Carbon dioxide storage in the Captain Sandstone aquifer: determination of in situ stresses and fault-stability analysis

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Abstract: The Lower Cretaceous Captain Sandstone Member of the Inner Moray Firth has significant potential for the injection and storage of anthropogenic CO2 in saline aquifer parts of the formation. Pre-existing faults constitute a potential risk to storage security owing to the elevated pore pressures likely to result from large-scale fluid injection. Determination of the regional in situ stresses permits mapping of the stress tensor affecting these faults. Either normal or strike-slip faulting conditions are suggested to be prevalent, with the maximum horizontal stress orientated 33°–213°. Slip-tendency analysis indicates that some fault segments are close to being critically stressed under strike-slip stress conditions, with small pore-pressure perturbations of approximately 1.5 MPa potentially causing reactivation of those faults. Greater pore-pressure increases of approximately 5 MPa would be required to reactivate optimally orientated faults under normal faulting or transitional normal/strike-slip faulting conditions at average reservoir depths. The results provide a useful indication of the fault geometries most susceptible to reactivation under current stress conditions. To account for uncertainty in principal stress magnitudes, high differential stresses have been assumed, providing conservative fault-stability estimates. Detailed geological models and data pertaining to pore pressure, rock mechanics and stress will be required to more accurately investigate fault stability.

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relative tectonic quiescence, resulted in the development of numerous half-graben and associated synrift deposits over the area (Hillis et al. 1994; Zanella & Coward 2003). The regional extension direction during this time was NE–SW, resulting in the formation of new NW-trending normal faults or reactivation of existing faults with normal or strike-slip components depending on their orientation: for instance, existing ENE-trending faults might have been reactivated with a strike-slip component (Zanella & Coward 2003). The progressive onlap shown by Lower Cretaceous shales and sands onto basin margins and of the Upper Cretaceous Chalk onto basin highs is interpreted as evidence of a post-rift thermal phase of subsidence, with the sedimentary environment in this area set against a background of rising sea level (Hillis et al. 1994). However, during the Lower Cretaceous, this general increase in sea level was punctuated by sea-level falls during the Hauterivian–Valanginian and later during the Aptian times, related to far-field tectonic events (Oakman 2005). These periods of lowered sea level exposed shelf areas and caused sand, originally sourced from north and west of the Wick Fault Zone, to be deposited in deeper water by gravity-flow processes feeding submarine fans that led to the accumulation of the Wick Sandstone Formation (Fig. 2) (Johnson & Lott 1993). The half-graben topography played an important role in the distribution of Lower Cretaceous sandstones in these basins (Rose et al. 2000). Deposition of the Late Cretaceous

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**Fig. 1.** Location of the study area, main geological features relevant to this study (IMF and OMF, Inner and Outer Moray Firth, respectively), wells (small dots, wells used in the study are labelled) and the British Geological Survey (BGS) seismicity catalogue up to 2012 (filled circles). Fault locations shown for the base Cretaceous and top Captain Sandstone depth contours (metres relative to the seabed) were derived from SCCS (2011). Note the Kopervik Fairway is known to extend further eastwards than shown (Law et al. 2000; Marshall et al. 2016). Offshore quadrant and field linework contain public sector information licenced under the Open Government Licence v3.0.

**Fig. 2.** Lithostratigraphy of the Inner Moray Firth after Johnson & Lott (1993). Significant sandstone bodies are highlighted grey.
Chalk Group reflects the widespread flooding of the basin/high topography during a time of relative tectonic quiescence but punctuated by pulses of compression related to the Alpine Orogeny, although in the study area the effects are thought to be quite weak (Zanella & Coward 2003). Regional uplift of the Scottish Highlands and East Shetland Platform at the beginning of the Paleocene led to the deposition of large volumes of silicilastic sediments (Ahmadi et al. 2003). In the study area, a shelf-environment setting prevailed with deposition characterized by transgression and restricted deposition along basin margins or regression leading to more widespread gravity-flow deposition into the basin itself (Garrett et al. 2000; Ahmadi et al. 2003). It is generally accepted that the subcrop of Mesozoic and Cenozoic rocks at the seabed in the Inner Moray Firth is the result of Cenozoic uplift (Argent et al. 2002), and Hills et al. (1994) suggested significant uplift and erosion during the Danian. Cenozoic uplift led to the reactivation of earlier faults, some of which have propagated to the seabed. However, Richardson et al. (2005) noted that the main bounding fault of the Beatrice Field had not propagated to the seabed and remained as a seal for the trapped hydrocarbons.

Over the study area, the post-Jurassic succession comprises Paleocene, Upper Cretaceous Chalk and Lower Cretaceous Cromer Knoll groups that shallow and progressively subcrop the seabed towards the coast (Fig. 1). The Lower Cretaceous Cromer Knoll Group generally rests conformably on Upper Jurassic sediments over much of the area (Thomson & Underhill 1993) and reaches thicknesses of more than 1000 m to the NW, adjacent to the Wick Fault Zone (Copestake et al. 2003), but thins and onlaps the Captain Ridge and Halibut Horst (Rose 1999). In some areas, the Lower Cretaceous and underlying Jurassic are absent, and Upper Cretaceous Chalk rests unconformably on Devonian Old Red Sandstone. The Upper Cretaceous Chalk varies in thickness from 250 to 500 m, and reaches over 750 m south of the Wick Fault Zone. It is absent along the western margin of the model due to erosion (Surlýk et al. 2003) and here the underlying Lower Cretaceous stratigraphy subcrops at the seabed (Fig. 1). The Paleocene is also absent along the western margin of the model, but thickens rapidly to more than 900 m on the southern side of the Halibut Horst, and varies between 200 and 750 m over much of the study area (Ahmadi et al. 2003).

The Lower Cretaceous Cromer Knoll Group (Fig. 2) (Johnson & Lott 1993) comprises the Rodby, Carrack, Valhall and Wick formations. The Lower Cretaceous Wick Sandstone Formation comprises laterally extensive units of occasionally thick sandstone interbedded with siltstone and mudstone that are interpreted as having been deposited by a range of mass-flow processes (Fig. 2) (Johnson & Lott 1993). The Wick Sandstone Formation has been divided into three members: the Captain Sandstone (Early Aptian–earliest Albian) is the youngest of three members, the others being the Coracle (latest Early Hauterivian–earliest Barremian) and the Punt (intra-Late Ryzanian–earliest Hauterivian). Because there are fewer well penetrations at depth, the older members are poorly resolved on seismic data, and the extent and disposition of the Coracle and Punt sandstones is not well known. The Wick Sandstone Formation passes laterally into the dominantly mud-prone successions of the Valhall Formation, which comprises interbedded calcareous mudstone and thin limestone, and the Carrack Formation that comprises non-calcareous, carbonaceous, pyritic, micaceous mudstone and siltstone: both of these formations may also locally contain mass-flow sandstone and occasional conglomerate (Johnson & Lott 1993). The overlying Rodby Formation comprises calcareous mudstone with occasional thin beds of argillaceous limestone.

**Geological model location and context**

Hydrocarbons are produced from the Captain Sandstone in several fields, notably the Captain and Blake oil fields, the Cromarty Gas Field, and the Atlantic and Goldeneye gas condensate fields. The Wick Fault Zone forms the northern boundary to the Captain Sandstone, while faulting and stratigraphic closure form the southern boundary. With the exception of the Captain Oil Field, which is situated on the Captain Ridge to the west of the Halibut Horst, the other fields are located along a thin sand-rich pan-handle termed the Kopervik Fairway (Law et al. 2000) that extends eastwards along strike of the South Halibut Trough. The depleted Goldeneye Field has been proposed as a site for the storage of CO$_2$ (Shell 2011a; Marshall et al. 2016): however, the present study focuses on the main depocentre to the West of the Halibut Horst, corresponding roughly to the Wick Sub-basin, the Smith Bank High and the Smith Bank Graben, where a pre-existing 3D geological model is available. The model does not extend eastwards beyond the Atlantic Field in the vicinity of the Grampian Arch, and so does not include the full length of the Kopervik Fairway (Fig. 1). The model comprises the Captain Sandstone aquifer and its under- and overburden, and has been adapted from interpretations used to generate the reservoir simulation model of Jin et al. (2012), based on interpretation of 2D seismic reflection and well data. The data and methodology that contributed towards the geometry and structure of the original model is described in a research report (Quinn et al. 2010), and is not described in detail here.

Unlike the proposed Goldeneye storage site, in this area there are no specific structural traps that have been specifically identified for CO$_2$ storage, so any prospective projects would need to take measures to avoid the updip migration of CO$_2$ towards shallower depths and, ultimately, towards the seabed. Water depth across the study area is in the range of 30–120 m, with an average of 90 m.

In the adapted model used here, faulting has been restricted to those faults that affect the Captain Sandstone reservoir and its overburden only, as these are the faults most likely to experience increased pressure during injection and to pose a risk to storage integrity. Deeper faults that do not cut the Captain Sandstone or its overburden would not be expected to experience significant increased pore-pressure perturbations as a result of injection, so reactivation of these faults, although possible, is not considered a risk to storage integrity despite the potential for induced seismicity. The number of faults within the model was therefore reduced from 43 to 15. It is noted that unmapped or non-seismically resolvable faults are also likely to be present across the study region given that no 3D seismic reflection data were available to the mapping exercise. The potential presence of such faults should also be considered in studies of regional geomechanical stability.

![Fig. 3. Pressure measurements and hydrostatic gradient to surface across the Captain Sandstone. Location of the wells shown in Figure 1.](http://pg.lyellcollection.org/Downloaded.html)
Table 1. Summary of wellbore breakouts interpreted from image logs. The mean and standard deviation have been calculated using the directional statistics of Mardia (1972). Image logs for well 13/24a-6 were not reinterpreted as part of this study.

| Well name      | Image type | Start depth (m) | Number of breakouts | Total length (m) | $S_{\text{hmax}}$ azimuth | Standard deviation | WSM rank |
|----------------|------------|-----------------|---------------------|------------------|--------------------------|-------------------|----------|
| 13/24a-4       | FMI        | 937             | 1                   | 0.73             | 30                       | –                 | D        |
| 13/24b-3       | UBI        | 1590            | 4                   | 2.9              | 42                       | 12                | D        |
| 13/26a-4       | FMI        | 1021            | 10                  | 8.15             | 29                       | 6                 | D        |
| 13/24a-6       | STAR       | –               | 27                  | –                | 33                       | –                 | –        |
| Combined (this analysis) | –          | 937–1590 (range) | 15                | 11.78           | 33                       | 9                 | D        |

As shown by Figure 1, the area is relatively aseismic, with the exception of a series of seismic events clustered around the Beatrice Oil Field. Although the co-location of the seismicity in relation to the field boundaries suggest that they may be related to petroleum production, Wilson et al. (2015) curiously observed little correlation in relation to the production and injection history of the field.

**Determination of the stress field**

In order to examine the stability of faults in the current stress regime, and to quantify the effects of increasing pore-fluid pressures, it is necessary to consider the 3D geometry of the faults, and to understand the orientations and magnitudes of the three principal stresses. Such information is either directly measurable or can be inferred from data acquired in hydrocarbon wells. In this section, the characteristics of the stress field affecting the Cretaceous and younger strata are derived from hydrocarbon well data.

**Pore-fluid pressure**

Direct measurements of pore-fluid pressure over the Lower Cretaceous are available from several hydrocarbon wells across the study region. Repeat Formation Tester (RFT), Modular Formation Dynamics Tester (MDT) and Formation Multi Tester (FMT) data provide pressure measurements over the Captain, Coracle and Ettrick sandstones, and record a pore-fluid pressure gradient of approximately 0.01 MPa m⁻¹ (Fig. 3). A similar pore-pressure gradient is seen in the Jurassic Claymore and Ross Sandstone members in well 13/26a-4. The pore-pressure measurements are slightly above an assumed hydrostatic gradient of 10 MPa km⁻¹ from the surface level, but as the Lower Cretaceous penetrated by these wells contains hydrocarbons, and given the lack of information regarding brine salinity variations with depth, a pore-pressure gradient of 10 MPa km⁻¹ to the surface is assumed over the wider area. Despite the history of oil and gas production from the Captain Sandstone, widespread pressure depletion of the reservoir pore pressure is unlikely in the area west of the Kopervik Fairway due to pressure maintenance in the Captain and Blake oil fields (Du et al. 2000; Pinnock & Clitheroe 2003). Owing to the good fit of the assumed gradient to the observed data, the variation in the pore-pressure gradient is expected to be small and should not significantly affect the results of the fault-stability analysis.

**Stress orientations**

The vertical stress ($S_v$) is generally considered to be one of the principal stresses in the subsurface, while the other two principal stresses are horizontal and orthogonal to each other. Borehole breakout and drilling-induced tensile fracture are modes of borehole failure resulting from stress concentration in the rock around a wellbore once the material supporting that rock is removed (Zoback et al. 1985; Bell 1990). Breakouts are enlargements of the borehole wall formed by the development of conjugate shear fractures, while drilling-induced tensile fractures develop as narrow features sub-parallel to the borehole axis in vertical wells and are not associated with significant borehole enlargement. In approximately vertical boreholes, such as those studied here, breakouts occur in the direction of the minimum horizontal stress ($S_{\text{hmin}}$) and therefore the borehole is enlarged in a direction perpendicular to the maximum horizontal stress ($S_{\text{hmax}}$), while drilling-induced tensile fractures strike in the direction of $S_{\text{hmax}}$ (Plumb & Hickman 1985; Aadnoy & Bell 1998).

Downhole ultrasonic televiwer and electrical borehole image logs provide a means by which to interpret the presence or absence of both borehole breakouts and drilling-induced tensile fractures, and therefore to determine the orientations of the horizontal principal stresses over the logged intervals. Ultrasonic borehole image (UBI) log data are available for the 13/24b–3 well, and Formation Micro Imager (FMI) logs are available for three other wells in the area, enabling an analysis of the stress orientations in the region. While no drilling-induced tensile fractures were observed from any of the logs, several breakouts are observed in three of the wells (Table 1). No reliable breakouts were detected in well 13/22a-21, possibly due to the limited borehole coverage imaged by the logs in this well. As such, it is not possible to determine that borehole breakouts are absent in this well, only that they are not detected using the logs available. Four discrete breakouts were observed in well 13/24b-3, examples of which are shown in Figure 4. Figure 5 shows examples of observed borehole breakouts from the FMI logs in well 13/26a-4. Although this well lies outside the extent of the Captain Sandstone Member, the FMI log provides some good examples of borehole breakout over the time-equivalent Valhall and Carrack formations.

Borehole breakouts observed from image logs in several wells from the IMF provide information relevant to the determination of stress orientation in the basin (Table 1). The measurements all support a generally NE–SW orientation of $S_{\text{hmax}}$. The measurements have been subjected to the quality ranking scheme utilized by the World Stress Map (WSM) project (Sperner et al. 2003; Heidbach et al. 2010). They are considered to represent good
measurements of the horizontal stress directions due to the clarity of the processed images: however, these would be classified only as category D measurements according to the WSM ranking scheme. This is due to the limited number of observed breakouts in these wells and to the short combined length (height) of the observed breakouts. As the breakout orientations appear to be consistent across the region, they are considered to be representative of the far-field orientation of $S_{\text{Hmax}}$, so the mean orientation of $33^\circ$–$213^\circ$ derived from all breakout orientations using the directional statistics of Mardia (1972) is used in this analysis. The orientations of $S_{\text{Hmax}}$ are shown in Figure 6. These observations are consistent with those of 27 breakouts that indicate $S_{\text{Hmax}}$ striking in a mean orientation of $33^\circ$–$213^\circ$ reported from the Valhall Formation in well 13/24a-6, interpreted from the analysis of Simultaneous Acoustic and Resistivity (STAR) image logs reported by Hilton (1999). Although the STAR image logs have not been reinterpreted for this study, the reported orientation of $S_{\text{Hmax}}$ from the well is also shown in Figure 6. Although it is noted that only a limited dataset is available, the mean $S_{\text{Hmax}}$ orientation is considered to be reasonably well constrained due to the similarity of orientations at different depths and in each of the studied wells, and due to the low standard deviation of all the breakouts (9.4°). It is not expected that a variation of this amount will be sufficient to significantly affect the fault-stability analysis.

The far-field stresses affecting NW Europe result from the configuration of tectonic plate boundaries and associated ridge-push forces (Golick & Coblenz 1996); however, the orientations of $S_{\text{Hmax}}$ observed from the IMF suggest a departure from the NW–SE orientation expected, which is observed onshore UK (Kingdon et al. 2016). This suggests that the structural lineaments bounding the IMF Basin have altered the orientation of the tectonic stresses, a feature of the North Sea stress field previously suggested by Cowgill et al. (1993). Perman evaporite sequences are relatively thin and do not impose a control on the Mesozoic–Recent stress regime as they have been proposed to do in the Central and Southern North Sea regions (Hillis & Nelson 2005; Williams et al. 2015).

### Stress magnitudes

The magnitude of the vertical stress ($S_v$) was obtained by integrating rock densities from downhole bulk density logs in three wells using equation (1), after Zoback et al. (2003):

$$S_v = \rho_w g z \rho + \int_{z_w}^{z_f} \rho(z) g \, dz = \rho_w g z_w + \rho g (z - z_w)$$

where $\rho(z)$ is density as a function of depth, $g$ is the acceleration due to gravity, $\rho_w$ is the mean overburden density, $\rho_w$ is the density of water (taken as 1 g cm$^{-3}$) and $z_w$ is water depth. As the strata in the shallower section were not logged by the density tool (Fig. 7a), an average rock density of 2.5 g cm$^{-3}$ was inferred for the unlogged section up to the seabed. An average overburden stress profile was calculated from the three wells and is shown in Figure 7b. The overburden stress gradient to the seabed can be conveniently expressed as a $S_v$ gradient of 25 MPa km$^{-1}$. The lack of density logs in the shallower section (Fig. 7a) gives rise to some uncertainty regarding the magnitude of $S_v$. Bulk density of the relatively less-consolidated Palaeogene in the shallower subsurface is likely to be less than that assumed, and so the calculated overburden stress profile could give rise to slightly elevated $S_v$ magnitudes at depth. This would result in greater differential stress between $S_v$ and the minimum principal stress, resulting in a higher susceptibility of faults to fail. The fault-stability analysis is therefore regarded as conservative.

The magnitude of the least principal stress (fracture pressure) is commonly estimated from leak-off tests (LOTs), during which small-scale hydraulic fracturing occurs. The tests are conducted in short open-hole well sections beneath cemented casing shoes primarily to assess suitable drilling mud densities, but can also be used to determine the magnitude of the least principal stress. Available LOT data for four wells in the area are shown in Table 2. Extended leak-off tests (XLOT) provide an improved estimate of the $S_{\text{hmin}}$ magnitude: however, no such data are available in the study area. In the absence of XLOT measurements, the lower bound of LOT data provides an estimate of $S_{\text{hmin}}$, although it is noted that XLOTs should be acquired where detailed stress data are required (Addis et al. 1998; White et al. 2002).

A single LOT value is reported for the 13/24b–3 well, recorded in the Tor Formation in the uppermost part of the Chalk Group. The value reported is close to the calculated $S_v$ of approximately 23.14 MPa at that depth. As the test was taken in strata described as firm–hard limestone at relatively shallow depth (998 m below sea level, as shown in Fig. 8), it is uncertain how the least principal stress orientations calculated from the observation of borehole breakouts in the study wells across the study region. No stress orientation could be determined for well 13/22a-21.
stress magnitude relates to the unconsolidated sandstones of the Captain Sandstone Member or to the mudstones of the overlying Rodby Formation caprock. The other three reported LOT values were all taken from the Aptian–Barremian-aged Valhall or Wick Sandstone formations, and the values are therefore more likely to represent those applicable to the Captain Sandstone and its clay-rich overburden. A $S_{\text{min}}$ gradient of 18 MPa km$^{-1}$ relative to the seabed appears to represent a suitable lower bound to the LOT data, and is taken here to represent $S_{\text{min}}$ in the fault-stability analysis (Fig. 8), although the Tor Formation measurement indicates that the magnitude of $S_{\text{min}}$ is not a simple linear gradient through the overburden. This gradient is similar to the assumed 18.09 MPa km$^{-1}$ fracture pressure gradient noted by Jin et al. (2012). Because leak-off pressure does not provide a direct measurement of $S_{\text{min}}$, depending as it does on other factors such as lithology, drilling fluids and wellbore stability, there is inherent uncertainty in the $S_{\text{min}}$ gradient determined, particularly given the limited number of test data available. The sand-rich nature of the lithologies tested by the lowest LOT measurements are expected to possess lower fracture pressures than the overburden lithologies, to some extent justifying the use of the lower bound to the LOT data to represent the lower bound of $S_{\text{min}}$ in the absence of more reliable XLOT data. Using the lower bound as an estimate of $S_{\text{min}}$ provides larger differential stresses, ensuring that the fault-stability analysis is conservative. Greater differential stresses would result in faults being closer to failure in the current stress regime, while smaller differential stresses will tend to increase the mechanical stability of faults.

According to critically stressed faulting theory, it is possible to determine the upper and lower bound magnitudes of $S_{\text{min}}$ and $S_{\text{hmax}}$ for any particular depth given knowledge of the pore pressure, $p$, and the coefficient of friction. A stress polygon (Moos & Zoback 1990; Zoback et al. 2003) can be constructed to illustrate the allowable stress states constrained by the strength of faults optimally oriented for failure in the current stress regime using equation (2), after Jaeger et al. (2007):

$$\frac{\sigma_1}{\sigma_3} = \frac{S_1 - P_p}{S_3 - P_p} \leq (\mu^2 + 1)^{1/2} + \mu^2$$

where $P_p$ is pore pressure, $S_1$ and $S_3$ are respectively the maximum and minimum principal stresses, and $\mu$ is the coefficient of friction. Byerlee (1978) shows that, commonly, $0.6 \leq \mu \leq 1$, so a value of 0.6 is taken here as a reasonable assumption for $\mu$, given that the Captain Sandstone is poorly cemented and consolidated. The occurrence or non-occurrence of wellbore breakouts and drilling-induced tensile fractures may be used to estimate the magnitude of $S_{\text{hmax}}$ using equation (3) for drilling-induced tensile fractures and equation (4) for borehole breakouts (see Barton & Zoback 1988; Moos & Zoback 1990; Zoback et al. 2003 for derivation of the equations):

$$S_{\text{hmax}} = \frac{3S_{\text{min}} - 2P_p - \Delta P - T_b - \sigma_p^{NT}}{2(1 + 2\cos 2\theta_b)}$$

$$S_{\text{hmax}} = \frac{C_0 + 2P_p + \Delta P + \sigma_p^{NT} - S_{\text{min}}}{1 - 2\cos 2\theta_b}$$

where $\Delta P$ is the difference in pressure between the pore-fluid pressure and the pressure exerted by the column of mud in the wellbore, $T_b$ is the tensile strength of the rock, and $\sigma_p^{NT}$ is the stress induced by the temperature differential between the formation and drilling fluids: and for breakouts:

$$S_{\text{hmax}} = \frac{(C_0 + 2P_p + \Delta P + \sigma_p^{NT} - S_{\text{min}})}{1 - 2\cos 2\theta_b}$$

where $2\theta_b = \pi - \theta_{bo}$.

In equation (4), $C_0$ is the rock strength and $W_{bo}$ represents the width of the observed breakout in units of degrees. Equations (3) and (4) have been used to estimate the magnitude of $S_{\text{hmax}}$ in wells 13/21a–4, 13/24b–3 and 13/26a–4. Figure 9a shows the constraints on the magnitudes of the horizontal stresses at a depth of 1564 m TVDSS (True Vertical Depth Subsea) where breakouts are observed in well 13/24b-3. The lack of tensile fractures over the logged interval suggests that, for a given value of $S_{\text{min}}$, the magnitude of $S_{\text{hmax}}$ should fall below the appropriate tensile failure contour denoted by the black dotted line in Figure 9a. The tensile strength of the Captain Sandstone is generally less than 70 kPa (Skopec 2001) and, as such, is considered here to be essentially zero. As shown by Figure 9a, greater tensile strength would reduce the magnitude of $S_{\text{hmax}}$ required to form a drilling-induced tensile fracture for any given value of $S_{\text{min}}$. As no information is available regarding the temperature-induced stress perturbation at the depth of interest, this parameter is also assumed to be zero. As shown by Zoback et al. (2003), the result of moderate cooling has a limited impact on the tensile fracture contours, whereas modest increases in mud weight

| Well | Depth subsa (m) | Pressure (MPa) | Description |
|------|----------------|----------------|-------------|
| 13/24b-3 | 988 | 23 | Tor Formation – firm to hard limestone |
| 13/22b-14 | 1563 | 29 | Valhall Formation, Aptian ‘Sandy’ Unit – soft to firm claystone grading to siltstone in parts |
| 13/22b-19 | 1611 | 31 | Valhall Formation, Early Aptian – loose sand and soft to firm claystone |
| 13/22b-20 | 1584 | 30 | Early Barremian Wick Sandstone Formation – loose fine- to medium- grained sandstone and calcareous claystone |

Table 2. Formation leak-off test data from wells in the study area. The leak-off pressure can be taken as the fracture pressure for the rocks at the depths tested. The lithological descriptions are taken from the company logs.

Fig. 7. (a) Example of a bulk density log from well 13/26a-4. (b) Vertical stress profiles calculated from integration of density logs and the average gradient of $S_v$ used in this study.
are far more influential to the formation of drilling-induced tensile fracture. In the event that significant borehole cooling had occurred, the magnitude of $S_{H_{\text{max}}}$ required to cause the formation of drilling-induced tensile fractures would be reduced for any given magnitude of $S_{h_{\text{min}}}$, and so the assumption of zero $\sigma_{\Delta T}$ gives an upper bound to the tensile fracture contour, providing the upper possible frictional limit of $S_{H_{\text{max}}}$. In the absence of equivalent circulating density data, static mud weight is used to calculate $\Delta P$. Despite the observation of borehole breakouts, the borehole breakout contours cannot be used to accurately constrain the magnitude of $S_{H_{\text{max}}}$ as a function of $S_{h_{\text{min}}}$ because the strength of the rock is unknown. However, contours are plotted for different rock strength values using equation (4) and the average breakout width in well 13/24b-3 of 41.6° (Fig. 9a). These contours may be used to provide constraints on the strength of the rock given the end-member magnitude of $S_{H_{\text{max}}}$ allowable. As breakouts have been observed, the magnitude of $S_{H_{\text{max}}}$ should lie above the appropriate rock strength contour. Breakout width can be difficult to measure accurately from image logs, and so this is considered an uncertain parameter and the breakout contours are not used here to predict the magnitude of $S_{H_{\text{max}}}$. Figure 9b shows the maximum allowable values of $S_{H_{\text{max}}}$ obtained from the analyses described above for each depth where borehole breakout has been observed. Albeit highly uncertain due to the uncertainty of the input parameters, a linear $S_{H_{\text{max}}}$ gradient of 31.95 MPa to the seabed has been derived from the outer envelope of the measurements in the three wells. This provides the end-member conservative case for the fault-stability study where differential stresses are at a maximum. As $S_{H_{\text{max}}} > S_{v} > S_{h_{\text{min}}}$, this would imply a strike-slip faulting stress state after Anderson (1951). As the true magnitude of $S_{H_{\text{max}}}$ is unknown and might, in fact, be significantly lower, a further two stress magnitude cases are considered for the fault-stability study corresponding to the normal/strike-slip and normal faulting stress states (Table 3).

### Fault-stability analysis

The stress orientations derived from borehole breakouts, and the stress magnitude gradients shown in Table 3, have been used to resolve the shear and normal stresses onto the faults using the 3D geological model. As the magnitude of $S_{H_{\text{max}}}$ is uncertain, all three cases have been considered. Slip tendency ($T_{s}$), the ratio of shear to normal stress (Morris et al. 1996; Ferrill et al. 1999), has subsequently been calculated for each node on the fault planes.

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**Table 3.** Constraints on principal stress magnitudes used in the fault-stability study

| Stress magnitude gradients (MPa km$^{-1}$ relative to seabed) | Strike-slip | Normal/strike-slip | Normal |
|----------------|-------------|-------------------|--------|
| $S_{v}$ | 25          | 25                | 25     |
| $S_{H_{\text{max}}}$ | 31.95      | 25                | 18     |
| $S_{h_{\text{min}}}$ | 18          | 18                | 18     |

Faults and CO$_2$ storage in the Captain Sandstone
sustainable to reactivation. Faults orientated perpendicular to the direction of $S_{\text{Hmax}}$ exhibit lower slip tendencies as a result of higher normal stresses. The normal/strike-slip case exhibits much lower slip tendencies, with no fault segments possessing a slip tendency greater than 0.3. Faults striking sub-parallel to $S_{\text{Hmax}}$ again possess the higher values of slip tendency. The normal faulting case possesses the least variation in slip tendency, with values of approximately 0.3 over most of the fault nodes, with the clear exception of the eastern part of the South Halibut Fault, which dips at a steeper angle of about 80° and is therefore less sustainable to failure in a normal faulting stress state. In this case, despite many of the faults dipping at optimal angles close to 60° (30° from $S_h$), none of the fault segments have particularly high slip tendencies because the gradient of $S_{\text{Hmin}}$ implies values higher than the frictional minimum illustrated by the stress polygon in Figure 9a. It is worth noting that, although the faults shown by Figure 10 extend from the Captain Sandstone and through the overburden to the seabed, the majority of the pressure increase resulting from the injection of CO$_2$ will be confined to the reservoir interval into which CO$_2$ is injected. Segments of faults with high slip tendencies in the shallower section are therefore less likely to experience a significant increase in pore-fluid pressure unless the fault zones become a conduit for fluid flow (either CO$_2$ or displaced formation fluids) from greater depths.

The slip-tendency results presented are dependent on the reliability of the 3D fault model and the validity of the input stress field (Worum et al. 2004). As the fault model presented is based on regional mapping using 2D seismic reflection profiles, with regional depth conversion applied, the model will inevitably contain some geometrical inaccuracies that will affect the calculated values. In particular, the depth conversion can affect the dip of the faults, which is critical as it affects the angle of the fault plane relative to the stress tensor. Despite this, the main structural trends are captured by the geological model, and the results are useful in assessing fault risk at the basin scale.

The susceptibility to failure of faults at a given depth can also be expressed in terms of the pore-pressure perturbation required in order to cause the reactivation of faults, known as the fracture stability. Fracture stability for the stress regimes shown in Table 3 are illustrated by Figure 11 for a depth of 1200 m. This is the average depth of the Captain Sandstone below 800 m, where it is most prospective for CO$_2$ storage and injected CO$_2$ would be expected to remain in its dense phase (Chadwick et al. 2008). Because not all faults and fractures will be accurately mapped using seismic reflection data, stereographic projections are useful as they can be used to calculate the change in pore pressure required to reactivate faults of any orientation at a given depth.

Poroelastic effects on fault stability are illustrated in Figure 12. Owing to coupling between pore pressure and stress (Hillis 2000), horizontal stress magnitudes are likely to decrease during depletion (Streit & Hillis 2004), and to increase during injection. Equation (5), after Brown et al. (1994), can be used to estimate the poroelastic effect in reservoirs with a high lateral extent compared to thickness:

$$\Delta S_{\text{Hor}} = \frac{1 - 2\nu}{1 - \nu} \Delta P_d$$

where $S_{\text{Hor}}$ is both $S_{\text{Hmax}}$ and $S_{\text{Hmin}}$, $\alpha$ is Biot’s coefficient and $\nu$ is Poisson’s ratio. For reasonable values for $\alpha$=1 and $\nu$=0.25 (Chiaramonte et al. 2008; McDermott et al. 2016), the horizontal stresses will increase by 2 MPa as a result of a 3 MPa pore-pressure increase, a reasonable far-field pore-pressure perturbation (Jin et al. 2012). It is noted that equation (5) should not be used for predicting actual stress values at depth as it has been derived for a homogeneous, isotropic and linear poroelastic reservoir. Nevertheless, it provides a useful guide as to the likely poroelastic effects that might result from CO$_2$ injection and the subsequent...

![Strike-slip regime](image1)

![Normal/strike-slip regime](image2)

![Normal regime](image3)

Fig. 10. Comparison of slip-tendency values on mapped faults in the study area, for different stress states as detailed in Table 3. Note that the slip tendency is scaled to 0.5 to highlight those faults with higher values closer to $\mu$. The top Captain Sandstone surface is shown for reference. The 800 m depth contour is shown as a black dotted line.

(Fig. 10). A slip tendency value equal to the coefficient of friction ($\mu$) corresponds to the frictional strength of a cohesionless fault: so faults or, more accurately, fault segments that have $T_s$ values close to 0.6 are most susceptible to reactivation in this analysis. The slip tendency of a fault depends on both the dip and the strike of the fault in relation to the stress tensor. A number of cases worldwide highlight that critically stressed faults are more likely to be hydraulically conductive than non-critically stressed faults (Barton et al. 1995; Wiprut & Zoback 2000; Finkbeiner et al. 2001; Hennings et al. 2012). Despite this, it must be noted that this is a conservative approach, as reactivated faults will not necessarily become fluid-flow pathways (Bjørlykke et al. 2005) and in addition, fault zones are not always characterized by cohesionless interfaces, so the assumption that the faults have zero cohesion is also conservative.

The slip tendency calculated for the strike-slip case is highly variable, with higher shear stresses acting on faults orientated close to approximately 30° from $S_{\text{Hmax}}$, resulting in some faults being...
pressure increases. This effect would be largely constrained to the reservoir interval where the majority of the pressure perturbation will occur during injection.

The results shown in Figures 11 and 12 show that the change in pore pressure ($\Delta P$) required to cause fault reactivation varies considerably across the different stress states. In the strike-slip stress state, optimally orientated faults at virgin reservoir pressures are approximately 1.5 MPa from failure, moving to approximately 0.5 MPa after a perturbation of 3 MPa (Fig. 12a). The poroelastic effect counteracts the effect of the reducing effective stresses, increasing the stability of the faults somewhat and allowing the faults to sustain more pressure than if the poroelastic effect is discounted. Chiaramonte et al. (2008) similarly found that the poroelastic effect increased the pressure required to cause failure of a fault bounding a prospective CO2 storage site in the USA. In the normal/strike-slip stress state, optimally orientated faults that strike parallel to $S_{Hmax}$ and dip at angles of 60° will fail at increased fluid pressures of approximately 5 MPa. Once poroelastic effects are accounted for, the stress state transitions to a strike-slip faulting regime as $S_{Hmax}$ exceeds the magnitude of $S_v$ (Fig. 12b). Optimally orientated faults are then vertical faults striking at angles of 30° from $S_{Hmax}$, and will fail at slightly lower pressures. In the normal stress state, where $S_{Hmax} = S_{hmin}$, faults dipping at 30° and striking in any orientation are those that are most susceptible to failure, with a required pore-pressure increase of approximately 5 MPa. Little change in the fault stability is seen once the poroelastic effect is considered, as the difference between the horizontal stress and $S_v$ magnitude is reduced, resulting in a smaller Mohr circle (Fig. 12c).

For comparison, a simplified analysis from the southern part of the North Sea suggests that a lower-bound pore-pressure increase of 3.3 MPa could be obtained without reactivating existing faults at a depth of 1000 m based on a simple, yet conservative, geomechanical analysis (Williams et al. 2014).

Thermal stress resulting from injection of cold or warm fluid into a rock mass can also affect fault stability in the near-well region, and can result in stress conditions moving closer towards failure. The effect of the thermal-stress perturbation due to CO2 injection into the Captain Sandstone has been presented elsewhere using a coupled numerical thermal and mechanical modelling tool (McDermott et al. 2016). The study found that the change in the stress field resulting from the combination of pore-pressure and thermal-stress effects is dependent on the permeability structure of different layers, such as the reservoir, underburden, primary caprock and overburden. Stress

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**Fig. 11.** Fault stability represented as equal-angle, lower-hemisphere stereographic poles to planes for (a) strike-slip, (b) normal/strike-slip and (c) normal faulting stress states at a depth of 1200 m below sea level. The numerical values refer to the increase in fluid pressure ($\Delta P$) required to cause fault reactivation, assuming a Griffith–Coulomb failure envelope for cohesionless faults with a value of $\mu$ of 0.6.

**Fig. 12.** Mohr–Coulomb diagrams showing stress states in relation to a cohesionless fault-failure envelope at a depth of 1200 m below sea level for (a) strike-slip, (b) normal/strike-slip and (c) normal faulting stress states. Poro-elastic stress change is shown for a pressure increase of 3 MPa. The pre-injection cases are shown as solid circles and the post-injection cases shown as dotted circles.
bridging and redistribution between layers with different mechanical properties can, in some cases, lead to enhanced geomechanical stability in the caprock (McDermott et al. 2016).

The presented fault-stability analysis considers only the effect of increasing the pore-fluid pressures as a result of CO2 injection. Production-induced stress perturbations have not been considered here, but are noteworthy given the history of hydrocarbon production from the Captain Sandstone reservoir in the Moray Firth area, but are noteworthy given the history of hydrocarbon production from the Captain Sandstone reservoir in the Moray Firth area, a potential target for CO2 storage, has been evaluated. The available data suggest that either normal, strike-slip or normal/strike-slip transitional faulting limits. Where stress-magnitude parameters are regarded to be uncertain, the analysis has assumed large differential stresses, meaning that a conservative approach has been taken to the fault-stability analysis. Given the paucity and quality of available stress-field indicators and measurements, such an approach is useful in determining the low end-member constraints on the pore-pressure window with which to operate without reactivating existing faults.

The stress tensor has been resolved onto 3D fault planes, derived from an existing geological model of the Captain Sandstone and its overburden, to evaluate the susceptibility of the larger faults to reactivation, the risk of which might be increased if pore-fluid pressure increases as a result of large-scale CO2 injection. The results suggest that some segments of the regional faults are likely to be near-critically stressed under some of the possible stress conditions, and therefore would not require a considerable pore-pressure increase in order to become reactivated. It is likely, however, that smaller local faults will become reactivated first. If this occurs in the area outside of the CO2 plume footprint, formation retardation across the faults. In terms of the major faults included in the model, cross-fault migration is expected to be fairly insignificant due to juxtaposition of the reservoir footwall blocks against primary or secondary sealing formations (Fig. 13), and along- or up-fault migration constitutes the greater risk to containment of any injected CO2. Careful juxtaposition mapping, preferably using 3D seismic reflection data, should be carried out in the vicinity of proposed CO2 injection sites.

In the fault-stability analysis presented, relatively few observed fault segments are seen to be critically stressed and so, provided that far-field pressure can be sustained at a reasonable level and CO2 isolated from near-critically stressed fault segments, the risk of leakage via faults can be seen as fairly low. It is possible that smaller faults not observed might be more optimally oriented for reactivation: however, it is argued that these are likely to be less extensive in terms of throw and vertical extent (as they are not observed on seismic reflection data), and as such will not necessarily penetrate the entire reservoir top seal and provide a conduit for injected CO2 if reactivation was to occur.

Although the analysis presented assumes that critically stressed faults in the current stress regime will present a risk to storage integrity due to an increase in along-fault permeability during slip, it has been shown that shear-stress hysteresis during uplift and exhumation can also affect the ability of faults to conduct fluids, even if they are not critically stressed in the present stress state (Sathar et al. 2012). Experiments on synthetic fault gouge composed of pure kaolinite found that, although fault orientation does have an effect on gas entry pressure, non-optimally oriented faults can also experience flow (Cuss et al. 2015). In addition, reactivation of a fault will not necessarily increase the permeability of the fault plane because in some materials, such as weakly cemented sand, initial dilation and continued shearing will result in the formation of low-porosity/low-permeability material (Bjørlykke et al. 2005). Processes such as clay smear can also act to reduce fault-zone permeability, and so the assumption that a reactivated fault will permit vertical flow of CO2 is conservative.

Conclusions

The in situ stress field affecting the Captain Sandstone in the Inner Moray Firth area, a potential target for CO2 storage, has been evaluated. The available data suggest that either normal, strike-slip or normal/strike-slip transitional faulting stress regimes might prevail at reservoir depth in the region, while the observation of borehole breakout indicators and measurements, such an approach is useful in determining the low end-member constraints on the pore-pressure window with which to operate without reactivating existing faults.

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brine rather than CO₂ would leak-off from the reservoir, potentially relieving some reservoir pressure (Hannis et al. 2013). As slip on existing faults could facilitate a risk to CO₂ storage integrity, it is suggested that aspects surrounding the in situ stress conditions (both regional and local) are critically assessed during site appraisal. In addition, thermal stresses, which affect an area relatively local to the injection well, have not been considered here, but can significantly alter the stress state locally as a result of the injection of cold fluid, and should be examined by coupled flow–geomechanical models (McDermott et al. 2016).

The results presented provide a useful indication of the fault geometries most susceptible to reactivation in the current in situ stress conditions across the IMS, at depths where CO₂ might be injected. To account for uncertainty in principal stress magnitudes, high differential stresses have been assumed in the analysis, providing conservative estimates of fault stability. Detailed geomechanical models and data pertaining to pore pressure, rock mechanics and stress will be required to more accurately investigate fault stability for specific storage sites.

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