13: Greenhouse Gas Emissions – Risks and Management

Processing of gas from the Greater Gorgon area fields into Liquefied Natural Gas (LNG) will result in greenhouse gas emissions over the full energy lifecycle of the proposed Development. These emissions will be approximately half those that would be generated from the use of alternative hydrocarbon fuels such as coal or fuel oil by the Gorgon Development's potential customers.

Integration of the Gorgon Development Greenhouse Gas Management Strategy into the gas processing facility design has resulted in the adoption of greenhouse efficient practices such as waste heat recovery and the proposal to inject the carbon dioxide (CO_2), contained in the reservoir gas stream, into the Dupuy Formation below Barrow Island. These actions represent a commitment to reduce emissions of greenhouse gases that exceed those of other LNG producers.

A thorough review of potential CO_2 injection locations has been conducted and has determined that the Dupuy Formation, accessed from the eastern side of Barrow Island, is the preferred location for this activity. Extensive monitoring of the injected CO_2 is planned and will assist with the ongoing management of the CO_2 injection operations. The Gorgon Joint Venturers undertake to make information from the monitoring program available to the public.

The proposed injection of reservoir CO_2 will reduce greenhouse gas emissions attributable to the Development (including domestic gas production and the provision of infrastructure support on Barrow Island) by 40% from 6.7 million tonnes per annum of CO_2 equivalent (MTPA CO_2e) to 4.0 MTPA CO_2e. A range of ongoing management actions and longer term performance targets have been established with the objective of further reducing greenhouse gas emissions below those presented in this Draft EIS/ERMP.

Management of CO_2 injection operations will be implemented as documented in the CO_2 Injection Operations Management Plan. This Plan incorporates a range of management responses in the unlikely event that unpredicted migration is detected.

The probability of CO_2 migrating to the surface has been determined to be remote with potential environmental consequences limited to localised impacts on flora and possible detrimental impacts on subterranean fauna. The environmental risks associated with the injection of CO_2 have been assessed and the environmental impact discussed in Chapter 10. The monitoring and reservoir management program will be critical in ensuring that the migrating CO_2 does not reach these environments.

Benchmarking of LNG plant efficiency shows that the Gorgon Development will be amongst the most efficient LNG developments in the world with an estimated greenhouse efficiency of 0.353 tonnes of CO_2e per tonne of LNG. This efficiency includes all emissions related to the production of the natural gas from the offshore fields, the energy required to inject reservoir CO_2 and the assumed volume of reservoir CO_2 vented.

13.1 Introduction

This Chapter is a discussion of the Gorgon Joint Venturers approach to the management of greenhouse gas emissions. Figure 13-1 provides an outline of the content of the chapter.

The two principle areas discussed are: the greenhouse gas emissions from the proposed Development; and the proposal to dispose of reservoir CO_2 by subsurface injection into the Dupuy Formation. The discussion on greenhouse gas emissions includes the sources of greenhouse gas emissions (based on an assumed reference case) and the engineering approaches adopted to minimise these emissions. A comparison of the emissions intensity with other LNG projects is also provided in Section 13.3.6.

The Gorgon Development will be the first project in Australia to significantly reduce greenhouse gas emissions to the atmosphere by the injection of CO_2 underground. This chapter provides information on the selection of the proposed injection site, a summary of the geology of Barrow Island, a description of the predicted behaviour of the injected CO_2 and the plans for ongoing monitoring and management. This is followed by a review of the potential failure modes and effects from injecting CO_2. The Joint Venturers' approach to the management of long-term responsibility, associated with the proposal to inject CO_2, is also discussed.

This Chapter concludes with a review of the Greenhouse Gas Management Plan for the Gorgon Development including the activities planned to be

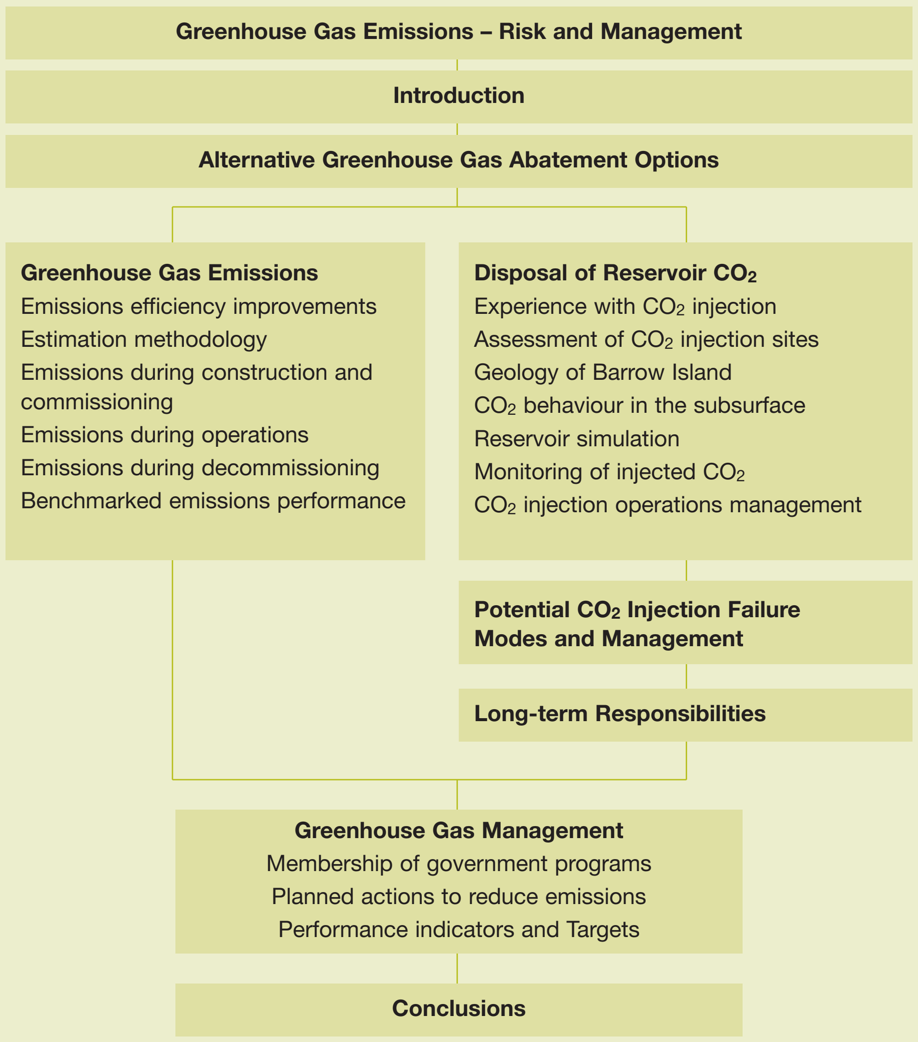


Figure 13-1:
Overview of Chapter Structure

undertaken to manage the Development's greenhouse gas emissions during the ongoing engineering and design work and through operations. A number of greenhouse emissions performance targets have been developed as part of this management plan to guide ongoing greenhouse gas reduction activities.

13.1.1 Commitment to Greenhouse Gas Management

The Gorgon Joint Venturers recognise and share the concern of the community, industry and government about the potential for global climate change, so have integrated these concerns into their business decisions. This commitment to responsible greenhouse gas emissions management is reflected in the adoption of the Gorgon Gas Development Greenhouse Gas Management Strategy (Figure 13-2). The commitments contained in this strategy have been used to guide the Joint Venturers in their planning for the Development and will continue to provide a framework for future engineering decisions and the ongoing management of greenhouse gas emissions.

The Gorgon Joint Venturers will sell LNG in the global energy market. As outlined in Section 13.1.3 the use of LNG from the Gorgon Development will result in significantly less greenhouse emissions over the full energy lifecycle than alternative energy sources such as coal or fuel oil. In order to realise these reduced life cycle emissions, the Gorgon Joint Venturers must maintain their international competitiveness against these competing energy suppliers. This limits the level of expenditure that can be applied to greenhouse gas reduction and requires expenditure to be targeted to achieve the greatest impact.

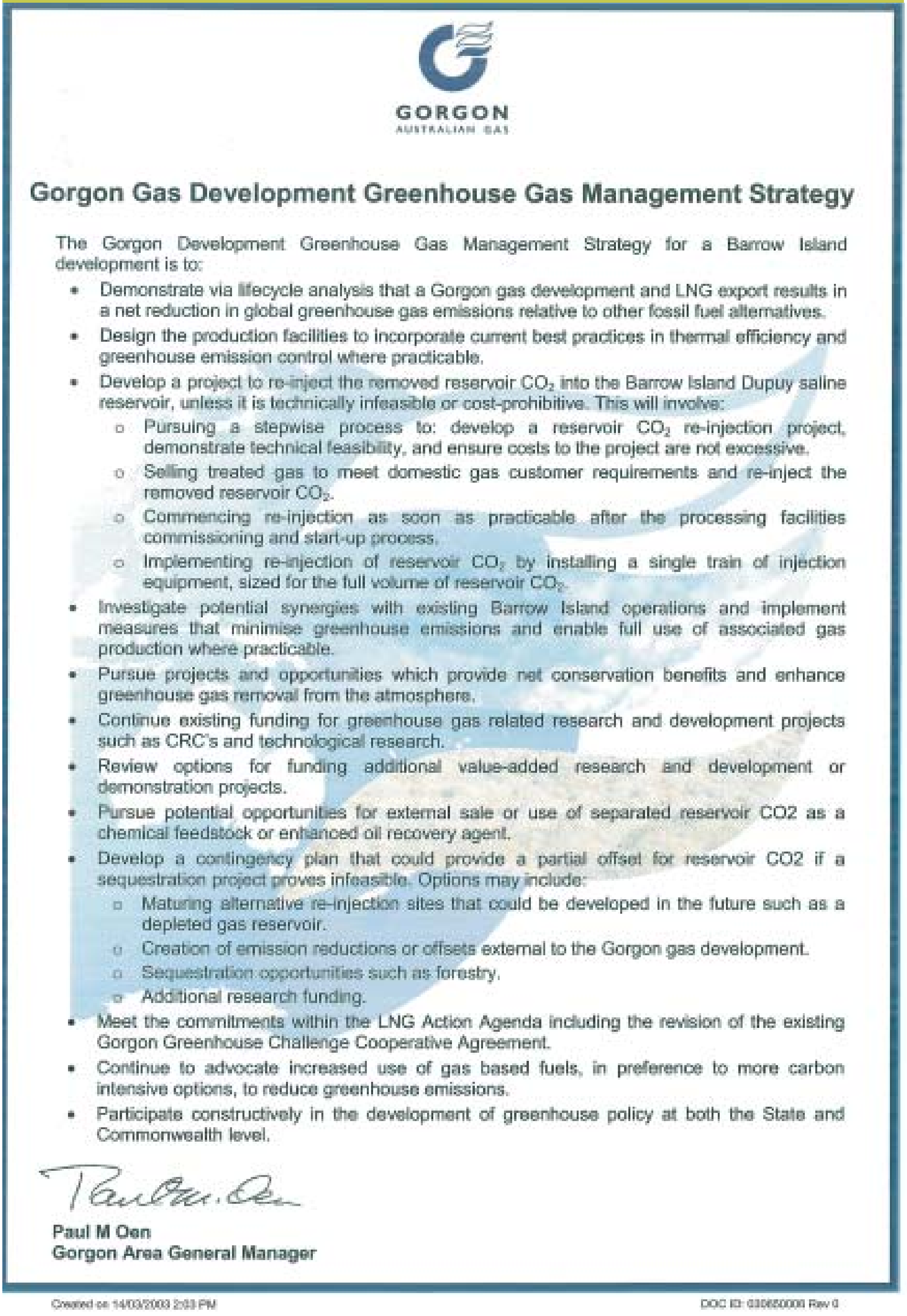
The use of best practice thermally efficient plant, with associated reduced greenhouse gas emissions, has been a key consideration in the design selection criterion, for the proposed gas processing facility. Section 13.3.4 provides details on the selection methodology for the LNG liquefaction processes technology and the gas turbine and waste heat recovery systems. These systems are the major drivers of plant greenhouse gas efficiency and the design selection represent currently applied best practice in Australia and internationally. The inherent technical risk and capital cost burden for unproven or 'leading edge' technologies cannot be justified on the basis of relatively minor improvements in greenhouse gas emissions.

The Gorgon Joint Venturers have determined that the subsurface injection of the CO_2 contained in the reservoir gas stream provides an opportunity within the scope of the Gorgon Development to significantly reduce greenhouse gas emissions. To ensure the efficient use of capital resources, CO_2 injection is planned to be implemented using injection equipment sized to handle the expected rate of reservoir CO_2 removed from the incoming gas stream to the gas processing facility. Venting of reservoir CO_2 will be required during commissioning, periods of maintenance and equipment downtime associated with the injection equipment or for reservoir constraints. The requirement to vent reservoir CO_2 during periods of plant downtime, or if reservoir constraints are encountered, was identified in the ESE Review (ChevronTexaco Australia 2003) as essential to maintaining the international competitiveness of the Development. Full redundancy in the CO_2 injection system to eliminate venting as a contingency, cannot be justified given the impact on project financial viability. Further discussion on the assumptions included in the reference case relating to the venting of reservoir CO_2 can be found in Section 13.3.4.

In common with the subsurface uncertainties encountered in the oil and gas industry, there remains an element of cost and technical uncertainty with the CO_2 injection proposal. This uncertainty is associated with the performance of the injection wells and the behaviour of the CO_2 once injected. The Gorgon Joint Venturers have committed to a range of activities, such as the drilling of a data well in the latter part of 2005 (which will be the subject of its own approval) and to an ongoing reservoir monitoring and management program to further reduce and manage these uncertainties. In the unlikely event that the proposed CO_2 injection should prove technically infeasible or cost prohibitive, such as if it is determined that a large number of additional injection wells are required, the Gorgon Joint Venturers will consult with government with the intent of maximising the injection of CO_2 within the commercial constraints of the Gorgon Development.

Studies undertaken by the Gorgon Joint Venturers indicate that risk of failure of CO_2 containment is extremely low. However, if at any time the Joint Venturers consider that the injection of reservoir CO_2 represents an unacceptable risk to the environmental values of Barrow Island, or a safety risk, then CO_2 injection operations would be suspended and the remaining reservoir CO_2 vented to the atmosphere. It is not the Gorgon Joint Venturers intention to ever have to

Figure 13-2:
Gorgon Development Greenhouse Gas Management Strategy



GORGON
AUSTRALIAN GAS

Gorgon Gas Development Greenhouse Gas Management Strategy

The Gorgon Development Greenhouse Gas Management Strategy for a Barrow Island development is to:

- Demonstrate via lifecycle analysis that a Gorgon gas development and LNG export results in a net reduction in global greenhouse gas emissions relative to other fossil fuel alternatives.
- Design the production facilities to incorporate current best practices in thermal efficiency and greenhouse emission control where practicable.
- Develop a project to re-inject the removed reservoir CO_2 into the Barrow Island Dupuy saline reservoir, unless it is technically infeasible or cost-prohibitive. This will involve:
    - Pursuing a stepwise process to: develop a reservoir CO_2 re-injection project, demonstrate technical feasibility, and ensure costs to the project are not excessive.
    - Selling treated gas to meet domestic gas customer requirements and re-inject the removed reservoir CO_2.
    - Commencing re-injection as soon as practicable after the processing facilities commissioning and start-up process.
    - Implementing re-injection of reservoir CO_2 by installing a single train of injection equipment, sized for the full volume of reservoir CO_2.
- Investigate potential synergies with existing Barrow Island operations and implement measures that minimise greenhouse emissions and enable full use of associated gas production where practicable.
- Pursue projects and opportunities which provide net conservation benefits and enhance greenhouse gas removal from the atmosphere.
- Continue existing funding for greenhouse gas related research and development projects such as CRC's and technological research.
- Review options for funding additional value-added research and development or demonstration projects.
- Pursue potential opportunities for external sale or use of separated reservoir CO2 as a chemical feedstock or enhanced oil recovery agent.
- Develop a contingency plan that could provide a partial offset for reservoir CO2 if a sequestration project proves infeasible. Options may include:
    - Maturing alternative re-injection sites that could be developed in the future such as a depleted gas reservoir.
    - Creation of emission reductions or offsets external to the Gorgon gas development.
    - Sequestration opportunities such as forestry.
    - Additional research funding.
- Meet the commitments within the LNG Action Agenda including the revision of the existing Gorgon Greenhouse Challenge Cooperative Agreement.
- Continue to advocate increased use of gas based fuels, in preference to more carbon intensive options, to reduce greenhouse emissions.
- Participate constructively in the development of greenhouse policy at both the State and Commonwealth level.

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Gorgon Area General Manager

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suspend CO_2 injection operations. In the unlikely event of unpredicted migration of CO_2 that could reach the surface, the Gorgon Joint Venturers will place the safety of the workforce and the environmental values of Barrow Island above the mitigation of increased atmospheric greenhouse gas emissions.

13.1.2 Impact on National and State Greenhouse Gas Emissions

The estimated annual greenhouse gas emissions (4.0 MTPA CO_2e) from the proposed Development will result in an increase in Australia's annual greenhouse gas emissions of approximately 0.8% and an increase in Western Australia's greenhouse gas emissions of 6.4% relative to their respective greenhouse gas emissions in 1990. However, the use of Gorgon LNG for power generation in Pacific Basin countries will provide the potential to avoid an additional 30 MTPA CO_2e of greenhouse gas emissions that would result from using more carbon intensive fuels.

Table 13-1 presents the greenhouse gas emissions from the proposed Development relative to Australia's 1990 and 2002 baseline emissions. Table 13-2 presents the same information relative to Western Australia's 1990 and 2002 emissions.

Table 13-1:
Predicted Greenhouse Emissions Relative to Australia's 1990 and 2002 Baseline

	Million Tonnes of CO_2e per Annum	**Percentage increase relative to the 1990 Baseline**
Australia's 1990 Baseline Emissions	536.9	–
Australia's 2002 Emissions	541.8	0.9%
Gorgon Development with Injection of Reservoir CO_2	4.0	0.8%

Data sourced from State and Territory Greenhouse Gas Emissions – An Overview (Australian Greenhouse Office 2005).

Table 13-2:
Predicted Greenhouse Emissions Relative to Western Australia's 1990 and 2002 Baseline

	Million Tonnes of CO_2e per Annum	**Percentage increase relative to the 1990 Baseline**
Western Australia's 1990 Baseline Emissions	62.8	–
Western Australia's 2002 Emissions	70.4	12.1%
Gorgon Development with Injection of Reservoir CO_2	4.0	6.4%

Data sourced from State and Territory Greenhouse Gas Emissions – An Overview (Australian Greenhouse Office 2005).

Box 13-1:
LNG as a Transition Fuel

Natural gas and LNG are often referred to as ‘transition’ fuels in the context of fossil fuel use and greenhouse gas emissions. This is due to the recognition that natural gas has a lower greenhouse gas intensity compared to other fossil fuels. Natural gas and LNG also have many properties that make them suitable fuels for high efficiency, low emission energy conversion devices such as fuel cells.

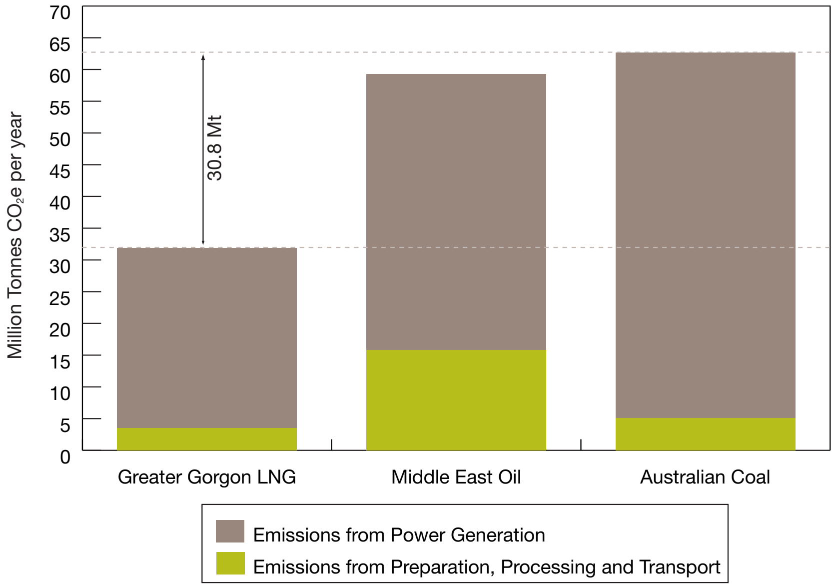
Natural gas is also a likely feedstock for the production of hydrogen, which may replace petroleum as a potential future transport fuel. In particular the combination of producing hydrogen from natural gas and the disposal, by injection into the subsurface of the carbon dioxide produced in the process, would result in a near zero emissions transport fuel. While the production of zero emissions hydrogen is not part of this proposal, the CO_2 injection technology being applied by the Gorgon Joint Venturers may assist in the development of this future fuel.

13.1.3 The Relative Greenhouse Impact of LNG

When used as a primary energy source, LNG has a number of benefits over competing fuels such as coal and oil (Box 13-1). These benefits include lower emissions of sulphur dioxide, particulate matter and greenhouse gas emissions. The quantity of greenhouse gases emitted over the full lifecycle (that is the emissions required to extract, produce and transport LNG) combined with the emissions from the end-user, such as an electricity power plant, is less than the comparable lifecycle emissions for either coal or oil to deliver the same amount of energy. Figure 13-3 demonstrates the relative lifecycle emissions associated with LNG, oil and coal to supply the Asian market in which Gorgon LNG will be competing. This data is based on a study conducted by the CSIRO into the life cycle advantages of LNG over coal and fuel oil (CSIRO 1996).

The Western Australian Greenhouse Strategy (Government of Western Australia 2004) and the LNG Action Agenda (Department of Industry Science and Resources 2000) support the increased use of LNG and natural gas to reduce greenhouse emissions from electrical power generation.

Figure 13-3:
Comparison of Lifecycle Greenhouse Gas Emissions for Gorgon LNG and Alternative Fuels for Electrical Power Generation in Asia



Basis: Over one year 10 Million tonnes of LNG will generate 73 Million MWh of electricity

13.2 Alternative Greenhouse Gas Abatement Options

The Gorgon Joint Venturers commenced a number of studies in 1998 to identify potential greenhouse gas reduction or offset opportunities that could be used to reduce the emissions from any proposed development of the Greater Gorgon gas fields. The options assessed in 1998 included:

- investing in commercial forestry
- assisting in revegetation or land rehabilitation plantings
- facilitating reduced land clearing
- undertaking the disposal of reservoir CO_2 by injection into the subsurface
- assisting other industries to switch fuels (e.g. gas for coal)
- facilitating the use of compressed natural gas (CNG) as vehicle fuel
- providing support for renewable energy technologies (wind, solar, biomass)
- promoting the sale of CO_2 as a feed stock to another company or industry.

As a result of these studies the Gorgon Joint Venturers concluded that the disposal of reservoir CO_2 by injection into the subsurface and investing in commercial forestry were two options that should be further considered to reduce the greenhouse emission impact of the Gorgon Development. As well as continuing the scientific and engineering investigations into the subsurface disposal of CO_2, Chevron Australia funded a trial planting of 65 ha of maritime pine to assess the potential for using plantation derived offsets to reduce the Developments greenhouse gas emissions. While the greenhouse offsets from this planting are small, involvement in the plantation has increased the Gorgon Joint Venturers familiarity and understanding of forestry issues such as carbon rights, costs and plantation management issues.

In parallel with the ongoing CO_2 injection studies, the Gorgon Joint Venturers have continued to review alternative greenhouse offset options to ensure that any proposal to reduce or offset the Development's greenhouse gas emissions will be cost effective. This culminated in an Offset Emissions Study undertaken by specialist consultants in 2004 (ACIL Tasman 2004) which considered:

- Sequestration options
    - commercial plantations
    - revegetation/rehabilitation plantations
    - reduced land clearing
    - mineral CO_2 sequestration
- Market based options
    - Mandatory Renewable Energy Target (MRET)/Renewable Energy Certificates (RECs)
    - New South Wales Greenhouse Abatement Certificates
    - Queensland Gas Electricity Certificates
    - Greenhouse Friendly Program (Australian Greenhouse Office)
- Overseas market based options.

The study concluded that commercial forestry plantations provide a viable mechanism to offset greenhouse gas emissions but may be unable to provide the scale of offsets required by the Gorgon Development. Additional benefits such as increased regional employment opportunities and potential reductions in salinity levels may be realised through plantation offsets; however the scale of commercial plantations required by the Gorgon Development may lead to increased demand for land for forestry plantations which could result in dislocation of communities and downward pressure on timber prices. Other options that were considered that may provide viable greenhouse gas offsets at some time in the future include: salt bush plantations, land clearing reductions, mineral CO_2 sequestration research and development of credit based schemes. A summary of these alternative greenhouse gas offset opportunities is provided in Table 13-3.

Considerable uncertainty is associated with all of the alternative greenhouse gas offset options particularly over the operational time frame of the Gorgon Development. For example, while a current price per tonne CO_2e can be determined for each of the alternative options, there is considerable uncertainty over future prices. In addition, many of the opportunities that have the potential to supply the large volumes of low cost offsets required by the Joint Venturers are not practical as they are derived from programs that have a limited life. That is the programs are only legislated to run until 2012 or 2020. It is not feasible to base a greenhouse gas emissions mitigation strategy for the Gorgon Development upon programs that have a short life span relative to the Gorgon Development, and have technical and price uncertainty as documented in Table 13-3.

Table 13-3:
Summary of Alternative Greenhouse Gas Offset Opportunities

Greenhouse Offset Opportunity	Independent Verification	Current Cost Estimate	Quantity	Risk
Commercial Timber Plantations	Verification is possible. But measurement remains an issue.	NSW Forestry selling CO_2 credits derived from plantations for $10 per tonne.	Around 100 000 ha required for 1 million tonnes CO_2 per year.	Drought, fire, future value of timber sales.
Revegetation/ Rehabilitation Plantations	No formal institutions available at present.	Cost per tonne CO_2 not known at this stage.	Around 77 000 ha required for 1 million tonnes CO_2 per year.	Growth conditions at site, commercial grazing, measurement uncertainty.
Reduced Land Clearing	Potentially more difficult than other sinks.	ABARE estimates cost at less than $1 per tonne for government mandated scheme, costs higher for voluntary scheme.	AGO have estimated up to 25 million tonnes per year in Queensland.	Establishing a base line needs further study. Unknown if government would make credits available.
Mineral Sequestration	Still to be established.	Not known at this time.	Unlikely to provide offsets of the scale required by the Gorgon Development.	Technology needs to be tested. Requires partnering with other industries that are likely to claim credits.
Australians Market Based Mechanisms (e.g. MRET)	Provided in legislation or through agencies such as AGO.	Uncertain, but possibly as low as $5 per tonne for low volumes, potentially much higher for larger volumes.	Potentially 10-20 million tonnes per annum, highly dependent on technology uptake.	Most market-based schemes in Australia have limited life, e.g. 2012 or 2020. Lack of certainty over time frame required for Gorgon.
Overseas Market Based Mechanisms linked to Kyoto (Note: opportunity currently not available to Australian companies)	Verification rules set by legislation consistent with the Kyoto Protocol.	Currently trading at approximately $45 per tonne. Costs post-2012 are very uncertain.	Potentially in the hundreds of millions of tonnes per annum.	Lack of certainty about how these mechanisms will continue to operate, if at all beyond 2012.
Overseas Market Based Mechanisms not linked to Kyoto (e.g. Chicago Climate Exchange)	Verification rules stipulate independent, internationally accredited organisations, but no government backing or verification.	Currently trading at approximately $2.20 per tonne, but trade volumes have been small (thousands of tonnes). Price highly dependent on country of origin energy and greenhouse policy.	Uncertain, but potentially many millions of tonnes per annum.	Success and long term viability of these mechanisms will be heavily dependent on country of origin energy and greenhouse policy.

Based on this analysis, the Gorgon Joint Venturers have elected to reduce the Developments greenhouse gas emission by the disposal of reservoir CO_2 by injection into the Dupuy Formation. The primary driver behind this decision is the higher level of certainty, particularly in the area of cost of abatement that the proposed injection of CO_2 offers over the offset alternatives.

Additional drivers behind the decision to inject CO_2 are:

- preference to reduce emissions rather than looking to offset emissions
- infeasible to meet the full demand for emissions offsets through forestry or revegetation planting with any degree of certainty over long term security or price
- familiarity with the technology and management issues associated with CO_2 injection
- less external factors such as rainfall and climate variation
- ease of greenhouse emissions estimation and reporting.

The proposed subsurface injection of reservoir CO_2 also provides benefits for Australia through the demonstration of CO_2 geosequestration, via access to data on the performance of the project.

13.3 Gorgon Development Greenhouse Gas Emissions

This section is a description of the actions taken during the engineering studies to date to reduce greenhouse gas emissions and the methodology used to estimate the greenhouse gas emissions from the Gorgon Development. It also provides estimates of greenhouse emissions over the life of the proposed Development and compares the resulting greenhouse efficiency of the LNG component of the Development with other recent LNG developments.

The greenhouse gas emissions estimates provided in this section are based on a reference case (details of which are provided in Section 13.3.4) that assumes a high level of emissions where engineering design work or operational procedures are yet to be finalised. Further actions, including longer term performance targets, to reduce emissions below those stated in the reference case are outlined in Section 13.5.

13.3.1 Greenhouse Gas Emissions Efficiency Improvements

Early design concepts for the development of the Gorgon field incorporated a gas processing platform located offshore in proximity to the gas field with a LNG processing facility on the Burrup Peninsula. This design concept formed the basis of the 1998 Greenhouse Challenge Cooperative Agreement between the Gorgon Joint Venturers and the Australian Greenhouse Office (WAPET 1998). The greenhouse gas emissions efficiency improvements identified below compare the current design with that used as the basis of the 1998 Cooperative Agreement.

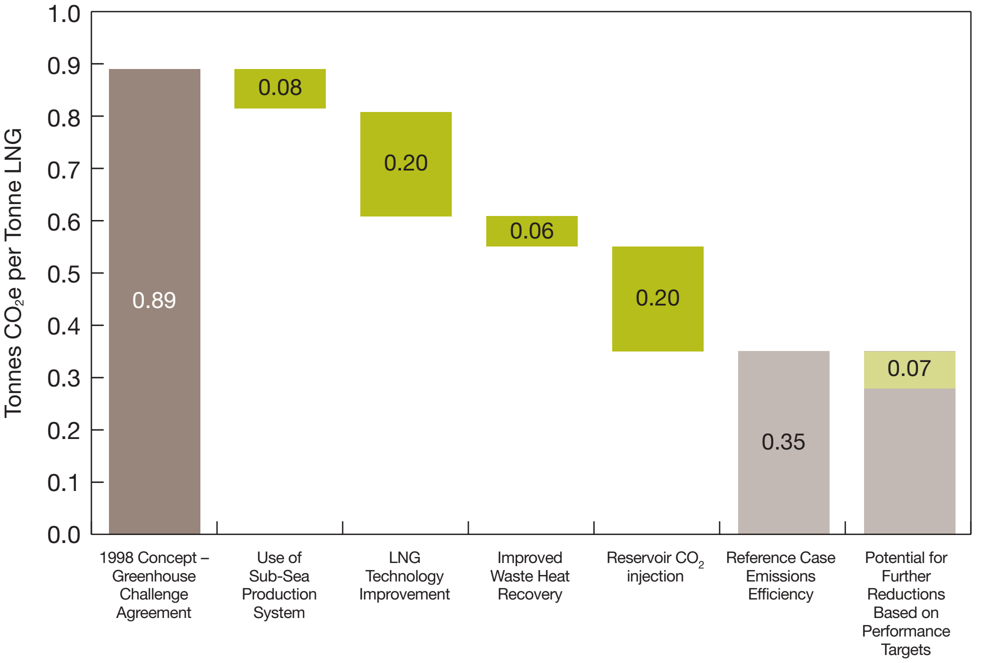
The greenhouse gas efficiency of the Gorgon Development as stated in the 1998 cooperative agreement was 0.89 tonnes of CO_2e emitted to the atmosphere for every tonne of LNG to be produced. Emissions efficiency expressed as tonnes of CO_2e per tonne of LNG has been used in this analysis to account for the different plant capacities between the basis of the Cooperative Challenge Agreement (8 MTPA LNG) and the current development concept (10 MTPA LNG). As the 1998 cooperative agreement did not include gas for domestic consumption, only emissions related to the processing of LNG have been included in this discussion.

Engineering decisions that have resulted in significant improvements in greenhouse gas emissions efficiency compared to the 1998 design case include:

- replacement of the offshore gas processing platform with an all subsea development
- changes in LNG process technology
- improved waste heat recovery on the gas turbines resulting in a significant reduction in the use of supplementary boilers and heaters
- significantly reducing greenhouse gas emissions by the injection of reservoir CO_2 into the subsurface.

The contribution to improved greenhouse gas emissions efficiency from each of these areas is shown graphically in Figure 13-4.

Figure 13-4:
Greenhouse Emissions Efficiency Improvements



The selection of Barrow Island as the preferred site for the development of the gas processing facilities has enabled the use of subsea technology rather than platform-based offshore gas processing. The offshore gas production platform in the 1998 design accounted for approximately 600 000 tonnes of CO_2e emissions per year. By eliminating the offshore gas production platform and utilising a subsea gas production system, the greenhouse gas emissions efficiency of the Gorgon Development has been improved by 0.075 tonnes of CO_2e per tonne of LNG to be produced.

LNG process technology has evolved significantly over the last ten years driven by larger more efficient plants and changes in technology used to remove CO_2 in the inlet gas stream. A range of design areas have been studied for incremental improvements in greenhouse gas emissions efficiency. These include:

- increasing the size of the LNG process trains to the maximum practical
- use of a-MDEA as the CO_2 removal medium in the acid gas plant
- use of dry compressor and hydrocarbon pump seals
- locating a cold recovery exchanger on the overhead gas from the nitrogen removal column.

These technology improvements have resulted in a greenhouse gas emissions efficiency improvement of 0.20 tonnes of CO_2e per tonne of LNG to be produced compared with the 1998 plant design.

The design concept upon which the Greenhouse Challenge Cooperative Agreement was based included the use of direct fired heaters/boilers. These boilers/heaters accounted for approximately 520 000 tonnes of CO_2e emissions per annum. Studies into the better capture and application of waste heat recovered from the process gas turbines has resulted in the restricted use of process heaters to during periods of plant start-up only. Ongoing design work may ultimately lead to the total elimination of boilers and heaters. The improved waste heat recovery in the reference case has resulted in a greenhouse gas emissions efficiency improvement of 0.058 tonnes of CO_2e per tonne LNG to be produced.

The Gorgon Joint Venturers have studied how they might further reduce the greenhouse gas emissions beyond those available through improved plant design such as the subsurface injection of CO_2. Greenhouse gas offsets such as forestry or land rehabilitation planting or purchasing greenhouse credits were also considered. Further discussion on the evaluation of offsets is included in Section 13.2. As a result of these studies the Gorgon Joint Venturers have elected to make a significant reduction in Development emissions by injecting the reservoir CO_2 removed during the gas processing operations into the Dupuy Formation. The reference case assumes that 2.7 MTPA of reservoir CO_2 will be injected into the Dupuy Formation. The reduction in greenhouse emissions by this method has resulted in a greenhouse gas emissions efficiency improvement of 0.20 tonnes of CO_2e per tonne LNG to be produced. Future activities, particularly in the area of developing operational procedures around CO_2 injection, are planned with the objective of increasing the volume of CO_2 injected to 3.2 MTPA.

While not included in the reference case, there is potential for further greenhouse emissions efficiency improvement. Section 13.5 outlines longer term performance targets and management actions to achieve those targets. If these performance targets are met, the resulting greenhouse efficiency will be further improved by approximately 0.066 tonnes of CO_2e per tonne LNG to be produced.

13.3.2 Emissions Estimation Methodology

This section is a description of the methodology used to estimate the greenhouse gas emissions that will result from the Gorgon Development and provides estimates of greenhouse emissions during the construction (including plant commissioning) and operational phases of the Development. As engineering and design work is ongoing not all issues around plant configuration and operations have been finalised. As a result the greenhouse gas emissions estimated during the operational phase are based on a reference case that has assumed a number of high emission (or worst case) design outcomes. The assumptions behind the reference case and the design options still under consideration are outlined in Section 13.3.4.

The emission estimates described throughout this Chapter were compiled based on the American Petroleum Institute's Compendium of Greenhouse Gas Emissions Estimating Methodologies of the Oil and Gas Industry (American Petroleum Institute 2004).

Estimations have been compiled by determining the type and quantity of fuel used and the resulting greenhouse emissions from the use of that fuel. The conversion factors used in determining the estimated greenhouse gas emissions are provided in Table 13-4.

Emissions of methane (CH_4) and nitrous oxide (N_2O) have a higher greenhouse effect than does CO_2. Greenhouse gas emissions are often reported in tonnes of carbon dioxide equivalent or CO_2e. The conversion factors used for CH_4 and N_2O to CO_2e are 21 and 310, respectively. Emissions of these products have been included in the calculation of the CO_2e figures presented in this document.

Once construction activities commence the Joint Venturers will track greenhouse emissions using the SANGEA™ Energy and Emissions Estimating System and report these emissions in accordance with the Gorgon Joint Venturers' obligations under the Greenhouse Challenge Program.

The SANGEA™ system was initially developed by Chevron but has been made freely available through the American Petroleum Institute in order to assist in

Table 13-4:
Greenhouse Emissions Conversion Factors

Fuel Type	**Conversion Factor**
Industrial diesel fuel	2.8 tonnes CO_2e per thousand litres
Natural Gas – WA Domestic (Full fuel cycle)	60.0 tonnes CO_2e per tera joule
Gorgon Gas Processing Facility Fuel Gas	54.7 tonnes CO_2 per tera joule
	0.004 tonnes CH_4 per tera joule
	0.0014 tonnes N_2O per tera joule
	Total CO_2, CH_4 and N_2O 55.2 tonnes CO_2e per tera joule

establishing uniform emissions estimation standards across the petroleum industry. SANGEA™ is designed to assist petroleum companies with estimating, managing and reporting greenhouse gas (GHG) emissions. It can also be used to track energy consumption and criteria pollutant emissions. Information on the SANGEA™ Emissions Estimating System can be found at http://projects.battelle.org/sangea/home.asp

13.3.3 Emissions During Construction and Commissioning

The Gorgon Joint Venturers estimate that greenhouse gas emissions during the construction and commissioning of the gas processing facility will be between 1.64 and 1.74 million tonnes CO_2e. As many of the construction and commissioning activities remain to be finalised, these emission estimates should be considered provisional. The greenhouse gas emissions from the main construction activities are presented in Table 13-5.

Recent offshore drilling operations conducted by Chevron Australia in the Greater Gorgon area have used diesel at the rate of approximately 34 000 litres per day to fuel the drilling rig and associated support vessels. This equates to approximately 95 tonnes CO_2e per day for a typical offshore drilling operation in the Greater Gorgon area. It is anticipated that between 18 and 25 wells will ultimately be required to develop the Gorgon gas field, with between 5 and 10 wells drilled during the initial field development. Assuming that it takes 65 days to drill each well and install the subsea equipment, the anticipated greenhouse emissions from fuel usage during offshore drilling activities over the life of Development will be between 110 000 and 160 000 tonnes CO_2e. An additional 4000 tonnes of CO_2e per well are estimated to be released from the flaring of natural gas during operations associated with completing the well. These operations generally entail ‘flowing’ the well for less than 24 hours. During this time, the produced gas will be flared.

Table 13-5:
Greenhouse Emissions During Construction and Commissioning

Construction Activity	Estimated Greenhouse Gas Emissions (tonnes CO_2e)
Offshore drilling activities (fuel consumption)	110 000–160 000 (in phases over life of Development)
Offshore drilling activities (well clean up operations)	70 000–100 000 (in phases over life of Development)
Pipe laying operations – Gorgon field to Barrow Island.	25 000
Multiple support vessel	45 000
Electrical power generation on Barrow Island	75 000–95 000
Mobile equipment and vehicle usage on Barrow Island	25 000
Dredging	75 000
LNG process commissioning operations	1 200 000
Pipe laying operations – Domestic gas pipeline	15 000
Total estimated greenhouse gas emissions related to construction and commissioning activities	1.64–1.74 million tonnes
The emissions stated in this table should be considered as order of magnitude estimates.	

A multiple support vessel (MSV) will be used to install the subsea production systems and umbilical control lines. These activities are estimated to take 175 days. Estimated energy consumption on the MSV is 40 MW provided by burning diesel fuel. This will result in 250 tonnes of CO_2e emissions per day or approximately 45 000 tonnes of CO_2e. This estimate includes a reasonable allowance for any support vessels.

Preliminary engineering studies indicate that it will take slightly over 100 days to lay the pipeline from the Gorgon gas field to Barrow Island. Estimated energy consumption on the pipelay barge is 40 MW provided by burning diesel fuel. This will result in 250 tonnes of CO_2e emissions per day or approximately 25 000 tonnes CO_2e over the duration of the pipeline installation works.

Greenhouse gas emissions from construction activities on Barrow Island will be dominated by two sources: emissions from electrical generation, including that to power the construction village for the workforce; and diesel fuel used to operate various plant and equipment on the island. Two energy sources are currently being evaluated for the supply of electrical power during the construction period: either obtaining local supplies of natural gas; or using diesel. If natural gas is chosen then the estimated energy demand is 1.3 petajoules (PJ) whereas if diesel is selected, the anticipated requirement is for 35 million litres. The resulting greenhouse gas emissions over the three to four year construction period are approximately 75 000 tonnes CO_2e for natural gas and 98 000 tonnes CO_2e for diesel. The anticipated diesel fuel usage to power equipment on Barrow Island, such as earth moving transport, welding machines and for the drilling of the CO_2 injection wells and pipeline shore crossing is estimated at 9 million litres. Greenhouse gas emissions from this fuel usage will be approximately 25 000 tonnes CO_2e.

Dredging operations are currently planned using two medium-to-large dredges. Anticipated fuel usage for each dredge is 250 000 litres of diesel per week. Dredging operations are anticipated to run for 12 months consuming a total of 26 million litres of diesel. This equates to 75 000 tonnes of greenhouse gas emissions from dredging operations.

Preliminary engineering studies around the installation of the domestic gas pipeline suggest that this operation will result in approximately half the emissions of the Gorgon field to Barrow Island pipeline. This is a result of a potentially smaller lay barge and anticipated faster installation rate. Anticipated greenhouse gas emissions for this activity are estimated at 15 000 tonnes of CO_2e.

Commissioning activities will involve progressively cooling down the LNG gas processing facility and storage facilities to operational temperature. This process will be conducted progressively over several weeks during which the gas flowing through the plant will be flared. The Gorgon Joint Venturers are investigating options for the recovery of this gas into the gas processing stream but for the purposes of this assessment, it is assumed that this gas will be flared. Further information on the commissioning operations is available in Chapter 6 (Section 6.4). For the purposes of calculating greenhouse gas emissions resulting from commissioning operations it has been assumed that the volume of gas flared will equate to two weeks of average LNG production (385 000 tonnes of LNG or 1 200 000 tonnes CO_2e).

13.3.4 Emissions from Operations

Greenhouse gas emissions during operation of the gas processing facility will be predominantly from combustion sources used to supply energy for LNG and domestic gas production; and to remove CO_2 from the feed gas stream and inject it into the Dupuy Formation. Figure 13-5 shows a schematic of the main sources of greenhouse gas emissions from the proposed Development.

Based on experience with similar gas processing facilities throughout the world, the on-stream availability of the facility during the first year of operation is expected to be lower due to bedding in and minor operational issues associated with bringing such a complex facility on-line. Additionally, the facility is expected to start-up at a low production rate and ramp-up to full production over a period of several years as market demand for the produced LNG and domestic gas increases. Maximum efficiency of the facility will be at the nominal design rate, so during this ramp-up period, the facility will be operating at less than optimum efficiency. As a result the corresponding CO_2e emissions per tonne of LNG will be higher than in the subsequent years of operation. Figure 13-6 shows the expected greenhouse emissions profile over the life of the Development. Note: greenhouse gas emissions related to construction emissions are not shown in this figure. In the following discussion only the emissions during the steady state operation of the facility are discussed.

For the purposes of this Draft EIS/ERMP, a reference case has been developed based on the facility design assumptions outlined in Chapter 6 and incorporates high emissions scenarios where engineering design work is ongoing or where operational uncertainty exists. High emissions scenarios have been assumed in the following areas:

- domestic gas sourced from the Gorgon gas field
- configuration of gas turbines used for electrical power generation
- waste heat recovery configuration
- percentage of reservoir CO_2 vented
- use of fired heaters (linked to use of waste heat recovery on power generations turbines)
- power generation standby gas turbine operated as spinning reserve.

Based on the reference case the estimated annual greenhouse gas emissions from the proposed Development are 4.0 million tonnes of CO_2e (MTPA CO_2e). Table 13-6 documents the estimated emissions from the LNG and domestic gas components of the facility and the estimated emissions resulting in the provision of support infrastructure and logistics to Barrow Island.

Ongoing engineering and design work and the actions contained in the Greenhouse Gas Management Plan (refer Section 13.5.2) may reduce these estimated greenhouse gas emissions by 660 000 MTPA CO_2e.

Figure 13-5:
Main Sources of Greenhouse Gas Emissions from the Proposed Gas Processing Plant

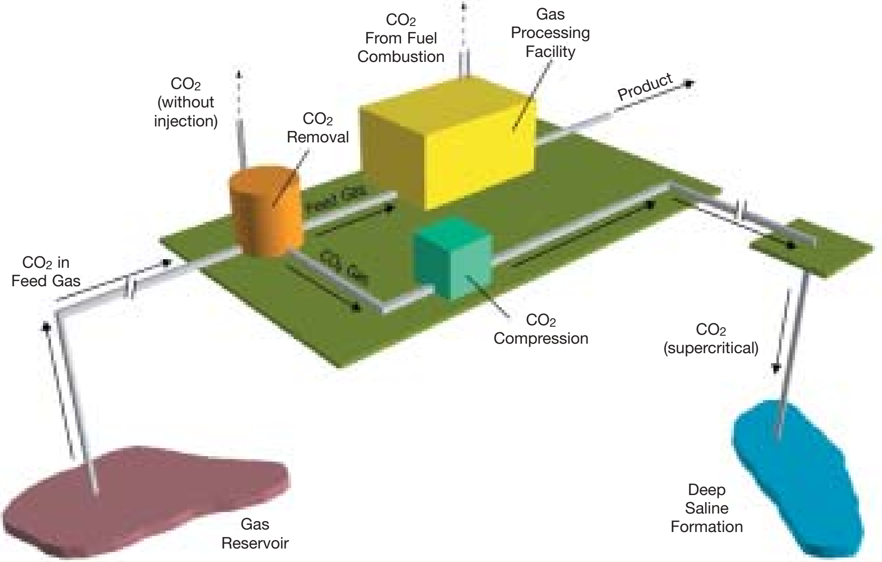
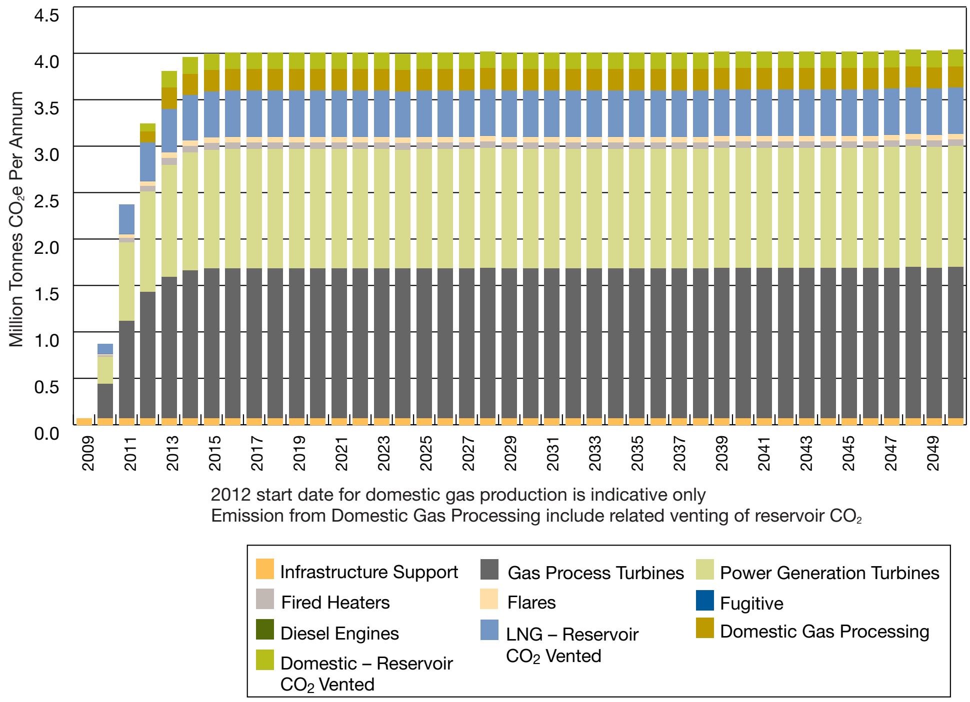


Figure 13-6:
Predicted Greenhouse Gas Emissions from the Proposed Gorgon Development



2012 start date for domestic gas production is indicative only
Emission from Domestic Gas Processing include related venting of reservoir CO_2

No perfluorocarbons are planned to be used in the gas processing facilities (therefore will not be emitted). Hydrofluorocarbons will be used in the heating ventilation and air conditioning systems and sulphur hexafluoride will likely be used for electrical switch gear. However, both these uses are for closed systems, so total emissions of these substances will be negligible (<0.01% of the total greenhouse gas emissions on a CO_2e basis) compared to the major emissions sources.

Table 13-6:
Predicted Annual Greenhouse Gas Emissions from the Gorgon Development

Emissions Source	**LNG Processing**	**Domestic Gas Processing**	**Island Infrastructure Support**
	TPA CO_2e	TPA CO_2e	TPA CO_2e
Gas Turbine – Gas Processing Drivers	1 612 000	Nil	Nil
Gas Turbine – Power Generation	1 287 000	200 000	60 000
Fired Heaters	71 000	28 000	Nil
Flare – Events	60 000	Minor	Nil
Flare – Pilots	2 000	Minor	Nil
Fugitive Emissions	Less than 1 000	Less than 1 000	Nil
Transport	Nil	Nil	10 000
Diesel Engines	Less than 300	Minor	Minor
Reservoir CO_2 Vented	500 000	180 000	Minor
Total	**3 534 000**	**409 000**	**70 000**

Reference Case Assumptions:

- LNG production is sourced equally from the Gorgon and Jansz fields.
- Domestic gas production is sourced from the Gorgon Field.
- Based on 8160 hours (340 days) plant operation per year.
- All power generation gas turbines (including spare) are operated at part load, resulting in an additional 65 000 tonnes per year of emissions over case where spare is on cold standby and online turbines are operated at maximum efficiency.
- 20% of reservoir CO_2 (0.68 MTPA) is vented rather than injected into the Dupuy Formation.
- Waste heat recovery is applied to LNG process drive gas turbines and hot oil used as the waste heat recovery medium.

The greenhouse emissions due to reservoir CO_2 venting shown in Table 13-6 are based on a reference scenario that assumes 20% of the reservoir CO_2 is vented rather than injected. The vented reservoir CO_2 has been allocated between LNG and domestic gas production based on the portion of gas from the Gorgon field used in each facility (26.5% to domestic gas and 73.5% to LNG).

The following sections expand on each of the main greenhouse gas emission sources. For the large emission sources, the basis on which the emissions were calculated or the assumptions used in developing the reference case are outlined.

Gas Turbines – Gas Processing Drivers

The gas turbines to be used in the LNG processing facility will represent 40% of the overall greenhouse gas emissions in the reference case. The level of these emissions is dictated by the liquefaction technology and process configuration selected for the Development which is heavily dependant on three interrelated decisions:

- liquefaction process vendor selection
- liquefaction capacity range
- liquefaction compressor driver selection as either direct drive gas turbines or electric drive motors.

During design selection, LNG process vendors were requested to supply process proposals based on three design cases:

- LNG capacity throughput range for each processing train of four to six million tonnes per annum (MTPA) with direct gas turbine refrigerant compressor drive
- LNG capacity throughput range for each processing train of four to six MTPA with electric motor refrigerant compressor drive
- LNG capacity throughput range of seven to nine MTPA with vendor choice of either direct gas turbine drive or electric drive.

The proposals were evaluated using the following criteria:

- safety hazard risk
- technology risk and contingency levels
- availability and reliability
- greenhouse gas emissions
- economics.

The greenhouse gas emissions per unit of LNG production, the risk profile (a combination of safety hazard, technology risk including construction and operational uncertainties and contingency risk) and the capital cost for each option, were similar for each of the high level process configurations considered.

Liquefied natural gas processing design incorporating direct drive gas turbines with an LNG throughput of approximately 5 MTPA represents established best practice in LNG process design. This configuration is similar to that being applied to the North West Shelf Project for the Train 4 expansion and planned Train 5 expansion. This configuration offers the optimum balance between capital cost, greenhouse emissions efficiency and risk profile.

The designs incorporating either electric drive or higher capacity LNG throughput show a potential for improved greenhouse emissions efficiency of approximately 0.03 tonnes CO_2e per tonne LNG, but at an increased risk profile. This reflects the essentially untested nature of these technologies. The Gorgon Joint Venturers have determined that risk profile associated with these unproved options is not compatible with the risk profile required for the Gorgon Development.

Based on this analysis, the Joint Venturers have selected a proven liquefaction process design based on LNG processing trains utilising gas turbine direct drives; and with a nominal LNG throughput of 5 MTPA for each processing train.

The greenhouse gas emissions estimate for the gas processing drivers provided in Table 13-6 have been calculated using the assumptions contained in Table 13-7.

The greenhouse gas emissions reference case developed for this document assumes that the gas turbines in the LNG processing facility include waste heat recovery to increase the recovered energy from combustion of the fuel gas. This waste heat will be used within the gas processing facility for heating duties, such as that required for the regeneration of the CO_2 removal solvent (accelerated MDEA), regeneration of hydrate inhibitor, feed gas preheating and fractionation.

Gas Turbines – Power Generation

Greenhouse gas emissions from the gas turbines used to generate electrical power for the gas processing facility and support infrastructure represent approximately 40% of the overall reference case greenhouse gas emissions.

Engineering options for the configuration of gas turbines for electrical power generation and the capture and use of waste heat throughout the gas processing facility are currently being studied. The timing for the selection of the final configuration falls after the date of the release of this Draft EIS/ERMP for public review. These issues are closely linked with the liquefaction technology selection and the heat load and power requirements of the facility.

The energy intensive need to remove moderate levels of CO_2 from the incoming gas stream from the Gorgon field dictates that the Gorgon Development will have a high demand for process heat. It is estimated that the thermal energy required by the gas processing facility will be approximately 430 MW. In addition, approximately 270 MW of electrical power will be required to be generated.

A range of options for electrical power generation and waste heat recovery have been developed and are being considered by the Gorgon Joint Venturers. These options will be evaluated using the following criteria:

- safety hazard risk
- capital and operating cost
- availability and reliability
- fuel consumption and resulting greenhouse gas emissions
- land area required to be cleared.

The greenhouse gas emissions reference case is based on the assumption that 270 MW of electrical power will be generated by five industrial gas turbines of approximately 85 MW ISO capacity and operated at partial load. Of the power generation options under consideration, this scenario represents a high emissions case.

Table 13-7:
Gas Processing Drivers – Greenhouse Gas Emissions

Gas Turbines – Gas Processing Drivers	
Number/type of gas turbines	4 x 85 MW industrial gas turbines
Assumed mechanical load – operating condition	4 x 79.8 MW = 319.2 MW
Assumed electrical load	Nil
Assumed heat load	4 x 107 MW = 428 MW
Fuel usage at operating conditions	4 x 894.6 = 3578 GJ/h
Operating time	8160 hours (340 days per year)
Greenhouse gas emissions	1 612 000 tonnes/year
Indicated gas turbine capacity is rated capacity at ISO conditions. Actual output will be approximately 6% lower due to operational conditions on Barrow Island.	

Table 13-8:
Power Generation – Greenhouse Gas Emissions

Gas Turbines – Power Generation	
Number/type of gas turbines	5 x 85 MW industrial gas turbines
Assumed mechanical load	Nil
Assumed electrical load – operating conditions	5 x 53.9 MW = 270 MW
Assumed heat load	Nil
Fuel usage at operating conditions	5 x 686.6 = 3433 GJ/h
Operating time	8160 hours (340 days per year)
Greenhouse gas emissions	1 547 000 tonnes/year
Indicated gas turbine capacity is rated capacity at ISO conditions. Actual maximum available output will be approximately 6% lower due to operational conditions on Barrow Island. While electrical load could be met with four turbines, five operating at part load have been selected to provide redundancy in the event of failure of one of the units.	

The greenhouse gas emissions estimates for the reference case electrical power generation gas turbines provided in Table 13-6 have been calculated using the assumptions contained in Table 13-8.

A Power Generation Study has been commissioned with the engineering design contractor to optimise the power generation configuration. The study will include examining installation of waste heat recovery on the power generation turbines in addition to the LNG process gas turbines and the utilisation of different turbine types including the use of aero-derivative gas turbines.

Fired Heaters

The reference case incorporates the use of fired heaters to provide process heat requirements during start-up, when the waste heat recovery units (on the LNG compression gas turbines) have not reached operating temperature. It is anticipated that the fired heaters will only be required when both LNG processing trains have been shut down. It is likely that only one LNG train would be taken offline at any particular time enabling waste heat from the operational train to be used in place of the fired heaters to start the second train.

Shut-down of both LNG processing trains is not anticipated to occur; however in the reference case, it is assumed that the use of fired heaters to provide process heat during a start-up of both LNG trains will be required once per year. The use of fired heaters in the reference case represents less than 2.5% of the Gorgon Developments greenhouse gas emissions.

Flaring of Gases

The gas processing facility will be designed to avoid routine gas flaring or venting. However, a flare is required to ensure the safe operation of the facility. A continuous purge may be required along with pilots to ensure the safe ignition of the flare. Alternatives which do not require the continuous flow of gas to the flare will be examined during the detailed design. The contribution to the Development’s total greenhouse gas emissions from flaring is estimated to be less than 2%.

Uncombusted gases, such as natural gas, have a higher greenhouse gas impact when simply vented rather than combusted. All flammable gases will be combusted at the flare.

The most significant periods of flaring will be during the start-up and shut-down of the LNG processing facility. The ability to reduce the volume of gas flared during plant start-up is limited as the flared gas will not meet the specification for LNG sales and may be outside specification for use as fuel. During a shut-down, it will be necessary to ensure the safety of the gas processing facility by depressurising and flaring either the entire inventory of the gas in the facility, or in the section subject to the shut-down. The development of operating procedures for the facility will consider methods for reducing the amount of flared gas during shut-downs to the minimum possible.

Flaring during commissioning will be minimised by appropriate design and control of commissioning procedures.

As a result of the policy to operate the gas processing facility without routine gas flaring, all low pressure hydrocarbon streams in the facility (including those from the various regeneration processes) will be redirected either to the fuel gas system or back into the process. Compressors and other systems in the LNG process will be designed to start-up, operate continuously and shutdown on full recycle to minimise flaring.

In order to undertake inspections of the feed gas pipelines (those linking the offshore fields with the gas processing facility and the domestic gas pipeline), it may be necessary to de-pressure the pipelines during the life of the Development. Should this need arise, then the pipelines will be depressurised in accordance with approved operational plans such that the quantity of gas flared during pipeline depressurisation for inspection work is minimised.

Fugitive Emissions and Venting of Hydrocarbons

As fugitive emissions represent potential safety or environmental hazards, significant engineering work has focused on ensuring such emissions are kept to a very low level. Fugitive emissions are estimated to represent approximately 0.1% of the total greenhouse gas emissions from the proposed Development.

The main sources of fugitive emissions throughout the gas processing facility will be:

- compressor seal losses
- flanges and fittings
- condensate storage tanks
- seals on stems and valves.

Measures taken to reduce greenhouse gas emissions from fugitive sources include: dry gas seals on compressors; maximum practicable use of welded piping; and the specification of high integrity valves (such as blowdown valves and relief valves), pump seals and joining materials.

All low pressure hydrocarbon vapour streams will be redirected back to the gas processing facility rather than being vented to atmosphere.

Transport

The proposed gas processing facility will require logistic support that would not be required if the facility was located on the mainland. This support will consist of aircraft to mobilise personnel and supply vessels to move equipment and supplies to Barrow Island.

Diesel Engines

There will be emissions from diesel powered equipment such as fire pumps and back-up power generation systems. While this equipment will not operate routinely, it will be tested on a regular basis to ensure operational integrity.

Venting of Reservoir Carbon Dioxide

As described in Chapter 6 (Section 6.2.3), it will be necessary to remove CO_2 and minor traces of H_2S from the reservoir gas stream as one of the first steps in gas processing. The volume of reservoir CO_2 will vary over the operational life of the facility due to the natural variability of the CO_2 content within the Gorgon gas field (the gas from the Jansz field contains very little reservoir CO_2). Some areas of the Gorgon gas field have higher CO_2 concentrations than others. On average, it is anticipated that 3.1 MTPA of reservoir CO_2 will be removed from the incoming gas stream. However the CO_2 removal and injection facilities will be designed to handle a maximum rate of 3.4 MTPA. The reference case, on which the greenhouse gas emissions in this document are estimated, is based on the maximum anticipated rate of 3.4 MTPA of reservoir CO_2 being removed from the incoming gas stream.

It is proposed that reservoir CO_2 extracted from the natural gas stream will be injected into the Dupuy Formation utilising injection equipment sized to handle 3.4 MTPA of CO_2. Under routine operations, all reservoir CO_2 removed from the incoming gas stream will be injected. However, venting of the reservoir CO_2 will be required during commissioning, periods of facility or injection system maintenance, unplanned downtime and in the event of unforeseen reservoir or injection well constraints. While it is anticipated that the amount of reservoir CO_2 vented in any particular 12-month period will be significantly less than 200 000 tonnes CO_2e, there is potential for a higher level of venting, particularly in the event of unexpected injection well failure. As a consequence, the reference case for greenhouse gas emissions used in this document is based on 680 000 tonnes (or 20% of the reservoir CO_2, available for injection) will be vented on an annual basis. The 680 000 tonnes represents an allowance of approximately 5% for maintenance and compressor down time plus an allowance of 15% assuming one of the seven injection wells is offline. This represents a worst-case outcome which is likely to be improved upon during the front end engineering and design phase and with the development of operational procedures. Section 13.5 outlines the management measures that are planned to ultimately reduce the percentage of reservoir CO_2 vented to a level below the 20% used in the reference case.

The anticipated volumes of reservoir CO_2 that will be vented along with the volumes anticipated to be injected are identified in Table 13-9. These volumes are expected to decline over time as the facility operation and CO_2 injection are optimised.

The anticipated scenarios that may result in venting of reservoir CO_2 are discussed below.

Venting Due to Maintenance

The combined time when the CO_2 injection facilities are offline for scheduled, or unscheduled, maintenance is anticipated to be less than 30-days per year. This is based on typical maintenance data from the LNG and gas processing industry. The Joint Venturers will minimise the scheduled downtime that results in venting by scheduling the injection facility maintenance to coincide as much as practical with scheduled maintenance of other equipment (within the constraints of LNG and domestic gas production commitments).

Venting Due to Unforeseen Reservoir Constraints

In designing the CO_2 injection system, the number and type of CO_2 injection wells is dependent upon the reservoir properties expected in the Dupuy Formation. The Gorgon Joint Venturers have a high level of understanding of the Dupuy Formation and the anticipated behaviour of the CO_2 once injected into the reservoir but an element of uncertainty remains about the exact nature and performance of the injection wells and the reservoir in proximity to the injection wells.

The Joint Venturers have incorporated the best current understanding of the reservoir and the CO_2 behaviour in the reservoir into estimates of well injectivity. However, it is possible that a particular well might fail to deliver the injectivity expected either at the commencement of injection operations or in the first few years of injection. The failure of a well to deliver the expected injection rates could result from a number of causes. These include intersecting a poorer quality reservoir than expected, plugging of the formation in the area around the well bore, or failure of the hardware within the well bore. All of these situations are encountered in the conventional oil and gas field

Table 13-9:
Volumes of Reservoir CO_2 Anticipated to be Vented and Injected

Percentage of Reservoir CO_2	Year 1	Year 2–5	Year 6+	Long Run Performance Target
Percentage of Reservoir CO_2 injected into the Dupuy Formation	60–90% (2.04–3.06 MTPA)	70–95% (2.38–3.23 MTPA)	80–95% (2.72–3.23 MTPA)	95% (3.23 MTPA)
Vented due to scheduled maintenance and unplanned facilities downtime	5–15% (0.17–0.51 MTPA)	5–10% (0.17–0.34 MTPA)	3–5% (0.10–0.17 MTPA)	3% (0.10 MTPA)
Vented due to unforeseen reservoir constraints (including well injectivity failure)	0–25% (0–0.85 MTPA)	0–20% (0–0.68 MTPA)	0–15% (0–0.51 MTPA)	2% (0.06 MTPA)

As the concentration of CO_2 varies in different parts of the Gorgon field, these figures represent the maximum anticipated rate of 3.4 MTPA of reservoir CO_2. Average rate over life of the Gorgon Development is 3.1 MTPA.

environment and all can be remedied through working over the well, stimulating the formation, or in extreme cases, drilling a new well. Planning, procurement and implementation of remediation activities for a particular well may take up to 12 months, partially as a result of the remoteness of Barrow Island and the requirement for quarantine management.

It is anticipated that as experience is gained with CO_2 injection into the Dupuy Formation, the ability to predict well and reservoir performance will also improve. Over time, the amount of CO_2 vented, due to well bore or reservoir performance issues is anticipated to decrease.

The Joint Venturers are continuing to undertake a range of activities during the detailed design phase the Development, including drilling a data well. The aim of these activities is to reduce reservoir uncertainty such that the probability of having to vent reservoir CO_2 is minimised.

13.3.5 Greenhouse Gas Emissions during Decommissioning

Estimates of greenhouse gas emissions for the decommissioning of facilities and the rehabilitation of disturbed sites has not been undertaken. A number of the activities such as the removal of the subsea production system or the decommissioning of the facility on Barrow Island will potentially involve similar emissions to their installation, whereas emissions related to the offshore drilling operations and plant commissioning will be substantially reduced. Likely emissions during decommissioning are presented in Table 13-10. These estimates are based on the assumption that offshore pipelines will be left in place following decommissioning.

13.3.6 Benchmarked Greenhouse Gas Emission Performance

Benchmark data for comparing the greenhouse gas emissions efficiency of the proposed Development is not widely published. The data that is available is restricted to the efficiency of LNG processing. The volume of greenhouse gas emissions emitted to the atmosphere for each tonne of LNG produced provides a recognised benchmark by which to assess the greenhouse emissions intensity of an LNG plant. However, the metric is not a direct reflection of the thermal efficiency of the LNG plant as it is influenced by:

- the composition of the incoming gas stream, particularly the concentration of reservoir CO_2 and nitrogen, as well as the level of ethane, propane, butanes and pentanes
- the ambient temperature in which the gas plant operates
- the energy used to inject reservoir CO_2, if it is to be injected
- the degree to which greenhouse gas emissions from supporting infrastructure have been included in the calculation.

The Gorgon Joint Venturers have not been able to benchmark the greenhouse gas efficiency of the domestic gas component of the gas processing facility as comparable data is not widely available in the public domain.

LNG processing efficiency data often does not represent the full suite of greenhouse gas emissions for a particular development as it does not include emissions from the gas production facilities. For example, many LNG developments are supplied with

Table 13-10:
Greenhouse Gas Emissions During Decommissioning

Decommissioning and Rehabilitation Activity	Estimated Greenhouse Gas Emissions (tonnes CO_2e)
Decommissioning of offshore wells (fuel consumption)	75 000–100 000
MSV to remove subsea production system and umbilicals	45 000
Electrical power generation on Barrow Island	75 000–95 000
Mobile equipment and vehicle usage on Barrow Island	25 000
Total estimated greenhouse gas emissions related to decommissioning and rehabilitation activities	**220 000–265 000 tonnes**
The emissions stated in this table should be considered as order of magnitude estimates	

gas produced from offshore gas processing platforms. The greenhouse gas emissions from these platforms are generally not included in the LNG efficiency benchmark.

The ability to estimate greenhouse emissions related to the initial gas production is prevented by many of these gas production facilities having more than one function. For example, in Australia the offshore gas platforms supplying gas to the North West Shelf and Darwin LNG Projects also undertake liquids stripping operations, whereby gas is produced from the field, the liquid hydrocarbons removed and the natural gas re-injected back into the reservoir. The North West Shelf gas platforms also produce a significant volume of gas for use in the domestic gas market.

Where gas is produced using a subsea production system, the LNG processing efficiency represents the efficiency of the overall LNG development as gas production from subsea production systems results in essentially no greenhouse gas emissions. In the following benchmarking discussion only the Gorgon and Snohvit Developments are designed around an all-subsea production system.

In order to make a meaningful comparison of overall greenhouse efficiency, an estimate of likely greenhouse gas emissions associated with gas production from the published benchmarked projects has been made. Previous proposals to develop the Gorgon field incorporated the use of an offshore gas production platform. The annual greenhouse gas emissions associated with this platform were estimated at approximately 600 000 tonnes CO_2e per annum, while supplying enough gas for the production of 8 MTPA LNG (WAPET 1998). This equates to an incremental 0.075 tonnes of CO_2e per tonne of LNG. This incremental emission performance has been applied to the LNG plant benchmarking data except for the Gorgon and Snohvit Developments.

The greenhouse efficiency of the LNG component of the reference case for the Gorgon Development is 0.353 tonnes of CO_2e per tonne LNG. This efficiency includes all emissions related to the production of the natural gas from the offshore fields, the energy required to inject reservoir CO_2 and the volume of reservoir CO_2 vented. As such, it represents the greenhouse efficiency of the overall LNG component of the proposed Development, not just the manufacture of LNG.

The greenhouse efficiency data from the Gorgon Development has been compared with data from the:

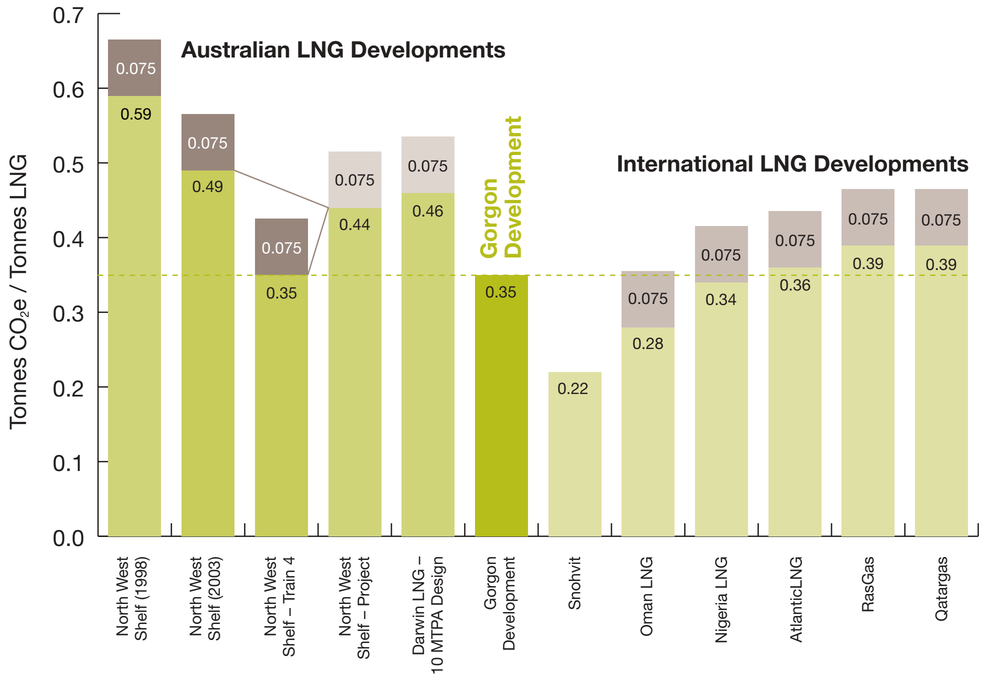
- North West Shelf Project
- Darwin LNG Project (under construction)
- Snohvit – Hammerfest, Norway (under construction)
- Oman LNG – Qalhat, Oman
- Nigeria LNG – Bonny Island, Nigeria
- RasGas – Ras Laffan, Qatar
- Qatargas – Ras Laffan, Qatar
- Atlantic LNG – Point Fortin, Trinidad and Tobago.

Figure 13-7 shows the LNG greenhouse gas emissions efficiency of the Gorgon Development benchmarked against these other LNG projects. The LNG efficiency includes emissions of reservoir CO_2 where these are vented to the atmosphere.

The North West Shelf LNG facility (Woodside 2004) has seen its greenhouse emissions efficiency for LNG production improve from 0.59 to 0.49 tonnes of CO_2e per tonne LNG for the initial three processing trains. This was due to process improvements and de-bottlenecking the process trains once commissioned. The recently commissioned Train 4 expansion and possible Train 5 are reported to have an efficiency of 0.345 tonnes of CO_2e per tonne LNG reflecting efficiency improvements related to the increased size of the process trains. This gives the current North West Shelf LNG processing facility a greenhouse emissions efficiency of 0.44 tonnes of CO_2e per tonne LNG (based on production from Trains 1, 2, 3 and 4). The feed gas supplying the North West Shelf LNG facility includes approximately 2.5% reservoir CO_2 which, once removed from the gas stream, is vented to the atmosphere and is included in the calculation of greenhouse efficiency. The benchmark numbers above exclude greenhouse gas emissions from the offshore gas production platforms required to produce the gas into the LNG processing facility.

ConocoPhillips is currently constructing an LNG facility in Darwin which will process gas from the Bayu-Undan and other gas developments in the Timor Sea. ConocoPhillips estimates that the Darwin LNG facility will have a greenhouse efficiency of 0.46 tonnes of CO_2e per tonne of LNG to be produced (ConocoPhillips 2002). The feed gas supplying the Darwin LNG facility includes approximately 6.0%

Figure 13-7:
Benchmarked Greenhouse Gas Efficiency



reservoir CO_2 which, once removed from the gas stream, will be vented to the atmosphere and is included in the calculation of the Darwin LNG Project's greenhouse efficiency. The greenhouse efficiency numbers stated above exclude the greenhouse gas emissions from the offshore gas processing platform required to produce the gas.

Statoil are currently constructing the Snohvit LNG development near the town of Hammerfest in northern Norway. Snohvit comprises a subsea development of an offshore gas field, LNG manufacturing onshore and the re-injection of CO_2 contained in the reservoir gas. The feed gas supplying the Snohvit development will include approximately 8.0% reservoir CO_2. The data published for Snohvit is based on the assumption that all reservoir CO_2 will be injected into the subsurface.

The Oil and Gas Journal has published benchmark data on five recent greenfield LNG developments: Oman LNG, Nigeria LNG, RasGas, Qatargas and Atlantic LNG (Yost and DiNapoli 2003). These LNG facilities have all been commissioned in the last five years and as such represent current design practice. All were commissioned as greenfield developments rather than as expansions to existing LNG projects. The reservoir CO_2 content in the feed gas supplying these developments is:

- Oman LNG – 1.0 mole %
- Nigeria LNG – 1.8 mole %
- RasGas – 2.3 mole %
- Qatargas – 2.1 mole %
- Atlantic LNG – 0.8 mole %.

The venting of the reservoir CO_2 from these projects is included in the calculation of their greenhouse gas efficiency.

Comparison to the Gorgon Development

This benchmarking analysis shows that the Gorgon Development will be amongst the most greenhouse efficient LNG developments in the world, particularly when emissions related to the initial gas production are considered. Based on this data, only Oman LNG and Snohvit have appreciably better LNG greenhouse gas efficiency. The benchmark data show that the Gorgon Development reference case greenhouse gas emissions are comparable to those from the North West Shelf Train 4 and proposed Train 5 expansion.

In comparison to Oman LNG, the Gorgon Development must remove a greater proportion of reservoir CO_2 from the incoming feed gas. The increased electrical power required to operate the larger Gorgon Development acid gas removal plant is estimated at 10 MW. The increased heat load associated with the larger acid gas removal plant has not been considered in this calculation as it is supplied by the waste heat recovery system.

The reference case greenhouse gas emissions include 500 000 tonnes per year of reservoir CO_2 that is assumed to be vented and 270 000 tonnes of CO_2e per year associated with operating the CO_2 compressors and pumps. If the Gorgon Development had the same gas composition as Oman LNG, the benchmarked greenhouse efficiency for Gorgon would reduce to 0.27 tonnes CO_2e per tonne LNG.

A calculation enabling the Gorgon Development greenhouse emissions benchmark to be compared with Oman LNG is provided in Table 13-11.

The Shohvit LNG development is currently being constructed in the Barents Sea and will potentially be the most greenhouse efficient LNG plant in the world. Shohvit will have less than half (4.1 MTPA LNG) the gas processing capacity of the Gorgon Development but shares a similar approach to the management of greenhouse gases. Both developments are based around a subsea gas production system and both propose to significantly reduce greenhouse gas emissions by the subsurface injection of reservoir CO_2. Data on the Snohvit development is available from www.snohvit.com/STATOILCOM/snohvit.

Snohvit is being constructed using aero-derivates gas turbines for power generation. Unlike the Gorgon Development, no spare electrical generation capacity will be installed, with redundancy being provided by a connection with the local electricity grid. If the Gorgon Development was able to rely upon a local grid connection to provide redundant electrical power, then the power generation turbines could be operated more efficiently saving 65 000 tonnes CO_2e per year.

The climate in which Snohvit will operate is very different from that of the Gorgon Development, as it is located above the artic circle. Average temperatures in the area where Snohvit will operate are approximately 0ºC compared to the design case for the Gorgon Development of 26ºC. This colder ambient temperature results in both the gas turbines and the LNG process working more efficiently. For every one degree reduction in ambient operating temperature LNG process capacity is increased by 0.6%. Assuming the same LNG plant configuration, if the Gorgon Development was operating in a similar climate to Snohvit, annual LNG production would lift from 10 MTPA to 11.56 MTPA. This would improve the benchmarked greenhouse gas efficiency by 0.047 tonne CO_2e per tonne LNG.

While the joint venturers of both the Snohvit and Gorgon Developments plan to inject reservoir CO_2 the reference case for Gorgon Development greenhouse gas emissions efficiency assumes that 500 000 tonnes of reservoir CO_2 will be vented each year. In order to compare the underlying LNG plant efficiency between these developments, the emissions associated with the venting of reservoir CO_2 have been removed.

Table 13-11:
Benchmark Comparison to Oman LNG

	Tonnes CO_2e per tonne LNG
Gorgon Development LNG Benchmark	0.353
Less power to acid gas removal plant	0.006 (10 MW = 127 GJ/h = 58 000 tonnes CO_2e/year)
Less reservoir CO_2 vented	0.05
Less power to run CO_2 compressors	0.027 (47.3 MW = 603 GJ/h = 270 000 tonnes CO_2e/year)
Gorgon Development LNG benchmark, assuming field gas has same CO_2 content as Oman	0.27
Oman LNG benchmarked greenhouse efficiency	0.28

Note: Above calculations do not include the reduction in process heat associated with CO_2 removal from the gas stream. Process heat required for CO_2 removal in the acid gas removal plants is provided from waste heat recovery system. This scenario assumes that less waste heat is recovered.

A calculation enabling the Gorgon Development greenhouse emissions benchmark to be compared with Snohvit is provided in Table 13-12.

The similarity in greenhouse gas emissions efficiency between the Gorgon Development and North West Shelf Train 4 (and planned Train 5) is testament to the appropriate balance being reached between capital cost, greenhouse emissions efficiency and risk profile as discussed in Section 13.3.4. The liquefaction process adopted by both the Gorgon Development and the North West Shelf Train 4, while deploying particular features from their respective LNG Licensors, is very similar.

As indicated above, the reservoir CO_2 content differs between the Gorgon Development and the North West Shelf Project and this underlies the main variation in the energy configuration (both electrical, heat and mechanical drive) adopted for each project. North West Shelf Train 4 has a relatively small electrical and heat requirement and has selected aero-derivative gas turbines (without waste heat recovery) as the appropriate choice for electrical power generation. The Gorgon Development has a high heat requirement due to both the level of reservoir CO_2 and the use of a subsea gas production system making waste heat recovery a paramount consideration. As a consequence, the Gorgon Joint Venturers have elected to maximise waste heat recovery from industrial type gas turbine generators.

13.4 Disposal of Reservoir Carbon Dioxide by Injection into the Dupuy Formation

The opportunity to reduce greenhouse emissions by the subsurface injection of CO_2 is relatively new; however the technologies to be applied by the Gorgon Joint Venturers are well established in the oil and gas industry and are being used to inject CO_2 in other parts of the world (Box 13-2). In addition there are a number of research programs looking into the application of injection of CO_2 into the subsurface as a means to reduce atmospheric greenhouse gas emissions (Box 13-3).

In order to ensure that the community remains well informed about the performance of the CO_2 injection project, the Gorgon Joint Venturers undertake to make information available to the public with regard to the ongoing monitoring program.

The reference to reservoir CO_2 throughout this Draft EIS/ERMP refers to the gas stream coming from the acid gas removal plant and being available for injection into the Dupuy Formation. This reservoir CO_2 stream will contain impurities such as hydrogen sulphide (200 ppm), methane (typically between 0.2% and 0.5%) and traces of benzene, toluene, etheylbenzene and xylene, together referred to as BTEX (generally less than 0.5 mol%). The level of BTEX in the reservoir CO_2 may be reduced during the detailed design phase. These impurities are expected to behave in much the same way as the CO_2 once injected. For simplicity the reference to reservoir CO_2 includes these other gases.

Table 13-12:
Benchmark Comparison to Snohvit

	Tonnes CO_2e per tonne LNG
Gorgon Development LNG Benchmark	0.353
Less emissions related to stand by power generation	0.0065 (65 000 tonnes CO_2e/year)
Efficiency improvement due to lower ambient operating temperature	0.047 (LNG throughput increased from 10 MTPA to 11.56 MTPA)
Less Gorgon Development reservoir CO_2 vented	0.05
Gorgon Development LNG Benchmark, assuming no standby power generation, no CO_2 venting and operations in cold ambient conditions	0.25
Snohvit benchmarked greenhouse efficiency	0.22

Box 13-2:
Worldwide Experience with Carbon Dioxide Injection

The disposal of reservoir CO_2 by injection into the Dupuy Formation, as proposed by the Gorgon Joint Venturers, will be one of only a few such projects worldwide. However, the concept of injection of fluids into a subsurface formation for enhanced oil recovery, gas storage and acid gas disposal is well accepted throughout the world and has a long history of successful operation.

The Joint Venturers have experience in other parts of the world in operating systems designed to inject mixtures of CO_2 and hydrogen sulphide into subsurface formations. Chevron's Acheson Field in Canada was one of the first to use this technique, referred to as 'acid gas injection', to dispose of hydrogen sulphide and CO_2 separated from a natural gas stream. Prior to this, these gases were vented or flared to the atmosphere. Acid gas injection typically involves compressing the mixed gas, dehydrating the gas and injecting it into a saline formation other than the oil or gas field. Chevron's Canadian subsidiaries have successfully operated four such acid gas injection projects since 1990, with 21 years of cumulative experience. The CO_2 content in the injected gas is up to 88 mol%. Acid gas injection is now commonly undertaken where gas fields have high concentrations of hydrogen sulphide.

The Gorgon Joint Venturers also have extensive experience in the design, construction and successful operation of enhanced oil recovery projects involving injection of substantial volumes of CO_2 into the oil-producing formations. The CO_2 acts to reduce the viscosity of the oil allowing it to flow into the production wells with greater ease.

Chevron's largest current CO_2 injection operation is the Rangely Weber Sand Unit in western Colorado, of the USA. Rangely is the largest oilfield in the US Rocky Mountain area and is the third largest CO_2 enhanced oil recovery operation in the world. Injection of CO_2 for enhanced recovery began in 1986. About three million tonnes of CO_2 per annum are injected into sandstone formations at a depth of about 1800 m. The CO_2 is compressed, dehydrated, then injected using a network of wells. The CO_2 supply for this enhanced oil recovery project is transported to Rangely via a CO_2 pipeline, built and operated by Chevron.

Chevron's North American exploration and production company currently operates six CO_2 injection projects. In addition, Chevron has a working interest in 11 non-operated CO_2 injection projects, two of which are the world's largest – the Seminole Unit and the Denver Unit.

Both Shell and ExxonMobil have experience in the operation of CO_2 injection based on enhanced oil recovery projects.

ExxonMobil is a joint venture partner in Sleipner, a large scale CO_2 injection project currently operating in the Norwegian sector of the North Sea. One million tonnes of CO_2 per annum have been injected at Sleipner since 1996.

Since the publication of the ESE Review (ChevronTexaco Australia 2003) the basis of design has been revised to include the development of the Jansz field (refer to Chapter 1). The reference case used for determining the volumes of reservoir CO_2 in this Draft EIS/ERMP is for the LNG processing trains to be sourced equally from the Gorgon and Jansz gas fields and for domestic gas to be supplied from the Gorgon field. As a consequence of the reduced CO_2 content in the Jansz field, the volume of reservoir CO_2 as a proportion of plant throughput has been reduced resulting in the injection of between 2.7–3.2 million tonnes of reservoir CO_2 per annum. Information on the gas compositions from both the Gorgon and Jansz fields is provided in Chapter 6 (Section 6.1.1).

13.4.1 Assessment of Potential Carbon Dioxide Injection Sites

The Gorgon Joint Venturers have undertaken a number of studies since 1992 to identify a suitable site to dispose of reservoir CO_2 by injection into subsurface formations. The region considered is shown in Figure 13-8.

Sites considered for CO_2 injection included saline reservoirs, depleted oil and gas fields and other formations that satisfy appropriate selection criteria. The Gorgon Joint Venturers' selection criteria include:

- the availability of subsurface data over the site
- the top of the injection target at least 800 m below the surface. At this depth the CO_2 will remain in a

Box 13-3:
Research into Carbon Dioxide Injection

Research is currently being conducted around the world to investigate the viability of subsurface injection of CO_2 to reduce greenhouse gas emissions. The four primary goals of research into CO_2 injection are to:

- lower the cost of injection and ensure reservoir integrity
- demonstrate environmental acceptability
- understand the behaviour of injected CO_2 and gain assurance on its predictability
- develop reliable monitoring and verification technology for CO_2 injection.

The Gorgon Joint Venturers are actively involved in several research and demonstration programs, participation in which has already contributed to the planning of the reservoir CO_2 injection below Barrow Island. These programs are:

- GEODISC
- Cooperative Research Centre of Greenhouse Gas Technologies (CO2CRC)
- CO_2 Capture Project
- Stanford University Global Climate and Energy Project (GCEP)
- Weyburn Project
- GEO-SEQ
- Saline Aquifer CO_2 Storage Project (SACS).

GEODISC was a program undertaken by the Australian Petroleum Cooperative Research Centre and was designed to address key technical, commercial and environmental issues associated with the injection of CO_2 in Australia. A key deliverable of this work was a high level assessment of potential CO_2 injection locations within Australia. The Research Centre has now closed with the work of the GEODISC program being continued and expanded by the CO2CRC. Information on the GEODISC program can be found at www.apcrc.com.au/Programs/geodisc_res.html.

The CO2CRC has continued the work commenced by the GEODISC program with the aim of further developing the CO_2 capture and storage technologies. A key component of the activities of the CO2CRC will be the operation of a number of demonstration CO_2 injection pilot projects. Information on the CO2CRC can be accessed at www.co2crc.com.au. The Gorgon Joint Venturers plan to maximise the transfer of knowledge between the Gorgon Development and the CO2CRC programs to assist in establishing Australia as a leader in CO_2 injection.

The CO_2 Capture Project is a major international collaboration aimed at reducing the cost of capturing CO_2 from combustion sources and developing methods for safely storing the CO_2 underground. Key work activities of the CO_2 Capture Project involve technology development of the injection and monitoring of CO_2 and work on the area of policy development dealing with CO_2 capture and storage. Information on the CO_2 Capture Project can be accessed at www.co2captureproject.com.

The Stanford University Global Energy Project (GCEP) is a long-term collaborative effort of the scientific and engineering community in universities, research institutions and private industry with the purpose of conducting fundamental pre-commercial research and to foster the development of global energy technologies (including CO_2 Capture and Storage) with significantly reduced greenhouse gas emissions. Information on GCEP can be accessed at http://gcep.stanford.edu/.

The Weyburn Project is utilising a major CO_2 enhanced oil recovery project in Canada to assist in understanding the behaviour of the CO_2 in the subsurface and to demonstrate potential monitoring activities. Information on the Weyburn Project can be accessed at www.ieagreen.org.uk/weyburn.htm.

GEO-SEQ is a public-private research and development partnership aiming to deliver the technology and information needed to enable the application of safe and cost effective methods of CO_2 injection. Information on GEO-SEQ can be accessed at esd.lbl.gov/GEOSEQ.

The SACS consortium was established to monitor the injection of CO_2 at the Sleipner gas field in the Norwegian North Sea. Information on the SACS consortium and the Sleipner CO_2 injection project can be accessed at www.ieagreen.org.uk/sacshome.htm.

dense state maximising the storage capacity of the reservoir to contain the CO_2

- a low risk of the CO_2 being able to migrate out of the reservoir
- a reservoir of sufficient permeability to handle the injection rates
- a reservoir of sufficient capacity to accept the volume of CO_2 being injected without build-up of pressure to a point where the integrity of the reservoir seals might be compromised
- close proximity to the CO_2 source to minimise risks related to transportation and energy required to transport the CO_2.

The existence of a well-defined geometric trap and high quality reservoir is not mandatory provided that CO_2 movement through the reservoir will be tortuous enough to ensure that the CO_2 is permanently immobilised before it can migrate to locations where its presence might be undesirable. In the absence of a well-defined geometric trap, a clear migration pathway and understanding of the rate of migration should be demonstrated to allow the ultimate containment of the CO_2 to be predicted.

Within the area of interest 17 sites were initially considered as candidates for CO_2 injection. Seven of these areas were quickly determined to be unsuitable and were eliminated from further consideration. These included:

- Exmouth area
- Barrow Island – Windalia Sandstone Member
- Wandoo area
- Barrow Group offshore
- Montebello Islands
- Burrup Peninsula area
- North Rankin.

These locations were excluded from further consideration due to a combination of reasons including risk to currently producing oil or gas fields, distance from potential gas processing facilities sites, and a lack of suitable CO_2 injection reservoirs.

This preliminary assessment left a total of nine locations to be evaluated in more detail as potential sites for CO_2 injection. Table 13-13 outlines the major advantages and disadvantages for each of this short list of locations and provides comments on their suitability.

The West Tryal Rocks and Gorgon gas fields represent ideal sites to inject reservoir CO_2 due to the presence of proven geometric traps and therefore a low technical risk of unpredicted migration to the surface. However the hydrocarbon in these fields would have to be depleted prior to the sites being available for CO_2 injection.

The Barrow Island Dupuy Formation has a number of attributes that make it a preferred location for

Figure 13-8:
Region of Investigation for CO_2 Disposal Sites

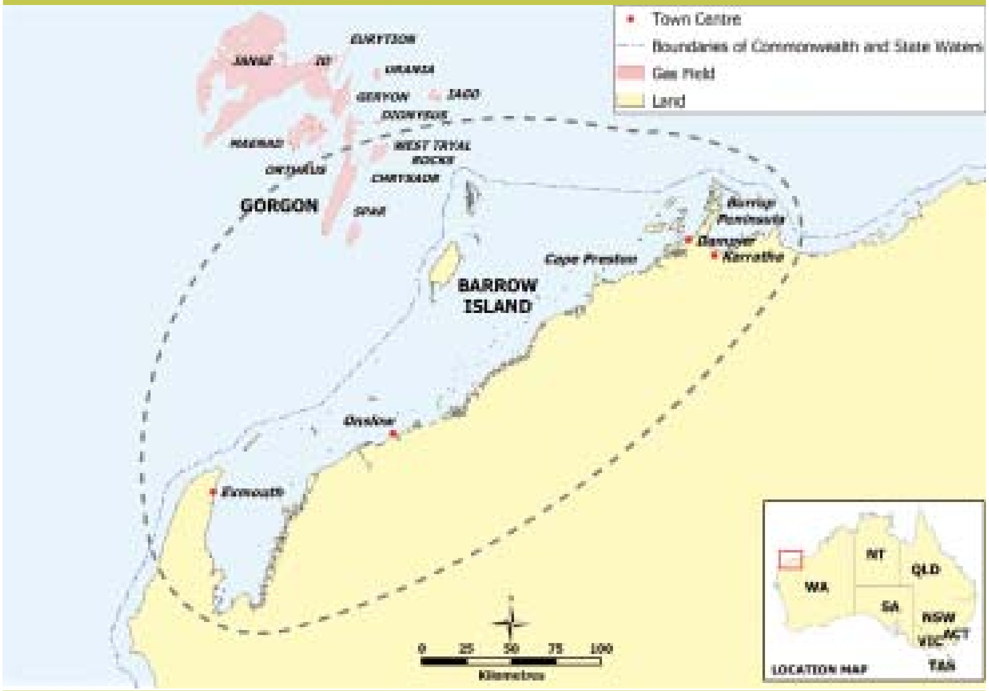


Table 13-13:
Potential CO_2 Injection Locations

Location	Approximate Distance to Plant Site (km)	Capacity to Accept Anticipated CO_2 Volumes	Risk to Potential Hydrocarbon Production	Cost	Comments
West Tryal Rocks	75 km	Yes	Yes (gas)	Very High	Would not be available until the field was depleted.
North Gorgon	75 km	Yes	Yes (gas)	Very High	Would not be available until the field was depleted.
South Gorgon	75 km	Yes	Yes (gas)	Very High	Would not be available until the field was depleted.
Spar	60 km	No	Yes (gas)	Very High	Insufficient capacity.
Barrow Island Dupuy Formation	**2–5 km**	**Yes**	**Minimal**	**Medium**	**Barrow Fault is known to be sealed at the Windalia Sandstone Member (reservoir for Barrow Island oilfield) but could pose a migration path risk if Dupuy formation reservoir pressure increase is excessive.** **Greater depth favours the Dupuy Formation over the shallower Flacourt and Malouet Formations of the Barrow Group.**
Barrow Island, Flacourt and Malouet Formations of the Barrow Group	2–5 km	Yes	Minimal	Medium	Possible targets, though considered less favourable than the Dupuy Formation because shallower and exhibits greater dip northwards. Barrow Fault is known to be sealed at the Windalia Sandstone Member (reservoir for Barrow Island oilfield) but could pose a migration risk if Flacourt or Malouet Formation pressure increase is excessive.
Kennedy Group Sands	45–70 km	Yes	No	Very High	High degree of uncertainty due to limited data. Significant cost to obtain sufficient data. Further data may show that the reservoir is not suitable.
Harriet – Campbell Group of Fields	35 km	No	Yes (oil and gas)	High	Insufficient capacity. Would not be available until the fields were depleted.
Saladin (Thevenard Island)	90 km	No	Yes (oil and gas)	High	Insufficient capacity.

Source: ESE Review (ChevronTexaco Australia 2003)

CO_2 injection and it would be available as soon as production commences from the Gorgon Development. The additional attributes that make the Dupuy Formation the preferred option include:

- the depth of the Dupuy Formation allows the CO_2 to remain in a supercritical phase
- the reservoir properties of the Dupuy Formation provide effective trapping of the injected CO_2
- the structure of the Dupuy Formation provides predictable migration pathways
- there is little potential to jeopardise current or future production of hydrocarbons
- injection wells that penetrate into the Dupuy Formation would allow access to other saline reservoirs (Flacourt and Malouet Formations) as mitigation/upside options
- the Dupuy Formation can be accessed from onshore and close to the source of CO_2, removing the need for subsea wells and offshore platforms and thereby reducing risk and cost
- 2-D and 3-D seismic data and stratigraphic information from 27 wells provide a comprehensive data set on which to base technical studies.

13.4.2 Location of Carbon Dioxide Injection on Barrow Island

The Gorgon Joint Venturers have undertaken a detailed study to identify the optimum location for the injection of CO_2 into the Dupuy Formation. A total of seven different injection scenarios around Barrow Island were evaluated before the preferred location was selected. The alternative injection scenarios evaluated were:

- Central East Coast Onshore
- Central West Coast Onshore
- Northern Onshore
- Western Offshore
- Eastern Offshore
- Northern Offshore
- Combined East and West Central Onshore.

Issues considered in the selection of the preferred location include:

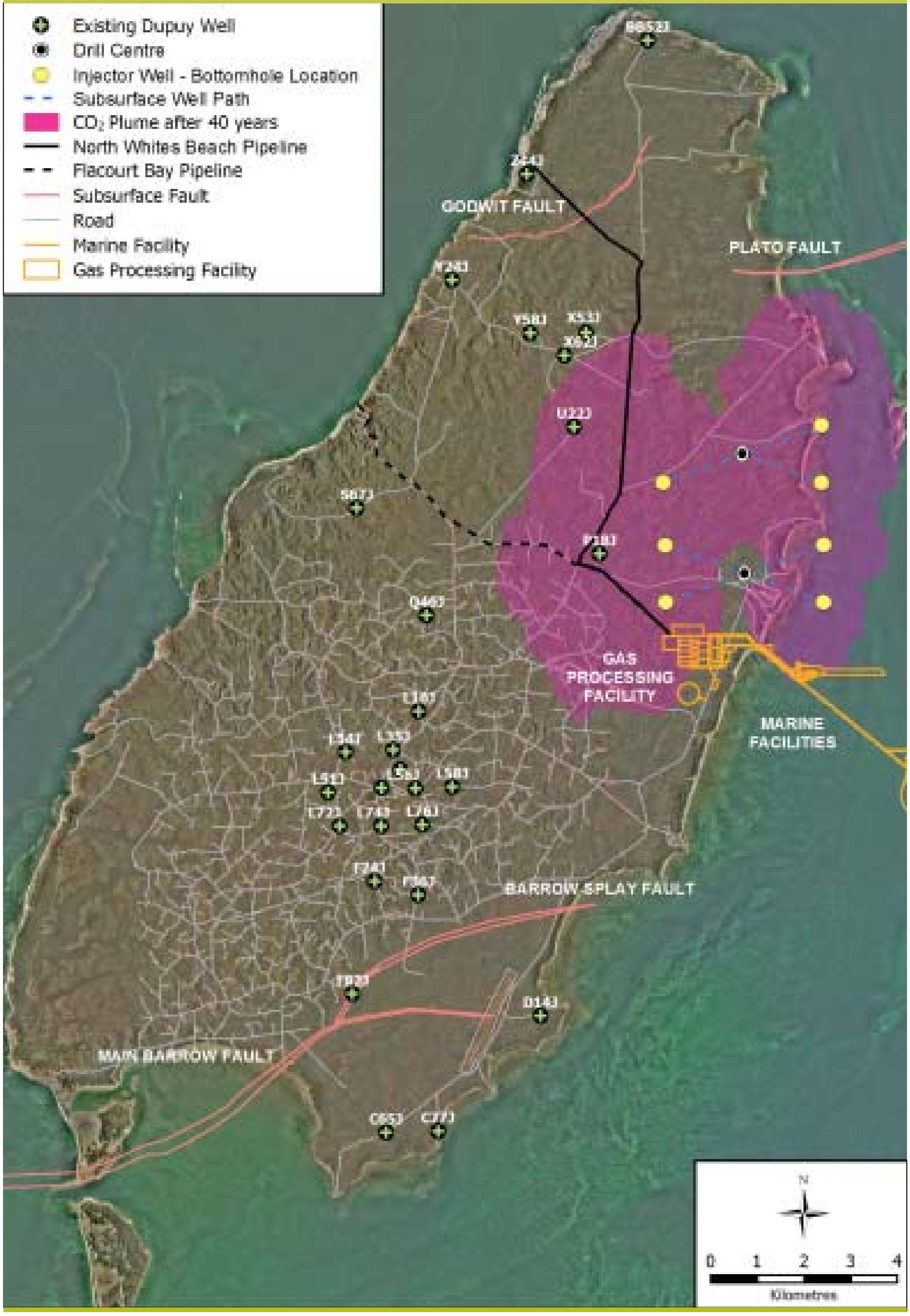
- maximising the distance of the injection wells from the major faults thereby reducing the risk of unpredicted migration
- minimising the area required to be cleared for the facilities on Barrow Island
- ensuring any areas to be cleared are of lower environmental sensitivity when compared to other proposed locations on Barrow Island
- identifying sites where the Dupuy Formation reservoirs is at, or near, its maximum thickness
- minimising the number of existing wells that will be intersected by the migrating CO_2 plume
- a preference for areas of fair to good seismic data quality so as to assist in the monitoring of the CO_2 plume.

The preferred location for CO_2 injection is on the central eastern coast of Barrow Island in the general location of the proposed gas processing facility. This site was selected so as to maximise the migration distance from the major faults while limiting environmental disturbance to areas around the proposed gas processing facility. The number of injection wells will be confirmed following further technical studies during 2005. For this Draft EIS/ERMP it is assumed that seven injection wells will be required. The wells are planned to be directionally drilled from two or three surface locations to minimise the area of land required for the well sites, surface facilities, pipelines and access roads. The CO_2 injection development concept is shown schematically in Figure 13-9. It is likely that an observation well (or wells) will be drilled from each cluster of injection wells to provide a sample point within the area of injection.

Faults which can be mapped from seismic and well data are known areas of disruption to the stratigraphy and therefore represent added risks to the containment capacity of an area. As such, they are areas to be avoided in planning the location of injection wells: firstly, to avoid the physical migration of the CO_2 plume to the fault; and secondly, to minimise the pressure increase within the injection zone at the fault.

The north onshore and western offshore sites were discounted as both provided similar technical risk and both are in areas of higher environmental significance than the preferred location.

Figure 13-9:
CO_2 Injection Development Concept



Box 13-4:
Geological Data

Rock samples can be obtained from surface rock outcrops, from conventional core, side wall cores and drill cuttings and provide information on the subsurface geology. Cores are cylinders of rock cut during the drilling process. Cores generally provide undisturbed samples of the rock and are considered to be the highest quality, direct physical data available. However, cores are expensive to acquire. Additional rock samples are obtained from drill cuttings brought to the surface as the well is being drilled and from sidewall cores which are acquired once drilling has ended.

Wireline logs are recorded in wells and measure the electrical, physical and radioactivity properties of the rocks and their contained fluids. Wireline logs provide only indirect information but when tied carefully to information from drilling samples and core, yield an accurate picture of the rock sequence and provide a convenient graphical basis for comparing well information.

Seismic surveys are usually acquired as either two dimensional (2-D) or three dimensional (3-D) surveys. The result of a 2-D seismic survey is a series of two dimensional displays which show the underground rock structure, much as it can be seen in a road cutting. 3-D seismic is based on a much larger data set which provides a three-dimensional view of the underground structure. Both 2-D and 3-D surveys can be reacquired over time (time lapse seismic) to provide an illustration of how the fluids in the subsurface have migrated. The ability to compare and contrast seismic images over time allows subtle changes in the formation fluids to be detected. These technologies are frequently employed in the oil and gas industry to assist in the management of oil and gas field operations and are likely to be used to assist in monitoring of the CO_2 plume.

Other sites were discounted due to the predicted absence of the lower Dupuy Formation sands, lack of well control and known areas of poor seismic quality. The central west coast location is considered an area which might provide an area for supplementary injection in the event that injectivity proves to be inadequate at the preferred location.

The extent of the CO_2 plume migration at year 1, 5, 40 and 1000, based on the reservoir simulation for the proposed injection scenario is shown in Figure 13-10. The contours on this figure represent the depth of the top of the Dupuy Formation below sea level.

13.4.3 Geology of Barrow Island

The Gorgon Joint Venturers' understanding of the geology of the Barrow Island area is based on extensive rock samples obtained during drilling, well logs and seismic or other geophysical data collected over more than 40 years of petroleum exploration and production. A description of some of the common methods used to obtain geologic data is contained in Box 13-4.

The geological description outlined in this section summarises the results of oil and gas exploration on and around Barrow Island. Over 900 wells have been drilled on Barrow Island with approximately 700 of these wells being drilled into the oil accumulation in the Windalia Sandstone Member at a depth of around 650 m. Approximately 50 wells have been drilled into the Barrow Group and 27 of those wells have penetrated the full thickness of the Barrow Group and reached the Dupuy Formation or sands within the underlying Dingo Claystone. Figure 13-11 shows the location of these deeper wells on Barrow Island.

Porosity is a measure of the void or pore space between the grains in a rock. Normally these pore spaces contain saline water (formation water) and occasionally oil or gas. It is into these pore spaces that the CO_2 will be injected.

Figure 13-10:
Extent of CO_2 Plume Migration Over 1000 years

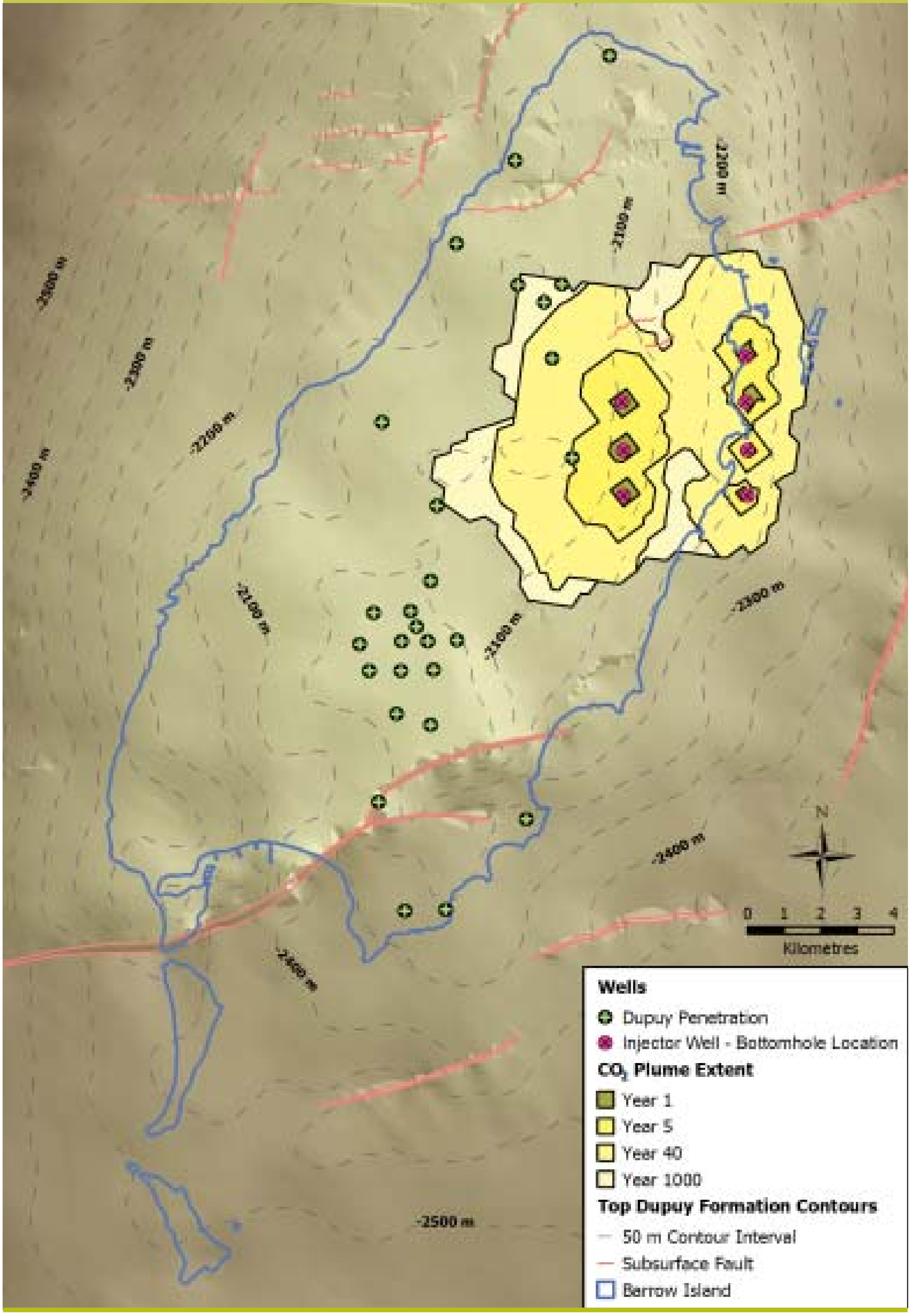


Figure 13-11:
Barrow Island Dupuy Formation Well Control

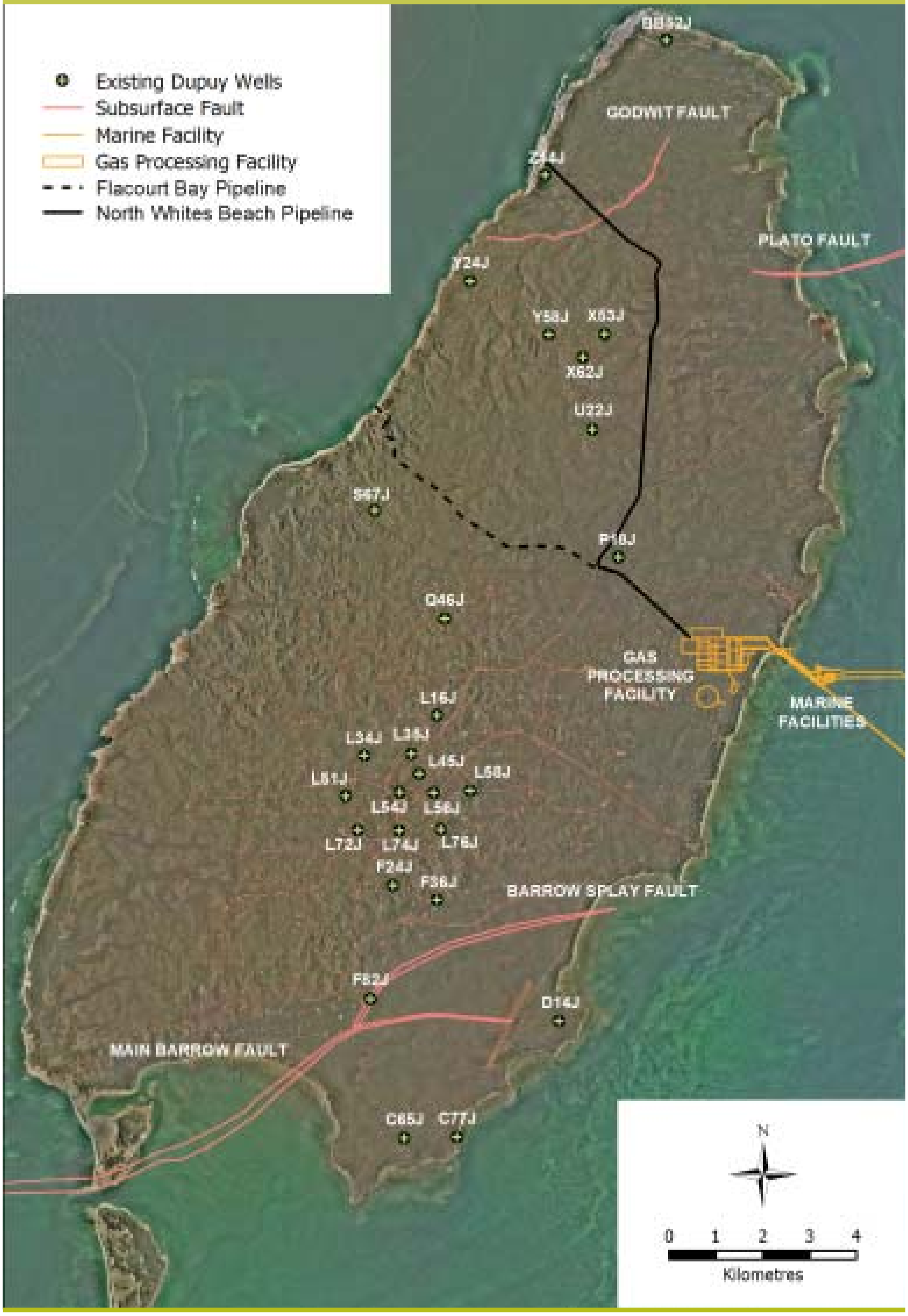


Figure 13-12:
Photo-micrograph Showing Clean Pore Space

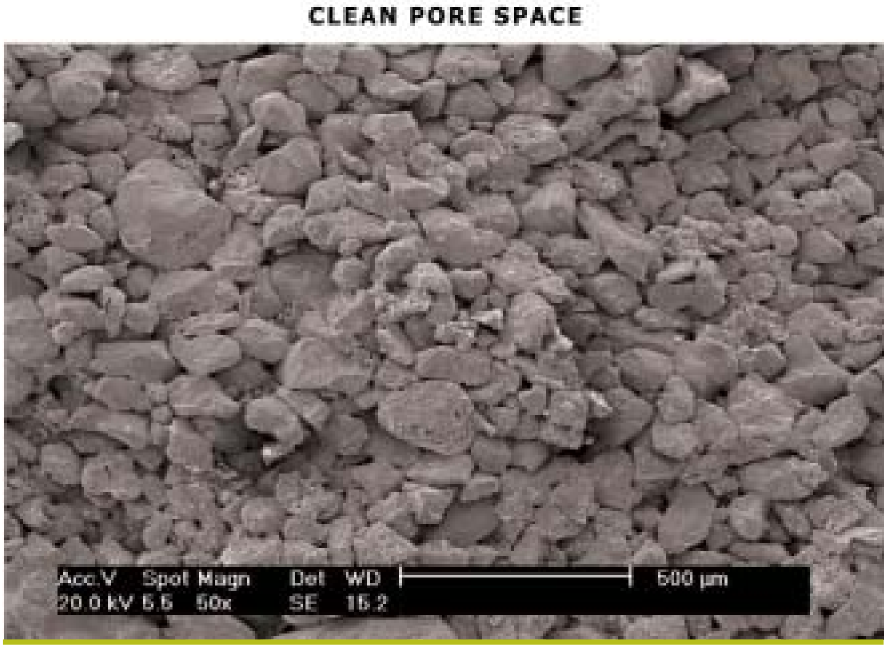
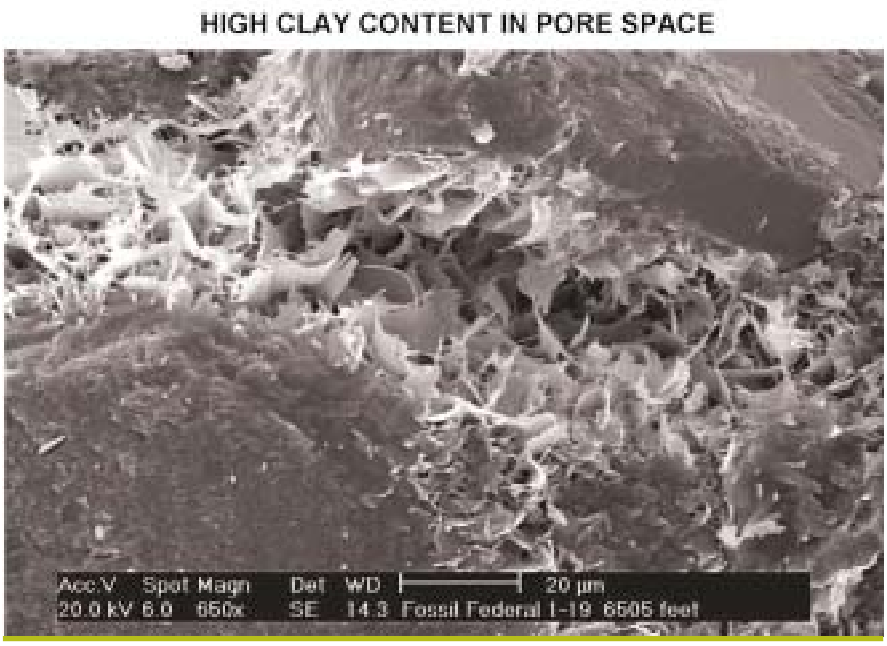


Figure 13-13:
Photo-micrograph Showing High Clay Content in Pore Space



Prior to compaction, sand typically contains over 40% porosity. That is, a one litre container full of clean sand contains room for over 400 ml of water in the pore space. Compaction with burial reduces the amount of porosity. Figure 13-12 shows a clean sandstone in which the pore spaces between the individual grains are sufficiently large and uncluttered (by particles of clay) to allow fluids to enter or exit them easily. Such rocks constitute excellent reservoirs and have high porosity and permeability. The sandstones under Barrow Island in which it is proposed to inject CO_2, are at a depth of over 2000 m with porosities of about 20%.

Permeability is a measure of how easily fluids can move through a formation. Permeability is a function of how individual pore spaces are interconnected, their size and the amount of finer-grained material such as clay in the pore space.

Rocks with a large amount of clay in the pore space (such as shown in Figure 13-13, note the increased magnification compared to Figure 13-12) have low permeability and will act as a type of geological ‘barrier’ or ‘baffle’ to the migration of the injected CO_2. The clay within the pore spaces acts to prevent the movement of fluids, including CO_2, through the pores. The role of baffles in the migration of CO_2 is discussed in Section 13.4.4.

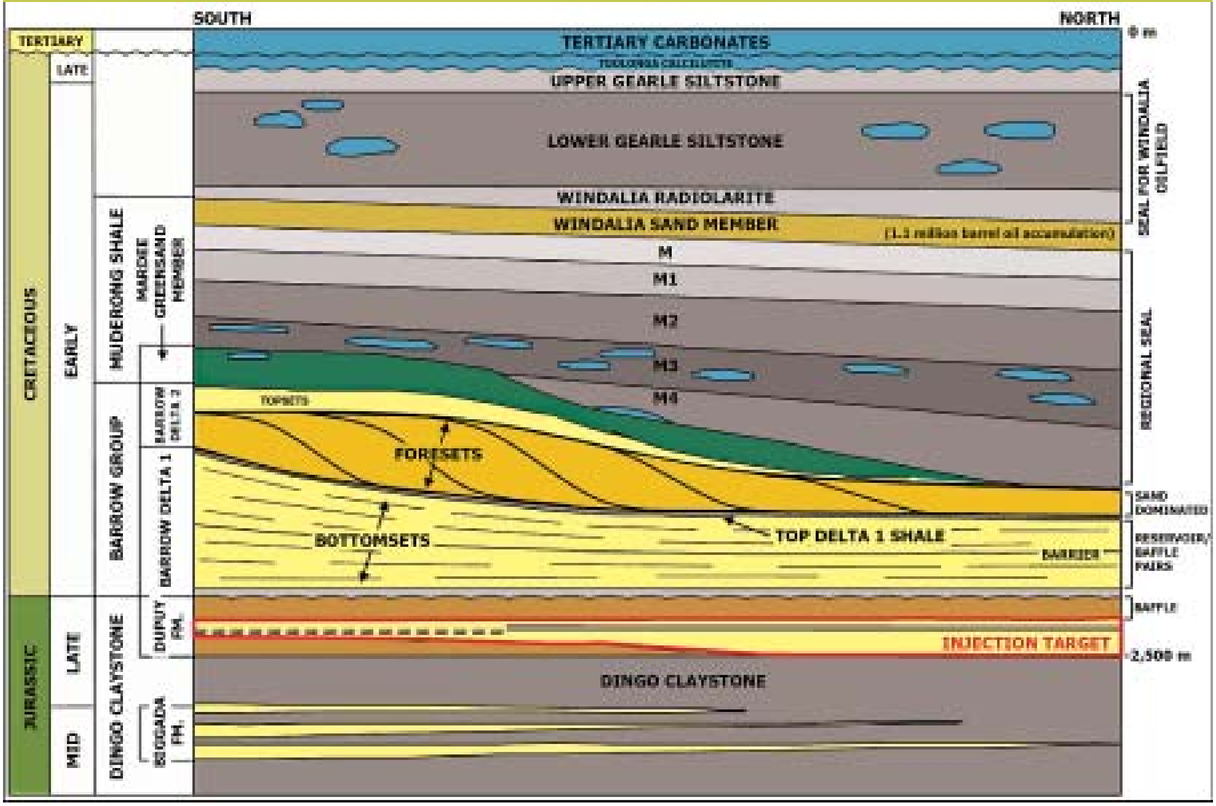
Rocks referred to as shale or claystone consist of individual grains which are so small (virtually water-borne dust) that they are easily transported in water and will be deposited only in a very deep water environment. The fine-grained nature of the rock means that the pore spaces between grains are so small that droplets of migrating fluid are unable to enter the pores easily. When a sufficient thickness of these fine-grained rocks has built up, it can form a seal or barrier which is impermeable to migrating fluids including CO_2.

Stratigraphy

Barrow Island sits in the Barrow Sub-basin of the Carnarvon Basin, a major accumulation of sedimentary rocks on the north-west coast of Western Australia. The regional stratigraphy of the Barrow Island area is shown diagrammatically on Figure 13-14.

The sedimentary rocks of the Barrow Sub-basin have predominantly been deposited under water, either in open marine (oceanic) conditions, or in a major delta.

Figure 13-14:
Regional Stratigraphic Section of the Barrow Island Area



They have accumulated to the thickness of at least 8000–10 000 m because of subsidence of the earth's crust under this area. The major rock types preserved in the Barrow Island area are:

- limestone, most notably the so-called Coastal Limestone, which forms a large part of the surface material on Barrow Island
- sandstone, which typically resembles a solidified beach sand
- shale/claystone, the finest grained of the sedimentary rocks, in which individual grains are not discernible to the naked eye
- siltstones, the grain size of which falls midway between those of sands and clays.

The surface rocks on the island are 'Recent' in age (that is, they were formed within the last 100 000 years) while the deepest well on Barrow Island, sampled rocks at over 4000 m which have been dated as Middle Jurassic (160–80 million years old).

The oldest rocks drilled on Barrow Island belong to the Dingo Claystone which is a sequence of claystone and siltstone 4000 to 6000 m thick. The Dingo Claystone is regionally extensive throughout the Barrow Sub-basin and accumulated because of abundant fine-grained sediment supply to an area which subsided steadily throughout the period of sediment accumulation.

The Dupuy Formation overlies the Dingo Claystone and forms a sandy and silty unit 300–500 m thick in the region of Barrow Island. Whereas the Dingo Claystone is present over the entire sub-basin, the Dupuy Formation is a more localised rock body, confined to the sub-basin's eastern flank. By the end of Dingo Claystone deposition, subsidence in the Barrow Island area had slowed and open ocean conditions were established. The Dupuy Formation sandstones are thought to have been deposited as a result of oceanic current activity and sediment gravity flows in which sand originally deposited in shallow water was redeposited further offshore on the continental shelf and possibly the continental slope. The lower Dupuy Formation sandstones have a restricted areal distribution under the island; they are absent in the wells in the south and south-west of the island but thick and well-developed in the wells in the north and north-west. The lower Dupuy Formation sand section consists of finely inter-bedded sands and siltstones. Individual sand bodies within the lower Dupuy Formation appear to have limited lateral extent.

The overlying upper massive sandstone of the Dupuy Formation can be correlated over the entire island; it is shown on logs and in core to be of higher porosity and permeability and is thickly bedded. The Perforans Shale occurs in the upper third of this unit and appears to extend over the northern half of the island. Several other shale/siltstone layers of varying lateral extent are also present. The upper massive sandstone represents shallower water, lower to middle shore face deposit, still within a normal oceanic environment.

The final phase of Dupuy Formation deposition was marked by fine-grained marine deposition with very limited input of sand.

Overlying the Dupuy Formation is the Barrow Group which represents the deposition of a major marine delta. Sediments in the Barrow delta were transported by a large river system which flowed from the south, draining a hinterland now totally removed by erosion. The resulting delta can be seen in wells and on seismic data to have built out from the Onslow area on the coast of Western Australia to Barrow Island. Deltas develop when the supply of sediment from a river system exceeds the capacity of oceanic processes, for example long shore currents, to disperse the sediment.

The geological units within the Barrow Group comprise the:

- basal, pro-delta shale unit
- interbedded sandstones and marine shales of the true bottomsets of the delta
- predominantly sandy foresets which dip to the north
- topsets comprising high permeability sandstone reservoirs.

The Barrow Group is overlain by the Muderong Shale which is between 300 to 500 m thick and 110 to 130 million years old. The Muderong Shale forms the regional seal within the basin; that is, it is sufficiently impervious to the movement of oil and gas to allow the accumulation of commercial deposits of hydrocarbons directly beneath it. Many of the major hydrocarbon accumulations discovered to date in the basin have been sealed by the Muderong Shale. Overlying the Muderong Shale are the Windalia Radiolarite and Gearle Siltstone, which seal the 285 million kilolitre (in place) Windalia oil accumulation. Overlying the Gearle Siltstone is a thick succession of marine carbonates.

Sampling of the formation waters contained in the Barrow Sub-basin in the area below Barrow Island has shown that the major aquifers contain levels of salt that prevent them from being considered as potential groundwater resources. Water in the Dupuy Formation has a salinity of between 4500 and 10 000 ppm sodium chloride (NaCl) equivalents while waters in the Barrow Group have a salinity of between 30 000 and 32 000 ppm NaCl equivalents. There is a lens of relatively fresh water directly below Barrow Island and at the very top of the water table. The limited size of the fresh water lens and its probable importance to stygofauna prevents its commercial exploitation. CO_2 injection operations will be managed to preserve the presence of this fresh water lens.

Structure

The major structural elements in the Barrow Sub-basin are shown in Figure 13-15. The Sub-basin is boarded to the west by the Alpha Arch, to the south-east by the Peedamullah Fault System and to the north by the Dampier Sub-basin.

Barrow Island has been elevated above the surrounding sea floor by the upward flexing of the underlying strata to form an anticline, an elongate dome in which the layers of rock are arched upwards in both the north-south and east-west directions. Figure 13-16 shows a north-west to south-east cross-section through the Barrow Sub-basin.

The presence of this regional structure assists in predicting the migration to CO_2 in the subsurface.

The structure beneath Barrow Island is shown in greater detail on the north-south and north-west south-east cross-sections shown in Figure 13-17 and Figure 13-18.

These cross-sections show the arching of the rock strata under Barrow Island and the location of a number of faults. Faulting occurs when geological strata are broken by tectonic forces greater than the rock strength. The Barrow Fault and the Godwit Fault are the most significant of these and may represent potential fluid migration pathways. The Barrow Fault has had a long history of movement, which is believed to have continued up until recent geological times, based on the observation that the fault is expressed at the surface of the island in a subdued topographic scarp. Movement on the Barrow Fault has resulted in the block on the southern side of the fault being displaced downwards, relative to the northern block. Relative to the Barrow Fault, the Godwit Fault appears to have been active comparatively few times.

The two cross-sections also show the distribution of sandstone within the lower Dupuy Formation. As mentioned above, the upper massive sand unit is uniformly present over the entire island, although it is thinner at the southern end of the island, whereas the lower Dupuy Formation sand is absent in the south and south-west of the island, but is present as a thick accumulation in the north and north-west.

13.4.4 Carbon Dioxide Behaviour in the Subsurface

Phase Behaviour of Carbon Dioxide

For CO_2 to be efficiently disposed in the subsurface, it is preferable for it to be in a supercritical phase so that the volume of the rock occupied by the CO_2 can be minimised. A supercritical fluid is any substance above its critical temperature and pressure. In the supercritical phase, the fluid will possess both gas and liquid like properties. It will have the density of a light liquid and the properties of a gas to allow it to fill the maximum pore space available. Figure 13-19 shows the phase diagram for CO_2 and the temperature and pressure anticipated in the Dupuy Formation. At a depth of approximately 2200 m, the reservoir pressure is 22 MPa and temperature is 100ºC. Under these conditions, CO_2 will have a density of 550 kg/m^3, compared with fresh water with a density of 970 kg/m^3 and normal ocean water with a density of about 1030 kg/m^3. As it is less dense than the waters already contained in the formation, supercritical CO_2 will tend to rise vertically due to buoyancy forces.

Trapping Mechanisms

There are four mechanisms that can trap injected CO_2 within the host reservoir:

- solution trapping
- residual gas trapping
- mineralogical trapping
- large-scale geometric trapping.

The process by which each of these mechanisms works to trap the injected CO_2 is discussed below. The longer the CO_2 remains in the reservoir and the more formation water is contacted the more effective these trapping mechanisms are at immobilising the CO_2 and the higher the proportion of CO_2 trapped.

Figure 13-15:
Barrow Sub-basin Structural Elements

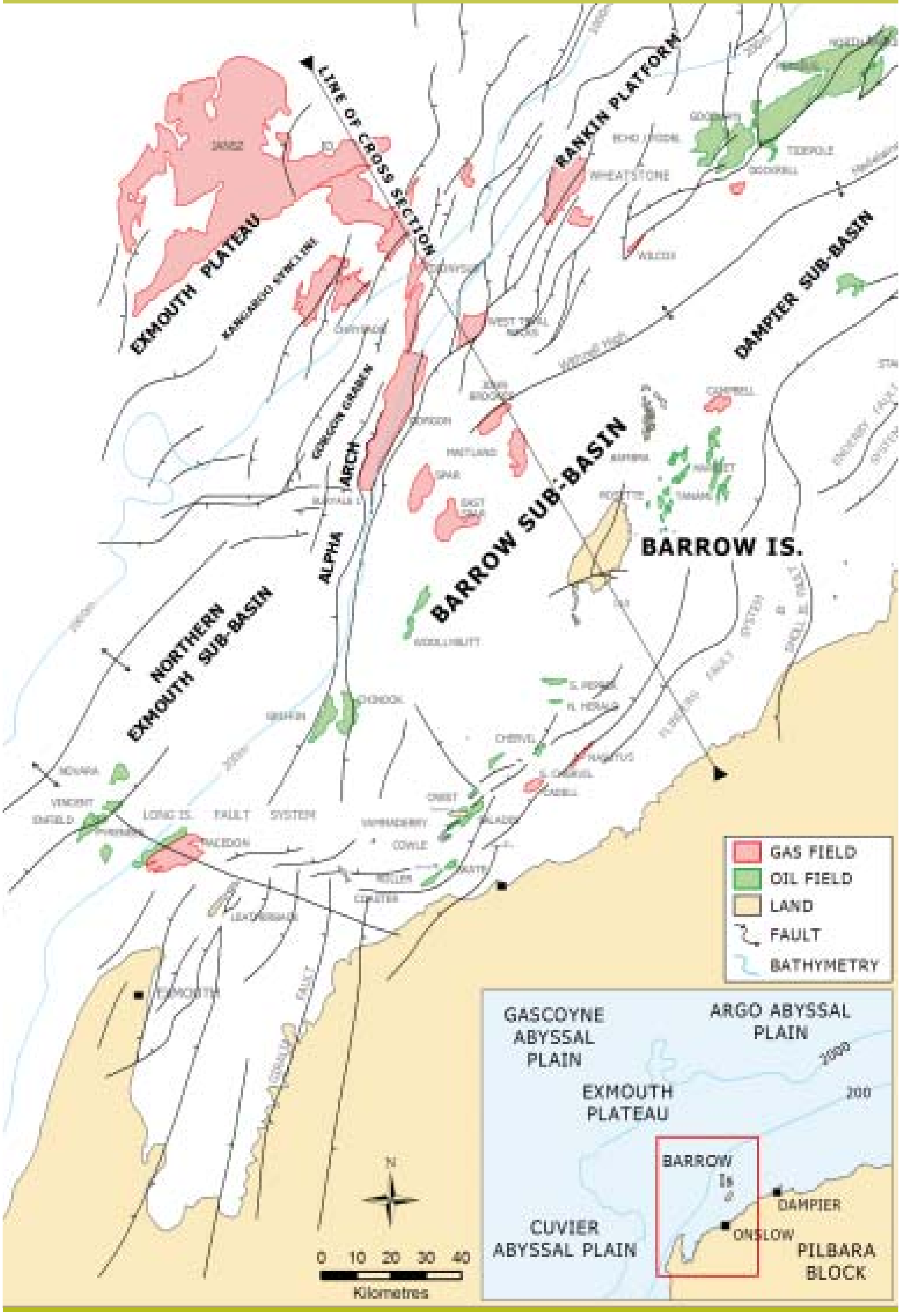


Figure 13-16:
Barrow Sub-basin Regional Cross-Section

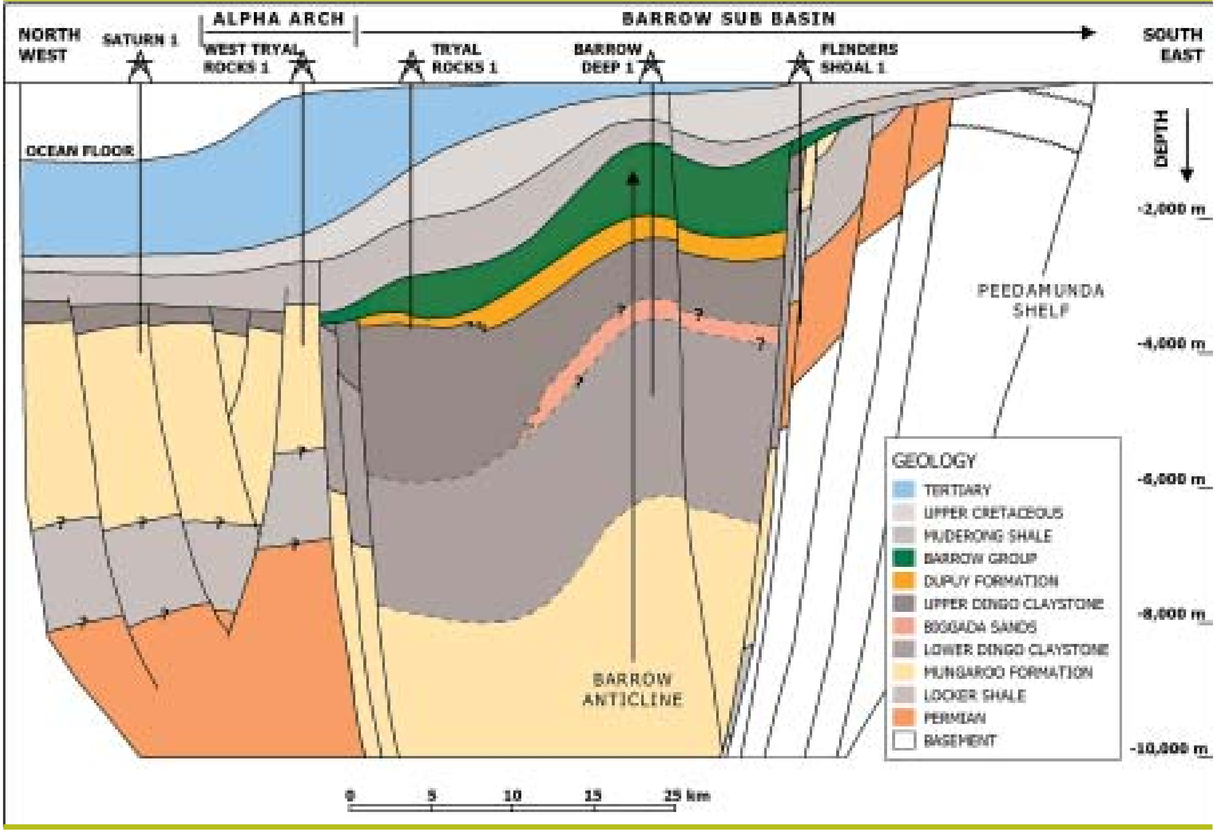


Figure 13-17:
North-South Cross-Section through Barrow Island

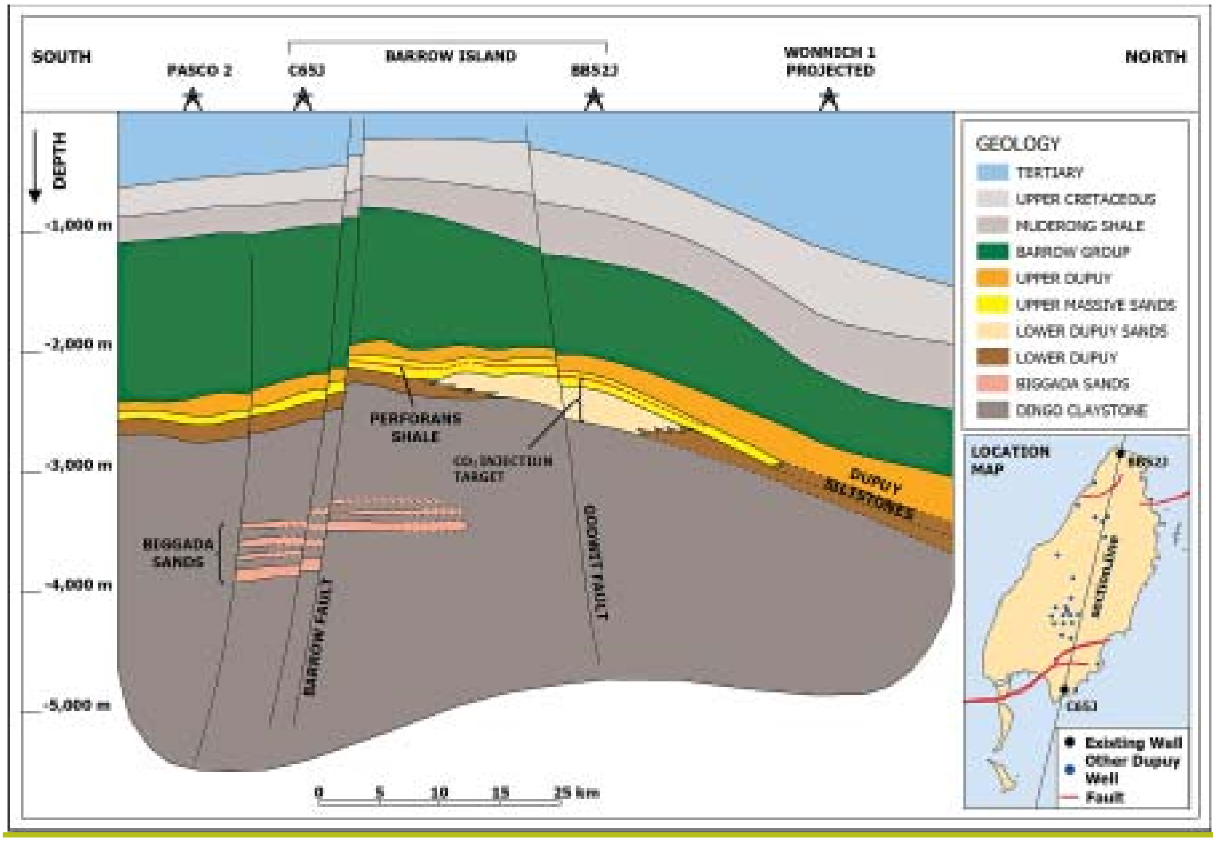


Figure 13-18:
North-West South-East Cross-Section through Barrow Island

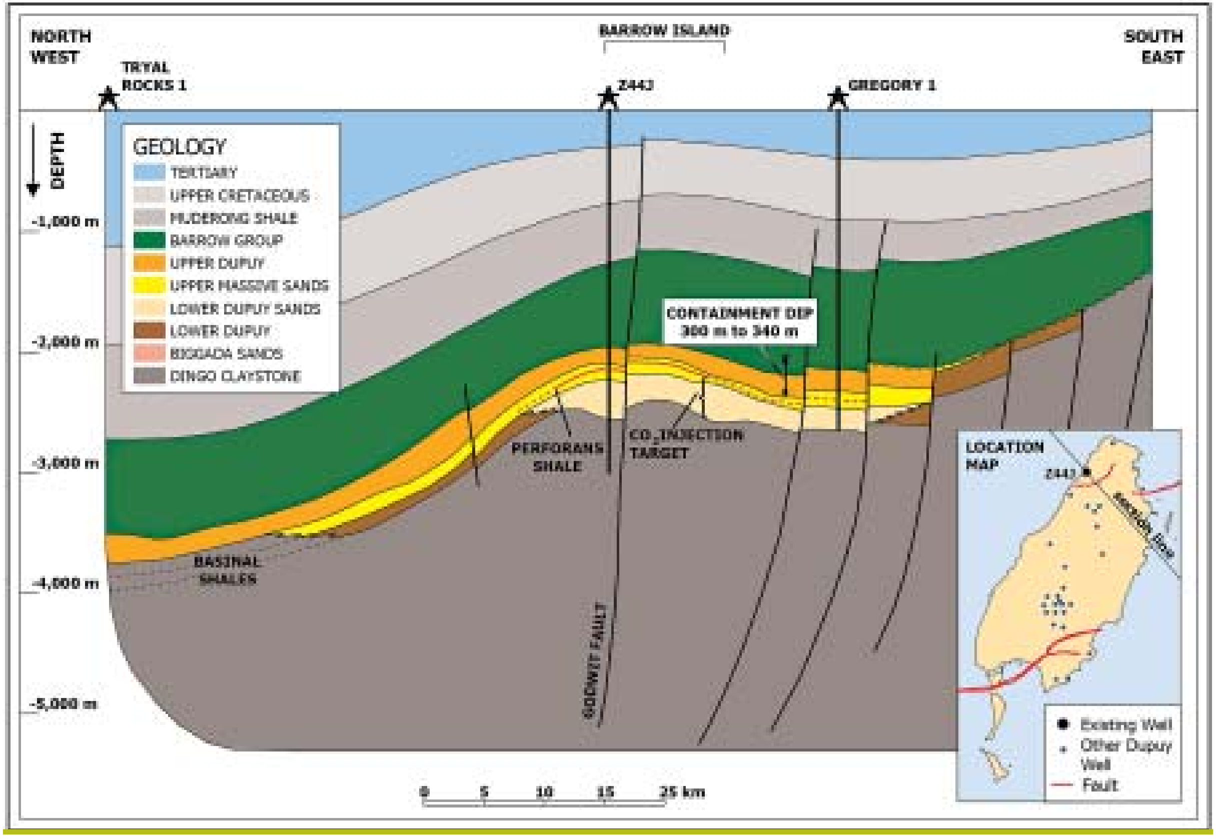
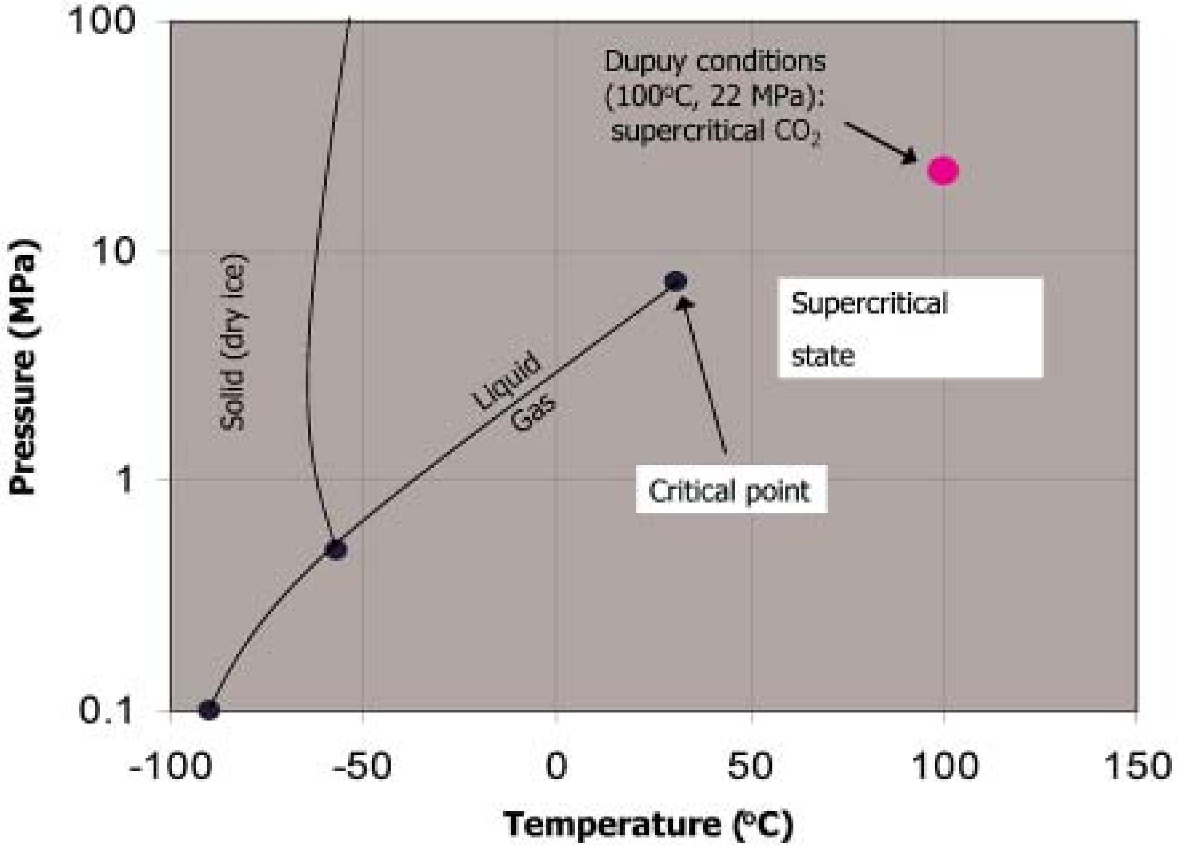


Figure 13-19:
CO_2 Phase Diagram



Solution Trapping

In its natural state the pore space within the formation contains saline water, often referred to as formation water. The migration of CO_2 under either the pressure of injection, or by buoyancy forces following injection will bring the injected CO_2 into contact with this formation water, enabling the CO_2 to dissolve into the water until the water becomes saturated with CO_2.

Figure 13-20 shows typical sandstone within the lower Dupuy Formation prior to the injection of CO_2. A thin layer of formation water is bound to the sand grains and clay platelets by the force of surface tension. The remainder of the pore space is occupied by formation water that is able to migrate through the formation. Figure 13-21 shows the predicted dissolution of the injected CO_2 into the formation water contained in the pore space.

It is anticipated that 10 to 20% of the total CO_2 injected will be trapped in solution during the injection period. Following the injection period, the CO_2 will continue to be trapped as it migrates and contacts unsaturated formation water. The resulting saturated formation water will be slightly denser (1% denser) than the unsaturated water and there will be a tendency for it to sink very slowly through the formation. This mechanism is expected to create convection whereby the dense saturated formation water sinks to the bottom of the formation, displacing unsaturated formation water into the upper parts of the formation. The remaining CO_2 then dissolves in the unsaturated formation water. In the longer term (thousands to hundreds of thousands of years) all of the CO_2 will dissolve in the saline formation waters by this process.

Residual Gas Trapping

During the injection phase, some of the formation water will be displaced by the injected CO_2 with the remainder adhering to the rock minerals due to surface tension. The portion of water that will remain in the pore space is termed the 'residual' or 'irreducible water saturation'. This is a function of the surface tension between the rock minerals and the formation fluids and the size of the pore spaces. The residual saturation around the injection wells is estimated to be between 20% and 40%. That is, between 20% and 40% of the original formation water will remain bound to the rock minerals by surface tension. Some of the injected CO_2 will dissolve in the residual water until that water becomes saturated.

As the CO_2 migrates through the reservoir, small droplets of supercritical CO_2 will also become trapped within the pore spaces by the surface tension between the formation water and the CO_2. This is shown diagrammatically in Figure 13-22. The mechanisms of residual trapping are well understood by the oil and gas industry as this is the primary control on ultimate recovery from oil and gas field operations. The amount of CO_2 trapped by this method is a function of the physical properties of the rock, the formation water and the injected CO_2. It is anticipated that residual gas saturations of approximately 20% will be achieved in the Dupuy Formation. That is, about 20% of the pore space through which the CO_2 has migrated will contain trapped CO_2. If the migration path is long enough, all the CO_2 will become immobilised by residual gas trapping and ultimately by dissolution into the formation water.

Residual gas trapping is a very significant mechanism for immobilising CO_2 and will likely be the dominant trapping mechanism during the first several thousand years following injection. In the longer term the CO_2 trapped by residual gas trapping will dissolve into the formation waters as unsaturated formation water migrates past the trapped CO_2 by the convection process discussed above.

Mineralogical Trapping

As the injected CO_2 dissolves into the formation water, it will produce a weak acid (carbonic acid) which can react with the minerals in the host rock. Some reactions can result in the precipitation of minerals in the formation pore space, which will effectively trap the injected CO_2. The geochemistry of CO_2 in the subsurface is an area of ongoing research but it is generally accepted that the reactions which will permanently trap the CO_2 will occur at very slow rates. The Gorgon Joint Venturers have assumed, for the purpose of reservoir simulation modelling, that this mechanism will not trap a substantive volume of CO_2 during the first 1000 years. However over tens of thousands of years, up to 10% of the injected CO_2 could be trapped by this mechanism in addition to that trapped by the mechanisms described above.

Figure 13-20:
Pre-Injection Distribution of Fluids within the Reservoir

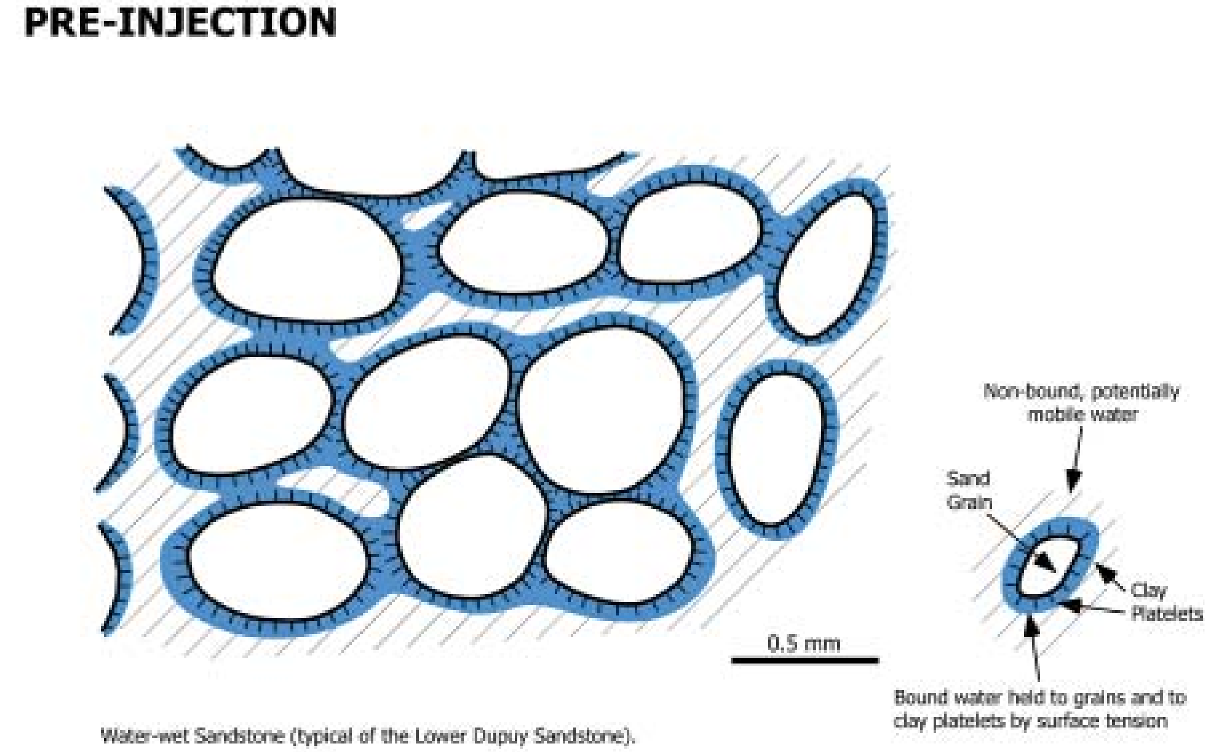


Figure 13-21:
Dissolution of Injected Fluid into the Formation Water

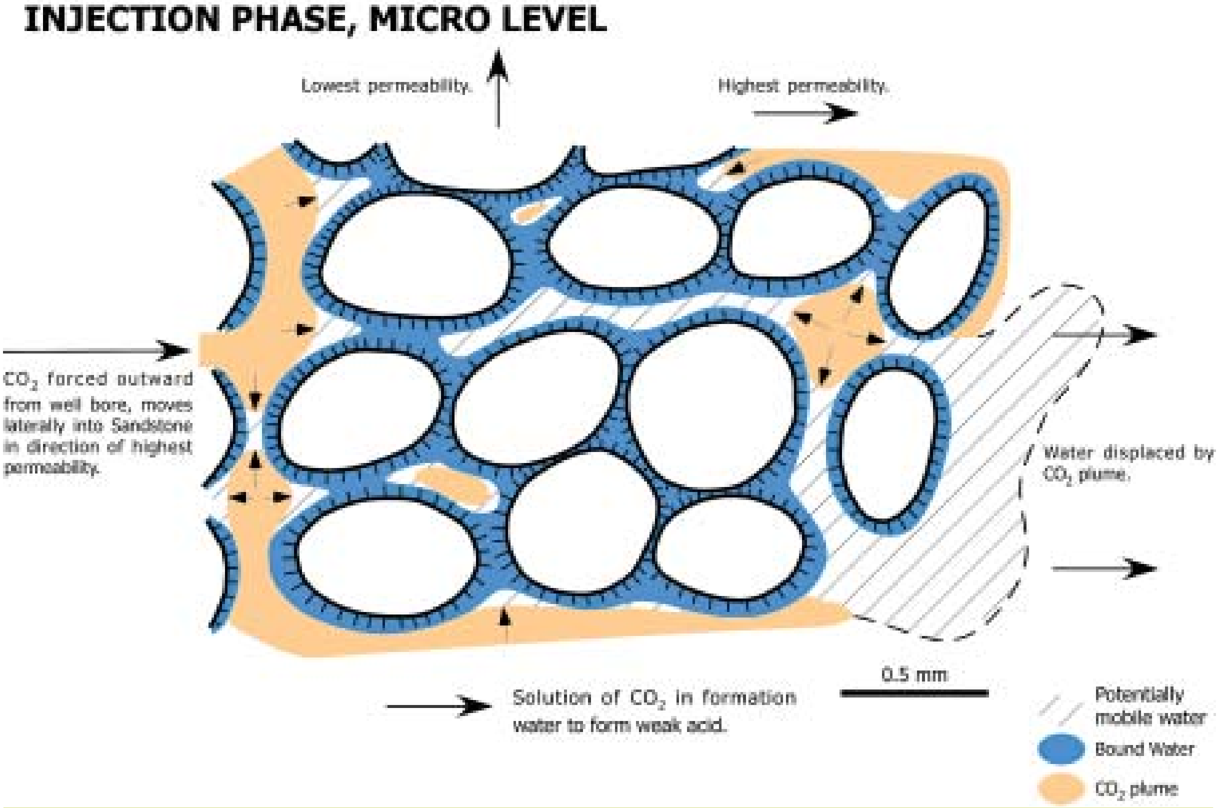
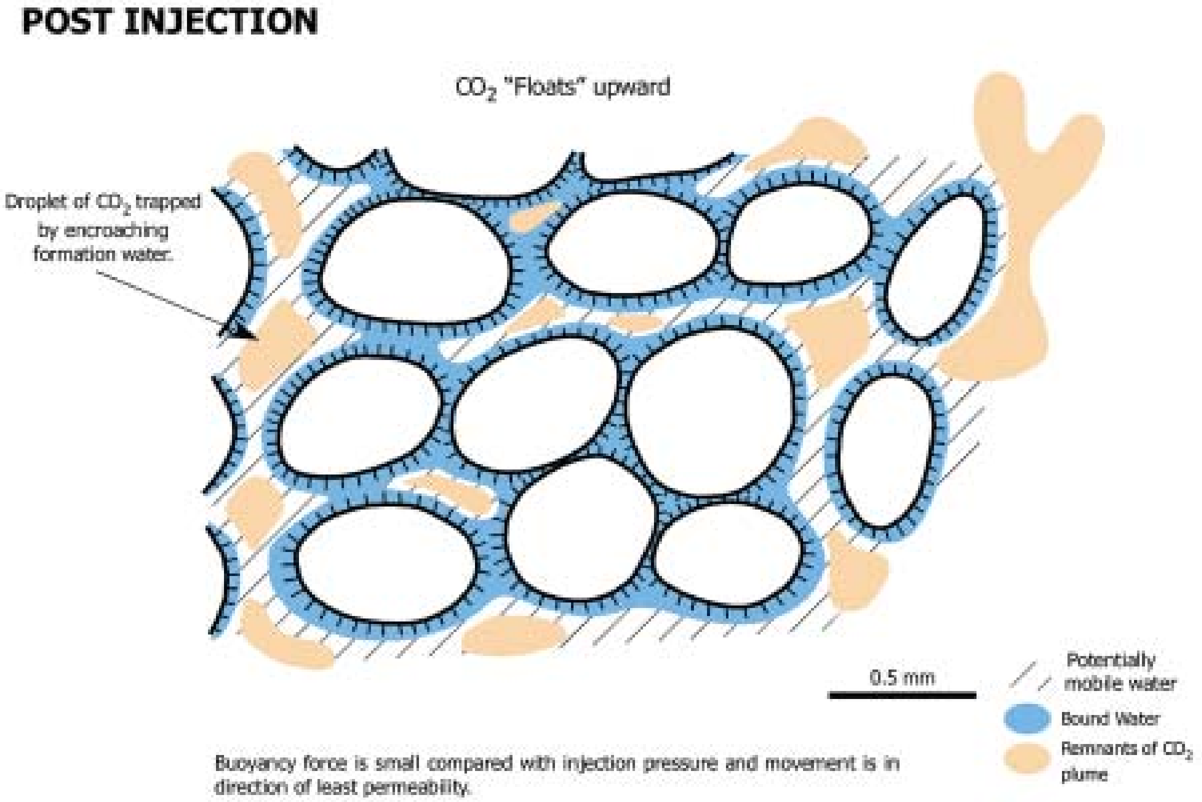


Figure 13-22:
Residual Gas Trapping of CO_2 Droplets



Large-scale Geometric Trapping

As is the case for conventional oil and gas fields, migrating CO_2 will become trapped in conventional underground traps in which an impervious barrier overlies or surrounds a body of permeable rock in all up-dip and lateral directions. The most easily envisaged trap type is a structure in which the shape of the barrier approximates that of an inverted saucer. Mapping from the existing seismic data set indicates that there are few conventional geometric traps at the Dupuy Formation level and those which can be mapped are small. This process is shown diagrammatically in Figure 13-23.

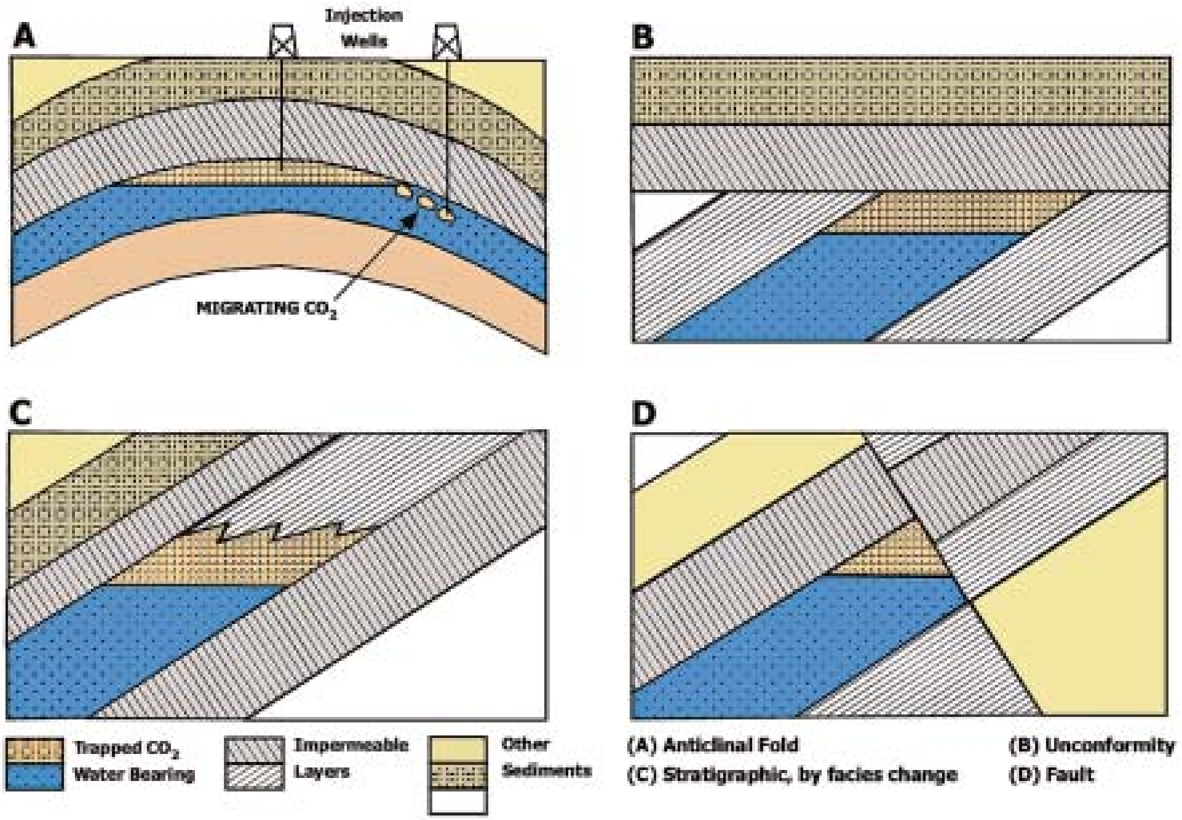
Injectivity/Tortuosity Compromise

Injectivity is a measure of how much CO_2 can be injected as a function of the injection pressure. The higher the 'injectivity', the less injection effort will be required, resulting in savings on injection equipment and injection wells. Tortuosity is a measure of how complex the migration path is through a particular reservoir: the more complex the migration path, the greater the ability for the trapping mechanisms (discussed above) to take effect. While it is not possible to alter the tortuosity of a reservoir, injectivity can be managed through investment in additional equipment, injection wells and well stimulation. Any disposal location represents a compromise between the requirements of having high injectivity and a tortuous migration path.

The Dupuy Formation provides an ideal balance between well injectivity and tortuosity. The Dupuy Formation is a tortuous system with relatively low permeability with many baffles and barriers (the impact of which is discussed below). This is anticipated to result in higher effective trapping rates but at a penalty of increased cost.

One of the major uncertainties with the choice of the Dupuy Formation sandstones as the primary disposal target lies in the injectivity of the sands. Much of the data about injectivity is from cores that are relatively old and subject to degradation. In order to reduce this uncertainty, it is proposed to drill a well to obtain additional data in the second half of 2005.

Figure 13-23:
Geometric Trapping of Injected CO_2



Baffles and Barriers

All hydrocarbon seals (the rock over the top of a hydrocarbon accumulation) will allow the very slow migration of hydrocarbon molecules into or, in some cases, through them over millions to hundreds of millions of years. Throughout the world, the hydrocarbon content of seals steadily increases downward to the oil or gas accumulation.
This demonstrates that the more mobile fractions of that accumulation have been able to move very slowly upwards through the seal over time.

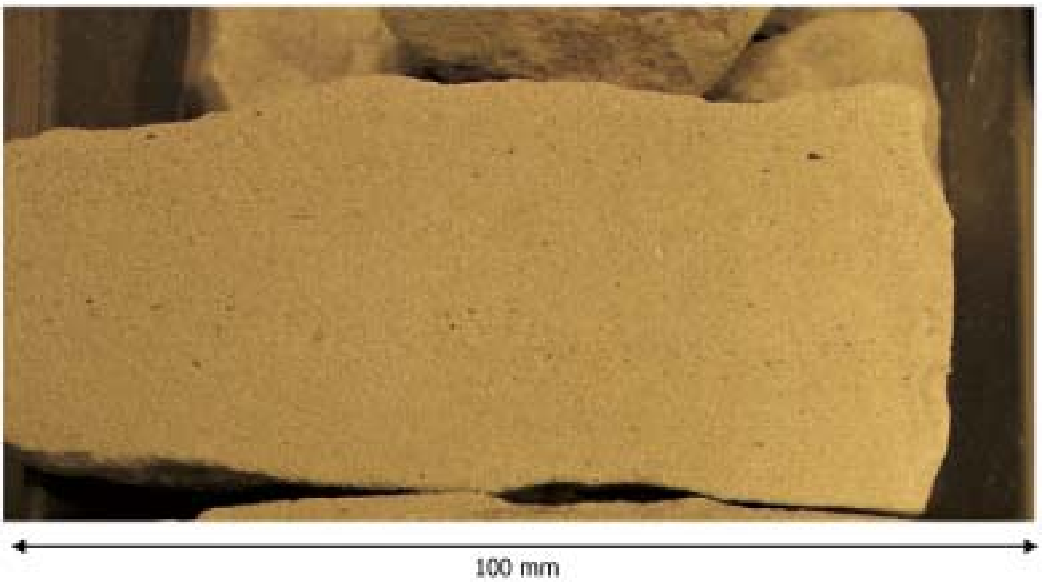
The rate of vertical migration is equally important in considering the underground disposal of CO_2 but the difference is that time scales are much shorter: tens of years for the active injection of the CO_2 and perhaps thousands of years to allow for complete immobilisation through dissolution, reaction, residual gas and large scale entrapment. Consequently, fine-grained intervals such as siltstones, which cannot be considered seals in the sense of being able to hold back hydrocarbons over millions of years, can function as effective baffles or barriers in the time scale of a CO_2 injection project. In this Draft EIS/ERMP 'barriers' are considered to be layers of rock which have sufficient areal extent to provide a major and predictable block to the upward movement of CO_2 over thousands of years during which the trapping mechanisms, discussed above, will permanently immobilise the CO_2. The term 'baffle' is used to describe layers of rock which are very slightly permeable to CO_2 over this time scale and/or lack sufficient predictable areal extent to constitute an identifiable barrier. Baffles impose tortuosity on the migration of the CO_2 plume, increasing the potential for the CO_2 to become trapped prior to reaching the major barriers.

Researchers at the Lawrence Berkley National Laboratory have attempted to quantify the rates at which CO_2 could migrate through a single barrier (Benson 2004). This work indicates that such migration would result in a CO_2 flux rate (a measure of the rate of leakage) of generally less than one micromole/m^2/sec. This compares with a range of naturally occurring ecosystem flux rates of between 2 and 20 micromole/m^2/sec indicating that leakage through a single barrier would be at a rate that would not be detectable against a normal background flux. It should be noted that there are multiple barriers between the proposed CO_2 injection reservoir in the Dupuy Formation and the surface.

Figure 13-24 shows photographs from cores obtained in the Dupuy Formation upper massive sand, the upper Dupuy Formation and the basal Barrow Group. The core from the Dupuy Formation upper massive sand shows very few internal barriers. This will enable the

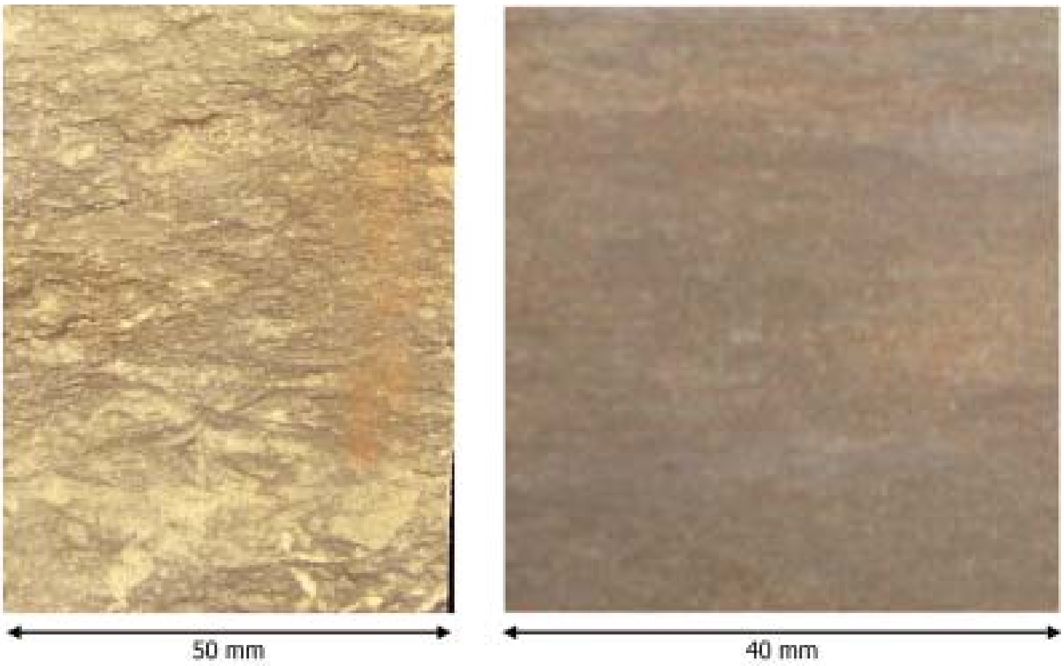
Figure 13-24:
Cores of the Dupuy Formation Upper Massive Sand, Upper Dupuy Formation and the Basal Barrow Group Shale

SANDSTONE
(Dupuy Formation Upper Massive Sand)



BIOTURBATED SILTSTONE
(Upper Dupuy Formation)

SHALE
(Basal Barrow Group Shale)



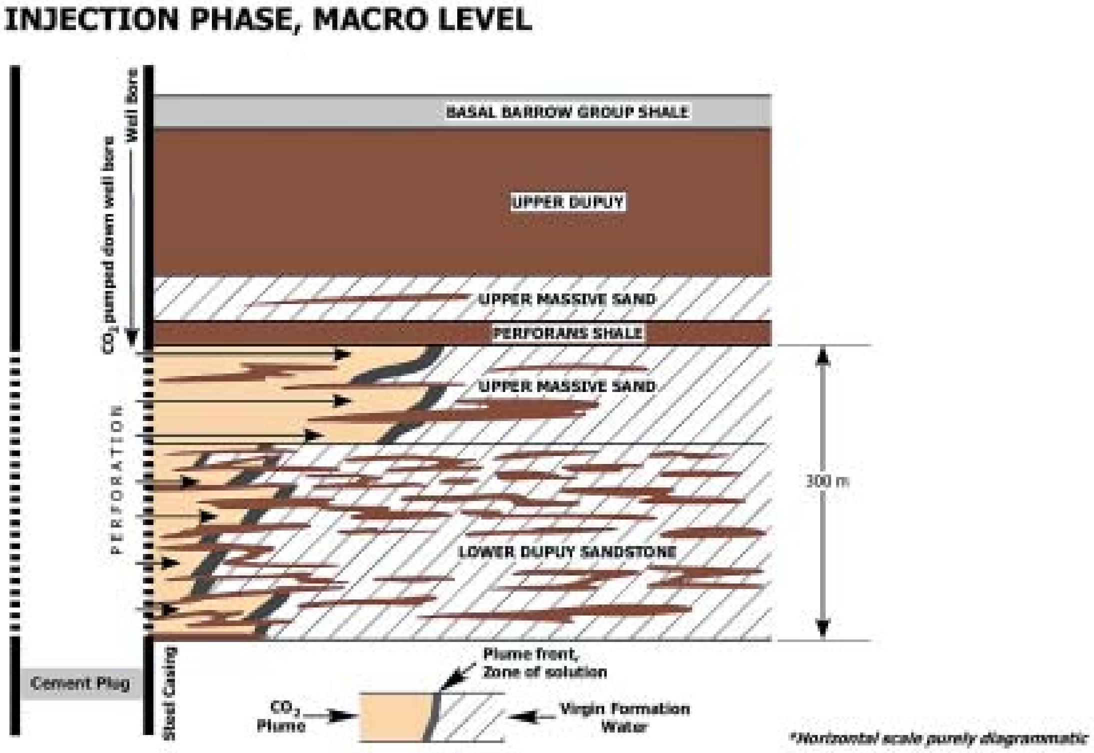
CO_2 to migrate relatively freely through the formation. The core from the upper Dupuy Formation shows low permeability, finely bedded siltstone which has been thoroughly disrupted (bioturbated) as it was being deposited by the action of burrowing organisms such as worms. Although the upper Dupuy Formation is aerially extensive, it can be considered as a baffle to migration of CO_2 because it is slightly permeable to CO_2 migration. The thickness of this unit (approximately 150 m) and the tortuous migration path will significantly reduce the rate of vertical migration and facilitate the trapping of CO_2. The basal Barrow Group shale is a marine shale and represents an effective barrier to vertical migration of CO_2.

The predicted distribution of baffles, barriers and seals in relation to the migration of the CO_2 plume after 40 years of injection is shown diagrammatically in Figure 13-25.

Further evidence for the effectiveness of the basal Barrow Group shale as a barrier to fluid migration is provided by the salinity contrast that exists between the formation waters in the Dupuy Formation and the Barrow Group. Water recovered from the Dupuy Formation has salinities between 4000 and 7000 ppm (total dissolved solids) which is much lower than the water recovered from the overlying lower Barrow Group where salinities range from 16 000 to 20 000 ppm. Waters recovered from sands higher in the Barrow Group have salinities ranging from 30 000 to 35 000 ppm. For reference, sea water has salinities between 30 000 to 35 000 ppm. The existence of this salinity contrast indicates either an effective seal or a very slow rate of formation water diffusion through the base Barrow Group shale. The effectiveness of the basal Barrow Group shale is also reinforced by a pressure differential between the Dupuy Formation and the Barrow Group. These pressure data are interpreted to show limited pressure communication over the 40 years of hydrocarbon production in the Barrow Sub-basin. Both the salinity and the pressure data provide evidence of the effectiveness of the base Barrow Group shale as a barrier to the vertical migration of CO_2.

In the unlikely event that CO_2 migrates through the basal Barrow Group shale into the overlying sands in the Barrow Group, it would migrate through the lower Barrow Group marine shales. These shales have an average thickness of 160 m and provide a further tortuous path and potential for trapping of the CO_2. The ability to correlate these shales over large distances is limited so they are best described as baffles.

Figure 13-25:
Relationship of the CO_2 Plume After 40-Years of Migration and Baffles, Barriers and Seals



The Barrow group is overlain by the Muderong Shale, which has proven sealing capacity, as shown by the 400–700 m columns of natural gas which it traps in the Carnarvon Basin. Any CO_2 which breached the Muderong Shale would then encounter the Windalia Radiolarite and Gearle Siltstone. For any of the injected CO_2 to reach the surface it must first pass through these baffles and barriers while not being trapped by the mechanisms identified earlier.

Operational Phase

When predicting the behaviour of the CO_2 in the subsurface there are two distinct phases to be considered: the operational or injection phase; and the period after injection ceases or the post operational phase.

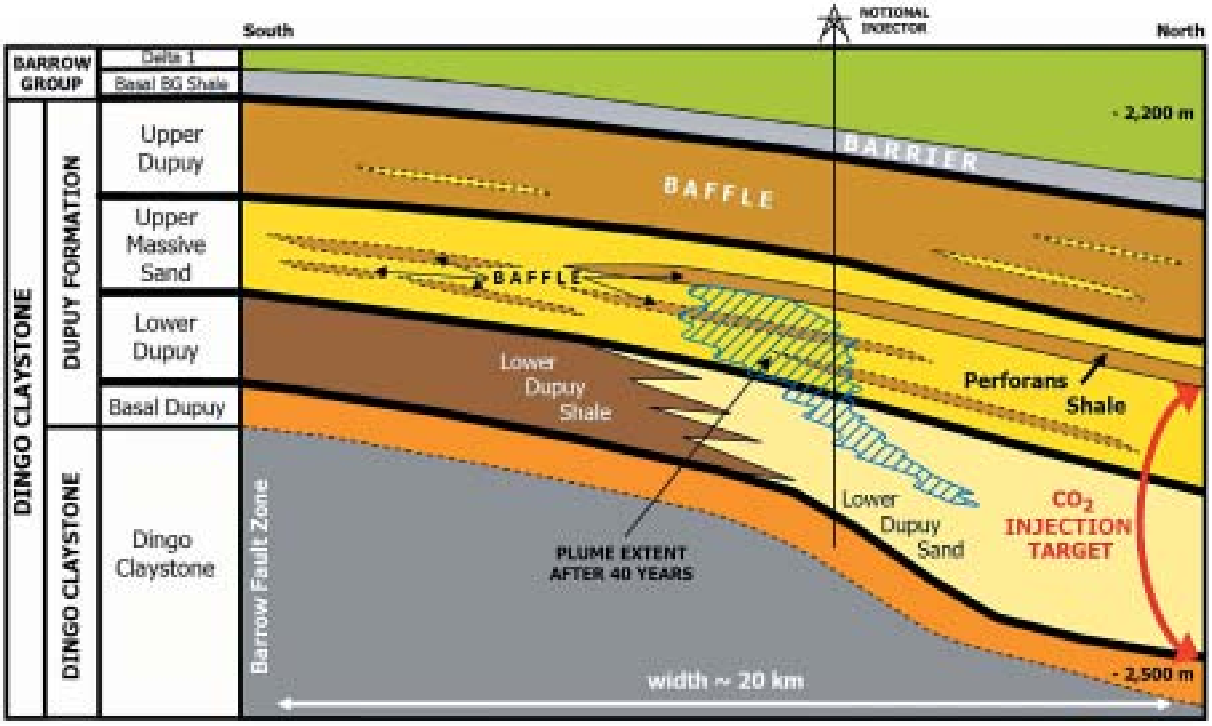
Modelling by the Gorgon Joint Venturers shows that during the operational phase, the CO_2 will initially move out from the well bore as a discrete plume, driven by the injection pressure. This is shown diagrammatically in Figure 13-26. The migration of the CO_2 during the operational phase is a function of the injection pressure and the permeability of the various layers in the reservoir. The CO_2 will migrate more rapidly in the high permeability layers. As the plume moves further away from the injector well, the injection pressure will dissipate and the rate of migration will slow. At this point, the CO_2 plume will migrate under buoyancy forces where the migration path is determined by the dip and heterogeneity of the reservoir. During the injection period, some of the CO_2 will be forced down dip against the force of buoyancy for a lateral distance of up to 2 km.

As the CO_2 migrates during the injection phase a portion of the injected CO_2 will become trapped in the formation by the solution and residual gas trapping mechanism discussed above.

Post Operational Phase

Once injection ceases, the injection pressures will rapidly dissipate and the buoyancy contrast between the CO_2 and the formation water will be the driving force for migration of the remaining CO_2. As a result, the rate of lateral CO_2 migration will dramatically reduce and the CO_2 will tend to migrate upwards with vertical movement being restricted by the baffles and barriers in the system. The rate of migration will be determined by the tortuosity of the formation with a large proportion of the CO_2 plume anticipated to be trapped by residual gas trapping in the low permeability layers in the upper Dupuy Formation. The post injection phase will see that part of the CO_2 plume which has been forced down-dip

Figure 13-26:
Predicted Migration of CO_2 Plume through Layers in the Dupuy Formation During the Operational Phase



under the injection pressure; respond to buoyancy and move back up-dip.

There will be further dissolution of CO_2 in the formation waters during the post operational phase as the migrating CO_2 plume contacts virgin formation water. Potentially an additional 35% of the injected CO_2 will dissolve over the first 1000 years.

Ultimately the CO_2 plume will continue to migrate until it is trapped by the mechanisms discussed earlier.

13.4.5 Reservoir Simulation

The technique used to mathematically model the behaviour of fluids in the subsurface is termed ‘reservoir simulation’. Reservoir simulation of oil and gas accumulations has been used for many years to predict the performance of oil and gas fields and provides a powerful tool to assist in management of oil and gas field development. Simulation is now used routinely to assist in the decision to develop a particular field and in the continual management of the field’s performance. Regulatory authorities accept reservoir simulation as a key tool in assessing oil and gas field development applications and as a guide to assessing performance in producing the resource once production commences. This tool has been applied to predict the behaviour of CO_2 that is to be injected.

The behaviour of CO_2 in the subsurface is similar to that of oil and gas enabling reservoir simulators developed for the oil and gas industry to be used to predict the behaviour of CO_2. Minor modifications to the oil and gas simulation models have been made in order to accommodate:

- the solubility of CO_2 in aquifer waters
- the density and viscosity of CO_2 in the supercritical state
- the timeframe over which the CO_2 plume dissipates once injection ceases.

The database from which the Dupuy Formation reservoir description has been derived contains seismic coverage and 27 wells which intersect the Dupuy Formation. Core coverage in most of these wells is restricted to the upper part of the Dupuy Formation, but direct measurement of reservoir permeability over the remaining sections has been obtained during well testing. Well testing involves the flowing of formation fluids and the recording of pressures, both while the well is flowing and once the well has been shut-in. Analysis of these pressures enables the permeability of the tested zone to be calculated. The permeability calculated from intervals that have been tested is within the range of permeability indicated by the core. This data will be supplemented by a data well which is planned to be drilled in 2005. It is planned to core the entire section from the basal Barrow Group through to the base of the lower Dupuy Formation in the data well. This well will be sited in the area of intended injection so that the data gathered will have direct application to the reservoir model.

Reservoir simulations not only predict the movement of the CO_2 plume but also describe the pressure changes occurring within the formation. Pressure changes will be transmitted far more rapidly and more widely than will the CO_2 plume. Care was taken in the modelling process to monitor the pressure increases which might be transmitted to the major faults as a result of a particular injection scenario. This is because faults are seen as potential migration pathways in the various barrier/baffle units above the CO_2 plume.

The reservoir simulation model will be regularly updated with:

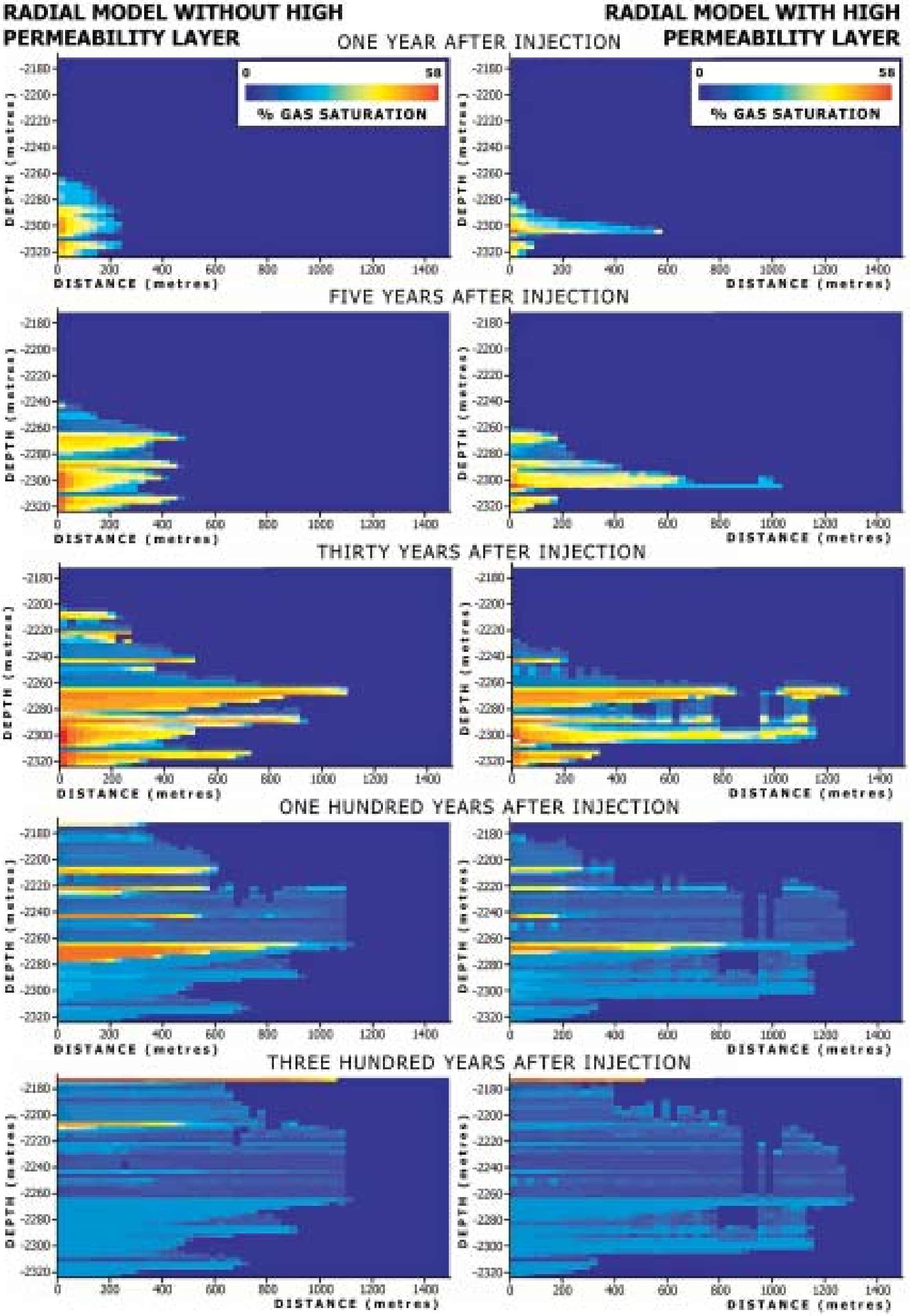
- extensive core data collected from the data well, planned to be drilled in 2005
- data obtained during the drilling of the injection and observation wells
- injection history from the injection wells
- pressure data from the observation wells
- data from the seismic and other monitoring programs.

Updating and validating of reservoir simulation models with data from the monitoring program is a primary activity in the Carbon Dioxide Injection Operations Management Plan. This management plan is discussed further in Section 13.4.8.

Single Injection Well Simulation

Figure 13-27 shows a single well model which highlights the effect of injection into a number of sandstone layers within the Dupuy Formation.
The model predicts a gradual advance of the CO_2 plume dominantly along the higher permeability layers and to a lesser degree, upwards during the injection period. Following injection, the buoyancy effect will be dominant with the CO_2 plume migrating vertically.
A 30-year injection period has been assumed in this particular model.

Figure 13-27:
Single Well Injection Model



The Gorgon Joint Venturers have investigated the possibility that if there was a layer in the Dupuy Formation with anomalously high permeability, it may cause the CO_2 plume to migrate greater distances than indicated by the reservoir simulation. In order to understand this potential impact, a model was run based on the assumption that one of the layers had permeability which was 10 times higher than those anticipated. The output from this model is also shown on the right-hand side of Figure 13-27. The initial impact of the higher than anticipated permeability is significant as the CO_2 plume migrates further along the layers in the reservoir. However by year 30, at the end of the modelled injection phase, the distance the CO_2 plume has migrated is similar to that in the base model. In addition, the behaviour of the CO_2 plume in the following 300 years is similar between the two models with the CO_2 plume only having migrated slightly further in the high permeability case. In this example, the extent of CO_2 migration is relatively insensitive to the presence of an anomalously high permeability layer in the reservoir.

Full Reservoir Simulation

Migration of the Carbon Dioxide Plume

The full reservoir simulation is based on an injection pattern with seven wells at the central east coast area of Barrow Island. The simulation predicts the migration and trapping of the CO_2 plume over a 1000 year period. The simulation is based on injection into the interval below the Perforans Shale for a period of 40 years and provides output in both cross-section form and map view. The production of reservoir CO_2 reduces significantly after 40 years. A typical series of cross-sectional outputs from the simulation are shown in Figure 13-28. Part A of Figure 13-28 shows a map of Barrow Island, the extent of the CO_2 plume and the location of the cross-sectional outputs from the reservoir simulation. Part B of Figure 13-28 shows an expanded cross section of the Dupuy Formation reflected in the cross-sectional outputs from the simulation. The series of six cross-cross sectional outputs in Figure 13-28 show the migration of the CO_2 plume through the Dupuy Formation over the injection period and for the next 1000 years. The cross-sectional outputs represent the Dupuy Formation with the upper boundary being marked by the base Barrow Group Shale over 2000 m below the surface of Barrow Island. During the injection period, the simulation predicts that the CO_2 plume will migrate along the higher permeability layers at a rate determined by the permeability within each layer. Most of the CO_2 will be contained within the higher quality upper massive sandstone below the Perforans Shale, while relatively little CO_2 will be contained in the poorer sands of the lower Dupuy Formation. In the 1000-year period following injection, migration will be dominated by vertical buoyancy forces with the CO_2 plume migrating slowly through the Perforans Shale and into the upper Dupuy Formation. In the 1000 year cross section, the lighter grey colours represent areas where the injected CO_2 has effectively become trapped by the mechanisms described in 13.4.4.

The upper Dupuy Formation is of similarly low permeability to the Perforans Shale, but 10 times the thickness. The model shows that over the 1000-year period, most of the CO_2 plume will become trapped within the Dupuy Formation. The remainder of the injected CO_2 will be prevented from migrating vertically by the basal Barrow Group shale.

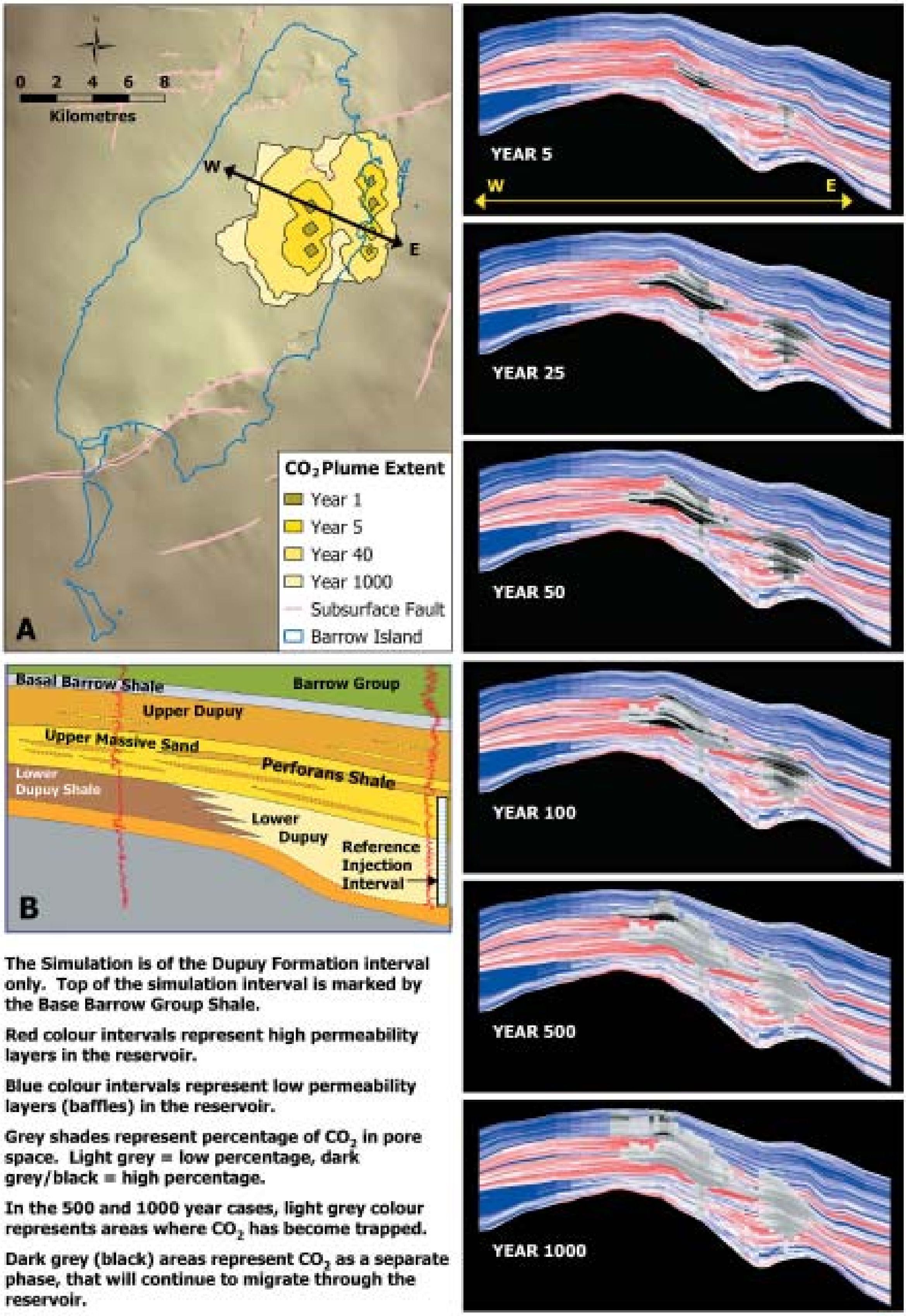
Pressure Field

In addition to predicting CO_2 saturation throughout the reservoir, the simulation model predicts pressure increases resulting from the injection process. Understanding reservoir pressure behaviour is a powerful management tool as pressure changes travel faster and further in the reservoir than the injected fluids. This enables pressure readings to be used to monitor the migration of the CO_2 plume in advance of its physical arrival.

Knowledge of the changes to the pressure field attributable to injection is significant for two reasons: excessive pressure increases can cause faults to leak and can fracture seals; and information on the performance of the reservoir can be used to calibrate reservoir simulation models.

Simulation studies have been undertaken to understand the potential increase in pressures within the Dupuy Formation as a result of the planned CO_2 injection. Simulations show the pressure at the main Barrow Fault will reach its peak after approximately 30 years of injection. Ongoing studies will determine an appropriate pressure that could be sustained at the main Barrow Fault. If the pressure at the fault is anticipated to approach this level, the Joint Venturers plan to drill a pressure relief well (or wells) to produce water from the Dupuy Formation and re-inject it into the lower Barrow Group. The pressure-relief well will be sited so that it produces water uncontaminated by the encroaching

Figure 13-28:
Reservoir Simulation Based on the Preferred Injection Scenario and Showing the Extent of the CO_2 Plume Over 1000 Years



The Simulation is of the Dupuy Formation interval only. Top of the simulation interval is marked by the Base Barrow Group Shale.

Red colour intervals represent high permeability layers in the reservoir.

Blue colour intervals represent low permeability layers (baffles) in the reservoir.

Grey shades represent percentage of CO_2 in pore space. Light grey = low percentage, dark grey/black = high percentage.

In the 500 and 1000 year cases, light grey colour represents areas where CO_2 has become trapped.

Dark grey (black) areas represent CO_2 as a separate phase, that will continue to migrate through the reservoir.

CO_2. In the area around Barrow Island, the Barrow Group has been pressure depleted by over 40 years of hydrocarbon production. Injection of Dupuy Formation water into the Barrow Group is not anticipated to result in formation pressures in the Barrow Group that are greater than that present prior to the commencement of hydrocarbon production operations.

Displaced Formation Water

The volume of the pores in the Dupuy Formation into which the CO_2 will be injected is several hundred times larger than the volume of CO_2 to be injected. As the CO_2 is injected, it will partially dissolve in the formation water with the remainder occupying pore spaces which previously contained formation water. As the rock minerals and formation water are only slightly compressible, the reservoir pressure will increase.

Modelling by the Gorgon Joint Venturers indicates that the average pressure in the Dupuy Formation would increase by approximately 1.4 MPa if the Dupuy Formation was totally isolated from the surrounding formations. However total hydraulic isolation of any formation is rare and some movement of formation water between formations is expected. This should limit the overall pressure increase in the Dupuy Formation.

The formation water will move from areas of high pressure to areas of lower pressure along any permeable pathway. It is likely that some of the major faults in the Barrow Sub-basin, such as the Flinders Fault zone or the Barrow Fault, may represent permeable pathways allowing some of the displaced formation water to move into the overlying formations. Since the pressure response travels much further in the reservoir than the CO_2 plume, the formation water will be displaced in areas distant to the injected CO_2.

As discussed earlier, 40 years of hydrocarbon production operations have reduced the pressure in the overlying Barrow Group. Therefore it is reasonable to expect that the displaced formation waters will move preferentially into this formation.

13.4.6 Deviations from Simulation Predictions

Reservoir simulation is a powerful tool for predicting the behaviour of fluids in the subsurface but is restricted by the data available to be input into the models. As a routine part of any reservoir simulation study a sensitivity analysis was undertaken in order to understand the impact of events which might lead to deviations from the model predictions. In understanding the behaviour of the injected CO_2, the Gorgon Joint Venturers determined that the conditions that could lead to deviations from the model predictions are:

- the presence of high permeability layers in the reservoir
- down dip migration
- leakage through existing wells
- faults and fractures.

Each of these conditions, as it relates to the reservoir simulation predictions, are discussed below.

High Permeability Layers

Layers of unexpectedly high permeability may result in more rapid and extensive migration of the CO_2 plume. As discussed in Section 13.4.5, the impact of high permeably layers on the migration of the injected CO_2 is most apparent during the initial injection phase. After approximately 30 years the impact of the high permeability layer on the migration of the CO_2 plume is likely to be low. Additionally, if such a layer were present, it would be readily detected by the performance of the injection wells. If it was determined that the layer was adversely affecting the migration of the CO_2 plume then remediation actions such as those described in section 13.4.8 would be undertaken.

Down Dip Migration

Concern has been raised by oil and gas field operators in the Barrow Sub-basin that the CO_2 plume will migrate ‘down dip’ and possibly affect operations to the east and north of Barrow Island. Down dip migration will occur during the injection or operational phase because the injection pressure will override the vertically upward force of buoyancy. The location of injection wells will be chosen carefully to minimise the possibility of migration into oil and gas fields down dip of Barrow Island. The reservoir simulation shows that the amount of down dip, lateral migration of the CO_2 plume will be limited to about 2 km.

The Gorgon Joint Venturers’ simulation scenarios have shown that down dip migration to the point where it could interfere with these oil and gas field operations is very unlikely. If such migration was detected, then remediation actions such as those discussed in Section 13.4.8 would be taken to redirect the CO_2 plume.

Existing Wells

Experience from CO_2 injection operations (refer to Box 13-2) indicates that existing well bores pose the greatest risk as conduits for upward migration of CO_2. Section 13.4.8 includes information on the proposed management of existing well penetrations.

Faults and Fractures

Fault planes can be conduits for migrating fluids because the rock along the fault plane can be crushed and pore space (and permeability) is created in the process. Sulphur deposits in claypans along the Barrow Fault scarp provide evidence that there has been natural fluid movement up the Barrow Fault and to the surface over the recent geologic past. However, the Barrow Fault currently seals the 285 million kilolitre Windalia oil accumulation, providing a lateral and vertical barrier to fluid migration at that level. Geomechanical data suggests some of the main faults (e.g. the Barrow Fault) may leak vertically at the Dupuy Formation level.

A significant source of potential migration pathways, associated with faulting, lies in the juxtaposition of permeable layers on either side of the fault. For example, it is probable that some movement of aquifer fluid may be occurring across the Barrow Fault from the upper Massive Sand on the northern, up-thrown side of the fault to sands of the basal Barrow Group on the southern, down-thrown side.

Researchers at the Lawrence Berkley National Laboratory (Benson 2004) have attempted to quantify the rates at which CO_2 could leak from a range of simulated faults and fractures. This work concluded that CO_2 flux rates resulting from migration along faults could be of such magnitude that the increased concentrations of CO_2 would have a detrimental impact on flora, but only within the relatively localised area of the fault, possibly impacting an area of between 1000 m^2 and 100 000 m^2.

The Gorgon Joint Venturers' precautionary approach to managing containment risk requires that the CO_2 plume should not impinge on the main faults (e.g. the Barrow Fault) and that migration near these fault zone should be minimised.

There is the possibility that faults and fractures, which are not conduits for fluid movement under the current pressure and formation fluid regime, might allow for fluid migration under the increased pressures which will be created by the injection of CO_2. Geomechanical studies undertaken by the Gorgon Joint Venturers have estimated that the operational reservoir pressures are unlikely to result in fault leakage. During injection, conservative pressure limitations will be employed to avoid possible fault and seal leaks.

13.4.7 Monitoring of Injected Carbon Dioxide

The Gorgon Joint Venturers continue to study the most appropriate techniques to monitor the injected CO_2. It is likely that these activities will evolve as the behaviour of the CO_2 in the subsurface is verified and as existing technologies improve and new technologies become available. The following section outlines the objectives for the CO_2 monitoring program and how these data will be integrated into the ongoing management of the CO_2 injection operations. Section 6.2.5 of Chapter 6 provides information on the type of seismic monitoring activities likely to be undertaken and Section 10.4.1 of Chapter 10 documents a number of environmental performance standards that will be incorporated into the design and operations of the monitoring programs.

Demonstrating the integrity of a CO_2 injection project through monitoring the behaviour of injected CO_2 will be integral to gaining community support for the subsurface injection of CO_2. Key objectives for the monitoring and verification activities therefore include:

- generating clear, comprehensive, timely and accurate information that will be used to effectively and responsibly manage environmental, health, safety and economic risks and to ensure that set performance standards are being met
- determining, to an appropriate level of accuracy, the quality, composition and location of gas captured, injected and stored and the net abatement of emissions. This should include identification and accounting of fugitive emissions
- demonstrating that the residual risk of leakage is acceptably low at the time of site closure.

In order to fulfil these objectives a range of monitoring activities are planned:

- routine observation and recording of injection rates and surface pressures
- health, environment and safety oriented surveillance to detect surface leaks before they can pose a risk to personnel or the environment
- verification via seismic surveys and/or observation wells of the CO_2 plume migration in the subsurface.

Experience from CO_2 injection operations (discussed in Box 13-2) has shown that a combination of observation wells and time-lapse seismic data provides the best possible means to track the progress of migrating CO_2 through the subsurface.

Seismic monitoring of the CO_2 plume in the subsurface will be supplemented by:

- running conventional wireline logging tools in wells to detect CO_2 migration at wells or leakage up the well bore
- conducting geochemical analyses of formation waters recovered from the Dupuy Formation to understand the dissolution of CO_2 and any chemical reactions taking place.

As in any conventional oil or gas field operation, the collection and evaluation of pressure and flow data provides information on the performance of an operation. It is planned to have continuous remote monitoring of pressure and flow data at a number of points from the CO_2 compressors to the injection wells. These data will be primarily used to: verify the volumes of CO_2 injected; to optimise the injection process; and detect leaks in the surface facilities. In addition, the pressure in each monitoring well will be recorded in order to detect any anomalous injection behaviour.

Reservoir modelling by the Gorgon Joint Venturers indicates that the CO_2 plume will have migrated only about 1 km from the injection wells during the first five years. The migration of the plume during this period and prior to the first repeat seismic survey will be assessed on the performance of the injection wells and the pressure response observed in the injection and observation wells.

Surveillance activities to detect surface leakage will comprise CO_2 detection equipment at locations within the compression and pipeline facilities, at each of the injection and observation wells and on any existing wells in the vicinity of the CO_2 plume. These detectors will be used to identify anomalously high levels of CO_2, which may indicate unplanned release of CO_2 from a well or facility.

As discussed in Section 13.4.5, the reservoir simulation model will be refined based on monitoring data in order to provide detailed predictions of the pressure transient caused by injection. Pressure changes in observation wells will provide a means to check the progress of the CO_2 plume in advance of its physical arrival at an observation well. The arrival of the CO_2 plume at an observation well can be detected by conventional well logging methods.

Monitoring activities will be reviewed on a regular basis with the regulatory agencies. Revisions to the injection operations and the monitoring program will be agreed in response to unpredicted migration or improvements in monitoring technology.

13.4.8 Carbon Dioxide Injection Operations Management Plan

Oil and gas field operations are often managed through a Reservoir Management Plan or an Operations Management Plan, which outlines how a field will be developed. The Gorgon Joint Venturers propose to adopt this process to assist in the management of the CO_2 injection operations. The primary objective of the CO_2 Injection Operations Management Plan will be to maximise the volume of reservoir CO_2 injected whilst ensuring that the injection does not pose a health or safety risk to people, an environmental risk to the conservation values of Barrow Island, or a risk to other assets such as oil or gas field operations around Barrow Island. The Plan will outline the following activities:

- routine injection operations
- objectives and nature of monitoring activities
- integration of monitoring data into the current understanding of CO_2 behaviour in the subsurface
- responses to unacceptably high formation pressures
- responses to unpredicted migration
- management of existing well penetrations
- corrosion management of pipelines and wells
- staffing and accountability plan to ensure the objectives outlined under the plan are achieved
- continued support of research into geosequestration and the application of this research into the Gorgon Development
- criteria by which the injection of reservoir CO_2 would be suspended, if it was found that an unacceptable health, safety or environmental risk was present.

The CO_2 Injection Operations Management Plan will be provided to the regulating authorities for their endorsement as part of the formal project proposal applications required under the *Barrow Island Act 2003* and its Schedule 1 (Gorgon Gas Processing and Infrastructure Project Agreement).

Responses to the unpredicted migration of CO_2, the avoidance of unacceptably high formation pressures and ensuring that existing well penetrations are appropriately managed are critical to the overall environmental and safety performance of the CO_2 injection operations. Management actions to ensure effective performance in these areas have been developed and are summarised in the following sections on CO_2 Injection Uncertainty Management, Management of Existing Well Penetrations and Response to Unpredicted Migration or Unacceptably High Pressures.

Carbon Dioxide Injection Uncertainty Management

Appropriately managing uncertainties associated with the subsurface injection of CO_2 is essential to the success of the CO_2 injection project on Barrow Island. Uncertainty management involves the consideration of possible outcomes which lie at or near the extremes of the range predicted by the objective analysis of all of the data and developing strategies to mitigate the downside and capitalize on the upside. In addition, some strictly deterministic ‘What if?’ scenarios have been framed to explore beyond the limits suggested by objective analysis. The basis of contingency planning is a sound understanding of the limits of accuracy of the input data, and of the models resulting from interpretation of those data.

From the outset, the Gorgon Joint Ventures have taken a rigorously probabilistic approach to uncertainty management, which has ensured that the level of uncertainty relating to each input parameter has been preserved in all outputs. In addition, the importance of each input parameter has been assessed, together with the impact of the current level of uncertainty. Technical work has been focused on reducing the level of uncertainty in the key subsurface areas.

A structured process to manage project uncertainty has been developed to:

- identify all of the subsurface risks
- evaluate the impact of each uncertainty
- generate options for managing the subsurface risks
- develop and implement surveillance plans to identify if any unexpected outcome occurs
- manage unexpected outcomes.

Figure 13-29 illustrates the work flow followed in managing the injection project uncertainties. The first phase in the process is to identify key project parameters and to define a range for each which captures the uncertainty inherent in that parameter. Work is then focused on reducing the level of uncertainty in key technical areas and then plans are developed to mitigate downside outcomes and capitalise on upside outcomes.

The uncertainty management process will be updated regularly as the project matures, particularly as new data becomes available to the project teams.

Potential impact on the project was evaluated in terms of:

- health, safety and environmental issues, including amount of land disturbance
- containment of CO_2 in the subsurface
- monitoring and verification
- injectivity
- capacity
- risk to hydrocarbon or other assets
- cost.

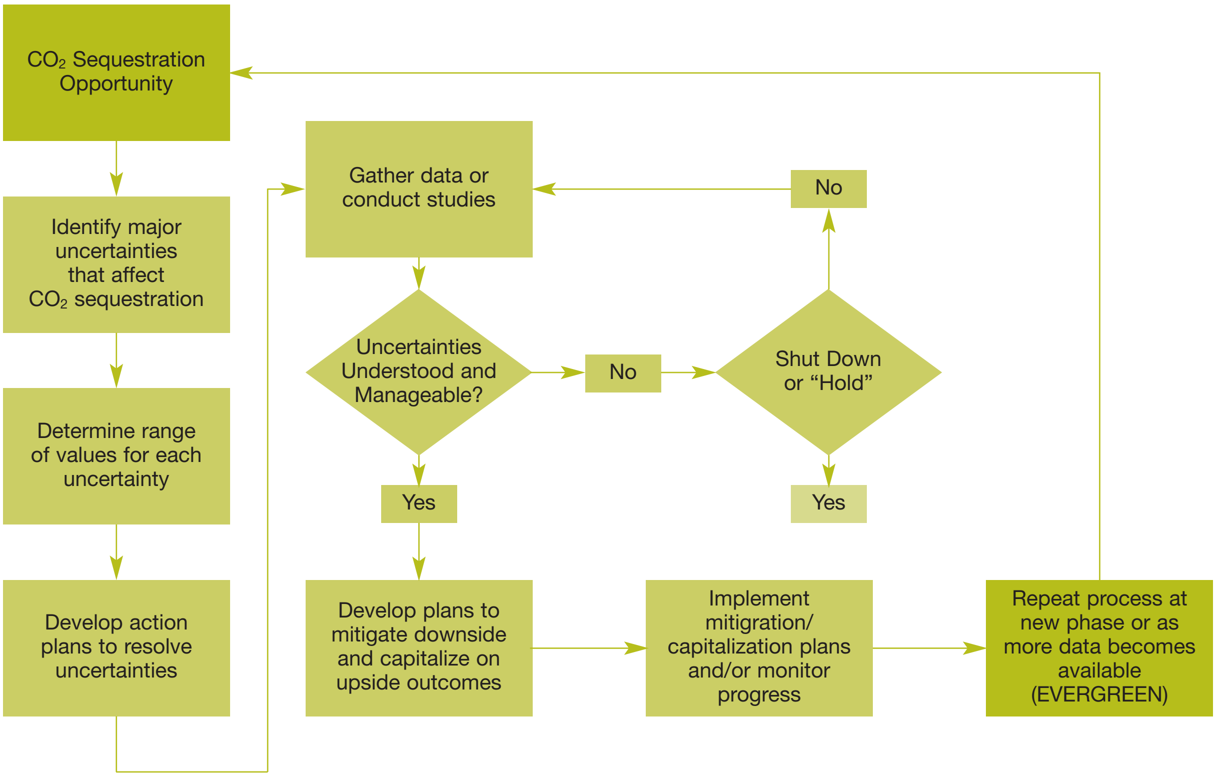
Parameters with the potential to significantly impact one or more of these areas were considered ‘high priority’ in terms of technical work planing. An objective of work planning is to identify tasks and studies that will reduce the level of uncertainty associated with key project parameters. For example, measurements from formation core samples might be required to reduce the level of uncertainty around formation permeability and CO_2 injectivity.

The process for identifying options to reduce uncertainty involves brainstorming multiple tasks that address high priority parameters. The effectiveness of the tasks in terms of reducing uncertainty, the time required to complete the tasks and notional cost estimates are documented for each, which support a team decision on whether to proceed with the reduction activity or to implement an alternative task. When reduction activities are completed, uncertainties are reassessed and a decision made to determine whether further work is required. When the level of uncertainty is considered manageable, or if a point is reached where the uncertainty cannot be further reduced, mitigation and realisation plans are developed for each uncertainty.

The process of developing mitigation and realisation plans involves:

- identifying indicators or ‘signposts’ for worse than expected or better than expected project outcomes
- determine the required monitoring technologies that would be required to identify deviations from the expected outcome
- estimating the timeframe in which signposts may become evident

Figure 13-29:
CO_2 Injection Project – Uncertainty Management Work Flow



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- developing mitigation plans for worse than expected outcomes and realisation plans for better than expected project outcomes
- estimating the probability that each mitigation plan will be effective in reducing the impact of the associated worse than expected outcome.

The selection of monitoring technologies is driven by the identification of signposts that signal worst than, or better than expected project outcomes.

Management actions have been designed to mitigate adverse project performance or environmental impacts, if a signpost indicating a worse than expected project outcome is identified. Table 13-14 outlines management actions for the key project uncertainties that may be undertaken in the event a signpost is identified indicating a worse than expected outcome. The table also identifies the monitoring technologies that are likely to be employed and an estimate of the time period over which the signpost may become evident.

Management of Existing Well Penetrations

Experience from CO_2 enhanced oil recovery operations has identified leakage of CO_2 along existing well penetrations as a potential failure mode for CO_2 containment. While the existing wells on Barrow Island are the responsibility of the Barrow Island oil field Joint Venture, the Gorgon Joint Venturers have undertaken a study to determine if the wells likely to be in the vicinity of the migrating CO_2 plume are appropriately completed or decommissioned for service in a CO_2 environment.

There are currently 27 wells on Barrow Island that have either been drilled into the Dupuy Formation or into formations underlying the Dupuy Formation.
The location of each of these wells is shown in Figure 13-11. Each of these wells has been studied by:

- reviewing the current well files and end of well reports
- reviewing the production operations reports to confirm the current status of the well

- undertaking field visits to assess the surface condition of the well
- assessing if the well is suitable for service in a CO_2 environment
- categorising each well as low, moderate or high-risk based on degree of difficulty in undertaking remedial action on the well
- developing a generic plug back and decommissioning plan for each category of well requiring remediation such that the well would then be suitable for service in a CO_2 environment
- developing specific remediation plans including time and cost estimates for each well requiring remediation.

Reservoir simulation studies discussed earlier provide an indication of the CO_2 migration path. During the injection phase, the CO_2 plume will spread several kilometres from the injection wells driven by the force of the injection pressure. Following the injection phase, the CO_2 will migrate more slowly driven by buoyancy in the water filled pore spaces. These simulation studies indicate the approximate timing and order that the existing well penetrations will be exposed to the CO_2 plume. It is anticipated that only two wells will be intersected by the CO_2 plume during the injection phase of operations. An additional four wells will likely be intersected within 1000 years following injection.

During operations, appropriate arrangements will be made with the Barrow Island Joint Venture to ensure that all wells in the path of the migrating CO_2 are assessed and if required, worked over, such that they are fit for service in a CO_2 environment.

The final sequence for undertaking any required remedial actions in the existing well penetrations will be driven by the monitoring and reservoir surveillance activities undertaken during the injection and post-injection phases of the project.

Generic plug and decommissioning plans have been developed for wells that have casing over the Dupuy Formation interval and for those wells that have not been cased (open hole). A key component of these plans is the use of cements that have been developed that are resistant to attack from the mildly acidic formation water that will result from CO_2 injection. Where a well has been completed with casing, the plans call for the milling of the steel casing so that the cement plug can seal against the formation. Schematics of the wells following these generic plug and decommissioning activities are provided in Figure 13-30.

Response to Unpredicted Migration or Unacceptably High Pressures

Unpredicted migration that results in the CO_2 remaining trapped in the subsurface will not result in risk to health, safety or the environment but needs to be understood in order to update and validate the reservoir simulation models. Managing unpredicted migration or unacceptably high reservoir pressures is a key objective of the uncertainty management plan discussed above.

If the monitoring program detects CO_2 migration that potentially could pose a health, safety or environmental risk, or a risk to other assets, a number of activities will be implemented to manage the further migration of the CO_2 plume including:

- drilling new injection wells to direct the injected CO_2 into different parts of the reservoir
- varying the injection rates at individual wells so as to direct the migration of the CO_2 plume
- drilling pressure relief wells ahead of the migrating CO_2 plume
- re-completing injection wells over a larger interval, thereby reducing the volume of CO_2 being injected into each layer of the formation
- upgrading technology where necessary.

If reservoir pressure is increasing more rapidly than expected, such that vertical migration along faults or fractures might occur, then relief wells will be utilised to reduce the pressure in the formation and mitigate the risk of migration along faults of fractures. As discussed earlier, pressure relief wells work by withdrawing water from the Dupuy Formation and placing it in the overlying Barrow Group.

If there are problems with injecting the desired volume of CO_2, or if CO_2 is disproportionately injected into a particular layer, the injection interval in each well will be modified so as to either increase the amount of CO_2 being injected or direct the CO_2 into alternative layers. Ultimately additional wells can be drilled to increase the amount of CO_2 that can be injected or to direct the CO_2 into a different part of the Dupuy Formation.

Highly unlikely events such as migration of CO_2 up an injector well will be detected as anomalous injection behaviour. In such cases, the well would be shut-in, the causes investigated and the well remediated.

If unpredicted migration is identified by the monitoring program the measures outlined above will be implemented. If it is then determined that any further

Table 13-14:
CO_2 Injection Management Actions

Well Injectivity					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
It may be difficult to inject CO_2 at the required rate in the case of a worse than expected geological outcome such as low permeability.	CO_2 cannot be injected at the required rates.	Unexpected bottom hole pressure increase (>6.9 MPa above virgin pressure in 3 months).	Wellhead pressure; down hole pressure gauges; flow rate gauges.	<6 months	Increase/alter monitoring activities to verify cause of bottom hole pressure increase and assess impact/implication and determine if managem.ent action is required.
					1) Re-complete injection wells; fracture stimulate. 2) Re-complete and perforate over entire interval if not already done. 3) Change well design for subsequent injection wells (e.g. horizontal). 4) Re-consider bottom hole locations for subsequent injection wells, based on additional knowledge of reservoir heterogeneity acquired from previous drilling. 5) Drill additional injection wells. 6) Complete injectors in another stratigraphic unit as well as the Dupuy Formation (e.g. Malouet 6000 ft Sand) to facilitate injection at the required rate.
	Initially injection rate meets expectations, but overall pore space limited.	Gradual increase in bottom hole pressure at injector wells in excess of expected pressure increase.	Wellhead pressure; down hole pressure gauges; flow rate gauges	10 years	1) Produce water from the Dupuy Formation to offset pressure increase (see Pore Volume and Compartmentalisation).
	CO_2 cannot be injected at the required rates due to chemical reaction with the formation.	Unexpected bottom hole pressure increase (>6.9 MPa in 3 months), and significant change in formation water chemistry near injectors.	Wellhead pressure; down hole pressure gauges; flow rate gauges; fluid samples & geochemical analysis.	0-30 years	1) Work over well and acid stimulate (depending on the specific change in water chemistry e.g. carbonate precipitation around the well bore). 2) Re-complete injection wells; fracture stimulate.

Table 13-14: (continued)
CO_2 Injection Management Actions

Existing Well Failure					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
Containment failure via existing well penetrations. Also refer to discussion on management of existing well penetrations. The actions in this table are in addition to the planned assessment and well remediation.	CO_2 migrates into overlying stratigraphy.	Seismic and/or borehole monitoring show CO_2 in stratigraphy above the Dupuy Fm in proximity to existing well penetration(s).	Surface & borehole geophysics.	Ongoing	Increase/alter monitoring activities to verify mode of failure and assess impact/implication and determine if management action is required. Secondary seals in the Malouet Formation may trap CO_2, or residence time in the Malouet Formation may be sufficient for 100% residual gas trapping and dissolution.
					1) Remediate leaking wells. 2) Modify injection pattern to drive migration away from 'problem' well penetration(s).
	CO_2 leakage at surface.	Surface monitoring indicates increased levels of CO_2 in proximity to well(s).	Atmospheric and soil gas CO_2 detectors, vegetation surveys, visual inspection of well heads.	Ongoing	1) Remediate leaking well(s); implement appropriate environmental remediation.
	Leakage of displaced formation water into higher stratigraphy via well penetrations.	Fluid sampling indicates Dupuy Formation water in overlying stratigraphy (above Malouet zone of intermediate salinity) and in proximity to existing well penetration(s).	Surface & borehole geophysics (fluid sampling from overlying stratigraphic unit).	0–30 yrs	Increase/alter monitoring activities to verify cause of displaced water and assess impact/implications and determine if management action is required.
					1) Remediate leaking wells, particularly if leaking well is along the expected migration path of CO_2 plume.

Table 13-14: (continued)
CO_2 Injection Management Actions

Top Seal Failure					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
Containment failure via inadequate top seal. Ability of the sealing lithologies to contain the migrating CO_2.	CO_2 moves into higher levels of the stratigraphy.	Seismic and/or borehole monitoring show CO_2 in stratigraphy above the Dupuy (unrelated to an existing well penetration).	Surface and borehole monitoring.	0–30 years	Increase/alter monitoring activities to verify top seal leakage. Assess impacts/implications and determine if management action is required (secondary seals in the Malouet Formation may trap CO_2, or residence time in the Malouet Formation may be sufficient for 100% residual gas trapping and dissolution). 1) Modify injection pattern to avoid area of top seal leakage. 2) Produce water from Dupuy Formation to lower aquifer pressure and control rate of leakage into overlying stratigraphy.
	Seal integrity compromised due to pressure increase caused by CO_2 injection.	Pressure drop during injection Seismic and/or borehole monitoring show CO_2 in stratigraphy above the Dupuy (unrelated to an existing well penetration).	Wellhead pressure; down hole pressure gauges; flow rate gauges; seismic and borehole monitoring; tilt meter; passive seismic.	0–30 years	Increase/alter monitoring activities to verify pressure increase and top seal leakage. Assess impacts/implications and determine if management action is required (secondary seals in the Malouet Formation may trap CO_2, or residence time in the Malouet Formation may be sufficient for 100% residual gas trapping and dissolution). 1) Modify injection pattern to avoid area of top seal leakage. 2) Lower injection rates/add more injectors to control pore pressure at the base of the seal. 3) Produce water from Dupuy Formation to lower aquifer pressure and control rate of leakage into overlying stratigraphy.

Table 13-14: (continued)

CO₂ Injection Management Actions

Fault Seal Failure					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
Containment failure via fault migration.	Faults act as a migration pathway for CO_2 into higher stratigraphy.	Seismic and/or borehole monitoring show CO_2 in stratigraphy above the Dupuy Formation in proximity to fault(s).	Surface and borehole geophysics, fluid sampling, down hole gauges.	Ongoing	Increase/alter monitoring activities to verify fault leakage. Assess impact/implication and determine if management action is required (fault leakage may not result in surface leakage and may be acceptable).
					1) Modify injection pattern to drive migration away from ‘problem’ fault.
					2) Produce water near the fault to lower pore pressure and control vertical leakage.
	Faults acts as a migration pathway for CO_2 to surface.	Atmospheric CO_2 in proximity of fault expression at surface. Ecological impacts observed as a result of increased levels of CO_2.	Surface monitoring.	Ongoing	1) Modify injection pattern to drive migration away from ‘problem’ fault.
					2) Use water production well(s) near the fault to lower pore pressure and control fluid leakage up fault.
	Faults are impermeable both laterally and vertically.	Unexpected pressure increase in a part of the Dupuy Formation that is thought to be isolated from the rest (fault bounded).	see Compartmentalisation.		

Table 13-14: (continued)
CO_2 Injection Management Actions

Pore Volume and Distribution

Uncertainty	Worse Than Expected Outcome	Signpost	Reservoir Surveillance	Timing	Management Action
Reduced pore volume or distribution may limit CO_2 injection.	Insufficient capacity for full volume of CO_2.	Rate of long-term pressure build up greater than expected.	Wellhead pressure; down-hole pressure gauges; flow rate gauges; multi-component seismic for pressure.	10–30 yrs	Increase/alter monitoring activities to verify cause of pressure build and determine that is due to limited pore volume and distribution. Assess impact/implication and determine if management action is required. 1) Complete injection wells over full Dupuy Formation and higher in stratigraphy (e.g. Malouet 6000' Sand). 2) Produce water from the Dupuy Formation to offset pressure increase. 3) Do not inject the full volume of Gorgon reservoir CO_2.

Permeability and Permeability Heterogeneity

Uncertainty	Worse Than Expected Outcome	Signpost	Reservoir Surveillance	Timing	Management Action
Permeability and permeability heterogeneity may limit CO_2 injection.	CO_2 cannot be injected at the required rates.	Unexpected bottom hole pressure increase (>6.9 MPa increase in 3 months).	Wellhead pressure; down hole pressure gauges; flow rate gauges.	see Well Injectivity.	
	Unexpected migration of the CO_2 plume.	Seismic and/or borehole monitoring show unexpected CO_2 distribution, possibly related to stratigraphic or depositional geometry which may allow rapid migration (>5 km in 10 yrs; see high permeability layers) related to lower than expected bottom hole pressure (~1.7 MPa vs. expected ~4.8 MPa).	Surface and borehole monitoring (well head pressure/down hole pressure gauges) production logging.	0–10 yrs	Increase/alter monitoring activities to verify cause of unexpected migration. Assess impact/implication and determine if management action is required (other uncertainties that may contribute include: structure, high permeability layers, hydrodynamic flow). 1) Re-enter well and squeeze off perforations associated with high permeability units. 2) Lower injection rate (drill additional injection wells). 3) Re-locate injection wells.

Table 13-14: (continued)
CO_2 Injection Management Actions

Structure					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
Structural uncertainty is primarily a reference to the geometry of the base seal surface, which is likely to be a significant control on CO_2 migration rate and direction.	Migration path not as expected.	Significant volumes of CO_2 move off structure (north, east or west).	Surface and borehole monitoring.	0–30 years	Increase/alter monitoring activities to determine if unexpected migration is caused by structure. Assess impact/implication and determine if management action is required (CO_2 may not move to structural spill point and may not represent a risk). 1) Modify injection pattern to drive migration in desired direction. 2) Use water production wells to deviate course of CO_2 plume.
	Insufficient capacity for full volume of CO_2.	Unexpected pressure increase during injection.	see Pore Volume.		
Compartmentalisation					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
Compartmentalisation (vertical & horizontal) may limit CO_2 injection. Either fault or stratigraphic compartmentalisation.	CO_2 can only migrate into an isolated part of the Dupuy Formation.	Unexpected bottom hole pressure increase, pressure transient analysis suggests hydraulically isolated wells.	Surface and borehole monitoring.	0–30 years	Increase/alter monitoring to verify compartmentalisation and assess impact/implication and determine if management action is required. 1) Re-complete and perforate injection wells over entire interval if not already done (Dupuy Formation upper and lower massive sands) 2) Drill additional injection wells outside the compartmentalised area. 3) Produce water from the Dupuy Formation to lower pore pressure in compartmentalised area.

Table 13-14: (continued)
CO_2 Injection Management Actions

High Permeability Layers					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
Presence of high permeability layers in reservoir. Thin, high permeability layers within the injection interval may result in rapid lateral migration of CO_2.	CO_2 migrates preferentially along a specific stratigraphic interval or layer (unpredicted rapid migration).	Seismic monitoring and/or borehole monitoring shows CO_2 migrating rapidly in a vertically thin unit (migration of >5 km in 10 yrs).	Surface and borehole monitoring (production logging).	0–30 years	Increase/alter monitoring to verify that unexpected migration is a result of high permeability layers. Assess impact/implications and determine if management action is required (preferential migration of CO_2 along high permeability layers may not represent a containment risk and are likely to result in less pore pressure build up at the injectors).
					1) Re-enter well and seal off perforations associated with the high permeability layer. 2) Modify injection pattern to allow for high permeability layers. 3) Do not inject the full volume of reservoir CO_2.
		Lower than expected bottom hole pressure (~1.7 MPa vs. expected ~4.8 MPa).	Wellhead pressure; down hole pressure gauges; flow rate gauges.	6–12 months	1) Re-enter well and seal off perforations associated with the high permeability layer. 2) Modify injection pattern to allow for high permeability layers. 3) Do not inject the full volume of reservoir CO_2.
	CO_2 moves off structure as a result of migration along high permeability layer.	Seismic shows CO_2 saturation in a vertically thin unit (~2 km offshore); may also be associated with lower than expected bottom hole pressure (see above).	Offshore seismic; wellhead pressure; down hole pressure gauges; flow rate gauges.	0–30 years	1) Re-enter well and seal off perforations associated with the high permeability layer. 2) Modify injection pattern to allow for high permeability layers. 3) Do not inject the full volume of reservoir CO_2.

Table 13-14: (continued)
CO_2 Injection Management Actions

Uncertainty	Worse Than Expected Outcome	Signpost	Reservoir Surveillance	Timing	Management Action
Hydrodynamic Gradients					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
Unexpected pressure gradients in the formation may alter the CO_2 migration path.	Migration path not as expected.	Significant volumes of CO_2 move off structure (north, east or west). Hydraulic gradient in aquifer the suspected cause.	Surface and borehole monitoring.	0–10 years	Increase/alter monitoring activities to verify that unexpected migration is as a result of hydrodynamic pressure gradients. Assess impacts/implications and determine if management action is required.
					1) Modify injection pattern to allow for hydrodynamic pressure gradient. 2) Use water production wells to alter/offset natural hydraulic flow.
Monitoring					
Uncertainty	**Worse Than Expected Outcome**	**Signpost**	**Reservoir Surveillance**	**Timing**	**Management Action**
Ability to image CO_2.	Subsurface CO_2 is not geophysically (seismically) resolvable.	CO_2 is being injected but cannot be imaged using surface geophysics.	Borehole geophysics.	5–10 years	1) Alter monitoring activities to determine if alternative geophysical methods can be used. Evaluate impact. 2) Alter monitoring strategy to fulfil reservoir surveillance objectives. For example develop an observation well based monitoring strategy.

Table 13-14: (continued)
CO_2 Injection Management Actions

Micro-Seismicity

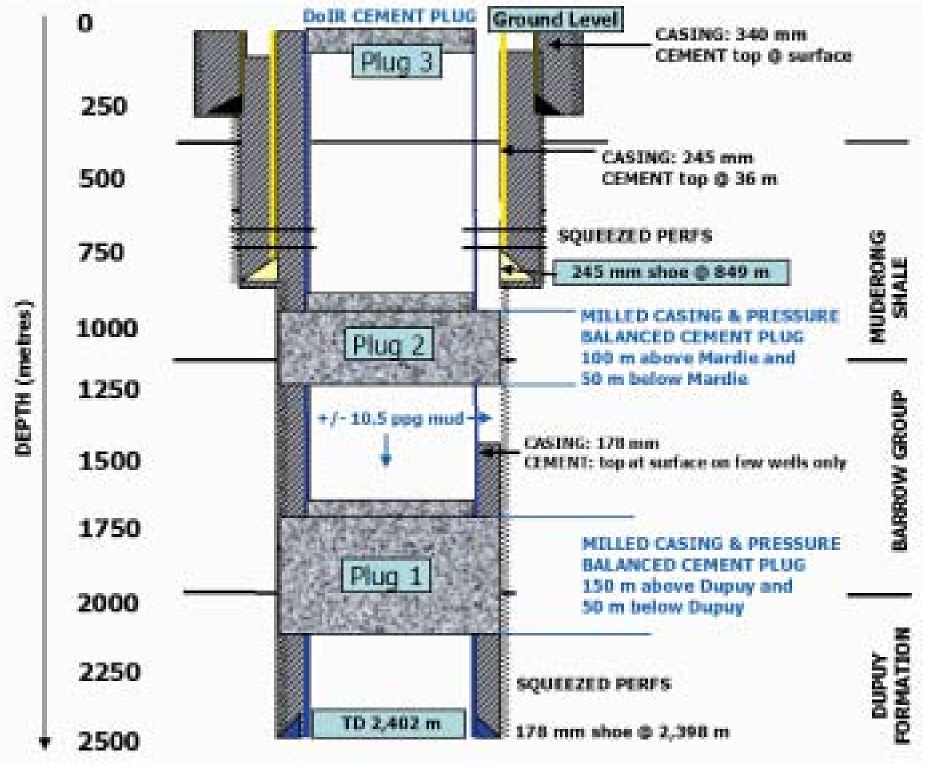
Uncertainty	Worse Than Expected Outcome	Signpost	Reservoir Surveillance	Timing	Management Action
All fluid injection operations (e.g. water flood, gas injection) are associated with micro-seismicity. Objective is to control events to low level.	Excessive micro-seismicity induced as a result of CO_2 injection.	Subsidence and seismicity above background natural level.	Passive seismic/tilt meters.	0–30 years	Increase/alter monitoring activities to verify nature of mirco-seismic events. Assess impact/implications and determine if management action is required. Is micro-seismicity is a result of CO_2 injection and not other operations on or around Barrow Island. 1) Reduce pore pressure, undertake actions identified for reduced pore volume and distribution.
CO_2 injection may result in fracturing or fault reactivation.	Seismicity induced as a result of CO_2 injection.	Passive seismic and tilt meter data suggest significant fracturing/faulting due to CO_2 injection.	Passive seismic/ tilt meters.	0–30 years	Increase/alter monitoring activities to verify nature of mirco-seismic events. Assess impact/implications and determine if management action is required. 1) Reduce pore pressure, undertake actions identified for reduced pore volume and distribution. 2) Modify injection pattern to avoid area of fracturing/faulting.

Residual Hydrocarbon Saturation (Sor)

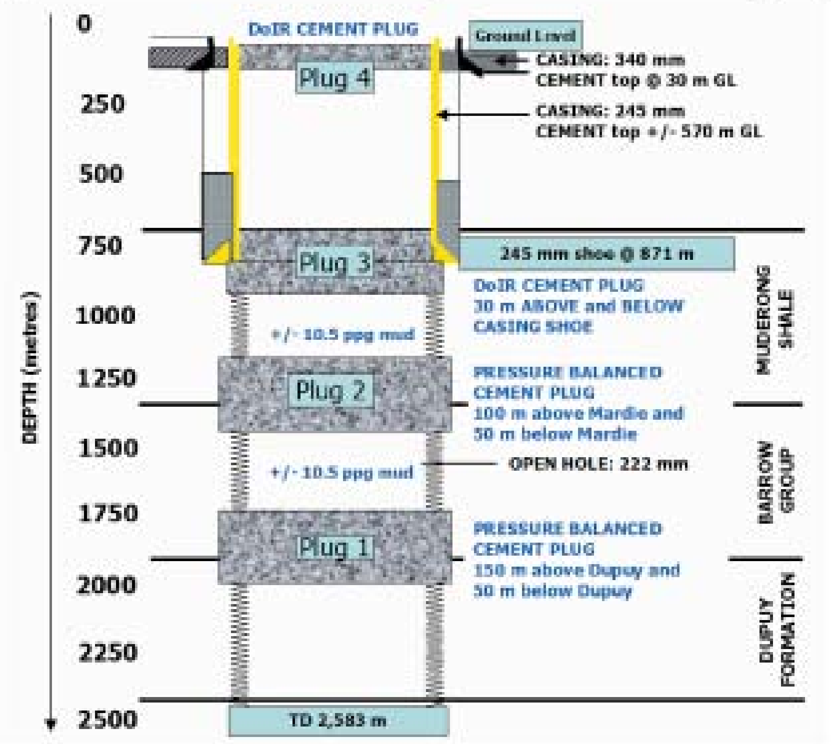
Uncertainty	Worse Than Expected Outcome	Signpost	Reservoir Surveillance	Timing	Management Action
There is some evidence for residual oil saturation in the Dupuy Formation. Residual oil saturations may reduce the relative permeability to CO_2.	Poor injectivity due to reduction in relative permeability to CO_2.	Unexpected bottom hole pressure increase (>6.9 MPa in 3 months).	Wellhead pressure; down hole pressure gauges; flow rate gauges.	0–5 years	Increase/alter monitoring activities to verify cause of pressure increase. Assess impact/implication and determine if management action is required. 1) Undertake actions identified for unexpected pressure increase related to reduced well injectivity.

Figure 13-30:
Well Configuration Following Remedial Action for Carbon Dioxide Service

CO_2 Comprehensive P&A Principle for an existing cased hole



CO_2 Comprehensive P&A Principle for an existing open hole



injection of reservoir CO_2 would result in an unacceptable risk to the personnel or conservation values of Barrow Island, the injection operations will be suspended.

13.4.9 Environmental Impact of Carbon Dioxide Injection Infrastructure

The facilities required for the injection of CO_2 are described in Chapter 6 (Section 6.2.4) and the environmental impact of these facilities has been incorporated into the terrestrial impacts discussed in Chapter 10.

The infrastructure required for the injection project will consist of:

- pipelines to transport the CO_2 from the gas processing facility to the injection wells
- drilling locations for the injection wells
- drilling locations for observation wells
- access roads to service each of these facilities outside the gas processing facility.

Management approaches to minimise the environmental impact of the surface CO_2 injection facilities include:

- submitting Environment Management Plans for the drilling of the injection and monitoring wells
- managing overall surface disturbance in accordance with commitments in the State Agreement
- consolidating the surface location of the injection wells and monitoring wells on a limited number of drill pads using directional drilling technology
- using previously disturbed areas where practicable
- fully integrating the CO_2 removal plant within the gas processing facility to reduce land required for buffer zones.

13.4.10 Potential Failure Modes Related to Carbon Dioxide Injection

The Gorgon Joint Venturers approach to the assessment of environmental risk is documented in Chapter 9 and has been applied in assessing the risks associated with CO_2 injection. The assessment provided here describes the likelihood of possible failure modes relating to CO_2 injection and the possible effects of such failure. The resulting environmental impacts are considered in the discussion on terrestrial impacts in Chapter 10.

Failures in the surface injection facilities or leakage of the injected CO_2 from the subsurface can create potential health, safety and environmental hazards. Hazards caused by the failure of the surface injection facilities are understood by drawing analogies from the operation of CO_2 injection projects and oil and gas operations around the world. Less is known about the risks of leakage from the subsurface as the opportunity to manage greenhouse emissions using subsurface injection has only come about in the last ten years. Consequently the number and variety of projects from which to draw quantitative information is limited. However, analogies can be made with the understanding of the subsurface behaviour of fluids, gases and liquids, drawn from the oil and gas industry.

The environmental impacts and risks associated with CO_2 and its interaction with the atmosphere, soil, water and biota are relatively well understood. Apart from potential climate change impacts, a CO_2 release to the atmosphere poses little environmental hazard provided that it is able to disperse quickly so that localised soil and atmospheric concentrations remain at or near normal levels. A hazard can arise if CO_2, which is denser than air, is allowed to accumulate in low lying, confined or poorly ventilated areas.

The effect of elevated CO_2 levels depends not only on the concentration but also the duration of exposure. The ambient concentration of CO_2 in the atmosphere is currently around 370 ppm or less than 0.004%. For humans, there are no adverse health effects for carbon dioxide concentrations up to 3%. Whilst some discomfort occurs between 3% and 5%, it is only for concentrations above 5% that there are serious, possibly fatal, consequences. At above 25% to 30%, loss of consciousness occurs within several breaths and death occurs quickly thereafter. The National Occupational Health and Safety Commission (NOHSC) have published standards (NOHSC 2005) for human exposure to CO_2. These standards will be adhered to in limiting human exposure to CO_2 resulting from the proposal to inject reservoir CO_2. The NOHSC exposure standards for CO_2 are:

- Time Weighted Average which covers exposure for an eight hour work shift 5000 ppm or 9000 mg/m^3.
- Short Term Exposure Limit which covers exposure for a maximum period of 15 minutes 30 000 ppm or 54 000 mg/m^3. Exposure at Short Term Exposure Limits should not occur more than four times in a work shift.

The Gorgon Joint Venturers have undertaken a study to identify potential risks associated with the proposed injection of CO_2 into the Dupuy Formation. This study commenced with a Failure Mode and Effects Workshop conducted in accordance with the principles and guidelines contained in AS/NZS 4360 for risk management and AS/NZS 3931 for risk analysis of technological systems (Standards Australia 1998 and 2004).

Workshop participants included technical specialists with expertise in CO_2 sequestration, reservoir geology, reservoir engineering and simulation, surface and subsurface engineering and environmental science. Attending the workshop were representatives of the Western Australian Environmental Protection Authority (EPA) Services Unit, the Western Australian Department of Industry and Resources and the CO2CRC. Table 13-15 contains a list of participants at the Failure Modes and Effects Workshop.

The objective of the workshop was to identify credible threats of failure of the proposed injection project, either through a failure in the injection facilities or a failure which might result in the loss of containment in the target reservoirs. A number of risk identification topics were considered to allow detailed assessment of a wide range of 'failure modes' by workshop participants. The risk identification topics were adapted from a risk assessment list of events used by the Australian Petroleum Cooperative Research Centre research program on the Geological Disposal of Carbon Dioxide (Bowden and Rigg 2004). Additional topics were also suggested by participants and discussed in the workshop.

The scope of the workshop was limited to a qualitative estimate of potential likelihood of failure using the definitions documented in Chapter 9, without making judgements of the potential consequences. Where statistical data is available these have also been

Table 13-15:
Failure Modes and Effects Workshop Participants

Name	Organisation/Company Affiliation	Title/Position/Area of Expertise
Technical Specialists		
Roger Bartlett	Chevron Australia	Subsurface Manager – Gorgon Development
Soolim Carney	Chevron Australia/ECOS Consulting	Environmental Advisor
Brian Evans	Curtin University	Professor, Geophysics
Lorna Fitzgerald	Department of Industry and Resources	Senior Project Officer, Office of Major Projects
Craig Gosselink	Chevron Australia	Environmental Engineering Advisor
Gerry McGann	Curtin University	Consulting Geologist
Ian Paton	Department of Industry and Resources	Special Projects Engineer/Development Engineer
Andy Rigg	Cooperative Research Centre for Greenhouse Gas Technologies	Deputy Chief Executive Officer, Storage Program Manager
Robert Root	Chevron Australia	Geoscientist
Richard Sutherland (Observer)	Western Australian Environmental Protection Authority, Services Unit	Environmental Officer
John Torkington	Chevron Australia	Greenhouse Gas Opportunity Manager – Gorgon Development
Facilitator		
Richard Stoklosa	E-Systems/Chevron Australia	Risk Advisor

incorporated into the assessment of likelihood. This was done to capture the circumstances of possible failure in sufficient detail for subsequent analysis of potential human health and ecological consequences by a range of appropriate specialist experts not represented at the workshop.

The identified failure modes associated with the CO_2 injection project have been grouped into four categories:

- leakage from surface injection facilities
- unpredicted CO_2 migration
- reduced well injectivity
- naturally occurring earthquakes.

This discussion on failure modes should be considered in conjunction with the earlier discussion on CO_2 Injection Operations Management which identifies sign posts and describes management actions that can be taken to reduce the risk of failure.

Leakage from Surface Injection Facilities

The potential likelihood of individual failure modes for surface injection facilities identified during this study ranged from unlikely to possible.

The various failure modes that might result in a leakage of CO_2 from the surface injection facilities are:

- mechanical failure of the CO_2 compressors/pumps
- mechanical failure of the CO_2 pipelines
- wellhead leakage, including casing corrosion at ground water level.

Further information on these failure modes including information safeguards or management measures and residual risk is provided in Table 13-16.

Carbon dioxide is transported by pipeline and injected for enhanced oil recovery in the USA, Canada, Turkey and Trinidad and Tobago. Worldwide, approximately 3100 km of CO_2 pipelines exist with a capacity of approximately 45 million tonnes per year of CO_2 (Gale and Davison 2003). Pipeline failures can range from either a pin-hole leak to a major rupture and can be caused by external interference such as unauthorised excavation, construction defects, corrosion or ground movement. The accident record for CO_2 pipelines in the USA shows eight accidents during the period 1968 to 2000 equating to an incident frequency rate of 3×10^{-4} incidents per km per year (Benson et al. 2002). There were no injuries or fatalities associated with these incidents. Statistics of incidents involving natural gas pipelines in the USA between 1986 and 2001 show an incident frequency rate of 2×10^{-4} per km per year (Gale and Davison 2003). Contributing significantly to the failure of these pipelines are external factors such as unauthorised excavation by third parties such as farmers or road construction crews. This factor is eliminated on Barrow Island due to the geographic isolation of the island and the absence of third parties. Consequently a likelihood of ‘Unlikely’ has been applied to mechanical failure of the CO_2 pipeline.

Wellhead leakage can be caused by construction defects, leaking pipe connections or corrosion. In the majority of well failures the amount of CO_2 release will be limited to less than the volume in the well tubing by the use of emergency shut-down devices. Only failure of the tree and emergency shut-down devices could lead to a blow-out of the injection well where reservoir fluids (CO_2 and formation water) would escape to the surface. Data on hydrocarbon well blow-outs while drilling in the Gulf of Mexico and North Sea between 1980 and 1996 are suggestive of failure rates of 1×10^{-4} per well per year (CMPT 1999).

The oil and gas industry has implemented a range of measures aimed at reducing the incidence of facility failure and the volume of gas released should such failures occur. Measures include material selection and design, the management and monitoring of corrosion rates and regular facilities inspections. Automated systems monitoring and the use of automatic shutdown devices ensure that any unplanned release is restricted to the volume contained in the part of the system that failed. These management systems will be applied to the CO_2 injection infrastructure of the Gorgon Development in order to reduce the potential for failure.

As CO_2 is not flammable, the consequence of an injection facility failure is expected to be less than for a comparable failure of a natural gas system. However CO_2 will tend to form a low lying blanket due to the higher density compared to air, whereas natural gas tends to dissipate into the air (Damen et al. 2003).

Any CO_2 released from these potential failures is anticipated to be at high pressure for the first few minutes before rapidly reducing as the gas within the failed facility escapes. Such a release of high pressure CO_2 represents a significant safety risk to personnel in the immediate vicinity of the failure. Given the limited

Table 13-16:
Potential Failure Modes Resulting in the Release of CO_2 – Facility Leakage (compressor, pipeline, well head)

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
Mechanical failure of CO_2 compressors and pumps resulting in release of CO_2 to the atmosphere. Likelihood: Possible	Design and operate the CO_2 compressors and pumps in accordance with petroleum industry standards. Preventative maintenance program. Apply industry operational experience with CO_2 compressors from North America. Design automatic shut-down and isolation of CO_2 injection equipment to limit release of CO_2 to the volume contained within that part of the facility. Many of the potential failure scenarios would occur within the compressor or pump and would only result in controlled release to atmosphere as equipment was repaired limiting health or environmental impacts. Design CO_2 detection system and alarms. Utilise appropriate personal protective equipment for people working around CO_2 compressors and pumps.	Analogous to existing oil and gas operational risk. Dependent upon nature of failure, there is a potential for release to atmosphere of that volume of CO_2 contained within the compressors and related facilities (several tonnes to several tens of tonnes of CO_2). Many failures would occur within the compressor or pump and would only result in controlled release to atmosphere as equipment was repaired.
Mechanical failure of CO_2 pipeline caused by either below standard operating practice or external factors such as unauthorised excavation resulting in release of CO_2 to the atmosphere. Likelihood: Unlikely	Design and operate CO_2 pipeline in accordance with Australian Standards for petroleum pipelines AS2885. Regular monitoring of pipeline. Apply industry operational experience with CO_2 pipelines from North America. Design automatic shut-down and isolation of pipeline to limit release of CO_2 to volume contained within the pipeline. Pipeline damage by external factors such as unauthorised excavation (which is a significant risk factor for most pipeline operators) are lessened by isolation of Barrow Island, and locating pipeline above ground.	Analogous to existing oil and gas operational risk. Dependent upon nature of failure, there is a potential for release to atmosphere of a moderate volume (several tens of tonnes to several hundred tonnes) of CO_2.
Leakage at the well head caused by worn gaskets, valves or by corrosion resulting in release of CO_2. Failure of well casing at the top of ground water table resulting in release of CO_2 into the near surface. Likelihood: Possible	Implement a wellhead inspection, preventative maintenance program and annular pressure monitoring. Design automatic isolation of wellhead to limit release to volume of CO_2 contained within the wellhead and upper portion of the injection well. Once failure is identified, well will be worked over and leak repaired limiting volume of CO_2 released. Manage ground water level casing corrosion by active cathodic protection. Leakage prevented by multiple casing strings and tubing.	Analogous to existing oil and gas operational risk. Dependent upon nature of failure, there is a potential for release of minor volume (several tonnes to tens of tonnes) of CO_2 to the atmosphere and/or the near surface cave systems. A consequence of well casing leakage at the top of the ground water table is that CO_2 could leak into the near surface cave systems with detrimental impact on the fauna in these systems.

volume of CO_2 that would be released over a very short time, it is not expected that the release would result in a material impact upon the biophysical environment in the vicinity of the release. There is a risk of the released CO_2 accumulating to levels where it represents an asphyxiation risk in low lying areas with poor ventilation. The gas processing facility will be designed to minimise these areas and the potential for high concentrations in low lying and poorly ventilated areas, identified as part of the Developments Safety Management Systems.

A failure of the well casing at the top of the ground water table would not normally result in a release of CO_2 into the near surface cave systems. This is because the CO_2 will be contained within the production tubing. In order for CO_2 to be released into the near surface cave systems, the wells production tubing would also have to fail. The resulting CO_2 release would be of limited volume and would persist until the well could be worked over and the leaks repaired. These types of leaks can be detected readily through annular pressure monitoring in each well.

Unpredicted Carbon Dioxide Migration

Individual failure modes that might result in the unpredicted migration of CO_2 in the subsurface have been divided into three groupings:

- failure of individual baffles and barriers to prevent the CO_2 from migrating vertically
- leakage of CO_2 along faults
- leakage of CO_2 through failures in well penetrations.

Further information on each of these failure modes including information on safeguards or management measures and residual risk is provided in Table 13-17, Table 13-18 and Table 13-19.

The potential likelihood of individual failure modes that could lead to unpredicted migration ranged from remote to likely, however this should not be construed as the potential likelihood of CO_2 escaping to the surface and posing a health, safety or environmental hazard.

Unpredicted migration within the Dupuy Formation into the overlying formations would not constitute a failure of the injection project as the CO_2 will remain trapped in the subsurface rather than being emitted to the atmosphere. Any unpredicted migration will require review and modification of the Gorgon Joint Venturers' reservoir simulation modelling in order to understand why the deviation to model predictions occurred and to predict future migration behaviour. In addition issues such as ensuring the security of existing well penetrations that may be impacted by the CO_2 will be appropriately managed as identified in Section 13.4.8.

Unpredicted migration would represent a failure of the injection project if the CO_2 is able to migrate to the surface (or near surface cave systems) or into the producing oil and gas accumulations around Barrow Island.

Modelling by the Gorgon Joint Venturers indicates that in the event of unplanned migration of CO_2 to the surface, it would most likely occur along one of the larger identified faults (refer Figure 13-11 for the location of the larger faults on Barrow Island). Benson (2004) concluded that flux rates for CO_2 migration along faults could be in the range of 1×10^2 and 1×10^6 micromole/m^2/sec but restricted to areas in close proximity to the fault, possibly impacting an area of between 1000 m^2 and 100 000 m^2. Carbon dioxide migrating to the surface along faults will likely be dispersed by the prevailing winds. The risk to personnel and other fauna from asphyxiation at these flux rates is therefore very low. However, the CO_2 flux rates associated with unpredicted migration along faults would enable the build up of CO_2 concentrations within the soil profile to the point where flora could be detrimentally impacted.

A significant consequence of unpredicted migration along faults or well bores is that CO_2 could migrate into the near surface cave systems. Even at low leakage rates, significant concentrations of CO_2 could accumulate in the air and water contained in these systems. This is anticipated to have a detrimental impact upon the fauna living in that environment.
It should be noted that the cave systems containing these fauna exist close to the surface of the island and are separated from the Dupuy Formation by approximately 2000 m of sandstone, mudstone and shale, comprising numerous reservoirs and baffles and barriers. Further discussion on the impact of elevated CO_2 levels in this environment is provided in Chapter 10 (Section 10.5.6).

Table 13-17:
Potential Failure Modes Resulting in the Unplanned Migration of CO_2 – Failure of Baffles and Barriers

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
Leakage of intra Dupuy Formation baffles such as the Perforans Shale, where injection occurs below these units. Buoyant CO_2 migrating over tens of years (or less) towards the upper Dupuy Formation baffles. Likelihood: Likely	Selection of Dupuy Formation provides multiple baffles and barriers to prevent/slow CO_2 migration. Nature of baffle provides tortuous migration path enhancing the ability for the migrating CO_2 to become trapped.	Intra Dupuy Formation seals are likely to behave as flow baffles. Many of these units are unable to be resolved on seismic data due to limited thickness so distribution is uncertain. CO_2 not trapped prior to leaking through the intra Dupuy formation shales will migrate upward towards the upper Dupuy Formation shales. May lead to contamination of oil and gas resources within the upper Dupuy Formation (undiscovered).
Leakage of upper Dupuy Formation baffles. Buoyant CO_2 migrating over tens of years to hundreds of years towards the base Barrow Group shale. Likelihood: Possible	Selection of Dupuy Formation provides multiple baffles and barriers to prevent/slow CO_2 migration. Nature of baffle provides tortuous migration path enhancing the ability for the migrating CO_2 to become trapped.	Shales in the upper Dupuy Formation are lithologically similar to those in the intra Dupuy Formation but thicker and more laterally extensive. CO_2 not trapped prior to leaking through the intra Dupuy formation shales will migrate upward towards the base Barrow Group shales. May lead to contamination of oil and gas resources within the upper Dupuy Formation (undiscovered).
If reservoir CO_2 should migrate to the base Barrow Group shale, leakage of base Barrow Group shale barrier. Buoyant CO_2 migrating over tens to hundreds of years into Barrow Group. Likelihood: Likely	Selection of Dupuy Formation provides multiple baffles and barriers to prevent/slow CO_2 migration. Nature of barrier provides tortuous migration path enhancing the ability for the migrating CO_2 to become trapped.	Shales at the base of the Barrow Group are 10s of metres thick and can be correlated over the Barrow Island region. There is some uncertainty as the extent of this shale in the area to the east of Barrow Island. Modelling indicates that the rate at which the CO_2 can migrate through shales will be very low (generally less than one micromole/m^2/sec) (Benson 2004). CO_2 not trapped prior to leaking through the base Barrow Group shale becomes trapped in the Barrow Group and below the Muderong Shale. May lead to contamination of oil and gas resources within the Barrow Group (both existing and undiscovered).

Table 13-17: (continued)
Potential Failure Modes Resulting in the Unplanned Migration of CO_2 – Failure of Baffles and Barriers

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
If reservoir CO_2 should migrate to the Muderong Shale, leakage of Muderong Shale barrier. Note: Leakage of the Muderong Shale was not considered during the Failure Modes and Effects Workshop as it was considered remote that the CO_2 would have leaked past the previous three sets of baffles and barriers. Buoyant CO_2 migrating over thousands of years into the Windallia Sandstone Member and the Gearle Siltstone. Likelihood: Remote	Selection of Dupuy Formation provides multiple baffles and barriers to prevent/slow CO_2 migration. Nature of barrier provides tortuous migration path enhancing the ability for the migrating CO_2 to become trapped.	The Muderong Shale occurs across the entire Barrow Sub Basin and is the sealing lithology of many (majority) of the hydrocarbon accumulations in the sub basin. Modelling indicates that the rate at which the CO_2 can migrate through shales will be very low (generally less than one micromole/m^2/sec) (Benson 2004). CO_2 not trapped prior to leaking through the Muderong Shale becomes trapped in the overlying Windalia Member and the Geale Siltstone. May lead to contamination of oil and gas resources within the Muderong Shale and Windalia Sandstone Member (both existing and undiscovered).

Table 13-18:
Potential Failure Modes Resulting in the Unplanned Migration or Release of CO_2 – Fault Leakage

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
Leakage along the Barrow Fault. Leakage of CO_2 to higher levels in the stratigraphy. Potential leakage of CO_2 to surface. The location of this fault is shown on Figure 13-11. Likelihood: Remote	Select the injection location such that CO_2 plume is not anticipated to approach the Barrow Fault. Reservoir modelling requires highly pessimistic scenario for CO_2 to migrate in proximity to the fault. For leakage to occur CO_2 would need to migrate to the Barrow Fault then fault would have to act as migration path. Pressure gradient and salinity differences between the Dupuy Formation and the Barrow Group suggest that faults are not fluid conduits at present.	The Barrow Fault is distant from injection location. Barrow Fault is currently sealing with respect to several hydrocarbon accumulations. Studies indicate that leakage along faults may occur at rates of between 1×10^2 and 1×10^6 micromole/m^2/sec but over relatively small areas (Benson 2004). Naturally occurring hydrocarbon seeps are geographically limited in area. May lead to contamination of oil and gas resources within the Barrow Group (both existing and undiscovered).

Table 13-18: (continued)

Potential Failure Modes Resulting in the Unplanned Migration or Release of CO_2 – Fault Leakage *(continued)*

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
		CO_2 migration to the surface could result in the localised build up of CO_2 concentrations within the soil profile to the point where flora could be detrimentally impacted. A significant consequence of migration along faults is that CO_2 could migrate into the near surface cave systems with detrimental impact on the fauna in these systems.
If reservoir CO_2 should migrate in proximity to the Godwit and Plato Faults, leakage along the Godwit and Plato Faults. Note these faults do not extend to the surface. Leakage of CO_2 to higher levels in the stratigraphy. Likelihood: Likely	Select the injection location such distant from the Godwit and Plato faults. The CO_2 plume is not anticipated to reach these faults for 1000 years by which time much of the CO_2 will have become trapped. For leakage to occur CO_2 would need to migrate to these faults then the faults would have to act as migration path. Pressure gradient and salinity differences between the Dupuy Formation and the Barrow Group suggest that faults are not fluid conduits at present.	Plato and Godwit Faults are distant from injection location. May lead to contamination of oil and gas resources within the Barrow Group (both existing and undiscovered). Impacts on surface and neat surface flora and fauna are not anticipated as faults are only identified from seismic and do not extend to the surface.
Leakage along faults or fractures that have not been detected on seismic. This requires the faults to be relatively small. Leakage of CO_2 to higher levels in the stratigraphy. Likelihood: Unlikely	If faults are present they must be small relative to the Barrow, Godwit and Plato Faults as they are not resolvable on seismic. Potential CO_2 flux would also be correspondingly less. Pressure gradient and salinity differences between the Dupuy Formation and the Barrow Group suggest that faults are not fluid conduits at present.	Potential for fault migration thought to be less than for mapped faults discussed above given smaller nature of the faults. Leakage rates are anticipated to be lower and more localised than for leakage along the Barrow Fault. May lead to contamination of oil and gas resources within the Barrow Group (both existing and undiscovered). CO_2 migration to the surface could result in the localised build up of CO_2 concentrations within the soil profile to the point where flora could be detrimentally impacted. A significant consequence of migration along faults is that CO_2 could migrate into the near surface cave systems with detrimental impact on the fauna in these systems.

Table 13-18: (continued)
Potential Failure Modes Resulting in the Unplanned Migration or Release of CO_2 – Fault Leakage *(continued)*

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
Leakage along offshore faults to north and east of Barrow Island. Leakage of CO_2 to higher levels in the stratigraphy. Likelihood: Possible	Pressure gradient and salinity differences between the Dupuy Formation and the Barrow Group suggest that faults are not fluid conduits at present. Pressure gradient and salinity differences between the Dupuy Formation and the Barrow Group suggest that if faults exist they are not fluid conduits at present.	May lead to contamination of oil and gas resources within the Barrow Group in the area of Double Island. (Both existing and undiscovered). Impacts on marine fauna are not anticipated as faults are only identified from seismic and do not extend to the surface.
Leakage along offshore faults to the north and west of Barrow Island. Leakage of CO_2 to higher levels in the stratigraphy. Likelihood: Remote	Select the injection location such that CO_2 plume is not anticipated to approach these faults. Reservoir modelling indicates that it is almost impossible for CO_2 to migrate in proximity to these faults. Pressure gradient and salinity differences between the Dupuy Formation and the Barrow Group suggest that faults are not fluid conduits at present. Potential for effective dissipation of leaking CO_2 in the marine water column.	May lead to contamination of oil and gas resources within the Barrow Group (both existing and undiscovered).
Operational error resulting in injection at pressure exceeding fracture gradient. Potential to fracture reservoir rock and overlying baffles and barriers leading to unpredicted migration to higher levels in the stratigraphy. Likelihood: Unlikely	The selection of the Dupuy Formation injection target as it has multiple barriers between injection reservoir and surface. Design the compressor operating pressure to remain below fracture pressure of reservoir rock. Develop operational management plans covering high reservoir pressure identified in injection wells. Refer to Section 13.4.8.	Existing hydrostatic pressure is approximately 10.3 MPa less than fracture threshold pressure. Higher than expected pressures in the formation may lead to faults that are currently sealing becoming migration pathways and fracturing of the overlying sealing units allowing CO_2 to migrate vertically into overlying stratigraphy.
Lack of formation capacity to accommodate injected CO_2. If capacity of the reservoir to contain the injected CO_2 is exceeded, CO_2 migration will be more extensive than predicted and ultimately reservoir pressure will increase potentially exceeding fracture gradient. Likelihood: Remote	Develop operational management plans in the event that migration greater than predicted is detected or if high reservoir pressure is identified in observation wells. Refer to Section 13.4.8. Refer above discussion on injection pressure exceeding fracture gradient.	Capacity of the Dupuy Formation has been thoroughly investigated by the Gorgon Joint Venturers and by independent studies commissioned by the Western Australian Government (DoIR). If the formation does not have the capacity to contain the injected volumes of CO_2, this may lead to more extensive CO_2 plume migration or over-pressuring of the formation with associated failure modes.

Table 13-19:
Potential Failure Modes Resulting in the Unplanned Migration or Release of CO_2 – Well Leakage

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
Inappropriate decommissioning of existing wells. Existing well penetrations may act as conduit for leakage of CO_2 to higher levels in the stratigraphy. Potential leakage of CO_2 to surface. Leakage rates could be higher than leakage through faults. Likelihood: Unlikely	Existing decommissioned wells did not contemplate CO_2 injection operations and will require workover to ensure suitability for CO_2 service. Plans to manage well penetrations and ensure they are fit for service have been developed. Refer to Section 13.4.8. If well does ultimately leak then well will be re-entered and leakage stopped.	Condition of wells and potential for leakage is understood and plans in place for remediation prior to CO_2 intersecting well. Limited release (tens to thousands of tonnes) of CO_2 until well re-entered and leakage stopped. May lead to contamination of oil and gas resources (both existing and undiscovered). CO_2 migration to the surface could result in the localised build up of CO_2 concentrations within the soil profile to the point where flora could be detrimentally impacted. A significant consequence of leakage is that CO2 could migrate into the near surface cave systems with detrimental impact on the fauna in these systems.
CO_2 leakage through CO_2 injection or monitoring wells. Conduit for leakage of CO_2 to higher levels in the stratigraphy. Potential leakage of CO_2 to surface. Leakage rates could be higher than leakage through faults. Likelihood: Unlikely	Implement wellhead maintenance program and monitoring of annular pressures. Design CO_2 injection and monitoring wells for CO_2 service. Utilise CO_2 service design from industry experience in enhanced oil recovery and CO_2 injection operations. If well does ultimately leak then well will be re-entered and leakage stopped.	Initial design and decommissioning procedures for CO_2 injection and monitoring wells will accommodate CO_2 service. Limited release (tens to thousands of tonnes) of CO_2 until well re-entered and leakage stopped. May lead to contamination of oil and gas resources (both existing and undiscovered). CO_2 migration to the surface could result in the localised build up of CO_2 concentrations within the soil profile to the point where flora could be detrimentally impacted. A significant consequence of leakage is that CO_2 could migrate into the near surface cave systems with detrimental impact on the fauna in these systems.

Table 13-19: (continued)

Potential Failure Modes Resulting in the Unplanned Migration or Release of CO_2 – Well Leakage

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
CO_2 leakage through future hydrocarbon exploration or development wells. Conduit for leakage of CO_2 to higher levels in the stratigraphy. Potential leakage of CO_2 to surface. Leakage rates could be higher than leakage through faults. Likelihood: Unlikely	Ensure that future hydrocarbon wells will be designed for CO_2 service. Utilise CO_2 service design from industry experience in enhanced oil recovery and CO_2 injection operations. If well does ultimately leak then well will be re-entered and leakage stopped.	Initial design and decommissioning procedures for future exploration and development wells will accommodate CO_2 service. Limited release (tens to thousands of tonnes) of CO_2 until well re-entered and leakage stopped. May lead to contamination of oil and gas resources (both existing and undiscovered). CO_2 migration to the surface could result in the localised build up of CO_2 concentrations within the soil profile to the point where flora could be detrimentally impacted. A significant consequence of leakage is that CO_2 could migrate into the near surface cave systems with detrimental impact on the fauna in these systems.
CO_2 leakage during routine workovers of injection or monitoring wells. Potential leakage of CO_2 to surface. Lowering of partial pressure in well could potentially lead to mineralisation and plugging. Likelihood: Possible	Adhere to three barrier rule during workovers (maintain three barriers to fluid escape at all times) Adopt best practice lessons learned from other enhanced oil recovery and CO_2 injection operations.	Equivalent to failure rates for workovers in the oil and gas industry. Failure is likely to lead to limited release of CO_2 to atmosphere until well can be shut in. Analogies with oil and gas operations indicate that release would be stopped within days or weeks.

Table 13-19: (continued)

Potential Failure Modes Resulting in the Unplanned Migration or Release of CO_2 – Well Leakage

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
CO_2 leakage via water source wells in Barrow Group. Note these wells provide saline water for reverse osmosis plants. Potential leakage of CO_2 to surface. Water supply wells produce CO_2. Likelihood: Unlikely	Existing water source wells do not contemplate CO_2 injection operations and will require decommissioning to ensure suitability for CO_2 service. Manage water source wells in accordance with Existing Well Remediation Plan. Refer to Section 13.4.8. If well does ultimately leak then well will be re-entered and leakage stopped.	Requires CO_2 to have migrated into upper parts of the Barrow Group. Condition of wells and potential for leakage is understood and plans in place for remediation prior to CO_2 intersecting well. May require decommissioning of water source wells and drilling of alternative water source wells away from the CO_2 plume. Limited release (tens to thousands of tonnes) of CO_2 until well re-entered and leakage stopped. May lead to contamination of oil and gas resources (both existing and undiscovered). CO_2 migration to the surface could result in the localised build up of CO_2 concentrations within the soil profile to the point where flora could be detrimentally impacted. A significant consequence of leakage is that CO_2 could migrate into the near surface cave systems with detrimental impact on the fauna in these systems.

Table 13-20:

Potential Failure Modes Resulting in the Unplanned Migration or Release of CO_2 – Reduced Well Injectivity

Description of Potential Failure Mode	Safeguards, Mitigation or Management Measures	Residual Risk
Precipitation of minerals in the formation in close proximity to the injection well bore. Repeated reduction in well/reservoir partial pressure may facilitate mineralisation. Reduced ability to inject CO_2 into well, requires increase in injection pressure to dispose of required volume of CO_2. Increased injection pressure may exceed fracture gradient as discussed above. Likelihood: Unlikely	Studies indicate that mineralisation reactions occur over time periods of thousands of years. Refer to Section 13.4.4 Develop injection well operation plans to minimise reduction in well/formation partial pressure. Develop management plans in the event that high reservoir pressure is identified in injection wells. Refer to Section 13.4.8.	Higher than expected pressures as a result of mineralisation in the injection wells may lead to faults that are currently sealing becoming migration pathways and fracturing of the overlying sealing units allowing CO_2 to migrate vertically into overlying stratigraphy.

In selecting the preferred CO_2 injection site, possible migration of CO_2 along faults and the resulting impact that this might have on cave fauna was considered. The preferred site was selected because it is distant from the large identified faults, enabling the CO_2 to become trapped in the formation prior to reaching these faults. A key objective of the proposed monitoring program is to identify whether unpredicted migration is occurring in order to enable the impact to be assessed and appropriate changes to the injection program made.

Based on this assessment, the Gorgon Joint Venturers have determined that the residual risk of unpredicted migration representing a health, safety or environmental impact is low.

Reduced Well Injectivity

The potential for an injection well to fail as a result of reduced injectivity was assessed at the workshop as unlikely. Reduced well injectivity will most likely be caused by the precipitation of minerals in the target injection formation and in proximity to the injection well, but could also be a result of the movement of clay minerals in the formation. Both these conditions are encountered in oil and gas field operations and can be remedied through redrilling or working over of the well. Further studies are planned to investigate the potential for reduced well injectivity on core obtained from a data well to be drilled in 2005.

The consequences of reduced injectivity are restricted to the economic cost of remedial work to re-establish injection in the well and potentially the need to vent reservoir CO_2 while the particular well is waiting for remediation. The potential for reservoir CO_2 emissions to the atmosphere as a result of a loss of well injectivity and the time taken to restore the well, have been considered in determining the reference case for greenhouse gas emissions used in this document. Refer to Section 13.3.4.

Further information on this failure mode including information on the potential environmental impact, safeguards or management measures and residual risk is provided in Table 13-20.

Naturally Occurring Earthquakes

Horizontal and vertical stresses occur routinely in the subsurface. Where these stresses exceed the strength of the rock, or are sufficient to overcome the frictional resistance along an existing fault plane, movement along a fault will occur. Fault movements through earthquakes redistribute stress in the crust around the earthquake epicentre and consequently affect the future earthquake activity in the region. It is worth noting that faults such as the Barrow Fault, which has displacement of over 500 m, are the result of repeated movements (earthquakes) over geologic time. Faults occurring during a single earthquake are of much lesser magnitude. For example scientists at Geoscience Australia (McCue et al. 2003) have studied the Lake Edgar fault scarp in Tasmania. This fault scarp is 30 km in length with the current day displacement of between 2.5 m and 6.5 m. While there is evidence of repeated movement along the fault scarp, scientists estimate that the earthquake that created the fault scarp was of a magnitude 6.5 to 7.0 on the open ended Richter Scale.

Naturally occurring earthquakes pose a hazard to CO_2 injection where they result in the creation of a new fault or change the properties of an existing fault, such that a fluid migration pathway is created. The risks of CO_2 migration along these faults is comparable to the risk of migration along existing faults discussed above. If fault leakage was to occur as a result of a naturally occurring earthquake, it would enable migration of CO_2 into the next higher level of the stratigraphy: in this case the Barrow Group. The Barrow Group contains an extensive set of baffles and is overlain by regionally significant barriers in the Muderong Shale and Geale Siltstone, providing further opportunities for the CO_2 to become trapped and preventing migration to the surface.

For a naturally occurring earthquake to result in a risk of failure of the CO_2 injection project, the earthquake would have to result in a fault that intersected the CO_2 plume. The fault would then have to be of a size and nature that it allowed the CO_2 to migrate higher in the stratigraphy, and the CO_2 would still need to migrate past the extensive baffles and barriers higher in the stratigraphy.

Leakage from conventional oil and gas fields as a consequence of naturally occurring earthquakes provide an analogy for the risks of CO_2 leakage. No references were found where an earthquake had lead to containment failure and leakage from an existing oil or gas accumulation implying that the risk of containment failure from a naturally occurring earthquake is remote.

Apart from the potential damage to facilities, a naturally occurring earthquake is not likely to pose an additional risk of containment failure for CO_2 injection operations.

Carbon Dioxide Injection Environmental Impact

The identified CO_2 injection failure modes and their potential impact have been considered in assessing the environmental impacts of the project. These are documented in Chapter 10.

13.4.11 Approach to Long-term Responsibilities

In proposing to dispose of reservoir CO_2 by injection into the Dupuy Formation, the Gorgon Joint Venturers recognise that there are community concerns about the management of long-term responsibilities, particularly with respect to the liabilities arising from potential CO_2 leakage from the subsurface. The subsurface injection of CO_2 has many parallels with existing activities such as the decommissioning and rehabilitation of oil and gas fields and mine sites that can provide a basis for how this should be managed. The Joint Venturers believe that existing statutory regulation and the common law provide appropriate mechanisms for managing liabilities associated with CO_2 injection.

Existing approaches to decommissioning oil and gas field operations utilise the concept of site closure to define the point where the owners/operators of the site reach agreement with government on the level of decommissioning and rehabilitation activities. This occurs soon after the oil or gas resources have been depleted. While the concept of site closure can be readily applied to the decommissioning and rehabilitation associated with the surface facilities and wells used for CO_2 injection, the ability to demonstrate that the site is safe from CO_2 leakage may take an additional period. The Gorgon Joint Venturers propose that their day-to-day involvement with the site continue after the cessation of injection operations, into a ‘Post-Injection Phase’. The Post-Injection Phase would end once agreement was reached with government that the closure criteria for the site had been met. The duration of the Post-Injection Phase will depend upon the migration of the CO_2 in the reservoir and the information obtained about the ability to monitor and predict the CO_2 migration. The additional monitoring undertaken during the Post-Injection Phase will be primarily to confirm the understanding developed during the operational phase.

Australian state and federal governments have been considering site closure criteria as part of a set of Draft Regulatory Principles for Carbon Dioxide Geosequestration. These draft principles (Department of Industry and Tourism 2004) propose that site closure should occur once government is satisfied to a high degree of certainty that:

- future land use objectives defined at the time of project approval have been met
- the residual risks of leakage and resulting liabilities are acceptably low
- the ongoing costs associated with the site are acceptably low or are otherwise appropriately managed.

It should be noted that these Draft Regulatory Principles have been put forward for the various federal and state governments to consider. Each government will then decide if and how it will regulate the subsurface disposal of CO_2. There is no obligation on any government to accept these recommendations. The Gorgon Joint Venturers support the use of these criteria to managing and agreeing site closure of the Gorgon CO_2 injection project with government.

At the time of site closure the Gorgon Joint Venturers will prepare a report for government that comprehensively documents the CO_2 injection operations, including monitoring activities and the status of all existing well penetrations in proximity to the CO_2 plume. In addition copies of all documentation and data relating to the CO_2 injection project would be made available to government. This commitment is in addition to the commitment to make data on monitoring activities available to the public throughout the life of the injection project.

Future Land Use Planning

The Draft Regulatory Principles for Carbon Dioxide Geosequestration (Department of Industry and Tourism 2004) propose that future land use objectives need to be defined at the time of development approval. Demonstrating that these future land use objectives can be achieved will become an important site-closure criterion. As a result of their studies, the Gorgon Joint Venturers firmly believe that the proposal to inject CO_2 below Barrow Island will result in the CO_2 becoming effectively trapped in the subsurface. Consequently, the Gorgon Joint Venturers believe that the following land use objectives are consistent with Barrow Island being used as a site for the subsurface disposal of CO_2:

- nature reserve status, with the objective of maintaining the conservation values of Barrow Island
- eco-tourism, both on Barrow Island and in the surrounding waters (the Gorgon Joint Venturers are not advocating eco-tourism on Barrow Island but indicating such a use would be consistent with the site being used for the underground disposal of CO_2)
- marine biodiversity conservation consistent with the proposed Marine Conservation Area around Barrow Island.

Future land use activities will need to be managed after site closure to ensure that they are consistent with the prior use of the site for CO_2 disposal (for example the further exploration and production of hydrocarbons). However, it is envisaged that management of these activities will require only a small increase in resourcing over and above that already required for activities on Barrow Island. By way of illustration, the existing arrangements for the approval of hydrocarbon drilling operations on Barrow Island require the proponents to address a wide range of safety and environmental hazards in planning and undertaking drilling operations. Government only approves such operations once it is satisfied that all the relevant issues have been addressed. In this context the presence of injected CO_2 in the subsurface will be simply another consideration for the proponent to address in designing and planning the drilling operation. Likewise it will be one of many issues for government to consider when assessing and approving drilling operations.

13.5 Greenhouse Gas Management Plan

The Gorgon Joint Venturers have developed a Greenhouse Gas Management Plan as a tool to manage the further reduction in greenhouse gas emissions from the Gorgon Development. The Greenhouse Management Plan documents:

- Gorgon Joint Venturers participation in a range of Government programs aimed at reducing greenhouse gas emissions, including the reporting of greenhouse gas emissions and reduction efforts under those programs
- performance indicators and performance targets for those indicators
- planned actions to be taken by the Gorgon Joint Venturers to minimise greenhouse gas emissions from the Gorgon development with the objective of meeting the set performance targets.

13.5.1 Membership of Government Programs

The Gorgon Joint Venturers will continue to participate in government programs aimed at the voluntary reduction in greenhouse gas emissions. The primary government program aimed at reducing greenhouse gas emissions is the Greenhouse Challenge Plus Program managed by the Department of Environment and Heritage, Australian Greenhouse Office.

Greenhouse Challenge Plus

The Gorgon Joint Venturers have been a member of the Greenhouse Challenge Program since its inception in 1998. The Greenhouse Challenge Program has recently undergone a major review and has been expanded as the Greenhouse Challenge Plus Program.

The existing Greenhouse Challenge Cooperative Agreement between the Gorgon Joint Venturers and the Commonwealth Government covers activities of the proposed Development during the design and approval phase. The decisions taken during this phase of the Development have exceeded the undertakings given by the Gorgon Joint Venturers through the cooperative agreement (refer Section 13.3.1). The Gorgon Joint Venturers commit to updating the existing cooperative agreement in line with the requirements of the Greenhouse Challenge Plus Program prior to the project moving into its operational phase.

The calculation of greenhouse gas emissions in each of the performance indicator categories identified in Section 13.5.3 shall be calculated for each calendar year and reported in accordance with the Gorgon Development Greenhouse Challenge Agreement.

Generator Efficiency Standards

Generator Efficiency Standards (GES) is a program managed by the Australian Greenhouse Office with the objective of encouraging generators of electrical power from fossil fuels to achieve best practice in reducing greenhouse gas emissions. The GES program has recently been incorporated into the Greenhouse Challenge Plus Program.

The program identifies best practice performance targets for thermal efficiency in new power generation plants. For gas fired electrical generation, the established new plant thermal efficiency (sent out) target is 52% of higher heating value (energy in fuel stream in MJ/kg) and assumes that gas fired electrical generation will be via a combined cycle plant.

Energy required in the proposed Gorgon Development gas processing facility comprises direct mechanical drive, electrical generation and process heat. The use of waste heat recovery is driven by process heat requirements during gas processing.

As identified in Section 13.3.4, the total energy required by the Gorgon Development amounts to 1017 MW (319 MW of mechanical load, 270 MW of electrical output and 428 MW of heat load) while the total fuel usage amounts to 7011 GJ/h (1948 MW). Dividing energy load by fuel usage equates to a thermal efficiency of 52%.

Energy Efficiency Assessment

In 2004 the Prime Minister announced as part of the Commonwealth Government's Energy Policy, Securing Australia's Energy Future, that all businesses in Australia using more than 0.5 PJ of energy per year will be required to undertake an energy efficiency opportunity assessment every five years; and to report publicly on the outcomes. Implementation of this policy is due to commence in 2006. Details of how the program will operate are still to be finalised but it was announced as part of the Prime Minister's policy speech that the program will be based on the following components:

- Businesses will have a specified time to complete their assessment and prepare a public report.
- Public reports will be made, where possible, through the Greenhouse Challenge Programs on line reporting system and membership of the Greenhouse Challenge Program would be available to those companies.
- Public reports will need to include details of energy efficiency opportunities as well as information on the energy performance of the business.
- The assessments will need to be conducted in accordance with specified guidelines that will be developed by the government in consultation with industry. The guidelines will be based on a thorough examination of operations, including a systematic analysis of potential systems rather than just an audit of existing plant. Assessments will be more rigorous than current Level 3 audits under Australian Energy Audits Standards.
- Assessments will be verified and assessors accredited.

The Gorgon Joint Venturers will fully comply with the obligations on businesses once this proposed program becomes operational.

13.5.2 Planned Actions to Reduce Greenhouse Gas Emissions

A number of actions are planned by the Gorgon Joint Venturers with the objective of reducing the Development's greenhouse gas emissions below those used as the reference case in this Draft EIS/ERMP and documented in Section 13.3.4. These actions include:

- Undertaking further studies during detailed design and engineering into the electrical generation gas turbine and waste heat recovery configuration.
- Investigating the further integration of the Gorgon Development and the Barrow Island Joint Venture activities on Barrow Island, with the aim of reducing greenhouse gas emissions. For example integration of electrical power systems.
- Undertaking energy optimisation studies during the detailed engineering and design of the development. Energy optimisation is a way to identify, understand, and optimise energy use over the operating lifetime of a project.
- Developing operational and maintenance procedures with the objective of reducing greenhouse gas emissions below those in the reference case and in line with the performance targets listed in Section 13.5.3. Maximising the percentage of reservoir CO_2 injected will be a primary focus in developing these operational and maintenance procedures.
- Once the gas processing facility is operational, undertake Energy Optimisation Studies in line with requirements in Chevron Australia's Operational Excellence Management System (OEMS). An overview of the OEMS is provided in Chapter 16.
- Continue to support research into carbon dioxide capture and storage technology development within Australia and overseas including the potential for provision of data from the Gorgon Development.

13.5.3 Greenhouse Gas Emissions Performance Indicators and Targets

Greenhouse gas emissions from the Gorgon Development will be determined annually for each of the following performance indicators:

- tonnes of CO_2e emitted from LNG processing operations
- tonnes of CO_2e emitted from domestic gas processing operations
- tonnes of CO_2e emitted from logistics and support infrastructure
- tonnes of CO_2e emitted from LNG processing operations per tonne of LNG loaded on ship
- percentage of reservoir CO_2e vented to atmosphere/injected into the subsurface
- tonnes of reservoir CO_2e injected into the subsurface
- incremental emissions of CO_2e resulting from injection of reservoir CO_2.

As the Gorgon Development is in the design phase, the estimated greenhouse gas emissions presented in Section 13.3.4 are based on a reference case which incorporates a number of design assumptions. It is envisaged that as the detailed design progresses and operational procedures are developed, opportunities to further reduce greenhouse gas emissions below those presented in Section 13.3.4 will be realised. Further, the ability to reduce emissions, in particular those related to the venting of reservoir CO_2, should be possible as operational experience is gained with the injection of CO_2. In light of this, a number of key performance targets related to greenhouse gas emissions have been generated as targets for the further reduction in emissions over the first 5–10 years of the operational life of the Development. These key performance targets are presented in Table 13-21.

Table 13-21:
Key Performance Targets for Greenhouse Gas Emissions from the Gorgon Development

Greenhouse Performance Indicator	Value Stated in the Draft EIS/ERMP Based On Reference Case Assumptions	Longer Term Performance Target
Tonnes of CO_2e emitted from LNG processing operations (without contribution from CO_2 venting)	3.03 MTPA CO_2e	5% less or 2.88 MTPA CO_2e
Tonnes of CO_2e emitted from domestic gas processing operations(without contribution from CO_2 venting)	0.23 MTPA CO_2e	5% less or 0.22 MTPA CO_2e
Tonnes of CO_2e emitted from logistics and support infrastructure	0.07 MTPA CO_2e	5% less
Percentage of reservoir CO_2e injected into the subsurface/vented to atmosphere	80% injected/20% vented	> 95% injected/< 5% vented
Tonnes of CO_2e emitted per tonne of LNG loaded on ship (includes contribution from CO_2 venting)	0.353 tonne CO_2e/tonne LNG	0.304 tonne CO_2e/tonne LNG (assumes both plant efficiency and CO_2 venting targets are met)

13.6 Compliance with EPA Guidance Notes

The EPA has issued a number of guidance notes dealing with managing environmental impacts. Two of these guidance notes deal with greenhouse gas emissions and the subsurface disposal of liquid industrial waste. The Gorgon Joint Venturers have complied with the objectives outlined in each of these guidance notes.

13.6.1 Guidance Note No 12: Minimising Greenhouse Gases

EPA Guidance Note No 12 (EPA 2002) provides direction on the minimising of greenhouse gas emissions from significant new or expanding operations. The objective of the EPA is to reduce greenhouse emissions to a level which is as low as practicable by ensuring that emissions from proposed projects are adequately addressed in the planning, design and operations.

The Gorgon Joint Venturers have incorporated energy efficiency and emissions management as key value drivers in designing the proposed Development and intends to restrict its atmospheric greenhouse gas emissions by the injection of reservoir CO_2 into the Dupuy Formation. These actions have delivered the proposed Development with world class benchmarked greenhouse efficiency, when normalised for climate and CO_2 content of reservoir gas, in accordance with the objectives of this guidance note.

13.6.2 Guidance Note No 4: Deep and Shallow Well Injection for Disposal of Industrial Waste

EPA Guidance Note No 4 (EPA 2003) provides guidance on the environmental assessment of deep and shallow well injection of liquid industrial waste into the ground waters of Western Australian by means of Class I, IV or V wells. The objective behind the guidance note is the protection of ground water resources which might be impacted by the subsurface injection of industrial waste. The guidance note outlines the approach that will be used by the EPA during its assessment of such proposals. In particular, the proponent would need to satisfy the EPA that no adverse effects on existing and potential environmental values and beneficial uses of water could occur.

The injection of CO_2 into the subsurface as a means to reduce greenhouse emissions does not appear to have been envisaged at the time this EPA guidance note was drafted (the derivation of the well categories dates to 1994). Consequently the injection of CO_2 does not readily fall within any of the existing well categories discussed in the Guidance Note. In addition, the definitions of industrial waste do not include CO_2. However the Gorgon Joint Venturers consider it appropriate to apply the objectives of the guidance note to the proposed CO_2 injection project on Barrow Island.

The technical studies undertaken by the Gorgon Joint Venturers indicate that there will be a low risk of impact on the environmental values of Barrow Island. Further, as there is no significant ground water resource in the vicinity of Barrow Island, the proposal to inject CO_2 is consistent with this guidance note.

13.7 Conclusions

The Gorgon Joint Venturers' commitment to the responsible management of greenhouse gas emissions is evidenced by the results of benchmarking the anticipated LNG emissions efficiency performance from the Gorgon Development with other LNG facilities. The expected performance of 0.35 tonnes of CO_2e per tonne LNG to be produced (based on the reference case assumptions) exceeds both operating and proposed LNG projects within Australian when greenhouse emissions related to gas production are considered.

As part of the strategy to minimise greenhouse gas emissions, the Gorgon Joint Venturers are proposing to inject the CO_2 contained in the reservoir gas stream. A thorough review of potential CO_2 injection locations has been conducted and has determined that the Dupuy Formation, accessed from the eastern side of Barrow Island, is the preferred location for this activity. Appropriate monitoring of the injected CO_2 is planned to assist with the ongoing management of the CO_2 injection operations. The proposed injection of the reservoir CO_2, will reduce greenhouse gas emissions attributable to the Development (including domestic gas production) from 6.7 million tonnes per annum of CO_2 equivalent (MTPA CO_2e) to 4.0 MTPA CO_2e.

Additional activities to be undertaken with the objective of reducing greenhouse gas emissions from the Gorgon Development include:

- Undertaking further studies into the electrical generation gas turbine and waste heat recovery configuration. Section 13.3.4 documents the options that are being considered.
- Investigating the further integration of the Gorgon Development and the Barrow Island Joint Venture activities on Barrow Island, with the aim of reducing greenhouse gas emissions. For example integration of electrical power systems.
- Undertaking energy optimisation studies during the detailed engineering and design of the development. Energy optimisation is a way to identify, understand, and optimise energy use over the operating lifetime of a project.
- Developing operational and maintenance procedures with objective of reducing greenhouse gas emissions below those in the reference case and in line with the performance targets listed in Section 13.5.3. Maximising the percentage of reservoir CO_2 injected will be a primary focus in developing these operational and maintenance procedures.
- Once the gas processing facility is operational, undertake Energy Optimisation Studies in line with requirements in Chevron Australia's Operational Excellence Management System (OEMS). An overview of the OEMS is provided in Chapter 16.
- Continuing to support research into carbon dioxide capture and storage technology development within Australia and overseas. Potential for provision of data from the Gorgon Development.

The Joint Venturers have developed a series of longer term performance targets with the objective of further reducing greenhouse gas emissions from the proposed Development.