ELSEVIER

CrossMark

Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 63 (2014) 5164 – 5171

Energy Procedia

GHGT-12

CO_2 storage potential at Forties oilfield and the surrounding Paleocene sandstone aquifer accounting for leakage risk through abandoned wells

Masoud Babaei[a], Rajesh Govindan[a], Anna Korre[a], Ji-Quan Shi[a], Sevket Durucan[a]*, Martyn Quinn[b], Mike McCormac[b]

[a]*Department of Earth Science and Engineering, Royal School of Mines, Imperial College London, London SW7 2BP, United Kingdom*
[b]*British Geological Survey, Murchison House, Edinburgh EH9 3LA, United Kingdom*

Abstract

A numerical simulation study of CO_2 injection into the Forties and Nelson oilfields to estimate their storage potential is presented in this paper. The estimation involves the consideration of key-performance indicator parameters that include: the pressure build-up for different rates and locations of injection, the regional mass fraction of CO_2, the volumetric efficiency of the storage reservoirs, and the plume size. Various injection scenarios were compared in terms of these parameters, and the best scenario was identified for the capacity estimation. Potential leakage through the wellbores in the surrounding saline aquifer was also investigated.

Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords:

1. Introduction

CO_2 storage in depleted or mature hydrocarbon fields, with proven traps that have retained oil (or natural gas) for millions of years, are considered to be advantageous over the storage in pristine saline aquifers with limited and

* Corresponding author. Tel.: +44 (0)20 7594 7354; Fax: +44 (0)20 7594 7444
E-mail address: s.durucan@imperial.ac.uk

1876-6102
Peer-review under responsibility of the Organizing Committee of GHGT-12
doi:10.1016/j.egypro.2014.11.546

uncertain knowledge of the geological environment, trapping potential, or storage capacity. This option might also be economically sustainable as it can enhance oil (EOR) or gas (EGR) recovery. Moreover, an additional benefit of using EOR for reducing CO_2 emissions is the potential to utilise at least some parts of the existing infrastructure of the hydrocarbon fields, as well as the petroleum engineering and operational knowledge base [1].

The Forties and Nelson oilfields located in the UK Sector of the Central North Sea, featuring high quality channel sands, have been considered as potential CO_2 storage sites. Ketzer *et al*. [2] evaluated the long-term CO_2 leakage risk from the Forties reservoir, assuming that it was filled with supercritical CO_2, and reported that the plume would travel only a small distance in the overburden during a post-injection period of 1,000 years. Cawley *et al*. [3] noted that the CO_2 pressure would not exceed the capillary entry pressure of the overburden at any time during the post-injection period. They concluded that the Forties oilfield is a suitable structure for CO_2 storage due to the absence of major faults, the hydrostatic conditions, the thickness of the reservoir, and very low permeability of its overburden. Although the risk assessment study conducted by Cawley *et al*. [3] accounted for different leakage pathways through the underlying saline aquifer, the caprock, the overburden, and the wellbore, there still remain uncertainties about the well integrity and potential leakage pathways to the seabed through abandoned wells.

Methodologies developed and used in estimating storage capacity have been reviewed extensively by Bradshaw *et al*. [4]. Static capacity estimations assume that the rock and fluid properties remain constant over time, whereas dynamic methods allow these properties to vary with pressure and temperature during the process of CO_2 storage. The most commonly used static methods are the volumetric method and the compressibility method. Examples of dynamic methods are the decline-curve analysis, material balance, and reservoir simulations. The numerical simulation technique is the most sophisticated method used in estimating CO_2 storage capacity, since it takes into account the heterogeneity of the storage site and allows the assessment of various site-specific scenarios of CO_2 storage operations.

The objective of the research presented in this paper was to estimate the static and dynamic storage capacities of the Forties and Nelson oilfields, assuming that the reservoirs have been fully depleted and are now saturated with brine [2, 3]. To estimate the static capacity, a simple volumetric method was used. The dynamic capacity was estimated by assessing the findings of a number of CO_2 injection scenarios for the Forties reservoir, subject to the constraint that, in each scenario, only one vertical well (or production platform) in each reservoir is utilised. By varying the rate of injection between 1, 3 and 5 Mt of CO_2 per annum, 12 scenarios of CO_2 injection were considered. Potential constraint of accounting for leakage risk through abandoned wells in the surrounding aquifer on the estimated dynamic storage capacity was also investigated.

2. Construction of a static and dynamic reservoir model

The study area is part of the Forties-Montrose High located in the North Sea Central Graben, encompassing the Forties and Nelson oilfields and the surrounding aquifer (Fig. 1). The Forties and Nelson reservoirs are submarine fan deposits contained in the Paleocene/Eocene Forties Sandstone Member and overlain by Lower Eocene shale [6, 7]. The two reservoirs are located in the proximal inner (interbedded sand/shale) to middle (mainly massive sand) fan region [6], and are mostly channelised and characterised by high net to gross ratios, good porosities, and high permeabilities [8]. A detailed geological description of the Forties and Nelson hydrocarbon fields in the UK sector of the North Sea has been reported by Kulpecz and van Geuns [9] and Kunka *et al*. [10]. The 3D geological model developed in this study broadly captures and represents the heterogeneities present within what is a very complex submarine fan environment. The fan system within the two fields comprises the main hydrocarbon producing fairways: large amalgamated stacked channel systems of the Late Paleocene Early Eocene Forties Sandstone Member within a four-way dip-closed anticlinal structure. Along with the channels are the associated channel margins and interchannel areas. The varying relative dominance and position of the different parts of the submarine fan system through time resulted in a high degree of lateral and vertical variation. This is represented in the lithologies found in the system and their associated petrophysical parameters. The reservoir zonation schemes in each of the fields has been unified and extended out with the field areas and, for the 3D model, consists of 7 reservoir Zones (D, E, F, H(a), J, K, and L) and capped by a seal (Zone M) including two field-wide permeability barriers (Top of Zones D and H(b)) to vertical flow based on published information [10, 11]. Fig. 2 shows a cross sectional view of Forties and Nelson reservoirs, and the regions lying inside and outside of the reservoir boundaries.

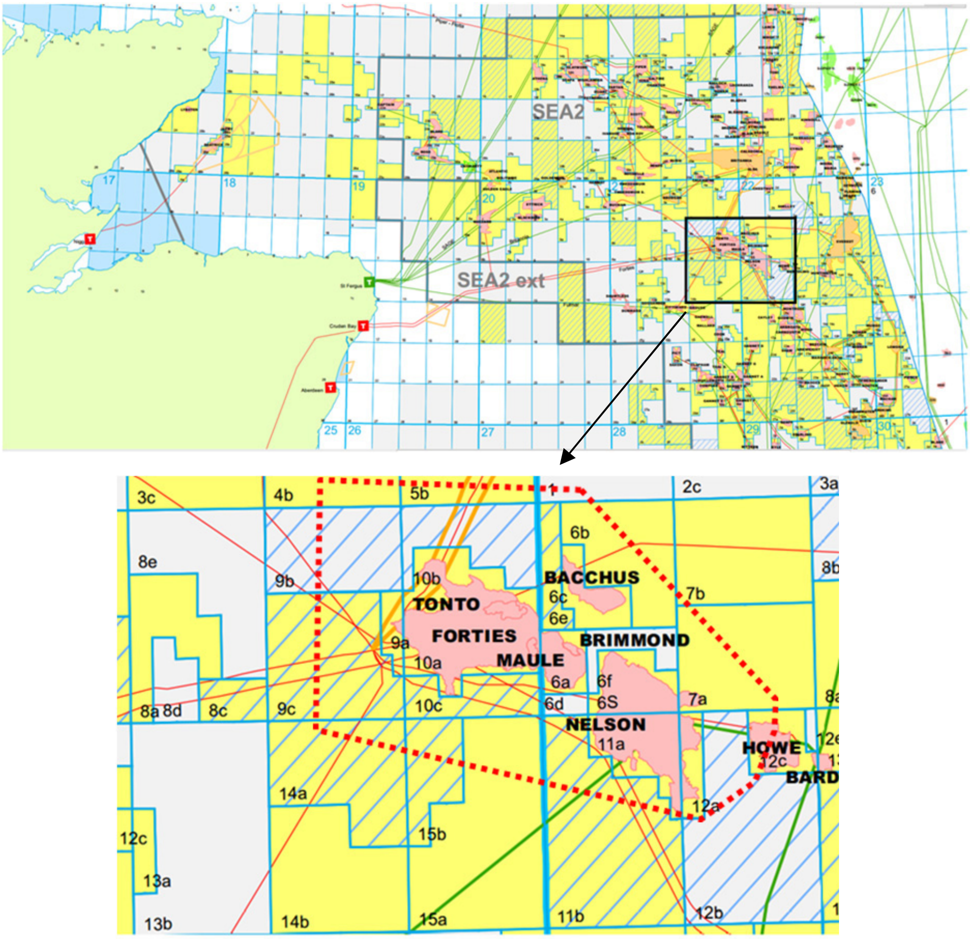


Fig. 1. The geographic location of the Forties and Nelson oilfields in the North Sea [5]. Pink areas represent the declination of the two oil reservoirs, i.e., the maximum extent of the reservoirs above the water-oil contact. The dashed red polygon shown in the lower image represents the boundaries of the aquifer area used in the simulations.

The attribution of the geological model with petrophysical properties, namely porosity, permeability and net-to-gross (NTG) ratio, was carried out using Gaussian Sequential Simulation. The ranges of values used are based on generalisations from literature references such as Kunka *et al*. [10] and Wills [12]. Fig. 3 illustrates one set of realisations that were generated for the above-mentioned properties.

Reservoir properties of the fluids for the Forties and Nelson oilfields were derived from Wills [12], Kunka *et al*. [10], and Hempton *et al*. [8]. The oil-gas and water-gas relative permeability curves used were derived from Cawley *et al*. [3], who investigated CO_2 enhanced oil recovery at a segment of the Forties field.

The numerical model developed was calibrated using the historical water and hydrocarbon production from the DECC database [13], as well as the historical pressure data found in the literature [14]. A key outcome of the model calibration was the determination of the pore volume multiplier (PVM) which is used in the simulations to account for the contribution and level of support provided by the surrounding aquifer system through the boundaries. The PVM applied on the boundary blocks which led to the agreement between the simulation results and the data increased the volume of formation brine in the system from 8,552 million sm^3 to 42,548 million sm^3, providing an adequate level of aquifer support.

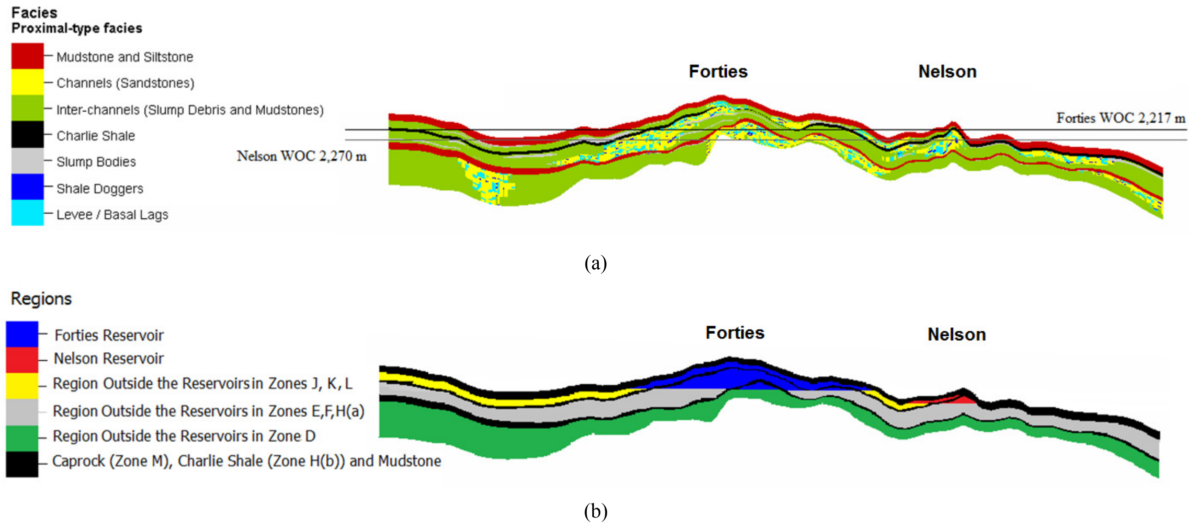


Fig. 2. (a) NW-SE cross section of the facies types in the geological model. Note that the z-direction is exaggerated by a factor of 10. Also shown are the water-oil contacts for the two reservoirs; (b) NW-SE cross section of the different regions of the model.

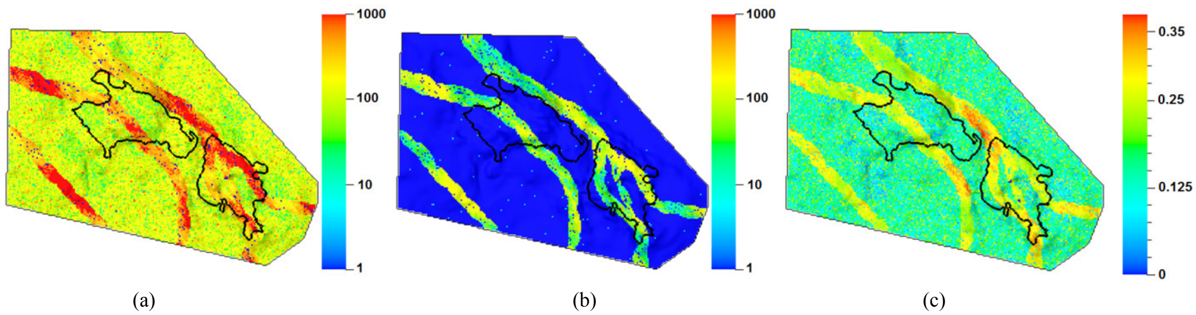


Fig. 3. An example set of realisations for top of Zone F, showing: (a) horizontal permeability (millidarcy); (b) vertical permeability (millidarcy); and (c) porosity.

3. CO_2 storage static capacity estimation for the Forties and Nelson depleted reservoirs

For depleted oil reservoirs, the static capacity for CO_2 storage can be estimated. using the equivalent mass of CO_2 that can replace the maximum recoverable oil at reservoir conditions [4]. The capacity estimates for the oilfields are given in Tables 1 and 2, considering ultimate oil recovery and fully depleted cases respectively.

Static capacity estimates suggest that the Forties field is by far a better candidate for CO_2 storage. While the literature is unanimous on the fact that Forties is a good candidate for CO_2 storage, the values reported exhibit considerable variation. The Scottish Centre for Carbon Storage [15] reported 138 million tonnes of CO_2 storage capacity for the Forties oilfield by CO_2-EOR and, assuming a range of 0.2% - 2% storage efficiency, they reported a storage capacity of 886 - 8,856 Mt CO_2 for an area encompassing the entire Forties formation. Elsewhere, Espie [16] reported that at least 75 Mt CO_2 could be stored by EOR in the Forties reservoir, with further potential if storage was continued for its own sake after EOR.

Wide variations seen in the estimates of static storage capacity demonstrate the importance of conducting flow simulations in order to obtain more reliable dynamic storage capacity estimates, which will be discussed in the next section. The dynamic capacity estimates presented assume that the oil reservoirs are fully depleted and the entire pore volume is available for CO_2 storage.

Table 1. Static capacity estimates for the Forties and Nelson reservoirs assuming they achieve ultimate oil recovery.

Properties	Forties	Nelson
Reservoir temperature (°C)	96	107
Initial hydrostatic pressure of the reservoir (bar)	222-242	229-237
CO_2 density at reservoir conditions (kg/m^3)	529-575	495-512
Initial oil in place (million sm^3)	690	125
Recovery Factor (%)	62-70	58-61
Formation volume factor (rm^3/sm^3)	1.24-1.32	1.357
Estimated static capacity (Mt CO_2)	**280-367**	**49-53**

Table 2. Static capacity estimates for the Forties and Nelson reservoirs assuming they are fully depleted and that their pore volumes are fully available for CO_2 storage.

Properties	Forties	Nelson
Estimated static capacity (Mt CO_2)	**329-431**	**61-66**

4. CO_2 storage dynamic capacity estimation for the Forties and Nelson depleted reservoirs

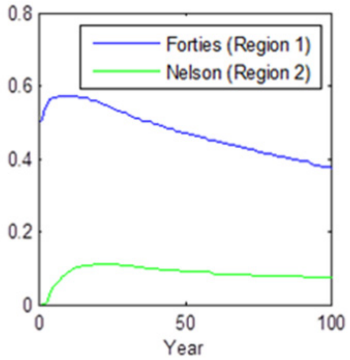
There are four main production platforms, evenly spaced over the area of the Forties field: Forties Alpha (FA), Bravo (FB), Charlie (FC) and Delta (FD), and an auxiliary platform Forties Echo (FE). There is only one platform for the Nelson reservoir which is referred to as N in the UK Department of Environment and Climate Change (DECC) database for production wells in the North Sea [17]. The dynamic capacity of the Forties and Nelson depleted reservoirs was estimated in two stages. In the first stage, only one of the four main platforms (FA, FB, FC and FD) and one vertical injection well in each platform were used each time in any one injection scenario in the Forties. After the analysis of all the scenarios were assessed and the most effective storage scenario defined, a vertical CO_2 injection well on Nelson platform was introduced to determine the dynamic storage capacity of each reservoir in the second stage simulations.

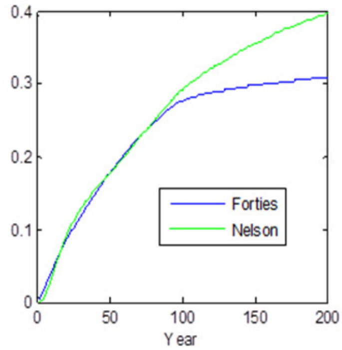
In order to assess the injection scenarios, four performance indicators (or metrics) were considered, namely: the pressure build-up for different rates and locations of injection, the regional mass fraction of CO_2, the volumetric efficiency of the storage reservoirs, and the plume size. Three different CO_2 injection rates (1, 3 and 5 Mt/year) constrained by the injection bottomhole pressure (1.3 times initial hydrostatic pressure) were simulated for up to 100 years, with further 100 years post-injection monitoring period considered. To help track the CO_2 plume movement and spillage outside the Forties dome, the model domain was divided into five regions: the Forties reservoir (Fig. 2b): Region 1 (shown in blue), the Nelson reservoir: Region 2 (shown in red) and three stratigraphically distributed regions lying outside the reservoirs in the pressure units: Region 3 in Zones J, K and L (shown in yellow); Region 4 in Zones E, F and H(a) (shown in grey); and Region 5 in Zone D (shown in green). Based on the analysis of the performance indicators for the injection scenarios considered in the first stage of dynamic capacity estimation, the following summary of the results was drawn:

- A uniform bottomhole pressure build-up ratio for the Forties and Nelson domes (Regions 1 and 2) generally suggests a good lateral communication between the two structures. It is also observed that, except for platform FC, all other platforms can safely sustain a CO_2 injection rate of 3 Mt/year while maintaining a conservative well bottomhole build-up ratio of 1.3. In terms of field pressure increase analysis, three critical model layers were identified, namely: Layer 7, which is the topmost layer in immediate contact with the caprock in Region 3; Layer 27, which is the topmost layer beneath the Charlie Shale in Region 4; and Layer 44, which is the layer immediately below the Mudstone formation in Region 5. Although the localised pressure increase in these layers varies significantly from one platform to another, it is noted that injection through platforms FA and FD leads to lower pressure increase.

- The mass fractional analysis determines the level of containment in and spillage out of the Forties dome (Region 1). It is observed that the containment drastically drops and consequently spillage increases when injection rates increase, suggesting that a control over CO_2 spill is best achieved by injecting at a rate lower that 3Mt/year. The results also indicate that injection through platform FD leads to the least spillage, even with the high rates of 3 Mt/year and 5 Mt/year that were simulated.
- In terms of volumetric efficiency analysis, injection through platform FD offers the highest increase in efficiency, estimated as 35 %, when the injection rates increased from 1 Mt/year to 3 Mt/year.
- Finally, based on the plume volume extent in the three critical layers (7, 27 and 44) CO_2 does not migrate significantly in all cases, except for injection through platform FC in layer 44.

Thus, the injection through platform FD at a rate of 2 Mt/year was then considered in the second stage of dynamic capacity estimation, simultaneously with the injection through platform N in the Nelson field at a rate of 1 Mt/year. Fig. 4 illustrates some key results of the dynamic storage capacity estimation. The mass fraction analysis results (Fig. 4a) show that after 100 years of injection, 40 % of the cumulative mass of injected CO_2 (120 Mt) remains in the Forties dome, whereas less than 10 % remains in the Nelson dome. In terms of volumetric efficiency (Fig. 4b), 30 % of the Forties dome and 40 % of the Nelson dome are utilised for CO_2 storage at the end of the simulation period.





(a) (b)

Fig. 4. (a) Mass fraction profiles illustrating the containment of CO_2 in the Forties and Nelson domes; (b) Fraction of pore volume utilised in the Forties and Nelson domes for the simulation period.

5. Risk of leakage through wellbores in the surrounding saline aquifer region

The whole domain including the two reservoirs and the surrounding aquifer were divided into five regions according to the level of risk they impose when CO_2 migrates into these regions. The prioritised regions in terms of CO_2 containment are naturally the dome regions. In contrast, one region (Charlie Sand) was given the least priority, so that CO_2 should not migrate to this region as the region is lying outside the domes, is in immediate contact with caprock and has been perforated with water injection wells during the oil production stage. There are numerous water injection wells outside the reservoir boundaries used to maintain the peripheral reservoir pressure during oil production. In an attempt to evaluate the potential risk posed by abandoned wells, it was assumed that these water injection wells represent a high risk of leakage. It was further hypothesised that these wells could not be accurately located. This line of reasoning is based on the fact that these wells may most likely be orphaned, leaving liability with the state and posing a risk of unsafe abandonment [17].

Dynamic estimates of the capacity of the reservoirs, conditioned on minimising the risk of leakage from the perforation to the surrounding aquifer outside the reservoirs, are evaluated using a probabilistic approach. The approach starts by calculating the mass of the free gaseous phase CO_2 that, at the end of simulation, lies beneath the caprock and is above the Charlie Shale for a number of reference locations outside the reservoirs (Fig. 5). The simulations are carried out for 100 years of injection and additional 100 years of post-injection stabilisation. The approach, then, aims to identify the injection platform which results to the lowest number of reference points outside the reservoirs where the mass of free CO_2 column is higher than a specified threshold. By implementing this approach, the probability of a free gaseous CO_2 leak from imperfectly sealed wellbores of uncertain location outside the reservoir boundaries is minimised.

In Fig. 5, the red crosses represent the reference locations where the mass of free CO_2 column is calculated (221 in total, out of which 197 lie outside the reservoir boundaries). Also shown are several well heads and trajectories. However, in the absence of accurate data, neither the number of wells, nor the exact coordinates of well trajectories can be confirmed. On the other hand, the position of the platforms in the model are specified [17]. Assuming a leakage threshold of only 1 tonne CO_2, the number of points that lie outside the reservoirs and could leak a mass of the free gaseous CO_2 higher than the threshold from the Charlie Sand for the 12 scenarios of injection (each scenario implemented for three realisations) are given in Table 3.

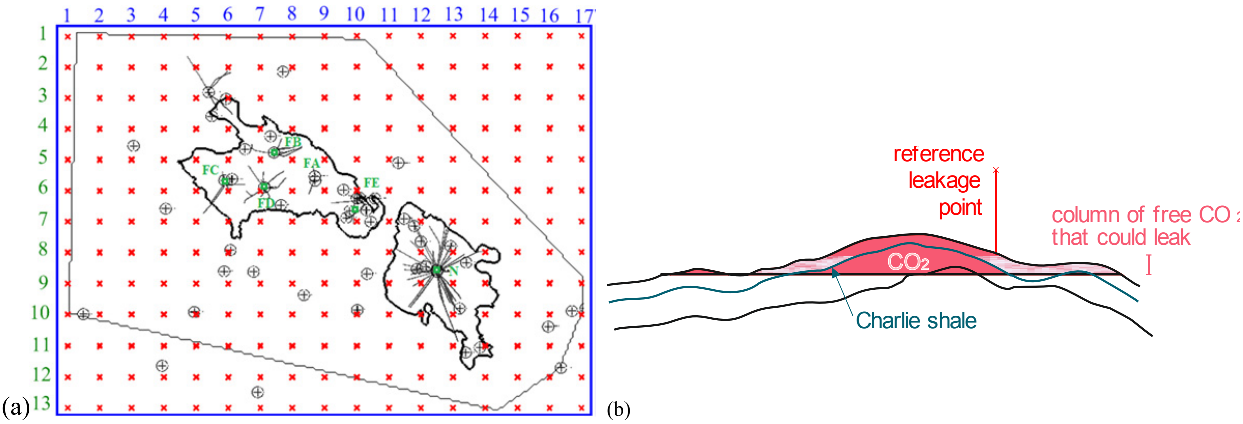


Fig 5. (a) Reference points in the system shown as red crosses, the Forties and Nelson boundaries shown by thick black polygons, the reliably accurate platforms' positions shown as green rectangles and approximate wellhead locations and well trajectories shown by black sun crosses and thin black lines. The numbers shown in blue (*x* direction) and green (*y* direction) represent the reference point coordinates considered in the leakage minimisation; (b) cross sectional view of the reservoir and mass of free CO2 considered in leakage minimisation.

Table 3. The number of reference points with over 1 tonne of free gaseous CO_2 leakage risk for the 36 Forties platform injection scenarios.

	Injection rate: 1 Mt CO_2 per annum			Injection rate: 3 Mt CO_2 per annum			Injection rate: 5 Mt CO_2 per annum		
Platforms utilised	Real. 1	Real. 2	Real. 3	Real. 1	Real. 2	Real. 3	Real. 1	Real. 2	Real. 3
FA and N	12	11	12	16	15	16	18	17	19
FB and N	11	10	10	18	15	16	23	23	23
FC and N	13	12	13	24	24	24	29	27	27
FD and N	9	9	9	12	14	12	18	17	18

It is shown that using platform FD infers the least number of points with risk of leakage over 1 tonne of CO_2, whereas using platform FC infers the most number of such points. Also, it can be observed that increasing the rate of injection from 1 to 3 Mt CO_2 per annum for platform FD, increases the number of risk-prone reference points to the same level as using a 1 Mt CO_2 injection rate per annum through platforms FA and FB. Therefore, if this was a criterion to decide on injection rate, it should be safe to use 2 Mt CO_2 injection per annum through platform FD. Consequently, the scenario of injecting 2 Mt CO_2 per annum by platform FD and 1 Mt CO_2 per annum by platform N, also selected in the previous section, also meet the selected leakage risk minimisation criterion.

6. Conclusions

In this study an analysis of CO_2 injection for Forties and Nelson oil reservoirs (assumed fully depleted) was performed. A mass analysis of migration of CO_2 has revealed that the injection may not be carried out through the wells branching from the Forties Charlie platform (FC) as this scenario leads to significant migration of CO_2 out of the spill point of the Forties reservoir and also leads to significant localised pressure build-up just beneath the caprock. By contrast, platform Forties Delta (FD) has shown the least amount of migrated mass of CO_2 into Charlie Sand. Other performance measures such as ratio of pressure increase, the fraction of pore-volume utilised and the plume size showed that an injection rate of 2 million tonnes of CO_2 per year through a vertical well in platform Forties Delta (FD) is not posing risk for storage operation. Adding the Nelson platform into utilisation, the results of CO_2 storage for 100 years of injection were reported. The results of this operation that injects 300 million tonnes of CO_2 are promising and indicate that the potential of CO_2 injection in these two reservoirs in the future is strong.

Based on a methodology to minimise the risk of leakage from abandoned wells outside the reservoir boundaries, an optimal scenario of CO_2 injection was chosen. Compared to the static estimates, the values are very conservative, but incorporate geological factors and risk of leakage.

Acknowledgements

This research was carried out as part of the UK Research Councils' Energy Programme funded project "Multiscale whole systems modelling and analysis for CO_2 capture, transport and storage", Grant Reference: NE/H01392X/1.

References

[1] Bachu S, Shaw J, Pearson R. Estimation of oil recovery and CO_2 storage capacity in CO_2 EOR incorporating the effect of underlying aquifers. SPE/DOE Symposium on Improved Oil Recovery 2004.

[2] Ketzer J, Carpentier B, Gallo YL, Thiez PL. Geological sequestration of CO_2 in mature hydrocarbon fields: Basin and reservoir numerical modelling of the Forties Field, North Sea. Oil & gas science and technology 2005; 60(2):259-273.

[3] Cawley S, Saunders M, Gallo YL, Carpentier B, Holloway S, Kirby GA, Bennison T, Wickens L, Wikramaratna R, Bidstrup T, Arkley SLB, Browne MAE, Ketzer, JM. The NGCAS Project - Assessing the potential for EOR and CO_2 storage at the Forties Oil field, Offshore UK - Results from the CO_2 Capture Project. Geologic Storage of Carbon Dioxide with Monitoring and Verification, S.M. Benson (ed.). London: Elsevier Science 2005; 2: 1163-1188.

[4] Bradshaw J, Bachu S, Bonijoly D, Burruss R, Holloway S, Christensen NP, Mathiassen OM. CO_2 storage capacity estimation: Issues and development of standards. International Journal of Greenhouse Gas Control 2007; 1(1):62-68.

[5] DECC. UKCS infrastructure wallmap showing oil and gas activity 2014. [online] Available from: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/316138/UKCS_Offshore_Infrastructure.pdf

[6] Hughes D, Teeuw D, Cottrell C, Tollas J. Appraisal of the Use of Polymer Injection To Suppress Aquifer Influx and To Improve Volumetric Sweep in a Viscous Oil Reservoir. SPE Reservoir Engineering 1990; 5(1):33-40.

[7] Whyatt M, Bowen J, Rhodes D. The Nelson Field: a successful application of a development geoseismic model in North Sea exploration. Geological Society, London, Special Publications 1992; 67(1):283-305.

[8] Hempton M, Marshall J, Sadler S, Hogg N, Charles R, Harvey C. Turbidite reservoirs of the Sele Formation, Central North Sea: geological challenges for improving production, in Geological Society, London, Petroleum Geology Conference series 2005; 6:449-459.

[9] Kulpecz AA, van Geuns LC. Geological Modeling of a Turbidite Reservoir, Forties Field, North Sea, in Sandstone Petroleum Reservoirs, edited by Barwis, John H. and McPherson, John G. and Studlick, Joseph R.J. New York: Springer 1990; 489-507.

[10] Kunka J, Williams G, Cullen B, Boyd-Gorst J, Dyer G, Garnham J, Warnock A, Wardell J, Davis A, Lynes P. The Nelson Field, Blocks 22/11, 22/61, 22/7, 22/12a, UK North Sea, Geological Society, London, Memoirs 2003; 20(1):617-646.

[11] Wills JM, Peattie DK. The Forties Field and the Evolution of a Reservoir Management Strategy, in North Sea Oil and Gas Reservoirs—II, edited by Buller, A.T. and Berg, E. and Hjelmeland, O. and Kleppe, J. and Torsæter, O. and Aasen, J.O., Netherlands: Springer 1990; 1-23.

[12] Wills J. The Forties Field, Block 21/10, 22/6a, UK North Sea, Geological Society, London, Memoirs 1991; 14(1):301-308.

[13] DECC. UK Continental Shelf Oil and gas: field data. [online] Available from: https://www.gov.uk/oil-and-gas-uk-field-data

[14] Brand P, Clyne P, Kirkwood F, Williams P. The Forties Field - 20 Years Young. Journal of Petroleum Technology 1996; 48(4):280-291.

[15] SCCS. Opportunities for CO_2 Storage around Scotland - an integrated strategic research study 2009. [online] Available from: http://carbcap.geos.ed.ac.uk/website/publications/regionalstudy/CO2-JointStudy-Full.pdf

[16] Espie A. Options for establishing a North Sea geological storage hub, in Greenhouse Gas Control Technologies: Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies. Victoria: CSIRO Publishing 2001; 266-271

[17] DECC. Well Production Data, Department for Business, Enterprise and Regulatory Reform 2007. [online] Available from: https://www.og.decc.gov.uk/information/wells/pprs/welldataindex.htm

[18] Ide ST, Friedmann, SJ, Herzog HJ. CO_2 leakage through existing wells: current technology and regulations, in Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies: International Energy Agency Greenhouse Gas Programme: Netherlands: Elsevier 2006.