Programme Area: Carbon Capture and Storage

Project: DECC Storage Appraisal

Title: WP5C – Hamilton Storage Development Plan

Abstract:

Storage in the Ormskirk Sandstone in the faulted horst block known as Hamilton (UKCS block 110/13) in the East Irish Sea. 3 well development of Hamilton from an unmanned platform supplied with CO2 from Point of Ayr via a 16” 26km pipeline. Final investment decision in 2022 and first injection in 2026. Capital investment of £114 million (PV10, 2015), equating to £0.9 for each tonne stored. The store can contain the 125Mt from the assumed CO2 supply profile of 5Mt/y for 25 years. Subsurface uncertainty is limited, but a complex transition needs to be engineered between early gas phase injection and later liquid phase injection.

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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D12: WP5C – Hamilton Storage Development Plan

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Document Summary			
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3 well development of Hamilton from an unmanned platform supplied with CO_2 from Point of Ayr via a 16" 26km pipeline.

Final investment decision in 2022 and first injection in 2026.

Capital investment of £114 million (PV_{10}, 2015), equating to £0.9 for each tonne stored.

The store can contain the 125Mt from the assumed CO_2 supply profile of 5Mt/y for 25 years.

Subsurface uncertainty is limited, but a complex transition needs to be engineered between early gas phase injection and later liquid phase injection.

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

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

Hamilton was selected as one of five target storage sites during 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 Hamilton gas field is a horst block structure located in the East Irish Sea Basin (EISB), block 110/13, approximately 23 km from the Lancashire coast, as illustrated in Figure 1-1. The gas reservoir and primary storage unit is within the Ormskirk and St Bees Sandstone Formations of the Triassic Sherwood Sandstone Group. The Sherwood Sandstone Group extends over most of the EISB and is the equivalent of the Bunter Sandstone Formation in the Southern North Sea.

The Ormskirk and St Bees Formations are comprised of excellent quality aeolian and fluvial sandstones with average porosity from logs between 13 – 19% and average permeability from core of 1,350 mD. The depth to the crest of the structure is 700 m tvdss (2300 ft tvdss) but, since the temperature in Hamilton is above the critical temperature for CO_2, the injected inventory will be able to remain in dense phase at this depth. Total thickness of Sherwood Sandstone at the Hamilton Field Site is approximately 900m (2964 ft) but the maximum thickness of reservoir sand above the GWC at the site (column height) is 185 m (610ft).

Secure containment is provided by laterally extensive mudstones and halites of the Mercia Mudstone Group which are a proven seal for multiple hydrocarbon fields in the EISB and provides an excellent caprock for the storage complex.

A seismic interpretation was carried out on the 1992 3D seismic survey for which only the original processing was available. A detailed geological model based on this and the petrophysical evaluation of 11 regional wells (5 within the site) was built. The static model was been upscaled and taken to dynamic compositional simulation modelling. This was used to generate the development plan.

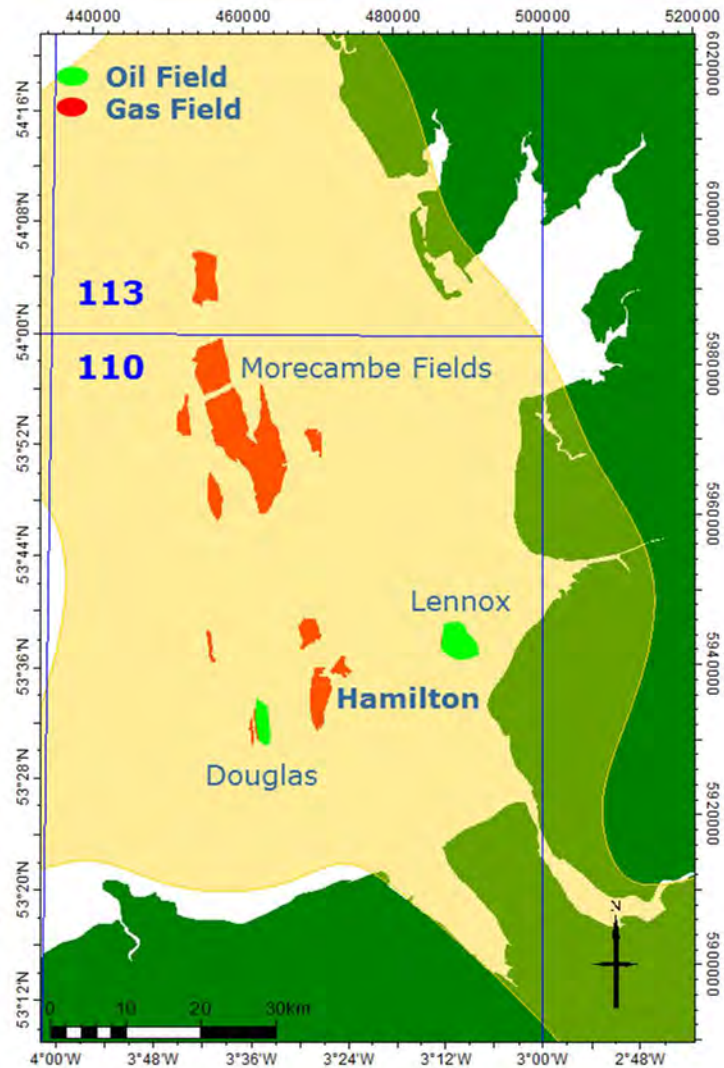


Figure 1-1 Hamilton Location Map

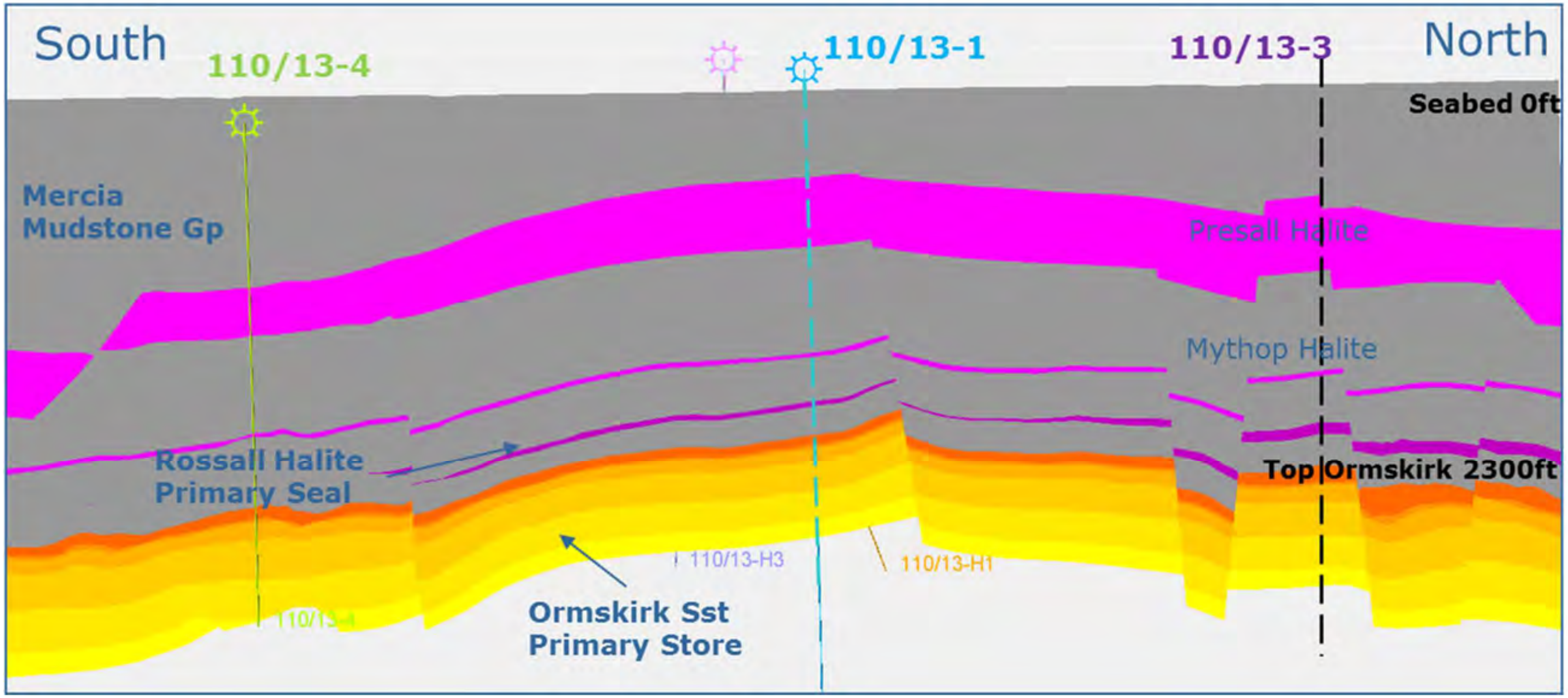


Figure 1-2 Hamilton Store and Seals

The basis for the development plan is an assumed CO_2 supply of 5Mt/y to be provided from the shore terminal at the Point of Ayr commencing in 2026. To maximise the economic benefit CO_2 will be transported offshore in liquid-phase via a new 26km 16" pipeline from Point of Ayr to a newly installed Normally Unmanned Installation (NUI), minimum facilities platform on a 3 legged steel jacket standing in 25m of water. During the operational period two wells are required to accommodate the supply profile.

The Hamilton reservoir is a depleted gas field and will have a very low reservoir pressure. Consequently CO_2 will initially have to be injected in gas-phase until the reservoir pressure has increased sufficiently for liquid-phase injection. Heating of the CO_2 will be required during the initial period to manage low temperature risks and ensure single phase conditions in the wells. Two replacement wells are assumed to be required when the operation changes from gas-phase injection to liquid–phase injection.

Geological and reservoir engineering work has concluded that the Hamilton reservoir is very well connected hydraulically and storage capacity is relatively insensitive to well placement. Injection wells will be placed in the vicinity of the existing gas production wells, to minimise the geological risk. Injectivity is expected to be good and only part of the reservoir section needs to be open to the wellbores to achieve the target injection rate of 5Mt/y.

During the operational periods, 2 of the wells are expected to be injecting at any point in time with the 3rd as backup in the event of an unforeseen well problem. In this manner, the facilities will maintain a robust injection capacity and inject 5Mt/y of CO_2 for the 25 year project life without breaching the safe operating envelope. Over the period a total of 124Mt CO_2 will have been stored.

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 2022. The capital intensive activities of procurement and construction follow FID and take place over a 3-4 year period. First injection is forecast to be in mid-2026.

The development of the offshore transportation and injection infrastructure is estimated to require a capital investment of £116 million (in present value terms discounted at 10% to 2015), equating to £0.9/T. The life-cycle costs are estimated to be £226M (PV_{10}), equating to a levelised cost of £14.2/T, as summarised in Table 1 1.

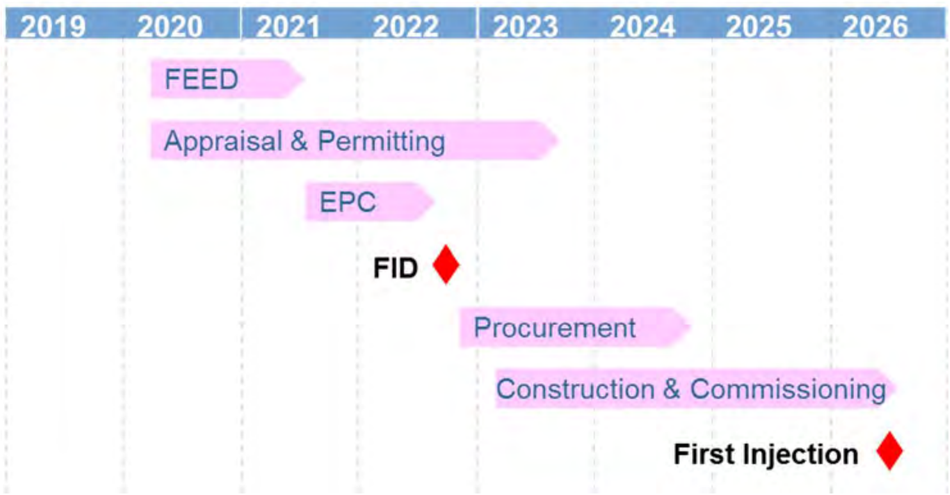


Figure 1-3 Summary Development Schedule

£million (PV_{10}, 2015)	Phase I	Phase II	Total
Pre-FID	15		15
Transportation	31		31
Facilities	46		46
Wells	25	5	30
Opex	99		99
Decommissioning & MMV	5		5
Total	221	5	226

Table 1-1 Project Cost Estimate (PV_{10}, 2015)

Of the £14.2/T levelised cost, it is estimated that the operations of gas phase injection and management of the phase transition have contributed £2.3/T (17%). Whilst it is clearly more attractive to avoid such operations, they can be safely included within a storage development plan. It should also be noted that whilst the heavily depleted nature of the Hamilton reservoir creates some operational challenges, the project storage efficiency at 70% is almost four times greater than the best saline aquifer systems.

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

- Improve the characterisation of how the fracture pressure will evolve during the re-pressurisation of the reservoir.
- Commission further work to better understand the options for managing the transition from gas-phase to liquid-phase operations and how best to select a preferred strategy.
- Review the current assumption that heating during the gas-phase operation is more beneficial than drilling additional wells.
- Further work should consider how best to deliver the heating requirements and identify alternatives to the 10MW electrical heating options evaluated for this study.

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

Hamilton 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.

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 Hamilton gas field is a horst block structure located in the East Irish Sea Basin (EISB), block 110/13, approximately 23 km from the Lancashire coast. The field was discovered in 1990 by well 110/13-1, and first gas was produced in February 1997.

The gas reservoir and primary storage unit is within the Ormskirk and St Bees Sandstone Formations of the Triassic Sherwood Sandstone Group. The Sherwood Sandstone Group extends over most of the EISB and is the equivalent of the Bunter Sandstone Formation in the Southern North Sea.

The distribution of the Sherwood Sandstone Group within the EISB, and the location of East Irish Sea hydrocarbon fields, is shown in Figure 3-1.

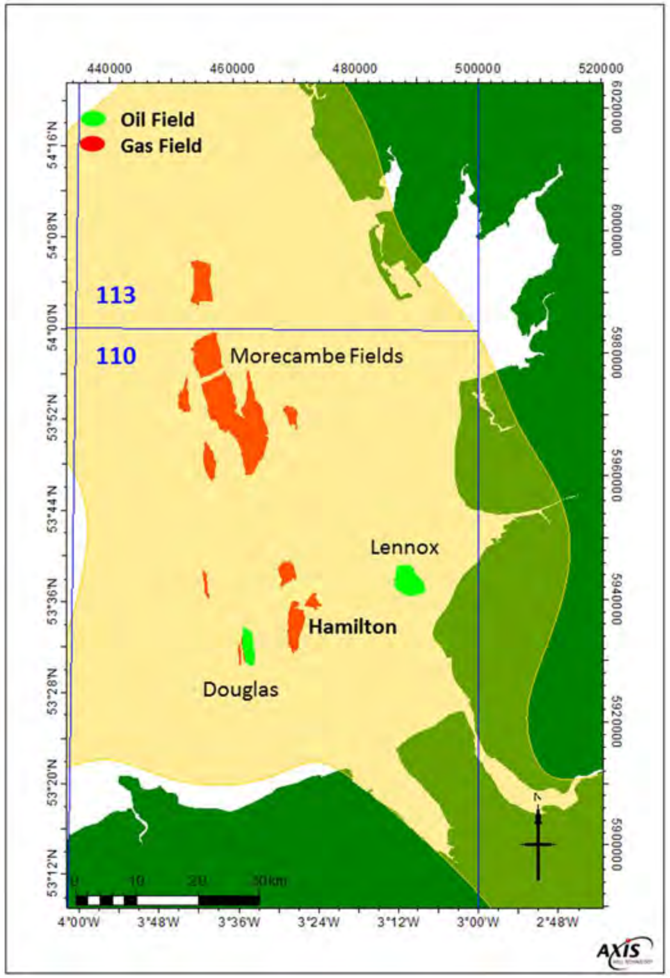


Figure 3-1 Location map (adapted from (Kirk, 2006))

3.2 Site History and Database

3.2.1 History

The Hamilton gas field is a N-S trending horst block, located on the southern edge of the East Irish Sea Basin. The field is dip closed to the north and south. It is bounded on the west by the N-S trending Hamilton Fault which throws the Sherwood Sandstone down by over 150m (500 ft), several hundred feet below the GWC. The structure is also cut by minor east-west and north south faults. Within the structure all faults have sand to sand juxtaposition and pressure data during production supports the interpretation that they are not sealing.

Interpretation indicates that extension occurred during the Early Permian, controlling facies and thickness variations, with fault activity continuing during Late Permian and the Triassic.

3.2.2 Hydrocarbon Exploration

The Sherwood Sandstone Group of the East Irish Sea Basin is an important and proven gas province, although there are also a small number of oil fields. The uppermost unit, the Ormskirk Sandstone Formation, contains the majority of the discovered reserves. South and North Morecambe Gas Fields were the earliest to be discovered (1974 and 1976 respectively) and put on production. They are also by far the largest fields in the basin. Subsequently a number of other discoveries have been made and put on production, including the Hamilton Gas Field (Discovery:1990, First Gas: 1997).

The East Irish Sea Basin is a simple petroleum system with a complex burial history (Cowan, et al., 1999). Carboniferous Namurian shales provide the source rock and are present across the whole basin. The overlying Mercia Mudstone provides a proven regional seal (Cowan, et al., 1999).

3.2.3 Seismic

The Hamilton gas field is covered by a single 3D dataset, acquired in 1992 and currently owned by ENI. The data is listed on the CDA database but stored by ENI. These data were loaded to Schlumberger's proprietary PETREL software where the seismic interpretation was undertaken. Figure 3-2 shows the extent of the 3D dataset and the location of the Hamilton Field site model. There is complete seismic coverage of the area.

Seismic data SEGY summary is provided in Appendix 3.

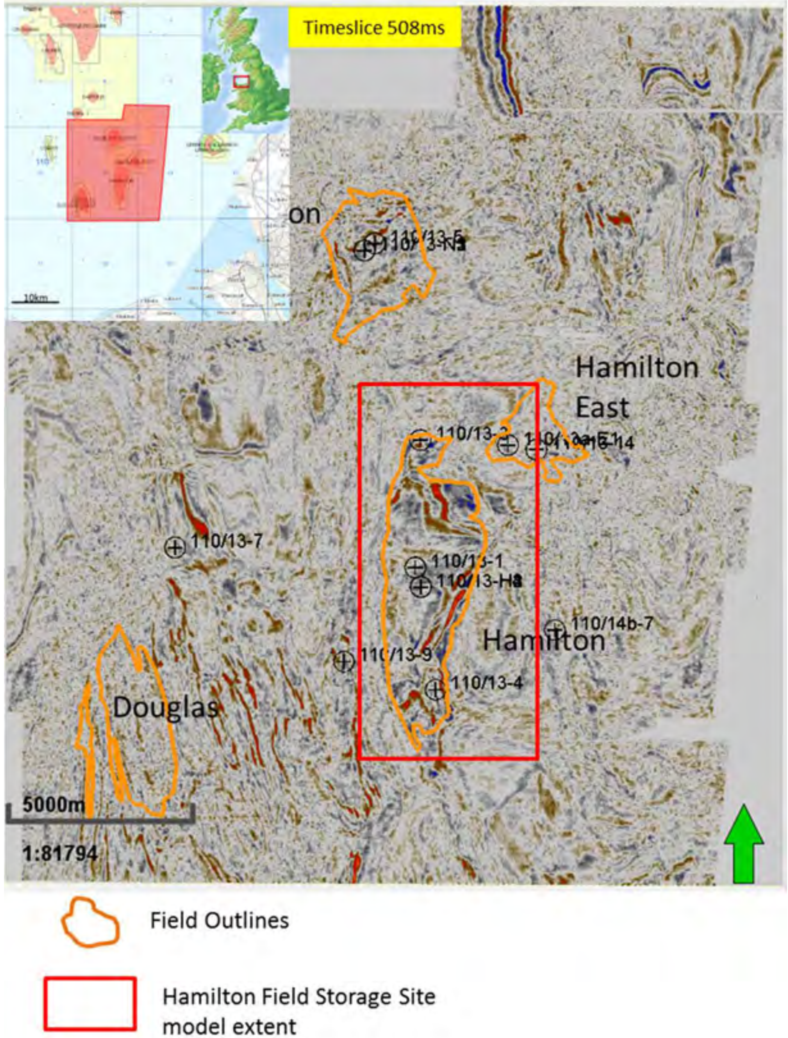


Figure 3-2 Time slice showing location and extent of Hamilton 3D seismic volume with Field outlines and model location highlighted

3.2.4 Wells

All well log data was sourced from the publically available CDA database. These data are variable in range and quality, but generally included LIS or DLIS formatted digital data files, field reports, end of well reports, composite logs and core reports. A total of 17 wells were screened for petrophysical evaluation (Table 3-1). These included wells from nearby Hamilton North and Hamilton East Fields. A total of 11 wells were selected that have suitable data for analysis over the Sherwood reservoir interval, of these a sub-set of 4 have conventional core data with only one well with SCAL data.

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

3.3 Storage Stratigraphy

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

Carboniferous

The deepest well in the site (110/13-1) penetrates interbedded sands and shales of the Carboniferous at a depth of over 2600 m tvdss (over 8100 ft tvdss). These sediments were deposited on the pro-delta slopes of the Namurian delta system prograding from the east. The shales are known to be the source rocks for sour gas and oil in areas of the basin where Carboniferous Westphalian sediments are absent (Cowan, et al., 1999).

Permian

The largely aeolian Collyhurst Sandstone Formation sits unconformably above the Carboniferous. This in turn is overlain by 150 m (500 ft) of claystones and dolomitic siltstones of the Manchester Marl Formation.

Triassic

The Sherwood Sandstone Group extends over most of the East Irish Sea Basin and is the equivalent of the Bunter Sandstone Formation found in the Southern North Sea. It reaches thicknesses of over 2000m (6560 ft) in the centre of the basin, the total thickness at the Hamilton Field Site is approximately 900m (2964 ft).

The St Bees Sandstone Formation comprises a thick sandstone sequence of mostly stacked fluvial sandstones. It is subdivided into two units of roughly equal thickness: The fluvially dominated Rottington Sandstone Member and mixed aeolian and fluvial facies of the Calder Sandstone Member (Meadows & Beach, 1993). Only a small section of the Calder Sandstone Member sits above the gas water contact (GWC). At the Hamilton Field Site the St Bees Sandstone Formation reaches 670 m (2,200 ft) in thickness, based on the 110/13-1 well.

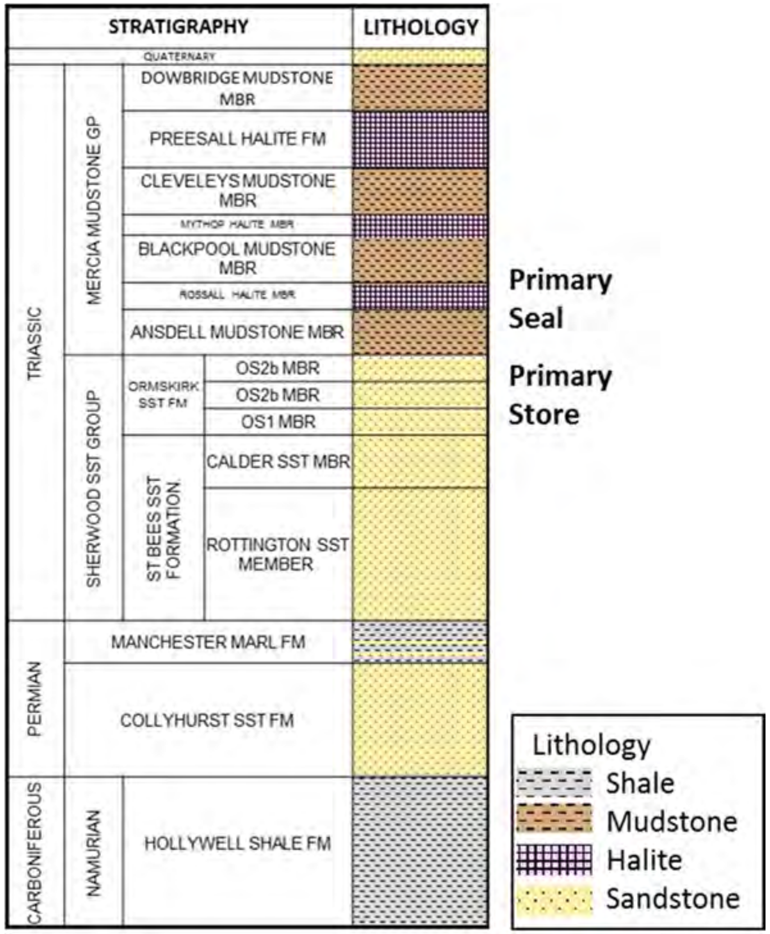


Figure 3-3 Stratigraphic Column at Hamilton Field Site, showing the overlying and underlying geological formations

The Ormskirk Sandstone Formation directly overlies the St Bees Sandstone at the top of the Sherwood Sandstone Group, and is the main reservoir and storage unit. In the southern area of the basin where the site is located it is stacked sequences of mixed aeolian dune, aeolian sand sheet, aeolian sabkha and fluvial facies deposited in a semi-arid environment. It has been divided into three distinct zones on the basis of lithofacies (OS2b, OS2a, OS1). The Ormsirk Sandstone is approximately 233 m (765 ft) thick at the Hamilton Field Site.

The overlying Mercia Mudstone Group provides a proven basin wide seal, and is composed of up to 5 cycles of alternating red mudstones and thick halites, deposited in lakes subjected to periodic flooding (Stuart, 1993). Reaching thicknesses of up to 3200 m (10500ft) within the basin, it is approximately 700 m (approx. 2300 ft) at the Hamilton Field Site and forms the majority of the overburden.

Quaternary

The Quaternary sediments comprise approximately 20m (67ft) of undifferentiated medium to coarse sands and gravels, with clays.

Well	Hamilton Field Areas	Wireline	MWD	Core	Mud Type
110/13-1	Main Field	✓		✓	Salt Saturated Polymer Mud System
110/13-3	Main Field	✓		✓	
110/13-4	Main Field	No data available		✓	
110/13-H1	Main Field				
110/13-H2	Main Field				
110/13-H3	Main Field				
110/13-H4	Main Field	No data, TLC logging			
110/13-14	East				
110/13-E1	East	No data			
110/13-5	North				
110/13-N1	North				
110/13-N2	North	No data			
110/13-N3	North	No data			
110/13-N4	North	No data			
110/13-7	Regional	✓			
110/13-9	Regional	✓		✓ + SCAL	
110/14b-7	Regional	✓			

Table 3-1 Wells screened for petrophysical evaluation

3.4 Seismic Characterisation

3.4.1 Database

The Hamilton gas field is covered by a single 3D dataset, acquired in 1992 and currently owned by ENI. The data is listed on the CDA database but stored by ENI. Navigation data is not present in the SEG-Y headers and was supplied as a separate P1/84 file.

A reprocessing project in 2010 is reported to have produced a significant uplift in quality. However, only the vintage processing from 1992 was provided by ENI and this is of moderate quality. The reprocessed volume is held by a subsidiary company called ENI Liverpool Bay but they did not reply to requests for data.

The seismic data was loaded to Schlumberger's PETREL software for interpretation. Figure 3-4 shows the extent of the 3D dataset and the location of the Hamilton Field site model. There is complete seismic coverage of the area.

Wavelet extraction shows that decreasing Acoustic Impedance (AI) is represented by a positive peak in the seismic volume (SEG reverse polarity). It also shows the seismic volume is close to zero phase with a change in acoustic impedance coinciding with a peak or a trough.

To aid fault identification, a Semblance attribute volume was generated using the OpendTect open source software then exported and loaded into the Petrel project.

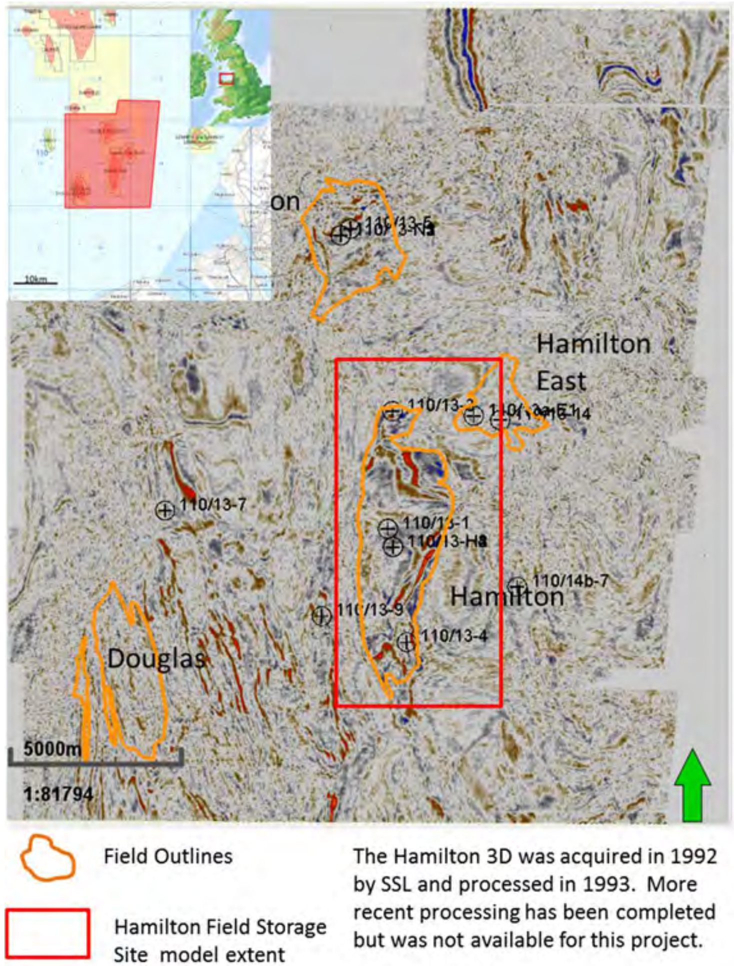


Figure 3-4 Time slice showing location and extent of Hamilton 3D seismic volume with field outlines and model location highlighted

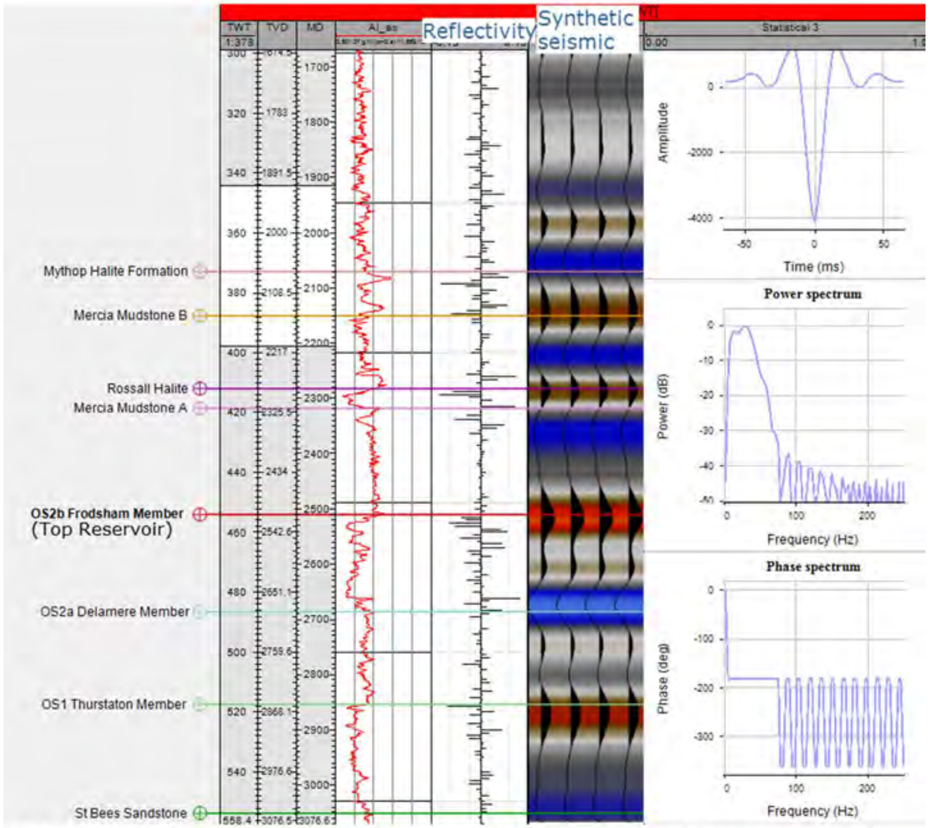
3.4.2 Horizon Identification

Log measurements acquired in the well bore allow detailed identification of the main formations in depth. Seismic data however, provides a much lower resolution image measured in travel time. Checkshot measurements recorded in some wells make it possible to convert between the time and depth domains by measuring seismic velocity at the well locations. This allows formation tops identified in the wells to be linked to reflection events in the seismic volume and interpreted away from the wells.

The observed seismic data can be compared directly to the signal expected at the wellbore by generating a synthetic reflectivity series from the density and sonic logs. High reflectivity corresponds to rapid changes in AI (Figure 3-5), where AI is the product of the velocity and density logs.

In the case of well 110/13-1 the full workflow involved the selection, editing and splicing of different sonic and density logging runs as well as the prediction of density data where logs were not present. Density prediction used Gardner's relationship between velocity and density with parameters calibrated over sections where both logs were present. The final prediction used parameters of a=0.22 and b=0.27 as defined in the Glossary. The synthetic seismic is generated by convolving the reflectivity series with a seismic wavelet of appropriate shape and frequency to mimic the seismic volume being modelled. In this case a statistical wavelet was extracted from traces in a 3x3 area around the well. The wavelet and the resulting synthetic are both shown in Figure 3-5.

The identified horizons, their pick criteria and general pick quality are listed in Table 3-2 and illustrated on a seismic line in Figure 3-6 and Figure 3-7.



Acoustic Impedance (AI, track1) is generated from the Sonic and Density logs. High reflectivity (track2) is produced where the AI changes rapidly. Convolving a seismic wavelet (track4) with the reflectivity series produces a synthetic seismic section (track3) that allows formation tops to be linked with specific seismic events.

Figure 3-5 Seismic well tie at well 110/13-1

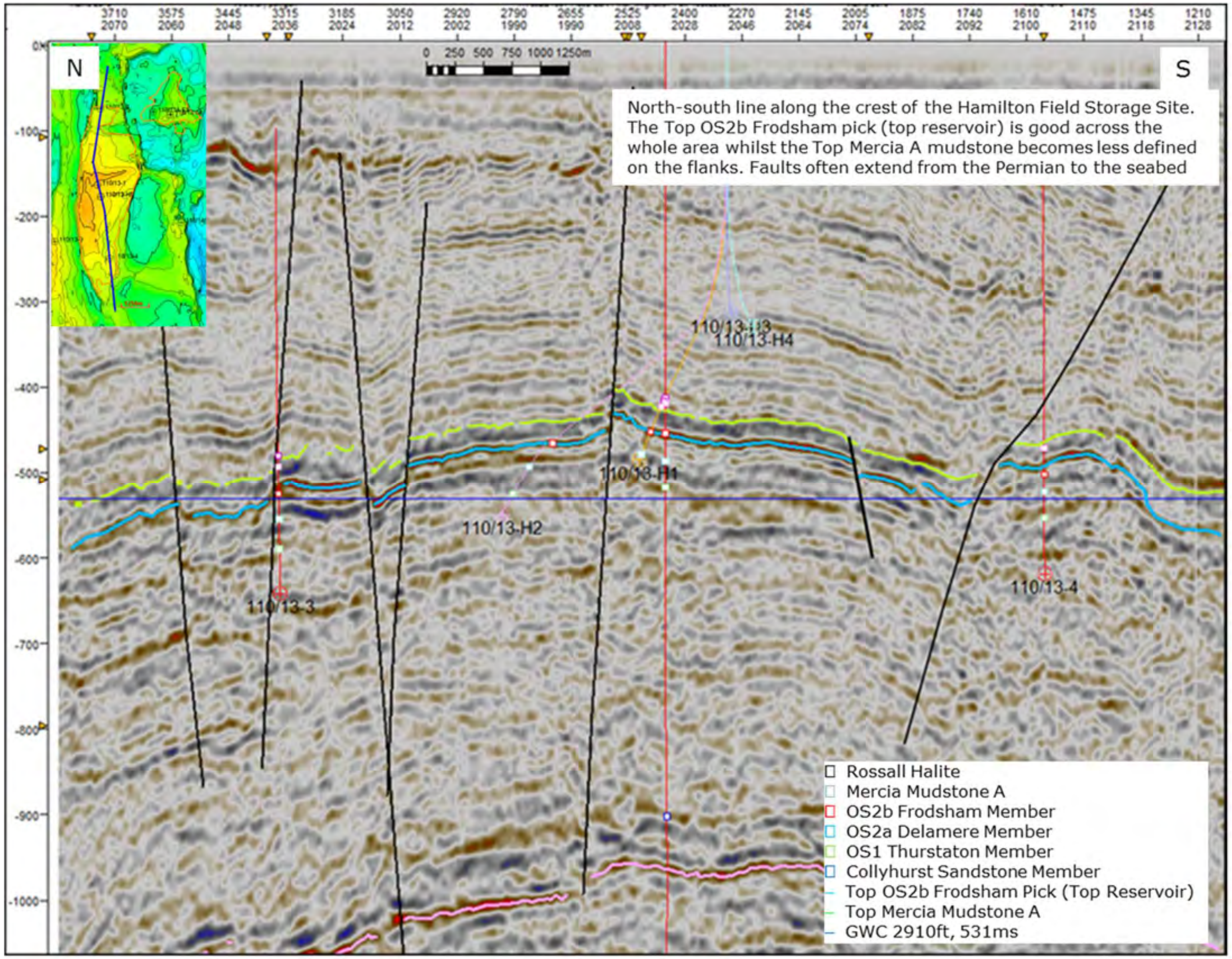


Figure 3-6 North-South arbitrary line through Hamilton Field storage site

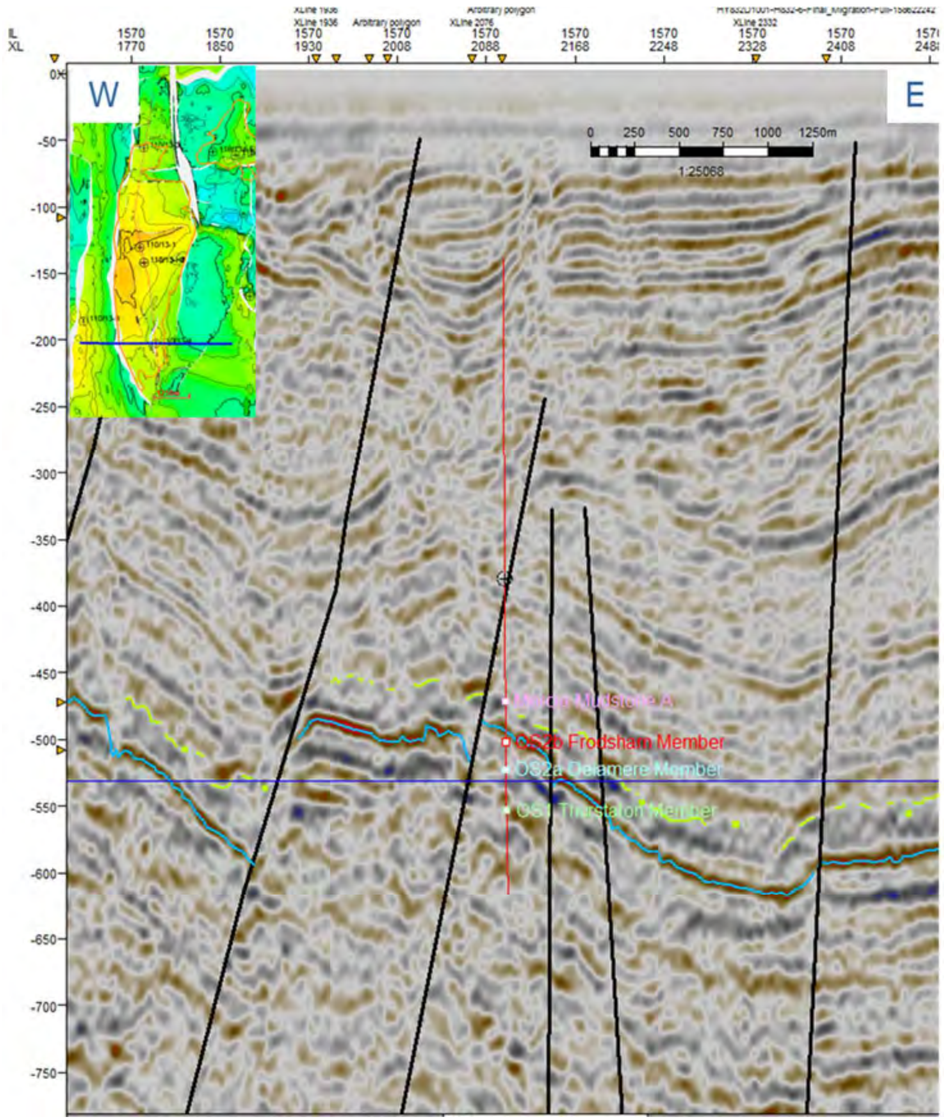


Figure 3-7 East-West arbitrary line through Hamilton Field storage site

Horizon	Event Type	Display Response	Pick Quality
Top Mercia Mudstone A	Hard	Peak-Trough (z) zero crossing	Poor
Top OS2b Member	Soft	Peak	Good
Top Collyhurst Lower Member	Soft	Peak	Moderate

Table 3-2 Interpreted horizons

3.4.3 Horizon Interpretation

A detailed seismic interpretation was carried out using reflectivity and semblance volumes to provide input faults and horizons to the Hamilton Field storage site Static Model. The interpretation extended to the Hamilton East and North fields to allow additional wells to be used in the depth conversion. Three horizons were initially interpreted;

- Top Mercia Mudstone A
- Top OS2b Member
- Top Collyhurst Lower Member

Only the Top OS2b Member horizon gave a continuous and reliable pick. The Top Collyhurst Sandstone Formation is a useful regional marker but was too deep to be used as the base of the Static model. The Primary seal is the Rossall Halite (section 3.5.3) however the Mercia mudstone gives a composite response with the Rossall Halite and this is generally very poor quality with considerable uncertainty in its position.

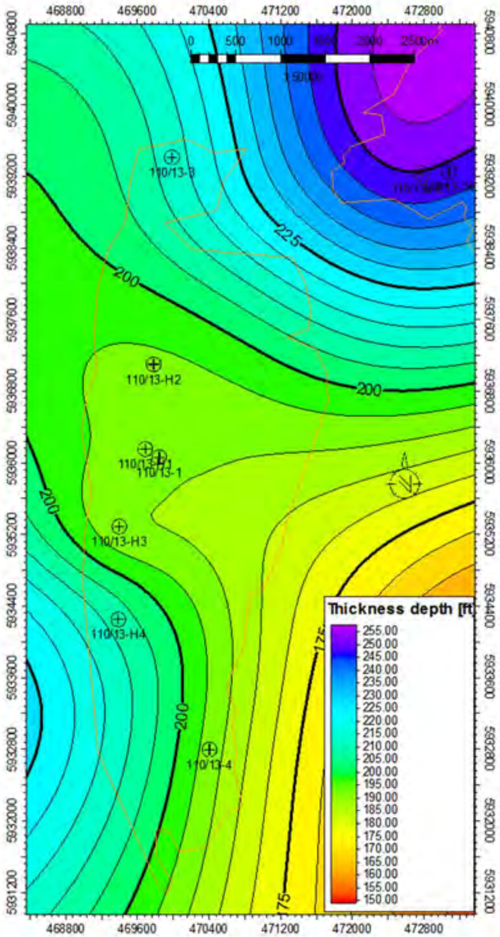
The synthetic section in Figure 3-5 shows the ideal seismic expression of each horizon. However, in reality, seismic noise and lateral changes in rock properties mean that these signatures may not be as well defined throughout the seismic volume as the synthetic implies.

The characteristics of the main horizons are as follows:

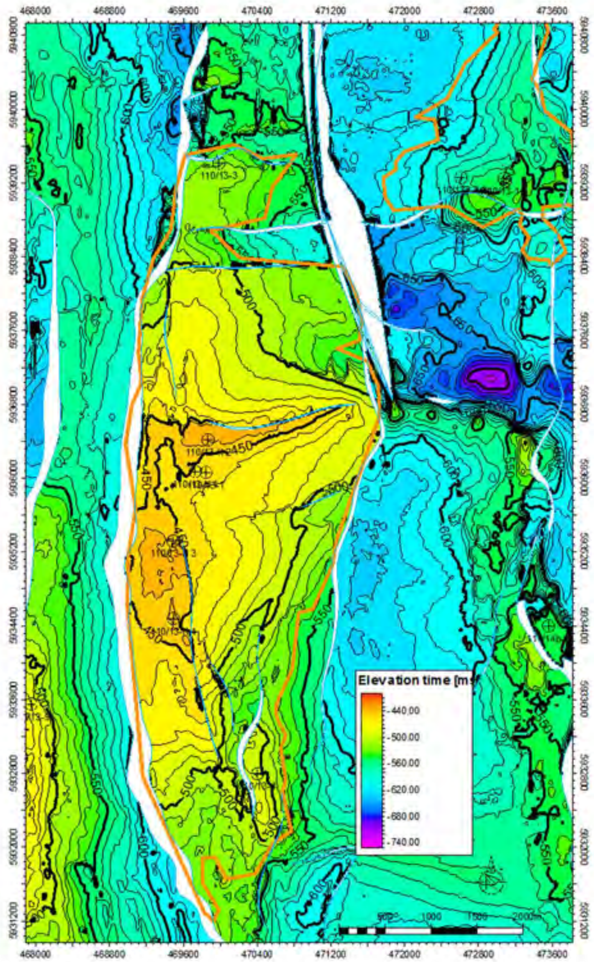
Top Mercia Mudstone A – This horizon defines the top of the static model where siltstones and muds of Mudstone A (also known as the Ansdell Mudstone) meet the impermeable seal of the overlying Rossall Halite.

Sonic logs show that the Mercia A mudstone is hard compared to the overlying Halite. However the Halite is thin (<50ft) relative to the seismic signal so that the two formations produce a composite response. Well ties showed that a peak-trough (z-shape) zero crossing gave the best indication of the Mercia Mudstone A. The composite nature of this reflection and the variable AI of the surrounding mudstones make this a poor and discontinuous pick. Consequently, the final surface used in the Static Model was calculated from well top isochores gridded into a continuous surface using Petrel (Figure 3-8). This isochore surface was then added to the OS2b Frodsham surface to give the top of the model.

Top OS2b Member - The OS2b Member of the Triassic Ormskirk Sandstone Formation was previously known as the Frodsham Member. This is the top of the reservoir zone over the Hamilton Field and is the most consistent seismic marker in Block 110/13. The transition from the overlying Ansdell mudstone to the soft aeolian sands of the Ormskirk Formation produce a clear drop in acoustic impedance and a correspondingly strong positive peak in the seismic volume.



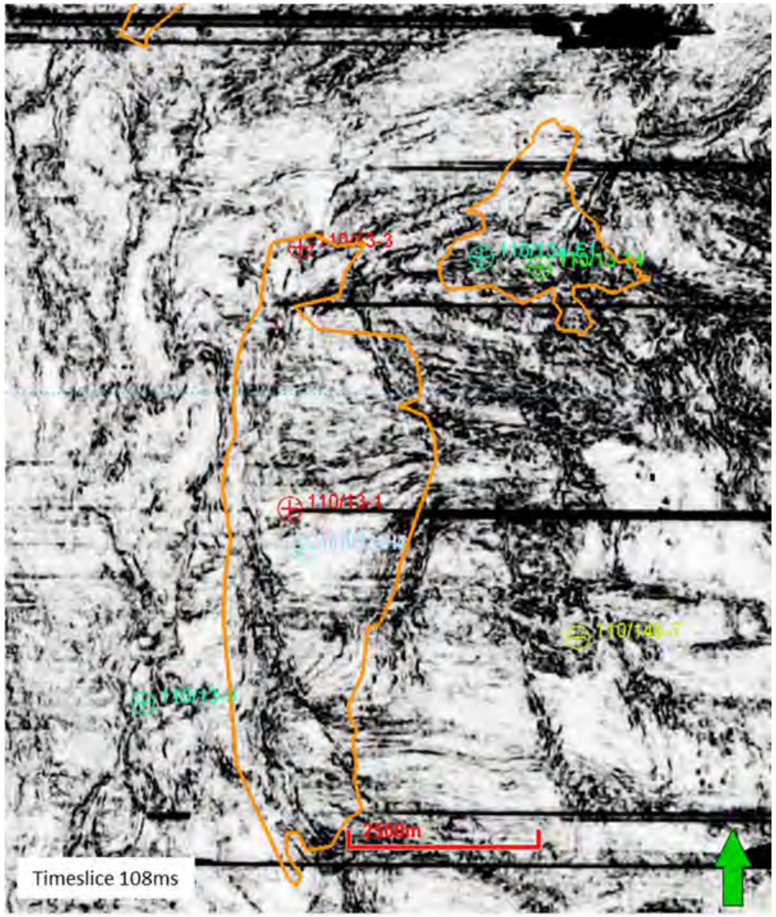
The Mercia Mudstone A seismic pick was too variable for use in the Static Model so the formation tops observed in the wells were used to build a thickness map of the Mercia A Mudstone. This was added to the OS2b Member horizon to produce the Mercia A Mudstone surface used in the Model.



Fault polygons (light blue) are generated from picked faults and horizons. They are used to constrain the gridding process to avoid interpolation across areas where the horizon has been faulted out and to prevent smoothing across genuine discontinuities in the surface.

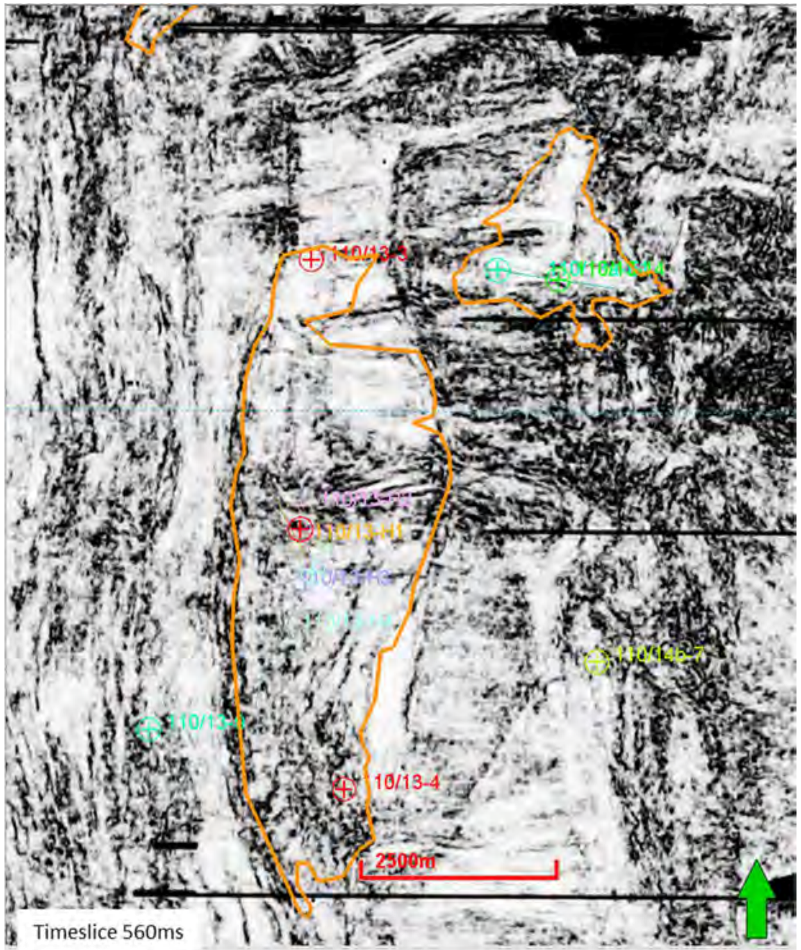
Figure 3-8 Gridded surface of OS2b Member to Mercia Mudstone A isochores calculated from well logs

Figure 3-9 Top OS2b member time surface including fault polygons



Many of the larger faults, including the East and West bounding faults for Hamilton continue to the surface and are still visible at the seabed. Note the slight E-W acquisition footprint and areas of missing data. Semblance calculated with Dip adapted 24ms window, after dip adapted median filter 5ms window, 5 trace radius.

Figure 3-10 Semblance timeslice just below seabed



The main faults show up clearly at all levels whilst the resolution of smaller and more subtle faults varies between slices. (Semblance calculated with Dip adapted 24ms window, after dip adapted median filter 5ms window, 5 trace radius)

Figure 3-11 Semblance timeslice at reservoir level

This should lend itself to autotracking within Petrel, however extensive internal faulting within the reservoir and noise present in the seismic data mean that manual picking was required with a spacing of 5 to 20 lines depending on complexity. The horizon picks were extended using Petrel's 3D autotracking function with a stringent 'Validated 5x5' quality test applied so as to reduce expansion of the horizon across faults. Fault polygons were generated from the 3D tracked horizon and applied as boundaries in the surface gridding process to produce a 12.5 x18.75 gridded surface that once depth converted can be used as input to the Static Model (Figure 3-9).

Top Collyhurst Lower Member - The soft positive peak of the Collyhurst sandstone forms a reliable Permian marker for larger scale modelling and fault placement throughout the block. The horizon was picked on a 32x32 line grid. However, being very deep, it was not used as the base of the Static Model. Instead the shallower Top St Bees Formation was deemed a more appropriate base for the detailed reservoir model (see Section 3.5.4).

3.4.4 Faulting

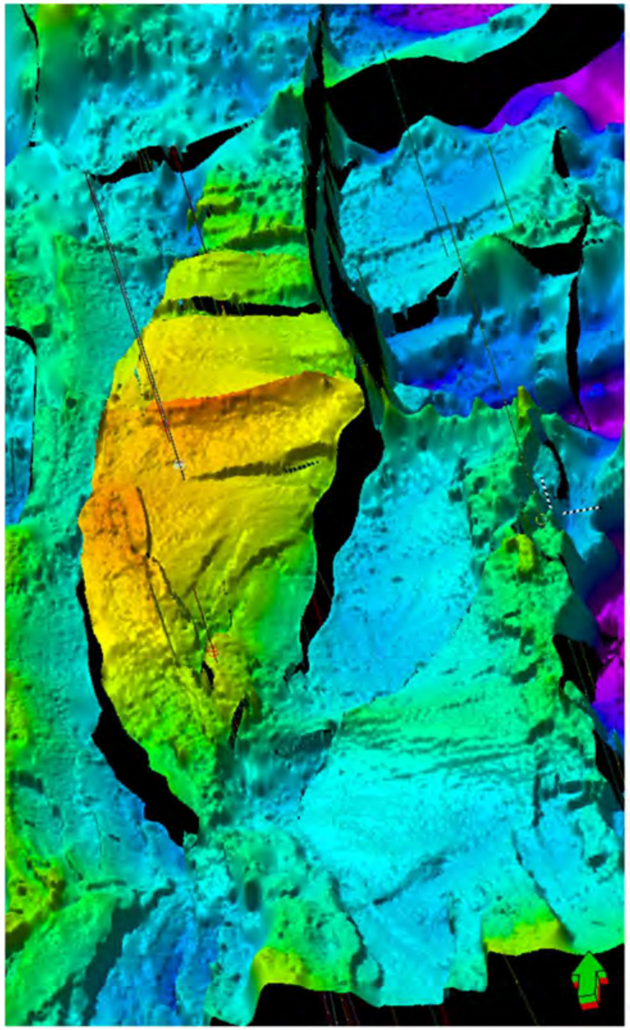
The Hamilton structure is a north-south orientated horst block bounded by large continuous faults to the east and west and dip closed to the north and south. Faulting was initiated by extension during the early Permian and continued into the Triassic such that the majority of faults continue through the Triassic section to the seabed (Figure 3-7). This is highlighted by time-slices through the Semblance display where the Hamilton structure is clear just below the seabed at 108ms (Figure 3-10). The Hamilton horst block is split by numerous North-South and East-West orientated faults producing a complex geometry with East-West faults dominating in the northern section whilst the southern half is split by intersecting North-South trending faults. Fault interpretation used the Dip Adapted Semblance attribute (Figure 3-11) to identify fault lineaments in timeslice or surface extraction views before picking faults sticks on inline or crossline displays with guidance from the Semblance map view. All the internal faults produce sand to sand contacts and pressure data has confirmed that they provide no barrier to gas flow (Yaliz & Taylor, 2003), none of them are currently active.

First pass fault interpretation was also extended to the Hamilton North and East Fields that are also strongly fault controlled. However, these areas were not used in the final model as they were outside the storage site. Figure 3-12 shows a 3D view of the Hamilton Horst block and gives a good qualitative illustration of the geometry of the storage site.

The interpreted faults and horizons are combined to generate fault polygons used to constrain the gridding process and ensure that the surface is not interpolated into area where it has been faulted out. The final Top OS2b Member Time surface with the fault polygons is shown in Figure 3-9.

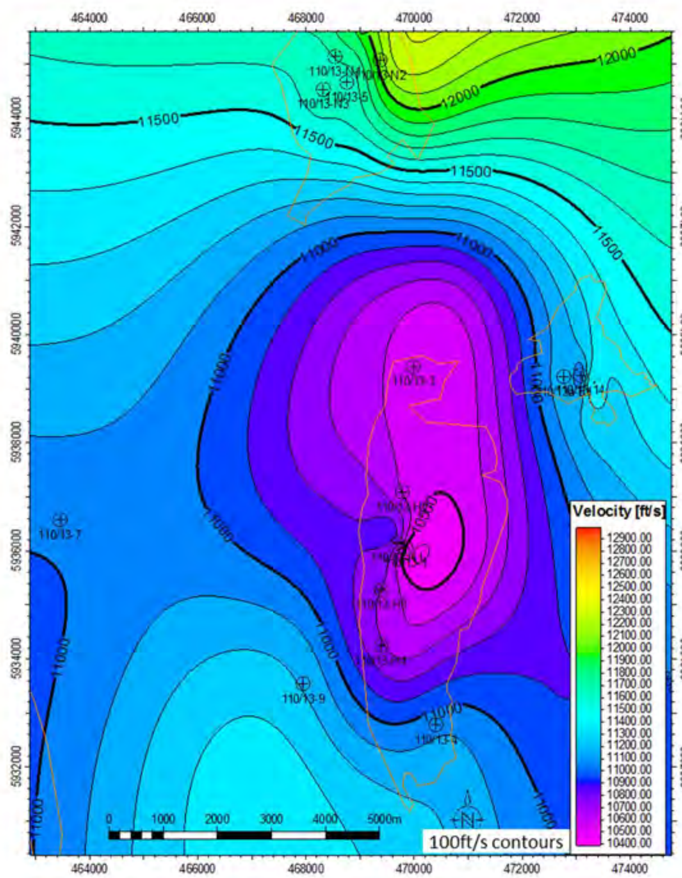
3.4.5 Depth Conversion

The Hamilton Field reservoir is exceptionally shallow (694m) with a near constant water depth, simple overburden geology and good well control. It is therefore appropriate to model the time to depth relationship as a single laterally varying interval velocity rather than a more complex multilayer model. For each well, the interval velocity (from mean sea level) was calculated from the log derived depth of the OS2b Member and the travel time of the seismic horizon intersecting the well. These velocities were then gridded into an interval velocity surface (Figure 3-13) using Petrel. The result was used to convert the interpreted faults and horizons to the depth domain for use in the Static Model



3D visualisation of the Hamilton Field horst block showing the fault boundaries to the east and west and the dipping structure to the south-east. By adjusting the direction of apparent illumination in the software, smaller internal faults are also highlighted. Vertical exaggeration is x20.

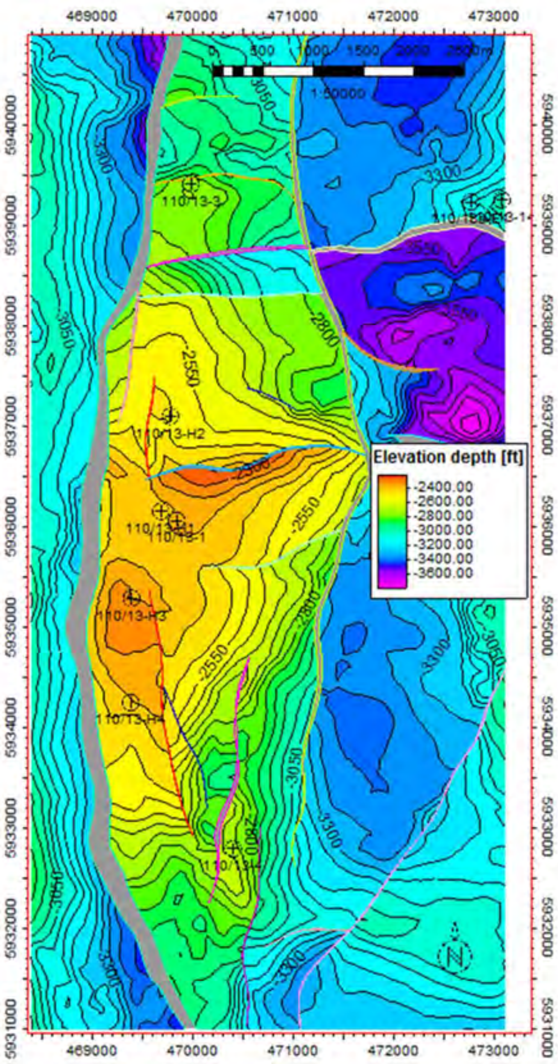
Figure 3-12 3D View of Hamilton faulted horst block at Top OS2b Member



Interval velocities were calculated using the depth to the OS2b Member marker identified on logs in each well and the time to the seismic horizon intersecting the well. The velocities were then gridded into a surface using Petrel. The Petrel Depth conversion module uses this surface to convert interpreted faults and horizons from time to depth for use in the Static Model.

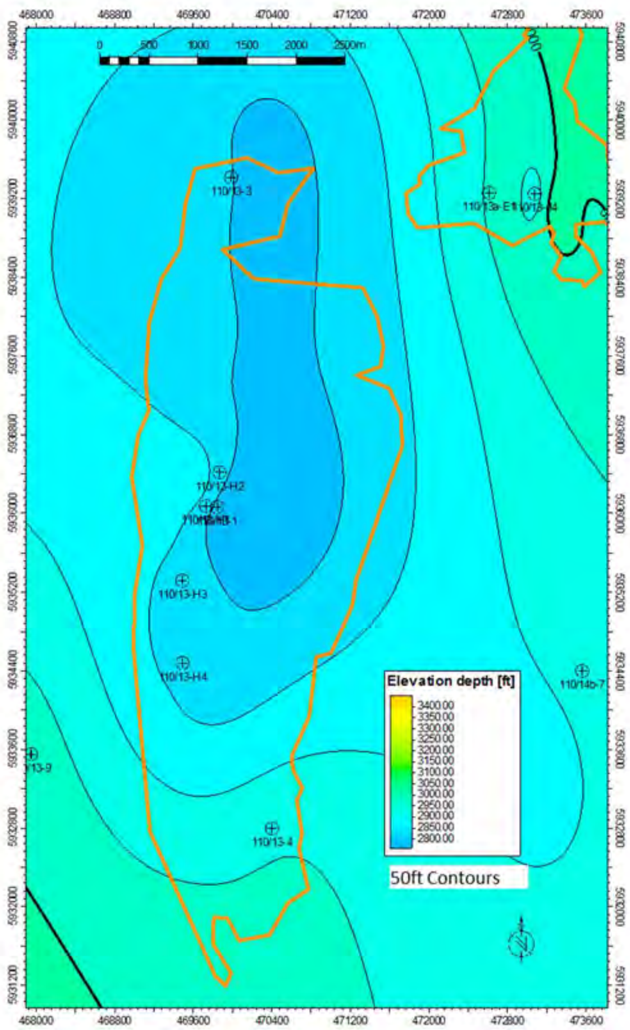
Figure 3-13 Interval velocity from Mean Sea level to OS2b Member

generation. The depth conversion was undertaken using the Petrel velocity modelling module and the final depth surface is shown in Figure 3-14.



The main reservoir section of the Ormskirk sandstone is the OS2b Member that gives a good quality pick across the entire reservoir area. The GWC is at 2910ft.

Figure 3-14 Hamilton Top Reservoir depth Map OS2b Member



The depth converted surface shows that variation in the overburden velocity accounts for almost 200ft of depth variation across the field. The variation along the crest has good well control and is likely to be a reliable estimate of the actual velocity variation. The flanks are less well controlled and in reality may have sharper, fault controlled velocity changes.

This display uses the same contour interval and colour scale as the Hamilton depth map.

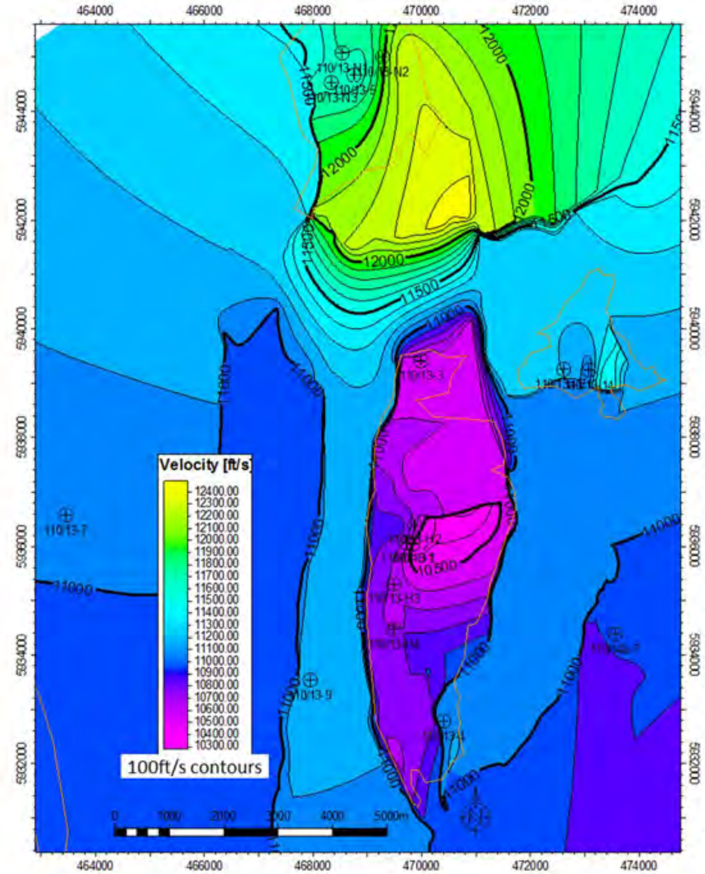
Figure 3-15 Timeslice 531ms (approximate Hamilton GWC) depth converted using calculated velocity surface

3.4.6 Depth Conversion Uncertainty

Gridding of the interval velocities from wells produces rounded contours with the lowest velocities over the main Hamilton Field (Figure 3-13). Lack of well control outside the field produces a gradual increase in velocity in most directions with some distortions to the contours where higher well densities and less reliable horizontal well data produce rapid apparent changes in velocity.

Figure 3-15 shows how the velocity variation influences the converted depth across the field. A constant time slice at 531ms (Hamilton GWC) was depth converted to determine how much depth variation is caused by changes in the overburden velocity. The resulting depth surface varies by almost 200ft across the field. Along the crest the velocity surface has good well control and is likely to be a reliable estimate of the actual velocity variation. The flanks are less well controlled and in reality may have sharper, fault controlled velocity changes.

A second velocity model was generated towards the end of the project to test the influence of faults on the depth conversion. Figure 3-16 shows well velocities gridded using fault polygons to constrain the gridding process. The velocity map appears very different to that used to produce the Static Model, however, an approximate calculation of the volume from the OS2b Member depth surface to the 2910ft GWC gives 1.30x10^{9} m^{3} using the fault constrained model compared to 1.29 x10^{9} m^{3} with the original. This is an increase of only 1% in total rock volume showing that the Static Model is fairly insensitive to changes in the detail of the depth conversion. Note that these are unrefined volumes from initial 2D grids and are not directly comparable to volumes calculated from the final 3D modelling process.



Gridding of the well velocities was repeated using faults as a constraint to the gridding process. This produced a very different appearance to the velocity map although the Gross Rock Volume from this model was only 1% higher than the map used for the Static Model

Figure 3-16 Interval velocity from surface to OS2b Member with fault constrained gridding

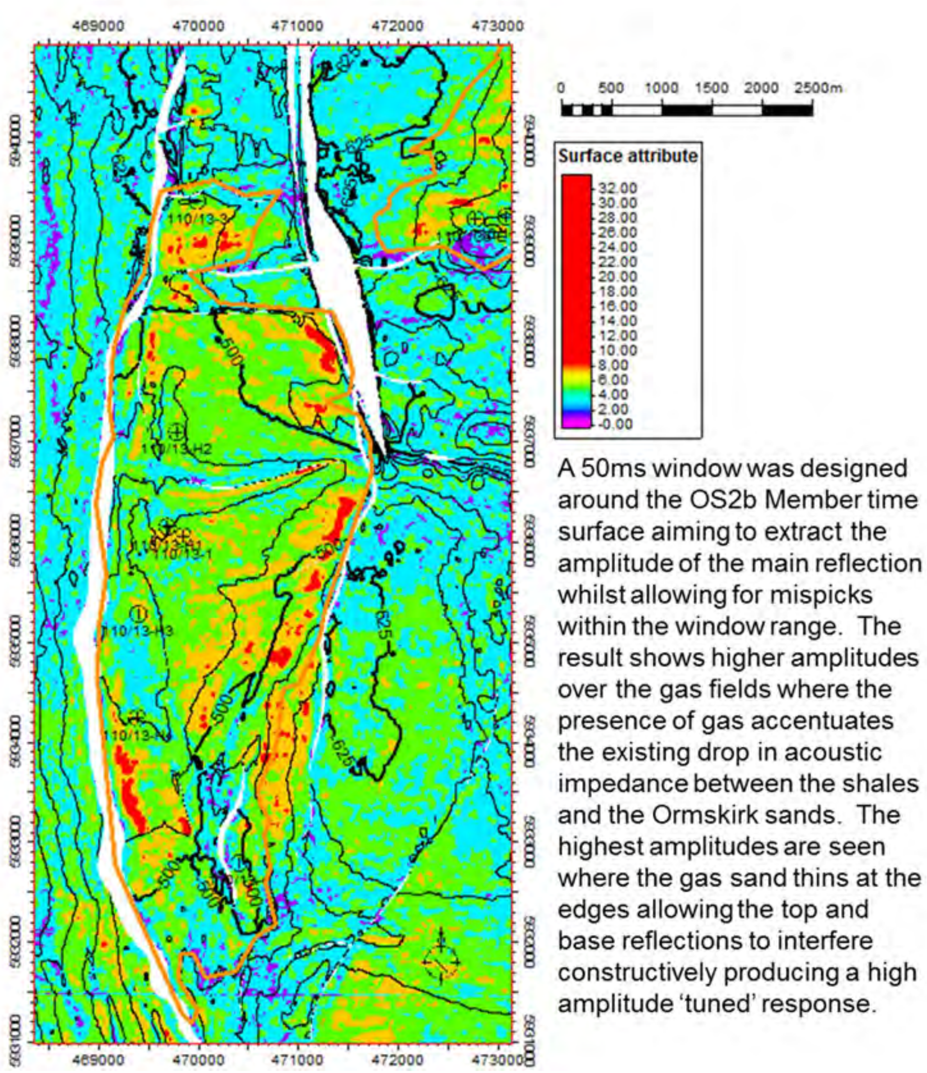


Figure 3-17 Seismic maximum amplitude extraction from OS2b -30ms

3.4.7 Seismic Attributes

Seismic attribute displays were generated from the supplied seismic volume to aid interpretation of the Hamilton Field. The attributes fall into two primary application groups:

Supporting structural definition – Attributes such as Semblance, Similarity, Continuity and Coherency use similar algorithms to detect edges in the seismic volume. 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. The attributes are mainly used for fault interpretation although they can be adapted to highlight gas chimneys and other abrupt changes in seismic character. The attributes and supporting processes are available in the OpendTect software from dGB Earth Sciences. Testing has shown that the Semblance algorithm produces particularly good results in a wide range of cases so this was the attribute used on Hamilton. Parameters in the software control the time range and size of the spatial window examined for changes. All these calculations are sensitive to seismic noise so additional denoise or smoothing operations are often used to precondition the data. In areas of steeply dipping geology the basic algorithms will detect steep reflectors as a series of data discontinuities. In these areas, a dip-adaptation step can be added to the process so that the dip of reflectors is calculated for all points. This dip volume is then used to steer the pre-processing and Semblance calculation parallel to the structure rather than the default flat, constant time calculations. The final Semblance volume is exported from OpendTect in SEGY format for import into Petrel.

Supporting interval characterisation - these include seismic amplitude which describes 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.

A 50ms window was designed around the OS2b Member time surface aiming to extract the amplitude of the main reflection whilst allowing for mispicks within the window range. The result shows higher amplitudes over the gas fields where the presence of gas accentuates the existing drop in acoustic impedance between the shales and the Ormskirk sands. The highest amplitudes are at the edge of the field where the gas sand thins towards the GWC. The thinning allows the top and base reflections to interfere constructively producing a 'tuned' high amplitude rim to the gas accumulation (Figure 3-17).

The strength of the gas and tuning effects mean that subtler changes related to reservoir properties cannot be isolated. However, the clear response to gas presence means that 4D seismic may be a useful reservoir monitoring tool.

3.4.8 Conclusions

The vintage data supplied by ENI is of moderate quality. Recent reprocessing is reported to have produced a big improvement in quality so any future work should access this data or undertake further reprocessing.

The existing data was acquired in 1992, and it is likely that modern acquisition and processing would produce a much improved image. The shallow position of the reservoir means that deep reflection surveys with long cables and record lengths are not necessary or appropriate. Therefore, any plans for new acquisition should look at the possibility of using high resolution site survey vessels and equipment. This has the advantages of being lower cost than using larger vessels and removes the need for additional site surveys for any new infrastructure in the area.

Despite the quality of the data, the main top reservoir event is a clear pick over the storage site area. There is some scope for variation of fault boundaries as the fault planes are not sharply imaged.

There is good well coverage across the crest of the structure so the depth conversion is tightly constrained over most of the field. The density of well data produces some distortions in the velocity map that may be related to faults or inaccurate data from horizontal wells. Velocities from wells were gridded with and without fault constraints with the resulting rock volume changing by only 1%. This gave confidence that the depth conversion is very robust in this area.

Amplitude extraction around the top reservoir shows a clear gas signature around the edges of the field. This implies that 4D seismic may be a viable option for reservoir monitoring although further modelling studies would be required to verify this.

3.5 Geological Characterisation

3.5.1 Primary Store

3.5.1.1 Depositional Model

The primary storage unit is the Triassic reservoir sands of the depleted Hamilton Gas Field. These comprise mainly the Ormskirk Sandstone Formation, but also include a small thickness of the St Bees Sandstone at the crest of the structure which sits above the GWC.

The depth to the crest of the structure is 700 m tvdss (2300 ft tvdss) and the maximum thickness of reservoir sand above the GWC at the site (column height) is 185 m (610ft).

The Top Ormskirk Sandstone Depth map for the site is shown in Figure 3-18.

The formation rock quality is moderate to excellent with zone average porosity from logs between 13 – 19% and average permeability from core of 1,350 mD. Within the best quality aeolian facies permeabilities in excess of 5 Darcy have been measured in core.

The Early Triassic was a period of major basin development in the East Irish Sea and coincided with the establishment of a major fluvial system, supplying the majority of the basin fill during the early stages of basin development.

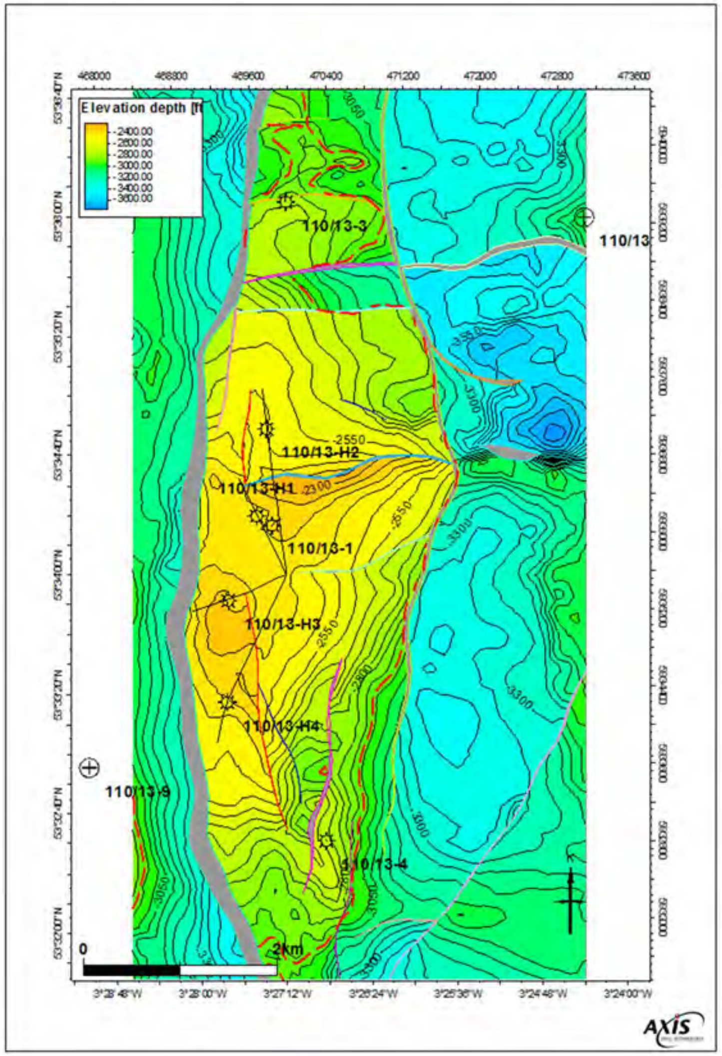


Figure 3-18 Top Ormskirk sandstone depth map, contour interval is 50ft, depth to crest is approximately 2300 ft TVDSS

The thick fluvially dominated sands of the St Bees Sandstone Formation give way to the more interdigitated, mixed facies of the Ormskirk Sandstone Formation which at the site location is dominated by aeolian facies but also includes intervals of fluvial channel and ephemeral playa lake facies. These are consistent with deposition in a semi-arid continental environment.

Fluvial palaeocurrents were towards the NNW, with later aeolian sandstones deposited under easterly palaeowinds.

A threefold division of the Ormskirk Sandstone Formation is recognised regionally and forms the basis of the zonation used for this study (OS2b, OS2a, OS1). Additionally a thin interval of playa margin with sheetflood sands has been correlated in the middle of the OS2b zone, and has been used to split the OS2b into and Upper, Middle and Lower zones for the purposes of geological modelling (Table 3-3).

Zone	Description
OS2b Upper	Mixed Aeolian (Dune, sandsheet and sabkha)
OS2b Mid	Playa margin shales with sheetfloods
OS2b Lower	Mixed Aeolian (Dune, sandsheet and sabkha)
OS2a	Fluvial Sandstones, abandonment and playa lake facies
OS1	Mixed Aeolian (Dune, sandsheet and sabkha)
St Bees Sst	Stacked fluvial channel deposits

Table 3-3 Subdivision of Triassic Sands in the Hamilton Gas Field

The reservoir has high NTG, with even the poorer quality OS2a fluvial sands having a good NTG of up to 75%. Fluvial abandonment and playa lake facies are the only possible permeability barriers, however pressure data taken during development and production of the field indicates that there no field wide permeability barriers and that the reservoir is very well connected.

OS2b has a fairly uniform thickness of approximately 50 m (170 ft) and is predominantly aeolian dune and sabkha facies. A zone of poorer quality sabkha facies is typically seen at the top of the interval. In the middle of the zone, a thin interval (7m or 23 ft) of playa margin shale and sheet flood sand facies can be correlated across the field and is included as a separate zone for the purposes of the static modelling. NTG for the aeolean intervals is in excess of 90%, with a lower NTG of 50% within the playa margin facies.

OS2a is 48 – 67 m (160 – 220ft) thick and consists predominantly of fluvial facies formed as stacked sequences. NTG for the field within this interval is a moderately high 72%.

OS1 is 57 – 72 m (186 – 236 ft) thick and is interpreted as a mixed sequence of Aeolian dune, Aeolian sabkha and sandsheet facies, with an average NTG of over 95%.

Only a thin section at the very top of the St Bees Sandstone Formation is present above the GWC. This comprises a sequence of stacked fluvial sands.

The well correlation (South – North) along the Hamilton Field site is shown in Figure 3-19.

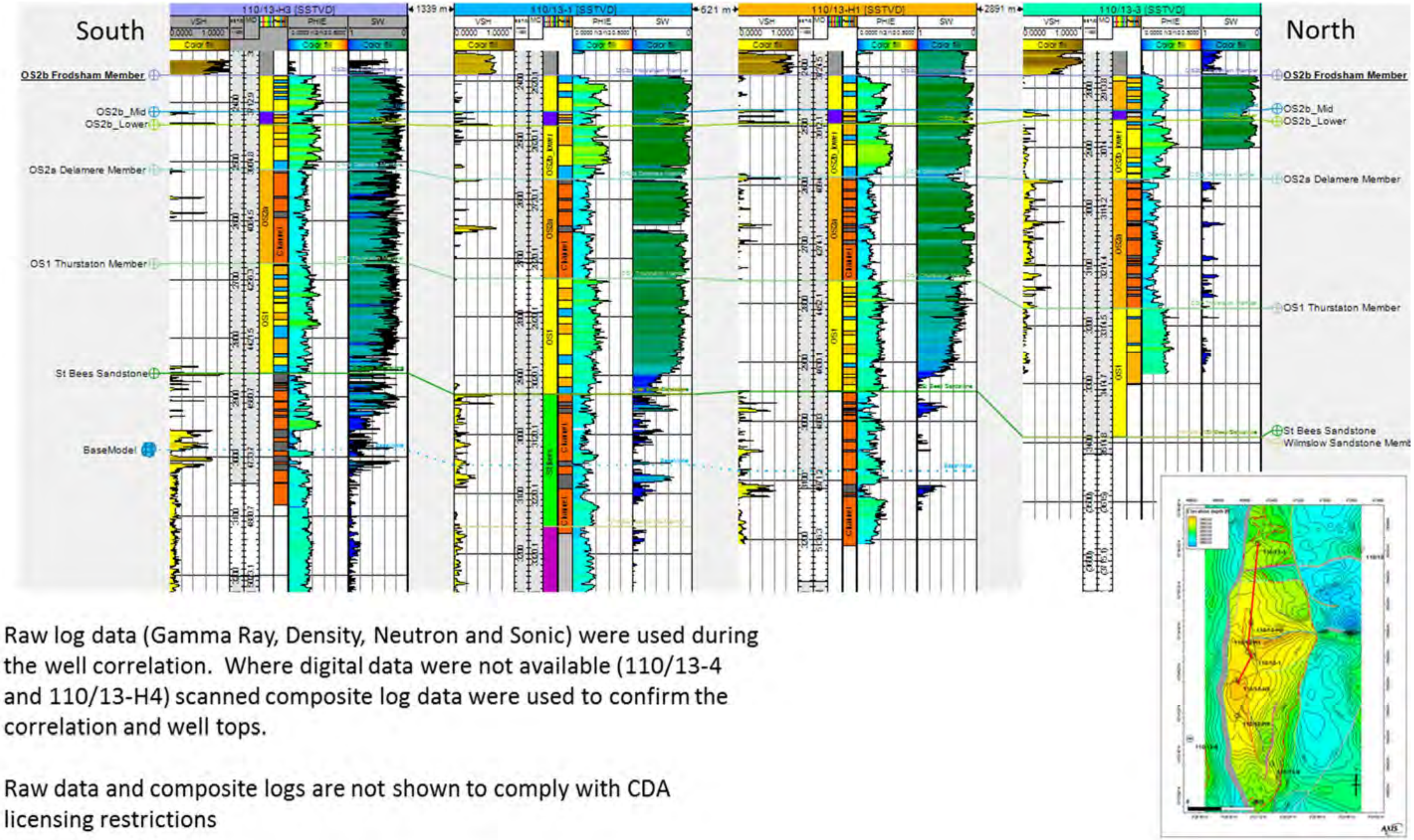


Figure 3-19 South to North well correlation section (Logs shown: Vshale, Facies, PHIE and Sw)

3.5.1.2 Rock and Fluid Properties

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

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

There were are few unresolved data quality issues, the most important being:

- 110/13-5: The neutron-density in aquifer does not plot on the sandstone matrix line; the neutron log is most likely to be in error, acquisition reports are not available to confirm environmental corrections or matrix calibration.
- 110/13-H2: High frequency oscillations in the data; the effected curves were smoothed using a running average algorithm.
- 110/13-N1: High frequency oscillations in the data; the effected curves were smoothed using a running average algorithm.
- 110/14b-7: Only MWD resistivity data is available, no porosity logs for the evaluation.

Conventional core data was available from four wells; 110/13-1, 110/13-3, 110/13-4 and 110/13-14. 110/13-3 was the only well with SCAL analysis; these data include electrical properties and porous plate capillary pressure measurements.

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 in Appendix 9 and illustrated in Figure 3-20.

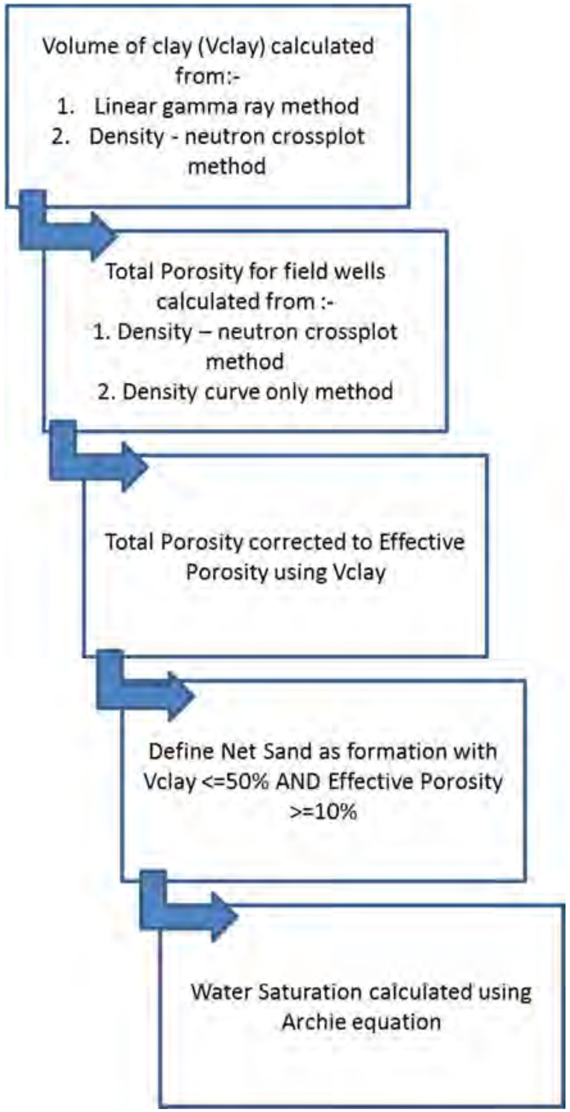


Figure 3-20 Summary of petrophysical workflow

The volume of clay in the reservoir is estimated by two independent methods, (i) gamma ray and (ii) neutron – density crossplot. Either the minimum, or the mean value, of the two methods is calculated as the effective volume clay for the saturation models.

Log porosity is calculated using a Density – Neutron cross-plot method for all Hamilton Field wells, with a single curve density model used for two off field wells in the regional database. The clay volume fraction correction is made to estimate 'effective' porosity from the 'total' porosity calculation.

Where core porosity data is available it was used for calibration of the calculated porosity log, the best fit porosity model has subsequently been preferentially selected for un-cored intervals and wells.

Water Saturation is calculated using an Archie saturation model, with the formation resistivity factor and saturation exponent calculated from the available log and core analysis (a=1, m=1.76, n=1.43). This has been 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.

Log based permeability has not been calculated. Permeability has been estimated directly in the primary static model based upon core based porosity vs permeability relationship. This is detailed in Section 3.5.4.

The results of the petrophysical analysis are summarised in Table 3-4 for the full Ormskirk Sandstone interval, across the Hamilton Field wells reviewed. Computer processed interpretation plots for each analysed well showing derived calculated information are also provided in Appendix 6. Note that the input curves have been provided under a CDA license and are not reproduced in this report.

Well	Zone	Gross [ft]	Net [ft]	NTG	Porosity	Sw
110/13-1	OS2b Upper	61.9	55.5	0.90	0.21	0.08
110/13-H3	OS2b Upper	122.8	119.6	0.97	0.20	0.13
110/13-H2	OS2b Upper	219.9	172.0	0.78	0.16	0.13
110/13-3	OS2b Upper	59.2	58.0	0.98	0.17	0.14
110/13-H1	OS2b Upper	109.7	98.0	0.89	0.17	0.07
All Wells	OS2b Upper	114.7	100.6	0.88	0.18	0.11
110/13-1	OS2b Mid	23.9	18.6	0.78	0.17	0.13
110/13-H3	OS2b Mid	42.5	37.5	0.88	0.17	0.22
110/13-H2	OS2b Mid	72.3	37.00	0.51	0.16	0.16
110/13-3	OS2b Mid	16.6	13.6	0.82	0.15	0.21
110/13-H1	OS2b Mid	44.9	34.9	0.78	0.15	0.09
All Wells	OS2b Mid	40.0	28.3	0.71	0.16	0.16
110/13-1	OS2b Lower	90.2	87.5	0.97	0.23	0.10
110/13-H3	OS2b Lower	144.7	144.5	1.00	0.21	0.14
110/13-H2	OS2b Lower	265.8	230.8	0.87	0.17	0.15
110/13-3	OS2b Lower	100.2	96.5	0.96	0.19	0.54
110/13-H1	OS2b Lower	163.4	157.7	0.97	0.19	0.10
All Wells	OS2b Lower	152.9	143.4	0.94	0.19	0.18
110/13-1	OS2a	168.0	142.3	0.85	0.14	0.14
110/13-H3	OS2a	280.0	246.3	0.88	0.13	0.19
110/13-H2	OS2a	523.0	265.8	0.51	0.13	0.22

Well	Zone	Gross [ft]	Net [ft]	NTG	Porosity	Sw
110/13-3	OS2a	219.0	134.3	0.61	0.13	0.89
110/13-H1	OS2a	316.0	255.8	0.81	0.13	0.25
All Wells	OS2a	301.2	208.9	0.69	0.13	0.25
110/13-1	OS1	197.0	197.0	1.00	0.19	0.25
110/13-H3	OS1	306.0	292.8	0.96	0.16	0.22
110/13-H2	OS1	275.0	271.8	0.99	0.18	0.62
110/13-3	OS1	219.0	113.3	0.52	0.20	0.89
110/13-H1	OS1	334.0	327.3	0.98	0.16	0.28
All Wells	OS1	266.2	240.4	0.90	0.17	0.41
110/13-1	St Bees	224.5	169.0	0.75	0.15	0.84
110/13-H3	St Bees	764.0	624.0	0.82	0.16	0.89
110/13-H1	St Bees	432.0	321.0	0.74	0.16	0.80

Table 3-4 Petrophysical averages by well and zone

Illite Precipitation

In terms of impact on reservoir quality, the most important reservoir diagenesis observed within the Sherwood Sandstone Group of the EISB is presence of platy illite. Whilst it has no measurable effect on porosity it can reduce permeability by up to two orders of magnitude.

Platy illite is seen within the South and North Morecambe Fields, where it formed below a palaeo-GWC after a first phase of gas migration. Due to later phases of gas migration and structural movement the illite affected sandstones now occur within the gas leg (Stuart, 1993)

At the Hamilton Gas Field no degradation in reservoir quality has been noted within the available data, with the core coverage available it would have been expected for platy illite degradation to be observed if present. The operator has also stated that based on their work clay cements are practically absent and have not impacted reservoir quality (Yaliz & Taylor, 2003).

The Hamilton formation water is highly saline, typically with a salinity of around 300,000ppm. The composition is Na-Cl dominated as expected due to the presence of Triassic halite-dominated evaporites immediately overlying the Lower Triassic sandstone reservoir. Appendix 9 contains additional detail.

3.5.1.3 Relative Permeability and Capillary Pressure

There is no specific SCAL data available to this project from the Hamilton Reservoir. As a result, appropriate analogues have been adopted. In particular the choice of analogues for relative permeability are discussed in section 3.6.6. In saline aquifer stores this is often a source of significant uncertainty. In Hamilton, a highly depleted gas field requiring gas phase CO_2 injection and with very limited water mobility from the aquifer evident after many years of production history, the importance of relative permeability to the forecasting of injection performance is significantly reduced.

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. Specifically, well information was used to ensure that the injection wells could be safely drilled, and that they could be operated without any significant sanding risk. Since Hamilton has already been through a significant depletion cycle and will be re-pressurised through any CO_2 injection operations, the variation of fracture pressure through this full cycle is important. The results of 3D geomechanical modelling are outlined in section 3.7. In summary, no significant issues are anticipated with the mechanical failure of the primary storage reservoir during injection operations and no major drilling problems are anticipated.

3.5.1.5 Geochemistry

Geochemcial modelling of the subsurface materials is reported in section 3.7. whilst specific data regarding both mineralogy and pore water composition from Hamilton is not available to the project, there is much in the public domain for the East Irish Sea which is helpful. Modelling has primarily focussed upon the cap rock reactivity and its potential degradation. In part due to the low water saturation within the reservoir and the low water mobility experienced, Injection of CO_2 into the Hamilton storage site is not expected to lead to any significant risk of formation failure through chemical degradation. The Sherwood sandstone is typically dominated by quartz with some illite and feldspar. Any reactions that might lead to minimal changes in porosity are expected to be slow because of the low temperature.

3.5.2 Primary Caprock

3.5.2.1 Depositional Model

The primary caprock of the Mercia Mudstone Group provides a proven basin wide seal, and is composed of up to 5 cycles of alternating red mudstones and thick halites, deposited in lakes subjected to periodic flooding (Stuart, 1993). Reaching thicknesses of up to 3200 m within the basin, it is approximately 700 m (approx. 2300 ft) at the Hamilton Field Site and forms the majority of the overburden.

3.5.2.2 Rock and Fluid Properties

Whilst there is no specific core available in the primary caprock, correlative intervals are effective seals for hydrocarbon gas in the Hamilton field itself and the other oil and gas fields of the East Irish Sea. Whilst it is possible than some thin sand laminations exist within the Mercia Mudstone the effective porosity and permeability of the halite intervals can reasonably be assumed to be zero as the halite will flow under subsurface conditions to occlude any adjacent pore space. There is no evidence of any gas shows in the overburden shallower than the first salt (Rossall Halite) above the reservoir.

Geomechanical analysis (Appendix 9) confirms that the site has minimal risk of caprock failure or fault reactivation.

3.5.2.3 Relative Permeability and Capillary Pressure

There is no specific SCAL data available for the Mercia Mudstone interval at the Hamilton storage site. There is high confidence in the ability of the caprock to hold back the injected CO_2 because of its performance in trapping the initial hydrocarbon gas column.

3.5.2.4 Geomechanics

3D Geomechanical modelling of the store and its caprock have been completed and is outlined in section 3.7. In summary, no significant issues are anticipated with the mechanical failure of the primary caprock reservoir during injection operations and no major drilling problems are anticipated. There remains a small residual uncertainty regarding the degree to which the fracture pressure limit will recover upon repressurisation because of CO_2 injection. The impact of this risk on storage capacity has been quantified during reservoir simulation work and is outlined in section 3.6.6. The likelihood of the fracture pressure not recovering is considered to be very low.

3.5.2.5 Geochemistry

Geochemical modelling of the impact of CO_2 injection on the rock fabric and the mineral assemblage of the Mercia mudstone caprock was carried out to assess the risk of any geochemical consequences during either the active injection period, or the post-injection, long term storage period.

The approach and methodology used are described in more detail in Appendix 9 but were focussed on one key question:

- Will elevated partial pressure of CO_2 compromise the caprock by mineral reaction?

A dataset of water and gas compositional data for the Hamilton Field (from published literature as no direct measurements were available in CDA) and caprock mineralogy (again from published petrographical data) were 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. Equilibrium modelling was then undertaken to assess the impact of increasing amounts of CO_2 at the relatively cool temperature of 31oC (the gas field being rather shallow in depth) to identify which mineral reactions are likely and to assess the impact on the composition and fabric of the rock. 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.

Mineralogical Changes under Elevated CO_2 Concentration

Four Middle and Upper Triassic caprock lithologies (Types 1 to 4) were modelled using an equilibrium approach:

- Type-1 is clay-rich, with low porosity-permeability, typically with abundant illite and chlorite, negligible gypsum and minor dolomite (Armitage, et al., 2013) (Jeans, 2006) (Seedhouse & Racey, 1997). Type 1 has about 10% porosity and permeability as low as 10^{-5} mD.
- Type-2 is poorer in clay but has abundant gypsum and more carbonate than type 1. Type 2 has about 10% porosity and permeability that is about as low as 10^{-3} or 10^{-14} mD.
- Type 3 is halite-dominated with minor clay minerals, quartz, gypsum and carbonates and has low porosity and permeability (probably as low as type 1).
- Type 4 is effectively pure halite with negligible porosity and permeability as low as 10^{-8} mD.

Type 4 (pure halite) is the most effective caprock under conditions of CO_2 injection as it is effectively non-reactive to aqueous CO_2; the equilibrium model reveals no geochemical reaction of the top seal following injection of CO_2. In general significant reactions only happen when aluminosilicate minerals (clays and feldspars) are present in the rock, as with Type 1. However, although there is a minor increase in the relative mineral volume after CO_2 injection due to the replacement of high density clay minerals (e.g. illite and chlorite) with low density minerals (e.g. dawsonite), there is only minor loss of porosity caused by the action of simply increasing the CO_2 partial pressure (fugacity) of the pore fluids. A similar result is seen in the clay-poor Type 2 caprock with the additional appearance of alunite at the expense of gypsum.

In the halite-rich with minor gypsum, calcite and dolomite caprock Type 3), a very minor porosity/permeability increase is possible as some solid volume loss of calcite dissolution is possible. If, however, any feldspar is present, the acid buffering effect of the feldspar prevents any volume loss (and hence porosity/permeability increase). This caprock type is the least dominant type observed in the overburden above the Hamilton Field reservoir and so even if dissolved CO_2 does come into contact with it, it is unlikely to have any significant impact on CO_2 containment.

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

Given the low quartz content of the caprock lithologies, it is possible that reaction rates may be controlled more by dissolution of the alumino-silicates (illite, chlorite, muscovite and K-feldspar). Putting kinetic considerations in place slows down the mineral reaction rate. Feldspar reaction slows down hugely (due to the small specific surface area), while the illite to dawsonite reaction also slows down but still occurs over the 20,000 year timeframe modelled. Note that again, these mineral changes lead to negligible porosity decrease.

Carbonate-bearing halite (e.g. caprock Type 3) is potentially reactive, if feldspar-free, and may lead to minor porosity increases, and thus permeability increases. However, as discussed above, this caprock lithology is considered to be a minor component of the immediate caprock and will not diminish the overall preservation of the low permeability of the caprock above the reservoir. No geochemical reaction is expected in the non-reactive Type 4, pure halite, caprock.

Injection of CO_2 into the Hamilton Field reservoir 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. In addition, contact between dissolved (reactive) CO_2 and the primary seal in the crest of the structure will be limited by the predominance of structurally-trapped (and therefore geochemically 'dry') CO_2 for the initial 1000 years post-injection.

3.5.3 Secondary Store

The Hamilton Field is overlayen by approximately 700 m (approx. 2300 ft) of alternating mudstones thick halites of the Mercia Mudstone Group. No secondary storage site with any significant storage potential has been identified within the overburden.

3.5.4 Static Modelling

Two static geological models have been developed as part of the characterisation effort of the Hamilton Field Site.

- Primary Static Model – The primary static model has been built over an area which included the Hamilton Gas Field only. The purpose of this model is to serve as the basis for building an effective reservoir simulation model over the site.
- Overburden model – The overburden model builds upon the footprint of the Primary Static model, but extends to describe the overburden geology. The model is primarily used for consideration of containment issues which are detailed in section 3.7.2.3.

3.5.4.1 *Primary Static Model*

Structural Model and Grid Definition

The static model described in this section focuses on the site geological model for the Hamilton Depleted Gas Field. A depth map at the top of the Primary Store (Top Ormskirk Sandstone) for the modelled site area is shown in Figure 3-18.

The area selected for the site model covers a 10km x 4.5km, the coordinates of the site model boundary are:

X Min 468395 X Max 473105 Y Min 5930995 Y Max 5940905

The stratigraphic interval for the site model is from the Top of the Ansdell Mudstone Member (Base of the Rossall Halite) to the St Bees Sandstone, the base of the model is defined approximately 30m (100ft) below the Top of the St Bees Sandstone. The total model thickness is approximately 260m (850 ft).

The Primary Store is the depleted gas sands of the Ormskirk Sandstone Formation. The primary seal for this interval is the overlying Mercia Mudstone Group.

Reservoir modelling has been carried out using Petrel v2014.

Reference system used ED50 (UTM30).

The model stratigraphy is shown in Table 3-5, and is based upon the zonation scheme defined during the well correlation.

The Top Ormskirk Sandstone depth horizon within the static model has been created from the depth surface interpreted from the seismic and time to depth converted (Section 3.4). It has been tied to the well tops using a radius of 800m.

The top of the model is the Top Ansdell Mudstone, at the base of the Rossall Halite, this is represented in the model by a single layer and for the purposes of the reference case model is assumed to be impermeable. It has been generated by subtracting a well based isochore (thickness map) from the Top Ormskirk Sandstone depth horizon.

The internal reservoir depth horizons (OS2b Mid, OS2b Lower, OS2a, OS1, St Bees Sst) have been calculated from well thickness information, derived from the well correlation.

The base of the model is within the St Bees Sandstone. This has been generated by adding a single cell with a thickness of 30 m (100 ft) to the Top St Bees Sandstone depth surface.

Horizon	Zone	Source	Number of Layers
Top Ansdell Mudstone (Mercia Mudstone 'A')	Mercia mudstone	Built up from the top Ormskirk using a well derived isochore	1
Top Ormskirk Sandstone (OS2b Upper)	OS2b Upper	Direct seismic interpretation and depth conversion	16
Top OS2b Mid	OS2b Mid	Built down from top Ormskirk using well derived isochore	6
Top OS2b Lower	OS2b Lower	Built down from top OS2b Mid using well derived isochore	40
Top OS2a	OS2a	Built down from top OS2b Lower using well derived isochore	30
Top OS1 Sandstone	OS1	Built down from top OS2a using well derived isochore	6
Top St Bees Sandstone		Built down from top OS1 using well derived isochore	30
Base Model		Built down from top St Bees with a constant thickness of 30m	

Table 3-5 Stratigraphy, zonation and layering for site model

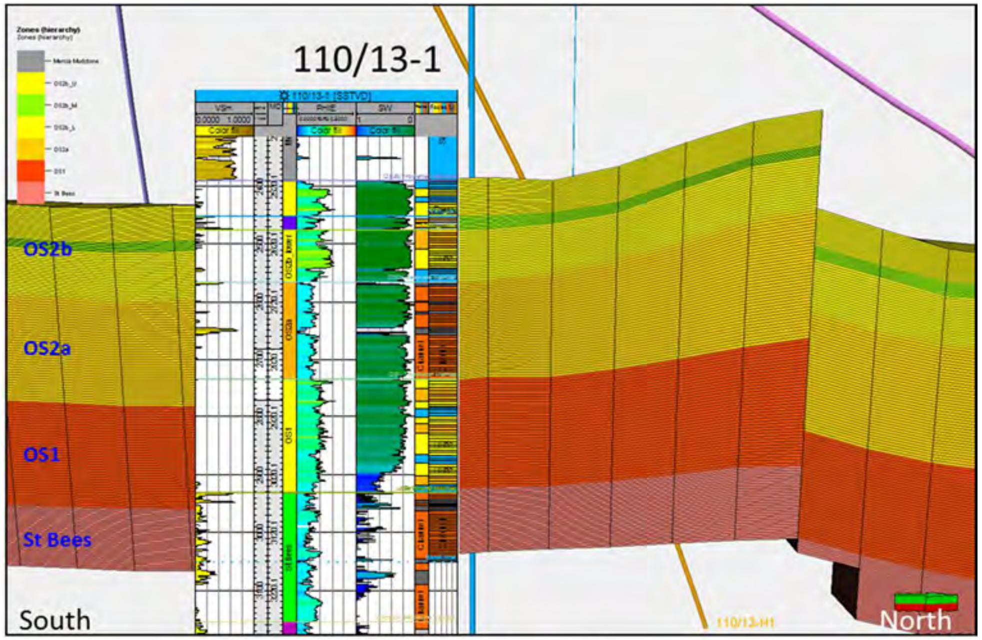
A total of 24 faults have been interpreted and incorporated into the model. With the exception of the main western boundary fault these do not have large enough throws to fully offset the store interval, all retain sand to sand juxtaposition and are assumed to be not sealing. Well by well production and pressure data are not available to this project. However, it is understood that all Hamilton gas production wells performed in a very similar way and arrived at similar depleted pressures. This can only really happen if there is good connectivity in the reservoir between the wells. Given that there are mapped faults between the wells, the clear implication of this is that the infield faults themselves are not sealing.

The bounding faults to the field continue through the caprock and displacement on them is recorded all the way up to the seabed. These faults are clearly sealing and do not permit flow along their planes since this would have compromised gas trapping for hydrocarbons. This is consistent with the overburden lithologies which comprise mudstones and ductile halite intervals which would be expected to move to infill any migration temporary flow pathways created by fault movement.

Further detailed fault sealing analysis of these faults will be useful in developing a more comprehensive understanding.

Faults have been incorporated into the grid using stair- stepped gridding. This allows for complex fault geometries to be included in the grid without the grid cells becoming distorted (which can cause problems for dynamic simulation).

A cross section through the structure showing the different zones and layering within the model is shown in Figure 3-21.



Colours in grid represent zones within the model.
Vshale, PHIE, Sw, Raw Facies and Upscaled Facies shown on log tracks.

Figure 3-21 South to North 3D grid cross section through well 110/13-1

The site model 3D grid was built with grid cells orientated north – south (i.e. no rotation) and grid cells of 100m x 100m 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 observed in the well data. The layering per zone is shown in Table 3-3.

The resulting static model grid has 153 layers and approximately 740,000 grid cells.

3.5.4.2 Property Modelling

As described in Section 3.5 the Sherwood Sandstone Group was deposited as a mix of fluvial and aeolian sands in a semi-arid climate.

The depositional facies control both the distribution of baffling shales and the distribution of porosity and permeability. A facies model had been built to capture these heterogeneities and rock property relationships.

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

3.5.4.3 Facies Log Interpretation

Core data is available for three of the field exploration and appraisal wells. The available core description has been used to define the facies classification and create facies logs for the cored intervals. This facies classification has been extended to uncored wells and uncored intervals manually through the use of wireline log character. A gamma ray cut-off of (greater than) 60 API was also used to quickly classify fluvial abandonment shales and silts in zones where these are present.

In line with published facies schemes (Meadows & Beach, 1993) (Yaliz & Taylor, 2003), five major facies types have been interpreted and included within the static model:

1. Aeolian dune facies
2. Aeolian sandsheet facies
3. Aeolian sabkha facies
4. Fluvial channels
5. Fluvial abandonment

The raw lithology curve is generated at the sample rate of 0.15 m (0.5 ft), this has been upscaled into the modelling grid using the most off upscaling method. The upscaling has been weighted to ensure that a representative proportion of the thin shales and cements have been captured within the gridded model.

Facies logs have been calculated for the following wells, and these have been used to control the facies modelling: 110/13-1, 110/13-3, 110/13-H1, 110/13-H2, 110/13-H4. No digital log data was available for wells 110/13-4 or 110/13-H4.

An example of the lithology log and upscaled lithology log is shown in Figure 3-22.

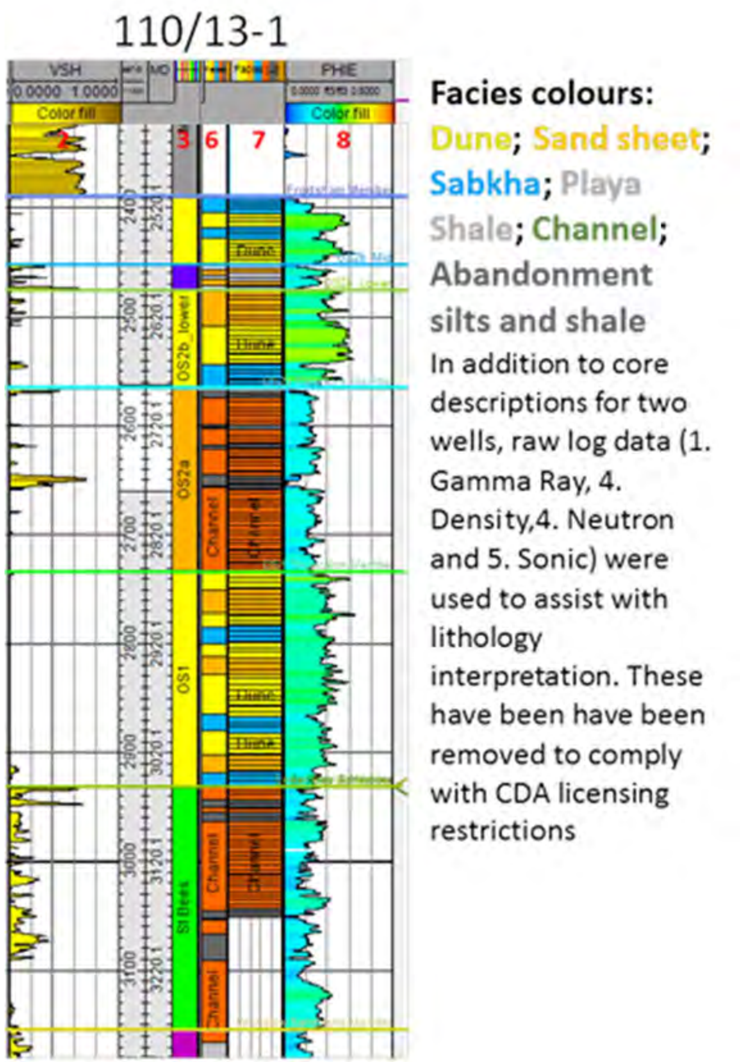


Figure 3-22 Example of facies interpretation in well 110/13-1, raw facies log and upscaled facies in the 3D grid shown in tracks 6 and 7

3.5.4.4 Facies Modelling

An industry standard method, Sequential Indicator Simulation (SIS), has been used for the modelling of facies within the aeolian dominated zones (OS2b Upper, OS2b Lower and OS1).

The proportion of each facies is calculated based on well data within the site area, for each zone in the model. The vertical distribution of these within each zone is controlled by vertical proportion curves, again calculated from the well data (Figure 3-23). Within the site there are no lateral trends interpreted or used for the facies modelling in these zones.

The facies model settings for these zones are shown in Table 3-6.

The orientation of the facies has been aligned based on an easterly palaeo-wind direction, with the long axis of the facies orientated north – south.

The Playa margin shales and sheetflood sands in zone OS2b Mid have also been modelled using SIS, the facies settings are shown in Table 3-7.

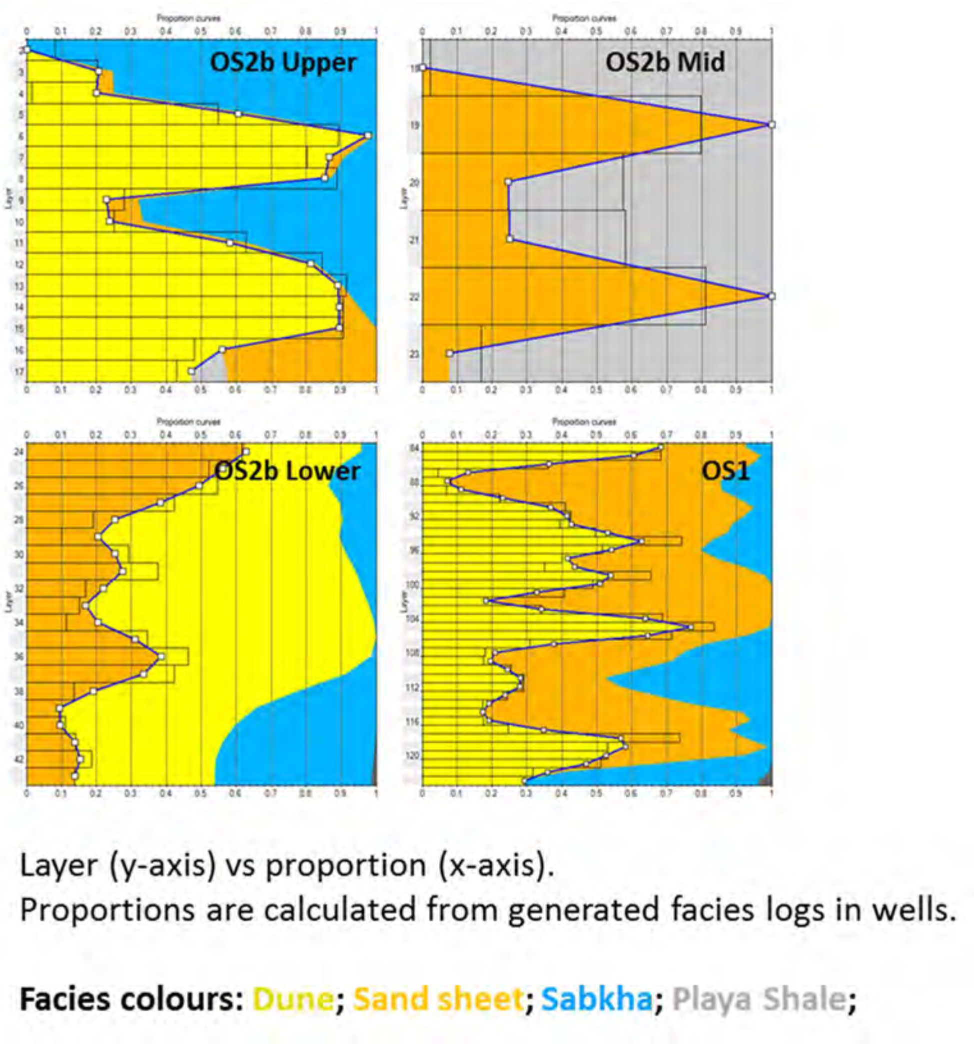


Figure 3-23 Vertical proportion curves for each zone

Zone	Facies	Orientation [Degrees]	Variogram Width [m]	Variogram Length [m]	Variogram Thickness [m]
OS2b Upper	Dune	0	1000	4000	3
	Sandsheet	0	1000	4000	3
	Sabkha	0	1000	4000	3
OS2b Lower	Dune	0	1000	4000	3
	Sandsheet	0	1000	4000	3
	Sabkha	0	1000	4000	3
OS1	Dune	0	1000	4000	3
	Sandsheet	0	1000	4000	3
	Sabkha	0	1000	4000	3

Table 3-6 Input properties used for SIS modelling in zones OS2b Upper, OS2b Lower and OS1

Zone	Facies	Orientation [Degrees]	Variogram Width [m]	Variogram Length [m]	Variogram Thickness [m]
OS2b Mid	Sandsheet	0	1000	4000	3
	Shale	0	1000	4000	3

Table 3-7 Input properties used for SIS modelling in zones OS2b Mid

The dominant facies within OS2a and the St Bees are fluvial channels, these have been modelled using channel based object modelled in a background of shale (representing channel abandonment).

The proportion of each facies is calculated based on well data within the zone. Within the site there are no vertical or lateral trends interpreted or used for the facies modelling in this zone.

The facies model settings for these zones are shown in Table 3-8.

Zone	Facies	Orientation [Degrees]	Width [m]	Thickness [width frac]	Amplitude [m]	Wavelegth [m]	Relative Sinuosity
OS2a	Channel	330 – 340 - 0	50 – 1000 - 2000	0.005 – 0.01 – 0.015	200 – 500 - 750	1000 – 2000 - 3000	0.2 – 0.3 - 04
St Bees	Channel	315 – 330 - 350	50 – 1000 - 2000	0.005 – 0.01 – 0.015	200 – 500 - 750	1000 – 2000 - 3000	0.2 – 0.3 - 04

Table 3-8 Zone OS2a: Main inputs for channel modelling (triangular distributions min-mid-max)

Modelled facies proportions are shown in Table 3-9.

Model Results	Dune	Sandsheet	Sabkha	Channel	Shale
OS2b Upper	59.7	12.5	27.8	-	-
OS2b Mid	-	50.9	-	-	49.1
OS2b Lower	70.4	11.4	18.2	-	-
OS2a	-	-	-	74.9	25.1
OS1	40.3	44.8	19.9	-	-
St Bees	-	-	-	71.0	29.0

Table 3-9 Modelled facies proportions (%)

An example cross section and slice through the facies model are shown in Figure 3-24.

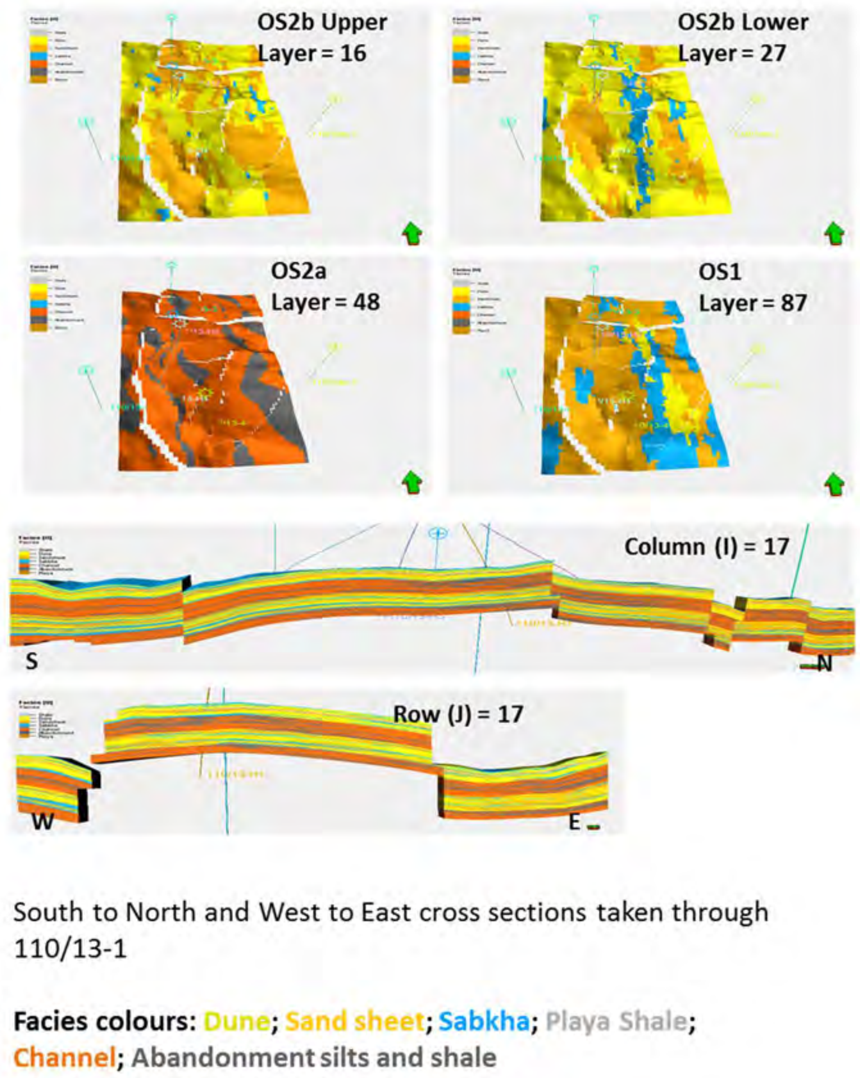


Figure 3-24 Cross sections and layer slices through the reference case facies model

3.5.4.5 Porosity Modelling

The following wells were used within the site model for the modelling of porosity: 110/13-1, 110/13-3, 110/13-H1, 110/13-H2, 110/13-H4.

The interpreted PHIE log was upscaled to the grid scale using arithmetic averages, biased to the interpreted 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 facies were distributed in the model, between wells, using a Sequential Gaussian Simulation method (SGS) and constrained to the facies model. This ensures that the property distributions for each facies (mean and standard deviation) in the original log porosity data are maintained in the final model. Playa shales in zone OS2b Mid are assumed to be impermeable and given a porosity of 0%.

Input settings for the SGS modelling are shown in Table 3-10.

Facies	Type	Major Axis [m]	Minor Axis [m]	Vertical [m]	Azimuth [deg]
Dune	Spherical	5000	1000	3	0
Sandsheet	Spherical	5000	1000	3	0
Sabkha	Spherical	5000	1000	3	0
Channel	Spherical	5000	1000	3	Follow Channel
Channel Abandonemnt	Spherical	5000	1000	3	340

Table 3-10 Input setting for porosity and permeability SGS modelling

3.5.4.6 Permeability Modelling

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

Playa shales in zone OS2b Mid are given a permeability of 0 mD.

A cross plot of porosity versus permeability for both the measure core data and final modelled data is shown in Figure 3-25.

A histogram showing horizontal permeability for the sand facies is shown in Figure 3-26.

Average horizontal permeability values by zone are shown in Table 3-11.

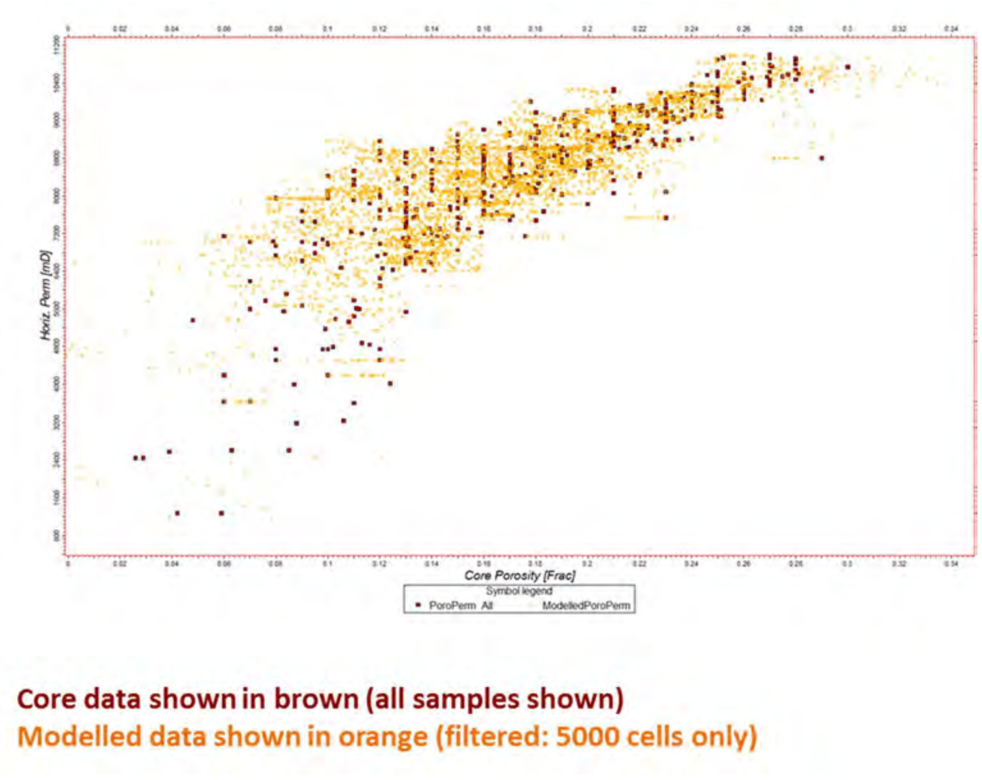


Figure 3-25 Cross plot of porosity versus permeability (log scale)

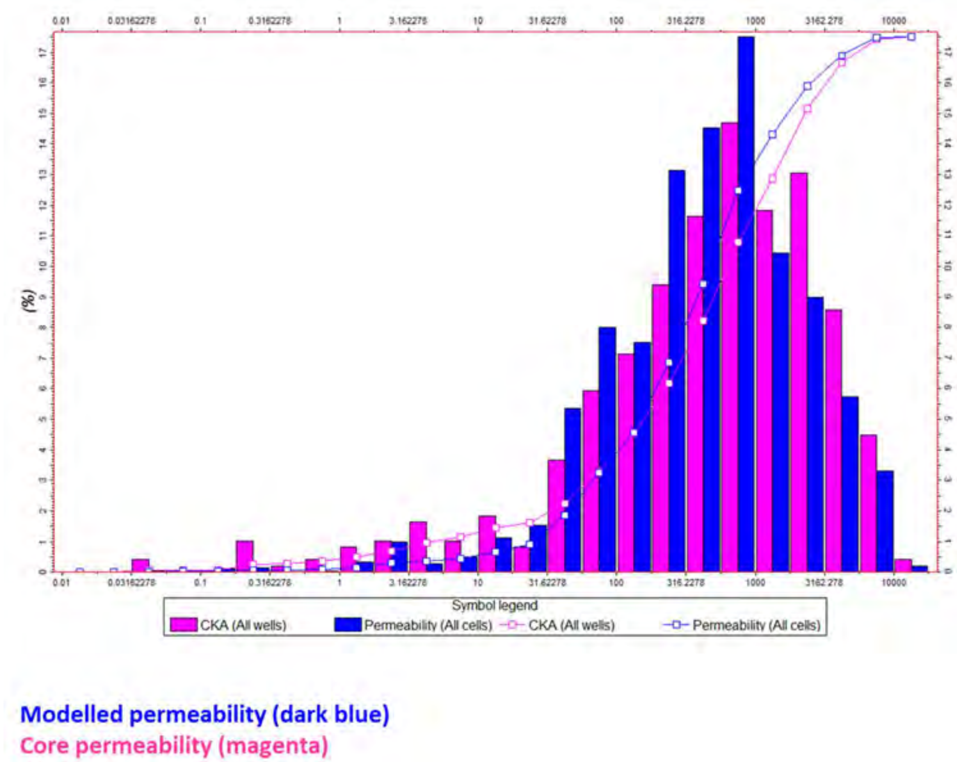


Figure 3-26 Histogram of horizontal permeability for all zones (log scale)

Average Perm [mD]	Dune	Sandsheet	Sabkha	Channel	Abandonment
OS2b Upper	1940	2200	546	-	-
OS2b Mid	-	16.4		-	-
OS2b Lower	2730	1599	663	-	-
OS2a	-	-	-	373	12
OS1	1605	711	647	-	-
St Bees	-	-	-	775	8

Table 3-11 Average modelled horizontal permeability values for each facies in each zone

A strong relationship exists between horizontal and vertical permeability. This has been incorporated into the model through the use of a function, derived from core data, which has been applied directly to the modelled horizontal permeability (Figure 3-27). The function used is and shown below.

$$Vertical\ Permeability \quad 10^{1.11795\times\log(Horiz.Permeability)-0.803356}$$

Average vertical permeability and Kv/Kh per facies are shown in Table 3-12.

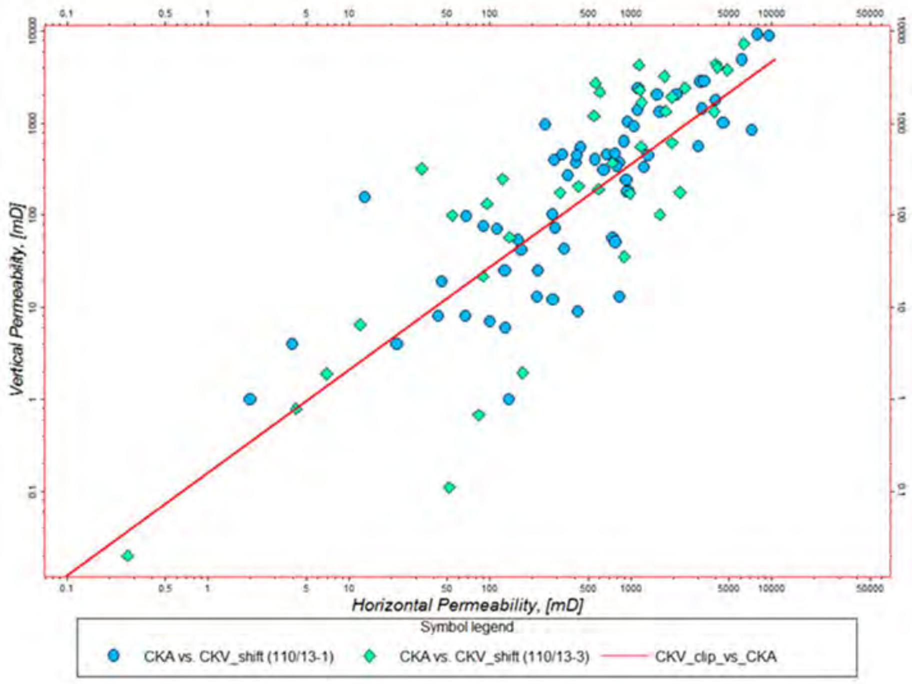


Figure 3-27 Cross plot of horizontal versis vertical core permeability (log scale) coloured by well

	Kv [mD)	Kv/ kh
Dune	860	0.36
Sandsheet	630	0.32
Sabkha	225	0.30
Channel	195	0.30
Abandonment	2	0.15

Table 3-12 Average modelled vertical permeability values and Kv/Kh for each facies

A histogram showing the vertical permeability for the sand facies is shown in Figure 3-28.

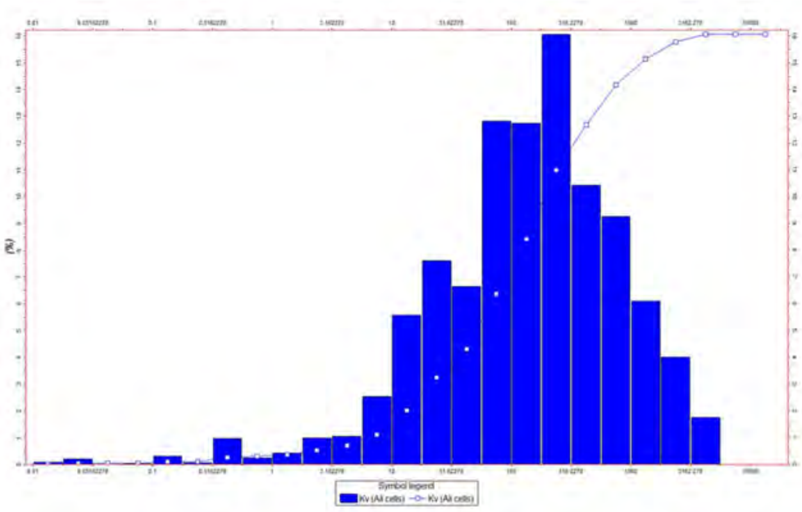


Figure 3-28 Histogram of modellied vertical permeability within sand facies (log scale)

3.5.4.7 Water Saturation Modelling

Modelling of initial reservoir water saturation was carried out using capillary pressure based method (Leverett J Function, calculated from the available SCAL data. This is a standard oilfield approach and is documented in more detail in Appendix 9.

$$Sw_J = \left(0.022884 \times Height \sqrt{\frac{k}{\emptyset}}\right)^{-0.4051}$$

3.5.4.8 Rock and Pore Volumetrics

Volumes in the static model have been calculated above the operator GWC (887 m tvdss or 2910 ft tvdss) and are shown in Table 3-13. They are in close agreement to that quoted by the operator (627 Bscf).

Zones	Bulk volume [$*10^6$ rm^3]	Pore volume [$*10^6$ rm^3]	GIIP [Bscf]
OS2b Upper	239	41.7	140.4
OS2b Mid	73	6.5	20.6
OS2b Lower	311	62.5	212.1
OS2a	511	47.2	151.0
OS1	201	37.7	117.9
St Bees	5	0.5	0.8
TOTAL	1340	209.6	642.8

Table 3-13 Gross rock and pore volumes for Hamilton Field

GEF = 108 SCF/RCF

Whilst the calculated in place gas volumes are in close agreement to that quoted by the operator (627 Bscf), DECC production data indicates that a total of 640 Bscf has been produced from the field to the end of February 2015.

The cause of this is most likely related to depth structure uncertainty. To account for this mismatch, and increase the GIIP in order that a history match could be achieved in the dynamic model, a deeper GWC has been used based on the deepest contact that can be picked from log data (893 m tvdss or 2930 ft tvdss). Siltstone facies within zones OS2a and the St Bees have also been included as net rock. These updates result in a total field GIIP of 709 Bscf.

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. Vertical coarsening from 153 layers in the static model to 115 layers in the dynamic model has been used to reduce the number of cells from approximately 740,000 to approximately 535,000 (approximately 390,000 active cells). The AOI, zonation (6 zones), lateral cell size (100m x 100m), and grid orientation (0°) remain the same as the static model.

Within the most heterogeneous zones (OS2b Mid and OS2a) the vertical grid resolution has been kept the same (1:1), in order to capture the impact of permeability baffles and barriers. Within OS2b Upper, OS2b Lower and OS1 a 2:1 upscaling ratio has been used. Within the St Bees the grid resolution for the top 5 layers has been kept the same, for deeper layers a 5:1 upscaling ratio has been used.

A comparison of the layering between static and dynamic models is shown in Figure 3-29.

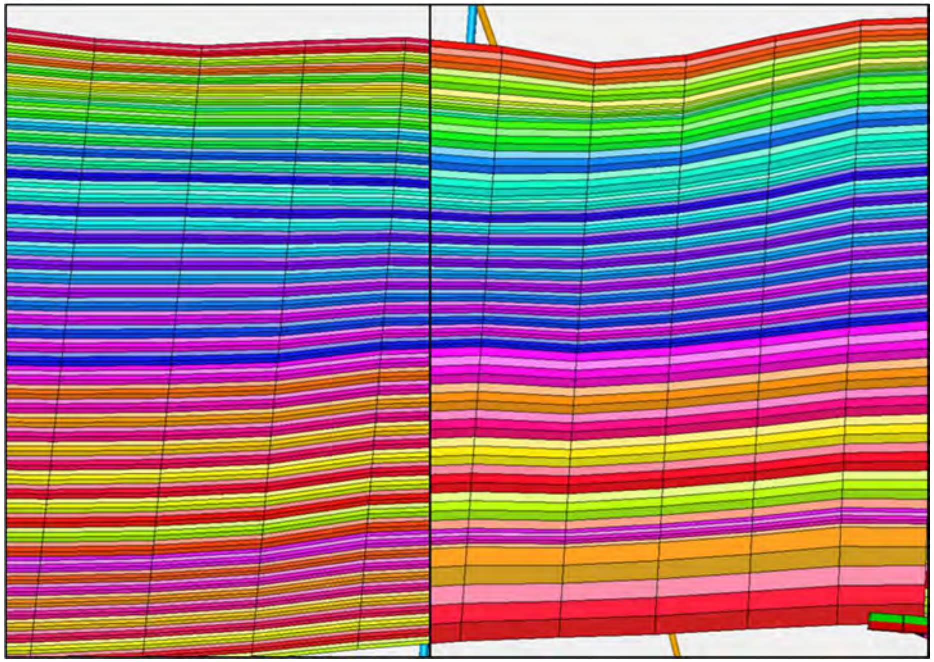


Figure 3-29 A South - North cross section through well 110/13-1 comparing: static modelling layering (left) and dynamic model layering (right)

The layering scheme is summarised in Table 3-14.

Zone	Static Model Layers	Dynamic Model Layers
OS2b Upper	2 - 17	2 - 9
OS2b Mid	18 - 23	10 - 15
OS2b Lower	24 - 43	16 - 25
OS2a	44 - 83	26 - 65
OS1	84 - 123	66 – 85
St Bees	124 - 153	86 - 95

Table 3-14 Summary of Static and Dynamic model layer equivalences

3.5.4.10 Primary Static Model Sensitivity Cases

A range of sensitivity cases has been run in the dynamic modelling. As part of these sensitivities three additional static model sensitivities have been generated capturing key static uncertainties. Results are discussed in section 3.6.6.

Fault Seal

The operator has stated that fault sand on sand juxtaposition and pressure data support the assumption that the faults are not sealing (Yaliz & Taylor, 2003). However as this project does not have access to pressure data to confirm this, a sensitivity with sealing faults has been generated to quantify any impact.

Permeability

Measured permeabilities from core indicate extremely high permeability, up to values in excess of 5 Darcy. To investigate the sensitivity to these extremely high permeability ranges, an upscaled permeability model clipped at 1 Darcy has been created.

Vertical Connectivity

The OS2b Mid zone forms the only laterally continuous vertical barrier within the field. In the other reservoir zones more limited vertical baffling is caused by the poorer facies (channel abandonment and aeolean sabkha), although the extent to which these baffle gas flow is uncertain. A sensitivity reducing the vertical permeability within these facies has been created to quantify the impact of increased baffling to vertical flow. The vertical permeability within the sabkha facies was reduced from an average of 226 mD to 50mD, the vertical permeability within the channel abandonment facies was reduced from an average of 3 mD to 0mD.

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 production history of the Hamilton gas field strongly suggests that the effective hydraulically connected pore space is strictly limited to the volume bounded by the Top Reservoir, the fault block boundaries and the gas water contact. The available production data indicate that there is negligible water influx from the aquifer below the gas water contact. As such the Hamilton CO_2 injection site can be effectively contained within the primary storage reservoir and overburden models. A specific Fairway Static Model was therefore not required.

3.5.6 Probabilistic Volumetrics

The sensitivity analyses in the static and dynamic modelling work have provided a range of estimates for rock volume, pore volume and dynamic CO_2 storage capacity. The complexity of the models and the number of variables conspire to make 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 modelling 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 x NGR x PHI x (1-SW) x Bo

Where:

STOIIP - Stock tank oil initially in place.

GRV - Gross rock volume - the geometric volume of the gross reservoir interval 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 - 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 here to be:

Dynamic Capacity = GRV x NGR x PHI x CO_2 Density x E

Where:

CO_2 Density - the average density of CO_2 in the store at the end of the injection period.

E - the Dynamic storage efficiency which is 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 estimations 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

For the purposes of this calculation, the gross rock volume is the potential gross storage reservoir bounded by the field limits which once contained natural gas. Whilst there will always remain uncertainty in the depth map to the top reservoir across the Hamilton field, the magnitude of uncertainty that this contributes to gross rock volume has been shown to be minimal. There are two primary reasons for this. The first is that the reservoir is shallow with a relatively simple overburden geology whose seismic velocity is well controlled. The second is that the measurement of the produced gas volume provides a constraint on the minimum size of the gross reservoir tank. There is some upside rock volume available from more optimistic fault positioning and a slightly deeper GWC. A simple triangular distribution is assumed weighted heavily to a volume of 1340 MMCUM which is matched to the cumulative production history.

3.5.6.2 Net to Gross Ratio

An average net to gross ratio of 79% for the gas bearing closure has been extracted from the static model. This is derived from an interpolation of the petrophysics from well control throughout the model appropriately weighted to the gas bearing zone. An upper and lower value of 81% and 77% have been assigned from consideration of the well data in the area and also that the resultant minimum pore volume has been calibrated through the match to the cumulative gas production.

At this stage, the project has assumed a 10% cut-off value for NTG but does recognise that this will ultimately depend on the commercial arrangements of the development. NTG cut-off is actually a commercial consideration calibrated for oil and gas production and so it is also a function of oil price. In a high oil price regime NTG cut off might be lower than 10% whilst in a low oil price regime it can be much greater than 10%.

3.5.6.3 Porosity

An average porosity of 18.9% has been extracted from the static model. This is derived from an interpolation of the petrophysics from well control and appropriately weighted to the gas bearing zone. A triangular distribution has been assumed with a small variance from 16% to 20%. Again the minimum pore volume is constrained by the match achieved to the cumulative gas production.

3.5.6.4 CO_2 Density

A range of 0.79 to 0.82 and 0.84 was established after consideration of low and high ranges of final temperature and pressure 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 has 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 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 areal sweep efficiency. It also fully accounts for limiting factors such as the fracture pressure limit. In the Hamilton storage project, the dynamic storage efficiency is tightly constrained at around 0.7 to 0.75 as a result of the ready diffusion of the injected CO_2 into the space occupied by low pressure natural gas. These efficiencies are very high as a result of the very high recovery factor experienced with gas production and the fact that the development plan has not had to displace water to inject CO_2. High mobility associated with the initial injection in gas phase also support these high efficiencies. There was one dynamic model run with a much lower injected inventory, this describes a situation where the fracture pressure does not recover from its reduced value at the point of maximum pressure depletion. Whilst considered to be very unlikely, if there was an issue such as this which made the transition from gas phase to dense phase injection complex or costly, then a much smaller dynamic storage efficiency factor can be anticipated of perhaps 0.25. This is captured in the Monte Carlo outcomes.

Well by well production and pressure data is not available to this project, but some pressure data has been published and has been used to match performance over production time. Based on the limited production data available, absence of evidence for water production at Hamilton over ~ 18-year life, extraction of ~ 640bcf gas and current low pressure indicates limited, if any aquifer support. History match analysis indicates an aquifer size of approximately 8000mmb. The top of the St Bees Formation is believed to be very heterogeneous and an effective barrier to flow especially to aquifer influx.

3.5.6.6 Probabilistic Volumetric Results

Figure 3-30 captures the inputs and outputs of the Monte Carlo assessment of dynamic CO_2 storage capacity for the Hamilton storage site. The P90 value (i.e 90% chance of exceeding) is 109MT, with P50 (50% chance of exceeding) of 123MT and a P10 (10% chance of exceeding) of 131MT. These numbers provide the context for the “deterministic” estimates from the dynamic modelling work for the “development reference case” of 124MT.

This shows that whilst there is downside capacity uncertainty with the proposed development plan which is largely associated with the risk of complexities arising from the transition between gas and liquid phase injection, there is at the same time, very little upside anticipated. This is because of the confidence in the accessible pore space volume which has been provided by the matching of the volume to the historical production data.

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 3-31.

There are no CO_2 storage reserves currently assessed for the Hamilton 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, seismic and very importantly historical production data 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 – 109MT – P90

2C – 123MT – P50

3C – 131MT – P10

The full scope of the probabilistic dynamic CO_2 storage capacity ranges from a P100 of 42.2MT to a P0 of 142.8MT.

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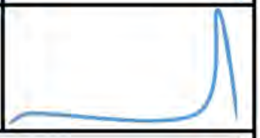
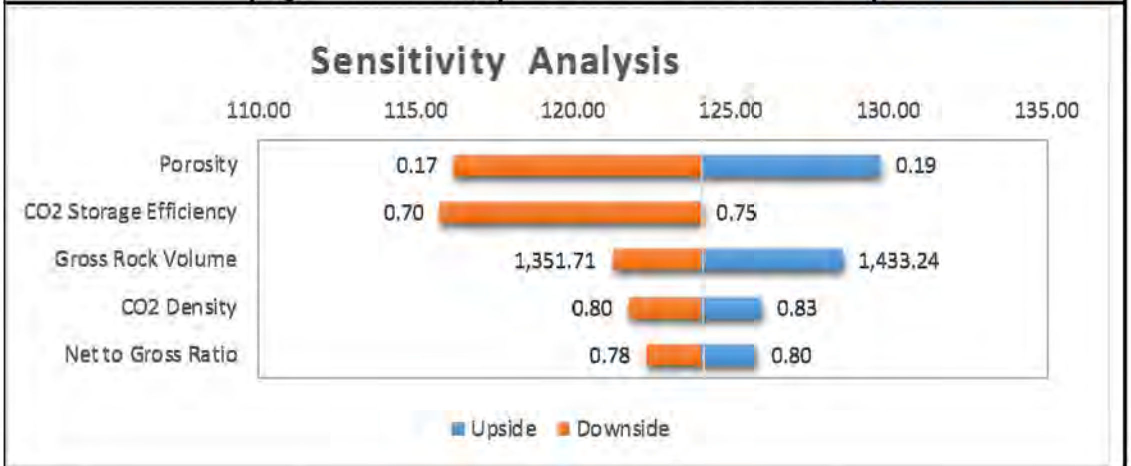
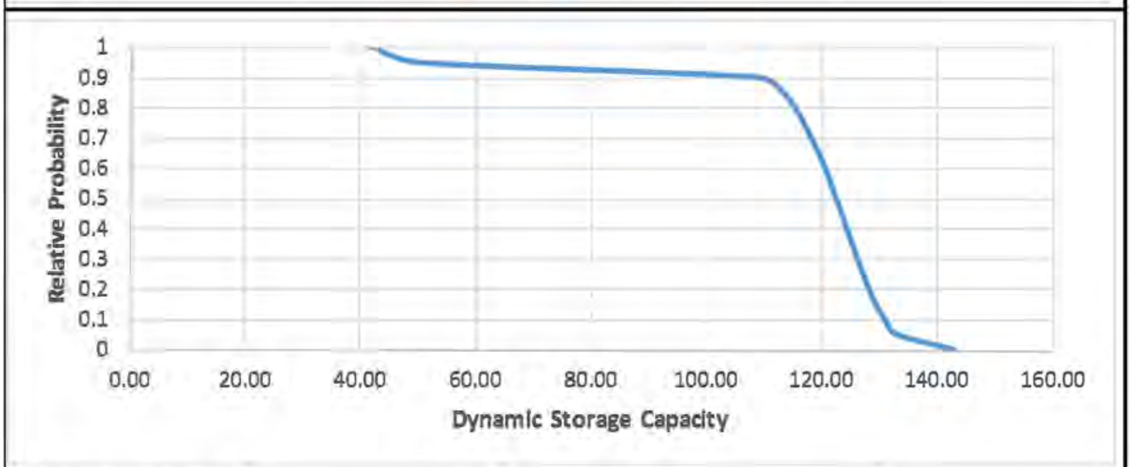
CO2 Capacity of Hamilton Storage Site

Run - 1

Parameter	Inputs		Comments	Distribution
Gross Rock Volume MMCUM	Low Mid High	1340 1350 1474	GRV from Petrel Model represents a minimum volume required to match production performance. Upside available linked to conservative fault	
Net to Gross Ratio	Low Mid High	0.77 0.79 0.81	Based on well and model averages. Smaller inputs are effectively eliminated due to match to production performance	
Porosity	Low Mid High	0.16 0.189 0.2	Mid Case based upon Petrel Model Average Phi	
CO_2 Density T/M^3	Low Mid High	0.7900 0.8200 0.8400	CO_2 density calculation at mid point pressure and temperature	
CO_2 Storage Efficien	Low Mid High	0.25 0.7 0.75	Storage effieicencies extracted from simulation runs over the full injection	





Dynamic Storage Capacity MT	P90 P50 P10	109 123 131		

Figure 3-30 Hamilton storage site – probabilistic volume capacity

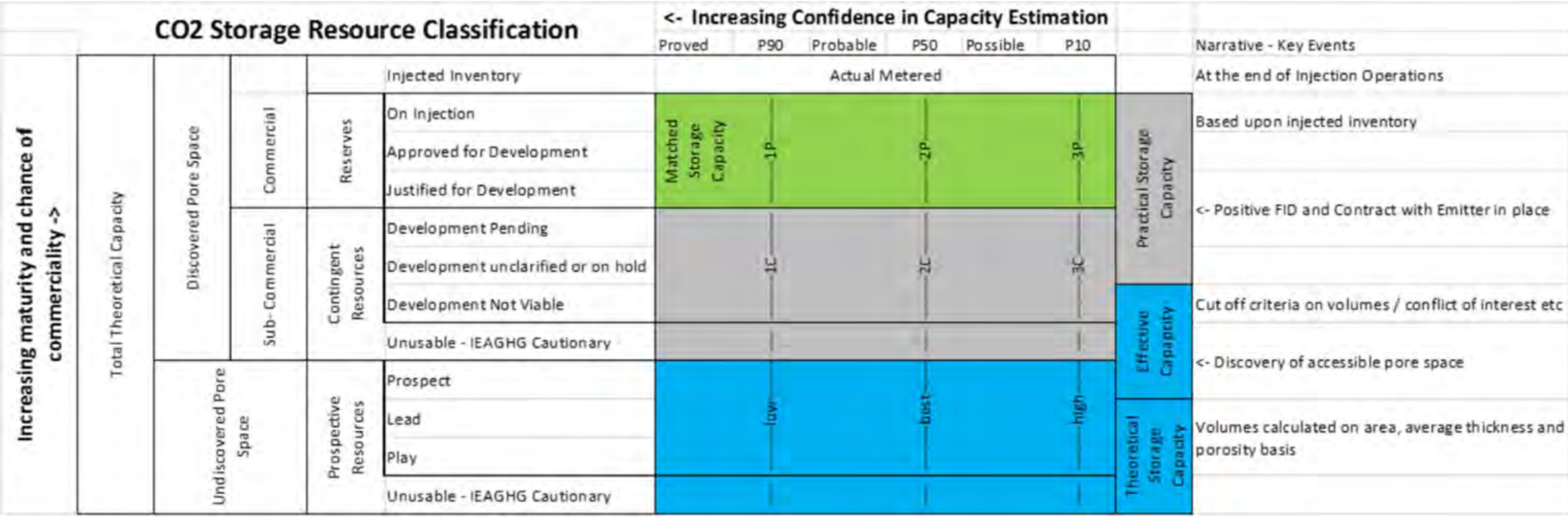


Figure 3-31 Adopted CO_2 storage resource classification

3.6 Injection Performance Characterisation

3.6.1 PVT Characteristics

The PVT properties were modelled using the Peng Robinson equation of state and the CO_2 density correction within the Petroleum Experts software package for modelling CO_2 injection. The injection fluid was modelled as 100% CO_2 in compliance with project CO_2 composition limits. The PVT description used is shown in Table 3-15.

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 from the National Institute of Standards and Technology (NIST). Comparisons were carried out for a range of temperatures and pressures (temperatures of 4°C to 6 °C and pressures of 30 bara to 350 bara), with the following results:

1. Density differs from the NIST calculated value by a maximum of 1.1% with an average of 0.3%.
2. Viscosity differs from the NIST calculated value by a maximum of 14.3% with an average of 7.9%.

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

Table 3-15 PVT properties

3.6.2 Well Placement Strategy

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

The Hamilton field is currently producing gas, with a COP (Cessation of Production) assumed to be around 2017. By this time, the field will have been in production for 20 years and it is assumed in this study that the infrastructure will not be suitable for re-use. Well and platform placement is therefore independent of existing facilities. However, with 4 long term producing wells situated in the west of the structure, it is considered best practice to take advantage of the reduction in geological risk offered by the data from these wells, by siting the new wells in this area.

Well by well data from Hamilton has led the operator to suggest that the reservoir is well connected. This well by well information is not available for release through this project. The operator conclusion is considered to be sound and is adopted in this study. The well connected nature of Hamilton (no vertical barriers and no significant lateral barriers to the field limits) means that its' development as a CO_2 store is thus relatively insensitive to well placement, providing that the reservoir thickness is sufficient at the chosen well site.

Injectivity is expected to be high and therefore high injection rates can be achieved without the full reservoir section being open. However, as with all injection wells where injection is performed below fracture pressure (matrix injection), the concern with respect to maintaining long term injectivity is formation plugging. This occurs when small particulates accumulate in the near wellbore, reducing the rock permeability over time. The source of particulates can be entrained solids from the production process, corrosion products from pipeline, wells or process plant, scale or re-injected formation fines. Formation fines may be back produced during shut-in, providing plugging material when injection re-starts. While some particulates can be filtered out of the injection stream at surface, it is not possible to eliminate all solids in the system. If halite precipitation is a problem for whatever reason –including water influx – injectivity will be impaired. The back-up well would be used to boost injectivity and water wash facilities are included to provide necessary remedial options.

Best practice is to expose as much sand face as practicable in order to maintain adequate injectivity for the planned well life. This is simply because the larger the sand face area open to injection, the longer it will take to plug, based on volume of particulates per square foot of sand face.

Reservoir engineering indicates that two large injection wells would provide sufficient injection capacity to meet target CO_2 volumes over field life. Given that this injection capacity needs to be maintained at all times to meet likely contractual obligations, this means that two injection wells are required in each phase (gas phase and liquid phase) plus a single back-up well for both phases.

As offshore heating and filtering will be required (as well as water wash – see section 3.6.4.1), a wellhead platform is the appropriate facility for Hamilton. This then dictates a single top hole well location for all development wells. The only other constraint considered (other than drilling constraints) was that each bottom hole target should be separated by a minimum 1,000m in order to eliminate the superposition of temperature effects. This rules out vertical wells from a single top hole location ('S' shape wells, with vertical reservoir penetration, are also unable to achieve sufficient separation).

Well bore stability and drilling review work considered data from offset wells and nearby hydrocarbon fields such as Lennox and Douglas, both of which were developed with high angle wells. This review concluded that that high well angles can be achieved for Hamilton, despite the shallow depth of the reservoir and the large bore completion options being considered for the gas phase injection. However, horizontal wells have been ruled out due to concerns over differential sticking while drilling the depleted reservoir section. The chosen well profiles are therefore deviated wells through the entire reservoir section. Hole angle has been limited to 70º (65º is preferred for wireline access, but 70º can be achieved with the use of rollers, if necessary, although regular well interventions are not planned). However, well deviation may be optimised at a later stage in the process.

3.6.3 Well Performance Modelling

The purpose of well performance modelling is to help select a suitable injection tubing size and to evaluate some of the factors that may limit injection performance. The results of this modelling are then made available to reservoir engineering, in the form of lift curves, which are used to predict well performance in the reservoir simulation models.

All modelling work needs to respect the safe operating limits described in section 1.1.1.

3.6.3.1 Methodology

Well modelling was carried out using Petroleum Experts' Prosper software, which is a leading software for this type of application. The field development plan stipulates several CO_2 injection wells for Hamilton. There will be two distinct types of injectors: Injectors used during the gas injection phase of field operations and injectors used during the liquid injection phase. Wells in the same group are expected to be similar and it was therefore decided to evaluate well performance using a single prototype well for each group, Injector 1 (INJ1) for gas phase injection and Injector 3 (INJ3) for liquid phase injection. The input of the well models is described in the following sections.

3.6.3.2 PVT

PVT behaviour was modelled using the Peng Robinson equation of state, as discussed in Section 3.6.1.

3.6.3.3 Downhole Equipment

Since part of the purpose of this study was to determine the optimal tubing size for the Hamilton wells a set of sensitivity cases was defined on downhole equipment (see section 3.6.3.7).

3.6.3.4 Wellbore Trajectory

The wellbore trajectory used for the Hamilton well models were simplified from the deviation surveys provided by the well design study (see section 5.3.1).

3.6.3.5 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 that reason, this model was not considered.

The full enthalpy balance model performs more rigorous heat transfer calculations (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.

Published temperature modelling data (ICES/EuroGOOS North Sea Pilot Project – NORSEPP ICES/EuroGOOS Planning Group for NORSEPP (PGNSP)

Update report on North Sea conditions – 2nd quarter 2007, Institute of Marine Research Bergen, Norway) shows that there are significant seasonal seabed temperature variations in the East Irish Sea (East Irish Sea data was derived from the POLCOMS shelf seas modelling system developed by Proudman Oceanographic Laboratory and run by the UK Met Office, which was quoted in the NORSEPP report). Seabed water temperatures at the Hamilton location are estimated to vary from 6°C to 16°C during a year.

For the modelling a base case delivery and seabed temperature of 10°C was assumed and the required background temperature gradient was defined as 10°C at the seabed and reservoir temperature at top perforation depth.

3.6.3.6 Reservoir Data and Inflow Performance Relationship (IPR)

A full review of likely reservoir and field parameters was carried out and the assumptions used in the IPR modelling are summarised in Table 3-16 and Table 3-17 below. These values are mainly derived from the Hamilton Petrel / Eclipse model after history matching. Water salinity is set at 300,000ppm.

Using these data three IPR models were defined in Prosper to represent high, medium and low reservoir performance. These are summarised in Table 3-18. For the purposes of completion design no variation in reservoir pressure has been assumed.

Parameter	Unit	Low	Best Estimate	High
Formation Top Depth (Datum)	*ft TVDSS*		2450	
Formation Gross Thickness	*ft*	464	507	556
Formation NTG	-	0.76	0.89	0.97
Current (Depleted) Reservoir Pressure	*bara (psia)*	9.4 (137)		10.3 (150)
Reservoir Temperature (assumed depth datum as top of reservoir)	*°F/°C*		89 / 31.7	
Permeability	*mD*	358	835	1204
Permeability Anisotropy (K_v/K_h)	-	0.09	0.30	0.50
Formation Water Salinity	*ppm*		300000	

Table 3-16 Hamilton Reservoir Data

Parameter	Unit	Low	Best Estimate	High
Water Depth	*ft*		87	
Total Field Drainage Area	*acres*		3707	

Table 3-17 Hamilton Field and well data

Parameter	Unit	Low	Medium	High
Depleted Reservoir Pressure @ top perforation depth (INJ1)	*bara (psia)*	9.8 (142.7)	9.8 (142.7)	9.8 (142.7)
Reservoir Temperature @ top perforation depth (INJ1)	*°C (°F)*	31.7 (89)	31.7 (89)	31.7 (89)
Initial Liquid Phase Injection Reservoir Pressure @ top perforation depth (INJ3)	*bara (psia)*	73.77 (1070)	73.77 (1070)	73.77 (1070)
Reservoir Temperature @ top perforation depth (INJ3)	*°C (°F)*	31.7 (89)	31.7 (89)	31.7 (89)
IPR Model	*n/a*	Jones	Jones	Jones
Permeability	*mD*	358	835	1204
Reservoir Thickness	*ft*	353	451	539
Drainage Area	*acres*	1853.5	1853.5	1853.5
Dietz Shape Factor	*n/a*	22.6	22.6	22.6
Perforation Interval	*ft*	353	451	539
Skin	*n/a*	20	10	0

Table 3-18 Hamilton IPR Definitions

3.6.3.7 Tubing Selection

Tubing selection was carried out for both the gas and liquid injection phases.

Injection Limits – Gas Phase Injection

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

Parameter	Unit	Value
Fracture Limit at Top Perforation Depth (Depleted)	*bara (psia)*	64.5 (935)
Minimum Fluid Temperature at Perforation Depth	*°C*	0

Table 3-19 Injection pressure and temperature limits

The results of the Geomechanical study suggest a wide range of potential fracture gradients dependent mainly upon the reservoir pressure. In the current depleted state, the fracture gradient in Hamilton is estimated to be 0.097 bar/m (0.43 psi/ft). The gradient is expected to increase with reservoir pressure during injection to a robust 0.195 bar/m (0.86 psi/ft) at the end of injection operations, as illustrated in Figure 3-47. In the simulation modelling the upper pressure constraint was set to 90% of the fracture pressure gradient.

- The fracture pressure constraint at top reservoir depth has been derived using a fracture gradient of 0.097 bar/m (0.43 psi/ft), which is the assumed fracture gradient for the depleted reservoir and a top reservoir depth of 737m (2417 ft) TVDSS. A factor of 0.9 was applied to the calculated fracture pressure to determine the maximum allowable reservoir pressure in the simulation modelling at each time-step and for each cell.
- The minimum fluid temperature at reservoir depth exists to prevent formation water from freezing during injection.

Sensitivity Cases – Gas Phase Injection

The sensitivity cases considered for gas phase injection are summarised in Table 3-20 below. Two tubing head temperatures were considered (ambient and gas heated to 30°C), as it was felt that ambient THT alone would be severely limiting.

Case	Reservoir Case	Tubing Size	THP (bara)	THT (°C)
1	High	7'' (29 ppf)	28.00	10
2	Medium			
3	Low			
4	High	9-⅝ (47 ppf)	29.50	10
5	Medium			
6	Low			
7	High	7'' (29 ppf)	46.00	30
8	Medium			
9	Low			
10	High	9-⅝ (47 ppf)	47.50	30
11	Medium			
12	Low			

Table 3-20 Sensitivity cases for gas phase injection

The high, medium and low reservoir cases are as described in section 3.6.3.6 above. The tubing head pressures have been chosen to comply with the minimum injection temperature limit.

Results – Gas Phase Injection

Table 3-21 summarises the rates achievable for the various sensitivity cases and Figure 3-33 provides a graphical representation. These well rates are not inconsistent with those reported during the production phase on Hamilton when wells produced up to 65 MMscf/d through 7" completions. 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.

Note that the tubing head pressures (THP) quoted in the table above are the maximum pressures that can be applied without reducing bottom-hole temperatures (BHT) to below 0°C at initial reservoir conditions. These limits will, however, increase as reservoir pressure increases, reaching a maximum of 63 bara for the gas phase injection period. THP limits are incorporated into the VLP curves supplied to reservoir engineering (see section 3.6.6.3). Figure 3-32 illustrates the drop in temperature versus depth due to reduction in pressure with depth. THP is dictated by BHP (reservoir pressure plus injection backpressure) and the losses due to friction in the wellbore.

Figure 3-34 shows the pressure and temperature behaviour along the tubing plotted as pressure versus temperature for the various tubing sizes considered. This summary graph also shows: the fluid phase boundaries; minimum temperature and minimum fracture pressure limits. Detailed graphs for each completion scenario are provide in Appendix 6.

Case	IPR Case	Tubing Size	THP (bara)	THT (°C)	Well Rate (MMscf/d)	Rate (Mte/yr)
1	High	7'' (29 ppf)	28.00	10	44.7	0.865
2	Medium				42.9	0.830
3	Low				34.2	0.661
4	High	9-⅝ (47 ppf)	29.50	10	111.2	2.151
5	Medium				101.4	1.962
6	Low				62.6	1.211
7	High	7'' (29 ppf)	46.00	30	77.1	1.491
8	Medium				73.4	1.420
9	Low				64.3	1.244
10	High	9-⅝ (47 ppf)	47.50	30	191.9	3.712
11	Medium				181.0	3.502
12	Low				135.2	2.616

Table 3-21 Rates achievable by case - gas phase injection

The results can be summarised as follows:

- The target well rate is 2.5Mt/yr.
- The target rate was not achieved for 7" tubing in any of the cases considered.
- The 9-⅝ tubing can meet the target rate at the higher THP & THT conditions and is thus the most suitable size for gas phase injection.
- Without heating, a minimum of 5 wells would be required to ensure that target storage rates of 5MMte/yr are achieved.
- By heating to 30°C, this rate can be achieved by 2 wells.
- Injection rates in the scenarios considered are limited by the need to keep the injection temperature at the sand face above 0°C. Whilst higher THPs can be used maintaining single phase gas injection raising this pressure by more than one bar leads to the temperature limit being broken for at least one reservoir case.

Note that a value for money review should be undertaken in pre-FEED in order to determine whether heating of the gas stream is more or less economic than drilling a larger number of wells. This study assumes that the heating of gas is suitable, and therefore limits the number of gas phase wells to 2.

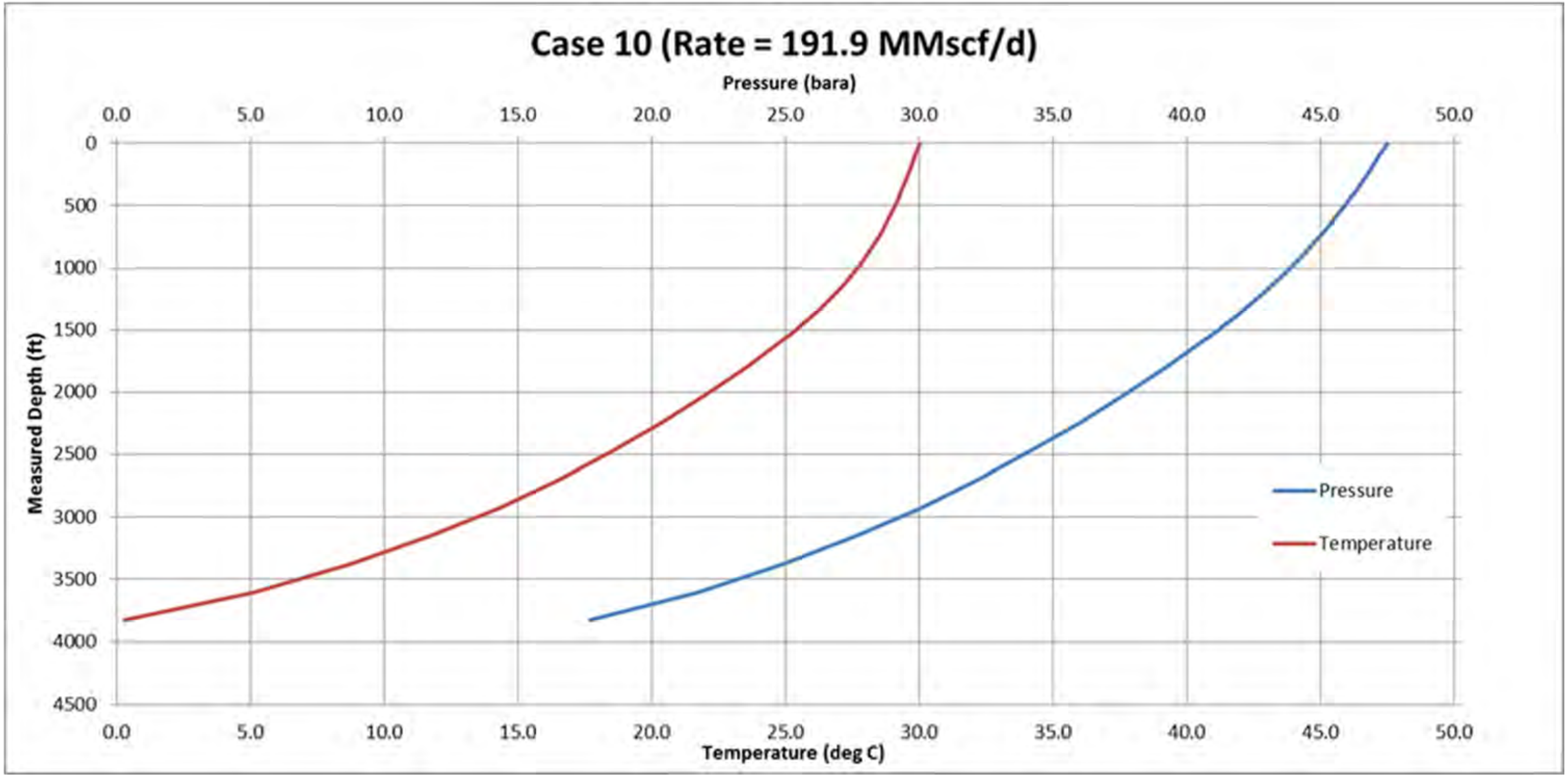


Figure 3-32 Sample temperature and pressure profile vs depth

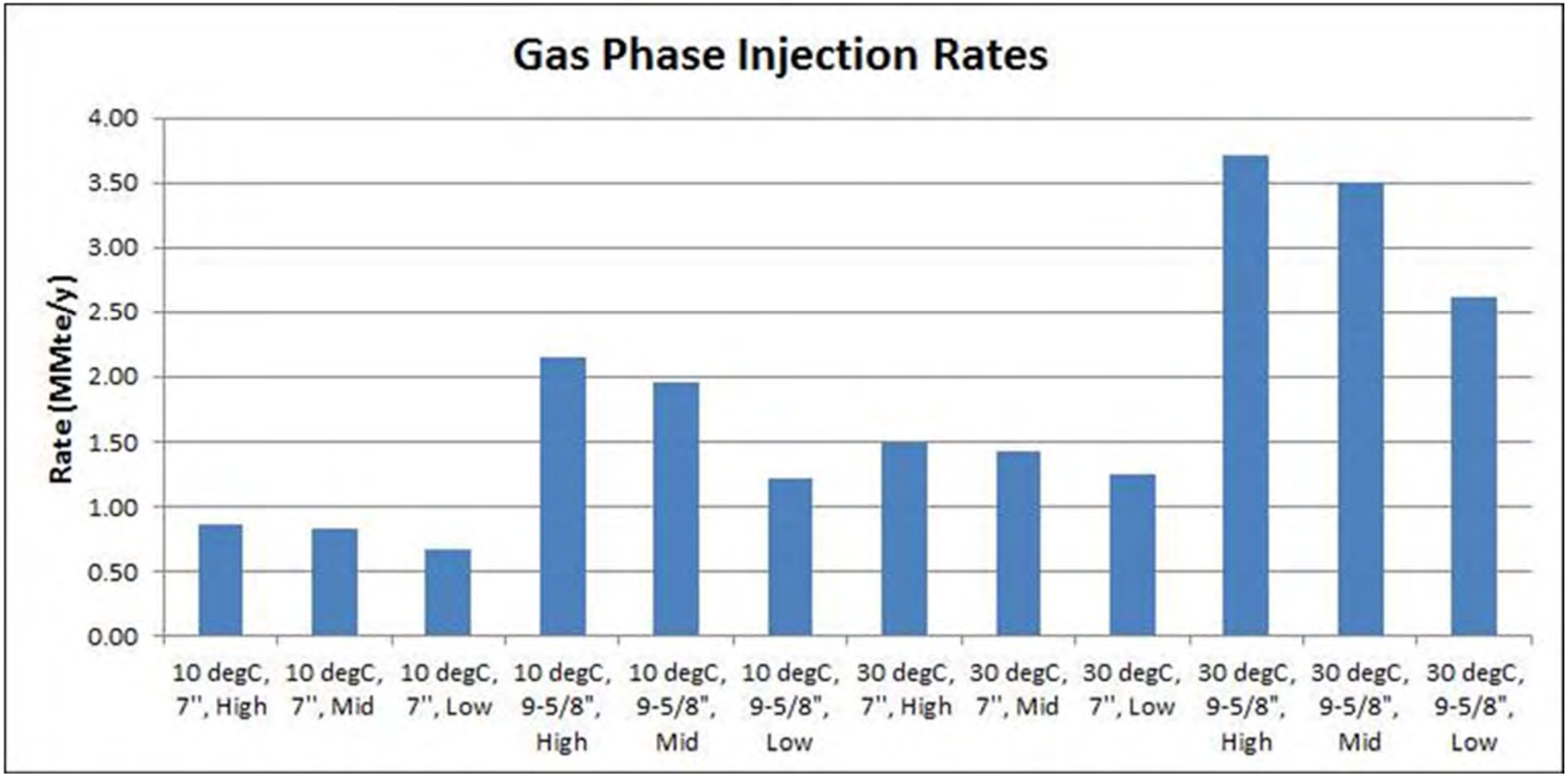


Figure 3-33 Rates achievable by case - gas phase injection

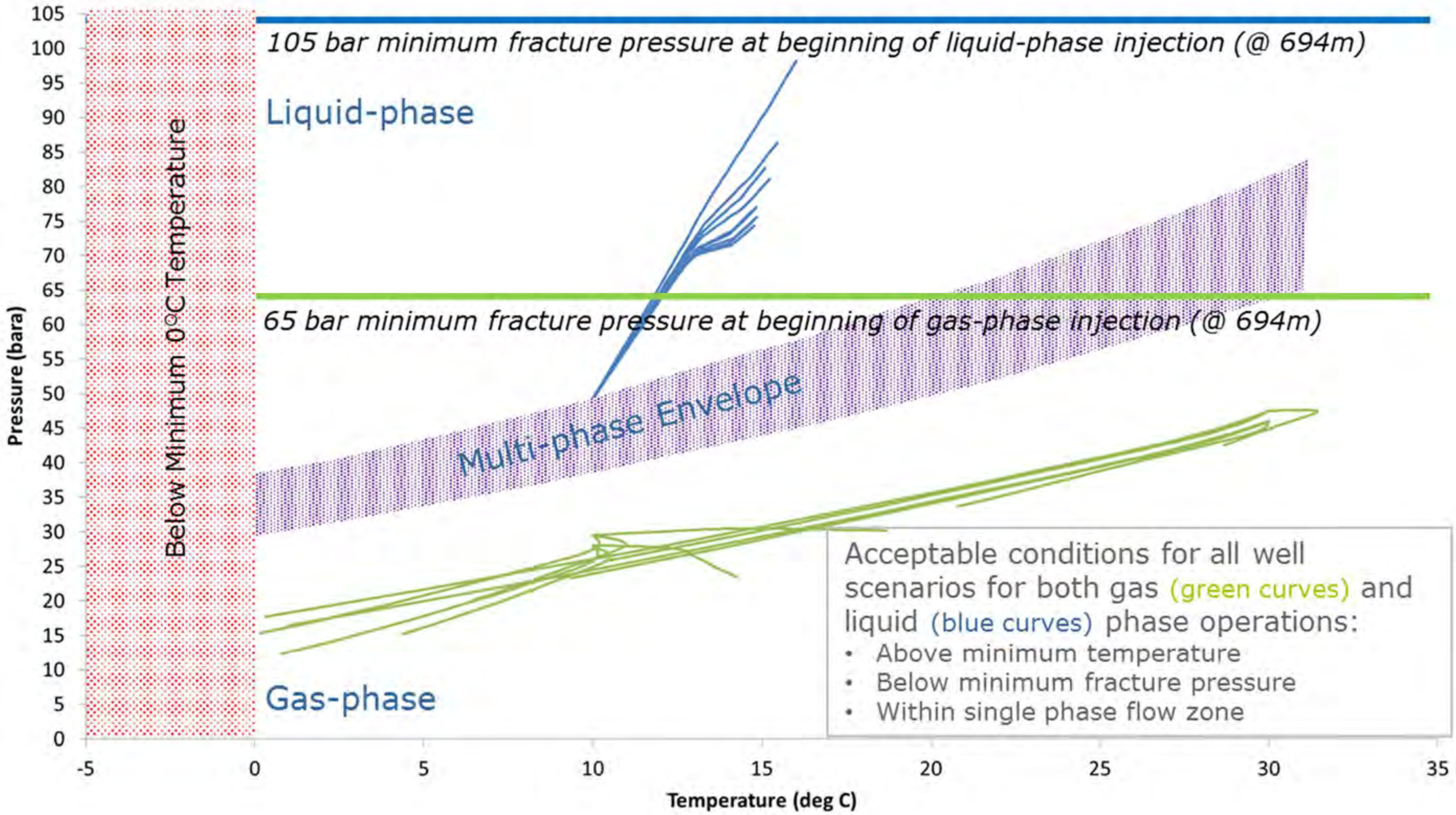


Figure 3-34 Temperature and Pressure Completion Modelling Results

Injection Limits – Liquid Phase Injection

The pressure and temperature limits on liquid phase injection operations have been summarised in Table 3 8 below.

Parameter	Unit	Value
Fracture Limit at Top Perforation Depth (Initial Liquid Phase)	*bara (psia)*	104.6 (1517)
Minimum Fluid Temperature at Perforation Depth	°C	0

Table 3-22 Injection pressure and temperature limits - Liquid phase injection

Notes:

- The fracture limit at top reservoir depth has been derived using a fracture gradient of 0.162 bar/m (0.72 psi/ft) , which is the estimated fracture gradient at the start of liquid phase injection (1070 psia or 74 bar), and a top reservoir depth of 724m (2374 ft) TVDSS (INJ3). An uncertainty factor of 0.9 was applied to the calculated fracture pressure.
- The minimum fluid temperature at reservoir depth exists to prevent formation water from freezing during injection.

Sensitivity Cases – Liquid Phase Injection

The sensitivity cases considered for liquid phase injection are summarised in Table 3-23 below. Note that ambient temperature only is considered.

Case	Reservoir Case	Tubing Size	THP (bara)	THT (°C)
1	High	5-½'' (17 ppf)	49.32	10
2	Medium			
3	Low			
4	High	7'' (29 ppf)	49.32	10
5	Medium			
6	Low			
7	High	9-⅝ (47 ppf)	49.32	10
8	Medium			
9	Low			

Table 3-23 Sensitivity Cases - Liquid Phase

The high, medium and low reservoir cases are as described in section 3.6.3.6 above. The tubing head pressure is the minimum safe injection pressure to ensure single liquid phase injection throughout the tubing.

Results – Liquid Phase Injection

Table 3-24 summarises the rates predicted for the various sensitivity cases and Figure 3-35 provides a graphical representation. As mentioned above 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)	Well Rate (MMscf/d)	Rate (Mte/yr)
1	High	5-½'' (17 ppf)	49.32	10	137.0	2.649
2	Medium				134.6	2.604
3	Low				123.9	2.396
4	High	7'' (29 ppf)	49.32	10	250.7	4.849
5	Medium				242.9	4.699
6	Low				207.2	4.007
7	High	9-⅝ (47 ppf)	49.32	10	591.2	11.435
8	Medium				535.3	10.354
9	Low				361.9	7.000

Table 3-24 Rates achievable by case liquid injection

Figure 3-34 shows the pressure and temperature behaviour along the tubing plotted as pressure versus temperature for the various tubing sizes considered. This summary graph also shows: the fluid phase boundaries; minimum temperature and minimum fracture pressure limits. Detailed graphs for each completion scenario are provide in Appendix 6.

The results can be summarised as follows:

- Target well rate is 2.5 Mt/yr.
- The target rate can be achieved for all tubing sizes, under all the conditions considered.
- The rates achieved in 7'' and 9-⅝'' tubing substantially exceed the target and those the rates predicted for the 5-½'' tubing are very to the target.
- 5-½'' tubing is considered optimum.
- In the scenarios considered no issues with phase changes in the tubing should be encountered. Neither the fracture limit should nor the bottom hole temperature limit should be breached.
- Should more experience be gained in CO_2 phase change behaviour and management prior to the drilling of the liquid phase wells, and a phase change in the lower completion is found to be acceptable, there is an option to utilise the liquid phase wells at an earlier point in the transition period (possibly even at the start) without resorting to reservoir injectivity impairment. This is because there is sufficient back pressure in the 5-½" tubing to maintain single (liquid) phase to the bottom of the tubing, leaving phase change to occur in the lower completion / near wellbore.

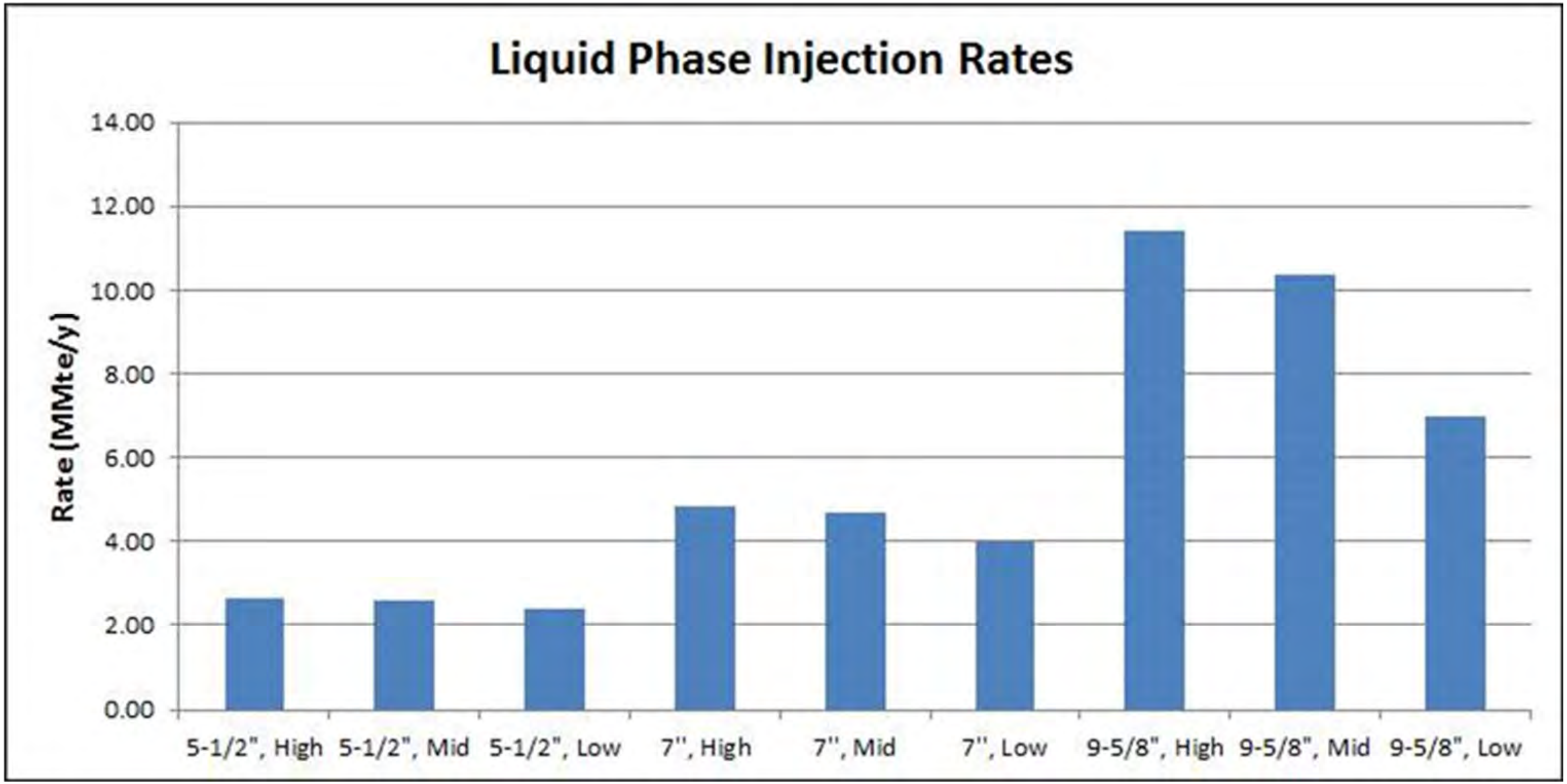


Figure 3-35 Rates predicted by case – liquid phase injection

3.6.3.8 Vertical Lift Performance Curve Generation

Vertical lift performance (VLP) curves were generated for the Hamilton wells for both gas and liquid phase injection with the tubing chosen for each case. 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.

Gas Phase Injection

Input parameters were as follows:

- Tubing Head Pressures: 130.5 psia (9.0 bara) to 960 psia (66.2 bara) in 10 equal steps
- Gas Rates: 10 MMscf/d to 148 MMscf/d in 20 equal steps

The performance envelope of the well is shown in Figure 3-36 below. It was ensured that for all points shown on the curves single phase gas injection was maintained throughout the tubing and that the temperature limit of 0°C was not broken.

Liquid Phase Injection

Input parameters were as follows:

- Tubing Head Pressures: 718 psia (49.5 bara) to 3771 psia (260 bara) in 10 equal steps
- Gas Rates: 5 MMscf/d to 400 MMscf/d in 20 equal steps

The performance envelope of the well is shown in Figure 3-37 below. It was ensured that for all points shown on the curves single phase liquid injection was maintained throughout the tubing and that the temperature limit of 0°C was not breached.

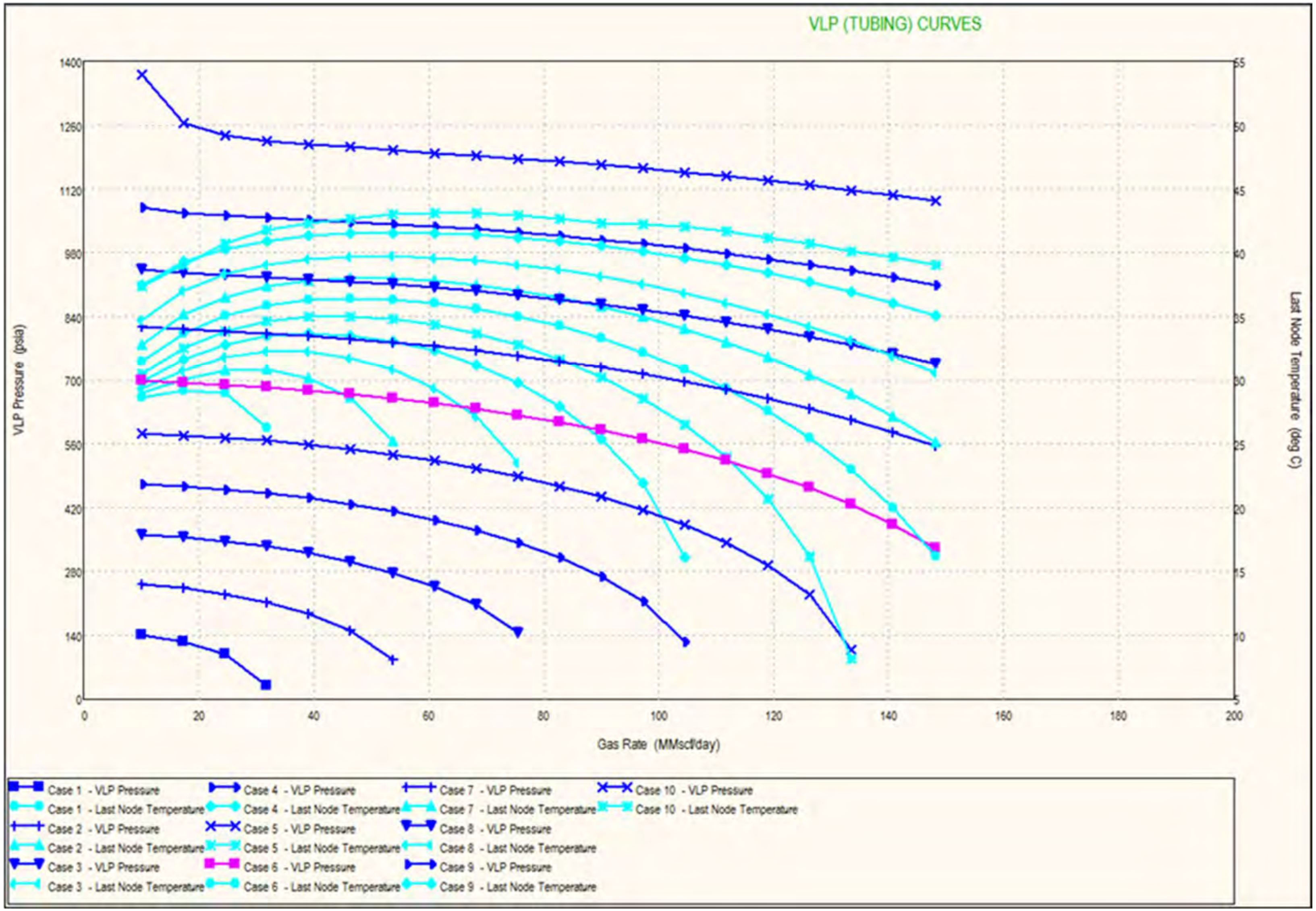


Figure 3-36 Performance envelope (gas phase) - 9 5/8" tubing

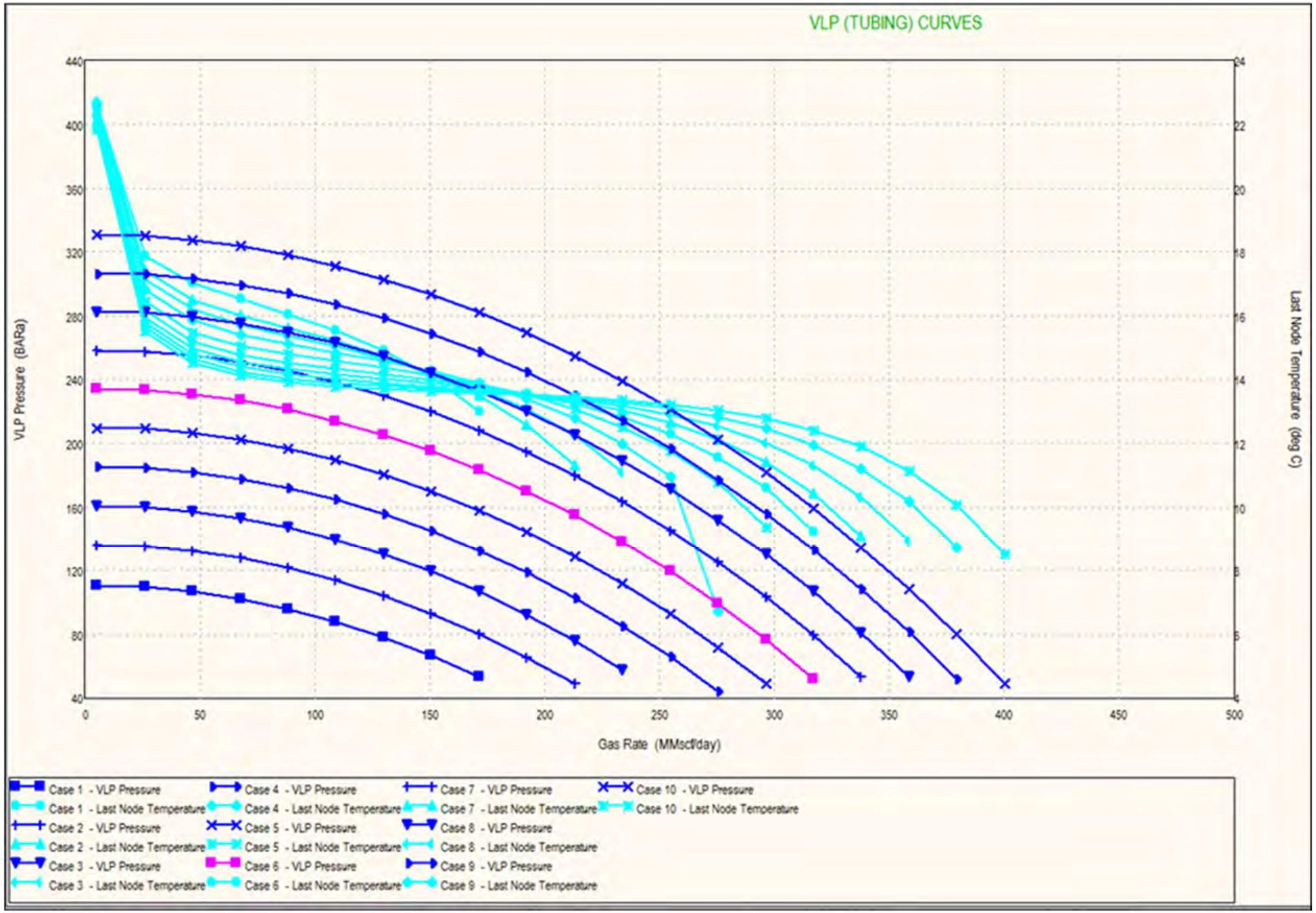


Figure 3-37 Performance envelope (liquid phase) - 5 1/2" tubing

3.6.4 Injectivity and Near Well Bore 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 Hamilton storage potential. Some authors indicate that the impact of these effects could be minimal (Tambach T., 2011).

3.6.4.1 Halite

The Hamilton formation water is a very saline brine. There is uncertainty in the composition of this brine, but some nearby fields have reported very high salinity (salt content) values, close to salt saturation. As a gas reservoir, the Hamilton brine will be primarily connate water (water adsorbed on the surface of the rock grains or on the walls of the pore channels). With water saturations around 25% in the Hamilton reservoir, water volumes are relatively low with respect to pore volume, and therefore the salt content in a 300,000ppm salt solution will be limited to around 7.5% of pore volume.

When gaseous CO_2 is injected into formations containing high salinity connate water, CO_2 will absorb the water phase, thus precipitating the salt out of solution. In other words, the near wellbore is dehydrated (water removed), leaving the salts behind. This dehydration process increases pore space and can increase permeability, despite the precipitation of salt crystals (up to 7.5% of pore volume as noted above), as total pore space is increased by the removal of water. Salt will only become an issue if salt crystals are mobilised and form bridges / plugs in the matrix rock pore throats. Given the large injection area (sand face) planned in the Hamilton wells, gas velocity through the matrix will be low and mobilisation may not occur. If it does occur, it is likely to be in the very near wellbore region only, and once removed, should not re-occur. The only exception to this might be due to connate water re-saturation in the near wellbore due to capillary pressures. In this case, more halite is fed into the system leading to a reduction in pore volume and considerably higher risk of pore throat plugging. However, with high permeabilities and poor aquifer support, capillary pressure re-saturation is likely to be limited to the lowermost reservoir sections.

Halite issues can also occur during liquid phase CO_2 injection (water is soluble in liquid CO_2, but salt is not). Salt crystals are much more likely to be mobilised by the more viscous liquid phase, so the issue may be more prominent as pore throat blocking is more likely. At this stage in the reservoir life, considerable dehydration is likely to have occurred already (both from hydrocarbon gas production and from CO_2 gas phase injection). The halite crystals may have formed bonds with the matrix rock and may no longer be considered mobile. However, this has not yet been experienced in any CO_2 storage site and considerable uncertainty remains surrounding the actual halite risk to injectivity in both phases.

The effect of halite precipitation can be mitigated by 'washing' the near wellbore with fresh or low salinity water (seawater is relatively low salinity at 35,000 ppm). The wash water dissolves the salt and carries it away from the near wellbore region, where the effects of permeability reduction have most impact. As the impacts of halite precipitation are not yet fully understood for Hamilton, it is recommended that provision is made for early time wash water operations. Note that a full column of fresh water is near to initial fracture pressure, and therefore it is recommended that slugs of fresh water are introduced into the gaseous CO_2 stream. Wash water should be treated with corrosion inhibitor, anti-oxidants and biocide in order to minimise potential corrosion of the completion.

Water wash facilities have been incorporated in the platform facilities to account for these operations.

3.6.4.2 Thermal Fracturing

The CO_2 stream injected into the Hamilton formation is colder (close to 0°C, depending on rate and phase etc) than the modelled ambient reservoir temperature (~31.7°C). This reduction in temperature may be quite extensive (thermal modelling done on similar reservoirs suggests that this may extend to a radius of 1,500ft). A drop in temperature will have an effect on the near wellbore stresses, and will make rock more liable to fracture (tensile failure). This thermal effect on the fracture pressure has not been investigated in this report. The applied safety margin (10%) on fracture pressure and the thickness and strength of the cap rock provides some security with respect to cap rock fracturing and containment issues. It is recommended that these issues be reconciled in the pre-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, whilst field-wide values can be generalised, the specifics of the well can impact on the required conditions for failure of the formation.

This work applied 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.

Critical Drawdown for Sanding

The critical drawdown for sanding was estimated using the methodology presented in (Bellarby, 2009) and SPE 78235. This method relates mechanical rock properties and the stress condition.

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

Where:

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

The cumulative rock strength (UCS) in the Ormskirk Sandstone as calculated from logs for the four analysed wells are shown in Figure 3-38, where the average range is between 250 bar (3628 psi) to 304 bar (4409 psi).

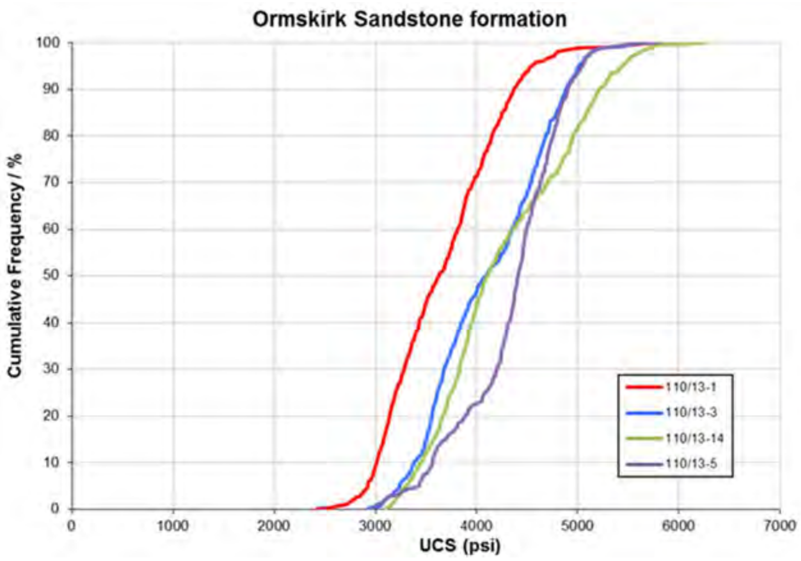


Figure 3-38 Ormskirk sandstone UCS cumulative distributions

Two cases were considered in this analysis of the critical total drawdown (CTD) for sanding: a) at original reservoir pressure condition; and b) at depleted reservoir conditions. The following figures indicates the CTD for the four wells evaluated in the Ormskirk Sandstone in Hamilton, Hamilton East and Hamilton North, including original and depleted reservoir pressure conditions. As can be seen, the CTD for all wells are above 552 bar (8000 psi) for the original condition and 345 bar (5000 psi) for the depleted conditions. This indicates that the Ormskirk sandstone is competent and there is minimal risk for sanding even for the depleted conditions. However, this is based on an uncalibrated rock strength so uncertainty remains.

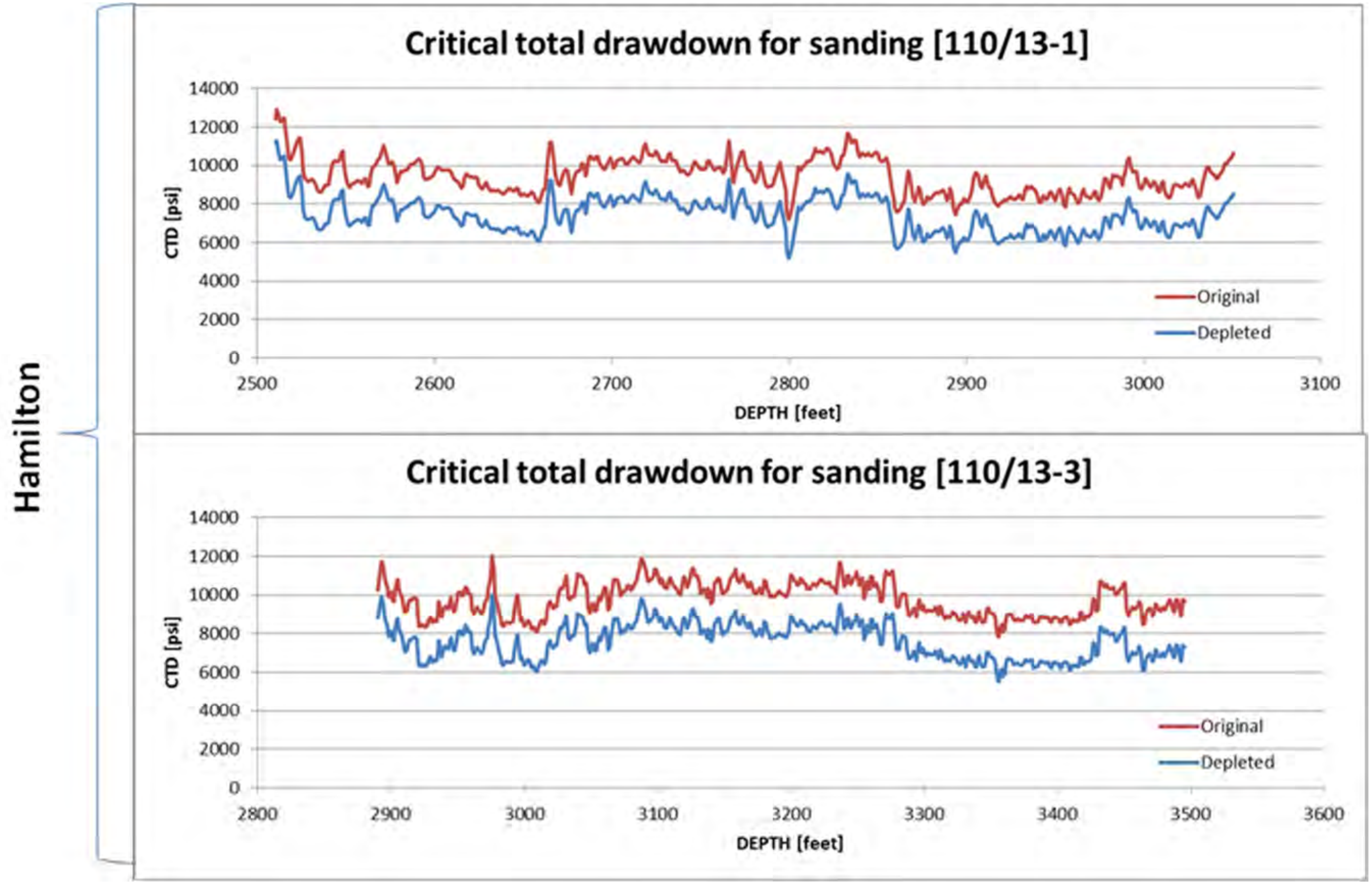


Figure 3-39 Critical drawdown pressure for the Hamilton field

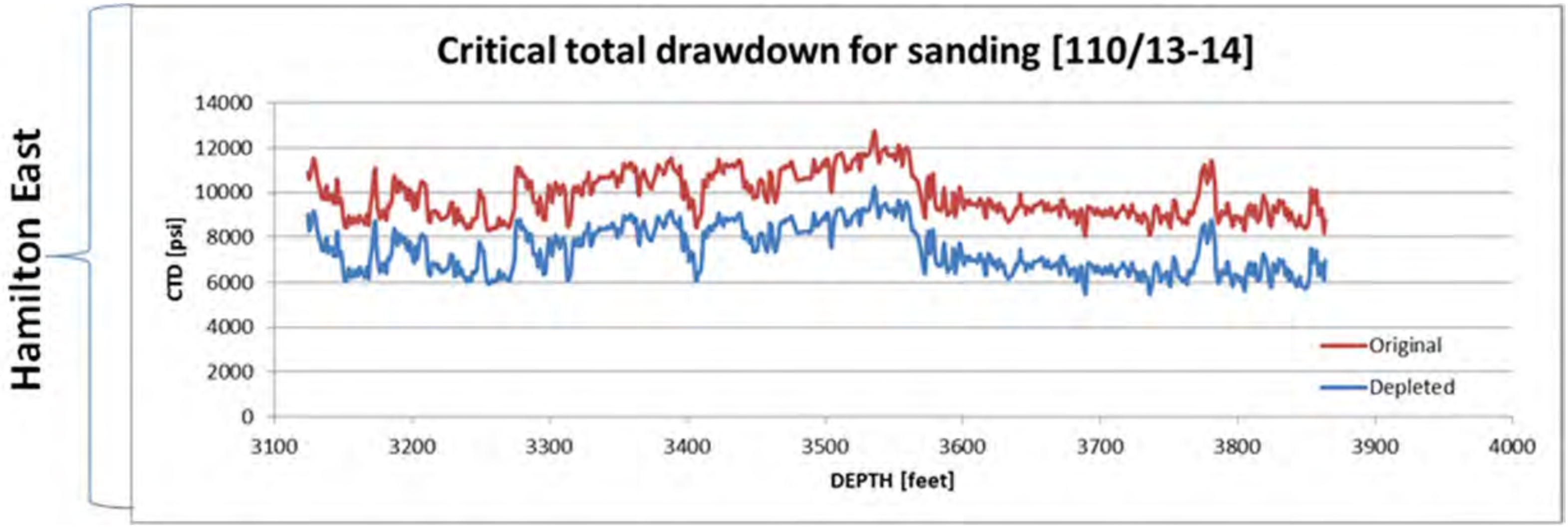


Figure 3-40 Critical drawdown for Hamilton East

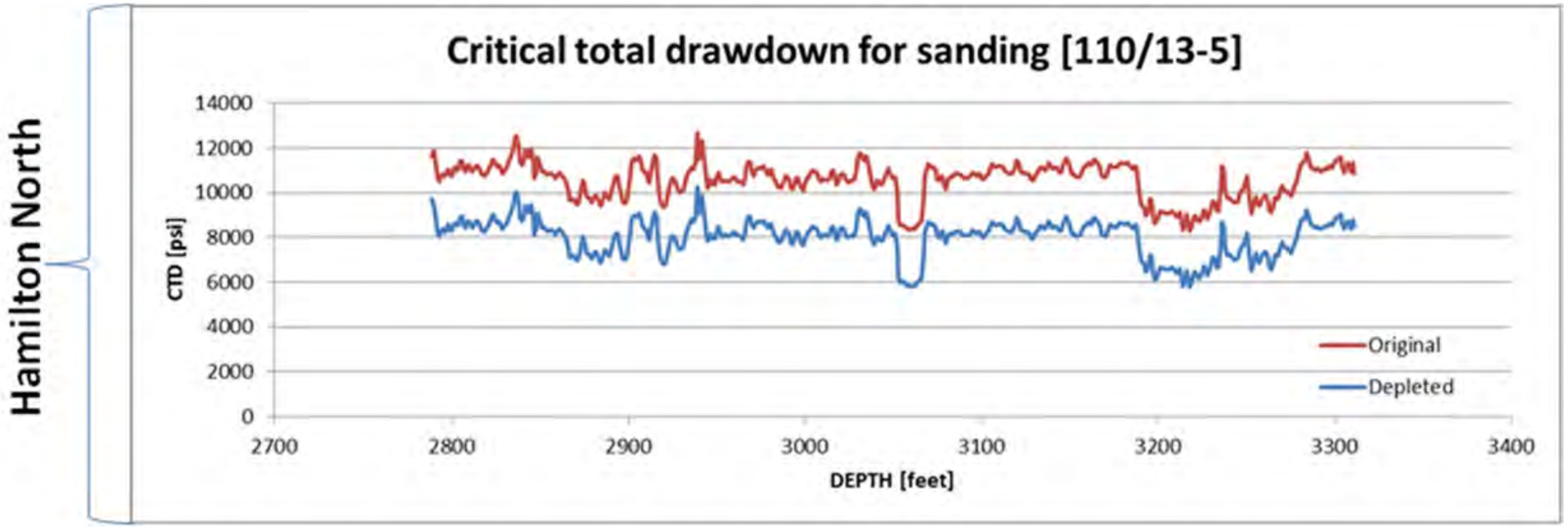


Figure 3-41 Critical drawdown for Hamilton North

Impact on Well Completion

The following completion options were selected to address the range of potential formation failure modes as identified in the guidelines from SPE 39436.

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 frac 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

Applying the guidelines from SPE 39436 suggests that the Ormskirk Sandstone in Hamilton could be considered as a Case D, indicating that a perforated cemented liner is suitable.

However, cementing a production liner in place on Hamilton under initial reservoir conditions may be challenging due to the uncertainty in fracture pressure (potentially less than the hydrostatic column during the cementing operation). Fracture pressure lies in a range, somewhere between 0.136 bar/m (0.6 psi/ft) and 0.097 bar/m (0.43 psi/ft). There are several options for low pressure cementing, including stage cementing and nitrified, or other light weight, cements. However, these add to the complexity and cost of the development.

Given the high rock strength, sanding is considered a low risk, especially during the gas phase injection where shock loading (stressing) is not expected due to the compressibility of gas. An open-hole completion is therefore recommended for the gas phase injector wells. Stand-alone sand screen (or slotted liner) could be used as a 'just in case' approach to sanding. However, given that the concept to deal with the transition phase is to include pumping a 'damaging' pill of gel or sized particulates, the preference is for this to plug the formation rather than the lower completion. Pre-perforated liner is therefore recommended as the lower completion conduit. This can be re-visited for the liquid phase injection wells, where fracture pressure and pore pressure will be higher and may be able to support cementing and perforating operations, as well as flowback for well/perforation clean-up.

3.6.4.4 Addressing Maximum Injection Limit and Transient Well Behaviour

In the gas phase injection, the maximum tubing head pressure (THP) limit is determined by the predicted bottom hole temperature (BHT), which must remain above 0°C to avoid the formation of ice (note that this limit is considerably lower than 0°C for saline brine, but the presence of fresh 'wash water' has been assumed). In order to increase injection rates, tubing head temperatures (THT) could be increased past 30°C. However, this incurs a penalty with respect to gas density, increased frictional pressures and thus mass injection rates. Further work should be done to determine the optimal gas heating limit with respect to well delivery, taking into account seasonal variations in gas delivery temperature.

Hydrate formation has not been considered in detail, as it was felt that, at the low formation pressures and already restrictive 0°C BHT limit, hydrate risk was minimal. However, more work on this may be required at the pre-FEED stage, with the construction of a full thermal model.

As noted earlier (section 3.6.4.1), the injection of a full column of wash water in the well may result in the unintentional fracturing of the formation. It is therefore recommended that wash water, if required, is injected in batches smaller than the well tubing volume, chased by gaseous CO_2 or nitrogen. The water may require to be heated (or an inhibitor such as MEG added) in order to prevent the formation of ice or hydrates.

Transient effects in the transition period and during the liquid phase injection may be more problematic. The full column of liquid CO_2 results in a lower injection window with respect to fracture pressures, especially during the transition from injection to shut-in. Furthermore, maintaining single phase in the wellbore during start-up of injection (before an injection back-pressure can be established) may be problematic. These transient issues require further well modelling in order to assess the true limits, which is beyond the scope of this study. Other transient effects include significant temperature drops during shut-in and well restart. These effects, and proposed mitigations, are discussed below.

Two transitional effects in the liquid phase injection have been identified:

- Shut-in at surface with a full column of CO_2 in the well
- Restarting CO_2 injection during the transition period or after a water wash

Shut in at Surface with a Full column of CO_2 in the Well

If the injection pressure is high and this pressure is transferred to the formation at shut-in on top of a static column of CO_2, then the formation fracture pressure may be exceeded (depending on where we are on the frac pressure hysteresis curve). This is considered as a 'worst case', similar to a water hammer effect (which induces high and low pressures into the system). This is unlikely to happen in practice because of the 'fall-off' pressure profile in the well: after shut-in the fluids continue to inject and the frictional pressure losses in the tubing act to reduce the bottom hole pressure at the same time as the surface injection pressure dissipates. It is more likely that 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 cause problems with exceeding fracture pressures or fall below sandface failure pressures.

Restarting CO_2 Injection During the Transition Period or after a Water Wash

During the 'transition period', where the reservoir pressure is below critical, but single phase gas injection can no longer be sustained, we are relying on reservoir 'back pressure' to maintain single phase in the wellbore. However, when shutting in the well at surface, a full column of liquid CO_2 cannot be supported, and gaseous CO_2 will evolve, filling the wellbore. When starting injection again, the back pressure is not yet generated and the high pressure liquid CO_2 will flash to gas in the wellbore. This will create a considerable temperature drop in the wellbore, with a final limit determined by the reservoir pressure (and thus THP) at the time.

If a large volume water wash is required in the transition period or liquid phase, the potential cooling effects on restarting CO_2 injection are more serious (see section 3.4 for near wellbore issues). At the end of a water wash, with a column of fresh water in the well, the surface pressure will be negligible. As the water may drain from the wellbore and be replaced by gaseous CO_2, there may not be a significant issue with water, however, this cannot be guaranteed. When injection restarts and high pressure liquid is introduced there is rapid cooling. If water is present at the interface, an ice plug may form. This might be mitigated by the introduction of sufficient MEG into the wash water, and this is a contingency that is allowed for in the platform design.

As stated previously, if water washing is required in these phases, small batches of fresh water injection may be preferred to large continuous water injection, although the effectiveness of this is, as yet, undetermined.

Because the Hamilton reservoir will be below fresh water hydrostatic pressure for the majority of the field life, the Tubing Head Pressure will be less than zero at the end of the water wash (although this may build up to reservoir pressure minus gas gradient over time as water 'inverts' in the wellbore and drains away). The time to pressure up the system will depend on the liquid hold up height in the wellbore, but even if the 'void' volume is small, it is unlikely to avoid flash freezing.

Attempting to 'pre-charge' the well with nitrogen would be effective if it could be injected at sufficient rate to create a suitable back pressure. However, this rate is likely to be unsustainably high. The alternate is to pump a temperature dependant viscous pill (breaks down to water viscosity at reservoir temperatures) ahead of the liquid CO_2 in order to generate the back pressure in both the wellbore and reservoir. However, this is likely to require the manned attendance on the platform for each re-start operation, which is not considered operationally sustainable.

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. While not eliminating the problem entirely, it would move the issues away from the wellhead to a much deeper – and hotter – location in the wellbore. If the valve could be reliably operated as a flow control valve, all phase transition effects could be moved to the lower completion temporarily, before transitioning to the reservoir,

Shut-in closer to the formation reduces the hydrostatic head of CO_2 acting on the formation and removes the risk of exceeding formation fracture pressures. 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, however, will still be considerable and may cause problematic transitional effects, although the higher temperatures at depth may limit these issues. Some modelling with suitable transitional software (e.g. Olga) 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 would mitigate the cooling at the CO_2 / water interface when injection restarts. However, higher pressure would need to be modelled in a hydrate prediction software in order to ensure that hydrates were avoided.

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
- Flow control functionality
- 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 preferred features not available are the ability to retrieve/set the valves on wireline, which means a workover is required to retrieve it in case of failure, and track record as flow control valves. 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, and that the maximum THP constraint introduced by injection pressure over a hydrostatic column of CO_2 does not apply. Transient effects are partially mitigated. However, further work is required in the pre-FEED and FEED stages to substantiate this approach, or to provide alternate solutions.

3.6.5 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.

3.6.5.1 Fracture Pressure Gradient Determination

In order to determine the fracture pressure for Hamilton, to be used as an upper injection pressure constraint, a geomechanical review was performed on the available well data. Several key data requirements for this study were not available, including current (depleted) reservoir pressure, rock strength data from core and actual in-situ stress orientation. With these data missing, several assumptions had to be made. For example, the reservoir pressure at the start of injection – or pore pressure – was estimated to be 8.3 bar (120 psi) (from initial reservoir simulation work). Regional stress maps were used in the assumption of a NW-SE maximum stress orientation. Correlations from well log data were used to determine rock strength. Different geomechanical correlations use different measured parameters from logs to estimate rock strength and these often result in a range of fracture pressure estimates, some more conservative than others. Field data are normally used to determine which of these correlations might be more representative of the in situ rock.

The geomechanics review was performed on well data acquired when the wells were drilled – in other words at original reservoir pressure. This resulted in an initial – un-depleted - fracture gradient estimate of 0.162 bar/m (0.718psi/ft). As the pressure in the reservoir depletes through production, relative stresses change and the horizontal stress reduces. This means that the rock can fracture at lower applied pressures. Again, various correlations exist to allow this process to be modelled analytically. Using the best fit correlation, a depleted fracture gradient of 0.135 bar/m (0.6psi/ft) was determined. This figure is thought to be a reasonable estimate for well design and drilling purposes, as it is understood that analogue fields in the area have been successfully drilled with the equivalent mud weights. If the fracture gradient is lower, it may be necessary to modify drilling techniques to suit.

As the reservoir is re-pressured with CO_2 injection, the accepted convention is that fracture pressure will increase back towards the original value. Wells drilled at a later stage in the field life will therefore be less exposed to fracture pressure limitations. It should be noted, however, that there is considerable uncertainty over the stress path during re-pressurisation (whether it follows back up the depletion path or whether there is a hysteresis effect) and this is considered a high project risk. However, this can be considerably de-risked by determining the true depleted fracture pressure as a starting point. It is therefore recommended that the current operators of the Hamilton field are approached, prior to field abandonment, in order to acquire fracture pressures from the current well stock (extended leak off tests for example).

For reservoir engineering purposes, where fracture pressure is an intrinsic limitation for CO_2 injection (nothing can be done about it), a more conservative approach was taken to determine the safe operating limit. The depletion process was replicated in a 3D geomechanical earth model. This modelling is discussed in Appendix 6. The work established a larger range of fracture pressures, with a low end range being 0.097 bar/m (0.43 psi/ft) to 0.083 bar/m (0.368 psi/ft) from the Mohr Coulomb correlation. At the time of writing, the 0.097 bar/m (0.43 psi/ft) value was adopted, and the safe operating range was therefore taken as 90%

of this (i.e. 0.087bar/m (0.387 psi/ft)). The fully pessimistic low case of 0.083 bar/m (0.368 psi/ft) was tested in the reservoir model and also found not to be limiting.

3.6.5.2 Phase Envelope

In order to minimise the risk associated with the uncertainty introduced by operating wells across a phase boundary, all injection in the wells will be limited to single phase. The reservoir pressure of Hamilton at the start of CO_2 injection (<10 bara) are well below the critical point for CO_2 (74 bara), and therefore injection will initially be limited to gas phase.

At the end of gas phase delivery, there is still a large storage potential remaining in the reservoir. As such, a liquid phase injection would be required to exploit it. However, injecting liquid phase CO_2 into a reservoir that is still below critical pressure would normally result in an unwelcome phase change in the wellbore. A number of options exist to manage this ‘transition’ from gas to liquid (or dense) phase injection.

The first option is to inject gas at ambient pipeline temperature up to maximum gas phase injection pressure, followed by injection in dense phase (supercritical). This avoids the gas–liquid phase change, but requires considerable heating of the gaseous CO_2 for the majority of the field life (see Figure 3-42 below). CO_2 would be delivered to the injection site in gas phase, requiring a large OD pipeline, and the gas heated on an offshore platform. Heating could be done onshore with an insulated pipeline, and this could be further investigated with respect to cost effectiveness.

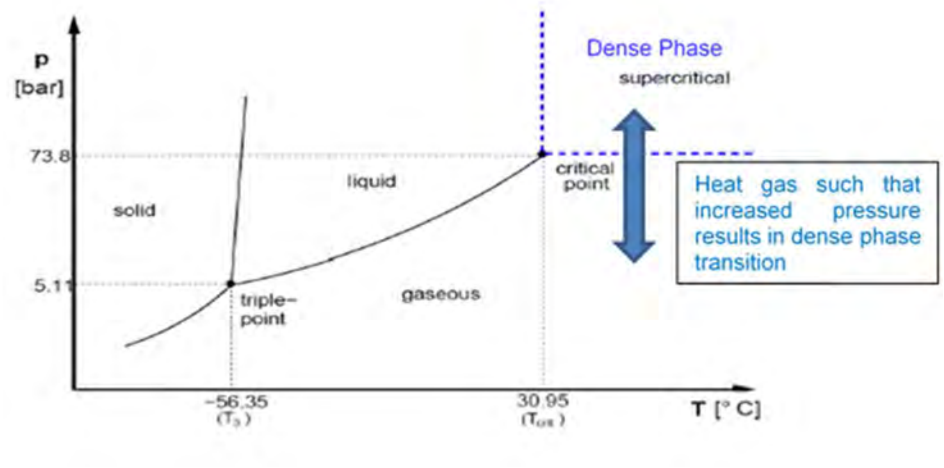


Figure 3-42 Phase change management option 1

The second option is to follow the gas phase injection with liquid phase heated to past dense phase (see Figure 3-43.). This is more complex, in that it would involve a liquid phase pipeline delivery (more cost effective) with a gas convertor / heater for the gas phase and a liquid phase heater for the dense phase, with all facilities offshore.

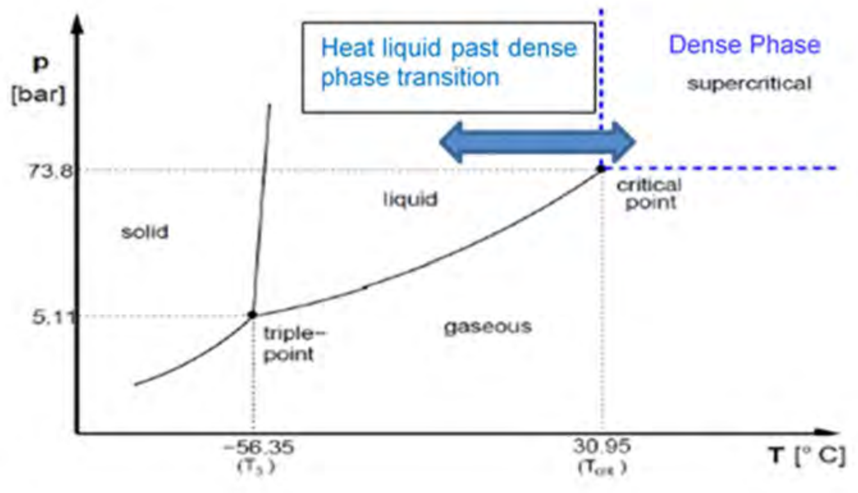


Figure 3-43 Phase change management option 2

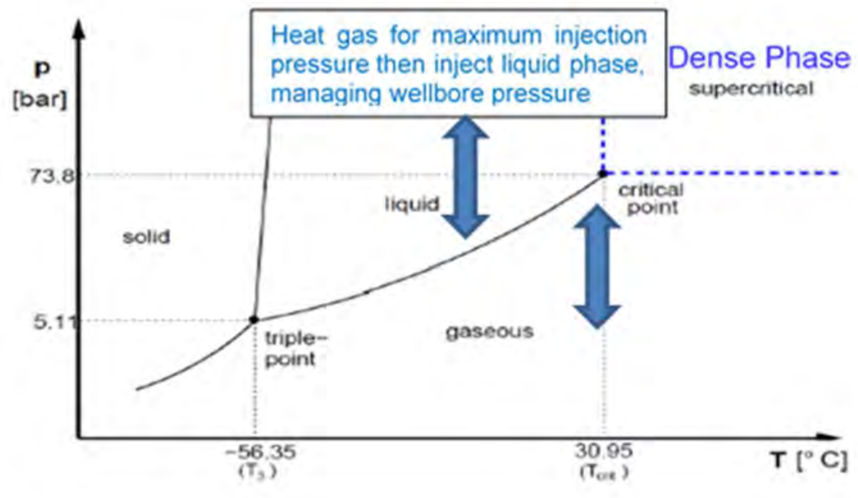


Figure 3-44 Phase change management option 3

The third option is to heat the gas in the initial phase in order to raise the reservoir pressure as close to critical as reasonably possible. This will maximise the storage potential in this period and minimise the 'transition' period for liquid phase injection. The liquid phase injection will be done at ambient delivery temperatures, using a 'mechanical' impairment to the well to ensure that pressures remain above the phase boundary. Once critical pressure is reached, the impairment will be removed and liquid phase injection will continue until the full reservoir storage potential is reached. See Figure 3-44 below. Delivery to the injection site would be in liquid phase from the start, with a gas convertor / heater for the gas phase. No heating is required for the liquid phase. This helps 'front load' the project with respect to offshore maintenance, reducing requirements as the facilities age.

There are a number of options for the introduction of a 'mechanical' impairment (or back pressure) to the injection wells. If further study suggests that lower completions (or sand face completion) can support phase change, then a simple deep set back pressure (injection) valve may be all that is required. Other mechanical alternatives include downhole flow control valves or simply changing the tubing for a smaller size. However, as the consequences for the lower completion are not yet proven (significant damage from multiphase flow and very low temperatures may occur), the other options considered were 'limited entry' – reducing the wellbore open to flow – and deliberated near wellbore damage (skin). These options move the back pressure into the near wellbore region of the reservoir, away from the well bore (lower completion). Plugging back the wellbore to produce the 'limited entry' effect may be problematic in an open hole completion, and is generally not desirable in injection wells where sand face plugging through transported solids is a real possibility. The preferred option is to introduce a near wellbore 'skin' through the injection of either a polymer gel or sized carbonate solids. These will, in effect, reduce the near wellbore permeability and increase the pressure loss through the near wellbore region. This 'damage' will reduce injectivity through the transition period, but will create sufficient back pressure as to maintain liquid phase in the well. The reduction in injectivity is partially compensated by the increase in density of the CO_2 in the liquid phase, resulting in a short and reasonable drop in injection rates over the period. The induced damage would be designed to be reversible (for example, through acid stimulation), allowing the gas phase wells to continue as liquid phase injectors, but as a precaution against as yet undefined damage induced by the near wellbore phase transition, two new liquid phase injectors would be drilled with a more optimised completion design.

This study assumed that the phase transition could be managed by impairing the injectivity. Future studies it is recommended that the pros and cons of each option listed should be further investigated in a pre-FEED study. Deliberately damaging injectivity is a novel concept and as such would require significant further study. The preferred alternate is to extend the gas phase injection by additional heating (generating dense phase injection) until the reservoir pressure is past critical pressure, then reverting to liquid injection at ambient conditions.

3.6.6 Dynamic Modelling

The dynamic modelling was carried out using the ECLIPSE compositional simulator to allow CO_2 injection into a depleted hydrocarbon gas reservoir to be modelled. A representative model, referred to as the Reference Case model was constructed. The inputs and results from the dynamic modelling are discussed in the following sections.

3.6.6.1 Model Inputs

Structural Grid and Reservoir Properties

The structural grid and reservoir properties modelling are discussed in detail in sections 3.4 and 3.5. The grid and properties were upscaled to a suitable engineering scale to allow for reasonable run times. Grid cells are 100m by 100m in the x and y directions and the number of active cells is approximately 400,000.

The GIIP in the dynamic model is 707Bscf, within 0.5% of the static model GIIP which is an acceptable accuracy. 640Bscf had been produced at February 2015 which equates to a recovery of 90%. This is high but not unreasonable for a mature field of this type. The modelled aquifer volume is 8147MMbbls. No additional aquifer is added to the model as there is no evidence of water production from the production records to support any additional aquifer support.

The fault transmissibility across the internal faults is calculated by Eclipse.

PVT

Compositional modelling is required to model CO_2 storage in a depleted gas field. In a compositional simulator oil and gas phases are represented by a multi-component mixture rather than by single or binary component representation in a black oil simulator. The compositional simulator can account for effects of phase behaviour and compositionally dependent phase properties such as viscosity and density on miscible displacement. In the case of CO_2 injection into the depleted Hamilton gas field, the reservoir pressure is initially below the critical pressure of CO_2 (74 bar/1071 psi). However, due to continuous CO_2 injection, the reservoir pressure will increase beyond the critical pressure of CO_2, resulting in CO_2 changing from gas phase to dense phase in the reservoir, as the reservoir temperature in Hamilton is above the critical temperature of CO_2 (31.7ºC). Dense phase CO_2 has a liquid like density and a gas like viscosity. The viscosity of CO_2 also changes with pressure. Using the Peng Robinson Equation of state in the ECLIPSE compositional simulator the density and viscosity changes with increase in reservoir pressure can be modelled correctly.

In addition to modelling the phase change behaviour of CO_2 correctly, a compositional simulator is required to model the natural gas and CO_2 gas system as there is a significant difference between the properties and phase behaviour of natural gas and CO_2. A Black Oil simulator is limited to modelling a single gas within the fluid system and is therefore not suitable for modelling CO_2 injection into a depleted gas field correctly.

The Hamilton gas properties and initial reservoir conditions were sourced from (Yaliz & Taylor, 2003).

The Hamilton gas composition is shown in Table 3-25 below.

Components	CO_2	C_1	C_2	C_3	C_4	C_5	N_2
Mole fraction	0.004	0.832	0.05	0.015	0.011	0.005	0.083

Table 3-25 Hamilton gas composition

H_2S concentration is relatively high in Hamilton with reported concentrations of 1100ppm.

The initial reservoir pressure is 97 bara (1404 psia) at a depth of 792 m TVDSS (2600 ft TVDSS) and the temperature is 31.7ºC (89ºF). This was used as input to the PVT model.

The component library in Petrel was used for the component properties. Petrel uses the original PVTi library, but with molecular weight, density, boiling points, critical properties and acentric factors taken from additional sources (Katz & Firoozabadi, 1978) (Ksler & Lee, 1976).

The pressure - temperature plot for the Hamilton gas field is shown in Figure 3-45 below.

The black vertical line in Figure 3-45 represents the Hamilton field reservoir temperature. This line is to the right of the dew point line indicating that the reservoir behaves as a dry gas.

A salinity value of 300,000 ppm was used. The salinity of water is used to tune the CO_2 solubility in water. The density of water was also modified to account for dissolved salts.

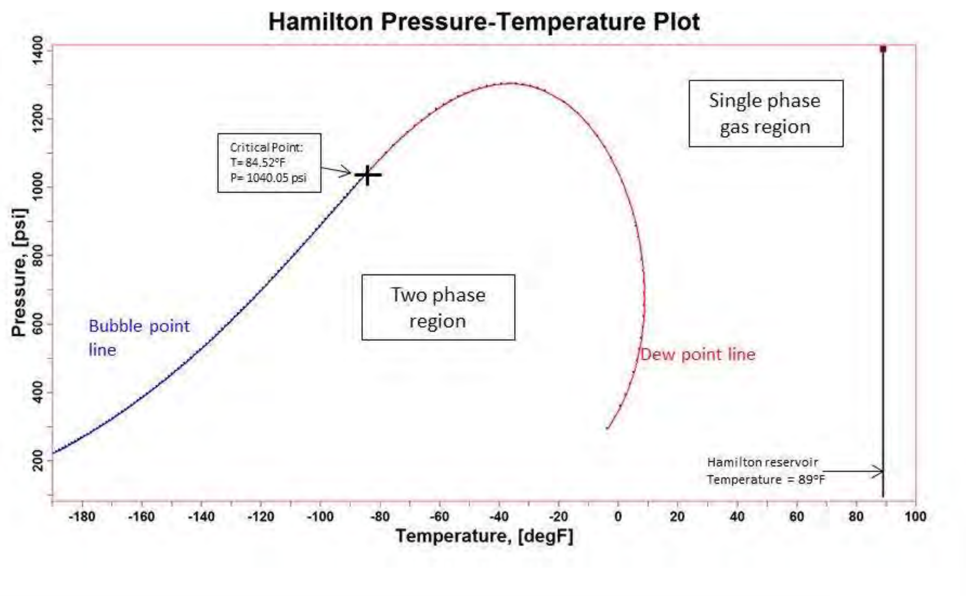


Figure 3-45 Hamilton pressure-temperature plot for Initial natural gas

Relative Permeability

In compositional simulation three phase relative permeability curves are used. The phases are oil, gas and water. The ECLIPSE compositional simulator solves for molar concentration and then uses the calculated critical temperature to label the phase as oil or gas. Oil and gas phases then use the respective relative permeability curves. ECLIPSE calculates an average critical temperature of the fluid. When this critical temperature is above the cell temperature it labels a single phase hydrocarbon as oil otherwise it is labelled gas. The pressure is not accounted for within the phase labelling of a single phase cell, only the temperature.

Software limitations dictate that CO_2 storage in a gas field can only be modelled in an isothermal mode, and as pressure is not accounted for in the phase labelling, CO_2 is labelled as either a gas or oil throughout the simulation run. The CO_2 phase change in the reservoir is modelled correctly but the dense phase CO_2 is labelled as gas. Therefore, in the Hamilton CO_2 storage model, both methane and CO_2 (gas and dense phase) use the gas relative permeability curve i.e. methane, gas phase CO_2 and dense phase CO_2 have the same mobility. The relative movement of CO_2 and hydrocarbon gas is dominated by density and viscosity differences.

The production history from Hamilton was modelled as part of the model calibration process. To date, no aquifer water production has been observed from the field and it is therefore unlikely that there has been any significant movement in the GWC. The production history indicates that water is relatively immobile in the Hamilton field. The modelling results also indicate that very little CO_2 dissolves into the aquifer. As the interaction between CO_2 and water is expected to have very little impact on the CO_2 injection performance in Hamilton, the relative permeability input curves are expected to have little impact on the results. A sensitivity was carried out as part of this study and the results confirm that the relative permeability inputs are not key controlling parameters.

Significant uncertainty exists in the relative permeability functions for CO_2 injection (Mathias, Gluyas, Gonzalez, Bryant, & Wilson, 2013). 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 (Yaliz & Taylor, 2003) a reasonable analogue for the Hamilton field, in terms of rock quality, 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, from the same analogue, is 0.29.

The functions were generated using Corey functions. The reference case drainage and imbibition curves are illustrated in Figure 3-46 and the input assumptions are detailed in Table 3.2.

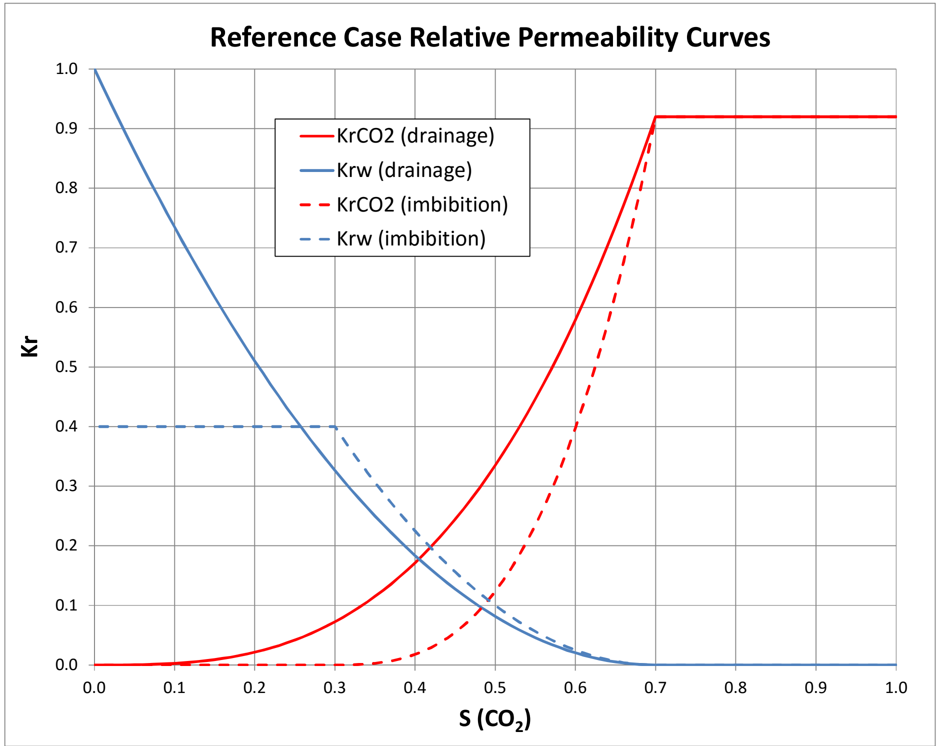


Figure 3-46 Reference case CO_2 - Water relative permeability functions

Relative Permeability Input	Drainage	Imbibition
Ng	3	3
Nw	2	2
Krw @ SGWCR	1.000	0.400
Krg @ SWCR	0.920	0.920
SWL	0.300	0.300
SWCR	0.300	0.300
SGWCR	0.000	0.290
SWU	1.000	0.710

Table 3-26 Corey exponents and end point inputs for the relative permeability curves

Pressure Constraint

The Hamilton field is a depleted gas field that has been on production since 1997. The field is unlikely to have any significant pressure support and current pressures are estimated to be approximately 10 bar. For this study it has been assumed that CO_2 injection will commence in 2026. As CO_2 is injected into the reservoir the reservoir pressure will increase. As discussed in section 3.6.5, it is important that the reservoir pressure is maintained below the fracture pressure to avoid uncontrolled fracturing of the formation rock which could potentially lead to an escape of CO_2 through the caprock. There is significant uncertainty in estimating the fracture pressure in the Hamilton field. The initial fracture pressure gradient decreases under pressure depletion and then increases when the reservoir is re-pressurised under CO_2 injection. It is likely that the fracture pressure gradient will return to the original value at the same rate that it decreased during the depletion phase but it is possible that this might not be the case. Hysteresis might occur resulting in a lower fracture pressure gradient than that experienced during depletion. In the worst case scenario, the fracture pressure gradient could remain at the lowest value seen during the depletion phase. This is considered to be an unlikely scenario but it has been evaluated as part of the sensitivity analysis.

A conservative approach has been adopted for the dynamic modelling. To avoid any chance of fracturing the reservoir the maximum pressure is limited to 90% of the fracture pressure. The model is set up so that if the pressure in any cell in the model reaches the pressure limit, injection will be stopped. At the start of CO_2 injection, into the depleted reservoir, the fracture pressure is estimated to be 0.083bar/m (0.368psi/ft). The most likely case is that the fracture pressure gradient will return to the initial fracture pressure gradient (pre-production) of 0.162bar/m (0.718psi/ft). The increase in fracture pressure gradient with increasing pressure is compared to the model pore pressure gradient prediction, per well and per region, for the reference case in Figure 3-47 below.

The final reservoir pressure is 101.5bar at a depth of 694m TVDSS. The fracture pressure at this depth is 112.8bar.

In all sensitivities it was found that the pressure limit is first met along the East –West trending fault. The location of the grid cell where the pressure limit is first met in the reference case model is shown in Figure 3-48 below

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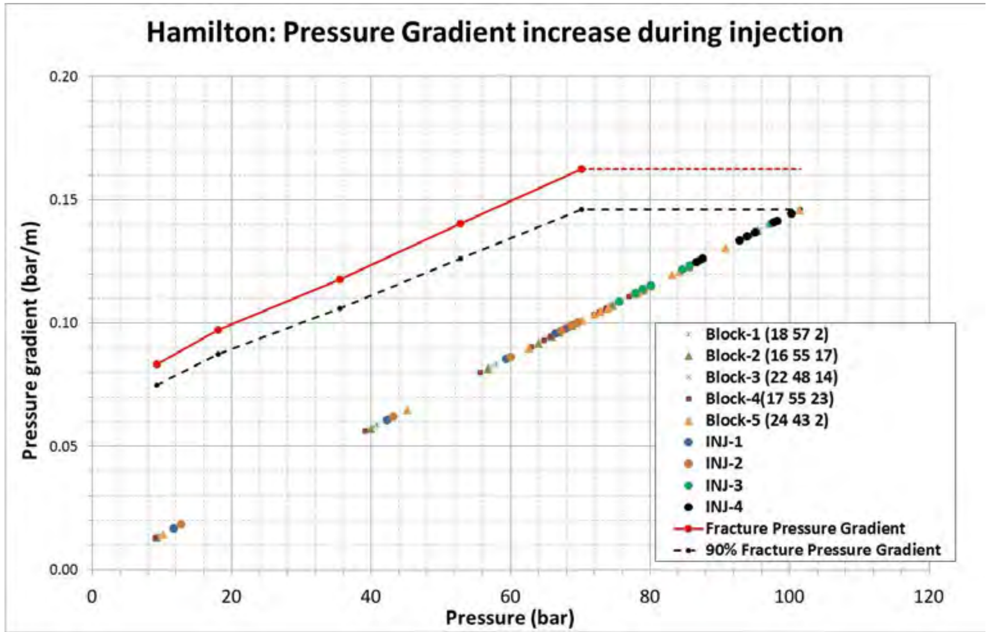

Figure 3-47 Pressure gradient increase during CO_2 injecton

Figure 3-48 Location where pressure limit is first violated in reference case model

Well Modelling

The target CO_2 injection rate for Hamilton is 5Mt/y. Due to the low initial reservoir pressure, CO_2 will initially be injected as a gas. As such, the initial injector wells require a large completion bore to reduce friction losses and maintain CO_2 in the gas phase. 7" and 9 ⅝" tubing sizes were evaluated for gas phase injection. To achieve the required injectivity two 9 ⅝" wells are required, each with a potential injectivity of 3.5Mt/y. In this case the THT is heated to 30ºC and the maximum THP for gas phase injection is estimated to be 63 bara.

As the reservoir pressure rises, gas phase CO_2 injection cannot be continued and the field will switch to liquid phase disposal. New 5 ½" wells will be used at this stage in the storage project to accommodate the change in injection fluid phase. Two wells are required, each with an injection potential of 2.5Mt/y.

The well performance modelling is discussed in detail in section 3.6.3 and the THP limits are incorporated into the VLP curves used in the dynamic model.

3.6.6.2 Model Calibration

The Hamilton field has been on production since 1997 and is being depleted by four development wells. Production data, on a field level, is available from DECC. At February 2015 the produced volume from the field was reported to be 640 Bscf. Small volumes of produced water are reported however the gas water ratio is small indicating that the water is likely to be condensed water as opposed to aquifer influx.

Reservoir Pressure

For this study it has been assumed that there is good pressure communication vertically and laterally within the Hamilton field and although there will be small pressure differences from well to well, pressure depletion is effectively uniform throughout the field. Post production RFT data indicates uniform pressure depletion across the reservoir zones and it has been reported that all faults within the field have sand to sand contact and do not provide barriers to gas flow, which is supported by pressure data from the development wells (Yaliz & Taylor, 2003).

It has been assumed that there is limited pressure support to the field resulting in the current reservoir pressure being very low and, with no pressure recharging after the field is shut-in, the reservoir pressure will be low at the start of CO_2 injection in 2026. No aquifer influx has been observed from the field production data during 18 years of production which could indicate limited pressure support from the aquifer. In addition, the neighbouring Douglas oilfield has been interpreted by the operator as having a low energy aquifer, with water injection required to assist development (Yaliz & Taylor, 2003).

Very limited pressure data from the production phase of Hamilton was available to this project, therefore a material balance (P/Z) calculation was carried out to estimate the current reservoir pressure. Post production pressure data are available for August 1998, 18 months after production started. Based on this data point the GIIP is estimated to be 640Bscf. Cumulative production from the field is 640Bscf indicating that this estimate is too low. Two alternative P/Z trends were generated representing GIIP volumes of 707Bscf and 800Bscf. These correspond to a 90% and 80% recovery factor respectively. The 707Bscf case matches the GIIP in the model used for this study and is considered to be the best estimate based on the data available for this study. Although a GIIP of 800Bscf is possible it is considered to be unlikely as the modifications to the static model required to increase the GIIP to 800Bscf become more unrealistic. Further work, using more comprehensive pressure and production data is required to evaluate the uncertainty in the GIIP estimate and to ascertain whether some of this uncertainty is due to the possible presence of a residual gas leg.

The estimated range of current pressure in Hamilton, from the P/Z analysis, is 10.2 bara (148psia) to 21 bara (300psia), corresponding to a GIIP of 707Bscf and 800Bscf respectively. The most likely case is the lower pressure, 10.2bara at a depth of 694m TVDSS, which corresponds to a GIIP estimate of 707Bscf. The P/Z plot is shown in Figure 3-49 below.

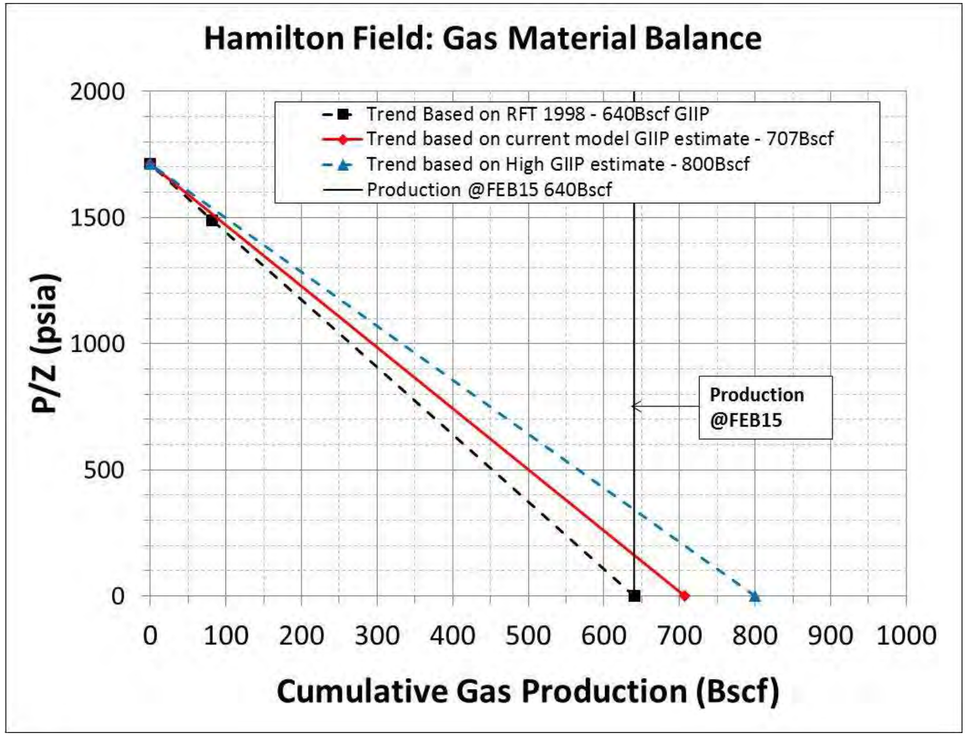

Figure 3-49 Gas material balance analysis: P/Z Plot

Model History Match at the end of Gas Production Phase

The four development wells were included in the dynamic model and the model was run on gas rate control, targeting the field production history rate reported by DECC. There were no productivity issues with the model. The pressure match was achieved with the modelled aquifer volume of 8147MMbbls. The gas rate match and the reservoir pressure prediction for the calibrated model are shown in Figures 3.6 and 3.7 below.

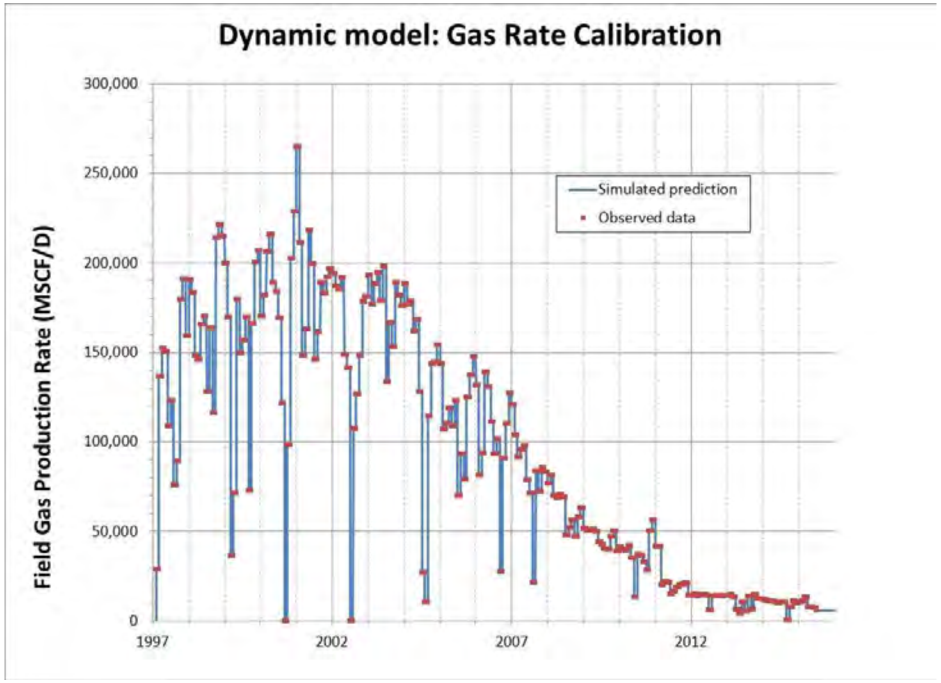

Figure 3-50 Hamilton gas field model calibration: gas rate

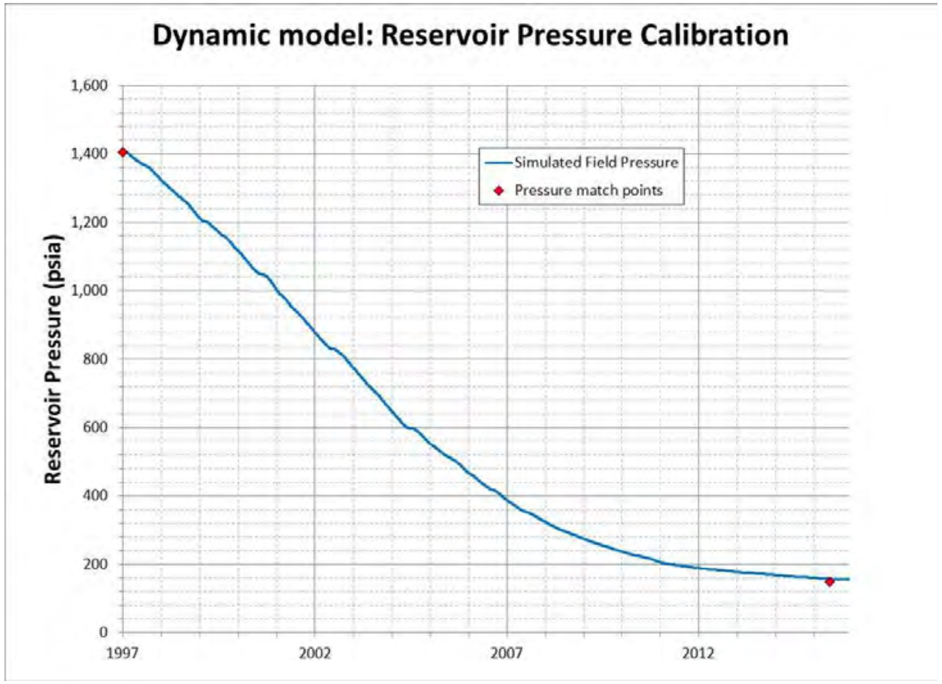

Figure 3-51 Hamilton gas field model calibration: reservoir pressure

The dynamic model was used to forecast the production to the end of 2017 when the field is estimated to cease production (COP). The model was then run until 2026, with the field shut-in, and the predicted pressure, fluid saturations and vapour and liquid mole fractions at this time were used to generate the initial conditions for the CO_2 Storage simulation cases.

3.6.6.3 Modelling results

Development Strategy

The Hamilton field is a shallow depleted gas field. The reservoir pressure at the start of the CO_2 injection is estimated to be 10.2 bara (148psia) at a depth of

694m TVDSS and the reservoir temperature is 31.7°C. Due to the low reservoir pressure, CO_2 will be injected in the gas phase initially. When the reservoir pressure increases to the point where gas phase injection can no longer be sustained within the wellbore, liquid phase injection will commence. At this point reservoir pressure at the liquid phase injector location will still be below the CO_2 critical point and there will be a gas column of approximately 466ft (as was the case prior to production).

To avoid phase change in the wellbore, reservoir injectivity will be mechanically reduced in order to achieve a suitable back pressure. This has been modelled using a PI modification in the dynamic model. This will ensure that the phase change occurs in the reservoir, away from the wellbore. The PI modifier around the wells was removed when the reservoir pressure was high enough to avoid phase change in the wellbore.

The injection rate target for Hamilton is 5Mt/y for 25 years. The proposed development case requires two 9 5/8" injection wells for gas phase injection and two 51/2" injection wells for liquid phase injection. Gas phase injection will continue for 13.6 years which will be followed by liquid phase injection of 11.4 years. The gas injection wells will be used during the transition period, prior to switching injection to the new wells, as there is a risk of permanent reservoir damage and the loss of these wells. The drilling and intervention requirements to ensure a continuous injection capability is detailed in section 5.3.

Well Placement

Several sensitivities were run to evaluate alternative injection well locations within the field. The initial evaluation was done for the gas phase injection period. Although the Hamilton field is relatively complex, with internal faulting and heterogeneous layering, under gas production it behaves like a well-connected system. CO_2 will be injected into the depleted gas leg and, to optimise injection performance and storage capacity, injection points should be high in the structure as CO_2 is denser than hydrocarbon gas and will therefore move downwards under gravity.

The well locations that were evaluated are shown in Figure 3-52.

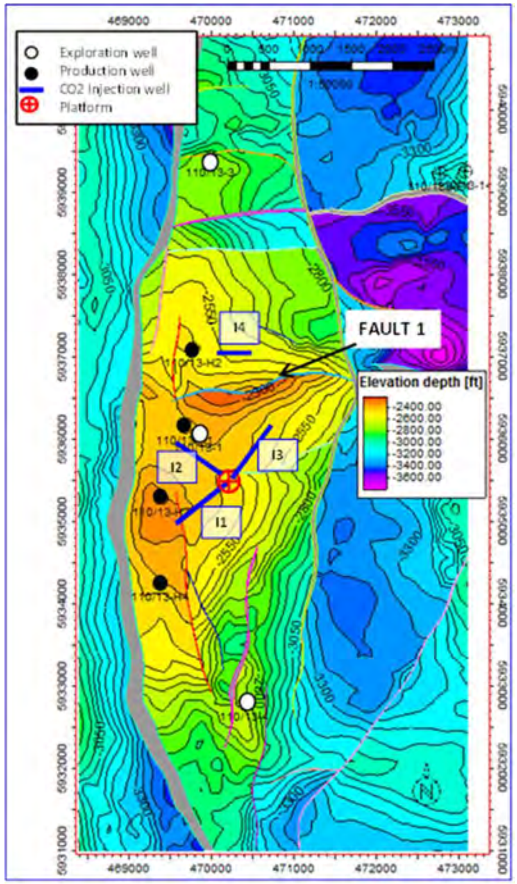

Figure 3-52 Hamilton field well locations

The optimum well locations are in the shallow areas of the field, close to the production well locations where there is more well control. The performance of the four locations shown in Figure 3-52 was evaluated. Locations 1 and 2 are close to the development well locations. The northern area is connected along the Western edge of Fault 1 but the offset increases to the East and disconnects the reservoir. The injectivity at locations 3 and 4 was tested as these locations could improve the storage efficiency if these areas are less well connected than modelled.

The results for the gas phase injection period, which are indicative of the behaviour under liquid phase injection, indicate that all well locations behave similarly. The mass injection rates are compared in Figure 3-53.

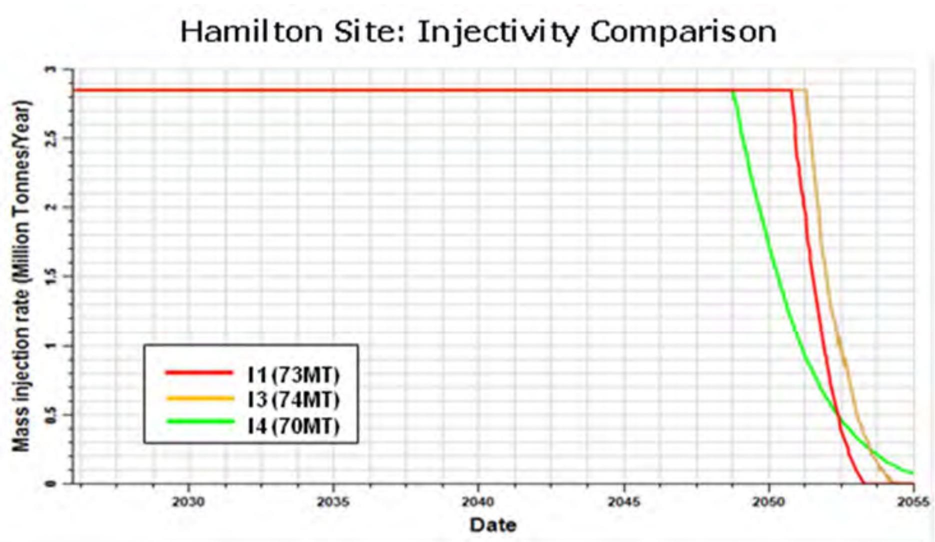

Figure 3-53 Comparison of alternative well locations

For all injection locations the CO_2 plume migration is also similar. CO_2 is injected into all reservoir layers and under injection the CO_2 migration is dominated by gravity. The lateral migration is dependent on the vertical transmissibility i.e. the CO_2 moves along the top of non-permeable layers. However, if the CO_2 can move downwards it will. The reservoir fills from the bottom and the depleted gas region (gas reservoir) is filled to the same extent in all cases, with the injected volume ranging from 70MT to 74MT per well (gas phase only). The change in CO_2 concentration over time is illustrated in Figure 3-54 to Figure 3-56.

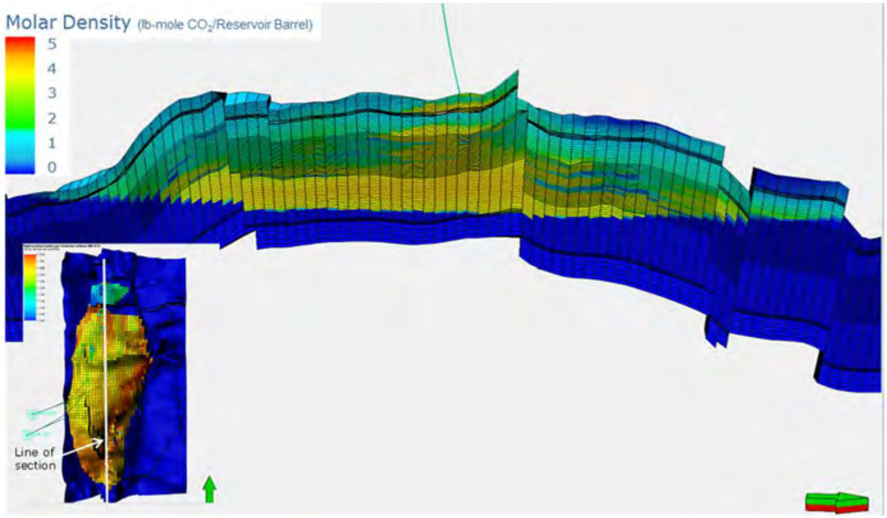

Figure 3-54 CO_2 concentration at year 2040, after 8 years of injection

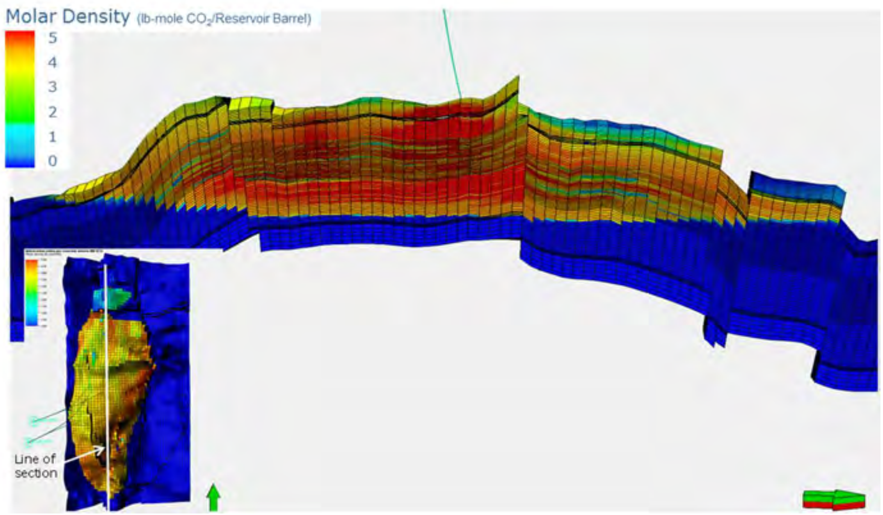

Figure 3-55 CO_2 concentration at year 2050, at end of injection

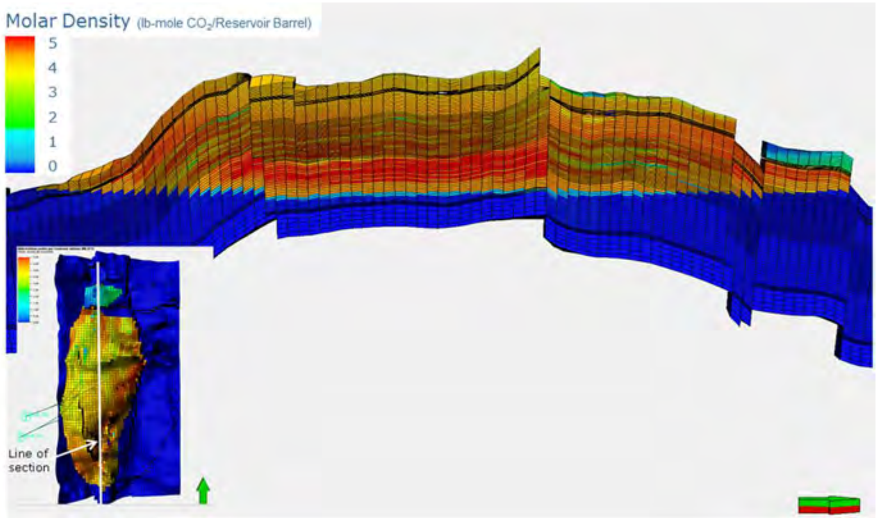

Figure 3-56 CO_2 concentration 1000 years after end of injection

Well Injectivity Potential

The Hamilton reservoir is a good quality sand system with an average permeability of 780mD. There is no record of productivity issues during gas depletion and there are not expected to be any injectivity issues associated with CO_2 injection. However, during the gas injection phase, injection rates are limited by the pressure constraint required to ensure the CO_2 remains in gas phase in the wellbore.

To achieve the required injection rate of 5Mt/y in the gas phase, two 9 ⅝" wells are required, each with a potential injectivity of 3.5Mt/y. In this case the THT is heated to 30ºC and the maximum THP for gas phase injection is calculated to be 63 bara.

As the reservoir pressure rises, the required rates of injection cannot be sustained as gas phase and liquid phase CO_2 injection will commence. New 5 ½" wells will be used at this stage in the storage project to accommodate the change in injection fluid phase. Two wells are required, each with an injection potential of 2.5Mt/y. At all times, the reservoir simulation model ensures that the weakest point in the reservoir is never exposed to pressures which exceed 90% of the fracture pressure limit.

The well performance modelling is discussed in detail in section 3.62 and the THP limits are incorporated into the VLP curves used in the dynamic model.

Sensitivity Analysis

Sensitivities were carried out to evaluate the impact of key uncertainty parameters on the capacity and injectivity of the Hamilton injection site. The following parameters were identified as the key uncertainties:

- Degree of sealing across intra reservoir faults

- Vertical connectivity
- Permeability
- Relative permeability
- Injection zone
- Fracture Pressure Gradient

The reference case inputs and the sensitivity values for each parameter are tabulated below. Note that the transmissibility calculated in eclipse is a simple consideration of cell juxtaposition with no consideration of fault plane effects and that particular sensitivity was to establish the impact of fully sealing faults.

	Reference Case	Sensitivity
GIIP (Bscf)	707	707
Connected Aquifer (MMbbls)	8517	8517
Fault Seal	Transmissibility calculated by Eclipse	All internal faults sealed
Average Permeability (mD)	781	446
Relative Permeability	$KrCO_2$=0.92	$KrCO_2$=0.8
Injection zone	All zones	Upper zone
Initial fracture pressure gradient (bar/m)	0.083	0.083
Final fracture pressure gradient (bar/m)	0.162	0.083

Table 3-27 Reference case model inputs

The results indicate that the only parameter to impact the capacity is the fracture pressure gradient. For this case the worst case scenario was tested in which the fracture pressure gradient remained at the depleted fracture pressure gradient throughout the injection period. This is considered to be unlikely but in this case the pressure limit is reached during the gas phase injection phase and the capacity is reduced from 124MT to 47MT. The change in fracture pressure gradient with increased pressure is uncertain. It is recommended that a measurement of the depleted fracture pressure gradient is made prior to the field being abandoned so that the initial fracture pressure is better defined.

The simulation model work checks every cell at every time-step for its compliance with the fracture pressure gradient limit. Only in the case that there is no re-pressurisation improvement in the fracture pressure gradient does this create an issue. However, this is considered very unlikely and so the failure risk of the halite caprock is considered to be minimal.

The results of the sensitivity analysis are shown in Figure 3-56 below and Table 3-28.

Sensitivity		Gas Period		Liquid Period		Both Periods	
	Rate	Total	Duration	Total	Duration	Capacity	Duration
	Mt/y	MT	Years	MT	Years	MT	Years
Reference	5.0	67.9	13.6	56.0	11.2	124.0	24.8
Fault Seal	5.0	67.9	13.6	50.6	10.1	118.5	23.7
Vertical Connectivity	5.0	23.6	4.7	100.2	20.1	123.8	24.8
Permeability	5.0	67.9	13.6	56.2	11.2	124.2	24.8
Relative Permeability	5.0	67.9	13.6	56.7	11.3	124.6	24.9
Injection to Upper Only	5.0	68.0	13.6	56.5	11.2	124.4	24.8
Low Frac. Pressure Gradient	5.0	47.2	9.5	0.0	0.0	47.2	9.5

Table 3-28 Sensitivtiy Analysis Results

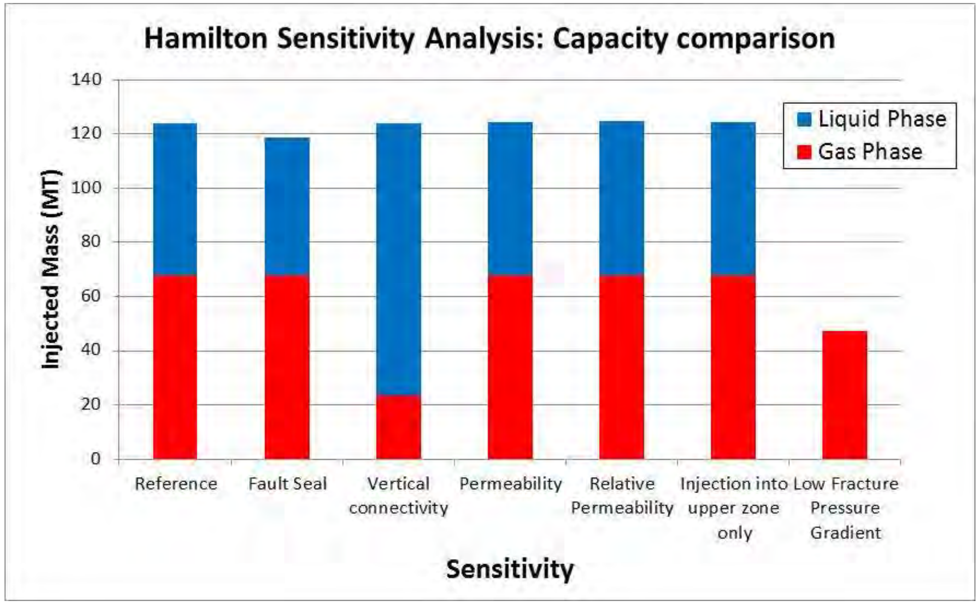

Figure 3-57 CO_2 concentration at year 2050, at end of injection

Production history indicates that there is very good vertical and lateral connectivity within the Hamilton field indicating that internal faults do not seal and that vertical flow barriers are not extensive. The fault seal and vertical connectivity sensitivities were carried out to evaluate the impact of a more poorly connected reservoir on CO_2 migration even though these cases are considered to be unlikely. Sealing the faults has little impact on the injection performance although the overall capacity is reduced from 124MT to 119MT. However, in the poorer vertical connectivity case the pressure build-up at the wells is much faster resulting in a shorter gas phase injection period but the pressure build-up away from the wells isn't significantly different. In this case, the pressure limit is reached in the same West-East fault area and the overall capacity 123.8MT compared to the reference case capacity of 124.0MT.

A sensitivity was run to evaluate the requirement for wells to extend through the entire reservoir. As the CO_2 will move downwards and there are no barriers to flow, the reservoir could be filled by injection into the upper zone only. This was shown to be the case however the additional cost of drilling the lower sections in this shallow reservoir is relatively low and injection into the full reservoir section ensures no loss of capacity in the event that barriers do disconnect parts of the reservoir.

3.6.6.4 Storage Site Development Plan

The injection rate target for Hamilton is 5Mt/y for approximately 25 years. Due to the low reservoir pressure, CO_2 will be injected in the gas phase initially. When the reservoir pressure increases to the point where gas phase injection can no longer be sustained within the wellbore, liquid phase injection will commence. Gas phase injection is predicted to last for 13.6 years in the reference case. The proposed development case requires two 9 5/8” injection wells for gas phase injection and two 51/2” injection wells for liquid phase injection. The gas injection wells require the THP to be heated to 30ºC to achieve the injectivity.

The gas and liquid injection well locations are shown in Figure 3-58.

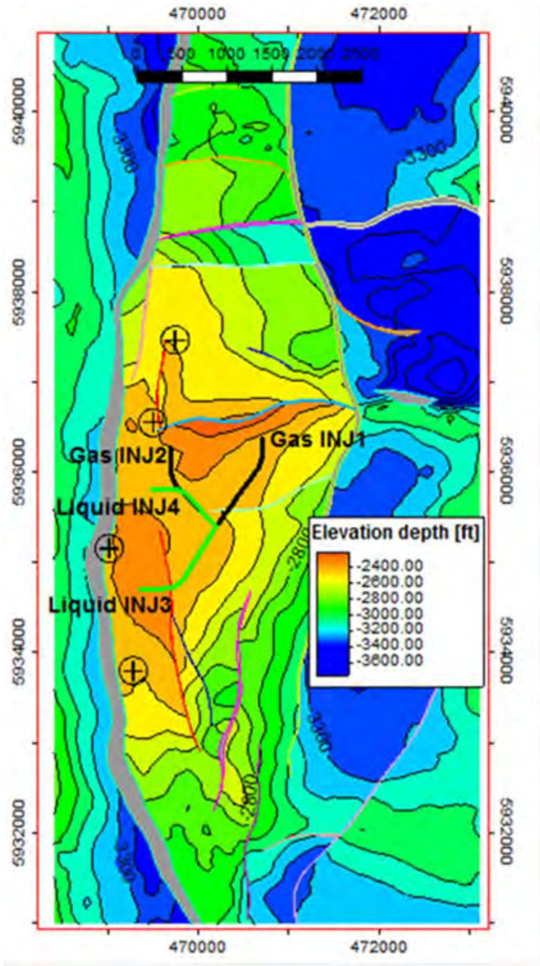

Figure 3-58 Development CO_2 injection well locations

The total injection forecast and the cumulative injected mass forecast are shown in Figure 3-59 below. The total injected mass is 124MT and is representative of the storage capacity for the site.

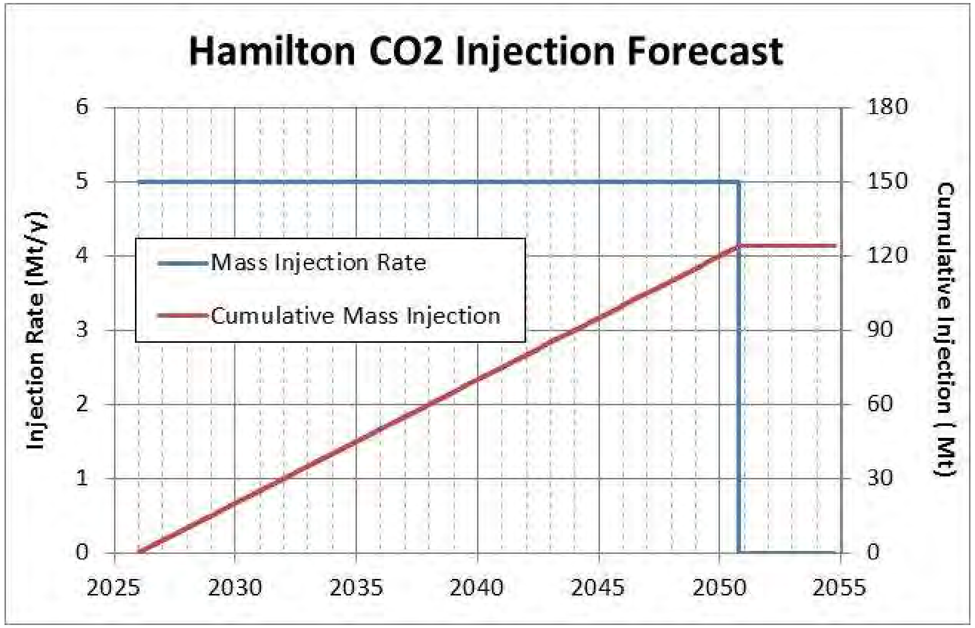

Figure 3-59 Field CO_2 injection forecast

The storage capacity is independent of the injection rate. The same injected mass volume (capacity) can be achieved by injecting at a higher rate but the injection period is shorter. Two wells are considered to be the minimum required for the development. A single back up well is also included in the development to provide operational redundancy for the times when one well is unavailable and therefore increase the likelihood of being able to provide continuous injection operations. Additional wells allow for a higher injection rate but do not increase the capacity of the store. The well number selection for the development is a balance between the cost of wells and the required duration of the injection period. For this study 5Mt/y for a 24.8 year injection period has been selected. This can be achieved with 2 wells for gas phase injection and 2 wells for liquid phase injection.

All wells inject at 2.5Mt/y during the injection period. The predicted THP for each well is shown in Figure 3-60 below.

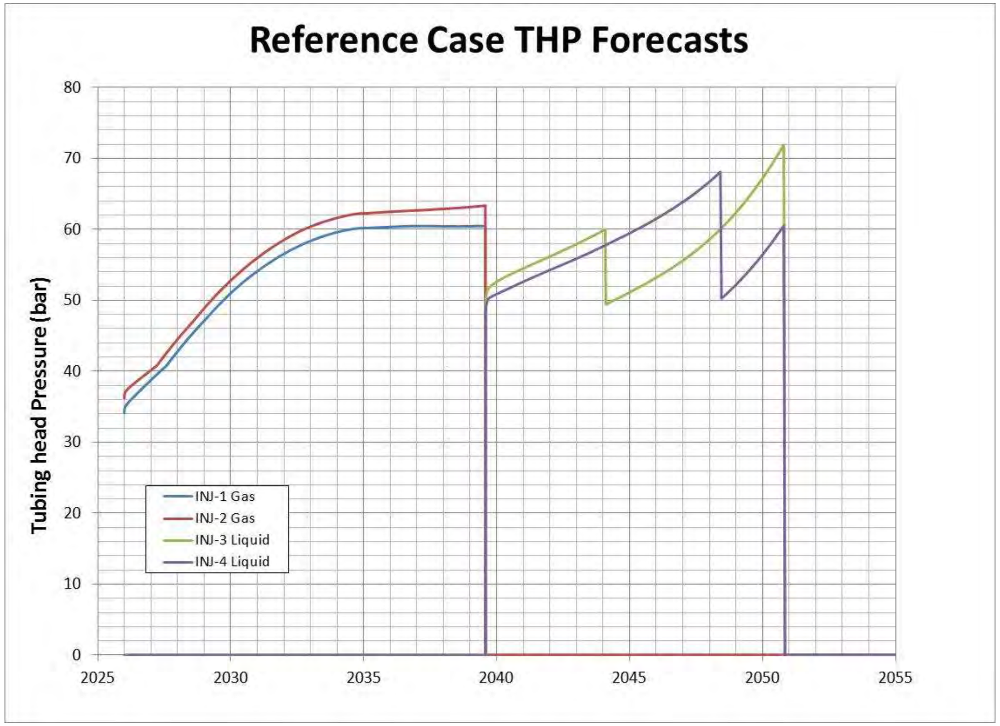

Figure 3-60 Reference case THP forecasts

3.6.6.5 CO_2 Migration

CO_2 is injected into all reservoir layers and under injection the CO_2 migration is dominated by gravity. The lateral migration is dependent on the vertical transmissibility i.e. the CO_2 moves along the top of non-permeable layers.

However, if the CO_2 can move downwards it will do so because it is denser than methane. At Hamilton, the CO_2 continues to move down until it reaches the GWC. This is in contrast to CO_2 injected at an aquifer site which would rise to the top of the reservoir because of its buoyancy. A very small proportion of the CO_2 dissolves into the aquifer (<1MT of the 124MT injected) but most of the CO_2 remains above the GWC and with continued injection the reservoir fills from the bottom up until the pressure constraint in met. In the proposed development case 124MT is injected into the store. When injection stops the CO_2 concentration equilibrates throughout the field area but does not migrate beyond the storage complex. The vertical migration is illustrated in Figure 3-54 to Figure 3-56 in the previous section. The lateral distribution at the end of the gas phase injection, at the end of liquid phase injection and after 1000 shut-in are shown in Figure 3-61.

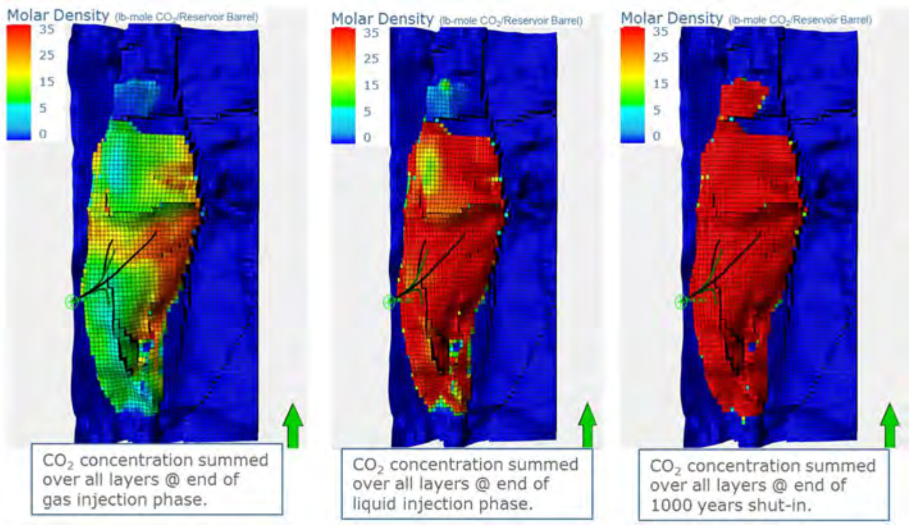

Figure 3-61 CO_2 saturation distribution during injection and after 1000 years shut in period

It has been noted that injecting CO_2 into fluvial reservoirs has proved problematic (Snohvit and In Salah). At Hamilton, the major fluvial reservoir uncertainty regarding reservoir connectivity and permeability has been fully de-risked through the extraction of 640 Bscf of gas. The remaining gas is estimated to be between 70 – 140 Bscf and it is anticipated that this will ultimately be fully miscible with the injected CO_2. During injection however, it is expected that the remaining gas will be concentrated at the top of the reservoir and protect the caprock from both thermal shock and direct CO_2 exposure. Furthermore, with no recorded water influx in the reservoir during depletion, overall gas saturations have not significantly changed. As a result, CO_2 migration is expected to be strongly controlled by pressure depletion and will effectively replace the gas produced.

3.6.6.6 Trapping Mechanism

All the CO_2 within Hamilton is structurally trapped. Less than 1Mt out of 124Mt injected dissolves into the aquifer Figure 3-62.

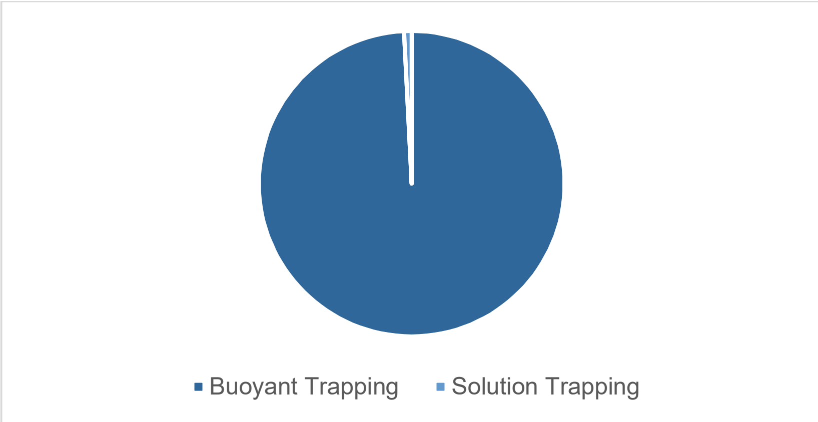

Figure 3-62 Hamilton Storage Site Trapping Mechanism

3.6.6.7 Dynamic Storage Capacity

Injection into the Hamilton site ceases when any cell in the model violates the imposed pressure constraint which is 90% of the fracture pressure. The injected mass at this time represents the storage capacity of the Hamilton site. Pressure increases relatively uniformly throughout the field during injection and the rate of pressure increase is dependent on the injected mass. The pressure reaches the limit along the West–East fault region in all cases, as shown in Figure 3-56. The capacity for the reference case is 124MT and is largely independent of the rate of injection. At a lower rate the capacity remains unchanged but the injection period is extended.

3.7 Containment Characterisation

3.7.1 Storage Complex Definition

The Hamilton Field storage complex is a subsurface volume with upper and base boundaries are the seabed and the Top Collyhurst Sandstone Formation. Due to the shallow depth of the field, and data quality, there are no interpretable seismic horizons between the top of the Sherwood Sandstone (Top Ormskirk Sst Formation) and the seabed. The Top Collyhurst Sandstone Formation is the next main seismic event below the Top Ormskirk Sst Formation.

The lateral limits of the site are defined on the west and east by the bounding faults, and to the north and south by the interpreted gas water contact (GWC). The complex boundary is defined as a slightly enlarged area which takes into account the possibility of some degree of structural uncertainty within the interpretation. This storage complex definition includes the storage reservoir and its primary caprock together with the underlying St Bees Sst Formation.

The proposed storage complex is illustrated in Figure 3-63.

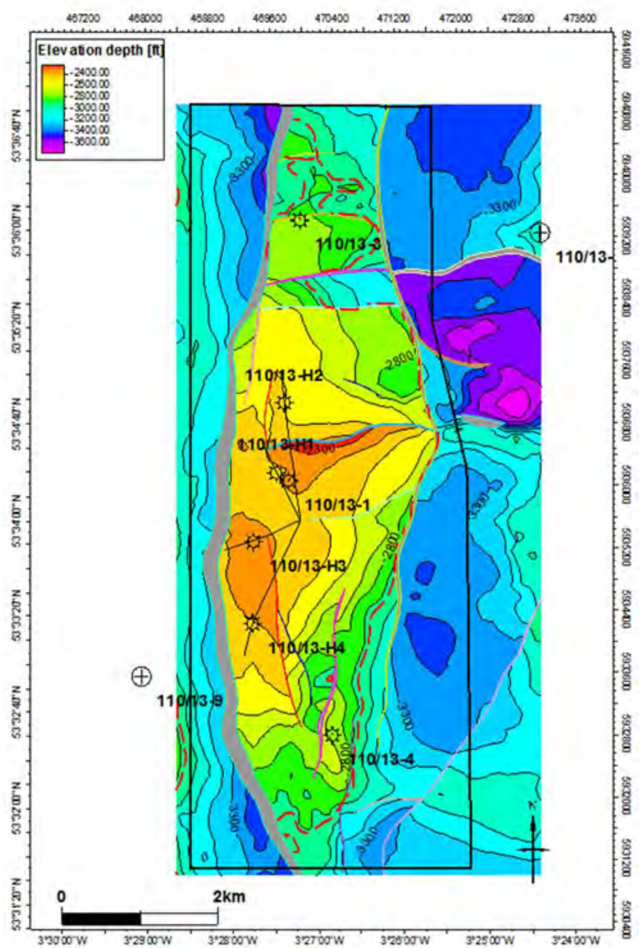

Figure 3-63 Proposed Storage Complex Boundary shown as black polygon on Top Ormskirk Sst Depth Map

3.7.2 Geological Containment Integrity Characterisation

3.7.2.1 Hydraulic Communication between Geological Units

One of the key attributes of the Ormskirk sandstone as a CO_2 storage reservoir is that it is overlain by laterally extensive mudstones and halites of the Mercia Mudstone Group which provide an excellent proven caprock.

Underlying the Ormskirk Sst Formation is a thick sequence of St Bees Sandstone Formation, within the Hamilton Field site these are mostly water filled with only a small thickness above the GWC at the crest of the structure. The top interval of the St Bees Sandstone Formation is very heterogeneous and may be an effective vertical barrier to flow. This is indicated by the lack of aquifer influx and minimal pressure support observed within the field during production.

Dynamic modelling work has shown that very little CO_2 will dissolve into the aquifer at the GWC, when injected into the depleted gas leg. The GWC therefore forms an effective barrier to CO_2 migration downwards into the aquifer.

The Ormskirk Sandstone Formation is a regionally extensive interval that can be correlated across the region, however lateral connectivity across the region is not anticipated as the structure is largely fault bounded. This is difficult to characterise at this time due to lack of publically available depletion pressure data for Hamilton and other fields in the East Irish Sea.

Most of the producing oil and gas fields in the local region (Hamilton East, Hamilton North, Douglas, Lennox, Asland, Hodder) are expected to have ceased production by the time CO_2 injection is scheduled to start at the Hamilton Field site in 2026. The small Darwen Field 10Km to the North is due to cease production in 2026. Morcambe North and South are due to cease production in 2026 and 2028 respectively.

3.7.2.2 Top Seal

The primary seal is provided by a thick sequence of mudstones and halites of the Mercia Mudstone Group. This is a proven seal in Hamilton and other hydrocarbon field in the area.

Sitting immediately above the top of the Ormskirk sandstone is approximately 60 m (195 ft) of the Ansdell Mudstone Member. Regional wells show that this can be comprised of finely laminated sandstone and mudstone, the primary seal is therefor considered to be the Rossall Halite and the Blackpool Mudstone above that.

Whilst there are no digital data available for 110/13-4 well at the southern end of the field, the composite log indicates that the Rossall Halite may be thin or absent. Top seal is however provided by a thick sequence of mudstones and other halite cycles. Both the halites and mudstones form excellent impermeable seals.

Many of the mapped faults on the field do extend into the overburden, with some extending almost to the seabed. The impermeable nature of the overburden halites and mudstones, and the proven seal (as demonstrated by the gas accumulation in the Hamilton structure) show that whilst the faults extend through the caprock, they are not leak paths and the seal is not breached.

3.7.2.3 Overburden Model

A simple overburden model was built covering the same area of interest as the site static model. As there are no reliable seismically interpretable horizons above the Top Ormskirk the halite intervals within the overburden have been mapped based on the available composite log data, and end of well reports where composite log data is absent. Table 3-29 summarises the horizons included in the overburden model. The overburden mode includes faults as interpreted during the seismic interpretation.

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 is shown in Figure 3-64.

Formation	Source
Seabed	Mapped from well data
Preesall Halite	Built up from the Cleveleys Mudstoneusing a well derived isochore.
Cleveleys Mudstone	Built up from the Mythop Halite using a well derived isochore.
Mythop Halite	Built up from the Blackpool Mudstone using a well derived isochore.
Blackpool Mudstone	Built up from the Rossall Halite using a well derived isochore.
Rossall Halite	Built up from the Andsell Mudstone using a well derived isochore.
Ansdell Mudstone	Built up from the Top Ormskirk using a well derived isochore.
OS2b Upper	Direct seismic interpretation and depth conversion.
OS2b Mid	Built down from Top Ormskirk using well derived isochore.
OS2b Lower	Built down from Top OS2b Mid using well derived isochore.
OS2a	Built down from Top OS2b Lower using well derived isochore.
OS1	Built down from Top OS2a using well derived isochore.
Bunter Shale	Built down from Top OS1 using well derived isochore.
Base of Model	Built down from Top St Bees with a constant thickness of 30m

Table 3-29 Summary of Horizons in the Overburden Model

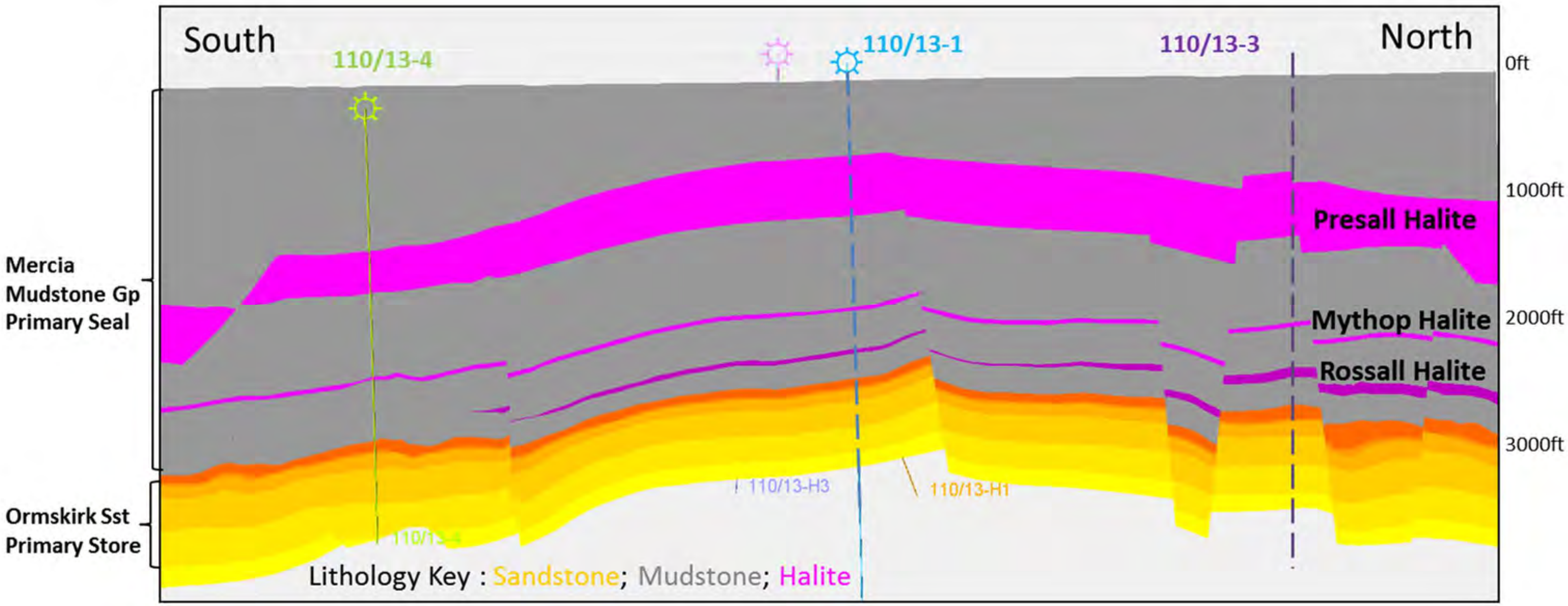

Figure 3-64 South - North Cross Section Through the Overburden Model for Hamilton Storage Site

3.7.2.4 3D Geomechanical Analysis and Results

A 3D geomechanical model was constructed to investigate the possibility of seal breach and/or fault reactivation in a sub-area of the crest of the Hamilton Field structure and the effects on the fracture gradient of depletion during gas production followed by injection. The process involves creating a small strain finite element model (i.e. the grid is not deformed) that allows elastic stress/strain relations and plastic failure effects to be investigated as a response to the actual production and proposed injection scheme(s). These reported parameters include the following:

- Displacement vectors to assess degree of overburden uplift
- Failure criteria thresholds (shear or tensile) in the Ormskirk Sandstone or overburden
- Matrix strains
- Fault reactivation strains
- Total and effective stress evolution
- Stress path analysis (elastic response to pore pressure changes)

The Hamilton Primary static model has been used as a basis for building a simplified 3D geomechanical model (Figure 3-65 and Figure 3-66). This model has the same top and base as the Primary static model within the Ormskirk Sandstone.

The various steps required to construct, initialise, run and analyse a 3D geomechanical model with specific reference to Hamilton Field are included in Appendix 6.

Two cases were run with non-linear Mohr-Coulomb material properties (unfaulted and faulted) and one with Drucker-Prager material properties within the Ormskirk Sandstone. This was primarily to assess the impact of depletion followed by injection on the fracture gradient.

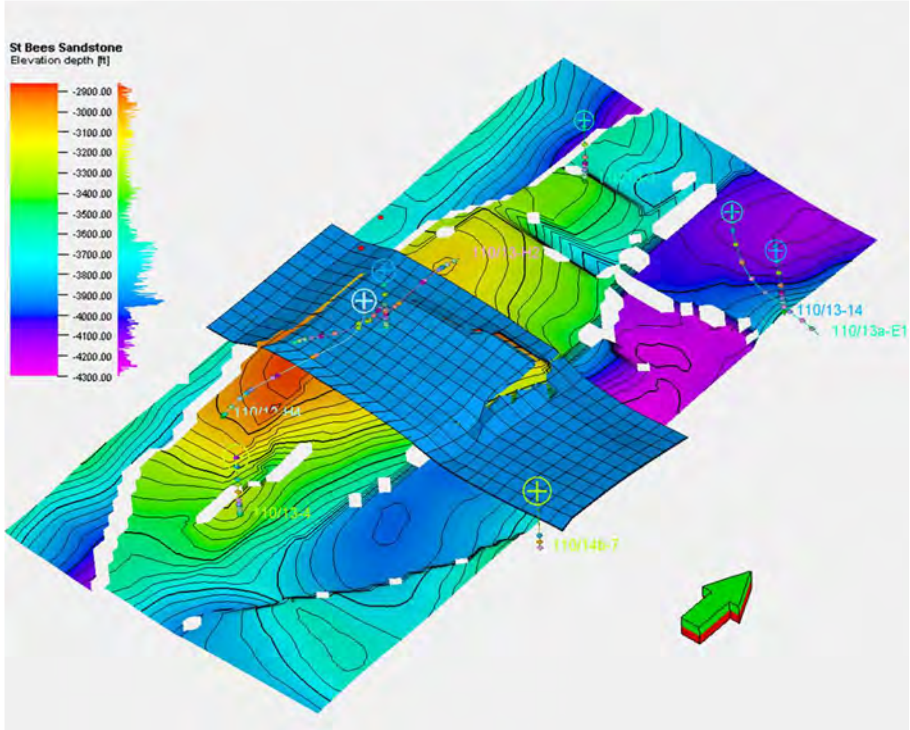

Figure 3-65 Geomechanical Sector model for Hamilton Storage SIte. (Top St. Bees Sandstone - Base of Model)

As described in the 1D analysis report, poroelastic theory predicts that the fracture gradient decreases during depletion and increases during re-pressurisation (injection). However, the exact trends these stress paths take may vary between each phase. There is also the potential for significant hysteresis such that the depleted fracture gradient only increases a little or not at all during subsequent injection (Santarelli, Havmoller, & Naumann, 2008). There are a number of factors that can lead to this effect including reservoir geometry, reservoir geomechanics property values compared to the surrounding rock, geometry and properties of faults and the temperature of the injected fluid. A full investigation of all these effects is beyond the scope of this project, but should be completed during FEED.

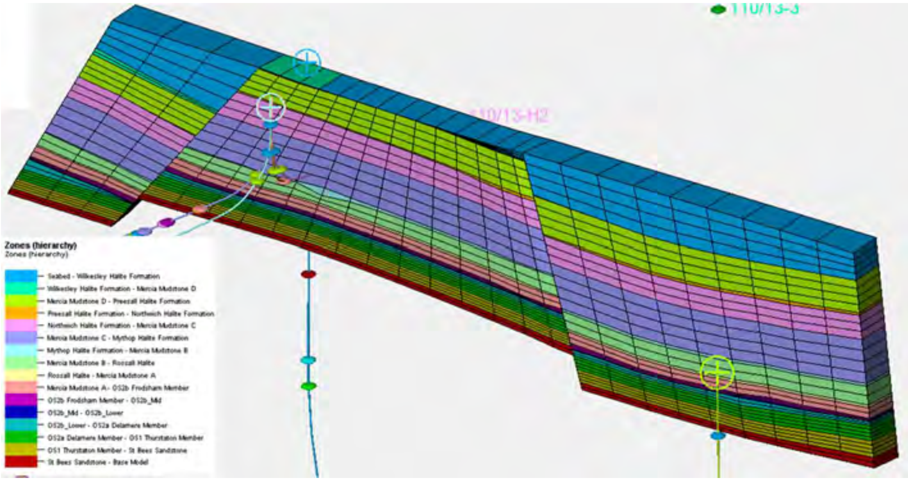

Figure 3-66 Pre-geomechnical Grid Layering Scheme

Reference Case – Modified Drucker-Prager

Drucker-Prager can be simplistically defined as a smoothed version of the Mohr-Coulomb failure function. The Drucker-Prager yield surface shape varies depending on which Mohr-Coulomb principal stress vertices it is fitted to. The modified version accounts for changes in the material responses in the tensile region (tensile cut-off) and at high confining stresses (end cap). With this material defined over the reservoir section and a few of the boundary cells, there is hysteresis in the strain and displacement such that the compressive strains attained during depletion are not fully recovered as illustrated in Figure 3-67. This is reflected in the net downward displacement of the overburden at end of injection in 2035 (Figure 3-68). Note that there is no failure of the caprock in this model as all the small amounts of strain are concentrated in the reservoir section.

Pessimistic Case – Mohr-Coulomb

Mohr-Coulomb is generally regarded as conservative in terms of failure modes and the Mohr-Coulomb failure model is therefore regarded as the pessimistic case for the reservoir response to depletion and injection. It can be seen from Figure 3-69 and Figure 3-70 that the elastic strain associated with depletion and injection is minimal (equivalent to a maximum of 0.3 mm at end depletion) but the depletion related strain and downward displacement are largely recovered during injection. There is no failure of the caprock and there is no plastic strain during depletion or injection.

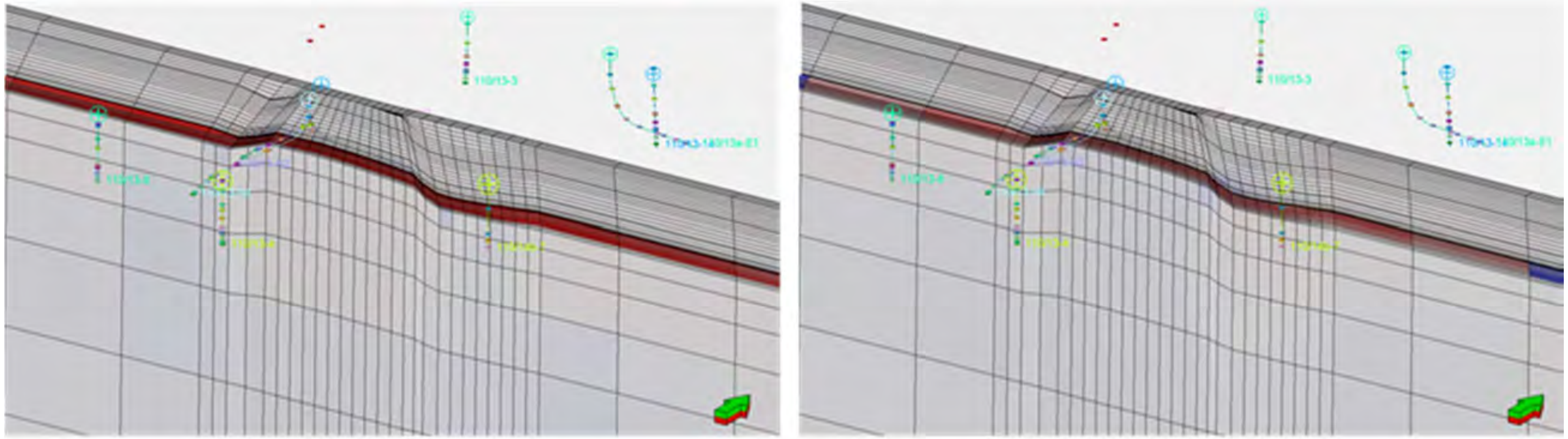

Figure 3-67 Modified Drucker-Prager vertical strain at end gas production in 2017 (left) and end CO_2 injection in 2035 (red +ve/blue -ve)

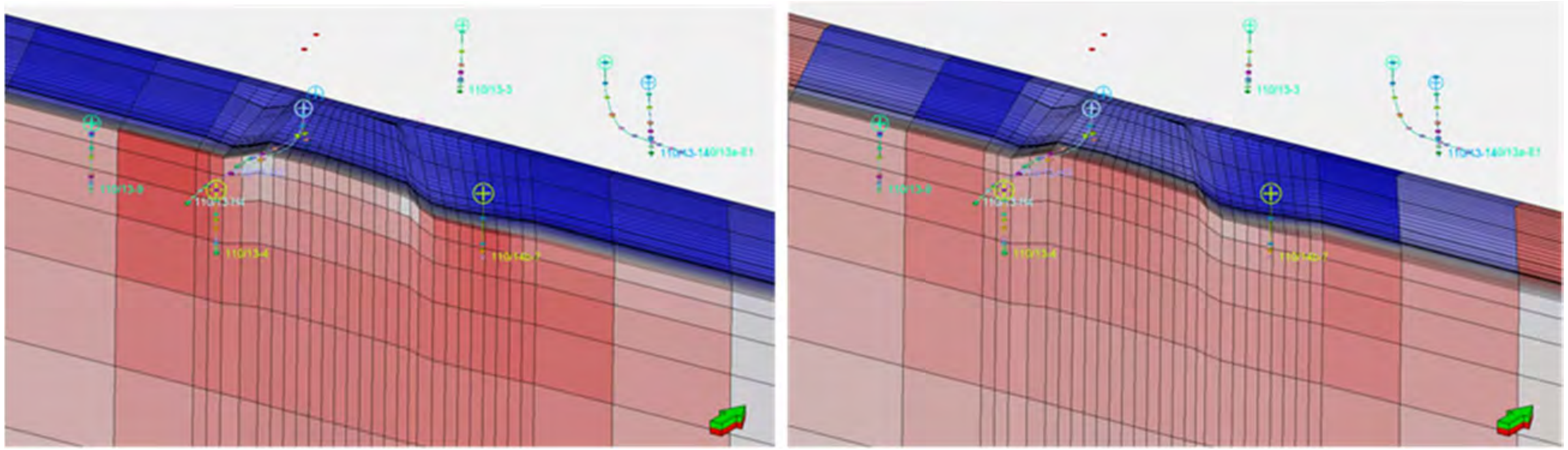

Figure 3-68 Modified Drucker-Prager vertical displacement at end gas production in 2017 (left) and end CO_2 injection in 2035. (red +ve/blue -ve)

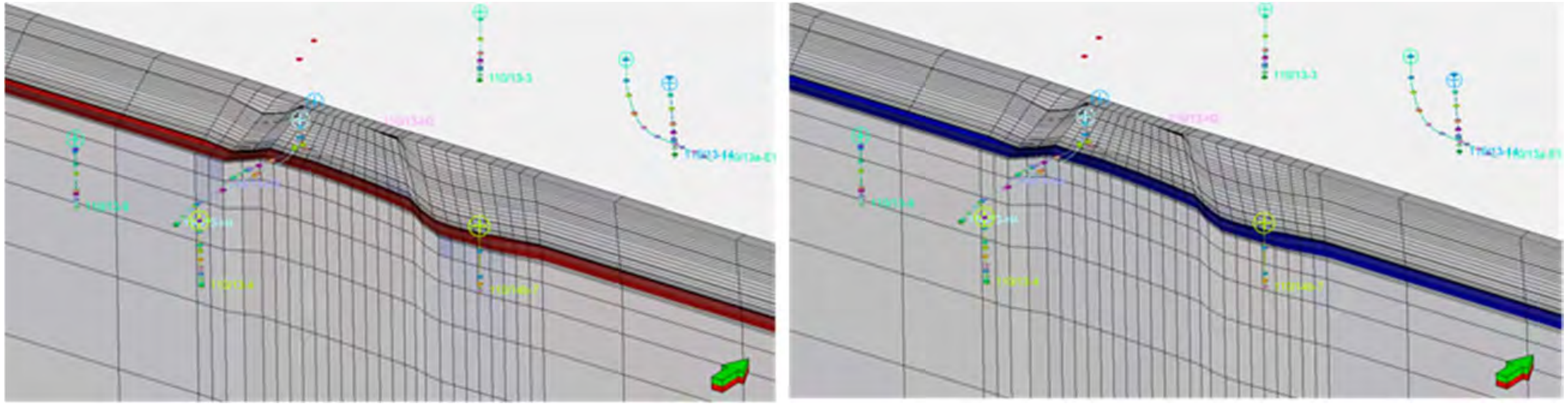

Figure 3-69 Mohr-Coulomb vertical strain at end gas production in 2017 (left) and end CO_2 injection in 2035. (red +ve/blue -ve)

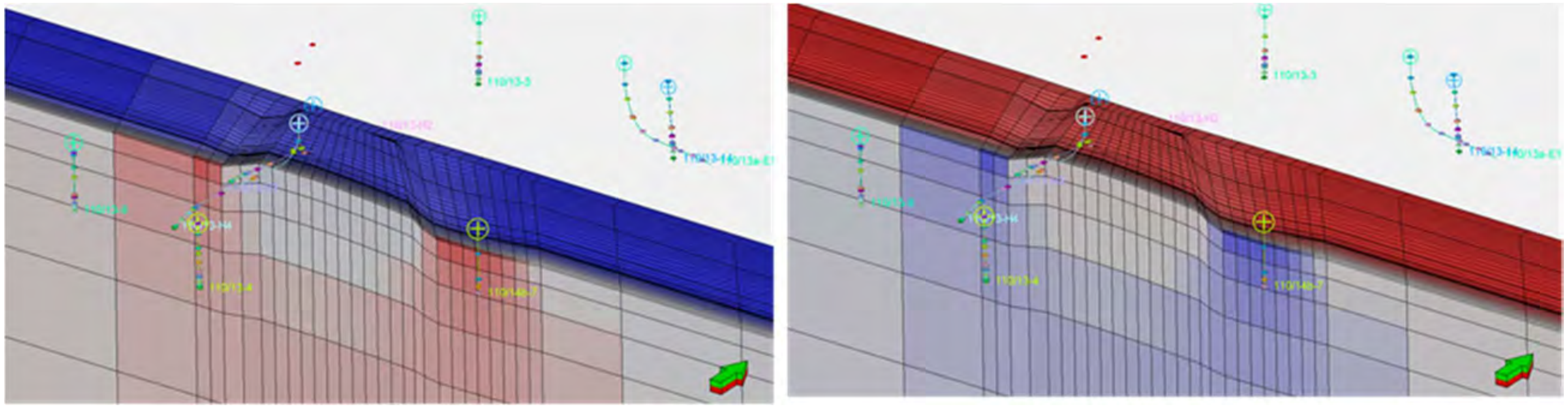

Figure 3-70 Mohr-Coulomb vertical displacement at end gas production in 2017 (left) and end CO_2 injection in 2035. (red +ve/blue -ve)

Faulted Case – Mohr Coulomb

This case was run with the addition of some faults with Reference case properties to see if this would cause significant displacement / strain changes in the Hamilton sector model. It was concluded that there are very few differences between the unfaulted and faulted Mohr-Coulomb cases in terms of strain and displacement over the reservoir section and immediate overburden. As such, there is minimal increased risk of failure in this model with the addition of faults with these properties.

Results

From the various 3D model runs it can be seen that deformation is concentrated within the Ormskirk sandstone with minimal strain seen in the caprock and immediate overburden. In the Modified Drucker Prager example there is some measurable plastic strain but the Mohr-Coulomb cases (non-faulted and faulted) show no plastic strain. This difference in the deformation response is also seen in the stress paths of the various cases. The stress path is the change in total minimum principal stress (SHmin or fracture gradient) with depletion. This is due to the poroelastic effect for reservoirs that have an approximate width vs height ratio of >= 10:1 (Zoback 2007). From Figure 3-71 it can be seen that the Mohr-Coulomb case shows a large change in the SHmin with depletion but on repressurisation, the changes are reversed. Conversely the Modified Drucker-Prager case (and an additional Modified Drucker-Prager case with a cohesion of 2000 instead of zero) show hysteresis with stress path on depletion more aligned with the 1D analysis and recovery to a higher SHmin value on repressurisation. It should be noted that these models do not account for any thermal effects so it is possible that the local fracture gradient around the wellbore will be reduced further due to cooling. In addition, (Santarelli, Havmoller, & Naumann, 2008) detail extreme stress path hysteresis (i.e. no recovery of the fracture gradient) after water injection in Norwegian sector reservoirs. This study at least partially accounted for cooling effects.

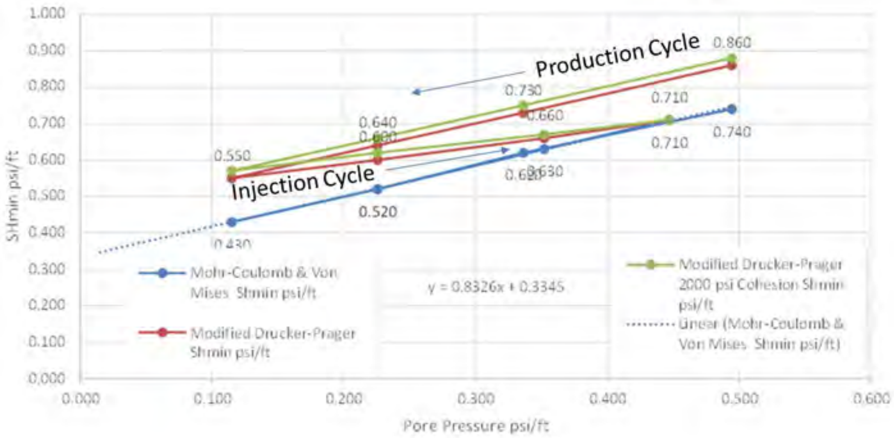

Figure 3-71 Plot of reservoir stress path (minimum principal stress) with modelled depletion and re-pressurisation.

From the various models and published information, the following conclusions are drawn.

1. Hamilton has minimal risk of caprock or fault failure for the modelled stress conditions, reservoir and overburden properties and fault properties.
2. Modified Drucker-Prager case fracture gradient reductions down to 0.55-0.57 psi/ft agree reasonably well with those derived from the 1D analysis (~0.6 psi/ft). The 1D analysis values are regarded as the most likely stress paths.

3. Mohr-Coulomb case fracture gradient reductions are modelled as low as 0.43 psi/ft at average depleted pressures of ~363 psi. If this is extrapolated to a depleted pressure of 120 psi the depleted fracture gradient is 0.37 psi/ft. This is regarded as a pessimistic case.
4. Note that a pessimistic limit case during injection of complete hysteresis (no increase in the fracture gradient during repressurisation) cannot be ruled out but is regarded as unlikely.
5. To mitigate these risks it is recommended that additional data is gathered from pilot holes prior to any significant drilling of injectors.

In conclusion the 3D geomechanical modelling indicates that with the reference case development and injection scheme there is minimal risk of caprock or fault failure.

3.7.2.5 *Geochemical Degradation Analysis and Results*

Geochemical modelling of the impact of CO_2 injection on the rock fabric and the mineral assemblage of the Mercia mudstone caprock was carried out to assess the risk of any geochemical consequences during either the active injection period, or the post-injection, long term storage period.

The approach and methodology used are described in more detail in Appendix 9 but were focussed on one key question:

- Will elevated partial pressure of CO_2 compromise the caprock by mineral reaction?

A dataset of water and gas compositional data for the Hamilton Field (from published literature as no direct measurements were available in CDA) and caprock mineralogy (again from published petrographical data) were 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. Equilibrium modelling was then undertaken to assess the impact of increasing amounts of CO_2 at the relatively cool temperature of 31°C (the gas field being rather shallow in depth) to identify which mineral reactions are likely and to assess the impact on the composition and fabric of the rock. 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.

Mineralogical Changes under Elevated CO_2 Concentration

Four Middle and Upper Triassic caprock lithologies (Types 1 to 4) were modelled using an equilibrium approach:

- **Type 1** is clay-rich, with low porosity-permeability, typically with abundant illite and chlorite, negligible gypsum and minor dolomite (Armitage et al., 2013; Jeans, 2006; Seedhouse and Racey, 1997). Type 1 has about 10% porosity and permeability as low as 10^{-8} mD.
- **Type 2** is poorer in clay but has abundant gypsum and more carbonate than type 1. Type 2 has about 10% porosity and permeability that is about as low as 10^{-6} or 10^{-7} mD.
- **Type 3** is halite-dominated with minor clay minerals, quartz, gypsum and carbonates and has low porosity and permeability (probably as low as type 1).
- **Type 4** is effectively pure halite with negligible porosity and permeability as low as 10^{-11} mD.

Type 4 (pure halite) is the most effective caprock under conditions of CO_2 injection as it is effectively non-reactive to aqueous CO_2; the equilibrium model reveals no geochemical reaction of the top seal following injection of CO_2. In general significant reactions only happen when aluminosilicate minerals (clays and feldspars) are present in the rock, as with Type 1. However, although there is a minor increase in the relative mineral volume after CO_2 injection due to the replacement of high density clay minerals (e.g. illite and chlorite) with low density minerals (e.g. dawsonite), there is only minor loss of porosity caused by the action of simply increasing the CO_2 partial pressure (fugacity) of the pore fluids. A similar result is seen in the clay-poor Type 2 caprock with the additional appearance of alunite at the expense of gypsum.

In the halite-rich with minor gypsum, calcite and dolomite caprock Type 3), a very minor porosity/permeability increase is possible as some solid volume loss of calcite dissolution is possible. If, however, any feldspar is present, the acid buffering effect of the feldspar prevents any volume loss (and hence porosity/permeability increase). This caprock type is the least dominant type observed in the overburden above the Hamilton Field reservoir and so even if dissolved CO_2 does come into contact with it, it is unlikely to have any significant impact on CO_2 containment.

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

Given the low quartz content of the caprock lithologies, it is possible that reaction rates may be controlled more by dissolution of the alumino-silicates (illite, chlorite, muscovite and K-feldspar). Putting kinetic considerations in place slows down the mineral reaction rate. Feldspar reaction slows down hugely (due to the small specific surface area), while the illite to dawsonite reaction also slows down but still occurs over the 20,000 year timeframe modelled. Note that again, these mineral changes lead to negligible porosity decrease.

Carbonate-bearing halite (e.g. caprock Type 3) is potentially reactive, if feldspar-free, and may lead to minor porosity increases, and thus permeability increases. However, as discussed above, this caprock lithology is considered to be a minor component of the immediate caprock and will not diminish the overall preservation of the low permeability of the caprock above the reservoir. No geochemical reaction is expected in the non-reactive Type 4, pure halite, caprock.

Geochemistry Results

Injection of CO_2 into the Hamilton Field reservoir 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. In addition, contact between dissolved (reactive) CO_2 and the primary seal in the crest of the structure will be limited by the predominance of structurally-trapped (and therefore geochemically 'dry') CO_2 for the initial 1000 years post-injection.

3.7.3 Engineering Containment Integrity Characterisation

Existing, legacy and new wells into the Hamilton 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 - 94	1994 - 01	2001 - 05	2005 - 09	2009 - 12	Post 2012
Issue/Rev	n/a	Issue 0	Issue 1	Issue 2	Issue 3	Issue 4

Table 3-30 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.

There have been seven wells drilled in the proposed Storage Complex. Three exploration and appraisal wells of which two have already been abandoned and four development wells on the Hamilton gas field.

Integrity Attribute	
Total Number of Wells	7
Total Number of Abandoned Wells	2
Total number abandoned before 1986	0
Total Number of at Risk Wells	7
Probability of a Well Leak in 100yrs	0.0171
Storage Area km^2	14.45
Well Density (wells/km^2)	0.48
Leakage Risk Assessment (Well Density * Leak Probability)	0.00827

Table 3-31 Hamilton Initial Engineering Containment Risk Review

As noted above, the engineering containment risk is relatively low, with only 7 wells considered at risk of leakage. The two wells that were plugged and abandoned (representing the highest risk) were abandoned in 1990 and 2012 respectively. One other well is currently suspended, with the rest remaining in production.

Unfortunately, there were no abandonment records in the CDA database, and no further engineering containment assessment is possible. In the absence of specific abandonment records for these wells, the 100yr probability of loss of containment on the site is estimated to be 0.0171, see Appendix 9 for details. Overall, given a well density factor is 0.48 wells/km2, an earlier due diligence assessment suggested a low containment risk assessment score of 0.00827.

Pre-existing, still operational, wells in the overlying Hamilton gas field will be abandoned before injection starts. The relevant authorities should require the petroleum operator to deploy the latest standards and practices to make them safe for a CO_2 storage environment, bearing in mind that the well construction itself was almost certainly not designed to be suitable for a CO_2 environment (e.g. material selection for corrosion resistance).

Previously abandoned wells 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. 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 (circa £38 million). It is unlikely that this would be attempted to remediate a perceived risk, but only in the event of a major loss of containment.

As the abandoned wells were abandoned relatively recently, and were abandoned to seal a hydrocarbon gas reservoir, it is expected that the risk of CO_2 leakage will be low. Furthermore, with CO_2 gas being denser than hydrocarbon gas (primarily methane), as it is stored in the reservoir it will sink to the bottom, displacing hydrocarbon gas to the top of the reservoir, adjacent to the well penetration points. It is therefore expected that well penetrations will suffer only modest long term exposure to CO_2.

A full review of the well's current status should be performed in the FEED stage after acquiring detailed well records from the current operator.

CO_2 injection wells which are decommissioned during the life of the storage facility, will be designed to be abandoned using the latest standards and practices. This will provide enhanced confidence in the long-term containment.

3.7.3.1 Degradation

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

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 1.8mm/yr in carbon steel for Hamilton conditions, when exposed to the flow of CO_2 / water). Under static conditions, the corrosion rate reduces significantly. A leak path (or constant flux) adjacent to the casing is therefore required to cause degradation concern. Note that, for the new injector wells, the corrosion rate for 13%Cr material is considerably lower. As the legacy wells are likely to be exposed to a flux of CO_2 during the 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. However, casing strings above the reservoir will only be affected if a leak path is initiated and there is no hydrocarbon gas 'buffer' as explained above.

3.7.3.2 Well Containment Risk Inventory

As the are no detailed reports regarding well abandonment available to this project the generic guidance on well risk loss of containment remains at a low level, as initially assumed. Given the behaviour of CO_2 in a depleted hydrocarbon gas reservoir, it is expected that the risk may be reduced yet more under further inspection.

At the end of any CO_2 Storage site development, the following well types are anticipated at the Hamilton site:

- Previously abandoned wells.
- Pre-existing wells that are operational, shut-in or suspended (to be abandoned).
- CO_2 injection wells.

- Wells drilled for CO_2 storage that are abandoned during the storage project's lifetime.

It is assumed 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. 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.

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 or failed then the well monitoring and management processes identify this and initiate appropriate remediation.

3.7.3.3 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. 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. These are outlined in Table 3-32 and displayed in a risk matrix plot in Figure 3-72.

The key containment risk perceived at the present time involved escape of CO_2 from the primary store via existing legacy wells and future injection wells leading to seabed release of CO_2. This risk can be reduced by ensuring the correct operating procedures during injection and having an effective monitoring plan in place to detect the first signs of possible CO_2 escape.

	Likelihood	Impact	Risk
Vertical movement of CO_2 from Primary store to overburden through caprock	1	2	
Vertical movement of CO_2 from Primary store to overburden via pre-existing wells	4	2	
Vertical movement of CO_2 from Primary store to overburden via injection wells	1	2	
Vertical movement of CO_2 from Primary store to overburden via both caprock & P&A wells	1	2	
Vertical movement of CO_2 from Primary store to overburden via both caprock & injection wells	2	4	
Vertical movement of CO_2 from Primary store to seabed via pre-existing wells	2	4	
Vertical movement of CO_2 from Primary store to seabed via injection wells	1	4	
Vertical movement of CO_2 from Primary store to seabed via both caprock & wells	1	4	
Vertical movement of CO_2 from Primary store to seabed via fault	2	2	
Lateral movement of CO_2 from Primary store out with storage complex w/in Ormskirk (via bounding faults as others do not apply)	2	2	
Primary store to underburden (well 110/13-1 drilled to Carboniferous - w/in Storage complex)	1	1	

Table 3-32 - Hamilton - Leakage Scenarios

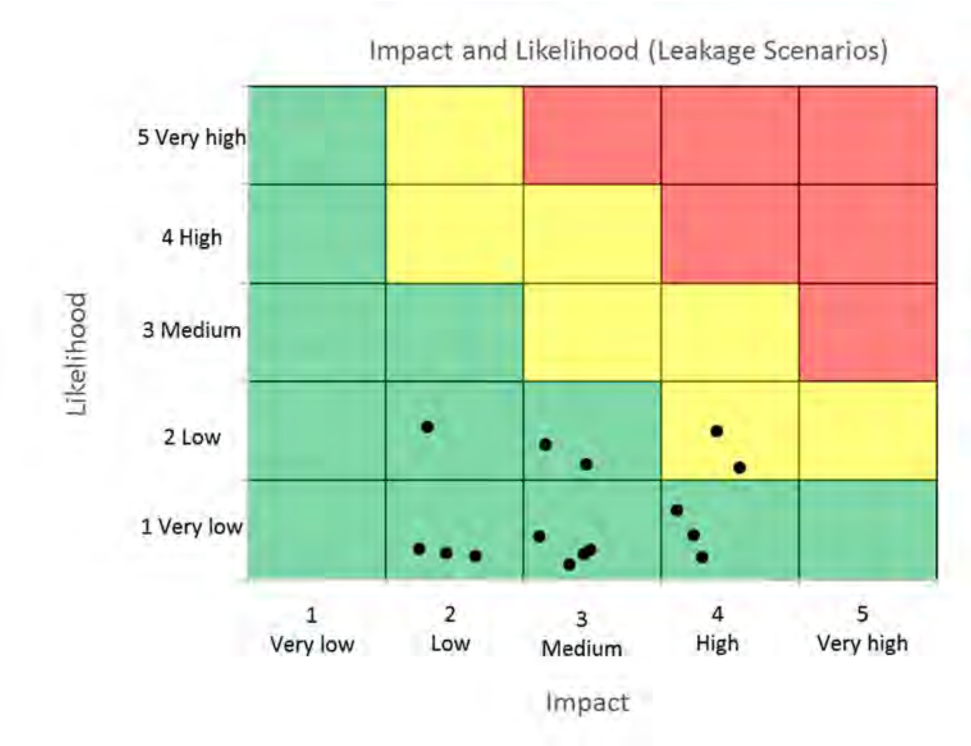

Figure 3-72 Hamilton Risk Matrix of leakage scenarios

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, 2009). 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 project 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.

3.7.5.1 *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.

3.7.5.2 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.

3.7.5.3 Monitoring Domains

Within the storage site and complex there are several monitoring domains, which have different monitoring purposes (Table 3-33).

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 3-33 Monitoring domains

3.7.5.4 Monitoring Technologies

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

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

A comprehensive list of existing technologies has been pulled together from NETL (2012) and IEAGHG (2015). This list of monitoring technologies and how they were screened is provided in Appendix 5.

3.7.5.5 Hamilton: 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.

High level screening 1D fluid substitution modelling was carried out for well 110/13-1 in the Hamilton field. The Kingdom 1D modelling package is simple but gives an indication of the detectability of CO_2 both in the storage site, where there is residual gas, and out with the storage complex (in brine-filled sand).

Modelling Inputs

The Sherwood Sandstone reservoir package from Top Ormskirk Sandstone Formation (2510ft MD) to top St Bees Sandstone (3051ft MD) was modelled. The in-situ case had bulk mineral density of 2.652g/cc, brine density of 1.1g/cc and gas density of 0.2g/cc (all from petrophysics), Vp, and density (RHOB) from well logs. Vs was calculated from Vp and Sw was taken as 0.1 from CPI.

The inputs above apply to data that were acquired pre-production, and so an initial fluid substitution was carried out to model the current reservoir pressure and temperature, or the "baseline" against which any injected CO_2 would be compared.

Different saturations of residual water, residual gas and dense phase CO_2 were then modelled.

In all cases, the CO_2 was modelled as a dense phase fluid, with a density of 0.8g/cc, which is close to the density for CO_2 at reservoir temperature of 31.7°C and final reservoir pressure of 101.5bara.

Using the same well, a 100% water-filled model was built and then a 60% CO_2/40% water saturation fluid substitution case run.

A 30Hz North Sea (reverse SEG) polarity Ricker wavelet was used to generate the synthetic seismogram for all cases.

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 density (rho) from well logs 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 3-73 shows the results with 100% brine-filled case and 60% CO_2 saturation on the seismic response.

As can be seen, a general decrease in acoustic impedance due to the presence of CO_2 is evident.

From the quick-look modelling carried out, the increase in amplitude at Top Ormskirk with 60% CO_2 and 40% brine saturation gives an indication that CO_2 may be detectable if it migrates outwith the storage site and within the storage complex. Therefore seismic should be incorporated into the monitoring plan for detection of any CO_2 movement out with the storage site. It is possible that with a more modern survey that the rising density of the injected CO_2 gas inventory might be tracked with 4D seismic although further modelling will be required during FEED to more accurately measure the density change of CO_2 in the reservoir over time (from gaseous phase in the first 14 years, to a dense phase fluid thereafter) and to understand this phase transition more fully.

Further work on the sensitivity of CO_2 detection limit (column height and saturation) should also be carried out during FEED.

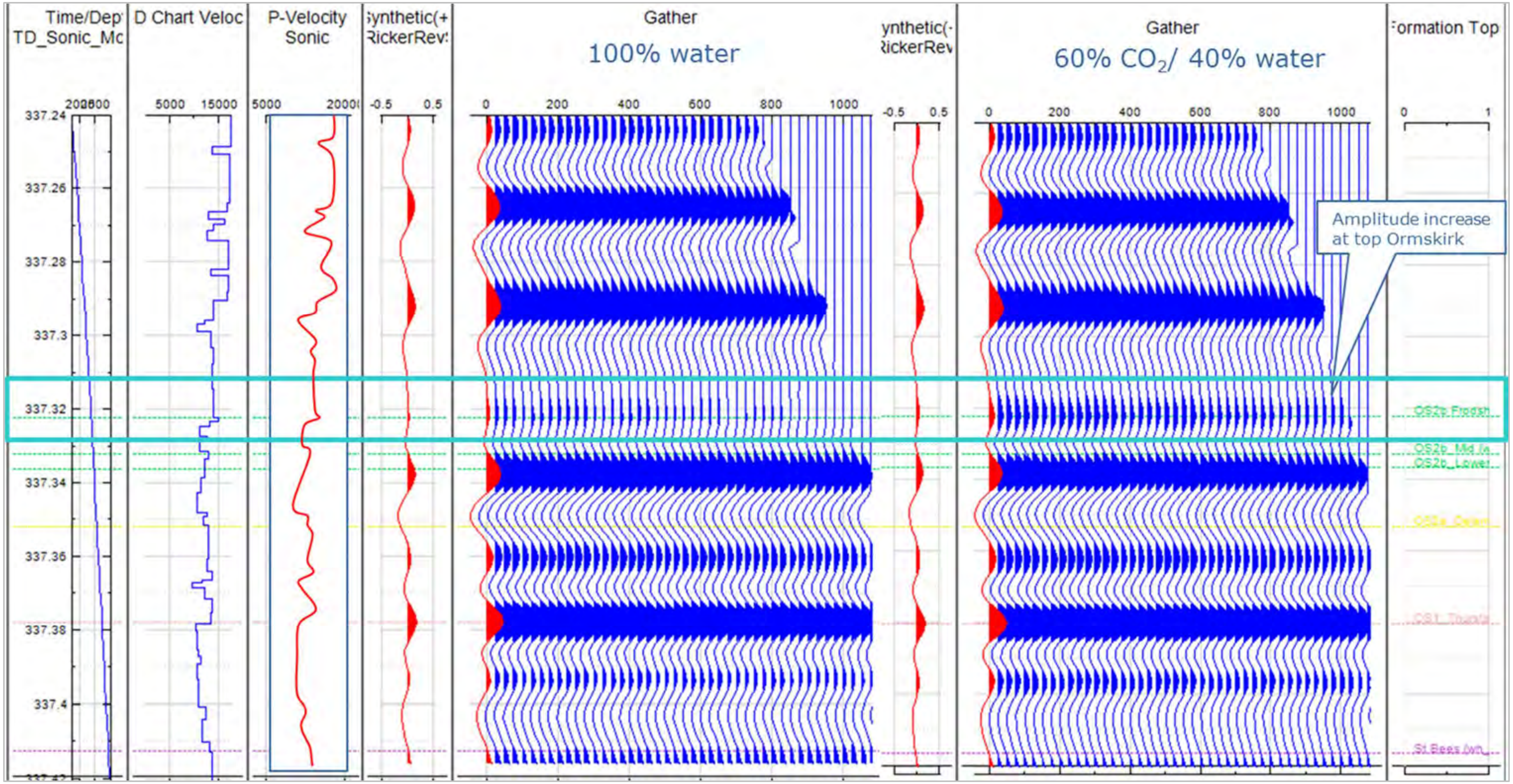

Figure 3-73 1D forward modelling: 100% brine-filled and 60% CO_2/40% water saturation

3.7.5.6 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 plan below is 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 "focussed application" (high cost, high benefit) categories.

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

Figure 3-74 Mapping between Leakage Scenarios and MMV technologies maps the selected technologies to the leakage scenarios discussed in Appendix 2.

4D seismic has been included in the monitoring plan, although additional work is required during FEED to more fully understand the seismic response of CO_2 in the reservoir, especially during the first 15 years of injection, when CO_2 is injected in gaseous phase to a storage site with residual natural gas. After 15 years, CO_2 will be injected in dense phase, and a seismic response may be detectable. This will require more detailed fluid substitution modelling across the phase transition, which should be undertaken during FEED.

From the initial modelling, CO_2 out with the storage site should be detected and therefore any movement within the broader storage complex should be detected using 4D seismic.

The costs for a regular 4D seismic survey over the Hamilton storage complex have been included. A new baseline is essential to provide a pre-injection baseline but also due to the quality of the existing data over the site. Regular surveys will be used for detection of CO_2 in thin carrier beds both above and below the reservoir.

- ● Critical
- ● Serious
- ● Moderate
- ● Minor

Leakage Scenario			Risk ranking: Likelihood	Risk ranking: Impact	Risk ranking: Ranking	Monitoring Technology: Seabed sampling, ecosystem response monitoring, geochemical analyses of water column	Monitoring Technology: Sidescan sonar survey, chirps, boomers & pingers	Monitoring Technology: 4D Seismic	Monitoring Technology: Wireline logging	Monitoring Technology: 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	2	●			X		X
	Overburden*	Vertical movement of CO2 from Primary store to overburden via pre-existing wells	4	2	●			X		
	Overburden*	Vertical movement of CO2 from Primary store to overburden via injection wells	1	2	●			X		X
	Overburden*	Vertical movement of CO2 from Primary store to overburden via both caprock & wells	1	2	●			X		X
	Seabed	Vertical movement of CO2 from Primary store to seabed via pre-existing wells	2	4	●	X	X			
	Seabed	Vertical movement of CO2 from Primary store to seabed via injection wells	2	4	●	X	X		X	X
	Seabed	Vertical movement of CO2 from Primary store to seabed via both caprock & wells	1	4	●	X	X	X	X	X
	Seabed	Vertical movement of CO2 from Primary store to seabed via fault	1	4	●	X	X			
	Lateral	Lateral movement of CO2 from Primary store out with storage complex w/in Ormskirk (via bounding faults)	2	2	●			X		
	Underburden	Vertical movement of CO2 from Primary store down to underburden via pre-existing wells (well 110/13-1 drilled to Carboniferous - w/in Storage Complex)	2	2	●			X		
	Underburden	Vertical movement of CO2 from Primary store through store floor	1	1	●			X		

Top of Storage Complex at seabed so any movement of CO2 in overburden is within Storage Complex

Figure 3-74 Mapping between Leakage Scenarios and MMV technologies

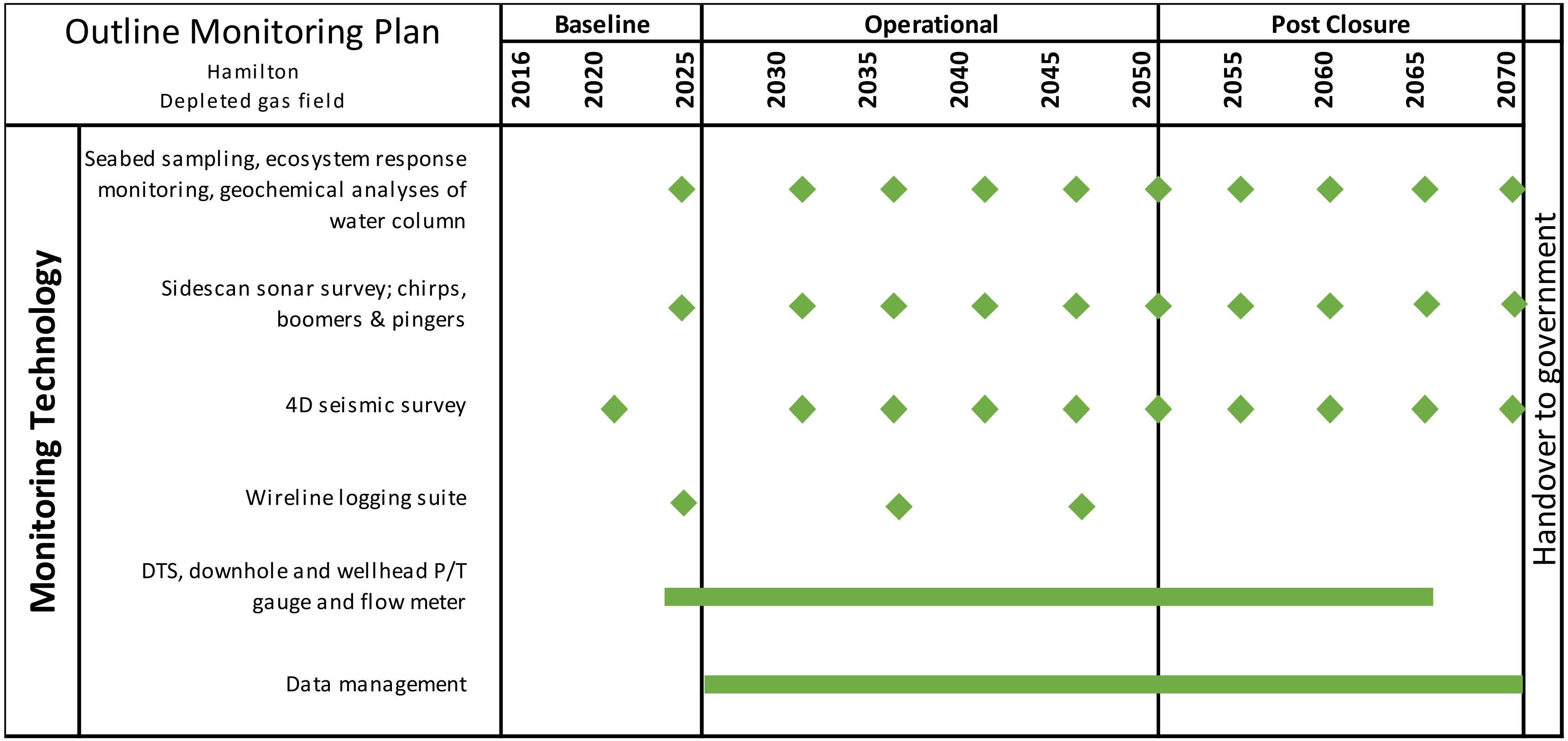

Figure 3-75 Outline Monitoring Plan

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 the storage complex.

Table 3-34 Baseline monitoring plan

Monitoring technology/ workscope	Rationale	Timing
Wireline logging suite (incl well bore integrity)	Gather data on the reservoir, overburden and wellbore integrity to ensure injection integrity and update reservoir models.	Every 10 years
4D seismic survey	Used to detect plume extent and update geological and dynamic models. Also looking for any early-warning signs of loss of containment, such as unexpected lateral or vertical migration of CO_2 within the storage complex.	Every 5 years
Sidescan sonar survey **Chirps, boomers & pingers**	Used to detect any bubble streams around abandoned wellheads, on the seabed or around pock-marks, which could indicate loss of containment to seabed.	Every 5 years
Seabed sampling, ecosystem response monitoring, geochemical analyses of water column	Used to detect any evidence of elevated CO_2 concentrations in sediment or water column which may indicate loss of containment.	Every 5 years
DTS, downhole and wellhead P/T gauge and flow meter readings	DTS for real-time monitoring of temperature along the length of the wellbore, which can indicate CO_2 leakage through tubing. Downhole pressure and temperature monitoring is required under EU Storage Directive, can be used to update models and is considered essential to ensure injection integrity. Flow meter for reporting.	Continuous
Data management	To collate, manage, interpret and report on monitoring data.	Continuous

All surveys to be carried out over the storage complex

Table 3-35 Operational monitoring plan

Monitoring technology/ workscope	Rationale	Timing
4D seismic survey (dependent on modelling results)	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 the storage complex.

Table 3-36 Post closure monitoring plan

3.7.5.7 Monitoring Well

Monitoring data can be acquired in injection wells (providing that some shut-in time is allowed for reservoir equilibrium) or in a dedicated monitoring well. Due to the cost and risk associated with well intervention, permanent data acquisition systems are recommended.

A dedicated monitoring well is a costly addition the development. However, additional injection capacity may be required during a well ‘outage’ (well shut-in for intervention, short or long term damage) in order to meet contractual obligations. It is therefore recommended that a vertical well is drilled as a monitoring well and a back-up injection well.

Surface facilities and equipment process monitoring

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.

Post-handover

After the post-closure monitoring period is complete, a handover payment will be provided to DECC to enable them to carry out post-handover monitoring, if deemed necessary.

3.7.5.9 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 3-37.

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 risk matrix in Appendix 1 contains examples of mitigation actions (controls) and potential remediation options. The leakage scenarios discussed in Appendix 2 are mapped to MMV technologies in Figure 3-75, some examples of control actions and remediation options are shown in Figure 3-76.

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 3-37 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 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.
		Vertical movement of CO_2 from Primary store to seabed via fault	Stop injection, investigate irregularity via additional monitoring at seabed, assess risk	Reduce injection rates and volumes, alter injection pattern, alternative site may be required
	Lateral	Lateral movement of CO_2 from Primary store out with storage complex w/in Ormskirk (via bounding faults)	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
	Underburden	Vertical movement of CO_2 from Primary store down to underburden via pre-existing wells (well 110/13-1 drilled to Carboniferous - w/in 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. 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)
		Vertical movement of CO_2 from Primary store through store floor	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 3-76 Outline Corrective Measures Plan

4.0 Appraisal Planning

4.1 Discussion of Key Uncertainties

Despite the fact that the Hamilton Storage site has been tested by seven deep wells, has extensive 3D seismic data coverage and has produced some 640 BCF of natural gas since 1997, some subsurface uncertainty still remains. Whilst this is normal for any subsurface project, the key uncertainties highlighted here are associated with the re-engineering of the site for permanent CO_2 storage service. Specifically, the key uncertainty captured through the sensitivity work in the dynamic modelling is linked with the definition of the fracture pressure gradient and how this changed with depletion of pressure under gas production and then how it might evolve during any re-pressurisation during CO_2 injection.

Whilst it is anticipated that the fracture pressure gradient will increase again once injection starts, the degree of change is not well understood and more assessment will be required to characterise this fully. In the worst case scenario, this might limit the injection inventory to some 47MT injected in gas phase only, although this is considered to be very unlikely.

The Hamilton storage site has an adequate existing 3D seismic data set with a good well data set from exploration and development activity. The wells were designed to investigate the same reservoir formation and so data quality is generally good. With the historical gas production data suggesting that there is very little aquifer water influx detectable, the role of relative permeability to this storage site is much more limited than with aquifers such as Bunter Closure 36 or Captain. As a result, whilst more data and samples for laboratory work are always welcome, it has been concluded that further dedicated appraisal drilling cannot be justified for the Hamilton Storage Site and is therefore not required.

It is noted that the 3D seismic data was acquired back in 1992. Since that time there have been significant technology advances in seismic acquisition and processing technology such that a much improved data set could now be acquired. It is suggested that a new 3D seismic survey is acquired such that it can be used to guide storage development well locations and also provide a modern base line data set from which quantitative 4D monitoring could be based. For clarity, it is not envisaged that this survey would be required prior to any final investment decision.

4.2 Information Value

Whilst some uncertainties remain regarding subsurface structure and reservoir and caprock properties, it is considered that these do not currently justify the expense of an additional appraisal well. Furthermore, the proposed 3D seismic acquisition is unlikely to make a material difference to the final investment decision given the significant confidence that there is already in place from the natural gas development and production history on the Hamilton field.

4.3 Proposed Appraisal Plan

Appraisal Drilling: with seven wells on the field bearing good quality log and core information, no further appraisal drilling is considered necessary at this time.

Seismic Acquisition: No further pre-FID seismic acquisition is considered necessary at this time however it is recommended that a modern 3D seismic data set is acquired before the development drilling commences.

Other Appraisal Activity: It is recommended that further modelling work be completed with reference to additional data from existing wells and analogues (Lennox, Morecambe fields etc.) to improve confidence regarding the evolution of fracture pressure during storage site re- pressurisation. As the reservoir is re-pressured with CO_2 injection, the accepted convention is that fracture pressure will increase back towards the original value. There is however, considerable uncertainty over the stress path during re-pressurisation (whether it follows back up the depletion path or whether there is a hysteresis effect) and this is considered a project risk. However, this can be de-risked by determining the true depleted fracture pressure as a starting point. It is therefore recommended that the current operators of the Hamilton field are approached, prior to field abandonment, in order to acquire fracture pressures from the current well stock (extended leak off tests for example) as a basis for a refined geomechanical model.

5.0 Development Planning

5.1 Description of Development

The Liverpool Bay Development is located within block 110/13a in the East Irish Sea and comprises four oil and gas fields, the Douglas Complex, Lennox, Hamilton and Hamilton North, together with significant offshore and onshore facilities used for extracting, transporting and processing these reserves.

The Hamilton site is located 25km from the North Wales coast and has been in production since 1997, with COP expected prior to commence of this project. The Hamilton reservoir will therefore be a depleted gas field that will have a very low reservoir pressure. It is anticipated therefore that CO_2 will be injected in gaseous and liquid phase during 2 distinct operational periods.

CO_2 arrives at the platform in liquid-phase at approximately 75 bar & 10ºC, it is then heated to ~30ºC and its' pressure reduced across the well choke to below 65 bar so that it is injected in gaseous phase into the depleted reservoir.

When the reservoir pressure has increased to 74 bar it will no longer possible to maintain single gaseous-phase in the wellbore. CO_2 will therefore need to be injected in liquid-phase to maintain single-phase flow in the wellbore. However, the CO_2 in the reservoir will still be in gaseous-phase and at this point the injection operations enter a transition period. This is assumed to commence with an injectivity impairment treatment in the near wellbore region to create an artificial back pressure. This will enable a full column of liquid-phase CO_2 to be maintained in the wellbore and allow the phase change to gas to occur in the reservoir, away from the wellbore, where the associated temperature and property changes will have a lower impact.

This period of liquid CO_2 injection continues until the reservoir pressure exceeds the critical pressure of CO_2, at which time it is possible to maintain a full column of liquid-phase CO_2 in the wellbore without the need for the artificial back pressure.

During the final period of injection, the CO_2 is in liquid phase in both the wellbore and the near reservoir (but may enter supercritical phase as the liquid CO_2 heats up away from the well). This period continues until the fracture pressure limit is reached and injection is stopped.

The current base case for the Hamilton CO_2 storage development consists of a new 26km 16" pipeline from Point of Ayr to a newly installed Normally Unmanned Installation (NUI) located at the Hamilton site. The CO_2 will be transported as a liquid and therefore continuous CO_2 heating will be required during phase 1 (and interim stage) to manage low temperature risks and ensure single phase conditions going downhole.

Due to the shallow water depth in the Liverpool Bay (<30m) the pipeline will be trenched and buried for stabilisation. The NUI will take the form of a conventional 3-legged steel jacket standing in 25m 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.

A power cable will provide electrical power to the Hamilton NUI from the Point of Ayr. 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 (chemicals, etc.), and carry out essential maintenance and inspection activities.

5.2 CO_2 Supply Profile

The assumed CO_2 supply profile for the Reference Case is for 5Mt/y to be provided from the shore terminal at the Point of Ayr, as illustrated in Figure 5-1.

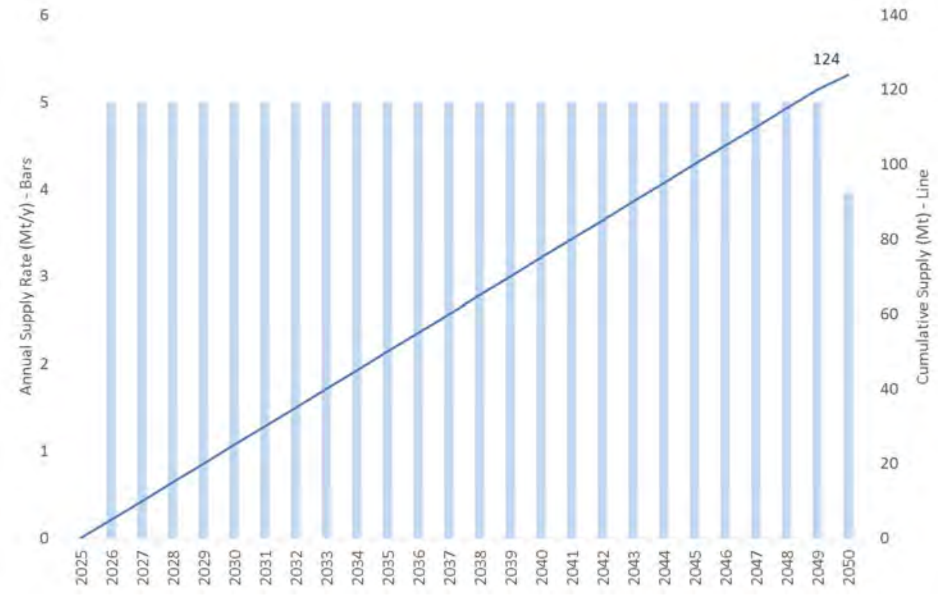

Figure 5-1 CO_2 Supply ProfileWell Development Plan

5.3 Well Development Plan

The cessation of production date for the Hamilton gas field estimated to be around 2017 (Pale Blue Dot Energy; Axis Well Technology, 2015). By this time the field will have been in production for 20 years and it is unlikely that the infrastructure will be suitable for re-use as a CO_2 facility. Well and platform placement is therefore independent of existing facilities.

The store will be supplied with dense-phase CO_2 from the shore and, due to the depleted nature of Hamilton, will have an initial gas-phase injection. During this time wellhead heating will be required to manage the Joule-Thompson effects of the transition from dense to gas phase and consequently a platform development is preferred to subsea. The subsequent dense-phase operation will require the wells to have a different configuration.

Geological and reservoir engineering work has concluded that the Hamilton reservoir is very well connected (no vertical barriers and no significant lateral barriers to the field limits) and storage capacity is relatively insensitive to well placement. Injectivity is expected to be good and only part of the reservoir section needs to be open to the wellbores to achieve the target injection rate of 5Mt/y.

Reservoir simulations indicate that for each operational period, two injection wells should provide sufficient injection capacity to meet the target CO_2 rates over field life. The injection capacity needs to be maintained at all times to meet likely contractual obligations and so a back-up well is for both periods.

Bottom-hole reservoir targets are planned to have a minimum separation distance a 1,000m in order to eliminate the superposition of temperature effects. This requires that the wells be drilled at a high angle through the reservoir to achieve enough reservoir section to provide the required injection rate. Well bore stability and drilling review work confirms that this is feasible.

Well placement does not appear to have a significant effect on injectivity or storage capacity and therefore the well location for the future CO_2 injection wells are in the vicinity of the existing gas production wells, to minimise the geological risk. The replacement wells for dense-phase operations will be located similarly. Both sets of wells are illustrated in the Top Ormskirk Sandstone map provided as Figure 5-2.

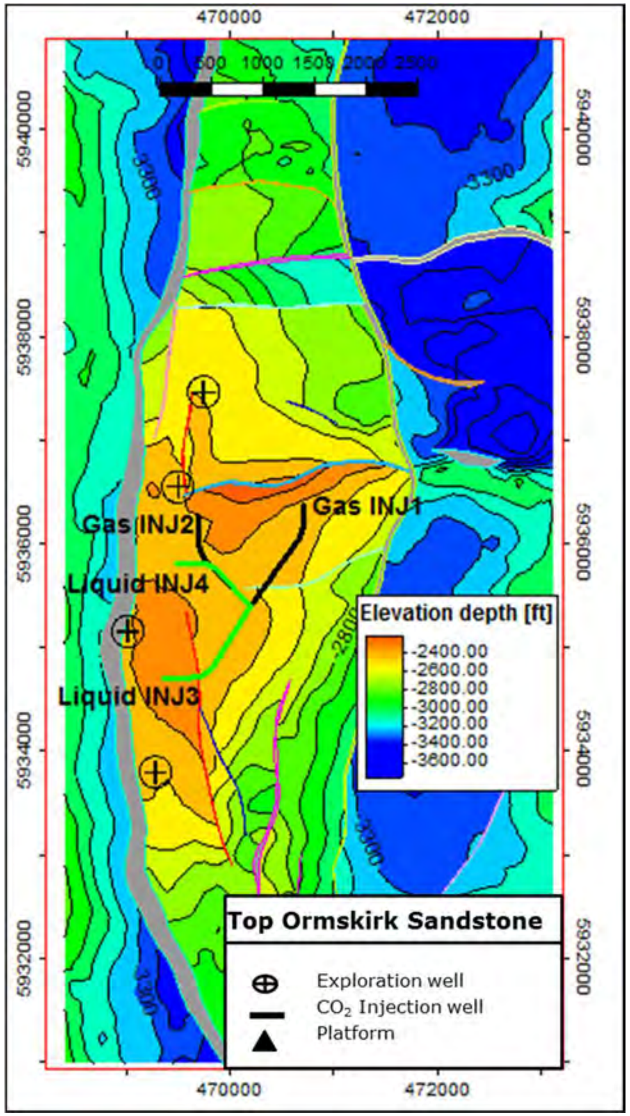

Figure 5-2 Potential Development Well Locations

5.3.1 Well Design

The key design criteria for the injection wells is that they must be capable of injecting 2.5Mt/Yr CO_2 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 standard North Sea jack-up.
2. Deviated up to 70 degrees in the tangent section,
3. Gas-phase wells with casing consisting of 26" conductor, 18-5/8" surface casing, 13-3/8" intermediate casing and 9-5/8" production liner.
4. Dense-phase wells with casing consisting of 26" conductor, 13-3/8" surface casing," 9-5/8" production casing and 7" production liner.
5. Completed with 9-5/8" tubulars for the gas-phase and 5-1/2" tubular for the dense-phase.
6. All flow wetted surfaces will be 13%Cr material.
7. Maximum FTHP will be 120 bar.
8. Maximum SITHP will be 49 bar (during dense-phase operations)
9. Maximum WHT will be 30°C (during gas-phase operations)

5.3.1.1 Well Construction

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 5-6). The following reservoir targets have been identified for the top of the Ormskirk Sand.

Target Name	TVDSS (m)	UTM North (m)	UTM East (m)
INJ1 (gas)	736.7	5,936,010.6	469,700.0
INJ2 (gas)	751.5	5,936,169.3	470,700.0
INJ3 (dense)	723.5	5,934,700.0	469,607.7
INJ4 (dense)	741.9	5,935,800.0	469,726.9

Table 5-1 Well Locations

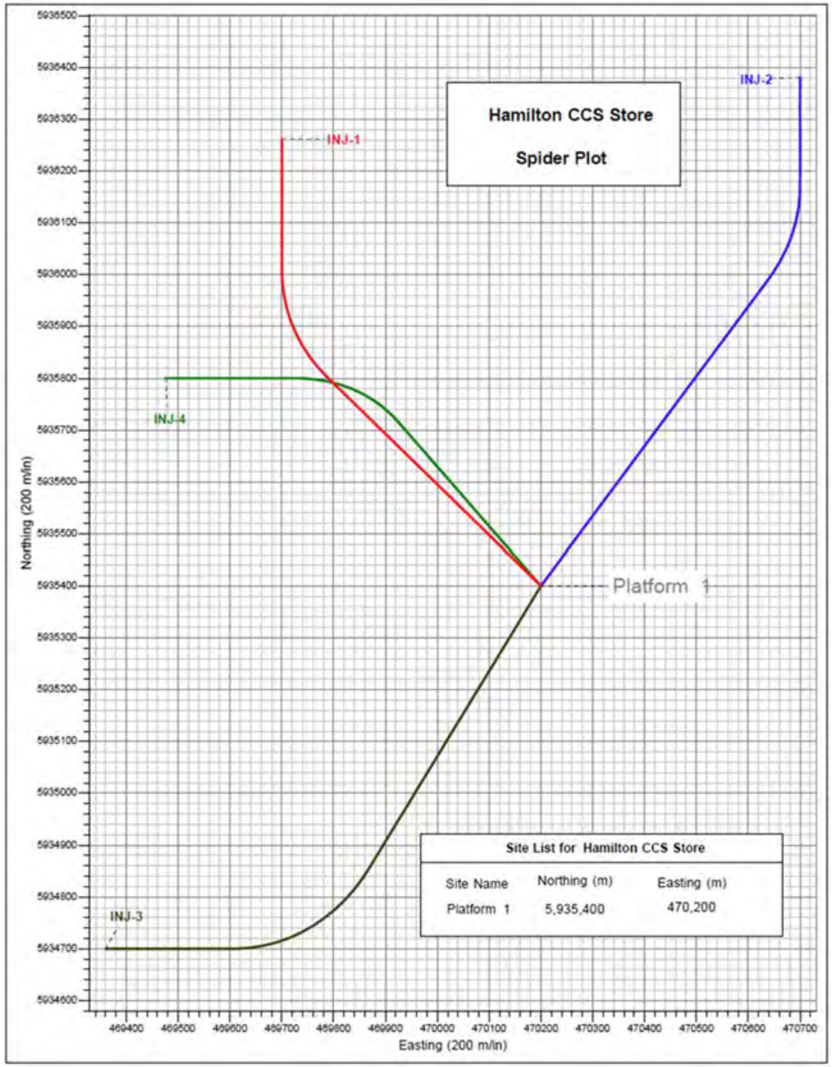

Figure 5-3 Well Directional Spider Plot

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

1. The injection wells will be drilled as high angle slant wells.
2. All wells will be kicked off directly below the conductor, with dog leg severity kept to 4.5° per 30m.
3. All directional work will be conducted in the formations above the reservoir.
4. A tangent section will be drilled through the reservoir-hole section, holding inclination to TD below the base of the Ormskirk Sand.

Directional profiles have been prepared for each well based on the reservoir targets and directional drilling limitations. The directional profile for Injector 1 is shown in Figure 5-3 and Figure 5-4. Profiles for all wells are provided in Appendix 7.

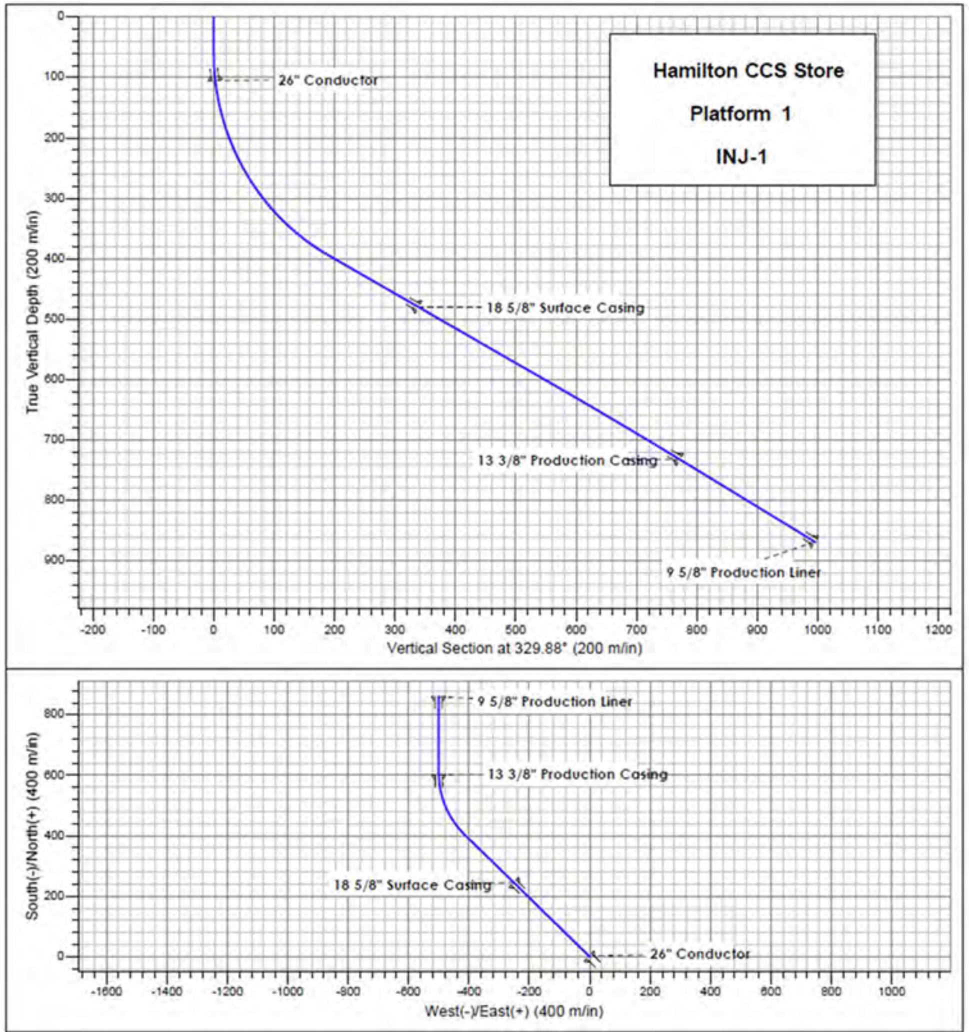

Figure 5-4 Directional Profile for Injector 1

During the gas-phase the lower completion is a 9-5/8" pre-perforated liner with a fluid loss valve. The dense-phase wells have a 7" cemented or pre-perforated liner.

5.3.1.2 Well Completion

Well performance modelling was used to identify the optimal tubing size and assess some of the factors that may influence well injection performance. The results of this work are provided in Section 3. In summary, either 9-5/8" or 5-1/2" tubing can meet the required injection duty for each well, depending on the operating period, without breaching the safe operating envelope of the reservoir.

For pure CO_2, with negligible water content (<300ppmv), carbon steel is suitable. For the purposes of this study, 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 but will not be present in high enough concentrations to cause corrosion/cracking issues. Consequently 13% chrome is assumed for all wetted components.

NBR nitrile elastomer can be used within the temperature range of -30 to 120°C (Appendix 7) and is therefore suitable for CO_2 injection wells. This elastomer gives the lowest operating temperature among the typical downhole elastomers.

For the gas-phase wells the upper completion consists of a 9-5/8" tubing string, anchored at depth by a production packer in the 13-3/8" production casing, just above the 9-5/8" liner hanger. Components include:

1. 9-5/8" 13Cr tubing (weight to be confirmed with tubing stress analysis work) with higher grade CRA from Barrier Valve to tailpipe
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. 13-3/8” V0 Production Packer

For the dense-phase wells the upper completion consists of a 5-1/2” tubing string, anchored at depth by a production packer in the 9-5/8” production casing, just above the 7” liner hanger. Components include:

1. 5-1/2” 13Cr tubing (weight to be confirmed with tubing stress analysis work) with higher grade CRA from Barrier Valve to tailpipe
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” V0 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).

Appendix 7 provides a detailed discussion of the well construction and well completion design.

5.3.2 Number of Wells

Two operational wells are required to inject the anticipated 5Mt/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 3.

Well Activity	Year						
	0	7	13	15	17	20	25
Gas-phase wells (including spare)	3						
Gas-phase workovers			2				
Local Sidetrack		1		2		1	
Dense-phase wells					2		
Abandonment							5

Table 5-2 Anticipated Well Activity over Field Life

5.3.3.1 Well Construction Programme

Gas Phase Wells

Section	Casing	Comments
Surface (32")	26", 60m below mudline	
Surface (22") **Water Based Mud**	18⅝", 480m Carbon steel Cemented to the mudline	Seal off Presall Halite
Intermediate 1 (17½") **Water Based Mud**	13⅜", 720m Carbon steel Cemented to 100m inside previous casing shoe	Base of the Ansdell Formations
Injection (12¼") **Oil Based Mud**	9⅝", 850m 13Cr below packer	

Table 5-3 Gas Phase Well Construction

Dense Phase Wells

Section	Casing	Comments
Surface (32")	26", 60m below mudline	
Surface (17½")") **Water Based Mud**	13⅜", 480m Carbon steel Cemented to the mudline	Seal off Presall Halite
Intermediate 1 (12¼") **Water Based Mud**	9⅝", 720m Carbon steel Cemented to 100m inside previous casing shoe	Base of the Ansdell Formations
Injection (8½") **Oil Based Mud**	7", 850m 13Cr below packer	

Table 5-4 Dense Phase Well Construction

5.4 Injection Forecast

Injection commences in 2026 and continues for approximately 25 years, the final year of injection is 2050.

The injection forecast for the Reference Case is for 5Mt/y over the estimated store life of 25 years which results in a cumulative injection of 124Mt CO_2. This forecast can be maintained by 2 active injection wells with an additional well held in reserve to provide redundancy.

A tabulation of the profile is provided in Table 5-5.

Year	Rate (Mt/y)	Total (Mt)	Year	Rate (Mt/y)	Total (Mt)	Year	Rate (Mt/y)	Total (Mt)
2026	5	5	**2036**	5	55	**2046**	5	105
2027	5	10	**2037**	5	60	**2047**	5	110
2028	5	15	**2038**	5	65	**2048**	5	115
2029	5	20	**2039**	5	70	**2049**	5	120
2030	5	25	**2040**	5	75	**2050**	4	124
2031	5	30	**2041**	5	80			
2032	5	35	**2042**	5	85			
2033	5	40	**2043**	5	90			
2034	5	45	**2044**	5	95			
2035	5	50	**2045**	5	100			

Table 5-5 Injection Profile

5.4.1 Movement of the CO_2 Plume

CO_2 is injected into all reservoir layers and migration is dominated by gravity so that CO_2 moves downwards until it reaches the GWC which is essentially impermeable. With continued injection the reservoir pressure increases until the constraint is met at which point injection ceases as described in section 3.6.6.

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

5.5 Offshore Infrastructure Development Plan

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

Platform	UTM Coordinates	
	Eastings (m)	Northings (m)
Hamilton NUI	470200	5935400

Table 5-6 Platform Location

5.5.1 CO_2 Transportation Facilities

This section provides an overview of the Hamilton CO_2 transportation (pipelines) development plan. CO_2 will be transported in the liquid phase.

5.5.1.1 Pipeline Routing

The figure below shows the pipeline route from the Point of Ayr (POA) Terminal to the Hamilton NUI.

The direct pipeline route from POA to Hamilton has been selected to minimise the pipeline route length while avoiding existing facilities (Windfarms, Douglas Complex etc) and maintaining appropriate crossing angles. There are no potential sites for future expansion along the pipeline route, however there are several other potential storage sites (including hydrocarbon fields) in the vicinity of Hamilton that could be utilised for step out CO_2 storage in the future, further discussion is included later in this chapter.

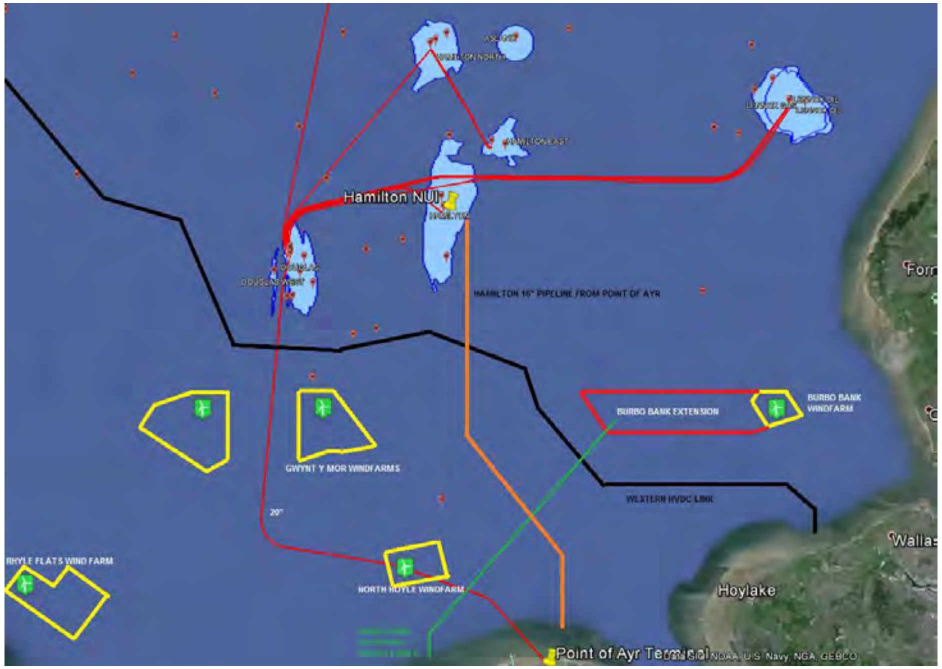

Figure 5-5 Pipeline route

The pipeline has been routed to avoid a number of existing windfarms (and planned extensions) as summarised in the table below.

Windfarm	Commissioned	Comment
Burbo Bank	2007	In operation (90 MW). Covers area of approx. 10 km^2
North Hoyle	2003	In operation (60 MW). Covers area of approx. 10 km^2
Gwynt y Mor	2015	In operation (576 MW). Covers area of approx. 80 km^2
Rhyl Flats	2009	In operation (90 MW). Covers area of approx. 10 km^2
Burbo Bank Extension	Planned 2017	Scheduled to be installed and commissioned early 2017. 40km^2 area. 258 MW name plate capacity.

Table 5-7 Liverpool Bay Windfarms

The pipeline route shown does not cross any existing pipelines, but does cross the Wester HVDC Link power cable, and may cross the Burbo Bank Extension power cable should that project proceed.

The Western HVDC Link comprises a converter station and new substation at Hunterston, Scotland connected by approximately 400 km of underground and subsea HVDC cable to a converter station at Connah's Quay, Wales.

Cable	Surface Laid / Trenched	Operator
Western HVDC Link	Trenched and Buried	National Grid / Scottish Power
Burbo Bank Extension Export	Trenched and Buried	DONG Energy

Table 5-8 Pipeline Crossings (Point of Ayr to Hamilton)

The pipeline will be taken offshore using either a cofferdam constructed on the beach/subtidal area, or using a caisson (which can be constructed entirely subtidally). Due to the shallow water depth throughout the Liverpool Bay (<30m) it is recommended that the pipeline will be trenched and buried throughout (with the exception of crossings which will need protection in the form of concrete mattresses or rock dump).

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

5.5.1.2 Preliminary Pipeline Sizing

Preliminary line sizing calculations have been performed to determine the Hamilton pipeline outer diameter. The pipeline route length is 26km.

Due to the low pressures in the Hamilton depleted gas reservoir, the CO_2 will be transported in the liquid (dense) phase, but CO_2 will initially be injected in the gaseous phase (stage 1) until the reservoir pressure is sufficient to maintain a liquid column of CO_2 in the well bore (stage 2).

The table below presents the pressure ranges required at the top of the well (injection point). During the early period of the gas injection phase the arrival pressures are such that the CO_2 is in gas phase under ambient sea temperatures throughout the year. However after a relatively short period of time, 2-3 years, the pressure in the well rises and would result in liquid drop out at the higher pressure end of the pipeline (at the shore pump) which could be 5-10 bars higher depending on the selected line size and flow rates. The amount of liquids would steadily increase over the remaining duration. Operating a 2 phase pipeline is problematic and may result in damage to the offshore facilities and wells.

The alternatives available consist of the following:

- Operating the pipeline continuously in liquid phase and then converting the liquids to gas with heaters during phase 1
- Operating the pipeline in gas phase however providing heat to the pipeline to raise the product temperature above the vapour point
- Seed the CO_2 with Nitrogen to artificially raise the vapour temperature.

Heated pipelines which are discussed further in Appendix 9 are not considered technically feasible and have been ruled out. Artificially raising the vapour point may be feasible how it requires a more thorough investigation into the effects on the subsurface performance and containment and there also needs to be a reliable source of Nitrogen (or alternative) at the source of the CO_2. This option has not been addressed further in this study.

Operating the pipeline in liquid phase during Phase 1 reduces the size of the pipeline but it will require significant amounts of offshore heating in order to ensure single gas phase conditions going downhole and to manage low temperature. Pressures in the liquid phase pipeline should also be kept to a strict limit both to avoid gas forming and to avoid large pressure drop across the injection chokes which would in turn require further heating. Note that this operating philosophy will be highly dependent on the composition of the supplied CO_2, and will require confirmation during FEED (steady state and transient analysis).

Gasifying liquid CO_2 at the rate of 5MT/yr before injection is an unusual operation for which direct experience is rare. In the USA, whilst large CO_2 inventories are moved around the country in dense phase, they are normally injected in dense phase also for EOR without the need for gasification. The technology is not however novel. The main source of experience for this technology comes from LNG tanker unloading where unloading rates of 600T/hr are common (>5MT/yr) there are a range of technologies in use to achieve this transition.

The required mass flow rate of 5 MT/Year has been selected to ensure a sustainable plateau rate over the 25 year design life (124 MT total injected). It has been assumed that the Point of Ayr pump station delivers up to 115 bar in pressure therefore the maximum pressure drop is in the region of 40 bar during stage 1 (gas injection) and stage 2 (liquid injection).

Well	Injector Type (CO_2 Phase)	Years in Operation	Min Tubing Head Pressure	Max Tubing Head Pressure	Mass Injection Rate
INJ1	GAS	0 – 17 [1]	34 bar	61 bar	2.5 MTPA
INJ2	GAS	0 – 17 [1]	36 bar	63 bar	2.5 MTPA
INJ3	LIQUID	17 – 25	46 bar	72 bar	2.5 MTPA
INJ4	LIQUID	17 - 25	45 bar	69 bar	2.5 MTPA

Table 5-9 Hamilton Well Development Plan

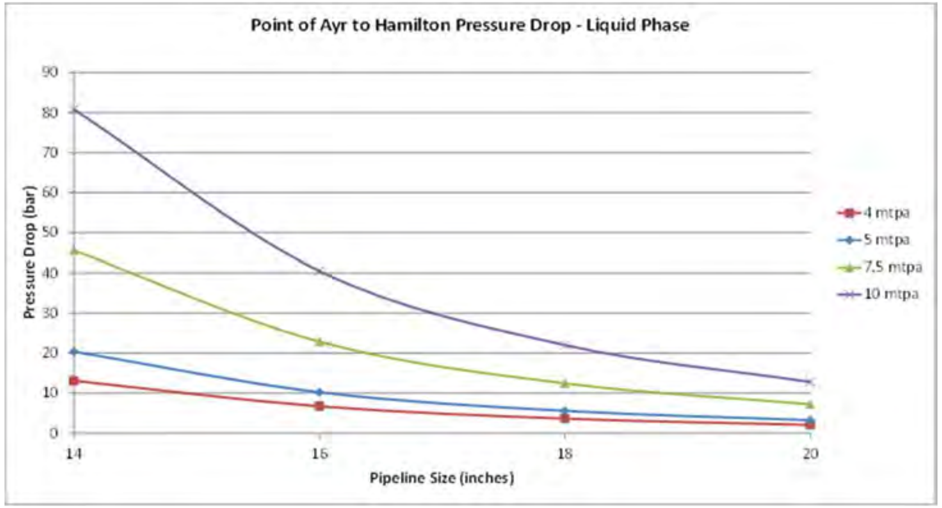

Figure 5-6 Pipeline Pressure Drops

There are a number of other potential storage sites and oil/gas developments in the vicinity of Hamilton which could be utilised for future build out of CO_2 storage (in particular North and South Morecambe approximately 35-45 km further north). Therefore there is merit in pre-investing in an increased ullage (larger) pipeline. There are no potential future storage sites that have been identified along the pipeline route, there is therefore no merit in pre-investing in future tie-in structures at set locations along the route. Options for expansion are discussed further in Section 5.7.

It can be seen from Figure 5-6 and Table 5-9 that a 14" pipeline from Point of Ayr is sufficient but there is very little spare ullage whereas a 16" pipeline at a flow rate of 5 MTPa results in a pressure drop of approximately 10 bar. At a flow rate of 7.5 MPTa this increases to 23 bar, and at 10 MTPa the pressure drop is approximately 40 bar. Therefore there is sufficient ullage in the 16" pipeline to deliver up to 100% extra ullage or alternatively the same ullage over twice the distance, beyond which additional pumping will likely be required. Further details are provided in the appendices.

The Hamilton pipeline is sufficiently large (OD ≥ 16") that is does not require burial or rockdumping for protection purposes. However, given the shallow water depth throughout the Liverpool Bay (<30m) it is recommended that the pipeline will be trenched and buried throughout (with the exception of crossings) for stability against wave and current forces.

A 16" pipeline is within the capabilities of installation by reel lay vessel, however assuming a typical vessel capacity of 2000 Te the 26km pipeline would require 3 trips from the spoolbase, the nearest of which is currently Evanton in the North of Scotland (25km North of Inverness), and a sail of approximately 3-4 days. A typical S-Lay barge capacity is in the region of 1600 Te, therefore the Hamilton pipeline could be installed without the need for pipe carriers. This results in an S-Lay solution being more economical (further discussion is included in Section 6). It is worth noting that there are a limited number of high spec reel lay vessels that utilise a dual reel configuration and may be capable of installing the Hamilton pipeline in a single trip. However, given the uncertainty in spoolbase locations in the next 10 years, and the adverse effect this could have on contracting strategy, an S-Lay solution has been assumed at this stage.

5.5.1.3 Subsea Isolation Valve (SSIV)

For conservatism development costs include for an actuated piggable ball valve SSIV structure being installed on the 16" pipeline adjacent to the Hamilton NUI Jacket. The requirement for SSIVs to be installed on CO_2 service pipelines feeding a normally unmanned installation (NUI) is not clear-cut. The Peterhead CCS Project Offshore Environmental statement (Shell, 2014) states that a new

SSIV will be put in place to support the proposed project and provide a means of isolation in the event of loss of containment close to the platform. The Offshore Environmental Statement for the White Rose CCS project (National Grid Carbon Ltd; Carbon Sentinel Ltd; Hartley Anderson Ltd, 2015) states that the White Rose 4/52 pipeline will not have a subsea isolation valve (SSIV). Comparatively the inventory of the proposed White Rose pipeline is greater than that of Goldeneye. The requirement for an SSIV for the Hamilton pipeline should be fully appraised in FEED. The Hamilton platform import riser will be fitted with an emergency shutdown valve (ESDV) and the riser located so as to mitigate risk of collision damage by support vessels. Full dispersion modelling will be required in order to position the ESDV and Riser and any temporary refuge facilities specified accordingly in compliance with PFEER regulations. If an SSIV is deemed necessary for the Hamilton pipeline then consideration must be given to the pressure rating of the piping, spools and riser to allow for thermal expansion of any potential trapped CO_2 inventory.

5.5.2 Offshore CO_2 Injection Facilities

It is proposed that CO_2 is injected into Hamilton from a single Normally Unmanned Installation (Platform) with a 6 slot wellbay that will enable 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 Hamilton.

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

NUI Jacket:

- 25m water depth
- 25 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
- Pre-Injection CO_2 heaters (x6)
- Power supplied via power cable from shore (Point of Ayr) with transformers
- Well and valve controls HPU and MCS package
- HVAC package
- Low temperature valving and manifolding pipework package
- Sampling and Metering package
- No compression / pumping
- Availability for a water wash skid
- Consumable tanks sized for 90 days self sustained operations

A process flow diagram of the Hamilton development is presented in Figure 5-7.

Requirement	Quantity/Value	Comment
Design Life	25 Years	2 wells (gas injection) for 18 years + 2 wells (dense phase injection) for 8 years, plus a spare injector and a spare slot.
Platform Well Slots	6	
Platform Wells	5	
Trees (XT)	5	-
Diesel Generator	1	Emergency (back-up) power generation only
Satellite Communications	2 x 100%	Dual redundant VSAT systems
Risers	2	1 spare for future tie-back/expansion
J-Tube	3	For future tie-back/expansion
Subsea Isolation Valve (SSIV)	1	SSIV at Hamilton only
Temporary Refuge	1	4 Man
Lifeboat	1	TEMPSC and Life rafts
Helideck	1	-
Pig Launcher Receiver	Permanent	-
CO_2 Filters	Yes	Bypassable
CO_2 Heaters	6	3 x 2.5 MW heaters per gaseous injector well (including 1 spare for each well) To manage low temperature risks and ensure single phase conditions going downhole
Transformers and Distributors	2	Conversion from 33kV to 690V
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 5-10 Master Equipment List

5.5.2.1 Platform Infrastructure

Jacket Design:

A conventional 3-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. The water depth is such that a SeaKing design jacket may be employed which would reduce the associated CAPEX and fabrication time of the Jacket. Suitability of such a jacket design would require to be fully appraised during FEED.

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), Process equipment including CO_2 heaters, emergency 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:

A power cable will provide electrical power to the Hamilton NUI from the Point of Ayr. The power cable itself is discussed in Section 5.5.3.

The power cable will provide high voltage (HV) and low voltage (LV) power to the Hamilton NUI. LV power supply shall be sufficient to power the Master Control Station (MCS), Hydraulic Power Units (HPU), plus the crane, HVAC system and all ancillary equipment.

A 690 voltage 3-phase power supply will be required for the CO_2 heaters. The following table provides the estimated continuous power loads for the system (during gaseous phase injection). It is envisaged that there will be three heaters per well, with one or two in operation as required (due to varying conditions), plus a spare/back-up.

The required capacity of the heaters depends on the injection rate, the down hole pressure and the required temperature rise. The power required to convert the liquid CO_2 into gas phase has been estimated to be 10 MW (at 5 MTPa flowrate) equivalent to 5MW per gas injector well. This requires further assessment to account for the range in ambient temperature conditions (both subsea and air), flow rates, CO_2 compositions and injection pressure and temperature requirements.

Well	Number of CO_2 Heaters	Assumed Power Capacity per Heater
Gas Injector 1	3	2.5 MW
Gas Injector 2	3	2.5 MW

Table 5-11 CO_2 Heaters

Topsides Process:

The primary Platform Injection facilities will consist of a topsides Emergency Shutdown Valve (ESDV), a pressure control valve (PSV) which will serve to safeguard the pipeline pressure and maintain the CO_2 in the pipeline in liquid phase, Fines Filters that will prevent solid contaminates entering the injection well bores, a vent stack to enable blowdown of the topsides pipework for maintenance, and an injection manifold which will facilitate injection of the CO_2 to the respective wells. As the CO_2 will be transported in the liquid phase the gas phase injector wells will also incorporate CO_2 heaters (x3) in the process pipework to manage low temperature risks and ensure single phase conditions going downhole.

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.

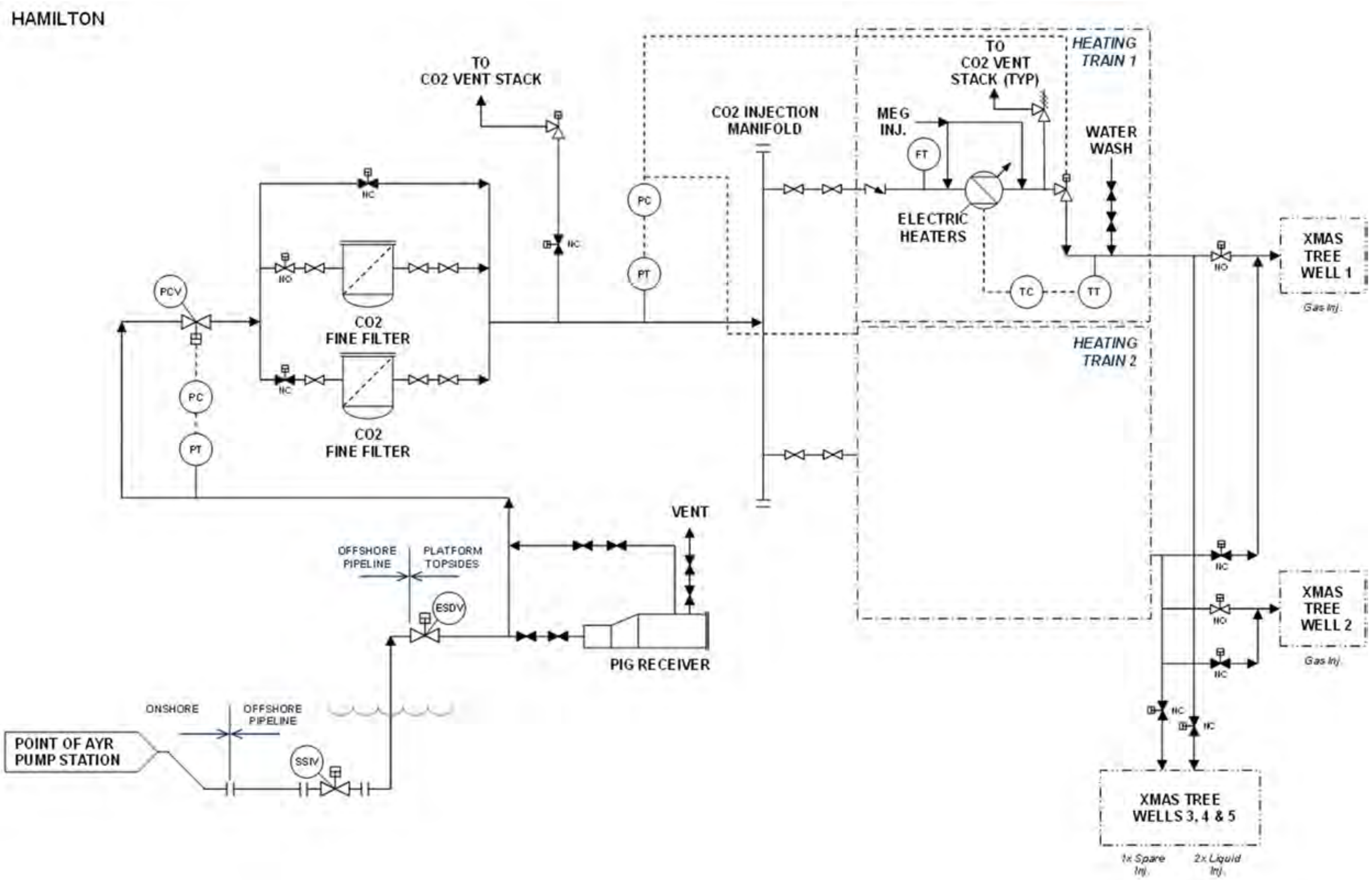

Figure 5-7 Process Flow Diagram

5.5.2.2 Rationale for a Platform-based Development

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

The Hamilton development requires 4 injection wells (plus a spare injector and a spare slot) over the field life. The proposed trajectories of the wells is such that they can be drilled from a single drill centre. The water depth at the proposed drilling location of Hamilton is 25m. This is sufficiently shallow to enable the wells to be drilled by a Jack Up drill rig cantilevered over a platform with 6 well slots (4 Wells + Spare injector + Spare slot).

The Hamilton development will involve the injection of CO_2 into a depleted gas reservoir. Liquid injection of CO_2 from the outset is not feasible due to the reduced reservoir pressure, therefore the injection strategy for the Hamilton development is based on initial gaseous injection of CO_2 (phase 1) until the reservoir pressure is sufficient to maintain a liquid column of CO_2 in the well bore (phase 2). This requires either gaseous transport of the CO_2 to the Hamilton development during phase 1, which would require a large diameter (heated) pipeline (and maintaining the CO_2 pressure at less than approximately 60 bar in order to avoid the risk of liquids forming), or transporting the CO_2 offshore in the liquid phase, and incorporating a vaporisation unit (consisting of a heating train and a choke valve) to facilitate injection into the wells in the gaseous phase. The latter philosophy has been adopted for the Hamilton development.

The offshore heating would not be feasible on a subsea development, and is required to ensure single phase gaseous flow and to protect the reservoir and wells from the very low temperatures generated by differential pressure across the choke valves (JT effect). The well development plan is discussed in detail in Section 5.3, the initial phase of gaseous CO_2 injection (phase 1) is expected to last approximately 13 years, after which there will be a period of approximately 5 years to transition from gas phase to liquid phase (phase 2). The gas injector wells will be utilised for this transition period, following which two new liquid phase injector wells will be utilised through to the end of field life (approx. 8 years). Heaters will be required continuously for the gaseous CO_2 injector wells and possibly for start-up for the liquid injectors.

Electrical heaters have been identified as the most feasible option for adding heat to the CO_2 on the Hamilton NUI. A fired heater train would require a manned platform, and excessive diesel storage or a fuel gas import pipeline. The power required to convert the liquid CO_2 into gas phase has been estimated to be 10 MW (at 5 MTPa flowrate). Three (x3) 2.5 MW electrical heaters on each of the gas injector wells (upstream of the choke) will therefore have sufficient redundancy, and can be powered by a 3 phase power cable from the shore. The power cable is discussed in Section 5.5.3.

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 would not facilitate the CO_2 heating that is required, as described above.

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.
- Pig receiver.
- Venting.
- Future connections are easier as the connections are above water thereby avoiding water ingress into existing systems and it's easier to dry any future pipelines.

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

- Process monitoring, and well allocation metering for reservoir management.
- Process chemical injection of MEG, and N2 for transient well conditions and wash water for halite control.

Due to the requirement of a heavy lift vessel to remove the platform and topsides at the end of field life the ABEX costs associated with decommissioning a NUI platform is likely to exceed that of a subsea development, however the P&A (plug and abandonment) of subsea wells will be approximately 25% more costly than the P&A of platform wells.

5.5.3 Power Supply

A power cable will provide electrical power to the Hamilton NUI from the Point of Ayr.

The power required to convert the CO_2 from liquid phase into gas phase is significant and has been estimated to be 10 MW for the 5Mtpa forecasted supply rates. This is above normal power generation on offshore facilities and requires special attention. There are three main options to consider for securing offshore power, namely:

- A self-contained generation and distribution network (typically gas turbine or diesel) – this requires extensive offshore power generation infrastructure as well as large fuel tanks and bunkering. This has been rejected due to the increase in offshore CAPEX costs, the additional manning requirements to service the generators and supply the fuel and the increase in the overall carbon footprint of the project.
- Utilising offshore renewable power from existing and or future offshore windfarms in close proximity. There is a relatively high density of wind farms planned in the vicinity of the site however the heating is required continuously for an extended period of time therefore an alternative would power source would be required during periods of low wind supply to avoid downtime. A combination of local generation and renewable power would be feasible and would reduce the carbon deficit associated with local power generation but it would also result in high expenditure as it factors two independent power sources.
- Securing supplies from an onshore electricity distribution network connection using a 26 km subsea cable – this minimises offshore infrastructure and allows power to be procured from a wide range of sources including renewables.

A detailed description of each of these is presented in the appendices, and gives an overview of the key factors to be considered in securing a power supply from an onshore source. A breakdown of the Capex and Opex costs is also included.

A 26km 33 kV power cable from Point of Ayr has been selected as the preferred solution. Utilising higher voltages (132kV) or DC systems are not necessary and cost considerably more. There may be a drive to increase the reliability of the system through the use of redundant systems however the cost of installing a completely separate power connection, transformer set and cable will increase the cost by almost an order of magnitude. A reliability and availability assessment is recommended to determine the optimum level of redundancy. More details are provided in Appendix 9.

5.6 Other Activities in this Area

There are several hydrocarbon fields in the vicinity of Hamilton. The nearest of these are shown in the figures in Section 5.5.1.1. The pipeline is routed to avoid the Douglas Complex facilities (and associated tie-backs) and the North Hoyle, Rhyl Flats and Burbo Bank windfarms (plus planned future expansions). The Hamilton field itself is a depleted gas reservoir, which was operated by BHP and tied back 8.5km to the Douglas platform to the South West and then back to the Point of Ayr terminal via a 20” pipeline. The Burbo Bank extension wind farm project is currently ongoing, with the project sanction / FID approved in December 2014 and scheduled to be installed and commissioned in early 2017.

Other activities in the area that are pertinent to the Hamilton development are fishing and shipping.

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

5.7 Options for Expansion

There are no potential future storage sites that have been identified along the pipeline route, therefore there is little merit in pre-investing in future tie-in structures.

There are a number of Ormskirk closures located to the west of the pipeline route, summarised in the figure and table below. It can be seen that none of the Omskirk Closures were ranked in the top 20 during WP3, and that access to these would require a significant pipeline route detour, therefore these options were not considered further for future expansion options at this stage.

Ormskirk Closure	Approximate Distance from Hamilton (NUI to Centre of Closure)	WP3 Ranking (Top 20)
1	20.8 km	Not Ranked
2	22.0 km	Not Ranked
3	17.9 km	Not Ranked
4	17.6 km	Not Ranked
5	23.7 km	Not Ranked
6	16.1 km	Not Ranked

Table 5-12 Potential stores close to Hamilton

There are a number of other potential storage sites and oil/gas developments in the vicinity of Hamilton which would be utilised for future build out of CO_2

storage, summarised in the table below. Cost estimate sensitivities, have shown that limiting the pipeline size to the minimum 14” results in an overall cost saving of approximately <1% of the total development cost compared with the 16” pipeline selected, therefore there is merit in pre-investing in an increased ullage (larger) pipeline to provide capability of reaching the sites. The distances from the Hamilton NUI to the centre of site have been extracted from CO_2Stored and are summarised in Table 5-13.

These sites were checked against the WP3 rankings (top 20). It can be seen the Morecambe sites are favoured, being the only ones that ranked in the top 20.

The South Morecambe gas field was ranked 3rd during WP3, and is located approximately 35 km North of Hamilton, while the North Morecambe gas field is located approximately 47km North of Hamilton. The COP of these fields is estimated to be 2026-2028.

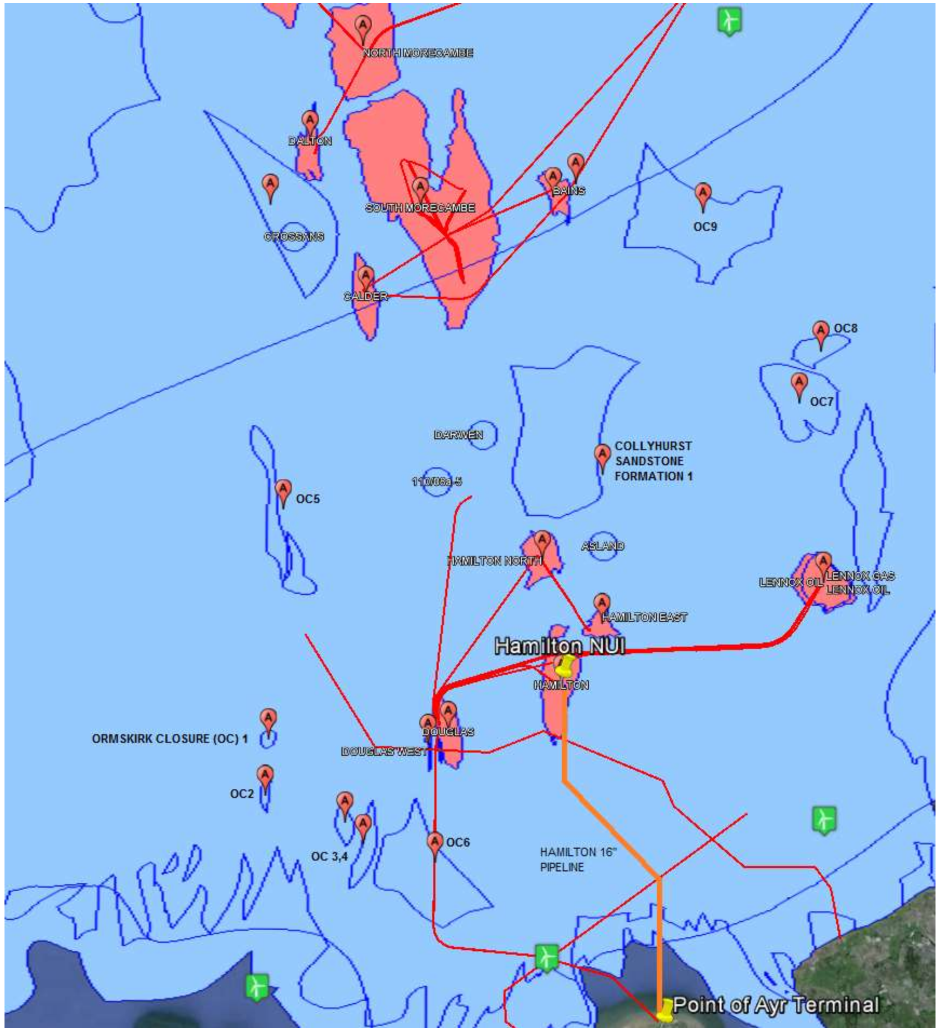

Figure 5-8 Options for Expanding the Development

Field	Type	Distance from Hamilton NUI	WP3 Ranking
Hamilton East	Gas	5.1 km	Not Ranked
Hamilton North	Gas	8.9 km	Not Ranked
Douglas	Oil	8.5 km	Not Ranked
Douglas East	Gas	10.0 km	Not Ranked
Lennox	Oil/Gas	19.9 km	Not Ranked
Collyhurst Sandstone Formation 1	Aquifer	17.2 km	Not Ranked
Ormskirk Closure 7	Aquifer	26.0 km	Not Ranked
Ormskirk Closure 8	Aquifer	27.0 km	Not Ranked
Ormskirk Closure 9	Aquifer	34.2 km	Not Ranked
Calder Gas	Gas	30.6 km	Not Ranked
South Morecambe	Gas	34.8 km	3
North Morecambe	Gas	46.6 km	8

Table 5-13 Options for Expansion

5.8 Operations

The Hamilton Development will inject CO_2 at a constant injection rate of 5 MTPa, via 2 platform based gaseous injector wells over 14 years, followed by 2 liquid phase injector wells over 11 years, plus a spare injector (drilled with stage 1 wells) and a spare slot.

The Hamilton platform will be a Normally Unmanned Installation (NUI), and will be capable of operating unattended for approximately 3 months (90 days). A power cable will provide electrical power to the Hamilton NUI from the Point of Ayr. 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 comms);
- IMR of mechanical handling (crane);
- IMR of HVAC system;
- IMR of venting system;
- IMR and certification of metering system for CO_2 injection;
- IMR of chemical injection system including pumps, tanks and associated equipment;
- IMR of CO_2 heaters;
- 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 pipeline and power cable will also require regular IMR. This will include regular (typically bi-annual) surveys (ROV) to confirm integrity. Although pigging facilities are available, the frequency will be minimal subject to an integrity management risk assessment of the control of the CO_2 quality.

5.9 Decommissioning

The decommissioning philosophy assumed for the Hamilton facilities is as follows:

Note that this philosophy is subject to the outcome of the comparative assessment process and subsequent approval by DECC.

- Wells plugged and abandoned.
- Topsides facilities are cleaned, prepared and disconnected.
- Removal of Topsides (reverse installation).
- Steel jacket completely removed and taken ashore for dismantling and recycling.
- Pipeline is cleaned and left in place, part end recovery and ends protected by burial/rockdump.
- Subsea power cable is cut and left in place.
- Hamilton pipeline (trenched and buried) is assumed to be covered by the UK fisheries offshore oil and gas legacy trust fund.
- Pipeline spools to be recovered.
- Subsea structures to be recovered (SSIV).
- Subsea concrete mattresses and grout bags recovered.

The crossed power cable(s) are discussed in Section 5.5.1.1. Note that if either of these are still in service the decommissioning of the pipeline crossing will likely have to occur as part of the associated crossed cable decommissioning.

5.10 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 Hamilton 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.

5.11 Handover to Authority

Immediately following the completion of the post closure period the responsibility for the Hamilton 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.

5.12 Development Risk Assessment

The following development risks have been identified:

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.

Environmentally sensitive area: The Liverpool Bay is considered an environmentally sensitive area therefore there is a risk that pipeline route deviations, landfall location or other unforeseen changes to the development plan will be required. It is recommended that open communication with authorities, environmental groups and the community is maintained throughout the project to ensure any environmental issues are identified early and dealt with appropriately.

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 proposed routed of the power supply umbilical and pipeline servicing the proposed Hamilton NUI cross the Western HVDC Link subsea cable. The Western HVDC Link cable is trenched and buried to 1.5m. Given the unique operating nature of the HVDC cable, 600kV DC, the costs associated with engineering and installing a crossing may exceed that of a more standard cable crossing.

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

Further investigation into artificially lifting the vapour temperature of the CO_2 through injection of Nitrogen is warranted as this would reduce possibly eliminate the amount of heating required. However it may have adverse effects on the well performance and containment and it could have significant cost penalties at the capture plant and the overall storage capacity of the reservoir.

Additional work to accurately determine the amount of heating required, heating technology and the process steps required to gassify the CO_2.

Value Engineering: A value engineering exercise should be carried out to assess all equipment to ensure all specified equipment is technically justified in its application and not included on the basis of accepted oil and gas practice. Some examples are provided below.CO_2 Screens: A reduction in CAPEX and OPEX could be realized by removing the requirement for CO_2 screens.

Venting: Opportunity to remove the requirement for venting, with all venting performed from the beach.

Pig Receiver: Temporary v Permanent. Should permanent facilities not be required this will result in a reduction in topsides weight and the associated savings in CAPEX/OPEX.

SSIV: Requirement for an SSIV can be challenged during FEED and potentially omitted which would reduce the requirement for increased pressure rating of the riser and associated piping between SSIV and ESDV, to account for thermal expansion of riser inventory during shut in.

SSIV Location: If it is not possible to remove the requirement for an SSIV the location should be optimized with consideration to the impact of the riser volume on temporary refuge specification.

Helideck: A significant reduction in cost may be realised by removing the Helideck and relying on Walk to Work vessels for platform visits. Helidecks have typically been specified for hydrocarbon producing NUI's due to the requirement for personnel to be on the facility to restart production following a shutdown, and the associated cost of deferred production until the restart can be enacted. Removing this requirement by enabling remote restart of CO_2 injection will improve uptime and negate the requirement for a Helideck for platform visits.

Pipeline: Availability of a high spec reel vessel utilising a dual reel configuration to be considered during FEED.

Pipeline: The pipeline has been sized to allow for future expansion/step outs (additional ullage) which results in a 16" pipeline. If this requirement were removed then it may be feasible to install a 14" or smaller pipeline in a single trip utilising a reel lay vessel. This should be considered further during FEED.

Pipeline design: 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 (British Standards Institution, 2015) or DNV OS F101, and should follow the requirements of DNV RP J202.

Geotechnical data – site surveys result in complex foundations and increased costs. Ensure 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.

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.

Opportunity may exist to run the power umbilical and/or pipeline along the same route as the Western Link HVDC subsea cable. Whilst this would entail a marginally longer route than the direct approach to shore, it would negate the requirement for either line to cross the subsea cable and would allow the use (if obtainable) of existing route survey data and trenching records.

The water depth is such that a SeaKing design jacket may be employed which would reduce the associated CAPEX and fabrication time of the Jacket. Suitability of such a jacket design would require to be fully appraised during FEED. The SeaKing design is an advancement of the SeaHorse platform design that allows for a larger well count (up to 6 wells) whilst maintaining the key characteristics of the highly successful SeaHorse family of platform designs that have been extensively utilised for minimum facility platforms in the UKCS.

Consideration should be given to utilising the power cable to supply all electrical power, signal, hydraulics and chemicals to the Hamilton development. This would increase the cost of the cable however it could reduce the running costs of the NUI.

Further process studies should also be performed to determine whether it would be prudent to include a heating train on the NUI vent line and the overall venting philosophy.

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 Q1 2020.
- 12 months of EPC ITTs, contract and financing negotiation prior to FID.
- Project sanction / FID summer 2022.
- Detailed design commences immediately following sanction.
- Hamilton NUI jacket and topsides installed prior to drilling (facilities on critical path).
- The pipeline, power system and facilities are pre-commissioned following completion of construction.
- Drilling and completing of the two gas injector wells commencing 2025.
- The pipeline, facilities and wells are commissioned in a continuous sequence of events.
- First CO_2 injection summer 2026 which coincides with the projected supply profile.

A total project duration from pre-FEED to first injection is projected to be approximately 6 years.

WP5 Hamilton Schedule

ID	Project Phase ID	Task Name	Duration	Start	Finish
1	MS0	Start of Project	0 days	Sun 01/03/20	Sun 01/03/20
2	MS1	End of FEED	0 days	Mon 30/08/21	Mon 30/08/21
3	MS2	Final Investment Decision	0 days	Tue 30/08/22	Tue 30/08/22
4	MS3	First Injection	0 days	Tue 30/06/26	Tue 30/06/26
5	**A**	**A. Pre-Final Investment Decision (Pre-FID)**	**1095 days**	**Sun 01/03/20**	**Tue 28/02/23**
6	A1.1	Transportation	548 days	Sun 01/03/20	Mon 30/08/21
7	A1.2	Facilities	548 days	Sun 01/03/20	Mon 30/08/21
8	A1.3	Wells	548 days	Sun 01/03/20	Mon 30/08/21
9	**A1.4**	**Other**	**1095 days**	**Sun 01/03/20**	**Tue 28/02/23**
10	A1.4.2	Seismic and Baseline Survey	180 days	Sat 30/05/20	Wed 25/11/20
11	A1.4.3	Engineering and Analysis	273 days	Thu 26/11/20	Wed 25/08/21
12	A1.4.4	Licencing and Permits	1095 days	Sun 01/03/20	Tue 28/02/23
13	MS1	End of FEED	0 days	Mon 30/08/21	Mon 30/08/21
14		EPC Contract and Financing Period	365 days	Tue 31/08/21	Tue 30/08/22
15	MS2	FID	0 days	Tue 30/08/22	Tue 30/08/22
16	**B**	**B. Post-Final Investment Decision (Post-FID)**	**1399.2 days**	**Wed 31/08/22**	**Tue 30/06/26**
17	**B1.1**	**Transportation**	**1399.2 days**	**Wed 31/08/22**	**Tue 30/06/26**
18	B1.1.1	Detailed Design	273 days	Wed 31/08/22	Tue 30/05/23
19	B1.1.2	Procurement	548 days	Tue 29/11/22	Wed 29/05/24
20	B1.1.3	Fabrication	180 days	Tue 30/07/24	Sat 25/01/25
21	B1.1.4	Construction and Pre-Commissioning	90 days	Sun 30/03/25	Fri 27/06/25
22	B1.1.4.1	Pipeline Commissioning	90 days	Wed 01/04/26	Tue 30/06/26
23	**B1.2**	**Facilities**	**1399.2 days**	**Wed 31/08/22**	**Tue 30/06/26**
24	B1.2.1	Detailed Design	365 days	Wed 31/08/22	Wed 30/08/23
25	B1.2.2	Procurement	548 days	Mon 27/02/23	Tue 27/08/24
26	B1.2.3	Fabrication	548 days	Wed 29/11/23	Thu 29/05/25
27	B1.2.4	Construction and Commissioning	180 days	Thu 29/05/25	Mon 24/11/25
28	B1.2.4.1	Platform Commissioning	90 days	Wed 01/04/26	Tue 30/06/26
29	**B1.3**	**Wells**	**1399.2 days**	**Wed 31/08/22**	**Tue 30/06/26**
30	B1.3.1	Detailed Design	548 days	Wed 31/08/22	Thu 29/02/24
31	B1.3.2	Procurement	730 days	Tue 29/11/22	Wed 27/11/24
32	**B1.3.4**	**Construction and Commissioning**	**127.2 days**	**Tue 25/11/25**	**Wed 01/04/26**
33	B1.3.4.1	Gas Injector 1 and 2 + Spare Well	127.2 days	Tue 25/11/25	Wed 01/04/26
34	B1.3.4.3	Wells Commissioning / First Injection	90 days	Wed 01/04/26	Tue 30/06/26
35	**B1.4**	**Other**	**1095 days**	**Sun 02/04/23**	**Wed 01/04/26**
36	B1.4.1	Approvals and Consents	1095 days	Sun 02/04/23	Wed 01/04/26
37	**MS3**	**First Injection**	**0 days**	**Tue 30/06/26**	**Tue 30/06/26**

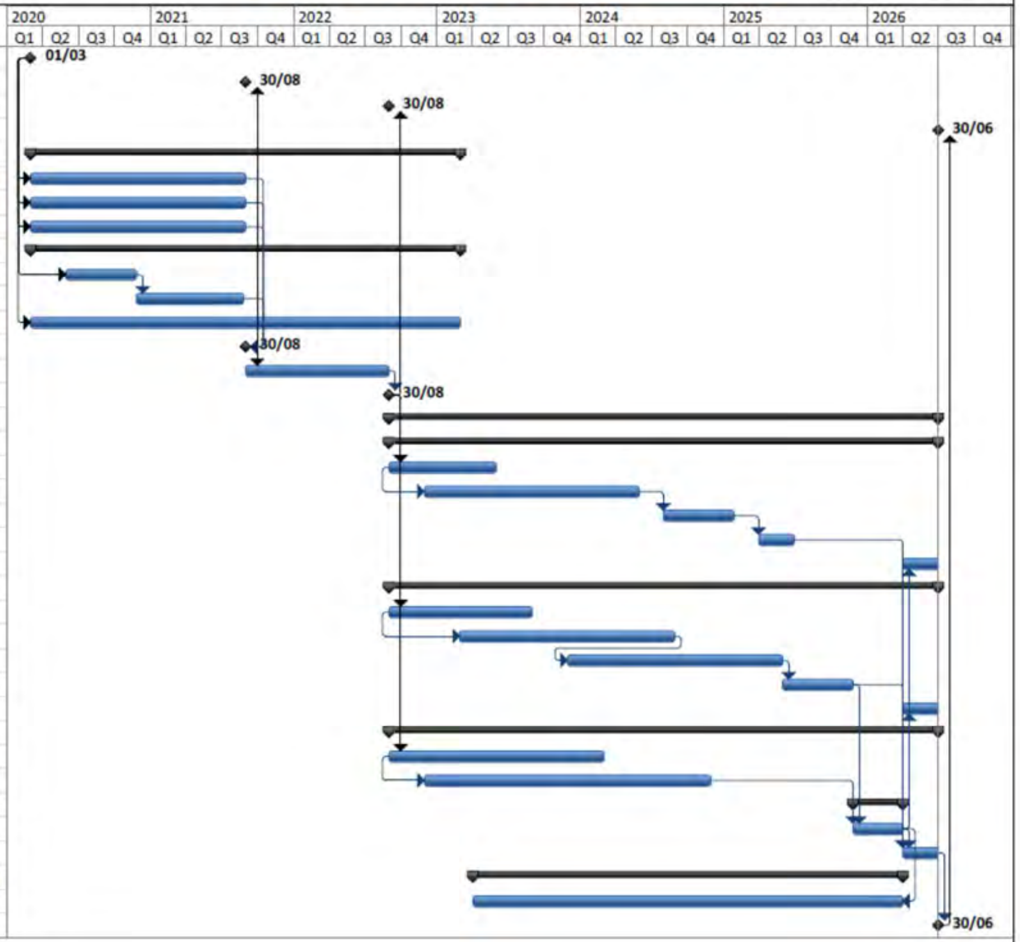

Figure 6-1 Summary Level Project Schedule

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 Hamilton facilities. The OPEX has been calculated based on a 25 year design life. A 30% contingency has been included throughout.

An overview of the Hamilton development (transportation, facilities, wells) is provided in Section 5. The cost estimate is made up of the following components:

- Direct pipeline and cable from Point of Ayr;
- Hamilton NUI (jacket and topsides);
- Two wells plus a spare well in stage 1 (gas injection) with two more wells in stage 2 (liquid injection).

6.2.1 Cost Estimate Summary

The cost estimate summary for the Hamilton development is outlined in Table 6-1. These numbers are current day estimates for the base case development. Details are provided in Appendix 8.

In the tables that follow estimates are provided in Real, 2015 terms and Nominal, 2015 PV10 terms.

- Real, 2015. These values represent current-day estimates and exclude the effects of cost escalation, inflation and discounting.
- Nominal, 2015 PV10. These values incorporate the time value of money into the estimates (i.e. including the effects of cost escalation and inflation (2%) that are then discounted back to a common base year of 2015 using an annual discount rate of 10%).

Unless specified otherwise, costs are presented in Real, 2015 terms.

Category	Cost £millions
CAPEX	281.1
OPEX	496.5
ABEX	95.7
Total Cost	873.4
Cost CO_2 Injected (£ per Tonne)	6.99

Table 6-1 Hamilton Development Cost Estimate Summary

It should be noted that cost estimates in Table 6-1 are 2015 estimates for 2015 activity and the present value estimates are provided in Table 6-3. These tables may contain minor rounding errors.

The investment profile is illustrated in Figure 6-2.

Figure 6-2 Phasing of capital spend (Real, 2015)

6.2.2 Life Cycle Costs

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

Category	£millions (PV_{10}, 2015 Nominal)
Transportation	31.7
Facilities	43.2
Power	9.5
Wells	37.4
Opex (excl power)	71.7
Opex - Power	27.6
Decommissioning & MMV	4.9
Total	226.1

Table 6-2 Project Cost Estimate (PV_{10}, Nominal 2015)

Details of when these costs are incurred based on 2015 spending activity are shown in Figure 6-3.

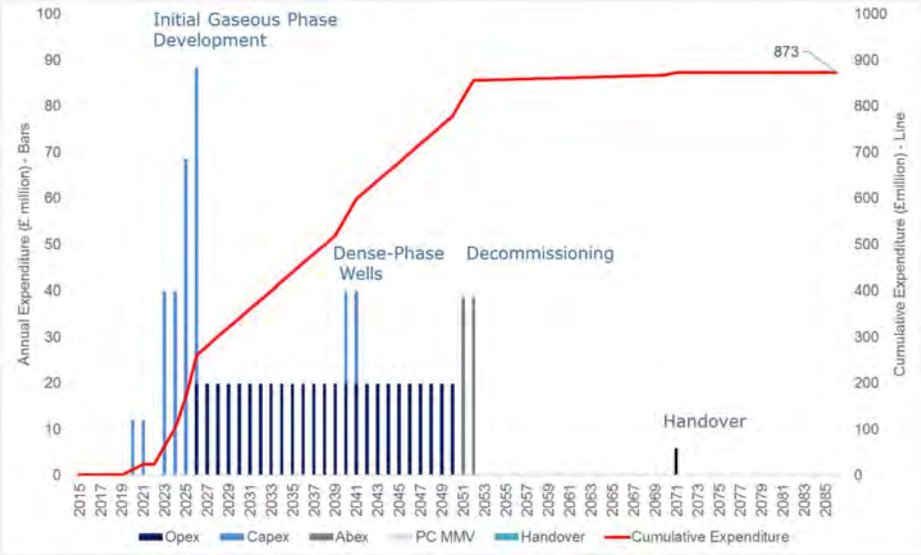

Figure 6-3 Elements of project cost over the project life (Real, 2015

6.2.2.1 Capital Expenditure

The CAPEX estimates for the Hamilton 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 terms.

CAPEX - Transport		
Pre-FID	Pre-FEED	0.4
	FEED	0.5
Post-FID	Detailed Design	1.6
	Procurement	12.9
	Fabrication	4.2
	Construction & Commissioning	46.1
Total CAPEX – Transportation (£MM)		65.7

Table 6-3 Hamilton Development - Transport CAPEX

The CAPEX for the Hamilton NUI (jacket + topsides) was generated using the Que$tor cost estimating software, and benchmarked using Costain Norms. The power system costs were developed using Costain Norms.

CAPEX - Facilities		
Pre-FID	Pre-FEED	4.2
	FEED	7.9
Post-FID	Detailed Design	16.9
	Procurement	29.1
	Fabrication	6.9
	Construction & Commissioning	41.8
Total CAPEX – Facilities (£MM)		106.8

Table 6-4 Total CAPEX Facilities

Both stages of well expenditure are included in the following estimate.

CAPEX - Wells		
Pre-FID	Pre-FEED / FEED PM&E	2.9
Post-FID	Detailed Design	2.9
	Procurement	29.1
	Construction and Commissioning (Drilling)	63.0
Total CAPEX – Wells (£MM)		97.8

Table 6-5 Hamilton Development - Wells CAPEX

CAPEX - Other		
Pre-FID	Seismic and Baseline Survey	2.7
	Appraisal Well	0
	Engineering and Analysis	2.9
	Licencing and Permits	2.6
Post-FID	Licencing and Permits	2.6
Total CAPEX – Other Costs (£MM)		10.8

Table 6-6 Hamilton Development - Other Capex

6.2.2.2 Operating Expenditure

The 25 year OPEX (Real, 2015) for the Hamilton development has been estimated to be £496.5 million based on the following:

- Transportation at 1% of pipeline CAPEX per year.
- Offshore facilities at 6% of facilities CAPEX per year, plus. Cost to provide power are discussed in the appendices and is equivalent to approximately £4.3MM per year (approximately £50/MWh).
- Wells based on requiring 4 major and 2 minor workovers during the project life as summarised in Table 6-7.
- Other, as summarised in Table 6-8.

OPEX Estimate	Total Cost (£MM)
Major workover or Local Sidetrack	76.7
Workover 1 and 2	22.5
Total	99.2

Table 6-7 Hamilton Development - Wells OPEX

A breakdown of the OPEX associated with “Other” costs is presented below.

OPEX Estimate	Total Cost (£MM)
Measurement, Monitoring and Verification	10.6
Financial Securities	70.4
Ongoing Tariffs and Agreements	0.0
Total	80.9

Table 6-8 Hamilton Development - Other OPEX

A sensitivity to the power component of OPEX was conducted by increasing the cost of power to £100/MWh. This increased the life-cycle cost by approximately 12% in either Real or PV_{10}, 2015 terms. Table 6-9 shows the results of the analysis.

	Life-cycle costs (£MM)	
	Real, 2015	PV_{10}, Nominal, 2015
Power @ £52/MWh	873.4	226.1
Power @ £100/MWh	974.7	251.8
Difference	101.3	25.7
Difference (%)	11.6	11.4

Table 6-9 Cost of Power Sensitivity Analysis

6.2.2.3 Abandonment Expenditure

Abandonment costs for the Hamilton CO_2 transportation (pipeline) system has been estimated at 10% of transportation CAPEX.

The decommissioning costs for the offshore facilities are summarised in the table below, these costs were also generated using Que$tor.

ABEX / Decommissioning	Total Cost (£MM)
Transportation	9.4
Jacket	21.2
Facilities	18.4
Wells	28.1
Total	77.1

Table 6-10 Hamilton Development - Facilities ABEX

A breakdown of the ABEX associated with “Other” costs is presented below.

Other	Total Cost (£MM)
Post Closure Monitoring	12.7
Handover	5.8
Total	18.5

Table 6-11 Hamilton Development - Other ABEX

6.4 Economics

This section summarises the cost based economic metrics for the proposed development.

6.4.1 Project Component Costs

£million	Real (2015)	Nominal (Money of the Day)	PV_{10} (Nominal, 2015)
Transport	66	78	32
Facilities	107	126	53
Wells	109	148	37
Opex	497	772	99
Decommissioning & Post Closure Activity	96	208	5
Total	873	1332	226

Table 6-12 Hamilton Development Cost in Real and Nominal Terms

6.4.2 Transportation and Storage Costs

The contribution of each major element of the development to the overall cost is summarised in Table 6-13.

£/Million	Real (2015)	Nominal (MOTD)	Levelised ($PV_{10,}$ Nominal, 2015)
Transportation	87	112	36
Injection	786	1220	190
Total	873	1332	226

Table 6-13 Transportation and Storage Costs

6.4.3 Unit Costs

The life-cycle costs of the development on a unit basis are summarised in Table 6-14, Table 6-15, Figure 6-4 and Figure 6-5.

£/T	Real (2015)	Levelised ($PV_{10,}$ Real 2015)	Nominal (MOTD)	Levelised ($PV_{10,}$ Nominal, 2015)
Transportation	0.7	2.0	0.9	2.2
Injection	6.3	8.9	9.8	12.0
Total	7.0	10.9	10.7	14.2

Table 6-14 Transportation and Storage Costs per Tonne of CO_2

Note: the calculation of levelised cost includes the discounted value of the CO_2 stored (16Mt rather than the undiscounted value of 124Mt).

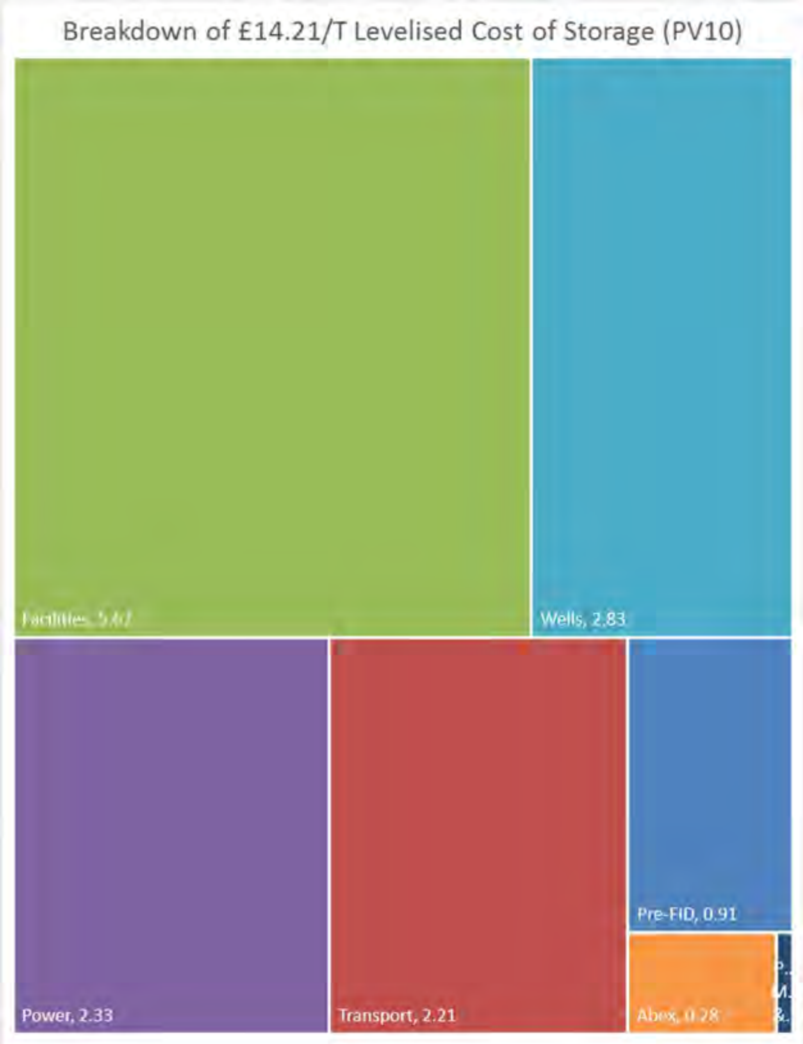

Figure 6-4 Breakdown of Levlised Cost

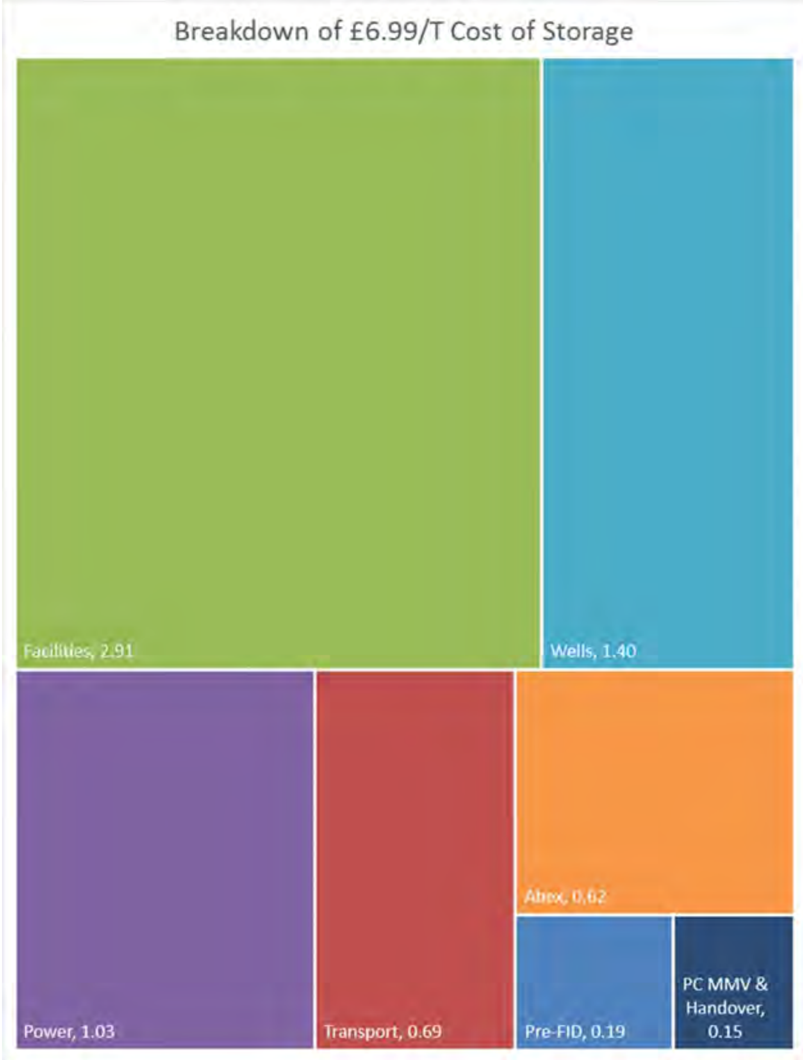

Figure 6-5 Breakdown of Life-cycle Cost

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 are 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	0.19	0.81	0.21	0.91
Transport	0.69	1.83	0.89	2.21
Facilities	2.91	4.23	4.39	5.62
Power	1.03	1.77	1.42	2.33
Wells	1.40	2.14	2.07	2.83
Abex	0.62	0.14	1.27	0.28
PC MMV & Handover	0.15	0.01	0.39	0.03
Total	6.99	10.93	10.65	14.21

Table 6-15 Unit Costs in Detail

7.0 Conclusions & Recommendations

7.1 Conclusions

Data

- There is 3D seismic coverage across the whole of the storage complex and the nearby relevant fairway. The survey is 1992 vintage and data quality is generally moderate. This is capable of providing a competent basis for a development decision, however a new 3D seismic survey would improve confidence in development well placement and also enable more quantitative information to be extracted as well as serving as a baseline survey for 4D monitoring.
- There is good regional well coverage and reasonable well data available within the storage complex including modern logs and core data.
- Comprehensive historical well by well production and pressure exists for Hamilton but was not available to this project. This represents a notable gap in the data set and accounts for much of the uncertainty in the simulation modelling.

Containment

- There is a high level of confidence that over 124Mt of CO_2 can be contained within the Ormskirk Sandstone in the Hamilton structure.
- 1000 years after injection has ceased the CO_2 plume is still contained within the Hamilton structure and the defined storage complex.
- The primary seal is provided by a 700m sequence of mudstones and halites of the Mercia Mudstone Group, specifically the Rossall Halite.
- Underlying the Sherwood Sandstone is approximately 670m of the tight St Bees Sandstone which prevented aquifer ingress during hydrocarbon operations. The St Bees Sandstone is likely to be virtually impermeable to CO_2 and provide a very effective containment feature at the floor of the store.
- Hamilton has minimal risk of caprock or fault failure for the modelled stress conditions, reservoir and overburden properties and fault properties.
- The geomechanical models do not account for thermal effects in the near well bore area and these effects may reduce the fracture pressure near the wells.

Site Characterisation

- The ENI seismic volume which extends over the Hamilton field and the regional fairway has been interpreted. The key horizons have been identified, interpreted and mapped. Seismic data quality is considered adequate for structural interpretation at this stage of the development.
- The main reservoir event is a clear pick over the storage site.
- The Hamilton structure is bounded by large continuous faults and the horst block is split by numerous faults creating a complex geometry. Internal faults seem to be restricted to sand-to-sand contact.

- There is a high degree of confidence in the depth conversion due to the high density of wells in the field.
- Amplitude extraction around the top reservoir shows a clear gas signature which define the edges of the field.

Capacity

- There is a high degree of certainty on most of the subsurface variables: the pore volume is well known from the volume of hydrocarbons extracted over Hamilton's operational life; there is good well data coverage with little variation and relative permeability to water is not relevant in a depleted gas field with an immobile water leg.
- Capacity estimates range between 109 - 131 Mt (P90 to P10) and is largely independent of injection rate, but strongly dependent on the amount of hydrocarbon production.
- In the unlikely event that the fracture pressure limit does not recover during re-pressurisation it may limit capacity to around 47Mt.

Appraisal

- No further appraisal drilling is considered necessary at this time.
- No further 3D seismic data is required before the Final Investment Decision.
- A key uncertainty is around how the fracture pressure of the reservoir formation will evolve as the store is re-pressured during CO_2 injection. Appraisal activity should address this issue.
- A further key uncertainty exists regarding the optimum way to manage the operations during the phase transition from gas to liquid CO_2 injection.

Development

- Final Investment Decision needs to be in 2022 in order to achieve the first injection date of 2026.
- The planning work indicates that approximately 7 years are required to fully appraise and develop the store.
- A £116 million (in present value terms discounted at 10% to 2015) capital investment is required to design, build, install and commission the pipeline, platform and initial tranche of wells. Provision has been made for an additional investment of £40 million (real terms) (£5 million in present value terms discounted at 10% to 2015) in 2040 to replace all wells prior to commencing dense-phase operations.
- The development is designed to accommodate the Reference Case supply profile of 5Mt CO_2/year from 2026 for approximately 25 years.
- Hamilton is estimated to have a current reservoir pressure of approximately 10 bara. This requires a development scheme split into two periods. During the first 13-14 years CO_2 is injected in the gas-phase and the in the subsequent 11 years CO_2 is injected in dense-phase.
- The Reference Case development includes all new infrastructure: a minimum facilities platform; 26km of 16" pipeline from Connah's Quay (Point of Ayr terminal) and two active injection wells.
- It is most cost-efficient to transport CO_2 in liquid-phase and then manage the low temperature effects of the phase change to gas using heating during the first development period.

- The dense-phase injection period requires wells with 5.5” completions rather than the 9 5/8” completions required to handle the created volumes during the gas-phase injection period.
- The main potential opportunities for cost reduction are: re-using the gas-phase wells in the liquid-phase period by recompleting them with the smaller tubing; fewer well interventions, heating requirements and potential re-use of some of the existing Hamilton infrastructure.

Operations

- The fracture pressure at top reservoir (723m) is estimated to be 64.5 bara at the beginning of the gas-phase injection period and 104.6 bara at the beginning of the dense-phase injection period.
- The safe operating envelope for the wells is based on geomechanical analysis and the maximum allowable pressure has been constrained to 90% of the fracture pressures (58 bar and 94 bar respectively).
- The wells will require a total of approximately 10MW of heating during the gas-phase operations to accommodate the 5Mt/y CO_2 supply profile. The power will be provided via a subsea cable from Point of Ayr. This accounts for approximately 17% of the life-cycle cost of the development.

7.2 Recommendations

Appraisal Programme

- Acquire a new 3D seismic survey focussed at the Ormskirk level to aid placement of development wells and provide a baseline for 4D monitoring.
- Plan to acquire the seismic survey after the final investment decision is taken. The primary use of the seismic would be for well positioning and establishing a baseline prior to injection commencing.
- Gain more detailed access to the field data set so that well status and abandonment status can be fully understood. Work to ensure that the Operator is 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.
- Improve the characterisation of how the fracture pressure will evolve during the re-pressurisation of the reservoir.
- Identify additional studies that could confirm the design and specification of 4D seismic to ensure maximum effectiveness as a monitoring tool.
- Secure the historical production and pressure for the gas production wells and use to improve calibration of the simulation model.

Operational Planning

- Identify and quantify opportunities for cost and risk reduction across the whole development, for instance designing and drilling the gas phase wells in such a way that they could become the liquid phase injection wells.
- Identify synergies with other offshore operations. This should include a careful review of the existing Hamilton platform and wells to check whether there might be a viable and cost effective re-use option.
- Commission further work to better understand the options for managing the transition from gas-phase to liquid phase operations and how best to select a preferred strategy.
- Further investigation into the range of operational issues identified in Section 5.
- Existing operational wells should be abandoned using best practice available to preserve the site for future CO_2 storage service.

Development Planning

- Consider the commercial aspects required for the development of Hamilton in the light of past petroleum use to ensure that all existing rights are honoured whilst enabling the development to proceed.
- Incorporate the regulatory licensing and permitting requirements into the development plan.
- Work with the petroleum operator of Hamilton and the regulator to ensure that the wells are abandoned using all best practice to secure the CO_2 integrity of the site.
- Review the current assumption that heating during the gas-phase operation is more beneficial than drilling additional wells. There may also be options to add a produced gas stream to the injection stream to modify the PVT properties to reduce or eliminate heating requirements.

- Further work should consider how best to deliver the heating requirements and identify alternatives to the 10MW electrical heating options evaluated for this study.
- Examine options for extending storage development to other nearby operations such as the Morecambe Bay gas fields.

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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.
Bottom Hole Pressure (BHP)	This the pressure at the midpoint of the open perforations in a well connected to a reservoir system
Clastic	Pertaining to rock or sediment composed mainly of fragments derived from pre-existing rocks or minerals and moved from their place of origin. Often used to denote sandstones and siltstones.
Closure	A configuration of a storage formation and overlying cap rock formation which enables the buoyant trapping of CO_2 in the storage formation.
CO_2 Plume	The dispersing volume of CO_2 in a geological storage formation
Containment Failure Mechanism	The geological or engineering feature or event which could cause CO_2 to leave the primary store and/or storage complex
Containment Failure Modes	Pathways for CO_2 to move out of the primary store and/or storage complex which are contrary to the storage development plan
Containment Risk Scenario	A specific scenario comprising a Containment Failure Mechanism and Containment Failure Mode which might result in the movement of CO_2 out of the primary store and/or storage complex
Evaporite	Sediments chemically precipitated due to evaporation of water. Common evaporates can be dominated by halite (salt), anhydrite and gypsum. Evaporites may be marine formed by the evaporation within an oceanic basin, or non-marine typically formed in arid environments.

Defined Term	Definition
Facies (Sedimentary)	A volume of rock that can be defined and recognised by a particular set of characteristics (physical, compositional, chemical) often reflecting its environment of deposition
Fault	Fracture discontinuity in a volume of rock, across which there has been significant displacement as a result of rock movement
Fluvial	Pertaining to or produced by streams or rivers
Formation	A formation is a geological rock unit that is distinctive enough in appearance and properties to distinguish it from surrounding rock units. It must also be thick enough and extensive enough to capture in a map or model. Formations are given names that include the geographic name of a permanent feature near the location where the rocks are well exposed. If the formation consists of a single or dominant rock type, such as shale or sandstone, then the rock type is included in the name.
Gardener's Equation	A relationship between seismic velocity V in ft/s (ie. The inverse of the sonic log measured in µs/ft) and density ρ in g/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
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.

Defined Term	Definition
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

The following appendices are provided separately:

11.1 Appendix 1 – Risk Matrix

11.2 Appendix 2 – Leakage Workshop Report

11.3 Appendix 3 – Database

11.4 Appendix 4 – Geological Information

11.5 Appendix 5 – MMV Technologies

11.6 Appendix 6 – 3D Geomechanical Modelling

11.7 Appendix 7 – Well Basis of Design

11.8 Appendix 8 – Cost Estimate

11.9 Appendix 9 – Methodologies

11.10 Appendix 10 – Well Performance Sensitivity Analysis

11.11 Appendix 11 – Fracture Pressure Gradient Calculation

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Disclaimer:

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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 Hamilton & 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 Hamilton 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 Hamilton 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
- CO_2 Storage expert

The well expert reviewed the findings following the meeting. There were no well abandonment records available for Hamilton as input to the workshop.

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:

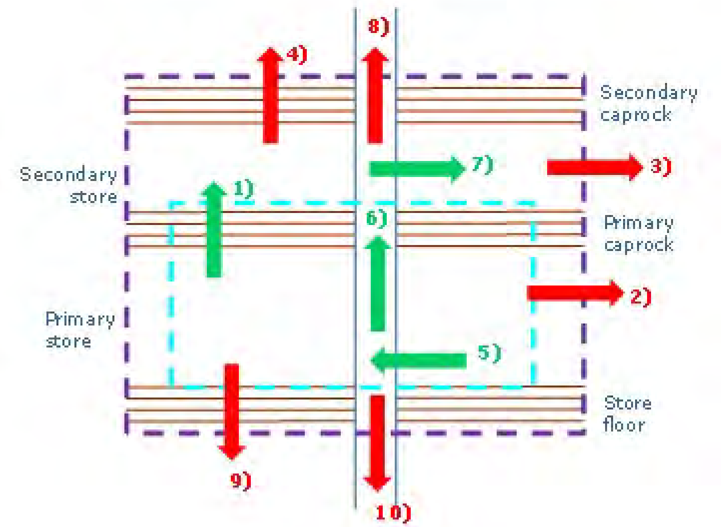


Figure 11-1 Containment failure modes

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 **Invalid source specified.** 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) **Invalid source specified.** database 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	2	
Vertical movement of CO_2 from Primary store to overburden via pre-existing wells	4	2	
Vertical movement of CO_2 from Primary store to overburden via injection wells	1	2	
Vertical movement of CO_2 from Primary store to overburden via both caprock & P&A wells	1	2	
Vertical movement of CO_2 from Primary store to overburden via both caprock & inj wells	2	5	
Vertical movement of CO_2 from Primary store to seabed via pre-existing wells	2	5	
Vertical movement of CO_2 from Primary store to seabed via injection wells	1	5	
Vertical movement of CO_2 from Primary store to seabed via both caprock & wells	1	5	
Vertical movement of CO_2 from Primary store to seabed via fault	2	2	
Lateral movement of CO_2 from Primary store out with storage complex w/in Ormskirk (via bounding faults as others do not apply)	2	2	
Primary store to underburden (well 110/13-1 drilled to Carboniferous - w/in Storage complex)	1	1	

Table 11-1- Leakage Scenarios

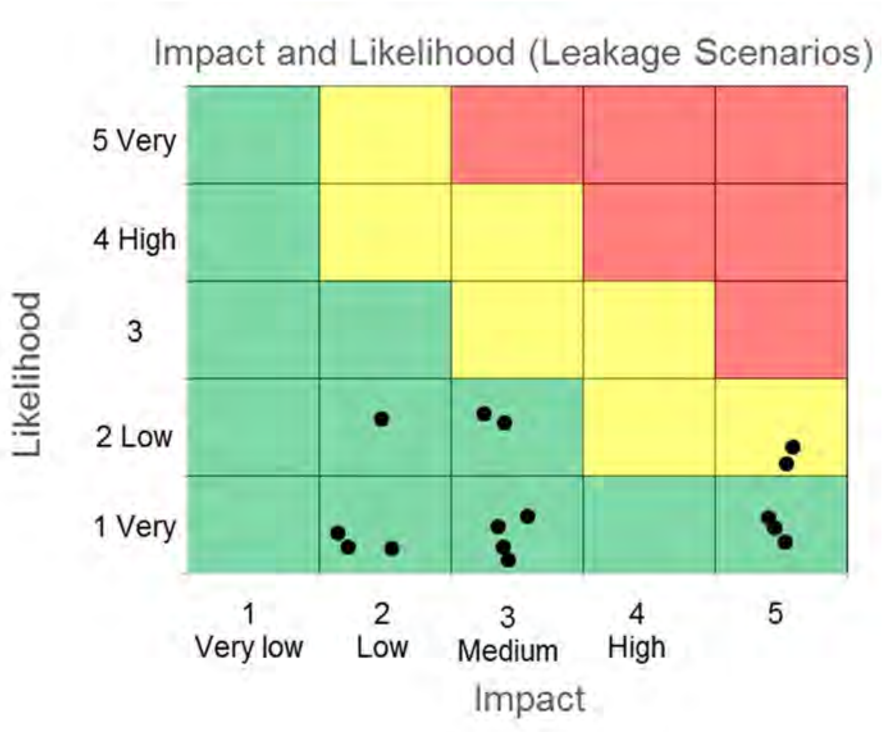


Figure 11-2 Risk matrix of leakage scenarios

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.

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 Hamilton Storage Site SEG-Y data summary

The Hamilton gas field is covered by a single 3D dataset, acquired in 1992 and currently owned by ENI. The data is listed on the CDA database but stored by ENI. These data were loaded to Schlumberger's proprietary PETREL software where the seismic interpretation was undertaken. Figure 11-4 Map showing distribution of the Hamilton 3D Seismic Datashows the extent of the 3D dataset and the location of the Hamilton Field site model. There is complete seismic coverage of the area.

CDA reference is BH923D2001(3D).

The seismic data was transcribed from original tapes and supplied as SEG-Y on a USB stick drive with no navigation data in the headers. A separate P1/84 navigation tape was also copied and supplied by email. The navigation parameters are as follows:

Survey Datum	Name:	ED50
Ellipsoid:	International 1924	
Semi Major Axis	6378388	
1/Flattening	297	
Map Projection	Projection	UTM 30N
Central Meridian	3 West	
Scale Factor on Central Meridian	0.9996	
Latitude of Origin	0.00N	
False Northing	0	
False Easting	500000	

Corner Points

	Start	End	Step
Inline	190	6430	5
Crossline	250	3656	2

	Origin	End First Inline	End First Crossline
X	458773.19	480060.47	458904.37
Y	5927697.97	5927578.59	5951097.40
Intervals		18.75m	12.5m
Rotation		90.321	0.321

The ebcdic header information including the processing summary is as follows:

HAMILTON OIL COMPANY. AREA: BLOCK 110/13

SUBLINE RANGE 2665-2735 RECORDED BY: S.S.L. M/V SEISQUEST

REEL SY729 DATE MARCH 1992 INTSRUMENTS: SYNTRAK 480(MSTP)

FILTER LOWCUT: 8HZ.18DB/OCT HIGHCUT: 250HZ.72DB/OCT

SAMPLE RATE: 2MS. CONTRACT NO: 150 RECORD LENGTH: 3.584MS.

SHOT INTERVAL: 12.5M ALTERNATE COVERAGE: 6X30 FOLD

CABLE LENGTH: 3X1500M. SEPERATION: 75M. TYPE TELEDYNE

CABLE DEPTH: 6M. AV. GUN DEPTH: 4.5M. NO. OF GROUPS: 3X120

GROUP INTERVAL: 12.5M. GUN DELAY: 130MS. SOURCE WIDTH: 20M.

SOURCE 2 X SLEEVE GUN ARRAY 2 X 1690 CU.INS. 2000 P.S.I.

SOURCE SEPARATION: 75M. AV. LENGTH: 12M. OFFSET: VARIABLE

FIELD FORMAT: SEGD 8015 CARTRIDGE TAPE DENSITY: 3480 BPI

NAVIGATION SYSTEM: SYLEDIS

FIELD POLARITY: COMPRESSION WAVE ON TAPE IS NEGATIVE

PROJECTION: UTM NORTH ZONE 30 SPHEROID: INTERNATIONAL

REFORMAT AND EDIT. FURTHEST CABLE FROM ALT. SP'S DROPPED

RESAMPLE FROM 2 TO 4MS. USING MINIMUM PHASE CONVERSION

USING SUPPLIED SYNTHETIC SIGNATURE + ANTI-ALIAS FILTER-

CUT OFF 90HZ./72DB. APPLICATION OF NAVIGATION BIN SIZE-

37.5M. X 6.25M. ROTATION ANGLE -0.321

APPLICATION OF TIDAL STATICS TO LOWEST ASTRONOMICAL TIDE

AND GUN AND CABLE DEPTH STATIC OF +8MS.

EXPONENTIAL GAIN +5DB/SEC. 0.0 TO 3.0 SECS. WHOLE TRACE

EQUALISATION. F/K FILTER LOW FREQUENCY PROTECTION 10HZ.

PASSING DIPS +/- 4MS. PER TRACE USING 'FILTKF

SPHERICAL DIVERGENCE CORRECTION. FIRST BREAK SUPPRESSION

DECONVOLUTION BEFORE STACK 120MS. OP + 8MS. GAP

DESIGN GATES NEAR 0.3 TO 1.5 FAR 1.3 TO 2.3 SECS.

TRACE EXCURSION: FULL BIN. 3D NMO CORRECTION USING

DIGICONS 'DIVAN' 600 X 500M. GRID. POST NMO MUTING

3D D.M.O. CORRECTION USING KIRCHHOFF ALGORITHM.

3D STACK 60 FOLD (ADJACENT CROSSLINES STACKED TO 12.5M

INTERVAL). DECONVOLUTION AFTER STACK 120MS OP. + 24MS.

GAP GATE 0.3-1.5 SECS. APPLIED 0.0-1.2 SECS. ONLY

PRE-MIGRATION FILTER. TRACE INTERPOLATION SUBLINE

INTERVAL 18.75M. PRE MIGRATION SCALING.

1 PASS OMEGA-X MIGRATION USING TIME VARIANT VELOCITY

PERCENTAGES 0.0 100%, 0.9 100%, 1.1 94% 1.3 92% 3.5 90%

ZERO PHASE CONVERSION WHITENED. TIME VARIANT FILTER

EXPANDED AGC. NOISE REDUCTION USING DECHEQUER

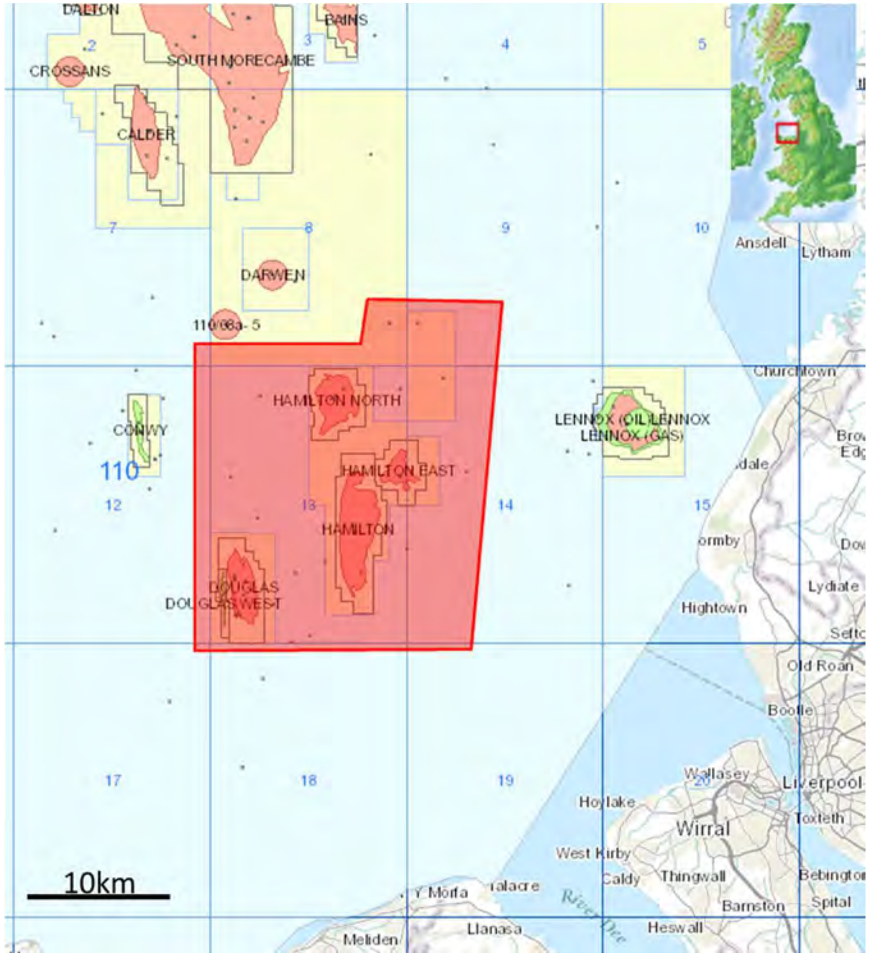


Figure 11-3 Hamilton 3D extents as listed on CDA

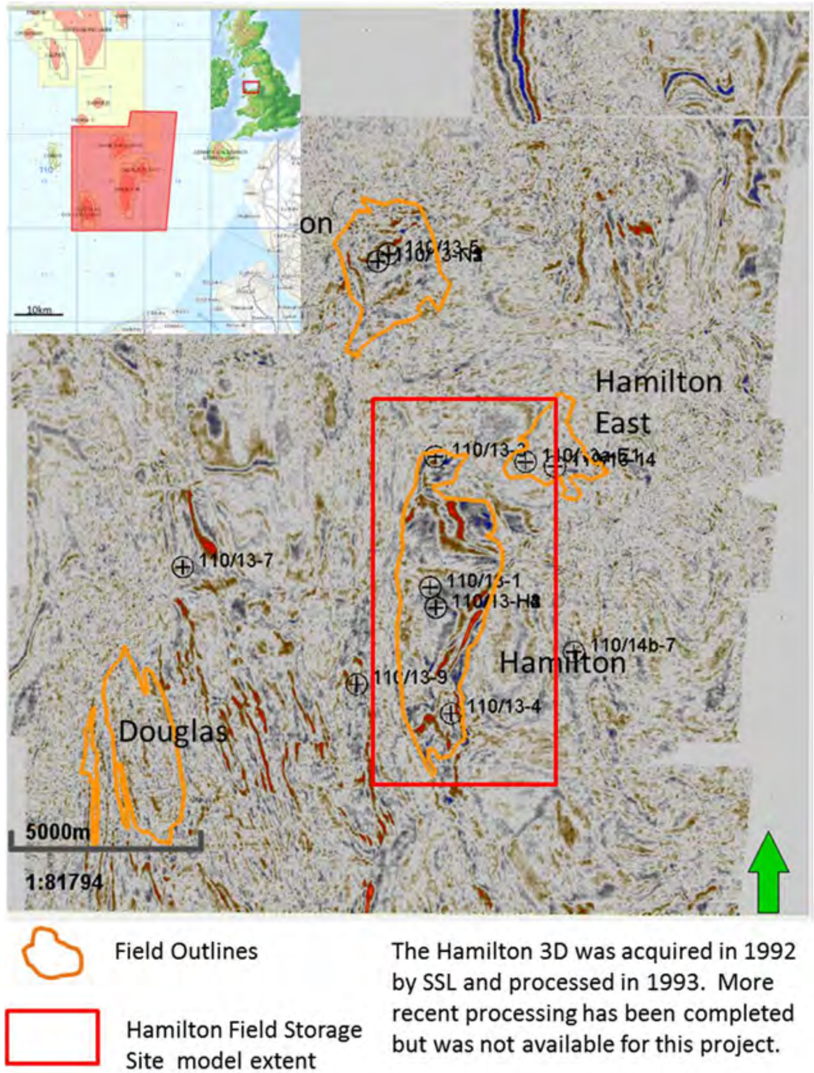


Figure 11-4 Map showing distribution of the Hamilton 3D Seismic Data

11.3.2 Hamilton Storage Site: Well log data summary

The table below shows a summary of the well data for Hamilton Storage Site, downloaded from CDA.

Field	Well	Completion Date	Interpreted Logs	Well used in site model	Well used in fairway model	Core Data	Checkshots
Hamilton	110/13-1	Jul 1990	Y	Y	n/a	Y	Y
	110/13-3	Dec 1990	Y	Y	n/a	Y	Y
	110/13-4	Apr 1991	N	Y	n/a	Y	Y
	110/13-H1	Apr 1996	Y	Y	n/a	N	N
	110/13-H2	Sep 1996	Y	Y	n/a	N	N
	110/13-H3	Dec 1996	Y	Y	n/a	N	N
	110/13-H4	Sep 1998	N	Y	n/a	Y	N
Hamilton East	110/13-14	Dec 1993	N	N	n/a	N	N
	110/13a-E1	Aug 2001	N	N	n/a	Y	Y
Hamilton North	110/13-5	May 1991	N	N	n/a	N	N
	110/13-N1	Oct 1995	N	N	n/a	N	N
	110/13-N2	Oct 1995	N	N	n/a	N	N
	110/13-N3	Oct 1996	N	N	n/a	N	N
	110/13-7	Jul 1991	Y	N	n/a	N	N
	110/13-9	Aug 1991	Y	N	n/a	N	N
	110/14b-7	May 2009	N	N	n/a	N	N

Table 11-4 Well log data summary

11.3.3 Hamilton Storage Site: Core data summary

The table below show a summary of the core data available over the Hamilton Storage site.

11.3.4 Data from Operators

In addition to the seismic and well data downloaded from CDA and the production history of the Hamilton gas field which was downloaded from DECC website, further information and guidance has been available from some petroleum operators in the area under Non-Disclosure Agreements. Whilst data from these disclosures is not included in this report or in any of the models developed for this study, this guidance has provided valuable context for the consideration of Hamilton as a CO2 storage development site.

Well	Cored interval (MD ft)	Cpor	CKH	CKV	Core Log	Core Description	Core Photos
110/13-1	2552-2944	Y	Y	Y	N	Y	Y
110/13-3	2903-3085	Y	Y	Y	Y	Y	Y
110/13-4	3140-3478	Y	Y	Y	N	N	N

Figure 11-5 Hamilton Site - Core Data Summary

11.4 Appendix 4 – Geological Information

11.4.1 CPI logs

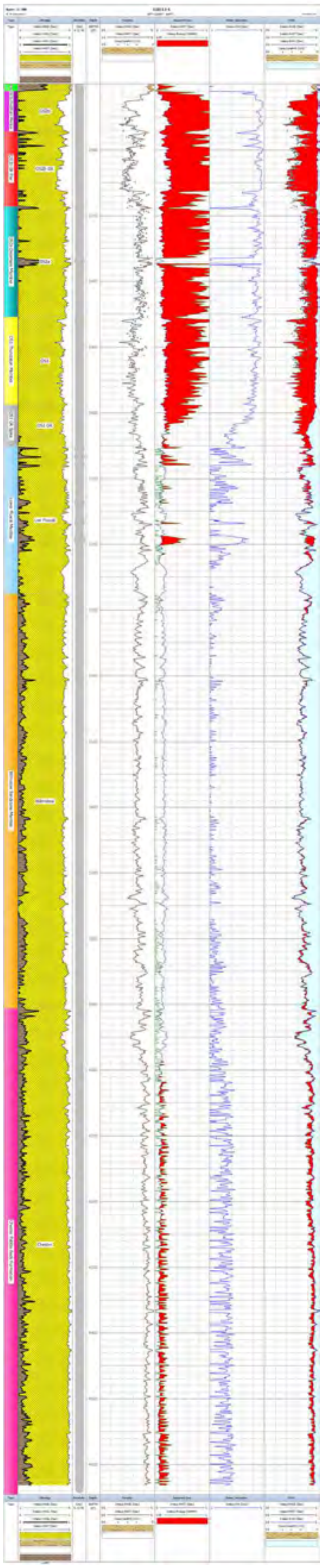


Figure 11-6 Well 110/13-1 Interpretation

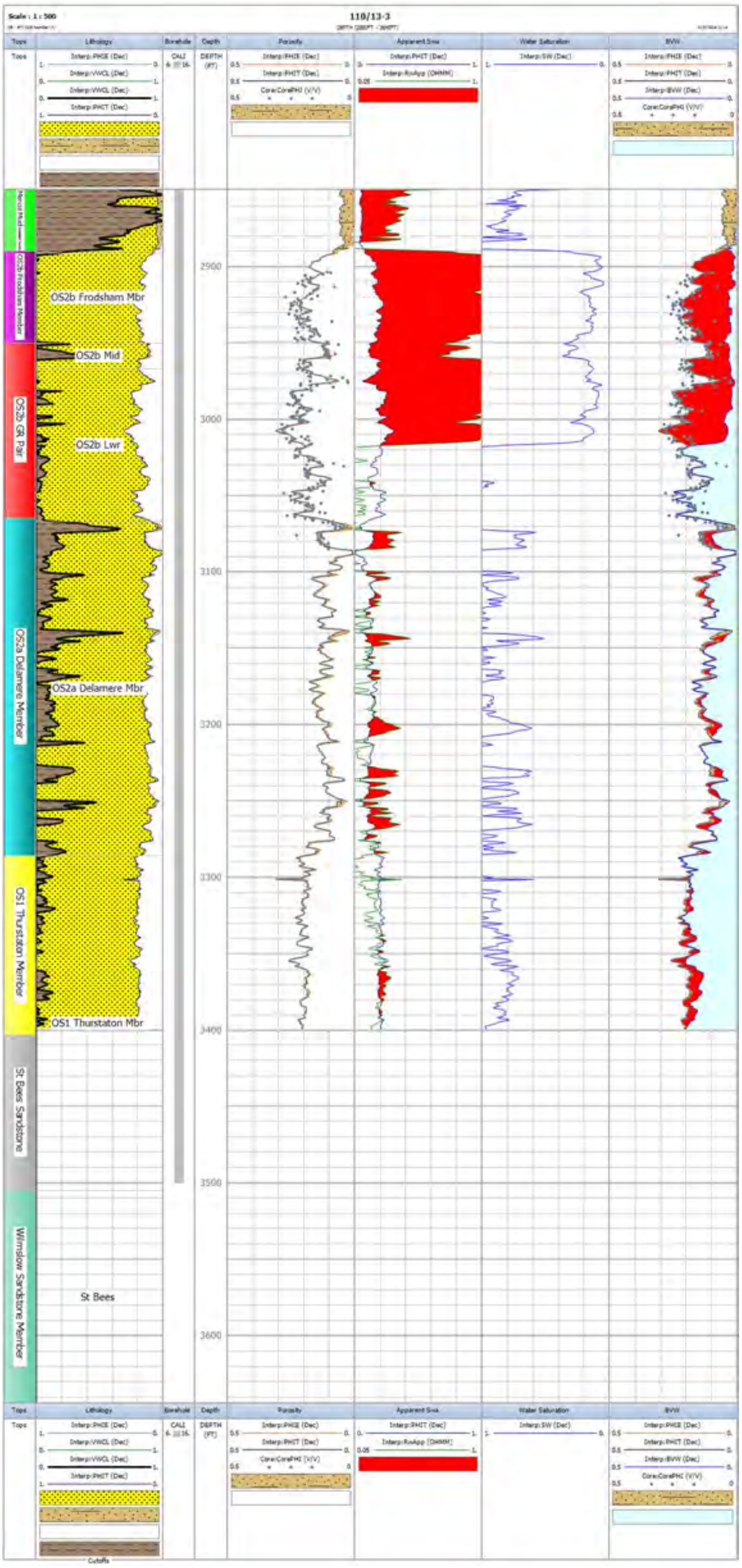


Figure 11-7 Well 110/13-3 interpretation

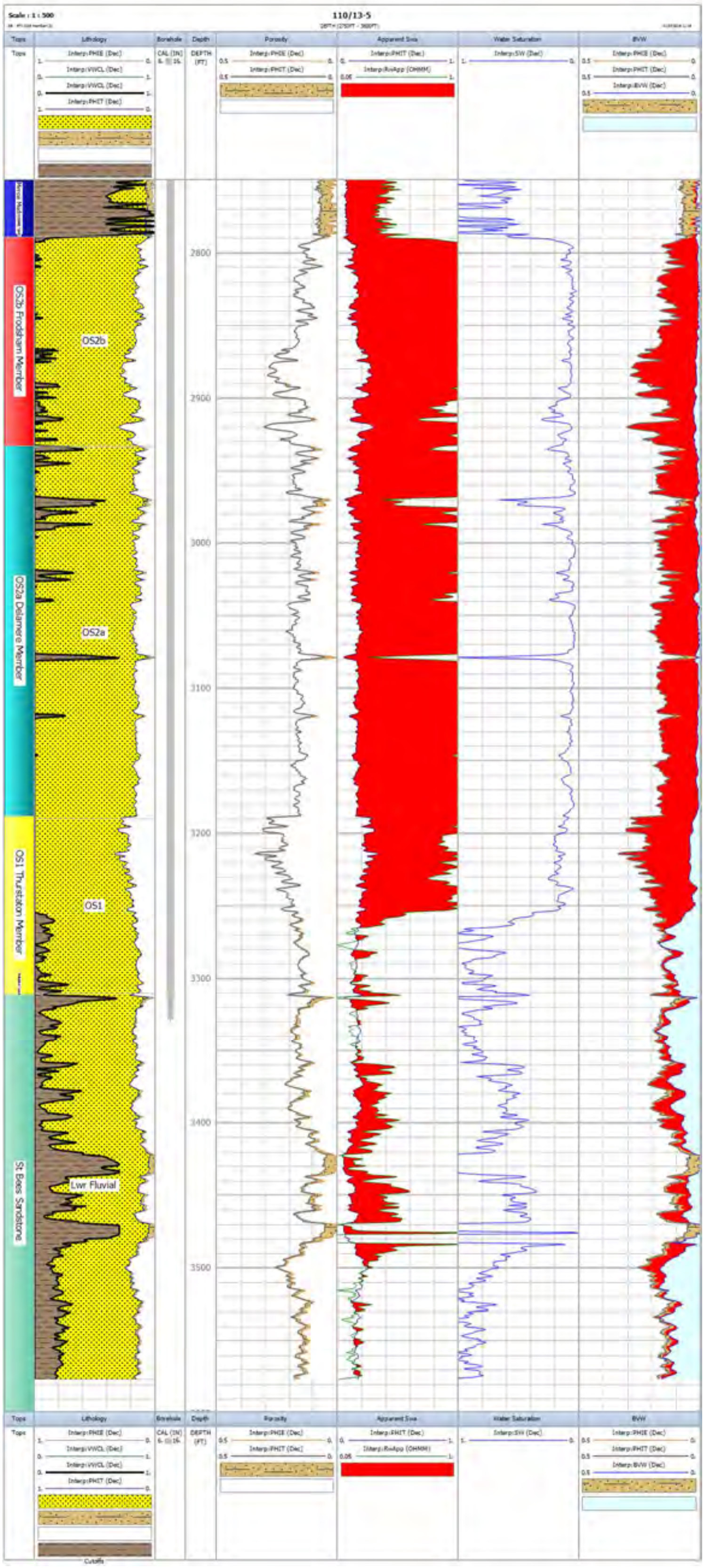


Figure 11-8 Well 110/13-5 interpretation

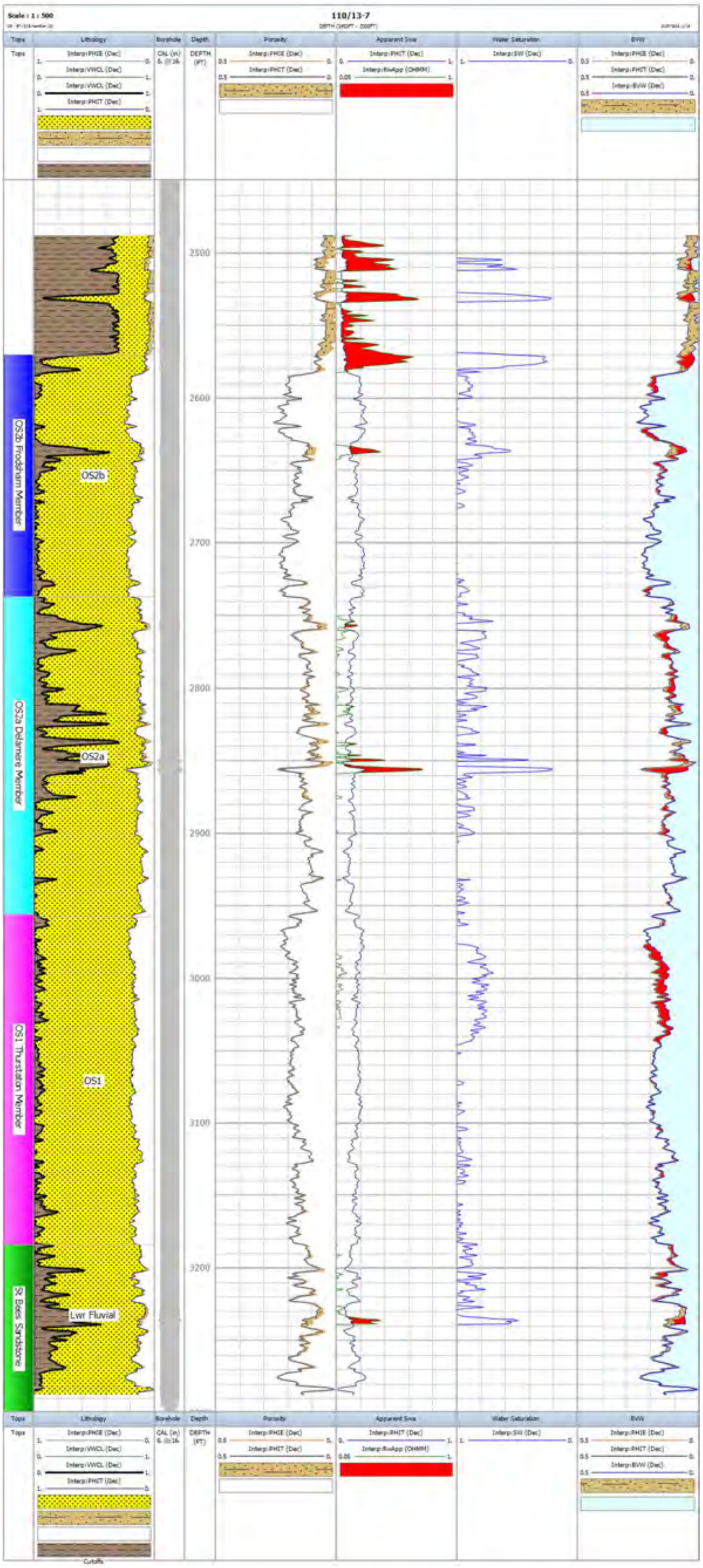


Figure 11-9 Well 110/13-7 interpretation

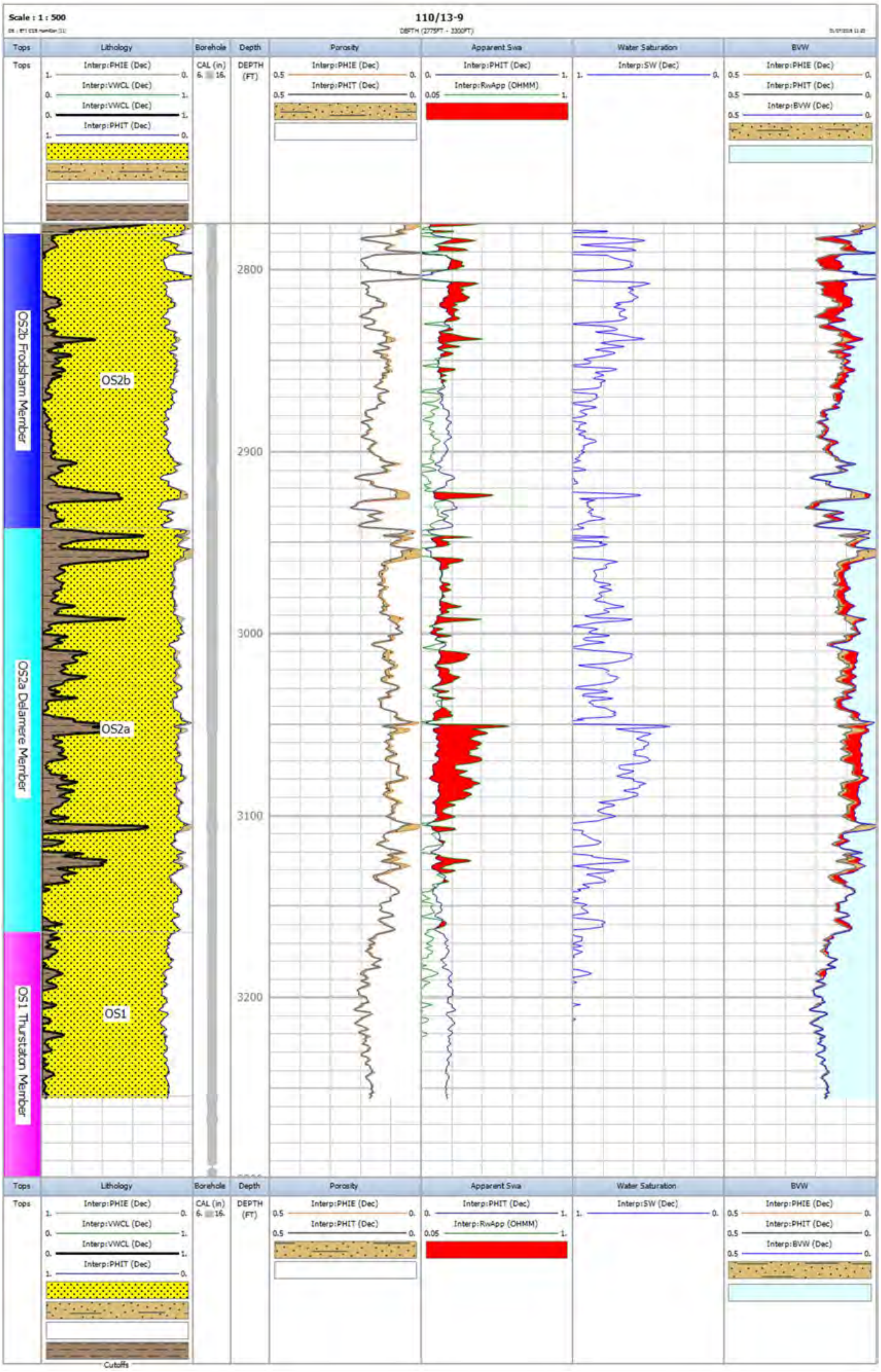


Figure 11-10 Well 110/13-9 interpretation

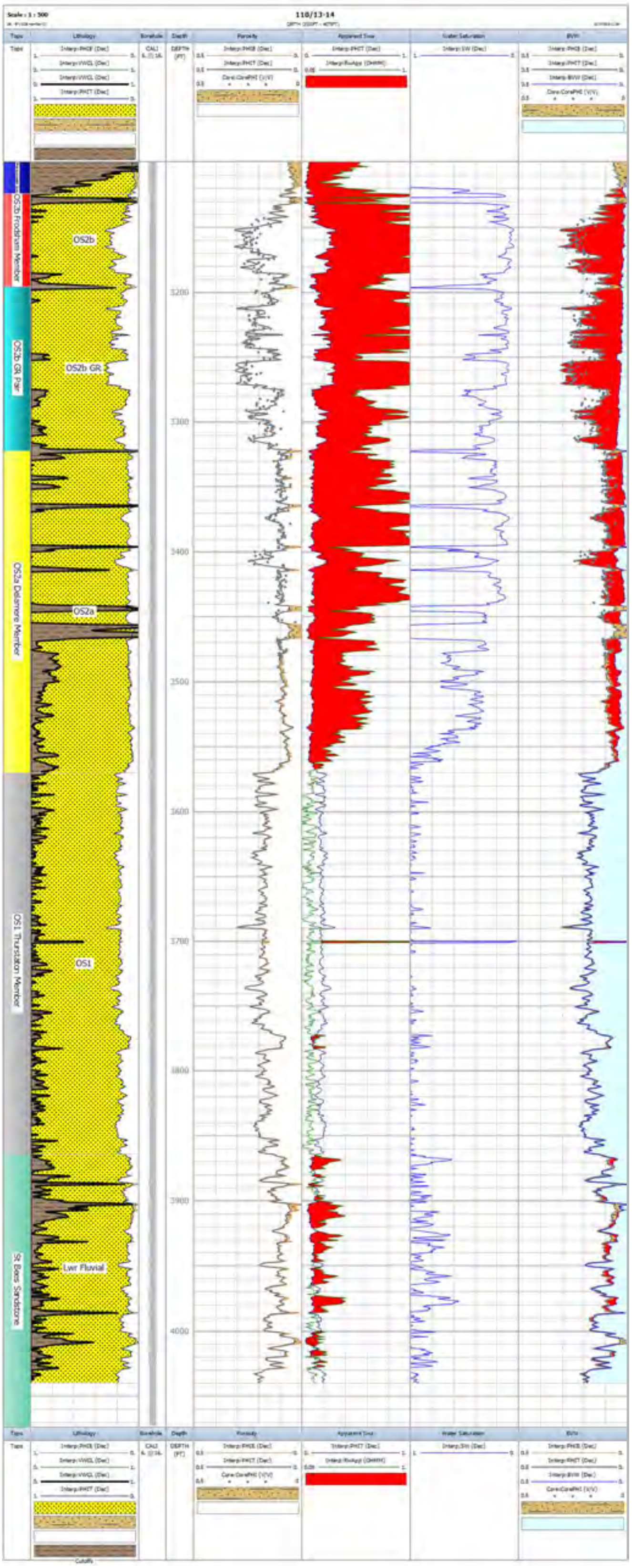


Figure 11-11 Well 110/13-14 interpretation

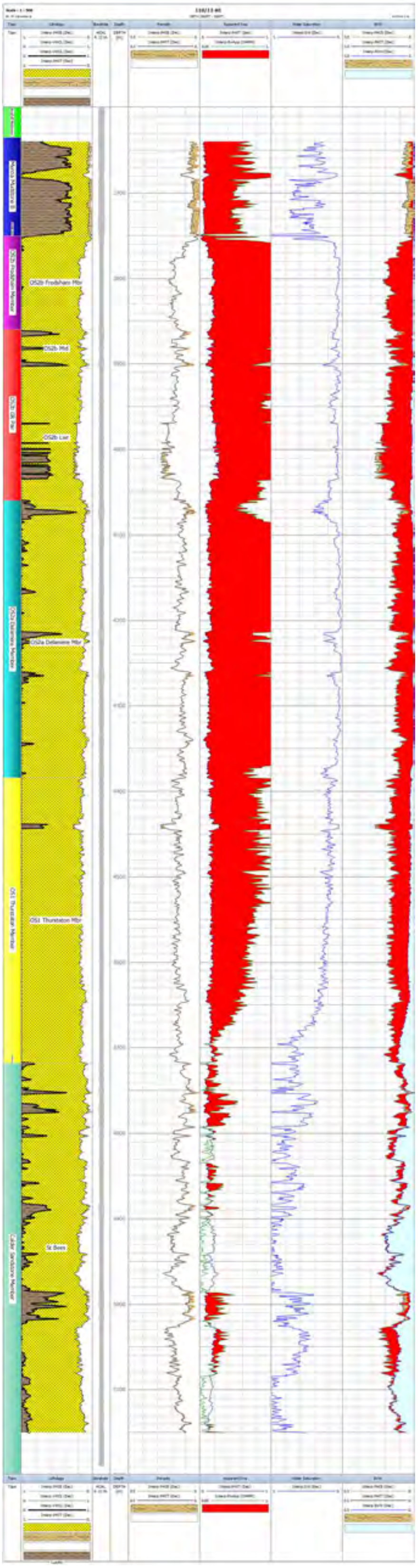


Figure 11-12 Well 113/13-H1 interpretation

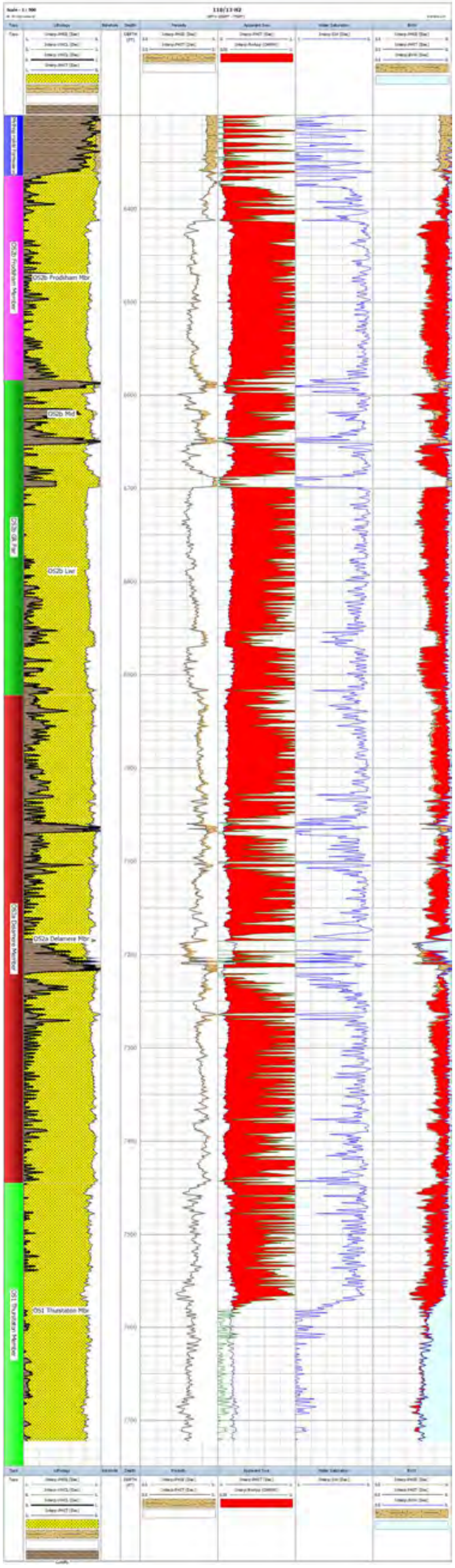


Figure 11-13 Well 113/13-H2 interpretation

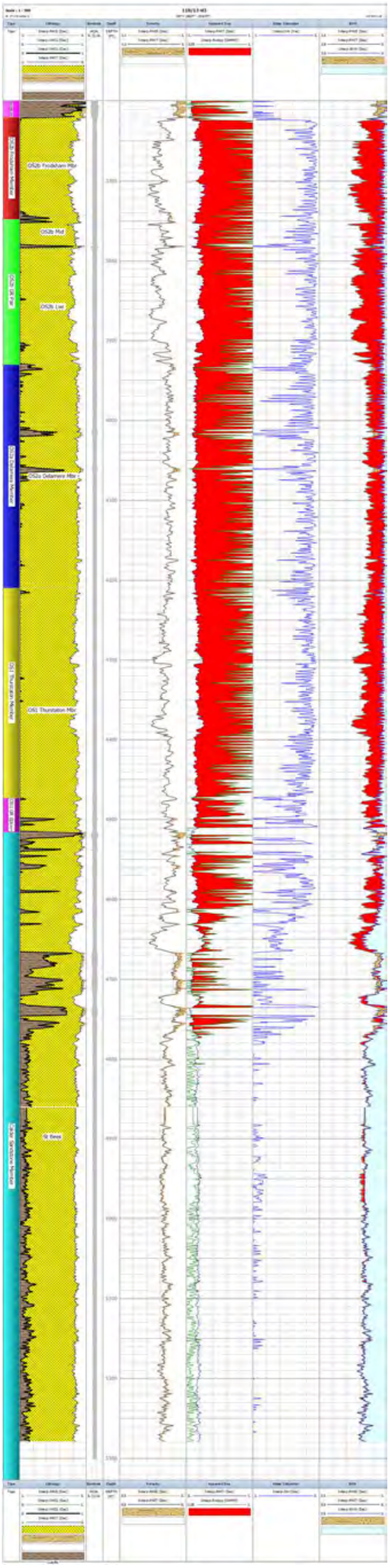


Figure 11-14 Well 110/13-H3 interpretation

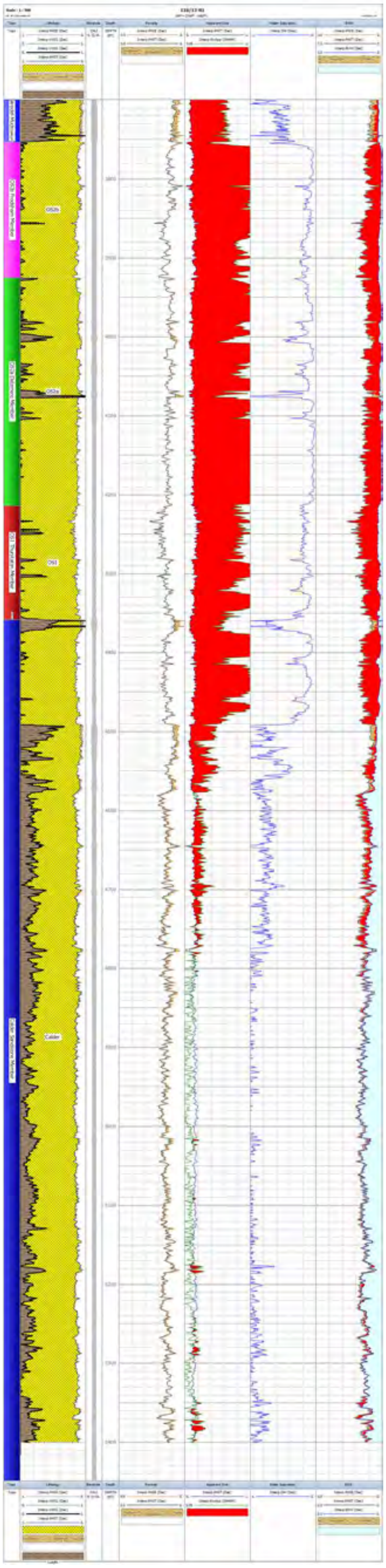


Figure 11-15 Well 110/13-N1 interpretation

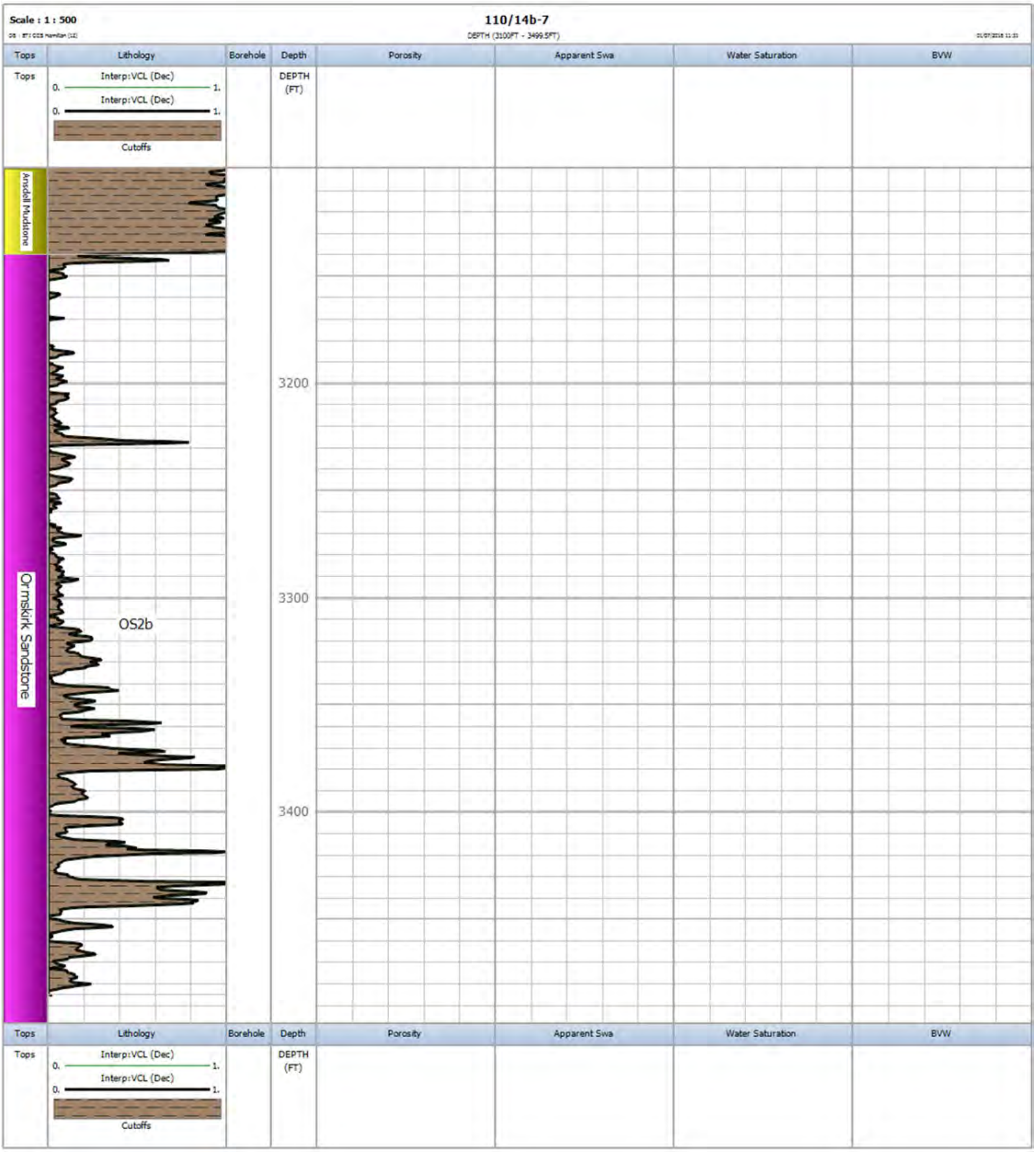


Figure 11-16 Well 110/14b-7 interpretation

11.5 Appendix 5 – MMV Technologies

11.5.1 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 NETL, 2012 (**MMV Ref 4)** and IEAGHG, 2015 **(MMV Ref 5).**

NETL, 2012 (**MMV Ref 4)** references a "field readiness stage" for each technology, based on its maturity:

- Commercial
- Early demonstration
- Development

IEAGHG, 2015 (**MMV Ref 5)** 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 11-17 and Table 11-5 provides additional information about each technology and the rationale for technologies in each quadrant.

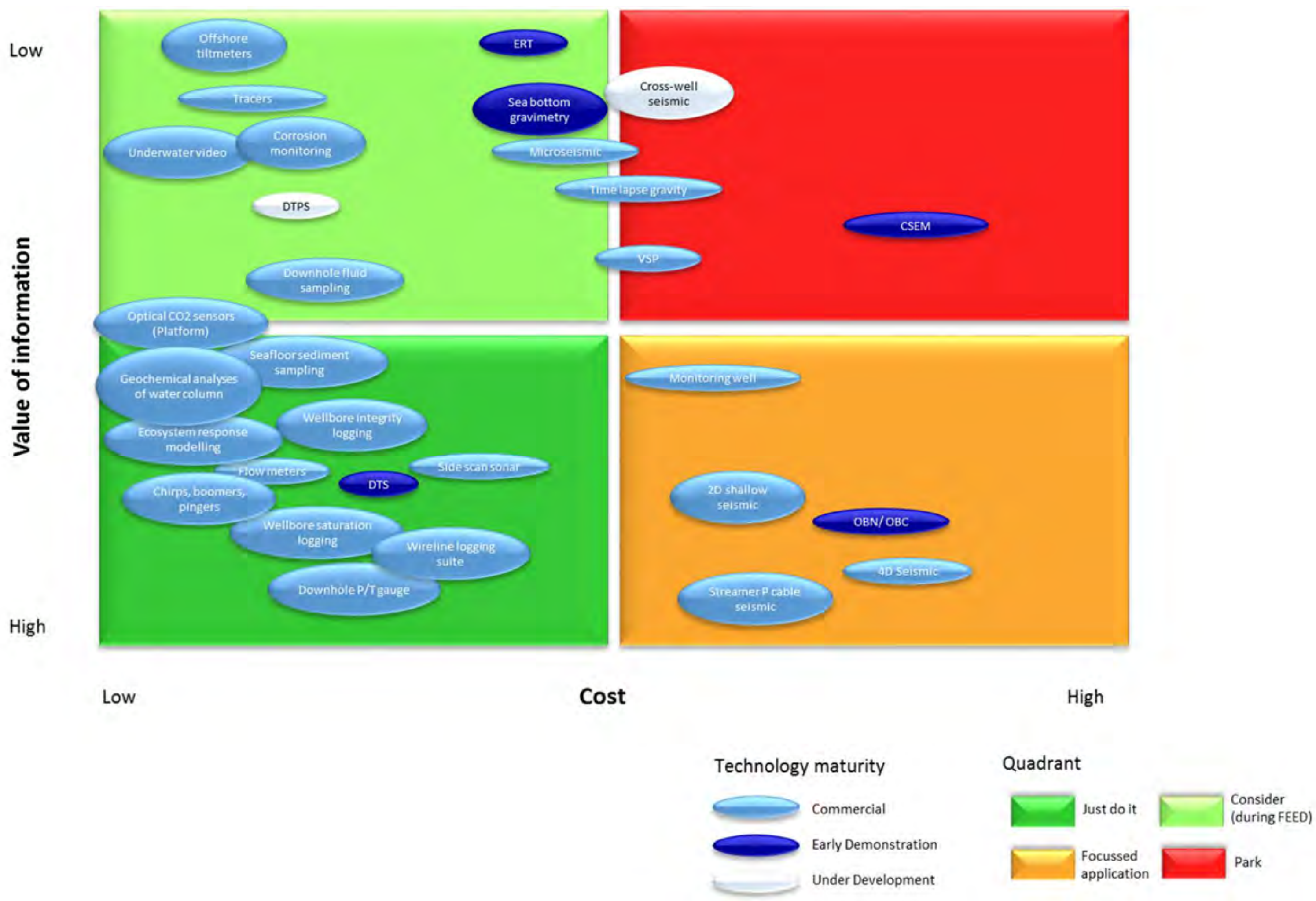


Figure 11-17 Boston square plot of monitoring technologies applicable offshore

11.5.2 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 migration from reservoir with associated temperature drop or any fluid temperature fluctuations which could indicate a poorly sealed wellbore.	Just do it	Considered essential to ensure integrity of injection operations. Also used to update reservoir models.
Subsurface	Permanent Downhole Tool	Development Stage	Distributed thermal pertubation sensor (DTPS)	Platform and subsea	DTPS measures the thermal conductivity of the formation and can estimate CO2 saturation within the zone of injection (decrease in bulk thermal conductivity indicates an increase in CO2 saturation). Equipment includes an electrical heater with DTS.	Consider	The technology is at development stage so monitor its maturation and consider inclusion in FEED.

Monitoring Domain	Type	Field Readiness	Technology	Applicability to Offshore	Description	Boston Square Box	Comments/ rationale
Subsurface	Permanent Downhole Tool	Commercial	Corrosion monitoring	Platform and subsea	CO_2 with brine can be corrosive and so corrosion monitoring can be used to prevent potential failures within the injection system. Two techniques: (i) expose a removable piece of casing to the corrosive fluid for a set amount of time, remove it and analyse it (ii) install a corrosion loop with the injection system which can be removed and examined for signs of corrosion	Consider	Wellbores will designed to minimise corrosion and injection CO_2 will be dehydrated to minimise corrosion. Therefore uncertainty over benefit. To consider further in FEED.
Subsurface	Permanent Downhole Tool	Commercial	Downhole & wellhead Pressure/ Temperature gauges	Platform and subsea	Located in the storage reservoir and can give continuous reservoir pressure and temperature throughout field life. The injected CO_2 will be at a lower temperature than reservoir temperature so can differentiate between CO_2 and brine. Pressure and Temperature data can be used as input to reservoir models. Pressure can be used to confirm mechanical integrity of wellbore. Can be used at monitoring wells to aid in detection of CO_2 arrival (CO_2 may be at lower temperature and higher pressure than fluids in the formation). Deployment required under the EU Storage Directive	Just do it	Required under the EU Storage Directive and considered essential to ensure integrity of injection operations and to update reservoir models.
Subsurface	Permanent Downhole Tool	Commercial	Flow meters	Platform and subsea	Directly measure rate and volume of injected CO_2. Different types: differential pressure meters, velocity meters, mass meters. Used for reporting of injected volumes of CO_2.	Just do it	Essential for reporting on injected volumes of CO_2.
Subsurface	Permanent Downhole Tool		Subsurface Fluid Sampling and Tracer Analysis	Platform and subsea	Collection of liquid or gas samples via wells (from either reservoir or overlying formation) for geochemical analysis of changes in reservoir due to CO_2 or identify any tracers. Data can be used to constrain reservoir simulation modelling (e.g. fluid chemistry, CO_2 saturation etc). Challenges with additional reservoir fluids of hydrocarbon and brine and preserving samples at reservoir temperature and pressure.	Consider	Moderate cost and can be conducted during wireline runs. To be more fully considered during FEED
Subsurface	Seismic Method	Early Demonstration	Microseismic/ passive seismic	Platform and subsea	Microseismic/ passive seismic monitoring includes installation of geophones down the wellbore when the wells are drilled and may provide real-time information on hydraulic and geomechanical processes taking place within the reservoir. This may give useful insight into reservoir and caprock integrity during the injection process. Challenges with reliability of sensors.	Consider	Moderately high cost and uncertainty over reliability of sensors and of information benefit (since caprocks in five storage sites are excellent). To be more fully considered during FEED.

Monitoring Domain	Type	Field Readiness	Technology	Applicability to Offshore	Description	Boston Square Box	Comments/ rationale
Subsurface	Seismic Method	Commercial	4D/time-lapse 3D seismic	Platform and subsea	Reflection 3D seismic uses the acoustic properties of geological formations and pore fluid to image the subsurface in a 3D volume. 4D seismic involves repeating the 3D survey over time to detect any changes. Each CO2 storage site is unique and site-specific modelling is required to understand if reflection seismic will detect CO2 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 CO2 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 CO2 in the shallow overburden.
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 CO2 due to the fact that CO2 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 CO2 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 CO2 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 CO2. 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

Monitoring Domain	Type	Field Readiness	Technology	Applicability to Offshore	Description	Boston Square Box	Comments/ rationale
Subsurface			Monitoring well		An additional well drilled for the purpose of monitoring, with no intent to inject CO2 into it. CO2 breakthrough at the monitoring well can give insight into plume movement (rates, extent, etc) through the reservoir and pressure and temperature measurements can provide information on aquifer connectivity. The draw-back is that monitoring wells can be expensive and only give one point source measurement.	Focussed application	A redundancy well is currently considered, which will monitor when not injecting.
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.
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.

Monitoring Domain	Type	Field Readiness	Technology	Applicability to Offshore	Description	Boston Square Box	Comments/ rationale
Seabed/ water column	Surface displacement monitoring	Development	Offshore tiltmeters	Platform and subsea	Reservoir pressure changes from CO_2 injection can cause surface deformation and so vertical displacement of seabed may indicate that this has occurred. GPS system may be able to measure this to 5mm accuracy. Measuring subsistence or uplift may provide evidence of containment and conformance.	Consider	Moderate cost but modelling required to understand detectability limit for store depth and injected CO_2 volumes and therefore information benefit.
Seabed/ water column	Geochemical Monitoring of water column	Commercial	Geochemical analyses of water column	Platform and subsea	CTD (conductivity, temperature and depth) probes from survey ships or platforms (for continuous measurement) can measure water column conductivity, used in addition to pH pCO_2, dissolved O_2 and other chemical components, any anomalous chemistry can be detected. Requires good baseline measurements and may have challenges detecting small quantities of CO_2 due to dispersion.	Just do it	Relatively cheap and can be used to rule out loss of containment of CO_2 to seabed over a large area and also around wellheads. Carry out survey at same time as side-scan sonar
Seabed/ water column	Tracer		Tracers		CO_2 soluble compounds injected along with the CO_2 into the target formation. Act as a "fingerprint" for the CO_2 in case of any leakage.	Consider	Tracers are in the “Consider” box as they are of moderate cost, but low benefit as containment loss at the storage sites is not expected. To explore further during FEED.
Seabed/ water column	Seabed Method		Seafloor sediment samples	Platform and subsea	Sediment samples are extracted from the seabed (for example using a Van Veen Grab, vibro corer, CPT+BAT probe, hydrostatically sealed corer) and analysed for CO_2 content. The CO_2 content may give insight into CO_2 flux (if any) above abandoned wellbores which penetrate the storage complex. Requires a good baseline to detect CO_2 above background levels.	Just do it	Relatively cheap and can be used to rule out loss of containment of CO_2 to seabed over a large area and also around wellheads. Carry out survey at same time as side-scan sonar
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 11-5 Offshore technologies for monitoring

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).
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).
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.	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).

ACTIVE WELL			
Risk Event	**Effect**	**Remediation**	**Cost**
	Sustained CO_2 annulus pressure will be an unsustainable well integrity state and require remediation.		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).
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 11-6 Hamilton Active Well Remediation Options and Costs

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 11-7 Hamilton Abandoned Well Remediation Options and Costs

11.6 Appendix 6 – 3D Geomechanical Modelling

11.6.1 Introduction

A 3D geomechanical model was constructed to investigate the possibility of seal breach and/or fault reactivation in a sub-area of the crest of the Hamilton structure and the effects on the fracture gradient of depletion during gas production followed by injection. The process involves creating a small strain finite element model (i.e. the grid is not deformed) that allows elastic stress/strain relations and plastic failure effects to be investigated as a response to the actual production and proposed injection scheme(s). These reported parameters include the following:

1. Displacement vectors to assess degree of overburden uplift
2. Failure criteria thresholds (shear or tensile) in the Ormskirk Sandstone or overburden
3. Matrix strains
4. Fault reactivation strains
5. Total and effective stress evolution
6. Stress path analysis (elastic response to pore pressure changes)

The Hamilton Petrel model supplied by Axis WT was used as a basis for building a simplified 3D geomechanical model (see section 3.7.2.4). This model has the same top and base as the Axis WT model within the Ormskirk Sandstone.

11.6.2 3D Geomechanical modelling process

The various steps required to construct, initialise, run and analyse a 3D geomechanical model are listed below.

1. Area selected and layering scheme identified. Layering scheme covers all units from Top St Bees Sandstone upwards to Seabed. The modelled area is a sector on the crest (see Figure 8 1).
2. Explicit surfaces used to generate a pre-geomechanical grid and zones over the area of interest (3D grid AGR V2a). Ormskirk Sandstone modelled as 5 zones, given 13 cell layers in total. Other zones given 1-4 cells to allow relatively gradual changes in cell thickness (see Figure 8 2).
3. Generate a geomechanical grid. This is a semi-automated process that adds geometrically expanding cells to the model sides (sideburden) and base (underburden). The sideburdens provide a buffer between the model and the boundary conditions. Note the edges of the lateral boundaries are defined by relatively stiff homogeneous plates approximately 50m thick. The underburden thickens the model and prevents buckling (see Figure 8 3). Also note that explicit faults in the grid are removed and the offsets approximated by changes in layer dip. Faulting can be added back in as a property during geomechanical modelling.
4. Geomechanical properties were upscaled and distributed from logs in 44/26-2. Young's Modulus, Poisson's Ratio and Uniaxial Compressive Strength (UCS) values generated from logs in Drillworks were used here and distributed using kriging to create smoothly varying properties within the layers from St Bees Sandstone to Seabed (see Figure 8 4).
5. Geomechanical Materials (e.g sandstone, shale, salt, faultrock) can be selected from a library and made available to the project. These materials can be assigned to cells based on regions (reservoir,

sideburden etc) or specific cell indices. The library materials are used in undefined areas in the log derived properties. The default is to create elastic properties (bulk density, Young's modulus, Poisson's ratio, Biots factor, thermal expansion coefficient and porosity). For this project, Mohr-Coulomb failure function and Drucker-Prager properties for plastic failure analysis were also created (UCS, cohesion, friction angle, dilation angle and tensile failure threshold) These parameters were defined over the zones from St Bees Sandstone to Seabed but with elastic properties in all cells except the Ormskirk Sandstone layers over the sector area and 3 cells in the I and j directions in the sideburden (see Figure 8 5). These elastic and plastic materials can be overridden by the properties upscaled and distributed in Petrel (see point 4).

6. Salt (halite) properties were treated differently to the other units. One variant were created –WkHal created by assigning the material library salt properties that have a low Young's modulus and high Poisson's ratio and thermal expansion coefficient (see). In reality salt acts as a viscous fluid over geological time and equilibrates to the lithostatic stress state. Petrel Geomechanics does not yet contain a salt creep model so the highly compliant elastic properties variant has been used as a proxy for the stress state obtained via viscous flow. This is generally regarded as adequate for small strains.

7. Pressure / saturation properties were created from a simplified series of pressure gradient steps that modelled the Hamilton depletion and subsequent injection as constant changes over the entire modelled area. Single steps are used for initialisation models to allow the stresses to be matched in certain layers (e.g. Ormskirk Sandstone and salt layers). Multiple pressure steps are used to model the geomechanical responses to the depletion and injection pressure steps. Here, 7 steps have been modelled; Initial: 2000. Depletion: 2002, 2006, 2017, Injection: 2020, 2025, 2035. Note that the modelled reservoir pressure at

8. Boundary conditions properties are created to setup the boundary condition SHmin stress magnitude, the SHmax/Shmin ratio and the SHmin orientation. These are modified to get a match to expected stress trends in the initialisation models. For the multi pressure runs, the starting stresses (6 component tensor) were defined explicitly by splicing the initialisation total stress properties from the Ormskirk Sandstone and lithostatic salt stress cases.

9. The cases were setup by selecting the relevant properties folders from items 4 to 8 and defining the run as either linear (elastic) or non-linear (plastic). Non-linear runs utilise both the Mohr-Coulomb and Drucker Prager materials defined in steps 4 and 5.

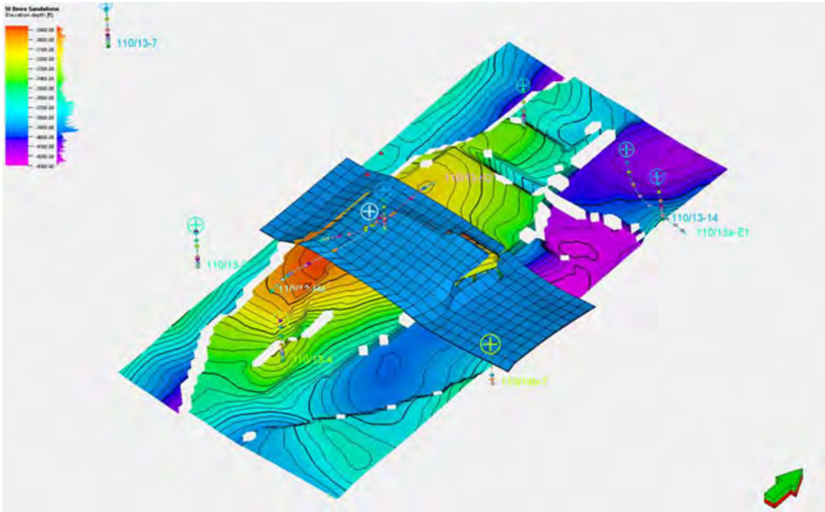


Figure 11-18 Hamilton Field geomechanical model sector area, surface is to St Bees Sandstone (base of model)

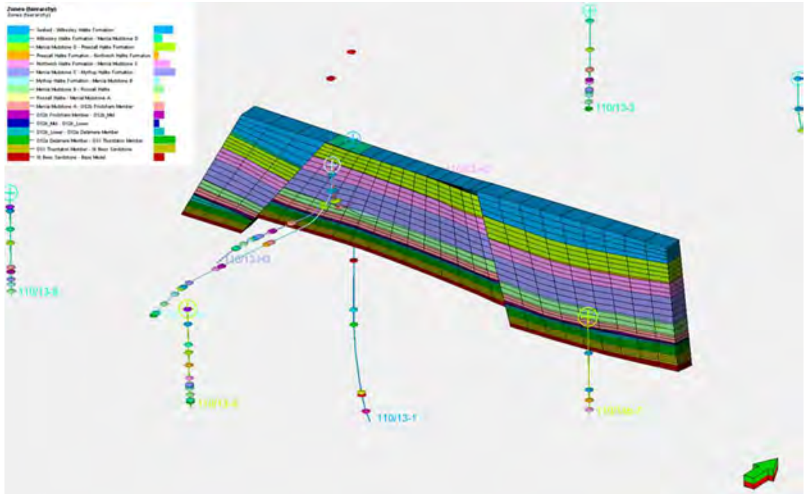


Figure 11-19 Pre-geomechanical grid layering scheme, note layer offsets by faults

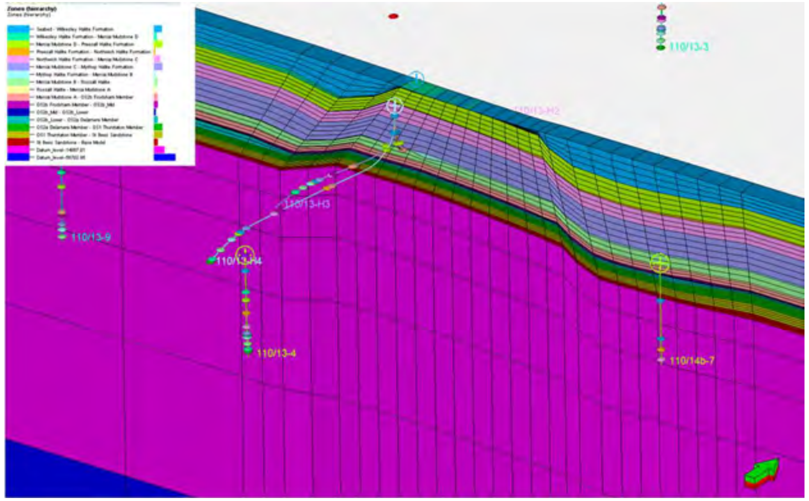


Figure 11-20 Geomechanical grid layering scheme, note fault offsets removed - these can be added back as property elements

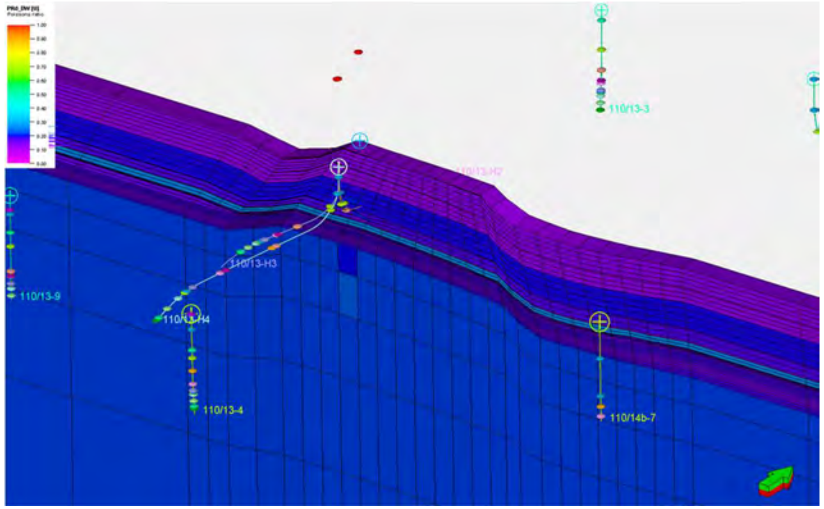


Figure 11-21 Poisson's ratio in the Hamilton geomechanical grid

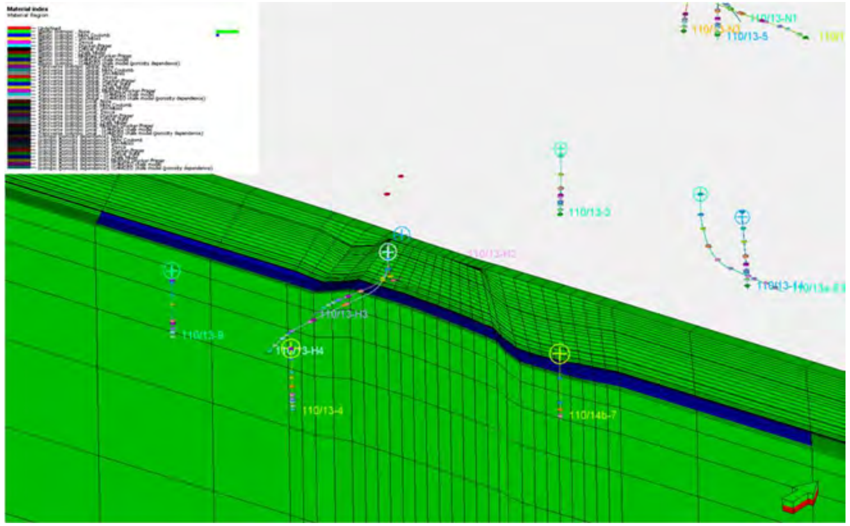


Figure 11-22 Material index for geomechanical modelling, blue is non-linear (plastic) and green is linear (elastic)

11.6.3 Geomechanics Results

Two cases were run with non-linear Mohr-Coulomb material properties (unfaulted and faulted) and one with Drucker-Prager material properties within the Ormskirk Sandstone. This was primarily to assess the impact of depletion followed by injection on the fracture gradient. As described in the 1D analysis report, poroelastic theory predicts that the fracture gradient decreases during depletion and increases during re-pressurisation (injection). However, the exact trends these stress paths take may vary between each phase. There is also the potential for significant hysteresis such that the depleted fracture gradient only increases a little or not at all during subsequent injection (e.g. Santerelli et al 2008). There are a number of factors that can lead to this effect including reservoir geometry, reservoir geomechanics property values compared to the surrounding rock, geometry and properties of faults and the temperature of the injected fluid. A full investigation of all these effects is beyond the scope of this project.

11.6.3.1 Reference Case – Modified Drucker-Prager

Drucker-Prager can be simplistically defined as a smoothed version of the Mohr-Coulomb failure function. The Drucker-Prager yield surface shape varies depending on which Mohr-Coulomb principal stress vertices it is fitted to. The modified version accounts for changes in the material responses in the tensile region (tensile cut-off) and at high confining stresses (end cap). With this material defined over the reservoir section and a few of the boundary are cells, there is hysteresis in the strain and displacement such that the compressive strains attained during depletion are not fully recovered (see Figure 11-23). This is reflected in the net downward displacement of the overburden at end injection in 2035 (see Figure 11-24). Note that there is no failure of the caprock in this model as all the small amounts of strain are concentrated in the reservoir section. The strain hysteresis is highlighted by the relatively high degree of plastic strain seen at end depletion but zero additional plastic strain during injection (Figure 11-25).

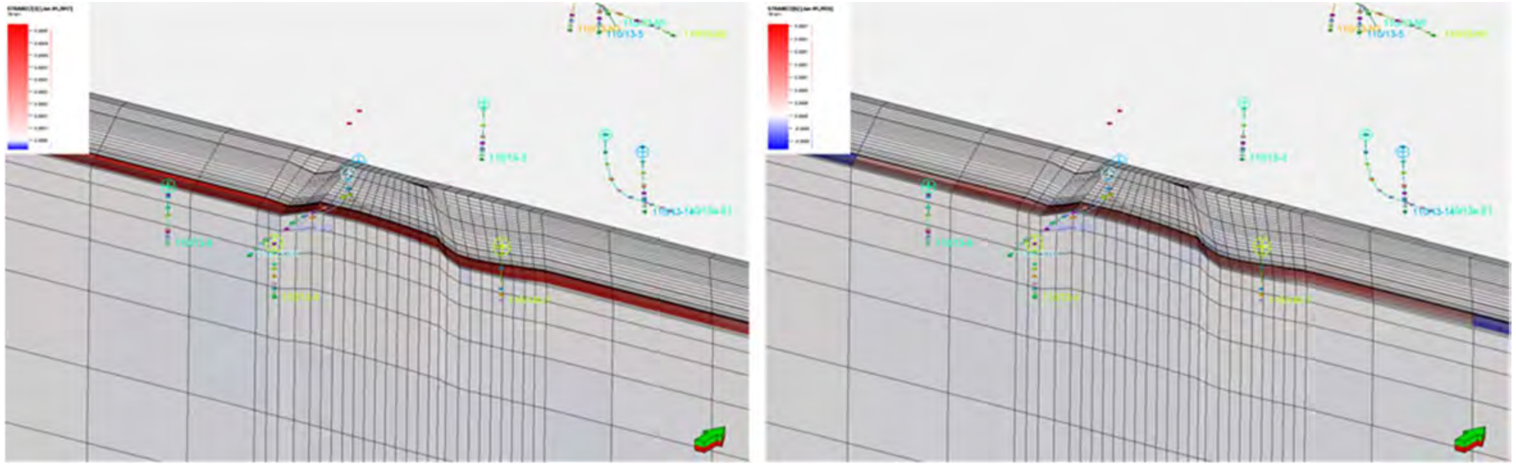


Figure 11-23 Modified Drucker-Prager STRAINZZ (vertical strain property) at end gas production in 2017 (left) and end CO_2 injection in 2035

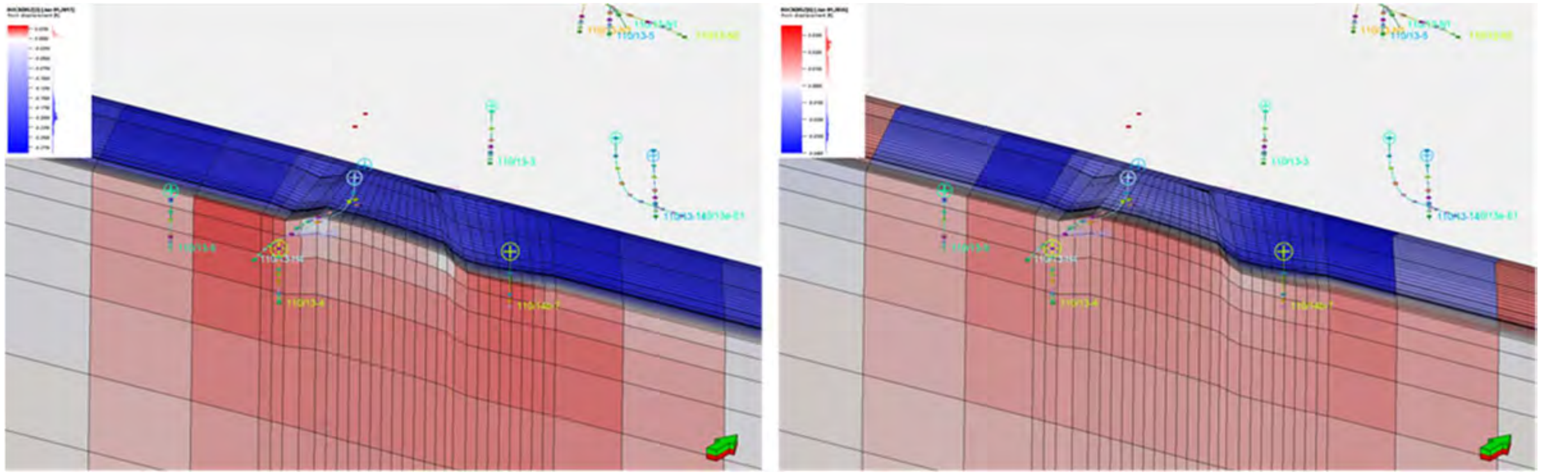


Figure 11-24 Modified Drucker-Prager ROCKDISZ (vertical displacement property) at end gas production in 2017 (left) and end CO_2 injection in 2035

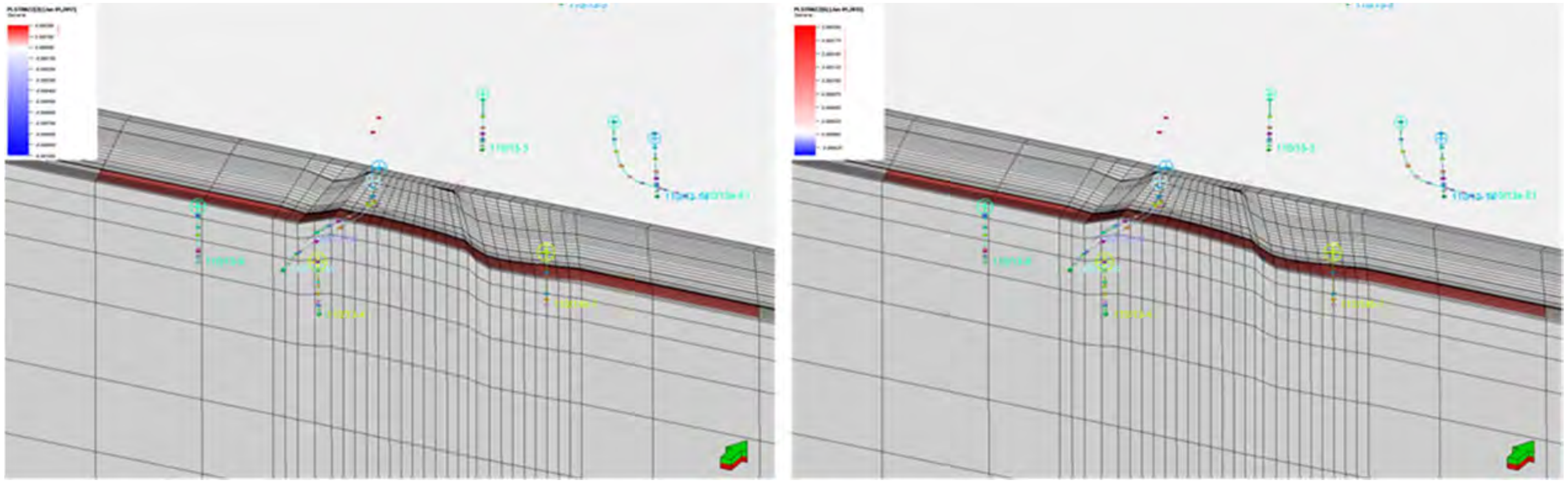


Figure 11-25 Modified Drucker-Prager PLSTRNZZ (plastic vertical strain property) at end gas production in 2017 (left) and end CO_2 injection in 2035

11.6.3.2 Pessimistic Case – Mohr-Coulomb

Mohr-Coulomb is generally regarded as conservative in terms of failure modes and the Mohr-Coulomb failure model is therefore regarded as the pessimistic case for the reservoir response to depletion and injection. It can be seen from Figure 11-25 and Figure 11-26 that the elastic strain associated with depletion and injection is minimal (equivalent to a maximum of 0.3 mm at end depletion) but the depletion related strain and downward displacement are largely recovered during injection. There is no failure of the caprock and there is no plastic strain during depletion or injection.

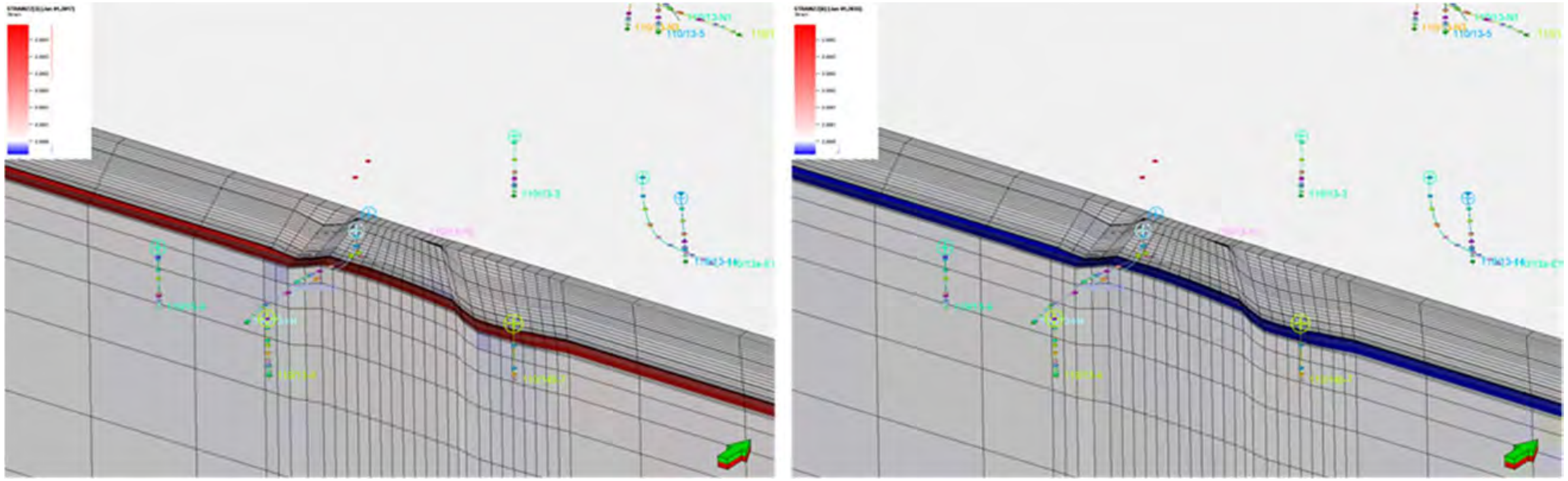


Figure 11-26 Mohr-Coulomb STRAINZZ (vertical strain property) at end gas production in 2017 (left) and end CO_2 injection in 2035

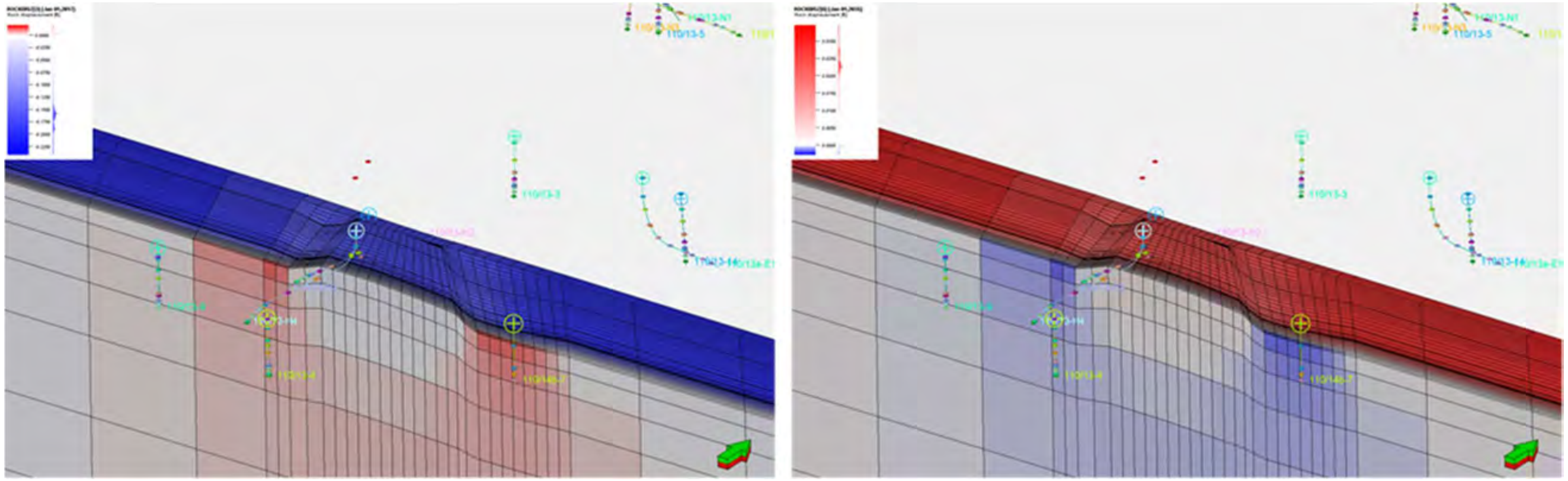


Figure 11-27 Mohr-Coulomb ROCKDISZ (vertical displacement property) at end gas production in 2017 (left) and end CO_2 injection in 2035

11.6.3.3 Faulted Case – Mohr Coulomb

This case was run with the addition of some faults with Reference case properties to see if this would cause significant displacement / strain changes in the Hamilton sector model (faulted cells shown in Figure 11-27). It can be seen from that there are very few differences between the unfaulted and faulted Mohr-Coulomb cases in terms of strain and displacement over the reservoir section and immediate overburden. i.e. there is minimal increased risk of failure in this model with the addition of faults with these properties.

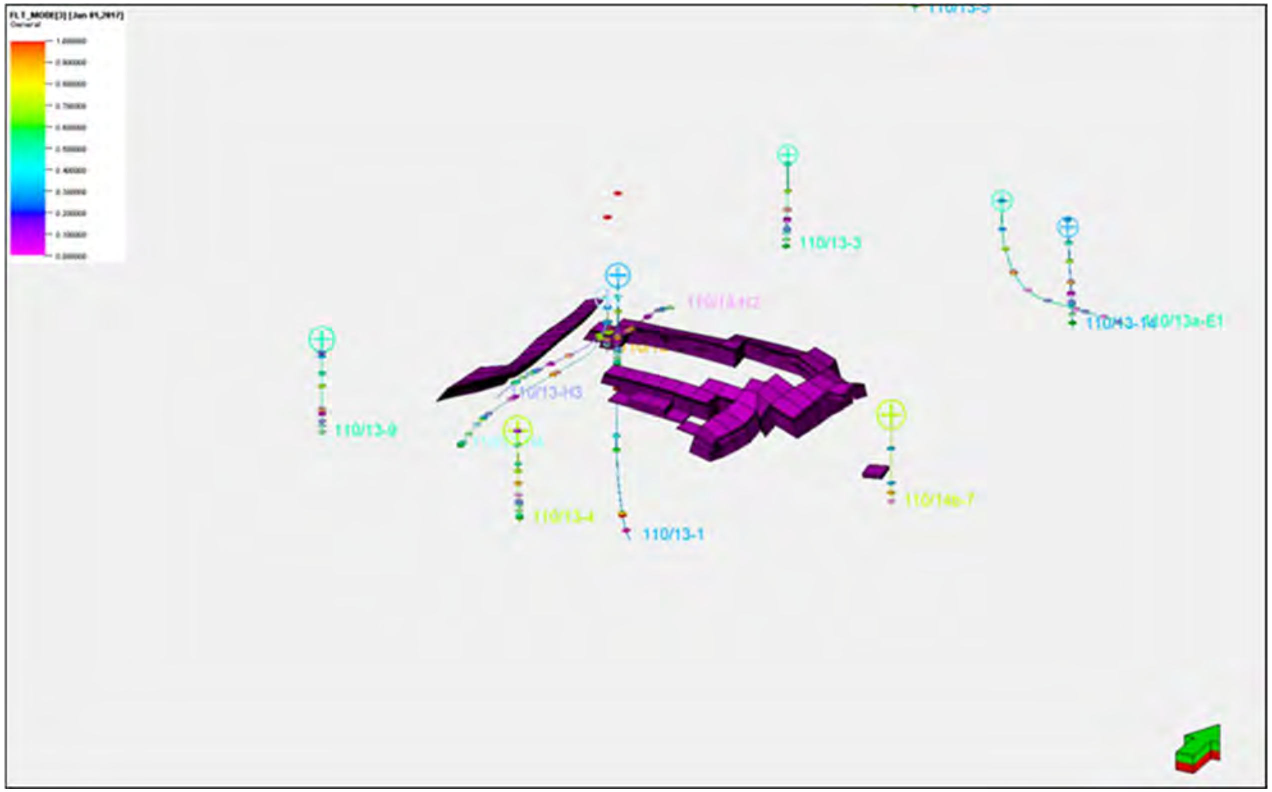


Figure 11-28 Faulted cells within Ormskirk sandstone of the sector model area

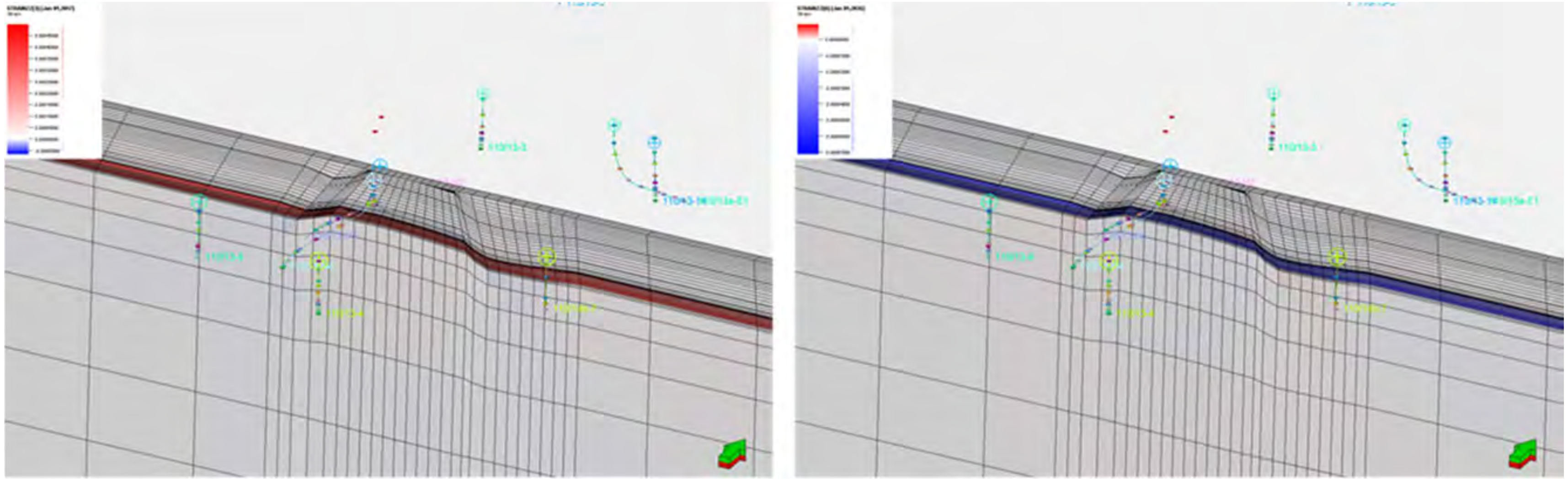


Figure 11-29 Faulted Mohr-Coulomb STRAINZZ (vertical strain property) at end gas production in 2017 (left) and end CO_2 injection in 2035

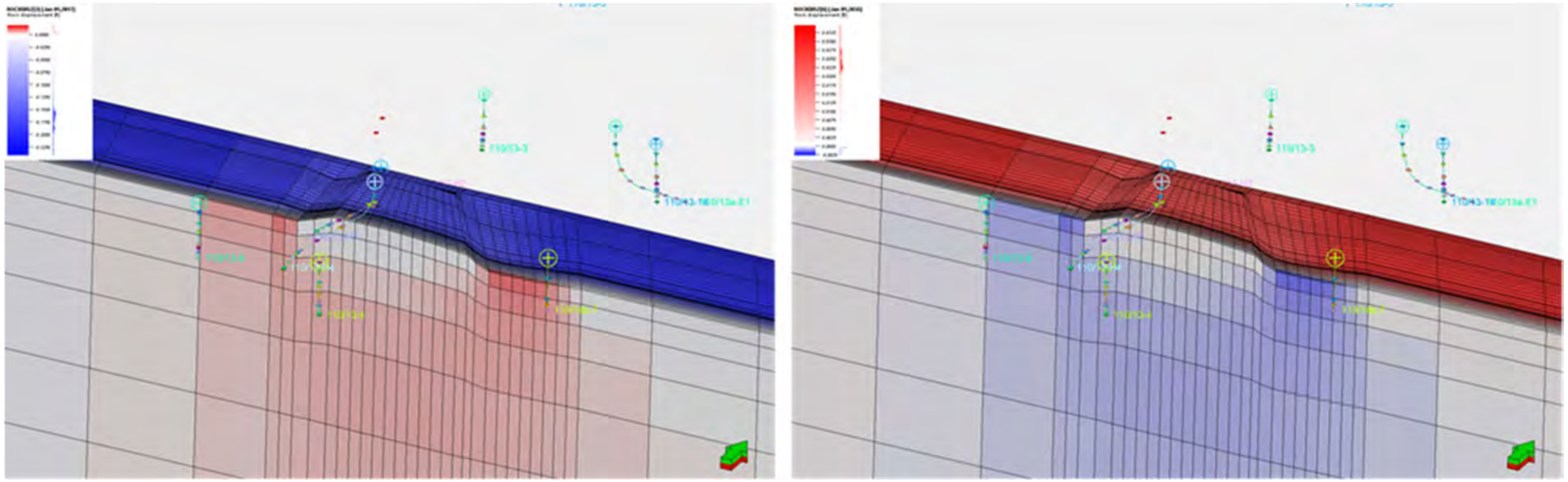


Figure 11-30 Faulted Mohr-Coulomb ROCKDISZ (vertical displacement property) at end gas production in 2017 (left) and end CO_2 injection in 2035

11.6.4 Discussion and Conclusions

From the various 3D model runs it can be seen that deformation is concentrated within the Ormskirk sandstone with minimal strain seen in the caprock and immediate overburden. In the Modified Drucker Prager example there is some measurable plastic strain but the Mohr-Coulomb cases (non-faulted and faulted) show no plastic strain. This difference in the deformation response is also seen in the stress paths of the various cases. The stress path is the change in total minimum principal stress (SHmin or fracture gradient) with depletion. This is due to the poroelastic effect for reservoirs that have an approximate width vs height ratio of >= 10:1 (Zoback 2007). From Figure 11-31 and Table 11-8 it can be seen that the Mohr-Coulomb case shows a large change in the SHmin with depletion but on repressurisation, the changes are reversed. Conversely the Modified Drucker-Prager case (and an additional Modified Drucker-Prager case with a cohesion of 2000 instead of zero) show hysteresis with stress path on depletion more aligned with the 1D analysis and recovery to a higher SHmin value on repressurisation. It should be noted that these models do not account for any thermal effects so it is possible that the local fracture gradient around the wellbore will be reduced further due to cooling. In addition,**Invalid source specified.** detail extreme stress path hysteresis (i.e. no recovery of the fracture gradient) after water injection in Norwegian sector reservoirs. This study at least partially accounted for cooling effects.

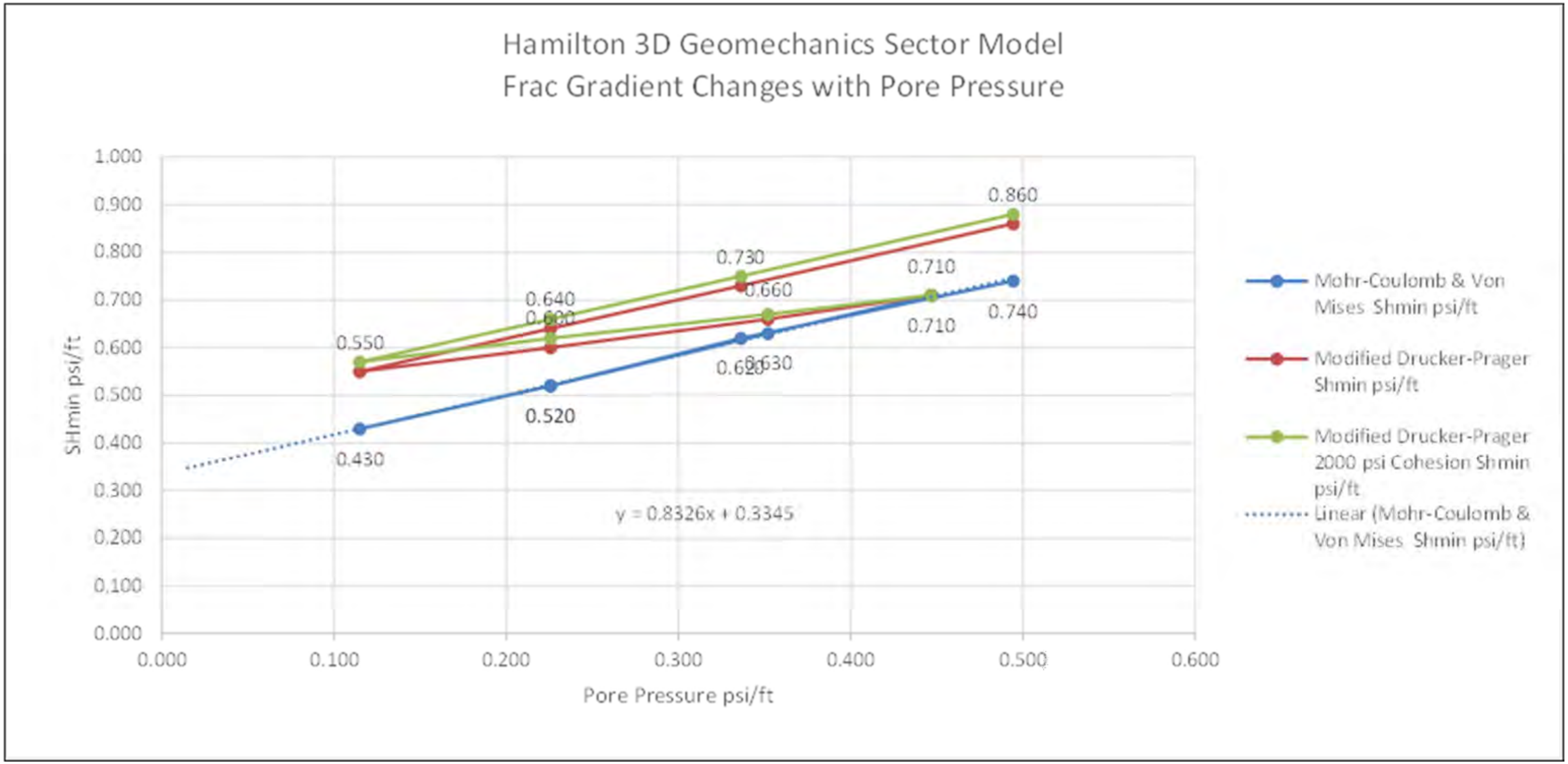


Figure 11-31 Plot of reservoir stress path (minimum principal stress) with modelled depletion and repressurisation

Year	Depth ftTVDss	Pore Pressure psi	Pore Pres grad psi/ft	Mohr-Coulomb & Von Mises Shmin psi/ft	Modified Drucker-Prager Shmin psi/ft	Modified Drucker-Prager 2000 psi Cohesion Shmin psi/ft	Von Mises Shmin psi/ft	Critical-State
2000	3162.23	1413.52	0.447	0.710	0.710	0.710	0.710	Failed
2002	3162.23	1113.52	0.352	0.630	0.660	0.670	0.630	Failed
2006	3162.23	713.52	0.226	0.520	0.600	0.620	0.520	Failed
2017	3162.23	363.52	0.115	0.430	0.550	0.570	0.430	Failed
2020	3162.23	713.52	0.226	0.520	0.640	0.660	0.520	Failed
2025	3162.23	1063.52	0.336	0.620	0.730	0.750	0.620	Failed
2035	3162.23	1563.52	0.494	0.740	0.860	0.880	0.740	Failed

Table 11-8 Table of reservoir stress path (minimum pricipal stress) with modelled depletion and repressurisation

From the various models and published information, the following conclusions are drawn.

1. Hamilton has minimal risk of caprock or fault failure for the modelled stress conditions, reservoir and overburden properties and fault properties.
2. Modified Drucker-Prager case fracture gradient reductions down to 0.55-0.57 psi/ft agree reasonably well with those derived from the 1D analysis (~0.6 psi/ft). The 1D analysis values are regarded as the most likely stress paths.
3. Mohr-Coulomb case fracture gradient reductions are modelled as low as 0.43 psi/ft at average depleted pressures of ~363 psi. If this is extrapolated to a depleted pressure of 120 psi the depleted fracture gradient is 0.37 psi/ft. This is regarded as a pessimistic case.
4. Note that a pessimistic limit case during injection of complete hysteresis (no increase in the fracture gradient during repressurisation) cannot be ruled out but is not regarded as likely.
5. To mitigate these risks it is recommended that additional data is gathered from pilot holes prior to any significant drilling of injectors.

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 11. The basic work flow in Drillworks 5000 was supplemented with safe mud weight windows and optimal wellbore trajectory analysis for the original reservoir pressure condition and for the potential depleted reservoir pressure condition. Note, the safe mud weight ranges are for zero losses and zero breakouts so they may be somewhat conservative.

11.7.1.1 Safe Mud Weight Windows -Original Reservoir Pressure Condition

Hamilton: Well 44/26-2

The MW used to drill this well was:

- Between 8.5 to 10 ppg in the Unit D and Northwich halite;
- Between 10 to 11 ppg in the Unit C, Mythop halite, Unit B and Rossall halite
- Between 13.5 to 12 ppg in the Unit A and Sherwood Sandstone

For the Mercia Mudstone Group and Sherwood Sandstone Group a safe MW would be between 11 to 16 ppg for a vertical well

Hamilton: Well 110/13-3

The MW used (yellow line) to drill this well was:

- Between 4 to 9 ppg in the Unit D and Northwich halite.
- Between 10 to 12 ppg in the Unit C, Mythop halite, Unit B, Rossall halite and Unit A.
- Between 11 to 11.5 ppg in the Sherwood Sandstone

For the Mercia Mudstone Group and Sherwood Sandstone Group a safe MW would be between 11 to 16 ppg (for a vertical well). Only the Rossall halite would require a MW between 13 to 16 ppg (for a vertical well).

Hamilton East: Well 110/13-14

The MW used to drill this well was:

- Between 10 to 10.5 ppg in the Unit D, Northwich halite, Unit C, Mythop halite and part of Unit B.
- Between 10.5 to 12 ppg in the rest of Unit B, Rossall halite, Unit A and Sherwood sandstone group.

For the Mercia Mudstone Group and Sherwood Sanstone Group a safe MW would be 11 to 15 ppg (for a vertical well). Only the Rossall halite would require a MW between 12 to 15 ppg (for a vertical well)

Hamilton North: Well 110/13-5

The MW used to drill this well was:

- Between 9 to 11 ppg in the Unit D, Northwich halite, and part of Unit C.
- Between 11 to 13 ppg in the rest of Unit C, Mythop halite, Unit B, Rossall halite and Unit A.

- 12 ppg for the Sherwood sandstone

For the Marcia Mudstone Group and Sherwood Sanstone Group a safe MW would be 11 to 15 ppg (for a vertical well)

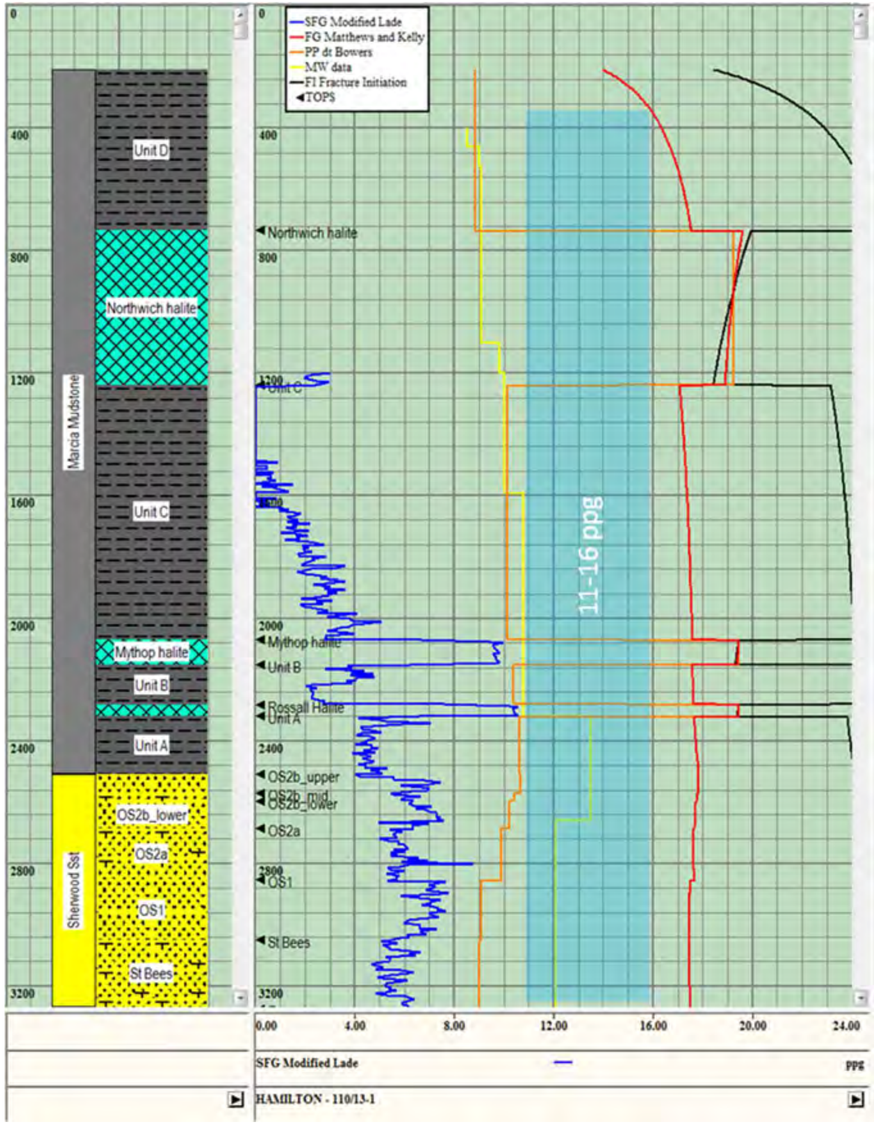


Figure 11-32 Safe mud weight analysis, Hamilton Well 110/13-1 (Original conditions)

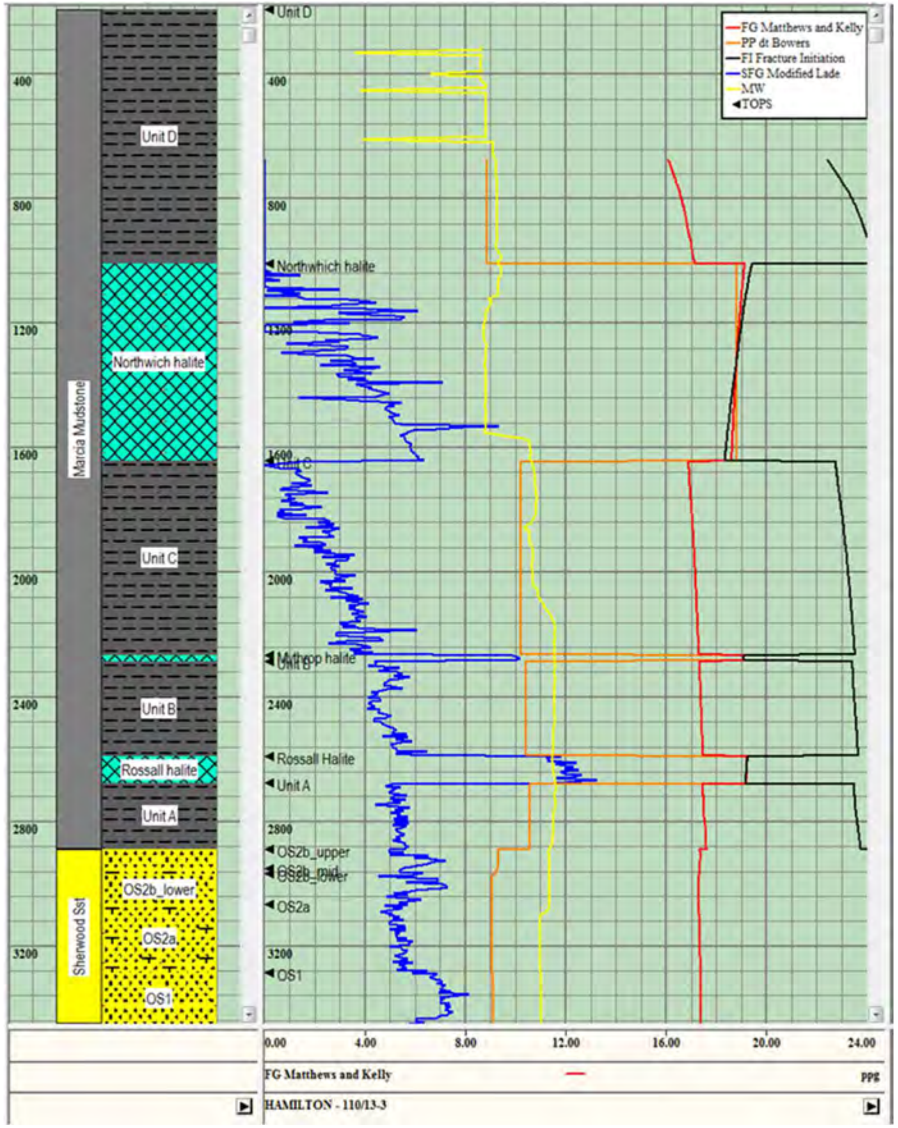


Figure 11-33 Safe mud weight analysis, Hamilton Well 110/13-3 (Original conditions)

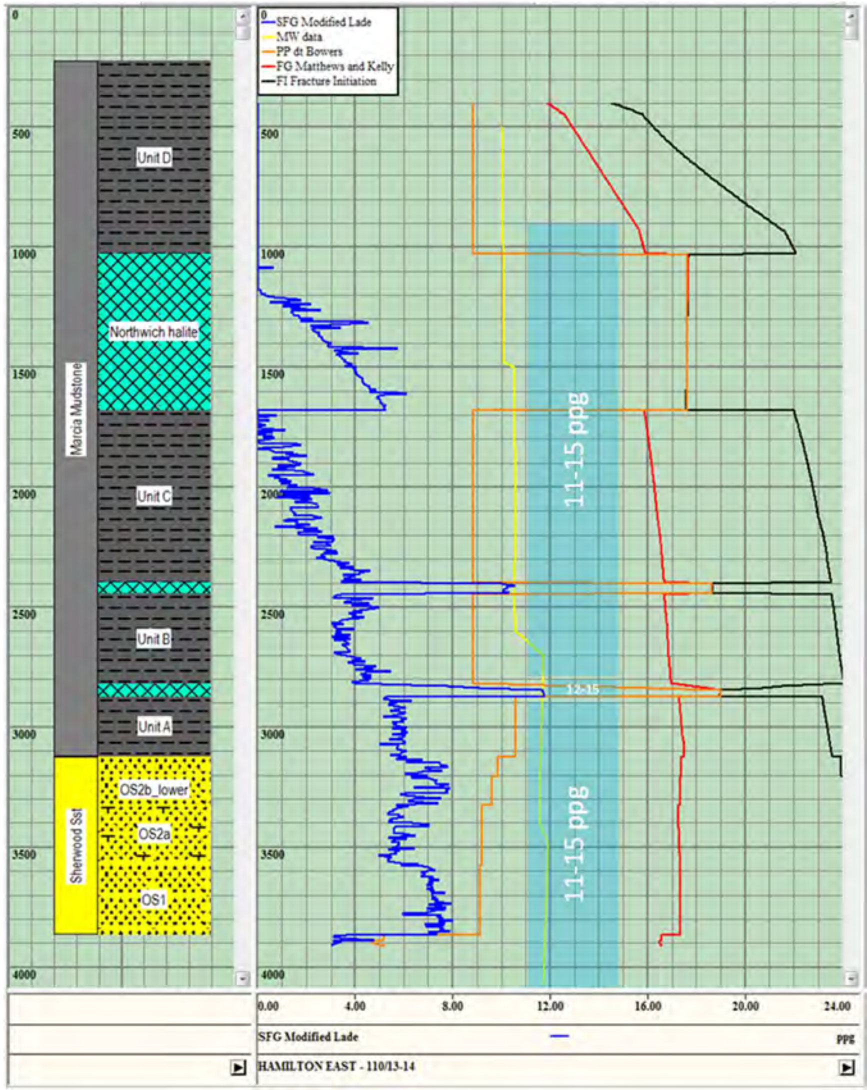


Figure 11-34 Safe mud weight analysis, Hamilton East Well 100/13-14 (Original conditions)

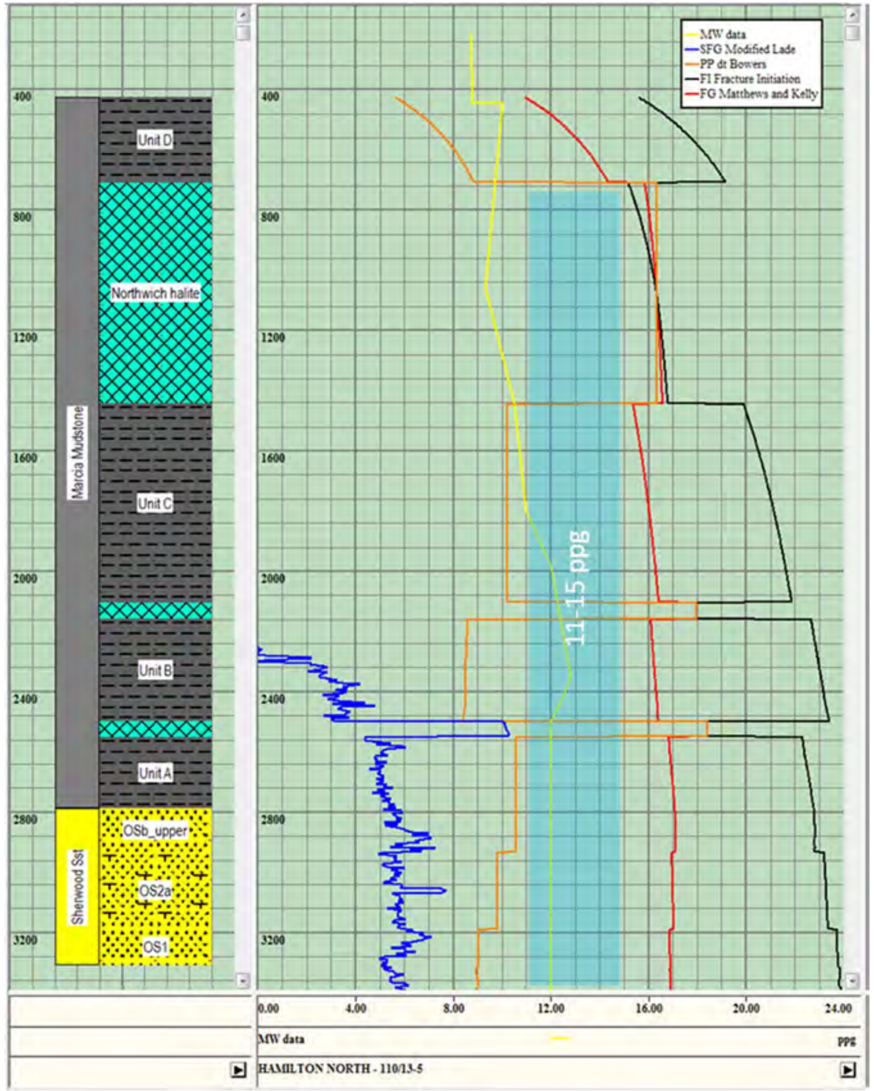


Figure 11-35 Safe mud weight analysis, Hamilton North Well 110/13-5

11.7.1.2 Wellbore Trajectory Analysis – Original Reservoir Pressure Condition

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

Figure 11-36 shows the Ormskirk Sandstone in the Hamilton field for the well 110/13-1 (at 2800 ft, OS2a), where a horizontal well with NW-SE orientation would increase the MW by up to 0.96 ppg (11.96ppg).

Figure 11-37 shows the Ormskirk Sandstone in the Hamilton field for the well 110/13-3 (at 3360 ft, OS1), where a horizontal well with NW-SE orientation would increase the MW by up to 0.91 ppg (11.91ppg).

Figure 11-38 shows the Ormskirk Sandstone in the Hamilton East field for the well 110/13-14 (at 3800 ft, OS1), where a horizontal well with NW-SE orientation would increase the MW by up to 0.90 ppg (11.90ppg).

Figure 11-39 shows the Ormskirk Sandstone in the Hamilton North for the well 110/13-5 (at 3060 ft, OS2a), where a horizontal well with NW-SE orientation would increase the MW by up to 0.90 ppg (11.90ppg).

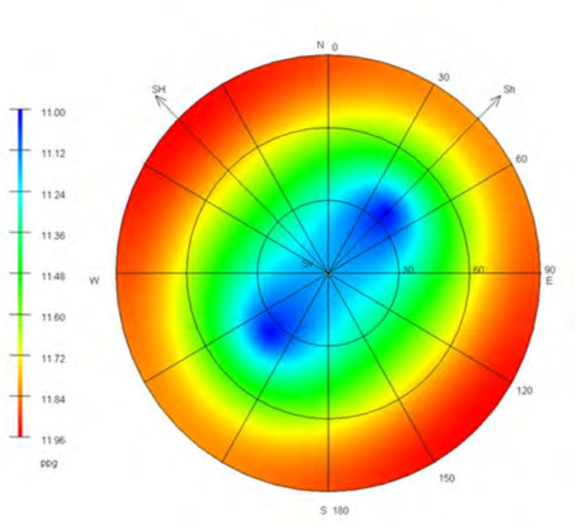


Figure 11-36 Well trajectory analysis, Hamilton Well 110/13-1 (Original condition)

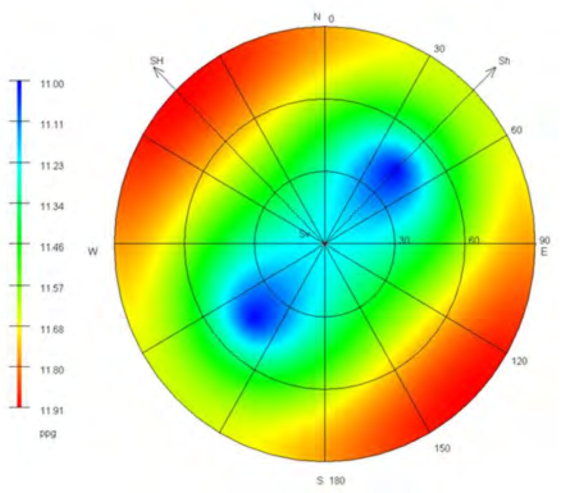


Figure 11-37 Well trajectory analysis, Hamilton Well 110/13-3 (Original condition)

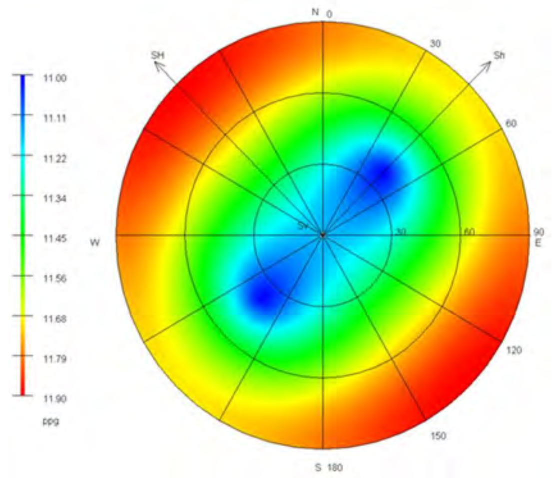


Figure 11-38 Well trajectory analysis, Hamilton East Well 110/13-14 (Original condition)

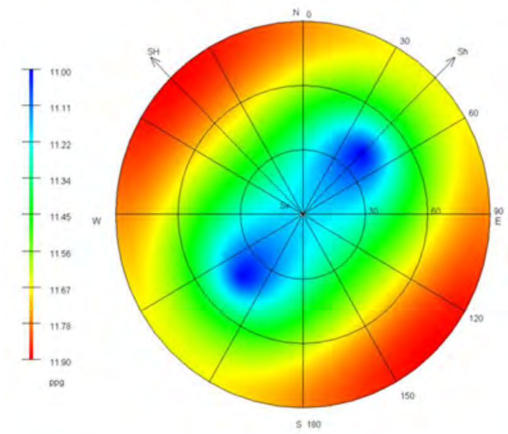


Figure 11-39 Well trajectory analysis, Hamilton North Well 110/13-5 (Original condition)

11.7.1.3 Safe Mud Weight Windows – Depleted Reservoir Pressure Conditions

As explained in Appendix 11, the depleted fracture gradient is a composite log from the Matthews and Kelly correlation for the non depleted layers and Breckels & Van Eekelen for the depleted layers.

For all the wells evaluated:

- For the depleted Sherwood Sandstone Group, a safe mud weight would be between 4 to 11 ppg (for a vertical well),
- For the non-depleted layers, the mud weight is the same as the original conditions.

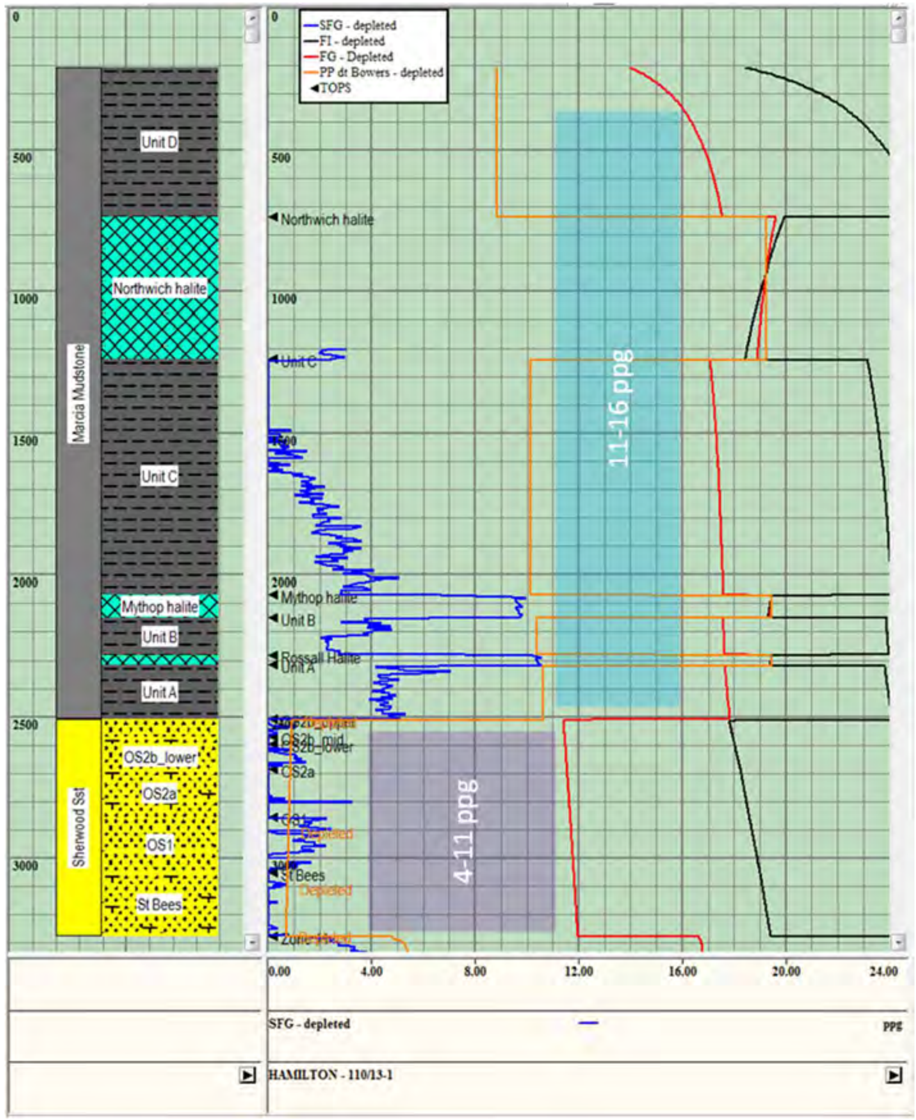

SFG - depleted
FI - depleted
FG - Depleted
PP dt Bowers - depleted
TOPS
Unit D
Northwich halite
Marcia Mudstone
Unit C
Mythop halite
Unit B
Unit A
Rossall Halite
Sherwood Sst
OS2b_lower
OS2a
OS1
St Bees
11-16 ppg
4-11 ppg
0
500
1000
1500
2000
2500
3000
0.00
4.00
8.00
12.00
16.00
20.00
24.00
SFG - depleted
ppg
HAMILTON - 110/13-1

Figure 11-40 Safe mud weight analysis, Hamilton Well 110/13-1 (Depleted conditions)

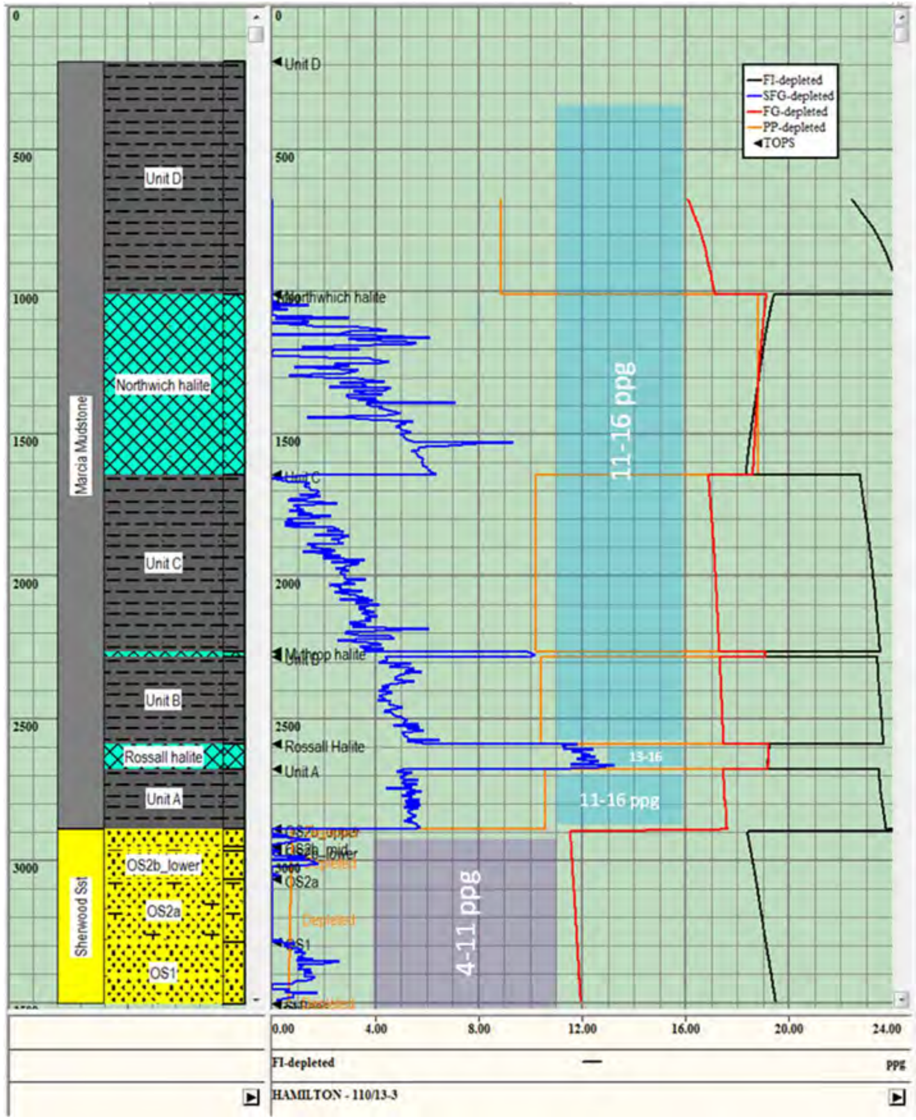


Figure 11-41 Safe mud weight analysis, Hamilton Well 110/13-3 (Depleted condition)

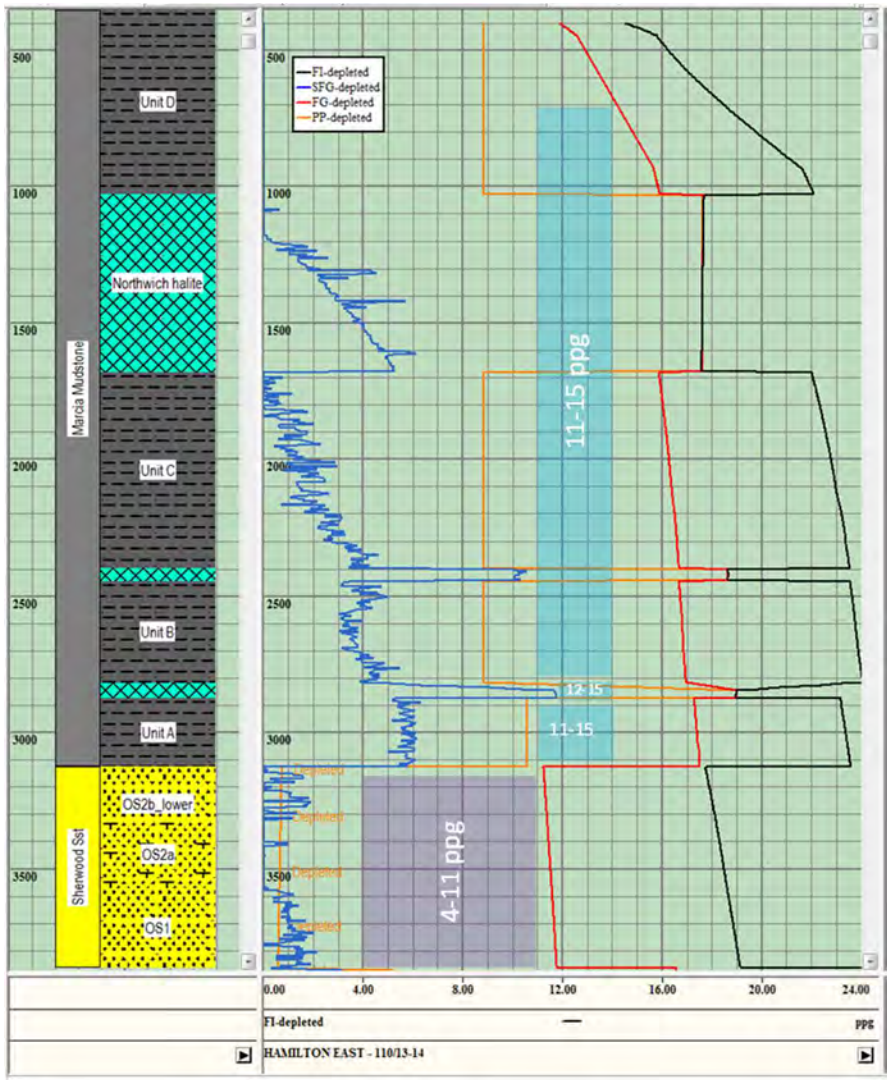


Figure 11-42 Safe mud weight analysis, Hamilton East Well 110/13-14 (Depleted condition)

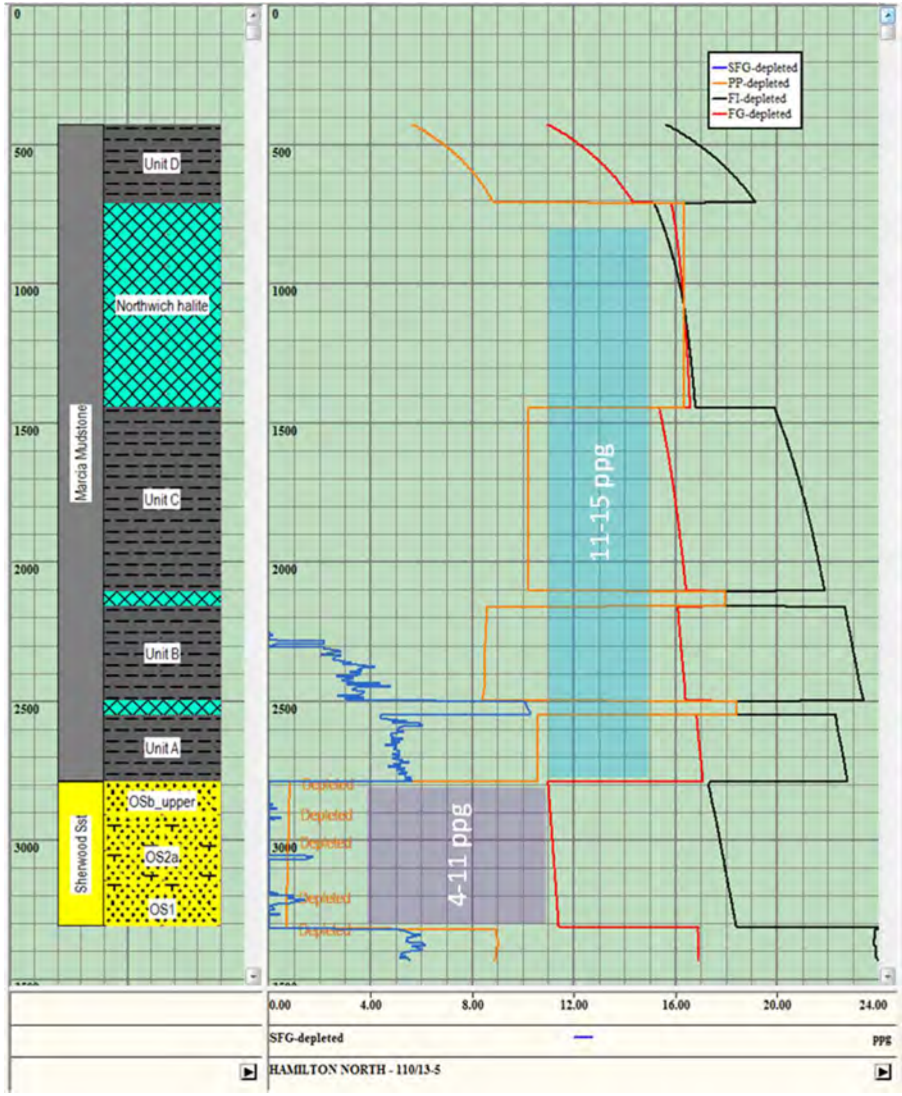


Figure 11-43 Safe mud weight analysis, Hamilton North Well 110/13-5 (Depleted condition)

11.7.1.4 Wellbore Trajectory Analysis – Depleted Reservoir Pressure Condition

The figures below indicate the variation of the minimum mud weight to prevent any breakout with wellbore inclination and orientation taking into account a depleted reservoir pressure in the Ormskirk sandstone.

Figure 11-44 shows the Ormskirk Sandstone in the Hamilton field for the well 110/13-1 (at 2800 ft, OS2a), where a horizontal well with NW-SE orientation would increase the MW by up to 3.5 ppg (7.5 ppg).

Figure 11-45 shows the Ormskirk Sandstone in the Hamilton field for the well 110/13-3 (at 3360 ft, OS1), where a horizontal well with NW-SE orientation would increase the MW by up to 3.4 ppg (7.4 ppg).

Figure 11-46 shows the Ormskirk Sandstone in the Hamilton East field for the well 110/13-14 (at 3800 ft, OS1), where a horizontal well with NW-SE orientation would increase the MW by up to 3.1 ppg (7.1ppg).

Figure 11-47 shows the Ormskirk Sandstone in the Hamilton North for the well 110/13-5 (at 3060 ft, OS2a), where a horizontal well with NW-SE orientation would increase the MW by up to 3.5 ppg (7.5ppg).

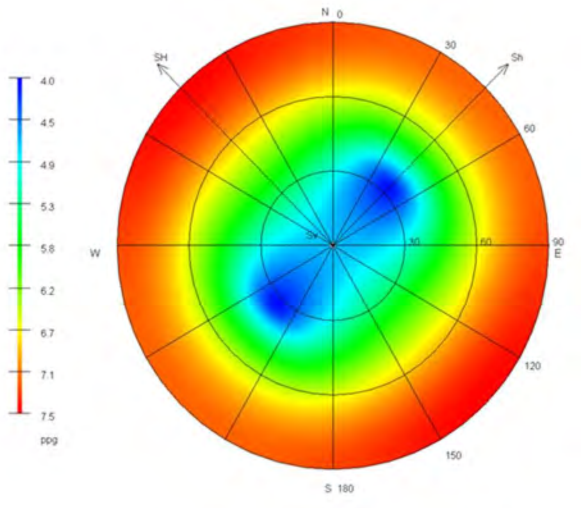


Figure 11-44 Well trajectory analysis, Hamilton Well 110/13-1 (Depleted condition)

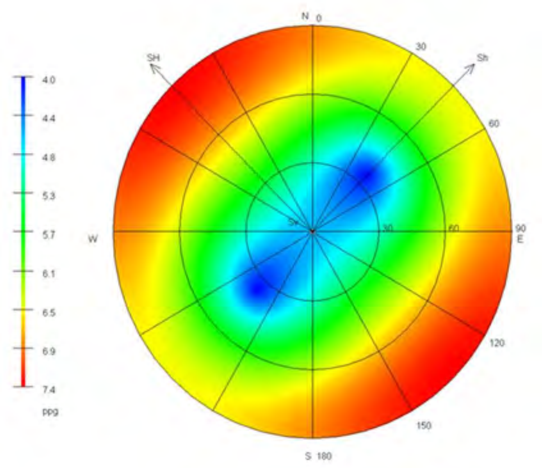


Figure 11-45 Well trajectory analysis, Hamilton Well 110/13-3 (Depleted condition)

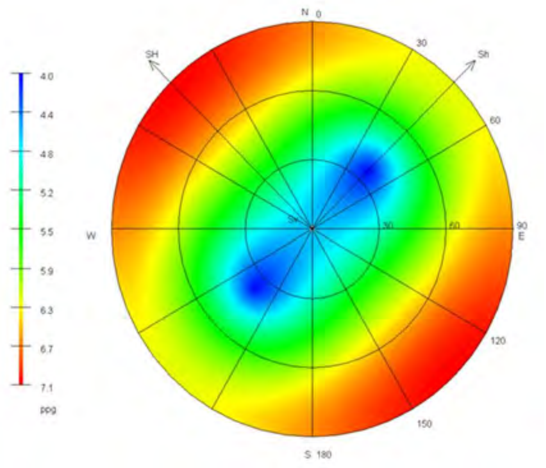


Figure 11-46 Well trajectory analysis, Hamilton East Well 110/13-14 (Depleted condition)

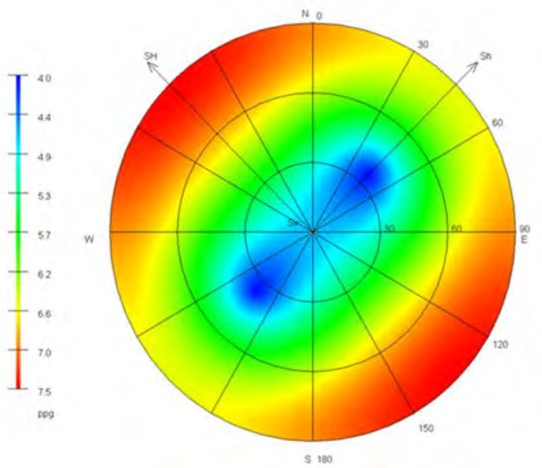


Figure 11-47 Well trajectory analysis, Hamilton North Well 110/13-5 (Depleted condition)

11.7.1.5 Conclusions

- 1D geomechanical analysis of existing wells and pore pressure depletion estimation indicates that a potential depleted SHmin gradient could be around 0.6 psi/ft in the Ormskirk Sandstone and that vertical wells can be drilled through the overburden and Ormskirk Sandstone with ~11 ppg mud weights. The actual depleted condition in the Ormskirk sandstone has not been confirmed with field data.
- For vertical wells in this sequence, the recommended mud weight is around 11 ppg. Some basic analysis on required mud weights at different injector orientations has been performed within the Ormskirk Sandstone. In general, mud weight increases of 3.1 to 3.5 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 Hamilton Structure. Real Shmax azimuth may be different (e.g. oriented N-S parallel to local structure).
- Note the reported static mud weight windows are for drilling 'gun barrel' hole with no losses. If some breakout is tolerated and or losses can be managed with LCM then the real mud window could be larger.
- No core has been available to calibrate the strength (breakout) information. This would need optimising for any planned wells.
- The wellbore trajectory analysis has been made on Ormskirk 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 depleted Hamilton field for carbon capture and storage, both CO_2 injection and monitoring wells will be required. The CO_2 injectors will be J-shaped, high angle wells in order to optimise CO_2 injection performance and the monitoring well will be vertical to minimise cost and complexity. The purpose of this section of the report is to:

- Identify well design risks and drilling hazards based on the available offset well data.
- Generate a preliminary well design for the identified injection and monitoring wells.
- Provide high level time and cost estimates for each well type.

This report proposes 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

The CDA database has been used to provide offset information on the original Hamilton development wells. The available data has been analysed to identify inputs for designing CO_2 injection and monitoring wells, with the key findings being as follows:

11.7.2.1.1 Surface Hole and Conductor

The surface hole sections were drilled vertically to approximately 80m below the seabed and a conductor cemented in place. The hole sections were drilled using seawater, and then displaced to 10.0 ppg spud mud prior to running casing. There were no recorded problems during drilling or conductor installation operations

11.7.2.1.2 Surface Hole and Casing

The 16” surface hole sections were directionally drilled to approximately 480m TVDSS, with the surface casing shoe being set in the Cleveleys Mudstone. The setting depth was selected to:

- Isolate the Presall Halite prior to drilling the intermediate hole section.
- Provide sufficient formation strength at the 13 ⅜” shoe to drill the next hole section with a weighted mud system.
- Coincide with the end of the build section.

All surface hole sections were drilled using salt saturated water based mud, in order to maintain gauge hole when drilling the Presall Halite. The mud weight used varied between 10.1 and 11.0 ppg, with no downhole losses occurring with this weight range.

All the surface hole sections were directionally drilled, with the build section being completed prior to casing point. Inclinations up to 80o were achieved, with dogleg severities (DLS) in the range of 4.5o to 6o per 30m being consistently delivered from directly below the conductor shoe. The reason for conducting directional drilling at these shallow depths was to allow the reservoir targets to be reached from a centrally located platform. No problems occurred in achieving the directional drilling objectives, and it is concluded that CO_2 injection wells may be planned with shallow dogleg severities of a similar magnitude.

There were no problems running the 13 ⅜" casing string to section TD at high angle, and no problems occurred when cementing these in place.

No major problems occurred when drilling the surface hole sections, however, the following issues were recorded as being problematic:

- The shallow Dowbridge Mudstone is reactive and can generate gumbo-related problems at surface. These problems mainly consisted of surface mud losses due to shaker screen blinding, however some flowline blocking issues also occurred.
- Hole cleaning at high angle in 16" hole was a problem, with high torque and packing off occurring when cuttings beds formed.

11.7.2.1.3 Intermediate Hole Section and Production Casing

The 12 ¼" intermediate hole sections were drilled through the Cleveleys, Blackpool and Ansdell mudstones. Two salt sections were also encountered, these being the Mythop and Rossall Halites.

The production casing shoe was set directly above the top of the Ormskirk Sands in order to:

- Case off the halite sections prior to drilling the reservoir.
- Case off the mudstones, thereby reducing the risk of wellbore instability when drilling the reservoir section.
- Allow the mud weight to be reduced when drilling the reservoir section.

In all the reviewed development wells, the 12 ¼" hole sections were drilled as tangent sections, with inclination being held to casing point. No directional drilling problems occurred with this strategy.

Salt saturated silicate water based mud was used in order to reduce the risk of washouts in the halite sections and chemically inhibit the mudstones. The use of this mud system achieved the primary objectives; however, hole cleaning issues were prevalent in all the 12 ¼" sections reviewed. This may have been a function of the silicate additives which make cuttings adhere to each other, generating cuttings agglomeration. The resulting cuttings "clusters" can prove difficult to remove from the wellbore, leading to cuttings bed formation and packing off. Therefore, it is recommended that alternative inhibited mud systems to silicate be considered in order to reduce the risk of hole cleaning problems occurring.

Due to the high inclinations, the 10 ¾" x 9 ⅝" casing strings were pushed to bottom using the casing fill-up tool. This technique was successfully applied, and all casings were set at the planned depths.

Problems occurred when cementing, which led to B-annulus communication with the reservoir. Poor cement quality allowed gas migration to percolate through the cement, and this may have been caused by one or more of the following:

- **Hole angle:** The production casing was cemented at high angle, with the inclination varying between 61o and 80o. At high angle, cement channelling can occur if the casing string is inadequately centralised.

- **Cuttings bed formation:** Cuttings beds were known to form when drilling and if these were not completely removed, a gas migration path could exist through these accumulations.
- **Mud filter cake removal:** Silicate mud systems act by coating the borehole wall with a silicate coating. This then prevents the water phase from reacting with the mudstones, and reduces the rate of clay swelling. However, if this coating is not adequately removed by the cementing spacer, then a gas migration path could exist.

In order to reduce the risk associated with poor cement jobs, and preserve the integrity of the CO_2 store, it is recommended that consideration be given to:

- Using an alternative mud system which will assist with effective hole cleaning.
- Designing the centraliser programme to deliver a minimum stand-off of 80%.
- Designing the cementing spacer system to deliver effective mud filter cake removal.

11.7.2.1.4 Production Hole Section and Liner

In the offset wells reviewed, high angle 8 ½" reservoir sections were drilled through the Ormskirk Sand. These sections were drilled with salt saturated water based mud, with the weight ranging between 11.0 and 12.3 ppg.

The only issues that arose when drilling the reservoir section were:

- **Differential sticking:** In well 110/13-H1, the mud weight used was 12.3 ppg. During a trip out of the hole, the BHA got differentially stuck, and could not be freed despite reducing the mud weight to 11.3 ppg. For subsequent wells, the mud weight used was 11.0 to 11.8 ppg, to reduce the risk of differential sticking.
- **Bit and BHA erosion:** The Ormskirk Sand is abrasive, and this led to bit and BHA component erosion.

No problems were recorded running and cementing the 7" production liners.

11.7.2.2 Drilling Risks and Hazards

The following drilling risks and hazards have been identified from the available offset data:

11.7.2.2.1 Shallow Gas

At present, it is assumed that shallow gas will not present below the platform location. However, this will be confirmed when the results of the shallow gas survey are available. In the event that shallow gas is identified at the selected surface location, this should be moved.

11.7.2.2.2 Shallow Swelling Dowbridge Mudstone

The Dowbridge mudstone swells when exposed to seawater or water based drilling fluids, with gumbo type problems affecting surface equipment. When drilling through this formation, gumbo catchers should be inserted into the flowline and shaker screens sized to avoid blinding issues.

11.7.2.2.3 Halite Sections

The Triassic halites are prone to washing out when drilled with water based mud systems. Therefore, in order to avoid overgauge hole and ledging problems, hole sections containing a halite should be drilled with either salt saturated water based or oil based mud.

11.7.2.2.4 Hole Cleaning

Hole cleaning has proven to be problematic at high angle in the 16” and 12 ¼” hole sizes, and consideration should be given to the mud systems used and the circulation rates employed. In addition, consideration should be given to the following when planning high angle hole sections:

- Use annular pressure while drilling (APWD) data to identify pressure increases.
    - These pressure increases can be generated by annular restrictions from cuttings bed formation or be indicative of increasing fluid column weight due to cuttings loading.
- Ensure that sufficient mud pumping capacity is available to deliver the annular velocities required to clean the hole.
- Employ frequent wiper trips if required to remove cuttings beds.
- Plan to pump hi-weight and viscous pills at regular intervals to assist with cuttings removal.

11.7.2.2.5 Ormskirk Sand

The Ormskirk Sand is hard and abrasive which can lead to low rates of penetration (ROP), therefore, bit selection will be a key consideration from a drilling performance perspective. Also, the abrasive nature of the formation can lead to bit and BHA wear, which then generates under-gauge hole. In order to avoid this problem, bit and BHA component selection should address the risk of tool wear by ensuring that suitable gauge protection is included in component design.

11.7.2.2.6 Hydrogen Sulphide (H_2S)

H_2S is known to be present in the Hamilton reservoir, at concentrations up to 1,200ppm. When drilling the reservoir section, H_2S personal protection systems must be available on the drill floor, with BA (breathing apparatus) kits also used in the shaker house and pit room.

11.7.2.2.7 Reservoir Depletion

The Hamilton reservoir is known to be severely depleted, with pore pressures as low as 1.0 ppge. As such, drilling with any fluid system will lead to a significant overbalance being applied to the formation. This generates the following risks:

- **Losses to weakened formation:** Losses due to fracture gradient reduction are not expected to be a major hazard due to the high initial formation strength of the Ormskirk Sand. However, should injection testing on the existing Hamilton wells show that the fracture gradient is at the low end of the predicted range, the drilling fluid system may have to be engineered to ensure that losses are avoided.
- **Differential Sticking:** The differential pressure applied by an 8.5 ppg fluid column would be approximately 1,000psi, which could lead to differential sticking. In order to reduce this risk, it is recommended that the following options are considered during the FEED stage:
    - **Drill with oil based mud:** The weight of oil based mud can be maintained at lower levels than water based systems due to the difference in base fluid density. For example, the density of base oil is approximately 7.0 ppg whereas fresh water is 8.3 ppg and seawater is 8.6 ppg. By using as low a mud weight as possible, differential pressure is reduced. In

addition, oil based mud generates a tighter filter cake, thereby reducing the contact area between the drillstring and the borehole wall.

- **Use stabilised drillpipe:** Stabilised drillpipe reduces the contact area between the drillstring and the borehole wall, which is turn reduces the differential sticking force (differential force = hydrostatic pressure x contact area).
- **Pipe motion:** Differential sticking only occurs when the drillstring is stationary. Therefore, in order to reduce the risk of differential sticking, minimise stationary time by planning connections and drilling with rotary steerable BHAs.

11.7.2.2.8 Production Casing Cementing

Production casing cementing has been problematic, with gas migration occurring from the reservoir into the B-annulus. In order to reduce this risk, it is recommended that the following issues are considered during the FEED stage:

- Use non-silicate salt saturated mud when drilling the intermediate hole section in order to maintain gauge hole, and assist with effective hole cleaning.
- Design the production casing centraliser programme to deliver a minimum stand-off of 80% across the casing covered by the tail cement.
- Design the cementing spacer system to deliver effective mud filter cake removal.

11.7.2.3 Directional Profiles

11.7.2.3.1 Reservoir Targets

The following reservoir targets have been identified for the top of the Ormskirk Sand:

Target Name	TVDSS (m)	UTM North (m)	UTM East (m)
INJ-1	736.7	5,936,010.6	469,700.0
INJ-2	751.5	5,936,169.3	470,700.0
INJ-3	723.5	5,934,700.0	469,607.7

Table 11-9 Reservoir targets for the top Ormskirk Sand

The coordinate system in use is UTM, ED50 Common Offshore, Zone 31N (0° to 6° West)

11.7.2.3.2 Surface Location

A central surface location has been selected, which is positioned to allow each well to be reached from a single platform. The coordinates of the surface location are:

- 5,935,400m North
- 470,200m East

The surface location and well position is shown in the spider plot below:

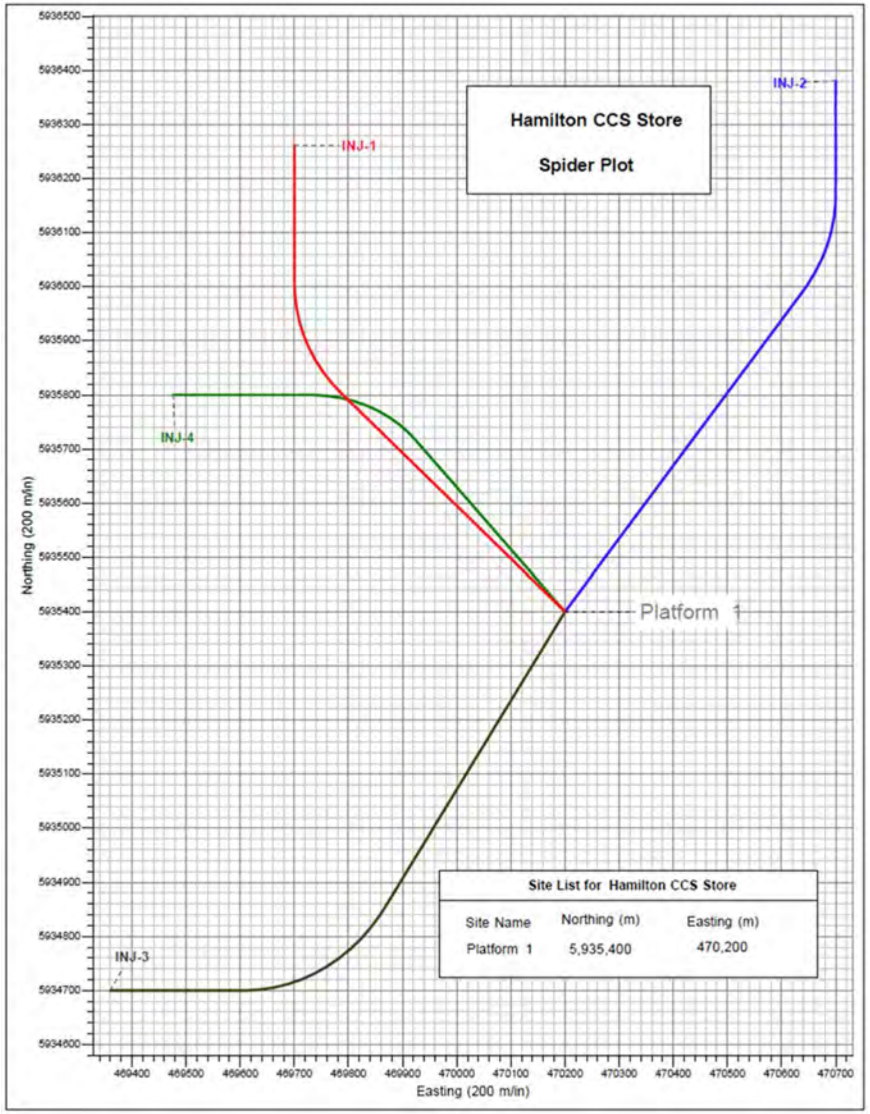


Figure 11-48 Directional spider plot

11.7.2.3.3 Directional Design

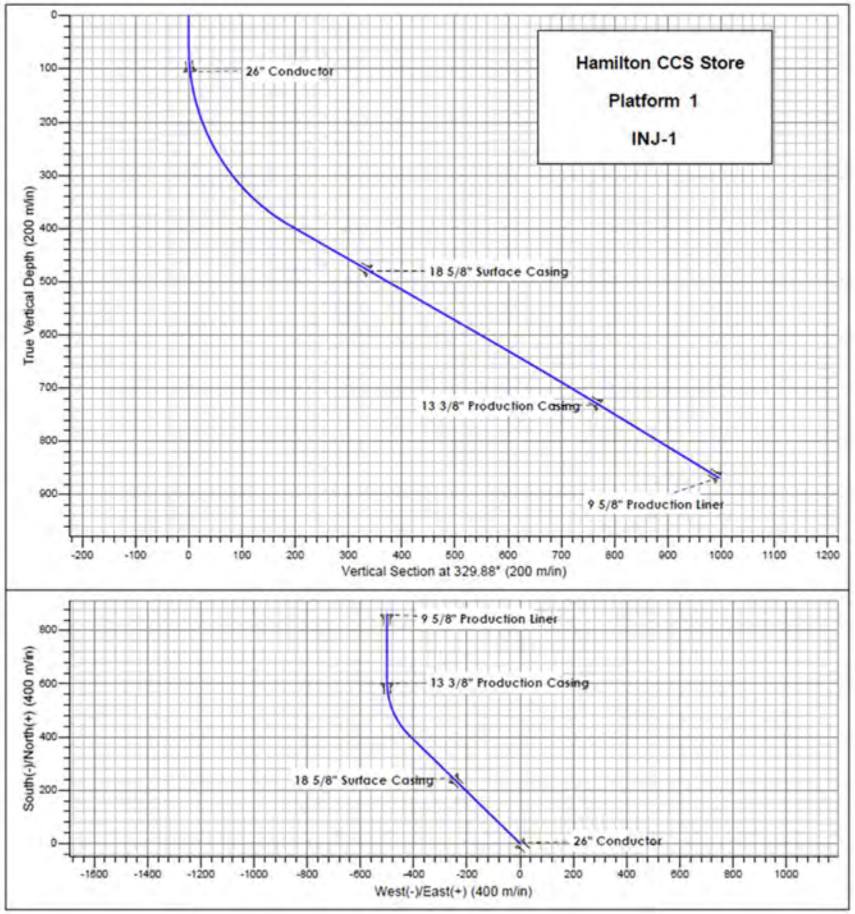
A platform surface location and well locations in the reservoir have been selected for conceptual well design purposes; however, it should be noted that these locations have not been optimised for reservoir management or directional drilling purposes. Therefore, it is recommended that the wells are re-planned 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:

- The injection wells will be drilled as slant wells.
- All wells will be kicked off directly below the conductor, with dog leg severity kept to 4.5o per 30m.
- All directional work will be conducted in the formations above the reservoir.
- A tangent section will be drilled through the reservoir hole section, holding inclination to TD below the base of the Ormskirk Sand.

The conceptual directional plan for the monitoring well assumes that a vertical well will be drilled directly below the platform location.

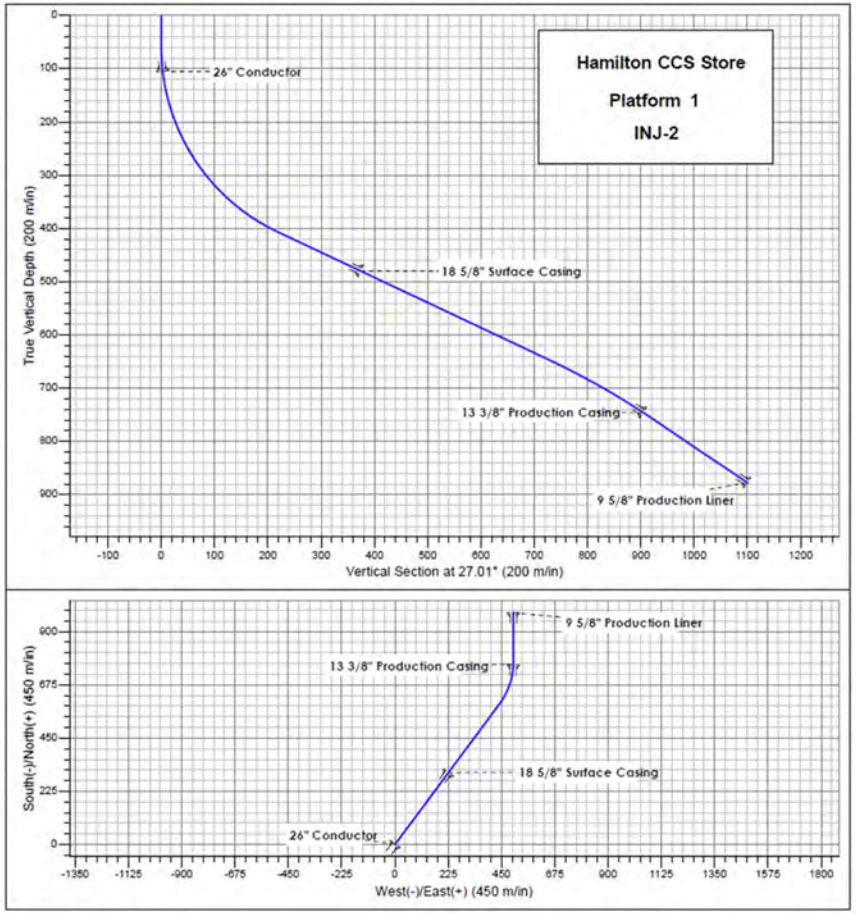
Directional profiles have been prepared for each well based on the reservoir targets and directional drilling limitations, as follows:



SECTION DETAILS

MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect
0.00	0.00	0.00	0.00	0.00	0.00	0.000	0.00	0.00
60.00	0.00	360.00	60.00	0.00	0.00	0.000	360.00	0.00
466.84	61.03	314.28	394.17	137.51	-140.99	4.500	314.28	189.69
901.13	61.03	314.28	604.54	402.79	-412.98	0.000	0.00	555.63
1167.66	62.19	360.00	736.67	610.56	-500.00	4.500	99.77	779.02
1167.69	62.19	0.00	736.68	610.59	-500.00	3.000	0.00	779.04
1421.82	62.19	0.00	855.24	835.37	-500.00	0.000	0.00	973.48
1421.85	62.19	360.00	855.25	835.40	-500.00	3.000	-180.00	973.51
1451.85	62.19	360.00	869.25	861.93	-500.00	0.000	0.00	996.46

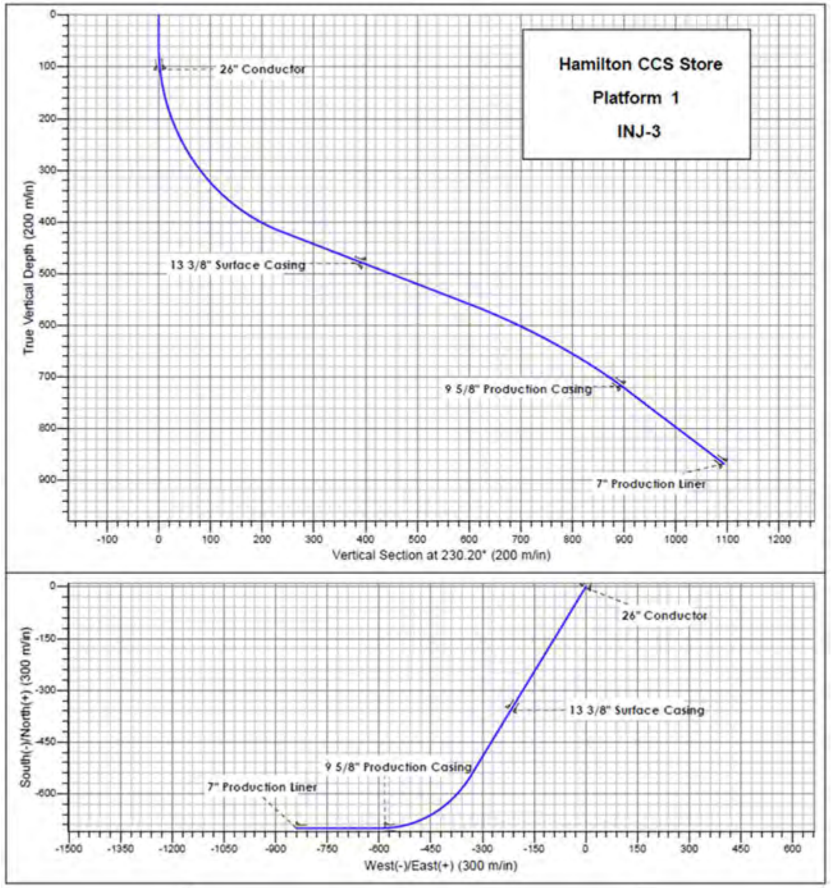
Figure 11-49 Gas phase slant injector 1 directional profile



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
60.00	0.00	360.00	60.00	0.00	0.00	0.000	360.00	0.00
493.62	65.04	36.61	406.31	177.25	131.68	4.500	36.61	217.72
1062.68	65.04	36.61	646.41	591.39	439.34	0.000	0.00	726.42
1280.93	59.05	360.00	751.45	769.27	500.00	4.500	-108.97	912.44
1280.98	59.05	0.00	751.47	769.31	500.00	3.000	0.00	912.48
1497.41	59.05	0.00	862.77	954.93	500.00	0.000	0.00	1077.85
1497.45	59.05	360.00	862.79	954.97	500.00	3.000	-180.00	1077.88
1527.45	59.05	360.00	878.22	980.70	500.00	0.000	0.00	1100.80

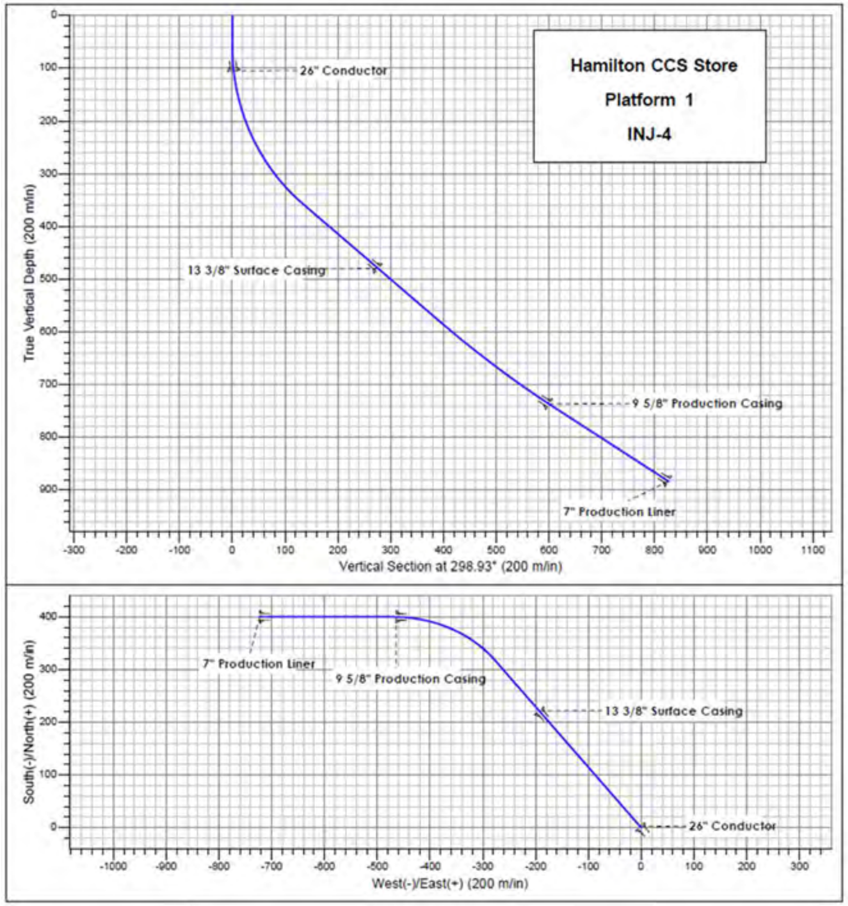
Figure 11-50 Gas phase slant injector 2 directional profile



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
60.00	0.00	360.00	60.00	0.00	0.00	0.000	360.00	0.00
526.22	69.93	211.32	418.78	-214.34	-130.43	4.500	211.32	237.42
938.90	69.93	211.32	560.38	-545.47	-331.94	0.000	0.00	604.20
1295.64	59.74	270.00	723.50	-700.00	-592.31	4.500	113.40	903.15
1295.68	59.74	270.00	723.52	-700.00	-592.34	3.000	0.00	903.17
1552.42	59.74	270.00	852.88	-700.00	-814.11	0.000	0.00	1073.54
1552.45	59.74	270.00	852.90	-700.00	-814.14	3.000	180.00	1073.57
1582.45	59.74	270.00	868.02	-700.00	-840.05	0.000	0.00	1093.48

Figure 11-51 Liquid phase Slant injector 3 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
60.00	0.00	360.00	60.00	0.00	0.00	0.000	360.00	0.00
400.33	51.05	318.90	357.05	106.89	-93.24	4.500	318.90	133.31
757.67	51.05	318.90	581.70	316.32	-275.91	0.000	0.00	394.49
1030.95	60.44	270.00	741.90	400.00	-473.10	4.500	-92.12	607.55
1030.99	60.44	270.00	741.92	400.00	-473.14	3.000	-180.00	607.59
1289.12	60.44	270.00	869.28	400.00	-697.65	0.000	0.00	804.09
1289.16	60.44	270.00	869.30	400.00	-697.69	3.000	0.00	804.12
1319.16	60.44	270.00	884.10	400.00	-723.79	0.000	0.00	826.96

Figure 11-52 Liquid phase slant injector 4 directional profile

11.7.2.4 *Detailed Well Design*

Due to the low initial reservoir pressure, CO_2 will initially be injected as a gas. As such, the initial injector wells require a large completion bore to reduce friction losses and maintain CO_2 in the gas phase. However, as reservoir pressure rises, gas phase CO_2 injection cannot be continued and the field will switch to liquid phase disposal. New slim well designs will be used at this stage in the storage project to accommodate the change in injection fluid phase.

11.7.2.4.1 Gas Phase CO_2 Injector

The conceptual well design for a gas phase CO_2 injector is as follows:

11.7.2.4.1.1 32" Surface Hole and 26" Conductor Setting Depth

The selected conductor size is 26" which is compatible with the conceptual well design, while minimising the tubular diameter for platform slot sizing purposes. Due to the hard nature of the seabed formations, conductor driving is impractical. Therefore, a 32" surface hole section shall be drilled, and a 26" conductor cemented in place.

The conductor setting depth has been specified as 60m below the mudline for the following reasons:

- Conductors have been successfully set at this depth regionally.
- The formation strength at this depth is sufficient to hold a mud weight of 10.5 ppg for drilling the surface hole section.
- Directional drilling can commence at this depth.

11.7.2.4.1.2 22" Surface Hole and 18 ⅝" Casing Setting Depth

The surface casing setting depth has been selected as 480m TVDSS in order to:

- Case off the Presall halite.
- Provide sufficient formation strength to drill the intermediate hole section with 12.8 ppg mud weight.

11.7.2.4.1.3 17 ½" Intermediate Hole and 13 ⅜" Production Casing Setting Depth

The production casing size has been selected as 13 ⅜" in order to accommodate a 9 ⅝" completion, which is required for gas phase CO_2 injection purposes.

- The 13 ⅜" production casing setting depth has been selected as the base of the Ansdell formation in order to:
- Case off the overburden mudstones and halites prior to drilling the depleted Ormskirk reservoir.
- By drilling the reservoir in a dedicated hole section, the mud weight can be reduced without risking wellbore stability in the overlying mudstones. In addition, the production liner cement design can be optimised, which will increase the probability of obtaining reservoir zonal isolation via a good cement job.
- Allow 9 ⅝" tubing to be run as close to the top of the reservoir as is practicable.
- Provide the longest available interval for cementing the 13 ⅜" casing, thereby reducing the risk of poor cement isolation and assisting with end of field life well abandonment design.

11.7.2.4.1.4 12 ¼" Production Hole and 9 ⅝" Liner Setting Depth

The 12 ¼" production hole will be drilled through the Ormskirk Sand, with the length of the section designed to maximise the available reservoir injection interval.

A 9 ⅝" pre-drilled liner will be run across the reservoir interval, with the liner size having been selected to optimise gas phase CO_2 injection performance.

- It should be noted that a pre-drilled liner is being run to avoid the risk of losses when cementing.

11.7.2.4.1.5 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 13 ⅜" production casing and opposite the Blackpool and Cleveleys mudstones. These formations have sufficient strength to contain reservoir pressure; therefore, by placing the abandonment plugs opposite these formations, store integrity will be assured.

11.7.2.4.2 Liquid Phase CO_2 Injector

For the later CO_2 liquid phase injection period, a smaller completion must be used than for gas phase injection. As such, a slimmer well design has been specified in order to benefit from lower well costs. Therefore, the conceptual well design for a liquid phase CO_2 injector is based on the same casing setting depths as for a gas phase injector, but with smaller hole and casing sizes.

11.7.2.4.2.1 32" Surface Hole and 26" Conductor Setting Depth

The conductor design will be as per a gas phase CO_2 injector.

11.7.2.4.2.2 17 ½" Surface Hole and 13 ⅜" Casing Setting Depth

The surface casing setting depth will be as per a gas phase CO_2 injector, but the 18 ⅝" tubular size will be replaced with 13 ⅜" casing.

11.7.2.4.2.3 12 ¼" Intermediate Hole and 9 ⅝" Production Casing Setting Depth

The production casing size has been selected as 9 ⅝" in order to accommodate a 5 ½" completion, which is required for liquid phase CO_2 injection.

The 9 ⅝" production casing setting depth will be as per a gas phase CO_2 injector.

11.7.2.4.2.4 8 ½" Production Hole and 7" Liner Setting Depth

The 8 ½" production hole will be drilled through the Ormskirk Sand, with the length of the section designed to maximise the available reservoir injection interval.

A 7" liner will be run and cemented in place, with the liner size having been selected to optimise CO_2 injection performance. Note that a pre-drilled or slotted liner (open hole completion) may still be an option if experience with the gas phase injection wells has been satisfactory, or concerns remain over cementing or perforation clean-up.

11.7.2.4.2.5 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 Blackpool and Cleveleys mudstones. These formations have sufficient strength to contain reservoir pressure; therefore, by placing the abandonment plugs opposite these formations, store integrity will be assured.

11.7.2.4.3 Monitoring Well

The conceptual well design for a monitoring well is as per a gas phase injector, with the well having been designed to allow its use as a contingency injector, should this be required.

11.7.2.4.4 Casing Metallurgy

When selecting the casing materials for CO_2 injectors, the following issues should be taken into consideration:

- Corrosion caused by exposure to gas or liquid phase CO_2
- Corrosion caused by exposure to hydro-carbon phase H_2S
- Material selection for low temperature

For casing strings with no direct exposure to reservoir fluids or the CO_2 injection stream, H_2S and 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 and H_2S. The corrosion potential will be dependent upon the water content of the injected CO_2, and/or latent water and H_2S in the wellbore, and some form of corrosion resistant alloy (CRA) will be required. It is recommended that detailed modelling be conducted during the FEED stage to confirm that this material is suitable for the injection stream specification and reservoir fluids composition. The casing strings to be designed using CRA materials are:

- Production casing below the production packer
- 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 from liquid to gaseous phase (which could occur when wellbore pressure is released later in field life). A reduction in wellbore pressure can occur due to planned operations (i.e. when pressure is bled off to test a downhole safety valve or during well servicing activities), or when an unplanned event occurs (i.e. there is a leak at the wellhead). When wellbore pressure is released either by design or unexpectedly, the liquid phase CO_2 will revert to its gaseous phase. At the liquid / gas interface, temperatures can be as low as -78°C, 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 FEED stage.

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 monitoring well 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 a liquid phase injector. This should provide the following benefits:

- Reservoir management flexibility is provided (i.e. it would ease conversion of a monitoring well to an injector later in field life).

11.7.2.4.5 Wellhead Design

As with the casing materials, the wellhead components must also be designed to provide suitable low temperature performance and corrosion resistance.

Wellhead component temperature rating is specified in API 6A with a class being assigned to reflect the temperature range to which the components are rated. For CO_2 injection wells, API 6A class K materials may be suitable, as the low temperature rating of these materials is -60oC. This should be acceptable for CO_2 injection purposes; however, it is recommended that detailed modelling is conducted for each wellhead component to confirm the lowest temperature to which they may be exposed, and that suitable materials are being selected.

In addition, the wellhead components which are directly exposed to the CO_2 injection stream should be specified from CO_2 resistant alloys.

11.7.2.4.6 Negative Wellhead Growth

When CO_2 injection commences, well temperatures are expected to drop. 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 18 ⅝" and 13 ⅜" 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.

11.7.2.4.7 Drilling Fluids Selection

11.7.2.4.7.1 Conductor Hole Section

This 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 conductor.

11.7.2.4.7.2 Surface Hole Section

This hole section should be drilled with 10.5 ppg KCl salt saturated mud, taking returns to the rig. KCl salt saturated water based mud has been selected to:

- Provide chemical inhibition in the mudstones via the K+ ion, thereby avoiding reactivity problems.
- Maintain borehole stability in the mudstones.
- Prevent washouts in the Presall Halite and maintain gauge hole.
  - This reduces the risk of hole cleaning problems and increases the probability of obtaining a good cement bond.
- It should be noted that:
- Silicate based muds have been used in some offset wells for both the surface and intermediate hole sections, however, these systems led to hole cleaning problems caused by cuttings agglomeration. Therefore, KCl has been selected to provide similar levels of inhibition, while improving hole cleaning efficiency.
- Oil based mud would provide effective inhibition for the surface and intermediate hole sections, and be suitable for hole cleaning purposes. However, the volume of oil-coated cuttings generated in 22" and 17 ½" hole size precludes the use of cuttings containment systems on a standard jack-up, making the selection of oil based mud impractical.

11.7.2.4.7.3 Intermediate Hole Section

This hole section should be drilled with 12.8 ppg KCl salt saturated mud, taking returns to the rig. KCl salt saturated water based mud has been selected to:

- Provide chemical inhibition in the mudstones via the K+ ion, thereby avoiding reactivity problems.
- Maintain borehole stability in the mudstones.
- Prevent washouts in the Mythop and Rossall Halites and maintain gauge hole.
  - This reduces the risk of hole cleaning problems and increases the probability of obtaining a good cement bond.

11.7.2.4.7.4 Reservoir Hole Section

The reservoir hole section should be drilled with oil-based mud weighted to 8.8 ppg (or lower if possible). The weighting agent should be $CaCO_3$ instead of barite in order to reduce the mud weight and provide the means to acidise the filter cake, should injection be impaired. This mud system has been selected in order to:

- Reduce the risk of losses by minimising mud weight and applied hydrostatic head.
- Reduce the differential sticking risk by keeping the mud weight as low as possible, thereby reducing the differential pressure applied to the drillstring.
- Generating a tight filter cake, thereby reducing the contact area between the drillstring and the borehole wall.
- Provide a remedial method of removing the filter cake, given that low reservoir pressure will prevent the well being back-flowed for clean-up purposes.
- In addition, oil based mud provides the following benefits:
- It minimises formation damage in the Ormskirk 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 in the Ormskirk Sand, 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 as a contingency.
- It can deliver higher ROPs.
- It increases lubricity and reduces the rate of erosion to bit and BHA components caused by the abrasive Ormskirk sands.

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.

Contingency Design

Should injection testing on the existing Hamilton wells show that the fracture gradient is at the low end of the predicted range, it is possible that conventional mud systems may need to be replaced with “low-head” drilling techniques (for example, foam or air drilling). It is recommended that the reservoir drilling fluid design for the gas-phase injectors is confirmed during the FEED stage, when additional fracture gradient data may be available.

11.7.2.4.8 Cement Programme

11.7.2.4.8.1 Conductor

The conductor should be cemented back to the mudline using a single, conventional rapid hardening cement slurry.

11.7.2.4.8.2 Surface Casing

The surface casing should be cemented back to the mudline using conventional lead and tail cement slurries.

11.7.2.4.8.3 Production Casing

The purpose of the production casing cement job is to provide a strong shoe prior to drilling the Ormskirk Sand, as well as preventing CO_2 leakage from the reservoir, and a tail slurry should be used to generate the compressive strength required to meet this objective.

The production casing should be cemented back to 100m inside the surface casing shoe in order to:

- Cement off all open formations, and minimise leak paths from the Ormskirk Sand.

11.7.2.4.8.4 Production Liner – Liquid Phase Injector

The purpose of the production liner 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 using a light weight 12.5 ppg slurry in order to minimise the risk of losses to the depleted sands.

11.7.2.4.9 Production Casing and Liquid Phase Liner Cement Design

At present, it is planned to cement the production casing and liquid phase injector 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 **Invalid source specified.**. 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 11-10 Cement degradation rates in CO_2 laboratory test results

For comparison purposes, the Ormskirk reservoir pressure is predicted to be approximately 8 bar. As such, the rate of cement degradation predicted by Duguid et al may be the most appropriate measurement to use. This suggests that cement would degrade at a maximum rate of 3.1m per 10,000 years. Given that the length of cement behind the production casing is designed to cover approximately 360m, 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 Gas Phase Wells

11.7.3.1.1 Lower Completion

The lower completion consists of a 9-5/8" pre- perforated liner with Fluid Loss Control Valve. No sand control is incorporated following the recommendations of the sanding risk review (section 3.6.4.3.).

Consideration should be given to mud removal prior to CO_2 injection. Recommendations include:

- Drill with solids free OBM and sized calcarb
- Circulate out to a solids free brine with wash pipe
- Displace lower completion to acid mud breaker
- POOH. Close FLCV.
- Run upper completion.
- Open FLCV.
- Start injection.

11.7.3.1.2 Upper Completion

The upper completion consists of a 9-5/8" tubing string, anchored at depth by a production packer in the 13-3/8" production casing, just above the 9-5/8" liner hanger. Components include:

- 9-5/8" 13Cr tubing (weight to be confirmed with tubing stress analysis work) with higher grade CRA from Barrier Valve to tailpipe
- 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
- 13-3/8" V0 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). If possible, the DTS should be run across the full sandface (this may be a complex installation, given the likely presence of a FLCV, but may be possible) in order to provide an injection profile and monitor minimum temperatures in the wellbore.

11.7.3.2 Liquid Phase Wells

11.7.3.2.1 Lower Completion

The lower completion consists of a 7" cemented or pre- perforated liner with Fluid Loss Control Valve. No sand control is incorporated following the recommendations of the sanding risk review (section 3.6.4.3.).

If a cemented liner is preferred (see section 3.6.4.3.2 for discussion), underbalanced perforating with wireline guns is recommended.

If the field experience with a pre-drilled liner is good, then completion methodology would follow those recommended for the gas phase wells.

Should sufficient pore pressure exist in order to allow back flow, consideration should be given to a well clean-up backflow prior to CO_2 injection.

11.7.3.2.2 Upper Completion

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

- 5-1/2" 13Cr tubing (weight to be confirmed with tubing stress analysis work) with higher grade CRA from Barrier Valve to tailpipe
- 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" V0 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). If possible, the DTS should be run across the full sandface (this may be a complex installation, given the likely presence of a FLCV, but may be possible) in order to provide an injection profile and monitor minimum temperatures in the wellbore.

11.7.3.3 Completion Metallurgy

11.7.3.3.1 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.

11.7.3.3.2 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
$CO_2 + H_2S$	25Cr
$CO_2 + H_2S + O_2$	Nickel Alloy
$CO_2 + NO_2/SO_2$	GRE

Table 11-11 Impact of contaminants on material selection

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.

NO_2 and SO_2 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 SO_2). Hamilton reservoir temperature is low (~89°F or 31.7°C) and therefore the impact of these contaminants is not significant.

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. Note that it is expected that out of spec conditions will be transient, with flow wetted components only exposed to these conditions for a short period of time. If longer periods of exposure are expected, then metallurgy requirements may be increased to suit.

While it is expected that the supply stream will have negligible H_2S content, the Hamilton reservoir gas contains around 1,100 to 1,200 ppm (~0.11%). At initial (depleted) reservoir pressures, the partial pressures of H2S are well within the tolerance levels for 13CR materials. However, towards the end of field life (liquid phase injection), partial pressures may exceed 0.103 bar, leading to higher levels of corrosion (pitting and potentially cracking). However, it should be noted that at this point in field life no water washes are expected and the near wellbore is likely to be fully dehydrated. This means that there is no (or very limited) water phase present. Corrosion to the reservoir liner is not considered a threat to well integrity, so 13CR is acceptable. However, in order to maintain long term integrity in gas and liquid phase injector wells, it is recommended that the bottom joints of production casing (up to and across the production packer and setting depth of any abandonment plug) is upgraded to a nickel alloy. Duplex material (25CR) may be suitable, pending further investigation, but given the moderate cost uplift for a few hundred feet of casing, the higher grade is recommended. Similarly, upper completion equipment, from tailpipe up to and including the production packer and deep set downhole shut-in valve, should be upgraded to Nickel alloy (or Austenitic stainless steels).

Material grade is limited to 80ksi (L-80) due to the potential for very low temperatures. Further work is recommended to determine the minimum temperatures likely to be seen during transient events such as blow down, and to ensure any material recommended is suitable for these extreme conditions.

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 Hamilton 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

11.7.3.5.1 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 gas / liquid phase injection system for Hamilton, the primary risk of hydrate formation is during re-start operations following wash water injection (see section 3.5.1.2). Further work on this area is recommended in FEED.

11.7.3.5.2 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. High saline brines (300,000ppm), such as is present in the reservoir, may freeze if temperatures drop below -20°C.

CO_2 injection is unlikely to reduce temperature to this low temperature in the well (see near wellbore modelling). 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.

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 should DTS installation prove problematic. Remedial stimulation may be required if formation damage occurs through plugging.

11.7.5 Wells Basis of Design Summary

The Hamilton Injector Well Basis of Design can be summarised as follows:

- The injector wells will be drilled from a NUI platform by standard North Sea jack-up
- The wells will be a deviated (up to 70 deg) in the tangent section, dropping to 60deg through the target formation
- The gas phase injector wells will consist of 26” conductor, 18-5/8” surface casing and 13-3/8” production casing and 9-5/8” pre-drilled liner (un-cemented). The wells will be completed with 9-5/8” production tubulars
- All flow wetted surfaces will be 13%Cr material with higher grade CRA for the lower sections
- Maximum injection rates will be 3.712 MMte/yr (191.9 mmscf/day)
- Maximum FTHP will be 63 bar
- Maximum SITHP will be <63 bar
- Maximum WHT will be 30oC
- Minimum Design Temperature (to be confirmed by transient modelling)
- The liquid phase injector wells will consist of 26” conductor, 18-5/8” surface casing, 13-3/8” intermediate casing and 9-5/8” production casing, with a 7” cemented liner (or un-cemented pre-drilled liner). The wells will be completed with 5-1/2” production tubulars
- All flow wetted surfaces will be 13%Cr material with higher grade CRA for the lower sections
- Maximum injection rates will be 2.649 Mte/yr (137 mmscf/day)
- Maximum FTHP will be 120 bar
- Maximum SITHP (<120bar)
- Maximum WHT will be 16oC
- Minimum Design Temperature (to be confirmed by transient modelling)

11.8 Appendix 8 – Cost Estimate

Provided Separately

11.9 Appendix 9 - Methodologies

11.9.1 Offshore Infrastructure Sizing

The preliminary calculations are based on fluid flow equations as given in **Invalid source specified.** and were performed to provide a high level estimate of pressure drop along the pipeline routes.

Erosional Velocity: $V_e = c/\sqrt{\rho}$

Where;

V_e = Erosional Velocity (m/s)

c = factor (see below)

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: $V = 4Q/\pi d^2$

Where,

V = Velocity (m/s)

Q = Mass flow rate (MTPa)

Reynolds Number: $Re = \frac{\rho V d}{\mu}$

Darcy Friction Factor: The friction factor is obtained from the Serghides' solution of the Colebrook-White equation.

$$A = -2\log_{10}\left(\frac{\varepsilon/D}{3.7} + \frac{12}{Re}\right),\ B = -2\log_{10}\left(\frac{\varepsilon/D}{3.7} + \frac{2.51A}{Re}\right),\ C = -2\log_{10}\left(\frac{\varepsilon/D}{3.7} + \frac{2.51B}{Re}\right),\ f = \left(\frac{A-(B-A)^2}{C-2B+A}\right)^{-2}$$

Pressure drop for single phase fluid flow: $\Delta P = \frac{fL\rho V^2}{\mu}$

Preliminary wall thickness calculations to PD8010 Part 2 **Invalid source specified.** 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 configuration is summarized in the table below.

Pipeline	Pipeline OD	Mass Flow Rate	Route Length	Pipe Roughness	Fluid Phase	Pressure Drop per km	Pressure Drop
Point of Ayr to Hamilton	16” (406.4mm)	4MTPa	26km	0.045	Liquid/Dense [1]	0.246 bar	6.7 bar
		5MTPa				0.375 bar	10.2 bar
		7.5MTPa				0.838 bar	22.9 bar
		10 MTPa				1.484 bar	40.5 bar

Table 11-12 Point of Ayr to Hamilton Pipeline Pressure Drop

Notes: Density of 980.3 kg/m^3 and viscosity 0.1016 kg/sm

Parameter	Value
Outer Diameter	406.4mm
Wall Thickness	21.4mm
Corrosion Allowance	3mm
Material	Carbon Steel
Corrosion Coating	3 Layer PP
Weight Coating	None
Pipeline Route Length	26km
Installation	S-Lay followed by Trenching and Burial
Crossings	2

Table 11-13 Hamilton Pipeline Specification

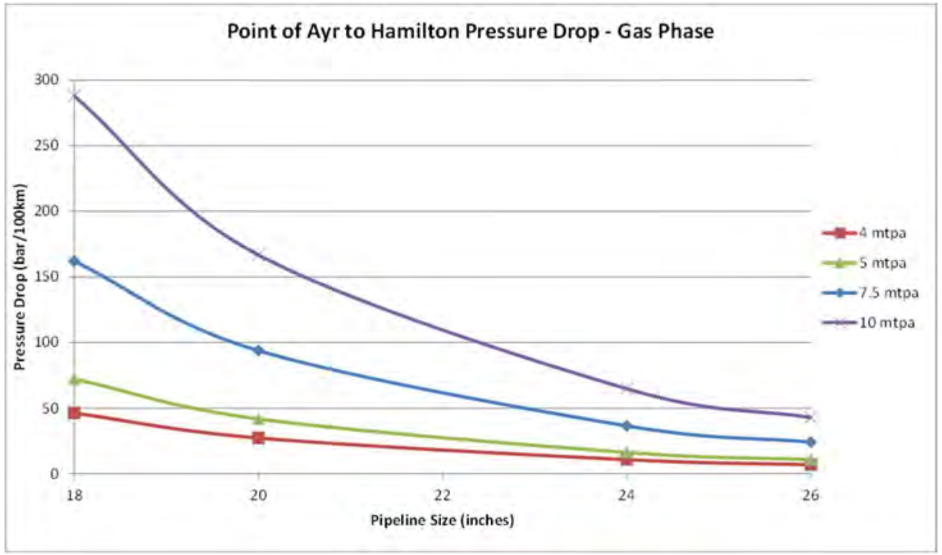


Figure 11-53 Pipeline Pressure Drop - Gas Phase

Pipeline	Pipeline OD	Mass Flow Rate	Route Length	Pipe Roughness	Fluid Phase	Pressure Drop per km	Pressure Drop
Point of Ayr to Hamilton	26" (660.4mm)	4MTPa	26km	0.045	Gas [1]	0.253 bar	6.9 bar
		5MTPa				0.394 bar	10.8 bar
		7.5MTPa				0.884 bar	24.1 bar
		10 MTPa				1.57 bar	42.8 bar

Table 11-14 Point of Ayr to Hamilton Pipeline Pressure Drop - Gas Phase

As discussed within Section 5 of the report, the CO_2 will be transported offshore in the liquid phase because a larger, heated, pipeline would be required to transport the CO_2 in the gas phase. Preliminary line sizing calculations have been performed to determine the required outer diameter of a gas phase pipeline to Hamilton. To meet the top hole arrival pressure requirements, the pipeline will need be operated in the region of 60 to 70 bar and to avoid liquids forming the pipeline will need to be heated to 20°C - 30°C. This results in a 26" diameter pipeline requirement for the 5MTPA flow capacity.

There are two methods of providing active heating to a pipeline (a bundle has been ruled out due to the number of bundles required and the nearest bundle fabrication and launching yard being Wick):

- Electrical Trace Heated Pipe in Pipe (ETHPIP);
- Direct Electrical Heating (DEH).

ETHPIP is a relatively new product offered by Technip and Subsea7. The system relies on passive insulation through a pipe-in-pipe system, with additional heating provided by passing current through trace heating cables that are installed onto the pipeline. ETHPIP is presently only available for PIP systems with a carrier (outer) pipe diameter of 16” or less. For this reason to employ ETHPIP on Hamilton would necessitate multiple pipelines in order to deliver the required capacity. ETHPIP also has a limited subsea track record. For these reasons, ETHPIP has not been considered further for Hamilton.

Direct Electrical Heating (DEH) of pipelines is a method whereby a conventional wet insulated pipeline (thermal insulation on the outside of the pipeline) is heated by passing a current axially through the pipeline. In order to deliver the current a high voltage electrical cable is run from the power source and piggybacked along the pipeline. While a 26” DEH pipeline is believed feasible, it has historically been utilised on much smaller diameter pipelines where intermittent heating is required. DEH is highly inefficient, typically not utilised for permanent heating and as such is not considered viable for application on a large diameter CO_2 supply pipeline. There are also thermal overheating issues associated with burial of the cable which would mean that the entire length of the pipeline would need to be laid on the seabed and then protected by means of rock dump which would involves vast amounts of rock.

11.9.2 Power Requirements and Supply

The power required to convert the CO_2 from liquid phase into gas phase is significant and has been estimated to be 10 MW for the 5Mtpa forecasted supply rates. This is above normal power generation on offshore facilities and requires special attention. There are three main options to consider for securing offshore power, namely: -

- A self-contained generation and distribution network (typically gas turbine or diesel) – this requires extensive offshore power generation infrastructure as well as large fuel tanks and bunkering. This has been rejected due to the increase in offshore CAPEX costs, the additional manning requirements to service the generators and supply the fuel and the increase in the overall carbon footprint of the project.
- Utilising offshore renewable power from existing and or future offshore windfarms in close proximity. There is a relatively high density of wind farms planned in the vicinity of the site however the heating is required continuously for an extended period of time therefore an alternative would power source would be required during periods of low wind supply to avoid downtime. A combination of local generation and renewable power would be feasible and would reduce the carbon deficit associated with local power generation but it would also result in high expenditure as it factors 2 independent power sources.
- Securing supplies from an onshore electricity distribution network connection using a 26 km subsea cable – this minimises offshore

infrastructure and allows power to be procured from a wide range of sources including renewables

This section considers some of the key factors in securing a power supply from an onshore source and considers outline Capex and Opex costs.

The critical and greatest cost sensitive elements of securing a power connection to the Hamilton Site are: -

- the land and subsea cable route (and length);
- seabed conditions for installing the submarine cable;
- working windows during offshore installation (weather and conditions);
- maintaining a high quality installation (to minimise on cable faults) during installation

11.9.2.1 Technologies

This section provides an overview of the technologies available for the provision of a high voltage offshore electrical supply to the Hamilton Site. It provides a high level description of the relevant features of an offshore connection based on economically feasible technologies. Budgetary costs for each technology are presented in the next section.

The majority of electricity systems throughout the world are Alternating Current (AC) systems. The voltage level is relatively easy to change when using AC electricity, which means a more economical electricity network, can be developed to meet power requirements. However AC systems incur a reactive power loss due to inductance and capacitance which are proportionately larger than comparable DC systems.

Direct Current (DC) electricity did not develop as the means of transmitting large amounts of power because DC is harder to transform to a lower or higher voltages. HVDC has recently become attractive for relatively long connections (such as the extension of an existing AC system or when providing inter-connections between different transmission systems) as HVDC technologies: cable and power electronics, have improved. HVDC incurs relatively lower operating losses than AC systems in long connections; however this is offset by an increase in capital cost of AC-DC converter stations that are required at each end of the HVDC link to connect AC systems together.

The electricity transmission network in England is owned and maintained by National Grid and operates at 275kV and 400kV. The distribution networks are owned and operated by Distribution Network Operators who operate in specific geographic areas at voltages which range from LV up to 132kV. The UK electricity transmission, distribution and market is regulated by OFGEM. In general terms higher voltage systems incur lower lifetime losses and have higher power capacities, though they incur significant levels of capital investment and cost more to repair in the event of failure.

There are two main technologies that can be used to provide high voltage connections offshore. These technologies have different features which affect how, when and where they can be used. The main technology options for offshore high voltage connections are: -

1. AC underground land and subsea cables and
2. High Voltage Direct Current (HVDC) land and subsea cables combined with at least two AC-DC converter stations

In the case of the Hamilton offshore connection any cables will be required to connect to substations at either end. Ultimately the land connection will be to a distribution network, which is owned and operated by an incumbent Distribution Network Operator (DNO). The offshore connection will be to an offshore substation that, depending upon the technology employed, will comprise conversion equipment to provide a suitable operating voltage for the heater system (typically 690V AC) and a suitable electrical system topology to meet with defined security, resilience and availability requirements of the overall CCS process.

The design of the electrical power system can be optimised using voltages which suit the connection requirements; DNO's operate standard voltage categories, such as 33kV, 66kV and 132kV. Bespoke voltages will require investment in their development, hence the FEED report has considered standard DNO voltages as assets and technology is thus developed and available.

The following is a brief overview of the technologies required to create an electrical high voltage connection between a public on-shore DNO network and an offshore privately owned distribution network incorporating the CCS process heating system.

11.9.2.2 Underground Cables

Underground cable systems are made up of two main components - the cable and connectors. Connectors can be cable joints, which connect a cable to another cable, or terminations which connect the cable to other equipment (such as switchgear or transformers or overhead lines), generally within a substation.

Figure 11-54 Images of Subsea Cabling

Cables consist of an electrical conductor in the centre, which is usually copper or aluminium, surrounded by insulating material and sheaths of protective metal and plastic. In subsea cables a layer of armouring is also incorporated to improve cable mechanical protection. The insulating material ensures that although the conductor is operating at a high voltage, the outside of the cable is at zero volts (and therefore safe).

Underground cables connect to above-ground electrical equipment at substations which are enclosed within a fenced compound.

An electrical characteristic of a cable system is capacitance between the conductor and earth. Capacitance causes a continuous 'charging current' to flow: the magnitude of which is dependent on the length of the cable overhead line (the longer the cable, the greater the charging current) and the operating voltage (the higher the voltage the greater the current). Charging currents have the effect of reducing the power transfer through the cable. High cable capacitance also has the effect of increasing the voltage along the length of the overhead line, reaching a peak at the remote end of the cable.

It is possible to reduce cable capacitance by connecting reactive compensation equipment to the cable, either at the ends of the cable, or, in the case of longer cables, at regular intervals along the route. Specific operational arrangements and switching facilities at points along the cable overhead line may also be needed to manage charging currents.

High voltage underground cables should be regularly maintained and inspected. Cable integrity tests are relatively straightforward and combined with continuous monitoring systems mean cables are relatively reliable and available assets. However, cable faults can result in length down-times as unless there are alternative sources of supply the cable will not be available for use on the repair is completed. Land based cable systems at 33kV may take a few hours to repair, whereas cables operating at 132kV and above repairs may take days to repair (or weeks if spare cable and joints are not readily available). Subsea cable repairs require specialist vessels and diving operations. For this reason asset owners often place operation, maintenance and repair contracts with specialist contractors.

Identifying faults in land based underground cables often requires multiple excavations to locate the fault and some repairs require removal and installation of new sections of cable, which can take a number of weeks to complete.

Identifying faults in subsea cables is more difficult than land cables as diving and/or Remote operated Vehicle (ROV) operations are required and repairs require specialist cable laying and jointing vessels.

The installation of land based underground cables requires significant civil engineering works.

Figure 11-55 Image and Schematic of an onshore construction swathe

The construction swathe required for a single, 3-phase, 33kV AC underground cable would be around 7-15m, with a trench approximately 1m deep by 1m wide. At higher voltages the construction swathes increase and cable trench width increases. In some cases two or more cables may be required to meet the require power capacity, in this case the swathe and trench widths increase proportionally.

Each of the two main components that make up land based underground cable system has a typical design life of 40 years. Subsea cables have lower design lives, due to their harsher environment, and are typically 20-25 years.

Subsea cables up to 132kV can incorporate a fibre optic cable bundle within the power cable. This saves having to install a separate fibre cable at the same time as installing the power cable. The fibres can be used for operational telecommunications, protection and SCADA systems as well as having the potential for continuous cable monitoring (such as DTS or partial discharge sensing).

Asset replacement is generally expected at the end of design life. However, asset replacement decisions (that are made at the end of design life) should account for the actual asset condition and may lead to actual life being longer than the design life.

Installation costs associated with cable systems are very sensitive to the type of ground conditions encountered and routes should be planned with great care. Subsea cables are often shallow buried to provide increased protection against the marine environment and any vessel operations. The seabed environment and cable route corridor is therefore as critical as it is on land.

A transition is required between the offshore cable and the land based cable systems. Subsea cables are typically winched onto shore and brought to a suitably located 'transition joint bay'. This connects the offshore cable to the land cable system. Joint bays can take up a relatively large area, approximately 10-20m long (for 33kV – 132kV) and 5-10m wide. A separate joint bay is required for each 3-phase cable.

11.9.2.3 High voltage Direct Current (HVDC)

HVDC technology can provide efficient solutions for the bulk transportation of electrical energy between AC electricity systems (or between points on an electricity system).

There are circumstances where HVDC has advantages over AC generally over very long distances >60km or between different, electrically separate systems, such as between different countries.

Proposed offshore wind farms to be located over 60km from the coast of the UK are likely to be connected using HVDC technology as an alternative to an AC subsea cable. This is because AC subsea cables over 60km long incur a number of technical limitations, such as high charging currents and the need for mid-point compensation equipment.

The connection point between AC and DC electrical systems has equipment that can convert AC to DC (and vice versa), known as a converter. The DC electricity is transmitted at high voltage between converter stations.

HVDC can offer advantages over AC underground cable, such as: -

1. A minimum of two cables per circuit (+ and -) is required for HVDC whereas a minimum of three-phase system (i.e. three cables or a three-core cable) is required for AC;
2. reactive compensation mid-route is not required for HVDC;
3. Cables with smaller cross sectional areas can be used (compared to equivalent AC system rating).

It is possible to deploy a single cable system and use the ground as a return. However this increases risks of ground potential rise along the route and may have a greater impact to the environment than a bipolar cable. In this report a two cable system has been considered, further studies may show a earth return system is acceptable.

HVDC systems have a design life of about 20 years. This design life period is on the basis that large parts of the converter stations (valves and control systems) would be replaced after 20 years.

Asset replacement is generally expected at the end of design life. However, asset replacement decisions (that are made at the end of design life) should account for the actual asset condition and may lead to actual life being longer than the design life.

11.9.2.4 DNO Connection and Metering

A physical and electrical connection must be made to an existing electricity network if power is to be exported (or imported) by the DNO.

The DNO will charge a fixed amount for infrastructure required to supply the request power (or a proportion thereof if the power is shared by a number of customers). In addition if the request exceeds the power capacity at that point of the DNO network they may also charge a proportion of costs for increasing the supply capacity on their network (known as upstream reinforcement). The connection charges are therefore sensitive to a) the requested power and b) the state of the existing network in proximity to the point of connection.

The final connection to the DNO network must be made by the DNO. The DNO is obliged to quote for all necessary equipment to the point at which the customer takes their supply, however, in cases where other equipment is necessary the customer may obtain quotes from other authorised installers (so long as the equipment meets the DNO requirements).

In general the fixed charge covers Opex costs, however if the equipment the DNO installs is only required for a single customer it may be appropriate to split Capex and Opex costs. In general DNO assets are inspected and maintained periodically on 4, 8 and 12 year cycles.

A meter operator is selected by the customer and is normally metered at the point of connection with the DNO. Metering and meter tariffs will be set by the operator and DNO and will be charged based upon units of electricity used.

11.9.2.5 Substations

Substations contain switchgear (to enable safe connection and disconnection of sections of network) and in certain instances, transformers which step-up or step-down voltage levels to suit overall system requirements.

11.9.2.6 Hamilton Concept Network Technologies

The following illustrate typical connections for a 10MW electrical load:-

	33kV – 690kV	132kV (11kV) 690V	HVDC
Connection Voltage (kV)	33	132	60
# of heaters (in operation)	4	4	4
Rating of heater (MW)	2.5	2.5	2.5
Aggregate Power (MW)	10	10	10
Power Factor (AC)	0.95	0.95	-
Total Apparent Power (MVA)	11	11	-
Current (A)	185	46	167

Table 11-15 Typical connections for a 10 MW electrical load

Three conceptual network topologies are included in the economic evaluation. The single circuit (non-firm) connection is the simplest arrangement. The firm supply arrangement includes duplicated circuits and the final arrangement shows a HVDC with AC-DC convertor stations. Figure 11-56 illustrates these topologies. Table 11-16 provides a generic appraisal of the merits of each connection type.

	Single Circuit	Duplicate Circuits	HVDC
Capex	Low	Medium	High
Opex	Low	Medium	High
Complexity	Simple	Medium	Complex
Typical Asset Life (yr)	40 (subsea 20-25)	40 (subsea 20-25)	20
Security/Resilience			

Table 11-16 Generic appraisal of the merits of each connection type

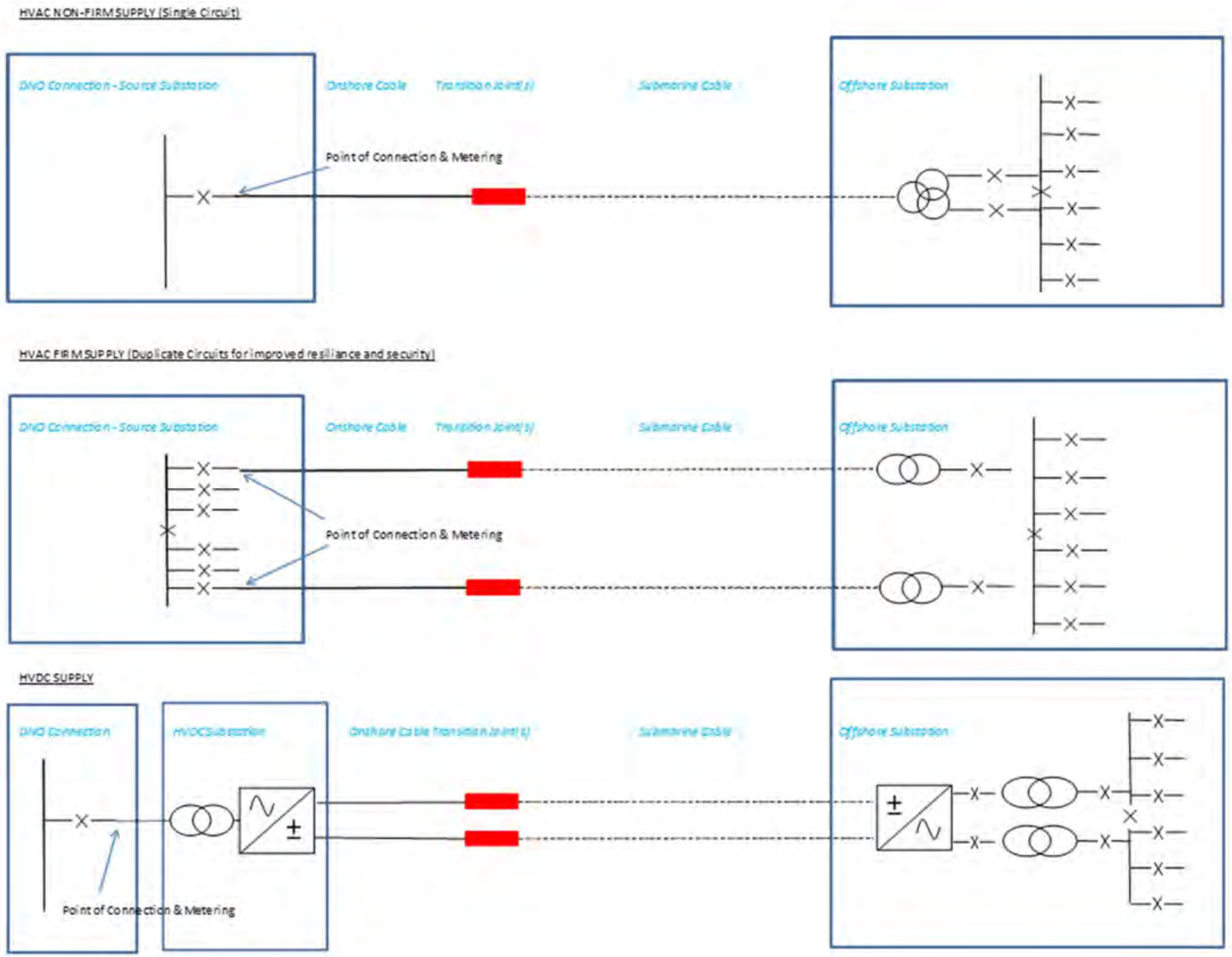


Figure 11-56 Schematics of each connetiction type

11.9.2.7 Economic Appraisal

For the economic appraisal of connections it is necessary to make a comparative assessment of the lifetime costs associated with each technology that is considered to be feasible. This section provides an overview of the cost information that is publically available and that which is based on experience of working within DNO's.

There is some publically available information for Capex and Opex costs for subsea cable and HVDC technologies; however they tend to be focussed on offshore windfarm development. The power requirements for offshore wind have increased significantly in the past 10 years and most modern technology is designed for 300MW -1,000MW. A 10MW supply, as anticipated at Hamilton, is small in comparison. The cost of a smaller capacity (when considering HVDC) does not necessarily mean a lower Capex and Opex cost per unit of power as HVDC technologies have been designed specifically for higher power rating. The Troll A offshore HVDC Platform is the closest comparable system to Hamilton, with a 40MW total power requirement over a 68km link comprising +/-60kV HVDC technology and was commissioned in 2005.

It is anticipated that a 33kV connection over 26km and circa 10MVA is towards the limit of voltage drop and capacitive charging/reactive power limits. This report is not intended to engineer a solution, but further investigation will be required (and reactive compensation may need to be added to this appraisal) in order that a 33kV connection is proved feasible.

11.9.2.8 Capital Cost Estimates

Initial Capex estimates are based on the high level scope of works defined for each option in respect of each technology option that is considered to be feasible using typical unitised costs.

Capex Option Costs (£)								
Arrangement (typical 40 year asset life)	Planning & Design	Preliminaries & Project Management	DNO Connection	Offshore Substation	Onshore Substation	Land Cable	Subsea Cable	Total
33kV Firm	1,009,000	1,720,000	200,000	3,500,000	-	4,940,000	22,800,000	**34,169,000**
33kV Non-Firm	1,009,000	1,720,000	100,000	2,000,000	-	2,600,000	12,000,000	**19,429,000**
132kV Firm	1,009,000	1,720,000	2,000,000	6,000,000	-	19,000,000	69,000,000	**98,729,000**
132kV Non-Firm	1,009,000	1,720,000	1,000,000	3,000,000	-	10,000,000	36,000,000	**52,729,000**
HVDC (1.3 x factor to adjust for reduced 20 yr design life) Non-Firm	1,151,914	1,720,000	1,000,000	3,300,000	3,300,000	5,000,000	15,000,000	**30,471,914**

Table 11-17 Capex for cabling options

Notes: -

1. Capital costs for all technologies are based upon rural/arable land installation with no major obstacles (examples of major obstacles would be roads, rivers, railways etc.) and subsea installations in beds that are conducive to 250m lay in an hour.
2. All underground AC cable technology costs are for direct buried installations only and 1 core per phase (i.e. a 3 core cable or 3 x single core cables)
3. AC cable installation costs exclude the cost of reactors and reactive compensation
4. Asset life is typically 40 years; manufacturing bespoke design life assets of 20 years is not considered to be cost effective.
5. HVDC converters typically have a life of 20 years. For consistency in capital cost analysis it has been assumed that life extension could be achieved without wholesale replacement. A 20% uplift has been factored into the capital cost of the HVDC converters to cater for spares provision

11.9.2.9 Maintenance & Repair Costs (based on 2015 prices)

The maintenance and repair costs associated with each option vary significantly. Most high voltage electrical equipment is inspected and maintained regularly to ensure system performance is maintained. More complex equipment, like HVDC converters, have a higher maintenance costs due to their specialist parts. Critical HV cables often incorporate cable temperature monitoring (and in some cases a means to detect partial discharge) so the asset condition can be continually assessed.

Table 11-18 provides an estimate of inspection, maintenance and repair costs of the major electrical components based on 2015 prices.

This report does not take account of replacement costs, except in the case of HVDC where the design life is typically less than the nominal 25 year design life anticipated. In general high voltage electrical assets have design lives of 40 years, with the exception of sub-sea cables where 25 years is more commonplace.

The following provides a high level summary of common replacement requirements applicable to specific technology options.

1. AC underground Cable - At the end of their initial design life, circa 40 years, replacement costs for underground cables are estimated to be equal or potentially slightly greater than the initial capital cost. This is because of works being required to excavate and remove old cables prior to installing new cables in their place in some instances.
2. HVDC - It should be noted at the end of the initial design life, circa 20 years, replacement costs for HVDC are similar to install costs.

Asset	Description	Maintenance Regime	Cost	Frequency (1/yr)	Annual Maintenance Costs (£/year)	*Repair*	*Repair Time (Est)*	*Repair Cost (£)*	*Repair Notes*
Land Cable	Single core, 3-Phase XLPE cable installed in the verge of highway	Inspection 4 yearly	7,400	0.25	**1,850**	33kV Cable, 20m with joints and install	0.3w	15,000	Costs inclusive of labour and materials and assumes spare materials held
Subsea Cable	Three-core, 3-Phase XLPE cable	Inspection 2 yearly	15,000	0.5	**7,500**	Vessel, jointing, ROV, Cable	1w	300,000	Costs inclusive of labour and materials and assumes spare materials held
Fluid Filled Transformer	33/11kV transformer 20/40MVA	Inspection & Maintenance 4 yearly. Assumes no oil change required	12,000	0.25	**3,000**	Replace Tx	8w	600,000	Costs inclusive of labour and materials (33kV transformer) and assumes spare materials held (note 33kV transformer lead time typically 32w)
AC GIS Switchgear	33kV GIS Switchgear	Inspection 8 yearly	7,400	0.125	**925**	Replace CB	4w	45,000	Costs inclusive of labour and materials (33kV GIS CB) and assumes spare materials held (note 33kV CB lead time typically 24w)
HVDC VSC Converter	HVDC Converter with associated DC switchgear and transformer	Inspection & Maintenance 2 yearly	13,000	0.25	**3,250**	Replace Components	4w	-	Spares should be procured or contract placed with OEM for spares provision, cost of this is unknown at this time.

Table 11-18 Maintenance and repair costs for major electrical components

11.9.2.10 Annual Electrical Losses and Cost

Losses occur in all electrical equipment and are related to the operation and design of the equipment. The main losses within a transmission system come from heating losses associated with the resistance of the electrical overhead lines, often referred to as I2R losses. As the load (the amount of power each overhead line is carrying) increases, the current in the overhead line is larger. There are also smaller losses in magnetisation and dielectric, which are not dependent on load, but on if the electrical equipment is energised. For the purpose of this report these have been ignored as they are small in comparison to the load losses.

In all AC technologies the power losses are calculated directly from the electrical resistance properties of each technology and associated equipment.

The process of converting AC power to DC is not 100% efficient. Power losses occur in all elements of the converter station: the valves, transformers, reactive compensation/filtering and auxiliary plant. Manufacturers typically represent these losses in the form of an overall percentage.

Losses (kW)	Land Cable Loss	Subsea Cable Loss	Substation/Tx Loss	Total Load Losses	Hours in a Year (h)	Load Losses (MWh)	Annual Loss (@£50/MWh)
33kV Firm	54	163	139	**357**	8,760	3,124	£ 149,971
33kV Non-Firm	109	327	278	**713**	8,760	6,249	£ 299,942
132kV Firm	5	14	9	**27**	8,760	234	£ 11,242
132kV Non-Firm	9	27	17	**53**	8,760	468	£ 22,484
HVDC	34	103	817	**955**	8,760	11,949	£ 401,617

Table 11-19 Electrical losses and associated cost

11.9.2.11 Distribution Use of System Charges and Tariffs

All DNO's are required to publish statements on their use of system charges for customers. Tariff and charges for 22kV connections and above are bespoke and calculated on the required capacity and network security, availability, reliability and capacity requirements.

It is likely the DNO would categorise Hamilton as a Designated EHV connection and thus a bespoke fixed charge and variable charge may be levied, dependent upon capital contributions for the initial connection.

In OFGEM's project discovery document they estimate the cost of electrical energy to be £50/MWh. Using this as a datum the annual cost of energy would be: -

50 x 24 x 365 x 10 = £4,380,000

11.9.2.12 Overall Costs Estimate

The following table provides an overview of each option and a summary of Capital and Operational expenditure. The OPEX costs are based on 2015 estimates and thus need to be discounted using appropriate rates to account for overall lifetime costs.

Arrangement	CAPEX	OPEX - Annual Costs		
		Operational Cost	Cost of Energy	Cost of Losses
33kV Firm	£ 34,169,000	£ 25,625	£ 4,380,000	£ 149,971
33kV Non-Firm	£ 19,429,000	£ 13,275	£ 4,380,000	£ 299,942
132kV Firm	£ 98,729,000	£ 25,625	£ 4,380,000	£ 11,242
132kV Non-Firm	£ 52,729,000	£ 13,275	£ 4,380,000	£ 22,484
HVDC Non-Firm	£ 30,471,914	£ 15,600	£ 4,380,000	£ 401,617

Table 11-20 Cost estimate summary for electrical connections

11.9.3 Cost Estimation

The CAPEX, OPEX and ABEX have been calculated for the engineering, procurement, construction, installation, commissioning, operation and decommissioning of the Hamilton facilities. The OPEX has been calculated based on a 25 year design life.

An overview of the Hamilton 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, Power Cable
- Wells: Drilling and the well materials and subsurface materials
- Other: Anything not covered under transportation, facilities or wells.

The cost estimate WBS adopted throughout is shown in Table 11-21. 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 40 year design life	
ABEX (Transportation, Facilities, Wells, Other)	
Decommissioning, Post Closure Monitoring, Handover	

Table 11-21 Cost Estimate WBS

11.9.4 Petrophysics

11.9.4.1 Parameter Definition

11.9.4.1.1 Formation Temperature Gradient

Reservoir temperature is reported to be 85 DegF at the datum depth of 2400ft TVDSS**Invalid source specified.**. There is a very limited database of maximum recorded maximum bottom hole temperatures, these a spread of temperatures between 85 DegF to 98 DegF over the depth intervals of interest with too much scatter to fit a reliable geothermal gradient (Figure 11-57). Given the scatter of data, the reservoir is assumed to be constant at 85 DegF over the zone of interest. This assumption is consistent with the Hamilton Petrophysical model used by the operator.

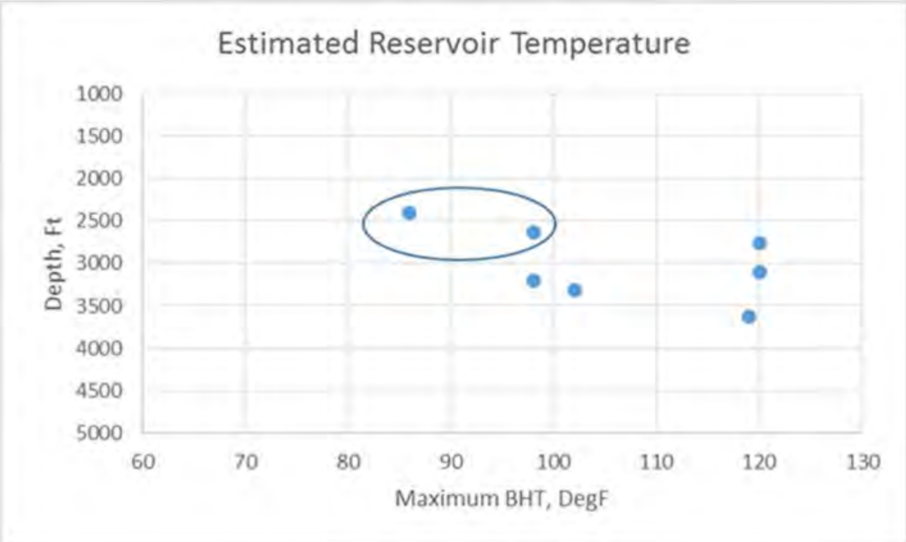


Figure 11-57 Recorded bottom hole pressure from wireline data °F

11.9.4.1.2 Formation Water Resistivity

Connate water resistivity was cross referenced for consistency from a number of sources. Apparent Rw (Rwa) was continuously calculated in net reservoir sands, the minimum value of Rwa is taken as representative of the true water resistivity for the reservoir. Crossplots of Porosity vs. Deep Formation Resistivity, (Pickett-plots) were used to collaborate the minimum Rwa method. Furthermore, the Rw estimates on a well by well basis were found to be consistent with the published values in the 'North Sea Formation Waters Atlas' **Invalid source specified.** for the Triassic Sherwood formation. Wells 110/2-3, 110/7-1 and 110/9-1 are the nearest wells to the study area published in the Atlas with Rw values of 0.062, 0.052 and 0.055 respectively all measured at 60 DegF. A default value of 0.050 ohm.m @ 60 DegF was used in all evaluations, with only minor zonal calibration adjustments as required.

11.9.4.1.3 Electrical Resistivity Properties

SCAL electrical properties of Formation Resistivity Factor (FRF) and Formation Resistivity Index (FRI) were measured on a selection of seven representative core samples from well 110/13-3 (Figure 11-58). The FRF was measured for all the core samples immersed in a synthetic formation brine of 0.0605 ohm.m at 20 DegC.

These measurements are used to estimate a (pore geometry factor), m (cementation factor) and n (saturation exponent) for input into the Archie saturation equation.

A cross plot of porosity vs FRF is shown in Figure 11-59 is used estimate the m and a. The slope of the regression line = m, where the intercept with the porosity axis = a. A fixed point regression where a=1 has been used, giving a values for m = 1.76

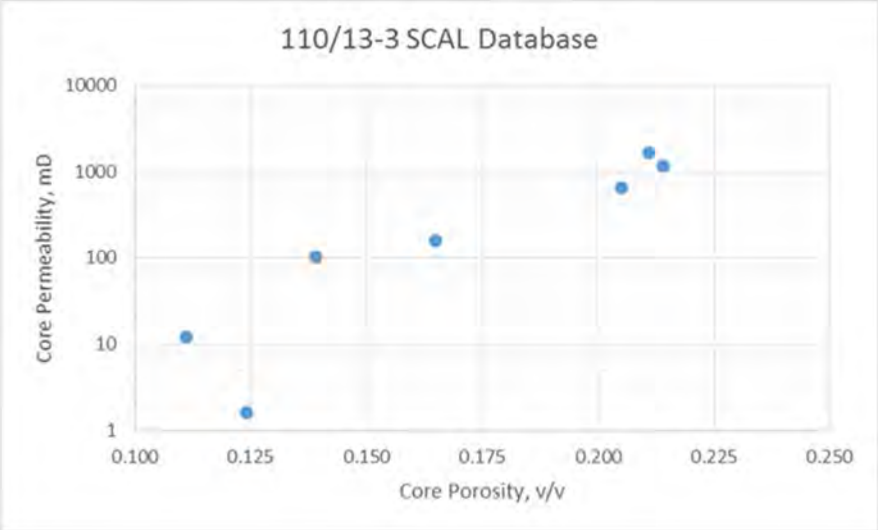


Figure 11-58 SCAL samples porosity-permeability crossplot

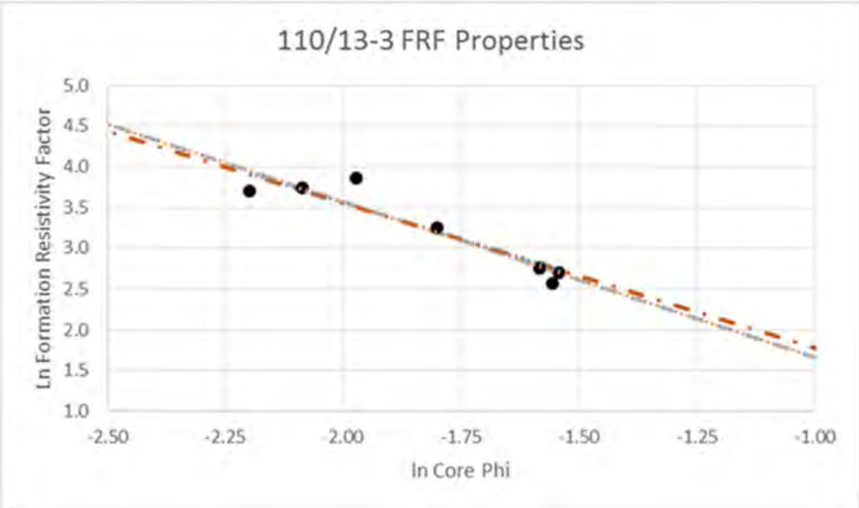


Figure 11-59 Measured formation resistivity factor 'm'

A cross plot of saturation vs FRI is shown in Figure 11-60, the slope of the regression line = n. A free regression of the measured data results in a very low n = 1.43, the operators model was similarly low (n=1.62).

The recommended Archie Saturation model is therefore:

$$Sw^{1.430} = \left[\frac{Rw \times 1 \times \emptyset^{-1.76}}{Rt}\right]$$

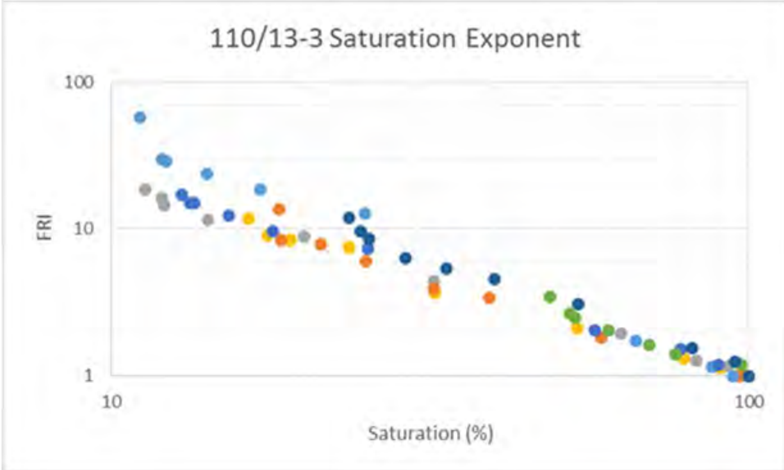


Figure 11-60 Measured formation saturation exponent 'n'

11.9.4.1.4 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

11.9.4.2 Clay and Shale Volume Estimates

The volume of clay in the reservoir is estimated by two independent deterministic methods.

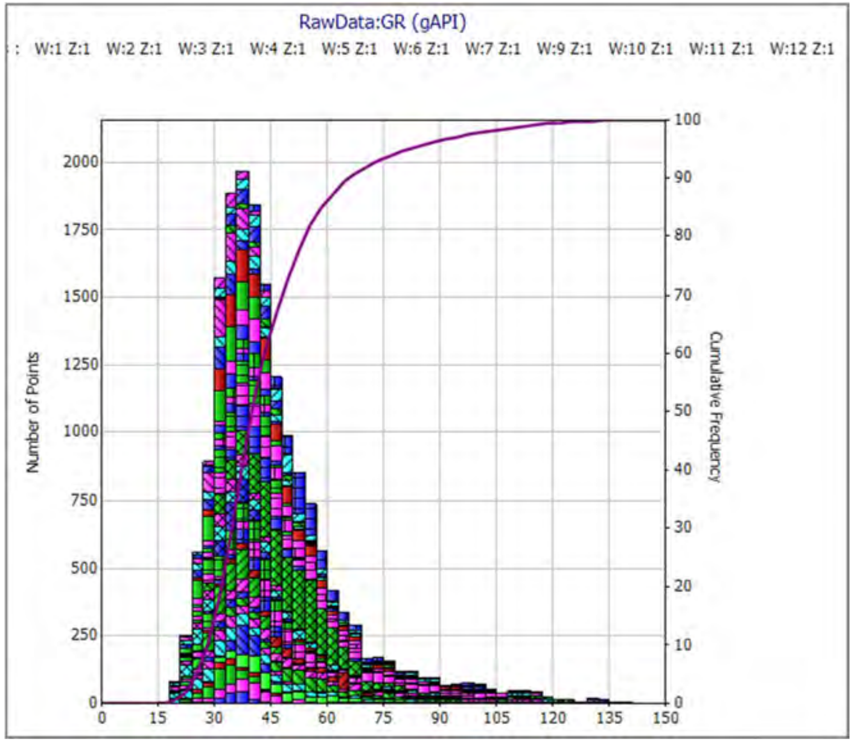


Figure 11-61 Multi-well gamma ray distribution

(i) gamma ray

The simplest model, for quartz sandstone, is to assume a linear relationship between clean and clay end-points. Given the generally very clean nature of the Sherwood sandstones and the clearly defined shale breakes the linear model has been used as the default volume clay calculation for the Sherwood sandstones

Figure 11-61 is a multi-well histogram of Gamma Ray over the entire reservoir interval for all the wells in the project. The plot shows a weak bimodal distribution for the sands and clays with the dataset dominated by the clean sand response, however on a well-by-well analysis clay endpoints are well defined.

The linear model gamma ray Vclay equation is shown below:

VClay = (GRlog-GRmin)/(GRmax-GRmin)

(ii) neutron – density crossplot.

A double clay indicator method. This method uses a cross-plot method that defines 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.

There is a distinct 'gas' effect seen on most of the neuton-density crossplots that needs to be corrected for when estimating clay end-points, Figure 11-62 illustrates the volume clay model for well 110/13-1, the same methodology is applied to all wells.

The Hamilton Fields report an almost total absence of clays from the reservoir interval, from Figure 11-62 is it likely that a true 100% clay points is not sampled. This high apparent density of the clay point is partially explanined by the complex mixture of authigenic minerals described in the various core reports including principally carbonates of ferroan and non-ferroan calcite and dolomite, plus quartz, gypsum, anhydrite, feldspar pyrite, illite, chlorite and halite.

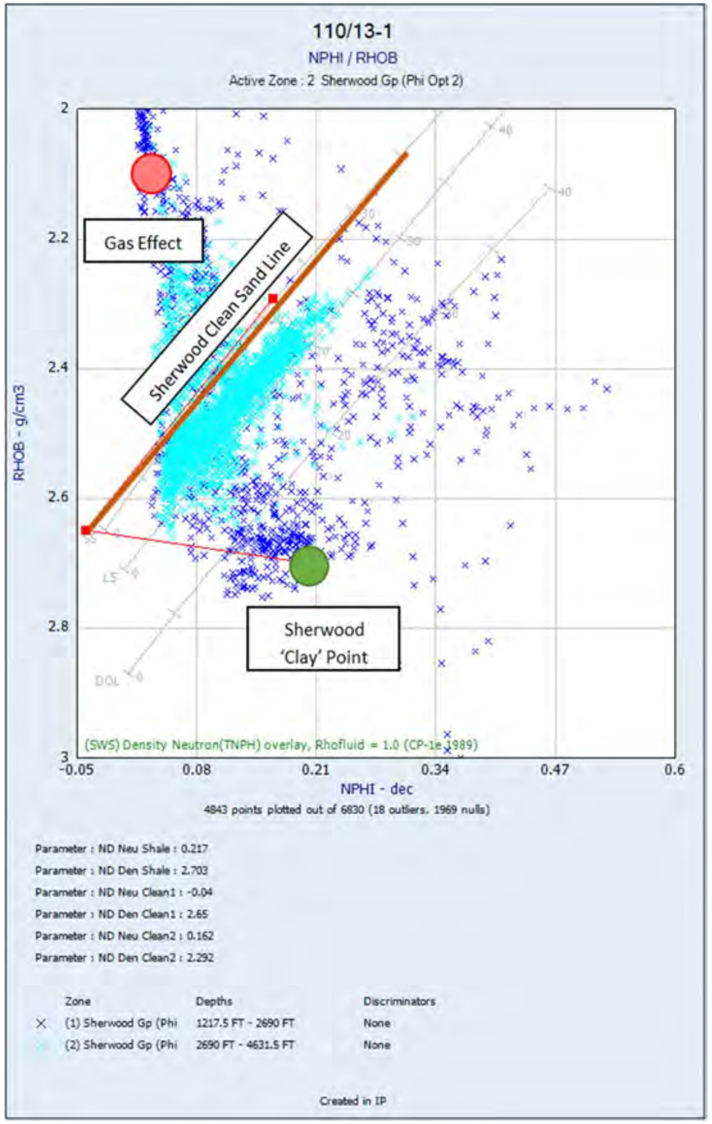


Figure 11-62 Neutron density crossplot

11.9.4.3 *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.

11.9.4.3.1 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.

Sandstone matrix density is estimated using the 444 core grain density measurements available, Figure 11-63, the mean grain density of these measurements is 2.652 g/cc, this is consistent with the assumption of a simple quartz dominated sandstone.

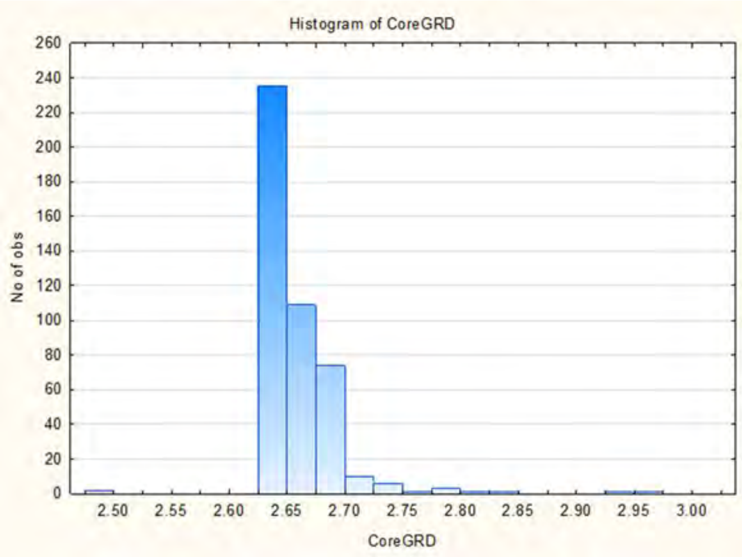


Figure 11-63 Measured core grain density

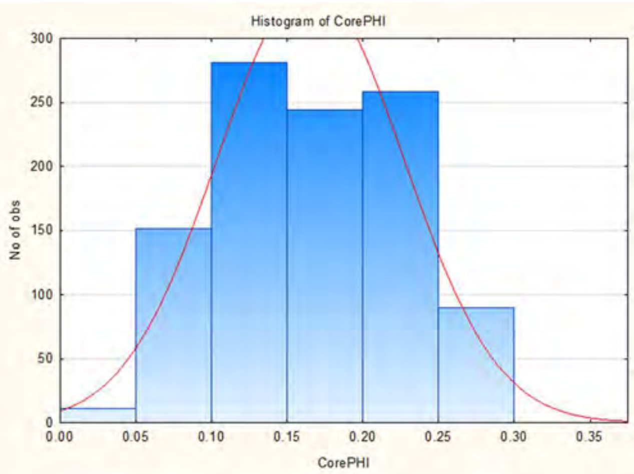


Figure 11-64 Measued core porosity

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 11-64 summarizes the distribution of the core porosity data, the plot is based upon 1044 validated data points and gives an approximation of normal distribution with a mean porosity of 16.46%; the average porosity from the petrophysical analysis is 15.9%.

11.9.4.3.2 Water Saturation

Water Saturation is calculated in the deep zone of the reservoir (Sw) and the invaded zone (Sxo) using deep and shallow resistivity respectively; where oil based mud is used as the drilling fluid an approximation of the invaded zone saturation is made with defined limits using an Sxo ratio factor.

Archie saturation exponents, Table 11-22, validated in the water zones with Pickett plots, are consistent with the Humble parameters for a clastic reservoir:

Exponent	Value
a	1.0
m	1.76
n	1.43

Table 11-22 Saturation equation exponents

11.9.4.4 Petrophysical Parameter Selection

Table 11-23 details the parameters used to estimate shale and clay volume.

The grain density for the sandstone is as expected for a quartz rich sandstone; given the reported almost total absence of clays from the reservoir interval is it likely that 100% clay points are not sampled and this is reflects in the high density and neuton porosity for the apparent shale or clay points.

Table 11-24 details parameter used to estimate porosity and water saturation.

Petrophysical Parameter Selection for Clays and Shales							
Well	GR_{Clean}	GR_{Shale}	$RHOB_{Shale}$	$NPHI_{Shale}$	PEF_{Clay}	Rt_{Clay}	DT_{Clay}
110/13-1	40	114	2.637	0.287		11.0	73
110/13-3	34	120	2.667	0.221	3.0	11.6	68
110/13-4	No Data						
110/13-H1	35	116	2.686	0.193	5.31	12.0	
110/13-H2	33	120	2.700	0.125	4	10.0	70
110/13-H3	34	121	2.686	0.113	3	14.1	73
110/13-H4	No Data						
110/13-14	30	112	2.668	0.176	3.9	15.0	69
110/13-E1	No Data						
110/13-5	28	122	2.668	0.230	3.83	12.6	73
110/13-N1	31	113	2.675	0.167	4.02	14.1	73
110/13-N2	No Data						
110/13-N3	No Data						
110/13-N4	No Data						
110/13-7	29	109	2.666	0.203	3.52	12.2	67
110/13-9	31	124	2.641	0.138			
110/14b-7	49	125			Not Acquired		
Average Values	**34**	**118**	**2.669**	**0.185**	**3.823**	**12.511**	**70.750**

Table 11-23 Clay parameter estimation

Petrophysical Parameter Selection for Porosity and Saturation Model							
Well	Phi Model	Rw at 60 DEGF	Sw Model	a	m	n	GWC
110/13-1	ND-Xplot	0.045	Archie	1	1.76	1.43	3,080.00
110/13-3	ND-Xplot	0.071	Archie	1	1.76	1.43	3,017.50
110/13-4	No Data						
110/13-H1	ND-Xplot	0.053	Archie	1	1.76	1.43	
110/13-H2	ND-Xplot	0.056	Archie	1	1.76	1.43	
110/13-H3	ND-Xplot	0.068	Archie	1	1.76	1.43	
110/13-H4	No Data						
110/13-14	ND-Xplot	0.064	Archie	1	1.76	1.43	3,562.0
110/13-E1		No Data					
110/13-5	ND-Xplot	0.065	Archie	1	1.76	1.43	3,266.0
110/13-N1	ND-Xplot	0.057	Archie	1	1.76	1.43	
110/13-N2	No Data						
110/13-N3	No Data						
110/13-N4	No Data						
110/13-7	Density	0.036	Archie	1	1.76	1.43	
110/13-9	Density	0.056	Archie	1	1.76	1.43	
110/14b-7	Not Acquired						

Table 11-24 Porosity and water saturation parameter selection

11.9.4.5 Cut off and Summation Definitions

A cut-off of less than 50% clay content has been selected to define "sandstone", with a further 10% porosity as the minimum for the sands to be considered of net reservoir quality. Figure 11-65 is a crossplot of all the available Sherwood core data colour coded by facies type; a porosity cut-off of 10% is effectively removes the tight reservoir of Facies 5.

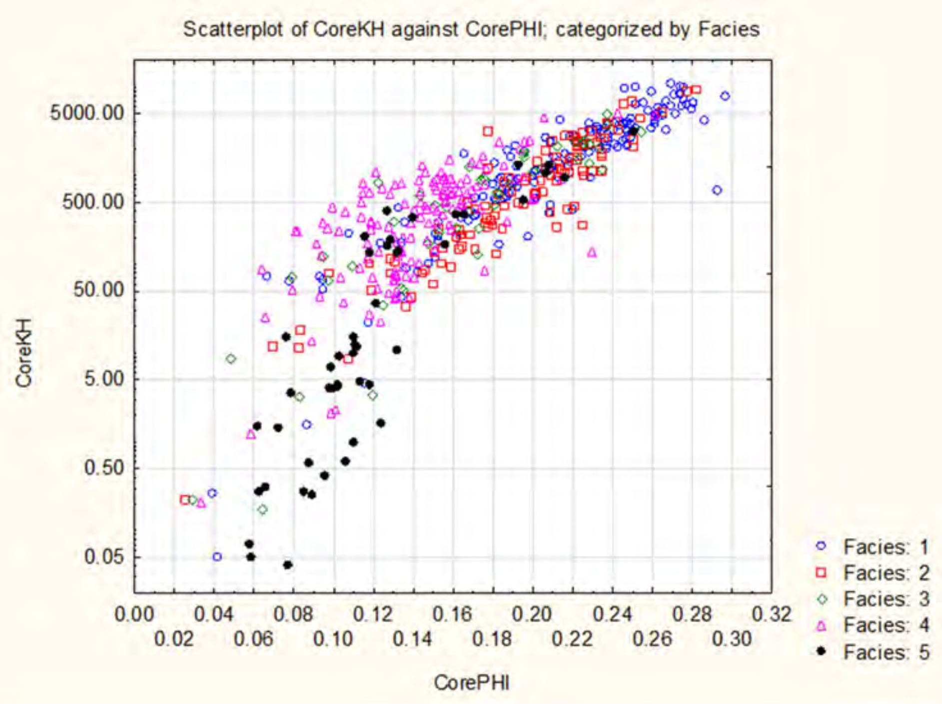


Figure 11-65 Core porosity-permeability crossplot

11.9.4.6 Capillary Pressure

A total of 7 samples were selected for analysis, Figure 11-66.

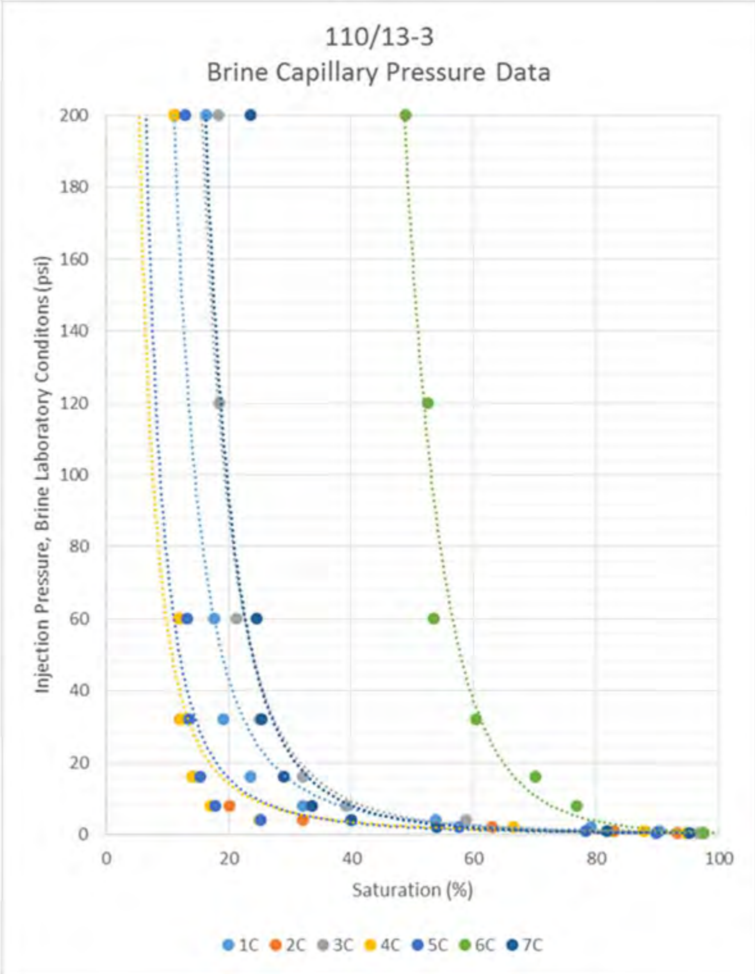


Figure 11-66 Capillary pressure data

A J-Curve normalisation was constructed for these data using the RQI function and an IFT in laboratory conditions of 72 dynes/cm; these data fell on a common trend line used to predict saturation as a function of pore throat geometry and height above the hydrocarbon contact (Figure 11-67).

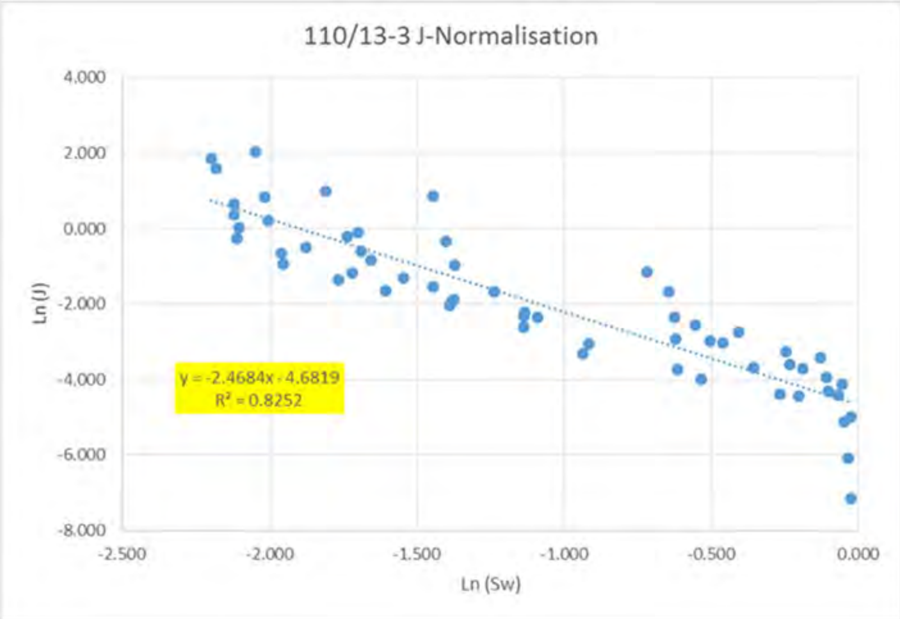


Figure 11-67 J-curve trend normalisation

A Gas-Water fluid system was assumed with a IFT of 57.74 dynes/cm at reservoir conditions and fluid density of 1.1 g/cc for water and 0.2 g/cc for gas. Figure 11-68 is a suite of saturation 'type-curves' based upon this system with the following function:

$$Sw_j = \left(0.022884 \times Height\sqrt{\frac{k}{\emptyset}}\right)^{-0.4051}$$

Height, Ft

Permeability, mD

Porosity, v/v

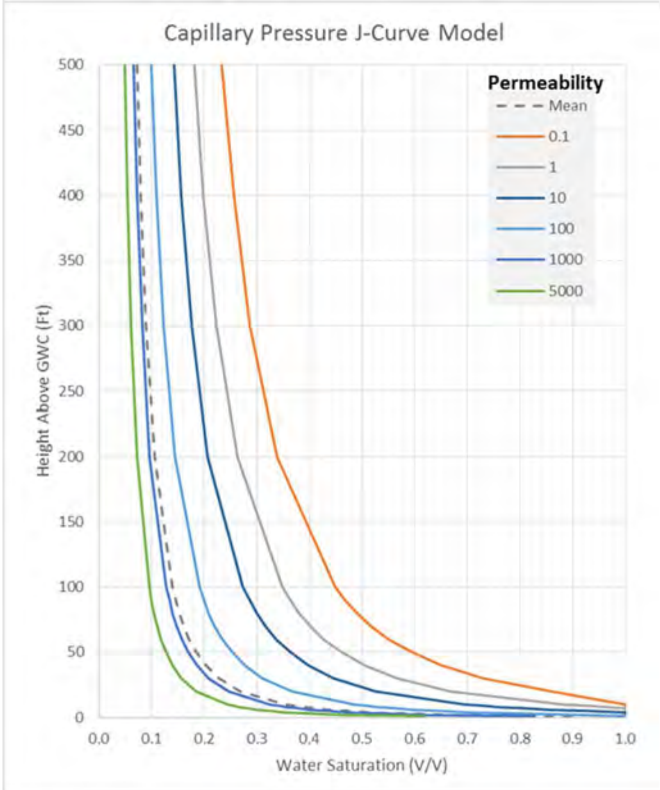


Figure 11-68 Capillary based Sw curves

11.9.5 Geochemistry

11.9.5.1 Objective

Geochemical modelling of the primary reservoir and caprock in the Hamilton Field, East Irish Sea was carried out to evaluate the likely impact of CO_2 injection on the rock fabric and mineralogy over both 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 Hamilton Lower Triassic reservoir/aquifer leads to mineral reactions which result in either an increase or decrease of the porosity and permeability of the overlying Middle and Upper Triassic Mercia Mudstone Group caprock.

11.9.5.2 Methodology

aa A study methodology was developed to answer a key question:

1. Will elevated partial pressure of CO_2 compromise the caprock by mineral reaction?

The work flow followed is shown in Figure 11-69. 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.

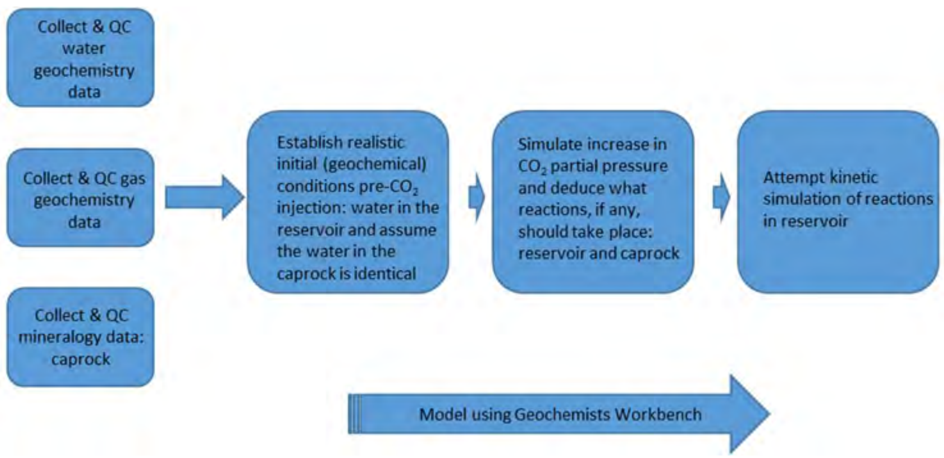


Figure 11-69 Geochemical modelling workflow

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.

11.9.5.3 Data Availability

1. No water compositional data from the Triassic part of the stratigraphy in the Hamilton Field are available in CDA. Water geochemical data were taken from a compilation of Triassic (Sherwood) sandstones in the East Irish Sea Basin created for previous studies. Highly relevant water compositional data were taken from well 110/13-3.
2. No gas compositional data from the Triassic part of the stratigraphy in Hamilton seem to be available in the CDA. Gas geochemical data from Triassic (Sherwood) sandstones in the East Irish Sea Basin were instead taken from published studies**Invalid source specified.**
3. While reservoir mineralogical data were available from sedimentology reports from exploration and appraisal wells, caprock mineral data are apparently not available in CDA. It is not uncommon for oil companies to totally ignore the mineralogy of caprocks so this is not totally unexpected. Analogue mineral data were therefore used for the Mercia Mudstone**Invalid source specified.Invalid source specified.Invalid source specified.**.

11.9.5.4 Water Geochemistry

The water compositional data used is shown in Table 11-25 Water geochemical data used in modelling

1. Water compositional data seem to be of good quality and fully credible given their molar charge difference is within the permissible 5% (Table 11-25).
2. One sample came from Hamilton (110/13-3). This water composition seems to be of excellent quality (very low charge difference observed). This water analysis has been used throughout the report.
3. Water compositions are all highly saline and Na-Cl dominated as expected due to the presence of Triassic halite-dominated evaporites immediately overlying the Lower Triassic sandstone reservoir.
4. Waters have high Ca concentrations and low HCO3 concentrations suggesting that the waters may be susceptible to changing composition (gas-water interaction) if, or when, the CO_2 partial pressure increases following CCS. This will be checked with geochemical models

11.9.5.5 Gas Geochemistry

Aa No gas geochemical data for Hamilton were available to this study so valid data are available from **Invalid source specified.**. The hydrocarbon gas compositional data assumed for this closure are shown in Table 11-26 Gas geochemical composition data used in modelling.

1. Gas compositions seem to be credible, especially from Hamilton.
2. Gases are CH4-rich, generally dry, N2-rich. Some structures are oil-bearing but they are not included in this phase of the assessment.

Well name	Density g/cm^3	TDS mg/l	TDS % salinity	pH	Ca^{2+} mg/l	Na^+ mg/l	K^+ mg/l	Mg^{2+} mg/l	Sr^{2+} mg/l	Cl^- mg/l	SO_4^{2-} mg/l	HCO_3^- mg/l	Charge balance %	Ionic strength
110/13-3 (Hamilton)	1.17	261564.00	22.27	6.89	1684	101000	527	148	53	158000	128	24	0.49	4.53
110/13-11 DST-1	1.18	265828.70	22.57	6.66	2365	104140	398	836	58	155610	2350	69	3.15	4.70
110/13-11	1.18	268731.10	22.78	6.85	2250	99600	370	810	61	163390	2160	90	-1.45	4.70
100/13-10 FMT(g)	1.19	277154.30	23.39	8.38	1860	106200	425	880	48	164890	2740	110	0.91	4.87
110/13-D3 RFT	1.21	317762.40	26.21	7.60	1052	122240	899	42	9	185800	7440	280	-0.04	5.50
110/13-5 FMT	1.19	285970.40	24.01	7.25	525	107700	485	590	26	174760	1160	720	-1.98	4.92
Average values					1623	106813	517	551	42	167075	2663	216		

Table 11-25 Water geochemical data used in modelling

	Reservoir	Approx Depth m	Approx Temp °C	Approx pressure at gas water contact psi	CH_4 %	C_2H_6 %	C_3H_8 %	C_4H_{10} %	C_5H_{12} %	C_6+ %	N_2 %	CO_2 %	H_2S ppm	Thiols (R-HS) ppm
Hamilton	Sherwood Sandstone	846	31	1420	83.00	5.00	1.50	1.10	0.50	0.30	8.30	0.40	1100.00	0.00
Hamilton North	Sherwood Sandstone	821	31	1550	83.00	5.00	1.80	1.30	0.60	0.50	8.10	0.40	30.00	0.00
Lennox Oil	Sherwood Sandstone				30.00	7.00	7.00	7.00	5.00	41.30	1.70	0.10	0.12	450.00
Lennox Gas	Sherwood Sandstone				77.00	5.00	2.50	1.40	0.50	0.50	12.30	0.10	400.00	0.00
Douglas	Sherwood Sandstone				2.00	4.00	5.00	8.00	7.00	72.00	0.70	0.10	0.50	1000.00
Lambda	Sherwood Sandstone				82.00	5.00	1.80	1.30	0.60	0.40	9.30	0.04	0.01	0.01

Table 11-26 Gas geochemical composition data used in modelling

Sample Number	M1	M4	M5	Average	St deviation	M2	M3	M6	Average	St Deviation
	Clay rich samples Type 1					Clay pore samples Type 2				
Quartz %	31.8	43.7	47.7	37.7	8.3	44.2	32.6	65.5	47.4	16.7
Illite %	39.9	33.8	37.1	36.9	3.0	15.6	17.9	4.2	12.6	7.3
Chlorite %	5.7	4.6	4.9	5.2	0.6	4.4	4.1	1.5	3.3	1.6
K-Feldspar %	15.9	7.7	8.7	11.8	4.5	11.5	11.6	6.5	9.8	2.9
Plagioclase %	1.9	0.6	0.1	1.3	0.9	1.7	2.3	1.0	1.7	0.7
Calcite %	3.4	0.2	0.1	1.8	1.9	0.5	0.2	1.0	0.6	0.4
Dolomite %	1.4	9.2	1.4	5.3	4.5	8.3	12.4	3.5	8.1	4.4
Gypsum %	0.0	0.1	0.0	0.1	0.1	13.8	18.9	16.7	16.5	2.6
Porosity %	7.4	9.1	9.7	8.2	1.2	10.3	10.7	9.5	10.2	0.6
Mean pore throat radius (nm)	19	21	29	20.2	5.3	66	46	118	76.7	37.0

Table 11-27 Caprock (type 1) mineralogy

	Clay rich sample	Clay poor sample	Halite dominated	Halite pure
For 1kg of water	Type-1	Type-2	Type-3	Type-4
Quartz cm^3	3393	4272	0	0
K-feldspar cm^3	1178	1032	0	0
Dolomite cm^3	479	727	100	0
Calcite cm^3	163	52	100	0
Illite cm^3	3317	1133	0	0
Gypsum cm^3	5	1486	200	0
Chlorite cm^3	465	298	0	0
Halite cm^3	0	0	8600	2000
Total Mineral Volume	**9000**	**9000**	**9000**	**2000**
Quartz average PC data %	34.9	43.0	0.0	0.0
K-feldspar average PC data %	12.1	10.4	0.0	0.0
Dolomite average PC data %	4.9	7.3	1.0	0.0
Calcite average PC data %	1.7	0.5	1.0	0.0
Illite average PC data %	34.1	11.4	0.0	0.0
Gypsum average PC data %	0.0	15.0	2.0	0.0
Chlorite average PC data %	4.8	3.0	0.0	0.0
Halite average PC data %	0.0	0.0	86.0	100.0
Total	**92.4**	**90.7**	**90.0**	**100.0**

Table 11-28 Modelling input for Hamilton Field caprock

1. Little or no CO_2 reported in the gas suggesting that an influx of CO_2 following CCS may cause reactions with the water-rock domain since there is little or none in the gas at present (the rocks are possibly not at equilibrium with a large volume of pre-existing CO_2).

11.9.5.6 Caprock Mineralogy

Middle and Upper Triassic mudstone caprocks come in four main types depending on the variable amounts of clay (illite and chlorite), pore filling carbonate and gypsum and halite. The data in Table 11-27 are from**Invalid source specified.**.

- Type-1 is clay-rich, with low porosity-permeability, typically with abundant illite and chlorite, negligible gypsum and minor dolomite (Armitage et al., 2013; Jeans, 2006; Seedhouse and Racey, 1997). Type 1 has about 10% porosity and permeability as low as 10-20 m2.
- Type-2 is poorer in clay but has abundant gypsum and more carbonate than type 1. Type 2 has about 10% porosity and permeability that is about as low as 10-18 or 10-19 m2.
- Type 3 is halite-dominated with minor clay minerals, quartz, gypsum and carbonates and has low porosity and permeability (probably as low as type 1).
- Type 4 is effectively pure halite with negligible porosity and permeability as low as 10-23 m2.

Caprocks Type 1 and 2 are probably volumetrically dominant with some layers of halite of varying purity. Type 3 (impure halite) is probably volumetrically more significant than Type 4 (pure halite).

The reservoirs at Hamilton are all rather shallow (less than 1000m below mudline). The caprocks are thus shallower. A temperature of 31ºC has been used for the simulation of CO_2 reactions with the caprock lithologies. This temperature is so low that gypsum is stable instead of anhydrite and chlorite clay is unstable relative to low temperature Mg-clay minerals such as saponite.

Modelling Approach: Types of Reaction Schemes Due to CO_2 Injection into the Reservoir.

If reaction happens at equilibrium with all the added CO_2, then the rocks are simply responding to the change 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. It is likely that minerals are metastably present in the caprock (e.g. some clay minerals want to react but their previous alteration has been inhibited by slow kinetics). Under equilibrium modelling, metastable minerals must transform. This explains why Mg-chlorite (clinochlore) transforms to saponite in the equilibrium models.

If reactions are kinetically influenced, e.g. by slow dissolution rates, then the rate of interaction with CO_2 are limited by the dissolution rate and not the rate of influx of CO_2. Carbonate and sulphate dissolution and growth kinetics are 6-10 orders of magnitude faster than silicate dissolution rates. Clay and feldspar dissolution rates are thus the most likely rate controlling steps. In this modelling exercise, 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.

11.9.5.7 Results: Equilibrium Modelling

The results of the equilibrium modelling for the Caprock Type-1 (clay-rich) are shown in Figure 11-70 toFigure 11-73.

The key reactions which are expected to take place given the starting clay-rich composition are:

- The reaction of Al-rich clay (illite) with dissolved sodium in the formation water and the influx of CO_2:

$$Illite + Na^{+} + CO_2 \rightarrow quartz + dawsonite + K^{+}$$

- The reaction of Al- and K-rich feldspar (K-feldspar) with dissolved sulphate derived from gypsum and acidity induced by the influx of CO_2:

$$K\text{-}feldspar + H^{+} + SO_4^{2-} \rightarrow quartz + alunite$$

[H^+ due to elevated CO_2 concentration]

- Under equilibrium conditions, all chlorite is unstable and reacts initially to make saponite (a low temperature clay typically found in near surface and surface zones):

$$chlorite \rightarrow saponite$$

- Saponite then reacts with other minerals and the influx of CO_2 making minor dolomite, alunite and dawsonite:

$$saponite + CO_2 + Na + SO_4 \rightarrow alunite + dawsonite + dolomite$$

Figure 11-70 to Figure 11-73 show the evolution of the mineral content as CO_2 fugacity increases in the model. Modelling was carried out at 31°C. A summary of the key mineral reactions for each caprock type is given in Table 11-29.

Caprock Type	Equilibrium Model Results
Type 1: illite-rich claystone	Minor solid volume gain due mainly to replacement of high density illite and chlorite by low density dawsonite. Minor loss of porosity and permeability.
Type 2: clay-poor/gypsum & dolomite-rich	Minor solid volume gain due mainly to replacement of high density gypsum and illite by low density dawsonite and alunite. Minor loss of porosity and permeability.
Type 3: halite –rich with gypsum, calcite & dolomite	Minor solid volume loss due to calcite dissolution in feldspar-free modelled rock. Possible very minor porosity or permeability increase. If *any* feldspar is present or in adjacent rock, this buffers the reaction and creation of acid and prevents any volume loss.
Type 4: pure Halite	No volume change since effectively halite does not react with CO_2-charged aqueous fluids. No porosity or permeability change.

Table 11-29 Equilibrium modelling reaction results for Hamilton field caprock types

Table 11-30 contains the mineral volume results from before and after addition of CO_2 for caprock types 1 to 3

Note: Type 4 (pure halite) caprock shows no volume change as halite effectively does not react with CO_2 charged aqueous fluids.

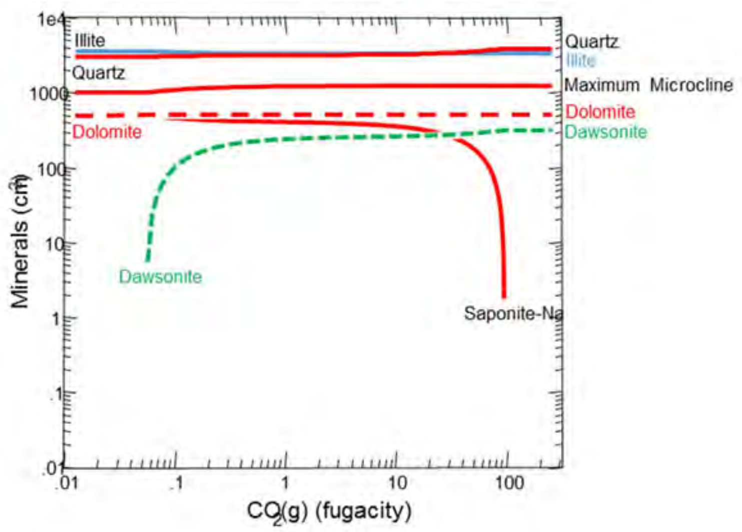


Figure 11-70 Equilibrium modelling results at 31°C for caprock type 1 Hamilton field

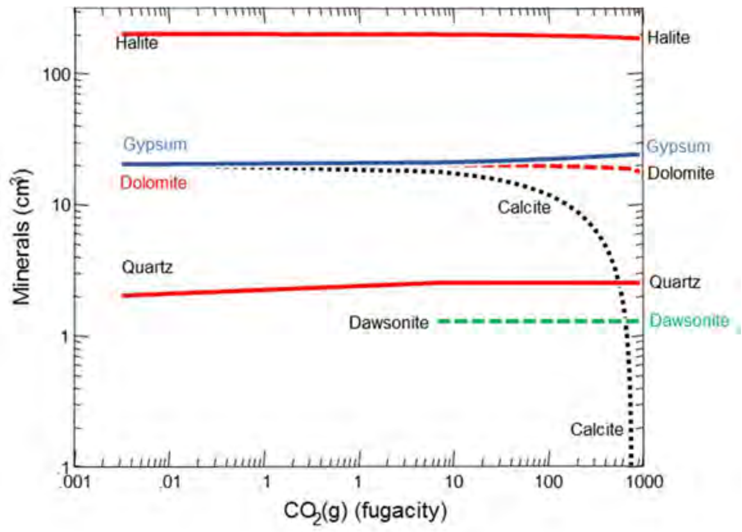


Figure 11-72 Equilibrium modelling results at 31°C for caprock type 3 Hamilton field

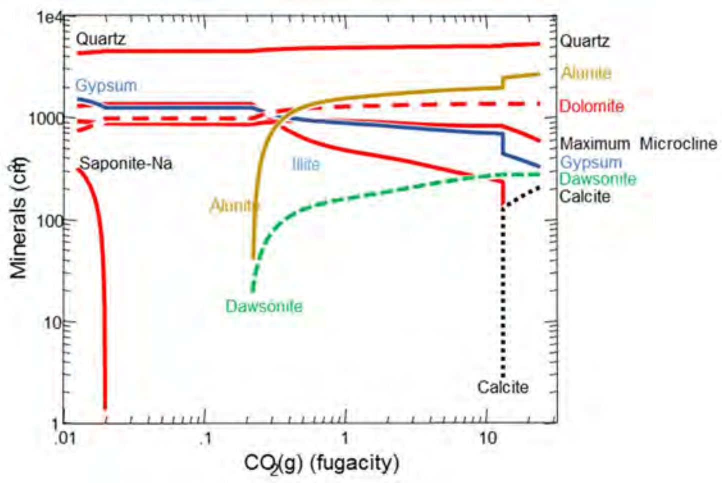


Figure 11-71 Equilibrium modelling results at 31°C for caprock type 2 Hamilton field

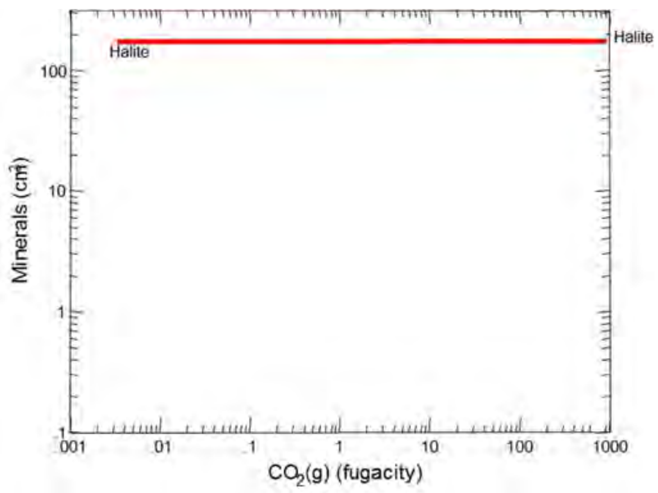


Figure 11-73 Equilibrium modelling results at 31°C for caprock type 4 Hamilton field

For 1kg of water	Type 1 before CO_2 flood	Type 1 after CO_2 flood	Type 2 before CO_2 flood	Type 2 after CO_2 flood	Type 3 before CO_2 flood	Type 3 after CO_2 flood
Quartz cm^3	3253.0	3551.0	4183.0	5208.0	2.0	2.5
K-feldspar cm^3	989.8	1198.0	909.2	567.7	0.0	0.0
Dolomite cm^3	478.9	485.4	727.4	1336.0	20.0	17.7
Calcite cm^3	0.0	0.0	0.0	203.2	20.0	0.0
Illite cm^3	3553.0	3279.0	1285.0	0.0	1.0	0.0
Gypsum cm^3	4.9	0.0	1486.0	320.3	20.0	23.9
Chlorite cm^3	0.0	0.0	0.0	0.0	0.0	0.0
Halite cm^3	0.0	0.0	0.0	0.0	200.0	1985.0
Dawsonite cm^3	0.0	302.3	0.0	268.8	0.0	1.3
Alunite cm^3	0.0	0.0	0.0	2619.0	0.0	0.0
Saponite-Na cm^3	485.7	0.0	311.6	0.0	0.0	0.0
Total mineral volume	8765	8816	8902	10523	2063	2030
Relative mineral volume change due to CO_2 injection		100.6%		118.2%		98.4%

Table 11-30 Mineral volume in caprock types 1 to 3 before and after CO_2 injection into reservoire under equilibrium modelling

The equilibrium modelling work suggests that the diagenetic changes induced by CO_2 injection into the reservoir immediately below the Mercia mudstone caprocks will, at equilibrium, lead to a very minor net reduction in porosity of the Type 1 and 2 caprocks due to the replacement of high density minerals (e.g. illite, chlorite, gypsum) to lower density minerals (e.g. dawsonite). In the non-clastic halite caprocks (Types 3 and 4), a very minor porosity/permeability increase is possible as some solid volume loss of calcite dissolution is possible in Type 3 lithologies. No volume change or porosity/permeability change will occur in the non-reactive pure halite caprock Type 4.

11.9.5.8 Results: Kinetic Modelling

In order to evaluate the kinetic effects on the reservoir, models reacting 30 mol CO_2(g) over 20000 years at 31°C for each caprock type mineralogy were run for the following conditions:

- With kinetic constraints placed as follows
- Microcline dissolution kinetics, rate constant 1x10-18 mol/cm2.s, 500 cm2/g surface area.

- Illite dissolution kinetics, rate constant 1x10-18 mol/cm2.s, 1000 cm2/g surface area.
- Chlorite dissolution kinetics, rate constant 1x10-18 mol/cm2.s, 1000 cm2/g surface area.

The key results derived from the kinetic modelling are shown in Table 11-31 below and in Figure 11-74 to Figure 11-76.

Caprock Type	Kinetic Modelling Results Summary
Type 1: illite-rich claystone	Minor solid volume gain due mainly to replacement of high density illite and chlorite by low density dawsonite and alunite. Minor loss of porosity and permeability. Negligible reaction over 5,000 years. No risk of permeability loss.
Type 2: clay-poor/gypsum & dolomite-rich	Minor solid volume gain due mainly to replacement of high density K-feldspar, chlorite, gypsum and illite by low density dawsonite and alunite. Minor loss of porosity and permeability. Negligible reaction over 5,000 years. No risk of permeability loss.
Type 3: halite –rich with gypsum, calcite & dolomite	Minor solid volume loss due to calcite dissolution in feldspar-free modelled rock. Possible very minor porosity or permeability increase over 5,000 years. If *any* feldspar is present or in adjacent rock, this buffers the reaction and creation of acid and prevents any volume loss.

Table 11-31 Kinetic modelling reaction results for hamilton field caprock types 1 to 3, caprock type 4 (pure halite) was not modelled as it is non reactive to aqueous CO_2 rich fluids

Table 11-32 shows the modelled relative mineral volume change in caprock Types 1-3 after CO_2 injection takes place in the reservoir. Putting kinetic considerations in place slows down the mineral reaction rate (Figure 11-74 to Figure 11-76). Feldspar reaction slows down hugely (due to the small specific surface area), while the illite to dawsonite reaction also slows down but still occurs over the 20,000 year timeframe modelled. Note that again, these mineral changes lead to negligible porosity decrease.

Under kinetically controlled conditions, chlorite breakdown is determined by its dissolution rate kinetics and surface area. It is unstable whether a CO_2 flux occurs or not but only breaks down under the acidic conditions that result from CO_2 influx. Chlorite interacts with dissolved sodium. Chlorite also interacts with the dissolution products of gypsum:

$$chlorite + CO_2 + Na + SO_4 \rightarrow alunite + dawsonite + dolomite$$

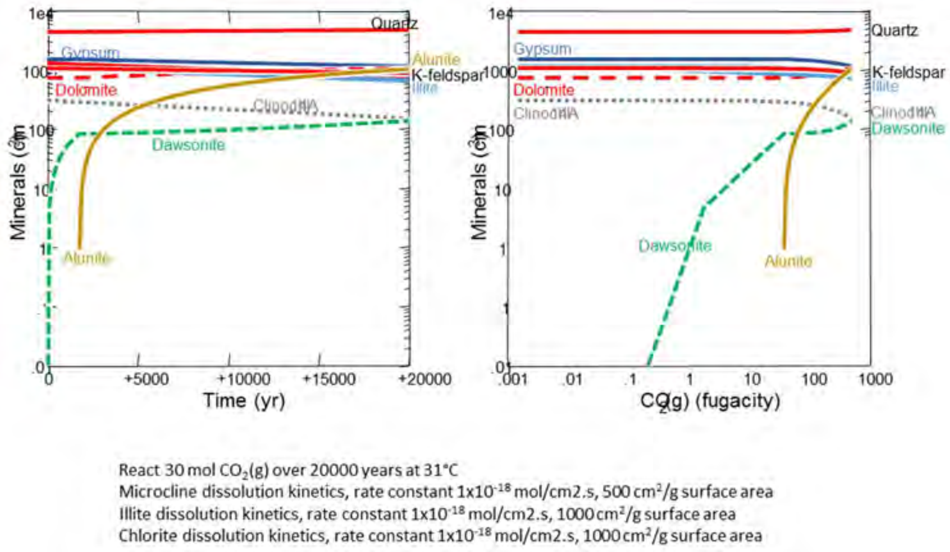


Figure 11-74 Kinetic modelling results at 31°C for caprock type 1 Hamilton field

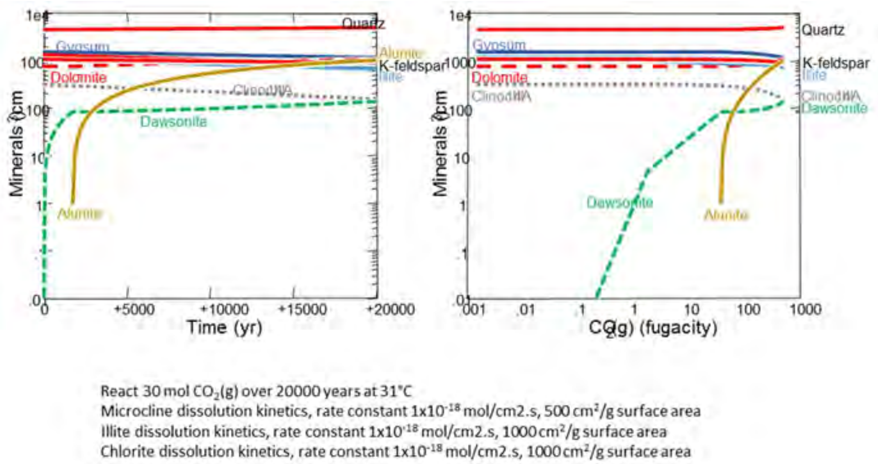


Figure 11-75 Kinetic modelling results at 31°C for caprock type 2 Hamilton field

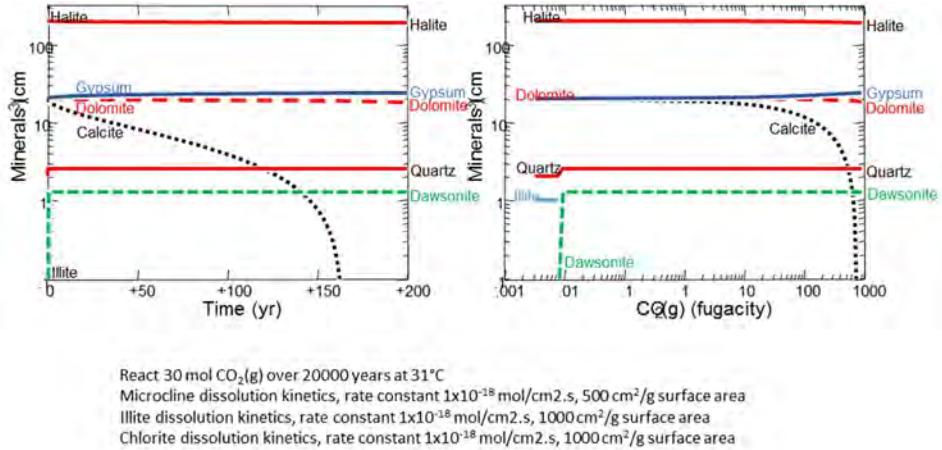


Figure 11-76 Kinetic modelling results at 31°C for caprock type 3 Hamilton field

For 1kg of water	Type 1 before CO_2 flood	Type 1 after CO_2 flood	Type 2 before CO_2 flood	Type 2 after CO_2 flood	Type 3 before CO_2 flood	Type 3 after CO_2 flood
Quartz cm^3	3393.0	3539.0	4272.0	4641.0	2.0	2.5
K-feldspar cm^3	1178.0	1288.8	1032.0	866.6	0.0	0.0
Dolomite cm^3	479.0	485.4	727.4	1042.0	20.0	17.7
Calcite cm^3	0.0	0.0	0.0	0.0	20.0	0.0
Illite cm^3	3316.4	3032.1	1132.9	685.5	1.0	0.0
Gypsum cm^3	5.0	0.0	1486.0	1113.0	20.0	23.9
Chlorite cm^3	465.2	230.6	298.2	147.9	0.0	0.0
Halite cm^3	0.0	00	0.0	0.0	2000.0	1985.0
Dawsonite cm^3	0.0	302.3	0.0	133.8	0.0	1.3
Alunite cm^3	0.0	218.5	0.0	1003.0	0.0	0.0
Saponite-Na cm^3	0.0	0.0	0.0	0.0	0.0	0.0
Total mineral volume	8837	9097	8949	9633	2063	2030
Relative mineral volume change due to CO_2 injection		102.9%		107.6%		98.4%

Table 11-32 Mineral volume in caprock types 1 to 3 before and after CO_2 injection into reservoir under kinetic modelling

Note: Type 4 (pure halite) caprock shows no volume change as halite effectively does not react with CO_2 charged aqueous fluids.

11.9.5.9 Conclusions

11.9.5.9.1 Caprock

The majority of clay-rich Middle and Upper Triassic overburden is unlikely to be significantly affected by CO_2 injection into the Hamilton Field reservoir. Crucially for CO_2 containment, permeability of the caprock lithology types likely to be present will not be increased as:

1. Pure halite layers will be unaffected by the increase in partial pressure of CO_2
2. Although the clay-rich and carbonate/gypsum-rich majority of the overburden might undergo reactions which may lead to reduced porosity (and probably reduced permeability) as the initially high density minerals (chlorite, gyspum and illite) are very slowly replaced by lower density reaction products (mainly alunite, dawsonite), these reactions are unlikely immediately above the the storage reservoir since there will be extremely limted access by dissolved CO_2.

Carbonate-bearing halite (e.g. caprock Type 3) is potentially reactive, if feldspar-free, and may lead to minor porosity increases, and thus permeability increases. However, this caprock lithology is considered to be a minor component of the immediate caprock and will not diminish the overall preservation of the low permeability of the caprock above the reservoir. Any pure halite layers will be essentially non-reactive to dissolved CO_2.

11.9.6 Probability of Well Leak Calculation

The probability of a CO_2 leak from the wells on the Hamilton structure was assessed during the Due Diligence activity completed as part of Work Pack 4. This aspect of risk has been termed engineering containment risk and it depends on several, well-specific factors primarily linked to the way in which the well has been abandoned, as illustrated in Table 11-33.

	Timing	Position Relative to Store	Chance of no leak	Number of Wells	Aggregate Factor
Active or Suspended	COP after 2025	In or below	1.0000	0	1.0000
	COP 2015 to 2025	In	0.9988	2	0.9976
	COP 2015 to 2025	Below	0.9976	3	0.9928
Abandoned	After 2012	In	0.9985	0	1.0000
	2001 - 2012	In	0.9982	0	1.0000
	1994 to 2001	In	0.9980	0	1.0000
	1986 to 1994	In	0.9977	0	1.0000
	Before 1986	In	0.9975	0	1.0000
	After 2012	Below	0.9970	1	0.9970
	2001 - 2012	Below	0.9964	0	1.0000
	1994 to 2001	Below	0.9960	0	1.0000
	1986 to 1994	Below	0.9954	1	0.9954
	Before 1986	Below	0.9950	0	1.0000
Total chance of no leak					0.9829
Total chance of a leak					0.0171

Table 11-33 Well Leak Calculation

The calculation is as follows:

- The *Aggregate Factor* is calculated as the *Chance of no Leak*, with exponent *Number of Wells*.
- The *Total chance of no leak* is the product of the Aggregate Factors
- The *Total chance of a leak* is 1 – *Total chance of a leak*

The values listed in the *Chance of no leak* column are derived from a report prepared for DECC (Jewell & Senior, 2012). In essence the report concludes the following.

- The chance of no leak is between 0.9988 and 0.9950 (i.e. the risk of loss of containment from abandoned wells ranges from 0.0012 to 0.0050), 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.

11.10 Appendix 10 – Well Performance Sensitivity Analysis

11.10.1 Injection Temperature Sensitivity

As discussed in section 3.6.3.5 the seabed temperature at the Hamilton location varies seasonally between approximately 6°C and 16°C and this has an impact on the arrival temperature of the injection gas.

For gas phase injection any impact of arrival temperatures on injection performance is negated by the fact that the injection gas will be heated to 30°C to optimise injection performance.

For liquid phase, however, no heating is recommended and therefore arrival temperature will have an effect on injection temperature and performance. This effect is twofold:

A higher injection temperature implies a higher minimum injection pressure to ensure single phase injection throughout the tubing.

Higher temperatures imply lower fluid density and increased friction leading to lower injection rates at the same injection pressure.

To evaluate these effects for the Hamilton liquid phase injector the sensitivities summarised in Table 11-34 below were run. The tubing head pressures chosen for cases 1-3 are the minima to ensure safe single phase injection at the various injection temperatures.

The table below also summarises the results. The impact on temperature along the tubing is show in Figure 11-77 below.

Case	Reservoir Case	Tubing Size	THP (bara)	THT (°C)	Rate (MMscf/d)	Rate (MMte/yr)
Case 1	Medium	5-½'' (17 ppf)	44.47	6	130.6	2.527
Case 2	Medium	5-½'' (17 ppf)	49.32	10	134.6	2.604
Case 3	Medium	5-½'' (17 ppf)	57.20	16	140.0	2.709
Case 4	Medium	5-½'' (17 ppf)	57.20	6	156.3	3.023
Case 5	Medium	5-½'' (17 ppf)	57.20	10	150.3	2.908

Table 11-34 Tubing Head Injection Temperature Sensitivities and Results

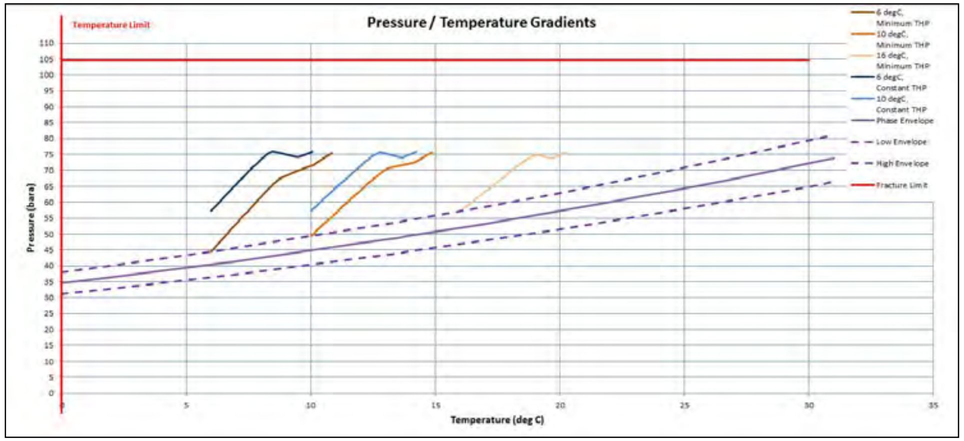


Figure 11-77 Pressure / Temperature Profiles – Tubing Head Temperature Variation

The results can be summarised as follows:

The impact on injection rates is minor with differences from the base case (injection at 10°C) limited to 7%.

The differences in injection temperature at the sand face track closely the differences in injection temperature at the well head.

There are no phase changes and the fracture and temperature limits are not broken.

As the dynamic reservoir modelling work is not rate constrained by well delivery, the effects of changes in delivery temperature are not considered critical. However, it is recommended that a full system delivery temperature sensitivity be performed during the pre-FEED work.

11.10.2 Minimum and Maximum Injection Pressure

11.10.2.1 Gas Phase Injection

Maximum tubing head injection pressures for gas phase injection were discussed in section 3.6.3.7.

The minimum initial injection pressure is 8.6 bara with a minimal rate (<1MMscf/d). Fracture pressure and temperature limits are not broken and no phase changes occur. These results are independent of reservoir case.

11.10.2.2 Liquid Phase Injection

Minimum tubing head injection pressures for liquid phase injection were discussed in section 3.6.3.7.

For the chosen tubing size of 5.5'' injection behaviour was modelled at a maximum assumed pipeline delivery pressure (120 bara).

Numerical results are summarised in Table 11-35 and pressure / temperature profiles are shown in Figure 11-78.

Case	Reservoir Case	Tubing Size	THP (bara)	THT (°C)	Rate (MMscf/d)	Rate (MMte/yr)
Case 1	High	5.5'' (17 ppf)	120.00	10	245.6	4.751
Case 2	Medium	5.5'' (17 ppf)	120.00	10	243.2	4.704
Case 3	Low	5.5'' (17 ppf)	120.00	10	231.2	4.471

Table 11-35 Rates Achievable by Case – Liquid Phase Injection – Maximum Tubing Head Pressure

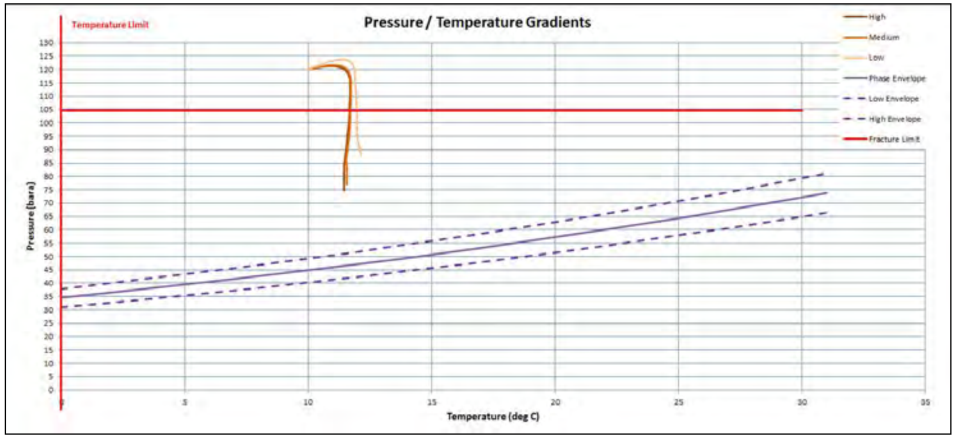


Figure 11-78 Pressure / Temperature Profiles – Liquid Phase – Maximum Tubing Head Pressure

Note that for the high rates reported friction exceeds hydrostatic effects and therefore the fracture limit is not broken at the sand face even though it is exceeded elsewhere in the tubing. The injection remains in single phase and the temperature limit is not broken.

11.10.3 CO_2 Impurity Sensitivity

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

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

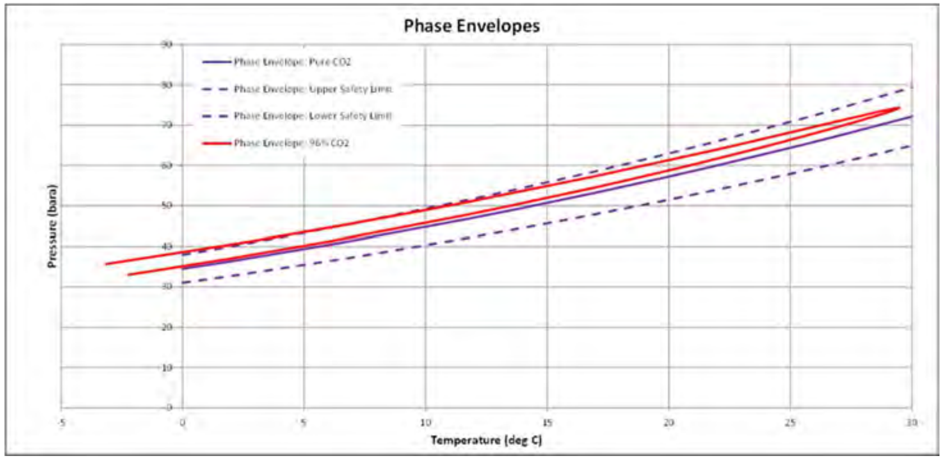


Figure 11-79 Effect of Impurities on the Phase Envelope

11.11 Appendix 11 – Fracture Pressure Gradient Calculation

In order to determine frac (and pore) pressure in the Hamilton, an analysis of available log data was carried out using DrillWorks 5000. The following tasks were performed for selected wells in each field (basic workflow):

- Overburden or Vertical stress (SV): based on bulk density log
- Pore pressure calculation: from RFT data
- Fracture Gradient or minimum horizontal stress (Shmin): Matthews and Kelly method and verified with LOT/FIT data
- Poisson's ratio: based on sonic log
- UCS: Lal's law correlation applied to the sonic log
- Stress regime: normal assumed (SV>SH>Shmin)
- Maximum horizontal stress (SH) calculated from SV and Shmin
- Stress orientation from the World Stress map

This process utilises log derived geomechanical properties combined with elastic stress calculations. The modified Lade shear failure criterion was applied. This utilises all three principal stresses and is generally less conservative than the Mohr-Coulomb failure criterion. The calculated fracture gradient is calibrated to well specific FIT or LOT data, where available, or to published results on regional analogues. 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.

11.11.1 Stress Orientation

The World Stress Map is a global reference for tectonic stress data when there is no any other data available (e.g. reliable dual arm calliper or image log data). The web link is in the References section.

The regional maximum horizontal stress (SH) is aligned NW-SE, and therefore the Shmin is aligned NE-SW. The presence of the Northwich halite may allow local structure related stress orientation variations in the overburden compared to the underlying Ormskirk Sandstone. It is a common observation in the offshore UK sector that SHmax is often parallel to the local structure, given that the Hamilton structures are generally oriented more N-S this is a plausible alternative SHmax orientation.

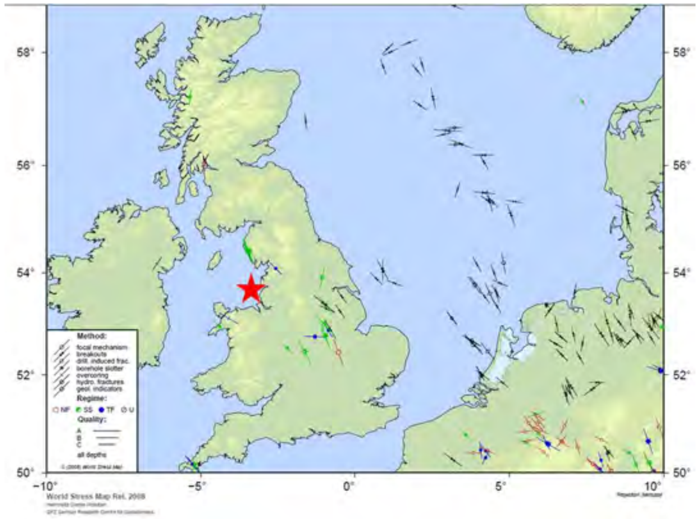


Figure 11-80 Hamilton stress orientation

11.11.2 Wells Evaluated

Logs available were obtained from the CDA website. The analysis was focused on four wells to cover the Hamilton field (110/13-1 and 110/13-3), Hamilton North field (110/13-5) and Hamilton East field (110/13-14).

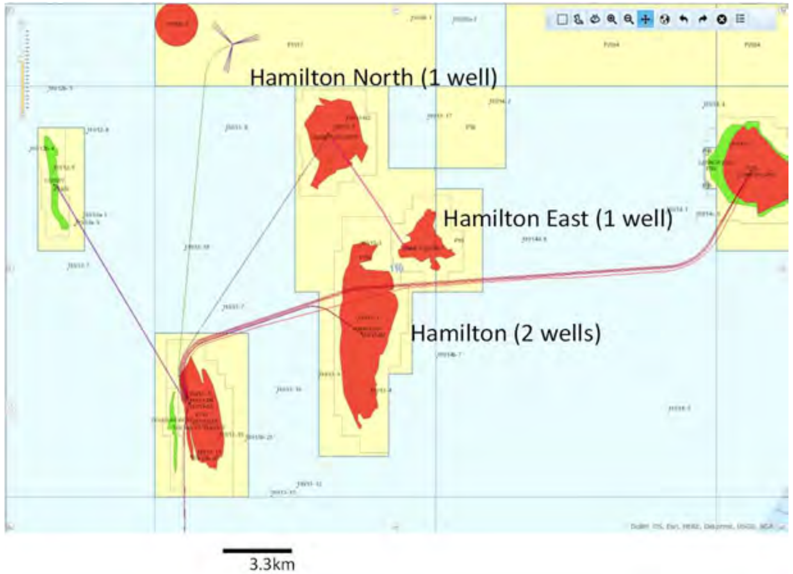


Figure 11-81 Hamilton, Evaluated Fields and Well Locations

11.11.3 Stress Path and Rock Mechanical Properties

The following figures describe the calculated stress curves and log derived rock mechanical properties in each well.

The calculated stress curves figures show pore pressure (orange line), minimum horizontal stress (red line), maximum horizontal stress (black line) and overburden (magenta line). The following considerations were used to calculate the stress path:

- Pore pressure in the sandstone was based on RFTs
- RFTs from 110/13-1 were used for layers above the sandstone
- Minimum horizontal stress (Shmin) calculated by Matthews and Kelly
- Normal stress regime assumed. Maximum horizontal stress calculated from average of Shmin and overburden (Sv)
- Halite Shmin gradient treated as lithostatic

The minimum horizontal stress curves were compared with LOT/FITs available as follows:

Well 110/13-1:

- FIT at 20” shoe was carried out in the Northwich halite (salt) and is lower than the calculated minimum horizontal stress (OK)
- FIT at 13 3/8” shoe was carried out in the Rossall Halite (salt) and this matches the overburden (in line with Shmin in the halite as lithostatic)
- FIT at 9 5/8” shoe reported as 28 ppg (0.33 bar/m or 1.46 psi/ft) which is considerably higher than the overburden or the theoretical fracture initiation pressure, this is not regarded as a reliable data point (not presented in the figure)

Well 110/13-3

- FIT at 13 3/8” shoe lower than the calculated minimum horizontal stress (OK)

- FIT at 9 5/8” is higher than the calculated Shmin (same case as well 110/13-1)

Well 110/13-14

- FIT at 9 5/8” shoe is slightly higher than the calculated overburden

Well 110/13-5

- FIT reported at the 13-3/8” shoe (31.1 ppg EMW) is considerably higher than the calculated overburden or the theoretical fracture initiation pressure. Note an LOT of 29.5 ppg EMW was also reported at the 13 3/8” shoe in 110/13-4. The reason for these very high FIT/LOT values is not clear (measurement error?) but they are not regarded as reliable for the purposes of this study and have not been used for model calibration. 110/13-4 also has an FIT at the 9-5/8” shoe (21.1 ppg EMW). This is noticeably higher than the calculated overburden stress but is lower than the theoretical fracture initiation pressure so it may be a valid data point.

The rock mechanical properties figures depict the following rock mechanical properties derived from logs:

- Poisson’s ratio (black line)
- Friction angle (blue line)
- Rock strength (UCS) (purple line)

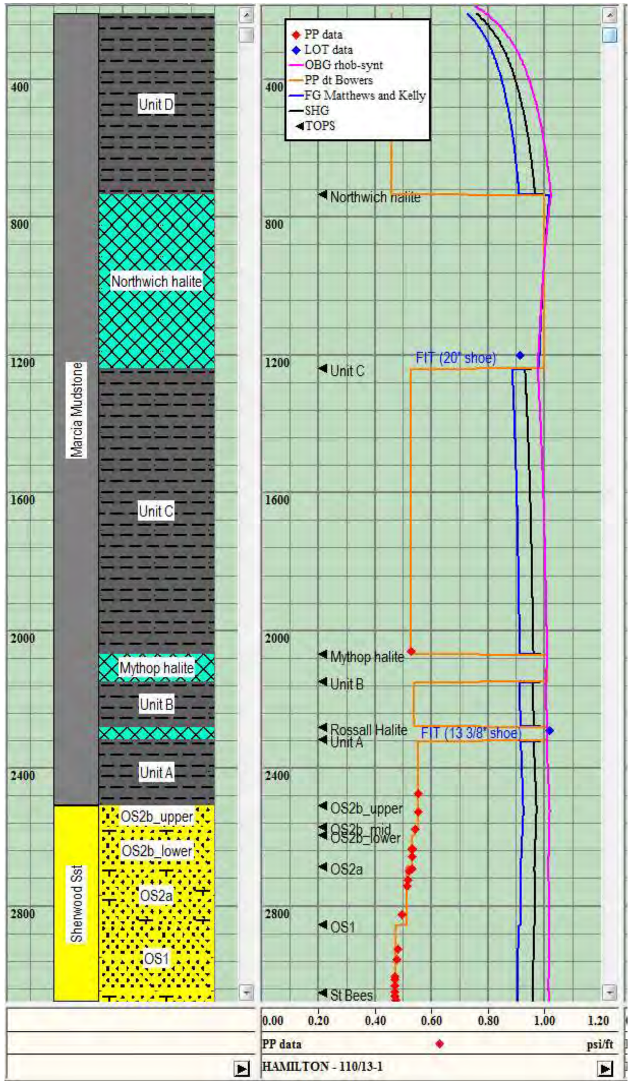


Figure 11-82 Calculated stress curves, Hamilton – Well 110/13-1

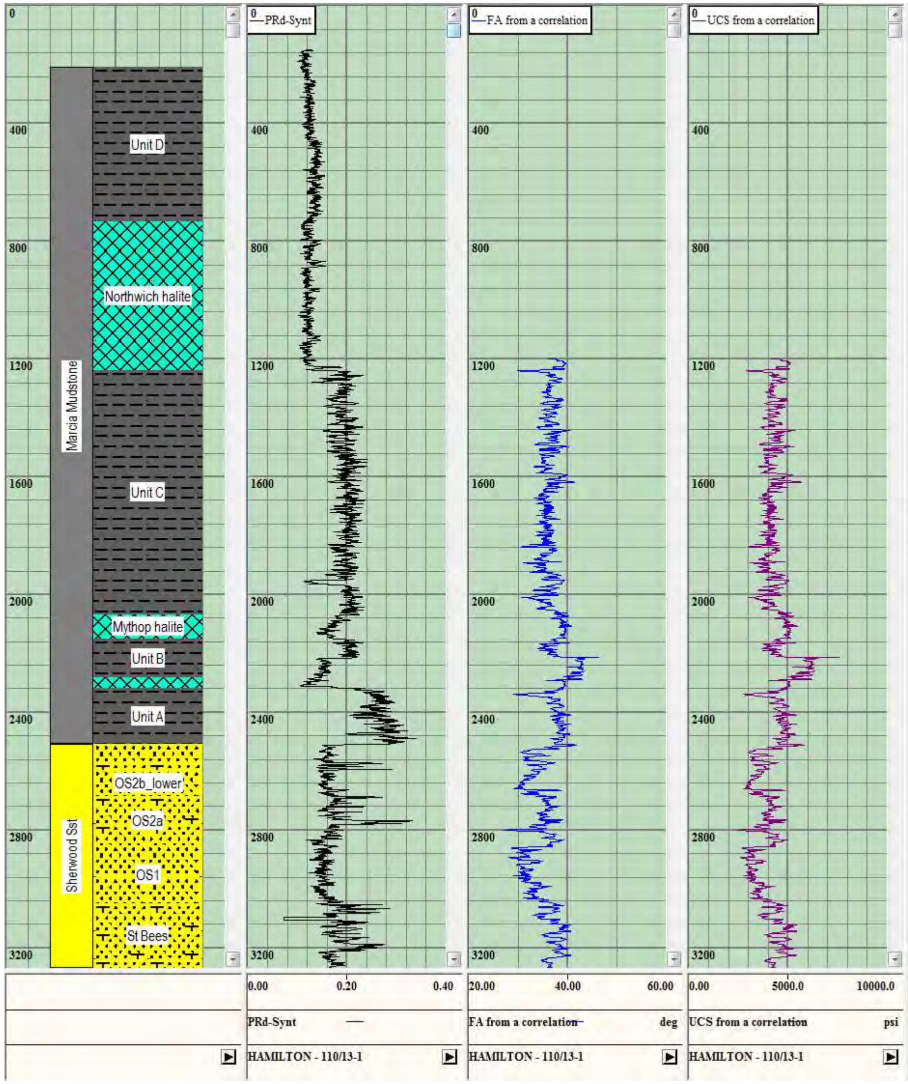


Figure 11-83 Rock mechanical properties, Hamilton – Well 110/13-1

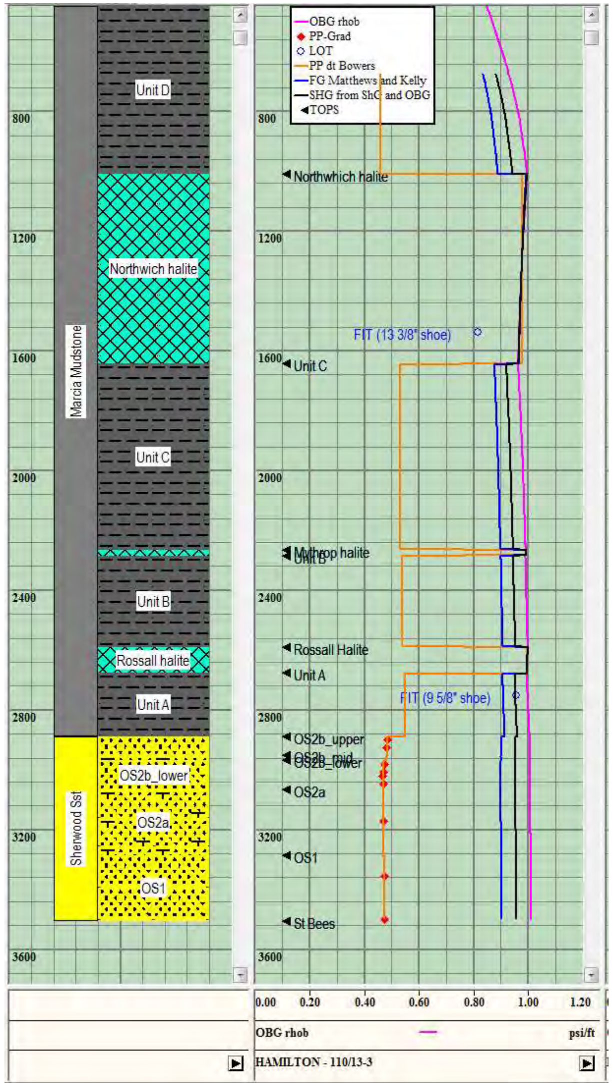


Figure 11-84 Calculated stress curves, Hamilton – Well 110/13-3

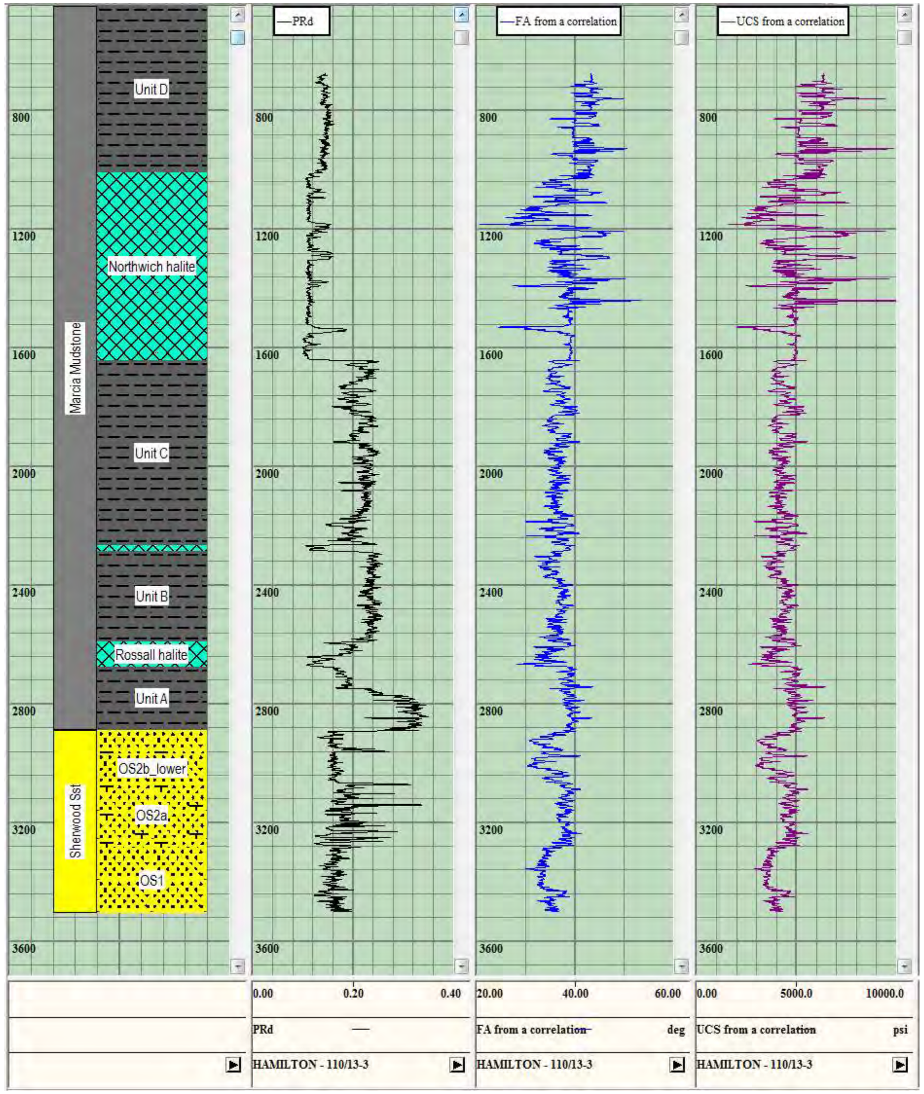


Figure 11-85 Rock mechanical properties, Hamilton – Well 110/13-3

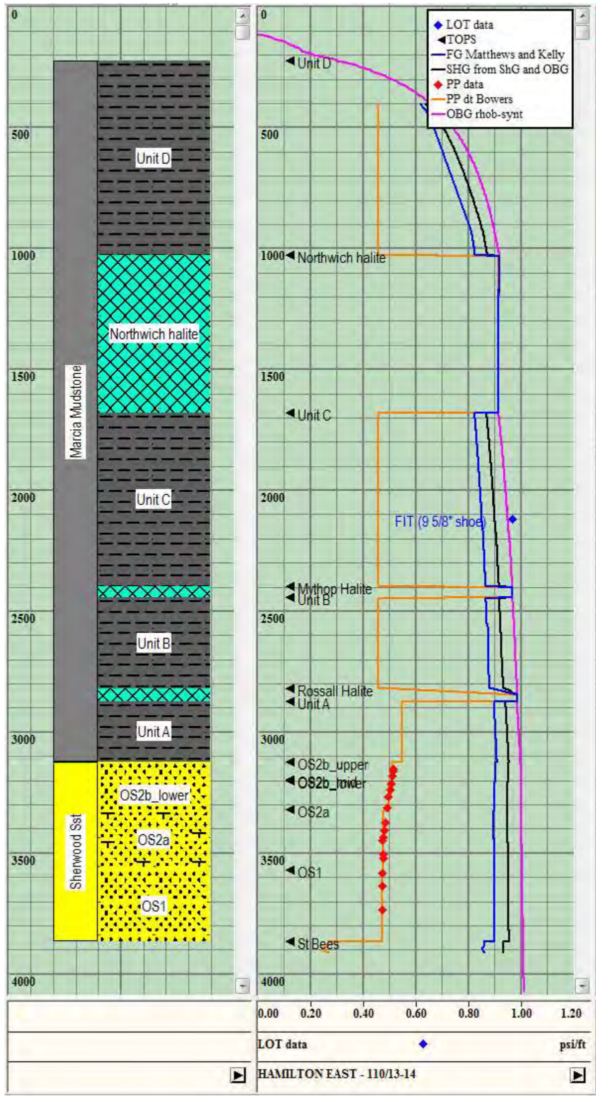


Figure 11-86 Calculated stress curves, Hamilton East – Well 110/13-14

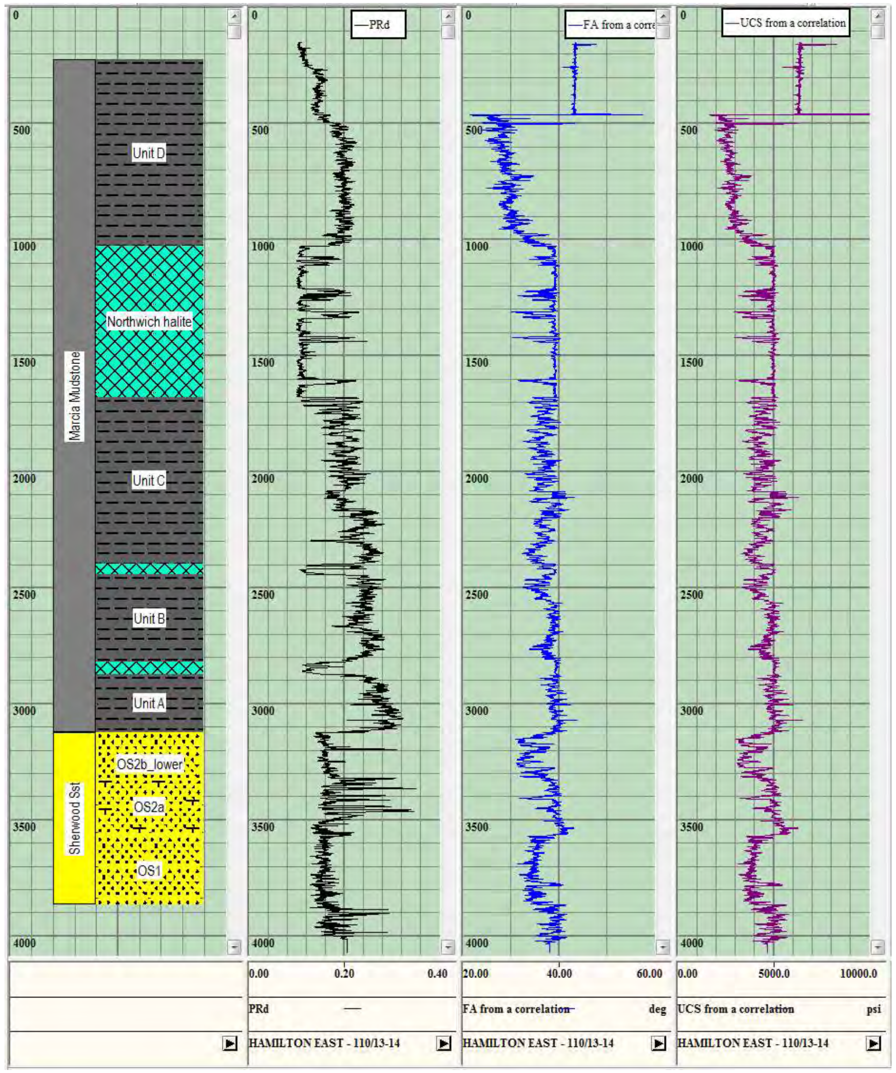


Figure 11-87 Rock mechanical properties, Hamilton East – Well 110/13-14

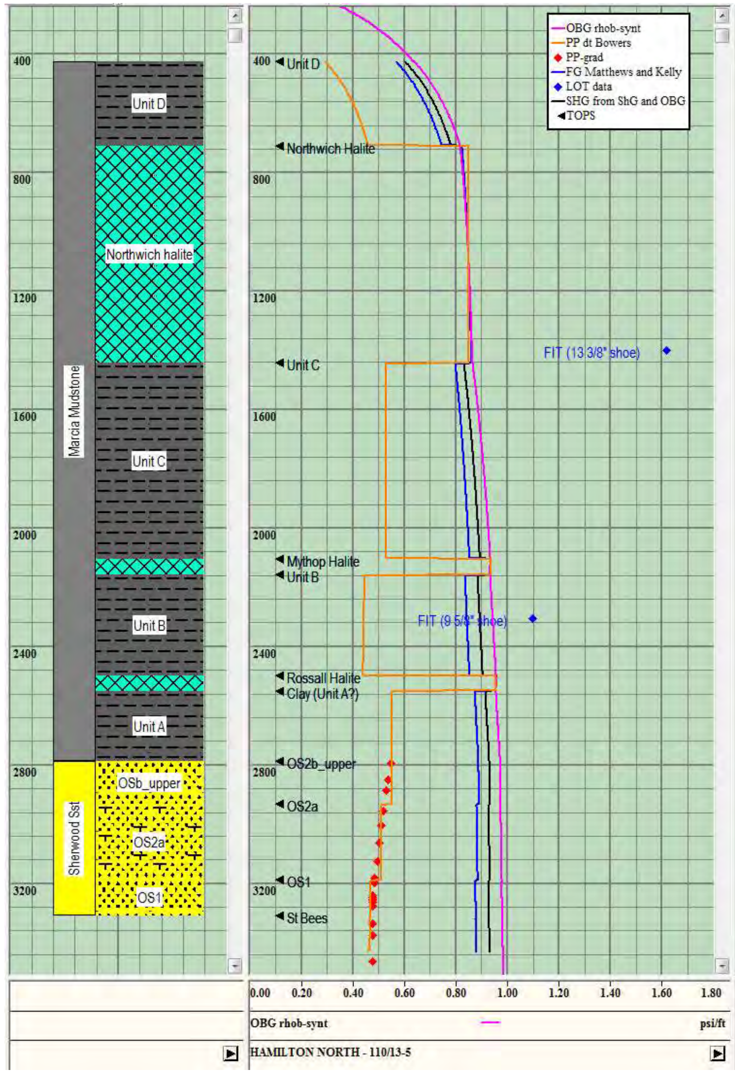


Figure 11-88 Calculated stress curves, Hamilton North – Well 110/13-5

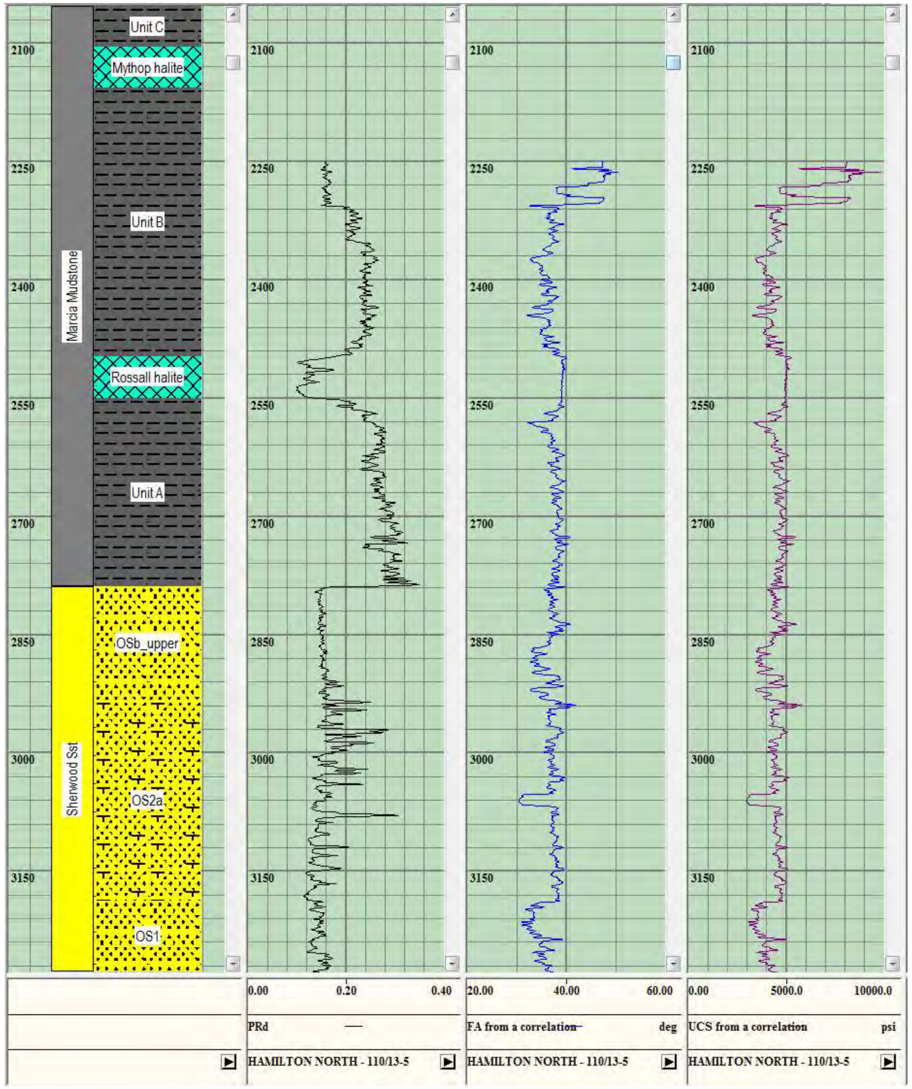


Figure 11-89 Rock mechanical properties, Hamilton North – Well 110/13-5

11.11.4 Depletion analysis – Poroelasticity

Depletion in a reservoir can lower the fracture gradient due to a combination of Biot's factor (pore pressure effectiveness) and Poisson's ratio (lateral strain/vertical strain). During depletion the total stress stays the same (weight of rock doesn't change) but the effective vertical stress (σ_v) increases as;

$$\sigma_v = S_v - \alpha P_p$$

Where:

α = Biot's factor.

The effective horizontal stresses also increase with depletion but the increasing vertical strain causes an increase in lateral strain that counteracts the horizontal stress increase. This means the net result is a total horizontal stress decrease during depletion. The equation for the change in total horizontal stress with pore pressure change (stress path or λ) is shown below:

$$\lambda = \alpha((1-2\nu)/(1-\nu)) = \Delta S_h/\Delta P_p \qquad \text{e.g. Zoback (2007)}$$

Where:

α = Biot's factor

ν = Poisson's ratio.

This formula is valid where the reservoir width is equal or higher than ten times (10x) the reservoir height (to prevent stress arching).

Using a combination of reasonable estimates for Biot and Poisson's Ratio yields a stress path factor range of 0.113 to 0.162bar/m (0.5-0.72 psi/ft) for Hamilton. This translates to a depleted fracture gradient range of 0.151 to 0.129bar/m (0.67-0.57 psi/ft) respectively. However, this simple relationship can only be used as a rough guide to the potential change in fracture gradient as it assumes a vertical stress with elastic response control on the horizontal stress system with depletion. The actual stress path may be affected by local variations in far field tectonic stresses, depletion variability, lithological changes or the local structure (folds and faults).

Even if this relationship is broadly correct, there is the potential for hysteresis if the reservoir pressure is increased from the depleted state. The worst case scenario for fracturing the reservoir is that during injection, the fracture gradient stays similar to the depleted fracture gradient.

The impact of the changes in reservoir pressure on the overburden units will be much less, meaning the seals should still have fracture gradients close to original conditions. If there are any stress arching effects then the horizontal stresses may increase slightly.

The following considerations were taken to calculate the fracture gradient at depleted condition in DrillWorks 5000:

- The depletion condition was applied only to the Ormskirk Sandstone.
- The depleted pore pressure was assumed to be 8.27 bar (120 psi).
- Three (3) fracture gradient correlations were reviewed to evaluate the depleted condition: 1) Eaton; 2) Matthews & Kelly; 3) Breckels & Van Eekelen
- The outputs of the three correlations were compared with the range of potential depleted fracture gradient (0.151 – 0.129 bar/m) (0.67-0.57 psi/ft) identified by poroelasticity principles (which is the yellow area in the following plot). The correlation within the potential range

was Breckels & Van Eekelen, this correlation will be used for the rest of the wells in Hamilton

- The final fracture gradient dataset for the depleted conditions will be a composite log that includes the original Matthews and Kelly correlation for the layers above the sandstone (not depleted) and Breckels & Van Eekelen for the depleted Ormskirk sandstone.

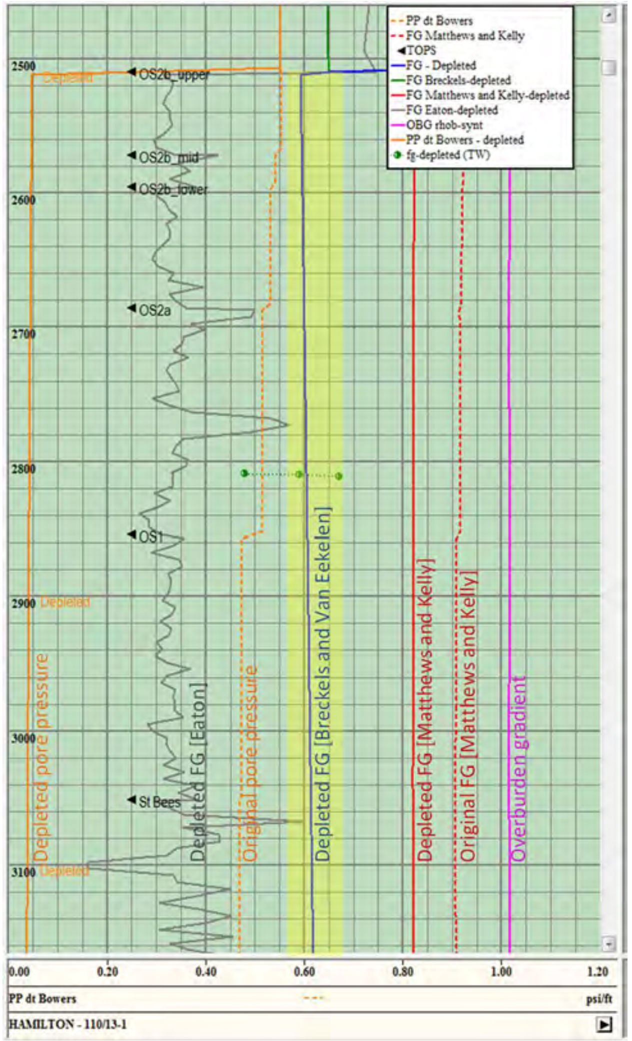


Figure 11-90 Depleted fracture gradient analysis, Hamilton – Well 110/13

RISK REGISTER

Hamilton - depleted gas field site

Document: D12 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 Hamilton 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 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.	
7	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				
8	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).
9	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.		
10	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	5	15	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).
11	Loss of containment from primary store to upper well/ seabed via injection wells	CO_2 leaks to seabed. Environmental, PR and cost implications	1	5	5	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.		
12	Loss of containment from primary store to underburden		2	3	6			Stop injection; corrective measures plan	
13	Fault reactivation through primary caprock		1	2	2		Maximum reservoir pressure during injection set to 90% of fracture pressure	Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes	
14	CO_2 flow through unreactivated, permeable fault in primary caprock		1	2	2		n/a		
15	Thermal fracturing of primary caprock from injection of cold CO_2 into a warm reservoir		1	2	2	Although likely to have thermal fractures within the reservoir during injection, there is a very low likelihood of thermal fractures being created in the Rot Halite caprock due to:		Stop injection, corrective measures plan, limit injection volumes/rate	
16	CO_2 and brine react with minerals in caprock and create permeability pathway		1	2	2		None required		
17	Buoyant CO_2 exposes caprock to pressures beyond the capillary entry pressure enabling it to flow through primary caprock		1	2	2			Stop injection, corrective measures plan, inject at reduced pressure, limit injection volumes to reduce column height of CO_2,	
18	Geology of caprock lithology is variable and lacks continuity such that its presence cannot be assured across the whole site		1	2	2	Even in the unlikely event that the CO_2 managed to migrate through, the volumes would be small and it would be trapped by the secondary store and still within the Storage Complex --> low impact.	Rot Halite primary caprock is very thick (80-100m), with 800-1000m of total seal thickness if incl all shales above it. The Rot Halite is well developed on logs across an extensive area --> very low likelihood that the primary caprock is patchy.	Stop injection, corrective measures plan	
19	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		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	
20	Depth conversion uncertainty around dip and spill point	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.	2	3	6		Appraisal well drilled on flank of greatest uncertainty to reduce uncertainty		
21	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		Model impacts; good engagement with other operators in the area to understand impact	Stop injection until situation understood; further detailed work	
22	Impact of injection and CO_2 storage on nearby fields (e.g. 5/42 Endurance) is greater than expected	Pressure build up quicker than expected so reduces storage capacity, potential loss of credibility of CCS project			0		Draft process for dispute resolution with nearby subsurface users	Stop injection until situation understood; further detailed work	
23	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.	2	3	6	Due to current technology and set procedures used during drilling campaigns, this is very unlikely, but not improbable --> Low likelihood			
24	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.	2	3	6	If CO_2 was injected into the wrong zone or the reservoir was damaged, it would be known from the injectivity of the well that this had occurred and so very unlikely that injection would continue to enable CO_2 to laterally exit the primary store. --> low likelihood.	Downhole P/T gauges and DTS along the wellbore as part of monitoring plan to detect first signs of loss of integrity.		
25	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	Dynamic modelling shows that some CO_2 will dissolve into the brine			
26	Blowout during drilling	Possible escape of CO_2 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).
27	Blowout during well intervention	Possible escape of CO_2 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).
28	Tubing leak	Pressured CO_2 in the A-annulus. Sustained CO_2 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).
29	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).
30	Cement sheath failure (Production Liner)	Sustained CO_2 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 CO_2 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).
31	Production Liner failure	Sustained CO_2 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 CO_2 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).
32	Cement sheath failure (Production Casing)	Sustained CO_2 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 CO_2 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).

33	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).
34	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).
35	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).
36	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).
37	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 CO2 inside the defined storage complex	Unexpected migration of CO2 outside the defined storage complex	Leakage to seabed or water column over small area (<100m2)	Leakage seabed water column over large area (>100m2)
Impact on local environment	Minor environmental damage	Local environmental damage of short duration	Time for restitution of ecological resource <2 years	Time for restitution of ecological resource 2-5 years	Time for restitution of ecological resource such as marine Biosystems, ground water >5 years
Impact on reputation	Slight or no impact	Limited impact	Considerable impact	National impact	International impact
Consequence for Permit to operate	None	Small fine	Large fine	Temporary withdrawal of permit	Permanent loss of permit

Likelihood categories (CO2QUALSTORE)

No.	1	2	3	4	5
Name	Very Low	Low	Medium	High	Very High
Description	Improbable, negligible	Remotely probably, hardly likely	Occasional, likely	Probable, very likely	Frequent, to be expected
Event (E)	Very unlikely to occur during the next 5000 years	Very unlikely to occur during injection operations	Likely to occur during injection operations	May occur several times during injection operations	Will occur several times during injection operations
Frequency	About 1 per 5000 years	About 1 per 500 years	About 1 per 50 years	About 1 per 5 years	About 1 per year or more
Feature (F)/ Process (P)	Disregarded	Not expected	50/50 chance	Expected	Sure

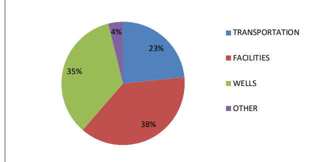
PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 19: HAMILTON
CLIENT	ETI
REVISION	A1
DATE	21/03/2016

LEVEL 2 COST ESTIMATE

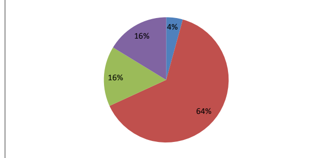
Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

	Category	Comment	Responsibility	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	-	**13.8**	**4.7**	**18.5**		**24.0**
A1.1	**Transportation**	CO2 Pipeline System Pre-FEED/FEED Design	CU	0.5	0.2	0.7	30%	0.8
A1.2	**Facilities**	Design of Platforms, Subsea Structures, Umbilicals, Power Cables	CU	6.4	2.9	9.3		12.1
A1.3	**Wells**	Pre-Feed / FEED Wells Engineering Design	AXIS	2.0	0.2	2.2		2.9
A1.4	**Other**			4.9	1.4	6.3		8.2
A1.4.1	Seismic and Baseline Survey	Data Acquisition & Interpretation	PBD	1.9	0.2	2.1		2.7
A1.4.2	Appraisal Well	Procurement for, and Drilling of, Appraisal Well(s) - Not Required	AXIS	0.0	0.0	0.0		0.0
A1.4.3	Engineering and Analysis	Additional subsurface analysis and re-engineering if required	PBD	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)			-	**182.9**	**16.5**	**199.4**	-	**257.1**
B1.1	**Transportation**		-	48.5	1.5	49.9	-	64.9
B1.1.1	Detailed Design	Detailed Design of CO2 Pipeline System	CU	1.0	0.2	1.2	30%	1.6
B1.1.2	Procurement	Long lead items (linepipe, coatings etc)		8.9	1.1	10.0		13.0
B1.1.3	Fabrication	Spoolbase Fabrication and Coating etc		3.1	0.2	3.3		4.2
B1.1.4	Construction and Commissioning	Logistics, Installation, WX, Function Testing and Commissioning		35.5	0.0	35.5		46.1
B1.2	**Facilities**		-	66.6	6.2	72.8	-	94.7
B1.2.1	Detailed Design		CU	10.0	3.0	13.0	30%	16.9
B1.2.2	Procurement	Jacket, Topsides, Templates, Umbilicals, Power Cables, etc		19.5	2.9	22.4		29.1
B1.2.3	Fabrication	Platform/NUI and Subsea Structures Fabrication		5.0	0.3	5.3		6.9
B1.2.4	Construction and Commissioning	Logistics, Transportation, Installation, HUC		32.1	0.0	32.1		41.8
B1.3	**Wells**		-	66.9	7.8	74.7	-	94.9
B1.3.1	Detailed Design	including submission of OPEP (or CO2 equivalent)	AXIS	2.0	0.2	2.2	30%	2.9
B1.3.2	Procurement	Wells long lead items - Trees, Tubing Hangers, etc		20.8	2.1	22.9		29.1
B1.3.3	Fabrication	-		0.0	0.0	0.0		0.0
B1.3.4	Construction and Commissioning	Drilling/Intervention, WX		44.1	5.6	49.6		63.0
		Gas Injector 1 and 2 + Spare Well		26.3	3.0	29.3		37.2
		Dense Phase Injector 1 and 2		17.8	2.6	20.4		25.8
B1.4	**Other**		-	1.0	1.0	2.0	-	2.6
B1.4.1	Licencing and Permits	Licenses, Permissions Permit, PLANC	PBD	1.0	1.0	2.0	30%	2.6
C. Total Operating Expenditure (OPEX)			-	**350.8**	**32.0**	**382.7**	-	**496.5**
C1.1	**OPEX - Transportation**	Inspections, Maintenance, Repair (IMR)	CU	15.6	0.8	16.4	30%	21.4
C1.2	**OPEX - Facilities**			226.3	17.5	243.9		317.0
C1.2.1	OPEX - Offshore Facilities	Manning, Power, IMR, Chemicals		146.9	13.4	160.2		208.3
C1.2.2	OPEX - Power Supply	Power supply from Beach		79.5	4.2	83.6		108.7
C1.3	**OPEX - Wells**	Workovers, Sidetracks, Power, Chemicals	-	52.2	8.0	60.2		77.2
C1.3.1	**Well Sidetracks and Workovers**	Local Sidetrack 1	AXIS	10.9	1.5	12.4		15.9
		Gas Injector Workover 1		5.6	1.4	6.9		8.8
		Gas Injector Workover 2		5.8	1.1	6.9		8.7
		Local Sidetrack 2		9.4	1.5	10.9		14.1
		Local Sidetrack 3		9.7	1.1	10.7		13.7
		Local Sidetrack 4		10.9	1.5	12.4		15.9
C1.4	**Other**			56.6	5.7	62.26	-	80.9
C1.4.1	Measurement, Monitoring and Verification	includes data management and interpretation	PBD	7.4	0.7	8.14	30%	10.6
C1.4.2	Financial Securities			49.2	4.9	54.12		70.4
C1.4.3	Ongoing Tariffs and Agreements	assume supplier covers 3rd party tariffs		0.0	0.0	0		0.0
D. Abandonment (ABEX)			-	**66.6**	**7.0**	**73.6**	-	**95.7**
D1.1	**Decommissioning - Transportation**	10% Transportation CAPEX	CU	6.6	0.7	7.2	30%	9.4
D1.2	**Decommissioning - Facilities**	Que$tor		27.7	2.8	30.5		39.7
D1.3	**Decommissioning - Wells**		AXIS	19.0	2.7	21.7		28.1
D1.4	**Other**		-	13.4	0.9	14.24	-	18.5
D1.4.1	Post Closure Monitoring	includes data management and interpretation	PBD	8.9	0.9	9.79	30%	12.7
D1.4.2	Handover	additional 10 years of coverage		4.5	0.0	4.45		5.8

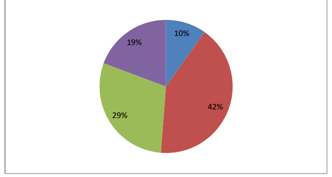
CAPEX BREAKDOWN [A+B]



OPEX BREAKDOWN [C]



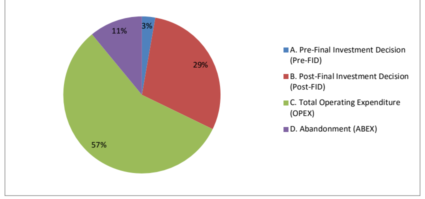
ABEX BREAKDOWN [D]



FIELD LIFE (YEARS)	25
CO2 STORED (MT)	125

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

LEVEL 1 COST ESTIMATE SUMMARY



CAPEX / OPEX / ABEX BREAKDOWN SUMMARY

COST	TOTAL COST (£ MM)	CATEGORY	COST (£ MM)
CAPEX [A + B]	281.1	TRANSPORTATION	65.7
		FACILITIES	106.8
		WELLS	97.8
		OTHER	10.8
OPEX [C]	496.5	TRANSPORTATION	21.4
		FACILITIES	317.0
		WELLS	77.2
		OTHER	80.9
ABEX [D]	95.7	TRANSPORTATION	9.4
		FACILITIES	39.7
		WELLS	28.1
		OTHER	18.5
TOTAL	873.4	-	873.4

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)		13.8	4.7	18.5	24.0
B. Post-Final Investment Decision (Post-FID)		182.9	16.5	199.4	257.1
C. Total Operating Expenditure (OPEX)		350.8	32.0	382.7	496.5
D. Abandonment (ABEX)		66.6	7.0	73.6	95.7
TOTAL COST (CAPEX, OPEX, ABEX)				674.3	**873.4**
COST CO2 INJECTED (£ PER TONNE)				£5.39	**£6.99**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: PROCUREMENT & FABRICATION**
TITLE	SITE 19: HAMILTON	
CLIENT	ETI	
REVISION	A1	
DATE	21/03/2016	

Pipeline	**Trunk Pipeline(s)**	**Infield Pipeline(s)**
Number	1	
Route Length (km)	26	
Route Length Factor	1.05	
Pipeline Crossings	2	
Tee Structures	0	
Outer Diameter (mm)	406.4	
Wall Thickness (mm)	21.4	
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**								**£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**								**£14,438,984**
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		-	-	-	-	-		**£9,983,984**
B1.1.2.1	Insurance and Certification		-	-	-		£500,000	*Insurance and Certification*	£500,000
B1.1.2.2	Geotechnical Testing		£2,000	km	27	£54,600	£28,000	*Documentation etc*	£82,600
B1.1.2.3	*Procurement - Linepipe (Trunk)*	*API 5L X65, OD 406.4mm, WT 21.4mm*	£1,500	Te	5,547	£8,320,500	£499,230	*Logistics/Freight @ 6%*	£8,819,730
B1.1.2.4	*Procurement - Coating (Trunk)*	*Corrosion Coating*	£20	m	27,300	£546,000	£32,760		£578,760
B1.1.2.5	*Procurement - Coating (Trunk)*	*Concrete Coating*	£30	m	0	£0	£0		£0
B1.1.2.6	*Procurement - Anodes (Trunk)*	*CP Protection*	£50	Each	55	£2,730	£164		£2,894
B1.1.3	Fabrication		-	-	-	-	-		**£3,255,000**
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	27,300	£1,365,000	£50,000	*Contractor Surveillance*	£1,415,000
B1.1.3.3	*Crossing Supports*	*Concrete Crossing Plinth/Supports*	£100,000	Per Crossing	2	£200,000	£20,000	*Contractor Surveillance*	£220,000
B1.1.3.4	*Tee-Piece Structure*	*To Facilitate Future Expansion*	£5,000,000	Each	0	£0	£20,000	*Contractor Surveillance*	£20,000

Total (Excluding Contingency)		**£15,091,484**
Pre-FID Contingency (%)	**30%**	**£195,750**
Post-FID Contingency (%)	**30%**	**£4,331,695**
Total (Including Contingency)		**£19,618,929**

PROJECT	Strategic UK Storage Appraisal Project	**TRANSPORTATION: CONSTRUCTION AND COMMISSIONING**
TITLE	SITE 19: HAMILTON	
CLIENT	ETI	
REVISION	A1	
DATE	21/03/2016	

Pipeline	Trunk Pipeline(s)	Infield Pipeline(s)
Number	1	
Route Length (km)	26	
Route Length Factor	1.05	
Pipeline Crossings	2	
Outer Diameter (mm)	406.4	
Wall Thickness (mm)	21.4	
Anode Spacing (m)	500	
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	£20,000,000	Landfall and Onshore tie-in for Pipeline

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 (S-Lay)	Mobilisation	S-Lay Vessel (14000Te)	£350,000	5	£1,750,000	£6,650,000
		Infield Operations			12	£4,200,000	
		Demobilisation			2	£700,000	
B1.1.4.3	Crossing Installation	Mobilisation	Survey Vessel	£100,000	2	£200,000	£1,000,000
		Infield Operations - 3 day per Crossing			6	£600,000	
		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	£750,000
		Infield Operations -SSIV			1	£150,000	
		Demobilisation			2	£300,000	
B1.1.4.7	Trenching and Backfill	Mobilisation	Ploughing Vessel	£100,000	3	£300,000	£1,312,500
		Infield Operations			8	£812,500	
		Demobilisation			2	£200,000	
B1.1.4.8	Construction Project Management and Engineering		-	Lump Sum (10%)	-	£1,406,250	£1,406,250
B1.1.4.9	Landfall and Onshore tie-in for Pipeline		-	Lump Sum	-	£20,000,000	£20,000,000
					Total (Excluding Contingency)		**£35,468,750**
					Contingency	**30%**	**£10,640,625**
					Total (Including Contingency)		**£46,109,375**

PROJECT	Strategic UK Storage Appraisal Project
TITLE	SITE 19: HAMILTON
CLIENT	ETI
REVISION	A1
DATE	21/03/2016

Facilities:
PROCUREMENT & FABRICATION

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**								**£9,342,205**
A1.2.1	Pre-FEED	3 Legged Jacket, Topsides, Power Cable	£2,277,160	LS	1	£2,277,160	£1,024,722	*Company Time Writing, Contractor Surveillance*	£3,301,882
A1.2.2	FEED	3 Legged Jacket, Topsides, Power Cable	£4,165,740	LS	1	£4,165,740	£1,874,583	*Company Time Writing, Contractor Surveillance*	£6,040,323
B. Post FID									
B1.2	**Facilities - Post FID**								**£72,832,660**
B1.2.1	Detailed Design	3 Legged Jacket, Topsides, Power Cable	£10,000,000	LS	1	£10,000,000	£3,000,000	*Company Time Writing, IVB, SIT etc*	**£13,000,000**
B1.2.2	Procurement		-	-	-		-	-	**£22,398,252**
	Jacket	3 Legged Jacket	-	-	-		-	-	***£1,453,315***
B1.2.2.1.1	Insurance and Certification		-	-	-		£394,000	*Insurance and Certification*	£394,000
B1.2.2.1.2	*Jacket Steel*		£1,333	Te	454	£605,333	£36,320		£641,653
B1.2.2.1.3	*Piles*		£1,301	Te	198	£257,532	£15,452	*Logistics/Freight @ 6%*	£272,984
B1.2.2.1.4	*Anodes*		£3,685	Te	30	£110,560	£6,634		£117,194
B1.2.2.1.5	*Installation Aids*		£1,127	Te	23	£25,929	£1,556		£27,484
	Topsides		-	-	-		-	-	***£12,707,041***
B1.2.2.2.1	Insurance and Certification		-	-	-		£1,360,667	*Insurance and Certification*	£1,360,667
B1.2.2.2.2	*Primary Steel*		£1,087	Te	118	£128,227	£7,694		£135,920.27
B1.2.2.2.3	*Secondary Steel*		£900	Te	135	£121,500	£7,290		£128,790.00
B1.2.2.2.4	*Piping*		£10,733	Te	50	£536,667	£32,200		£568,866.67
B1.2.2.2.5	*Electrical*		£19,200	Te	25	£480,000	£28,800		£508,800.00
B1.2.2.2.6	*Instrumentation*		£36,333	Te	20	£726,667	£43,600		£770,266.67
B1.2.2.2.7	*Miscellaneous*		£8,800	Te	15	£132,000	£7,920		£139,920.00
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	7	£3,225,133	£193,508		£3,418,641.33
B1.2.2.2.10	*General Utilities*	*Drainage, Diesel Storage etc*	£50,000	Te	4	£200,000	£12,000		£212,000.00
B1.2.2.2.11	*Vent Stack*	*Low Volume (venting done at beach)*	£6,933	Te	35	£242,667	£14,560	*Logistics/Freight @ 6%*	£257,226.67
B1.2.2.2.12	*Diesel Generators*	*Power Generation*	£52,067	Te	0	£0	£0		£0.00
B1.2.2.2.13	*Power Distribution*		£36,067	Te	10	£360,667	£21,640		£382,306.67
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	5	£96,333	£5,780		£102,113.33
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 Receiver*	£10,000	Te	2	£20,000	£1,200		£21,200.00
B1.2.2.2.20	*Heaters*	*CO2 Heating*	£300,000	Each	6	£1,800,000	£108,000		£1,908,000
B1.2.2.2.21				m		£0	£0		£0
	Power Supply - Cable+Onshore Tie-in	*Connection into Local Distribution*	£7,771,600	Each	1	£7,771,600	£466,296		£8,237,896
B1.2.3	Fabrication		-	-			-		**£5,297,351**
	Jacket		-	-			-		***£1,896,411***
B1.2.3.1	*Jacket Steel*		£3,245	Te	454	£1,473,079	£88,385		£1,561,463
B1.2.3.2	*Piles*		£1,022	Te	198	£202,356	£12,141	*Logistics/Freight @ 6%*	£214,497
B1.2.3.3	*Anodes*		£755	Te	30	£22,660	£1,360		£24,020
B1.2.3.4	*Installation Aids*		£3,955	Te	23	£90,973	£5,458		£96,431
	Topsides		-		-		-	-	***£3,400,939***
B1.2.3.2.1	*Primary Steel*		£5,467	Te	118	£645,067	£38,704		£683,771
B1.2.3.2.2	*Secondary Steel*		£7,200	Te	135	£972,000	£58,320		£1,030,320
B1.2.3.2.3	*Equipment*		£1,513	Te	125	£189,167	£11,350		£200,517
B1.2.3.2.4	*Piping*		£14,867	Te	40	£594,667	£35,680	*Logistics/Freight @ 6%*	£630,347
B1.2.3.2.5	*Electrical*		£26,467	Te	20	£529,333	£31,760		£561,093
B1.2.3.2.6	*PLR*	*Pig Receiver*	£25,000	Te	2	£50,000	£3,000		£53,000
B1.2.3.2.7	*Miscellaneous*		£10,867	Te	21	£228,200	£13,692		£241,892
B1.2.4	Construction and Commissioning		-	-	-		-	-	**£32,137,057**
B1.2.4.1	Power Cable Installation	lump sum	£9,714,500	Each	1	£9,714,500	£0		£9,714,500
B1.2.4.2	Installation Spread	Jacket Installation	£596,206	Days	28	£16,693,768	£0	-	£16,693,768
B1.2.4.3	Installation Spread	Topsides Installation	£135,533	Days	7	£948,733	£0	-	£948,733
		Mobilisation	£57,236	Days	4	£228,944	£0	-	£228,944
B1.2.4.4	*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
B1.2.4.5	*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
B1.2.4.6	*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
B1.2.4.7	*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)					**£82,174,865**
				Pre-FID Contingency (%)				**30%**	**£2,802,662**
				Post-FID Contingency (%)				**30%**	**£21,849,798**
				Total (Including Contingency)					**£106,827,325**

PROJECT	Strategic UK Storage Appraisal Project	**WELLS: COST SUMMARY**
TITLE	SITE 19: HAMILTON	
CLIENT	ETI	
REVISION	A1	
DATE	21/03/2016	

Pale Blue Dot. COSTAIN AXIS WELL TECHNOLOGY FROM CONCEPT TO COMPLETION

Well Cost Summary (including 30% Contingency)

Well Name	Days	Well Cost (£,000)
Year 0		
Gas Injector 1	45.5	16,625.0
Gas Injector 2	39.0	14,550.0
Spare Well	42.7	14,675.0
Year 7		
Local Sidetrack 1	53.3	17,379.0
Year 13		
Gas Injector Workover 1	26.7	9,137.5
Gas Injector Workover 2	26.7	9,087.5
Year 15		
Local Sidetrack 2	46.8	15,504.0
Local Sidetrack 3	46.8	15,304.0
Year 17		
Dense Phase Injector 3	43.6	15,637.5
Dense Phase Injector 4	42.1	15,062.5
Year 20		
Local Sidetrack 4	53.3	17,379.0
Year 25		
Abandonment Gas Injector 1	20.8	6,100.0
Abandonment Gas Injector 2	14.3	4,025.0
Abandonment Dense Phase Injector 3	14.3	4,025.0
Abandonment Dense Phase Injector 4	14.3	4,025.0
Abandonment Monitoring Well	20.8	5,650.0
TOTAL	550.8	184166

Note: This figure does not include the PM & Eng costs.

Drilling Overhead Cost Summary

Drilling Campaign	Overhead (£MM)
Gas Injector 1 and 2 + Spare Well	3.00
Dense Phase Injector 1 and 2	2.55

OPEX Overhead Cost Summary

OPEX Campaign	Overhead (£MM)
Local Sidetrack 1	1.50
Gas Injector Workover 1	1.35
Gas Injector Workover 2	1.05
Local Sidetrack 2	1.50
Local Sidetrack 3	1.05
Local 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)	
Development Wells - CAPEX Breakdown						
Gas Injector 1	3500	5650	2625	4850	1455	18080
Gas Injector 2	3000	4900	2250	4400	1320	15870
Spare Well	3400	5800	2175	3300	990	15665
Dense Phase Injector 3	3350	5425	2512.5	4350	1305	16942.5
Dense Phase Injector 4	3350	5675	2137.5	3900	1170	16232.5
Wells - OPEX Breakdown						
Local Sidetrack 1	4102	6802	3075	3400	1020	18399
Gas Injector Workover 1	2050	3500	1537.5	2050	615	9752.5
Gas Injector Workover 2	2050	3750	1537.5	1750	525	9612.5
Local Sidetrack 2	3602	5802	2700	3400	1020	16524
Local Sidetrack 3	3602	6052	2700	2950	885	16189
Local Sidetrack 4	4102	6802	3075	3400	1020	18399
Wells - ABEX Breakdown						
Abandonment Gas Injector 1	1600	2400	1200	900	270	6370
Abandonment Gas Injector 2	1100	1650	825	450	135	4160
Abandonment Dense Phase Injector 3	1100	1650	825	450	135	4160
Abandonment Dense Phase Injector 4	1100	1650	825	450	135	4160
Abandonment Monitoring Well	1600	2400	1200	450	135	5785

	CAPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
						%	£MM	
A1.3	Pre-FEED / FEED PM & E	2	0.2	Company Time Writing, IVB, SIT, Insurance etc	2.2	30%	0.7	**2.9**
B1.3.1	Detailed Design PM & E	2	0.2		2.2	30%	0.7	**2.9**
B1.3.2	Procurement	20.8	2.1	Trees, Gauges etc.	22.9	30%	6.2	**29.1**
B1.3.4	Construction and Commissioning (Drilling)	44.1	5.55	Well Management Fees, Insurance, Site Survey, Studies etc.	49.6	30%	13.4	**63.0**
	Total	68.9	8.0	-	76.9		20.9	**97.8**

OPEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
					%	£MM	
OPEX	69.2	7.95	Well Management Fees, Insurance, Site Survey, Studies etc.	77.1	30%	22.1	**99.2**

ABEX Summary	Excluding Contingency (£MM)	Overhead (£MM)	Overhead Description	Sub-Total (£MM)	Contingency		Total Cost (£MM)
					%	£MM	
ABEX	19.0	2.7	Well Management Fees, Insurance, Site Survey, Studies etc.	21.7	30%	5.7	**27.3**

Level 1 Cost Estimate Summary - Wells

	Total CAPEX (£MM)	97.8
C1.3	Total OPEX (£MM)	99.2
D1.3	Total ABEX (£MM)	27.3
	TOTAL (£MM)	**224.4**