Available online at www.sciencedirect.com
ScienceDirect
Energy Procedia 114 (2017) 4787 – 4796
Energy Procedia

13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland

Pressure control for managing and optimizing adjacent subsurface operations in large scale CCS

Carsten M. Nielsen[a*], Alv-Arne Grimstad[b], Robert Drysdale[b], John D.O. Williams[c]

[a]Geological Survey of Denmark and Greenland, Øster Voldgade 10, DK-1350 Copenhagen K, Denmark
[b]SINTEF Petroleum Research, S.P. Andersen vei 15B, NO-7031 Trondheim, Norway
[c]British Geological Survey, Nicker Hill, Keyworth, Nottingham NG12 5GG, UK

Abstract

Injecting CO_2 in to the subsurface for safe storage of CO_2 the pressure propagates far away from the injection point and this can be a potential problem if the overpressure extents to neighbouring subsurface activities or potential leakage pathways. For structural closure trap configurations the CO_2 plume is captured within the local structural closure but the pressure footprint is on a more regional scale.
This rise the question on, how large the storage complex needs to be for any individual storage operations and how large an area monitoring activities have to cover. The EC CCS guidance document addresses the issues with statements on competitions between subsurface operations but returns no absolute values.
Pressure modelling of CO_2 injection process with state of the art reservoir simulation tools is challenges by use of realistic model boundary conditions in order to model a realistic pressure level. Combined use of models on a site scale and on a regional scale can instruct how boundary conditions are set-up for a site scale model.
Pressure management through pressure release wells could be an option to mitigate undesirable over-pressure developments. For local structural closures the pressure release wells can be placed outside the closure hereby mitigate the overpressure without introducing a potential leakage by drilling inside the trap.
The paper addresses the issue of selecting model boundary conditions and modelling mitigation of pressure development by use of a large regional model with local structural traps in the Bunter Sandstone Formation in the UK Southern North Sea.

© 2017 Published by Elsevier Ltd. This is an open access article under the CC BY-NC-ND license (http://creativecommons.org/licenses/by-nc-nd/4.0/).
Peer-review under responsibility of the organizing committee of GHGT-13.

1876-6102 © 2017 Published by Elsevier Ltd. This is an open access article under the CC BY-NC-ND license (http://creativecommons.org/licenses/by-nc-nd/4.0/).
Peer-review under responsibility of the organizing committee of GHGT-13.
doi:10.1016/j.egypro.2017.03.1618

Keywords: Pressure management; large scale CCS,

1. Introduction

After the concept of geological storage of CO_2 was identified, studies showed that the pressure increase in the individual storage site caused by CO_2 injection would be significant (*e.g.* Birkholtzer *et al*., 2009[1],). The increase in pressure was quickly recognised as posing a risk to the integrity of the reservoir, principally by causing fracturing of the caprock or by re-activating sealing faults (Obdam *et al.* 2003[2], Ceila *et al.* 2006[3], Chang and Bryant 2007[4]). Later when the concept developed, the need for large scale implementation emerged and the challenges with lateral overpressure development identified (Birkholzer *et al.,* 2009[1], 2011[5], Bergmo *et al.* 2011[6], Schäfer, *et al.,* 2011[7])

When flow simulations were performed to estimate the storage capacity of potential sites it was found that the boundary conditions applied in the models had a great effect on the pressure attained in the reservoir and in addition, that they affected the migration of both CO_2 and the displaced water. Closed boundary conditions gave rise to the highest reservoir pressures and least migration of CO_2 which is considered to be unrealistic, open boundaries led to the lowest pressures but the greatest extent of migration, while partly-open boundaries appeared to offer the best compromise and is the most realistic. In addition, reservoirs with good vertical permeability heterogeneous caprocks, i.e. not totally sealing, is considered the most realistic (Eckert *et al*., 2012[8], Schäfer *et al.,* 2011[7], Smith *et al.,* 2011[9], Oruganti *et al.,* 2009[10]).

There is a general consensus that CO_2injection would create a large area of increased pressure, if not otherwise managed although the area experiencing brine displacement appears to be more dependent on the site/model conditions (Noy *et al*., 2012[11], Surdam *et al*., 2011[12], Birkholzer *et al.,* 2009[1]). Increased pressure outside the license area would probably have a significant effect on other potential storage sites in the same overall formation, which may suffer reduced storage capacity (Mitiku *et al.,* 2013[13]). There is also the possibility of diversion of flow of the displaced water into unexpected directions due to heterogeneities or unforeseen geological structures, which increases the risk (Surdam *et al.,* 2011[12]).

Allowing the increased pressure created by CO_2 injection to dissipate by the outward movement of water may not be an acceptable strategy if the reservoir permeability and fracture-pressure do not allow a high enough injection rate. Injecting via more distributed wells may help, but a more effective approach to reduce the over-pressure might be to be to produce water out of the reservoir (Bergmo *et al.,* 2011[6]). The produced volumes required are expected to be roughly equivalent to the volume of CO_2 injected, which can pose a considerable problem for treatment and disposal (Surdam *et al.*, 2011[12])

A recent study by the IEAGHG (Pearce *et al.* 2014[14]) investigated the CGS licensing policies in the UK, the Netherlands, Australia, Texas and Alberta, most of which use systems whereby storage licenses are granted on a "first come, first served" basis, in which potential operators can identify and apply for their preferred storage site based on geological, technical and economic criteria, without making allowances for future neighbouring as-yet unlicensed storage sites. This system may well reduce the potential storage capacity of a regional aquifer, e.g. due to extended pressure effects, unless legislation is changed towards a more strategic approach. The EC storage directive and the guidelines to the directive do not give any direct values for any undesirable pressure development outside the storage complex (EC directive, 2009[15] and 2011[16]) rather than National authorities are to be consulted.

The purpose of the present work is to illustrate the effect of pressure management on two neighbouring storage structures, plus the required water production to prevent loss of storage capacity and to illustrate the importance of proper model boundary conditions. An existing model of the Bunter Sandstone Formation in the UK Southern North Sea is used (Noy *et al*., 2012[11]). The Bunter Sandstone, one of the two competitors for UK governmental funding aims to store CO_2 within a closed structure in the Bunter Sandstone (the White Rose Project), so the Bunter Sandstone is considered a key prospect for large-scale aquifer CO_2 storage in the UK North Sea (Fig. 1). The Bunter Sandstone, has previously been used for large-scale injection studies by Noy *et al*. (2012)[11], though this study did not consider the possibility of pressure manage by water production. Smith *et al*. (2011)[9] discussed the effect of varying the boundary conditions on the same model.

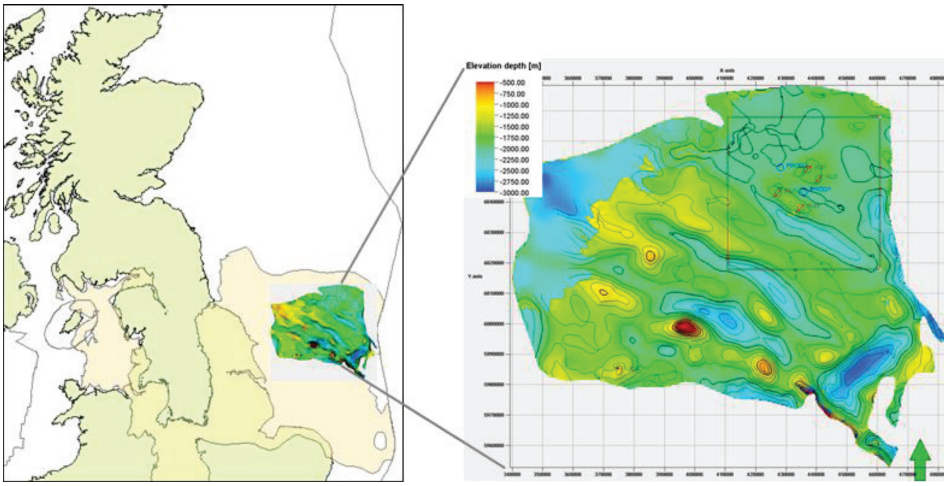

Fig. 1. Location of the Bunter Sandstone Formation offshore east of UK. Insert map: Top Bunter Sandstone Formation. Part model is delineated by the red rectangle.

2. Bunter Sandstone model, UK

2.1. Geological model

The geological model used in the present study consists of the Bunter Sandstone Formation reservoir, underlain by the low permeability Bunter Shale Formation. Below this, further underburden is not included because the Zechstein evaporites are expected to be impermeable. The Bunter is overlain by a thin shale Horizon, the Solling Claystone, which is then overlain by the Röt Halite Member, which is not expected to possess any effective permeability (Fig. 2). The remaining overburden to seabed has been lumped together, as it is not expected that fluids or pressure will transmit through the Röt Halite. In the far southeastern part of the model, an erosional surface cuts the overburden and down into the reservoir (the Base Cretaceous Unconformity), but in this area the lower Cretaceous Speeton Clay is expected to act as an effective topseal, and this area is some distance from the Bunter domes where CO_2 would most likely be stored.

Two structural closures to the north-east are chosen for injection and to study the impact from neighbouring activity on the pressure development. The regional Bunter model spans an area of approximate 130 km x 110 km, whereas a part model delineating the two closures covers an area of 50 km x 50 km (Fig. 1).

The lateral regional model boundary conditions are defined by a series of major fault zones, salt walls and stratigraphic pinch out (Noy *et al.* 2012[11]). For the present study only injecting in to the two local structural closures the large pore volume of the regional model will act if as the part model is situated in an almost infinite aquifer. To honour some of the structural elements and the fact that the part model is close to the north-east delineation of the regional model the part model will be modelled as if the north-east boundaries are fully closed.

A fine and a coarse model version of the regional grid were constructed. A fine model at a resolution of 200 m x 200 m x 2 m containing almost 25 million active grid cells. To handle export of the model for reservoir simulations a coarse model version was produced at a resolution of 600 m x 600 m x 6 m using the same input data. The coarse model consist of approximate 1.2 million active cells. Grid properties were up-scaled from the fine model using a layer-mapping approach to maintain the integrity of the property distribution across the different layers. The layering scheme of the model contains many eroded cells and layer truncations to fully capture the vertical variation. The part model was constructed from the coarse model with grid refinement in the lateral direction (200 m x 200m) but keeping the vertical resolution.

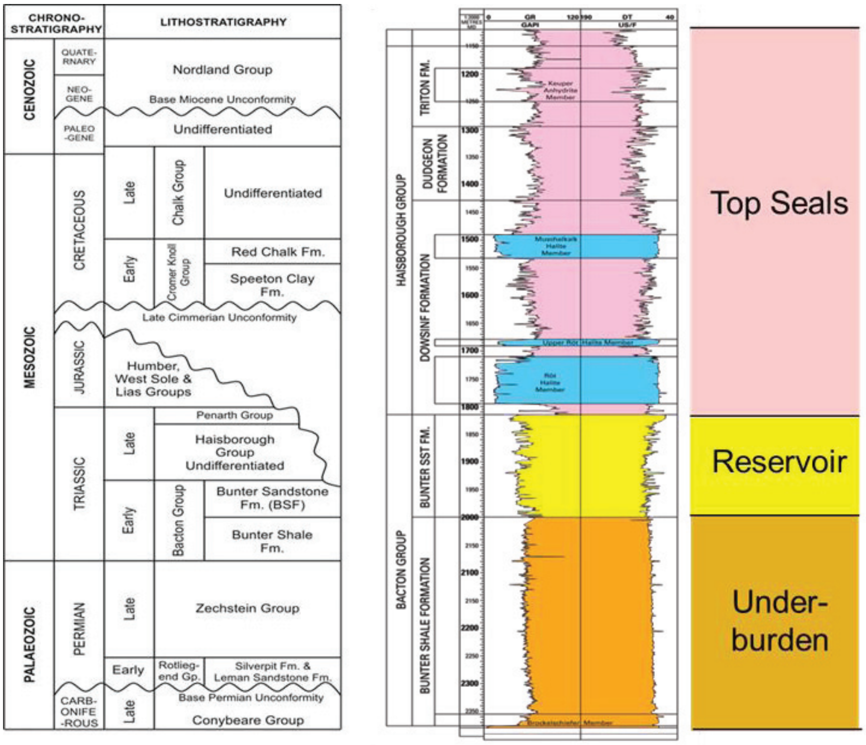

Fig. 2. Stratigraphic column for the model area.

2.2. Reservoir properties

Porosity and N/G have been calculated from ~30 wells in a smaller (20 x 40 km) part of the model, and have been stochastically distributed across the whole region based on a shale volume derived facies distribution and some simplified geological assumptions. Porosity–permeability relationships have been derived using core data, and used to generate the permeability distribution from the modelled porosities. Different properties are provided for vertical permeability to account for thin shale volumes.

Shale porosity and permeability values in the over and underburden are given as constant values taken from analogues.

Simulation model

The coarse geological model was exported to Eclipse 100 for simulation of the CO_2 injection processes.

Compressibility

Williams *et al*. (*2013*)[17] use a rock compressibility of 5.5675 x 10^{-4} 1/MPa, and water compressibility of 3.1325 x 10-4 1/MPa, with values taken from the UK Storage Appraisal Database (see Gammer *et al*. 2011[18]). These values were adopted for the present study.

2.3. Fluid properties

A considerable variation in brine salinity is recorded across the study area. Salinity ranges from 130,000–205,000 ppm in the Esmond. Forbes and Gordon Fields (Ketter, 1991[19]), and is 250,000 ppm in the Caister B Field (Ritchie & Pratsides 1993[20]). Warren & Smalley (1994)[21] provide alternative brine salinities of 294,000 and 303,000 ppm for the Esmond and Forbes fields respectively. A brine salinity of 160,000 ppm was used in the present study. Brine viscosity of 0.39 cp was used by Williams *et al*. (2013)[17] and adopted herein.

The Mesozoic succession in the Southern North Sea is hydrostatically pressured, with regional data suggesting a pore pressure gradient of 10.07 km^{-1}. Noy *et al*. (2012)[11] give a conservative estimate of the fracture pressure gradient of 16.9 km^{-1}, relative to seabed. Wiprut & Zoback (2000)[22] give a fracture pressure gradient of 0.8 psi/ft as a typical fracture pressure value reported from formations beneath the North Sea. Small-scale faulting within the reservoir occurs, but is not explicitly represented in the model due to the large scale of the region, and lack of detailed 3D seismic data available for the project. These faults are expected to be relatively local features, and are particularly evident over the crests of anticlinal structures. Williams *et al*. (2014)[23] suggest that these faults are at risk of reactivating if reservoir pressures exceed ~1.3 x hydrostatic, in the worst-case scenario (*i.e.* if faults are optimally oriented for slip in the current stress-regime).

2.4. Saturation functions

No relative permeability curves are available for the Bunter Sandstone Formation. The Viking 2 measurements of Bennion and Bachu (2006, 20088[24, 25]) are assessed to be applicable for the relative fine-grained nature of the Bunter reservoir sandstone, and their Calmar values to be applicable for the mudstones.

3. Simulation cases

3.1. Boundary conditions

With the objectives of assessing the effect of pressure management from water production on two neighbouring storage sites computational time can be optimised by use of only a smaller part from the regional model. In the site specific model the pressure development must reflect the true nature of the physical site, *i.e.* the boundary conditions of the site model must account for the response from the regional model *e.g.* open aquifer, semi-open aquifer etc. A closed box can only be an endpoint member of a structural closure in a regional aquifer.
Performing detailed site simulations, the pore volume multiplication (MULTPV) option is widely used as boundary condition, but it has to be matched to the response from running the regional model as a to high value for the multipliers suppress the pressure at the boundary as well as a to low values converges to the case of a closed box. Simulation cases are run with both the regional model as well as with the small part model and comparison of the pressure distributions are used to adjust the values of the multipliers.

3.2. Pressure management

The two structural closures in the part model are used to assess the impact on the pressure development from the CO_2 injection process and the process of mitigating pressure increase with passive and active water production. The well configuration is shown in Fig. 3.

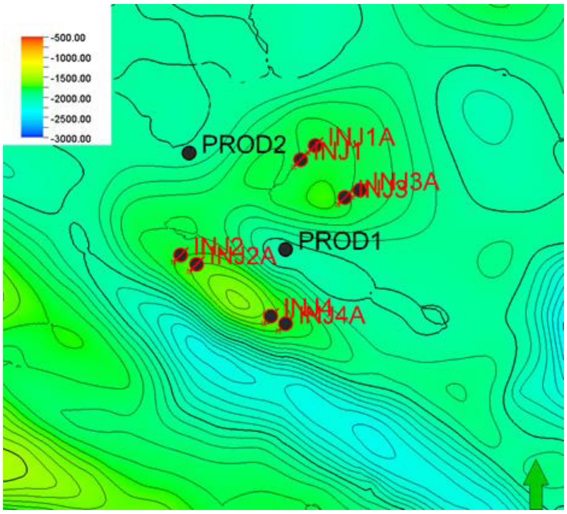

Fig. 3. Part model showing well configuration for the two structural closures. Two production wells are placed on each site of the structural spill point for the two closures. Top Bunter Sandstone map.

4. Simulation results and discussion

All simulations were run in bottom hole pressure control mode, *i.e.* the injection pressure was not allowed to exceed a threshold value of 75% of the lithostatic pressure. The threshold value is assessed to be below the formation fracture pressure.

Figure 4 displays the grid cell pressures for all the grid cells in the uppermost part of the Bunter Sandstone reservoir after 40 years of constant CO_2 injection at a rate of 1 mio tonnes/d/well. Pressure values are plotted in a pressure gradient diagram illustrating that the cell pressures do not exceed the threshold value at any placed in the model.

3.3. Boundary conditions

The 50 km x 50 km large part model was used to simulate same injection scenario as with the regional model. The pressure distribution from the regional model was used to match the values of MULTPV (at the outermost grid cells for the part model. After trial and error a set of MULTPV values were found to match the regional pressure distribution; a MULTPV value of 55 was used for the western and southern boundaries and a MULTPV value of 10 was used for the eastern and northern boundaries (Fig. 5).

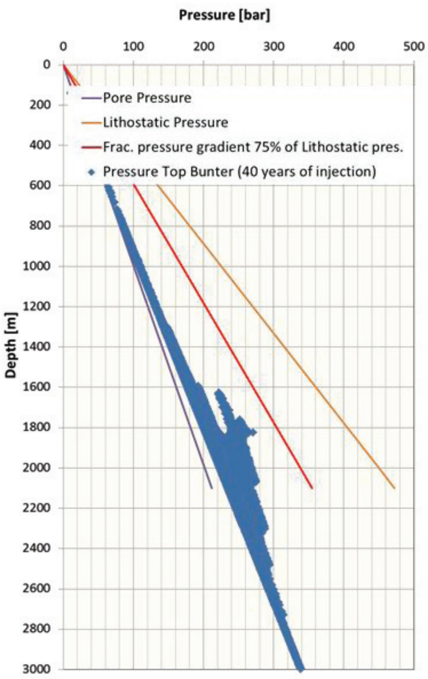

Fig. 4. Pressure gradients. Fracture pressure gradient assessed to be 75% of lithostatic pressure. Blue diamonds are pressure values in grid cells at top Bunter Sandstone level after 40 years of constant CO_2 injection. Injection rate 1 mio tonnes/d/well.

From Fig. 5 it is clear that simulating the part model as a closed box returns to high pressure values. At the opposite; choosing a to high MULTPV value the pressure will be fixed at the boundary resulting in a situation, where the pressure distribution can not increase at the boundary and this also results in an erroneously pressure development. The MULTPV values will depend on the specific injection scenario, *i.e.* the regional model has to be run if the injected volumes changes and especially if the total injected volume changes. The MULTPV match is not that dependent a specific well configuration but depends strongly on the total voidage balance, meaning that if production wells are introduced for pressure management the matching procedure must be re-run.
The correct use of MULTPV is dependent on access to a regional model. The regional model do not need to be very detailed but a reasonable permeability distribution is vital together with overall compressibility values.

3.4. Pressure management

After the pressure development in a part/site model are qualified with the correct and matched boundary conditions, the model can be used to study the concept of pressure management and how much interferes two neighbouring activities can co-exist.

Figure 6 shows the pressure development when injecting 4 mio tonnes/y of CO_2 in to the northern-most closure. The part model is used. The pressure is displayed as a 5 bar overpressure, *i.e.* overpressure values below 5 bar are filtered. After approximate 3.5 years the 5 bar overpressure reach the crest at the southern-most closure.
The 5 bar overpressure are arbitrarily chosen, as there are no regulatory guidelines in either the EC directive or the guidelines (EC directive, 2009[15], EC guidelines 2011[16]). In the concept of "storage complex" in the EC directive focus is on the containment of the CO_2 plume and not on pressure development outside the storage complex. This can be a challenge for both an operator and a regulator in both the context of interfering with neighbouring activities but also in the context of setting up a measuring and mitigation plan and finally the transfer of responsibility between operator and the competent authority.

When two neighbouring activities are on-going concurrently the overpressure distributes very fast and mitigation actions can be to produce water to balance the overpressure. It can be a challenge to keep the overpressure interference at a low level and it will be a site specific problem that will depend on the actual configuration, *i.e.* distance between the individual closures, reservoir properties or ability to dissipate pressure, injection scheme etc. Figure 7 shows how fast the overpressure distributes even that a vast quantity of water is produced out of the subsurface.

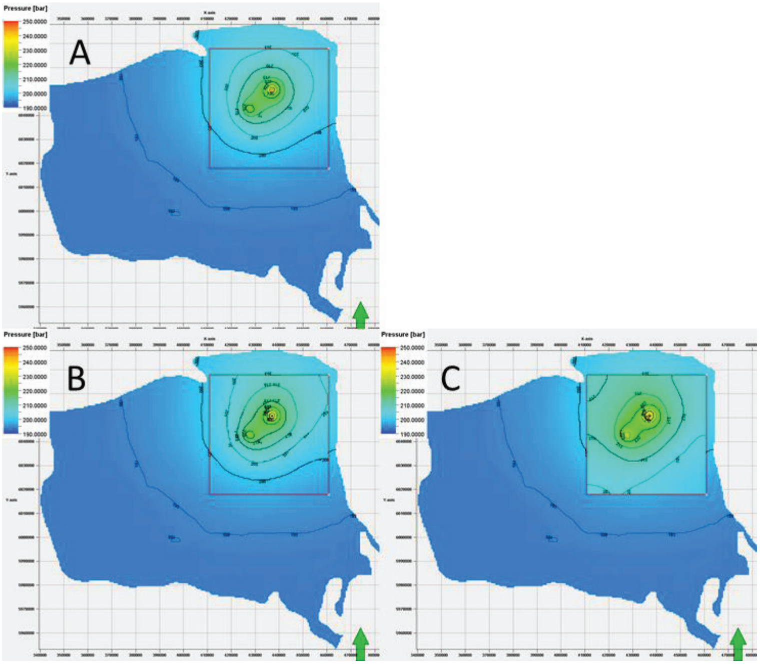

Fig. 5. Matching pressure distribution. A: Pressure distribution after 40 years of injection simulated with regional model. B: Simulated pressure distribution with part model (red rectangle) and a MULTPV set of 55 at the southern and western boundaries and MULTPV set of 10 at the northern and eastern boundaries. Result form part model placed on top of the regional model, almost coinciding isobars. C: Simulated pressure distribution with part model, but with no MULTPV, *i.e.* closed box. Pressure level erroneously too high.

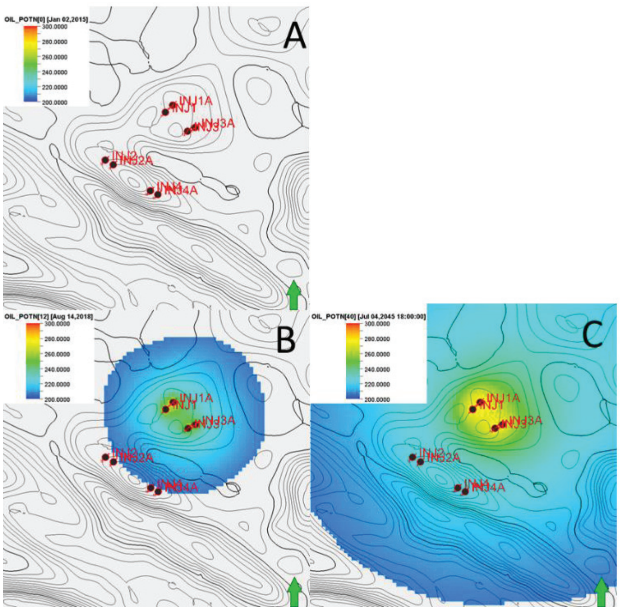

Fig. 6. Pressure development when injecting 4 mio tonnes/y of CO_2 in to the northern-most closure. A: Well configuration. B: Development of a minimum 5 bar overpressure. After approximate 3.5 years the 5 bar overpressure reach the crest at the southern-most closure. C: Pressure distribution after 30 years of injection.

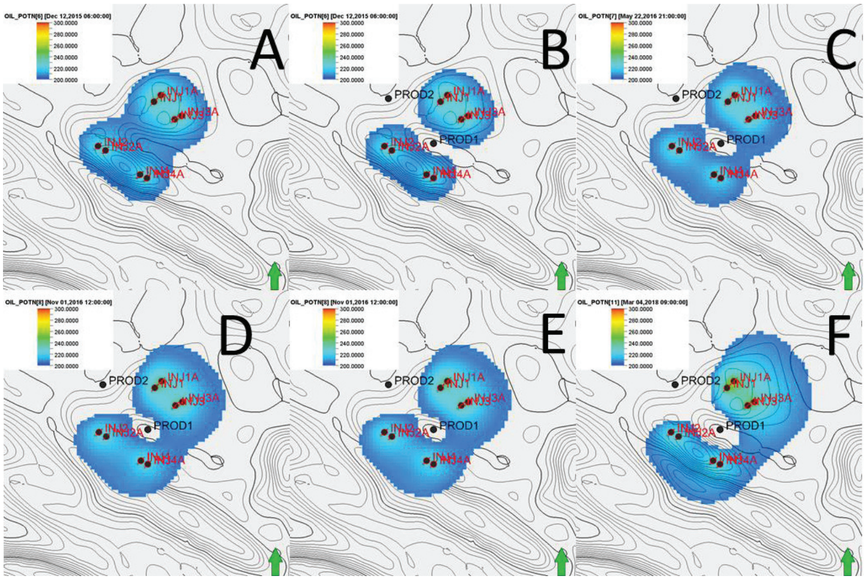

Fig. 7. Development in 5 bar overpressure for different ratios (res. vol. inj. CO_2 / res. vol. prod. water) between total injected CO_2 and total produced water. Two production wells are placed across the structural spill point between the two structural closures. A: CO_2 injection on both structures, 4 mio tonnes/y/structure, overpressure coincide after less than one year. B: Ratio=7; after approx. one year the production wells can halt the overpressure development. C: Ratio=4. D: ratio=2.5. E: Ratio=2.3. F: Ratio=1.4; production wells Prod1 & 2 are modelled as being 60deg. deviated in order to obtain a better drawdown for producing a high volume.

4. Conclusion

- Using site specific reservoir simulation models for detailed modelling of CO_2 injections proper boundary conditions are vital for modelling the correct pressure level.
- Use of a regional model to help setup correct boundary conditions are instructive and to some degree essential.
- Overpressure develops very fast and can potentially conflict with neighbouring activities.
- Pressure management through water production are a potentially solution but depends on a good reservoir engineering approach and will be site specific.
- Regulations on how to manage interference between neighbouring activities are indefinite.

Acknowledgements

This publication has been produced with support from the BIGCCS Centre, performed under the Norwegian research program Centres for Environment-friendly Energy Research (FME). The authors acknowledge the following partners for their contributions: ConocoPhillips, Gassco, Shell, Statoil, TOTAL, ENGIE and the Research Council of Norway (193816/S60).

References

[1] Birkholzer, J.T., Zhou, Q. and Tsang, C.-F. 2009. Large-scale impact of CO_2 storage in deep saline aquifers: A sensitivity study on pressure response in stratified systems, International Journal of Greenhouse Gas Control 3, 181-194.

[2] Obdam, A., van der Meer, L., May, F., Kervevan, C., Bech, N. & Wildenborg, A. 2003. Effective CO_2 storage capacity in aquifers, gas fields, oil fields and coal fields. GHGT-6. *Energy Procedia (2002).*

[3] Celia, M.A., Bachu, S., Nordbotten, J.M., Kavetski, D. & Gasda, S. 2006. A risk asensssment tool to quantify CO_2 leakage potential through

wells in mature sedimentary basins. Paper presented at the 8th International Conferences on Greenhouse Gas Control Technologies, Trondheim, Norway, June (2006).
[4] Chang, W.K. & Bryant, S.L. 2007. Dynamics of CO_2 plumes encountering a fault in a reservoir. Paper preseented at the 6th annual Conference on Carbon Capture and Sequestration, Pittsburg, Pensylvania, May (2007).
[5] Birkholzer, J.T., Zhou, Q., Cortis, A. & Finsterle, S. 2011. A sensitivity study on regional pressure buildup from large-scale CO_2 storage projects. GHGT-10. *Energy Procedia 4, 4371-4378.*
[6] Bergmo, P.E.S., Grimstad, A-A. & Lindeberg, E. 2011. simultaneous CO_2 injection and water production to optimise aquifer storage capacity. International Journal of Greenhouse Gas Control 5, 555-564.
[7] Schäfer, F., Walter, L., Class, H. & Müller, C. 2011. The pressure impact of CO_2 storage on neighbouring sites. GHGT-10. *Energy Procedia 4, 465-4471.*
[8] Eckert, A., Nygaard, R., Bai, B., Liu, X. & Paradeis, M. 2012. Role of geometrical influences of CO2 sequestration in anticlines. ARMA 12-255.
[9] Smith, D.J., Noy, D.J., Holloway, S. & Chadwick, R.A., 2010. The Impact of Boundary Conditions on CO_2 Storage Capacity Estimation in Aquifers. GHGT-10. *Energy Procedia*, 4, 4828–4834.
[10] Oruganti, YD. & Bryant, S.L. 2009. Pressure build-up during CO2 storage in partially confined aquifers. GHGT-9. *Energy Procedia 1 3315-3322.*
[11] Noy, D.J., Holloway, S., Chadwick, R.A., Williams, J.D.O., Hannis, S.D. & Lahann, R.W. 2012. Modelling large-scale carbon dioxide injection into the Bunter Sandstone in the UK Southern North Sea. *International Journal of Greenhouse Gas Control*, 9, 220–233.
[12] Surdam, R.C., Jiao, Z., Stauffer, P. & Miller, T. 2011. The key to commercial-scale geological CO_2 sequestration: Displaced fluid management. *Energy Procedia 4, 4246-4251.*
[13] Mitiku, A.B., Bauer, S. 2013. Optimal use of a dome-shaped anticline structure for CO_2 storage: a case study in the North German sedimentary basin. *Environmental Earth Sciences*. 70 (8), 3661–3673.
[14] IEAGHG. 2014. (ed.) Pearce, J., Bentham, M., Kirk, K., Pegler, R., Remmeltrs, G., van Gessel, S., Young, K. & Hovorka, S. Comparing different approaches to managing CO2 storage resources in mature CCS futures. GCI report 2014/01.
[15] EC. 2009. Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EC, European Parlimaent and Council Directives 200/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006. Official Journal of the European Union, L 140/114.
[16] EC. 2011. Implementation of Directive 2009/31/EC on the Geological Storage of Carbon Dioxide – Guidance Document 2. Characterization of the Storage Complex, CO_2 Stream Composition, Monitoring and Corrective Measures. ISBN-13978-92-79-19834-2.
[17] Williams, J.D.O., Jin, M., Bentham, M., Pickup, G.E., Hannis, S.D. & Mackay, E.J. 2013. Modelling carbon dioxide storage within closed structures in the UK Bunter Sandstone Formation. *International Journal of Greenhouse Gas Control.*18, 38–50.
[18] Gammer, D., Green, A., Holloway, S. & Smith, G. 2011. The Energy Technologies Institute's UK CO_2 Storage Appraisal Project (UKSAP). SPE 148426. *Presented at the SPE Offshore Europe Oil and Gas Conference and Exhibition, Aberdeen, UK, 6–8 September, 2011*.
[19] Ketter, F.J. 1991. The Esmond, Forbes and Gordon Fields, Blocks 43/8a, 43/13a, 43/15a, 43/20a, UK North Sea. In: Abbotts, I.L. (ed.), *United Kingdom Oil and Gas fields, 25 Years Commemorative Volume,* Geological Society, London, Memoir 14, 425–432.
[20] Ritchie, J.S. & Pratsides, P. 1993. The Caister fields, Block 44/23a, UK North Sea. In: Parker, J.R. (ed.), *Petroleum Geology of Northwest Europe: Proceedings of the Fourth Conference,* Geological Society, London, 759–769.
[21] Warren, E.A. & Smalley, P.C. 1994. North Sea Formation Waters Atlas. Geological Society, London, Memoir 15.
[22] Wiprut, D. & Zoback, M. 2000. Constraining the stress tensor in the Visund field, Norwegian North Sea: Apllication to wellbore stability and sand production. *International Journal of Rock Mechanics and Mining Sciences*. 37, 317–336.
[23] Williams, J.D.O., Holloway, S., & Williams, G.A. 2014. Pressure constraints on the CO_2 storage capacity of the saline water-bearing parts of the Bunter Sandstone Formation in the UK Southern North Sea. *Petroleum Geoscience*. Online First.
[24] Bennion, D.B. & Bachu, S. 2006. The impact of interfacial tension and pore-size distribution/capillary pressure character on CO_2 relative permeability at reservoir conditions in CO_2-brine systems. SPE 99326. *Presented at the SPE/DOE Symposium on Improved Oil Recovery, Tulsa, Oklahoma, 22–26 April, 2006.*
[25] Bennion, D.B. & Bachu, S. 2008. Drainage and imbibitions relative permeability relationships for supercritical CO_2/brine and H_2S/brine systems in intergranular sandstone, carbonate, shale and anhydrite rocks. SPE 99326. *SPE Reservoir Evaluation and Engineering*. **11** (3) 487–496.