Planning for Commercial Scale CO\textsubscript{2} Storage in a Massive UK Saline Aquifer

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1. Introduction

National Grid Carbon (NGC) is a wholly owned subsidiary of National Grid PLC whose primary function is building and managing the network of high pressure gas pipelines and high voltage electricity transmission lines that provide the energy infrastructure in mainland Great Britain. NGC is seeking to develop a Carbon Capture and Storage (CCS) business in the Yorkshire and Humber area of North Eastern England by connecting large scale CO\textsubscript{2} emitters via a 24” onshore and offshore pipeline to potential geological stores in the UK Southern North Sea (SNS).

NGC is working with the Don Valley Power Project (a new power plant with carbon capture at Hatfield) and with Capture Power Limited (a new power plant with carbon capture at Drax) on the White Rose CCS Project. White Rose is one of two full chain commercial scale demonstration projects selected for support from the UK Government CCS Commercialisation Programme (Front End Engineering and Design [FEED] funding was confirmed in December 2013, [UK Government, 2013]). These projects are part of a hub and spoke arrangement that NGC call “The Humber Cluster Project”, see Figure 1.

In the context of large scale CCS in the UK the expectation is that all CO\textsubscript{2} storage sites will be located offshore; this is because of a lack of suitable onshore stores, likely public hostility, etc. [Senior, 2010].

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{possible_hub_and_spoke_scheme.png}
\caption{Possible NGC Hub and Spoke Scheme}
\end{figure}
2. Historical and Geological Setting

NGC began investigating storage options about five years ago, supported by funding from the European Commission, by purchasing multi-client seismic surveys and compiling a database of well data. Initial high level screening compared the merits of both depleted gas reservoirs and saline aquifers.

In the UK Southern North Sea (SNS) depleted gas fields were either considered too small or with insufficient reservoir quality whilst the larger fields are often still producing and hence unavailable in the timescale of interest. However, several large scale saline aquifer structures were identified as prospective storage locations, see Figure 2 from [Brook et al., 2003]. These structures are found in the Triassic age Bunter Sandstone Formation (BSaF) at depths over 1000 m. The depth, and hence pressure which will exceed 100 bars, will insure that any injected CO₂ will be in its supercritical state at reservoir conditions. The BSaF has an average thickness of 275 m and has fair to good porosities of 15-25% and permeability's of 10-1000 mD. Several generic studies looking at the potential of the BSaF for CO₂ storage can be found within the CCS literature, i.e. [Brook et al., 2003, Heinemann et al., 2012, and Noy et al., 2012].

Figure 2: Saline Aquifers and Esmond Gas Field in the BSaF of the UK SNS
Informed by these generic studies along with specific site analyses undertaken by NGC, a structure called 5/42 was selected for detailed review. 5/42 is a massive anticline structure at around 25 km long, 8 km wide with a reservoir section in excess of 250 m thick. It was selected not just because of its size but it is relatively close to shore, has few existing penetrations, has good seismic coverage and has no existing hydrocarbon coverage on the over-lying seabed.

In terms of seismic information, two surveys were available over at least part of the 5/42 structure. The Ravenspurn Ocean Bottom Cable (OBC) survey shot by Western Geophysical in 1997 covers the whole 5/42 structure. The PGS Mega Merge multi-client survey consists of various vintages of towed streamer data and covers the western half of the structure. Note that a new speculative survey has very recently been shot over quadrants 42 and 43 of the UK SNS, see [Polarcus, 2013].

The two existing penetrations of structure 5/42 were hydrocarbon exploration wells drilled on the crest of the structure in 1970 (43/21-1) and 1990 (42/25-1). Formation evaluation logs were acquired in both wells with some core and a Repeat Formation Tester (RFT) acquired in the later well; this will be discussed further in Section 6. No water samples were taken that could be analysed and the core coverage was found to be limited. A number of other wells have been drilled around the 5/42 structure targeting deeper stratigraphic intervals. The amount of log data acquired over the Bunter interval in these wells was limited but has proved useful in constraining the structure whose Bunter Top Surface map is shown in Figure 3. The red line surrounding much of the structure is the Seismic Phase Reversal (SPR) which is discussed in detail in Section 4.

Figure 3: Bunter Top Depth Surface (m TVDSS), Appraisal Well Location and SPR Contour

1 In 2015, the field was renamed Endurance, but the name 5/42 is retained here.
As of mid-2012 some uncertainties remained with respect to the suitability of 5/42 for CO₂ disposal. In particular, little was known about the strength and permeability of the cap rock which consists of 10-12 m of shale, known as the Röt Clay, overlain by about 80 m of halites and thin inter-bedded mudstones, known as the Röt Halite. Both layers display uniform thickness in all the wells surrounding the structure. In [Heinemann et al., 2012] the extent of this regional seal is discussed and it is noted how it becomes a proven seal in the Bunter hydrocarbon gas fields which lie about 50 km north of 5/42.

Although the target structure was well defined, there was little reservoir permeability data, especially vertical permeability and no flow test, production or injection, had been undertaken in 5/42.

To address these issues, the company applied for and was awarded the UK’s first Carbon Storage licence from the UK Government in November 2012 which permitted the drilling of appraisal well 42/25d-3 in the summer of 2013. The bulk of the funding for the well came from the European Energy Programme for Recovery (EEPR) along with some funding from the Energy Technologies Institute (ETI) as well as NGC. The ETI is using the NGC experience in designing and delivering the appraisal well to develop its generic understanding of the requirements for appraising aquifers, following on from its UK Storage Appraisal Project, the results of which are now available through the CO₂ Stored database, [CO2Stored, 2014]. The ETI are also promoting the idea of hub and spoke developments, such as that shown in Figure 1, connecting a number of potential geographically co-located onshore CO₂ sources like those in Yorkshire and Humberside to a set of co-located offshore storage sites like those in the UK SNS, [ETI, 2014].

3. Stratigraphy

A simplified stratigraphic column through the 5/42 structure is shown in Figure 4.
Underlying the BSaF, which is the target for the CO$_2$ injection, is the Bunter Shale and beneath that is the Zechstein salt. It is the movement of this salt which has created the 5/42 anticline.

Above the BSaF is a 10-12 m thick claystone called the Röt Clay; the presence and extent of this layer can be clearly seen from seismic. Overlying the Röt Clay is an 80-100 m interval called the Röt Halite. This particular interval is seen as especially beneficial to this project as it is known that halite, if disturbed, will move or creep to self-heal the perturbation. This movement is thought to take place relatively quickly in months or years, see [Orlic et al., 2014], depending on the size of the disturbance; further discussion of this topic can be found in [Xie et al., 1999], [IEAGHG, 2008] and [Hou et al., 2011].

There is further evidence for this conjecture on the self-healing properties of the overlying Röt Halite from the seismic coverage over the 5/42 structure. Figure 5 shows a WNW-ESE 2D seismic line shot from the survey boat that assessed the seabed in preparation for the 42/25d-3 well (and its backup location). The line was extended 20 km further east to cover an area where the Zechstein salt has created a diapir which has exposed the Bunter Shale and BSaF at the seabed; a feature called the “outcrop”.

The seismic line shows the interpreted horizons (top BSaF in green) and a number of faults in the overburden, all of which sole out in the Röt Halite.

Overlying the Röt Halite are alternate layers of shale and salt, some 900 m in total. Given the thickness of this package and the nature of the salt within it, it is hard to see how CO$_2$ stored in the 5/42 formation could leak from BSaF because of a geological pathway.

4. Seismic Phase Reversal (SPR)

As discussed in the previous section there were a number of possible locations for the appraisal well that were considered. With two penetrations in the crest, albeit with what was considered at the time to be limited poor quality core acquisition and a set of logs from the 42/25-1 well over only part of the reservoir, it was decided to focus down-dip toward the spill point of the structure. This was done to investigate the SPR seen on the seismic coverage of 5/42 and the surrounding area. The phase reversal
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is the red contour that surrounds 5/42 as seen in Figure 3. This feature opens out at the eastern and southern end of 5/42 where it extends for 10’s of kilometers on a regional basis.

Inside the contour, all wells show good quality reservoir through the whole of the Bunter sandstone interval with the upper part of the formation having porosity of 25% or more. Outside the phase reversal, the top of the Bunter sandstone is of poor quality with porosity less than 10%. Diagenetic cementation by halite is believed to be to be the cause of the reduction in reservoir quality.

This feature can be seen via seismic as a phase reversal as depicted in the north-south line across 5/42 shown in Figure 6. Explaining why this feature has occurred has proved very challenging and it took the intervention of our sedimentologist to offer up a plausible explanation, see [Blackbourn et al., 2015], that being Thermohaline Convection (THC) over geological timescales driven by temperature and salinity differences.

![Figure 6: North-South 2D Seismic line across 5/42 showing SPR](image)

The 5/42 anticline was formed by the movement of the underlying Zechstein salt. Beneath the centre of the structure the thickness of salt is about 1 km, twice that at the flanks. Typical ranges of thermal conductivity of salt, shale and sandstone are shown in Table 1; these ranges have been taken from [Railsback, 2011]. Consider that the BSaF is very clean with little clay or cement, the Röt Clay seems to contain predominantly illite finely interspersed with dolomite and the salt zones also appear quite clean on the Gamma Ray and are composed mainly of halite. Sub-dividing the thermal conductivity of the zones by lithology was considered unlikely to improve on the subsequent analysis because the reservoir and cap rock zones are relatively pure from the mineralogy point of view. With this caveat, note how the thermal conductivity of salt is about twice that of shale and sandstone.
The result of this variation is that a location in the centre of the structure at a given depth is likely to be hotter than a downdip location at the same depth using a simple 1-Dimensional (vertical) analysis. This temperature gradient can then drive convective flow. Dense saline fluid toward the centre of 5/42, being warmer and less dense, rises toward the top of the BSaF where it cools and becomes more likely to precipitate halite. To offset the rising plume, downdip brine will sink, dissolving halite as it warms and thus becoming denser. The upward and downward movement constitute a convective cell, i.e. THC. This is a well-known phenomenon that has been postulated and modelled in several localities, i.e. Gulf of Mexico and onshore Germany; the latter is of particular interest for this study as the BSaF is present across much of this area, see [Magri et al., 2009].

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>$\lambda$ [W/m$^2$/°C]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shale</td>
<td>1.0-3.0</td>
</tr>
<tr>
<td>Sandstone</td>
<td>2.0-4.0</td>
</tr>
<tr>
<td>Salt</td>
<td>6.0</td>
</tr>
</tbody>
</table>

Table 1: Typical Values of Thermal Conductivity by Rock Type

In itself the existence of convective cells within 5/42 is insufficient to remove any or all of the halite, it merely moves the salt from the base to the top of structure. Many of logs taken through the BSaF in wells surrounding 5/42 and outside the SPR show porosities of less than 10% in the upper part of the sequence with better quality rock below.

The final piece of this story is believed to be the outcrop to the east of 5/42 where the BSaF is considered to be open to the seabed. The salt diapir will accentuate thermal convection within the BSaF and this could allow sea water to enter the system. In the saddle between 5/42 and the outcrop, exchange between two convection cells is considered to be the mechanism by which salt has been removed from within the SPR.

5. Data Acquisition Program for 42/25d-3

The data acquisition program associated with the 42/25d-3 appraisal was arguably the most comprehensive in a UK SNS well in many years, see [Furnival et al., 2014]. A number of objectives were set which included:

- Retrieve core, especially from the cap rock and a significant portion of the BSaF
- Brine samples, ideally from more than one depth to identify any compositional effects, i.e. salinity versus depth
- Production and injection tests
- Conventional logging, i.e. Gamma Ray, Resistivity, Neutron and Density
- Special logging, i.e. Dipole Sonic for geomechanical modelling, Ultrasonic Borehole Imager (UBI) and Oil-Based Micro-Imager (OBMI) to look for fractures and faults, Nuclear Magnetic Resonance (NMR) to allow for permeability prediction and Electron Capture Spectroscopy (ECS) to identify mineral assemblages.
- Pressure measurements
- Mini-Frac and Vertical Interference Test (VIT)
- Formation Integrity Tests (FIT) in the overburden
- Production and injection Drill Stem Tests (DST) to assess dynamic reservoir performance
The core has been subject to a variety of tests including Conventional Core Analysis (CCA), Special Core Analysis (SCAL) which is discussed further in Section 7 and geomechanical evaluation. To complement the latter, some of the specialist logs, the FITs and Mini-Frac’s have been important to allow the development of a geomechanical model of the reservoir, its under-burden, side-burden and over-burden. The geomechanical data all suggest the reservoir and its cap rock are very strong.

The pressure measurements from Modular Dynamic Tester (MDT) will be discussed further in Section 6. The MDT tool also enabled three brine samples to be taken from different depths in the reservoir. Some of the key measurements taken from these samples are shown in Table 2 which indicates that as well as being very saline brine there is a clear variation in Total Dissolved Solids (TDS) and cation and anion concentrations with depth.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Unit</th>
<th>MDT Water Samples</th>
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<tbody>
<tr>
<td></td>
<td></td>
<td>1.04</td>
</tr>
<tr>
<td>MD</td>
<td>ft</td>
<td>5167.5</td>
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<tr>
<td>MD</td>
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<tr>
<td>pH</td>
<td></td>
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</tr>
<tr>
<td>TDS</td>
<td>mg/kg</td>
<td>253426</td>
</tr>
<tr>
<td>Sodium</td>
<td>mg/kg</td>
<td>85512</td>
</tr>
<tr>
<td>Potassium</td>
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<tr>
<td>Magnesium</td>
<td>mg/kg</td>
<td>2543</td>
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<tr>
<td>Chloride</td>
<td>mg/kg</td>
<td>154146</td>
</tr>
<tr>
<td>Sulphate</td>
<td>mg/kg</td>
<td>296</td>
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<tr>
<td>Bromide</td>
<td>mg/kg</td>
<td>473</td>
</tr>
<tr>
<td>Total BiCarb</td>
<td>mg/kg</td>
<td>51</td>
</tr>
<tr>
<td>Fluoride</td>
<td>mg/kg</td>
<td>0.15</td>
</tr>
</tbody>
</table>

Table 2: Concentration of Anions/Cations from MDT Samples

The VITs showed that the ratio of vertical to horizontal permeability was $0.10 < K_v/K_h < 0.36$ with a most likely value of 0.15. The production flow test indicated the average $K_h = 270$ mD with no discernible baffles or barriers within 1.3 km of the well.

Prior to the drilling of 42/25d-3, the permeability data for 5/42 was limited to just over 10 m of core taken from the 42/25-1 well along with data from analogue hydrocarbon gas fields in the Bunter like Esmond gas field. The accuracy of the measurements made on the 42/25-1 core was always considerable questionable as it was unclear how the drilling and coring had been carried out, i.e. Oil Based Mud (OBM) or Water Based Mud (WBM). This is considered extremely important given the highly saline nature of the brine. In 42/25d-3, the drilling fluid was switched from WBM to OBM well when a casing shoe was set near the base of the Lias, see Figure 4.
What was therefore surprising was that the porosity-permeability trend generated from the 42/25d-3 core was very close to that from the limited 42/25-1 core data and the analogue fields. The new trend is:

$$\log_{10}(K) = 15.6\phi - 0.9$$

(1)

Where $K$ is the permeability (mD) and $\phi$ is the porosity (fraction). With porosity varying from about 0.14 at the base of the Bunter to 0.27 at the top, the permeability varies between 20 and 2000 mD. With no baffles or barriers seen on seismic or from the well logs, any CO$_2$ injected into 5/42 is expected to move quickly towards the crest of the structure where it will initially form a secondary gas cap.

The porosity versus permeability (vertical and horizontal) distribution measured from the core is shown in Figure 7.

![Figure 7: Core $K_v$ and $K_h$ Measurements versus Porosity](image)

6. Pressure History of 5/42

As discussed in Section 5, the data gathering program undertaken in the 42/25d-3 well was very extensive. Part of the program included the collection of twenty pressure measurements throughout the BSaF using a MDT tool. This data is plotted in Figure 8 along with the RFT data measured in 42/25-1 in 1990. Note the pressure has fallen by 0.7 bar over the 23 years between the two sets of measurements and both sets of gauges are considered high quality.
The explanation for the fall in pressure is believed to lie in the behaviour of the Esmond gas field. Esmond is one of just eight hydrocarbon gas fields in the BSaF and lies about 50 km north of 5/42; see Figure 2.

In Esmond there are two Bunter sequences called the Upper and Lower sands. Production started from both sands in 1985 from an initial pressure of 157 bar and ceased in 1995 when the pressure had fallen to just 10 bar; the recovery factor was estimated to be 93%. The field was considered as a candidate for gas storage and was re-drilled in 2008 by well 43/15a-5 when it was found the pressure in the Lower sand had risen to 121 bar whilst the Upper sand remained at its abandonment pressure. A tank model with a transient aquifer description was used to estimate the size of the connected volume to Lower sand; the Upper sand, not present at 5/42, is considered isolated. The most likely transient model suggested Esmond was connected to an aquifer whose outer radius was 150 km or more, i.e. most of the BSaF in the UK SNS is thought to be connected, see Figure 2.

Another aspect of this pressure data worth considering is the likely hydrodynamic connection to the seabed outcrop some 20 km ESE of 5/42, far closer than the Esmond gas field. The detailed seismic covering the area, of which Figure 5 is just one 2D line, does not show any baffles or barriers to preclude a connection. Detailed sedimentological analysis of the 43/28a-3 well which was drilled through the western edge of the outcrop shows good quality sands that are more likely to flow than not. Finally, the THC hypothesis postulated to explain why 5/42 is good quality reservoir surrounded by poor quality (halite occluded) reservoir requires that there has been an exchange of low salinity brine with high salinity brine. Note some of the exchange fluid could even have been fresh water as the outcrop was above sea-level at the time of the last ice age some 10,000 years ago; this area is known as Doggerland.
If 5/42 and the outcrop are in pressure communication then the pressure at the outcrop which is at a depth of 65 m should be just over 7.5 bar. However, extrapolating the data in Figure 8, 140 bar at 1300 m True Vertical Depth Sub-Sea (TVDSS) to 65 m predicts a negative pressure assuming a constant gradient of 0.115 bar/m. To honour the known pressure in 5/42 and at the seabed it is necessary to have some variation in salinity and hence brine density, a gradient that would be developed via the THC mechanism.

### 7. Relative Permeability Measurements

One of the major data acquisition requirements from the 42/25d-3 appraisal well was collecting core for a wide range of measurements. In total 192 m of core was cut which included 14 m of Röt Halite and 12 m of Röt Clay. Some of the 166 m of BSaF core was plugged for Special Core Analysis (SCAL); after careful screening 37 plugs of varying porosity and permeability were used in this programme.

The SCAL program consisted of measuring capillary pressure by Mercury Injection (MICP) and centrifuge tests and core flooding at ambient and reservoir conditions (140 bar, 57 °C) using CO₂ and a synthetic brine of the required salinity; no contact angle was reported but the Interfacial Tension (IFT) was reported as 39.5 ± 0.8 mN/m (dyne/cm) at the stated pressure and temperature. Some of the results were, at first sight, somewhat unusual.

Figure 9 shows the plot of water permeability measured at 100% water saturation, $K_w(S_w=1)$, versus the Klinkenberg or Gas (CO₂) permeability measured at irreducible water saturation $S_{wir}$, $K_g(S_{wir})$. The solid line would imply $K_w(S_w=1) = K_g(S_{wir})$ whereas the dashed fitted line shows $K_w = 0.3879 \, K_g^{1.0835}$, i.e. for all values of permeability $K_g(S_{wir}) > K_w(S_w=1)$. Now because the reservoir is brine filled, the water permeability $K_w(S_w=1)$ is considered to be the reference absolute permeability $K_{abs}$ making the end-point water relative permeability $K_{rw}(S_w=1) = 1$ and therefore the end-point gas relative permeability $K_{rg}(S_{wir}) > 1$. The measurements were repeated several times to ensure they were consistent.

The laboratory measurements were undertaken by a team with many years of experience who have seen these “anomalous” results many times. Two arguments are offered for these results [Cable et al., 2011 and Cable, 2011]:

- The effect of clays, particularly fibrous illite
- A “lubrication” effect

Both the 42/25-1 and 42/25d-3 wells found little clay within the sampled BSaF but what presented was predominately illite. This mineral swells considerably in the presence of brine, see [Cable 2011], and presumably shrinks when the pore space is mostly CO₂ thereby enhancing permeability to the latter fluid. The term lubrication is not considered to be the appropriate description in [Cable, 2011] but it is described thus. “In a strongly water-wet system as exists in 5/42, the irreducible water saturation will occupy the smallest pores and wet all of the rock surfaces. This will leave all of the larger pores and channels accessible to the flowing non-wetting phase. The non-wetting phase would be insulated from all surface roughness and asperities, possibly reducing drag”. Both hypothesised mechanisms are consistent with the observed results.
The resulting set of drainage (solid lines) and imbibition (dashed lines) relative permeability data for the mid-permeability set of plugs is shown in Figure 10. Note the irreducible water saturation $S_{wi} = 0.078$, the imbibition critical or trapped gas saturation $S_{gt} = 0.359$ and the maximum gas relative permeability at irreducible water saturation $K_g(S_{wi}) = 1.554$; the drainage critical gas saturation was reported by the laboratory as $S_{gc} = 0.0$.
The Corey exponents varied for water (i.e. brine) between $4.7 < N_w < 6.0$ and for the gas (i.e. CO$_2$) between $2.5 < N_g < 3.0$. The irreducible water saturation, trapped gas saturation and maximum gas relative permeability were all found to be functions of the absolute permeability as shown below:

- $S_{wi} = 0.3069 K_{abs}^{-0.2440}$
- $\text{max}-K_{rg} = 2.3960 K_{abs}^{-0.0771}$
- $S_{gt} = S_{gi}/(1 + 1.7 S_{gi})$

Note that the trapped gas saturation is written in terms of the initial gas saturation $S_{gi} = 1 - S_{wi}$ and could therefore be written directly in terms of the absolute permeability.

The “high” values of CO$_2$ relative permeability and low value of irreducible water saturation is as might be expected given the fair to excellent rock properties found in the BSaF.

8. Pressure Response to CO$_2$ Injection

As discussed in Section 6 the likelihood is 5/42 is connected to the greater BSaF, see Figure 2. This is considered to be highly beneficial for CO$_2$ injection in this aquifer.

Using a classical material balance approach, the pressure increase $\Delta P$ caused by injecting a CO$_2$ volume of $\Delta V$, measured at reservoir conditions, is approximated by:

$$\Delta V \approx c_T V \Delta P$$

(2)

Here $V$ is the connected pore volume and $c_T$ is the total compressibility which in this case can be taken to be the sum of the rock compressibility $c_R \approx 5.6\times10^{-5}$/bar and brine compressibility $c_B \approx 3.0\times10^{-5}$/bar so that $c_T \approx 8.6\times10^{-5}$/bar.

The first phase of the CCS scheme envisages an injection rate of 2.68 Million tonnes of CO$_2$ per year (Mt/yr) with a 20-year injection period, i.e. total mass injected $\Delta M = 53.6$ Mt (53.6x10$^9$ kg). Note injecting 1.0 Mt/yr of CO$_2$ has an equivalent surface volumetric rate of 52 MMscf/d or 1.47 Mm$^3$/d. The temperature varies between 48.3 °C at the 5/42 crest (of 1050 m TVDSS) and 62.0 °C at the nominal spill (of 1500 m TVDSS) whilst initial pressure is 110.7 and 162.8 bars at these same depths. As shown in the next section, the most likely pressure increase from injecting 53.6 Mt CO$_2$ is about 35 bars so the maximum pressure in 5/42 will be around 200 bars at 1500 m TVDSS. Given this range of temperature of pressure CO$_2$ density in the reservoir will likely be $600 < \rho < 800$ kg/m$^3$ depending on temperature and pressure, see [Whitson and Brule, 2000]. Assuming an average density of $\rho_h = 700$ kg/m$^3$, the injected volume $\Delta V = \Delta M/\rho_h = 76.6\times10^9$ m$^3$. Combining this with the total compressibility value, the maximum increase in pressure can be estimated from (1) as $\Delta P \approx 891\times10^{-9}/V$ bar.

With reference to Figure 3 the 5/42 spill lies either to the south or south-east at about 1500 m TVDSS. Using this spill the low-mid-high pore volume has been estimated to be 3.6, 4.6, 5.1 Bm$^3$ respectively. Consequently, the most likely pressure increase from injecting the first load is 194 bar, almost certainly enough to damage the reservoir and the immediate cap rock. However as seen in Section 6 there is strong evidence to suggest that 5/42 is connected to a much larger volume than that of the anticline alone. This will be investigated further in the next section.
9. Simulation Modelling

Geological, simulation and geomechanical models of 5/42 and its surroundings have been constructed at the local and regional scale to investigate different issues related to CO₂ injection in 5/42; Figure 11 gives a flavour of these models.

The regional structural model covering an area of 47 km by 21 km is somewhat larger than the 5/42 anticline which is, as previously stated 25 km by 8 km. The increased size is so that the seabed outcrop to the ESE of 5/42 can be incorporated in any dynamic simulation model as it is believed they are in hydrodynamic communication, see Section 6.

Figure 11: Regional and Local Geological, Simulation and Geomechanical Models

The final dynamic simulation model (not shown in Figure 11) was 41 km long by 11 km wide and used a tartan grid, concentrating grid cells over the 5/42 anticline and over the outcrop with coarser cells between and at the margins of the model. Three levels of refinement where built in which the finest scale cells were either 100 m by 100 m, 200 m by 200 m or 400 m by 400 m. Vertical grid cell thickness was about 2 m in all cases. Some differences were seen in performance of the three models as measured by CO₂ arrival time at the crest, discussed in detail shortly, but as these were small it was decided to use the mid-scale model (200 m by 200 m aerially) for most work. This mid-scale model
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has dimensions of \((N_x, N_y, N_z) = (129, 41, 228)\) or 1.2 million total cells of which about 730,000 are active.

Note the pore volume of the simulation model is 20.0 Bm\(^3\) so that the expected pressure increase from injecting 76.6 Mm\(^3\) into this system would be 44.5 bar from Equation (2).

In order to test the effect of S/42 and its likely connection to the greater BSaF, Finite Radial Carter-Tracy (FRCT) analytic aquifers were attached to the sides of the simulation model. The size of the FRCT aquifer was varied as described by the dimensionless radius \(r_{\text{D}} = R_{\text{aq}}^\text{Out}/R_{\text{aq}}^\text{In}\) where \(R_{\text{aq}}^\text{In}\) and \(R_{\text{aq}}^\text{Out}\) are the inner and outer radius of the aquifer; based on the model size the equivalent \(R_{\text{aq}}^\text{In}\approx 12\) km. Also varied were the porosity and permeability of the attached aquifers using Equation (1).

![Crestal Top Bunter Pressure versus Aquifer Size](image)

Figure 12: Sensitivity of Crestal Pressure Increase to Aquifer Size

The sensitivity of the first phase of the CCS scheme to aquifer size and strength is shown in Figure 12 and Figure 13 respectively. Plotted is the pressure at the crest of the S/42 structure. Note the maximum increase in pressure after 20 years of injection is 63.0 bar for the case where no additional aquifer volume is attached, i.e. \(r_{\text{D}} = 1.0\); geomechanical modelling of the system indicates that both the reservoir and its surroundings will not fail at this level of pressure increase.

Post injection the pressure continues to fall because the outcrop is open to flow (of formation brine). Flow commences from the outcrop 2.5 years after the start of CO\textsubscript{2} injection, reaches a peak of 3500 m\(^3\)/d after 9.0 years and is still flowing at 30 m\(^3\)/d some 450 years after cessation of injection. This outflow is not considered an issue as the rates are far less than that from water-flooded oil fields in the UK North Sea and the brine expelled from the outcrop is expected to be comparable to that of sea-water rather than the reservoir brine.
As aquifer size is increased beyond $r_{eo} > 2.0$ the maximum increase in pressure does not fall significantly as the extra volume is too far away to have much effect over the relatively short injection period. It does have an effect post-injection but even then an aquifer with $r_{eo} = 3.6$ seems more than large enough. This dimensionless radius implies an outer aquifer radius of 43.0 km, less than the distance to Esmond.

In Figure 13 the aquifer size was fixed at $r_{eo} = 3.6$ and the reservoir porosity and permeability were varied with $(\phi, K) = [(0.06, 1.25), (0.13, 12.5), (0.19, 125), (0.26, 1250)]$. It is unclear what average values of $(\phi, K)$ best represent the Greater BSaF but the most likely values are considered to be $(\phi, K) = (0.19, 125)$. Thus injecting 53.6 Mt of CO$_2$ over a 20 year period is likely to increase the pressure at the crest of S/42 by 35 bar, well below the value likely to result in hydraulic fracturing of the reservoir and/or its surroundings.

The speed with which CO$_2$ will migrate from the proposed down-dip injectors in the North-West of the structure to the crest can be estimated by considering Darcy’s law applied in the vertical direction. Because the density of the supercritical CO$_2$ in the reservoir [$600 < \rho_C < 800$ kg/m$^3$] is always considerably less than that of the native brine [$\rho_B \approx 1170$ kg/m$^3$] the CO$_2$ will migrate upward until a barrier such as the Röt Clay is reached. The upward pressure gradient driving the CO$_2$ migration is therefore:

$$\frac{dP}{dZ} = (\rho_B - \rho_C)g$$  \hspace{1cm} (3)
Where \( g \) is the acceleration due to gravity (9.81 m/s\(^2\)). Assuming an average CO\(_2\) density of 700 kg/m\(^3\) the pressure gradient will be \( dP/dZ \approx (1170 - 700) \times 9.81 = 4610\) Pa/m. The upward Darcy velocity \( v_z \) is given by:

\[
v_z = \frac{K_v K_{rC}}{\mu_C} \frac{dP}{dZ}
\]

Where \((\mu_C, K_C)\) are the viscosity and relative permeability of CO\(_2\) and \(K_v\) is the average vertical permeability. The viscosity of supercritical CO\(_2\) at typical reservoir conditions is \(\mu_C \approx 0.06\) cP = \(6 \times 10^{-5}\) Pa.s, see [Whitson and Brule, 2000]. From Figure 10 an average value of CO\(_2\) relative permeability can be taken as \(K_{rC} \approx 1.0\). Finally, it was noted in Section 5 that the average horizontal permeability from the production test was \(K_H = 270\) mD \(\approx 270 \times 10^{-15}\) m\(^2\) whilst the most likely ratio of vertical to horizontal permeability \((K_V/K_H) = 0.15\) making the average vertical permeability \(K_V = K_H (K_V/K_H) = 40.5 \times 10^{-15}\) m\(^2\). Entering these values in Equation (4) gives \(v_z \approx (40.5 \times 10^{-15}) (1.0) (4610.0) / (6.0 \times 10^{-5}) = 3.11 \times 10^{-6}\) m/s \(= 98\) m/year.

This vertical velocity estimate can be compared with the cross-section taken from the simulation model after five years of injection, see Figure 14. The cross-section is taken along a line from the one of the proposed injectors in the North-West of 5/42 towards the crest.

![CO\(_2\) Saturation Cross-Section after 5 Years of Injection](image)

Figure 14: CO\(_2\) Saturation Cross-Section after 5 Years of Injection

The proposed wells are inclined at 60° to the vertical so that they can be accessed via wireline operations and only the lower half of the trajectory is perforated. The vertical distance between the top perforation and the crest of the structure is about \(\Delta Z = 300\) m hence the time to migrate to the crest is estimated to be \(\Delta t = \Delta Z/v_z \approx 3.1\) years. As is evident from Figure 14 the CO\(_2\) has reached the crest in this simulation (five years).

The sensitivity of crestal arrival time to average horizontal permeability is shown in Figure 15. The crestal arrival time for the \(K_H = 270\) mD case is 3.3 years which is comparable to that estimated above.
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The rapid advance is a combination of the high permeability, especially towards the top of the BSaF, the high $K_v/K_h$ and especially the high CO₂ relative permeability as described in Section 7. This behaviour is consistent with what is currently the world’s most famous CCS project in Sleipner, Norway. In this field the CO₂ has migrated beneath the cap rock seal more rapidly than expected, [Chadwick et al., 2010] and under-prediction of the absolute permeability has been suggested as the likely cause. The work done here suggests that the CO₂ relative permeability is potentially a more likely cause given that it is the permeability-relative permeability product, i.e. effective permeability which affects the CO₂ velocity.

![Figure 15: Sensitivity of Crestal CO₂ Arrival to Average Horizontal Permeability](image)

The CO₂ saturation after 20 years of injection and 60 years of shut-in is shown in Figure 16. The low saturation around the well and towards the 42/25-1 wellbore (light blue) is the residually trapped CO₂ whilst that at the crest under the 43/21-1 well is a secondary gas cap of free CO₂.

10. Long Term Behaviour

The CO₂ distribution shown in Figure 16 will not be the long term fate of the injected fluid. Over a period of 10’s years, CO₂ will diffuse from the secondary gas cap into the under-lying brine where it will dissolve. CO₂ saturated brine is slightly more dense than fresh brine. At the pressure, temperature and salinity pertinent to this project, about 10 sm$^3$ of CO₂ will dissolve in each sm$^3$ of contacted brine and the density will increase by about 1.5 kg/m$^3$ or 0.013%. After a few more 10’s years, this dense brine will start to sink to be replaced by less dense fresh brine flowing upward. This Diffusion Dissolution Convection (DDC) process has been discussed extensively in the CCS modelling literature and the interested reader is referred to [Pruess et al., 2008]. It is noted that geochemical reactions will take place between the brine, the CO₂ and the various minerals in the reservoir; this was out of
the scope of the work undertaken here but the interested reader is referred to [Liu et al., 2012] and [Amin, 2014].

The time required to reach the base of the BSaF can be estimated using the same logic as that used in the previous section via Equation (4). There is no relative permeability consideration as it is brine/brine flow for which a viscosity of \( \mu_B \approx 1 \text{ cP} = 1.0 \times 10^{-3} \text{ Pa.s} \) is used because of the high salinity. The pressure gradient will now be smaller than that of the buoyant \( \text{CO}_2 \), namely 
\[
\frac{dP}{dZ} \approx (1.5) (9.81) = 14.7 \text{ Pa/m}
\]
and the same average vertical permeability of \( 40.5 \times 10^{-15} \text{ m}^2 \) will be applicable. Combining these values gives an estimated downward velocity for the \( \text{CO}_2 \) saturated brine of \( 6 \times 10^{-10} \text{ m/s} \) or 0.019 m/year. Given that the distance between the base of the secondary gas cap and the base of the BSaF is about 200 m, as shown in Figure 15, then it will take around 10,000 years for the \( \text{CO}_2 \) saturated brine to reach the bottom of the structure.

![Figure 16: CO\(_2\) Saturation Cross-Section after 20 Years of Injection and 60 Years Shut-In](image)

This estimate was confirmed by detailed modelling. It was not feasible to use the Full Field Simulation Model (FFSM) with diffusion active. Instead a 2D cross-sectional model in which porosity varied linearly with depth from 27% at the top and 14% at the base was constructed. Permeability was calculated from Equation (1) and a small random perturbation of \( \pm 1\% \) was added to initiate the formation of dense brine fingers. The horizontal and vertical grid sizes are just 5 m and 1 m respectively and outside a central horizontal section of 100 grid cells (500 m), the flanks of the models consist of 200 grid cells each which dip at an angle of 2°, comparable to the dip seen in 5/42. Pore volume multipliers are added to the edge cells to take account of huge volume connected to 5/42.

The model is initialised with a primary \( \text{CO}_2 \) cap corresponding to the end of simulation in the FFSM. Figure 17 then shows the \( \text{CO}_2\)-Brine-Ratio in \( \text{sm}^3/\text{sm}^3 \) at a number of years into the future. The number displayed on each image is the year in question. Thereafter the \( \text{CO}_2 \) starts to diffuse into the underlying fresh brine. After 60 years, in 2100, some very small fingers of saturated brine are evident. These fingers become more prominent in years 2300 and 2500. After 2500, the fingers continue to grow but also to coalesce as small perturbations in pressure caused by the small changes in density between fresh brine and saturated brine start to cause some lateral movement. Eventually the saturated plume
becomes more evenly distributed and it reaches the base of the model in the year 12,000, about 10,000 years after the cessation of injection as predicted from the simple analysis above. From here the plume continues to spread throughout the model over the coming 1000’s of years.

Translating this behaviour to 5/42, it might be expected that the saturated CO$_2$ will eventually find its way to the saddle between 5/42 and the outcrop where the THC process has been postulated in which case there must be a risk that some CO$_2$ could find its way to surface. However, the timeframe for such a possibility must be the order of 100,000’s years and this is not considered a problem as the biosphere can manage such slow CO$_2$ emissions, see [Lindeberg et al., 2003].

Figure 17: CO$_2$-in-Brine Distribution at Stated Years
It is expected the convection phase of the DDC process will be retarded by the THC process and so the time to reach the base of the reservoir and then its saddle will be even longer. This is because the centre of the reservoir is likely to be warmer than the flanks at the same depth, the change in density will be negative, counter-acting the positive density increase which drives the convection of the saturated brine fingers. It has not been possible to simulate this possibility as the preferred software of choice does not support diffusion and thermal effects.

11. Where Next for 5/42?

NGC submitted its Storage Permit Application (SPA) to the UK government regulator in the summer of 2015. Subsequently the UK government withdrew its funding from the CCS Commercialisation Programme. Currently, the project is on hold whilst other sources of funding are being sought.

NGC has continued discussions with other emitters in the Yorkshire and Humber area who may wish to use both the main 24” CO$_2$ pipeline with a capacity of 17 Mt/yr and the 5/42 store. The first phase of the CCS scheme considered in this paper is thought to be about a quarter of maximum rate that could be injected in 5/42, i.e. 10 Mt/yr although this maximum rate will almost certainly require the production of fresh brine to create pore space and thereby avoid over-pressurisation. As mentioned previously however, this is not a concern given the rate of water production that has been occurring from UK oil fields over the last 40 years.

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# Symbols

- **c**: Compressibility \(1/\text{bar}\)
- **g**: Acceleration due to Gravity \(\text{m/s}^2\)
- **K**: Permeability \(\text{mD} \approx 10^{-15} \text{ m}^2\)
- **N**: Number of Grid-Blocks
- **P**: Pressure \(\text{bar}\)
- **r**: Radius \(\text{m}\)
- **S**: Saturation (fraction)
- **t**: Time \(\text{s}\)
- **v**: Velocity \(\text{m/s}\)
- **V**: Volume \(\text{m}^3\)
- **Z**: Vertical Direction \(\text{m}\)

- **ϕ**: Porosity
- **μ**: Viscosity \(\text{cP} = 1.0 \times 10^{-3} \text{ Pa.s}\)
- **λ**: Thermal Conductivity \(\text{W/m}^2/\text{C}\)
- **Δ**: Change in

## Subscripts

- **A**: Average
- **aq**: Aquifer
- **eD**: Equivalent Dimensionless
- **H**: Horizontal
- **r**: Relative
- **t**: Trapped (Imbibition Residual)
- **V**: Vertical
- **X**: X-Direction
- **Z**: Z-Direction

- **abs**: Absolute
- **C**: CO2
- **g**: Gas
- **i**: Irreducible
- **R**: Rock
- **T**: Total
- **w**: water
- **Y**: Y-Direction
- **H**:
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