970	E	n	n	y	y	n	y	y	n	y	y	n
22/10a-2	1982	E	y	y	y	y	y	y	y	n	y	n	n
22/10a-3	1982	A	y	y	y	y	y	n	y	n	y	n	n
22/10a-4	1984	A	y	y	y	y	y	n	y	n	y	y	y
22/10a-5	1986	A	y	y	y	y	y	y	n	y	y	y	n
22/10a-7	2011	D	n	n	n	n	n	y	y	n	y	y	n
22/10b-6	1988	E	y	y	y	y	y	y	n	y	y	y	y
22/12a-1	1987	E	y	n	n	y	y	y	y	y	y	y	n

Well	Date	E/A/D	GR	Neutron	Density	DT/ Sonic	SP	Comp Log	Geol Report/Final Well Report	Digital Checkshots	Deviation Data	Well Tops	Core Data over Forties
22/12a-3	1990	A	y	n	y	y	n	y	y	n	y	y	n
22/12a-9	2004	D	y	n	n	n	n	y	n	n	y	y	n
22/13a-1	1988	E	y	n	n	y	y	y	y	y	y	y	n
22/13a-2	1989	A	y	n	n	y	n	y	y	n	y	y	n
22/13a-4	1989	A	y	n	n	y	n	y	y	n	y	y	n
22/13a-8	2009	D	y	n	n	n	n	y	y	n	y	y	n
22/13b-3	1989	E	y	n	y	y	y	y	y	n	y	y	n
22/13b-5	1994	E	y	y	y	y	y	y	y	n	y	y	n
22/13b-6	1997	E	y	y	y	n	n	y	y	n	y	y	n
22/13b-7	2007	E	y	n	y	n	n	y	y	n	y	y	n
22/14-1	1974	E	y	y	y	y	n	y	y	n	n	y	y

Well	Date	E/A/D	GR	Neutron	Density	DT/ Sonic	SP	Comp Log	Geol Report/Final Well Report	Digital Checkshots	Deviation Data	Well Tops	Core Data over Forties
22/14a-2	1985	E	y	n	y	y	n	y	y	n	y	y	y
22/14a-7	2007	E	y	y	y	y	n	y	y	y	y	y	n
22/14b-3	1988	E	y	y	y	y	n	y	y	n	y	y	n
22/14b-4	1992	E	y	y	n	n	n	y	y	y	y	y	n
22/14b-5	2007	E	y	y	y	y	n	y	y	y	y	y	y
22/14b-6q	2007	A	y	n	y	n	n	y	y	n	y	y	y
22/14b-8	2007	A	y	n	n	n	n	y	y	n	y	y	y
22/14b-9	2008	A	y	n	y	n	n	y	y	n	y	y	n
22/15-1	1982	E	y	n	n	y	n	y	y	n	y	y	n
22/15-2	1988	E	y	y	y	y	n	y	y	n	y	y	y
22/15-3	2005	E	y	y	y	y	y	y	y	n	y	y	y

Well	Date	E/A/D	GR	Neutron	Density	DT/ Sonic	SP	Comp Log	Geol Report/Final Well Report	Digital Checkshots	Deviation Data	Well Tops	Core Data over Forties
22/18-3	1981	E	y	y	y	y	y	n	y	n	y	y	y
22/18-5	1991	E	y	y	y	y	n	y	y	n	y	y	y
22/19-2	1985	E	y	n	n	n	y	y	n	n	y	y	n
22/19b-4	1993	E	y	n	y	n	n	y	y	y	y	y	n
23/06-1	1989	A	y	y	y	n	n	y	y	n	y	y	n
23/11-3Z	1992	E	n	n	n	n	n	y	y	n	y	y	n
23/11-2	1988	E	y	n	y	n	y	y	y	n	y	y	y
23/11-4	2005	E	y	n	n	n	n	y	y	n	y	y	n

Well	Well Top Change	X Section	Date	E/A/D	Loaded in petel project	GR	Neutron	Density	DT/Sonic	SP	Comp Log	Geol Report/Final Well Report	Digital Checkshots	Deviation Data	Well Tops	Core Data over Forties
22/05a-11	n	A	1988	A	y	n	n	n	n	n	y	y	n	y	y	n
22/05a-13	n	1	1990	E	y	y	y	y	y	n	y	y	y	y	y	n
22/05a-6	n	1	1983	E	y	y	y	y	y	n	y	y	n	y	y	n
22/07-2	n	1	1989	E	y	y	y	y	y	y	y	y	y	y	y	n
22/08a- 4	n	1	1990	E	y	y	n	n	y	y	y	n	n	y	y	n
22/08a-2	y	1	1981	E	y	y	y	y	y	y	y	y	y	n	y	n
22/08a-3	n	1	1985	E	y	y	y	y	n	n	y	n	y	y	y	y
22/09-1	y	3	1975	E	y	y	n	y	y	y	y	y	n	y	n	n
22/09-2	y	1	1985	E	y	y	y	y	y	n	y	y	n	y	y	y
22/09-3	n	2	1985	A	y	y	y	y	y	n	n	y	n	y	y	y
22/09-4	n	2	1986	A	y	y	y	y	y	y	y	n	n	y	y	y

22/09-5	n	1	1997	E	y	y	y	y	y	y	y	y	n	y	y	n
22/09-7Z	n	3	2000	D	y	y	n	n	n	n	y	y	n	y	y	n
22/09-8	n	3	2000	D	y	y	n	n	n	n	y	y	n	y	y	n
22/10-1	n	2	1970	E	y	n	n	y	y	n	y	y	n	y	y	n
22/10a-2	y	1	1982	E	y	y	y	y	y	y	y	y	n	y	n	n
22/10a-3	n	2	1982	A	y	y	y	y	y	y	n	y	n	y	n	n
22/10a-4	y	3	1984	A	y	y	y	y	y	y	n	y	n	y	y	y
22/10a-5	y	2	1986	A	y	y	y	y	y	y	y	n	y	y	y	n
22/10a-7	n	1	2011	D	y	n	n	n	n	n	y	y	n	y	y	n
22/10b-6	y	4	1988	E	y	y	y	y	y	y	y	n	y	y	y	y
22/12a-1	n	1	1987	E	y	y	n	n	y	y	y	y	y	y	y	n
22/12a-3	n	1	1990	A	y	y	n	y	y	n	y	y	n	y	y	n

22/12a-9	n	1	2004	D	y	y	n	n	n	n	y	n	n	y	y	n
22/13a-1	n	2	1988	E	y	y	n	n	y	y	y	y	y	y	y	n
22/13a-2	n	2	1989	A	y	y	n	n	y	n	y	y	n	y	y	n
22/13a-4	n	2	1989	A	y	y	n	n	y	n	y	y	n	y	y	n
22/13a-8	n	A	2009	D	y	y	n	n	n	n	y	y	n	y	y	n
22/13b-3	n	3	1989	E	y	y	n	y	y	y	y	y	n	y	y	n
22/13b-5	n	2	1994	E	y	y	y	y	y	y	y	y	n	y	y	n
22/13b-6	n	3	1997	E	y	y	y	y	n	n	y	y	n	y	y	n
22/13b-7	n	4	2007	E	y	y	n	y	n	n	y	y	n	y	y	n
22/14-1	n		1974	E	y	y	y	y	y	n	y	y	n	n	y	y
22/14a-2	n	3	1985	E	y	y	n	y	y	n	y	y	n	y	y	y
22/14a-7	n	3	2007	E	y	y	y	y	y	n	y	y	y	y	y	n

22/14b-3	n	4	1988	E	y	y	y	y	y	n	y	y	n	y	y	n
22/14b-4	n	4	1992	E	y	y	y	n	n	n	y	y	y	y	y	n
22/14b-5	n	A	2007	E	y	y	y	y	y	n	y	y	y	y	y	y
22/14b-6q	n	A	2007	A	y	y	n	y	n	n	y	y	n	y	y	y
22/14b-8	n	3	2007	A	y	y	n	n	n	n	y	y	n	y	y	y
22/14b-9	n	3	2008	A	y	y	n	y	n	n	y	y	n	y	y	n
22/15-1	n	5	1982	E	y	y	n	n	y	n	y	y	n	y	y	n
22/15-2	n	4	1988	E	y	y	y	y	y	n	y	y	n	y	y	y
22/15-3	n	5	2005	E	y	y	y	y	y	y	y	y	n	y	y	y
22/18-3	y	5	1981	E	y	y	y	y	y	y	n	y	n	y	y	y
22/18-5	n	5	1991	E	y	y	y	y	y	n	y	y	n	y	y	y
22/19-2	n	5	1985	E	y	y	n	n	n	y	y	n	n	y	y	n

22/19 b-4	n	5	19 93	E	y	y	n	y	n	n	y	y	y	y	y	n
23/06 -1	n	4	19 89	A	y	y	y	y	n	n	y	y	n	y	y	n
23/11 - 3Z	n	5	19 92	E	y	n	n	n	n	n	y	y	n	y	y	n
23/11 -2	n	5	19 88	E	y	y	n	y	n	y	y	y	n	y	y	y
23/11 -4	n	5	20 05	E	y	y	n	n	n	n	y	y	n	y	y	n

Table 11-6 Well log data summary

11.3.3 Forties 5 Site 1: Core data summary

The table below show a summary of the core data available over the Forties 5 Site 1 site.

Well	Core Depths (ft MD)
22/08a-3	8694.50-8753.58
22/09-2	8560.62-8624.30
22/09-3	8571.00-8734.00
22/09-4	8556.47-8853.66
22/10a-4	8444.74-8600.17
22/10b-6	8553.74-8623.58
22/14-1	8750.17-8760.77
22/14a-2	8609.86-8843.31
22/14b-5	8979.72-9289.84
22/14b-6q	9876.67-9966.45
22/14b-8	9502.83-9662.22
22/15-2	8769.12-8931.14
22/15-3	8823.32-8919.19
22/18-3	8805.00-8856.59
22/18-5	8673.92-8770.85
23/11-2	8892.78-9299.92

Table 11-7 Core data summary

11.3.4 Data from Operators

Well data (including some abandonment records) from Operators in the Forties 5 Site 1 area were provided under Non-disclosure Agreements, but did not include any pressure or production data.

11.4 Appendix 4 – Geological Information

11.4.1 Maps

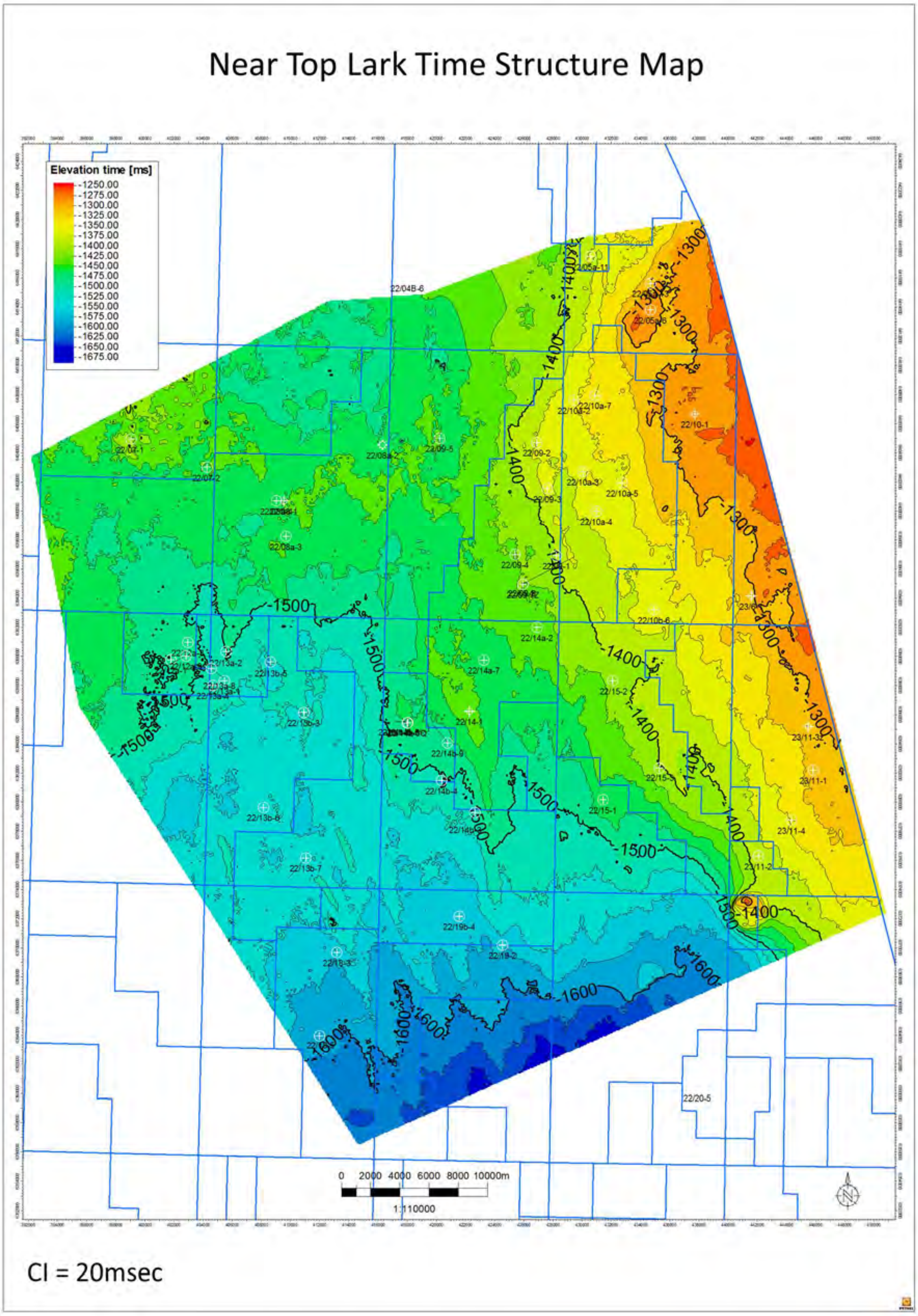


Figure 11-5 Near Top Lark time structure map

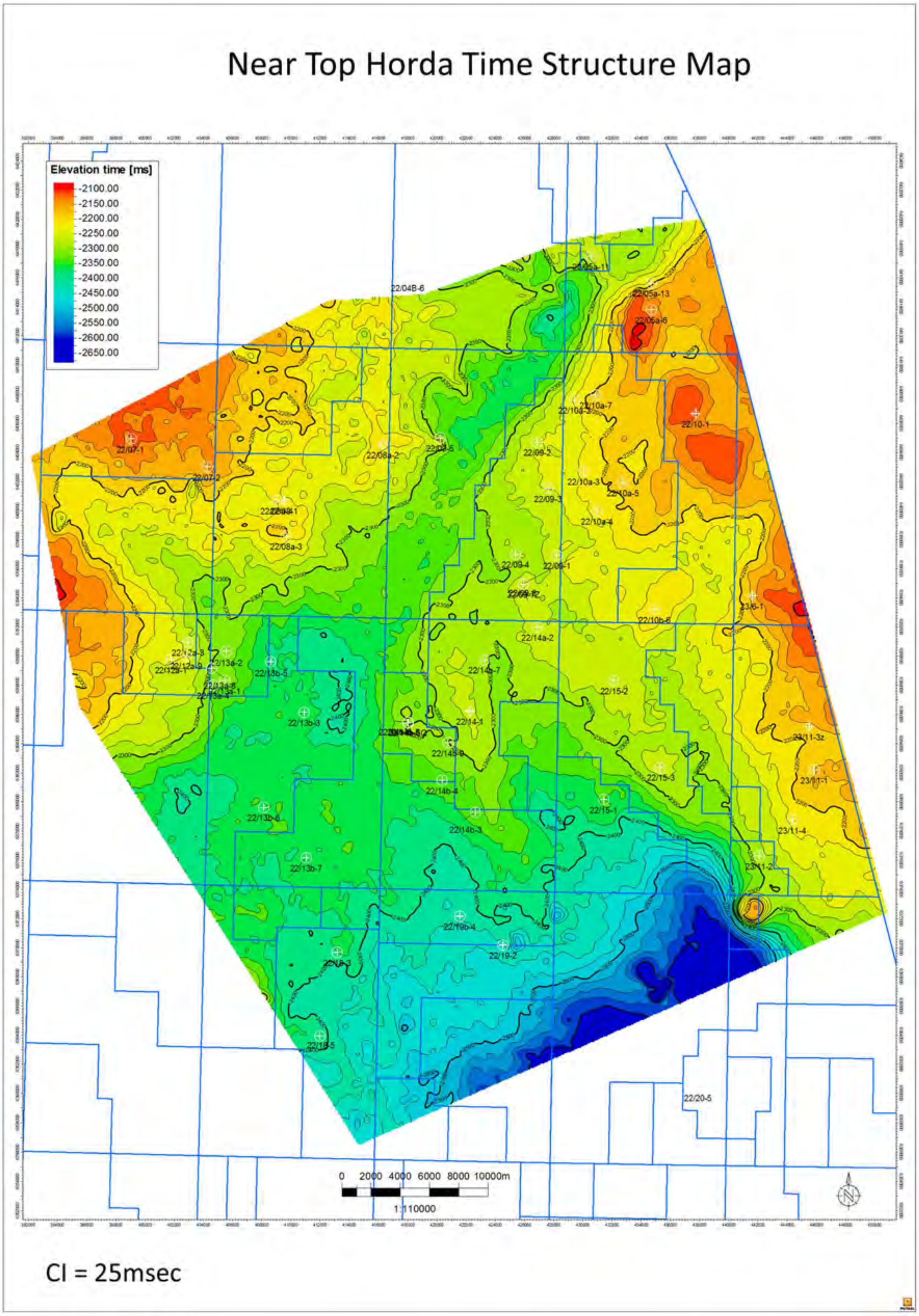


Figure 11-6 Near Top Horda time structure map

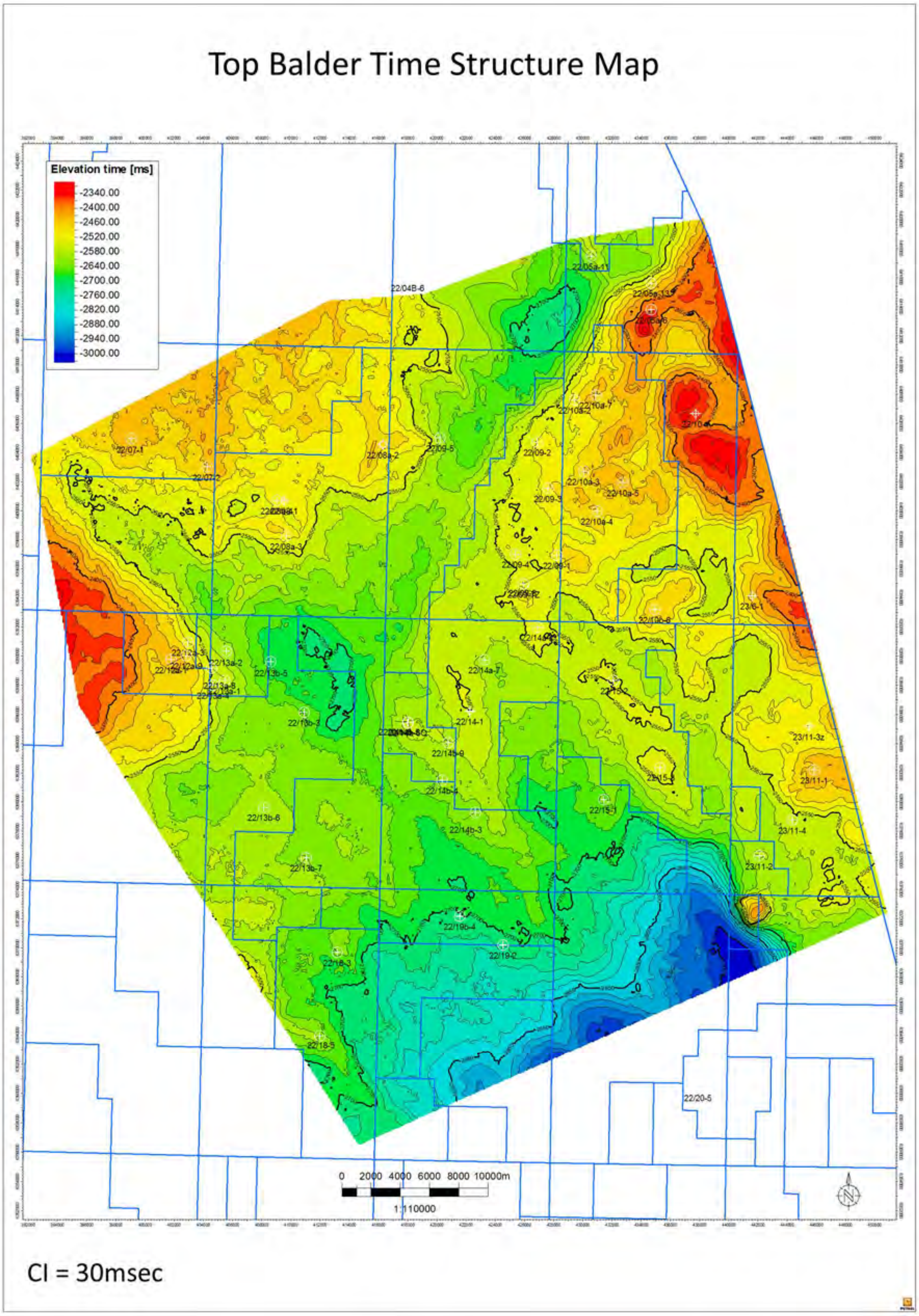


Figure 11-7 Top Balder time structure map

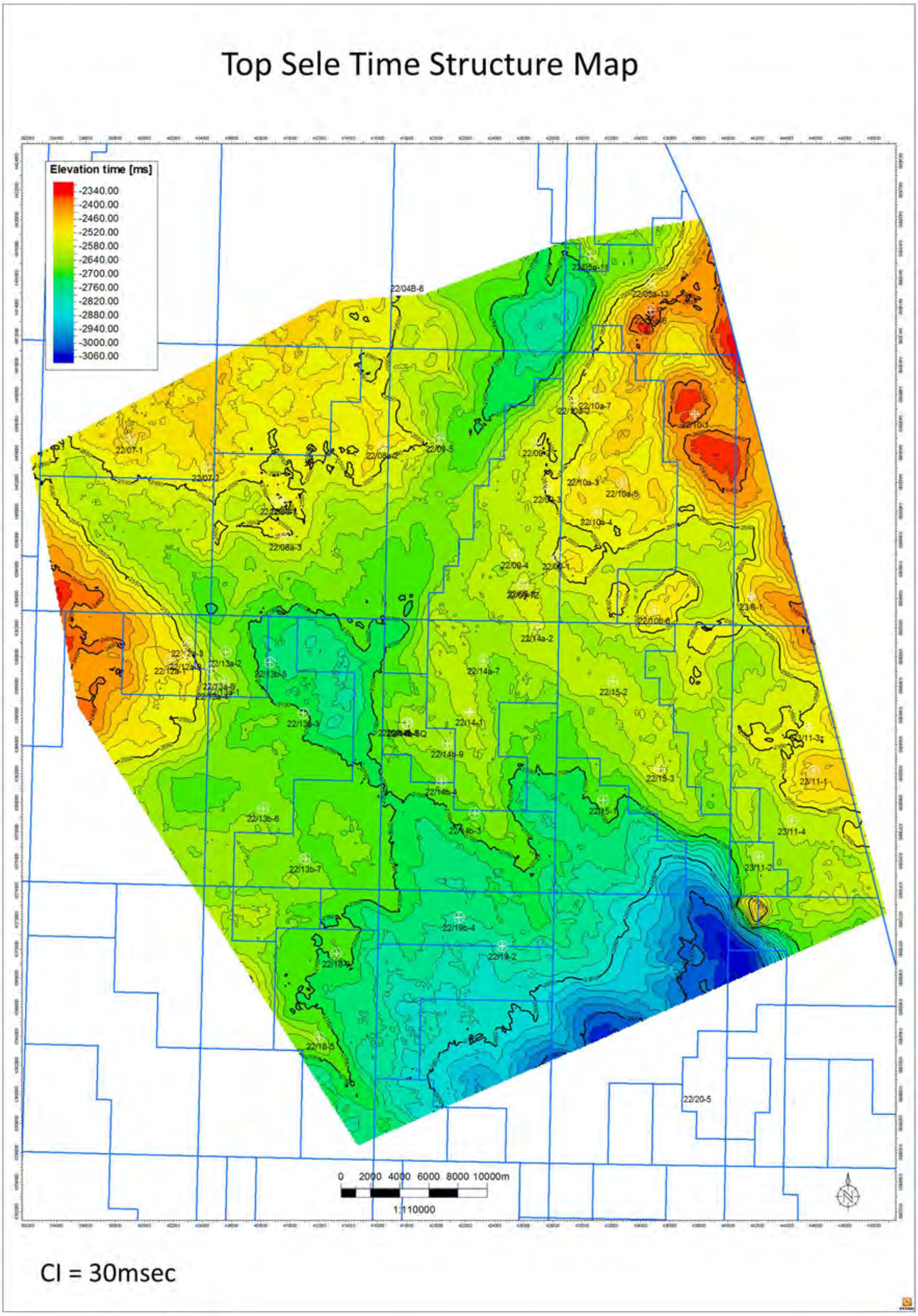


Figure 11-8 Top Sele time structure map

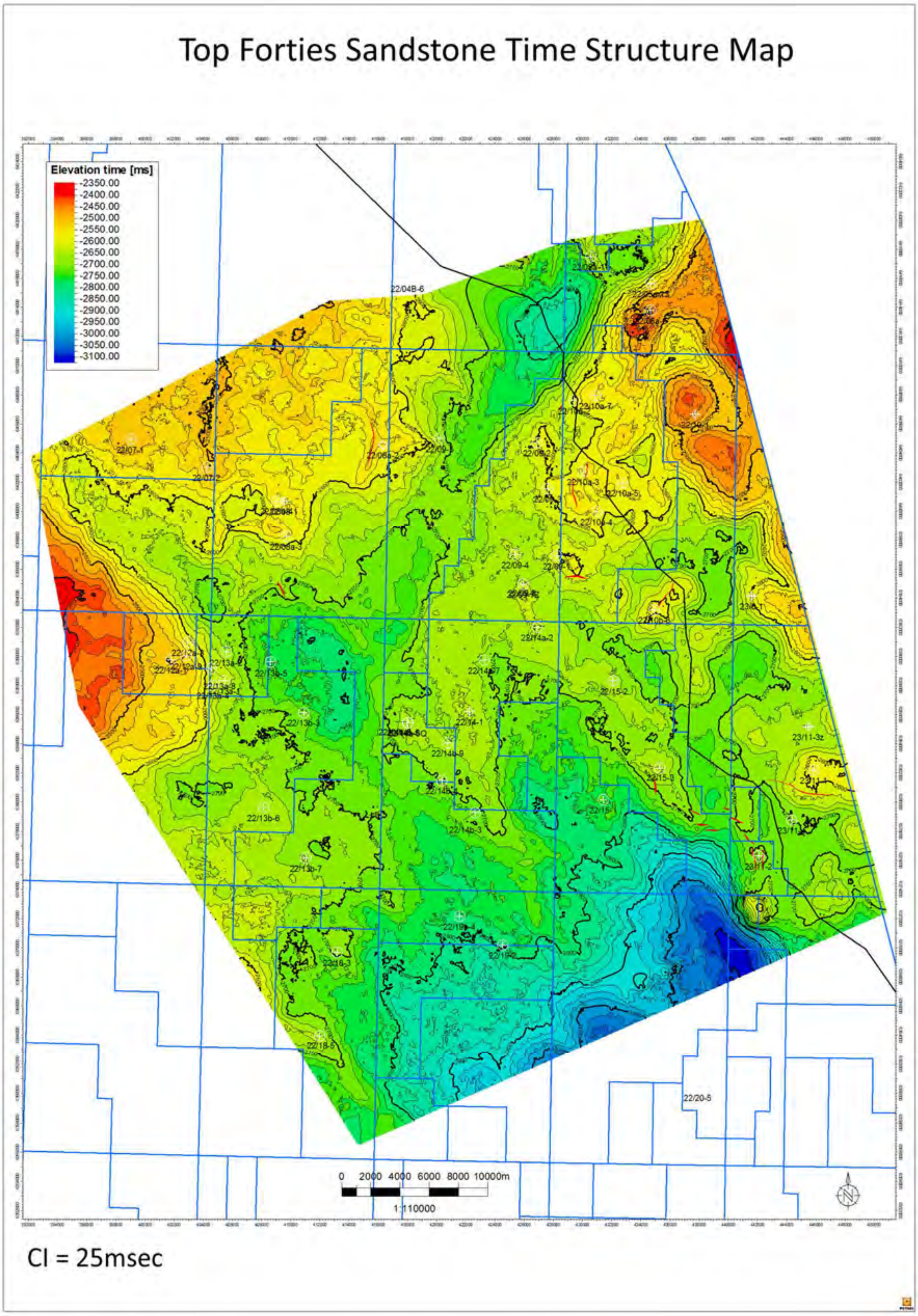


Figure 11-9 Top Forties Sandstone time structure map

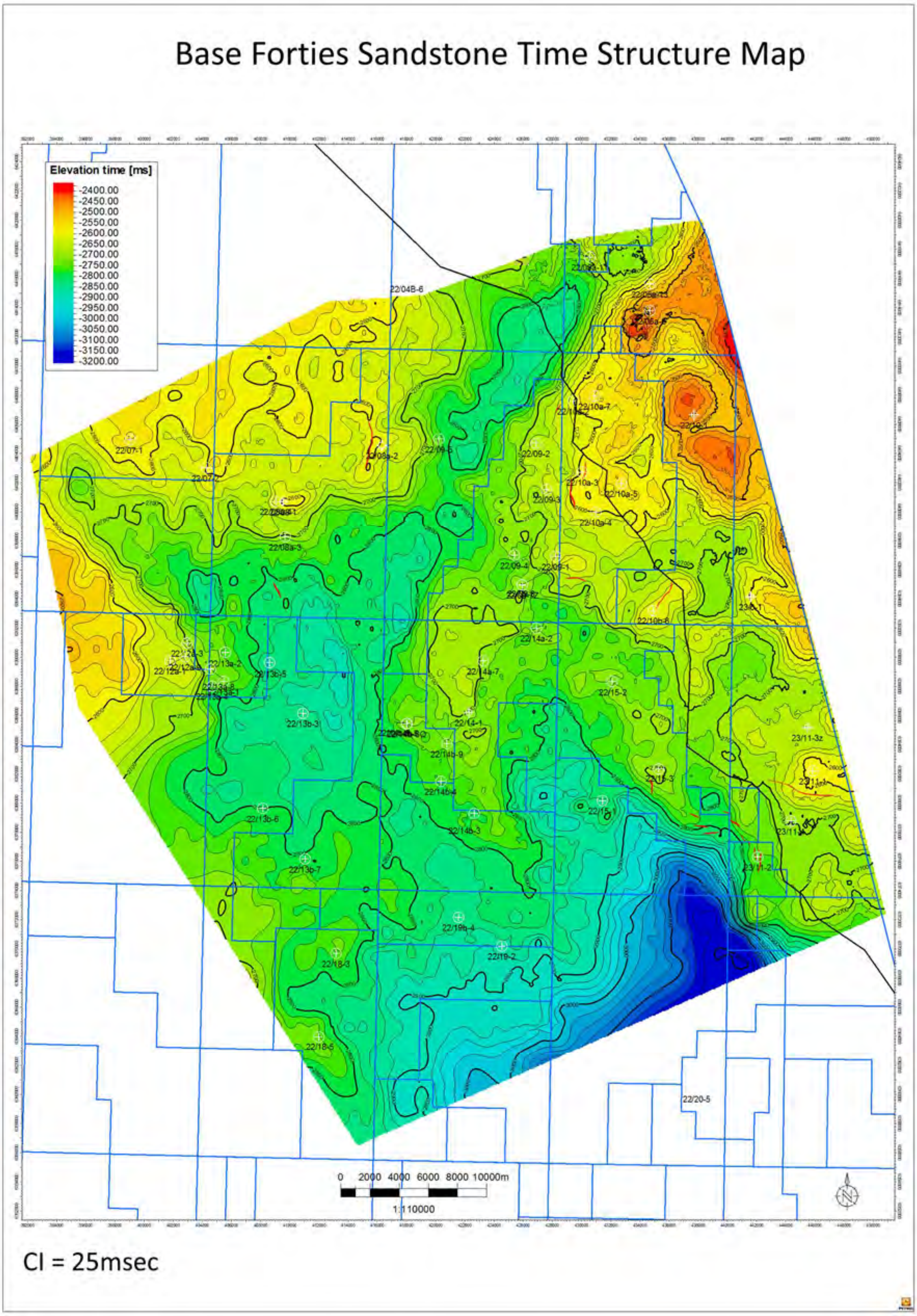


Figure 11-10 Base Forties Sandstone time structure map

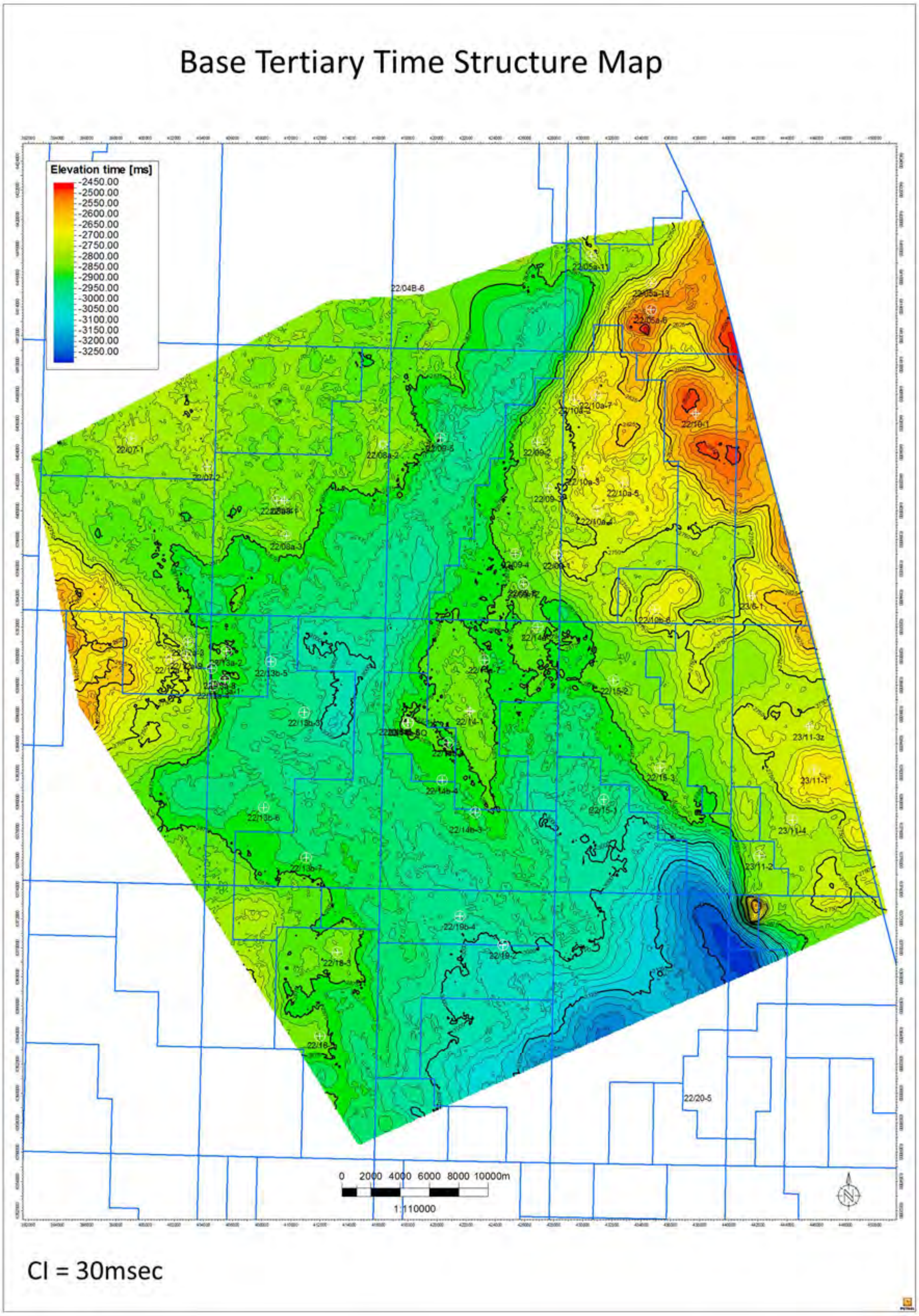


Figure 11-11 Base Tertiary time structure map

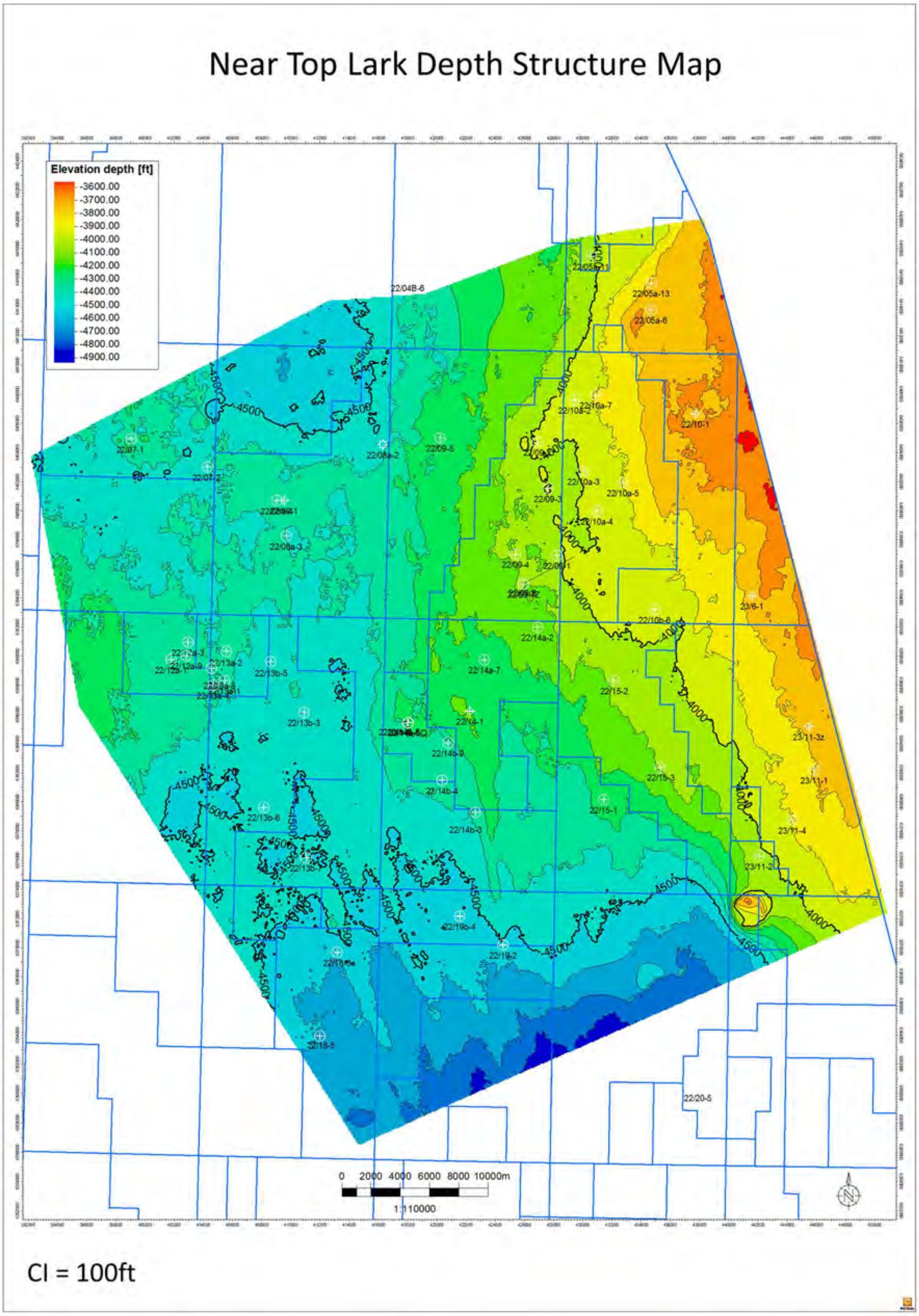


Figure 11-12 Near Top Lark depth structure map

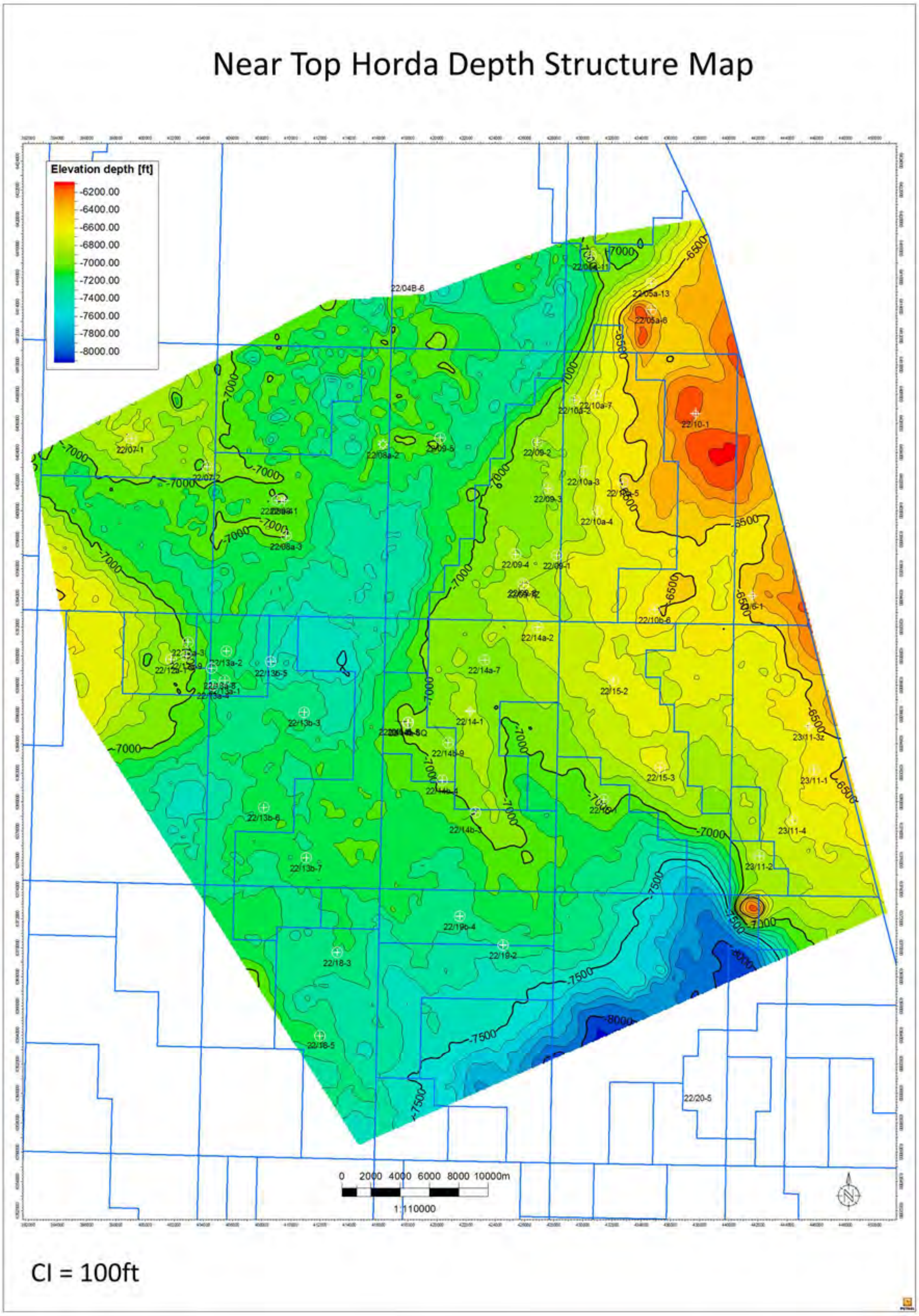


Figure 11-13 Near Top Horda depth structure map

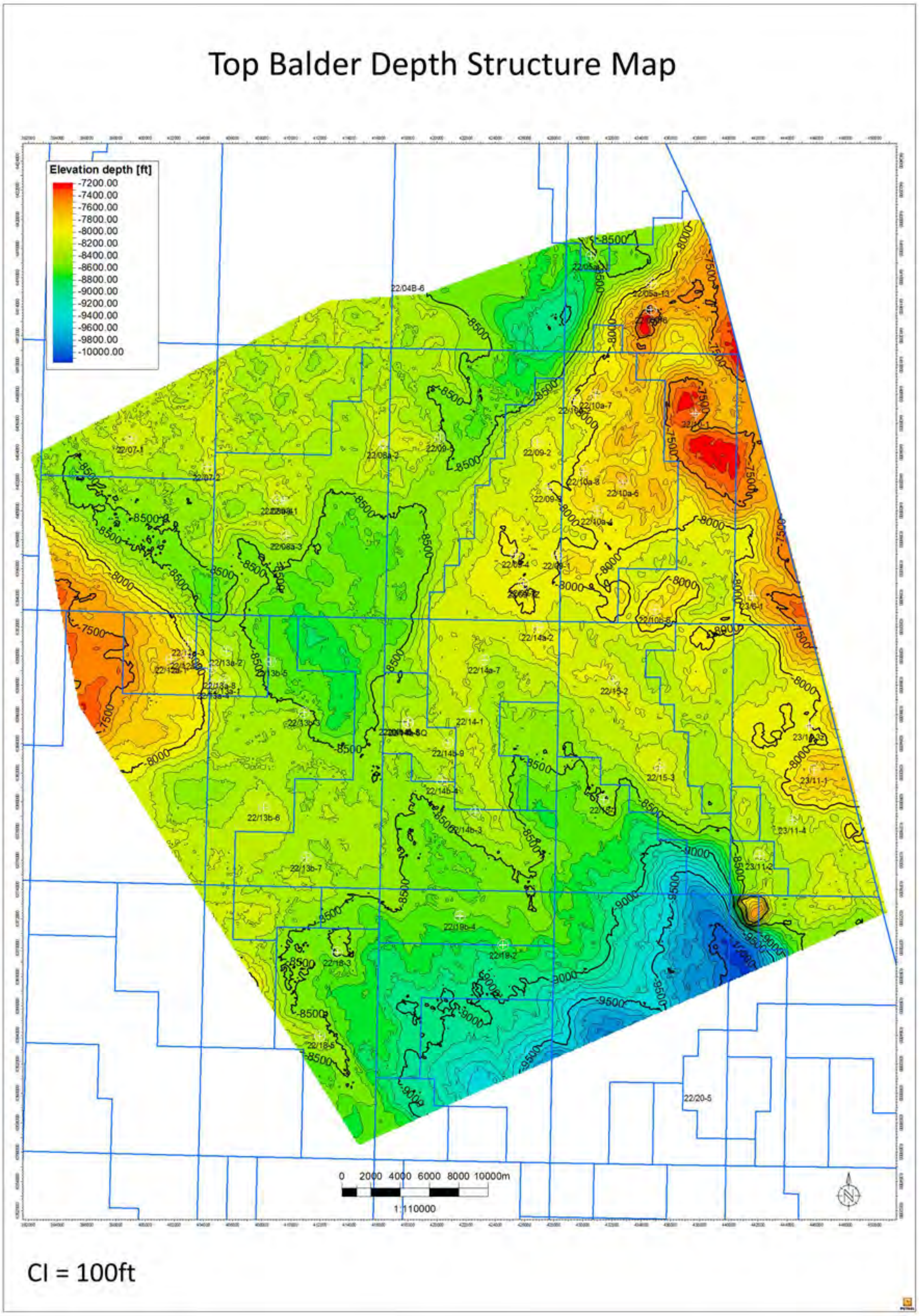


Figure 11-14 Top Balder depth structure map

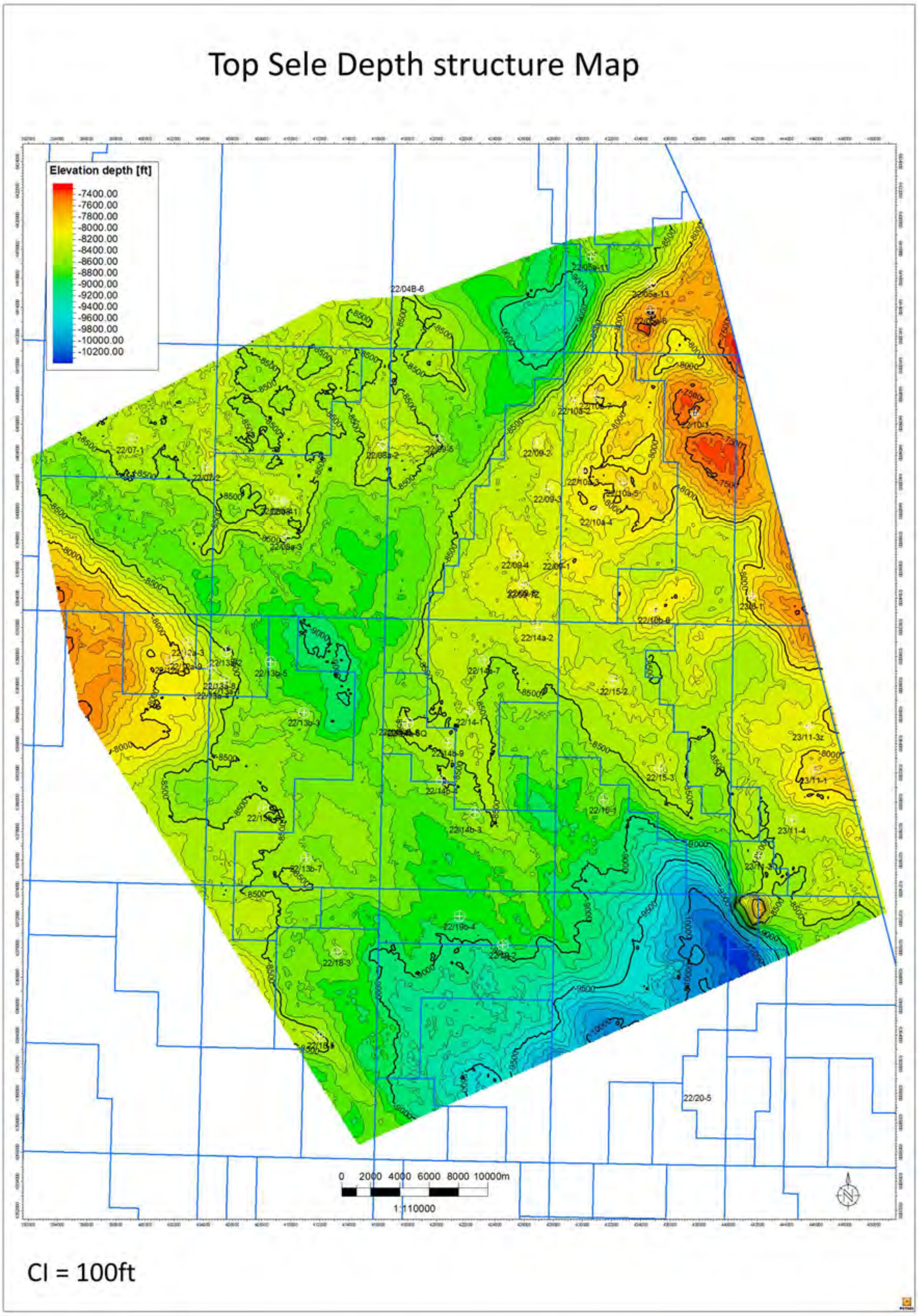


Figure 11-15 Top Sele depth structure map

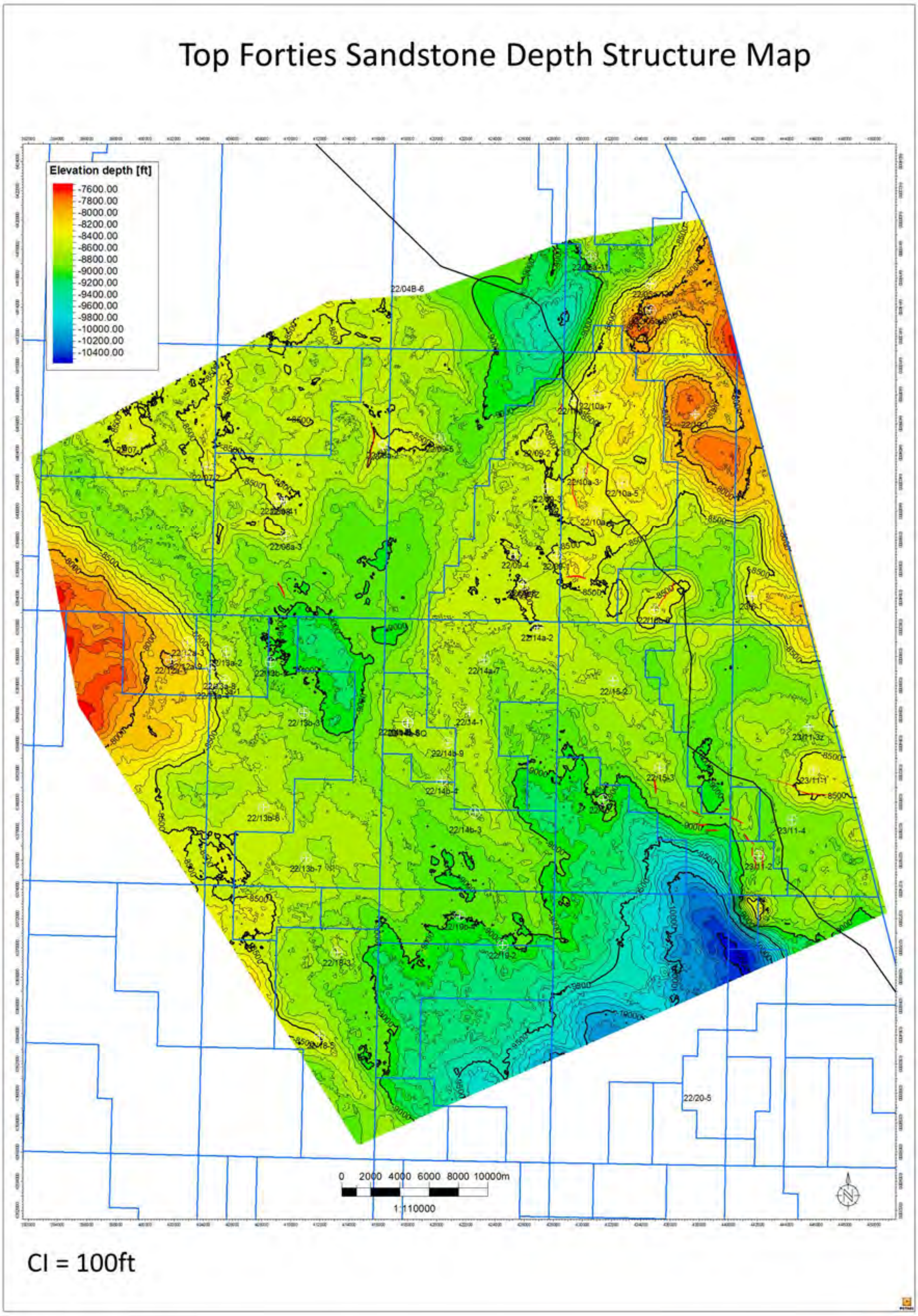


Figure 11-16 Top Forties Sandstone depth structure map

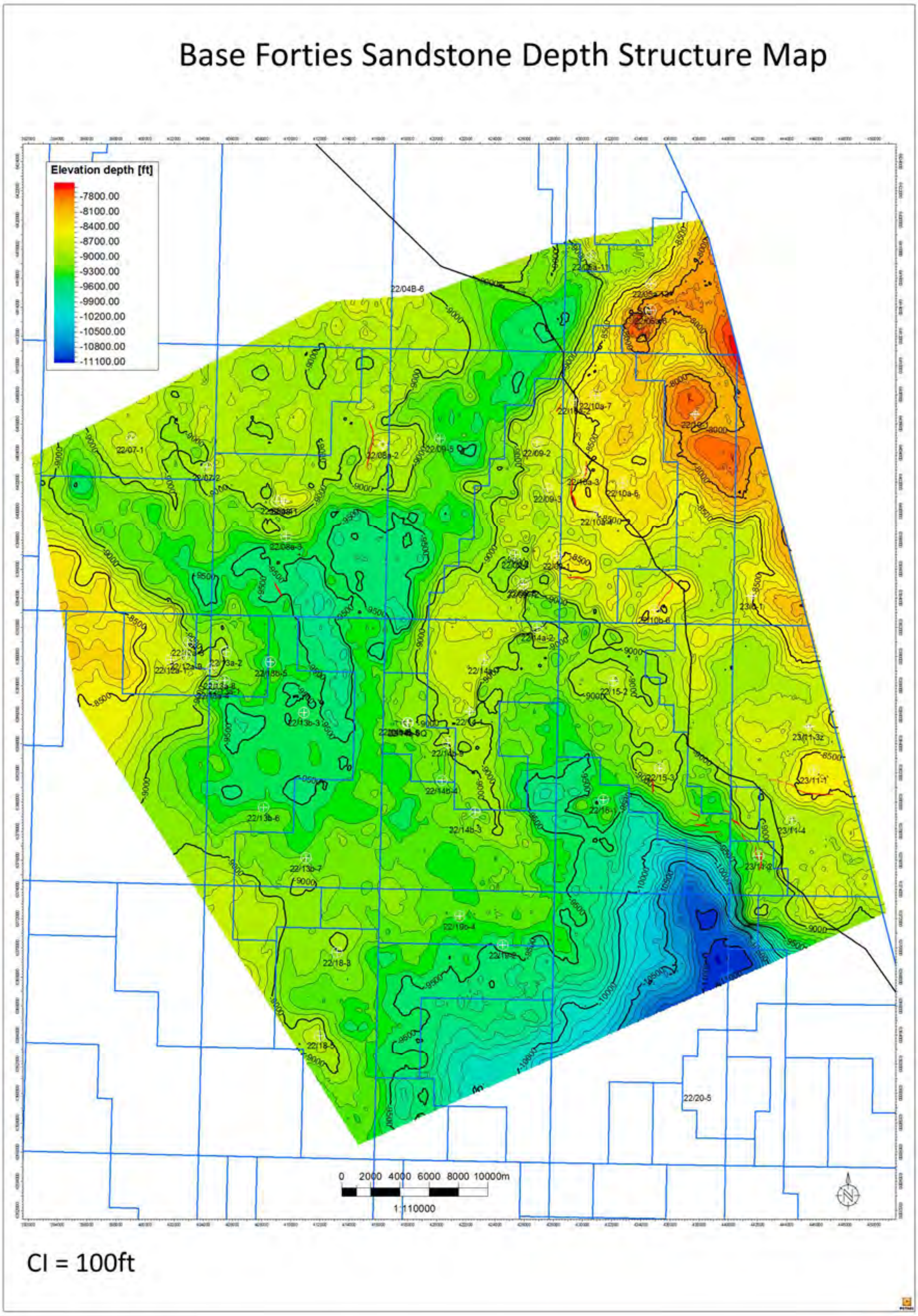


Figure 11-17 Base Forties Sandstone depth structure map

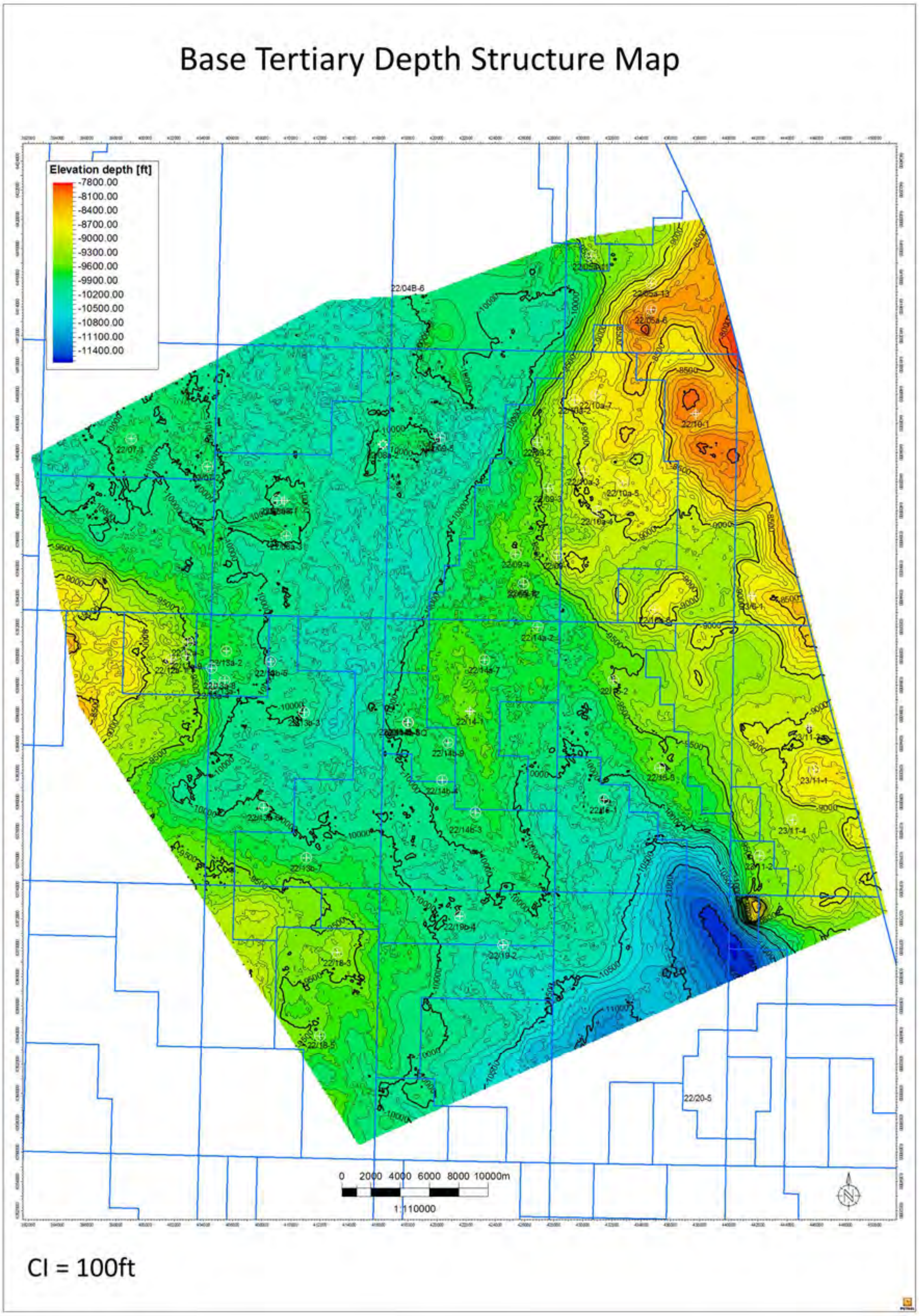


Figure 11-18 Base Tertiary depth structure map

11.4.2 CPI logs

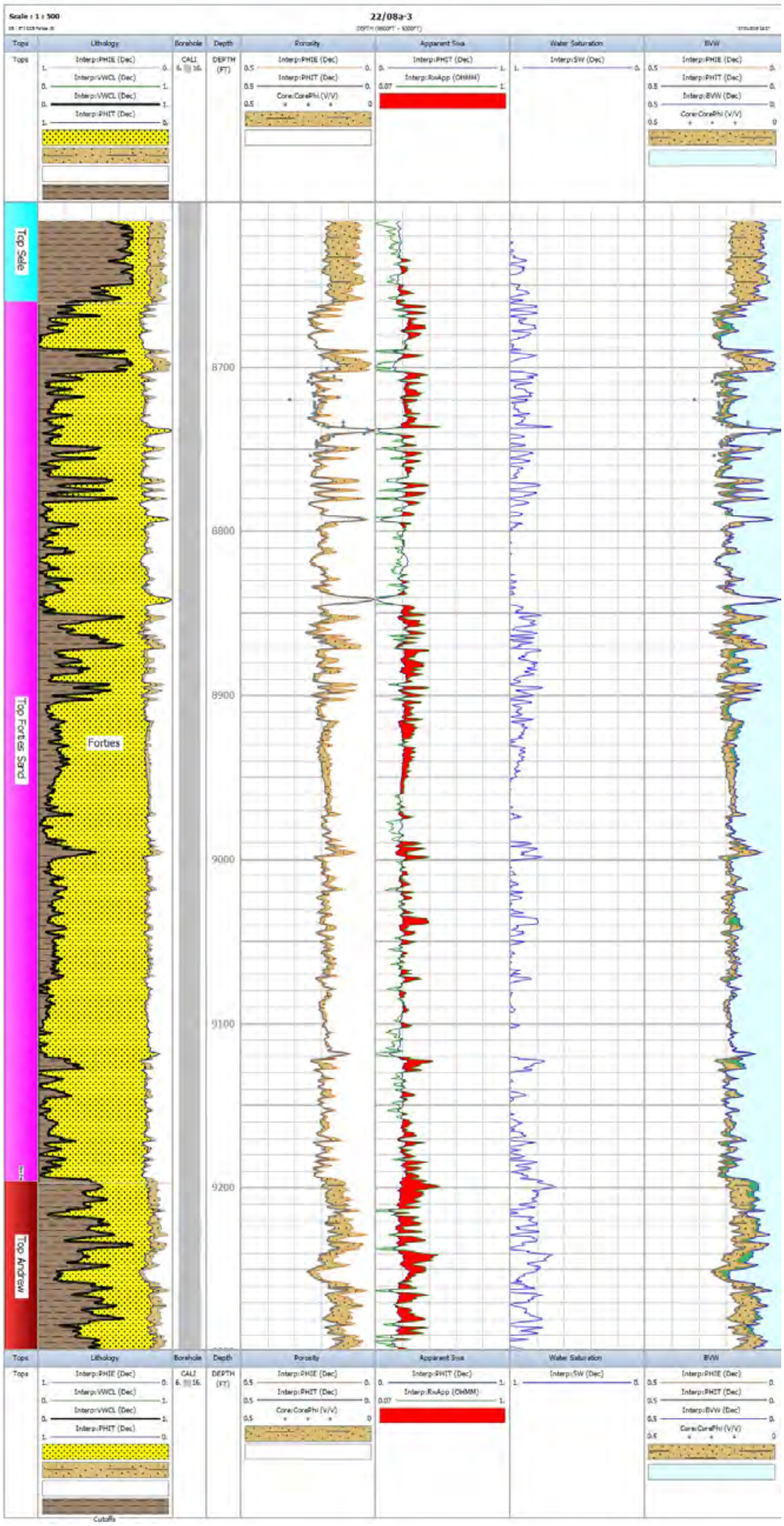


Figure 11-19 Well 22/08a-3

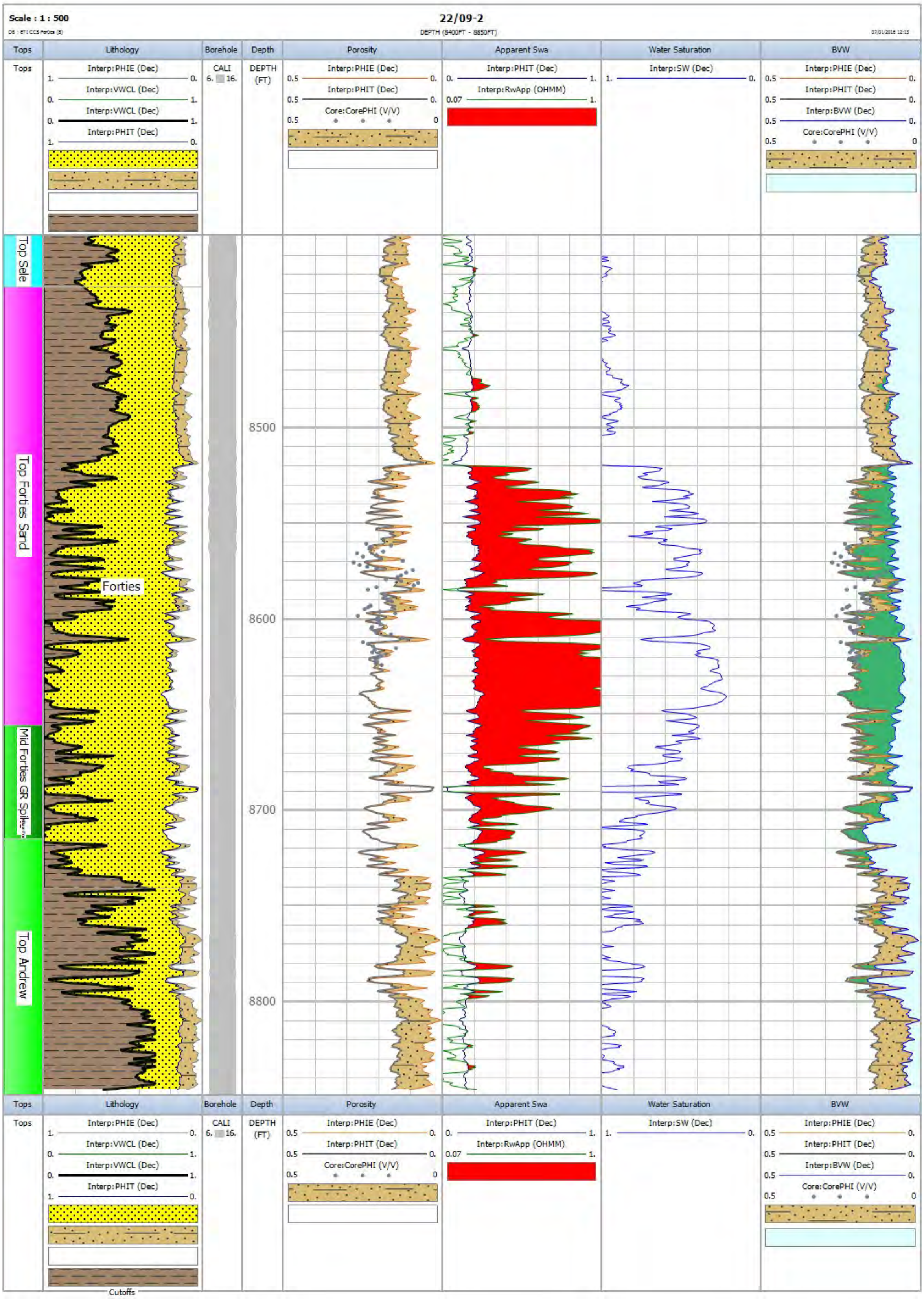


Figure 11-20 Well 22/09-2

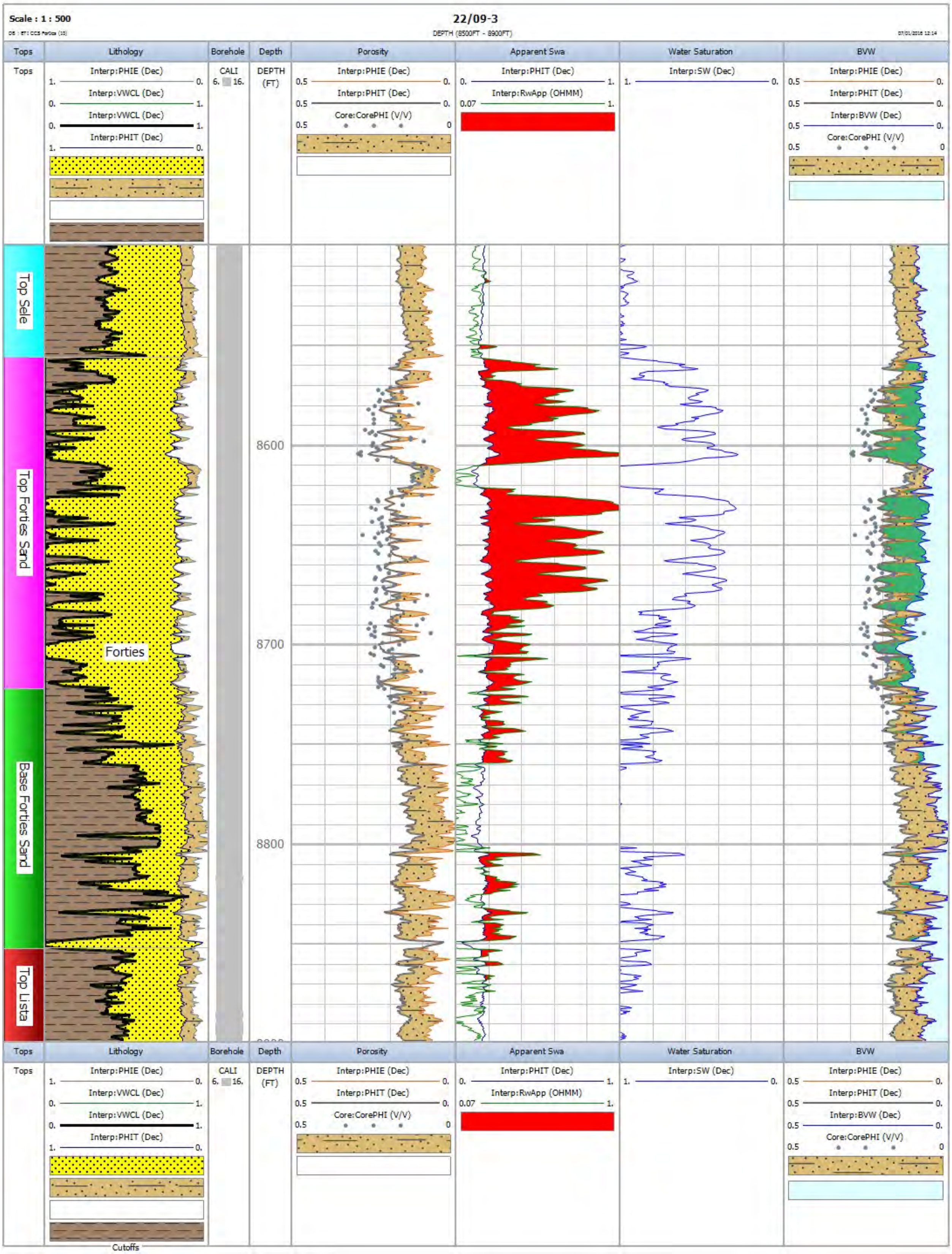


Figure 11-21 Well 22/09-3

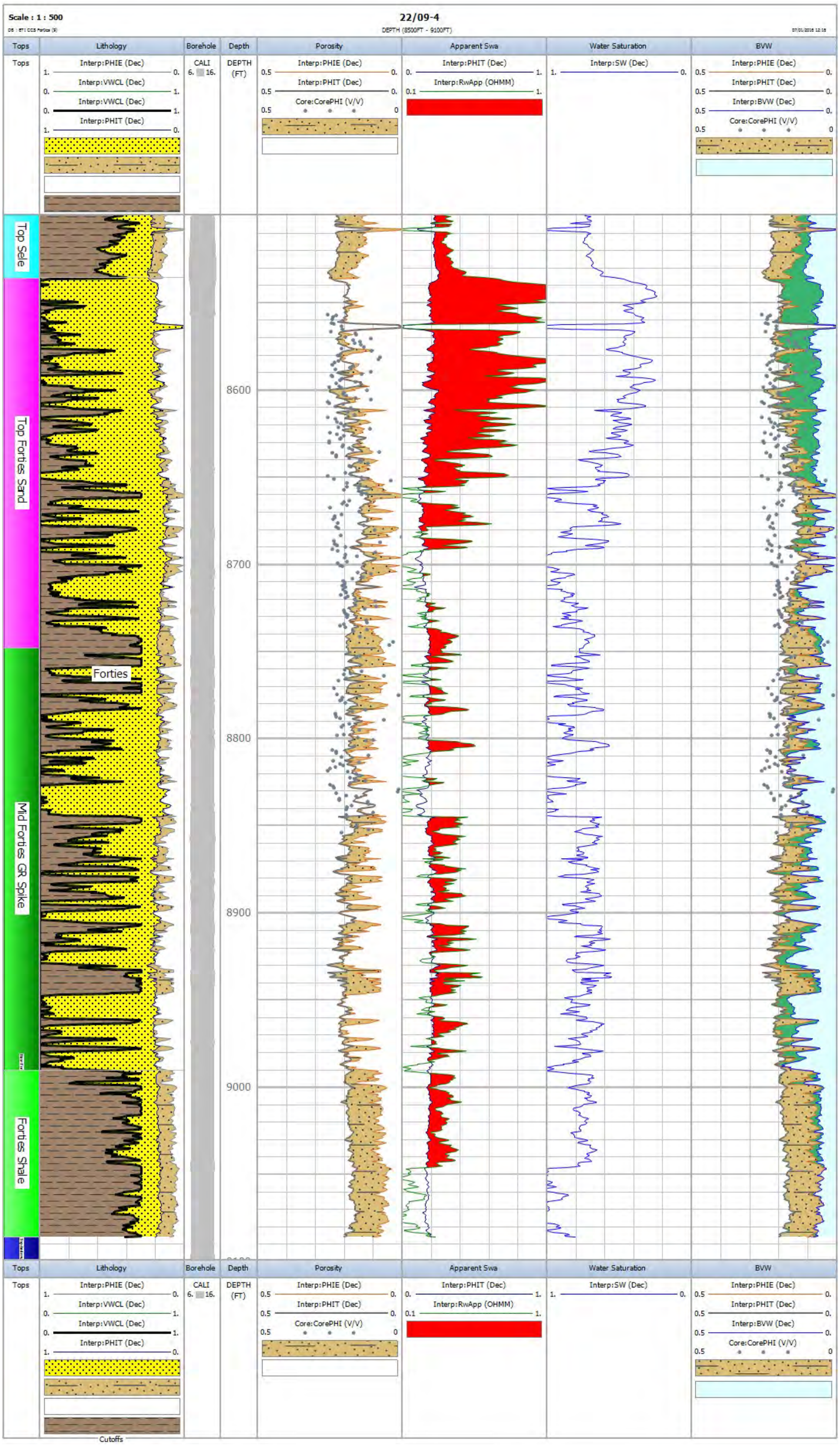


Figure 11-22 Well 22/09-4

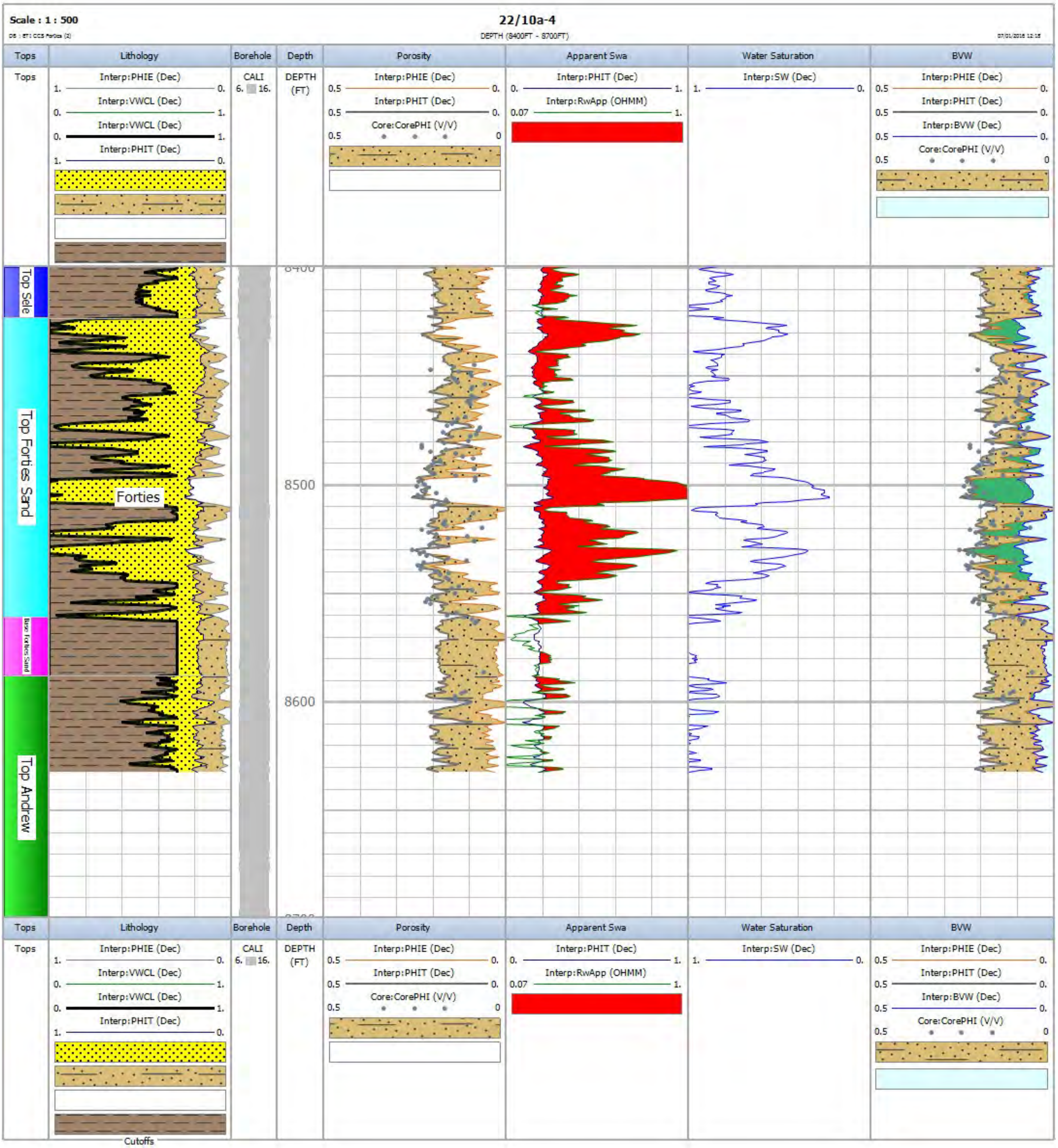


Figure 11-23 Well 22/10a-4

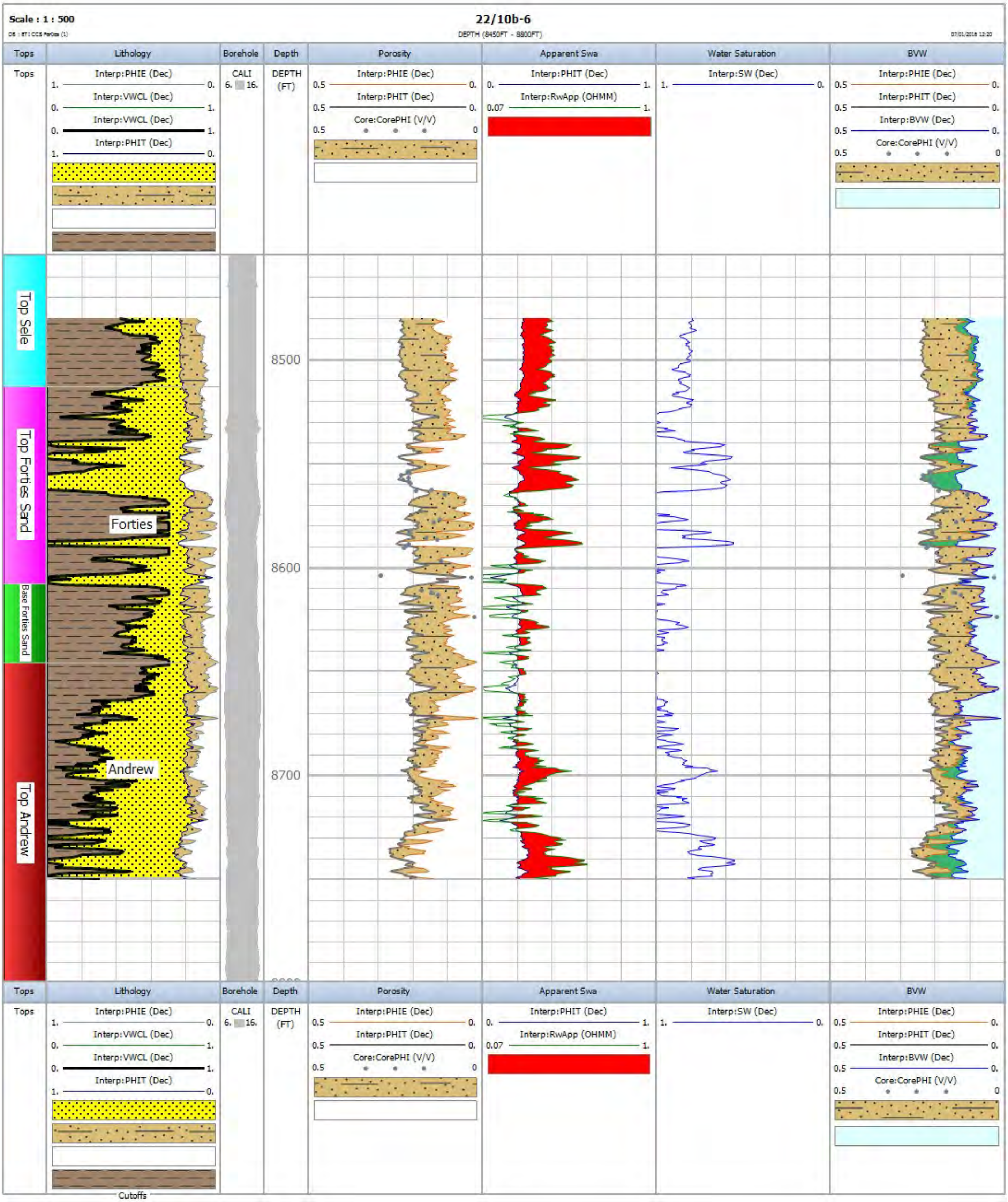


Figure 11-24 Well 22/10b-6

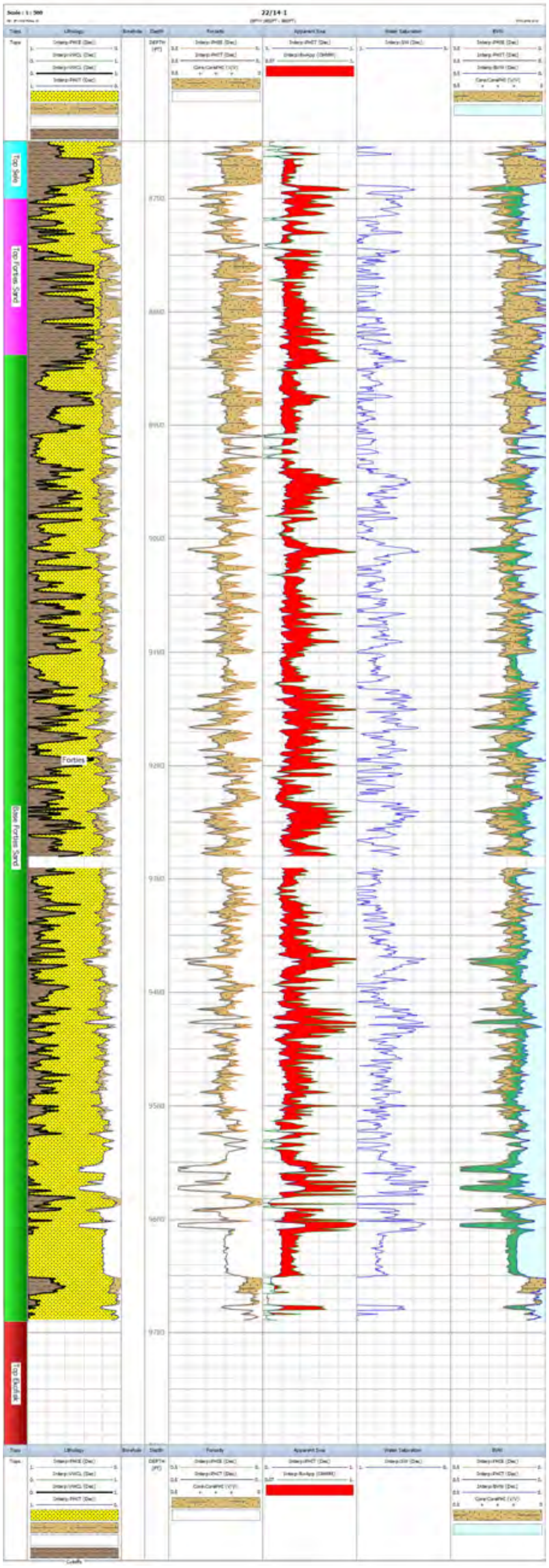


Figure 11-25 Well 22/14-1

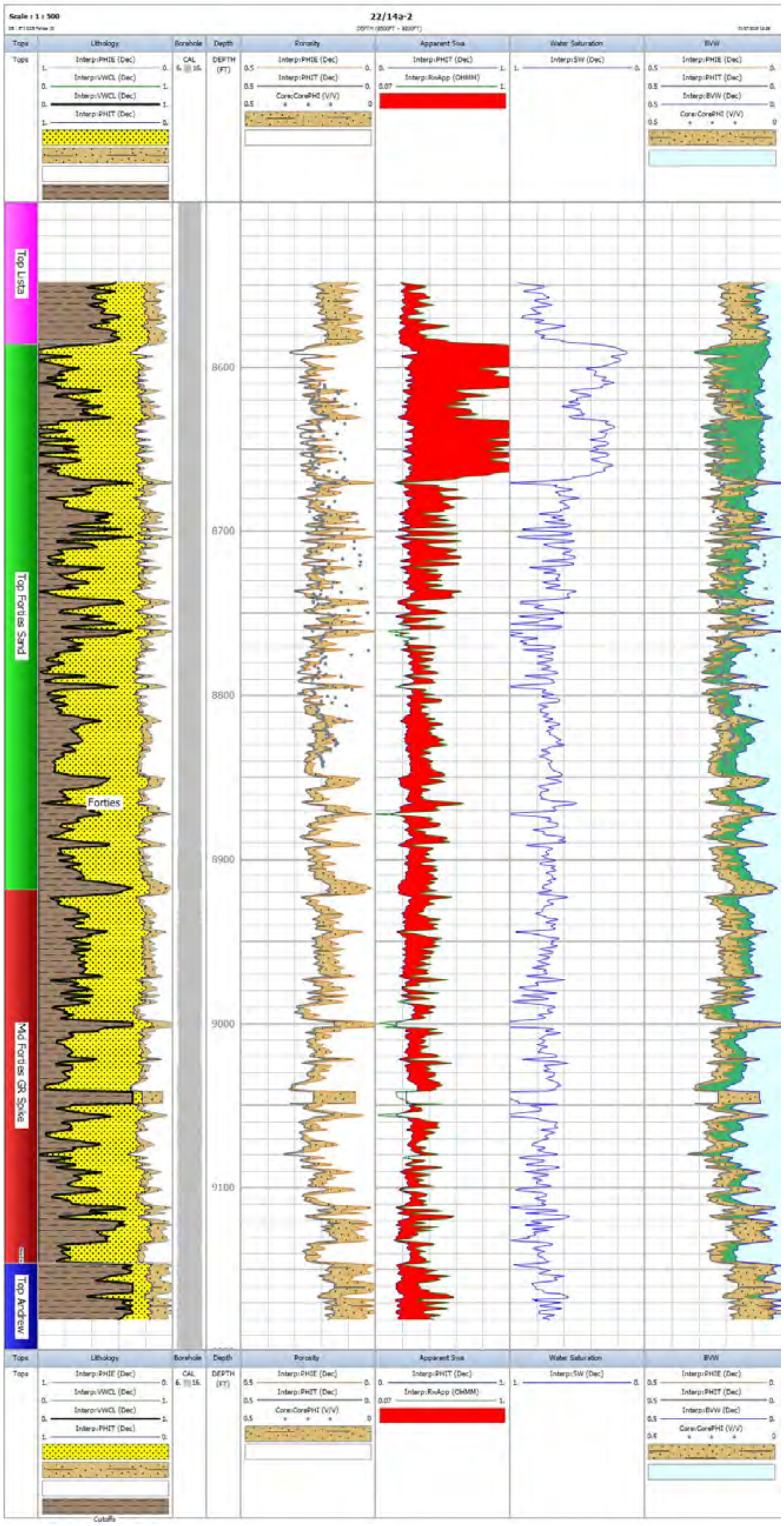


Figure 11-26 Well 22/14a-2

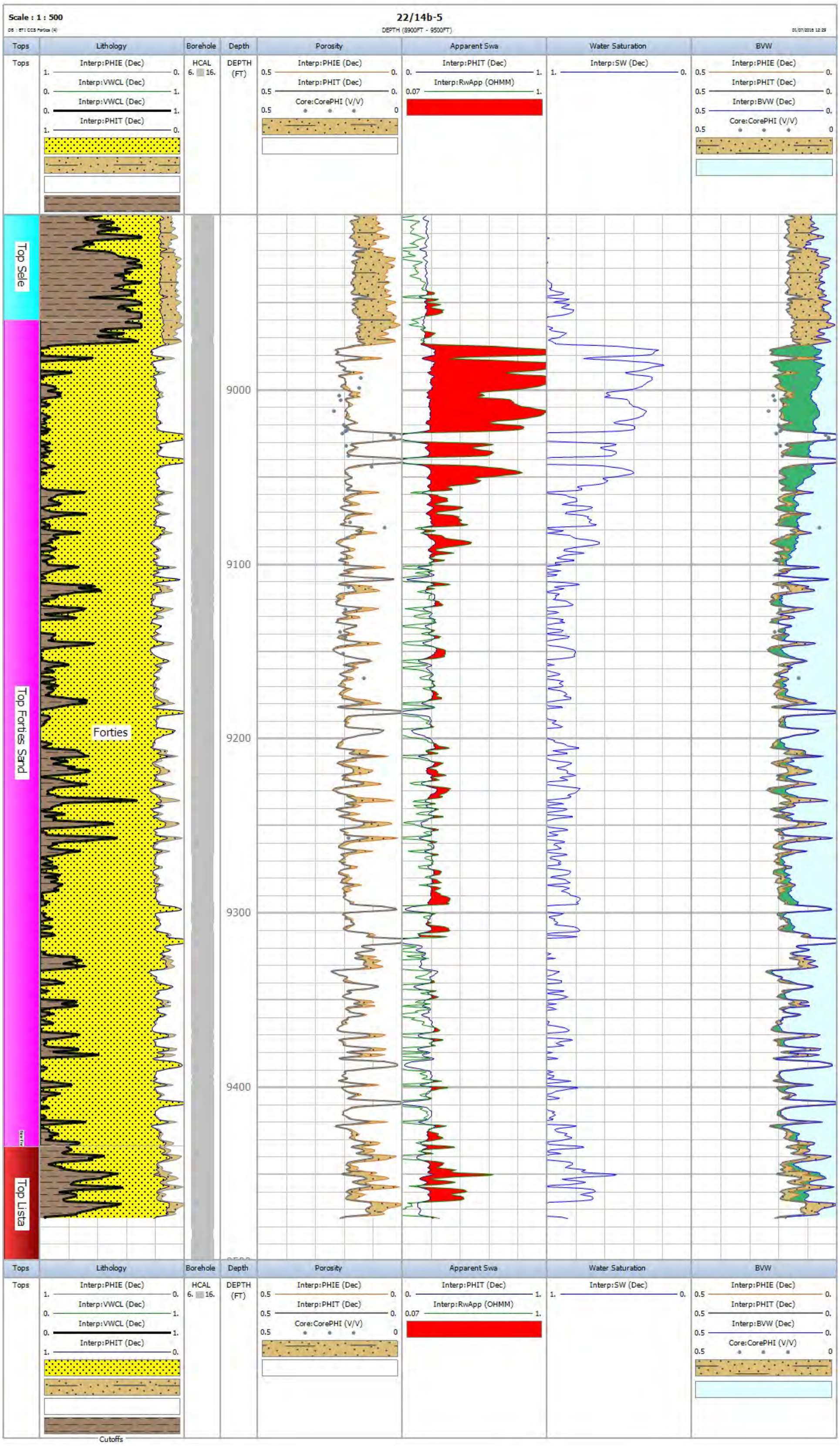


Figure 11-27 Well 22/14b-5

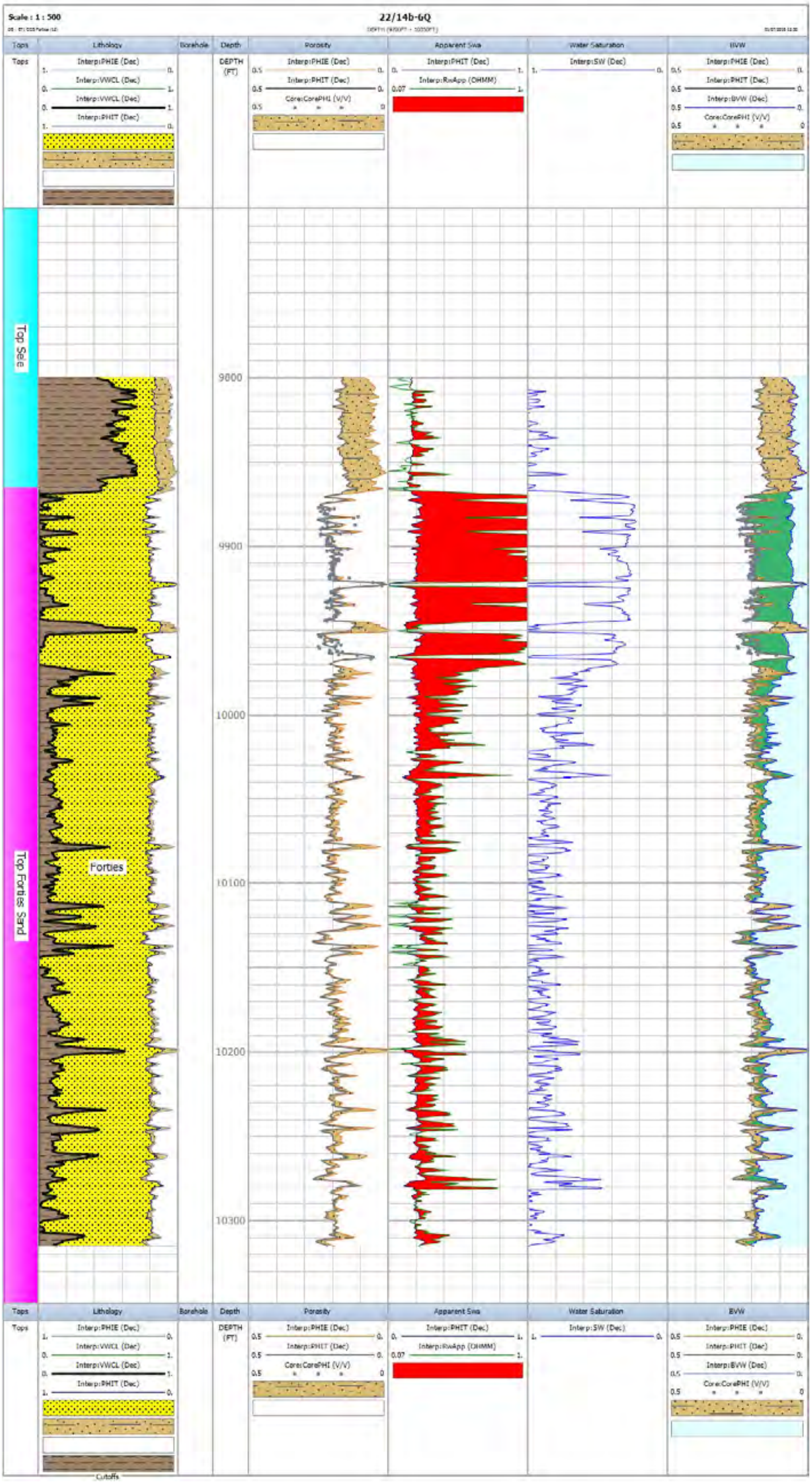


Figure 11-28 Well 22/14b-6Q

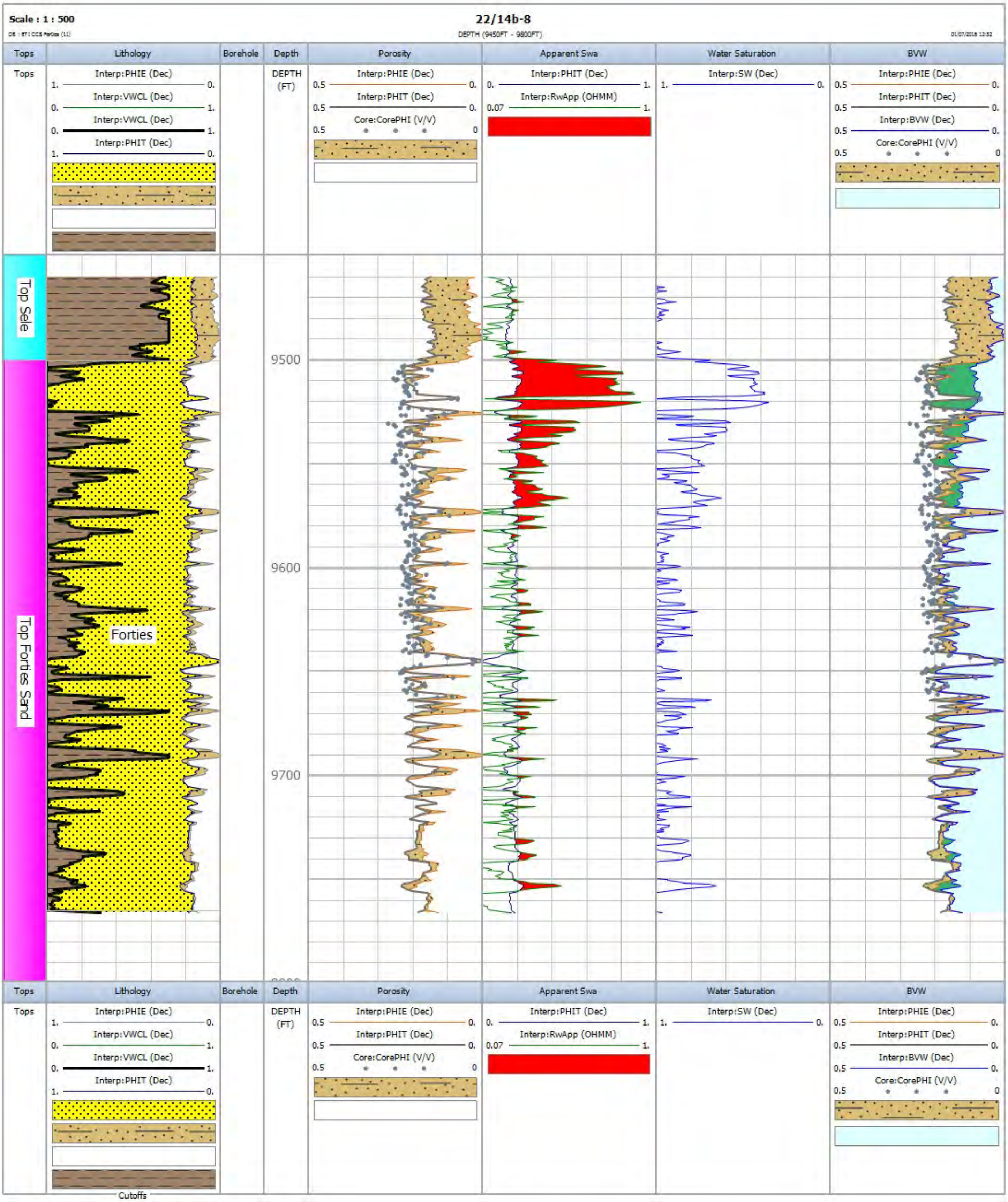


Figure 11-29 Well 22/14b-8

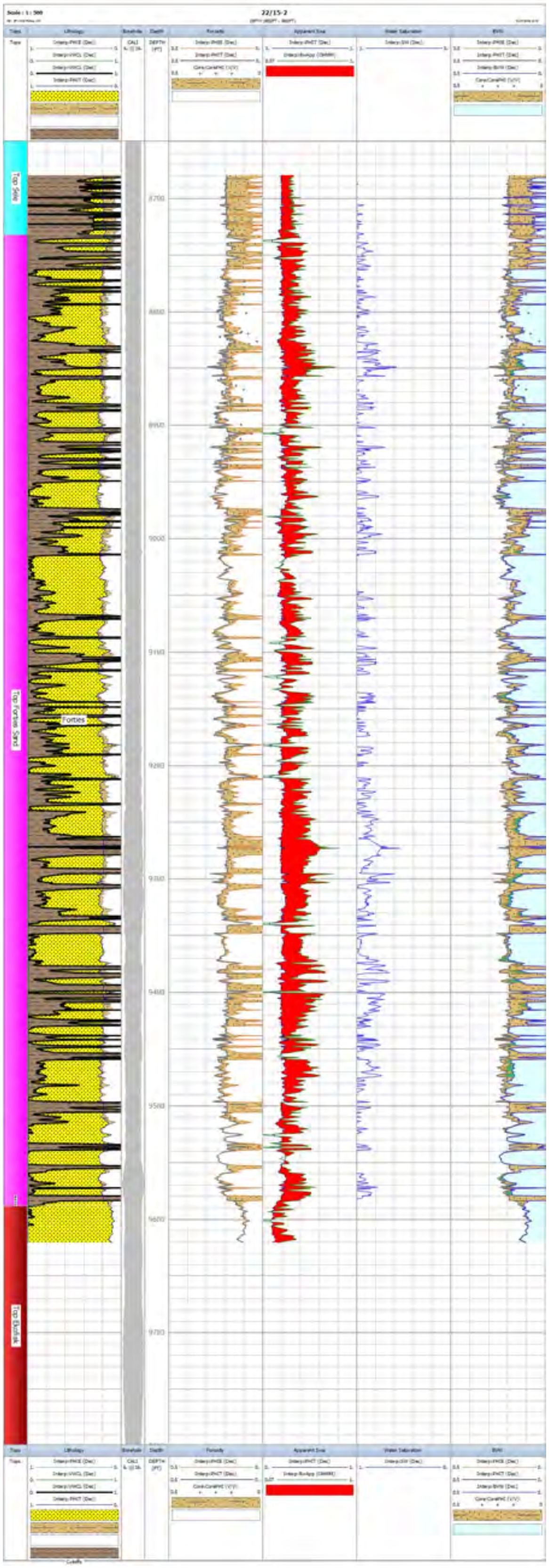


Figure 11-30 Well 22/15-2

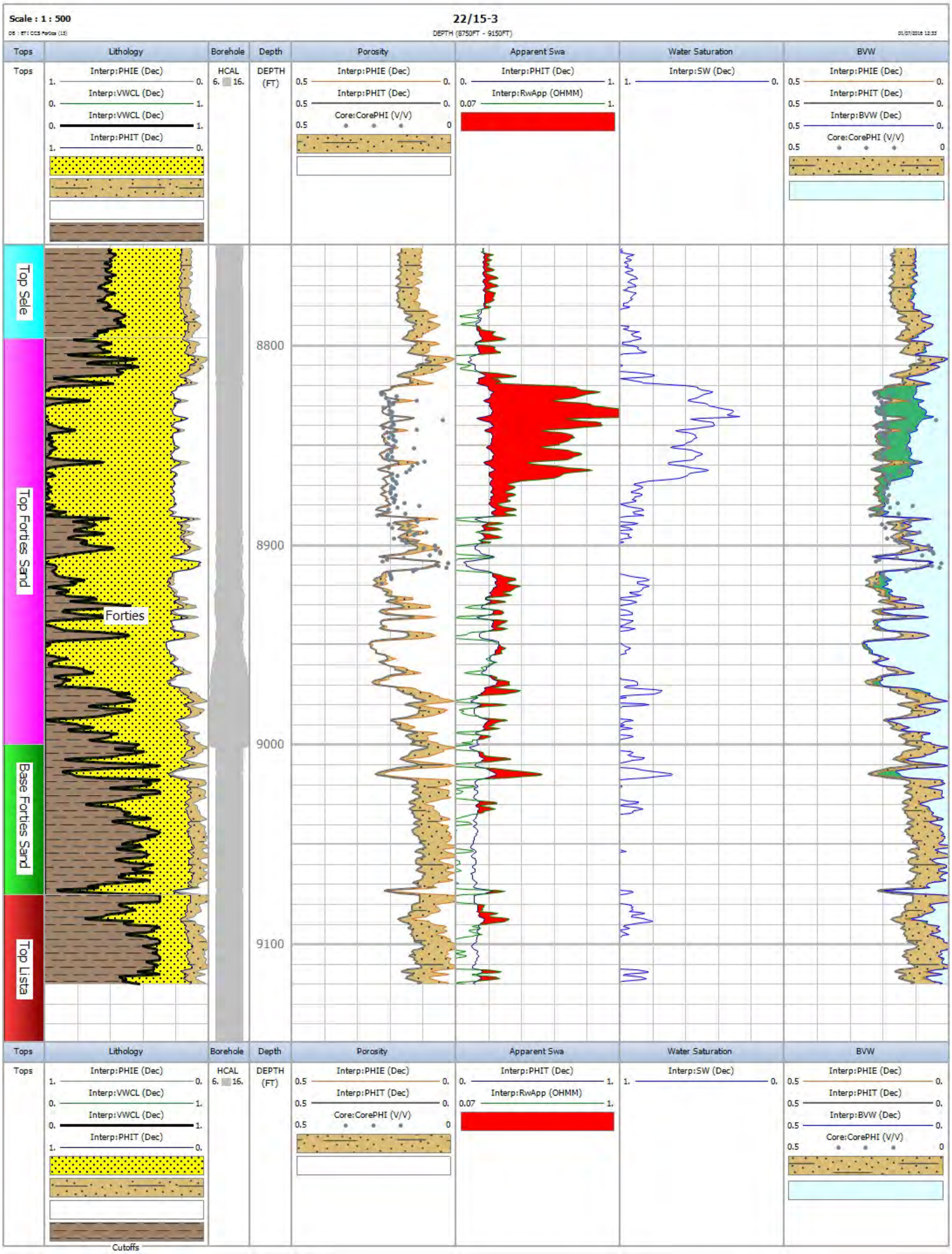


Figure 11-31 Well 22/15-3

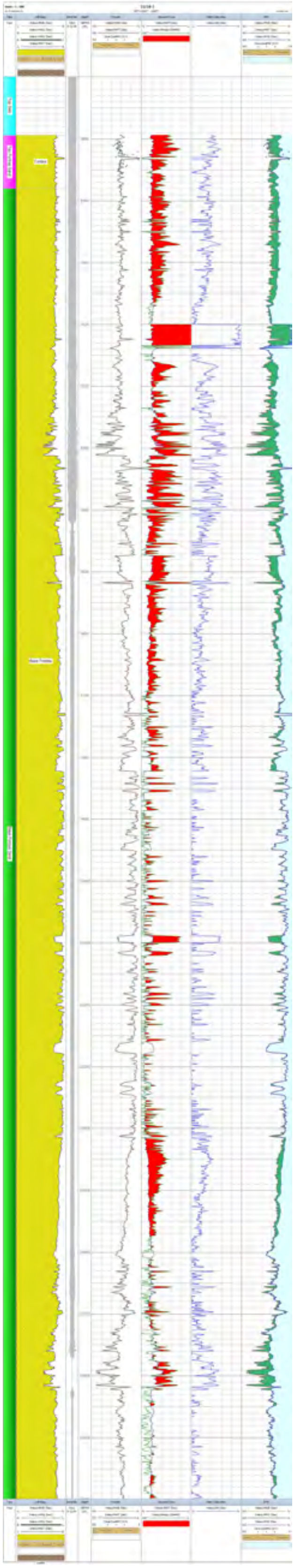


Figure 11-32 Well 22/18-3

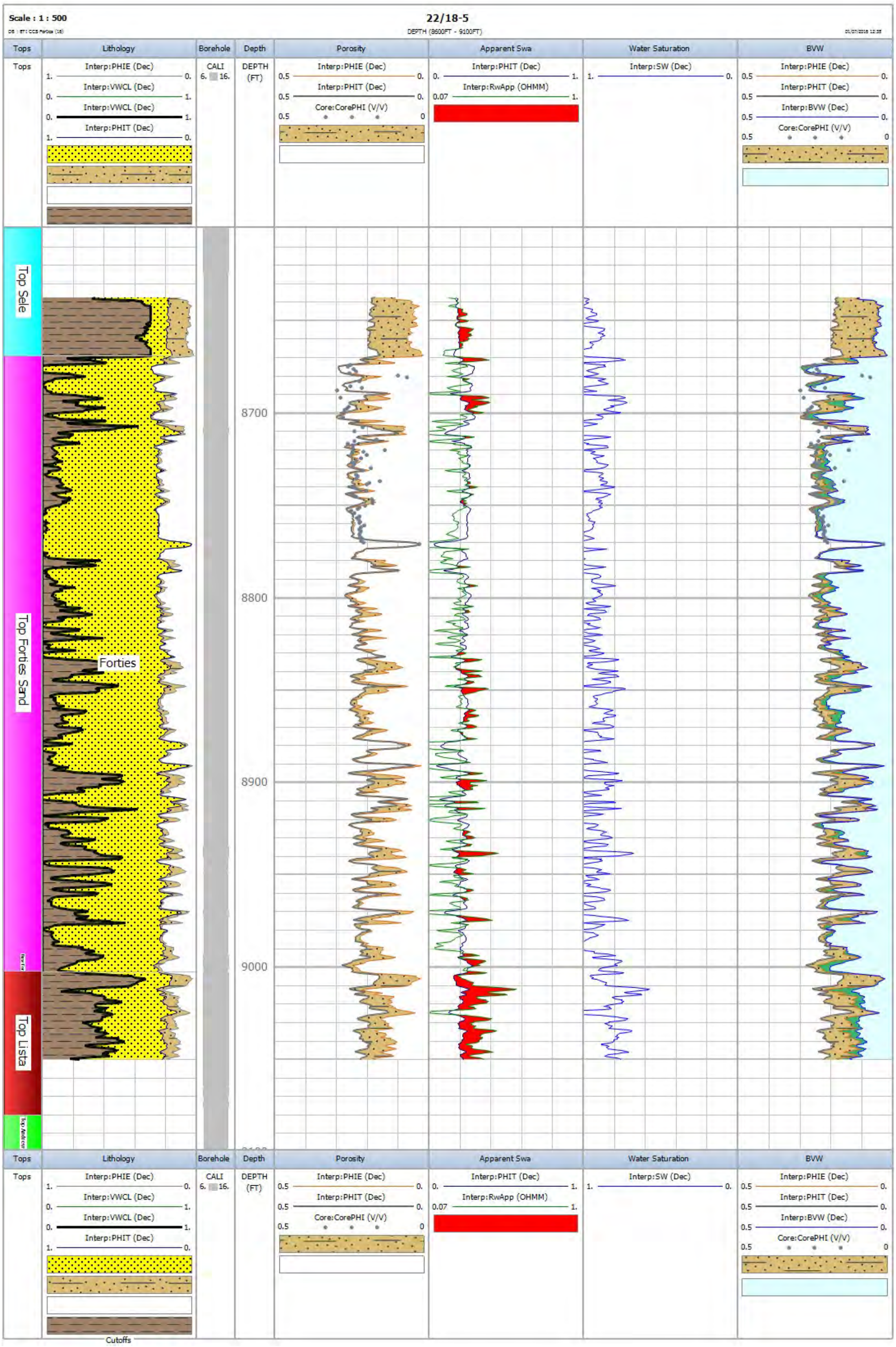


Figure 11-33 Well 22/18-5

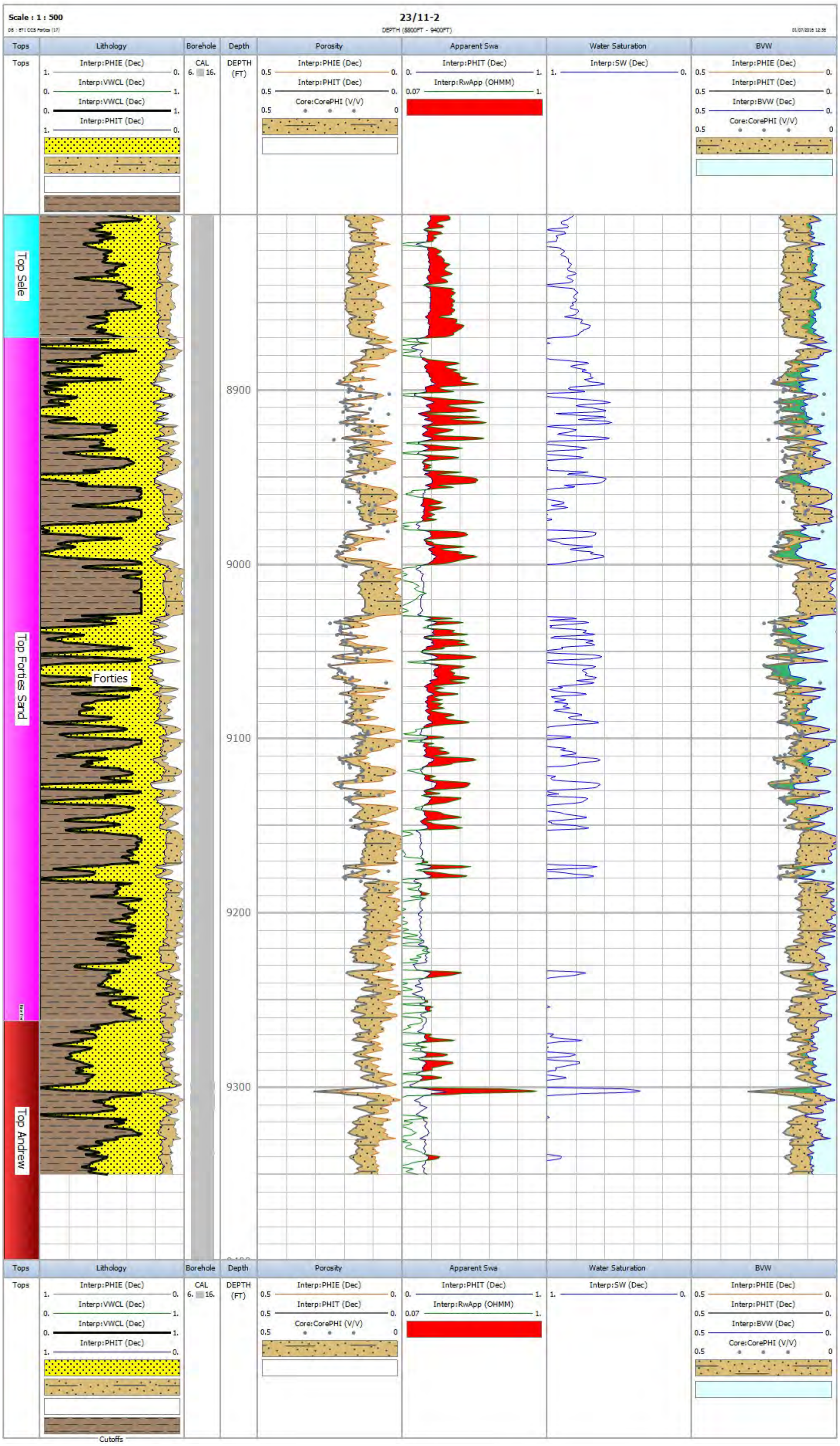


Figure 11-34 Well 22/11-2

11.5 Appendix 5 – MMV Technologies & Corrective Measures

11.5.1 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 (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.

11.5.1.3 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 Quantification of CO_2 leakage

Table 11-8 Monitoring domains

11.5.2 Monitoring Technologies

Many technologies which can be used for offshore CO2 storage monitoring are well established in the oil and gas industry.

Monitoring of offshore CO2 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).

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 CO2 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.

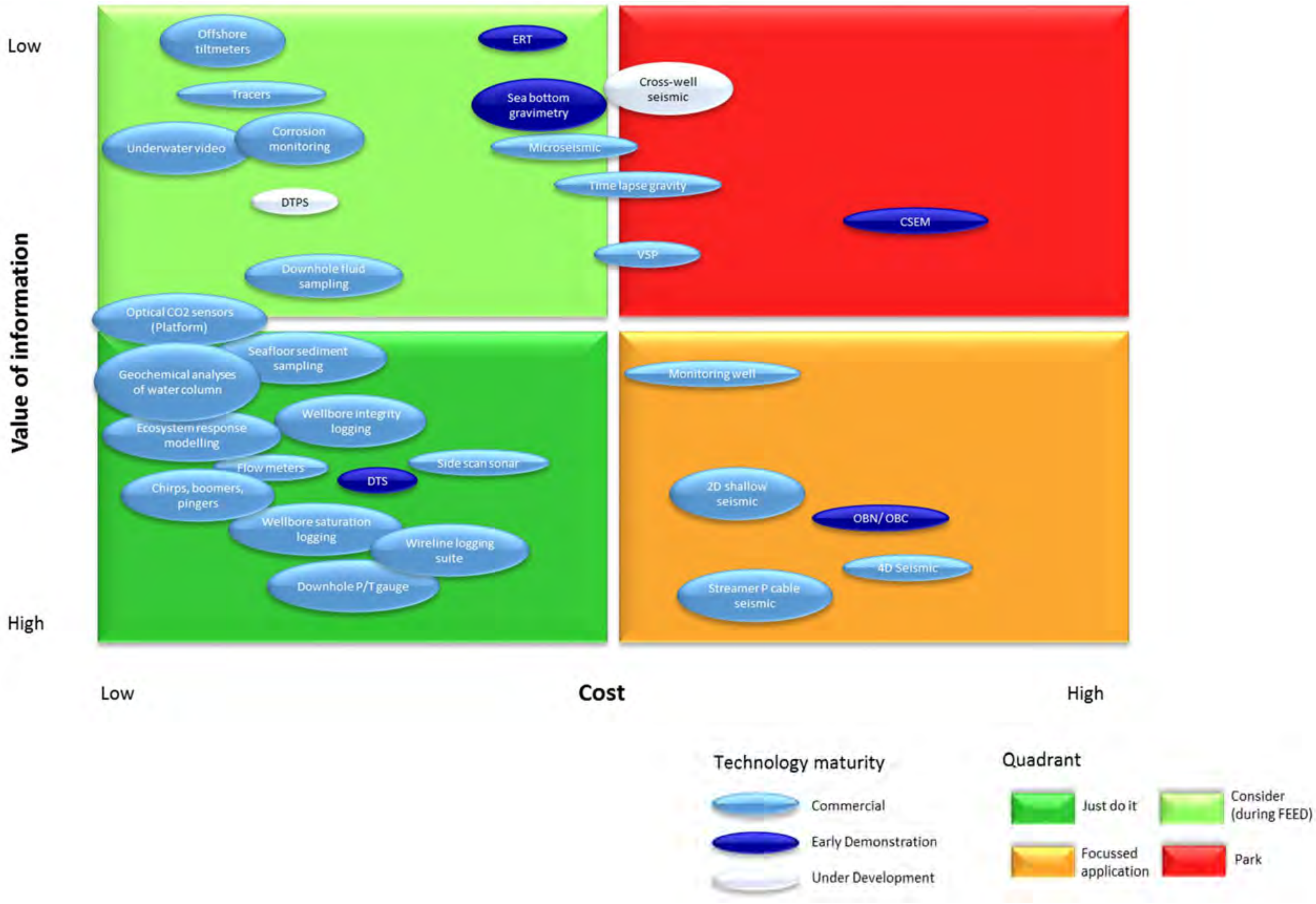


Figure 11-35Boston square plot of monitoring technologies applicable offshore

11.5.3 Technologies for monitoring offshore

The table below 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 CO2 due to velocity contrasts between CO2 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 CO2 (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.
Subsurface	Wireline Logging Tool	Commercial	Pulsed neutron tool (PNT)	Platform and subsea	A standard wireline tool using pulsed neutron techniques to measure CO2 saturation. Sensitive to changes in reservoir fluids and can distinguish between brine, oil and CO2. PNT will not detect CO2 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 CO2	Just do it	Considered essential to ensure integrity of injection

Monitoring Domain	Type	Field Readiness	Technology	Applicability to Offshore	Description	Boston Square Box	Comments/ rationale
					migration from reservoir with associated temperature drop or any fluid temperature fluctuations which could indicate a poorly sealed wellbore.		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.
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.
Subsurface	Permanent Downhole Tool		Subsurface Fluid Sampling	Platform and subsea	Collection of liquid or gas samples via wells (from either reservoir or overlying formation) for geochemical analysis	Consider	Moderate cost and can be conducted during wireline

Monitoring Domain	Type	Field Readiness	Technology	Applicability to Offshore	Description	Boston Square Box	Comments/ rationale
			and Tracer 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.		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.
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.
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	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
					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.		
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.
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.

Monitoring Domain	Type	Field Readiness	Technology	Applicability to Offshore	Description	Boston Square Box	Comments/ rationale
Seabed/ water column	Seabed Method	Commercial	Underwater Video	Platform and subsea	Recording and high definition images of bubbles and other features which could indicate CO2 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 CO2 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 CO2 volumes and therefore information benefit.
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 pCO2, dissolved O2 and other chemical components, any anomalous chemistry can be detected. Requires good baseline measurements and may have challenges detecting small quantities of CO2 due to dispersion.	Just do it	Relatively cheap and can be used to rule out loss of containment of CO2 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		CO2 soluble compounds injected along with the CO2 into the target formation. Act as a "fingerprint" for the CO2 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 CO2 content. The CO2 content may give insight into CO2 flux (if any) above abandoned wellbores which penetrate the storage complex. Requires a good baseline to detect CO2 above background levels.	Just do it	Relatively cheap and can be used to rule out loss of containment of CO2 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 - Cavity ring-down spectroscopy (CRDS): Sensors to measure continuous or intermittent CO_2 in air. . Work better over smaller areas and may be difficult to detect any CO_2 release from background CO_2 emissions. Relatively cheap and portable. - Non-dispersive infrared (NDIR) spectroscopy. CO_2 detectors for health and safety monitoring. - 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

11.5.4 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.

Baseline

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 **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 an area of 800km² around each injection site

Table 11-10 Baseline monitoring plan

Operational

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 **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 an area of 800km^2 around each injection site

Table 11-11 Operational monitoring plan

Post-Closure

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 **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 an area of 800km² around each injection site

Table 11-12 Post closure monitoring plan

11.5.5 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.

11.5.5.1.1 Well Containment Risks

This section examines the containment risks from wells in the Forties 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 (CO2 Storage Liabilities in the North Sea: An Assessment of the Risks and Financial Consequences; Summary Report (including Annexes) for DECC, 2012) (CO2 Wells: Guidelines for the Risk Management of Existing Wells at CO2 Geological Sites; DNV report 2011-0448, 2012) (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 (discussed earlier in this section). 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.

11.5.5.1.2 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.

11.5.5.1.3 Containment Risks and Remediation Options

The following tables catalogue the well containment failure mode and the associated effect, remediation and estimated cost. 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. 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. 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: - a failure of the liner packer or - failure of the liner above the production packer before there is pressured CO_2 in the A-annulus. Sustained CO_2 annulus pressure will be an unsustainable well integrity state and require remediation.	Repair by cement squeeze (possible chance of failure). Requires the completion to be retrieved and rerun (if installed).	\$3-5 million (5 days & tangibles). \$18-25 million (if a workover required).

ACTIVE WELL			
Risk Event	Effect	Remediation	Cost
Production Liner failure	Requires: - a failure of the liner above the production packer and - a failure of the cement sheath before there is pressured CO_2 in the A-annulus. 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. Requires the completion to be retrieved and rerun (if installed). Will change the casing internal diameter and may have an impact on the completion design and placement. Repair by side-track.	\$3-5 million (3 days & tangibles). \$18-25 million (if a workover required). Side-track estimated to be equal to the cost of a new well - \$55 million (60 days & tangibles).
Cement sheath failure (Production Casing)	Requires: - a failure of the Production Liner cement sheath or - a pressurised A-annulus and - failure of the production casing before there is pressured CO_2 in the B-annulus. Sustained CO_2 annulus pressure will be an unsustainable well integrity state and require remediation.	Repair by cement squeeze (possible chance of failure). Requires the completion to be retrieved and rerun (if installed).	\$3-5 million (5 days & tangibles). \$18-25 million (if a workover required).

ACTIVE WELL			
Risk Event	Effect	Remediation	Cost
Production Casing Failure	Requires: - a pressurised A-annulus and - a failure of the Production Casing cement sheath before there is pressure CO_2 in the B-annulus. Sustained CO_2 annulus pressure will be an unsustainable well integrity state and require remediation.	Repair by patching (possible chance of failure). Requires the completion to be retrieved (if installed). Will change the casing internal diameter and may have an impact on the completion design and placement.	$3-5 million (3 days & tangibles). $18-25 million (if a workover required). 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: - installation of insert back-up by intervention or - replacement by workover	£1 million to run insert (1 day & tangibles). $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). Subsea: $5-7 million (vessels, ROV, dive support & tangibles).

ACTIVE WELL			
Risk Event	Effect	Remediation	Cost
Wellhead seal leak	Requires: - a pressurised annulus and - multiple seal failures before there is a release to the biosphere. 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). 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). Abandonment $15-25 (21 days & tangibles).
Xmas Tree seal leak	Requires multiple seal failures before there is a release to the biosphere. 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. 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). Subsea: $12-15 million (12 days & tangibles).

Table 11-13 Well containment risks and remediation options

ABANDONED WELL			
Risk Event	**Effect**	**Remediation**	**Cost**
Well Leak	Escape of CO_2 to the biosphere. 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. A relief well is required.	Relief well: $55 million (60 days & tangibles).

Table 11-14 Abandoned well containment risks and remediation options

11.7 Appendix 7 Well Basis of Design

11.7.1 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 Appendix 9. 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.

Based on the available drilling information, the initial calculated strength profiles in the Hordaland yielded collapse (breakout) pressures that were considerably higher than the drilled mud weights in some of the wells. This did not fit with the report drilling problems (which were minimal). Therefore the, rock strength values were modified to produce collapse pressures that were just below or at the drilled mudweight depending on the record of drilling problems.

11.7.1.1 Safe Mud Weight Windows -Original Reservoir Pressure Condition

Well 22/14b-6Q

- This well was drilled with 13.1 ppg (as presented in yellow in the plot) from 5400 ft to TD with no reported issues
- A safe MW for Sele and Forties would be between 9 to 14 ppg (for a vertical well)
- A safe MW for the layers above Sele up to 4500' TVD would be between 12 to 14 ppg (for a vertical well).
- Above 4500' TVD, the safe MW could be between 11 to 14 ppg (for a vertical well)

Well 22/07-2

- This well was drilled with MW between 9 to 11 ppg (as presented in yellow in the plot).
- A safe MW for Sele and Forties would be between 9 to 14 ppg (for a vertical well).
- A safe MW for layers above Sele up to 4900' TVD would be between 12 to 14 ppg (for a vertical well)
- Above 4900' TVD, the safe MW could be between 10 to 14 ppg (for a vertical well)
- Washing & reaming were reported in this well, where the MW was close to the collapse pressure (as shown in the plot)

Well 22/14a-2

- This well was drilled with MW between 10.5 to 11.65 ppg (as presented in yellow in the plot).
- A safe MW for Sele, Lista and Forties would be between 9 to 14 ppg (for a vertical well).
- A safe MW for layers above Sele would be between 11.5 to 14 ppg (for a vertical well)
- Washing & reaming were reported in this well at 5050', where the MW was close to the collapse pressure (as shown in the plot)

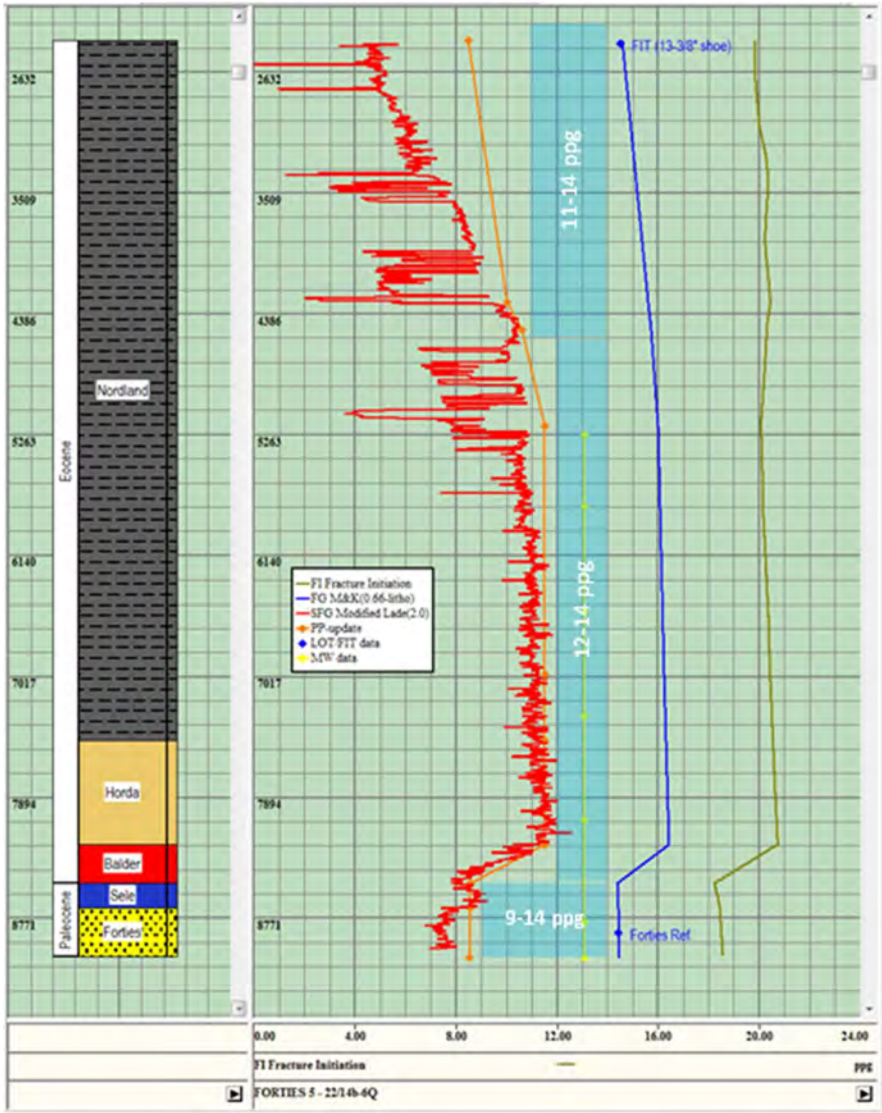


Figure 11-36 Safe mud weight analysis Well 22/14b-6Q

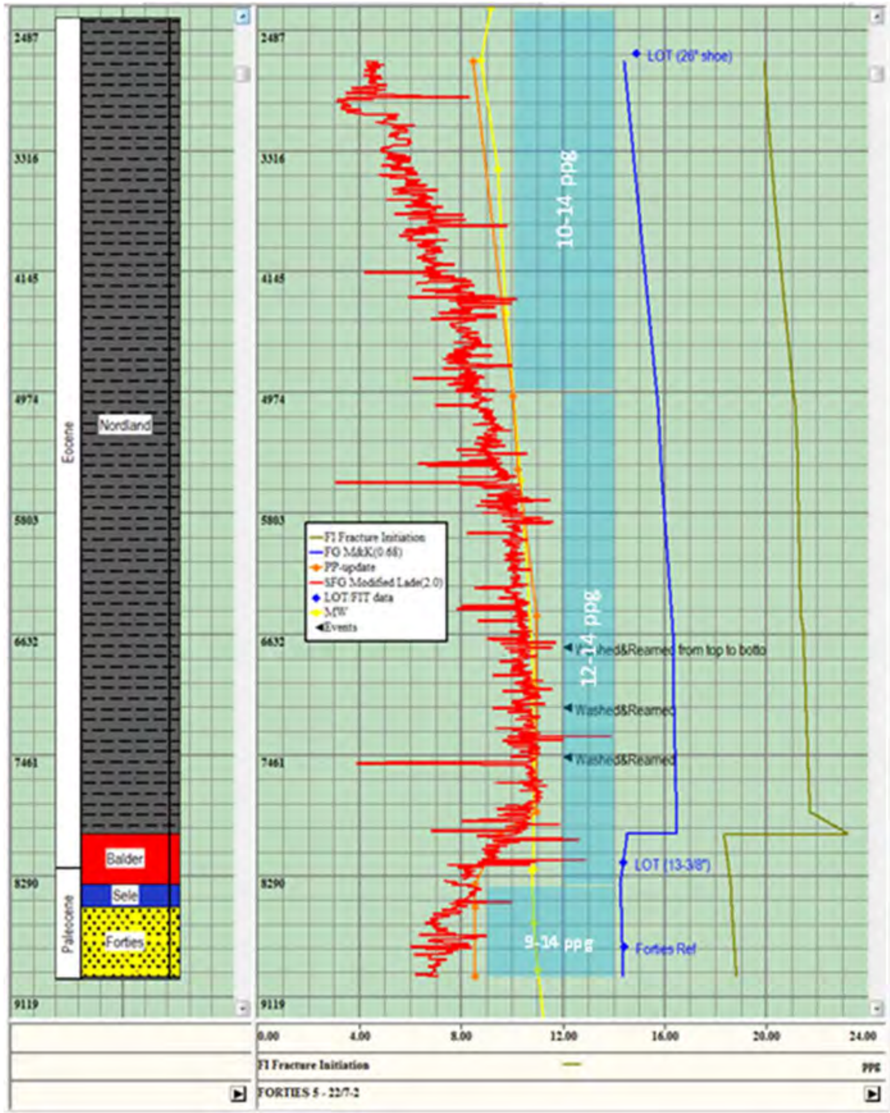


Figure 11-37 Safe mud weight analysis Well 22/07-2

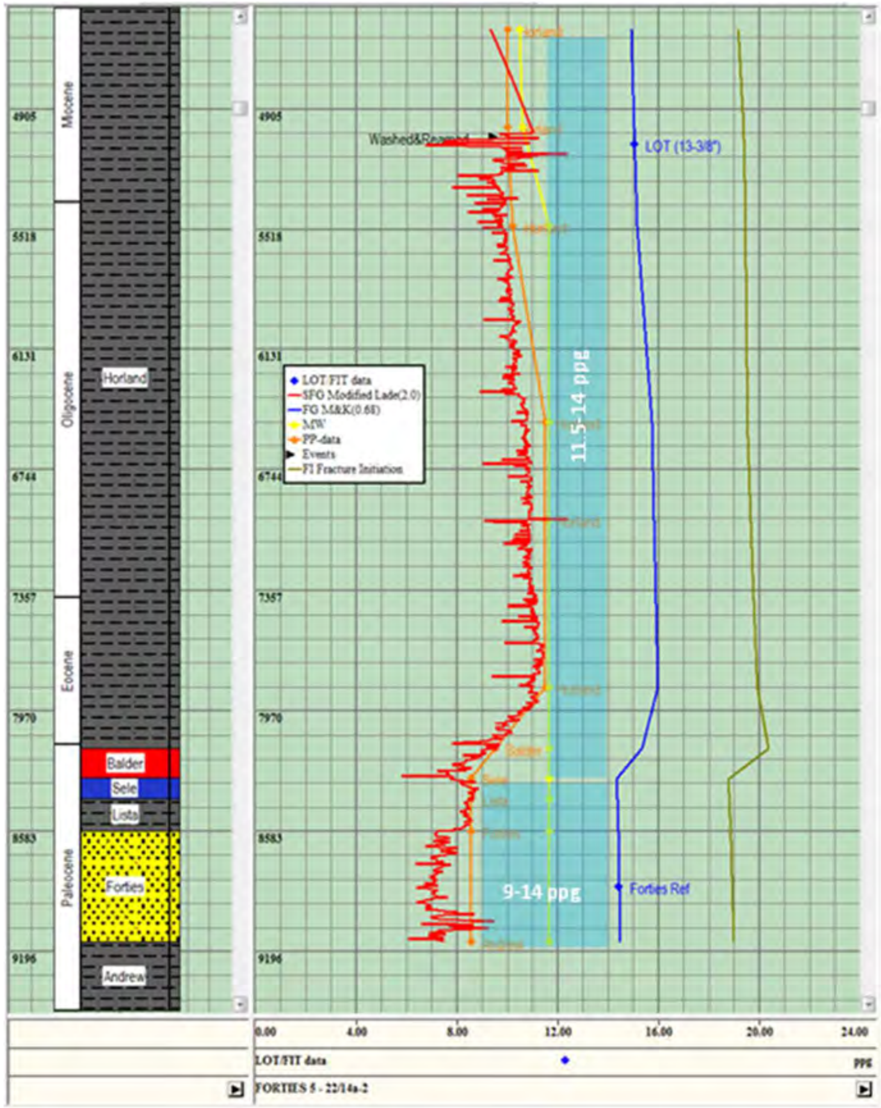


Figure 11-38 Safe mud weight analysis Well 22/14a-2

11.7.1.2 Wellbore Trajectory Analysis

aa The figures below indicate the variation of the minimum mud weight to prevent any breakout with changes in wellbore inclination and orientation.

Figure 11-39 shows the Forties sandstone (at 8771 ft TVDRT) in the well 22/14b-6Q, where a horizontal well with NW-SE orientation would increase the MW by up to 0.94 ppg (9.94 ppg). Figure 11-40 shows the Forties sandstone (at 8658 ft TVDRT) in the well 22/07-2, where a horizontal well with NW-SE orientation would increase the MW by up to 0.90 ppg (9.90ppg). Figure 11-41 shows the Forties sandstone (at 8900 ft TVDRT) in the well 22/14a-2, where a horizontal well with NW-SE orientation would increase the MW by up to 0.86 ppg (9.86ppg).

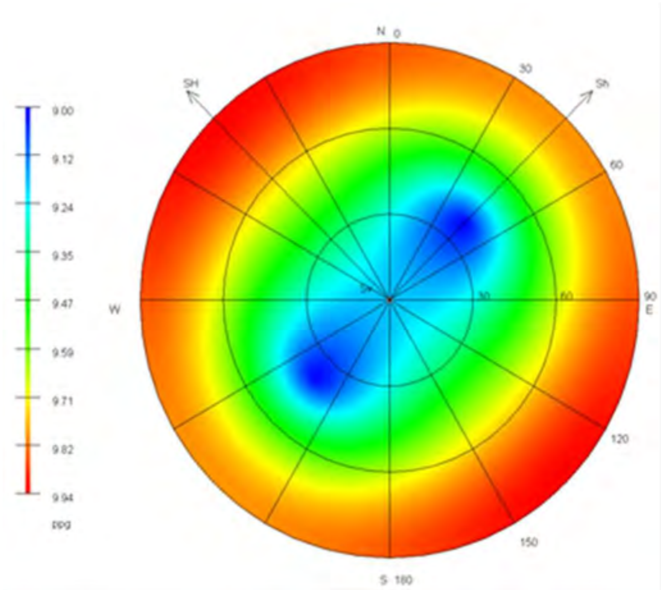


Figure 11-39 Well trajectory analysis Well 22/14b-6Q

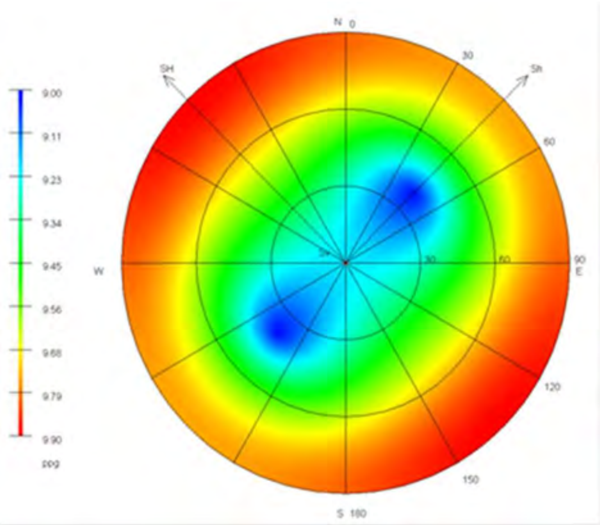


Figure 11-40 Well trajectory analysis Well 22/07-2

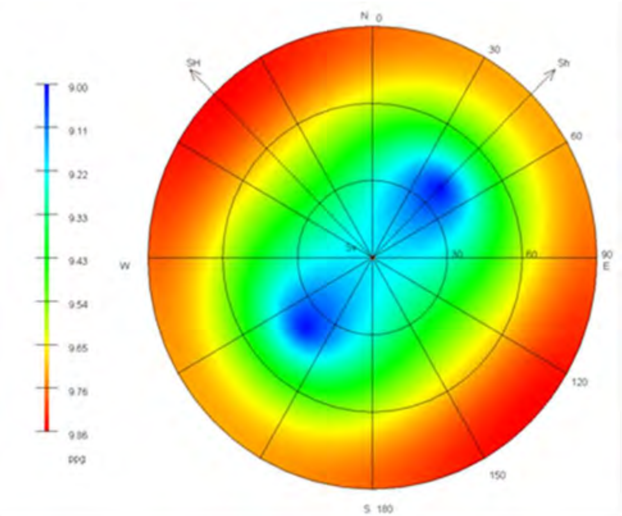


Figure 11-41 Well trajectory analysis Well 22/14a-2

11.7.1.3 Conclusions

- For vertical wells in the Forties sandstone, the recommended mud weight is around 9-14 ppg. Some basic analysis on required mud weights at different injector orientations has been performed within the Forties Sandstone. In general, mud weight increases of around 1.0 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 Forties Structure. Real SHmax magnitude and azimuth may be different especially as there are two perpendicular structural trends in the area.
- 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 Forties 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.

11.7.2 Well Design

In order to develop the Forties aquifer for carbon capture and storage and optimise CO_2 injection performance, horizontal injection wells will be required.

In addition, an appraisal well will be drilled prior to beginning the development in order to gather reservoir data.

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 well types.
- Provide high level time and cost estimates for each well type.

This report proposes conceptual well designs that could form the basis of a detailed well design. It should be stressed that the well designs suggested herein are not fully developed and may be subject to change following detailed engineering analysis.

11.7.2.1 Offset Review

Well data from available sources has been analysed in order to identify inputs for designing the Forties aquifer CO_2 injection and monitoring wells. The key findings are as follows:

Surface Hole and Conductor

For the development wells drilled in the area, a 36” surface hole section was drilled and a 30” conductor cemented in place. No significant problems were recorded in the available data, however, boulders are known to occur regionally which could lead to high vibration levels during drilling.

Surface Hole and Casing

The surface hole sections were drilled through the shallow marine clays with surface casing being set based on a pre-selected depth. This setting depth was selected to provide sufficient formation strength to drill the next hole section to:

- The intermediate casing shoe setting depth, or;
- The top of the Forties reservoir.

The casing setting depth varies depending on whether an intermediate casing string was used, with these setting depths being as follows:

- Intermediate casing string in use: Surface casing setting depth was at +/- 2,000ft (610m) TVDSS.
- No intermediate casing string: Surface casing setting depth was at +/- 3,000ft (915m) TVDSS.

All surface hole sections were drilled using seawater, with bentonite sweeps being used to assist with hole cleaning. No significant problems occurred when drilling to either 2,000ft or 3,000ft TVDSS, with casing being run and cemented without issue.

It should be noted that some Operator’s contemplated drilling surface hole deeper then 3,000ft TVDSS. However, below this depth, pore pressure begins to rise, and drilling into over-pressure shales with seawater was considered to be a high risk strategy.

Some surface hole sections were directionally drilled for two reasons, these being to:

- Reduce the risk of wellbore collision.
- Allow wells to reach outlying reservoir targets from a central platform location.

There were no reported issues associated with nudging the surface hole sections, making this a viable option for reservoir placement of the CO_2 injectors from a single drill centre.

Intermediate Hole Section and Production Casing

Some of the earlier development wells on Arbroath, Everest and Nelson were drilled using two intermediate hole sections. In these cases, intermediate casing was set to case off the reactive shales in the Lark formation, as well as to provide sufficient formation strength to support the mud weight required to maintain wellbore stability in the Hordaland, Nordland and Eocene Shales.

The intermediate casing string was required when surface casing was set at 2,000ft TVDSS. However, more recent development wells set surface casing at 3,000ft TVDSS because the formation strength at this depth was sufficient to allow the intermediate hole section to be drilled to top reservoir. By adopting this approach, the cost of a casing string was saved.

When required, the intermediate hole sections were drilled through the Lark and Nordland Shales, with the casing shoe being set at a convenient point between 4,000ft and 5,000ft TVDSS. This setting depth performed two functions, these being:

- There was sufficient formation strength to allow the mud weight to be raised to 13.5 to 14.0 ppg for drilling the Eocene shales in the next hole section.
- The risk of losses to the surface shoe when cementing the production casing string was reduced.
- The findings from the first intermediate hole section offset analysis were as follows:
- All the reviewed wells were directionally drilled, with some problems occurring below the surface shoe when attempting to build. Due to the soft nature of the formations, it sometimes proved difficult to obtain BHA reaction, which led to lower dog-leg severities than planned.
    - In order to obtain BHA reaction, higher weight-on-bit was sometimes required. This in turn led to high rates of penetration (ROP's), with large volumes of cuttings being generated over a short time interval. Cuttings bed formation occurred on occasion, which led to lost time conducting hole cleaning wiper trips.
- Oil based mud was used to drilling the hole section in order to maintain wellbore stability in the Lark and Hordaland shales, and deliver gauge hole for hole cleaning purposes.
    - These formations are known to be reactive in the presence of water based mud.
- Hole cleaning was problematic in 16" and 17 ½" hole, with tight hole and packing off occurring on numerous occasions due to the presence of cuttings beds.
- Relatively high mud weights were required to maintain wellbore stability in the shales, and low level losses to the weak formations directly below the surface casing shoe was a common occurrence.
- Running the 13 ⅜" intermediate casing to bottom was not always straightforward, with the casing string having to be washed and worked to bottom on several occasions.
    - Wellbore instability and cutting bed formation were the two most commonly identified issues associated with casing running problems.
- Some of the 13 ⅜" cement jobs were affected by losses, with the loss zone thought to be the weak formations directly below the surface casing shoe.

It may be concluded from the offset analysis that drilling a large bore hole section (i.e. 16” or 17 ½”) is not straightforward. The problems that have been outlined above were some of the reasons that led to modified well designs being adopted, with a deeper set surface casing shoe and a single 12 ¼” intermediate hole section drilled to the top of the Forties reservoir.

Intermediate Hole Section and Production Casing

Later development wells in the Forties area were drilled using one intermediate hole sections, with the production casing string set either directly above or directly below top Forties. The casing setting depth was selected to isolate the Sele, Balder and Eocene Shales, which require a high mud weight to maintain wellbore stability (especially at high angle). By isolating these formations, a lower mud weight could be used to drill the Forties reservoir section, thereby reducing the risk associated with differential sticking, losses to weak sand units and formation damage from a high overbalance.

The longer intermediate hole sections were drilled through the Lark, Nordland, Hordaland, Eocene, Balder and Sele Shales, and the findings of the offset analysis were as follows:

- All the reviewed wells were directionally drilled, with some problems occurring below the surface shoe when attempting to build. Due to the soft nature of the formations, it sometimes proved difficult to obtain BHA reaction, which led to lower dog-leg severities than planned.
- Oil based mud was used to drilling the hole section in order to maintain wellbore stability and deliver gauge hole for hole cleaning purposes.
    - These formations are known to be reactive in the presence of water based mud.
- Hole collapse occurred in the Eocene and Sele shales when mud weights below 12.5 ppg were used. On all occasions, this led to the loss of the hole section and a sidetrack.
- The Balder formation contained volcanic tuffaceous streaks which were weaker than the surrounding shales. Losses to the Balder at the mud weights required to maintain wellbore stability in the Eocene and Sele shales occurred on several occasions.
    - At high angle, the mud weight required to maintain wellbore stability ranged between 13.2 and 13.5 ppg.
    - The equivalent circulating density (ECD) associated with these mud weights and the flow rates need to clean the hole was very close to the Balder formation strength.
    - The hole sections were designed to minimise ECD by ensuring that hole cleaning was effective (i.e. cuttings loading was minimised) and by keeping tight control on the mud properties.
- Hole cleaning was occasional problematic in 12 ¼” hole, with tight hole and packing off occurring. However, the occurrence of hole cleaning issues in this hole size were significantly less than in the large bore intermediate sections.
    - It should be noted that rates of penetration (ROP’s) were fast, with large volumes of cuttings being generated over a short time interval. Drilling procedures were adopted to manage ROP and cuttings bed formation.

- The casing setting depth was normally specified in a tight window, to ensure that the reactive Sele shales were cased off while either setting casing directly above, or directly below top Forties. Various techniques were used to identify the formation being drilled, to ensure that casing was set at the correct depth. These included:
    - LWD gamma ray at bit.
    - Real-time biostrat and palaeontology analysis.
- Running the 9 ⅝" casing to bottom was not always straightforward, with the casing having to be washed and worked to bottom on several occasions.
    - Wellbore instability and cuttings bed formation were the two most commonly identified issues associated with casing running problems.
- Some of the 9 ⅝" cement jobs were affected by losses, with the loss zone either at:
    - Weak formations directly below the surface casing shoe, or;
    - Weak volcanic zones in the Balder.
        - When losses to the Balder occurred, top of cement behind the 9 ⅝" casing was low, and this had an impact on managing well integrity as well as well abandonment.

Production Hole Section and Sandface Completion

The geometry of the reservoir hole section varied, with both slant and horizontal wells being drilled. In most cases, the production hole section was cased with a cemented liner and perforated, however, on occasion sand screens or expandable sand screens were used for sand control purposes.

The findings of the offset analysis were as follows:

- All the reviewed wells were directionally drilled. There were no problems associated with maintaining directional control, or obtaining the required doglegs to deliver the well objectives.
- The reservoir sections were drilled with oil based mud in order to:
    - Maintain wellbore stability in the intra-Forties shales, while allowing a lower mud weight to be used than would have been the case with water based mud.
    - Reduce the risk of differential sticking.
    - Provide gauge hole for hole cleaning and cementing purposes.
    - Minimise formation damage via filtrate invasion into the reservoir.
    - Reduce drilling and casing running friction factors.
- The mud weights required to maintain wellbore stability varied with hole angle, with 10.5 to 11.0 ppg being used for low angle penetrations (i.e. up to 30o inclination), and 12.0 to 13.0 ppg being required for horizontal wells.
    - Differential sticking occurred on occasion when using the higher mud weights.
- Ledging occurred in some wellbores at the interface between sand and shale bodies. This resulted in problems running liners to bottom, with reamer shoes and rotating liner hangers being employed to increase the probability of the liner reaching TD.
- Cementing losses occurred on occasion due to the narrow window between formation strength and the mud weight required to maintain

wellbore stability. However, in the majority of cases, the liner was successfully cemented, with cement reaching the liner hanger.

11.7.2.2 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 selected subsea and platform locations. However, this will be confirmed when the results of the shallow gas survey are available. In the event that shallow gas is identified at either selected location, the affected location should be moved.

Overburden Wellbore Instability

The overburden shales are reactive and require high mud weights to maintain wellbore stability. In addition, oil based mud is required to avoid the risks associated with clay swelling.

At high angle, the mud weights required to maintain wellbore stability are close to the formation strength at the surface casing shoe and in the Balder. Therefore, the mud system properties must be tightly controlled in order to minimise equivalent circulating density (ECD), and reduce the pressure applied to the formation.

When drilling the overburden formations, it is recommended that the minimum mud weights recommended in the wellbore stability model are adhered to in order to manage the balance between mud weight and losses to the formation.

Hole Cleaning

High rates of penetration (ROP) have been experienced in the overburden 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 deposited cuttings beds.

Losses to the Balder Formation

Losses to weak volcanic stringers in the Balder formation are a significant risk at the mud weights required to maintain wellbore stability in the overburden formations. Therefore, this risk should be managed by adopting the following drilling strategy:

- Prior to drilling into the Balder, circulate the hole clean to remove cuttings from the fluid column and reduce ECD.
- If required, conduct a wiper trip to remove / clean up any cuttings beds.
- Condition the mud system to reduce plastic viscosity (PV) and ECD.

Production Casing Cementing Losses

Losses when cementing the production casing string are a significant risk, with the potential loss zones being:

- Weak formations directly below the surface casing shoe.
- Weak volcanic stringers in the Balder formation.

A loss zone in the Balder formation is the greater risk, because this is close to the production casing shoe, and can compromise the quality of the cement job. Should only a short interval of cement be present from the casing shoe to the top of the Balder, the risk of communication from the reservoir to the B-annulus is increased, which would affect well integrity as well as the seal on the carbon store. Therefore, in order to reduce the risk of a poor cement job, the following mitigations should be considered:

- Reduce the plastic viscosity (PV) and yield point (YP) of the mud system prior to running casing.
- Pump and displace the cement at the lowest acceptable pump rate (to reduce ECD).
- Add low levels of lost circulation material to the mud system and cement prior to cementing.

Reservoir Wellbore Instability

The intra-Forties reservoir shales are reactive and require high mud weights to maintain wellbore stability. If too low a mud weight is used, collapse can occur leading to hole enlargement in the shales and ledging at the sand/shale interface. Ledging can prevent the liner reaching TD, and cement quality may be compromised in the enlarged shale sections.

If too high a mud weight is used to ensure wellbore stability, the following problems may occur:

- High ECD applied to the sand bodies, leading to losses.
- Differential sticking.

In order to reduce the risks associated with wellbore instability in the reservoir section, it is recommended that the minimum mud weights recommended in the wellbore stability model are adhered to in order to manage the balance between mud weight and losses to the formation.

Differential Sticking

The Forties Sands are 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 reservoir section 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.

Production Liner Installation

Running the production liner to TD through the Forties reservoir section can be problematic if ledges or enlarged hole section are present. This risk may be mitigated by:

- Running the liner with a reamer shoe, to allow rotation off ledges.
- Use a rotating liner hanger system to allow the liner to be worked and rotated to bottom, if required.

11.7.2.3 Directional Profiles

Reservoir Targets

The following reservoir targets have been identified for the top of the Forties reservoir:

South Platform Site

Target Name	TVDSS (m)	UTM North (m)	UTM East (m)
INJ-01S Heel	2,873	6,379,785.9	426,156.7
INJ-01S Toe	2,873	6,380,084.0	426,220.0
INJ-02S Heel	2,883	6,380,304.6	428,701.6
INJ-02S Toe	2,883	6,380,538.1	428,897.5
INJ-04S Heel	2,835	6,375,418.3	422,436.8
INJ-04S Toe	2,835	6,375,289.5	422,160.6
INJ-06S Heel	2,737	6,378,534.8	422,518.5
INJ-06S Toe	2,737	6,378,687.2	422,252.6
INJ-08S Heel	2,739	6,376,321.8	425,917.2
INJ-08S Toe	2,739	6,376,072.1	426,092.0

Table 11-15 South platform reservoir targets - coordinate system in use is UTM ED50 Common Offshore Zone 31 (0° to 6° East)

North Subsea Site

Target Name	TVDSS (m)	UTM North (m)	UTM East (m)
INJ-03N Heel	2,763	6,397,073.2	411,088.2
INJ-03N Toe	2,763	6,397,202.0	410,812.0
INJ-05N Heel	2,865	6,394,488.1	415,611.9
INJ-05N Toe	2,865	6,394,272.6	415,827.4
INJ-07N Heel	2,781	6,399,563.2	415,881.8
INJ-07N Toe	2,781	6,399,839.4	416,010.6
INJ-08N Heel	2,822	6,396,015.0	417,357.1
INJ-08N Toe	2,822	6,395,988.5	417,660.7

Table 11-16 North subsea reservoir targets

Surface Location

A central surface location for both the platform and subsea sites has been selected, with the coordinates of these being:

- South Platform Location:
    - 6,377,000m North
    - 425,500m East
- North Subsea Template Location:
- 6,396,500m North
- 414,000m East

The surface location and well position for each site is shown in the spider plots below:

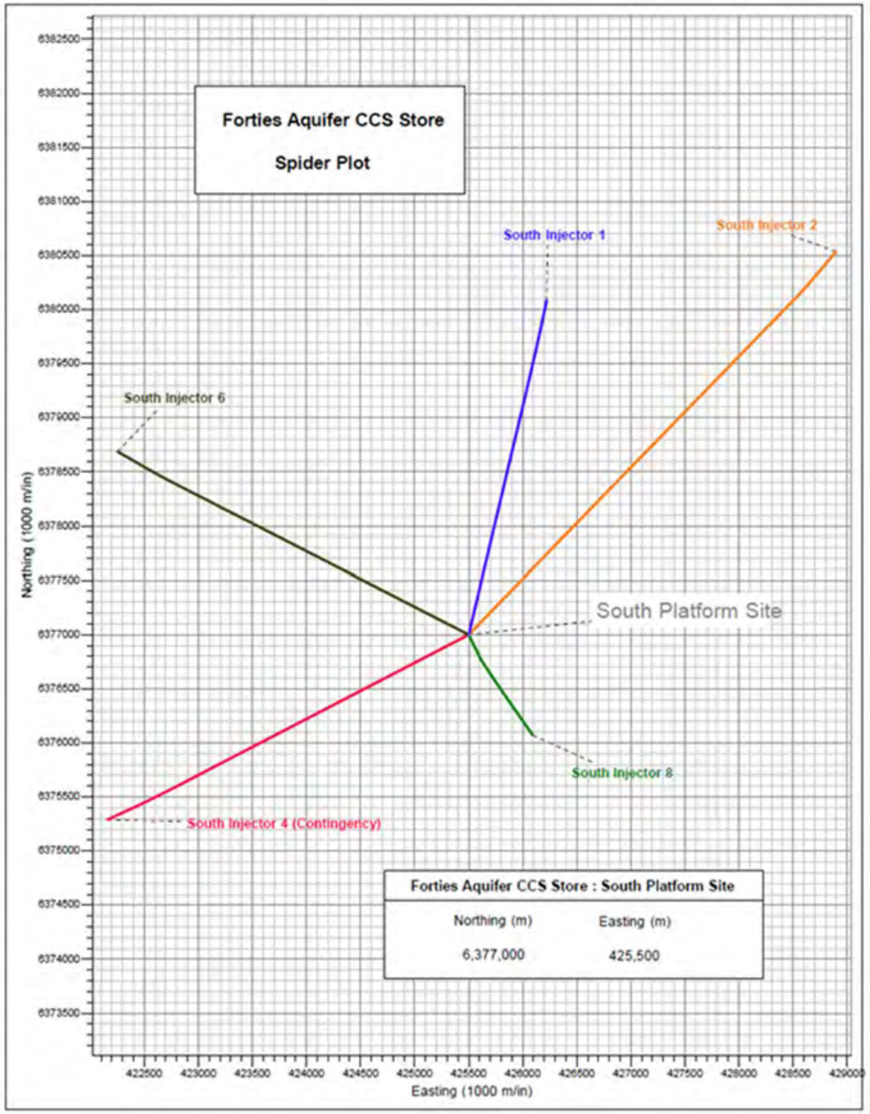


Figure 11-42 South platform directional spider plot

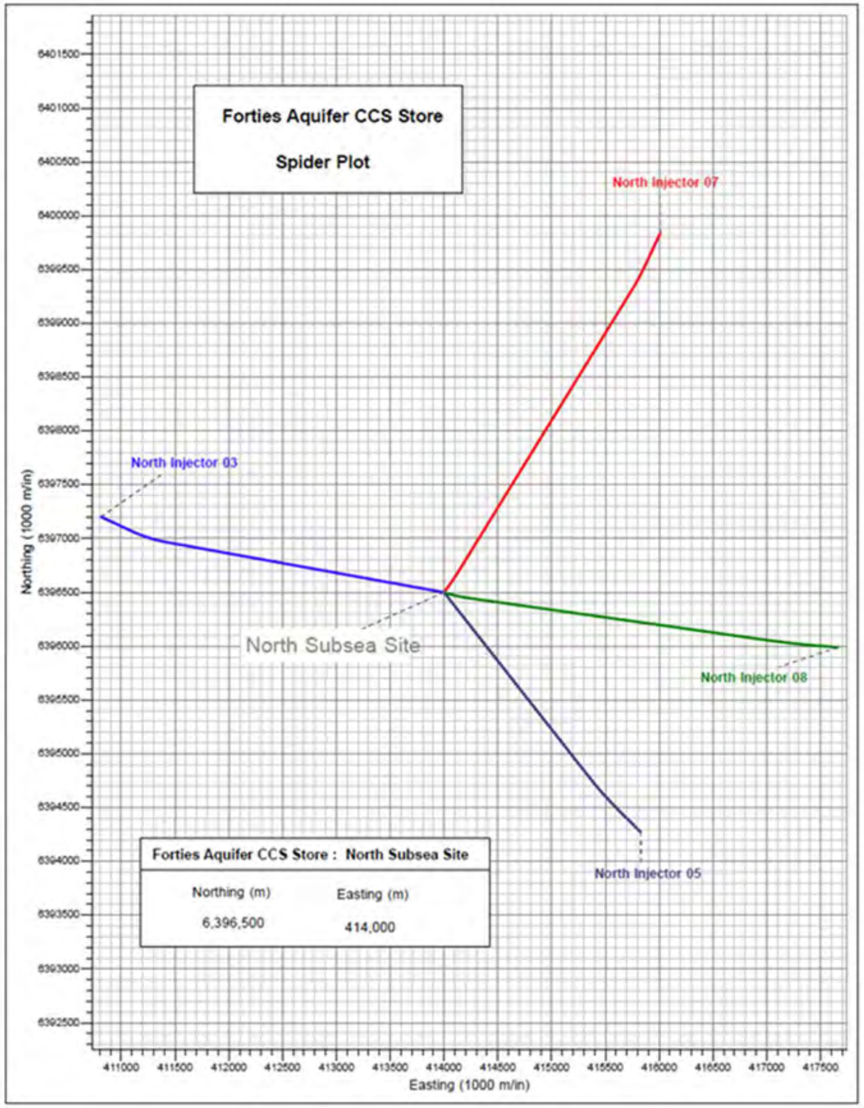


Figure 11-43 North subsea template directional spider plot

Directional Design

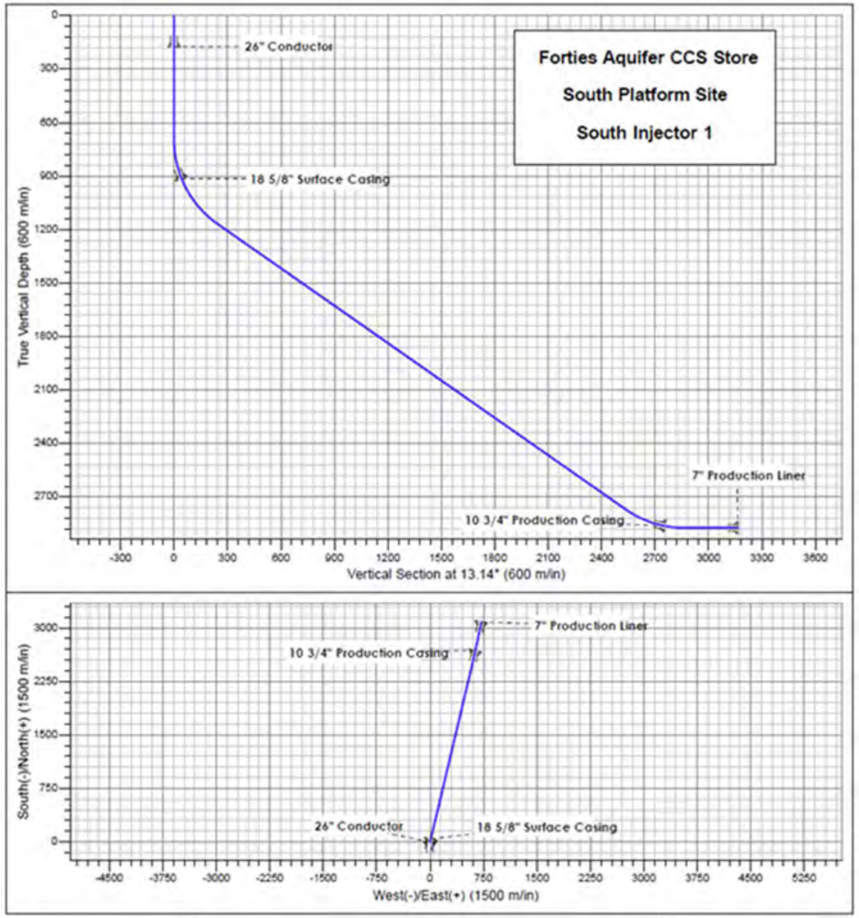
The site surface and well reservoir locations have been selected for conceptual well design purposes; however, it should be noted that these locations have not been optimised for reservoir management or directional drilling purposes. Therefore, it is recommended that the wells are re-planned and anti-collision 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 horizontal wells, including the monitoring well which will also act as a spare injector.
- All wells will be drilled vertically to 200m (i.e. 25m below the conductor shoe).
- Where required to keep the tangent angle within wirelining capability, the surface hole section will be nudged from 200m to 700m MD at a dogleg severity (DLS) of 1o per 30m.
    - Wells will remain vertical to 700m if a nudge is not required to keep tangent angle below 60o.
- All wells will be kicked off below 700m MD, with a planned dogleg severity of 3.0o per 30m. The wells will be built to the required tangent angle, while turning the wellpath onto the required azimuth.
- After drilling a tangent section through the overburden formations, a second directional section will be drilled directly above the reservoir targets, building inclination to horizontal while turning the well path onto the required azimuth through the reservoir.
- A horizontal section will then be drilled through the reservoir, holding inclination at 90o and maintaining azimuth.

The appraisal well will be drilled vertically.

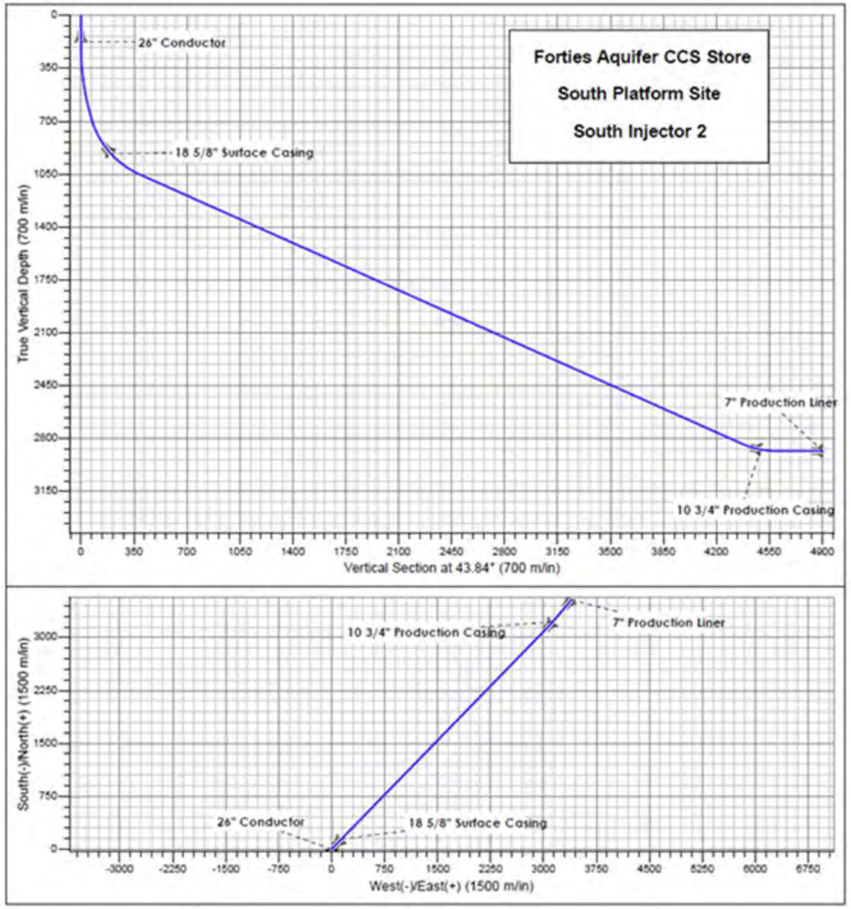
Directional profiles have been prepared for each injection well based on the reservoir targets and directional drilling limitations, as follows:



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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	0.00	13.35	700.00	0.00	0.00	0.000	13.35	0.00
1250.48	55.05	13.35	1169.62	238.11	56.50	3.000	13.35	244.72
4043.32	55.05	13.35	2769.59	2465.38	585.01	0.000	0.00	2533.82
4393.07	90.00	12.00	2873.00	2785.90	656.70	3.000	-2.35	2862.25
4393.18	90.00	11.99	2873.00	2786.01	656.72	3.153	-90.00	2862.36
4697.70	90.00	11.99	2873.00	3083.89	719.98	0.000	0.00	3166.82
4697.81	90.00	12.00	2873.00	3084.00	720.00	3.153	90.00	3166.93

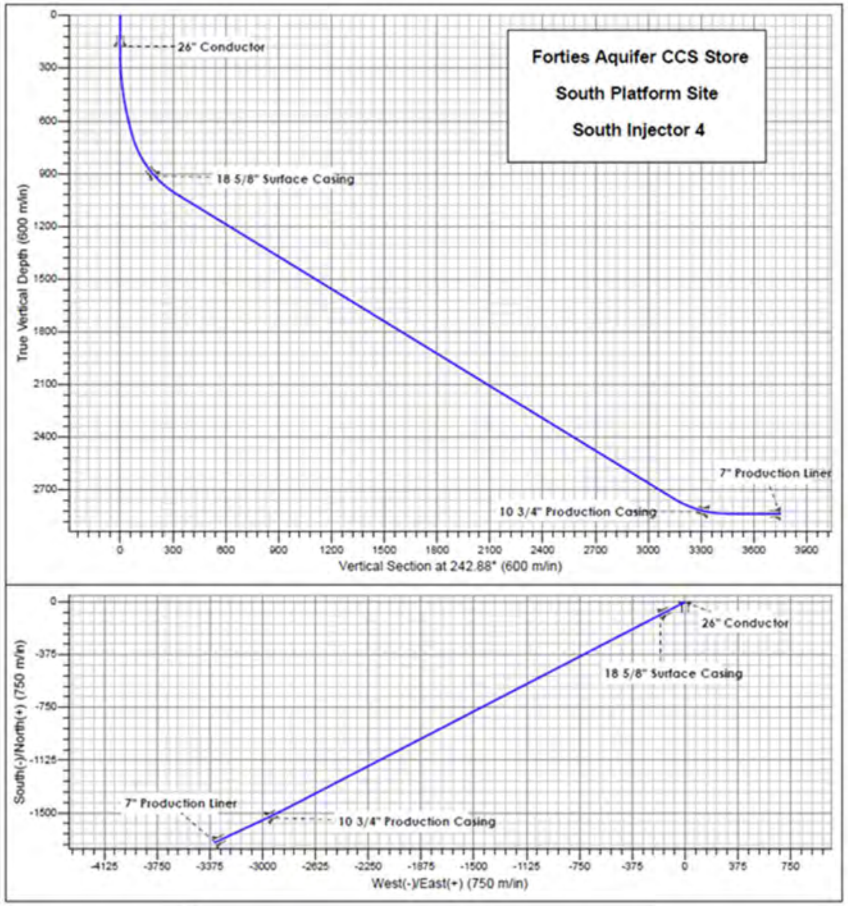
Figure 11-44 South platform injector 01 directional profile



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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	16.67	44.21	692.98	51.76	50.35	1.000	44.21	72.21
1192.13	65.88	44.21	1051.59	277.38	269.81	3.000	0.00	386.95
5549.53	65.88	44.21	2832.24	3128.19	3042.72	0.000	0.00	4363.82
5794.16	90.00	40.00	2883.00	3304.60	3201.60	3.000	-10.20	4601.11
5794.20	90.00	40.00	2883.00	3304.63	3201.63	3.000	-90.00	4601.15
6098.91	90.00	40.00	2883.00	3538.07	3397.47	0.000	0.00	4905.17
6098.95	90.00	40.00	2883.00	3538.10	3397.50	3.000	90.00	4905.22

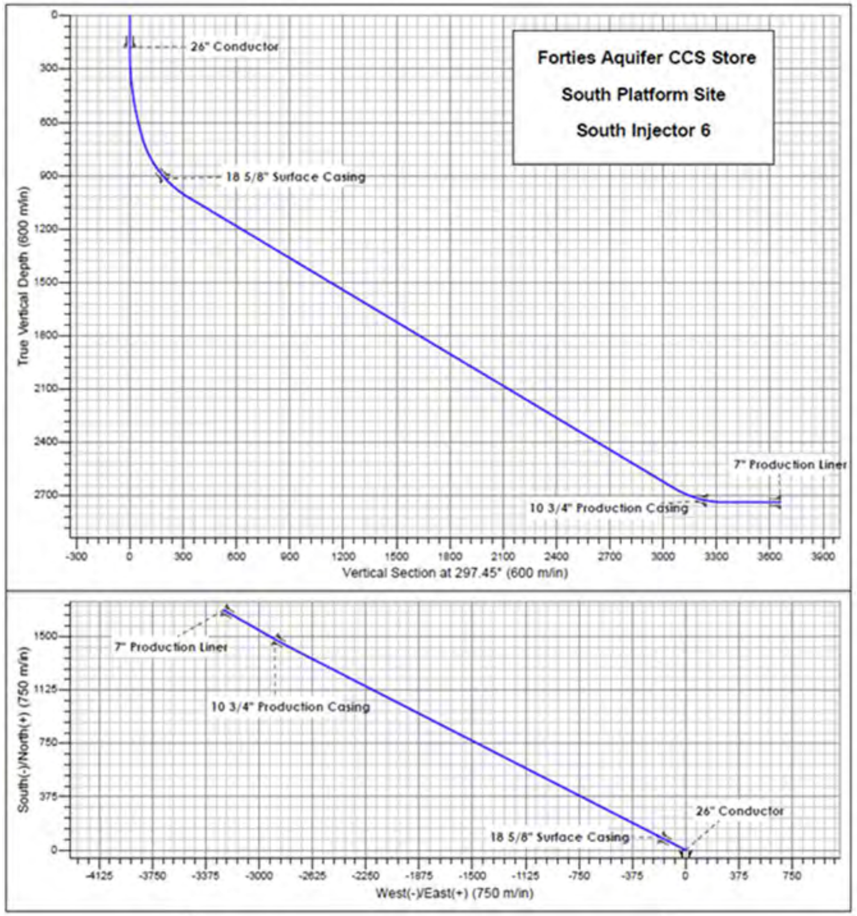
Figure 11-45 South platform injector 02 directional profile



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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	16.67	242.58	692.98	-33.25	-64.10	1.000	242.58	72.21
1118.10	58.48	242.58	1017.06	-148.08	-285.40	3.000	-0.01	321.52
4432.94	58.48	242.58	2750.21	-1449.50	-2793.52	0.000	0.00	3147.15
4749.01	90.00	245.00	2835.00	-1581.70	-3063.20	3.000	4.63	3447.44
4749.02	90.00	245.00	2835.00	-1581.70	-3063.21	3.000	-90.00	3447.45
5053.76	90.00	245.00	2835.00	-1710.50	-3339.39	0.000	0.00	3751.98
5053.77	90.00	245.00	2835.00	-1710.50	-3339.40	3.000	90.00	3751.99

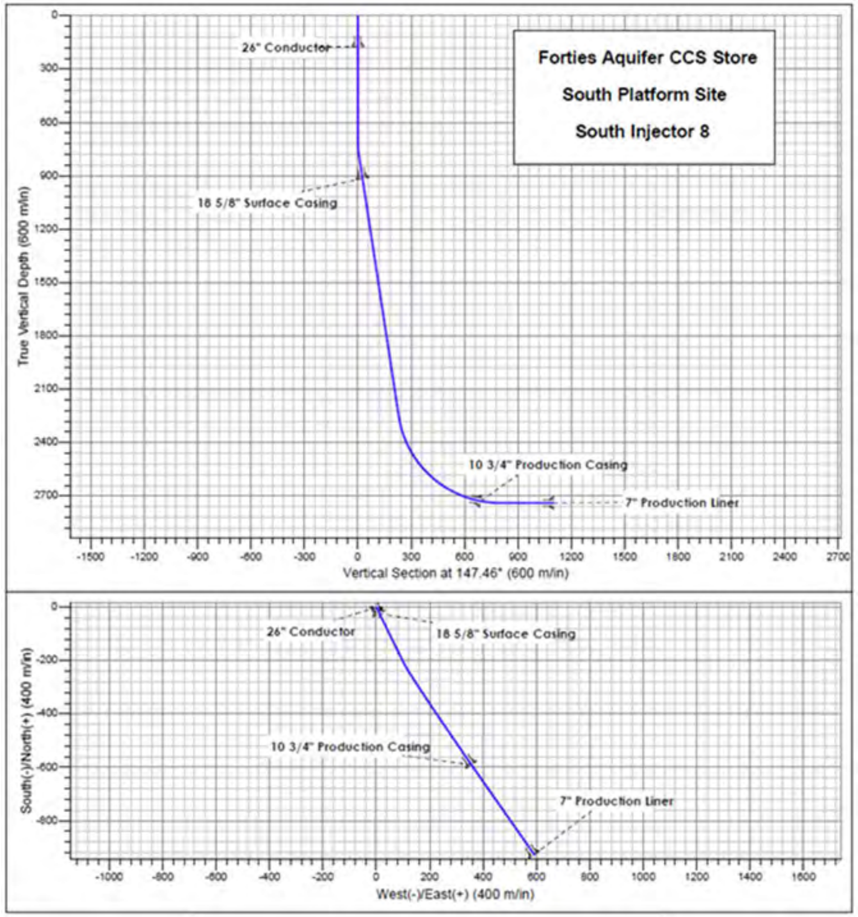
Figure 11-46 South platform injector 04 directional profile



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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	16.67	297.11	692.98	32.91	-64.28	1.000	297.11	72.21
1124.27	59.09	297.11	1020.25	148.92	-290.90	3.000	0.00	326.80
4307.63	59.09	297.11	2655.35	1393.59	-2722.17	0.000	0.00	3058.10
4617.77	90.00	299.82	2737.00	1534.80	-2981.50	3.000	5.27	3353.33
4617.78	90.00	299.82	2737.00	1534.80	-2981.51	3.000	-90.00	3353.33
4924.24	90.00	299.82	2737.00	1687.20	-3247.39	0.000	0.00	3659.53
4924.25	90.00	299.82	2737.00	1687.20	-3247.40	3.000	90.00	3659.54

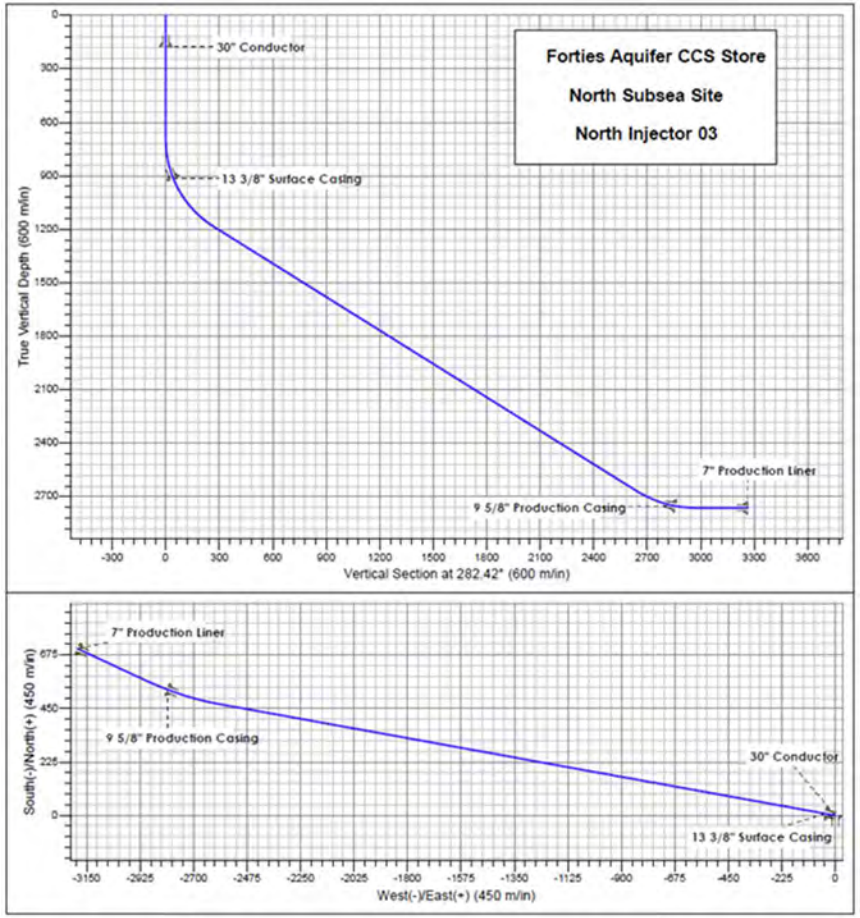
Figure 11-47 South platform injector 06 directional profile



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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	0.00	153.89	700.00	0.00	0.00	0.000	153.89	0.00
787.12	8.71	153.89	786.78	-5.94	2.91	3.000	153.89	6.57
2269.35	8.71	153.89	2251.92	-207.53	101.71	0.000	0.00	229.66
3083.29	90.00	145.00	2739.00	-678.20	417.20	3.000	-8.99	796.14
3083.36	90.00	145.01	2739.00	-678.25	417.24	3.000	90.00	796.21
3388.03	90.00	145.01	2739.00	-927.85	591.96	0.000	0.00	1100.60
3388.09	90.00	145.00	2739.00	-927.90	592.00	3.000	-90.00	1100.66

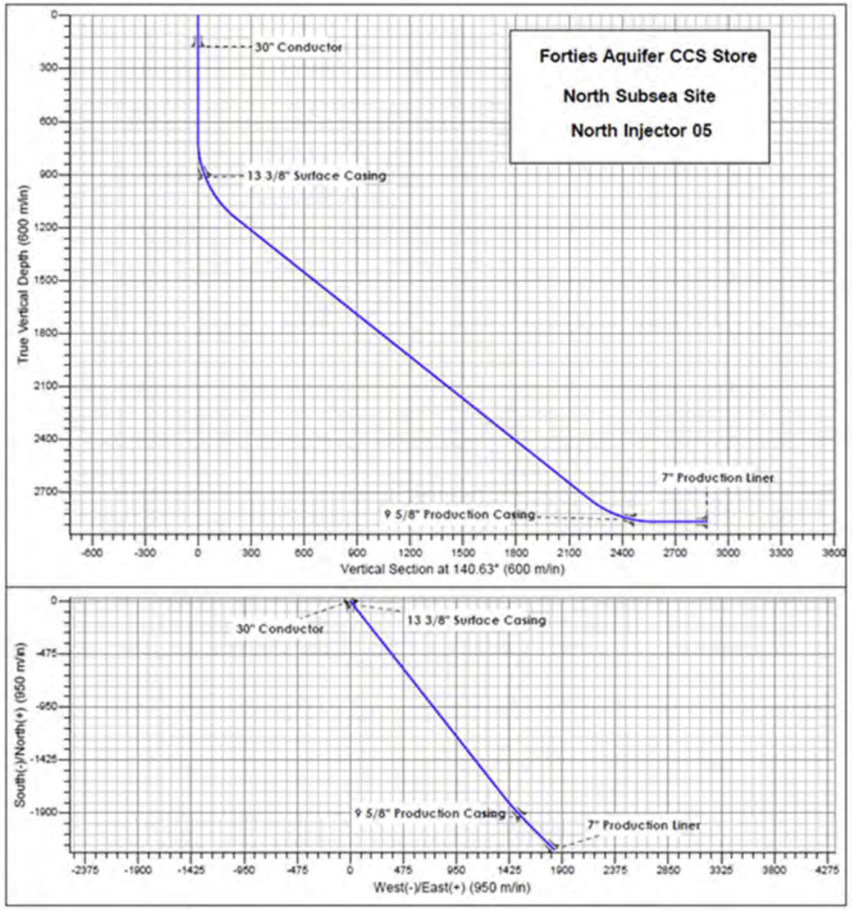
Figure 11-48 South platform injector 08 directional profile



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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	0.00	269.66	700.00	0.00	0.00	0.000	269.66	0.00
1279.99	58.00	280.25	1185.89	47.93	-265.03	3.000	280.25	269.13
4075.90	58.00	280.25	2667.54	469.89	-2598.22	0.000	0.00	2638.48
4424.96	90.00	295.00	2763.00	573.20	-2911.80	3.000	26.42	2966.94
4424.97	90.00	295.00	2763.00	573.20	-2911.81	3.000	90.00	2966.95
4729.70	90.00	295.00	2763.00	702.00	-3187.99	0.000	0.00	3264.37
4729.71	90.00	295.00	2763.00	702.00	-3188.00	3.000	-90.00	3264.38

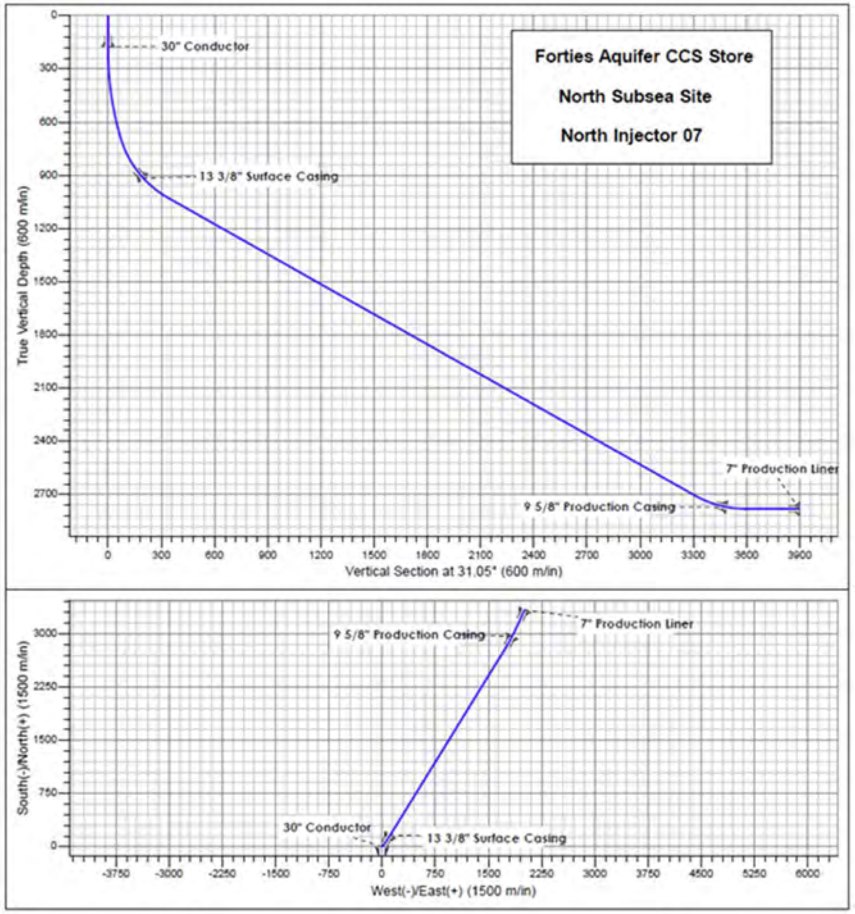
Figure 11-49 North subsea injector 03 directional profile



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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	0.00	148.12	700.00	0.00	0.00	0.000	148.12	0.00
1215.28	51.53	141.84	1148.58	-170.22	133.78	3.000	141.84	216.46
3771.43	51.53	141.84	2738.84	-1743.68	1370.40	0.000	0.00	2217.26
4161.25	90.00	135.00	2865.00	-2011.90	1611.90	3.000	-10.91	2577.80
4161.25	90.00	135.00	2865.00	-2011.90	1611.90	3.000	0.00	2577.80
4466.01	90.00	135.00	2865.00	-2227.40	1827.40	0.000	0.00	2881.09
4466.01	90.00	135.00	2865.00	-2227.40	1827.40	3.000	0.00	2881.09

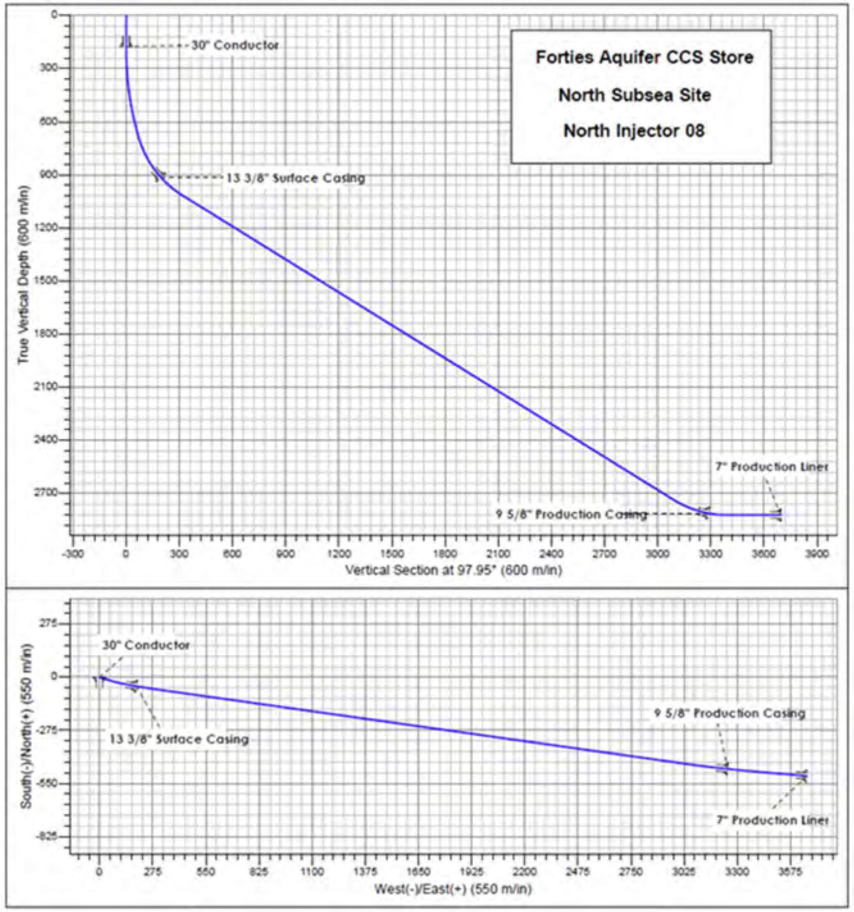
Figure 11-50 North subsea injector 05 directional profile



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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	16.67	36.95	692.98	57.71	43.41	1.000	36.95	71.83
1139.58	60.54	31.64	1028.25	282.11	188.90	3.000	-6.66	339.13
4548.73	60.54	31.64	2705.12	2809.05	1746.14	0.000	0.00	3307.20
4850.10	90.00	25.00	2781.00	3063.20	1881.80	3.000	-13.32	3594.90
4850.11	90.00	25.00	2781.00	3063.21	1881.80	3.000	90.00	3594.91
5154.85	90.00	25.00	2781.00	3339.39	2010.60	0.000	0.00	3897.95
5154.86	90.00	25.00	2781.00	3339.40	2010.60	3.000	-90.00	3897.96

Figure 11-51 North subsea injector 07 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
200.00	0.00	360.00	200.00	0.00	0.00	0.000	360.00	0.00
700.00	16.67	106.92	692.98	-21.02	69.08	1.000	106.92	71.33
1117.79	58.19	98.01	1017.72	-65.17	313.10	3.000	-11.39	319.10
4377.03	58.19	98.01	2735.59	-451.29	3055.82	0.000	0.00	3088.87
4696.39	90.00	95.00	2822.00	-485.00	3357.10	3.000	-5.70	3391.92
4696.50	90.00	94.99	2822.00	-485.01	3357.21	3.000	-90.00	3392.03
5001.03	90.00	94.99	2822.00	-511.49	3660.59	0.000	0.00	3696.15
5001.14	90.00	95.00	2822.00	-511.50	3660.70	3.000	90.00	3696.26

Figure 11-52 North subsea injector 08 directional profile

11.7.2.4 Detailed Well Design

The Forties CCS store will be developed via a platform in the south and a subsea template in the north. In addition, a subsea appraisal well will be drilled prior to developing the CCS store in order to gather reservoir data.

The designs for the platform and subsea wells vary due to the different tubing sizes required at each location. As such, different casing sizes have been selected for each well type to allow the specified completion geometry to be accommodated.

CO_2 Injector – Platform Well

The conceptual well design for a platform CO_2 injector is as follows:

26" Conductor

To reduce the risk of shallow soil destabilisation, the conductor string is normally driven to depth on platform wells in the Central North Sea, and this method has been selected for setting the conductors in the Forties Aquifer area. The conductor setting depth has been specified as 75m 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.

22" Surface Hole and 18 5/8" Casing Setting Depth

The surface casing setting depth has been selected as 915m TVDSS (3,000ft TVDSS). This setting depth has been selected to provide sufficient formation strength to drill the intermediate hole section to the top of the Forties reservoir, while avoiding drilling into the top of the over-pressured shale section with seawater. This is considered to be advantageous for the following reasons:

- **Cutting Collection:** Collecting and shipping the oil based mud coated cuttings to shore for re-processing is logistically difficult when drilling 16" or 17 ½" hole. By reducing the hole size, the volume of cuttings is significantly reduced, thereby making cuttings collection a practical proposition.
- **Hole Cleaning:** The overburden formations can be drilled in 14 ¾" hole, thereby providing hole cleaning benefits when compared with a larger hole size.
- **Casing Cost:** Drilling one intermediate hole section allows the cost of running an intermediate cost string to be saved.

14 ¾" Intermediate Hole and 10 ¾" Production Casing Setting Depth

A 14 ¾" intermediate hole section will be drilled through the overburden formations to the top of the Forties aquifer, with 10 ¾" production casing being set directly below the top of the Forties reservoir sands. This casing seat has been selected to isolate the Eocene, Balder and Sele formations prior to drilling the reservoir with a lower mud weight.

The 10 ¾" casing size has been selected to accommodate a 7" completion. This is the smallest casing size compatible with this size of completion, and allows a 14 ¾" hole size to be drilled. This hole size is preferable to drilling a conventional 16" or 17 ½" hole section, as it reduces the issues associated with hole cleaning and packing off.

8 ½" Production Hole and Production Liner Setting Depth

An 8 ½" horizontal hole section will be drilled through the Forties Sand, with the section length being optimised for CO_2 injection purposes.

A 7" liner will be run to TD and cemented across its entire length for reservoir management and zonal isolation purposes.

End of Field 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 10 ¾" production casing and opposite the Sele and Eocene shales. These formations have sufficient strength to contain reservoir pressure; therefore, by placing the abandonment plugs opposite these formations, store integrity will be assured.

CO_2 Injector – Subsea Well

The conceptual well design for a platform CO_2 injector is as follows:

36" x 30" Conductor

The conductor setting depth has been specified as 75m below the mudline for the reasons specified for a platform well.

The selected conductor size is 30" which is compatible with the selected well design, and will provide sufficient structural strength for subsea applications. A top joint of 36" has been selected to provide sufficient fatigue resistance and bending strength against trawlboard impact.

17 ½” Surface Hole and 13 3/8” Casing Setting Depth

The surface casing setting depth has been selected as 915m TVDSS (3,000ft TVDSS). This setting depth has been selected to provide sufficient formation strength to drill the intermediate hole section to the top of the Forties reservoir, while avoiding drilling into the top of the over-pressured shale section with seawater. This is considered to be advantageous for the following reasons:

- **Cutting Collection:** Collecting and shipping the oil based mud coated cuttings to shore for re-processing is logistically difficult when drilling 16” or 17 ½” hole. By reducing the hole size, the volume of cuttings is significantly reduced, thereby making cuttings collection a practical proposition.
- **Hole Cleaning:** The overburden formations can be drilled in 12 ¼” hole, thereby providing hole cleaning benefits when compared with a larger hole size.
- **Casing Cost:** Drilling one intermediate hole section allows the cost of running an intermediate cost string to be saved.

12 ¼” Intermediate Hole and 9 5/8” Production Casing Setting Depth

The 12 ¼” intermediate hole section will be drilled through the overburden formations to the top of the Forties aquifer, with 9 ⅝” production casing being set directly below the top of the Forties reservoir sands. This casing seat has been selected to isolate the Eocene, Balder and Sele formations prior to drilling the reservoir with a lower mud weight.

8 ½” Production Hole and Production Liner Setting Depth

An 8 ½” horizontal hole section will be drilled through the Forties Sand, with the section length being optimised for CO_2 injection purposes.

A 7” liner will be run to TD and cemented across its entire length for reservoir management and zonal isolation purposes.

End of Field 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 Sele and Eocene shales. These formations have sufficient strength to contain reservoir pressure; therefore, by placing the abandonment plugs opposite these formations, store integrity will be assured.

Subsea Appraisal Well

The conceptual well design for the appraisal well is as follows:

36” x 30” Conductor

The conductor design will be as per a subsea CO_2 injector.

17 ½” Surface Hole and 13 ⅜” Casing Setting Depth

The surface casing setting depth will be as per a subsea CO_2 injector.

12 ¼” Intermediate Hole and 9 ⅝” Production Casing Setting Depth

The 9 ⅝” production casing setting depth will be as per a subsea CO_2 injector.

8 ½” Production Hole and Production Liner Setting Depth

An 8 ½” hole section will be drilled through the Forties Sand, into the Ekofisk Chalk, in order to appraise the entire Forties Sand sequence.

A 7” liner will be run to TD and cemented across its entire length for well testing purposes.

Well Abandonment

The casing sizes and setting depths have been selected to ensure that the well can be abandoned after testing by placing cement plugs inside cemented 9 ⅝" production casing and opposite the Sele and Eocene 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 CO_2 injectors, the following issues should be taken into consideration:

- Corrosion caused by exposure to 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:

- Conductor
- Surface casing
- Production casing above the production packer

However, below the production packer, the casing and liner 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 modelling be conducted during the FEED stage to confirm that this material is suitable for the injection stream specification. The strings to be designed using CRA materials are:

- 9 ⅝" production casing below the production packer
- 7" production liner

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, 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.

The appraisal and monitoring wells will not be exposed to the same concentrations of CO_2 and/or water as an injector. However, it is recommended that the selected casing grades are the same for a monitoring well as for an injector. This should provide the following benefits:

- Reservoir management flexibility is provided, i.e. it allows the monitoring well to be used as a contingency injector.
- It would minimise the number of differing casing joints and string components purchased.

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 -60°C. 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.

Negative Wellhead Growth

When CO_2 injection commences, well temperatures are expected to drop. For platform wells, this could lead to casing contraction and negative wellhead growth (i.e. the wellhead made up to the surface casing will move lower, and the tensile stresses in the 13 ⅜” and 9 ⅝” casing strings will decrease). This scenario should be modelled during the FEED stage, to confirm that the selected casing strings remain within their tensile and compression design limits.

In addition, wellhead downward movement could lead to the wellhead, annulus valves and flowline clashing with the top of the conductor. Therefore, it is recommended that casing contraction is modelled during the FEED stage to determine the movement magnitude, and to confirm that the gap between the top of the conductor and the surface casing starter wellhead is sufficient to prevent component clashes.

Drilling Fluids Selection

42” x 36” Hole Section

This hole section will only be drilled in subsea wells, and should be drilled with seawater and viscous sweeps, taking returns to the seabed. At section TD, the hole should be displaced to 10.0 ppg spud mud, to maintain wellbore stability prior to running the conductor.

Surface Hole Section

The 22” or 17 ½” surface hole section should be drilled with seawater and viscous sweeps, taking returns to the seabed. 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.

Intermediate Hole Section

The 14 ¾” or 12 ¼” intermediate hole section should be drilled with a mud weight between 13.0 and 13.5 ppg, taking returns to the rig. The mud weight should be selected using the recommendations in the wellbore stability model for the planned hole inclination.

Oil based mud has been selected to:

- Maintain wellbore instability in the overburden shales.

- Maintain gauge hole in order to reduce the risk of hole cleaning problems and increases the probability of obtaining a good cement bond.
- Minimise ECD via tight control of mud properties.
- Reduce the friction factors for running drillstrings and casing.

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.

Reservoir Hole Section

The 8 ½" reservoir hole section should be drilled with a mud weight between 12.0 and 12.5 ppg, taking returns to the rig. The mud weight should be selected using the recommendations in the wellbore stability model for vertical and horizontal applications.

Oil based mud has been selected to:

- Maintain wellbore instability in the intra-Forties shales.
- Minimise the risk of hole enlargement and ledging at sand / shale interfaces.
- Reduce the risk of differential sticking in the Forties Sand by building a tight filter cake.
- Maintain gauge hole in order to reduce the risk of hole cleaning problems and increase the probability of obtaining a good cement bond.
- Reduce the friction factors for running drillstrings and the liner.
- Minimise formation damage in the Forties Sand by building a tight filter cake and reducing the depth of filtrate invasion.
    - It should be noted that oil-based mud can also cause damage if incorrectly specified. Fluid loss to the reservoir can affect porosity; therefore it is important to maintain mud system fluid loss at very low levels. In addition, filter cake deposition must be tightly controlled, to ensure that any damage that does occur is local to the wellbore, allowing the perforation tunnels to extend beyond the damaged zones.

Cement Programme

Conductor

For subsea wells, the conductor should be cemented back to the mudline using a single, conventional rapid hardening cement slurry.

For platform wells, the conductor will be driven to depth.

Surface Casing

The purpose of the surface casing cement job is primarily to provide a strong shoe prior to drilling the intermediate hole section into the top of the Forties reservoir. As such, a tail slurry should be used to generate the compressive strength required to meet this objective.

For both platform and subsea wells, the surface casing should be cemented back to the seabed in order to provide structural stability, and minimise abandonment costs.

Conventional lead and tail slurries should be selected for this cement job.

Production Casing

The purpose of the 10 ¾" or 9 ⅝" production casing cement job is to provide a strong shoe prior to drilling the Forties Sand, as well as preventing CO_2 leakage from the reservoir. Therefore, a tail slurry should be used to generate the compressive strength required to meet this objective.

For platform wells, the 10 ¾” casing should be cemented to 1,000m above the 10 ¾” shoe in order to:

- Minimise the cement column hydrostatic head applied to the Balder formation, in order to reduce the risk of losses.
- Minimise leak paths from the Forties Sand.
- Optimise the end of field life abandonment design, by providing sufficient annular cement for full wellbore coverage across the Sele and Eocene Shale formations.

For subsea wells, the 9 ⅝” casing should be cemented to 1,000m above the 9 ⅝” shoe in order to:

- Minimise the cement column hydrostatic head applied to the Balder formation, in order to reduce the risk of losses.
- Minimise leak paths from the Forties Sand.
- Avoid the pressures associated with a trapped B-annulus, should it be decided to flow the well to clean-up prior to initiating CO_2 injection.
- Optimise the end of field life abandonment design, by providing sufficient annular cement for full wellbore coverage across the Sele and Eocene Shale formations.

Production Liner

The purpose of the 7” cement job is to provide zonal isolation in the reservoir and prevent CO_2 leakage. The liner should be cemented over its entire length to the liner hanger.

Production Casing and Liquid Phase Liner Cement Design

At present, it is planned to cement the production casing and liner strings 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 and 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 11-17 Cement degradation rates in CO_2 Laboratory test results

For comparison purposes, the Forties reservoir pressure is predicted to be approximately 225 bar. As such, the rate of cement degradation predicted by Bruckdorfer may be the most appropriate measurement to use. This suggests that cement would degrade at a maximum rate of 7.9m per 10,000 years. Given that the length of cement behind the 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.

11.7.3 Completion Design

11.7.3.1 Lower Completion

The lower completion consists of a 7” cemented and perforated liner. No sand control is incorporated following the recommendations of the sanding risk review (section 3.6.3).

Perforating options include:

- TCP shoot and pull
- Coiled tubing conveyed perforating
- Wireline/tractor perforating

As the well is close to hydrostatic, TCP shoot and pull could be used without significant formation damage (low salinity brine or base oil used to create a slight underbalance). The upper completion can be run in hole while taking losses (topped up with seawater). However, should pressures be slightly higher, well control will be required. In this case Coiled Tubing conveyed perforating might be favoured (TCP gun drop is not an option in horizontal wells). Coil could also be used for off-loading the well with nitrogen if back-flow is required to clean up the well. Wireline perforating with tractors may be an option, but with a large zone to perforate, gun lengths per wireline run will be limited and a large number of perforating runs required. Given the length of perforations and the depth (long trip time) TCP shoot and pull is the favoured option, using dynamically underbalanced guns to ensure good perforation tunnel clean out. No flow-back clean up would be attempted in this scenario.

11.7.3.2 Upper Completion

The upper completion consists of a 7” tubing string in the southern platform wells and a 5-1/2” tubing string in the northern subsea wells, anchored at depth by a production packer in the 9-5/8” production casing, just above the 7” liner hanger. Components include:

- 7” / 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).

11.7.3.3 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.

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 11-18 Suitable materials for use with different contaminants

While nitrogen, methane and some other gases may be 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.

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 Forties (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). Forties reservoir temperature is moderate (~ 105°C) and therefore the impact of SO2 should be 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

11.7.3.4 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 Forties 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.

11.7.3.5 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 Forties, the primary risk of hydrate formation is following any wash water injection operations. 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 (90,000ppm), such as is present in the reservoir, may freeze if temperatures drop below -7°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.

11.7.4 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. Remedial perforating may be required if formation damage occurs, as might well clean-out with coiled tubing (if sand back-production occurs).

11.7.5 Wells Basis of Design Summary

- The Forties Site Injector Well Basis of Design can be summarised as follows:
- The injector wells will be drilled from two sites: a southern NUI platform by standard North Sea jack-up and a northern subsea template by a semi-sub drilling rig
- The wells will be a deviated (up to 65deg) in the tangent section, dropping to horizontal through the target formation
- The platform wells will consist of 26” conductor, 18-5/8” surface casing and 10-3/4” production casing and 7” production liner (cemented and perforated)
- The subsea wells will consist of 30” conductor, 13-3/8” surface casing and 9-5/8” production casing and 7” production liner (cemented and perforated)
- The platform wells will be completed with 7” production tubulars
- The subsea wells will be completed with 5-1/2” production tubulars
- All flow wetted surfaces will be 13%Cr material

- Maximum injection rates in the platform wells will be 4.5 Mte/yr (232.6 mmscf/day)
- Maximum injection rates in the subsea wells will be 2.589 Mte/yr (133.9 mmscf/day)
- Maximum FTHP will be 160 bar
- Maximum SITHP will be 80 bar
- Maximum WHT will be 6oC
- Minimum Design Temperature (to be confirmed by transient modelling)

11.8 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: $V_e = \frac{c}{\sqrt{\rho}}$

Where;

V_e = Erosional Velocity (m/s)

c = factor (see below)

ρ = 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/πd^2

Where,

V = Velocity (m/s)

Q = Mass flow rate (MTPa)

Reynolds Number: Re=ρVd/μ

Darcy Friction Factor: The friction factor is obtained from the Serghides' solution of the Colebrook-White equation.

$$A = -2\log_{10}\left(\frac{\frac{\varepsilon}{D}}{3.7} + \frac{12}{Re}\right), B = -2\log_{10}\left(\frac{\frac{\varepsilon}{D}}{3.7} + \frac{2.514}{Re}\right),$$

$$C = -2\log_{10}\left(\frac{\frac{\varepsilon}{D}}{3.7} + \frac{2.514}{Re}\right), f = \left(\frac{A - (B-A)^2}{C - 2B + A}\right)^{-2}$$

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 Forties 5 NUI	24” (609.6mm)	6MTPa	217km	0.045	Liquid/Dense [1]	0.068 bar	15.4 bar
		8MTPa				0.118 bar	26.9 bar
		10MTPa				0.183 bar	41.8 bar
		12MTPa				0.263 bar	60.0 bar

Notes:

1. Density of 980.3 kg/m^3 and viscosity of 0.1016 kg/sm

Table 11-19 St Fergus to Forties 5 NUI pipeline pressure drop

Pipeline	Pipeline OD	Mass Flow Rate	Route Length	Pipe Roughness	Fluid Phase	Pressure Drop per km	Pressure Drop
Forties 5 NUI to Northern Template	12” (323.9 mm)	2MTPa	24km	0.045	Liquid/Dense [1]	0.197 bar	4.9 bar
		3MTPa				0.0.428 bar	10.6 bar
		4.3MTPa				0.872 bar	21.6 bar
		5MTPa				1.177 bar	29.2 bar

Notes:

1. Density of 980.3 kg/m^3 and viscosity of 0.1016 kg/sm

Table 11-20 Forties NUI to Northern Template

Preliminary wall thickness calculations to PD8010 Part 2 (British Standards Institution, 2015) have also been performed. As the product is dry CO_2 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 Forties 5 NUI	NUI to Northern Template
Outer Diameter	609.6mm	323.9
Wall Thickness	25.4mm	14.3
Corrosion Allowance	1mm	1mm
Material	Carbon Steel	Carbon Steel
Corrosion Coating	3 Layer PP	3 Layer PP
Weight Coating	Concrete Weight Coating	-[1]
Pipeline Route Length	217km	24km
Installation	S-Lay	Reel Lay
Crossings	7	1

Notes:

1. Density of 980.3 kg/m^3 and viscosity of 0.1016 kg/sm

Table 11-21 Forties 5 Development pipeline specifications

As discussed within Section 5 of the report, there are a large number of other potential storage sites along the Forties pipeline route and in the vicinity of the NUI and subsea template. The 24” pipeline above has been sized for a mass flow rate of up to 10 MTPA. Should subsequent studies determine that there is merit in pre-investing in a significantly larger pipeline to allow for further expansion of CO_2 storage (or Enhanced Oil Recovery (EOR)), the table below summarises at a high level the additional CAPEX associated with procurement, fabrication and installation of pipelines up to 32” diameter, to deliver up to 15 or 20 MTPA of CO_2 to the Forties 5 NUI.

Note that no consideration has been given to any additional CAPEX associated with procuring such large diameter pipelines in non-standard wall thicknesses, or any modifications to the St Fergus pump station that may be required to provide the required compression.

The current base case Transportation CAPEX for the 24” pipeline capable of delivering up to 10 MTPA is £343 MM (see Section 6).

OD	MASS FLOW RATE = 15 MTPA				MASS FLOW RATE = 20 MTPA			
	DP (bar)	MAOP (bar) [1]	WT (mm)	CAPEX (£ MM)	DP (bar)	MAOP (bar) [1]	WT (mm)	CAPEX (£ MM)
24”	93.3	280.3	33	383.3	165.2	352.2	40	430.9
26”	61.8	248.8	32	397.4	109.3	296.3	38	441.8
28”	42.2	229.2	32	417.9	74.6	261.6	36	450.2
30”	29.6	216.6	32	438.1	52.3	239.3	35	464.5
32”	21.3	208.3	32	458.6	37.5	224.5	35	486.8

Table 11-22 CAPEX associated with a larger diameter pipeline from St Fergus to Forties NUI

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 Forties 5 facilities. The OPEX has been calculated based on a 40 year design life.

An overview of the Forties 5 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, Template, Umbilical
- 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 6-1. 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 30-40 year design life	
ABEX (Transportation, Facilities, Wells, Other)	
Decommissioning, Post Closure Monitoring, Handover	

Table 11-23 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 below and illustrated in Figure 11-53.

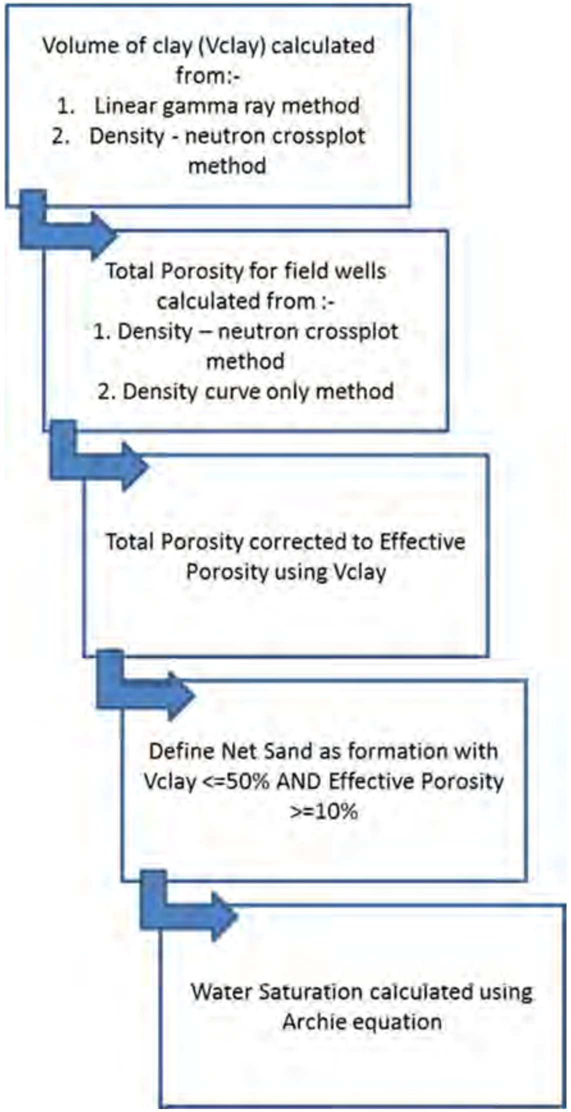


Figure 11-53 Summary of petrophysical workflow

11.8.3.1 Parameter Definition

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, resulting in a geothermal gradient of 1.5 DegF/ 100ft (Figure 1).

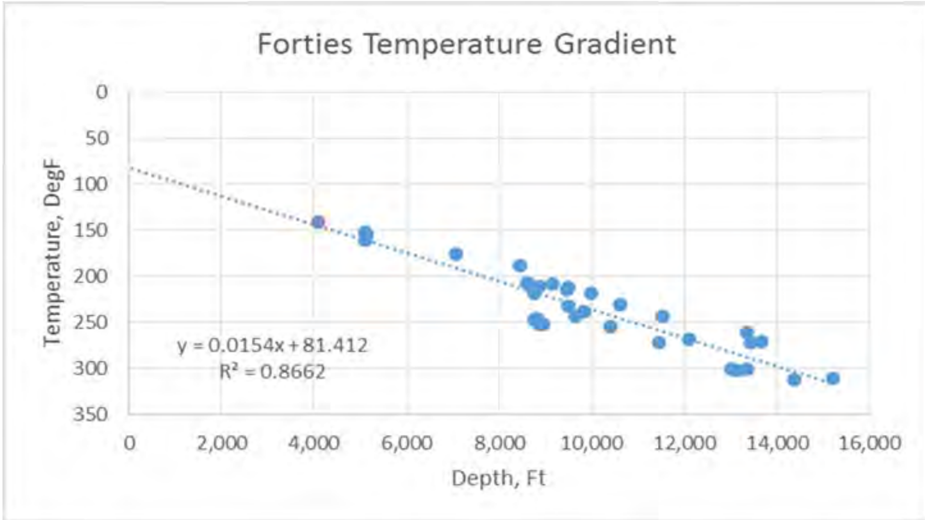


Figure 11-54 Recorded bottom hole pressure from wireline data°F

Temperature gradient, in degrees Fahrenheit, is estimated using the following equation:

$$BHT = 0.0154 \times TVD + 81.4$$

Formation Water Resistivity

The Forties aquifer is moderately saline, with 85k to 95k mg.l-1 NaCl eq. and of a uniform composition, the formation connate water is less saline than the aquifer, and more variable, with a reported range of 50k to 95k mg.l-1 NaCl eq.

A number of Forties area wells are published in the SPWLA Rw Atlas (Warren & Smalley, 1994), Table 11-24:

Well	Field	Rw at 60°F
21/10-5	Forties	0.099
22/9-4	Everest	0.162
22/14-1		0.100
22/18-2	Montrose	0.100

Table 11-24 Regional Connate Rw

Electrical Resistivity Properties

No SCAL data was identified to validate the electric properties used for the porosity and saturation exponents. Table 11-25 details the assumed parameters that were validated in the water zones with Pickett plots, and are consistent with the Humble parameters for a clastic reservoir.

Exponent	Value
a	0.62
m	2.15
n	2.00

Table 11-25 Saturation component exponents

Formation Resistivity

The deepest penetrating resistivity curve is always used as the measurement 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:

$$Vclay = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

Figure 11-55 is a multi-well histogram of Gamma Ray over the entire reservoir interval for all the wells in the project. The cumulative distribution curve for all the data has been used as a baseline calibration for sand and shales, picking the 10th percentile as the clean sand point and the 90th percentile as the shale point. The P10 (clean sand) and P90 (shale point) for the Forties zone is 28.6 and 66.1 API respectively

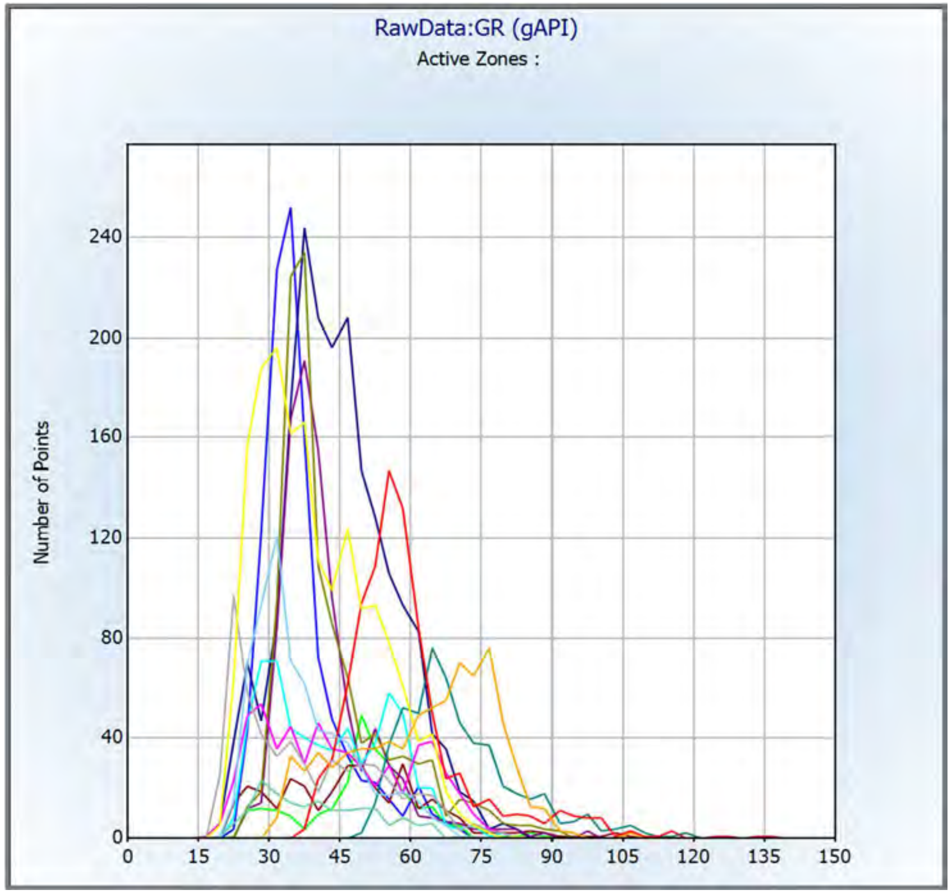


Figure 11-55 Multi-well gamma ray distribution

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 11-56 is a multi-well crossplot of the Neutron-Density over the Forties zone of interest. These data fall on a consistent ‘clean’ sand line with an expected global ‘clay-point’ falling at approximately 0.45pu and 2.5 g/cc respectively for the Neutron and Density.

Note that the proposed ‘clay-point’ will be offset to an equivalent ‘shale-point’, as presented in Table 11-27, where the ‘shale-point’ average position is estimated to be 0.336pu and 2.45g/cc respectively for the Neutron and Density logs.

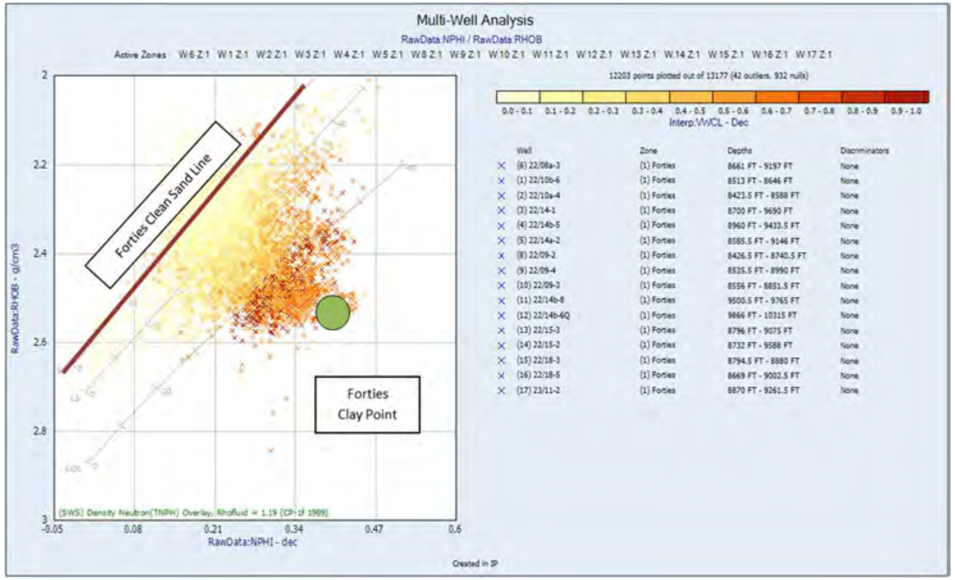


Figure 11-56 Neutron density crossplot for evaluated wells

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.

Based upon a fairly extensive database of 1,323 measurements of core grain density, Figure 11-56, a mean matrix density for the Forties sandstone of 2.666 g/cc is assumed. This is consistent with the assumption of a quartz dominated sandstone.

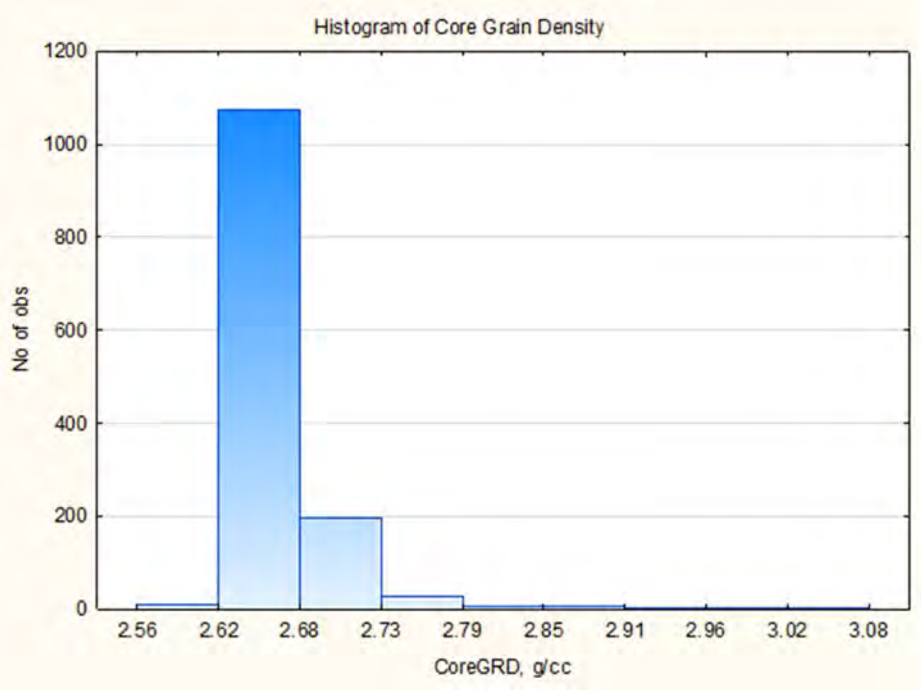


Table 11-26 Measured core grain density

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. Figure 11-57 summarizes the distribution of the core porosity data, the plot is has 1,807 validated data points with a mean porosity of 18.5%, the data distribution has a negative skew, with the median and mode value of 19.8%.

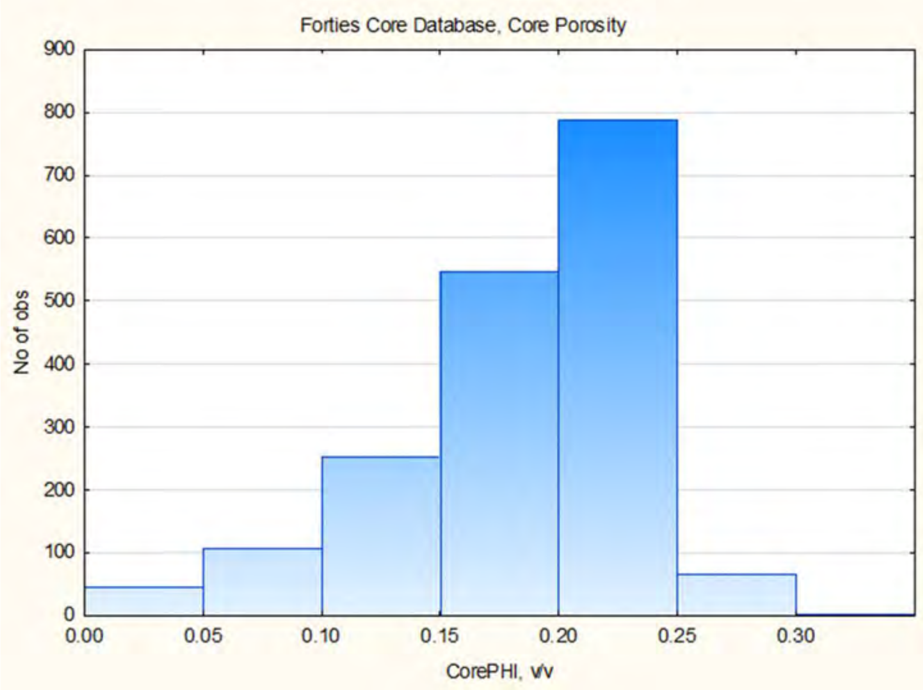


Figure 11-57 Measured core porosity

The core porosity measurements available are all made at ambient conditions, there are no SCAL measurements made at uniaxial confining pressures that simulate overburden conditions. A correction in the order of 0.96 is often used to scale core porosity from ambient to overburden conditions in the absence of these data.

There is a slight mismatch between the wireline and core porosity averages that is likely to be the result of comparing ambient core porosity to overburden measured porosity by the wireline logs.

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.

No SCAL data was identified to validate the electric properties used for the porosity and saturation exponents. Table 11-25 details the assumed parameters that were validated in the water zones with Pickett plots, are consistent with the Humble parameters for a clastic reservoir.

11.8.3.4 Petrophysical Parameter Selection

Table 11-27 details the parameters used to estimate shale and clay volume:

Petrophysical Parameter Selection for Clays and Shales							
Well	GR_{Clean}	GR_{Shale}	$RHOB_{Shale}$	$NPHI_{Clay}$	PEF_{Clay}	Rt_{Clay}	DT_{Clay}
22/08a-3	29	81	2.479	0.288	3.8	0.9	96.0
22/09-2	31	91	2.506	0.325	3.9	0.9	104.0
22/09-3	28	94	2.462	0.440	4.0	0.9	107.0
22/09-4	36	78	2.491	0.296	3.8	1.2	93.0
22/10a-4	27	60	2.481	0.333	4.0	0.8	107.0
22/10b-6	32	61	2.388	0.392	6.1	1.0	104.0
22/14-1	31	62	2.234	0.446		0.8	109.0
22/14a-2	35	80	2.401	0.387		0.7	90.5
22/14b-5	35	86	2.452	0.288	4.0	0.8	108.0
22/14b-6Q	44	126	2.444	0.357		0.9	107.0
22/14b-8	53	106	2.454	0.324	3.0	0.9	80.0
22/15-2	24	67	2.443	0.260	3.6	1.3	105.0
22/15-3	21	59	2.506	0.302	3.0	1.0	101.0
22/18-3	12	89	2.630	0.323		1.4	98.0
22/18-5	33	104	2.436	0.312	5.1	0.9	108.0
23/11/2	37	80	2.426	0.302	4.2	1.2	107.0
Average Values	**32**	**83**	**2.452**	**0.336**	**4.0**	**1.0**	**101.5**

Table 11-27 Clay parameter estimation

Table 11-28 details parameter used to estimate porosity and water saturation.

Petrophysical Parameter Selection for Porosity and Saturation Model			
Well	**Phi Model**	**Rw at 60 DEGF**	**Sw Model**
22/08a-3	Density	0.125	Indo.
22/09-2	Density	0.125	Indo.
22/09-3	Density	0.125	Indo.
22/09-4	Density	0.100	Indo.
22/10a-4	Density	0.100	Indo.
22/10b-6	Density	0.100	Indo.
22/14-1	Density	0.100	Indo.
22/14a-2	Density	0.100	Indo.
22/14b-5	Density	0.100	Indo.
22/14b-6Q	Density	0.100	Indo.
22/14b-8	Density	0.100	Indo.
22/15-2	Density	0.196	Indo.
22/15-3	Density	0.137	Indo.
22/18-3	ND-Xplot	0.104	Indo.
22/18-5	Density	0.100	Indo.
23/11/2	Density	0.097	Indo.

Table 11-28 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 cutoff is increased to greater than 15%. Figure 11-58 is a crossplot of all the available Forties core data, there is clearly at least two 'populations' of data and no effective reservoir is excluded using 10% porosity.

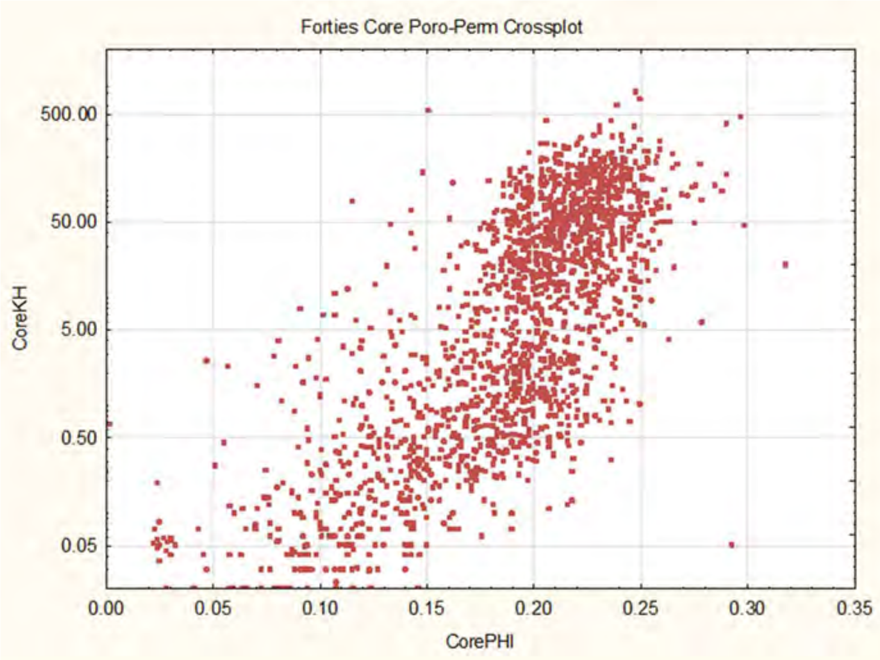


Figure 11-58 Core permeability cross plot

11.8.4 Geochemistry

11.8.4.1 Objective

Geochemical modelling of the primary caprock for the Forties Eocene aquifer, UKCS 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. Specifically, the main objective in this study was to assess if, increasing the volume (partial pressure) of CO_2 in the Forties Eocene reservoir sands leads to mineral reactions which result in either an increase or decrease of the porosity and permeability of the overlying Sele Formation caprock.

11.8.4.2 Methodology

A study methodology was developed to answer a key question:

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

The work flow followed is shown in Figure 11-59. Water and any gas geochemical data, and mineral proportion data from the reservoir and the caprock (representing the pre-CO_2 injection conditions) were collected from published analogue data.

Following data QC, the initial gas-water-rock compositions were modelled, using a range of CO_2 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 CO_2 that has arrived at the reaction site (as reflected in the fugacity [as stated approximately the partial pressure] of CO_2]).
- 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.

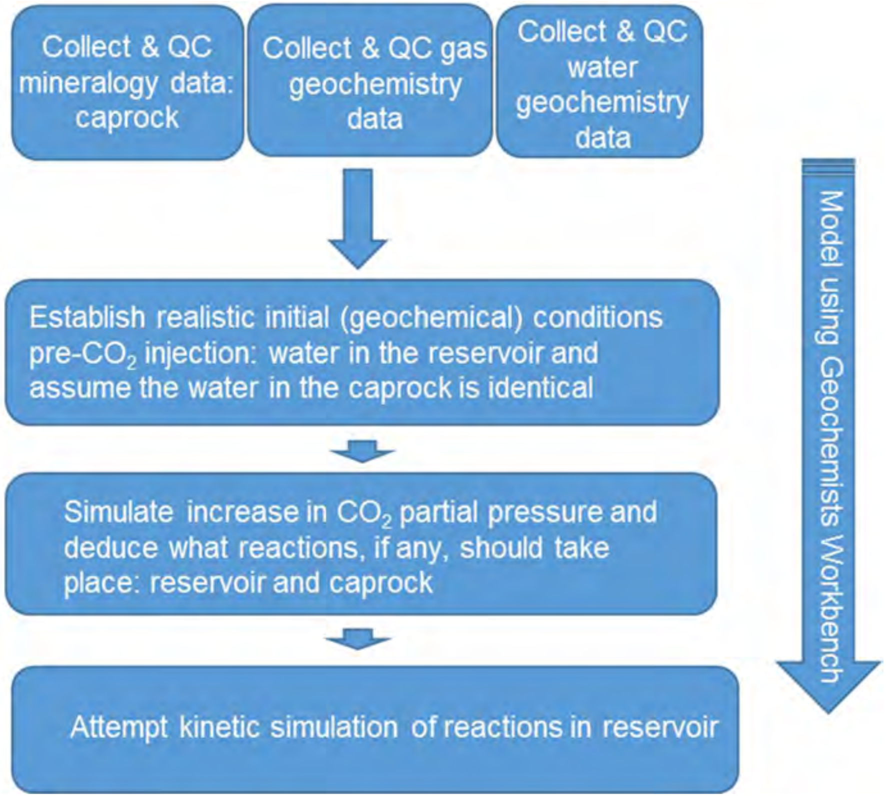


Figure 11-59 Geochemical modelling workflow

11.8.4.3 Data Availability

1. Water compositional data were taken from a regional compilation (Warren & Smalley, 1994) and from other local produced water 10-ion

analyses (Core Laboratories UK Ltd, 1985) (Core Laboratories UK Ltd, 2008) available in the CDA.

2. Gas compositional data were taken from a report (Petrophase, 2006) for well 22/15-3.
3. Caprock mineralogy data were taken (International Drilling Fluids, 1975) and validated by recent published data (Marcussen, et al., 2009) (Nielson, Rasmussen, & Thyberg, 2015) (Peltonen, Marcussen, Bjorlykke, & Jahren, 2008) (Peltonen, Marcussen, Bjorlykke, & Jahren, 2009)

11.8.4.4 Water Geochemistry

The water compositional data used are shown in Table 11-29.

1. Water compositional data seem to be of good quality and fully credible given their molar charge difference is within the permissible 5% (Table 11-29).
2. Water compositions have intermediate salinity and are Na-Cl dominated. Ca, Ba and Sr concentrations are reasonably high with, as expected, low sulphate and bicarbonate concentrations.
3. If, or when, the CO_2 partial pressure increases following CO_2 injection, then some carbonate mineral precipitation can be expected.
4. Na concentrations are not especially high suggesting limited chance of dawsonite precipitation.

name	Field	Source	Density g/cm3	TDS mg/l	TDS % salinity	pH	Ca++ mg/l	Na+ mg/l	K+ mg/l	Mg++ mg/l	Sr++	Ba++	Cl- mg/l	Br- mg/l	SO4-- mg/l	HCO3- mg/l	sum of positive charges	sum of negative charges	charge balance %	Ionic strength
21/10-FA12	Forties	Warren and Smalley (1994)	1.03	50770.00	4.91	7.00	926	18835	288	211	128	121	30241	0	20	0	0.89	0.85	2.37	0.91
21/10-FA51	Forties	Warren and Smalley (1994)	1.06	86743.00	8.20	7.00	2809	29364	372	504	574	252	52361	0	11	496	1.49	1.49	-0.01	1.58
21/20-FA34	Forties	Warren and Smalley (1994)	1.03	41905.00	4.08	7.00	720	14050	218	178	85	94	26372	165	23	0	0.67	0.75	-5.35	0.73
21/20-FB33	Forties	Warren and Smalley (1994)	1.04	65849.00	6.31	7.00	1720	23200	293	384	244	104	39900	0	4	0	1.14	1.13	0.68	1.19
21/20-FB62	Forties	Warren and Smalley (1994)	1.05	76640.00	7.29	7.00	2190	25600	360	474	364	244	47400	0	8	0	1.28	1.34	-2.08	1.39
21/20-FC44	Forties	Warren and Smalley (1994)	1.04	56140.00	5.41	7.00	1080	20000	253	252	202	64	34100	183	6	0	0.96	0.96	-0.40	1.00
21/20-FD43	Forties	Warren and Smalley (1994)	1.05	81551.00	7.73	7.00	2420	28770	369	398	490	204	48555	340	5	0	1.43	1.37	1.94	1.48
21/20-FD44	Forties	Warren and Smalley (1994)	1.05	80770.00	7.66	7.00	2460	28770	357	374	482	207	47779	340	1	0	1.43	1.35	2.73	1.47
22/6A-FE01	Forties	Warren and Smalley (1994)	1.06	93286.00	8.78	7.00	3490	31550	620	620	589	267	56144	0	6	0	1.63	1.58	1.46	1.72
22-9-2.	Forties	CDA	1.04	55703.20	5.37	5.92	1230	19990	240	135	145	100	33670	0	8	185	0.95	0.95	0.00	0.99
22/14b-5	Huntington	CDA	1.05	75553.90	7.19	7.32	2390	25340	565	330	450	180	45860	0	4	435	1.28	1.30	-0.97	1.37
average values							1949	24134	358	351	341	167	42035	93	9	101				

Table 11-29 Water geochemical composition used in modelling

11.8.4.5 Gas Geochemistry

Gas geochemical data for Forties were taken from reports by (Core Laboratories UK Ltd, 1985) and (Petrophase, 2006).

1. Gas compositions from gas caps seem to be credible and consistent. No gas concentration data from gas exsolved from aquifer water are available (as is typical).
2. Free gas in sampled gas caps contains some CO_2 (approx. 2.5%) but the low amount of total dissolved gas means that the fugacity of the gas in the water leg will be very low. In the model, the concentration of dissolved bicarbonate (that is strongly controlled by the fugacity of CO_2), is very low (see Table 11-30) suggesting that the initial CO_2 fugacity in the water is also very low.
3. In the model, the initial CO_2 fugacity was locked in to the water geochemistry with carbonate minerals controlling HCO3- and Mg2+ and Ca2+ concentration defined as the average reported for Forties

Reservoir	Approx depth m	Approx temperature °C	Approx pressure at testing interval	CH4 %	C2H6 %	C3H8 %	C4H10 %	C5H12 %	C6+ %	N2 %	CO2 %	H2S ppm
Forties	2597	102	3795	84.28	6.37	2.97	1.40	0.54	0.34	1.39	2.72	0.00
Forties	2689	105	3988	76.19	7.35	3.88	2.39	1.32	5.25	1.25	2.39	0.00

Table 11-30 Gas geochemical composition data used in modelling

11.8.4.6 Caprock Mineralogy

Mudstone caprocks above the Forties Eocene sandstone, known locally as the Sele Formation, were reported by (International Drilling Fluids, 1975). However, this report combined the kaolinite and illite totals, even though their responses to changing fluid composition and temperature are quite different. The report also failed to define the type of feldspar present. It also failed to define the type of smectite. The report did specify three mudstone types:

- Type 1: low smectite content
- Type 2: intermediate smectite content
- Type 3: high smectite content

For the geochemical modelling in this study, kaolinite and illite (summed total) have been split into two equal percentage amounts.

Published studies confirm the smectite-rich nature of the Palaeogene (Sele Formation) mudstones (Marcussen, et al., 2009) (Nielson, Rasmussen, & Thyberg, 2015) (Peltonen, Marcussen, Bjorlykke, & Jahren, 2008) (Peltonen, Marcussen, Bjorlykke, & Jahren, 2009). These reports also confirm the lack of chlorite in these mudstones and suggest that there are roughly equal amounts of illite and kaolinite.

(International Drilling Fluids, 1975) defined three different mudstone compositions. Sample 3 (Table 11-31) looks to be the best representative of the Sele Formation (Forties topseal) but all three have been used for the modelling to test for sensitivity.

The type of smectite has not been defined by any study but it assumed to be a Fe-Mg-poor Al-rich smectite, typical of mudstones (also referred to as montmorillonite).

Mineral	Sample 1	Sample 2	Sample 3
Quartz XRD %	14.0	10.0	16.0
Illite XRD %	28.0	26.5	22.0
K-feldspar XRD %	6.0	3.0	5.0
Dolomite XRD %	7.0	4.0	4.0
Calcite XRD %	6.0	4.0	4.0
Kaolinite XRD %	28.0	26.5	22.0
Pyrite XRD %	9.0	14.0	11.0
Smectite XRD %	2.0	8.0	12.0
Barite XRD %	0.0	4.0	4.0
total	100.0	100.0	100.0

Table 11-31 Caprock (Sele formation) mineralogy

The caprock mineralogy used in the geochemical modelling are shown below in Table 11-32.

Mineral	Sample 1	Sample 2	Sample 3
Quartz XRD %	14.0	10.0	16.0
Illite XRD %	28.0	26.5	22.0
K-feldspar XRD %	6.0	3.0	5.0
Dolomite XRD %	7.0	4.0	4.0
Calcite XRD %	6.0	4.0	4.0
Kaolinite XRD %	28.0	26.5	22.0
Pyrite XRD %	9.0	14.0	11.0
Smectite XRD %	2.0	8.0	12.0
Barite XRD %	0.0	4.0	4.0
total	100.0	100.0	100.0

For 1kg of water	Sample 1	Sample 2	Sample 3
Quartz cm3	280	200	320
Illite cm3	560	530	440
K-feldspar cm3	120	60	100
Dolomite cm3	140	80	80
Calcite cm3	120	80	80
Kaolinite cm3	560	530	440
Pyrite cm3	180	280	220
Smectite cm3	40	160	240
Barite	0	80	80
Total mineral volume	2000	2000	2000

Table 11-32 Modelling input for the Forties caprock

- The three types of mudstone all look to be part of a standard series of clay-rich, quartz, carbonate and pyrite bearing rocks.
- For the modelling in this study, the mudstones have been assumed to contain about 12% porosity (water-filled pores where reactions occur).
- The volumes of the different minerals that collectively interact with the standard 1kg of water and the flooding CO_2 are listed in Table 11-32. Each modelled rock had a similar volume (2,000 cm^3).

11.8.4.7 Modelling Approach: Types of Reaction Schemes Due to CO_2 Injection into the Reservoir

If reaction happens at equilibrium with every bit of added CO_2, then the rocks are simply responding to the changing in gas partial pressure, the added dissolved bicarbonate and the reduced pH. Under assumed equilibrium, any minerals that are unstable over and above the added CO_2, must transform. Minerals are metastably present in the Sele Formation caprock (e.g. smectite clay minerals want to react but their previous alteration has been inhibited by slow kinetics; Table 11-33). Under equilibrium modelling, metastable minerals must transform. This explains why smectite instantly transforms to muscovite and chlorite in the equilibrium models. Equilibrium models are of no merit in the Forties case since they lead to instant transformation of smectite, at the ambient 100°C, to other minerals. They are not reported here.

If reactions are kinetically influenced, e.g. by slow dissolution rates, then the rate of interaction with CO_2 is limited by dissolution rate and not the rate of influx of CO_2. 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, Sonnethal, Spycher, & Pruess, 2006)

	Mineral	Alternative name	Formula	Mineral type
reactants	K-feldspar	Maximum Microcline	$KA_3Si_3O_8$	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
	Barite		$BaSO_4$	sulphate
products	Dawsonite		$NaAl(CO_3)OH$	carbonate
	Alunite	Alum	$KAl_3(SO_4)_2(OH)_6$	sulphate
	Siderite		$FeCO_3$	carbonate
	Witherite		$BaCO_3$	carbonate
	Hematite		Fe_2O_3	oxide

Table 11-33 Mineral resctants and products in the Sele formation geochemical model

11.8.4.8 Results

Mineral Reactions in the Sele Formation

Illite is partly replaced by muscovite (the two having roughly the same composition) but it also reacts with dissolved sodium in the formation water and the influxing CO_2 to make dawsonite:

Illite + Na+ + CO_2 → quartz + dawsonite + K+

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+ → kaolinite + quartz + Na+ + Fe2+ + Mg2+ + K+

Calcite reacts with released Mg from smectite-breakdown to create dolomite:

Calcite + Mg2+ +CO_2 → dolomite

CO_2 reacts with released Fe from smectite-breakdown to create siderite:

CO_2 + Fe2+ → siderite

The dominant reactions therefore lead to the replacement of illite, smectite and calcite by the minerals quartz, dawsonite, kaolinite, dolomite and siderite after CO_2 enters the geochemical system.

Kinetic Modelling: Caprock

In order to evaluate the kinetic effects on the reservoir, models reacting 10 mol CO_2(g) over both 5000 and 20000 years at 100°C for each of the 3 caprock types were run for the following conditions:

- Kinetic constraints 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.
    - Illite dissolution kinetics: pre-exponential rate constant 1.047x10-11 mol/m2.s, activation energy 23.67kJ/mol, 2000 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 Tables 6-8 below and in Figure 11-60 to Figure 11-62. Table 11-34 to Table 11-36 shows the modelled relative mineral volume change in caprock Types 1-3 after CO_2 injection takes place in the reservoir.

The main changes modelled in all three Sele Formation caprock types are that: illite is partly replaced by dawsonite (and muscovite), smectite is partly replaced by kaolinite, and calcite is partly replaced by dolomite. Precipitation of siderite, dolomite and dawsonite represent the sequestration of the fluxed CO_2 in the mineral phase. The growth of kaolinite and quartz represent the acidity-induced breakdown of smectite and illite.

Overall, there is a solid volume increase due to CO_2 flooding of the Sele Formation meaning that there is no increase in porosity and thus no increase in permeability.

The same reactions in happen in all three caprock types, but to different degrees of intensity as a function of the initial amount of smectite. Tables 6-8 shows the modelled mineral volume change in caprock Types 1-3 after CO_2 injection takes place in the reservoir after 5000 years and after 20000 years.

Table 11-37 shows the modelled relative mineral volume change in caprock Types 1-3 after CO_2 injection takes place in the reservoir, under kinetic modelling.

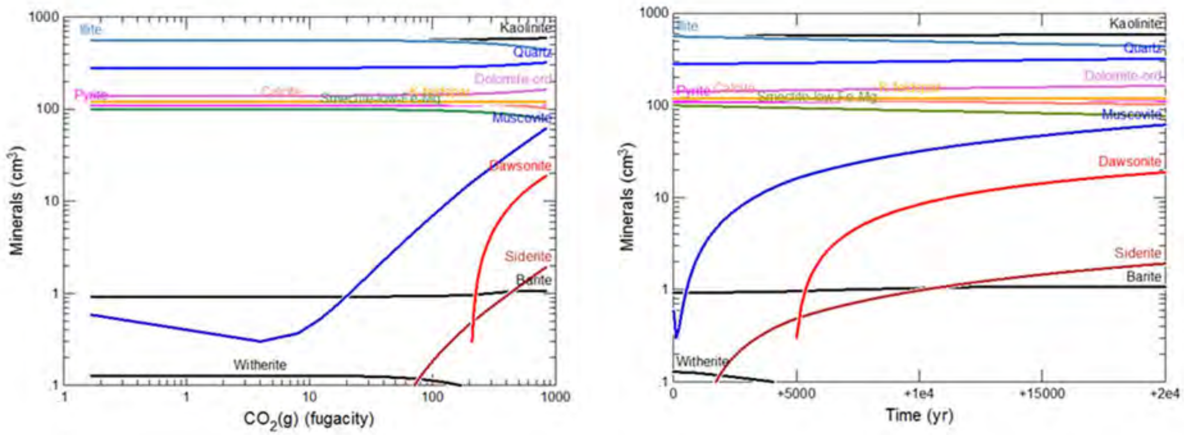


Figure 11-60 Kinetic modelling results: Caprock type 1 smectite poor

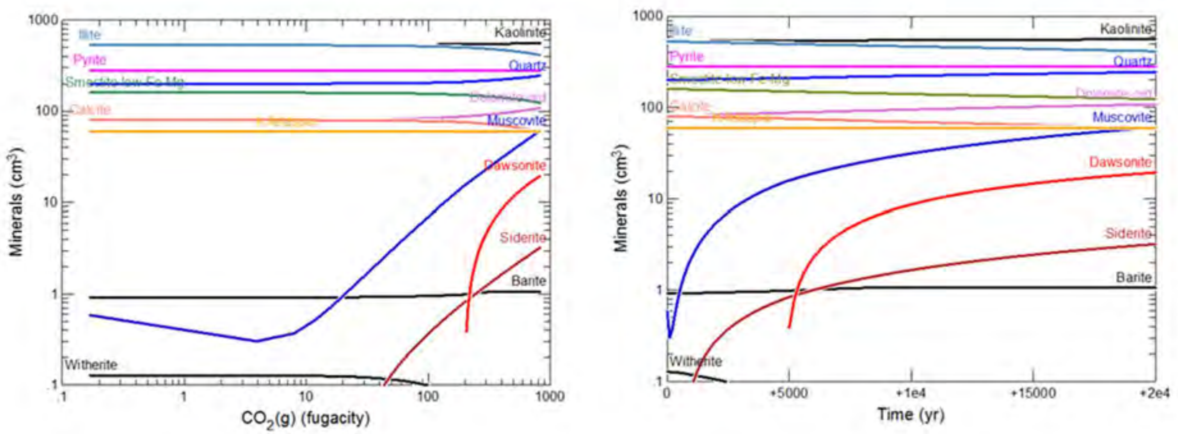


Figure 11-61 Kinetic modelling results: Caprock type 2 intermediate smectite

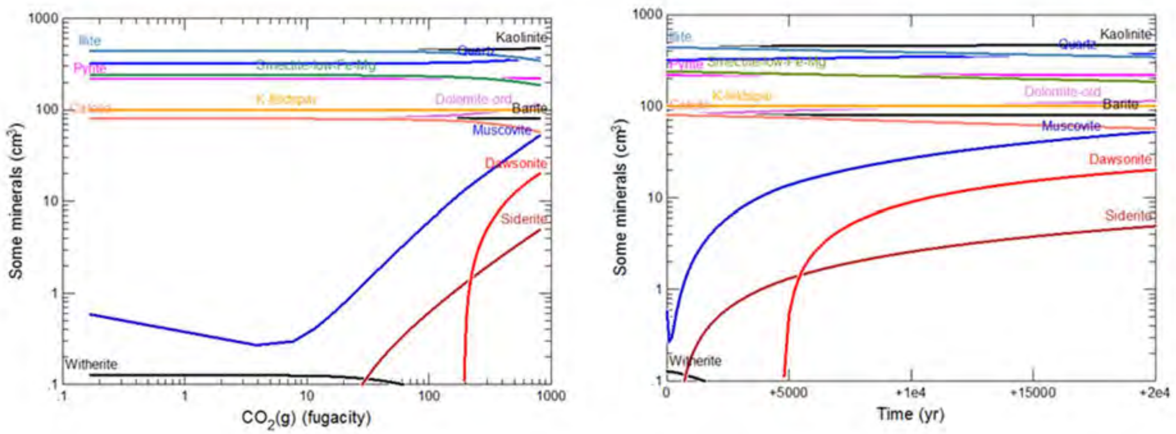


Figure 11-62 Kinetic modelling results: Caprock type 3 smectite rich

Mineral	initial moles	initial volume cm3	5000 yr moles	5000 yr volume cm3	20000 yr moles	20000 yr volume cm3
Illite	4.031	560.184	3.791	526.751	3.149	437.613
K-feldspar	1.102	119.981	1.102	119.981	1.102	119.981
smectite	0.7194	99.951	0.6746	93.727	0.5561	77.263
barite	0.01769	0.9214	0.0185	0.9637	0.02048	1.067
calcite	3.244	119.8	3.147	116.2	2.774	102.4
dawsonite	0	0	0.005067	0.3005	0.317	18.8
dolomite	2.175	139.9	2.275	146.4	2.538	163.3
kaolinite	5.621	559.4	5.756	572.8	5.927	589.8
muscovite	0.004	0.5859	0.1145	16.11	0.4383	61.68
pyrite	4.595	110	4.594	110	4.593	110
quartz	12.34	280	12.75	289.2	14.12	320.5
siderite	0	0	0.01701	0.4871	0.06718	1.923
witherite	0.0027	0.1277	0.001981	0.3909	0	0
Total volume cm3		1990.851		1993.312		2004.327

Table 11-34 Kinetic modelling reaction results for the Sele formation caprock type 1 (smectite poor)

Mineral	initial moles	initial volume cm3	5000 yr moles	5000 yr volume cm3	20000 yr moles	20000 yr volume cm3
Illite	3.815	530.167	3.588	498.545	2.981	414.266
K-feldspar	0.5511	60.001	0.5511	60.001	0.5511	60.001
smectite	1.151	159.917	1.079	149.913	0.8897	123.612
barite	0.01769	0.9214	0.01909	0.9948	0.02049	1.068
calcite	2.161	79.82	2.044	75.5	1.616	59.7
dawsonite	0	0	0.00655	0.3884	0.3265	19.36
dolomite	1.243	79.96	1.364	87.76	1.683	108.3
kaolinite	5.319	529.4	5.458	543.2	5.639	561.2
muscovite	0.004	0.5859	0.1127	15.86	0.4305	60.58
pyrite	11.7	280	11.7	280	11.69	279.9
quartz	8.815	200	9.273	210.4	10.8	244.9
siderite	0	0	0.02947	0.8439	0.1124	3.219
witherite	0.0027	0.1277	0.001383	0.06335	0	0
Total volume cm3		1920.900		1923.470		1936.107

Table 11-35 Kinetic modelling reaction results for the Sele formation caprock type 2 (intermediate smectite)

Mineral	initial moles	initial volume cm3	5000 yr moles	5000 yr volume cm3	20000 yr moles	20000 yr volume cm3
Illite	3.167	440.115	2.986	414.961	2.474	343.809
K-feldspar	0.9185	100.002	0.9185	100.002	0.9185	100.002
smectite	1.727	239.945	1.623	225.495	1.335	185.481
barite	1.534	79.92	1.536	80.03	1.537	80.07
calcite	2.161	79.82	2.031	75.02	1.537	56.75
dawsonite	0	0	0.0019	0.1127	0.34	20.16
dolomite	1.243	79.96	1.381	88.87	1.765	113.6
kaolinite	4.415	439.4	4.552	453	4.733	471
muscovite	0.004	0.5859	0.09371	13.19	0.3729	52.48
pyrite	9.19	220	9.188	220	9.185	219.9
quartz	14.1	320	14.58	330.8	16.26	368.8
siderite	0	0	0.04427	1.267	0.1728	4.946
witherite	0.0027	0.1277	0.000724	0.033	0	0
Total volume cm3		1999.875		2002.781		2016.999

Table 11-36 Kinetic modelling reaction results for the Sele formation caprock type 3 (smectite rich)

Kinetically controlled reactions	initial log fugacity CO2(g)	5000 yr log fugacity CO2(g)	20000 yr log fugacity CO2(g)	initial mineral volume	5000 yr mineral volume	20000 yr mineral volume	Change in mineral volume due to CO2 flood in 5000 yr	Change in mineral volume due to CO2 flood in 20000 yr	Commentary
2% smectite mudstone	-0.772	2.320	2.922	1990.851	1993.312	2004.327	100.12%	100.68%	Minor solid volume increase (loss of porosity) mainly due to growth of new dawsonite, quartz, dolomite at th expense of illite and smectite
8% smectite mudstone	-0.772	2.314	2.916	1920.9	1923.47	1936.107	100.13%	100.79%	As above but slightly more intense due to the greater amount of smectite
12% smectite mudstone	-0.772	2.288	2.908	1999.875	2002.781	2016.99	100.15%	100.86%	Also as above but most intense due to the greatest amount of smectite

Table 11-37 Summary of kinetic modelling results for caprock types 1-3: relative mineral volume changes 5000 years after CO_2 influx and 20000 years after CO_2 influx

11.8.4.9 Conclusions

Primary Caprock: Sele Formation

On flooding the Forties aquifer with CO_2, the clay-rich Sele Formation and younger overburden lithologies are considered unlikely to be geochemically affected in a way that increases permeability:

1. Mineral reactions are slow, and effectively negligible on the 5,000 year timescale;
2. The reactions that do occur lead to a very small net solid volume increase due to the replacement minerals having low density and reaction with the fluxing CO_2.
3. 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 kaolinite and quartz, releasing the cations: sodium, iron and magnesium, which leads to the growth of the carbonate minerals: dawsonite, siderite and dolomite.
4. Calcite undergoes replacement by dolomite instead of wholesale dissolution.
5. Overall, the most likely mineralogy is represented by caprock-3 (smectite-rich) leading to a miniscule solid volume increase of 0.15% in 5,000 years and 0.86% in 20,000 years.

Sele 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 Forties, an analysis of available log data was carried out using DrillWorks 5000. The following tasks were performed for selected wells within the field (basic workflow):

- Overburden or Vertical stress (SV): based on bulk density log
- Pore pressure calculation: based on an analysis presented on well 22/14a-2
- Fracture Gradient or minimum horizontal stress (Shmin): Matthews and Kelly method calibrated with reference frac gradient for Forties (0.75 psi/ft) and LOT/FIT data available.
- Poisson's ratio: based on sonic log
- UCS: Lal's law correlation applied to sonic log with modifications to match the drilling events.
- 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 fracture gradient of 0.75 psi/ft for the Forties sandstone (source material in the Reference section), therefore the calculated fracture gradient is calibrated to this reference fracture gradient and also 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 regional Shmin is aligned NE-SW. SHmax is often parallel to the main structural grain in the North Sea. The general Forties structural alignment in the area of interest is NW-SE in the SE part of the area and NE-SW in the NW part of the area. Shmax has been assumed to be aligned NW-SE for the purposes of this study as that orientation is deemed more relevant for the injection sites in the SW and NW parts of the area of interest (see Figure 11-64).

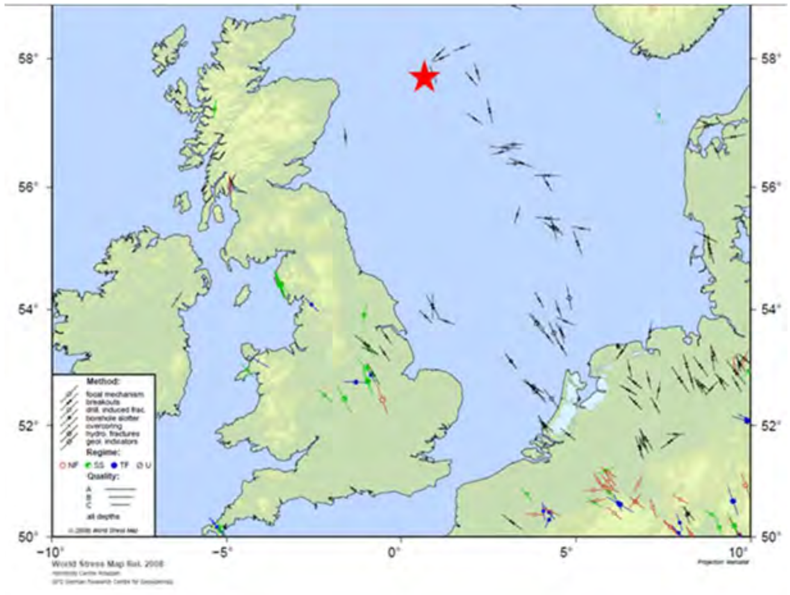


Figure 11-63 Forties stress orientation

11.9.2 Wells Evaluated

Logs available were obtained from the CDA website. The analysis was focused on three wells to cover the Forties field: 22/14b-6Q, 22/07-2 and 22/14a-2 (see orange ellipses in Figure 11-64). These wells were chosen on the basis of log availability, coverage and quality and the presence of adequate drilling records. The wells are not particularly central to the injection sites but given the relatively uniform nature of the Forties Sandstone and overburden sequences they are deemed to be representative.

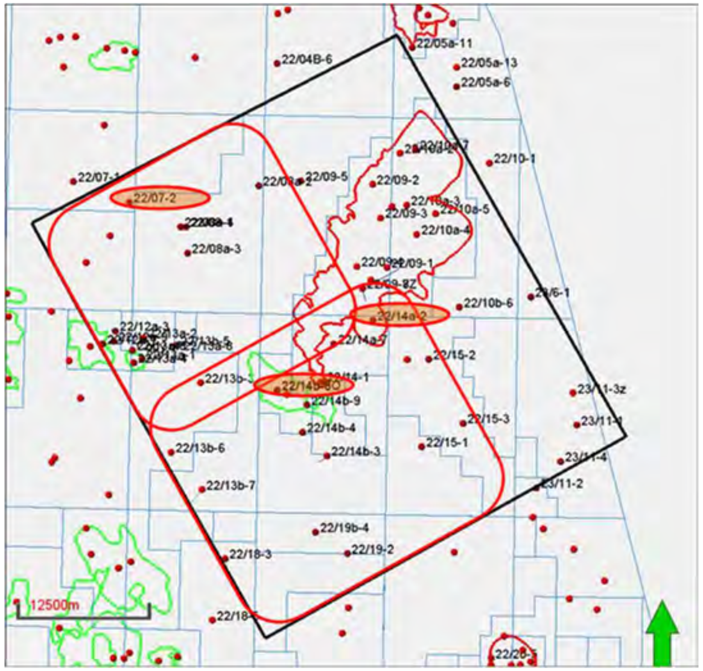


Figure 11-64 Forties 5 evaluated wells

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 following information was used to calculate the stress path:

- Pore pressure based on previous analysis from well 22/14a-2 (as shown in Figure 0 3). This estimated curve from the EoWR was used directly in 22/14a-2 and scaled to the lithological boundaries in 22/07-2 and 22/14b-6Q. Note the pressure ramp up within the Hordaland that then drops back in the Balder and Sele.
- Minimum horizontal stress (Shmin) calculated by Matthews and Kelly and calibrated with reference frac gradient (0.75 psi/ft) in Forties sandstone and also calibrated with FIT/LOT when available.
- Normal stress regime assumed. Maximum horizontal stress calculated from average of Shmin and overburden (Sv)

The calculated stress curves figures (e.g. Figure 11-65) show pore pressure (orange line), minimum horizontal stress (red line), maximum horizontal stress (black line) and overburden (magenta line).

The minimum horizontal stress curves were calibrated with LOT/FITs available as follows:

Well 22/14b-6Q:

- FIT at the 13-3/8” shoe (14.5 ppg at 2422 ft)
- Well 22/07-2
- LOT at the 26” shoe, which was very close to overburden (14.86 ppg at 2644 ft)
- LOT at the 13-3/8” shoe (14.36 ppg at 8197 ft)
- Well 22/14a-2
- FIT at the 20” shoe, very high, even higher than the overburden (not used for calibration)
- LOT at the 13-3/8” shoe (15.04 ppg at 5084 ft)

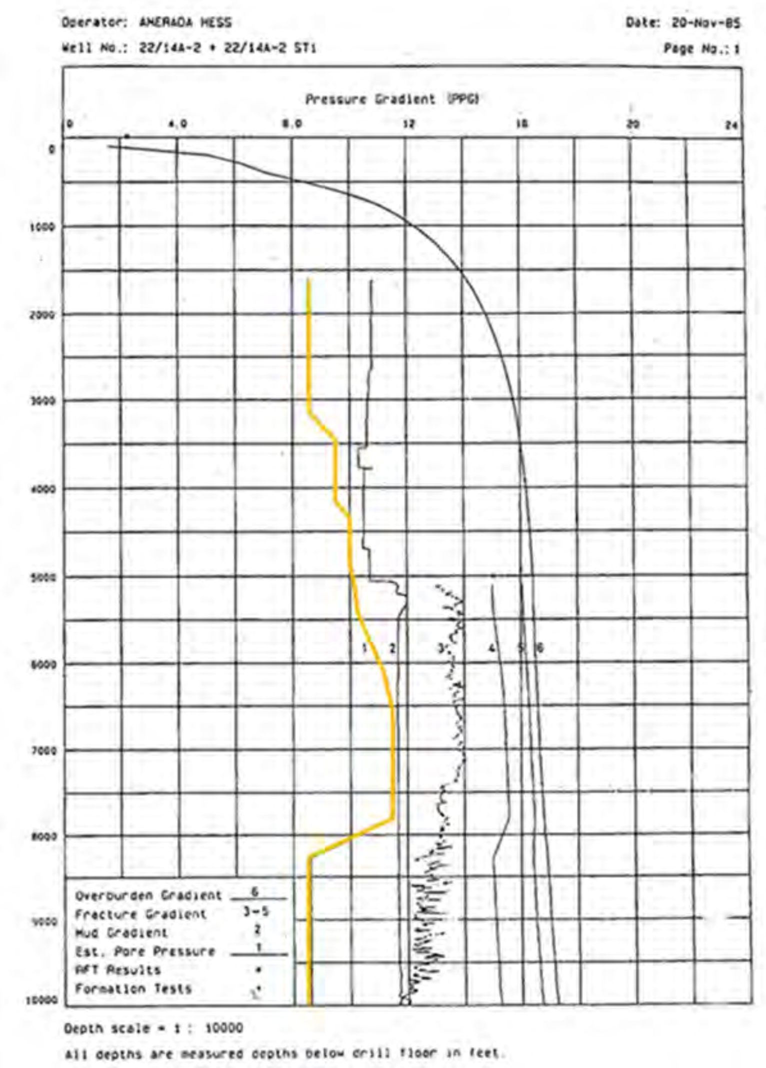


Figure 11-65 Pore pressure estimation for 22/14a-2

The rock mechanical properties figures (eg. Figure 11-67) depict the following rock mechanical properties derived from logs:

- Poisson's ratio (black line)
- Friction angle (blue line)
- Rock strength (UCS) (purple line)

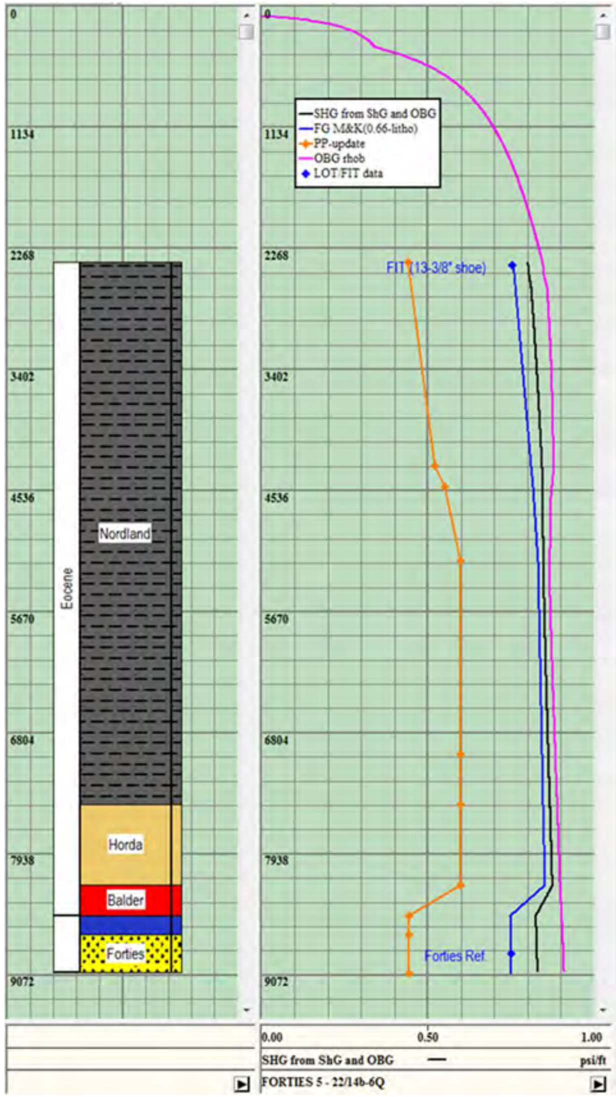


Figure 11-66 Calculated stress curves - Well 22/14b-6Q

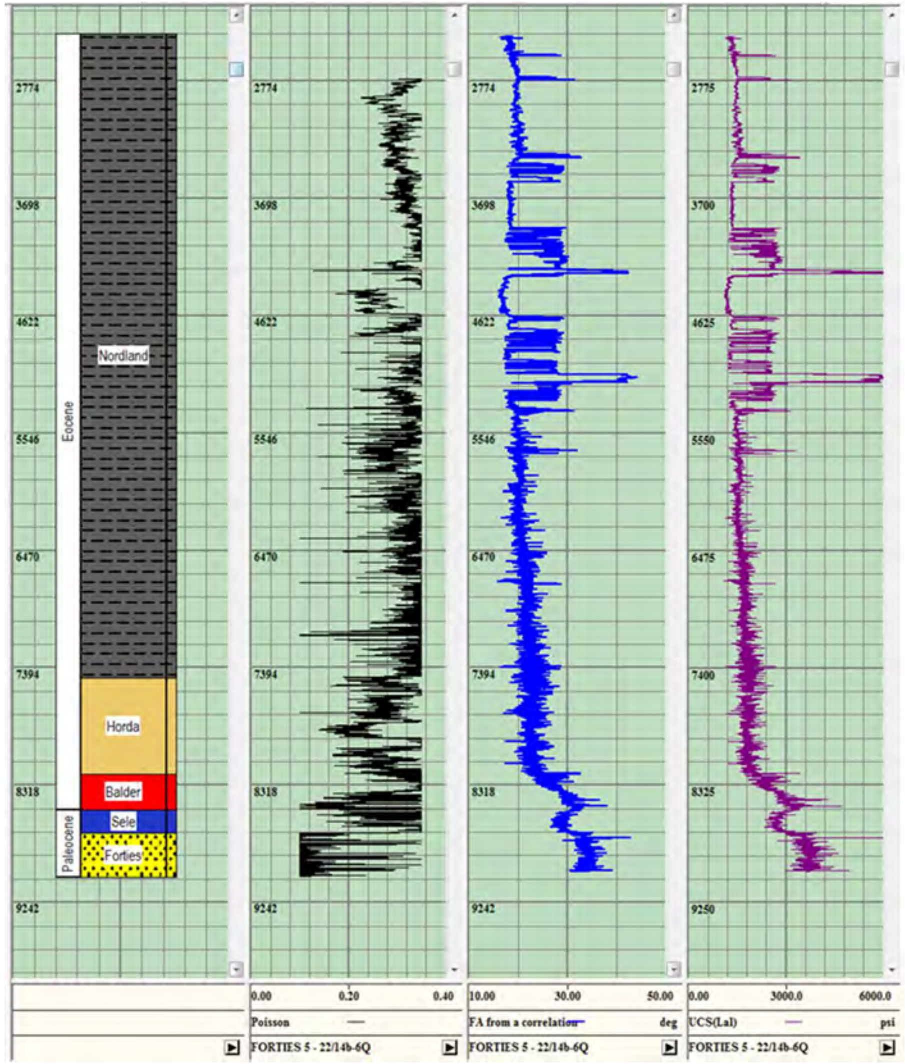


Figure 11-67 Rock mechanical properties - Well 22/14b-6Q

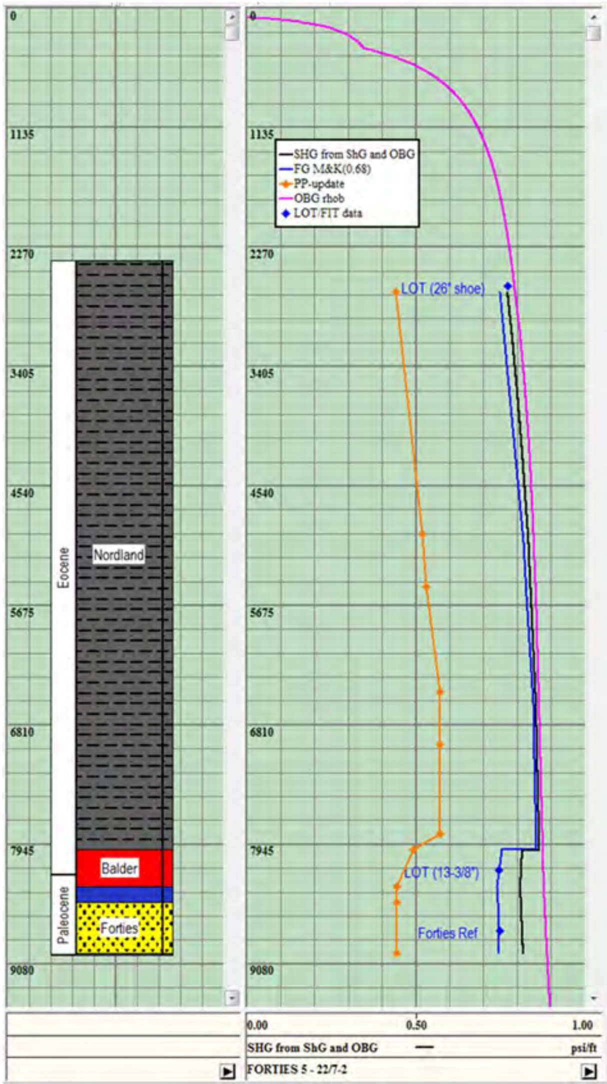


Figure 11-68 Calculated stress curves - Well 22/7-2

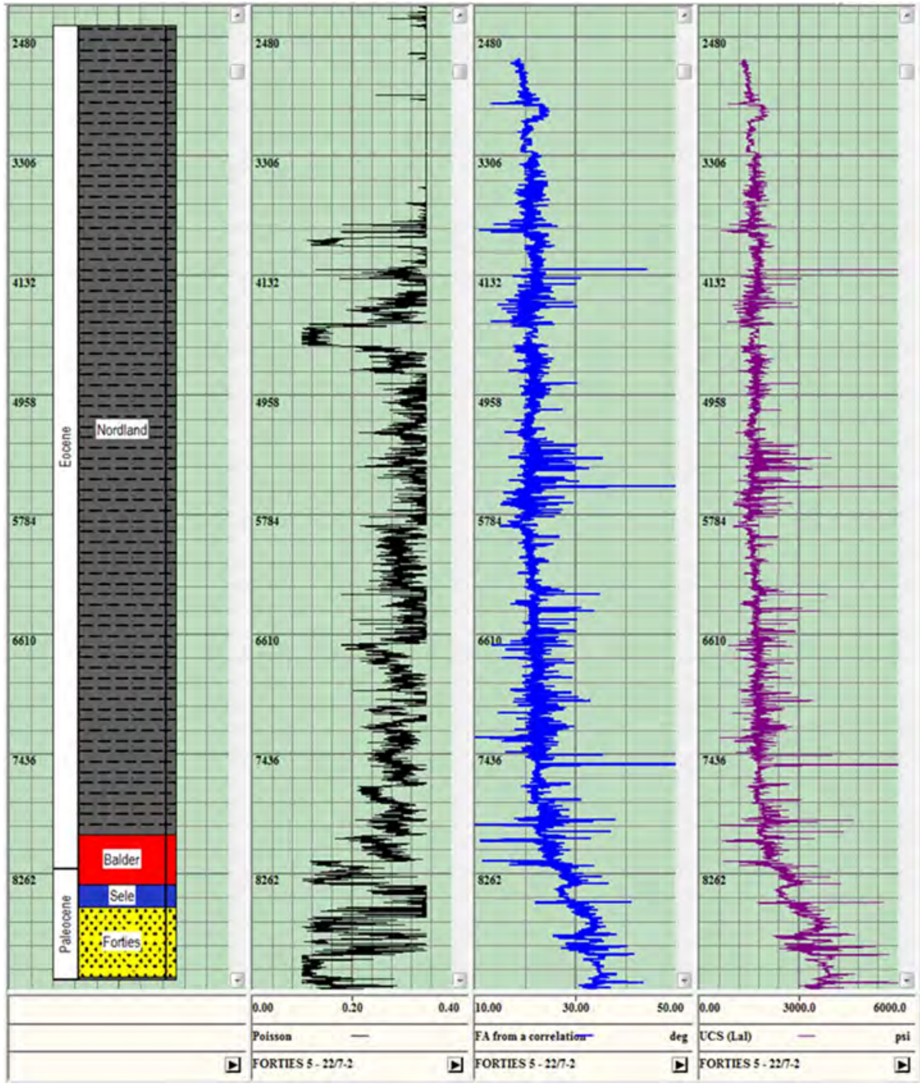


Figure 11-69 Rock mechanical properties – Well 22/7-2

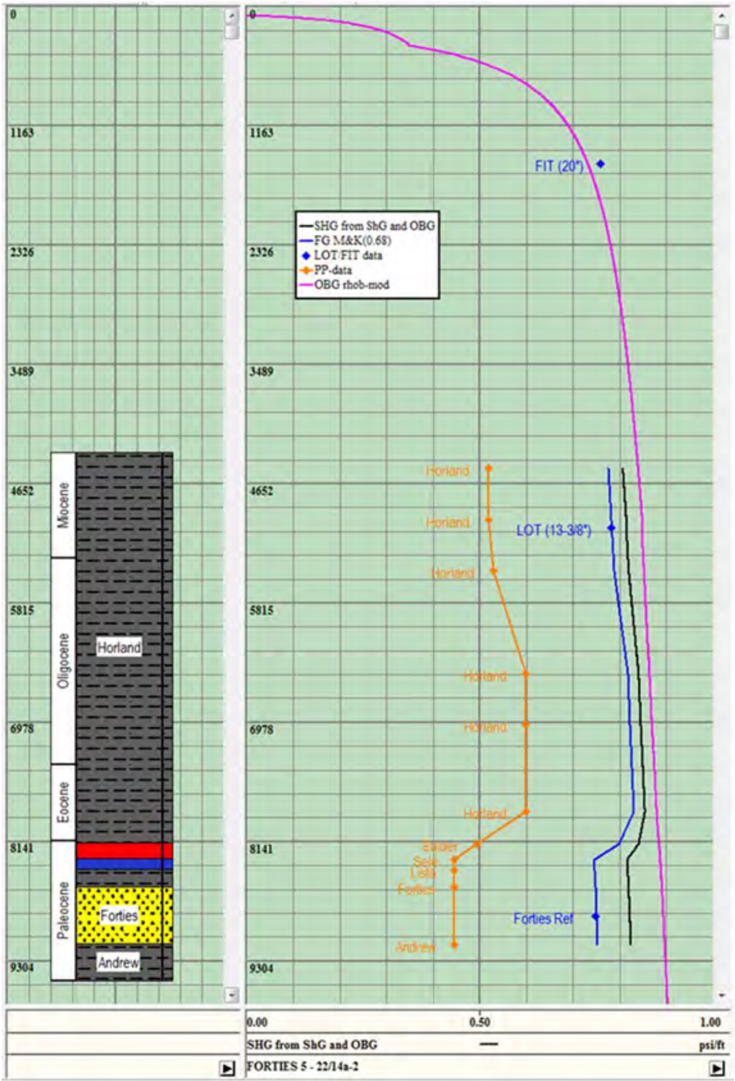


Figure 11-70 Calculated stress curves – Well 22/14a-2

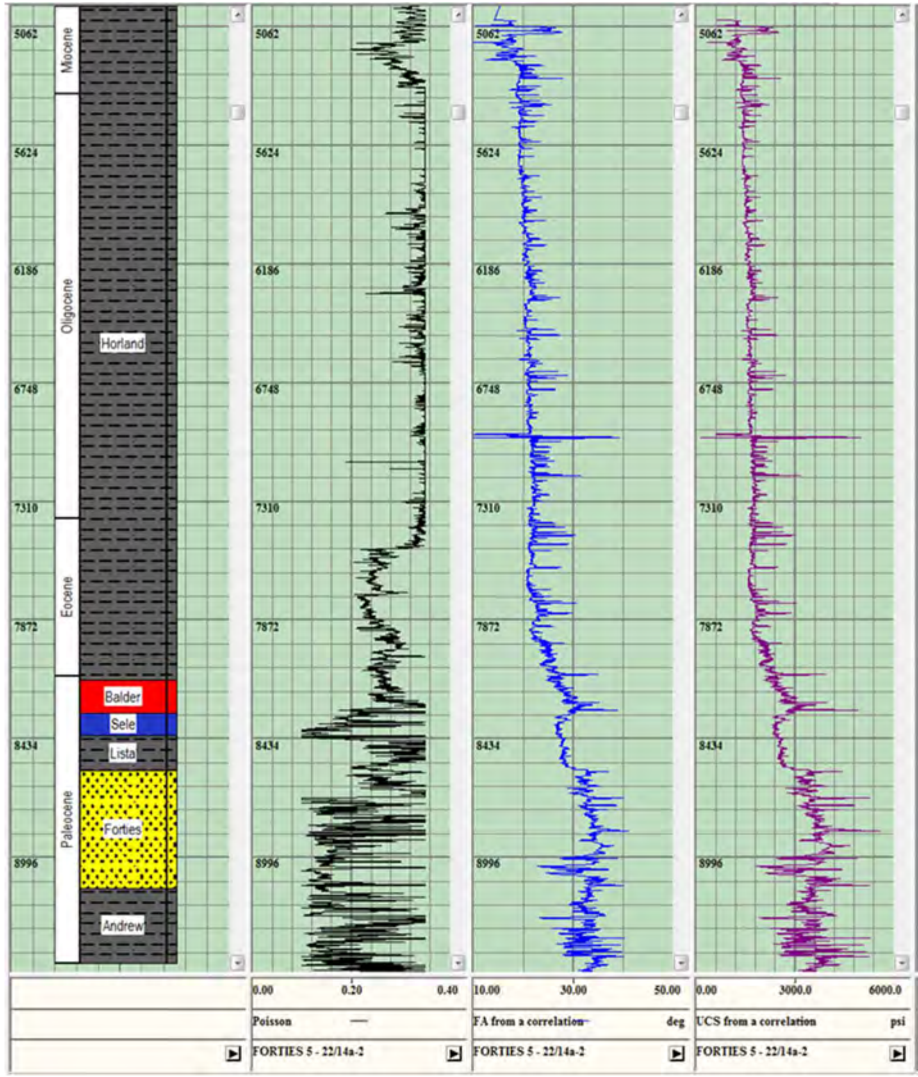


Figure 11-71 Rock mechanical properties - Well 22/14a-2

11.9.4 Conclusions

- The Forties site appears to have a reasonable amount of seismic and well data control.
- Assumptions are made that the regional NW-SE in-situ maximum horizontal stress orientation is relevant to the Forties Structure. Real maximum horizontal stress azimuth may be different.
- No core has been available to calibrate the strength (breakout) information.
- The average pore pressure gradient in the wells analysed was 0.44 psi/ft. Reservoir pressures from RFT measurements in wells 22/15-2 and 22/10b-6 and 22/14a-2, when combined with the best estimate of top Forties depth in the area (8700ftTVD) and the deepest Forties depth (9,500 ftTVD), give a range of 0.432 to 0.458 psi/ft. This data is consistent with regional pressures obtained from the literature. The most conservative figure (0.458 psi/ft) is recommended for use in this study. Further work to refine this figure, or results from an appraisal well, may find an upside opportunity.
- A review of CDA data and an SPE paper (124666) suggested a frac pressure range of 0.70-0.76 psi/ft (0.158-0.172 bar/m) at or near base Sele.
- 1D geomechanical analysis of existing wells in the Forties storage site indicates that an SHmin gradient of around 0.75 psi/ft (14.4ppg / 0.17bar/m) is valid for the Forties Sandstone, based on actual data points.

RISK REGISTER

Forties - saline aquifer site

Document: D11 10113ETIS WP5B 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 Forties 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	Drilling activities near the storage site (either for O&G or CO_2 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		
3	Future O&G extraction operations hindered by presence of CO_2 in storage site	Presence of injected CO_2 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 CO_2 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		
4	Accidental or intentional damage to injection process or storage site that disrupts storage site	Depending on scale of damage, could result in release of CO_2 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.	
5	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.	
6	Loss of containment of CO_2 from primary store to overburden through caprock		1	3	3				
7	Loss of containment of CO_2 from primary store to overburden via fault (Northern injection site)		1	3	3				
8	Loss of containment from primary store to overburden through caprock & P&A wells		1	3	3			Re-entry into an abandoned well is complex, difficult and has a very low chance of success. A relief well is required.	
9	Loss of containment from primary store to overburden through caprock & inj wells	Unexpected movement of CO_2 outwith the storage site, but within the storage complex in the overburden, considerable reputational impact, large fine likely	1	3	3				
10	Loss of containment from primary store to overburden through via P&A wells	Unexpected movement of CO_2 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. A relief well is required.	Relief well: $55 million (60 days & tangibles).
11	Loss of containment from primary store to overburden through via injection wells	Unexpected movement of CO_2 outwith the storage site, but within the storage complex in the overburden, considerable reputational impact, large fine likely	1	3	3		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.		
12	Loss of containment from primary store to upper well/ seabed via P&A wells	CO_2 to seabed. Environmental, international rep and cost implications	3	4	12	Only the final event – leak to the biosphere – will be detected. Wells 22/8a-3 and 22/15-1 fail to meet spec - both wells are reliant on unknown Top Of Cement levels (TOC) and cement plugs which are not lapped with annular cement to provide a secondary barrier for a leak up the A annulus. 22/15-1 lies at the eastern edge of the projected CO_2 plume extent in the reference case development plan. 22/8a-3 lies near to one of the northern site injection locations and will likely be exposed to CO_2 from very early injection operations.	It may be possible through injector placement optimisation to reduce the risk of the CO_2 plume reaching these wells. Nevertheless, any final development plan must seek to further mitigate the containment risk that these wells present.	Re-entry into an abandoned well is complex, difficult and has a very low chance of success. A relief well is required.	Relief well: $55 million (60 days & tangibles).
13	Loss of containment from primary store to upper well/ seabed via injection wells	CO_2 leaks to seabed. Environmental, PR and cost implications	2	4	8	Injection wells designed to have low risk of loss of containment	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.		
14	Loss of containment of CO_2 from primary store to seabed via combination of both caprock and wells		1	4	4				
15	Loss of containment from primary store to underburden (e.g. via Everest well to Andrew Fm)		2	2	4	Flowing down the well due to injection pressure; scenario that CO_2 could get into Everest well and down to Andrew via depleted well. However if this was the case, would have seen some flow from Forties down at the moment. CO_2 would then have to displace water first.		Stop injection; corrective measures plan	
16	Primary store to underburden via store floor (out with storage compelx)		1	3	3	CO_2 would have to go into the chalk & through Tertiary; limestone, maureen			
17	Fault reactivation through primary caprock		1	2	2	Very few faults & very small; those that are there have minor offset, limit injection pressure to 90% frac pressure	Maximum reservoir pressure during injection set to 90% of fracture pressure	Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes	
18	CO_2 flow through unreactivated, permeable fault in primary caprock		1	2	2	Very few faults & very small; those that are there have minor offset	n/a		
19	Thermal fracturing of primary caprock from injection of cold CO_2 into a warm reservoir		1	2	2	Thick 450ft caprock so v unlikely; well design means injecting near base of Forties in horizontal well; thermal effects less than with Bunter (10s of ft) as CO_2 will be warmer when in the well		Stop injection, corrective measures plan, limit injection volumes/rate	
20	Mechanical fracturing of primary caprock from injection pressure of CO_2 exceeding the fracture pressure of the caprock		1	2	2	inject at 90% of frac pressure; growing a fracture to the top of the formation is challenging as rel high inj (few cms)			
21	CO_2 and brine react with minerals in caprock and create permeability pathway		1	2	2	Results of geochemical modelling show that there is a small solid volume increase due to CO_2 flushing, which means a reduction in porosity and thus no enhanced permeability for Forties either in 5000 or 20000 years.	None required		
22	Buoyant CO_2 exposes caprock to pressures beyond the capillary entry pressure enabling it to flow through primary caprock		1	2	2	Many hydrocarbon fields in the area show that caprock is excellent; also plume distribution = less plume height		Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes to reduce column height of CO_2,	
23	Geology of caprock lithology is variable and lacks continuity such that its presence cannot be assured across the whole site		1	2	2	Seen caprock extensively, especially with hydrocarbon fields		Stop injection, corrective measures plan	
24	Relative permeability curves in the model move the CO_2 too slowly within the primary store relative to reality	In the unlikely event that CO_2 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	Uncertainty in rel-perm; rel-perms same as Bunter; w/in model boundary	Site specific relative permeability study from core in appraisal well to constrain curves	Stop injection, corrective measures plan, re-model expected CO_2 plume movement with new data and re-assess injection volumes to ensure containment integrity	
25	Permeability anisotropy (e.g. channels) causes the CO_2 to move more quickly than expected		3	3	9	Uncertainty in permeability (although more likely to be lower than modelled so modelling is conservative); plume movement is controlled by permeability (e.g. channels)			
26	Depth conversion uncertainty	In the unlikely event that the depth conversion uncertainty caused CO_2 to laterally exit the primary store, this would be unexpected migration but at reservoir level. Considerable impact on reputation and large fine likely.	1	3	3	Lots of well control and plume movement not controlled by depth conversion			
27	Depletion or pressure gradient from nearby fields	In the unlikely event that depletion or pressure gradient from nearby fields caused CO_2 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	Oil fields with small capacity compared to aquifer capacity so suggest low gradient; site is large and so large distance before pressure is felt; oil fields also injecting water so less likely to draw CO_2 away from storage site	Model impacts; good engagement with other operators in the area to understand impact	Stop injection until situation understood; further detailed work	
28	Impact of injection and CO_2 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	site is large and so large distance before pressure is felt	Draft process for dispute resolution with nearby subsurface users	Stop injection until situation understood; further detailed work	
29	Well placement error	In the unlikely event that the well was drilled at the edge of the storage complex and caused CO_2 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	n/a as site is large			
30	Inject in wrong zone of reservoir or damage reservoir	In the unlikely event that CO_2 was injected into the wrong zone or the reservoir was damaged and caused CO_2 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	Horizontal well so low chance	Downhole P/T gauges and DTS along the wellbore as part of monitoring plan to detect first signs of loss of integrity.		
31	CO_2 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.	2	2	4	Remotely probable & would be unexpected migration within storage complex			
32	CO_2 laterally exits the secondary store	n/a as no secondary store	1	1	1	No secondary store so n/a			
33	Fault reactivation through secondary primary caprock		1	3	3	Horda is 600ft; one fault right in the north cuts the Horda		Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes	
34	CO_2 flow through unreactivated, permeable fault in primary caprock		1	3	3	Horda is 600ft; one fault right in the north cuts the Horda			
35	Thermal fracturing of primary caprock from injection of cold CO_2 into a warm reservoir		1	3	3	Horda is 600ft; one fault right in the north cuts the Horda; 450ft above priimary caprocks		Stop injection, corrective measures plan, limit injection volumes/rate	

36	Mechanical fracturing of primary caprock from injection pressure of CO2 exceeding the fracture pressure of the caprock			1	3	3	Horda is 600ft; one fault right in the north cuts the Horda; 450ft above priimary caprocks			
37	CO2 and brine react with minerals in caprock and create permeability pathway			1	3	3	low likelihood of co2 reacting with and flowing through very thick Horda			
38	Buoyant CO2 exposes caprock to pressures beyond the capillary entry pressure enabling it to flow through primary caprock			1	3	3	Large footprint area of plume so reduced column height		Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes to reduce column height of CO2,	
39	Geology of caprock lithology is variable and lacks continuity such that its presence cannot be assured across the whole site			1	3	3	1000ft and extremely extensive Horda		Stop injection, corrective measures plan	
33	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).
34	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).
35	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).
36	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).
37	Cement sheath failure (Production Liner)	Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation.					Requires: - a failure of the liner packer or - failure of the liner above the production packer before there is pressured CO2 in the A-annulus.		Repair by cement squeeze (possible chance of failure). Requires the completion to be retrieved and rerun (if installed).	$3-5 million (5 days & tangibles). $18-25 million (if a workover required).
38	Production Liner failure	Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation.					Requires: - a failure of the liner above the production packer and - a failure of the cement sheath before there is pressured CO2 in the A-annulus.		Repair by patching (possible chance of failure) or running a smaller diameter contingency liner. Requires the completion to be retrieved and rerun (if installed). Will change the casing internal diameter and may have an impact on the completion design and placement. Repair by side-track.	$3-5 million (3 days & tangibles). $18-25 million (if a workover required). Side-track estimated to be equal to the cost of a new well - $55 million (60 days & tangibles).
39	Cement sheath failure (Production Casing)	Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation.					Requires: - a failure of the Production Liner cement sheath or - a pressurised A-annulus and - failure of the production casing before there is pressured CO2 in the B-annulus.		Repair by cement squeeze (possible chance of failure). Requires the completion to be retrieved and rerun (if installed).	$3-5 million (5 days & tangibles). $18-25 million (if a workover required).
40	Production Casing Failure	Sustained CO2 annulus pressure will be an unsustainable well integrity state and require remediation.					Requires: - a pressurised A-annulus and - a failure of the Production Casing cement sheath before there is pressure CO2 in the B-annulus.		Repair by patching (possible chance of failure). Requires the completion to be retrieved (if installed). Will change the casing internal diameter and may have an impact on the completion design and placement.	$3-5 million (3 days & tangibles). $18-25 million (if a workover required). Side-track estimated to be equal to the cost of a new well - $55 million (60 days & tangibles).
41	Safety critical valve failure – tubing safety valve	Inability to remotely shut-in the well below surface. Unsustainable well integrity state.							Repair by: - installation of insert back-up by intervention or - replacement by workover	£1 million to run insert (1 day & tangibles). $18-25 million (if a workover required).
42	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). Subsea: $5-7 million (vessels, ROV, dive support & tangibles).
43	Wellhead seal leak	Seal failure will be an unsustainable well integrity state and require remediation.					Requires: - a pressurised annulus and - multiple seal failures 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). 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). Abandonment $15-25 (21 days & tangibles).
44	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. 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). 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 ($<100m^2$)	Leakage seabed water column over large area ($>100m^2$)
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	**LEVEL 2 COST ESTIMATE**	
TITLE	SITE 2: FORTIES 5 (NORTH AND SOUTH COMBINED)		
CLIENT	ETI		
REVISION	A1		
DATE	19/01/2016		

	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	**73.6**	**9.2**	**82.8**		**103.0**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	1.1	0.5	1.5		2.0
A1.2	**Facilities**	Design of template and umbilical	5.0	2.2	7.2		9.3
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	4.0	0.4	4.4		5.7
A1.4	**Other**		63.6	6.1	69.7	30%	86.0
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	28.2	2.8	31.0		40.3
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	29.5	0.9	30.4		34.7
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	4.0	0.4	4.4		5.7
A1.4.4	Licencing and Permits	Licenses, Permissions Permit, PLANC	2.0	2.0	4.0		5.2
B. Post-Final Investment Decision (Post-FID)			**806.6**	**50.4**	**857.0**	**-**	**921.9**
B1.1	**Transportation**		275.1	10.8	285.8	-	371.6
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	2.0	0.4	2.4		3.1
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	150.1	10.0	160.1	30%	208.2
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	26.4	0.4	26.8		34.8
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	96.6	0.0	96.6		125.5
B1.2	**Facilities**		78.0	9.5	87.4	-	113.7
B1.2.1	Detailed Design	Design of template and umbilical	11.0	3.3	14.3		18.6
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	29.4	5.3	34.6	30%	45.0
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	15.2	0.9	16.1		20.9
B1.2.4	Construction and Commissioning	COVERED WITHIN TRANSPORTATION CONSTRUCTION	22.4	0.0	22.4		29.1
B1.3	**Wells**		451.6	28.2	479.7	-	431.4
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	4.0	0.4	4.4		5.7
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc	60.0	6.0	66.0		88.8
B1.3.3	Fabrication	-	0.0	0.0	0.0		0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	387.6	21.8	409.3	30%	336.9
		Platform Injector 1-4 + MW	186.3	11.4	197.7		101.1
		Subsea Injector 1-4	99.9	4.7	104.5		116.3
		Platform Injector 5-8 + MW2	101.4	5.7	107.1		119.5
B1.4	**Other**		2.0	2.0	4.0	-	5.2
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	2.0	2.0	4.0	30%	5.2
C. Total Operating Expenditure (OPEX)			**1056.5**	**86.9**	**1143.4**	**-**	**1445.7**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	139.0	7.3	146.4		190.3
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	256.5	23.3	279.8		363.8
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	234.8	13.7	248.4		282.3
C1.3.1	**Well Sidetracks and Workovers**	Local Platform Sidetrack 1	25.3	1.5	26.8		30.8
		Local Platform Sidetrack 2	25.3	1.5	26.8	30%	30.8
		Local Platform Sidetrack 3	25.3	1.5	26.8		30.8
		Local Platform Sidetrack 4	25.3	1.5	26.8		30.8
		Subsea Workovers and Sidetracks	133.7	7.7	141.3		159.0
C1.4	**Other**		426.1	42.6	468.7	-	609.4
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	169.3	16.9	186.3		242.1
C1.4.2	Financial Securities		256.8	25.7	282.5	30%	367.2
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0.0		0.0
D. Abandonment (ABEX)			**365.2**	**26.6**	**391.8**	**-**	**497.7**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	37.4	3.7	41.1		53.4
D1.2	**Decommissioning - Facilities**		37.9	3.8	41.7	30%	54.3
D1.3	**Decommissioning - Wells**		78.6	5.0	83.6		97.0
D1.4	**Other**		211.3	14.1	225.4	-	293.0
D1.4.1	Post Closure Monitoring	includes data management and interpretation	140.9	14.1	154.9	30%	201.4
D1.4.2	Handover	additional 10 years of coverage	70.4	0.0	70.4		91.6

FIELD LIFE (YEARS)	40
CO2 STORED (MT)	300

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]	1024.8	TRANSPORTATION	373.6
		FACILITIES	123.0
		WELLS	437.1
		OTHER	91.2
OPEX [C]	1445.7	TRANSPORTATION	190.3
		FACILITIES	363.8
		WELLS	282.3
		OTHER	609.4
ABEX [D]	497.7	TRANSPORTATION	53.4
		FACILITIES	54.3
		WELLS	97.0
		OTHER	293.0
TOTAL	2968.2	-	2968.2

LEVEL 1 COST ESTIMATE SUMMARY

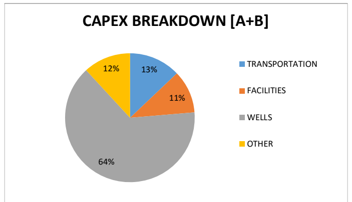
Category	Primary Cost (£ MM)	Overheads (£ MM)	Total Cost excluding Contingency (£ MM)	Total Cost inc. Contingency (£ MM)
A. Pre-Final Investment Decision (Pre-FID)	73.6	9.2	82.8	103.0
B. Post-Final Investment Decision (Post-FID)	806.6	50.4	857.0	921.9
C. Total Operating Expenditure (OPEX)	1056.5	86.9	1143.4	1445.7
D. Abandonment (ABEX)	365.2	26.6	391.8	497.7
TOTAL COST (CAPEX, OPEX, ABEX)			2475.0	**2968.2**
COST CO2 INJECTED (£ PER TONNE)			£8.25	**£9.89**

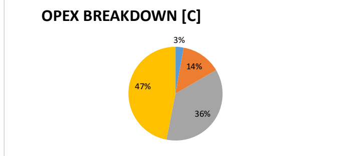
PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 2: FORTIES 5 - NORTH SITE
CLIENT	ETI
REVISION	A1
DATE	21/03/2016

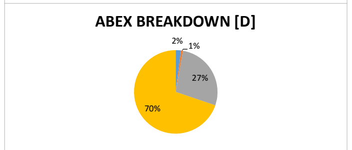
LEVEL 2 COST ESTIMATE

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	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	**20.0**	**3.2**	**23.2**		**30.2**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	0.5	0.2	0.7	30%	0.8
A1.2	**Facilities**	Design of template and umbilical	0.5	0.2	0.7		0.8
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	2.0	0.2	2.2		2.9
A1.4	**Other**		17.1	2.6	19.7		25.6
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	14.1	1.4	15.5		20.1
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)			**163.0**	**11.1**	**174.1**	**-**	**207.5**
B1.1	**Transportation**		21.7	1.2	22.9	-	29.8
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	1.0	0.2	1.2	30%	1.6
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	5.4	0.8	6.2		8.1
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	2.9	0.2	3.0		3.9
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	12.5	0.0	12.5		16.2
B1.2	**Facilities**		17.2	1.9	19.1	-	24.8
B1.2.1	Detailed Design	Design of template and umbilical	1.0	0.3	1.3	30%	1.7
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc	15.2	1.5	16.7		21.7
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	1.0	0.1	1.1		1.4
B1.2.4	Construction and Commissioning	COVERED WITHIN TRANSPORTATION CONSTRUCTION	0.0	0.0	0.0		0.0
B1.3	**Wells**		123.1	7.0	130.1	-	150.2
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	2.0	0.2	2.2	30%	2.9
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc	21.2	2.1	23.3		31.1
B1.3.3	Fabrication	-	0.0	0.0	0.0		0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	99.9	4.7	104.5		116.3
		Subsea Injector 1-4	99.9	4.7	104.5		116.3
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)			**327.6**	**26.2**	**353.9**	**-**	**435.3**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	8.7	0.5	9.2	30%	12.0
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	42.3	3.8	46.2		60.0
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	133.7	7.7	141.3		159.0
C1.3.1	**Well Sidetracks and Workovers**	Subsea Workovers and Sidetracks	133.7	7.7	141.3		159.0
C1.4	**Other**		142.9	14.3	157.2	-	204.3
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	70.6	7.1	77.6	30%	100.9
C1.4.2	Financial Securities		72.3	7.2	79.5		103.4
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0		0.0
D. Abandonment (ABEX)			**157.9**	**9.7**	**167.6**	**-**	**210.0**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	3.1	0.3	3.4	30%	4.4
D1.2	**Decommissioning - Facilities**	Estimated	1.0	0.1	1.1		1.4
D1.3	**Decommissioning - Wells**		48.2	2.3	50.5		57.7
D1.4	**Other**		105.6	7.0	112.7	-	146.5
D1.4.1	Post Closure Monitoring	includes data management and interpretation	70.4	7.0	77.5	30%	100.7
D1.4.2	Handover	additional 10 years of coverage	35.2	0.0	35.2		45.8

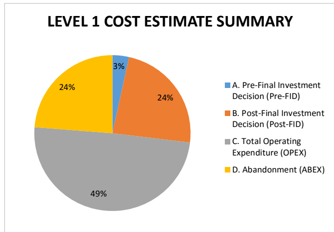






FIELD LIFE (YEARS)	30
CO2 STORED (MT)	130

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]	237.6	TRANSPORTATION	30.7
		FACILITIES	25.7
		WELLS	153.1
		OTHER	28.2
OPEX [C]	435.3	TRANSPORTATION	12.0
		FACILITIES	60.0
		WELLS	159.0
		OTHER	204.3
ABEX [D]	210.0	TRANSPORTATION	4.4
		FACILITIES	1.4
		WELLS	57.7
		OTHER	146.5
TOTAL	882.9	-	882.9

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)	20.0	3.2	23.2	30.2
B. Post-Final Investment Decision (Post-FID)	163.0	11.1	174.1	207.5
C. Total Operating Expenditure (OPEX)	327.6	26.2	353.9	435.3
D. Abandonment (ABEX)	157.9	9.7	167.6	210.0
TOTAL COST (CAPEX, OPEX, ABEX)			718.8	**882.9**
COST CO2 INJECTED (£ PER TONNE)			£5.53	**£6.79**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: PROCUREMENT & FABRICATION**
TITLE	SITE 2: FORTIES 5 - NORTH SITE	
CLIENT	ETI	
REVISION	A1	
DATE	21/03/2016	

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number		1
Route Length (km)		24
Route Length Factor		1.05
Pipeline Crossings		1
Tee Structures		0
Outer Diameter (mm)		323.9
Wall Thickness (mm)		14.3
Anode Spacing (m)		500

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.1	**Transportation - Pre FID**								**£652,500**
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	£250,000	LS	1.00	£250,000	£112,500	*Company Time Writing, Contractor Surveillance*	£362,500
B. Post FID									
B1.1	**Transportation - Post FID**								**£10,458,393**
B1.1.1	Detailed Design	Lump Sum	£1,000,000	LS	1.00	£1,000,000	£200,000	*Company Time Writing, IVB, SIT, Insurance etc*	£1,200,000
B1.1.2	Procurement		-	-	-	-	-		**£6,238,393**
B1.1.2.1	Insurance and Certification		-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.2	Geotechnical Testing		£2,000	km	25	£50,400	£28,000	*Documentation etc*	£78,400
B1.1.2.3	*Procurement - Linepipe (Infield)*	*API 5L X65, OD 323.9mm, WT 12.7mm*	£1,500	Te	2,752	£4,128,000	£247,680	*Logistics/Freight @ 6%*	£4,375,680
B1.1.2.4	*Procurement - Coating (Infield)*	*Corrosion Coating*	£24	m	25,200	£604,800	£36,288		£641,088
B1.1.2.5	*Procurement - Coating (Infield)*	*Concrete Coating*	£24	m	25,200	£604,800	£36,288		£641,088
B1.1.2.6	*Procurement - Anodes (Infield)*	*CP Protection*	£40	Each	50	£2,016	£121		£2,137
B1.1.3	Fabrication		-	-	-	-	-		**£3,020,000**
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	25,200	£1,260,000	£50,000	*Contractor Surveillance*	£1,310,000
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	1	£100,000	£10,000	*Contractor Surveillance*	£110,000
B1.1.3.4	*Tee-Piece Structure*	*To Facilitate Future Expansion*	£5,000,000	Each	0	£0	£0	*Contractor Surveillance*	£0
						Total (Excluding Contingency)			**£11,110,893**
						Pre-FID Contingency (%)		**30%**	**£195,750**
						Post-FID Contingency (%)		**30%**	**£3,137,518**
						Total (Including Contingency)			**£14,444,161**

PROJECT	Strategic UK Storage Appraisal Project	TRANSPORTATION: CONSTRUCTION AND COMMISSIONING
TITLE	SITE 2: FORTIES 5 - NORTH SITE	
CLIENT	ETI	
REVISION	A1	
DATE	21/03/2016	

Pipeline	Trunk Pipeline(s)	Infield Pipeline(s)
Number	0	1
Route Length (km)	0	24
Route Length Factor	0	1.05
Pipeline Crossings	0	1
Outer Diameter (mm)	0	323.9
Wall Thickness (mm)	0	14.3
Anode Spacing (m)	0	500
Landfall Required?	NO	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	DSV	£150,000	-
Pipelay (Carrier)	Pipe Carrier (1600Te)	£50,000	-
Structure Installation	DSV	£150,000	-
Umbilical Installation	Construction Vessel	£150,000	500

Landfall Cost	£0

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	£600,000
		Infield Operations			2	£200,000	
		Demobilisation			2	£200,000	
B1.1.4.2	Pipelay (Reel)	Mobilisation	Reel Lay Vessel	£150,000	4	£600,000	£1,650,000
		Infield Operations			3	£450,000	
		Demobilisation			4	£600,000	
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	£300,000	£1,650,000
		Infield Operations			7	£1,050,000	
		Demobilisation			2	£300,000	
B1.1.4.5	Commissioning	Mobilisation	DSV	£150,000	2	£300,000	£1,650,000
		Infield Operations			7	£1,050,000	
		Demobilisation			2	£300,000	
B1.1.4.6	Structure Installation	Mobilisation	DSV	£150,000	3	£450,000	£1,050,000
		Infield Operations - SSIV and Template			2	£300,000	
		Demobilisation			2	£300,000	
B1.1.4.7	Umbilical Installation	Mobilisation	Construction Vessel	£150,000	3	£450,000	£1,350,000
		Infield Operations			3	£450,000	
		Demobilisation			3	£450,000	
B1.1.4.8	Trenching and Backfill	Mobilisation	Ploughing Vessel	£100,000	4	£600,000	£2,700,000
		Infield Operations			11	£1,650,000	
		Demobilisation			3	£450,000	
B1.1.4.9	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£1,135,000	£1,135,000
B1.1.4.10	Landfall		-	Lump Sum	-	£0	£0
					Total (Excluding Contingency)		£12,485,000
					Contingency	30%	£3,745,500
					Total (Including Contingency)		£16,230,500

PROJECT	Strategic UK Storage Appraisal Project	**Facilities: PROCUREMENT & FABRICATION**
TITLE	SITE 2: FORTIES 5 - NORTH SITE	
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**								**£652,500**
A1.2.1	Pre-FEED	4 Slot Template, Umbilical	£150,000	LS	1	£150,000	£67,500	*Company Time Writing, Contractor Surveillance*	£217,500
A1.2.2	FEED	4 Slot Template, Umbilical	£300,000	LS	1	£300,000	£135,000	*Company Time Writing, Contractor Surveillance*	£435,000
B. Post FID									
B1.2	**Facilities - Post FID**								**£19,080,000**
B1.2.1	Detailed Design	4 Slot Template, Umbilical	£1,000,000	LS	1	£1,000,000	£300,000	*Company Time Writing, IVB, SIT etc*	**£1,300,000**
B1.2.2	Procurement		-	-	-		-	-	**£16,720,000**
	Template	4 Slot Template, Umbilical	£2,000,000	LS	1	£2,000,000	£200,000	*Company Time Writing, IVB, SIT, etc*	£2,200,000
	EHC Umbilical	*Electrical Power, Hydraulics, Chemicals*	£500	per m	26,400	£13,200,000	£1,320,000	*Company Time Writing, IVB, SIT, etc*	£14,520,000
B1.2.3	Fabrication	*4 Slot Template, Umbilical*	£1,000,000	LS	1	£1,000,000	£60,000	*Logistics/Freight @ 6%*	**£1,060,000**
B1.2.4	Construction and Commissioning	COVERED WITHIN TRANSPORTATION	-	-	-		-		**COVERED IN TRANSPORTATION**
				Total (Excluding Contingency)					**£19,732,500**
				Pre-FID Contingency (%)				**30%**	**£195,750**
				Post-FID Contingency (%)				**30%**	**£5,724,000**
				Total (Including Contingency)					**£25,652,250**

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 TECHNOLOGY FROM CONCEPT TO COMPLETION

Well Cost Summary (including 30% Contingency)		
Well Name	**Days**	**Well Cost (£,000)**
Year 10		
Subsea Injector 1	91.0	37990.0
Subsea Injector 2	84.0	35280.0
Subsea Injector 3	84.0	35280.0
Subsea Injector 4	88.2	36705.0
Year 15		
Local Subsea Sidetrack 1	102.2	37705
Year 25		
Subsea Injector Workover 1	42.8	17687.5
Subsea Injector Workover 2	37.1	15335
Subsea Injector Workover 3	37.1	15335
Local Subsea Sidetrack 2	95.2	35190
Year 35		
Local Subsea Sidetrack 3	102.2	37705
Year 40		
Abandonment Subsea Injector 1	49.0	16130
Abandonment Subsea Injector 2	42.0	13445
Abandonment Subsea Injector 3	42.0	13445
Abandonment Subsea Injector 4	46.2	14705
TOTAL	943.0	361937.5

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary	
Drilling Campaign	**Overhead (£MM)**
Subsea Injector 1-4	4.65
Abandonment	2.25

OPEX Overhead Cost Summary	
OPEX Campaign	**Overhead (£MM)**
Subsea Workovers + Sidetracks	7.65

Level 1 Cost Estimate Summary - Wells	
Total CAPEX (£MM)	153.1
Total OPEX (£MM)	159.0
Total ABEX (£MM)	57.7
TOTAL (£MM)	**369.8**

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						
Subsea Injector 1	10,725	15,350	3,075	6,800	2,040	37,990
Subsea Injector 2	9,900	14,275	2,850	6,350	1,905	35,280
Subsea Injector 3	9,900	14,275	2,850	6,350	1,905	35,280
Subsea Injector 4	10,395	15,070	2,985	6,350	1,905	36,705
Wells - OPEX Breakdown						
Local Subsea Sidetrack 1	12,045	16,895	3,435	4,100	1,230	37,705
Subsea Injector Workover 1	5,610	8,136	687	2,550	705	17,688
Subsea Injector Workover 2	4,785	7,013	672	2,250	615	15,335
Subsea Injector Workover 3	4,785	7,013	672	2,250	615	15,335
Local Subsea Sidetrack 2	11,220	15,820	3,210	3,800	1,140	35,190
Local Subsea Sidetrack 3	12,045	16,895	3,435	4,100	1,230	37,705
Wells - ABEX Breakdown						
Abandonment Subsea Injector 1	5,775	7,200	1,725	1,100	330	16,130
Abandonment Subsea Injector 2	4,950	6,150	1,500	650	195	13,445
Abandonment Subsea Injector 3	4,950	6,150	1,500	650	195	13,445
Abandonment Subsea Injector 4	5,445	6,780	1,635	650	195	14,705

	CAPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
						%	£MM	
A1.4.2	Appraisal Well (inc Procurement)	0.0	0	-	0.0	-	0.0	**0.0**
A1.3	Pre-FEED / FEED PM & E	2.0	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	30%	0.7	**2.9**
B1.3.1	Detailed Design PM & E	2.0	0.2		2.2	30%	0.7	**2.9**
B1.3.2	Procurement	21.2	2.12		23.3	30%	7.8	**31.1**
B1.3.4	Construction and Commissioning (Drilling)	99.9	4.65	Well Management Fees, Insurance, Site Survey, Studies etc.	104.5	30%	11.8	**116.3**
	Total	**125.1**	**7.2**	-	**132.3**	-	**20.8**	**153.1**

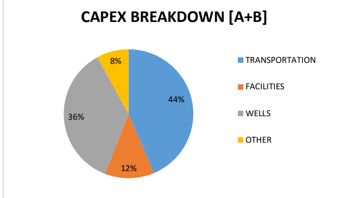
OPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
					%	£MM	
OPEX	133.7	7.65	Well Management Fees, Insurance, Site Survey, Studies etc.	141.3	30%	17.6	**159.0**

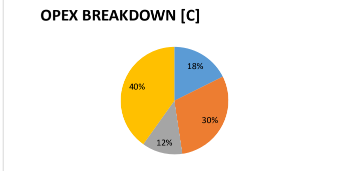
ABEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
					%	£MM	
ABEX	48.2	2.25	Well Management Fees, Insurance, Site Survey, Studies etc.	50.5	30%	7.3	**57.7**

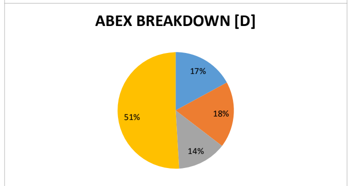
PROJECT	Strategic UK Storage Appraisal Project	**LEVEL 2 COST ESTIMATE**					
TITLE	SITE 2: FORTIES 5 - SOUTH SITE						
CLIENT	ETI						
REVISION	A1						
DATE	21/03/2016						

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	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	**53.6**	**6.0**	**59.6**		**72.8**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	0.6	0.3	0.9		1.1
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**		46.5	3.5	50.1	30%	60.4
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	14.1	1.4	15.5		20.1
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s)	29.5	0.9	30.4		34.7
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)			**542.2**	**33.6**	**575.8**	**-**	**714.4**
B1.1	**Transportation**		253.3	9.6	262.9	-	341.8
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	1.0	0.2	1.2		1.6
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)	144.7	9.2	153.9	30%	200.1
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc	23.5	0.2	23.7		30.8
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning	84.1	0.0	84.1		109.3
B1.2	**Facilities**		60.8	7.6	68.4	-	88.9
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	14.2	3.7	17.9	30%	23.3
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication	14.2	0.8	15.0		19.5
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC	22.4	0.0	22.4		29.1
B1.3	**Wells**		227.1	15.5	242.6	-	281.2
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	38.8	3.9	42.7		57.7
B1.3.3	Fabrication	-	0.0	0.0	0.0	30%	0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX	186.3	11.4	197.7		220.6
		Platform Injector 1-4 + MW	85.0	5.7	90.7		101.1
		Platform Injector 5-8 + MW2	101.4	5.7	107.1		119.5
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)			**728.9**	**60.7**	**789.5**	**-**	**1010.4**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	130.3	6.9	137.2		178.3
C1.2	**OPEX - Facilities**	Manning, Power, IMR, Chemicals	214.2	19.5	233.6		303.7
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	101.1	6.0	107.1		123.3
C1.3.1	**Well Sidetracks and Workovers**	Local Platform Sidetrack 1	25.3	1.5	26.8	30%	30.8
		Local Platform Sidetrack 2	25.3	1.5	26.8		30.8
		Local Platform Sidetrack 3	25.3	1.5	26.8		30.8
		Local Platform Sidetrack 4	25.3	1.5	26.8		30.8
C1.4	**Other**		283.3	28.3	311.6	-	405.1
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	98.8	9.9	108.6		141.2
C1.4.2	Financial Securities		184.5	18.5	202.95	30%	263.8
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs	0.0	0.0	0		0.0
D. Abandonment (ABEX)			**207.3**	**16.9**	**224.2**	**-**	**287.6**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	34.3	3.4	37.7		49.0
D1.2	**Decommissioning - Facilities**	Que$tor	36.9	3.7	40.6	30%	52.8
D1.3	**Decommissioning - Wells**		30.4	2.7	33.1		39.3
D1.4	**Other**		105.6	7.0	112.7	-	146.5
D1.4.1	Post Closure Monitoring	includes data management and interpretation	70.4	7.0	77.5	30%	100.7
D1.4.2	Handover	additional 10 years of coverage	35.2	0.0	35.2		45.8

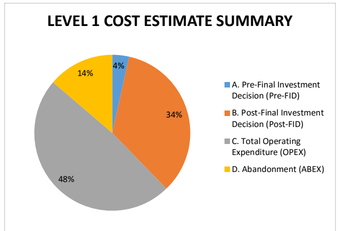






FIELD LIFE (YEARS)	40
CO2 STORED (MT)	170

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]	787.2	TRANSPORTATION	342.9
		FACILITIES	97.3
		WELLS	284.0
		OTHER	63.0
OPEX [C]	1010.4	TRANSPORTATION	178.3
		FACILITIES	303.7
		WELLS	123.3
		OTHER	405.1
ABEX [D]	287.6	TRANSPORTATION	49.0
		FACILITIES	52.8
		WELLS	39.3
		OTHER	146.5
TOTAL	2085.3	-	2085.3

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)	53.6	6.0	59.6	72.8
B. Post-Final Investment Decision (Post-FID)	542.2	33.6	575.8	714.4
C. Total Operating Expenditure (OPEX)	728.9	60.7	789.5	1010.4
D. Abandonment (ABEX)	207.3	16.9	224.2	287.6
TOTAL COST (CAPEX, OPEX, ABEX)			1649.2	**2085.3**
COST CO2 INJECTED (£ PER TONNE)			£9.70	**£12.27**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: PROCUREMENT & FABRICATION**
TITLE	SITE 2: FORTIES 5 - SOUTH SITE	
CLIENT	ETI	
REVISION	A1	
DATE	21/03/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	216	
Route Length Factor	1.05	
Pipeline Crossings	7	
Tee Structures	2	
Outer Diameter (mm)	609.6	
Wall Thickness (mm)	25.4	
Anode Spacing (m)	500	

No.	Item	Description	Unit Cost (£)	Unit	Qty	Total (£MM)	Overhead (£)	Description (Overheads)	Total Cost (£)
A. Pre-FID									
A1.1	**Transportation - Pre FID**								**£720,000**
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	£400,000	LS	1.00	£250,000	£180,000	*Company Time Writing, Contractor Surveillance*	£430,000
B. Post FID									
B1.1	**Transportation - Post FID**								**£178,830,791**
B1.1.1	Detailed Design	Lump Sum	£1,000,000	LS	1.00	£1,000,000	£200,000	*Company Time Writing, IVB, SIT, Insurance etc*	£1,200,000
B1.1.2	Procurement		-	-	-	-	-		**£153,900,791**
B1.1.2.1	Insurance and Certification		-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.2	Geotechnical Testing		£2,000	km	227	£453,600	£28,000	*Documentation etc*	£481,600
B1.1.2.3	*Procurement - Linepipe (Trunk)*	*API 5L X65, OD 609.6mm, WT 22.2mm*	£1,500	Te	82,997	£124,495,500	£7,469,730	*Logistics/Freight @ 6%*	£131,965,230
B1.1.2.4	*Procurement - Coating (Trunk)*	*Corrosion Coating*	£42	m	226,800	£9,525,600	£571,536		£10,097,136
B1.1.2.5	*Procurement - Coating (Trunk)*	*Concrete Coating*	£45	m	226,800	£10,206,000	£612,360		£10,818,360
B1.1.2.6	*Procurement - Anodes (Trunk)*	*CP Protection*	£80	Each	454	£36,288	£2,177		£38,465
B1.1.3	Fabrication		-	-	-	-	-		**£23,730,000**
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	226,800	£11,340,000	£50,000	*Contractor Surveillance*	£11,390,000
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	7	£700,000	£20,000	*Contractor Surveillance*	£720,000
B1.1.3.4	*Tee-Piece Structure*	*To Facilitate Future Expansion*	£5,000,000	Each	2	£10,000,000	£20,000	*Contractor Surveillance*	£10,020,000

Total (Excluding Contingency)		**£179,550,791**
Pre-FID Contingency (%)	**30%**	**£216,000**
Post-FID Contingency (%)	**30%**	**£53,649,237**
Total (Including Contingency)		**£233,416,029**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: CONSTRUCTION AND COMMISSIONING**
TITLE	SITE 2: FORTIES 5 - SOUTH SITE	
CLIENT	ETI	
REVISION	A1	
DATE	21/03/2016	

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	0
Route Length (km)	216	0
Route Length Factor	1.05	0
Pipeline Crossings	7	0
Outer Diameter (mm)	609.6	0
Wall Thickness (mm)	25.4	0
Anode Spacing (m)	500	0
Landfall Required?	YES	-

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	DSV	£150,000	-
Pipelay (Carrier)	Pipe Carrier (1600Te)	£50,000	-
Structure Installation	DSV	£150,000	-

Landfall Cost	£25,000,000

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	£1,700,000
		Infield Operations			13	£1,300,000	
		Demobilisation			2	£200,000	
B1.1.4.2	Pipelay (S-Lay)	Mobilisation	S-Lay Vessel (14000Te)	£350,000	5	£1,750,000	£35,700,000
		Infield Operations			95	£33,250,000	
		Demobilisation			2	£700,000	
B1.1.4.3	Crossing Installation	Mobilisation	Survey Vessel	£100,000	2	£200,000	£2,500,000
		Infield Operations - 3 day per Crossing			21	£2,100,000	
		Demobilisation			2	£200,000	
B1.1.4.4	Spoolpiece Tie-ins	Mobilisation	DSV	£150,000	2	£300,000	£2,100,000
		Infield Operations			10	£1,500,000	
		Demobilisation			2	£300,000	
B1.1.4.5	Commissioning	Mobilisation	DSV	£150,000	2	£300,000	£1,650,000
		Infield Operations			7	£1,050,000	
		Demobilisation			2	£300,000	
B1.1.4.6	Structure Installation	Mobilisation	DSV	£150,000	2	£300,000	£1,050,000
		Infield Operations -SSIV and TeeS			3	£450,000	
		Demobilisation			2	£300,000	
B1.1.4.7	Pipelay (Carrier)	Mobilisation	Pipe Carrier (1600Te)	£50,000	2	£100,000	£9,000,000
		Roundtrip Operations - 4 days per Trip			176	£8,800,000	
		Demobilisation			2	£100,000	
B1.1.4.8	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£5,370,000	£5,370,000
B1.1.4.9	Landfall		-	Lump Sum	-	£25,000,000	£25,000,000
					Total (Excluding Contingency)		**£84,070,000**
					Contingency	**30%**	**£25,221,000**
					Total (Including Contingency)		**£109,291,000**

PROJECT	Strategic UK Storage Appraisal Project	Facilities:
TITLE	SITE 2: FORTIES 5 - SOUTH SITE	**PROCUREMENT & FABRICATION**
CLIENT	ETI	
REVISION	A1	
DATE	21/03/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

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**								**£68,358,801**
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		-	-	-		-	-	**£17,925,265**
	Jacket	4 Legged Jacket	-	-	-		-	-	***£8,903,613***
B1.2.2.1.1	Insurance and Certification		-	-	-		£1,940,000	*Insurance and Certification*	£1,940,000
B1.2.2.1.2	*Jacket Steel*		£1,333	Te	2,700	£3,600,000	£216,000		£3,816,000
B1.2.2.1.3	*Piles*		£1,301	Te	1,850	£2,406,233	£144,374	*Logistics/Freight @ 6%*	£2,550,607
B1.2.2.1.4	*Anodes*		£3,685	Te	110	£405,387	£24,323		£429,710
B1.2.2.1.5	*Installation Aids*		£1,127	Te	140	£157,827	£9,470		£167,296
	Topsides		-	-	-		-	-	***£9,021,652***
B1.2.2.2.1	Insurance and Certification		-	-	-		£940,000	*Insurance and Certification*	£940,000
B1.2.2.2.2	*Primary Steel*		£1,087	Te	170	£184,733	£11,084		£195,817.33
B1.2.2.2.3	*Secondary Steel*		£900	Te	100	£90,000	£5,400		£95,400.00
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	15	£545,000	£32,700		£577,700.00
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	20	£294,667	£17,680		£312,346.67
B1.2.2.2.9	*Control and Communications*	*Sat Comms*	£460,733	Te	3	£1,382,200	£82,932		£1,465,132.00
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	15	£781,000	£46,860		£827,860.00
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		-	-			-		**£15,010,978**
	Jacket		-	-			-		***£11,965,421***
B1.2.3.1	*Jacket Steel*		£3,245	m	2,700	£8,760,600	£525,636		£9,286,236
B1.2.3.2	*Piles*		£1,022	m	1,850	£1,890,700	£113,442	*Logistics/Freight @ 6%*	£2,004,142
B1.2.3.3	*Anodes*		£755	Each	110	£83,087	£4,985		£88,072
B1.2.3.4	*Installation Aids*		£3,955		140	£553,747	£33,225		£586,971
	Topsides		-		-		-	-	***£3,045,557***
B1.2.3.2.1	*Primary Steel*		£5,467	Te	170	£929,333	£55,760		£985,093
B1.2.3.2.2	*Secondary Steel*		£7,200	Te	100	£720,000	£43,200		£763,200
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
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.3	*Tug Transport - Jacket*	*Infield Operations*	£57,236	Days	16	£915,776	£0	-	£915,776
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
		Mobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.4	*Barge Transport - Jacket*	*Infield Operations*	£8,672	Days	56	£485,632	£0	-	£485,632
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.5	*Tug Transport - Topsides*	*Infield Operations*	£57,236	Days	30	£1,717,080	£0	-	£1,717,080
		Demobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
		Mobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
B1.2.4.6	*Barge Transport - Topsides*	*Infield Operations*	£8,672	Days	70	£607,040	£0	-	£607,040
		Demobilisation	£8,672	Days	4	£34,688	£0	-	£34,688
				Total (Excluding Contingency)					**£74,883,801**
				Pre-FID Contingency (%)				30%	**£1,957,500**
				Post-FID Contingency (%)				30%	**£20,507,640**
				Total (Including Contingency)					**£97,348,941**

PROJECT	Strategic UK Storage Appraisal Project	
TITLE	SITE 2: FORTIES 5 - NORTH SITE	**WELLS: COST SUMMARY**
CLIENT	ETI	
REVISION	DRAFT	
DATE	42382	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Well Cost Summary (including 30% Contingency)		
Well Name	**Days**	**Well Cost (£,000)**
	Year -2	
Appraisal Well	97.3	34747.5
	Year 0	
Platform Injector 1	68.3	27884.8
Platform Injector 2	61.8	25460.3
Platform Injector 3	61.8	25460.3
Platform Injector 4	61.8	25460.3
Monitoring Well 1 / Spare Injector	66.8	26865.3
	Year 5	
Local Platform Sidetrack 1	85.2	30837.45
	Year 15	
Local Platform Sidetrack 2	85.2	30837.45
	Year 20	
Sidetrack for new Platform Injector 5	81.3	30263.75
Sidetrack for new Platform Injector 6	74.8	27839.25
Sidetrack for new Platform Injector 7	74.8	27839.25
Sidetrack for new Platform Injector 8	74.8	27839.25
Sidetrack for Monitoring Well 2 / Spare Injector	79.8	29504.25
	Year 25	
Local Platform Sidetrack 3	85.2	30837.45
	Year 35	
Local Platform Sidetrack 4	85.2	30837.45
	Year 40	
Abandonment Platform Injector 5	28.6	9263.8
Abandonment Platform Injector 6	22.1	6839.3
Abandonment Platform Injector 7	22.1	6839.3
Abandonment Platform Injector 8	22.1	6839.3
Abandonment Monitoring Well 2	28.6	8678.8
TOTAL	1266.9	470974.3

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary	
Drilling Campaign	**Overhead (£MM)**
Appraisal Well	**0.90**
Platform Injector 1-4 + MW	**5.70**
Platform Injector 5-8 + MW2	**5.70**
Abandonment	**2.70**

OPEX Overhead Cost Summary	
OPEX Campaign	**Overhead (£MM)**
Local Platform Sidetrack 1	**1.50**
Local Platform Sidetrack 2	**1.50**
Local Platform Sidetrack 3	**1.50**
Local Platform Sidetrack 4	**1.50**

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)**	
Appraisal Well - CAPEX Breakdown						
Appraisal Well	10,418	16,243	3,278	3,700	1,110	34,748
Development Wells - CAPEX Breakdown						
Platform Injector 1	6,983	10,988	2,245	5,900	1,770	27,885
Platform Injector 2	6,318	10,013	2,045	5,450	1,635	25,460
Platform Injector 3	6,318	10,013	2,045	5,450	1,635	25,460
Platform Injector 4	6,318	10,013	2,045	5,450	1,635	25,460
Monitoring Well 1 / Spare Injector	6,983	11,013	2,045	5,250	1,575	26,865
Sidetrack for new Platform Injector 5	8,313	12,938	2,644	4,900	1,470	30,264
Sidetrack for new Platform Injector 6	7,648	11,963	2,444	4,450	1,335	27,839
Sidetrack for new Platform Injector 7	7,648	11,963	2,444	4,450	1,335	27,839
Sidetrack for new Platform Injector 8	7,648	11,963	2,444	4,450	1,335	27,839
Sidetrack for Monitoring Well 2 / Spare Injector	8,313	12,963	2,444	4,450	1,335	29,504
Wells - OPEX Breakdown						
Local Platform Sidetrack 1	8,712	13,773	2,763	4,300	1,290	30,837
Local Platform Sidetrack 2	8,712	13,773	2,763	4,300	1,290	30,837
Local Platform Sidetrack 3	8,712	13,773	2,763	4,300	1,290	30,837
Local Platform Sidetrack 4	8,712	13,773	2,763	4,300	1,290	30,837
Wells - ABEX Breakdown						
Abandonment Platform Injector 5	2,926	4,140	1,028	900	270	9,264
Abandonment Platform Injector 6	2261	3165	828.3	450	135	6839.3
Abandonment Platform Injector 7	2261	3165	828.3	450	135	6839.3
Abandonment Platform Injector 8	2261	3165	828.3	450	135	6839.3
Abandonment Monitoring Well 2	2926	4140	1027.8	450	135	8678.8

	CAPEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
						%	**£MM**	
A1.4.2	Appraisal Well (inc Procurement)	29.5	0.90	Well Management Fees, Insurance, Site Survey, Studies etc	30.4	30%	4.4	**34.7**
A1.3	Pre-FEED / FEED PM & E	2.0	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	30%	0.7	**2.9**
B1.3.1	Detailed Design PM & E	2.0	0.2		2.2	30%	0.7	**2.9**
B1.3.2	Procurement	38.8	3.9		42.7	30%	15.1	**57.7**
B1.3.4	Construction and Commissioning (Drilling)	186.3	11.40	Well Management Fees, Insurance, Site Survey, Studies etc.	197.7	30%	22.8	**220.6**
	Total	**258.6**	**16.6**		**275.2**	**-**	**43.6**	**318.8**

OPEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
					%	**£MM**	
OPEX	101.1	6.00	Well Management Fees, Insurance, Site Survey, Studies etc.	107.1	30%	16.2	**123.3**

ABEX Summary	**Excluding Contingency (£MM)**	**Overhead (£MM)**	**Overhead Description**	**Sub-Total (£MM)**	**Contingency**		**Total Cost (£MM)**
					%	**£MM**	
ABEX	30.4	2.70	Well Management Fees, Insurance, Site Survey, Studies etc.	33.1	30%	5.4	**39.3**

	Level 1 Cost Estimate Summary - Wells	
	Total CAPEX (£MM)	318.8
C1.3	Total OPEX (£MM)	123.3
D1.3	Total ABEX (£MM)	39.3
	TOTAL (£MM)	**481.4**