Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project

Geologic Storage of Carbon Dioxide with Monitoring and Verification

Volume 2

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Geologic Storage of Carbon Dioxide with Monitoring and Verification

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Chapter 5

THE NGCAS PROJECT—ASSESSING THE POTENTIAL FOR EOR AND CO_2 STORAGE AT THE FORTIES OILFIELD, OFFSHORE UK

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ABSTRACT

The Next Generation Capture and Storage Project studied the potential to store underground 2 million tonnes of CO_2, approximately half the annual CO_2 emissions from the Grangemouth refinery and petrochemicals complex near Edinburgh, Scotland. The study concluded that the best potential storage site for these emissions was the Forties oilfield in the UK sector of the North Sea. Numerical simulation indicated that enhanced oil recovery using a WAG process and CO_2 as the injection gas would yield significant incremental oil. A Features–Events–Processes (FEP) identification process was used to narrow down the risks to storage at the Forties field. Numerical modelling was then used to assess the risks of CO_2 escape. It was concluded that the geological risks of CO_2 escape were negligible, but it was not possible to analyse the chances of CO_2 escape via pre-existing wells. The wells are perceived as the main uncertainty in the analysis and it is recommended that a comprehensive risk assessment methodology for wells is developed.

INTRODUCTION

The Next Generation Capture and Storage Project (NGCAS) was conceived in 2000 as a case study to test the potential for geological storage of large volumes of anthropogenic CO_2 captured from industrial plants.

By the time the project was conceived, there was already an indication that an attractive option for CO_2 storage on this scale might be to use CO_2 for enhanced oil recovery (EOR) in Europe's major oil province, the North Sea. The additional oil recovered would partly offset the costs of storage and there would be a more rational use of resources as a greater proportion of the oil resources in place would be produced. The Forties field stood out amongst BP's North Sea assets in terms of its storage volume: at least 75 million tonnes (Mt) of CO_2 could be stored underground as a result of EOR [1], with further potential if storage was continued for its own sake after EOR. Looking to the future, if a case could be made to build a CO_2 pipeline to the North Sea oilfields, there would be every opportunity for further CO_2-EOR projects because many North Sea oilfields appear technically suitable [1,2]. This would accrue further benefits to the EU in terms of import reduction and security of supply. This option clearly merited further investigation, but it was decided that the choice of a storage site should not be completely pre-judged as it was uncertain whether Forties really was the most cost-effective storage option, given the long transport distances from even the most northerly major industrial point sources of CO_2 in the UK and the high costs of offshore operations. Therefore onshore and nearshore areas which might have CO_2 storage potential were also considered.

Given the above it was considered that the source(s) of CO_2 selected for the study should be chosen from amongst the largest industrial point sources in the northern UK because these are relatively close to the oilfields, which lie in the Northern and Central North Sea. An obvious possibility was BP's Grangemouth refinery and petrochemical complex, some 30 km west of Edinburgh in Scotland, where a study was taking place to determine CO_2 capture costs. The Grangemouth site emits about 4 Mt of CO_2 annually. The Longannet and Cockenzie coal-fired power plants, which emitted 8.76 and 2.47 Mt CO_2, respectively, in 2000, are nearby. It was clear that these could be supplementary sources if required: they also added a "Cleaner Coal Technology" dimension to the project. Thus the Grangemouth site was selected as the nominal source for the project. It was arbitrarily assumed to have an additional 25 years of production, and thus it would emit roughly 100 Mt of CO_2 in the future. If half of this were to be made available to be stored rather than emitted to the atmosphere, the operation of the capture plant would emit an additional 600,000 tonnes/year of CO_2 [3]. The net CO_2 avoided would be 1.4 Mt/year and the net emission reduction would be 35%. It has been estimated that this might cost about \$50–60 per tonne CO_2, representing a total cost of about \$100–120 million/year [3]. However, the cost is sensitive to the price of natural gas, which is used as fuel in the capture plant.

STUDY METHODOLOGY

Strategy for Finding a Storage Site

The selected storage site needed to be able to receive 2 Mt CO_2 per year (half the CO_2 emissions from the Grangemouth site) and required a total capacity exceeding 50 Mt CO_2. The paramount requirement was that storage should be safe and secure. Thereafter, the minimum cost solution would be sought. Socio-economic factors, such as public acceptance and planning issues, would not be considered in the analysis. It was decided to investigate the storage possibilities in the onshore area around Grangemouth first, on the grounds that there would be low transport costs. If this proved fruitless, the search would move to the nearby offshore area to the east of the Firth of Forth known as the Forth Approaches, and then to Forties (Figure 1), which was the nearest oilfield known to have sufficient CO_2 storage capacity and where the greater transport costs might in part be offset by the potential revenue from EOR.

Potential for CO_2 storage onshore, near the Grangemouth site

The area around the Grangemouth site, known geologically as the Midland Valley of Scotland, is about 90 km wide and 300 km long and its long axis trends ENE (Figure 1). It is the most densely populated part of Scotland, containing the cities of Glasgow and Edinburgh and four-fifths of the Scottish population; approximately 3.9 million people.

Geologically, the Midland Valley of Scotland is a complex graben. It is bounded to the south by the Southern Uplands (which comprise mainly highly faulted and folded Ordovician to Silurian "greywacke" sandstones) and the north by the Scottish Highlands (mostly Dalradian and older metamorphosed sedimentary and igneous rocks). The geological contacts between the three terrains are defined by the major fault complexes of the Southern Upland and Highland Boundary faults. None of the indurated rocks of the Southern Uplands or the Scottish Highlands are suitable for CO_2 storage.

Within the Midland Valley of Scotland itself are several partly superimposed sedimentary basins of Upper Palaeozoic (i.e. Devonian, Carboniferous and Permian) age. Four major synclines, each containing Namurian and Westphalian Coal Measures, occur along its length. The easternmost of these is entirely offshore, in the Firth of Forth. Thus at first glance there seemed to be two possibilities for storing CO_2 in the Midland Valley: as free CO_2 in the pore spaces of sandstone reservoir rocks and adsorbed onto coal.

In general, the Devonian and Carboniferous sandstones of the Midland Valley of Scotland have low to fair porosity (up to 20%), very low primary permeability but sometimes quite significant secondary (fracture) permeability. They are probably unsuitable as CO_2 storage reservoirs because their permeability and porosity are thought to be too low at depth [4]. The Permian sandstones have good reservoir characteristics but are unsuitable because they are not sealed.

Coal seams are plentiful in the Midland Valley in both the Namurian Limestone Coal Formation and the Westphalian Coal Measures. Additionally, individual economically important coal seams occur

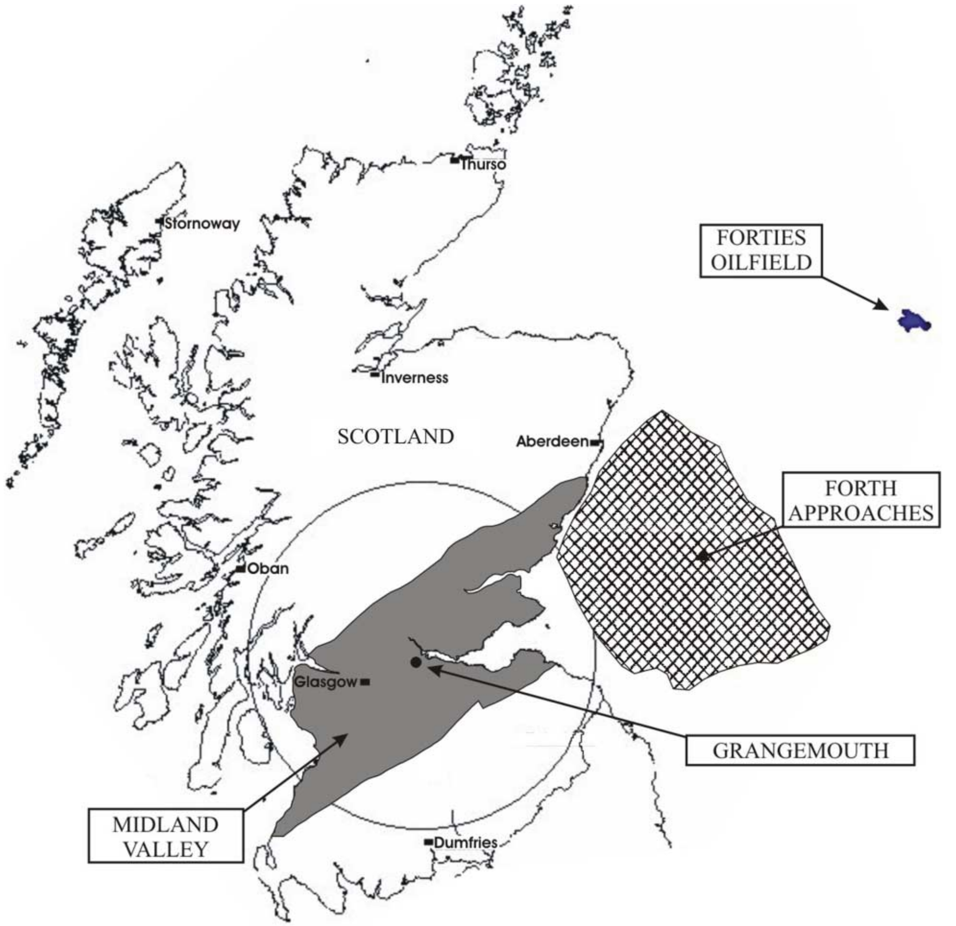


Figure 1: Location of the Grangemouth plant, the Midland Valley of Scotland, the studied area of the Forth Approaches and the Forties oilfield.

sporadically in other Carboniferous formations. However, the coal seams themselves may not be sufficiently permeable for large scale CO_2 storage. Moreover, the scale of operations that would be required to store 2 Mt of CO_2 per year indicates that storage in coal seams would be impractical at present [4].

The Midland Valley contains more than 100 boreholes that are in excess of 700 m deep and hundreds of abandoned coal mines. Both boreholes and mines are concentrated in the coalfields. There is clear potential for leakage through these, and also via pathways to the surface created by mining subsidence and natural migration pathways such as faults. Furthermore, groundwater abstraction and coal mining represent alternative uses of the subsurface that might take precedence over CO_2 storage.

Having considered and rejected the onshore Midland Valley as a potential storage site, attention was directed to the area immediately offshore, in the Forth Approaches (Figure 1). The Carboniferous and Devonian geology of this area is thought to be similar to that of the Midland Valley itself, but there was a possibility that the highly porous and permeable Permian sandstones seen onshore might be capped by Zechstein evaporites that would provide a good seal to retain any injected CO_2. However, it became clear that there was significant uncertainty as to whether the Permian sandstone reservoir was present and whether the evaporites would form a good cap rock, because in places the evaporites had clearly been subject to dissolution. Consequently, the Forth Approaches area was also rejected as a potential storage site and attention was focused on the Forties field.

Simulation of CO_2 Injection and EOR at the Forties Oilfield

The first step in the investigations at the Forties field was to use a numerical simulation model to investigate the optimisation of incremental oil recovery and storage of CO_2 at the field. The study was conducted using the VIP compositional simulation model to represent a sector of the Forties Charlie Sand. The model was initially waterflooded and then subjected to WAG with CO_2 as the injection gas. A range of simulations was performed to investigate different WAG strategies, timing of initiation of postflood gas injection, well placement, and well completions.

An existing VIP sector model of the Charlie Sands, provided by BP, was used as a starting point for the modelling. The model represents a volume of 1500 m by 500 m by 38 m, divided into 60 by 5 blocks areally and with 76 layers. This gives a total of 22,800 blocks, of which 16,618 blocks are active. Average grid block dimensions are 25 m by 100 m by 0.5 m. The total pore volume in the model is 26.3 MMrb, with a hydrocarbon pore volume of 21.3 MMrb; this corresponds to a stock tank oil initially in place (STOIIP) of 17.8 MMstb. The model includes two wells, located at either end of the model. The fluid behaviour is represented by an EoS model with seven components (CO_2, $N_2 + C_1$, C_2–C_3, C_4–C_5, C_6–C_{13}, C_{14}–C_{19} and $C_{20}+$) and has a saturation pressure of 1165 psia at 205 °F (96 °C). Representative values of the fluid densities at reservoir conditions are included in Appendix A.

The oil–water relative permeabilities that were used in the BP sector model are presented graphically in Figure 2a (linear plot) and b (logarithmic plot). These show that a waterflood is likely to yield an efficient piston-like displacement. A portion of the remaining oil could then be displaced by the continuing waterflood also. Consequently oil recovery from the waterflood should be very good. This can also be seen in the fractional flow curve presented in Figure 3. The gas–oil relative permeabilities are shown in Figure 4. Three-phase relative permeabilities were determined using Stone's calculation method 2.

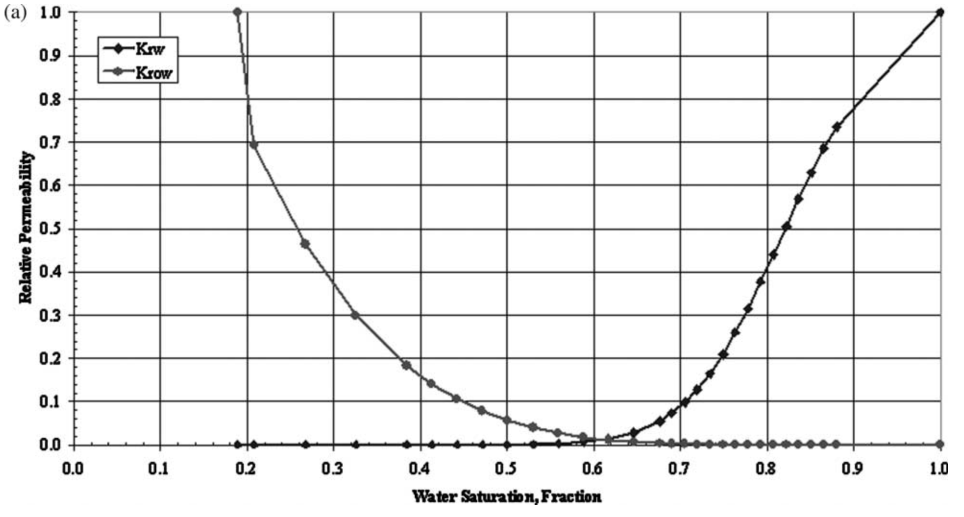
A 3D view of the whole model showing the horizontal permeability (K_x) is presented in Figure 5. Although the detail of the permeability distribution is not clear in the black and white illustration, it can be seen that the model is very heterogeneous. Note that the z-direction has been greatly exaggerated. A slight incline can be seen in the 3D view, so mobile gas may tend to collect at the top of the model near the producer.

The model initially contains undersaturated oil at an average reservoir pressure of 3220 psia with no free gas. The simulation starts on 1st January 1976 with no production until June 1976. Waterflood is then performed until January 2005. The production rate is specified as 1900 rb per day, which represents production of approximately 3% of the initial hydrocarbon pore volume per annum. Voidage replacement is used to maintain the reservoir pressure at 3000 psia, and the fluid remains above its saturation pressure. Recovery of stock tank oil to January 2005 represents 67.1% of STOIIP. A summary of the fluids in place on 1st January 2005 is presented in Table 1. The high oil recovery is consistent with the oil–water relative permeabilities discussed earlier. Following the waterflood, a WAG process is simulated, with the simulations continuing until January 2050.

Simulation cases

In addition to the base case waterflood, which was run until 2050, a number of variant cases were run to investigate a range of different issues. The main variants are described briefly in the following sections.

Base case WAG. Gas injection was commenced in 2005, with 10 WAG cycles (each consisting of 2 years gas injection followed by 2 years water injection, with equal volumes of gas and water injected). The final WAG cycle finished in 2044 and was followed by a waterflood until 2050. It is noted that in this study we did not investigate the effect of shorter WAG cycles; there may be potential for improving the recovery by optimising the cycle length.



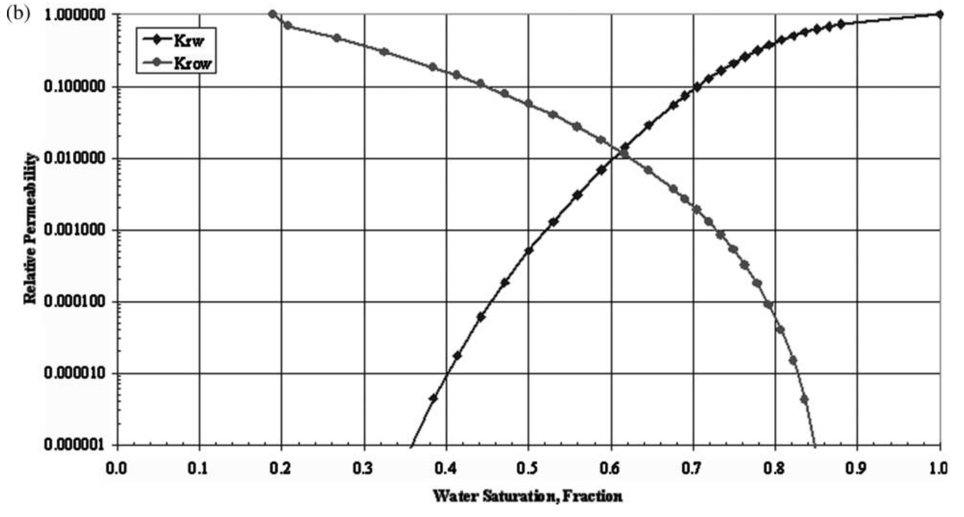


Figure 2: (a) Oil–water relative permeability (linear plot). (b) Oil–water relative permeability (logarithmic plot).

Postflood with gas. This case was similar to the base case WAG until 2025 (5 WAG cycles). The fifth WAG cycle was followed by postflood gas injection which continued till the end of the run.

3-Cycle WAG. In this case, the length of the gas injection periods was increased by a factor of three (giving a gas to water volume ratio of three to one for each WAG cycle) and the number of cycles reduced to three. The final WAG cycle concluded in 2028. Two alternatives were considered beyond this. In the first case,

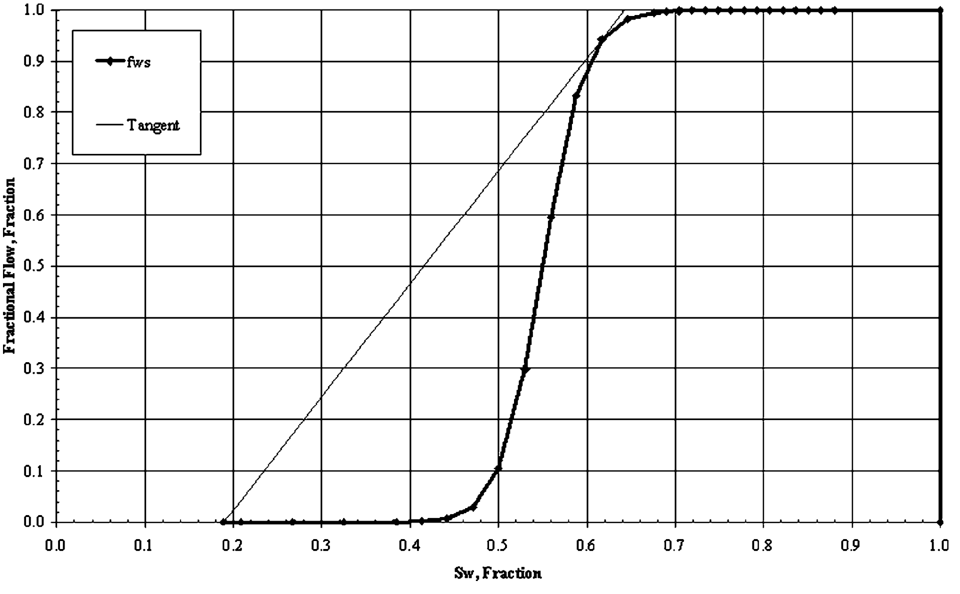


Figure 3: Fractional flow curve.

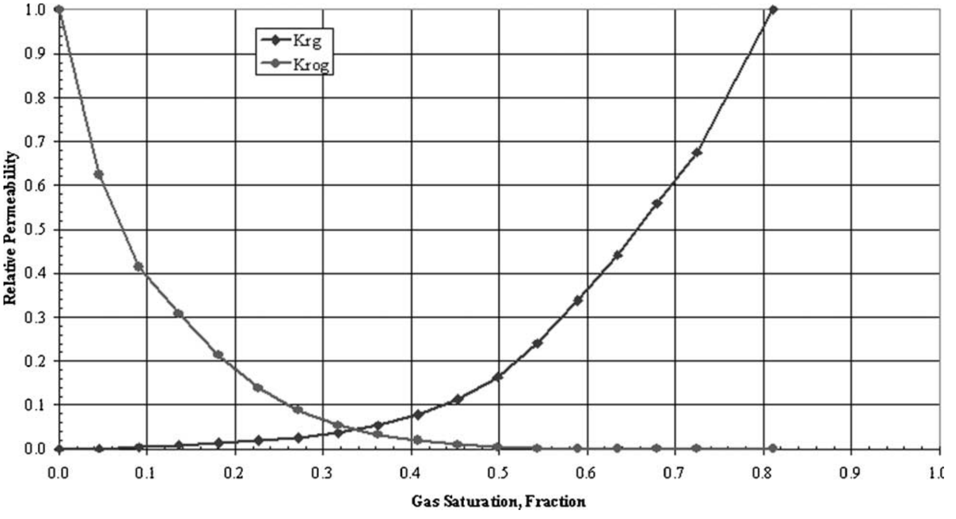


Figure 4: Gas–oil relative permeabilities.

the final WAG cycle was followed immediately by postflood gas injection, while in the second it was followed by three units of water injection and then the postflood gas injection.

Other sensitivities. Further sensitivity cases were undertaken to investigate the sensitivity to flow rate, injection well location and the position of completions as well as to look at the redistribution of fluids beyond 2050 once all the wells were shut-in.

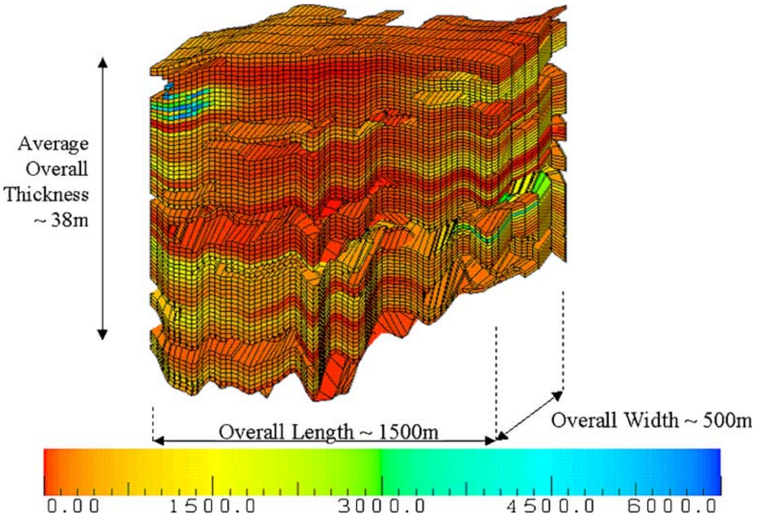


Figure 5: Model permeability (K_x) showing heterogeneity.

TABLE 1
FLUIDS IN PLACE ON 1ST JANUARY 2005

Fluid	**Amount in place**
Oil	5.9 MMstb
Oil recovery	67.1% STOIIP
Average So	26.7%
Water	18.7 MMstb
Average Sw	73.3%

Results of simulations
The 10-cycle WAG case showed an increase in oil recovery compared to the base case waterflood, of 6.5%, with almost 25% of the hydrocarbon pore volume containing CO_2 at the end of the run (see Table 2). The effect of the postflood gas injection was to increase the CO_2 storage while also resulting in a further small increase in oil recovery.

The 3-cycle WAG resulted in an acceleration of oil production, while further increasing the amount of CO_2 stored in the reservoir. Inclusion of the extra water slug at the end of the final WAG cycle had a detrimental effect on the oil recovery.

The maximum volume of CO_2 stored in the reservoir was around 50% of the hydrocarbon pore volume; this required approximately 1.2 hydrocarbon pore volumes of gas injection, so that a significant proportion of the injected gas was produced, indicating a need for gas recycling.

The 3-cycle WAG (postflood gas) case was run beyond 2050 with all wells shut-in. This showed a marked redistribution of fluids over a period of more than 100 years after shut-in. Gas moved upwards until trapped under shales or at the top of the reservoir, while oil continued to accumulate through the effects of gravity drainage.

TABLE 2
IOR AND AMOUNT OF CO_2 SEQUESTERED IN 2050

Case	**Oil recovery (% STOIIP)**	**IOR (rel waterflood, % STOIIP)**	**CO_2 stored (% HCPV)**
Waterflood	73.0	0.0	<0.1
10-Cycle WAG	79.5	6.5	22.7
10-Cycle WAG (postflood gas)	80.9	7.9	43.7
10-Cycle WAG (postflood gas) and relocate injector	82.8	9.8	48.9
3-Cycle WAG (postflood gas)	79.8	6.8	44.4
3-Cycle WAG (waterslug, then postflood gas)	79.2	6.2	40.1

It was observed that the use of WAG accelerated oil production, while maximizing the storage of CO_2 led in turn to an increase in oil recovery.

Modelling of Regional Fluid Flow to Underpin Risk Assessment

Following the favourable conclusions of the numerical simulation of WAG using CO_2 as the injection gas, it was recognized that risk assessment would be necessary, both to evaluate the likely safety and security of storage of CO_2 within the field and to secure any putative carbon credits for the storage of CO_2.

Assuming that there are no faults or other fractures in the cap rock, CO_2 stored in hydrocarbon fields can escape from the trap via the following routes: (1) abandoned or producing wells, (2) diffusion through the cap rock, and/or (3) dissolution and transport of CO_2-charged waters along the aquifer by groundwater flow (see below). In order to underpin the assessment of the risk of CO_2 escaping via route 3, a study of the regional (i.e. basin-scale) fluid flow patterns was undertaken, to constrain the likely rates of fluid flow along aquifers and across aquitards surrounding the Forties field. This would simulate the likelihood of CO_2 migrating out of the reservoir and eventually reaching the seabed.

For a realistic fluid flow model to be constructed, a regional cross-section from basin margin to basin centre, that passed through or close by the Forties oilfield, was required. The section needed to detail the geometry of key geological horizons, emphasizing sandy stratigraphic units and the connectivity of these with the Forties reservoir rocks. A seismic profile from a speculative survey shot by WesternGeco, passing within 20 km of the Forties field was chosen to provide this information. It is 250 km long and data quality is good. The profile is oriented approximately EW, from a position 42 km off the coast of NE Scotland near Fraserburgh, eastwards into Norwegian waters (Figure 6). It passes through or close by many key hydrocarbon wells and hence geological control on the interpretation of reflectors is good.

Seismic interpretation

Interpretation was concentrated from the western limit of the seismic profile to, and slightly beyond, the North Sea basin centre; the Forties field lies on the western basin margin, and any escape of CO_2 would be either driven upwards across the stratigraphy by buoyancy, or westwards by regional fluid flow due to compaction, using porous and permeable layers within the stratigraphic succession as conduits.

The interpreted seismic profile is presented in Figure 7 and reveals the complex nature of the basin fill. The Forties field lies to the south of the profile but the Forties-Montrose Ridge, on which the Forties field lies, can be clearly seen. The stratigraphic level of the Forties reservoir and hence of the potential CO_2 injection is indicated. The base of the Cretaceous Chalk is marked, and below this the succession is faulted and very variable in thickness. The lowest horizon is the Variscan unconformity, regarded for modelling purposes as impermeable and the base of the model. The Chalk extends across the faulted succession and, although folded, appears essentially unfaulted. Above the top of the Chalk, the Cenozoic to Recent succession extends to the seabed and can be divided into prograding basin margin successions that progressively move further

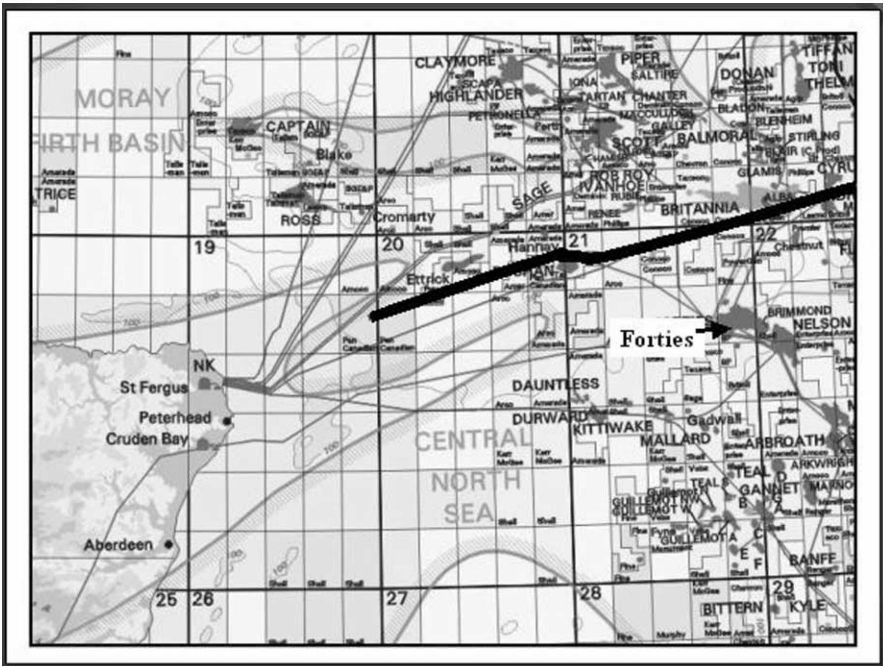


Figure 6: Location of the seismic profile.

towards the basin centre, and basin fill successions that infill and lap out against the prograding successions. Wells permit the identification of particularly sandy intervals, and these are shaded. It is immediately evident that there is a thick, and dominantly shaley and therefore assumed sealing, succession above the Forties reservoir rocks. Detailed analysis of well logs through this interval suggests that in the Forties field location, and also farther towards the basin centre, there are a few slightly sandier horizons within this shaley unit. However, they do not appear to be laterally continuous and are thought therefore to provide little significance in the way of migration paths for any CO_2 that might escape vertically from the Forties field.

Of particular importance in the Cenozoic succession is the thick sequence of stacked sandy basin floor fans immediately above the Chalk in western and central areas and the overlying prograding sandy interval. A more detailed image of this section of the seismic profile, circled in Figure 7, is presented in Figure 8.

The topmost of the stacked basin floor fans is the Forties Sand, which forms the lower of the two main reservoirs in the Forties field. This appears to pinch out to the west under a thick and dominantly shaley and therefore “sealing” prograding succession. It is thought that any CO_2 migrating laterally out of the Forties Sandstone would not have an obvious path to the surface via this route. The upper reservoir in the Forties field, the Charlie Sand, appears to form the distal “toe sets” of the prograding Dornoch Delta succession immediately to the west. Wells penetrating this interval show that this prograding unit is largely sandy in its upper part, which is known as the Dornoch Sandstone. Seismic evidence therefore suggests that the Charlie and Dornoch Sands may be contiguous and therefore provide a potential migration path for any CO_2 that may move laterally out of the Forties field.

Basin modelling
The main aims of the regional 2D basin modelling were to give an indication of the basin-scale natural fluid flow to be expected within the various rock layers surrounding the Forties field reservoir, and evaluate

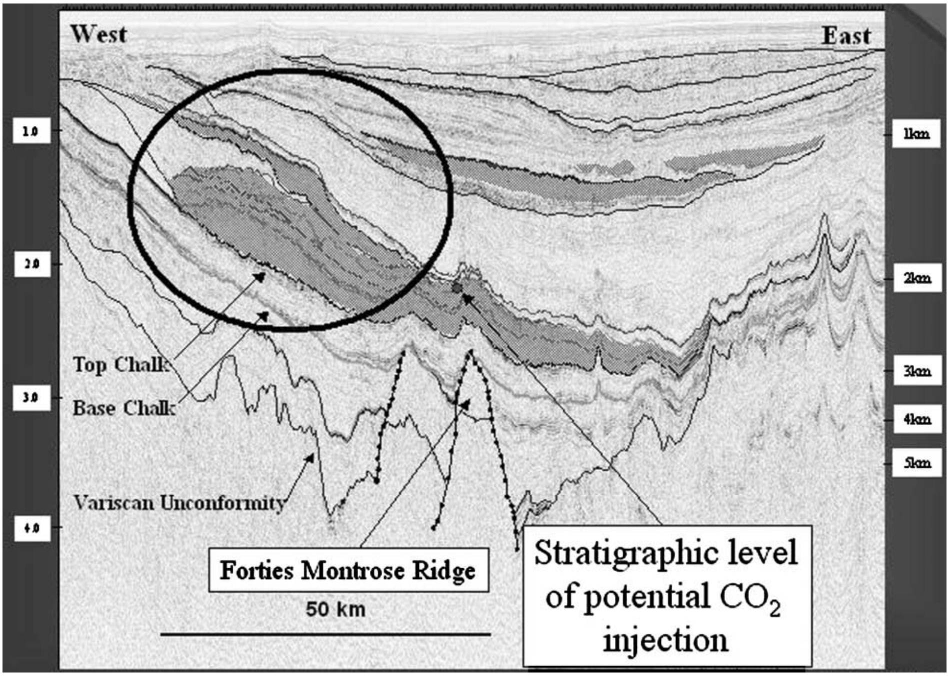


Figure 7: Interpreted seismic profile. Potentially sandy units shaded. Data courtesy of WesternGeco.

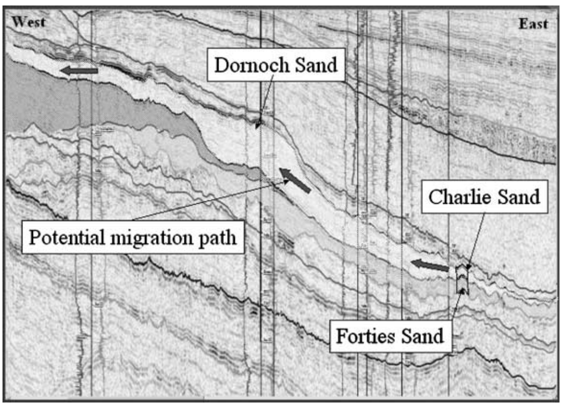


Figure 8: Detail of the lateral extent of the Forties reservoir sands.

pressure boundary conditions for input into a more detailed 3D model of the field itself. The modelled profile does not cross the Forties field and therefore was not necessarily expected to match the pressure data measured at Forties exactly. PETROMOD basin modelling software was used. The methodology used was to set up a "base case" model using the geological framework obtained from the interpreted seismic profile and the boundary conditions described below. The model was then run to calculate the pore fluid pressure distribution within the various rock layers making up the profile. Subsequently, scenarios were run in which the geology or other parameters of the model were varied, to assess how these might affect the pore fluid pressure distribution.

Model construction. The interpreted seismic section was depth-converted using check-shot surveys from seven of the in-line wells. The section was then extended to the west, using seabed outcrop data so that the termination of the stratigraphic layers at the seabed could be defined, which is important for the flow calculations. The depth-converted horizons were input into the basin modelling program, together with information on the lithological composition of the seismic intervals, and the likely age of the horizons. This resulted in a "base case" 2D model consisting of 62 "events" (model layers) and 108 grid points along the 2D section. The geometry and lithology of the base case model are shown in Figure 9. Each layer has a standard pre-defined lithology, porosity, and permeability and each event was assigned a duration, to allow different scenarios to be modelled.

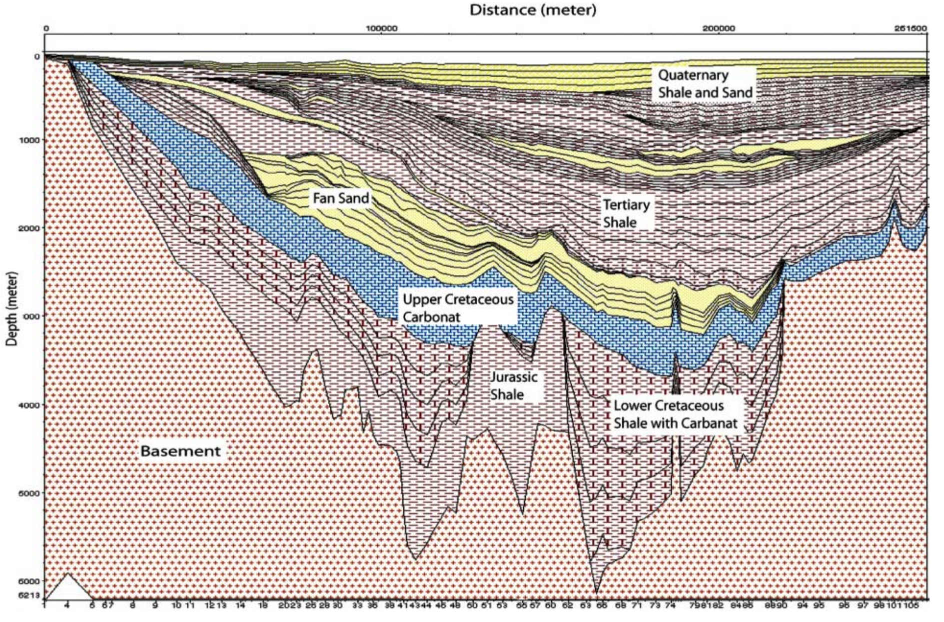


Figure 9: Geometry and lithology of the "base case" model.

Boundary conditions. The flow boundary conditions assumed for the 2D model were open, except for a no-flow boundary imposed at the impermeable basement rocks at the base and the western side of the model. The section was chosen such that the depocentre for the Cenozoic shale generating most of the overpressure in the Cenozoic section is located some 50 km from the eastern boundary (Figure 10). Fluids were expected to move away from this area. Towards the western end of the profile fluids were expected to move to the seabed, particularly along carrier beds. At the eastern end of the profile fluids were expected to move to the east through the open boundary.

Base case. The base case model (Figure 9) was based on the following simplified geological assumptions: The base of the Jurassic is taken as a no-flow boundary. The lowest layer in the model is the Jurassic section, which is represented as shale with source-rock properties. The overlying Lower Cretaceous section also contains shale, but it also contains some carbonate, especially in the South Viking Graben, therefore the lithology chosen for this event was shale with a little carbonate. This is followed by a section of Upper Cretaceous Chalk. On top of the Chalk there is a series of fan sands of Palaeocene to Eocene age. These

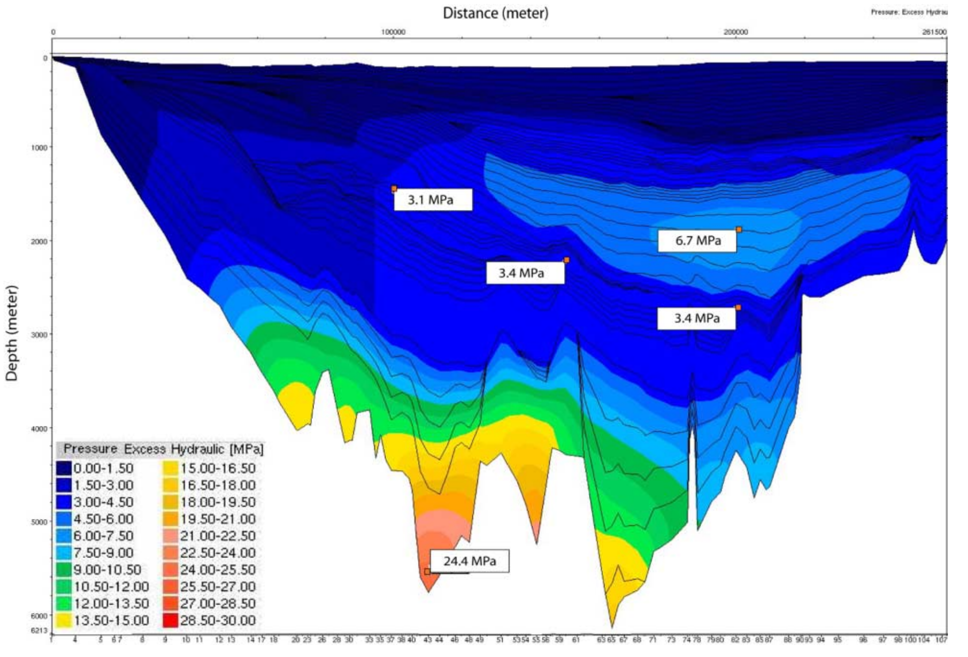


Figure 10: Calculated overpressure distribution for the "base case" model shows two separate centres of overpressure—one in the Cenozoic and one in the Jurassic/Lower Cretaceous.

sands include the Forties Sandstone. A thick series of shales with a few sand layers overlies these sands—none of the sand layers has direct contact with the seabed in the base model (Figure 9). The lithologies used in the base case model were standard lithotypes.

The overpressure distribution for the base case model can be seen in Figure 10. It shows two different pressure centres; one in the Jurassic/Lower Cretaceous and one in the Cenozoic, and a pressure gradient in the fan sand of 0.4 MPa/100 km.

Model scenarios. Different scenarios were simulated, first by adding shale layers in the fan sand, then lowering the sedimentation rate in the last part of the Quaternary from approximately 50 m/100,000 years to 25 m/100,000 years and finally removing the active petroleum system in the Jurassic. This lowers the overpressure in the Jurassic almost 20 MPa, but the overpressure in the fan sand drops less than 1 MPa and the pressure gradient is only changed 0.2 MPa/100 km.

Scenarios with permeability in the fan sand, lowered by up to two orders of magnitude, show that the overpressure in the Forties position varies from 3.4 MPa in the "base case" model to 2.3 MPa in the case with the lowest permeability. The pressure gradient changes by only 0.1 MPa/100 km.

In a scenario with no active hydrocarbon system and with Cenozoic shales with one order of magnitude higher permeability, the overpressure in the Cenozoic shales drops approximately 5 MPa. However, the pressure in the fan sand only drops 1.7 MPa and the pressure gradient in the sands is unchanged. This scenario was further modified with more sand, a better hydraulic connection to the seabed and a leaking fault approximately 70 km east of the Forties position. The overpressure drops to almost hydrostatic (0.4 MPa) at the location similar to the Forties and the pressure gradient becomes almost zero and it actually reverses close to the location of the fault. The calculated pressure distribution for this case can be seen in Figure 11.

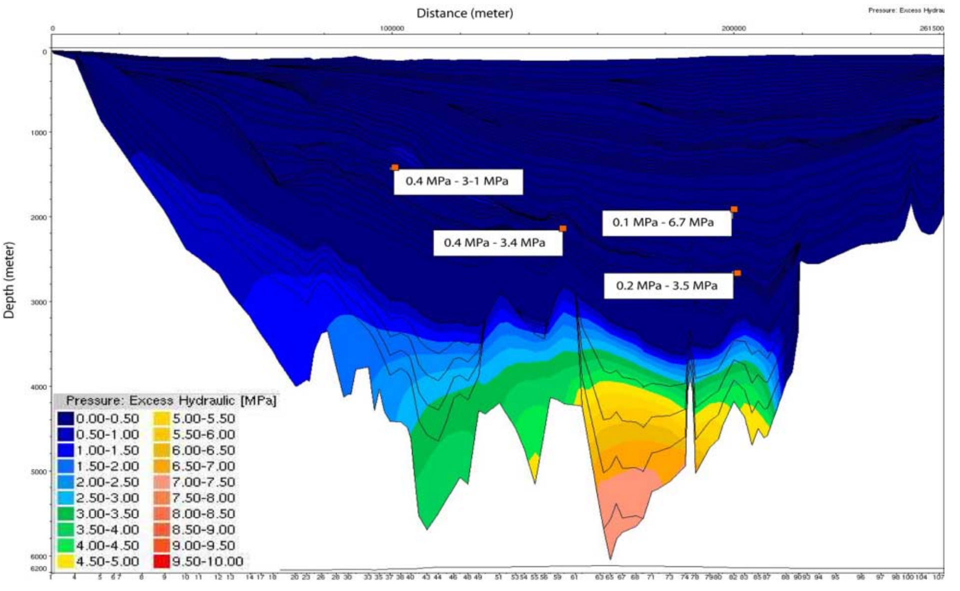


Figure 11: Calculated distribution of overpressure for case with no active hydrocarbon system, Cenozoic shales with one order of magnitude higher permeability, good hydraulic connection to the seabed and a leaking fault approximately 70 km east of the Forties position. Numbers to the left, this case; to the right, "base case" model.

Results. The 2D modelling reveals two almost separate pressure systems: (1) a Jurassic–Lower Cretaceous system which is related to grabens with tight shale and active hydrocarbon systems (2) a Palaeocene/Neogene system of which the Forties Sand is a part. Pressure changes in the Jurassic of 20 MPa only generate a pressure change in the fan sand of 0.3 MPa, demonstrating the small degree of communication between the two systems.

Whilst one of the main factors influencing the Jurassic–Lower Cretaceous system is hydrocarbon generation, a variety of factors influence the Palaeogene–Neogene system. The most important factor is the composition of the Eocene–Miocene shales, but factors such as Quaternary loading and composition, geometry of the fan sand and distance to leaks also have influence on the pressure system.

The results from the 2D modelling show that the potential range of pressures in the Forties Sands along strike from the Forties Field may vary from almost hydrostatic (zero overpressure) to an overpressure of 3.5 MPa. The pressure gradient is very stable, being less than 1 MPa/100 km in all scenarios, with an average for all scenarios close to 0.5 MPa/100 km. The regional pressure gradient from West Central Graben to Inner Moray Firth is 10 MPa over 320 km which, with average Forties Sandstone parameters from the Montrose Field (permeability 80 mD, porosity 23%), gives a flow velocity of 33 cm/year (330 m per thousand years) [5]. Using the same parameters, the modelled pressure gradient in this study of less than 1 MPa/100 km results in even smaller flow velocities.

The scenario that assumes a connection between the Charlie Sand and the Dornoch Sand, and thus a better hydraulic connection to the seabed, gives almost hydrostatic pressure in the Forties Sand on the Forties-Montrose ridge, which is in good agreement with published data [6] and pressure data from the Forties Field.

The regional 2D modelling shows that the pressure boundary conditions for the 3D modelling should be close to hydrostatic and that the pressure gradient across the field should lie between 0 MPa/100 km and 1 MPa/100 km.

Modelling Potential Escape Routes for CO_2 from the Forties Field

The next step in the workflow necessary to underpin the assessment of the potential risks of CO_2 leakage from the Forties field was to model the field in detail using a 3D model. We defined a multi-scale approach comprising two stages: (1) 3D simulation of the fluid flow in the Forties field and its surrounding drainage area using the TEMIS3D basin modelling software [7]; and (2) simulation of the interaction between CO_2 and water (diffusion) using the Institut Francais du Petrole (IFP) SIMUSCOPP fluid flow simulator. The basin model was used to quantify the groundwater flow pattern (direction and velocity) within the Forties main drainage area. This flow pattern was then used to determine pressure boundary conditions for reservoir simulations performed by the IFP SIMUSCOPP code.

The scope of the fluid flow modelling with SIMUSCOPP was to compute the CO_2 escape routes and quantify the CO_2 transfer to the underlying aquifer and the overburden once the CO_2 is in place within the Forties Field. At prevailing reservoir conditions the bulk of the CO_2 would be supercritical.

Geological setting

The Forties field consists of an anticline with sandy reservoirs, known as the Forties Sand and Charlie Sand, located in the Central North Sea (Figure 11). The original oil–water contact was at 2217 m [8]. Temperature in the reservoir is 90 °C and pressures are close to hydrostatic. There are no large faults present in the reservoir or the overburden sequence and the minor faults encountered are believed to have no significant influence on reservoir continuity or production [8].

Basin model (TEMIS3D). Primarily designed to simulate compaction, source-rock maturation and hydrocarbon migration, TEMIS3D can also be used, as here, as a single-phase water flow simulator able to quantify the development of overpressures and the direction and magnitude of water flow. Fluid flow is defined by Darcy's law, using permeability as a function of porosity through the Kozeny–Carman law. The TEMIS3D block construction followed the classical numerical modelling steps [7].

Database. Provided by BP, the database included 10 isobath maps, high-resolution petrophysical data from seismic inversion of a 3D reservoir block, well logs and core description.

Gridding. Due to CPU limitation, a model grid of approximately $400 \times 400\ m^2$ in horizontal plan was chosen in order to compromise between cell size and total number of cells (Figure 12).

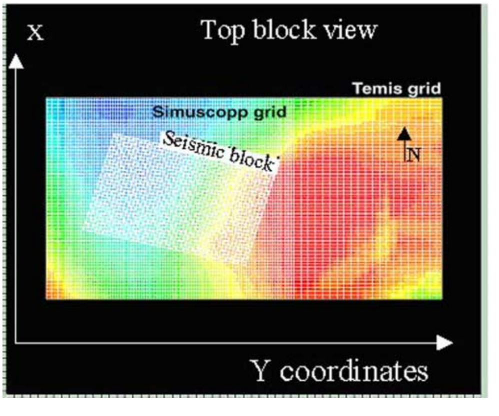


Figure 12: Optimised TEMIS3D horizontal grid pattern.

Layers. The 3D TEMIS initial block comprised nine seismically derived layers. In order to take advantage of the more detailed information that was available and facilitate importation of the high-resolution lithological data, 31 additional interpolated layers were created, particularly in the intervals associated with the Forties reservoir (14 layers) and the cap rock (five layers).

Lithology. For each layer, lithology maps were created. These maps were elaborated from the studied wells. Additional high-resolution lithological information, obtained from seismic inversion, was incorporated into the TEMIS3D block using a geo-modeller (Figures 13 and 14). Porosity vs. depth curves originated from default TEMIS3D lithology types or were extracted from literature [9] and references therein.

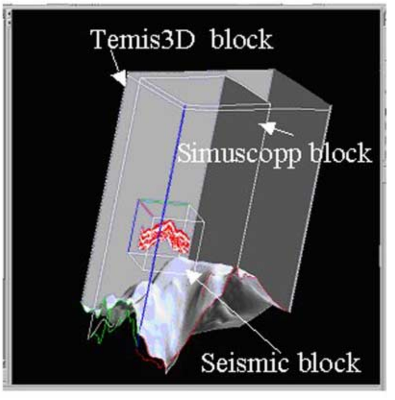


Figure 13: Model block location.

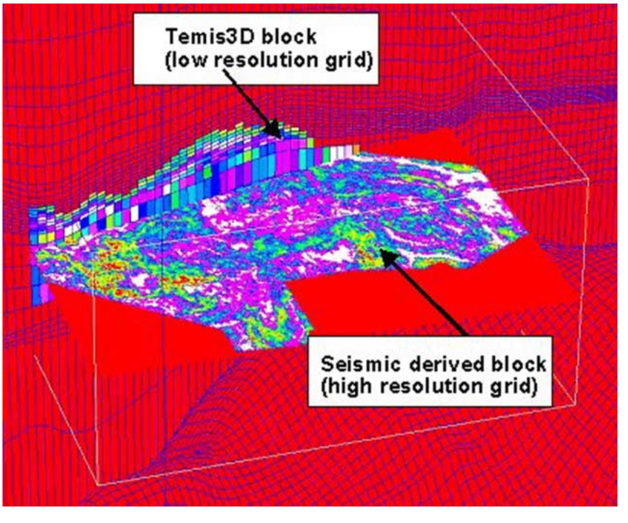


Figure 14: Distribution of grid blocks.

Boundary conditions. Data from the Forties reservoir indicates pressure close to hydrostatic [10]. This agrees with the results of the 2D numerical modelling described above. However, regional studies suggest that there is a small pressure gradient between the depocentre of the basin and the region to the NW (Figures 15 and 16).

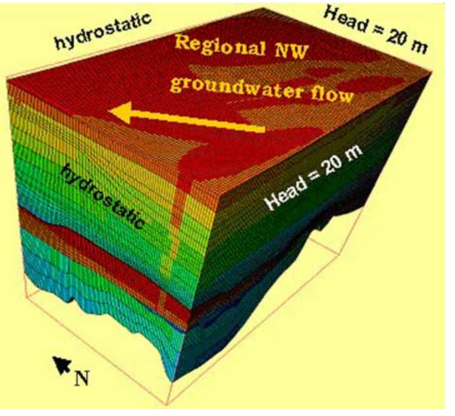


Figure 15: TEMIS3D boundary conditions (base model).

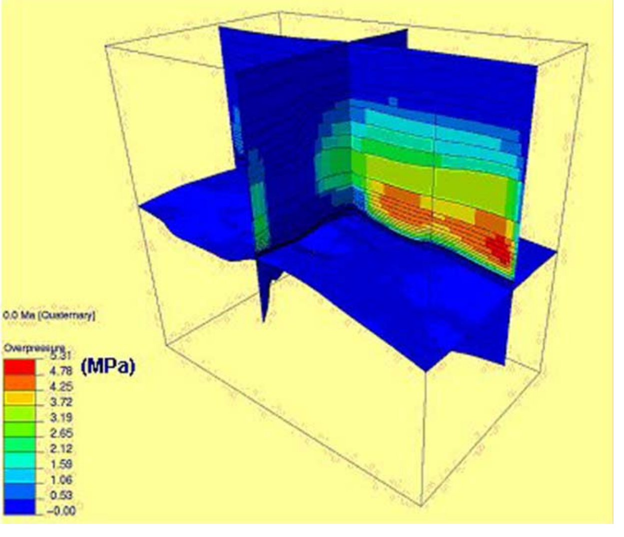


Figure 16: TEMIS3D overpressure distribution, present day.

Sensitivity tests. A first simulation, referred to as the "base case", was performed using the above (most realistic) input data. Additionally, as part of sensitivity tests, 12 simulations were made to encompass the uncertainty of the input parameters (mainly permeability—both of the reservoir and overburden intervals—and the water head boundary condition).

Results. The base case scenario, where calculated properties are calibrated with measured data, suggests that in the overburden interval, overpressures are up to 5.3 MPa, and mainly located in the centre and southern and eastern parts of the model, approximately between 1800 and 2300 m depth (Figure 16). In the centre of the model overpressure drops to <1 MPa. In the Forties reservoir there is an overall decrease in pressure from the south and east to north and west. This pressure distribution pattern exerts a strong influence on the present-day water circulation pattern. The base case scenario indicates that at present, the water in the

Forties reservoir flows dominantly horizontally, from southeast to northwest, at a velocity lower that 500 m/Ma (Figures 17 and 18). Water flow in the upper overburden interval (0 to approximately 1400 m) typically ranges from below 60 m/Ma in the mudstones up to perhaps 150 m/Ma in the siltstones, with flow vectors pointing predominantly upwards (Figure 17). In the lower overburden interval (>1400 m) water flow typically ranges from below 10 m/Ma in the mudstones up to perhaps 30 m/Ma, with flow vectors pointing predominantly downwards. Water flow in the interval below the reservoir (Cretaceous and Danian) is less than10 m/Ma, in part because of the low permeability values encountered (<0.01 mD). The sensitivity tests showed no significant changes in the orientation of the regional water flow, and pressure in the reservoir interval was always near hydrostatic (i.e. overpressure <0.01 MPa).

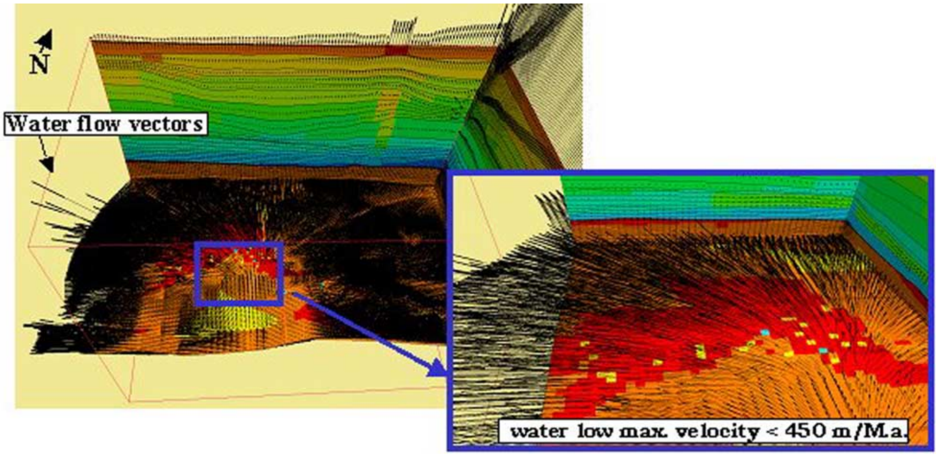


Figure 17: TEMIS3D fluid flow distribution at present day (base case).

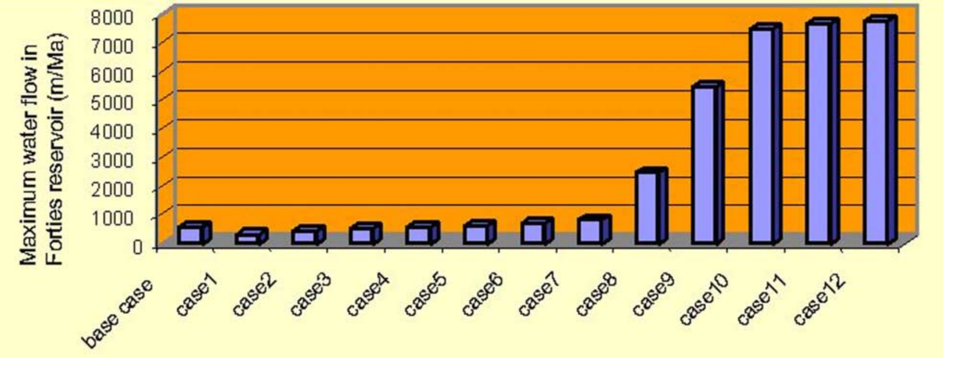


Figure 18: Sensitivity tests—maximum water flow at present day.

The modelling results suggest the following.

1. The present-day water flow is dominantly horizontal, from southeast to northwest, with velocity likely to be lower than 500 m/Ma.
2. The sensitivity tests show that with the worst case scenario water flow reaches 8000 m/Ma (Figure 18). This means that water flow is still too slow to remove significant amounts of CO_2 from the reservoir

by dissolution in the aquifer (maximum horizontal displacement = 8 m in the time framework of the storage-1000 years).

3. The near hydrostatic pressures lead to the conclusion that the boundary conditions for reservoir simulation (SIMUSCOPP IFP software) can be set as hydrostatic.

Fluid Flow Simulator (SIMUSCOPP)

SIMUSCOPP is a 3D, 3-phase compositional fluid flow simulator, which uses Darcy's law and mass conservation to compute pressure and saturation variation over the whole model. The conservation equations are solved using the classical finite volume method. SIMUSCOPP assumes a block-centred grid but easily handles local grid refinement and dual media to better characterize fluid flow. It is designed to handle complex, laterally variable aquifers. Fluid flow properties can be described through user-defined data or by using a governing equation such as the Peng–Robinson equation of state to compute phase density variation or the Lorehnz–Bray–Clark correlation to compute phase viscosity variation with pressure. In its current version, SIMUSCOPP is isothermal. However, SIMUSCOPP handles CO_2 dissolution in water through (tabulated user-defined) equilibrium constants and also CO_2 diffusion in the water phase. SIMUSCOPP has been successfully applied to model CO_2 behaviour [11,12]. In its current version, SIMUSCOPP does not handle any fluid-rock chemical reaction. SIMUSCOPP simultaneously solves for pressure and saturation within the whole field either using a fully implicit numerical scheme or a numerical scheme implicit for pressure and explicit for saturation. To compute its initial conditions, SIMUSCOPP assumes a capillary-gravity initial equilibrium. Then, using mass conservation and Darcy's law, it computes the evolution of pressure and saturation with time.

Fluid flow data

In order to understand CO_2 behaviour in Forties after the CO_2 injection period, CO_2 diffusion and dissolution in water must be modelled. Furthermore, the overburden and underlying strata must be characterized in terms of their lateral extension and petrophysical properties such as permeability and porosity and, most importantly, capillary pressure behaviour and relative permeability.

The fluid flow model (SIMUSCOPP) takes significantly longer to run for an equivalent size of problem than the basin model (TEMIS3D). Therefore the fluid flow calculations had to be carried out on a smaller grid. To avoid any upscaling issues between the basin and the local scale, the fluid flow model only covers a part of the region covered by the basin model; this allows the same grid block size to be used with the same porosity and permeability as in the basin model. The boundary conditions for the fluid flow model are assumed to be hydrostatic on all lateral boundaries and no-flow conditions otherwise, based on the TEMIS3D results and the location of the fluid flow model within the basin model.

The multiphase data for the Forties Sand are derived from the reservoir model of the field. Since no data is available for multiphase flow properties in the shale (overburden), the capillary pressure and its displacement pressure are derived form a permeability based correlation [13]

$$P_e = 7.37K^{-0.43}$$

where P_e is the pore entry pressure (psi), K the permeability (mD) of the media, and the CO_2–water relative permeability and capillary pressure (P_c) follow the classical Van Genuchten relation [14]

$$k_{rg} = \sqrt{S_g^*}\left\{1 - (1 - [S_g^*]^{1/\lambda})^{\lambda}\right\}^2 \quad \text{and} \quad P_c = -P_0([S_g^*]^{1/\lambda} - 1)^{1-\lambda}$$

where λ is the Land exponent of the shale and S_g the dimensionless gas saturation.

The petrophysical model was reduced to only two rock-types: sand, i.e. the Forties Sand within the reservoir and shale anywhere else.

The CO_2 thermodynamic properties are derived from literature [15] whilst the CO_2 equilibrium solubility is computed from Duan equation of state [16].

After CO_2 injection, the Forties reservoir is assumed to be at its original pressure (22.7 MPa) and the CO_2/water contact is located at the initial water–oil contact (2217 m). The CO_2 saturation is assumed uniform and constant at 50%.

Fluid flow results
The goal of the fluid flow simulation was to compute a "reasonable" worst case scenario and determine the CO_2 escape rate out of Forties over a 1000-year period. To achieve this, some the model parameters were varied within reasonable limits to maximize the CO_2 leakage rate, e.g. by assuming the same effective diffusion within the sand and the shale, i.e. assuming a uniform and constant tortuosity and bulk diffusion coefficient.

CO_2 does not break the capillary barrier of the overburden (2125 m) at any time during the 1000-year period, since no gaseous nor supercritical CO_2 is seen above the Forties reservoir (Figure 19). However, CO_2 diffusion within the water phase transports CO_2 upward but only less than 50 m into the first layer of the overburden (Figure 20). Due to CO_2 dissolution in water and high permeability within strata underlying the Forties reservoir, CO_2-saturated water migrates downward, driven by the density contrast with undersaturated aquifer water. In this base case scenario, only 3.6% of the original mass of CO_2 migrated out of the reservoir over the 1000-year period.

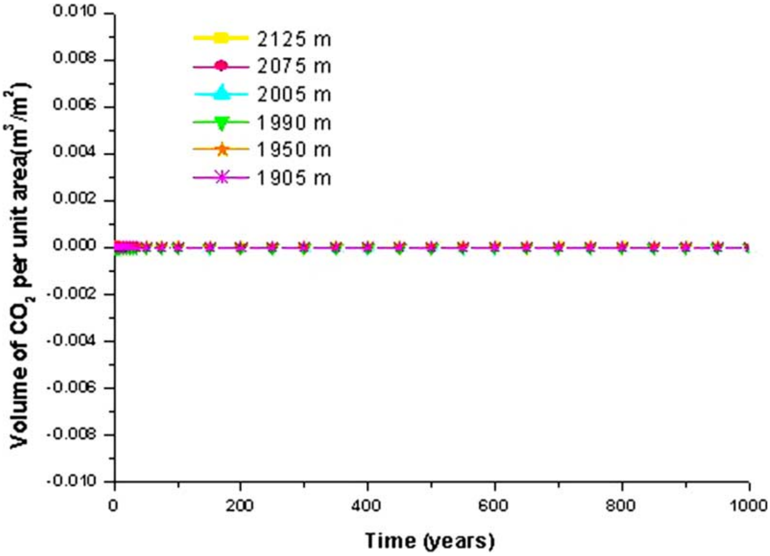


Figure 19: Volume of CO_2 versus time at different depths within the overburden of Forties.

In the worst case scenario approach, assuming a complete capillary barrier failure of the cap rock (i.e. zero pore entry pressure in the shale) the CO_2 migrates upward both in gaseous form (Figure 21) but more importantly through diffusion within the water phase (Figure 22). The upward migration of CO_2 is quite significant since the dense supercritical CO_2 rises almost 175 m within the overburden during the 1000-year period (Figure 21). The influence of water diffusion is still quite significant since dissolved CO_2 rises almost 350 m in the same period (Figure 22). In this worst case scenario, nearly 37% of the original mass of CO_2 migrated out of the reservoir over the 1000-year period.

Despite the quite extreme assumption of complete failure of the cap rock capillary barrier, CO_2 migration from Forties is limited to an area up to 350 m above the reservoir. Under a more realistic set of assumptions,

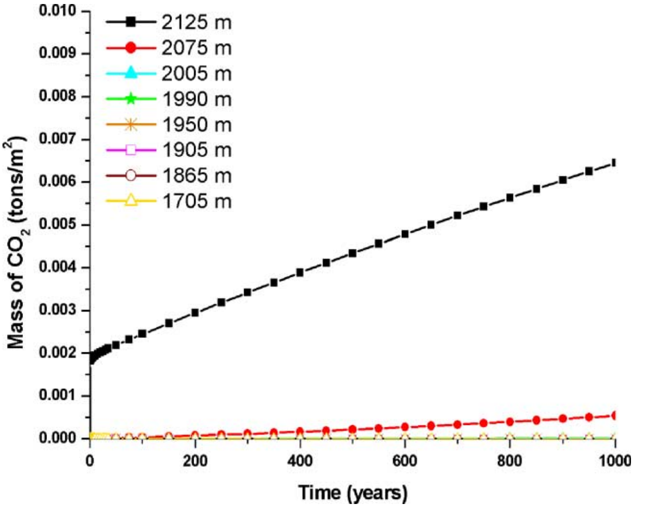


Figure 20: Mass of CO_2 versus time at different depths within the overburden of Forties.

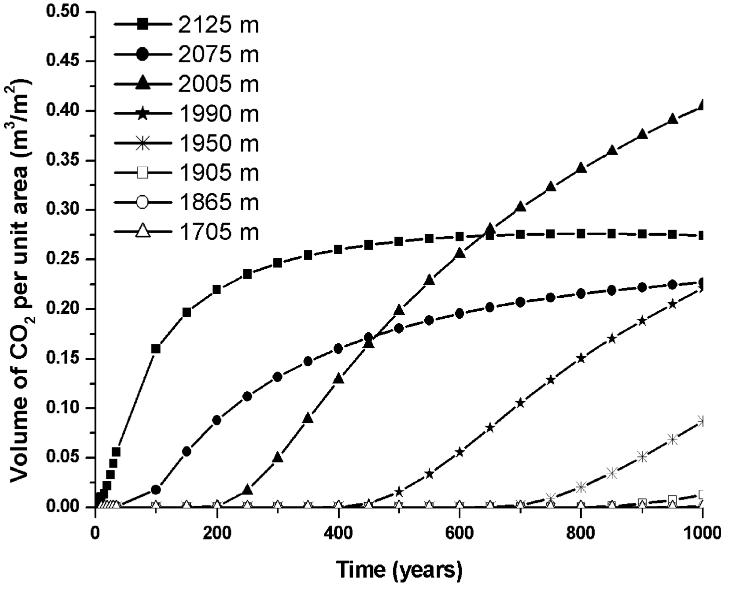


Figure 21: Volume of CO_2 versus time at different depths within the overburden of Forties cap rock failure case.

minimal CO_2 migration above the Forties cap rock is predicted. Due to the absence of major faults, hydrostatic conditions (mainly due to its offshore location), and the thickness and very low permeability of its overburden, Forties is an appropriate structure for CO_2 storage as long as significant cap-rock characterization (capillary and permeability properties) is available to validate the model hypothesis.

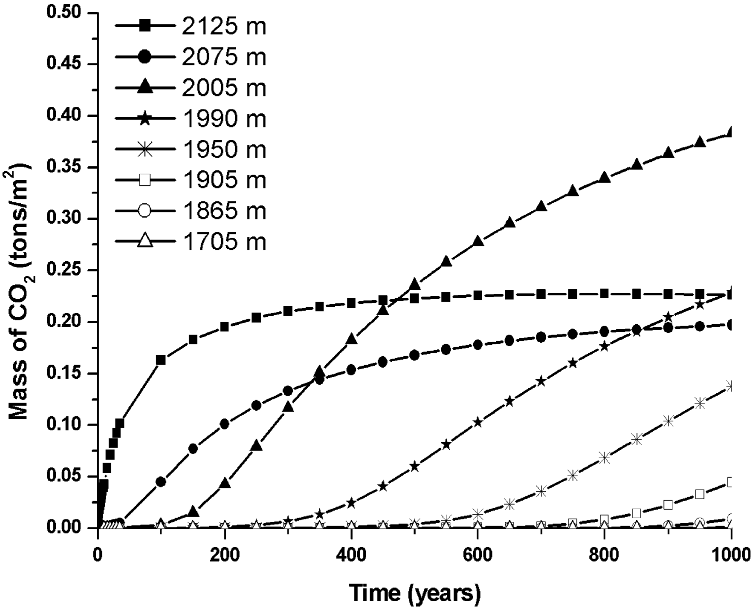


Figure 22: Mass of CO_2 versus time at different depths within the overburden of Forties cap rock failure case.

Risk Assessment

This section describes an assessment of the risks associated with long-term geological storage of carbon dioxide in a depleted oil reservoir. Illustrative calculations were undertaken using data representative of the Forties reservoir, in which it is assumed that a WAG process would be applied for CO_2 injection; the approach that was adopted and the results of the calculations are outlined in the Appendices. A similar approach could be taken in applying the methodology to a different field or to a different injection strategy; however, the particular calculations used to bind the risks from any specific pathway may need to be modified for such a case. There may be some pathways where a very simplistic calculation can provide an adequate bound on the flux in one-field situation, whereas a much more detailed and complex calculation may be required in applying the same approach in a different field. Equally, there may be particular pathways where the outcome of the risk assessment for another field may be very different, perhaps leading to a different conclusion about the suitability of the field for CO_2 storage.

The main steps in the risk assessment process can be identified as follows.

(i) Identify potential pathways for release (FEP analysis—identification of features, events and processes (FEP) that may impact on the release rates and/or the risk).
(ii) Use analytical models and/or numerical simulation to establish bounds on the release rates and/or the risk for different pathways and potential release scenarios. As a general principle, the approach is to use the simplest model that permits an adequate bound to be established for the magnitude of the release and/or the risk.

FEP analysis

In undertaking an FEP analysis of the problem, the objective is to identify the potential escape routes without making judgments about the relative significance of the different routes. It is important to be as comprehensive as possible during this initial stage of the process. The assessment of the significance of potential escape routes forms a separate stage of the risk assessment process; it will be seen in practice that many of the potential escape routes identified during the FEP analysis can in fact be demonstrated to be insignificant at the assessment stage.

Figure 23 captures in schematic form the key FEP that need to be assessed in order that CO_2 release routes and potential release rates can be determined. The diagram can be divided into three main areas: CO_2 storage, CO_2 escape and CO_2 migration to surface. Each of these is briefly summarized below.

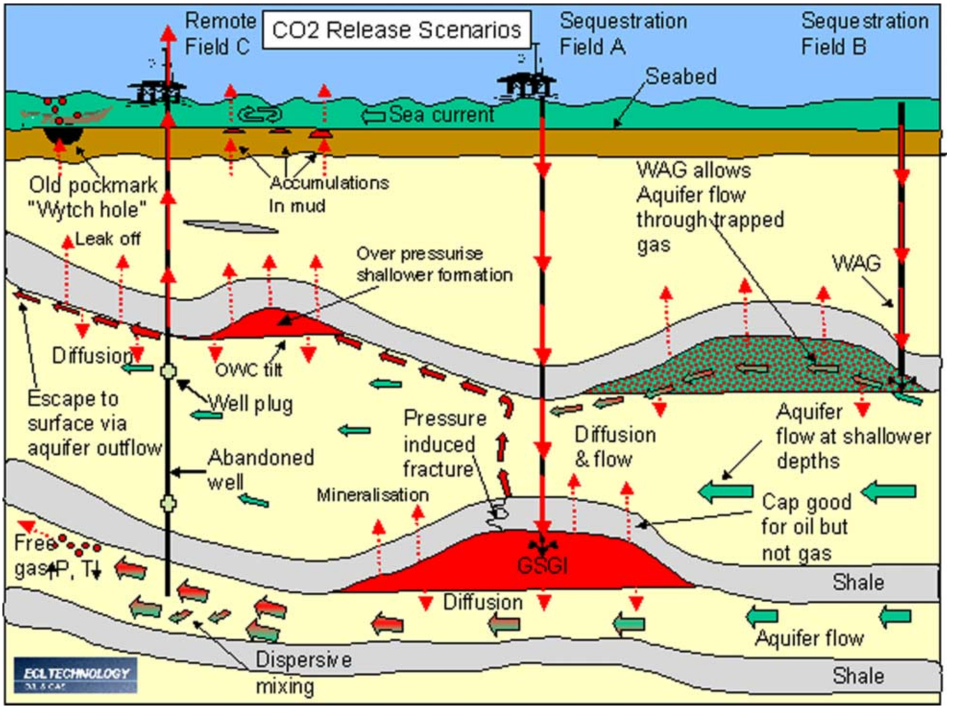


Figure 23: Schematic of the key features, events and processes that need to be considered when assessing the potential release paths and release rates of CO_2 sequestered into a subsea oil reservoir.

Storage of CO_2 in an oil reservoir with the subsidiary aim of enhancing oil recovery could typically be by either a gravity stable gas injection (GSGI), vertical sweep process or a water alternating gas (WAG) horizontal sweep process. The key difference between these approaches is that WAG alternates CO_2 slugs with water slugs to help control gas mobility whereas GSGI injects only CO_2. The WAG process has generally been favoured for EOR. After closure of the storage facility, the objective is to retain the CO_2 over an extended period of time (many hundreds or thousands of years).

The geological trap into which the CO_2 is stored has kept oil and any associated gas cap in place for, in many cases, millions of years. The key issue is therefore whether CO_2 behaves differently. Figure 23 illustrates routes for potential CO_2 escape from the trap.

Once CO_2 has escaped from the trap, the migration routes to surface depend on the regional geology, the extent of CO_2 transport by aquifer flow (either dissolved or as bubbles), and the availability and condition of man-made pathways such as wells.

Assessment of risks for key pathways in Forties
In assessing the risks associated with complex pathways to the surface, it can be useful to construct a fault tree to represent both the sequence of events that might lead to a release and also the interactions that might occur between those events. The features and processes identified in the FEP analysis provide a means to help compute potential release rates for scenarios identified in the fault tree. Figure 24 is a schematic example of a high-level fault tree. The circles at the bottom represent lower level events in the fault tree that are not shown explicitly in this diagram.

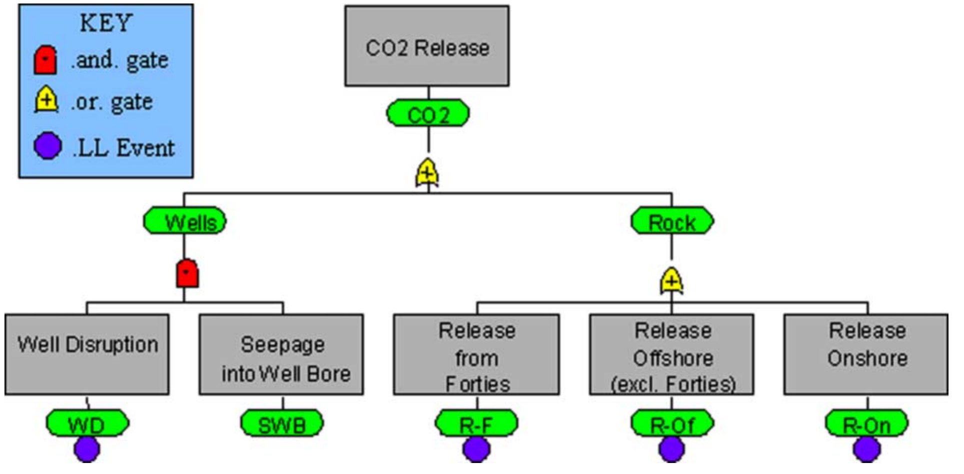


Figure 24: Illustrative example of a high-level fault tree showing potential CO_2 release paths.

Figure 25 shows some of the key parameters relating to the location, depth and dimensions of the Forties reservoir that are of relevance to the risk assessment. Appendix A details the values of key parameters (relating to Forties) that have been used in the risk calculations.

In considering the potential for escape of CO_2 that has been stored in Forties, the pathways can most conveniently be considered in three groups: pathways through the underlying aquifer; pathways through

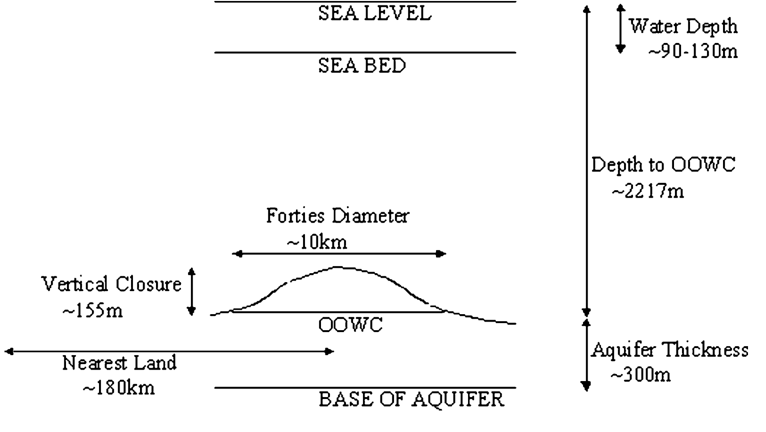


Figure 25: Key parameters, relating to the location, depth and dimensions of the Forties reservoir.

the cap rock and overburden; and well pathways. Appendices B, C and D, respectively, detail the calculations that were undertaken to assess the risks associated with each of these three groups of pathways.

Pathways through the underlying aquifer. Pathways that have been considered include convective and diffusive transports of dissolved CO_2, and transport of supercritical liquid-phase CO_2, either with or through the aquifer water.

(i) Transport of dissolved CO_2 through the underlying aquifer represents one potential pathway. Calculations described in Appendix B show that the advective flux of dissolved CO_2 in the aquifer water is insignificant compared to the volumes that are stored, and that the distance over which the dissolved gas might be transported in 1000 years is insignificant compared to the size of the Forties reservoir. Bounds calculated on the diffusive flux are negligible by comparison with the bound calculated for the advective flux.
(ii) The very low groundwater flow velocities in the Forties aquifer indicate that transport of liquid-phase CO_2 entrained in the aquifer flow makes no significant contribution.
(iii) There are two other potential causes of supercritical liquid-phase CO_2 flow through the aquifer that need to be considered. The first is that high injection pressures at the wells may lead to a downward flow of liquid-phase CO_2 away from the injection points and out of the Forties trap; we note that this is a transient effect that applies primarily during the injection period and perhaps for a short time thereafter. The second is that the total volume of CO_2 injected is sufficient to completely fill the trap down to the spill point and that as a result the trap becomes over-filled and CO_2 escapes. It is assumed that the CO_2 injection strategy will be designed in such a way as to mitigate against these possible effects and therefore there will be negligible impact on the risk assessment from them.

Based on these calculations and analysis, which are described in more detail in Appendix B, we conclude that the risks associated with transport pathways through the underlying aquifer are negligible.

Pathways through cap rock and overburden. There are a number of issues relating to pathways through the cap rock and the overburden.

(i) One such issue is the increase in overpressure due to replacing the oil originally present in the reservoir with CO_2. It is shown in Appendix C that the levels of overpressure in the reservoir are unlikely to be sufficient to allow liquid-phase CO_2 to escape into the cap rock.
(ii) There may be local increases in pressure around the injection wells during the period of injection. It is assumed that the injection strategy will be designed to ensure that these short-term levels of overpressure are such that they do not cause any problems during the injection period. Pressures in the immediate vicinity of the injection wells will tend to fall once injection ceases.
(iii) Analytical calculations (see Appendix C) show that the vertical diffusive flux of dissolved CO_2 through the cap rock and into the overburden is negligible.
(iv) Arguments outlined in Appendix C, based on historical observations, demonstrate that the risk of damage to the seal as a result of earthquakes or other seismic activity is negligible.
(v) Chemical reactions involving CO_2 are considered to have negligible risk associated with them in the short and medium terms. However, in the longer term (timescales of hundreds of years) we do not as yet have any experience of the effect of injected CO_2 on the seal in oil reservoirs.

Based on these calculations and analysis, which are described in more detail in Appendix C, we conclude that the risks associated with transport pathways through the cap rock and through the overburden are negligible. Some further work may be required to consider the long-term effects of CO_2 on the seal in the reservoir; this may need to include both field and laboratory studies to improve our understanding of the processes involved, followed by the development of appropriate models.

Well pathways. Pathways involving wells represent the biggest remaining area of uncertainty in the risk analysis. The Forties cap rock has been penetrated by several hundred wells, of which perhaps half have been abandoned to date. Appendix D outlines some calculations relating to levels of overpressure that might be anticipated in well bores, and make comparisons with the fracture pressures for the formation; similar comparisons might be made for cement plugs that are placed in the well bore on abandonment.

A more comprehensive assessment of the risks associated with well pathways requires a detailed audit of all the wells, which needs to focus in particular on the abandonment strategy that has been adopted in each of the wells that has been abandoned to date and also any changes to the abandonment strategy to be applied in the future, especially in the light of the potential for CO_2/water/rock, CO_2/water/cement and CO_2/water/steel reactions. Issues that need to be considered in relation to well pathways include

(i) circumstances under which CO_2 might enter an abandoned well bore in the reservoir;
(ii) how easily the CO_2 might move up the well bore, and how far it might travel;
(iii) location and circumstances under which CO_2 might escape from the well bore into the overburden, the sea or back to the platform.

Conclusions from Forties risk assessment
In this study we have identified potential pathways for escape of CO_2 from the Forties reservoir, and made an assessment of risks associated with those pathways. The risk assessments that have been made are based on a combination of analytical models and numerical simulation, and the results of these assessments are specific to the particular reservoir and the particular assumptions that have been made. It should be noted that a similar approach might be used to assess the risks associated with CO_2 injection in a different reservoir; however, the results of the risk assessment and the relative importance of the different risk factors depend on the particular circumstances that applied. The main conclusions from the risk assessment of CO_2 storage in the Forties reservoir are as follows.

(i) There are remaining uncertainties about well integrity and potential pathways to seabed through abandoned well bores. These need to be addressed through an audit of the well abandonment strategies that have been adopted to date and a review of well abandonment strategies to be applied in the future.
(ii) The risks associated with the escape of CO_2 through the cap rock and into the overburden (relating in particular to levels of overpressure and sealing of cap rock) have been shown to be negligible. A particular requirement for further work would be to address the long-term integrity of the seal in the presence of CO_2. This is an area where there is little historical experience to date.
(iii) Transport pathways through the underlying aquifer have been shown to have no significant areas of concern in the longer term. There are some possible short-term issues relating to the levels of overpressure around the injection wells and the detailed injection strategy that would need to be addressed as part of the design of the particular gas injection strategy that is adopted.

CONCLUSIONS FROM THE STUDY AS A WHOLE

The workflow necessary to select and characterize a site for storage of captured CO_2 emissions from a major industrial site has been illustrated by a case study based on the emissions from the Grangemouth refinery and petrochemicals complex.

Having selected the Forties oilfield as the most suitable storage site, a multi-scale, integrated approach was used to evaluate possible long-term leakage of geologically stored CO_2 in this mature oilfield. This approach was based on the use of commercial software. The workflow moved from the regional (basin) scale to the site-specific (field) scale, allowing a reliable reconstruction on the fluid flow pattern around the gas storage target.

The approach comprised several stages:

- simulation of the fluid flow at basin-scale using a 2D model
- simulation of the fluid flow in the aquifers around the field by 3D modelling
- evaluation of CO_2 and water interactions (diffusion) using a reservoir simulator
- risk evaluation using sensitivity tests taking into account the uncertainties of the data.

Using this novel approach the most significant risks of CO_2 escape from the Forties field can be bounded numerically using a combination of numerical simulation and scoping calculations. The potential for escape of CO_2 via geological pathways (diffusion and advective flow through the cap rock, dissolution of CO_2 into the aquifer below the oilfield and transport of CO_2-charged waters along the aquifer) is regarded as low. This is mainly due to:

- the quality and thickness of the cap rock and the overburden
- the very slow natural fluid flow velocity in the Forties reservoir and surrounding strata, controlled here by the sediment compaction rate.

Given that the risk of CO_2 escape by geological pathways appears to be very low, the potential for escape of CO_2 from the Forties field via active or abandoned wells, which could not be assessed meaningfully within the scope of the project, is perceived to be the most important unknown in the risk analysis.

Provided the risk from wells can be demonstrated to be acceptable, the Forties field appears to be an excellent potential location for CO_2 storage.

RECOMMENDATIONS

It is recommended that a comprehensive methodology for assessing the risks of leakage of stored CO_2 via wells is developed.

ACKNOWLEDGEMENTS

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APPENDIX A: KEY DATA USED IN RISK CALCULATIONS

This appendix specifies the values of key parameters pertaining to Forties. The parameter values listed here have been used in the risk calculations that are detailed in Appendices B, C and D.

Geometry
Depth to original oil–water contact = 2217 m.

Thickness of Forties aquifer ~300 m.

Height from original oil/water contact to highest point in Forties reservoir = 155 m.

Closed area of Forties structure ~90 km^2.

Volumetrics
Forties STOIIP = 6.5×10^8 m^3.

Volume of Charlie Sand = 1.8×10^8 m^3.

Reservoir Conditions
Representative Forties temperature ~205 °F.

Representative Forties pressure ~220 bar.

Fluid Densities
Density of brine at reservoir conditions = 1030 kg/m^3.

Density of oil at reservoir conditions = 750 kg/m^3.

Density of CO_2 at reservoir conditions = 540 kg/m^3.

Volume conversion for CO_2 surface to reservoir conditions $\sim(1/300)$ rm^3/sm^3.

Representative density of CO_2 at 1000 m depth, temperature 320 K = 450 kg/m^3 (note that the CO_2 density can be sensitive to the temperature value chosen).

Aquifer Flow
Estimates of Forties fluid flow patterns and rates are described in the section "Modelling of Regional Fluid Flow to Underpin the Risk Assessment". The maximum regional flow velocities in the aquifer underlying the Forties field were estimated from the TEMIS3D results. Based on these results, the values used in the risk analysis were as follows:

Maximum Darcy velocity for Forties aquifer flow $\sim$6000 m/million years (from TEMIS3D simulation) $\sim$0.006 m/year.

CO_2 Solubility and Diffusion Parameters
CO_2 solubility in water (at 200 bar, 212 °F) $\sim$150 scf/rbbl $\sim$26 sm^3/rm^3.

Diffusion in water phase (using Tyn and Calus correlation) $\sim$0.0001 $m^2/d \sim 10^{-9}$ m^2/s.

Frequency of Earthquakes
Historical data concerning the magnitude and frequency of UK earthquakes[1] enable a first pass assessment of earthquake likelihood and magnitude in the Forties area to be made.

The magnitude and frequency of Forties earthquakes can be estimated (see Table A1) using the relative size of the Forties area and the area used to compile the UK data (the Forties area is assumed to correspond to a zone of radius 100 km, beyond which seismic events will have little effect). We note that over a 22-year period the Forties area has had no seismic events above magnitude 4.0.

TABLE A1
FREQUENCY OF EARTHQUAKES OF DIFFERENT MAGNITUDES

Magnitude of earthquake	Frequency—UK area (year)	Frequency—Forties area (year)
>3.7	1	25
>4.7	10	250
>5.6	100	2500

Effects of Earthquakes of Different Magnitude
Table A2 summarizes the perceived effects at the Earth's surface from earthquakes of different magnitudes.

TABLE A2
EFFECT OF EARTHQUAKES OF DIFFERENT MAGNITUDES

Magnitude of earthquake	Effect
7	Moderate damage to buildings (chimneys fall, cracks in walls)
6	People run out in alarm, slight damage to buildings (plaster cracks)
5	Felt by most indoors, small objects fall over
4	Felt by many indoors, windows and doors rattle
3	Felt by few

[1] R.M.W. Musson, A catalogue of British earthquakes, BGS Technical Report No. WL/94/04, 1994.

Other Parameters, Assumptions
Acceleration due to gravity = 10 m^2/s.

Conversion factor 1 N/m^2 = 1 Pa = 10^{-5} bar.

Assume no overpressure in aquifer.

Assume base of concrete plug set at 1000 m depth (in well overpressure calculations).

APPENDIX B: RISK CALCULATIONS—PATHWAYS THROUGH UNDERLYING AQUIFER

This appendix details the calculations of risk for each of the pathways considered through the underlying aquifer. Note that the parameter values listed in Appendix A have been used where appropriate in these calculations without further detailed justification; reference should be made as required to Appendix A for details of the parameter values that have been used.

Dissolution in Aquifer Water—Transport by Convection
Diameter of Forties (assuming circular, based on closed area) = 10,700 m.

Upper bound on flux of water through Forties aquifer (upper bound Darcy velocity times cross-sectional area for flow) = 0.006 m/year × 300 m × 10,700 m = 19,260 m^3/year.

Suppose that all water flowing in aquifer beneath Forties is saturated with CO_2 (in practice this is an upper bound on the concentration) then maximum advective flux of CO_2 in the aquifer away from Forties = 19,260 m^3/year × 26 sm^3/rm^3 = 5×10^5 sm^3/year. At reservoir conditions, this corresponds to 5×10^5 sm^3/year × (1/300) rm^3/sm^3 = 1670 rm^3/year.

Suppose that just 15% of Forties oil volume replaced with CO_2, then reservoir volume of CO_2 stored = 10^8 rm^3. Lower bound on time to remove this amount of CO_2, by advection alone = 10^8 rm^3/(1670 rm^3/year) = 60,000 years. Proportion of stored CO_2 removed in 1000 years by advection of dissolved CO_2 in aquifer water is at most 2%.

Suppose that just 15% of Charlie Sand volume replaced with CO_2, then reservoir volume of CO_2 stored = 2.5×10^7 rm^3. Lower bound on time to remove this amount of CO_2, by advection alone = 2.5×10^7 rm^3/(1670 rm^3/year) = 15,000 years. Proportion of stored CO_2 removed in 1000 years by advection of dissolved CO_2 in aquifer water is at most 6.7%.

Note that both these calculations represent significant over-estimates of the amounts of CO_2 removed since the calculations used the maximum possible concentration of dissolved CO_2 whereas the average concentration in the aquifer water will be significantly lower.

The pore water velocity in the underlying aquifer can be calculated by dividing the Darcy velocity by the porosity of the aquifer. A different way of looking at the advective transport of dissolved CO_2 is to estimate the maximum distance that the water will move in a given time. In 1000 years, this will be at most 600 m, even if the porosity were as low as 0.01.

The above calculations have demonstrated that the advective flux of dissolved carbon dioxide in the aquifer water is insignificant compared with the volumes that are stored, and that the distance over which the dissolved gas might be transported in 1000 years is insignificant compared with the size of the Forties reservoir.

Dissolution in Aquifer Water—Transport by Diffusion
Model
A model of radial diffusion in a hollow cylinder was used (see Figure B1). The hollow represents that part of the Forties aquifer underlying the Forties structure, and we assume that the water in this

region is fully saturated with CO_2 (leading to a boundary condition on the inner surface of the cylinder).

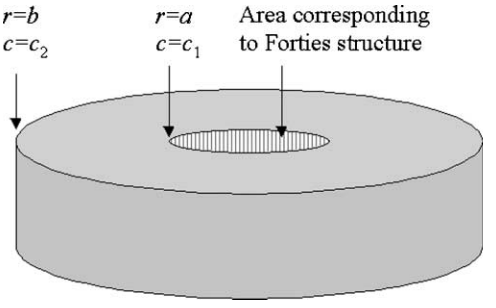

Figure B1: Model of radial diffusion in a hollow cylinder.

The governing equation is the radial diffusion equation

$$\frac{\mathrm{d}}{\mathrm{d}r}\left(r\frac{\mathrm{d}c}{\mathrm{d}r}\right) = 0 \qquad a < r < b$$

with boundary conditions $c = c_1$ at $r = a$and $c = c_2$ at $r = b$.

This has the general solution:

$$c = \frac{c_1 \log\left(\frac{b}{r}\right) + c_2 \log\left(\frac{r}{a}\right)}{\log\left(\frac{b}{a}\right)}$$

The diffusive flux through unit length of the cylinder is

$$Q = \frac{2\pi D(c_2 - c_1)}{\log\left(\frac{b}{a}\right)}$$

and through a cylinder of height h is

$$Qh = \frac{2\pi h D(c_2 - c_1)}{\log\left(\frac{b}{a}\right)}$$

where D represents the diffusion coefficient in the medium comprising the hollow cylinder.

Result of calculation
Radius of Forties (assuming circular, based on closed area) = 5350 m (a).

Concentration at inner radius = 26 sm^3/rm^3 = (26/300) rm^3/rm^3 = 0.087.

Take zero concentration at outer radius (b).

Upper bound on diffusive flux, reservoir conditions (in m^3/s) is:

$$\frac{2\pi(300\ \mathrm{m})(10^{-9}\ \mathrm{m}^2/\mathrm{s})(0.087)}{\log(b/a)}$$

Upper bound on diffusive flux (in rm^3/year) is:

$$\frac{2\pi(300\ \mathrm{m})(0.0315\ \mathrm{m}^2/\mathrm{year})(0.087)}{\log(b/a)}$$

TABLE B1
BOUNDS ON DIFFUSIVE FLUX OF CO_2 IN THE FORTIES AQUIFER

Forties radius *a* (m)	**Outer radius *b* (m)**	**(*b*/*a*)**	**Bound on diffusive flux (rm^3/year)**
5350	6500	1.215	26.5
5350	5850	1.093	57.8
5350	5500	1.028	186.8
5350	5400	1.009	555.3

Table B1 shows a range of values for the bound on the diffusive flux, using the Forties radius as the inner radius and a range of different outer radii. These bounds can be compared with the bound calculated for the advective flux of 1670 rm^3/year. Even at a distance of just 50 m beyond the Forties footprint area, the diffusive flux is therefore small by comparison with the bound already calculated for the advective flux. The bound on the diffusive flux reduces as the distance from the Forties footprint increases, and becomes negligible at distances greater than about 500 m beyond the Forties footprint area.

Transport of liquid-phase CO_2 entrained in the aquifer flow
The pore water velocity in the underlying aquifer can be calculated by dividing the Darcy velocity by the porosity of the aquifer. In 1000 years, the lateral distance moved by the aquifer water will be at most 600 m, even if the porosity were as low as 0.01. This provides an upper bound on the distance moved by the supercritical liquid-phase CO_2. If liquid-phase CO_2 were entrained in the aquifer flow and convected along with the aquifer water, then the distance moved by the CO_2 in a given time would at most be equal to the distance moved by the aquifer water. It should be noted that in the situation being considered here, any buoyancy effects will tend to retain the liquid-phase CO_2 within the Forties reservoir, preventing it from being carried downwards and out of the reservoir by the very slow groundwater flow. There are other circumstances (e.g. in a steeply dipping formation) where buoyancy effects might enhance the flow rate of the liquid-phase CO_2, and in such a case the buoyancy effect would need to be taken into account.

Effect of injection pressure on transport of liquid-phase CO_2
At the injection wells, the pressure will clearly be higher than in the surrounding region. There is a possibility that the increased pressure in the region of the injection wells may result in downward flows of supercritical liquid-phase CO_2 away from the injection point, with a possibility of eventually escaping from the Forties reservoir as a liquid-phase flow in the underlying aquifer.

This is clearly a short-term issue, which will need to be addressed as a component part of the planning of the injection phase of the project. If the location of the injection wells and/or the rates of injection are such that CO_2 is able to escape below the original oil–water contact and out of the reservoir, then this will not be an acceptable injection strategy. It is assumed that the injection strategy will be planned in such a way that this is not an issue during the injection period.

Note that once injection has ceased, pressures will decline over time and buoyancy forces will then tend to transport the CO_2 back up towards the top of the reservoir. It is sufficient therefore to consider the issue during the injection period alone. If it is not an issue during the injection period, this should ensure that there are no issues at later times.

APPENDIX C: RISK CALCULATIONS—PATHWAYS THROUGH CAP ROCK AND OVERBURDEN

This appendix details the calculations of risk for each of the pathways considered through the cap rock and overburden. Note that well pathways are considered separately, in Appendix D.

Note that the parameter values listed in Appendix A have been used where appropriate in these calculations without further detailed justification; reference should be made as required to Appendix A for details of the parameter values that have been used.

Effects of Increased Overpressure Due to CO_2 in the Reservoir

When Forties was initially filled with oil, there was a certain level of overpressure below the cap rock, arising as a result of the density difference between oil and water. If the oil is subsequently replaced by CO_2, then there will potentially be an increase in the level of overpressure, due to the fact that at reservoir conditions the density of the supercritical liquid-phase CO_2 is less than that of the oil.

Calculation

An estimate of the overpressure at the highest point of the reservoir due to a column of fluid density ρ_f (assuming no overpressure in the aquifer) is given by:

$$P_0 = (\rho_b gh - \rho_f gh)$$

For initial Forties conditions (oil-filled) this gives a maximum overpressure of 4.3 bar. Following CO_2 storage, the overpressure will be less than that due to replacing all the oil with CO_2, which gives an upper bound of 7.6 bar. The increase in overpressure due to CO_2 storage will therefore be significantly less than 3.3 bar.

Significance of overpressure

The initial pressure in Forties is approximately 220 bar. The pressure maintenance scheme that has been implemented during production of the Forties reservoir was designed to keep reservoir pressures above 170 bar. Hence we might expect to see differential pressures of tens of bars without significant leakage of fluids into Forties from overlying shale. When considering the potential escape of CO_2 from the Forties reservoir through the cap rock and into the overburden, the differential pressure has the opposite sign; however, it is instructive to make a comparison of the magnitude of the differential pressure that might be generated in each case. An increase in overpressure of 3 bar is very small in magnitude compared to the differential pressures (specifically, underpressures) that have been generated historically within Forties, and it is therefore considered unlikely to have a significant impact on the seal integrity.

Effects of Increased Overpressure Due to CO_2 Injection

At the injection wells, the pressure will clearly be higher than in the surrounding region. There is a possibility that the increased pressure in the region of the injection wells may result locally in overpressures, at the top of the reservoir, that are higher than the maximum steady state overpressures that have been calculated above. This is clearly a short-term issue, which will need to be addressed as a component part of the planning of the injection phase of the project. It is considered unlikely to be a serious issue since the injection does not commence until after the reservoir pressures have declined significantly. Note that this represents a short-term transient effect only. Once injection has ceased, pressures will decline over time. It is sufficient therefore to consider the issue during the injection period alone.

Potential for Damage to Seal Due to Earthquake

Appendix A includes a discussion of frequency and magnitude of earthquakes in the UK. Damage to the seal due to earthquakes is considered unlikely. This can be demonstrated using a historical argument, based on the relatively low likelihood and magnitude of earthquakes, and the fact that the seal is good—evidenced by the fact that on discovery the Forties trap was full to the spill point.

Potential for Damage to Seal Due to Chemical Reactions

In the short and medium term this is considered unlikely to be an issue, based on current field experience. It is known that the seal has long-term resistance to reactions with hydrocarbon gas, evidenced by the fact that the trap must have existed over extremely long timescales for the hydrocarbon to have accumulated. There is evidence from CO_2 injection for EOR that putting CO_2 into oil reservoirs does not cause seal damage in the short to medium term (i.e. tens of years). In the longer term there is as yet no field experience on which to base any assessment (either for or against). We may need to undertake further work to demonstrate that this is not an issue on the 100–1000 year timescale.

Potential for CO_2 Escaping through Cap Rock

Estimates of Forties fluid flow patterns and rates are described in the section “Modelling of Regional Fluid Flow to Underpin the Risk Assessment”. The SIMUSCOPP simulator was used to assess the potential for CO_2 escaping through the cap rock and into the overburden. SIMUSCOPP is a 3-phase, 3D, compositional porous medium flow simulator, which can model the effects of dissolution and diffusion. The model, which covered the Forties footprint area, was based on a submodel taken from the basin-scale TEMIS3D model. The rock properties and boundary conditions for the model were extracted from the appropriate region of the TEMIS3D model. The SIMUSCOPP model was initialised with brine and CO_2 only; the initial CO_2 saturation was 0.5 in all grid blocks within the Forties reservoir that lay above the Forties initial oil–water contact and zero elsewhere. This initial condition was set up to be a simplified representation of the conditions at the end of the storage phase. The SIMUSCOPP model was used to provide an estimate of the leakage of CO_2 through the cap rock, including the effects of dissolution and diffusion of dissolved CO_2, for a number of different scenarios. The conclusion from these calculations is that escape through the cap rock is most unlikely to represent a significant risk of release of CO_2 into the overburden and ultimately to the seabed.

Base case

In the base case run, the shale properties were set up to be representative of Forties; the capillary entry pressure for CO_2 to enter the shale was taken to be 4 bar (equivalent to the original overpressure in Forties when it was oil-filled). In this case, there is negligible escape of CO_2 into the cap rock and overburden (of the 3.9×10^8 tonnes of CO_2 in the SIMUSCOPP model, less than 0.2% enters into the overlying layers on a 1000 year timescale).

Sensitivity cases

Two sensitivity cases were carried out. The first of these was identical to the base case except that the capillary entry pressure for the shale layers overlying the reservoir was set to zero. The second sensitivity case also had zero capillary entry pressure and in addition the vertical permeability was increased by a factor of 10 in the shale layers. The modifications made in the sensitivity cases were designed to make it significantly easier for the CO_2 to escape from the reservoir and are not considered to be realistic. As expected, both sensitivity cases showed some CO_2 escaping through the cap rock, but in neither case did the CO_2 get anywhere near the surface. Even in the worse case, on a timescale of 1000 years the maximum vertical distance moved by any of the CO_2 was less than half-way to the seabed.

Diffusion of Dissolved CO_2 through Overburden

It is possible to perform an analytical calculation to estimate a bound on the vertical diffusive flux of dissolved CO_2 through the cap rock and into the overburden.

Analytical model

A model of 1D (vertical) diffusion was used. The base of the model represents the base of the Forties cap rock, and we assume that the water in this region is saturated with CO_2 (leading to a boundary condition at $z = 0$). The diffusive flux at a height h above the top of Forties is bounded by the flux calculated from the solution of the linear steady-state diffusion equation

$$\frac{\mathrm{d}}{\mathrm{d}z}\left(D\frac{\mathrm{d}c}{\mathrm{d}z}\right) = 0 \qquad 0 < z < h$$

with boundary conditions $c = c_0$ at $z = 0$ and $c = 0$ at $z = h$, where D represents the diffusion coefficient in the medium comprising the cylinder.

Hence

$$D\frac{dc}{dz} = A$$

and

$$c = \left(\frac{A}{D}\right)x + B$$

Applying the boundary conditions:

$$c = c_0 - \frac{Ax}{Dh}$$

The quantity $(-A)$ represents the vertical diffusive flux per unit area of the reservoir.

Results of calculation
Concentration at base of cap rock = 26 sm^3/rm^3 = (26/300) rm^3/rm^3 = 0.087

$$A = \frac{10^{-9}(m^2/s) \times 0.087(m^3/m^3)}{h(m)} = \left(\frac{8.7 \times 10^{-11}}{h}\right)(rm^3/s/m^2)$$

Forties area = 90 km^2 = 9×10^7 m^2. Hence bound on total diffusive flux is:

$$\left(\frac{8.7 \times 10^{-11} \times 9 \times 10^7}{h}\right)(rm^3/s) = \frac{7.83 \times 10^{-3}}{h}(rm^3/s) = \frac{2.5 \times 10^5}{h}(rm^3/year)$$

Take $h = 100$ m (for example), then the total vertical diffusive flux 100 m above the base of the cap rock is less than 2500 rm^3/year. Suppose that just 15% of Forties oil volume replaced with CO_2, then reservoir volume of CO_2 stored = 10^8 rm^3.

Lower bound on time to remove this amount of CO_2, by vertical diffusion through cap rock and overburden to a distance of at least 100 m above reservoir = 10^8 rm^3/(2500 rm^3/year) = 40,000 years. The proportion of stored CO_2 removed in 1000 years to at least 100 m above reservoir by vertical diffusion of dissolved CO_2 through the cap rock and overburden is at most 2.5%.

APPENDIX D: RISKS ASSOCIATED WITH WELL PATHWAYS

In this appendix we detail the key pathways associated with wells. A full assessment of risk for these pathways would require detailed information about the well design and abandonment strategy that has been adopted in the field to date, and may also require specification of well abandonment strategies for wells that are still operating. Some aspects of the risks have been quantified where appropriate information is available. Well pathways are identified as a key area requiring further study in order to gain a comprehensive and in-depth understanding of the risks.

Note that the parameter values listed in Appendix A have been used where appropriate in these calculations without further detailed justification; reference should be made as required to Appendix A for details of the parameter values that have been used.

Potential for Escape along Well Pathways
The cap rock has been penetrated many hundreds of times, in different locations, as a result of drilling activities associated with field development. A comprehensive risk assessment needs to consider the potential for CO_2 escape along each of the resulting well pathways at different stages in field life.

The long-term issues relate mainly to abandoned wells, since all wells will eventually be abandoned. In the short and medium terms, there are potential issues relating to operational wells (both producers and injectors), suspended wells and abandoned wells.

Once CO_2 has entered a well there are a range of pathways for transport to the surface. These include transport up the well bore followed by release into the formation at shallower depth, release at the seabed, or release at a platform. Note that release on the platform is only an issue for any particular well up to the time of final removal of casing strings down to the seabed. This is therefore also a well abandonment issue.

Number of Potential Well Pathways

The estimates of the number of potential well pathways shown in Table C1 are based on information provided by Apache North Sea (the operator of Forties) in December 2003.

Apache have estimated that they will drill a further 30 wells over the next 10 years (of which most are expected to be sidetracks, usually from dead or suspended wells) and that the program will result in a further 24 abandoned well bores over this period.

TABLE C1
ESTIMATES OF NUMBER OF POTENTIAL WELL PATHWAYS

Current well status	Well count
Producers	55
Water injectors	12
Dead (not used, but not formally suspended)	7
Suspended	27
Abandoned	89
Total	190

Well Abandonment Guidelines

The UK Offshore Operators Association has issued Guidelines for the Suspension and Abandonment of Wells. These guidelines require that two permanent barriers be set between the surface or seabed and any hydrocarbon-bearing permeable zone. A cement column of at least 100 ft measured depth of good cement is considered to constitute a permanent barrier; where possible 500 ft plugs are set. In addition, a single permanent barrier is required to isolate any water-bearing permeable zones from the seabed.

The guidelines recommend that the base of the first barrier be set across the top permeable zone of the reservoir or the top perforations, whichever is shallower, and should extend at least 100 ft above the highest point of potential inflow. The fracture pressure for the cement at the base of the first barrier should be in excess of the potential internal pressure (which is defined to be the maximum anticipated pressure that may develop below plugs in the well bore following abandonment).

On final abandonment it is good practice to retrieve all casing strings to a minimum of 10 ft below the seabed. In certain cases where large (e.g. concrete) structures remain permanently on the seabed, the requirement may be relaxed such that no casing strings may extend above the remaining structure.

Two categories of well pathways need to be considered in relation to abandoned wells.

(i) In the first group are the wells that have already been abandoned, where a detailed audit would be required to establish the criteria that have been used to design the abandonment strategy. It should be recognized that well abandonment design may have been carried out without anticipating the potential for leakage of CO_2 into the well bore, and that the abandoned well may not meet the same criteria that would apply to a future abandonment.

(ii) In the second group are all wells that have yet to be abandoned. The design of the abandonment strategy for these wells needs to take full account of the presence of CO_2 in the reservoir.

Effects of Increased Overpressure Due to CO_2 Filling Well Bore

The following sections consider some of the issues relating to the potential for leakage of carbon dioxide along well pathways and, in particular, the maximum level of overpressure that might arise below a permanent barrier in an abandoned well due to the accumulation of carbon dioxide below the plug and the possible consequences of that level of overpressure.

Calculation

The overpressure at base of concrete plug due to height h of CO_2 below it is given by

$$P_\mathrm{w} = (\rho_\mathrm{b} - \rho_\mathrm{c})gh$$

The maximum overpressure due to a height h of CO_2 is $5.8 \times 10^{-2}h$ bar (taking the minimum value for the density of CO_2 that has been estimated at 1000 m depth, corresponding to a pressure of 100 bar, and temperature 320 K). This is shown in Table D1 for various values of h.

We note the following.

(i) The Forties original oil–water contact is at 2217 m, corresponding to the spill point. Hence the maximum possible column of CO_2 below a plug set at 1000 m depth would be 1217 m, and the overpressure calculated for 1250 m represents an upper bound.

(ii) The effect of any overpressure would be to increase the average CO_2 density in the column and therefore to reduce the level of overpressure compared with the tabulated values.

TABLE D1
OVERPRESSURE AT BASE OF CONCRETE PLUG

h **(m)**	**Overpressure (bar)**	**Overpressure (psi)**
10	0.58	8.4
100	5.80	84.0
1000	58.00	840.0
1250	72.50	1050.0

Comparison with fracture pressure for rock

The fracture pressure of a rock can be estimated as a fraction (typically around 90%) of the overburden pressure; the overburden pressure gradient is approximately 1 psi/ft, so the fracture pressure can be related to the depth by

$$P_\mathrm{frac} = 0.9d$$

where the fracture pressure is measured in psi and the depth is in ft. At a depth of 1000 m (= 3280 ft), the fracture pressure is around 2950 psi. This compares with the potential internal pressure below the cement plug of 2500 psi (equal to the sum of the hydrostatic pressure at 1000 m, which is 100 bar or 1450 psi, and the maximum overpressure of 1050 psi that results from a 1250 m column of CO_2 below the plug). This is still significantly lower than the fracture pressure.

Comparison with fracture pressure for cement plug

As discussed above, the UKOOA Guidelines for the Suspension and Abandonment of Wells require the strength of the cement to be such that the fracture pressure of the cement exceeds the potential internal pressure at the base of the plug. Two key questions are: what is the design strength of the concrete that has actually been used to date when abandoning wells, and how is this likely to degrade over long periods of time (e.g. over a 1000 year period) in the presence of CO_2?

Sensitivity to Depth of Placement for Cement Plug

The density of CO_2 changes very rapidly around 600–800 m depth (e.g. at 1000 m depth, 100 bar pressure the density is $\sim$450 kg/m^3; at 600 m depth, 60 bar pressure, the density reduces to $\sim$200 kg/m^3). If the plug is set shallower than 800 m, then we need to consider carefully the possible effects of fracturing of the cement plug. Below the plug, the pressure will depend on the thickness of the CO_2 column, and pressure will be higher than in surrounding formation and higher than that in the well bore above the plug. If the cement fractures, and CO_2 is able to escape, there will be a sudden drop in pressure and a corresponding (potentially large) rapid increase in gas volume. This might lead to an explosive blowout of the contents of the well bore.

If the cement plug is set closer to the surface, then the fracture pressure of the formation will also be correspondingly reduced. If the overpressure were sufficient to fracture the formation, then the same issues relating to sudden pressure release might apply, depending on the nature of the pathways that were formed. If the plug is set any higher than about 800 m depth, the risk is likely to be increased compared to a plug set at a deeper level. It will be necessary to consider the abandonment strategy and the depths at which the first and second permanent barriers are set and it would be prudent to ensure that second permanent barrier is set deeper than 800 m.

Leakage from Well into Formation Resulting from Overpressure

It has been shown above that fracturing of the formation is not likely to occur in the Forties scenario as a result of the level of overpressure that might arise from the accumulation of CO_2 in an abandoned well bore. Another issue that must be considered is the potential for leakage of CO_2 into permeable zones in the overburden. The UKOOA Guidelines for the Suspension and Abandonment of Wells require a permanent barrier to be set across any permeable water-bearing zones, the intention being to prevent leakage in either direction between the permeable layer and the well bore. A key question therefore is what permeability threshold has been applied in identifying a zone as permeable and what leakage might potentially occur into layers where the permeability was just below this threshold. The question of what leakage might potentially occur from the well bore into the formation, and what the fate of any such leakage would be (pathways to the seabed, timescales, etc.) is identified as an area for future investigation. This question can only be addressed through a detailed investigation of a range of specific examples of abandoned wells; this is beyond the scope of the present study.

Leakage from Well into the Sea

Risks associated with leakage from a well into the sea include the reduction in buoyancy due to gas bubbles; increased levels of dissolved CO_2 leading to an adverse impact on marine life; density-driven convection (reduced density resulting from dissolved CO_2) and a potential for instability with gas subsequently coming out of solution at reduced depths; and finally the effects of CO_2 release at sea surface.

Leakage Through Well with Release on Platform

Prior to the final removal of casing strings between platform and seabed there is a possibility of leakage back to the platform. Risks include CO_2 build-up in enclosed spaces on platform (e.g. sleeping areas); the build-up of a layer of dense CO_2 on platform (primarily of concern in calm conditions when it might lead to dangers of asphyxiation for workers.

Potential for Damage to Wells Due to Earthquake

Appendix A includes a discussion of frequency and magnitude of Earthquakes in the UK. Over a 22 year period the Forties area has had no seismic events above magnitude 4. There has been no reported damage to any North Sea wells due to earthquake over this period. Given the low frequency of earthquakes and their limited magnitude, this is considered to be a negligible risk.

NOMENCLATURE

BGS	British Geological Survey
EOR	enhanced oil recovery
EU	European Union
FEP	features, events and processes
GEUS	Geological Survey of Denmark and Greenland
GSGI	gravity stable gas injection
IFP	Institut Francais du Petrole
Ma	million years
mD	millidarcies
MMrb	million reservoir barrels
MMstb	million standard barrels
psia	pounds per square inch (absolute)
STOIIP	stock tank oil initially in place
WAG	water alternating with gas

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