Report

The Latrobe Valley CO_2 Storage Assessment

Cooperative Research Centre for Greenhouse Gas Technologies

November 2005

CO2CRC Report No: RPT05-0220

CSIRO

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THE UNIVERSITY OF NEW SOUTH WALES

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The Latrobe Valley CO_2 Storage Assessment

The Latrobe Valley brown coal deposits within Victoria's Gippsland Basin are a world class resource characterised by very large reserves of very low-cost coal. They provide Australia's lowest cost electricity but, because the coal has a high moisture content, they also produce a relatively large volume of CO_2 per unit of electricity. Carbon capture and storage (CCS) technology could, however, provide a means of drastically reducing the CO_2 emissions associated with the use of the Latrobe Valley's brown coal.

The adjacent offshore Gippsland Basin is the site of large mature petroleum fields which have securely trapped and stored large volumes of oil and gas for many millions of years. As some of these fields start to approach depletion, the offshore reservoirs offer the potential for secure storage of CO_2 from the Latrobe Valley (Figure 1).

Figure 1. Location of Gippsland Basin and the Latrobe Valley.

In July 2004, the Department of Transport and Regional Services (DoTaRS) awarded a grant to Australian Power and Energy Limited (APEL) - now Monash Energy - to undertake the Latrobe Valley CO_2 Storage Assessment (LVCSA), drawing on the expertise of the CO2CRC. The scope for the assessment was developed in late 2004 and evaluation by CO2CRC researchers commenced in early 2005.

The LVCSA provides a medium to high-level technical and economic characterisation of the volume and cost potential for secure geosequestration of CO_2 produced by the utilisation of Latrobe Valley brown coal. It identifies key issues and challenges for implementation and provides a reference framework for the engagement of stakeholders, including the identification of items that will require further focused verification studies.

The project is by definition an early assessment of the risks and uncertainties of a major infrastructure investment. It is intended to provide strong indications of the potential viability of such a project leading to higher levels of definition as more scoping and development proceeds.

The outcomes agreed by Monash Energy with DoTaRS for the LVCSA were:

- Definition of the capacity of the Gippsland sedimentary basin to provide a high integrity storage site for CO_2 sourced from the Latrobe Valley over the long term.

- Definition of the costs of providing transportation, injection and monitoring / verification of CO_2 from the Latrobe Valley from commencement through until around 2050.

- Evaluation of the potential synergies and challenges of implementing the CO_2 storage project while oil and gas operations continue through to ultimate field depletion.

- Definition of an optimum CO_2 storage infrastructure roll-out plan including preferred injection locations.

- Definition of the specific uncertainties associated with implementation and specification of the work necessary to ensure that these are mitigated to the extent necessary.

- Collaboration during the assessment between Monash Energy, the CO2CRC, the Federal and Victorian Governments and, ideally, key oil and gas producers operating in the area of prospective CO_2 storage.

- A framework for engagement with community stakeholders.

CO2CRC, through their researchers at the Australian School of Petroleum, CSIRO and the University of New South Wales, worked to address these outcomes under the following scope:

1. Broad characterisation of regional storage potential within the Gippsland Basin presumably leading to the identification of the offshore Basin as the preferred storage repository.

2. Identification and description of prior storage studies, relevant petroleum studies, data coverage and availability for the offshore Gippsland basin.

3. Identification, ranking and qualitative and quantitative characterisation of preferred injection site(s) and horizons - including storage capacity and storage security.

4. Reservoir simulation to predict migration path, ultimate long-term destination and form, of CO_2 injected at the preferred injection site(s) for each of the volume scenarios.

5. Interaction with oil and gas developments, including synergies and potential cost savings as well as any potential adverse impact on oil and gas recovery.

6. Storage assurance – identification of potential risks and uncertainties to be addressed in subsequent project approvals technical evaluations.

7. Preliminary specification of the compression, pipeline and injection infrastructure required linking Latrobe Valley coal utilisation developments to the preferred injection site(s) and horizons, for each of the volume cases.

8. The estimation of the corresponding capital and operating costs for each of the volume cases.

9. The identification of key potential impacts, risks and uncertainties, associated with the development and operation of the infrastructure, to be addressed in subsequent technical, safety and environmental evaluations for project approvals.

10. Summary of the potential of geosequestration to facilitate ongoing development of Latrobe Valley coal resources, together with an identification of the key challenges and requirements for project approvals evaluations.

The resulting work was grouped into the following broad themes:

1. Geological/hydrological analysis and modeling;

2. Interaction with the Bass Strait producers on development plans;

3. Risk assessment and storage assurance;

4. Development of infrastructure plans for transportation and injection;

5. Techno-economic studies; and

6. Communication.

The assessment is based around a series of generic storage volume cases, indicatively 2 million tonnes of CO_2 per year, 15 million tonnes per year and 50 million tonnes per year, which provide the basis for techno-economic assessment.

Understanding CCS

CCS comprises four main steps:

1. Capturing the CO_2 at the source, such as a power plant or industrial facility.

2. Transporting the captured CO_2, typically via a pipeline, from the source to the geological storage site.

3. Injecting the CO_2 deep underground into a geological reservoir.

4. Storing the CO_2 in the geological reservoir.

The capture of CO_2 from a stationary source, such as a power plant, involves separating and purifying CO_2 from the bulk of the flue gas stream rather than allowing it to be released to the atmosphere. The purified CO_2 stream is then available for geological storage.

The main sources suitable for CO_2 capture are: industrial processes; electricity generation; and, in the future, hydrogen production from fossil fuel sources. Industrial processes that lend themselves to CO_2 capture include natural-gas processing; ammonia production; and cement manufacture, however the total quantity of CO_2 produced by these processes is relatively small. A far larger source of CO_2, accounting for one-third of total CO_2 emissions in Australia, is fossil-fuelled electricity generation. Research is underway on the capture of CO_2 from this source.

Geological storage of CO_2 secures the gas deep underground in a geological reservoir. In addition to the careful selection of a suitable geological reservoir, a comprehensive monitoring system is required initially to ensure that the gas is safely contained.

Geological reservoirs into which CO_2 can be injected include depleted oil and natural gas fields, and deep saline formations. Since the stored CO_2 will be less dense than the water in and around the reservoir rocks, it needs to be stored in carefully studied sites where it will be geologically trapped to ensure that it does not reach the surface. The exact trapping mechanism depends on the geology. In depleted oil and gas fields, similar to those nearing depletion in the Gippsland Basin, a geological trap and a regional seal rock will contain the CO_2.

CO_2 is usually transported from a source, such as a power station, to the geological storage site in a compressed form via a pipeline. It is injected from a tanker, truck or pipeline deep underground into the geological reservoir. CO_2 geosequestration includes the capture, transport, injection and storage of CO_2 into deep geological formations.

Geological/hydrological analysis and modeling

Previous studies and data coverage

The LVCSA is not the first study to assess the geosequestration potential of the Gippsland Basin. The GEODISC^{TM} program of the Australian Petroleum Cooperative Research Centre (APCRC) undertook a study of the geosequestration potential of the upper Latrobe Group stratigraphy in the vicinity of the northern gas fields (Marlin, Snapper, Barracouta) in the offshore Gippsland Basin. The study reviewed an injection rate of 10 million tonnes per year for 20 years, equating to a 200 million tonnes total storage volume. The GEODISC^{TM} study comprised a PhD by Rob Root (in prep.) on the sedimentology, sequence stratigraphy and 3D geological model, plus reports by the National Centre for Petroleum Geology and Geophysics (now known as the Australian School of Petroleum) on the geomechanics, and reports by CSIRO on the hydrogeology and long-term reservoir simulation. The key results from these studies are publicly available[1].

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[1] Root, R S, Gibson-Poole, C M, Lang, S C, Streit, J E, Underschultz, J R and Ennis-King, J, 2004. Opportunities for geological storage of carbon dioxide in the offshore Gippsland Basin, SE Australia: an example from the upper Latrobe Group. *In*: P J Boult, D R Johns & S C Lang (eds.) *Eastern Australasian Basins Symposium II*, Special Publication, 19-22 September 2004, Adelaide. Petroleum Exploration Society of Australia, pp. 367-388.

A second study was conducted by APEL and CSIRO in 2003/04. The area of interest was the nearshore western part of the offshore Gippsland Basin, with proposed injection into the Golden Beach Subgroup in the vicinity of the Dolphin and Perch oil fields. The APEL/CSIRO study reviewed a total storage volume of ~220–260 million tonnes, injected at a rate of ~11–13 million tonnes per year for 20 years.

By Australian standards, the Gippsland Basin is a mature basin and one of Australia's most prolific oil and gas provinces. Petroleum exploration has been active onshore since the 1920s and in the offshore region since the 1960s, thus there is a considerable amount of data that has been accumulated. In particular, as of 2001 there was over 80,000 kilometres of 2D seismic data, more than 25 3D seismic surveys, 160 exploration wells onshore, and 204 exploration and appraisal wells offshore. The average exploration well density throughout the basin is about one well in 125 kilometres^2, which increases to around one well in 50 kilometres^2 in the main producing areas.

The present offshore oil and gas production is generally in water depths of 40- 90 metres deep from reservoirs that are 1-2.5 kilometres below the sea floor.

Methodology

Safe and reliable containment of CO_2 in geological structures begins with a structured assessment of the characteristics and features of the target reservoir or location.

The methodology for evaluating a site for geological CO_2 storage is shown in Figure 2.

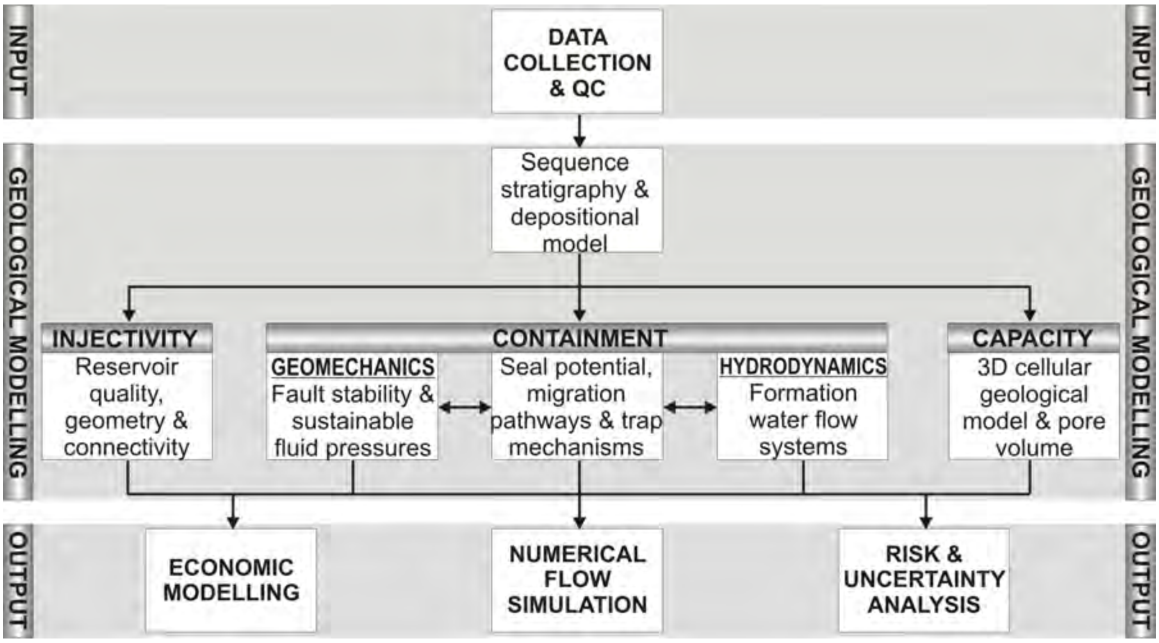

Figure 2. Workflow for CO_2 geological storage assessment[2].

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[2] Gibson-Poole, C M, Root, R S, Lang, S C, Streit, J E, Hennig, A L, Otto, C J and Underschultz, J R, in press. Conducting comprehensive analyses of potential sites for geological CO_2 storage. In: E Rubin, D Keith & C Gilboy (eds.) *Greenhouse Gas Control Technologies: 7th International Conference on Greenhouse Gas Control Technologies*, 5-9 September 2004, Vancouver, Canada.

CO2CRC researchers studied the Gippsland sedimentary basin using this methodology and completed this technical work in the context of the LVCSA scope, namely:

- Regional evaluation
- Geology and geophysics interpretation
- Seal capacity study
- Geochemical evaluation
- Geomechanical analysis
- Hydrodynamic assessment
- Short-term (injection phase) numerical flow simulations
- Long-term (post-injection phase) numerical flow simulations
- Economic modeling
- Risk assessment

Site evaluation can be a complex and interdependent task requiring considerable iteration and interaction between key research groups and stakeholders. The outputs are quite sensitive to the geological parameters.

For instance, the required storage capacity is a critical feature of any CCS project, with proponents requiring considerable certainty to underpin large capital expenditures. Storage assessments can be predicted reasonably well at early stages of evaluation for some target sinks such as depleted oil and gas fields. However saline aquifer capacities can only be confirmed by numerical modelling which may not be available until some time into the evaluation. Further iterations may be required if it proves necessary to redirect attention to other horizons to achieve the capacity. New horizons are likely to display different injectivity conditions which in turn can have significant impacts on the capital cost of the project.

The capacity, containment and injectivity parameters form the basis for further assessment. Once these parameters have been determined, numerical flow and economic modelling, in addition to risk assessments, will dictate the acceptability of a storage site.

Geoscience characterisation

The Gippsland Basin is an east-west trending rift basin, located mostly offshore in south-eastern Australia, Victoria. It contains sediments over 10 kilometres thick from Early Cretaceous to Recent in age. CO2CRC researchers evaluated and ranked potential CO_2 storage sites in terms of their location, injectivity, containment, storage capacity and proximity to existing natural resources. Results indicated that the Gippsland Basin stratigraphy is highly favourable for CO_2 storage. In particular, the upper Latrobe Group sediments are of good to excellent reservoir quality and the Lakes Entrance Formation provides a substantial regional seal, which has proven its capability by the retention of hydrocarbons in the area for millions of years.

A number of regions in the basin were reviewed as part of the study (Figure 3) and a more detailed study was conducted over the Kingfish Field location, where it is expected that the field will be conventionally depleted within the period 2015 – 2025. Mindful of the sensitivity to CO_2 entering these significant oil and gas producing reservoirs, a deep injection strategy was chosen for the base case for scenario analysis. This involves injecting up to

15 million tonnes per year deep beneath West Kingfish into the intra-Latrobe Group stratigraphy (550-800 metres deeper than the main oil accumulation, at a depth of 2750-3000 metres below sea level). CO_2 is predicted to migrate upwards and eastwards towards the top of the Latrobe Group. The discrete nature of the stratigraphy and structure will ultimately control the rate at which this occurs. Free CO_2 that reaches the base of the Lakes Entrance Formation would subsequently accumulate in the depleted Kingfish Field structural closure. Although the spill point of the Kingfish structure is somewhat ambiguous, it is postulated that if the capacity of the Kingfish closure is exceeded, and if still mobile, CO_2 would then migrate westwards towards the structural closure of the Bream Field.

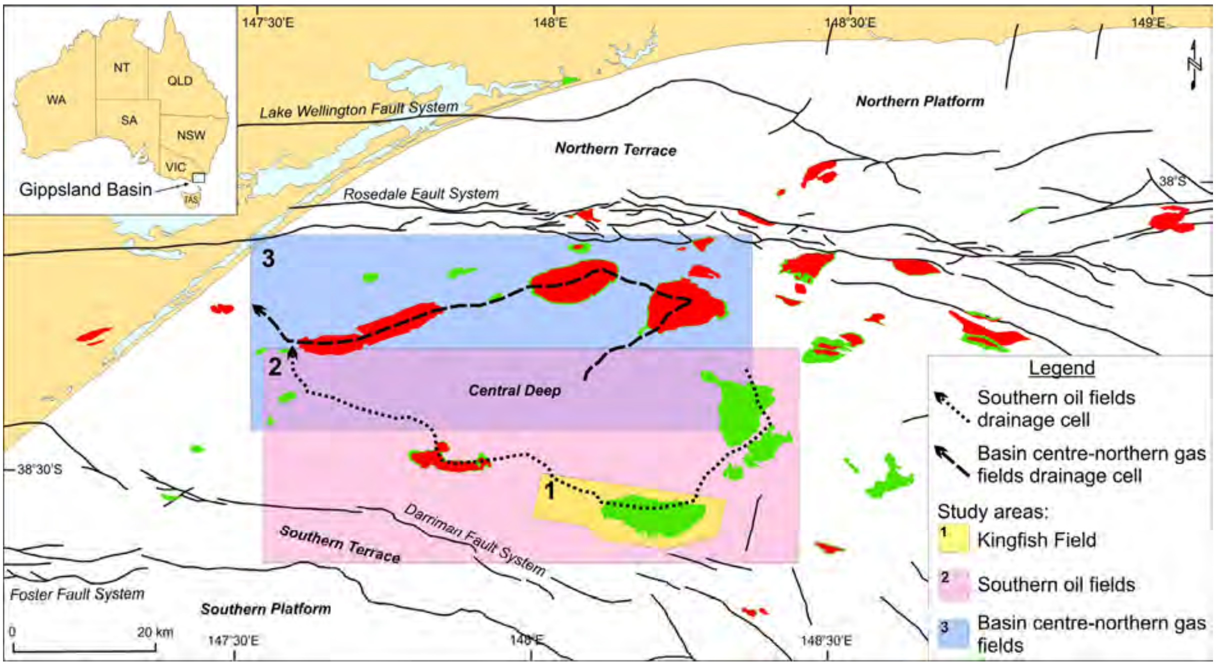

Figure 3. Study areas for the Latrobe Valley CO_2 Storage Assessment (tectonic elements after Power et al., 2001).

The detailed characterisation concluded that the reservoirs are of sufficient quality to allow injection. The complex intra-Latrobe stratigraphy may provide baffles and intraformational seals that could hinder and slow the migration of the CO_2, thus allowing other trapping mechanisms such as residual gas saturation to take effect. While permeabilities are much lower in the deeper stratigraphic horizons, drilling strategies were identified to mitigate cost increases. The seals evaluation work to date indicated that the Lakes Entrance Formation has sufficient seal capacity to successfully retain the CO_2. The geochemical assessment of the likely CO_2-water-rock interactions revealed that mineral reactions were unlikely in the low-reactive reservoir units during the short-term (injection period), thus the injectivity of the reservoir units would not be compromised. However, mineral reactions were possible in the Gurnard Formation at the top of the Latrobe Group (but still below the regional top seal), which would provide mineralogical storage of CO_2.

Most of the faults detected around the Kingfish Field are not in the predicted immediate CO_2 migration, and most do not cut the top seal. However, geomechanical assessment indicated that some have a potential for reactivation, and therefore pore pressure increases adjacent to faults would need to be carefully monitored.

The hydrodynamic analysis determined that the formation water flow has been affected by hydrocarbon production in the region. The Latrobe Aquifer System has been drawn-down and depressurised by decades of offshore petroleum production, onshore irrigation and mine de-watering. The locally steepened hydraulic gradients oppose the expected buoyancy-driven CO_2 migration direction, which may positively impact on the predicted migration direction and containment of CO_2 in the short-term (tens to hundreds of years). The injection of CO_2 into the offshore reservoirs is likely to offset some of the aquifer depressurisation, but detailed numerical analysis will be required to assess the extent of this impact.

Sensitivity studies conducted on short-term numerical simulation (25–40 years) determined that permeability and the maximum injection pressure affect the injectivity of CO_2. Lower permeabilities and lower injection pressures result in a reduction of the maximum injection rate of CO_2 that can be achieved. Thus, a greater number of wells are required to compensate for this effect. The long-term numerical simulations of the scenarios analysed verified that the first arrival of CO_2 at the oil-producing zone was 50 to 200 years after injection commenced (i.e. post-production of the Kingfish Field) and that a deep injection strategy results in greater CO_2 storage via residual gas saturation. However, further verification studies will be required in order to confirm that all possible scenarios have been considered to mitigate any earlier arrival of CO_2 at the oil-producing zone.

The Kingfish site, in conjunction with other similar sites within the basin (e.g. Fortescue, basin centre) will provide sufficient capacity for 50 million tonnes CO_2 per year storage for the 40 years injection duration. It is envisaged that the individual sites would be used sequentially, ramping up the volume of CO_2 stored to 50 million tonnes per year but timed such that existing hydrocarbon assets are not compromised.

CO2CRC researchers have documented and analysed the CO_2 storage potential of larger areas within the offshore Gippsland Basin as part of this assessment. The immediate modeling scenarios and assumptions completed under this study showed CO_2 storage potential in excess of 2 billion tonnes. More comprehensive studies of the basin's stratigraphy, particularly at deeper levels such as the intra-Latrobe Group sediments, will be required to confirm overall basin storage capacities. However, broad indications, based on the increase in capacity when using both the intra-Latrobe and top Latrobe stratigraphy at the Kingfish Field, suggest a basin-wide storage capacity of possibly 6 billion tonnes. The veracity of this figure would need to be confirmed by further studies.

Development of infrastructure plans

The availability of CO_2 for injection in the Gippsland Basin is hard to predict, as it is influenced by breakthroughs in science and engineering, community opinions on climate change and CCS, and government policy on a range of issues including carbon pricing. The basis for this assessment is that up to 15 million tonnes of CO_2 will be available for injection from the proposed Monash Energy facility in 2015. Case A is a 2 million tonnes per year injection scenario intended to represent a possible five-year demonstration facility, whereas Case B represents a Monash Energy facility type scenario (15 million tonnes per year). The large-scale injection scenario of Case C (50 million tones per year) required more complex definition (Table 1). A number of scenarios predicting the availability of CO_2 from subsequent facilities, including possible closures of ageing power plants, introduction of new gas-fired and low emission coal-fired power stations and low emission gas to liquids plants were considered. The conservative scenario considered in this assessment is that CO_2 will become available from two subsequent pre-combustion facilities. It was assumed that the amount of CO_2 available for injection will increase in step-wise increments up to 50 million tonnes per year.

Table 1. Description of volume cases assessed.

Case	Type	Volume Injected
Case A	Demonstration facility	2 million tonnes per year
Case B	Monash Energy facility	15 million tonnes per year
Case C	Large-scale injection	50 million tonnes per year

The depletion dates of existing oil and gas reservoirs are both commercially sensitive and uncertain to predict. Primarily due to the uncertain nature of predicting ultimate depletion dates, the Producers could only provide depletion date ranges for existing oil reservoirs. They indicated that the Kingfish Field and other southern oil fields, were likely to be available before the gas reservoirs starting with the Kingfish Field in the range 2015-2025. With this agreed strategy, CO2CRC researchers initially focused on the southern oil reservoirs in the offshore Gippsland Basin as opposed to the northern gas reservoirs considered in a previous study by the GEODISC^{TM} Program.

Considering these uncertainties and an initial review of the geological modeling, the final roll-out plan was chosen to spread injection over three storage areas. CO_2 would first be injected at Kingfish at 15 million tonnes per year, then the Fortescue region at 15 million tonnes per year, then in the basin centre at 20 million tonnes per year. CO_2 can be injected at sustainable rates from a geological viewpoint that complements this source scenario (Figure 4).

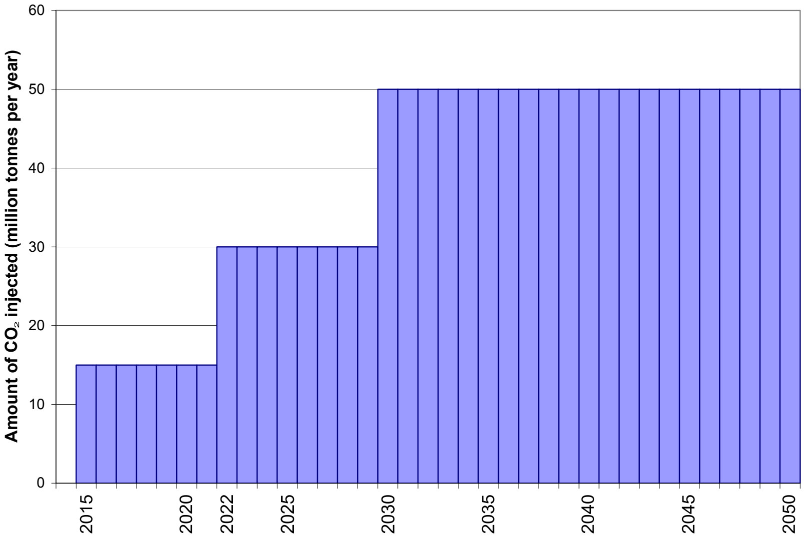

Figure 4. Scenario for the amount of CO_2 available for Case C1 over the study period.

Interaction with oil and gas producers in the region

The area of the offshore Gippsland Basin that is best suited for CO_2 storage is also the focus of oil and gas production, and is entirely subject to existing petroleum exploration and production tenements. Whilst oil and gas production will decline in the medium to long-term as the fields are progressively depleted, there will need to be close cooperation between petroleum producers and CO_2 injectors in the short to medium-term. The LVCSA was designed by Monash Energy to foster that cooperation from the outset by inviting the largest oil and gas producers in the region to collaborate in the study.

As part of that collaboration Esso and BHP Billiton assisted CO2CRC by providing access to confidential geoscience information and by providing constructive comment on the CO2CRC's injection scenarios, assessments and conclusions. It was at Esso's suggestion that the Kingfish Field was selected as the area for first injection, on the grounds that it will be the first depleted of the fields and therefore least susceptible to any possible adverse impact from CO_2 injection on oil production.

Although the likely depletion of the Kingfish Field is in approximate alignment with the earliest commencement of CO_2 injection, there can be no guarantee that oil production will have ceased when first CO_2 injection could commence. Consequently, the injection strategy adopted was designed to effectively eliminate the risk of injected CO_2 reaching the oil reservoirs before production has been completed. Under this strategy the CO_2 is injected at a depth at least 500 metres deeper than the oil-producing reservoir, from which point it would take a minimum of 50 years to migrate upward through the strata to reach the trap from which oil production has by then long ceased.

The adoption of this over-riding risk management strategy removed the need for any more detailed LVCSA evaluation of potential impacts of CO_2 injection on oil production but, planning for future proposals involving adjacent injection and production will require more detailed risk management strategies – and continuing cooperation between prospective injectors and existing producers.

Enhanced oil recovery (EOR) is often considered an excellent synergy between CO_2 storage and oil recovery providing improved recovery from existing fields. However, following discussion with Esso and BHP Billiton as part of this assessment, there is some doubt as to the economic viability of such an approach in the Gippsland Basin, particularly given the wholesale re-configuration to wellbores and facilities that would be required. Esso already expect to extract a significantly higher proportion of the oil in place than elsewhere in the world and many factors such as high permeability rock, light oil characteristics and reservoir geometry suggest developing an economic EOR project to be challenging. One of the significant challenges identified is the likely time delay of decades between CO_2 injection after the completion of primary oil production and any additional oil recovery after the reservoir becomes filled with CO_2.

Given the need for detailed evaluations using commercially sensitive data, it has not been possible to reach a conclusion on the viability of EOR in this assessment. Additional studies may resolve some of the issues identified and determine scenarios where EOR can be developed economically, however given the uncertainties, no economic benefits for EOR have been assumed for this assessment.

Risk assessment and storage assurance

The construction and implementation of a major CO_2 geosequestration project, such as that envisaged in the LVCSA, has associated risks like any other major infrastructure or production project. However, the hazards and associated risks can be clearly identified and addressed by project proponents. They can draw on the extensive international experience obtained from existing CO_2 pipelines, EOR operations and demonstration CCS projects to help identify uncertainties and mitigation measures.

A range of risk assessment processes were conducted to confirm the project as a safe and reliable project for long-term containment of CO_2 and to demonstrate the risk assessment process. Risk assessments were performed on the project infrastructure and the geological storage integrity.

Major projects such as the LVCSA are typically developed in stages and consequently the safety and risk assessments are conducted in ever increasing levels of sophistication as the project definition increases. Accordingly, two types of initial hazard study were performed on the LVCSA infrastructure, a preliminary risk assessment and a quantitative risk assessment.

The preliminary risk assessment identified key potential impacts, risks and uncertainties from the process, as well as several specific mitigation actions that had already been factored into the costings for the project. The screening analysis conducted under the LVCSA indicates that all issues associated with the proposed injection infrastructure have the potential to be managed within accepted safety levels.

A quantitative risk assessment of CO_2 compression and transport and the risk and consequence modeling of pipeline leaks identified potential hazards along with issues that will need to be addressed by project proponents. This more detailed risk assessment also confirmed that the risks from compression and pipeline infrastructure are low and manageable using well-known methods common to industry. There are no likely impediments to development based on risks imposed by the infrastructure of such a project.

The geological assessment of the target sites in the Gippsland Basin confirmed previous studies showing the sites to be excellent candidates for safe and reliable containment of CO_2. A quantitative risk assessment of the geosequestration sites, using the technique developed under GEODISC^{TM}, determined that the reservoir could contain CO_2 to an acceptable level. A CO_2 leakage rate of 1% over 1000 years is commonly used as an acceptable level for storage assurance and the targeted reservoirs within the offshore Gippsland Basin are predicted to be below this level. A plot of the results of the Kingfish Field (Figure 5) shows the components of containment risk. These provide guidance on the risk mitigation issues CCS proponents should focus on, namely pursuing a process for well maintenance and evaluation and further work to enhance data for reservoir modeling and flow prediction.

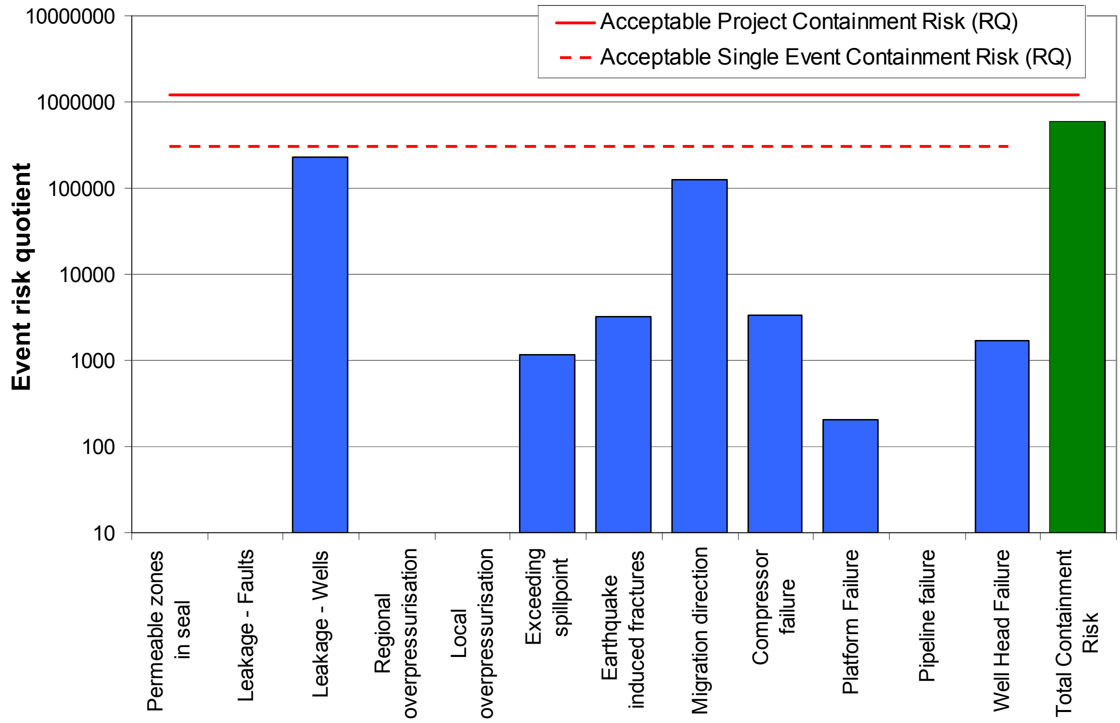

Figure 5. Kingfish event risk quotient (a measure of containment risk).

The risk assessment processes performed under the LVCSA provide strong indication that the Gippsland Basin can be a safe and effective storage site for CO_2 for thousands of years.

Techno-economic studies

Techno-economic modeling was used to define the costs of providing compression, transport, and injection for all the scenarios using an integrated capture and storage model developed to investigate CCS projects. It uses a cash flow modeling approach to design compression, transportation and injection components of any source-sink combination.

Specifically for this project, additional cost data on compressors, pipelines (onshore and offshore), platforms and wells were sought from engineering consultants and used to supplement data in the model. All costs are 2005 Australian dollars. The results from the model have an order of accuracy of ± 30% for any given set of source and sink characteristics.

Analyses were carried out for CO_2 injection rates for 2 million tonnes per year (Case A), 15 million tonnes per year (Case B) to 50 million tonnes per year (Case C). Offshore costs were based on an assumption of new stand-alone infrastructure, and on injection deep below the oil and gas fields, i.e. no integration with existing oil and gas production. The resulting cost estimates for cases considering injection of 15 million tonnes per year and 50 million tonnes per year are shown in Tables 2 and 3.

Table 2. Real (2005) capital and operating costs of CO_2 storage (not including Capture) in Australian dollars based on a permeability of 150mD.

Annual CO_2 flows	15 million tonnes per year	50 million tonnes per year
Capital costs	$1,199 m	$3,861 m
Compression[3]	$408 m	$1,163 m
Pipeline	$242 m	$750 m
Injection[4]	$516 m	$1,836 m
Oil well remediation	$34 m	$112 m
Operating costs /year	$62 – 71 m	$204 – 227 m

Table 3. Total capital and operating cost per tonne of CO_2 avoided in Australian dollars.

Annual CO_2 flows	Total cost
15 million tonnes per year	$10.9 per tonne
50 million tonnes per year	$10.5 per tonne

The unit costs of storage are comparable to those developed under GEODISC™ for the high volume cases. The costs include that of compression so care must be taken when comparing to other studies.

A 2 million tonne per year (Case A) was assessed in order to investigate the relationship between injection rate and cost per tonne. At this low rate it was considered to represent a small-scale demonstration plant and was modeled as such. As expected, the storage costs were determined to be relatively high at $34.2 per tonne of CO_2. The comparison of the costs for the three injection rates over a similar 40 year basis is shown in Figure 6.

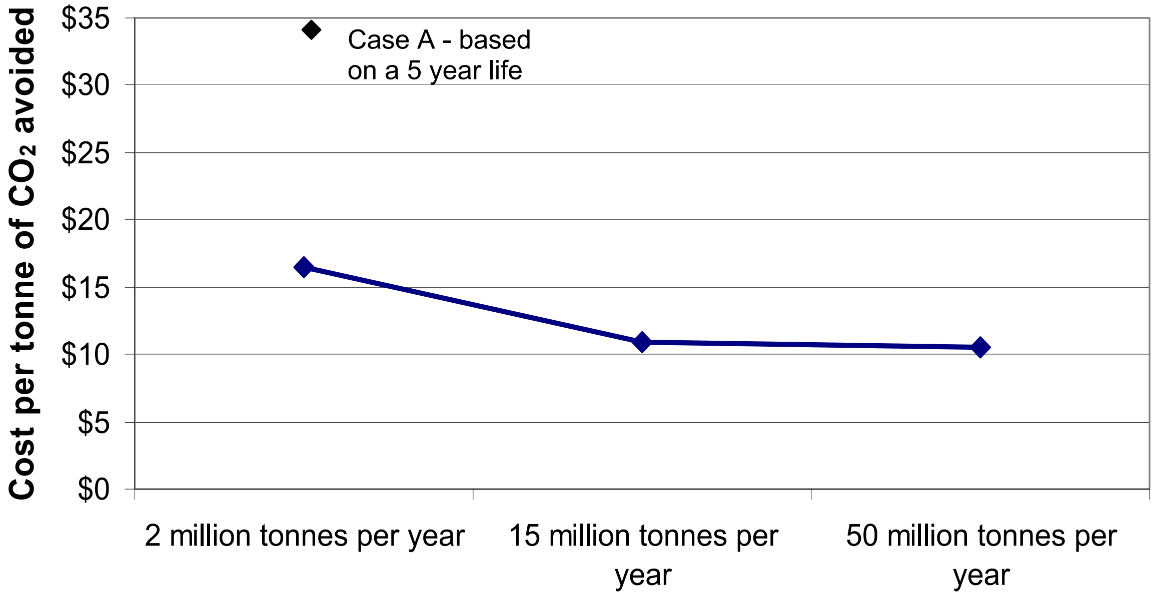

Figure 6. The relationship between injection rate and cost per tonne of CO_2.

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[3] Compression comprises the cost of compressors and power plant to drive them.

[4] Injection comprises the cost of well drilling, platforms and remediation of old oil production wells.

The capital cost estimates and costs per tonne of CO_2 avoided are quite sensitive to project parameters such as project scope, injection depth, reservoir permeability, ramp-up time, policies on equipment sparing, methodologies for providing compressor drive power and project life.

Sensitivity studies were conducted on a number of parameters using Case B1 as the base (Figure 7). The analysis compared scenarios with: no spare compressors; a shallow staged injection concept for the top Latrobe Group at Kingfish and Fortescue; high permeability of 1000mD (as opposed to 150mD) for intra-Latrobe Group injection (purely for comparative purposes); and horizontal well injection. The most sensitive parameter is reservoir permeability, which affects the number of wells and hence the size and cost of offshore injection facilities.

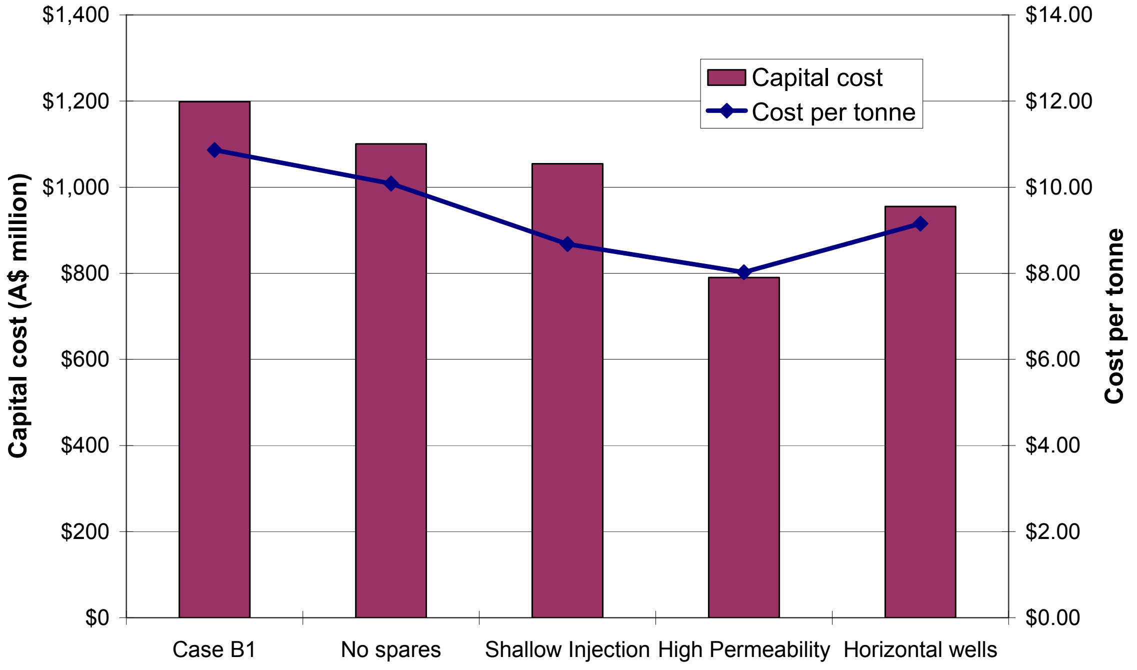

Figure 7. Sensitivity analysis.

Horizontal wells were considered to reduce costs by allowing increased reservoir penetration, moderating pressure interference and reducing the number of wells required. This showed the potential for reduced costs if long-run horizontal wells are used.

The base cases included a compressor sparing policy for greater reliability. Relaxing this requirement reduced costs which should be considered more closely in final designs.

A final sensitivity was run on a shallower injection for the B1 case. While not chosen as the base case because oil production may not have ceased before injection starts, a two-stage step-out of the Kingfish Field followed by the Fortescue Field could conceptually be employed to achieve Case B volumes for 40 years. Little reservoir modeling was performed on this shallow injection and it may not be viable for Case C due to storage constraints. Nevertheless, costs were reduced as shown in Figure 7.

Conclusion

The LVCSA provides strong indications that the Gippsland Basin has sufficient capacity to safely and securely store large volumes of CO_2 and may provide a viable means of substantially reducing greenhouse gas emissions from coal-fired power plants and other projects using brown coal in the Latrobe Valley.

The LVCSA has addressed the agreed outcomes and fulfilled the requirements of the Australian Government's Sustainable Regions Programme.

an emission free vision for the future

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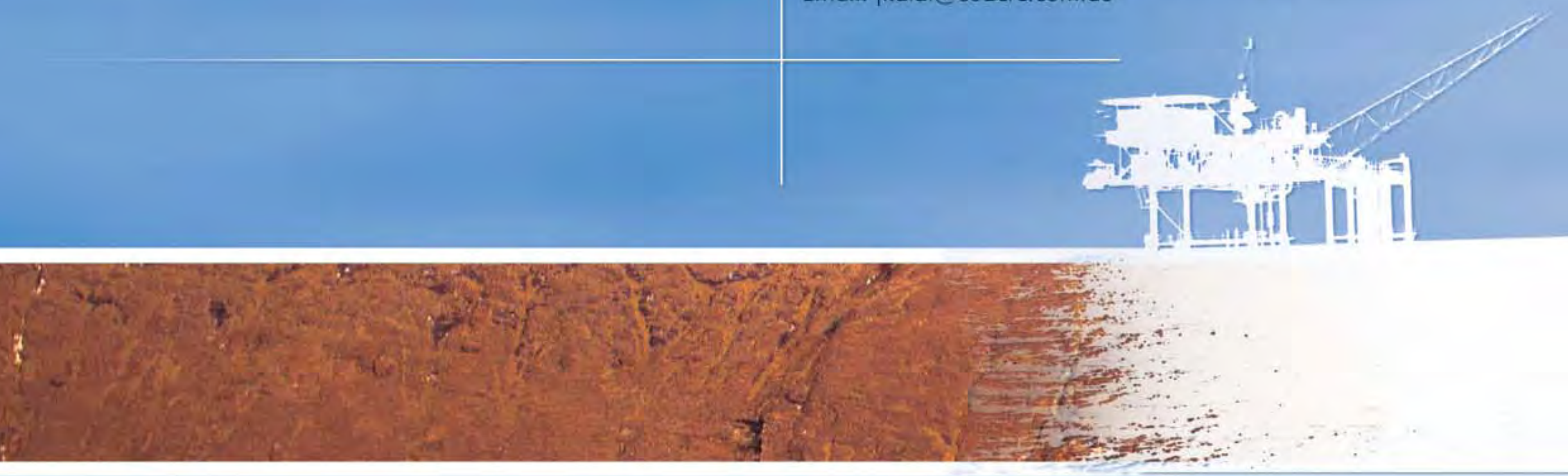

reducing carbon dioxide emissions to the atmosphere