GEOLOGICAL CHARACTERISATION OF AUSTRALIA'S FIRST CARBON DIOXIDE STORAGE SITE

by

Francesca (Tess) Dance

The Australian School of Petroleum

THE UNIVERSITY of ADELAIDE

This thesis is submitted in fulfilment of the requirements for the degree of Doctor of Philosophy in the Faculty of Engineering, Computer & Mathematical Sciences.

January, 2019

Abstract

This is a PhD thesis by publication consisting of four journal papers and two chapters in books. Each manuscript details the geological characterisation that has underpinned scientific field research and operations at the CO2CRC Otway Project. This is Australia's first site to geologically store carbon dioxide and has been operating in Victoria, Australia, since 2008. Site screening, planning, and development began four years prior to that. During the course of the past 14 years the project has achieved demonstrated storage in both a depleted gas field, and a saline aquifer, and investigated the dynamic processes and monitorability of both scenarios in a series of controlled field experiments. This has provided a unique opportunity to test and validate interpretations of the geological characteristics that are thought to influence storage efficacy and containment.

The research presented in this thesis has the distinction of being able to test geological heterogeneity at both the core and field scale by comparing the core analysis and laboratory experiments with actual injection data. It shows that small scale geological influences, particularly vertical permeability, have an impact on capacity and trapping. Furthermore, the time-lapse monitoring datasets provide evidence to which the conformance of reservoir models are assessed. The body of work herein has established that valuable insights may be used to improve site characterisation before, during, and post-injection. This is particularly important for updating models to enhance reservoir management, as well as for predicting the long-term evolution and stabilization of injected CO_2. This in turn will influence enduring monitoring strategies and the potential transfer of liability for many sites post-closure.

The research presented here examines the whole of life site assessment process from site selection through to execution and completion. It dispels the myths that

depleted fields have little uncertainty and risk because they have held hydrocarbons in the past and are already well characterised by the previous operators. Instead the findings show that characterisation for CO_2 storage has very a different focus from that of petroleum exploration and development methods, and targeted data acquisition and integrated analysis is essential to reduce uncertainty. The study also shows that information gathered for CO_2 storage site characterisation of a previously poorly characterised saline aquifer can have greater implications for the regional understanding of basin stratigraphy and geological controls on fluid migration. Thus the investigations may be of interest to those beyond just the carbon capture and storage research community.

Table of Contents

Abstract……..………………………………………………………………………i

Citation Listing………………………………………………………………….v

Declaration………..……………………………………………………………ix

Acknowledgements…………………………………………………………..x

Statement of Authorship……………………………………………………….xii

Chapter 1: Contextual Statement………………………………………….................1

Introduction………………………………………………….................1

Paper 1……………………………………………………………….……….5

Paper 2……………………….……………………………………………….6

Paper 3………………………………………………………………………..8

Paper 4………………………………………………….................9

Summary……………………………………………………..…………...11

Supplementary publications………………………………………….....11

Chapter 2: Literature Review……………………………………………………13

Introduction…………………………………………………………………13

The link between fossil fuel use and global warming……………………....13

A brief history of Carbon Capture and Storage as a mitigation measure…...15

Site assessment and characterisation for geological storage of CO_2………..18

Key Issues and Gaps………………………………………………………...32

CCS demonstration and pilot projects………………………………………34

Chapter 3: References ………………………………………………………………46

Chapter 4: Thesis Body-Publications………………………………………………73

4.1 Publication 1: *Assessment and geological characterisation of the CO2CRC Otway Project CO_2 storage demonstration site: From prefeasibility to injection*……….……….....75

4.2 Publication 2: *Characterisation of the Paaratte Formation for a CO_2 storage demonstration project*……………………………………………………………...95

4.3 Publication 3: *Observations of carbon dioxide saturation distribution and residual trapping using core analysis and repeat pulsed-neutron logging at the CO2CRC Otway site*……………………………………………………………………..142

4.4 Publication 4: *Illuminating the geology: Post-injection reservoir characterisation of the CO2CRC Otway site*……………….………………………………………156

Chapter 5: Thesis Conclusions……………………………………………………161

Chapter 6: Additional Supporting Publications (chapters in books)………………165

6.1 Supporting publication 1: *Monitoring CO_2 Saturation from Time-Lapse Pulsed Neutron and Cased-Hole Resistivity Logs*……………………………......…..167

6.2 Supporting publication 2: *Characterising the storage site*………………….....181

Citation Listing

Publication 1: Dance, T., 2011. Assessment and geological characterisation of the CO2CRC Otway Project CO_2 storage demonstration site: From prefeasibility to injection. *Marine and Petroleum Geology.*

Publication 1 has been cited by 13 publications between 2014 and 2018. References as follows:

1. Schacht, U. and Jenkins, C., 2014. Soil gas monitoring of the Otway Project demonstration site in SE Victoria, Australia. International Journal of Greenhouse Gas Control. May 2014 (24) pp. 14-29. 10.1016/j.ijggc.2014.02.007

2. Krawczyk, C.M., Tanner, D.C., Ziesch, J., Beilecke, T. and Henk, A., 2015. Deformation Prediction in the Otway Basin - A Seismo-mechanical Workflow for Sub-seismic Fault Detection. The Third Sustainable Earth Sciences Conference and Exhibition, EAGE 13th -15th October 2015, Celle Germany; 5 pp., 10.3997/2214-4609.201414247

3. Ito Takuma,·Nakajima Takahiro, Chiyonobu Shun, Xue Ziqiu, 2015. Geostatistical modeling for the spatial mud content: an application to the Nagaoka CO_2 storage site, Japan. Journal of the Geological Society of Japan, Vol. 121, No. 9, p. 311–323, September 2015.

4. Ito Takuma,·Nakajima Takahiro, Xue Ziqiu, 2016. Depositional environments and characteristics of grain size and pore-throat size distributions of CO_2 storage aquifer as a controlling factor of injectivity: a case study of the Nagaoka site, Japan. Journal of the Sedimentological Society of Japan 75(1):3-15 July. DOI: 10.4096/jssj.75.3

5. Glubokovskikh, S., Pevzner, R., Dance, T., Caspari, E., Popik, D., Shulakova, V., Gurevich, B., 2016. Seismic monitoring of CO_2 geosequestration: CO2CRC Otway case study using full 4D FDTD approach. International Journal of Greenhouse Gas Control. June 2016, 49, pp. 201-216. 10.1016/j.ijggc.2016.02.022.

6. Ziesch, J., Aruffo, C. M., Tanner, D. C., Beilecke, T., Dance, T., Henk, A., Weber, B., Tenthorey, E., Lippmann, A., Krawczyk, C. M., 2017. Geological structure and kinematics of normal faults in the Otway Basin, Australia, based on quantitative

analysis of 3-D seismic reflection data. Basin Research. APR 2017 (29) 2, pp. 129-148, 10.1111/bre.12146.

7. Aminu, M. D., Nabavi, Seyed A., Rochelle, C. A., Manovic, V., 2017. A review of developments in carbon dioxide storage. Applied Energy. DEC 15 2017, (208) pp. 389-1419. 10.1016/j.apenergy.2017.09.015

8. Ito, T., Ohbuchi, A., Nakajima, T., Xue, Z., 2017. Identifying the source of natural gamma-rays in shallow-marine siliciclastic strata and their significance for shale evaluation: A case study of the CO2 storage aquifer at the Nagaoka site, Japan. Journal of Natural Gas Science and Engineering. Volume 46, 2017, Pages 782-792, ISSN 1875-5100, https://doi.org/10.1016/j.jngse.2017.08.034.
9. Reynolds, C., Krevor, S., Dixon, T., Laloui, L, Twinning, S., 2017 Capillary limited flow behaviour of CO_2 in target reservoirs in the UK. 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13 November 14-18, 2016, (114) pp. 4518-4523. 10.1016/j.egypro.2017.03.1568

10. Popik, D., Shulakova, V., Tertyshnikov K.V.,·Pevzner, R., Ziramov, S., Urosevic, M., 2017. Model-guided Processing of Time-lapse Seismic for Real-time Monitoring of CO_2 Geosequestration - CO2CRC Otway Project Case Study. 79th EAGE Conference and Exhibition 2017, Paris, June 2017 DOI: 10.3997/2214-4609.201701388

11. Aminu, M. D., Nabavi, Seyed, A., Manovic, V., 2018. CO_2-brine-rock interactions: The effect of impurities on grain size distribution and reservoir permeability. International Journal of Greenhouse Gas Control, Volume 78, 168-176, ISSN 1750-5836.

12. Raza, A., Gholami, R., Rezaee, R., Bing, C. H., Nagarajan, R., Hamid, M. A., 2018. CO_2 storage in depleted gas reservoirs: A study on the effect of residual gas saturation, Petroleum, Volume 4, Issue 1, Pages 95-107, ISSN 2405-6561, https://doi.org/10.1016/j.petlm.2017.05.005.

13. Pevzner, R, Urosevic, M, Popik, D, Tertyshnikov, K, Caspari, E, Correa, J, Kepic, A, Glubokovskikh, S, Ziramov, S, Gurevich, B, Shulakova, V and Dance, T, 2017. Seismic monitoring of CO_2 geosequestration: Preliminary results from Stage 2C of the

CO2CRC Otway Project one year post injection. In: SEG 2017 Annual Meeting. DOI: 0.1190/segam2017-17670937.1

Publication 3: Dance, T. and Paterson, L., 2016. Observations of carbon dioxide saturation distribution and residual trapping using core analysis and repeat pulsed-neutron logging at the CO2CRC Otway site. *International Journal of Greenhouse Gas Control*.

Publication 3 has been cited by 9 publications between 2016 and 2018. References as follows:

1. Soltanian, M. R., Amooie, M. A., Cole, D. R., Graham, D. E., Hosseini, S. A., Hovorka, S., Pfiffner, S. M., Phelps, T. J., Moortgat, J., 2016. Simulating the Cranfield geological carbon sequestration project with high-resolution static models and an accurate equation of state. International Journal of Greenhouse Gas Control.

2. Ritzi, R. W., Freiburg, J. T., Webb, N. D., 2016. Understanding the (co)variance in petrophysical properties of CO_2 reservoirs comprising sedimentary architecture. International Journal of Greenhouse Gas Control AUG 2016, 51, pp. 423-434 10.1016/j.ijggc.2016.05.001.

3. Serno, S., Johnson, G., LaForce, T. C., Ennis-King, J., Haese, R. R., Boreham, C. J., Paterson, L., Freifeld, B. M., Cook, P. J., Kirste, D., Haszeldine, R. S., Gilfillan, S. M. V., 2016. Using oxygen isotopes to quantitatively assess residual CO_2 saturation during the CO2CRC Otway Stage 2B Extension residual saturation test. International Journal of Greenhouse Gas Control. SEP 2016, (52). Pp. 73-83 10.1016/j.ijggc.2016.06.019

4. Serno, S., Flude, S., Johnson, G., Mayer, B., Karolytė, R., Haszeldine, R. S., Gilfillan, S. M. V., 2017. Oxygen isotopes as a tool to quantify reservoir-scale CO_2 pore-space saturation, International Journal of Greenhouse Gas Control, Volume 63, 2017, Pages 370-385, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2017.06.009.

5. Soltanian, M. R., Amooie, M. A., Gershenzon, N., Dai, Z., Ritzi, R., Xiong, F., Cole, D., Moortgat, J., 2017. Dissolution Trapping of Carbon Dioxide in Heterogeneous

Aquifers. Environmental Science & Technolog. JUL 4 2017. (51) 13 pp. 7732-7741. 10.1021/acs.est.7b01540

6. Huang, F., Bergmann, P., Juhlin, C., Ivandic, M., Lueth, S., Ivanova, A., Kempka, T., Henninges, J., Sopher, D., Zhang, F., 2018. The first post-injection seismic monitor survey at the Ketzin pilot CO_2 storage site: results from time-lapse analysis. Geophysical Prospecting, JAN 2018 (66)1 pp. 62-84 10.1111/1365-2478.12497

7. Ennis-King, J., LaForce, T., Paterson, L., Black, J. R., Vu, H. P., Haese, R. R., Serno, S., Gilfillan, S., Johnson, G., Freifeld, B., Singh, R., Dixon, T., Laloui, L, Twinning, S., 2017. Stepping into the same river twice: field evidence for the repeatability of a CO_2 injection test. 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13 NOV 14-18, 2016. 114, pp. 2760-2771. 10.1016/j.egypro.2017.03.1392.

8. Green, C., Michael, K., Paterson, L., Dixon, T., Laloui, L., Twinning, S., 2017. Simulation of CO_2 migration for the planning of well test configurations at the South West Hub Project, Western Australia. 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13 NOV 14-18, 2016, 114 pp. 3445-3455 10.1016/j.egypro.2017.03.1475,

9. Bui, M., Adjiman, C. S., Bardow, A., Mac Dowell, N., et al., 2018. Carbon capture and storage (CCS): The way forward. Review Article, Energy & Environmental Science 11(Part A), March, 11, 1062-1176. DOI: 10.1039/c7ee02342a

Declaration

I certify that this work contains no material which has been accepted for the award of any other degree or diploma in my name in any university or other tertiary institution and, to the best of my knowledge and belief, contains no material previously published or written by another person, except where due reference has been made in the text. In addition, I certify that no part of this work will, in the future, be used in a submission in my name for any other degree or diploma in any university or other tertiary institution without the prior approval of the University of Adelaide and where applicable, any partner institution responsible for the joint award of this degree.

I give consent to this copy of my thesis when deposited in the University Library, being made available for loan and photocopying, subject to the provisions of the Copyright Act 1968.

The author acknowledges that copyright of published works contained within this thesis resides with the copyright holder(s) of those works.

I also give permission for the digital version of my thesis to be made available on the web, via the University's digital research repository, the Library Search and also through web search engines, unless permission has been granted by the University to restrict access for a period of time.

I acknowledge the support I have received for my research through the provision of an Australian Government Research Training Program Scholarship.

Tess Dance Candidate

Acknowledgements

I feel extremely privileged to have been the chief geologist for the Otway project for the past 15 years and for that opportunity I would like to thank the CO2CRC and my predecessor Lynton Spencer for trusting me to take on the role all those years ago. In the course of that time I have met so many brilliant people with a passion for the research and I feel humbled to have worked alongside the following individuals: Malcom Arnot, Chris Boreham, Mark Bunch, Eva Caspari, Richard (Ric) Daniel, David Etheridge, Barry Freifeld, Stanislav Glubokovskikh, Boris Gurevich, Ralf Haese, Anton Kepic, Dirk Kirste, Mark Lawrence, Maxim Lebedev, Evelina Paraschivoiu, Roman Pevzner, Ulrike Schacht, Sandeep Sharma, Valeriya Shulakova, Rajindar Singh, Eric Tenthorey, Milovan Urosevic. Also the folks at CO2CRC including Peter Cook, Matthias Raab, Maxwell Watson, Steve Marshall, Paul Barraclough, Fiona Koelmeyer, Sara Calkoen and the sponsors and funding institutions including ANLEC R&D that have made my research possible. Special thanks to industry champions at Chevron Mark Trupp, Ishtar Barranco, and Scott Ryan that have peer reviewed my work over the years.

I would especially like to acknowledge my colleagues at CSIRO Charles Jenkins, Linda Stalker, Jonathan Ennis-King, Tara La Force and Ludovic Ricard that have worked on Otway with me, as well as past colleagues Kevin Dodds and Jim Underschultz for encouraging me to do the PhD in the first place, Allison Hortle for being my inspiration to keep going with it while balancing a career and family, and thanks to Karsten Michael for a supportive environment in which to get it finished. Most importantly, I thank my supervisors Lincoln Paterson, John Kaldi, and Bruce Ainsworth for being patient, and kicking me in the pants on the final stretch to get it done.

Lastly I would like to thank my family and friends. Andrew, you are my rock (I couldn’t let you be the only one in the family with a doctorate), and Mischa, I hope this shows you can do whatever you choose in life (with a bit of persistence, love and support). This is dedicated to my dear Mum and Dad.

Statement of Authorship

All publications included in this thesis derive from research undertaken within the term of the higher degree by research candidature between February 2010 and February 2018. Three of the publications were produced with the candidate as sole author, the other three were co-authored with the candidate as first author. Co-authors that contributed to the publications include Lincoln Paterson (co-supervisor); Ashish Datey (Schlumberger); Tara La Force and Jonathan Ennis-King (CSIRO); Stanislav Glubokovskikh and Roman Pevzner (Curtin University). A detailed statement of their relative contributions precede each publication.

Chapter 1: Contextual Statement

Introduction

The development of acknowledged procedures for the selection, characterisation and modelling of Carbon Capture and Storage (CCS) sites has been the topic of many national and intergovernmental studies aiming to establish a consistent approach around the world (CSFL, 2014 and CO2CRC, 2011 and references there in). While it will be problematic to employ a prescriptive methodology for all storage sites, regulators are aiming to identify a common practice and inform a set of recommendations and guidelines necessary for large scale commercial projects.

In Australia, the Federal Government has developed a regulatory framework for offshore CO_2 storage based on amendments to existing petroleum legislation (Australian Minerals Council, 2005). Although their site characterisation guidelines are non-binding, there is a requirement to conduct an environmental impact assessment and adhere to relevant occupational health and safety legislation. Part of this process is to prove that proper site selection and effective monitoring and verification is in place. For this purpose static and dynamic models are frequently used (Ennis-King and Paterson, 2003; Doughty and Pruess, 2004; Green and Ennis-King, 2010; Zhou et al, 2010; Mekel et al., 2015). The aim of building three dimensional geological models for reservoir simulation of injected CO_2 is to address key questions related to reservoir heterogeneity and storage capacity. Firstly, given the average parameters of porosity, permeability and reservoir pressure it must be established there is sufficient injectivity. This will inform the planning for maximum rate of injection and design requirements of potential injectors. By gathering petrological and geochemical information about the reservoir, coupled reactive transport simulation modelling may be used to estimate dissolution rates and the site's potential for mineral trapping. This, combined with the preliminary volumetric estimates, provides "effective capacity" results, indicating if the sink will be sufficient to accommodate the source. Similarly, once the CO_2 has been injected there is the need to accurately predict its long-term behaviour and possible migration pathways. By modelling subsurface features and likely heterogeneity a project may determine whether CO_2 will flow to regions of high risk to containment, such as faults or abandoned wells, or if the operations will impact neighbouring natural resources. This information is then used to plan optimal techniques for down-hole and surface monitoring of the CO_2.

The challenge for those involved in building static models that address all these purposes, is to be sure the models contain sufficient "realistic" detail of the structure, stratigraphy, and reservoir facies; yet maintain computationally manageable models to support timely dynamic simulations and risk assessments. Pilot projects and demonstrations sites offer the CCS regulators and research community a setting in which to scrutinize characterisation, modelling, and monitoring methods. Sensitivity studies allow the assessment of model parameters against field results to determine which geological parameters matter most. Thus transparent communication of workflows and results from such sites is essential for sharing lessons learnt to plan appropriate appraisal programs at similar sites.

The research I present in this thesis is from the CO2CRC Otway Project, the first CCS demonstration site to show the safe transport, underground storage and monitoring of CO_2 rich gas in an Australian setting. The sub-surface research facility is situated in the onshore Port Campbell Embayment in south-western Victoria (Figure 1) an area known for small structurally bound gas fields hosted in the late Cretaceous Waarre Formation of the lower Sherbrook Group. The CO_2-rich gas sourced for the experiments is produced from the Buttress Field. Injection is into the depleted Naylor Field and overlying Paaratte Formation saline aquifer.

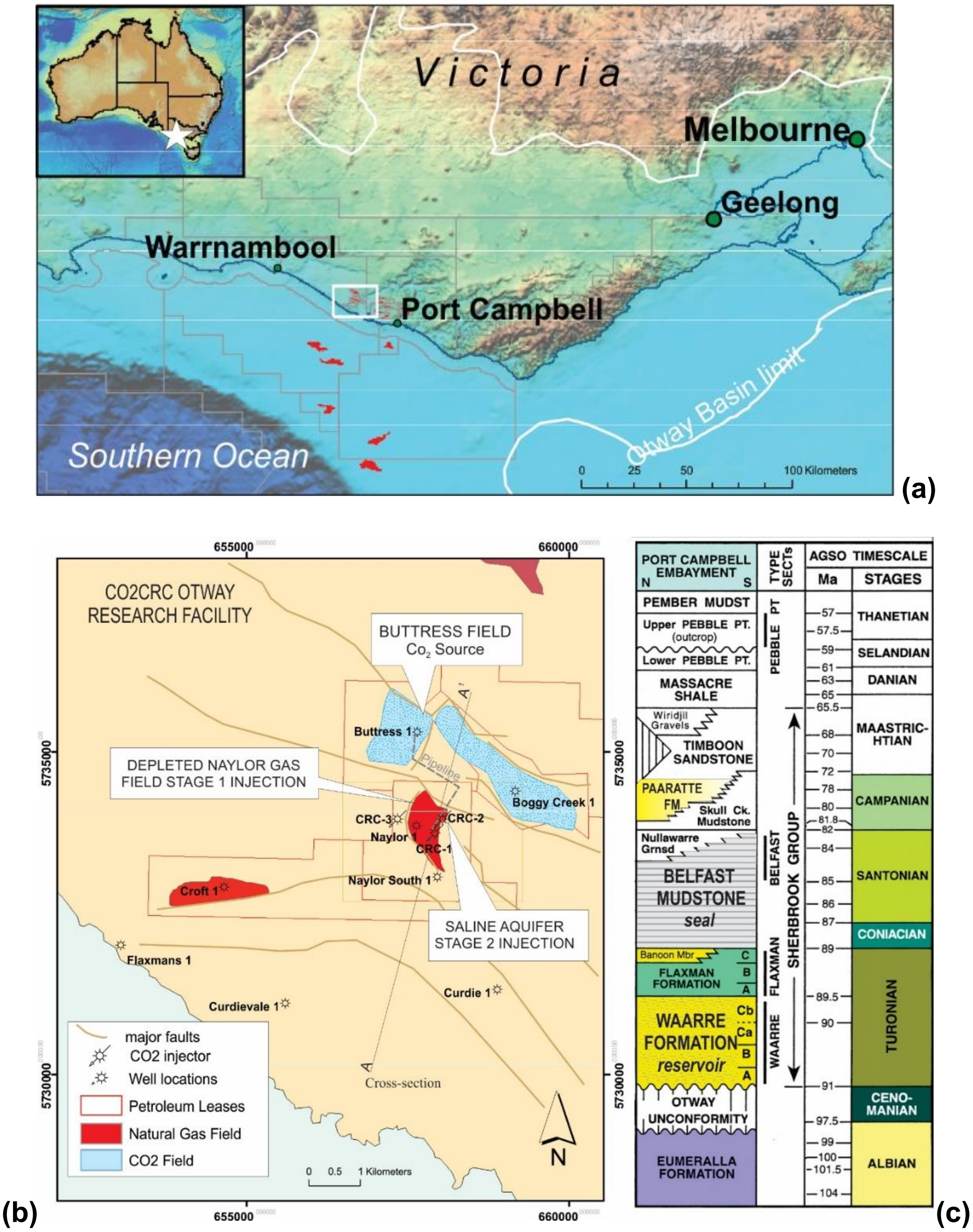


Figure 1: (a) Regional setting of the Otway Research Facility in the Port Campbell Embayment, (b) site location, and cross-section location in figure 2 also shown, (c) stratigraphy of the CO2CRC Otway Project, stratigraphic column modified from Partridge, (2001).

The four papers I have included detail the reservoir characterisation and static modelling through various progressive stages of the project's development, from pre-feasibility, to injection, through to storage and monitoring in an on-shore location. My research has involved planning all the wells at the site, including designing the coring and formation evaluation programs, and selection of perforation intervals in order to reduce risk and maximise the scientific benefit. The aim of this thesis is to highlight the differences between conventional characterisation and modelling for oil and gas, and to show the different data that should be prioritised at a CO_2 storage site.

This research has the distinction that the geological interpretations and conceptual depositional models have been tested under controlled conditions in the field. The time-lapse monitoring data was used for calibration, static models were updated, and the site characterisation process further refined. Furthermore, the research was able to compare site characterisation of two separate formations that were targeted with distinctly differing storage mechanisms dictating the containment. The two case examples presented are: a) a small structural trap in a depleted gas field with a legacy database resulting from mature petroleum exploration and production; and b) a large, open saline aquifer with very limited reservoir data where capillary and dissolution trapping dominate the storage concept (Figure 2). I present observations of the impact that vertical permeability has on residual trapping. My conclusions, based on the monitoring data which includes saturation profiles from time-lapse pulsed neutron logging, highlight the need to understand geological heterogeneity in relation to the propagating plume pathway for improving modelling hysteresis and the capacity estimation. Finally, I demonstrate that the most valuable characterisation information can result from the post-injection data; which is essential for updating models to enhance reservoir management.

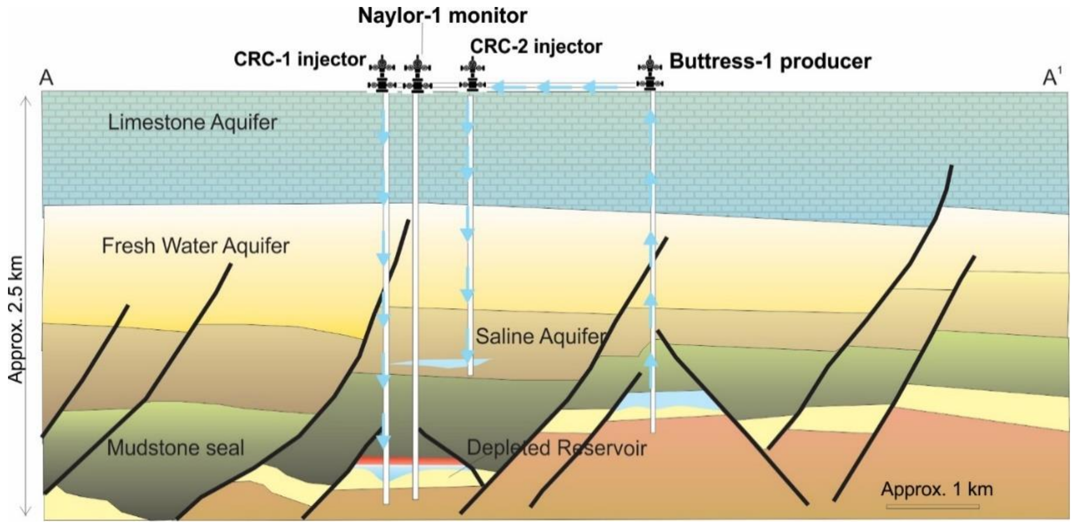


Figure 2: Schematic cross-section through site showing stage 1 injection into a depleted gas field in the Waarre Formation, and stage 2 injection into an overlying saline aquifer of the Paaratte Formation.

These publications have been important for others around the world contemplating this type of project because they show that valuable insights may be used to improve site characterisation during and after injection. This is particularly important for predicting the long-term evolution and stabilization of injected CO_2 which in turn will influence enduring monitoring strategies and the potential transfer of liability for a site.

In the following paragraphs I summarize the key points of the papers that constitute my thesis and how each manuscript is linked.

Paper 1

In the first publication I outline the life cycle of a CCS project and explore how characterisation evolves from early site selection through to operation. This paper covers the workflow used at the Otway Site for Stage1 (Injection storage and monitoring in a depleted gas field). It provides an introduction to the role of geoscience in a real project, and how it has underpinned all research outcomes (e.g. Jenkins et al., 2012; Underschultz, et al., 2011).

The workflow is broken down into a three stage process: 1) prospecting stage: site characterisation using available data, 2) pre-injection modelling stage: acquisition and integration of new data and construction of detailed depositional reservoir models, and 3) post-injection modelling stage: using field observations to calibrate models. The first models presented in this paper were designed to cover a huge range of geological uncertainty due to lack of data, but uncertainty was reduced using a targeted data acquisition program during drilling of CRC-1 (Dance et al., 2009). Improvements to the pre-injection models are then compared with the monitoring results and subsequent breakthrough observations.

This paper is unique in that many other published site characterisation workflows available at the time were mainly focused on regional scale site assessment or the prefeasibility stage; and publications from other pilot sites did not necessarily detail their site selection and characterisation workflow (see literature review for more information). It also showed that site characterisation should be an integration of many discipline areas across of number of scales, and modelling should cover a range of cases to improve insight into the impact of uncertainty. A final conclusion was that site characterisation of a depleted gas field is no less rigorous when establishing the same structural trap that held methane is suitable for containing the injected CO_2. Although the containment mechanisms may be similarly exploited, the geomechnical stresses that accompany injection operations, and the geochemical interactions that result from CO_2 dissolved into formation water must be considered.

Paper 2

The second paper is included next to provide a comparison of site characterisation as it deals with storage in a deep saline aquifer. In contrast to the storage concept in paper 1, in this setting containment of the CO_2 relies on non-structural trapping mechanisms such as capillary, residual, and dissolution trapping. This paper has a focus on the common issues encountered when modelling saline aquifers, which are often large basin-scale reservoirs, with limited databases. Saline aquifer storage sites work on the principal of trapping CO_2 along long migration pathways and are often in the scale of 100s of kilometres. Reservoir geometry and heterogeneity at centimetre-scale will influence the migrating CO_2. However, in such sites distribution and extent of reservoir bodies and shale baffles are often highly uncertain. In my example from the Otway Stage 2 (injection and monitoring in a saline aquifer), the Late Cretaceous Paaratte Formation is targeted. The area of investigation is an order of magnitude larger than the Naylor Field studied in paper 1 yet only 15% the volume of CO_2 is proposed for injection in this stage (15 kt versus 100 kt). This goes to the nature of storage in an open system, and has implications for commercial scale projects contemplating this type of reservoir. For example, there will no doubt be increased lead-times and economic investment needed to prove up such vast sites.

In this paper I also demonstrate that reservoir characterisation is not a new science, drawing on tried and tested practices such as sequence stratigraphy, advanced geophysical mapping, formation evaluation, and analogue studies long used in the oil and gas industry. Understanding subsurface fluid behaviour at a CO_2 storage site uses the same methods but place a particular emphasis on characterising effects of vertical permeability, large scale hydrodynamics (Hortle et al., 2013), geochemical interactions, and long term containment. The static geological model is the basis for all these analyses and in my example I show how it is central to decision making such as perforation location, and injection rates. Furthermore, in this paper I show that static modelling needs to be suitable for different modelling domains such as: 1) dynamic simulation; 2) fault seal risking (Tenthorey et al., 2014; Ziesch et al, 2015); and 3) rock physics simulation of seismic response (Caspari et al., 2015; Lebedev et al., 2013). So particular emphasis needs to be placed on designing models that are fit for each purpose.

Paper 3

My initial results in paper 2 show a strong correlation between the depositional facies of the Paaratte Formation and reservoir quality (porosity and permeability). In this third paper I further challenge the hypothesis these properties are influential for CO_2 storage. I test if absolute porosity and permeability, as well as the small-scale geological features characterised in paper 2, are major contributing factors to residual trapping. Modelling has shown that residual or capillary trapping can make an important contribution to immobilising injected carbon dioxide at a geological storage site (Ideet al., 2007; Saadatpoor et al., 2009 & 2010); but there is a need to characterise this at various scales. Single well tests can address that need at an intermediate scale (Zhang et al., 2011). Paper 3 discusses the observations of the micro-scale pore trapping of CO_2 observed in core flood tests from the Paaratte Formation and compares this to the field observations from the Otway 2B residual saturation and dissolution single well test. I interpret results from time-lapse pulsed neutron logging to understand the detailed geological characteristics that may impact the amount of CO_2 that remains after imbibition. This naturally leads to a review of the logging technology to better understand the results (presented in supplementary publication 1). I find that the correlation between initial and final saturation from the well test measurements gives a similar fit to a Land coefficient derived from the laboratory measurements. The residual trapping is a function of the initial saturation achieved and is only somewhat sensitive to porosity and permeability, the most influential geological property being facies grain sorting and vertical permeability. What is a key influencing factor is the spatial distribution of the heterogeneity in relation to the direction of the migrating CO_2 flood front. Small laminae can from barriers or baffles to flow, which in turn produces build-up of the non-wetting phase during drainage. The increased initial gas saturation that is a consequence of this build up, results in higher residual saturation during imbibition. This important observation, confirmed in both the core-scale laboratory measurements and the well bore-scale test, is then considered in the final paper at the field-wide scale.

Paper 4

Paper 4 details what can be learned from post-mortem reservoir characterisation at the field-scale. The Otway Stage 2C experiment involved injection, storage, and monitoring of 15 kt of CO_2 rich gas into the Paaratte Formation using the same well that was analysed in paper 3. The objective of this test was to use 4D seismic techniques to detect and monitor greenhouse gas storage in a deep aquifer and confirm the ensuing plume stabilization (Pevzner et al., 2013). The pre-injection predictions relied on the interpretation that an extensive intra-formational baffle, above the perforated zone, would impede vertical migration of the CO_2 allowing it to spread laterally and be stabilised and contained by capillary and dissolution trapping. An up-scaled prediction from what was observed in paper 3. The conceptual geological model was based on sequence stratigraphic principals used to correlate a series of 4^{th} order parasequence flooding surfaces across the study site as outlined in paper 2. Some residual uncertainty remained about the continuity of these sequences and sealing properties within the inter-well region. Similarly, there was a wide range of probability for the interconnectivity of sand facies between wells given the extremely heterogeneous nature of the formation.

In this paper the geological model is compared against field observations from three monitoring modalities: pressure, pulsed-neutron logging, and 4D seismic, for the period spanning injection and 12 months after injection ended. Deterministic modelling is then performed to match bulk reservoir properties, plume distribution from seismic images and vertical saturation profiles. The south-eastern progress of plume development, as seen on the time-lapse seismic, has led to a review of the structural interpretation and horizon-fault geometry represented in the models and has illuminated the extent of splay faults previously unresolved on the baseline seismic. Pressure data from several injection events has been used to refine the characterisation of the average horizontal permeability of the reservoir zone, and the vertical permeability of the intra-formational baffle. It has also been used to infer near-field bounding conditions of the interior splay fault. Saturation profiles interpreted from pulsed-neutron logs at the injection and monitor wells shows a preference for higher saturations occurring in a high permeability distributary channel penetrated by each of the wells. This reduces uncertainty in modelling connectivity of this facies between the wells. Most importantly, data from all the monitoring modalities has provided further evidence to support the interpretation of the parasequences, presented in paper 2, as being continuous across the site, and added confidence that the associated flooding surfaces provide a sufficient barrier to prevent vertical flow.

Thus the injection of CO_2 has indeed “illuminated the geology”, and reduced prior uncertainties about the geological structure and the distribution of permeability. This has been used to refine the static and dynamic models for other future projects planned for the site (Jenkins et al., 2018), and in turn added assurance about the long-term stabilization of the CO_2 plume.

Summary

The case study presented in this collection of publications, describes the targeted data acquisition and analysis employed at the CO2CRC Otway Project where CO_2 storage has been demonstrated in: 1) a depleted gas field, where structural trapping is the dominant containment mechanism; and 2) a saline aquifer where residual trapping will contain the CO_2. Comparisons are made of the drilling program, core analysis, and formation evaluation conducted for both storage options. Additionally, the integration of data at various scales has been explored. All the papers form a common thread outlining the principals of site characterisation and geological modelling for CO_2 storage from the core to well-bore to field scale. Specifically the main goal is to articulate the lessons learnt from conducting a pilot scale project, and the role modelling and characterisation plays in reducing risk at a CCS site. The results of this thesis is an entire workflow that can be applied to larger commercial projects elsewhere. Therefore, the research forming this thesis has substantial economic and environmental significance to Australia and has further application world-wide.

Supplementary publications

In Chapter six I include two additional publications I have written during the period of candidature, where I have been the first or sole author. These are not included in the main thesis so as not to interrupt the common thread, but they support the body of published work of the thesis topic. They complement the main publications by providing extra technical background to the monitoring modalities discussed or provide more details on the overall Otway Project research.

Supplementary publication 1 is a chapter from an industry published, peer reviewed, book. It details the technical application of pulsed neutron logging as presented in paper 3. Assessment of the application to CO_2 monitoring conditions is directly relevant to the interpreted results of publication 3. Supplementary publication 2 is a chapter in the Otway Project book (Cook et al., 2014). It is an expanded version of publication 1, and is included to add information about the characterisation priorities and how they related to the project objectives. It also shows how the project was a result of many multidisciplinary studies where the geological component was integral.

Chapter 2: Literature Review

Introduction

This literature review explores the published work behind the rationale for the research and the gaps that may be addressed. The first topic tracks the literature that has shown that carbon dioxide (CO_2) is the main greenhouse gas responsible for global warming and hence the motivating factor for mitigating emissions. The history of carbon capture and storage (CCS) research and development as a means for reducing greenhouse gas is thus explored, with particular emphasis on characterising site capacity and the development of reservoir characterisation tailored specifically for geological storage of CO_2. Also presented is a review of the pursuit of CCS in Australia that lead to the initiation of the CO2CRC's Otway Project as a means of demonstrating its safety and monitorability. Finally, learnings are compared from other similarly sized demonstration projects conducted elsewhere, with a focus on the literature that present geological characterisation efforts.

The link between fossil fuel use and global warming

The first recorded use of the term "greenhouse effect" was in 1822, when French physicist Joseph Fourier produces his analytical theory of heat. In it he writes: "*The temperature* [of the Earth] *can be augmented by the interposition of the atmosphere, because heat in the state of light finds less resistance in penetrating the air, than in re-passing into the air when converted into non-luminous heat.*" (Fourier, 1822). In 1896, Swedish chemist Svante Arrhenius concludes that enhancement of the greenhouse effect will result from coal burning in the industrial-age (Arrhenius, 1896). His predictions that a doubling of CO_2 due to fossil fuel burning would lead to temperature increases of 3 to 4 °C, are very close to the predictions from current day sophisticated computer modelling (Hansen et al., 2006; Solomon et al., 2007; Smith et al., 2007). In 1938, by analysing records from 147 weather stations around the world, British engineer Guy Callendar showed that temperatures and CO_2 levels had indeed risen over the previous century (Callendar, 1938). But this link was widely dismissed by meteorologists as coincidence until 1975, when US scientist Wallace Broecker showed the links between abrupt changes in ocean temperatures and the carbon cycle. He introduced the term "global warming" into the public domain in the title of his *Science* paper (Broecker, 1975).

In 1988 the intergovernmental panel on climate change was established to review scientific, technical and socio-economic information produced worldwide, and in 1990 the IPCC produced its First Assessment Report (IPPC, 1990). It concluded that temperatures have risen by 0.3-0.6 °C over the last century, that humanity's emissions are adding to the atmosphere's natural complement of greenhouse gases, and that the addition would be expected to result in warming. In 1995, the IPCC's Second Assessment Report concluded that the balance of evidence suggests "a discernible human influence" on the Earth's climate (IPCC, 1995). This has been called the first definitive statement linking human activity to climate change. Over more recent times, the subject of the consensus of scientific research has been widely reported (e.g. Oreskes, 2004; Cook et al, 2016); and in the IPCC's fifth assessment report it concludes that scientists are 95% certain that humans are the "dominant cause" of global warming (IPCC, 2013).

International climate change negotiations have been focused on finding ways to introduce policy in order to reduce global emissions, mitigate the effects and encourage adaption. Political actions include the formation of the United Nations Framework Convention on Climate Change in 1992, The Kyoto Protocol in 1997, the

2009 Copenhagen Accord, the 2010 Cancun Agreement, and the Paris Agreement which entered into force on 4 November 2016 (King, 2009: King et al., 2011; Willett et al., 2009; Bodansky 2010; Ghezloun et al, 2017). In 2016, coal's share of global primary energy consumption fell to 28.1%, the lowest share since 2004 (BP, 2017). However, fossil fuels, including oil and natural gas, continue to meet more than 80% of global primary energy demand, and CO_2 from fossil fuel combustion still accounts for over 90% of energy-related emissions (IEA, 2017). The continued demand for fossil based energy will mean that carbon capture and storage (CCS) will need to play a major part in reducing emissions, along with energy efficiency and increasing the share of non-fossil based fuel consumption, if political targets are to be met.

A brief history of Carbon Capture and Storage as a mitigation measure

The use of deep geological injection of CO_2 as a mitigation measure for climate change did not appear in the literature until 1992 (Huurdeman, 1992; van der Meer, 1992; Hendriks and Blok, 1993). Although earlier Baes et al. (1980) had proposed that CO_2 from coal fired power plants could be separated and captured requiring a substantial fraction of the energy content of the fuel. The paper also recommended that the disposal would be best in the deep ocean. Prior to that, CO_2 injection was only considered in its usefulness for enhance oil recovery (EOR). This concept first appeared in the literature in the early 1950s (Martin, 1951; Johnson et al., 1952; Holm, 1959), and the first field-wide application was in the United States in 1972 in the West Texan Permian Basin (Kane, 1979). This application showed CO_2 transport and injection was technically feasible, and was logical where the revenues exceed the costs, but the economic challenges were seen as a potential barrier for global uptake of CO_2 capture and disposal purely for greenhouse gas abetment. Turkenburg, (1992), proposed that "CO_2 removal" would first take place in countries where there is high social awareness of the greenhouse problem, that have implemented a high carbon tax, and that can recover and store CO_2 at relative low cost.

Indeed all of these conditions were the driver of the first, and longest running CCS project in the world. In 1991 the Norwegian government introduced a tax of 40 $(US) per tonne on emissions, and in 1996 Statoil began to develop CO_2 separation and storage at the Sleipner Vest gas field in the North Sea in order to avoid the tax on emissions from the field which has 9% CO_2 (Korbol & Kaddour, 1995; Chadwick et al., 2000). The CO_2 is separated at an off-shore treatment platform and injected into the Utsira Sandstone ~1,012 m below sea level. The project has been injecting around 1 million tonne per annum to date and the lessons learnt have been presented in the world's first "Best Practice Manual" by Chadwick et al. (2006) (Table 1), with much focus on the use of time-lapse seismic methods for monitoring and verification of the plume (Arts et al., 2004; Chadwick et al., 2005).

The next large scale CCS project to be conducted in the world similarly had an economic incentive. In 1997 the Dakota Coal Gasification Company plant in North Dakota, United States, began to send CO_2 through a 320 km pipeline to the Weyburn EOR field in Southeastern Saskatchewan, Canada. It was predicted that the use of CO_2 and alternating water floods would add 25 years to the life of the field (Wilson & Monea, 2004). Current projections show that 155 million gross barrels of incremental oil are slated to be recovered by 2035 and the field is predicted to be able to store 30 million tonnes of CO_2 (GCCSI & PTRC, 2014). Weyburn was also the host site of the IEA GHG R&D Programme international research project on CO_2 storage from 2000 to 2012 (White et al., 2004; Wilson & Brown, 2007). Its contributions include another best practice manual (Rostron & Whittaker, 2011) but this time with emphasis on conducting a project in an onshore environment where wellbore integrity is a risk and geochemistry, water, and soil monitoring is essential for demonstrating and defending containment (PTRC, 2011; Law et al., 2005; Bowden et al., 2013; Nickel et al., 2011; Jensen et al., 2013).

Other significant large scale[1] projects with dedicated geological storage that have made a contribution to our understanding of CCS include: the In Salah Gas joint venture project, with BP, Sonatrach and Statoil Hydro in central Algeria, which involved the injection of up to 4,000 tonne per day of CO_2 into a tight gas reservoir (Wright, 2007; Ringrose et al., 2013); the Norwegian Snøhvit CCS project in the Barents Sea which begun in April 2008 (Freund, 2007; Frederiksen and Torp, 2007); the Quest project in Alberta, Canada, which as of July 2017 had captured and stored two million tonnes of CO_2, and the Illinois Basin Decatur Industrial CCS project, which commenced injection in November 2011 (Finley et al, 2013). The commonality of all these projects lies in either an economic or legislative incentive, or significant investment from government. The reasons most commonly cited for delayed or cancelled projects are either concerning community opposition (Feenstra et al, 2010; Voosen, 2011) or a lack of a business case (Folger, 2013). The belief in the private sector is that in the absence of economic incentives, or a carbon tax, CCS is both costly to install and, once in place, has increased operating costs. There are presently 21 large-scale CCS facilities in early stages of operation or under construction globally; these facilities have the potential to remove 37 million tonne per annum (Mtpa) of CO_2 that otherwise will be emitted to the atmosphere (GCCSI, 2017). Effective, well-

[1]Large-scale integrated CCS facilities are defined as facilities involving the capture, transport, and storage of CO_2 at a scale of: at least 800,000 tonnes of CO_2 annually for a coal–based power plant, or at least 400,000 tonnes of CO_2 annually for other emissions–intensive industrial facilities (including natural gas–based power generation) (Source: Global CCS Institute, 2017).

designed policy that includes community support and a price on carbon is essential in overcoming these barriers and enabling deployment of these large scale projects (Bachu, 2008; IEA, 2012). It has been recognised that demonstration projects go a long way to proving the technology, and potentially lowering the engineering/operational costs for projects (Herzog, 2017). Moreover, small-scale demonstration and pilots such the CO2CRC's Otway Project, which offer independent and transparent reporting of results, can be a vehicle for gathering support within the political environment, and persuading communities that it can be an effective mitigation measure (Cook, 2014; Lipponen et al., 2017). Thus these types of research and demonstration projects play an essential role in moving the CCS concept forward in a carbon constrained world.

Site assessment and characterisation for geological storage of CO_2

Ever since CCS was proposed it was recommended that sites should be carefully selected and well understood so that they meet the objectives of containing the CO_2, not only for the purpose of meeting the greenhouse gas abatement goals, but to protect the environment and communities that may be affected if a leak occurred (Hendriks and Blok, 1993; Holloway, 1997; Bachu, 2000, 2001 & 2002; White et al, 2003; Baines and Worden, 2004; Hepple and Benson, 2005; IPCC, 2005; Clark, 2006; Wilson and Gerard, 2007). Then again, site assessment in the life of a project has several stages, each with increasing data requirements and level of investigative detail: 1) The initial regional screening stage whereby a country, province, or basin is reviewed for potential sites that are then ranked according to a set of criteria; 2) the site selection stage which requires the definition of a potential project or source for which suitable candidate sites may be matched; and 3) the detailed site characterisation stage which often requires further outlay in new data to determine if a site qualifies for further commercial investment (DOE NETL, 2017).

Regional site screening

In the first decade of the 2000s there was increasing interest from Governments (provincial/state and federal) to better understand their regional, national, and even global wide storage potential (e.g. Garg et al., 2005; Schreurs, 2002; Bøe et al., 2002; Koukouzas et al., 2009). At this time there was a rise in publication of many studies contributing to the development of site selection and regional screening methodologies to establish consistency and assist decision makers with the initial stages of site prospecting. An example of one of the first global-scale assessments of prospectivity is given in Bradshaw and Dance (2005). Global geological provinces were mapped and used to compare with the regions where CO_2 emission sources occur (Figure 3). High prospectivity was associated with prospective hydrocarbon provinces due to the presence of geological properties similarly required for storage of CO_2, such as thick sedimentary sequences with porosity, and permeability, and some sort of containment mechanism. Igneous or metamorphic belts and provinces (such as continental cratons) were considered as non-prospective. While this study was useful in visualising globally areas that may be further investigated for suitable sites, it was acknowledged that detailed technical studies would be needed to prove the viability of a specific site.

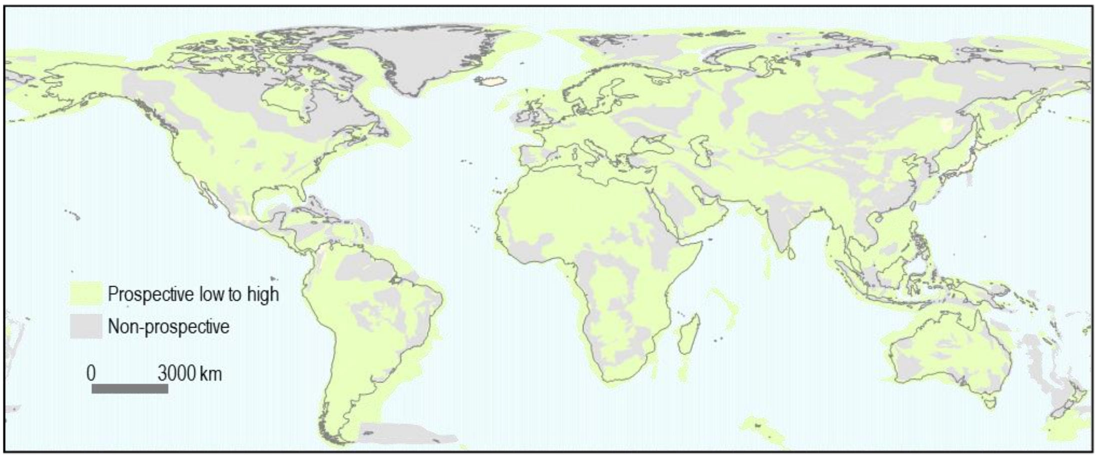


Figure 3: Global map of prospective and non-prospective regions (modified from Bradshaw and Dance, 2006)

There were also many studies looking at screening for CO_2 utilisation for enhanced oil recovery (EOR) and enhanced coalbed methane production (ECBM), as these types of projects were seen as the early adopters of CCS worldwide (Stevens et al., 2000; Reeves and Schoeling, 2001; Shaw and Bachu, 2002; van Bergren et al., 2004; Damen et al., 2005; Cawley et al., 2005). Screening was also conducted for EOR and ECBM at national scale including Japan (Yamazaki et al., 2006) and China (Yu et al., 2007). However, interest also emerged in the screening methodology for saline aquifers. The attraction is that deep aquifers are widespread, are geographically associated with fossil fuel sources, and, because it is not necessary to identify and inject directly into closed structural traps, are likely to have large storage volumes and suitable injection sites in close proximity to power-plant sources of CO_2 (Hitchon, 1996; Hitchon et al. 1999; Saylor and Zerai, 2004; Xu et al., 2004).

Two prominent publications by Bachu (2001 & 2003) looking at saline aquifer storage introduced 15 site suitability criteria. Using a parametric normalization procedure, a basin is scored against each other. The scores are summed to a total score using weights that express the relative importance of comparative differences, which lead to distinguishable order of suitability. Bachu (2003) concluded that geothermal gradients will have the biggest impact on site capacity owing to the relationship of depth and temperature on CO_2 density. At depths greater than 800 m, CO_2 density is high enough to allow efficient pore filling and to decrease the buoyancy difference compared with in situ fluids (Benson and Cole, 2008). Thus so called warm basins would be less suitable for storage and geothermal gradients may be a useful first pass screening criteria.

In Australia, the GEODISC program of the Australian Petroleum Cooperative Research Centre (APCRC) performed basin ranking and source to sink matching in a deterministic risk assessment using 5 key criteria: storage capacity, injectivity potential, site details (geographic location, infrastructure etc.), containment, and interaction with natural resources. With an assumption that some economic imperative will apply, and that emission hubs are formed, the results were that Australia may have the potential to store a maximum of 25% of total annual net emissions, or approximately 100–115 Mtpa and therefore would warrant investment in CCS research and development (Bradshaw et al., 2002). The study also showed that the most prospective areas were in the off-shore regions of the Gippsland Basin and the North-West Shelf. Other potential sites were also identified closer to emission hubs onshore, but would require detailed site characterisation to prove the capacity was sufficient (Bradshaw et al., 2003).

Site capacity assessment

The topic of capacity was often the main focus of these large regional studies with the priority to determine if a country or region would be able to meet demand and make significant reduction to emissions (van der Straaten et al., 1996; May et al., 2005; Grammer et al., 2011; Carbon Storage Taskforce, 2009; Takahashi et al., 2009; Höller and Viebahn, 2011). In response to this increased interest, the USGS developed a so-called capacity tool (Brennan and Burruss, 2003) where rather than evaluate a particular geological region to appraise how much may be stored at at a given site, the process was reversed by examining the sequestration volumes, i.e. the amount of geologic formation needed to sequester a given mass of CO_2. Obdam et al (2003) investigated a suite of different storage scenario cases, from oil, gas, and coal fields to aquifers, and analysed a series of governing factors. The authors concluded that: "*no estimate of the CO_2 storage capacity of a reservoir or formation can be made without a reservoir simulation*". However, many still insisted that so called "static" or "theoretical" capacity estimations are useful for early regional screening providing the methods and assumptions are well understood (eg. Bacchu, 2003; Newlands et al., 2006). Thus the research literature became subject to examination of the underlying methods behind the numbers. Review of estimates by the IEAGHG, (2004), found major differences in the approaches, and similarly concluded that estimates derived without detailed consideration of the input parameters were far less relaible than site specific studies. A paper by Frailey et al., (2006) called for more capacity estimation consistency, and a study by the British Geological Survey suggested that there should be a minimum requirement of input data underlying the estimates and concluded: "*No widely accepted methodology for calculating aquifer storage capacity of reservoir formations has yet been developed, and it is difficult to marshal the minimum data and other resources necessary to make a crude estimate, even in the UK, where data is comparatively easy to maintain.*" (Holloway et al., 2006).

Subsequently, Bradshaw et al. (2007) examined the various published estimates of the CO_2 storage potential at the worldwide level finding ranges in the order of 100s to 10,000s Gt CO_2, and attributed the contradictory assessments and errors in calculated storage capacity to the desire or need to make quick assessments with limited or no data. In the paper they introduced the Carbon Sequestration Leadership Forum (CSLF), an international body of technical experts formed to facilitate the development and deployment of CCS technologies via collaborative efforts that address key technical, economic, and environmental obstacles. They proposed a classification system that would define capacity estimates in the context of a “Techno-Economic Resource Pyramid” in order to reflect the level of detail behind the estimate, the scale of the estimate (regional to site specific), and the level of certainty. The CSLF follow with a paper by Bachu et al. (2007) which highlighted the challenges of capacity estimation in saline aquifers due to a lack of practical evaluation of the mechanisms that govern storage efficiency, particularly residual trapping, which Juanes, et al. (2006) showed is a function of relative permeability hysteresis. In 2008 the US Department of Energy National Energy Technology Laboratory Carbon Sequestration Program relased a clear set of defintions and formula to accompany their storage Atlases (Atlas I DOE NETL, 2007; Atlas II, DOE NETL, 2008). The method adopted a volumetric formula which uses reservior porosity, area, and thickness, combined with various efficiency terms included to account for ranges of variations in the geologic volumetric properties and the fraction of the accessible pore volume that is most likely to be contacted by injected CO_2. By introducing an efficiency factor and a monte carlo approach it was one of the first methods to assess the range in uncertainty of the estimation.

A dynamic estimation approach is proposed by Zhou et al. (2008), and shows that most importantly it is the aquifer’s boundary conditions that has the greatest impact on capacity and that closed systems are far more limited versus open systems. However, Allinson et al. (2011) point out that active pressure management (i.e. drilling pressure relief wells, injection/production strategies) can overcome this and other geological limitations. In doing so they claim capacity becomes a function of engineering and economics and propose a classification of storage resources using the SPE resource and reserves reporting equivalent terms.

Others have reviewed all these various methods for site capacity assessment (e.g.CO2CRC, 2008; Prelicz et al., 2012; Goodman et al., 2013; Bachu, 2015; Kearns et al., 2017). They all observe that significant differences exist between methods depending on the storage efficiency factors used (E), and whether they include pressure management as an option. Other differences arise whether the approach includes policy constraints; e.g. exclusion of sites in proximity to potable water; depth cut-offs; or minimum storage size. In the review by Goodman et al., (2013), it was found that assessments using the different methods, at the prospective scale, generally give similar storage capacity estimates. Statistical differences exist between closed-boundary and open-boundary methods mainly, but the results from open boundary methods are not vastly different at 95% confidence level. The main conclusion, however, was that uncertainty in underlying input parameters was of far more significance than choice of methodology, and this goes to the local nature of site characterisation priorities.

Detailed site characterisation

Local-scale storage capacity estimates and site risking requires a range of parameters that need to be collected, depending on the particular circumstances of the site (Cook, 2006). The difficulty is then to ensure in meeting those different situations that standards for storage are maintained or there is a transparent acceptance of remaining uncertainty. To this end there has been a development of a series of “Best Practice Manuals” (BPM) to assist with establishing a systematic appraisal of storage potential as regions, particularly North America, Europe and Australia grapple with regulations and establishing a benchmark for which to aspire. Some examples include policy recommendations from the International Risk Governance Council (IRGC, 2008) and the World Resources Institute (WRI, 2008) which both call for consistent siting guidelines that may be tailored to local geology. In 2011 the CO2CRC conducted a review of all BPM including the varying scales of investigation and level of technical detail (CO2CRC, 2012). These manuals ranged from a number of generic, non-site specific manuals, to learnings that are taken from explicit projects. Table 1 is summary of those BPM that specifically address recommendations for site characterisation. When compared, the reported recommendations are based on different criteria reflecting different countries with different issues. For example, North America has an emphasis on addressing well bore integrity and leakage (DOE NETL, 2017). Furthermore, for conducting site characterisation at a detailed level, all BPM paradoxically emphasise a non-prescriptive approach. The argument being that one needs to know the site specifics, the political and project objectives and tailor the efforts to be fit-for-purpose (Bruant et al., 2002).

Table 1: Literature review of Best Practice Manuals, restricted to those that specifically cover the process of initial site assessment through to simulation and modelling (table modified from CO2CRC [2012]).

	YEAR	TITLE	Pre-feasibility	Site Selection	Capacity Estimation	Simulation & Modelling
SACS/ CO2STORE	2003-2008	Best practice for the storage of CO_2 in saline aquifers	Basic	Technical	Technical	Technical
NETL (SS)	2010	Best Practices for: site screening, site selection, and initial characterization for CO_2 storage in deep geologic formations	Basic	Detailed	Technical	Basic
NETL (RA)	2011	Risk analysis and simulation for geological storage of CO_2	-	-	-	Technical
NETL (GS)	2010	Best Practices for: Geological storage formation classification: Understanding its importance and impacts on CCS opportunities in the United States.	Technical	Technical	-	-
WRI (CCS)	2008	Guidelines for CCS	Basic	Detailed	Basic	Basic
DNV	2010	Guideline for selection and qualification of sites and projects for geological storage of CO_2	Detailed	Detailed	Detailed	Basic
CO2Capture	2009	A technical basis for carbon dioxide storage.	-	Basic	Basic	-
GEOSEQ	2004	Geologic carbon dioxide sequestration: Site evaluation to implementation.	-	Basic	Basic	Basic
CO2NET	2004	CO2NET2 Work Package 7 Best Practice Review	-	Basic	Basic	Basic
GCCSI/ICF	2010	CCS ready policy: Considerations and recommended practices for policy makers.	Detailed	Basic	Basic	Basic
PTRC	2011	Best Practice Manual developed through learnings from the Weyburn Project.	-	Basic	Basic	Basic

KEY:

-	Not Covered
Basic	Briefly covered in a generic way
Detailed	Some comprehensive discussion, but generally generic
Technical	Provides technical detail of real projects, and generally comprehensive

Acronyms: SACS (Saline Aquifer CO_2 Storage), NETL (National Energy Technology Laboratory), WRI (World Resource Institute), DNV (Det Norske Veritas), CO2NET (Carbon Dioxide Knowledge Transfer Network), GCCSI (Global Carbon Capture and Storage Institute), PTRC (Petroleum Technology Research Centre), SS (Saline Storage), RA (Risk Analysis), GS (Geologic Storage).

Definitions and workflow

The international scientific community recognise 2005 as a significant year for CCS with the publication of the first dedicated volume on carbon capture and storage from the Intergovernmental Panel on Climate Change. Chapter 5 includes recommendations for fit-for-purpose storage site characterisation which is summarised as follows: "*An inter-disciplinary process of gathering and integrating all available data for the purpose of evaluating the site against the key criterion of injectivity, capacity, and containment*" (IPCC, 2005); and many others adopt this definition (for example Bachu and Grobe, 2006; Birkholzer and Tsang, 2008; Cook , 2006). However, the inclusion of the term "interdisciplinary process" leads to multiple notions of what reservoir characterisation can mean. For example the Schlumberger oil field glossary definition is as follows:

"A model of a reservoir that incorporates all the characteristics of the reservoir that are pertinent to its ability to store hydrocarbons and also to produce them. Reservoir characterization models are used to simulate the behavior of the fluids within the reservoir under different sets of circumstances and to find the optimal production techniques that will maximize the production."

This is followed by yet another definition:

"*The act of building a reservoir model based on its characteristics with respect to fluid flow.*" (Schlumberger, 2018)

These definitions have a central focus on modelling, but to a geologist reservoir characterisation often means the integration of well logs, core, outcrops and analogues, to understand sedimentary depositional environments in order to extrapolate and predict reservoir quality (Schatzinger and Jordan, 1999). To the petrophysicist it is a process of incorporating core analysis with fluid and rock chemistry for a comprehensive formation evaluation from well logs (Tiab and Donaldson, 2016). To the geophysicist the definition surrounds the use of seismic attributes and inversion, for example, amplitude versus offset (AVO) analysis, to image reservoir features (Marfurt, 2018; Robertson, 1989). Lastly, the engineer's definition is centered on dynamic flow modelling and history matching (Baker et al., 2015; Dake, 1983); and some engineering papers claim that all that is needed for predictions may be only injection or production data (e.g., Gaskari and Mohaghegh, 2007).

This demonstrates that if the process is to follow the IPCC definition, then the challenge lies in reconciling these various perspectives and sources of data that range from pore to basin scale. The problem of scale dependency and data integration/extrapolation is a well-known issue in the petroleum industry from which CCS reservoir characterisation methods have been derived (e.g. Lake and Caroll, 1986; Aminzadeh and Dasgupta, 2013). Here the approach is a pragmatic one that is risk specific, in an operational environment, with clear focus to reduce costs in production and development, and uncertainty in exploration. Fowler et al. (1999) describe the essential role of reservoir characterisation in an overall reservoir management plan, and summarise it as the integration of core data, 3-D seismic data, wireline log data, pressure data and any other data deemed "necessary" into reservoir models for use in simulation. The ultimate goal being an efficient plan that maximises the profitability of a reservoir to its operator.

In CCS we should also use pragmatism to building a "fit-for-purpose" understanding of the storage site, but the "purpose" extends further than just the field operator. We must prove up an efficient storage site, matched to a CO_2 source (volume and rate), that will be safely contained without risks to natural resources or the community, and the approach needs to be scrutinised by the regulators, experts and non-experts alike. Furthermore, the expectation is that the characterisation is sufficient enough to provide reliable prediction in the long-term before there can be transfer of liability post-closure. Ideas of what "long-term" means range from 50 years post closure (Anderson, 2017), up to 100 years or even 1000 years (IPCC, 2005; Shaffer, 2010). This presents a challenge in the reliability of long-term forecasting. Added to the challenge is that the prospective sites are often in areas with very little constraining data.

Characterising Heterogeneity

At the foundation of reservoir characterisation for fluid flow prediction, whether it be for studying oil and gas, ground water, or CO_2, is the principle that, along with gravity, heterogeneity of the porous media governs flow behaviour. Many modelling and simulation studies have established the link between reservoir heterogeneity and CO_2 plume migration and trapping capacities (Doughty and Pruess, 2004; Obi and Blunt, 2006; Bryant et al., 2006; Flett et al., 2007; Ide et al., 2007; Saadatpoor et al., 2009; Zhou et al., 2010; Hesse and Woods, 2010; Green and Ennis-King, 2010; Han et al., 2010; Gershenzon et al., 2015). A study by Hovorka et al., (2004), showed that capacity efficiency can be increased by stratigraphic heterogeneity. In a homogeneous formation, buoyant CO_2 flow paths may bypass much of the rock volume, diminishing net storage capacity. In contrast, a heterogeneous formation disperses flow paths, resulting in more of the rock volume being contacted by the injected CO_2. Ambrose et al., (2008) further explored this concept using case studies from oil and gas reservoirs, the assumption being that hydrocarbon recovery efficiency in clastic reservoirs is applicable to understanding the potential for CO_2 injectivity, migration, and storage. Elements like tortuosity of connected reservoir bodies, and distribution of baffles and seals that impede the vertical flow, can enhance containment.

However, in very low net-to-gross, highly anisotropic reservoirs, these occurrences may conversely impede injectivity and be less desirable. It stands then that a well constrained understanding of the degree of heterogeneity at a given site is essential.

A study by Gibson-Poole et al., (2002) was one of the first comprehensive papers to detail the entire methodology of characterisation heterogeneity for a saline aquifer site at the basin scale. The workflow is graphically represented in Gibson-Poole's thesis (Figure 4.1 in Gibson-Poole, 2010) a study that explores the practical application of workflows for geological storage (Figure). The workflow links the various scales of investigation and highlights the progressive phases of the project from regional screening through to post-injection. The emphasis of the geoscientific tasks is on a sequence stratigraphic approach to describing heterogeneity, which combines geophysical mapping and sedimentology to predict reservoir and seal properties and reduce uncertainty over a large-scale. This approach is similarly followed in the study of the Gippsland Basin by Root et al. (2004). By integrating core descriptions, well correlations, and geophysical interpretations to establish the paleo-depositional setting, the authors showed that likely reservoir architecture and sources of heterogeneity can be modelled to better understand the trapping mechanisms (structural and hydrodynamic) that would contribute to the storage concept. This approach, for the development of facies models, is outlined in many text books such as Allen and Allen (1990); Miall (1997); Posamentier and Allen, (1999); Boggs (2000); and Catuneanu (2006). The practice has evolved in the petroleum industry as a way to predict and correlate genetically related packages of lithology and to better represent subsurface heterogeneity as a function of the processes and preservation of depositional sediments. This was first applied to the interpretation of seismic stacking patterns in the seventies (Vail et al., 1977); and then extended to a more integrated approach including well data and outcrops in the 1990's (Van Wagoner et al., 1990).

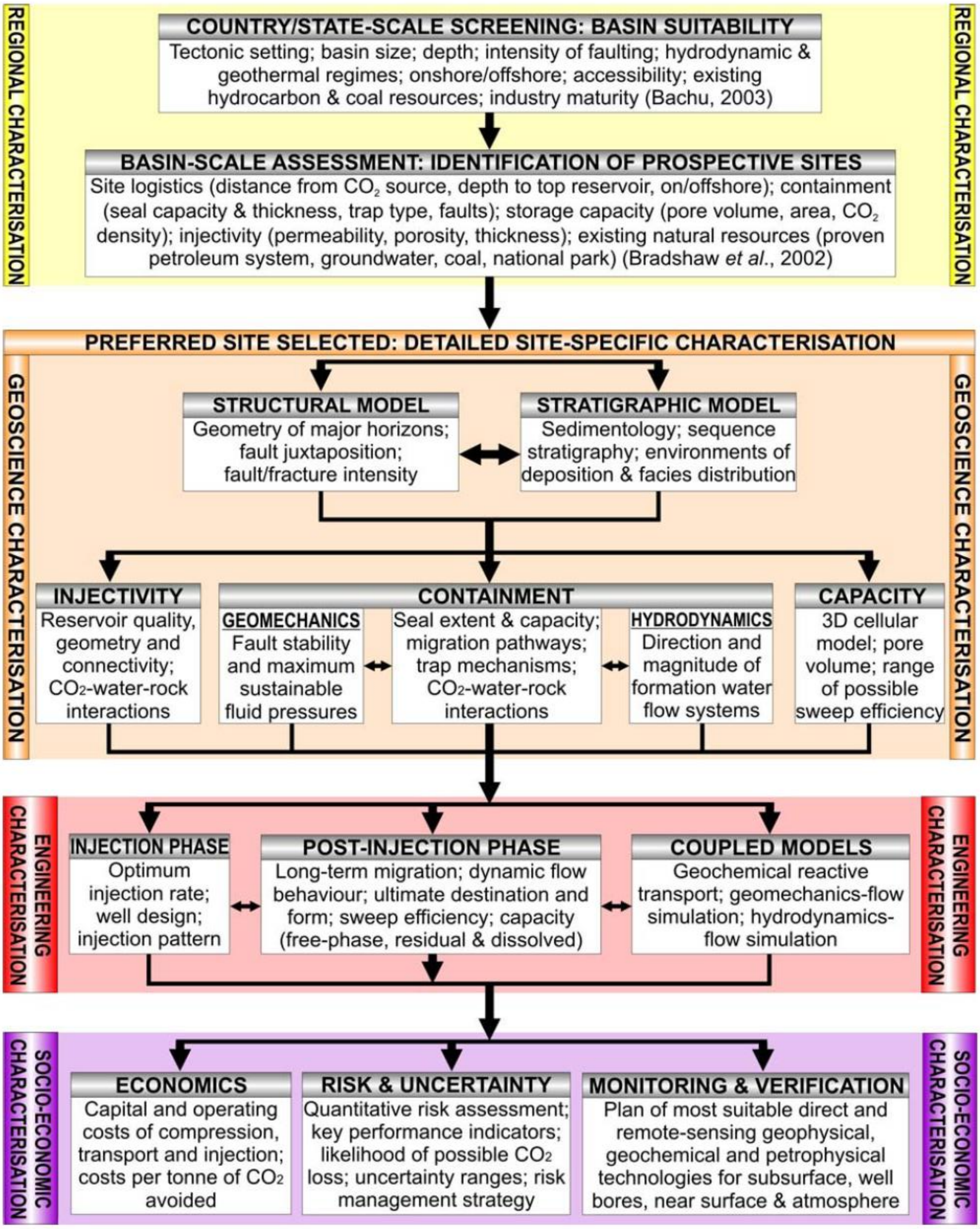


Figure 4: Workflow of CO_2 storage site characterisation (From Gibson-Poole, 2010).

Key Issues and Gaps

Characterisation for CCS, compared to petroleum exploration and production, is most notable for extending the area of investigation laterally, often over a sub-regional to regional scale, and through the overburden (and sometimes under burden), including the presence of secondary reservoirs and seals, and the location, vertical extent and connectivity of fractures and faults (Imbus et al, 2018). Issues lie with being able to characterise such enormous regions often with little constraining data (Kaldi et al., 2009). Similarly, there remains a key gap in the CCS literature that links laboratory experiments with theoretical modelling and observations from field data. Specialised core analysis (SCAL) has provided valuable data on relative permeability and displacement characteristics of CO_2-brine systems (Burnside & Naylor, 2014 and references therein). These laboratory measurements are very useful, but upscaling lab measurements in order to predict field-scale processes is still challenging (Doughty et al., 2007). Approaches to upscaling pore and core scale fluid behavior properties to the reservoir scale using "bedforms" was investigated by Trevisan et al., (2016) in a series of models, but was not confirmed in the field. Conversely, several modelling studies of convective mixing and field-scale residual trapping have been carried out (Ennis-King and Paterson, 2003; Kumar et al., 2005; Doughty and Myer, 2007; Al-Khdheeawi et al., 2017) but none of them involved a comparison to laboratory data.

In the Petroleum industry, the issues with trying to reconcile various measurements in terms of their volume scale of investigation, measurement mechanism, interpretation, and integration has been long studied. In a paper comparing well test permeabilities interpreted from drill stem tests with core plug permeability measurements from a North Sea Oil field, Zheng et al., (2000) attempted to better understand the heterogeneity of a fluvial sandstone for the guidance of reservoir models in such a system. The well test permeability interpretations were generally found to differ from the core estimates, and no consistent explanation could be found. However, the probe permeameter data, taken at much higher resolution, were able to further constrain the understanding of small-scale permeability heterogeneity and give a better match to the bulk reservoir data. There are numerous others that have used facies hierarchy as a way to try to capture this scale-dependency of petrophysical property variations (e.g., Anderson, 1989, 1991 & 1997; Davis et al., 1997; Allen-King et al., 1998; Barrash and Clemo, 2002; Gaud et al., 2004; Biteman et al., 2004; Dai et al., 2005; Ritzi et al., 2016; Soltanian and Ritzi, 2014).

These studies prove that if accuracy is desired in field scaled models, a sufficient density of measurements is essential to quantify the local reservoir heterogeneity in thin reservoir units to a reasonable level of statistical confidence. Additionally a fundamental understanding of sedimentary facies, facies associations, and hierarchical sequences is crucial. It follows that heterogeneous reservoirs will require a greater characterisation effort, and large saline aquifers, that are vast and underexplored are especially vulnerable to issues associated with data extrapolation (Michael et al., 2010).

An evaluation of global CCS projects IEAGHG (2013) suggested that the high level of geoscientific investigation required to prove up a suitable injection site, was often underestimated. This in turn often led to a lack of appreciation of the significant resources that is needed for proving up a storage site. This is perhaps particularly the case for experts in other parts of the CCS chain such as power station engineers, chemical engineers, government regulators, and finance providers who may have no direct experience in exploration for resources and may underestimate the costs involved. Similarly, vast saline aquifers require much longer lead times. It has been claimed up to 15 years of pre-exploration may be required before a saline aquifer storage site is deemed suitable (IEAGHG, 2011; Niemi et al., 2017).

In summary, the key issue for site characterisation in the development of a CO_2 storage site is to meet multiple stakeholder expectations of providing reliably detailed sub-surface models, at very large scale, in a cost effective and timely manner. Additionally, in order to prove the models are suitably constrained, they will require some sort of field calibration.

CCS demonstration and pilot projects

Pilot and demonstration projects allow for cross validation of predictions with field data under very controlled conditions. There is no strictly defined difference between a demonstration and pilot project but the terminology tends to be commonly used to describe the size of the injection (Cook, 2014); or non-integrated projects restricted to just capture or storage. There are some commercial-scale projects also termed "demonstration projects" (for example the boundary dam/Aquistore project [Stéphenne, 2014]) due to an independently funded R&D component.

The list of pilot and demonstration scale projects globally is extensive (GCCSI, 2017). There are 24 operational projects, with the United States leading the way with nine projects, and China with six. There are seven in construction, a further eight in advanced development, and 49 listed as completed (Figure 5). Four examples have been selected here to compare with this study (shown in Figure 5 and discussed below in chronological order). These are projects with injection and monitoring underway, or that have been completed. They are comparable in size to the CO2CRC Otway Project, and were all conducted with the focus on storage research. They also share the distinction of being world firsts in one aspect or another. Furthermore, all injection experiments incorporated several independent measurements for the purpose of characterising several scales of investigation which is most relevant to this research.

Figure 5: Global map of pilot and demonstration scale projects either completed, operational, or in construction/advanced development (as of January 2018). Projects with similarity to the Otway Project are: The Frio Brine Project, Texas; The Aquistore Project, Canada; CO_2SINK Project, Ketzin in Germany; and Nagaoka in Japan.

Frio Brine Sequestration Pilot

This project was conducted between 2003 and 2007 by the Bureau of Economic Geology (BEG) at the University of Texas at Austin with contributions from Lawrence Berkley National Laboratory (LBNL), Sandia Technologies LLC, US Geological Survey (USGS), and Schlumberger, and funded by the DOE's National Energy Technology Laboratory (NETL). It was the first pilot project to investigate the CO_2 sequestration process in an onshore aquifer in the Texas Gulf Coast, and the first closely monitored case study that linked predictive modelling with field observations (Müller et al., 2007; Kharaka et al., 2009; Ghomian et al., 2008; Hovorka and Knox, 2003; Xu et al., 2010; Havorka et al., 2005; Ilgen, and Cygan, 2016; Freifeld et al., 2005a). In phase 1 (Frio-I) 1600 t of CO_2 were injected into a high-permeability, high net-to-gross sandstone representative of a broad area that is an ultimate target for large-volume sequestration (Havorka and Knox, 2003). The site had two wells, the down-dip injector and a dedicated, up-dip, observation well, 30 m apart. The plume of CO_2 was monitored using a variety of hydrogeological, geophysical, and geochemical techniques, including the first use of the U-tube fluid sampling technique to obtain multi-phase samples at in situ pressures (Freifeld et al., 2005b). It was also the first project to demonstrate pulsed neutron logging as a suitable technology to monitor CO_2 saturation in high porosity saline formations (Müller et al., 2007).

Although the broad aim was to show that CO_2 can be injected into a brine formation without adverse health, safety, or environmental effects, results were also important to demonstrate the validity of conceptual and numerical models. For example, Havorka et al., (2006) showed that simulated two-phase flow processes on the trailing edge of the plume contributing to trapping and dissolution were correctly conceptualized; however the front of the CO_2 plume moved more quickly than had been modelled. The CO_2 arrived about 18 hours earlier and slightly higher than predicted by the model. The cross-well seismic tomographic images revealed a thin horizontal by-pass zone between the wells, showing that the pre-injection models inadequately represented the inter-well heterogeneity (Havorka et al., 2006).

A second injection of 380 t was competed in October, 2006 (Frio-II). This 5-day injection was at the same site as the Frio-I pilot, but 150 m deeper (Daley et al., 2007). Post-injection monitoring including more comprehensive cross-well seismic was completed in September 2007. This initial model also did not correctly estimate CO_2 breakthrough time, predicting 5 days versus the 2 days observed with U-tube sampling. These discrepancies are thought to be resulting from model simplification (Kharaka et al., 2009). The pattern of arrival of CO_2 along various seismic ray paths within the reservoir suggests strongly localised flow of CO_2 along preferential pathways.

In Doughty et al. (2007) it was shown that data collected during CO_2 injection is essential to refine reservoir models, and reservoir characterisation is an ongoing process. An updated model used the cross-well seismic images to constrain inter-well heterogeneity and it better captured the localised flow, providing an improved estimate of the CO_2 plume shape and increased lateral extent (Daley et al, 2011). The model conformance, along with no detection at surface of perfluorocarbon tracers, meant that in 2010 permission to plug and abandon both wells was received, and the Frio Brine project was the first of the CCS projects to attain site closure (CSLF, 2010).

Nagaoka

The first pilot project to be conducted in Japan was performed between July 2003 and January 2005 and involved injection of 10,400 t of CO_2 into a saline aquifer on-shore at the Minami-Nagaoka gas and oil field (Kikuta et al., 2004). The injection zone was at 1110 m and was monitored largely by well based techniques (cross-well seismic tomography; induction, sonic, and neutron logging; pressure and temperature measurements; and microseismicity) via three monitoring wells located between 40 and 120 m from the injection well (Xue et al., 2006; Sato et al., 2011). This was complemented by baseline and post-injection 3D seismic surveys (Mito and Xue, 2011).

In the early years of the project, simulation studies were performed to examine the technical feasibility of the planned injection scheme and to optimise the locations of three observation wells, as well as to examine the technical feasibility of the injection scheme (Kikuta et al., 2004). Injection was on the flank of an anticline and simulations predicted the plume to radiate in a circle outward. The observation well locations were determined based upon the numerical simulation results and placed surrounding the injection well.

During the test CO_2 was observed to migrate up-dip from the injection well and breakthrough was observed at two out of three of the observation wells after 8 months (Yamamoto et al., 2017).

In reviewing the literature about this project it seems that the focus of much of the publications generated about the project were on getting a good prediction for the geophysical response of the monitoring tools, rather than characterisation of geology or understanding flow behavior and subsurface processes. For example Xue et al., (2006) reported on the history matching of changes in sonic P-wave velocity to estimate CO_2 saturation from logs after breakthrough. Later publications then report on improvements to sub-surface characterisation with the evolution of the simplified model to one with anisotropic permeability that better explains the irregular shaped plumed (Nakajima et al., 2016; Nakajima, and Xue, 2016). In a static modelling study by Ito et al. (2015), the heterogeneity of the CO_2 distribution was explained by the distribution of mud rich sediments around the observation well that did not receive any CO_2, which is interpreted to penetrate distal depositional facies. They conclude that “genetic interpretations of the spatial distribution of mud is useful for predicting and estimating the distribution of injected CO_2 in a reservoir”. In other words, models that are used for plume forecasting should include realistic property distributions based on the paleo-depositional setting. With the exception of this paper, and two others by the same authors focused on post-injection characterisation of the mud distribution (Ito et al., 2016 & 2017), there seems to be very little focus on the pre-injection geology of the site. This impression may be partially due to the fact it is the injection result that is the focus of most of the papers in the public domain and the full extent of pre-injection characterisation that was carried out may not have been reported.

Ketzin

At the Ketzin site in the North German Basin, post-mortem studies have similarly yielded better-quality understanding of the subsurface but publications are more widely available (e.g. Wagner and Wiese, 2018; Ivanova et al., 2012; Frykman et al., 2009; Lengler et al., 2010; Lüth et al., 2015; Class et al., 2015; Chen et al., 2014). The project ran between 2004 and 2017 and included the initial site characterisation, injection and monitoring (CO_2SINK project 2004-2010), and reservoir management and monitoring (CO2CARE, CO2ReMoVe, CO2MAN projects 2010-2013), and further long-term post injection monitoring (the COMPLETE project 2014-2017). Conducted at a natural gas storage facility, it was the first geological CO_2 storage project on the European mainland (Wuerdemann et al., 2010; Giese et al., 2009). Injection of 67,000 t was at a depth of 630 to 650 m into the Stuttgart Formation via a single injector. Three deep monitoring bores are drilled into the reservoir and one shallow bore is used to monitor above the injection zone.

Publications generated by the participating research partners has been prolific (Ketzin, 2018). In contrast to research at Nagaoka, there are many papers on the geology (Förster et al., 2006, 2007 & 2009; Frykman et al., 2006; Blaschke et al., 2008), the static and dynamic modelling (Frykman et al., 2009; Lengler et al., 2010); and post-injection validation (Norden and Frykman, 2013). These form a compendium of resources that not only detail the geological characteristics of the site but also document their workflow for modelling of fluvial reservoirs and the impact of channel geometry on numerical flow predictions. The study by Norden and Frykman, (2013) emphasized the iterative nature of reservoir characterisation and discuss the progressive improvements that can be made as monitoring data became available. For example, the conceptual geological model at Ketzin was improved to match sub-surface channel orientation and geometry with seismic and electromagnetic data (Chen et al. 2014). The more realistic geological model was then used to explain the contrasted CO_2 arrivals at observation wells (Kempka and Kühn, 2013). This project was the first to publish a conformance metric for comparing models with seismic images (Lüth et al., 2015), providing a quantitative framework to judge if reservoir performance matches predictions. This is an important notion to define with respect to regulation of site closure.

The Aquistore Project.

Located in the Williston Basin, Saskatchewan, Canada, this pilot project is linked to the world's first commercial CCS project capturing and storing CO_2 from a Post-Combustion coal-fired powerplant, the Boundary Dam Power Station operated by SaskPower (Whittaker and Worth, 2011; Worth et al., 2014; Jensen and Rostron, 2014; Preston, 2015; White et al, 2017). Approximately 3,000 t of CO_2 per day is captured from flue gases, transported by pipeline and sold to oil fields in southern Saskatchewan and northern United States for EOR. The Aquistore injection site, 2 km west of the Boundary Dam Power station, provides a buffer during times of low demand, storing on average 500 t per day in a siliclastic, hyper-saline, formation at a depth of ~3.3 km. There is a cased observation well offset 150 m from the injection well drilled to similar depth. The Petroleum Technology Research Center (PTRC) conduct the research component of the project, which includes reservoir characterisation and modelling (Cheong et al, 2014; Rostron et al., 2014; Peck et al., 2014; White et al., 2016), geomechanical modelling (Stork et al., 2018), groundwater and soil gas sampling (Klappstein and Rostron, 2014;), repeat pulsed neutron logging (Hawkes et al., 2018; Kennedy et al., 2018), 4D seismic monitoring (utilizing a permanent seismic array) (White et al., 2015), vertical seismic profiling (Harris et al., 2016), and passive seismic monitoring (Verdon et al., 2016). Injection began in April 2015 with widely fluctuating injection rates due to the sporadic nature of everyday operations (Chalaturnyk et al., 2018). As of November, 2017, ~110,000 t of CO_2 has been stored at Aquistore (Nickel et al., 2018).

Reservoir characterisation was initially based on cores (conventional and side-wall plugs) and well logs, and a static model was produced using stochastic methods to estimate porosity and permeability between the wells (Rostron et al, 2018). The initial dynamic model predictions specified breakthrough would occur in the observation well, one month after the start of injection (Hawkes, et al., 2018). Detection of CO_2 via the observation well's fluid recovery system show first indications of plume arrival (in the form of aqueous CO_2) in July, 2015, two months later than predicted (Worth et al., 2017). Interpretation of plume arrival from the pulsed neutron logging (which only responds to free CO_2), was in-between the December, 2015 and February, 2016 surveys (seven to nine months later than predicted). This agrees well with interpretations from the seismic monitoring which showed an impedance anomaly at the observation well in early February 2016 (nine months later than predicted) (Hawkes et al., 2018).

Subsequent 3D seismic characterisation, using quantitate inversion by White et al. (2018) has shown that seismic-based mean porosity are 14-16% higher than those measured at the injection well, and reservoir thickness and quality follows a strong NNW directional trend related to basement structure. This is in the opposite direction to the observation well which is offset NE to the injection well. The enhanced plume flow away from the observation well following the higher porosity trend is the most likely explanation for the discrepancies of later breakthrough than was predicted.

Summary

A commonality shared by these projects is that modelling consistently underestimates the speed at which the leading edge of the plume travels, both during the injection phase (under viscous forces) and post-injection phase (under buoyancy forces). Breakthrough was early at most projects' observation wells. The source of discrepancies between predicted flow dynamics and observations of plume migration in the field were discussed in a recent review paper by Bui et al., (2018). The authors concluded these inconsistencies can be attributed small-scale geological features that can manifest in the reservoir at larger scales with significant impacts on flow (Li and Benson, 2015; Rabinovich et al., 2015) and trapping (Saadatpoor et al., 2010; Mekel et al, 2015; Krevor et al., 2011).

Where breakthrough was late (Aquistore) or missed an observation well completely (one of the wells at Nagaoka) it appears that reservoir anisotropy was not appropriately captured in the simulations until after some monitoring data was incorporated. In a review paper by Imbus et al., (2018), the authors observe that the development of a static (computer based) geological model does not seem to have been regarded as an essential early step in all projects. Furthermore, in many cases where the characterisation of the injection site geology is mentioned it is a description of the reservoir properties, as known from the existing data that is discussed rather than the process of site characterisation itself.

Perhaps due to constraints in time, or availability of data, fully integrated reservoir characterisation seems to be performed in late stages of projects, or even following injection. For example, at Aquistore the seismic inversion would have been useful to decide on a more optimal location of the observation well before it was drilled (White et al., 2017 and 2018). Early seismic characterisation was more focused on establishing that the site would have capacity and contain the CO_2, two very important risk factors, and breakthrough at the observation well less so.

These onshore projects have shown the advantage of well-based methods for monitioring and characterisation. Fluid sampling at all of these projects has highlighted uncertainties about the process and magnitude of geochemical stabilization, in particular the amount of CO_2 that is dissolved during injection and long-term trapping (Micheal et al., 2010). However, it is not clear if these uncertainties are material to the performance of a storage facility in terms of retaining CO_2 or assuring there are no unacceptable risks. Additionally, continued logging and fluid sampling within the reservior may prove very expensive to design and conduct in an offshore project (Freund P. 2006). Most likely, investment in field based sampling of geochemical processes, while of value in research-oriented projects, will not be a priority monitoring modality at commercial projects (Hovorka and Lu, 2019).

Therefore, predicting breakthrough at observation wells with accuracy may not be a focus either.

Model conformance to other monitoring methods, however, has proven very important for site closure (e.g. at Frio and Ketzin); and updating models to match seismic images or to better explain diversion from predictions is has been vital (Reiner, 2015). This has demonstrated that site characterisation should not just be reserved to pre-feasibility decision making, but needs to be continually updated throughout the lifetime of any project.

Chapter 3: References

Al-Khdheeawi, E.A., Vialle, S., Barifcani, A., Sarmadivaleh, M., Iglauer, S., 2017. Impact of reservoir wettability and heterogeneity on CO_2-plume migration and trapping capacity, International Journal of Greenhouse Gas Control: 58, 142-158, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2017.01.012.

Allen, P. A., and Allen, J.R., 1990. Basin Analysis. Principles and Applications. Blackwell, Oxford.

Allen-King, R.M., Halket, R.M., Gaylord, D.R., Robin, M.J.L., 1998. Characterizing the heterogeneity and correlation of perchloroethene sorption and hydraulic conductivity using a facies-based approach. Water Resour. Res.: 34,. 385-396

Allinson, W. G., Cinar, Y., Neal, P. R., Kaldi, J., and Paterson, L. 2014. CO_2-Storage Capacity--Combining Geology, Engineering and Economics. Society of Petroleum Engineers. doi:10.2118/133804-PA

Ambrose, W., Lakshminarasimhan, S., Holtz, M., Nunez-Lopez, V., Hovorka, S., Duncan, I., 2008. Geologic factors controlling CO_2 storage capacity and permanence: case studies based on experience with heterogeneity in oil and gas reservoirs applied to CO_2 storage Environ. Geol., 54 (8), 1619-1633

Aminzadeh, F., and Dasgupta, S. N., 2013. Chapter 6 - Reservoir Characterization. In: Developments in Petroleum Science. Aminzadeh, F.,. Dasgupta, S.N, (eds.) Elsevier: 60, 151-189, ISSN 0376-7361, ISBN 9780444506627.

Anderson, M.P., 1989. Hydrogeological facies models to delineate large-scale spatial trends in glacial and glacio-fluvial sediments. Geological Society of America, Bullettin, 101, 501-511

Anderson, M.P., 1991. Aquifer heterogeneity – A geologic perspective. Parameter Identification and Estimation for Aquifer and Reservoir Characterization, Association of Ground-Water Scientists and Engineers, Columbus, Ohio

Anderson, M.P., 1997. Characterization of geological heterogeneity. G. Dagan, S.P. Neuman (eds.), Subsurface Flow and Transport: A Stochastic Approach, Cambridge University Press, Cambridge: 23-43

Anderson, S.T., 2017. Risk, Liability, and Economic Issues with Long-Term CO_2 Storage—A Review. Natural Resource Research, Jan Volume 26, Issue 1, pages 89-112. https://doi.org/10.1007/s11053-016-9303-6

Arrhenius, S., 1896. On the influence of carbonic acid in the air upon the temperature of the ground. Philosophical Magazine and Journal of Science, Series 5, Vol. 41, No. 251, April, 237-276.

Arts, R., Eiken, O., Chadwick, R.A., Zweigel, P., Van Der Meer, L., and Kirby, G.A., 2004. Seismic monitoring at the Sleipner underground CO_2 storage site (North Sea). In: Baines, S. and Worden, R.J. (eds.) Geological Storage for CO_2 emissions reduction. Geological Society, London, Special Publication 233, 181-191.

Australian Ministerial Council on Mineral and Petroleum Resources 2005. Carbon dioxide capture and geological storage: Australian regulatory guiding principles. Ministerial Council on Mineral and Petroleum Resources, Canberra, https://trove.nla.gov.au/work/30967080

Bach, W., Pankrath, J. William, J., (Eds.), 1980. Interaction of Energy and Climate, D. Reidel, Dordrecht: 495-519

Bachu, S., 2000. Sequestration of carbon dioxide in geological media: Criteria and approach for site selection. Energy Conservation and Management, 41(9), 953–970.

Bachu, S., 2001. Geologic sequestration of anthropogenic carbon dioxides; applicability and current issues: AAPG Studies in Geology: 47, 285-303.

Bachu, S., 2002. Sequestration of CO_2 in geological media in response to climate change: Road map for site selection using the transform of the geological space into CO_2 space: Energy Conversion and Management: 43, 87-102.

Bachu, S., 2003. Screening and ranking of sedimentary basins for sequestration of CO2 in geological media. Environmental Geology, 44(3), 277–289.

Bachu, S., Bonijoly, D., Bradshaw, J., Burruss, R., Holloway, S., Christensen, N. P., Mathiassen, O.M., 2007. CO_2 storage capacity estimation: Methodology and gaps, International Journal of Greenhouse Gas Control, 1 (4), 430-443, ISSN 1750-5836, https://doi.org/10.1016/S1750-5836(07)00086-2.

Bachu, S. and Grobe, M., 2006. Characterization of sites for geological storage of carbon dioxide. Environmental Geosciences: 13 (2), 67-70. The American Association of Petroleum Geologists/Division of Environmental Geosciences. DOI:10.1306/eg.intro0606020906

Bachu, S., 2008. CO_2 storage in geological media: Role, means, status and barriers to deployment, Progress in Energy and Combustion Science: 34 (2), 254-273, ISSN 0360-1285, https://doi.org/10.1016/j.pecs.2007.10.001.

Bachu, S., 2015. Review of CO_2 storage efficiency in deep saline aquifers, International Journal of Greenhouse Gas Control: 40, 188-202, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2015.01.007.

Baes, C.F., Beall, S. E., Lee, D.W., Marland, G., 1980. The collection, disposal and storage of carbon dioxide. In: Bach W., Pankrath J., Williams J. (eds) Interactions of Energy and Climate. Springer, Dordrecht, https://doi.org/10.1007/978-94-009-9111-8_28

Baines, S.J., and R.H. Worden, eds., 2004, Geological storage of carbon dioxide: London, Geological Society Special Publication 233, 255 p.

Baker, R. O., Yarranton, H. W., and Jensen, J. L., 2015. Chapter 11 - The Practice of Reservoir Characterization, In: Practical Reservoir Engineering and Characterization, Gulf Professional Publishing, Boston: 435-493, ISBN 9780128018118, https://doi.org/10.1016/B978-0-12-801811-8.00011-0.

Barrash, W., and Clemo, T., 2002. Hierarchical geostatistics and multifacies systems: Boise hydrogeophysical research site, Boise, Idaho. Water Resour. Res. 18-381, 10.1029/2002WR001436

Benson, S. M., and Cole, D. R., 2008. CO_2 Sequestration in Deep Sedimentary For-mations. Elements, 4, 325-331. http://dx.doi.org/10.2113/gselements.4.5.325

van Bergren, F., Gale, J., Damen, K.J., and Wildenborg, A.F.B., 2004. Worldwide selection of early opportunities for CO_2-enhanced oil recovery and CO_2-enhanced coal bed methane production: Energy: 29, 1611-1621.

Birkholzer, J., and Tsang C., 2008. Introduction to the special issue on site characterization for geological storage of CO_2. Environmental Geology 54(8):1579-1581 DOI: 10.1007/s00254-007-0938-9

Biteman, S., Hyndman, D.W., Phanikumar, M.S., Weissmann, G.S., 2004. Integration of sedimentologic and hydrogeologic properties for improved transport simulations. J. Bridge, D. Hyndman (eds.), Aquifer Characterization, Spec. Publ. SEPM, Soc. Sediment. Geol. 80, 4-13

Bøe, R., Magnus, C., Osmundsen, P.T,. and Rindstad, B.I., 2002. CO_2 point sources and subsurface storage capacities for CO_2 in aquifers in Norway. Norsk Geologische Undersogelske, Trondheim, Norway, NGU Report 2002.010, 132 pp.

Bodansky, D., 2010. The Copenhagen Climate Change Conference: A Post-Mortem. American Journal of International Law: 104(2) p. 230 - 241.

Boggs, S., Jr., 2000. Principles of Sedimentary Stratigraphy. Prentice Hall.

Bowden, A., Pershke, D., and Chalaturnyk, R., 2013. Geosphere risk assessment conducted for the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project. International Journal of Greenhouse Gas Control: 16. S276-S290. 10.1016/j.ijggc.2013.02.014.

BP, 2017. Statistical Review of World Energy, London: British Petroleum. http://www.bp.com/en/global/corporate/energy-economics/statistical-review-ofworld-energy/downloads.html. last access in March 2018.

Bradshaw, J.B., Bradshaw, E., Allinson, G., Rigg, A.J., Nguyen V., Spencer, A., 2002. The potential for geological sequestration of CO_2 in Australia: preliminary findings and implications to new gas field development. Australian Petroleum Production and Exploration Association Journal. 42(1), 24–46.

Bradshaw, J., Allinson, G., Bradshaw, B.E., Nguyen, V., Rigg, A.J., Spencer, L., and Wilson, P., 2003. Australia's CO_2 geological storage potential and matching of emissions sources to potential sinks. Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies (GHGT-6), J. Gale and Y. Kaya (eds.), 1–4 October, Kyoto, Japan, Pergamon, v.I, 633–638.

Bradshaw, J.B. and **Dance**, **T.,** 2005. Mapping geological storage prospectivity of CO_2 for the world sedimentary basins and regional source to sink matching. Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), September 5–9, Vancouver, Canada, v.I, 583-592.

Bradshaw. J., Bachu, S., Bonijoly, D., Burruss, R., Holloway, S., Christensen, N.P. and Mathiasen, O.M., 2007. CO_2 storage capacity estimation: Issues and development of standards. International Journal of Greenhouse Gas Control, 1(1), 62-68.

Brennan, S.T., and Burruss, R.C., 2003. Specific Sequestration Volumes: A Useful Tool for CO_2 Storage Capacity Assessment. USGS OFR 03-0452 available at http://pubs.usgs.gov/of/2003/of03-452/.

Broecker, W. S., 1975. Climatic Change: Are We on the Brink of a Pronounced Global Warming? Science. 189 (4201): 460–463. Bibcode:1975Sci...189..460B. doi:10.1126/science.189.4201.460.

Bruant, R., Guswa, A., Celia, M., and Peters, C., 2002. Safe Storage of CO_2 in Deep Saline Aquifers. Environmental Science & Technology: 241-245.

Bryant, S.L., Lakshminarasimhan, S., and Pope, G.A., 2006. Buoyancy-dominated multiphase flow and its impact on geological sequestration of CO_2. SPE/DOE

Symposium on Improved Oil Recovery: Society of Petroleum Engineers, Tulsa, Oklahoma, USA, 22–26 April.

Bui, M., Adjiman, C. S., Bardow, A., Mac Dowell, N., et al., 2018. Carbon capture and storage (CCS): The way forward. Review Article, Energy & Environmental Science 11(Part A), March, 11, 1062-1176. DOI: 10.1039/c7ee02342a

Burnside, N.M., and Naylor, M., 2014. Review and implications of relative permeability of CO_2/brine systems and residual trapping of CO_2. International Journal of Greenhouse Gas Control, 23: 1-11.

Callendar, G. S., 1938. The artificial production of carbon dioxide and its influence on temperature. Quarterly Journal of the Royal Meteorological Society, doi: 10.1002/qj.49706427503.

Carbon Storage Taskforce, 2009. National Carbon Mapping and Infrastructure Plan – Australia: Full Report, Department of Resources, Energy and Tourism, Canberra: http://www.parliament.wa.gov.au/Parliament/commit.nsf/($lookupRelatedDocsByID)/518FAC2BBA6C246648257C29002DB8E6/$file/NCM_Full_Report.pdf

Caspari, E., Pevzner, R., Gurevich, B., **Dance, T.**, Ennis-King, J., Cinar, T., Lebedev, M., Feasibility of CO_2 plume detection using 4D seismic: CO2CRC Otway Project case study — Part 1: Rock-physics modeling. Geophysics 05/2015; 80(4):B95-B104. DOI:10.1190/geo2014-0459.1

Catuneanu, O., 2006. Principles of Sequence Stratigraphy. Elsevier, pp 375.

Cawley, S., Saunders, M., Le Gallo, Y., Carpentier, B., Holloway, S., Kirby, G.A., Bennison, T., Wickens, L., Wikramaratna, R., Bidstrup, T., Arkley, S.L.B., Browne M.A.E., and Ketzer, J.M., 2005. 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, v.2: Geologic Storage of Carbon Dioxide with Monitoring and Verification, S.M. Benson (ed.), Elsevier Science, London, 1163–1188.

Chadwick, R.A., Holloway, S., Kirby, G.A., Gregersen, U. & Johannessen, P.N., 2000. The Utsira Sand, Central North Sea – an assessment of its potential for regional CO_2 disposal. Proceedings of the 5th International Conference on Greenhouse Gas Control Technologies (GHGT-5), Cairns, Australia, 349 – 354.

Chadwick, A., Noy, D., Lindeberg, E., Arts, R., Eiken, O., Williams, G., 2005. Calibrating reservoir performance with time-lapse seismic monitoring and flow simulations of the Sleipner CO_2 plume. 8th Greenhouse Gas Control Technologies conference (GHGT-8), Trondheim, June.

Chadwick, R.A., Arts, R., Bernstone, May, Thibeau and Zweigel, 2006. Best Practice for the Storage of CO_2 in Saline Aquifers-Observations and Guidelines from the SACS and CO2STORE Projects, http://www.co2store.org.

Chalaturnyk, R., Zambrano, G., Holderness, D., Nickel, E., Moghadam, A., and Talman, S., 2018. Dynamic Response of CO_2 Injection: Well based on Tubing and Casing Conveyed Instrumentation at the Aquistore CO_2 Storage Site, Saskatchewan, Canada. GHGT-14 21st -25th October 2018, Melbourne, Australia

Chen, F., Wiese, B., Zhou, Q., Kowalsky, M.B., Norden, B., Kempka, T., and Birkholzer, J.T., 2014. Numerical modeling of the pumping tests at the Ketzin pilot site for CO_2 injection: Model calibration and heterogeneity effects. International Journal of Greenhouse Gas Control: 22, 200-212.

Cheong, S., Kim, B-Y., Shinn, Y.J., Park, M-H., 2014. Aquifer characterization using seismic data on the Aquistore CCS project, Canada. Economic and Environmental Geology 47 (6): 625-633

Clark, J.R., 2006. Clean coal urged for CO_2 control, energy security: Oil & Gas Journal, v. 104.16, p. 35-38.

Class, H., Mahl, L., Ahmed, W., Norden, B., Kühn, M., and Kempka, T., 2015. Matching pressure measurements and observed CO_2 arrival times with static and dynamic modelling at the Ketzin storage site. European Geosciences Union General Assembly 2015, EGU, Division Energy, Resources & Environment, ERE, Energy Procedia 76, 623 - 632, doi: 10.1016/j.egypro.2015.07.883.

CO2CRC (Cooperative Research Centre for Greenhouse Gas Technologies), 2008. Storage Capacity Estimation, Site Selection and Characterisation for CO_2 Storage Projects. Canberra. CO2CRCReport No. RPT08-1001. 52pp Availble at: https://www.scribd.com/document/96564914/Storage-Capacity-Estimation-Site-Selection-and-Characterisation-for-CO2-Storage-Projects-CO2CRC-March-2008

CO2CRC (Cooperative Research Centre for Greenhouse Gas Technologies), 2011. A review of existing best practice manuals for carbon dioxide storage and regulation. A desktop study prepared for the Global CCS Institute. Availble at: https://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/publication_20110420_best-practice-manuals-co2-storage-reg.pdf

Cook, J. et al, 2016. Consensus on consensus: a synthesis of consensus estimates on human-caused global warming. Environmental Research Letters Vol. 11 No. 4, (13 April); DOI:10.1088/1748-9326/11/4/048002

Cook, P. J., 2006. Site characterization. In: Proceedings International Symposium on Site Characterization for CO_2 Geological Storage (CO2SC Symposium). Lawrence Berkeley National Laboratory, Berkeley, California, March 20-22, 2006.

Cook, P.J., 2014. Geologically Storing Carbon: Learning from the Otway Project Experience. CSIRO Publishing, 2014, available at: http://www.publish.csiro.au/pid/7317.htm#sthash.VzM4yodp.dpuf

CSLF (Carbon Sequestration Leadership Forum), 2014. Reviewing Best Practices and Standards for Geologic Storage and Monitoring of CO_2, an Initial Compilation of Standards, Best Practices and Guidelines for CO_2 Storage and Monitoring. Available at: https://www.globalccsinstitute.com/publications/report-cslf-task-force-6-reviewing-best-practices-and-standards-geologic-storage-and-monitoring-co2

Dai, Z., Ritzi, R.W., Dominic, D.F., 2005. Improving permeability semivariograms with transition probability models of hierarchical sedimentary architecture derived from outcrop analog studies. Water Resour. Res., 41 W07032, 10.1029/2004WR003515

Dake L.P., 1983. Fundamentals of Reservoir Engineering, Volume 8 1st Edition eBook Elsevier Science Published Date: 1st January 1983 ISBN: 9780080568980 Paperback ISBN: 9780444418302 Page Count: 462

Daley, T.M., Solbau, R.D., Ajo-Franklin, J.B., and Benson, S.M., 2007. Continuous active-source seismic monitoring of CO_2 injection in a brine aquifer. Geophysics 72 (5), A57-A61

Daley, T.M., Ajo-Franklin, J.B., and Doughty, C., 2011. Constraining the reservoir model of an injected CO_2 plume with crosswell CASSM at the Frio-II brine pilot, International Journal of Greenhouse Gas Control: 5 (4), 1022-1030, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2011.03.002.

Damen, K., Faaij, A., van Bergen, F., Gale, J., Lysen, E., 2005. Identification of early opportunities for CO_2 sequestration—worldwide screening for CO_2-EOR and CO_2-ECBM projects, Energy: 3 (10) 1931-1952, ISSN 0360-5442, https://doi.org/10.1016/j.energy.2004.10.002.

Dance, T., Spencer., L. and Xu, J., 2009. Geological characterisation of the Otway Project pilot site: What a difference a well makes. Energy Procedia. 1 (1), 2871-2878.

Davis, J.M., Wilson, J.L., Phillips, F.M., Gotkowitz, M.B., 1997. Relationship between fluvial bounding surfaces and the permeability correlation structure. Water Resour. Res.: 33, 1843-1854

DOE NETL (United States Department of Energy, National Energy Technology Laboratory), 2007. Methodology for Development of Carbon Sequestration Capacity Estimates. In Carbon Sequestration Atlas of the United States and Canada, (Atlas I) March 2007.

DOE NETL (United States Department of Energy, National Energy Technology Laboratory), 2008. Methodology for Development of Geologic Storage Estimates for Carbon Dioxide. In Carbon Sequestration Atlas of the United States and Canada (Atlas II).

DOE NETL (United States Department of Energy, National Energy Technology Laboratory), 2013. Comparison of publically available methods for development of geological storage estimates for CO_2 in saline formations. Technical report NETL-TRS-1-2013.

DOE NETL (United States Department of Energy, National Energy Technology Laboratory) 2017. BEST PRACTICES: Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects, 1844 National Energy Laboratory.

Doughty, C. and Pruess, K., 2004. Modeling supercritical carbon dioxide injection in heterogeneous porous media. Vadose Zone J.: 3 (3), 837-847.

Doughty, C., Myer, L., 2007. Scoping calculations on leakage of CO_2 in geologic storage: the impact of overburden permeability, phase trapping, and dissolution. B.J. McPherson, E.T. Sundquist (eds.), Carbon Sequestration and Its Role in the Global Carbon Cycle. Geophysical Monograph Series 183, American Geophysical Union, Washington: 217-237

Doughty, C., Freifeld, B. M., and Trautz, R. C., 2007. Site characterization for CO_2 geologic storage and vice versa: the Frio brine pilot, Texas, USA as a case study. Environmental Geology, 54, 1635–1656.https://doi.org/10.1007/s00254-007-0942-0

Ennis-King, J.P. and Paterson, L., 2003. Role of convective mixing in the long-term storage of carbon dioxide in deep saline formations. Presented at Society of Petroleum Engineers Annual Technical Conference and Exhibition, Denver, Colorado, 5–8 October, SPE paper no. 84344.

Feenstra, C.F.J., Mikunda, T., and Brunsting, S., 2010. What happened in Barendrecht? Case study on the planned onshore carbon dioxide storage in Barendrecht, the Netherlands. CSIRO report for the Global CCS Institute. Avalialbe at: http://www.globalccsinstitute.com/publications/what-happened-barendrecht

Finley R. J., Frailey, S. M., Leetaru, H. E., Senel, O., Couëslan, M. L., Scott, M., 2013. Early Operational Experience at a One-million Tonne CCS Demonstration Project, Decatur, Illinois, USA. Energy Procedia, Volume 37, Pages 6149-6155, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2013.06.544.

Flett, M., Gurton, R., Weir, G., 2007. Heterogeneous saline formations for carbon dioxide disposal: impact of varying heterogeneity on containment and trapping. J. Pet. Sci. Eng., 57 (1), 106-118

Folger, P., 2013. FutureGen: A Brief History and Issues for Congress. Congressional Research Service publication number 7-5700. Availble from: www.crs.gov

Förster, A., Norden, B., Zinck-Jørgensen, K., Frykman, P., Kulenkampff, J., Spangenberg, E., Erzinger, J., Zimmer, M., Kopp, J., Borm, G., Juhlin, C., Cosma, C., and Hurter, S., 2006. Baseline characterization of the CO2SINK geological storage site at Ketzin, Germany. Environmental Geosciences: 13 (3) 145-161. DOI:10.1306/eg.02080605016.

Förster, A., Springer, N., Beutler, G., Luckert, J., Norden, B., and Lindgren, H., 2007. The mudstone-dominated caprock system of the CO_2 storage site at Ketzin, Germany. Proceedings of the 2007 AAPG Annual Convention and Exhibition, Long Beach, USA, CD-ROM.

Förster, A., Giese, R., Juhlin, C., Norden, B., Springer, N., and the CO_2SINK Group, 2009 The Geology of the CO_2SINK Site: From Regional Scale to Laboratory Scale. Energy Procedia: 1 (1) 2911-2918.

Fourier, J., 1822. Théorie analytique de la chaleur (Paris). [English translation by Freeman A., 1878. The Analytical Theory of Heat. Cambridge University Press; Dover reprint, 1955].

Fowler, M.L., Young, M.A., Madden, M.P. and Cole, E.L., 1999. The Role of Reservoir Characterization in the Reservoir Management Process, Reservoir Characterization Recent Advances, Schatzinger, R., Jordan, J. (eds.) AAPG Memoir 71, 3-18

Frailey, S.M., Finley, R.J., and Hickman, T.S., 2006. CO_2 sequestration: storage capacity guideline needed: Oil & Gas Journal, 104.30, 44-46, 48-49.

Frederiksen, K.L. and Torp , T., 2007. Breaking New Ground. The Petroleum Economist Ltd – PE: Fundamentals of Carbon Capture and Storage Technology, London, September.

Freifeld, B.M., Doughty, C., Trautz, R.C., Hovorka, S.D., Myer, L.R., and Benson, S.M., 2005a. The Frio brine pilot CO_2 sequestration test—comparison of field data and predicted results. Paper presented at the science and technology of carbon sequestration: methods and prospects for verification and assessment of sinks for anthropogenic carbon dioxide, AGU Chapman Conference, San Diego, CA, 16–20 January

Freifeld, B.M., Trautz, R.C., Kharaka, Y.K., Phelps, T.J., Myer, L.R., Hovorka, S.D., and Collins, D.J., 2005b. The U-tube: a novel system for acquiring borehole fluid samples from a deep geologic CO_2 sequestration experiment. Journal of Geophysical Research, 110, B10203

Freund P. 2006. International developments in geological storage of CO_2. Exploration Geophysics 37, 1-9. https://doi.org/10.1071/EG06001

Freund, P. and Karstaad, O., 2007. Keeping the Lights on – Fossil Fuels in the Century of Climate Change, Universitetsforlaget, Norway.

Frykman, P., Zinck-Jørgensen, K., Bech, N., Norden, B., Förster, A., and Larsen, M., 2006. Site characterization of fluvial, incised-valley deposits. Proceedings CO_2SC International Symposium on Site Characterization for CO_2 Geological Storage. Lawrence Berkeley National Laboratory, Berkeley, USA, Pages 121-123.

Frykman, P., Nielsen, C. M., Norden, B., and Förster, A., 2009. Modelling and predictions in the Ketzin CO_2 storage experimental site. 13th Annual Conference of the International Association of Mathematical Geosciences IAMG09 (Stanford, CA, USA), CD-ROM.

Gammer, D., Green, A., Holloway, S., Smith, G., 2011. The Energy Technologies Institute's UK CO_2 Storage Appraisal Project (UKSAP). SPE paper 148426 presented at the SPE Offshore Europe Oil and Gas Conference, Aberdeen

Garg, A., Menon-Choudhary, D., Kapshe, M., and Shukla, P.R., 2005. Carbon dioxide capture and storage potential in India. Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), September 5–9, Vancouver, Canada.

Gaskari, M. R., and Mohaghegh, S., 2007. Fieldwide reservior characterisation based on a new technique of production data analysis: verification under controlled environment. In: SPE Eastern Regional Meeting held in Lexington, Kentucky, U.S.A., October, pp. 17-19, SPE 11120.

Gaud, M.N., Smith, G.A., and McKenna, S.A., 2004. Relating small-scale permeability heterogeneity to lithofacies distribution. J. Bridge, D. Hyndman (eds.), Aquifer Characterization, Spec. Publ. SEPM, Soc. Sediment. Geol. 80, 55-66

GCCSI (Global CCS Institute), 2017. Database of large-scale CCS projects. http://www.globalccsinstitute.com/projects/large-scale-ccs-projects. Accessed February, 2018.

GCCSI (Global CCS Institute) and PTRC (Petroleum Technology Research Centre), 2014. What happens when CO_2 is stored underground? Q&A from the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project. Published April 2014. ISBN Number 978-0-9871873-3-1

Gershenzon, N.I., Ritzi, R.W. Jr., Dominic, D.F., Soltanian, M., Mehnert, E., Okwen, R.T., 2015. Influence of small-scale fluvial architecture on CO_2 trapping processes in deep brine reservoirs. Water Resour. Res., 51 (10), 8240-8256

Ghezloun, A., Saidane, A., Merabet, H., 2017. The COP 22 New commitments in support of the Paris Agreement, Energy Procedia: 119, 10-16, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2017.07.040.

Ghomian, Y., Pope, G.A., Sepehrnoori, K., 2008. Reservoir simulation of CO_2 sequestration pilot in Frio brine formation, USA Gulf Coast, Energy: 33 (7), 1055-1067, ISSN 0360-5442, https://doi.org/10.1016/j.energy.2008.02.011.

Gibson-Poole, C.M., Lang, S.C., Streit, J.E., Kraishan, G.M., and Hillis, R.R, 2002. Assessing a basin's potential for geological sequestration of carbon dioxide: an example from the Mesozoic of the Petrel Sub-basin, NW Australia. In: Keep, M., and Moss, S.J., (eds.) The Sedimentary Basins of Western Australia 3, Proceedings of the Petroleum Exploration Society of Australia Symposium, Perth, Western Australia, 439–463.

Gibson-Poole, C. M., 2010. Site characterisation for geological storage of carbon dioxide: examples of potential sites from the North West Shelf, Australia. Thesis for the award of PhD. Issue Date: 2010, University of Adelaide, Australian School of Petroleum. Availble at: https://digital.library.adelaide.edu.au/dspace/handle/2440/63078?mode=simple

Giese, R., Henninges, J., Lüth, S., Morozova, D., Schmidt-Hattenberger, C., Würdemann, H., Zimmer, M., Cosma, C., Juhlin, C., and CO2SINK Group, 2009. Monitoring at the CO2SINK Site: A Concept Integrating Geophysics, Geochemistry and Microbiology, Energy Procedia, 1 (1), 2251-2259.

Goodman, A., Bromhal, G., Strazisar, B., Rodosta, T., and Guthrie, G., 2013. Comparison of Publicly Available Methods for Development of Geologic Storage Estimates for Carbon Dioxide in Saline Formations; NETL-TRS-1-2013; NETL Technical Report

Series; U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, 2013; p 182.

Green, C.P., and Ennis-King, J., 2010. Effect of vertical heterogeneity on long-term migration of CO2 in saline formations. Transp. Porous Media, 82 (1) (2010), pp. 31-47hovor

Han, W.S., Lee, S.Y., Lu, C., McPherson B.J., 2010. Effects of permeability on CO2 trapping mechanisms and buoyancy-driven CO2 migration in saline formations. Water Resour. Res., 46 (7).

Hansen, J. Sato, M., Ruedy, R., Lo, K.,W. Lea, D., Medina-Elizade, M., 2006. Global temperature change. Proceedings of the National Academy of Sciences Sept, 103 (39) 14288-14293; DOI: 10.1073/pnas.0606291103

Harris, K., White, D., Melanson, D., Samson, C., and Daley, T.M., 2016. Feasibility of time-lapse VSP monitoring at the Aquistore CO_2 storage site using a distributed acoustic sensing system. International Journal of Greenhouse Gas Control. 50, 248-260.

Hawkes, C.D., Sohail, G.M., and Leniuk, A., 2018. Interpretation of CO_2 Saturations in the Aquistore Observation Well using Pulsed Neutron Logs. Int. J. Greenh. Gas. Control, (submitted under review).

Höller, S., and Viebahn, P., 2011. Assessment of CO_2 storage capacity in geological formations of Germany and Northern Europe, Energy Procedia: 4, 4897-4904, ISSN 1876-6102.

Hovorka, S.D., and Knox, P.R., 2003. Frio Brine Sequestration Pilot in the Texas Gulf Coast, In: J. Gale, Y. Kaya, (eds.) Greenhouse Gas Control Technologies - 6th International Conference, Pergamon, 583-587, ISBN 9780080442761, https://doi.org/10.1016/B978-008044276-1/50093-3.

Hovorka S. D., Doughty, C., Benson, S. M., Pruess, K., and Knox, P.R., 2004. The impact of geological heterogeneity on CO_2 storage in brine formations: a case study from the Texas Gulf Coast. In: Baines, S.J., Worden, R.H., (eds.), Geological Storage of Carbon dioxide, Geological Society: 147-163, London, Special Publication 233.

Hovorka S. D., Doughty, C., and Holtz, M.H., 2005. Testing efficiency of storage in the subsurface: Frio brine pilot experiment. In: E.S. Rubin, D.W. Keith, C.F. Gilboy, M. Wilson, T. Morris, J. Gale, K. Thambimuthu, (eds.) Greenhouse Gas Control Technologies 7, Elsevier Science Ltd, 1361-1366, ISBN 9780080447049, https://doi.org/10.1016/B978-008044704-9/50150-6.

Hovorka S. D., Doughty, C., Benson, S. M., Freifeld, B. M., Sakurai, S., Daley, T. M., Kharaka, Y. K., Holtz, M. H., Trautz, R. C., Nance, H. S., Myer, L. R., and Knauss, K. G., 2006. Measuring permanence of CO_2 storage in saline formations: the Frio experiment: Environmental Geosciences, 13 (2), 105–121.

Hovorka, S., and Lu, J., 2019. Chapter 3 - Field Observations of Geochemical Response to CO_2 Injection at the Reservoir Scale, In: Newell, P., Ilgen, A. G., (eds.) Science of Carbon Storage in Deep Saline Formations, Elsevier: 25-45, ISBN 9780128127520, https://doi.org/10.1016/B978-0-12-812752-0.00003-4.

Hendriks, C.A., and Blok, K., 1993. Underground storage of carbon dioxide, Energy Conversion and Management: 34 (9–11), 949-957, ISSN 0196-8904, https://doi.org/10.1016/0196-8904(93)90041-8.

Hepple, R.P., Benson, S.M., 2005. Geologic storage of carbon dioxide as a climate change mitigation strategy: Performance requirements and the implications of surface seepage. Environmental Geology 47: 576-585

Herzog, H., 2017. Financing CCS Demonstration Projects: Lessons Learned from Two Decades of Experience, Energy Procedia:114, 5691-5700, ISSN 1876-6102.

Hesse, M., and Woods, A. 2010. Buoyant dispersal of CO2 during geological storage Geophys. Res. Lett., 37 (1).

Hitchon, B. (ed) 1996. Aquifer Disposal of Carbon Dioxide: Hydrodynamics and Mineral Trapping -Proof of Concept. Geoscience Publishing Ltd., Alberta, Canada.

Hitchon, B., Gunter, W. D., Gentzis, T., and Bailey R. T., 1999. Sedimentary basins and greenhouse gases: a serendipitous association. Energy Conversion and Management, 40, 825-843.

Huurdeman, A.J.M., 1992. Injection of CO_2 into the subsurface: Confining and abating CO_2 from fossil fuel burning - a feasible option? TNO Institute of Applied Geoscience, TNO report 91-250.

Holloway, S., 1997: Safety of the underground disposal of carbon dioxide. Energy Conversion and Management, 38(Suppl.), S241–S245.

Holloway, S., Vincent, C.J., Bentham, M.S., Kirk, K.L., 2006. Top-down and bottom-up estimates of CO_2 storage capacity in the UK sector of the Southern North Sea Basin. Environ. Geosci. 13 (2), 71–84.

Holm, L.W., 1959. Carbon dioxide solvent flooding for increased oil recovery processes: Petroleum Transactions: 216, 225–231

Hortle, A., Xu, J., and **Dance, T.,** 2013 Integrating hydrodynamic analysis of flow systems and induced-pressure decline at the Otway CO2 storage site to improve reservoir history matching. Marine and Petroleum Geology. 45(0): p. 159-170.

Ide, S.T., Jessen, K., Orr, F.M., 2007. Storage of CO2 in saline aquifers: effects of gravity, viscous, and capillary forces on amount and timing of trapping Int. J. Greenh. Gas Control, 1 (4), 481-491

IEAGHG (International Energy Agency Greenhouse Gas R&D Programme), 2004. A Review of Global Capacity Estimates for the Geological Storage of Carbon Dioxide, IEA Greenhouse Gas R&D Programme Technical Review (TR4), March 23, 2004, 27 pp.

IEAGHG (International Energy Agency Greenhouse Gas R&D Programme), 2011. Global storage resource gap analysis for policy makers. 2011/10, Sept, 2011.

IEAGHG (International Energy Agency Greenhouse Gas R&D Programme), 2013. The process of developing a test injection: Experince to date and Best practice, 2013/13, UK.

IEA (International Energy Agency), 2012. A Policy Strategy for Carbon Capture and Storage.

IEA (International Energy Agency), 2016. Energy Technology Perspectives. Paris: OECD/IEA; 2016.

IEA (International Energy Agency), 2017. CO_2 Emissions from Fuel Combustion, Paris. ISBN PRINT 978-92-64-27818-9 / PDF 978-92-64-27819-6

Ilgen, A.G., and Cygan, R.T., 2016. Mineral dissolution and precipitation during CO_2 injection at the Frio-I Brine Pilot: Geochemical modeling and uncertainty analysis, International Journal of Greenhouse Gas Control: 44, 166-174, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2015.11.022.

Imbus, S., Trupp, M., Dodds, K., Hovorka, S., Nunez, V., Jenkins, C., Benson, S., 2018. The CO_2 geologic storage (CGS) technology development experience: Applications to oil and gas reservoir management and subsurface integrity (SSI). In: Proceedings of GHGT-14, Melbourne October 22-26.

IPCC (Intergovernmental Panel on Climate Change), 1990. Climate Change: The IPCC Scientific Assessment [Houghton, J.T., G.J. Jenkins, and J.J. Ephraums (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 365 pp.

IPCC (Intergovernmental Panel on Climate Change), 1995. IPCC Second Assessment of Climate Change. Availble at: https://www.ipcc.ch/pdf/climate-changes-1995/ipcc-2nd-assessment/2nd-assessment-en.pdf

IPCC (Intergovernmental Panel on Climate Change), 2005. In:Metz, B., Davidson, O., de Coninck, H.C., Loos, M. and Mayer, L.A. (Eds.), Special Report on Carbon Dioxide Capture and Storage. Cambridge University Press, Cambridge, U.K. and New York, NY, U.S.A., 195–276 (Chapter 5).

IPCC (Intergovernmental Panel on Climate Change), 2013. Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel On Climate Change. Climate Change 2013: The Physical Science Basis. Availble at: http://www.climatechange2013.org/

IRGC (International Risk Governance Centre), 2008. Policy Brief: Regulation of Carbon Capture and Storage. Avalible at: http://irgc.org/wp-content/uploads/2012/04/Policy_Brief_CCS3.pdf

Ito, T., Nakajima, T., Chiyonobu, S., and Xue, Z., 2015. Geostatistical modelling for the spatial mud content: an application to the Nagaoka CO_2 storage site, Japan, Journal of Geological Society of Japan, Vol. 121, No. 9, p. 311-323 (in Japanese with English abstract).

Ito T.,·Nakajima T., and Xue Z., 2016. Depositional environments and characteristics of grain size and pore-throat size distributions of CO_2 storage aquifer as a controlling factor of injectivity: a case study of the Nagaoka site, Japan. Journal of the Sedimentological Society of Japan 75(1):3-15 July. DOI: 10.4096/jssj.75.3

Ito, T., Ohbuchi, A., Nakajima, T., and Xue, Z., 2017. Identifying the source of natural gamma-rays in shallow-marine siliciclastic strata and their significance for shale evaluation: A case study of the CO_2 storage aquifer at the Nagaoka site, Japan. Journal of Natural Gas Science and Engineering. Volume 46, 2017, Pages 782-792, ISSN 1875-5100, https://doi.org/10.1016/j.jngse.2017.08.034.

Ivanova, A., Kashubin, A., Juhojuntti, N., Kummerow, J., Henninges, J., Juhlin, Ch., Lüth, S., and Ivandic, M., 2012. Monitoring and volumetric estimation of injected CO_2 using 4D seismic, petrophysical data, core measurements and well logging: a case study at Ketzin, Germany. Geophysical Prospecting, 60, 957 - 973, doi: 10.1111/j.1365-2478.2012.01045.x.

Jenkins, C.R., Cook, P.J., Ennis-King, J., Undershultz, J., Boreham, C., **Dance, T**., de Caritat, P., Etheridge, D.M., Freifeld, B.M., Hortle, A., Kirste, D., Paterson, L., Pevzner, R., Schacht, U., Sharma, S., Stalker, L., and Urosevic, M.,2012 Safe storage and effective monitoring of CO2 in depleted gas fields. Proceedings of the National Academy of Sciences. 109(2): p. E35-E41.

Jenkins, C., Bagheri, M., Barraclough, P., Dance, T., Ennis-King, J., Freifeld, B., Glubokovskikh, S., Gunning, J., La Force, T., Marshall, S., Paraschivoiu, E., Paterson, L., Pevzner, R., Tenthorey, E., and Watson, M., 2018. Fit for purpose monitoring - a progress report on the CO2CRC Otway Stage 3 project. In: proceedings of, GHGT-14, Melbourne Australia, 21-24 October.

Jensen, G.K.S., and Roston, B.J., 2014. Monitoring and verification of injected CO_2 at the Aquistore site, Saskatchewan Canada: Sampling of Tertiary, Cretaceous, and Devonian aquifers to establish a baseline and continued monitoring during CO_2 injection. Energy Procedia. 12th International Conference of Greenhouse Gas Control Technologies. Austin, TX. 63, 4145-4149.

Jensen, G. K.S., Nickel, E. H., Rostron, B. J., 2013. Refinement of the Weyburn-Midale geological and hydrogeological model: Developing a better framework to determine reservoir response to injected CO_2 and subsequent CO_2 movement. International Journal of Greenhouse Gas Control: 16S, S5-S14.

Johnson, W.E., Macfarlane, R.M., Breston, J.N., and Neil, D.C., 1952. Laboratory experiments with carbonated water and liquid carbon dioxide as oil recovery agents: Producers Monthly, 17 (1) November, 18–22.

Juanes, R., Spiteri, E.J., Orr Jr., F.M., Blunt, M.J., 2006. Impact of relative permeability hysteresis on geological CO_2 storage. Water Resour. Res. 42, W12418, doi:10.1029/2005WR004806.

Kaldi, J. G., Gibson-Poole, C. M., and Payenberg, T. H. D., 2009. Geological input to selection and evaluation of CO_2 geosequestration sites, in Grobe, M., Pashin, J. C., and Dodge, R. L. (eds.): Carbon dioxide sequestration in geological media—State of the science: AAPG Studies in Geology: 59, 5– 16.

Kane, A.V., 1979. Performance review of a large-scale CO_2-WAG enhanced recovery project, SACROC Unit—Kelly-Snyder field. Journal of Petroleum Technology, February. 217–231.

Kearns, J., Teletzke, G., Palmer, J., Thomann, H., Kheshgi, K., Chen, Y. H., Paltsev, S., and Herzog, H., 2017. Developing a Consistent Database for Regional Geologic CO_2 Storage Capacity Worldwide, Energy Procedia: 114, 4697-4709, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2017.03.1603.

Kempka, T., and Kühn, M., 2013. Numerical simulations of CO_2 arrival times and reservoir pressure coincide with observations from the Ketzin pilot site, Germany. Environmental Earth Sciences, Special Issue, Pages 1-11, doi:10.1007/s12665-013-2614-6.

Kennedy, M., **Dance, T.,** Hawkes, C., Leniuk, A., Nickel, E., 2018. Interpreting CO_2 Saturation Changes from Pulsed Neutron Logs at the AQUISTORE Site, 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14 21st - 25th October, Melbourne, Australia

Ketzin, 2018. http://www.co2ketzin.de/en/publications, accessed on November 20th 2018.

Kharaka, Y. K., Thordsen, J.J., Hovorka, S.D., Nance, H.S., Cole, D.R., Phelps, T.J., Knauss, K.G., 2009. Potential environmental issues of CO_2 storage in deep saline aquifers: Geochemical results from the Frio-I Brine Pilot test, Texas, USA, Applied Geochemistry, 24 (6), 1106-1112, ISSN 0883-2927, https://doi.org/10.1016/j.apgeochem.2009.02.010.

Kikuta, K., Hongo, S., Tanase, D., and Ohsumi, T., 2004. Field Test of CO_2 injection in Nagaoka, Japan: Presented at the 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), Vancouver.

King, D., 2009. The Climate in Copenhagen. Science, 326: p. 1319.

King, D., Richards, K., Tyldesley, S., 2011. Copenhagen and Cancun, International climate change negotiations: Key lessons and next steps, Oxford, UK: Smith School of Enterprise and the Environment, University of Oxford, p. 12

Klappstein, G., and Rostron, B., 2014. Shallow hydrogeological and hydrochemical characterization of the Aquistore CO_2 sequestration site in Estevan, Saskatchewan, Canada. Proceedings of the 12th International Conference on Greenhouse Gas Technologies, Energy Procedia

Korbol, R. and Kaddour, A., 1995. Sleipner vest CO_2 disposal - injection of removed CO_2 into the Utsira Formation. Energy Conversion and Management: 36 (6-9), 509-512 ISSN 0196-8904, https://doi.org/10.1016/0196-8904(95)00055-I.

Koukouzas, N., Ziogou, F., and Gemeni, V., 2009. Preliminary assessment of CO_2 geological storage opportunities in Greece, International Journal of Greenhouse Gas Control: 3 (4) 502-513, ISSN 1750-5836.

Krevor, S., Pini, R., Li, B., and Benson, S.M., 2011. Capillary heterogeneity trapping of CO_2 in a sandstone rock at reservoir conditions. Geophys Res Lett 38:L15041. doi: 10.1029/2011GL048239

Kumar, A., Noh, M.H., Sepehrnoori, K., Pope, G.A., Bryant, S.L., and Lake, L.W., 2005. Simulating CO_2 storage in deep saline aquifers, Carbon Dioxide Capture for Storage in Deep Geologic Formations - Results from the CO_2 Capture Project, v.2: Geologic Storage of Carbon Dioxide with Monitoring and Verification, S.M. Benson, (ed.), Elsevier, London. 977–898.

Lake, L. W. & Carroll, H. B., 1986. Reservoir characterization, Proceedings of the Reservoir Characterization Technical Conference, April 29-May 1, 1985, at the Westin Hotel--Galleria in Dallas, edited by Larry W. Lake, Herbert B. Carroll, Academic Press Orlando, 659 p.

Law D.H.S., Uddin, M., and Cuthiell, D., 2005. CO_2 storage capacity predictions for Weyburn CO_2-EOR project, In Greenhouse Gas Control Technologies 7, Elsevier Science Ltd, Oxford: 2063-2067, ISBN 9780080447049, https://doi.org/10.1016/B978-008044704-9/50273-1.

Lebedev, M., Pervukhina, M., Mikhaltsevitch, V., **Dance, T.,** Bilenko, O., and Gurevich, B., 2013 An experimental study of acoustic responses on the injection of supercritical CO_2 into sandstones from the Otway Basin. Geophysics. 78(4): p. D293-D306.

Lengler, U., De Lucia, M., and Kühn, M., 2010. The impact of heterogeneity on the distribution of CO_2 : Numerical simulation of CO_2 storage at Ketzin. International Journal of Greenhouse Gas Control: 4 (6), 1016-1025. doi:10.1016/j.ijggc.2010.07.004.

Li, B., and Benson, S. M., 2015. Influence of small-scale heterogeneity on upward CO_2 plume migration in storage aquifers. Adv. Water Resources, 83, 389 – 404. ISSN 0309-1708, https://doi.org/10.1016/j.advwatres.2015.07.010.

Lipponen, J., McCulloch, S., Keeling, S., Stanley, T., Berghout, N., Berly, T., 2017. The Politics of Large-scale CCS Deployment, Energy Procedia, 114, 7581-7595, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2017.03.1890.

Lüth, S., Ivanova, A., and Kempka, T., 2015. Conformity assessment of monitoring and simulation of CO_2 storage: A case study from the Ketzin pilot site. International Journal of Greenhouse Gas Control. 329-339. DOI: 10.1016/j.ijggc.2015.08.005.

Marfurt K. J., 2018. Seismic Attributes as the Framework for Data Integration Throughout the Oilfield Life Cycle. Society of Exloration Geophysicists Distinguished Instructor Series, ISBN: 978-1-56080-351-5 p. 508.

Martin, J.W., 1951. Additional oil production through flooding with carbonated water: Producers Monthly, v. 15 (9) p. 18–22.

May, F., Müller, C., Bernstone, C., 2005. How much CO_2 can be stored in deep saline aquifers in Germany? VGB PowerTech: 85, 32-37.

van der Meer, L.G.H., 1992. Investigation regarding the storage of carbon dioxide in aquifers in the Netherlands. In: K. Blok, W.C. Turkenburg, C. Hendriks and M. Steinberg (eds.), Proceeding of the first international conference on carbon dioxide removal, 33, No. 5-8, v. Amsterdam, Pergamon , p. 611-618.

Meckel, T.A., Bryant, S.L., Ganesh, P.R., 2015. Characterization and prediction of CO_2 saturation resulting from modeling buoyant fluid migration in 2D heterogeneous geologic fabrics. Int. J. Greenhouse Gas Control. 31, 34:85-96.

Miall, A. D., 1997. The geology of stratigraphic sequences. Springer-Verlag, Berlin.

Michael, K., Golab, A., Shulakova, V., Ennis-King, J., Allinson, G., Sharma, S., Aiken, T., 2010. Geological storage of CO_2 in saline aquifers—A review of the experience from existing storage operations, International Journal of Greenhouse Gas Control, 4 (4), 659-667, ISSN 1750-5836

Mito, S., and Xue, Z., 2011. Post-Injection monitoring of stored CO_2 at the Nagaoka pilot site: 5 years time-lapse well logging results, Energy Procedia, Volume 4, 2011, Pages 3284-3289, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2011.02.248.

Müller, N., Ramakrishnan, T.S., Boyd, A., Sakruai, S., 2007. Time-lapse carbon dioxide monitoring with pulsed neutron logging. International Journal of Greenhouse Gas Control: 1 (4), 456-472, ISSN 1750-5836, https://doi.org/10.1016/S1750-5836(07)00071-0.

Nakajima, T., and Xue, Z., 2016. Trapping mechanisms in field scale: Results from Nagaoka geologic CO_2 storage site, GHGT-13.

Nakajima, T., Ito, T., and Xue, Z., 2016. Numerical simulation of the CO_2 behaviour to obtain a detailed site characterization: A case study at Nagaoka pilot-scale injection site, GHGT-13.

Newlands, I.K., Langford, R.P., Causebook, R., 2006. Assessing the CO_2 storage prospectivity of developing economies in APEC—applying methodologies developed in GEODISC to selected sedimentary basins in the Eastern Asian region. In: Gale, J., Rokke, N., Zweigel, P., Svenson, H. (Eds.), Proceedings of the Eighth International Conference on Greenhouse Gas Control Technologies. Elsevier, CD-ROM.

Nickel, E., Jensen, J., Rostron, B., 2011. Refinement of the Weyburn geological model: Overcoming challenges in data compilation and management. Energy Procedia: 4, 4785-4792, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2011.02.443.

Nickel, E., 2018. Unique Findings at a large integrated Carbon Storage Site: Lessons Learned and Ongoing Challenges at Aquistore. 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14. 21st -25th October, Melbourne, Australia

Niemi, A., Bear, J., and Bensabat, J. (Eds.) 2017. Geological Storage of CO_2 in Deep Saline Formations. Springer. 10.1007/978-94-024-0996-3.

Norden, B., and Frykman, P. ,2013. Geological modelling of the Triassic Stuttgart Formation at the Ketzin CO_2 storage site, Germany. International Journal of Greenhouse Gas Control. doi:10.1016/j.ijggc.2013.04.019.

Obdam, A., van der Meer, L.G.H., May, F., Kervevan, C., Bech, N., and Wildenborg, A., 2003. Effective CO_2 storage capacity in aquifers, gas fields, oil fields and coal fields. Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies (GHGT-6), J. Gale and Y. Kaya (eds.), 1–4 October Kyoto, Japan, Pergamon, v.I, 339–344.

Obi, E.O.I, and Blunt, M.J., 2006. Streamline-based simulation of carbon dioxide storage in a north sea aquifer Water Resour. Res., 42 (3).

Oreskes, N., 2004. Beyond the Ivory Tower: The Scientific Consensus on Climate Change. Science (306) 5702, p. 1686 (3 December); DOI: 10.1126/science.1103618.

Peck, W.D., Bailey, T.P., Liu, G., Klenner, R.C.L., Gorecki, D.C., Ayash, S.C., Steadman, E.D., and Harju, J.A., 2014. Model development of the Aquistore CO_2 storage project. Energy Procedia. 12th International Conference of Greenhouse Gas Control Technologies. Austin, TX. 63, 3723-3734.

Pevzner, R., Caspari, E., Gurevich, B., **Dance, T.**, Cinar, Y., 2015. Feasibility of CO_2 plume detection using 4D seismic: CO2CRC Otway Project case study — Part 2: Detectability analysis. Geophysics 06/2015; 80(4):B105-B114. DOI:10.1190/geo2014-0460.1

Posamentier, H. W., and Allen, G. P, 1999. Siliciclastic Sequence Stratigraphy - Concepts and Applications, published by the Society of Economic Petrologists and Paleontologists, 216 pages.

Prelicz, R.M., Mackie, E.A.V., and Otto, C.J., 2012. Methodologies for CO_2 storage capacity estimation: Review and evaluation of CO_2 storage. First Break. 302. 70-78. 10.3997/2214-4609.20144131.

Preston C., 2015. Integrated Carbon Capture and Storage Project at SaskPower's Boundary Dam Power Station. IEAGHG Report #2015-06. 63 pp.

PTRC (Petroleum Technology Research Center), 2011. IEAGHG Weyburn-midale CO_2 Monitoring & Storage Project: Response to a Soil Gas Study Performed By Petro-Find Geochem Ltd. PTRC January 20.

Rabinovich, A., Itthisawatpan, K., and Durlofsky, L.J., 2015. Upscaling of CO_2 injection into brine with capillary heterogeneity effects. J Petrol Sci Eng 134:60–75. doi: 10.1016/j.petrol.2015.07.021

Reeves, S.R., Schoeling, L., 2001. Geological sequestration of CO_2 in coal seams: reservoir mechanisms, field performance, and economics. In: Williams, D.J., Durie, R.A., McMullan, P., Paulson, C.A.J., Smith, A.Y. (Eds.), Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies. CSIRO Publishing, Collingwood, VIC, Australia, 593–598.

Reiner D., 2015. Learning through a portfolio of carbon capture and storage demonstration projects. Nature Energy 1:doi:10.1038/nenergy.2015.11.

Ringrose, P.S., Mathieson , A.S., Wright, I.W., Selama, F., Hansen, O., Bissell, R., Saoula, N. and Midgley, J., 2013. The In Salah CO_2 Storage Project: Lessons Learned and Knowledge Transfer, Energy Proc., 37, 6226 – 6236.

Ritzi, R.W., Freiburg, J.T., and Webb, N.D., 2016. Understanding the (co)variance in petrophysical properties of CO_2 reservoirs comprising fluvial sedimentary architecture. Int. J. Greenh. Gas Control, 51, 423-434, 10.1016/j.ijggc.2016.05.001

Robertson, J. D., 1989. Reservoir management using 3 - D seismic data. SEG 1988 distinguished lecture. SEG Technical Program Expanded Abstracts: pp. 897-897. https://doi.org/10.1190/1.1889809

Root, R.S., Gibson-Poole, C.M., Lang, S.C., Streit, J.E., Underschultz J., and Ennis-King, J., 2004. Opportunities for Geological Storage of Carbon Dioxide in the Offshore Gippsland Basin, SE Australia: An Example from the Upper Latrobe Group. In: Eastern Australasian Basins Symposium II EABS04; 19-22 November, Adelaide, South Australia. 367-388.

Rostron, B., Whittaker, S., 2011. 10+ years of the IEA-GHG Weyburn-Midale CO2 monitoring and storage project: Successes and lessons learned from multiple hydrogeological investigations, Energy Procedia, Volume 4, 2011, Pages 3636-3643, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2011.02.294.

Rostron, B., White, D., Hawkes, C., and Chalaturnyk, R., 2014. Characterization of the Aquistore CO_2 Project Storage Site, Saskatchewan, Canada. Energy Proc. 63: 2977–2984, doi:10.1016/j.egypro.2014.11.320.

Rostron, B., Hawkes, C., Chalaturnyk, R., and Smith, E., 2018. Multiple scales of porosity and permeability measurements at the Aquistore Project, Saskatchewan: Results, implications, and lessons learned. GHGT-14 21st -25th October, Melbourne, Australia

Saadatpoor, E., Bryant, S.L., Sepehrnoori, K., 2009. Effect of capillary heterogeneity on buoyant plumes: a new local trapping mechanism. Energy Procedia, 1 (1), 3299-3306

Saadatpoor, E., Bryant, S.L., Sepehrnoori, K., 2010. New trapping mechanism in carbon sequestration. Transp Porous Media 82(1):3–17. doi: 10.1007/s11242-009-9446-6

Sato, K., Mito, S., Hoie, T., Ohkuma, H., Saito, H., Watanabe, J., and Yoshimura, T., 2011. Monitoring and simulation studies for assessing macro- and meso-scale migration of CO_2 sequestered in an onshore aquifer: Experiences from the Nagaoka pilot site, Japan. Int. J. Greenhouse Gas Control, doi:10.1016/j.ijggc.2010.03.003.

Saylor, B. Z., and Zerai, B., 2004. Injection and trapping of carbon dioxide in deep saline aquifers. *In:* Gieri~, R. & St1lle, P. (eds) 2004. Energy, Waste, and the Environment: a Geochemical Perspective. Geological Society, London, Special Publications: 236, 285-296 doi:10.1144/GSL.SP.2004.236.01.17

Schatzinger, R. A. and Jordan, J. F., 1999. Reservoir Characterization, recent advances, AAPG Memoir 71.

Schlumberger, 2018. Oil field glossary of terms http://www.glossary.oilfield.slb.com, Accessed January 2018.

Schreurs, H.C.E., 2002. Potential for geological storage of CO_2 in the Netherlands. Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies (GHGT-6), J. Gale and Y. Kaya (eds.), 1–4 October, Kyoto, Japan, Pergamon, v.I, 303–308.

Shaffer, G., 2010. Long-term effectiveness and consequences of carbon dioxide sequestration. Nature Geoscience letter: 3, 464–467.

Shaw, J., Bachu, S., 2002. Screening, evaluation, and ranking of oil reservoirs suitable for CO_2-flood EOR and carbon dioxide sequestration. J. Can. Petrol. Technol. 41 (9), 51–61.

Smith, D.M., Cusack, S., Colman, A.W., Folland, C.K., Harris, G.R., Murphy, J.M., 2007. Improved Surface Temperature Prediction for the Coming Decade from a Global Climate Model. Science 10 Aug, 796-799

Soltanian, M.R., and Ritzi, R.W., 2014. A new method for analysis of variance of the hydraulic and reactive attributes of aquifers as linked to hierarchical and multi-scaled sedimentary architecture Water Resour. Res. 10.1002/2014WR015468

Solomon, S. Qin, D., Manning, M., Chen, Z., Marquis, M., Averyt, KB., et al. (Eds.), IPCC, 2007: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, United Kingdom, p. 996

Stork, A.L., Nixon, C.G., Hawkes, C.D., Birnie, C., White, D.J., Schmitt, D.R., Roberts, B., 2018. Is CO_2 injection at Aquistore aseismic? A combined seismological and geomechanical study of early injection operations, International Journal of Greenhouse Gas Control: 75, 107-124, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2018.05.016.

van der Straaten, R., Elewaut, E., Koelewijn, D., Baily, H., Holloway, S., Barbier, J., et al., 1996. Inventory of the CO_2 Storage capacity of the European Union and Norway, in: Final Report of the Joule II Project No. CT92-0031: The Underground Disposal of Carbon Dioxide, British Geological Survey, Nottingham: 16–115.

Stéphenne K. , 2014. Start-up of World's First Commercial Post-combustion Coal Fired CCS Project: Contribution of Shell Cansolv to SaskPower Boundary Dam ICCS Project, Energy Procedia: 63, 6106-6110, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2014.11.642.

Stevens, S.H., Kuuskraa, V.A., Gale, J.J., and Beecy, D., 2000. CO_2 injection and sequestration in depleted oil and gas fields and deep coal seams; worldwide potential and costs: AAPG Bulletin: 84, 1497-1498.

Takahashi, T., Ohsumi, T., Nakayama, K., Koide, K., Miida, H., 2009. Estimation of CO_2 Aquifer Storage Potential in Japan, Energy Procedia: 1 (1) 2631-2638, ISSN 1876-6102.

Tenthorey, E., **Dance, T**., Cinar, Y., Ennis-King, J., and Strand, J.,2014 Fault modelling and geomechanical integrity associated with the CO2CRC Otway 2C injection experiment. International Journal of Greenhouse Gas Control. 30: p. 72-85.

Tiab, D. and Donaldson, E. C., 2016. Chapter 10 - Reservoir Characterization, In Petrophysics (Fourth Edition), Gulf Professional Publishing, Boston, 583-640, ISBN 9780128031889.

Trevisan, L., Krishnamurthy, P.G., and Meckel, T.A., 2016. Impact of 3D capillary heterogeneity and bedform architecture at the sub-meter scale on CO_2 saturation for buoyant flow in clastic aquifers. Int. J. Greenhouse Gas Contr, 56: 237-49.
https://www.sciencedirect.com/science/article/pii/S1750583616303139

Turkenburg W.C.T., 1992. CO_2 Removal; Some Conclusions. Energy Conversion and Management: 33 (5–8), 819-823

Underschultz, J., Boreham, C., Stalker, L., Freifeld, B., Xu, J., Kirste, D., and **Dance, T.,** 2011 *Geochemical and hydrogeological monitoring and verification of carbon storage in a depleted gas reservoir: Examples from the Otway Project, Australia.* Int. l J. of Greenhouse Gas Control, doi: 10.1016/j. ijggc. 9.

Vail, P.R., Mitchum Jr. R.M., and Thompson, S., III, 1977. Seismic Stratigraphy and Global Changes of Sea Level: Part 3. Relative Changes of Sea Level from Coastal Onlap: Section 2. Application of Seismic Reflection Configuration to Stratigrapic Interpretation Memoir 26, 63 – 81

Verdon, J.P., Kendall, J-M., Horleston, A.C., and Stork, A.L., 2016. Subsurface fluid injection and induced seismicity in southeast Saskatchewan. International Journal of Greenhouse Gas Control. 54, 429-440.

Voosen, P., 2011. Public Outcry Scuttles German Demonstration Plant, Greenwire, December 6, http://www.eenews.net/Greenwire/2011/12/06/archive/10?terms=vattenfall.

Wagner, F.M, and Wiese, B.U., 2018. Fully coupled inversion on a multi-physical reservoir model – Part II: The Ketzin CO_2 storage reservoir, International Journal of Greenhouse Gas Control: 75, 273-281, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2018.04.009.

van Wagoner, J.C., Mitchum, R. M., Campion, K. M., and Rahmanian, V. D., 1990. Siliciclastic Sequence Stratigraphy in Well Logs, Cores, and Outcrops: Concepts for High-Resolution Correlation of Time and Facies. AAPG Methods in Exploration, 7, 55

White, C.M., Strazisar, B.R., Granite, E.J., Hoffman, J.S., and Pennline, H.W., 2003. Separation and capture of CO_2 from large stationary sources and sequestration in geological formation—coalbeds and deep saline aquifers: Journal of the Air and Waste Management Association, v. 53, p. 645-715.

White, D.J., Burrowes, G., Davis, T., Hijnal, Z., Hirsche, K., Hutcheon, I., Majer, E., Rostron, B., and Whittaker, S., 2004. Greenhouse gas sequestration in abandoned oil reservoirs: The International Energy Agency Weyburn pilot project: GSA Today: 14 (7), 4-10.

White, D.J., Roach, L.A.N., and Roberts, B., 2015. Time-lapse seismic performance of a sparse permanent array: Experience from the Aquistore CO_2 storage site. Geophysics 80(2): WA 35-WA48.

White, D.J., Hawkes, C.D., and Rostron, B.J., 2016. Geological characterization of the Aquistore CO_2 storage site from 3D seismic data. International Journal of Greenhouse Gas Control 54, 330-34.

White, D.J., Harris, K., Roach, L.A.N., Samson, C., 2017. Monitoring results after 36 ktonnes of deep CO_2 injection at the Aquistore CO_2 storage site, Saskatchewan, Canada. Energy Procedia. 13th International Conference of Greenhouse Gas Control Technologies, Lausanne, Switzerland

White, D.J., 2018. 3D architecture of the Aquistore reservoir: Implications for CO_2 flow and storage capacity, International Journal of Greenhouse Gas Control: 71, 74-85, ISSN 1750-5836, https://doi.org/10.1016/j.ijggc.2018.02.009.

Whittaker, S., and Worth, K., 2011. Aquistore: a fully integrated demonstration of the capture, transportation and geologic storage of CO_2. Energy Procedia. 10th International Conference of Greenhouse Gas Control Technologies. Amsterdam, NL. 4 ,5607-5614.

Willett, K.M., Alexander, L.V. and Thorne, P.W., 2009. Global Climate. In: State of the Climate in 2009. Bulletin American Meteorological Society: 91(7).

Wilson, M. and Monea M., 2004. IEA GHG Weyburn CO_2 Monitoring and Storage Project Summary Report 2000-04. Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, Volume III, Vancouver, http://www.ieagreen.org.uk/glossies/weyburn.pdf.

Wilson, M. and Brown, K., 2007. Weyburn provides Platform for CCS, the Petroleum Economist, London, September.

Wilson, E.J., and D. Gerard, eds., 2007, Carbon capture and sequestration: Blackwell Publishing, 296 p.

Worth, K., White, D., Chalaturnyk, R., Sorensen, J., Hawkes, C., Rostron, B., Johnson, J., and Young, A., 2014. Aquistore Project measurement, monitoring and verification: from concept to CO_2 injection, Energy Procedia: 63, 3202–3208, doi:10.1016/j.egypro.2014.11.345.

Worth, K., White, D., Chalaturnyk, R., Sorensen, J., Hawkes, C., Rostron, B., Risk, D., Young, A., and Sacuta, N., 2017. Aquistore: year one – injection, data, results. Energy Procedia. 13th International Conference of Greenhouse Gas Control Technologies, Lausanne Switzerland.

WRI (World Resources Intsitute), 2008. Guidelines for Carbon Dioxide Capture, Transport, and Storage. by Sarah Forbes, Preeti Verma, Thomas E. Curry, M.J. Bradley and Associates LLC, Dr. S. Julio Friedmann, Lawrence Livermore National Laboratory and Sarah M. Wade, AJW, Inc. - October 2008. Availble from: http://www.wri.org/publication/guidelines-carbon-dioxide-capture-transport-and-storage

Wright, I., 2007. The In Salah Project – CO_2 Storage Monitoring and Verification. http://www.cslforum.org/documents/InSalahProjectPoster0307.pdf.

Wuerdemann, H., Moeller, F., Kuehn, M., Heidug, W., Christensen, N.P., Borm, G., Schilling, F.R., and the CO2Sink Group, 2010. CO2SINK: From site characterisation and risk assessment to monitoring and verification: One year of operational experience with the field laboratory for CO_2 storage at Ketzin, Germany. International Journal of Greenhouse Gas Control: 4 (6), 938-951.

Xu, T., Apps, J.A., and Pruess, K., 2004. Numerical simulation of CO_2 disposal by mineral trapping in deep aquifers: Applied Geochemistry: 19, 917-936.

Xu, T., Kharaka, Y.K., Doughty, C., Freifeld, B.M., and Daley, T.M., 2010. Reactive transport modeling to study changes in water chemistry induced by CO_2 injection at the Frio-I Brine Pilot, Chemical Geology: 271 (3–4), 153-164, ISSN 0009-2541, https://doi.org/10.1016/j.chemgeo.2010.01.006.

Xue Z., Tanase, D., and Watanabe, J., 2006. Estimation of CO_2 saturation from time-lapse CO_2 well logging in an onshore aquifer, Nagaoka, Japan. Exploration Geophysics: 37, 19-29. https://doi.org/10.1071/EG06019

Yamamoto, H., Nakajima, T., and Xue, Z., 2017. Quantitative Interpretation of Trapping Mechanisms of CO_2 at Nagaoka Pilot Project a History Matching Study for 10-Year post-injection –, Energy Procedia: 114, 5058-5069, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2017.03.1659.

Yamazaki, T., Aso, K., and Chinju, J., 2006. Japanese potential of CO_2 sequestration in coal seams: Applied Energy: 83, 911-920.

Yu, H., Zhou, G., Fan, W., and Ye, J., 2007. Predicted CO_2 enhanced coalbed methane recovery and CO_2 sequestration in China: International Journal of Coal Geology: 71, 345-357.

Zhang, Y., Freifeld, B., Finsterle, S., Leahy, M., Ennis-King, J., Paterson, L., and **Dance, T**., 2011 Single-well experimental design for studying residual trapping of supercritical carbon dioxide. International Journal of Greenhouse Gas Control. 5(1): p. 88-98.

Ziesch, J., Aruffo, C. M., Tanner, D. C., Beilecke, T., **Dance, T.,** Henk, A., Weber, B., Tenthorey, E., Lippmann, A., & Krawczyk, C. M.: Geological structure and kinematics of normal faults in the Otway Basin, Australia, based on quantitative analysis of 3-D seismic reflection data. Basin Research 06/2015; DOI:10.1111/bre.12146

Zhou, Q., Birkholzer, J.T., Tsang, C., and Rutqvist J., 2008. A method for quick assessment of CO_2 storage capacity in closed and semi-closed saline formations. International Journal of Greenhouse Gas Control, 2, 626-639.

Zhou, Q., Birkholzer, J.T., Mehnert, E., Lin, Y.F., and Zhang, K., 2010. Modeling basin-and plume-scale processes of CO_2 storage for full-scale deployment. Ground Water, 48 (4), 494-514

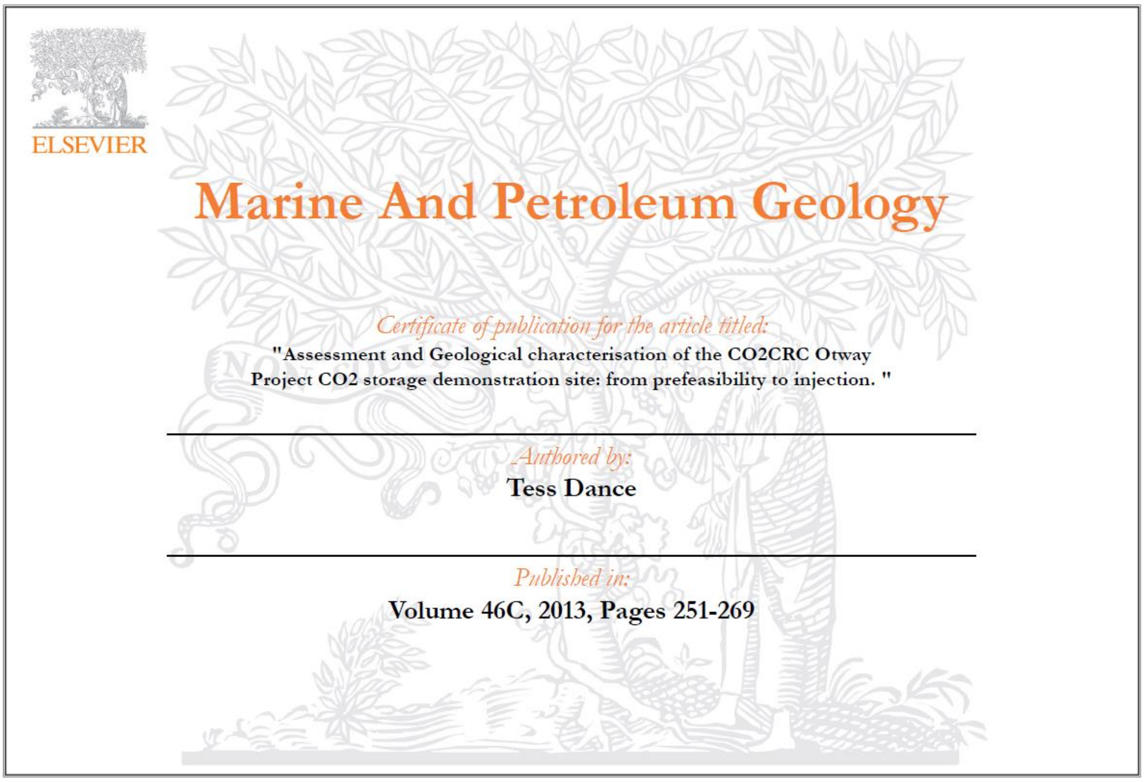
Zheng, S., Corbett, P.W.M., Ryseth, A., Stewart; G., 2000. Uncertainty in Well Test and Core Permeability Analysis: A Case Study in Fluvial Channel Reservoirs, Northern North Sea, Norway. AAPG Bulletin: 84 (12): 1929–1954. doi: https://doi.org/10.1306/8626C72B-173B-11D7-8645000102C1865D

Chapter 4: Thesis Body-Publications

4.1 Publication 1: Otway Project CO_2 storage demonstration site: From prefeasibility to injection.

Published in: Marine and Petroleum Geology 46 (Sept 2013) 251-269

Author: Tess Dance


ELSEVIER

Marine And Petroleum Geology

Certificate of publication for the article titled:

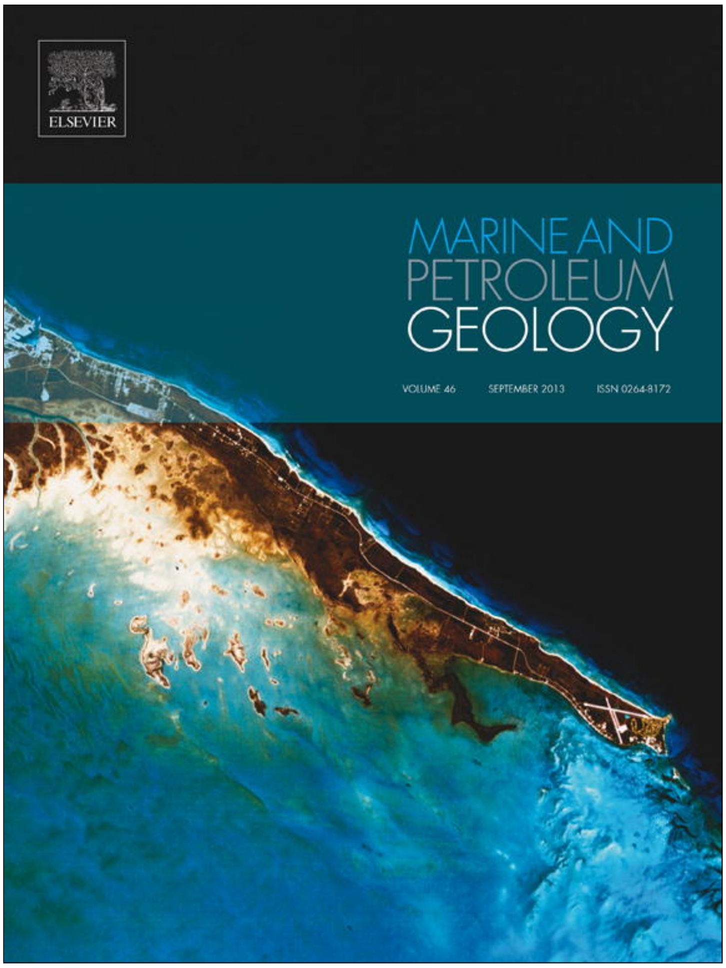
"Assessment and Geological characterisation of the CO2CRC Otway Project CO2 storage demonstration site: from prefeasibility to injection. "

Authored by:

Tess Dance

Published in:

Volume 46C, 2013, Pages 251-269


ELSEVIER
MARINE AND
PETROLEUM
GEOLOGY
VOLUME 46
SEPTEMBER 2013
ISSN 0264-8172

Marine and Petroleum Geology 46 (2013) 251–269

Contents lists available at SciVerse ScienceDirect

Marine and Petroleum Geology

journal homepage: www.elsevier.com/locate/marpetgeo

Assessment and geological characterisation of the CO2CRC Otway Project CO_2 storage demonstration site: From prefeasibility to injection

Tess Dance [a,b,*]

[a] Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), Kensington, WA 6151, Australia
[b] CSIRO Earth Science and Resource Engineering, Kensington, WA 6151, Australia

ARTICLE INFO

Article history:
Received 25 October 2012
Received in revised form
8 May 2013
Accepted 9 June 2013
Available online 18 June 2013

Keywords:
CO_2 storage
Reservoir characterisation
Geosequestration
Carbon dioxide

ABSTRACT

The CO2CRC Otway Project, located in south-eastern Australia, has demonstrated geological storage of CO_2 in a depleted natural gas field. Prior to injection, a comprehensive site characterisation study established that the site should meet the requirements of safe and effective storage. In contrast to the conventional methods applied to characterising oil and gas reservoirs for production purposes, CO_2 storage site assessments place greater emphasis on injectivity, capacity, and long-term containment. The site location was assessed in the context of accessibility for monitoring activities and impact on local communities and natural resources. Additional well-log data and cores were acquired from the gas field, in conjunction with the drilling of the CRC-1 injector well, in order to reduce the uncertainty surrounding the geological heterogeneity of the reservoir, capacity of the seal to retain CO_2, fault seal geomechanics, and regional hydrodynamics. Specialised core analysis revealed that small scale sedimentary features, related to depositional environment impact reservoir quality, CO_2 trapping and plume migration behaviour. Based on these effects, a depositional model was established to better understand storage potential away from well control. Finally, a nearby gas storage facility provided a valuable analogue for the project and added confidence that the CO2CRC Otway Project site would be suitable to inject, store and contain CO_2 within the technological and economical limits of the project. Following the injection period, long term monitoring of the reservoir, as well as the overlying aquifers, soil, groundwater and the atmosphere above the site, have confirmed the storage concept is effective and that the CO_2 is safely contained. As a result, the site characterisation methodology serves as an example for others contemplating CO_2 storage into depleted gas fields.

1. Introduction

For a number of years geological storage of carbon dioxide (CO_2) has been investigated around the world as a practical method for reducing greenhouse gas emissions (IEA, 2005, 2008; IPCC, 2005). The practice is called carbon capture and storage (CCS). It involves capturing CO_2 from stationary sources that would otherwise emit it to the atmosphere, compressing it, transporting it to a suitable site, and injecting it into deep geological formations where it will be trapped for many thousands of years. For this mitigation option to be successful and widely accepted, it is essential that the technology can be safely demonstrated at well characterised sites where the long term fate of injected CO_2 can be assured. With this in mind, attempts have been made to develop a best practice approach to guide site specific characterisation efforts.

In 2008, the World Resources Institute released a set of guidelines for carbon dioxide capture, transport and storage which included recommendations for site characterisation to focus on: the effectiveness of the confining zone (seal) in preventing the upward migration of CO_2; the injectivity of the storage reservoir; and the volumetric capacity of the reservoir to hold injected CO_2 (WRI, 2008). However, when comparing site-specific assessment workflows developed by projects actually completed or currently underway at pilot and commercial scale (for example Maldal and Tappel, 2004; Wilson and Monea, 2004; Hovorka and Knox, 2003, 2006; Riddiford et al., 2003; Kikuta et al., 2005; Förster et al., 2006, 2010; Chadwick et al., 2007; Flett et al., 2008, 2009;

* Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC), Kensington, WA 6151, Australia. Tel.: +61 8 64368718.
E-mail address: tdance@co2crc.com.au.

0264-8172/$ – see front matter © 2013 Elsevier Ltd. All rights reserved.
http://dx.doi.org/10.1016/j.marpetgeo.2013.06.008

Hitchon, 2009), and evaluating lessons learnt from industry operators of analogous oil and gas projects, enhanced gas recovery projects and natural gas storage facilities (Cooper, 2009), it is clear that although the technology and expertise exists to safely address the technical aspects for large-scale CO_2 storage deployment, there is no "one-size fits all" solution for site characterisation. Due to the inherent geological variability, different operational objectives and site specific risks, each project will focus data acquisition and analysis efforts accordingly. Future projects will need to draw from a diverse array of case studies that have experienced the entire project life cycle, from initial site assessment to detailed characterisation, injection, and post injection monitoring to see what techniques are most applicable for their conditions.

This paper provides details of the site assessment and geocharacterisation of one such demonstration project conducted in Australia, the Cooperative Research Centre for Greenhouse Technologies (CO2CRC) Otway Project. It is the first of its kind in Australia to have demonstrated transport, injection, storage and monitoring of CO_2 in a depleted gas field, and provides a valuable example for others contemplating utilising depleted gas fields for commercial scale CCS.

1.1. Project overview and objectives

The study site is located in the Otway Basin of Victoria (Fig. 1) in the onshore Port Campbell Embayment approximately 300 km southwest of the City of Melbourne in Victoria, between the coastal towns of Port Campbell to the east, and Warrnambool to the west. This area of the Otway Basin is structurally restricted by the Otway Ranges to the east and bounded by structural highs to the north and west (Fig. 1). Its development, and that of the adjacent Shipwreck Trough, which extends off-shore, was coeval with eastern Gondwanan breakup along the Australian Southern Margin and with Tasman Sea seafloor-spreading to the east (Hill and Durrand, 1993; Woollands and Wong, 2001; Krassay et al., 2004). It is a region with numerous small natural gas and CO_2 fields with 2-P reserves ranging from 0.0168×10^9 m^3 to 0.532×10^9 m^3 (0.6 billion cubic feet (Bcf)–19 Bcf).

In 2004 the CO2CRC purchased two adjacent petroleum tenements containing the Buttress CO_2 field (estimated reserves of 0.1372×10^9 m^3 or 4.9 Bcf), and the depleted Naylor natural gas field (0.1456×10^9 m^3 or 5.2 Bcf initial 2-P reserves) to the south. This offered the opportunity to utilise a CO_2 source and sink adjacent to one another (Fig. 2). The Buttress gas field, the CO_2 source

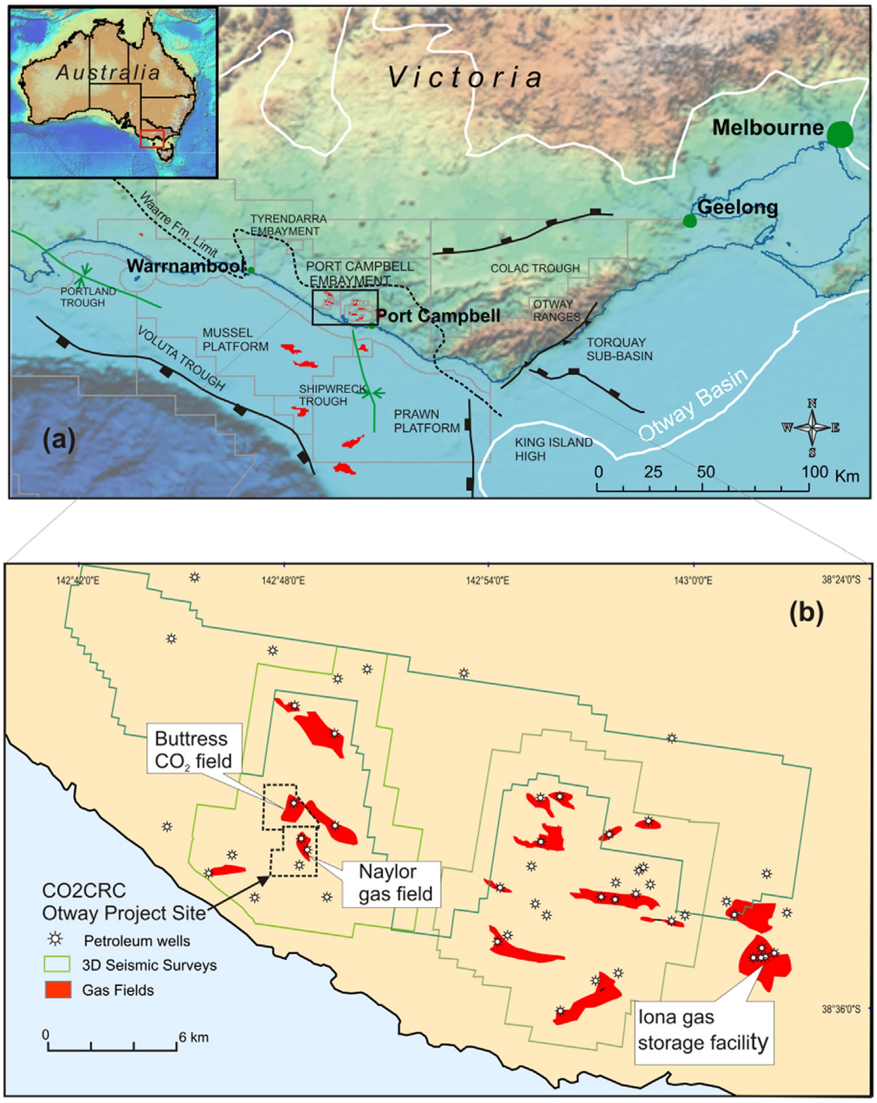


Figure 1. (a) Location of the CO2CRC Otway Project, major structural elements, petroleum leases and gas fields of the Otway Basin, Victoria, Australia. (b) Enlargement of the Port Campbell gas field region, petroleum wells and 3D seismic surveys used in the study, as well as the Iona field used as an analogue for the study.

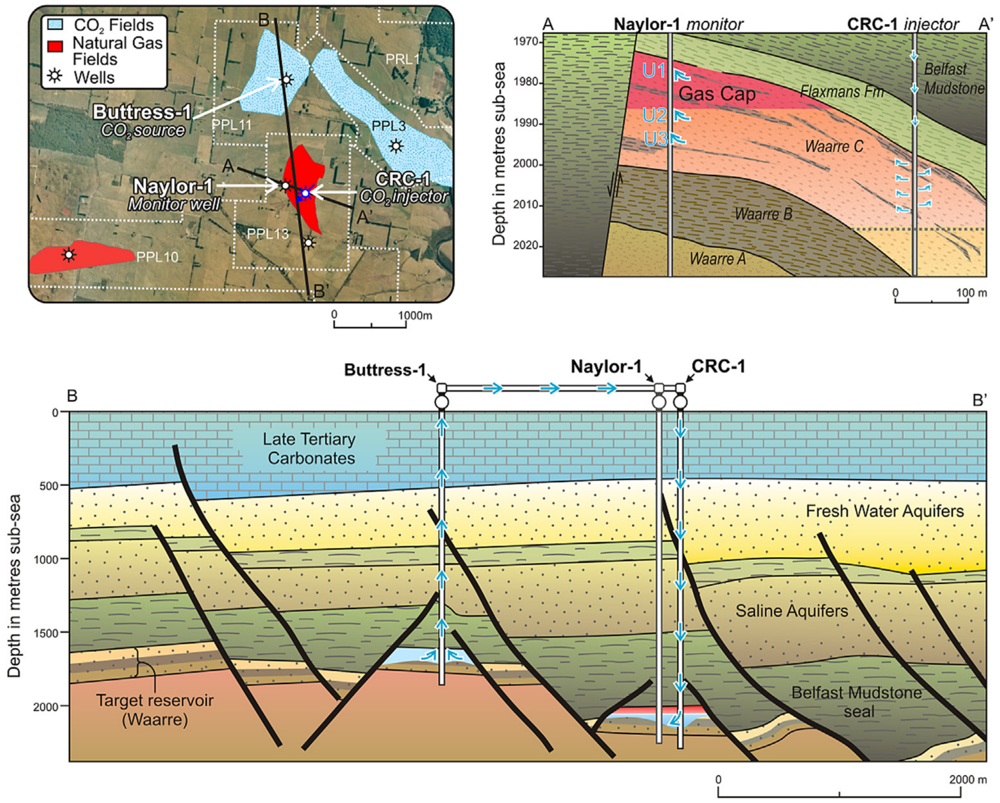


Figure 2. Site map with location of the CO2CRC's petroleum leases PPL11, containing the Buttress CO_2 field, the source for the experiment, and PPL13, containing the depleted Naylor gas field, the storage site. Cross-section AA′: approximate east–west dip section at reservoir level showing the location of the CO_2 injector well (CRC-1), down-dip of the monitoring well. Near the top of the structure is the post production gas cap and further down-dip the pre-production gas water contact (dotted line), which also indicates the spill point of the reservoir. The three U-tube inlet locations used for fluid sampling at the monitoring well are labelled: U1 in the methane gas cap, U2 just below the gas water contact, and U3 near the base of the reservoir. Cross-section BB′: north–south section through the fault bound CO_2 source and sink reservoirs, overlying seal and aquifers (figure modified from Jenkins et al., 2012).

used in the experiment, has a molar composition of approximately 75.4 mol% CO_2 and 20.5 mol% methane plus other minor components (Boreham et al., 2011). Residual methane (average 20% S_{gr}) was present throughout the Naylor field storage reservoir and a small methane gas cap at the top of the structure remained after production ceased in 2003. In 2007, following a comprehensive site characterisation and risk evaluation, the existing Naylor-1 (the previously abandoned original production well located on the crest of the reservoir) was recompleted for monitoring, and an injection well (CRC-1), was drilled and extensively cored and logged, 300 m down-dip from the monitoring well (Fig. 2). Over the course of 18 months, between March 2008 and August 2009, 65,445 tonne of CO_2/methane mixed gas was produced from the Buttress field, dried, compressed and then transported along 2.25 km of specially built underground pipeline to the CRC-1 injector well and injected into the targeted Waarre C Formation reservoir. At a depth of around 2000 m below the surface, this gas bearing reservoir is bound on three sides by faults which juxtapose the sandstone against the overlying Belfast Mudstone seal providing a fault sealed structural trap for the stored CO_2.

The Otway Project incorporated an intensive monitoring and verification (M&V) programme (Dodds et al., 2009). An array of techniques were used including down-hole fluid geochemical sampling, pressure and temperature analysis, and repeat down-hole logging in order to observe the rate of CO_2 migration from the injector up-dip to the monitoring well and the dynamic chemical changes that occurred as the plume filled the structure. For assurance that the CO_2 is contained, time-lapse 3D seismic was used to image the reservoir and overlying aquifers. Tracer compounds (CD_4, SF_6 and Kr) were co-injected along with the CO_2 to discriminate it from other naturally occurring CO_2 (Stalker et al., 2009). At the time of this writing, ground water, soil gas, and atmospheric monitoring were still being routinely carried out to detect if there are any signs of these chemical tags at the surface; none have been so far.

The primary aim of the demonstration project was to assure regulators, direct stakeholders and the general public that CO_2 can be safely transported, injected, geologically stored and monitored under Australian conditions (Sharma et al., 2006; 2008). Considerable effort was directed to consultation with landowners, public outreach and engagement with international research groups and other operators interested in carbon storage. Specific scientific and technical objectives included, can we: 1) effectively predict the CO_2 behaviour in the subsurface; 2) reduce geological uncertainty and better assess geological risk by acquiring appropriate well, core and geophysical data; 3) verify that CO_2 remains within the storage formation, or in the unlikely event of leakage to the surface, demonstrate the capacity to detect surface leakage; and 4) develop, test and deploy additional new and enhanced M&V technology. A technical overview and results of the monitoring may be found in Underschultz et al. (2011); and overall research implications and impacts of the demonstration are in Jenkins et al. (2012).

The case study presented herein focuses on objective number 2, the geological characterisation of the Otway site from regional to field scale. It details the prefeasibility site assessment, the data acquisition programme which was planned to reduce the uncertainty unique to CO_2 injection, and provides results of the integrated core, well log, and seismic interpretation that were conducted as part of the detailed geological characterisation prior to injection. This is unique compared to many other published site characterisation workflows that, until now, have mainly focused on the regional scale site assessment or prefeasibility stage (for example: Bachu, 2000, 2003; Bradshaw et al., 2002; Gibson-Poole et al., 2005; Varma et al., 2009). The following sections outline the workflow and the key questions that were addressed as the Otway project evolved.

2. Initial site assessment

During the project initiation phase, a high level site assessment was performed using existing datasets and regional geological information. Existing data included well completion reports, regional geological studies, and a small number of cores from surrounding fields. Contrary to the widely held belief that depleted gas fields make good storage sites because they are already well understood and data exists for the CO_2 site characterisation process, the Naylor field itself was relatively data poor. That is, there was no conventional core, no side wall cores, and only a basic set of wire-line logs. In order to develop the field economically, the operator drilled a single well, and completed the well as a mono-bore with 3½ inch (88.9 mm) casing and did no additional sampling or testing.

There was, however, good quality 3D seismic data available, acquired in 2000. Seismic interpretation of the reservoir and seal, as well as overlying stratigraphy was carried out on the existing Nirranda-Heytesbury 3D Survey, an amalgamation of all the surveys shown in Figure 1. This survey has excellent resolution, with 24 fold data to a depth of 4 s, a bin size of 20 m and covers an extensive total area of 83.5 km^2. Specifically, this phase of the study aimed to establish:

- **The site's geological setting**: Is there a suitable reservoir? How thick and extensive is the seal? How extensive are the faults flanking the Naylor field structure and where is the spill point? Are there existing natural resources or secondary seals in the stratigraphy above the field?
- **The site's geographic setting**: What is the site's location in relation to existing infrastructure? What is the environment and community above the site in the context of site access for operational and monitoring activities?
- **The field production history**: How much methane was produced and what storage capacity remains? What is the current pressure and the extent of remaining reservoir fluids after pressure depletion and/or recovery? What dynamic predictions can be made using this data?
- **The key uncertainties**: Should the project proceed? What is needed from the data acquisition program to reduce the remaining uncertainty?

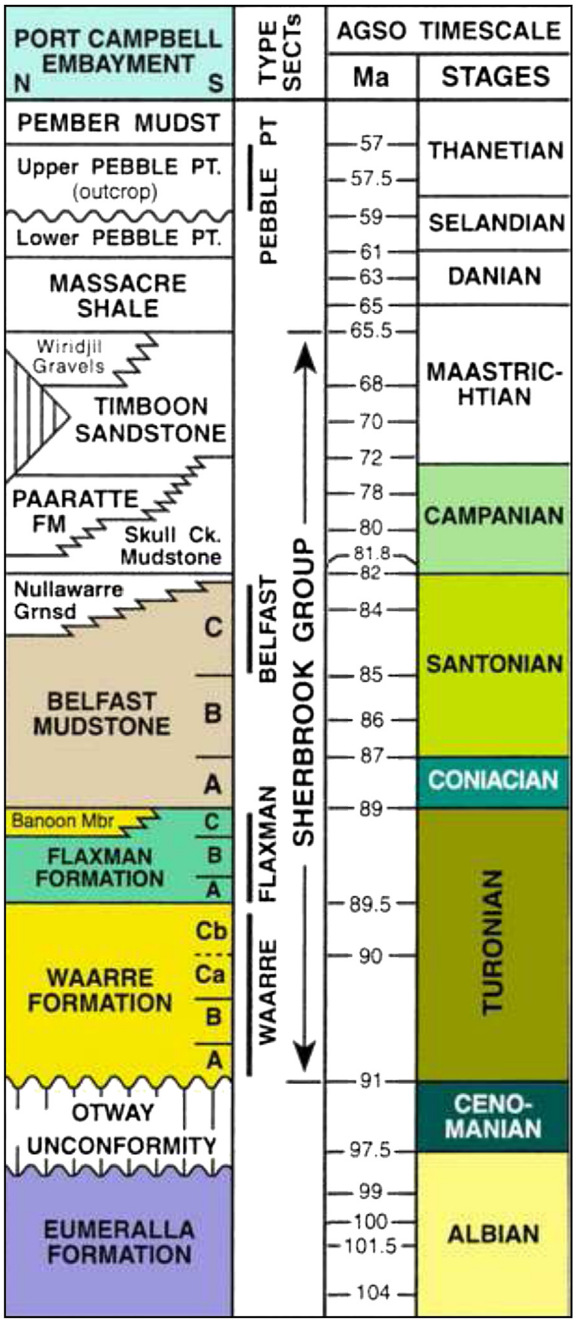


Figure 3. Stratigraphic column of sedimentary units in the Port Campbell Embayment (after Partridge, 2001).

2.1. Geological setting

From the regional well and seismic data, correlation of key formations was performed over the area to determine their depth and continuity. There are several broadly similar sequence stratigraphic chronostratigraphic systems and descriptions of lithostratigraphy in use in the Otway Basin (Laing et al., 1989; Kopsen and Scholfield, 1990; Morton et al., 1995; Geary and Reid, 1998; Boult et al., 2002). The authors chose to adopt the system published by Partridge (2001) because it is relatively recent and focuses on the Sherbrook Group in wells close to the study site. The Waarre Formation (the reservoir) is the basal unit of the Sherbrook Group (Turonian – Maastrichtian ~91 ma–65.5 ma) sitting directly on top of the Otway Unconformity (Fig. 3). In this scheme, Partridge (2001) subdivides the Waarre Formation into units A, B and C. The basal unit, A, is a fine-grained lithic sandstone with low to moderate porosity. Unit B overlies unit A and consist of hard, grey to black carbonaceous mudstone. Unit C is the main gas producing reservoir in the area and consist of poorly sorted very fine to course quartz sands and occasional gravels, 2–14 m thick, separated by minor mudstones which vary from 0.5 m to 3 m in thickness. Reservoir quality in the area is good to excellent with porosity ranging from 10% to 28% (average 17%), and average permeability of 2700 md (Mehin and Constantine, 1999). At the time of the initial site assessment, two depositional models existed for the Waarre C Formation. The first proposed by Buffin (1989) was a transgressive shoreline model in which the dominant depositional direction of reservoir bodies was in an east–west orientation. The second, and more recent, was a regressive, braided fluvial model, whereby deposition was dominantly north-south (Sharp and Wood, 2004; Faulkner, 2000).

A well correlation panel is shown in Figure 4 highlighting the reservoir, seals, and freshwater aquifers present in the study area. In the onshore area the Waarre C Formation (reservoir) is relatively thin and is particularly thin in the area of the Naylor and surrounding fields (∼25 m–40 m). Overlying the Waarre Formation is the Flaxmans Formation, consisting of interbedded siltstone and fine grained sandstone, fining upwards to highly bioturbated mudstone, and the Belfast Mudstone, black, pyritic, offshore mudstone. The Belfast Mudstone has low porosity and permeability (average <15%, <1 mD) and provides the primary seal to the gas bearing Waarre Formation. Immediately overlying the Belfast Mudstone is the Skull Creek Mudstone, deposited in the Early Campanian. It consists of dark grey to black, carbonaceous mudstone with minor interbedded siltstones and sandstones. Because the Skull Creek Mudstone is mostly fine grained sediment it has low hydraulic conductivity, so it contributes to the primary seal capacity of the underlying Belfast Mudstone across the study area.

No hydrocarbon resources have been encountered above the primary sealing units. However, there are several fresh water aquifers that were flagged during the prefeasibility site assessment. Overlying the Skull Creek Mudstone is the Paaratte Formation and Timboon Sandstone consisting of interbedded sandstones, siltstones and mudstones deposited in a shallow marine to delta plain setting. Water samples obtained from the Timboon sands generally have total dissolved solids (TDS) values around 500 ppm, suggesting this unit may have significant potential for use as town water supply (Duran, 1986) and is categorised by the Victorian state Environmental Protection Agency as "potable" water. To date this aquifer has not been exploited due to both its depth (>1000 m) and the abundance of freshwater in shallower aquifers. Nevertheless, it has been flagged as a future resource and as such its integrity must be assured.

Above the Timboon Sandstone are the formations of the Wangerrip Group. Of interest is the Massacre Shale and the Pember Mudstone and these were characterised in the context of their potential to provide secondary seals to the site in the unlikely event that CO_2 should breach the primary container. The Massacre Shale lies at between 931 m and 1026 m true vertical depth subsea (mTVDSS). It is a glauconitic mudstone deposited by a widespread transgressive event and although it is relatively thin (∼20 m–∼30 m thick) it can be mapped with continuity across much of the Otway Basin. The Pember Mudstone is a pro-deltaic, silty mudstone approximately 50 m thick in the study area.

Above the Pember Mudstone is the Dilwyn Formation. It comprises a thick (∼250 m) sequence of shallow marine to coastal plain sandstones and mudstones. The Dilwyn Formation is a major fresh water aquifer (<1000 ppm TDS), supplying water for urban use to surrounding towns in times of drought. Overlying the Dilwyn Formation is the Heytesbury Group. The main freshwater aquifer in this Group is the Port Campbell Limestone. The aquifer is relied on as the primary ground water supply in the region and is currently exploited for urban use, agriculture and irrigation.

Key formation tops were tied to the seismic reflection data and mapped across the study area in detail. Two seismic section examples are provided in Figure 5, with the interpreted formation horizons displayed in two way time. The gas bearing Waarre C reservoir reflector is a relatively "bright" (high amplitude) peak. The depth converted top reservoir surface and seal thickness maps are shown in Figure 6. The Waarre C lies at a depth of between 1980 mTVDSS and 2180 mTVDSS. The Belfast Mudstone is between 1340 mTVDSS and 2010 mTVDSS and is 280 m thick on average over the site, significantly thicker in comparison, to the Waarre C. At this level the faulting is well developed and juxtaposes the Waarre with the Belfast Mudstone. The contrast in thickness between the reservoir and seal provides fault bound, anticline, and roll-over structural traps. The Naylor Field itself is fault bound on three sides and has a dip closure to the east. At the time, the spill point of the reservoir was estimated at between 2020 mTVDSS and 2012 mTVDSS, the uncertainty being related to the depth conversion of the surface away from well control. Unlike many of the larger faults in the region that were reactivated through to the Tertiary, the faults flanking the Naylor Field terminate within the Santonian Belfast Mudstone seal. Furthermore, there was no evidence such as paleo gas chimneys or hydrocarbon related digenesis to suggest any of the existing methane had migrated out of the reservoir via these faults. The risk the faults would provide vertical leakage pathways into the overlying aquifers was therefore considered unlikely.

It is desirable for CO_2 storage to have pressure and temperature conditions of the reservoir in excess of the critical point where CO_2 enters the supercritical state (i.e. greater than 7.38 MPa and 31 °C

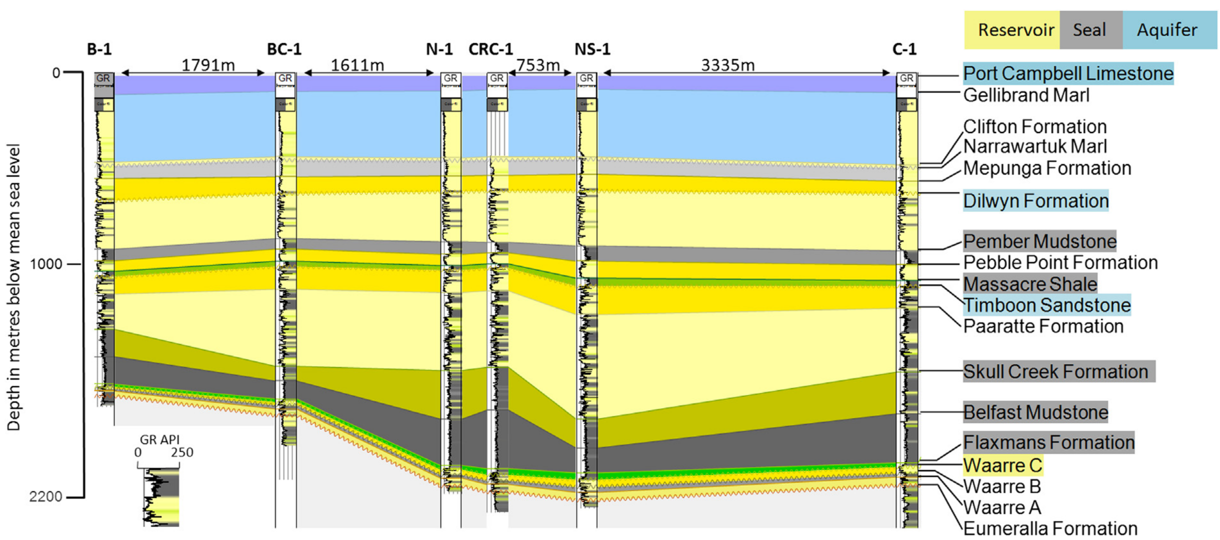


Figure 4. Well log (gamma ray) correlation of stratigraphic formation tops in the study area with the key aquifers and seals highlighted. Refer to Figure 2 for well locations: B-1(Buttress-1), BC-1 (Boggy Creek-1), N-1 (Naylor-1), NS-1, (Naylor South-1), C-1 (Croft-1).

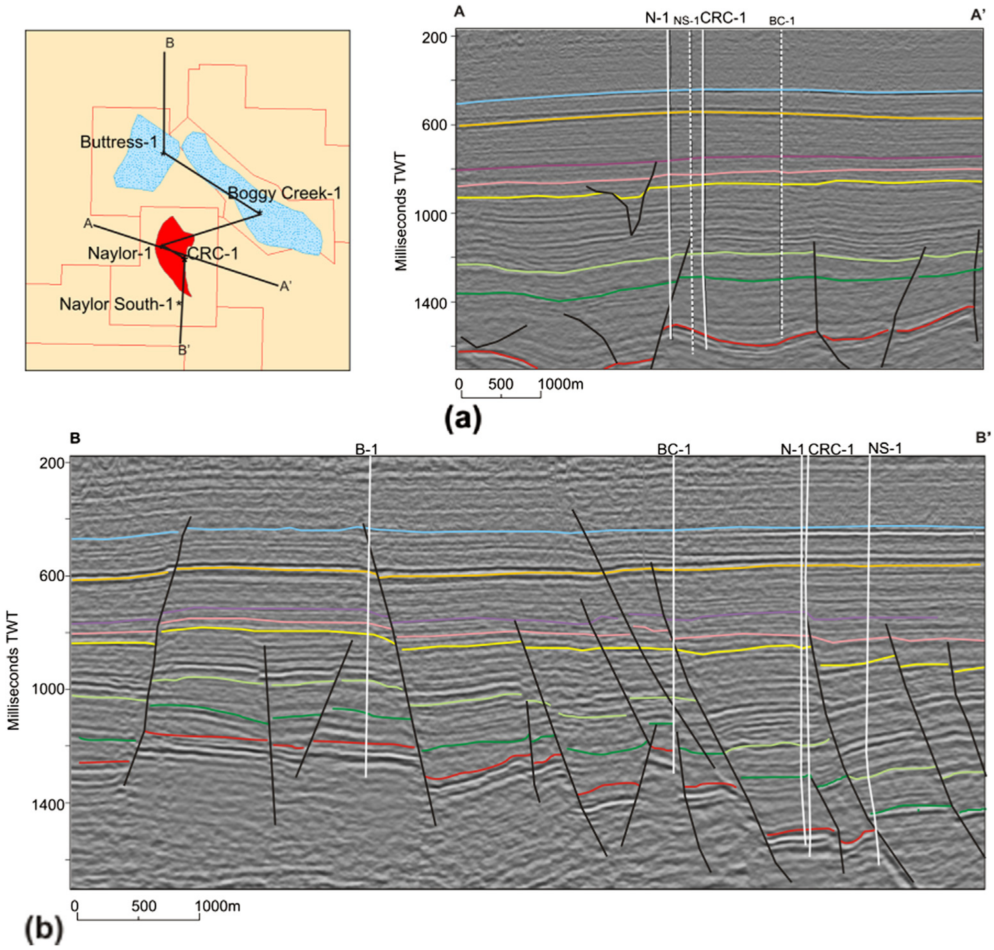


Figure 5. Seismic sections, (a) approximate east–west, and (b) north–south, over the study area. Key formation horizons from the base up are: Waarre C (red), Belfast Mudstone (green), Skull Creek Mudstone (light green), Timboon Sandstone (yellow), Massacre Shale (pink), Pebble Point Formation (purple), Dilwyn Formation (orange), Clifton Formation (blue). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

(Andrews, 1869)). This is important because in this form it is much denser than gaseous CO_2 and therefore a greater volume of CO_2 can be stored in the pore space available. For the Otway project the source gas contained a mixture of methane and CO_2. According to the Peng-Robinson equation of state (1976), 8.5 MPa and 14.9 °C is predicted for the critical point of the CH_4–CO_2 mixed gas. An assessment of well data from surrounding fields indicated the average pressure gradient is 9.56 MPa/km, and temperature gradient is 20 °C/km. The depth map of the Naylor Field, indicates the site is at depth greater than 1980 mTVDSS and therefore will provide supercritical CO_2 storage.

2.2. Geographic setting

Site geography, the local environment and the community, are of no less significance than the geological characteristics when selecting a site for a CO_2 storage project. Among some of the issues that need to be considered are land access for rig mobilisation, pipelines, facilities and regular monitoring activities; along with the obvious considerations of understanding any pre-existing community perceptions and potential opposition to the technology.

In the case of the Naylor field, conditions are not considered adverse. The site is located in a predominantly rural region of south-western Victoria, approximately 6 km from the coast. The major urban centres in the area are Warrnambool, 40 km to the west, with a population of about 28,000, and Port Campbell 24 km to the east, with a population of about 400 (Fig. 1). Agriculture, mainly dairy farms, and tourism are the mainstay of the region. The climate is mild with average daily temperatures 21 °C in summer and 9 °C in winter. Annual rain fall is relatively high (average around 700 mm) and rain fall is highest in the winter months when the ground normally becomes saturated. Therefore drilling and seismic acquisition activities need to be conducted during the summer months for minimal ground disturbance. The local residents are not unfamiliar with petroleum exploration and production in the area with many small fields operating in the vicinity. The Boggy Creek CO_2 production facility operates less than 3 km from the site and the Iona Field (30 km to the east), has been used for underground gas storage since the year 2000. This comes with both positives: drilling and gas storage has been conducted safely for many years; and some negatives: larger operators have been able to provide monetary compensation for land access for seismic survey acquisition which has set a precedent.

2.3. Field history

At Naylor-1 production of methane began in June 2002 at which time the discovery pressure was 19.5928 MPa at 1993.34 mTVDSS (towards the top of the reservoir). Production ceased in October 2003 when the well started taking in water. Reservoir pressure at the end of production was down to 11.8612 MPa (converted from the reported flowing tubing head pressures). The Naylor-1

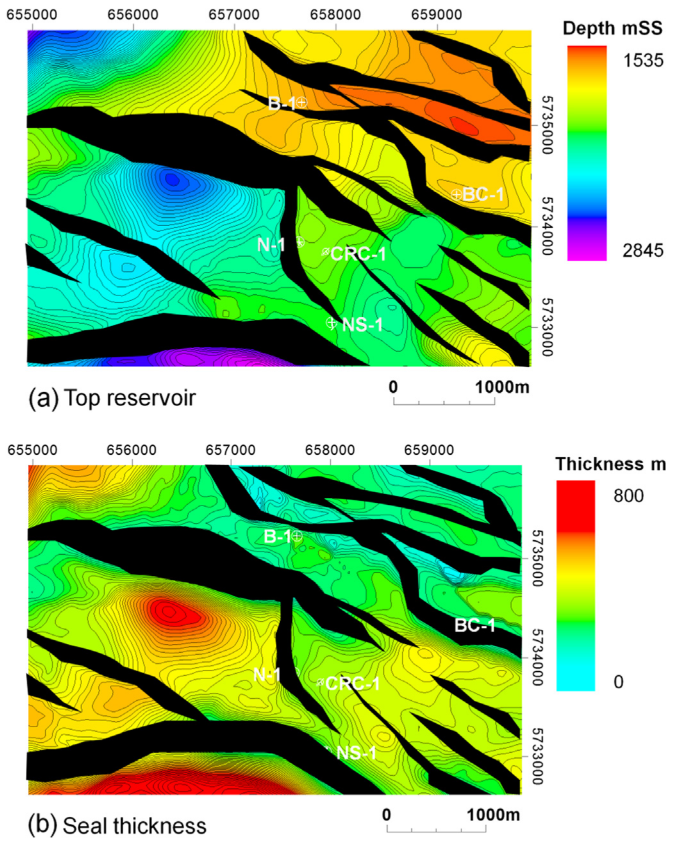


Figure 6. (a) Depth structure map of the top of the reservoir in metres sub-mean-sea-level; and (b) seal thickness map in metres. Well name abbreviations: B-1(Buttress-1), BC-1 (Boggy Creek-1), N-1 (Naylor-1), NS-1, (Naylor South-1), C-1 (Croft-1). Black polygons denote faults.

production data, provided by the field's previous operators, were used to predict a theoretical storage capacity. This involved a simplistic production based calculation of storage capacity assuming the volume of gas produced equates to the equivalent intended injection volume. The Naylor field originally contained an estimated 1.47×10^8 m^3 or ~5.2 BSCF (billion standard cubic feet) of initial gas in place (measured at standard temperature and pressure). The cumulative production from the Waarre C reservoir was 9.5×10^7 m^3 (~3.3 BSCF), which is about 64% of the initial gas in place. This volume of produced gas is equivalent to approximately 150,000 tonne of the source gas from the Buttress Field. In the preliminary stages of site selection for the CO2CRC Otway Project a maximum of 100,000 tonne of this CO_2 rich gas was proposed to be injected and stored. At the time other projects around the world were running tests with much lower tonnages so it was considered that this demonstration project was relatively "large-scale", making it more relevant to a commercial scale injection project. On this basis it was predicted there was 150% of the required storage capacity at the depleted Naylor field.

The field history data was also used to constrain a preliminary dynamic model. This model was created in order to investigate the reservoir's estimated bulk permeability, aquifer properties, structure, and sedimentary facies and what impacts these have on CO_2 storage and the likely flow behaviour of any injected CO_2 (Xu et al., 2006). More specifically it was used to predict what the field's pressure would be prior to injection, how much it would increase during injection, and what would be the time to breakthrough at the Naylor-1 well (a target of between 6 and 18 months was desired in order to perform monitoring of the plume within the project timeframe). Data paucity was an issue so a large number of multi-realisation cases were created in the static geological model in order to cover the full range of geologically possible scenarios. These considered variations in average reservoir permeability, reservoir geometry as a result of depositional environments (transgressive shoreline versus braided stream), and the depth conversion error of ±25 m on interpreted structural dip. Uncertainty also existed in the reservoir relative permeability and two scenarios for the draining curve were considered (based on special core analysis and gas saturation logging data from surrounding fields). Results for the sensitivity study are shown in Table 1.

By calibrating the dynamic models to the field's pressure data, in a process known as "history matching", a probability could then be assigned to each case based on how much each model needed to be adjusted in order to produce a satisfactory match. A range of 6–14 months for the breakthrough time was considered most likely. The reservoir bulk permeability was more likely to be in the order of 1000 md, and the depositional model was more likely to match the recent interpretation of a fluvial braided stream setting (Spencer et al., 2006). This was considered as the "base case" model shown in Figure 7. The results for the extreme migration rate cases are also shown in Figure 7 for comparison. The fast migration model assumes maximum structural dip, high bulk permeability (>1000 md), and few barriers to flow (i.e. shale baffles) built in the static models. Breakthrough occurs at 50 days and the plume is of limited lateral extent. The slow migration model has minimal structural dip, low permeability (mean of 250 md), and extensive low flow permeability barriers between the wells. This resulted in a small plume, and no breakthrough at the monitoring well even after 2 years of injection. These extreme cases were useful in terms of defining the end member outcomes given the degree of uncertainty; however, they were considered least likely as they did not produce a match to the history data.

Conclusions from the preliminary modelling were that the proposed injection rate of 85,020 m^3/d (3 MMscfd), which equates roughly to 100,000 tonne over 2 years, was feasible for models with absolute reservoir permeability values in the order of >100 md (Table 1). The reservoir was most likely to have recovered to a pressure of 13 MPa by the time injection was to begin, and reach 17 MPa at the end of injection, approximately 3 MPa below the field's discovery pressure (Xu et al., 2006; Underschultz et al., 2011). Conducting the demonstration so as not to go excessively beyond the discovery pressure was an important consideration in order to comply with the conditions of approval set down at the time under the Environment Protection Act (Sharma et al., 2008). In theory, depleted gas fields may be engineered to have pressure build up minimised by producing any remaining natural gas (enhanced gas recovery) or water using pressure caused by the injection of CO_2 making capacity more of a function of reservoir dynamics and economic feasibility. However, this option was beyond the scope of the CO2CRC Otway demonstration project.

2.4. Discussion of key uncertainties

The results from the initial site assessment were that the reservoir most likely contained sandstone with porosity (>17%) and permeability of, at the very least, several hundred millidarcy. However, core and logs were needed to evaluate actual reservoir quality, heterogeneity, and assess potential mineral reactions. Numerous freshwater resources were identified above the reservoir. Containment of the injected gas, and thus preservation of these aquifers, relied on the structural offset of a thick and extensive mudstone seal. Therefore coring needed to also sample this seal, and the secondary seals above, to provide much needed capillary entry data to confirm how much CO_2 can be contained.

Table 1
The sensitivity analysis performed in the prefeasibility modelling, break through results, and interpretation of the likelihood based on the history match.

Model case/Sensitivity	**Time to Breakthrough at monitor well** (days) 0 100 200 300 400 500 600	**Interpretation**
Average permeability (1000, 700, 250 mD)		All geologically possible, 1000 mD provided better match.
Relative permeability curves ("Fast" versus "slow")		Both geologically possible, however the "fast" curve was more likely.
New well location (200, 300, 400 m down dip)		300 m used as base case in other models.
Transgressive Shoreline Model. (large shale bodies orientated east-west acting as barriers to CO_2 flow).		Considered geologically possible at the time, good history match.
Regressive Braided Fluvial Model (High net-to-gross sandstone with minor shale baffles orientated in the direction of structure).		Geologically most likely, least adjustment needed for history match.
Fastest Migration Rate (High permeability, few shale baffles, maximum dip).	Breakthrough at 50 days.	No match to history data, geologically unlikely.
Slowest Migration Rate (Low permeability, low connectivity, gentle dip).	?→ No breakthrough, even after 2 years.	No match to history data, geologically unlikely.

Similarly rock mechanical testing and geomechanical modelling was required to understand fault seal and reactivation potential under the predicted pressure increase associated with injection. Site analogue analysis was seen as desirable to the geomechanical modelling in order to extrapolate experience from a nearby gas storage project.

Preliminary modelling suggested there appeared to be sufficient capacity and injectivity for the intended volume, and the predictions of CO_2 migration, although covering a large range, indicated it was likely the gas would migrate to the monitoring well in the project timeframe. However, there was a lack of relative permeability information, so this had to be included in the core analysis plan. Distribution of shale baffles and reservoir bodies associated with the two depositional models also impacted the dynamic simulation results, so sedimentology from cores was needed to improve the interpretation of the paleoenvironment. Uncertainty remained of the structural dip away from the monitoring well due to a lack of time-to-depth information, so vertical seismic profiling was required in both the monitoring well and injector. Similarly, the position of the gas water contact and re-pressurisation since production needed to be confirmed with logging.

3. Detailed geological characterisation

The injector, CRC-1, was spudded on February 15th, 2007 and reached a total depth of 2249mRT (2199.3 mTDVSS), on the 8th of March, 2007. This provided the opportunity to gather the much needed data for detailed characterisation of the site (Dance et al., 2009). The core programme included recovery of 24 m of continuous core through the Waarre C and an additional 25 m of core from the overlying reservoirs and seals. The suite of wire-line log information gathered comprised Gamma Ray, Nuclear Magnetic Resonance (CMR), Elemental Capture Spectroscopy (ECS) and Formation Micro Imager (FMI) which were recorded to complement the standard resistivity–density–porosity logs. In addition several modular formation dynamic tester (MDT) samples allowed multiple pressure measurements and the recovery of multiple fluid samples from the Waarre C as well as from shallower reservoir sections. Vertical Seismic Profiling (VSP) was also acquired at CRC-1 contributing to an improved database for understanding the velocities for time to depth conversion of the horizons.

New data acquired in the monitoring well (Naylor-1) prior to the installation of the down hole monitoring assembly included a VSP, petrophysical wire-line logs for interpreting porosity, and thermal neutron logging using a reservoir saturation tool (RST) which indicated the level of the current (post production/pre-injection) gas-water contact at 1988.4 mTVDSS. A static gradient survey was also run in the well in 2006 indicating the reservoir pressure had recovered to 17.5 MPa in the three years since the end of production. This was significantly greater than the initial dynamic predictions of 13 MPa. This rapid pressure recovery has been attributed to the strong regional aquifer drive of the greater Waarre C (Hortle et al., 2008). A regional hydrodynamic assessment of the greater Waarre aquifer by Hortle et al. (2013) concluded that the Waarre Formation aquifer is a well connected aquifer in regional hydraulic communication across the Port Campbell Embayment. The flow rate within the Waarre Formation is quite fast at about 0.39 m/yr; estimated assuming an average permeability greater than 500 md. Although there is strong evidence of regional draw-down, due to a long history of production across the Port Campbell Embayment, the Naylor field still maintains a relatively rapid pressure recovery.

Existing pre-production 3D Seismic was reinterpreted with the new well tie at CRC-1 confirming the top and base of the reservoir and the bounding faults geometry. The new structural model, shown in Figure 8, was better constrained due to the new VSP data

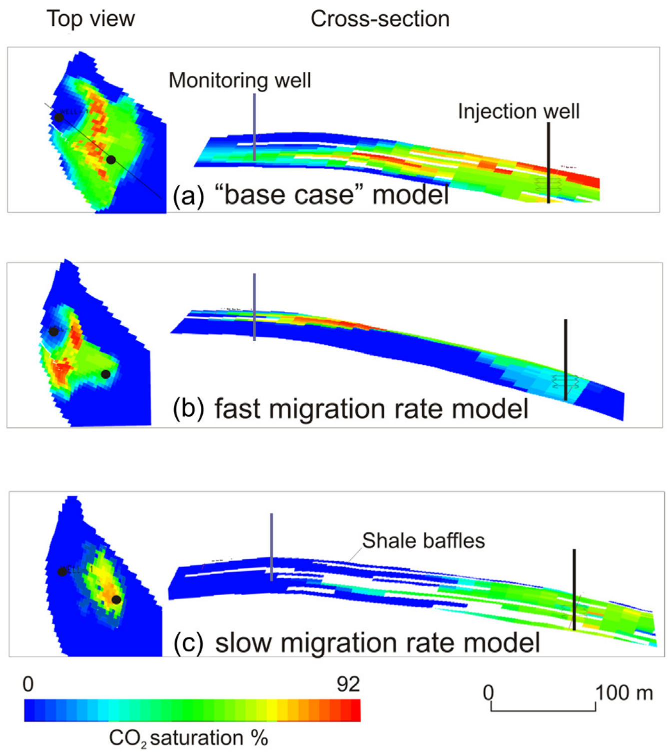


Figure 7. Comparison of the CO_2 saturation prediction from the prefeasibility dynamic simulation of: (a) the base case model, which assumes average permeability of 1000 md, a fast relative permeability curve, well placement at 300 m down-dip, and the regressive braided fluvial static model; (b) the fast migration rate model, which incorporates maximum structural dip (+25 m), high permeability (>1000 md), and few shale baffles; and (c) the slow migration rate model, which assumes minimum structural dip, low permeability (250 md), and a greater number of extensive shale baffles.

in the closely spaced wells (<300 m apart). As the key area of interest is the migration path between Naylor-1 and CRC-1, the uncertainty in depth difference of a surface between the two wells is expected to be in the order of ±1 m. The structural dip was estimated at approximately 14°. The throw of the main Naylor field bounding fault was examined at the point where juxtaposition of sand on sand turned to sand on shale and so an estimate of the maximum depth for the structural spill point (−2015 mTVDSS) could be ascertained (Fig. 8).

3.1. Reservoir quality

A detailed sedimentological description of the core identified the heterogeneous nature of the Waarre-C reservoir which contains sandstone bodies of varying grain sizes and thin (1 m– 3 m) shale baffles (Dance and Vakarelov, 2008). The sedimentary structures (e.g. mud cracks, tidal couplets, and flaser bedding) and presence of marine biota fossils suggest the sands of the Waarre C Formation at the Naylor field were deposited by tidally influenced channels in a near-shore marine setting. Shales intersected in the wells within the Formation were most likely the muddy facies associated with channel abandonment. Porosity and permeability measurements were performed on vertical and horizontal core plugs at in-situ stress conditions, and supplemented by profile permeametry (mini-perm) measurements recorded on the whole core surface every 5–10 cms. The plug results correlated against down-hole petrophysical logs, shown in Figure 9, indicated the porosity of the Waarre C ranged from 2% to 25% while the permeability averaged 1–2 darcy in some of the cleaner sandstone intervals of the formation. The conclusions drawn from the above analysis was that high porosity (>15%) high permeability (>100 md) sands exist in the reservoir and that injectivity should not be impeded. However, reservoir heterogeneity was notable. For example permeability of the sandstones ranged from as low as 8 md up to 6 darcy. The differences in reservoir potential of the sandstones is a function of

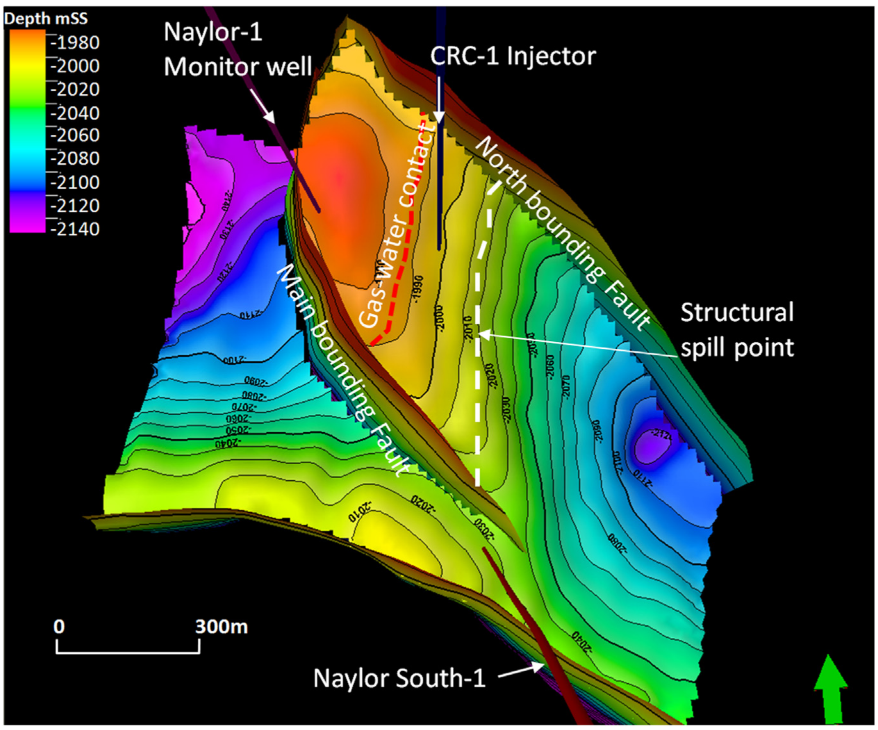


Figure 8. The Naylor Field 3D structural model, including re-interpreted top reservoir horizon, faults, spill point, and post production gas–water contact.

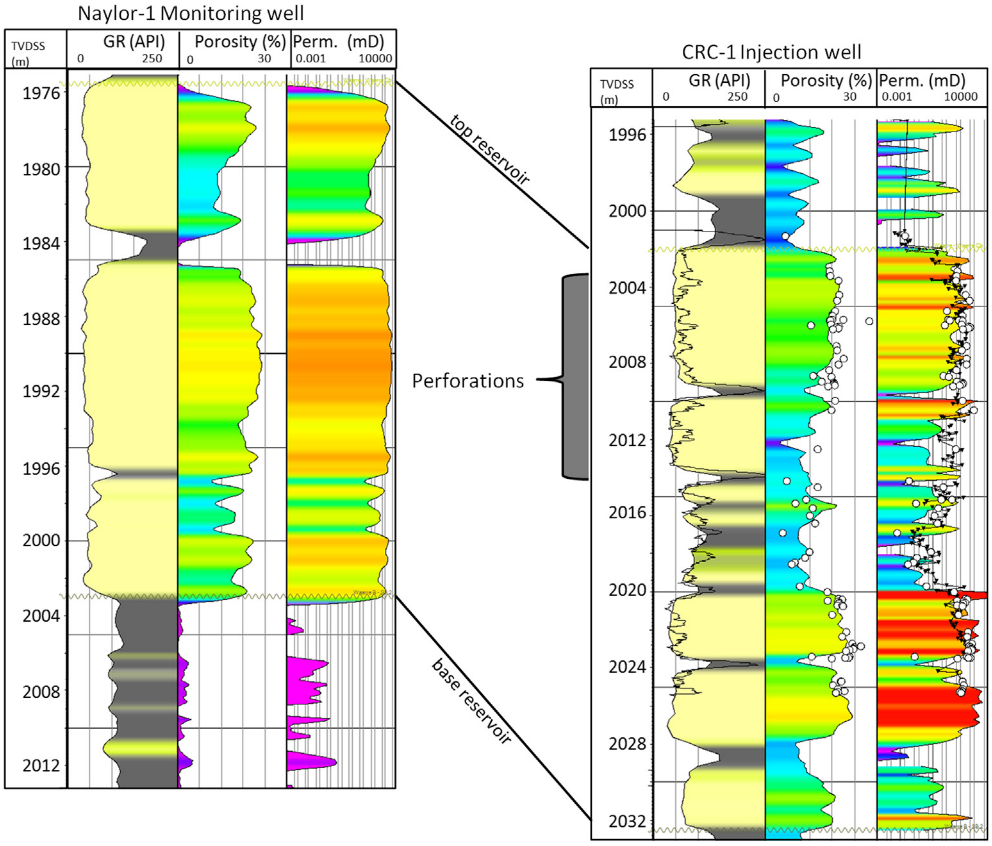


Figure 9. Naylor-1 and CRC-1 well composites. Logs from left to right gamma ray, porosity, permeability. Also overlaid in CRC-1 tracks are core gamma ray (black curve), porosity, permeability (circles), and mini-perm (black triangles).

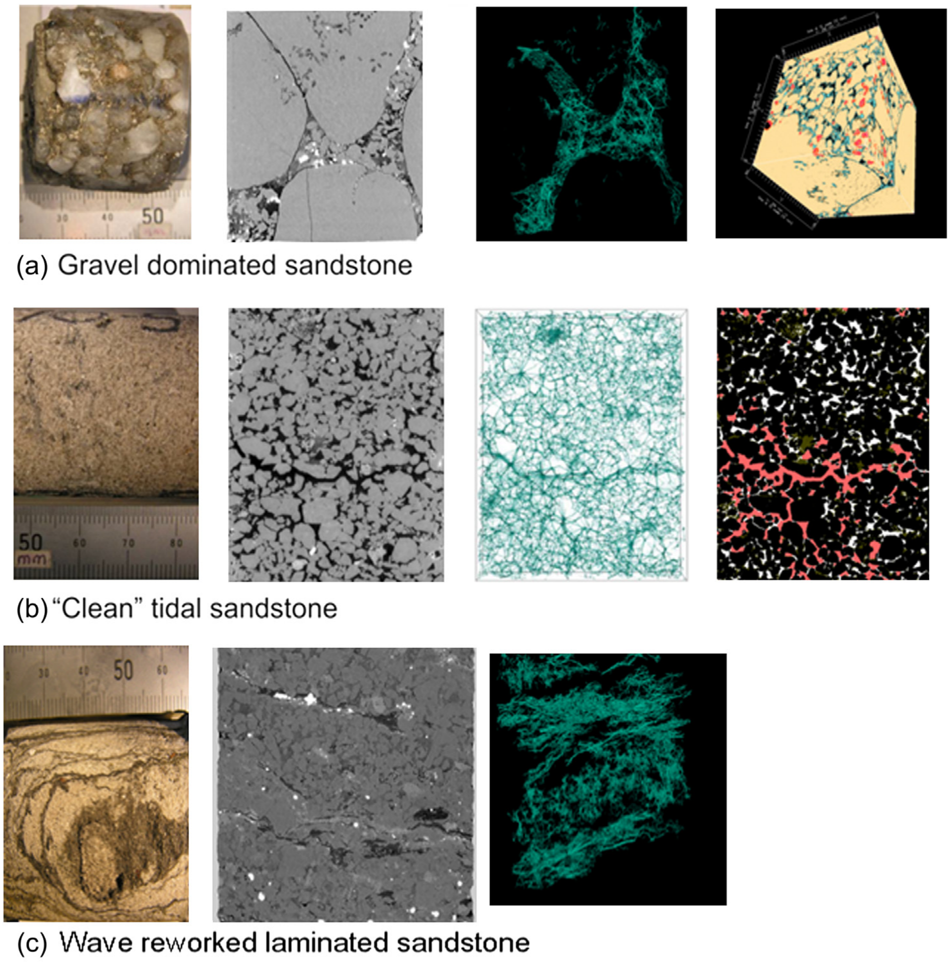
grainsize, composition, and sorting; this in turn being related to changes in depositional environment in which the sediments were laid down.

Relative permeability information was derived from laboratory work on a core sample from the Waarre C in order to understand CO_2-water two-phase flow at reservoir pressure and temperature conditions. The analysis, performed at Stanford University, California USA (Perrin et al., 2009), involved flooding the core sample with mixed CO_2 and brine and measuring the pressure at the inlet and outlet with two high accuracy pressure transducers. The difference of the two pressures gives the pressure drop across the core which is used to calculate the relative permeability of the rock to each fluid. X-Ray CT scanning was also used to determine CO_2 saturation at a fine scale after the flooding and provided 3D porosity and saturation maps of the sample. The results give a residual water saturation (*Slr*) of 44.4% and a relative permeability to gas at this saturation (*krgmax*) of 0.608. The study revealed that microscopic grain size heterogeneities and clay lamina impact porosity distribution and consequently distribution of CO_2 saturation in the reservoir.

Recent advances in digital core analysis allowed for the relationship of depositional facies and reservoir quality, as well as residual trapping potential, to be studied in further detail at the pore-scale using X-ray microtomographic images. The pore and mineral phase structure of the reservoir core material from CRC-1 was enumerated in 3D using X-ray microtomographic technology (Knackstedt et al., 2010). Quantification of the pore space interconnectivity, pore to throat ratio, and pore shape allowed for analysis of the permeability heterogeneity and anisotropy of each sand type. The main aim was to characterise the differences in vertical versus horizontal permeability (K_v/K_h), and residual trapping potential of the various sand facies present in the reservoir. This information could then be up-scaled and used directly in population of reservoir properties in the static and dynamic models.

Three examples of sandstone facies are shown in Figure 10a) a poorly consolidated, poorly sorted gravel dominated channel sandstone; b) a relatively clean, well sorted, well rounded quartz tidal channel sandstone; and c) a highly laminated wave reworked sandstone. 1.5 inch (38 mm) plugs were imaged with micro-CT at a resolution of ~20 microns. 2D backscattered scanning electron microscopy (SEM) and automated mineralogical identification (QEMSCAN®) data were acquired and registered on the 3D image so that virtual slices of the sample grains, pores and minerals could be viewed from any angle. The samples were flooded with an analogue fluid (*n*-hexane) that mimics CO_2 behaviour at ambient conditions, and were scanned again at various states of saturation. This provided insight into fluid distribution in the pore-spaces (Fig. 10).

The results for the micro-tomographic derived mean pore size, mean throat size, pore to throat aspect ratio, and connectivity factor for the facies are also shown in Figure 10. The key parameter here is the average coordination number of the pore network, *Zn*. For example low *Zn* (<4) and high aspect ratios have been correlated to high trapped non-wetting phase saturations (Chatzis et al., 1983). Where as $Zn > 4$ is correlated with lower residual gas saturation. The wave reworked, laminated sample is an example of this. It has distinct anisotropy in the pore network due to the strong laminations and relatively good permeability horizontal to bedding ($k_x = 130$ md and $k_y = 165$ md), but low permeability perpendicular to bedding (<1 md in the *z* direction). The low connectivity value of 3.3 would lead to expectations of quite high trapped non-wetting phase residual saturations. For the gravel dominated sample the



Facies	K_v/k_h	pore size	Throat size	Pore/Throat ratio	Connectivity (Zn)
Gravel dominated	0.4	10.2	5.3	2.4	5.1
Tidal sands	0.8	23	10.3	3.5	4.9
Laminated sands	0.01	11.6	3.8	3.0	3.3

Figure 10. Examples of the micro-tomographic analysis performed on: (a) the poorly consolidated gravel; (b) the well sorted, quartz rich tidal sandstone; and (c) the laminated wave reworked samples. From left to right the images are of the core specimen, an image slice parallel to bedding, the 3D pore network connectivity (green), and the simulated residual non-wetting phase CO_2 (red), including the quantitative results for micro-tomographic derived pore properties for each sample. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

horizontal and vertical permeability obtained was 2.8 and 2.1 darcy respectively. The mean connectivity for the sample is relatively high (5.1), due to the large angular grains, therefore the facies has relatively lower residual (non-wetting phase), trapping potential. The clean tidal sandstone has well connected porosity throughout, and at this scale, there is little heterogeneity observed. Permeability values are isotropic in the order of 500 md. The higher connectivity of 4.9 indicates relatively lower potential for high residual (non-wetting phase), saturations.

This detailed analysis was used to constrain reservoir properties within the updated static models (see static and dynamic modelling discussion). This allowed for spatial population of vertical permeability and more specific residual saturation endpoints by facies (i.e. a unique relative permeability curve for virtually each rock type) for the dynamic model inputs. Thus adding more detail to the models than conventional core analysis alone can provide.

3.2. Petrology

Various petrological analyses, including X-ray diffraction (XRD) and scanning electron microscopy (SEM), were performed on 34 samples from the Waarre C Formation and two from the Flaxman Formation in order to examine the effects of carbonate precipitation (Schacht, 2008). This is an important consideration for CO_2 storage as it can have a positive impact by increased storage security through mineral trapping (Gunter et al., 1993); but may conversely impact the rates of CO_2 injection through salt precipitation, fines mobilisation and mineralisation (Burton et al., 2009).

Waarre C Formation samples present subarkoses in the sandstone classification range. The samples show a wide range of grain sizes, from medium grained to very coarse grained with the occasional pebble. Samples are sometimes moderately but mainly poorly sorted. The framework component of samples is dominated by monocrystalline quartz. Feldspar is a minor to moderate (0.55–9.38%) component of the samples and comprises mostly potassium feldspar. Partial dissolution of potassium feldspar is common in most samples enhancing the porosity of the sandstones. Plagioclase is rare with a maximum composition of 1.01%. Lithic grains are also a minor component and are dominantly metamorphic rock fragments with a minor amount of sedimentary rock fragments. Micas, commonly muscovite, in traces are present in nearly all samples, while other accessory minerals (zircon, tourmaline) are rare. Kaolinite and traces of illite are common authigenic phases filling intergranular pore spaces. Carbonate cement is seen in some of the samples, but these occurrences are of limited extent (Schacht, 2008).

Likely CO_2 chemical interaction within the Waarre C Formation was predicted to involve the in-place potassium feldspar and mica, as well as the dissolution of patchy carbonate cements. However, CO_2-induced diagenetic products were expected to be minor, due to the low modal abundance of these minerals in the formation. As a result CO_2–water–rock interactions were not expected to interfere with the ability to inject CO_2 at CRC-1.

Conversely, a study of the greensand units of the Flaxman Formation by Watson and Gibson-Poole (2005), found that the mineral trapping potential of this overlying formation will provide increased security to CO_2 storage in the Waarre C. Not only does the lower porosity of the greensands slow down the vertical migration of the CO_2 plume, but the abundance of labile minerals in this formation, including carbonate, glauconite, and chlorite, provides the cations necessary for mineralogical storage of CO_2.

3.3. Static and dynamic modelling

Structure, bulk permeability, relative permeability, and depositional environment were the key uncertainties in the preliminary static and dynamic models. All were shown to have an impact on the breakthrough times and plume development. The improved structural model, better constrained permeability, and relative permeability data from the core analysis meant a single base case could be assumed for these modelling inputs. However, spatial distribution of permeability streaks and baffles related to the depositional environment was still uncertain. Sedimentological observations of the cores showed complex stratigraphy that included presence of incised valley fill deposits within the Waarre C Formation, overlain by transgressive to offshore open marine deposits in the Flaxman Formation (Dance and Vakarelov, 2008). Because of the strong relationship identified between the depositional facies and reservoir quality, the new models used facies objects (gravel lag, sand channels, and shales) to constrain the spatial arrangement of permeability streaks and low flow baffles between the wells.

Both Naylor-1 and CRC-1 intersected at least two 1 m–3 m shales. The main uncertainty was if these were continuous or truncated between the wells. This would have implications for interpreting vertical connectivity between the injection perforations and the U-tube sampling inlets which spanned these shales in the monitoring well. A review of suitable analogues was made from modern settings, outcrop data, and literature in attempt to guide the ranges of the expected length and width of facies bodies (Fig. 11). For example the abandoned channel fill shale baffles commonly associated with transgressive estuarine settings occupying former incised valleys are not expected to be extensive due to the repeated channel incision (Shanley and McCabe, 1993). Specific ranges for length and width of channel bodies were derived from numerous analogue studies that were compared and summarised in Miall (1991). Channels were likely to be highly connected over the distance of 300 m between the injector and monitoring well. The abandoned channel fill shale baffles were not expected to exceed more than 80 m wide and 100 m long (Stephen and Dalrymple, 2002). Geophysical attributes, derived from the 3D seismic (acoustic impedance) and dip metre data were used to help guide anisotropy of the channel bodies which were approximately in a north-west to south-east orientation, this is roughly parallel to dip.

Two cases were then created to capture the geological range. Case 1 used a small correlation length for the shales (60 m–80 m), and case 2 used a long correlation length (120 m–240 m). Five equiprobable realisations were generated for each case, and examples of these are shown in Figure 12. The facies models were used as a constraint for populating petrophysical properties upscaled from well data to the grid resolution (0.5 m–2 m cell thickness). Similarly a method of incorporating facies-based permeability anisotropy was developed, and was set directly in the simulator whereby K_v/K_h ratios from the microtomography were applied as multipliers for each facies code. This approach was an improvement on just using one ratio for the whole reservoir because the impact of low vertical permeability in the shale rich facies could now be discretely assessed.

The pre-injection reservoir simulations were then again constrained using a history matching process that honours flow rate and cumulative production data, bottom-hole pressure during production and post production aquifer recharge (Underschultz et al., 2011; Xu et al., 2006). The model predictions from reservoir simulation, using ECLIPSE software, suggested an expected arrival time of between 4 and 8 months (Fig. 13). CO_2 would arrive first at the monitoring well just below the methane gas cap. Post injection the plume would not go beyond the pre-production gas-water contact (i.e. the spill point of the reservoir). The predicted maximum bottom-hole injection pressure was less than 19.7 MPa (i.e. an increase of 1.5 MPa). The heterogeneity did not seem to impact the bulk behaviour of the plume. However, as expected high permeability contrasts resulted in differences in the precise vertical location of breakthrough at the monitoring well. More can be found on this in Ennis-King et al. (2010).

3.3.1. Capacity

The 3D static geocellular model of the reservoir was used for estimating volumetric-based capacity (G_{CO_2}) using the equation proposed by the United States Department of Energy (DOE, 2006):

$$G_{CO_2} = A\, h_n\, g\, \phi_e\, \rho\, E$$

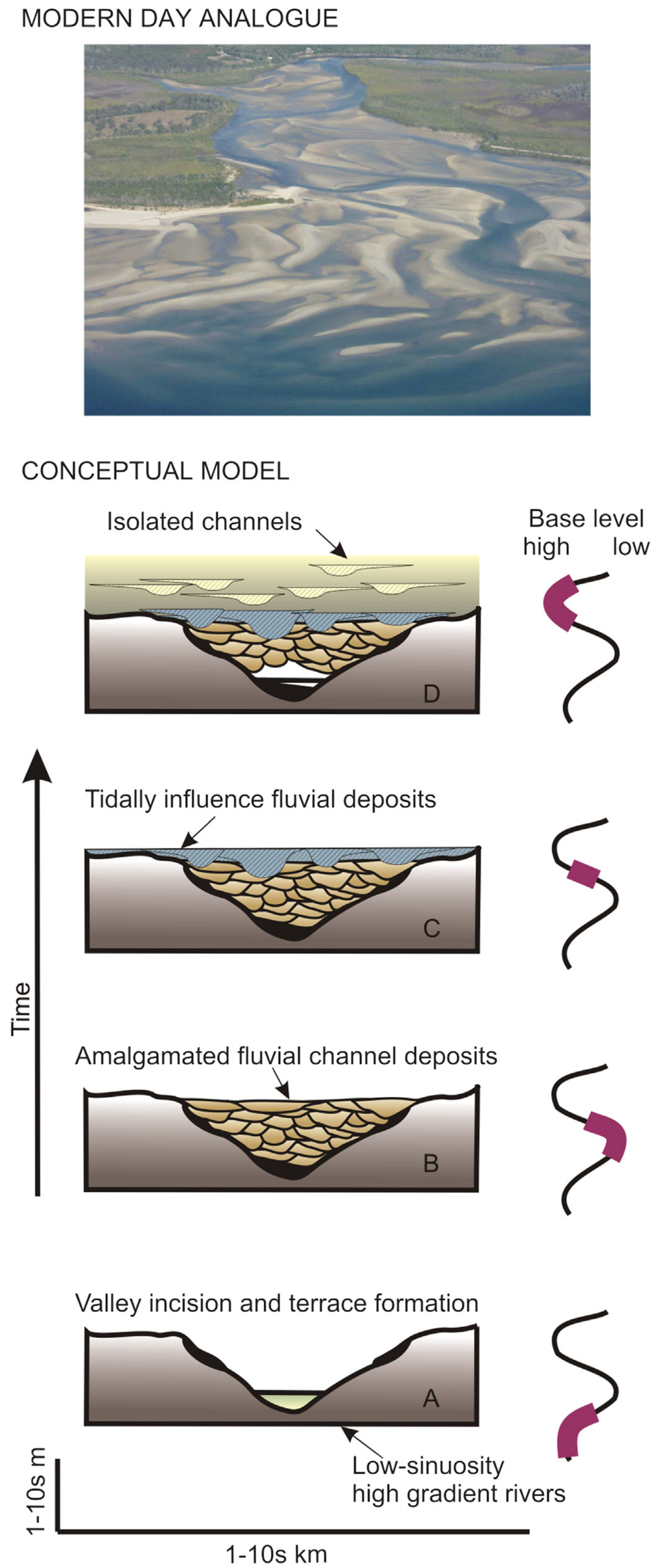


Figure 11. Hervey Bay in Northern Australia, a modern day analogue for the paleo-depositional environment for the Waarre C Formation (photograph courtesy of Simon Lang). And a conceptual depositional model for an incised valley fill sequence (modified from Shanley and McCabe, 1993).

The bulk rock volume was calculated from the static model by multiplying together the reservoir area (A), net gas column height (h_n), and geometry of the structural spill of the three way closure (g). An average effective porosity (ϕ_e), in combination with the bulk rock volume (A h_n g) provides an estimate of total pore space available for storage. The storage efficiency factor (E) provides a measure of the fraction of this total pore volume from the gas that has been produced and that can be filled by CO_2. The storage efficiency factor accounts for irreducible water saturation, as well as an estimate of the irreducible gas saturation; as the structure is interpreted to have been filled to spill point the irreducible gas saturation estimate can be blanket applied to the whole bulk rock volume.

Logging ascertained that the remaining methane gas cap occupies the top of the structure down to 2039.5 m RT at Naylor-1 (equivalent to ~1989 mTVDSS). Below the post production gas–water contact, prior to injection, the pore space contained an average 20% residual methane saturation with the remaining 80% being formation water. This was confirmed by the Reservoir Saturation Tool logging at CRC-1 and Naylor-1. On the time scale of the injection period (1–2 years), the injected CO_2 methane mixed gas can displace some of the formation water but will not access the entire 80% of the pore space previously occupied by formation water. Numerical simulation, run prior to injection, suggests that the water saturation within the reservoir at the end of the injection period will be 40–50% leaving only 30–40% of the pore space accessible for storage of injected gas. The density of the injected CO_2–CH_4 mixed gas is 360 kg/m^3, giving an estimated storage capacity within the Naylor Field of between 113,000 and 151,000 tonne. This supports the initial conclusion that the site has sufficient capacity to meet the project aims.

3.4. Containment

3.4.1. Seal capacity

Structural trapping is the dominant mechanism for containment of the CO_2 at the Naylor field. The CO_2 rises due to buoyancy, towards the top of the fault bound trap. The CO_2 settles beneath the methane gas cap that occupies the top of the structure as it is slightly denser than the methane; nevertheless some mixing of the two gas volumes is expected to occur. This mixed composition, but continuous gas column, is contained by both the overlying seal and the seal juxtaposed across the bounding fault.

Coring at CRC-1 allowed sampling of the primary seals in the Belfast Mudstone and Flaxman formation, as well as overlying intraformational seals within the Paaratte Formation and the Pember mudstone. The Belfast Mudstone is an exceptionally good seal, that is known to have held hydrocarbons throughout the Otway Basin (Stilwell and Gallagher, 2009); and provides a seal to the source gas at the Buttress field. Mercury injection capillary pressure tests were conducted on samples of the seal by Daniel (2007). These tests determined threshold or breakthrough pressures which were subsequently used to calculate the carbon dioxide retention height of the sealing rocks. Pore throat size distributions were also determined for the analysed samples and the laboratory mercury/air values were converted to equivalent subsurface supercritical carbon dioxide ($scCO_2$) values to determine subsurface water saturation versus height relationships. Results of this analysis are displayed in Figure 14. Recent experimental evidence by Chiquet et al. (2007) shows that $scCO_2$ may be partially wetting (depending on contact angle), with respect to quartz and mica rocks at subsurface conditions. As a consequence of this evidence CO_2 column heights were calculated with contact angle sensitivities from 0° to 60° in 20° increments to indicate the possible minimum column height. For example, at contact angle of

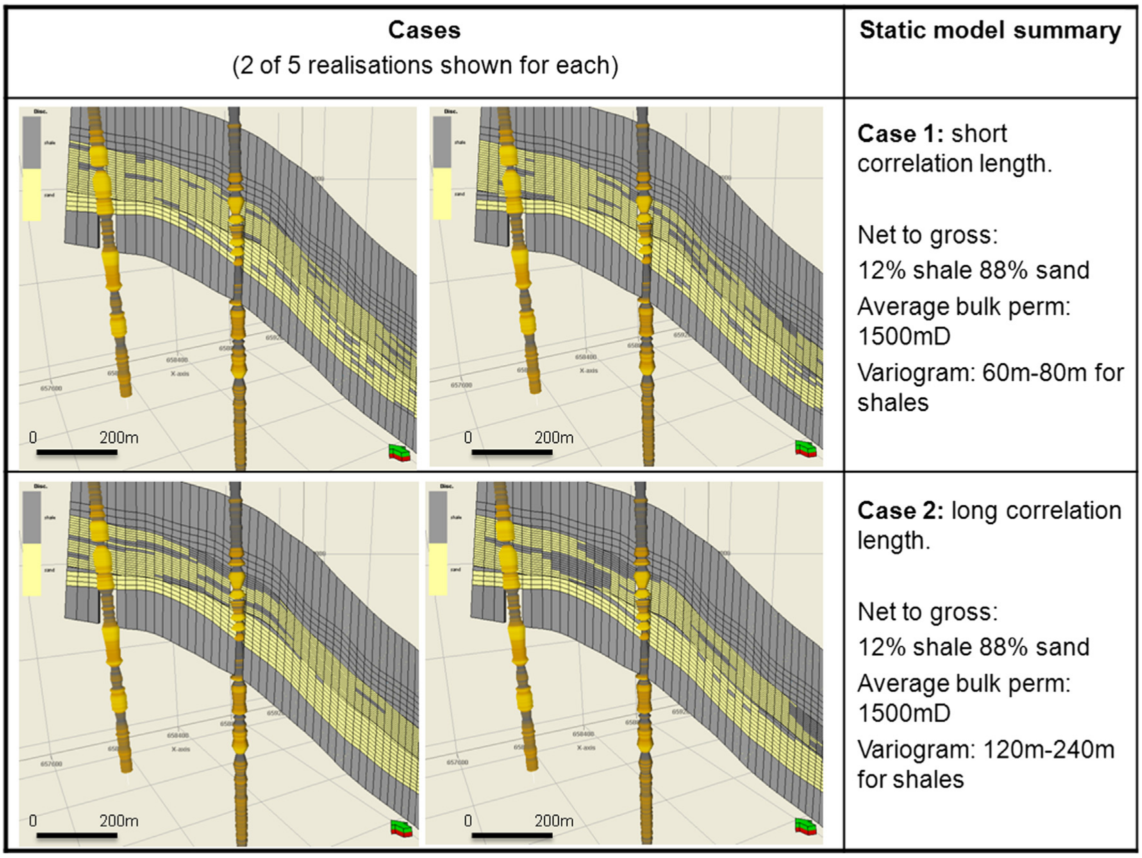


Figure 12. Two example realisations for the sand and shale distribution for each static model case. Sand is yellow and shale is grey. The overlying Flaxmans Formation and a portion of the Belfast Mudstone are shown as well as the underlying Waarre B shale unit at the base of the reservoir. The position of the wells and gamma ray logs coloured to represent sand and shale lithology are also shown. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

0° the Belfast Mudstone sample minimum column heights ranged from 607 m to 851 m with an average $scCO_2$ column height of 754 m (Fig. 14). However, using a contact angle of 60° showed that the minimum column heights for the same samples ranged from 303 m to 426 m. The maximum possible column height of the plume was expected to be in the order of 43 m given the top of the structure is at 1972 mTVDSS and the spill point is at 2015 mTVDSS. Therefore the primary seal was estimated to hold a minimum column height that was nearly an order of magnitude greater than the proposed plume height, and thus sealing capacity was considered excellent. Secondary seals within the Paaratte Formation were also considered good with one shale rich unit estimated to have a minimum column height of 110 m (Daniel, 2007).

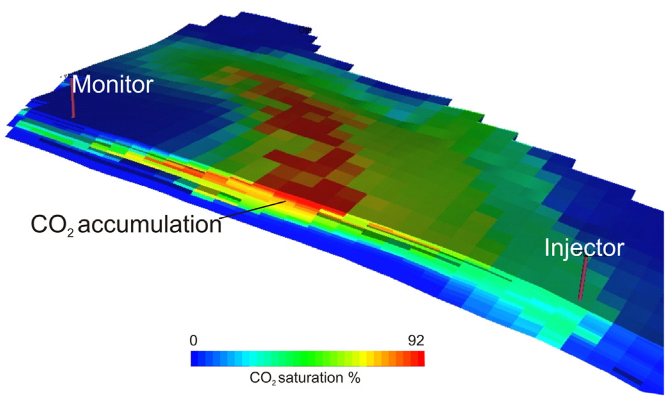


Figure 13. Cross-section view through the pre-injection dynamic model for CO_2 saturation at the end of injection of 100,000 tonne.

3.4.2. Geomechanics

Geomechanical assessments were conducted (van Ruth and Rogers, 2006) in order to estimate the maximum pore pressure increase the seal could sustain during injection. These studies concluded that the maximum sustainable pore pressure increase the seal could sustain before fracturing was an increase of up to 16.5 MPa above the pre-injection conditions. However, the sandstone units within the reservoir are more brittle and the maximum sustainable pore pressure increase is 9.6 MPa. Given that the dynamic modelling predicted that in each modelled case, the maximum injection pressure (bottom-hole pressure) would be approximately 2 MPa at the injection well, and post injection the pressure would be below the initial discovery pressure of the reservoir (19.5 MPa), hydraulic fracture development in the reservoir as a result of injection was considered highly unlikely.

The potential reactivation of the faults bounding the field was the subject of a study by Vidal-Gilbert et al. (2010). Modelling was constrained by the results from triaxial rock mechanical tests on CRC-1 cores. This reduced uncertainty of the minimum pore pressure increase required to cause fault reactivation. However, there was still large uncertainty surrounding the assumptions about the current regional Otway Basin stress regime, and the fault cohesion (C = the magnitude of sheer stress the fault can sustain before failure). Table 2 is a summary of the sensitivity analysis which considered different cases for these uncertainties as well as for the reservoir stress paths and Biot's coefficient.

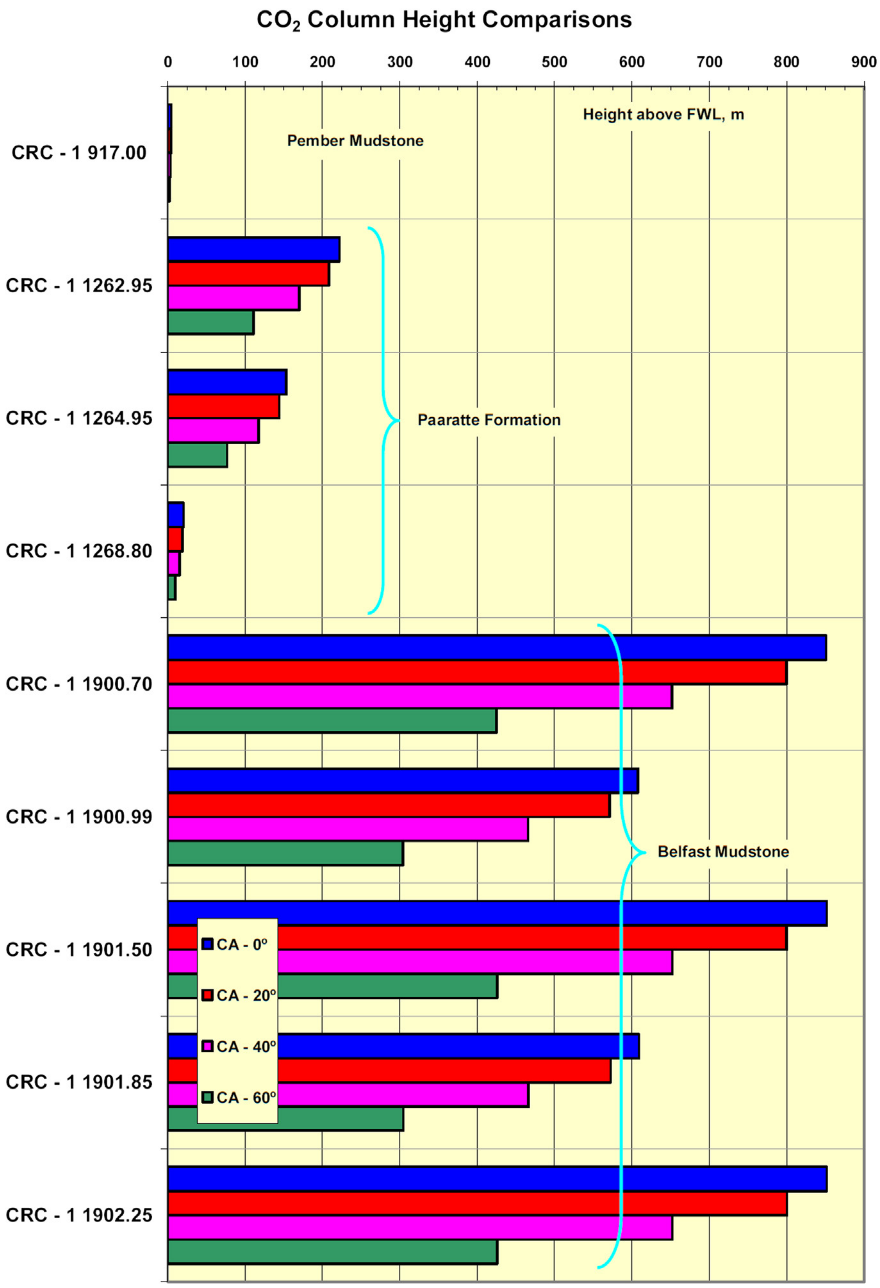


Figure 14. Carbon dioxide retention heights for the samples from CRC-1, Otway Project (linear). Contact angle sensitivities from 0° to 60° are included (Daniel, 2007).

Because the Belfast Mudstone was unconsolidated to semi-consolidated during the syn-depositional phases of tectonic deformation, it is more likely that many of the fault planes that are interpreted to go through the lithology are in fact, effectively 'annealed' through shale gouge and smearing at the fault zone. But without direct confirmation of this it was considered prudent to investigate two fault strength scenarios; healed faults ($C = 5$ MPa) and cohesionless faults ($C = 0$ MPa). In addition, three stress regime scenarios have been considered investigating both a strike-slip (SSFR) and normal (NFR) fault regimes, as well as changes in the maximum and minimum horizontal stress magnitude (σ_{Hmax} and σ_{hmin}):

$$\begin{aligned}&\text{Scenario 1 : SSFR with } \sigma_{hmin} = 14.5 \text{ MPa/km and } \sigma_{Hmax} = 26 \text{ MPa/km;}\\&\text{Scenario 2 : NFR with } \sigma_{hmin} = 14.5 \text{ MPa/km and } \sigma_{Hmax} = 18 \text{ MPa/km}\\&\text{Scenario 3 : SSFR with } \sigma_{hmin} = 18.5 \text{ MPa/km and } \sigma_{Hmax} = 37 \text{ MPa/km}\end{aligned}$$

The vertical stress gradient is constant (21.45 MPa/km) for all cases. As a result there is large range between 1 MPa and 37 MPa estimated for the minimum pore pressure increase (Δp_p) required to cause fault reactivation given the initial pore pressure at the top of the reservoir was 17.5 MPa just prior to injection. The most risky

Table 2
Results of the fault sensitivity study for determining pore pressure increase (Δp_p) required to reactivate optimally-oriented faults depending on assumptions made about in-situ stress regime, fault strength, reservoir stress path and Biot's coefficient. The highest risk scenario is highlighted in red, and the least risky in green (Vidal-Gilbert et al., 2010).

Scenario	Stress Regime	Fault Strength	Reservoir Stress Path	Biot's Coefficient	Δp_p MPa	p_p MPa
Scenario 1	SSFR	Cohesionless faults	β = 0	α = 1	1	18.5
	SSFR	Cohesionless faults	β = 0.4	α = 1	1.8	19.3
	SSFR	Cohesionless faults	β = 0	α = 0.7	8.9	26.4
	SSFR	Cohesionless faults	β = 0.4	α = 0.7	9.9	27.4
	SSFR	Healed faults	β = 0	α = 1	10.8	28.3
	SSFR	Healed faults	β = 0.4	α = 1	11.5	29
	SSFR	Healed faults	β = 0	α = 0.7	22.9	40.4
	SSFR	Healed faults	β = 0.4	α = 0.7	23.9	41.4
Scenario 2	NFR	Cohesionless faults	β = 0	α = 1	5.3	22.8
	NFR	Cohesionless faults	β = 0.4	α = 1	12.9	30.4
	NFR	Cohesionless faults	β = 0	α = 0.7	15.1	32.6
	NFR	Cohesionless faults	β = 0.4	α = 0.7	25.9	43.4
	NFR	Healed faults	β = 0	α = 1	13.9	31.4
	NFR	Healed faults	β = 0.4	α = 1	20.7	38.2
	NFR	Healed faults	β = 0	α = 0.7	27.3	44.8
	NFR	Healed faults	β = 0.4	α = 0.7	37	54.5
Scenario 3	SSFR	Cohesionless faults	β = 0	α = 1	2.3	19.8
	SSFR	Cohesionless faults	β = 0.4	α = 1	3.8	21.3
	SSFR	Cohesionless faults	β = 0	α = 0.7	10.8	28.3
	SSFR	Cohesionless faults	β = 0.4	α = 0.7	12.9	30.4
	SSFR	Healed faults	β = 0	α = 1	14.3	31.8
	SSFR	Healed faults	β = 0.4	α = 1	15.7	33.2
	SSFR	Healed faults	β = 0	α = 0.7	27.9	45.4
	SSFR	Healed faults	β = 0.4	α = 0.7	29.9	47.4

scenarios are a cohesionless fault in a strike-slip regime with low horizontal stress gradient ($\Delta p_p = 1$ MPa), highlighted in red in Table 2, and the least risky scenario is a healed fault in a normal fault regime ($\Delta p_p = 37$ MPa), coloured green. Given that the predicted pressure increase was expected to be approximately 2 MPa, further work was required to understand if the worst case scenario was likely at all.

The Iona Field is a produced natural gas field in south eastern Victoria that is approximately 20 km east of Naylor Field. 0.532×10^9 m^3 of the initial recoverable gas reserve were produced from the field and it is currently being used as a peak demand underground gas storage site supplying to the domestic market during the winter months. As the injection reservoir is also the Waarre C, it provides a valuable analogue for the Otway Project. The site has proven capability to inject up to nearly 2000 tonne of natural gas per day and withdraw around 5000 tonne per day without incident (Mehin and Kamel, 2002). There was a wealth of engineering data from the constant injection/withdrawal cycles that could be used to complement the geomechanical modelling and improve the understanding of the mechanical stresses on the reservoir and seal. A study by Tenthorey et al. (2010) analysed the results of dynamic simulations of the injectivity, pressure evolution, storage capacity and maximum fluid pressures sustained by the faults. The geomechanical simulations for the Iona field were re-run using CO_2 gas instead of methane in order to evaluate the effects of the different physical properties on fault seal retention column heights (i.e. wetting behaviour). Modelling the worst case scenario, where the faults have no cohesion, it was found the faults could sustain 2 MPa of pore-pressure increase without reactivation. In the more than 10 years of operation, the Iona field has experienced pressure oscillations in the order of 1–2 MPa with no observable seismicity (Tenthorey et al., 2010).

4. Results of site performance

Injection began in March of 2008 and continued until August of 2009. A total of 65,445 tonne of mixed gas (methane and CO_2), was injected at an average rate of 124 tonne per day (long-term average including shut down periods). Arrival of the plume at the Naylor-1 monitoring well occurred in July 2008 after the injection of 21,100 tonne. CO_2 arrival at the monitoring well was measured using a novel U-Tube system (Freifeld et al., 2005), whereby weekly fluid samples were retrieved under pressure from the reservoir to quantify changes in gas saturation over time. Three U-Tube inlet locations were positioned in the Naylor-1 wellbore to sample fluid from the gas cap, just below the gas water contact, and towards the bottom of the reservoir. Some dissolved CO_2 and tracer concentrations were first picked up in the U-tube below the gas cap 121 days after injection commenced. CO_2 mol% continued to show a steady increase and at 142 days sampling transitioned from mainly formation water to gas, reaching maximum gas saturation at 177 days. This confirmed the predictions that the injected gas mixture would be denser than the *in-situ* methane cap, but less dense than water, and thus would be first detected at the gas water contact. The observed arrival time was also within the predicted forecasts for breakthrough which ranged from 4 to 8 months. The highly channelised, well connected nature of the reservoir sands may explain why arrival of CO_2 was at the early end of the simulated results.

Several monitoring techniques in and above the storage reservoir provide evidence that containment has been achieved. Repeat logging was conducted at CRC-1 using a Reservoir Saturation Tool (RST) which combines pulsed neutron and sonic logs to determine reservoir fluid saturations. The logs were compared, before and after injection, and the effects of formation water being replaced by the injected mixed gas were computed based on the hydrogen index of gas versus water. This yields estimates for CO_2 saturation in the sands adjacent to the perforations of between 15% and 20%, which indicates the plume has migrated as predicted, up-dip towards Naylor-1. Another important observation is that no changes were observed in the logs below the lowest perforation, adding assurance that the injected gas has not filled downwards beyond the estimated structural spill point of the reservoir (2015 mTVDSS).

Imaging of the injection plume within the reservoir, using seismic techniques, was not expected to yield results due to the low acoustic contrast with the residual gas saturation already present. Seismic monitoring is further complicated by the fact the target is small, relatively thin and deep, and repeatability of surface seismic on-shore is hindered by seasonal effects. However, 4D seismic was used to monitor the overlying aquifers. Forward modelling predicted the seismic would be able to detect even small volumes of gas within the saline water if any reached the overlying formations. Three subsequent surveys have shown no seismic anomalies. In addition no significant micro-seismic events have been recorded on the faults surrounding the site indicating inducement of movement during injection. This suggests that faults cutting across the Waarre C possess some cohesion and the bounding faults at the Naylor Field have not shown any signs of reactivation under the injection pressures.

Groundwater flow and composition monitoring has been continually undertaken biannually in the Dilwyn and Port Campbell aquifers. The groundwater levels, flow, and chemistry have not been affected by the production, injection and storage associated with the project (de Caritat et al., 2012). Similarly, the atmospheric and soil monitoring has not detected any signs of the mixed gas injected or traces above the site.

A community consultation program was established in the Local Government shire of Moyne to gage public opinion and provide opportunities for landholders to raise any issues (Ashworth et al., 2010). The program followed the values and best practices of the International Association of Public Participation. The CO2CRC also employed a local resident as the Project Liaison Officer to provide land holders, researchers, and visitors with a local contact. As a result, good relations are maintained between the project proponents and the residents allowing for continued access for on-site operations, and access to farms for water monitoring and sampling surveys. Most importantly throughout the experiment, the community has remained supportive and interested. Monitoring will continue for several more years until regulators are satisfied that the site continues to behave as predicted and effective storage has been achieved.

5. Conclusions

Depleted gas fields have been identified as viable and secure options for geological storage of CO_2 on the basis that they have trapped hydrocarbons in the past (Stevens et al., 2000); nevertheless, the level of site characterisation at these locations is no less stringent when assessing their injectivity, capacity and containment of CO_2. A field or structure that was charged naturally over perhaps millions of years may not have the same response when being injected with CO_2 at high rates in a short space of time. Similarly, the CO_2 storage capacity at these sites won't necessarily equate to the original volume of gas produced, particularly in reservoirs with strong aquifer drive. Lastly the geochemical reaction potential of CO_2, once it is dissolved in water, may compromise seal integrity at a site where the original gas (e.g. methane in the reservoir), had relatively low reaction potential.

Site Characterisation of the Naylor Field for the CO2CRC Otway Project was carried out in two distinct phases: 1) An initial site screening phase, which assesses the regional geology and utilises existing data; and 2) the targeted characterisation phase, which involves data acquisition specifically to address uncertainty unique to the CO_2 storage concept. For others wishing to utilise depleted fields for CO_2 storage, much can be learnt in the early stages of characterisation. A theoretical capacity may be derived, reservoirs and seals mapped, and any impacts the project may have on resources in overlying stratigraphy. In many ways the dynamic modelling in the initial stages may be time consuming, covering a large range of possible scenarios. However, history matching to production data demonstrates the importance of capturing the range of uncertainty in the geology, and the consequent scatter in forward predictions.

This research has demonstrated the need for targeting data acquisition programs to reduce uncertainty. Costs and time limitations associated with any acquisition program will of course have to be considered and it may follow that at some sites, uncertainty surrounding reservoir characterisation will be negligible to the project's success. For example, regionally derived permeability information may be sufficient to characterise a relatively homogeneous reservoir, and there will be less of a need for expensive core analysis. Other sites may be considered higher risk and as such require greater detailed work. At the Otway site, it was essential to establish that the injection rates and planned CO_2 volumes would be accommodated, and that long term containment would be assured. Key outcomes from the study are that:

- Cores, well logs (in particular formation micro imaging (FMI), nuclear magnetic resonance (CNMR), and modular dynamic testing (MDT) samples), and seismic data acquired by the CO2CRC were necessary to better understand reservoir and seal properties.
- Specialised analysis such as SCAL core flooding, X ray microtomography and tri-axial rock mechanics were employed to better understand reservoir potential and fracture limits.
- Combined petrographic analysis, mercury injection capillary pressure tests, and stratigraphic mapping are necessary to characterise the overlying mudstone seal. The potential for CO_2/mineral reactions within the overlying seal means containment may be compromised by dissolution or further enhanced by precipitation.
- Underground gas storage facilities can provide useful analogues to CO_2 storage sites, particularly if they are in close proximity, or have similar reservoir settings to the planned

injection sites. Residual gas estimates, injectivity rates, rock mechanics, can provide substitute information in situations where data is otherwise lacking.

Site characterisation will always be specific to the project objectives of how much CO_2 is intended to be injected and at what rate. The degree of data acquisition and analysis will depend on the level of risk at the site. Above all it should aim to address the uncertainty surrounding these risks and can be tested and updated as necessary during the storage performance monitoring of the project.

Acknowledgements

The author would like to acknowledge the support from the CO2CRC Otway Project team leader, Sandeep Sharma and in particular the substantial contributions from members of the team involved in the early stages of site characterisation: Lynton Spencer, Frank La Pedalina, Peter van Ruth, Max Watson, Don Sherlock, Alison Hortle, Ric Daniels, Ulrike Schacht, and Josh Xu. Technical guidance and advice was provided by Lincoln Paterson of CSIRO, and John Kaldi and Bruce Ainsworth of the Australian School of Petroleum, Adelaide University. The paper was improved by comments from two anonymous reviewers. Funding that made this study possible was provided through the Australian Government CRC program and the CO2CRC member organisations.

References

Andrews, T., 1869. The Bakerian lecture: on the continuity of the gaseous and liquid states of matter. Philosophical Transactions of the Royal Society of London 159, 575–590.

Ashworth, P., Rodriguez, S., Miller, A., 2010. Case Study of the CO2CRC Otway Project. CSIRO Report, Pullenvale, Australia, 10.5341/RPT10–2362 EP 103388.

Bachu, S., 2000. Sequestration of CO_2 in geological media: criteria and approach for site selection in response to climate change. Energy Conversion Management 41, 953–970.

Bachu, S., 2003. Screening and ranking of sedimentary basins for sequestration of CO_2 in geological media in response to climate change. Environmental Geology 44, 277–289.

Boreham, C., Underschultz, J., Stalker, L., Kirste, D., Freifeld, B., Jenkins, C., Ennis-King, J., 2011. Monitoring of CO_2 storage in a depleted natural gas reservoir: gas geochemistry from the CO2CRC Otway Project, Australia. International Journal of Greenhouse Gas Control 5 (4), 1039–1054.

Boult, P.J., White, M.R., Pollock, R., Morton, J.G.G., Alexander, E.M., Hill, A.J., 2002. Lithostratigraphy and environments of deposition. In: Boult, P.J., Hibburt, J.E. (Eds.), The Petroleum Geology of South Australia, Petroleum Geology of South Australia Series, second ed., vol. 1. Department of Primary Industries and Resources, Otway Basin, South Australia.

Bradshaw, J., Bradshaw, B.E., Allison, G., Rigg, A., Nguyen, V., Spencer, L., 2002. The potential for geological sequestration of CO_2 in Australia: preliminary findings and implications for new gas field development. Australian Petroleum Production and Exploration Association Journal 42, 25–46. part 1.

Buffin, A.J., 1989. Waarre Sandstone development within the Port Campbell Embayment. Australian Petroleum Exploration Association Journal 29 (1), 299–311.

Burton, M., Kumar, N., Bryant, S.L., 2009. CO_2 injectivity into brine aquifers: why relative permeability matters as much as absolute permeability. Energy Procedia 1 (1), 3091–3098.

de Caritat, P., Hortle, A., Raistrick, M., Stalvies, C., Jenkins, C., 2012. Monitoring groundwater flow and chemical and isotopic composition at a demonstration site for carbon dioxide storage in a depleted natural gas reservoir. Applied Geochemistry. Available at: http://www.sciencedirect.com/science/article/pii/S0883292712001230.

Chadwick, A., Arts, R., Bernstone, C., May, F., Thibeau, S., Zweigel, P. (Eds.), 2007. Best Practice for the Storage of CO_2 in Saline Aquifers – Observations and Guidelines from the SACS and CO2STORE Projects: Nottingham. British Geological Survey, p. 267.

Chatzis, I., Morrow, N.R., Lim, H.T., 1983. Magnitude and detailed structure of residual oil saturation. SPE Journal 23, 311–326.

Chiquet, P., Broseta, D., Thibeau, S., 2007. Wettability alteration of caprock minerals by carbon dioxide. Geofluids 7 (2), 112–122.

Cooper, C. (Ed.), 2009. A Technical Basis for Carbon Dioxide Storage: CO_2 Capture Project. CPL Press, UK, p. 92.

Dance, T., Vakarelov, B., 2008. Sedimentology of the Flaxman Formation and Waarre C Formation from the CRC-1 Cores 5&6. CO2CRC Report No: RPT08–1293, Canberra, Australia. Available at: http://www.co2crc.com.au/publications/.

Dance, T., Spencer, L., Xu, J., 2009. Geological characterisation of the Otway Project pilot site: what a difference a well makes. Energy Procedia 1 (1), 2871–2878.

Daniel, R.F., 2007. Carbon Dioxide Seal Capacity Study, CRC-1, CO2CRC Otway Project, Otway Basin, Victoria. CO2CRC Report No: RPT07–0629, 67, Canberra, Australia. Available at: http://www.co2crc.com.au/publications/.

Dodds, K., Daley, T., Freifeld, B., Urosevic, M., Kepic, A., Sharma, S., 2009. Developing a monitoring and verification plan with reference to the Australian Otway CO_2 pilot project. The Leading Edge 28 (7), 812–818. http://dx.doi.org/10.1190/1.3167783.

DOE, 2006. Carbon Sequestration Atlas of the United States and Canada: Appendix a – Methodology for Development of Carbon Sequestration Capacity Estimates. National Energy Technology Laboratory, Department of Energy. Available from: http://www.netl.doe.gov/publications/carbon_seq/atlas/Appendix%20A.pdf.

Duran, J., 1986. Geology, Hydrogeology and Groundwater Modelling of the Port Campbell Hydrogeological Sub-basin, Otway Basin, S.W. Victoria. Report 1986/24. In: Geological Survey of Victoria, Victoria.

Ennis-King, J., Dance, T., Boreham, C., Xu, J., Freifeld, B., Jenkins, C., Paterson, L., Sharma, S., Stalker, L., Underschultz, J., 2010. The role of heterogeneity in CO_2 storage in a depleted gas field: history matching of simulation models to field data for the CO2CRC Otway Project, Australia. In: Oral Presentation Given at the 10th International Conference on Greenhouse Gas Control Technologies (GHGT-10), Amsterdam, The Netherlands, 19–23 September.

Faulkner, A., 2000. Sequence Stratigraphy of the Late Cretaceous Sherbrook Group, Shipwreck Trough, Otway Basin. (B.Sc. (Hon) thesis), National Centre for Petroleum Geology and Geophysics, University of Adelaide.

Flett, M., Beacher, G., Brantjes, J., Burt, A., Dauth, C., Koelmeyer, F., Lawrence, R., Leigh, S., McKenna, J., Gurton, R., Robinson IV, W.F., Tankersley, T., 2008. Gorgon Project: subsurface evaluation of carbon dioxide disposal under Barrow Island. In: SPE Asia Pacific Oil and Gas Conference and Exhibition, 20–22 October, Perth, Australia, p. 21.

Flett, M., Brantjes, J., Gurton, R., McKenna, J., Tankersley, T., Trupp, M., 2009. Subsurface development of CO_2 disposal for the Gorgon Project. Energy Procedia 1, 3031–3038.

Förster, A., Norden, B., Zinck-Jørgensen, K., Frykman, P., Kulenkampff, J., Spangenberg, E., Erzinger, J., Zimmer, M., Kopp, J., Borm, G., Juhlin, C., Cosma, C.G., Hurter, S., 2006. Baseline characterization of the CO2SINK geological storage site at Ketzin, Germany. Environmental Geoscience 13, 145–161.

Förster, A., Schoner, R., Forster, H.-J., Norden, B., Blaschke, A.-W., Luckert, J., Beutler, G., Gaupp, R., Rhede, D., 2010. Reservoir characterisation of a CO_2 storage aquifer: the Upper Triassic Stuttgart Formation in the Northeast German Basin. Marine and Petroleum Geology 27, 2156–2172.

Freifeld, B.M., Trautz, R.C., Yousif, K.K., Phelps, T.J., Myer, L.R., Hovorka, S.D., Collins, D., 2005. The U-Tube: a novel system for acquiring borehole fluid samples from a deep geologic CO_2 sequestration experiment. Journal of Geophysics, 110.

Geary, G.C., Reid, I.S.A., 1998. Hydrocarbon Prospectivity of the Offshore Eastern Otway Basin, Victoria for the 1998 Acreage Release. In: Victorian Initiative for Minerals and Petroleum Report, vol. 55. Department of Natural Resources and Environment.

Gibson-Poole, C.M., Root, R.S., Lang, S.C., Streit, J.E., Hennig, A.L., Otto, C.J., Underschultz, J.R., 2005. Conducting comprehensive analyses of potential sites for geological CO_2 storage. In: Rubin, E.S., Keith, D.W., Gilboy, C.F. (Eds.), Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, 5–9 September, Vancouver, Canada. Elsevier, Oxford, pp. 673–681.

Gunter, W.D., Perkins, E.H., McCann, T.J., 1993. Aquifer disposal of CO_2-rich gases: reaction design for added capacity. Energy Conversion and Management 34 (9–11), 941–948.

Hill, K.C., Durrand, C., 1993. The western Otway Basin: an overview of the rift and drift history using serial composite seismic profiles. PESA Journal 21, 67–78.

Hitchon, B. (Ed.), 2009. Pembina Cardium CO_2 Monitoring Pilot – a CO_2-EOR Project, Alberta, Canada. Geoscience Publishing, Sherwood Park, Alberta, Canada, p. 392.

Hortle, A., Xu, J., Dance, T., August 2013. Integrating hydrodynamic analysis of flow systems and induced-pressure decline at the Otway CO_2 storage site to improve reservoir history matching. Marine and Petroleum Geology 45, 159–170. ISSN 0264-8172, http://dx.doi.org/10.1016/j.marpetgeo.2013.04.013.

Hortle, A., Xu, J., Dance, T., 2008. Hydrodynamic interpretation of the Waarre formation aquifer in the onshore Otway Basin: implications for the CO2CRC Otway Basin project. In: Proceedings of the 9th International Conference on Greenhouse Gas Technologies (GHGT-9), 16–20 November, Washington DC.

Hovorka, S.D., Knox, P.R., 2003. Frio brine sequestration pilot in the Texas Gulf Coast. In: Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, October 1–4, Kyoto, Japan, pp. 583–587.

Hovorka, S.D., Benson, S.M., Doughty, C., Freifeld, B.M., Sakurai, S., Daley, T.M., Kharaka, Y.K., Holtz, M.H., Trautz, R.C., Seay Nance, H., Myer, L.R., Knauss, K.G., 2006. Measuring permanence of CO_2 storage in saline formations: the Frio experiment. Environmental Geoscience 13, 105–121.

IEA (International Energy Agency), Leblond, D., 2005. CO_2 capture, storage offer emissions solution. Oil & Gas Journal 103 (2), 29–30.

IEA (International Energy Agency), 2008. CO_2 Capture and Storage: a Key Carbon Abatement Option. OECD/IEA, Paris.

Intergovernmental Panel on Climate Change (IPCC), 2005. In: Metz, B., Davidson, O., de Coninck, H.C., Loos, M., Mayer, L.A. (Eds.), Special Report on Carbon Dioxide Capture and Storage. Cambridge University Press, Cambridge, U.K. and New York, NY, U.S.A, pp. 195–276. (Chapter 5).

Jenkins, C., Cook, P., Ennis-King, J., Underschultz, J., Boreham, C., de Caritat, P., Dance, T., Etheridge, D., Hortle, A., Frefeld, B., Kirste, D., Paterson, L., Pevzner, R., Schacht, U., Sharma, S., Stalker, L., Urosevic, M., 2012. Safe storage and effective monitoring of CO_2 in depleted gas fields. Proceedings of the National Academy of Science of the USA 109 (2), 353–354.

Kikuta, K., Hongo, S., Tanase, D., Ohsumi, T., 2005. Field test of CO_2 injection in Nagaoka, Japan. In: Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, September, Vancouver, Canada, pp. 1367–1372.

Knackstedt, M., Dance, T., Kumar, M., Averdunk, H., Paterson, L., 2010. Enumerating permeability, surface areas, and residual capillary trapping of CO_2 in 3D: digital analysis of CO2CRC project core. In: Presented at SPE Annual Technical Conference and Exhibition, Florence, Italy, 19–22 September. SPE paper 134625.

Kopsen, E., Scholfield, T., 1990. Prospectivity of the Otway Supergroup in the central and western Otway Basin. Australian Petroleum Exploration Association Journal 30 (1), 263–279.

Krassay, A.A., Cathro, D.L., Ryan, D.J., 2004. A regional tectonostratigraphic framework for the Otway Basin. In: PESA Eastern Australasian Basins Symposium, vol. II, pp. 97–116.

Laing, S., Dee, C.N., Best, P.W., 1989. The Otway Basin. Australian Petroleum Exploration Association Journal 29 (1), 417–429.

Maldal, T., Tappel, I.M., 2004. CO_2 underground storage for Snøhvit gas field development. Energy 29, 1403–1411.

Mehin, K., Constantine, A.E., 1999. Hydrocarbon Potential of the Western Onshore Otway Basin in Victoria: 1999 Acreage Release. In: Victorian Initiative for Minerals and Petroleum Report 62. Department of Natural Resources and Environment.

Mehin, K., Kamel, M., 2002. Gas Resources of the Otway Basin in Victoria. Department of Natural Resources and Environment, (State of Victoria), Petroleum Development Branch, ISBN 0 7306 9481 X. Available at: http://www.nre.vic.gov.au/minpet/index.htm.

Miall, A.D., 1991. The Three-dimensional Facies Architecture of Terrigenous Clastic Sediments and its Implications for Hydrocarbon Discovery and Recovery. In: Concepts in Sedimentology and Paleontology. Soc. for Sedim. Geol., Tulsa.

Morton, J.G.G., Alexander, E.M., Hill, A.J., White, M.R., 1995. Lithostratigraphy and environments of deposition. In: Morton, J.G.G., Drexel, J.F. (Eds.), 1995. The Petroleum Geology of South Australia, vol. 1. Mines and Energy South Australia, Otway Basin, pp. 127–139. Report 95/12.

Partridge, A.D., 2001. Revised stratigraphy of the Sherbrook group, Otway Basin. In: Hill, K.C., Bernecker, T. (Eds.), PESA Eastern Australasian Basins Symposium, pp. 455–464.

Peng, D.Y., Robinson, D.B., 1976. A new two-constant equation of state. Industrial and Engineering Chemistry: Fundamentals 15, 59–64.

Perrin, J.C., Krause, M., Kuo, C.W., Miljkovic, L., Charoba, E., Benson, S.M., 2009. Core-scale experimental study of relative permeability properties of CO_2 and brine in reservoir rocks. Energy Procedia 1, 3515–3522.

Riddiford, F.A., Tourqui, A., Bishop, C.D., Taylor, B., Smith, M., 2003. A cleaner development: the In Salah gas project, Algeria. In: Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, October 1–4, Kyoto, Japan, pp. 595–600.

Schacht, U., 2008. Petrological Investigations of CRC-1 Core Plug Samples: Waarre C, Flaxman, and Paaratte Formation. CO2CRC report number RPT08-1234, Canberra Australia. Available at: http://www.co2crc.com.au/publications/.

Shanley, K.W., McCabe, P.J., 1993. Alluvial architecture in a sequence stratigraphic framework: a case history from the Upper Cretaceous of southern Utah, USA. In: Flint, S.S., Bryant, I.D. (Eds.), The Geological Modeling of Hydrocarbon Reservoirs and Outcrop Analogues, International Association of Sedimentologists Special Publication, vol. 15, pp. 21–56.

Sharma, S., Cook, P.J., Robinson, S., Anderson, C., 2006. Regulatory challenges and managing public perception in planning a geological storage pilot project in Australia. In: Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies, June, Trondheim, Norway.

Sharma, S., Cook, P., Berly, T., Lees, M., 2008. The CO2CRC Otway Project: overcoming challenges from planning to execution of Australia's first CCS project. Energy Procedia 1 (1), 1965–1972.

Sharp, N.C., Wood, G.R., 2004. Casino gas field, offshore Otway Basin, Victoria — the appraisal story and some stratigraphic enlightenment. In: Boult, P., Johns, D., Lang, S.C. (Eds.), PESA Eastern Australasian Basins Symposium II, Petroleum Exploration Society of Australia, Special Publication, pp. 1–11.

Spencer, L., Xu, Q., LaPedalina, F., Weir, G., 2006. Site characterization of the Otway Basin storage pilot in Australia. In: Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies (GHGT-8), 19–22 June, Trondheim, Norway.

Stalker, L., Boreham, C., Underschultz, J., Freifeld, B., Perkins, E., Schacht, U., Sharma, S., 2009. Geochemical monitoring at the CO2CRC Otway Project: tracer injection and reservoir fluid acquisition. Energy Procedia 1, 2119–2125.

Stephen, K.D., Dalrymple, M., 2002. Reservoir simulations developed from an outcrop of incised valley fill strata. AAPG Bulletin 86 (5), 797–822. http://dx.doi.org/10.1306/61EEDBA2-173E-11D7-8645000102C1865D.

Stevens, S.H., Kuuskraa, V.A., Gale, J.J., Beecy, D., 2000. CO_2 injection and sequestration in depleted oil and gas fields and deep coal seams; worldwide potential and costs. AAPG Bulletin 84, 1497–1498.

Stilwell, J.D., Gallagher, S.J., 2009. Biotratigraphy and macroinvertebrate palaeontology of the petroleum-rich Belfast Mudstone (Sherbrook Group, uppermost Turonian to mid-Santonian), Otway Basin, southeastern Australia. Cretaceous Research 30, 873–884.

Tenthorey, E., Nguyen, D., Vidal-Gilbert, S., 2010. Applying underground gas storage experience to geological carbon dioxide storage: a case study from Australia's Otway Basin. In: Proceedings of the 10th International Conference on Greenhouse Gas Control Technologies (GHGT-10), Amsterdam, The Netherlands, 19–23 September.

Underschultz, J., Boreham, C., Dance, T., Stalker, L., Freifeld, B., Kirste, D., Ennis-King, J., 2011. CO_2 storage in a depleted gas field: an overview of the CO2CRC Otway Project and initial results. International Journal of Greenhouse Gas Control 5 (4), 922–932.

van Ruth, P., Rogers, C., 2006. Geomechanical Analysis of the Naylor Field, Otway Basin, Australia. CO2CRC Report number RPT06–0039, Canberra Australia. Available at: http://www.co2crc.com.au/publications/.

Varma, S., Underschultz, J., Dance, T., Langford, R., Esterle, J., Dodds, K., van Gent, D., 2009. Regional study on potential CO_2 geosequestration in the Collie Basin and the southern Perth Basin of Western Australia. Marine and Petroleum Geology 26, 1255–1273.

Vidal-Gilbert, S., Tenthorey, E., Dewhurst, D., Ennis-King, J., Van Ruth, P., Hillis, R., 2010. Geomechanical analysis of the Naylor field, Otway Basin, Australia: implications for CO_2 injection and storage. International Journal of Greenhouse Gas Control 4 (5), 827–839.

Watson, M., Gibson-Poole, C., 2005. Reservoir selection for optimised geological injection and storage of carbon dioxide: a combined geochemical and stratigraphic perspective. In: Conference Proceedings of the Fourth Annual Conference on Carbon Capture and Sequestration, DOE/NETL, May, Virginia, United States.

Wilson, M., Monea, M. (Eds.), 2004. IEA GHG Weyburn CO_2 Monitoring & Storage Project–Summary Report 2000–2004. Proceedings of the 7th International Conference on Greenhouse Gas Technologies, September, Vancouver, Canada, vol. 3, p. 273.

Woollands, M.A., Wong, D. (Eds.), 2001. Petroleum Atlas of Victoria. Victorian Department of Natural Resources and Environment. Available at: http://dpistore.efirst.com.au/product.asp?pID=9&cID=6.

WRI, 2008. CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage. World Resources Institute, Washington, DC, p. 144.

Xu, J., Weir, G., Ennis-King, J., Paterson, L., 2006. CO_2 migration modelling in a depleted gas field for the Otway Basin CO_2 storage pilot in Australia. In: Proceedings of the 8th International Conference for Green House Gas Control Technologies (GHGT-8), 19–22 June, Trondheim, Norway.

4.2 Publication 2: Characterisation of the Paaratte Formation for a CO_2 storage demonstration project

Submitted to: Journal of Petroleum Geology
Under review (2018)

Author: Tess Dance

Characterisation of the Paaratte Formation for a CO_2 storage demonstration project

Tess Dance

CO2CRC Ltd and CSIRO
Energy Business Unit, Australian Resources Research Centre, Kensington, WA, 6151
Tess.dance@csiro.au
Phone: +61 8 6436 8718

Abstract

The Late Cretaceous Paaratte Formation is targeted for conducting various Carbon dioxide (CO_2) injection and monitoring experiments for the CO2CRC Otway project Stage 2 and Stage 3 activities. The aims of these projects are to reduce uncertainty and cost in CO_2 storage in saline aquifers and monitoring. The concept of saline aquifer storage is to exploit hydrodynamic and capillary trapping over vast migration pathways and it is seen as having the most promise globally for large storage capacity. Thus field scale demonstration of this type of storage is of most interest for commercial-scale operators. The sub-surface research facility is located in the on-shore portion of the Otway Basin in the state of Victoria, Australia. Here the formation is at depths greater than 1000 m (below mean sea level) and is approximately 400 m thick. The Paaratte Formation is selected as it represents an emblematic example of a deep saline aquifer with no laterally limiting structural closure.

At various stages of the project, geocharacterisation supported decisions about well and perforation locations and to meet operational and scientific objectives. It was found that the deltaic depositional environment of the formation has given rise to interbedded heterogeneous facies of sandstones, mudstones, heterolithics, and diagenetic cements, providing ideal geological reservoir facies with sufficient injectivity for the tests (1,500 md permeability) combined with baffles and seals that could be exploited to impede the vertical flow of the CO_2 improving the monitorability and plume stabilisation. To date the data acquisition and reservoir evaluation at the site, including recovery of over 300 m of cores, has resulted in the single most complete and comprehensive dataset for the Paaratte Formation in existence. The age for the formation ranges from the upper part of the Lower Campanian to approximately the Campanian/Maastrichtian boundary, and it is recommended there be a subdivision of the formation into three-fold member units “A, B, and C” on the basis of the palynology and correlation to major regional unconformities and global eustatic cycles. The structural setting at the time was dominated by half-graben development separated by the linkage of transfer fault blocks. The paleao environment was almost entirely marine- deltaic and estuarine, with only minor fluvial deposits.

Introduction

The Paaratte Formation comprises the upper part of the Sherbrook Group, Campanian to Maastrichtian in age (Partridge, 2001), and was deposited in the Otway Basin during the later stage of rifting and extension of the Australian southern margin (Lavin, 1997; Palmowski et al., 2001; Aburas and Boult, 2001; krassay et al., 2004). The formation was first formally identified from the Port Campbell-1 well in 1959 and the name Paaratte was adopted after the parish in south-western Victoria where the well was drilled. McQueen (1961) first published the description for the formation overlying the Belfast Mudstone “consisting of interbedded sandstone, siltstone and mudstone, dolomitic and pyritic in parts and containing marine fossils”. Subsequent exploration in the onshore Otway Basin revealed discoveries of natural gas, some condensate, or carbon dioxide. All of these are reservoired in the much deeper Waarre Formation (with the exception of some minor gas and waxy paraffinic oil recovered from the Eumeralla Formation). This lack of hydrocarbon prospectivity in the Paaratte Formation has meant that there is a scarcity of core data from wells drilled after 1961, when the Commonwealth Government ceased its subsidy scheme, the Petroleum Search Subsidy Act, to encourage petroleum exploration, and there are no conventional cores from petroleum wells drilled in this part of the basin after 1967. Thus much of the publically available data comprises only very basic logs, occasional side wall cores, and cuttings acquired incidentally on the way down to the more prospective targets below. Figure 1 is a map of wells and gas fields in the Port Campbell Embayment, onshore Otway Basin, showing the location of Port Campbell-1 well and other wells with publically available data from the Paaratte Formation at the time of writing. These are summarised in Table 1 below.

Table 1: Conventional cores from wells in the Port Campbell Embayment through the Paaratte Formation available prior to his study.

Well Name	Spud date	*Sum of cores (m)
Flaxmans (Hill) -1	3/05/1961	15.8
Port Campbell-1	9/09/1959	8
Port Campbell-2	12/07/1960	0.60
Port Campbell-4	10/06/1964	8.50
Pecten-1A	12/04/1967	10.6
Sherbrook-1	19/11/1963	15.9

** Victorian data inventory accessed 13/01/2018 at the earth resources data store, Vic. Gov.*

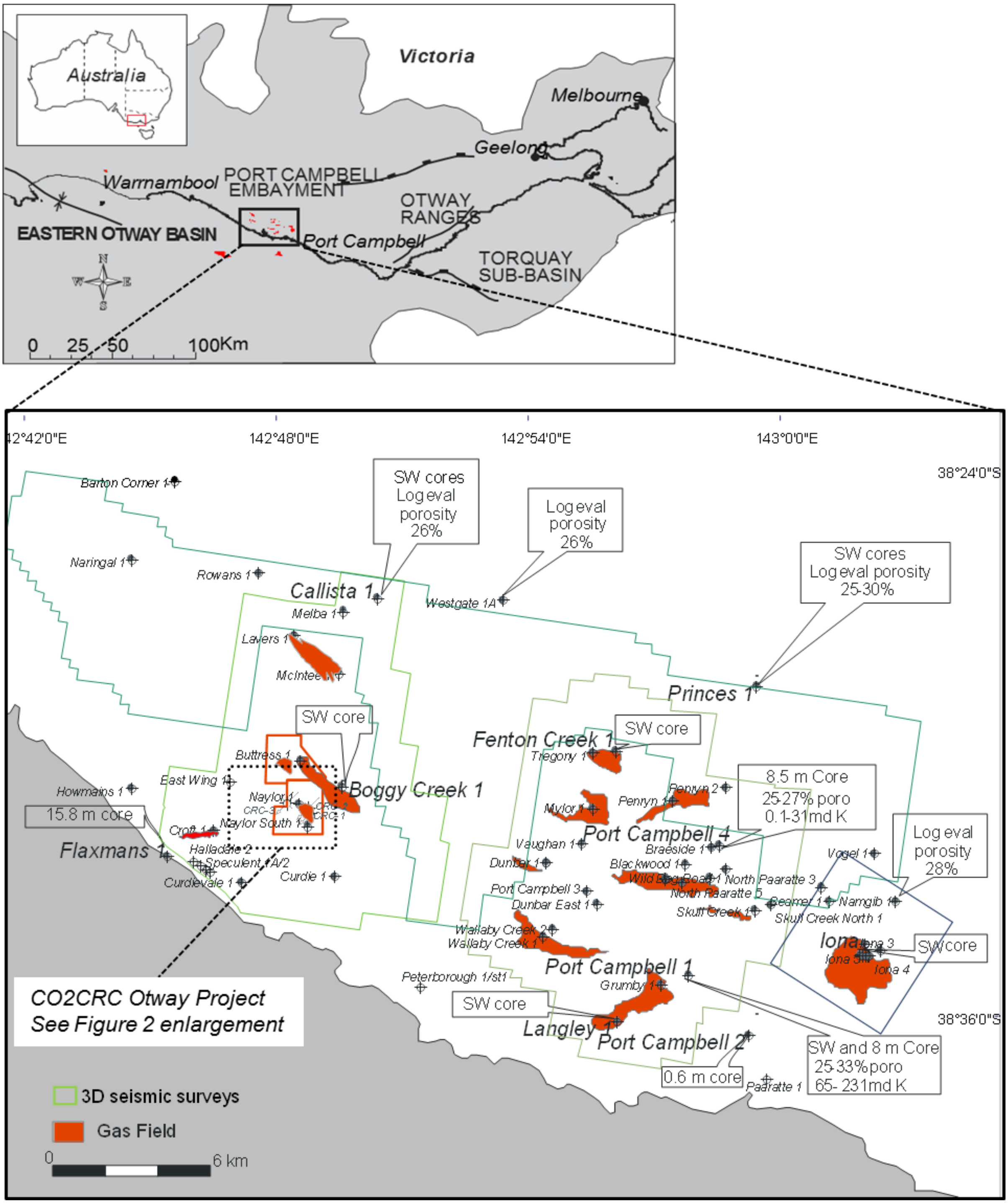


Figure 1: Map of the Otway Basin, Victoria, Australia, and enlargement of the Port Campbell Embayment gas fields. Wells that penetrate the Paaratte Formation in this part of the basin are shown and those that recovered core or side wall cores (SW) are in bold along with any porosity or permeability information reported in the public domain. Note conventional cores were gathered in Port Campbell No.1, No.2, No.4, and Flaxmans -1, also in wells not shown: Pecten-1A drilled offshore, Sherbrook-1 drilled east of the map.

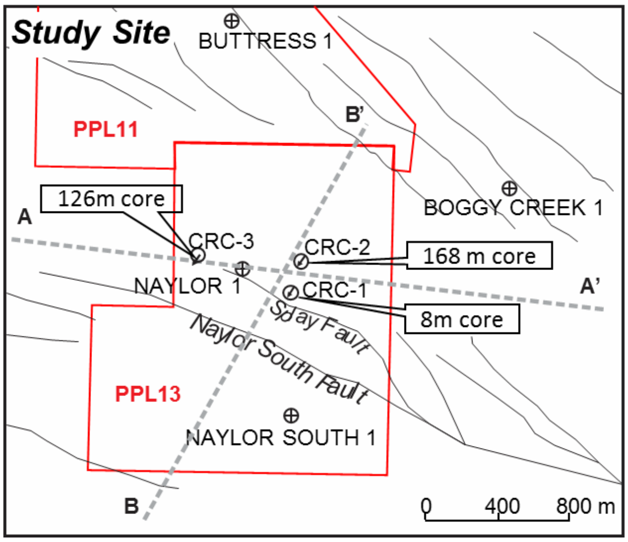


Figure2: Map of the CO2CRC Otway project site including wells and core data for the Paaratte Formation, and cross-section locations for Figure 4.

In petroleum tenements PPL 11 and PPL 13, from 2004 until the present, the CO2CRC Ltd. has conducted three consecutive stages of a carbon dioxide (CO_2) storage demonstration experiment known as the CO2CRC Otway Project (Cook, 2014) (Figure 2). Carbon capture and storage (CCS) is seen as a promising technology for reducing greenhouse gas emissions and mitigating climate change. Naturally regulators and the community are seeking assurance that sub-surface injection and storage processes can be well understood and monitored. To this end the learnings from the Otway Project have been principal to the social environmental acceptance of CCS in Australia.

The lower part of the Late Cretaceous Paaratte Formation has been the target for the most recent CO2CRC Otway Project experiments. Here the research is focused on a concept known as saline aquifer storage. This is where geological aquifers may be exploited for CCS because they are too deep or the formation water too saline to be used for ground water extraction (Bachu et al, 1994; SACS/CO2Store, 2008). Containment of the CO_2 relies on hydrodynamic trapping. In the absence of lateral structural closure the CO_2 is able to move over long distances, and residual trapping and dissolution is expected to dominate (IPPC, 2005).

A detailed geological characterisation effort has supported ongoing planning for the operational side of the project, for example, selecting the appropriate stratigraphic interval for perforations, and determining the optimal volume to be injected. Features of the sub-surface geological architecture that influence the behaviour of the injected CO_2 are characterised from sources such as geophysical surveys and well-based data, and incorporated in three dimensional model representations of static rock properties. This has resulted in the most extensive core and log data base tied to seismically mapped horizons for the Paaratte Formation to date.

This paper serves as a reference to those involved or interested in research pertaining to the Paaratte Formation at the Otway Project site and sets out the geological framework, petrophysical evaluation, and facies schema pertinent to simulation and modelling. Furthermore, the density of high-quality core and log samples provides a hither to unavailable opportunity to more precisely define the typical characteristics and age of the formation within reasonable proximity of the type section of the formation designated in the early Port Campbell-1 well. This new revision is presented herein including a proposal to sub-divide the Paaratte into three A, B, and C unit members.

Otway Project Context and Data

Australia's first CO_2 sequestration demonstration project was established in 2004 in the Otway Basin, Victoria (Figure 2). A schematic cross-section is provided in Figure 3 showing the targets for the CO2CRC Otway Project, and Table 2 provides a summary of data for the Paaratte Formation generated from project activities thus far. Stage 1 of the project (2008-2009) demonstrated the viability of geological storage of CO_2 into an onshore depleted natural gas reservoir, where structural trapping dominates. The Naylor field was selected as it was close to a naturally occurring, high CO_2 felid (Buttress), which has served as the injection source for the experiments. The project was the first of its kind in Australia to inject and monitor over 65,000 tons of CO_2 rich mixed gas in the sub-surface (Cook, 2014). The experiment was conducted in the Waarre C Formation, the main hydrocarbon bearing reservoir in this part of the Otway Basin, but was depleted at the site after production from the Naylor-1 well in 2002. The injector, CRC-1, drilled in 2007, reached total depth in the Eumeralla Formation -2249 m depth below mean sea-level (SS) (Dance, 2013). The Paaratte Formation was encountered in CRC-1 between -1079.4 m and -1463.1 m SS (377.2 m thick). Over 49 m of conventional core was recovered during drilling, mostly from the Waarre C and Flaxmans Formations, but also including nine metres of cores recovered from the upper part of the Paaratte Formation (from approximately -1211 m to -1220 m SS). During and post-injection, various geophysical and geochemical monitoring techniques were employed at the reservoir level as well as in groundwater, soil and the atmosphere to characterise behaviour of the plume and to verify containment (Jenkins et al. 2012, Underschultz et al., 2011).

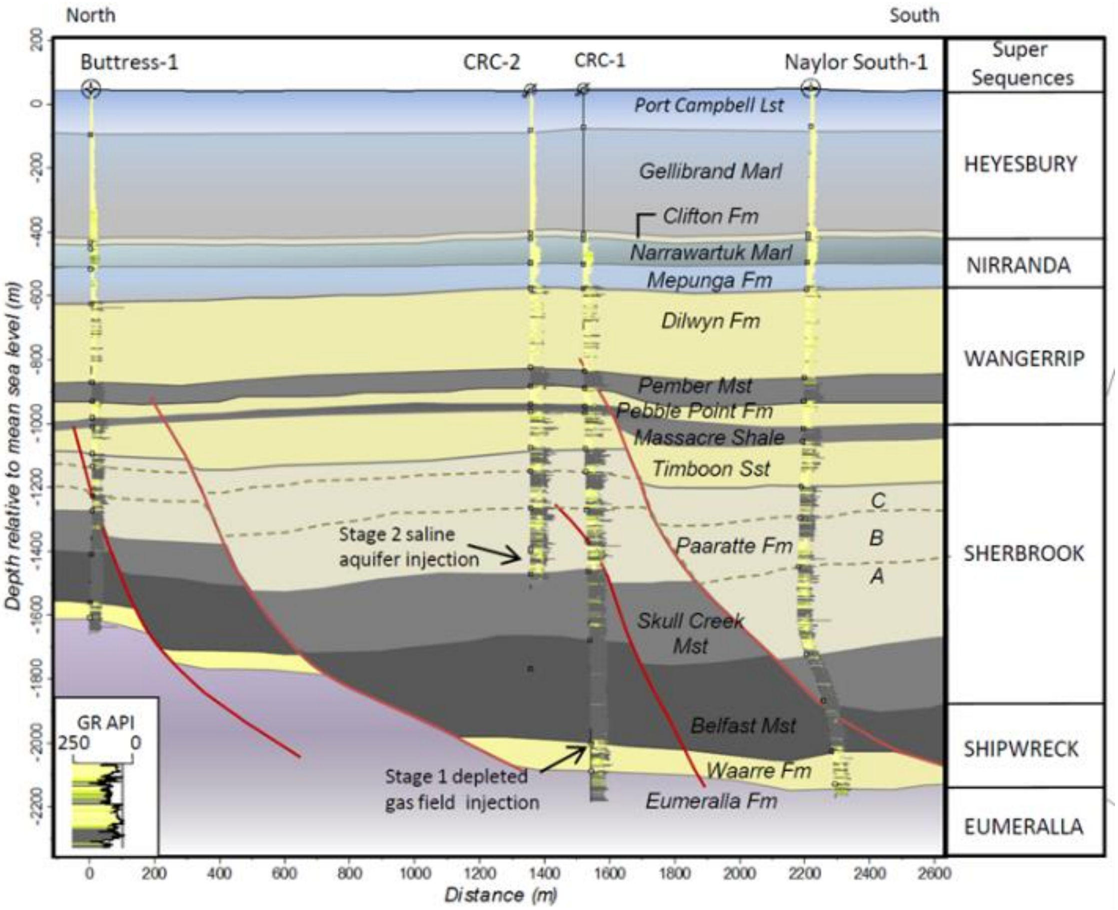


Figure 3: Schematic cross-section showing the current CO2CRC Otway Project injection target in the Paaratte Formation Unit A, and the super sequences identified in the eastern Otway Basin by Geoscience Australia.

Table 2: Summary of geological data generated for the Paaratte Formation as a result of the CO2CRC Otway Project activities. (Note: this is not an exhaustive list of all Otway Project data, which goes beyond just the Paaratte Formation).

Well data			
	CRC-1	**CRC-2**	**CRC-3**
Cores	9 m	168 m	126 m
Cuttings	✓	✓	✓
Core Gamma ray	✓	✓	✓
Routine core analysis (poro/perm)	1 plug	72 plugs	84 plugs
Mini-permeametre		1,233 readings	506 readings
Special Core analysis		3 tests	2 tests
Mercury Injection Capillary Pressure		✓	✓
Geomechanical tests		✓	✓
Geochemical	✓	✓	✓
Hylogger		✓	✓
Acoustic properties	✓	✓	✓
Palynology		✓	✓
Well logs:			
Gamma Ray, density, neutron	✓	✓	✓
Formation Micro-image logs	✓	✓	✓
Nuclear Magnetic Resonance	✓	✓	✓
Elemental Capture Spectroscopy	✓	✓	✓
Pulsed Neutron logging	✓	✓	
Fluid samples	MDT	MDT/water production	
VSP	✓	✓	✓

Stage 2C 3D Seismic data – Processed to image the Paaratte Fm.		
Survey	**Date**	**Volume CO_2 injected**
Baseline		**0**
Monitor 1	January 2016	5,000 ton
Monitor 2	February 2016	10,000 ton
Monitor 3	April 2016	15,000 ton
Monitor 4	January 2017	9 months after the end of injection
Monitor 5	March 2018	2 years after the end of injection

Subsequent experiments as part of Stage 2 and Stage 3, have been specifically targeting the Paaratte Formation for the purpose of demonstration of CO_2 storage in a saline aquifer. Stage 2 commenced in 2010 with the drilling of a new injection well, CRC-2, at the site, and analysis of the well's log and core data by Bunch et al. (2012) identified the Late Cretaceous Paaratte Formation between -1075.1 m and -1472.3 m SS (397.2 m thick) as a suitable candidate for the experiments as it is structurally unconfined in the vicinity of the site, but contains a high degree of vertical herterogentiy that could contribute to CO_2 trapping. This is because the containment concept for saline aquifer storage relies on the permeable reservoir units to contain inter-formational baffles to inhibit vertical movement of the buoyant CO_2 long enough for residual and solubility trapping to immobilise free-phase CO_2 in the pore space (Bruant et al. 2002). A total of 29 cores were cut in CRC-2 with 176 m of material recovered. Approximately 168 m was from the Paaratte, and the remainder from the Pember Mudstone above. Routine core analysis (RCA), petrographic thin section descriptions, and geochemical analysis was performed on samples acquired from intervals of interest for an injection experiment (Daniel et al. 2012a). Other core analysis included special core flood analysis (SCAL) to determine relative permeability and saturation end points (Krevor et al. 2012); microtomography to quantify the pore-scale geometry; and HyLogger mineralogical scanning which provided high resolution core mineralogy to calibrate against the downhole logs.

A single well test was performed in CRC-2 in June 2011, to examine techniques useful to characterising non-structural trapping potential of formations. The test incorporated five independent measurement techniques to quantify residual saturation and dissolution at various scales in the near well bore region. The aim being that a similar test may be applied in commercial appraisal programs prior to full scale injection (Zhang et al. 2009; Paterson et al. 2012). Later another injection test added knowledge of residual saturation quantification using oxygen isotopes (Serno et al. 2016). Data resulting from these activities includes six repeated time-lapse pulsed neutron log runs (Dance and Paterson, 2016) and formation water samples.

The last phase of Stage 2 involved the injection of 15,000 ton of CO_2-rich gas (approximately 80 mol% carbon dioxide; 20 mol% methane from the nearby Buttress field) from November 2015 to April 2016. Injection was into the lower Paaratte Formation via CRC-2, accompanied at the surface with deployment of improved time-lapse geophysical monitoring techniques to image plume evolution and eventual stabilisation (Pevzner et al. 2013; Pevzner et al., 2012). This has generated no less than six high resolution 3D surveys, designed and processed specifically to image the Paaratte Formation, as well as numerous vertical seismic profiles (VSP).

The most recent instalment at the Otway facility is focused on reducing the cost of geological CO_2 storage and monitoring and reducing the surface footprint of monitoring techniques (Stage

3). Another small injection is planned for 2019 (<30,000 ton), this time via a new well, CRC-3, drilled in early 2017, located to the west of CRC-1 and CRC-2 and similarly targeting the lower Paaratte Formation. CRC-3 encountered the Paaratte between -1098.4 m and -1512.7 m SS (414.3 m thick), and recovered approximately 126 m of core from the Paaratte Formation, 110 m of which comprising a continuous section through the lower Paaratte to Skull Creek Mudstone below. The experiment aims to use well based monitoring, pressure tomography and cross-well geophysics, and a further four wells are planned in 2018 for this purpose (Jenkins et al. 2017).

Geological Characterisation Method

Reservoir Characterisation for geological storage of CO_2 is an inter-disciplinary process of gathering and integrating all available data for the purpose of evaluating the site against the key criterion of injectivity, capacity, and containment (Bachu and Grobe, 2006; Birkholzer and Tsang, 2008; Bruant et al., 2002; Cook, 2006; IPCC, 2005). Many simulation studies looking at CO_2 trapping and plume development have highlighted the importance of understanding the spatial distribution and correlation of geological heterogeneity with respect to storage site efficiency, safety, and performance (Ghanbari et al. 2006; Havorka et al. 2004; Kumar et al. 2005). However, the hierarchical description of heterogeneity can span multiple scales. At the very largest scale (e.g. basin-wide prospecting) the mapping of sequence stratigraphic boundaries is recommended to sub-divide the sedimentary succession into linkages of similarly related strata and allow for forming a model of the temporal evolution of the paleogeography from which likely reservoir-seal pairs can be identified (Root et al., 2004; Gibson-Poole et al., 2005). At the other end of the scale, classification of the microscopic heterogeneity impacting the pore geometry and interconnectivity of pore throats is the focus when estimating the potential for capillary trapping (Herring et al. 2013; Pentland et al., 2011; Pini et al., 2012).

In advance of all the Otway Project injection experiments, the objective of geocharacterisation was to provide a geologically constrained 3D model that could be used concurrently for many different modelling domains. For example: dynamic simulation and prediction (Watson et al. 2012; Dance and Cinar, 2009); fault seal risking (Tenthorey et al. 2014); and rock physics simulation of seismic response (Glubokovskikh et al. 2016). The characterisation approach at Otway has always been to use sequence stratigraphy to define the zones or reservoir and seal units; and use sedimentology combined with an understanding of the diagenetic history as these principals have been proven predictors for reservoir properties in reservoir characterisation workflows (Alpay 1972; Weber 1986; Lassiter et al. 1986; van de Graaff & Ealey 1989). The premise is that the sedimentary rocks' pore network, grain size, sorting, grain packing, lamination, sedimentary structures, and the vertical and lateral development of sequences, are all a function of the environment in which the rocks were laid down through time and subsequent pressure and temperature changes related to burial processes. This geo-characterisation focused modelling workflow is of methodological value since it provides a reliable basis for dynamic simulation, seismic feasibility studies, and development of uncertainty-driven risk assessments. The method for characterising reservoir sequences in the Paaratte Formation can be surmised as follows:

1. Place the Formation in its regional stratigraphic and structural setting.
2. Conduct detailed core sedimentological analysis to derive facies, facies associations and classify them in the context of paleo-depositional environments.
3. Extrapolate image log derived facies interpretations to intervals and wells where there is no core.
4. Pick major flooding surfaces and parasequence boundaries based on core interpretation, electro log signatures, biostratigraphy and seismic reflectors.
5. Examine the relationship of reservoir quality with depositional facies and digenesis.
6. Compare facies architecture with analogue data to predict geometric correlation scales and anisotropy.

Structural setting

The study site is in an area of the Otway Basin known for numerous small methane and CO_2 rich fields. Structurally, the basin forms part of the Southern Rift System originating during the continental separation of Australia and Antarctica (krassay et al., 2004). As a result, this part of the basin is dominated by West to North-West trending depocentres characterised by half-graben development separated by the linkage of transfer fault blocks. The Otway Project site is located within one such fault block, bound to the south by the Naylor South Fault, and bound to the north by the Buttress and Boggy Creek fault complexes. It sits almost on the crest of a structural saddle between the terminating fault zones.

Over the Naylor field there exists an extensive and high quality 3D survey seismic volume acquired in 2000 for petroleum exploration, as well as the local baseline and monitoring surveys gathered for monitoring of the 15,000 t injection in 2015-16 (Table 1). Detailed interpretation of faults and horizons was conducted on a combination of all the surveys to map the extents of regional surfaces tied to wells and also to map the intra-formational horizons (Figure 4). Figure 4a is a regional east-west seismic section showing the major formation horizons. The horizon tops and intra-formational unit boundaries within the Paaratte provide strong acoustic contrasts on the seismic data resulting in strong reflection amplitudes and high quality coherency reflectors that are tracked easily across the study area. Faulting associated with Late Cretaceous extension is marked in the older sequences but tends to die out before the top of the Sherbrook Group. For example, the faults flanking the Naylor field at the Waarre C level have not been reactivated through to the late Tertiary. In contrast, the faults associated with the Naylor South, Buttress, and Boggy Creek structures have been reactivated, forming large normally faulted half grabens. Figure 4b is a dip section through the Paaratte Formation, and figure 4c shows the top of an intraformational horizon (unit A) depth structure surface. The Paaratte strata is gently dipping in the study area with average dip angles between two to six degrees. Down-dip is towards the west and there is a slight incline to the East-South-East along a ridge associated with the up-thrown side of a splay fault. Analysis of the orthocontours (pathways of steepest accent orthogonal to the structural dip) shows there is a likely resulting CO_2 migration direction along this ridge to the east and toward the north indicated by the black arrows in Figure 4c.

The interpretation for the Naylor South fault reveals it has a throw in the Otway site area of up to 190 m. The vertical extent of the fault appears to increase from the west to the east, and so too the fault throw increases in this direction. A smaller synthetic fault exists parallel to the Naylor South fault but trends more NW-SE and is intersected by both CRC-1 and Naylor-1. It's approximately 1800 m long with a maximum offset at the Paaratte level on the order of 15 to 30 m. This fault appears to die out below the top of the unit A in the Paaratte Formation but has influence on the local dip near the injection target.

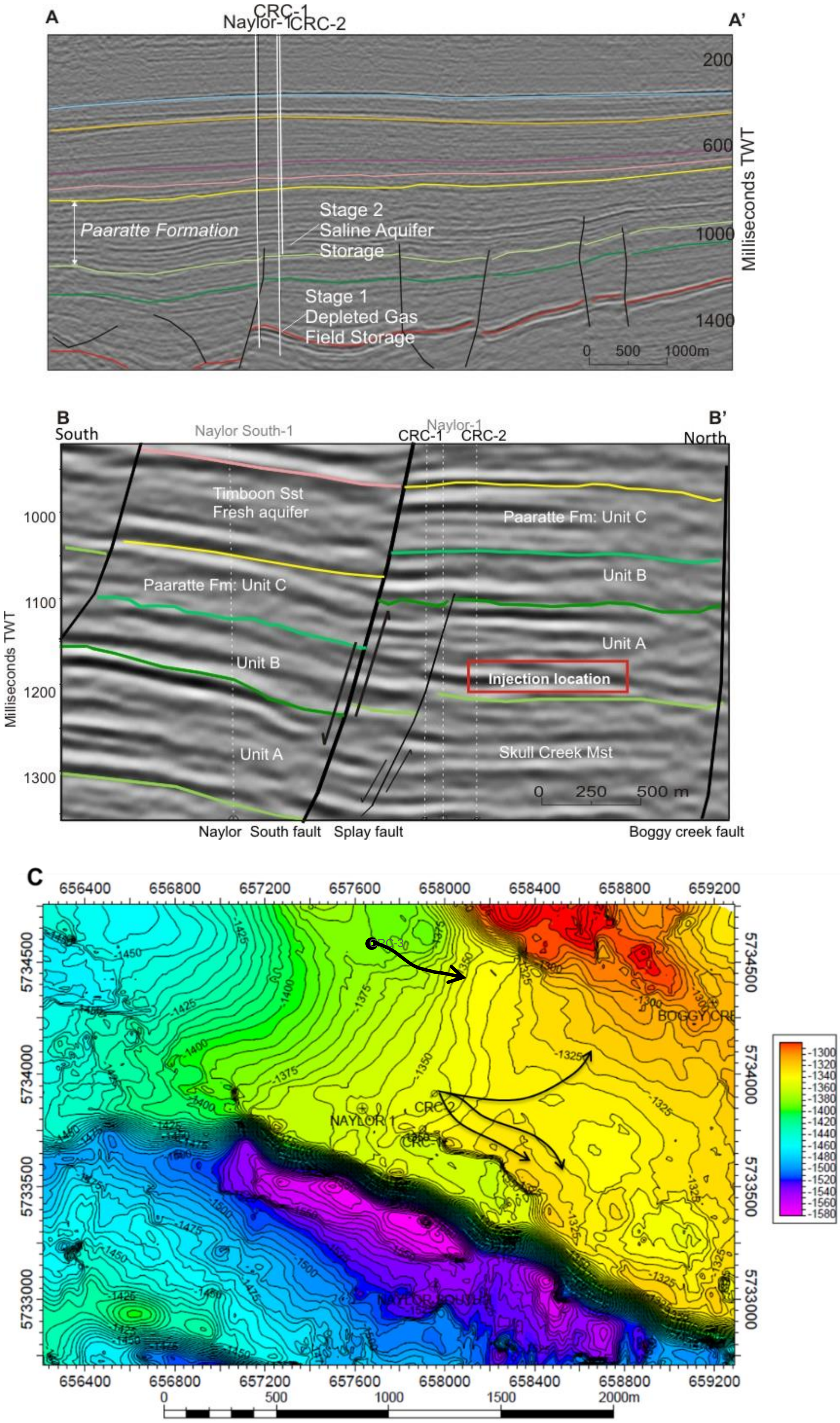


Figure 4: Seismic cross-sections and depth map at the study site, key formation top horizons, wells, and faults (locations of sections shown in Fig. 2). A) strike section showing location of the stage 1 and stage 2 experiments. B) dip section, perpendicular to the main faults through the Paaratte Formation and the Timboon Sandstone fresh water aquifer juxtaposed to the upper units of the Paaratte Formation on the down-thrown side of the Naylor South Fault. C) Depth structure map of the top Unit A horizon in meters below mean sea level (5 m contour intervals) and inferred CO_2 migration directions indicated by black arrows.

Stratigraphic Assessment

Review of the Type Section

The Paaratte Formation was originally proposed for a relatively thin interval of interfingering sandstones and mudstones between 1294 m and 1503 m in Port Campbell–1 by Bain & McQueen (1964 ***in*** BMR 1964). This original "type" section is illustrated by the black bar labelled BMR 1964, adjacent to the Port Campbell-1 well in Figure 5. Subsequently, Bock & Glenie (1965) and Glenie (1971) applied the name Paaratte to a much broader formation concept, covering all interbedded sandstones, mudstones and occasional coals between the top of the Flaxman Formation and the top of the Sherbrook Group. Within this broad interval the Belfast Mudstone, Nullawarre Greensand and Timboon Sand were treated as local members that were interpreted as time equivalent to the interbedded facies of the more expansive concept of the Paaratte Formation. The designated "type" section for this broad concept of the formation is the interval 886 m to 1685 m, illustrated by the red & black bar labelled Glenie 1971, adjacent to the Port Campbell-1 well in Figure 5. The bottom black interval from 1501 m to 1685 m was assigned to the Belfast Mudstone Member, while the top black interval from 886 m to 1295 m was assigned to the Timboon Sand Member (Glenie, 1971). This meant the middle red interval from 1295 m to 1501 m defaulted to undifferentiated Paaratte Formation, as the Nullawarre Greensand Member was not identified in the well by Glenie (1971, p.206).

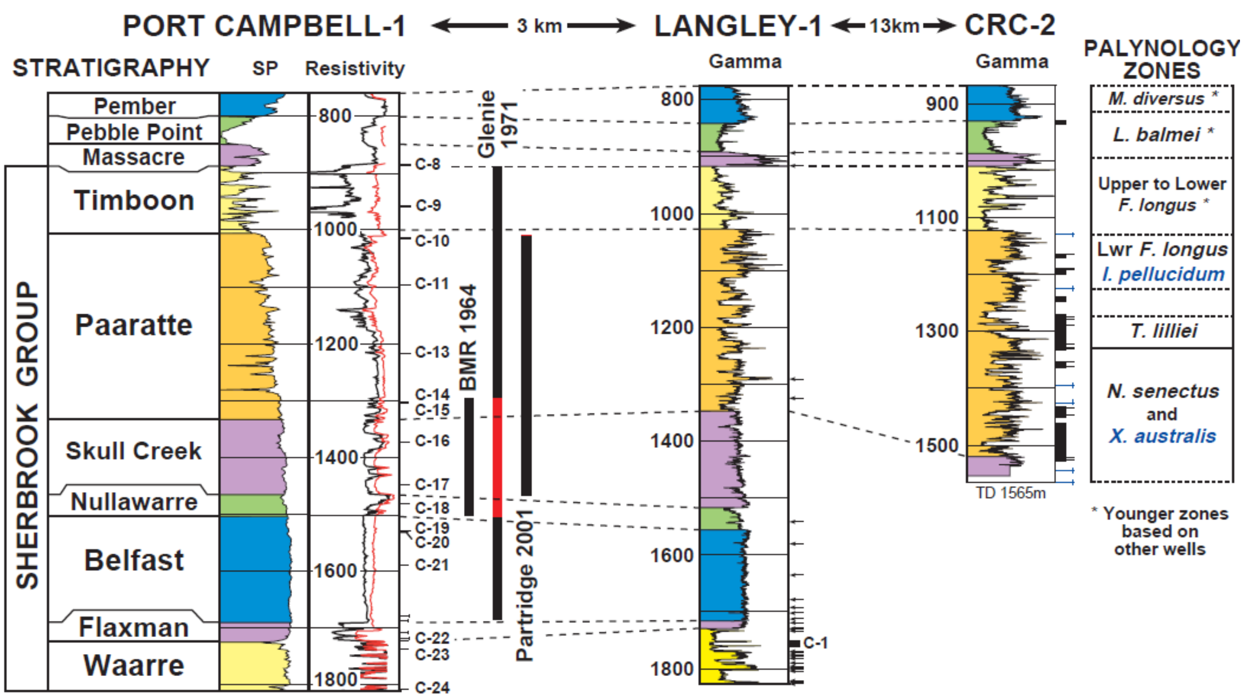


Figure 5: Type section correlation review.

This broad and somewhat "amorphous" concept of the Paaratte Formation was followed by most authors for the next three decades, until the mid-1990s when each of the members, Belfast, Nullawarre and Timboon, were re-designated as separate formations by different authors (GSV, 1995; Morton et al., 1995). Also at this time the Skull Creek Mudstone Member was erected to distinguish the lower comparative shale-rich portion of the Paaratte Formation (GSV, 1995; p.18).

The next step in the evolution of our understanding of the formations within the Sherbrook Group were the new palynological studies of most of the type sections, also initiated in the mid-1990s (GSV 1995; Morton et al. 1994)., which culminated in the revised stratigraphy of the Sherbrook Group proposed by Partridge (2001). In that paper the "type" section for the Paaratte Formation was again revised (although no new palynology studies were undertaken), and designated as the interval from 1010 m to 1466 m in the Port Campbell-1 well, and this choice is illustrated by the black bar labelled Partridge 2001, adjacent to the well in Figure 5. Although Partridge (2001) raised the rank of the Skull Creek Mudstone Member to that of a formation, the author did not recognise the unit in Port Campbell-1, instead treating the Paaratte as a lateral facies of the Skull Creek in this part of the embayment. That must now be acknowledged as an oversight and consequently the "type" section of the Paaratte Formation in Port Campbell-1 should be restricted to the interval from 1010 m to 1332 m. Although this choice is not entirely satisfactory, as it includes only the top 38 metres of the original type section of Bain & McQueen (1964), it is representative of the most widely accepted usage of the term Paaratte Formation in most recent reports and publications. Most of the lower interval has now been reassigned to the Nullawarre Greensand and Skull Creek Mudstone, with only a thin interval from 1294 m to 1332 m still retained within the Paaratte Formation.

Palynological analysis of CRC-2 and CRC-3

A detailed palynological study was conducted by Partridge (2011) on the CRC-2 cores and cuttings, and followed up in 2017 on the CRC-3 samples (Partridge, 2017). The aim was to review the sequence stratigraphy for the Paaratte Formation and its relationships with the Skull Creek Mudstone below and Timboon Sandstone above. The results of this first detailed palynological study of an extensively cored section through the Paaratte Formation has substantially modified our understanding of the duration of the formation within the Sherbrook Group and its age dating in relation to the latest International Geologic Time Scale.

The new insights gained from this study are discussed with reference to the diagrammatic cross-section just discussed in Figure 5, linking the type section of the Paaratte Formation in the early Port Campbell-1 well, with the new age dating in the CRC-2 well, and the revised stratigraphic table in Figure 6, which updates the stratigraphy of the Sherbrook Group to the latest revision of the International Geologic Time Scale by Gradstein et al. (2004), and a recalibration of the Global Cycle chart of Haq et al. (1987) to this time scale. The palynological analysis of cores in the CRC-2 well establish that the Paaratte Formation ranges from the upper part of the Lower Campanian to approximately the Campanian/Maastrichtian boundary. It includes part of the *Nothofagidites senectus*, all of the *Tricolporites lilliei*, and part of the Lower *Forcipites longus* spore-pollen Zones. The formation also contains microplankton assemblages representative of most of the *Xenikoon australis* Zone, non-descript assemblages probably equivalent to the *Isabelidinium korojonense* Zone (although this index species was not found), and assemblages assigned to the new local *Isabelidinium pellucidum* Zone (Figure 6).

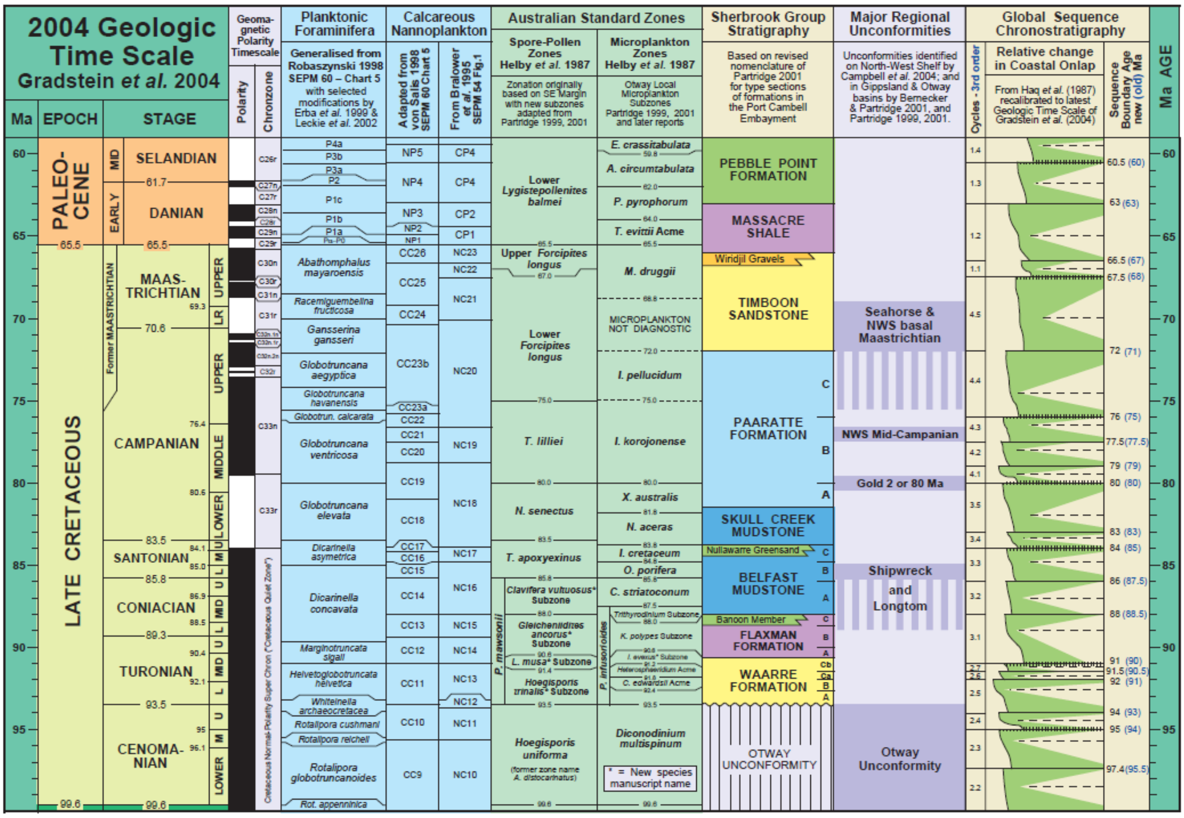


Figure 6: Revised Sherbrook Group stratigraphy of Partridge (2001), and global onlap cycles of Haq *et al.* (1987), updated to latest International Geologic Time Scale of Gradstein *et al.* (2004). Correlation of Australian palynological zones to latter time scale based on Partridge (2006a-b).

Furthermore, the detailed palynological analysis of the Paaratte Formation in the CRC-2 well has provided a potential three-fold unit (or member) subdivision of the formation. These members can also be potentially correlated with major regional unconformities, and global eustatic cycles recognised from sequence stratigraphy. Figure 7 is a well correlation from Boggy Creek-1 to CRC-2, CRC-1, Nalyor-1, and CRC-3 to demonstrate the interpretation of the Units A, B, and C on a local scale. The cross-over of the neutron/density logs are used as a proxy for lithology (sand/shale).

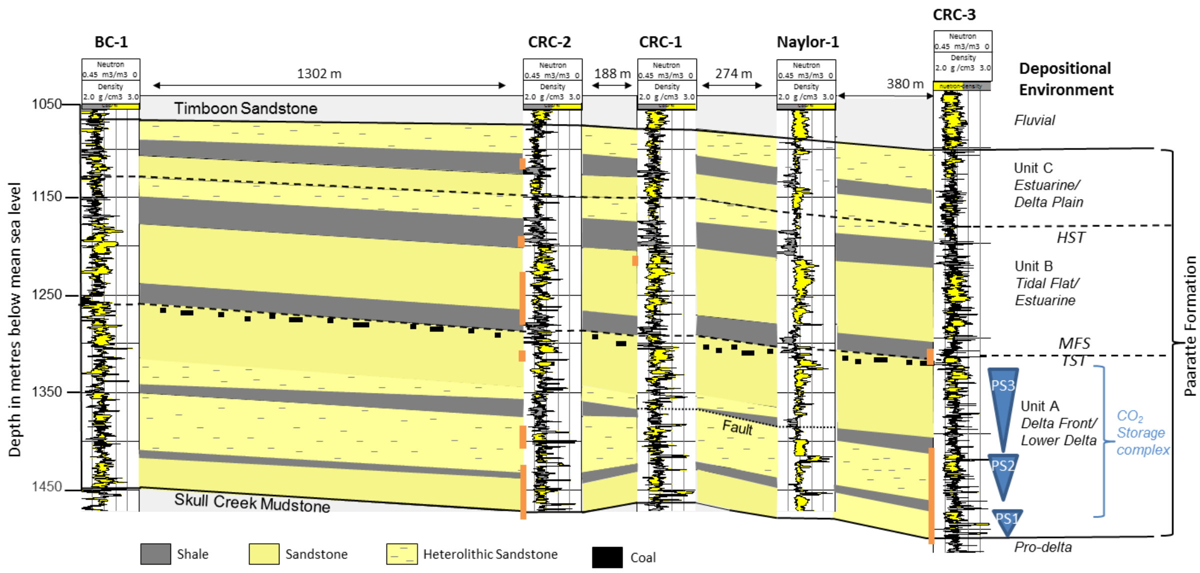


Figure 7: Well section of the Campanian Paaratte Formation at the study site and correlation of the proposed Units A B and C, including the three Unit A parasequences (PS). Neutron/density logs are shown with the cross-over and separation used a proxy for sand and shale, core locations are shown by orange bars (see Figure 2 for well locations).

The base of the Paaratte Formation is identifiable by the change from a shale dominated heterogeneous section to a more sandstone dominated section. An erosional surface has been interpreted in core and on formation micro-imager logs (FMI) at the CRC- 1 and CRC-2 wells suggesting this boundary could represent a weak unconformity, but is more likely caused as a result of an influx of coarse grained sediments scouring the fine-grained mudstones below (Lawrence et al., 2012). The top of the Paaratte Formation is indicated by a more abrupt change in the logs from the heterogeneous Paaratte Formation to the largely “blocky” log signature of the coarse grained dominated Timboon Sandstone. This lithological boundary is consistent with the regional sequence boundary “SB 4” identified in a study by Faulkner (2000) representing the change in stacking patterns from progradational to an aggradational system. The proposed three member units of the Paaratte Formation are correlated with third order stratigraphic cycles in Figure 6 and are described below:

Unit A is designated for the lower portion of the Paaratte which is characterised by the *N. senectus* and *X. australis* Zones, and equates to the lower most stratigraphic package correlated across the study site in Figure 7. The top of this unit, within the limits of our current biostratigraphic resolution, can be correlated with the Gold 2 or 80 Ma unconformity in the Gippsland Basin (Johnstone et al., 1991; Lowry & Longley, 1991), and the 80 Ma sequence boundary recognised by Haq et al. (1987). In contrast, there is no obvious regional break at the boundary between the Paaratte and Skull Creek formations, and this is consistent with the lack of any clear palynological zone boundary between these formations in the CRC-2 well. This is also consistent with the idea that this particular formation boundary crosses time lines, as suggested by Partridge (2001).

Unit B is designated for the middle portion of the Paaratte Formation which is characterised by the *T. lilliei* Zone, and the middle stratigraphic package in Figure 7. The position of the top of this unit is somewhat uncertain due to difficulties in precisely correlating the *T. lilliei* to *F. longus* Zone boundary to the International Geologic Time Scale. It is however suggested that there is an approximate alignment of the Middle/Upper Campanian Stage boundary, with the Mid-Campanian unconformity identified on the North West Shelf by Campbell et al. (2004), and the Type 2 Sequence Boundary located at 75 Ma (= recalibrated age 76 Ma) on the Cretaceous cycle chart of Haq et al. (1987).

Unit C is designated for the upper portion of the Paaratte and is considered to equate to the Lower *F. longus* and *I. pellucidum* Zones, and the Upper Zuni third order cycle UZA-4.4 on the Cretaceous cycle chart of Haq et al. (1987). The top of this unit and the Paaratte Formation is considered to potentially correlate with the following events: **1)** the Seahorse Unconformity established in the Gippsland Basin by Bernecker & Partridge (2001; fig.2); **2)** the basal Maastrichtian to Campanian unconformity identified on the North West Shelf by Campbell et al. (2004), and Howe et al. (2003); **3)** the Type 1 Sequence Boundary located at 71 Ma (= recalibrated age 72 Ma) on the Cretaceous cycle chart of Haq et al. (1987); and **4)** the relocated position of the Campanian to Maastrichtian Stage boundary in the latest version of the Global Geologic Time Scale of Gradstein et al. (2004). The potential alignment of all these events can never be proved in the Otway Basin as the succession lacks the calcareous planktonic foraminifera and nannofossils that are needed to more precisely calibrate the palynological zones.

The CRC-3 well has provided further insight into a parasequence/bio zone separation for the Unit A (Table 3). The samples are from a 200 metre interval between 1366 m and 1565.6 m (measured depth from rotary table (MDRT)) straddling the base of the Paaratte Formation, and uppermost Skull Creek Mudstone. The results reveal a further subdivision of the Unit A into three informal Biounits A to C which are interpreted to relate to sequence stratigraphic cycles, or 4th order parasequences shown as PS 1, PS 2 and PS 3 in the correlation panel in Figure 7. The lower Biounit A is characterised by microplankton assemblages dominated by *Heterosphaeridium* spp., and spore-pollen microfloras with frequent to common *Australopollis obscurus* and rare *Nothofagidites senectus* pollen. The middle Biounit B contains microplankton assemblages dominated by *Xenikoon australis*, and spore-pollen microfloras with frequent to common *Nothofagidites senectus* and rare *Australopollis obscurus* pollen. The upper Biounit C is distinguished by a clear decline in the frequency of *X. australis* and the incoming of common

Xenascus australiensis, together with the rare first occurrences of accessory marker species for the *Tricolporites lilliei* Zone suggesting a transition interval to that zone.

Table 3. Palynological summary of the Unit A interval analysed in CRC -3.

AGE	STRATIGRAPHY		SAMPLES	PALYNOLOGY ZONES		
early Middle Campanian	**Paaratte Formation Unit A**	**Top shale**	1366m 1370m	**Upper *Nothofagidites senectus* spore-pollen Zone**	***Xenikoon australis* microplankton Zone**	**Biounit C**
late Early Campanian		**PS3 sand**	1380m			**Biounit B**
		Mid shale	1456m 1461m 1469m			
		PS2 sand	1498.5m			**Biounit A**
		Base shale	1511m 1524.5m			
		PS1 sand	1529m 1551m			
	Skull Creek Mudstone		1565.6m			

When related back to the lithology and electric log profiles in CRC-2 and CRC-3 it seems likely the boundaries between Biounits A/B and B/C correlate to the boundaries between the coarsening up profiles of sandy facies and overlying shaly seal sections (Table 3). These boundaries mark the flooding surfaces at the top of the PS 1 sand and the PS 2 sand, with the change in the composition of the spore-pollen microfloras suggesting the presence of short time breaks between the top of the sands and base of the overlying shales. The shale units can therefore be interpreted as transgressive system tracts and the sand units as high-stand system tracts, while the low-stand system tracts are probably missing at the biounit boundaries. A thin (~2-3 m) coal was cored in CRC-3 at approximately 1378 m – 1381 m MDRT. This is located at the top of the PS 3 interval in Unit A. It is truncated at the top by a marine, tidally influenced fine grained sandstone that fines upward to a prodelta mudstone. Diessel (1992), presents a model of peat accumulation in paralic seams whereby the roof of the seam is the point at which the peat is drowned by a flooding maxima. Holz et al. (2002) also illustrates that stacking patterns may result in transgressive coals within an overall progradational highstand systems tract. If this sequence stratigraphic interpretation of the section is accepted, the top of Unit A of the Paaratte Formation should be placed at the top of the PS 3 coal layer.

Sedimentology

Regionally the Paaratte Formation lithology has been described as extremely heterogeneous, comprising intercalations of medium to high permeability sands and gravels thinly interbedded with carbonaceous mud rich lithologies, and over printed with diagenetic carbonate cement layers which serve as seals of varying quality (Felton & Jackson, 1987; Morton et al., 1995; Edwards et al., 1996; Geary & Reid, 1998; Geary et al., 2001). At the Otway Project site, the cores from the Paaratte Formation comprise conglomerates, interbedded sandstones, heterolithics (laminated mudstone, siltstone and sandstone), and mudstones. Individual sandstone packages within the Paaratte Formation have variable thickness. Typically they are from around 4 m to 12 m in the lower part and up to 25m to 35 m towards the upper part of the formation. This is indicative of an overall regressive sequence. Throughout the lower Paaratte Formation, the frequent diagenetic cemented sandstones are mainly less than 1 m thick but up to 4 m in places. Their presence is indicated on down-hole logs by very high density and high resistivity, and low porosity and permeability values on the interpreted petrophysical logs.

To characterise the paleo-depositional environment from the Otway Project wells, we use a combination of sedimentary facies, facies associations, sedimentary structures and fossils, particularly trace fossil assemblages, as they indicate the environment in which they lived (Alplay 1972; Reading 1996; Miall 1984.). Some typical sedimentary structures and grain fabrics are presented in Figure 8, and trace fossils with example bioturbation index (BI) are presented in Figure 9. The BI is the scheme for grading the amount of trace fossil activity on a scale of 0–6; a value of 0 indicates that bioturbation is entirely absent, whereas the highest grade indicates 100% trace fossil reworking and overprinting (Taylor and Goldring, 1993). Table 4 places the descriptions of the Paaratte facies against the facies associations and environmental interpretations. In total there are 10 facies associations described in the Paaratte cores. In stratigraphic succession from the base of the cores upward, these are briefly described as follows:

Delta front facies comprise highly bioturbated (BI=5) mudstones interbedded with very fine siltstone lamina less than 1 cm thick with minor heterolithics. The base of the association usually marks a flooding surface, and beginning of an upward coarsening vertical profile associated with delta front progradation. These are important markers for the definition of the 4th order parasequences.

Distal mouthbar facies are dominated by heterolithics which comprise a mud-rich lithology and fine interbedded silts and very fine argillaceous sandstones. The bioturbation index is moderate to high (BI=3-4) in the mud-rich sections, so too is the presence of tidal couplets, paired mud drapes and possible hummocky cross-stratification suggesting some sediments were storm affected. The heterolithic inter-beds could represent minor flood events. Wavy bedding is common, and indicates varying energy conditions, possible resulting tidal couplets and possible wave action. The base of the distal mouthbar association, when overlying shallower water facies associations, marks a minor flooding surface, and beginning of an upward coarsening vertical profile associated with delta front progradation.

Proximal mouthbar facies are dominated by fine sands comprising moderate to well sorted, rounded, mainly quartz grains with some micas. Bioturbation is low and mud drapes are much finer and less frequent than in the distal mouthbars. The Proximal mouthbars are often characterised by fine to medium grained massive sandstones with some planar crossbedding, fine planar mud laminated beds, and minor heterolithics. The dominance of massive sandstone and crossbedding is indicative of higher energy in a more proximal setting upon a delta mouth bar. There are minor mud laminations related to mud drape deposition during temporary lower energy conditions. The planar crossbedding in this facies is possibly indicative of tidal/wave action.

Distributary channel facies are poorly sorted conglomeratic sandstone with grains up to granule and pebble size of mixed quartz, feldspar, and rock fragments. There are many mud rip-up clasts and wood fragments in this facies. Sandstone channel deposits at the base of the Paaratte are interpreted as sub aqueous, as the wavy carbonaceous mud drapes preserve the effects of mud flocculation, a condition in which charged clay particles become attached together. This is often observed in stressed environments where sedimentation occurs at the interface where fresh and saline waters mix, likely related to flooding or storm events.

A highly cemented sandstone defines a diagenetic facies. These dolomitic layers are mainly less than 1 m thick but up to 4 m thick. They appear to be common to the more massive (structureless) sands within the proximal mouthbar facies, however, they can overprint any of the aforementioned facies. They have no visual porosity in hand specimen and very low values from conventional core plug tests. These precipitate in the sandstones as a result of brackish, organic rich, meteoric-influenced water flushing through porous, permeable, sediments. Typically they overlie proximal mouth bar, and overlain by the distributary channel or distal mouth bars.

The interpretation of facies that are thought to represent deposition within an estuarine to embayment setting was first presented by Arnot et al. (2012). The Authors describe **Estuarine Sandstones** by the bioturbation and repetitive interbedded coarse and fine grained sandstones. **Esturaine channels** are distinguished from the sandstones by the presence of planar and low angle cross-bedded stratifications. **Tidal Flats** are characterised by the presence of desiccation cracks in the dark, organic rich mudstones. Arnot el al. (2012) were also the first to interpret a non-marine **fluvial channel** section in CRC-2, Core 5 (1271 m to 1275 m MDRT). This is based on the presence of rootlet horizons in the top of sandstone beds, and very organic rich almost coaly mudstone. It was the only section also to record non-marine biostratigraphic indicators (Partridge 2011).

Table 4: the interpretation of facies and facies associations and the environment of deposition for the Paaratte Unit A.

Facies	Facies associations	Depositional environment
Coarse pebbly and pebbly stratified sandstones with carbonaceous material throughout	Fluvial Channel	**Upper delta plain**
Sandstone beds with rootlet horizons at the top		
Organic rich coaly mudstone.		
Dark moderately organic intensely bioturbated siltstone and mudstones	Tidal Flat	**Estuarine/tidal flat**
Mudstones with desiccation like cracks		
Fine to medium grained planar, low angle /cross stratified sandstones with minor bioturbation	Estuarine Channels	
Moderate to intensely bioturbated fine to medium grained sandstone with coarse pebbly sandstone beds.	Estuarine Sands	
Poorly sorted sandstone with grains up to granule and pebble size of mixed quartz, feldspar, and lithofragments. Mud rip-up clasts, carbonaceous wavy lamina, flocculated mud, and wood fragments are common.	Distributary channel	**Lower delta plain/shallow marine**
Highly indurated, no visible porosity, reactive to HCl acid.	Carbonate cemented Sandstone	
Massive fine sands comprising moderate to well sorted, rounded, mainly quartz grains with some micas. Very fine and infrequent mud drapes.	Proximal Mouth Bar	
Fine interbedded mudstones, silts and very fine sands.	Distal Mouth bar	**Delta front/Pro-delta marine**
Tidal couplets, paired mud drapes and possible hummocky cross-stratification, moderate bioturbation.		
Dark organic rich mudstone and mudstone with very high bioturbation index.	Delta front	

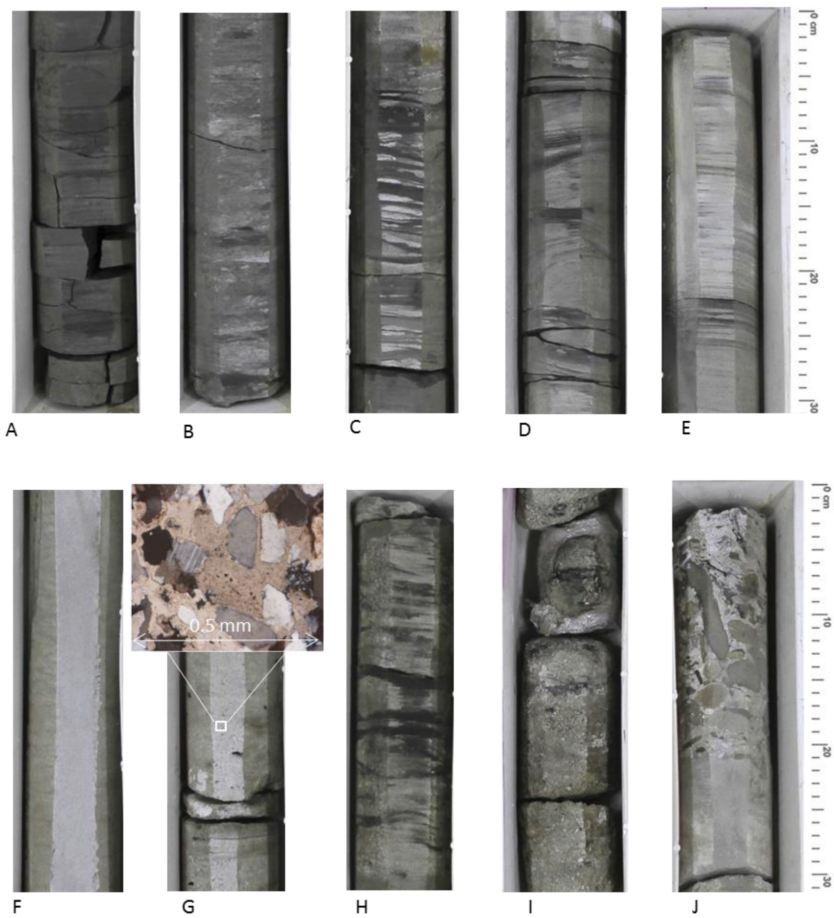


Figure 8: Examples of Paaratte Formation sedimentary facies observed in the CRC cores, shown in order of increasing grain size from top left to bottom right: (A) Dark mudstone (B) mudstone with intense bioturbation (C) interbedded mudstone and very fine sandstones with evidence of tidal couplets, and moderate bioturbation; (D) hummocky/trough cross-bedded sandstone; (E) thinly planar laminated fine grained sandstone; (F) Massive, fine to medium grained, well sorted sandstone; (G) dolomitic cemented sandstone; (H) medium to coarse grained sandstone with wavy carbonaceous laminae and rip up clasts; (I) poorly sorted, coarse to very coarse pebbly stratified channel facies; (J) coarse pebbly and conglomeritic sandstones.

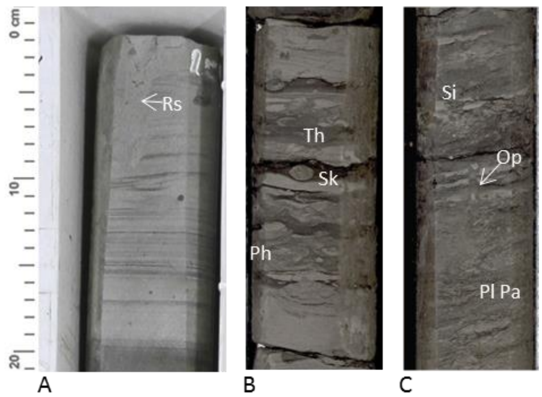


Figure 9: Examples of the Ichnofabrics and bioturbation index (BI) observed in the CRC cores: (A) CRC-3 1558 m sparse bioturbation (BI=1) Rosselia ichnofabric (Rs). (B) CRC-2 1485 m moderate bioturbation (BI = 3-4) with bedding still just visible and Silt filled burrows in mudstone laminations Thalassinoides (Th), Skolithos (Sk), and Pheobichnus (Ph) ichnofabrics. (C) CRC-2 1525 m showing the intensity of bioturbation that is characteristic of the Skull Creek Mudstone (BI=5) where most of original bedding fabric disrupted by high degree of bioturbation and burrows disturbed by other burrows and diverse ichnofacies: Thalassiniodes (Th), Siphonites (Si), large and small Planolites (Pl), Palaeophycus (Pa), and Ophiomorpha (Op).

The detailed sedimentary log for CRC-2 is shown in Figure 10 for the Unit A PS 1 interval (a high priority injection interval for stage 2 and stage 3 of the CO2CRC Otway project). The interpretation of PS 1 is that the succession represents an overall regressive sequence resulting from the progradation of the system from delta front mudstones/distal mouth bars to proximal mouthbars and distributary channels. At the top of the sequence there is evidence of channel waning and abandonment. This is common in deltaic settings when accommodation space is filled and the delta system switches lobes. As the sediments subside due to differential compaction, the base level becomes lower than the relative mean sea level and deposition of the finer grained distal mouth bars/delta front sediments ensue representing a local transgression (Elliot, 1986).

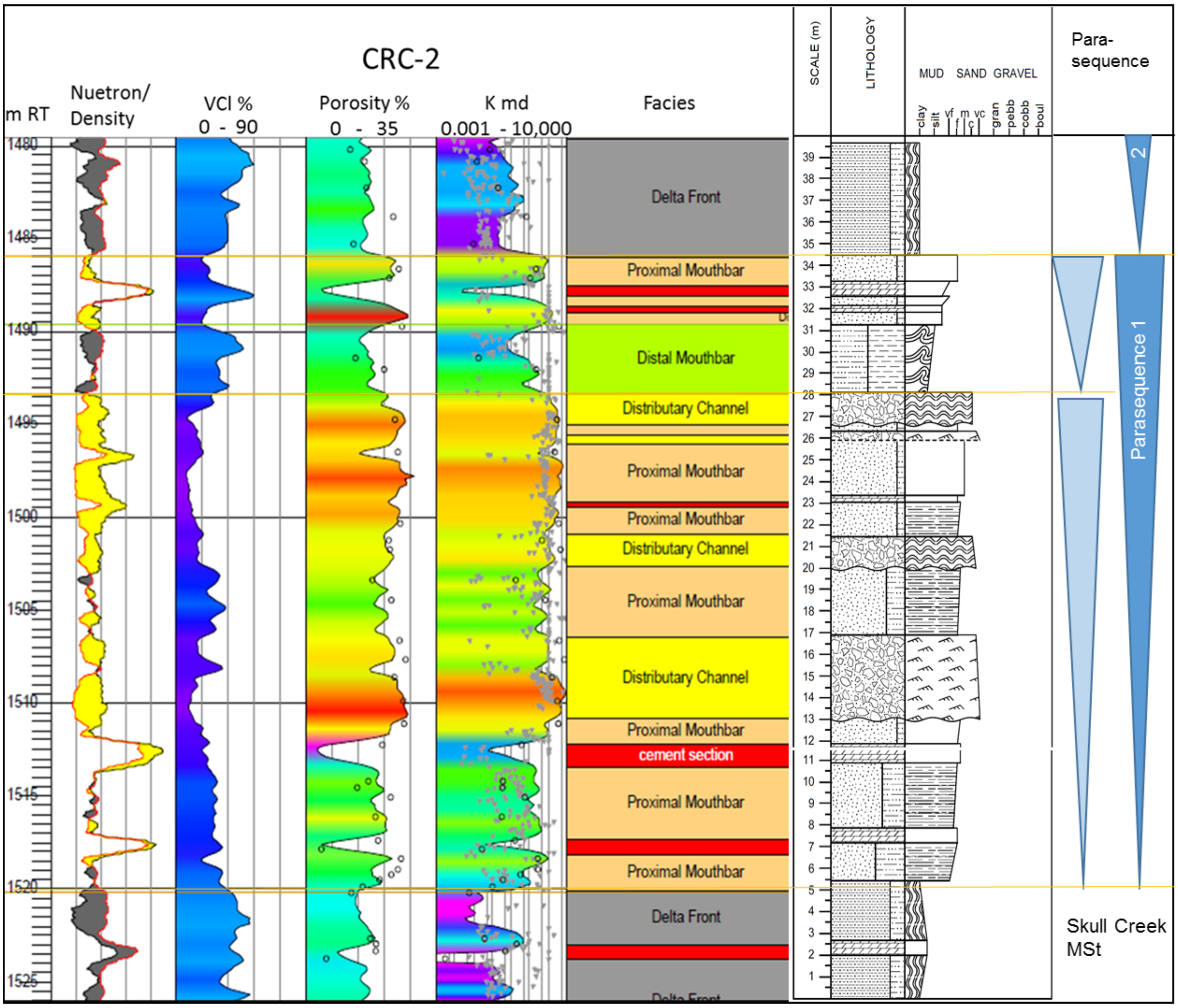


Figure 10: Well composite log of parasequence 1. From left to right tracks are: neutron density cross over showing sand (yellow) and mudstone (grey), volume of clay, total porosity (core plug porosity: circles), permeability from nuclear magnetic resonance logs and from core plugs (circles) and miniperm profile (grey triangles). The facies associations are shown against the sedimentological log digitised using Sedlog (Zervas, 2009). The succession from PS 1 to PS 2 is indicative of a shallow marine depositional setting, prograding from prodelta/delta front mudstone to deltaic mouth bars with sub aqueous channels.

Paleo-environmental interpretation

In other studies, the depositional environment for the Paaratte Formation has been interpreted by Boyd & Gallagher (2001) as regressive marine, lower to upper delta plain. More specifically Gallagher et al. (2005) describe it as being overall pro-grading in nature from the offshore pro-delta sediments of the Skull Creek Mudstone below, to near-shore marine at the base, to brackish lagoonal and fluvial delta plain at the top, passing into overlying fluvial sediments of the Timboon Sandstone above (Figure 11).

In the CRC wells the succession of facies is indeed fitting with the regional interpretation of Gallagher (2005). The sedimentology indicates an overall upward change in depositional environment from a more deltaic setting interpreted in the CRC-3 cores and the CRC-2 cores 17-29 (1433 m to 1527 m MDRT) that cover the lower Paaratte Formation, to a more marine estuarine/embayment punctuated with elements of entirely non-marine fluvial deposition interpreted in the upper Paaratte Formation (1364 m to 1164 m MDRT at CRC-2).

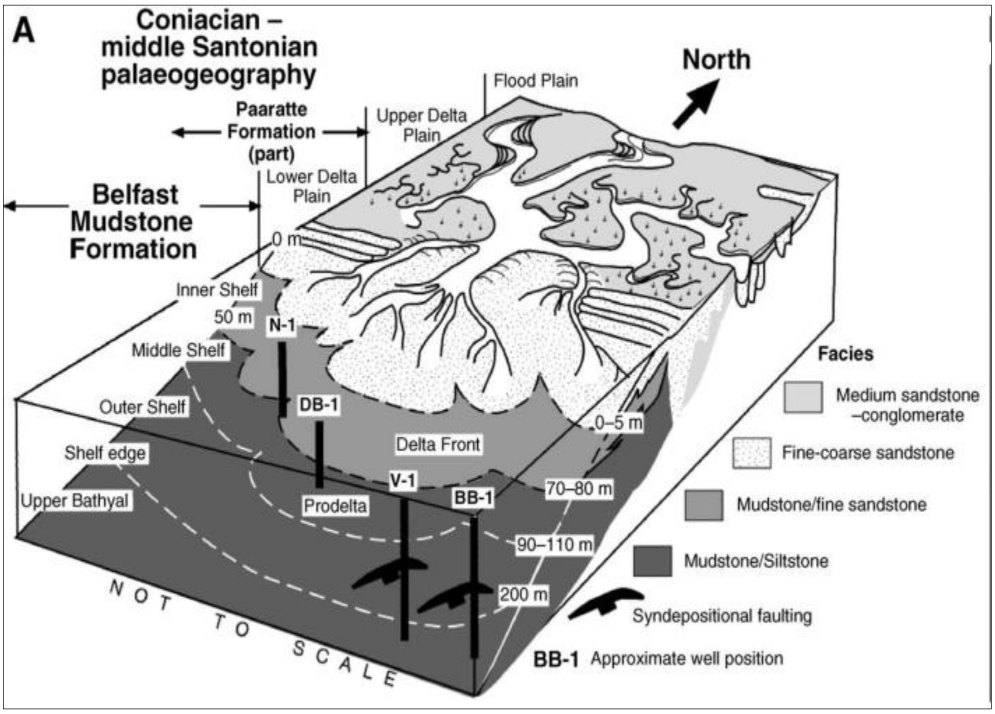


Figure 11: Schematic model of the environmental setting during the Coniacian to middle Santonian (from Gallagher, 2005).

The biostratigraphic analysis throughout the Paaratte shows strong evidence of an almost entirely marine dominated biota in the shale rich sections (Partridge 2011), and the intervals of scattered burrows of the Ophiomorpha and Rosselia ichnofabric (Figure 9), which are often associated with shallow marine settings (Frey et al. 1978), similarly supports an interpretation of a marine environment. Furthermore, the diagenetic process responsible for forming the cements has provided insight into the paleo-environment as can be seen in the schematic of the cements' evolution given in Figure 12 (Daniel et al. 2012). These zones probably formed by precipitation of dolomite early on in the diagenetic process as a result of brackish, organic rich, meteoric-influenced water being flushed through the highly porous, permeable, proximal mouthbar sandstones. The cements preferentially precipitated in the massive sandstones due to an absence of clays coating the matrix grains. The most likely depositional environment for this to occur is in an estuarine to shallow marine setting, very close to the fresh water discharge from the upper delta-plain (Taylor & Gawthorpe 2003).

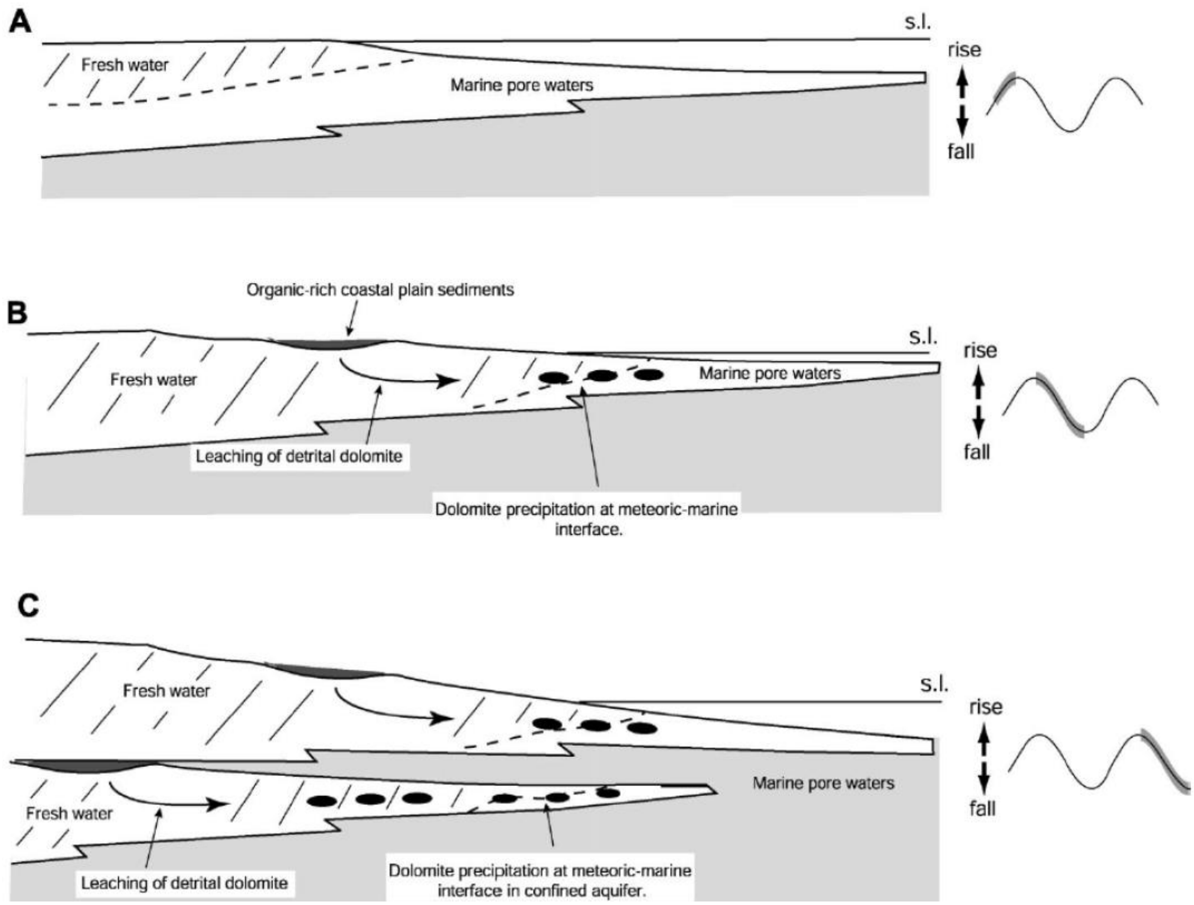


Figure 12: In the study by Daniel et al. (2013), it was found the most likely model for the development of the dolomite cement is one proposed by Taylor and Gawthorpe, (2003), whereby the dolomite precipitates at the interface of the fresh groundwater and the saline marine water.

In order to carry the interpretation of facies associations and depositional environment over intervals without cores, the image logs in the CRC wells are used. An image facies schema is developed by picking sedimentary packages with genetically similar bedsets, these are described on the basis of grain fabric and bedding features reflected in the logs. The CRC-2 well logs were first interpreted by Lawrence et al. (2012). In this study it was found the image facies schema could equally be applied to define the facies associations described from the core hand specimens by attributing intervals with core as the control, and then applying the classification to the entire Paaratte section. The results were then carried across to the CRC-1 image log as a training dataset.

In 2017 the CRC-3 FMI facies associations were interpreted by Lewis (2017) to infer similar depositional environments to those interpreted at CRC-1 & CRC-2, and the sedimentological interpretation of the CRC-3 cores, with the addition of one more facies association called **Estuarine – mixed flats**. Figure 13 shows the resulting total distribution of the facies associations over the entire Paaratte Formation interval as interpreted from the combination of cores and image logs. It is clear, from the relative percentage, in this part of the basin, the majority of the sequence has been laid down in a deltaic (~30%) or tidal/estuarine (~65%) paleo-environment with only a small percentage of sediments attributed to a fluvial (3.6 %) or flood plain setting (1.8%).

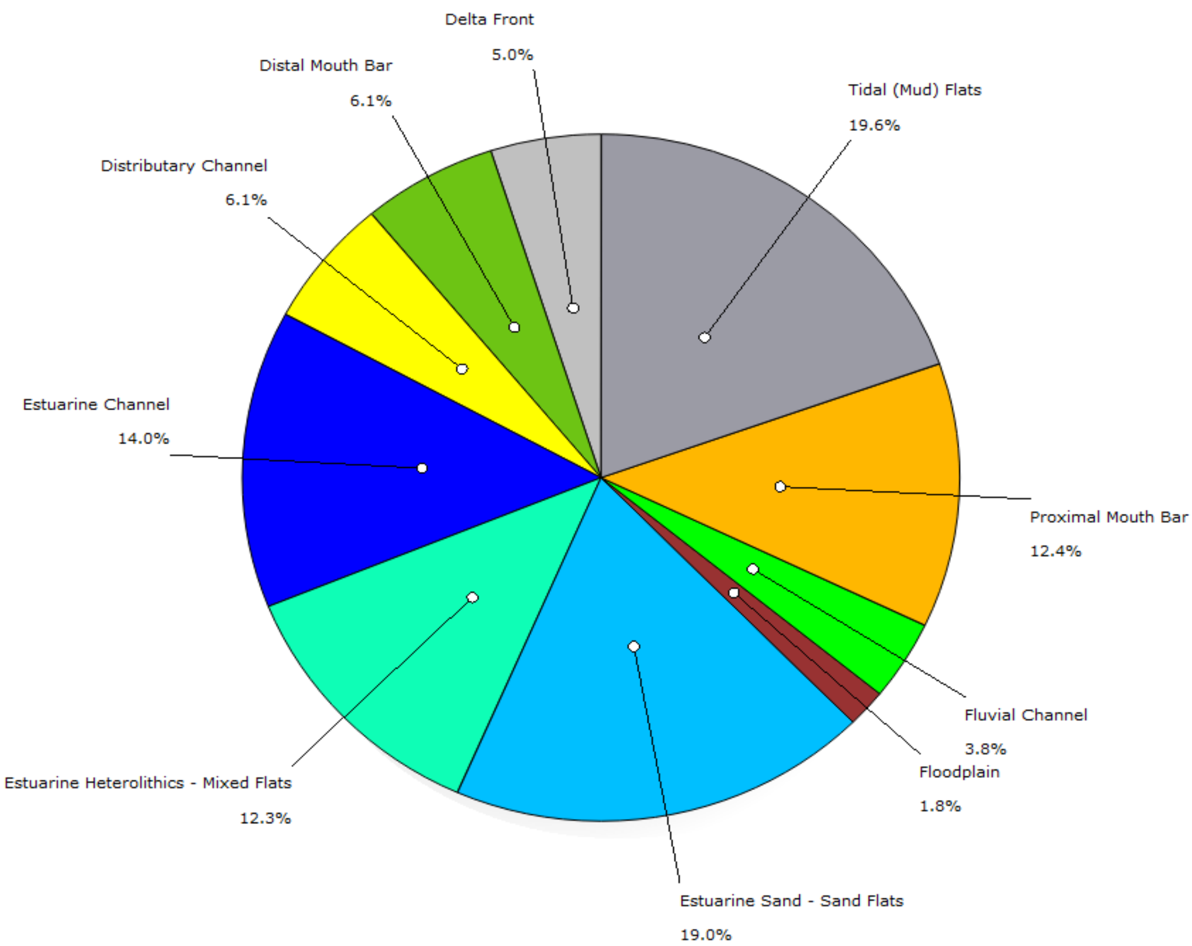


Figure 13: Facies association percentage of occurrences for the entire Paaratte Formation interval (Lewis, 2017).

Reservoir Quality

Porosity and permeability were evaluated from log and core data (Figure 10). Reservoir quality is considered good to excellent with average porosity 25-30% and permeability up to several Darcy. There appears to be a strong relationship between interpreted facies associations and reservoir quality. By cross-plotting measurements of porosity against permeability by each facies, results show that the highest reservoir potential lies within the proximal mouthbars and distributary channel sandstones (Figure 14a). The distal mouthbars and delta front mudstones, as well as the diagenetic cemented beds are considered to be the "non-reservoir" facies. These have been termed non-reservoir on the basis of their low average porosity (<15%) and permeability (<10 md) as well as having high capillary entry pressure (Figure 14c). This was measured using mercury injection (MICP) for each lithology and converted into the equivalent CO_2 column height that may potentially be retained (Daniel, 2012). The delta front facies have the potential to act as seals to a plume several tens of metres thick. The cements are more likely to act as baffles, as they lack the extensive continuity of the delta front facies. Similarly, the vertical permeability is important as it also impacts the buoyant flow of the CO_2. In shallow marine and deltaic environments vertical permeability has a strong relationship with the percentage of clay in the facies as it commonly occurs in highly laminated intercludes parallel to bedding (Ringrose, 2005). This is shown by the delta front shales having lowest vertical permeability, and highest clay volume, whereas the massive sandstone dominated proximal mouth bars have the highest vertical permeability (Figure 14d).

Reservoir Analogues

Having established the strong relationship between petrophysical properties and facies associations means that the reservoir architecture is critically important for building static geological models to correctly predict porosity and permeability trends. In the absence of any outcrop from the Paaratte Formation, modelling the facies continuity and geo-body dimensions relies on observations from modern analogues and ancient systems.

The Frontier Formation of central Wyoming, USA, has been extensively mapped and reflects a paleo environmental system that is very similar to the Paaratte Formation. Work by Willis et al. (1999) describes the geometry, bedding architecture, and internal facies variations of the lowstand, tidally influenced deltaic sandstone. The sandstone bodies themselves are 20 km long and 3 km wide.

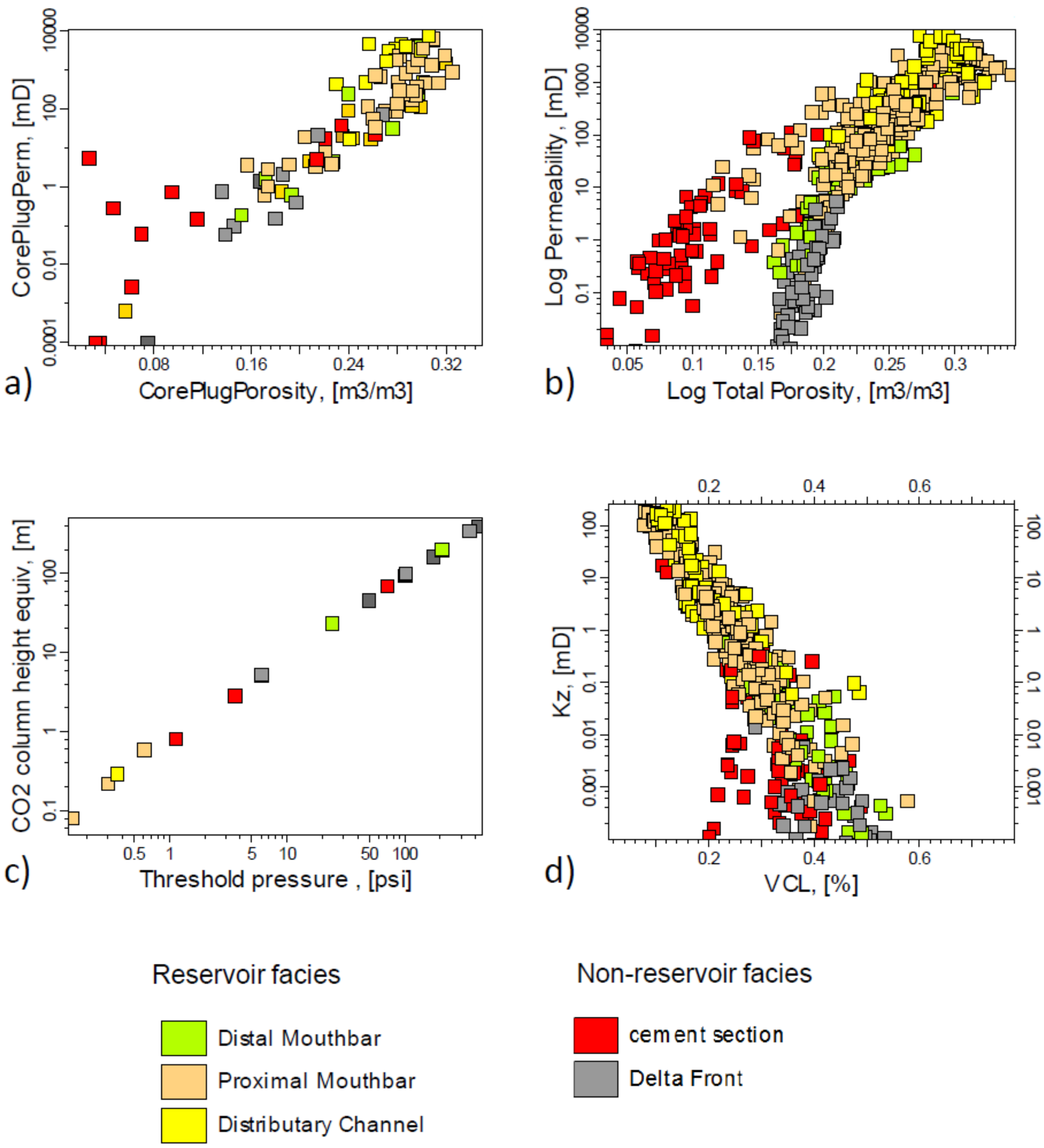


Figure 14: Reservoir properties coloured by individual facies a) Core plug porosity versus permeability; b) total porosity and permeability from CMR logs; c) capillary entry pressure measurements and the corresponding CO_2 column height equivalent from MICP; d) vertical permeability versus volume of clay.

Channel system bedsets within the sandstones can be correlated over a distance greater than 500 m. For the Paaratte Formation, the type of depositional setting, at this period in the geological time scale, would give rise to mouth bar deposits in the order of several kilometres across, and indeed it has been possible to correlate proximal mouth bar sediments, and distal mouth bars across the closely spaced (<400m) Otway Project wells.

Interpretation of cement body dimension is based on an outcrop analogue, again from the Frewens Sandstone within the Frontier Formation, Wyoming, but using the work by Dutton et al. (2002). This study mapped the size and distribution of calcite concretions from outcrops of the

Frewens sandstone. Figure 15 shows the outcrop photograph and facies map for scale. Large, tabular calcite concretions in this deltaic sandstone generally follow basin ward-inclined bedding. Median thickness of the concretions is 0.6 m, length is 4.2 m, and width is 5.3 m; and the largest being only 30m across. Similar to the Paaratte Formation, the highest cement fraction is in the high-permeability facies at the top of the sandstone bodies.

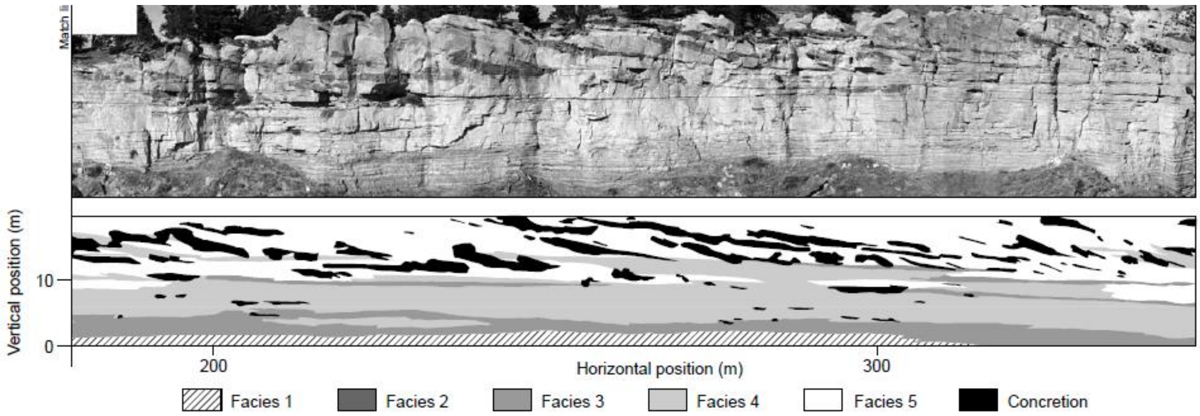


Figure 15: Outcrop photograph and facies map of cement concretion distribution in the Frewens sandstone (Dutton et al., 2002).

The study by Dutton et al. (2002) was of particular use to the Paaratte Formation static modelling because it incorporated the observations made in the outcrop study into a series of models use for flow simulation in order to investigate the impact these baffles have on fluid migration. The spatial distribution of calcite cement in the Frewens sandstone was modelled using Sequential Indicator Simulation. Base case variograms were inferred from the outcrop maps of cement and had a maximum range of 30 m horizontally and 2.5 m vertically, dimensions that correspond approximately to the size of the largest concretions. The conclusion was that the concretions make flow paths more tortuous and retard flow in the reservoir sandstone facies, and that if the cement baffles are not included, the bulk reservoir permeability is grossly overestimated.

Another important input into modelling was the geometry of the sedimentary bodies from the sedimentary dip dispersal directions to determine predominant reservoir depositional trends. The imaged successions in wells CRC-1, CRC-2, and CRC-3 display dips that are commonly <5º, but with a spread of azimuths predominantly in a NNE/SSW direction (Lawrence et al., 2012; Lewis 2017). This data can be used along with the facies association ranges as direct input for dip and azimuth variograms that constrain static modelling anisotropy. Figure 16 shows an example of a static model realisation of the lower Unit A created for stage 2 of the CO2CRC Otway project. It may be seen in the cross-sectional view that the delta front facies are characterised to be extensive such that they act as seals to separate the parasequences across the site. The reservoirs are modelled as highly anisotropic, with the high horizontal continuity, and low vertical continuity of sandstone bodies. The baffles provided by the distal mouthbar and cements also adding to the layered and heterogeneous nature of the intervals.

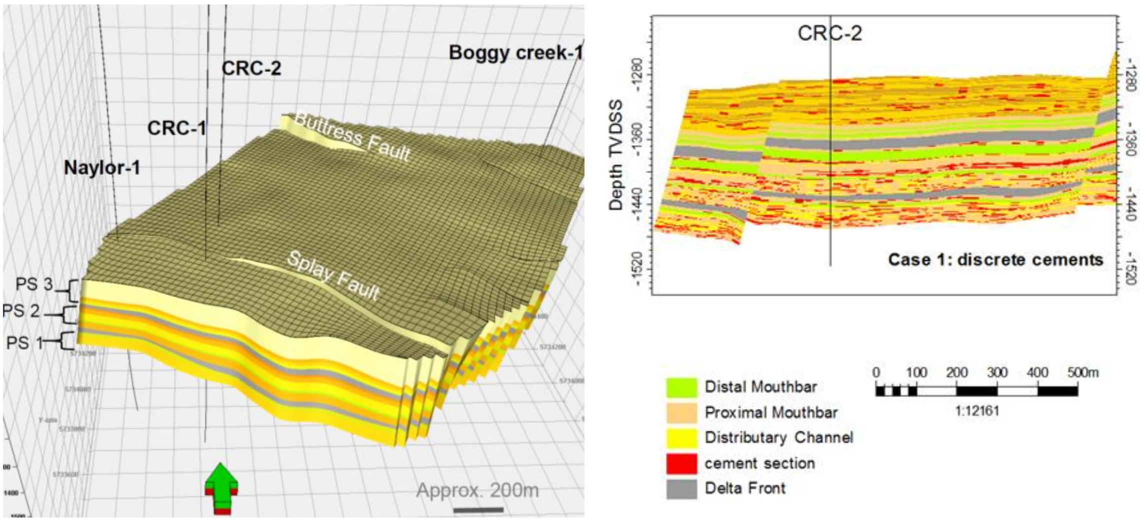


Figure 16: Static model (left) 3D grid showing the main fault features, parasequence zones, and the CRC-2 injection well (no vertical exaggeration). North-south section through the static model (right) of facies model.

Characterisation for the CO2CRC Otway Project

The characterisation presented in the preceding sections served a purpose for planning the CO2CRC Otway project. Specifically optimisation of injection locations, design for monitoring, and predicting the long term fate of CO_2. Static and dynamic modelling has played an important role in support of this (Dance & Cinar, 2009; Zhang et al, 2011; Watson et al, 2012), but is not covered in detail in this paper. Instead here we present the project objectives against the geological characteristics of the Paaratte Formation shown in the Figure 17 well section that has made it suitable, along with any outcomes.

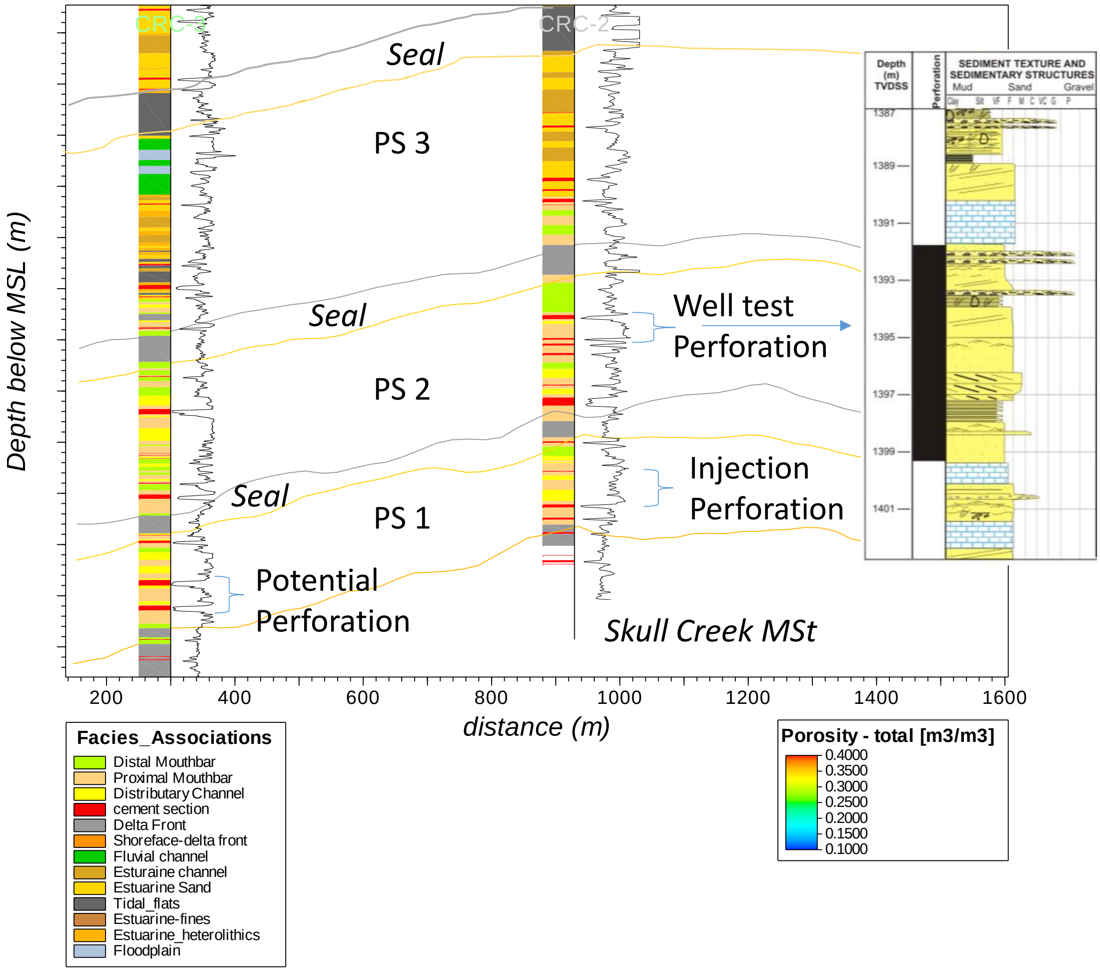


Figure 17: Perforation intervals in the Unit A parasequences for CRC-2 (right) and CRC-3 (left) selected on the basis of the geological characterisation (total porosity and facies association logs shown).

Selecting the storage complex:

The identification of the regional seal at the top of Unit A was significant to the context of the Otway Project, because the shale interpreted, as the maximum flooding surface, provides a "seal" horizon that is readily mapped on the seismic (Figure 4c). This seal marks the top of what is considered the primary storage container for the Otway Project Stage 2 and Stage 3. Above Unit A, faulting at the Naylor South fault has resulted in Units B and C being juxtaposed against the Timboon Sandstone (Figure 4b). This aquifer may have significant potential for use as town water supply due to low salinity (500 ppm TDS) (Duran, 1986) and is categorised by the Victorian state Environmental Protection Agency as "potable" water. As such it has been decided that no CO_2 injection will take place in the B and C units to maintain the integrity of the Timboon Sandstone aquifer. The parasequences shales are expected to limit vertical migration of small volumes of CO_2. However, the extensiveness of the regional Unit A seal provides added assurance it can provide important secondary confining layer.

Selecting a well test perforation zone:

The interbedded nature and the contrasting reservoir quality between the sandstones and the, shales and the cements has been important for the selection of the interval for the residual trapping and dissolution well test. The perforated zone needed to have sufficient injectivity and to be representative of most of the reservoir units in the lower Paaratte Formation (inset in Figure 17).The 7 m interval sits mainly within a proximal mouth bar facies which comprises very fine to medium grained, sub-angular to rounded, moderate to well sorted sandstone with mainly quartzose grains and some micas. At the top of the perforated zone is a distributary channel facies. This section is poorly sorted with grains up to granule and pebble size of mixed quartz, feldspar, and lithofragments.

The interval has excellent reservoir quality (porosity and permeability) with average porosity of 27% and permeability of 2.3 darcy. The sedimentary structures and bedding features, particularly in the highly laminated facies, do however, impact vertical permeability. As expected, the highly laminated facies have strong anisotropy in reservoir properties that results in low vertical permeability. Diagenetic carbonate cement zones overprint the more massive (structureless), fine-grained sandstones above and below the perforations. They have porosity of very low values (5–10 %) from the logs and conventional plug tests and the permeability is very low (1–10 md). Seal capacity column heights of between 10 m and 400 m were derived from mercury injection capillary threshold pressure experiments on samples of the cemented lithology. This means the zone above the perforations acts much like a caprock, having the effect of vertically confining the injected fluid to the high permeability sandstones in the vicinity of the well test interval. Selecting this interval, bounded by baffles above and below, restricted the injected CO_2 to the sandstone interval immediately adjacent to the perforations. This allowed the well test to be easier to interpret owing to little vertical pressure communication and vertical migration of CO_2 above the zone of interest (Dance and Paterson, 2014), and provided a suitably restricted reservoir zone to assess the repeatability of the test (Ennis-King et al, 2016).

Selecting the injection interval:

The Stage 2 seismic monitoring test set itself three distinct but progressive objectives: 1) to detect injected gas in the subsurface using seismic methods and ascertain minimum detection limit; 2) to observe dynamic plume development using time-lapse seismic; and 3) to verify stabilisation of a plume within the storage complex. Analysis of the monitoring has produced a series of discernible seismic images of the plume (Pevzner et al, 2017). This has depended on a strong time-lapse signal, compared to the time-lapse noise level. Signal strength is a function of the depth, size and thickness of the plume; the contrast of the injected gas with the pore fluids and the elastic properties of the rock; and the survey acquisition and processing parameters (e.g. source, fold, angle versus offset) (Arts & Winthaegen 2005; Brevik et al. 2000; Johnston 2013). The aim of selecting the injection interval was to enhance the likelihood that the plume will be large enough (>200 m), and thick enough (>5 m) to produce a strong signal yet not spread excessively beyond the area covered by the seismic survey footprint and petroleum lease boundary. The objective was also to see the plume stabilise (cease to migrate) within the 5 year period of the post-injection monitoring period. Thus the injection well CRC-2 was positioned at the top of the structural saddle, north of faults, where dip would have the least impact. The 11 m perforation zone within the lower parasequences (PS 1) interval was selected because there was sufficient injectivity (1500 md), but relative to the well test perforation interval, the lower porosity, lower vertical permeability, and higher heterogeneity was predicted to produce a thicker plume. The concept being that by injecting at the base of a heterogeneous section the plume would be forced to spread horizontally and vertically as it migrates away from the well and is contained by the seal at the top of PS 1. Monitoring data to date have shown that CO_2 is being contained by the parasequence boundary shale and plume propagation is restricted to PS 1 (Pevzner et al, 2016, Pevzner et al, 2017).

Selecting multi-well test location:

The current experiment being designed for the Otway project uses a combination of multi-well four dimensional and continuous automated source vertical seismic profiling; and pressure tomography and inversion (Stage 3). These methods use downhole/cross-well data, and possibly water injections, to obtain crude images of an encroaching CO_2 plume (Jenkins et al., 2017). For this purpose the reservoir interval needs to comprise series of connected sand bodies over a long migration fetch (~600 m) directed up-dip towards the monitoring array. Thus the structural mapping of the Paaratte Formation was used to locate the optimal location for the injector CRC-3 to the west of the structural saddle to maximise the effect of the dip down to the west (Figure 4). It will rely on a continuous confining layer over the distance to guide the plume, and in order for the pressure monitoring wells to be effective the interval needs to be confined vertically. Ideally the net sand thickness in the reservoir interval should be in the order of 10-20 m as the signal will be steadily diluted as thickness approaches >30 m. Being that we assume the water injection volume is constant (increasing the injected water volumes introduces operational difficulties and additional expense) this is major constraint. The correlation of the PS 1 interval between CRC-3 and CRC-2 appears to meet this criteria and a potential injection location in CRC-3 has been identified (Figure 17). From the analogue studies the distal mouth bars and delta front facies (seals) above PS1 and PS2 are expected to be laterally continuous (>1000 m). This is yet to be tested, but a preliminary water injection test at CRC-3 shows the seals are having a definite vertical compartmentalising effect on the pressure response (Jenkins et al., 2017).

Conclusions

The geo-characterisation study has been used to assess the suitability of the lower Paaratte Formation for the purposes of injection, storage, and monitoring for experiments at the CO2CRC Otway Project site. It has also provided the most comprehensive set of good quality core and formation evaluation data ever acquired in the Otway Basin for the Paaratte Formation. This has improved the characterisation of reservoir and seal quality distribution over the targeted injection locations, and the interpretations have provided new insights as to the regional structural setting, sequence stratigraphy, sedimentology and paleo-depositional environment for the formation. This was only possible due to the success of a targeted data acquisition program and integration of many specialist disciplines and analysis. Key conclusions are:

- The age of the Paaratte Formation ranges from the upper part of the Lower Campanian to approximately the Campanian/Maastrichtian boundary, and a review of the type section in the Port Campbell-1 well restricts it to only the section between the Skull Creek Mudstone and the Timboon Sandstone.
- There is a recommendation to subdivide the formation into three-fold member units “A, B, and C” on the basis of the palynology and correlation to major regional unconformities and global eustatic cycles.
- North-East to South-West orientated faulting associated with Late Cretaceous extension tends to die out before the top of the Sherbrook Group. In contrast, the more east –west orientated faults have been reactivated through the late Tertiary, forming large normally faulted half grabens with smaller associated synthetic relay faults.
- The majority of the sequence comprises deltaic (~30%) or tidal/estuarine (~65%) facies with only a small fraction attributed to a fluvial (3.6 %) or flood plain facies (1.8%).
- Facies interpreted from cores compare well with facies interpreted from image well-logs, demonstrating that Image logs are valuable datasets to characterise intervals or wells where there are no cores.
- Reservoir quality is strongly related to depositional facies, with the porosity, permeability and vertical permeability being a function of the proximity of the deposition to the main delta system.

- Analogue data is essential for characterising and predicting continuity of facies and for conditioning experimental variograms for rock property models.

The case study presented describes a basic workflow for a small scale CO_2 storage project and highlights the importance of understanding the relationship of facies and vertical heterogeneity for CO_2 storage in an open saline aquifer. The deltaic-estuarine depositional environment of the Paaratte Formation gives rise to the development of stacked parasequences defined by repeated transgressive events within an overall prograding system resulting interbedded reservoir sands and intraformational seals and baffles. This arrangement has been exploited to enhance trapping mechanisms for improved CO_2 storage and the characterisation of these has contributed to successful outcomes in the CO_2 injection projects conducted in the Paaratte Formation (Cook et al, 2014; Ennis-King et al 2017b; Haese et al, 2013; La Force et al, 2014; Myers et al, 2014; Paterson et al, 2013; Pevzner et al, 2017; Serno et al, 2016). Thus selection of perforation intervals that take advantage of these types of features will also be important for larger scale CCS projects wishing to maximise capacity and containment.

Acknowledgements

The author acknowledges the whole CO2CRC Otway Project team particularly Mark Bunch (Australian school of Petroleum), Malcom Arnot, Mark Lawrence, and Greg Browne (GNS Science) for collaboration on the sedimentological interpretation of CRC-2 core data. Also thanks to Alan Partridge for the biostratigraphy, Dale Lewis of Schlumberger for processing and interpreting the CRC-3 Image log data, and Ric Daniel from the University of Adelaide for the seal characterisation data. The authors also thank Bruce Ainsworth and Simon Lang, Chevron, for advice on geological analogues. Thanks to Lincoln Paterson for providing revisions and advice; and Charles Jenkins of CSIRO and expert reviewers from the Journal of Petroleum Geology for suggestions that have improved the paper. The authors acknowledge funding provided by the Australian government through its CRC program to support the CO2CRC Otway research project. Financial assistance was also provided through Australian National Low Emissions Coal Research and Development (ANLEC R&D). ANLEC R&D is supported by Australian Coal Association Low Emissions Technology Limited.

References

ABURAS, A.N. and BOULT, P.J., 2001. New insights into the structural development of the onshore Otway Basin. In HILL, K.C. and BERNECKER, T., (eds): Eastern Australasian Basins Symposium: a refocused energy perspective for the future. Petroleum Exploration Society of Australia. Special Publication 1, 447-453.

ALPAY, O. A., 1972. A practical approach to defining reservoir heterogeneity: Journal of Petroleum Technology, 24: 841–848.10: 2118-3608

ARNOT, M., LAWRENCE, M., BROWNE, G. and BUNCH, M., 2012. Integrated Sedimentological and Borehole Image Log Interpretation of Core from Otway Project Well CRC-2. Poster presented at the CO2CRC Research Symposium, Coolum, Australia, 27-29 November.

ARTS, R. and WINTHAEGEN, P., 2005. Monitoring Options for CO2 Storage. Geologic Storage of Carbon Dioxide with Monitoring and Verification. 2. 1001-1013. 10.1016/B978-008044570-0/50147-1.

BACHU, S., GROBE, M., 2006. Characterization of Sites for Geological Storage of Carbon Dioxide. Environmental Geosciences, 13(2): 67-70.

BAIN, J.S. and MCQUEEN, A.F., 1964. Port Campbell No.1 and No.2 wells Victoria. Bureau of Mineral Resources (BMR), Geology and Geophysics, Petroleum Search Subsidy Acts Publication No.18: 1-121, pl.1-2.

BIRKHOLZER, J.T. and TSANG, C.F., 2008. Introduction to Special Issue on Site Characterization for Gelogical Storage of CO_2. Journal of Environmental Geology, 54(8): 1579-1581.

BOCK, P.E. and GLENIE, R.C., 1965. Late Cretaceous and Tertiary depositional cycles in south-western Victoria. In: Proceedings Royal Society of Victoria, 79, pt.1, 153-163.

BOYD, G.A. and GALLAGHER, S.J., 2001. The sedimentology and palaeoenvironments of the Late Cretaceous Sherbrook Group in the Otway Basin. In: HILL, K.C. and BERNECKER, T., (eds.): Eastern Australian Basins Symposium: a refocussed energy perspective for the future, Petroleum Exploration Society of Australia, Special Publication 1, 475-484.

BREVIK, I., EIKEN, O., ARTS, R.J., LINDEBERG, E., and CAUSSE, E., 2000. Expectations and results from seismic monitoring of CO_2 injection into a marine aquifer. 62nd EAGE meeting, Glasgow, paper B-21.

BRUANT, R.G., GUSWA, A.J., CELIA, M.A. and PETERS, C.A., 2002. Safe storage of CO_2 in deep saline aquifers. Environmental Science & Technology, 36(11): 240a-245a.

BUNCH, M., LAWRENCE, M., DANIEL, R., DANCE, T., MENACHERRY, S., BROWNE, G. and ARNOT, M., 2012. Multi-scale characterisation of the Paaratte Formation, Otway Basin, for CO2 injection and storage. Oral presentation given at the AAPG 2012 International Conference and Exhibition, Marina Bay Sands Hotel, Singapore, 16-19 September 2012.

CAMPBELL, R.J., HOWE, R.W. and REXILIUS, J.P., 2004. Middle Campanian—lowermost Maastrichtian nannofossil and foraminiferal biostratigraphy of the northwestern Australian margin. Cretaceous Research, 25: 827-862.

COOK, P.J., 2006. Site characterization, International Symposium on Site Characterization for CO_2 Geological Storage, Lawrence Berkeley National Laboratory, March 20-22, Berkeley, CA, 3-5.

COOK, P. 2014. Geologically storing carbon: Learning from the Otway Project experience. CSIRO Publishing, Melbourne, 384pp. ISBN: 9781486302314

DANCE, T and CINAR, Y, 2009. Static and Dynamic Modelling of the Paaratte Formation Zone 1 Reservoir. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra, Australia, CO2CRC Publication Number RPT09-1720.

DANCE, T., ARNOT, M., BUNCH, M., DANIEL, R., HORTLE, A., LAWRENCE, M. and ENNIS-KING, J., 2012. Geocharacterisation and static modelling of the lower Paaratte Formation. CO2CRC Otway

Project - Phase II. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra, Australia, CO2CRC Publication Number RPT12-3481.

DANCE, T. 2013. Assessment and geological characterisation of the CO2CRC Otway Project CO_2 storage demonstration site: From prefeasibility to injection. Marine and Petroleum Geology, September 2013, 46: 251-269.

DANCE, T. and PATERSON, L., 2016. Observations of carbon dioxide saturation distribution and residual trapping using core analysis and repeat pulsed-neutron logging at the CO2CRC Otway site. International Journal of Greenhouse Gas Control. APR 2016 47: 210-220. 10.1016/j.ijggc.2016.01.042

DANIEL, R., MENACHERRY, S. and BUNCH, M., 2012. Characterisation of dolomitic intraformational barriers, CRC-2 Stage 2B injection interval, Paaratte Formation, CO2CRC Otway Project, Otway Basin, Victoria. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra, Australia, CO2CRC Publication Number RPT12-3532, 84pp.

DANIEL, R., 2012. Containment/ Injectivity Results from MICP Analysis for Seals, Intraformational Barriers and Reservoir Samples, CRC-2, Otway Basin. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra, Australia, CO2CRC Publication Number: TBN12-3830 (77pp).

DIESSEL, C.F.K., 1992. Coal-Bearing Depositional Systems, Springer, Berlin 721

DURAN, J., 1986. Geology, hydrogeology and groundwater modelling of the Port Campbell hydrogeological sub-basin, Otway Basin, S.W. Victoria. Report 1986/24. Geological Survey of Victoria, Victoria.

DUTTON, S.P., WHITE, C.D., WILLIS, B.J. and NOVAKOVIC, D., 2002. Calcite cement distribution and its effect on fluid flow in a deltaic sandstone, Frontier Formation, Wyoming. AAPG Bulletin, 86 (12) December: 2007–2021

EDWARDS, J., LEONARD, J.G., PETTIFER, G.R. and MCDONALD, P.A., 1996. Colac 1:250 000 Map Geological Report Geological Survey of Victoria. Report 98.

ELLIOTT, T., 1986. Chapter 6 – Deltas. In*:* READING, H.G. (ed): Sedimentary environments and facies (2nd ed.), Blackwell, Oxford, 113-154.

ENNIS-KING, J., LA FORCE, T., PATERSON, L., BLACK, J., VU, H., HAESE, R., SERNO, S., GILFILLAN, S., JOHNSON, G., FREIFELD, B. and SINGH, R., 2017a. Stepping into the same river twice: field evidence for the repeatability of a CO2 injection test. 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland. Energy Procedia, 114: 2760-2771.

ENNIS-KING, J., LAFORCE, T., PATERSON, L., DANCE, T., JENKINS, C. and CINAR, Y. 2017b. Interpretation of above zone and storage zone pressure responses to carbon dioxide injection in the 2016 CO2CRC field test. 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland. Energy Procedia, 114: 5671-5679, ISSN 1876-6102.

FAULKNER A., 2000. Sequence stratigraphy of the late Cretaceous Sherbrook Group, Shipwreck Trough, Otway Basin; B.Sc. (Hon) Thesis, National Centre for Petroleum Geology and Geophysics, University of Adelaide.

FELTON, A. and JACKSON, K.S., 1987. Hydrocarbon generation potential in the Otway Basin, Australia. BMR Journal of Australian Geology and Geophysics 10(3): 213-224.

FREY, R. W., HOWARD, J. D. and PRYOR, W. A., 1978. Ophiomorpha: Its morphologic, taxonomic, and environmental significance, Palaeogeography, Palaeoclimatology, Palaeoecology, 23: 199-229, ISSN 0031-0182.

GALLAGHER, S.J., TAYLOR, D., APTHORPE, M., STILWELL, J.D., BOREHAM, C.J., HOLDGATE, G.R., WALLACE, M.W. and QUILTY, P.G., 2005. Late Cretaceous dysoxia in a southern high latitude siliciclastic succession, the Otway Basin, southeastern Australia Palaeogeography, Palaeoclimatology, Palaeoecology 223(3-4): 317-348.

GLENIE, R.C., 1971. Upper Cretaceous and Tertiary rock-stratigraphic units in the central Otway Basin. In: The Otway Basin of Southeastern Australia, H. Wopfner & J.G. Douglas, (eds.), Geological Surveys of South Australia and Victoria Special Bulletin, 193-215.

GHANBARI, S., AL-ZAABI, Y., PICKUP, G.E., MACKAY, E., GOZALPOUR, F., and TODD, A.C., 2006. Simulation of CO_2 storage in saline aquifers. Chemical Engineering Research and Design, 84 (9): 764-775, ISSN 0263-8762.

GIBSON-POOLE, C. M., ROOT, R. S., LANG, S. C., STREIT, J. E., HENNIG, A. L., OTTO, C. J. and UNDERSCHULTZ, J. R., 2005. Conducting comprehensive analyses of potential sites for geological CO_2 storage. In: RUBIN, E. S., KEITH, D. W. AND GILBOY, C. F., (eds.): Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, 5-9 September, Vancouver, Canada. Elsevier, Oxford. 673-681.

GLUBOKOVSKIKH, S., PEVZNER, R., DANCE, T., CASPARI, E., POPIK, D., SHULAKOVA, V, and GUREVICH, B., 2016. Seismic monitoring of CO_2 geosequestration: CO2CRC Otway case study using full 4D FDTD approach. International Journal of Greenhouse Gas Control. 49. 201-216. 10.1016/j.ijggc.2016.02.022.

GRADSTEIN, F.M., OGG, J.G. and SMITH, A.G., 2004. A geological time scale 2004. Cambridge University Press, Cambridge, United Kingdom, i-xx: 1-589, 1 chart.

GEARY, G.C., CONSTANTINE, A.E., and REID, I.S.A, 2001. New perspectives on structural style and petroleum prospectivity, offshore eastern Otway Basin. In: HILL, K.C. and BERNECKER, T. (eds): Eastern Australian Basins Symposium: a Refocussed Energy Perspective for the Future, Petroleum Exploration Society of Australia, Special Publication, 507-517.

GEARY G. C., and REID I. S. A., 1998. Hydrocarbon prospectivity of the offshore eastern Otway Basin, Victoria for the 1998 Acreage Release. Victorian Initiative for Minerals and Petroleum Report 55, Department of Natural Resources and Environment.

GSV (Geological Survey of Victoria), 1995. The stratigraphy, structure and geophysics and hydrocarbon potential of the Eastern Otway Basin. Geological Survey of Victoria Report 103, p.1-241, figs 1-85, enclosures 1-16.

HAQ, B.U., HARDENBOL, J. and VAIL, P., 1987. Chronology of fluctuating sea levels since Triassic. Science 235: 1156–1167.

HERRING, A. L., HARPER, E. J., ANDERSSON, L., SHEPPARD, A., BAY, B. K and WILDENSCHILD, D., 2013. Effect of fluid topology on residual nonwetting phase trapping: Implications for geologic CO_2 sequestration, Advances in Water Resources, 62 (part A): 47-58. ISSN 0309-1708, doi.org/10.1016/j.advwatres.2013.09.015.

HOLZ, M., KALKREUTH, M. and BANERJEE, I., 2002. Sequence stratigraphy of paralic coal-bearing strata: an overview, International Journal of Coal Geology, 48 (3 & 4): 147-179, ISSN 0166-5162.

HOVORKA, S.D., DOUGHTY, C., BENSON, S.M., PRUESS, K. and KNOX P.R., 2004. The impact of geological heterogeneity on CO_2 storage in brine formations: A case study form the Texas Gulf Coast. In: BAINES, S.J. and WORDEN, R.H. (Eds.): Geological Storage of Carbon Dioxide, Special Publication 233, Geological Society, London (2004), 147–163.

HOWE, R.W., CAMPBELL, R.J. and REXILIUS, J.P., 2003. Integrated uppermost Campanian—Maastrichtian calcareous nannofossil and foraminiferal biostratigraphic zonation of the north-western margin of Australia. Journal of Micropalaeontology, 22: 29-62.

Intergovernmental Panel on Climate Change (IPCC), 2005. In: METZ, B., DAVIDSON, O., DE CONINCK, H.C., LOOS, M. and MAYER, L.A. (Eds.): Special Report on Carbon Dioxide Capture and Storage. Cambridge University Press, Cambridge, U.K. and New York, NY, U.S.A., 195-276 (Chapter 5). http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf

JENKINS, C., COOK, P., ENNIS-KING, J., UNDERSCHULTZ, J., BOREHAM, C., DE CARITAT, P., DANCE, T., ETHERIDGE, D., HORTLE, A., FREFELD, B., KIRSTE, D., PATERSON, L., PEVZNER, R., SCHACHT, U., SHARMA, S., STALKER, L. and UROSEVIC, M., 2012. Safe storage and effective monitoring of CO_2 in depleted gas fields. Proceedings of the National Academy of Science of the USA. 109 (2), 353-354.

JENKINS, C., DANCE, T., ENNIS-KING, J., GLUBOKOVSKIKH, S., GUREVICH, B., LA FORCE, T., MARSHALL, S., PATERSON, L., PEVZNER, R., TENTHOREY, E. and WATSON, M., 2017. Validating subsurface monitoring as an alternative option to surface Monitoring. Energy Procedia, 114: 3374-3384, ISSN 1876-6102, https://doi.org/10.1016/j.egypro.2017.03.1469.

JOHNSTON, D., 2013. Practical Applications for Time-lapse Seismic Data, 2013 Distinguished Instructor Short Course, Distinguished Instructor Series, No. 16

JOHNSTONE, E.M., JENKINS, C.C. and MOORE, M.A., 2001. An integrated structural and palaeogeographic investigation of Eocene erosional events and related hydrocarbon potential in the Gippsland Basin. In HILL, K.C. and BERNECKER, T., (eds): Eastern Australian Basins Symposium. A Refocused Energy Perspective for the Future, Petroleum Exploration of Australia, Special Publication, 403-412.

KRASSAY, A.A., CATHRO, D.L. and RYAN, D.J. 2004. A regional tectonostratigraphic framework for the Otway Basin. In BOULT, P.J., JOHNS, D.R. and LANG, S.C. (Eds): Eastern Australasian Basins Symposium II, Petroleum Exploration Society of Australia, Special Publication, 97-116.

KREVOR, S. C. M., PINI, R., ZUO, L. and BENSON, S. M., 2012. Relative permeability and trapping of CO_2 and water in sandstone rocks at reservoir conditions. Water Resour. Res., 48, W02532, doi:10.1029/2011WR010859.

KUMAR, A., OZAH, R., NOH, M., POPE, G.A., BRYANT, S., SEPHEHRNOORI, K. and LAKE L.W., 2005. Reservoir simulation of CO_2 storage in deep saline aquifers. SPE Journal, 10 (3): 336–348.

LA FORCE, T., ENNIS-KING, J., BOREHAM, C. and PATERSON, L., 2014. Residual CO2 saturation estimate using noble gas tracers in a single-well field test: the CO2CRC Otway project. International Journal of Greenhouse Gas Control, 26: 9-21.

LASSITER, T. K., WAGGONER, J. R. and LAKE, L. W., 1986. Reservoir heterogeneities and their influence on ultimate recovery. In LAKE, L. W. and N. B. CARROLL, Jr. (eds.): Reservoir Characterization: Orlando, FL, Academy Press, 545-560.

LAVIN, C.J., 1997. The Maastrichtian breakup of the Otway Basin margin - a model developed by integrating seismic interpretation, sequence stratigraphy and thermochronological studies. Exploration Geophysics, 28: 252-259.

LAWRENCE, M., ARNOT, M., BROWNE, G., BUNCH, M., MENACHERRY, S. and DANCE, T., 2012. Geological interpretation of Otway Project wells CRC-1 and CRC-2. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra, Australia, CO2CRC Publication Number 358.

LEWIS, D., 2017. FMI Image interpretation, CRC-3, Software Integrated Solutions, Schlumberger Australia Pty Ltd. In DANCE, T. and GLUBOKOVSKIKH, S., 2017. Geological appraisal and static modelling for the CO2CRC Otway Project Stage 3: Incorporating outcomes from the CRC-3 well. CO2CRC Limited, Melbourne, Australia, C2CRC Publication Number RPT17-5751 (Appendix G)

LOWRY, D.C. and LONGLEY, I.M., 1991. A new model for Mid-Cretaceous structural history of the northern Gippsland Basin. The APEA Journal, 31 (1): 143-153.

MCQUEEN, A.F., 1961. The Geology of the Otway Basin. APPEA Conference Papers 1961, 25-29.

MIALL, A. D., 1984, Principles of Sedimentary Basin Analysis: New York, Springer-Verlag, 490.

MORTON, J.G.G., ALEXANDER, E.M., HILL, A.J. and WHITE, M.R., 1995. Lithostratigraphy and environments of deposition. In MORTON, J.G.G. and DREXEL, F.J. (eds.): The petroleum geology of South Australia. Volume 1, Otway Basin, Mines and Energy South Australia, Report Book 95/12: .47-94.

MYERS, M., STALKER, L., LA FORCE, T., PEJCIC, B., DYT, C., HO, K.-B. and ENNIS-KING, J., 2014. Field measurement of residual carbon dioxide saturation using reactive ester tracers. Chemical Geology, 399: 20-29

PALMOWSKI, D., HILL, K.C., HOFFMAN, N. and BERNECKER, T., 2001. Otway Basin rifting to sea-floor spreading -- hydrocarbon implications. In HILL, K.C. and BERNECKER, T. (eds): Eastern Australasian Basins Symposium: a refocused energy perspective for the future. Petroleum Exploration Society of Australia. Special Publication 1: 499-505

PENTLAND, C. H., EL-MAGHRABY, R., IGLAUER, S. and BLUNT, M. J. 2011. Measurements of the capillary trapping of super-critical carbon dioxide in Berea sandstone, Geophys. Res. Lett., 38, L06401, doi:10.1029/2011GL046683.

PARTRIDGE, A.D., 2001. Revised stratigraphy of the Sherbrook Group, Otway Basin. In HILL, K.C. and BERNECKER, T. (eds): Eastern Australian Basins Symposium. A Refocused Energy Perspective for the Future, Petroleum Exploration of Australia, Special Publication, 455-464.

PARTRIDE, A.D., 2011. Palynological analysis of core and cuttings samples from the Paaratte Formation in the CRC No.2 well, Otway Basin. Biostrata Pty Ltd, Biostrata report 2011/01.

PARTRIDGE, A.D., 2017. Palynological analysis of core samples from the CRC No.3 well, Otway Basin. Biostrata Pty Ltd, Biostrata Report 2017/02.

PATERSON, L., BOREHAM, C., BUNCH, M., DANCE, T., ENNIS-KING, J., FREIFELD, B., HAESE, R., JENKINS, C., LAFORCE, T., RAAB, M., SINGH, R., STALKER, L. and ZHANG, Y., 2013, Overview of the CO2CRC Otway residual saturation and dissolution test: Energy Procedia, 37: 6140-6148.

PINI, R., KREVOR, S.C.M. and BENSON, S.M., 2012. Capillary pressure and heterogeneity for the CO_2/water system in sandstone rocks at reservoir conditions. Advances in Water Resources, 38: 48-59.

PEVZNER, R., UROSEVIC, M., POPIK, D., SHULAKOVA, V., TERTYSHNIKOV, K., CASPARI, E., CORREA, J., DANCE, T., KEPIC, A., GLUBOKOVSKIKH, S., ZIRAMOV, S., GUREVICH, B., SINGH, R., RAAB, M., WATSON, M., DALEY, T., ROBERTSON, M. and FREIFELD, B., 2017. 4D surface seismic tracks small supercritical CO_2 injection into the subsurface: CO2CRC Otway Project. International Journal of Greenhouse Gas Control. 63. 150-157. 10.1016/j.ijggc.2017.05.008.

PEVZNER, R., UROSEVIC, M., TERTYSHNIKOV, K., GUREVICH, B., SHULAKOVA, V., GLUBOKOVSKIKH, S., POPIK, D., CORREA,J., KEPIC,A., FREIFELD, B., ROBERTSON,M., WOOD,T., DALEY, T. and SINGH, R., 2016. Stage 2C of the CO2CRC Otway Project: Seismic monitoring operations and preliminary results. Energy Procedia,

Pevzner, R., UROSEVIC, M., CASPARI, E., GALVIN, R. J., MADADI, M., DANCE, T., SHULAKOVA, V., GUREVICH, B., TCHEVERDA, V. and CINAR, Y., 2013. Feasibility of time-lapse seismic methodology for monitoring the injection of small quantities of CO2 into a saline formation, CO2CRC Otway Project. Energy Procedia, 37(0): 4336-4343.

READING H.G., 1996. Sedimentary environments: processes, facies and stratigraphy. Blackwell Publishing Limited.

RINGROSE, P., NORDAHL, K. and WEN, R., 2005. Vertical permeability estimation in heterolithic tidal deltaic sandstones. Petroleum Geoscience, 11: 29-36.

ROOT, R., 2007. Geological evaluation of the Eocene Latrobe Group in the offshore Gippsland Basin for CO_2 geosequestration. Thesis (Ph.D.) -- University of Adelaide, Australian School of Petroleum, 2007 http://hdl.handle.net/2440/57413

SACS/CO2STORE, 2008. Best practice for the storage of CO_2 in saline aquifers: observations and guidelines from the SACS and CO2STORE projects. British Geological Survey.

SERNO, S., JOHNSON, G.C., LAFORCE, T., ENNIS-KING, J., HAESE, R. J., BOREHAM, C., PATERSON, L. M., FREIFELD, B. J., COOK, P., KIRSTE, D., HASZELDINE, R. S. and GILFILLAN, S., 2016. Using oxygen isotopes to quantitatively assess residual CO_2 saturation during the CO2CRC Otway Stage 2B extension residual saturation test. International Journal of Greenhouse Gas Control. 52: 73-83. 10.1016/j.ijggc.2016.06.019.

TAYLOR, A., M., and GOLDRING, R., 1993. Description and analysis of bioturbation and ichnofabric. Journal of the Geological Society, 150 (1): 141-148.

Taylor, K.G., and Gawthorpe, R.L., 2003. Basin-scale dolomite cementation of shoreface sandstones in response to sea-level fall. Bulletin of the Geological Society of America, 115 (10): 1218-1229.

TENTHOREY, E., DANCE, T., CINAR, Y., ENNIS-KING, J. and STRAND, J., 2014. Fault modelling and CO_2 migration potential associated with the CO2CRC Otway 2C injection experiment. International Journal of Greenhouse Gas Control, 30: 72.

UNDERSCHULTZ, J., BOREHAM, C., DANCE, T., STALKER, L., FREIFELD, B., KIRSTE, D. and ENNIS-KING, J., 2011. CO_2 storage in a depleted gas field: an overview of the CO2CRC Otway Project and initial results. International Journal of Greenhouse Gas Control. 5 (4): 922-932.

VAN DE GRAAFF, W. J. E., and P. S. EALEY, 1989. Geological modeling for simulation studies: AAPG Bulletin, 73: 1436-1444.

WATSON, M., CINAR, Y., DANCE, T., PEVZNER, R., TENTHOREY, E., CASPARI, E., ENNIS-KING, J., SHULAKOVA, V., BUNCH, M., UROSEVIC, M., SINGH, R., GUREVICH, B., PATERSON, L., JENKINS, C. and RAAB, M., 2012. Otway Stage 2C science report - verification of CO2 storage in a saline formation (Paaratte) using time-lapse seismic. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra, Australia, CO2CRC Publication Number RPT12-4109. 220pp.

WEBER, K. J., 1986. How heterogeneity affects oil recovery. In: L. W. Lake, and H. B. J. Carroll, (eds.) Reservoir Characterization: Orlando, FL, Academy Press, 487-544.

WILLIS B.J., BHATTACHARYA J.P., GABEL S.L. and WHITE C.D., 1999. Architecture of a tide-influenced delta in the Frontier Formation of central Wyoming, USA. Sedimentology, 46: 667-688

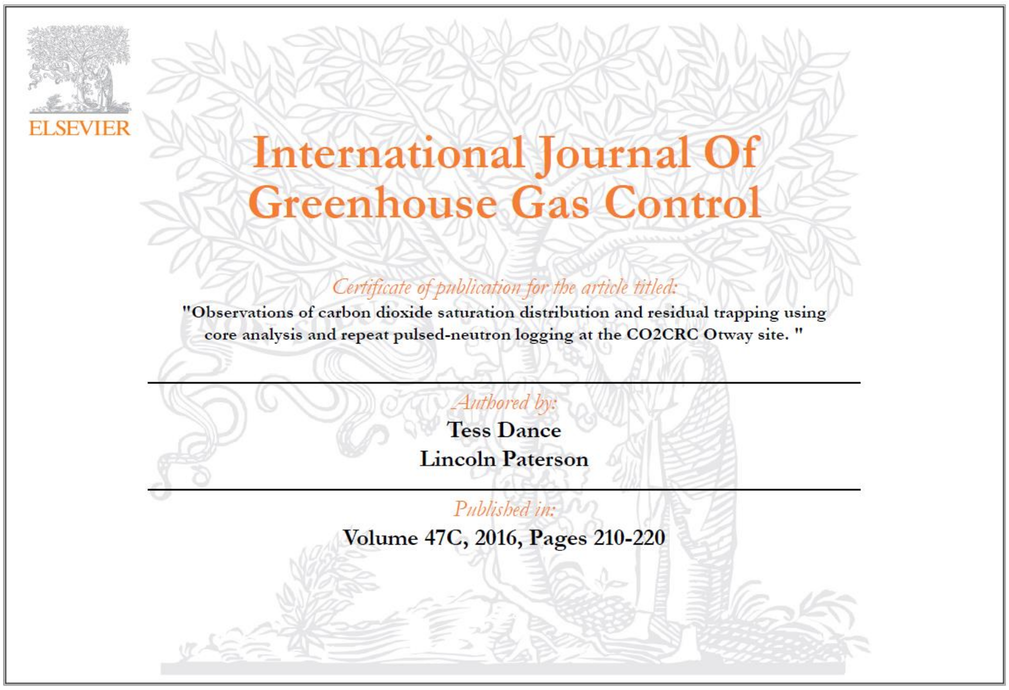
ZHANG, Y., FREIFELD, B., FINSTERLE, S., LEAHY, M., ENNIS-KING, J., PATERSON, L., and DANCE, T., 2011. Single-well experimental design for studying residual trapping of supercritical carbon dioxide. International Journal of Greenhouse Gas Control, 5(1): 88-98.

4.3 Publication 3: Observations of carbon dioxide saturation distribution and residual trapping using core analysis and repeat pulsed-neutron logging at the CO2CRC Otway site.

Published in: International Journal of Greenhouse Gas Control 47 (2016) 210-220

Authors: Tess Dance and Lincoln Paterson

CO2CRC/CSIRO, Earth Science and Resource Engineering, PO Box 1130, Bentley, W.A., 6102, Australia, email: tess.dance@csiro.au.



ELSEVIER

International Journal Of Greenhouse Gas Control

Certificate of publication for the article titled:

"Observations of carbon dioxide saturation distribution and residual trapping using core analysis and repeat pulsed-neutron logging at the CO2CRC Otway site. "

Authored by:

Tess Dance

Lincoln Paterson

Published in:

Volume 47C, 2016, Pages 210-220

Statement of Authorship

Title of Paper	Observations of carbon dioxide saturation distribution and residual trapping using core analysis and repeat pulsed-neutron logging at the CO2CRC Otway site
Publication Status	☑ Published ☐ Accepted for Publication ☐ Submitted for Publication ☐ Unpublished and Unsubmitted work written in manuscript style
Publication Details	Published in: International Journal of Greenhouse Gas Control volume 47 (2016) pages 210-220, authors: Tess Dance and Lincoln Paterson CO2CRC/CSIRO, Energy.

Principal Author

Name of Principal Author (Candidate)	Tess Dance		
Contribution to the Paper	Prepared the manuscript, provided geological context, selected core samples for analysis, interpretation of the results against logs, evaluated the saturation Land Co-efficient against geological characteristics, corresponding author, revision, and corrections.		
Overall percentage (%)	75%		
Certification:	This paper reports on original research I conducted during the period of my Higher Degree by Research candidature and is not subject to any obligations or contractual agreements with a third party that would constrain its inclusion in this thesis. I am the primary author of this paper.		
Signature		Date	28/11/18

Co-Author Contributions

By signing the Statement of Authorship, each author certifies that:

i. the candidate's stated contribution to the publication is accurate (as detailed above);

ii. permission is granted for the candidate in include the publication in the thesis; and

iii. the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

Name of Co-Author	Lincoln Paterson		
Contribution to the Paper	25% Co-supervised candidate, guided research and provided leadership, expert reservoir engineering advice, revised the manuscript.		
Signature		Date	30/11/2018

International Journal of Greenhouse Gas Control 47 (2016) 210–220

Contents lists available at ScienceDirect

International Journal of Greenhouse Gas Control

journal homepage: www.elsevier.com/locate/ijggc

Observations of carbon dioxide saturation distribution and residual trapping using core analysis and repeat pulsed-neutron logging at the CO2CRC Otway site

T. Dance[a,b,*], L. Paterson[a,c]

[a] CO2CRC, PO Box 1182, Carlton, VIC 3053, Australia
[b] CSIRO, PO Box 1130, Bentley, WA 6102, Australia
[c] CSIRO, Private Bag 10, Clayton South, Vic. 3169, Australia

ARTICLE INFO

Article history:
Received 11 August 2014
Received in revised form 22 January 2016
Accepted 29 January 2016

Keywords:
Residual CO_2 saturation
Time-lapse monitoring
Pulsed-neutron logging
CO2CRC Otway project

ABSTRACT

Time-lapse pulsed-neutron well logging has been applied at the CO2CRC Otway site to measure changes in carbon dioxide saturation profiles across an injection interval. Three stages of contrasting saturation were logged: when the formation was fully water saturated; after CO_2 was injected; and after water was injected to drive the CO_2 to residual saturation. This allowed for a unique opportunity to observe changing fluid saturation responding to relative permeability hysteresis at the field scale as part of a controlled experiment. The high vertical resolution of the logs (< 0.2 m) provided detailed fluid saturation profiles of the near-well region. These data were used to interpret the thickness and variability of saturation from the injected carbon dioxide plume. The interpreted saturation profiles from the Otway site show an average residual saturation of 0.20, with an overall range of 0.07 to 0.32. A consistent correlation was observed between the saturation values measured before and after water injection. Higher values for residual CO_2 saturation were obtained in the upper portion of the 7 m thick injection interval where higher initial CO_2 saturations were reached. In a comparison study with core-scale fluid saturation measurements from the same interval, it was found that the correlation between initial and final saturation from the field measurements gives a similar fit to a Land coefficient derived from the laboratory measurements. Observations of the spatial variation in the trapped gas from both core and logs show that residual trapping is a function of the initial saturation achieved and is sensitive to geological heterogeneity.

1. Introduction

Residual or capillary trapping can make an important contribution to immobilising injected carbon dioxide at a geological storage site. Residual trapping of a non-wetting phase has been determined to result from two mechanisms: snap-off and bypassing. From this, Chatzis et al. (1983) concluded that residual trapping depends on the pore-throat aspect ratio and the coordination number or connectivity of the pore system.

Most studies of residual trapping of a non-wetting phase have considered a porous rock initially filled with oil. In contrast, in a saline aquifer, the rock is initially filled with water before carbon dioxide is injected. This means that the carbon dioxide saturation starts at zero, then attains a level after injection that is not expected to be uniform. If water is then injected the carbon dioxide saturation decreases until residual trapping is obtained. This saturation path can be described on a plot of relative permeability, where the difference in the drainage and imbibition relative permeability curves is known as relative permeability hysteresis (Juanes et al., 2006). In this case residual trapping depends not just on the properties of the porous solid, but also on the geometry and topology of the injected carbon dioxide (i.e., the connectivity of CO_2 ganglia) at maximum saturation (Herring et al., 2013).

At the pore scale, it is possible to measure CO_2 saturation, and observe the dynamics of relative permeability during core flood experiments (Al Mansoori et al., 2010; Doughty et al., 2003; Krevor et al., 2011; Pentland et al., 2011; Pini et al., 2012; Saeedi et al., 2011). Advances in microtomography and 3D image registration means pore-scale capillary trapping may be enumerated directly at similar pressure and temperature conditions as the storage reservoir (Andrew et al., 2014; Blunt et al., 2013; Iglauer et al., 2011; Knackstedt et al., 2010). Although these analyses provide accurate results at centimeter, millimeter, and even micron scale, up-scaling this information to predict residual trapping potential at the

* Corresponding author at: CO2CRC, PO Box 1130, Bentley, WA 6102, Australia.
E-mail address: tess.dance@csiro.au (T. Dance).

http://dx.doi.org/10.1016/j.ijggc.2016.01.042
1750-5836/

Nomenclature

c.u.	Capture cross section units, 10 ^{3} cm ^{1}
PNC	Pulsed neutron capture
SIGM	Neutron capture cross section, c.u.
SIGM TDL	Sigma with TDT-like processing
s.u.	Saturation units
TDT	Thermal Decay Time tool
TRAT	Thermal count rate ratio (near/far)
	Sigma
$_T$	Thermal neutron porosity, pu (also called TPHI elsewhere)
$_{tot}$	Total porosity from open hole logs (PHIT).

reservoir scale can be problematic. There are issues with sampling bias when just a few core samples are taken to be representative of the overall reservoir heterogeneity (Busch and Müller, 2011). Numerical simulation of residual trapping and relative permeability in heterogeneous formations by Paterson et al. (1998) investigated these issues. It was found that trapping is sensitive to anisotropy of reservoir properties and bedding structures in relation to the dominant flow direction. Residual trapping for flow perpendicular to bedding can be substantially greater than for flow parallel to the bedding. The greater the anisotropy the stronger the effect and biased core samples may not accurately capture this.

A recent review of all published information surrounding relative permeability and residual trapping of CO_2 by Burnside and Naylor (2014) identified there is a need for a body of evidence to support a link between the experimental studies and numerical models with field scale observations. For this purpose, high resolution (<0.5 m), well-log derived fluid saturation profiles of the near-well region may be used to provide a calibration point between core-scale and reservoir-scale fluid saturation measurements. Pulsed -neutron logging tools, which distinguish formation fluids on the basis of how fast thermal neutrons are captured (denoted by sigma or), are commonly used for this purpose (Al Arayni et al., 2013; Freifeld et al., 2009; Quinlan et al., 2012). For example, Müller et al. (2007) and Sakurai et al. (2006) demonstrated that time-lapse pulsed-neutron logging is an appropriate method to monitor near-well CO_2 saturation changes in highly saline reservoirs due to a large contrast between the saline formation waters (high) and the injected CO_2 (low). Baumann et al. (2014) developed an extended saturation model used in conjunction with time-lapse pulsed-neutron logging to determine displacement and dry out regions at the Ketzin pilot site wells. By combining time-lapse cross-well seismic tomography (Saito et al., 2006) with time-lapse induction and pulsed-neutron logging techniques at the Nagaoka pilot project, Xue et al. (2006) demonstrated that it is possible to observe timing of breakthrough and migration direction of a CO_2 plume over time.

The CO2CRC Otway project provided an opportunity to observe and measure residual trapping at the field-scale through the application of pulsed-neutron logging, providing the basis for this study. The injection interval for this project used 7 m of perforated casing, but design simulations determined that the injected volume would not enter the perforations uniformly. Buoyancy results in higher saturations being obtained towards the top of the interval, and superimposed on this, higher saturations are obtained in the parts of the interval with higher permeabilities (Paterson et al., 2013) (Fig. 4). This distribution is supported by the pulsed-neutron logging measurements taken after carbon dioxide injection and before water injection at Otway. Subsequently after water injection, the final carbon dioxide saturation was observed to depend consistently on the maximum saturation achieved throughout the depth of the interval. This in turn is influenced by the dominant flow direction of the injected fluids and anisotropy of reservoir properties. These observations are the subject of this paper. Moreover, this relationship between maximum and final saturation is consistent with laboratory measurements performed on a core from the same interval described in Krevor et al. (2012).

2. Reservoir description

The CO2CRC Otway project is located in South-eastern Australia, 300 km Southwest of the city of Melbourne in the state of Victoria. The study site sits within the Otway Basin, in the Eastern side of the Port Campbell Embayment, the onshore extension of the Ship Wreck Trough. Stage 2 of the CO2CRC Otway project, which is focused on understanding non-structural trapping mechanisms for storage in heterogeneous saline aquifers, commenced in 2010 with the drilling of a new injection well (CRC-2) at the site. The well targeted the 400 m thick, Late Cretaceous, Paaratte Formation, which was intersected approximately 600 m above the depleted gas reservoir used for storage in stage 1, at between 1079 and 1473 mSS (metres sub-sea level). The Paaratte Formation is considered as a relevant analogue for deep saline aquifer storage sites as it has no apparent structural closure at the site, but instead contains considerable reservoir heterogeneity that may be exploited for CO_2 storage. This is typical of many prospective geological systems under consideration for future commercial-scale CO_2 storage whereby the containment concept relies on the permeable reservoir units to contain inter-formational baffles to inhibit vertical movement of the buoyant CO_2 long enough for residual and solubility trapping to immobilise free-phase CO_2 in the pore space. To this end the Paaratte Formation was selected because it is a heterogeneous formation with intercalations of medium to high permeability sands thinly interbedded with carbonaceous, mud-rich lithologies, and over printed with diagenetic carbonate cement layers which serve as seals and baffles of varying quality (Geary and Reid, 1998; Geary et al., 2001).

An injection interval was selected for the well test within a 7 m thick sandstone bed between approximately 1392 and 1399 mSS following a detailed core and well-log interpretation of data acquired from the CRC-2 well (Bunch et al., 2012). The sedimentary log is shown in the well composite in Fig. 1 compared with the porosity and permeability data over the injection interval. Sedimentary structures, ichnofacies and biostratigraphic fauna all point to a shallow marine paleo-depositional environment for these facies in which sediments were deposited sub-aqueous in a restricted marine embayment (Gallagher et al., 2005). The perforated zone sits mainly within a proximal mouth bar facies. It comprises very fine to medium grained, sub-angular to rounded, moderate to well sorted sandstone with mainly quartzose grains and some micas. Sedimentary structures within the proximal mouth bar sandstone facies include planar, ripple, and cross-bedded lamination as well as fine (<10 cm) laminations of siltstones and some minor bioturbation. At the top of the perforated zone is a distributary channel facies. This section is poorly sorted with grains up to granule and pebble size of mixed quartz, feldspar, and lithofragments. There are many mud rip-up clasts and wood fragments in this facies contributing to the overall grain type heterogeneity.

The interval has excellent reservoir quality (porosity and permeability) most likely due to wave and tidal processes reworking the fine-grained sediment. Conventional core plug tests and downhole logs indicate the sandstone has average porosity of 27% and permeability of 2.3 darcy. The sedimentary structures and bedding features, particularly in the highly laminated facies, do however, impact vertical permeability. As expected, the highly laminated facies have strong anisotropy in reservoir properties that result in

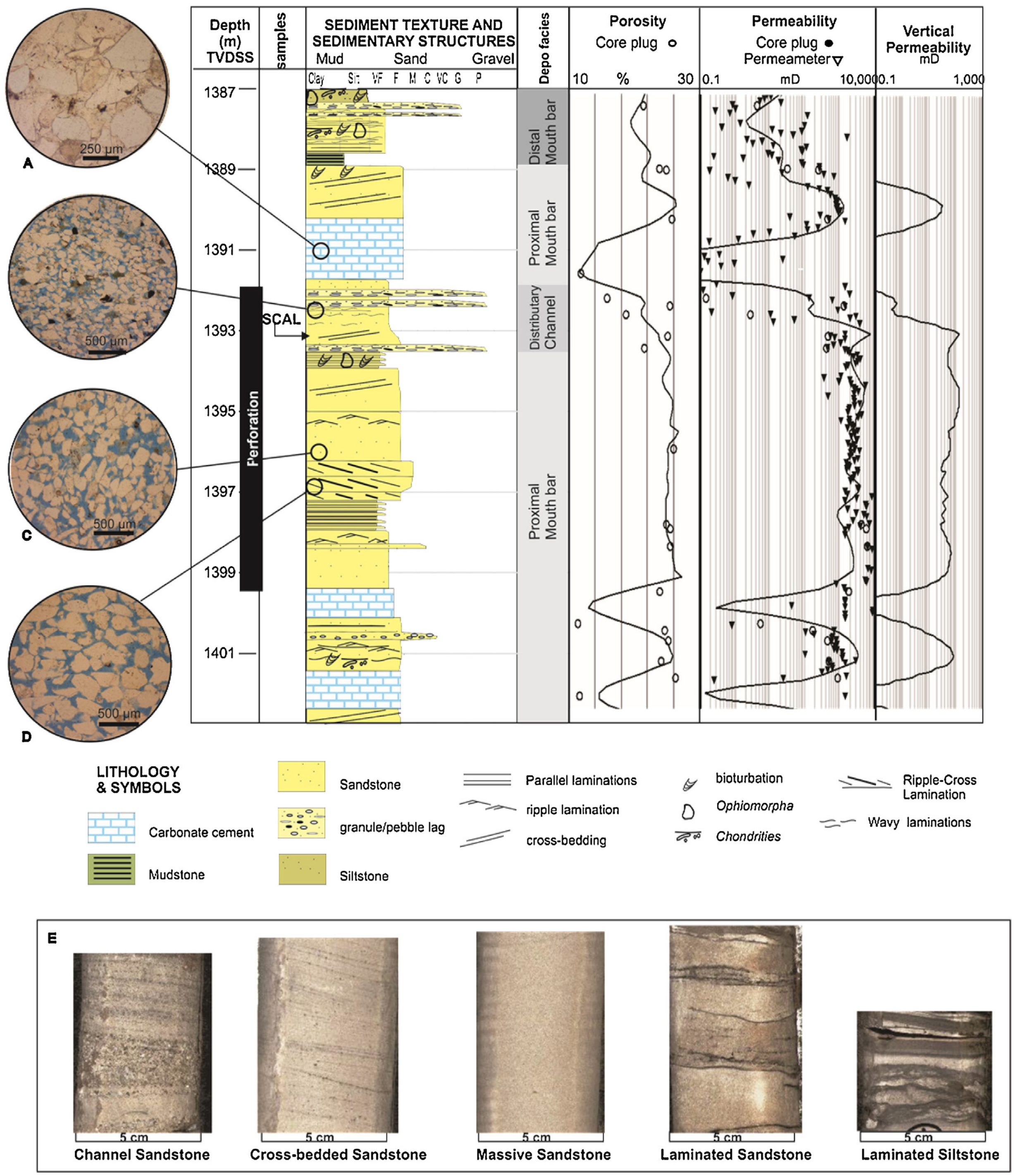


Fig. 1. Well composite of the injection interval including location of the special core analysis plug (SCAL); the detailed sedimentary core log; depositional facies associations; and interpreted porosity, permeability, and vertical permeability from NMR logs, core plug analysis, and mini-permeameter data. Photomicrographs of the reservoir sandstone and cemented zones bounding the injection interval: (a) Subarkose, fine grained, moderately sorted sandstone with > 35% dolomite cement and < 1% porosity. (b) Sublitharenite, fine grained, moderately sorted sandstone with detrital clay and 29% porosity. (c) Sublitharenite, fine grained, well sorted sandstone comprising mainly Quartz > 75% and 30% porosity. (d) Sublitharenite, medium grained, moderate to well sorted sandstone with 29% porosity. (e) Core photographs of the main reservoir facies.

low vertical permeability. Diagenetic carbonate cement zones overprint the more massive (structureless), fine-grained sandstones above and below the perforations. They have no visual porosity in the hand specimens and return very low values (5–10%) in the logs and conventional plug tests. Petrological analysis indicates the reduction in porosity is attributed to dolomitisation occluding the pore space between grains (Fig. 1) (Daniel et al., 2012). As a result, the permeability is very low (1–10 md). Seal capacity column heights of between 10 and 400 m were derived from mercury injection capillary threshold pressure experiments on samples of the cemented lithology. This means the zone above the perforations acts much like a caprock, having the effect of vertically confining the injected fluid to the high permeability sandstones in the vicinity of the well test interval. This effect allowed the well test to be easier to interpret owing to little vertical pressure communication and vertical migration of CO_2 above the zone of interest.

The baseline conditions of the reservoir were assessed prior to the test. Pressure and temperature were 14 MPa and 59 C,

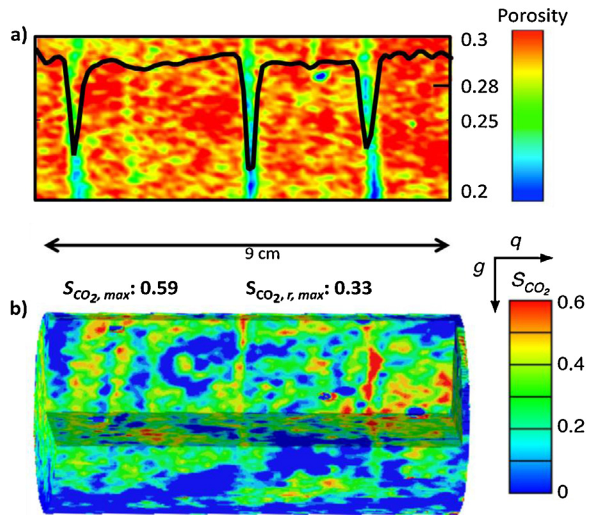


Fig. 2. a) Core porosity map of SCAL plug, with the black line showing the average porosity across the profile. There are three distinct bands of low porosity as a result of clay rich laminations in the sandstone. b) CT scan 3D image after the 9 cm core plug was flooded with CO_2 (red: areas of high saturation, blue: areas of little or no CO_2) (modified from Krevor et al., 2012).

respectively. Estimates of salinity (total dissolved solids (TDS)) derived from fluid samples taken from the reservoir in the area of the project were in the order of 800 to 2000 mg/L TDS.

2.1. Core measurements

Experimental investigations into the multiphase flow properties of a sample of the core were carried out to determine capillary pressure, drainage relative permeability, and residual CO_2 saturation (Krevor et al., 2012). The sample was recovered from 1393.5 mSS within a well-sorted sandstone, with angular to sub-angular grains, and minor clay rich laminations. A vertical plug was cut perpendicular to the bedding plane measuring approximately 90 mm in length and 50 mm in diameter. Absolute water permeability was obtained for the sample and was around 1156 – 20 md. Steady-state core-flood measurements were conducted under reservoir conditions and x-ray computed tomography used to observe fluid distributions during CO_2 displacing water (drainage) and water displacing CO_2 (imbibition). This is a common technique used to produce three-dimensional maps and two dimensional image profiles of porosity and saturation and allows the drainage/imbibition front to be tracked and quantified (Perrin and Benson, 2010, Iglauer et al., 2011). Results for residual trapping in the core indicate the sandstone to be strongly water-wet. The maximum CO_2 saturation measured following drainage was 59%, and maximum residual CO_2 saturation of 33% following imbibition. A comparison of the porosity profile image of the core plug and the three dimensional CO_2 saturation map at 90% fractional flow is shown in Fig. 2. Overall the plug exhibits good inter-granular porosity of around 28–29%, except for three distinct bands of low porosity resulting from clay rich laminations in the sandstone. It is apparent from the corresponding 3D image of CO_2 saturation that these bands produce adjacent zones of high CO_2 build-up as the fluid is flowed across the plug.

The Land trapping model (Land, 1968) is a widely used empirical model for accounting for gas trapping in a two-phase system that is strongly water-wet. It is the basis for most relative permeability models that incorporate hysteresis (Juanes et al., 2006; Kumar et al., 2005). It is applied here to interpret residual trapping potential of the reservoir from core test observations. In this model the saturation of residually trapped CO_2 (after imbibition) $S_{CO_2,r}$ is proposed

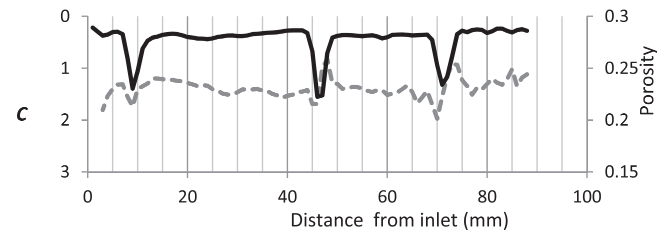


Fig. 3. The Land trapping coefficient profile (dashed line) from the SCAL plug shown in conjunction with the porosity profile (solid line) where it is apparent that the low porosity bands produce zones of CO_2 trapping heterogeneity as the fluids are flowed across the plug from left to right (modified from Krevor et al., 2012).

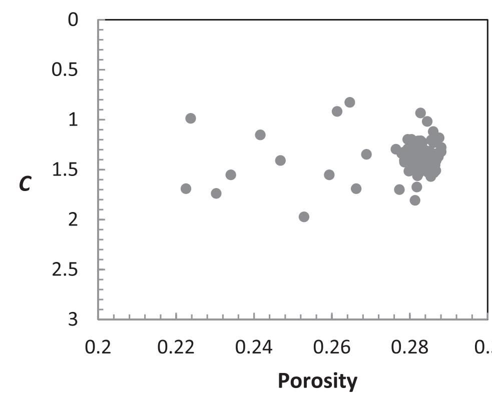


Fig. 4. The Land trapping coefficient (C) measured during the core flood test sequence as a function of the average porosity across the plug.

to be a function of the initial maximum non-wetting phase saturation $S_{CO_2,i}$ that can be achieved (before imbibition). The trapped non-wetting phase saturation is computed as

$$S_{CO_2,r} = \frac{S_{CO_2,i}}{1 + CS_{CO_2,i}} \quad (1)$$

where C is the dimensionless Land trapping coefficient. The coefficient is dependent on the types of fluids, and the pore and pore throat geometry of the rock. It can take on all values greater than or equal to zero, with $C = 0$ representing the case in which all gas is trapped. It is straightforward to calculate with data from the initial and residual saturations:

$$C = \frac{1}{S_{CO_2,r}} \quad \frac{1}{S_{CO_2,i}}. \quad (2)$$

For the Paaratte core sample analysed by Krevor et al. (2012), the Land trapping coefficient is calculated along the plug and the average is 1.3 (Fig. 3). In the zones corresponding to low porosity barriers the Land trapping coefficient increases (trapping is low), and in the zones immediately adjacent to the low porosity barriers the Land trapping coefficient decreases (trapping is higher). In Fig. 4 the Land trapping coefficient from the core is plotted as a function of the average porosity at the corresponding distance along the plug. There is no obvious relationship when the data is compared in this way. The variability in C may be explained instead by the low porosity layers acting as baffles to flow perpendicular to the flooding front causing increased retention in the pore space on the other side of the barriers. This would mean that C is influenced by the spatial distribution of heterogeneity in relation to the flow path of the invading CO_2 and water rather than just the absolute values for porosity. In order to understand the representativeness of the sample, these results are compared to well-logging field measurements of CO_2 saturation to see if similar saturation and trapping is observed.

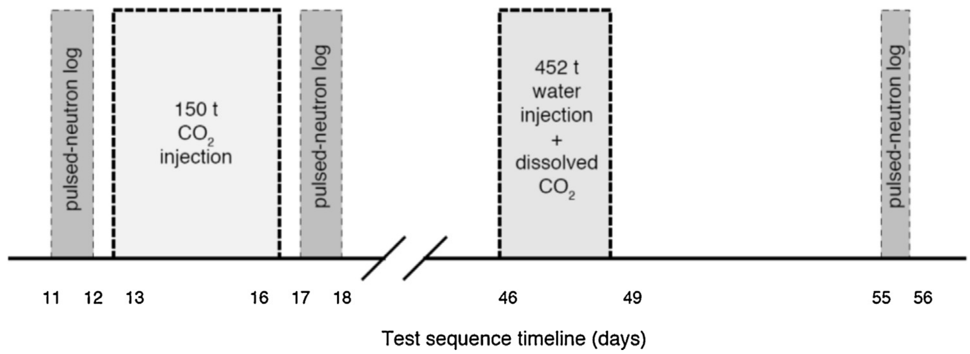


Fig. 5. Simplified schematic of the injection sequence and pulsed-neutron logging during the various stages of the Otway well test (Paterson et al., 2013).

2.2. Field measurements

The parts of the CO2CRC Otway project residual saturation and dissolution test sequence relevant to this study are summarised in Fig. 5. The entire test sequence was conducted over 77 days between June and September 2011. Baseline pulsed-neutron logging was carried out in order to characterise the initial reservoir conditions when 100% water saturated. Following this, 150 t of pure CO_2 were injected over a four-day interval. A second pulsed-neutron log was then run. The next stage was to drive the CO_2 down to residual saturation by injection of 454 t of water saturated with 26 t of CO_2 to avoid dissolving the residually trapped CO_2. Then a third pulsed-neutron log was run. In addition to the logs, a series of tests were conducted to characterise the residual gas field around the well using techniques including field pressure (Zhang et al., 2011), geochemical measurements of dissolution (Haese et al., 2013), noble gas and reactive ester tracers (Myers et al., 2014; Myers et al., 2012; LaForce et al., 2014), and thermal dynamic monitoring (Zhang et al., 2011). This resulted in interpretations for residual saturation ranging between 11 and 20%. An overview of the entire test sequence is given in Paterson et al. (2014) where each technique is described. It was found that these estimates varied depending on the depth of investigation, the timing, and the sensitivity of each of the methods.

3. Pulsed-neutron logging and processing methods

Pulsed-neutron logging tools work by emitting bursts, or pulses, of neutrons in a "dual burst" pattern: short burst followed by a long burst. As the neutrons interact with various elements in the formation, gamma rays are generated that are measured by the tool. These gamma rays are recorded and analysed to interpret fluid saturation. The short burst is used to infer properties of the near well environment, and the long burst is used for the interpretation far into the formation (Albertin et al., 1996). The tool's depth of investigation is approximately 0.25 m and it gives a detailed fluid saturation profile along the borehole, with about 0.15 m vertical resolution i.e., measurements are taken at 15 cm depth intervals (Adolph et al., 1994).

The pulsed-neutron tool used during the Otway experiment was run in "sigma mode" thus outputting formation neutron capture cross section (Σ) and thermal decay porosity (ϕ_T). Σ is heavily influenced by chlorine and hydrogen; hence the response is largely determined by salinity and molecules like methane and water that contain hydrogen. ϕ_T is a measure of the hydrogen index obtained from the ratio of the "near to far" detector capture count rates. Measurements were recorded through the tubing (tool diameter: 43 mm) in the interval 1152 to 1407 mSS. Processing of each of the logging outputs followed the same approach that is described in Al-Arayni et al. (2013). Particular attention was paid to correcting for CO_2 that was still present in the borehole. This is an important consideration that needs to be made at storage sites using this technology to monitor saturation in CO_2 injection wells. The same complication will not apply when logging in dedicated monitoring bores that are not used for injection. The input logs are shown in Fig. 6 and the workflow used for processing each of the outputs follows.

3.1. Processing of ϕ_T logs

For accurate comparison between the various logging runs it is important to match the depth of measurements for each pass. A depth match is performed using total porosity (ϕ_{tot}). First total porosity is calculated from the open-hole logs using

$$\phi_{tot} = \frac{\rho_{ma} - \rho_B}{\rho_{ma} - \rho_f} \tag{3}$$

where ρ_{ma} is the sandstone density, average from core analysis is 2.65 g/cm^3, and ρ_f is the formation water density, assumed to be 0.98 g/cm^3 for the salinity and temperature at the Otway site; ρ_B is from the "RHOZ" density log in Fig. 6. The cable stretch can vary between open-hole and cased-hole logs (see for example Spalburg (1989)), and even between successive logs in the same hole, so some manual adjustment was used to get the logs to align. To do this the outputs from the various passes of ϕ_T were depth matched to the total porosity over intervals where no change of formation fluids is expected. For this purpose the cemented sandstones above and below the perforations served as very useful lithological calibration markers. As ϕ_T is not a calibrated porosity, these intervals were also used to calculate a bulk shift of the post-water injection logs by 0.035 p.u. to match the pre-injection logs.

The next step was to account for the effects of changing borehole conditions during each pass. The response of the pulsed-neutron logs is not calibrated in the case where the tool is surrounded by CO_2 in the borehole. Computation of ϕ_T for saturation is well defined for conditions when fluid in the wellbore has a hydrogen index (HI) of $\approx$1, i.e., when surrounded by water, but is not well defined for conditions when the fluid does not have a HI of one. The post-CO_2 injection log was completed with CO_2 in the wellbore, which has a HI $\approx$ 0. Thus a correction was applied to the ϕ_T log over the intervals with CO_2 in the borehole to account for the changed response in the near-tool region. Following a similar approach that was applied at the Frio site by Müller et al. (2007), pressure information was used to identify the various well bore fluid interfaces. The well bore pressure logs, labelled "WPRE" in Fig. 6 were used for this purpose. Difference of WPRE with depth provided the borehole fluid density "MWFD". In the interval between 1389.4 and 1394.5 m CO_2 with a density $\approx$ 0.55 g/cm^3 was present in the casing and between the tubing and casing. So a shift was applied to account for the changed response in the near-tool region. The shift was applied

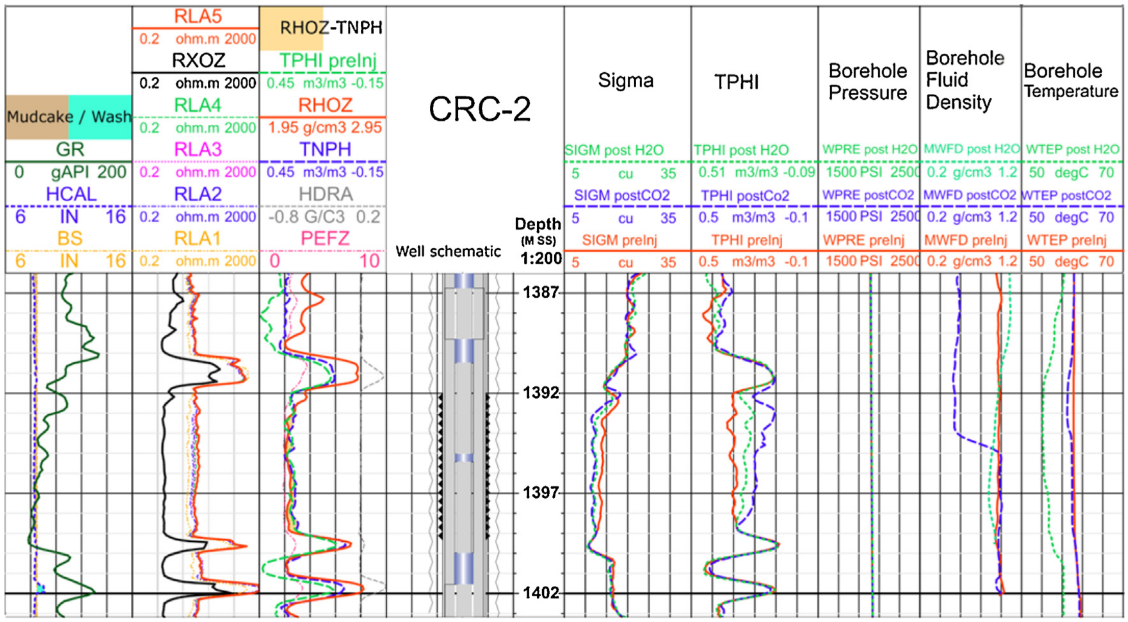


Fig. 6. The input logs used to interpret saturation post-CO_2 injection and post-water injection. In the tracks from left to right are: 1) gamma ray (GR), calliper (HCAL), bit size (BS); 2) resistivity logs; 3) pre-injection thermal decay porosity (TPHIpreInj), standard resolution formation density (RHOZ), post-CO_2 injection thermal neutron porosity (TNPH), bulk density correction (HDRA), standard resolution formation photoelectric factor (PEFZ); 4) well-bore perforations; and tracks 5-9) monitoring log outputs from baseline (red), post-CO_2 injection (blue), and post-water injection (green).

to the post-CO_2 injection near/far capture ratio output (TRAT) so that it matches the pre-injection TRAT in the cemented interval between 1390 and 1391.5 m This is a high density, very low porosity, tight interval and no CO_2 invasion was expected to take place and thus no change in pre-injection to post-CO_2 injection TRAT was expected. Once the shift was performed to the post-injection TRAT then saturation from $_T$ was re-computed with the previously mentioned porosity normalisation applied. Alternatively it is possible to use the inelastic capture count rates (IRAT), or early burst ratio, which is sensitive to changes in the completion, to correct the near/far capture ratio for different fluids in the bore-hole. This method is used in the studies by Quinlan et al. (2012) and Al Arayni et al. (2013). However, specific details are not documented.

In the interval between 1352.1 and 1394.5 m, CO_2 was present in the tubing and water was present between the tubing and casing. The tubing has an internal diameter of 5.07 cm and the logging tool has a diameter of 4.29 cm. When the tool was inside the tubing, most of the CO_2 in the tubing was excluded by the presence of the tool. Thus the near-tool response of the pulsed-neutron logging tool was dominated by water present between the tubing and casing. This is similar case to pre-injection and thus no shift to TRAT or re-computation of $_T$ was required over this interval.

3.2. Processing of logs

The depth match process was also performed on the Sigma logs against the total porosity log. In order to account for well bore fluids, in the Sigma output processing thermal decay time-like processing (SIGM-TDTL) was used for evaluation as its computation is less affected by CO_2 in the well bore than the standard processing for Sigma (Al Arayni et al., 2013). This method estimates using algorithms developed for the earlier generation thermal-decay time-tool (Morris et al., 2005) and is most representative of true when CO_2 is present in the borehole.

3.3. Saturation computation from pulsed-neutron data

Sigma and $_T$ from the pulsed-neutron logging data were both independently assessed to estimate the sensitivity margin of each method when inverting for CO_2 saturation. The predicted change in both Sigma and $_T$ for the Paaratte reservoir conditions was computed using a commercial nuclear parameter code (McKeon and Scott, 1989). Fig. 7 shows the estimated change for both Sigma and $_T$ as CO_2 replaces water for a clastic sandstone with 30% porosity and formation water salinity around 5000 mg/L TDS, at pressure and temperature of 13.8 MPa and 60 C, respectively. The quoted accuracy for Sigma logs from the tool used is 1 capture units (1 c.u.) (Adolph et al., 1994; Morris et al., 2005). Since the salinity in the Paaratte Formation is low (800–2000 mg/L TDS), the change in Sigma when CO_2 (with Sigma of 0.03 c.u.) replaces formation water was expected to be marginal compared to the precision of the measurement. A study by Climent (2009) on the tool response for CO_2 in sandstone concluded that in lower salinity formations (<6000 mg/L), the contrast between Sigma in zones with and without CO_2 is not adequate to determine saturation. Instead the use of count rate ratios from the $_T$ provides the contrast necessary to detect CO_2. Although the $_T$ is not as affected by salinity, the corrections applied for CO_2 in the borehole bring an additional layer of uncertainty. However, by using the cemented reservoir sections as calibration markers to correct for the presence of gas in the well the $_T$ is considered more reliable for CO_2 saturation interpretation in the Paaratte Formation. The workflow for calculating the saturation from $_T$ follows.

Saturation from $_T$

Compute the change in $_T$ ($_T$) between the pre-injection baseline ($_{T\ pre}$) and the post-CO_2 injection ($_{T\ CO_2}$) and post-water injection ($_{T\ H_2O}$) cases using

$$_T = _{T\ pre} \quad _{T\ CO_2} \tag{4}$$

and this calculation is repeated for the post-water injection case.

From the nuclear parameter code of McKeon and Scott (1989) compute the effect of formation water being replaced by CO_2 ($_{T\ CO_2}$) on $_T$ for specific Paaratte Formation conditions:

$$_{T\ CO_2} = 1.0356(\ _T)^2 + 0.66702 \ _T + 0.0038282 \tag{5}$$

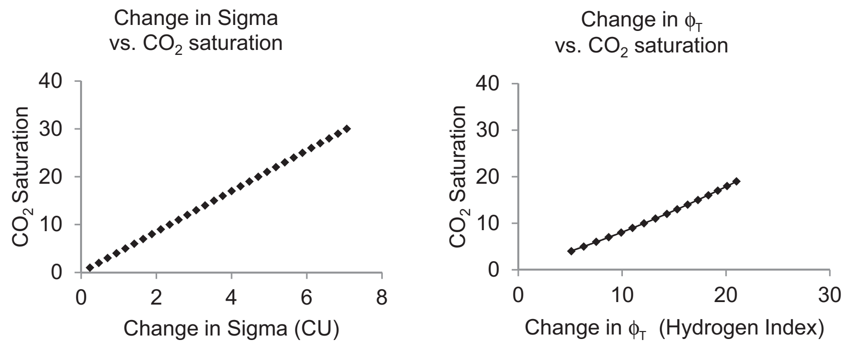


Fig. 7. The predicted change in Sigma (left) and $_T$ (right) when the CO_2 replaces formation water at the formation pressure and temperature, for sandstone with 30% porosity and formation water salinity around 5000 mg/L TDS. The $_T$ output is more sensitive to changes in saturation at such low salinity.

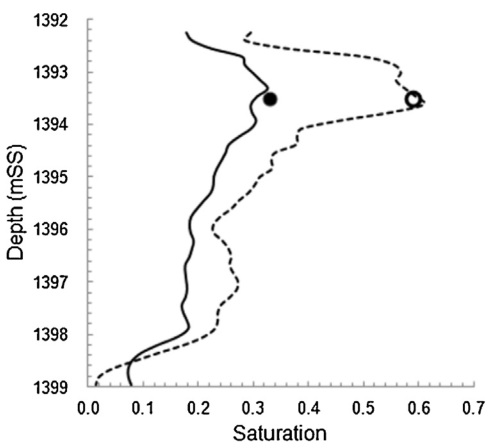


Fig. 8. Carbon dioxide saturation interpreted from the T outputs of the pulsed-neutron logs. The dashed curve is after initial CO_2 saturation and the solid curve is after residual saturation. There is good agreement with the core plug derived $S_{g;max} = 0.59$ (open circle) and $S_{gr;max} = 0.33$ (solid circle) at sample depth of 1393.5 mSS.

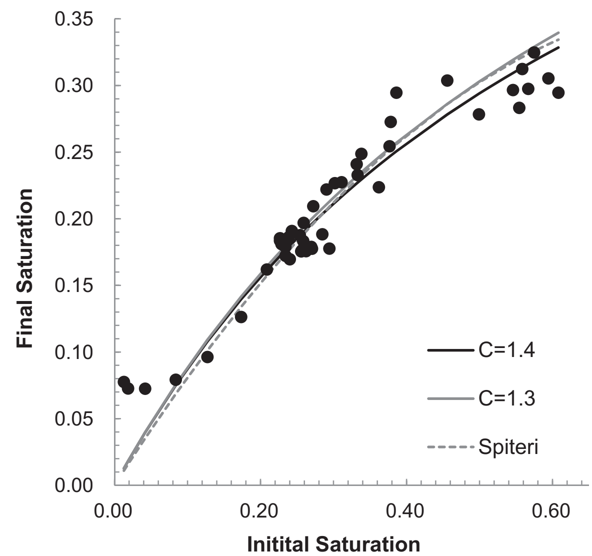


Fig. 9. Pulsed-neutron logging measurements (using the $_T$ outputs) of the final carbon dioxide saturation as a function of the maximum initial saturation reached. The black solid line shows the Land hysteresis model using Land coefficient of $C = 1.4$ from pulsed-neutron logging data. The grey line is the average Land coefficient $C = 1.3$ determined from laboratory core tests by Krevor et al. (2012), the dashed line is the Spiteri hysteresis model using $= 0.86$ and $= 0.53$, also from Krevor et al. (2012).

Compute CO_2 Saturation logs (S_{CO_2}) from total porosity logs ($_{tot}$) using

$$S_{CO_2} = {}_{TCO_2} / {}_{tot}. \tag{6}$$

This workflow is applied to derive saturation after the initial CO_2 injection and repeated for the post-water injection logs.

The results from the $_T$ logs are displayed in Fig. 8. Here the dashed curve is the initial CO_2 saturation after CO_2 injection (S_{gi}), and the solid curve is final saturation after water injection (S_{gr}). The interpretation is that the CO_2 has displaced formation water over the entire interval from 1392 to 1399 mSS following the initial injection. From the detailed $_T$ profile it is apparent that a higher saturation is achieved in the upper 2 m of the perforations. Values for S_{gi} range from 28% to 61% in the upper 2 m, and from <5% to 29% in the lower 5 m. Values for the final residual saturation (S_{gr}), following water injection range from a minimum of 4% to maximum of 32%. Similarly, to the initial saturation, higher values of S_{gr} are achieved in the upper region of the perforation interval and are around 20% and <18% in the lower half. The S_{gi} and S_{gr} results from the core flood are compared to the saturation interpretation from the pulsed-neutron logging results in Fig. 8. There appears to be good agreement at the plug location depth with the $_T$ saturation interpretation, near the top of the perforation interval where the maximum CO_2 saturation is believed to have been achieved.

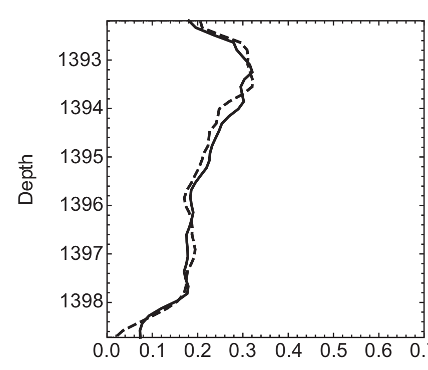


Fig. 10. Final saturation measurements (solid line) compared to predicted values from a Land model with $C = 1.4$:$S_{gr} - S_{gi}/(1 + C\ S_{gi})$ (dashed line). The Land model under-predicts by around 1–4 s.u. in the range 1394 to 1396.4 m, but over-predicts predicts by around 1–2 s.u. above and below that interval, except below 1398.5 m it under-predicts by up to 6 s.u.

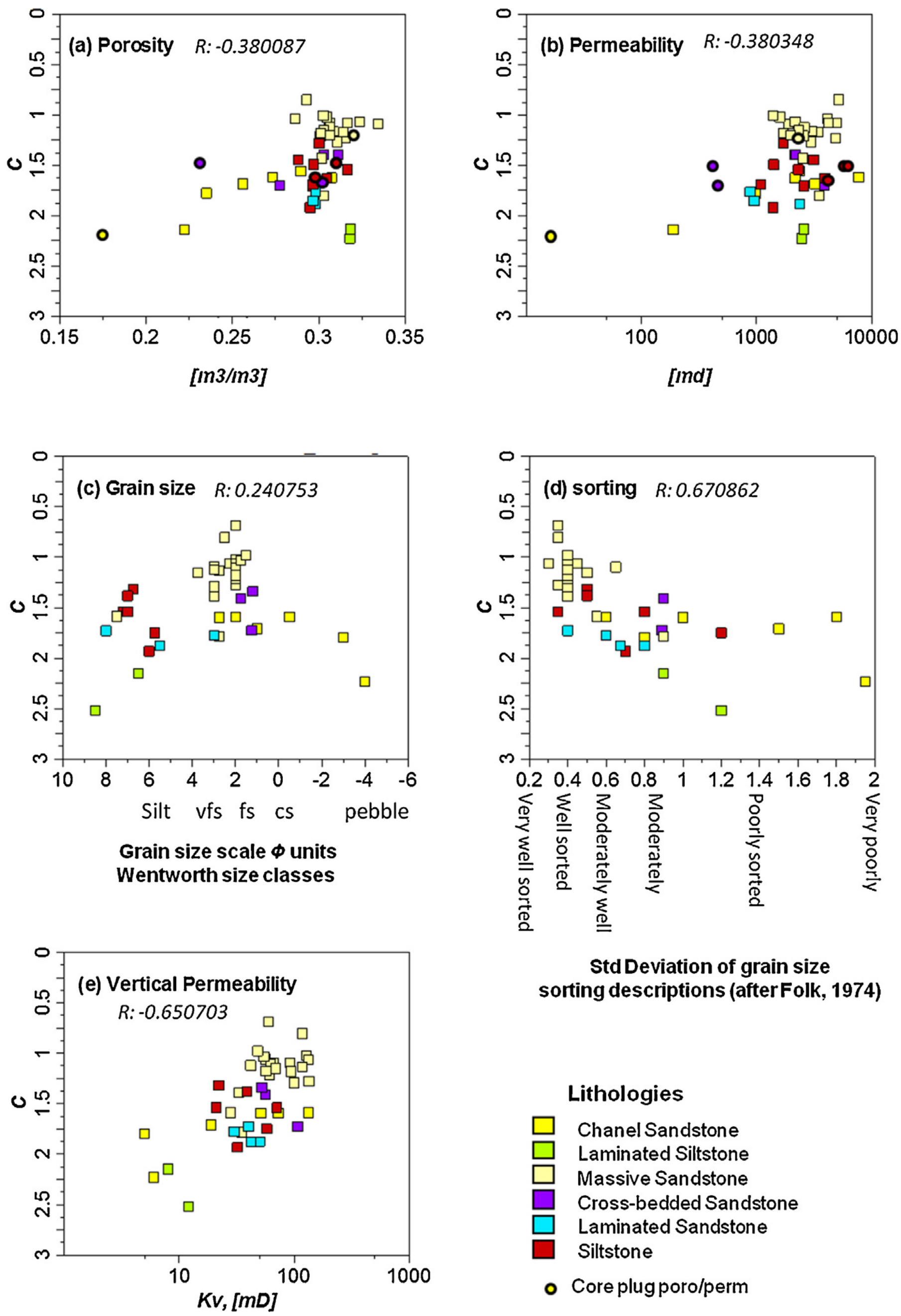


Fig. 11. The Land trapping coefficient (C) as a function of the geological properties of the reservoir rock coloured by the different reservoir facies (Fig. 1); (a) porosity from the NMR logs and conventional core plug analysis (circles), (b) permeability from the NMR logs and conventional core plug analysis (circles), (c) mean grain size observed in the core hand specimens expressed as phi (Φ) units and descriptive Wentworth size classes, and (d) sorting observed in core as a measure of the grain size standard deviation and verbal terms after Folk (1974), (e) the vertical permeability interpreted from the logs. The correlation coefficient (R) is displayed for each geological property. Sorting and vertical permeability show evidence of a very weak correlation with C, the other properties show no correlation. Overall the laminated siltstone with low vertical permeability, fine grainsize, and poor sorting exhibits the highest values for C (i.e., trapping is low), and the massive sandstone, with few bedding features, high permeability, and best sorting, has the lowest values for C (i.e., trapping is high).

3.4. Interpretation of Land trapping coefficient

Plotting of the final saturation, S_{gr}, as a function of the initial saturation, S_{gi}, (both derived from the $_{T}$ logs) shows a consistent correlation, i.e. the higher the initial CO_2 saturation, the higher the final residual saturation (Fig. 9). The correlation can be fitted using the Land hysteresis model (Land, 1968). Curves with Land coefficients C=1.4 and C=1.3 are shown in Fig. 9 for comparison, C=1.4 is given by a least-squares best fit to the full set of field data. Using measurements from a laboratory core test from this interval, Krevor et al. (2012) fitted a Land coefficient of 1.3 to their data. They also fitted the Spiteri hysteresis model (Spiteri et al., 2008) using =0.86 and =0.53 to their data (Krevor et al., 2012), the curve to this fit is also shown in Fig. 9. The similar correlation between the core and well-log results in the Paaratte Formation is significant. For tests on cores from other locations Krevor et al. (2012) obtain C values of 1, 2.1, and 1.7. At least at the Otway site this provides evidence that the Land coefficient determined from core measurements is consistent with the field scale.

The vertical saturation profile shows that the CO_2 was not evenly distributed across the interval. The higher initial saturation towards the upper part of the reservoir is largely driven by buoyancy within the well in the perforation interval during injection and by variations in injectivity. Buoyancy has a strong effect on the initial saturation in the way the well fills with CO_2. As CO_2 has to displace the water downward out of the perforations, CO_2 starts entering the top of the interval while water is still being pushed into the bottom of the interval, thus more CO_2 ends up entering at the top. To understand if there is any geological dependence of S_{gr}, beyond the Land model a comparison of measured S_{gr} and predictions from a Land model using the initial S_{gi} are shown in Fig. 10. This analysis shows differences in S_{gr} that may be attributed to the more subtle lithological factors. The Land model under-predicts by around 1–4 s.u. in the range 1394–1396.4 m, but over-predicts by around1–2 s.u. above and below that interval, except below 1398.5 m it under-predicts by up to 6 s.u.

3.5. Effect of geological heterogeneity

To further investigate any lithological controls on the trapping coefficient, an examination of the sedimentological descriptive data and core analysis was undertaken (Fig. 11). The comparison was obtained by calculating a value of C for each data point from the pulsed-neutron logs and plotting against petrophysical data from logs and core analysis obtained at the same depth. The advantage of deriving C from the logging data is that the scale of the vertical log profile is comparable with the scale of the bedding features described in the reservoir (10 cm–1 m scale). In Fig. 11a the trapping coefficient, C, is compared with the effective porosity interpreted from nuclear magnetic resonance logs (NMR) and effective porosity measured on core plugs (circles). Fig. 11b compares C with the interpreted permeability from NMR logs and horizontal permeability as measured on core plug samples. The grain size and sorting in Figs. 11c and 11d are from detailed core descriptions. The vertical permeability is interpreted using a log of the ratio of vertical to horizontal permeability (K_v/K_h) that was generated using V_m (bulk volume of mud) and a model for analogous deltaic sediments developed by Ringrose et al. (2005). In essence this model assumes that heterolithic interbedded deltaic reservoir units (i.e., those with higher V clay) show a significantly smaller vertical-to-horizontal permeability ratio than more homogeneous reservoir. The lithofacies classifications are shown by colored symbols in each plot. A correlation coefficient (R) was generated for each plot using linear regression, least squares method, with $R = 1$ being the highest correlation and $R = 0$ being no correlation at all. There does not appear to be a direct correlation of C with porosity, permeability, or grainsize. The lack of a relationship between C and porosity is similarly observed in the Paaratte SCAL data of Krevor et al. (2012) (Fig. 3). In Fig. 11d there does, however, appear to be a weak relationship with sorting where $R =$ 0.67. The trapping coefficient C appears to generally decrease with poorer sorting. However, in some of the very poor, to extremely poorly sorted sandstones and conglomerates, C is high. This is similarly observed in Krevor et al. (2012), where the poorly sorted sample has the highest value for C. In Fig. 11e, C appears to be weakly related to vertical permeability, where $R =$ 0.65. The correlation with vertical permeability is supported in the study by Krevor et al. (2012) where an observation is made that the Land coefficient increases with high- to low-permeability samples. The permeability in that study is measured in the vertical direction (on vertical plugs taken perpendicular to bedding).

Beyond the analysis of the correlation between C and the individual properties, there are some observations that may be made about the different groups of lithofacies. Overall the laminated siltstone and channel sandstone with low vertical permeability, and poor sorting exhibits the highest values for C (i.e., trapping is low); and the massive sandstone, with few bedding features, high permeability, and best sorting, has the lowest values for C (i.e., trapping is high). The complex interrelationship of sorting and grainsize with

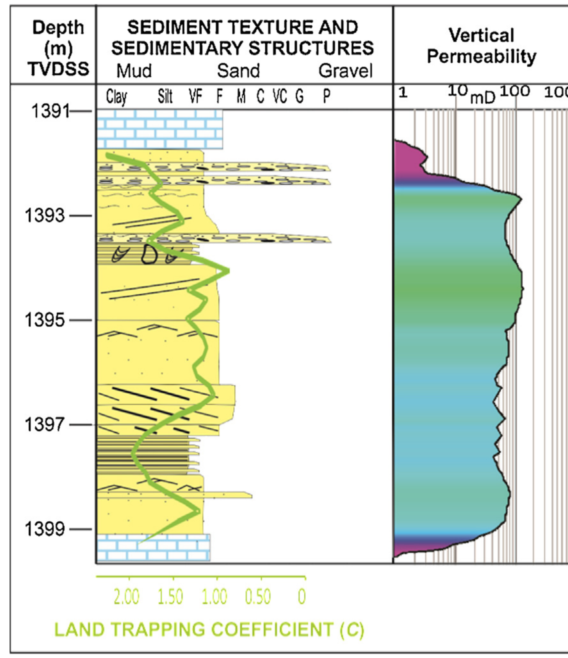


Fig. 12. Comparison of the lithological description from core and vertical permeability with the Land trapping curve from the pulsed-neutron logging data (Fig. 1 for sedimentology legend).

pore and pore-throat geometry, and subsequently the resulting porosity and permeability with saturation has been recognised for some time (Jerauld, 1997). To confirm with better certainty how the geology impacts microscopic controls on the trapped CO_2 in the Paaratte Formation, microtomographic investigation of the core samples from each of the facies would be necessary.

3.6. Anisotropy

When interpreting these results we must also consider the orientation of bedding features within these lithologies in relation to the dominant flow direction of the fluids during the different stages of the test. The lithological description from core, vertical permeability and the Land trapping curve from the pulsed-neutron logging measurements are compared in Fig. 12. During CO_2 injection, the flow path of the invading phase is initially horizontal, outward from the perforations under the pressure of injection. After injection ceases, the plume is then predominantly influenced by buoyancy and capillary forces. Upward movement perpendicular to the bedding and capillary spreading can occur at this time. During the water injection, the dominant water flow direction is horizontal, or parallel to bedding. The differences between residual saturation resulting from flow parallel and flow perpendicular to the bedding was the subject of a modelling study by Paterson et al. (1998). In this study it was found that both residual saturation and relative permeability are sensitive to the degree of correlated heterogeneity and anisotropy of the porous media. Correlated heterogeneity is described in terms of connectivity of porous medium that has flow properties parallel to the dominant stratified fabric. Sedimentary bedding features in the reservoir correspond to such anisotropic correlations. For flow perpendicular to bedding, the residual saturation is substantially greater than for flow parallel to the bedding. The directional difference in residual saturation increases with the degree of anisotropy. The results in Fig. 12 support this theoretical work and show there is a higher retention of CO_2 in the sandstones where flow is dominated by buoyancy due to high vertical permeability. For example, the Land trapping coefficient curve reaches lower values at approximately 1393.4–1396.5 m, a bed-form that corresponds to well-sorted sandstone. *C* appears to be increased (trapping is lower), however, in the region of a 1 m thick laminated siltstone at approximately 1397.5 mSS, evidenced by a large deviation in the Land trapping coefficient curve. At this depth there is greater anisotropy in the permeability (vertical versus horizontal) and consequently lower trapping.

These barriers, however, do encourage increased initial CO_2 saturation, S_{gi}, and subsequently, increased residual saturation, S_{gr}, in the sandstones adjacent. This can be seen at the scale of the well test whereby the highest saturations are obtained at the top of the interval beneath a low porosity, low permeability cemented sandstone barrier (Fig. 8). Moreover, similar trends can be seen in the core flood data albeit at a smaller scale. In the CT scanned image of the core plug after the CO_2 flood (Fig. 4), there is lower CO_2 retention in the zones of the plug that contain clay-rich lamina orientated perpendicular to the flow direction of fluids, but they encourage saturation to build-up in the pore space adjacent. This again suggests that the core flood results have applicability to the reservoir scale provided the sample captures relevant heterogeneity. Ideally non-biased sampling of core plugs at frequent intervals (>0.5 m) down the well would potentially capture all the various geological facies. In practice, however, core analysis is expensive and time consuming and often only a few samples can be tested. In this case it would be necessary to perform biased sampling, with careful consideration of extrapolating the results to similar rock types within the reservoir.

4. Conclusions

During the CO2CRC Otway project well test, pulsed-neutron logging was used to measure CO_2 saturation following CO_2 injection and a following subsequent water injection. This enabled vertical saturation profiles to be determined and compared before and after the water injection. From this a Land coefficient could be fitted to the data. The average residual saturation over the entire interval was around 0.20, with higher values in the upper part of the interval and lower values towards the bottom. A Land coefficient approximately of 1.4 was fitted to the field data. This is important because a similar Land coefficient of 1.3 was fitted to data from a laboratory core test on a sample from the same interval (Krevor et al., 2012). This is noteworthy because the scales of the two sets of measurements vary significantly, with centimetres for the core and several metres for the logs. If this observed behaviour holds more widely, it supports the use of parameters from representative core tests in field-scale simulations.

Using the thermal decay porosity ($_T$) output from the pulsed-neutron logging tool provided the preferred measurement for calculating saturation due to the low salinity of the formation water (approximately 800–2000 mg/L). This may be useful at other sites using logging for integrity monitoring of freshwater aquifers above an injection zone.

To back up laboratory studies, this study provides field evidence that the proportion of the initial saturation that gets trapped is mostly a function of the initial maximum saturation that is achieved. However, geological reservoir anisotropy in relation to the dominant flow direction of the CO_2 can also impact trapping. Low permeability barriers can increase the residual trapping of CO_2 in the regions immediately adjacent as they encourage local areas of CO_2 build up as the plume flows through the formation. From this it can be seen that the residual saturation at a given site can be engineered through the injection location and scheme in order to take advantage of reservoir anisotropy and optimize capacity.

Acknowledgements

The authors thank Ashish Datey of Schlumberger for processing the raw pulsed-neutron data and providing technical advice, and Sam Krevor for collaboration and provision of core analysis data. The authors also thank Karsten Michael of CSIRO and two anonymous expert reviewers for suggestions that have improved the paper. The authors acknowledge funding provided by the Australian government through its CRC programme to support the CO2CRC Otway research project. Financial assistance was also provided through Australian National Low Emissions Coal Research and Development (ANLEC R&D). ANLEC R&D is supported by Australian Coal Association Low Emissions Technology Limited.

References

Adolph, B., Brady, J., Flaum, C., Melcher, C., Vittachi, A., 1994. Saturation monitoring with the RST reservoir saturation tool. Oilfield Rev. 6 (1), 29–39.
Al Arayni, F., Obeidi, A., Brahmakulam, J., Ramamoorthy, R., 2013. Pulsed-neutron monitoring of the first CO_2 enhanced-oil-recovery pilot in the middle east. Spe. Reserv. Eval. Eng. 16 (1), 72–84.
Al Mansoori, S.K., Itsekiri, E., Iglauer, S., Pentland, C.H., Bijeljic, B., Blunt, M.J., 2010. Measurements of non-wetting phase trapping applied to carbon dioxide storage. Int. J. Greenh. Gas. Con. 4 (2), 283–288.
Albertin, I., Darling, H., Mahdavi, M., Plasek, R., Cedeno, I., Hemingway, J., Richter, P., Markley, M., Olesen, J.R., Roscoe, B., Zeng, W., 1996. Many facets of pulsed neutron cased-hole logging. Oilfield Rev. 8 (2), 28–41.
Andrew, M., Bijeljic, B., Blunt, M.J., 2014. Pore-scale imaging of trapped supercritical carbon dioxide in sandstones and carbonates. Int. J. Greenh. Gas. Con. 22, 1–14, http://dx.doi.org/10.1016/j.ijggc.2013.12.018.
Baumann, G., Henninges, J., De Lucia, M., 2014. Monitoring of saturation changes and salt precipitation during CO_2 injection using pulsed neutron-gamma logging at the Ketzin pilot site. Int. J. Greenh. Gas. Con. 28, 134–146.
Blunt, M.J., Bijeljic, B., Dong, H., Gharbi, O., Iglauer, S., Mostaghimi, P., Paluszny, A., Pentland, C., 2013. Pore-scale imaging and modelling. Adv. Water Resour. 51, 197–216.
Bunch, M., Daniel, R., Lawrence, M., Browne, G., Menacherry, S., Dance, T., Arnot, M., 2012. Multi-scale characterisation of the Paaratte Formation, Otway Basin, for CO_2 injection and storage. In: APPEA 2012 Conference, Adelaide, South Australia, APPEA, Canberra, Australia, Published as part of the APPEA volume distributed to attendees on DVD, pp. 13–16.
Burnside, N.M., Naylor, M., 2014. Review and implications of relative permeability of CO_2/brine systems and residual trapping of CO_2. Int. J. Greenh. Gas. Con. 23, 1–11.
Busch, A., Müller, N., 2011. Determining CO_2/brine relative permeability and capillary threshold pressures for reservoir rocks and caprocks: Recommendations for development of standard laboratory protocols. Energy Procedia. 4, 6053–6060.
Chatzis, I., Morrow, N.R., Lim, H.T., 1983. Magnitude and detailed structure of residual oil saturation. SPE Journal 23 (2), 311–326.
Climent, H., 2009. CO_2 detection - response testing of RST in sandstone formation tank containing CO_2 and water-based fluid. In: Eide, L.I. (Ed.), Carbon Dioxide Capture for Storage in Deep Geologic Formations - Results from the CO_2Capture Project. Volume 3: Advances in CO_2 capture and storage technology results (2004-2009). CPL Press, p. 3.
Daniel, R., Bunch, M., Golab, A., Lawrence, M., 2012. Using palaeoenvironmental evidence from petrography and diagenesis modelling to characterise CO_2 storage reservoir architecture. In: Oral presentation given at the AAPG 2012 International Conference and Exhibition, September, Singapore.
Doughty, C., Benson, S.M., Pruess, K., 2003. Capacity investigation of brine-bearing sands for geologic sequestration of CO_2. In: Gale, J., Kaya, Y. (Eds.), Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, October 1-4, Kyoto, Japan. Elsevier Science Ltd., pp. 1645–1648.
Folk, R.L., 1974. Petrology of Sedimentary Rocks. Hemphill Pub. Co, Austin, Texas.
Freifeld, B.M., Dayley, T., Hovorka, S.D., Henninges, J., Undershultz, J., Sharma, S., 2009. Recent advances in well-based monitoring of CO_2 sequestration. Energy Procedia. 1, 2277–2284.
Gallagher, S.J., Taylor, D., Apthorpe, M., Stilwell, J.D., Boreham, C.J., Holdgate, G.R., Wallace, M.W., Quilty, P.G., 2005. Late Cretaceous dysoxia in a southern high latitude siliclastic succession, the Otway Basin, southeastern Australia. Palaeogeogr. Palaeocl. 223, 317–348.
Geary, G.C., Reid, I.S.A., 1998. Geology and prospectivity of the offshore eastern Otway Basin, Victoria - for the 1998 Acreage Release. Victorian initiative for minerals and petroleum report 55. Department of Natural Resources and Environment.
Geary, G.C., Constantine, A.E., Reid, I.S.A., 2001. New perspectives on structural style and petroleum prospectivity, offshore Eastern Otway Basin. In: Hill, K.C., Bernecker, T. (Eds.), Eastern Australian Basins Symposium, a Refocussed Energy Perspective for the Future, Petroleum Exploration Society of Australia, Special Publication. , pp. 507–517.

Haese, R.R., LaForce, T., Boreham, C., Ennis-King, J., Freifeld, B.M., Paterson, L., Schacht, U., 2013. Determining residual CO_2 saturation through a dissolution test - results from the CO2CRC Otway Project. Energy Procedia. 37, 5379–5386.

Herring, A.L., Harper, E.J., Andersson, L., Sheppard, A., Bay, B.K., Wildenschild, D., 2013. Effect of fluid topology on residual nonwetting phase trapping: implications for geologic CO_2 sequestration. Adv. Water Resour. 62 (Part A), 47–58, ISSN 0309-1708, doi.org/10.1016/j.advwatres.2013.09.015.

Iglauer, S., Paluszny, A., Pentland, C.H., Blunt, M.J., 2011. Residual CO_2 imaged with X-ray micro-tomography. Geophys. Res. Lett. 38, L21403, http://dx.doi.org/10.1029/2011GL049680.

Jerauld, G.R., 1997. Prudhoe Bay gas/oil relative permeability. SPE Reservoir Eng. 12 (1), 66–73.

Juanes, R., Spiteri, E.J., Orr Jr., F.M., Blunt, M.J., 2006. Impact of relative permeability hysteresis on geological CO_2 storage. Water Resour. Res. 42, 1–13, W12418.

Knackstedt, M.A., Dance, T., Kumar, M., Averdunk, H., Paterson, L., 2010. Enumerating permeability, surface areas, and residual capillary trapping of CO_2 in 3D: digital analysis of CO2CRC Otway project core. In: SPE 134625, presented at the SPE Annual Technical Conference and Exhibition, Florence, 19-22 September.

Krevor, S.C.M., Pini, R., Zuo, L., Benson, S.M., 2012. Relative permeability and trapping of CO_2 and water in sandstone rocks at reservoir conditions. Water Resour. Res. 48, W02532, http://dx.doi.org/10.1029/2011WR010859.

Krevor, S.C.M., Pini, R., Li, B.X., Benson, S.M., 2011. Capillary heterogeneity trapping of CO_2 in a sandstone rock at reservoir conditions. Geophys. Res. Lett. 38, L15401, http://dx.doi.org/10.1029/2011GL048239.

Kumar, A., Noh, M.H., Pope, G.A., Sepehrnoori, K., Bryant, S.L., Lake, L.W., 2005. Simulating CO_2 storage in deep saline aquifers. In: Thomas, D., Benson, S.M. (Eds.), Carbon Dioxide Capture for Storage in Deep Geologic Formations - Results from the CO_2 Capture Project, vol. 2. Elsevier, pp. 877–896.

LaForce, T., Freifeld, B., Ennis-King, J., Boreham, C., Paterson, L., 2014. Residual CO_2 saturation estimate using noble gas tracers in a single-well field test: The CO2CRC Otway project. Int. J. Greenh. Gas. Con. 26, 9–21.

Land, C.S., 1968. Calculation of imbibition relative permeability for two- and three-phase flow from rock properties. SPE Journal 8 (2), 149–156.

McKeon, D.C., Scott, H.D., 1989. SNUPAR-a nuclear parameter code for nuclear geophysics applications. Nuclear Science, IEEE Transactions on 36 (1), 1215–1219.

Morris, C.W., Morris, F., Quinlan, T.M., Aswad, T.A., 2005. Reservoir monitoring with pulsed neutron capture logs. In: In SPE 94199-MS, presented at the SPE Western Regional Meeting held in Irvine, CA, USA, 30 March - 1 April.

Müller, N., Ramakrishnan, T.S., Boyd, A., Sakruai, S., 2007. Time-lapse carbon dioxide monitoring with pulsed-neutron logging. Int. J. Greenh. Gas. Con. 1 (4), 456–472.

Myers, M., Stalker, L., La Force, T., Pejcic, B., Dyt, C., Ho, K.-B., Ennis-King, J., 2014. Field measurement of residual carbon dioxide saturation using reactive ester tracers. Chem. Geol. 399, 20–29.

Myers, M., Stalker, L., Ross, A., Dyt, C., Ho, K.B., 2012. Method for the determination of residual carbon dioxide saturation using reactive ester tracers. Appl. Geochem. 27 (10), 2148–2156.

Paterson, L., Boreham, C., Bunch, M., Dance, T., Ennis-King, J., Freifeld, B., Haese, R., Jenkins, C., Raab, M., Singh, R., Stalker, L., 2014. CO2CRC Otway Stage 2B residual saturation and dissolution test. In: Cook, P.J. (Ed.), In Geologically Storing Carbon: Learning from the Otway Project Experience. CSIRO Publishing, Melbourne, pp. 343–380, chap. 17.

Paterson, L., Boreham, C., Bunch, M., Dance, T., Ennis-King, J., Freifeld, B., Haese, R., Jenkins, C., LaForce, T., Raab, M., Singh, R., Stalker, L., Zhang, Y., 2013. Overview of the CO2CRC Otway residual saturation and dissolution test. Energy Procedia. 37, 6140–6148.

Paterson, L., Painter, S., Zhang, X., Pinczewski, W.V., 1998. Simulating residual saturation and relative permeability in heterogeneous formations. SPE Journal 3 (3), 211–218.

Pentland, C.H., El-Maghraby, R., Iglauer, S., Blunt, M.J., 2011. Measurements of the capillary trapping of super-critical carbon dioxide in Berea sandstone. Geophys. Res. Lett. 38, L06401, http://dx.doi.org/10.1029/2011GL046683.

Perrin, J.C., Benson, S., 2010. An experimental study on the influence of sub-core scale heterogeneities on CO_2 distribution in reservoir rocks. Transport Porous. Med. 82 (1), 93–109.

Pini, R., Krevor, S.C.M., Benson, S.M., 2012. Capillary pressure and heterogeneity for the CO_2/water system in sandstone rocks at reservoir conditions. Adv. Water Resour. 38, 48–59.

Quinlan, T.M., Sibbit, A.M., Rose, D.A., Brahmakulam, J.V., Zhou, T., Fitzgerald, J.B., Kimminau, S.J., 2012. Evaluation of the carbon dioxide response on pulsed-neutron logs. In: SPE 159448, presented at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, USA, 8-10 October.

Ringrose, P., Nordahl, K., Wen, R., 2005. Vertical permeability estimation in heterolithic tidal deltaic sandstones. Petrol Geosci. 11, 29–36.

Saeedi, A., Rezaee, R., Evans, B., Clennell, B., 2011. Multiphase flow behaviour during CO_2 geo-sequestration: Emphasis on the effect of cyclic CO_2-brine flooding. J. Petrol Sci. Eng. 79 (3–4), 65–85.

Saito, H., Nobuoka, d., Azuma, H., Xue, Z., Tanase, D., 2006. Time-lapse crosswell seismic tomography for monitoring injected CO_2 in an onshore aquifer, Nagaoka. Japan. Exploration Geophysics 37, 30–36.

Sakurai, S., Ramakrishnan, T.S., Boyd, A., Mueller, N., Hovorka, S., 2006. Monitoring saturation changes for CO_2 sequestration: petrophysical support of the Frio Brine pilot experiment. Petrophysics 47 (6), 483–496.

Spalburg, M.R., 1989. An algorithm for simultaneous deconvolution, squaring and depth-matching of logging data. In: SPWLA 30th Annual Logging Symposium. Denver, Colorado, Society of Petrophysicists and Well-Log Analysts, 11–14 June, SPWLA-1989-P.

Spiteri, E.J., Juanes, R., Blunt, M.J., Orr, F.M., 2008. A new model of trapping and relative permeability hysteresis for all wettability characteristics. SPE Journal 13 (3), 277–288, http://dx.doi.org/10.2118/96448-PA.

Xue, Z., Tanase, D., Watanabe, J., 2006. Estimation of CO_2 saturation from time-lapse CO_2 well logging in an onshore aquifer, Nagaoka. Japan. Exploration Geophysics 37 (1), 19–29.

Zhang, Y., Freifeld, B., Finsterle, S., Leahy, M., Ennis-King, J., Paterson, L., Dance, T., 2011. Single-well experimental design for studying residual trapping of supercritical carbon dioxide. Int. J. Greenh. Gas. Con. 5 (1), 88–98.

4.4 Publication 4: Illuminating the geology: Post-injection reservoir characterisation of the CO2CRC Otway site

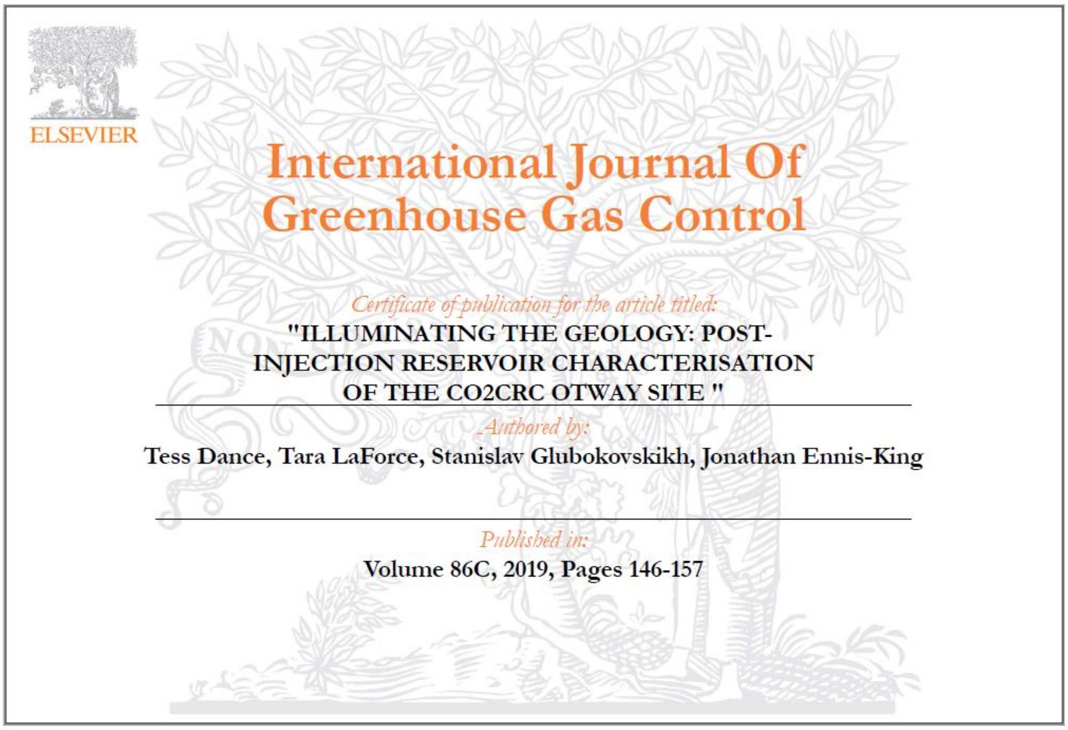
Published in the special issue of the Int. Journal of Greenhouse Gas Control (2019).

Authors: Tess Dance[1,2], Tara LaForce[1,2], Stanislav Glubokovskikh[1,3], Jonathan Ennis-King[1,2], Roman Pevzner[1,3]

[1]CO2CRC Ltd

[2]CSIRO

[3]Curtin University



ELSEVIER

International Journal Of Greenhouse Gas Control

Certificate of publication for the article titled:

"ILLUMINATING THE GEOLOGY: POST-INJECTION RESERVOIR CHARACTERISATION OF THE CO2CRC OTWAY SITE "

Authored by:

Tess Dance, Tara LaForce, Stanislav Glubokovskikh, Jonathan Ennis-King

Published in:

Volume 86C, 2019, Pages 146-157

Statement of Authorship

Title of Paper	Illuminating The Geology: Post-Injection Reservoir Characterisation of the CO2CRC Otway Site
Publication Status	☑ Published ☐ Accepted for Publication ☑ Submitted for Publication ☐ Unpublished and Unsubmitted work written in manuscript style
Publication Details	Invited for publication in a special issue of the International Journal of Greenhouse Gas Control, Submitted November 2018. Under review.

Principal Author

Name of Principal Author (Candidate)	Tess Dance		
Contribution to the Paper	Prepared the manuscript, provided geological context, geological interpretation of the monitoring results, evaluated the Pulsed Neutron logs, corresponding author, wrote the majority of the text, prepared all but 1 of the figures, managed submission, revision, and corrections.		
Overall percentage (%)	60%		
Certification:	This paper reports on original research I conducted during the period of my Higher Degree by Research candidature and is not subject to any obligations or contractual agreements with a third party that would constrain its inclusion in this thesis. I am the primary author of this paper.		
Signature		Date	20/11/18

Co-Author Contributions

By signing the Statement of Authorship, each author certifies that:

i. the candidate's stated contribution to the publication is accurate (as detailed above);

ii. permission is granted for the candidate in include the publication in the thesis; and

iii. the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

Name of Co-Author	Tara La Force		
Contribution to the Paper	10% Interpretation of pressure data, history matching of dynamic simulations and production of pressure results figures, as well as provided expert dynamic reservoir engineering advice.		
Signature		Date	Nov 28, 2018

Name of Co-Author	Stanislav Glubokovskikh		
Contribution to the Paper	10% Performed the inversion on the seismic monitoring data to produce the time-lapse plume thickness attributes; expert geophysical interpretation of the time-lapse seismic data; and provided text for the seismic data section of manuscript as well as overall revision to improve the manuscript.		
Signature		Date	27/11/2018

Name of Co-Author	Jonathan Ennis-King		
Contribution to the Paper	10% Interpretation of pressure data and write-up of section on pressure results, as well as provided expert dynamic reservoir engineering advice, and overall revision of the manuscript.		
Signature		Date	22/11/2018

Name of Co-Author	Roman Pevzner		
Contribution to the Paper	10% Conceived the seismic monitoring program; expert to lead on the acquisition, processing, and interpretation of the seismic data; and provided overall revision of the manuscript.		
Signature		Date	20/11/2018

International Journal of Greenhouse Gas Control 86 (2019) 146–157

Contents lists available at ScienceDirect

International Journal of Greenhouse Gas Control

journal homepage: www.elsevier.com/locate/ijggc

Illuminating the geology: Post-injection reservoir characterisation of the CO2CRC Otway site

Tess Dance[a,b,*], Tara LaForce[a,b,1], Stanislav Glubokovskikh[a,c], Jonathan Ennis-King[a,b], Roman Pevzner[a,c]

[a] CO2CRC Ltd, 11 – 15 Argyle Place South Carlton VIC, 3053, Australia
[b] CSIRO 26 Dick Perry Ave, Kensington, WA, 6151, Australia
[c] Curtin University Kent Street Bentley, WA, 6102, Australia

ARTICLE INFO

Keywords:
Storage performance
Static modelling
Monitoring
Dynamic simulation

ABSTRACT

Proper site characterisation is vital in the planning stages of a CO_2 storage project; but we can also learn a good deal about the reservoir once the injection is underway or has been completed. During CO2CRC Otway Project Stage 2C, sources of valuable information about storage performance have been generated as a consequence of the staged injection of 15,000 t of CO_2 rich gas, as well as observations from time-lapse seismic surveys and well monitoring data. Now that injection has ceased for Stage 2C, the geological model is compared against field observations for the period spanning injection and 23 months after injection ended. The post-injection reservoir characterisation has proven important to refine the static and dynamic models for future field development and added assurance about the long-term stabilisation of the CO_2 plume. The south-eastern progress of plume development, as seen on the time-lapse seismic data, has led to a review of the structural interpretation and horizon-fault geometry represented in the models. The developing plume has illuminated the extent of splay faults previously unresolved on the baseline seismic data. Saturation profiles interpreted from pulsed-neutron logs at the injection and observation wells show a preference for higher saturations occurring in high permeability distributary channels penetrated by each of the wells. This has reduced the uncertainty in predicting connectivity of this facies between the wells. The pressure data from numerous injection events has been used to refine the characterisation of the average horizontal permeability of the reservoir zone, and the vertical permeability of the intra-formational seal. It has also been used to infer near-field bounding conditions of the interior splay fault, which in turn improves our understanding of containment at the site.

1. Introduction

Site assessment and characterisation has several stages in the life of a CO_2 storage project, each with increasing data requirements and level of investigative detail at progressive investment decision points (DOE/NETL, 2017). Often the emphasis is on the site screening stage, the feasibility stage, and the pre-injection stage when stakeholders require assurance that the project's residual risk is of an acceptable level to proceed. A global review of experiences of storage in saline aquifers (Michael et al., 2010) concluded that although the limited operations have been extremely helpful to establish that the technology is feasible, there is a need for more data from post-injection monitoring, for storage validation, model calibration, and long-term assessment of monitoring strategies. 4D seismic data has been proven as one of the most valuable sources of post-injection observation data for validating structural and stratigraphic features highlighted by the evolving plume. Perhaps the most well-known example of all is at the Sleipner storage site, where seismic imaging of stratified baffles was augmented over time by the propagating CO_2 front (Chadwick et al., 2004; Chadwick and Noy, 2010; Cavanagh and Haszeldine, 2014). At the West Pearl Queen Field, New Mexico, analysis of the higher than expected down-hole injection pressure showed the pre-injection estimation of bulk reservoir permeability was initially overestimated by the laboratory values from core samples (Pawar et al., 2006). At the Ketzin demonstration site, Germany, a number of geophysical monitoring methods were combined to update several generations of static and dynamic models, building the subsurface picture of sandstone, thickness, connectivity and anisotropy overtime (Huang et al., 2018; Kempka et al., 2017); and long term post-

* Corresponding author at: CSIRO 26 Dick Perry Ave, Kensington, WA, 6151, Australia
E-mail address: tess.dance@csiro.au (T. Dance).
[1] Present address: Sandia National Laboratories, P.O. Box 5800, Albuquerque, NM, 87185, USA.

https://doi.org/10.1016/j.ijggc.2019.05.004
Received 17 January 2019; Received in revised form 2 May 2019; Accepted 3 May 2019
1750-5836/

injection water sampling at the Wallula Basalt Pilot Demonstration Project has shown to be effective in reducing uncertainty in prediction of *in-situ* geochemical reactions (McGrail et al., 2017).

The advantage of these projects is that they allow for cross validation of predictions with observation data under very controlled conditions. One other project is the long-running CO2CRC Otway Project in south-western Victoria, Australia. Stage 2C of the project was designed to test injection, storage, and monitoring of 15,000 t of CO_2 rich gas in a deep aquifer (Watson et al., 2018). The rationale was to demonstrate field-scale time-lapse seismic surveillance for detecting small volumes of CO_2 as this is a Carbon Capture and Storage (CCS) monitoring technology that is very likely to be required for many commercial saline formation storage projects for conformance monitoring as well as assurance of storage integrity above zone. The objectives of stage 2C were to: 1) detect injected CO_2 rich gas in the subsurface and ascertain a minimum seismic detection limit; 2) observe the gas plume development during injection using 4D seismic data; and 3) verify stabilization of the plume in the saline formation by comparing 4D seismic images.

The reservoir target was the Late Cretaceous Paaratte Formation which comprises high quality sandstones with excellent porosity (˜25%) and permeability (˜1-2 Darcy), as well as extensive intra-formational seals consisting of heterolithic interbedded siltstone and mudstone units deposited in a shallow marine tidal-fluvial deltaic setting. Overprinting the system are numerous dolomitic stringers, a product of post-depositional diagenesis resulting in irregularly occluded porosity and zones of reduced permeability. The pre-injection technical evaluation of the Paaratte Formation employed the use of a series of models. First was the geologically constrained 3D reservoir model, which is descriptive in nature and captures the static reservoir properties. Following on was the dynamic model, a predictive tool for assessing fluid flow behavior and dynamic reservoir properties. Now, at the end of the modelling chain, is the post-injection model. It is performed as a postmortem after injection commences, it closes the loop by way of history match calibration to the injection and monitoring data. This workflow allows successive updating of the models and for ongoing informed decision making about the site's technical performance. This is commonly referred to as the "reservoir management model" in the petroleum industry and is used after the initial production data is attained to forecast future field performance (Thakur, 1996; Fowler et al., 1999).

Here we discuss the conceptual geological and static models for the lower Unit A of the Paaratte and how they have been enlightened by monitoring data during and after injection. The study has the advantage that it can draw on the following three independent monitoring modalities to verify the characteristics of the subsurface: time-lapse seismic data, pressure monitoring, and down-hole time-lapse pulsed neutron logging.

2. Pre-injection characterisation

The aims of the pre-injection models were to test the feasibility of being able to detect and monitor the injected gas via time-lapse seismic data; and to assess the likely spatial extent of the plume. Success of the experiment depended on a strong time-lapse signal, compared to the time-lapse noise level. Signal strength is a function of the depth, size and thickness of the plume; the contrast of the injected gas with the pore fluids and the elastic properties of the rock; and the survey acquisition and processing parameters (e.g. source, fold, angle versus offset) (Arts and Winthaegen, 2005; Brevik et al., 2000; Johnston, 2013). The objective was to assess the likelihood that the plume would be large enough (at least approximately 200 m wide), and thick enough (approximately 5 m) to produce a strong signal (Pevzner et al., 2015), yet not spread excessively beyond the area covered by the seismic survey footprint and petroleum lease boundary (Fig. 1).

In order to see the plume stabilize (i.e. cease to migrate at the resolution of seismic data) within the 5 year period of the post-injection monitoring period, the injection well CRC-2 was positioned at the top of a structural saddle, north of the Naylor South fault, where the flatter structure would allow for limited mobility and quicker plume stabilization. A small synthetic splay fault exists parallel to the larger Naylor South fault but trending NW-SE and is intersected by both CRC-1 and Naylor-1. It's approximately 1800 m long with a maximum offset at the Paaratte Formation level on the order of 15 m–30 m. This fault appears to die out below the top of the unit A in the Paaratte Formation but has influence on the local dip near the injection target which made it likely the plume would be directed toward to the CRC-1 well (observation well).

2.1. Storage interval

Fig. 2 is a west to east seismic section through the key wells showing the major intra-formational horizons that were included in the pre-injection static models of the storage complex. The unit A (top of complex) and Skull Creek Mudstone (base) boundaries, and intra-formational horizon tops within the Paaratte provide strong acoustic contrasts on the baseline seismic data resulting in strong reflection amplitudes and high-quality coherency reflectors that are tracked easily across the study area. The Paaratte strata is gently dipping in the study area with average dip angles between two to six degrees. Down-dip is towards the west and there is a slight incline to the East-South-East along a ridge associated with the up-thrown side of the splay fault.

Sequence stratigraphic principals were used to correlate a series of 4th order parasequence flooding surfaces across the study site (Dance, 2018). The lithology interpreted on cores is related back to electric log profiles to define the parasequence which mark the flooding surface boundaries between the coarsening up profiles of sandy facies and overlying shale-rich seals. These correspond to the tops of the parasequence horizons shown in Fig. 2. The sequence stratigraphic interpretation of the top of the Unit A section is placed at the top of PS 3 which represents a drowned transgressive coal within an overall progradational highstand systems tract. This marks the ultimate seal at the top of the 2C storage complex. The 11 m perforation zone within the lower Paaratte Formation PS 1 interval was selected because there was sufficient injectivity (1500 md) to inject 15,000 t in the time-frame of the project, yet the low net-to-gross, heterogeneous nature of the base of the reservoir would enhance the chance of producing a thick plume.

2.2. Reservoir quality

Porosity and permeability were evaluated from log and core data (Fig. 3). Reservoir quality is considered good to excellent with average porosity 25–30% and permeability up to several darcy. There appears to be a strong relationship between interpreted facies associations and reservoir quality. By cross-plotting measurements of porosity against permeability by each facies, results show that the highest reservoir potential lies within the proximal mouthbars and distributary channel sandstones (Fig. 3c). The distal mouthbars are mixed lithology with some poor and some good reservoir in the laminated siltstone. The delta front mudstones, as well as the diagenetic cemented beds are considered to be the "non-reservoir" facies. These have been termed non-reservoir on the basis of their low average porosity (< 15%) and permeability (< 10 mD) as well as having high capillary entry pressure. This was measured using mercury injection (MICP) for each lithology and converted into the equivalent CO_2 column height that may potentially be retained (Daniel, 2012). The delta front facies have the potential to act as seals to a plume several tens of metres thick. The cements are more likely to act as baffles, as they lack the extensive continuity of the delta front facies. Similarly, the vertical permeability is important as it also impacts the buoyant flow of the CO_2. In shallow marine and deltaic environments vertical permeability has a strong relationship with the percentage of clay in the facies as it commonly occurs in highly laminated intercludes parallel to bedding (Ringrose, 2005). The delta front shales, with highest clay volume, have the lowest

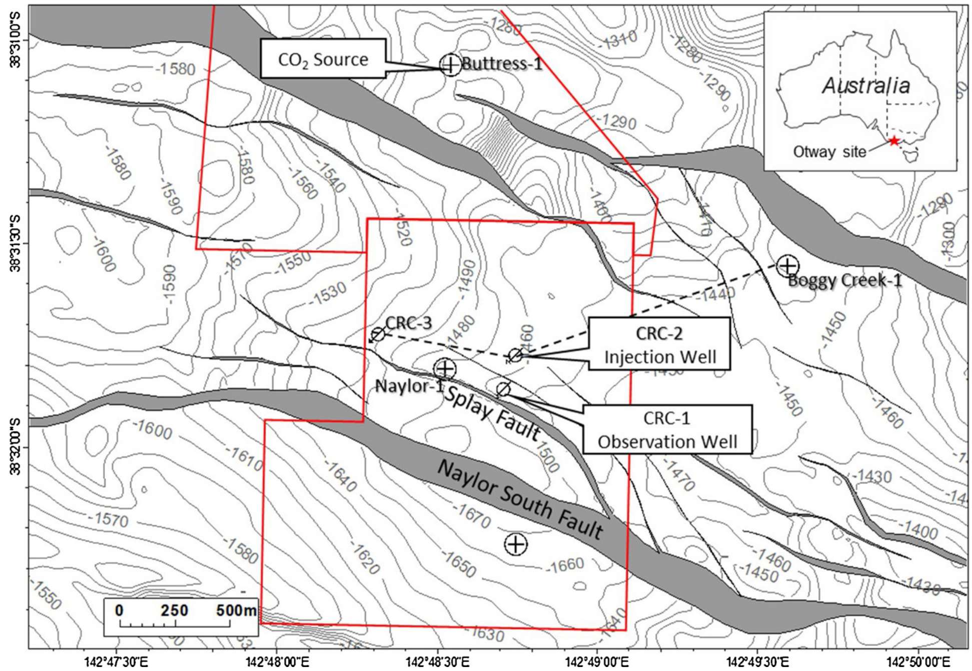


Fig. 1. The CO2CRC Otway Project site including top depth structure map of the injection interval in PS 1 (10 m depth contour intervals in TVD metres sub-sea level), faults, wells, and lease boundary (red polygons). The Fig. 2 cross-section location is indicated by the dashed line.

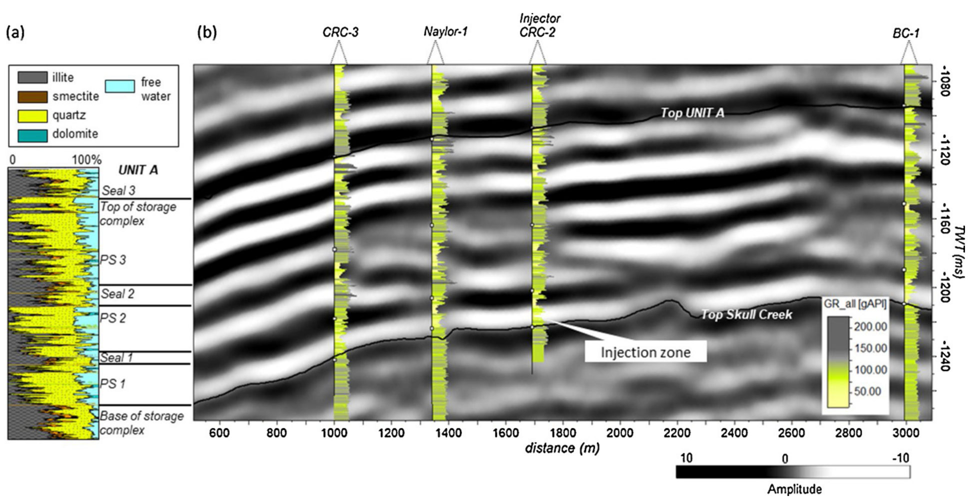


Fig. 2. (a) Stratigraphic section of the Paaratte Formation Unit A parasequences PS 1–3 representing the reservoir and seal pairs within the storage complex compared with (b) the seismic cross-section through key wells (see Fig. 1 for location).

vertical permeability, whereas the massive sandstone dominated proximal mouth bars with very little clay have the highest vertical permeability (Fig. 3d).

2.3. Conceptual model

The Stage 2C pre-injection concept was based on the interpretation that an extensive intra-formational baffle at the top of the PS 1, above the perforated zone, would act as a seal and impede vertical migration of the CO_2 allowing it to spread laterally and be stabilized and contained by capillary and dissolution trapping. Some uncertainty remained about the continuity of these sequences and sealing properties within the inter-well region. Similarly, there was a wide range of probability for the interconnectivity of sand facies between wells given the extremely heterogeneous nature of the formation. Static geological modelling of Stage 2C employed sequential indicator simulation. Sequential indicator simulation (SIS) is most appropriate when either the shape of particular facies body is uncertain or where a number of trends control the total facies distribution. The modelling of depositional facies honours well data and then propagation away from wells starts from a random seed and is guided by experimental variograms (defining a minimum and maximum range for similarity). This process draws heavily from the depositional environment analogues. Very different realisations can result if a variable seed is used.

Modern analogues and ancient systems as seen in outcrops for deltaic to shallow marine systems are described by Coleman and Prior (1982) and Miall (1984, 1991), and a process based classification scheme is presented in Ainsworth (2010). In general, for the tidal-fluvial deltaic to shallow marine system interpreted for the Paaratte Formation in this part of the Port Campbell Embayment, the proximal mouth bar sands and delta front shales of the parasequences are expected to be laterally continuous over the area modelled (10 s Km). The Frontier Formation of central Wyoming, USA, has been extensively mapped and reflects a paleo- environmental system most applicable to

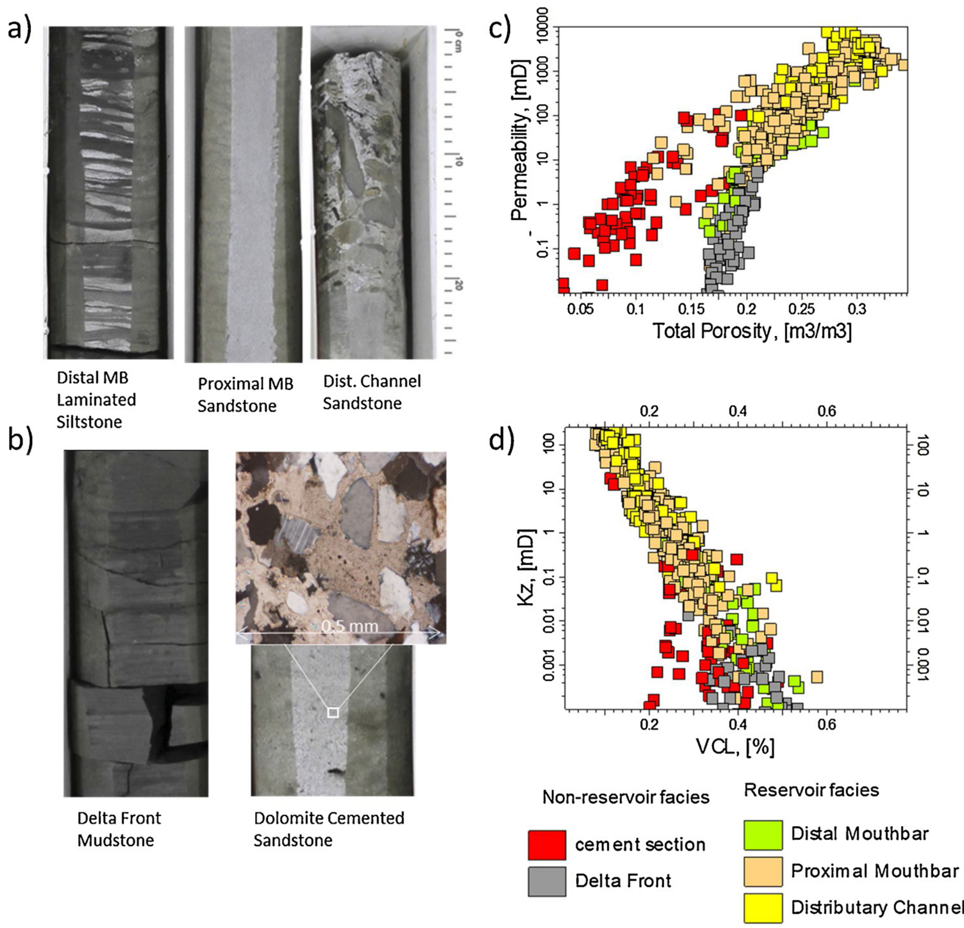


Fig. 3. Examples from core photos of (a) reservoir facies, and (b) non-reservoir facies; cross plots of (c) total porosity versus permeability; and (d) volume of clay versus vertical permeability coloured by each of the facies.

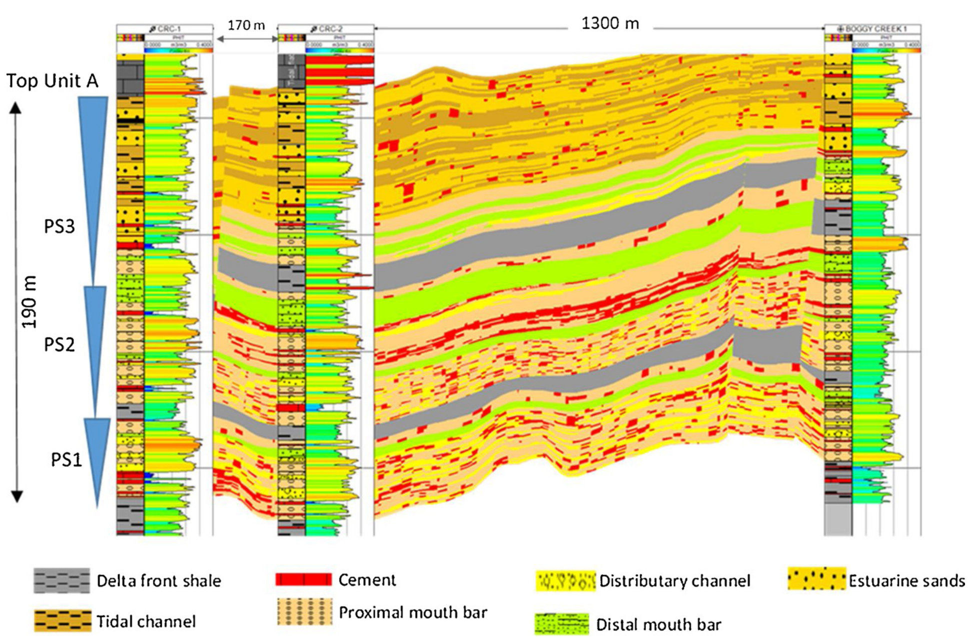


Fig. 4. conceptual geological model and facies correlation between the wells.

that of the Paaratte Formation. Work by Willis et al. (1999) describes the geometry, bedding architecture, and internal facies variations of the lowstand, tidally influenced deltaic sandstone. The sandstone bodies themselves are 20 km long and 3 km wide. Channel system bedsets within the sandstones can be correlated over a distance greater than 500 m. Using this as our conceptual geological model, the correlation of the Paaratte Formation facies in the pre-injection static model is shown in Fig. 4. For the distributary channels, the thickness to width ratios expected to be less than 1:50. With the most likely channel range around 200 m wide and up to 800–1000 m long.

The extent of the cemented sandstone facies remained a key uncertainty. They are obviously indicated on downhole logs by very high density and high resistivity, and low porosity and permeability values on the interpreted petrophysical logs. They are very clearly identifiable in core. However, their patchy nature, and the observation of similar facies in the Frewens Sandstone within the Frontier Formation analogue suggested they are likely to be discrete stringers on the order of 40 m–200 m (Dutton et al., 2002), which is much smaller than the correlation distance between wells.

Another uncertainty was the potential for CO_2 interaction with the splay fault located south of the injection well. A detailed fault analysis study was performed and showed that the chance of across fault flow of CO_2 was very unlikely due to sufficient shale gouge ratio and high probability of sand on shale juxtaposition (Tenthorey et al., 2014). However, it was desirable to obtain field scale evidence for the sealing properties of the fault.

3. Results and discussion

The three main monitoring modalities for the stage 2C experiment and the relative timing are listed in Table 1. The data gathered during injection and following the end of injection are compared to the baseline to identify changes attributed to the CO_2.

3.1. Pressure data used to update permeability distribution

The observed in-zone pressure response at CRC-2 to the injection contains information about the average reservoir permeability, the presence of barriers to flow, and the response of nearby aquifers. The observed above-zone pressure response contains information about the degree of connection between the two formations (PS1 and PS2), and the permeability of the intervening rock.

The standard way to extract this information from the pressure data is first by pressure transient analysis on the water injection test, and secondly by history-matching the whole dynamical model to the field data. For the pressure transient analysis, the match to the in-zone PS2 pressure was consistent with a fully or partially sealing feature within a few hundred meters of the well. The most likely feature to cause this kind of pressure signature is the splay fault near CRC-2 well.

In order to simultaneously match the above-zone (PS 2) and in-zone (PS 1) pressure data it was necessary to fit suitable boundary conditions to the dynamic modelling grid. The Naylor South Fault along the southern boundary is considered to be impermeable. The Buttress and Boggy Creek fault complex to the north may have some sealing characteristics but are not considered impermeable. There are no nearby structures that are likely to provide a sealing boundary to the east or west.

The three open boundaries were modelled as a series of three vertically stacked aquifers. Fetkovich aquifer models were used for the aquifers. This type of model uses a pseudosteady-state aquifer productivity index to represent the system compressibility and allows for the productivity index and size of each aquifer to be defined (Fetkovich, 1971). Fetkovich aquifers with a high productivity index were used adjacent to PS1 and PS2, while an aquifer with productivity index an order of magnitude lower was used adjacent to the baffle between PS1 and PS2. The aquifers to the east and west were considered to be large in all three layers of the model.

The Boggy Creek and Buttress Fault complex beyond the northern boundary of the model are considered to be partially sealing. The boundary to the north was modelled as a small aquifer to capture the restriction to flow caused by the Boggy Creek and Buttress Fault complex. The simulated pressure and CO_2 distribution in the reservoir were not sensitive to the size of the aquifer on the northern boundary.

The above-zone pressure response in PS2 was highly sensitive to the contrast between the productivity indices of the aquifers and the baffle, due to under- or over-estimation of vertical pressure communication within the bounding aquifers. However, once the correct ratio was chosen the predicted pressure perturbation was relatively insensitive to further changes in the boundary conditions.

Fig. 5 shows the pressure matched to the observed pressure in the injection well during the bulk CO_2 injection. Gauge 3, in parasequence 2, refers to RGA5304, with a measured depth of 1450.58 m. Gauge 2, in parasequence 1, refers to RGA5303, with a measured depth of 1497.77 m. The simulation pressures shown are gridblock pressures. In PS2, data from any of the other three gauges could be used, with an identical pressure increase observed.

In PS1, the difference between the gauge pressures can be used to track the height of the CO_2-brine interface during injection. Because of a small discrepancy in depth between the actual gauge and the centre of the well completion in the simulation model it was necessary to normalise the pressures i.e. to subtract a reference pressure value. The RMS (root mean squared) or L2 error of the normalised pressure is used to determine the best fit to the pressure data. Simulations were performed increasing the average horizontal permeability of the model in 0.1 Darcy increments and the simulation with 1.7 times the original permeability had the lowest RMS error.

There is a substantial time lag in the pressure response in the above-zone as compared with the injection zone. This indicates that there is a sealing formation with lateral extent much larger than the CO_2 plume between the PS 1 and PS 2 parasequences. The dynamic model was also fit to the above-zone pressure data in PS 1 and a very low vertical permeability (< 1md) was required in the barrier between PS 1 and PS 2 to match the gradual increase and decline in the pressure signal measured above-zone, as shown in Fig. 6.

3.2. Plume images from 4D surface seismic data

Injection of CO_2 into aquifers reduces the elastic moduli of reservoir rocks, changing the seismic image response. Thus, time-lapse seismic surveys have become a conventional tool for CO_2 sequestration projects (Johnston, 2013). Seismic monitoring program for Stage 2C comprised six 3D seismic surveys, including the baseline and five repeat surveys during injection in three stages 5000 t, 10,000 t, 15,000 t (end of injection) and 9 months and 23 months afterwards. A sufficiently strong time-lapse seismic anomaly was observed after injection of 5000 t and the consequent evolution could be clearly identified (Pevzner et al., 2017). However, relatively small thickness and lateral dimensions of the CO_2 plume make quantitative interpretation of the detected

Table 1
Field Observation data.

Time stage	Pressure data	Pulsed Neutron logs	4D Seismic data
pre-injection	Water injection test (build-up and fall-off)	Baseline run	Baseline survey
at 5,000 t	injection pressure		Monitor 1
at 10,000 t	injection pressure		Monitor 2
at 15,000 t 1 month after end-injection	injection pressure	run in INJ and OBS wells	Monitor 3
9 months post-injection			Monitor 4
23 months post-injection			Monitor 5

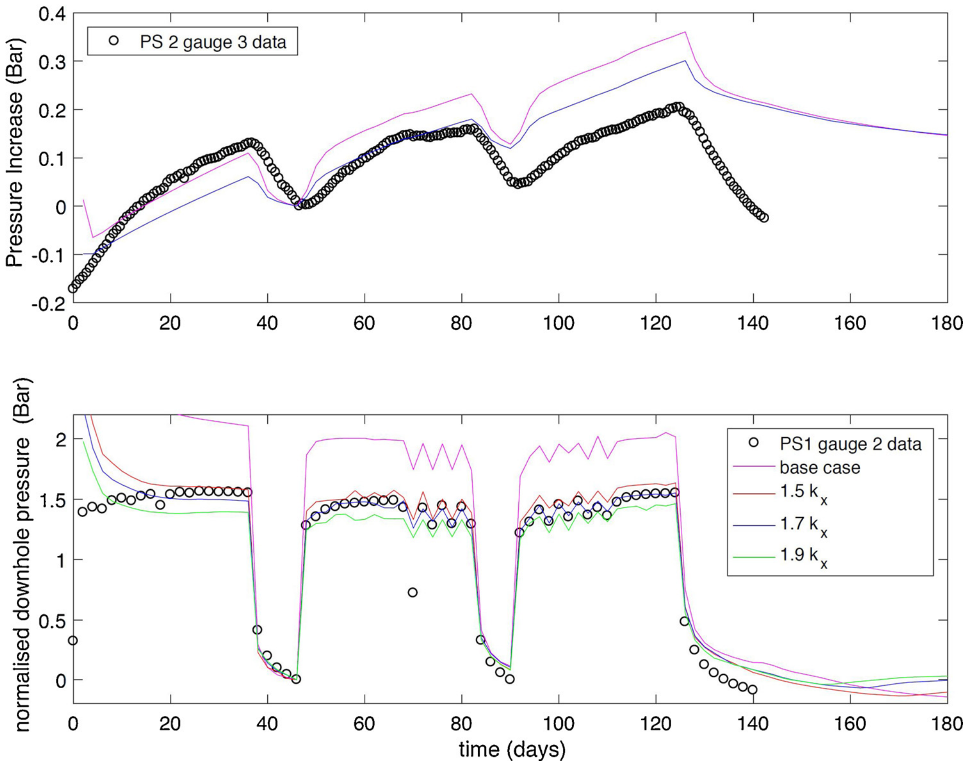


Fig. 5. History-matching of the pressure change in dynamic simulations as a function of days since the start of injection. Top: Pressure in the above-zone interval, PS2. Bottom: Pressure in the injection interval, PS1. Note the order-of-magnitude difference in the pressure scale in the subfigures. The depth locations of the pressure gauges are discussed in the text.

response challenging. Superposition of reflections from the top and bottom of the plume smears the vertical structure of the injected CO_2 and masks its thinner parts.

In order to refine the plume characterisation, we needed to reduce the smearing effect of the source signature and attribute observed intensity of the time-lapse signal to actual changes of the subsurface. Seismic inversion assimilates available borehole geophysical measurements and geological models to explain the observed seismic data, thus, the time-lapse seismic difference is converted to relative change of the acoustic impedance (analogue of the rock stiffness):

$$\Delta AI = \frac{Z_M - Z_B}{Z_B} \tag{1}$$

where Z_B and Z_M denote baseline and monitor acoustic impedance.

Since the presence of CO_2 in pore space increases fluid compressibility, ΔAI should respond to the injection with a negative anomaly (i.e. produces an increase in impedance. It gives us a physically rigorous criterion for the plume extraction. However, the threshold needs to be more severe to filter out noise artefacts, which is typically done through iterative changing of inversion parameters and noise models. That is why, a prototype inversion workflow is first tested on a full-scale time-lapse 3D synthetic data set generated by Glubokovskikh et al. (2016). Shulakova et al. (2017) examined a conventional multi vintage sample-based acoustic inversion to characterization of the Stage 2C plume. The authors found that the inversion is not sensitive to CO_2 saturation and produces some uncertainty in effective gas column height. By changing the threshold, we may effectively regulate confidence of the CO_2 detection and estimates of the plume thickness.

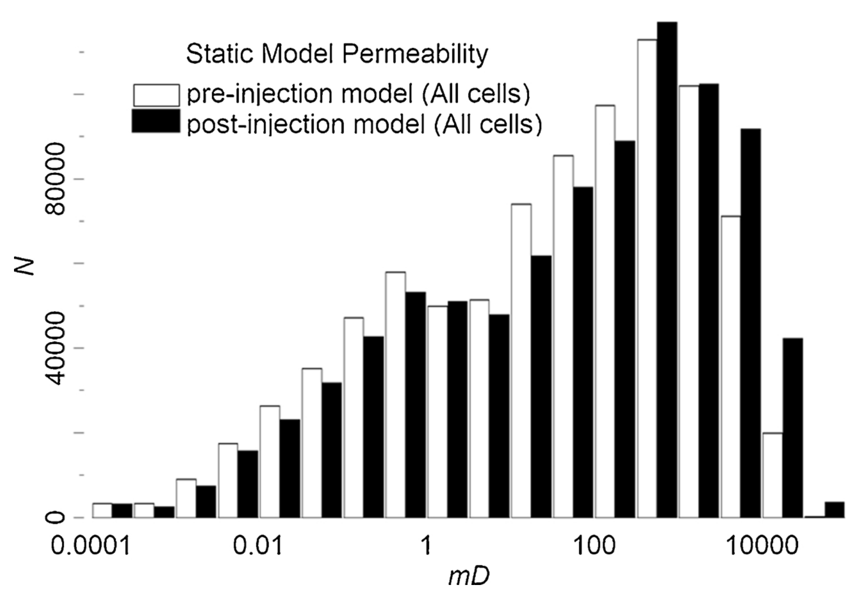


Fig. 6. updated Permeability distribution in the static models.

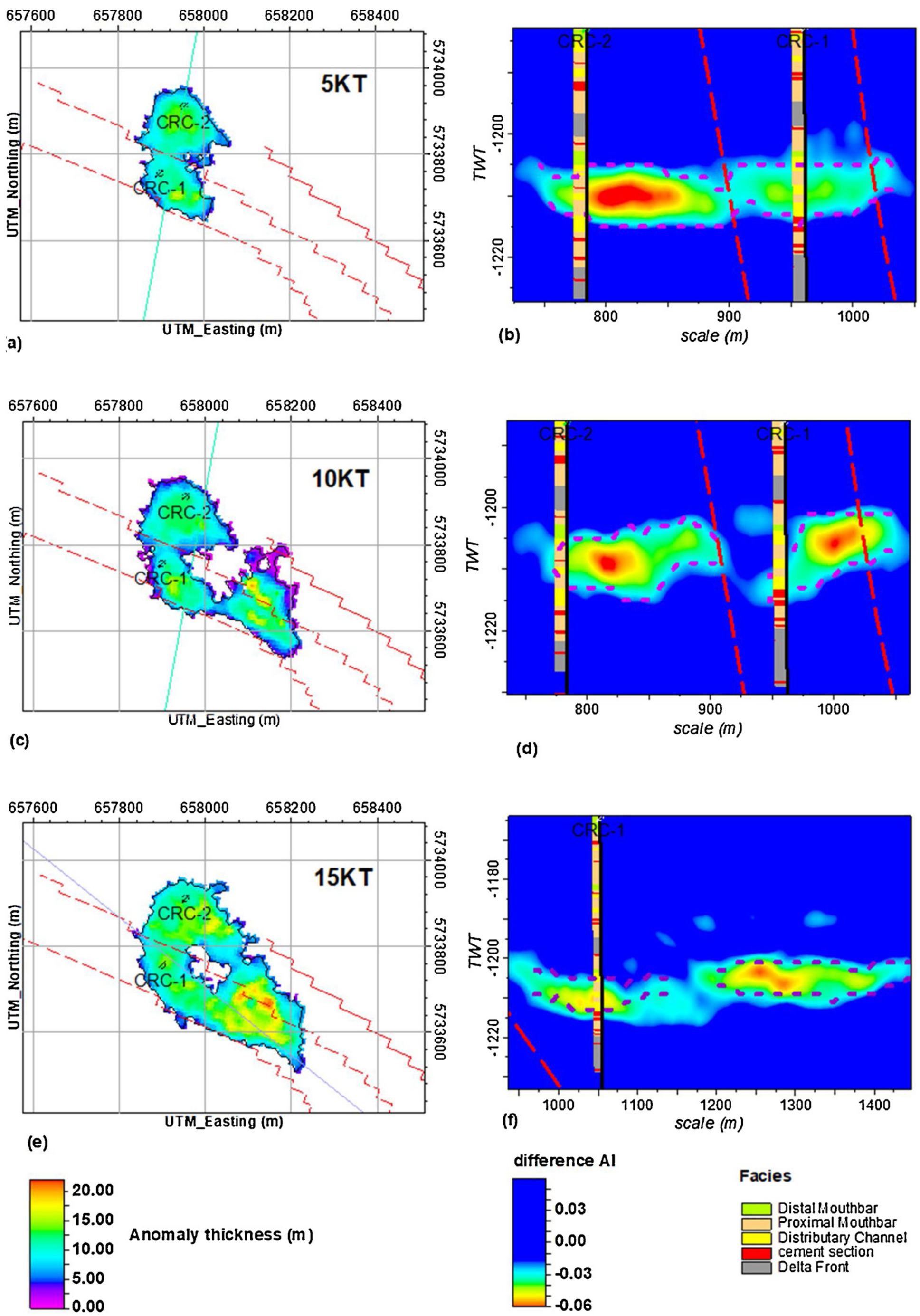


Fig. 7. Inverted relative changes of acoustic impedance ΔAI corresponding to seismic vintages acquired during the injection. Left column contains plume thickness maps along with the interpreted faults (red lines) and cross-section locations (blue lines). The plume bodies are extracted from the noisy inversion results based on the intensity and connectivity of the ΔAI samples as shown in the vertical sections on the right.

The key findings of the feasibility study are used to set up the inversion workflow for the Stage 2C field data (Glubokovskikh et al., 2018). The high quality of the monitoring vintages allowed us to get good agreement between the synthetic and actual seismic images (correlation coefficient ˜90%). Final 3D cubes of the inverted relative acoustic changes are shown in Figs. 7 and 8, with the main features being:

- variation of ΔAI is confined to ± 6%;
- a positive anomaly below the plume is caused by the time shifts between the baseline and monitor seismic surveys below the CO_2 plume;
- dispersed patches of smaller and less intense anomalies are caused by time-lapse noise.

The synthetic inversion shared the same features both qualitatively and quantitatively, and that increases the credibility of the results. The final plume body (dotted contours in Figs. 7 and 8) is extracted according to thresholds imposed on the ΔAI samples and their spatial connectivity, so the patchy noise artefacts are removed.

The time-lapse seismic data to date have shown that CO_2 is being contained by the parasequence boundary shale and plume propagation is restricted to PS 1. The extracted CO_2 plume bodies agree well with other independent measurements, including repeat pulsed-neutron

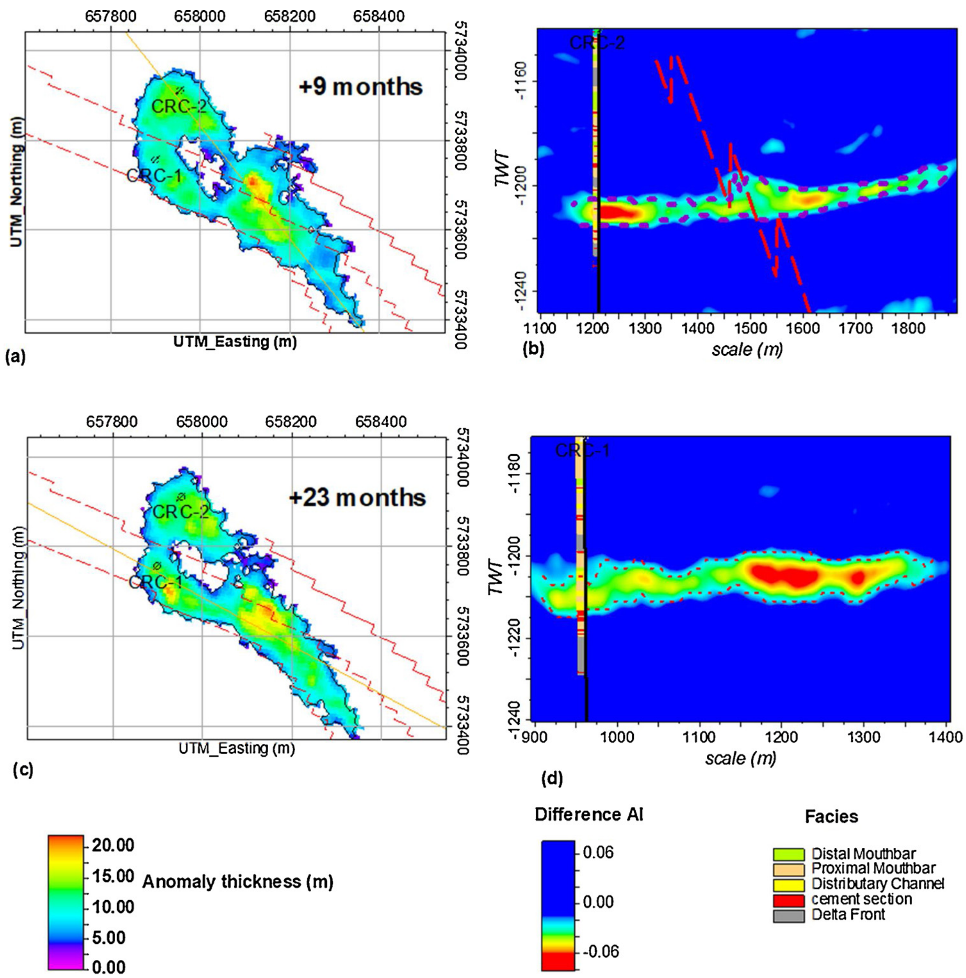


Fig. 8. Inverted relative changes of acoustic impedance ΔAI corresponding to seismic vintages acquired after the injection. Left column contains plume thickness maps along with the interpreted faults (red lines) and cross-section locations (yellow lines). The plume bodies are extracted from the noisy inversion results based on the intensity and connectivity of the ΔAI samples as shown in the vertical sections on the right.

logging, in- and above-zone pressure monitoring and full-waveform-inversion of offset vertical seismic profiles.

3.3. Improved structural interpretation

The development of the seismic anomaly shows the plume is clearly favouring flow along the main Splay fault, and parallel to two more smaller internal splay faults (shown in red on the maps in Figs. 7 and 8) which indicates a high-permeability zone in this area. Two explanations for this may be: 1) because the fault has a high permeability fracture zone near it; or 2) because there is a high-permeability facies occurring parallel to this location. It is highly likely that both of these are combining to produce a dual porosity flow pathway. As can be seen in cross-section through the anomaly, there is a bifurcation of the feature, and it splits into two distinct lobes as it propagates towards the south east. The vertical offset would indicate a fault. Fig. 9 compares the pre-injection and post-injection structural interpretation of the top of the PS 1 injection horizon. The geometry of the seismic anomaly has been interpreted as an extension of the two minor faults parallel to the north of the main splay fault.

3.4. Pulsed neutron logging data

The pulsed neutron logs were acquired approximately one month after the CO_2 injection ceased. (Marsh et al., 2018). In the CRC-2 and CRC-1 wells, the pulsed neutron logs were used for detection and quantification of the CO_2 plume in terms of the vertical extent and saturation, based on the expected gas density and composition. The interpretation of the CRC-2 well logs the saturation across the injection zone varies with the formation quality and the presence of water in the tubing-to-casing annulus. The height of the formation showing CO_2 injection is 10 m from 1453 m to 1463 m (TVDSS). This corresponds to the perforated zone. The top 2 m of the perforations show close to full CO_2 saturation in the formation. In CRC-1 the interpreted gas saturation is less than 50%. The CO_2 plume extends for 2 m vertically from 1450 m to 1452 m (TVDSS).

Channel facies are identified in PS 1 in both CRC-2 and CRC-1 approximately 170 m apart. The most likely channel range is around 200–600 m wide and 1000 m long, so it is highly probable these channels are interconnected between these two wells. Fig. 10 shows that the highest CO_2 saturation interpreted from the pulsed neutron logs correspond with these channel facies. In CRC-2 highest saturation is observed in channel 2 at approximately 1454 m (TVDSS). In CRC-1 saturations are observed in channel 1 which sits stratigraphically lower in the sequence, but 5 m higher in true depth. The likely explanation is that channel 2 is juxtaposed with channel 1 by the fault observed in seismic data creating a localized flow path for the plume between wells.

The logs also show no evidence for CO_2 above the delta front mudstone facies. This is an important verification that the CO_2 is contained within the zone.

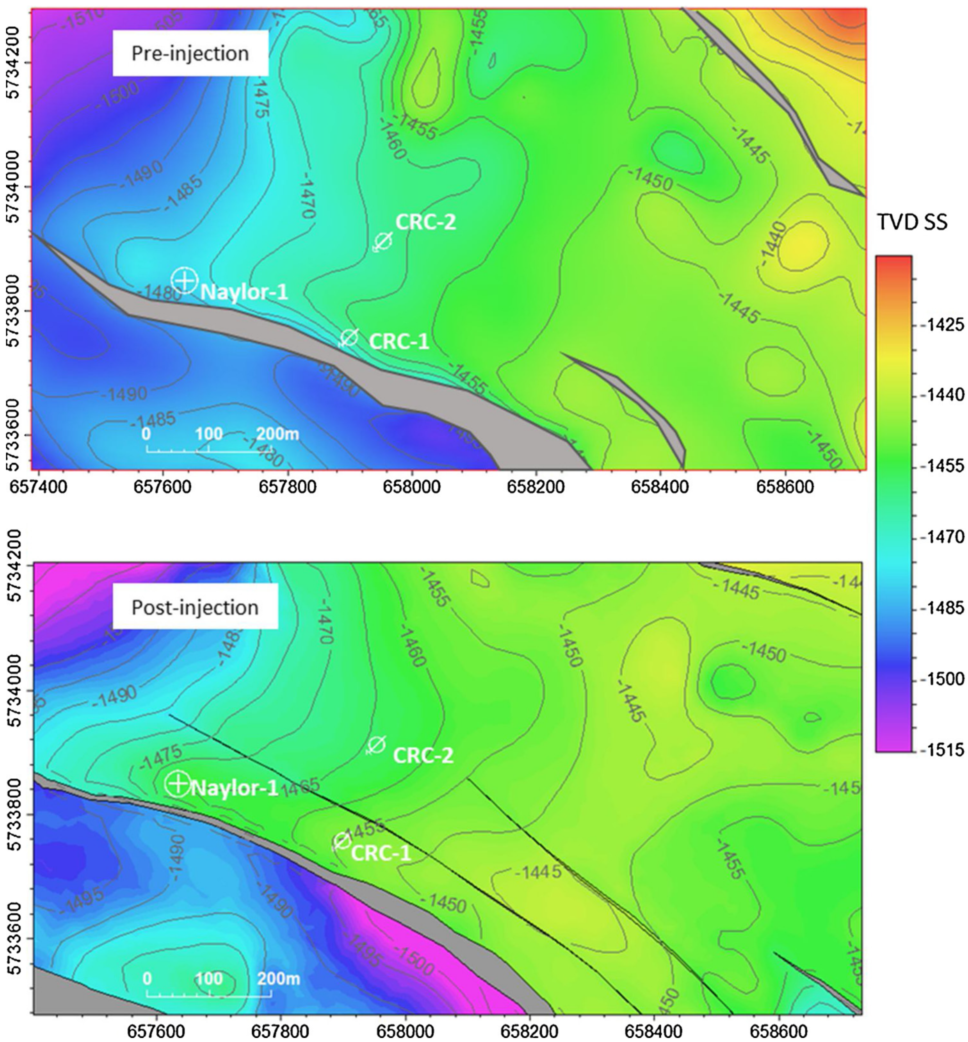


Fig. 9. Before and after maps of new faults and top structure.

4. Post-injection static modelling

As was demonstrated in the previous section, the difference of the inverted acoustic impedance from the monitor surveys minus the baseline survey corresponds to the likely location of the plume, and the anomaly highlights the extents of a fault. The pulsed neutron logs also showed that the higher saturations correspond to high permeability channel facies. In general, for the tidal-fluvial deltaic to shallow marine system interpreted for the Paaratte Formation it is common to see high permeability and porosity preserved in channel features. Also of note is evidence on the seismic interpretation of growth faults (thickening of sequences on the foot wall side of the faults). This indicates that the faults were active during the time of deposition. In this setting, channels have a tendency to propagate parallel to the fault plane as a result of the increased accommodation space provided during extension. It is not certain that the CO_2 plume is following the channel away from the wells, but it is highly likely and by incorporating a channel facies in the static models co-located to the plume may improve the match of the simulated plume to the seismic anomaly.

Thus, in the post-injection static modelling, there was an opportunity to use the ΔAI results to guide the facies distribution to produce a more reliably constrained property model in the inter-well region. However, the seismic data, with relatively coarse resolution, could not be used purely deterministically as it does not resolve small scale (< 5 m) heterogeneity in the vertical direction. So the post-injection 2C geological model was re-constructed using SIS combined with a probability trend model for each facies derived from the seismic attribute data. The modelling workflow involved using the distribution of the seismic anomalies, sampled back into the static grid in the depth domain for conditioning the probability trend model (Fig. 11). In essence, cells which contained the plume property were assigned 95% probability for channels.

Similar rationale was used to constrain the trend modelling of baffles in the vicinity of the plume, but using the inverse of the seismic anomaly, i.e. where there were “holes” in the plume geo-body, or where it was limited vertically, it was assumed that less permeable reservoir facies were impeding the plume propagation. Thus probability of cements and distal mouth bar facies were high on the upper bounding cells above the plume and in patches within the plume. The porosity and permeability modelling was then constrained to the facies model using the ranges from the well data analysis. The resulting permeability field at the top of PS 1 is shown in Fig. 12, where permeability greater than 1000 mD following along the eastern splay fault can clearly be seen in gold, corresponding the location of the channel geo-body. The low permeability is related to the cement baffle geo-bodies as well as the distal mouthbar facies overlying the high permeability channel. It is important to note that properties interpreted at the wells were still preserved, and thus the models honoured the hard data at known locations.

These newly revised static models are currently being used for Otway Project Stage 3, and model predictions have benefited from the ongoing performance history match to the Stage 2C time-lapse seismic

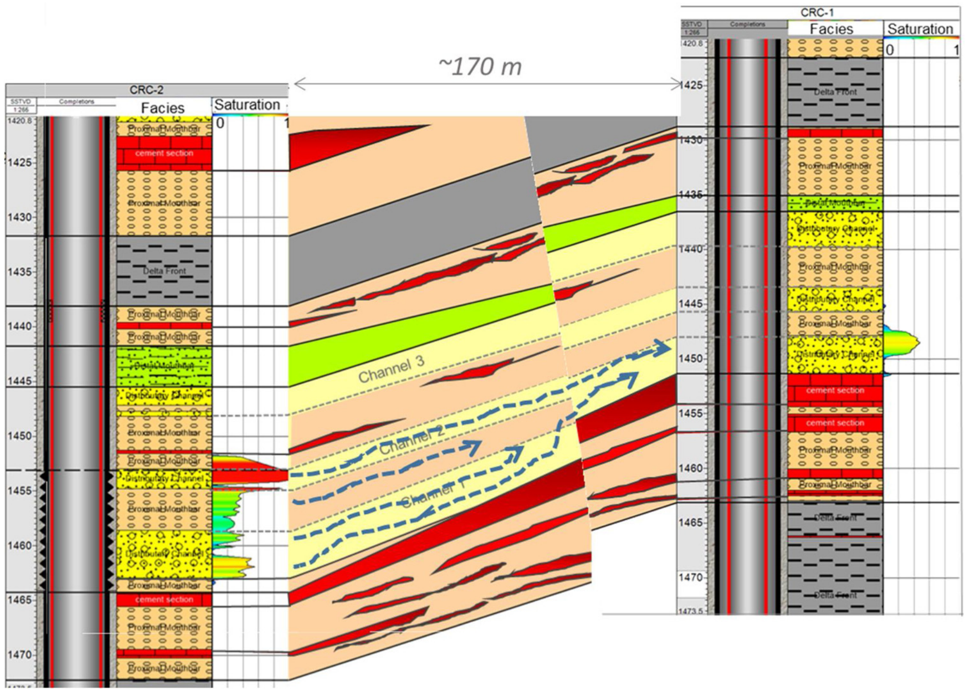


Fig. 10. saturation logs at end injection and interpretation of the inter-well connectivity post-injection whereby the inclusion of the newly imaged fault between the wells means channel 2 is juxtaposed with channel 1 creating a flow path to the lower sand in the observation well.

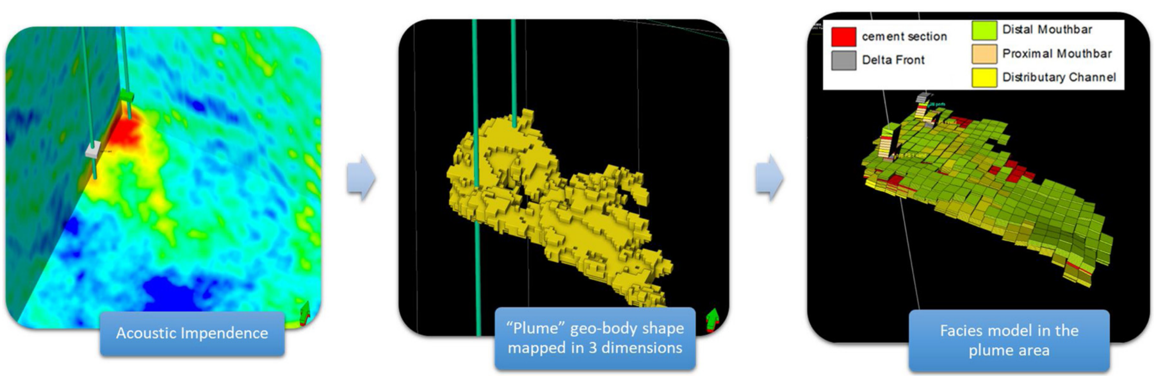


Fig. 11. New conceptual modelling workflow including trend modelling of channel and baffle facies based on the co-location of the plume geo-body in the 3D model.

monitoring experiment (La Force et al., 2018; Watson et al., 2018). Currently the Stage 3 project is in its Execute phase, having completed its Opportunity Definition, Evaluate and Define phases. The improved static and dynamic models are providing the foundation for new well designs as the drilling program is imminent (Jenkins et al., 2018). The post-injection characterisation has been critical for updating geo-models to enhance reservoir management during the storage development period, as well as for reducing prior uncertainties about the geological structure and the distribution of permeability.

5. Conclusions

The time-lapse seismic data has been used to revealed the extent of minor splay faults previously unresolved on the baseline seismic survey. Most importantly, data from all the monitoring modalities has provided further evidence to support the interpretation of the parasequences as being continuous across the site and added confidence that the associated flooding surfaces provide a sufficient barrier to prevent vertical flow and contain the plume long enough for it to stabilize. The time-lapse seismic images and vertical saturation profile interpretation from well logs suggest the CO_2 is being vertically confined at the top of the PS1 injection interval in the vicinity of CRC-2. The in-zone and above-zone pressure data has also improved our understanding of containment potential of the intra-formational seals. More specifically the learnings from each monitoring technique are summarized as follows:

1 Post-injection seismic survey data has informed us of the plume spatial extent, the continuity of baffles above the plume, the likely location of channels and their orientation, as well as highlighted faults that were previously unseen.
2 Pressure monitoring has helped to better understand connectivity and thickness of zones, average horizontal permeability, splay fault properties, intra-formational seal effectiveness, and shown that permeability is underestimated in core and log measurements.
3 Saturation at the wells as interpreted from pulsed neutron logging has shown where the CO_2 has entered the formation at the injector, and the vertical distribution of saturation shows the upper part of the perforation receives the most CO_2. The saturation profile at the monitoring well shows there is connection via a channel facies between the two wells, and it has also shown there is no CO_2 above the primary storage zone.

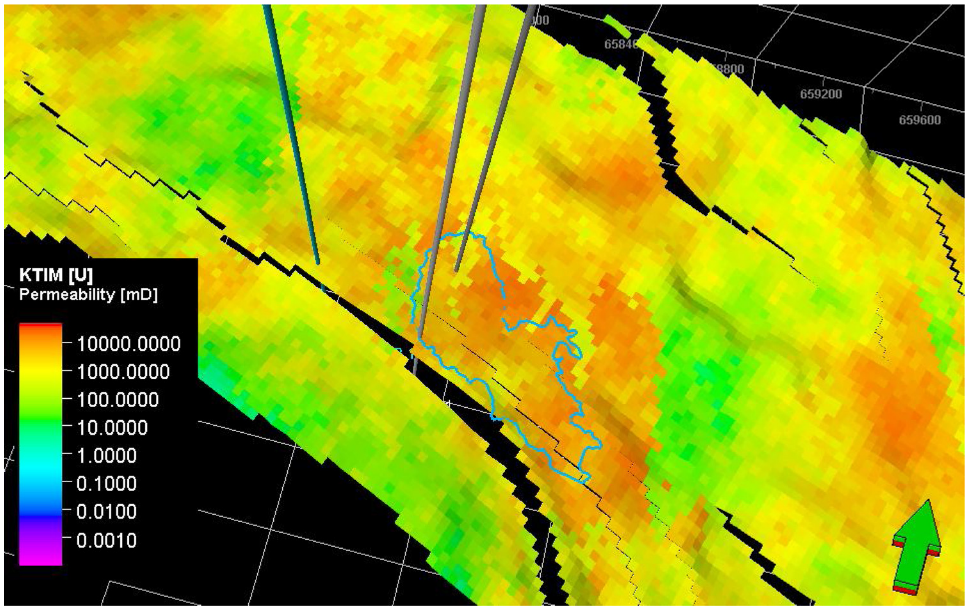


Fig. 12. View of the post-injection permeability model at the top of the injection horizon and the outline of the seismic anomaly at the end of injection (blue polygon).

By performing this post-injection reservoir characterisation, we have been able to reduce uncertainty in our understanding of reservoir and seal connectivity between wells and have illuminated our understanding of the structure of the site. Most importantly, data from all the monitoring modalities has provided further evidence to support the interpretation of the parasequences as being continuous across the site and added confidence that the associated flooding surfaces provide a sufficient barrier to prevent vertical flow. Thus, the injection of CO_2 has indeed "illuminated the geology" and reduced prior uncertainties about the geological structure and the distribution of permeability. This post-injection characterisation can be applied to refine the static and dynamic models for other field projects and adds assurance about the long-term stabilization of a CO_2 plume. This in turn will influence long-term monitoring strategies and the potential transfer of liability for a site.

Acknowledgements

The authors acknowledge CO2CRC for allowing access to The CO2CRC Otway Research Facility. The Otway Stage 2C project received CO2CRC funding through its industry members and research partners. Financial assistance was provided through Australian National Low Emissions Coal Research and Development (ANLEC R&D) supported by the Australian Coal Association Low Emissions Technology Limited and the Australian Government through the Clean Energy Initiative. The Otway Stage 2C technical team and leaders are thanked for their support and advice, specifically Eric Tenthorey, Charles Jenkins, Lincoln Paterson, Max Watson and Rajindar Singh. This paper describes objective technical results and analysis. Any subjective views or opinions that might be expressed in the paper do not necessarily represent the views of the U.S. Department of Energy or the United States Government. Sandia National Laboratories is a multi-mission laboratory managed and operated by National Technology & Engineering Solutions of Sandia, LLC, a wholly owned subsidiary of Honeywell International Inc., for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA0003525.

References

Ainsworth, R.B., 2010. Prediction of stratigraphic compartmentalization in marginal marine reservoirs. Geol. Soc. London Spec. Publ. 347 (8 November), 199–218. https://doi.org/10.1144/SP347.12.

Arts, R., Winthaegen, P., 2005. Monitoring options for CO_2 storage. Geol. Storage Carbon Dioxide Monit. Verification 2, 1001–1013. https://doi.org/10.1016/B978-008044570-0/50147-1.

Brevik, I., Eiken, O., Arts, R.J., Lindeberg, E., Causse, E., 2000. Expectations and results from seismic monitoring of CO_2 injection into a marine aquifer. 62nd EAGE Meeting.

Cavanagh, J.A., Haszeldine, R.S., 2014. The Sleipner storage site: capillary flow modeling of a layered CO_2 plume requires fractured shale barriers within the Utsira Formation. Int. J. Greenh. Gas Control. 21, 101–112. https://doi.org/10.1016/j.ijggc.2013.11.017.

Chadwick, R.A., Noy, D.J., 2010. History-matching flow simulations and time-lapse seismic data from the Sleipner CO_2 plume. Petroleum Geology Conference 1171–1182.

Chadwick, R.A., Zweigel, P., Gregersen, U., Kirby, G.A., Holloway, S., Johannessen, P.N., 2004. Geological reservoir characterization of a CO_2 storage site: The Utsira Sand, Sleipner, northern North Sea. Energy 29 (9-10), 1371–1381.

Coleman, J.M., Prior, D.B., 1982. Deltaic environments of deposition. In: Scholle, P.A., Spearing, D. (Eds.), Sandstone Depositional Environments. AAPG Memoir 31, pp. 139–178.

Dance, T., 2018. Characterisation of the Late Cretaceous Paaratte Formation, a heterogeneous saline aquifer, for an Australian CO_2 storage project. J. Pet. Geol (submitted).

Daniel, R., 2012. Containment/ injectivity results from MICP analysis for seals. Intraformational Barriers and Reservoir Samples, CRC-2, Otway Basin. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra, Australia CO2CRC Publication Number: TBN12-3830 (77pp).

DOE/NETL, 2017. Best Practices: Site Screening, Site Selection, and Site Characterization for Geologic Storage Projects. 2017/1844 National Energy Laboratory.

Dutton, S.P., White, C.D., Willis, B.J., Novakovic, D., 2002. Calcite cement distribution and its effect on fluid flow in a deltaic sandstone. Front. Form. Wyoming AAPG Bull. 86 (12), 2007–2021.

Fetkovich, M.J., 1971. A simplified approach to water influx calculations—finite aquifer systems. J. Pet. Technol. 23 (7), 814–828. https://doi.org/10.2118/2603-PA. SPE-2603-PA.

Fowler, M.L., Young, M.A., Madden, M.P., Cole, E.L., 1999. The role of Reservoir characterization in the Reservoir management process (as reflected in the department of energy's Reservoir management demonstration program). In: Schatzinger, R.A., Jordan, J.F. (Eds.), Reservoir Characterization-Recent Advances. AAPG Memoir 71, pp. 3–18.

Glubokovskikh, S., Pevzner, R., Dance, T., Caspar, E., Popik, D., Shulakova, V., Gurevich, B., 2016. Seismic monitoring of CO_2 geosequestration: CO2CRC Otway case study using full 4D FDTD approach. Int. J. Greenh. Gas Control. 49, 201–216.

Glubokovskikh, S., Gunning, J., Pevzner, R., Shulakova, V., Popik, D., Dance, T., Proud, C., Gurevich, B., 2018. Towards seismic characterisation of a small CO_2leakage: CO2CRC Otway project case study. Proceedings of, *GHGT-14* 21–24 October.

Huang, F., Bergmann, P., Juhlin, C., et al., 2018. The first post-injection seismic monitor survey at the Ketzin pilot CO_2 storage site: results from time-lapse analysis. Geophys. Prospect. 66 (1), 62–84. https://doi.org/10.1111/1365-2478.12497.

Jenkins, C., Bagheri, M., Barraclough, P., Dance, T., Ennis-King, J., Freifeld, B., Glubokovskikh, S., Gunning, J., La Force, T., Marshall, S., Paraschivoiu, E., Paterson, L., Pevzner, R., Tenthorey, E., Watson, M., 2018. Fit for purpose monitoring - a progress report on the CO2CRC Otway stage 3 project. Proceedings of, GHGT-14

21–24 October.
Johnston, D., 2013. Practical Applications for Time-lapse Seismic Data, 2013 Distinguished Instructor Short Course. Distinguished Instructor Series, No. 16.
Kempka, T., Norden, B., Ivanova, A., et al., 2017. Revising the static geological reservoir model of the upper Triassic Stuttgart formation at the Ketzin pilot site for CO_2 storage by integrated inverse modelling. Energies 10 (10). https://doi.org/10.3390/en10101559.
La Force, T., Dance, T., Ennis-King, J., Paterson, L., Cinar, Y., 2018. How Good Is Good Enough in CO_2 Storage Modelling? Looking Back Over Three Generations of Models for the Otway Stage 2C Project. Oral presentation given at the GHGT-14, Melbourne, pp. 21–25 October.
Marsh, R.J., Dance, T., Kim, Y., Chance, D., Singh, R., 2018. Well based monitoring of a CO_2 plume in a carbon dioxide storage project. SPWLA 2018. 59th Annual Symposium 2–6 June.
McGrail, B.P., Schaef, H.T., Spane, F.A., Horner, J.A., Owen, A.T., Cliff, J.B., Qafoku, O., Thompson, C.J., Sullivan, E.C., 2017. Wallula Basalt Pilot Demonstration Project: post-injection results and conclusions. Energy Procedia 114, 5783–5790.
Miall, A.D., 1984. Deltas. In: Walker, R.G. (Ed.), Facies Models, 2nd ed. Geoscience Canada Reprint Series 1, pp. 105–118.
Miall, A.D., 1991. The Three-dimensional facies architecture of terrigenous clastic sediments and its implications for hydrocarbon discovery and recovery. Concepts in Sedimentology and Paleontology. Soc. for Sedim. Geol., Tulsa.
Michael, K., Golab, A., Shulakova, V., Ennis-King, J., Allinson, G., Sharma, S., Aiken, T., 2010. Geological storage of CO_2 in saline aquifers—a review of the experience from existing storage operations. Int. J. Greenh. Gas Control. 4, 659–667.
Pawar, R.J., Warpinski, N.R., Lorenz, J.C., Benson, R.D., Grigg, R.B., Stubbs, B.A., Stauffer, P.H., Krumhansl, J.L., Cooper, S.P., Svec, R.K., 2006. Overview of a CO_2 sequestration field test in the West Pearl Queen reservoir, New Mexico; characterization of sites for geological storage of CO_2. Environ. Geosci. 13 (3), 163–180.
Pevzner, R., Caspari, E., Gurevich, B., Dance, T., Cinar, Y., 2015. Feasibility of CO_2 plume detection using 4D seismic: CO2CRC Otway project case study — part 2: detectability analysis. Geophysics 80 (4), B105–B114. https://doi.org/10.1190/geo2014-0460.1.
Pevzner, R., Urosevic, M., Popik, D., Shulakova, V., Tertyshnikov, K., Caspari, E., Correa, J., Dance, T., Kepic, A., Glubokovskikh, S., Ziramov, S., Gurevich, B., Singh, R., Raab, M., Watson, M., Daley, T., Robertson, M., Freifeld, B., 2017. 4D surface seismic tracks small supercritical CO_2 injection into the subsurface: CO2CRC Otway project. Int. J. Greenh. Gas Control. 63, 150–157. https://doi.org/10.1016/j.ijggc.2017.05.008.
Shulakova, V., Pevzner, R., Glubokovskikh, S., Popik, D., Tertyshnikov, K., 2017. Time-lapse seismic data inversion for CO_2 sequestration: CO2CRC Otway project. Expanded Abstract for 79th EAGE Conference and Exhibition 2017. https://doi.org/10.3997/2214-4609.20170.
Tenthorey, E., Dance, T., Cinar, Y., Ennis-King, J., Strand, J., 2014. Fault modelling and CO_2 migration potential associated with the CO2CRC Otway 2C injection experiment. Int. J. Greenh. Gas Control. 30, 72.
Thakur, G.C., 1996. What Is Reservoir Management? Society of Petroleum Engineers. Distinguished Author Serieshttps://doi.org/10.2118/26289-JPT.
Watson, M., Pevzner, R., Dance, T., Gurevich, B., Ennis-King, J., Glubokovskikh, S., Urosevic, M., La Force, T., Tenthorey, E., Paterson, L., Cinar, Y., Freifeld, B., Caspari, E., Singh, R., Raab, M., 2018. The Otway stage 2C project: End to End CO_2 saline formation characterisation, injection and monitoring. Proceedings of, GHGT-14 21–24 October.
Willis, B.J., Bhattacharya, J.P., Gabel, S.L., White, C.D., 1999. Architecture of a tide-influenced delta in the Frontier Formation of central Wyoming, USA. Sedimentology 46, 667–688.

Chapter 5: Thesis Conclusions

The four thesis-related publications (published or submitted to peer reviewed technical journals) form a body of work that describes a workflow of site characterisation from project conception to maturity. Understanding subsurface fluid behavior at a CO_2 storage site draws on the same methods that have been developed in the hydrocarbon exploration industry, but places a particular emphasis on characterising injectivity, effects of vertical permeability, large-scale hydrodynamics, geochemical/geomechanical interactions, and long-term containment. Only a few case studies from around the world have fully documented their workflows in the public domain as "best Practice" site characterisation for CO_2 storage sites. All advocate a multidisciplinary approach bringing together available data in order to identify potential risks. This in turn identifies where more data needs to be gathered in order to reduce uncertainties. When this is not practical, characterisation depends heavily on analogues and multi-case scenario modelling to perform sensitivity analysis and provide ranges rather than a definitive answer to questions surrounding injection rates, migration times, total capacity, and trapping. What defines an adequate or "fit for purpose" site assessment will become evident as more and more practical examples like this can be examined.

This thesis also compares geological characterisation approaches and data sets for both a depleted gas field and a saline aquifer, and related seals, with a special focus on depositional facies heterogeneity. This thesis has shown that the level of characterisation needs to be risk appropriate, as well as source and sink appropriate. In other words, how much CO_2 is intended to be stored, and whether it will likely migrate to sensitive areas, for example a fault (real), or lease boundary (imposed). Furthermore, where the intrinsic uncertainties in reservoir heterogeneity remain, the impacts and sensitivities can be addressed by a series of geo-cellular models. In the case of saline aquifer storage, it is more challenging as these characteristics must be addressed over large areas often with very little data available.

The suitability of the lower Paaratte Formation was investigated for the purposes of non-structural trapping and monitoring in a saline aquifer. This work has provided the most comprehensive set of good quality core and formation evaluation data ever acquired in the Otway Basin for this formation. This has improved the characterisation of reservoir and seal quality distribution over the targeted injection locations, and the interpretations have provided new insights as to the regional structural setting, sequence stratigraphy, sedimentology and paleo-depositional environment for the formation. This was only possible due to the success of a targeted data acquisition program and integration of many specialist disciplines and analysis.

I have shown in my research that characterisation of saline aquifers, compared to depleted fields, is substantially involved. There is requirement for a higher degree of assurance that CO_2 will be contained. In an “open” system that relies on non-structural trapping mechanisms to stabilise and dissolve the plume over time, there is somewhat higher uncertainty, than in a system where a structural or stratigraphic trap has been well described. The potential for migration in saline aquifers are what makes them attractive in the sense of kinetics for residual and dissolution and mineral trapping. The dynamics dictate that the plume will encounter water saturated rock along its pathway leading to the trapping. Conversely, this leads to a requirement that models and area of investigation are substantially larger than that of a depleted field.

Pre-injection well tests afford the opportunity to reduce risk and uncertainty prior to full scale injection. Endpoint saturations and relative permeability data gathered in the laboratory can be compared to results in the perforation zone. The analysis of CO_2 saturation and capillary trapping interpretation from the geophysical logs at the stage 2 injection well provided field evidence that the proportion of the initial saturation that gets trapped is mostly a function of the initial maximum saturation that is achieved. However, geological reservoir anisotropy in relation to the dominant flow direction of the CO_2 can also impact trapping. Consequently understanding vertical permeability effects and the distribution of low permeability barriers can increase the residual trapping estimation more broadly.

In the case study presented here, the well test results substantiated the relative permeability results from the core flood tests which allowed for the next stage of injection to proceed with added certainty. However, if they were widely different, then it may have triggered a decision to revise the simulations or go back and acquire more data. This is an example of how a real project deals with real decisions made on the basis of the characterisation.

Finally, post-injection monitoring data have been invaluable for model calibration and validation. This study has integrated a number of plume monitoring methodologies (pressure, time-lapse seismic, well logs) for post CO_2 injection reservoir characterisation, which demonstrates the importance of ongoing iterative modelling to reduce risk. The injection of CO_2 can "illuminate the geology", and reduce prior uncertainties about the geological structure and the distribution of permeability. This post-injection characterisation can be applied to refine the static and dynamic models for other field projects, and in turn adds assurance about the long-term stabilization of a CO_2 plume.

Future work

The cost involved in CCS is one of the main obstacles cited for preventing commercial deployment. Future work on this topic will no-doubt lean towards exploring cheaper methods of getting the same value of information. At the Otway site Stage 3 is underway. In the current drilling campaign, there is a plan to substitute core and expensive analysis with bore-hole image logs. This is an example of doing more with less.

Other work that will be of interest is to better understand the definitions of model conformance. The question remains "how good is good enough" at various stages of a project, and what will be the requirement for transfer of liability at the end.

Chapter 6: Additional Supporting Publications

(chapters in books)

6.1 Supporting publication 1: Monitoring CO_2 Saturation from Time-Lapse Pulsed Neutron and Cased-Hole Resistivity Logs.

Chapter 34 in: Carbon Dioxide Capture for Storage in Deep Geological Formations, Volume 4, Karle F. Gerdes (Editor.) 2014 CPL Press and BP.

Authors: Tess Dance[1] and A. Datey[2]

[1]CO2CRC/CSIRO, Earth Science and Resource Engineering, PO Box 1130, Bentley, W.A., 6102, Australia, email: tess.dance@csiro.au.

[2]Schlumberger Data Services, Melbourne, Victoria, Australia.

Statement of Authorship

Title of Paper	Monitoring CO_2 Saturation from Time-Lapse Pulsed Neutron and Cased-Hole Resistivity Logs.
Publication Status	☑ Published ☐ Accepted for Publication ☐ Submitted for Publication ☐ Unpublished and Unsubmitted work written in manuscript style
Publication Details	Book Chapter 34 in: Carbon Dioxide Capture for Storage in Deep Geological Formations, Volume 4, Karle F. Gerdes (Editor.) 2014 CPL Press and BP.

Principal Author

Name of Principal Author (Candidate)	Tess Dance		
Contribution to the Paper	Prepared the manuscript, provided geological context, interpretation of the final results, evaluated the technique in the application to CO_2 monitoring, corresponding author, revision, and corrections.		
Overall percentage (%)	75%		
Certification:	This paper reports on original research I conducted during the period of my Higher Degree by Research candidature and is not subject to any obligations or contractual agreements with a third party that would constrain its inclusion in this thesis. I am the primary author of this paper.		
Signature		Date	

Co-Author Contributions

By signing the Statement of Authorship, each author certifies that:

i. the candidate's stated contribution to the publication is accurate (as detailed above);
ii. permission is granted for the candidate in include the publication in the thesis; and
iii. the sum of all co-author contributions is equal to 100% less the candidate's stated contribution.

Name of Co-Author	Ashish Datey (Schlumberger)		
Contribution to the Paper	25% Interpretation of raw data and production of saturation log figures, as well as provided expert petrophysical advice.		
Signature		Date	07-FEB-2018

Chapter 34

MONITORING CO_2 SATURATION FROM TIME-LAPSE PULSED NEUTRON AND CASED-HOLE RESISTIVITY LOGS

Tess Dance[1] and A. Datey[2]
[1]CO2CRC/CSIRO, Earth Science and Resource Engineering, PO Box 1130, Bentley, W.A., 6102, Australia, email: tess.dance@csiro.au.
[2]Schlumberger Data Services, Melbourne, Victoria, Australia.

ABSTRACT: Time-lapse well logging has long been a valuable petroleum reservoir management technique for monitoring relative changes in near-well bore hydrocarbons and formation fluid. As interest grows in the monitoring and accounting of Carbon Dioxide (CO_2) for enhanced recovery and sequestration, techniques such as pulsed neutron and cased-hole resistivity logging have been put to the test in the quantitative evaluation of CO_2. Despite this being beyond the original design purpose of the tools, and a lack of calibration specific to CO_2 injection conditions, results from demonstration projects and storage sites around the world have shown promise. In this chapter a case study is presented from the CO2CRC Otway project, Australia, where time-lapse well logging was applied to monitoring of CO_2 storage in a depleted gas field. Not all of the interpreted products for the quantitative characterisation of CO_2 saturation were as definitive as hoped. This was due to a variety of factors related to timing of logging runs, low salinity of the formation water, high mud filtrate invasion, the presence of CO_2 inside the borehole, and existing residual hydrocarbons in the reservoir. Nevertheless, the more reliable log outputs were evaluated and corrected accordingly in order to produce a semi-quantitative evaluation of saturation post-injection. The results were used to verify that the CO_2 plume is contained above the structural spill point of the storage complex. The lessons learned from Otway show that these logging techniques can be used effectively as part of a monitoring portfolio at CO_2 storage sites provided the execution is carefully controlled and variables are well understood.

KEYWORDS: Time-lapse monitoring; carbon storage; pulsed neutron logging; cased-hole resistivity; residual CO_2 saturation; CO2CRC Otway project.

INTRODUCTION

Time-lapse wireline logging methods, that are standard practice for petroleum field development in order to locate and manage stranded resources, are routinely applied to monitoring of CO_2 and play a vital role in monitoring injection profiles, detecting gas or water fronts, and for fine-tuning formation evaluations. Despite having a limited depth of penetration, well logs provide a high vertical resolution profile (<0.2 m) of the formation. This data can then be used to calibrate between the finer scale direct measurements from cores and fluid samples, and the coarser scale geophysical and pressure data from the reservoir. Thus fluid saturation logs are seen as essential in the monitoring portfolio at CO_2 storage sites for regulatory conformance, CO_2 accounting, model validation, and storage integrity assurance [1].

Two examples of logging methods that are commonly used for this purpose are: i) cased-hole resistivity which differentiates hydrocarbons from formation water on the basis of changes in resistivity [2]; and ii) pulsed neutron logging which is used to record the carbon-oxygen ratio and Sigma log (denoted by Σ), from which formation fluids may be distinguished on the basis of how thermal neutrons interact with various atoms in the formation [3, 4].

These logging methods have proven successful in well based monitoring of CO_2 saturation at a number of storage sites around the world [1, 5, 6]. For example, at the Frio Brine Project in Texas, it was demonstrated that time-lapse pulsed neutron logging is an appropriate method to monitor near-well CO_2 saturation changes in highly saline reservoirs due to a large sigma (Σ) contrast between the saline formation waters (high Σ) and the injected CO_2 (low Σ) [7, 8]. At the Nagaoka site in Japan, it was shown that by combining time-lapse induction and pulsed neutron logging techniques [9, 10], with time-lapse cross-well seismic tomography [11], it is possible to observe timing of breakthrough and migration direction of a plume over time [12], which in turn provides indication of the dissolution of the injected plume, displacement of water, and residual trapping potential within the reservoir [13]. At the Cranfield site in Mississippi, both techniques were used in an integrated monitoring study which revealed complex fluid flow in the sub-surface [14]; and at Svelvik Ridge Norway, down-hole electrical resistivity methods were used to monitor a controlled leak experiment [15]. Pulsed neutron logging has also recently been applied to monitor CO_2 flooding during an enhanced oil recovery project in the

Middle East [5], and assessed in the context of enhanced gas recovery at the Altmark site in Germany [16].

The examples listed above uphold these methods as promising technologies for CO_2 monitoring at field scale. However, a gap in the literature exists surrounding the pitfalls and uncertainty that may be encountered during execution and interpretation of the data products when acquired under less than ideal conditions. This chapter presents a case study from the CO2CRC Otway site, Australia, where time-lapse logging was conducted during stage 1 of the project. Specifically this stage was aimed at demonstrating geological storage of over 65,000 tonne of CO_2 rich gas in an onshore depleted natural gas field and testing an array of conventional and novel monitoring techniques [17-19]. The post-injection conditions were logged at the injection well with a Slim Cased-hole Formation Resistivity Tool (SFRT) 14 months after injection ceased. The results were compared to the open-hole laterolog data to assess any changes in resistivity that may be attributed to CO_2. Pulsed neutron logging with a Reservoir Saturation Tool (RST) was also run (using Inelastic Capture and Sigma mode) 23 months after injection ceased and compared to a base line RST acquired shortly after the well was cased. The aim of this paper is to document the complications that arose during the quantitative interpretation of CO_2 saturation from these methods. The lessons learned can be applied to improve the design of similar logging programs and interpretation workflows for CO_2 storage monitoring in time-lapse mode.

OVERVIEW OF LOGGING TOOLS USED AT OTWAY

The following provides details of the tools specific to the Otway Project monitoring. To this end the authors feel it is necessary to use vendor specific language. However, it must be acknowledged that there are equivalent tools available through other service providers that work on similar principles.

Cased-hole resistivity with the SFRT

The Cased-hole Formation Resistivity tool (CHFR) provides deep-reading measurements for an estimate of the formation resistivity behind steel casing. The slim-hole version of the formation resistivity tool (SFRT) fits in casing as small in diameter as 2 7/8 inches (~73 mm). An overview of the development of the cased-hole logging tools can be found in Ferraris, [20]. In essence the tools work by inducing a current into the casing, which acts as a focusing electrode to force the current deep into the formation, past the zone of invasion. This current returns to a surface electrode. Most of the injected current will flow back to the surface within the casing thickness but a small fraction of it will leak into the formation. At a given depth the amount of leaking current is proportional to the formation/fluid conductivity. Some of the limitations of the tool as outlined in Aulia et al. [21], include loss of data in areas of the casing collars, or due to scale build up which prevents good electrical contact between electrodes and the casing. Similarly, heavy casing or tubing can limit its use. However, a significant advantage of the SFRT is the depth of investigation which is between 2 and 10 m. This is more than an order of magnitude deeper than nuclear measurements and provides reliable results from beyond the invaded zone. Vertical resolution is a function of voltage spacing and station reading and is in the order of 1.2 m for bedding features, and fluid contacts can be identified +/- ~30 cm. In principal the SFRT measurement is comparable to that recorded by a laterolog, for example the HALS (or High resolution Azimuthal Laterolog Sonde) which passes current into the formation through electrodes that are in contact with the open bore-hole. Thus interpretations of formation saturation based on resistivity changes (e.g. high resistivity gas replacing low resistivity formation brine) often use the open-hole logs as a baseline.

Pulsed neutron logging with the RST

Pulsed neutron logging tools work by emitting bursts, or pulses, of neutrons into the formation. As the neutrons interact with various elements in the borehole, rock matrix and formation fluids, gamma rays are generated that are measured by the tool. These gamma rays are recorded and analysed to interpret fluid saturation. The RST (reservoir saturation tool) can operate in both Sigma and inelastic capture mode. Sigma (Σ) is the neutron capture cross section recorded with a "dual burst" pattern: short burst of neutrons followed by a long burst. The short burst is influenced by properties of the near well environment, and the long burst provides information from the formation. The depth of investigation is approximately 0.25 m. The neutron capture cross section is heavily influenced by chlorine and hydrogen; hence the response is largely determined by salinity and molecules like methane and water that contain hydrogen. Examples of the application of pulsed neutron capture logging for reservoir monitoring are provided by Morris et al. [22]. Inelastic capture measurements are made using a single long burst, and period where the generator is turned off. The gamma-ray energy resulting from inelastic scattering and capture is used to produce a spectrum from which the carbon-oxygen ratio (C:O) can be derived. Although it is less accurate and depth of penetration is limited to ~ 0.15 m, this method has the advantage of being independent of formation salinity.

As part of the CO_2 Capture Project 2, a series of experiments were conducted at Schlumberger's Environmental Effects Calibration Facility to evaluate the RST's ability to detect CO_2 in a sandstone formation under controlled conditions [23]. It was concluded that sigma mode measurements show the best promise when the formation is saturated with highly saline brine prior to injection. This is because of the large capture cross-section difference between CO_2 and brine. However, when the formation water is relatively fresh (<20-50 ppk) the difference between the sigma of CO_2 and formation water is not adequate. To compute saturation from the C:O ratio method requires calibration database in the same completion, formation and borehole fluids as the acquired log. Since such a database does not exist for CO_2 in formation and borehole means that the inelastic-capture measurement should only be used in qualitative interpretations in order to provide a method for detecting CO_2 rather than estimate saturation or quantify changes.

An ancillary measurement of the RST is thermal decay porosity (TPHI). TPHI is a measure of the hydrogen index (HI) obtained from the ratio of the "near to far" detector capture count rates. Changes in the HI can be used to interpret changes in saturation, for example CO_2 with HI ≈ 0 replacing water with HI ≈ 1. The large difference between the HI of formation water and CO_2 makes TPHI an attractive measurement to consider especially in low salinity formations as the difference between Sigma of fresh formation water and CO_2 is not significant. Complications can arise, however, in the case where the tool is surrounded by CO_2 in the borehole, logging injection wells for example. Furthermore, TPHI is not a calibrated porosity and the output from the various passes needs to be matched over intervals where no change of formation fluids is expected. For this purpose shales or highly cemented sandstones above and below the reservoir, can serve as useful lithological calibration markers.

When compared to the SFRT outlined above, the RST has significant limitation in the depth of investigation. This means that measurements may be completely invalid in formations with high mud filtrate invasion. However, the tool can provide a detailed fluid saturation profile along the borehole, with approximately 0.15 m vertical resolution– i.e. measurements are taken at 15 cm depth intervals (Adolph et al., 1994). Also RST measurements can be recorded through dual casing and tubing strings while the SRFT can only be recorded through a single casing string.

MONITORING AT OTWAY

Project background and aims

The CO2CRC Otway project, stage 1, was conducted in the depleted Naylor gas field, located in the onshore Otway Basin, south western Victoria, Australia. Over the course of 18 months, between March 2008 and August 2009, 65,445 tonnes of CO_2 rich gas with a composition of 80% CO_2 / 20% CH_4 mole fraction was injected into the field. The existing production well, Naylor-1, was recompleted for the purpose of monitoring and a new well, CRC-1, was drilled down-dip for use as an injector targeting the 25 m thick Waarre C Formation reservoir (Figure 1). The reservoir comprises heterolithic sandstone and mudstone. The porosity of the reservoir sandstones is between 18 % and 29 %, and permeability is in the order of 1.5 Darcy. Salinity of the formation water is approximately 20 ppk TDS (total dissolved solids), and pressure and temperature at the beginning of injection was 85 ^{o}C and 17.4 MPa respectively. Containment at the field is via mudstone seal juxtaposed to reservoir in a three way structural dip closure providing a spill point at a depth of around 2015 m below mean sea level. For containment assurance it is essential the injected CO_2 does not exceed the spill point which corresponds to the pre-production gas water contact. At the time of injection residual methane (average 19 % S_{gr}) was present throughout the storage reservoir as well as small gas cap at the top of the structure (Fig 1).

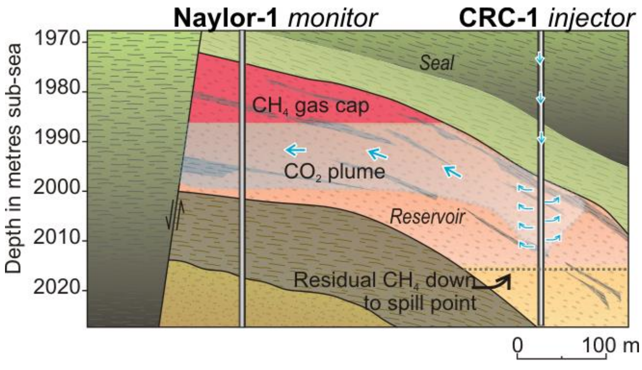


Figure 1. Diagrammatic subsurface cross-section of CO_2 storage at the Naylor Field.

An array of monitoring techniques was evaluated as part of the project including a comprehensive down-hole geochemical program that employed a U-tube fluid sampling system [24, 25]. These were deployed at the Naylor-1 well along with several down-hole pressure and temperature gauges, geophones and sensors in order to observe the rate of CO_2 migration from the injector up-dip to the monitoring well and the dynamic chemical changes that occur as the plume filled the structure. For a detailed background and overview of the project see Cook [26]. Further details of the project's operation and planning can be found in Sharma et al. [27], site characterisation is in Dance [28], a technical overview and initial results of the monitoring in Underschultz et al. [18], and overall research implications and impacts in Jenkins et al. [19].

Time-Lapse well logging

The permanent installations in the Naylor-1 monitoring well meant it was prohibitive to access the borehole for wire line logging at any stage of the experiment. Instead the CRC-1 injector was used for this purpose. CRC-1 is a steel cased, 4½ inch (11.43 cm), vertical monobore, perforated over 11 meters in the top half of the target reservoir. At four stages of the project wireline logs were acquired at CRC-1. A summary of the timeline of logging and other key events at the well is given in table 1. Baseline for the resistivity monitoring was provided by the HALS laterologs acquired in the open hole soon after drilling. Six months later baseline RST in sigma and inelastic capture modes were acquired in the cased-hole. The well was perforated and a well injection test was attempted using water with Potassium Chloride (KCl) added to prevent the swelling of clays in the reservoir. The test revealed blocked perforations so the perforations were extended a few meters down and the formation water allowed to back flow into the well. The well test was not repeated after this, nevertheless it is acceptable to assume during this stage fluid salinity changes occurred in the near-well bore region due to the saline injection fluid and then from the "fresher" formation water flushing the mud invasion zone. Unfortunately RST or SFRT logging was not run after this critical step to observe the effects of the exchange of fluids on formation salinity, radioactivity response and porosity in the invaded zone. Furthermore, this would have provided a more appropriate baseline of logs in the cased-hole prior to injection.

Post injection logging was performed first with the SFRT 14 months after injection ceased. Then the RST monitoring logs were run 9 months after that (i.e. nearly two years after the end of injection) (Figures 2 & 3).

Table 1. CRC-1 logging timeline.

Logging stage	Date	event
	Feb 2007	Well spudded
Baseline	March 2007	Open hole well logs acquired
Baseline	Sept 2007	RST: sigma & inelastic capture logs run in cased-hole
	Dec 2007	Well perforated & well test attempted with KCl brine
	Feb 2008	Well perforations extended & well test not repeated
	March 2008 to Aug 2009	**CO_2 rich gas injected**
Monitoring	October 2010	Slim cased-hole formation log (SFRT) acquired
Monitoring	July 2011	RST: Sigma & inelastic capture logs acquired

.

Figure 2. Logging of the Otway Project CRC-1 injection well with RST in July 2011.

Figure 3. Close up view of the RST logging at the well head.

Predicted response

The two measurements that were used to invert for saturation were Sigma (Σ) and TPHI. In order to estimate the sensitivity margin of each, the predicted change in for the specific reservoir conditions was computed using a commercial nuclear parameter code (SNUPAR Schlumberger's Nuclear Parameter Code [29]). Figure 4 shows the estimated change in Σ and Figure 5 is the change in THPI, as when the mixture fluid (80% CO2 and 20% CH4 fluid at formation temperature and pressure) replaces water for a clastic sandstone with 18 % porosity and formation water salinity around 20000 mg/L TDS (20 ppk). The quoted accuracy for Σ logs from the RST is 1 capture units (1 cu). Although salinity in the formation is low, the change in Σ when CO_2 (with Σ of ~0.03 cu) replaces formation water was expected to be visible on the logs compared to the precision of the measurement. The change in TPHI, is less affected by salinity and therefore this output from the tool is considered more reliable for CO_2 saturation interpretation.

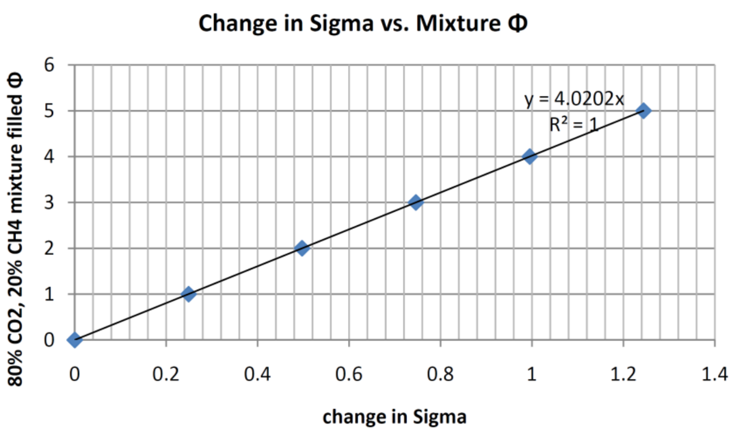


Figure 4. The estimated change in Sigma with CO_2 saturation

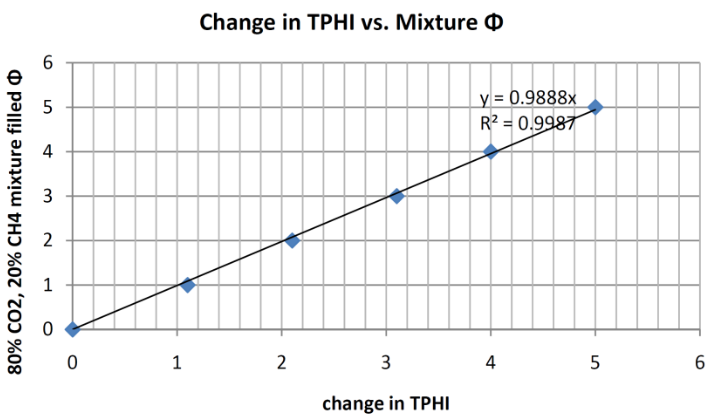


Figure 5. The estimated change in TPHI when the CO_2 rich mixture replaces formation water.

RESULTS AND INTERPRETATION

A composite display of all logging outputs is shown in Figure 6 (depth is in meters measured from rotary table). The Waarre C Formation is the interval from 2052 m to 2082 m. The interval 2052 m to 2062 m represents the perforated sand across which the CO_2 rich gas was injected. CO_2 saturation is quantitatively interpreted from the sigma logs and the thermal decay porosity logs (TPHI). Due to low salinity of the formation brine (~20 ppk), the change in Σ is not significant and can be prone to statistical errors. Thus TPHI is the preferred inversion method. These interpretations, as well as the results from each of the other logging methods, are discussed in more detail below.

Gamma ray

Four sets of Gamma Ray (GR) logs were recorded:

1. - GR open hole: recorded with open hole Platform Express logs.
2. - GR preInj RST: recorded in cased-hole with RST before the injection.
3. - GR postInj SFRT: recorded in cased-hole with SFRT after the injection.
4. - GR postInj RST: recorded in cased-hole with RST after the injection.

In the first track in Figure 6 the open hole GR is presented from scale 0-250 gAPI and cased-hole GRs are presented from scale 0-150 gAPI, so that the open hole and cased-hole GR log can be compared when presented on the same track. The log indicates that GR open hole, pre-injection and post-injection match across all intervals except over 2052 m to 2064 m and 2071 m to 2078 m which corresponds to the permeable sandstones. The GR from post-injection acquisition for both these intervals are higher than the GR from pre-injection acquisition. A possible explanation is that the potassium in the KCl mud cake has precipitated out and increased radioactivity over this interval [30]. Another source of increased gamma can be from radioactive scale precipitation on the well casing [31].. However, without independent verification, no reasonable interpretation is offered for the source of increased GR at CRC-1.

Resistivity

Results of the resistivity measurements are shown in the second track in Figure 6. The pre-injection, open hole logs comprise laterolog (HART), deep resistivity (HLLD) and shallow (HLLS). The post-injection SFRT logs (RTCH_K) were calibrated to the open hole logs over shale markers. The zones where cased-hole resistivity is greater than the open hole measurements are shaded yellow and are apparent throughout the formation (from 2055 m to 2083 m). In principal this difference may be used to compute the change in water saturation (S_w) between the timing of the logs. The assumption being the increased resistivity is attributed to the resistive CO_2 rich gas displacing the conductive formation water. However, the observations did not match the expected response over some intervals. For example, the greatest change in resistivity was in the sands below the perforations. It appeared from the interpretation that S_w was reduced from nearly 100% to 60-70% and the implication was that CO_2 had displaced the water. Furthermore, increases in resistivity were also observed in sandstone beds several hundreds of meters above the injection zone. From the simulation studies, it was highly unlikely CO_2 would migrate to sandstones beneath the perforations and even less likely to be above the seal. Before jumping to the conclusion that CO_2 has displaced water in the overlying aquifers, thus implying there is a breach of containment, we must consider the multiple phenomenon that may be attributed to the source of increased resistivity in the time between the open hole logs and the post-injection logs.

Firstly, during drilling, the low salinity *in situ* formation brine was highly invaded and mixed with saline fluid from the KCl drill mud. This was intentional as the well was drilled slightly overbalanced to improve well bore stability. The contrast is even more pronounced in the relatively fresh Paaratte Formation above that has salinity of 2-8 ppk and permeability in the order of 2 Darcy. Evidence from core plug analysis shows there was substantial invasion, as well as the failed well injectivity test in an otherwise highly permeable sandstone also supports the interpretation that mud invasion was high. Furthermore, the test itself was performed with KCl brine after the open hole logging and may or may not have contributed to lowering the resistivity. Unfortunately, due to poor injectivity, it is unknown as to what degree the well test fluids entered the formation. However, it is certain that the process of back flowing water from the formation into the well at this time would result in additional changes to the resistivity response. The implication is that the low conductivity "fresh" formation fluid flushed the high conductivity KCl solution from the near well region. Therefore using the open-hole laterologs as a baseline would artificially set the starting point for resistivity too low in the region of the perforations resulting in an overestimation of gas saturation in this zone. What is puzzling is that the sands below the perforated interval show a greater difference in resistivity than the sandstones that actually received CO_2 during injection. As a result the resistivity logs are inconclusive in determining reservoir saturation changes.

The lesson here is to log a pre-injection cased-hole SFRT measurement and compare it to the post-injection cased-hole SFRT measurement. This will eliminate any interpretation anomalies and add assurance that any resistivity changes would be a result of injection. When acquiring SFRT some bad measurement points will be unavoidable due to poor electrode contact, casing joints, mud-cake in the annulus, non-conductive cement. This can also result in a mismatch between the open-hole data and cased-hole data. The addition of a pre-injection cased-hole baseline SFRT measurement would reduce these uncertainties in the subsequent interpretation.

Capture cross-section (Σ)

The logs from the RST run in Σ mode are used to compute saturation (track 4 in Figure 6). The SIGM postInj is less than SIGM preInj across the interval from 2052 m to 2064 m adjacent to the perforations. This decrease is attributed to the injected CO_2 which has low capture cross section replacing water with higher capture cross section across this zone. The interpreted CO_2 saturation is between 10-30 pu. Σ is unchanged over the rest of the interval. Due to the low salinity of the formation brine, the Σ response is not very sensitive to the change in water / CO_2 saturation

Thermal Decay Porosity (TPHI)

Thermal Decay Porosity is one of products of RST Sigma log acquisition. Two sets of RST TPHI were recorded (Figure 6, tracks 6 & 7).

1. TPHI preInj: recorded in cased-hole with RST before the Injection
2. TPHI postInj: recorded in cased-hole with RST after the Injection

TPHI is not a calibrated porosity and the TPHI from the two passes need to be matched over the intervals where no change of formation fluids is expected. Thus a bulk shift of -0.01pu is applied to TPHI postInj before comparing it to TPHI preInj. The TPHI postInj is less than TPHI preInj across the perforated interval 2052 m to 2064 m and is largely unchanged over rest of the interval. This indicates that CO_2 which has Hydrogen Index ≈ 0 has replaced water with Hydrogen Index ≈ 1, across the interval 2052 m to 2064 m. The TPHI logs were used to compute CO_2 saturation and at the time of logging was in the order of 15-20 pu. The estimated structural spill point for the Naylor field at a minimum depth of ~2015 m TDV SS, translates to ~2066 m MD in CRC-1. An important observation is that no changes can be observed in the TPHI logs below the lowest perforation at 2064 m, adding assurance the injected gas has not filled downwards to the estimated structural spill point of the reservoir.

At the time of this study, the RST was not calibrated for operating with CO_2 in well bores. At CRC-1 the post-injection logs were acquired nearly two years after the end of injection. However, it is likely that CO_2 was still present in the borehole and annulus. There are available methods that can account for this effect during the analysis. Pressure information is first used to identify the various well bore fluid interfaces. Then a shift applied to the TPHI log over the intervals where CO_2 was in the borehole to account for the changed response in the near-tool region. Similarly, for the Σ output processing, the Thermal Decay Time-Like processing (SIGM TDTL) can be used for evaluation as its computation is less affected by CO_2 in the wellbore than the standard processing for Σ. However, these adjustments bring with them an additional layer of uncertainty.

The Carbon:Oxygen logs

Two sets of RST Inelastic Capture (IC) log were recorded.

1. - IC preInj: recorded in cased-hole with RST before the Injection
2. - IC postInj: recorded in cased-hole with RST after the Injection

The Far Carbon to Oxygen (C:O) ratio was computed from the log. FCOR: CO ratio is computed using spectral data from far detector. FCOR has good accuracy but has poor statistics. Acquiring reasonable statistics for FCOR would have required equivalent logging speed of ~ 6 ft/hr which is currently not possible. FWCO: CO ratio is computed using windows method from the far detector. This method obtains the ratio of C:O by placing broad windows or "bins" over the carbon and oxygen spectral peaks [3]. The windows method has good statistics and therefore is more precise but is often less accurate. Hence the FWCO from the two passes need to be matched over the intervals where no change of formation fluids is expected. A shift of +0.05 units is applied to FWCO postInj before comparing it to FWCO preInj. Comparing the pre-Inj and post-Inj FWCO clearly indicates CO_2 replacing formation water across the perforated interval. The FWCO logs are picking up the increased levels of CO_2 at the injection interval (and above) 2052 m to 2063 m, and it is interpreted that this is a result the injected gas. When the RST Inelastic Capture logs were evaluated in Schlumberger's Environmental Effects Calibration Facility for CO_2 in formation, the response was difficult to model [28]. Thus FCOR or FWCO cannot yet be converted to CO_2 saturation but can be used qualitatively. A specific method of interpreting the carbon isotope data at Otway with CO_2 in the borehole is outlined in Quinlan et al. [6]. The inelastic capture ratio count rates (IRAT), which characterise near well and bore hole fluids, is used to correct for late capture ratios (TRAT), which see deeper in the formation.

Discussion

Current petrophysical logging techniques do not provide a direct measurement of the property we ultimately want to solve for (i.e. saturation). Tools measure the physical response from various elements and one must make assumptions to derive the end output. One complication for quantitative interpretation of the logs from the Otway site is the presence of residual methane in the baseline data. Prior to injection, the formation fluid is a mixture of water and gas. In all likelihood the injection fluid could be displacing existing water and gas from the formation. The assumption for the resistivity, sigma and TPHI interpretation is that the injection fluid is only displacing water. One measurement is being made with the RST tool (Sigma and TPHI are non-unique responses). One measurement can solve of only one variable. Thus change in volume of only one fluid can be computed when comparing the baseline measurement and post-Injection measurement. If a change in Sigma or TPHI response is due to a change in fluid salinity, CH_4 volume and CO_2 volume, a unique solution cannot be determined. The assumption in the workflow is that only CO_2 volume has changed. TPHI logs combined with core corrected/gas corrected NMR porosity logs, coupled with the density logs may be used as a combination to identify the methane in the reservoir.

In time-lapse mode, the interpretations are further complicated by physical or geochemical changes that may have occurred during well operations. These include changes as a result of casing, patches, collars, the drill mud itself, well test fluids, and well bore scale. Using oil based muds will minimise the issues associated with induced apparent salinity changes. But in order to record the most accurate baseline characterisation, logs would need to be acquired at each stage of the well work over up to the point of injection.

Similarly, post-injection logging should be properly timed to optimise results. At CRC-1 the post-injection monitoring logs were acquired long after injection stopped (i.e. >12 months for resistivity, and nearly 2 years for the RST). Simulation results predicted that the free gas would migrate up-dip from the injection well, and a strong aquifer drive would enhance the imbibition process leaving only residually trapped CO_2 behind. Dissolution would further reduce the percentage of CO_2 remaining. This coupled with the difficulty that there was already 10-20% residual methane in the reservoir at the time of the baseline logs, complicates the log interpretation further. With this in mind, timing of the post-injection monitoring as soon as feasible after injection may improve the likelihood of detecting higher saturation and as a consequence enhance the contrast between logs.

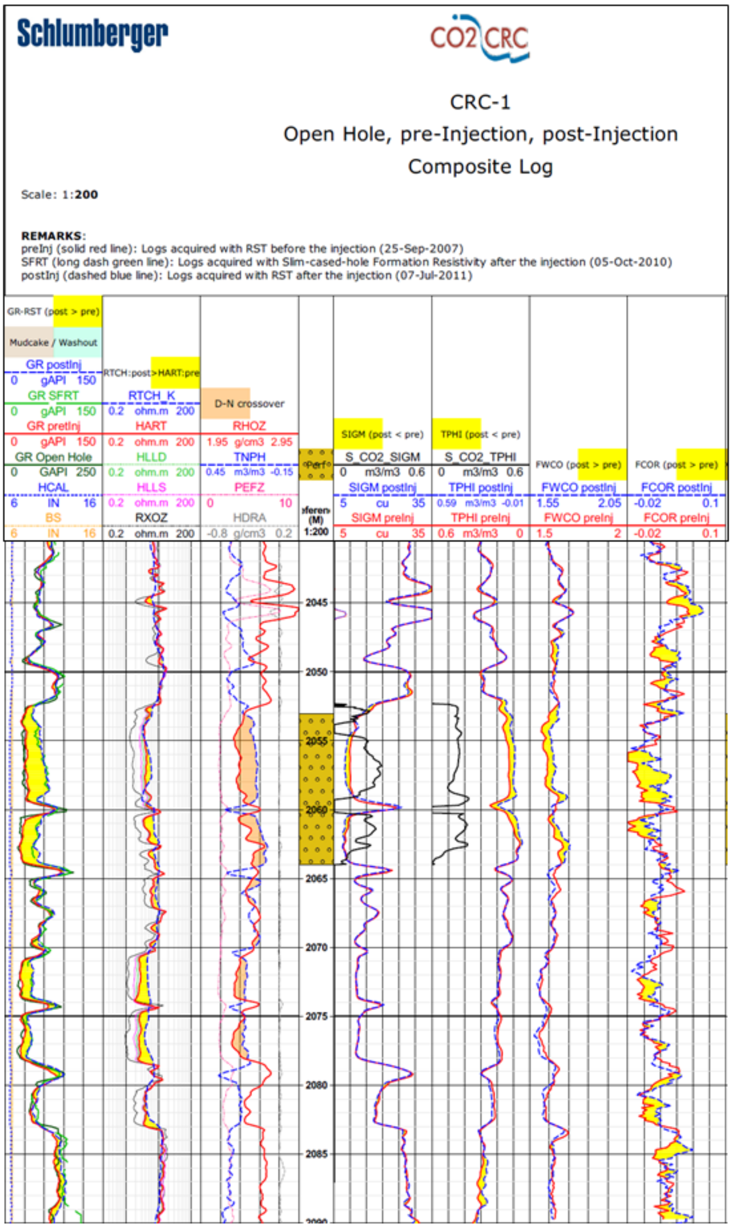


Figure 6: the integrated display of all logging outputs acquired in the Waarre C Formation (2052 m to 2082 m). From left to right: gamma ray; resistivity from the open hole (HART, HLLD - deep, and HLLS - shallow) and the cased-hole resistivity (RTCH_K); the density-neutron cross over used as a proxy for lithology; the perforated section; the derivation of CO_2 saturation from Sigma logs; and from the Thermal Decay Porosity (TPHI) logs; the carbon-oxygen ratio computed using the windows method (FWCO); and from the spectral data from the far detector (FCOR).

CONCLUSIONS

Monitoring CO_2 saturation from time-lapse pulsed neutron and cased-hole resistivity logs can deliver useful qualitative information that can be helpful in managing the CO_2 reservoir. At the CO2CRC Otway Project all logging products were cross-evaluated to detect petrophysical changes that were attributed to the injected gas. However, the timing of logs at Otway and conditions in which they were acquired were not ideal for reliable quantitative interpretation of CO_2 saturation. . The summary of findings include:

1. Although the reduced conductivity in the zone below the perforations is unexplained, both the Sigma and TPHI logs, as well as the C:O logs independently confirm that injected gas did

not encroach the sands below the perforations, which was useful for containment assurance and may encourage further use of this combination for cross validation purposes.

2. The gamma ray and the resistivity from the SFRT are prone to unexplainable uncertainties which in hindsight may have been avoided if logs were run after every event. A baseline log run is highly recommended. **The baseline log must be as representative as possible of pre-injection conditions with no other variables changing. Open hole logs are not a good quantitative baseline for cased hole logs.**

3. In order for the usage of RST to be optimised for CO_2 related operations, the tool needs to be fully characterised for CO_2 conditions.
4. This study has highlighted a few issues in the interpretation workflow that need to be addressed if RST is to be used for CO_2 estimation in depleted fields with mixed fluids. TPHI logs combined with core corrected/gas corrected porosity curve with the density logs can help to account for the methane in the reservoir. This not so critical for saline aquifer storage monitoring which are expected to be more commonly used for CO_2 injection.

5. The timing of logs with respect to well work overs is an important consideration that needs to be made at storage sites using this technology to monitor saturation in CO_2 injection wells. The same complication will not apply when logging in dedicated monitoring bores that are not used for injection.

NOMENCLATURE

PNC = Pulsed neutron capture

SIGM = Neutron capture cross section, cu

TPHI = PNC neutron porosity, pu

TPHI = Thermal neutron porosity

TRAT = Thermal count rate ratio (near/far)

TDT = Thermal Decay Time tool

SIGM TDL = Sigma with TDT-Like processing

Σ = Sigma

cu = Capture cross section units, 10^{-3} cm^{-1}

s.u. = Saturation units

pu = Porosity units

ACKNOWLEDGEMENTS

The authors wish to acknowledge the support given by the CO2 Capture Project for acquiring the valuable logging data at CRC-1 which made this study possible. The CO2CRC acknowledge the funding provided by the Australian government through its CRC program to support the Otway research project. Financial assistance is provided through Australian National Low Emissions Coal Research and Development (ANLEC R&D). ANLEC R&D is supported by Australian Coal Association Low Emissions Technology Limited. Special thanks to Tom McDonald for analysis of the cased-hole resistivity logs. Thanks also to Rajindar Singh, Lincoln Paterson, Tom Daley, and Kevin Dodds for their expert technical input and advice.

REFERENCES

1. Freifeld, B.M., Daley, T.M., Hovorka, S.D., Henninges, J., Underschultz, J., and Sharma, S. (2009). *Recent advances in well-based monitoring of CO_2 sequestration*. Energy Procedia **1**: pp. 2277-2284.

2. Zhou, Q., Julander, D., and Penley, L. (2002). *Experiences with cased-hole resistivity logging for reservoir monitoring*, Society of Petrophysicists and Well-Log Analysts, 8 p.

3. Albertin, I., Darling, H., Mahdavi, M., Plasek, R., Cedeno, I., Hemingway, J., Richter, P., Markley, M., Olesen, J.-R., Roscoe, B., and Zeng, W. (1996). *Many facets of pulsed neutron cased-hole logging.* Oilfield Review. **8**(2): p. 28-41.

4. Adolph, B., Stoller, C., Brady, J., Flaum, C., Melcher, C., Roscoe, B., Vittachi, A., and Schnorr, D. (1994). *Saturation monitoring with the RST reservoir saturation tool.* Oilfield Review. **6**(1): p. 29-39.

5. Al Arayni, F., Obeidi, A., Brahmakulam, J., and Ramamoorthy, R. (2013). *Pulsed-neutron monitoring of the first CO_2 enhanced-oil-recovery pilot in the middle east.* SPE 141490-PA, SPE Reservoir Evaluation & Engineering, **16**(1): p. 72-84.

6. Quinlan, T.M., Sibbit, A.M., Rose, D.A., Brahmakulam, J.V., Zhou, T., Fitzgerald, J.B., and Kimminau, S.J. (2012). *Evaluation of the carbon dioxide response on pulsed neutron logs*, SPE 159448, presented at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, USA, 8-10 October.

7. Sakurai, S., Ramakrishnan, T.S., Boyd, A., Mueller, N., and Hovorka, S. (2006). *Monitoring saturation changes for CO_2 sequestration: Petrophysical support of the Frio Brine pilot experiment.* Petrophysics. **47**(6): p. 483-496.

8. Müller, N., Ramakrishnan, T.S., Boyd, A., and Sakruai, S. (2007). *Time-lapse carbon dioxide monitoring with pulsed neutron logging.* Int. J. Greenhouse Gas Control. **1**(4): p. 456-472.

9. Xue, Z., Tanase, D., and Watanabe, J. (2006). *Estimation of CO_2 saturation from time-lapse CO_2 well logging in an onshore aquifer, Nagaoka, Japan.* Exploration Geophysics. **37**(1): p. 19-29.

10. Nakatsuka, Y., Xue, Z., Garcia, H., and Matsuoka, T. (2010). *Experimental study on CO_2 monitoring and quantification of stored CO_2 in saline formations using resistivity measurements.* International Journal of Greenhouse Gas Control. **4**(2): p. 209-216.

11. Saito, H., Nobuoka, d., Azuma, H., Xue, Z., and Tanase, D. (2006). *Time-lapse crosswell seismic tomography for monitoring injected CO_2 in an onshore aquifer, Nagaoka, Japan.* Exploration Geophysics. **37**: p. 30-36.

12. Mito, S. and Xue, Z. (2011). *Post-injection monitoring of stored CO_2 at the Nagaoka pilot site: 5 years time-lapse well logging results.* Energy Procedia. **4**: p. 3284-3289.

13. Nakajima, T. and Xue, Z. (2013). *Evaluation of CO_2 saturation at Nagaoka pilot-scale injection site derived from the time-lapse well logging data.* Energy Procedia. **37**: p. 4166-4173.

14. Butsch, R., Brown, A.L., Bryans, B., Kolb, C., and Hovorka, S. (2013). *Integration of well-based subsurface monitoring technologies: Lessons learned at SECARB study, Cranfield, MS.* International Journal of Greenhouse Gas Control. **18**: p. 409-420.

15. Denchik, N., Pezard, P.A., Neyens, D., Lofi, J., Gal, F., Girard, J.-F., and Levannier, A. (2014). *Near-surface CO_2 leak detection monitoring from downhole electrical resistivity at the CO_2 field laboratory, Svelvik Ridge (Norway).* International Journal of Greenhouse Gas Control. **28**: p. 275-282.

16. Baumann, G. and Henninges, J. (2012). *Sensitivity study of pulsed neutron-gamma saturation monitoring at the Altmark site in the context of CO_2 storage.* Environmental Earth Sciences. **67**(2): p. 463-471.

17. Dodds, K., Daley, T., Freifeld, B., Urosevic, M., Kepic, A., and Sharma, S. (2009). *Developing a monitoring and verification plan with reference to the Australian Otway CO_2 pilot project.* The Leading Edge. **28**(7): p. 812-818.

18. Underschultz, J., Boreham, C., Dance, T., Stalker, L., Freifeld, B., Kirste, D., and Ennis-King, J. (2011). *CO_2 storage in a depleted gas field: An overview of the CO2CRC Otway Project and initial results.* International Journal of Greenhouse Gas Control. **5**(4): p. 922-932.

19. Jenkins, C.R., Cook, P.J., Ennis-King, J., Undershultz, J., Boreham, C., Dance, T., de Caritat, P., Etheridge, D.M., Freifeld, B.M., Hortle, A., Kirste, D., Paterson, L., Pevzner, R., Schacht, U., Sharma, S., Stalker, L., and Urosevic, M., (2012). *Safe storage and effective monitoring of CO_2 in depleted gas fields.* Proceedings of the National Academy of Sciences. **109**(2): p. E35-E41.

20. Ferraris, P. (2002). *Current affairs.* Middle East & Asia Reservoir Review. **3**: p. 33-45.

21. Aulia, K., Poernomo, B., Richmond, W.C., Wicaksono, A.H., Béguin, P., Benimeli, D., Dubourg, I., Rouault, G., VanderWal, P., and Boyd, A. (2001). *Resistivity behind casing.* Oilfield Review. **13**(1): p. 2-25.

22. Morris, C.W., Morris, F., Quinlan, T.M., and Aswad, T.A. (2005). *Reservoir monitoring with pulsed neutron capture logs*, SPE 93889, presented at the SPE Western Regional Meeting held in Irvine, CA, USA, 30 March - 1 April.

23. Climent, H. (2009). *CO_2 detection - response testing of rst in sandstone formation tank containing CO_2 and water-based fluid.*, in *Carbon dioxide capture for storage in deep geologic formations - results from the CO_2 capture project. Volume 3: Advances in CO_2 capture and storage technology results (2004-2009)*, Editor: L.I. Eide, CPL press.

24. Boreham, C., Underschultz, J., Stalker, L., Kirste, D., Freifeld, B., Jenkins, C., and Ennis-King, J. (2011). *Monitoring of CO_2 storage in a depleted natural gas reservoir: Gas geochemistry from the CO2CRC Otway Project, Australia.* International Journal of Greenhouse Gas Control. **5**(4): p. 139-154.

25. Freifeld, B.M., Trautz, R.C., Kharaka, Y.K., Phelps, T.J., Myer, L.R., Hovorka, S.D., and Collins, D.J. (2005). *The U-Tube; a novel system for acquiring borehole fluid samples from a deep geologic CO_2 sequestration experiment.* J. Geophys. Res. **110**(B10): p. B10203.

26. Cook, P.J.E., (2014). *Geologically storing carbon: Learning from the Otway Project experience.*, P.J.E. Cook, Editor, Wiley CSIRO Publishing: Melbourne. p. 400.

27. Sharma, S., Cook, P., Robinson, S., and Anderson, C. (2007). *Regulatory challenges and managing public perception in planning a geological storage pilot project in Australia.* Int. J. Greenhouse Gas Control. **1**(2): p. 247-252.

28. Dance, T. (2013). *Assessment and geological characterisation of the CO2CRC Otway Project CO_2 storage demonstration site: From prefeasibility to injection.* Marine and Petroleum Geology. **46**: p. 251-269.

29. McKeon, D.C. and Scott, H.D. (1989). *SNUPAR-a nuclear parameter code for nuclear geophysics applications.* Nuclear Science, IEEE Transactions on. **36**(1): p. 1215-1219.

30. Fertl, W.H. and Frost Jr., E. (1982). *Experiences with Natural Gamma Ray Spectral Logging in North America*, SPE 11145, presented at the Society of Petroleum Engineers Annual Technical Conference and Exhibition, 26-29 September, New Orleans, Louisiana.

31. Crabtree, M., Eslinger, D., Fletcher, P., Miller, M., Johnson, A., and King, G. (1999) *Fighting scale—removal and prevention*. Oilfield Review. **11**(3): p. 30-45.

6.2 Supporting publication 2: Characterising the storage site.

Chapter 5 in: "Geologically Storing Carbon: Learning from the Otway Project Experience". Edited by: Peter Cook, CSIRO Publishing, 2014, available at:

http://www.publish.csiro.au/pid/7317.htm#sthash.VzM4yodp.dpuf

Author: Tess Dance.

CO2CRC/CSIRO, Earth Science and Resource Engineering, PO Box 1130, Bentley, W.A., 6102, Australia, email: tess.dance@csiro.au.

5. CHARACTERISING THE STORAGE SITE

5.1 Introduction

Site characterisation is defined by the CO2CRC as *"The collection, analysis, and interpretation of subsurface, surface and atmospheric data (geoscientific, spatial, engineering, social, economic, environmental) and the application of the knowledge to judge, with a degree of confidence, if an identified site will geologically store a specific quantity of CO_2 for a defined period and meet all required health, safety, environmental, and regulatory standards"*. Depleted petroleum reservoirs, such as the Naylor Field, are regarded as desirable CO_2 storage sites, due to the perception that much of the data gathering and characterisation was done in the exploration and development phase of the field's life and that they are proven traps, having held hydrocarbons in the past (Stevens et al. 2000). However, it cannot be assumed that the extent of site characterisation needed for a depleted petroleum reservoir sites will be any less stringent than that needed for any other site when assessing injectivity, capacity and containment of CO_2. A field or structure that was charged naturally with hydrocarbons over perhaps millions of years may not have the same physico-chemical response when injected with CO_2 at high rates over a short space of time. Similarly, the CO_2 storage capacity of depleted oil or gas fields will not necessarily equate to the original volume of gas produced, particularly in reservoirs with strong aquifer drive. Finally the geochemical reaction potential of CO_2, once it is dissolved in water, may compromise seal integrity at a site where the original gas (e.g. methane in the reservoir), had a relatively low reaction potential.

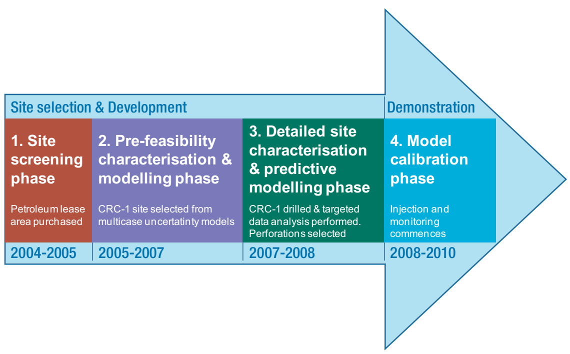


Figure 5.1: Timeline and four phases of site characterisation during site selection, development, and demonstration of the CO2CRC Otway Project.

Table 5.1: Data base comparison before and after targeted acquisition programme.

Initial site screening database	Uncertainty	Updated CO2CRC Database	Improvements
No full hole or side wall cores.	2 depositional models, no palynological or reservoir analyses available.	49 m of core, 24 m through the reservoir.	Conventional and special core analysis provided quantitative data on porosity/permeability. Core logging improved facies model.
Minimum wire-line log suites.	Only basic petrophysics: porosity and water saturation	Sonic, FMI, petrophysical logs, MDT, and injection test.	Stress estimation for mechanical rock strength and fault model. Petrophysical interpretation and fluid saturations incorporated in static model.
No VSP.	Poor understanding of velocity gradient.	Naylor-1 and CRC-1 VSP data and baseline 3D seismic survey.	Full earth velocity model constructed. Confirmation of depth conversion model.
Poorly constrained gas-water contact/local water gradient.	Reserves estimation imprecise and simulation models less constrained.	Naylor-1/CRC-1 RST logs and hydrodynamic data.	Reduced uncertainty in the post-production gas water contact. Improved dynamic modeling history matching.

Whilst the data available for the Naylor depleted gas field was sufficient for CO2CRC to determine the structure had held hydrocarbons within a porous and permeable sandstone, at a depth of about 2000 m overlain by impermeable mud rock and that it might be suitable as a storage site, in many respects the available data could not meet the requirements for a comprehensive CO_2 storage site characterisation. For example, there was no conventional core, or side wall cores from either the reservoir or seal, there was only a very basic suite of pre-production logs. Although the production pressure data proved useful in the early stages of flow simulation history matching, it only provided half the picture when trying to assess the post-production aquifer recharge potential.

The CO2CRC Otway Project addressed each of these issues with targeted data acquisition and specialist analysis. Core and logs were gathered during drilling of the injector well, and the existing production well was re-logged to understand hydrodynamic conditions prior to injection. As a result, the Project provides a valuable example of the process of site characterisation.

5.1.1 Workflow

Site characterisation activities at the Otway site were divided into four distinct phases (Figure 5.1). Phase 1 began in 2004 when CO2CRC undertook initial site screening of sedimentary basins close to major Australian emission centres. The three main regions under investigation were the Bowen Basin in south-east Queensland (Sayers et al. 2007), the Perth Basin in Western Australia (Causebrook et al. 2006) and the Otway Basin in Victoria. As discussed in Chapter 1, the Otway Basin was chosen (Figure 1.2) when the depleted Naylor natural gas field and the Buttress CO_2 field became available.

The second phase of modelling then commenced in 2005 to assess the feasibility of the site against the project objectives. Initially injection into the shallower formations (Figure 1.5), above the gas reservoir, was considered, and for a while these became the subject of seismic mapping, looking for structural trapping above the Waarre Formation using the Naylor-1 well as a "conceptual" injector. It was soon recognised that there were few structural traps at this level. In addition this proposal introduced key risks associated with injection into freshwater aquifers.

Therefore it was decided to concentrate on the Waarre Formation as the injection reservoir at the Naylor structure (Figure 1.6). It was accepted that due to the production well's small diameter (3.5 inch or 88.9 mm), Naylor-1 could not be used for both injection and monitoring, so planning and modelling was undertaken to site a new injector, CRC-1 (Spencer et al. 2006).

Following the drilling of CRC-1, phase 3 then commenced, which provided the opportunity to incorporate the much needed core data and high resolution wire-line log information into a new set of static models (Dance et al. 2009). This new data was combined with the pre-existing data from nearby wells and fields, as well as with a good quality 3D seismic survey covering most of the Port Campbell Embayment, in order to better characterise the reservoir and overlying formations. Table 5.1 summarises the improvements made to the existing database that addressed the key uncertainties at the field.

Finally, the last phase in characterisation of the field was achieved during the "demonstration" stage of the CO2CRC Otway Project and encompassed the post-injection model calibration. History matching of the dynamic model against the injection and monitoring data provided insights into the reservoir's bulk permeability, pressure response, and reservoir heterogeneity (see later details of dynamic modelling in Chapter 16).

In the entire Project time line, phases 2 and 3 of the site characterisation required by far the most resources and time to complete, and comprised the bulk of the geological characterisation workload. This will most likely be true for many other projects because it is in these phases where a detailed assessment is made against the criteria for a suitable storage site, namely injectivity, capacity, and containment. Therefore, this chapter focuses mainly on these important phases in the site selection and development stage of the CO2CRC Otway Project. A summary of the earth science and reservoir engineering objectives is given below, and the following sections describe in more detail the methodology used and lessons learnt.

5.1.2 Objectives

The schematic in Figure 5.2 summaries the objectives of the comprehensive site assessment and lists examples of the types of data and analysis that were necessary for the Project to proceed. In summary the steps at Otway were to:

1. assess the **site details** in a regional sequence stratigraphic setting, establish the regional hydrodynamics and field history and map the Naylor structure to plan for optimal injector location
2. determine from core, logs, and well tests that the reservoir has sufficient **injectivity** to allow for up to 100,000 tonnes of CO_2 to be injected over the two years allocated for the experiment
3. build a static three dimensional geological model of the structure and determine that there is sufficient **capacity** based on the spill points of the reservoir, porosity distribution and current fluid/gas saturations to accommodate the planned maximum 100,000 tonnes of CO_2

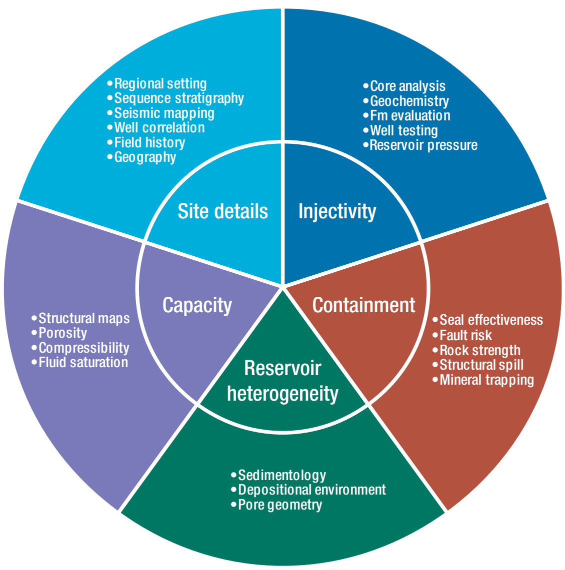


Figure 5.2: Datasets and analysis used for the five criteria of CO_2 storage site assessment.

4. characterise the **reservoir heterogeneity** to understand how sedimentary features are likely to affect vertical and horizontal fluid flow within the reservoir sands
5. assess any risks to **containment** in the overlying Belfast Mudstone seal or from adjacent faults, by mapping seal continuity and 3D fault geometry on the seismic section; and testing cores for CO_2 retention potential and geomechanical rock strength properties (see Chapter 6 & 7).

5.2 Site details

Details of the geology of a site, reservoir seal pairs, existing natural resources which may be impacted by CO_2 injection (as well as production history in the case of a depleted oil or gas field) are critical in the first stages of a site assessment.

5.2.1 Regional geology and stratigraphy

Regardless of the size of a CCS project, understanding the regional, basin-wide, geological setting is an important step in characterising the targeted reservoir-seal pairs. A sequence stratigraphic approach is preferred as it combines well correlations, biostratigraphy and seismic mapping to provide a predictive model for distribution of reservoir and seal lithologies. A regional review of the Otway Basin tectonic and stratigraphic development is given in Krassay et al. (2004). The western part of the Otway Basin is structurally restricted by the Otway Ranges to the east and bounded by structural highs to the north and west. Its development, and that of the adjacent Shipwreck Trough, which extends off-shore, was coeval with the eastern Gondwanan breakup along the Australian Southern Margin and with the Tasman Sea seafloor-spreading to the east. (Woollands and Wong, 2001). The Waarre Formation is the basal unit of the Sherbrook Group (Turonian – Maasrichtian ~91 65.5 ma) sitting directly on top of the Otway Unconformity, which marks a period of compression, folding, uplift and erosion in the Mid Cretaceous (Krassay et al. 2004). The Waarre Formation is overlain and sealed by the Flaxman Formation and the Belfast Mudstone. Turonian deposition was associated with the initial syn-depositional faulting during a phase of basin extension. Deposition of the overlying Flaxman Formation and Belfast Mudstones occurred during the subsequent sea level rise. Following on from this Mesozoic extension, which ended in break-up and subsequent sea floor spreading along the southern margin, there was a long interval of margin subsidence. This was punctuated in the mid Eocene by local inversion, and since the mid Miocene, by regional compression and fault reactivation. The resulting structural style in the vicinity of the study site (Figure 5.3) comprises large north dipping half-grabens separated by the linkage of transfer fault zones (Hill & Durrand 1993).

There are several broadly similar sequence stratigraphic chronostratigraphic systems and descriptions of lithostratigraphy in use in the Otway Basin (Laing et al. 1989; Kopsen & Scholefield 1990; Morton et al. 1995; Geary & Reid 1998; Boult et al. 2002). Here, the system published by Partridge (2001) (see Figure 5.4) has been adopted because it focuses on the Sherbrook Group in wells close to the study site. Partridge (2001) subdivides the Waarre Formation into units A, B and C. The basal unit, A, is a fine-grained lithic sandstone with low to moderate porosity. The middle Unit B consists of hard, grey to black carbonaceous mudstone. The upper unit (Unit C) is the main gas producing reservoir in the area and consist of poorly sorted very fine to coarse

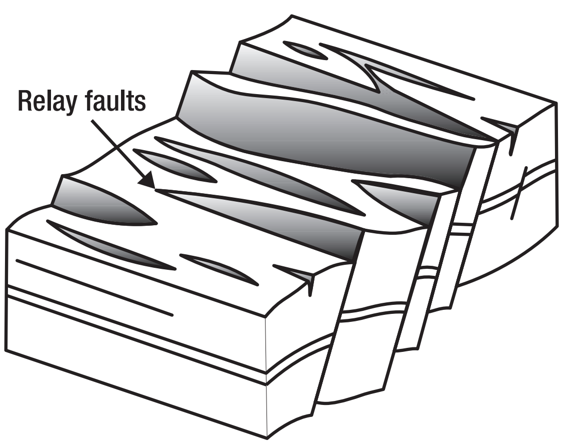


Figure 5.3: Structural model for the Otway Basin showing the development of half-grabens through the linkage of transfer faults.

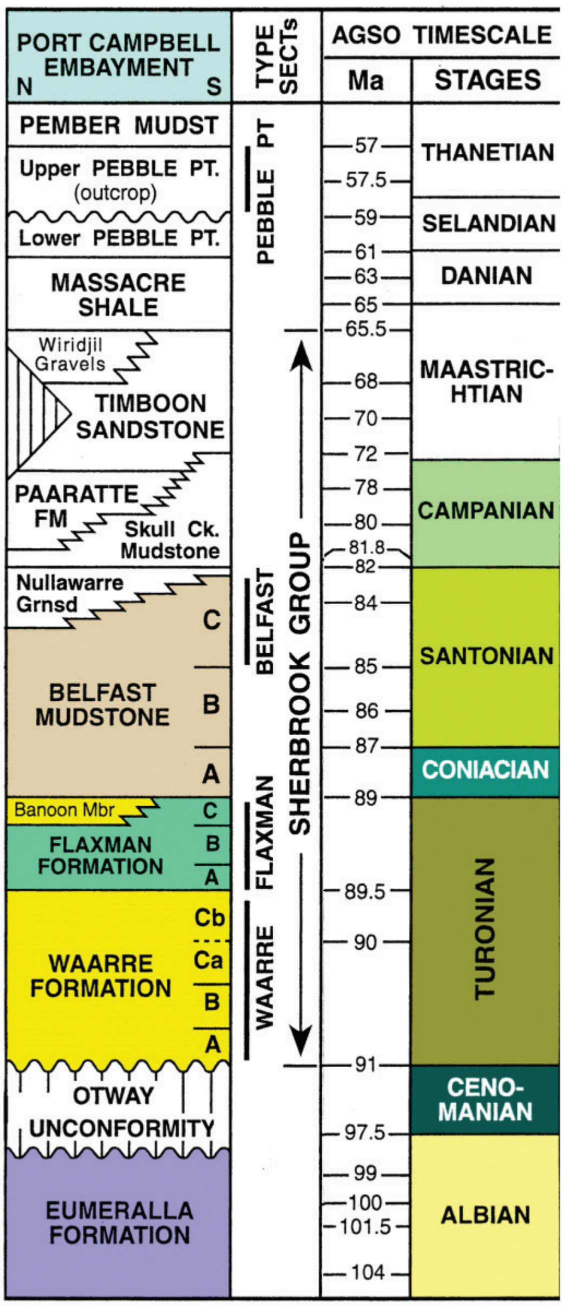


Figure 5.4: Stratigraphic column of sedimentary units in the Port Campbell Embayment (after Partridge 2001).

quartz sands and occasional gravels, 2 to 14 m thick, separated by minor mudstones which vary from 0.5m to 3m in thickness.

The first step in site selection was to perform well correlations of these reservoirs and seals over the area (Figure 5.5). In the onshore area, the Waarre C Formation is relatively thin particularly in the area of Naylor and surrounding fields (approximately 25 m to 40 m thick). By comparison, the Belfast Mudstone (seal) is up to 400 m thick. The local Waarre C lithostratigraphic correlation around the Naylor area is relatively straight forward. The Buttress-1 and Boggy Creek-1 wells form a natural grouping that has a fairly uniform but thin Waarre C sand (approx. 10 m to 20 m). The CRC-1, Naylor-1, Naylor South-1, and Croft-1 wells (Figure 1.2) also form a natural group, but with a thicker Waarre C section (approx 30 m to 40 m); the thickness difference between the two groups is interpreted as due to thickening across the approximately north northwest syn-depositional growth fault to the north of Naylor-1 (Figure 5.6). This interpretation of a sequence of stacked episodic relatively thin deposits separated by poorly defined sequence boundaries is consistent with deposition in a rift margin environment subject to episodic faulting and extension.

Seismic interpretation was carried out on the existing Nirranda-Hetysbury 3D Survey. This survey has excellent resolution, with 24 fold data to a depth of 4 seconds, a bin size of 20 m and covers an extensive total area of 83.5 km^2. Supplementing this was the CO2CRC 2008 baseline 3D seismic, ZVSP, walk-away VSP and 3D VSP data which provided even greater detail directly over the study area. These were all acquired prior to injection as part of the Otway Project time lapse monitoring programme (Dodds et al. 2009). The new data also allowed a thorough well-to-seismic tie for the CRC-1 well. The polarity convention used was SEG negative: i.e. an increase in impedance is represented by a trough. The gas- bearing Waarre C reservoir reflector is a relatively "bright" (high amplitude) peak (Figure 5.7). The Naylor structure is bound on three sides by faults; variance and instantaneous frequency volumes were used to help image these faults with clarity in 3D.

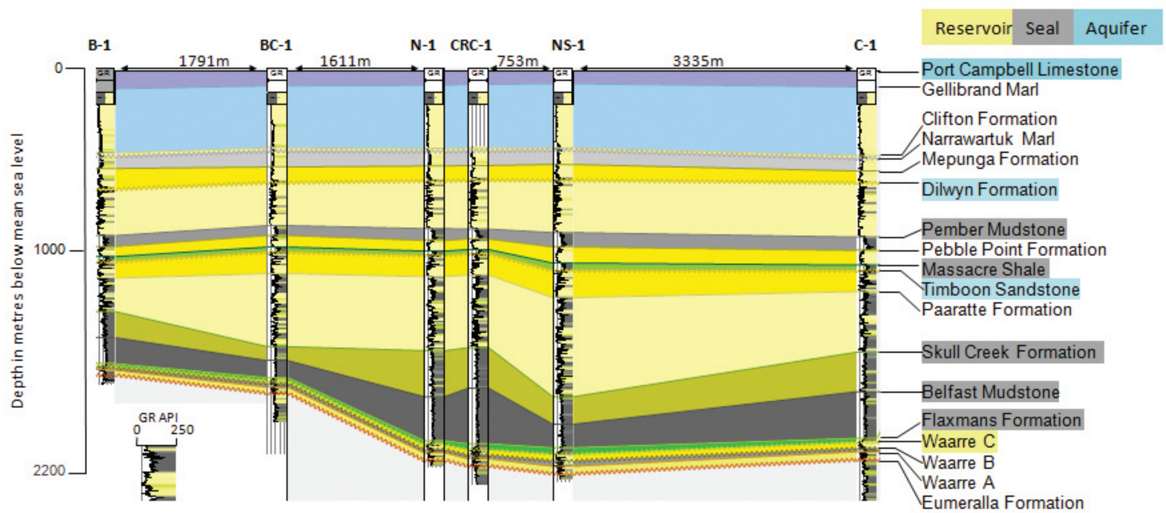


Figure 5.5: Well log (gamma ray) correlation of stratigraphic formation tops in the study area. Refer to Figures 1.2 and 5.7 for well locations: B-1(Buttress-1), BC-1 (Boggy Creek-1), N-1 (Naylor-1), NS-1, (Naylor South-1), C-1 (Croft-1).

The top and base of the reservoir were mapped, in addition to the top of the Flaxman Formation and top Belfast Mudstone seal. Mapping of these horizons was extended away from the Naylor field to confirm their regional continuity throughout the Port Campbell Embayment. The resulting surfaces were depth converted using velocity derived from check shot data at the wells.

The Waarre C Formation lies at a depth of between1980 m TVDSS and 2180 m TVDSS (Figures 1.6 and 5.5). The Belfast Mudstone is between 1340 m TVDSS and 2010 m TVDSS and is 280 m thick on average throughout the site. At this depth the pressure and temperature of the reservoir are in excess of the critical point where the CO_2 / methane gas mixture enters the supercritical state. This is important because in this form it is much denser than gaseous CO_2 and therefore a greater volume of CO_2 can be stored in the pore space available (Holloway & van der Straaten 1995; Cook et al. 2000).

In addition to focusing on the injection interval and cap rock, a full earth model was constructed to map the faults and the overlying stratigraphy that may be impacted by injection. Figure 5.7 includes two seismic sections: a) an approximate east-west section over the field and b) a north-south section, with mapped formations delineated by coloured lines.

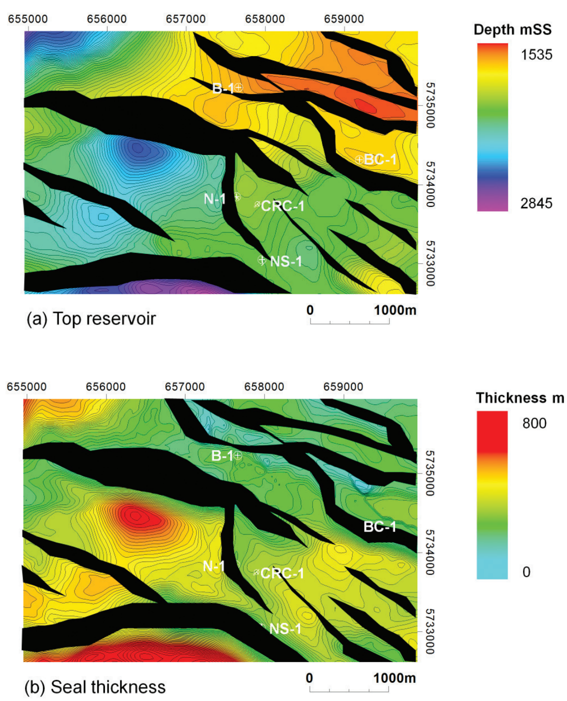


Figure 5.6: (a) Depth structure map of the top of the reservoir in metres sub-mean-sea-level; and (b) Seal thickness map in metres. Well name abbreviations: B-1(Buttress-1), BC-1 (Boggy Creek-1), N-1 (Naylor-1), NS-1, (Naylor South-1), C-1 (Croft-1). Black polygons denote faults.

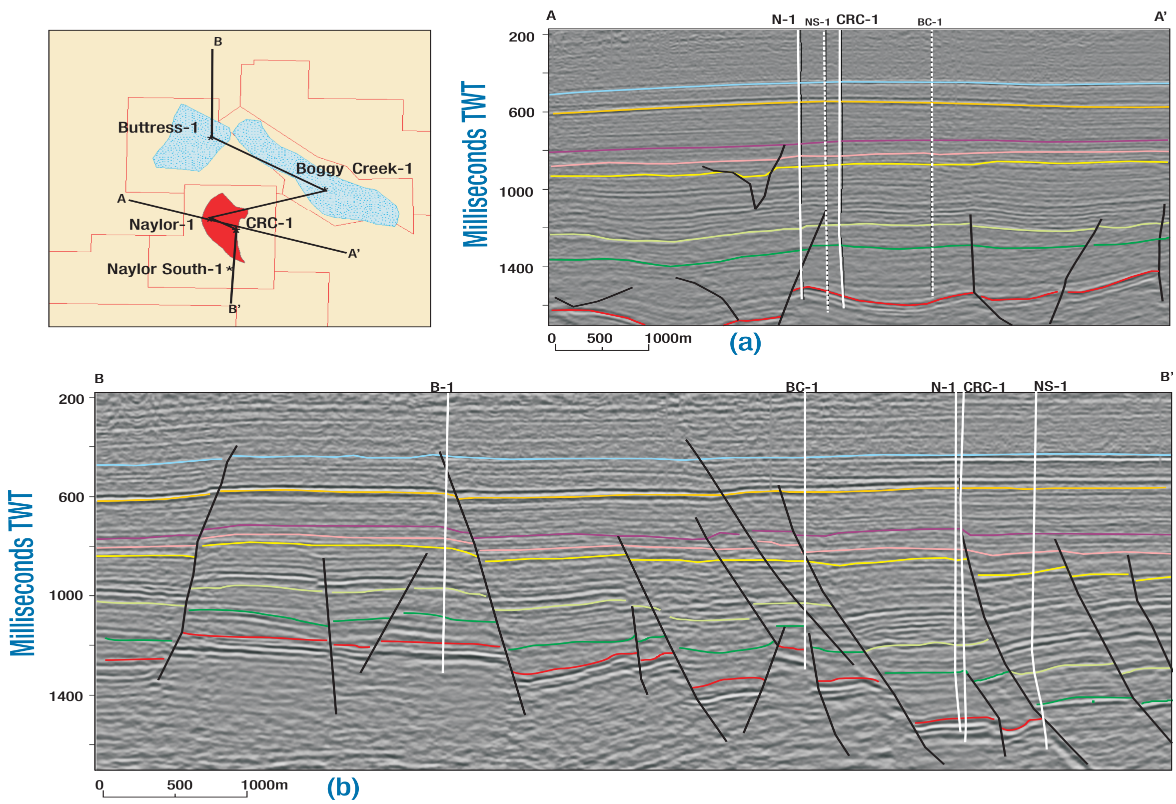


Figure 5.7: seismic sections, (a) approximate east-west, and (b) north-south, over the study area. Key formation horizons from the base up are: Waarre C (red), Belfast Mudstone (green), Skull Creek Mudstone (light green), Timboon Sandstone (yellow), Pebble Point Formation (pink), Pember Mudstone, (purple), Dilwyn Formation (orange), Clifton Formation (blue).

Immediately overlying the Belfast Mudstone is the Skull Creek Mudstone, deposited in the Early Campanian. The Skull Creek Mudstone consists of dark grey to black, carbonaceous mudstones, with minor interbededd siltstones and sandstones that become more frequent towards the top. The section probably represents the outermost prograding toe of a delta system deposited in an open marine environment. Because the Skull Creek Mudstone is mostly fine grained, it consequently has low hydraulic conductivity and it contributes to the primary seal capacity of the underlying Belfast Mudstone across the study area.

Overlying the Skull Creek Mudstone is the Paaratte Formation (the focus of the Otway Stage 2 experiments) , which is Campanian to Maastrichtian in age. It comprises laminated fine-grained sandstones with moderate to good porosity and fair to excellent permeability, interbedded with siltstones and mudstones. The Formation is up to 400 m thick in the study area. The overall coarsening upward nature of the sequence suggests a prograding deltaic to shallow marine depositional environment.

The Timboon Sandstone overlies the Paaratte Fomation, from which it is distinguished by a "blocky" electric log signature (Figure 5.6). It consists of predominately poorly consolidated, fine grained, micaceous sand, believed to have been deposited by fluivial processes in an upper delta plain (Gallagher et al. 2005). Water samples obtained from the Timboon Sandstone generally have total dissolved solids (TDS) values around 500 ppm, suggesting this unit may have significant potential for future use as town water supply (Duran 1986). It is categorised by the Victorian state EPA as potable water, which is water with between

501 ppm and 1000 ppm TDS. However, the potential of the Timboon Sandstone as a water supply is limited, as it does not outcrop and is only recharged by downward vertical flow from the overlying sediments. To date, this aquifer has not been exploited because of its depth and the abundance of freshwater in shallower aquifers. Nevertheless, it has been flagged as a future resource and as such, its integrity must be assured.

Above the Timboon Sandstone are the formations of the Wangerrip Group including the Massacre Shale and the Pember Mudstone which were characterised in the context of their potential to provide secondary seals at the site, in the unlikely event that CO_2 were to breach the primary container. The Massacre Shale, which lies between 931 m and 1026 m TVDSS is a glauconitic mudstone deposited during a widespread transgressive event and although it is relatively thin (approx 20 m to 30 m thick) it can be mapped with continuity across much of the Otway Basin. The Pember Mudstone is a pro-deltaic, silty mudstone approximately 50 m thick in the study area. Facies changes are recognised on the regional scale that could compromise the seal continuity, however, sealing potential appears good in the study area.

Above the Pember Mudstone is the Dilwyn Formation. It comprises a thick (approximately 250 m) sequence of shallow marine to coastal plain sandstones and mudstones. The Dilwyn Formation is a major fresh water aquifer (<1000 ppm TDS), supplying water for urban use to surrounding towns in times of drought.

Overlying the Dilwyn Formation is the Heytesbury Group. The main aquifer in this Group is the Port Campbell Limestone. This karstic limestone outcrops extensively in the area and forms spectacular cliff exposures at the coast. The aquifer is the primary ground water supply in the region and is currently exploited for urban use, agriculture and irrigation. Understanding the baseline hydrological conditions of these two major aquifers as well as water chemistry and pH was critical in the overall Otway Project site characterisation, and more information on this can be found in de Caritat et al. (2009), Hortle et al. (2011) and Chapter 13.

5.2.2 Field history

The Naylor Field was discovered by SANTOS with the drilling of the Naylor-1 well in May, 2001. It was drilled on the basis of a direct hydrocarbon seismic indicator at the level of the Waarre C Formation and reached total depth in the Eumeralla Formation at 2105 m TVDSS. Initial proven plus probable (2-P) reserve estimates for this small structural closure were 1.47 x 10^8 m^3 (or approximately 5.4 Bscf) original gas in place. The discovery pressure was 19.5928 MPa at 1993.34 m TVDSS (around the middle of the Waarre C). Because the field was expected to be small prior to drilling, economic considerations required exceptional cost minimization during development. The operator completed the well as a mono-bore with 3½ inch (88.9 mm) casing and there was no additional sampling or testing. That is, there was no conventional core, no side wall cores, and only a basic set of wire-line logs. The well was perforated over the upper 4m of the Waarre C and produced approximately 9.5 x $10^7 m^3$ (or ~3.3 Bscf) of natural gas (~86% methane) from the Waarre C between June 2002 and October 2003 at which time the well started taking in water. As the cost of water handling equipment was prohibitive, production from the Waarre C was no longer economically viable. Reservoir pressure at this time was down to 11.8612 MPa (converted from the reported flowing tubing head pressures). A casing patch was installed and the well was re-perforated at the Waarre A stratigraphic level and a further 0.8 x $10^7 m^3$ (or ~0.3 Bscf) was produced briefly between November 2003 and July 2004 until the well was again killed due to the influx of formation water; it was subsequently shut in. The nearest well, Naylor South-1 (~860 m to the south east), was drilled because the post Naylor-1 assessment suggested a possible field extension across to the Naylor South structure (Figure 5.8). The well did not intersect producible hydrocarbons (only residual methane), and was subsequently abandoned. As in the case of Naylor-1, Naylor South-1 had a minimal test program, with no cores or any side wall cores.

In 2006, Naylor-1 was logged by CO2CRC using the Schlumberger reservoir saturation tool (RST) which confirmed the position of a post-production Gas-Water Contact (GWC) at 1988.4 m TVDSS, approximately

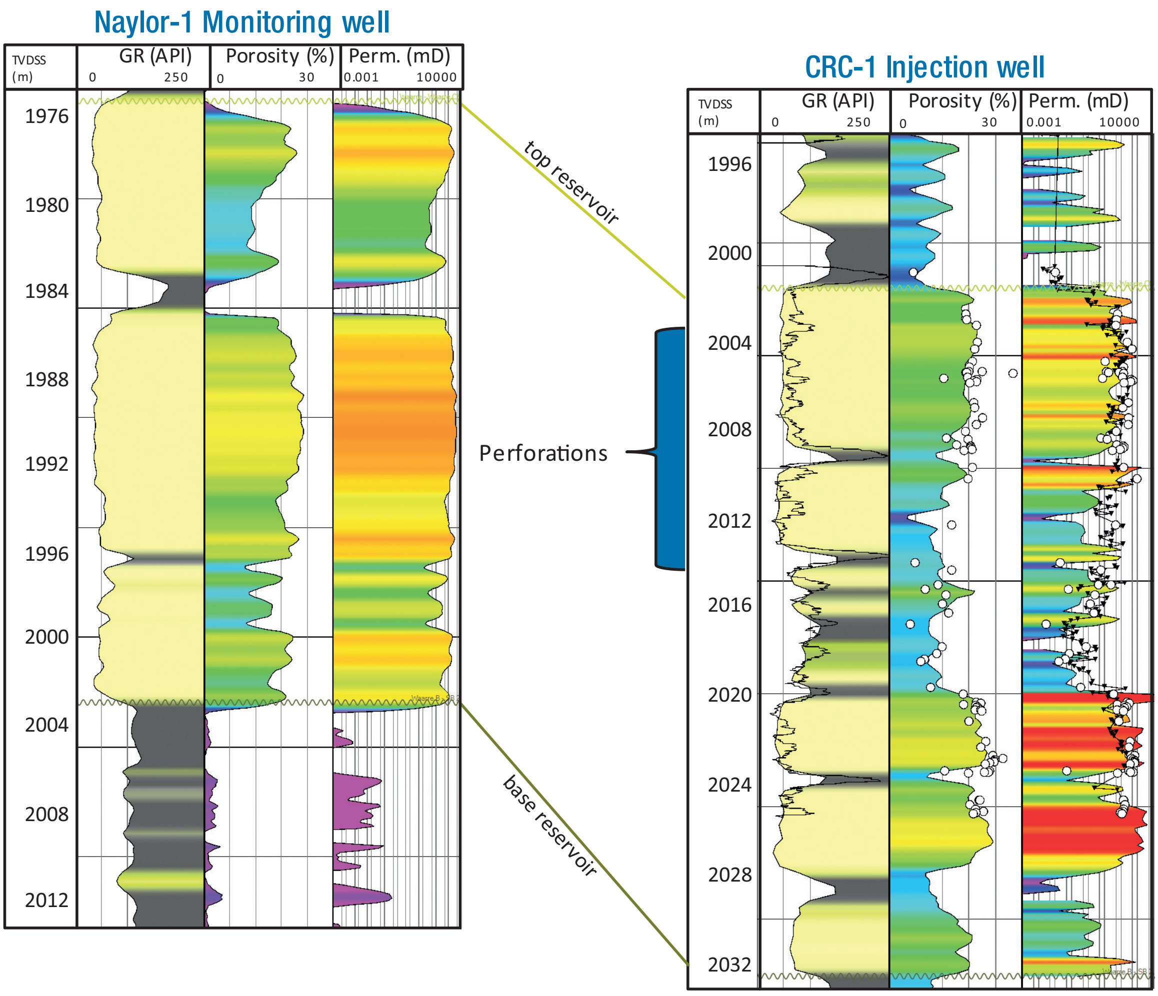


Figure 5.8: Naylor-1 and CRC-1 well composites. Logs from left to right gamma ray (GR), porosity, permeability. Also overlaid in CRC-1 tracks are core gamma ray (black curve), core porosity, core permeability (circles), and mini-perm (black triangles).

11m below the top of the Waarre C. There was an average residual gas saturation of 20% throughout the remaining 14.5 m down to the boundary with the Waarre B. Pressure information was also obtained at this time which indicated re-pressurisation to 17.4 MPa after depletion from production. This pressure recovery has been attributed to the strong regional aquifer drive of the greater Waarre C (Hortle 2008).

The injection well, CRC-1, was spudded on 15 February 2007 and reached a total depth of 2249 mRT (2199.3 m TDVSS, 109 m in the Eumeralla Formation) on 8 March 2007. It was set and cased as a 4½ inch (114.3 mm) vertical mono bore. Along with vital core and log information, it also provided reservoir temperature (82 °C), and pressure (17.8 MPa) information , adding to the dynamic history profile of the field. The pre-injection reservoir simulations were then constrained using a history matching process that honours flow rate and cumulative production data, bottom hole pressure during production and post production aquifer recharge (Xu et al. 2006).

5.3 Injectivity

Focusing on the reservoir itself, it was necessary to establish that the target had sufficient injectivity to cope with planned volumes and rates. For the Otway Project, the target was up to 100,000 tonnes of CO_2 over 2 years. This translates roughly to 3 MMscf/d (~150 tonnes per day). For this to be feasible with only a single injection well operation, in a reservoir 25 m thick, it was desirable to have absolute reservoir permeability values in the order of >100 millidarcies. Even though Naylor lacked any permeability information from core, production data and cores from nearby fields (Boggy Creek-1), suggested that highly permeable sands were likely be encountered down dip where the injection was planned. This was confirmed when CRC-1 was drilled. The core programme included recovery of over 49 m of core, including 24 m of continuous core through the Waarre C. The suite of wire-line log information gathered comprised Gamma Ray, Nuclear Magnetic Resonance (CMR), Elemental Capture Spectroscopy (ECS) and Formation Micro Imager (FMI) which were recorded to complement the standard resistivity-density-porosity logs. In addition several modular formation dynamic tester (MDT) samples allowed multiple pressure measurements and the recovery of multiple fluid samples from the Waarre C Formation, as well as from shallower reservoir sections (Figure 5.8).

Porosity and permeability measurements were performed on vertical and horizontal core plugs at in-situ stress conditions, and supplemented by profile permeametry (mini-perm) measurements recorded on the whole core surface every 5 to 10cms. The down hole depths from the 96 core measurements and mini-perm were corrected using core gamma-ray correlated against down-hole gamma-ray logs, so the core porosity and permeability could be matched to the log curves. The core-derived bulk density was compared to the log derived bulk density and the match was found to be satisfactory. Results shown in Figure 5.8, indicate the porosity of the Waarre C ranged from 2% to 25% while the permeability averaged 1 darcy, with up to 5 darcy measured in some of the cleaner sandstone intervals of the formation.

Relative permeability information was derived from laboratory work on a core sample from the Waarre C in order to understand CO_2/water two-phase flow at reservoir pressure and temperature conditions. The analysis, performed at Stanford University (Perrin et al. 2009), involved flooding the core sample with mixed CO_2 and brine and measuring the pressure at the inlet and outlet with two high accuracy pressure transducers. The difference of the two pressures was used to calculate the relative permeability. X-ray CT scanning was also used to determine CO_2 saturation at a fine scale after the flooding and provided 3D porosity and saturation maps of the sample. The results gave a residual water saturation *Slr* of 44.4 % and a relative permeability to gas at this saturation (*krgmax*) of 0.608. The study also revealed that microscopic grain size heterogeneities and clay lamina impact on porosity distribution and consequently on the distribution of CO_2 saturation in the reservoir.

Injectivity testing at the well using water, provided information on the bulk permeability of the reservoir. Initially injectivity was poor and pressure built up rapidly. This was assessed as being due to a combination of formation invasion by the drill fluids and mud build-up on the surface of the high permeability reservoir sands and was in keeping with high permeability (1–5 darcy) recorded by conventional core analysis of some of the sands within this interval. Subsequently the perforated interval was extended and the reservoir allowed to back-flow into the well. This flushed the mud filtrate and consequently injectivity was much improved.

Other factors can impact on the rates of CO_2 injection including near-well bore dry-out, salt precipitation, fines mobilisation and mineralisation (Burton et al. 2009). Various petrological analyses, including X-ray diffraction (XRD) and scanning electron microscopy (SEM), were performed on 34 samples from the Waarre C Formation and two from the Flaxman Formation, in order to examine these potential effects (Schacht, 2008). Samples were taken as 1.5 inch (38 mm) core plugs from existing CRC-1 cores and thin sections of the samples were cut perpendicular to the bedding plane. In general, the petrographic analyses focused on the mineral content and textural relationships of the rocks. Likely CO_2 chemical interaction within the Waarre C Formation was predicted to involve the in-place potassium feldspar and mica, as well as the dissolution of patchy carbonate cements. CO_2-induced diagenetic products were expected to be minor, due to the absence of cations suitable for mineral trapping of CO_2 in this formation. As a result CO_2-water-rock interactions were not expected to interfere with the ability to inject CO_2 at CRC-1.

Geomechanical assessments were also conducted (van Ruth and Rogers, 2006, and Vidal-Gilbert et al., 2010) in order to estimate the maximum pore pressure increase the reservoir could sustain during injection. These studies concluded that the maximum sustainable pore pressure increase for the reservoir was 9.6 MPa (~1395 psi) and that the seal could sustain an increase of up to 16.5 MPa above the pre-injection conditions (Chapter 7). The study by Vidal-Gilbert (2010), used results from triaxial rock mechanical tests on CRC-1 cores to constrain models of the minimum pore pressure increase required to cause fault reactivation. For faults oriented optimally with respect to the regional Otway Basin stress regime, the values ranged from 1 MPa to 15.7 MPa, given the initial pore pressure at the top of the reservoir was 17.5 MPa just prior to injection. These limits were used in a series of dynamic models (Xu et al., 2006; and Undershultz et al., 2011). In each modelled case, the maximum injection pressure (bottom-hole pressure), was below the initial discovery pressure of the reservoir (19.5 MPa), at the end of the injection, and therefore, the proposed injection rate of 150 tonnes/d (about 3 MMscf/d) was considered feasible.

5.4 Capacity

In the preliminary stages of site selection for the CO2CRC Otway Project (2004-2006) up to a maximum of 100,000 tonnes of CO_2 was proposed to be injected and stored. At the time other projects around the world were running tests with much lower tonnages (see Figure 19.1) so it was considered that this demonstration project was relatively "large-scale", making it more relevant to a commercial scale injection project. During the site characterisation study this relatively large reservoir storage capacity requirement was a key assessment issue in the context of the question: "Will there be sufficient storage space available for up to 100,000 tonnes"? More specifically it needed to be technically feasible to achieve this tonnage given the size of the structure down to the spill point, the thickness of the reservoir, and the net-to-gross. Reservoir storage capacity is a complex function of the density of the CO_2 at subsurface reservoir conditions, the pressure and temperature at the time of injection, and the effective pore space available minus the space occupied by the existing gas cap and the residual methane, whilst still remaining below the maximum allowable pore pressure increase. There is an important difference in this estimate compared to asking: "How much space can be available at the site"?

Estimating the total effective capacity of a depleted field for storing CO_2 requires a calculation that accounts for dynamic effects such as the increasing pressure due to the hydrodynamic aquifer drive and consequent change in size of the free gas cap. Similarly, in theory the site may be engineered to make more useable space available and the pressure build up minimised, by producing natural gas and water using increased pressure caused by the injection of CO_2 making capacity more of a function of reservoir dynamics and economic feasibility.

A simplistic production-based calculation of storage capacity at the Naylor Field was first undertaken assuming the volume of gas produced equated to the equivalent intended injection volume. The Naylor Gas Field originally contained an estimated 1.47 x 10^8 m^3 or ~5.2 BSCF (billion standard cubic feet) of initial gas in place (measured at standard temperature and pressure). The cumulative production from the Waarre C reservoir was 9.5 x 10^7 m^3 (~3.3 BSCF), which was about 64% of the initial gas in place. This volume of produced gas was equivalent to approximately 1.5 x 10^5 tonnes of the Buttress Field gas mixture of 80% CO_2 and 20% CH_4 by mole fraction. On this basis there was 150% of the required storage capacity at the depleted Naylor Field.

However, this volume-for-volume basis for capacity estimates is only useful in depleted fields where there is weak aquifer drive and injection is performed soon after depletion. If there is only minor invasion of formation water post production, the same pore space in the reservoir is still available for gas, and so in returning to the original reservoir pressure, the same subsurface volume can be stored as originally produced. Hydrodynamic assessment of the greater Waarre aquifer by Hortle (2006) concluded that the regional Waarre Formation aquifer is a well connected

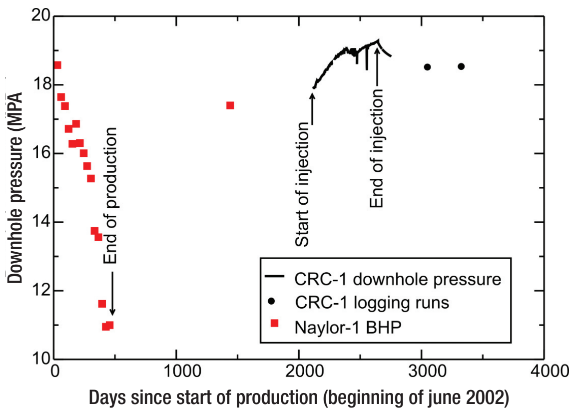


Figure 5.9: Pressure versus time recorded at the Naylor-1 and CRC-1 wells during production (pressure depletion), post-production (recovery), CO_2 injection, and post injection.

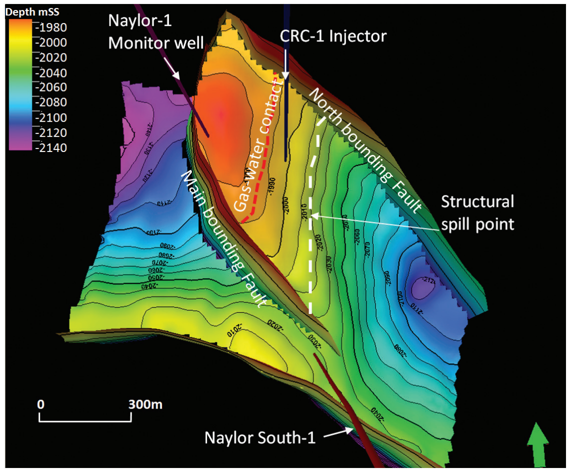


Figure 5.10: The Naylor Field 3D structural model, including top reservoir horizon, faults, spill point, and post production gas-water contact.

aquifer in regional hydraulic communication across the Port Campbell Embayment. The flow rate within the Waarre Formation is quite fast at about 0.39 m/yr; estimated assuming an average permeability of 500md. Although there is strong evidence of regional draw-down, due to a long history of production across the Port Campbell Embayment, the Naylor field still maintained a relatively rapid pressure recovery. Production at Naylor-1 ceased at the end of October 2003, when the formation pressure was around 10 MPa. When injection began in March 2008, the reservoir pressure had recovered to around 17.8 Mpa (Figure 5.9). This indicated a substantial influx of formation water from the aquifer system, and a consequent reduction in capacity given the desire not to exceed the discovery pressure of 19.5 MPa.

Having mapped the structure in detail and derived average porosity from cores and logs, a 3D static geocellular model of the reservoir was constructed from which volumetric-based capacity could be estimated using the equation proposed by the United States Department of Energy (DOE, 2006):

$$G_{CO_2} = A\, h_n\, g\, \phi_e\, \rho\, E$$

The bulk rock volume was calculated from the static model by multiplying the reservoir area (A), net gas column height (h_n), and geometry of the structural spill of the three way closure (g). An average effective porosity (ϕ_e), in combination with the bulk rock volume (A h_n g) provides an estimate of total pore space available for storage. The storage efficiency factor (E) provides a measure of the fraction of this total pore volume from the gas that has been produced and that can be filled by CO_2. The storage efficiency factor accounts for irreducible water saturation, as well as an estimate of the irreducible gas saturation. As the structure was interpreted to have been filled to spill point the irreducible gas saturation estimate could be "blanket-applied" to the whole bulk rock volume

A methane gas cap remained at the top of the structure down to 2039.5m RT at Naylor-1 (equivalent to-1989 m TVDSS). Below the post-production gas-water contact, prior to injection, the pore space contained an average 20% residual methane saturation, with the remaining 80% being formation water. This was confirmed by the Reservoir Saturation Tool logging at CRC-1 and Naylor-1. On the time scale of the injection period (1–2 years), it was considered that the injected CO_2/methane mixed gas could displace some of the formation water but would not access the entire 80% of the pore space previously occupied by formation water. Numerical simulation, run prior to injection, suggested that the water saturation within the reservoir at the end of the injection period would be 40-50%, leaving only 30–40% of the pore space accessible for storage of injected gas. The density of the injected CO_2-CH_4 mixed gas was 360 kg/m^3, giving an estimated storage capacity within the Naylor Field of between 113,000 and 151,000 tonnes, which exceeded the proposed injection volume, and therefore it was concluded from both capacity estimation methods that the site had more than sufficient capacity to meet the Project aims.

5.5 Reservoir heterogeneity

Reservoir heterogeneity will impact on the migration behaviour of injected CO_2 as well as storage effectiveness. The spatial distribution of sand and shale bodies as well as their grain size, sorting, roundness, clay content and mineral digenesis can control vertical and horizontal connectivity within a reservoir (Ambrose et al. 2007). Modelling by Flett et al. (2004), found the increased number of baffles in heterogeneous formations (shale layers etc.), results in tortuous migration pathways which slow the movement of CO_2. Hovorka et al. (2004), suggested these tortuous flow paths increase the volume of rock contacted by the CO_2 resulting in a larger net storage capacity for heterogeneous formations. The reservoir quality (porosity and permeability distribution), of the clastic Waarre C Formation is strongly linked to the original depositional facies (see Table 5.2), as there has been only very minor mineral digenesis- mainly kaolinite replacement of feldspar with no net change in porosity. This was advantageous for any reservoir characterisation, because once a depositional model had been established, and the size and spatial distribution of sand bodies and shale baffles ascertained from well-studied reservoir analogues, then the length, width and anisotropy ranges of these depositional facies could be used to predict the flow pathways away from the wells without significant cause for concern that diagenetic overprinting would complicate the model. Consequently, at the Naylor Field, it was important to characterise the depositional setting and resulting sedimentary features that could have any impact on migration of CO_2 and timing of plume arrival at the Naylor-1 monitoring well.

5.5.1 Sedimentary facies-scale

The cored interval from CRC-1 intersected the lower portion of the Flaxman Formation and the Waarre C, terminating a few metres above the Waarre B. High resolution X-ray CT scanning was performed on the CRC-1 cores to visualise the internal sedimentary and structural features at millimetre scale. Few fractures were noted, but fine laminae in the form of thin carbonaceous layers were recorded throughout. A few millimetres of the core was cut from the entire length to provide a clean flat surface along the length of the core; the core was then described in detail and selected photographs taken. Sedimentological interpretations of the cores showed a complex stratigraphy that included incised valley fill deposits within the Waarre C Formation, overlain by transgressive to offshore open marine deposits in the Flaxman Formation (Dance & Vakarelov 2008); a weak unconformity sequence boundary was noted, separating the two units. The interpretation that the two formations were not contemporaneous was supported by biostratigraphic evidence (Partridge, 2006), as well as by the nature of the different depositional environments. These included a transgressive tidally-influenced fluvial succession transitioning

Table 5.2: Results of conventional core analysis and micro-tomographic derived reservoir quality for each of the depositional facies.

Facies	Porosity %	k mD	Kv/kh	pore size	Throat size	Pore/Throat ratio	Connectivity
Transgressive sand	10–19	62–2795	0.63	11.2	4.1	2.4	3.4
channel sands	9–34	8–2428	0.38	_	_	_	_
Gravel dominated	6–28	3–3750	0.4	10.2	5.3	2.4	5.1
Abandoned channel fill	1–3	0.002–0.3	0.9	_	_	_	_
Wave re-worked sands	9–14	1–281	0.3	11.6	3.8	3.0	3.3
Tidal sands	18–21	440–6000	0.8	23	10.3	3.5	4.9

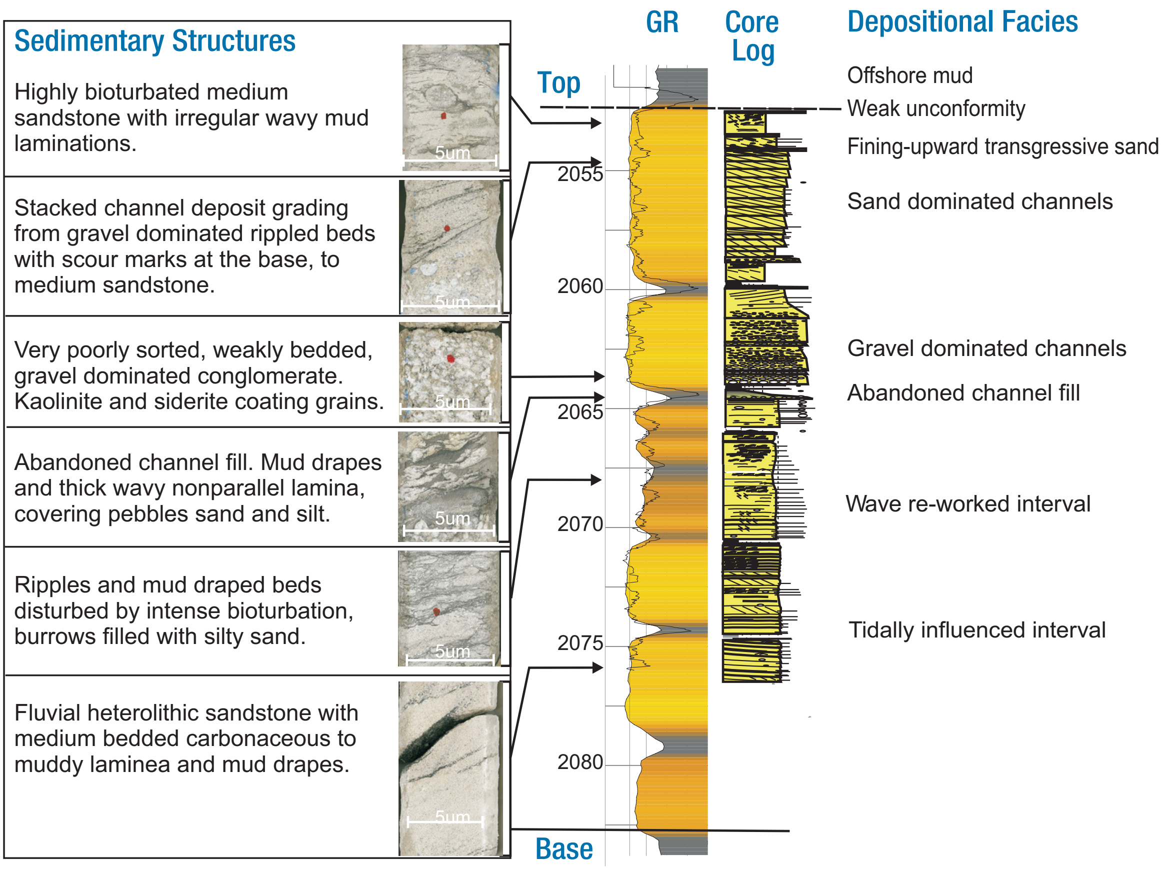


Figure 5.11: Reservoir core sedimentary description log, core photographs, and depositional facies.

into a marine-dominated succession in the lower part of the core; a fluvially-dominated stacked channel interval in the middle portion of the core; and a transgressive to offshore marine interval in the Flaxman Formation. The tidally-influenced fluvial interval in the Waarre C was interpreted to have been deposited in an incised valley during a lowstand to transgressive system tract. The fluvial interval was deposited during a drop and then rise of relative sea level, and probably related to a pulse of valley incision followed by valley fill. The Flaxman Formation was deposited during a subsequent transgression (under open marine conditions), floored by a transgressive surface of erosion topping the fluvially- dominated interval of the Waarre C. Tidally-influenced fluvial intervals overlain by restricted marine facies are commonly associated with transgressive estuarine settings occupying former incised valleys (Shanley & McCabe 1993).

Six depositional facies were identified which contribute to the overall heterogeneous nature of the Waarre C Formation (Figure 5.11). These were defined by their grain fabric and sedimentary structures, which in turn reflected the environment in which they were deposited.

A strong relationship was identified between these six depositional facies and reservoir quality, the facies (sand channels and shales) undoubtedly constrain the spatial arrangement of permeability streaks and low flow baffles between the injector and monitoring wells. A paleo-environmental model was therefore essential to understanding the dimensions and orientations of the six interpreted facies. The stacked nature of the sediments interpreted from core observations suggested the environment was dominated by river courses forced to conform to the north-west/south-east trending topographic troughs.

Regionally, deposition of the Waarre C Formation was probably affected by contemporaneous structural control, which would have had an important influence over orientation of feeder systems, valley incision and marine incursion, suggesting the river courses would be forced to conform to the northwest/southeast trending topographic troughs. Subsequently the study drew on depositional models and analogues for fluvially- dominated low sinuosity channels, feeding shallow marine inlets, frequently influenced by tidal processes and marine storm surges such as those encountered at present-day Hervey Bay, Queensland, Australia (Figure 5.12). Resulting sand and shale distribution appropriate to this type of setting, mean the permeability conduits within channels can be expected to be highly connected in excess of the distance between the injection and monitoring wells (>300 m). Both Naylor-1 and CRC-1 intersected at least two 1m-3m thick shale baffles. The main uncertainty was whether they were continuous or truncated between the wells. This had implications for interpreting vertical connectivity between the injection perforations and the sampling points at Naylor-1 which span these shales. Unlike the channel sands, the distribution of shale-dominated abandoned channel fill was expected to be more restricted due to down-cutting channels eroding the fine grained sediment. Thus the resulting permeability baffles were not expected to be greater than 80 m to 200 m wide.

5.5.2 Pore-scale

Recent advances in digital core analysis now mean that pore-scale properties can be studied from X-ray microtomographic images (Figure 5.13). The pore and mineral phase structure of the reservoir core material from CRC-1 was enumerated in 3D using X-ray microtomographic technology (Knackstedt 2010). Quantification of the pore space interconnectivity, pore to throat ratio, and pore shape allowed for analysis of the permeability heterogeneity and anisotropy of each sand type present in the reservoir. The results supported the conclusion that reservoir quality and resulting CO_2 flooding processes are related to the different depositional facies.

The X-ray microtomographic study involved sampling four of the facies: 1) the poorly consolidated, poorly sorted gravel dominated channel sandstone; 2)the fine laminated wave

Modern Day Aanalogue

Conceptual Model

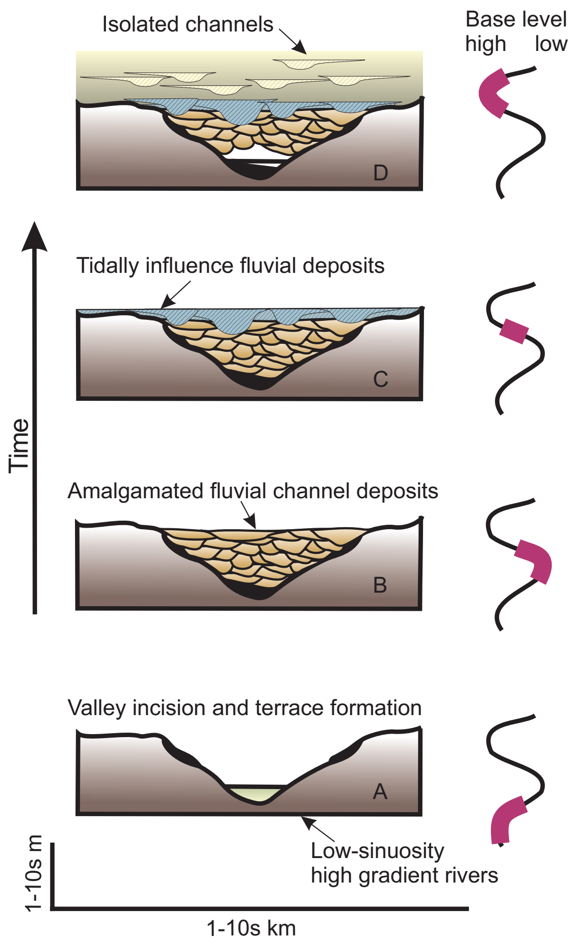


Figure 5.12: Hervey Bay in Australia, a modern day analogue for the paleo-depositional environment for the Waarre C Formation (photograph courtesy of Simon Lang); and a conceptual depositional model for an incised valley fill sequence (modified from Shanley and McCabe, 1993).

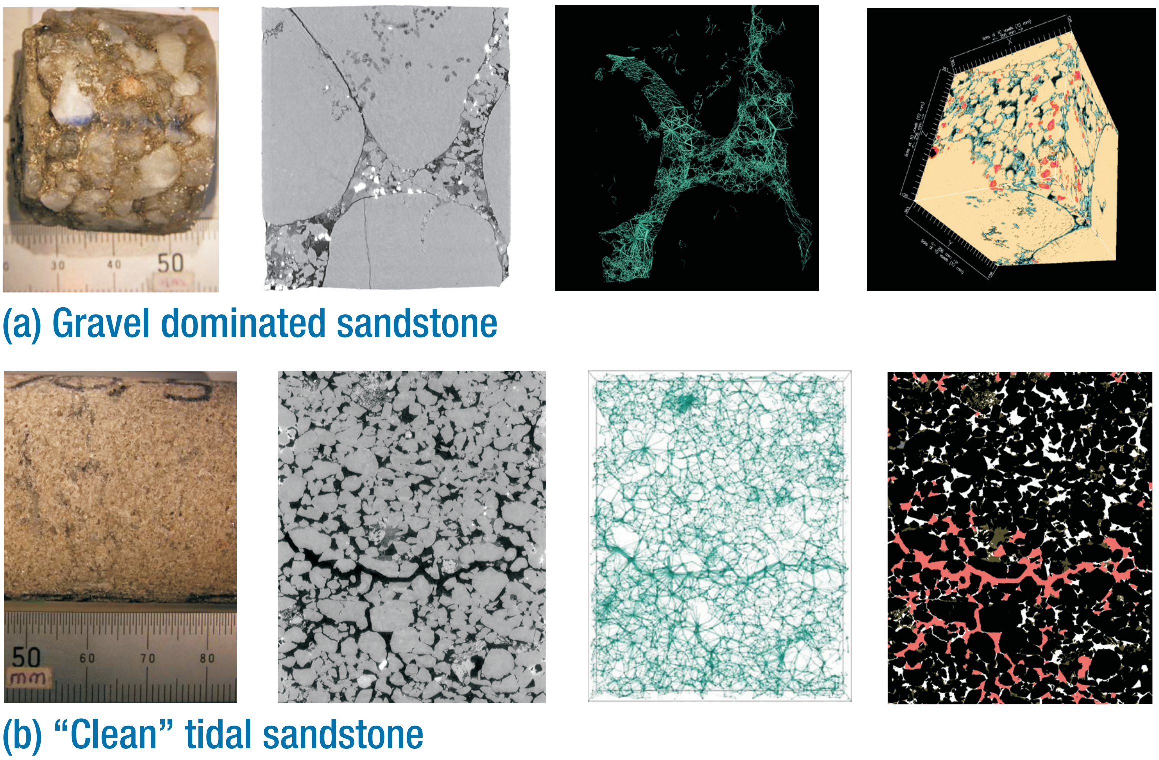


Figure 5.13: Examples of the micro-tomographic analysis performed on (a) the poorly consolidated gravel; and (b) the well sorted, quartz-rich tidal sandstone; from left to right the images are of the core specimen, an image slice parallel to bedding, the 3D pore network connectivity (green), and the simulated residual non-wetting phase CO_2 (red).

reworked sandstone; 3) the highly bioturbated transgressive sandstone; and 4) the relatively clean, well sorted, well rounded quartz sands of the tidal channel sandstone. 1.5 inch (38 mm) plugs were imaged with micro-CT at a resolution of ~20 microns. 2D backscattered scanning electron microscopy (SEM) and automated mineralogical identification (QEMSCAN®) data were acquired and registered on the 3D image so that virtual slices of the sample grains, pores and minerals could be viewed from any angle. The samples were flooded with an analogue fluid (n-hexane) that mimics CO_2 behaviour at ambient conditions, and were scanned again at various states of saturation. This provided insight into fluid distribution in the pore-spaces (Figure 5.13).

Results are summarised in Table 5.2. Porosity and permeability from conventional core analysis is compared for each facies along with the micro-tomographic derived mean pore size, mean throat size, pore to throat aspect ratio, and connectivity factor for the four facies tested. These parameters were shown to be related to the residual (non wetting phase) fluid saturation. For example low connectivity (<4) and high aspect ratios have been correlated to high trapped non-wetting phase saturations (Chatzis, et al. 1983). The wave-reworked sample appears to be an example of this: It has distinct anisotropy in the pore network due to the strong laminations and relatively good permeability horizontal to bedding (k_x=130 md and k_y=165 md), but low permeability perpendicular to bedding (<1 md in the z direction). The low connectivity value of 3.3 suggested quite high trapped non-wetting phase residual saturations. Similarly, the heavily bioturbated sample exhibited lower connectivity (3.4), due to extensive clay-filled burrows and pyrite-rich laminations reducing the porosity. This indicated higher residual (non-wetting phase) trapping was possible in these rocks. For the gravel-dominated sample the horizontal and vertical permeability obtained was 2.8 and 2.1 darcy respectively. The mean connectivity for the sample is relatively high (5.1), due to the large angular grains, therefore the facies had relatively lower residual (non-wetting phase) trapping potential. The clean tidal sandstone had well connected porosity throughout and at this scale, little heterogeneity was observed. Permeability values were isotropic—in the order of 500 md. The higher connectivity of 4.9 indicated relatively lower potential for high residual (non-wetting phase) saturations.

5.6 Containment

5.6.1 Primary containment mechanisms

Structural trapping was considered to be the dominant mechanism for containment of the CO_2 at the Naylor field. The CO_2 would rise due to buoyancy, towards the top of the fault-bound trap (as a result of the CO_2 being the non-wetting phase). The CO_2 would settle beneath the methane gas cap at the top of the structure, as it was slightly denser than the methane; nevertheless some mixing of the two gas volumes was expected to occur. This mixed composition, but continuous gas column, was contained by both the overlying seal and the seal juxtaposed across the bounding fault.

Coring at CRC-1 allowed sampling of the primary seals in the Belfast Mudstone and Flaxman Formation. The Belfast Mudstone is an exceptionally good seal, that is known to have diapiric and shale flow features throughout the Otway Basin (Stilwell and Gallagher, 2009). Mercury injection capillary pressure tests were conducted on samples of the seal by Daniel (2007). These tests determined threshold or breakthrough pressures which were subsequently used to calculate the carbon dioxide retention height of the sealing rocks (see Chapter 6). Pore throat size distributions were also determined for the analysed samples and the laboratory mercury/air values were converted to equivalent subsurface supercritical carbon dioxide ($scCO_2$) values to determine subsurface water saturation versus height relationships. Recent experimental evidence by Chiquet and Broseta, (2005) showed that $scCO_2$ may be partially wetting (depending on contact angle), with respect to quartz and mica-rich rocks under subsurface conditions. As a consequence of this evidence, CO_2 column heights were calculated with contact angle sensitivities from 0º to 60º in 20º increments to indicate the possible minimum column height. For example, at a contact angle of 0^o the Belfast Mudstone sample minimum column heights ranged from 607 m to 851 m with an average $scCO_2$ column height of 754 m. However, using a contact angle of 60º the minimum column heights for the same samples ranged from 303 m to 426 m. The maximum possible column height of the plume was expected to be in the order of 43 metres, given the top of the structure is at 1972 m TVDSS and the spill point is at 2015 m TVDSS.

Samples from the seal were also analysed using Scanning Electron Microscopy (SEM) which confirmed the geological interpretation and inferred that the formations' exceptionally good sealing capacity was due to burial depth and depositional environment. Significant compaction reduced the mudstone's microporosity; the high percentage of clay minerals, specifically smectite and illite suggested it was deposited in a distal marine depositional environment. Because it was unconsolidated to semi-consolidated during the syn-depositional phases of tectonic deformation, it is possible that many of the fault planes interpreted to go through the Belfast Mudstone lithology are in fact, effectively 'annealed', excepting perhaps those reactivated during the late Tertiary. Backing up the assertion that the Belfast Mudstone forms an exceptionally good seal, is the fact that there are virtually no significant gas fields in formations shallower than the Waarre Formation, nor any gas effects (e.g. small bright spots on seismic sections indicative of migration of gas through this otherwise immature section) in any reservoirs above the Waarre Formation.

The faults flanking the Naylor Field, terminate within the Belfast Mudstone and do not appear to have been reactivated during the Tertiary. Their reactivation potential was the subject of a study by Vidal-Gilbert et al. (2010) that investigated fault activation propensity in both strike slip and normal stress regimes. The minimum pore pressure increase required to cause fault reactivation for optimally-oriented faults ranged from 1 MPa to 37 MPa, with an initial pore pressure at the top of the reservoir of 17.5 MPa, depending on assumptions made about stress regime, fault strength, reservoir stress paths and Biot's coefficient.

5.6.2 Secondary containment mechanisms

Residual gas trapping was likely to be a containment mechanism for some of the CO_2 as it migrated up-dip from the injector to the top of the structure. The CO_2 becomes trapped in the pore space as a residual immobile phase by capilliary forces. The injected gas displaces methane and formation water (gas-water relative permeability hysteresis). At the tail of the migrating CO_2 plume, imbibition processes are dominant, as the formation water (wetting-phase) re-enters the pore space behind the migrating CO_2 (non-wetting phase). When the saturation level of the CO_2 falls below a certain level, it becomes trapped in the intragranular pore space by capillary pressure forces (snap-off), and ceases to flow (Ennis-King & Paterson, 2001; Holtz, 2002; Flett et al., 2003; Flett et al., 2004). A trail of residual immobilised CO_2 is left behind the plume as it migrates upward (Juanes et al., 2006). Estimates for the residual gas saturation (S_{gr}) were derived for the Waarre C from the special core analysis (SCAL) tests, RST logging, and digital core analysis. The values for S_{gr} vary between 20-40 % and are a function of the ratios of pore throats to pore bodies in the sandstone. As mentioned in the previous section, these characteristics were imaged in detail using X-ray microtomography (Knackstedt et al., 2010). By characterising the formation at multiple scales (*in-situ* down-hole, core plug scale and at the pore scale), this type of secondary containment can be better understood. It is apparent that reservoir heterogeneity in the form of small scale sedimentary features has a strong relationship with residual trapping potential of the reservoir sands just as it does with K_v/K_h.

Mineral trapping results from the precipitation of new carbonate minerals (Gunter, et al., 1993). Long-term trapping of CO_2 in carbonate phases is limited in the Waarre C due to the low abundance of necessary reactive minerals (Schacht, 2008). Additionally, the limited contact the injected gas had with moving formation water inhibited the gas reacting with any cations. Similarly, trapping by dissolution of CO_2 into the formation water was limited (Boreham et al., 2011). Conversely, a study of the greensand units of the Flaxman Formation by Watson and Gibson-Poole (2005), found that the mineral trapping potential of this overlying formation provided increased security to CO_2 storage in the Waarre C. Not only does the lower porosity of the greensands slow down the vertical migration of the CO_2 plume, but the higher proportion of labile minerals (carbonate, glauconite, and chlorite) provided the cations necessary for mineral storage of CO_2.

5.7 Site Analogue

The Iona Field is a produced natural gas field in south eastern Victoria approximately 20 kilometres east of Naylor Field. 0.532 Bcm of the initial recoverable gas reserve was produced from the field and the depleted field is currently being used as a peak demand underground gas storage site, supplying to the domestic market during the winter months. As the injection reservoir is also the Waarre C, it provides a valuable analogue for the Otway Project. The Iona storage operation commenced in December 2000 with the injection of 0.28 Bcm gas by April 2001 in its first year of operation (Mehin and Kamel, 2002). The site has proven capability to be able to inject up to nearly 2,000 tonnes of natural gas per day and withdraw around 5,000 per day without incident.

Eight wells have been drilled in the Iona Field area, in a dense array, where the wells are often less than a few hundred meters apart. This well density offers an insight into the potential variability and heterogeneity of the Waarre C reservoir that is not available at any other location. Significant core, dipmeter and reservoir studies have been undertaken in an effort to better characterise the reservoir at this site and optimise engineering practice. The minimum thickness of the Waarre C at the site is 33.1 m and the maximum is 40.2 m. None of the Iona wells have particularly thick shales within the upper sandstone section of the Waarre C unit. The thickest shale occurs in the upper Waarre C section in Iona Observation-1, but is absent in Iona-4, only 500 m away. From dip metre and down-hole log interpretation, the general depositional channel orientation is 35-40 degrees (i.e. NNE to NE), and the effective shale-out distance is estimated to be as little as 200 m. Sedimentary event units (e.g. channel bodies) are 2-3 m thick within the sandstone facies. Unlike at Naylor, there is no indication of bioturbation within either the sands or the shales. The most likely paleo-environment, based on the dip patterns, is that the sands of the reservoir interval at Iona were deposited by a high energy braided stream system, with a general northeast-southwest trend, that flowed towards the northeast.

Three of the Iona Field wells have core data for the Waarre C interval, and recent interpretations of the available cores have strengthened the view that the depositional environment was predominantly fluvial (Tenthorey et al., 2013). The dominant lithology for the Waarre C Formation, is quartz arenite with minor feldspars. The reservoir quality is exceptional and available core reports show that porosities range from 13 to 30% with the average in the high 20%. The overburden air permeability is in the range 244 md to 20 darcy with most samples between 5 darcy and 20 darcy It was established that because of the exceptionally high permeability, water flow through the reservoir is strongly channelised. Vertical to horizontal permeability ratios vary from 0.1 to greater than 1. Eight core plugs from Iona-4 underwent special core analysis (SCAL) tests. The average S_{lr} was 9.5 %, the average S_{gr} was 34.2 %, the average relative permeability k_{rgmax} at S_{gw} was 0.86, and the average relative permeability to water at residual gas saturation, was 0.11.

The Iona Field Waarre C unit is not exactly analogous to the reservoir encountered at Naylor Field. The interpretation that sediments at Iona are almost entirely fluvial is in contrast to the tidal channels and marine influence observed at Naylor, including marine biota in the biostratigraphic studies. However, reservoir quality at both Naylor and Iona is exceptionally good; porosities within the sands are generally in the high 20% and the associated permeability (at reservoir conditions), is in the multi-darcy range. Consequently injectivity is excellent. This geological information was most relevant in the early stages of CO2CRC Otway Project site selection as it implied, along with data from other wells, that good reservoir quality was regional and that the Waarre C reservoir thickness would be relatively uniform in the immediate area of Naylor (Spencer et al. 2006).

Iona was also useful as an analogue to complement the geomechanical modelling (Chapter 7). There was a wealth of engineering data from the constant injection/withdrawal cycles that could be used to improve the understanding of the mechanical stresses on the reservoir and seal. Tenthorey et al. (2013) analysed the results of dynamic simulations of the injectivity, pressure evolution, storage capacity and maximum fluid pressures sustained by the faults. The geomechanical simulations for the Iona field were re-run using CO_2 gas instead of methane in order to evaluate the effects of the different physical properties on fault seal retention column heights (i.e. wetting behaviour). Modelling the worst case scenario, where the faults have no cohesion, it was found the faults could sustain 2 MPa of pore-pressure increase without reactivation. In the more than 10 years of operation, the Iona field has experienced pressure oscillations in the order of 1-2 MPa with no observable seismicity (Tenthorey et al. 2010, 2013). Similarly modelling at the Naylor field suggested that faults cutting across the Waarre C interval possess some cohesion and the bounding faults at the Naylor Field have shown no signs of reactivation under the injection pressures.

5.8 The evolution of the static models

5.8.1 Phase 2 pre-feasibility uncertainty models

As already mentioned, in the initial pre-feasibility phase, there were little data available to guide the reservoir modelling. There was no core from the field and therefore no evidence for sedimentological facies modelling and no direct measurement for porosity and permeability. Vital checkshot data was missing in order to constrain the time-to-depth conversion of seismic horizons that defined the structural model. Well information was supplemented from regional data and extrapolated from adjacent fields (Spencer et al., 2006). Adding to this uncertainty, there were two plausible regional paleo-depositional models for the Waarre C Formation: 1) a transgressive shoreline model, whereby the main depositional trends are perpendicular to the expected CO_2 flow direction (Buffin, 1989), and 2) a braided fluvial model (Faulkner, 2000) where reservoir sands are highly connected and deposited parallel to the direction of flow. A series of static models were created to investigate the optimal location for the injector well (CRC-1). Along with the two depositional model cases mentioned above, two additional extreme cases for reservoir connectivity were also investigated 1) A fast migration model with high permeability and no shale baffles, and 2) a slow migration model with low permeability with major barriers to flow. These were considered geologically improbable but remotely possible. Without cores it was necessary to include these models for completeness, in order to understand the end member limits to the geological uncertainty.

Uncertainty in the seismic interpretation was also investigated by modelling several different possibilities for the structural dip of the reservoir that would result from shifts in the depth conversion of the horizons. This was important in order to risk the potential impacts of breakthrough occurring too early to record meaningful results, or the risk of CO_2 not arriving at the monitoring bore in the Project timeframe. All of the cases were simulated against the production data from Naylor-1 using the ECLIPSE modelling package (Xu et al. 2006). The extreme cases could not match the pressure or production data and so these cases were discounted. The braided fluvial model provided a suitable history match with the least adjustments required to the bulk permeability. Results from a biostratigraphic study (Partridge, 2006) became available during the course of these initial simulations which further discounted the transgressive shoreline model, lending more weight to the braided fluvial model (Spencer et al., 2006). This model characterised the reservoir as having a net to gross of 90%, (i.e. 90% sands to 10% shale) and an average of 700mD for bulk permeability. The optimal placement of the well, which was derived from these results, was between 280 m and 300 m in the down dip direction from Naylor-1, with breakthrough of injected CO_2 at the Naylor well, predicted to be between 6 and 14 months from the commencement of injection.

5.8.2 Phase 3 detailed pre-injection static models

A new suite of static models were created which incorporated geological details such as porosity, permeability, pressure, and the geometry of the reservoir including faults, sedimentary layers, and facies (rock types) distribution. These are the primary characteristics controlling the behaviour of stored CO_2. The underlying PETREL™ geo-cellular grid is based on a UTM projection of a 20m x 20m optimally-oriented (for the direction of flow) grid. Layering was 0.5 to 2 m thick and upscaling of the petrophysical logs to this resolution appeared to capture the vertical variation in the data and adequately represent vertical permeability. The Petrel model and a subsequent ECLIPSE model used for pre-injection modeling (Underschultz et al. 2011), uses an irregular cell geometry which honours the geometry of stratigraphic bedding, i.e. on-lap and erosional surfaces between the incised valley fill and the overlying transgressive sands. The ECLIPSE grid maintained this geometry and also incorporated local grid refinement to investigate near-well bore effects. The TOUGH2 simulation grid converted the geological model to a regular grid (see Chapter 16).

Because of the strong relationship identified between the six depositional facies and reservoir quality, the new models used facies objects (sand channels and shales) to constrain the spatial arrangement of permeability streaks and low flow baffles between the wells. Similarly a method of incorporating facies-based permeability anisotropy was developed, and was set directly in ECLIPSE™. Kv/Kh ratios from core were applied as multipliers for each facies code; this was an improvement on just using one ratio for the whole reservoir because the impact of low vertical permeability in the shale rich facies could now be discretely assessed. Depositional analogues, appropriate to this type of setting, indicated the permeability conduits within channels were likely to be highly connected over the distance of 300 m between the injector and monitoring well.

Due to the fact that the lengths predicted for sand bodies exceeded the correlation distance between wells, there was less uncertainty in the stochastic modelling. There was also uncertainty in the distribution of shale barriers as analogues suggested they were not expected to be greater than 80 m to 100 m wide due to down-cutting channels eroding the fine grained sediment. Both Naylor-1 and

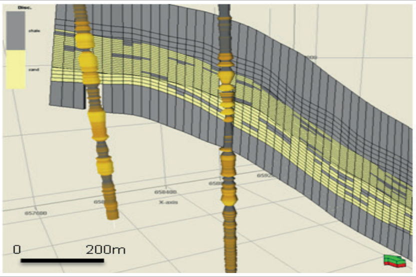
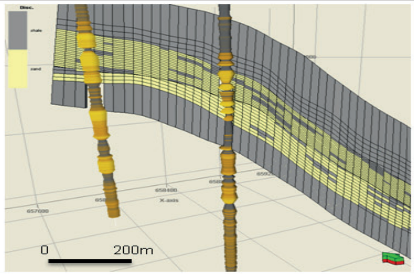
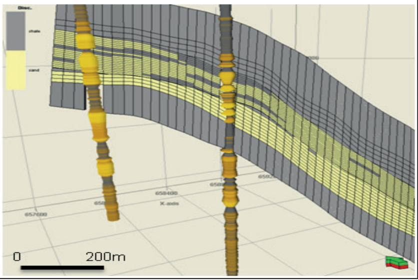
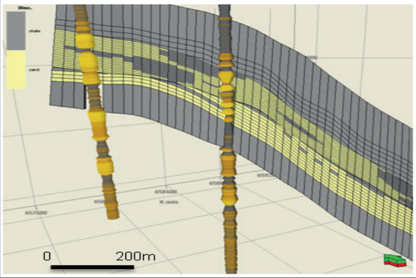
Cases (2 of 5 realisations shown for each)		Static model summary
		**Case 1:** short correlation length **Net to gross:** 12% shale 88% sand **Average bulk perm:** 1500mD **Variogram:** 60m-80m for shales
		**Case 2:** long correlation length **Net to gross:** 12% shale 88% sand **Average bulk perm:** 1500mD **Variogram:** 120m-240m for shales

Figure 5.14: Four examples of the static model realisations in cross section between the injection and monitoring boreholes. These were used in the pre-injection simulation and characterisation phase.

CRC-1 intersected at least two 1m-3m shale intervals. The main uncertainty was whether these intervals were continuous or truncated between the wells, which had implications for interpreting vertical connectivity between the injection perforations and the U-tubes which spanned these shales in both wells. Two cases were then created to address this (Figure 5.14). Case 1 used a small correlation length for the shales (60 m – 80 m), and Case 2 used a long correlation length (120 m – 240 m). Five equi-probable realizations were generated for each case, giving a total of ten models. These are summarised in Figure 5.14. Prior to injection, dynamic simulation was performed on four of the ten static models using ECLIPSE the resulting predictions suggested an expected arrival time of CO_2 at the monitoring bore of between 4 and 8 months.

5.9 Conclusions

The site characterisation of the Naylor Field for the CO2CRC Otway Project was essential to establish the injection rates and CO_2 volumes that could be accommodated and that long term containment would be assured. The workflow comprised four distinct phases: 1) An initial site screening phase; 2) A pre-feasibility phase, which assessed the regional geology and utilised existing data; 3) the targeted characterisation phase, which involved data acquisition specifically to address uncertainty unique to the CO_2 storage concept; and finally 4) the post-injection model calibration phase which was used to assess the storage performance. The geo-engineering workflow identified five key criteria that should be addressed: site details, injectivity, capacity, reservoir heterogeneity and containment. Cores, well logs (in particular formation micro imaging (FMI), nuclear magnetic resonance (CNMR), and modular dynamic testing (MDT) samples), and seismic data acquired by CO2CRC, were necessary to better understand reservoir and seal properties. Specialised analysis such as SCAL core flooding, X ray micro-tomography and tri-axial rock mechanics were employed to better understand reservoir potential and fracture limits. Other outcomes from the study were that:

- Reservoir characterisation needed to extend to the regional scale, in order to understand the hydrodynamic relationship a proposed injection site may have on adjacent producing fields and overlying aquifers, particularly if the latter contained important freshwater resources.

- Injectivity may be hindered by low permeability, mobilisation of fines, mineral precipitation, or excessive pressure build up. Cores, well testing, and time-lapse pressure measurements were required to assess these effects. These types of data may not always be available from the field production phase.
- When calculating pre-injection storage capacity, a storage efficiency factor is applied to account for both irreducible water saturation, as well as the irreducible gas saturation. Managing the volumes injected within the pressure limits of the field meant the capacity estimate would change over time particularly in the case of a depleted field with strong water recharge. The influx of water and partial re-pressurisation due to a strong aquifer drive meant the volume of gas produced did not equate to CO_2 equivalent capacity.
- Reservoir heterogeneity at the facies scale impacted plume migration and preferential channels flow through high permeability streaks. Pore scale heterogeneity impacts residual trapping potential and vertical versus horizontal permeability within reservoir sands.
- Combined petrographic analysis, mercury injection capillary pressure tests, and stratigraphic mapping was necessary to characterise the overlying mudstone seal. The potential for CO_2-mineral reactions within the overlying seal meant containment may be compromised by dissolution or further enhanced by precipitation.
- Underground gas storage facilities can provide useful analogues to CO_2 storage sites, particularly if they are in close proximity, or have similar reservoir settings to the planned injection sites as was the case with the Iona facility and the Otway site. Residual gas estimates, injectivity rates, rock mechanics, geo-body connectivity and heterogeneity (for reservoir modelling) all provided substitute information in situations where data was otherwise lacking.

Site characterisation will always be specific to project objectives such as how much CO_2 is to be injected and at what rate. The extent of data acquisition and analysis will impact on the level of risk at the site. Above all, site characterisation should aim to address the uncertainty surrounding risks and should be tested and updated as necessary during the storage performance monitoring of the project.

5.10 References

Ambrose, W.A., Lakshminarasimhan, S., Holtz, M.H., Núñez-López, V., Hovorka, S.D. and Duncan, I., 2007. Geologic factors controlling CO_2 storage capacity and permanence: case studies based on experience with heterogeneity in oil and gas reservoirs applied to CO_2 storage. Environmental Geology. 54, 1619–1633.

Bachu, S., 2000. Sequestration of CO_2 in geological media: criteria and approach for site selection in response to climate change. Energy Conversion Management. 41, 953–970.

Bachu, S., 2003. Screening and ranking of sedimentary basins for sequestration of CO_2 in geological media in response to climate change. Environmental Geology. 44, 277–289.

Boreham, C., Underschultz, J., Stalker, L., Kirste, D., Freifeld, B., Jenkins, C. and Ennis-King, J., 2011. Monitoring of CO_2 storage in a depleted natural gas reservoir: gas geochemistry from the CO2CRC Otway Project, Australia. International Journal of Greenhouse Gas Control. 5 (4), 1039–1054.

Boult, P.J., White, M.R., Pollock, R., Morton, J.G.G., Alexander, E.M. and Hill, A.J., 2002. Lithostratigraphy and environments of deposition. In: Boult, P.J. and Hibburt, J.E. (Eds.), The petroleum geology of South Australia. Volume 1: Otway Basin, South Australia. Department of Primary Industries and Resources. Petroleum Geology of South Australia Series, v. 1, 2nd edition.

Bradshaw, J., Bradshaw, B. E., Allison, G., Rigg, A., Nguyen, V. and Spencer, L., 2002. The potential for geological sequestration of CO_2 in Australia: Preliminary findings and implications for new gas field development. Australian Petroleum Production and Exploration Association Journal. 42, part 1, 25–46.

A. J. Buffin,. 1989. Waarre Sandstone development within the Port Campbell Embayment; Australian Petroleum Exploration Association Journal, v. 29(1), p.299–311.

Burton, M., Kumar, N. and Bryant, S.L., 2009. CO_2 injectivity into brine aquifers: Why relative permeability matters as much as absolute permeability, Energy Procedia. 1(1), 3091–3098.

Caritat, P. de, Hortle, A., Stalvies, C. and Kirste, D.M., 2009. CO2CRC Otway Project groundwater baseline: results of pre-injection monitoring of groundwater levels and chemistry. CO2CRC Report RPT09-1557, Canberra, Australia. Available at http://www.co2crc.com.au/publications.

Caritat, P. de, Hortle, A., Raistrick, M., Stalvies, C. and Jenkins, C., 2012. Monitoring groundwater flow and chemical and isotopic composition at a demonstration site for carbon dioxide storage in a depleted natural gas reservoir. Applied Geochemistry. Available at http://www.sciencedirect.com/science/article/pii/S0883292712001230.

Causebrook, R., Dance, T. and Bale, K., 2006. Southern Perth Basin site investigation and geological model for storage of carbon dioxide. CO2CRC Report Number: RPT06-0162, Canberra, Australia. Available at http://www.co2crc.com.au/publications.

Chadwick, A., Arts, R., Bernstone, C., May, F., Thibeau, S. and Zweigel, P. (eds.), 2007. Best practice for the storage of CO_2 in saline aquifers – Observations and guidelines from the SACS and CO2STORE Projects: Nottingham, British Geological Survey, 267 p.

Chatzis, I., Morrow, N.R. and Lim, H.T., 1983. Magnitude and detailed structure of residual oil saturation, SPE Journal, 23, 311–326.

Chiquet, P., Broseta, D., Thibeau, S., 2007. Wettability alteration of caprock minerals by carbon dioxide. Geofluids 7 (2), 112–122.

Cook, P.J., Rigg, A.J. and Bradshaw, J., 2000. Putting it back from where it came from: Is geological disposal of carbon dioxide an option for Australia? APPEA Journal. 40 (1), 654–666.

Cooper, C. (ed.), 2009. A technical basis for carbon dioxide storage: CO_2 Capture Project: UK, CPL Press, 92 p.

Dance, T. and Vakarelov, B., 2008. Sedimentology of the Flaxman Formation and Waarre C Formation from the CRC-1 cores 5&6. CO2CRC Report No: RPT08-1293, Canberra, Australia. Available at http://www.co2crc.com.au/publications.

Dance, T., Spencer., L. and Xu, J., 2009. Geological characterisation of the Otway Project pilot site: What a difference a well makes. Energy Procedia. 1 (1), 2871–2878.

Dance, T., 2013. Assessment and geological characterisation of the CO2CRC Otway Project CO2 storage demonstration site: From prefeasibility to injection. Marine and Petroleum Geology, 46(0): 251–269.

Daniel, R.F., 2007. Carbon dioxide seal capacity study, CRC-1, CO2CRC Otway Project, Otway Basin, Victoria. CO2CRC Report No: RPT07-0629, 67, Canberra, Australia. Available at http://www.co2crc.com.au/publications.

Dodds, K., Daley, T., Freifeld, B., Urosevic, M., Kepic, A. and Sharma, S., 2009. Developing a monitoring and verification plan with reference to the Australian Otway CO_2 pilot project. The Leading Edge, vol. 28 (7), 812-818. DOI: 10.1190/?1.3167783.

DOE, 2006. Carbon sequestration atlas of the United States and Canada: Appendix A – Methodology for development of carbon sequestration capacity estimates. National Energy Technology Laboratory, Department of Energy. Available from: http://www.netl.doe.gov/publications/carbon_seq/atlas/Appendix%20A.pdf.

Duran, J., 1986. Geology, hydrogeology and groundwater modelling of the Port Campbell hydrogeological sub-basin, Otway Basin, S.W. Victoria. Report 1986/24. Geological Survey of Victoria, Victoria.

Ennis-King, J. and Paterson, L., 2001. Reservoir engineering issues in the geological disposal of carbon dioxide. In: Williams, D.J., Durie, R.A., McMullan, P., Paulson, C.A.J. and Smith, A.Y., (eds.). Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies (GHGT-5), 13–16 August, Cairns, Australia. CSIRO Publishing, 290–295.

A. Faulkner. Sequence stratigraphy of the late Cretaceous Sherbrook Group, Shipwreck Trough, Otway Basin; B.Sc. (Hon) Thesis, 2000; National Centre for Petroleum Geology and Geophysics, University of Adelaide.

Flett, M.A., Taggart, I.J., Lewis, J. and Gurton, R.M., 2003. Subsurface sensitivity study of geologic CO_2 sequestration in saline formations. In: The Second Annual Conference on Carbon Sequestration, 5–8 May, Alexandria, USA. National Energy Technology Laboratory, United States Department of Energy.

Flett, M., Gurton, R.M. and Taggart, I.J., 2004. Heterogeneous saline formations: long-term benefits for geo-sequestration of greenhouse gases. GHGT7: Proceedings of the 7th International Conference on Greenhouse Gas Technologies, 5–9 September, Vancouver, Canada.

Flett, M., Beacher, G., Brantjes, J., Burt, A., Dauth, C., Koelmeyer, F., Lawrence, R., Leigh, S., McKenna, J., Gurton, R., Robinson IV, W. F. and Tankersley, T., 2008. Gorgon Project: Subsurface evaluation of carbon dioxide disposal under Barrow Island: SPE Asia Pacific Oil and Gas Conference and Exhibition, 20–22 October, Perth, Australia, p. 21.

Förster, A., Norden, B., Zinck-Jørgensen, K., Frykman, P., Kulenkampff, J., Spangenberg, E., Erzinger, J., Zimmer, M., Kopp, J., Borm, G., Juhlin, C., Cosma, C. G. and Hurter, S., 2006. Baseline characterization of the CO2SINK geological storage site at Ketzin, Germany. Environmental Geoscience. 13, 145–161.

Förster, A., Schoner, R., Forster, H.-J., Norden, B., Blaschke, A.-W., Luckert, J., Beutler, G., Gaupp, R. and Rhede, D., 2010. Reservoir characterisation of a CO_2 storage aquifer: the Upper Triassic Stuttgart Formation in the Northeast German Basin. Marine and Petroleum Geology. 27, 2156–2172.

Freifeld, B.M., Trautz, R.C., Yousif, K.K., Phelps, T.J., Myer, L.R., Hovorka, S.D and Collins, D., 2005. The U-Tube: A novel system for acquiring borehole fluid samples from a deep geologic CO_2 sequestration experiment. Journal of Geophysics. 110.

Gallagher, S.J., Taylor, D., Apthorpe, M., Stilwell, J.D., Boreham, C.J., Holdgate, G.R.,Wallace, M.W. and Quilty, P.G., 2005. Late Cretaceous dysoxia in a southern high latitude siliclastic succession, the Otway Basin, southeastern Australia. Palaeogeography, Palaeoclimatology, Palaeoecology. 223, 317–348.

Geary, G.C. and Reid, I.S.A., 1998. Hydrocarbon prospectivity of the offshore eastern Otway Basin, Victoria for the 1998 Acreage Release. Victorian Initiative for Minerals and Petroleum Report 55, Department of Natural Resources and Environment.

Gibson-Poole, C. M., Root, R. S., Lang, S. C., Streit, J. E., Hennig, A. L., Otto, C. J. and Underschultz, J. R., 2005. Conducting comprehensive analyses of potential sites for geological CO_2 storage. In: Rubin, E. S., Keith, D. W. and Gilboy, C. F., (eds.). Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, 5–9 September, Vancouver, Canada. Elsevier, Oxford. 673–681.

Gunter, W.D., Perkins, E.H. and McCann, T.J., 1993. Aquifer disposal of CO_2-rich gases: reaction design for added capacity. Energy Conversion and Management. 34 (9-11), 941–948.

Hill, K. C. and Durrand, C., 1993. The western Otway Basin: an overview of the rift and drift history using serial composite seismic profiles. PESA Journal. 21, 67–78.

Hitchon, B. (ed.), 2009. Pembina Cardium CO_2 monitoring pilot - A CO_2-EOR Project, Alberta, Canada. Geoscience Publishing, Sherwood Park, Alberta, Canada, 392 p.

Holloway, S. and Savage, D., 1993. The potential for aquifer disposal of carbon dioxide in the UK. Energy Conversion and Management. 34 (9–11), 925–932.

Holloway, S. and van der Straaten, R., 1995. The Joule II Project: the underground disposal of carbon dioxide. Energy Conversion and Management. 36 (6–9), 519–522.

Holtz, M.H., 2002. Residual gas saturation to aquifer influx: a calculation method for 3-D computer reservoir model construction. In: SPE Gas Technology Symposium, 30 April – 2 May, Calgary, Alberta, Canada. Society of Petroleum Engineers, SPE Paper 75502.

Hortle, A., de Caritat, P., Stalvies, C. and Jenkins, C., 2011. Groundwater monitoring at the Otway project site, Australia. Energy Procedia, 4, 5495–5503.

Hortle, A., Xu, J. and Dance, T., 2008. Hydrodynamic interpretation of the Waarre Formation Aquifer in the onshore Otway Basin: Implications for the CO2CRC Otway Basin Project. Proceedings of the 9th International Conference on Greenhouse Gas Technologies (GHGT-9), 16–20 November, Washington DC.

Hovorka, S. D. and Knox, P. R., 2003. Frio Brine sequestration pilot in the Texas Gulf Coast. In Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, October 1–4, Kyoto, Japan, p. 583–587.

Hovorka, S.D., Doughty, C., Benson, S.M., Pruess, K. and Knox, P.R., 2004. The impact of geological heterogeneity on CO_2 storage in brine formations; a case study from the Texas Gulf Coast. In: Baines, S.J. and Worden, R.H., (eds.) Geological Storage of Carbon Dioxide. Geological Society Special Publication 233, 147–163.

Hovorka, S. D., Benson, S. M., Doughty, C., Freifeld, B. M., Sakurai, S., Daley, T. M., Kharaka, Y. K., Holtz, M. H., Trautz, R. C., Seay Nance, H., Myer, L. R. and Knauss, K. G., 2006. Measuring permanence of CO_2 storage in saline formations: the Frio experiment. Environmental Geoscience. 13, 105–121.

IEA (International Energy Agency), Leblond, D., 2005. CO_2 capture, storage offer emissions solution: Oil & Gas Journal. 103.2, 29–30.

IEA (International Energy Agency), 2008. CO_2 capture and storage: a key carbon abatement option. OECD/IEA, Paris.

Intergovernmental Panel on Climate Change (IPCC), 2005. In:Metz, B., Davidson, O., de Coninck, H.C., Loos, M. and Mayer, L.A. (Eds.), Special Report on carbon dioxide capture and storage. Cambridge University Press, Cambridge, U.K. and New York, NY, U.S.A., 195–276 (Chapter 5).

Jenkins, C., Cook, P., Ennis-King, J., Underschultz, J., Boreham, C., de Caritat, P., Dance, T., Etheridge, D., Hortle, A., Frefeld, B., Kirste, D., Paterson, L., Pevzner, R., Schacht, U., Sharma, S., Stalker, L. and Urosevic, M., 2012. Safe storage and effective monitoring of CO_2 in depleted gas fields. Proceedings of the National Academy of Science of the USA. 109 (2), 353–354.

Juanes, R., Spiteri, E.J., Orr, F.M. and Blunt, M.J., 2006. Impact of relative permeability hysteresis on geological CO_2 storage. Water Resources Research. 42 (12), 1–13.

Kikuta, K., Hongo, S., Tanase, D. and Ohsumi, T., 2005. Field test of CO_2 injection in Nagaoka, Japan. In Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, September, Vancouver, Canada, p. 1367–1372.

Knackstedt, M., Dance, T., Kumar, M., Averdunk, H. and Paterson, L., 2010. Enumerating permeability, surface areas, and residual capillary trapping of CO_2 in 3D: Digital analysis of CO2CRC Project core. Presented at SPE Annual Technical Conference and Exhibition, Florence, Italy, 19-22 September. SPE paper 134625.

Kopsen, E. and Scholfield, T., 1990. Prospectivity of the Otway Supergroup in the central and western Otway Basin: Australian Petroleum Exploration Association Journal. 30(1), 263–279.

Krassay, A. A., Cathro, D.L. and Ryan, D.J., 2004. A regional tectonostratigraphic framework for the Otway Basin. PESA Eastern Australasian Basins Symposium II. 97–116.

Laing, S., Dee, C. N. and Best, P.W., 1989. The Otway Basin. Australian Petroleum Exploration Association Journal. 29(1), 417–429.

Maldal, T. and Tappel, I. M., 2004. CO_2 underground storage for Snøhvit gas field development. Energy. 29, 1403–1411.

Mehin, K., Kamel, M., 2002. Gas resources of the Otway Basin in Victoria. Department of Natural Resources and Environment (State of Victoria), Petroleum Development Branch, ISBN 0 7306 9481 X. Available at http://www.nre.vic.gov.au/minpet/index.htm.

Morton, J.G.G., Alexander, E.M., Hill, A.J. and White, M.R., 1995. Lithostratigraphy and environments of deposition. In: Morton, J.G.G. and Drexel, J.F. (Eds.), The petroleum geology of South Australia, Volume 1: Otway Basin. Mines and Energy South Australia, Report 95/12, 127–139.

Partridge, A.D., 2001. Revised stratigraphy of the Sherbrook Group, Otway Basin. In: Hill, K.C., Bernecker, T., (Eds.), PESA Eastern Australasian Basins Symposium, p.455–464.

Partridge, A.D., 2006. Depositional environments of the Waarre C unit – the palynological constraints. International Biostrata Pty Ltd Report 2005/24.

Perrin, J.C., Krause, M., Kuo, C.W., Miljkovic, L., Charoba, E. and Benson, S.M., 2009. Core-scale experimental study of relative permeability properties of CO_2 and brine in reservoir rocks. Energy Procedia. 1, 3515–3522.

Riddiford, F. A., Tourqui, A., Bishop, C. D., Taylor, B. and Smith, M., 2003. A cleaner development: the In Salah Gas Project, Algeria. In Proceedings of the Sixth International Conference on Greenhouse Gas Control Technologies, October 1–4, Kyoto, Japan, p. 595-600.

Riddiford, F., Wright, I., Bishop, C., Espie, T. and Tourqui, A., 2005. Monitoring geological storage in the In Salah Gas CO_2 storage project. In Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies, September, Vancouver, Canada, p. 1353–1359.

Sayers, J., Marsh, C., Scott, A., Cinar, Y., Bradshaw, J., Hennig, A., Barclay, S. and Daniel, R., 2007. Assessment of a potential storage site for carbon dioxide: a case study, southeast Queensland, Australia. Environmental Geosciences. 13 (2), 123–142.

Schacht, U., 2008. Petrological investigations of CRC-1 core plug samples: Waarre C, Flaxman, and Paaratte Formation. CO2CRC report number RPT08-1234, Canberra Australia. Available at http://www.co2crc.com.au/publications.

Sharma, S., Cook, P.J., Robinson, S. and Anderson, C., 2006. Regulatory challenges and managing public perception in planning a geological storage pilot project in Australia. In Proceedings of the 8th International conference on Greenhouse Gas Control Technologies, June, Trondheim, Norway.

Sharma, S., Cook, P., Berly, T. and Lees, M., 2008. The CO2CRC Otway Project: overcoming challenges from planning to execution of Australia's first CCS project. Energy Procedia. 1 (1), 1965–1972.

Shanley, K. W. and McCabe, P. J., 1993. Alluvial architecture in a sequence stratigraphic framework: a case history from the Upper Cretaceous of southern Utah, USA. In Flint, S.S. and Bryant, I.D., (eds.). The geological modeling of hydrocarbon reservoirs and outcrop analogues: International Association of Sedimentologists Special Publication 15, 21–56.

Spencer, L., Xu, Q., LaPedalina, F. and Weir, G., 2006. Site characterization of the Otway Basin Storage Pilot in Australia. Proceedings of the 8th International Conference on Greenhouse Gas Control Technologies (GHGT-8), 19–22 June, Trondheim, Norway.

Stalker, L., Boreham, C., Underschultz, J., Freifeld, B., Perkins, E., Schacht, U. and Sharma, S., 2009. Geochemical monitoring at the CO2CRC Otway Project: Tracer injection and reservoir fluid acquisition: Energy Procedia. 1, 2119–2125.

Stevens, S.H., Kuuskraa, V.A, Gale, J.J. and Beecy, D., 2000. CO_2 injection and sequestration in depleted oil and gas fields and deep coal seams; worldwide potential and costs. AAPG Bulletin. 84, 1497–1498.

Stilwell, J.D. and Gallagher, S.J., 2009. Biotratigraphy and macroinvertebrate palaeontology of the petroleum-rich Belfast Mudstone (Sherbrook Group, uppermost Turonian to mid-Santonian), Otway Basin, southeastern Australia. Cretaceous Research. 30, 873–884.

Underschultz, J., Boreham, C., Dance, T., Stalker, L., Freifeld, B., Kirste, D. and Ennis-King, J., 2011. CO_2 storage in a depleted gas field: an overview of the CO2CRC Otway Project and initial results. International Journal of Greenhouse Gas Control. 5 (4), 922–932.

Varma, S., Underschultz, J., Dance, T., Langford, R., Esterle, J., Dodds, K. and van Gent, D., 2009. Regional study on potential CO_2 geosequestration in the Collie Basin and the southern Perth Basin of Western Australia. Marine and Petroleum Geology. 26, 1255–1273.

Tenthorey, E., Nguyen, D. and Vidal-Gilbert, S., 2010. Applying underground gas storage experience to geological carbon dioxide storage: A case study from Australia's Otway Basin. In proceedings of the 10th International Conference on Greenhouse Gas Control Technologies (GHGT-10), Amsterdam, The Netherlands, 19–23 September.

Tenthorey, E, Vidal-Gilbert, S, Backe, G, Puspitasari,R, John, Z, Maney,B and Dewhurst,D, 2013. Modelling the geomechanics of gas storage: A case study from the Iona Gas Field, Australia. International Journal of Greenhouse Gas Control, vol. 13, pp. 138–148.

van der Meer, L. G. H., 1993. The conditions limiting CO_2 storage in aquifers. Energy Conversion and Management. 34 (9-11), 959–966.

van Ruth, P. and Rogers, C., 2006. Geomechanical analysis of the Naylor Field, Otway Basin, Australia. CO2CRC Report number RPT06-0039, Canberra Australia. Available at http://www.co2crc.com.au/publications.

Vidal-Gilbert, S., Tenthorey, E., Dewhurst, D., Ennis-King, J., Van Ruth, P. and Hillis, R., 2010. Geomechanical analysis of the Naylor Field, Otway Basin, Australia: implications for CO_2 injection and storage. International Journal of Greenhouse Gas Control. 4 (5), 827–839.

Watson, M. and Gibson-Poole, C., 2005. Reservoir selection for optimised geological injection and storage of carbon dioxide: a combined geochemical and stratigraphic perspective. In Conference Proceedings of the Fourth Annual Conference on Carbon Capture and Sequestration, DOE/NETL, May, Virginia, United States.

Wilson, M. and Monea, M., (Eds.), 2004. IEA GHG Weyburn CO_2 Monitoring & Storage Project – Summary Report 2000-2004. In Proceedings of the 7th International Conference on Greenhouse Gas Technologies, September, Vancouver, Canada. 3, 273.

Woollands, M.A. and Wong, D., (Eds), 2001. Petroleum Atlas of Victoria. Victorian Department of Natural Resources and Environment. Available at http://dpistore.efirst.com.au/product.asp?pID=9&cID=6.

WRI, 2008. CCS Guidelines: Guidelines for carbon dioxide capture, transport, and storage. Washington, DC, World Resources Institute, p. 144.

Xu, J., Weir, G., Ennis-King, J. and Paterson L., 2006. CO_2 migration modelling in a depleted gas field for the Otway Basin CO_2 storage pilot in Australia. In Proceedings of the 8th International Conference for Green House Gas Control Technologies (GHGT-8), 19–22 June, Trondheim, Norway.