Department for
Business, Energy
& Industrial Strategy

Primary Store Dynamic Model and Report

Key Knowledge Document

NS051-SS-REP-000-00015

August 2021

Acknowledgements

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1.0 Foreword

The Net Zero Teesside (NZT) project in association with the Northern Endurance Partnership project (NEP) intend to facilitate decarbonisation of the Humber and Teesside industrial clusters during the mid-2020s. Both projects will look to take a Final Investment Decision (FID) in early 2023, with first CO2 capture and injection anticipated in 2026.

The projects address widely accepted strategic national priorities – most notably to secure green recovery and drive new jobs and economic growth. The Committee on Climate Change (CCC) identified both gas power with Carbon Capture, Utilisation and Storage (CCUS) and hydrogen production using natural gas with CCUS as critical to the UK's decarbonisation strategy. Gas power with CCUS has been independently estimated to reduce the overall UK power system cost to consumers by £19bn by 2050 (compared to alternative options such as energy storage).

1.1 Net Zero Teesside Onshore Generation & Capture

NZT Onshore Generation & Capture (G&C) is led by bp and leverages world class expertise from ENI, Equinor, and TotalEnergies. The project is anchored by a world first flexible gas power plant with CCUS which will compliment rather than compete with renewables. It aims to capture ~2 million tonnes of CO2 annually from 2026, decarbonising 750MW of flexible power and delivering on the Chancellor's pledge in the 2020 Budget to "support the construction of the UK's first CCUS power plant." The project consists of a newbuild Combined Cycle Gas Turbine (CCGT) and Capture Plant, with associated dehydration and compression for entry to the Transportation & Storage (T&S) system.

1.2 Northern Endurance Partnership Onshore/Offshore Transportation & Storage

The NEP brings together world-class organisations with the shared goal of decarbonising two of the UK's largest industrial clusters: the Humber (through the Zero Carbon Humber (ZCH) project), and Teesside (through the NZT project). NEP T&S includes the G&C partners plus Shell, along with National Grid, who provide valuable expertise on the gathering network as the current UK onshore pipeline transmission system operator.

The Onshore element of NEP will enable a reduction of Teesside's emissions by one third through partnership with industrial stakeholders, showcasing a broad range of decarbonisation technologies which underpin the UK's Clean Growth strategy and kickstarting a new market for CCUS. This includes a new gathering pipeline network across Teesside to collect CO2 from industrial stakeholders towards an industrial Booster Compression system, to condition and compress the CO2 to Offshore pipeline entry specification.

Offshore, the NEP project objective is to deliver technical and commercial solutions required to implement innovative First-of-a-Kind (FOAK) offshore low-carbon CCUS infrastructure in the UK, connecting the Humber and Teesside Industrial Clusters to the Endurance CO2 Store in the Southern North Sea (SNS). This includes CO2 pipelines connecting from Humber and Teesside compression/pumping systems to a common subsea manifold and well injection site at Endurance, allowing CO2 emissions from both clusters to be transported and stored. The NEP project meets the CCC's recommendation and HM Government's Ten Point Plan for at least two clusters storing up to 10 million tonnes per annum (Mtpa) of CO2 by 2030.

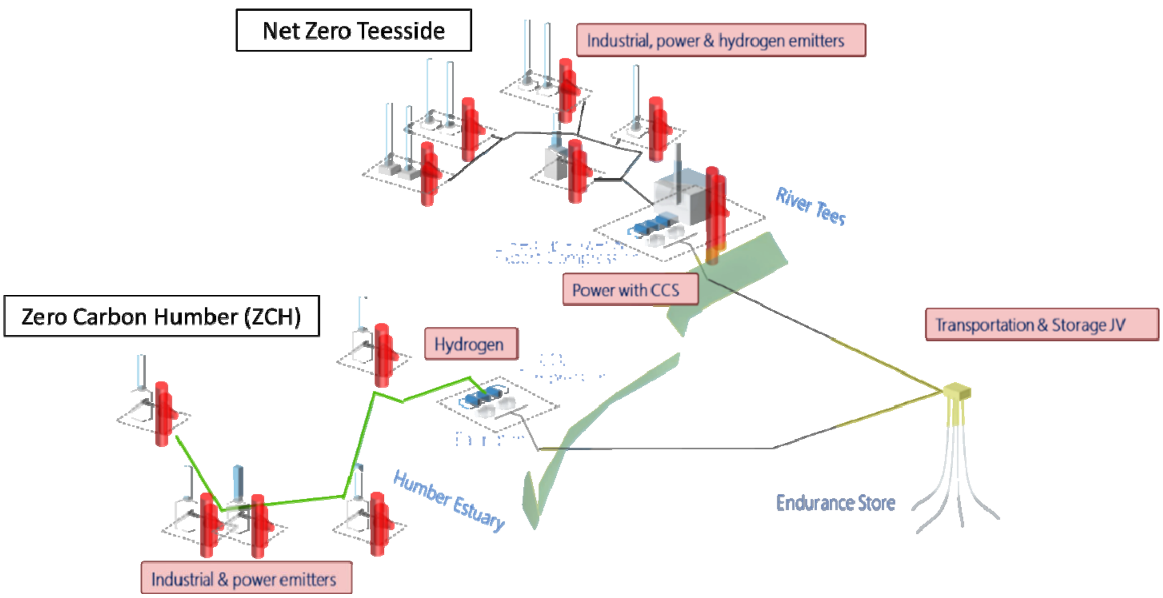


Figure 1: Overview of Net Zero Teesside and Zero Carbon Humber projects.

The project initially evaluated two offshore CO2 stores in the SNS: 'Endurance', a saline aquifer formation structural trap, and 'Hewett', a depleted gas field. The storage capacity requirement was for either store to accept 6+ Mtpa CO2 continuously for 25 years. The result of this assessment after maturation of both options, led to Endurance being selected as the primary store for the project. This recommendation is based on the following key conclusions:

- The storage capacity of Endurance is 3 to 4 times greater than that of Hewett
- The development base cost for Endurance is estimated to be 30 to 50% less than Hewett
- CO2 injection into a saline aquifer is a worldwide proven concept, whilst no benchmarking is currently available for injection in a depleted gas field in which Joule-Thompson cooling effect has to be managed via an expensive surface CO2 heating solution.

Following selection of Endurance as the primary store, screening of additional stores has been initiated to replace Hewett by other candidates. Development scenarios incorporating these additional stores will be assessed as an alternative to the sole Endurance development.

2.0 Executive Summary

2.1 Key Facts About Endurance (Primary Store)

Endurance is a large anticline Bunter structure (25km long and 8 km wide) located in the Southern North Sea, UK sector (quadrants 42 & 43) and is penetrated by 3 wells 43/21-1, 42/25-1, and 42/25d-3, as shown (Figure 2). 42/25d-3 was drilled in 2013 by National Grid Carbon Ventures with the intent to appraise the store for CO2 sequestration (190 meters of core acquired from Rot Clay down to the Bunter L1 with extensive conventional and special core analysis, a DST production and injection test over 20 meters in the upper Bunter, mini-frac tests in the Rot Clay caprock as well as in the Bunter sandstone). The 4-way structure presents circa 400 meters of structural relief and offers circa 26 billion barrels of brine above the spill point to be displaced for CO2 storage (Net Pore Volume (NPV)).

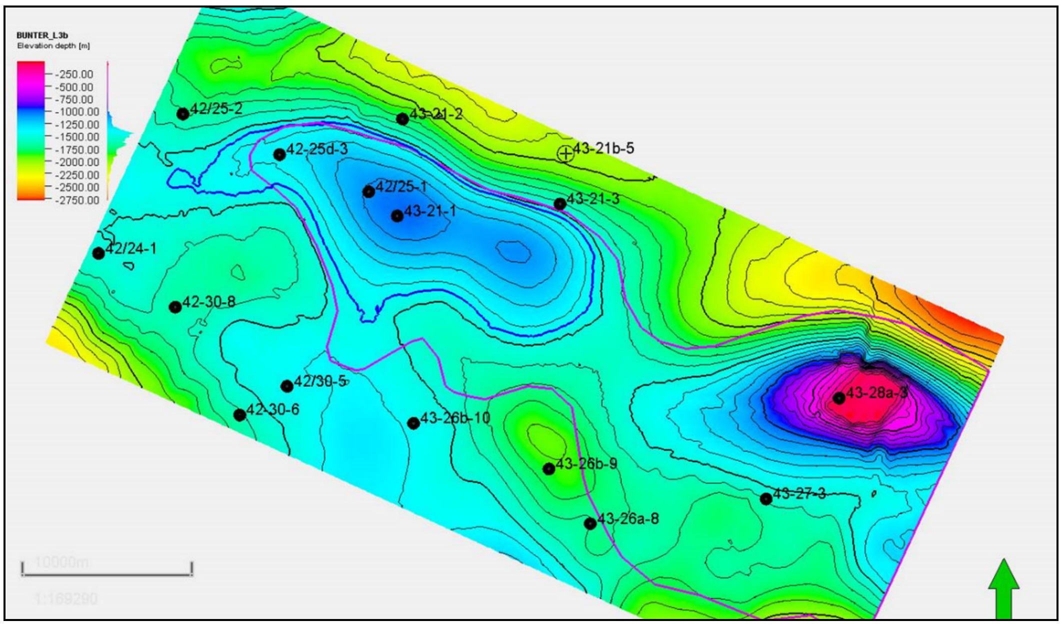
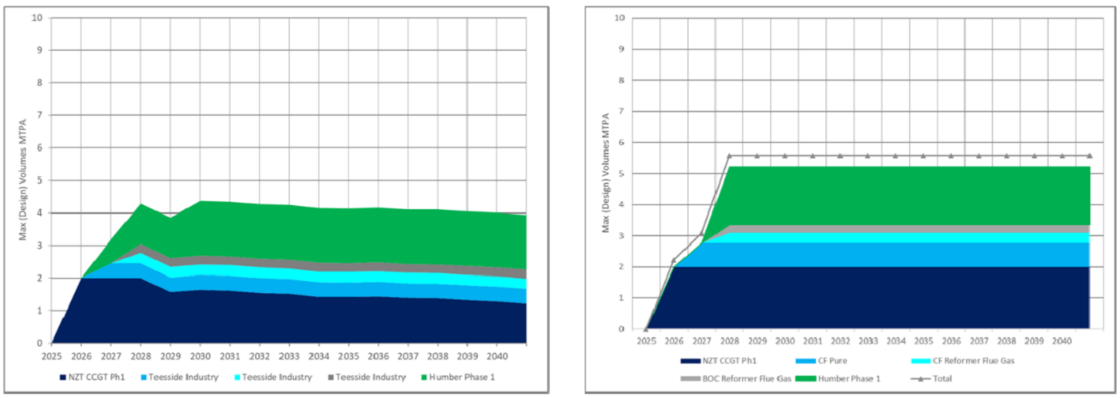


Figure 2 - Endurance structure and legacy wells drilled in the area

The Net Zero Teesside subsurface team has been carrying out due diligence on the store characterization throughout 2H 2019 to 3Q 2020 to assess capacity and integrity of the structure to support sequestration of CO2 captured from the Teesside and Humber industrial region and ensure that Phase 1 volumes can be stored within Endurance with high confidence.

2.2 Northern Endurance Partnership (NEP) Project Overview

Northern Endurance Partnership is an integrated Carbon Capture, Utilisation and Storage (CCUS) project based in the North East of England. It is being developed on its behalf of six by five companies; BP, Eni, Equinor, Shell, and Total and National Grid NV, the former oner of the licence., with BP leading as operator. The aim is to decarbonise two clusters of carbon-intensive businesses by as early as 2030 (power generation and industrial emissions). The project is sequenced with a first phase (referenced as phase 1) planned to start in 2026 with an average annual CO_2 injection rate of 4 MTPA (with peak value at 5.6 MTPA), as shown below in Figure 3.



Average Injection Rates

Peak injection rates (up to 5.6 MTPA)

Figure 3 – Northern Endurance Partnership Phase 1

The CCUS Project comprises both onshore and offshore elements, with a high-pressure CO_2 pipeline being utilized to transport the captured CO_2 to the Endurance storage offshore site with a capacity of circa 450-500 MT (base case estimation).

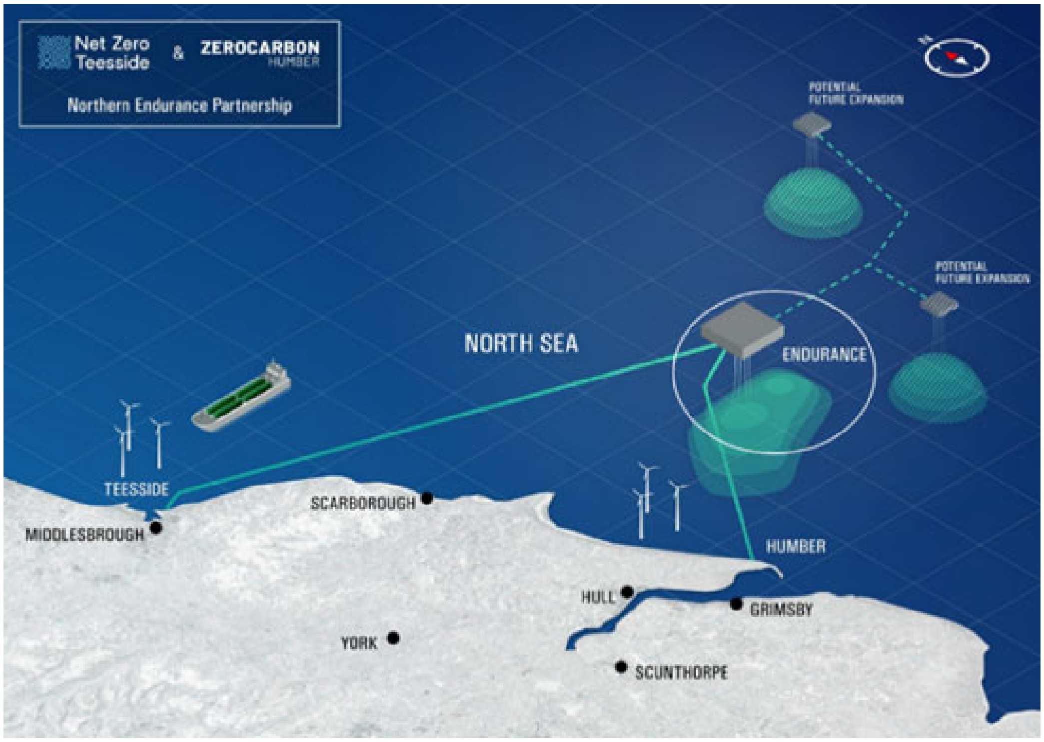


Figure 4 - Northern Endurance Partnership and Zero Teesside net zero cluster Transportation and Storage (T&S) overview

3.0 Development Plan Summary

Initially, Phase 1 considered four CO2 injection subsea wells (CI1, CI2, CI3, CI4), to deliver an initial capacity of 4 MTPA (3 MTPA average) over 25 years with one additional well CI5 in the crest to be utilized as an observation cum spare injection well. Exact well number and subsea vs. platform concept was finalized during the optimize phase with the additional of the CO2 volumes from the Humber cluster leading to the following:

- the addition of an additional injector leading to 5 injectors (plus one observation well) to accommodate up to 5.6 MMTPA peak (4 MTPA average)
- de-clustering of the subsea wells (subsea distributed) for Phase 1 to maximize pressure dissipation to mitigate against any potential sub-seismic baffling or compartmentalization and optimize the layout for future expansion (as shown above in Figure 5)

Expansion to 10 MTPA would require the addition of 5 CO2 injectors (1 MTPA per injector over field life and 6 brine producers (10 CO2 injectors (red)- and 8 brine producers(blue)) as shown in Figure 6.

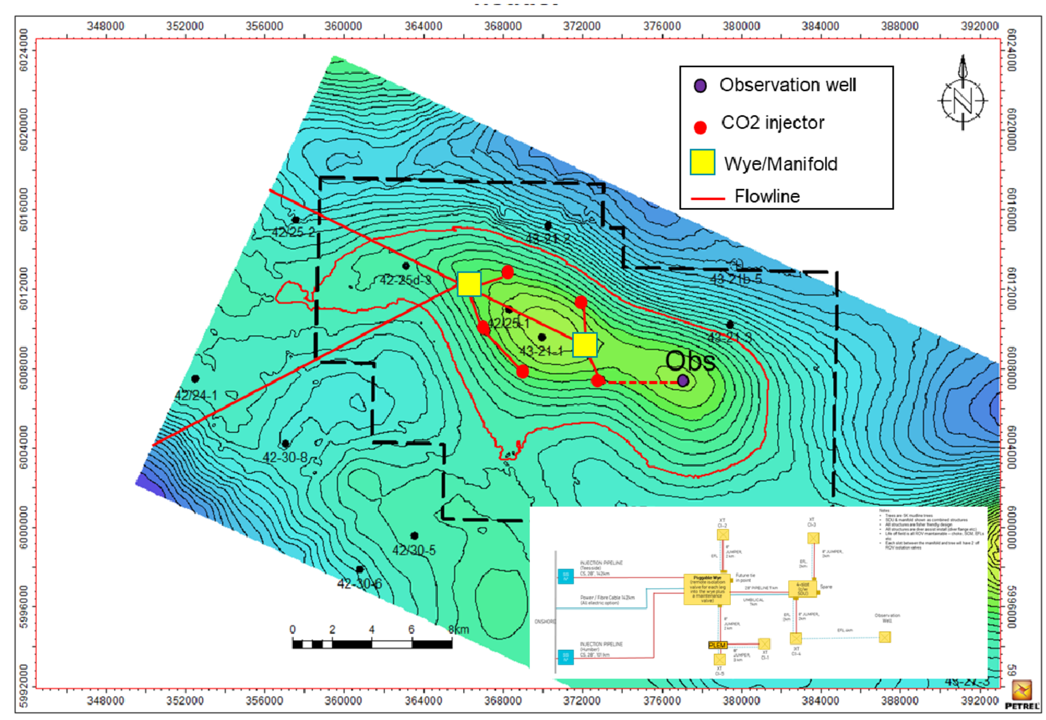


Figure 5 - Phase 1 development concept with single cluster (5 CO2 injectors and one monitoring well) - 4 MTPA

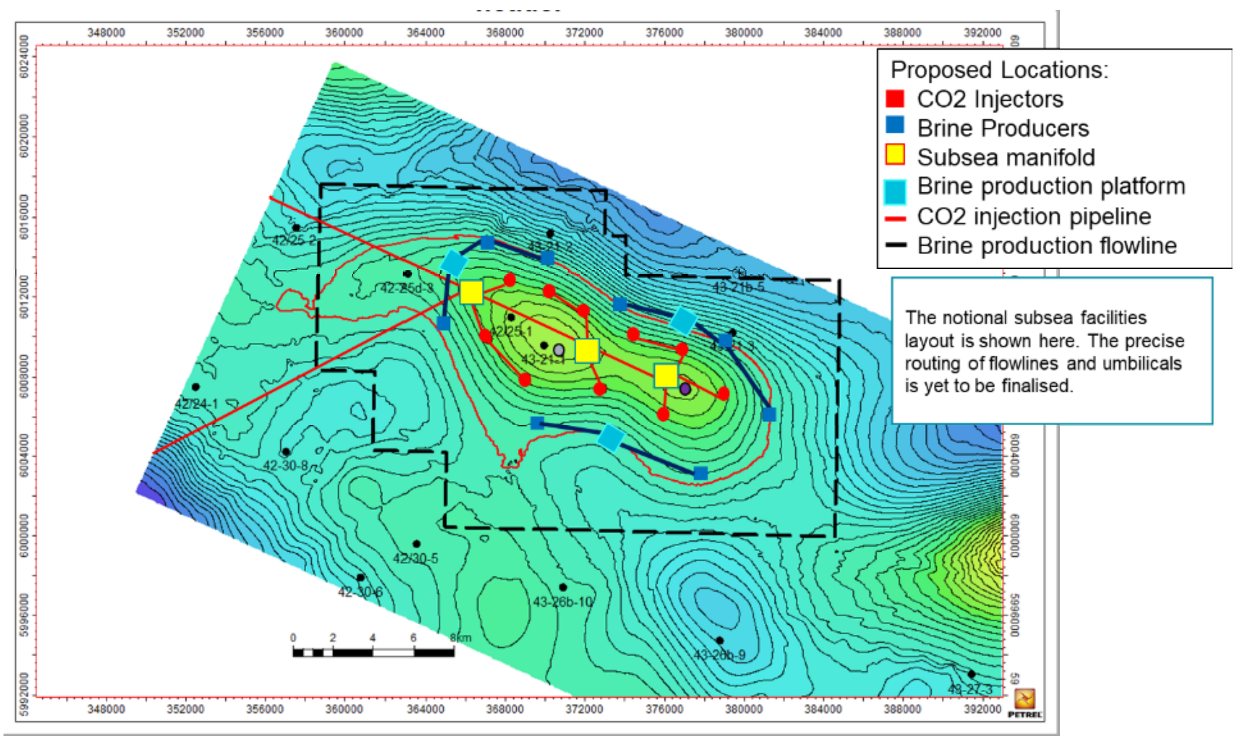


Figure 6 - Notional Development for Phase 2 and beyond for Net Zero Teesside over Endurance (10 MTPA with 10 injectors and 8 brine producers)

4.0 Description of the Reservoir Management Unit (Bunter Sandstone)

The Triassic-age Bunter sandstone was deposited in a broad, land-locked, and gradually subsiding basin situated between 20-30 degrees N of the Equator. The rivers and streams drained into the basin from surrounding highs in a semi-arid climate and terminated in a playa lake situated within the basin centre.

Table 1 - Bunter reservoir management unit for endurance

Parameter	Units	
Reservoir Rock		Sandstone
Reservoir Type		Fluvial- Aeolian Clastics
Reservoir Reference (Datum) Depth	mTVDss	1300
Initial Reservoir Pressure at Reference Depth	psi	2030
Spill Point	mTVDss	1450
Minimum Reservoir Pressure at Reference Depth	psia	2030 at 1300 m TVDss
Temperature at Reference Depth	°C	57

During drier periods, aeolian processes dominated, redistributing the sands and desiccating the mudstones leading to expected excellent lateral continuity (Figure 7). Bunter Sandstone Formation comprises several large-scale fining upwards units in which predominantly fluvial and aeolian sandstones fine upwards into siltstone and claystone alternations of the playa margin facies. Lower permeability facies such as clay-rich playa mudstones and playa margin flood plain siltstones, deposited during periods of low energy or lake expansion, are abundant in the Lower Bunter (L1). Coarser grained deposits are more common in the middle and upper parts of the Bunter Sandstone (L3 and L2). Key reservoir properties are summarized in Table 1 and Table 2.

Table 2 - Key reservoir properties for Bunter Reservoir in Endurance (within seismic phase reversal)

Formation Properties	Units		Comments
Permeability (P90-P50-P10)	mD	100-300-500	Expected range for any given well.
Permeability Directionality		horizontal	
Kv / Kh	Fraction	Macroscale: 0.04 (derived from DST in 42/25d-3), core scale ranging from 0.01 (heterolithics or cemented sand facies) to 10% (clean sand facies)	
Porosity (P90-P50-P10)	Fraction	0.164-0.225-0.241	Expected range for any given well.
Net-to-Gross (P90-P50-P10)	Fraction	0.74-0.94-0.97	Expected range for any given well.

A DST in 42/25d-3 has demonstrated good reservoir properties across the tested interval (20 meters tested out of 230 meters of reservoir gross thickness) with permeability around 290 mD and low Kv/KH (~0.4%) i.e. limited partial penetration effect due to extensive lateral barrier over instigated volumes (radius of investigation estimated of the order of 1.2 km).

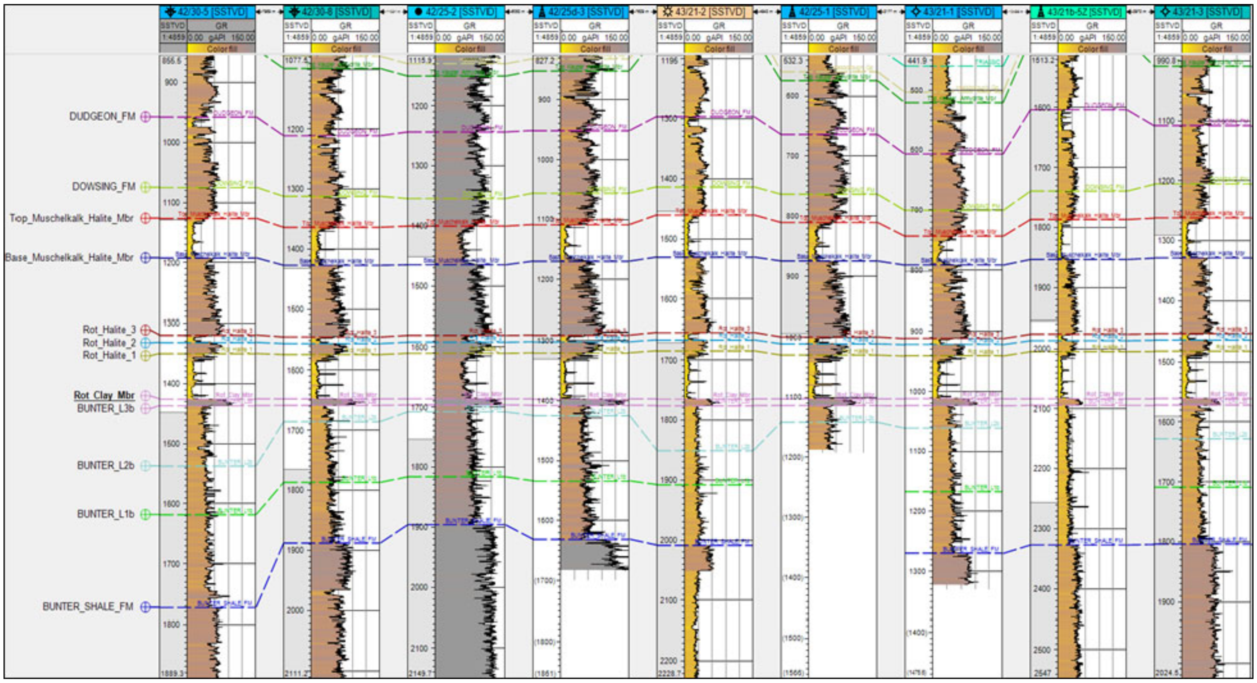


Figure 7 - Well correlation panel showing GR (0-150 API) in 9 wells around the Endurance structure

5.0 Reservoir Performance

5.1 Reservoir Fluids

Fluid characterization in Endurance currently assumes pure CO2 which is deemed to be appropriate for business decision at the pre-FEED (Front-End Engineering Design) project stage (<4% impurities). Additional work is expected as project matures further toward FEED to refine fluid model and evaluate the impact of impurities further (when the gas stream composition is better defined due to uncertainties around the emission sources i.e. industrial vs. power).

The work was conducted by bp's Fluid Expertise Group and led to a PVT (Pressure-Volume-Temperature) fluid model for use in the simulator:

- Development of a tuned Peng-Robinson equation of state (EoS) for pure CO2 for use in the Nexus® Full Field Model (FFM) run with the Landmark Graphics reservoir simulator Nexus®.
- Generate black-oil table (GAS-WATER model) for Nexus® reservoir simulation
- Generate Water Property table with saline water
    - Water properties without hydrocarbon solubility (black oil model) – used for uncertainty study
    - Water properties with hydrocarbon solubility (compositional model)
    - Calculate CO2-brine solubilities at reservoir condition
    - Salinity gradient

Gas-water PVT modelling (immiscible CO2 without solubility into brine) has been mainly used for the dynamic modelling of the CO2 injection into the reservoir model.

5.1.1 Brine

Endurance brine is hypersaline (circa 250,000 ppm %w) and presents a pH <7 as shown in Figure 8 and Figure 9. In-situ fluid samples were recovered from well 42/25d-3 (MDT samples and downhole/separator samples from Drill Stem Test). There is potentially an indication of a salinity vs. depth gradient from the 3 analyzed MDT samples which could explain the pressure difference observed between 42/25d-3 (drilled in 2013) and 42/25-1 (drilled in 1990).

	units	L1a	L2a	L3b		Röt Clay
Sample Reference		1.04	1.09	1.13	2.1	2.14
Sampling Point / Depth	ft	5167.5	4722	4634	Separator Water Line	4589.37
Physicochemical Parameters						
pH immediate @ 20.7 ± 1.2°C Initial		6.20	5.25	5.34	-	4.55
Resistivity @ 20°C	ohm.m	0.0461	0.0466	0.047	0.0466	0.0465
Density @ 20.00 ± 0.08°C	kg/L	1.1958	1.1881	1.1868	1.1976	1.1976
TDS - Measured @ 0.2 µm - By Mass	mg/kg	256146	247659	247730	259680	258925

Figure 8 - Physicochemical Parameters (pH, Resistivity, Density) and TDS from White Rose K40 report [1] courtesy of National Grid Carbon Limited.

The brine recovered at 42/25d-3 is close to saturation, estimated at circa 270,000 ppm %w at reservoir conditions (132.8 degrees F). The seismic phase reversal could be associated with limits when brine becomes over-saturated (250,000 ppm %w at 42/25d-3) as salinity increases with depth. Further MDT samples at various depths will be required for future wells to confirm observation made in well 42/25d-3.

When gas solubility is not activated in the model, the water table is as shown in Figure 9 (specifying a reference water density, water compressibility, water formation volume factor and water viscosity at reference pressure, temperature, water salinity):

```
! Endurance Brine Properties - Salinity = 250,000 mg/kg. Generated by RETooIkit, YL Sept. 2019
! Tres=132.8F
DENW        74.33 ! lb/ft3    ! Density of the stock tank brine with salinity of 250,000 mg/kg
CW       1.97E-06 ! 1/psia    ! Water compressibility @ reference reservoir pressure 2030psia
VISW         0.99 ! cp        ! Water viscosity @ reference reservoir pressure 2030psia
BW         1.0151 ! rb/stb    ! Water formation volume factor at initial datum pressure
PREF         2030 ! psia      ! Ref. pressure for water compressibility
```

Figure 9 - Endurance brine properties at reservoir conditions (CO2 solubility not included) [2]

TEMP 132.8 ! Tres=132.8F

SALINITY 250000 ! ppm, water salinity (meq/ml, ppm) =250,000 mg/kg
DENW 74.33 ! lbm/ft3, brine water density at standard conditions
SOLUBILITY
COMP CO2
UNITS STD

PSAT	RSW	BW	CW	VISW
! psia	SCF CO2/STB WATER	RB/STB	1/psia	cP
14.7	0	1.019756	2.19E-06	0.9462
1000	31.58	1.026452	2.11E-06	0.9507
2000	42.99	1.027674	2.02E-06	0.9553
3000	47.9	1.027674	1.93E-06	0.9599
4000	51.87	1.027674	1.85E-06	0.9644
5000	55.43	1.027674	1.76E-06	0.969
6000	58.74	1.027674	1.68E-06	0.9736
7000	61.89	1.027674	1.59E-06	0.9781
8000	64.91	1.027674	1.50E-06	0.9827
9000	67.83	1.027674	1.41E-06	0.9873
10000	70.68	1.027674	1.32E-06	0.9918

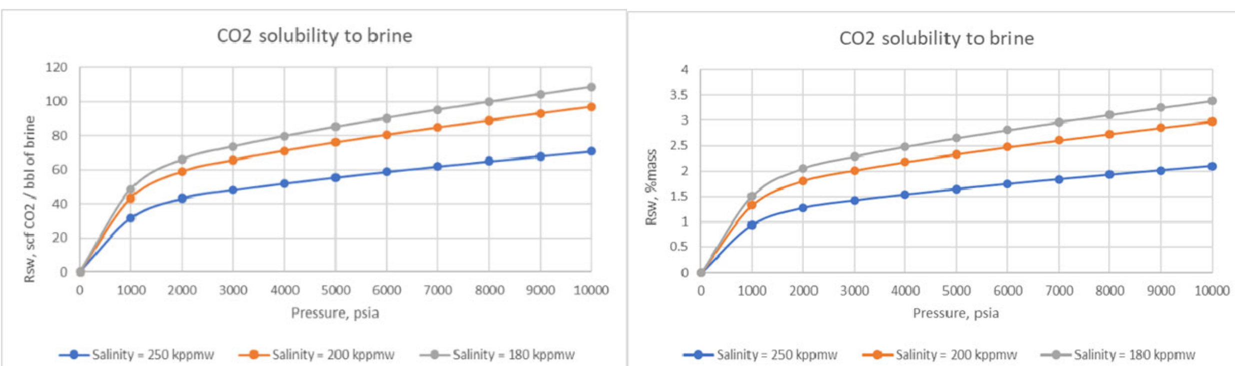


Figure 10 - Water PVT table when CO2 solubility into brine is activated for Endurance [2]

The solubility in the aqueous phase is solved by:

- Henry's Law (WinProp): The salinity of the aqueous phase is expressed as NaCl concentration. The brine salinity is used to adjust the internally estimated Henry's constants
- Aqueous flash with components of CO2/water/salts in vapor/liquid/aqueous phases, and the choice of mixing rule to account for polar component (PVTSim): mixing rule suggested by Huron and Vidal (H&V) (1979) is used for interactions of non-polar component with water and salts

CO_2 solubility in brine for Endurance is expected to be low due to the water salinity of circa 250,000 ppm %w (1-1.5% mass over pressurization range considered for the reservoir). Solubility of CO_2 into the brine is therefore not considered significant for consideration at this stage of the project (concept development). When gas solubility is considered – water table for compositional model is as follows (Figure 10).

5.1.2 CO2

Pure CO_2 is assumed to be an accurate representation of the injected CO_2 at this stage (similar to White Rose study assumptions [3]). In order to model appropriately the physical properties of the CO_2 in the reservoir, an equation of state PR78 (Peng Robinson EoS) was developed in Winprop™ (CMGTM) and compared against the NIST webbook and SRK EOS model.

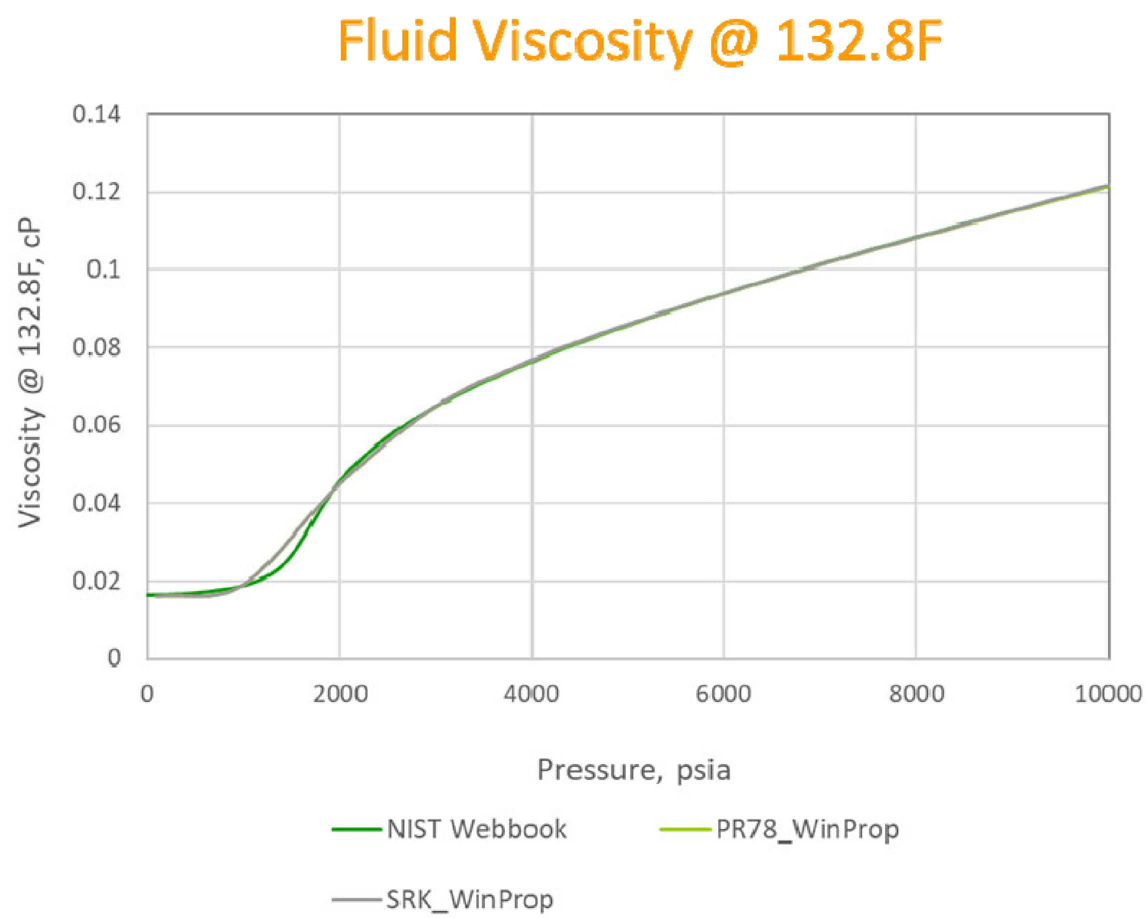
! Endurance Clean Gas Project: Pure CO2 EoS								
! 1-component EOS, developed by YL in 2019								
EOS	NHC	1						
	COMPONEI	CO2						
TEMP	132.8							
ENGLISH	FAHR							
EOSOPTIONS	PR							
LBC1	0.0977589							
LBC2	0.0228854							
LBC3	0.070239							
LBC4	-0.045784							
LBC5	0.009457							
PROPS								
COMPONENT	MOLWT	OMEGAA	OMEGAB	TC	PC	VC	ACENTR	VSHIFT
CO2	44.01	0.45723553	0.077796074	88.16000	1069.865	1.50574	0.225	-0.080
ENDPROPS								

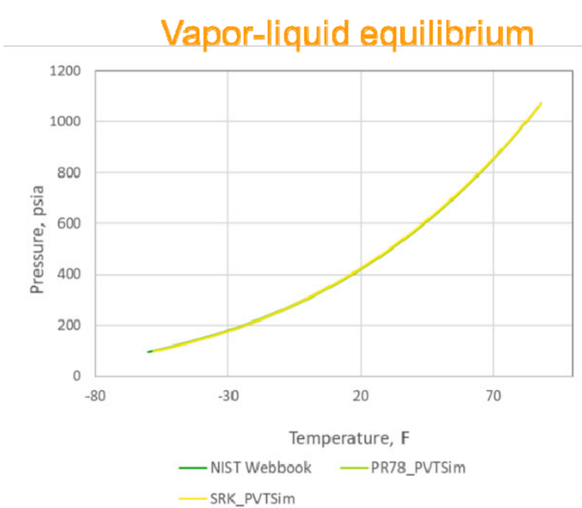
Figure 11 - Equation of State for pure CO2 generated for Endurance compositional reservoir model [2]

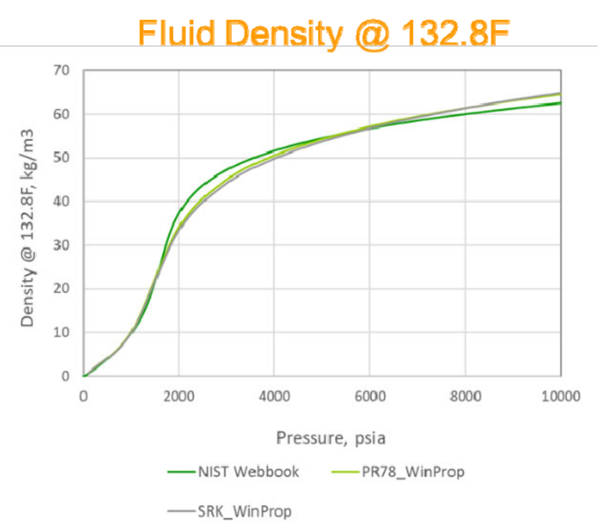
```
! Endurance Clean Gas Project: Pure CO2 Gas Table
!  Generated from 1-component EOS, developed by YL in 2019
GASWATER        SPECG       1.51943573  ! Specifies the gas specific gravity

GAS
PRES            BG          VG
! Psia          RVB/MCF     CP
     9000         0.3278      0.1145
     8500         0.3319      0.1113
     8000         0.3364      0.1080
     7500         0.3414      0.1047
     7000         0.3469      0.1013
     6500         0.3532      0.0978
     6000         0.3604      0.0942
     5500         0.3687      0.0904
     5000         0.3786      0.0864
     4500         0.3904      0.0822
     4000         0.4052      0.0775
     3500         0.4245      0.0723
     3000         0.4515      0.0662
     2500         0.4940      0.0585
     2000         0.5798      0.0474
     1500         0.9108      0.0290
     1000         2.0095      0.0191
      500         5.0731      0.0168
     14.7       202.1580      0.0160
```

Figure 12 - Modelling CO2 using PR78 - Gas Table for Gas-water system

The generated Equation Of State (EoS) was implemented in Nexus® (Figure 11 and Figure 13) and used to generate the gas-water table as shown in Figure 12.


Fluid Viscosity @ 132.8F
Viscosity @ 132.8F, cP
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
0
2000
4000
6000
8000
10000
Pressure, psia
NIST Webbook
PR78_WinProp
SRK_WinProp


Vapor-liquid equilibrium
Pressure, psia
1200
1000
800
600
400
200
0
-80
-30
20
70
Temperature, F
NIST Webbook
PR78_PVTSim
SRK_PVTSim


Fluid Density @ 132.8F
Density @ 132.8F, kg/m3
70
60
50
40
30
20
10
0
0
2000
4000
6000
8000
10000
Pressure, psia
NIST Webbook
PR78_WinProp
SRK_WinProp

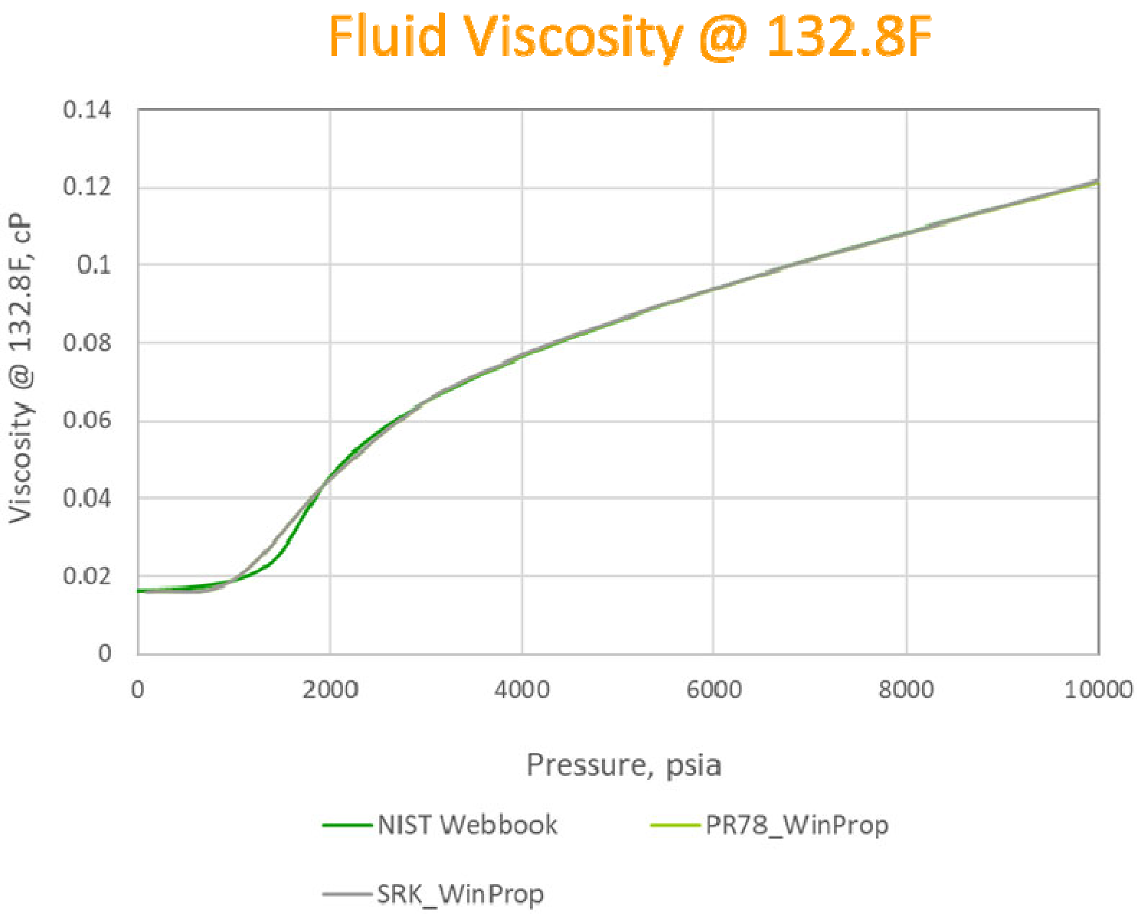


Figure 13 - Comparison between various PVT models for pure CO2 (Peng Robinson, SRK, and data from the NIST Webbook)

5.2 Initial Reservoir Pressure and Temperature

MDT and Repeat Formation Tester pressures taken respectively in 42/25d-3 and in the appraisal crestal well 42/25-1, are plotted below. Reservoir pressure of Endurance is assumed to be 140 bars and 56 degrees C (132.8 deg F) at datum of 1300 m TVDss. The decrease in reservoir pressure, of the order of 0.7 bar (10 psia) at 1300 m TVDSS, is seen between the two fitted trendlines. The White Rose study (K41) [3] suggested that this reduction in pressure is due to expansion in the Greater Bunter Sandstone Formation to fill the void created by gas production from some of the Bunter hydrocarbon gas fields (the Esmond Complex), 50 km north of Endurance. This interpretation would suggest that Endurance is in pressure communication with a large, connected volume.

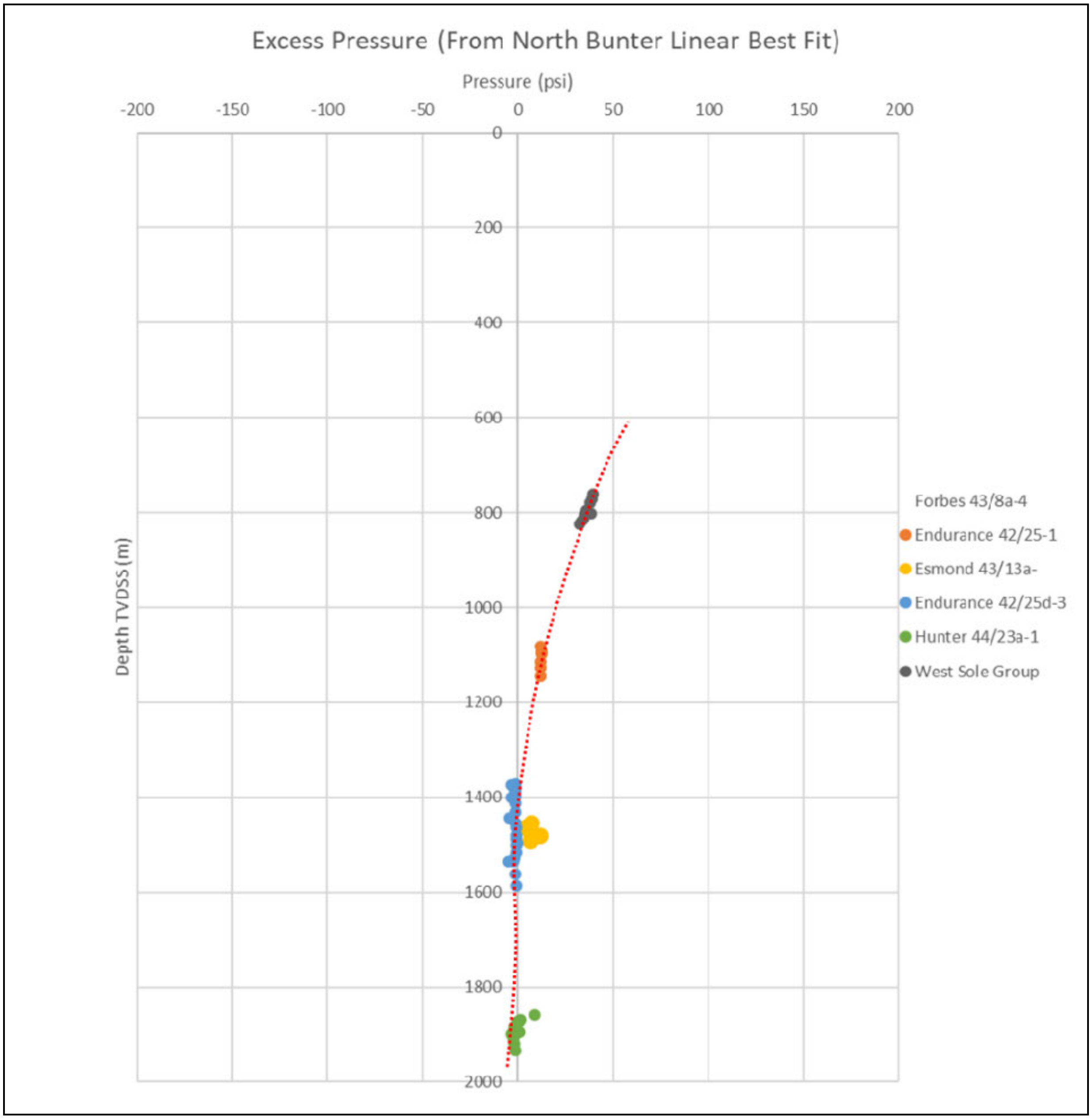


Figure 14 - Regional pressure data for Bunter sandstone

Plotted in terms of excess pressure (relative to pressure gradient observed at Endurance 42/25d-3) suggesting potential salinity gradient across basin. Hunter and West Sole pressure and fluid data would support a regional salinity gradient with depth.

However, this interpretation has been questioned by latest review of the data. Brine salinity data from 42/25d-3 would indicate that there is a significant salinity gradient across the brine column. The former could explain the pressure differential between the two wells (Figure 14) in its own. Interference testing has also been carried out to see what depletion could be expected at Endurance 20 years after the cessation of production in Esmond 50 km away (of the order of 1 psia) as shown in Figure 16. Temperature across the column could also explain some of the difference as shown in Figure 15 and Figure 18.

There is also a third reason that could be attributed for the pressure difference: Intra-reservoir baffling from cemented layers or faulting could cause pressure difference. However, no faulting has been observed at the reservoir level and formation pressure across well 42/25d-3 does not suggest any vertical baffling (absence of pressure break). Cemented layers are not expected to be laterally continuous. This is the least preferred option and appears unlikely.

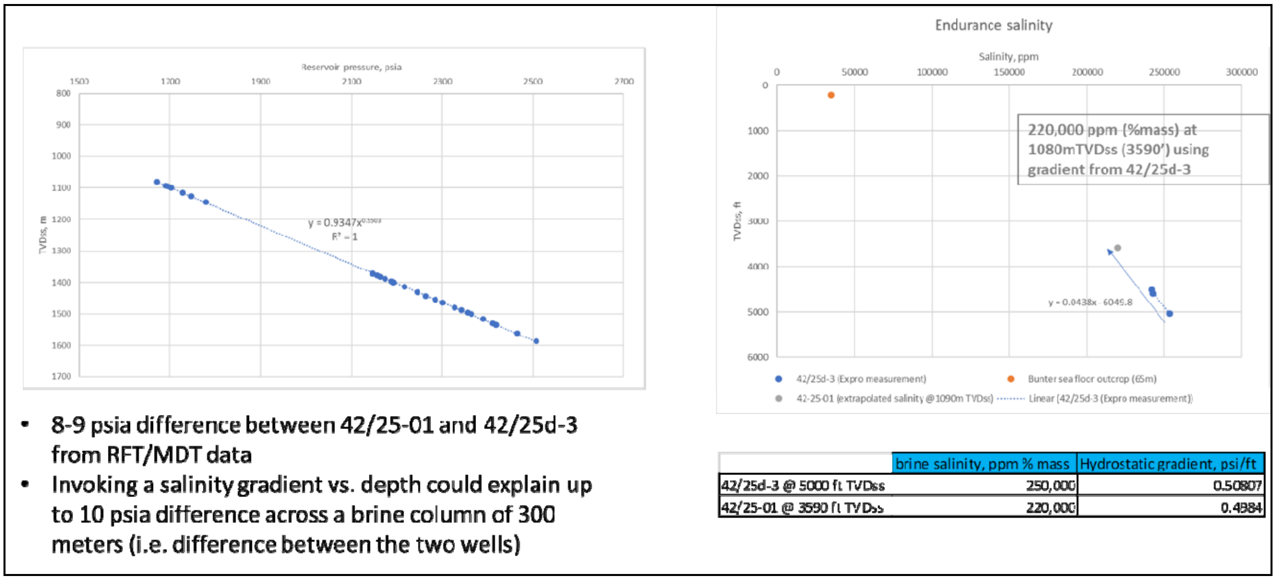


Figure 15 - Salinity and pressure for Endurance

Salinity gradient with depth inferred at 42/25d-3 could explain the pressure difference when linear gradient is invoked. A non-linear pressure gradient with depth (e.g. a power law) would be more appropriate to model decreasing salinity toward shallower depths.

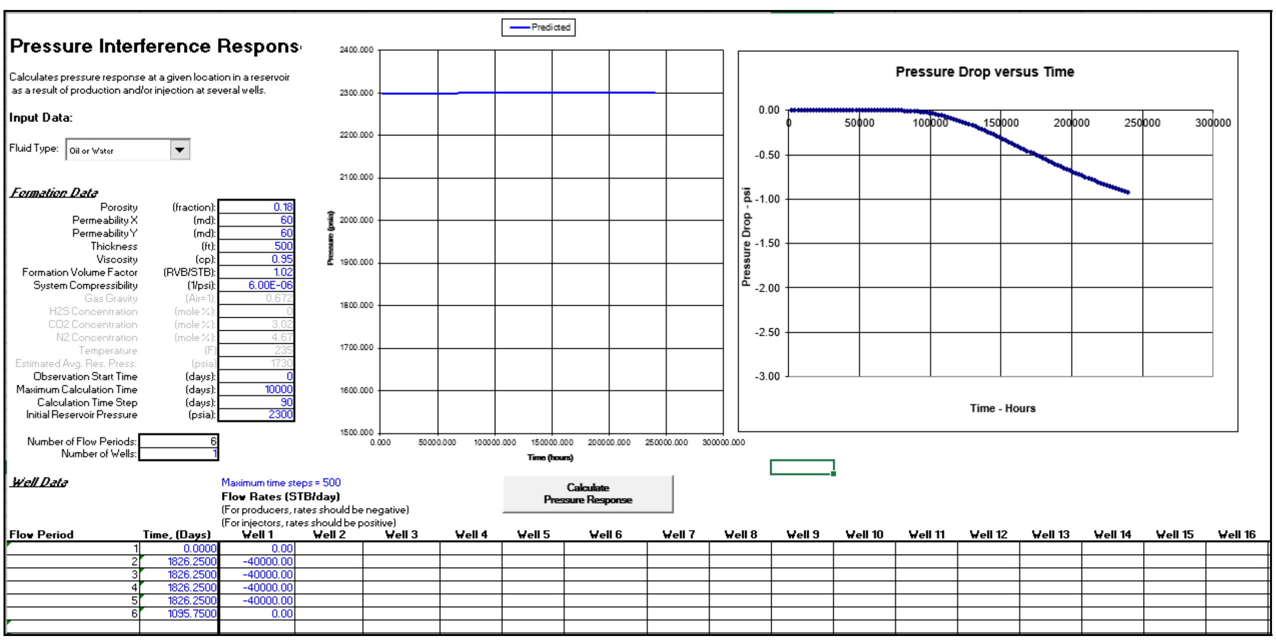
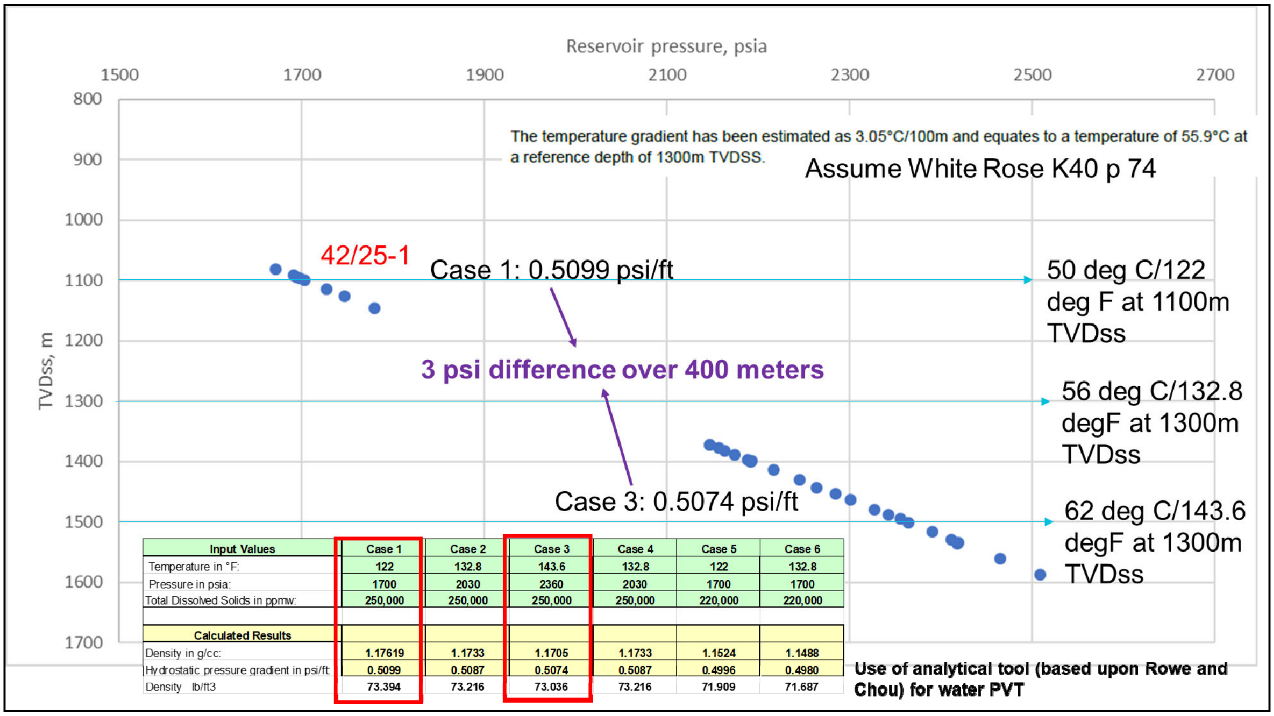


Figure 16 - Single-phase interference test between Esmond and Endurance

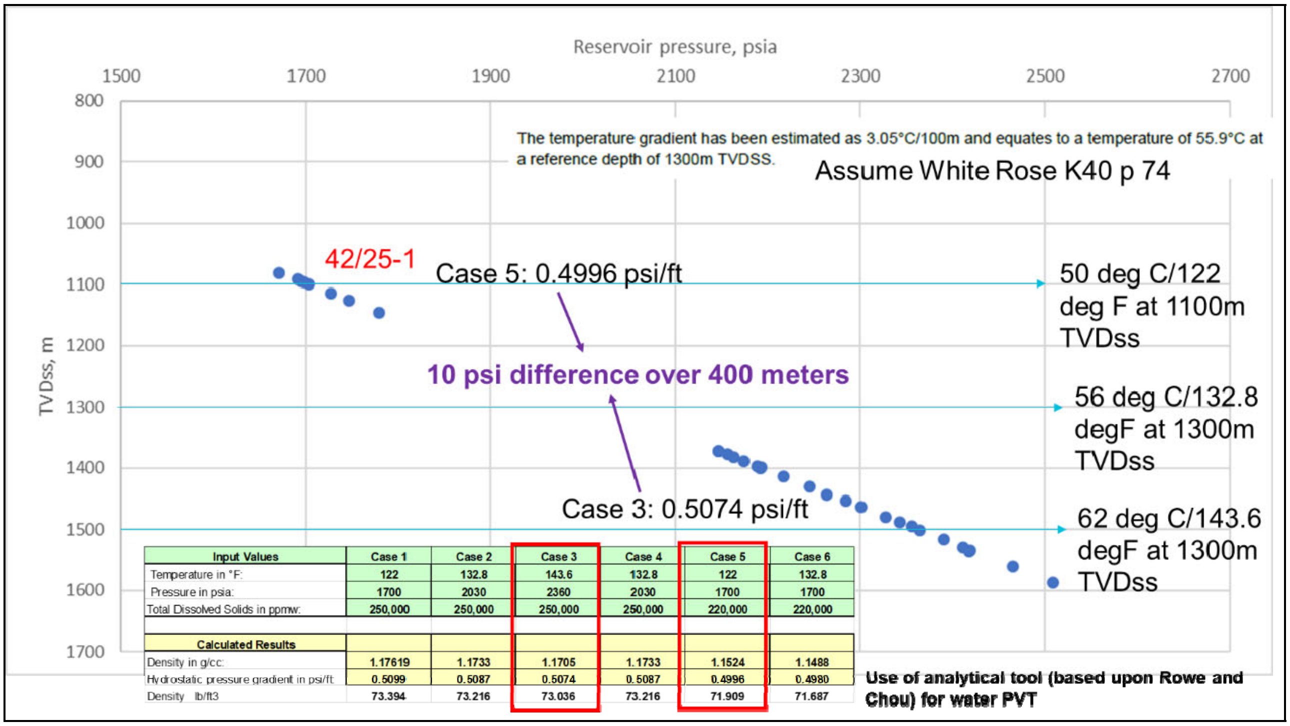
Assuming a water influx of circa 300 million reservoir barrels into gas leg and Endurance indicating that circa 1 psia difference could have been seen between 1990 and 2013. It does not include depletion from Forbes or other Bunter gas fields or heterogeneities across the sub-regional basin.

At this stage, it is not possible to demonstrate with reasonable certainty that the difference between 42/25-1 and 42/25d-3 was caused by depletion from Esmond over time (not conclusive as any depletion from Esmond may be smeared by salinity and temperature effects). Future data acquisition in Phase 1 wells (formation water sample and reservoir pressure from formation tester tool), is required to refine the understanding of salinity vs. depth gradient, connectivity, and its impact of pressure gradient and potential depletion. For instance, measured reservoir pressure by the time of drilling in 2025 for instance could indicate further depletion (greater than 10 psia compared to pressures in 1990 in 42/25-1) as basin-wide re-equilibrium might continue and help rule out effect of salinity across the column.



Input Values	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Temperature in °F:	122	132.8	143.6	132.8	122	132.8
Pressure in psia:	1700	2030	2360	2030	1700	1700
Total Dissolved Solids in ppmw:	250,000	250,000	250,000	250,000	220,000	220,000
Calculated Results						
Density in g/cc:	1.17619	1.1733	1.1705	1.1733	1.1524	1.1488
Hydrostatic pressure gradient in psi/ft	0.5099	0.5087	0.5074	0.5087	0.4996	0.4980
Density lb/ft3	73.394	73.216	73.036	73.216	71.909	71.687

Figure 17 - Impact of temperature across the column for water with constant salinity



Input Values	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
Temperature in °F:	122	132.8	143.6	132.8	122	132.8
Pressure in psia:	1700	2030	2360	2030	1700	1700
Total Dissolved Solids in ppmw:	250,000	250,000	250,000	250,000	220,000	220,000
Calculated Results						
Density in g/cc:	1.17619	1.1733	1.1705	1.1733	1.1524	1.1488
Hydrostatic pressure gradient in psi/ft	0.5099	0.5087	0.5074	0.5087	0.4996	0.4980
Density lb/ft3	73.394	73.216	73.036	73.216	71.909	71.687

Figure 18 - Impact of temperature across the column for water with variable salinity

Pressure gradients were also investigated across the entire column up to seabed should the Bunter outcrop 20 km east of Endurance be in hydraulic communication with Endurance as shown in Figure 19 and Figure 20. Analysis would suggest a column of at least 250 to 300 meters (from seabed) of brine with salinity similar to seawater at the outcrop chimney.

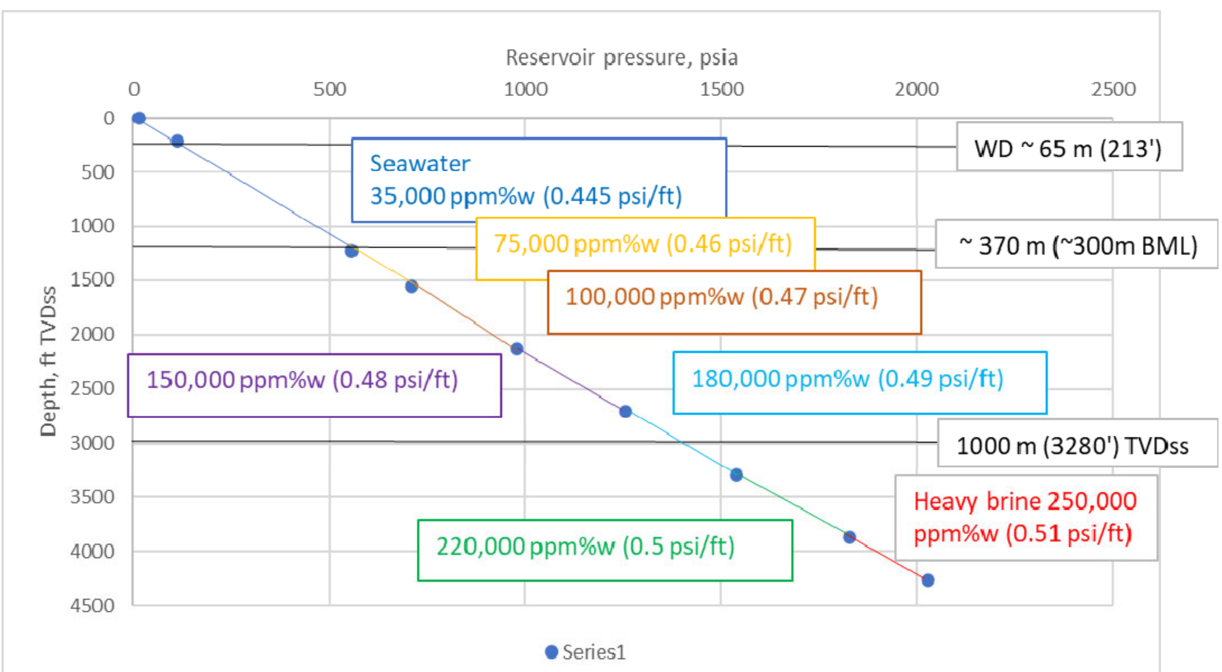


Figure 19 – Pressure profile with variable salinity gradient with depth (non-unique)

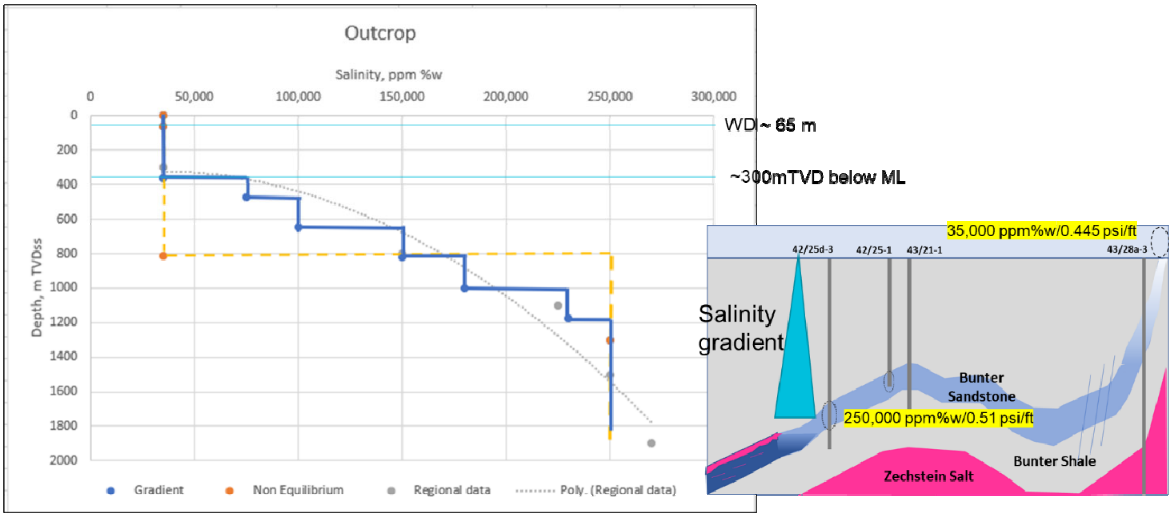


Figure 20 – Salinity vs. depth potential gradient inferred from matching pressure at Endurance and fluid gradients

5.3 Reservoir Energy

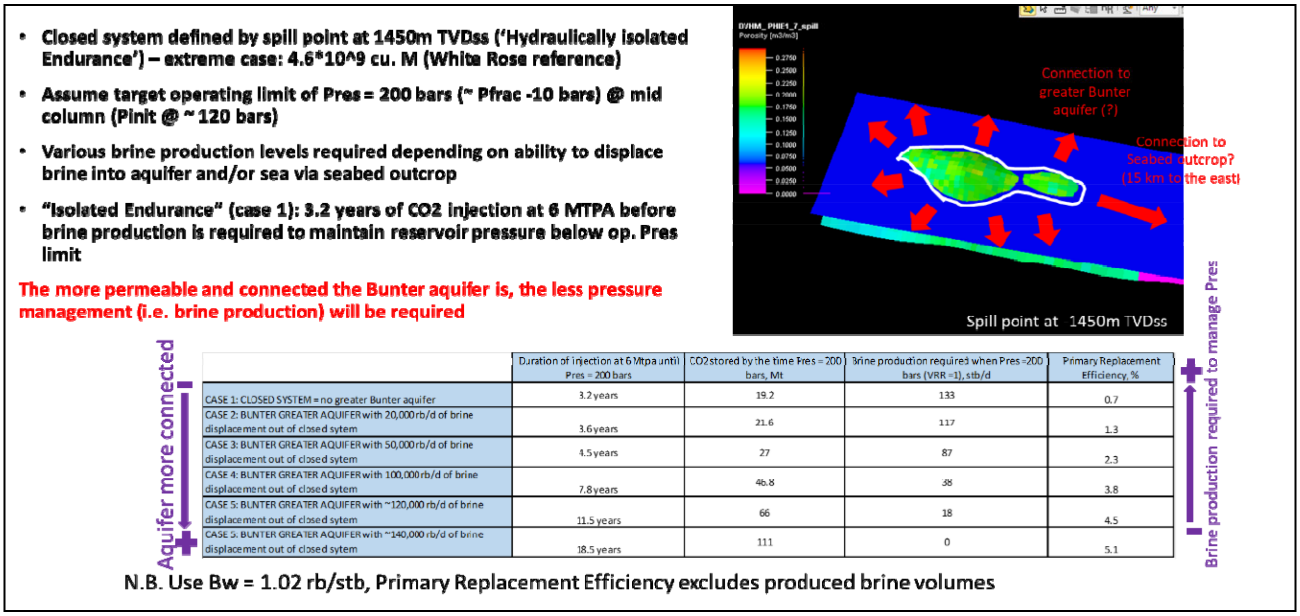
5.3.1 Water Expansion

Water compressibility is estimated to be around 2*10-6 psi-1 as shown in Figure 9.

5.3.2 Rock Compressibility

Rock compressibility of Endurance is assumed to be 4*10-6 psi-1 (5.6*10-5 bar-1) similar to White Rose assumptions [3]. No pore volume vs. net confining stress experiment has been conducted to measure pore volume compressibility at reservoir conditions (staircase experiment to estimate Cpv). Measurement of static Young's modulus by FracTec on 42/25d-3 (E=1,800,000 psi) core would indicate a consolidated sandstone: rock compressibility of the order of 4 microsips appears therefore consistent with industry correlation such as Eaton for range or porosities (18-20%). Further core measurement could be carried out in the future to refine assumptions. Literature would indicate rock compressibility for the Bunter sandstone in the area of the order of 4 to 6*10^-5 bar -1 (Bentham et al5). This range appears to be consistent with pore volume compressibility data from Bunter core in well 44/23-3 & 44/23-5.

5.3.3 Aquifer Connectivity



	Duration of injection at 6 Mtpa until Pres = 200 bars	CO2 stored by the time Pres = 200 bars, Mt	Brine production required when Pres =200 bars (VRR =1), stb/d	Primary Replacement Efficiency, %
CASE 1: CLOSED SYSTEM = no greater Bunter aquifer	3.2 years	19.2	133	0.7
CASE 2: BUNTER GREATER AQUIFER with 20,000 rb/d of brine displacement out of closed sytem	3.6 years	21.6	117	1.3
CASE 3: BUNTER GREATER AQUIFER with 50,000 rb/d of brine displacement out of closed sytem	4.5 years	27	87	2.3
CASE 4: BUNTER GREATER AQUIFER with 100,000 rb/d of brine displacement out of closed sytem	7.8 years	46.8	38	3.8
CASE 5: BUNTER GREATER AQUIFER with ~120,000 rb/d of brine displacement out of closed sytem	11.5 years	66	18	4.5
CASE 5: BUNTER GREATER AQUIFER with ~140,000 rb/d of brine displacement out of closed sytem	18.5 years	111	0	5.1

Figure 21 - Endurance schematic connectivity to the Greater Bunter aquifer

The injection of dense phase CO2 into the reservoir will lead to the pressurization of the formation as the system is poorly compressible (i.e. 2*10-6 psi-1 for brine and 4*10-6 psi-1 for rock). The rate of pressurization will therefore depend on the ability of displacing the brine outside of the spill point volume (for instance considering the base case volume from White Rose study of circa 4.6 billion of cubic meters above spill point at 1450m TVDss), as shown in Figure 21.

Offset wells around the 4-way closure would indicate reasonable rock properties outside of the seismic phase reversal across the middle Bunter despite potential diffuse cementation as shown in Figure 22 . Reservoir lateral and vertical variability has been modelled in the full-field model to accurately model this variability.

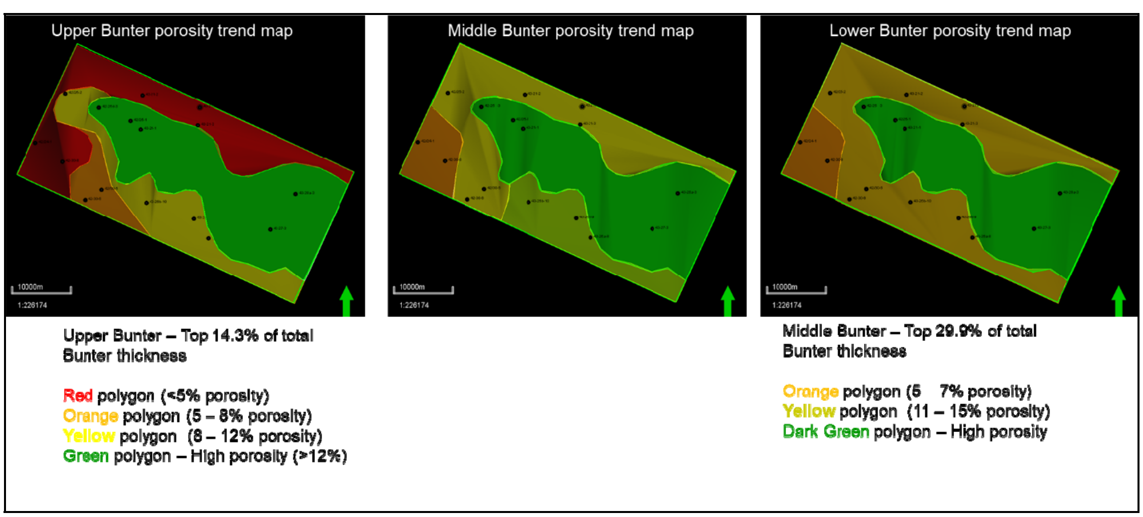


Figure 22 - Porosity trends from offset wells around Endurance structure

Green zone represents the area within the seismic phase reversal in which porosities are not affected by cementation.

Residual uncertainty remains in the terms of near permeability for the aquifer outside of the seismic phase reversal as there are no cored wells to refine log-derived property modelling. The use of existing porosity-permeability transform (fitted against core data from wells 42/25-1 and 42/25d-3) would suggest permeabilities of the order of 30-50 mD for the middle Bunter reservoir outside of the seismic phase reversal (compared to 200 mD in average for the volumes inside the seismic phase reversal (Figure 23).

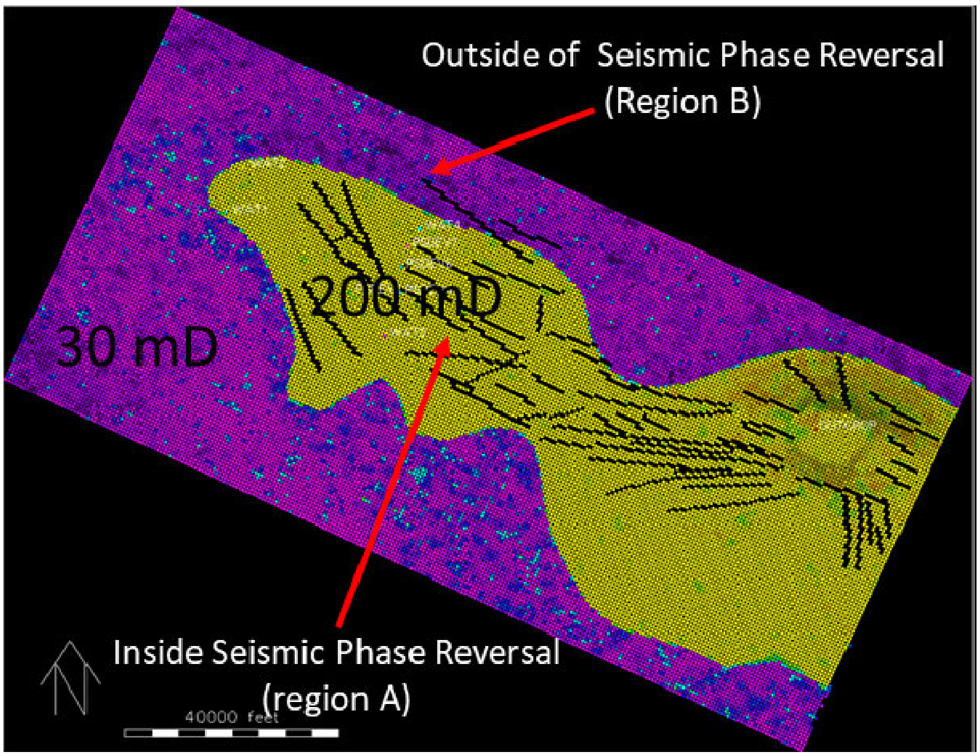


Figure 23 - Overview of reservoir quality outside and inside the seismic phase reversal with overprint of possible fault across the structure

Connectivity to the broader Bunter basin is at present unknown and the uncertainty has been factored by considering several scenarios in terms of connected volumes (Figure 24). A behaviour similar to Esmond performance (Bentham et al [5]) would lead to connected volumes corresponding to a radius of 20 to 30 km. The Net Zero Teesside team has investigated the Esmond reservoir performance data and came up with similar interpretation as shown in Figure 25 and Figure 26 from material balance. The pressurization back to 120 bars observed by the Encore Oil and Gas well in 2008 (from abandonment pressure of 10 bars in 1995) can be explained by a large, connected aquifer around Esmond (radius of 20-30 km and average permeability of 20-25 mD).

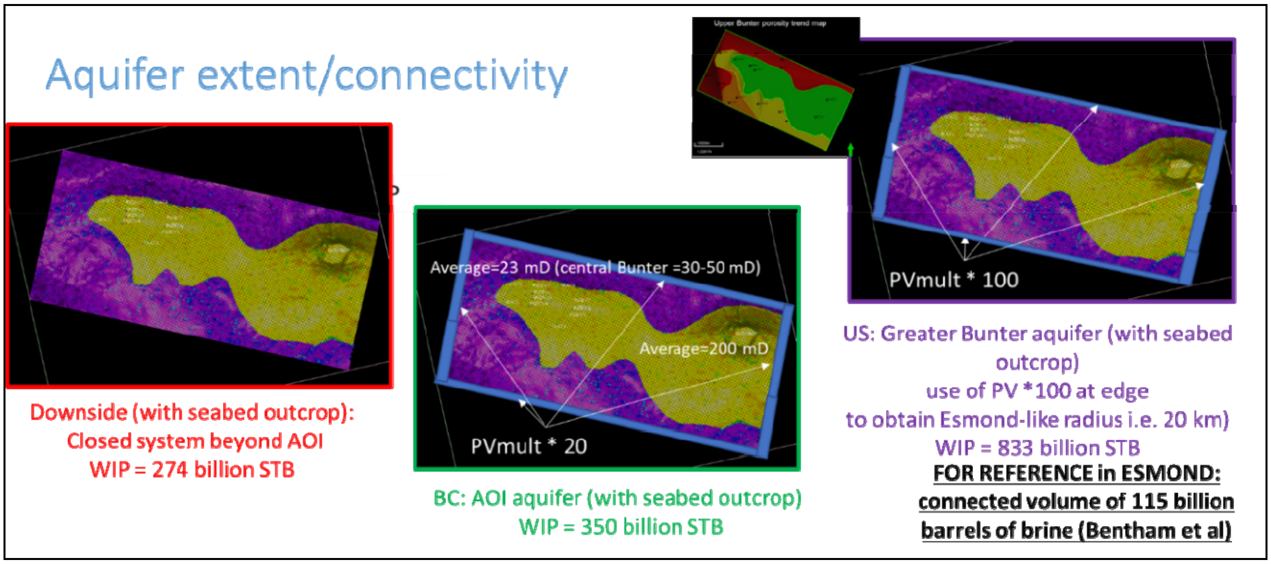


Figure 24 - Discrete connectivity scenarios for Endurance considered for simulation

CO2 injection of Phase 1 volumes will be required to assess broader connectivity to the Bunter sands across the area and confirm long-distance connectivity. At present there is not enough certainty that connectivity around Endurance will be as good as that demonstrated at Esmond (represented by upside case with pore volume multiplier of 100). The reference case for Endurance reservoir model assumes a reduced area (pore volume multipliers of 20 corresponding to 4 km). The downside scenario for Endurance would consider only the area of interest of the model, which still constitutes nearly 300 billion barrels of brine.

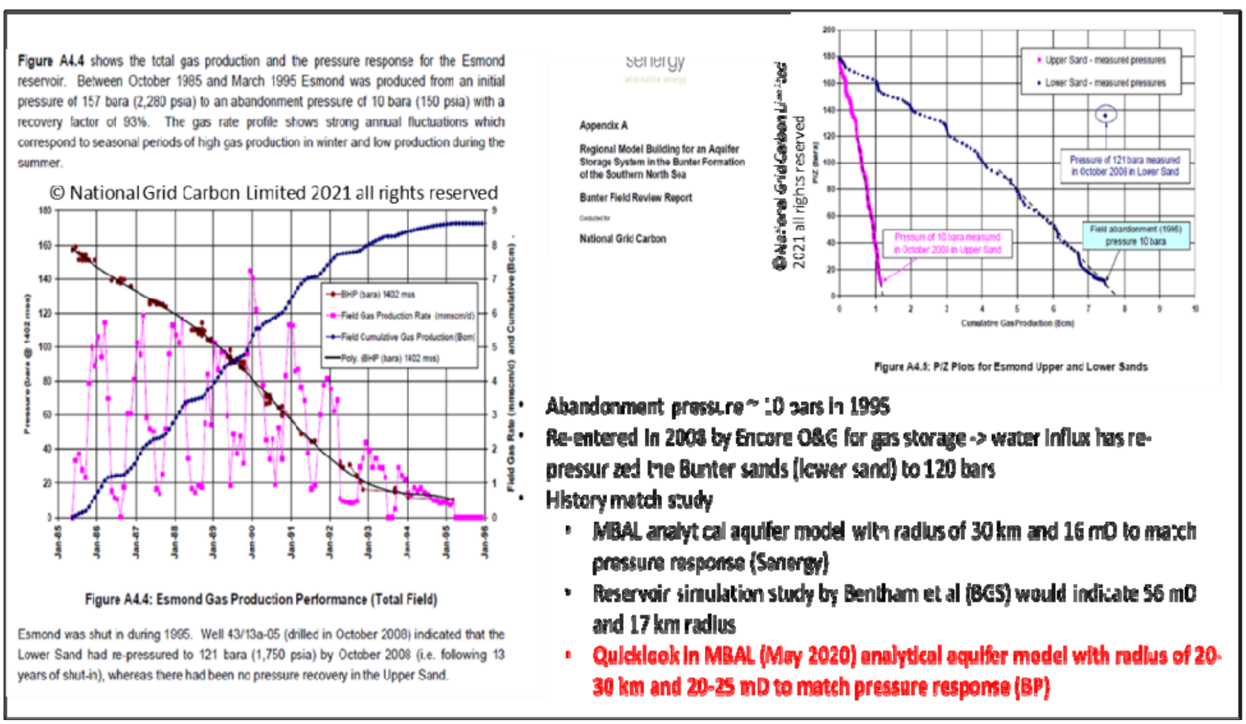


Figure 25 - Overview of Esmond reservoir performance

(Figures from White Rose study courtesy of National Grid Carbon Limited, and bp comparison)

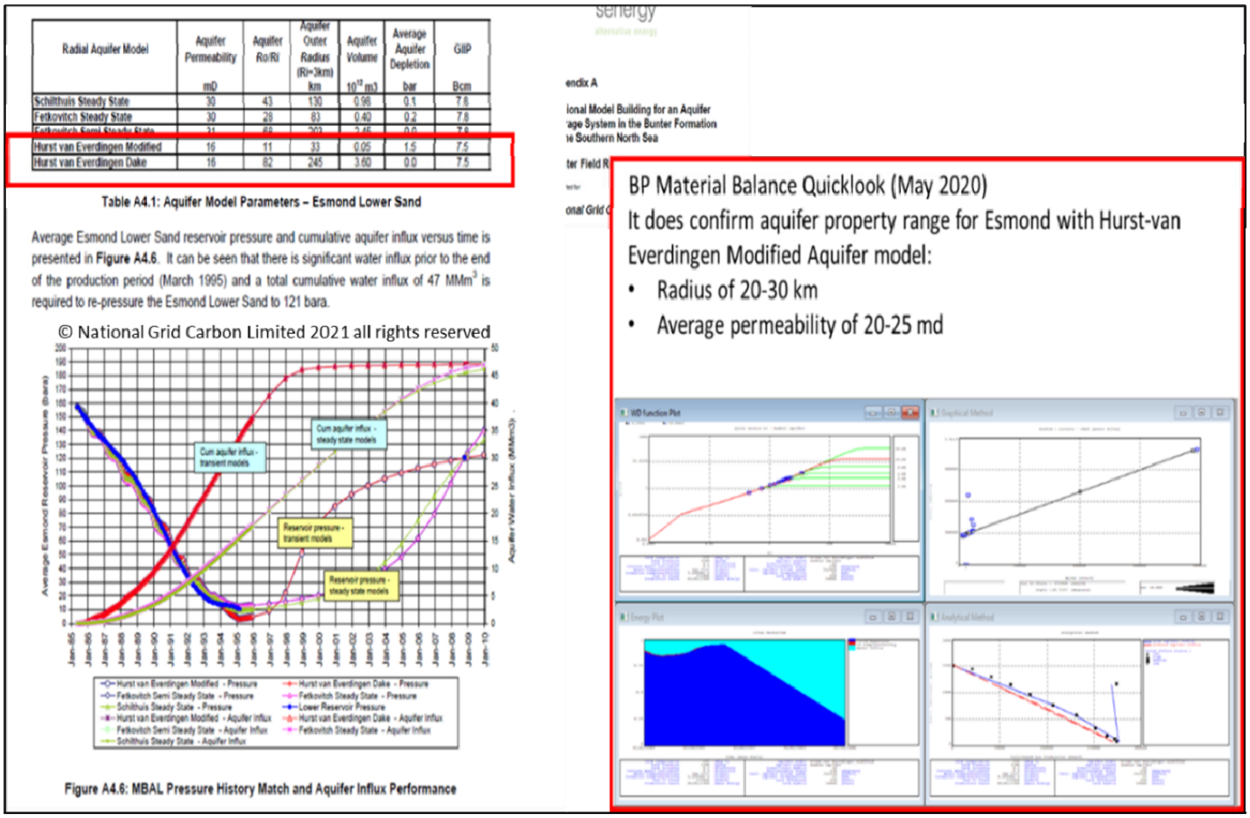


Figure 26 - Material Balance studies to assess aquifer strength around Esmond

White Rose Study courtesy of National Grid Carbon Limited (left) and bp (right)

A series of uncertainty workflows (Monte Carlo in TDRM™) was considered to generate model ensemble and test development scenario robustness against these three aquifer connectivity scenarios.

The use of pore volume multipliers has been compared with the use of analytical aquifer i.e. Carter-Tracy as shown in Figure 27. To account for the poorer rock quality in the west, a dual set of Carter-Tracy models have been utilised with a smaller, poor-quality western aquifer connected to the far western side of the grid whereas a more extensive and good-quality aquifer being connected to the eastern side of the grid.

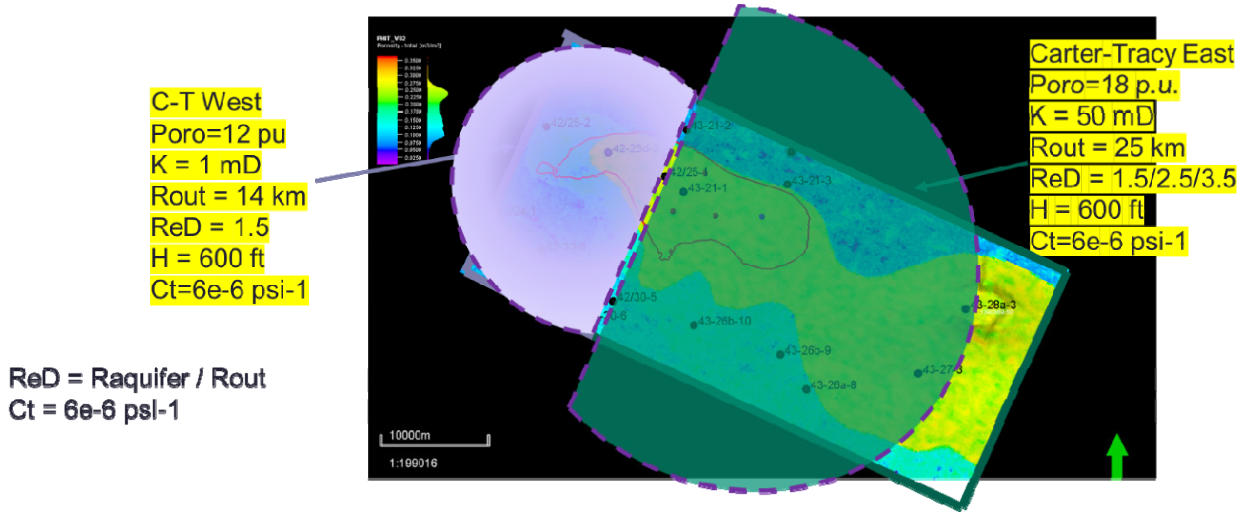


Figure 27 – Use of analytical Carter-Tracy aquifer model at the edge of the full-field model for comparison with pore volume multipliers.

A set of pore volume multiplier of 40 applied to the edge of the model has found to be equivalent to the eastern aquifer analytical model with a ReD of 1.5 whereas the upside case with pore volume multiplier of 100 presents a pressure response similar to ReD of 2.5 and 3.5 (Figure 28).

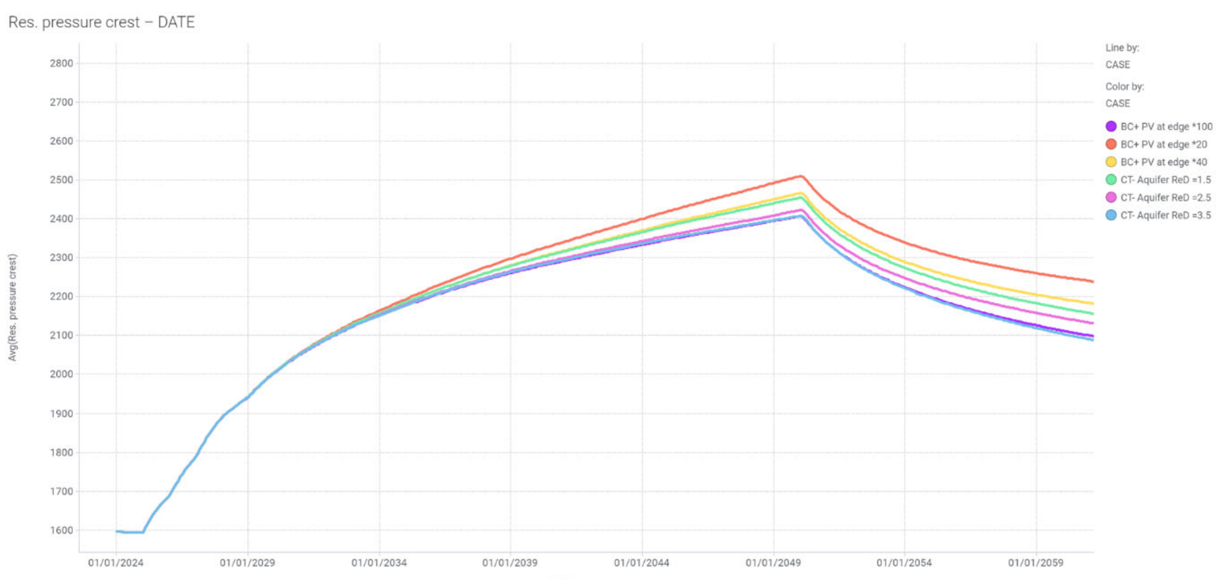


Figure 28: Crestal reservoir pressure for a 4 MTPA injection for various aquifer models.

5.4 Displacement Efficiency

A series of conventional and SCAL measurements were carried out on 42/25d-3 core at East Grinstead (RCA) and Winfrith (SCAL) by Weatherford Laboratories, including a series of unsteady state core flood with CO2 displacing brine under reservoir conditions and counter-current imbibition (trapped gas saturation), as shown in Figure 29.

A series of gas (CO2) – water relative permeability models (downside/base/upside) were generated to explore a range of uncertainties demonstrated by the SCAL data from Endurance (Figure 30):

- Krg endpoint (downside/base/upside): 0.7-0.7- 0.9
- Corey exponents: Nw: 3 – 4 – 6, Ng 1.8 – 2.5 – 3.5 (from SCAL CO2-brine flood results)

The reference permeability in the reservoir model for water saturation at 100% was assumed to be the brine permeability (kw) as the model has been calibrated to match interpreted well test permeability from pressure build-up in well 42/25d-3 (single-phase brine production test)

Swrg (residual water saturation) is relatively closely defined by the capillary pressure data (range of ~0.1 – 0.2 from Pc curves) and by observations of water saturation in analogous gas reservoirs. An observed “downside” value of 0.5 is derived from the endpoint reached during SCAL experiments. Although krw was definitely low by the time at which the experiments were terminated, there was in fact no indication that it was about to tend to zero. Forces such as gravity acting over timescales of years might be able to cause drainage beyond that point. The CO2 injection process is therefore modelled using the correct ultimate Swr (~0.1 – 0.2) with the krw curves extrapolated downwards from the SCAL curves, and with the measured capillary pressure curves.

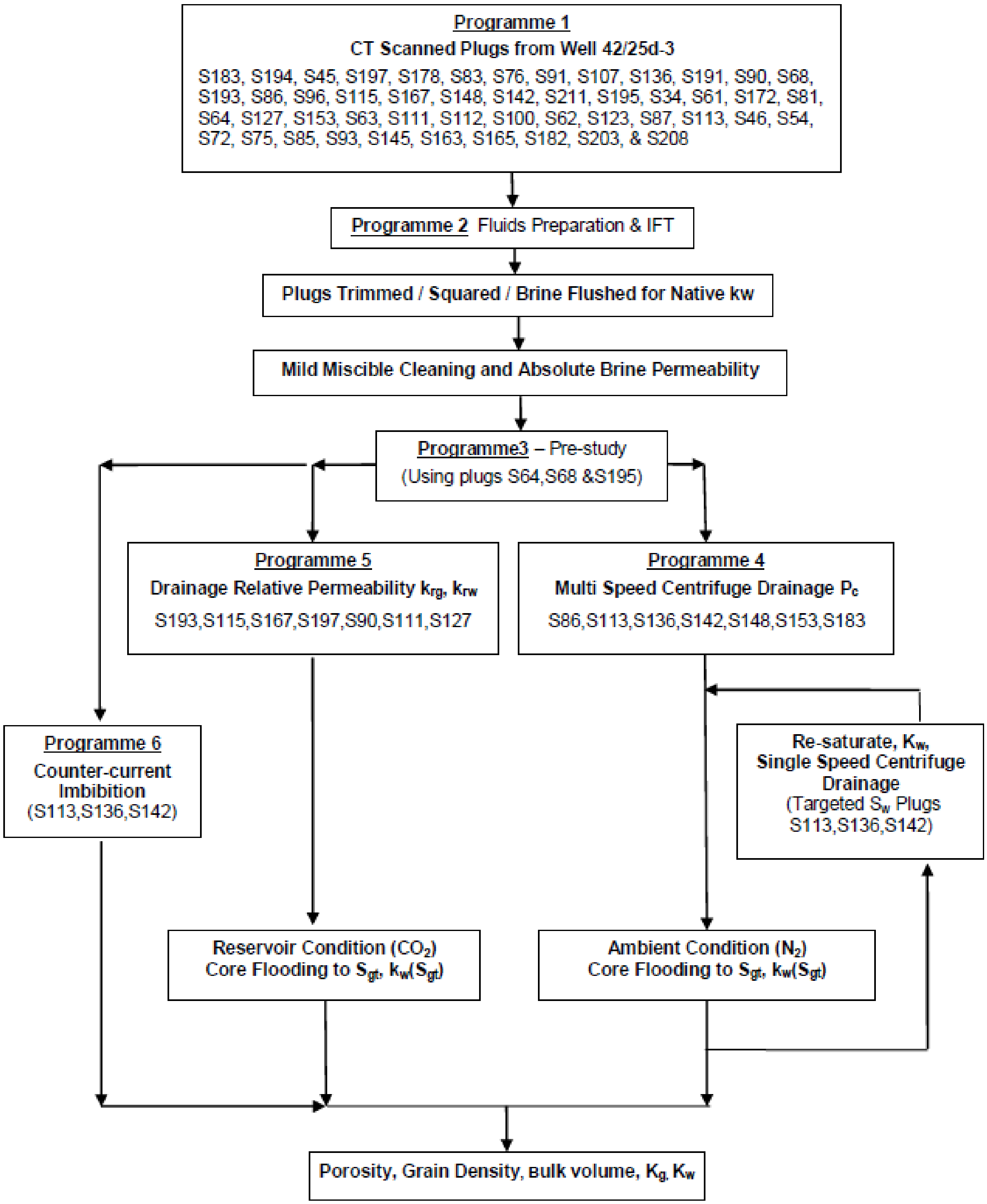
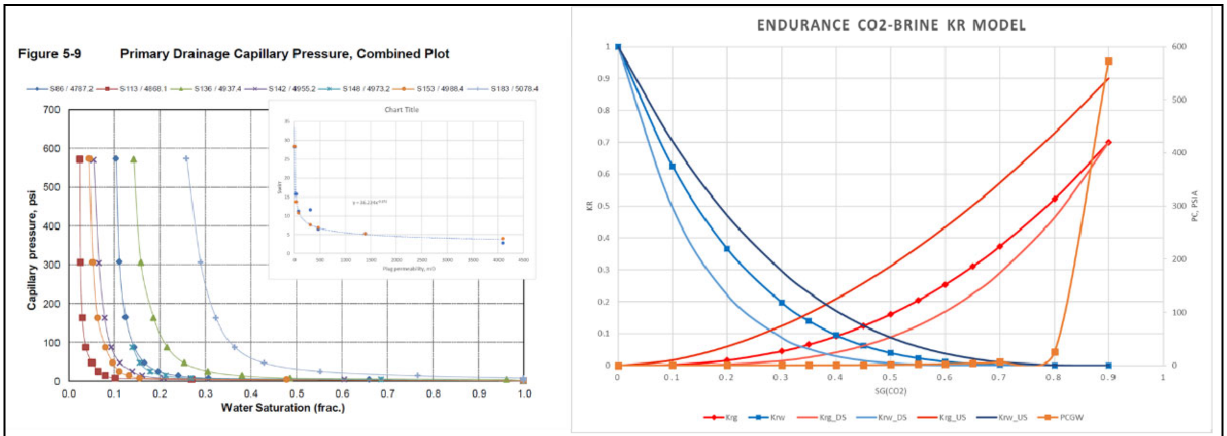


Figure 29 - Summary of SCAL experiments carried out by Weatherford on well 42/25d-3 core (Courtesy of National Grid Carbon Limited)



- Corey exponents from SCAL CO2-brine core flood (bp expert review of SCAL data)
- Use of S86 plug sample for Pc curve (plug permeability ~ Well test K in 42/25d-3)

Uncertainty	Downside	Base Case	Upside
Effective Swrg/Sgtmax	25%/40%	20%/35%	10%/25%
Kr	nw=6; ng=3.5; krg@endpoint = 0.7	nw=4; ng=2.5; krg@endpoint = 0.7	nw=3; ng=1.8; krg@endpoint = 0.9

Figure 30 - Relative permeability model for Endurance model

In practice, apparent residual water saturation in the plume will never drop below 35-40% as shown in

Figure **31** as Krw becomes very low (displacement driven by viscous forces). Post-injection, gravity drainage (along the capillary curve incorporated with the relative permeability table) will enable further displacement toward lower residual water saturation values (20% for base case).

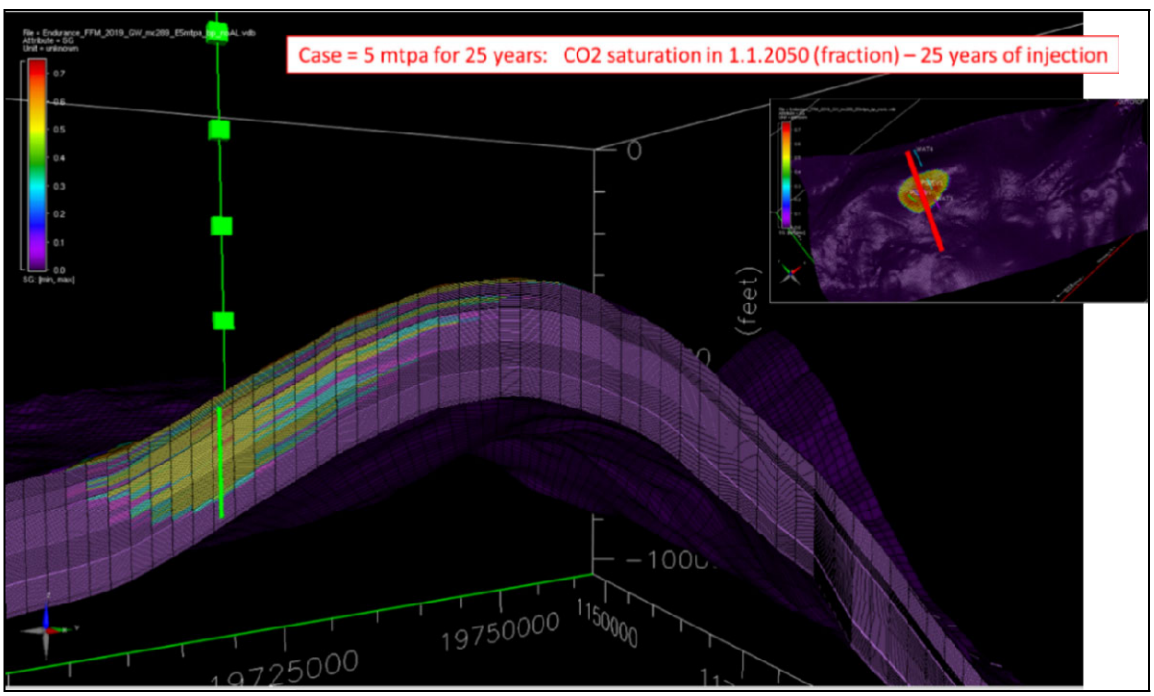


Figure 31 - CO2 saturation cross-section after 25 years of injection

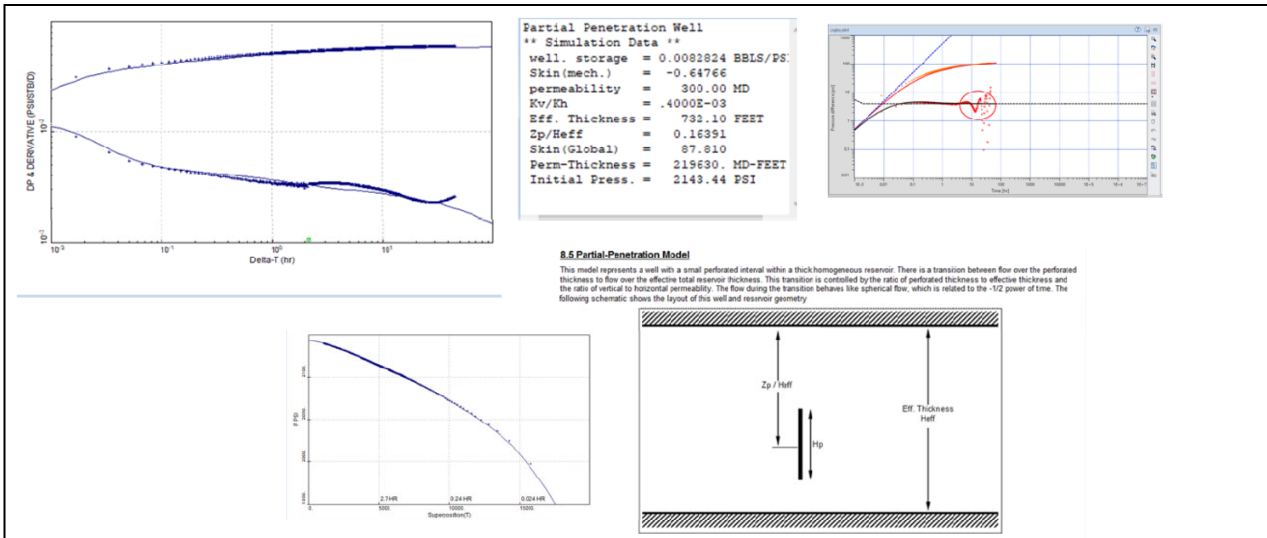
5.5 Reservoir Architecture

5.5.1 Well 42/25d-3 DST Interpretation

The Bunter reservoir has been tested in well 42/25d-3 test (20 meters) at ~ 5000 stbwd for 24 hours followed by a 48–hour Pressure Build-Up (PBU). An injection step-rate test at 5000, 10000, and 15000 stbd have been carried out afterward. The injection of seawater led to the rapid blockage of the perforations and subsequent fracking during injectivity test (preliminary scale risk assessment carried by bp in 1Q2020 indicate high risk of scaling for $CaSO_4$ when Endurance brine is mixed with sea water hence the requirement to use fresh water for any future well bore wash to avoid skin build-up).

The PBU test re-interpretation was broadly consistent with previous White Rose interpretation3:

- No lateral barrier observed once tidal effect corrected – no seabed pressure gauge makes the interpretation of the derivative difficult (not practical with Kappa-SaphirTM, somewhat successful with PIE).
- Kh (horizontal permeability) ~ 260-300* mD with radial, homogeneous model with partial penetration.
- Very low ratio of vertical (Kv) over horizontal permeability (Kh) i.e. Kv/Kh = 0.004 (0.4%) to make spherical analytical model matchable (i.e. Kv ~ 0.5-1 mD).
- Low macro-scale Kv/Kh (over 50-100's meters, < 1%) & moderate to good Kv/Kh from Vertical Interference Test #1 (over smaller scale i.e. 1-10's meters, ~10%).



N.B.: Non-uniqueness: match could be found with higher Kv/Kh and lower Eff. Thickness for instance (i.e. well has not seen the entire reservoir section)
* White Rose brine viscosity at 0.95 cp – BP brine viscosity modelled at 0.99 cp for reservoir conditions & 250,000 ppmw

Figure 32 - Re-interpretation of PBU for Well 42/25d-3

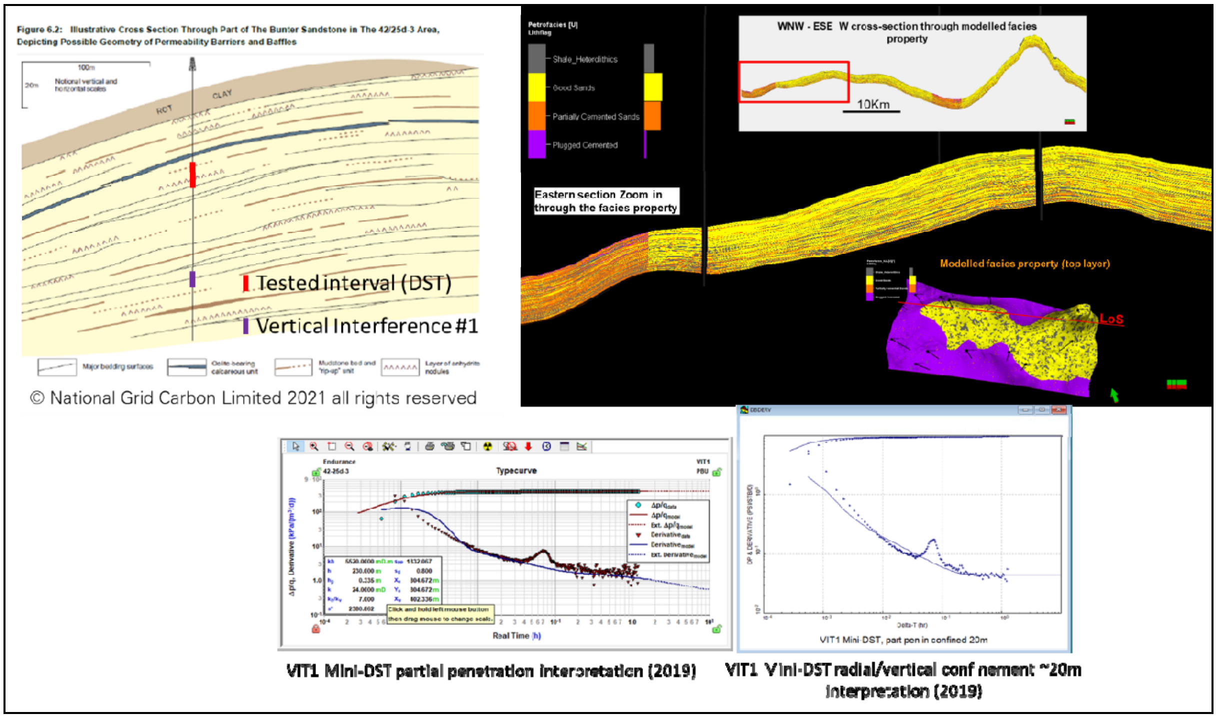


Figure 33 - Re-interpretation of Vertical Interference Tests for Well 42/25d-3

The 2013 Vertical Interference Test (VIT) data from Endurance have been re-examined in order to try to arrive at consistent description of vertical permeability. The original White Rose interpretation led a view of high Kv/Kh ~ 0.15 which was incorporated into the White Rose simulation Eclipse model, despite much lower Kv/Kh <0.01 coming from interpretation of the 2013 DST.

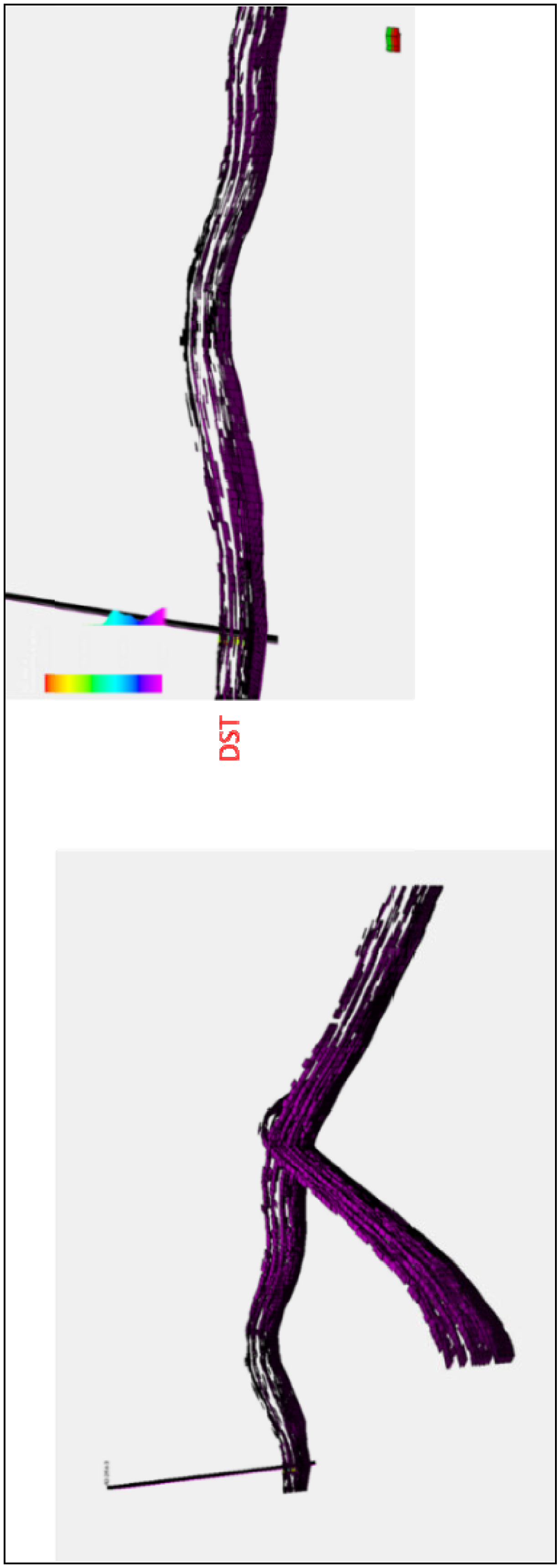


Figure 34 - Vertical permeability (KZ) for model v2 (base case connectivity).

Values less than 1.1 mD filtered out to illustrate the extensiveness of the vertical baffles across the reservoir

A consistent model should have the following characteristics:

- Sand intervals of 1 to 10-meter thickness with good internal vertical communication, corresponding to Kv/Kh in the range of ~0.1 for good-quality sandstones in the NZT/NEP reservoir model.
- These good-quality intervals are separated by thin low permeability baffles with severely reduced vertical communication on the scale of the full 230-meter-thick reservoir (represented by partially cemented sandstones modelled in the NZT/NEP reservoir model).
- The VIT data indicate that baffles extend at least 50 meters. However, the longer DST test does suggest that some of these baffles may extend at several hundred meters (up to 1.2 kilometers per the radius of investigation of the test).

5.5.2 Modelled Heterogeneities in the Reservoir Model

Well test interpretation was incorporated into the reservoir model by ensuring that the macro-scale vertical permeability across the Bunter remains low for downside and base case6. The heterolithics facies provide most of the baffling at the fine-scale model leading to poor vertical permeability over >50 meters at the coarse scale as shown in Figure 34. An upside model with increased vertical connectivity (model v3) was built to model a more optimistic scenario which rends to present similar behaviour as the White Rose model build in 2013-2014.

6.0 Well Performance

6.1 CO2 Injectors

Well performance and Benchmarking (CO2 injectors - SUBSEA): A well performance model in IPM-Prosper was built to assess initial injection rates for Phase 1 wells:

- 5.5’’ C&P completion, skin 5 (Nexus® FFM assumes skin = 5 as well)
- 200’ to 320’ of perforations (formation thickness of 656’)
- Sensitivities made around reservoir pressure, skin, permeability thickness, and permeability: well injectivity 1.5 MPTA+ for reservoir pressure up to 200 bara. Injectivity does decrease rapidly beyond as maximum WHP = 110 bara
- Pressurization depends on connectivity. It will take at least 36 months by monitoring reservoir pressure to determine whether one falls within a relatively closed or open system
- Thermal fracturing has been investigated with the REVEAL™ study

Instantaneous rate prediction does not account for downtime (e.g. brine wash), late-life pressurization or skin build-up (halite precipitation). Global analogues for water injectors would indicate 40 mbd for maximum continuous rates for high-injectivity wells. For some reservoirs, wellbore rates are reduced and controlled toward an average of 25-30 mbd ('steady-state', long-term). However, 1.5 Mtpa per well would represent ~ 38,000 rb/d deep into the reservoir which looks optimistic (need confirmation through on-injection performance during early years of injection) on an annualized basis for the entire life of the project as reservoir will pressurize to some extent (no contiguous depletion from gas producers e.g. In Salah CCS)

Average injection rate is therefore assumed to be 1 MTPA per well over the life of the project (25 years) based upon benchmarking against analogous offshore CCUS project such as Sleipner, Snohvit, and Northern Lights. Peak injection rate is assumed to be 1.5 MTPA per well accounting for reservoir pressurization and potential well injectivity deterioration over time (Figure 37).

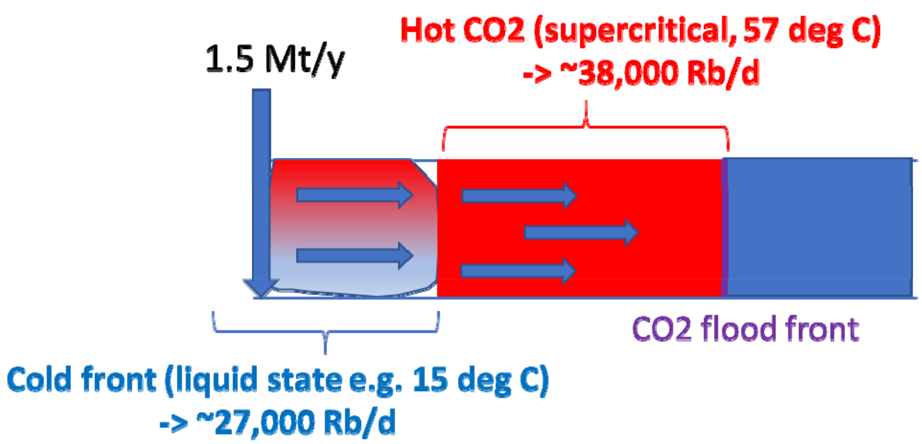


Figure 35 - Volumetric rates for 1.5 MTPA for Endurance CO2 injectors

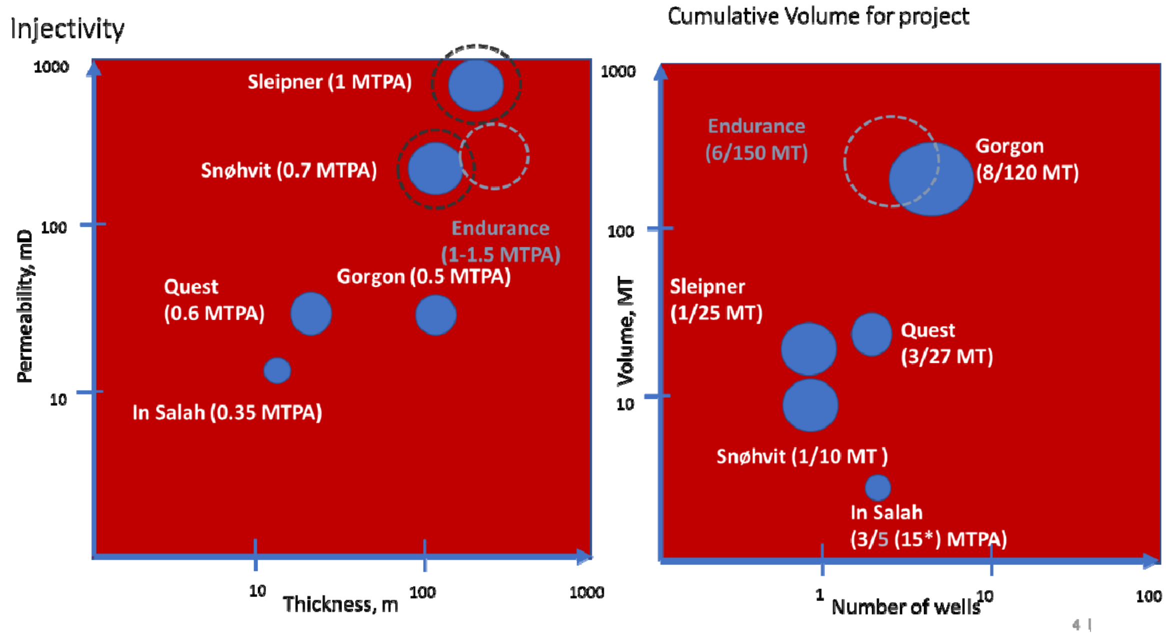


Figure 36 - CCUS analogues considered for benchmarking performance

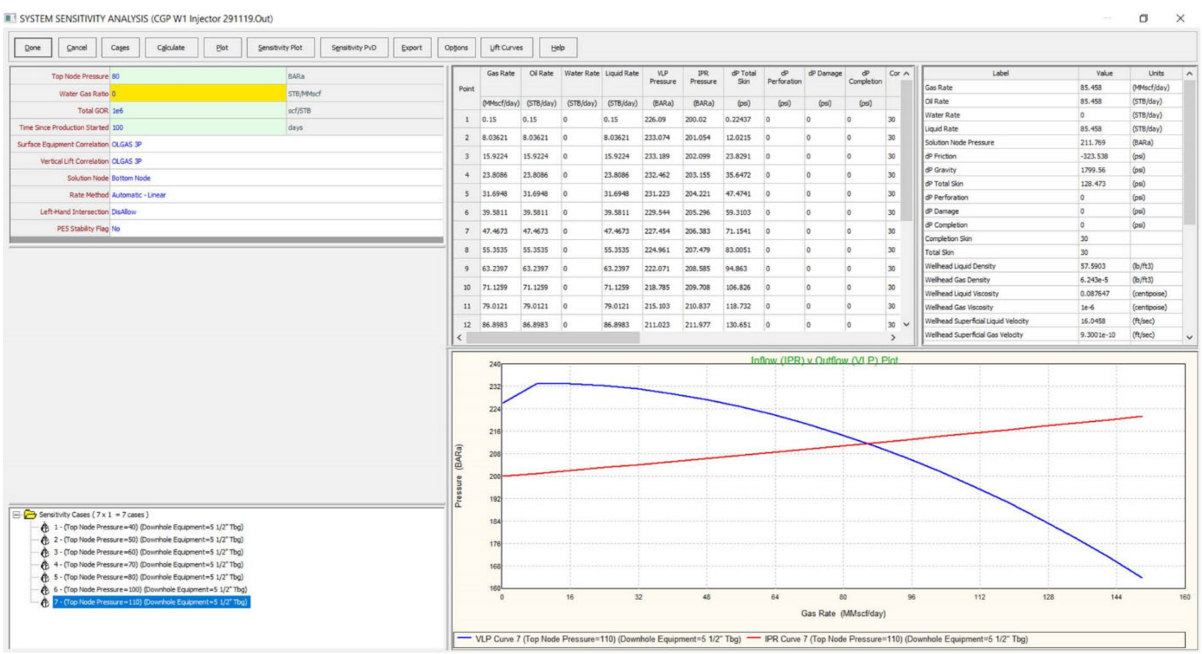


Figure 37 - System sensitivity to wellhead pressure for Endurance CO2 injector (Prosper)

Indicating 1.5 MTPA (78 mmscfd) is achievable in late life (reservoir pressure at 200 bars) and conservative reservoir properties (mechanical skin = 30 and Keg = 120 mD or 40% of tested permeability in well 42/25d-3)

6.2 Brine Producers

Well performance (Brine producers - SUBSEA): A well performance model in IPM-Prosper was built to assess brine production rates for future NZT/NEP phases i.e. 10 MTPA (beyond Phase 1):

- 7'' C&P or FracPack completion, skin 3 assumed (depending on completion type for required rates i.e. frack-pack completion might be required to increase productivity index)
- Sensitivities made around reservoir pressure, skin, permeability thickness, perforation length and permeability: well productivity strongly impacted by min. WHP (10 bars to accommodate pressure losses across 5-km F/L back to platform for reference case)
- Horizontal well not an option with low Kv/Kh to improve PI: increased perforated interval might be required (>300-400') to manage outflow of brine across reservoir interval
- Reservoir pressure >> 160 bars will be required to lift brine without artificial lift.

Rates of 20 to 25 mbd can be expected when pressurization exceeds 180 bars (without artificial lift). Higher production rates (up to 40 mbd) will require artificial lift if needed to manage voidage in early life when reservoir has not sufficiently pressurized.

NO BRINE PRODUCTION will be required for Phase 1 as CO2 injected volumes are not expected to exceed 100 MT over 25 years (even for downside geologic cases considered i.e. P90 case).

Minimum wellhead pressure of 10 bars would be required to flow the produced brine back to a facility (e.g. platform for surface discharge or transport for re-injection) along a 12'' 5-km-long flowline based upon early screening carried in GAP.

6.3 Brine Management and Operational Limits (RDOL/WDOL)

Reservoir and Wells Defined Operating Limits: The Rot Halite is considered the primary seal for the store hence the upper safe operating limit is 2958 psia/204 bars at structural crest (~1020m TVDss). CO2 injectors will be drilled at various location and will have to be managed based upon their respective average reservoir pressure (PTA) relative to their structural offset to the crest as described below in Figure 38 (Upper safe operating limits for reservoir considered at 1250m TVDss at top perforation). In terms of Wells Defined Operating Limits, the well shall operate in order not to fracture the reservoir up to the cap rock. It is important to understand that fracturing could extend vertically to caprock (thermal fracturing) so gauge pressure limit (USDL) needs to ensure that pressure in wellbore at depth Dcp is less than caprock fracture pressure at well.

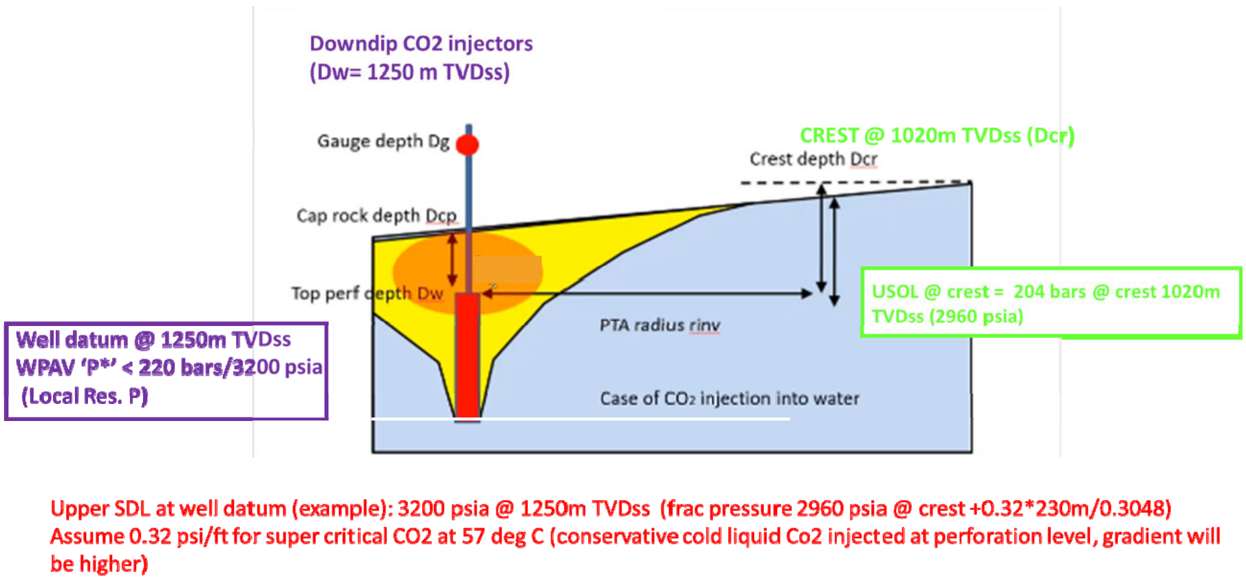


Figure 38 - Reservoir defined operating limits for Endurance

Upper safe operating limit for reservoir is defined as facture pressure at crest for Rot Halite plus corresponding CO2 column down to top perforation depth. Upper safe operating limit for wells (maximum flowing bottom hole pressure) will be defined based upon local fracture pressure immediately above the wells and well design considerations.

Brine production: No brine production is required with reasonable certainty up for plateau rates of 4 MTPA for the considered probabilistic downside (P90) cases. Phasing is therefore critical at low-rate plateau to understand the reservoir connectivity into the Greater Bunter Aquifer (pressurization response to injection), injection conformance (in-well monitoring such as ILT, time-lapse saturation logging), and early plume movement (4D seismic). Reservoir monitoring data will be used to further calibrate reservoir model and refine brine producer requirement. Any higher-rate plateau acceleration will tend to increase the risk of accelerated CO2 breakthrough into poorly placed brine producers by limiting the dynamic appraisal of the store before significant investment for brine production is required to ramp up to 10 and 15 MTPA.

6.4 Halite Precipitation and Mitigations

Salt precipitation is considered a significant risk to injectivity over time for Endurance due to the high salinity of the brine (250,000 ppm %w). The injected CO2 will be undersaturated with respect to water at bottom hole conditions and will therefore trigger the creation of a dry-out zone in the near wellbore region (the in-water being vaporised into the CO2 leading to the precipitation of salts, mostly halite).

A study in CMG GEM™ has been conducted (near-wellbore model [6]) to evaluate the benefits of water flush in terms of preventing catastrophic drop in injectivity if precipitation is left unmitigated (See Endurance Geochemical Model & Report (KKD) NS051-SS-REP-000-00016):

- Propagation of the dry-out front depends on injection rate – at high injection rate, the effect of brine back-flow is limited therefore no injectivity loss is predicted by the model. There is therefore a clear bias for base load (continuous) injection in CO2 injectors as infrequent injection would increase precipitation risk (periodic shut-in should be limited as much as possible.
- Injectivity losses due to halite precipitation in dry-out zone depends on injection rate as well as cumulative injected volumes, capillary pressure, frequency/duration of shut-in, and relative permeability (i.e. water mobility).
  - GEM modelling study would indicate that a minimum rate of 0.5 Mtpa is needed to keep the well/near wellbore reservoir safe of brine presence (preservation of the dry out area further into the reservoir)

Pre-injection initial flush (with fresh water) is recommended to dilute high-salinity reservoir brine in the vicinity of the wells and delay onset of injectivity losses (for low injection cases in which the issue occurs). A 1 to 2-day-long freshwater flush (1000 bpd + some MEG) per well / per year is considered a safe base case to keep the integrity of wells injectivity. Subsea intervention vessel will be required to carry out the flush workover.

7.0 Dynamic Modelling

7.1 Reservoir Modelling and Dynamic Performance Prediction Overview

A simulation reservoir model has been created in 4Q 2019 to run the full-field development scenarios (NI=252*NJ=118*NK=88, ~2,000,000 active cells) in Nexus®. Static properties and grid were generated in Petrel™ in 4Q 20197. The reservoir model has a black-oil PVT formulation (solubility of CO2 into brine of the order of 1-1.5% per mass so it is not considered – GAS-WATER immiscible displacement) so as to limit the run time and allow the generation of ensemble (500 cases per workflow) for scenarios analysis (pressure prediction and brine management scoping).

Near wellbore effects (halite precipitation) are being modelled in GEM™ with mechanistic models [6] (**Figure 39**). Well performance has been assessed in Prosper™ (compositional fluid description) and checked against relevant CCUS benchmarks.

Thermal fracturing effects have been investigated with REVEAL™ to evaluate the impact of the reservoir cooling on conformance and injectivity over time.

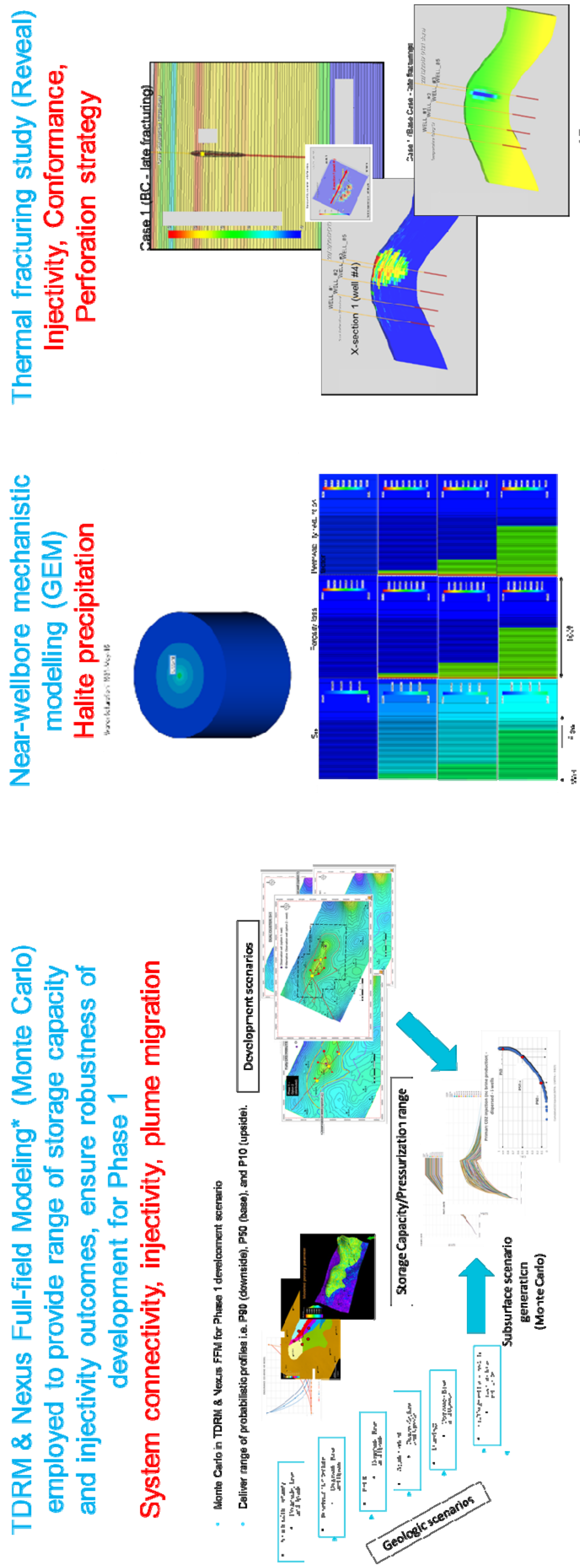


Figure 39 - Dynamic modelling strategy for Endurance.

7.2 Geologic Model Calibration for Dynamic Modelling

A permeability model has been created based on a single Porosity-Permeability transform for all facies and applied directly to the modelled porosity at the fine-scale. Permeability was thereafter upscaled to the coarse scale model [7]. Following the initial permeability modelling, the Porosity – Permeability transform was adjusted to better match the permeability observed in the well test on 42-25d-3 well.

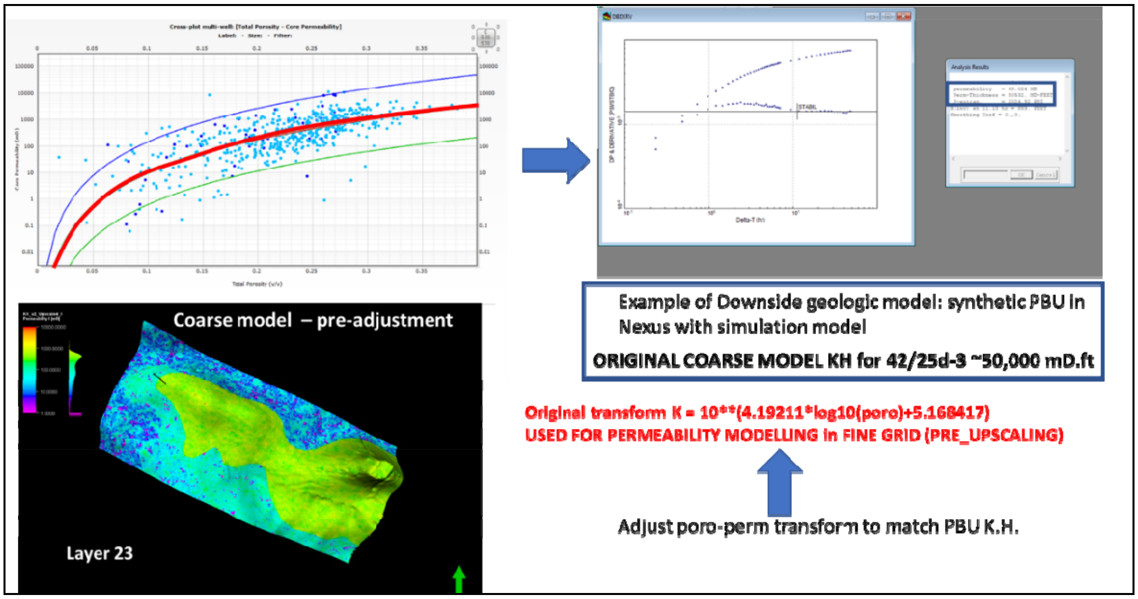


Figure 40 - Permeability modelling workflow (calibration to well test in 42/25d-3) – pre-adjustment to well test

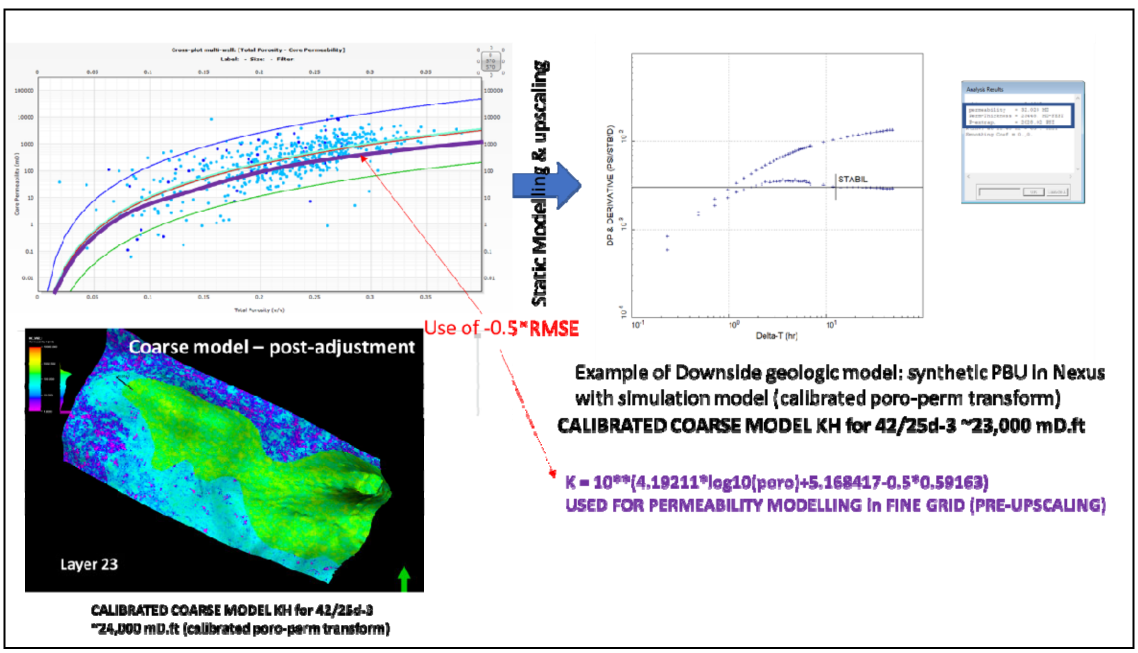


Figure 41 - Permeability modelling workflow (calibration to well test in 42/25d-3) – post-adjustment to well test

7.3 Summary of Reservoir Uncertainties Considered for Uncertainty Workflow

7.3.1 Structural and gross thickness uncertainties

Three distinct grids have been generated to account for uncertainty in structure and gross thickness across the area of interest as described throughout Figure 42 to Figure 44.

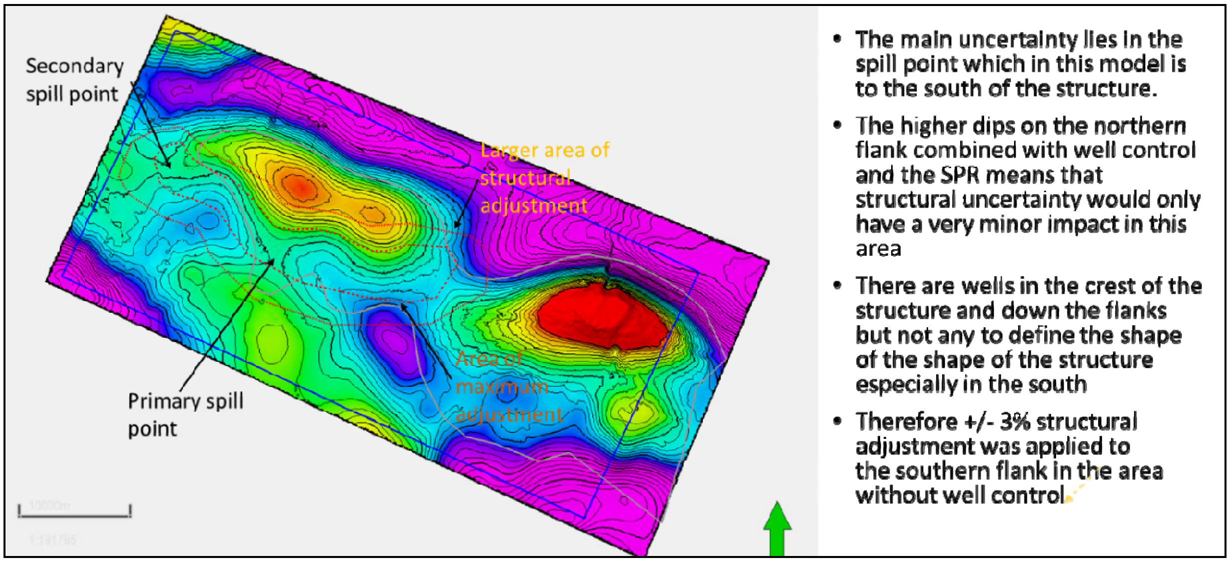


Figure 42 - Structural uncertainty for Endurance

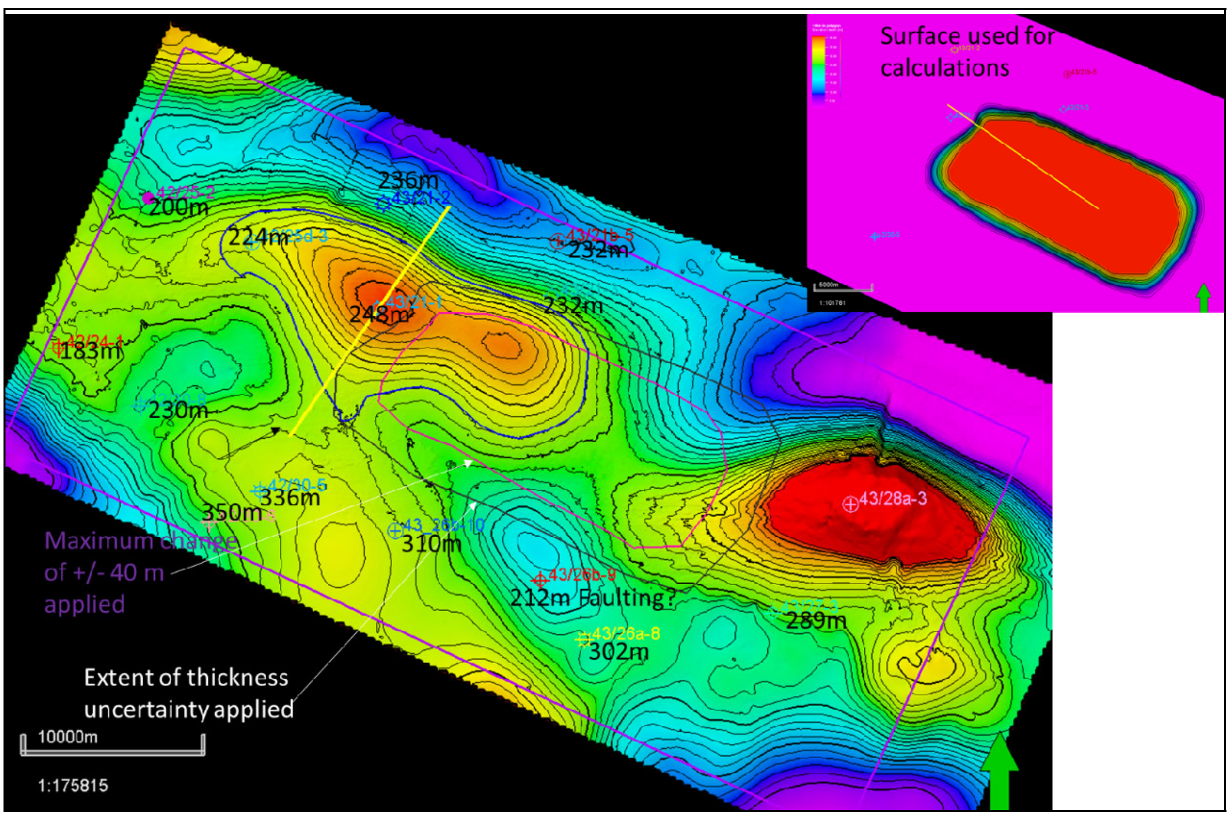


Figure 43 - Gross thickness uncertainty around Endurance

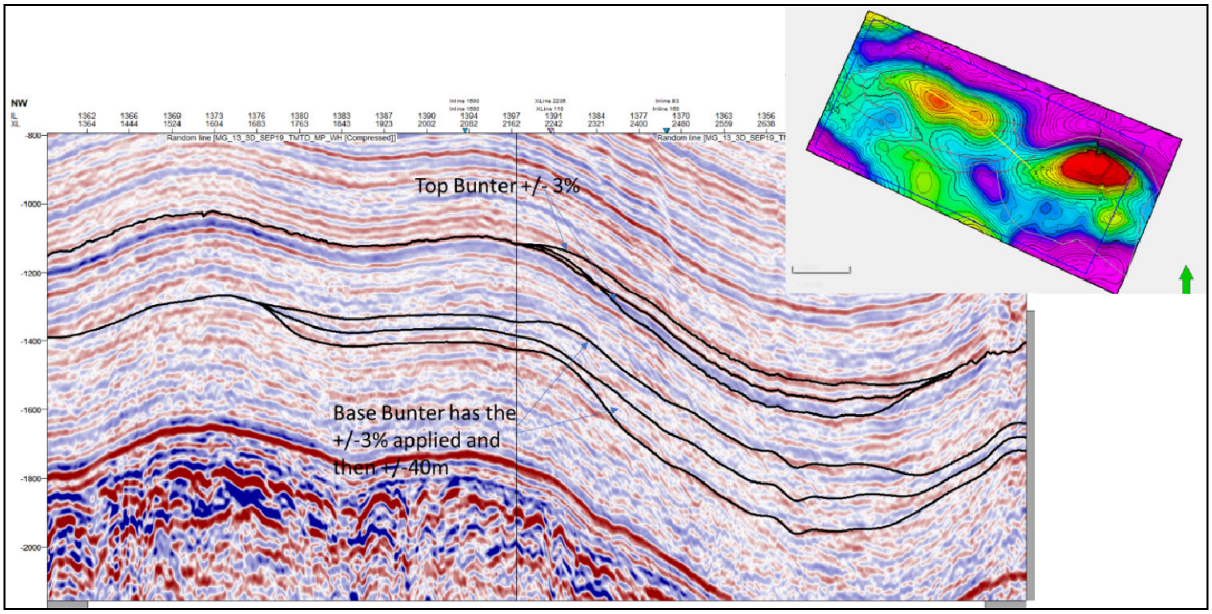
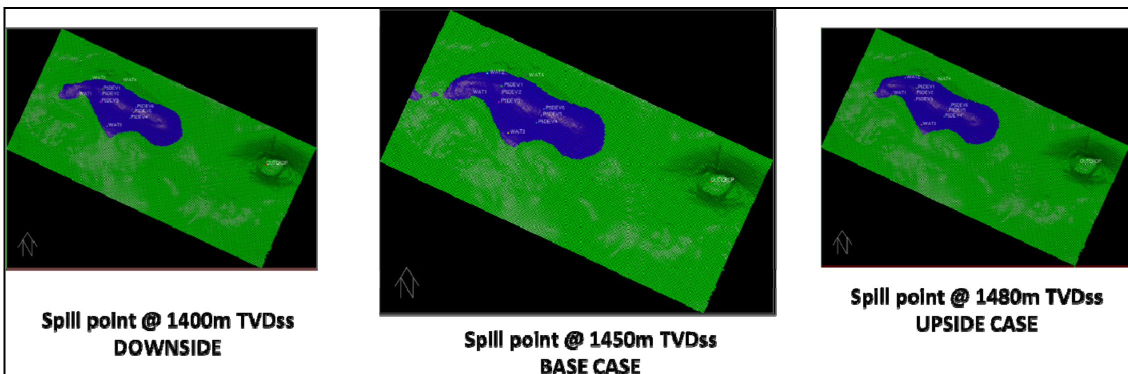


Figure 44 - Resulting upside and downside cases



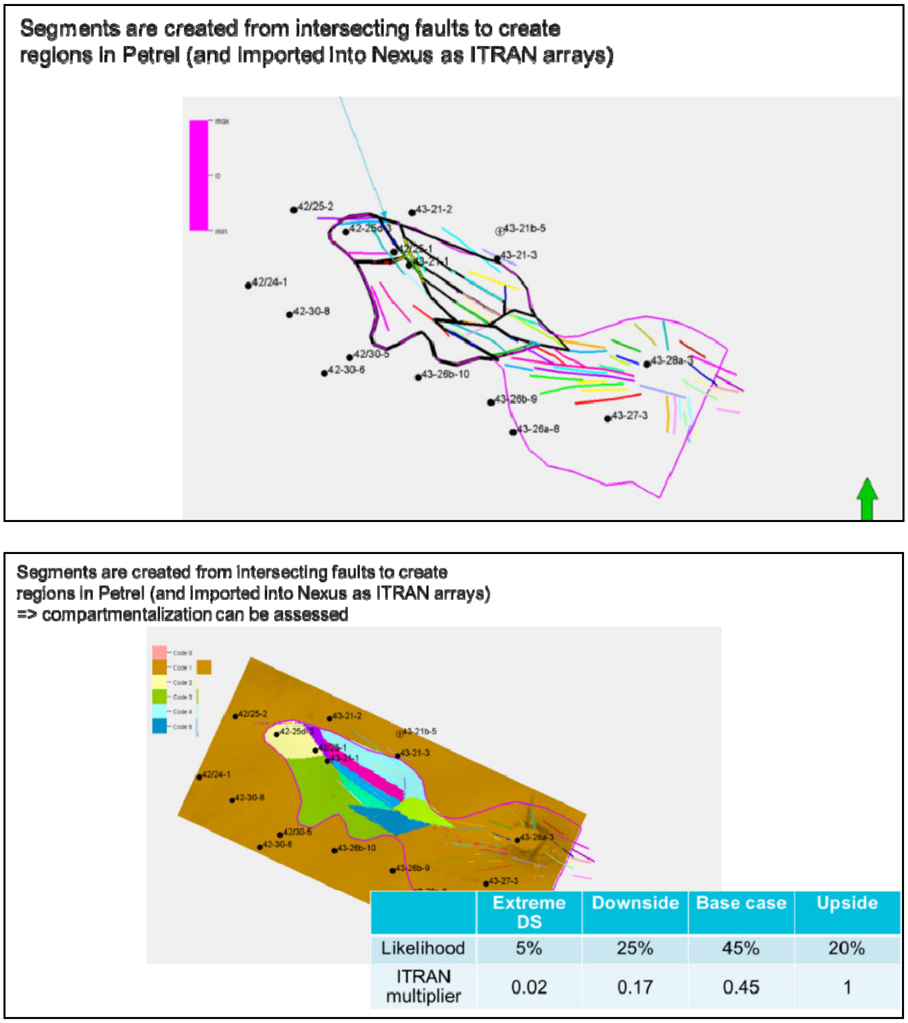
	Downside	Base case	Upside
Likelihood	30%	40%	30%
Water in-place, Billion STB	21.15 (-16%)	26.05	27.5 (+6%)

NB: Use Swanson's law for probability

Figure 45 - downside/base/upside grids used for modelling study

7.3.2 Fault, Segment, and Lateral Continuity

No fault can be mapped extending into the reservoir over the anticline from seismic data. Fault that can be possibly mapped in the overburden section were therefore extended into Bunter reservoir section. There is a degree of uncertainty around the presence of these features. For instance, some of the extended faults in the north-western side of the anticline (in the vicinity of the well 42/25d-3) were not identified by the well test (radius of investigation of 1.2 km). It is likely that these features will not present significant level of transmissibility reduction as shown in **Figure 47**. For the uncertainty study, some segments were created from the fault framework to use these regions as potential compartment (with inter-region transmissibility used as a variable).



	Extreme DS	Downside	Base case	Upside
Likelihood	5%	25%	45%	20%
ITRAN multiplier	0.02	0.17	0.45	1

Figure 46 - Generation of conceptual segment from faulting used for uncertainty study

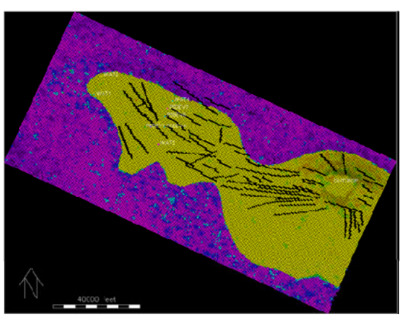
Cell Length	Cell Permeability	Fault Zone Thickness	Fault Zone Permeability Reduction	Fault Zone Permeability	Transmissibility multiplier	Multiplier Chosen?	Description	Transmissibility without fault	Transmissibility With Fault	Likelihood?
200	300	Modelled using 4 100 micron aperture fractures per metre			2	Transmissible upside	Open fractures in fault damage zone	1.5	3	5
200	300	0.2	100	3	0.90992	y - Upside	Fault zones are narrow, with 2orders perm reduction - low strain cataclasites	1.5	1.36488	25
200	300	0.5	300	0.6	0.44494	y - Base Case	Faults have similar thickness to that observed in field, 500x (2.5 orders) perm reduction (in line with model for relatively low strain cataclasites.	1.5	0.66741	45
200	300	1	1000	0.3	0.16811	y - Downside	Thick fault zone with high strain cataclasites and some cementation (3 orders magnitude permeability reduction)	1.5	0.252165	20
200	300	1	10000	0.03	0.01961	Extreme downside?	Thick fault zone with highly cemented cataclasites - 4 orders magnitude perm reduction	1.5	0.029415	5

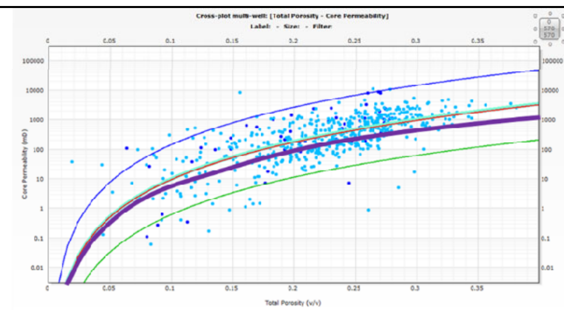
	Extreme DS	Downside	Base case	Upside
Likelihood	5%	25%	45%	20%
KX/KY multiplier	0.02	0.17	0.45	1

Figure 47 - Range of transmissibility multipliers used based upon fault assessment carried out by NZT/NEP team

7.3.3 Petrophysical Uncertainty

Global multipliers were utilized to shift porosity-permeability distribution upward or downward.





	Downside	Base case	Upside
Likelihood	30%	40%	30%
Phi Multiplier (Region A/B)	0.9/0.9	1/1	1.1/1.1
KX/KY Multiplier (Region A/B)	0.65/0.65	1/1	1.5/1.5

0.65/1.5 KX/KY multiplier for region B does honour range for Esmond aquifer permeability

NB: Use Swanson's law for probability

Figure 48 - Petrophysical uncertainty for Endurance

7.3.4 Reservoir Architecture (Vertical Baffle Extent)

Three distinct geological models were generated [7] to account for uncertainty in the extent of the baffles which could affect the vertical migration of the CO_2 toward the crest and the associated gravity drainage post-injection (Figure 49).

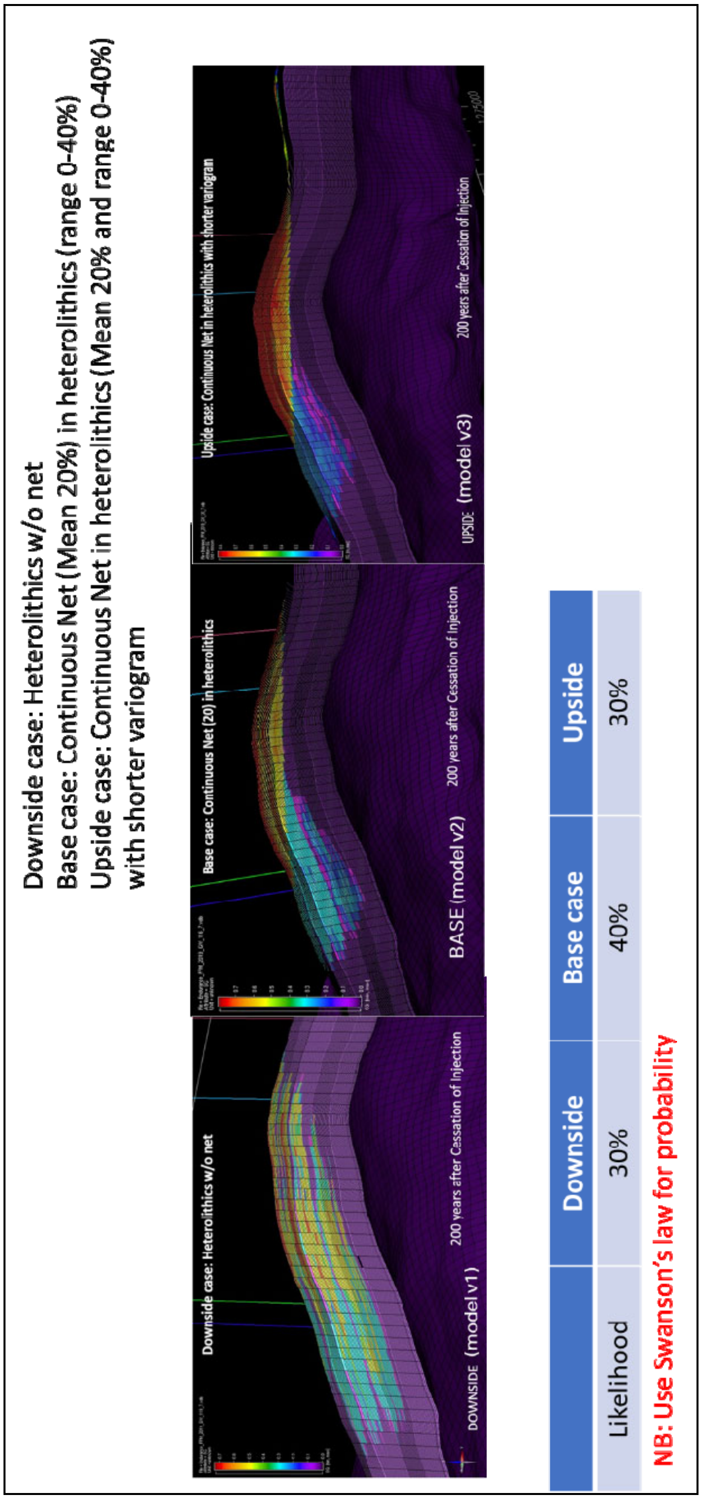
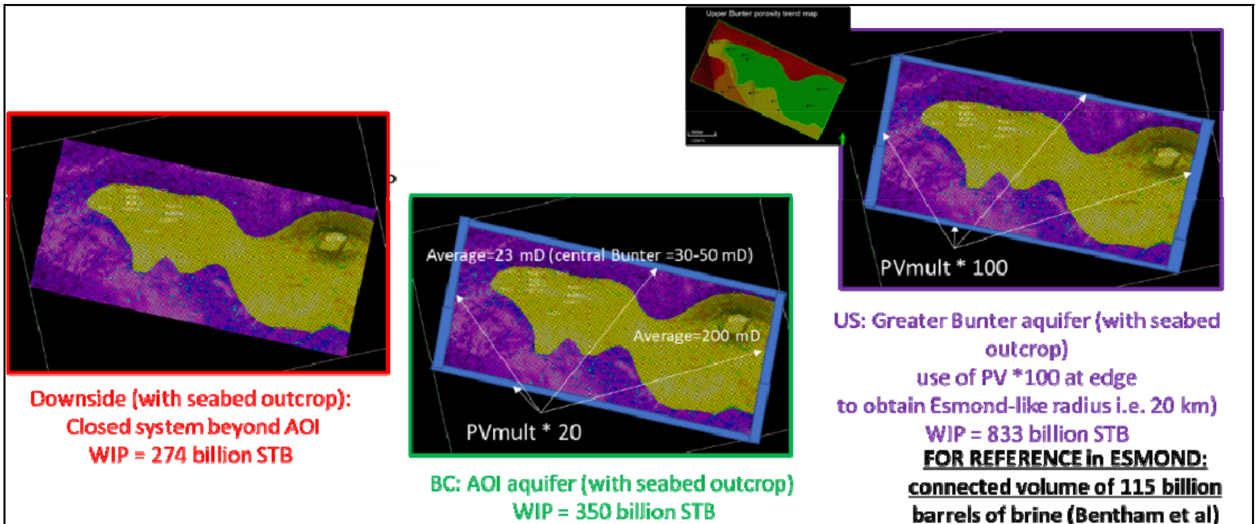


Figure 49 - Reservoir architecture uncertainty (impact on CO_2 saturation)

7.3.5 Aquifer Connectivity

Uncertainty around aquifer extent beyond the area of interest of the model was dealt with the use of pore volume multipliers as shown in Figure 50.



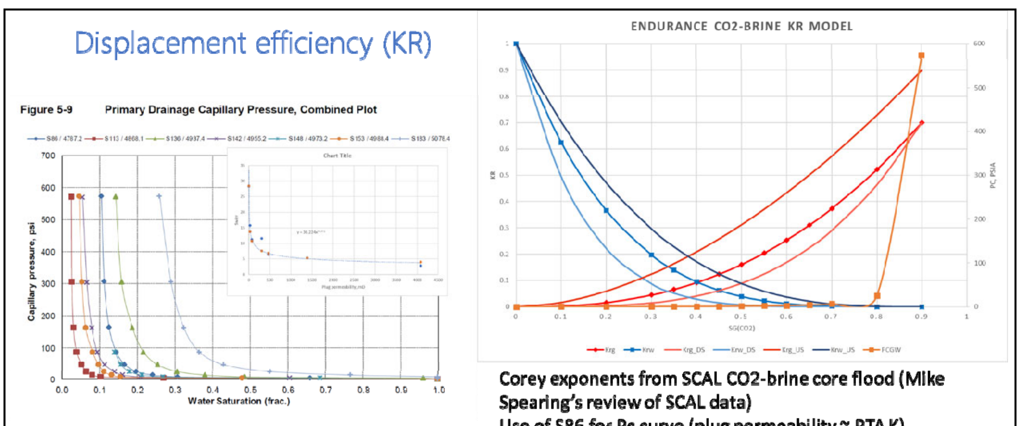
Uncertainty	Downside	Base Case	Upside
Aquifer extent – EACH EDGE CONSIDERED INDEPENDENT	Closed system	Current AOI + PV *20 at edges	Greater Bunter Aquifer (Esmond-like extent)
Likelihood	30%	40%	30%

NB: Use Swanson's law for probability

Figure 50 - Uncertainty in the extent of the Bunter aquifer

7.3.5 Displacement Efficiency

As described in section 3.4, uncertainty in displacement efficiency was dealt with the use of three distinct sets of relative permeability curves (Figure 51).



Uncertainty	Downside – 30%	Base Case – 40%	Upside – 30%
Effective Swrg/Sgtmax	25%/40%	20%/35%	10%/25%
Kr	nw-6; ng-3.5; krg@endpoint - 0.7	nw-4; ng-2.5; krg@endpoint - 0.7	nw-3; ng-1.8; krg@endpoint - 0.9

NB: Use Swanson's law for probability

Figure 51 - Relative permeability uncertainty

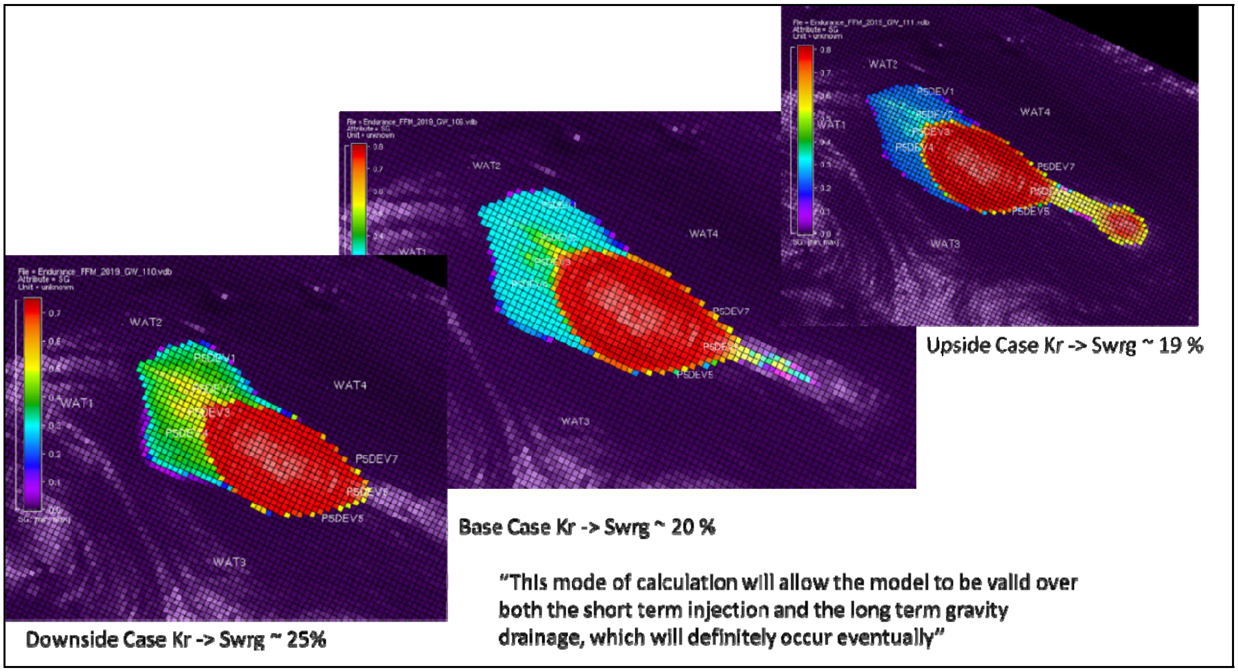


Figure 52 - Impact of displacement efficiency uncertainty on residual water saturation in the secondary CO2 gas cap

8.0 Uncertainty Study for Endurance

8.1 Overview

A series of Monte Carlo workflows in TDRMTM (MC16 and MC17) has been run throughout concept development stage to evaluate the impact of subsurface uncertainties on pressure and injected volumes for Phase 1 as shown in Figure 53 with the Nexus® full-field model.

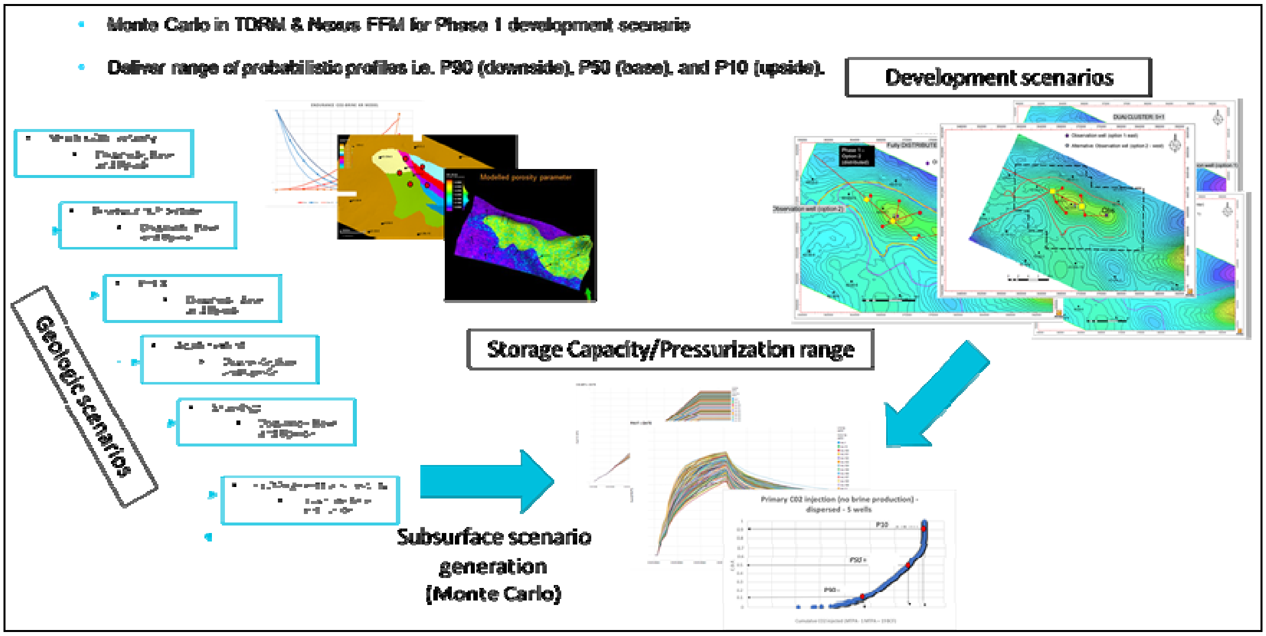


Figure 53 - Probabilistic workflow (Monte Carlo)

Used to generate 500-case ensemble to deliver range of profiles for reservoir pressure, CO2 injection profiles, and outcrop production.

Uncertainty	Downside	Base Case	Upside
Structure (BRV, Billion STB)	21.15 (-16%)	26.05	27.5 (+6%)
Segment transmissibility & outcrop fault damage	0.02/0.17	0.45	1
Phi Multiplier (Region A/B)	0.9/0.9	1/1	1.1/1.1
Permeability Multiplier (Region A/B)	0.65/0.65	1/1	1.5/1.5
Aquifer connectivity (North/East/West/South)	PV multiplier =1 at edges	PV multiplier =20 at edges (4km)	PV multiplier =100 at edges (20km) – Esmond-like radius
Reservoir architecture	No net in heterolithics (NTG=0%)	net in heterolithics (NTG=20%)	heterolithics (NTG=20%) and shorter variogram for heterolithics
Kr & Sgtmax	nw=6; ng=3.5; krg endpoint= 0.7, Swrg ~25%, Sgtmax =40%	nw=4; ng=2.5; krg endpoint= 0.7, Swrg ~20%, Sgtmax =35%	nw=3; ng=1.8; krg endpoint = 0.9, Swrg ~19%, Sgtmax =25%

Figure 54 - Summary of variables used in uncertainty study

Subsurface uncertainties have been defined by a series of discrete variables (as described in previous section and Figure 54) and recombined through a Monte Carlo iterator in TDRM™:

- Structural uncertainty: 3 distinct grids have been generated accounting for uncertainty in thickness and structure in the unpenetrated eastern side of the Endurance structure. It represents an uncertainty of -16%/+6% relative to volumes above spill point for base case (3 cases).
- Fault transmissibility: a series of fault were mapped in the overburden and assumed to be extended into the Bunter reservoir section (faults can be mapped at reservoir level in the vicinity of the outcrop further east) (4 cases).
- Petrophysical uncertainty: global permeability and porosity multipliers have been used to account for uncertainty in permeability prediction (3 cases).
- Aquifer connectivity: pore volume multipliers at the edge of the model (3*3*3*3 cases).
- Reservoir architecture: the three geologic models have been utilised to account for uncertainty in the extent and severity of the heterolithics-rich intervals (3 cases).
- Displacement efficiency (3 cases)

It results in a range for the brine in-place volumes above the spill point from 19 to 32 billion standard barrels as shown in section 10.3.

The Monte Carlo workflow (MC16) has been utilized to generate an ensemble of 500 geologic scenarios as shown in Figure 53. A development case with 5 clustered subsea wells (Phase 1) was utilized to deliver a plateau of 5 MTPA for 25 years without brine production in the workflows. It was used to deliver a range of profiles for brine production at the outcrop, reservoir pressure at the crest, and CO2 injection profiles.

A notional injection profile with 3 MTPA over 2025 to 2028 followed by a 5 MTPA plateau from 2029 to year-end 2054 has been utilized:

- No pressure management hence wells could come off plateau (max. WHP = 110 bars)
- Reservoir pressure tracked passively
- Series of Tornado and Monte Carlo runs (500 realizations for each workflow) used to understand uncertainties and their impact on injection rates, pressurization, and timing for brine management requirement
- Crestal region to track reservoir pressure against safe operating limits

The key objective was to identify downside (probabilistic downside circa P90) and upside case (probabilistic upside circa P10) in addition to the reference case (base case) for profile, reservoir technical limits and scenario evaluation. Various development scenarios (4 MTPA, 5 MTPA, and 10 MTPA plateau) were run on these cases i.e. reference, P90, and P10 cases.

8.2 Summary of Well and Reservoir Model Assumptions in the Nexus® Full-field Model

The key assumptions are as follows:

- CO_2 injectors (C&P) – 5 wells would be deviated as drilled from unique drill centre for clustered scheme and distributed across structure for distributed scheme.
- Skin = 5 accounting for mechanical skin build-up and thermal fracturing and low viscosity in the near wellbore cool region. Further injectivity considerations were investigated with separate reservoir modelling in GEM™ and Nexus®
- 100 meters of perforations (40 layers i.e. layer 20 -> 60) i.e. mitigation against downside geologic scenario (low KV)
- 1 MTPA per well (Benchmarking)
- Simulation until 1.1.2055 (YE 2054) per the provided injection profile (30 years of injection)
- Bunter outcrop is modelled as a unique water producer which starts discharging brine when pressurization is sufficient.

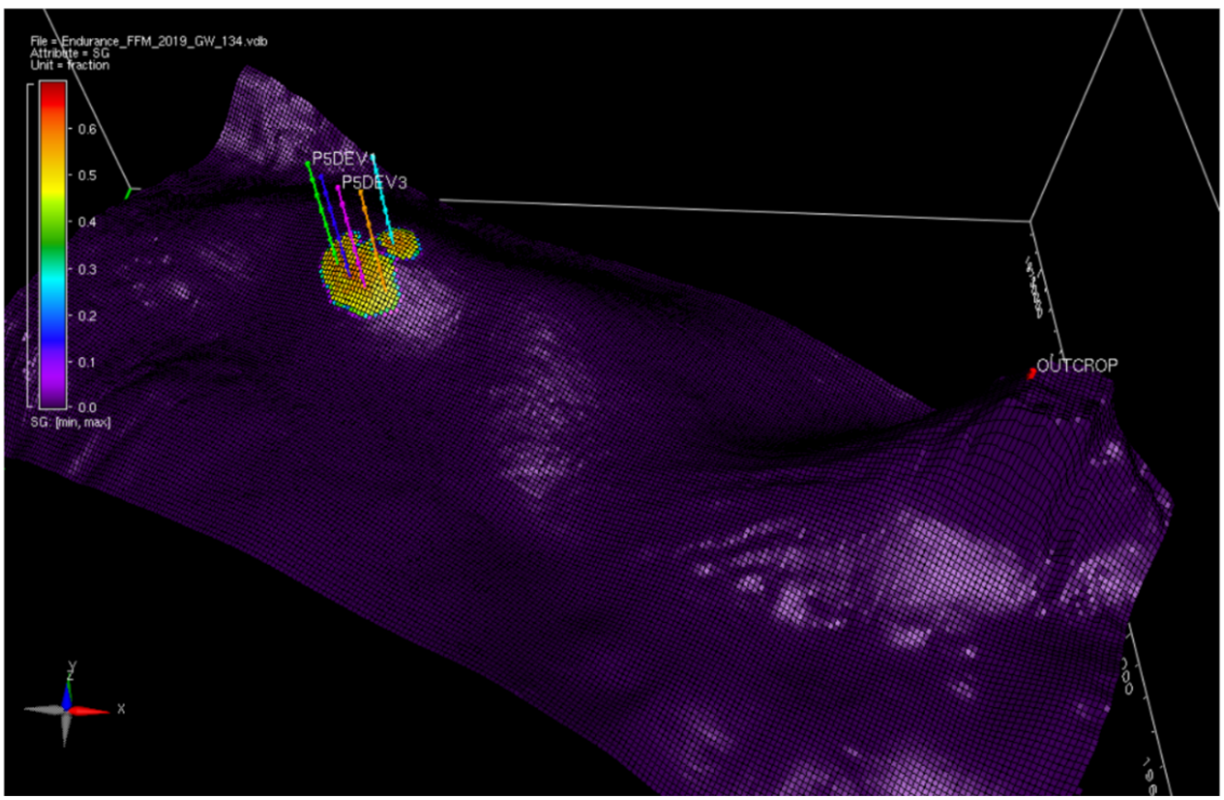


Figure 55 - Full-field reservoir model for Endurance (example of single subsea cluster)

(CO_2 saturation map after 25 years of injection)

8.3 Endurance Volumetrics

Volume above spill point for the 500-case ensemble can be seen in Figure 56 (strongly influenced by discretized variables as there are a limited number of combinations from discretised variables).

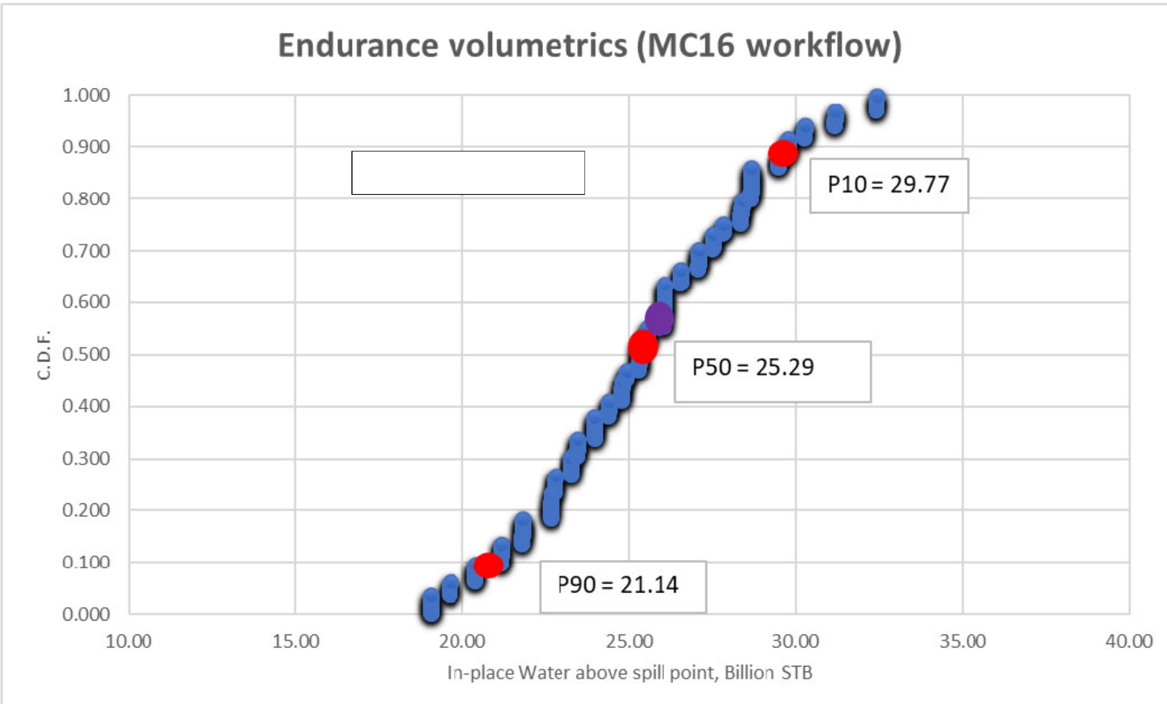


Figure 56 - Volumetrics for the Endurance structure above the spill point.

8.4 Key Results

The model ensemble results were analysed in DXP Spotfire® (Figure 57 to Figure 60).

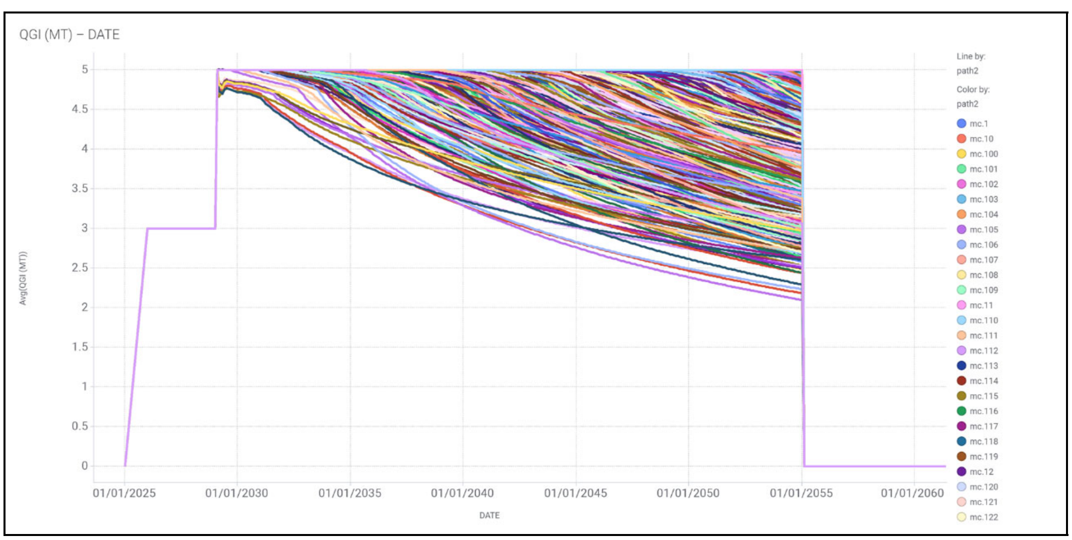


Figure 57 - CO2 injection rate (MTPA) for Phase 1 development (distributed 5-well scheme, MC17)

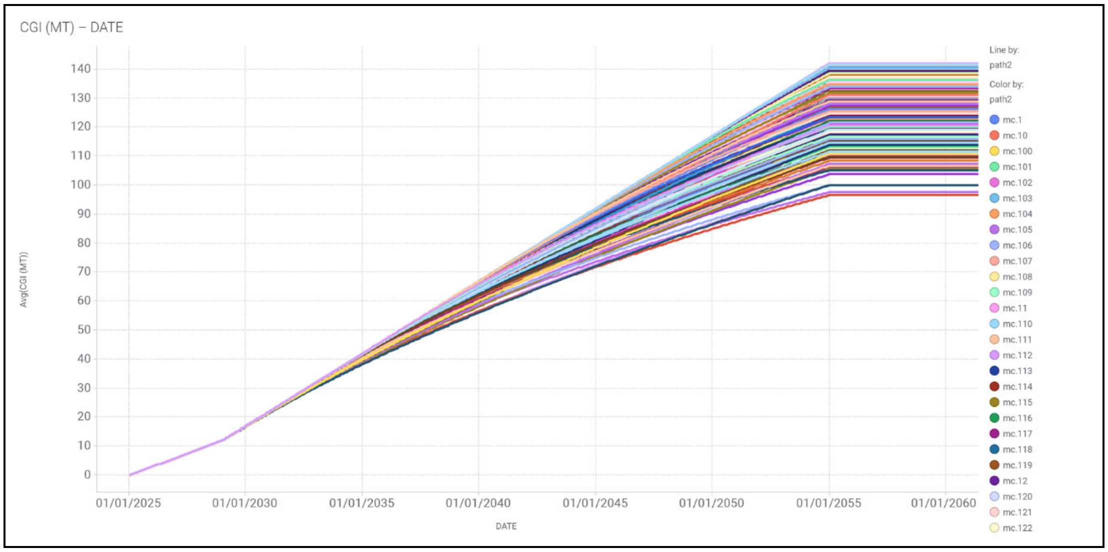


Figure 58 - CO2 cumulated injected volumes (MT) for Phase 1 development (distributed 5-well scheme, MC17)

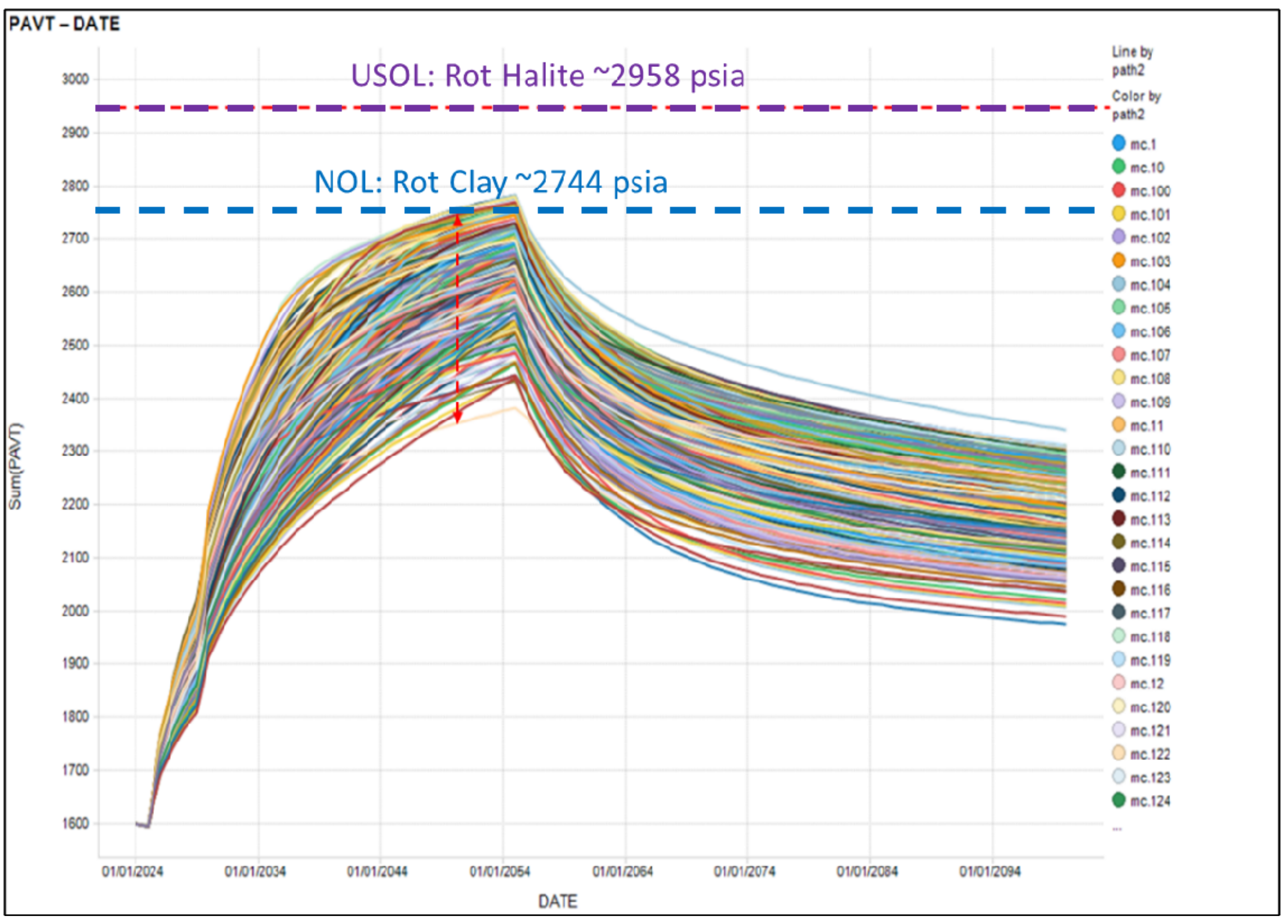


Figure 59 - Crestal pressure (psia) for Endurance for 500-case ensemble MC16 (clustered 5-well scheme)

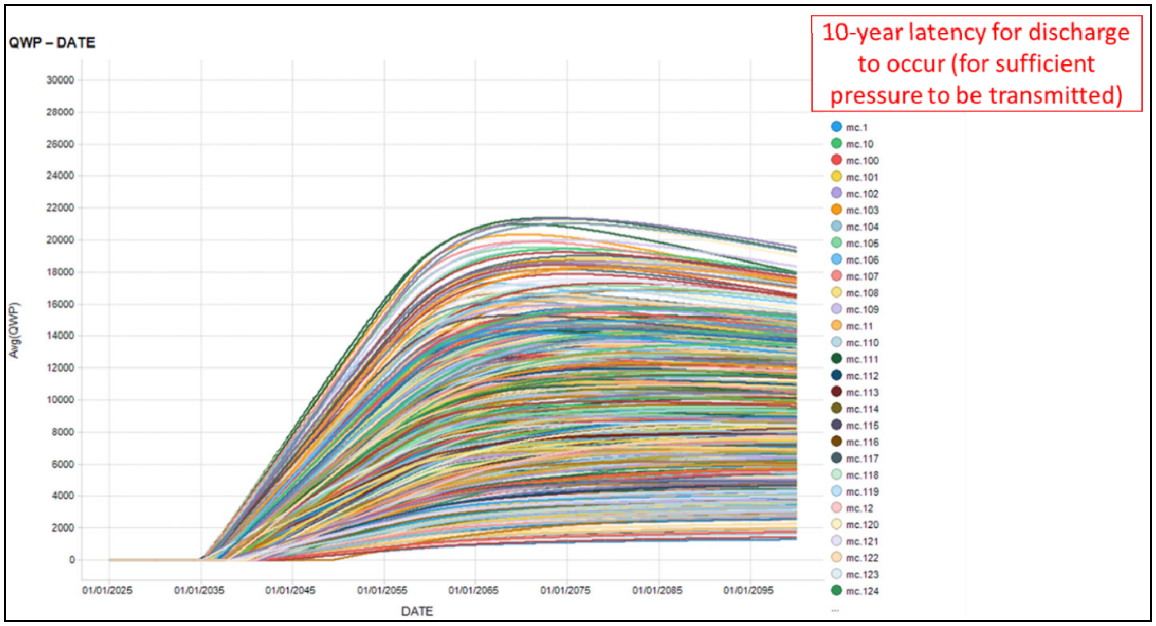


Figure 60 - Outcrop discharge (stbw/d) for the 500-case model ensemble (clustered 5-well scheme, MC16)

Ultimate storage capacity is impacted by well placement as a subsea development scheme can allow for the wells to be better distributed across the structure providing a robust mitigation against any compartmentalization as shown in **Figure 61**.

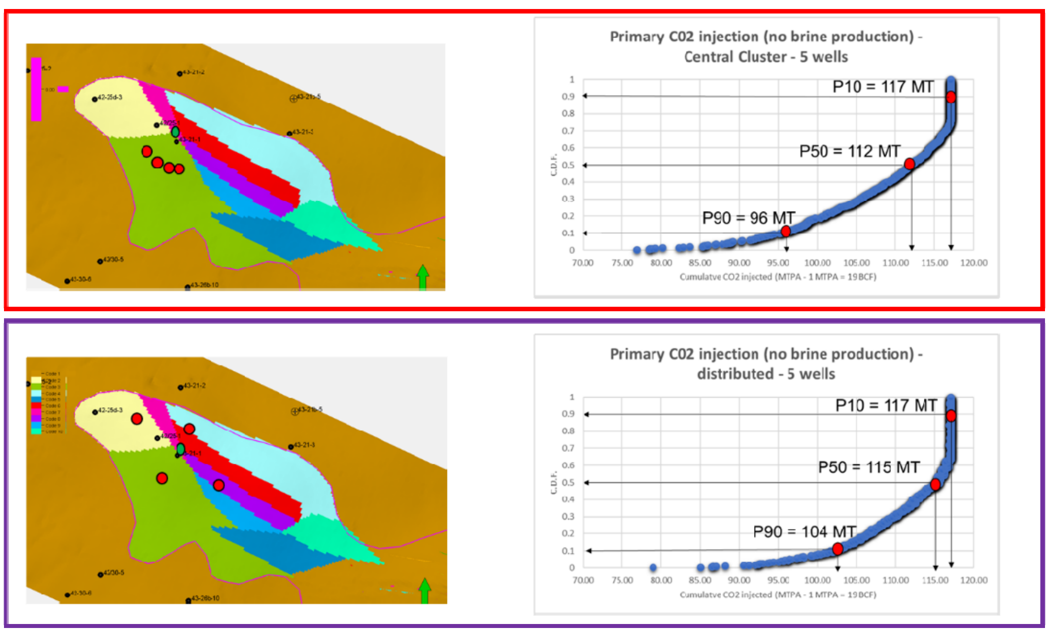


Figure 61 - Storage capacity for Phase 1 clustered (above) and distributed (below) development without pressure management (brine production) for 25 years. Downside (P90), base case, and upside (P10) cases are highlighted

Note that cumulative injected volumes are capped for high percentile as 5 MTPA is achieved for 30 years for some cases where long-distance connectivity is excellent.

8.5 Downside, Base, and Upside Scenarios

Probabilistic downside case (~P90) and upside case (~P10) in addition to the reference case were identified from the Monte Carlo-derived ensemble of 500 models (Figure 62). These three cases have been used to assess various development scenarios including the reference case for Phase 1 where circa 4 MTPA is injected for 25 years. Storage capacity for Endurance without brine management is at least 104 MT of CO2 (P90 subsurface case) for a distributed well layout for 25 year-long project (Figure 61).

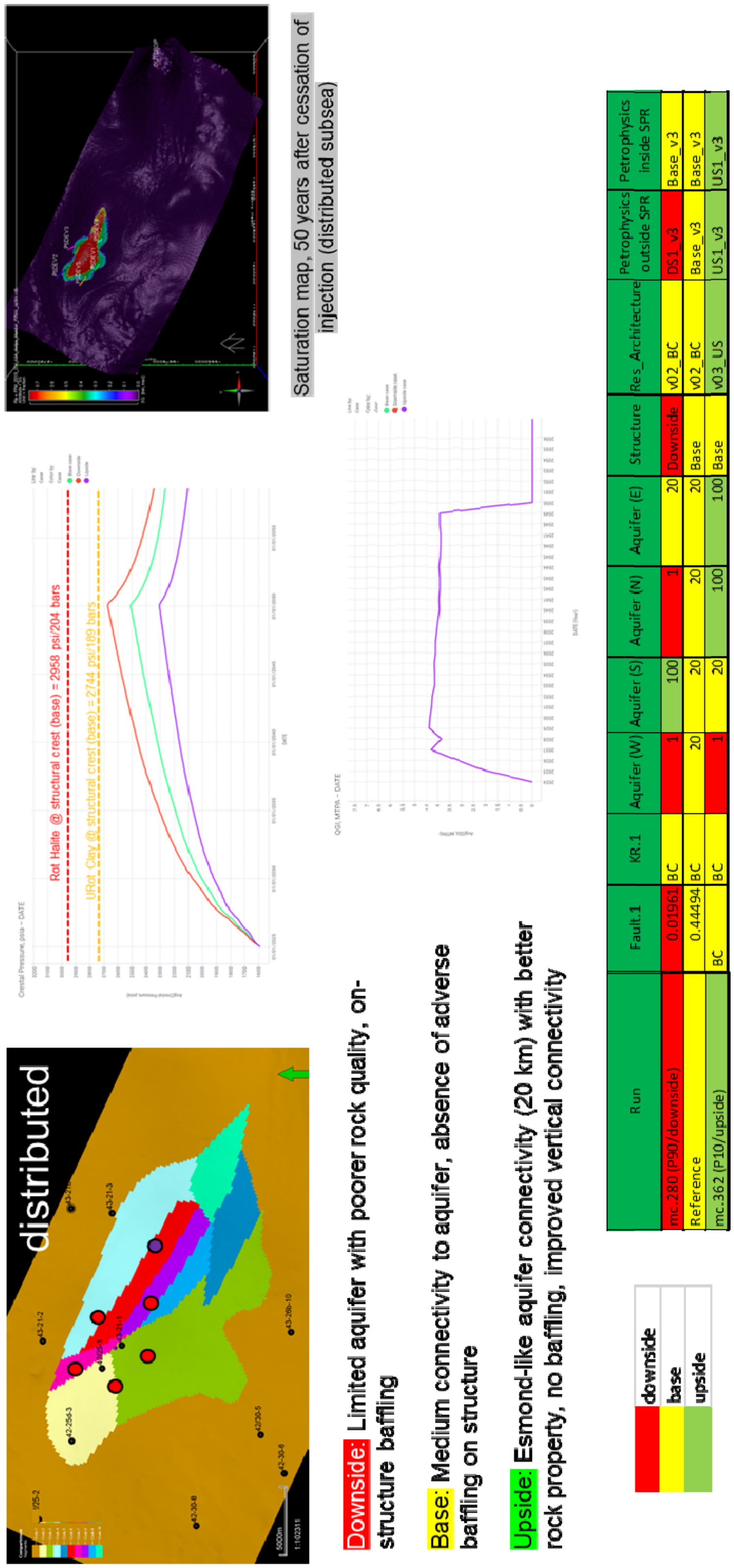
Phase 1 is therefore expected not to require pressure management for 4 MTPA over 25 years (at least 100 MT storage capacity).

The downside scenario does offer some degree of compartmentalization and limited connected aquifer (with poorer properties than base assumptions). The upside scenario offers greater connectivity to the Bunter aquifer as well as improved vertical connectivity (upside case for reservoir architecture). These two cases present reasonable end members in terms of the overall system connectivity and its associated response when CO2 volumes are injected.

A limited aquifer associated with some sub-seismic baffling will lead to rapid compartmentalization (hence faster requirement for active pressure management through brine production) i.e. probabilistic downside. On the other end of the spectrum, excellent rock properties for an extensive aquifer alongside favourable reservoir architecture (i.e. high Kv/Kh) would enhance the pressure dissipation and allow the injection for longer without brine production.

In fine, early dynamic appraisal through a low-rate scheme will allow to improve understanding of the system connectivity and its capacity to accommodate larger volumes of CO2 without excessively pressuring to avoid pressure management with brine extraction.

The pressurization of the structure in Endurance might also lead to the release of brine into the sea through the underwater Bunter outcrop 20 km east of Endurance (always provided that the Bunter outcrop be in hydraulic communication with the Endurance store). Outflow from the outcrop is indeed expected for Phase 1 as shown in **Figure 60**. This release is expected to be quite marginal in terms of flux i.e. potentially in the order of thousands of barrels over 1 to 2 square kilometers of Bunter exposure in late life of the project with mobilized brine from the shallow depths of the outcrop through which brine composition is expected to be close to sea water (static equilibrium expected).



Run	Fault.1	KR.1	Aquifer (W)	Aquifer (S)	Aquifer (N)	Aquifer (E)	Structure	Res_Architecture	Petrophysics outside SPR	Petrophysics inside SPR
mc.280 (P90/downside)	0.01961	BC	1	100	1	20	Downside	v02_BC	DS1_v3	Base_v3
Reference	0.44494	BC	20	20	20	20	Base	v02_BC	Base_v3	Base_v3
mc.362 (P10/upside)	BC	BC	1	20	100	100	Base	v03_US	US1_v3	US1_v3

Figure 62 - Geologic scenarios against revised average injection profile with Humber Phase 1 volumes (3.7-4 MTPA plateau over 25 years)

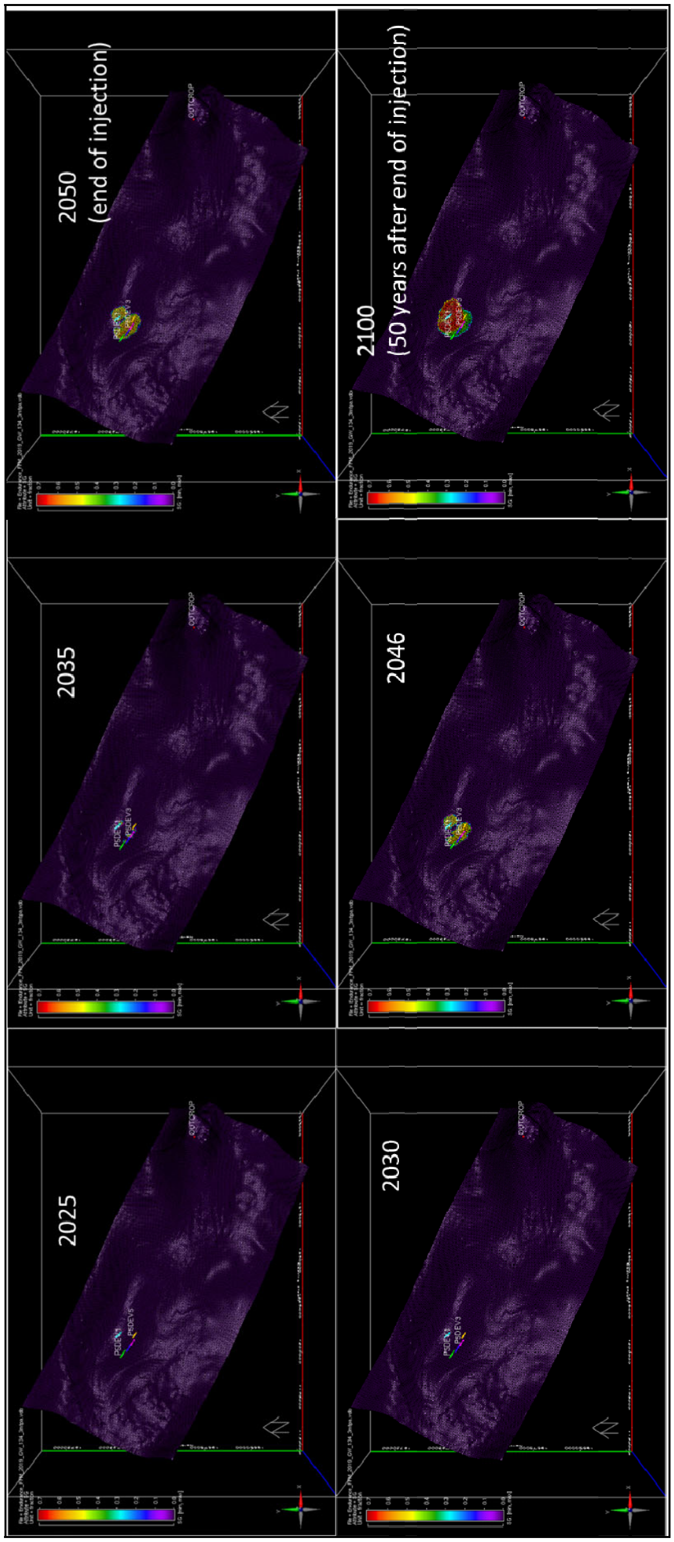


Figure 63 - CO2 saturation map (top reservoir) for various time steps for single-cluster with 3 MTPA.

(initial = 2025, 2030, 2035, 2046, 2050 = end of injection after 25 years, and 2100 = 50 years after end of injection)

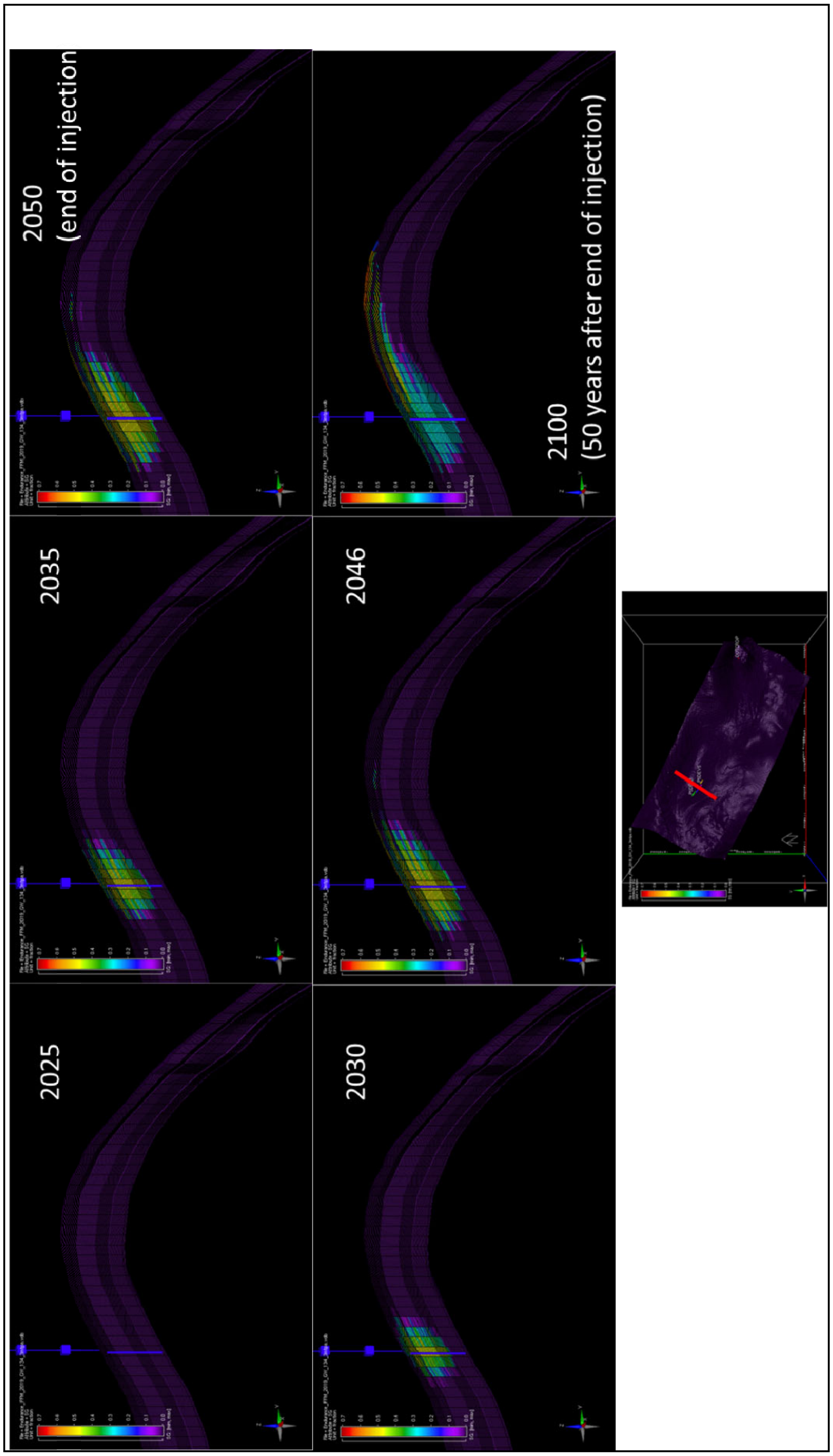


Figure 64 - CO2 saturation map (top reservoir, cross-section) for various time steps for single-cluster with 3 MTPA.

(initial = 2025, 2030, 2035, 2046, 2050 = end of injection after 25 years, and 2100 = 50 years after end of injection).

8.6 Impact of Thermal Effects

The injected CO2 is expected to reach 10-12 degrees centigrade at bottom hole location and analytical screening with a bp internal tool (LM Frac™) has indicated that injectors might be likely to be subject to thermal fracturing. The cooled region is expected to be restricted to the near-wellbore region as shown in **Figure 65** when Endurance model is run with thermal option in the commercial simulator GEM™ (by Computer Modelling Group Ltd).

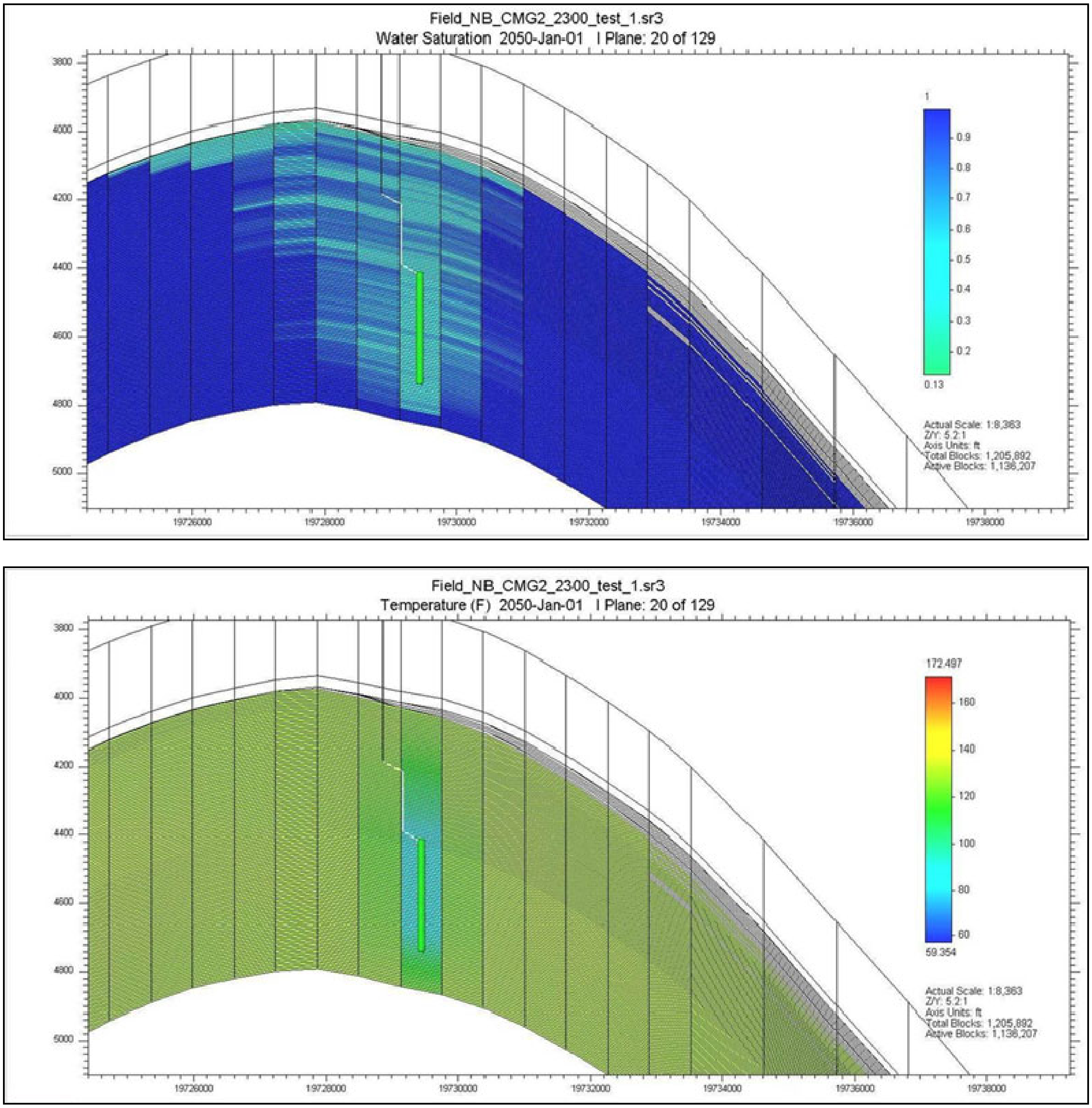


Figure 65 - GEM™ thermal simulation to screen cooling in the vicinity of an CO2 injector

The impact of thermal fracturing on injectors has evaluated in REVEAL™ (coupled fluid flow-geomechanics commercial simulator by Petroleum Experts Ltd) for a sector model to inform injection conformance, injectivity over time, and wells defined operating limits (risk of vertical fracture growth). The results of the study have indicated the following:

- The Risk of vertical fracture growth is manageable and low based upon screened tested cases:
  - No case presents fracture reaching top Bunter by the end of injection
  - The study has demonstrated the value of leaving a section of the Bunter unperforated (at least 20-30 meters), both for pressure limit and conformance
- Skin build-up (and associated injectivity loss) is likely to be offset by thermal fracturing. In the low probability case where fracturing does not occur and there is formation damage (case #4/V37 with low Young's Modulus and high skin), late life BHP could require curtailment due to WDOL pressure limit for the crestal well. This indicates the importance of avoiding high skin in order to achieve acceptable injection rate across the full uncertainty range. Further assurance on Young's modulus would help, for example from quantitative analysis of the 2013 water injection test in 42/25d-3, in which fracturing did occur.
- Thermal fracturing is not adversely impacting the confinement of CO_2 plume movement. In particular, there appears to be a low risk of CO_2 moving vertically through a fracture to top reservoir. The potential low kv/kh system (well 42/25d-3 PTA interpretation) would support longer perforated interval i.e. 80 meters. The well is unlikely to thermally fracture immediately hence maintaining good conformance over the initial period.

9.0 Technical Limits for Endurance Store

The Nexus® reservoir model for Endurance (base case geologic scenario) has been used to assess potential technical limits with plateaus at 10 MTPA, 15 MTPA, 18 MTPA, and 20 MTPA based upon the reference reservoir model. The maximum CO_2 storage capacity of Endurance is estimated to be circa 450 MT (25 years at 18 MTPA or 30 years at 15 MTPA). Storage tipping point is around 18 MTPA, above which plateau cannot be maintained to 2050 (25 years) and CO_2 starts to break through into brine producers. The technical limits are based upon the reference case are dependent on the level of reservoir complexities.

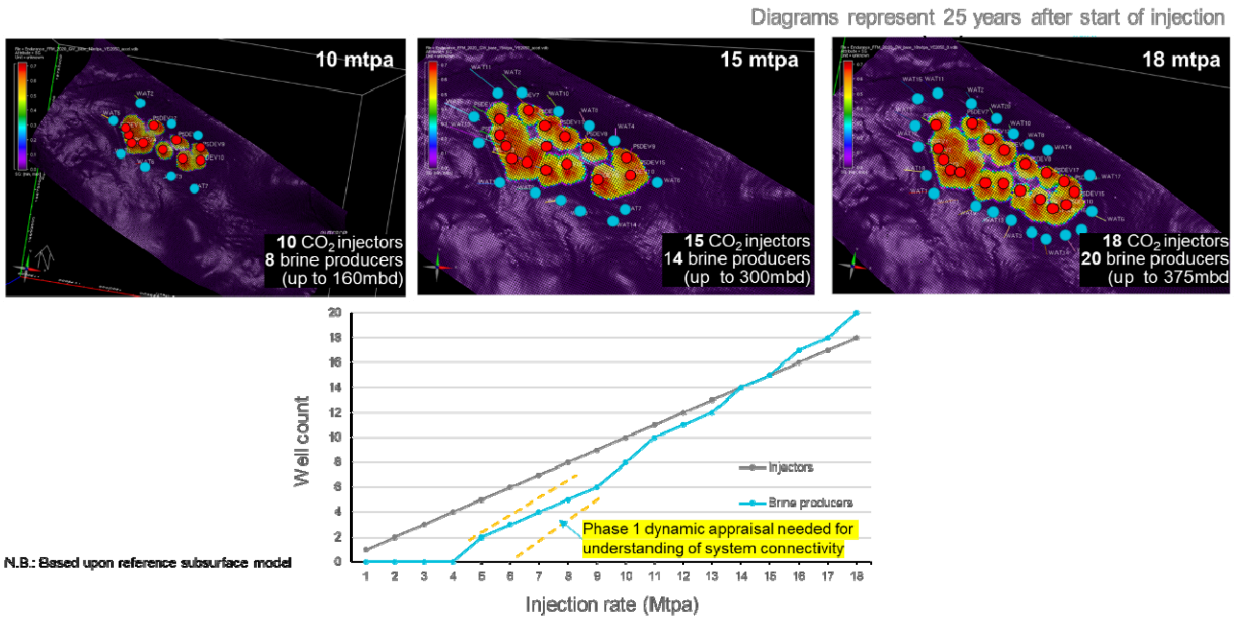


Figure 66 - Technical limits for Endurance store

Phasing is critical i.e. 3-5 years at low-rate plateau to understand reservoir connectivity to the greater Bunter aquifer (pressurization response), injection conformance (in-well monitoring such as ILT, time-lapse saturation logging), and early plume movement (4D seismic). Reservoir monitoring data will be used to further calibrate reservoir model.

Any higher-rate plateau acceleration will tend to increase the risk profile by limiting the dynamic appraisal of the store before significant investment for brine production is required to ramp up to 10 MTPA and beyond.

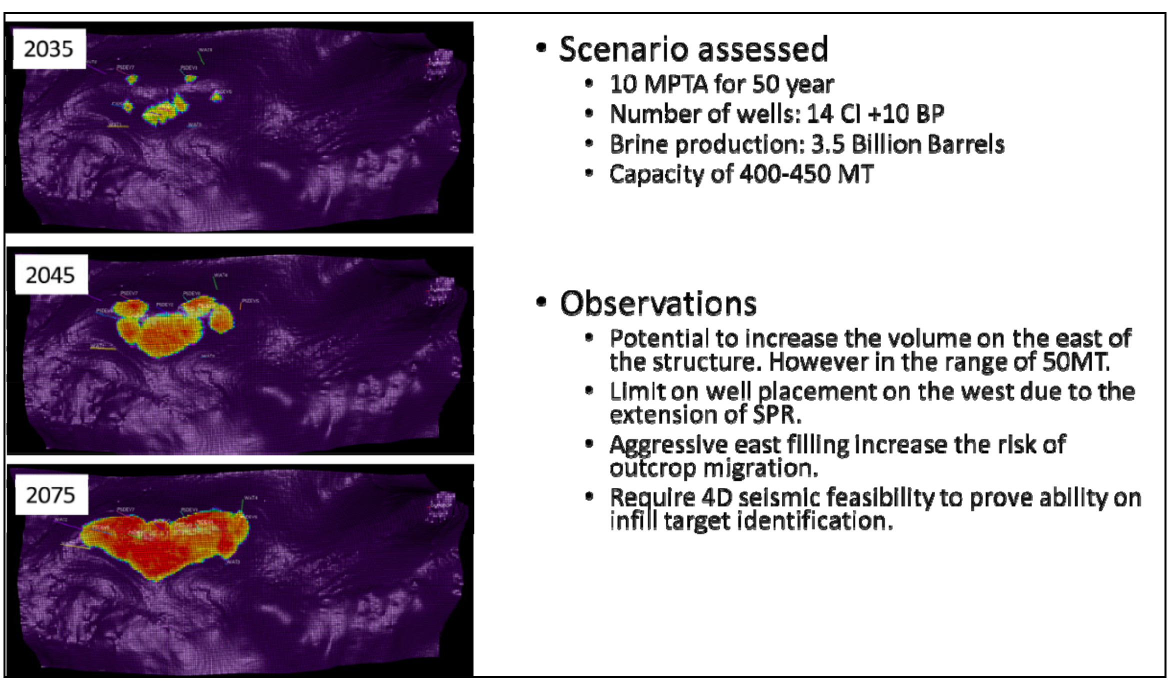


Figure 67 - Technical limits for the store at 10 MTPA for 50 years

10.0 Storage Efficiency Estimation (Base Case Geologic Scenario)

Storage efficiency for the full-field model ranges from 3 to 4% for cases without pressure management (i.e. Phase 1 with stored CO2 around 90 MT). The use of pressure management, through brine production is expected to increase the storage efficiency up to 15% or 450 MT.

	Phase 1 (90 MT)	10 MTPA Expansion	10 MTPA Technical Limits
1. CO2 injected (MRB)	8.99*10^5 (88 MT)	24.1*10^5 (250 MT)	39.2*10^5 (435 MT)
2. Brine volume above spill point @1450m TVDss (MRB)	2.65*10^7	2.65*10^7	2.65*10^7
3. Offtake from brine producers (MRB)	0 (0 BP)	9.2*10^5 (8 BP)	23.9*10^5
4. Storage efficiency (brine replacement ratio) including brine production	3.4%	9.1%	14.8%

Figure 68 - Storage Efficiency for considered life of notional field cases

Row 4 is defined as the ratio of row 1 (CO2 injected) and row 2 (brine volume over the spill point). Note that reference case is considered.

11.0 Surveillance Requirements

Monitoring, Measurement, and Verification (MMV) requirements for Endurance are described in Figure 69.

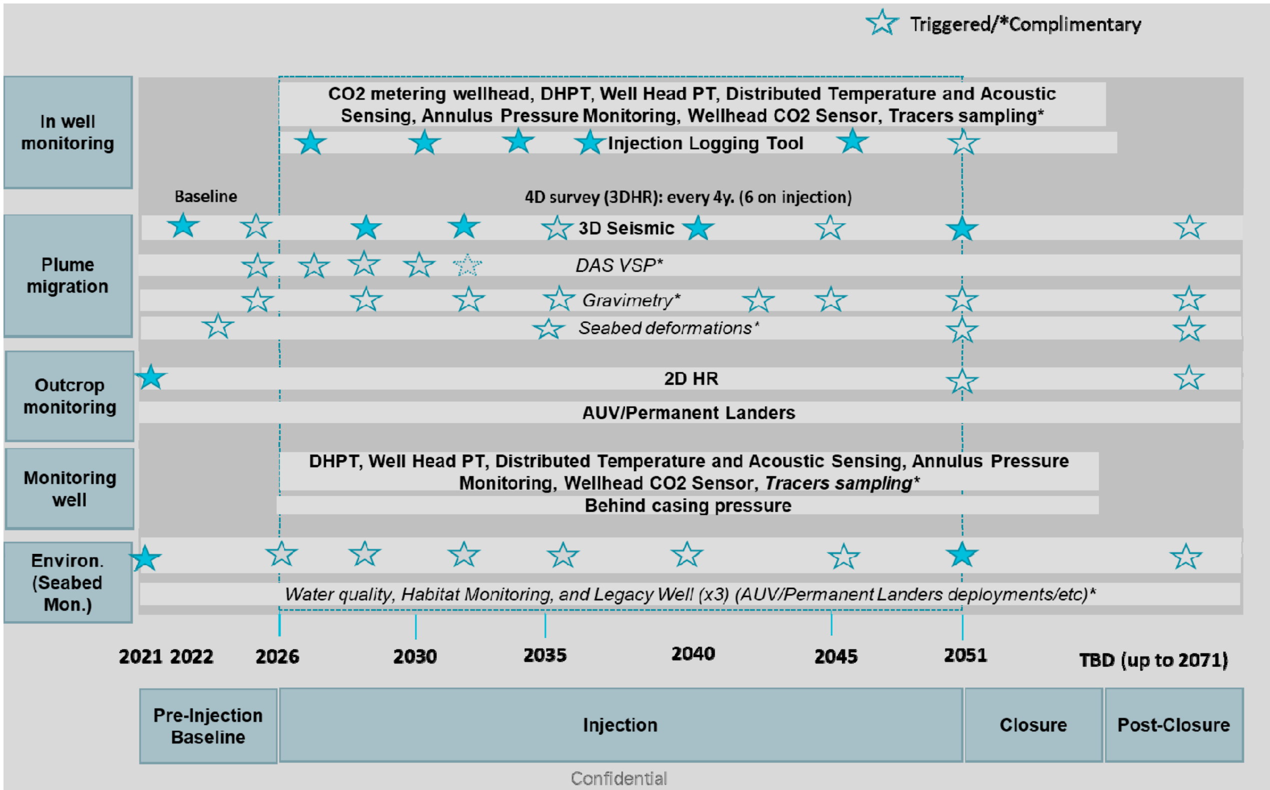


Figure 69 – Provisional MMV program for Endurance

11.1 Summary

- MMV is a vital part of CO2 storage projects, including communication with authorities and local communities.
- Industry experience suggests the use of 4D seismic, extended well monitoring and seabed surveys as the core set of data acquisition for MMV in offshore fields. This will enable effective CO2 monitoring with high.
- Repeats of 2D HR seismic data (2D/4D) can be considered as a viable alternative of traditional 3D repeats to achieve high frequency repeats at reasonable cost within the constraints of the windfarm. Proof of concept data will be acquired in 2020/2021 to demonstrate imaging and 4D repeatability.
- A base line survey, with the focus on seabed observations and fluctuations over the seasons, is critical for interpretation of future data.
- New technology development based on autonomous underwater vehicles and landers should allow for sufficient seabed monitoring for both CO2 leaks and environment impact assessment.

Figure 70 is a table produced as an outcome of this assessment (In white the main proven methods, in yellow the complementary ones, in red, the studied ones but not (yet) matured).

Area	CO_2 Plume Migration Mon.	Well Integrity	Outcrop Monitoring	Brine Management Monitoring (Phase 2++)	Environmental/ Seabed Mon. (not subsurface perimeter)
Mitigated risks	Geological leakage. Unexpected plume migration. Wells leakage.	Well leakage. Legacy wells leakage.	Outcrop leakage (CO_2 and Brine). Unexpected plume migration.	CO_2 leakage via brine producers. Brine disposal impact to seabed.	Environmental impact of CO_2 leakage and brine disposal.
Methods	Seismic methods (4D combined with 2D HR) 2D HR 3D Survey Saturation logs (cased hole) Well rates/pressure ILT Gravimetry VSP DAS DTS to the top perf ILT DAS Borehole gravity Behind casing monitoring on crestal well Tracers Seabed deformation measurements EM (CSEM)	Annulus A Acoustic cement logs VSP DAS Visual survey (Landers) Casing inspection tools	AUV Landers Tracers Deep Geological Borehole	Brine producers well rates CO_2 content/Ph/Salinity AUV PLT Tracers Landers Saturation logs (cased hole)	Comprehensive Base line Time-lapse AUV Landers Tracers

Figure 70 - Monitoring technology assessment for Endurance

11.2 Intervention Requirements and In-well Monitoring

A series of intervention requirements and in-well monitoring will be required to support Phase 1 offshore storage project.

11.2.1 Water Washing

Based on GEM™ modelling for halite deposition, two days per injector per year are expected to flush the near wellbore with fresh water after an initial pre-flush prior to CO_2 injection. This will be done from a vessel set up to connect to either the tree or manifold in a similar manner to a scale squeeze.

11.2.2 Intentional Surveillance (Light Interventions)

- Baseline Injection Logging Tool (ILT) in the 4 wells for NZT/NEP Phase 1 to establish inflow profile after one year of injection.
- Regular ILT surveys carried out from a light well intervention vessel (LWIV) to provide time-lapse monitoring of sweep.
- Time-lapse Saturation log in the observation well

Heavy intervention from a rig might be required for well intervention such as recompletion or workovers.

11.2.3 In-well Monitoring

In-well continuous surveillance is planned as follows:

- Downhole Pressure-Temperature Gauge (DHPTG) in both the tubing and the annulus. The annulus gauge is included to allow 'A' annulus pressure monitoring when the fluid level drops due to thermal contraction on injection. Under these conditions, the conventional gauge in the tree is not in contact with the fluid and so does not register. An alternative is to install a nitrogen-cushion to expand to fill the void, but this is operationally more complex.
- Behind-casing pressure monitoring is a technology option. Systems are available from several vendors that allow pressure to be monitored behind cemented casing, which would enhance reservoir surveillance particularly in the observation well close to the crest.

12.0 Uncertainty and Risks

The major subsurface risks for Phase 1 are as follows:

- Unexpected plume migration
- Leakage risks (Separate risk assessment reports– Risk and MMV KKD [8], Risktec [9], and Endurance Field Legacy Well Integrity Assessment [10])
- Reservoir architecture uncertainty and implication on injectivity and capacity
- Monitorability of the structure and well placement in the presence of the wind farm
- Halite precipitation and impact on injectivity
- Environmental impact of outcrop brine release should the former be in hydraulic communication with Endurance store.

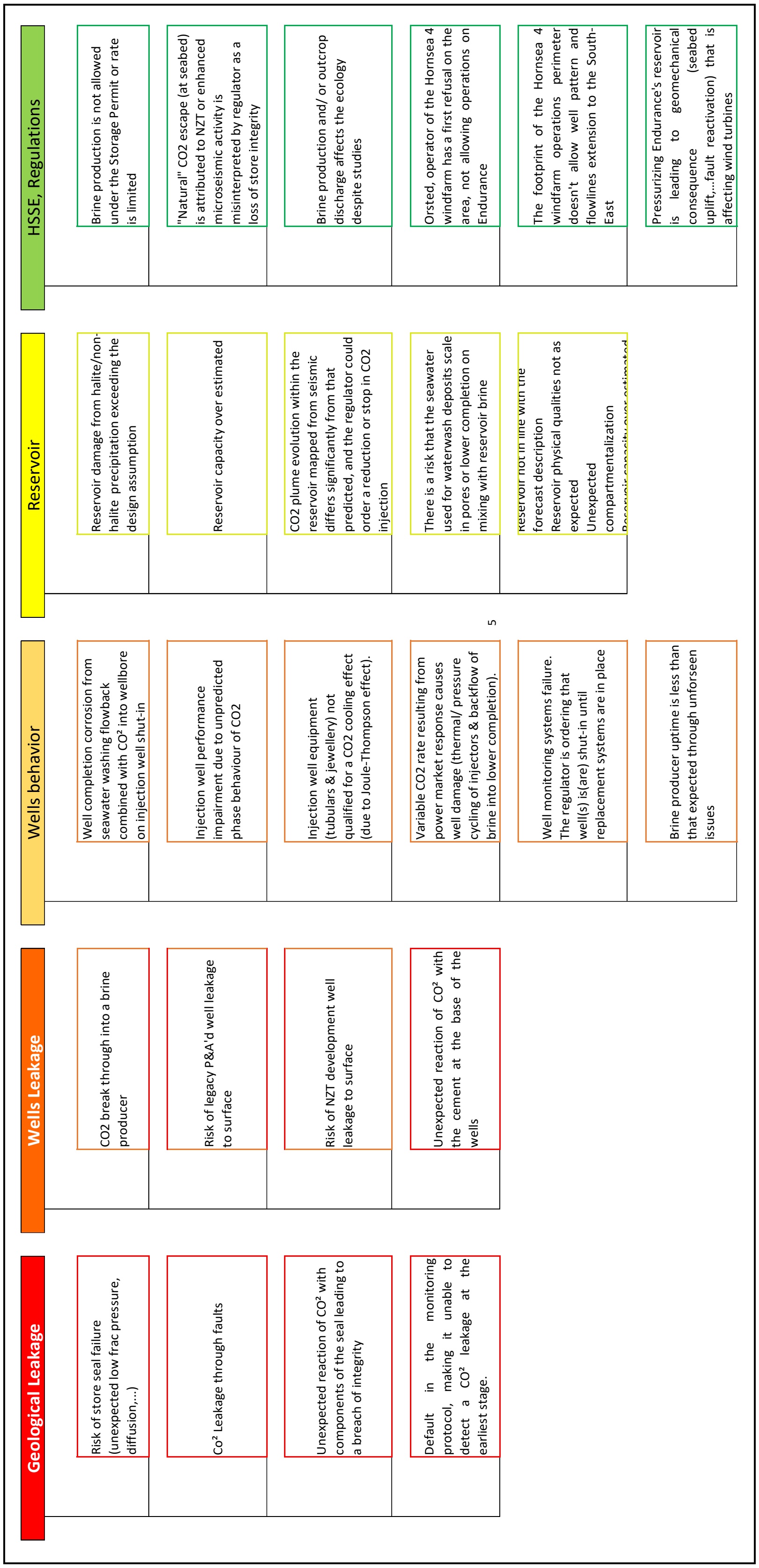


Figure 71 - Subsurface Risks for Endurance

13.0 References

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- [6] Reactive transportation modelling in GEM™ for Endurance, Endurance Geochemical Model & Report (KKD)
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