Report to the Joint Working Group on Natural Gas Supply

Natural Gas in Australia

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MMA McLennan Magasanik Associates

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Disclaimer

This report has been prepared solely for the Joint Working Group, MCE-SCO and MCMPR-SCO for the purpose of assisting the Group to assess: barriers to gas supply; risks and benefits of major inter-jurisdictional gas projects; and policy options that balance domestic and export needs. McLennan Magasanik Associates Pty Ltd shall have no liability (other than specifically provided for in contract) for any representations or information contained in or omissions from the report or any written or oral communications transmitted in the course of the project.

EXECUTIVE SUMMARY[1]

The Joint Working Group on Natural Gas Supply, established by the Ministerial Council for Mineral and Petroleum Resources and the Ministerial Council on Energy, has engaged McLennan Magasanik Associates to undertake a study that assesses three related gas supply issues: the barriers to domestic gas supply; the risks and benefits of major inter-jurisdictional gas projects; and policy options that balance domestic and export needs.

The study is a detailed investigation of the institutional structures in the Australian gas industry, of how they are working, where they may be failing in regard to ensuring competitive domestic gas supply and what Governments could do about it.

We have obtained the views of government and industry and subjected it to critical review, as well as conducting extensive internal analysis. To the extent possible our views have been quantified, to provide answers to the questions, "how much of a problem is this?" and "what are the important issues?"

The study has been conducted within the current framework of a market-based industry in which Governments regulate and the industry makes investment and operating decisions. The study has identified a number of areas in which changes to regulation or to regulatory practice could lead to improved market outcomes but has not found any compelling reasons for Government "intervention" in the market at the present time. By intervention we mean more direct involvement in the market than practiced under the current competitive market paradigm, such as by directing gas supply, providing funding, purchasing gas or investing in infrastructure. More effective policy design and usage is not considered to be market intervention. This interpretation of intervention is implied throughout the report.

Further developments in the gas industry may change this perception and to this end it is recommended that industry and Governments develop a shared understanding of the conditions that would constitute "market failure" and the Government interventions that could address such failures. These issues could be pursued under the auspices of a National Natural Gas Plan.

[1] Readers are advised to note that this report contains detailed analyses of and recommendations in relation to a number of different matters, of which this executive summary provides an overview. MMA's recommendations are fully represented, in context, in the body of the report.

E1 Barriers to gas supply

Barriers (or potential barriers) to supply of gas to the domestic market can be physical and/or institutional. The only purely physical barrier would be the absence of gas resources but even an apparent lack of resources can be the result of a lack of exploration, that is, an institutional problem.

All other barriers are a combination of physical and institutional issues, such as when gas resources cannot be developed economically in competition with other sources of energy, or purely institutional, as when the overall resource economics are sound but the economics of one element of the supply chain is not and development does not proceed. The focus of this study is largely on the last category of barriers to supply, because they are the ones that can potentially be removed by changing the institutional framework.

E2 Gas Market Status and Outlook

E2.1 Western Australian Wholesale Market

The Western Australian domestic gas market has for some time seen low prices as a result of competition between one large producer that is also an exporter and a number of smaller producers dedicated to the domestic market. At a time when there is demand for new and replacement gas contracts, only one of these producers is currently in the market, most of the others having contracted all their developed reserves, with the result that prices have doubled.

Western Australia is therefore in urgent need of commitments to new production. A limited number of "domestic" projects are possible but none will be producing before 2010 and large scale developments are conditional upon export sales whose timing is not linked to domestic needs.

The market has reached a position in which it is more difficult for the demand/supply/price balance to be struck:

- At the most recent price buyers would undoubtedly prefer short-term contracts, with a view to negotiating lower prices for supply in three to five years with developers of new gas resources, but these are unlikely to lead to development commitments
- The long-term level of demand at higher prices is uncertain
- Producers face cost increases and uncertainty

In view of the relatively small scale of domestic demand relative to most of the potential gas developments, such market instability could be viewed as a normal market cycle – when a big development happens there is a supply surplus and prices fall and if the next big development is delayed there is a shortfall and prices rise. To avoid this situation it is imperative for buyers to negotiate firm contracts well in advance of supply requirements but under the circumstances in Western Australia this has been difficult due to:

- Contingency of contracts with export projects on export commitments
- Difficulty for buyers to commit to higher prices for new "domestic" projects two to three years ago, when price expectations were lower.

E2.2 Eastern Australian Wholesale Market

The Eastern Australian supply outlook is relatively benign. Buyers and sellers appear willing to contract ahead to avoid supply shocks and concerns mostly relate to long-term supply and the possibility that higher costs will increase future contract prices.

E2.3 Northern Territory Wholesale Market

Northern Territory demand from existing end users appears to be covered by supply contracts for up to 15 years. Unsupplied demand at Gove and for petrochemical projects in Darwin competes for supply with LNG and offshore production of export products.

E2.4 Retail markets

Robust retail competition has been established in electricity and gas markets in most Eastern States. The number of retailers and concentration of market share is considerably higher for gas than electricity but the market shares of new entrants are similarly low. Retail churn is comparable in gas and electricity and indicative of highly competitive conditions in most jurisdictions.

E2.5 Export markets

The LNG market has changed dramatically in response to the rise in oil prices and constraints on domestic gas production in Europe and North America. As oil prices have risen, LNG has become relatively more attractive in Asia and rising prices of pipeline gas in Europe and North America have also made LNG more attractive in those markets.

LNG production increased by 11% in 2006 and continuing growth of 7.5%-9% a year is expected. Some of this production will be met by projects already under construction, such as NWS Train 5, but most projects are suffering from significant cost overruns. New LNG plant commitments are proving difficult in this environment which clearly favours brownfield over greenfield developments. LNG prices are expected to remain high in the short-medium term.

E3 Barriers to Domestic Gas Supply

Sixteen potential barriers to gas supply have been identified in the study. Summary assessments of the barriers and recommended management options are tabled below. Many of the barriers and the options for ameliorating their impacts are interrelated and it is unlikely that barriers will be reduced without an integrated approach on a number of fronts. A number of options will require further evaluation and all will require further detailed specification prior to implementation. Factors that have previously been reviewed but which are still considered to be barriers by some stakeholders are discussed in light of recent market changes, particularly in Western Australia.

Barriers to gas supply and recommended management options

Barrier to gas supply	Recommended management options
Attraction of export prices High prices may stimulate development of export/domestic projects. Price impact on domestic gas negative Timing of development becomes important Real barrier if fields are also suitable for domestic development	**Initiatives to enhance domestic supply** ▪ Increased funding for pre-competitive geological data acquisition ▪ Provision of infrastructure supporting exploration, such as roads ▪ Taxation reform to assist small exploration companies (“flow through” shares) ▪ Improvement of project approval processes and project facilitation eg Major Project Facilitation status ▪ Royalty reductions or holidays for onshore production **Delays to export projects** ▪ Cost escalation and uncertainty – (refer below) ▪ Delays in domestic approvals – (refer below) ▪ Delays in contracts and approvals overseas - Commonwealth Government lobbying **Fields suitable for domestic development** ▪ Application of retention lease management. The Joint Authority administering an area should use domestic supply as the basis of commerciality if appropriate.

Barrier to gas supply	Recommended management options
Acreage management (retention leases and production licences) Retention leases and production licences could be used to withhold gas from the domestic market	Retention lease issues can be managed by: ▪ Requesting re-evaluation of commerciality under the terms of lease ▪ Non-renewal of retention leases ▪ Considering a minor P(SL)A amendment to remove a loophole ▪ Considering replacing the lease renewal process with an auction to evaluate commerciality Production licences in which no petroleum is produced for five years can be terminated
Joint marketing Factors supporting separate marketing have improved significantly.	▪ Implementation of the STTM is recommended as the primary means of taking market development to the stage where separate marketing is supported.
Gas quality The WA gas specifications are a barrier to entry of gas from certain fields.	▪ The Western Australian Government should consider the costs and benefits of revising the Western Australian Gas Standards (Gas Supply and System Safety) Regulations to comply with the National Standard, AS 4564. ▪ ERA and DBP should then consider broadening the DBNGP specification to match AS 4564
Cost increases Global cost increases and uncertainty threaten export and domestic gas developments	▪ Long-term skilled labour availability - better resource planning and investment in training ▪ Supply of oil and gas equipment - it is not anticipated that Australian Governments' policy decisions could materially change this
Market concentration Upstream concentration is high Downstream concentration is medium-high	▪ Separate marketing would reduce upstream market concentration in Eastern Australia. In the WA domgas sector this would not be of assistance owing to the participation of a limited number of producers in the domgas joint ventures. In WA exploration and discovery of additional reserves would be a more effective means of reducing concentration. ▪ Downstream concentration can be reduced by eliminating some of the barriers to entry by new participants, such as access to delivery point capacity (see below).

Barrier to gas supply	Recommended management options
Infrastructure approvals processes Approval processes are time consuming, particularly when multiple jurisdictions are involved	▪ COAG has recognised the need to harmonise regulations across jurisdictions, to remove duplication of effort by infrastructure providers. ▪ Harmonisation would facilitate the appointment of one jurisdictional authority over each aspect of a cross jurisdictional project and/or the appointment of further cross-jurisdictional single function regulators along the NOPSA model ▪ The creation of the new National Gas Law and National Gas Rules is intended to reduce the burden of regulation on gas pipelines, particularly those with limited market power ▪
Retail market balancing mechanisms Balancing mechanisms are inefficient and present a barrier to new entrants	▪ The STTM, which has been conceived as a means of replacing the problematic physical balancing arrangements in New South Wales and South Australia, is the preferred solution.
Delivery point capacity access Non-access frustrates delivery of competing gas to networks	No easy solutions have been found. The STTM may be of assistance but this is not confirmed. The following could be considered: ▪ Inclusion in the NGR rules relating to provision of capacity information: a) That unutilised contracted pipeline capacity information should include delivery point information b) A definition of unutilised capacity ▪ New entrants to use interruptible capacity. ▪ Use it or lose it (capacity) ▪ Delivery points (city-gates) to be owned by distribution companies.
Greenhouse gas reduction schemes Inconsistency and uncertainty of GHG schemes is a barrier to	▪ Two groups are currently investigating establishment of a broader national emissions trading scheme: the Prime Ministerial Task Group on Emissions Trading and the National Emissions Trading Task Force. Their work should resolve this issue for the gas industry.

Barrier to gas supply	Recommended management options
investment in gas infrastructure	
Vertical integration Vertical integration increases effective market concentration. At present the impact is limited.	▪ Vertical integration is typically a response to market inefficiencies (within and outside the gas market). There are no obvious options for controlling vertical integration other than maintaining or creating market conditions that do not make it necessary or attractive, such as reducing market concentration upstream and downstream.
Pipeline regulation The NGL and NGR discriminate against expansion of existing pipelines	▪ The new National Gas Law and National Gas Rules will remove or reduce the disincentives to new pipeline investment. ▪ Flexible rules to ensure capacity expansions of existing pipelines are optimal should be considered
Non-standardisation including market rules and operations Multiple rules and procedures create inefficiencies	▪ Establishment of the STTM will resolve the multiplicity of market arrangements outside Victoria but will not have any authority over upstream or pipeline matters. ▪ Government should encourage the industry to establish a standardisation board to work with the Australian Energy Regulator and other authorities to remove the inefficiencies caused by different gas days, nomination/bid timing and procedures etc.
Tax and depreciation conditions Junior gas explorers are handicapped by the tax system. Project economics could be enhanced by changes to the tax system. Differences between upstream and downstream regimes create distortions in favour of exports	▪ Consider introduction of a "flow through" share scheme ▪ Consider tax changes proposed by APPEA ▪ Review application of transfer pricing in PRRT

<table>
<tr><th>Barrier to gas supply</th><th>Recommended management options</th></tr>
<tr><td>Aging infrastructure

Failure of assets creates short-term supply shortfalls.</td><td>Options for improving management of gas supply failure have been identified in previous studies:

▪ Creation of NGERAC to co-ordinate inter-jurisdictional emergency responses

▪ The Bulletin Board being developed by GMLG

▪ The STTM, the detailed design of which is being developed by GMLG, which will facilitate a market based response to gas supply shortfalls</td></tr>
<tr><td>Gas reserves accessibility

Ichthys and Torosa fields may be developed from remote sites not accessible to the WA domestic market</td><td>▪ Discussing the options with the developers, to promote a Burrup Peninsula option.

▪ Ensuring that there are no barriers to considerable expansion of processing facilities on the Burrup Peninsula.

▪ Ensuring there are no barriers to construction of the offshore pipeline and possibly promoting third party construction of a shared pipeline.</td></tr>
</table>

Implementation of the identified management options should reduce the barriers to supply and improve the functioning of the market in all jurisdictions, though some have limited relevance in the Northern Territory. Implementation will take time, as will arrangements for further domestic supply in Western Australia. During this time there may be claims that the Western Australian market has failed and that Government intervention is therefore justified. Governments are urged to resist these claims at least until the recommended options have been given a reasonable chance to succeed, for both policy and practical reasons:

- Australia successfully introduced competitive market principles to its energy sector over a decade ago. Any material change from this principle would be a major policy shift that itself would take significant time to debate and formalise – any unilateral intervention is likely to have significant consequential impacts, not the least being the uncertainty as to policy directions.
- In practice it is unlikely that any intervention would result in a more rapid resolution of supply issues. The existing stakeholders have the greatest capability to negotiate new supply agreements and mobilise the resources to provide supply, hence resolution will be fastest when the institutional barriers to negotiation and supply are minimised.

In regard to the Northern Territory, its domestic gas market remains in monopoly-monopsony mode and is extremely illiquid, with negotiations for additional supply required only every 15 to 25 years. In view of the scale and structure of demand and supply this is likely to change only if there is significant market growth.

In these circumstances market outcomes can be more influenced by the players' inclinations than by the policy settings. A number of the policy settings that are directed at improving wholesale market competition, such as separate marketing, which is unlikely ever to be possible in the Northern Territory, are therefore largely irrelevant there. However other settings, including a focus on ensuring that gas developments occur, are highly relevant.

E4 Risks and benefits of major inter-jurisdictional gas projects

The Australian natural gas industry's initial development phase involved only two inter-jurisdictional projects:

1. Supply to New South Wales, which is without significant conventional gas resources of its own and is only now developing its CSG resources.
2. Development of the offshore Gippsland oil and gas fields for supply to Victoria.

All other supply developments occurred on a state by state basis using onshore gas resources. Significant barriers to interstate trade developed within each isolated gas supply system, in the form of political resistance to "exports" and in the form of commercial franchises. Industry reform has removed both these barriers and since the mid-1990s a number of inter-jurisdictional pipelines have been constructed in Eastern Australia to take advantage of opportunities to supply gas. Offshore gas production development for domestic use has not faced any comparable barriers but the North West Shelf export project was subject to Commonwealth approval of exports. This control was removed in 1997.

Construction of further inter-jurisdictional pipelines is highly likely, ranging from a relatively short 180km link between Queensland and South Australia to a 2,500km Transcontinental Pipeline or pipelines of similar scale to bring remote resources from the Timor Sea or PNG to Australia. The need for these pipelines will be determined by changing regional demand-supply balances, including price considerations. Construction of further offshore production facilities is also highly likely in Victoria, Western Australia and the Northern Territory.

The risks and benefits of inter-jurisdictional gas projects are:

- Risks, type 1 – project is too late or doesn't happen – supply shortfall, prices rise in the importing region
- Risks, type 2 – project constructed but other local supply is found – supply surplus, prices fall in the importing region, the asset is unprofitable or other supply is stranded
- Benefits – project constructed – supply/demand in balance, project profitable

These must be managed in the context of investment decisions that have to be made four to five years in advance of first supply. Type 1 risks can be managed primarily by ensuring that current supply security is well understood and that there are no surprises. As the current situation in Western Australia indicates, this is easier said than done and because of the negative impacts on end users, supply failure attracts wide publicity.

Type 2 risks are also difficult to avoid because further supply options can be discovered at any time after the pipeline is constructed. The benefits of pipelines that have been considered to date are summarised in the table below.

Potential inter-jurisdictional gas supply projects

Project	Status	Project benefits
Ballera-Moomba Interconnect (dry-gas pipeline)	To be constructed by EPIC Energy by 2009. Foundation contracts with AGL.	Permits Queensland CSG to supply NSW and SA markets via Moomba
Queensland Hunter pipeline (Surat Basin to Newcastle)	Under consideration by Hunter Energy.	Permits Queensland CSG to supply NSW, provides first gas supply to Nth NSW and provides market access for Nth NSW CSG
Great Northern Pipeline	Under consideration by ARC Energy.	Connects Canning basin resources with WA domgas market
Timor Sea Pipeline (Darwin to Mt Isa and/or Moomba)	Not under active consideration.	Permits long-term supply of Eastern States from large Timor Sea reserves. Provides NT with additional competitive supply. May encourage exploration of NT onshore basins
PNG pipeline (Bamaga to Mt Isa and/or Moomba)	Not under active consideration.	Permits long-term supply of Eastern States from large PNG reserves
Transcontinental pipeline	Not under active consideration.	Permits long-term supply of Eastern States from large WA reserves

Governments have had considerable involvement in past inter- and intra-jurisdictional gas projects. In the current competitive industry context more direct forms of involvement are now viewed as potentially inefficient.

E4.1 Support through approvals processes

Approvals processes have been reported as a barrier to gas supply by a number of stakeholders and Government support through the approvals processes is welcomed. However it is also clear that stakeholders would value streamlining the approvals processes more than just support in dealing with the existing processes.

E4.2 Project studies

Project studies play a similar role to an industry plan but are generally focused on particular regions or infrastructure that may not be visible in a national plan. Stakeholders are supportive of Governments undertaking project studies, particularly co-operative studies with industry, as a means of obtaining a shared view of the likely economics of development opportunities.

Some stakeholders cautioned that Governments should not use studies to conclude that particular infrastructure should be constructed, as other competing infrastructure not considered in the study may be a better option. In regard to major gas pipeline projects a national gas plan would provide the most coherent view of potential options.

E4.3Project initiation

Stakeholder support for project initiation by Governments is more qualified. Initiation in the form of broad requests for expressions of interest in providing gas supply (for example), which are intended to lead to commercially negotiated outcomes, are viewed positively. Narrower processes, such as for construction of a specified pipeline, are viewed as having the potential to result in the wrong assets being constructed and ultimately requiring Government financial support.

It is also noted that the current Gas Code contains provisions for persons to apply to the Relevant Regulator to conduct a tender process for construction of a pipeline, whereby the pipeline tariffs will be determined by the tender process rather than by the regulator. The Gas Code provisions are carried forward in the National Gas Law.

E4.4 Introduction of measures favourable to gas projects

A level playing field is preferred to measures favourable to gas but if the playing field remains tilted in their view, stakeholders would consider favourable measures an acceptable second-best solution.

E4.5 Financial support

Financial support of gas infrastructure by Government or Government agencies is viewed by the majority of stakeholders as inconsistent with the gas industry structure that has developed over the past fifteen years. Financial support, whether by direct subsidies, contractual guarantees or offtake agreements, are highly likely to favour one participant at the expense of another, to the detriment of competition in general.

E4.6 Asset ownership

Over the past fifteen years the Commonwealth and State Governments have sold almost all their gas assets. The industry's ability to fund and develop recent major inter-jurisdictional projects such as the SEAGas Pipeline and keen competition for infrastructure assets by superannuation funds suggests that Government asset ownership is unlikely to be required to ensure gas supply in the future.

E5 Policy options that balance export and domestic needs

E5.1 Australian policy to date

Gas is currently exported as LNG from Dampier in WA (based on North West Shelf gas resources) and from Darwin (based on Timor Sea gas resources). Prospects of gas exports from other jurisdictions have until recently appeared to be limited but Arrow Energy has recently announced plans to export LNG from Gladstone from 2010.

Export related policy development has therefore largely been the concern of the Commonwealth, Western Australian and Northern Territory Governments though it may now also become a concern of the Queensland Government in relation to CSG.

Until 1997 Commonwealth approval of exports was required to ensure the adequacy of gas reserves and that prices received were satisfactory, including ensuring that transfer pricing did not occur. Federal controls on LNG exports were removed in 1997 and policy has subsequently been that gas developers should be free to sell their products into the markets of their choice.

The initial development of the North West Shelf project to supply domestic and export markets involved an extensive policy and financial assistance package securing both the LNG and domgas projects for the state, ratified by the North West Gas Development (Woodside) Agreement Act 1979.

In 2006 the Western Australian Government adopted a policy of securing domestic gas commitments up to the equivalent of 15% of LNG production from all future export developments, to replicate the initial agreement with the NWSV and because of a perceived decline in availability of gas from non-export developments. Woodside has agreed to a reservation from the Pluto development but domgas from this reservation will only be available 5 years after LNG supply. Under the Barrow Island Act 2003, the Gorgon development is committed to reserving 2000 PJ of gas for domestic supply.

E5.3Policy assessment

Domestic gas supply security concerns in other countries

Many gas exporting nations have experienced concerns and difficulties regarding balanced exploitation of natural gas for export and domestic use and have put in place policies giving domestic use a preferential allocation. They have two causes for concern: insufficient gas reserves for both uses; and inadequate development of gas supply for domestic use. Most exporters have substantial gas reserves endowments and gas reserves are seldom the problem – only Trinidad and perhaps Indonesia have gas reserves issues. More frequently the problem is inadequate development due to inefficiencies in gas investment and regulatory frameworks and in many countries the policy responses have at best failed to address the problems and at worst compounded them. None of these countries have established competitive domestic gas markets.

Exporters which have established competitive domestic markets, such as Canada, have moved away from domestic allocation policies even though this has ultimately led to higher domestic prices and the need to import some gas requirements.

Long-term energy demand –supply considerations

To what extent should energy policy take into account the long-term energy demand and supply balance and in particular domestic gas supply? In framing an answer to this question we have considered:

- Energy using technology time frames. The possibility of major change increases dramatically further into the future. Although many business-as-usual projections indicate ever rising gas (and oil) demand, it is entirely possible that demand (and supply) will be transformed in response to the GHG challenge and/or supply changes.
- Australia currently imports over 40% (net) of its oil requirements, having been self sufficient as recently as 2000. Although the import bill is large this has not slowed the economy significantly.

These observations suggest that:

1. Concern with domestic gas supply over the next 20 to 30 years is legitimate.
2. Domestic gas supply does not have to come from domestic gas resources but could come from pipeline gas (PNG) or LNG imports.

A traffic light scheme may provide useful guidance. Based on the above and the reserves security accepted in other countries the following scheme is recommended:

- Green - over 25 years reserves - no reserve concerns, policy can focus on gas development to maximise economic and environmental benefits, no concerns with exports
- Amber - 15 to 25 years reserves – growing concern with reserves and incremental exports, policy should focus on promoting reserves/supply growth.
- Red - under 15 years reserves – significant reserves concerns, prices are likely to rise to constrain demand and consideration of imports is warranted.

It is observed that condition “red” is not an indication of market failure and the consequent need for Government intervention, particularly if it has been arrived at progressively, with sufficient time for suppliers to consider imports and for users to adjust to higher prices.

It is recommended that a traffic light or similar scheme, including agreed definitions of market failure, be considered for implementation as part of a National Natural Gas Plan.

Current reserves position

At present consumption levels Australia's proved reserves have a life substantially longer than the 40 years since the initial natural gas discoveries were made. This represents sub-optimal exploitation of the resource, both from a national perspective and from the perspective of resource lease and licence holders. While domestic demand growth for power generation could be substantial, gas exports as LNG represent the major opportunity for increasing gas exploitation.

At the national level, an allocation of reserves to export and domestic use is therefore unnecessary.

Gas market development options

The principal markets into which significant additional gas could be sold include:

- Domestic power generation
- Domestic transportation (LNG or CNG)
- Gas to liquids conversion (for domestic or export markets)
- Ammonia and other chemical production (for domestic or export markets)
- Export as LNG or CNG

At present there seems little doubt that LNG exports offer the highest returns and are most attractive to gas producers for whom export is an option. It is recommended that an assessment of the alternatives be undertaken and if options other than LNG exports are found to offer greater economic returns, means of aligning gas producers' interests with those of the national economy could be sought, to enable the market to deliver the economically optimum outcome.

Gas development facilitation

A balance between gas for domestic and export use cannot be achieved by developing gas separately for each market – in Western Australia and the Northern Territory export development is required to fulfill domestic needs as well. Policy should therefore have the objective of facilitating gas development for both export and domestic use.

Options to facilitate gas development include:

- Project facilitation (Major Project Facilitation Status)
- Improved infrastructure approvals processes
- Commonwealth Government assistance with overseas project approvals and contract negotiation

- Investment in training oil and gas industry personnel
- Ensuring that retention lease principles are rigorously applied so that commercial fields are developed. If the domestic market is under supplied and there is any field that can supply the market on a commercial basis, this mechanism is the last resort to ensure supply in the current framework.

MMA believes that these options and others identified under "Barriers to gas supply" provide the best means to ensure balanced exploitation of gas for export and domestic uses over the next decade.

E5.4 The need for a national natural gas plan

The current gas planning and decision making processes can be characterised as:

- Distributed – undertaken by individual participants
- Confidential – planning documents are not available for public scrutiny

Pipelines regulated under the Code do submit Access Arrangements in which their projected demand and capital spending plans are publicly outlined. However there is a trend for Access Arrangements to relate only to existing capacity, with capacity expansion negotiated separately with shippers. An exception to this model has been instituted in Victoria where the gas transmission and market operator VENCorp publishes a Gas Annual Planning Report (GAPR).

Stakeholders consulted by MMA indicated that they are satisfied with their own current planning arrangements, which involve supply-demand projections of varying levels of national integration. They do not believe they will derive much benefit from a national natural gas plan (NNGP) but would support preparation of an indicative gas plan if it was of value to governments. Some stakeholders also acknowledged that new entrants to the gas market may derive some benefits from a plan.

MMA believes that a NNGP will be of value to Governments and gas users, as well as to the gas industry as an independent means of communicating on gas supply security with Governments. However its introduction will require the exercise of considerable care to establish a suitable balance between the level of detail (sufficient to generate information of value) and wasting resources.

E5.5 Elements of a national natural gas plan

Objectives

A NNGP should be designed to meet well-defined objectives. Considering the issues addressed by this study MMA believes that the NNGP objectives could be:

1. Capacity adequacy: to indicate short-term domestic demand supply imbalances and the options open to redress them within the available timeframe.
2. Reserves adequacy: to indicate long-term domestic and export demand growth potential and the implications for supply, taking into account current reserves, likely new discoveries and potential imports.

Key features

The features MMA would expect to see in a NNGP are similar to those in the GAPR and the National Electricity Market SOO but with different details and approach for the long-term projections:

- Demand projections
- Supply projections
- Supply-demand balance indicators
- Constraints and capacity development requirements
- Measures of reliability and supply security. The traffic light scheme or a similar scheme could be adopted. This could include definitions of the circumstances under which the gas market is deemed to have failed and Government intervention is required.

Stakeholders would prefer information provision to be voluntary but it is noted that the GAPR relies upon information obtained under the Victorian gas market rules.

The most sensible choice as a planning body is the new National Energy Market Operator, NEMO, proposed by the MCE, since it will also prepare the electricity SOO. A question remains regarding preparation of the NNGP for areas where NEMO will not operate a gas market.

1 INTRODUCTION

1.1 The Joint Working Group on Natural Gas Supply

The Joint Working Group on Natural Gas Supply (the Working Group) was established by the Ministerial Council for Mineral and Petroleum Resources and the Ministerial Council on Energy in recognition of the need to realise the twin goals of becoming one of the world's major LNG exporters and ensuring the long term supply of gas for domestic users. Working Group membership is tabled in APPENDIX A .

At the same time that Australia is experiencing unprecedented growth in the LNG export market, Australian governments are moving to increase use of natural gas domestically, as a clean, competitively priced, plentiful Australian energy source. Domestic gas therefore has an increasingly significant role in guaranteeing Australia's long-term energy security. The Working Group will consider issues surrounding domestic gas supply/demand balances. This will include consideration of the allocation of economic benefits, costs and risks associated with gas activities. The Working Group recognises that these issues must be considered in the context of the particular circumstances of different regions and jurisdictions in Australia. The three main issues for consideration are domestic supply/demand and prices, long term energy security and economic growth.

1.1.1 Terms of reference

The Working Group's terms of reference are to:

1. Investigate and quantify the likely demand for domestic gas against supply (including conventional sources and non-conventional sources such as tight gas and coal seam methane) for existing and future markets, including new gas industries using a multi-scenario approach.

2. Using a multi-scenario approach, review the benefits, costs and risks associated with both exporting LNG and ensuring domestic gas security (including drawing on the work done previously by MCMPR SCO on gas supply issues) in order to:

   - Understand, at an Australian regional and State level, the structure, scope and size of:

     a) The Australian upstream gas industry/market; and

     b) The Australian domestic gas market.

   - Analyse the pricing differential between the export market and domestic gas markets.

3. Investigate barriers to domestic gas supply including upstream supply infrastructure and outline practical strategies that will ensure the availability of competitively priced gas to every State/Territory as required.

4. Analyse the risks and benefits to the States, Territories and Commonwealth jurisdictions with regard to the development of major inter-jurisdictional gas projects.

5. Consider options that deliver natural gas resources for export and the supply of domestic natural gas to meet jurisdictional and national long term needs and taking into account national energy security issues consistent with COAG's National Energy Policy Framework.

   Consider the need for a national gas plan.

6. Deliver a draft report to the MCMPR/MCE SCO by August 2007 for subsequent consideration by Ministers in Council in 2007.

1.1.2 Working Group advisors

The Working Group engaged two advisors to assist with its work program:

- The Australian Bureau of Agricultural & Resource Economics (ABARE), to conduct a study of terms of reference 1 and 2
- McLennan Magasanik Associates (MMA), to assess terms of reference 3, 4 and 5, the "Natural Gas in Australia" study

1.2 MMA's brief

MMA's brief sets out further details of terms of reference 3, 4 and 5.

ToR 3. *Investigate barriers to domestic gas supply including upstream supply infrastructure and outline practical strategies that will ensure the availability of competitively priced gas to every State/Territory as required.*

The principal role of the consultant is to provide analysis and advice on factors impeding the supply of competitively priced gas to Australian gas consumers.

The principal tasks that the consultant will undertake include:

a) Review previous work that has been undertaken by the MCMPR and MCE and stakeholders, as identified by JWG members.

b) Review any other work/reports deemed relevant either by the consultant or the JWG members.

c) Identify barriers to domestic gas supply including upstream supply infrastructure.

d) Prepare options aimed at overcoming identified barriers to supplying gas to Australian consumers in each jurisdiction.

e) Identify special options that may be required to address barriers specific to individual jurisdictions.

ToR 4. *Analyse the risks and benefits to the States, Territories and Commonwealth jurisdictions with regard to the development of major inter-jurisdictional gas projects.*

The principal tasks that the consultant will undertake will include:

a) Review and document the various forms of support provided to facilitate the development of major inter-jurisdictional gas projects.

b) Outline other forms of support that are considered to be effective in facilitating the development of major inter-jurisdictional gas projects.

c) Assess past major inter-jurisdictional gas project developments, particularly the distribution of risks and benefits by jurisdiction.

d) Identify and report on strategies that effectively mitigate the risks and maximise the benefits to jurisdictions.

This should include an assessment of the merits of co-support arrangements between jurisdictions to increase the benefits while minimising risk to individual jurisdictions.

ToR 5. *Consider options that specifically deliver the exploitation of natural gas resources for export and the supply of domestic natural gas to meet jurisdictional long term needs and taking into account national energy security issues consistent with COAG's National Energy Policy Framework. (a) Consider the need for a national gas plan.*

The principal tasks that the consultant will undertake include:

a) Review both Australian (State, Territory and Commonwealth) and international policies that address the need to balance the exploitation of natural gas resources for export with the need to satisfy domestic natural gas demand.

b) Research and develop any possible policy approaches/suggestions not previously considered or implemented.

c) Compare and contrast Australian and international policies.

d) Provide an evaluation of the likely effectiveness and benefit of complementing existing Australian natural gas policies with policies implemented in international jurisdictions.

e) Based on this analysis, assess the need for a national natural gas plan.

f) If appropriate, provide an outline of elements of a national natural gas plan considered crucial to achieving successful outcomes.

1.3 Study approach

This study is a detailed investigation of the institutional structures in the Australian gas industry, of how they are working, where they are failing in regard to ensuring competitive domestic gas supply and what Governments could do about it.

We have obtained the views of government and industry and subjected it to critical review, as well as conducting extensive internal analysis. To the extent possible our views have been quantified, to provide answers to the questions, "how much of a problem is this?" and "what are the important issues?"

The study addresses a number of issues that were no considered important until recently.

1.4 Work program

MMA's work program included extensive stakeholder consultation with desk top research and analysis. Consultation has involved the Joint Working Group, ABARE, in relation to their study of ToRs 1 and 2, and the gas industry. Research has included reviews and analyses of material provided by the Working Group, industry submissions and material discovered by MMA. The same approach and work plan was applied to all three tasks.

1.4.1 Stakeholder consultation

MMA's program of work in relation to terms of reference 3, 4 and 5 included consultation with all sectors of the gas industry, including gas consumers, and members of the Joint Working Group.

Industry consultation was undertaken through the Gas Market Leaders Group (GMLG), a group representing all sectors of the gas industry which has been established by MCE to guide the development of a gas market bulletin board and a short-term gas trading market. GMLG membership is tabled in APPENDIX B .

A discussion paper describing the study was prepared to facilitate the consultation process and circulated to GMLG members prior to their meeting on 29th March 2007. MMA also made a presentation on the study to the GMLG at this meeting. Both the discussion paper and the presentation requested GMLG members to:

- Make written submissions in relation to the issues raised and/or
- Convey their views to MMA through discussion (face-to-face or teleconference) and/or
- Circulate the discussion paper to other stakeholders in their sector to give them an opportunity to make submissions or discuss their views with MMA

To meet study timelines stakeholders were initially given a limited period of 4 weeks to respond, subsequently this was extended to 6 weeks. In view of the time limits it was anticipated that a majority would elect to respond through discussions and MMA subsequently received 3 written submissions, held 8 face-to-face discussions, and 4 via teleconference, a total of 15 responses, over the period 5th April to 24th May.

All information that MMA has received through this process has been treated as confidential, unless it is known also to be in the public domain, and is reported in a manner that cannot be attributed to individual stakeholders.

MMA has similarly consulted with and received inputs from the members of the Joint Working Group, including responses to a draft version of this report.

The information gathered from the discussions has been invaluable to the study and the contributions of all stakeholders are gratefully acknowledged. All views expressed in this report are nevertheless those of MMA unless specifically attributed to stakeholders.

1.5 Layout of this report

The body of this report contains the following sections:

2. The Australian gas industry – a brief outline of the institutional arrangements
3. Gas market status and outlook – a comprehensive review of the factors underlying gas demand/supply, providing the market context for assessing barriers to gas supply and suitable policy responses
4. Barriers to domestic gas supply - a detailed review of sixteen barriers suggested by stakeholders and management options for reducing or eliminating them
5. Risks and benefits of major inter-jurisdictional gas projects - a review of the roles played by governments in past projects and appropriate roles in future projects
6. Policy options that balance domestic and export needs – consideration of options available and their relevance in Australia, with reference to overseas policies, and the value and potential structure of a national gas plan.

APPENDIX A lists the members of the Working Group.

APPENDIX B lists the members of the Gas Market Leaders Group.

APPENDIX C provides a glossary of abbreviations

2 THE AUSTRALIAN GAS INDUSTRY

2.1 What is a barrier to gas supply?

Barriers (or potential barriers) to supply of gas to the domestic market can be physical and/or institutional. The only purely physical barrier would be the absence of gas resources, whose distribution is determined by natural, geological processes, but even an apparent lack of resources can be the result of a lack of exploration, that is, an institutional problem.

All other barriers are a combination of physical and institutional issues, such as when gas resources cannot be developed economically in competition with other sources of energy, or purely institutional, as when the overall resource economics are sound but the economics of one element of the supply chain is not and development does not proceed. The focus of this report is largely on the last category of barriers to supply, because they are the ones that can potentially be removed by changing the institutional framework. The ABARE study of terms of reference 1 and 2 addresses the resource and overall economic barriers questions.

2.2 Institutional arrangements

This section outlines the institutional arrangements in each major[1] sector of the supply chain, within and between which barriers to supply could be created. Consistent with national competition policy, the gas industry operates in an environment that emphasizes competitive outcomes in each sector and relies upon regulation only to deal with issues of market power, as summarised below:

- Exploration and production – fully competitive
- Transmission – new pipelines are established in competition with existing pipelines, some of which are price regulated to control their market power
- Distribution – generally distribution networks have strong monopoly characteristics and are price regulated
- Retail – fully competitive but with some price controls for small end-users that have not switched retailer

Industry ownership is almost entirely in the private sector and there is limited centralised planning input. Investment decisions in most sectors are in the hands of industry participants though distribution capacity expansion is subject to regulatory approval of cost recovery from system users.

[1] Minor sectors include gas storage (generally part of production or transmission) and trading (generally part of retail in Australia at present)

2.2.1 Exploration and production

The exploration and production (E&P) sector is part of the broader petroleum industry. Sector participants seek to discover, market and produce hydrocarbons such as natural gas, ethane, LPG, condensate and crude oil. Many sector decisions are based upon multi-product considerations and many of the products, including natural gas, are sold into both domestic and export markets.

Hydrocarbons result from geological processes and are generally found in sandstone reservoirs or coal seams at depths ranging from several hundred metres for the latter up to several thousand metres for the former. Rights to underground resources vest in the relevant jurisdictional government, or the Commonwealth where they are in Australian territorial waters.

The jurisdictions generate or collect pre-competitive geological information regarding potential petroleum resources and regularly call for bids from participants for permits to explore defined exploration lease areas. Permits are awarded on the basis of participant commitments to explore by means of seismic surveys and by drilling wells. A hydrocarbon discovery may be converted into either a production lease, if development is to proceed immediately, or a retention lease[2], if production is not at that time commercially viable but is expected to become so within 15 years. Retention leases are granted for periods of 5 years, after which they can be renewed, and authorities can require lessees to re-evaluate the commerciality viability of petroleum production in a lease area once during the term of a lease. Permits that are unsuccessful are relinquished and may be retendered.

The above aspects of offshore E&P are governed by the Petroleum (Submerged Lands) Act (PSLA, Commonwealth), with similar jurisdictional legislation governing onshore E&P. National policy is determined by the MCMPR. Resource extraction in Australia is generally subject to royalty payments in addition to income tax – offshore petroleum resources are subject to the Petroleum Resources Rent Tax (PRRT) and onshore resources are subject to jurisdictional royalty regimes.

Producers market gas domestically to buyers such as retailers, generators and large industrial users. The structure of these transactions is determined by the participants, with almost all being long-term arrangements that lock-in prices and quantities with limited flexibility for a number of years. Further details about this key market are provided in section 3.

A characteristic feature of the E&P sector worldwide is the use of joint ventures (JVs) as a risk management tool. The majority of exploration permits, retention leases and production leases are granted to joint ventures comprised of two or more E&P companies. One company acts as the operator but all costs and production are split in proportion to

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[2] Queensland does not have separate retention leases. Retention is managed under the Authority to Prospect (a potential commercial area). However, the concepts of retention are the same as other States.

share of the JV. Many products, such as crude oil, are sold separately by each JV partner but natural gas has typically been marketed and sold jointly, a legacy from the natural gas start up period in the 1960s and 1970s when producers had to deal with monopsony buyers.

2.2.2 Transmission

The transmission sector constructs and operates high pressure, large diameter pipelines that convey gas from receipt points (producers' plant gates or other pipelines' delivery points) to delivery points into distribution networks (city gates) or large customer offtake points. The pipelines generally have multiple receipt and delivery points and have unidirectional flows, though many offer notional backhaul services (delivery upstream of receipt) and in some the flow reverses from time to time.

New pipelines and incremental capacity are generally constructed in response to a gas buyer's desire to transport additional gas, or gas from a new source, to a new or existing market. The initial capacity of the pipeline is tailored to the buyer's needs and capacity expansion can usually be achieved by adding additional intermediate compression or by partially duplicating the pipeline, known as looping. Investment cost recovery risk is reduced by the contract commitments made by the gas buyer - very few gas pipelines have been constructed on a merchant basis i.e. build and they will come.

Transmission pipelines generally provide services on a third party basis, that is, do not carry gas on their own behalf. Third party access to transmission (and distribution) pipelines is currently governed by the national gas access regime established under the Gas Pipelines Access Law (GPAL), which was enacted by all jurisdictions in 1997/98, and has as its key element the National Third Party Access Code for Natural Gas Pipeline Systems (the Code). The Law and Code are to be replaced by the National Gas Law and National Gas Rules during 2007/08.

The Code contains a "coverage" test related to the pipeline's market power, which determines whether pipelines are subject to the Code ("covered") or not. The Code regulates covered pipelines' prices for specific reference services and uncovered pipelines set prices on a commercial basis in competition with other pipelines. Uncovered pipelines remain subject to the third party access provisions of the Trade Practices Act.

Commercial arrangements for pipelines tend to reflect those upstream, with gas buyers taking up long-term contacts for pipeline capacity to guarantee transportation of the gas they are committed to buying. For covered pipelines the contract prices are generally comparable to regulated reference service prices. The Victorian Principal Transmission System (VPTS) is a key exception to these "contract carriage" arrangements. On the "market carriage" VPTS gas buyers do not contract for capacity but incur some risks regarding capacity availability at times of peak demand. VPTS capacity expansion is undertaken subject to regulatory approval of cost recovery from system users.

2.2.3 Distribution

The distribution sector constructs and operates the network of high to low pressure, large to small diameter pipelines that convey gas from receipt points from transmission pipelines (city gates) to customer meters. The networks generally have a large diameter high pressure spine that delivers gas to very large end-users and also conveys gas to the small diameter pipes serving a large number of small to medium size end-users.

Distribution networks provide services on a third party basis under the same Law and Code as transmission pipelines. Duplication of distribution networks is very rarely economic and the networks generally hold considerable market power, hence all the major distribution networks are covered by the Code. A number of small independent networks serving regional towns have become uncovered on the grounds that the cost of regulation under the Code would be excessive relative to network revenue and would outweigh the benefits.

Network capacity is generally incremented in response to growth in the number of end-users, such as residential users in a new housing estate. From time to time the capacity of the spine is also increased. Although distribution networks outside Victoria operate under contract carriage, in all distribution networks capacity expansion is undertaken subject to regulatory approval of cost recovery from system users rather than on the basis on contracts with retailers. This is consistent with the fact that new end-users, such as new home owners, do not select a retailer until they start using gas, well after the gas network serving them has been constructed.

Some jurisdictions have also introduced non-price related distribution regulations that go beyond the Code, for example obligations to provide connection services to small customers. These regulations are to be consolidated in a National Framework for Distribution and Retailing, which will apply to both gas and electricity retailing.

2.2.4 Retail

The retail sector purchases gas from producers and arranges transmission and distribution, either on its own behalf, in the case of electricity generators and large industrial gas users, or on behalf of its retail customers, in the case of full service retailers. It also includes some gas traders, who buy from producers and sell to retailers.

The majority of gas retailers are also electricity retailers, owing to the synergies between the two businesses, such as the economies of scope in selling two products to a customer and the value that can be extracted from a gas supply portfolio by a gas-fired peaking generator used to hedge electricity retail price risks.

Although gas retailing is a competitive activity, each jurisdiction has introduced non-price related regulations governing aspects of retailing such as: small customer marketing; contracts and obligations to supply; and retailer failure mechanisms. These regulations are to be consolidated in a National Framework for Distribution and Retailing, which will apply to both gas and electricity retailing.

2.2.5 Wholesale gas market structure

The wholesale gas markets in both Eastern and Western Australia are largely based on bilateral trading between gas producers and buyers such as retailers, generators and large industrial users. The structure of these bilateral trades is determined by the market participants and the majority of trades take the form of long-term gas sales agreements (contracts). Each contract typically specifies a delivery point (usually the producer's plant gate but sometimes a transmission pipeline city gate), an offtake schedule (minimum and maximum daily and annual gas quantities) and pricing, together with a raft of other commercial and legal conditions of sale. Contract durations are typically in the range from three to twenty years.

The gas pipeline system, with the exception of that in Victoria, operates on a similar contractual basis. Gas scheduling takes place by means of gas buyers nominating daily quantity requirements to producers, pipeliners and retail market operators under the terms of their contracts. Pipelines and retail market operators then co-ordinate actual gas flows and ensure that each participant's imbalances between injections and withdrawals are addressed by adjustments to subsequent nominations. In Victoria a price-based balancing regime, in which nominations are replaced by bids into a gas pool, has been operated by an independent system operator, VENCorp, since 1999. Most of the gas bid into the pool is bid by buyers, sourced from long term contracts with producers, and the pool price has reflected the dominant contract prices.

Outside Victoria shorter-term gas markets are relatively undeveloped and illiquid, though some bilateral secondary trading is known to occur. The Ministerial Council on Energy has initiated a program of short-term market development under the auspices of the Gas Market Leaders Group (GMLG), which it is anticipated will result in price based gas balancing regimes being implemented in New South Wales, South Australia and possibly elsewhere. These regimes are likely to be simpler versions of the Victorian regime and as such are not expected to replace long term agreements as the principal wholesale market transactions.

This market structure has a number of advantages and disadvantages. Long-term contracts provide financial security for producers and pipelines, which facilitates new producer entry, a pre-condition for greater wholesale market competition. It also provides security of supply to the user market, for the contract period, but the limited quantity flexibility presents risks to buyers already in competitive markets, who find it difficult to manage the risks in the absence of short-term market liquidity. The contract market also lacks price transparency and suffers from infrequent price discovery (to the extent prices are known). The principal objective of the MCE initiative is to reduce some of these risks.

Competition in the long-term contract market in general relies upon the potential entry of new capacity. To maximise the number of new entrants involved, negotiations must therefore take place three to four years in advance of first gas requirements, to allow capacity to be constructed.

2.2.6 Retail gas market structure

The day to day operations of gas buyers that are large end-users with daily-read meters is fully catered for by wholesale market functions. Retailing of gas to the large number of smaller users with meters that are read at less frequent intervals (one, two or three months) requires further agreed processes to deal with customer transfer (keeping track of which retailer is supplying which customers) and the associated issues for gas allocation and balancing. Independent retail market operators have been established in New South Wales (GMC), Victoria (VENCORP), Queensland (VENCORP), South Australia (Remco), Western Australia (Remco) and the ACT (GMC) to undertake these functions.

3 GAS MARKET STATUS AND OUTLOOK

3.1 Introduction

Barriers to gas supply arise within the context of the gas market. The following sections present reviews of the status of the three relevant interacting market sectors, domestic wholesale, domestic retail and export, to provide a perspective within which barriers to supply can be examined.

3.1.1 Wholesale market

The wholesale market is a key element in delivering gas to the domestic market. It covers the long and short-term arrangements whereby gas producers sell gas to buyers. Our overview of the wholesale market outlook in Western Australia, Eastern Australia and the Northern Territory focuses on:

- Demand projections
- Gas supply - the contracted supply position
- The new contract requirement , in terms of scale and timing
- Potential sources of new contract supply, based on developed and undeveloped gas reserves, including the level of competition among producers

It is noted that the projections developed in this section are purely for the purpose of illustrating new contract requirements. They are not intended to replace projections developed for the Joint Working Group by ABARE.

3.1.2 Retail market

The retail market covers the arrangements whereby gas is sold to end users by retailers. Our overview of the retail market outlook in Eastern Australia (the retail markets in Western Australia and the Northern Territory are relatively undeveloped) focuses on the level of competition among retailers:

- The number of retail participants and their market shares
- Customer churn
- Retailer gas contract positions

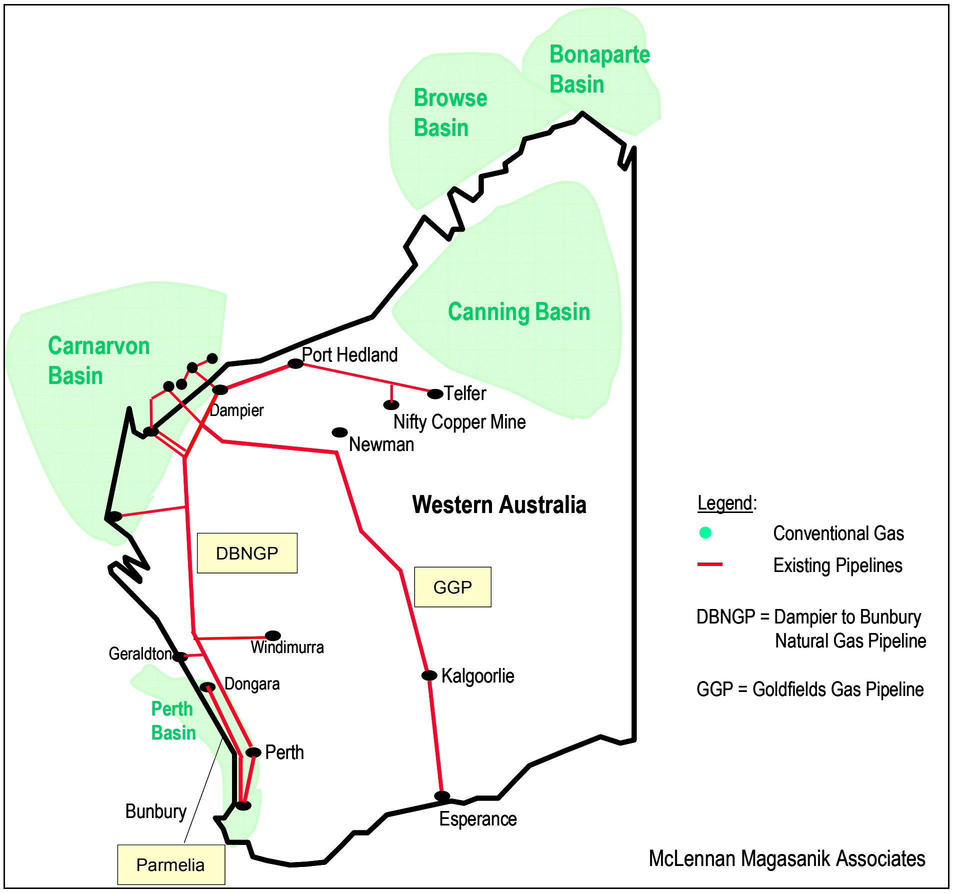
3.1.3 Export market

Australia exports liquefied natural gas (LNG) to Asian markets, primarily in Japan, Korea, Taiwan and China. Our overview of this market focuses on market growth and pricing trends that could influence the quantities and price of gas in the domestic market.

3.2 Western Australian Wholesale Market

3.2.1 Introduction

Figure 3-1 Gas infrastructure, Western Australia



Western Australia has extensive gas reserves (125,000 PJ as at 31 Dec 2005, at the P50 level) that support a strong domestic market (estimated at 280 PJ in 2005) and export market (estimated at 610 PJ in 2005). The domestic market, which is considerably larger than those of other individual states in Australia, is supported by several transmission pipelines linking reserves to market centres (Figure 3-1) and has until recently benefited from lower well-head prices than elsewhere in Australia.

Following the introduction of third party access in 1995 the wellhead gas price in new contracts fell from approximately \$4/GJ to under \$2/GJ owing to the competition to the dominant seller, the North West Shelf Venture (NWSV), from producers with smaller gas reserves that had previously been kept out of the market.

3.2.2 Gas demand

3.2.2.1 Domestic demand

Natural gas supplies approximately 53% (280PJ) of Western Australia's non-transport primary energy, excluding gas used in oil and gas production[3]. Recent demand trends in the major end-use sectors are shown in Table 3-1. Strong growth in all sectors from 2000/01 to 2003/04 was offset by the closure of the bhpbilliton Direct Reduced Iron plant at Boodarie near Port Hedland in 2005. Annual growth in the non-iron & steel sectors from 2000/01 to 2004/05 was 3%.

Table 3-1 Demand trends (PJ)

Sector	2000/01	2001/02	2002/03	2003/04	2004/05	% Growth
Non-ferrous metals	93.4	94.1	95.2	99.9	100.2	1.8%
Iron & Steel	21.5	22.9	33.5	32.0		-100.0%
Non-metallic minerals	13.7	14.4	14.2	14.5	14.8	1.9%
Other	18.5	19.1	21.2	24.1	26.9	9.8%
Total Manufacturing	**147.1**	**150.5**	**164.1**	**170.5**	**141.9**	**-0.9%**
Electricity generation	**101.4**	**101.7**	**104.5**	**110.5**	**113.3**	**2.8%**
Gas transmission & distribution	**9.7**	**11.1**	**11.6**	**11.6**	**12.3**	**6.1%**
Commercial	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**0.0%**
Residential	**8.8**	**9.1**	**9.0**	**8.7**	**9.1**	**0.8%**
Total	**270.1**	**275.5**	**292.3**	**304.4**	**279.7**	**0.9%**

3.2.2.2 Domestic gas demand projections

MMA's demand projections incorporate the forecasts developed for the recent DBNGP Access Arrangement[4] up to 2010 and assume growth of 3% p.a. thereafter, consistent with recent historical growth in the non-iron & steel sectors. These projections are advanced as reasonable "business as usual" estimates, i.e. consistent with constant gas prices and strong economic growth, but would have to be adjusted for any significant long-term gas price increases. The projections do not include any major new gas intensive projects such as gas-to-liquids, methanol or minerals processing.

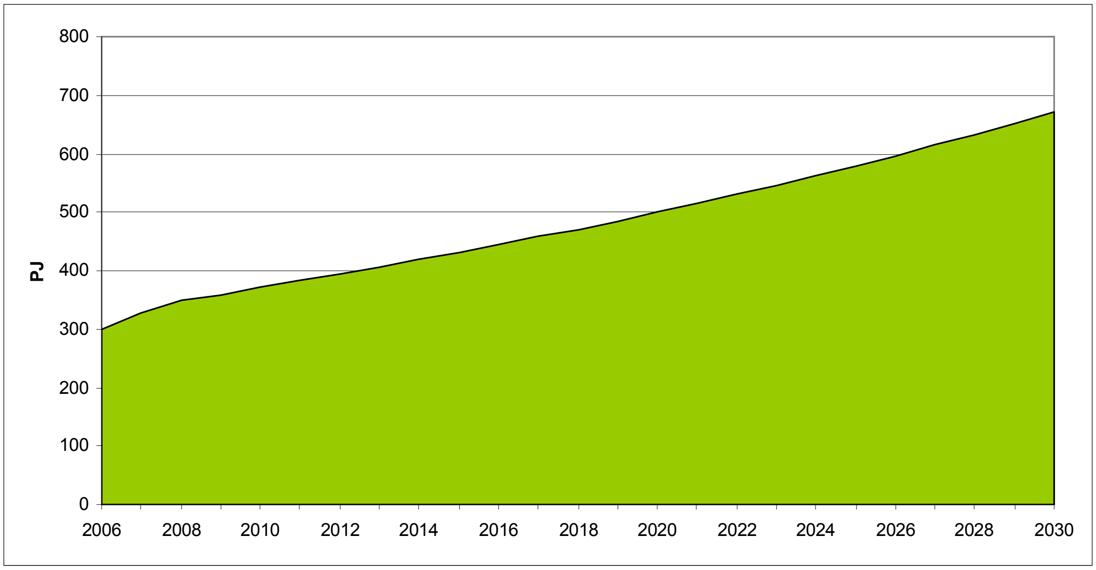
Demand to 2012 is shown in Table 3-2 and longer term demand is presented in Figure 3-2.

Table 3-2 Western Australia - annual domestic demand projections (PJ/yr)

2006	2007	2008	2009	2010	2011	2012
300	327	349	357	372	383	395

[3] ABARE Energy Update 2006, June 2006, Table f.
[4] Access Arrangement Information for the Dampier to Bunbury Natural Gas Pipeline, 15 December 2005

Figure 3-2 Western Australia – long-term annual domestic demand projections (PJ/yr)



3.2.2.3 *Export gas demand*

Australian LNG produced at Dampier (WA) and Darwin currently supplies markets in Asia, predominantly Japan but also Korea, China and India. Australian LNG is likely to be competitive in the US West Coast market but it has not been and is unlikely to be competitive in the European or US East Coast markets. Further details of gas export markets are provided in section 3.6.

3.2.3 Gas supply

3.2.3.1 *Gas reserves*

Western Australia has approximately 125,000 PJ of gas reserves remaining as at 31 December 2005 at the P50 level (50% probability of being exceeded), excluding resources that have yet to be found (Table 3-3).

WA's reserves are concentrated in the offshore Carnavon and Browse basins (Figure 3-1), with only very minor reserves left in the onshore Perth basin which was the sole source of WA's supply until the North West Shelf came on-stream in 1984. Other resources, for which there are no P50 reserve estimates, include coal seam gas from the Vasse Shelf coal fields and the Whicher Range tight gas fields, both of which are in the southern Perth Basin, and the relatively unexplored Canning Basin. The combined reserves of these resources could be several thousand PJ. On July 6 2007 Westralian Gas & Power announced a deal whereby ERM Gas will explore WGP's CSG leases with the intent of supplying CSG to ERM Power affiliated power stations.

Table 3-3 Western Australian P50 gas reserves as at 31 December 2005 (PJ)

Field (s)	Basin	Developed	Undeveloped	Retention Lease	Total
Beharra Springs	Perth	16	0	0	16
Browse Northern	Browse	0	690	849	1,539
Dongara	Perth	38	3	0	42
East Spar	Carnavon	1	0	0	1
Gorgon	Carnavon	33	15,097	5,347	20,477
Griffin	Carnavon	15	0	0	15
Harriet	Carnavon	168	172	193	533
Ichthys	Browse	0	10,222	0	10,222
Io/Jansz	Carnavon	0	0	32,025	32,025
John Brookes	Carnavon	1,456	0	0	1,456
Macedon	Carnavon	0	0	749	749
NWSV	Carnavon	20,321	4,023	967	25,311
Pluto	Carnavon	0	3,600	0	3,600
Reindeer	Carnavon	0	580	0	580
Scarborough	Carnavon	0	0	5,586	5,586
Torosa[5] et al	Browse	0	0	22,349	22,349
Woodada	Perth	2	0	0	2
Total		**22,050**	**34,388**	**68,065**	**124,503**

Source: Condensed from "Oil and Gas Review 2006", WA Dept of Industry and Resources

Relative to current production of approximately 1,000 PJ p.a. (280 PJ domestic plus 610 PJ LNG, plus gas used in production) this indicates a "simple" reserve life of approximately 125 years. Even allowing for a significant acceleration in LNG production, Western Australia faces no appreciable overall reserve risk over the next 20 years.

3.2.3.2 Reserve Accessibility

Western Australia's gas reserves are not all equally accessible however, particularly to the domestic market. Many of the large discoveries lie a considerable distance offshore, in relatively deep water and one, Gorgon, has a high level of CO2 (Table 3-4). These factors all add to the cost of developing the reserves and in the case of the most remote fields, such as Ichthys and Torosa, could make floating or remote island developments for LNG or GTL the most attractive options, though it is noted that Woodside is now considering the option of linking Torosa to existing LNG processing facilities on the Burrup Peninsula via a 950km pipeline[6]. Floating or remote island development options would preclude any domestic sales.

[5] Formerly known as Scott Reef. Other fields include Brecknock and Calliance
[6] Presentation to UBS – Australian Energy and Utilities Conference by Don Voelte, Woodside, 27 June 2007

Table 3-4 Large field accessibility parameters

			Gas Composition			
Field(s)	Distance offshore (km)	Water depth (m)	Methane	Other Hydrocarbons	CO2	Nitrogen
Gorgon	130	500-1000	76.7%	4.5%	14-15%	2-3%
Io/Jansz	140	1400	91.5%	5.9%	0.3%	2.3%
Ichthys	440	600	N/a	N/a	N/a	N/a
Scarborough	280	900	95%	Incl in methane	Low	5%
Torosa	430	400-800	N/a	N/a	N/a	N/a

Sources: Kimber[7], Oil & Gas Review 2006

3.2.3.3 Contracted supply

MMA maintains a data base of both domestic and LNG gas supply contracts, derived from information published by the WA Office of Energy[8] and buyer/seller websites. While there are likely to be some contracts missing from the data base, either because their existence is not on the public record or because we have failed to find it, MMA is confident that 95% of gas volume contracted is accounted for. In addition a number of agreements between NWSV and various customers that are to result in incremental sales in 2007[9] are not included because the volumes are unknown. For many contracts however only the term and total volume committed are known and annual volumes can only be estimated. Table 3-5 shows the total domestic and LNG contracted volumes, based on 43 and 30 contracts respectively, compared with developed reserves as at 31 December 2005. It is noted that the Harriet and John Brookes contract figures have been adjusted by assuming some Harriet contracts will be supplied from John Brookes. This is due to the Harriet fields apparently being contracted beyond P50 reserves, which has resulted in one of the Harriet producers, TAP, declaring reserves force majeure in relation to their contracts with Burrup Fertilisers. It has been assumed that the Harriet operator, Apache, has elected to supply its reserves deficit from John Brookes. It is noted that uncontracted reserves are small and in the case of NWSV may be overstated because the gas used in LNG liquefaction and transportation has not been accounted for in the gas contracted figures.

[7] Review of gas specification for Dampier to Bunbury Natural Gas Pipeline & determination of an appropriate gas composition for design of stage 5 expansion. MJ Kimber and Associates, 22 February 2006
[8] Energy Western Australia, published up to 2002, contained a list of major contracts
[9] Chairman's address, Woodside Petroleum AGM, 19 April 2007.

Table 3-5 Developed gas at 31 December 2005

Field (s)	Developed	Contracted	Uncontracted
Beharra Springs	16	16	0
Dongara[10]	40	27	13
Griffin	15	17	-2
Harriet	168	343	-175
John Brookes	1,456	987	468
NWSV	20,321	16,152	4169
Total	**22,014**	**17,542**	**4,472**

Source: MMA estimates of contracted gas

All gas that could be contracted in the near future (without additional reserves development, which would take about three years) is clearly controlled by the John Brookes and NWSV joint ventures. Moreover the other four current producers also have very limited undeveloped reserves that are not committed and development of LNG projects such as Gorgon that could also supply the domestic has yet to be committed.

3.2.4 New contract requirements

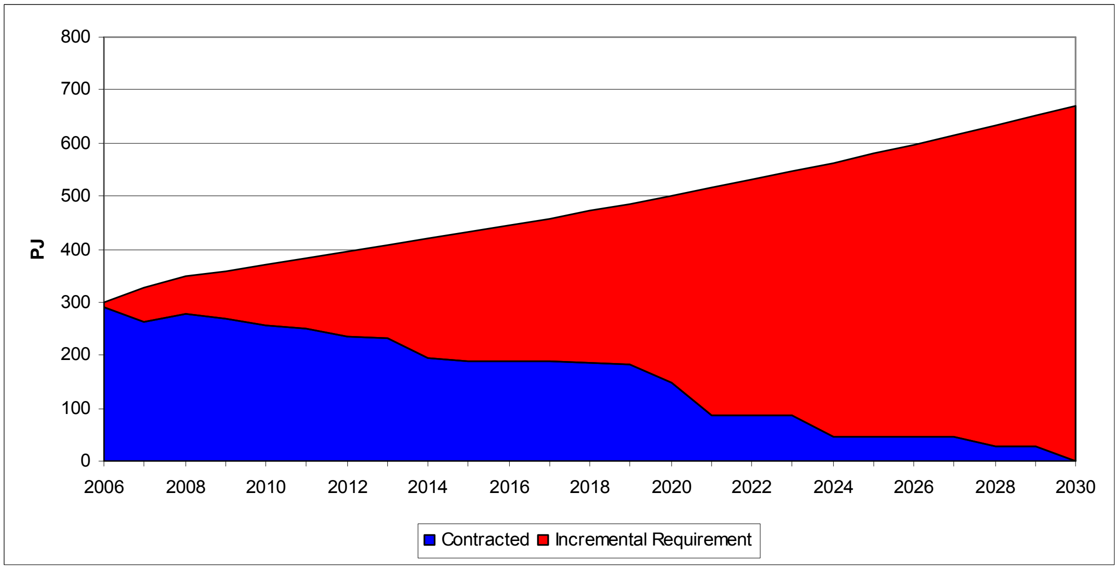
Domestic market requirements for additional contracts are presented in Figure 3-3. There appears to be an immediate requirement for 63 PJ in 2007 that grows to 116 PJ by 2010 and 244 PJ by 2015. The cumulative requirement to 2015 is approximately 1,300 PJ, growing to 2,700 PJ by 2020. This picture is consistent with that presented by Alcoa[11] and other industry estimates, for example 500 TJ/d (=170 PJ/year) of new and replacement gas required by 2013. Even if a 5% understatement of contracted volume is allowed for, a significant quantity of new contract volume is required in the near future.

The 2007 requirement is due to the large number of contracts that are understood to have ended in 2006 and has occurred despite the availability of take-or-pay gas from the bhpbilliton DRI plant contract, which lasts until 2013. Most of the contracts that are/have ended are with producers that do not have further reserves that can be contracted so it appears unlikely that they have been extended.

[10] Includes Woodada

[11] Figure 6 in "WA Domestic Gas Policy – Department of Industry and Resources, Submission by Alcoa of Australia", 19 April 2006

Figure 3-3 Incremental domestic gas requirements



3.2.5 Potential sources of new domestic supply

3.2.5.1 Short-term

On the basis of our assessment of uncontracted developed reserves, the short-term contract requirement, to about 2010, can only be met by the John Brookes and NWSV joint ventures. However gas purchasers report that the NWSV has withdrawn from the market, creating a very tight gas supply position. The Economic Regulation Authority has stated that NWSV's withdrawal is due to technical difficulties encountered during an upgrading program being undertaken on its two domestic gas processing trains[12]. The upgrading program had been intended to increase domgas capacity by 100 TJ/day to meet growing demand. However Woodside has stated that it is still actively marketing to customers, even though it is believed to have withdrawn term sheets for the extra 100TJ/day[13].

The tight supply position is reflected in recent pricing for new contracts. In January 2007 a new three-year contract for John Brookes gas was signed between Santos and Newmont Mining, which is reportedly paying $5.50/GJ, compared with average market prices of $2.50/GJ to $2.75/GJ a year earlier. In May and July 2007 three further low volume short-term contracts for John Brookes gas were signed between Santos and: Windimurra Vanadium (3 years at an estimated price of $5.80/GJ); Barrick Gold (5 years at an estimated price of $7.50/GJ; and Jabiru Metals (3 years at an estimated price of $4.70/GJ).

These prices are reflective of Santos' short-term market power, which has arisen for reasons discussed in section 3.2.6.

[12] Discussion Paper: Gas Issues in Western Australia. Economic Regulatory Authority, June 2007.
[13] Gas deals still done: Woodside, www.thewest.com.au, 15th June 2007

MMA is not aware of any new domestic supply projects that are already under development and it is therefore unlikely that new development gas will enter the market until 2010 or later, even with expedited planning processes. Unless higher prices attract the NWSV to re-enter the domestic market, the new contracts required in 2007, 2008 and 2009 may therefore all be priced at $5-8/GJ. These prices may act to constrain demand for new contracts to levels below those projected above. Although this price level is comparable to LNG equivalent prices (LNG delivered prices net of liquefaction and shipping costs) the John Brookes gas cannot be exported so there is no direct connection between the prices.

In volume terms John Brookes alone is unlikely to be able to supply the additional contract requirement unless its reserves are used over a very short–term. If incremental capacity is used over a ten year period, the 468 PJ of uncontracted reserves would supply 47 PJ per year, insufficient for 2007 and 44 PJ short of 2009 requirements. To meet the 2009 contract requirement John Brookes' incremental capacity would have to be used over a five year period. A further consideration is that Santos, the only party selling John Brookes gas, has recently stated that it has only 200PJ of uncontracted reserves[14] (prior to recent contracts for 15 PJ), rather than the 468 PJ we have estimated. In addition, Citic Pacific is reported to be negotiating with Santos for supply of up to 120 TJ/day (40 PJ/yr) from 2010 for its Cape Preston magnetite project[15], which may take up the remaining John Brookes reserves and require commitment of Reindeer reserves.

On balance it seems unlikely that the projected short-term incremental contract requirement can be met, unless the NWSV re-enters the market, with the result that demand growth will be constrained to the available supply. As noted above this may also be the outcome of higher prices for new contracts. NWSV's re-entry appears to be conditional on rectifying the difficulties with the upgrading, which may add up to 100 TJ/day (36 PJ/year) of capacity. Timing is unknown but if rectification is possible it is likely to be completed within twelve months. Further NWSV expansion may require a third gas processing train, a two to three year project.

3.2.5.2 Medium-term

The majority of WA's undeveloped gas reserves are in large offshore accumulations. Conventional wisdom suggests that gas fields or groups of fields under a certain size, 3,000 PJ say, cannot support an LNG project and that fields over a certain (but different) size, 5,000 PJ say, are too big to develop for the domestic market alone. There has therefore been a tendency to view the majority of fields as "domestic" or "export".

In terms of this duality, until export projects are fully committed to development, domestic buyers can only negotiate with "domestic" sellers and would have a limited choice, even if they are negotiating for supply from 2010 or later, which would allow time for new developments to proceed. From Table 3-3 the most prospective undeveloped

[14] 2006 Full Year Results Roadshow Presentation, Santos 22 February 2007
[15] Gas deals still done: Woodside, www.thewest.com.au, 15th June 2007

resources under 3,000 PJ are Macedon (bhpbilliton (operator) and Apache) and Reindeer (Apache (operator) and Santos), the Browse North resources being too distant from gas markets to warrant development. Santos has recently stated[16] that a feasibility study of the Reindeer opportunity is already under way, with a first production target of 2010. The Western Australian Oil and Gas Review 2006 (DOIR 2006) reports that bhpbilliton is continuing to investigate market opportunities for Macedon gas but bhpbilliton's most recent presentation in December 2006[17] does not suggest that it is under active consideration.

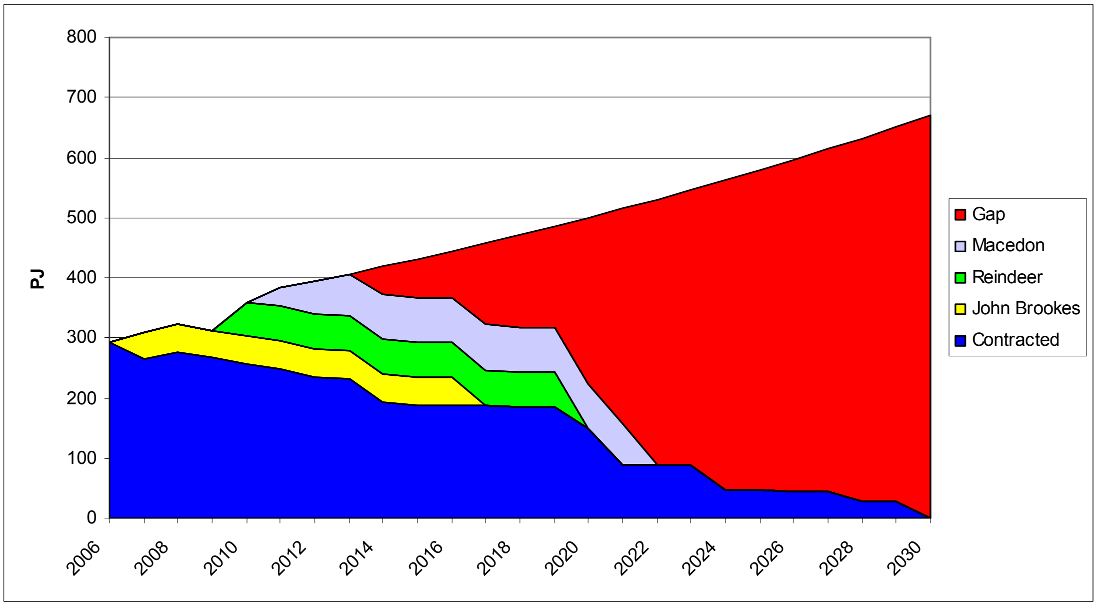
A further medium term option that has been put forward is the Canning Basin. ARC Energy[18] has suggested that the Canning Basin may contain a number of 500PJ+ fields, the size ARC believes is the threshold for domgas supply from this area. ARC is committed to a twenty well exploration effort in the Canning Basin over the next three years and believes an early discovery could be in production by 2010. In July 2007 ARC and Alcoa announced an agreement under which Alcoa will prepay $40m to ARC to accelerate this development, in return for an option on 500 PJ of gas from discoveries. Gas produced under this agreement would be shipped to Dampier through the Great Northern Pipeline, which is discussed in more detail in section 5.4.6.

Figure 3-4 shows how much of the incremental contract requirement can be met if the uncontracted John Brookes gas meets requirements to 2009, to the extent possible, with Reindeer start up in 2010 and Macedon in 2011, all with constraints that maximum production is 10% of initial reserves. Up to 2010 some 45 PJ/year of demand growth is deferred but after 2010 the incremental requirement is met in full until 2013. If price rises reduce demand growth by 1.5% the incremental requirement will be met until 2016. Beyond 2013 or 2016 the market would rely upon supply from either an "export" project or newly discovered "domestic" fields. The picture would be improved if NWSV re-entered the market.

It is noted that this picture is relatively independent of whether or not various reserves (John Brookes and Reindeer) are committed to the Citic Pacific project noted above. If they are committed some of the yellow and green bands transfer to blue – the length of contracts will affect the picture however.

[16] ibid
[17] Petroleum Analyst Presentation, bhpbilliton, 12 December 2006
[18] ARC Energy Corporate Update, March 2007.

Figure 3-4 Potential supply contribution of John Brookes, Reindeer and Macedon



3.2.5.3 Long-term

All other resources listed in Table 3-3 have been earmarked for export developments, whose status is summarised in Table 3-6. The most advanced projects are Pluto and Gorgon, followed by Pilbara (Scarborough) and Ichthys. The degree of difficulty of bringing these projects to fruition should not be underestimated. In its final determination on joint marketing by the NWSV in 1998[19] the ACCC reported likely development of Gorgon by 2002/03 and Scarborough by 2004/05, as well as Macedon by 2000, but as yet none are even fully committed to development.

Table 3-6 LNG project status

Project	Status
Greater Gorgon including Io Jansz	Started FEED in 2005. HoAs in place with Tokyo Gas, Chubu Electric and Osaka Gas. Received conditional environmental approval. Final decision date deferred and unknown. Potential production from 2011. Proposed plant on Barrow Island and domgas supply would require an 80-100 km pipeline to the mainland. Under the Barrow Island Act 2000 PJ is reserved for domestic marketing and domgas production is to commence in 2013.

[19] ACCC. Determination. Application for Authorisation. North West Shelf Project. Authorisation 90624, 29 July 1998

Project	Status
Ichthys	Project granted major facilitation status. Development scheme in planning stage – LNG, GTL and domestic gas considered. Proposed plant on Maret Island, in the far north of WA. Targeting production by 2012.
Outer Browse (Torosa and Brecknock)	Operator (bhpbilliton) still focussed on exploration. Production is unlikely before 2015. Plant location options include, floating, Broome and Burrup Peninsula.
Pilbara LNG (Scarborough field)	LNG pre-feasibility study commenced 2004. Proposed plant at Onslow.
Pluto	Final investment decision mid 2007. MoUs in place with Tokyo Gas & Kansai Electric. Woodside has agreed to market 15% domestically, starting 5 years after LNG delivery i.e. domestic by 2015. Proposed plant at Dampier.

3.2.5.4 *Participants' views*

The above independent assessment of contractual requirements is consistent with those of other parties, including Alcoa[20] and ARC Energy[21].

Views on the short-term outlook expressed by stakeholders, both in the media and through the consultation process for this study, are widely divergent. Those with downstream interests view the potential constraint on demand as clear evidence of market failure while producers believe that uncontracted demand is exaggerated and that there is no evidence of market failure.

A number of stakeholders consulted by MMA also expressed the view that the conventional wisdom that distinguishes "export" from "domestic" resources is an oversimplification and that a number of resources could be developed for either market. ARC Energy[22] has observed that "There are several large fields (in addition to those under development) that could be developed at present LNG prices but are held back for want of customers. However if developers of such fields were to receive LNG-equivalent prices for their gas then these reserves would be commercially viable to develop for the domestic sector."

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[20] WA Domestic Gas Policy – DOIR Submission by Alcoa of Australia, 19 April 2006

[21] Meeting the Energy needs of WA The onshore and ARC's role, ARC Energy, 21 February 2007

[22] Submission by ARC Energy Limited on WA Government Policy for Securing Domestic Gas Supplies, ARC Energy, 21 April 2007

By way of an example, the Greater Gorgon area covers eighteen permits/licences and contains a large number of fields, including Chrysaor, Dionysus, Geryon, Gorgon, Io, Jansz, Maenad and Orthrus. It is believed that a number of these may be able to support a smaller domestic-only project, should the large scale export project not proceed. Most of the fields are in 1,000m of water and development costs would be higher than for conventional domestic resources.

Equally, domestic resources could potentially be exported if a merchant liquefaction plant was established or if an established plant required more gas. An example of this potential is Arrow Energy's recently announced plans to export 55 PJ/year of LNG from Gladstone, utilising gas from Arrow's CSG resources (section 3.3.2).

3.2.6 How did the market arrive at this point?

There is little doubt however that the demand-supply position is very tight and that additional domestic supply is required. From both the market and policy perspectives it is important to gain an understanding of the factors that have contributed to arriving at this point, in particular why contracts for gas supply commencing in 2007 were not put in place earlier, when a more competitive outcome involving new entrants may have been possible. Based on both stakeholder and MMA observations a number of factors have contributed:

- For a period up to 2005 expansion of DBNGP capacity was put on hold due to a regulatory dispute. This made it difficult for shippers to commit to gas supply contracts for incremental demand.
- Competition between NWSV and "domgas" producers created a benign domestic market but domgas reserves are now almost fully contracted and NWSV has withdrawn from the market.
- The domgas reserves position is due to a combination of a large contract for an essentially export project (Burrup Fertilisers) and relatively less successful exploration.
- Expectations that gas from the Gorgon project, being developed principally for LNG export, would be in production and available to domestic buyers by 2008 (the latest date contemplated under the Barrow Island Act 2003 is 2013). The project is not yet committed and earliest gas production is now 2011.

3.2.7 Summary

The Western Australian domestic gas market has for some time seen low prices as a result of competition between one large producer that is also an exporter and a number of smaller producers dedicated to the domestic market. At a time when there is demand for new and replacement gas contracts, only one of these producers is in the market, most of the others having contracted all their developed reserves, with the result that prices have doubled.

Western Australia is therefore in urgent need of commitments to new production. A limited number of "domestic" projects are possible but none will be producing before 2010 and large scale developments are conditional upon export sales and their timing is not linked to domestic needs.

The market has reached a position in which it is more difficult for the demand/supply/price balance to be struck:

- At the most recent price buyers would undoubtedly prefer short-term contracts, with a view to negotiating lower prices for supply commencing in three to five years time with developers of new gas resources. However short-term contracts are unlikely to lead to development commitments
- The long-term level of demand at higher prices is uncertain
- Producers face cost increases and uncertainty (section 3.7)

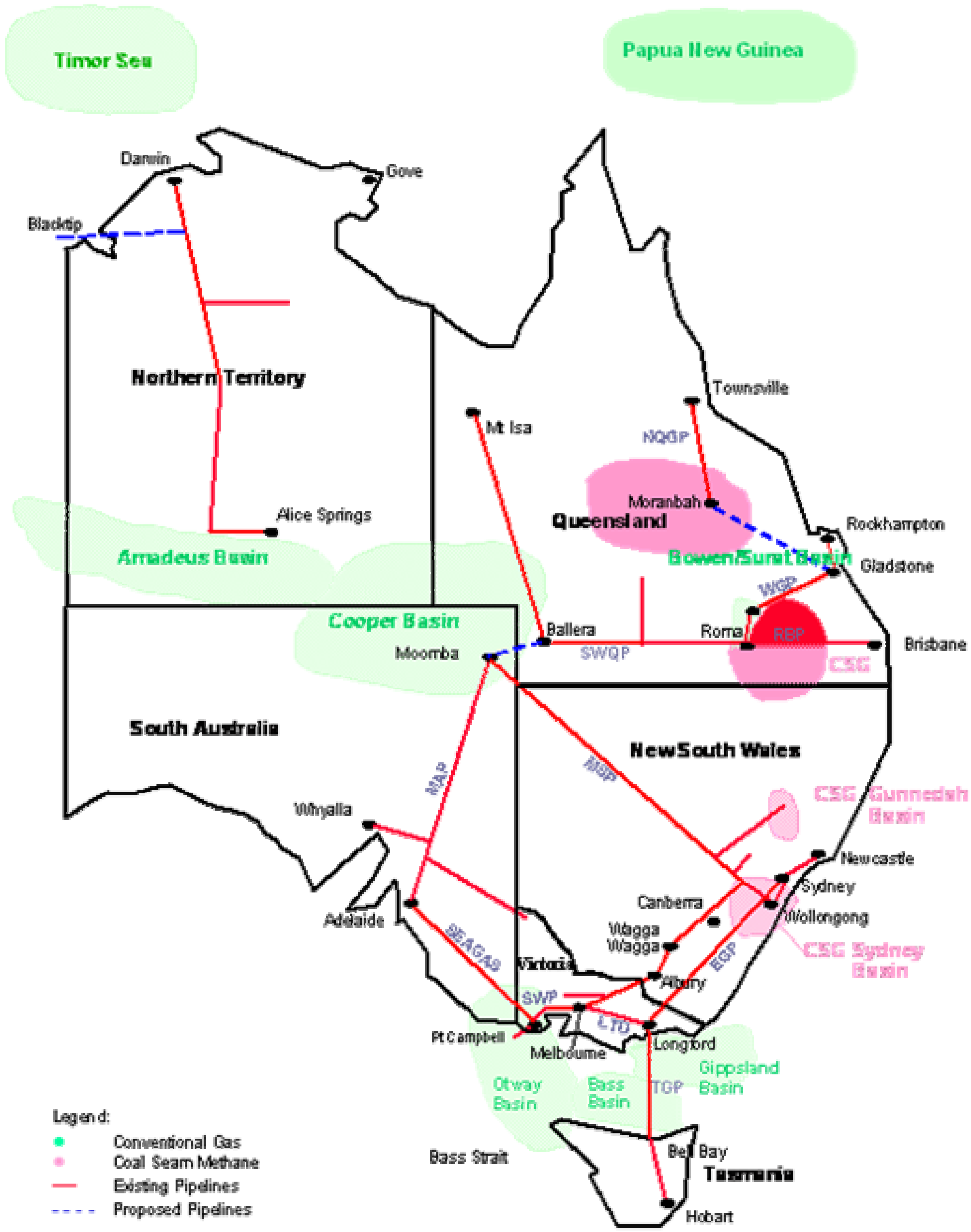
In view of the relatively small scale of domestic demand relative to most of the potential gas developments such market instability could be viewed as a normal market cycle – when a big development happens there is a supply surplus and prices fall and if the next big development is delayed there is a shortfall and prices rise. To avoid this situation it is imperative for buyers to negotiate firm contracts well in advance of supply requirements but under the circumstances in Western Australia this has been difficult due to:

- Contingency of contracts with export projects on export commitments
- Difficulty for buyers to commit to higher prices for new "domestic" projects two to three years ago, when price expectations were low.

3.3 Eastern Australian Wholesale Market

3.3.1 Introduction

Figure 3-5 Gas infrastructure, Eastern Australia and Northern Territory



McLennan Magasanik Associates

Eastern Australia has approximately 16,000PJ of gas reserves, less extensive than those in Western Australia but providing ample support for a domestic market of 540 PJ. There are no gas exports from Eastern Australia at present but projects to import gas from PNG, the Timor Sea and Western Australia have been contemplated from time to time.

The majority of Eastern States sub-markets are now served by multiple basins and/or pipelines, the key exceptions being Mt Isa and Townsville. Queensland is also indirectly linked to the South East through the Ballera-Moomba wet gas pipeline and the planned construction of a parallel dry gas line will consolidate this linkage.

Significant new resources of gas have been developed since the introduction of third party access in 1997, principally in the Otway and Bass Basins in Victoria and the Bowen-Surat Basin in Queensland (refer to Figure 2-5), providing competition to the formerly dominant production centres in the Gippsland and Cooper Basins. New pipelines have also been constructed (EGP, TGP and SEAGas) to bring competing gas to market.

The level of competition has been sufficient to maintain price levels in the south-east and to reduce prices in some Queensland sub-markets. Since the termination of the PNG-Australia gas project in 2006 there has been speculation that an emerging supply gap would allow prices to rise significantly but the market evidence to date is contrary – in March Alinta entered a conditional contract to purchase gas from the Basker Manta field operated by Anzon/Beach at an implied price of $2.67/GJ[23], well below the current Victorian gas market price of $3.35/GJ. Although this contract has been terminated because Anzon/Beach has deferred the final investment decision in order to optimise oil development, the JV expects to commit to gas development within 12 months.

3.3.2 Gas demand

Current Eastern States gas demand by sector is shown in Table 3-7. Sector strength varies considerably from state to state: residential and commercial demand is strongest in Victoria; industrial in NSW, Victoria and Queensland; and generation in SA and Queensland. Tasmania has been connected to gas only since 2002 and the reticulation network is incomplete.

Table 3-7 Eastern States gas demand 2004 (PJ)

	NSW	Vic	SA	Tas	Qld	Total
Industrial	82	80	19	1	59	241
Power Generation	2	12	78	8	34	134
Commercial	9	28	4	0	2	43
Residential	22	89	8	0	2	121
Total	**116**	**209**	**109**	**9**	**97**	**540**

[23] Power Industry News, 26 March 2007

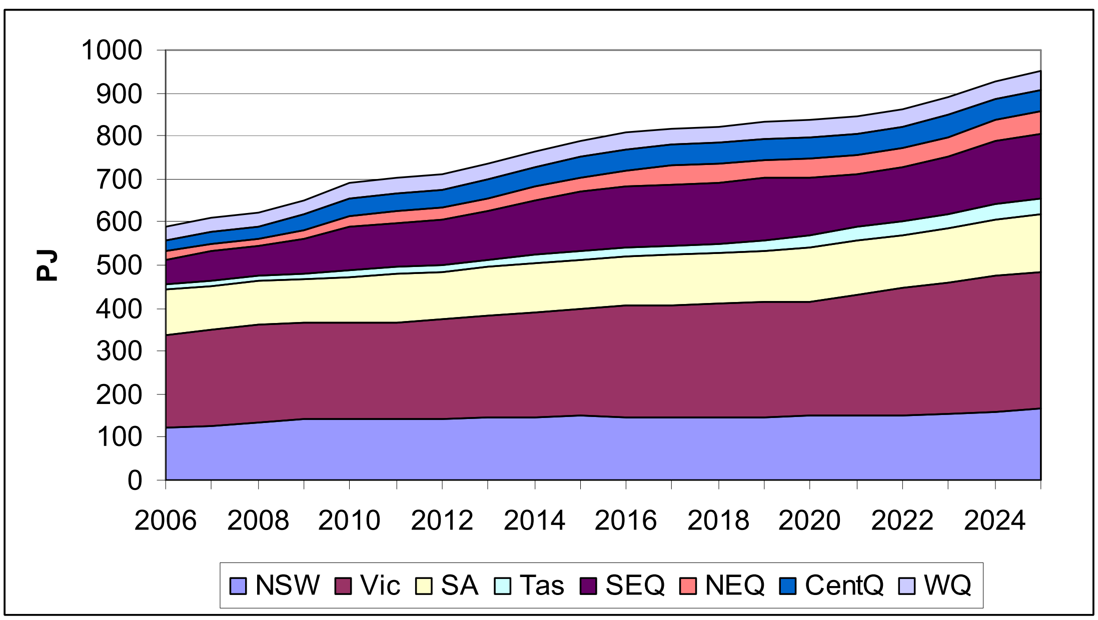
3.3.2.1 Demand projections

Demand projections based on MMA forecasts of generation use, derived from comprehensive modeling of the National Electricity Market, and ABARE projections of non-generation use, are presented in Table 3-8 and Figure 3-6. Growth is projected to be strongest in the generation sector generally, with strong industrial growth in Queensland.

Table 3-8 Eastern Australian demand projections (PJ/yr)

	NSW	Victoria	SA	Tas	SE Qld	NE Qld	Cent Qld	NW Qld	Total
2006	123	215	105	11	59	19	25	33	590
2007	124	226	103	10	70	17	25	35	610
2008	134	226	103	11	72	16	26	35	623
2009	143	222	103	12	82	21	33	35	651
2010	143	223	107	16	99	26	41	36	690
2011	143	224	112	17	102	27	41	36	702
2012	144	229	112	17	104	28	41	36	712

Figure 3-6 Eastern Australian demand projections (PJ/yr)



These projections do not take into account the development of an export market for Eastern Australian gas. Arrow Energy has recently announced plans to export 55 PJ/year of LNG from Gladstone for 12 years from late 2010, with an option for another 55 PJ/year from 2011[24]. Gas will be supplied from Arrow's CSG interests in the Bowen and Surat Basins and a program to prove up 1,100 PJ of 2P reserves is planned for 2007/08.

3.3.3 Gas supply

3.3.3.1 Gas reserves

Eastern Australian gas reserves are spread across five basins, Sydney, Gippsland, Otway, Cooper and Surat-Bowen (Figure 3-5). Total 2P (proved and probable) reserves remaining as at 31 December 2004 (refer to Table 3-9 for definition of timing), excluding resources that have yet to be proved, are estimated to be approximately 16,400 PJ (Table 3-9). There are also minor coal seam gas (CSG) reserves in the Clarence Morton and Gunnedah basins.

Table 3-9 Eastern Australian proved and probable reserves backdated to 31 December 2004[25] (PJ)

Basin	Operator	2P Reserves
Sydney (CSG)	Sydney Gas Co	83
Gippsland	Exxon-BHPB	6,233
Gippsland	Other operators	746
Bass	Origin, AWE	363
Otway (Minerva/La Bella)	BHP/Santos	375
Otway (Thylacine/Geographe)	Woodside, Origin	900
Otway (Casino)	Santos, AWE, Mitsui	510
Otway onshore	Origin	38
Cooper (SA + Qld)	Cooper Basin JV	1,781
Cooper (SA + Qld)	Other operators	100
Surat-Bowen (CSG)	Arrow South	443
Surat-Bowen (CSG))	Origin	1,300
Surat-Bowen (CSG)	Anglo Coal	317
Surat-Bowen (CSG)	Santos	1,696
Surat-Bowen (CSG)	Arrow North	558
Surat-Bowen (CSG)	Qld Gas Co	932
Total Eastern Australia	**All**	**16,374**

Notes:

1. Sources: Geoscience Australia, RLMS[26] and industry sources
2. Cooper Basin JV excludes ethane
3. Santos includes Mosaic which sells some gas to Santos
4. Origin and Santos CSG includes small volumes of conventional gas
5. Reserves of less than 25 PJ each in the Gunnedah and Clarence Morton Basins have been excluded from the above table. Neither resource is connected to the transmission network.

[24] Arrow Energy Media Release, 30 May 2007

[25] Reserves are as at 31 December 2004 for all fields in production plus subsequent reserve updates.

[26] The significance of Coal Seam Gas in Eastern Australia, Graeme Baker, RLMS, 2006.

Eastern Australian reserves are comprised of approximately 11,000 PJ of gas in conventional sandstone reservoirs and 5,400 PJ of CSG in coal seams, which are up from a zero base in 1995. While conventional gas and CSG are virtually indistinguishable to the end user, their different origins lead to significant differences in the interpretations that can be placed on gas reserves.

Whereas the reserves in accumulations of conventional gas can be estimated from seismic surveys and the results of a few exploratory wells, CSG currently requires many wells to adequately map the economically producible resource i.e. to demonstrate reserves (refer to text box below for further background information). Furthermore the search for oil has motivated much exploration that has resulted in conventional gas discoveries but the commercial incentive to drill wells to prove up CSG reserves is generally lacking until a potential buyer is found[27].

Conventional Gas vs CSG[28]

Conventional gas reservoirs are comprised of largely homogeneous porous sandstone capped by impermeable rock. The gas is stored at high pressure and flows to the surface spontaneously at high flow rates from each well. The reserves in a conventional gas accumulation can be estimated from seismic surveys and the results of a few exploratory wells.

The coal formations that store CSG have two separate porosity mechanisms, micropores within the coal matrix and a system of natural fractures called cleats. Methane is adsorbed into the micropores under water pressure and is released when the water pressure falls. It then flows through the matrix to the cleats and then to the well bore. Free gas exists in the cleats only when the water pressure equals the adsorption pressure.

Coal permeability, and the ability of gas to flow within the coal, is significantly affected by pressure but the relationship is not uniform. Some coals shrink when dewatered, increasing permeability, but others do not and can be self sealing. The significant variability of coal characteristics, even within a single seam, means that many wells are required to adequately map and produce the resource.

The production characteristics of CSG are also different to those of conventional gas. In the short term (daily timeframe) conventional gas production can be ramped up and down but CSG wells do not respond as rapidly. However because of the lower cost of additional wells, CSG production can be more readily increased over annual time frames.

These characteristics significantly impact the risk profile of CSG developments.

[27] Buyers enter contracts tat are conditional upon the proving up of reserves.
[28] Material in this text box is based upon: Gaffney, Cline & Associates, Focus Newsletter Issue No 34, October 2003; and "You have a coal seam methane lease – will it produce", Sigra Pty Ltd, December 2002.

Thus, to the extent that exploration has covered a large part of the most prospective conventional gas basins, conventional gas reserves in those basins are well known, with bounded upside potential. In contrast, CSG reserves may have a very significant upside, because well coverage is limited while the inferred resource in place (methane in coal seams) is two orders of magnitude greater than current 2P reserves[29]. A number of commentators have noted that CSG reserves are "demand driven" in that producers seem to have be little difficulty proving up resources once a customer is found. This has led to a number of conditional contracts in which producers have undertaken to prove-up reserves to meet the contract volumes, examples of which include the Arrow LNG export plans described above and arrangements between CS Energy and Metgasco to prove up 540 PJ in the Clarence Morton basin and between Macquarie Generation and Gastar/ Eastern Star Gas to prove up 500 PJ in the Gunnedah basin. Further experience in coal seam gas exploration and production may enable the industry to delineate how much of the resource is economically recoverable without saturation drilling.

Eastern Australia may also be able to access the significant resources in the Timor Sea and PNG if or when local reserves, together with future local discoveries, are no longer able to meet demand, contingent upon these reserves not being contracted to other export markets.

3.3.3.2 Future discoveries

Future gas discoveries are by nature very difficult to estimate and highly speculative. Gas reserves are clearly ultimately finite but a number of facts support the view that it will be many years before a reliable estimate of this ultimate level can be determined:

- Continued growth in reserves and steady reserve/production levels
- Growing exploration expenditure
- Significant recent discoveries in the Otway basin - Thylacine/Geographe (800PJ) and Casino (300PJ) – in response to the newly available commercial opportunities
- Growth in CSG reserves

Estimates of future discoveries (additions to 2P reserves) have been derived from published figures where available eg Geosciences Australia for the Gippsland Basin. The total estimated for conventional gas at the 50% confidence level (that actual discoveries will exceed this estimate) is 10,550 PJ, approximately 95% of today's 2P reserves. For CSG the current 3P (proved, probable and possible) reserve estimates for existing developments are over 13,000 PJ, which implies that future 2P reserve additions will comfortably exceed today's 2P reserves of 5,400 PJ. Many industry participants and commentators believe the figure will be substantially higher.

[29] 300,000-500,000 PJ according to the Australian Gas Association (Gas Supply and Demand Study 1997)

In the case of conventional resources these figures represent discoveries over the next thirty years, assuming exploration expenditure is maintained at current levels, i.e. an average annual discovery rate of 350 PJ. For CSG the additional 5,400 PJ is more likely to be capable of being proved within ten years, i.e. at an annual rate of 540 PJ, contingent on demand growth. Total discoveries would then exceed the replacement rate, until either demand/production caught up or discoveries fell because of a lack of demand.

The only dark cloud that can be seen on the horizon at present is the escalation in industry costs (section 3.7) which will reduce the effectiveness of exploration expenditure for an unknown period.

3.3.3.3 Reserve life

Relative to current production of approximately 540 PJ p.a. current 2P reserves indicate a “simple” reserve life of approximately 30 years, to 2034. Allowing for forecast demand growth reserve life would be only 20 years, to 2025, but P50 discoveries extend this by 15 years, to 2040.

3.3.3.4 Contracted supply

MMA maintains a data base of Eastern states gas supply contracts, derived largely from information published on buyer/seller websites. While there are likely to be some contracts missing from the data base, either because their existence is not on the public record or because we have failed to find it, MMA is confident that 95% of gas volume contracted is accounted for. For many contracts however only the term and total volume committed are known and annual volumes can only be estimated.

Table 3-10 shows the total contracted volumes, compared with 2P reserves as at 31 December 2004. The volumes of gas contracted to the domestic market in each year to 2024 are illustrated in Figure 3-7.

Table 3-10 Comparison of 2P reserves at 31 December 2004 and gas contracted from 1 January 2005 (PJ)

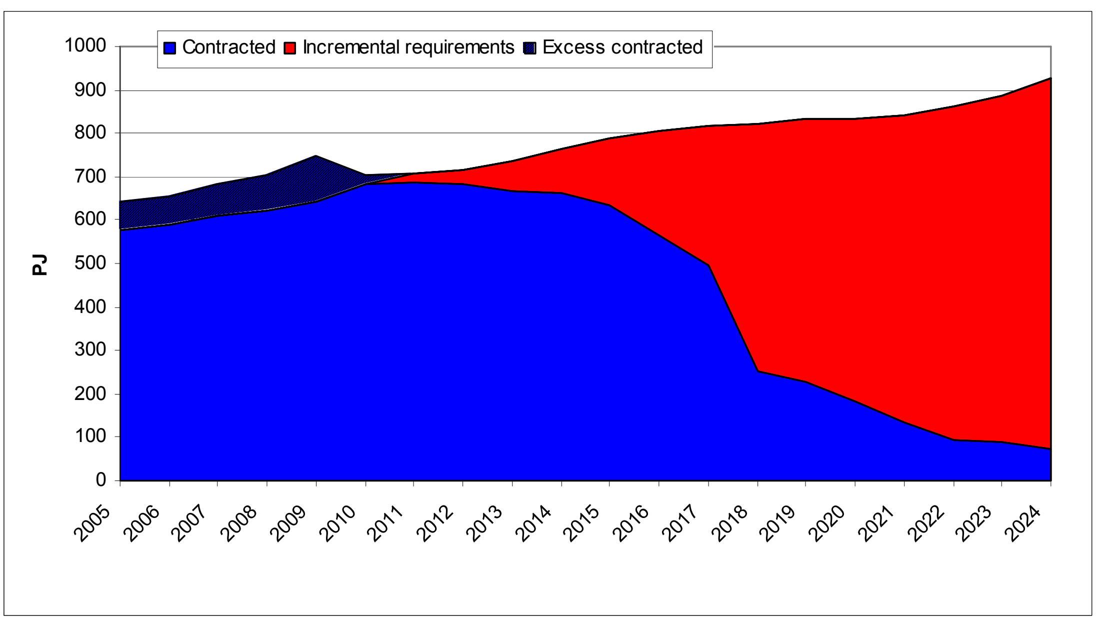
Basin	Operator	2P Reserves	Contracted	Uncontracted
Sydney (CSG)	Sydney Gas Co	75	84	-1
Gippsland	Exxon-BHPB	6,233	3,275	2,958
Gippsland	Other operators	746	280	4661
Bass	Origin, AWE	363	256	107
Otway (Minerva/La Bella)	BHP/Santos	375	300	75
Otway (Thylacine/Geographe)	Woodside, Origin	900	729	171
Otway (Casino)	Santos, AWE, Mitsui	510	395	115
Otway onshore	Origin	38	24	14
Cooper (SA + Qld)	Cooper Basin JV	1,781	1446	336
Cooper (SA + Qld)	Other operators	100	0	100
Surat-Bowen (CSG)	Arrow South	443	463	-20
Surat-Bowen (CSG))	Origin	1,300	1018	282
Surat-Bowen (CSG)	Anglo Coal	317	54	263
Surat-Bowen (CSG)	Santos	1,696	421	1,275
Surat-Bowen (CSG)	Arrow North	558	381	177
Surat-Bowen (CSG)	Qld Gas Co	932	737	195
Sub-total Eastern Australia	**All**	**16,374**	**9,862**	**6,511**

Source: MMA estimates of contracted gas

3.3.4 New contract requirements

Eastern Australian market requirements for additional contracts are presented in Figure 3-7. The market appears to be fully supplied to 2009 and then has a small but growing requirement to 2016 and a larger requirement after 2018.

Figure 3-7 Incremental Eastern Australian gas requirements



3.3.5 Potential sources of new domestic supply

3.3.5.1 Short-term

There does not appear to be any aggregate requirement for additional contracts in the near term unless there is significant new gas load beyond that forecast.

3.3.5.2 Medium-term

Medium-term supply can be sourced from uncontracted reserves (Table 3-10), including those that are not yet developed, and resources discovered over the next two to three years. Increased costs of production (section 3.7) may impact upon gas prices, particularly for offshore developments.

3.3.5.3 Long-term

For the past thirty years it has been assumed that long-term supply for Eastern Australia would be sourced from the more plentiful reserves in Western Australia, PNG or the Timor Sea. Projections now suggest that imports may not be necessary until 2025 or later though they could be commercially feasible from about 2015 on the basis of the contractual opening. CSG performance is critical in the longer-term.

3.3.6 Summary

The Eastern Australian supply outlook is relatively benign. Buyers and sellers appear willing to contract ahead to avoid supply shocks. Concerns mostly relate to long-term supply and the possibility that higher costs will increase future contract prices.

3.4 Northern Territory Wholesale Market

The Northern Territory has a small domestic market with substantial reserves in the Timor Sea and LNG export is still in its infancy, currently exporting only to Japan. NT infrastructure is depicted in Figure 3-5.

3.4.1 Gas demand

3.4.1.1 Domestic

The NT has seen limited growth in demand, as shown in Table 3-11, with the main demand coming from the electricity sector, which is growing at about 2.3% pa. Although other sectors have experienced strong growth, this is from a very low base and usage is at present negligible.

Table 3-11 Demand trends (PJ)

Sector	2000/01	2001/02	2002/03	2003/04	2004/05	% Growth
Mining	0.16	0.15	0.15	0.73	1.39	**71.7%**
Other	0.15	0.15	0.15	0.10	0.10	**0%**
Electricity generation	**21.4**	**21.9**	**22.2**	**22.3**	**23.4**	**2.3%**
Total Manufacturing	**0.06**	**0.06**	**0.06**	**0.17**	**0.17**	**29.7%**
Commercial	**0.16**	**0.16**	**0.16**	**0.16**	**0.16**	**0%**
Residential					**0.01**	
Total	**21.9**	**22.4**	**22.7**	**23.5**	**25.3**	**0.9%**

Source: 'Australian energy consumption and production, 1974-75 to 2004-05', ABARE June 2006

The Alcan alumina refinery at Gove is currently using around 20PJ pa of fuel oil, conversion of which to gas would allow the potential for a 'stage 3' expansion to be realised, increasing demand to about 43 PJ. Alcan has in the past negotiated conditional contracts for gas from Blacktip and the PNG Project but neither supply has eventuated. Further options in PNG and the Timor Sea are understood to be under consideration.

The NT Government has promoted Darwin as a location for gas-based petrochemical projects such as methanol and GTL but no commitments have been made as gas producers currently obtain higher returns on LNG developments. It is recommended that Governments undertake an assessment of which developments offer the highest returns to the Australian and state/territory economies (section 6.3.5), with a view to resolving how to get other options off the ground if LNG does not offer the best returns.

3.4.1.2 Export

Exports of LNG commenced from Darwin in 2006, based on gas supply from the Bayu Undan field in the Timor Sea. Full year exports are expected to be 3.2mt (170 PJ). The plant is expandable to 10 mt/year, using gas from other fields. The Bayu Undan field reserves are viewed as too limited to support other developments in Darwin.

3.4.2 Gas supply

The Northern Territory has two operating gas fields, Mereenie and Palm Valley, both located in the Amadeus Basin in central Australia. The two main pipelines from the basin feed Alice Springs and Darwin, via Tennent Creek, Daly Waters and Katherine. There is also a lateral pipeline to the McArthur River mine. These fields are in decline and from 2009 Blacktip will become NT's principal supply source.

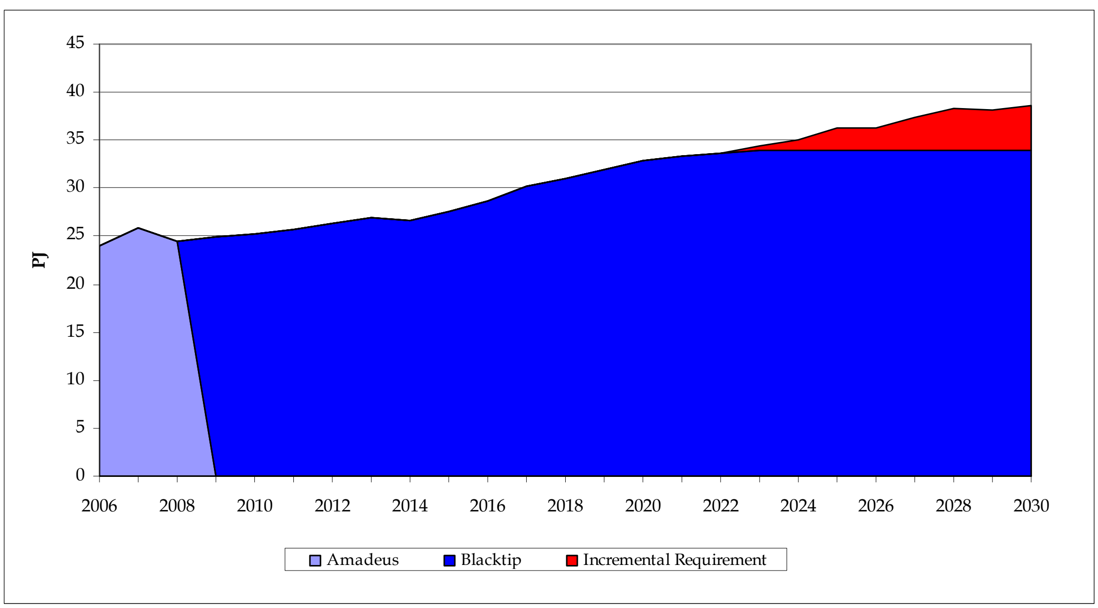
The other potential sources of gas for the NT domestic market are the Timor Sea/Bonaparte Basin on the border with, but mostly located in WA.

3.4.2.1 Gas reserves and contracts

Total reserves for the Amadeus Basin were 228 PJ as at beginning 2005 and the current gas supply contract held by PowerWater, the NT Government owned electricity and water utility, is due to end in 2009.[30] PowerWater has contracted with ENI Australia for supply from the Blacktip field in the Bonaparte Basin from 2009. Blacktip is estimated to have 1.1 Tcf (1,200 PJ) recoverable reserves and the contract is for 850 PJ over 25 years, which allows for growth in demand but not a major gas using project.[31] Gas from Blacktip will land on the NT coast near Wadeye and will be transported to the existing pipeline to Darwin through the 280km Bonaparte Gas Pipeline.

The projected supply demand balance for the NT is shown in Figure 3-8. Current markets have approximately 15 years of contract cover. Potential supply of residual Amadeus Basin gas is not shown.

Figure 3-8 Incremental Northern Territory gas requirements



[30] 'Oil and Gas Resources of Australia 2004', Geoscience Australia, 2006
[31] 'Northern Territory Oil and Gas 2006', Department of Primary Industry, Fisheries and Mines, April 2007

3.4.2.2 *Future developments*

The offshore Bonaparte Basin which borders WA and Timor Leste, commonly referred to as the Timor Sea, contains several large fields whose reserves and development prospects are shown in Table 3-12. The LNG developments are likely to take the form of 2nd and 3rd trains in Darwin.

Table 3-12 Undeveloped fields in the Bonaparte Basin

Field	Estimated reserves (PJ)	Contract/ preferred development
Sunrise	8,100	LNG
Evans Shoal	6,900	Methanol production in situ
Petrel/Tern	1,500	LNG or domestic gas supply
Caldita/ Barossa	1,600	LNG
Abadi	5,300	LNG

Source NT Government

The Blacktip production centre could form a hub for the production of other fields, including Petrel/Tern, from which they could be transported to Darwin for processing into LNG or to meet other incremental demand.

Further exploration in the Amadeus Basin and other onshore basins in the Northern Territory is anticipated but current reserves are negligible.

3.4.2.3 *Impact of market characteristics*

The Northern Territory domestic gas market remains in monopoly-monopsony mode, though the monopoly is about to be changed, and is extremely illiquid, with negotiations for additional supply required only every 15 to 25 years. In view of the scale and structure of demand and supply this is likely to change only if there is significant market growth.

In these circumstances market outcomes can be more influenced by the players' inclinations than by the policy settings. A number of the policy settings that are directed at improving wholesale market competition, such as separate marketing, which is unlikely ever to be possible in the Northern Territory, are therefore largely irrelevant there. However other settings, including a focus on ensuring that gas developments occur, are highly relevant.

3.4.3 Summary

Northern Territory demand from existing end users appears to be covered by supply contracts for up to 15 years. Unsupplied demand at Gove and for petrochemical projects in Darwin competes for supply with LNG and offshore production of export products.

3.5 Retail markets

3.5.1 Retail competition

Competition has been progressively introduced to Australian gas and electricity retail markets since 1995, in line with the national Competition Principles Agreement. Commencing with contestability (choice of retailer) for the relatively small number of large users, business rules and systems were developed to support contestability among larger and larger groups of users, culminating in full retail contestability (FRC) i.e. all users. FRC was introduced first in New South Wales, Victoria and the ACT, followed by South Australia and Western Australia (gas only) (Table 3-13).

Table 3-13 Timing of FRC Introduction

Jurisdiction	Gas	Electricity
New South Wales	January 2002	January 2002
Victoria	November 2002	January 2002
Queensland	July 2007	July 2007
South Australia	July 2004	January 2003
Australian Capital Territory	January 2002	July 2003
Western Australia	May 2004	

FRC schedules in the remaining markets are:

- Western Australia is moving to FRC in electricity – the contestability threshold is currently 50 MWh/yr.
- Tasmania has de facto FRC in its new gas market, as there are no franchised customers, and is scheduled to introduce electricity FRC in 2010.
- The Northern Territory is scheduled to assess the costs and benefits of electricity FRC in 2008.

This section covers the markets in Eastern Australia: New South Wales; the Australian Capital Territory; Victoria; Queensland; and South Australia. The small user gas market in Western Australia shows little evidence of competition, due to the combination of no electricity FRC and difficulties faced by new entrants in obtaining gas supply.

3.5.2 Retail licensees

The numbers of retail licensees in the ten major markets covered by this report, as at 1st May 2007, are listed in Table 3-14. A key feature of these figures is the lower number of gas retailers compared to electricity retailers, which suggests that the gas retail sector may be less competitive.

Table 3-14 Retail licensees Eastern Australia as at 1st May 2007

	NSW		ACT		Victoria		Queensland		South Australia		
	Elec	Gas	Elec	Gas	Elec	Gas	Elec	Gas	Elec	Gas	Total
ActewAGL	Yes	Yes	Yes	Yes	Yes						5
AGL Sales Pty Ltd	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	9
Aurora Energy Pty Ltd	Yes		Yes		Yes		Yes		Yes		5
Australian Power and Gas Pty Ltd	Yes				Yes	Yes	Yes				4
Bhpbilliton Petroleum		Yes				Yes					2
CitiPower	Yes				Yes						2
Click Energy Pty Ltd					Yes						1
Country Energy	Yes	Yes	Yes	Yes	Yes		Yes		Yes		7
CS Energy							Yes				1
Dalby Town Council								Yes			1
Delta Electricity	Yes										1
EA-IPR Retail Partnership					Yes	Yes			Yes	Yes	4
Elgas Ltd								Yes			1
Energy Australia	Yes	Yes	Yes	Yes	Yes		Yes				6
Energy Brix Australia					Yes						1
Energy One Limited	Yes		Yes		Yes		Yes				4
Eraring Energy	Yes										1
Ergon Energy							Yes				1
Esso Australia Resources		Yes				Yes					2
Flinders Power Pty Ltd									Yes		1
Independent Electricity Retail Solutions	Yes										1
Integral Energy Australia	Yes	Yes	Yes		Yes		Yes				5
International Power Pty Ltd					Yes				Yes		2
Jackgreen (International) Pty Ltd	Yes				Yes		Yes		Yes	Yes	5
Momentum Energy	Yes				Yes		Yes		Yes		4
NSW Electricity Pty Ltd	Yes										1
Origin Energy	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	10
Our Neighbourhood Energy Pty Ltd					Yes						1
Powercor	Yes				Yes						2
Qenergy Pty Ltd							Yes				1
Red Energy			Yes		Yes	Yes	Yes		Yes		5
Roma Town Council								Yes			1
Santos Direct		Yes				Yes				Yes	3
South Australia Pty Ltd									Yes	Yes	2
SPI Electricity					Yes						1
Stanwell Corporation							Yes				1
Tarong Energy							Yes				1
TRUenergy	Yes	Yes	Yes	Yes	Yes	Yes	Yes		Yes	Yes	9
Victoria Electricity					Yes	Yes					2
Wesfarmers Kleenheat Gas		Yes						Yes			2
Total Licenses	18	11	10	5	22	10	17	6	12	7	

3.5.3 Retailer market share

Retail customer share has been estimated using the best publicly available data. Insufficient data is published to estimate reliable energy shares. Figure 3-9 and Figure 3-10 show the estimated gas and electricity customer shares after the sale of the Queensland retailers Sun Retail and Power Direct.

Figure 3-9 Gas customer shares post sale of Queensland retailers

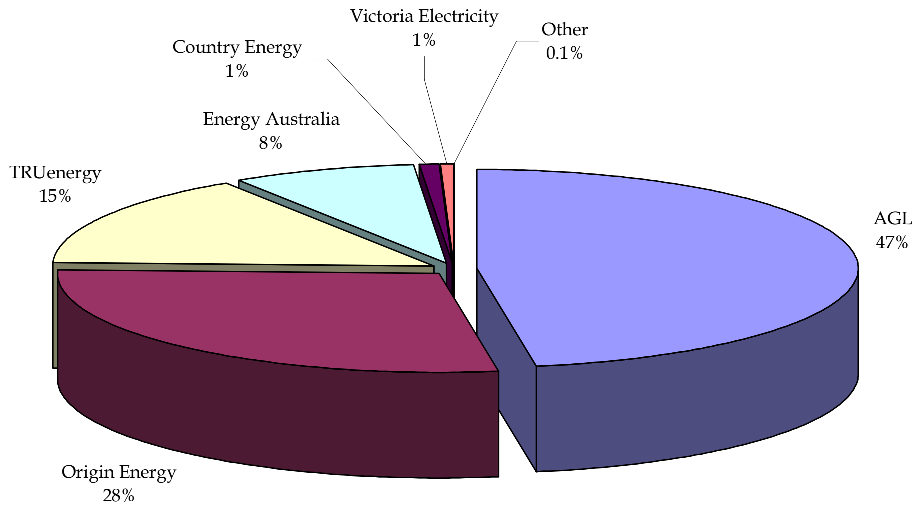
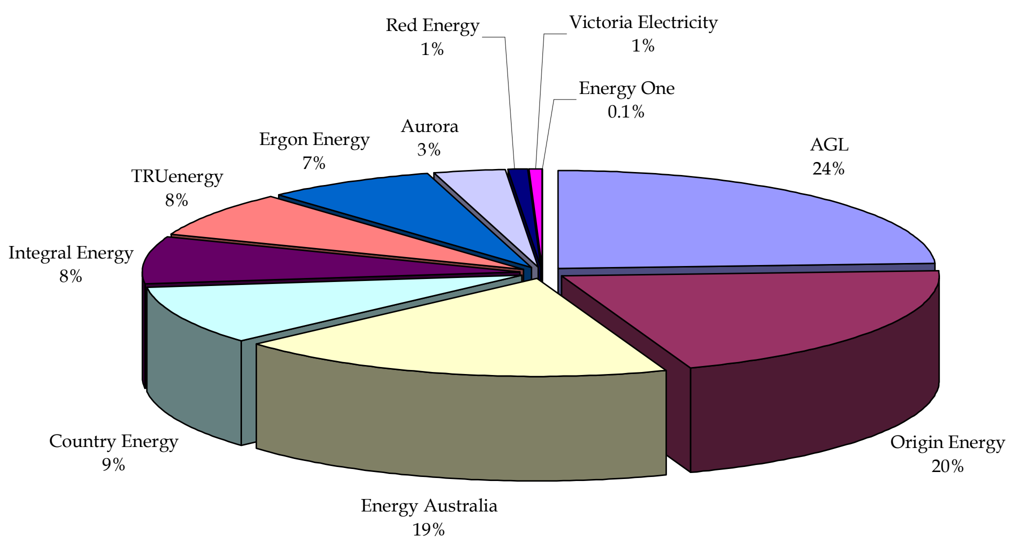


Figure 3-10 Electricity customer shares post sale of Queensland retailers



It is clear that the gas retail market is significantly more concentrated than the electricity retail market, which supports the evidence based simply on licensee figures. However in terms of market share of new entrants there is very little difference between gas and electricity. Evidence of gas retail market concentration is also provided by gas contract information for Western and Eastern Australia (Table 3-15 and Table 3-16).

Table 3-15 Gas contracted by buyers, Western Australia (PJ)

Buyer	Category	Contracted	% of Contracts
Alcoa	Industrial user	1,025	25%
Verve	Generator	782	19%
Burrup Fertiliser	Industrial user	710	17%
Alinta	Retailer	574	14%
BHPB DRI	Industrial user	343	8%
NewGen	Generator	340	8%
Telfer	Industrial user	120	3%
Wesfarmers	Industrial user	51	1%
Origin Energy	Trader	45	1%
EDL	Industrial user	42	1%
Newmont Gold	Industrial user	26	1%
Hamersley Iron	Industrial user	23	1%
Edison Mission	Generator	21	1%
Centaur Mining	Industrial user	16	0%
Midland Brick	Industrial user	8	0%
Windimurra Vanadium	Industrial user	6	0%
AGL	Trader	6	0%
TiWest	Industrial user	4	0%
Wiluna	Industrial user	2	0%
Great Central	Industrial user	2	0%
Total		**4,146**	

Source: MMA estimates of contracted gas

Table 3-16 Gas contracted by buyers, Eastern Australia (PJ)

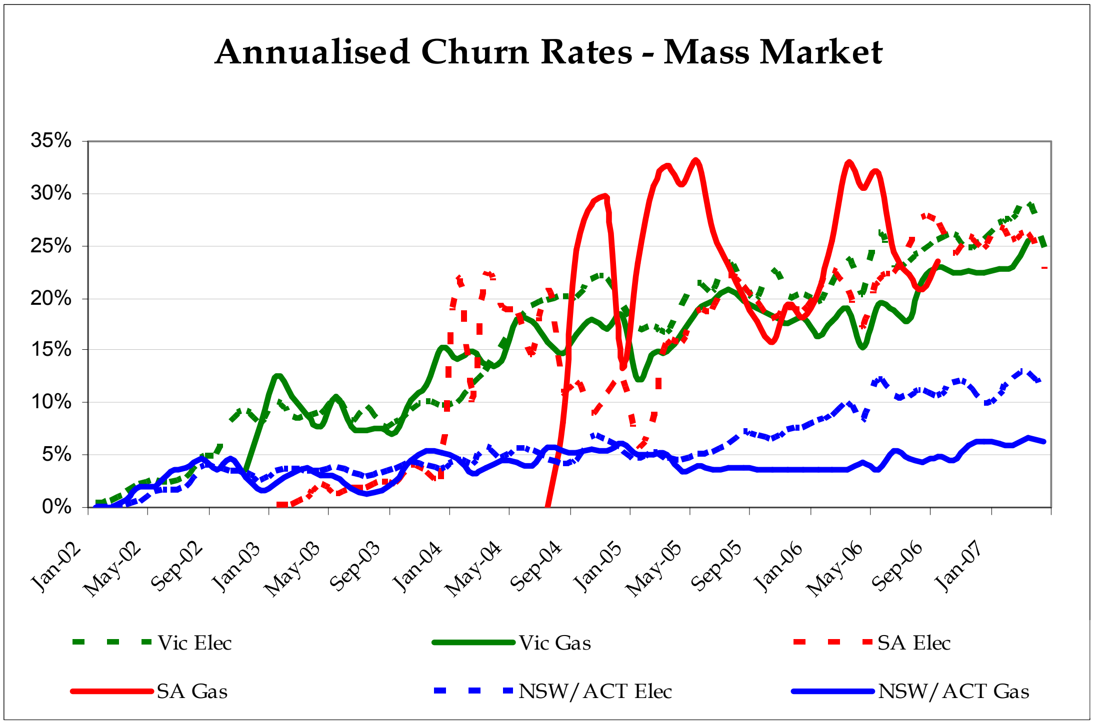
Buyer	Category	Contracted	% of Contracts
AGL	Retailer	3,096	33%
TRUEnergy	Retailer	1,958	21%
Origin	Retailer	1,299	14%
Braemar PS	Generator	400	4%
Alinta	Trader	393	4%
Enertrade	Trader	285	3%
International Power	Generator	270	3%
Incitec Pivot	Industrial user	270	3%
CS Energy	Generator	247	3%
QAL	Industrial user	214	2%
Xstrata	Industrial user	182	2%
Dyno	Industrial user	96	1%
Ergon	Retailer	59	1%
Orica	Industrial user	19	0%
Daandine PS	Generator	15	0%
BP	Industrial user	15	0%
Cannington	Industrial user	13	0%
Visy	Industrial user	11	0%
Country Energy	Retailer	11	0%
Other		494	5%
Total		**9,346**	

It is noted that in Western Australia there is a slightly greater diversity of buyers and retailer/aggregators play a significantly smaller role.

3.5.4 Market churn

Market churn, the switching of customers from one retailer to another, is the most accessible indicator of whether competition in a retail market is effective. Reported mass market churn rates are illustrated in Figure 3-11.

Figure 3-11 Annualised churn rates – Mass Market



Note: reported SA churn rates have been adjusted to eliminate switches which reflect a change of the customer's relationship with the same retailer

Noteworthy features of the mass market churn are:

- Initial churn rates were low in all markets except SA gas. Victorian rates increased when gas became contestable in November 2002, reflecting the marketing importance of dual-fuel contracts.
- NSW churns have remained significantly lower than Victorian and SA churns. The NSW electricity churn rates have seen a continuous increase, rising to over 10%pa, while gas churn rates have stayed flat at around 5%pa. The cause of this is most likely lower levels of competitive marketing due to the late entry of two major retailers, TRUEnergy and Origin.

- Victorian churns are now averaging over 25% pa and the market is extremely competitive with all major retailers and many new entrants participating.
- The SA market has been more volatile than Victoria owing to a $50 government incentive to switch from default to contract tariffs paid during 2004.

3.5.5 Summary

Robust retail competition has been established in electricity and gas markets in most Eastern States. The number of retailers and concentration of market share is considerably higher for gas than electricity but the market shares of new entrants are similarly low. Retail churn is comparable in gas and electricity and indicative of highly competitive conditions in most jurisdictions.

3.6 Export markets

Australian gas, exported as LNG, can potentially be supplied to any of the primary world gas markets in Asia, Europe and North America. At present, owing to the greater transport distances to Europe and the main LNG terminals on the east coast of North America, it competes only in Asia but it is also likely to be competitive in the US West Coast market. LNG imports and exports by country in 2005 are summarised in Table 3-17. In 2005 the Asian market totalled 4,722 PJ (Japan, 3000 PJ) of which Australia supplied 610 PJ (13%), its principal competitors being Indonesia, Malaysia and Qatar.

Table 3-17 LNG Imports and Exports, 2005 (PJ)

Exporter	Importer			
	Asia	Europe	N America	Total
Indonesia	1179			1179
Malaysia	1068	5	9	1083
Qatar	864	169	3	1036
Algeria	3	825	102	930
Australia	610			610
Trinidad		22	461	482
Nigeria		442	8	450
Oman	286	64	3	353
Brunei	350			350
UAE	276	12		288
Egypt	17	170	76	264
US (Alaska)	68			68
Libya		33		33
Other		9		9
Total	4722	1751	663	7135

Source: Energy Information Administration

Most Asian import markets have little or no domestic natural gas and have emerged and matured with LNG supply. In contrast European and North American markets matured on a combination of town gas, domestic gas and pipeline imports and until recently LNG played a minor role. Owing to constraints on domestic gas supply in the US, including imports from Canada, and a desire to diversify supply away from Russian pipeline gas in Europe, European and North American LNG imports are now growing rapidly.

Over the past five years the LNG market has changed dramatically in response to both the rise in oil prices and constraints on domestic gas supply in Europe and North America. Asian LNG prices have traditionally been linked to an oil benchmark through an "S-Curve" relationship illustrated in Figure 3-12, which allowed for price variation but protected the seller against low oil prices and the buyer against high oil prices. As oil prices have risen LNG has become relatively more attractive in Asia (Figure 3-13), and rising prices of pipeline gas in Europe and North America have also made LNG more attractive in those markets. The net result has been rising demand and prices, a seller's dream.

Figure 3-12 Traditional LNG "S-Curve" pricing against an oil benchmark

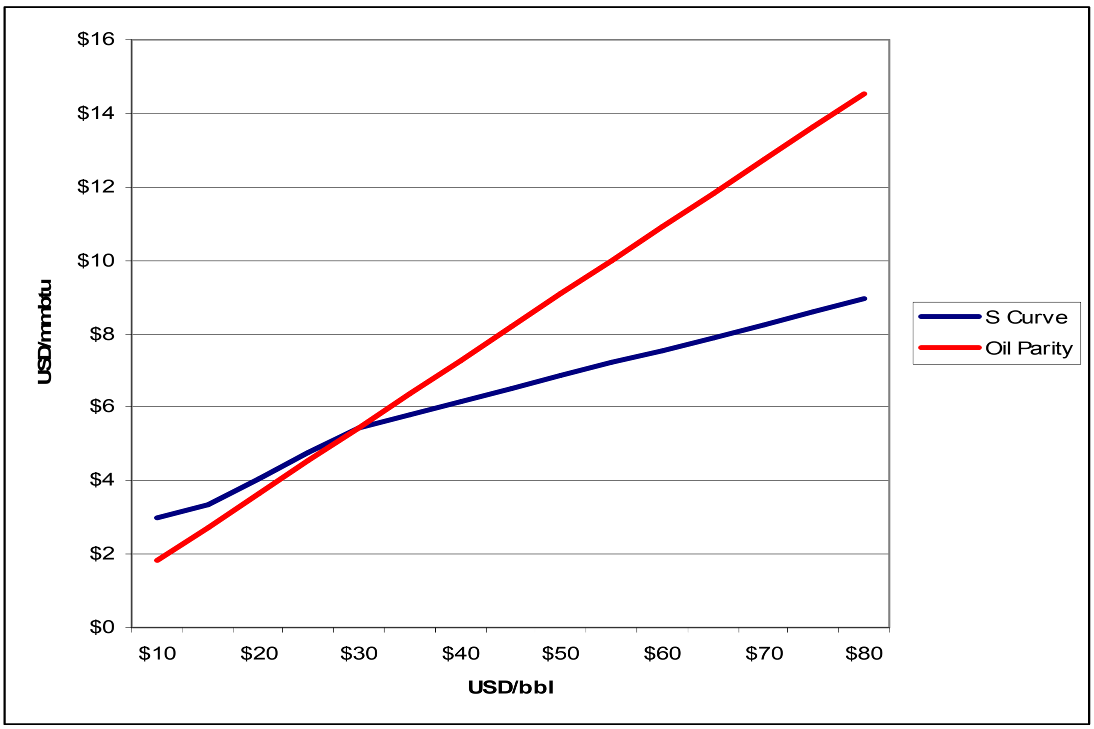
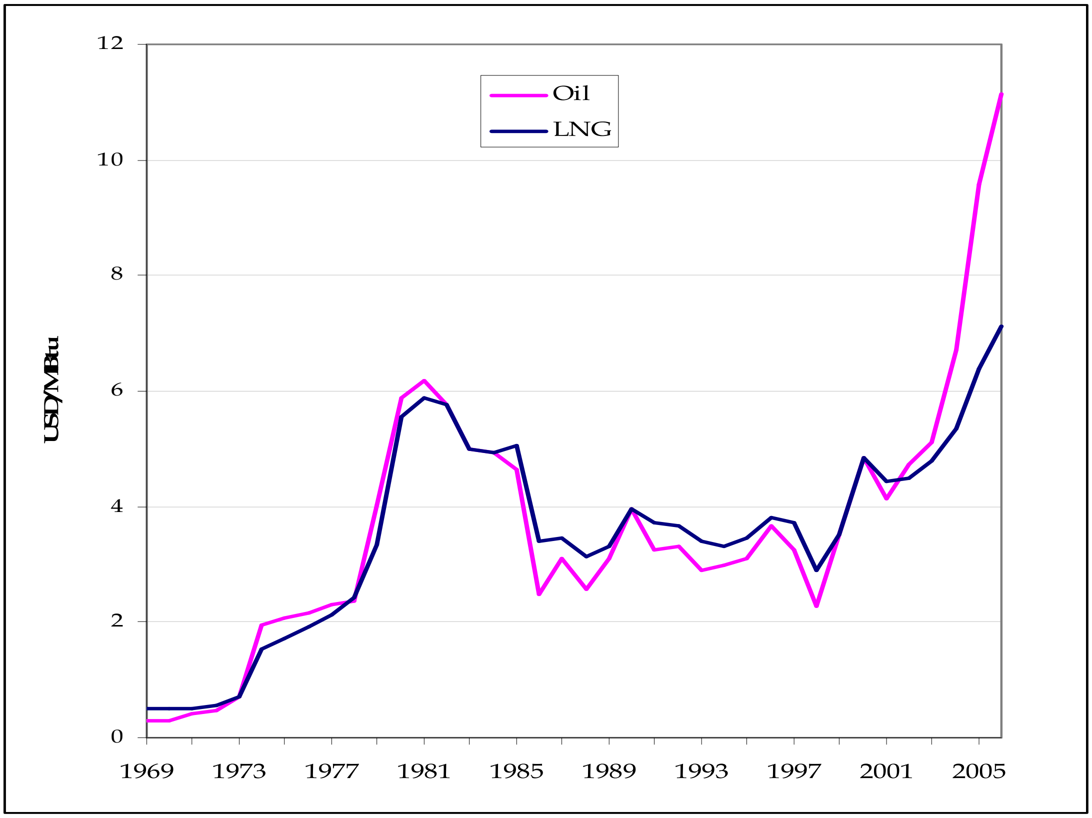


Figure 3-13 Japanese LNG prices



To meet this surging demand LNG production increased by 11% in 2006 and continuing growth of 7.5%-9% a year is expected, though some markets, such as China and India, are expected to be resistant to higher prices.[32] Some of this production will be met by projects already under construction, such as NWS Train 5, QatarGas II-IV, Yemen LNG, Sakhalin II and Norway's Snohvit. Most of these projects are however suffering from significant cost overruns caused by a tight engineering market and high steel and labour costs, as discussed in section 3.7 below. New LNG plant commitments are proving difficult in this environment and IEA reports that no final investment decisions for LNG plants were made in 2006[33]. This environment also clearly favours brownfield over greenfield developments, particularly in new entrant countries such as PNG, and is consistent with the delays to the Gorgon project reported in section 3.2.5.

IEA expects the linkage of LNG prices to more liquid price indicators to continue, with oil prices favoured in Asia but some Atlantic Basin suppliers such as Nigeria have moved to indices based on the US Henry Hub gas price. The Henry Hub price also provides a floor price for spot cargoes of LNG.

32 Natural Gas Market Review 2007, International Energy Agency, May 2007
33 Ibid

A number of projects are progressing under novel contracting arrangements whereby a proportion of production will be taken by upstream participants and marketed more flexibly, eg on a spot basis, which could lead to globalisation of LNG prices.

In view of the cost increases, LNG price pressures are clearly upward in the short-medium term. However buyers are likely to resist long-term commitments at higher prices, as evidenced by the recent renewals of NWSV contracts with its foundation buyers, which were for shorter 6 to 12 year terms. Buyer resistance may also mean that higher prices do not translate into higher netback values, as producer margins will be squeezed.

3.6.1 Summary

The LNG market has changed dramatically in response to the rise in oil prices and constraints on domestic gas supply in Europe and North America. As oil prices have risen LNG has become relatively more attractive in Asia and rising prices of pipeline gas in Europe and North America have also made LNG more attractive in those markets.

LNG production increased by 11% in 2006 and continuing growth of 7.5%-9% a year is expected. Some of this production will be met by projects already under construction, such as NWS Train 5, but most projects are suffering from significant cost overruns. New LNG plant commitments are proving difficult in this environment which clearly favours brownfield over greenfield developments. LNG prices are expected to remain high in the short-medium term.

3.7 Gas production cost increases

One of the most critical factors currently affecting gas markets is the rapid rise in production costs. The IEA[34] reports that in the petroleum sector generally costs have increased sharply in recent years due to:

- Increases in materials costs, primarily steel and concrete
- Increases in demand for limited skilled labour and equipment resources, due to the number of large scale projects under development and the need to enhance output at mature fields

IEA estimates that upstream costs had increased in real terms by 100% between 2000 and 2006 and that underlying demand for experienced personnel will grow at 7% per year.

IHS/CERA[35] report that their UCCI (upstream capital costs index) increased by 67% between 2000 and Q3 2006, with most of the increase occurring since 2004 (Figure 3-14). Recent increases have been driven primarily by equipment and skilled labour costs, steel prices having begun to moderate over the past twelve months. IHS/CERA notes that:

- Construction of over 100 new drilling rigs is planned, which should ease leasing rates by late 2009.

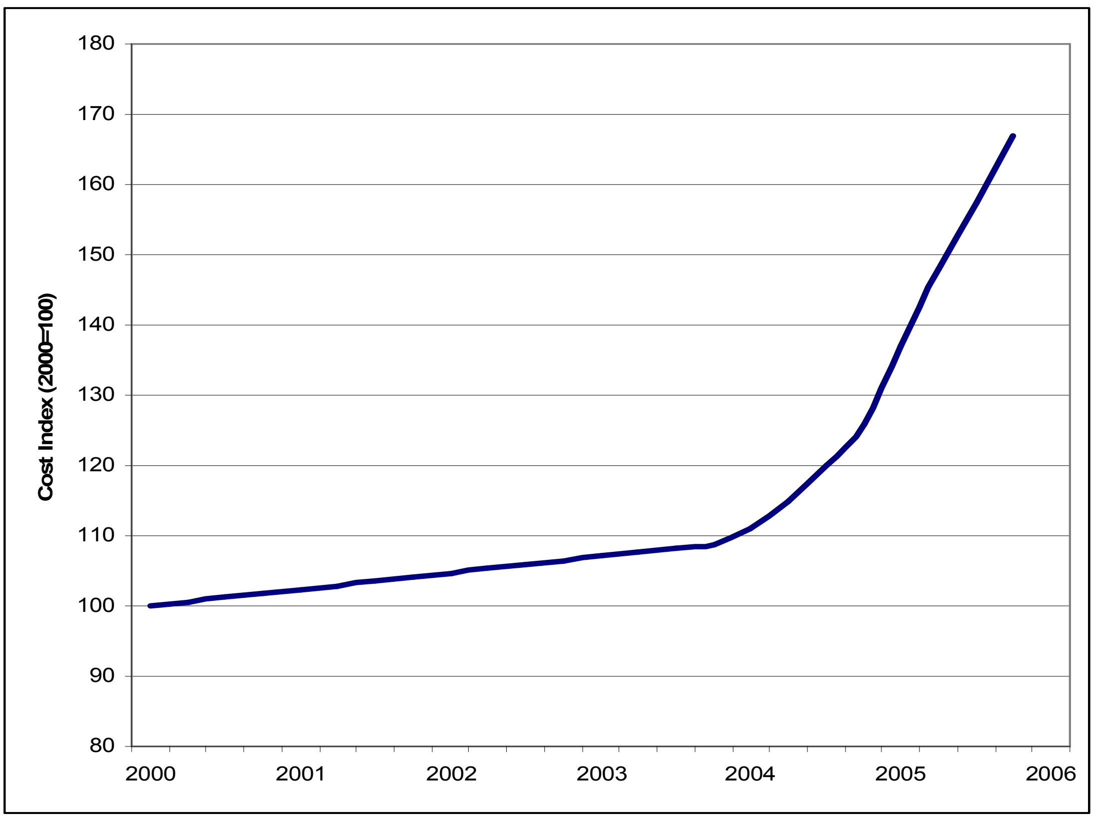
[34] Ibid
[35] Available on www.cera.com

- Vendors of equipment such as compressors, heat exchangers and towers are not expanding their capacity even though demand is high and delivery times are extended
- Shipyards are at capacity and even with an expected 15% expansion will remain so. Plans to expand the number of pipeline installation and heavy lift vessels will barely keep pace with short-term demand.
- It will be at least five years before skilled labour costs stop escalating

Overall IHS/CERA believes that cost escalation will moderate in the short-term. The long-term outlook depends ultimately on the complex interaction of the impact of cost increases on oil and gas prices, which in turn impact demand for oil and gas, and the number of projects that are needed to meet demand.

The rate of cost inflation and the resulting cost uncertainty has already led to delays in projects that will tighten the gas supply demand balance over the next five years.

Figure 3-14 Upstream capital costs index



The above cost increases affect the Australian gas production sector directly and the level of escalation is consistent with views expressed to MMA during the stakeholder consultation process - in its recently published Strategic Leaders Report[36], APPEA identified a critical shortage of skills in many industry subsectors. Clearly the international cost pressures will affect Australian offshore projects most directly since they compete internationally for all resources. Onshore projects may be somewhat protected from cost pressures on drilling but not in relation to skilled labour or gas processing equipment. The cost pressures will apply equally to projects targeting export and domestic markets, apart from the fact that export projects are offshore (with the exception of possible CSG exports) whereas some domestic projects are onshore.

Further cost increases may also impact development of gas fields with higher CO2 contents. Venting of significant quantities of CO2 is no longer acceptable and sequestration options or other offset mechanisms must be sought.

Costs of transmission projects have also increased over the same period but we have not found an up to date capital cost index. Costs of the PNG gas pipeline are estimated to have escalated by at least 30% before the project was halted in 2006 and other recent published cost estimates have been consistent with this.

At this stage it appears that market forces are still effectively allocating resources but the market may become less efficient if supply tightens further and bids for resources become more extreme. This is not to suggest that an alternative allocation method would be preferable.

[36] Strategic Leaders Report. Platform for Prosperity. Australian Upstream Oil and Gas Industry Strategy. APPEA, April 2007

4 BARRIERS TO DOMESTIC GAS SUPPLY

4.1 Introduction

Barriers (or potential barriers) to supply of gas to the domestic market can be physical and/or institutional. In the long-term the primary physical barrier is that presented by nature, namely the absence of sufficient gas resources. Our knowledge of the existence of resources is however heavily influenced by institutional factors, such as the incentives for further exploration, and in reaching any conclusions about long-term supply the potential for further discoveries should be taken into account.

The nature of resources, for example large scale deep water gas reserves, may also contribute to the existence of a barrier if it precludes exploitation on a scale compatible with the domestic market. Transmission capacity does not prima facie present a long-term physical barrier to domestic gas supply since it can be constructed wherever justified by resources and markets. Questions related to the adequacy of Australia's gas resources and transmission network relative to demand are being addressed by ABARE and the focus of MMA's work is on the institutional barriers.

Once resources are known to exist the principal question is whether they are being exploited efficiently, i.e. being delivered to customers at prices reflecting efficient construction and operation of the gas extraction and delivery infrastructure, with due rewards for the risks undertaken by various parties and providing incentives for further resource discovery and delivery capacity construction.

If prices are higher than efficient prices, then some parts of the market will not be supplied and a barrier to supply may be said to exist. Determining whether a barrier to supply exists therefore revolves primarily around efficiency and can be difficult to establish because it requires consideration of a counter-factual higher efficiency scenario. The majority of barriers to supply considered in this and other studies are barriers to greater gas market efficiency.

Lack of supply capacity due to a barrier should also not be confused with temporary lack of capacity and price rises, which may be part of the normal workings of the market and associated institutions, including unanticipated demand growth and supply reductions or delays. In this regard it is important to note the critical role of new gas supply developments in meeting demand growth and replacing depleted gas resources. Commitment to new developments must be made three to four years prior to first gas supply, to allow time for detailed planning, approval and construction. This also requires gas buyers to commit to purchase contracts three to four years in advance of supply – buyers that cannot undertake this commitment and approach the market for new contracts less than two years ahead of supply are likely to find their supply negotiation options restricted to producers with developed reserves. If this group of producers is limited in number, each producer may have significant market power with the result that the buyer pays a higher price.

Potential barriers to gas supply to the domestic market identified in the stakeholder consultation process are discussed in section 4.4 below.

4.2 Previous work undertaken by the MCMPR and MCE

A number of potential barriers to gas supply have been investigated by MCMPR and MCE, as outlined in the following sections.

4.2.1 MCMPR

A number of issues raised in the COAG *Energy Market Review* were referred to MCMPR and addressed during 2003.

4.2.1.1 Joint marketing

MCMPR has not supported the Energy Market Review's recommendations regarding mandatory notification of all future joint marketing authorisations or preclusion of further authorisations by jurisdictions. It has noted that most jurisdictions prefer that no new State exemptions for joint marketing arrangements be put forward.

4.2.1.2 Unproduced areas in existing production licenses

MCMPR has concluded that that there is no systemic problem concerning exploration effort in production licence areas in both the Gippsland and Carnarvon Basins, though it is possible that there has been inadequate exploration in individual production licences in the Gippsland Basin. However, Ministers noted that Victoria was preparing a separate report looking at issues associated with certain production licenses in the Gippsland Basin and strategies to deal with these issues.

4.2.1.3 Retention leases

MCMPR has reviewed the retention lease regime, which provides security of title for petroleum fields that are not currently commercial but which have genuine development potential, and found that the objectives of the regime are sound and are being achieved through current administrative arrangements. The review was conducted because of concerns expressed to the COAG *Energy Market Review* that it could be used to reduce upstream competition and delay development of offshore petroleum resources.

4.2.1.4 Review of the gas industry's principles for third party access to upstream facilities

A review of upstream third party access principles was undertaken, based primarily on a stakeholder survey. The review found there was no evidence of abuse of market power, or a deterioration of the ability to negotiate access. It was concluded that there was support for the continuation of the current arrangements and no compelling case to amend the APPEA principles.

4.2.2 MCE

The study "Energy Supply and Demand in Australia" has been reported to MCE SCO by SESSWG. In relation to barriers to supply to domestic markets the study has noted that:

"Although Australia is endowed with vast natural gas resources, the NIEIR study notes that most of them are remote from infrastructure and key domestic markets, making development costs considerably higher. This, coupled with the limited ownership and lack of supply diversity in the Eastern markets, could lead to limited gas competition, consequently constraining market and economic growth.

NIEIR highlights the importance of encouraging upstream competition and the development of key infrastructure to offset the effects of these characteristics of the market."

"With reference to the use of Australia's natural gas resources, the scenarios suggest that, while exports of natural gas could generate income for Australia in the short term, the neglect of the domestic market to serve export markets could translate into lower levels of security of supply of natural gas and economic stagnation in the longer term.

….NIEIR is of the view that the focus on serving international markets exclusively may lead to the neglect of the domestic energy sector. New infrastructure projects are put on hold, consequently eliminating inter-basin competition, pushing prices up and putting security of supply at risk. Eventually, energy intensive projects are relocated offshore in developing countries."

4.3 Other studies

4.3.1 ANZMEC review of the P(SL)A

A 'National Review of Petroleum (Submerged Lands) Legislation Against Competition Policy Principles' was referred by ANZMEC to a Review Committee in November 1999.

At the ANZMEC Ministerial Council meeting held on 25 August 2000, the Council considered the review reports[37] and resolved to adopt the review recommendations. These contained proposed responses to recommendations put forward in an April 2000 independent consultant's report by ACIL Consulting Pty Ltd[38].

The main conclusion of the Review Committee was that the legislation is essentially pro-competitive and, to the extent that there are restrictions on competition (for example, in relation to safety, the environment, resource management or other issues), these are

[37] Review of Petroleum (Submerged Lands) Legislation Against Competition Policy Principles, 'Final Report to the Australian and New Zealand Mineral and Energy Council by the Review Committee', August 2000, Australian Government Publishing Service, Canberra ACT.

[38] ACIL Consulting Pty Ltd, National Competition Policy Review of the Petroleum (Submerged Lands) Legislation, 'Report to the Petroleum (Submerged Lands) Review Committee', April 2000.

appropriate given the net benefits to the community. The outcomes of the review were to be implemented.

In relation to retention leases the Review Committee accepted industry submissions that two reviews of commerciality every five years was excessive and reduced the maximum number to one. One justification, identified by the Review Committee, for the reevaluation process is that it empowers the joint authority to intercede and cancel a retention lease when there is a disagreement between joint lessees as to the commercial viability of reserves held under the lease.

The Review Committee noted that comparable gas producing nations, such as the United Kingdom, Norway, the United States and Canada, all have legislative provisions based on a presumption that resources discovered will be developed and that the absence of such a requirement in Australia might have adverse consequences, such as the scheduling of Australian discoveries for development after the development of discoveries elsewhere, despite similar rates of return.

The Review Committee also noted that Australia's retention lease regime is more flexible than that of the US where if an explorer finds commercial resources it can develop them but if sub-commercial resources are found, there is no title equivalent to a retention lease and the explorer will have no further rights over the sub-commercial resources.

4.3.2 Inquiry into investment in mineral and petroleum exploration

In May 2002, the Federal Minister for Industry, Tourism and Resources requested the Standing Committee on Industry and Resources of the House of Representatives to inquire into and report on any impediments to increasing investment in mineral and petroleum exploration in Australia. After accepting industry submissions that the Petroleum Resource Rent Tax be reviewed, the Standing Committee went on to say:

"3.101 However, there should be a concomitant obligation for greater accountability placed on exploration companies and the Committee recommends accordingly.

RECOMMENDATION 4

3.102 The administration of retention leases be reviewed to require:

- Work program technical details (excluding financial information), relating to retention leases issued to petroleum exploration companies under the Petroleum (Submerged Lands) Act 1967, to be made public;
- Holders of retention leases under the Petroleum (Submerged Lands) Act 1967 applying for re-issue of those retention leases, should show cause why those retention leases should not be made contestable after expiry of the first five years of tenure, and any subsequent five years of tenure."

It is understood that these recommendations have yet to be acted upon.

4.3.3 Gas Market Development Plan

The Gas Market Leaders Group (GMLG) was established by MCE in 2005 to establish a Gas Market Development Plan (GMDP) incorporating market arrangements that would provide greater price transparency, market liquidity and competition. The GMDP[39] contained the following recommendations:

- The establishment of a Bulletin Board (BB) covering all major gas production fields, major demand centres and transmission pipeline systems, providing information for both the gas market and the National Gas Emergency Advisory Committee (NGERAC).
- Detailed design of a Short Term Trading Market (STTM), for all states except Victoria, which aligns with the augmented Gas Market Development Principles set out by MCE.
- Formation of a single National Gas Market Operator to manage the wholesale and retail gas markets, administer the BB and the STTM, and produce an annual national gas supply and demand statement. The Market Operator should assume the functions of The Gas Market Company (GMC) and REMCo and the gas functions of VENCorp.
- The Market Operator to support NGERAC in the collection, maintenance, publication and analysis of gas system information and in the provision of technical advice on the management of significant gas supply constraints.
- Rule making and change processes be as streamlined and cost effective as possible, incorporating rule development and consultation by the Market Operator and approval by the AEMC.
- Interim continuation of the GMLG to develop the BB and STTM and work with the MCE on the formation of the Gas Market Operator, with the costs shared between government and industry.
- The Market Operator to prepare an annual gas supply/demand statement providing long-term outlooks, over 5-10 years, of demand forecasts and supply capabilities, highlighting where potential supply shortfalls or transmission/transportation constraints may occur in the future.

The Bulletin Board (BB) would be an electronic communications system providing up-to-date gas system and market information relating to pipelines, production and storage capacities and daily demand to all interested parties, promoting improved decision making and facilitating trade in gas. It would not directly provide a market price or a mechanism for trading gas or pipeline capacity.

[39] National Gas Market Development Plan. Gas Market Leaders Group Report to Ministerial Council on Energy, June 2006.

The STTM is to establish a price based balancing mechanism for gas delivered to, and withdrawn from, defined market hubs, replacing current balancing arrangements outside Victoria. The benefits of the STTM have been identified as:

- Participants will be able to purchase gas from the STTM without the need to contract with a supplier or pipeliner thereby reducing the previous complexities and barriers to entry.
- Facilitating gas trading on a daily basis at market driven short-term prices, providing transparent pricing signals between hubs, and facilitate greater demand side responses by users.
- The competitive market for gas will better enable existing participants and new entrants to manage financial risks and match short-term variations in supply or demand.
- A daily clearing price signal will directly assist the ability of the market to respond efficiently to shortages of supply, and so avoid the adverse commercial impacts of intervention and/or the exercise of emergency powers by jurisdictions in rationing scarce gas supplies.

The GMDP recommendations have been accepted by MCE and GMLG is moving ahead with implementation. The National Gas Market Operator’s responsibilities are to be taken up by the National Energy Market Operator (NEMO). Detailed requirements of a planning statement are considered in section 6.5.

4.3.4 Energy Reform Implementation Group

During 2006 ERIG was tasked by COAG to develop detailed implementation arrangements for further energy market reform. ERIG commissioned KPMG to investigate impediments to efficient development of gas markets in Australia[40]. The principal findings of this report were that:

- The GMDP in its entirety should be endorsed by ERIG.
- The development of secondary financial markets should be encouraged to evolve on its own through the short-term trading market mechanism.
- Future policies should encourage standardisation to the maximum extent possible.
- SCO must formally advise MCE on the formation of a national Gas Market Operator (including if this function should be merged with NEMMCO) to prevent delays to the recommendations of the GMDP.
- Further work needs to be undertaken on upstream issues, including the current prevalence of joint marketing arrangements which may restrict competition.

ERIG’s report to COAG was primarily concerned with electricity reform matters.

[40] KPMG report to ERIG. The gas markets in Australia. Impediments to efficient development. December 2006

4.3.5 APPEA Strategic Leaders Report

The APPEA Strategic Leaders Report[41], released in April 2007, describes the Australian Upstream Oil and Gas Industry Strategy prepared by APPEA with the assistance of the Australian and state and territory Governments, CSIRO and other major stakeholders. The objective of the report is:

"To ensure the value of Australia's oil and gas resources to the Australian people is maximised, petroleum energy security delivered and long-term sustainability of an Australian oil and gas industry assured."

The report addresses barriers to gas (and oil) supply from an upstream perspective and formed the major part of an APPEA submission to the present study. The priorities identified by APPEA include:

1. A fiscal framework that further encourages the development of gas-based production projects. Industry advocates a five-year company tax depreciation regime.
2. An improved framework for exploration—particularly frontier exploration.
3. A more efficient and consistent national petroleum regulation regime, informed by a Productivity Commission review of the regulatory framework.
4. Harnessing the greenhouse benefits of gas by establishing a level playing field for fuel-on-fuel competition on the basis of 'competitive neutrality' across competing energy sources.
5. Continuous improvement of the industry's environmental and safety performance and increased community awareness of the industry's performance and values.
6. Enhanced and coordinated research and development with a view to Australia being a global leader in gas-related technology development and deployment.
7. Development of a national petroleum sector skills and vocational training plan.

With the exception of priorities 5 and 6, which are not seen as potential barriers to gas supply per se, all of the above are included in the 16 potential barriers identified in this study.

4.3.6 CCIWA Discussion Paper

In May 2007 the Chamber of Commerce and Industry, Western Australia (CCIWA) released a discussion paper focussed on improving gas supply security for the domestic market in Western Australia[42]. CCIWA consulted with both member companies and other key participants in the Western Australian gas market in preparing the paper.

[41] Strategic Leaders Report. Platform for Prosperity. Australian Upstream Oil and Gas Industry Strategy. APPEA, April 2007
[42] Meeting the Future Gas Needs of Western Australia. CCIWA, May 2007.

The discussion paper covers similar ground to the market outlook and barriers to domestic gas supply sections of the present report, though of course restricted to consideration of Western Australia. The paper concludes that there are opportunities to improve supply security by:

1. Using retention lease processes more proactively
2. Using the taxation framework to promote gas development
3. Improving development project approval processes
4. Broadening gas specifications for the DBNGP
5. Varying pipeline pressure limitations to increase capacity
6. Considering the need for a demand aggregator
7. Development of a more integrated energy policy at the national level

The paper also raises issues such as joint marketing of gas without reaching any definitive recommendation.

Items 1 to 4 are included in the 16 potential barriers identified in this study. Item 5 is not considered a material barrier and item 6 is considered as part of the market concentration issue. The impacts of gas policies on other energy sources and vice versa are considered on an issue by issue basis.

4.3.7 Assessment of current initiatives

4.3.7.1 Gas Market Development Plan

MMA has advised GMLG on the prospective costs and benefits of the BB and the STTM and found that both were likely to have positive net benefits[43]. Relative to the scale of the industry the calculated benefits are relatively small, less than $100m in NPV compared to wholesale gas markets worth over $3,000m annually, and the value of the BB is considerably less than that of the STTM. The major implementation risks for these initiatives are believed to be:

- Bulletin Board

  The key risk is potential inability to source information. Based on a public presentation by GMLG we understand this will be resolved by making data provision mandatory under the new National Gas Law/National Gas Rules.

- Short-Term Trading Market

  The key risks are:

[43] Gas Market Options Cost-Benefit Analysis. MMA report to GMLG, 13 June 2006.

i. That hubs cannot be defined sufficiently broadly because of incompatibilities with pipeline pricing structures or other factors. It may be possible to resolve this by changing the pricing by agreement with the pipeline owner, regulator and other stakeholders or by adopting multiple hubs.

ii. That the method of pipeline operation places market power in the hands of users of particular pipelines. To date where two pipelines feed a single hub, one operates on a set flow basis (flow controlled), the other operates on a pressure basis (pressure controlled) and variations in demand through a gas day are met by the latter pipeline. Users of the pressure controlled pipeline may at times have the power to set prices for variations in demand. The significance of this cannot be determined until the market design has been analysed in greater detail, which we understand GMLG plans to do over the next six months.

In view of the key role of the STTM in resolving a number of barriers to gas supply identified in the following sections, the earliest resolution of these issues is desirable.

4.3.7.2 APPEA Strategic Leaders Report

The APPEA report has a strong focus on external constraints on upstream oil and gas industry performance and identifies issues beyond barriers to gas supply. However coverage of internal industry structural factors that impact on other participants, particularly in the downstream gas market, is somewhat narrower. Structural options which may have neutral/negative implications for the sector but benefits for the broader economy are not considered.

The report nevertheless provides a valuable analysis of key issues facing upstream oil and gas which has been drawn upon in the preparation of this report.

4.3.7.3 CCIWA Discussion Paper

The CCIWA discussion paper broadly parallels this report and draws similar conclusions. MMA differs from CCIWA in detail on the interpretation of WA market and we feel the CCIWA report would have benefited from a more detailed comparison of the WA market with the Eastern States gas market.

4.4 Potential barriers to domestic gas supply

Stakeholder consultation undertaken by MMA has revealed fifteen factors considered to be barriers to domestic gas supply:

1. Attraction of export prices
2. Acreage management (retention leases and production licences)
3. Joint marketing
4. Gas quality
5. Cost increases
6. Market concentration
7. Infrastructure approvals processes
8. Retail market balancing mechanisms
9. Delivery point capacity access
10. Greenhouse gas reduction schemes
11. Vertical integration
12. Pipeline regulation
13. Non-standardisation incl market rules and operators
14. Tax and depreciation conditions
15. Aging infrastructure

A further factor identified in section 3.2.3.2, gas reserves accessibility in Western Australia, is also considered.

In this section the impact of each factor on the market is reported and assessed, using independent information where available, followed by a review of options for ameliorating the impact of each factor. A number of options will require further evaluation and all will require further detailed specification prior to implementation. Factors that have previously been reviewed but which are still considered to be barriers by some stakeholders are discussed in light of recent market changes, particularly in Western Australia.

As the discussion highlights, many of these factors and the options for ameliorating their impacts are interrelated and it is unlikely that barriers will be reduced without an integrated approach on a number of fronts.

For completeness and to show their relationship to other factors this list includes matters that are currently being progressed by the MCE, such as the overall gas access regime (a new National Gas Law and National Gas Rules are currently being drafted) and the short-term gas market development being pursued by GMLG. However for these matters no management options other than those currently being progressed have been identified.

4.4.1 Attraction of export prices

4.4.1.1 Issues

At current Japanese LNG prices of approximately US$7/mmbtu (Figure 3-13), equivalent to $8.30/GJ, the netback value to an Australian producer after shipping and liquefaction costs are deducted is estimated to be in the range from $5/GJ for a new project to $6/GJ for an existing producer. This is clearly higher and more attractive to producers than historical Western Australian domestic ex-plant prices of approximately $2.50-$2.75/GJ, though it is comparable with the most recent domestic prices of $4.70/GJ to $7.50/GJ (refer to section 3.2).

Developers of resources suitable for export may therefore prefer to export than sell domestically unless domestic prices rise permanently to this higher level. This perception, together with the limited "domestic" gas resource, motivated the Western Australian Government to introduce its Policy on Securing Domestic Gas Supplies, under which all export gas projects are to dedicate 15% of LNG production to the domestic market (further details are provided in section 6.2.1).

4.4.1.2 Assessment

The impact of export prices on domestic gas availability and pricing depends upon a number of factors:

1. The likely future levels of export prices
2. Availability of "domestic" gas
3. The ability of export projects to export their entire reserve base

As discussed in section 3.6, export prices are under upward pressure in the short-term. While there are indications as to when this pressure may moderate (c2010) it is not possible to say when or whether prices will actually fall. Export price levels are therefore likely to remain a factor in domestic gas supply.

Availability of domestic gas is discussed at length in section 3. Absent new discoveries, domestic gas is in short supply in Western Australia and in the medium- to long-term the domestic market may be dependent upon gas from export projects.

The key consideration in determining whether the attraction of export prices constitutes a barrier to domestic gas supply is whether development of the resources for the domestic market alone would be economic. As discussed in section 3.2.3, the conventional view is that larger fields or groups of fields are not suitable for stand-alone domestic development and the majority of Western Australia's resources fall into this category. From this perspective the attraction of export prices is not a barrier to supply; on the contrary it should be seen as enhancing the likelihood of resources being developed for export with domestic supply as a flow-on.

In this case the only negative aspect of high export prices is the price impact on domestic supply. Setting the current Western Australian domestic gas policy to one side, producers would have no reason not to sell domestic gas at a price equivalent to the netback export price, in the longer term, providing they have spare capacity. Spare capacity is an issue of whether reserves can support a minimum sized LNG train for a minimum period, which is becoming shorter as LNG supply diversifies. The majority of projects are therefore likely to have reserves to sell to the domestic market as was the case with the North West Shelf development, though not in the case of the smaller Bayu-Undan LNG project. There may also be additional gas demand at a lower price, for example to power stations competing with coal, which producers may choose to supply. Export prices are therefore expected to provide a ceiling for domestic prices, which may be lower if there is sufficient supply.

This view of the impact of export prices does not apply to gas fields which may be suitable for both domestic and export development. In such cases, which may include some fields in the Greater Gorgon area (refer to section 0), the attractiveness of export developments can be an active barrier to a smaller, less profitable development for the domestic market. If the export development proceeds and provides some domestic gas the barrier is unimportant but if the export development is delayed and no domestic gas is available the barrier may become more real.

4.4.1.3 Management options

There are three distinct issues to be considered:

1. Dependence of domestic supply on export projects
2. Potential delays to export projects
3. Fields suitable for domestic development

Initiatives to enhance domestic supply

Initiatives to enhance domestic supply must focus on the discovery and development of new resources in onshore or near shore basins. Potential initiatives include:

- Increased funding for pre-competitive geological data acquisition in relevant basins. Further details have been described by APPEA[44]
- Provision of infrastructure supporting exploration, such as roads
- Taxation reform to assist small exploration companies (refer to "flow through" shares in section 4.4.14)
- Improvement of project approval processes and project facilitation eg granting Major Project Facilitation status (refer to section 4.4.7)
- Royalty reductions or holidays for onshore production

[44] APPEA Op Cit

Delays to export projects

MMA understands that export project delays can be caused by:

- Cost escalation and uncertainty
- Delays in approvals
- Difficulties in finalising customer contracts (notably for the US West Coast market)

Options for managing cost escalation and domestic approvals are discussed in sections 4.4.5 and 4.4.7. Unrestricted access to overseas markets may be gained under free trade agreements but the opportunity to include gas in an agreement is presented infrequently. It is also noted that the Australia – United States Free Trade Agreement covers only manufactured goods, agricultural products and services. Commonwealth Government lobbying may be effective in securing approvals and contracts overseas, particularly in countries whose governments are directly involved in the contract negotiation.

Fields suitable for domestic development

This is ultimately a question of retention lease management. If a field held under retention lease is believed to be capable of supplying the domestic market on a commercial basis then the Joint Authority administering the area should use this as the basis of assessment. (Further discussion is presented in the following section).

4.4.2 Acreage management (retention leases and production licences)

4.4.2.1 Issues

Notwithstanding the reviews of various aspects of exploration and production acreage management conducted by the MCMPR (section 4.2.1), a number of stakeholders consulted by MMA believe that acreage management, in particular retention leases, are creating barriers to domestic gas supply. Alinta[45] has expressed the view that the retention lease process is lenient and allows retention leases to be granted for fields for which a ready domestic market exists, though not at LNG equivalent prices. Over 50% of Western Australia's reserves are held under retention leases, including one of the most prospective sources of domestic gas, Macedon (Table 3-3). A further 25% of reserves are held as undeveloped gas in production licences. These claimants agree with the principle of retention leases but believe that commerciality is not being adequately assessed in changing circumstances. It has also been noted by others[46] that retention leases can act as a deterrent to further exploration.

A number of retention leases have been converted to production as the fields became commercial without going through the renewal process. MMA understands that to date

[45] Submission Re "Western Australian Government policy on securing domestic gas supplies" Consultation Paper, Alinta, 21 April 2006

[46] David Maloney, "Stranded Gas – Australia's Offshore Retention Leases", Journal of Energy and Natural Resources Law, August 2004.

two retention leases have been refused renewal on the grounds of commerciality. The Kipper retention lease renewal was refused because of submissions by two of the then lessees, out of four in total, that a market for the gas existed at that time. The Kipper joint venture has subsequently applied for a production licence. During the first twenty years of the retention lease regime, to 2005, there were no instances of the Joint Authority refusing renewal as a result of its own disagreement with the lessees as to commerciality[47].

4.4.2.2 Assessment

The very tight Western Australian gas supply position has been known for over twelve months and it is understandable that buyers feel that developable gas reserves are being withheld from the market. It would seem that conditions could not become more favourable for the development of domestic gas supplies and that any "domestic" gas that is not commercial at present is unlikely to be more commercial in 15 years time. Such gas is therefore unlikely to be granted a retention lease renewal if it was sought at the end of the current lease (refer to Retention Lease Criteria box below) and the lease holders would be obliged to apply for a production lease or forfeit the acreage.

Retention Lease Criteria

To grant a retention lease the Joint Authority administering the area must be satisfied that:

"The recovery of petroleum from that area is not at the time of the application, commercially viable but is likely to become commercially viable within 15 years after that time[48]."

Guidelines[49] to section 38B of the P(SL)A state that:

"Commercially viable petroleum should be interpreted to mean that the petroleum could be developed:

- Given existing knowledge of the field
- Having regard to prevailing market conditions, and
- Using proven technology readily available within the industry

such that the commercial rates of return from recovery of the petroleum (including recovery of all operating and capital costs and taxes, royalties and other charges) meet or exceed the minimum return considered acceptable for the type of project under consideration by a reasonable petroleum developer and by investors or lenders to the industry (i.e. an acceptable rate of return). Existing knowledge of the field includes mapping and resource estimates at proved, probable and possible probability levels.

[47] Ibid
[48] P(SL)A section 38B
[49] Offshore Petroleum Guideline for Grant and Administration of a Retention Lease. Department of Industry, Tourism and Resources. Updated June 2006.

A petroleum accumulation cannot be claimed to be not commercially viable because of the inability or unwillingness of the titleholder to acquire or apply proven technology readily available within the industry or because of the applicant's lack of skilled personnel or financial capability.

In addressing market issues including market access, prices and timing of market opportunities, it will be accepted that a potential market exists for crude oil, condensate or LPG recoverable from a project and that terms of and conditions of supply will determine the viability of the project. However it is recognised that the market for natural gas is often characterised by large, long term contracts, at specified rates over specified periods, and specific quality. Therefore in some circumstances, the Joint Authority may agree that an otherwise commercially viable gas project (assuming current prices) is not commercially viable and may not proceed due to an inability to obtain a contract at prevailing market terms and conditions, which would support development. Alternatively the Joint Authority may accept that the level of resources, while substantial may be insufficient to meet any currently available market opportunity (eg a LNG project).

In recognition that market considerations can stall an otherwise commercially viable 'dry' gas project, the Joint Authority will give favourable consideration to an application for a lease if the applicant has demonstrated reasonable attempts in good faith to obtain gas supply contracts which were unsuccessful. In such a case, the major test in assessing whether the criteria have been met is likely to be assessing the applicant's efforts in obtaining a market for gas if the project can be demonstrated to be viable at prevailing prices (i.e. otherwise passes the commerciality test). However in order to enhance the marketability of a project, it might be reasonable to expect that the lessee better define the resource if this would be necessary to demonstrate supply capability to potential buyers."

4.4.2.3 Management options

Request re-evaluation of commerciality

The urgency of the Western Australian supply position suggests that unless retention leaseholders indicate some intention of developing their reserves in the near future, rather than waiting until the end of current leases the Joint Authority could request a re-evaluation of the commercial viability of production, as it is entitled to do under s38H of the P(SL)A. If the Joint Authority then forms the view that production is commercial it may cancel the lease unless the lessee applies for a production licence (s38E). The area could then be re-tendered and granted as a production licence to a different licensee.

Consider minor P(SL)A amendment

It is noted that s38E and s38H are silent in regard to reviewing the second retention lease criterion, namely whether production is likely to become commercially viable within 15 years. This criterion appears to apply only to the five-yearly renewal process and not to a re-evaluation during the term of a lease. Thus if during a re-evaluation under s38E and s38H the Joint Authority forms the view that production is not commercial at present nor is it likely to become commercially viable within 15 years, it is not empowered to cancel the lease, even though the second criterion, is not met. As other parties may take a different view of commerciality to both the current lessee and the Joint Authority, Governments should consider whether the P(SL)A should be amended to include review of the second criterion as well as the first in the case of a re-evaluation under s38E and s38H, so that the Joint Authority can cancel leases under these clauses where it is of the view that production is not commercial at present nor is it likely to become commercially viable within 15 years.

Replace renewal process with an auction

The possibility that other parties may have different views of commerciality has led to the suggestion that the retention lease application/renewal process should incorporate receipt of alternative proposals to develop the resource, to place competitive pressures on retention lessees. Alternative proponents would have to commit to unconditional development and lessees would have first rights of refusal. Proposals would also have to include a price payable to the incumbent lessee reflecting the commercial value of the retention lease. Values can be considerable even though fields are not commercial – in 1999-2000 Woodside paid $42.6m for 27.5% of the Kipper retention lease[50].

This proposal would turn the retention lease application/renewal process into an auction, a similar concept to that envisaged by the Standing Committee on Industry and Resources in 2002 (refer to section 4.3.2). It is noted that non-lessees may be disadvantaged by lack of information about the prospect and that better outcomes may be obtained by a conventional sale process, which could be triggered by non-renewal of a lease, under which non-lessees would receive information in the course of the sale.

MMA recommends that the feasibility of the auction option and the possibility of triggering sales be considered in greater detail.

4.4.2.4 Production Licences

In the case of undeveloped reserves held under production licences, section 53A of the P(SL)A provides that: "if no operations for the recovery of petroleum under a licence referred to in paragraph 53(1)(c) or subsection 53(2) have been carried on for a continuous period of at leat 5 years, the Joint Authority may, by written notice served on the licensee, inform the licensee that the Joint Authority proposes to terminate the licence after the end of one month after the notice is served."

This provides the Joint Authority with a mechanism to terminate production licences where the licensee fails to commit to any development of gas reserves after a long period.

[50] Woodside Annual Report 2000.

4.4.3 Joint marketing

4.4.3.1 Issues

The joint marketing and sale of gas on common terms by participants in a production joint venture has for some time been viewed as a barrier to upstream competition, and therefore potentially a barrier to domestic gas supply, and was raised as such by stakeholders consulted by MMA. The most recent review of gas market efficiency by ERIG (section 4.3.4) has concluded that from a market efficiency perspective further work needs to be undertaken on joint marketing. For oil and LPG separate marketing is the norm because of the diverse and liquid markets for these products and for LNG it is increasingly possible because of the number of competing projects and a growing spot market. It is noted that the Gorgon area partners have elected to sell LNG separately.

A number of stakeholders also noted the interactive effects of joint marketing and retention leases, namely that separate marketing could expose different views among the participants as to the commerciality of gas fields, with the result that development is more likely to occur.

4.4.3.2 Assessment

Joint ventures generally entitle participants to own, take and dispose of output in direct proportion to their share in the venture. Where the options to dispose of output are limited, such as by the absence of liquid markets, the participants must either arrange for sales to be in direct proportion to venture shares or agree upon a mechanism for resolving imbalances between entitlements and actual offtakes. It is generally held that balancing mechanisms are effective only when imbalances are short-term, hence arranging for sales to be in direct proportion to venture shares, by conducting marketing and sales jointly, is the preferred solution to this problem.

Joint marketing of gas has therefore been the norm in Australia since the earliest natural gas contracts were entered during the 1960s, at which time most producers were selling to either one or a very small number of buyers enjoying monopsony positions. Since the introduction of downstream gas competition in 1997, downstream interests have been lobbying for separate marketing to be enforced while upstream interests have contended that markets remain insufficiently liquid for separate marketing to be practical.

In a landmark decision in relation to an application by the NWSV for authorisation of joint marketing to the domestic market in 1998, the ACCC observed that it is not possible to be prescriptive about the conditions under which separate marketing became feasible but that the greater the number of the following market developments occur, the more likely that separate marketing would be viable:

- A significant increase in the number of customers (of gas producers)
- The entry of new competitive suppliers
- Additional transportation options

- Gas storage
- The entry of brokers/aggregators
- The creation of gas-related financial markets
- The development of substantial short-term and spot markets

In its authorisation decision the ACCC formed the view that separate marketing is clearly preferable to joint marketing but that few of the above developments had occurred in the Western Australian gas market by 1998 and that separate marketing may not be feasible at that time. As the applicants had indicated that they would prefer to market separately and as the ACCC was of the view that some developments were likely to occur quite soon, the ACCC authorised joint marketing for a limited period of seven years, to 2005. The authorisation has not been extended beyond 2005.

The ACCC's expectations regarding developments after 1998 have been met to a greater extent in Eastern Australia than in Western Australia or the Northern Territory:

- The number of customers (gas buyers) has increased slightly in both Eastern Australia and Western Australia and the buyers market is slightly less concentrated than the sellers market (section 4.4.6). Market integration in Eastern Australia has given producers access to a greater proportion of the total customer base.
- New competitive suppliers from the Otway, Gippsland and Bass Basins together with CSG producers in Queensland and New South Wales have entered the Eastern Australian market. The number of suppliers in Western Australia has if anything decreased with the end of production at Tubridgi and supply concentration in the Northern Territory is unchanged. The level of upstream market concentration is considered in more detail in section 4.4.6, where it is noted that it is slightly more concentrated than downstream but that this could be reversed by separate marketing.
- Major new pipelines that have expanded the interconnectivity of the Eastern Australian market include the NSW-Victoria Interconnect, the Eastern Gas Pipeline, and the SEAGas pipeline, while the Tasmanian Gas Pipeline and the North Queensland Gas pipeline have extended gas to new customers. In Western Australia the Telfer and Kambalda-Esperance pipelines have extended gas to new customers but there are no options that would significantly increase interconnectivity. The NT pipeline grid is unaltered.
- Commercial gas storage has been developed in Victoria at the Iona gasfield and in Western Australia at Mondarra.
- Gas broking/aggregation has been limited to pipeline affiliates marketing gas for the purpose of enhancing pipeline usage, in the cases of the Eastern Gas Pipeline, the Tasmanian Gas Pipeline and the North Queensland Gas pipeline.

- ERIG[51] has found that the trading of gas-related financial products is virtually limited to Victoria, where it is supported by a spot market. There have also been substantial physical swap arrangements that enable Queensland CSG to be "supplied" to markets in New South Wales, Victoria and South Australia.

- The Victorian spot market has been operating since March 1999 and in revised form since February 2007. The spot market operates as a pool and facilitates acquisition of gas by new entrant participants whose withdrawals are too low to warrant entering a long-term contract with a gas producer and disposal of gas by buyers with gas excess to their requirements. Outside Victoria limited short-term bilateral trading is increasing but participants do not expect a deep or liquid market to develop. Consequently the gas industry supports development of the STTM.

There is growing evidence that the level of market development in Victoria, particularly the flexibility provided by the spot market, is sufficient to support separate marketing, as both the Minerva and Thylacine developments in the Otway Basin have involved separate marketing of gas:

- bhpbilliton sold its 90% share of Minerva to International Power and Santos is trading its 10% through it's subsidiary Santos Direct

- Woodside sold its 51.55% share of Thylacine to TRUEnergy and Origin Energy will take its own 29.75% share and the shares of minority interests

To the extent that gas from the Victorian region is shipped to South Australia or New South Wales, this also applies to those markets. As the spot market is the principal difference between Victoria and other Eastern states MMA believes that the introduction of the STTM should prove sufficient to support separate marketing across the Eastern Australian market as a whole, provided that the STTM covers a sufficient proportion of each state's gas market.

Even though the level of market development in Western Australia is less advanced, separate marketing of domestic gas from the John Brookes field has occurred. Implementation of the STTM in Western Australia would further support separate marketing (subject to the STTM covering a sufficient proportion of the Western Australian gas market) and indeed at this stage it is difficult to foresee further market developments in Western Australia beyond this. Thus separate marketing would either be judged to be feasible when the STTM becomes operational in Western Australia or it is not likely to be feasible for some time after that.

In relation to the Northern Territory, it seems unlikely that the market will develop sufficient depth to support separate marketing.

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[51] KPMG report to ERIG. The gas markets in Australia. Impediments to efficient development. December 2006

4.4.3.3 *Management options*

STTM

Implementation of the STTM is recommended as the primary means of taking market development to the stage where separate marketing is supported. It is noted that this is a necessary condition. Whether it is sufficient will depend upon other market factors at the time of implementation and the process whereby this is tested by the ACCC has not been determined.

4.4.4 Gas quality

4.4.4.1 *Issues*

Australian Standard AS 4564-2005 establishes a national standard for natural gas suitable for transportation and general purpose use and the range of properties consistent with safe operation of the natural gas appliance population. The standard provides certainty for appliance manufacturers that supply appliances in Australia. It is intended to apply to all pipelines conveying gas for general purpose users but not to gas supplied solely to large industrial or power generation customers. More stringent specifications can be used without compromising appliance safety but can add to gas processing costs and act as a barrier to gas supply.

Table 4-1 AS 4564 Gas Specification Limits

Characteristics and components	Limit
Wobbe Index	Minimum 46.0 MJ/m3 Maximum 52.0 MJ/m3
Oxygen	Maximum 0.2 mol %
Hydrogen sulfide	Maximum 5.7 mg/m3
Total sulfur	Maximum 50 mg/m3
Water content	Maximum Dewpoint 0°C at the highest MAOP in the relevant transmission system (in any case, no more than 112.0 mg/m3)
Hydrocarbon dewpoint	Maximum 2.0°C at 3500 kPa gauge
Total inert gases	Maximum 7.0 mol%

AS 4564 documentation notes that:

1. Some transmission pipelines have reported operational problems with gas at lower sulphur concentrations than the 50 mg/m3 in the standard and research on this issue is continuing. No other specific problems are noted.

2. Higher heating value, which is not part of the specification, is expected to be in the range 37 MJ/m3 to 42 MJ/m3 for gases likely to be available commercially. No problems are noted with gas outside this range but still within the Wobbe Index range.

3. For some applications gas may need to be dried.

4.4.4.2 Assessment

AS 4564 was first established in 2003, prior to which each jurisdiction had its own gas quality standard, usually deviating only slightly from AS 4564. MMA understands (but has not verified in each case) that pipelines in Eastern Australia have converted their quality specifications to AS4564, with a number of exceptions. For example the Roma-Brisbane pipeline has an alternative hydrocarbon dewpoint, has retained a maximum carbon dioxide specification, until such time as it is connected to another pipeline system, and allows gas carried under contracts pre-dating the change to meet the former specification. Importantly, stakeholders consulted by MMA did not raise gas quality specifications in Eastern Australia as a potential barrier to supply.

It has however been suggested by stakeholders that the quality specifications for the Dampier to Bunbury Natural Gas Pipeline (DBNGP) in Western Australia do present a barrier to entry. Prior to 2005 the DBNGP had two specifications, Category A for gas received into the pipeline and Category B for gas delivered to users. The Category A specification set a minimum level of LPG (1.45 t/TJ) to enable contractual obligations to the LPG extraction plant in Kwinana to be met. Some other specifications such as the Wobbe Index also had narrower ranges than AS 4564 and it was widely believed that the specifications presented a barrier to supply of gas from fields with low liquid content.

In its revised Access Arrangement in 2005 the DBNGP proposed the same specifications without the minimum LPG content, as the LPG obligation has ended. The Western Australian Energy Regulatory Authority (ERA) however determined that some other elements of the specifications should be broadened, to reduce the barriers to supply[52]. This decision was supported by gas producers but opposed by some end users – ERA addressed these concerns at length in its Final Decision, referring in particular to the Broadest Specification of the Dampier to Bunbury Natural Gas Pipeline Regulations 1998, which governed DBNGP gas specifications until 2004 and foreshadowed its decision. ERA noted that broadening of the specifications: would bring them closer to the national gas standard (AS 4564); would align DBNGP specifications with those of other Western Australian pipelines; and that adoption of the Broadest Specification would not result in any technical or safety issues, on the advice of the Director of Energy Safety and the Director of Gas and Emergency Management, of the Department of Consumer and Employment Protection.

[52] Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline, ERA, November 2005.

In determining the new specifications however the ERA took the view that it had to adopt the more stringent of the Broadest Specification and the specifications under the Western Australian Gas Standards (Gas Supply and System Safety) Regulations 2000, which govern specifications for gas supplied to an end-user, are narrower than the Broadest Specification and AS 4564 and include additional components (Table 4-2).

Table 4-2 Dampier to Bunbury Natural Gas Pipeline Gas Specification Limits

Characteristics and components	Limit and AS limit
Wobbe Index	Minimum 46.5 MJ/m3 (AS 46.0) Maximum 51.0 MJ/m3 (AS 52.0)
Oxygen	Maximum 0.2 mol % (AS same)
Hydrogen sulfide	Maximum 2.0 mg/m3 (AS 5.7)
Total sulfur	Maximum 20 mg/m3 (AS 50)
Water content	Maximum 48 mg/m3 (AS 112.0 mg/m3)
Hydrocarbon dewpoint	Maximum 0.0°C over pressure range 2500 to 8720 kPA (AS 2.0°C at 3500 kPa gauge)
Total inert gases	Maximum 7.0 mol% (AS same)
Higher heating value	Minimum 37.0 MJ/m3 (AS n/a) Maximum 42.3 MJ/m3 (AS n/a)
Carbon dioxide	Maximum 4.0 mol% (AS n/a)
Hydrogen sulphide	Maximum 2 mg/m3 (AS n/a)
Radioactive components	Maximum 600 Bq/m3

In 2005 bhpbilliton[53] made it known that gas from the Macedon field would not meet the heating value requirement in this new specification and this was confirmed by Kimber and Associates[54], who estimated the heating value of Macedon gas as 35.7 MJ/m3 and it's Wobbe Index as 46.8 MJ/m3. Macedon gas would therefore meet AS 4564 (and the Broadest Specification, which has lower heating value limit of 35.1 MJ/m3) but not the additional heating value component of the DBNGP specification. In view of the significant

[53] Application for Revocation of Pipeline Coverage under the National Access Code for Natural Gas Pipeline Systems – Tubridgi Pipeline (PL 16) and Griffin Pipeline (PL 19), bhpbilliton 28 October 2005.

[54] Review of gas specification for Dampier to Bunbury Natural Gas Pipeline & determination of an appropriate gas composition for design of stage 5 expansion. MJ Kimber and Associates, 22 February 2006

role Macedon gas can play in meeting medium term domgas requirements, this is a significant barrier to supply in Western Australia.

4.4.4.3 Management options

Change Western Australian gas specification

Although the gas specification issue has been addressed at length by the ERA in relation to the DBNGP, adoption of AS 4564 was not considered because the ERA decision was constrained by gas specifications set in the Western Australian Gas Standards (Gas Supply and System Safety) Regulations 2000, which were set prior to the establishment of AS 4564. In view of the significance of the barrier to supply it is recommended that:

1. The Western Australian Government should consider revising the Western Australian Gas Standards (Gas Supply and System Safety) Regulations to comply with the National Standard. In view of the design of AS 4564 to meet end-user requirements this should not pose any difficulties for the operation of combustion equipment, including all residential appliances. The needs of other users and the pipelines for more restrictive specifications, on sulfur or CO2 for example, should be taken into account.

2. ERA and DBP should then consider broadening the DBNGP specification to match AS 4564, taking into account the need to possibly impose lower sulfur limits for operational reasons. It is recognised that further changes to gas specifications may impact on the available capacity of the DBNGP and that the cost of expanding capacity should be taken into account – if possible the cost of expansion should be compared with the cost of additional processing of Macedon gas required to meet the DBNGP specification, for example the cost of removing nitrogen.

Blending

An alternative option is to blend out-of-specification gas with other gas such that the specification is met in aggregate at some point on the pipeline prior to withdrawal by end users. This has been used in the past with gas from the Tubridgi field but is generally not satisfactory in the long term as it relies on availability of other gas and supply of out-of-specification gas is otherwise subject to interruption.

4.4.5 Cost increases

4.4.5.1 Issues

The cost of gas exploration and production has increased significantly over the past three years. These costs will flow on to the costs of gas for new contracts, to the extent that they are not constrained by competition and buyers ability to pay. The costs themselves are not critical to creating a barrier to supply, rather it is the uncertainty created for both sellers and buyers. Sellers have experienced significant cost blowouts in recent years and may become more conservative in pricing gas for new contracts, while buyers will be unsure of their ability to absorb higher prices and may prefer shorter term contracts. Overall, it becomes more difficult for the market to find the price at which supply and demand balance and which supports investment in new infrastructure, in view of the limited number of contract negotiations and limited transparency.

4.4.5.2 Assessment

MMA's assessment of exploration and production cost increases is documented in section 3.7. Most of the increases have resulted from international competition for scarce skilled labour and equipment and affect domestic and export projects almost to the same extent (onshore production for the domestic market may be less affected as it competes internationally only for skilled labour and not equipment). The cost increases are both significant, at least 65% since 2000, and are not likely to be reversed in the medium term.

At this stage it appears that market forces are still effectively allocating resources but the market may become less efficient if supply tightens further and bids for resources become more extreme. This could occur because more resources are consumed re-evaluating projects. This is not to suggest that an alternative allocation method would be preferable.

4.4.5.3 Management options

Skilled labour supply

Long-term skilled labour availability can only be secured by better resource planning and investment in training. APPEA's Strategic Leaders Report[55] identifies five initiatives that could be lead by Government:

1. An expedited qualification pathway based on current skills recognition.
2. Ensure that immigration policies and procedures are not impediments to necessary skilled migration options. Countries such as China, India, Indonesia, Mexico and Venezuela have surplus petroleum graduates[56] in spite of the shortages elsewhere.
3. An Australian government Petroleum Industry Bursary instituted to encourage year 10, 11 and 12 students to select mathematics and science and nominate an oil and gas–related career path—similar to the Mining Industry Bursary already in place.
4. Increased vocational education training in schools in petroleum-related disciplines such as the Process Plant Operators Vet being piloted in Western Australia, with companies providing support by employing student trainees.
5. A reduction in university fees for courses not attracting sufficient students to meet long-term industry requirements—particularly in the less popular science disciplines.

Industry acknowledges that it will have to do its part in association with any Government initiatives, as reflected in the APPEA report. A number of stakeholders observed that staff retention was difficult and needed more effort on their part.

[55] Op cit
[56] Natural Gas Market Review 2007, International Energy Agency, May 2007

Equipment supply

It is not anticipated that Australian Governments' policy decisions could materially change the supply of oil and gas equipment, particularly for offshore projects, because the majority is constructed in overseas plants and shipyards.

Market uncertainties

Removing uncertainties affecting the market would improve the gas market's ability to deal with cost pressures. Stakeholders consulted by MMA nominated the future of greenhouse gas reduction schemes as the key uncertainty affecting gas at present. This is discussed further in section 4.4.10.

4.4.6 Market concentration

4.4.6.1 Issues

Market concentration among both sellers and buyers has been put forward by stakeholders consulted by MMA as both a barrier to domestic gas supply and to gas market efficiency. Although upstream/production concentration has reduced significantly over the past ten years in Eastern Australia, concentration issues have recently re-emerged as mergers and take-overs threaten to increase concentration in the Eastern States, for example, Santos takeover of Tipperary, the Arrow-CH4 merger and AGL's purchase of 50% of CH4.

4.4.6.2 Assessment

Using the market information discussed in section 3 we have derived useful comparative indicators of upstream and downstream market concentration. The Herfindahl-Hirschman Index (HHI) is a relatively simple and widely used measure of market concentration – it is the sum of the squares of participant market shares in the relevant market multiplied by 100. HHIs below 10 are viewed as indicative of a competitive market (low concentration and very limited market power), HHIs between 10 and 18 indicate medium levels of concentration (some market power) and HHIs above 18 indicate high level concentration (significant market power). If participants have equal market shares this means that ten participants are required for a competitive market and at least five or six are required to avoid significant market power.

Market definitions that give a useful indication for future competitiveness are:

- Upstream – shares of uncontracted reserves, which are more relevant to current and future market conditions than shares of total reserves or production. Shares are stated in both joint venture and company terms, to illustrate the effects of joint and separate marketing.
- Downstream – shares of gas contracted and retail shares of customers. Unfortunately there is no readily available forward looking measure comparable to uncontracted reserves.

All these market share measures ignore the ability of new entrants to reduce concentration but also ignore the fact that at any time not all the participants in gas contract markets will be looking to buy or sell gas, which can lead to extreme concentration as currently being experienced upstream in Western Australia - if the NWSV is excluded, the short-term upstream HHI in Western Australia is 100 and if it is included it is 88.

Longer term upstream markets are less concentrated in both regions, though only on a company basis is the concentration actually reduced to medium levels (Table 4-3). The high concentration in Eastern Australia on a joint venture basis is due to the high proportion of uncontracted reserves held by the Gippsland joint venture. If only domgas reserves as defined in section 3.3.3 are counted in Western Australia, the concentration is much higher on both joint venture and company bases (Table 4-4). Concentrations that are higher on a company basis than on a joint venture basis simply reflect the involvement of a small number of companies in a large number of joint ventures.

Table 4-3 Upstream market concentration based on total uncontracted reserves

	Eastern Australia		Western Australia	
	Joint venture basis	Company basis	Joint venture basis	Company basis
HHI	23	17	19	14
Market concentration	High	Medium	High	Medium

Table 4-4 Western Australian upstream market concentration based on uncontracted reserves

	All reserves		"Domgas" reserves	
	Joint venture basis	Company basis	Joint venture basis	Company basis
HHI	19	14	28	32
Market concentration	High	Medium	High	High

Table 4-5 Downstream market concentration

	Gas buyers		**Eastern retail markets**	
	Eastern Australia	Western Australia	Gas	Electricity
HHI	18	16	33	16
Market concentration	Medium	Medium	High	Medium

Concentration of gas purchasing appears to be slightly lower than upstream concentration (Table 4-5) due to the number of small to medium industrial and generation purchasers. However the gas retail market (measured by customer share rather than energy share) remains highly concentrated.

4.4.6.3 Management options

The above analysis clearly shows that concentration is an issue both upstream and downstream.

Upstream

Separate marketing would demonstrably reduce upstream market concentration and would most likely be the most effective mechanism. However in the WA domgas sector this would not be of assistance owing to the participation of a limited number of producers in the domgas joint ventures. In WA exploration and discovery of additional reserves would be a more effective means of reducing concentration.

Downstream

Downstream concentration can be reduced by eliminating some of the barriers to entry by new participants, as discussed in sections 4.4.8 and 4.4.9.

It is noted that a number of stakeholders have promoted the formation of a gas purchasing aggregator as a means of reducing the imbalance of market power between sellers and buyers in Western Australia. Formation of a private sector aggregator is a purely commercial matter, with no regulatory barriers other than the provisions of the Trade Practices Act, and if the aggregator served only the smaller buyers it would not lead to a marked increase in downstream concentration. If Government involvement was required to establish the aggregator this would imply a need for some form of subsidy, possibly in the form of underwriting risk, which the majority of stakeholders would reject[57].

[57] CCIWA, op cit.

4.4.7 Infrastructure approvals processes

4.4.7.1 Issues

Approvals processes frequently take longer than construction of infrastructure, especially where multiple authorities are involved, and obtaining approvals can necessitate costly design changes. APPEA's Strategic Leaders Report[58] documents a small oil project that required 163 approvals from 22 separate authorities, including 61 approvals simply for the construction of a pipeline to bring the resource, which is in Commonwealth waters, to an onshore processing facility. Pipeline stakeholders consulted by MMA reported similar concerns, particularly with regard to inter-jurisdictional pipelines.

APPEA acknowledges the work of the Prime Minister's Taskforce on Reducing Regulatory Burdens on Business[59], as a result of which commitments have been made to introduce tougher rules for making new regulation, including cost benefit analysis, and to screen all regulation at least every five years. The Commonwealth Government has also enunciated six principles of good regulatory process and measures to ensure they are adhered to:

- establishing a case for action;
- examining alternatives to regulation;
- adopting the option that generates the greatest net benefit to the community;
- providing effective guidance to relevant regulators and affected stakeholders;
- reviewing regularly to ensure the regulation remains relevant and effective; and
- consulting effectively with stakeholders at all stages of the regulatory cycle.

4.4.7.2 Assessment

In view of the availability of the Major Project Facilitation (MPF) scheme administered by Invest Australia, which assists proponents of strategic projects to obtain decisions on necessary approvals, the continuing level of dissatisfaction with approvals indicates either that MPF is not effectively reducing the burden, that it is not sufficiently widely available, or that the burden is overstated. Stakeholders did not mention MPF spontaneously and it is noted that it is intended to expand the scheme to a wider range of projects in 2007/08.

There is a general absence of objective or consistent subjective measures of the costs of compliance with infrastructure and regulatory approvals, which is being addressed by the Productivity Commission's project "Performance Benchmarking of Australian Business Regulation". The project's first report[60] establishes a methodology for benchmarking the

[58] Op cit
[59] www.regulationtaskforce.gov.au
[60] Performance Benchmarking of Australian Business Regulation. Productivity Commission. 19 February 2007.

regulatory burden and establishing the level of unnecessary regulation. Over the next three years it will assess occupational health and safety regulations, environmental approvals, stamp duty and payroll tax administration, financial services regulation, food safety regulation and land development assessment.

While environmental approvals are very material to the oil & gas industry, the PC's plan does not envisage that it will be conducting an industry wide study that would clearly establish whether the burden was excessive or reasonable. APPEA has therefore requested the Commonwealth to commission the PC to undertake an extensive review of the regulatory system for petroleum activities across all jurisdictions. MMA supports this request, to resolve the materiality of the approvals burden.

4.4.7.3 Management options

Harmonisation of regulations

Harmonisation of regulations across jurisdictions would remove duplication of effort by infrastructure providers, even if they continued to have to deal with multiple authorities[61]. The importance of harmonisation has been recognised by COAG[62]: "In many areas, regulation reform and red tape reduction are best achieved through cooperation between governments. COAG has committed as part of the new National Reform Agenda to work together to reduce the regulatory burden on business from all three levels of government and to improve regulation-making processes."

No additional actions beyond the COAG initiative are recommended.

Single authority over cross jurisdictional projects

Harmonisation will facilitate the appointment of one jurisdictional authority over each aspect of a cross jurisdictional project. The appointments would be project specific. Without harmonisation the single authority approach would be more complex but could work if one jurisdiction's regulations were a subset of the other's. Appointment of another jurisdiction's regulatory authority has precedents in gas distribution regulation, where the Victorian regulator has regulated gas distribution in Albury NSW.

A further step could be taken by appointing single authorities to manage functions across all jurisdictions on a permanent basis, using the National Offshore Petroleum Safety Office (NOPSA) model. In this model the jurisdictions do not cede authority but use a single office to administer their responsibilities. APPEA has indicated its support for extending this model in the upstream sector.

It is noted that COAG has agreed to work towards a single regulator for mine safety and it is recommended that further single regulators be considered, including: environmental approvals (an extension of the Environment Assessors Forum); and infrastructure

[61] It is noted that NSW's Environmental Planning and Assessment Act has reduced the number of approvals and planning time for new pipeline developments

[62] Report of the Taskforece on Reducing Regulatory Burdens on Business — Final Government Response, 15 August 2006

construction authorisation. It is recognised that establishment of some of these regulators will have ramifications beyond the gas industry that will need to be considered.

Harmonisation has already been achieved in petroleum legislation through the commonality of the P(SL)A.

Special authority

APPEA has suggested that the viability of a national regulatory authority to manage all regulatory approvals for the oil and gas industry should be considered. This proposal extends well beyond the NOPSA model, to a cross-functional regulator specific to the oil and gas sector. If this model were pursued it would require similar cross-functional regulators for other industries, which from a national perspective would involve duplication and possibly different interpretations of specific functions in each regulator. Implementing this model would be costly in time and resources, as none of the jurisdictions currently has a cross-functional regulator to use as a template.

On balance it would seem that pursuing the cross-jurisdictional, single function regulator model is likely to bring greater returns sooner, at the national level. It may be useful however for one of the jurisdictions to consider and report to COAG on what a cross-functional regulator would look like and what the implications are for sectors outside oil and gas.

Pipeline regulation

The creation of the new National Gas Law and National Gas Rules is intended to reduce the burden of regulation on gas pipelines, particularly those with limited market power.

Parallel processing

Parallel processing of approvals, design and component ordering may offer a means of reducing project timeframes. While project developers clearly cannot make final commitments until approvals are finalised, it may be possible to make further project progress under conditional approvals. It is recommended that Governments and industry investigate the potential and the nature of the conditional approvals that would be necessary.

4.4.8 Retail market balancing mechanisms

4.4.8.1 Issues

Most stakeholders, including the relevant retail market operators, agree that the current retail market gas balancing mechanisms in New South Wales and South Australia do not operate efficiently and present high barriers to retail market entry and, thereby, to gas supply efficiency. The central problem is that the balancing mechanisms create extreme financial exposures that are disproportionate to the underlying costs and new entrants are evidently unable to hedge the risks. The reasons for the complexity of the balancing arrangements are understood to originate in the fact that the major distribution zones in both regions, in Sydney and Adelaide, are supplied by two transmission pipelines. Stakeholders contrasted this with the hedging opportunities provided by the Victorian spot market (which is also supplied by multiple pipelines).

Stakeholders did not make any observations regarding the Western Australian or Queensland balancing mechanisms. In both these regions the major distribution zones, in Perth and Brisbane, are effectively supplied by single transmission pipelines[63] and the markets may therefore be expected to be more effective. Stakeholders also do not have much experience of these markets, owing to the very low levels of retail competition in Western Australia and the fact that the Queensland market was not operational until 1st July 2007.

4.4.8.2 Assessment

This aspect of retail markets has been comprehensively documented in submissions and reports relating to the Gas Market Development Plan. For example Energy Australia[64] observed in 2005 that: " the new SA wholesale gas market in South Australia and Western Australia, operated by REMCo is based on a 'swing' model where gas imbalances are deemed 'parked' and 'loaned' between transmission pipelines with users paying for the service allocated to them. Gas and pipeline capacity is tightly held in the SA market by incumbent participants, making access to gas and swing service problematic in that market. The swing market has little or no liquidity and consequently prohibitive balancing gas costs, as the incumbents can set price."

4.4.8.3 Management options

STTM

The STTM has been conceived as a means of replacing the problematic physical balancing arrangements in New South Wales and South Australia with a price based approach. Its further development is endorsed as part of the GMDP and additional analysis in this study does not appear to be warranted.

Operational Balancing Arrangements

An alternative approach to resolving the specific problems caused by having multiple transmission pipelines could be the use of operational balancing arrangements (OBAs) between the transmission pipelines supplying distribution zones. This approach is widely used in the US (we understand it is the default option) but the OBA initially established in New South Wales broke down after a number of years and the concept has not been revived in Australia. This approach would not offer the other features of the STTM such as price transparency.

[63] The Parmelia Pipeline provides about 5% of Perth's transmission capacity

[64] Energy Australia submission to MCE in relation to the Options for the development of the Australian wholesale gas market", 15 April 2005.

4.4.9 Delivery point capacity access, pipeline interconnection and pricing

4.4.9.1 Issues

Inability to access pipeline capacity under the contract carriage model can be a barrier to market entry, according to a number of stakeholders. At present this is manifested more through a lack of capacity at certain delivery points because it is fully booked by others, which prevents new entrants from selling gas to end users downstream of those delivery points, than through aggregate pipeline capacity constraints. When delivery into the downstream distribution network is not physically constrained, this is an artificial barrier to market entry and to gas supply efficiency.

The lack of interconnection between some major pipelines has created regions which only have access to very limited gas supply options. Such regions include regions upstream of Adelaide on the MAP, which cannot avail themselves of backhaul services from suppliers using the SEAGas pipeline because of a lack of interconnection between the pipelines.

Other stakeholders have raised the pricing of non-reference services, such as overrun charges, as a factor contributing to access difficulties. They believe that overrun charges are set at high levels unrelated to costs, and that this encourages inefficient over-booking of capacity to avoid overrun payments. More general potential pricing inefficiencies, such as uniform pricing, have also been raised.

4.4.9.2 Assessment

MMA does not have access to information on capacity bookings at pipeline delivery points and is therefore unable to assess whether the capacity booking issue is material. A similar lack of information prevents us from determining the materiality of the overrun issue.

Lack of interconnection of MAP and SEAGas is well known – In its 2005 Access Arrangement Review Envestra proposed to construct an interconnection at some time prior to 2009 and this has been approved by ESCOSA[65].

4.4.9.3 Management options

The NGL places requirements on pipeline users to provide information on the quantity, type and availability of the user's unutilised contracted pipeline capacity, to any person requesting it. The NGR further requires pipeline users to provide the information to the pipeline service provider, which must then include the unutilised capacity in its spare capacity (uncontracted capacity) register.

Implementation of these provisions may assist in measuring and managing access to delivery points though delivery point information is not explicitly required to be provided

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[65] Proposed revisions to the Access Arrangement for South Australian Gas Distribution System, Final Decision, ESCOSA, June 2006.

and no definition of "unutilised" is given in the NGR. It is recommended that MCE-SCO consider including in the NGR:

a) That unutilised contracted pipeline capacity information should include delivery point information

b) A definition of unutilised capacity

Alternatively point b) could be referred to the AEMC.

The STTM may assist with capacity management but participants felt that the market operator was not likely to be able to take on a role of capacity management.

Capacity

The ability of shippers to hoard capacity on contract carriage pipelines to create barriers to entry for others is an unfortunate aspect of the contract carriage model. Reluctance to trade capacity may be due to fear of market illiquidity i.e. capacity traded may not be regained. As with other responses to illiquidity however, such as vertical integration, this only compounds the problem for others.

A number of options to promote capacity availability have been put forward over time but none appear to fully resolve the problem:

- Use it or lose it. The failing here is that capacity is not fully used every day, which raises the question as to when it has not been used i.e. what level of security should users allow for?
- New entrants to use interruptible capacity. This may be acceptable to a retailer but depends on what their customers require.
- Delivery points (citygates) to be owned by distribution companies. This would enable capacity contracted at the delivery point to be related to capacity needed to deliver gas to a retailer's customers, by the distribution operator.

Interconnection

Envestra has seen a commercial opportunity to construct a connection between MAP and SEAGas during its current access period. MMA understands that this proposal has industry support.

Pricing

MMA believes that pricing issues could be investigated by the AER.

4.4.10 Greenhouse gas reduction schemes – inconsistency and uncertainty

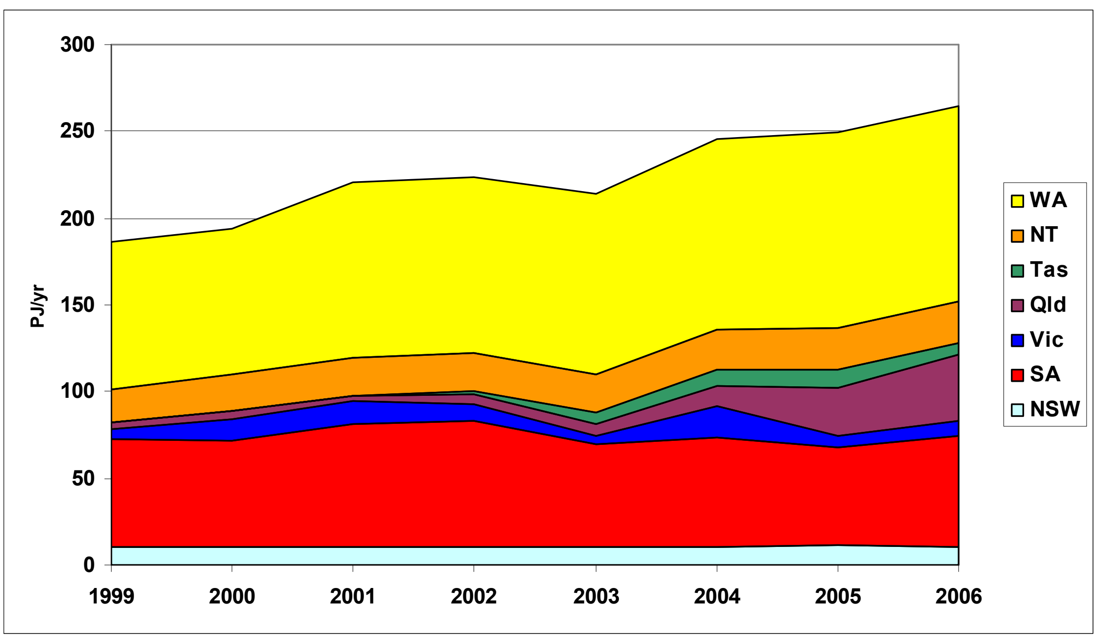
4.4.10.1 Issues

Inconsistency and uncertainty of Australia's many greenhouse gas reduction schemes has been argued by stakeholders consulted by MMA to be a barrier to investment in gas infrastructure and therefore a barrier to gas supply. Examples of inconsistency cited include renewable targets, which exclude many options for reducing emissions including use of natural gas, and the Queensland 13% gas scheme[66], which favours gas above all else.

4.4.10.2 Assessment

Natural gas results in lower greenhouse gas emissions than other fossil fuels and has therefore frequently been cast in the role of the transition fuel between the high carbon present and a low carbon future. To date however gas is not fully on target to fulfil this role. Although use of gas in power generation has grown nationally at 5% p.a. since 1999 (Figure 4-1), growth has been concentrated in Western Australia (supported by low priced gas) and Queensland (supported by the 13% gas policy) and has stagnated in other major Eastern states. A number of major gas generation projects, such as the Mortlake Power Station in Victoria, are said to be on hold until the future of carbon trading is clearer[67].

Figure 4-1 Gas used in power generation



Sources: NEMMCO and ABARE

[66] To be increased to 18% by 2020
[67] Delayed projects wait for carbon price. The Age 17 May 2007.

4.4.10.3 Management options

Two groups are currently investigating establishment of a broader national emissions trading scheme: the Prime Ministerial Task Group on Emissions Trading and the National Emissions Trading Task Force. MMA is confident that a national emissions trading scheme will be developed from these groups' work by 2012. This scheme should resolve the above issues for the gas industry.

4.4.11 Vertical integration

4.4.11.1 Issues

Vertical integration, i.e. participation in both upstream and downstream sectors of an industry, has been raised as a barrier to gas supply and market efficiency by stakeholders consulted by MMA. Participants with interests in only one sector believe that a vertically integrated counterparty that is also a competitor is likely to favour its related interests over independents, resulting in less competitive outcomes. In a tight market vertically integrated companies could also withhold supply from independents. Stakeholders noted that when competition was introduced to Australian energy markets, almost all the former vertically integrated energy utilities were disaggregated, particularly in the electricity industry, where vertical integration of retailers and generators has also since been re-established.

4.4.11.2 Assessment

Vertical integration has been pursued more vigorously in electricity, where it has been put forward as a means of hedging electricity market price risks at a time when financial hedging markets are not as liquid or deep as they could be. Three of the major electricity retailers, AGL, Origin Energy and TRUEnergy, have gas fired generation portfolios that limit their exposure to peak electricity prices. Few generators have moved into retail however, with the exception of International Power which has a joint venture arrangement with Energy Australia.

In gas the upstream multinationals are generally not interested in retailing and there has been limited spot price volatility and risk until recently, even in Victoria. Vertical integration is therefore less necessary or attractive and has been pursued mainly by Origin Energy, though it is observed that a number of Queensland CSG producers have initiated gas-fired generation projects that compete with some of their CSG customers.

Vertical integration of gas production and gas-fired generation avoids the inefficiency created by a gas contract, which constrains electricity market bidding by the generator. For example a generator with a gas contract price of $3.50/GJ and a typical heat rate of 10 GJ/MWh can only profitably bid prices above $35/MWh. An integrated generator however can bid based on short-term marginal costs of gas production, which may be as low as $0.50/GJ, and is therefore more likely to be scheduled and will earn more revenue and higher profits. Although gas contracts can be more cost reflective than just a flat price, all contracts place some constraints on the generator. Similar inefficiencies may be experienced by gas retailers, for example a contract may constrain them from selling lower priced incremental gas to an industrial user, but are generally less of a disadvantage than for generators.

These gains to individual participants are offset by losses of efficiency in the market as a whole. These include losses due to a reduction in trading and losses due to increased market power. MMA estimates that Origin Energy Retail currently purchases about 40% of its gas from Origin's production ventures, which suggests that other stakeholders' fears are only partly true, but the proportion may increase over time as Origin's legacy contracts with other producers expire. If other Eastern Australian gas buyers faced a market without Origin as a seller, the sellers' market concentration to them would rise moderately, from an HHI of 17 to 21 on a company basis (i.e. assuming separate marketing, because the impact on a joint marketing basis is difficult to estimate).

Further vertical integration would be a concern as it could clearly increase concentration levels beyond those due to joint marketing, result in greater market power for remaining producers and further reduce market efficiency, creating greater incentives for vertical integration. Ultimately, if all participants sought to be vertically integrated and not to trade with one another the wholesale gas market would disappear. It is difficult to believe that this outcome would be more efficient than current arrangements or an intermediate arrangement in which participants are partly integrated and also trade.

4.4.11.3 Management options

The stimulus for vertical integration is market inefficiency and options that improve efficiency should reduce the tendency to integration. These include creation of short-term trading via the STTM (section 4.3.7.1) and ensuring that market concentration is maintained or reduced so that both buyers and sellers have willing counterparties. Section 4.4.6 covers options for managing market concentration.

The effects of vertical integration involving regulated transmission or distribution pipelines are controlled by the ring fencing and associate contract provisions of the Code, which are to be carried forward into the NGL. Ring fencing provides for strict separation of business activities and the associate contract provisions require approval of contracts by the regulator.

These provisions do not apply to the competitive gas production, energy retailing or electricity generation sectors. While we believe that vertical integration results in an increase in market concentration, the arrangements within vertically integrated firms do not per se constitute restrictive trade practices or any other conduct contravening the Trade Practices Act and there are no obvious options for controlling vertical integration directly.

4.4.12 Pipeline regulation

4.4.12.1 Issues

Gas pipeline operators have for some time expressed the view that the current gas access regime acts as a disincentive to gas pipeline investment, particularly in relation to the inability of new pipelines to get pre determined "regulation holidays". Stakeholders consulted by MMA repeated these views while observing that the review of the gas access regime by the Productivity Commission and the subsequent revisions to the Gas Pipelines Access Law and the recasting of the regime through the National Gas Law and National Gas Rules are intended to remove or reduce the disincentives to pipeline investment.

A particular inefficiency that is from time to time a barrier to market entry for small end users or shippers is the process of capacity expansion on contract carriage pipelines. In view of the regulatory barriers to constructing speculative capacity, pipelines are reluctant to expand unless they have long-term contracts for the expansion. Small capacity expansions are usually inefficient owing to the fixed costs of planning, approvals and mobilisation and may not be undertaken if the unit cost is too high.

4.4.12.2 Assessment

MMA has not undertaken a detailed review of the impacts of the gas access regime. In Eastern Australia a number of significant new pipelines have been constructed under the regime without becoming regulated under the Code. The most significant barrier to gas supply created under the Code has been in Western Australia where the impasse between the former owners of the DBNGP and the ERA regarding the pipeline's capital base and tariffs led to a five year period during which no investment was made in necessary capacity expansion (section 3.2).

4.4.12.3 Management options

Stakeholders are in general agreement that recent revisions to the Gas Pipelines Access Law and further changes in the new National Gas Law and National Gas Rules will remove or reduce the disincentives to new pipeline investment. The recent changes to the GPAL introduced:

- 15 year biding no coverage rulings available to all new pipelines
- 15 year price regulation exemptions available to international pipelines bringing foreign gas to Australian markets.

This new NGL and NGR also introduce:

- An overarching objects clause
- Coverage (price regulation) of pipelines where coverage would result in a material increase in competition
- A new light-handed form of regulation excluding assessment of reference tariffs

However these reforms do not apply to expansion of existing pipelines. Stakeholders have suggested that more flexible rules are required to ensure such expansions are optimal and that to this end the rules should treat expansions in a similar manner to new pipelines.

4.4.13 Non-standardisation, including market rules and operators

4.4.13.1 Issues

Non-standardisation is widespread in the gas industry and creates significant inefficiencies though probably not definitive barriers to gas supply. Among the issues brought to our attention by stakeholders are:

- Gas purchase agreements are bespoke documents that take significant resources to develop and are therefore inappropriate for shorter-term agreements
- The multiplicity of balancing arrangements/market systems places cost burdens on smaller participants.
- Gas and pipeline nominations processes are complex and reports from each operator are different
- Gas days in Eastern Australia are different, even though the Victorian gas day was recently changed to 6-6 EST. SA and NSW are 6:30-6:30 and Queensland is 8-8.

Further examples are provided in KPMG's report to ERIG[68].

4.4.13.2 Assessment

Non-standardisation clearly creates inefficiencies but there is also a cost to establishing standards. KPMG has noted that the costs of changing some long-term contracts may be prohibitive and that standardisation may never be complete. Nevertheless the US gas industry, which is far larger and more diverse that the Australian one, set up an industry owned body, the Gas Industry Standards Board, in 1995 to develop standard or default models for a range of industry operations, including gas nominations, gas measurement and allocation, invoicing, capacity trading and gas contracts. A standard gas day based on central time was also agreed. GISB became the North American Energy Standards Board in 2002.

4.4.13.3 Management options

STTM

Establishment of the STTM will resolve the multiplicity of market arrangements outside Victoria but will not have any authority over upstream or pipeline matters.

[68] KPMG Op cit p 31.

Industry Standards Board

Governments should encourage the industry to follow the US model and establish a standardisation board to work with the Australian Energy Regulator and other authorities to remove the inefficiencies caused by different gas days, nomination/bid timing and procedures etc.

Gas contracts

MMA understands that a number of parties have established master agreements governing the sale and purchase of gas, to facilitate creation of new contracts to meet changing load. Similar arrangements by other buyers and sellers, even if not under the same master agreement format, would generate significant efficiencies.

4.4.14 Tax and depreciation conditions

4.4.14.1 Issues

Producer and pipeline stakeholders both considered their tax and depreciation conditions relatively unfavourable, with producers paying PRRT or royalties and pipelines having lower asset depreciation rates. In addition it was argued that tax and depreciation concessions available to extractive industries to facilitate development should be available to pipelines serving them.

CCIWA has suggested that junior gas explorers are handicapped by their inability to exploit tax deductions due to unsuccessful exploration, owing to a lack of income to deduct against. Tax losses have to be accumulated and cannot be transferred to investors.

4.4.14.2 Assessment

APPEA[69] has undertaken an analysis of taxation impacts on (LNG export) project returns and concluded that income tax has a greater impact on project outcomes than PRRT and that the most significant improvements to project economics can be achieved by changing income tax depreciation provisions. MMA has no reason to doubt these conclusions but has not confirmed them. APPEA suggests that to achieve a high impact a five year effective life cap for depreciation and a 150% investment allowance would need to be introduced.

Tax differentials can also bias investments and preferred gas markets. PRRT uses a notional transfer price to estimate tax liabilities of integrated developments such as LNG. When prices are high this allows profit sharing between upstream (58% marginal tax rate) and the downstream (30 per cent marginal tax rate) so that the transfer price is lower than the real netback price. This provides tax concessions to LNG over domestic sales. MMA has not estimated the scale of this concession. In terms of domestic supply it is the same as the LNG price issue – the tax concessions become part of the netback equivalent price calculation.

[69] APPEA Op Cit section 6.2

APPEA[70] has recommended a "flow through" share scheme to enable junior gas explorers to exploit tax deductions by passing them through to investors, based on the apparent success of a similar scheme in Canada. This is believed to be likely to improve junior explorers' access to investment funds. Similar recommendations have been made by the Prosser Inquiry into minerals and petroleum exploration and by the Minerals Exploration Action Agenda.

4.4.14.3 Management options

- The APPEA proposals need to be considered in the broader context of resource project taxation.
- In view of the likely persistence of high LNG prices, review of the application of transfer pricing in PRRT should be considered.
- Introduction of a flow through share scheme should be considered. It is noted that the Commonwealth has created the Early Stage Venture Capital Limited Partnership (ESVCLP) scheme to increase the supply of funding to the early stage venture capital sector – the scheme became operative in June 2007. The scheme is a flow through share scheme applicable to funds whose investments are constrained to initial investments (no trading) in unlisted companies and its applicability to typical petroleum exploration companies is not clear.

4.4.15 Aging infrastructure

4.4.15.1 Issues

A number of stakeholders consulted by MMA considered that aging infrastructure presented a barrier to gas supply and market efficiency. Their concerns are due to relatively frequent minor outages at gas processing plants and pipeline capacity restrictions imposed because of corrosion. Recently these have been on a scale which has not affected end users but outages on a scale like those at Longford in Victoria in 1998 and Moomba in 2004 are feared and could have significant economic impacts.

4.4.15.2 Assessment

MMA believes that infrastructure failure will result only in short-term supply problems and is unlikely to create a long-term barrier to supply. Following previous gas emergencies, infrastructure has been repaired as rapidly as possible to minimise the duration of the outage and there is no reason to believe that infrastructure owners will not do the same in future.

[70] APPEA 2006/07 Pre-Budget submission.

The costs of short-term gas supply interruption to users should not be underestimated however. In a study undertaken for VENCorp[71] MMA estimated the costs of lost production and plant damage incurred by industrial users in Victoria due to non-supply of gas to be in the range $68/GJ to $184/GJ, an order of magnitude greater that the actual price of gas.

A related issue is the lack of redundancy in some new, smaller gas plants, which may therefore require periods of scheduled maintenance during which no gas is produced. These plants rely upon diversity of production to support demand, whereas older "legacy" plants had built in redundancy. MMA considers this a natural market development.

4.4.15.3 Management options

The options for improving management of gas supply failure have been identified in previous studies and are:

- Creation of NGERAC to co-ordinate inter-jurisdictional emergency responses
- The Bulletin Board being developed by GMLG
- The STTM, the detailed design of which is being developed by GMLG, which will facilitate a market based response to gas supply shortfalls

4.4.16 Gas reserves accessibility

4.4.16.1 Issues

The remoteness and gas composition of many of the larger Western Australian gas fields may prevent them from being supplied to the domestic market, as discussed in section 3.2.3.2.

4.4.16.2 Assessment

All of the fields concerned, Gorgon, Io Jansz, Ichthys, Scarborough and Torosa, are subject to development plans (Table 3-6). The plans suggest that three, Gorgon, Io Jansz, and Scarborough will be readily accessible to the domestic market, one, Torosa, may be accessible if the option to link it to the Burrup Peninsula is taken, and one, Ichthys, is on present plans unlikely to be accessible to the domestic market.

If the Burrup option is economic for Torosa however, a Burrup option could be economic for Ichthys as they are a similar distance from the peninsula, though the Ichthys developer, Inpex, does not have existing facilities there. Moreover, the two projects could share most of the offshore pipeline to the peninsula, generating significant economies of scale, if compatible project timing could be established.

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[71] The value of customer reliability for gas. MMA report to VENCorp, 20 September 2005, available at www.VENCorp.com.au

4.4.16.3 *Management options*

Governments may be able to influence the development of Torosa and Ichthys to ensure their accessibility to the domestic market by:

- Discussing the options with the developers, to promote a Burrup Peninsula option.
- Ensuring that there are no barriers to considerable expansion of processing facilities on the Burrup Peninsula.
- Ensuring there are no barriers to construction of the offshore pipeline and possibly promoting third party construction of a shared pipeline.

4.5 Options aimed at overcoming identified barriers to gas supply

The options identified in the previous section are summarised in the following table.

Table 4-6 Barriers to gas supply and recommended management options

Barrier to gas supply	Recommended management options
Attraction of export prices High prices may stimulate development of export/domestic projects. Price impact on domestic gas negative Timing of development becomes important Real barrier if fields are also suitable for domestic development	**Initiatives to enhance domestic supply** ▪ Increased funding for pre-competitive geological data acquisition ▪ Provision of infrastructure supporting exploration, such as roads ▪ Taxation reform to assist small exploration companies (“flow through” shares) ▪ Improvement of project approval processes and project facilitation eg Major Project Facilitation status ▪ Royalty reductions or holidays for onshore production **Delays to export projects** ▪ Cost escalation and uncertainty – (refer below) ▪ Delays in domestic approvals – (refer below) ▪ Delays in contracts and approvals overseas - Commonwealth Government lobbying **Fields suitable for domestic development** ▪ Application of retention lease management. The Joint Authority administering an area should use domestic supply as the basis of commerciality if appropriate.

Barrier to gas supply	Recommended management options
Acreage management (retention leases and production licences) Retention leases and production licences could be used to withhold gas from the domestic market	Retention lease issues can be managed by: ▪ Requesting re-evaluation of commerciality under the terms of lease ▪ Non-renewal of retention leases ▪ Considering a minor P(SL)A amendment to remove a loophole ▪ Considering replacing the lease renewal process with an auction to evaluate commerciality Production licences in which no petroleum is produced for five years can be terminated
Joint marketing Factors supporting separate marketing have improved significantly.	▪ Implementation of the STTM is recommended as the primary means of taking market development to the stage where separate marketing is supported.
Gas quality The WA gas specifications are a barrier to entry of gas from certain fields.	▪ The Western Australian Government should consider revising the Western Australian Gas Standards (Gas Supply and System Safety) Regulations to comply with the National Standard, AS 4564. ▪ ERA and DBP should then consider broadening the DBNGP specification to match AS 4564
Cost increases Global cost increases and uncertainty threaten export and domestic gas developments	▪ Long-term skilled labour availability - better resource planning and investment in training ▪ Supply of oil and gas equipment - it is not anticipated that Australian Governments' policy decisions could materially change this
Market concentration Upstream concentration is high Downstream concentration is medium-high	▪ Separate marketing would reduce upstream market concentration in Eastern Australia. In the WA domgas sector this would not be of assistance owing to the participation of a limited number of producers in the domgas joint ventures. In WA exploration and discovery of additional reserves would be a more effective means of reducing concentration.

Barrier to gas supply	Recommended management options
	▪ Downstream concentration can be reduced by eliminating some of the barriers to entry by new participants, such as access to delivery point capacity (see below).
Infrastructure approvals processes Approval processes are time consuming, particularly when multiple jurisdictions are involved	▪ COAG has recognised the need to harmonise regulations across jurisdictions, to remove duplication of effort by infrastructure providers. ▪ Harmonisation would facilitate the appointment of one jurisdictional authority over each aspect of a cross jurisdictional project and/or the appointment of further cross-jurisdictional single function regulators along the NOPSA model ▪ The creation of the new National Gas Law and National Gas Rules is intended to reduce the burden of regulation on gas pipelines, particularly those with limited market power ▪
Retail market balancing mechanisms Balancing mechanisms are inefficient and present a barrier to new entrants	▪ The STTM, which has been conceived as a means of replacing the problematic physical balancing arrangements in New South Wales and South Australia, is the preferred solution.
Delivery point capacity access Non-access frustrates delivery of competing gas to networks	No easy solutions have been found. The STTM may be of assistance but this is not confirmed. The following could be considered: ▪ Inclusion in the NGR rules relating to provision of capacity information: a) That unutilised contracted pipeline capacity information should include delivery point information b) A definition of unutilised capacity ▪ New entrants to use interruptible capacity. ▪ Use it or lose it (capacity) ▪ Delivery points (city-gates) to be owned by distribution companies.

Barrier to gas supply	Recommended management options
Greenhouse gas reduction schemes Inconsistency and uncertainty of GHG schemes is a barrier to investment in gas infrastructure	▪ Two groups are currently investigating establishment of a broader national emissions trading scheme: the Prime Ministerial Task Group on Emissions Trading and the National Emissions Trading Task Force. Their work should resolve this issue for the gas industry.
Vertical integration Vertical integration increases effective market concentration. At present the impact is limited.	▪ Vertical integration is typically a response to market inefficiencies (within and outside the gas market). There are no obvious options for controlling vertical integration other than maintaining or creating market conditions that do not make it necessary or attractive, such as reducing market concentration upstream and downstream.
Pipeline regulation The NGL and NGR discriminate against expansion of existing pipelines	▪ The new National Gas Law and National Gas Rules will remove or reduce the disincentives to <u>new</u> pipeline investment. ▪ Flexible rules to ensure capacity expansions of existing pipelines are optimal should be considered
Non-standardisation including market rules and operations Multiple rules and procedures create inefficiencies	▪ Establishment of the STTM will resolve the multiplicity of market arrangements outside Victoria but will not have any authority over upstream or pipeline matters. ▪ Government should encourage the industry to establish a standardisation board to work with the Australian Energy Regulator and other authorities to remove the inefficiencies caused by different gas days, nomination/bid timing and procedures etc.
Tax and depreciation conditions Junior gas explorers are handicapped by the tax system. Project economics could be enhanced by changes to the tax system.	▪ Consider introduction of a “flow through” share scheme ▪ Consider tax changes proposed by APPEA ▪ Review application of transfer pricing in PRRT

Barrier to gas supply	Recommended management options
Differences between upstream and downstream regimes create distortions in favour of exports	
Aging infrastructure Failure of assets creates short-term supply shortfalls.	Options for improving management of gas supply failure have been identified in previous studies: ▪ Creation of NGERAC to co-ordinate inter-jurisdictional emergency responses ▪ The Bulletin Board being developed by GMLG ▪ The STTM, the detailed design of which is being developed by GMLG, which will facilitate a market based response to gas supply shortfalls
Gas reserves accessibility Ichthys and Torosa fields may be developed from remote sites not accessible to the WA domestic market	▪ Discussing the options with the developers, to promote a Burrup Peninsula option. ▪ Ensuring that there are no barriers to considerable expansion of processing facilities on the Burrup Peninsula. ▪ Ensuring there are no barriers to construction of the offshore pipeline and possibly promoting third party construction of a shared pipeline.

4.6 Special options that may be required to address barriers specific to individual jurisdictions

Two barriers that are jurisdiction specific have been identified:

- Gas quality specifications in Western Australia. It is recommended that Western Australia consider changing to gas specification AS4564-2005.
- Gas reserves accessibility in Western Australia. It is recommended that Western Australia promote development options that could make the reserves accessible and ensure that there are no barriers to the adoption of these options.

4.7 Reliance upon market solutions

As discussed in section 3.2.5.4 a number of stakeholders are of the view that the domestic gas market in Western Australia has failed, though others are of the view that it has not. Our conclusion in that regard is that the WA gas market has undoubtedly reached a difficult position, with limited options for short-term supply.

In the above sections we have identified a number of barriers to gas supply and competition together with management options which we believe will reduce the barriers to supply and improve the functioning of the market in all jurisdictions, if implemented by Governments.

Implementation of the management options to improve the market will take time, as will arrangements for further domestic supply in Western Australia. During this time there may be further claims that the market has failed and that Government intervention is therefore justified. Governments are urged to resist these claims at least until the recommended options have been given a reasonable chance to succeed, for both policy and practical reasons:

- Australia successfully introduced competitive market principles to its energy sector over a decade ago. Any material change from this principle would be a major policy shift that itself would take significant time to debate and formalise – any unilateral intervention is likely to have significant consequential impacts, not the least being the uncertainty as to policy directions.
- In practice it is unlikely that any intervention would result in a more rapid resolution of supply issues. The existing stakeholders have the greatest capability to negotiate new supply agreements and mobilise the resources to provide supply, hence resolution will be fastest when the institutional barriers to negotiation and supply are minimised.

Recommendations concerning market monitoring are presented in section 6.5.

5 RISKS AND BENEFITS OF MAJOR INTER-JURISDICTIONAL GAS PROJECTS

5.1 Inter-jurisdictional gas projects

5.1.1 Jurisdictional boundaries

Australian jurisdictional boundaries comprise:

- Onshore boundaries – the land boundaries between states and territories
- Offshore boundaries – extensions of the land boundaries between states and territories and the "three nautical mile line" that separates coastal waters administered by states and territories from the Australian territorial sea, the Australian exclusive economic zone and the Australian continental shelf , all administered by the Commonwealth.

Any gas project in which infrastructure, usually a pipeline, crosses a jurisdictional boundary is an inter-jurisdictional project.

Most offshore gas production projects are inter-jurisdictional as the gas is produced in Commonwealth waters and transported by pipeline to onshore processing plants. Production and shipping of LNG from an island under state jurisdiction could be offshore but not inter-jurisdictional. Onshore, the majority of inter-jurisdictional projects are high-pressure transmission pipelines. Exceptions include a lower pressure connection from Queensland to Tweed Heads in Northern New South Wales and the Ballera-Moomba wet gas pipeline, which is part of a gas production project.

5.1.2 Inter-jurisdictional project history

The Australian natural gas industry's initial development phase involved only two inter-jurisdictional projects:

1. Supply to New South Wales, which is without significant conventional gas resources of its own and is only now developing its CSG resources. NSW initially sought gas from Victoria but did not achieve the desired terms of supply and ultimately purchased gas from South Australia, an arrangement that created significant concerns regarding the adequacy of South Australia's reserves of gas in the Cooper Basin.
2. Development of the offshore Gippsland oil and gas fields for supply to Victoria.

All other supply developments occurred on a state by state basis using onshore gas resources. Significant barriers to interstate trade developed within each isolated gas supply system, in the form of political resistance to "exports" [72] and in the form of commercial franchises. Industry reform has removed both these barriers and since the

[72] Details may be found in "A National Strategy For The Natural Gas Industry. A Discussion Paper", Department of Primary Industries and Energy July 1991.

mid-1990s a number of inter-jurisdictional pipelines have been constructed in Eastern Australia to take advantage of opportunities to supply gas.

Offshore gas production development for domestic use has not faced any comparable barriers but the North West Shelf export project was subject to Commonwealth approval of exports to ensure the adequacy of gas reserves and that prices received were satisfactory (refer to section 6.2.1). This control was removed in 1997.

Construction of further inter-jurisdictional pipelines is highly likely, ranging from a relatively short 180km link between Queensland and South Australia (confirmed in July 2007) to a 2,500km Transcontinental Pipeline or pipelines of similar scale to bring remote resources from the Timor Sea or PNG to Australia. The need for these pipelines will be determined by changing regional demand-supply balances, including price considerations.

Construction of further offshore production facilities is also highly likely in Victoria, Western Australia and the Northern Territory.

This section considers the need for and appropriateness of various forms of Government support for inter-jurisdictional gas supply projects, in particular to manage the risks and ensure that benefits are achieved.

5.2 Managing the risks and ensuring the benefits

The risks and benefits of inter-jurisdictional gas projects are relatively straightforward:

- Risks, type 1 – project is too late or doesn't happen – supply shortfall, prices rise in importing region
- Risks, type 2 – project constructed but other local supply is found – supply surplus, prices fall in importing region, the asset is unprofitable or other supply is stranded
- Benefits – project constructed – supply/demand in balance, project profitable

These must be managed in the context of investment decisions that have to be made four to five years in advance of first supply.

Type 1 risks can be managed primarily by ensuring that current supply security is well understood and that there are no surprises. As the current situation in Western Australia indicates, this is easier said than done and because of the negative impacts on end users, supply failure attracts wide publicity.

Type 2 risks are also difficult to avoid. Although the industry has thus far avoided premature commitment to Transcontinental or PNG pipelines, the growth of CSG production in the Surat Basin in Queensland has reduced volumes flowing on the South West Queensland Pipeline, which was constructed in 1996 to cover declining conventional reserves in the Surat Basin. This is not to suggest that additional foresight would have predicted the CSG growth with sufficient confidence to defer investment in the SWQP, moreover the SWQP will probably continue to operate in the reverse direction. The consequences of supply excess are usually less obvious than those of supply shortfall but may include company failure and a period of under investment in capacity.

5.3 Past major inter-jurisdictional gas project developments

This section provides background documentation of the major historical inter-jurisdictional gas project developments and some major intra-jurisdictional gas supply projects of interest. MMA's understanding of the level of Government involvement in each project and the impact of government involvement is summarised in Table 5-1.

Some of the projects have resulted in clear benefits that may not have eventuated without Government involvement. Of particular note are the North West Shelf project, in which the Western Australian Government was heavily involved through the state energy authority, SECWA, and the Tasmanian gas supply project, which the Tasmanian Government initiated by means of a tender.

It is recognised that Government actions taken prior to 1997 in the context of monopoly-monopsony markets may not provide guidance on appropriate Government support or involvement in the current market-driven, private ownership, competitive environment.

Table 5-1 Inter-jurisdictional gas projects

Project	Jurisdictions Covered	Project Initiator	Government Involvement and *Impact*
Gippsland development (1969)	C'wealth and Vic	Exxon/ bhpbilliton	Vic Govt re supply to NSW *Project prevented from supplying NSW*
Gas supply to NSW (1970s)	NSW and SA	AGL	SA Govt re Cooper Basin gas reserves *Preserved reserves for SA*
Moomba-Sydney Pipeline (1977)	NSW, Qld and SA	AGL	Commonwealth ultimately constructed and owned the pipeline through The Pipeline Authority *Lower tariffs. TPA was unprofitable for many years.*
North West Shelf Project (1984)	C'wealth and WA	NWS JV	WA Govt re domestic gas reservation, pipeline construction. *Extended gas availability for WA domestic market. Gas purchases and pipeline construction by SECWA*

Project	**Jurisdictions Covered**	**Project Initiator**	**Government Involvement and *Impact***
Ballera-Moomba wet gas pipeline (1990)	Qld and SA	Santos	Qld govt approved export of Ballera gas *Accelerated royalty return to QLD govt, increased supply security to SA.*
Interconnect Pipeline (1998)	NSW and Vic	Gasnet & EAPL (owner of MSP)	Vic Govt via ownership of Gasnet *Interstate trading and increased supply security for both states*
Gas Supply to Tasmania (1998)	C'Wealth, Vic and Tas	Tasmanian Government	Tas Govt arranged gas supply tender *Gas supply to Tasmania.* *Financial support for distribution rollout*
Eastern Gas Pipeline (2002)	NSW and Vic	BHPP	None or limited *Not known*
SEAGas Pipeline (2004)	Vic and SA	Origin Energy, International Power, TRUEnergy.	SA Govt gas supply tender in 2000 to improve supply security *Interstate trading and increased supply security for SA*
Carpentaria PL (1996)	Intra Qld		Qld funded project study and participated in PL tender *Gas producers involved in pipeline*
SWQ PL	Intra Qld		Qld funded project study and ran PL tender in response to Surat Basin depletion *Continuity of gas supply to SE Qld.*

5.4 Potential inter-jurisdictional projects

The context for future Government involvement includes the potential future inter-jurisdictional gas supply projects. A number of projects that are under active consideration at present or have been considered in the past are discussed in this section.

5.4.1 Queensland to South Australia and New South Wales Link (formerly known as the Ballera-Moomba Interconnect)

5.4.1.1 Background

During the 1990s a pipeline was constructed between the Cooper Basin production centres at Ballera in South West Queensland and Moomba in North East South Australia, to transport unprocessed, "wet" gas from the Queensland area of the basin to supplement production at Moomba and meet incremental gas sales requirements in the South Australian market.

In 2002 AGL purchased quantities of Queensland CSG for delivery at Moomba from 2005. Two options were available to arrange delivery at Moomba:

1. Physical transmission from Wallumbilla in central Queensland to Ballera by backhauling along the SWQ pipeline and transmission from Ballera to Moomba along an as yet unconstructed dry gas pipeline.

2. Swap the CSG for gas produced at Ballera and transmitted to Wallumbilla. The gas at Ballera would instead be transmitted down the wet gas pipeline and processed at Moomba.

The second option has obvious financial advantages, as it avoids the cost of constructing the dry gas pipeline, but may be constrained by the quantities of gas transmitted from Ballera to Wallumbilla. The parties took up the swap option and the wet gas pipeline now functions as a virtual part of the transmission grid though not subject to the gas access regime. MMA understands that the quantity constraints may prevent others from duplicating the arrangements however and may become more significant after 2011. Notwithstanding that other swap structures could be implemented, demand for a dry gas pipeline is growing.

5.4.1.2 Status

In July 2007 AGL and EPIC, owner of the SWQ and MAP pipelines, announced an agreement[73] under which EPIC would construct the Interconnect (to be known as the Queensland to South Australia and New South Wales Link or QSN Link) and transport 390 PJ of gas for AGL over 15 years from 2009. The 180 km, 350mm diameter pipeline will be an extension of the SWQP, will connect with both the MAP and MSP near Moomba and will have a capacity of 190 TJ/d or 69 PJ/year. Based on earlier EPIC cost estimates[74],

[73] EPIC announcement 13 July 2007 on www.epicenergy.com.au
[74] EPIC announcement 13 November 2006, on www.epicenergy.com.au

which were in the range $100-120m, MMA estimates that the transmission tariff will range from 20c/GJ at full capacity to 45c/GJ at the AGL contract volumes.

5.4.2 Queensland Hunter Gas Pipeline

5.4.2.1 Background

The Queensland Hunter Gas Pipeline from Wallumbilla to Hexham near Newcastle has been conceived as a more direct route for bringing Queensland CSG to New South Wales, compared to the Ballera/Moomba route. The pipeline could also promote development of CSG production along its route in NSW. The origins of the concept may be found in a 2004 study into gas development in North East NSW[75] which recommended that such a pipeline would provide a stimulus to regional gas exploration and development and increase gas supply competition and security.

5.4.2.2 Status

The pipeline was granted State Significant Critical Infrastructure status under Part 3A of the NSW EP&A Act 1979 in November 2006 and in February 2007 the Queensland Government granted environmental approval for a pipeline permit. Further status details are not known.

Developer Hunter Gas Pipeline Pty Ltd estimates that the 850km, 500 mm diameter pipeline would cost $700m. MMA's brief assessment of the project suggests that it faces two hurdles:

- Although it offers a more direct route than North Gas Link it offers transmission only to New South Wales and not to South Australia and may struggle to capture market share, particularly as the Newcastle market itself is small.
- With six times higher costs it is dependent on higher load to achieve competitive transmission charges.

The announcement of the above QSN deal further raises the bar. Two projects that may stimulate development of pipelines in this region are the CS Energy/Metgasco and Macquarie Generation/Eastern Star Gas projects noted in section 3.3.5. If these are successful in proving up CSG reserves, they will respectively require pipelines from the Clarence Morton basin to the Brisbane area and the Gunnedah basin to Newcastle.

[75] Facilitating the Development of Natural Gas in NorthEastern New South Wales. Sleeman Consulting for NSW Department of Mineral Resources, February 2004

5.4.3 PNG Gas Pipeline

5.4.3.1 Background

The PNG Gas Project has been under consideration for a decade in a number of forms. The most recent concept envisaged a wet gas pipeline from the gasfields in the PNG highlands, a processing plant on the PNG coast and sales gas pipelines across Torres Strait, down Cape York and branching to Gove (across the Gulf of Carpentaria), Moomba (for southern markets) and Townsville/Gladstone. The project was to deliver gas by 2010/11. The 3,800 km pipeline system was estimated to cost up to $4bn in 2006, 30% up on earlier estimates.

5.4.3.2 Status

The project reached FEED status in October 2004 and this was completed in early 2006. In mid-2006 the pipeline joint venture withdrew from the project, which led to a re-evaluation of PNG gas commercialization options. Studies showed that the project was viable but that other options such as LNG exports offered better returns. Field integration agreements supporting the project were allowed to expire in 2007 and the project was then officially suspended[76].

It is noted that in 2002 the project had come close to going into FEED only to have customers withdraw from MoUs because of competitive offers from Australian producers. Obtaining a critical mass of gas sales is a key to making large scale supply projects happen and in view of additional gas supply contracts entered since mid-2006 the earliest feasible date of entry for a new PNG gas project would about 2015 (refer to Figure 3-7). Given the prospects of further CSG and conventional gas reserve expansion, Eastern Australia may not need remote gas until 2025 or later.

It is now uncertain whether PNG gas will be available to Australia in future, or whether it will only be available at an LNG equivalent price.

5.4.4 Timor Sea Gas Pipeline

5.4.4.1 Background

A proposal to pipe Timor Sea gas to Eastern Australia via Darwin and Moomba or Mt Isa was promoted between 1999 and 2002 as an alternative to the PNG gas project. The proposal was associated with projects to convert gas into methanol and other liquids in Darwin and the project scale would have been similar to that of the PNG project.

The proposal received some interest from users but ultimately was no more able to secure a critical mass of gas sales than was the PNG project at that time. Dependence on multiple production projects and disputes over the treaty with Timor Leste may also have contributed to its demise.

[76] www.oilsearch .com

5.4.4.2 Status

This project appears to have been inactive for five years. As with a new PNG project, it may not be required until 2025 and if a PNG project enters the market at that stage, Timor Sea gas would probably not be required for a further ten years. By this time it is quite possible that the currently known reserves would be fully committed to other markets.

5.4.5 Transcontinental Pipeline

5.4.5.1 Background

The obvious inequality in gas reserves between Eastern and Western Australia has for many years encouraged the view that a pipeline would ultimately be constructed from the North West (Dampier) to East (Moomba or another point of connection with the Eastern transmission network), when Eastern Australian reserves were depleted below a level at which production could meet demand. Many studies of the likely cost of such a pipeline have been conducted to establish its economics, particularly the likely delivered cost to end users, and the continued viability of gas in the marketplace. As recently as 2004 some commentators believed that if the PNG Project did not proceed then the Transcontinental Pipeline would be needed by 2015.

5.4.5.2 Status

Most if not all studies and commentators on the Transcontinental Pipeline have explicitly or implicitly assumed that the (domestic) price of gas in the West would remain below that in the East, otherwise economics would cause gas to flow the other way, from East to West. As discussed in section 3.2 this price relativity can no longer be taken for granted and the prospect of the pipeline being constructed while it isn't seems very low.

Given the current WA supply position, a pipeline flowing east to west is no longer inconceivable. At 2,500 km minimum length the capital cost would be of the order of $3bn and the tariffs at annual volumes of 150 PJ (50% of the current domgas market) would be $2/GJ to $2.50/GJ. The delivered gas price in Dampier could therefore be $5/GJ to $6/GJ, not much more attractive than LNG equivalent prices, but if the pipeline were constructed to Perth the price in Perth would be at least $1 lower. The impact of this demand on Eastern Australian reserves would be significant but if WA domestic prices remain high and CSG continues to perform the concept may gain momentum.

5.4.6 Great Northern Pipeline

5.4.6.1 Background

Not an inter-jurisdictional pipeline but one that could be significant for the Western Australian domestic market, the Great Northern Pipeline is conceived as connecting new gas discoveries in the Canning Basin with Port Hedland or Dampier to supply existing domestic markets.

5.4.6.2 *Status*

According to ARC Energy[77] the pipeline is already at the pre-FEED design stage. Based on a minimum distance of 1,000 km from the gas fields the pipeline cost would be comparable to that of the Queensland Hunter Pipeline and tariffs would be $1.50/GJ to $2/GJ at 50PJ/yr and $1/GJ to 1.25/GJ at 100 PJ/yr. Unless volumes are at the higher end, the cost of the gas in Dampier could be $5/GJ also not much more attractive than LNG equivalent prices.

The recent agreement between ARC and Alcoa for funding exploration in the Canning Basin (section 3.2.5) increases the likelihood that this pipeline will be constructed.

5.4.7 Gas production projects in Western Australia

A range of potential gas production projects in Western Australia are discussed in section 3.2.5.3

5.4.8 Summary

Table 5-2 Potential inter-jurisdictional gas supply projects

Project	Status	Project benefits
Ballera-Moomba Interconnect (dry-gas pipeline)	Under consideration by EPIC Energy and APT. FEED completed.	Permits Queensland CSG to supply NSW and SA markets via Moomba
Queensland Hunter pipeline (Surat Basin to Newcastle)	Under consideration by Hunter Energy.	Permits Queensland CSG to supply NSW, provides first gas supply to Nth NSW and provides market access for Nth NSW CSG
Great Northern Pipeline	Under consideration by ARC Energy.	Connects Canning basin resources with WA domgas market
Timor Sea pipeline (Darwin to Mt Isa and/or Moomba)	Not under active consideration.	Permits long-term supply of Eastern States from large Timor Sea reserves. Provides NT with additional competitive supply. May encourage exploration of NT onshore basins

[77] Meeting the Energy needs of WA- the onshore and ARC's role. ARC Energy 21 February 2007.

Project	Status	Project benefits
PNG pipeline (Bamaga to Mt Isa and/or Moomba)	Not under active consideration.	Permits long-term supply of Eastern States from large PNG reserves
Transcontinental pipeline	Not under active consideration.	Permits long-term supply of Eastern States from large WA reserves

5.5 Stakeholder views on Government and Industry Roles

Stakeholders consulted by MMA for this study expressed very clearly the view that Government and industry roles in gas supply should be very distinct but interactive, on the following lines:

- Government promulgates gas (energy) sector legislation and regulation, in consultation with industry (including end users)
- Government agencies fund and undertake pre-competitive geological research, prior to exploration permit tenders and make the information available to industry
- Industry bids for exploration permits, undertakes exploration and subsequently relinquishes the permit or applies for a retention lease or production license, contingent on making a petroleum discovery, subject to relevant laws and regulations
- Industry determines the development and timing of all gas (energy) infrastructure required to bring gas into production and deliver it to end users and subsequently constructs, funds, owns and operates it, subject to Government approval and regulation.

Many stakeholders view this demarcation as the natural outcome of ten years of pro-competitive reform, during which all Governments have progressively withdrawn from gas asset ownership. Stakeholders also generally agree that Governments should only intervene in the market (i.e. the industry side) when the market has "failed". In the case of short-term supply shortfalls due to infrastructure failure, a consensus on when or whether the market has failed is being developed through NGERAC. In the case of longer-term failure however a consensus may be harder to reach, as evidenced by stakeholders' divergent views on gas supply in Western Australia (section 0).

Naturally the above is a somewhat simplified view and there are a number of issues such as training, information and planning where government and industry roles overlap.

5.6 Forms of support provided to facilitate the development of major inter-jurisdictional gas projects

As documented above, Governments have had involvement in a number of major inter-jurisdictional gas projects over the past forty years up to and including the current decade. Involvement in other projects with a more regional flavour also suggests other potential forms of support.

Table 5-3 Potential forms of support and examples of their application

Form of support	Examples
Support through approvals processes	Major Project Facilitation State Significant Critical Infrastructure
Project studies	"Facilitating the Development of Natural Gas in North Eastern New South Wales", NSW Department of Mineral Resources "Energy for Minerals Development in the South West Coast Region of Western Australia", WA Dept of Industry and Resources
Project initiation (calling for expressions of interest)	Tasmanian gas supply project South Australian gas security project (SEAGas)
Introduction of measures favourable to gas projects	Queensland 13% gas policy (13% of generation in Queensland must be gas-fired. Retailers purchase and surrender Gas Electricity Certificates.)
Financial support, e.g. direct subsidy of a pipeline, long-term purchase agreements	Victorian Natural Gas Extension Program (Marginally uneconomic gas extensions were subsidised. Subsidy levels were determined by competitive tender.) North West Shelf Project (Long-term gas purchases by SECWA)
Asset ownership	Prior to 1995, the majority of major pipelines were owned by Government agencies, including: Moomba-Sydney Pipeline; Victorian pipeline network; Moomba Adelaide Pipeline; and Dampier to Bunbury Natural Gas Pipeline.

Stakeholders' views on the use of these forms of support by Governments in future reflect their general views on Government and Industry roles. Stakeholders welcome support with approvals, Government involvement in project studies and Government project initiation (qualified) but generally do not believe Governments should have any financial involvement.

5.6.1 Support through approvals processes

Approvals processes have been reported as a barrier to gas supply by a number of stakeholders and Government support through the approvals processes is welcomed. However it is also clear that stakeholders would value streamlining the approvals processes more than just support in dealing with the existing processes. Suggestions for improving approvals processes are documented in section 4.4.6.

5.6.2 Project studies

Project studies play a similar role to an industry plan (section 6.4) but are generally focused on particular regions or infrastructure requirements that may not be visible in sufficient detail in a national plan. Stakeholders are supportive of Governments undertaking project studies, particularly co-operative studies with industry, as a means of obtaining a shared view of the likely economics of development opportunities.

Some stakeholders cautioned that Governments should not use studies to conclude that particular infrastructure should be constructed, as other competing infrastructure not considered in the study, perhaps outside the region studied, may be a better option. In regard to major gas pipeline projects a national gas plan would provide the most coherent view of potential options.

5.6.3 Project initiation

Stakeholder support for project initiation by Governments is more qualified. Initiation in the form of broad requests for expressions of interest in providing gas supply (for example), which are intended to lead to commercially negotiated outcomes, are viewed positively. Narrower processes, such as for construction of a specified pipeline, are viewed as having the potential to result in the wrong assets being constructed and ultimately requiring Government financial support. It is noted that this view is stated in the context of major inter-jurisdictional projects and is held less strongly in relation to smaller distribution projects.

It is also noted that the current Gas Code contains provisions for persons to apply to the Relevant Regulator to conduct a tender process for construction of a pipeline, whereby the pipeline tariffs will be determined by the tender process rather than by the regulator. This process has been used primarily by local governments to determine the potential for getting gas to their regions and has led to both successes resulting in pipeline construction (Central Ranges Pipeline in New South Wales and Mildura in Victoria) and failures not resulting in any pipeline (Yarra Ranges and Loddon Valley in Victoria in 2000 and 2001 respectively). The failures suggest that provided there are no subsidies the negative effects of project initiation will be limited. The Gas Code provisions are carried forward in the National Gas Law.

5.6.4 Introduction of measures favourable to gas projects

The industry's desire for a level playing field in regard to greenhouse gas mitigation policies is documented in section 4.4.10. A level playing field is preferred to measures favourable to gas but if the playing field remains tilted in their view, stakeholders would consider favourable measures an acceptable second-best solution.

There is no disputing however that such measures can have significant impacts. The Queensland 13% gas scheme has resulted in a significant increase in gas-fired generation in Queensland (refer to Figure 4-1) which has been a major factor behind the growth of CSG in that state.

5.6.5 Financial support

Financial support of gas infrastructure by Government or Government agencies is viewed by the majority of stakeholders as inconsistent with the gas industry structure that has developed over the past fifteen years. Financial support, whether by direct subsidies, contractual guarantees or offtake agreements, is highly likely to favour one participant at the expense of another, to the detriment of competition in general.

Stakeholders pointed to the examples of the Ballera Moomba Interconnect and Queensland Hunter Pipelines discussed above – if any Government were to subsidise either of these pipelines, both of which have the primary purpose of enabling Queensland CSG to be transmitted to New South Wales and/or South Australia, it would adversely affect the other, possibly preventing it from being constructed.

Some stakeholders believe that subsidies of small scale infrastructure, such as distribution extensions, are acceptable to meet transparently stated Government objectives, subject to evidence that the objectives are being met in the most efficient way. An example of the latter could be a test of whether the benefits of extending natural gas (lower costs to users and lower emissions) could not be achieved at lower cost by subsidising solar water heating and reverse cycle heating to regional communities that don't have access to gas.

The effectiveness of subsidies in achieving policy objectives has been demonstrated by the Victorian Government's Natural Gas Extension Program, which since 2004 has resulted in gas being extended to 29 towns, including the Yarra Ranges region, where an earlier unsubsidised tender failed.

5.6.6 Asset ownership

Over the past fifteen years the Commonwealth and State Governments have sold almost all their gas assets including: Moomba-Sydney Pipeline; Victorian transmission and distribution networks; Queensland State Pipeline; Moomba-Adelaide Pipeline; Dampier-Bunbury Natural Gas Pipeline; and Alinta Network. Only the assets of Country Energy and some small gas networks in Queensland remain in Government ownership.

The industry's ability to fund and develop recent major inter-jurisdictional projects such as the SEAGas Pipeline and keen competition for infrastructure assets by superannuation funds suggests that Government asset ownership is unlikely to be required to ensure gas supply in the future.

5.7 Strategies that effectively mitigate the risks and maximise the benefits to jurisdictions

In our assessment the most effective strategy for Governments will be to:

- Engage in project studies with industry to investigate in greater detail the opportunities presented in the national natural gas plan
- Initiate projects which studies show to be viable but for which there are no industry proponents
- Provide support with and streamline the approvals processes

6 POLICY OPTIONS THAT BALANCE EXPORT AND DOMESTIC NEEDS

6.1 Introduction

Natural gas resources are as unevenly distributed around the world as oil resources, hence there are strong economic pressures for a substantial international trade in gas. Natural gas' physical characteristics however have dampened trade in gas compared to oil: liquefaction is costly; and pipelines create importer/exporter vulnerabilities. Trade in LNG is only now growing rapidly, in response to persistently high oil prices (section 3.6).

Gas exports are a major source of income in many exporting countries, particularly those such as Qatar and Trinidad which do not have significant oil exports. Many exporting countries have limited domestic gas markets but are nevertheless concerned that their resources that are being exported could generate more value domestically. Typically this involves substituting gas for oil in industrial, commercial, residential and generation markets or pursuing value-added industrial developments based on gas. It is generally considerably cheaper to meet domestic gas demand from indigenous resources than from imports (although some countries such as the US are both importers and exporters), hence it is natural that the domestic market would take priority over exports.

The key question is how is this priority established? In countries with centralised gas industries, which include the majority of current exporters, the steps required to determine a reasonable level of exports are: estimate current reserves; set a timeframe for depletion of current reserves; estimate domestic demand over this timeframe; and reserves available for export are then those remaining after domestic demand is met. A difficulty that many such countries face is establishing the fiscal and regulatory regimes that ensure that resources are in fact developed for their domestic markets. Capital tends to be more attracted to export projects because of the well-defined offtake contracts with financially sound buyers in countries like Japan, and several countries have imposed production sharing contracts (PSCs) or other mechanisms on export projects, oil as well as gas, to ensure that sufficient production is available to supply the domestic market. PSCs give governments or national oil/gas companies the right to a share in the production stream.

In countries with competitive gas industries similar reserve availability considerations come into play but demand-supply matching for both domestic and export markets is left to market forces.

6.2 Australian and international export policies

This section reviews the explicit policies in a range of countries in which gas exports have been deliberately pursued or restricted.

6.2.1 Australia

Gas is currently exported as LNG from Dampier in WA (based on North West Shelf gas resources) and from Darwin (based on Timor Sea gas resources). Prospects of gas exports from other jurisdictions have until recently appeared to be limited but Arrow Energy has recently announced plans to export LNG from Gladstone from 2010 (section 3.3.2).

Export related policy development has therefore largely been the concern of the Commonwealth, Western Australian and Northern Territory Governments though it may now also become a concern of the Queensland Government in relation to CSG.

Until 1997 Commonwealth approval of exports was required to ensure the adequacy of gas reserves and that prices received were satisfactory, including ensuring that transfer pricing did not occur[78]. We have been unable to determine the reserve adequacy criteria used to approve the initial exports by the North West Shelf Venture. Federal controls on LNG exports were removed in 1997 and policy has subsequently been that gas developers should be free to sell their products into the markets of their choice.

The initial development of the North West Shelf project to supply domestic and export markets involved seven years negotiations between the producers, the State Government and the Commonwealth, culminating in the North West Gas Development (Woodside) Agreement Act 1979. This was an extensive policy and financial assistance package securing both the LNG and domgas projects for the state. The assistance included infrastructure and land provision as well as tax and royalty concessions but the greater value lay in SECWA's construction of the DBNGP and the commitment to a 20 year sales agreement with a 95% take-or-pay (ToP) level and at a price comparable to the expected netback from the LNG development at the time.

At the time of the disaggregation of the SECWA contract in 1995, North West Shelf gas was subject to five priority levels[79]:

1. 3023 PJ reserved for the disaggregated contracts to 2005
2. LNG exports
3. 2041 PJ for further domgas sales, including the sale to bhpbilliton for the DRI plant.
4. Associated gas reinjected into reservoirs
5. Gas produced and sold for any other purpose.

It is understood that all gas under priorities 1 and 3 has now been contracted.

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[78] "A National Strategy For The Natural Gas Industry. A Discussion Paper", Department of Primary Industries and Energy July 1991

[79] ACCC. Determination. Application for Authorisation. North West Shelf Project. Authorisation 90624, 29 July 1998

In 2006 the Western Australian Government issued a discussion paper[80] proposing a policy of securing gas from all future LNG export developments for domestic use as a condition for access to Western Australian land for processing facilities. The policy seeks to replicate the initial agreement with the NWSV and was motivated by a perceived decline in availability of gas from non-export developments. The policy would only apply to projects utilising land based processing. Many submissions in response to the discussion paper suggested that the policy would be counter-productive as it would lead to LNG projects becoming uneconomic and could discourage exploration for "domestic" gas – other submissions suggested alternative policy options which have been taken into consideration in section 4 on this report.

A modified policy was adopted in October 2006[81], setting out the State's objective of securing domestic gas commitments up to the equivalent of 15% of LNG production from each export project. The commitment can be met from sources other than the fields produced for export. Woodside has agreed to a domestic reservation from the Pluto development but domgas from this reservation will only be available 5 years after LNG supply. Under the Barrow Island Act 2003, the Gorgon development is committed to reserving 2000 PJ of gas for domestic supply. The project proponents are to submit proposals to the Minister by 31 December 2010 for the establishment of a domgas project by 31 December 2012, the project being capable of being expanded to a capacity of 300TJ/day.

6.2.2 Canada

Canada is the only major gas exporter other than Australia which has an established competitive gas industry structure. Canada's gas market is comprehensively integrated into the US market and demand, supply and prices are set by market wide forces. Canadian pipeline exports have supplied an increasing proportion of the US market since the US supply bubble was used up at the end of the nineties, reaching 15% in 2006 (3,400 PJ out of total Canadian production of 7,220 PJ).

Table 6-1 North American gas demand-supply balance, 2006 (PJ)

	Demand	Production/Imports	Reserves	R/P ratio
Canada	3,800	7,220	114,000	15.8
US	23,484	19,950	197,600	9.9
Mexico	1,900	1,520	38,000	25.0
LNG	76	646		
Total	29,260	29,336	349,600	11.9

Source: IEA. LNG demand is US exports from Alaska. The net demand-supply imbalance is due to changes in storage.

[80] "WA Government Policy on Securing Domestic Gas Supplies, Consultation Paper", Department of Industry and Resources, February 2006

[81] "WA Government Policy on Securing Domestic Gas Supplies", Department of Premier and Cabinet, October 2006

Canadian reserves are now less than those in Western Australia and the reserve/production ratio is only 16 years. Canadian demand is expected to be stable except for the growing oil sands processing industry which currently makes up 10% of demand and is likely to double over the next 5 years. Production is expected to remain stable with exports declining and LNG imports into the Eastern Seaboard commencing. Canadian prices are linked to those in the US and have risen substantially since 2003 in response to supply tightening and rising oil prices.

Until 1986, when the competitive industry structure was introduced, the Canadian National Energy Board[82] applied a three-test formula for determining the effect of proposed export projects on gas supplies: a current deliverability test that confirms deliverable supplies from established reserves would exceed the sum of annual domestic requirements plus authorized exports; a reserves test that determines the reserves that would remain after setting aside 25 times the then current annual Canadian domestic plus export requirements; finally, a future deliverability test that ensures that annual deliverability of supplies from both established reserves and estimated future finds would exceed Canadian needs and exports for 10 years. The current reserves would clearly fail this reserves test.

6.2.3 United Kingdom

The UK has been a minor exporter of gas to Europe through the Interconnector with Belgium, constructed in 1998 to take advantage of price differentials between Europe (high price) and the UK (low price at that time). In less than ten years the UK has moved to becoming a significant importer from Norway through the Langeled pipeline, from the Netherlands through the BBL pipeline and through various old and new LNG terminals. We are not aware of any restrictions on gas exports from the UK having been contemplated, even though imports were imminent.

6.2.4 Russia

Russia has the world's largest gas reserves and is the biggest exporter, via pipeline to CIS states and Europe. The Sakhalin LNG projects will export to Asia and the US West coast from 2008. Until recently Russia's priorities appeared to be to encourage export developments by oil majors, to secure expertise and cashflow. It has now imposed 50% limits on foreign ownership, the Russian share being held by Gazprom, and domestic prioritisation with subsidised pricing. As a concession the domestic-export price differential can be claimed as a cost against taxes. Projects that produce sufficient gas can pay taxes through royalty-in-kind payments, i.e. transfer of gas to the state.

[82] "National Energy Board`s report on Canadian natural gas supply and requirements", NEB 1979.

6.2.5 Iran

The second country largest by gas reserves, Iran has at present only minor exports to Turkey. Domestic demand for oil substitution and enhanced oil recovery is well developed but pipeline projects to Pakistan and India have been frustrated by regional politics. Iran has ambitions to become a significant exporter by pipeline and LNG, to exploit its favourable location relative to both Europe and Asia. Given its reserves it is not expected that Iran would put further constraints on exports, though Turkish users experience gas curtailment during extreme cold periods and Turkey has recently started importing LNG to reduce its reliance on Iran.

6.2.6 Qatar

Third largest by reserves, Qatar has recently become the largest LNG exporter and is set to triple its exports to over 4,000 PJ/year by 2011. Further expansion is awaiting the outcome of a reserve integrity management study on the massive North Field, due to be completed in 2009. Qatar does not appear to have any specific policies relating to gas for domestic use.

6.2.7 Indonesia

Indonesia was the world's largest LNG exporter for 22 years until losing the position to Qatar in 2006 and has also been a significant exporter of pipeline gas to Singapore and Malaysia. It has used PSCs between Pertamina, the Indonesian state petroleum company, and overseas oil companies to implement a domestic market obligation (DMO) policy. Exports currently run at 54% of production, however a combination of declining production in East Kalimantan and growing domestic demand has resulted in 20% cuts to LNG shipments over the past three years, which has damaged Indonesia's reputation as a reliable exporter. Japanese buyers hope to renew contracts expiring in 2010/11 but have yet to finalise agreements. Pertamina has however advised CPC Corp of Chinese Tapei that is contracts will not be renewed in 2010. Indonesian gas reserves are approximately 90,000 PJ, considerably less than Australia's.

Declining production is largely the result of under investment in oil and gas production, attributed to problems in the investment regime and governance of the sector. Growth in domestic demand is partly due to the same factors – oil prices have risen as Indonesia has become a net oil importer, hence a deliberate policy to substitute gas for oil. The Indonesian Government has made it clear that domestic gas demand will be met at the expense of exports[83].

The Government has also announced policies to address the investment shortcomings, to ensure rational pricing of domestic gas and "meet the dual objectives of fulfilling rising

[83] Natural Gas Market Review 2007, International Energy Agency, May 2007

domestic needs while supplying the export market"[84]. At this time it is too early to determine the effectiveness of these policies.

6.2.8 Algeria

Algeria is the fourth largest LNG exporter. Sonatrach, the state petroleum company, has a long history of collaboration with overseas oil companies and uses PSCs with a proportional requirement to contribute to the domestic market. Sonatrach recently entered a MoU with Gazprom, its Russian equivalent, covering a wide range of activities – over 85% of their exports are to Europe and both are seeking diversity of customers.

6.2.9 Trinidad and Tobago

Trinidad has significant reserves of gas that were initially developed to supply domestic energy intensive industries such as nitrogen, fertilisers, methanol, urea and steel, using increased revenues from oil production after 1973. For a variety of reasons these industries did not help Trinidad avoid a severe recession from 1982 to 1989 and further gas markets were actively sought to generate revenue. LNG exports to the US and Europe commenced in 1999 and were expanded in 2002/03 [85].

With proved reserves of only 20,000 PJ Trinidad is now confronting a need to decide between further LNG expansion or gas for four planned petrochemical plants and an integrated steel plant. In response to producer reluctance to negotiate supply contracts for the domestic buyers the Government has foreshadowed introduction of a new gas use policy that will "clearly define what percentage of gas will be used for export and what will be channelled into the domestic sector"[86]. Details of this policy have not been seen.

6.2.10 Venezuela

Venezuela has significant gas reserves as well as its better known heavy crude oil but while the oil is onshore most of the gas is offshore and has barely been developed. Most gas currently produced is used for enhanced oil recovery. Venezuela needs more gas for eor, to promote domestic demand and for export to replace falling oil revenue but needs overseas gas experience. Foreign participation has been restricted to 49% in oil projects and potential participants are waiting to find out if they can get up to 100% as promised under a Gaseous Hydrocarbons Law.

6.2.11 Saudi Arabia

Saudi has relatively "limited" gas reserves (compared to oil) of 240,000 PJ, the worlds fourth largest after Russia, Iran and Qatar, and uses them solely for targeted domestic projects such as combined power, desalination and petrochemical plants aimed at making

[84] Opening Ceremony Speech the the 3rd International Indonesia Gas Conference and Exhibition, by the President of the Republic of Indonesia, 16 January 2007.

[85] "Liquefied Natural Gas from Trinidad and Tobago – The Atlantic LNG Project", James A Baker III Institute for Public Policy Energy Forum

[86] "Grave concerns for Natural Gas Reserves", Trinidad and Tobago News October 18 2006.

more oil available for export. Until recently most gas was produced in association with oil and used for enhanced oil recovery. It is not known whether Saudi will consider exporting gas once it has established gas as the dominant domestic fuel.

6.2.12 Norway

Norway is currently the third largest exporter of natural gas, exporting 90% of its production to Europe by pipeline and about to commence exports of LNG from Snohvit, the first arctic LNG project. Norway has very limited domestic demand, mostly for enhanced oil recovery, because of its hydro-electric endowment and the unsuitability of its terrain for pipeline construction.

6.3 Policy approaches that address the balanced exploitation of natural gas for export and domestic use

6.3.1 Domestic gas supply security concerns in other countries

Many gas exporting nations have experienced concerns and difficulties regarding balanced exploitation of natural gas for export and domestic use and have put in place policies giving domestic use a preferential allocation. In these countries there are two causes for concern: insufficient gas reserves for both uses; and inadequate development of gas supply for domestic use. Most exporters have substantial gas reserves endowments and gas reserves are seldom the problem – only Trinidad and perhaps Indonesia have gas reserves issues. More frequently the problem is inadequate development due to inefficiencies in gas investment and regulatory frameworks and in many countries the policy responses have at best failed to address the problems and at worst compounded the problems. None of these countries have established competitive domestic gas markets and intervention by Government is not inconsistent with market structures.

Exporters which have established competitive domestic markets, such as Canada, have moved away from domestic allocation policies even though this has ultimately led to higher domestic prices and the need to import some gas requirements.

The following sections provide an assessment of suitable policy guidelines for Australia.

6.3.2 Long-term energy demand –supply considerations

To what extent should energy policy take into account the long-term energy demand and supply balance and in particular domestic gas supply? In framing an answer to this question we need to consider:

- Energy using technology time frames. The possibility of major change increases dramatically further into the future. Although many business-as-usual projections indicate ever rising gas (and oil) demand, it is entirely possible that demand (and supply) will be transformed in response to the GHG challenge and/or supply changes. There may be limited evidence of this by 2015 but by 2030 and even more by

2050 substantial GHG reductions will of necessity change the face of the energy sector – BAU will not be feasible.

- Australia currently imports over 40% (net) of its oil requirements, having been self sufficient as recently as 2000. Although the import bill is large this has not slowed the economy significantly.

These observations suggest that:

1. Concern with domestic gas supply over the next 20 and possibly 30 years is legitimate.
2. Domestic gas supply does not have to come from domestic gas resources but could come from pipeline gas (PNG) or LNG imports.

A traffic light scheme may provide more useful guidance than any fixed number. Based on the above and the reserves security accepted in other countries the following scheme is recommended:

- Green - over 25 years reserves - no reserve concerns, policy can focus on gas development to maximise economic and environmental benefits, no concerns with exports
- Amber - 15 to 25 years reserves – growing concern with reserves and incremental exports, policy should focus on promoting reserves/supply growth.
- Red - under 15 years reserves – significant reserves concerns, prices are likely to rise to constrain demand and consideration of imports is warranted.

Perceptions will of course be contingent on history – Governments and the market will be more comfortable with a steady 20 year reserves position than with 20 years reserves that have steadily fallen. If imports were to become a supply component, the "reserves" backing the imports would have to be set at whatever is contracted to Australian buyers.

It is also observed that condition "red" is not an indication of market failure and the consequent need for Government intervention, particularly if it has been arrived at progressively, with sufficient time for suppliers to consider imports and for users to adjust to higher prices. A condition "red "arrived at suddenly, for example due to a significant downgrading of reserves, may however warrant intervention.

It is recommended that a traffic light or similar scheme, including agreed definitions of market failure, be considered for implementation as part of a National Natural Gas Plan (section 6.5).

6.3.3 Gas market setting

Over the past decade the Australian gas market has been deregulated and market forces have brought forward additional supply for domestic and export use. The new supply arrangements put in place over the last decade in Eastern Australia include several significant pipelines, such as the EGP and SEAGas, and over 7,300 PJ of additional gas has been contracted during this period, of the current total of 9,300 PJ. In Western Australia, notwithstanding the current supply position, pipeline capacity is being expanded and over 2,500 PJ of additional gas has been contracted during this period, of the current total of 4,100 PJ, and in the Northern Territory the new supply arrangements for Blacktip gas have been agreed. On the export front over the same period the NWSV and Darwin LNG have contracted to deliver approximately 14,000 PJ and 2,700 PJ of additional LNG exports respectively.

Our assessment of policy options assumes that the deregulated market setting continues.

6.3.4 Current reserves position

Total proved Australian gas reserves, including the Timor Sea, were approximately 165,000 PJ at the beginning of 2005, of which approximately 35,000 PJ are now contracted. Maximum future committed production rates, including NWS Train 5 LNG, are approximately 2,500 PJ/year, at which rate the proved reserves have a life of 66 years.

This substantial period is considerably longer than the 40 years since many of the initial gas discoveries were made. It represents sub-optimal exploitation of the resource, both from a national perspective and from the perspective of resource lease and licence holders, who would have undertaken the initial exploration in the hope and expectation of being able to initiate exploitation of discoveries within a commercial timeframe, ideally within ten years and at worst within twenty years.

The conclusion to be drawn from this is that total gas reserves are not a key factor in balancing exploitation of natural gas for export and domestic use at this time. If all the potential export projects discussed in section 3.2.5 were to proceed immediately, reserve sufficiency may become a concern but they are unlikely to do so and by the time they do further discoveries will have been made.

The position regarding potential exports from Queensland is different. The Eastern States reserve life is less than half the national aggregate and if it were all conventional gas there may be a case against exports. However the demand driven reserve growth potential of CSG has been noted and if additional reserves are proved up specifically for export projects the case against exports is not one of reserves per se but one of allocation of resources and effort to expand reserves. Without having established any clear upper limit to CSG potential the case against exports is substantially weakened.

At the national level allocation of reserves to export and domestic use is therefore unnecessary. This conclusion is reinforced by the much shorter reserve lifetimes accepted by other major gas exporters such as Canada and Trinidad.

6.3.5 Gas market development options

The principal markets into which significant additional gas could be sold include:

- Domestic power generation
- Domestic minerals processing, in which a large proportion of gas use is for generation
- Domestic transportation (LNG or CNG)
- Gas to liquids conversion (for domestic or export markets)
- Ammonia and other chemical production (for domestic or export markets)
- Export as LNG or CNG

At present there seems little doubt that LNG exports offer the highest returns and are most attractive to gas producers for whom export is an option. Assessment of whether LNG exports offer the highest returns to the Australian and state/territory economies is outside the scope of the present study but clearly of interest to Governments. We therefore recommend that such an assessment be undertaken and if options other than LNG exports are found to offer greater economic returns, means of aligning gas producers' interests with those of the national economy could be sought, to enable the market to deliver the economically optimum outcome. If the question is simply one of allocation of profit between gas sellers and buyers, rather than benefits to other sectors of the economy, it could be resolved by adjusting gas pricing or promoting vertical integration.

6.3.6 Gas development facilitation

One of the factors underlying the current domestic supply position in Western Australia is the nature of the reserves relative to the domestic market. The WA domestic market is currently supplied primarily by a combined export/domestic project and our analysis suggests that future supply will rely upon the development of additional export/domestic projects that are unlikely to proceed without the export component, as well as dedicated domestic projects.

A balance between gas for domestic and export use cannot be achieved by developing gas separately for each market – export development is required to fulfill domestic needs as well. Policy should therefore have the objective of facilitating gas development for both export and domestic use.

In section 4.4 the following options that could be used to facilitate gas development were identified in the context of domestic supply (and export supply where a project supplies both markets):

- Project facilitation (Major Project Facilitation Status)
- Improved infrastructure approvals processes
- Commonwealth Government assistance with overseas project approvals and contract negotiation

- Investment in training oil and gas industry personnel
- Ensuring that retention lease principles are rigorously applied so that commercial fields are developed. If the domestic market is under supplied and there is any field that can supply the market on a commercial basis, this mechanism is the last resort to ensure supply in the current framework.

MMA believes that progressing these options and others identified in section 4.4 will provide the best means to ensure balanced exploitation of gas for export and domestic uses over the next decade.

6.3.7 Other policies considered

6.3.7.1 International parity pricing

A number of stakeholders consulted by MMA suggested that to ensure continued domestic gas supply some form of international parity pricing may be appropriate, even in those regions where gas is not exported, to ensure that exploration and production resource allocations are not distorted towards those regions where gas export options exist. The stakeholders recognised that this would raise broader policy issues, particularly the relativity of coal and gas prices (should coal also be subject to international parity pricing?) and its impact on carbon trading.

As a practical matter at present there are no suitable international gas price benchmarks on which an international parity price could be based and most LNG contract prices are oil-linked (section 3.6) but there are signs that this may break-down and that the Henry Hub price in the US may become an international benchmark. A more fundamental objection to the imposition of international parity pricing however is that under the deregulated industry model, if international parity pricing is necessary to ensure continued domestic supply, then the market should arrive at that price by itself, including in those areas where there are no exports. A more detailed discussion of the impact of export prices on domestic prices is presented in section 4.4.1. The limited liquidity of Australian gas markets could make the process of arriving at this price quite bumpy but it may be less disturbing to participants than an imposed price.

In view of the above issues we do not recommend any further consideration of this policy option.

6.3.7.2 Royalty in kind

Royalty in kind (RIK) involves Governments receiving royalties in the form of an allocation of gas (or oil) at a producer's wellhead or plant gate rather than in the form of cash. It has been suggested that RIK could be used to obtain gas from export projects for the domestic market.

RIK has been successfully implemented by the US Minerals Management Service[87] which is currently trading 800 TJ of gas and 150,000 bbl of oil per day. US oil and gas leasing laws give the Government the option of receiving royalties as cash or in kind and MMS has identified efficiencies in administrative costs and revenues in some areas, including offshore in the Gulf of Mexico and California and onshore in Wyoming. Some of the oil is used to fill the Strategic Petroleum Reserve.

RIK may be a long-term option for Australia but it involves many steps, at each of which the process could fail:

1. Establishing the RIK option in legislation. It is not clear to MMA that an RIK equivalent to PRRT is possible or that the upstream industry will accept it retrospectively unless it offers cost savings
2. Demonstrating that it is cost effective
3. Establishing a government gas trader to receive and sell the gas. Unless a transparent market price is available, this will involve difficult probity issues.

Use of RIK to take gas from export projects for the domestic market would have similar gas market impacts to the Western Australian policy of securing domestic gas from export developments. As the latter is far easier to implement we do not recommend RIK for Australia.

[87] Refer to www.mrm.mms.gov

6.4 The need for a national natural gas plan

6.4.1 Current framework

From the first production of natural gas in the late 1960s to the mid 1990s the gas industry mostly comprised separate, state-based, single producer, single pipeline, single retailer/distributor relationships and all planning was readily undertaken on a distributed basis. From the retailer/distributor perspective planning was either internal or involved bilateral negotiations with the pipeline or producer for more capacity. Generators using gas were either integrated (SECWA) or conducted parallel negotiations for their requirements (SECV) and in South Australia the pipeline authority, PASA, purchased gas for its downstream customers. Pipelines and producers largely responded to downstream requests for capacity.

The new supply arrangements put in place over the last decade in Eastern Australia, in response to the dismantling of the monopoly/monopsony framework, are also largely the result of distributed planning and bilateral negotiation. Several significant pipelines, such as the EGP and SEAGas, have been constructed and over 7,300 PJ of additional gas has been contracted during this period, of the current total of 9,300 PJ. In Western Australia, notwithstanding the current supply position, pipeline capacity is being expanded and over 2,500 PJ of additional gas has been contracted during this period, of the current total of 4,100 PJ. In the Northern Territory the new supply arrangements for Blacktip gas have been agreed. The scale of projects contemplated, but not yet implemented, extends to the 3,800 km, $4bn PNG gas pipeline project.

The current planning and decision making processes can be characterised as:

- Distributed – undertaken by individual participants
- Confidential – planning documents are not available for public scrutiny

Pipelines regulated under the Code do submit Access Arrangements in which their projected demand and capital spending plans are publicly outlined. However there is a trend for Access Arrangements to relate only to existing capacity, with capacity expansion negotiated separately with shippers.

An exception to this model has been instituted in Victoria where the gas transmission and market operator VENCorp publishes a Gas Annual Planning Report (GAPR). The GAPR presents:

- Five year projections of annual, monthly, daily peak and zonal gas demand
- Five year supply/capacity projections for each gas injection point
- Assessment of transmission system capacity
- Five year supply-demand balance
- Assessment of system constraints and network development requirements

In preparing the GAPR VENCorp relies upon information provided by market participants with respect to their obligations as outlined under Clause 5.2 of the Victorian Market and System Operations Rules (MSOR). The GAPR places no obligation upon participants to implement any of the identified supply options.

The Gas Market Leaders Group in its National Gas Market Development Plan recommended preparation of an annual gas supply/demand planning statement by the market operator established in connection with the BB and STTM.

6.4.2 Gas demand-supply studies

A number of public studies of long-term gas supply and demand have been conducted by government and industry bodies. Prominent among the latter is the series of four "Gas Supply and Demand Study" reports by the Australian Gas Association between 1985 and 1997[88]. These sought to illustrate how growing demand could be accommodated and to estimate the infrastructure requirements and costs. The earlier studies in the series, produced during the era of barriers to trade and restrictions on the use of natural gas for power generation, were used to argue for the removal of barriers and restrictions, to enable economically efficient gas supply and demand patterns to develop.

Government sponsored studies include:

- "Australian Energy – national and state projections" produced annually by ABARE. Gas demand-supply is considered in the broader energy context.
- "Energy Western Australia", a high-level overview produced annually by the WA Office of Energy up to 2003
- "Queensland Gas Meeting The Challenge", a report by the Queensland Gas Industry Task Force in 1996 that considered supply demand in Queensland up to 2006.
- "Report on Gas Regulation in NSW", produced by a Ministerial Working Party in July 1989, which contained a national overview of supply-demand.

6.4.3 Stakeholder views

Stakeholders consulted by MMA indicated that they are satisfied with their own current planning arrangements, which involve supply-demand projections of varying levels of national integration. They do not believe they will derive much benefit from a national natural gas plan (NNGP) but would support preparation of an indicative gas plan if it was of value to governments. Some stakeholders also acknowledged that new entrants to the gas market may derive some benefits from a plan.

[88] The Australian Gas Association. Gas Supply and Demand Study. Third Report – Public. AGA July 1992.

Some stakeholders suggested that governments would benefit from a consistent, independent view of future gas demand-supply scenarios and particularly a clearer picture of both short and long-term demand–supply imbalances and options to redress them.

Some of the planning do’s and don’ts mentioned by stakeholders are:

- It should be an indicative plan only and there should be no obligation or authority to implement it
- It could present a forward view of constraints and possible solutions but not a preferred solution
- Resources used and data required from industry should be reasonable.
- It should be recognised that plans soon date and should therefore not be over ambitious
- Conversely it may be possible to avoid wasting resources by updating the plan only every two to three years
- Plans could be modelled on the VENCorp GAPR or the electricity Statement of Opportunities (SOO) prepared by the National Electricity Market operator, NEMMCO
- Plans do not need to make price projections (neither GAPR nor SOO rely upon price projections)

6.4.4 Conclusion

MMA believes that a NNGP will be of value to Governments and gas users, as well as to the gas industry as an independent means of communicating on gas supply security with Governments. However its introduction will require the exercise of considerable care to establish a suitable balance between level of detail (sufficient to generate information of value) and wasting resources.

6.5 Elements of a national natural gas plan

6.5.1 Objectives

A NNGP should be designed to meet well-defined objectives. Considering the issues addressed by this study MMA believes that the NNGP objectives could be:

1. Capacity adequacy: to indicate short-term domestic demand supply imbalances and the options open to redress them within the available timeframe.

2. Reserves adequacy: to indicate long-term domestic and export demand growth potential and the implications for supply, taking into account current reserves, likely new discoveries and potential imports.

The first objective is similar to that of the GAPR and SOO and could be met by a plan with a similar structure i.e. a five to ten year timeframe. The Gas Market Leaders Group intended its annual planning statement to be similar to the GAPR and SOO. However these approaches and particularly the timeframes do not address the long-term adequacy of reserves that invariably attach to questions relating to gas exports.

The two objectives require different levels of detail and information, to the extent that they could be met by different plans, but it would almost certainly be more efficient for the objectives to be met in a single plan.

6.5.2 Key features

The features MMA would expect to see in a NNGP are similar to those in the GAPR and SOO but with different details and approach for the long-term projections. A key initial decision would be how many zones to include in projections – the number could range from one to several per state, for example demand in Western Australia could be represented as located in three zones: South-West (Perth and environs); Pilbara; and Goldfields (offtakes from the GGP). In this case capacity adequacy in each zone, eg on the DBNGP, can be assessed but with only one zone only the aggregate WA supply-demand balance can be assessed.

6.5.2.1 Demand projections

Short-term

- Five or ten year projections of annual (PJ) and daily peak (TJ/d) gas demand in each zone, based on socio-economic projections and assumed retail prices (or a default of no price change)

- Projections of annual gas exports from each export facility

- Projections of co-incident peak load across multiple zones

- Demand could be disaggregated into one of a number of user categories: generation, industrial, commercial and residential or generation, over 10TJ/yr and under 10TJ/yr. Different disaggregations may be necessary in each zone

Long-term

- Extended projections of annual demand only. In each zone.
- Projections of annual gas exports from each export facility

6.5.2.2 *Supply projections*

Short-term

- Current and committed capacity (TJ/d) contracted at each injection point over the period
- Volume (PJ) restrictions on storage injections

Long-term

- Gas reserves by basin (2P)
- Potential new gas discoveries by basin (P50 and/or others)
- Developable gas production capacity by basin, including timing
- Developable import (PNG, Timor Sea) production capacity by basin, including timing

6.5.2.3 *Supply-demand balance indicators*

Short-term

- Peak demand v supply by zone
- Co-incident peak demand v supply across multiple zones, where zones are unlikely to have co-incident peaks.

Long-term

- Timing of reserve insufficiency, when reserves can no longer support production capacity to meet demand (eg assuming a minimum reserve/production ratio). This is simply a more sophisticated version of the R/P ratio.
- Separately for Eastern Australia in aggregate, Western Australia and the Northern Territory and in combination.
- Also with and without potential new discoveries.

6.5.2.4 *Constraints and capacity development requirements*

Short-term

- Assessment of gas injection capacity shortfall and options that can meet the shortfall within the available timeframe

- Assessment of transmission system capacity shortfall and options that can meet the shortfall within the available timeframe

Long-term

- Assessment of major transmission interconnection requirements
- Assessment of gas import requirements

6.5.2.5 Measures of reliability

Short-term

- Measures of gas supply reliability (related to the number of sources and pipelines supplying demand zones). Standards of reliability may need to be agreed before this information can have any practical use.

Long-term

- Measures of gas supply security, eg number of years prior to reserve insufficiency that are considered adequate to allow for further discoveries or the development of further transmission interconnections or import options. The traffic light scheme discussed in section 6.3.2 or a similar scheme could also be adopted. This could include definitions of the circumstances under which the gas market is deemed to have failed and Government intervention is required, in a manner similar to gas emergencies caused by short-term supply failures.

6.5.3 Information requirements

It has been noted that the GAPR relies upon information obtained under the Victorian gas market rules. It may be necessary to rely upon a similar authority associated with the gas market in other jurisdictions to obtain the short-term supply information detailed above, though it is noted that a number of stakeholders prefer voluntary to mandatory information provision. If the (future) gas market rules do not provide such an authority the short-term plan may have to be simplified. The Bulletin Board being developed to support emergency management and gas trading may help in this regard.

6.5.4 The planning body

The precedents set by the GAPR and the SOO, both of which are produced by market operators, suggest that the short-term side of the NNGP might be prepared by the future operator(s) of the gas markets (the STTM, which is expected to replace the existing gas markets in New South Wales and South Australia, and the Victorian gas market). Although the STTM is expected to be less complex than the Victorian gas market and the operator will not be operating pipelines in the way that VENCorp does, we believe that the STTM operator will have sufficient market knowledge to fulfil the task.

MCE has recently determined that all the energy market operators (GMCO, REMCO, VENCorp and NEMMCO) should be merged into NEMO, the National Energy Market

Operator, hence NEMO becomes the logical vehicle for the short-term side of the NNGP. An MCE Working Group is currently considering a suitable structure for NEMO. As noted we believe that the short and long-term aspects of the NNGP should be combined for the sake of efficiency, though NEMO may rely more upon outside advice in addressing the long-term issues.

A question remains regarding preparation of the NNGP for areas where NEMO does not operate a gas market, which will probably include the Northern Territory, Tasmania and some parts of states outside of STTM hubs or other markets (in Western Australia and Queensland). Apart from the NT, which is an isolated network, it would not be realistic to exclude parts of states outside hubs or Tasmania, because their supply is intimately connected to that in the hubs. At this time the only realistic option would be for NEMO to prepare the plan for these regions using the best data it can obtain.

A number of stakeholders suggested alternative planning bodies, notably an alliance of industry associations or independent service providers such as ABARE. MMA has no doubt that either of these alternatives have the ability to prepare a plan but is of the view that the market operator is more likely to have the authority to obtain information and to be seen as neutral in managing it. Within Victoria this authority already exists.

APPENDIX A JOINT WORKING GROUP ON NATURAL GAS SUPPLY, NOMINATED MEMBERS

WESTERN AUSTRALIA

Jim Limerick
Director General
Dept of Industry and Resources

Dianne Forde
General Manager Industry
State Development Strategies
Department of Industry and Resources

Jason Banks
A/Coordinator of Energy
Office of Energy

Rolando Custodio
A/Director Markets and Regulatory Policy
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VICTORIA

Kathy Hill
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Marianne Lourey
Executive Director,
Energy Division,
Department of Primary Industries, Resources and Energy

Peter Naughton
Director, National Energy Market Development
Department of Primary Industries, Resources and Energy

TASMANIA

Dr Tony Brown
Director, Mineral Resources
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Department of Infrastructure, Energy & Resources

NORTHERN TERRITORY

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John Hartwell
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Bob Pegler
General Manager
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Resources Division

Drew Clarke
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SOUTH AUSTRALIA

Barry Goldstein
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Petroleum & Geothermal
Department of Primary Industries & Resources

QUEENSLAND

Gayle Leaver
Principal Policy Officer
Dept of Mines & Energy

Kay Gardiner
Manager Gas Policy Industry & Markets

APPENDIX B GAS MARKET LEADERS GROUP MEMBERS

Table B 1 Gas Market Leaders Group

Association / Organisation	Name	Company
Chair of Gas Market Leaders Group	Ted Woodley	
APPEA nominees on behalf of gas producers	James K Hunsaker Gas & Power Marketing Director	ExxonMobil
	Rick Wilkinson Vice President Gas Marketing and Commercialisation	Santos
APIA nominees on behalf of transmission gas network owners and operators	Jim McDonald	
	Stephen Livens Manager Regulation Risk & Insurance	Epic Energy
ENA nominee on behalf of distribution gas network owners and operators	Peter Fennessy Manager Commercial Development Eastern Australia	Alinta
ERAA nominees on behalf of gas retailers	Michael Fraser General Manager Merchant Energy	AGL
	Dennis Barnes General Manager Generation Operations	Origin Energy
VENCorp, Remco, GMCo nominee on behalf of gas retail and wholesale market operators	Matt Zema Chief Executive Officer	VENCorp
	Patricia McKenzie Chief Executive Officer	Gas Market Company
	Stephen Thomson Chief Executive Officer	Retail Energy Market Company
Major Energy Users, Energy Intensive Alliance, EUAA nominees on behalf of gas users	Mark Gell General Manager, Corporate Development	One Steel
	Dr Stephen Bell General Manager Commercial	Qenos
National Generators Forum (NGF) nominee on behalf of gas-fired generator	David Murphy Director Portfolio Management	International Power

APPENDIX C ABBREVIATIONS

Term	Definition
2P	Proved and probable
ABARE	Australian Bureau of Agricultural & Resource Economics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Markets Commission
AER	Australian Energy Regulator
AGL	Australian Gas Light Co
ANZMEC	Australia New Zealand Minerals and Energy Council
APA	Australian Pipeline Trust
APPEA	Australian Petroleum Production and Exploration Association
BB	Bulletin Board
CCIWA	Chamber of Commerce and Industry, Western Australia
CO2	Carbon dioxide
COAG	Council of Australian Governments
Code	National Third Party Access Code for Natural Gas Pipeline Systems
CNG	Compressed Natural Gas
CSG	Coal Seam Gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DMO	Domestic market obligation
DOIR	Department of Industry and Resources (WA)
DRI	Direct reduced iron
E&P	Exploration and Production
EGP	Eastern Gas Pipeline
ERA	Energy Regulatory Authority (WA)
ERIG	Energy Reform Implementation Group

Term	Definition
EST	Eastern standard time
FEED	Front end engineering design
FRC	Full Retail Competition
GAPR	Gas Annual Planning Report
GGP	Goldfields Gas Pipeline
GHG	Greenhouse gas
GISB	Gas Industry Standards Board
GJ	Gigajoule (10^9 joules)
GMC	Gas Market Company
GMDP	Gas Market Development Plan
GMLG	Gas Market Leaders Group
GPAL	Gas Pipelines Access Law
GTL	Gas to liquids
HHI	Herfindahl-Hirschman Index
HoA	Heads of agreement
IEA	International Energy Agency
JV	Joint Venture
JWG	Joint Working Group
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MAOP	Maximum operating pressure
MAP	Moomba Adelaide Pipeline
MCE	Ministerial Council on Energy
MCMPR	Ministerial Council on Mineral and Petroleum Resources
MMA	McLennan Magasanik Associates
MoU	Memorandum of understanding
MPF	Major Project Facilitation

Term	Definition
MSOR	Market and System Operations Rules
MWh	Megawatt-hour
NEMO	National Energy Market Operator
NGERAC	National Gas Emergency Advisory Committee
NGL	National Gas Law
NGR	National Gas Rules
NIEIR	National Institute for Economic and Industrial Research
NNGP	National natural gas plan
NOPSA	National Offshore Petroleum Safety Office
NWSV	North West Shelf Venture
OBA	Operational balancing arrangement
P(SL)A	Petroleum (Submerged Lands) Act
P50	50% probability
PC	Productivity Commission
PJ	Petajoule (10^{15} joules)
PNG	Papua New Guinea
PRRT	Petroleum Resource Rent Tax
PSC	Production sharing contract
QSN Link	Queensland to South Australia and New South Wales Link
Remco	Retail Energy Market Company
RiK	Royalty in kind
SCO	Standing Committee of Officials
SECV	State Electricity Commission of Victoria
SECWA	State Energy Commission of Western Australia
SESSWG	Strategic Energy Supply and Security Working Group
SOO	Statement of Opportunities
STTM	Short Term Trading Market

Term	Definition
SWQP	South West Queensland Pipeline
TGP	Tasmanian Gas Pipeline
TJ	Terajoule (10^{12} joules)
ToP	Take or Pay
UCCI	upstream capital costs index
VENCorp	Victorian Energy Networks Corporation
VPTS	Victorian Principal Transmission System