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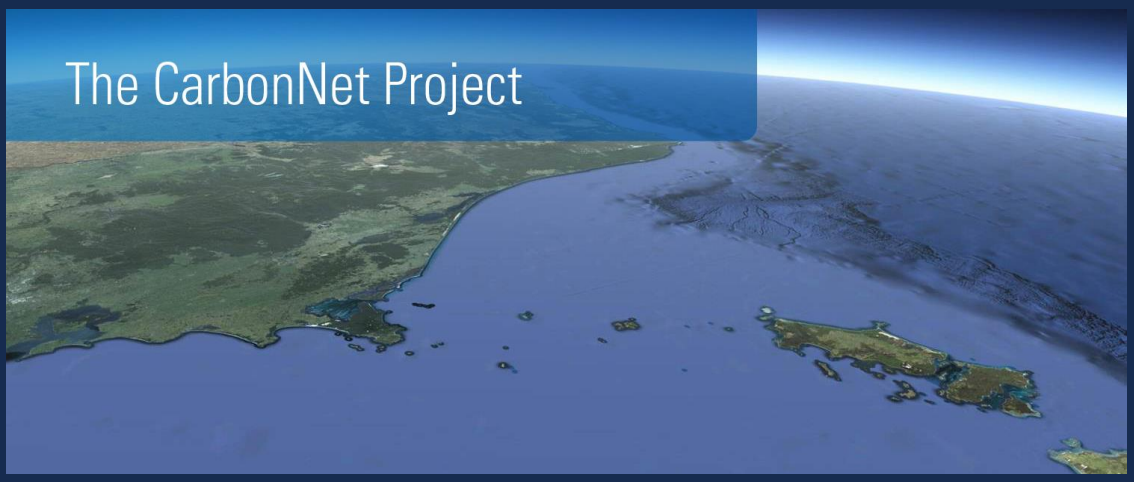

Site characterisation for carbon storage in the near shore Gippsland Basin

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Site characterisation for carbon storage in the near shore Gippsland Basin

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Abstract

During its assessment of carbon storage sites in the nearshore Gippsland Basin, the CarbonNet Project screened a large number of potential sites, comparing storage capacity (total CO_2 volume), injectivity (CO_2 rate), and containment (security). Several play fairways and a range of trap types were compared and progressively more-detailed geological models built to enable site- and scenario specific injection modelling, and for studies of the evolution of the injected CO_2 plume using state-of-the-art petroleum industry software.

After screening, three key sites were high-graded in the nearshore, each with a minimum secure storage capacity of >25 Mt CO_2, and safe containment over 1000 years of plume modelling. The geological context, storage concept, and specific reservoir and seal elements of these three sites will be described and compared, in the context of Australian legislation which requires a demonstration of the "fundamental suitability determinants for CO_2 storage".

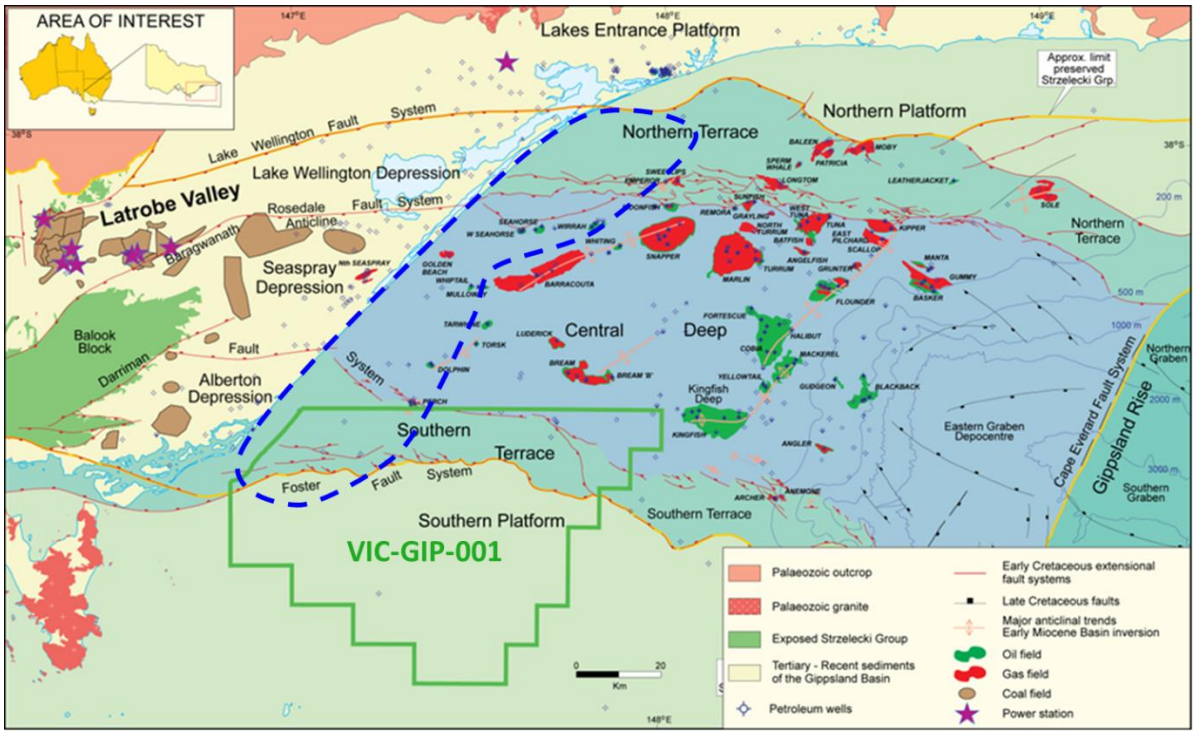
Different trap types can more or less easily meet the regulatory requirements for a Declaration of Storage Formation. The nuances of meeting these regulations are discussed and, in particular, the extent of any supercritical or dissolved CO_2 plume and any interactions coupled by reservoir pressure with nearby resource owners. Depending on the location of each site, and the trap concept, different approaches are required to address the regulatory requirements but all of these require a detailed and functional geological model of not just the site, but the wider area within which it sits. Given this model, a detailed dynamic reservoir model can be built, the quality and accuracy of the model reviewed and used for a wide range of purposes including plume extent, pressure influence, storage security, and development of a site monitoring plan including the best locations and technologies for surface and subsurface monitoring.

A number of preconceptions for the basin were addressed that directly affect seal integrity (both the regional petroleum caprock, and additional intraformational seals). In order to understand the capacity and effectiveness of these seals, updated petroleum migration models were required that explain the existing distribution of primary hydrocarbons, and those modified by water washing, biodegradation, and other processes. Significant advance has been made in understanding the basin paleogeography and palaeobathymetry during seal deposition, and mapping seal facies and seal perturbations in unprecedented detail.

1 Introduction

In this paper, the approach to and results of geological site characterisation for the CarbonNet Project are presented and discussed (see Figure 1 for project location).

Figure 1: Basin Map



The CarbonNet area of interest (blue dashed line) covers the nearshore Gippsland Basin out to approx 25 km from the coastline, but avoiding major hydrocarbon accumulations. Basin architecture is a classic E-W rift basin with fill of fluvial clastics from the west and a shoreline backstepping over time from the eastern limit of the basin at ~80 Ma to behind the modern (intra-glacial) shoreline at ~25Ma, then advancing to the shelf edge at glacial lowstands. The northern and southern boundaries of the basin are fault-delimited and the rift section is thinned/partially eroded with poorer trapping potential.

The site screening process used by CarbonNet follows that laid out in DNV GL Recommended Practice DNV-RP-J203 (DNV, 2012) and leads to an initial set of screening requirements. In this basin, for the commercial-scale sites required by CarbonNet for the storage of up to 125 Mt of CO_2, the key constraints relate to capacity, injectivity, and containment.

Capacity is used as a screening tool to eliminate sites with inadequate volumetric potential. Injectivity is a fundamental requirement for an offshore project. Important comparisons are made to other worldwide projects on a reservoir permeability-thickness diagram which graphically illustrates injectivity on a per-well and whole project basis (Figure 3).

In this report, we introduce the concept of classification of carbon storage projects into three reservoir types (Figure 3). TYPE 1 covers high permeability reservoirs such as Sleipner where injectivity per well is high, storage capacity is determined by the physical geometry of the reservoir containing lateral plume movement, and vertical containment is by an effective topseal. TYPE 2 covers lower permeability reservoirs such as the basal Cambrian play in North America where well injectivity is moderate, capacity is determined by well number and distribution, and to a lesser extent by plume migration and sub-regional pressure constraints, and vertical confinement is again by an effective topseal. TYPE 3 are low permeability reservoirs as favoured by acid gas storage projects where injectivity per well is low, and total project capacity is low and is constrained by local geomechanical

stability. Vertical containment may be by an effective topseal, or merely by the limited permeability of the reservoir itself.

Containment is a fundamental requirement of storage and the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (OPGGSA, 2006) emphasises this appropriately with a number of key tests for storage sites to demonstrate conformance of the CO_2 plume to predictions and a risk-based approach to containment assessment.

The project has followed a process of site screening for a portfolio of sites, on a play fairway basis, allowing multiple sites to be assessed in a single pass of technical work. In this way, the substantial cost of technical assessment of a CO_2 storage site is shared between multiple sites in a cost-effective manner. The portfolio of sites is characterised by depositional environment, sedimentary processes, petrophysical properties, and aquifer geochemical and geomechanical context. A deliberate decision is taken to select a mixture of independent sites which share some characteristics but differ in other significant aspects with regards to their storage concept and key sealing features. As a result, failure at one site would not invalidate all sites, but success in one site may reduce risk at one or more other sites.

The key characteristic of the CarbonNet sites is that they are TYPE 1 sites and have high natural injectivity – almost as high as for the Sleipner project. As a consequence, there are almost no pressure or capacity issues, and confining seals are not put under stress. High per-well injectivity of up to 5 Mtpa allows for economic offshore development. Onshore projects may find that an order of magnitude less injectivity is sufficient, with lower onshore costs, but a further order of magnitude reduction is likely to render a project unfeasible – as seen by several failed projects worldwide.

The three CarbonNet high-graded sites are described, and an analysis made of the key requirements under the OPGGSA, 2006. With high injectivity comes high plume mobility, and the legislative need to forecast plume travel path with 90% accuracy leads to a preference for structural traps, where the natural movement of the plume is automatically confined by structural closure.

However, higher trapping efficiency through dissolution and residual gas trapping in more open aquifer traps with long plume migration distance is the best option in CarbonNet's high permeability reservoirs. The best method to utilise these long plume migration traps is found to be downflank injection adjacent to a structural trap, with relatively long-distance migration before arriving at a secure trapping geometry. In this way, the maximum storage efficiency and maximum plume path confidence can be combined.

During this study of subsurface geometry and reservoir properties, two substantial factors have assisted the rapid accumulation of comprehensive basin and site understanding:-

1. The basin is a successful and prolific petroleum province, and therefore there is a large amount of industry data (wells and seismic surveys) and many detailed studies, reports, and scientific papers about the oil and gas accumulations, their reservoirs and seals, and the basin stratigraphy, depositional setting, and tectonic history.
2. Australia has a comprehensive open-file data system where petroleum data is released after a time period of 3-5 years and stored for free public access. Without this foresighted regime, only established petroleum companies would be able to work-up sites for CO_2 storage with existing confidential data that they already own or have access to through trades or other arrangements.

CarbonNet has progressed three sites to the stage of detailed study and one of these is now ready for site appraisal – the next step in site characterisation, to bring it to an injection-ready condition.

2 Project background

CarbonNet is one of two Australian Government Carbon Capture and Storage Flagship Program projects. The project is currently in feasibility and commercial definition stage, and is investigating the potential for establishing a world class, large scale, multi user carbon capture and storage (CCS)

network in the Gippsland Region of Victoria, Australia (Figure 1). The network will bring together multiple CO_2 capture projects in Victoria, transporting CO_2 via a shared pipeline, and injecting it deep into an underground offshore storage site. As a first step in establishing commercial storage in this basin, CarbonNet seeks to demonstrate capacity and integrity of CO_2 storage such that the selected site will be suitable for storage of a minimum of 25 Mt of CO_2 and up to 125 Mt. Anticipated injection rates at the selected site will range from a minimum of one Mtpa up to five Mtpa, which would occur over a period of at least 25 years. Scalable infrastructure will be designed to underpin long term growth and deployment of a CCS network, at which time additional storage sites may become viable, including depleted oil and gas fields, basin-centre storage, large-scale stratigraphic traps, and some of the targets excluded in the earlier rounds of investigation. Detailed infrastructure design is not part of this study.

The Gippsland Basin has long been recognised as one of the most promising sedimentary basins in Australia for CO_2 storage, due to the combination of a world-class petroleum system with excellent Latrobe Group reservoirs, overlying seals, and giant traps (Table 1), combined with proximity to the Latrobe Valley where 60 Mt of CO_2 is emitted annually by brown-coal power generation and easily accessible, large coal reserves provide the opportunity for other products.

The present CarbonNet Portfolio of Storage Sites is the end result of a broad two-stage screening process. Firstly, a review of the basins across Victoria as potential repositories for Latrobe Valley CO_2. The second stage then progressively focussed on the Gippsland Basin, sub-regions within it, and then compiled an inventory of prospective storage sites and progressively winnowed that inventory to retain only large and secure prospects. See also Hoffman et al., 2015a.

Table 1: Gippsland Basin stratigraphy - reservoirs and seals

Group	Subgroup	Comments
Seaspray Group		Cover section dominated by marine carbonates and marls, including 500m-2000m Gippsland Limestone Formation and basal 100-300m Lakes Entrance Formation (regional seal for oil and gas fields)
Latrobe Group	Cobia Subgroup	High net:gross and excellent quality terrestrial to paralic clastic reservoirs with several giant gas fields and smaller oil fields. Meteoric aquifer with internal aquitards such as the Traralgon Formation T2 member
	Halibut Subgroup	High net:gross good to excellent quality terrestrial to paralic clastic reservoirs with several giant oil and gas fields. Divided into Upper, Middle, and Lower Halibut Subgroups
	Golden Beach Subgroup	Fringing facies of generally coarse-grained terrigenous clastics and conglomerates with relatively poor porosity and permeability. Paralic facies developed in furthest offshore part of basin.
	Emperor Subgroup	Early lacustrine phase of Latrobe Group. Contains range of facies including lacustrine shales and fringing coarse clastics.
Strzelecki Group		Poorly-sorted volcaniclastics with poor porosity and permeability. Formerly deeply buried and now uplifted. Effectively economic basement but has some tight gas potential onshore.

Early work identified the nearshore of the Gippsland Basin as the prime study area for CarbonNet to search for and quantify prospective storage sites for the following reasons:-

1. Location should be within known Gippsland Basin reservoirs and under proven topseals.
2. Location should avoid large-value, currently producing oil and gas fields in the offshore basin.

3. Location should avoid storage under land areas where access for storage is potentially more difficult and where the top of the Latrobe Group is generally too shallow for supercritical phase.

This determined the area of study in the nearshore Gippsland Basin, from the shoreline to approximately 25 km offshore, and with southern and northern boundaries defined by major fault systems where the basin stratigraphy thinned significantly (Figure 1).

CarbonNet has, during the past three years, performed numerous technical and non-technical investigations using available data from the three sites and their surrounding area. Results of this work allowed site screening to be completed, resulting in confirmed high-grading of the three potential storage sites from an initial portfolio of 20+ sites distributed across the nearshore Gippsland Basin, within 25 km of the coastline.

To ensure that the CarbonNet site screening process and the future Appraisal Plan for the selected site(s) meets the highest standards for quality, rigor and international best practice, the CarbonNet team has chosen to follow the recommended practice guidelines established by Det Norske Veritas (DNV GL). DNV GL is a worldwide, leading organization in the field of risk management for the safeguarding of life, property, and the environment. This recommended practice involves a multi-step, stage-gated process and is detailed in DNV GL Recommended Practice DNV-RP-J203 (DNV, 2012). The CarbonNet process is more fully detailed by Hoffman et al., 2015a. The first step in the process is site screening, which CarbonNet successfully completed early in 2013, with the issuance of DNV Statement of Feasibility for the portfolio of three sites.

3 Available regional database

The OPGGSA, 2006 and its precursor petroleum Acts have a regulatory requirement to release all basic data within a few years of acquisition. As a result, a very large database is available to all explorers, including those seeking CO_2 storage. In the Gippsland Basin over 1500 exploration and development wells are available on open-file databases, and all of the 3D and 2D data recorded is also available for the cost of copying to digital media (Figure 2).

Figure 2: Database

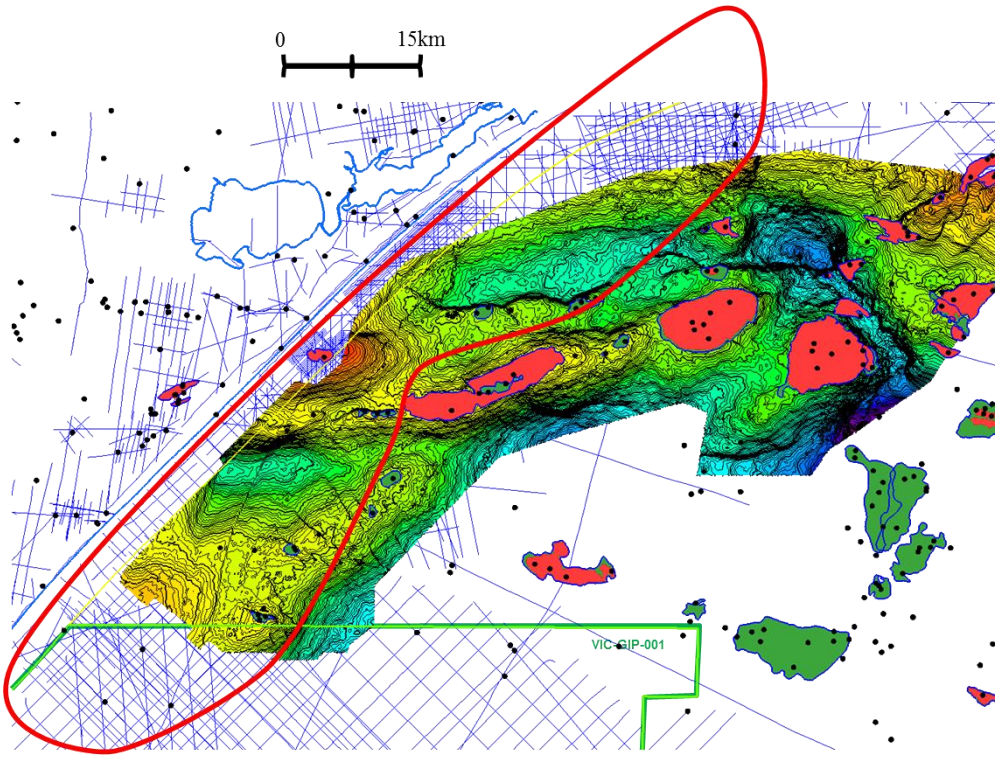


Figure 2 is a map showing exploration wells (black dots), oil and gas fields (green and red fill), 2D seismic data (dark blue lines) and 3D coverage in nearshore – structure contour map from CarbonNet mapping and depth conversion. 3D data extends further into the basin but is less relevant at this stage to CarbonNet nearshore area of interest – red line. As at April 2015, CarbonNet holds Greenhouse Gas Assessment Permit VIC-GIP-001 on the southern margin (green line). Coastline and major lakes marked with light blue lines. Yellow line parallel to shore is 3 nautical mile limit of State jurisdiction.

4 Key screening parameters for storage projects

In practice, capacity, injectivity and containment are the key screening parameters that have proven to be more effective or decisive in determining whether a prospective storage site is adequate, but before analysing those parameters and how they have been used to screen sites in the Gippsland Basin, it is important to consider the nature of potential storage site reservoirs in a range of worldwide storage projects.

The concept of classification of carbon storage projects into three reservoir types is introduced (Figure 3). The figure shows a crossplot of permeability and thickness for the main reservoirs selected by a number of projects worldwide. These reservoir types are relatively homogenous reservoirs (generally clastic, but some carbonates) that form distinct layers or units from 10m to 1km+ in thickness. The diagram is a log-log plot, and each order of magnitude of injectivity is marked by a bold black diagonal line. The right-most of these is 1000 darcy-metres, and it can be seen that the Sleipner project exceeds this value of injectivity. The Gippsland Basin falls in the next segment below Sleipner, at about 18% of its injectivity. In the future, if depleted oil and gas fields at top Latrobe Group become available, they will have an injectivity of about 40% that of Sleipner.

Figure 3: Thickness-Permeability crossplot for Injectivity

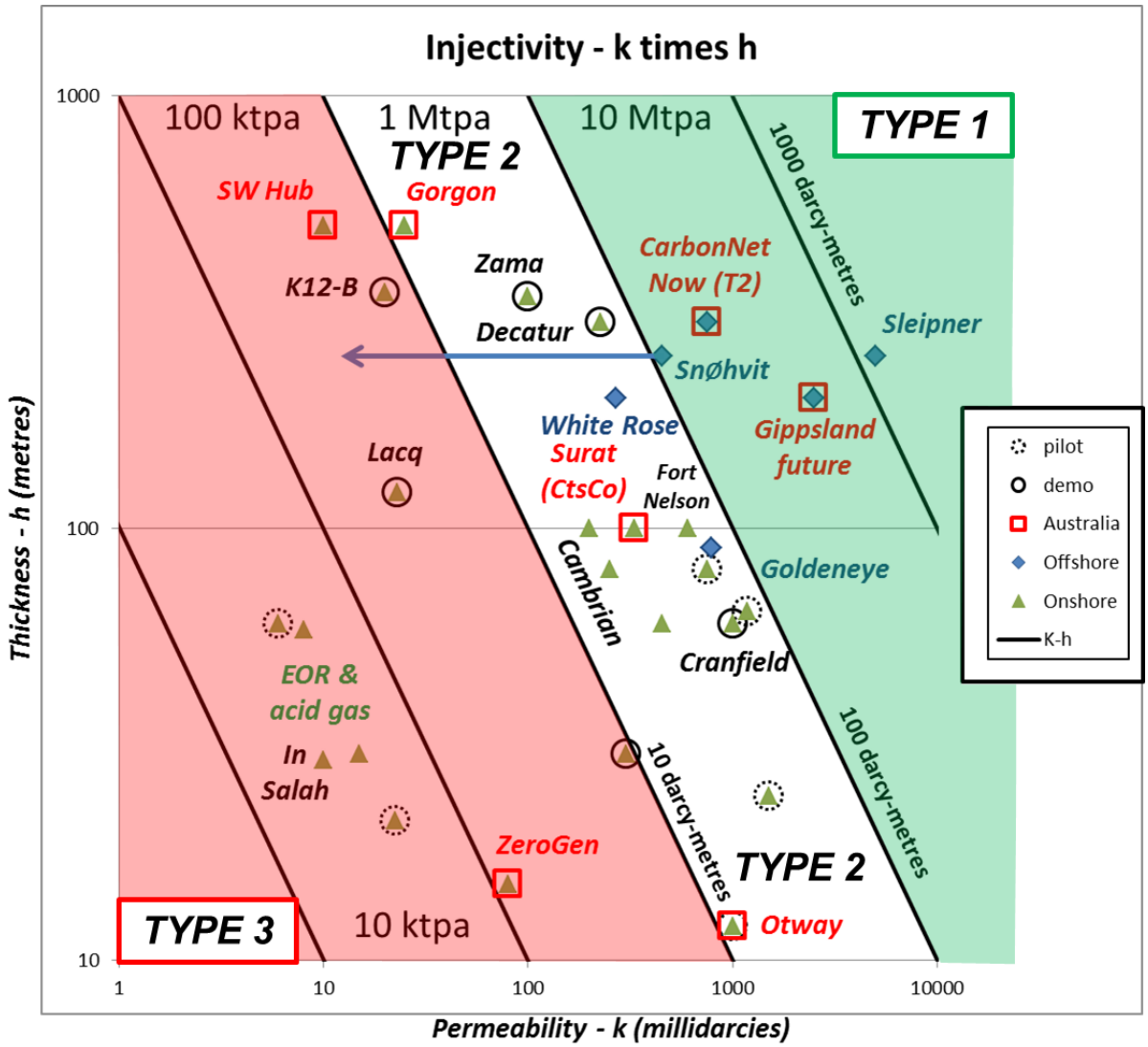


Figure 3 shows injectivity in darcy-metres as diagonal black lines. The proposed new classification of storage projects according to reservoir quality (injectivity) is colour-coded for TYPE 1 (green fill), TYPE 2 (white fill), and TYPE 3 (red fill). Onshore projects are displayed as green triangles, offshore as blue diamonds. Australian projects are highlighted in red, Demonstration projects (100kt to 10 Mt) in solid black circle, pilot projects (<100kt) in dotted black circle. All data from project reports and compilations including Global Carbon Capture and Storage Institute website and Hosa et al., (2010).

TYPE 1 covers high permeability reservoirs such as Sleipner where injectivity per well is high, capacity is determined by physical geometry of the reservoir containing lateral plume movement, and vertical containment is by an effective topseal. TYPE 2 covers lower permeability reservoirs such as the basal Cambrian play in North America where well injectivity is moderate, capacity is determined by well number and distribution, and to a lesser extent by plume migration and sub-regional pressure constraints, and vertical confinement is again by an effective topseal. TYPE 3 storages are low permeability reservoirs, as favoured by acid gas storage projects, where the plume is effectively immobile but injectivity per well is low, and total project capacity is low and is constrained by local geomechanical stability (In Salah). Although having a distinct and effective seal layer will increase the containment security of a TYPE 3 storage, it may in practice be sufficient that the plume is immobilised at depth by the poor reservoir permeability. The principal characteristics of TYPE 1, 2 and 3 reservoirs are listed in table 2.

Data in Figure 3 are derived from project reports, and from the compilation of Hosa et al., (2010). Some caution should be used in interpreting these published data since often only a single value is given for permeability (k) and there is no indication whether this is a maximum, a mean, or some more complex weighting of the raw permeability data which typically varies by one or two orders of magnitude within a single well penetration of the reservoir interval. Thickness (h) is also subject to interpretation. Pilot projects may only have a limited perforation interval because their planned volume and rate of injection requires no more and several such research projects do not fall within the graph area which requires a minimum of 10m thickness. Where available, total formation thickness is used rather than perforated interval.

Reservoir intervals in excess of 500m are also sometimes not reported and are discounted here, since buoyancy effects limit effective injection to a few hundred metres of vertical perforations. Multiple wells with different completion intervals or complex single-well completions can access the greater thickness but in all TYPE 1 and most TYPE 2 reservoirs, the plume will rise to the upper zone of the reservoir (a plume thickness of a few tens to hundreds of metres) within a few years, negating the benefit of separate injection zones. If multiple layered reservoirs are separated by effective seals, then the project can exploit larger parts of the reservoir. Such options exist for CarbonNet, for example, where three main reservoir zones and effective topseals exist within the 3km thickness of the Latrobe Group. This multi-storey option is not part of the current project and is therefore not reported here or shown in Figure 3, but does offer future volume upside to the CarbonNet Project.

Despite these caveats, Figure 3 can be used as a good first-pass analysis of the nature of most planned or active projects worldwide and a (retrospective) understanding of project issues can be made based on their relative location in the figure. In the future, project proponents should carefully refer to such an analysis of reservoir injectivity, since many of the commercial and technical aspects of an injection project are determined by the geology, which cannot easily be altered by mere engineering.

For example, a poor quality or thin reservoir can achieve short-term high per-well injectivity by drilling a long horizontal well and completing a significant length of perforations (substituting l for h). Permeability enhancement will also improve local k, but the plume will soon reach the limit of the engineered zone, and pressure will be trapped within the thin layer and increase rapidly, leading to significant geomechanical effects including measurable ground uplift, fracturing of caprocks, and potential reactivation of natural fractures and faults leading to induced seismicity. CarbonNet does not envisage engineering enhancement for its project.

There is no substitute for injectivity, other than drilling large numbers of separate injector wells, which strongly affects commerciality.

Table 2: Principal characteristics of carbon storage projects, by reservoir type

Attribute	TYPE 1	TYPE 2	TYPE 3
Injectivity (k times h)	> 100 darcy-metres	10-100 darcy-metres	< 10 darcy-metres
Typical permeability	1 to many darcies	100 millidarcies to a few darcies	generally < 100 millidarcies
Typical reservoir zone thickness	> 100 m	> 10 m	Not constrained
Individual well injection capacity	Tubing-limited, up to 5 Mtpa for 7” completion	~ 1 Mtpa	100 ktpa or less
Maximum project scale	100 Mt to 1 Gt	10-100 Mt	< 10 Mt
Injector geometry	Simple vertical wells with 10-250m completion.	Deviated wells with 100 to 1000m completion.	Long-reach horizontal wells with extensive completion intervals.
Plume behaviour	Highly mobile (10 km in a few decades	Moderately mobile (a few km in a century)	Almost immobile
Seismic imaging of plume	Excellent	Adequate	Marginal

Residual CO_2 saturation	Low (15% of fluid volume)	Moderate (20-30%)	High (50%+)
Aquifer	Extensive	Good	Fair to poor
Pressure response	Wide regional dissipation with low values (a few Mpa).	Semi-regional coupling at higher values (several to many Mpa).	Significant local overpressure may approach fracture limit.
Geomechanic stability	Excellent	Good	Poor
Potential for induced seismicity	Low (limited and widely diffused pressure response).	Moderate. Occurrence is possible to likely (distinct local to semi-regional pressure response reaching beyond plume area), but magnitude likely to be low to moderate.	Low (pressure is highly localised and unlikely to reach fault planes), but if one is intersected, induced seismic magnitude may be high due to concentration of pressure into one fault zone with high overpressure over a wide surface area.
Trap types (structural vs aquifer)	Structural traps preferred to guarantee plume localisation. Aquifer traps cover large spatial extent.	No strong preference.	Immaterial. Residual saturation alone can trap modest volumes in a 3D plume.
Key advantages	High injectivity, small number of simple wells, no pressure issues, low site / project cost, highly commercial Suitable for offshore storage.	Adequate injectivity, and well number. Good for onshore storage and some offshore projects. Good balance of plume visibility and extent.	Plume immobility.
Key disadvantages	High plume mobility, Wide monitoring extent.	Possible induced seismicity, need for pressure management and fluid disposal, limits to project scale without multiple sites, Offshore projects need upper end of TYPE 2, or infrastructure re-use	Poor injectivity, geomechanical stability (fracturing, and high magnitude induced seismicity), well number and complexity. High site / project cost, poor plume imaging, ground uplift.
Examples	Sleipner, CarbonNet.	Decatur, Quest, White Rose, Cranfield, Otway, Gorgon.	ZeroGen, In Salah.

Additional reservoir types can be envisaged, but are not discussed here. For instance, a reservoir with fracture-dominated porosity and permeability would behave in very different ways from a homogenous matrix reservoir, and carbonate reservoirs that may be wetted by the CO_2 phase will also have a different behaviour from non-wetting clastic reservoirs.

4.1 Capacity

Given the CarbonNet Project intended scale of operations, the selection of sites is made relatively straightforward, with a significant requirement for capacity and a preference for structural storage in a TYPE 1 reservoir. The subsurface volume required to store up to 125 Mt of supercritical CO_2 at depths of 1000-1500m is roughly comparable to that required for 1.25 billion barrels of oil, or 1.25 Tcf of gas. As a consequence, only large sites can act as viable long-term stores for CO_2 at commercial

scale, and these can be easily mapped using the large volume of existing open-file 3D and 2D data in the basin.

For the CarbonNet Project, a minimum required capacity of 25 Mt per trap equates to a gross rock volume requirement of at least 0.3 cubic km, given typical porosity (22-27%) and net:gross ratios (60%-85%) of Latrobe Group sediments. The larger sites in the CarbonNet portfolio have storage capacities in excess of 50 Mt per trap and one trap easily exceeds 125 Mt capacity as an independent development.

4.1.1 Injectivity

Injectivity is not as a decisive relative factor in Gippsland, unless deeper and thinner/discontinuous reservoir units are selected for injection. Several prospective sites did fail on this basis, and were discarded from future analysis.

For successful sites in the main Latrobe Group reservoir fairways, CarbonNet requires injectivity of at least 1 Mtpa, per well (3,000 tonnes per day, or the volume equivalent of 36,000 bopd), in a range of development scenarios. These rates are easily achievable in the high quality and thick TYPE 1 reservoirs of the Latrobe Group. Typical permeabilities range from several hundred millidarcies to many darcies, and many hundreds of metres of stacked reservoir are available for an effective kh of >100 darcy-metres. As noted above, this is close to the operating condition for the successful Sleipner project in Norway, and the CarbonNet plume is anticipated to behave in similar ways to the Sleipner plume (high mobility) and be similarly visible on 3D seismic images.

By comparison, other worldwide projects often operate at very different conditions. The Shell Quest project, for example, envisages injection into a reservoir interval of less than 40 m gross, with 250 md average permeability (and porosity of 17%, vs. Gippsland 20-25%). Quest would be classified as a TYPE 2 reservoir, with an effective kh of the order of 10 darcy-metres and hence would require a larger number of wells for similar injection volumes. In an onshore low-cost drilling environment, this well count is affordable.

For TYPE 1 reservoirs, the geological formation could accept 10 Mtpa from a single vertical well with a nominal 100m completion interval (although well flow analysis shows that only 5-7 Mtpa can be reliably injected down a single 7” tubing string without adopting a high flow “big bore” well design). The top of Figure 3 is labelled with the single vertical well injectivity for that nominal 100m completion. The majority of large scale projects proposed and under development fall in the 1 Mtpa class. These include Zama, Decatur, White Rose, Fort Nelson, Goldeneye, and Cranfield, and the suite of Basal Cambrian sand sites in North America, including Aquistore and Quest.

Sites which have less than 1 Mtpa capacity for a single well are unlikely to lead to a viable large-scale injection project. Gorgon, for instance, appears viable, but is close to the boundary of this zone and is reported to require nine injection wells and four pressure relief wells, and a water disposal well. A project with TYPE 3 reservoirs would require even higher well count and more complex well completions and pressure management.

As discussed above, injectivity can be engineered, especially in the short term. A longer interval can be completed, although vertical completions greater than about 300m lead to little extra injectivity unless there is careful pressure management of the upper and lower completion intervals by means of a dual-bore completion or pressure control valves, which mean additional complexity. Alternatively, a thick injection interval can be serviced by multiple wells, with completions into different stratigraphic intervals. Finally, deviated or horizontal wells can be drilled to add completion length in a thinner formation.

All of these techniques for increasing the initial injectivity of a well do not address the ultimate problem – formation pressure build-up. The In Salah project used multiple wells, each deviated to sub-horizontal and completed over a significant interval, but the project was terminated due to pressure build-up. A (retrospective) glance at Figure 3 would have identified this outcome as a significant risk.

Similarly, the Australian ZeroGen project was abandoned after failing to find sufficient injectivity - but only after a dozen exploration wells had been sunk. The ZeroGen reservoirs may have been adequate for a small-scale project but, during the process of reservoir characterisation, the project scale was expanded to a level that the local geology could not accommodate. An important learning, therefore, is to decide relatively early what the project scale will be and to understand that a change of project scale may require a change of geology (i.e. site location) including moving to a completely different geological basin which may be hundreds of kilometres away from the proposed source of CO_2.

Offshore projects need to be at the upper end of the injectivity scale (TYPE 1 or high TYPE 2), due to the higher unit cost of wells and facilities, compared to onshore projects. Pilot projects were often developed with a nominal completion interval of 1-30m, which may be substantially less than the full formation thickness available, but was sufficient for the rate and volume required for the pilot. Demonstration and full-scale projects tend to maximise the injection interval, to increase injectivity per well and reduce the total number of wells required, but there is the constraint that long vertical perforation intervals in a single wellbore do not offer additional injectivity, due to the buoyancy of CO_2 compared to formation fluid. Injection overpressure (wellbore pressure minus formation pressure) is always higher at the top of the perforation interval, and injectivity is concentrated in the upper few hundred metres.

The ultimate well flow limit is wellbore capacity. Flow performance studies conducted for CarbonNet using PROSPER software have suggested that up to 5.8 Mtpa well flow rate is achievable in conventional vertical well completions with 7” tubing to 1500m with a surface pressure of 11 Mpa and reservoir injection pressure of 1.5 Mpa above pre-injection – i.e. an injectivity index of approx. 3 Mtpa/Mpa. This pressure is well within geomechanical limits for this area which are constrained most strongly by the reactivation of optimally oriented, cohesionless fractures. CarbonNet geomechanical studies, based on an update of the regional work of van Ruth et al., (2007), demonstrate a minimum reactivation pressure of 2.6 Mpa/km, i.e. 3.9 Mpa overpressure at an injection depth of 1500m. Large-bore well completions have not yet been examined by CarbonNet but could offer benefits in some circumstances. For development concepts with extended reach wells drilled from onshore to injection points offshore, a lower flow limit of 2.15 Mtpa per well applies. In all cases, the development scenario would include redundant injection wells on an (n+1) basis, so that there is always one “spare” well available to maintain project injection rates when one borehole is out of service for maintenance, logging, etc.

4.1.2 Containment

The Gippsland Basin has a world-class topseal in the Lakes Entrance Formation (VicGCS Report 1, 2009, VicGCS Report 2, 2009, Goldie Divko et al., 2010). This is the topseal to 80% of all the petroleum resources in the basin, and is an obvious candidate for a CO_2 topseal. This seal unit has been well-studied in the existing literature, but contains significant complexity of sub-units and facies variations that may affect its seal capacity and have not been well-described (Hoffman et al., 2012, Hoffman et al., 2015b). Mapping the evolving palaeobathymetry at the (diachronous) time of deposition of this seal sequence is vital to understanding its local facies and seal potential.

Intraformational seals within the Latrobe Group are also important targets for CO_2 storage (Hoffman et al., 2015 (in prep.)). Using these seals offers a number of advantages:

1) Deeper trapping with better volume efficiency due to greater compression of the CO_2.
2) Avoidance of top Latrobe Group petroleum activities – whether direct conflict or pressure interaction with neighbouring developments in the same stratigraphy.
3) Opportunity for multi-level stacking of CO_2 storage and hence greater volume per storage site.
4) Lower-risk storage if the Lakes Entrance Formation is available as an additional backup seal, rather than being the primary seal.

For the CarbonNet project, at some sites an intraformational seal is identified as the main seal for CO2 storage. In order to avoid confusion with the petroleum regional seal, the intraformational seal is referred to as the "Key Seal". At these sites, the regional petroleum seal acts as a back-up or secondary seal. At other CarbonNet sites, the regional petroleum seal is the primary seal for CO2, and the intraformational seals are relegated to a more minor role as baffles which act to slow the ascent of CO2 to the primary seal. The principal intraformational seal identified by the CarbonNet Project is the Traralgon Formation T2 member, which is described in detail in Hoffman et al., 2015b.

Intraformational seals are demonstrated to trap 20% of hydrocarbons by volume and about 70% of the number of accumulations in the Gippsland Basin and therefore these seals are proven in principle but must be checked in detail on a site-specific basis for seal continuity, seal capacity, and resilience to permeation in mapped or sub-seismic fault zones (Hoffman, 2015b). CarbonNet MICP measurements of intraformational seals suggest that some are as good as, or even better than, the traditional Lakes Entrance Formation petroleum topseal although they generally form thinner seals and are therefore more vulnerable to fault permeation (Hoffman, 2015b).

4.2 Australian Legislation and screening parameters

The OPGGSA, 2006 envisages a series of stages of licensing, progressing from pure exploration through to progressively more focussed site-specific licences for injection and storage. The first step is to apply for and be awarded a Greenhouse Gas (GHG) Assessment Permit (equivalent to a Petroleum Exploration Permit). CarbonNet holds the first offshore GHG permit in Australia, VIC-GIP-001 on the southern flank of the Gippsland Basin (Figure 1).

Once a GHG Assessment Permit is held, the operator can conduct exploration activities to search for suitable GHG storage sites. At any time, a company can conduct desktop studies, but field operations require a GHG Assessment Permit (or other special search authority) and activity-specific permitting for e.g. drilling wells and conducting seismic surveys.

Once an operator has identified a prospective site for GHG storage, it can notify the regulator (NOPTA) that it has done so and make an application for a "***Declaration of an Identified Storage Formation***".

In the OPGGSA, 2006, "Storage Formation" has a similar meaning to the European "Storage Complex", with the proviso that the geographic boundaries of the storage formation are not natural geological features, but are the boundaries of whole, 5 minute graticular blocks that contain and enclose those natural boundaries.

Declaration application requires the operator to first indicate that a number of ***Fundamental Suitability Determinants of the Storage Formation*** exist, or have been identified, as a result of the investigative work and tests of the operator. The operator must then address a number of detailed points relating to the description of the geology of the storage formation and a risk assessment of storage at that site. In obtaining a Declaration, the operator must demonstrate that plume migration can be predicted at this site and that at least 90% of potential plume paths have been modelled, and remain within the Storage Formation boundaries. This is not a requirement that 90% of the CO_2 remain within the Storage Formation, but that in at least 90% of cases, the CO_2 remains within the Storage Formation.

4.3 Fundamental Suitability Determinants

The OPGGSA, 2006 described above contains a requirement to demonstrate certain fundamental suitabilities of the site for GHG storage (Table 3).

Table 3: Fundamental suitability requirements for GHG storage.

Application Requirements – OPGGSA, 2006
Fundamental suitability determinants **(8) For the purposes of this Act, the following are the *fundamental suitability determinants* of an eligible greenhouse gas storage formation:**
(a) the particular amount referred to in whichever of paragraph (1)(a) or (b) is applicable;
(b) the particular greenhouse gas substance referred to in whichever of paragraph (1)(a) or (b) is applicable;
(c) the particular point or points referred to in whichever of paragraph (1)(a) or (b) is applicable;
(d) the particular period referred to in whichever of paragraph (1)(a) or (b) is applicable;
(e) if paragraph (1)(b) is applicable—the engineering enhancements referred to in that paragraph;
(f) the effective sealing feature, attribute or mechanism that enables the permanent storage referred to in whichever of paragraph (1) (a) or (b) is applicable.

These requirements equate to the following:-

a) That site capacity is adequate for the intended storage volume.
b) That the chemical composition of CO_2 plus admixed impurities is not incompatible with the storage reservoir and seal lithologies, and the formation fluids.
c) That suitable injection points exist from which it is possible to inject the defined volume of CO_2.
d) That injection rates and duration can and have been defined.
e) Whether any engineering enhancements are required to allow the safe and permanent storage.
f) That there is an effective containment mechanism for the CO_2.

These determinants require that the operator has built detailed site-specific geologic static models and has conducted injection simulations to track plume migration and containment over a long enough time to demonstrate permanent containment.

In the case of the three CarbonNet sites, many of these fundamental requirements have been addressed by modelling each site for 1000 years and demonstrating either permanent structural trapping or cessation of plume movement for the injected volume.

Each of the sites already contains a number of petroleum exploration wells which prove the stratigraphy and suitability of the site for storage. These have all been safely abandoned, except at one site, where late-stage oil recovery is ongoing, with high water-cut. All three sites are covered by a dense grid of modern-quality 3D and/or 2D data.

5 Play Fairways and Trap Types in the Gippsland Basin

5.1 Play Fairways

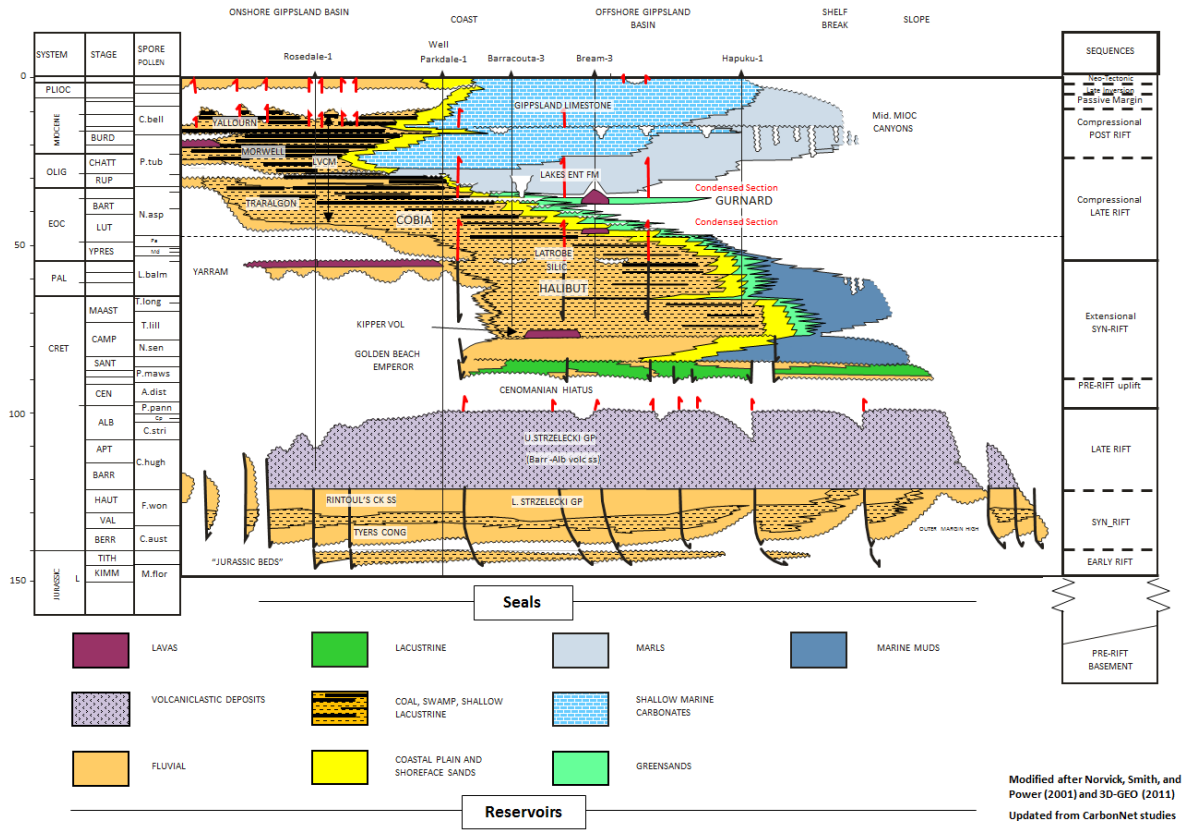
In petroleum exploration, the concept of a play fairway is of a family of potential traps that share key characteristics, and hence the learnings derived from drilling one member of a fairway inform on the chance of success for others in the same fairway. Fairways generally share the same reservoir and may also, or alternatively, share structural characteristics, seal lithofacies, or migration and charge.

In the CO_2 storage context, fairways can usefully describe similar collections of potential storage sites that share common characteristics and can be evaluated in a single co-ordinated study so that success or failure at one site can be translated to other sites without new work being required. This fairway approach allows a large number of sites to be evaluated for the same effort and in the same timeframe as evaluating a couple of independent sites with no correlation. This is an important way to speed up the supply of drill-ready storage sites and to reduce the quantity of appraisal work required to prove each site as injection-ready.

In the Gippsland Basin, there are a series of reservoir play fairways. In the upper section of the Latrobe Group, there are a number of barrier-bar fairways that progressively backstep across the basin from Upper Cretaceous to Upper Eocene (Upper *N. asperus*) age (Figure 4). The palaeoshoreline moves into what is now the onshore, reaching a landward limit some 40 km inland, between Sale and Rosedale at end of the Oligocene and is recognised as the maximum flooding event of the Latrobe Group. Subsequently, barrier-bar systems continue (the Balook Formation), but now step forward into the basin, behind the prograding shelf edge of the Gippsland Limestone Formation, building forward to a shelf edge around 100 km offshore, at the 100m isobath, with palaeo-shelf edges and fluvial channels mapped from aeromagnetic data across the present-day interglacial shelf (Mitchell et al., 2007). These sand fairways have various formation names, depending on the field or area in which they were first encountered, but in fact are part of a single continuous depositional sequence and should be named collectively as a single formation.

At intra-Latrobe Group, there are a series of fluvial and lower coastal plain sands. These are poorly differentiated as to geographic fairways, but recent work (Hoffman et al., 2015b) has shown that persistent fluvial inputs can be mapped on merged 3D seismic megavolumes to define zones of higher net:gross with fewer shale and coal interbeds (i.e. reservoir play fairways), and alternating zones of seal fairways.

Figure 4: CarbonNet Chronostratigraphy



Gippsland Basin chronostratigraphy is well-known after 1500+ exploration and development wells and "wall-to-wall" 3D in the offshore core basin area. A clastic-rich retrogradational sequence of terrestrial upper and lower coastal plain sediments is bounded by a backstepping series of paralic barrier bar sands of exceptional (multi-darcy) quality. The entire package is up to 3 km thick with high net:gross (65-75%) and represents an excellent opportunity for multi-storey CO_2 storage, using intraformational seals proven from oil and gas traps.

5.2 Trap types

5.2.1 Structural – anticline and upthrown fault traps

The simplest trap concept is where four-way structural closure exists, a dome, an elongate plunging anticline, or a combination of dip and fault closure. In the Gippsland Basin, a number of large inversion anticlines have developed during post-Eocene compressive events and these now host the giant oil and gas fields of the prolific Bass Strait province. This is the type of trap that has been high-graded by the CarbonNet screening process. Smaller structures also exist, but the challenge in this basin is finding large enough structures that do not already contain oil or gas, and are therefore available for CO_2 storage.

This paucity of available structures can be addressed by seeking storage at deeper structural levels, or targeting known producing assets that are close to the end of their operating life, or that are undeveloped and uncommercial.

5.2.2 Large stratigraphic traps

Alternatively, non-structural traps can be utilised. In a petroleum context, an ultimate updip closure is always required, or the petroleum will escape over geologic time and not accumulate as a distinct buoyant phase ready for extraction. These traps are described as stratigraphic traps and involve updip pinchout, or truncation at an unconformity, of a reservoir in combination with effective top, side, and base seals.

It is difficult to develop large stratigraphic trap concepts in the Gippsland Basin. The Latrobe Group reservoirs backstep shorewards and there tend to be open aquifers towards the basin margins. The Latrobe aquifer is proven to be open onshore, since meteoric recharge of an artesian aquifer occurs along the western margin (Michael et al., 2015, Hoffman et al., 2015b). To some degree the cluster of shallow gas fields on the northern margin (Sole, Moby, Patricia Baleen; Figure 1) are quasi-stratigraphic traps, with productive sands intercalated in the normally non-net greensand, but there is a strong component of structural closure to each of these fields.

CarbonNet assesses that the challenges of defining a large stratigraphic trap in the Gippsland Basin are too high, given the very extensive and high quality reservoirs, the overall good lateral and vertical reservoir connectivity, and the existence of excellent basin-wide 3D data that has been thoroughly explored by experienced petroleum professionals with no drilling program having ensued for large stratigraphic traps. Therefore, this category has not been carried beyond concept stage.

5.2.3 Small stratigraphic traps

Small stratigraphic traps certainly exist in this basin. On an oilfield production timeframe, unswept oil is hung-up by stratigraphic details within the giant Latrobe Group oilfields, and oil exploration for small independent stratigraphic traps may be viable to an oil explorer, but is high risk due to the difficulty of distinguishing on seismic data between clastic sand and clastic shale in a coal-rich sequence. For CO_2 storage, volumes in small stratigraphic traps are inadequate and this trap concept has not been pursued further by CarbonNet.

5.2.4 Downthrown Fault traps

On the northern and southern margin of the basin, downthrown traps can be mapped against major fault systems. On the northern flank, these offer demonstrated oil trapping potential (e.g. Longtom). Volumetrically these are relatively small for CO_2 storage and the risk of fault seal is not insignificant.

One such trap is mapped by CarbonNet on the southern basin margin, in the northeast of VIC-GIP-001, but the trap is not high-graded at present. Another candidate on the northern margin around the Cuttlefish-1 well was ruled out as high risk during basin screening.

5.2.5 Aquifer traps

In a CO_2 context, there is no requirement to create and trap a long-term stable buoyant phase, since the goal is ideally to disperse the CO_2 throughout the pore space of the target reservoir where it can dissolve into the formation fluid and react with mafic and other minerals to form permanent rock-forming carbonate minerals. A four-stage process of trapping, beyond structural and stratigraphic closure, has been described by IPCC (2005) whereby initially mobile CO_2 is consumed by:

1) residual trapping in the pore spaces of the reservoir as the CO_2 plume migrates – depends on Sgr, and operates on a migration timescale of decades to centuries.
2) dissolution of CO_2 into formation water - depends on salinity, pressure, temperature and operates on a timescale of centuries to millennia.
3) mineral reactions with existing rock matrix and secondary minerals to form new rock-forming minerals - depends on complex geochemical reactivity with rock minerals and formation fluids, and may have an intermediate step where some existing minerals are dissolved prior to new mineral deposition in the same or remote locations, and operates on scales up to millions of years).

All of these processes are enhanced if the mobile CO_2 moves through a large rock volume while the various processes act to progressively consume the CO_2. For this reason, relatively long distance migration of the CO_2 plume over tens of kilometres is favoured in a concept that is known as a saline aquifer trap. These traps do not fundamentally require high salinity – indeed, dissolution is enhanced in lower salinity waters.

These saline aquifers may ultimately be stratigraphic traps in the petroleum sense, in which case they are described as “closed saline aquifer traps” or there may be no updip limit to the trap – an “open saline aquifer trap”. Closed saline aquifer traps offer an additional level of security because no matter how far or how fast the CO_2 migrates, it will eventually be stopped by the stratigraphic trap, even if this leads to a delay in ultimate dissolution and mineralisation of the CO_2. Open aquifer traps must be more carefully managed in terms of injected volume and expected travel path to ensure that there is effectively no chance that the CO_2 will arrive at the open end of the aquifer. In practice, until it is better understood for a specific area, this results in cautious estimates of allowable CO_2 volume to be injected and under-use of the available storage volume and hence low storage efficiency.

CarbonNet recognises open aquifer trap potential on the northern, southern, and western margins of the basin and a number of these sites were screened for volume and risk. One such site proved to be potentially acceptable and remains in the CarbonNet portfolio.

5.2.6 Migration assisted storage trap

One interesting category of traps is where a significant structural closure is augmented by a significant element of aquifer migration to reach the closure. This trap concept combines useful elements of structural trapping (5.2.1), where ultimate containment is confidently assured for a known volume of CO_2, and aquifer trapping (5.2.5), where significant amounts of dissolution and residual trapping occur. A trap of this style can store larger volumes than the structural trap alone (for example if it were filled by near-crestal injection) and has strong certainty for plume containment compared to an open aquifer trap with no significant structural component.

5.2.7 Basin centre traps

One distinct subset of open aquifer traps is where there is essentially no formation dip. In areas near local and regional basin depocentres, relatively flat dip exists over large areas and injected CO_2 will not move rapidly under buoyancy forces. In principle, storage could take place in these sectors of

basins without migrating laterally into adjacent structure, within the timeframe that producing assets are active. However, there is generally limited data in these areas which are considered unprospective for conventional petroleum resources. In addition, the potential for novel, untested resource opportunities such as basin-centred gas is in direct competition with this storage concept.

As an example, CarbonNet recognises a basin-centre style trap in the Bullseye-1 well area, based on prior CSIRO work (VicGCS Report 5, 2012). Although this trap lies within VIC-GIP-001, and can potentially be combined with the downthrown fault trap noted above, it is still not attractive enough to high-grade at this stage of basin exploration – principally because it lies too far offshore for a commercial delivery of CO_2 by pipeline.

6 Site Characterisation

The geology of the nearshore Gippsland Basin is very well known, based on the large number of petroleum wells and extensive 3D and 2D petroleum industry data, all placed on open file. Compared to an independent CO_2 storage project in a jurisdiction where petroleum data is not open file, the CarbonNet site performance can be reliably and confidently predicted.

Regional and site-specific characterisation is described for the CarbonNet sites in the main areas of:

- Storage Concept
- Database
- Mapping
- Reservoirs
- Seals
- Overburden
- Basement
- Aquifers
- Geochemistry
- Reservoir Engineering
- Dynamic Modelling
- Geomechanics
- Non-Geoscience characterisation

These aspects are all well-characterised for the current pre-appraisal stage, and the CarbonNet Project is in a strong technical position, supported by a data-rich environment. The level of subsurface uncertainty is very low, compared to many storage projects which might have no well data and only limited 2D seismic data at this stage of the project. The original data has been extensively built on by CarbonNet during the site selection process (Hoffman et al., 2015a) to produce a robust and broad geoscience basis for the planned project and a high level of confidence in predictions of plume behaviour in a range of injection scenarios.

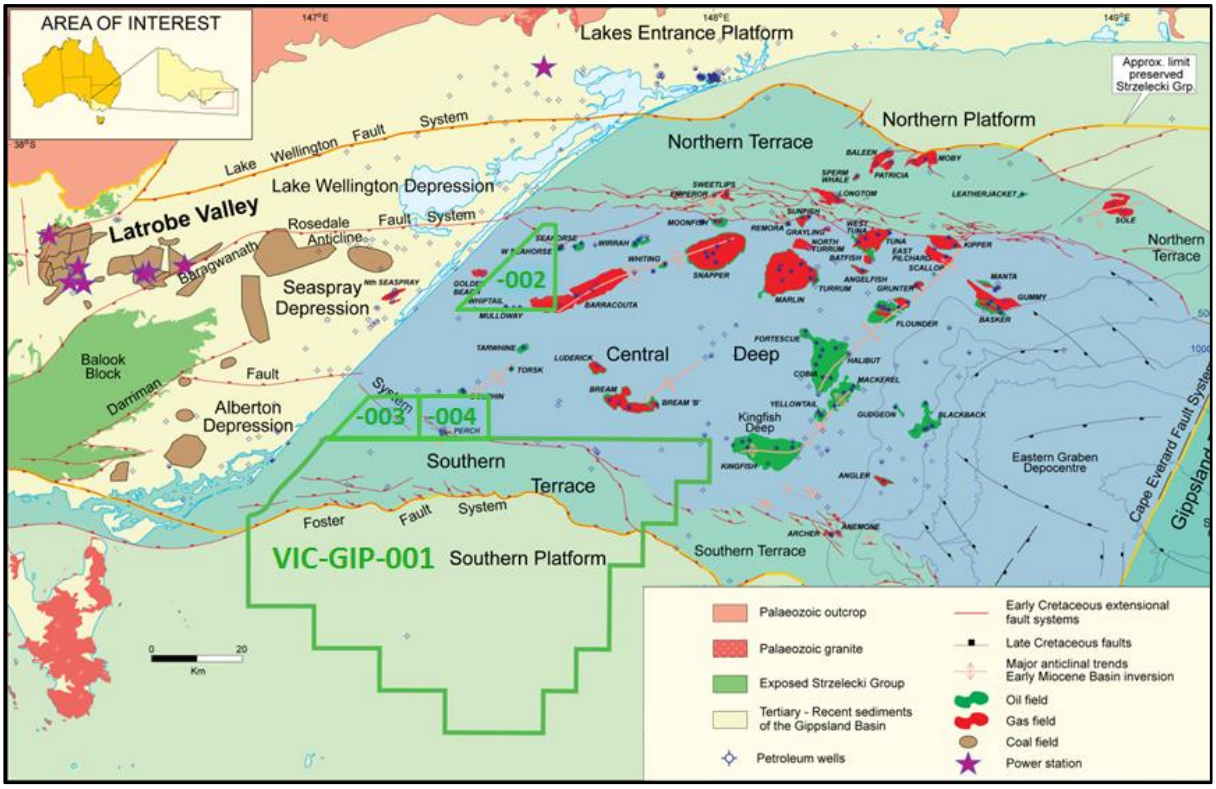
The framework of site characterisation, as presented in this document, will nonetheless be refreshed and the details of site knowledge progressed as appraisal activities occur (new well(s) and 3D seismic data), and site injection planning proceeds, significant new data is collected, new static, dynamic, and geomechanical models are built and run, and geochemical reactivity is assessed.

6.1 Storage Concept for CarbonNet sites

The three sites in the CarbonNet portfolio represent the high-graded survivors of a rigorous screening process that has downgraded 90% of the initial candidates, on grounds of inadequate capacity, mappable defects, or higher risk. The three high-graded candidates are relatively large, have no mapped defects, and appear to offer low-risk long-term storage. Each of the three sites is suitable for appraisal for commercial storage, but the CarbonNet Project will only appraise one site initially, since Site ONE offers the full storage volume required at this time.

In 2015, the Commonwealth government awarded three new GHG Assessment Permits to CarbonNet in its nearshore area of interest (Figure 5). Additional site(s) and storage concepts, including some of those currently downgraded by CarbonNet, and depleted oil and gas fields – if and when they become available - may be appraised in the future, to meet the growing need for commercial CO_2 storage, if this becomes viable in the Gippsland Basin.

Figure 5: 2015 Gippsland Basin GHG acreage status



6.2 Local well and seismic data

Forty nine wells were imported into PETREL software and available well logs were examined. A commercial database of cleaned and merged logs was used as the main source of valid data. Well correlation and lithostratigraphic cross-sections were constructed for forty seven wells within the nearshore area which had well log data available for modelling. The imported data were quality controlled for missing data points and log issues using standard petroleum industry techniques. Alternative data was used were possible and/or the defective data was excluded from the database. The final logs were deemed satisfactory, except for a few DT logs which showed higher than normal readings. High DT log readings were scaled using DT logs from surrounding wells as a reference.

A Gippsland nearshore well correlation model which contained all 49 wells was used as the principal well correlation model in generating horizons and zones for all the localised models over prospective injection targets, and to select local well correlations for each model. Besides the four major interpreted formation tops from seismic (top Lakes Entrance Formation, top Cobia Subgroup, top Halibut Subgroup, top Strzelecki Group), an extra 30 well tops were created and used for fine lithology zonation.

Open-file 3D and 2D seismic data was imported from GeoScience Victoria and Geoscience Australia digital archives and workstation data compilations for petroleum acreage review. In the course of project review and interpretation, a number of missing seismic lines were recovered from mis-labelled files, or scanned from original paper copies. One key 3D survey was reconstructed from digital data damaged by 9-track tape oxide loss, supplemented by scans of seiscrop images and prime in-lines.

6.3 Mapping

Several generations of mapping have been conducted within CarbonNet and this work is built on a foundation of earlier work to map the basin as a more regional scale. In-house interpretation is ongoing, focussed on the high-graded storage sites and incorporating newly-reprocessed vintage 2D data onshore and reconstructed reconnaissance 3D data offshore, to augment the available open-file 3D-GEO Megavolume.

For the static and dynamic models described below, the mapping is based on a basin-wide seismic project consisting of multiple 2D and 3D seismic surveys which was commissioned by DPI's Geoscience Victoria and interpreted by 3D-GEO Pty Ltd in the Gippsland 3D Framework project (3D-GEO 2011). Nearshore seismic data from this project was selected and made available for use by CarbonNet. The resulting dataset was refined to improve details of fault geometry and to infill picks to all key 2D seismic lines rather than only the regional framework.

Subsequently, further refinement has taken place in-house on the top Lakes Entrance Formation, top Latrobe Group and top Halibut Subgroup horizons. Recent work has concentrated on additional intra-Latrobe Group picks and has identified at least one weak intra-Latrobe Group unconformity below top Halibut Subgroup. These unconformities are being used to shape the internal layering of the geologic static models to accurately represent the 3D architecture of flow units. The project also includes well formation tops picked from combined well log data and seismic and updated during 2011-2014 by CarbonNet.

6.3.1 Depth conversion

Depth conversion utilised a range of methods, based on a regional burial depth trend and average velocity down to the target horizon, with a component of lateral velocity input from 3D velocity data compilation undertaken within Geoscience Victoria and published as an open file dataset (VicGCS Report 9, 2013). The 3D velocity dataset was re-worked by CarbonNet in the context of burial depth- and compaction as a first-order determinant on velocity.

6.3.2 Facies analysis

Seismic horizons were correlated to available well-tops within the regional modelling area. Seismic and well data were combined for facies modelling, and log and core data were used for facies assignment and petrophysical modelling.

6.3.3 Aspect ratio of sands and seals

A detailed seismic attribute study within the 3D volume analysed the aspect ratio and dimensions of coal bodies, sand channels, and other features. This data is fed into the geologic model which is based on broadly sub-parallel layering of sediments within the Latrobe Group with no major regional unconformities above top Golden Beach Subgroup.

Top-most Latrobe Group (Cobia Subgroup) shoreline facies is highly elongate along the palaeoshoreline (aspect ratio >10:1) while other lithologies (e.g. shale and coal), and sands at deeper levels are more equant (aspect ratio 2:1), but still oriented parallel to the palaeoshoreline. Shoreline orientation does not significantly vary during the time interval contained in the CarbonNet site models. At top Latrobe Group there is a disconformity with an abandonment facies of greensand transitioning to the draping Lakes Entrance Formation topseal.

6.3.4 Static Modelling

The geological principal of uniformitarianism – often expressed by the phrase "The Present is the Key to the Past", is nowhere more true than in the Gippsland Basin. The processes and geometry of the modern-day Ninety Mile Beach, and the lakes system trapped behind it, are the direct successors of the Latrobe Group reservoirs that contain the giant oil and gas fields of Bass Strait. Study of the modern depositional systems allows direct analogy with those in the past.

CarbonNet uses a refined version of the accepted Gippsland Basin chronostratigraphy (Figure 4, Hoffman et al., 2012), derived from earlier precedents (Rahmanian et al., 1990, Partridge, 1999, Norvick et al., 2001, Bernecker and Partridge, 2001). This allows the construction of detailed 3D reservoir models with realistic lateral extent of sand, shale, and coal bodies, based on observed geometries within the 3D megavolume, calibrated dimensions of present-day onshore lakes, rivers, and coastlines, and well correlations within and between offshore oil and gas fields and dry holes.

Static models have been constructed for each storage site using Schlumberger's industry leading PETREL™ software as part of a work flow sequence that includes the following steps:

1. Well data interpretation for lithologies, stratigraphy and petrophysics and correlations.
2. Formulation of a conceptual geological model to predict facies associations and geometries.
3. A constant orientation of 010° is adopted for intra-Latrobe Group geobodies, matching the palaeoshoreline.
4. Seismic data interpretation using PETREL™ modules and some limited use of the Kingdom Suite software to generate depth surfaces of key horizons and seismic lithofacies associations. (Some iteration between steps-1-2-3).
5. Static modelling: receive step-3 surfaces and construct stratigraphic zones recognised in step-1.
6. Construction of higher resolution zonal layer also identified in step-1.
7. Fault modelling and Pillar Gridding.
8. Characterisation of the layers with step-1 petrophysical properties moulded to seismic lithofacies through use of variograms and indicator kriging/sequential Gaussian methods.

The CarbonNet Project has built three full generations of static models. In the first generation, a large-scale coarse model of the entire nearshore was constructed to provide a context for the multiple local fine-scale models required – one for each site, or cluster of sites. At all subsequent stages, only fine-scale models were constructed. At each stage, static models were designed to be fit-for-purpose and were generated using horizon and fault frameworks in depth, isopachs of key reservoir facies, and geostatistical parameters derived from well petrophysics and 3D seismic analysis of geobody extents, aspect ratios, and orientations. The models evolved in complexity over time, but were designed not to be excessively complex. As an example, faults were generally verticalised in the models, rather than explicitly mapped as dipping surfaces. However, the requirements for dynamic modelling of CO_2 injection include the consideration of long-distance migration, and significant vertical penetration of the stratigraphy by the CO_2 plume. Therefore these models are more complex and extensive than an equivalent oilfield model would be.

The CarbonNet team developed in-house high-resolution PETREL™ static models to honour 49 local wells and 2D and 3D seismic facies analysis (Figures 6 and 7). These models were used to evaluate possible available pore space for static capacity assessment and for dynamic simulation to estimate dynamic structural storage capacity of individual sites. The largest model covered an area of ~900 square kilometres and was gridded to an average cell size of 50x50m. A total of 222 layers were generated based on the variation in lithological facies, which range from a few centimetres to ~10 metres. Total model size was 82 million cells. This model was used for CarbonNet's latest dynamic modelling (February 2014 onward).

Figure 6: Construction of Geological Static model from 3D seismic data

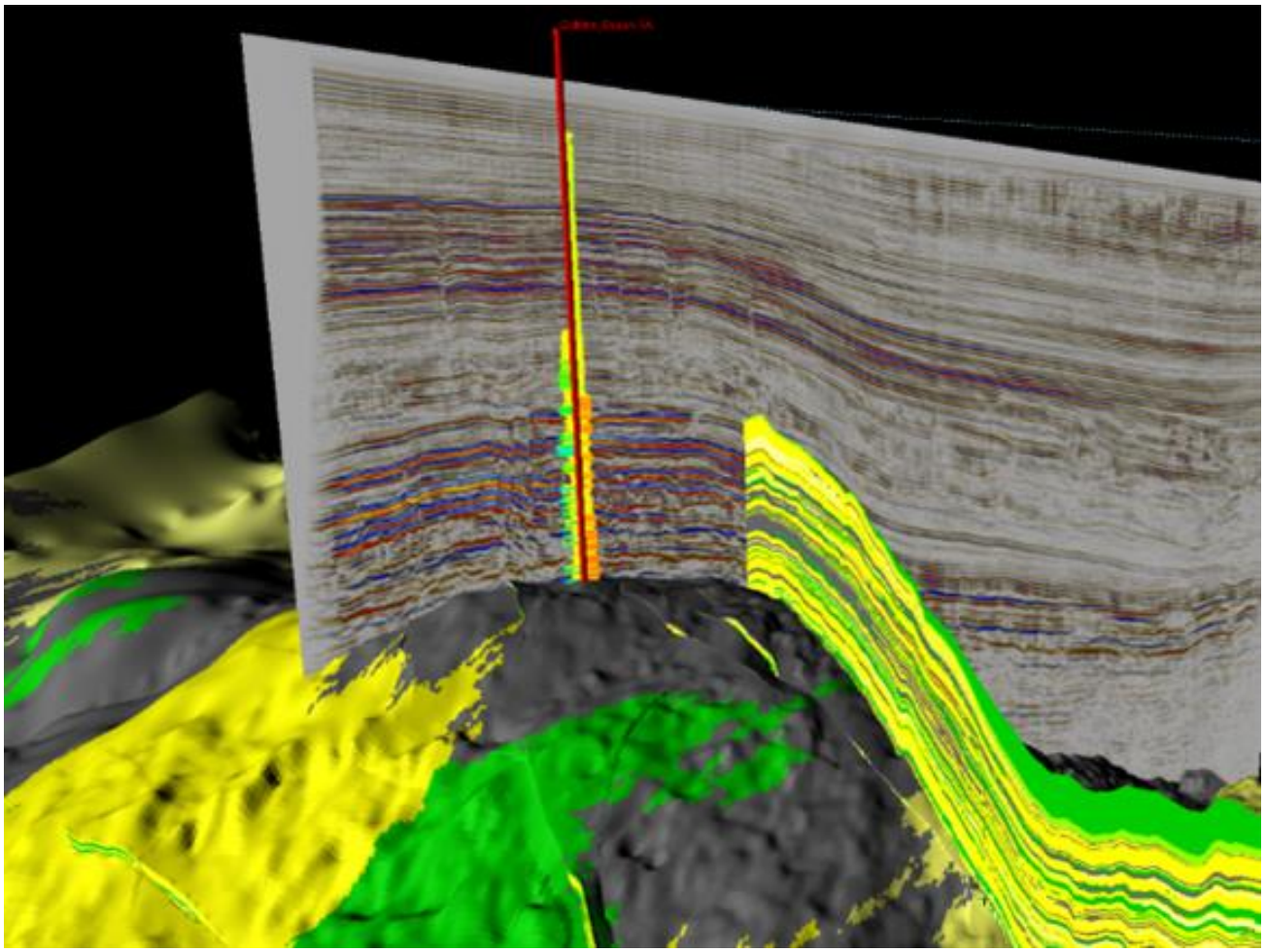


Figure 6. 3D and 2D seismic lines are used to calibrate geobodies in the 222-layer static model. Each layer has variable lithology (yellow=sand, green=shale, black=coal) and each lithology has variable porosity and permeability (not shown).

Figure 7: Example of Static Model for a structural closure

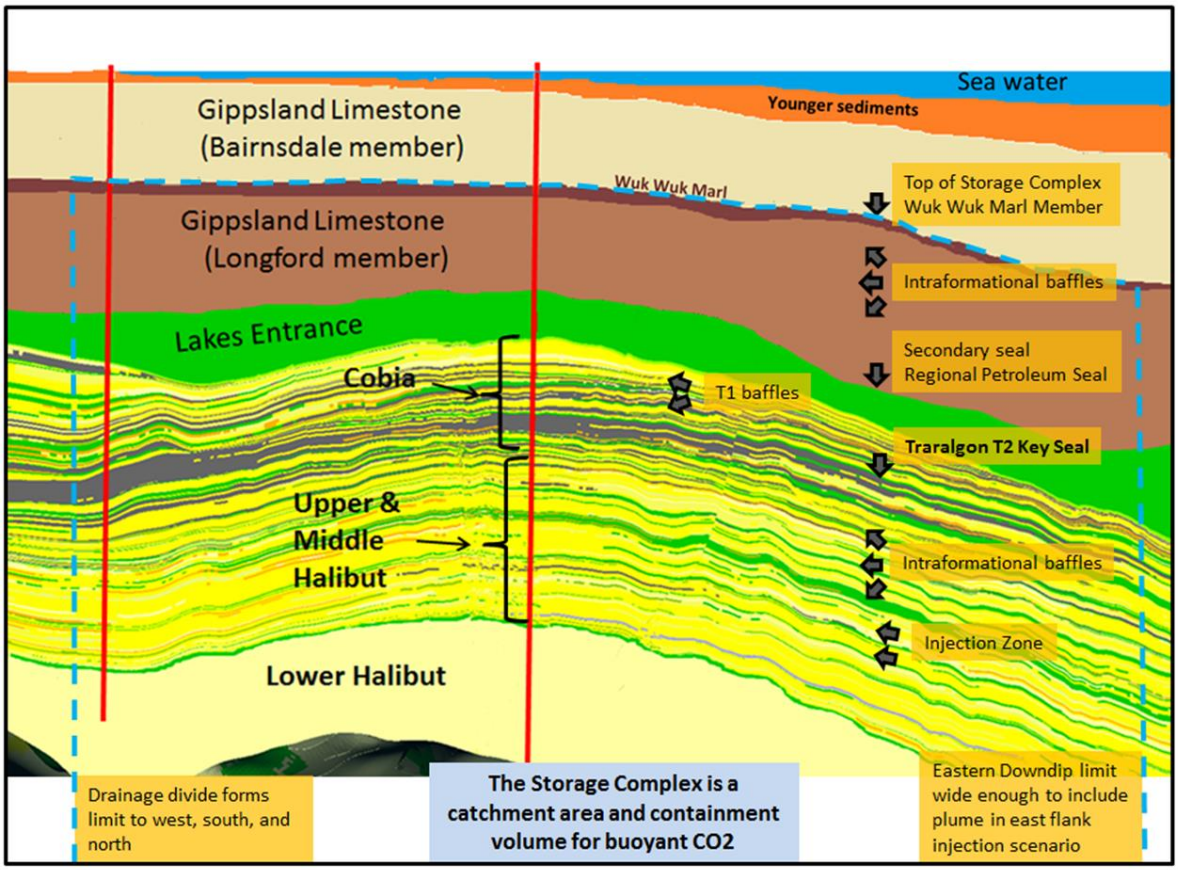


Figure 7. The 222-layer geologic model is overlain by a cover section of seals (Lakes Entrance Fm. and Wuk Wuk Marl) and interbedded limestone/marl sequences (Longford and Bairnsdale members). Storage will take place beneath the Traralgon Formation T2 member – the main local intraformational seal. Additional intraformational seals (green and black) occur below and above T2 and lead to multi-storey trapping.

6.4 Reservoirs

As noted above, Gippsland Basin reservoirs, the Upper and Middle Halibut Subgroups (Latrobe Group) are world-class, consisting of high net:gross ratio clean quartz-rich sands and subarkoses with excellent porosity and permeability. In petroleum exploitation, these reservoirs are renowned for high initial oil saturation (up to 85%), low residual water saturation (15% or less), and excellent sweep efficiency with primary oil recovery of 85%+.

VicGCS reports 1 (2009), 2 (2009), 4 (2012), and 5 (2012) studied storage concepts in a variety of locations in the Gippsland Basin. These reports show that the Latrobe Group has excellent storage characteristics with strong aquifer support, and thick reservoirs with high net:gross ratio and high porosity (25%+) and permeability (multi-darcy).

These reservoir attributes make the reservoirs ideal for structural storage of fluids, including CO_2, but make open aquifer traps less efficient since the plume tends to rise rapidly to top reservoir levels, and during migration relatively little CO_2 is left behind due to residual trapping.

6.5 Seals

At each of the CarbonNet sites the primary petroleum seal of the basin is proven to be effective, either by retaining a small hydrocarbon pool, or from MICP measurements (or both). At two of the CarbonNet sites, the Lakes Entrance Formation petroleum seal acts as a secondary seal

stratigraphically above the primary seal. At one of those sites, that backup will only be required after a storage time of around 50 years. In an alternative scenario, if the small oilfield were abandoned in the next decade or so, a redevelopment could utilise some of the existing facilities, and in this case, storage could occur more centrally in the field, and utilise the proven petroleum topseal. The backup seal will likely never be required, but offers a safety margin to storage at that site. At the third site, as discussed below, the petroleum seal is required almost immediately, and the key issue relates to the spatial extent over which the seal can be proven.

Lakes Entrance Formation seal quality is well mapped with a combination of thickness, depth of burial, mineralogy, MICP quality, and facies. Whilst some seal defects can be mapped in the general area, – due to submarine channels in the basin (Hoffman et al., 2012), these occur rarely, at predictable and mappable locations, and off-structure. Although additional minor channels are mapped near each of the three high-graded sites, they do not have the scale and character to act as defects in any of the three storage sites.

The intraformational Traralgon Formation T2 member (T2) coal-related seal is developed at all sites and acts to distribute CO_2 over a wider range of stratigraphy and to defer or prevent the CO_2 rising to top Latrobe Group level (Figure 7). Additional intraformational seals exist both above and below T2. Intraformational seals, including the T2, are described in detail in Hoffman et al., 2012 and Hoffman et al., 2015b.

Storage simulations at Site ONE demonstrate that less than 1% of the stored CO_2 rises to contact the T2 seal within 300 years, due to almost totally effective deeper seals. The T2 intraformational seals are proven by MICP calibration, and by the trapping of intraformational oils in a number of local oilfields (Hoffman et al., 2015b). T2 seal quality seems to be related to the presence or absence of fluvial throughputs which are confined to tectonic lows and on key paleo-river alignments, all of which can be mapped. Good seal quality is found in the inter-channels which can be mapped as extensive and continuous coal facies in raised bogs and in swampy areas.

6.6 Overburden

The overburden to the Lakes Entrance Formation is the Seaspray Group, consisting of the Gippsland Limestone Formation (Figure 4) in the bulk of the nearshore and offshore, transitioning to the Swordfish Formation in deeper water parts of the basin. In the nearshore, a cover sequence of terrigenous sediments occurs in the upper 300-400m of section, comprising clastics (sands and shales) and occasional in-situ or reworked coals. The central part of the Gippsland Limestone in the nearshore area consists of interbedded marls with modest to good seal capacity. These units can act as additional backup seals to the deeper main seals.

6.6.1 Shallow aquifers

The cover sequence (Seaspray Group) subcrops to the seafloor and is proven by numerous offshore wells to have saline formation water in all porous intervals. It is normally pressured and has no beneficial uses. Onshore, similar sequences have a freshwater aquifer in some areas but there appears to be limited lateral connectivity. In any case, the storage concept does not envisage any fluids or pressure entering or leaving this interval, so there will be no detectable change from storage operations at the three sites.

6.7 Latrobe aquifer

The Latrobe aquifer offshore is a thick and generally well-connected sand-rich interval with a total thickness of 2-3 km. The salinity of this aquifer changes from <5,000 ppm in the nearshore to 35,000 ppm in the eastern part of the Central Deep. Aquifer pressure was originally artesian with ~ 50m hydraulic head in the nearshore area but has been depleted by offshore hydrocarbon production to normal hydrostatic (Varma and Michael, 2012).

The offshore aquifers in the Latrobe Group have a significant body of meteoric water, emplaced in a dynamic process over the past million years or so (Michael et al., 2015). This aquifer has a number of characteristics that make it suitable for CO_2 injection:-

- Relatively low salinity – dissolution is enhanced in lower-salinity aquifers and CarbonNet expects 33 to 43% of the injected CO_2 to be dissolved within 1000 years.
- Movement from onshore to offshore – the flow velocity of the aquifer is of the order of 1-5 m per year, from 14C ages (Hofmann and Cartwright, 2013). This will tend to sweep any dissolved CO_2 away from the shore, by about 1-5 km in 1,000 years.
- Regional pressure support – the Latrobe aquifer has a proven lateral pressure-connected extent of over 100 km. This allows rapid dissipation of injection pressure and leads to injection occurring into aquifers already modestly pressure-depleted from extensive aquifer abstraction onshore and offshore (Varma & Michael, 2012). As a consequence, pressure thresholds for geomechanical stability are highly unlikely to be breached and pressure-mediated resource interaction will be mild, but probably beneficial (Michael et al., 2015).

A provisional correlation has been developed between the established onshore aquifer zonation (Gippsland Groundwater Atlas, 2012) and the offshore chronostratigraphy as understood from hydrocarbon exploration. The majority of the Latrobe aquifer including the Halibut Subgroup and the lower Cobia Subgroup (Traralgon Formation) correlates in broad terms with what is defined as the lower Tertiary aquifer onshore (Figure 4). The offshore units above the Traralgon Formation (i.e. the Seaspray Group sands) correlate with the M2C aquifer of the Morwell Formation and are grouped as the lower middle Tertiary aquifer in the Gippsland Groundwater Atlas. Therefore, a sub-regional onshore aquitard is associated with the Traralgon Formation coals. This aquitard, which separates different aquifer salinities and pressures onshore and in the nearshore, is identical to the intraformational seal that holds oil columns further offshore and will be used by CarbonNet for CO_2 storage in the nearshore region (Hoffman et al., 2015b).

6.8 Basement

The effective basement for hydrocarbon production and CO_2 injection in the nearshore area is the low-permeability Strzelecki Group, representing the first phase of the Gippsland Rift of Berriasian to Albian age (Figure 4).

6.9 Geochemistry

The status of geochemical knowledge of the CarbonNet storage sites has been reviewed. To date, a number of geochemical analyses have been undertaken to assess the possible reactivity between CO_2, pore water and minerals of the reservoirs and seal lithologies of the Latrobe and Seaspray Groups in the Gippsland Basin. Data is well-characterised and includes core samples from several wells on and around the sites, but the available samples have suffered from long term storage under poor conditions in the core store.

The Latrobe Group reservoirs are generally quartzarenites, sublitharenites, or occasionally litharenites with a limited amount of quartz overgrowths/cementation and occasional dolomite-cemented zones. The shales are terrestrial clays - sometimes carbonaceous. Numerous sub-bituminous coals are interbedded within the reservoirs and basal shales to the coal seams such as seat earths and ganisters [1]are noted.

Mineralogy is quartz-dominated but includes subordinate feldspar, siderite, dolomite, and lithics (volcanoclastic debris). Accessory minerals include mica, rutile, zircon, tourmaline, and pyrite. Extensive reactions between the injectate, formation water and minerals are not expected.

[1] Seat earth is a British term for a bed of rock underlying a coal seam, representing an old soil that supported the vegetation from which the coal was formed; specifically underclay. A highly siliceous seat earth is known locally as ganister.

As a first step to understanding the reactivity of Gippsland Basin rocks with CO_2, studies have been undertaken by the CO2CRC research organisation analysing gas fields containing a natural CO_2 component. This CO_2 is thought to come from a volcanic source in the Gippsland Basin, associated with the Victorian “older volcanics” (Birch, 2003). The CO_2 has been reservoired, along with the oil and gas, for millions of years, trapped by similar topseals and intraformational seals as planned for the CarbonNet storage sites. CO_2 compositions of the reservoired gas range from a few percent, up to 40% (Schacht, 2008, Goldie Divko et al., 2010).

Studies of natural CO_2-bearing fields such as Tuna and Kipper show a consumption of mafics and K-feldspars, replacement with authigenic kaolinite and carbonate, and enhanced carbonate and quartz cementation (Schacht, 2008). The outcome of CO_2 exposure is degradation of porosity and permeability due to cementation and enhanced diagenesis. Rock fabrics are not observed to degenerate, even if the precursor sediments are friable.

Reactions are concentrated in zones of poorer original reservoir quality, where quartz is less dominant and more reactive minerals are more common. In contrast, the main reservoir zones show relatively low reactivity and less mineral change on exposure to CO_2.

Results of these studies suggest the occurrence of geochemical reactions between rock minerals and CO_2 injectate will be relatively limited, due to the highly permeable, clean, quartz rich sandstones of the Gippsland Basin and their limited carbonate cementation in the proposed injection and storage zones. Possible carbonate alteration in the reservoirs will be restricted to limited intervals of lesser reservoir quality, and will not affect the overall structure or mechanical properties of the rocks.

To date, near-wellbore geochemical reactions have not been studied, but based on the regional studies by Schacht of generic reservoirs, these are not predicted to substantially affect the injection capacity of the wells over a timescale of a few decades. In any case, the CarbonNet project is planning to have sufficient injection capacity to accept modest amounts of injection fall-off due to either geochemical or mechanical processes.

The geochemistry of the T2 sealing shales is less well known. It appears that, due to their low permeability, there will be little reactivity within the main body of the shale. Some thin shales may be exposed towards the base of the seal interval where, in places, the shale is interbedded with permeable sands that allow CO_2 fluids to contact the shale and perhaps permeate a small distance into them. In this situation, CarbonNet anticipates that the shales will act as cation donors and encourage mixed-cation carbonate deposition from dissolved bicarbonate ions in the formation water. This carbonate deposition will immobilise the plume, occlude the porosity, and reduce permeability, acting as a reinforcement to the existing seal.

Schacht presented x-ray diffraction (XRD) analysis and scanning electromicroscopy (SEM) examination of Gippsland Basin sealing lithologies and these have been supplemented by additional unpublished in-house work by CarbonNet. These studies show that the Lakes Entrance Formation regional seal, T2 key seal and other intraformational seals can potentially undergo chemical reactions between CO_2 and rock forming minerals when exposed in core-flood experiments or in natural CO_2 systems (Schacht, 2008). However, geochemical reaction path modelling illustrates low chemical reactivity for the same samples. The laboratory results are interpreted to be due to mineral alterations which have occurred during long storage of the samples.

Despite the low chemical reactivity of the sampled seal when exposed to CO_2, nuclear magnetic resonance (NMR) and surface area measurements suggest that exposure of the CarbonNet seal samples to CO_2 may result in a surface skin alteration characterised by an increase in pore volume and reduction in capillary pressure. Nevertheless, it is noted that chemical reactions do not proceed deep into sealing lithologies due to their limited permeability and limited fluid transport in sealing lithologies.

Studies undertaken by/for CarbonNet conclude overall that results satisfy the fundamental suitability determinants for CO_2 storage, required by Australian legislation, but available samples have

degenerated from mineral alteration during an extended period (up to 50 years) of poor storage, and pure CO_2 was generally used for analysis and studies. Fresh samples and more representative injectate compositions will be used in additional geochemical data collection and laboratory studies that are planned during the Appraisal Program and will inform on a future CarbonNet application for an Injection Licence.

6.10 Reservoir Engineering

A Well Engineering Study has been completed. This study describes appropriate injection well designs for a (sub-) vertical well drilled from an offshore rig and a second option of high deviation angle (Extended Reach Drilling, ERD) wells that can be drilled to the reservoir from onshore. The conceptual well designs demonstrate technical feasibility for both injection operations. The study also considered the estimated injection zone injectivity and expected injection rates and wellhead delivery pressure with detailed Vertical Flow Performance studies.

The cementing program for each string of casing is designed to bring cement back to surface. Thermalock™ cement is recommended for each string and across the annulus. At the relatively low pressure and temperature of the Latrobe Group, 13Cr pipe is recommended for the liner in the CarbonNet wells.

Spare or redundant wells need to be considered in the event of an injection well failure, and for well downtime for periodic logging and integrity checks, so as to ensure that there is no upstream effect on facilities causing necessity for venting.

Well design and site access must be considered for ongoing monitoring of well integrity and potential well remediation to ensure injectivity.

6.11 Dynamic Modelling

A number of generations of dynamic modelling have been conducted by CarbonNet with a wide range of injection scenarios for each site to establish likely options for injector location, injection well geometry and completion requirements, injection rates, top hole and bottom hole pressure constraints, and plume paths travelled (working towards the 90% probability expressed in OPGGSA, 2006).

Relative permeabilities are the key descriptors in classical formulations of multiphase flow in porous media. The processes of CO_2 injection and migration, and the storage of CO_2 as an immobile phase in the pore space through irreducible saturation all depend on the relative permeability of CO_2 and formation water systems and CO_2-brine capillary pressure character. The parameters above depend highly on the rock physical properties and need to be determined using experimental works for each specific reservoir rocks. Obviously, as CO_2 storage was not the objective of the petroleum exploration, appraisal and production wells in the basin, these experiments (CO_2-Water special core analysis, SCAL) were not carried out on the Gippsland Basin cores. Because of that, some analogues from literature have been used in this work to supply relative permeability data. The base case model was taken as the Cardium Sandstone (Bennion and Bachu, 2008). As with other CarbonNet methodologies, this approach has been validated by peer review panels, and by DNV GL (2012).

In the latest suite of simulations, a number of cases were investigated using Eclipse[300] and the March 2013 version of the geological static model.

The scenarios tested different factors such as completion interval, surface location, injection point, well trajectory and injection rate to observe the parameters below for 1000 years of storage:

1. CO_2 plume migration to ensure that it stayed safely offshore and did not affect other nearby resources.
2. Carbonated water migration to ensure that it stayed safely offshore and did not affect other nearby resources.
3. pH alteration to ensure that it did not affect nearby resources.

4. Bottom hole pressure to ensure that it stayed within safe geomechanical bounds.
5. Average and peak near-field and far-field pressure to ensure seal integrity and no adverse resource interaction.
6. CO_2 plume permeation through T2 seal to demonstrate long-term safe storage.

An example of plume evolution for one structural site, in two different scenarios is presented in Figure 8.

A variety of injection scenarios were modelled, based on the static models described above. Injection rates ranged from 1 to 5 Mtpa, through nominal wells designed to exploit the perceived advantages of different sites. Injection was commenced at deeper stratigraphic levels than the ultimate mapped trap geometry – i.e. at mid- or lower-Halibut Subgroup level for upper-Halibut Subgroup or Cobia Subgroup trapping (Figure 8). A vertical component of migration was anticipated to assist in dissolution and residual trapping, as well as to remove the local near-well pressure effect of injection from the vicinity of the topseal. Bottom hole pressures were monitored to ensure that geomechanical constraints were managed, and plume evolution was modelled for 300 years in screening scenarios and 1000 years in detailed design scenarios.

Figure 8: Example of plume migration

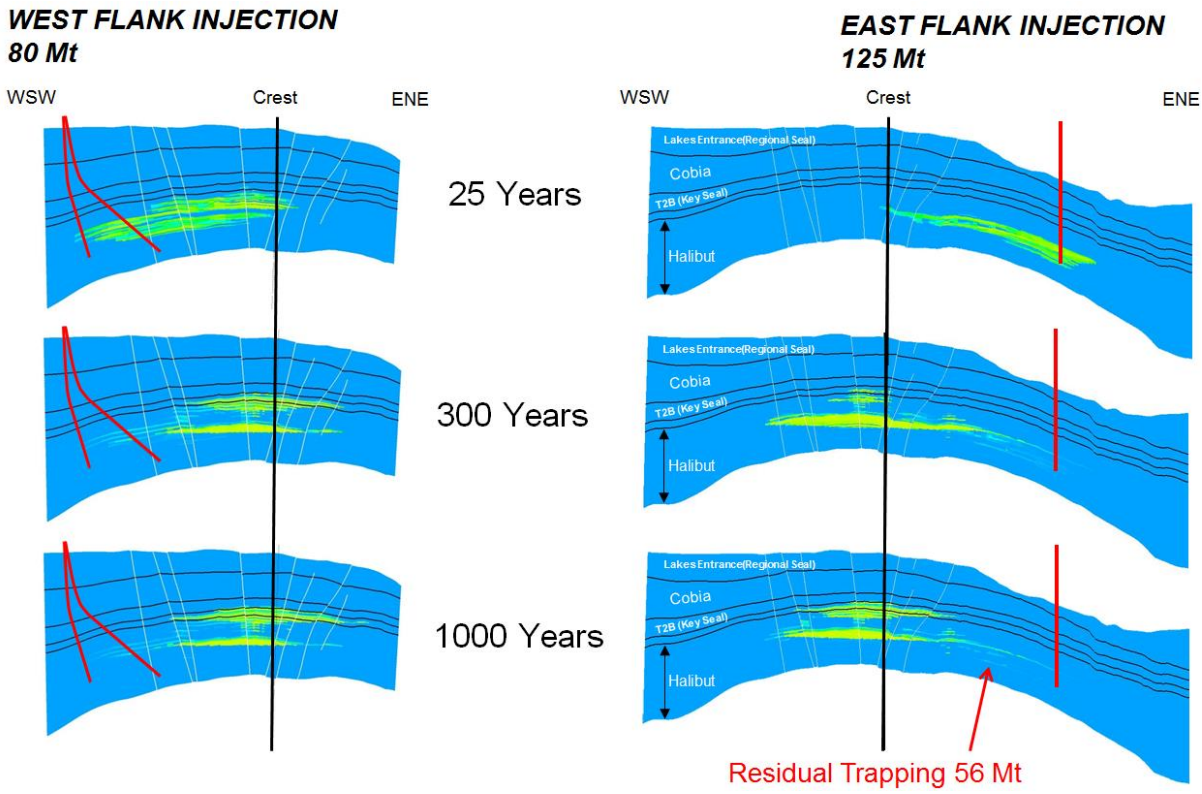


Figure 8. Plume migration is modelled by dynamic simulation in a large structural storage site with injection either from the east flank or the west flank. West flank injection is nearer to the coastline with lower infrastructure costs, but has less total capacity due to limited solution and residual trapping in the short distance migration. Long distance migration from injection on the east flank combines the residual and solution trapping efficiency of aquifer trapping with the assurance of a secure structural trap updip.

Plume evolution

From the studies above, three stages of plume evolution have been identified. Initially, a pressure driven plume of CO_2 is developed symmetrically around the injection borehole. This migrates

outwards in all available directions including upwards and downwards, but is limited by minor baffles and major seals from progressing too far up or down section. Therefore the plume tends to take the form of a squat cylinder or ellipsoid. When injection ceases, the plume will tend to relax into a longer-term shape, controlled by buoyancy.

Even before injection ceases, buoyancy forces begin to act, and part of the plume tends to move updip. In Figure 8, the 25-year snapshot represents this phase with a residual pressure plume or squat cylinder centred on the well(s) and a large body extending buoyantly updip. With more time, larger volumes, and in areas of stronger dip, the migrating plume is more dominant. After injection ceases (300 years snapshot), the earlier pressure-driven plume will stop expanding as the pressure gradient subsides, and migrate updip through buoyancy alone, leaving only a “fingerprint” of residual CO_2 as the plume migrates updip. In aquifer traps, this is the final stage of plume movement.

In structural closures, a third phase of evolution occurs. The plume arrives buoyantly at the top of a structural closure and begins to concentrate within it (1000 years snapshot). Buoyancy leads to gravity segregation, and formation water is expelled downwards while CO_2 rises upwards. In time, a good flat CO_2-water contact develops with relatively high and uniform CO_2 saturation above, and low residual CO_2 saturation below, essentially equivalent to a conventional petroleum pool.

In some aquifer traps, small local structures can retain pools of CO_2 via the third mechanism, while the main plume continues migrating further updip and leaves these pools behind as detached bodies.

6.12 Geomechanics

Previous literature on the geomechanics of the Gippsland Basin is usefully summarised in van Ruth et al., 2007. SHmax is oriented at around 139° and the basin is in a relatively highly stressed state, on the border between strike-slip and compression. The VicGCS project (Ciftci et al., 2011) addressed regional geomechanical stability in the basin and produced a number of reports, concentrating on identifying the orientation of faults with highest slip tendency and highest dilation tendency.

Given the stress condition of the basin, dilation is an unlikely outcome of stress, except in a near-wellbore condition (e.g. drilling-induced tensile fractures), or approaching the leak-off limit. The highest risk, therefore is for shear motion on high-angle faults oriented roughly E-W and N-S. Faults of this orientation are not developed in the plume areas modelled for CarbonNet storage sites.

The CarbonNet sites have been characterised by a preliminary geomechanical analysis which shows that the modelled injection scheme results in a modest pressure increase (~1.5 Mpa) which is well within the safe limit of ~3.9 Mpa at 1500m before reactivation of hypothetical, optimally-oriented cohesionless faults – the worst case scenario. Additional geomechanical data collection is planned during the Appraisal Program.

7 Three potential sites overview

CarbonNet has progressed three different sites through the DNV screening process (DNV, 2012) to meet the minimum requirements of 1 Mtpa injectivity and 25 Mt storage capacity. It has obtained DNV certification for the portfolio of three sites. In the case of the three CarbonNet sites, the fundamental suitability determinants described in OPGGSA, 2006 have been addressed by modelling each site for 1000 years and demonstrating either permanent structural trapping or cessation of plume movement in an open aquifer trap for the injected volume.

Each of the sites already contains a number of petroleum exploration wells, which prove the stratigraphy and suitability of the site for storage. These have all been safely abandoned, except at one site, where late-stage oil recovery is ongoing, with high water-cut. All three sites are covered by a dense grid of modern-quality 3D and/or 2D data.

The three sites offer different opportunities and have strengths and weaknesses that must be assessed in deciding which is the most likely candidate for a CO_2 injection project. The location of the sites is currently confidential and so they are generically named Sites ONE, TWO and THREE.

7.1 Site ONE

This site underlies an undeveloped small hydrocarbon pool, lying relatively close to shore. This would be the lowest cost development due to its ease of access and is the largest site, with more than 125 Mt capacity. A key constraint is the requirement not to adversely affect the shallow hydrocarbon pool.

At the site, Latrobe Group sediments are thickly developed (3 km+). The T2 seal is particularly prominent on seismic and easily mapped and correlated into nearby structures where they are proven by several wells that trap small oil pools or act as pressure and salinity barriers within the Latrobe aquifers (Hoffman et al., 2015b). Good quality reservoirs are developed and regional aquifer support is excellent, with the nearshore meteoric water flushing extending a further 30 km offshore beyond the site.

A stand-alone CO_2 storage scheme can easily be developed at this site, using the standard CarbonNet model of intraformational trapping, under the T2 seal, with upside potential using additional intra-Latrobe Group seals.

7.2 Site TWO

The second site underlies a working small oilfield, approaching the end of its productive life. The actual date of the end of operations is unclear, and depends on external factors such as the international oil price, the operator's cost structure, maintenance requirements of the field and pipelines, and abandonment liabilities.

At the site, a reasonable thickness of Latrobe Group sediments is developed (400m to 1 km), and the T2 seal mapped in the nearshore is correlated securely into this site and proven by local wells (Hoffman et al., 2015b). Good quality reservoirs are developed and regional aquifer support is excellent, with the nearshore meteoric water flushing extending out to, and past this oilfield. The capacity of the site is in excess of 50 Mt.

A stand-alone CO_2 storage scheme could be developed at this site, using the standard CarbonNet model of intraformational trapping, under the T2 seal. Unfortunately, the T2 seal is relatively thin at this location and there are two major faults that locally breach T2. The extent of each breach is easily mapped and no other defects are visible in the T2 seal, therefore the injection site can be chosen to delay the arrival time of the CO_2 plume at the mapped breaches, and hence to delay the ascent of CO_2 to the existing oil facilities.

The delay time is of the order of 50 years, which is clearly longer than the predicted economic life of the field, but any stand-alone development would require the approval of the oilfield operator, and careful monitoring of the plume to avoid adverse impact to field operations.

7.3 Site THREE

The third site is an (open) aquifer trap on the southern margin of the basin, where the stratigraphy is relatively thin (about 400m maximum thickness of Latrobe Group sediments), but still adequate for seal and reservoir development. This trap involves migration southwards through a string of connected small closures.

The T2 seal is less well developed here and, after a few decades, most of the CO_2 rises to top Latrobe Group level. Reservoir fairways at top Latrobe Group are easily mapped here, even on 2D data, and Lakes Entrance Formation seal is proven nearby with good MICP entry pressures. Additional work on topseals will be required before this site can be demonstrated to be suitable for long-term storage.

Given the relatively flat dip, several crossing fault trends, and the lack of existing 3D data, it is difficult to predict the actual geographic plume path as precisely as for a structural trap. Indeed, significant uncertainties exist as to the ultimate trap capacity and/or the ultimate updip limit of travel of the plume. These two factors are coupled – a more mobile plume will move faster and further and thus allow less CO_2 to be injected. The extent of plume travel will depend on many reservoir properties such as residual CO_2 saturation (Sgr), which has yet to be accurately determined in this part of the basin. Given these uncertainties, the storage capacity of the site is less well known but is clearly in excess of 25 Mt.

At each of these three sites, CarbonNet has developed a sophisticated understanding of the geological setting, reservoir and seal fairways, and the distribution of geobodies. A single fairway-wide mapping exercise has allowed 20+ sites to be mapped, screened for fundamental suitability for CO_2 storage, and assigned to high- or low- ranking in a definitive prospect inventory.

8 Discussion: Overview of meeting requirements for Declaration

Our work has shown that it is easier in some classes of trap to demonstrate adherence to the fundamental suitability determinants of the OPGGSA, 2006. The principal issue is with the requirement that 90% of potential plume paths have been modelled, and remain within the storage formation boundaries.

8.1 Structural vs Aquifer traps

For a structural trap, it is relatively easy to demonstrate, through well, seismic, or other remote monitoring, that the CO_2 is contained within an overall structural trap, and is accumulating at the crest in a buoyant fashion. The structural trap can be shown to be secure and effective so long as the topseal has:

- Sufficient sealing capacity and is geographically extensive.
- No leaks are observed during operation.
- No adverse geochemical reactions are predicted or observed.

Even if slow movement of CO_2 is still taking place as the plume adjusts to its structural confinement, the plume will settle into the crestal area with slowly increasing CO_2 saturation and storage efficiency, expelling excess formation water downward.

In an aquifer trap, it is more difficult to demonstrate the “90% of plume paths” of the OPGGSA, 2006, since many variables can have a distinct effect, especially at long times, on the actual plume path:

- Variations in residual CO_2 saturation (Sgr) will strongly affect the distance the plume travels before it is consumed by a combination of residual trapping and dissolution, precursors to geologic time scale mineralisation.
- Details of depth conversion, especially lateral velocity variation, will affect whether the plume swings slightly left or right and, in time, may influence it to enter an entirely different migration chain of connected swells and small culminations.
- The presence of faults may deflect or channel the plume.
- Stratigraphic variations (seal and reservoir fairways or alignments of permeability) can strongly steer a plume in the absence of a strong updip direction.

The net result of all this is that the plume continues moving through the aquifer for longer times than for a structural trap and there is uncertainty about exactly which parts of the aquifer it will ultimately contact and interact with. In a comparison of two injection scenarios at a structural site, a 25 Mt plume was confined within the structure after 300 years with a dimension of 6.5 x 3 km, while in an open aquifer trap the same volume extended over 15 x 5 km and had not stopped migrating.

In an ideal world, the best type of trap to select would be a migration-assisted structural trap where a substantial element of updip and/or lateral migration occurred before reaching the ultimate security of

a structural closure. The structure would be ideally located on the flanks of a basin, with migration out of the basin deep and towards or into a medium to large structural trap, acting as a “backstop” to plume movement.

One of the CarbonNet sites can, in fact, be developed in this mode, with injection of 125 Mt downdip to the eastern flank and 5-10 km of updip migration before reaching the crest of the large structural trap (Figure 8). In this scenario, dynamic modelling shows that 56 Mt of CO_2 (45%) is consumed by residual trapping after 1000 years and 41 Mt (33%) by dissolution, leaving only 28 Mt (22%) of the original injected volume to be structurally trapped. As noted above, these proportions are volume and scenario dependent, and should not be applied to other projects or reservoirs without new modelling.

9 Conclusions

The CarbonNet project has built-up a significant level of understanding of the nearshore region of the Gippsland Basin and demonstrated the fundamental suitability of a portfolio of three sites for the storage of 25-125 Mt of CO_2, injected over 25 years.

CarbonNet has compared reservoir characteristics at its sites to those in other projects worldwide and has developed a system of classification into three types of reservoir:

TYPE 1 reservoirs are the highest quality, thick, and extensive with good aquifer support. Project commerciality is high and technical issues are few, with good plume imaging and no pressure control issues, however plume mobility is high. These reservoirs are ideally suited to offshore storage projects and are exemplified by the Sleipner project. CarbonNet is working in this class of reservoirs.

TYPE 2 reservoirs are of average quality and thickness. Project commerciality is also acceptable, especially onshore. Plumes can generally be imaged adequately and reservoir pressure can be managed, but additional effort may be required.

TYPE 3 reservoirs are generally unsuitable for CO_2 storage, except at low volume. There are significant pressure management issues and several failed projects lie in this category.

During our study of subsurface geometry and reservoir properties, two substantial factors have assisted the rapid accumulation of comprehensive basin and site understanding:

1. The basin is a successful and prolific petroleum province, and therefore there is a large amount of industry data (wells and seismic surveys) and many detailed studies, reports, and scientific papers about the oil and gas accumulations, their reservoirs and seals, and the basin stratigraphy, depositional setting, and tectonic history.
2. Australia has a comprehensive open-file data system where petroleum data is released after a time period of 3-5 years and stored for free public access. Without this foresighted regime, only established petroleum companies would be able to work-up sites for CO_2 storage with existing confidential data that they already own or have access to through trades or other arrangements.

If either of these two criteria did not apply, The CarbonNet Project would have had to start from scratch and expensively acquire its own unique and confidential data through field operations, purchases, and trades (once a material volume of proprietary data had been accumulated). Basin understanding would have to commence from a very low level, based on scout quality data. This is the challenge that faces potential CCS participants in many other countries, and acts as a formidable barrier to new entrants to the industry, in the lack of a high-value commodity such as oil or gas to finance the activity.

Given the advantages of extensive pre-existing data, CarbonNet has been able to work-up three high-graded sites for potential future CO_2 storage. These sites are the survivors of ~28 original targets and the site screening process has enforced a rigorous quality control by excluding or downgrading 90% of the initial candidates.

Site evaluation and screening has followed a play fairway approach, with independent but adjacent sites benefitting from mutual data collection and understanding. Three distinct sites have been high-graded:

1. A large structural closure which can meet the project storage volume as a stand-alone.
2. A candidate for future re-use of a depleted small oilfield, within a larger closure that is material for CCS.
3. An (open) aquifer trap that offers a very different storage concept and is well away from petroleum infrastructure.

The CarbonNet Project has completed initial site characterisation to demonstrate the fundamental suitability determinants for safe and permanent storage of CO_2. In particular, due to the abundance of pre-existing data, including legacy wells on each site, and extensive 3D and 2D seismic data, CarbonNet is ready to prepare a ***Declaration of Storage Formation*** – the initial step of licensing a site for future injection.

There remain some legislative issues to be resolved before CarbonNet can submit the Declaration.

By the end of 2015, CarbonNet will be ready to proceed with appraisal of a prioritised site, subject to the approval of project sponsors and regulators.

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