Meeting the Future Gas Needs of Western Australia

Discussion Paper

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Prepared by the Chamber of Commerce and Industry of Western Australia

CCI

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List of Acronyms

ABARE – Australian Bureau of Agriculture and Resource Economics

APIA – Australian Pipeline Industry Association

APPEA – Australian Petroleum Production and Exploration Association

ALNG – Australian Liquefied Natural Gas

APT – Australian Pipeline Trust

ABS – Australian Bureau of Statistics

CCI – Chamber of Commerce and Industry of Western Australia

CME – Chamber of Minerals and Energy

CPI – Consumer Price Index

COAG – Council of Australian Governments

DBP – Dampier Bunbury Pipeline

DBNGP – Dampier to Bunbury Natural Gas Pipeline

DOIR – Department of Industry of Resources of WA

EMP – Environmental Management Plan

EP – Environmental Plan

EPA – Environmental Protection Agency

ERA – Economic Regulation Authority

GGP – Goldfields Gas Pipeline

HHV – Higher Heating Value

HBI – Hot Briquetted Iron

IPGJV – Incremental Pipeline Gas Joint Venture

LNG – Liquefied Natural Gas

LPG – Liquefied Petroleum Gas

MAOP – Maximum Allowable Operating Pressure

NCC – National Competition Council

NCP – National Competition Policy

NOPSA – National Offshore Petroleum Safety Authority

NWS – North West Shelf

NWSG – North West Shelf Gas

ODAC – Office of Development Approvals Co-ordination

PEPL – Pilbara Energy Pipeline

PRRT – Petroleum Resource Rent Tax

QP – Qatar Petroleum

SMS – Safety Management System

SMYS – Specified Minimum Yield Strength

SECWA – State Energy Commission of WA

TPA – Trade Practices Act

WANG – Western Australian Natural Gas

WAPET – West Australian Petroleum Pty Ltd

About CCI

The Chamber of Commerce and Industry of Western Australia (CCI) is the leading business association in Western Australia.

It is the second largest organisation of its kind in Australia, with a membership of 5,000 organisations in all sectors including manufacturing, resources, agriculture, transport, communications, retailing, hospitality, building and construction, community services and finance.

Most members are private businesses, but CCI also has representation in the not-for-profit sector and the government sector. About 80 per cent of members are small businesses, and members are located in all geographical regions of WA.

Background and Introduction

In February 2006, the Department of Industry and Resources (DOIR) released its consultation paper, WA Government Policy on Securing Domestic Gas Supplies. The Consultation Paper sought industry feedback on specific policy proposals aimed at ensuring that Western Australia has sufficient supplies of competitively priced gas to underpin its future needs.

The key proposal identified in the Consultation Paper was for the WA Government to intervene in the market and reserve gas for domestic consumption. This proposal was based on the assumption that market forces would be unable to deliver the WA Government with a degree of comfort that future supplies would come to the domestic market.

The release of the Consultation Paper, and more specifically the policy to reserve gas for domestic purposes, generated a significant amount of debate, with submissions received from stakeholders across the gas supply chain – from explorers and producers, distributors and wholesalers/retailers.

While there was some support for the proposal for a gas reservation policy from Alcoa, Synergy (two of the largest consumers of gas) and Horizon Power, the majority of the submissions did not support such a policy. These submissions suggested that while the potential existed to improve Government policy relating to gas supply, no identifiable market failure exists in relation to the supply of gas to the domestic market. Many of these submissions suggested that if the WA Government were to intervene in the market and impose a reservation policy, this would have adverse consequences for the industry and the State.

Notwithstanding these concerns, on 12 October 2006, the Premier announced the WA Government's policy on securing domestic gas supplies – with the centrepiece being the requirement to set aside for domestic use the equivalent of up to 15 per cent of gas available from any future offshore development.

The production of this report represents a six month study into the WA gas market, which has included a detailed consultation period with key players in the gas supply chain.

It has been undertaken on behalf of a group of member companies, which formed for the specific purpose of discussing the issue of improving the security of gas supplies for the domestic market. Members of the Gas Reference Group include: Alcoa, Australian Pipeline Trust (APT), BHP Billiton, CSBP, Dampier Bunbury Pipeline, Griffin Group, Horizon Power, Midland Brick, North West Shelf Gas, Origin Energy, Synergy and TiWest.

However, CCI also consulted with other key players in the gas supply chain which were not members of this Group, including Alinta, Apache, ARC Energy, Chevron, Perth Energy and Woodside.

Given that CCI's membership includes companies throughout the gas supply chain, CCI has sought to present a balanced view as to the appropriate policy settings in relation to the gas market.

The report is structured in four main sections:

- The first section will provide a comprehensive overview of the gas market in Western Australia, including detailed analyses of the basic characteristics of gas, the evolution of the gas market in WA, a review of the supply and demand for gas, and the role of government in the gas market.

- The second section will then discuss the key elements of the Consultation Paper, and the issues identified in the submissions to the paper, as well as providing details of the subsequent policy decision of the WA Government.

- The third section will use a supply chain analysis to investigate the key issues that are potentially impacting on the supply of gas to the domestic market.

- The final section will detail the key findings developed throughout the report.

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Executive Summary

The availability of a reliable long term supply of gas is a key issue in relation to the future economic development of Western Australia.

Western Australia is rich in natural gas, with most of the state's endowment of gas contained in offshore deposits in the north west of the state. Of the total reserves of gas in Western Australia, only 18 per cent relates to developed or producing fields. The remaining 82 per cent of the state's gas resources are located in undeveloped fields.

There are a number of key issues which have a significant effect on the ability of producers to bring gas supplies into the domestic market. All of the large undeveloped gas resources currently planned for development in WA suffer from a number of factors that increase the development cost, and therefore the scale required to achieve a commercial development.

Notwithstanding these issues, in recent years a number of large LNG projects have been developed, or are under consideration for development. Given the field economics associated with these projects, and a desire by Australian suppliers to secure export market share, gas supplied from these projects has been earmarked for export overseas. By comparison, supplies for the domestic market have not matched the increase in supply going overseas.

Supply of gas to the domestic market has increased by just 0.3 per cent per annum over the past five years, primarily as a result of lower supply from non-North West Shelf suppliers. Growth in gas supplied to the domestic market from these suppliers has fallen by an average of 5.3 per cent each year over the past five years, compared to an increase from the North West Shelf on average by 3.6 per cent per annum over the same period.

At the same time, domestic gas consumption has increased strongly in recent years. Consumption of natural gas in Western Australia has increased by an average of 6.2 per cent per annum between 1986-87 and 2004-05. The strength of gas consumption growth here lies in the state's reliance on gas being a fuel source, with natural gas currently accounting for around 41 per cent of total net fuel consumption in Western Australia.

By virtue of its industry structure, gas is a key input for the state's key manufacturing, electricity generation and mining industries, which together consume up to 90 per cent of the state's natural gas supplies each year. In turn, this volume of consumption by industry is concentrated among only five major users.

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These industries have been able to source a secure supply of gas at relatively low prices, providing them with a key competitive advantage relative to their competitors – whether they are interstate or overseas.

However, as these industries, and the WA economy more generally, have grown, supply has not kept pace with demand, prompting concerns that supplies of gas into the domestic market will not be able to meet future demand beyond 2020.

For these reasons, the WA Government has been prompted to look at the issue of future supplies of gas for the domestic market. While such an investigation is important, the WA Government's approach does not consider a broader set of policy measures which will also be required to help promote greater supply of gas into the domestic market.

After a period for consultation, the WA Government announced its gas reservation policy on 12 October 2006, with the centrepiece of the policy requiring producers of LNG projects to set aside for domestic use up to 15 per cent of gas available from any future offshore development. Whilst Alcoa, Synergy and Horizon Power were generally supportive of the WA Government's policy, there was little support for government intervention from other market participants, who believed that market mechanisms would be the most efficient means by which domestic gas supplies could be secured.

While the policy contains certain shortcomings, it remains the view of some participants in the domestic gas market that some form of reservation is necessary in order to guarantee continued security of supply. While such participants broadly favour market mechanisms over government intervention, for the most part, their views are based on the fact that there is no fungible market for gas in WA, with domestic supplies concentrated among only two projects.

This report has found that in order to develop the domestic gas market further, there are a range of issues that should be considered across the gas supply chain. Addressing such issues will help to deliver efficient market outcomes in order to secure domestic gas supplies in Western Australia.

To ensure that the key issues in relation to the gas industry are identified and properly considered, this report has focussed on a supply chain analysis.

Key Findings

Overall, the report found that notwithstanding the state's considerable endowment of natural gas, there is substance to ongoing concerns, both inside government and amongst key players in the natural gas market, that there may in future arise a deficiency of supply of natural gas to the domestic market. Indeed, there is already

evidence of difficulties from some consumers in sources additional sources of gas supply.

This report has identified a range of issues that require the immediate policy attention of all levels of government. Further details are provided throughout the body of the report, with a summary of findings detailed in the Findings section on page 143.

Gas Production

At the production end, it was found that high barriers to entry mean that a relatively few large companies dominate the production of gas in Western Australia, and also hold a large proportion of undeveloped reserves and exploration acreage.

However, the concentration of resource ownership was not found to be the primary concern, but rather the extent to which supply is made available to the market in a timely fashion. In this context, the success or otherwise of a producer (large or small) relies on the ability to obtain exploration permits and then retention leases. The extent to which production eventuates will depend on the characteristics of the field and the demand for gas, all of which underpin the economics of the field.

A key proposal promoted in order to address issues at the production end was to reform the **retention leases** process. The concern with retention leases was that the large producers were "hoarding" acreage, blocking out other suppliers that may wish to develop the areas under retention lease.

While it was found that the current process provides the appropriate checks and balances to address concerns about the hoarding of acreage, there exists room for government in the form of a designated authority to be more proactive in seeking information from third parties regarding the veracity of any factual claims made in any application. It was also found that greater advantage should be taken of the opportunities that exist for third parties to make submissions to government as to whether a particular retention lease is commercially viable. Such scrutiny would help to enhance the stringency with which the government assesses the retention lease applications.

Another proposal that has been suggested is that **infrastructure support** be provided to assist producers in bringing supply to market. Overall, it was found that such support does not represent an appropriate mechanism to encourage proponents to supply gas into the domestic market. Projects should proceed only if commercially viable, as government subsidies tend too often to take money from efficient businesses and give it to inefficient ones, to the detriment of overall economic efficiency.

It was also suggested that gas gathering and processing infrastructure be subject to the same **open access principles** that apply to other essential infrastructure. The report found that while it has never been tested, it is unclear whether such infrastructure would be declared to be essential infrastructure under Part IIIA of the *Trade Practices Act* (TPA). This is largely because it would need to be demonstrated that, among other things, the infrastructure is uneconomical to duplicate and that it has natural monopoly characteristics – both of which are debatable.

This report found that there are opportunities to encourage greater development of gas fields through the **taxation** framework. One reform proposed in this report is the introduction of a flow through share scheme, which would essentially enable the transfer of tax deductions of individual exploration companies to individual investors. This could attract external investors rather than being accumulated tax losses, which will only be realisable if the company earns taxable income. It is argued that such a reform would provide a significant incentive for junior exploration companies to develop fields on which they have a licence.

Approvals processes are often cited as a key impediment to timely project development. Approvals are complex, and often lengthy and uncertain. Duplication between levels of government adds to these problems. The report has found that while the Commonwealth and the State Government have taken steps both individually and together to reform approvals processes, there is more that needs to be done, particularly by the State Government. The growing involvement of local government in approval of major projects also threatens to make some of the processes more rather than less complex.

The **joint marketing** arrangements of the North West Shelf (NWS) venture were identified as another issue that reduces competition in the supply of gas to the domestic market. In 1998, the ACCC authorised the joint marketing arrangements of the NWS Venture, accepting the view that separate marketing was impractical or unachievable. While the Authorisation enabled each of the applicants to jointly market and sell natural gas with protection under the *Trade Practices Act 1974* (TPA), the Act itself does not mandate that all joint marketing ventures are required to seek an authorisation. As a result, the NWS Venture did not seek a new authorisation from the ACCC for their coordinated marketing beyond August 2005 based on their belief that their gas marketing practices meet the requirements of the TPA.

The centrally important consideration in ACCC joint marketing determinations is whether it is practically feasible at the time of the application for separate marketing rather than joint marketing to occur in the relevant market. At present, there appears to be a substantial variance in views regarding whether the WA gas

market has made separate marketing a more feasible opportunity since the ACCC determination in 1998.

Gas Transmission

In relation to the transmission of gas to the domestic market, a constraint that has been identified in the report is **pipeline capacity**. Additional investment into pipeline capacity in Western Australia is constrained by the *Gas Pipeline Access (Western Australia) Act 1998* which incorporates the National Third Party Access Code for Natural Gas Pipeline Systems. The manner in which these laws regulate the price of access (through formal access arrangements) is the main obstacle to investment.

The interpretation of reference tariffs by regulators has been found to create a psychological barrier in the minds of access seekers, such that any agreement negotiated at a price higher than the reference tariff is perceived as being too high. Therefore, the access regime often impinges on commercial negotiation, and on many occasions, access agreements tend to take place at a price equal to, or near the regulated access price.

Although reforms to the Code are currently underway in the form of a draft Gas Legislative Framework supplemented by a set of National Gas Rules, it is debatable whether the framework will actually deliver better outcomes in terms of encouraging efficient investment into pipeline capacity. In this regard, further amendments to the new set of regulations are encouraged in order to deliver meaningful reforms to the gas transmission sector, particularly in relation to the proposed 'light' regulation provisions, and incentives for Greenfield developments.

Pipeline capacity can also be increased by varying the regulated **pressure limitations** on natural gas pipelines. The report has found that an opportunity exists for current limitations to be amended (provided that it does not compromise safety), which may then provide a viable short-term solution to raising pipeline capacity in WA, and meeting unmet demand for gas.

Gas **quality specification** has also been found to serve as an impediment to the development of gas reserves in Western Australia. The quality of gas can vary markedly from one field to another and quality from existing producing fields can itself vary over the life of the field. This means that any field (undeveloped and developed) which falls below the minimum specification cannot be transmitted along the pipeline without having its composition amended.

The report found that there remains scope for a **broadening** of the gas specifications (specifically on the Dampier Bunbury Pipeline) as a means to encouraging further development of gas fields in Western Australia. While there

are valid arguments both for and against a further broadening in the specification, this should be analysed with reference to a supply chain wide cost benefit analysis. Any further widening of the gas specification would need to involve a fair tariff adjustment so that pipeline owners could recoup any losses incurred as a result of lower transportation capacity and increased operating costs.

Gas Consumption

The key issue that emerged in the supply chain analysis with respect to consumers concerned their competitive positioning relative to each other, and relative to suppliers.

One option explored in the report was the introduction of **aggregation**. It is suggested that aggregating loads would increase the availability of gas to smaller customers, and would also provide a catalyst for new field developments, therefore bringing extra supplies onto the market in a more timely fashion.

Demand aggregation is already undertaken by gas retail companies. However, these entities currently do not aggregate on a scale necessary to meet the demands of some industrial users. While it has been suggested by some industry participants that this function could be undertaken by a state purchasing entity, it remains to be seen whether there exists a market failure which would justify the government intervening in the market in such a way. That said, there may be scope for an aggregation role (in some form or scale) to be undertaken by a government trading enterprise.

It also remains to be seen whether a private purchasing entity would initially have the capacity to assume significant credit support requirements on behalf of its buyers while maintaining a margin in on-selling that does not price some buyers out of the market.

An Overall Energy Policy

The range of issues identified across the whole gas supply chain highlights the need for this issue to be considered in the context of an overall energy policy – one which looks at energy supply through the entire supply chain, and across different sources of energy.

An overall energy policy would allow the development of a coherent and consistent policy framework that would deliver superior outcomes for the State than any ad hoc approaches.

To be effective, overall energy policy would also need to be agreed nationally, ensuring that those dimensions of energy policy (such as the taxation policy framework) are addressed by the relevant level of government.

Action Agenda

Decisions regarding future domestic gas supplies need to be undertaken today in order to address what is increasingly becoming a critical issue for the future growth and development of the Western Australian economy.

This report has found that there is a range of issues that require immediate consideration, which collectively could help to bring new supplies to the domestic market:

1. In relation to retention leases, the Government must decide whether the designated authority will actively and as a matter of course seek information from interested or relevant third parties (i.e. both gas developers and customers) to a retention lease decision as a means of further testing assertions contained in the relevant lease application.

2. Rather than making statements at large regarding the generalities of the retention lease system, individual third parties with a perceived interest in the grant of any given retention lease should at an early stage decide whether to take the opportunity to put a view to government and make submissions to the designated authority as to whether a particular retention lease should or should not be granted.

3. The Commonwealth Government should introduce a flow through share scheme in order to provide a significant incentive for junior exploration companies to develop fields on which they have a licence.

4. The Commonwealth and WA state governments should outline an ongoing program to streamline approvals processes and investigate the extent to which local governments are further complicating approvals processes.

5. If it is deemed that the joint marketing arrangements are adversely impacting on competition in the supply of gas to the domestic market, this needs to be tested by the ACCC.

6. The WA Government should investigate the extent to which pipeline capacity is being inhibited by the governing legislation, and whether there exists an opportunity to vary pressure limitations to further increase capacity.

7. The WA Government should investigate the scope to which gas quality specifications can be broadened in order to stimulate gas field developments which under the current specifications could not be transmitted on the pipelines, taking into consideration the impact on feedstock users of gas.

8. The WA Government should initiate a process to develop a state energy policy in consultation with industry.

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The Natural Gas Market in WA

Characteristics of Gas

Formation and Location

Natural gas is a fossil fuel found in reservoirs deep beneath the surface of the earth and beneath the ocean floor. Fossil fuels form as organic matter (i.e. the remains of a plant or animal) which has been compressed under the earth, at very high pressure for long periods of time. Over time, sediment formations pile on top of the organic matter, placing pressure on the matter and compressing it.

This compression, combined with high temperatures underneath the earth, break down the carbon bonds in the organic matter, producing both oil and gas. At lower temperatures (shallower deposits), more oil is produced relative to natural gas, while more natural gas is created at higher temperatures. This process occurs continuously and naturally over long periods of time.

Reflecting this, raw natural gas can come from oil wells, gas wells and/or condensate wells. Natural gas that comes from oil wells is typically termed 'associated gas', and can exist separate from oil in the formation (known as 'free gas'), or dissolved in the crude oil ('dissolved gas'). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'non-associated gas'.

Western Australia has a mix of both associated and non-associated fields currently in production, development or under consideration. The Angel gas and condensate field currently under development in the Carnarvon Offshore Basin is an example of an associated deposit, containing both oil and gas elements, while the Pluto gas field (also in the Offshore Carnarvon Basin) is a non-associated deposit, containing little condensate.

Geology

The geology of gas fields can vary markedly and this can have an effect on the economic viability of a project. Fields are generally formed as methane from organic matter rises up into geological formations that 'trap' the gas under the ground.

These formations are made up of layers of porous, sedimentary rock, with a denser, impermeable layer of rock on top. The impermeable layer traps the natural gas underground. There are a number of different types of these formations, but the most common is created when the impermeable sedimentary rock forms a 'dome' shape, with the oil and gas rich sediment forming a reservoir underneath the dome-shaped impermeable rock.

Such deposits are arguably the easiest to tap, although this depends on the depth at which the gas is located. At reasonable depths, the gas can be accessed by drilling a hole through the impermeable rock to release the fossil fuels under pressure. In reservoirs that contain oil and gas, the gas is found closest to the surface (because it is the least dense) with the oil beneath it, typically followed by deposits of water.

In addition to being found in a traditional reservoir such as the one described above, natural gas may also be found in other unconventional formations which typically entail higher extraction costs. Generally, this relates to the depth of the resource, its permeability and the pressure it is under.

Chemical & Physical Properties

Natural gas can be defined as a gaseous fossil fuel consisting primarily of the hydrocarbon, methane. It also contains heavier gaseous hydrocarbons such as ethane, propane and butane, as well as impurities such as carbon dioxide, sulphur dioxide and inert gases like nitrogen and helium.

Although methane is the primary component of gas, it is important to note that gas is not a homogenous commodity. No one gas field is the same in terms of its chemical content (Table 1).

Indeed, the proportion of methane in a reservoir of gas can vary between 70 per cent and 90 per cent, while the content of other hydrocarbons can make up as much as 20 per cent. Conversely, carbon dioxide can make up as much as eight per cent, although some fields can have much higher carbon dioxide contents than this indicative figure.

The chemical composition of a gas deposit has an impact on the economic viability of various fields, as natural gas must be processed in order to separate the various hydrocarbons and fluids from the raw gas to produce what is known as ‘dry’ natural gas (or ‘pipeline quality’ gas).

Table 1
Typical Chemical Composition of Natural Gas

Component	Symbol	Proportion
Methane	CH_4	70 to 90%
Ethane	C_2H_6	0 to 20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0 to 8%
Oxygen	O_2	0 to 0.2%
Nitrogen	N_2	0 to 5%
Hydrogen sulphide	H_2S	0 to 5%
Rare gases	Ar, He, Ne, Xe	Trace

Source: Natural Gas Supply Association

Major transportation pipelines, such as the Dampier to Bunbury Natural Gas Pipeline, usually impose restrictions on the composition of the natural gas that is allowed into the pipeline. This means that before the natural gas can be transported it must be purified via processing which usually involves stripping out oil and condensate (if applicable), ethane, propane, butane, pentanes

and carbon dioxide. As an example, gas from the Scarborough field in the Carnarvon Offshore Basin is low in carbon dioxide (believed to be less than one per cent), while the Pluto field similarly contains low levels of carbon dioxide, as well as small amounts of condensate.

In contrast, the greater Gorgon fields are believed to contain between 12 per cent to 15 per cent carbon dioxide, which makes the economics of the Gorgon field more difficult, particularly in relation to disposal of the carbon dioxide prior to processing.

Traditionally, the reservoir of carbon dioxide is vented into the atmosphere, adding to a development's greenhouse gas emissions. In the case of the Gorgon project, the partners have undertaken to reduce these emissions by disposing of the carbon dioxide through injection into the earth's subsurface – a technique often referred to as 'geo-sequestration', although this can be a very costly exercise.

In terms of its physical properties, natural gas is colourless, shapeless and odourless in its pure form. There are two reasons for its attractiveness as a commodity: (1) its latent energy potential, as natural gas releases a large amount of energy when combusted (one cubic foot of dry natural gas yields approximately 1.1 mega joules of energy when burned); and (2) as a source of hydrocarbons as building blocks for the production of chemicals.

The attraction of natural gas over other traditional fossil fuels lies in its environmental benefits. Per unit of energy released, natural gas produces much less greenhouse gas than other fossil fuels such as oil and coal.

As an example, it is estimated that in producing an equivalent amount of heat, burning natural gas produces about 30 per cent less carbon dioxide than burning petroleum and about 45 per cent less than burning coal.

Measurement

Natural gas can be measured in a number of different ways. It is often measured by the volume it takes up at normal temperatures and pressures, commonly expressed in cubic feet. One cubic foot is equal to approximately 28 litres.

In Australia, most market participants measure natural gas in thousands of cubic feet (Mcf), millions of cubic feet (MMcf), billions of cubic feet (Bcf) or trillions of cubic feet (Tcf).

In other jurisdictions, natural gas is normally measured on an energy basis. In the United States for example, natural gas is commonly measured and expressed in British thermal units (Btu).

One Btu is the amount of natural gas that will produce enough energy to heat one pound of water by one degree at normal pressure. By way of example, one cubic foot of natural gas contains about 1,031 Btu's.

Gas is also often expressed in terms of joules, which like Btu's is a measurement of energy. One mega joule of energy (one million joules) is equivalent to 955 Btu's or 0.92 cubic feet of gas. The energy measurement of joules can also be expressed in giga joules (one billion joules), tera joules (one trillion joules) or peta joules (10^{15} joules).

Gas is also often expressed in terms of cubic metres (m^3). One cubic metre of gas is equivalent to approximately 35 cubic feet of gas and 36,409 Btu. It is also equivalent to approximately 38 mega joules.

A History of Natural Gas in Western Australia

Western Australia is rich in natural gas with a total endowment of around 112 Tcf (at a 50 per cent recovery level). By this measure, Western Australia currently holds approximately 80 per cent of the nation's total reserves of natural gas[i].

Most of the state's endowment of gas is contained in offshore deposits in the north west of the state. The Carnarvon (83.9 Tcf), Browse (26.5 Tcf) and Bonaparte Basins (WA share of 2.3 Tcf) together account for most of the 112 Tcf of total gas reserves in WA. Meanwhile, the Perth Basin contains around 0.05 Tcf of gas.

Exploration

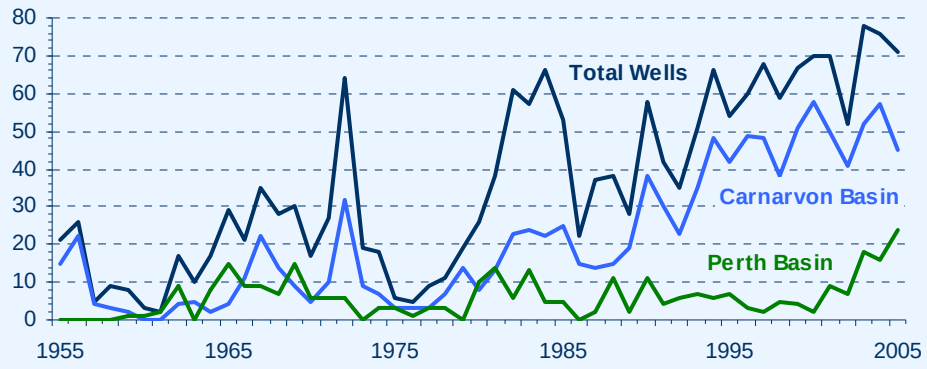
Western Australia has very high rates of exploration success for natural gas. Drilling an exploratory well both onshore and offshore is an expensive, time consuming effort, and the decision to drill depends on a variety of factors, not least of which is the economic characteristics of the potential gas reservoir (see page 32 for a discussion of field economics).

Given the significant costs entailed in drilling, as well as the inherent risk that no hydrocarbons may be found, exploratory wells are only drilled in areas where geological survey data has indicated a high probability of formation.

According to the Australian Bureau of Statistics (ABS)[1], over $5.4 billion has been expended on petroleum exploration in Western Australia over the past decade,

[i] It should be noted that references to WA gas includes gas that is within the Western Australian jurisdiction as well as gas in adjacent waters under Commonwealth jurisdiction. Most of WA's gas reserves fall in adjacent waters under Commonwealth jurisdiction.

Chart 1
Petroleum Wells Spudded in Western Australia
Number of Wells by Year and Basin



Source: DOIR, CCI Economics

which accounts for almost 60 per cent of petroleum exploration expenditure nationally during this period. This includes oil and gas exploration spending, as the ABS does not have a breakdown of investment by oil and by gas.

Exploration activity is very volatile from year to year, however, expenditure in WA has generally increased over time, rising by an average of 9.3 per cent each year over the past decade. Some $594 million was spent on petroleum exploration in Western Australia during 2005-06 alone, representing an increase of almost 13 per cent on the previous year.

These costs include exploration, determination of recoverable reserves, engineering and economic feasibility studies, procurement of finance, gaining access to reserves, construction of pilot plants and all technical and administrative overheads directly associated with these functions.

The concentration of petroleum exploration spending in WA reflects the state's rich endowment of hydrocarbons both onshore and offshore, while the large amount expended in petroleum exploration explains the large volume of known natural gas reserves here.

Indeed, Western Australia had 115 separate fields containing oil, condensate and/or natural gas at the end of 2005. The amount of wells spudded[2] also illustrates the extent of exploration activity in WA (Chart 1). Generally, wells are spudded where geological survey data indicate a high probability of formation.

Spudding has risen since the mid 1980s, with most of these wells located in the Carnarvon Basin. Given the estimated size of reserves in this basin (a total of 83.9 Tcf), much of the exploration in this area is likely to be focussed on uncovering large deposits of oil and gas conducive to the export market.

Table 2
Significant Gas Discoveries in WA

Year	Field/s
1964	Yardarino
1966	Dongara
1968	Legendre North
1971	North Rankin, Angel, Torosa
1972	Goodwyn
1973	West Tryal Rocks
1979	Brecknock, Scarborough
1980	Brewster, Gorgon
1989	Chinook/Scindian
1993	East Spar
1994	Chrysaor
1995	Wonnich
1996	Dionysus, Perseus
1998	Rose, Legendre South, John Brookes
1999	Geryon
2000	Linda, Janz, Calliance, Wheatstone
2001	Io
2002	Endymion
2005	Pluto
2006	Chandon, Clio

Source: DOIR, CCI Economics

However, exploration in the smaller Perth Basin tends to be exclusively aimed at discovering reserves for the domestic market. Spudding in the Perth Basin has risen in the past four years, with a record number of wells (24) spudded in this basin during 2005 out of a total of 71 wells spudded during that year.

While it is difficult to ascertain exactly how many of these wells were drilled with the specific intention of locating gas, it should be noted that most exploration activity in this area is primarily aimed at oil discovery.

The successful location of gas often does not guarantee immediate development and extraction of a new field.

Market conditions ultimately dictate how quickly a field should be developed, and if a discovery is not commercially viable for immediate development but is likely to be commercially viable some time in the future, then the exploration permit holder is normally granted a retention lease over the area pending development. In Australia, a retention lease may be granted for a five-year term with renewal periods every five years. The lease provides a security of title to the resource in recognition of the significant outlay made by the exploration permit holder in locating the field.

Indeed, a high proportion of Western Australia's known reserves of natural gas are currently held under retention lease.

Table 2 illustrates the major natural gas discoveries in Western Australia over time. The success of oil and gas exploration is clearly evident, with significant discoveries made at regular intervals over the past 40 years.

Major Producing Projects and Pipelines

Perth Basin

Large-scale exploration for oil and gas began in Western Australia in 1952 when West Australian Petroleum Pty Ltd (WAPET) was formed to operate on behalf of

oil majors Ampol and Caltex. WAPET began operating in the onshore Carnarvon, Canning and Perth basins.

WAPET made its first major gas discovery in 1964, encountering natural gas in the onshore Perth Basin in the form of the Yardarino field – the same year it struck oil on Barrow Island. While the state's first commercial oil field commenced production in 1967 on Barrow Island, the small size of the Yardarino field meant gas production from the field did not commence until October 1978.

In 1966, the much larger Dongara gas field was discovered in the Perth Basin by WAPET. The Dongara field had an original recoverable reserve of some 0.44 Tcf of gas – roughly 900 times larger than the Yardarino field. While the Dongara field was of sufficient size for commercial extraction, its development also required complimentary investment in associated greenfield infrastructure.

The Dongara Gas Processing Facility was constructed in the early 1970's in line with the commissioning of production from the Dongara field, and the facility (now owned by ARC Energy) remains the largest in the Perth Basin providing gas separation, dehydration, and compression.

The 416 kilometre Parmelia Transmission Pipeline was also completed in 1971 to coincide with the commissioning of production at Dongara. The pipeline extends from Dongara, south of Geraldton to Pinjarra, and has an average installed capacity of up to 65TJ/day.

Originally known as the Western Australian Natural Gas (WANG) Pipeline, the Parmelia line was the sole pipeline supplying natural gas to residential, commercial and industrial customers in the Perth metropolitan area and southwest (to Pinjarra) at the time. This infrastructure was owned and operated by WAPET, but has since changed hands.

Although this pipeline is not as large as other pipelines which currently operate in WA, it is strategically important for the state as it services smaller industrial customers in the Perth metropolitan area and the south west.

With the Parmelia pipeline in place, commercial production from the Dongara field commenced in 1971. Over 35 years later, the Dongara field still supplies gas to the domestic market.

Several other commercial gas fields have been developed in the Perth Basin since the discovery of the Dongara field in 1966. Fields including Woodada, Beharra Springs and Xyris continue to supply gas to the domestic market, with a particular focus on servicing smaller industrial users.

North West Shelf

In 1963, the year prior to the discovery of the Yardarino field, Woodside Petroleum secured exploration permits for areas off the North West of the Western Australian coast. Offshore exploration for oil and gas had begun some years earlier in 1961, with seismic surveys being conducted by WAPET, although this was concentrated in the smaller area of the Exmouth Gulf.

After several years of exploration, oil was discovered at Woodside's Legendre (number 1) well in 1968. This was the first discovery of offshore hydrocarbons in WA. However, the drilling program showed only a small deposit of oil, which was considered non-commercial at the time.

However, it gave Woodside the impetus to continue exploring offshore, and in 1971, Woodside discovered a major gas field in the Carnarvon Basin, some 130 kilometres north-west of Karratha.

The fields became known as North Rankin and Angel, and this discovery was followed in 1972 by the Goodwyn gas field, which is located 23 kilometres south west of the North Rankin field.

Together, these fields contained reserves of nearly 50 Tcf of natural gas – one of the biggest reserves in the world - and considerably larger than the Dongara field (0.44 Tcf), which was the largest gas discovery in WA until this time.

These initial discoveries by Woodside provided the basis of the $19 billion North West Shelf Venture, Australia's largest natural resource development.

The North West Shelf Venture comprises six internationally recognised companies, with each participant holding an equal 1/6th share in future gas sales (subject to various joint venture arrangements).

The participants are BP Developments Australia Ltd, Chevron Australia Pty Ltd, Japan Australia LNG (MIMI) Pty Ltd, Shell Development (Australia) Ltd, BHP Petroleum (North West Shelf) Pty Ltd and Woodside Energy Ltd. Woodside is the Operator of the project.

The Western Australian Government played a major role in assisting the development of the North West Shelf reserves. Through its energy utility, the (then) State Energy Commission of WA (SECWA), the state government underpinned the development of the North Rankin field in 1977 by signing long-term 'take-or-pay' contracts to purchase natural gas from the project for domestic consumption for a period of 20 years.

With this initial State Agreement in place, the project was developed between 1980 and 1984 at a cost of $2.5 billion, including an on-shore gas processing plant on the Burrup Peninsula, near Dampier.

Key to the development of this offshore resource in the 1980s was the construction of the Dampier to Bunbury Natural Gas Pipeline (DBNGP), although at the time the line stretched only from the Burrup Peninsula to the Kwinana industrial area, located 40 kilometres south of Perth.

This stretch of pipeline was commissioned in 1984, with deliveries of natural gas from the North West Shelf to customers in Western Australia commencing soon afterwards. It was only one year later that the pipeline extension south to Bunbury was commissioned, taking the total length of the mainline to approximately 1,596 kilometres.

The DBNGP is the longest pipeline in Western Australia and the market which it services in the south west is primarily a market for energy as opposed to feedstock and domestic usage[3]. While some supply is used for these purposes, it represents a very small proportion of total gas transfer in this line. The current average installed capacity of the pipeline is 710 TJ/day, which rose to 735 TJ/day upon completion of the stage 4 expansion by the current joint owners.

As mentioned, the development of the DBNGP was initially undertaken by the state government through its energy utility, SECWA and with the support of Alcoa and the Commonwealth Government. However, the state government sold the pipeline to Epic Energy in 1998, and in October 2004 the pipeline was subsequently purchased by the current joint owners - Diversified Utilities and Energy Trusts (60 per cent), Alcoa (20 per cent) and Alinta (20 per cent).

The initial discoveries by Woodside in the Carnarvon Basin which formed the backbone of the North West Shelf development were followed by later discoveries of the Echo field in 1988, the Yodel field in 1990 (often referred to collectively as the Echo-Yodel field) and the Perseus gas field in 1996. The latter two fields both commenced production in 2001, while development of the Angel gas field commenced in late 2005 at a cost of $1.6 billion.

Initially, the remainder of gas produced from the North West Shelf was exported to overseas markets under the branding of Australian Liquefied Natural Gas (ALNG). This began in 1989 under 20-year contracts with eight power and gas utilities in Japan, although several other contracts have ensued since then.

Today however, the volume of LNG sales dominates domestic gas sales, with approximately 7.7 billion cubic metres of natural gas (or 0.27 Tcf) supplied to the WA domestic market in 2005-06, compared to around 17.1 billion cubic metres of equivalent gas (or 0.41 Tcf) shipped overseas in liquefied form.

Although the discovery of the North West Shelf fields in the 1970s spurred further offshore exploration for gas, the North West Shelf project is currently the only LNG project in Western Australia.

East Spar and Harriet Area

With the North West Shelf Venture and SECWA firmly established as the key players in the domestic gas sector, a key milestone in the evolution of the domestic gas market occurred in the early 1990s with the development of the East Spar and Harriet area fields.

Apache Energy discovered the East Spar field in April 1993 in the offshore Carnarvon Basin, northwest of Barrow Island. Production from the field commenced in November 1996, with Apache and Santos Limited, operating as joint venture partners in the project.

Meanwhile, the Harriet area fields, owned by Apache, Tap and Kufpec Australia, had been producing gas for a number years before East Spar commenced.

This consortium used Varanus Island as the production base for its oil, condensate and gas processing activities. The current total gas processing capacity on Varanus Island is 480 tera joules per day (TJ/d). The Harriet gas-gathering project had been commissioned in July 1992 and was the state's first offshore gas project to tap associated gas, which is produced during the oil recovery process.

The project currently involves the transport of gas from a number of fields, including Bambra, Endymion, Linda, Rose and Sinbad, as well as associated gas from the oil fields.

At the time that East Spar was being assessed, the state government was seeking interest in the construction of a pipeline to the Goldfields. The right to build and develop the Goldfields Gas Pipeline (GGP) was eventually awarded to a joint venture comprising Wesminco Oil Pty Ltd, Normandy Pipelines Pty Ltd and BHP Minerals Pty Ltd, together with Western Mining Corporation and Normandy Poseidon.

However, during the development of the GGP, the SECWA gas contracts with the North West Shelf Partners were restructured upon facilitation by the state government. This restructuring, in conjunction with the development of the major new Goldfields pipeline, was the catalyst for a marked shift in the domestic gas market, as smaller gas developments had the opportunity to increase production and capture a slightly larger share of the domestic gas market.

The East Spar gas field was subsequently developed as part of the GGP project, and this field (along with other smaller fields, including the Harriet Area fields)

were successful in securing new gas supply contracts with numerous users along both the GGP and the DBNGP.

The GGP also originates from the North West Shelf, and stretches 1,380 kilometres south east to Kalgoorlie. The pipeline has an average installed capacity of 130 TJ/day per day and mostly services mining operations along its route, with eight laterals and spurs before the line reaches Kalgoorlie.

These developments resulted in key changes in the state's gas industry by shifting away from the long term gas contracts so prevalent in the industry at the time, to multiple supply contracts of different periods, as well as different pricing and supply options.

The East Spar project was also landmark in terms of its infrastructure sharing, with sales gas from both the East Spar and Harriet area fields transported from the processing facilities on Varanus Island to the mainland through either of two pipelines - one of which was jointly commissioned by the East Spar (70 per cent) and Harriet (30 per cent) joint ventures in July 1999.

In addition, the two ventures also entered into an infrastructure-sharing agreement whereby the Harriet gas transportation and liquids storage facilities on Varanus Island can be utilised by the East Spar joint venture, while it was also agreed to share the cost of all operating resources and contract services between the projects.

This was the first infrastructure-sharing agreement made in the North West Shelf gas province.

John Brookes

Following on from East Spar, the John Brookes field has been the only major addition to the state's domestic gas supplies. John Brookes is located in the Carnarvon offshore basin, some 60 kilometres northwest of Varanus Island and is jointly owned by Apache and Santos.

It is one of the largest producing fields at present, although gas did not flow from the development until September 2005, despite it being discovered in 1998. The field is located some distance from Santos' existing facilities at Varanus Island, although it was fast-tracked to meet growing demand for energy from new and existing WA projects.

Key to the development of this field was its proximity to existing infrastructure, with a pipeline built to link the wellhead platform to the existing Varanus Island gas treatment facilities, while the East Spar gas plant was also 'de-bottlenecked' to handle gas from the John Brookes field.

Aside from the Parmelia, DBNGP and GGP, a fourth major downstream transmission pipeline exists in the state's northwest. Stretching 219 kilometres from Karratha to Port Hedland, the Pilbara Energy Pipeline (PEPL) has an average installed capacity of 188 TJ/day and transports gas from the North West Shelf to Port Hedland.

Owned by Epic Energy, the line was built to service Alinta's power stations at Port Hedland and the Port Hedland to Telfer gas pipeline. It previously also serviced BHP Billiton's Boodarie Hot Briquetted Iron (HBI) plant, before its official closure in August 2005.

Other major downstream transmission pipelines in WA include the Kambalda to Esperance Gas Pipeline (6TJ/day), the Mid West Pipeline (20TJ/day), the Kalgoorlie to Kambalda lateral (20TJ/day) and the Telfer Gas Pipeline (25TJ/day).

Future Major Projects

Gas exploration and development in Western Australia has developed undoubtedly since the early failures and frustrations of the 1950s.

Nearly 25 billion cubic metres of gas (or 0.87 Tcf) was sold domestically and to overseas buyers in 2005-06 – four times the amount sold in 1989-90 when exports of LNG commenced. The state had a total endowment of 112.4 trillion cubic feet (Tcf) of natural gas as at 31 December 2005, giving it a 1.8 per cent share of global reserves.

Although WA contains only a small share of world reserves, there is scope for further development with several major projects currently under consideration. Most of these involve supplying LNG to the export market.

The largest of these projects is the Gorgon area fields. These deposits were discovered in 1973 by WAPET at West Tryal, located south west of the North Rankin and Goodwyn fields. Over the next two decades, five fields were discovered – Gorgon, Chrysaor, Dionysus, West Tryal Rocks and Spar - collectively termed the Greater Gorgon area. Today, the deposits are owned by ExxonMobil and Chevron in a joint venture agreement.

The Greater Gorgon area is one of the largest gas deposits in the world, with an estimated 43.8 Tcf of natural gas. Plans have been underway to develop the Gorgon fields for many years, although the location of the fields and the carbon dioxide content of the gas make them more difficult to develop than other fields.

A further LNG project is being considered in the Carnarvon Basin, drawing gas from the Scarborough field located 270 kilometres northwest of Onslow (as well as other existing and potential gas resources in the area).

BHP Billiton estimates the Scarborough and associated gas fields contain a proven plus probable gas resource in excess of 8 Tcf. Pre-feasibility studies for an LNG project commenced in January 2004, while a preferred site (4.5 kilometres southwest of Onslow) has already been chosen for the planned gas-processing, liquefaction, storage and export facilities.

Significant discoveries have also been made in the Browse Basin, with the Brecknock, Calliance and Torosa fields believed to contain up to 21 Tcf of gas. The deposits have been earmarked for a future LNG project (Browse LNG).

The deposits are owned by a consortium including Woodside and BHP Billiton, although as operator, Woodside has been working on project development concepts and marketing of the gas reserves. A key issue in the development of Browse LNG is the distance of the deposits from existing infrastructure. The fields are located around 425 kilometres north of Broome.

Also in the Browse Basin, around 9.5 Tcf of gas is believed to be contained in the Ichthys deposits (Brewster and Plover), which is owned by INPEX Browse Ltd. Plans to develop the project have been underway, with the project having been granted 'Major Project Facilitation' status by the Commonwealth Government. It aims to produce up to 6 million tonnes of LNG each year for export.

While the deposit also contains associated LPG and condensate, its distance from existing infrastructure (the field is located 440 kilometres north of Broome) is also believed to be the main hurdle in advancing the development.

More recently, Woodside discovered the Pluto gas field in April 2005, located approximately 180 kilometres from the Burrup Peninsula. It contains around 4.1 Tcf of gas, making it conducive to export. Woodside plans to develop LNG facilities on the Burrup Industrial Estate to produce five to six millions tonnes of LNG per annum from the field. A final investment decision on the development is planned for mid 2007.

Developments aimed solely at servicing the domestic gas market are also being considered in Western Australia.

The Macedon project joint venture (comprising BHP Billiton and Apache Energy) is seeking to draw gas from the Macedon field, located 40 kilometres north of Exmouth in the Carnarvon Basin. The joint venture estimates that the Macedon field contains a gas resource of up to 1.2 Tcf.

However, gas recovered to date is dry, containing no condensate or LPG meaning the project's economics are less favourable (see page 32 for a discussion of project economics). The resource size and composition suggest development is suited to service the domestic market, as either industrial gas feedstock for power generation, or for commodity chemicals such as methanol or ammonia-urea.

A major hurdle for this project is the specification of the Macedon gas, which falls outside of the minimum requirement currently set for the DBNGP. This pipeline is closest to the project's potential onshore facility (the existing Griffin/Tubridgi facility). The issue of gas specification with regard to the DBNGP is discussed in further detail on page 126.

Aside from the Macedon project, another potential domestic gas development is currently being considered involving development of the Reindeer gas field. This field is jointly owned by Apache Energy and Santos, and is located north west of Dampier, and just south of some of the major fields which make up the North West Shelf project.

The joint venture estimates that the Reindeer field contains gas reserves of around 0.4 Tcf, although the field's distance from existing infrastructure appears to be the main obstacle to developing the field further.

Although the field is close to the existing infrastructure of the North West Shelf project, it is far from the joint venturers' existing facilities at Varanus Island. Development options, such as a tie-in to the Varanus Island facilities or direct to the mainland, are currently being investigated.

Gas Reserves and Supplies

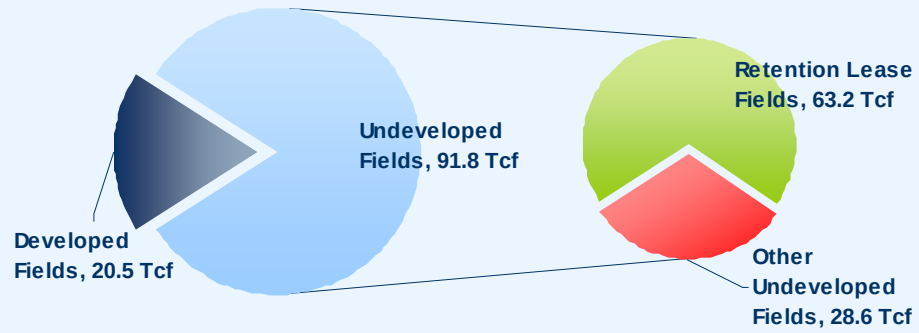
Reserves

According to estimates by the Department of Industry and Resources of Western Australia (DOIR), the state had a total endowment of 112.4 trillion cubic feet (Tcf) of natural gas as at 31 December 2005.

This figure includes all known fields, which are generally classified as developed or undeveloped. Within undeveloped fields, deposits can be further classified as retention lease resources.

Fields held under retention lease are viewed as being not currently viable, while the remaining undeveloped fields have a greater scope to be developed in the short to long term. Developed fields meanwhile are currently producing gas and may be located offshore in either Commonwealth or state waters, or onshore within Western Australia.

Chart 2
Natural Gas Reserves in Western Australia (P50)
Volume of Reserves by Type, 31 December 2005



Source: DOIR, Tcf - Trillions of Cubic Feet

Fields are further classified according to their probability of resource recovery. The estimate of 112.4 Tcf of gas in WA captures the deposits of those fields with at least a 50 per cent probability of recovery (termed 'P50'). However, just over 64 per cent of the 112.4 Tcf (i.e. 72.2 Tcf) of total reserves is accounted for by gas deposits characterised by a recovery probability of at least 90 per cent.

At P50, Western Australia currently holds approximately 80 per cent of the nation's total reserves of natural gas.

Most of the state's endowment of gas is contained in offshore deposits in the north west of the state. The Carnarvon (83.9 Tcf), Browse (26.5 Tcf) and Bonaparte Basins (WA share of 2.3 Tcf) together account for most of the 112 Tcf of total gas reserves in WA. Meanwhile, the Perth Basin contains around 0.05 Tcf of gas.

Outside Western Australia, the largest gas deposit is located in the Northern Territory portion of the Bonaparte Basin (20.4 Tcf), while the next biggest deposit is held in Victoria's Gippsland Basin (3.1 Tcf).

World proven reserves of natural gas were estimated at approximately 6,182 Tcf as at 1 January 2007[4], giving Western Australia a 1.8 per cent share of global reserves in terms of gas deposits with a recovery probability of at least 50 per cent.

Of the 112.4 Tcf of gas reserves in WA, only 18 per cent (or 20.5 Tcf) relates to developed fields. Within this portion, around 90 per cent (or 18.6 Tcf) of the deposits belong to the North West Shelf Venture alone.

Table 3
Fields Held Under Retention Lease (P50)

Field	Operator	Related Project	Tenement Owners	Tcf
Jansz	Mobil	Gorgon Area	Shell, Mobil, Chevron	13.5
Torosa	Woodside	Browse LNG	Woodside, BP, BHPB, Chevron, Shell	11.5
Io	Chevron	Gorgon Area	Shell, Mobil, BP, Chevron	6.3
Brecknock	Woodside	Browse LNG	Woodside, BP, BHPB, Chevron, Shell	5.3
Scarborough	Mobil	Scarborough LNG	BHPB, Esso Australia	5.2
Wheatstone/Iago	Chevron	Wheatstone & Iago	Shell, Chevron	4.9
Calliance	Woodside	Browse LNG	Woodside, BP, BHPB, Chevron, Shell	4.0
Geryon	Chevron	Gorgon Area	Shell, Mobil, Chevron	3.3
Chrysaor/Dionysus	Chevron	Gorgon Area	Shell, Chevron	2.9
West Tryal Rocks	Chevron	Gorgon Area	Shell, Mobil, Chevron	1.7
Orthrus/Meanad	Chevron	Gorgon Area	Shell, Mobil, Chevron	1.2
Macedon	BHPB	Macedon Gas	BHPB, Apache Energy	0.6
Other	-	-	-	2.9
Total	**-**	**-**	**-**	**63.2**

Source: DOIR, CCI Economics

The remaining 82 per cent (or 91.8 Tcf) of the state's P50 gas resources are located in undeveloped fields. Of this, retention lease resources account for 69 per cent (or 63.2 Tcf) of the 91.8 Tcf of gas held in undeveloped fields.

Retention lease resources make up 56 per cent of the state's total endowment of P50 gas resources. Notably, a large proportion of WA's gas deposits currently under retention lease relate to two projects in particular.

Nearly 46 per cent of the 63.2 Tcf under lease relate to the Greater Gorgon area, while approximately one-third relates to the Browse LNG project. The collective sizes of these fields and their close proximity to one another make them ideally suited to LNG production. Indeed, of the fields currently held under retention lease in WA, only two (Macedon and Wheatstone/Iago) are not firmly attached to an LNG project.

However, the remaining 28.6 Tcf of undeveloped gas resources relate to deposits which are viewed as having some scope to be developed in the short to long term, and some these deposits may be more suited to servicing the domestic market exclusively.

Notably, the analysis above does not include the discovery of gas by Chevron at its exploration wells in the Greater Gorgon area. While detailed information on these fields is not yet available, the Clio deposit (discovered in early November 2006) is believed to hold up to 623 feet (190 meters) of net gas sands, which places Clio as one of the top wells in Australia in terms of total net pay[5].

In addition to the 112.4 Tcf of known reserves in Western Australia, DOIR estimated in December 2005 that there was a further 6.7 Tcf of gas located in fields around the state with some scope for recovery.

Economics of Field Development

Although Western Australia contains significant natural gas reserves, most of these reserves remain undeveloped. Therefore, the key issue to consider is whether these resources could be developed and supplied into the domestic market.

These considerations are largely contingent upon the economics of each gas field development. No one gas field is identical, making the economics of development a complex area. In essence however, there are a number of key issues which have a significant effect on the commercial viability of any one gas field.

Every field development requires special purpose design, which is generally matched to the resource's characteristics in order to optimise the recovery of the resource relative to its development costs.

In general, the optimal production rate of a particular field will be a trade-off between maximising the production rate at a reasonable development cost per unit of production, as well as maximising the recovery factor of the field.

A typical development will aim to recover between 60 per cent and 80 per cent of the gross gas hydrocarbons present in the reservoir (typically referred to as 'gas initially in place').

In this context, there are a number of important factors that determine the development cost and optimal gas production profiles of a given field. These include:

- gas specification, the presence of inert gases such a CO_2 and other impurities, or the presence of high value LPG or condensate as by-product of gas production;
- depth of resource below ground surface and ease of drilling;
- level of 'compartmentalisation' of the resource (requiring discrete production well facilities);
- the permeability of reservoir (gas bearing rocks) and level of water/gas saturation within reservoir;
- presence of aquifer drive and rate of water production associated with gas production;

- pressure of resource/requirement for compression to either recover more gas from the reservoir or export the gas;
- water depth and distance from shore (if offshore);
- topography and terrain (if onshore);
- access to existing infrastructure and services;
- wider environment factors (for example, the case of Gorgon Gas and Barrow Island); and
- other gas market constraints that may reduce the production level below an optimal level for the resource in the context of the above parameters.

The matching of the optimal development to the market is important to understanding the potential viability of gas projects in Western Australia.

Typically a large resource containing a large volume of gas (typically a multiple Tcf resource as many of the fields currently under retention lease are) will have an optimal production rate that requires the field to be produced over ten to 25 years.

In the case of a field containing 5 Tcf, for example, this implies an optimal production rate of between 550 and 1,400 million cubic feet per day, or between 70 per cent and 180 per cent of Western Australia's total rate of current domestic demand.

Hence, for WA's larger undeveloped gas resources it is virtually impossible to achieve an optimal production rate without some form of export project – either LNG or a world scale gas-to-liquids project, as the domestic market is far too small to underpin on its own a development of such size.

This is not to say that the domestic market is a completely unattractive proposition for proponents of major field developments.

Rather, the domestic market provides proponents with an opportunity to earn immediate revenues from the field given the typically long lead times to develop LNG facilities, as well as the high cost of liquefaction and storage of LNG.

This means that for any significant project, the supply of a proportion of gas from the field into the domestic market is to a large extent contingent upon the timing and viability of the export project, which provides the foundation for the overall development of the resource.

Therefore, any factors that delay export from the project in effect risks making less gas available for the domestic market. That is, at least until a combination of gas

price and latent gas demand builds to the point that it can underpin a very large scale domestic development.

The latter scenario prevailed in the establishment of the North West Shelf project, whereby the State Government helped to underpin the export project through committing to purchase significant volumes of gas for the domestic market.

It is also important to recognise that all of the large undeveloped gas resources currently planned for development suffer from a number of factors that increase the development cost and therefore the scale required to achieve a commercial development.

These factors include many of the issues outlined above such as significant water depths, complex reservoirs, the presence of inert gases (Gorgon), long distances from shore (Browse LNG and Ichthys), little or no access to existing infrastructure and services (Reindeer and Macedon) and low levels of condensate (Macedon).

To offset these disadvantages, it is very important to maximise production to a level that is close to an optimal rate for the field. It is this inability to do so that makes so many fields uneconomic to develop.

Supply

Gas supplies to domestic market in WA have risen markedly over time even though most of the state's gas reserves remain in undeveloped fields.

According to DOIR, approximately 25 billion cubic metres of WA gas was sold in 2005-06. Around 7.7 billion cubic metres (or 31 per cent) of this was supplied to the WA domestic market in 2005-06, which is equivalent to approximately 0.27 Tcf or 294.2 peta joules.

Gas supply is often expressed in terms of the amount of energy delivered each day within a calendar year. In the context of WA, the 294.2 peta joules supplied in 2005-06 is equivalent to around 806 tera joules of natural gas per day.

Natural gas supply to the domestic market has risen by an average of 5.6 per cent per annum over the past 20 years to 2005-06. Indeed, the 7.7 billion cubic metres of gas sold domestically in 2005-06 is almost three times the amount consumed in 1985-86.

This rise in supply primarily reflects the growth in supply from the North West Shelf, as well as the development of smaller fields.

Some 19 projects produced gas in Western Australia during 2005. The varying ownership proportions of the fields which make up these projects make it difficult

to ascertain which entities account for exactly what proportion of gas production in WA.

Moreover, although some 19 projects currently produce gas in Western Australia (Table 4), not all of this production is supplied into the domestic market. In some cases the project participants consume most or all of the gas extracted for use within their businesses (often gas is reinjected for improved oil recovery). Table 4 sets out all the gas projects operating in Western Australia during 2005, showing that production is concentrated among only a few projects.

In terms of those that do service the domestic gas market, by far the largest supplier is the North West Shelf Joint Venture. Over the past five years, the North West Shelf Venture has supplied an average of 534 tera joules of gas per day[6] into the domestic market, which accounts for around 65 per cent of total domestic gas supply in each of these years.

The 65 per cent domestic market share accounted for by the North West Shelf project stands in contrast to its 90 per cent share of all developed gas reserves in WA. This 'discrepancy' reflects the fact that this project is also focussed on

Table 4
WA Domestic Gas Production by Project, 2005

Project	Operator	Tenement Owner/s	Bcf	% of Total
NWSJV	Woodside	Woodside, BP, BHPB, Chevron, Shell	184.80	63.5%
Harriet Area	Apache	Apache, Kufpec, Tap Pty Ltd	55.44	19.0%
John Brookes	Apache	Apache, Santos	12.31	4.2%
Legendre	Woodside	Woodside, Apache, Santos	9.85	3.4%
Griffin	BHBP	BHPB, Mobil, Inpex Alpha	7.19	2.5%
Dongara	ARC Energy	ARC Energy	5.39	1.9%
East Spar	Apache	Apache, Santos	3.30	1.1%
Beharra Springs	Origin Energy	Origin Energy, ARC Energy	2.75	0.9%
Wandoo	Vermilion Energy	Vermilion Energy, Wandoo Petroleum	2.49	0.9%
Thevenard Island	Chevron	Chevron, Santos, Mobil	2.03	0.7%
Barrow Island	Chevron	Chevron, Santos, Mobil	1.65	0.6%
Woollybutt Oil	ENI	ENI, Mobil, Tap Oil	1.04	0.4%
Woodada	ARC Energy	ARC Energy	0.86	0.3%
Hovea–Eremia Oil	ARC Energy	ARC Energy, Origin Energy	0.81	0.3%
Stag Oil	Apache	Apache, Santos	0.78	0.3%
Jingemia Oil	Origin Energy	Origin Energy, ARC Energy, Victoria Petroleum Offshore, Norwest Energy, Roc Oil, J.K Geary	0.26	0.1%
Mutineer-Exeter	Santos	Santos, Kufpec, Nippon Oil, Woodside	0.19	0.1%
Tubridgi Gas	BHPB	BHPB	0.04	0.01%
Laminaria–Corallina	Woodside	Woodside, Talisman Oil & Gas, BHPB	0.03	0.01%
Total			**291.2**	**100.0%**

Source: DOIR, BHP Billiton, CCI Economics

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international supplies of LNG, so a portion of its production from these fields is shipped offshore.

The remaining 35 per cent of domestic gas supplies are made up by smaller projects, which are operated by entities including ARC Energy, BHP Billiton, Santos Limited, Apache Corporation and Origin Energy. Over the past five years, these smaller projects have together supplied an average of 282 tera joules of gas per day into the domestic market.

The unbundling of SECWA contracts in the 1990s was central to encouraging the development of these smaller fields, as has been the growth in gas demand both as a source of energy and as a feedstock for the chemical industry in WA over the past 20 years. To a lesser extent, environmental constraints on flaring of gas as part of oil extraction may have also prompted some smaller developments.

In 2005-06, these smaller producers supplied 239 tera joules of gas per day (accounting for 30 per cent of domestic supplies) to domestic consumers, while the North West Shelf supplied 567 tera joules of gas per day to the domestic market (70 per cent of domestic supplies).

Notably, the 567 tera joules of gas supplied to the domestic market by the North West Shelf partners in 2005-06 is higher than the amount agreed to under the initial State Agreement between the partners and the WA Government (the volume of gas 'reserved' for the domestic market under that agreement has now been completely supplied). The initial agreement specified the supply of about 414 tera joules of gas per day to the domestic market over 20 years.

The Harriet area joint venture is the largest of the smaller gas projects currently servicing the domestic market, with DOIR field production data for 2005[7] showing that these associated fields accounted for 19 per cent of domestic gas supply in that year (Table 4), with the North West Shelf making up approximately 63 per cent of domestic supplies during that period.

While more producers have entered the domestic gas market in WA over the past 20 years, supply growth has slowed in recent years (Chart 3). For example, in the ten years to 2005-06, domestic gas supplies in WA have increased by 2.2 per cent per annum, and in the past five years they have grown by only 0.3 per cent each year.

While growth in domestic gas supplies has slowed recently, sales of gas overseas as LNG has risen. Of the 25 billion cubic metres of WA gas extracted and sold in 2005-06, some 17.1 billion cubic metres (or 69 per cent) was exported overseas as LNG[8] (equivalent to approximately 0.60 Tcf). As the only LNG project in Western Australia, all of these export sales relate to the North West Shelf project. Since LNG shipments commenced in 1989-90, supplies of WA gas to overseas markets have risen by an average of 13.4 per cent per annum. Supplies of LNG have grown by 5.8 per cent each year in the past ten years, and by 9.1 per cent in the past five years.

This growth reflects higher demand for WA gas by consumers in Japan and China in particular. However, the pick-up in the growth of LNG supplies and the slowing in growth of domestic supplies can not be pinned on an increasing focus by the North West Shelf partners on overseas markets.

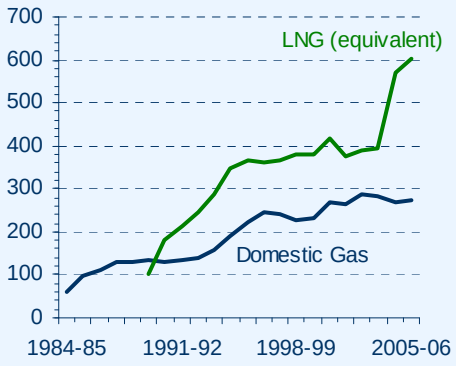
Indeed, gas supplies from this project to the domestic market have increased over the past five years, with supplies rising by an average of 3.6 per cent per annum during this period, including a 9.1 per cent rise in 2005-06 (Chart 4). Notably, growth during the period from 2001 until the sale of the DBNGP to its current owners was inhibited by the general lack of new capacity on the pipeline.

Nonetheless, the growth in supply to the domestic market from this project is primarily likely to reflect higher demand for gas domestically.

In contrast, domestic supplies by producers other than the North West Shelf partners have fallen by an average of 5.3 per cent each year over the past five years (Chart 4). Indeed, non-North West Shelf supplies fell by 14.3 per cent in 2005-06 alone.

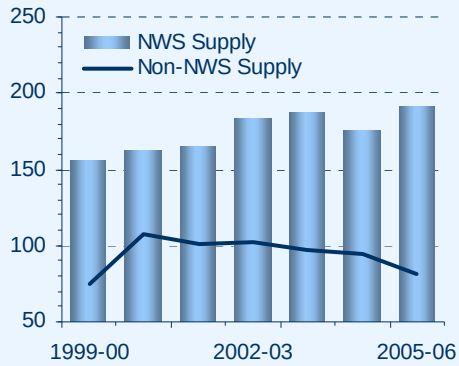
The recent decline in output from smaller projects is likely to reflect the ageing fields from which they extract gas, as well as economic constraints in bringing

Chart 3
Total Gas Supplies in Western Australia
Domestic & Overseas Supply, Bcf/yr



Source: DOIR, CCI Economics

Chart 4
Domestic Gas Supplies in WA
By Supply Source, Bcf/yr



Source: DOIR, CCI Economics

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other smaller fields to market (e.g. Macedon and Reindeer). Indeed, The John Brookes development, which came on stream in 2005, was the only major addition to domestic supply following the development of East Spar in the earl 1990s (excluding output from the North West Shelf project).

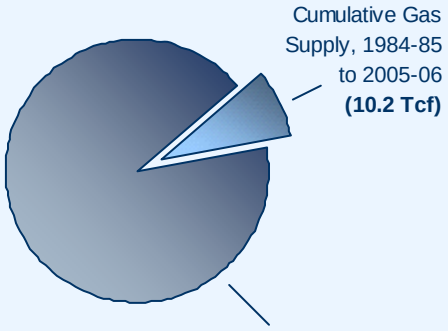
While supplies of natural gas from WA to both domestic and overseas markets have increased over time, it is important to note that the 25 billion cubic metres (or 0.88 Tcf) of natural gas extracted and sold in WA during 2005-06 represents only a small proportion of the state's developed reserves.

As reported above, developed fields in WA held approximately 20.5 Tcf of gas (at the 50 per cent probability level) as at 31 December 2005, meaning that the total volume supplied in 2005-06 represents just 4.3 per cent of all developed gas reserves in the state.

Including all known reserves of gas in WA (112.4 Tcf at the 50 per cent probability level), the amount supplied in 2005-06 represents just 0.78 per cent of reserves.

This illustrates that exploration and development of reserves in Western Australia have risen over time as have gas supplies. Moreover, approximately 10.2 Tcf has been supplied to both domestic and overseas markets since gas supply in WA commenced in 1984-85 (cumulative total). This volume of production represents only 9.1 per cent of total gas reserves in WA as at 31 December 2005 (Chart 5).

Chart 5
Total Gas Reserves & Supplies, WA
Trillions of Cubic Feet (Tcf)



Source: DOIR

Demand for Gas

Western Australia is the single largest natural gas consumer in Australia (Chart 6). According to data collected by the Australian Bureau of Agriculture and Resource Economics (ABARE) on gas consumption across Australia (measured in peta joules as opposed to cubic feet), consumption of natural gas in Western Australia increased by an average of 8.9 per cent per annum over the 20 years to 2004-05[9].

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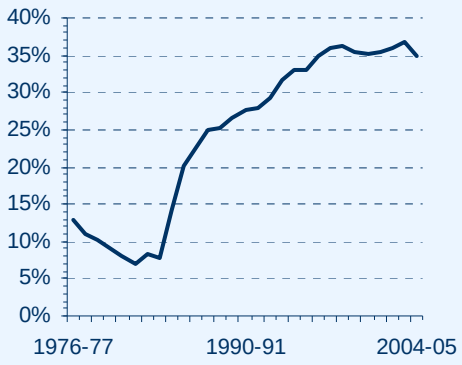
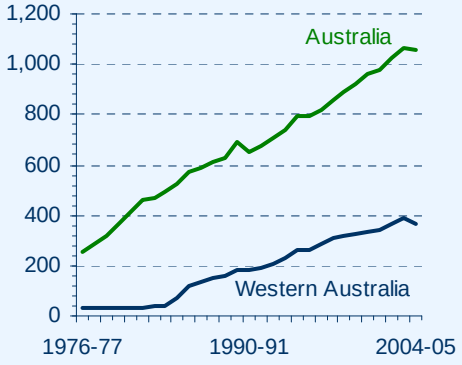
Chart 6
Western Australian Gas Consumption
As a Percentage of National Consumption



Source: ABARE

Chart 7
Gas Consumption, WA & Australia
Volume, in Peta Joules (PJ)



Source: ABARE

However, omitting the initial sharp rise in consumption in 1985-86, gas consumption in WA has grown by around 6.2 per cent per annum (i.e. 1986-87 to 2004-05), which compares to an average rate of consumption growth across Australia of 3.2 per cent per annum over this same period (Chart 7).

The strength of demand for gas in Western Australia relative to the rest of the nation is also demonstrated by the state's total share of national consumption of natural gas, which has risen from less than 20 per cent in the mid-1980s to around one-third of national consumption currently.

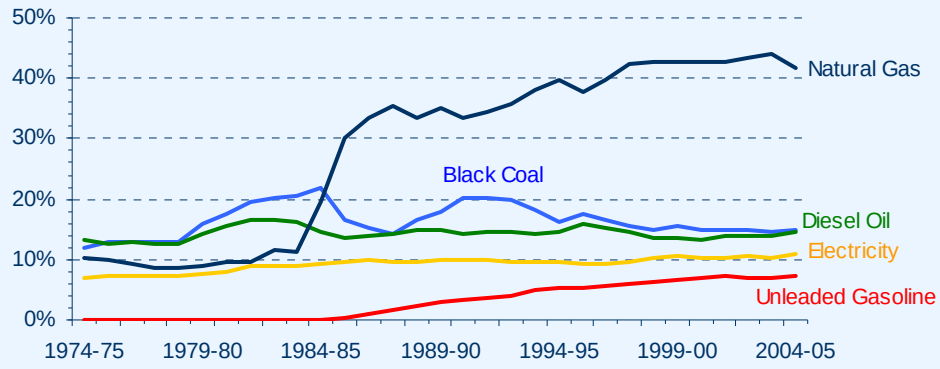
This is a considerable share considering that the net amount of energy consumed[10] each year in WA accounts for only 14 per cent of total energy consumption in Australia. This reflects the importance of natural gas as both a fuel source and a chemical feedstock in WA relative to other parts of Australia.

Indeed, natural gas currently accounts for around 41 per cent of total energy consumption in Western Australia (Chart 8). Across Australia, natural gas currently makes up less than 20 per cent of the nation's energy source.

This marked difference reflects the different endowment of energy resources in WA relative to the rest of the country. In particular, the rich endowment of black and brown coal in the Eastern States makes these commodities more important contributors to the nation's overall energy mix. In WA, the state's endowment of natural gas makes this a more important energy source.

However, despite the high usage of coal in other states, this commodity is still not used as intensely as natural gas is in Western Australia. For instance, although black coal is the single largest fuel source across Australia, it only makes up 30 per cent of all energy consumption currently. This is in contrast to WA, where the

Chart 8
Major Fuel Sources in Western Australia
Energy Usage as a % of Total Energy Consumption



Source: Australian Bureau of Agriculture & Resource Economics

state's single largest energy source, natural gas, accounts for almost half of all energy usage.

This reflects the fact that Western Australia's fuel sources are less diversified than the country as a whole with gas, electricity and automotive diesel oil currently making up around three-quarters of the state's energy mix. In addition, there is very limited hydro capacity in WA.

Although WA is the single largest consumer of gas, the eastern states market is larger by way of the interconnection of the pipeline network across those states. Victoria (25 per cent), New South Wales (15 per cent) and Queensland (10 per cent) together account for around half of the nation's annual gas consumption compared to Western Australia's one-third share.

The sharp growth in demand for gas in WA and its importance as a fuel source here also lies in the state's heavy industry base. Activities related to manufacturing, electricity generation and mining consume up to 90 per cent of the state's natural gas supplies each year.

Indeed, this volume of consumption is made up of only five entities[11] – Alcoa (mineral manufacturing), BHP Billiton (mining), Alinta (utilities), Verve Energy (electricity generation) and Burrup Fertilisers (chemical manufacturing).

Manufacturing

The manufacturing sector consumes up to 40 per cent of the state's annual gas supplies (Chart 9), and natural gas makes up around 60 per cent of this sector's overall energy needs.

Within the manufacturing sector, the largest volume of gas is used to produce basic non-ferrous metals, notably alumina. The manufacture of basic non-ferrous

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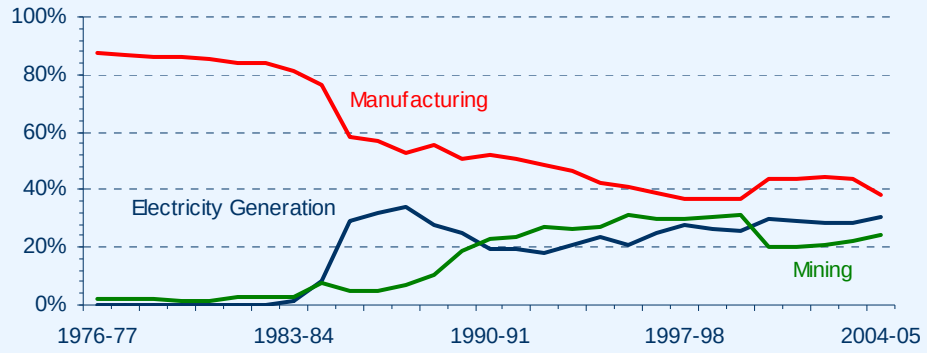
Chart 9
Major Uses of Natural Gas in Western Australia
% of Total Gas Consumption by Selected Sectors



Source: ABARE

metals accounts for 60 to 70 per cent of the total gas consumed each year by WA manufacturers, or around one quarter of all gas consumed across the state.

This is followed by iron and steel production, which accounts for around 20 per cent of gas consumed in the manufacturing sector, or some eight per cent of total state gas consumption. Most of this activity is concentrated in the production of pig iron, where gas is often used to pre-heat the metal.

Natural gas is also used as a feedstock for the manufacture of a number of chemicals and products in WA. In this regard, in 2004-05 the manufacture of basic chemicals accounted for around 14 per cent of total manufacturing related gas consumption, or five per cent of total domestic gas consumption in WA. However, this sector's consumption of natural gas is now likely to be much higher following the commissioning of Burrup Fertilisers' ammonia plant in 2006 along with some incremental expansion of existing production facilities, with some estimates[12] suggesting that the chemical sector's contribution to total domestic gas consumption is now around 15 per cent.

Basic chemicals include products such as ammonia, which are used in the production of fertilisers and explosives, where methane is used as the feedstock, while gases like butane, ethane, and propane (as smaller components in natural gas) and inert gases (such as carbon dioxide and nitrogen) are also extracted from natural gas. A variety of other chemicals for industrial use are also produced using natural gas as a feedstock.

Production of non-mineral products such as glass, ceramics, cement and concrete accounts for around 10 per cent of gas consumed by manufacturers, or four per cent of total gas consumed in the state. Here, gas may be used for a variety of purposes, from drying and dehumidification to glass melting and the fuelling of industrial boilers.

Gas usage in the WA manufacturing sector has steadily grown over time, averaging around 4.2 per cent growth per annum since 1986-87, which compares to wider growth in WA gas consumption of 6.2 per cent per annum over this same period. Although gas for manufacturing has grown on average, and manufacturers remain as the single largest consumer of gas in WA, this sector's share of gas consumption has fallen steadily over time.

For example, the sector accounted for as much as 85 per cent of domestic gas consumption in the early 1980s, although this slice was part of a much smaller pie than is currently the case. As stated above, total gas consumption in WA amounted to just 38 peta joules in the early 1980s, roughly ten times less than what is currently consumed.

The decline in this share is also attributable to a higher usage of black coal as an energy source in the manufacturing sector from the mid 1980s. Manufacturers currently account for up to 18 per cent of black coal consumption in WA compared to less than 10 per cent in the early 1980s.

Electricity Generation

Following its use in manufacturing, the next most prominent usage of natural gas in Western Australia is for electricity generation. Gas consumption for these purposes currently accounts for approximately 30 per cent of the total gas consumed in the state. Gas is the key source of electricity generation in Western Australia, with some 60 per cent of the state's electricity generation sourced from natural gas (Chart 10).

Natural gas can be used to generate electricity in a variety of ways, but the most basic method is through steam generation, whereby gas and other fossil fuels are burned to heat water and produce steam, which then turns a turbine to generate electricity.

In contrast, centralised gas turbines solely utilise hot gases from burning fossil fuels (particularly natural gas) to turn the turbine and generate electricity. Gas turbine plants are used primarily for peak-load demands, and the Kemerton gas-fired peaking station near Bunbury is an example of this. However, primary gas-fired plants (such as the Pinjar gas turbine station) can also be used for mainstream electricity generation, although centralised turbines lack efficiency and are rarely built on a large scale as a result.

Many new natural gas fired power plants are combined-cycle units, which contain both a gas turbine and a steam unit. This allows for more efficient generation, as the waste heat from the gas-turbine process (as above) is directed towards generating steam, which can then also be used to generate electricity. The

Cockburn power station uses this combined-cycle technology to generate electricity.

Cogeneration is another method, which uses the unique advantage WA holds in having a heat sink (alumina refineries) located close to where the majority of electricity demand is located. Cogeneration uses waste heat from the gas turbines, which is in turn used to produce steam for the Bayer process (process used to convert bauxite into alumina). As a result, cogeneration has a thermal efficiency of more than 70 per cent and produces the least amount of greenhouse gases of all gas fired electricity generators.

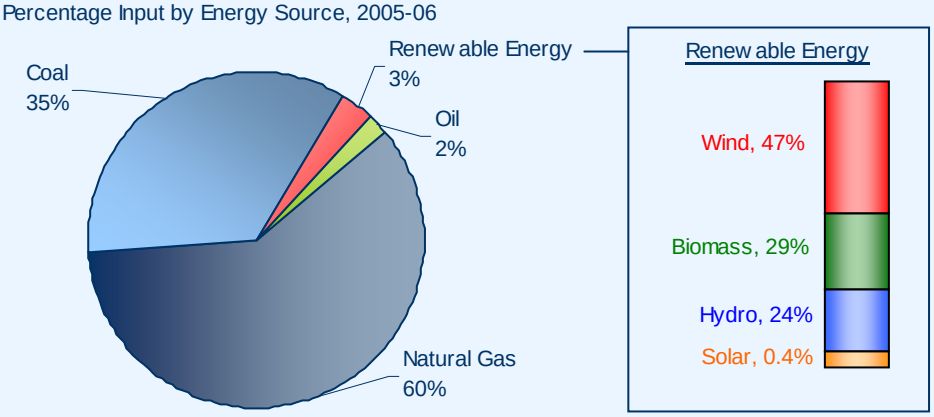
While the proportion of gas used in WA each year by manufacturers has reduced over time, the use of gas for electricity generation has grown rapidly.

Gas consumption for electricity generation has grown at an average of almost eight per cent per annum since 1986-87, which compares to wider growth in WA gas consumption of 6.2 per cent per annum over this same period. Reflecting this, the proportion of total state gas consumption attributable to electricity generation has grown from around 10 per cent in the mid 1980s to 30 per cent currently.

This rise in gas usage for electricity production in WA is due to the emergence of new technology (such as combined-cycle units) and growing environmental sensitivities, which have allowed natural gas to play an increasing role in the clean generation of electricity.

Moreover, the secure supply and low cost of gas from the North West Shelf has also made it a more attractive proposition as a fuel source compared to other fossil fuels. Indeed, the contracts signed in the early 1980s between the then SECWA and the North West Shelf partners for gas supply to the domestic market resulted in an immediate, sharp increase in the proportion of domestic gas used for electricity generation in the mid 1980s.

Chart 10
Sources of Electricity Generation in WA
Percentage Input by Energy Source, 2005-06



Source: Office of Energy, WA Government

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The availability of natural gas has been a key feature in reducing the cost of electricity generation in regional areas of Western Australia. The substitution of gas for liquid fuels such as diesel has significantly reduced costs and improved the viability of key resource developments throughout the State. The construction of the Goldfields Gas Transmission pipeline brought natural gas to the goldfields region and the construction of a natural gas pipeline to the Telfer goldmine in the Pilbara was a key feature in the decision to re-open and develop that mine.

Western Power commenced a process that is being continued by Horizon Power to adopt gas fired generation wherever possible to reduce the cost of generation in regional areas. The generation of electricity from natural gas is now found at many of Horizon Power's supply centres in the Pilbara and Mid West regions, and Esperance. The supply centres in the West Kimberley will shortly be supplied with new power stations fuelled from LNG trucked from Karratha. The availability of competitively priced natural gas is consequently a very important part of reducing the supply cost of electricity in regional Western Australia.

Western Australia's high dependence on natural gas for electricity generation is a key issue in the context of the current policy on gas reservation.

Although some entities interviewed as part of this project expressed concern that an absence of reservation may in the short term result in higher electricity prices, they were also concerned that the ambiguity surrounding the reservation policy will not provide the necessary comfort to electricity providers in order to invest into new generation capacity. This is a crucial issue in the current environment of tight supply of and demand for electricity in WA.

Mining

Miners consume approximately 20 per cent to 25 per cent of total domestic gas supply each year. Natural gas is an important component of this sector's energy mix, currently accounting for around 60 per cent of its total energy consumption.

In this sector, gas may be put to a variety of uses, but it mostly tends to be used for power generation on energy-intensive operations (industrial generation as opposed to centralised generation).

Natural gas is also the principal energy source for residential electricity generation in the major northwest coastal and inland mining communities, particularly in the Pilbara region.

Natural gas is also used by miners as a co-firing technology, which refers to a process in which gas is used as a supplementary fuel in the combustion of other fuels. This can increase industrial energy efficiency, and reduce greenhouse emissions.

Like other sectors, gas usage in the mining sector has risen substantially over time, growing by an average of 18 per cent per annum since 1986-87. However, most of this growth occurred in the mid to late 1980s. Annual consumption has risen by an average of 3.2 per cent each year over the past decade.

This growth in consumption has seen the mining sector become a more important gas user in WA, with its share of annual consumption rising from less than 10 per cent in the mid-1980s to almost one quarter currently.

Natural gas has also grown to become a major source of this sector's overall energy needs, growing from around 30 per cent of its energy mix to 60 per cent currently. The reasons for the marked growth in gas usage in this sector are similar as that for electricity generation, given the environmental benefits and plentiful supply of natural gas in WA.

The WA mining sector currently accounts for almost 60 per cent of the total volume of natural gas consumed across the national mining sector each year. This reflects the concentration of resource sector activity in WA.

This gives the resources sector in WA a much greater slice of total gas supplies in WA than elsewhere in Australia. Indeed, the national mining sector consumes approximately 15 per cent of national gas supplies each year, whereas the mining sector in WA consumes up to one quarter of the state's total gas supplies.

Other Uses

Activities related to manufacturing, electricity generation and mining consume up to 90 per cent of the state's natural gas supplies each year. The remaining 10 per cent is put to a variety of uses.

The transportation and storage sector consumes up to three per cent of natural gas supplies in Western Australia each year. Most of this is consumed by entities involved in 'other' transportation services, although in WA, this is most likely to relate to gas pipeline transportation, where natural gas is used as an input in compressor stations which keeps the gas at high pressure as it travels through the line.

Around three per cent of the state's annual gas supplies are used for residential purposes. While small in terms of overall demand, natural gas usage by WA residences has increased markedly in the past 20 years (average of 6.5 per cent growth per annum).

This reflects growth in the wider population, but also the low cost of natural gas as an energy source relative to electricity. Natural gas currently makes up approximately 27 per cent of the total energy consumption of WA households,

while electricity accounts for around half of all energy usage in the home. These shares are broadly in line with household energy usage nationally.

Notably, Western Australian households consume a much smaller proportion of the state's annual gas supplies than their counterparts in other states. Indeed, some 13 per cent of gas supplies across Australia are currently consumed by residential sources, compared to just three per cent of WA supplies being consumed by households here.

This difference might be due to the larger population in the eastern states, as well as the prevalence of retail competition for residential gas supply on the east coast compared to WA, where retail contestability is still at its infancy.

The commercial services sector (such as wholesale and retail trade, communications, property and business services, finance and insurance etc.) utilise around 0.8 per cent of total gas supplies in Western Australia each year. The main uses of natural gas in this sector include space and water heating, as well as in cooling systems (e.g. absorption chillers and gas-based desiccant systems).

Prices and Market Characteristics

Unlike other more developed markets, there is no formal measure of natural gas prices in WA. Drawing from DOIR data reporting on the volume and value of natural gas sales in WA, it is apparent that wholesale gas consumers in Western Australia paid an average price of A$2.34 per giga joule for natural gas in 2005-06.

Domestic gas prices in WA have been considered to be low compared to 'average world prices' for natural gas. The initial DOIR consultation paper noted that:

> *"The domestic gas reservation for the North West Shelf project is considered to have created an incentive for the project to sell gas into the domestic market, even if the price obtained was less than for exported LNG, as the only available alternative would be to leave the reserved gas in the ground, providing no return at all. This has effectively resulted in the price of domestic gas being significantly less than average world prices."*[13]

While reservation has had some influence on pricing in WA, there are other more significant issues relating to market structure which underpin the pricing of gas here. The characteristics of the WA gas market are explored in more detail in the following section.

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Market Characteristics

Like any other commodity, the price of natural gas is set by market forces. That is, the buying and selling of the commodity by market participants based on supply and demand determines the price of the commodity.

There are two primary types of natural gas marketing and trading – physical trading and financial trading. Physical natural gas trade involves the buying and selling of the physical commodity negotiated directly between buyer and seller. In contrast, financial trading involves derivatives and sophisticated financial instruments in which the buyer and seller might never take physical delivery of the natural gas.

In more developed markets, natural gas is primarily 'financially traded' on formal exchanges characterised by transparent pricing and a reasonably high level of liquidity and market organisation. Exchange or financially traded contracts for gas are more evident in the larger markets of the United States and Europe, where formal spot and futures markets for natural gas exist.

The spot market is essentially the 'daily' market, where natural gas is bought and sold for immediate or short-term delivery. On the other hand, the futures market consists of buying and selling natural gas under contract for future delivery. This often entails periods of at least one month, but can be up to three years.

In the futures market, a significant amount of trade in natural gas derivatives takes place, where contracts for supply are traded as a means of hedging risk, for example, in order to secure sales or supply and/or avoid the risk related to high price variability.

In Australia, the gas market is not as developed and there is no formal exchange or financial traded means of buying and selling gas. Rather, most large wholesale transactions for gas in WA and the eastern states occur through private negotiation between buyers and sellers – or physical trading.

Indeed, gas markets in Australia have traditionally comprised state-based market structures in which monopolies operated at the production, distribution and retailing stages.

The supply chain was previously characterised by a high degree of integration, with legislative and regulatory barriers restricting interstate trade. However, reforms throughout the late 1990s have seen full retail contestability in gas introduced in New South Wales, Victoria, South Australia, Western Australia and the Australian Capital Territory, as well as a more formal wholesale market on the eastern seaboard.

For example, in 1997 the Victorian Government established the state-owned private entity, VenCorp to administer that state's gas and electricity industries. Funded by energy industry participants, VenCorp has major operational, planning and development roles for both gas and electricity, including as the independent system operator for the Victorian gas transmission network, as well as manager and developer of the Victorian wholesale gas market.

WA was not party to initial moves toward a national energy market given the distance between WA and other states and hence the lack of interconnectivity for energy transfer.

However, the WA State Government has implemented a range of structural reforms in the state's gas industry which have improved retail competition in the market. These initiatives include disaggregating the major domestic gas supply contracts, introducing compulsory third-party access to the transmission and distribution networks, and structural separation of the gas transmission and distribution functions.

These changes together with the removal of legal and other barriers have helped move the market towards full retail contestability, although a more formal wholesale market for participants trading large volumes of gas does not currently exist in WA.

This is mostly because large scale gas consumption here is concentrated among a handful of consumers, with around 90 per cent of domestic supply consumed by just five large buyers.

These major buyers have largely evolved from the disaggregation of the original SECWA contracts in the 1990s, with Alinta and Western Power (more recently Verve following the break-up of Western Power) the traditional aggregators and suppliers to smaller industrial, commercial and residential off-takers (subject to the provisions of the Gas Markets Moratorium).

This concentration of consumption among a few buyers breeds a greater requirement for longer term contracts built around reliability and security of supply to meet the specific needs of these large product off-takers, as well as their financiers. Most of these large wholesale transactions for gas in WA occur through the negotiation of physical contracts.

Even at the smaller end of the gas buying spectrum, Western Australia is largely a project-driven market – particularly in the resources sector – meaning that many of the smaller wholesale transactions for gas also typically involve long-term supply horizons. This tendency for gas to be sold via long term contracts is part of the reason why prices here have remained fairly low over time.

The concentration of supply among long term contracts also lends itself to a less liquid and less fungible market for gas in Western Australia, which also has some impact on pricing.

Also contributing to this lack of liquidity is the fact that WA has relatively few developed gas supplies, while there is also a very large geographical distance between the location of major deposits and end users (requiring long haul pipelines with few genuine hubs).

Markets in Europe and the USA on the other hand contain sufficient 'liquidity' (in terms of choice of supplier, several hubs and large numbers of consumers) to support a more short-term, fluid market for natural gas. Reflecting this, gas in these markets tends to be sold on spot a basis rather than on long term contracts.

It is estimated that the value of trading of natural gas contracts that occurs on financial markets in the United States is some 10 to 12 times greater than the value of physical natural gas trading[14].

The larger size of markets overseas, with their greater frequency of trade and greater propensity to trade on exchange traded financial bourses mean prices in larger markets may be higher and more volatile, while also more closely reflecting market conditions.

This is not to say that prices in WA do not reflect supply and demand fundamentals. Instead, the long term nature of gas supply contracts in WA means that rather than price signals (i.e. set by supply and demand fundamentals) being conveyed to the market on a daily basis as in other markets, signals tends to be periodic, coinciding with points in which large supply contracts reach expiry.

This leads to another unique aspect of the Western Australian market, which also partly explains why gas prices here have been relatively low over time.

Generally, major consumers seek to secure new supplies on long term contracts some four to five years before existing supply contracts expire. The prices of other smaller supply contracts then tend to follow these larger, benchmark supply contracts in terms of pricing.

These periods in which significant supply contracts reach renewal can result in price competition among suppliers as they seek to establish market share. Indeed, some industry participants have suggested that some smaller suppliers often engage in price discounting in order to establish market share as these major contracts are re-negotiated.

Notably, this was not the case prior to the disaggregation of SECWA contracts in the 1990s. Before this restructure occurred, the domestic gas market was

dominated by the North West Shelf as the major supplier and SECWA as the largest buyer, with little price competition.

However, the unbundling of these contracts by the State Government in conjunction with the construction of the Goldfields Gas Pipeline re-shaped the competitive dynamics of the local market.

Importantly, this resulted in the break up of the purchase of gas by SECWA between a few major consumers, allowing smaller producers to establish a stronger foothold in the domestic market. Indeed, this change underpinned the establishment of the East Spar venture and the further development of the Harriet area fields during the 1990s.

Although the domestic market is characterised by regular periods of competition, the NWS joint venture remains the major force in the market, accounting for up to 63 per cent of supply in Western Australia, while 19 per cent is attributable to the Harriet area project. The remaining proportion of production is spread across a number of projects.

Competition between energy sources also plays a role in determining natural gas prices in Western Australia. As renewable energy sources cannot currently provide the load required by many large industrial electricity users, the major alternative to natural gas as an energy source is coal.

In this context, competition between new gas-fired and coal-fired power generation has also had a key influence on pricing in Western Australia, particularly as gas consumption for power generation currently accounts for approximately 30 per cent of the total gas consumed in the state.

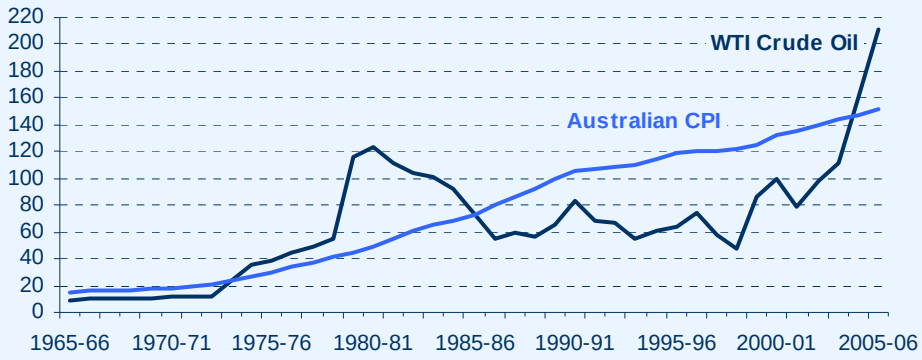
Hence, gas suppliers selling to users involved in power generation must be sensitive to the price of coal as a substitute. Indeed, gas pricing in the 1980s explicitly recognised the competing fuel sources of coal and liquid fuels.

The other major characteristic of the WA domestic market which lends itself to low prices is the manner by which prices negotiated as part of physical contracts are escalated or indexed during the course of the contract.

In the 1980s, supply contracts with SECWA were typically indexed to oil prices. This is similar to current contracts for LNG supplies which index some component of the negotiated contract price to changes in the world price of crude oil with ‘cap’ and ‘floor’ limits.

In the 1990s, parties involved in domestic contracts for physical gas supply began to index price increases during the term of the contract to changes in consumer prices rather than world crude oil prices, or other gas market indicators.

Chart 11
West Texas Intermediate Crude and Australian CPI
Price Indexes



Source: IMF, ABS Cat. 64010

Typically in the domestic market, indexation has been set at 75 per cent of the Australian consumer price index (CPI)[ii] on a quarterly basis. There has been a recent trend towards indexing to crude prices, but this is mostly among large gas producers who also sell LNG.

Some contracts also include 'price re-openers' which provide for one or either party to renegotiate the contracted price of the gas in the occurrence of some agreed event, typically if market prices (or the price of oil and/or substitutes such as coal) change significantly.

This linkage of domestic gas prices in WA to movements in the CPI rather than crude oil prices might also explain why domestic gas prices in WA have not been driven higher by the volatility in world crude oil prices, as spot gas prices in overseas markets have been in recent years (Chart 11).

While the initial State Agreement with the WA Government is often pointed to as the reason behind the state's low gas prices, it is important to note that no such reservation agreement existed in the eastern states to explain the low gas prices which have prevailed there amidst rising prices elsewhere. Gas prices in the eastern states have remained "flatter" in fact, and are lower than they are now in WA despite significantly smaller reserves and greater overall demand. This could indicate that the presence of alternative energy sources (particularly coal) may influence domestic gas prices in the eastern states more so than gas demand and supply.

[ii] The formula often used is: CPn = BP * (1+ (0.75 * ((CPIn/CPIb) -1))); where 'CPn' is the contract price applicable for quarter n. The adjustment can be up to 100 per cent of CPI in some cases.

Certainly, the buyer profile/category of the eastern states consumer has very much influenced pricing. The predominance of domestic gas consumption and retail competition in that market has impacted on gas prices. The WA Government introduced full retail contestability in 2004, enabling any company to sell gas to customers of any size. However, the market is yet to experience full retail contestability in its entirety to date, given the limited competition that still exists.

There is also no opportunity to export gas on the east coast given the lack of scale of most of the fields. Most of the gas for the Eastern States markets is sourced on-shore through the Cooper and Eromanga basins, which are similar in size to the Perth Basin, and hence entail lower cost to develop.

Prices

Understanding the structure of the WA domestic gas market and the issues which influence prices provides the context in which to consider price trends and comparisons.

As described above, most of the gas sold in WA is done so through long-term contracts (the details of which are generally confidential), and combined with the lack of liquidity, this has meant that pricing has been very opaque. Some gas is sold on a spot basis from time to time, but for the most part, no fungible market for gas exists in Western Australia.

This reflects the unique characteristics of the WA gas market in that it has relatively few developed gas supplies together with concentrated demand, while there is also a very large geographical distance between the location of gas deposits and end users (requiring long haul pipelines with few genuine hubs).

This makes the comparison of WA domestic gas prices to other jurisdictions a difficult task.

Markets in Europe and the USA for example contain sufficient ‘liquidity’ (in terms of choice of supplier, several hubs and large numbers of consumers) to support a short-term, fluid market for natural gas. Reflecting this, gas in these markets tends to be sold on a spot basis rather than on long term contracts.

Such a market for natural gas on occasion has brought with it higher prices than what has been seen in WA. In Europe for example, gas prices averaged A$8.39/GJ during 2005-06. Similarly, prices averaged A$11.27/GJ in the United States during 2005-06.

In addition to this, the limited availability of data and the different measures used to report official price levels (i.e. wellhead prices, price into the pipeline, or price out of the pipeline) make price comparisons difficult.

For example, the European price quoted above is measured by the Russian Federation natural gas price (Russian border price in Germany), while the US price is measured according to the Louisiana natural gas price (also known as Henry Hub) – both of which are spot price measures.

Prices in these jurisdictions also tend to be volatile reflecting the short term nature of these markets. Indeed, prices in Europe and the US are currently coming off high rates of growth following two periods of rapid growth in 2000-01 and in 2004-05. Henry Hub spot prices rose by 124 per cent in 2000-01 mostly due to tight supply conditions, low storage stocks and strong demand for gas in that year, as well as rising crude oil prices[15].

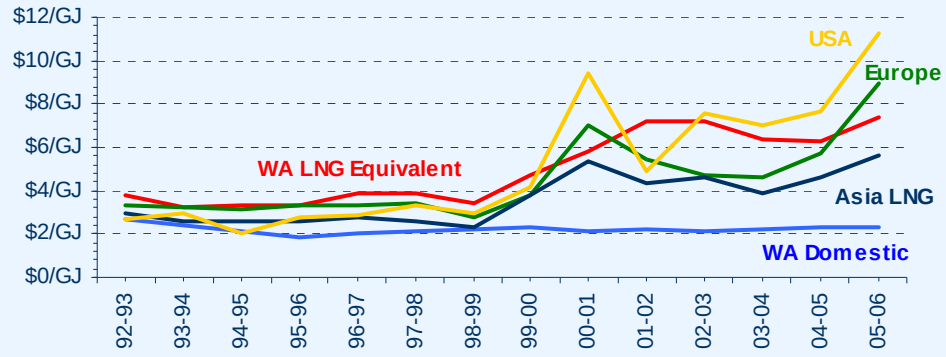
European and UK gas prices followed a similar trend in 2000-01 driven by higher crude oil prices[16], but in both cases prices eased in the following years as crude prices and tight gas market conditions eased. Domestic gas prices in WA have remained fairly flat over the long term, rising by an average of just 2.5 per cent per year over the ten years to 2005-06. Gas prices on the east coast of Australia mirror that of WA, with prices there also remaining fairly flat recently, although at a slightly higher margin than in WA.

LNG prices also rose during this period but not to the extent of the spot markets of the United States and Europe. In 2005-06, the equivalent[17] price of LNG sold out of WA rose sharply to an average of A$7.37/GJ (based on DOIR data detailing volume and value of LNG sales).

Some caution must be taken in interpreting this number, as LNG equivalent pricing methodology does not account for the additional costs associated with LNG over natural gas supply. In particular, cooling and liquefying the gas and storing it can cost up to A$2.50/GJ according to anecdotal evidence.

Generally, LNG prices in WA have risen recently due to the growth in world oil

Chart 12
Natural Gas Prices
Selected Jurisdictions, AUD per Giga Joule



Source: IMF, DOIR, CCI Economics, Note: US price - spot price, Lousisana; Europe - Russian border price in Germany; Asian Price - Indonesia , liquid natural gas in Japan.

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prices (most LNG contracts have a price component linked to crude oil prices), although high world prices are not the only driver of this growth.

The rise in world LNG prices also reflects stronger global demand for natural gas, particularly from rapidly growing economies such as China, as well as established markets such as the United States and Japan, where gas is becoming more widely used in industry and for domestic power generation given its cleaner and more efficient burning properties.

Although WA domestic gas prices are referred to as being 'significantly less than average world prices', there are other jurisdictions with far lower prices. For example, anecdotes suggest that natural gas prices in Qatar are currently as low as US$0.75/GJ, while prices in Trinidad and Tobago are also very low at around US$1/GJ.

Additionally, anecdotes also suggest that contracts currently being negotiated may have risen to an average price in the order of $5.50/GJ[18]. This is reflective of the tight market conditions which have prevailed in recent years.

Although the initial DOIR consultation paper explained that the consistently low price of gas in WA was due to the domestic gas reservation agreement between the State Government and the North West Shelf project, it is important to understand the differing nature of the natural gas market in WA compared to markets overseas.

The Role of Government

Introduction

The State and Commonwealth Governments have a significant influence on the Western Australian gas market. This is because governments, rather than private individuals, hold ownership rights over oil and gas deposits in Australia.

However, government is not involved in the development of oil and gas projects, which is primarily the role of the private sector.

This disconnection between ownership and commercialisation of fields means the private sector and government must work closely in the development of oil and gas deposits in Australia, given the importance of energy to the broader economy.

In general, governments today have four responsibilities in relation to the oil and gas sector. These include:

- establishing the macro-economic environment (broad economic policy);

- providing a regulatory framework for exploration, development, project approval processes, safety, environmental assessment and revenue provision;
- reducing commercial risk in petroleum exploration by generating and disseminating basic geo-scientific information; and
- examining ways to improve industry competitiveness.

However, it should be noted that, historically, government trading enterprises (such as the former SECWA) have underwritten part of the cost of developing gas projects. Such entities have also underwritten, or contributed to, gas pipeline infrastructure (e.g. Onslow and Mid West Gas Pipelines).

Effective performance by government in these aspects helps to ensure the long-term security of energy supply in Western Australia.

While the myriad of regulations can potentially impact upon an oil and gas development depending on the qualities of the deposit, the following section examines some of the key laws and regulations which affect participants in the sector.

A detailed examination of taxation and approvals processes is provided on pages 97 and 101 respectively.

Responsibilities of the State and Commonwealth Governments

In the Australian federal system, both the federal government and the state government have roles in petroleum exploration and development.

The Commonwealth is responsible for broad economic policy and international matters, such as company tax, interest rates, certain spending responsibilities (eg. welfare), foreign investment guidelines, trade and customs, corporations law and international agreements.

In contrast, the state has a more micro role in that it owns and allocates petroleum rights (within its territorial boundaries), administers petroleum operations including occupational health and safety, and collects royalties on petroleum produced (within its territorial boundaries). While offshore deposits seaward of the first three nautical miles of the territorial sea are owned by the Commonwealth, the day-to-day administration of such fields is by agreement the responsibility of the State.

In this regard, Western Australia is the only state that has a petroleum code common to both its onshore and offshore areas.

The code mirrors the *Commonwealth Petroleum (Submerged Lands) Act 1967 (Cth)*, which was established by the federal government in conjunction with all state and territory governments. The code varies little between the offshore and onshore, and only where it is necessary to recognise the requirement of other land tenures and usage.

The basic premise for this common petroleum code is that all petroleum resources of Western Australia and its adjacent submerged lands are reserved to the Crown, as is the right of access for the purpose of searching for, and recovering these resources.

In addition to state and Commonwealth governments, local governments are increasingly taking an active role in certain aspects concerning approvals of major projects.

In particular, some local governments have recently determined that building licences and planning approvals must be obtained from the local government for all development, regardless of any State Agreement Act provisions that may apply to a project.

Other local government powers are provided under the *Building Code* (structural, fire, safety etc for ancillary buildings) and the *Health Act* (approval and periodic inspection of messing and accommodation facilities).

Despite the growing involvement of local government, the major regulatory processes pertaining to the oil and gas sector remain with the state and Commonwealth governments.

Key Legislation in Western Australia

In Western Australia, exploration for and production of petroleum is only permitted under the provisions of legislation applying to the State and its adjacent submerged lands. There are three key pieces of legislation in this regard:

- *The Petroleum Act 1967 (WA)*, which covers all onshore areas of the State, including its islands and, in certain circumstances, areas of submerged lands internal to the State (i.e. those waters landward of the base line), other than 'subsisting' permit areas under the *Petroleum (Submerged Lands) Act 1982*;

- *The Petroleum (Submerged Lands) Act 1982 (WA)*, which applies to Western Australia's territorial sea to the three nautical mile mark, including the territorial sea around state islands, and under certain circumstances, some areas of internal waters; and

- *The Petroleum (Submerged Lands) Act 1967 (Cth)*, which applies to the submerged lands of the continental shelf beyond three nautical mile territorial sea boundary, which are designated as being adjacent to Western Australia.

Both the *Petroleum Act 1967 (WA)* and the *Petroleum (Submerged Lands) Act 1982 (WA)* are administered solely by Western Australia, while the Commonwealth Act, in respect to the Western Australian adjacent area is administered by a Joint Authority, comprising the Commonwealth and State Ministers responsible for petroleum administration.

Oil and gas exploration and development in Western Australia is subject to the *Petroleum (Submerged Lands) Act 1982 (WA)* for offshore areas and the *Petroleum Act 1967 (WA)* for onshore areas. The State of Western Australia and the offshore area are divided into 'blocks' which constitute the basis for all exploration and production titles.

Exploration

The prime title for exploration under the Commonwealth and State Petroleum codes is the 'Exploration Permit'. Permits are made available through a periodic release of vacant acreage for a work programme based competitive bid process.

The formal release of vacant areas is by way of a notice in the *Government Gazette*. Each individual area is identified by map sheet block numbers illustrated in an accompanying plan, and applications are generally made in respect to an entire area.

The exception to the periodic release process is applications for Special Prospecting Authorities. Should an explorer require a particular offshore area to be made available under these circumstances, an approach to the Petroleum and Royalties Division of DOIR may be made giving broad details of the general area of interest.

Special Prospecting Authorities are for the purpose of enabling geophysical surveys to be undertaken in vacant areas as a preliminary means of assessment prior to applying for a more permanent exploration title. These authorities are restricted in time to six months, and do not allow any drilling to be undertaken.

On the other hand, as part of an application to explore released vacant acreage, an applicant is required to supply details of the proposed work programme on a year-by-year basis for the term of the permit.

Generally, the extent, timing and appropriateness of the work programme are the main considerations for the award of an exploration permit. However, there are other important criteria, particularly the financial and technical ability of the

applicant. The best possible application is selected giving due consideration to all the assessment criteria.

The initial term of the permit is six years in the State areas, and in Commonwealth areas, permits can only be renewed for two further periods of five years, with 50 per cent relinquishment of the area at the end of each term, for a total of 16 years.

Permits are granted subject to specific minimum work commitments that must be met each year. Permits in the Commonwealth area must complete the first three years guaranteed work program before they can be surrendered.

Production

If a commercial discovery is made as part of an exploration work program, the successful explorer has a statutory right to the grant of a 'Production Licence'.

The initial term of an onshore production licence is 21 years and it may be renewed at any time for further periods as determined by the Minister. A Production Licence in the Commonwealth Adjacent Area is granted for an indefinite term.

When petroleum is discovered within a permit area, the permit holder or the Minister may declare a 'location' covering the extent of the pool. The establishment of a 'location' is a means of setting aside and identifying a specific number of blocks from which a Production Licence may be selected.

The holder of a tenement in which a 'location' is declared has two years in which to apply for a production licence or retention lease. This period may be extended for a further two years at the discretion of the Minister. Within this period the permit holder selects from this 'location' the blocks to be included in a production licence and/or retention lease.

A retention lease may be applied for if a petroleum discovery proves to be non-commercial at current market conditions, but has the potential to become commercial within 15 years.

The initial term of a retention lease is five years and it may be renewed provided it still meets the required commerciality criteria. When the discovery is deemed to be commercial, the retention lease must be converted to a production licence.

Transmission

Regulation of gas transmission pipelines in Western Australia can be split into licensing and access.

Gas pipeline licensing in Western Australia generally falls under one of three Acts: the *Petroleum (Submerged Lands) Act* (Commonwealth or State as appropriate); the *Petroleum Pipelines Act 1969*; or the *Energy Coordination Act 1994 (WA)*.

The Commonwealth and State *Petroleum (Submerged Lands) Acts* are identical for offshore state areas. Meanwhile, state onshore pipelines fall under the jurisdiction of *Petroleum Pipelines Act 1969*.

Generally, transmission pipelines under these Acts are defined as those that convey naturally occurring hydrocarbons and are generally in respect to high pressure trunk lines.

Field gathering lines, which transfer gas or oil from a well to a point where there is either a custody transfer of the gas, or where the gas enters a common carrier pipeline, are not usually licensed as a petroleum pipeline, but are included as part of the production licence facilities.

Pipelines under the *Petroleum Pipelines Act 1969* and *Petroleum (Submerged Lands) Act* are granted for an initial term of up to 21 years with subsequent renewal terms of no more than 21 years each, while pipelines under *Petroleum (Submerged Lands) Act* are granted for an indefinite term.

A pipeline licence permits the holder to construct a petroleum pipeline, which is generally buried and visually unobtrusive, along a narrow corridor which is accommodated by way of easements registered under the appropriate legislation. In addition to these requirements, licences are also subject to stringent public safety and environmental conditions.

Meanwhile, the *Energy Coordination Act 1994 (WA)* governs the construction, alteration or operation of a gas distribution system or gas transport system operating at a pressure of less than 1.9 mega pascals and to the supply of gas to customers using less than one tera joule of gas per year (i.e. small use customers).

The Act makes provision for the grant of a distribution licence or trading licence to facilitate: the installation and operation of gas distribution systems and the sale of gas through the grant of land access and acquisition powers; provide consumer protection; and ensure the technical, managerial and financial capability of licence holders.

Aside from licensing, pipelines may also be regulated in terms of access. In Western Australia, a legal right of access to gas transmission and distribution systems has been created by the *Gas Pipelines Access (Western Australia) Act 1998 (WA)*, which implemented the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Access Code).

The covered pipelines include the major gas transmission pipelines and the gas distribution system in Western Australia. The core principles of the Code are:

- to enable third parties to negotiate access to pipeline haulage services on fair and reasonable commercial terms and conditions;
- to facilitate negotiations, and to redress the imbalance in negotiating power between pipeline operators and seekers of pipeline access;
- to establish tariffs known as 'reference tariffs' for a number of standard services called reference services for third party access to pipelines. The reference tariffs to be established by a uniform process using established principles;
- to provide a regulator-approved competitive bidding process to enable reference tariffs for new pipelines to be developed;
- to ensure access seekers have sufficient information to determine whether the tariff proposed for access is fair and reasonable;
- to provide flexibility for an access seeker to accept a reference service at the reference tariff or seek to negotiate with the pipeline operator for a different service, or for a discount for the reference service;
- to allow disputes about access to be resolved in a timely manner by binding arbitration and to require the Arbitrator to apply the reference tariff relevant to the reference service in a dispute over access to a reference service;
- to provide a high level of discretion within the Code, to enable pipeline-specific circumstances to be taken into account by the Relevant Regulator;
- to ensure the monopoly component of a pipeline business is ring-fenced from related but contestable components of the business; and
- to facilitate the trading of unused pipeline capacity.

Petroleum Taxation

In Western Australia, all mineral and energy resources existing in their natural form are owned by the State, being held in trust by the government on behalf of the community.

Title to the resources is held by the Government on behalf of the community, until title to these non-renewable resources is transferred to developers at the wellhead

at the time of production. Upon production, the government expects a return to the community in the form of a royalty. The royalty is paid to the State and recognises the use and loss of an asset to the community.

Generally, there are three systems used for the collection of petroleum royalties – wellhead, resource rent royalty and resource rent tax.

Petroleum royalties are administered and collected under state and Commonwealth legislation. Royalties collected for onshore projects are retained by the state government, while offshore projects are collected by the Commonwealth (although provision exists in the case of North West Shelf Royalties to be shared by the Commonwealth and State). There are seven Acts that apply in Western Australia:

- The *Petroleum (Submerged Lands Royalty) Act 1967* covers production from fields originating from the North West Shelf project covered by permits WA-1-P and WA-28-P. This is an area of Commonwealth jurisdiction in which a wellhead value royalty system is used;

- The *Petroleum (Submerged Lands) Act 1982* covers fields within a defined Territorial Sea, generally being between 3 and 12 nautical miles from land, as well as certain 'subsisting' permit areas located within State inland waters. The State administers a wellhead value royalty system;

- The *Petroleum Resources Rent Tax Assessment Act 1987* applies to all offshore waters seaward of the Territorial Sea other than the North West Shelf project area. The Commonwealth administers a resource rent tax, which is effectively a profit-based royalty introduced to replace a wellhead royalty and excise system;

- The *Petroleum Act 1967* applies to onshore areas and waters landward of the Territorial Sea, other than 'subsisting' permit areas under the Petroleum (Submerged Lands) Act 1982. The State administers a wellhead value royalty system; and

- The *Barrow Island Royalty Variation Agreement Act 1982* applies only to Barrow Island. The royalty regime was developed in negotiations between the WAPET Consortium, the State and the Commonwealth. It replaced the wellhead royalty and excise system that had previously applied;

- The *Excise Tariff Act 1921* applies crude oil excise to eligible crude oil production from coastal waters, onshore areas, and the North West Shelf project area in Australian waters;

- The *Petroleum Revenue Act 1985* allows the Commonwealth to waive excise on particular onshore projects. To do this, the state or territory, with the

agreement of the production licensee, must introduce a resource rent royalty for that project, and make a revenue sharing agreement with the Australian Government. Currently, the resource rent royalty is applied only to production from Barrow Island, WA.

For a detailed discussion of royalties and how they impact on oil and gas developments, see page 98.

Land Access

Land access is a crucial step in the development process for oil and gas fields. In Western Australia, DOIR facilitates land access in accordance with relevant legislation and policy concerning native title and land-use planning for the exploration, production and development of oil and gas resources on all land areas of the State and adjoining coastal and Commonwealth waters.

Beyond the three nautical mile limit, Commonwealth petroleum legislation applies, and is administered for the Western Australian adjacent area by a joint authority arrangement with the Commonwealth.

In Western Australia, land is classified as private, public or Aboriginal land. Private land is freehold while public land includes land leased for pastoral purposes. On Aboriginal land, exploration requires the consent of the owners.

In 1992, the High Court determined that a form of native title to land also exists where that title has not been extinguished by some other form of land title. Under the *Native Title Act 1993 (Cth)*, all applications for onshore petroleum titles, other than those on freehold land, must be assessed to decide if they need to be subject to the procedures of the Act.

Offshore areas may also fall within the jurisdiction of the Act. For the purposes of the *Native Title Act*, "offshore" is regarded as being all submerged lands below the mean low water mark of the coastline (that is, the average level of all low tides).

In addition to the *Native Title Act 1993 (Cth)*, the protection of places or objects of significance to indigenous Australians is also provided through other Commonwealth and State Acts, including the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (Cth)*, the *Environmental Protection and Biodiversity Conservation Act (Cth)* and the *Aboriginal Heritage Act 1972 (WA)*.

Environment

Environmental regulations also play a key role in project development. The Petroleum and Royalties Division of DOIR is responsible for the assessment, evaluation and approval of petroleum operation proposals. Proposals are assessed

by officers from the Titles, Environment, Engineering, Resources and Safety sections of the DOIR before final approval is given.

In general, proponents of a development located within the boundaries of the State Government (i.e. as per the *Petroleum (Submerged Lands) Act 1982 (WA)*) submit an application form to the Director of the Petroleum and Royalties Division at DOIR for a proposed development, which is also accompanied by an Environmental Management Plan (EMP).

The EMP provides background information regarding the proposal and the receiving environment, and the environmental issues and potential effects of the proposal. The EMP document forms an integral component of the assessment phase in that it assists DOIR to determine if the proponent can satisfactorily manage potential effects associated with the proposal.

Based on the nature of the proposal, its location and related environmental aspects, and management commitments, DOIR will either assess the proposal or refer it to the Environmental Protection Agency (EPA) for assessment under Section 38 of the *Environmental Protection Act 1986 (WA)*.

Upon completion of formal assessment, the EPA prepares a report detailing the environmental issues and effects of the proposal, and makes recommendations on managing these issues and effects. This report is submitted to the Minister for Environment who makes a decision on approval based on the advice provided by the EPA.

The Minister for Environment is able to set legally binding conditions on the proposal under the *Environmental Protection Act 1986 (WA)* before giving approval. The proposal is then referred back to DOIR for the setting of the additional conditions under petroleum legislation before final environmental approval of the proposal is granted.

Proposals located offshore from Western Australia between three nautical miles and 200 nautical miles are situated in Commonwealth waters and are under the jurisdiction of the Joint Authority.

Similar to the process for State applications, proponents submit an application form to the Director of the Petroleum and Royalties Division at DOIR. Under the *Petroleum (Submerged Lands) (Management of Environment) Regulations 1999 (Cth)*, the application form must be accompanied by an Environmental Plan (EP) that provides background information regarding the proposal and the receiving environment, and the environmental aspects and potential effects of the proposal.

The Joint Authority or DOIR, on behalf of the designated authority, assesses the application and EP to ensure that proponents have adequately met all requirements

for identifying and managing environmental issues, and have complied with all relevant environmental laws and regulations.

If the assessing authorities determine that the significant effects associated with the proposal can be managed and the management commitments are satisfactory, as outlined by the proponent in the EP, the proposal and EP will be approved subject to Ministerial conditions. All conditions set are legally binding and must be observed.

Prior to submitting an EMP or EP to DOIR, it is a requirement of the *Environmental Protection and Biodiversity Conservation Act (Cth)* that the proponent determine that the proposal has, will have or is likely to have a significant impact on matters of 'National Environmental Significance'. The proponent makes a decision on whether or not to refer the proposal and initiate the separate Act process.

Regulation as well as increased public awareness of environmental issues has also seen many oil and gas operators adopt greenhouse gas abatement options during extraction. Generally, this can take the form of flaring gas, direct use, selling into the market (where some scale exists) and re-injection of gas into oil fields.

Safety

Occupational safety is a key tenet of the regulatory regime in which businesses in the oil and gas sector operate, given the risk inherent in such heavy industry. From January 2005, all safety regulation for facilities and operations covered under the Commonwealth and State *Petroleum (Submerged Lands) Acts* were transferred from DOIR's Petroleum and Royalties Division to the National Offshore Petroleum Safety Authority (NOPSA).

The regulation of safety in the Australian petroleum industry is covered under the 'Safety Case' regime, which entails a risk-based objective-setting approach to safety management (developed following the inquiry into the 1988 Piper Alpha disaster in the United Kingdom's North Sea).

The Safety Case was introduced in 1992 and was required under the *Petroleum (Submerged Lands) Acts* for all existing offshore facilities and mobile offshore drilling units from July 1996. The Safety Case requirement has been progressively implemented for onshore facilities covered by WA state legislation since 1996.

Under this regime, an operator of a facility must submit a Safety Case to the regulator and must have an 'accepted' Safety Case in order to commence construction, operate, or commence decommissioning of a facility or pipeline at a petroleum site.

To demonstrate compliance with the legislative safety objective, each operator must provide evidence that they have an effective integrated Safety Management System (SMS) in place that identifies, assesses, eliminates and/or manages risk at the facility. It is essential that the workforce (those who are major stakeholders) is involved in the Safety Case development and review processes.

The written safety case, once formally accepted, becomes the basis of co-regulation between governments and operators and is the agreed standard against which operators are assessed.

The Safety Case is however a living set of documents, and must be subject to a process of continual improvement, planning, implementation, monitoring and review.

As part of this, the SMS will include processes, programs and procedures for auditing, incident investigation, change-management, SMS monitoring and Safety Case review. In particular, the Safety Case must be revised in the event of any significant change, and/or at least every five years.

State Agreements

State Agreements are contracts between the State and major project developers that are ratified by Parliament. Most major projects in WA operate under State Agreements, which were established to provide long term certainty, security of land tenure, facilitation of complex approvals and reduction of sovereign risk.

State Agreements differ from other primary regulatory approvals in that they are a facilitating mechanism for development for specific projects. Agreements specify the rights, obligations, terms and conditions for development of the project, and establish a framework for ongoing relations and cooperation between of the State and project proponent.

The development proposals clause in a State Agreement requires the proponent to submit detailed proposals on its overall development. Detailed information is required on operational plans, plant and equipment, workforce, workforce accommodation, project specific infrastructure, social infrastructure, impact on public infrastructure and services, land requirements and environmental management. The development proposal is submitted to the Minister for State Development for final go-ahead approval of a project.

However, before the Minister approves proposals, all primary approvals must be finalised, such as environmental approval, native title agreements, and heritage clearances.

WA Government Policy on Securing Gas Supplies

Consultation Paper

In February 2006, DOIR released its consultation paper, *WA Government Policy on Securing Domestic Gas Supplies*. The Consultation Paper suggests that it is necessary for the Government to seek to reserve gas for domestic consumption based on the assumption that:

> *"… in the absence of reservations, gas producers will prefer to market their gas in export markets where they can get higher returns, and will therefore restrict the amount of gas that they provide to the domestic market (or avoid the domestic market altogether). Alternatively, gas producers will only sell gas domestically if they can get a price equivalent to LNG netback price."*[19]

The Consultation Paper then goes on to state that the objective behind the state's imposition of domestic gas reservation was:

> *"to ensure that sufficient supplies of competitively priced gas are available to underpin Western Australia's long term energy security and economic development."*[20]

In order to evaluate whether or not gas reservation is necessary, the Consultation Paper undertook an analysis of current WA gas reserves and the likely future demand and supply position. On the basis of this analysis, it concluded that:

> *"WA's forecast gas demand in the medium and longer term can only be satisfied if the State has access to a share of the reserves that have been identified as underpinning existing or potential LNG export projects."*

The Consultation Paper suggested that market forces would be unable to deliver the WA Government with a degree of comfort that future supplies would come to the domestic market, and suggested that even if market forces were allowed to operate, the price for domestic gas would be likely to increase.

The Consultation Paper also discussed possible mechanisms for reserving domestic gas, and also briefly detailed other potential alternatives to gas reservation.

The Consultation Paper concludes by noting that the discussion centres only around issues associated with the development of natural gas resources, and that in the absence of the perceived need for an immediate response, decisions regarding

approvals for new LNG projects would preferably be taken in the context of a broader State Energy Policy.

Limitations of the Consultation Paper

The analysis of the gas market and the perceived need for a gas reservation policy in Western Australia was based on the view that there will be a shortage of gas that will be supplied to the domestic market by 2020.

However, this statement rests on a number of critical assumptions, all of which need to be examined in more detail. These include:

- known gas reserves are noted as currently standing at approximately 113 Tcf, but for the purposes of the analysis are assumed to be fixed, despite the fact that new supplies of gas are being found all the time;
- the 113 Tcf of gas, whilst having only a 50 per cent probability of being commercialised, is assumed to have a higher proportion of commercialisation than 50 per cent, potentially overstating available reserves;
- the 113 Tcf includes gas reserves in both the Browse and Bonaparte Basins which are assumed to be able to be tied back into infrastructure to make them available to the domestic market; and
- future gas projects are assumed to supply gas for export only, rather than for the domestic market.

In addition, the Consultation Paper should have investigated:

- the potential for new domestic-only fields to emerge to supply gas to the domestic market (rather than a reliance on existing or potential LNG projects for gas);
- the current market conditions with respect to the domestic price of gas, the trends in domestic prices over time, and the comparisons against LNG export prices;
- the factors that may be inhibiting the supply of gas to the domestic market;
- possible alternatives to gas reservation; and
- the possibility of reviewing the issue of domestic gas supply within the context of a State Energy Policy.

Such concerns were echoed in some of the public submissions by key stakeholders across the industry. A brief summary of the key issues raised in the submissions is provided in the next section.

Responses from Submissions

Some 26 (public) submissions were made in response to the initial DOIR Consultation Paper. Of these, six were prepared by gas consumers, while 11 were from suppliers or producers (including BHP Billiton, although it is both a producer and consumer).

Two submissions were made by pipeline operators being the two major transmission systems in WA – DBP and GGP. A further seven submissions were made by entities not directly involved in the gas supply chain, but with an interest in the industry.

This included the CCI, the Australian Petroleum Production and Exploration Association, the Chamber of Minerals and Energy, as well as the Department of Treasury and Finance of WA. It also included the Griffin Group, a direct competitor to gas in the WA energy market.

The public submissions to the Consultation Paper presented a range of issues that required consideration in the context of a possible WA Government policy to reserve gas supplies for the domestic market.

Overall, the central themes identified in the submissions were:

- whether market mechanisms or government intervention were most appropriate in relation to the gas market;
- the implications of a reservation policy; and
- other policy approaches to ensure security of supply.

Each of these themes is briefly summarised below.

Market Mechanisms versus Government Intervention

Overall, the majority of the submission did not support the adoption of a formal reservation policy, on the grounds that there was no identifiable market failure. Alcoa and Synergy (two of the largest consumers of gas) and Horizon Power were supportive of a reservation policy on the basis there was an identifiable risk that market failure could occur warranting government intervention.

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On one hand, many submissions[21] suggested market mechanisms would help to ensure that the domestic gas needs for Western Australia will be met, without the need for market intervention. This is on the grounds that:

- there does not exist a supply problem, given the stated gas reserves and the strong likelihood that additional reserves will be found in future;
- major gas consumers have strong bargaining positions – so can secure commercially attractive prices; and
- there exists a strong incentive to supply into the domestic market, as it provides accelerated returns for large LNG projects with long time horizons, is less capital intensive to supply to the domestic market and provides diversification (in terms of supply to different customers) for gas producers – meaning that domestic gas can be supplied to the domestic market and potentially at prices below the netback price.

In addition, many submissions suggested that the current reservation policy, which has helped to set the price of domestic gas at artificially low levels, is indeed impeding the efficient functioning of the market. By contrast, Alcoa argued that low market prices resulted from competition by Apache. It has been suggested that the underinvestment in domestic gas production was due to the low market prices, while at the same time there has been significant investment in LNG for export due to the higher prices received. Accordingly, keeping prices artificially low has in fact reduced the supply of domestic gas.

In this regard, an efficient functioning market will necessitate an increase in price, although the extent of the required price rise was not made clear.

On the other hand, submissions from key gas customers[22] suggested that existing market mechanisms would be unlikely to guarantee continued security of gas supply for domestic use on the grounds that:

- the domestic gas market is not sufficiently developed to operate efficiently – leading to a situation where the availability of gas would be constrained and the price of gas significantly increased;
- there is little competition in the production and supply of gas to the domestic market; and
- the inherent characteristics of the gas market make it unlikely that an efficient market would operate, due to the fact that gas has historically been sold under long term contracts, and that international benchmark pricing mechanisms do not exist.

Implications of Domestic Gas Reservation

There were a number of key concerns expressed in the submissions over the potential impact of a domestic gas reservation policy. These are set out below.

- *Sovereign Risk*: A key concern is that intervention in the market could impact on Western Australia's reputation as an investment destination. It could force companies to reconsider their global project priorities, potentially looking to develop other resources where sovereign risk is not apparent. (However, the extent to which sovereign risk remains an issue is debatable in light of the current requirements of the reservation policy – see discussion on page 73.)

- *Reduced Competition*: A reservation requirement would mean that the market balance would be tilted very much in favour of the larger international exploration companies, and therefore reduce supply-based competition by crowding-out smaller suppliers.

- *Competitiveness of Other Energy Sources*: A reservation policy would be incompatible with National Competition Policy to the extent that it would place other energy sources (such as coal) at a competitive disadvantage in the domestic market to the extent that gas would be sold below market prices. It could also jeopardise the Government's own renewable energy target, by placing renewable sources of energy (which are already cost uncompetitive) at an even greater disadvantage.

- *Competitiveness Against Other Nations*: A reservation requirement imposed on gas producers in Western Australia would impose a further cost, and potentially place them at a competitive disadvantage with other gas producing nations.

- *Impact on Economic Viability of Projects*: A uniform reservation policy would not be equitable as it would not take into account the differences in development and gas transport costs for different fields. Marginal fields would be burdened to a far greater extent relative to larger more viable fields. It would also impact on the viability of larger LNG fields to the extent that it would make it more difficult for projects to achieve their required rate of return.

- *Impact on Exploration Industry*: A reservation policy would create a disincentive to the development of smaller gas fields which require a modest increase in the gas price to achieve commercial viability, thereby discouraging exploration targeted solely to the domestic market.

- *Impact on the WA Economy*: To the extent that investment in the gas industry could be diminished from a reservation policy, this would have significant consequences for the WA economy, of which gas is a key input.

Some submissions highlighted experiences in other jurisdictions which have imposed a reservation policy.

- *Victoria and South Australia*: Reservation requirements were arguably responsible for the delay in the development of an integrated gas market in the eastern states.

- *India*: Decades of intervention and subsidised gas prices have resulted in a misallocation of resources and reduced investment in new gas production infrastructure.

- *Indonesia*: The Indonesian Government's decision to give priority to the domestic use of gas has resulted in the cancellation of a number of LNG cargoes for 2006 and seriously damaged Indonesia's reputation for reliability of supply and attractiveness for gas investment.

- *Peru*: The world class Camisea gas field is required to meet internal market supply considerations before even contemplating export. As a result, after two decades and three different owners, production has yet to commence.

- *Venezuela*: Law requires that developers must not only supply gas to the domestic market, but also help develop the domestic gas market. Venezuela is said to have the seventh largest reserves in the world, with many ideal candidates for a large LNG development. However, none of these fields has been developed because of the mandated condition to participate in the domestic market.

- *Russia*: Government insistence on a domestic gas reservation has meant that buyers have thus far been reluctant to sign long term supply contracts with project developers, because of the uncertainty associated with the domestic requirement.

While there are shortcomings to several of the reservation policies currently adopted by governments around the world, there are examples where governments have successfully aided in the development of the oil and gas sector, whilst also catering to the needs of domestic users.

One such example is Qatar, where the government continues to have a leading role in the gas industry through its holding company Qatar Petroleum (QP), which is responsible for all phases of the oil and gas industry. Indeed, QP has adopted the need to meet national oil and gas demand in a cost-effective way as one of its specific commercial objectives.

Table 5
Examples of Specific Oil and Gas Reservation Policies

Country	Policy Details
United States	Strategic Petroleum Reserve (SPR): *oil stockpile for use in case of severe energy supply disruption.* Royalty in Kind Program: *delivery of oil and gas royalties to government as physical product rather than as cash.*
Indonesia	Domestic Market Obligation (DMO): *explicit policy of reservation of a proportion of oil and gas produced for domestic use, instituted via Production Sharing Contracts (PSCs). There has also been a DMO proposed for coal.*
Algeria	Satisfaction of Domestic Gas Needs: *each producer will help cover the domestic market's gas needs if necessary, based on their proportion of overall national production.*
Tunisia	Domestic Market Obligation (DMO): *for oil, 20 per cent of production must be dedicated to the domestic market. For gas, there is a priority to supply the domestic market with any gas discovered and which is in excess of the producer's own needs (ie. its' own power generation or re-injection to enhance oil recovery).*
Malaysia	National Depletion Policy: *domestic production limits for oil and gas.*
Timor-Leste	Domestic Market Obligation (DMO): *option for government to purchase from producers their proportionate share in national production, up to 25 per cent, in case of "national need" for crude oil and natural gas liquids.*

Source: Curtin University

Initially, the country's immense gas reserves were exploited wholly by QP for local consumption, however, with a view to significantly increasing production and concentrating on export markets, QP entered into partnerships with overseas companies (although QP maintains the controlling stake in each) to form two Qatari joint stock companies – Qatargas in 1984 and RasGas in 1993.

This structure has proved successful, with significant amounts invested into Qatar's oil and gas sector by foreign companies, while downstream processing of gas has also been established (not least because of considerable infrastructure assistance from the Qatar government).

Table 5 gives some examples of policies introduced in some oil and gas producing nations, although these policies have generally not been applied retrospectively.

Other Policy Responses

A number of policy responses have been presented in the public submissions. These are detailed below.

- *A State Energy Policy*: A consistent view was presented of the need for such an issue to be considered in the context of a State Energy Policy, which includes

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all components of energy, and addresses issues across the whole gas supply chain.

- *Retention Leases*: It has been suggested that stricter enforcement of an explorer's/producer's right to hold gas under a retention lease be initiated, which would help to ensure that reserves are developed rather than "banked" for the future.

- *Encourage Investment in Infrastructure*: Government could continue to subsidise key infrastructure for future gas developments to assist in improving the commerciality of domestic gas projects.

- *Infrastructure Access*: Open access principles, such as those applied to gas pipeline infrastructure, could be extended to include gas gathering and processing infrastructure in order to facilitate the development of new sources of supply.

- *Tradeable Reservation Requirements*: This would help minimise the need to duplicate domestic gas processing plants by allowing LNG projects to "pay" domestic gas producers to meet their obligations in return for LNG cargoes.

- *Taxation Policy*: It has been suggested that the Federal Government could assist in the development of the domestic gas market by addressing high PRRT rates and capital depreciation for smaller gas developments.

- *Approvals Processes*: Submissions were particularly concerned over the time taken for projects to go through the necessary approvals processes. Any changes to speed up the approvals process would assist in bringing supply on stream much faster.

Gas Reservation Policy

On 12 October 2006, the Premier announced the WA Government's policy on securing domestic gas supplies. The centrepiece of the policy is to set aside for domestic use the equivalent of 15 per cent of gas available from any future offshore development.

The final policy noted that:

- the WA Government will negotiate with proponents of LNG projects to include a domestic gas supply commitment as a condition of access to Western Australian land for the location of processing facilities;

- the objective is to secure domestic gas commitments up to the equivalent of 15 per cent of LNG production from each export gas project;

- negotiations with LNG project proponents will be undertaken on a case by case basis, regarding the method by which they will meet their domestic gas commitments. Market mechanisms designed to provide gas producers with maximum flexibility will be considered – including the option of fulfilling the obligation from a different source; and

- the price of gas sold onto the domestic market will be determined through commercial negotiations between the gas producers and the consumers of that gas.

The finalisation of the policy has taken into consideration the range of issues and options presented in the submissions to the Consultation Paper.

It is not clear, however, that the policy alone will help to deliver the objective of providing WA consumers with certainty over supplies, given that the policy is targeted at only one section in the gas supply chain.

The remainder of this report will look at the key issues that have been discussed in the submissions to the Consultation Paper and during interviews with market participants across the whole gas supply chain – rather than simply at the production end, and more specifically through formal gas reservation requirements.

Supply Chain Analysis

The issues detailed in the submissions to the Consultation Paper highlight the need investigate the whole gas supply chain, not just at the production level.

By looking at the gas industry across the whole supply chain, it is possible to determine those issues which are potentially impacting on the supply of gas to the domestic market.

At its broadest level, the gas supply chain can be broken down into production, distribution and consumption. Each of these broader categories can be further broken down. For example, production can be sub-classified into: (1) exploration; (2) extraction; (3) processing and storage; and (4) sales and marketing, while at the other end, consumption can be sub-classified into: (1) wholesalers; (2) retailers; and (3) end consumers.

Production

There are currently up to 19 projects producing gas in Western Australia, although not all of these compete in the domestic gas market, as the supply from some projects is used entirely in the operations of the project participants.

Supply is concentrated within the North West Shelf Gas (NWSG), which comprises Woodside Energy (as operator), BP Developments Australia, Chevron Australia, BHP Billiton and Shell Development (Australia) and Japan Australia LNG (MIMI) – all of which have equal one-sixth interests in the venture.

This project currently accounts for up to 63 per cent of domestic gas supply in WA. NWSG is the specialist marketing agency established by the North West Shelf Venture participants to market gas and administer contracts with customers in Western Australia. It therefore specialises only in the marketing of gas to customers.

Other project operators involved in the production of gas for the domestic market are generally integrated across all of the key aspects associated with the production of gas – that is, they tend to be in the business of exploring and producing gas, while marketing is often undertaken on a joint basis or by the operator.

The Harriet area project is Western Australia's second biggest supplier, accounting for almost 19 per cent of the domestic gas market. The remaining 18 per cent of domestic gas supplies are made up by smaller projects, most of which are owned on a joint basis (see Table 4 on page 35).

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There are a number of external environmental factors that must be taken into consideration when making an assessment of the gas production industry. These include:

- *Natural Environment* – including critical gas field characteristics such as location of the field, ocean depth, gas quality, condensate content, distance from shore and proximity to infrastructure – all of which impact on the costs and economic viability associated with a particular project;

- *Economic* – including broader economic variables such as inflation, interest rates, exchange rates and overall economic growth, which influence the level of demand. Unlike oil, gas production requires foundation customers to help to underpin a project, given the significant capital costs associated with a gas project;

- *Technological* – including technological advances which make possible the exploration, extraction and processing of gas from deeper and more hostile ocean environments; and

- *Government* – including the stability of legal and political systems, the impact of taxation policies, approvals processes and other government laws and regulations pertinent to the gas industry – including exploration permits and retention leases, as well as reservation policies.

In addition to these external environmental factors, industry-related factors can impact on the gas industry. A common approach to assessing the industry environment is Porter's Five Forces Model[23]. This model focuses on the five forces that shape competition within an industry: (1) the risk of entry by potential competitors; (2) the degree of rivalry amongst established companies within an industry; (3) the bargaining power of buyers; (4) the bargaining power of suppliers; and (5) the closeness of substitutes to an industry's products. Overall, it can be said that the stronger each of these forces, the more limited the ability of established companies to raise prices and earn greater profits.

Analysing the production industry with reference to these five forces, it can be concluded that there are competitive elements to the upstream sector, although competition is constrained by certain characteristics to the extent that:

- *significant barriers to entry exist* with respect to the production of gas due to the capital investment requirements and long time horizons associated with developing a gas field;

- there is a *high degree of market power*, with a small number of large players in the market, and this degree of market power is even more concentrated when one looks at the North West Shelf Venture as one entity;

- there is a *medium degree of bargaining power on the part of domestic customers*, to the extent that five large customers demand around 90 per cent of total domestic supplies, and the size of these customers has the potential to underpin new developments as supplies start to dry up. However, once international markets are taken into account, the degree of bargaining power on the part of domestic customers is diminished, particularly if gas producers weigh up the benefits from domestic production against LNG exports;

- as large vertically integrated entities, *the degree of bargaining power of suppliers (such as capital equipment suppliers) is low*; and

- the *threat of substitutes is medium* to the extent that gas faces strong competition from coal and renewable energy sources which benefit from various forms of government subsidy. As other sources of energy, including renewable energy and nuclear energy, become more cost effective over time, this threat may increase. Admittedly, this is more of a long-term issue.

Based on the above analysis, it can be concluded that the production industry has had competitive elements which helped deliver some efficient outcomes. However, high barriers to entry mean that a relatively few large companies dominate the production of gas in Western Australia and also hold a large proportion of undeveloped reserves.

In this context, the external environmental assessment shows that the success or otherwise of a producer (large or small) relies on the ability to obtain exploration permits and retention leases. The extent to which production eventuates will depend on the characteristics of the field and the demand for gas, all of which underpin the economics of the field.

Government policy is the other key factor which can have a large bearing on the industry. It is in relation to government policy, and changes in government policy which will be the focus of this analysis.

Gas Reservation Policy

The announcement by the Premier on 12 October 2006 of the WA Government's policy on securing domestic gas supplies was based around a reservation requirement equivalent to 15 per cent of gas available from any future offshore development.

The method by which such commitments will be met will be negotiated between the producers and the WA Government, with consideration given to allow for such obligations to be fulfilled from a different source.

In doing so, the WA Government has signalled that it does not believe that market mechanisms will be able to achieve secure supplies of gas to the domestic market, therefore requiring government intervention in the form of a reservation requirement on producers.

In general, the majority of submissions to the Consultation Paper did not support the introduction of a reservation requirement on gas producers. Instead, there was a strong belief that market mechanisms would be the most efficient means by which domestic gas supplies could be secured.

This view was not only raised by the large LNG producers (such as NWS venture, BHP Billiton, BP and ExxonMobil), but also smaller domestically-focussed producers (such as ARC Energy, Santos and Strike Oil), distributors (such as Goldfields Gas Transmission) and even consumers (such as Alinta).

There were also a range of other key stakeholders (including CCI, APPEA, CME, Griffin Group, ResourcesLaw International, Inpex Browse, WA Department of Treasury and Finance, Collie Region and Coal Industry Futures Group) which did not support the introduction of a reservation policy.

However, some participants favoured some form of reservation policy (Alcoa and Synergy) in order to guarantee continued security of supply. This point of view stems from the nature of the WA gas market, in that it is not fungible and fluid like other commodity markets (e.g. oil) meaning market mechanisms may not be relied upon to guarantee efficient outcomes.

Policy Issues

The high-level nature of this policy has meant that there is a degree of uncertainty as to how the policy will be implemented at a practical level.

What is clear in the policy statement is that there will be a reservation requirement equivalent to 15 per cent of gas from future developments, and that the WA Government will afford some flexibility in its negotiations with producers over the method by which such requirements will be met.

The extent to which such flexibility is afforded is unclear. For example, the policy document is silent as to whether the commerciality of bringing gas to the domestic market will be considered for those LNG fields. The recent decision in relation to Woodside's Pluto project clearly demonstrates the government's willingness to ensure commerciality tests are included.

Such a commerciality provision is included in the State Agreement for the Gorgon Gas Project. Such a provision is vital for such projects and it is therefore essential that future agreements be required to bring gas to the domestic market only where

it is commercial to do so, and that the test for commercial viability includes significant consultation with end consumers.

It is also unclear whether each project will be bound by the 15 per cent requirement, in the event that it is considered to be uncommercial to supply gas to the domestic market.

If such a requirement remains, then it amounts to an additional impost on gas producers. This will mean that producers may be required to fulfil their obligations through other methods (such as by trading their requirements to other "domestic-only" producers, or by investing in smaller fields only suited to domestic production), although this largely depends on the economic characteristics of each proposed development.

If a particular producer is absolved on the grounds that it is not commercial for that producer to supply gas to the domestic market, this would make the policy inequitable.

While the policy may contain certain shortcomings, it remains the view of Alcoa and Synergy that some form of reservation is necessary in order to guarantee continued security of supply.

While such participants broadly favour market mechanisms over government intervention, for the most part, their views are based on the fact that there is no fungible market for gas in WA, with domestic supplies concentrated among only two projects.

Hence, in the absence of any intervention, there is concern that supplies could dwindle and the domestic price of gas could escalate, putting at risk broader economic growth given the importance of gas as an energy source for WA.

While there is merit in this view, most proponents of this position agree that a reservation policy should ideally be implemented in the short term, while wider issues such as infrastructure, approvals processes and taxation could be adjusted to provide greater incentives and ability for field development. Getting these wider settings right would be less distortionary than a direct reservation requirement.

If intervention in the market is deemed necessary in the short term, it will be essential that reservation requirements be individually negotiated to ensure that they represent a balance of interests between the producer and the WA Government.

Admittedly, such a balance may be difficult to reach in practice, given the range of issues that need to be taken into account – from project specific factors that impact

on its commerciality (see page 32 for discussion of project economics), to broader factors that ensure agreements are equitable and efficient relative to other projects.

In addition, there is a risk that reservation could result in protracted negotiations and delays for development proposals, as well as disputes between the state and federal governments on both the constitutional and taxation fronts.

Hence, this policy even if implemented as a stop-gap will potentially add to the development costs for producers and could bring about a similar outcome to that which would have resulted without government intervention – that is, the development of fields for the domestic market.

Retention Leases

In its submission to the Consultation Paper, Alinta put the view that:

> *"..the fundamental issue relating to the ability to process gas for the domestic gas market is the explorer / producer's ability to hoard gas supply."*

Alinta's submission suggested that there was a lack of stringency in the legislative substance of the present retention lease system operating in the WA jurisdiction or in the practical operation of the system.

Alinta believes that an improvement can be achieved within the existing legislative scheme applying to retention leases through a more stringent assessment of claims by parties seeking retention leases that the reserves the subject of the lease are not presently commercially viable. It is argued that this could be achieved by changing the mechanics of the legislative process through a gazetting process that allows other players to submit development options with an associated absolute undertaking to develop the field.

Legislative Issues

A retention lease is said to provide for security of title for petroleum resources that are not presently commercially viable but which have genuine development potential. Genuine development potential is said to mean a commercial viability within 15 years.[24]

Western Australia has its own legislation relating to the exploration for and the production of petroleum located onshore. Depending on the location of an offshore reserve, a retention lease may be granted pursuant to either the relevant Commonwealth or State Act, namely the *Petroleum (Submerged Lands) Act 1967 (Cth)* or the *Petroleum (Submerged Lands) Act 1982 (WA)*.

Originally, the administrative basis for offshore petroleum exploration and production was contingent upon a 1967 agreement between the Commonwealth

and the States (including the Northern Territory).[25] The reasoning behind the system of Commonwealth legislation with mirror State acts was that the jurisdiction over offshore resources was, at the time, unclear and by providing for the application of identical Commonwealth and State legislation exploration was protected regardless of which government was ultimately found to have legislative power.

In 1973 the Commonwealth enacted the *Seas and Submerged Lands Act 1973 (Cth)* which asserted Commonwealth sovereignty in respect of the territorial sea.

The High Court upheld the validity of this legislation in *New South Wales v Commonwealth (Seas and Submerged Lands Case)*, with the effect of the ruling being that the seaward boundaries of the States were determined to lie at the low water mark except in the case of bays, gulfs and other indentations within the limits of a State as at the date of federation.

Subsequent to this decision agreement was reached at the October 1977 Premiers' Conference to establish a joint Commonwealth-State scheme relating to the mineral and petroleum resources of the Australian territorial sea.[26]

The agreement was effected by complementary State and Commonwealth legislation.[27] In due course the Northern Territory and the States each passed their own Petroleum (Submerged Lands) Act in terms substantially identical to the *Petroleum (Submerged Lands) Act 1967 (Cth)* as amended in 1980. This 'mirror' legislation is collectively referred to as the 'Offshore Acts'.[28]

The effect of the Commonwealth agreement and subsequent legislation was to vest in each of the States and the Northern Territory proprietary rights and title in respect of lands beneath the coastal waters to the three nautical mile limit.[29] The legislation also provided, in effect, that the provisions of laws in force in the State from time to time (other than criminal laws and laws of the Commonwealth) would apply to the coastal sea as if the coastal sea were part of the State. Where, the coastal sea was defined as:[30]

- the territorial sea adjacent to the State; and
- the sea on the landward side of the territorial sea adjacent to the State that was not within the limits of the State, and including the airspace over and the seabed and subsoil beneath any such sea.

With respect to offshore petroleum, the Commonwealth has sovereignty in respect of the territorial sea,[31] as well as sovereign rights in respect of the continental shelf[32] and the exclusive economic zone[33] for the purpose of exploitation of their natural resources.[34]

Consequently, in strict constitutional terms, the sovereignty over petroleum of the States and the Northern Territory extends only to the low-water mark and it is the Commonwealth which is entitled under international law to exercise sovereignty over petroleum under the territorial sea, within the exclusive economic zone and on the continental shelf.[35]

However, following the agreement negotiated between the Commonwealth Government and the States in 1979[36], the Commonwealth conferred power on the States and the Northern Territory to make laws for matters including mining operations in respect of the coastal waters[37] and granted them proprietary rights to the seabed[38], where importantly section 4(2) of the *Coastal Waters (State Powers) Act 1980 (Cth)* provides that coastal waters extend three nautical miles from the low-water mark.

An important conclusion is to be drawn from the history of the legislation is that any proposal that effectively makes it more difficult for an applicant to be granted a retention lease (or have one renewed) by changing the legislative criteria for grant or renewal, would require such a level of interstate and Commonwealth cooperation as to render such amendment unlikely.

Legislative Criteria for Assessing Retention Lease Applications

According to the Commonwealth Department of Industry, Science and Resources (Petroleum and Electricity Division) 'Offshore Petroleum Guideline for Grant and Administration of a Retention Lease ("Offshore Petroleum Guideline"), the retention lease system is said to:

- provide security of title for petroleum resources that are not currently commercially viable but which have genuine development potential. That is where development is likely to be commercially viable within 15 years;

- ensure exploration acreage which may contain potentially commercial exploration targets is periodically opened up to competitive exploration through the normal permit partial relinquishment provisions and the work program bidding system. They also promote development of commercial discoveries;

- Another objective of the lease provisions is to ensure the lessee actively seeks to address those matters inhibiting the commercialisation of the discovery.[39]

Section 38B of the *Petroleum (Submerged Lands) Act 1967 (Cth)* provides for the grant of a Retention Lease over a less than commercial petroleum discovery. Such a grant follows the grant of a permit under the provisions of Part III Division 2 of the *Petroleum (Submerged Lands) Act 1967 (Cth)*.[40]

Under section 38A(1) of the *Petroleum (Submerged Lands) Act 1967 (Cth)*, a permittee may apply to the Designated Authority for a retention lease in respect of a block or blocks, pursuant to which an exploration permit is in force. The application must, among other things, set out the commercial viability of the recovery of petroleum from the area, and particulars of the possible future commercial viability of the recovery of petroleum from that area.

The Designated Authority may require the applicant to furnish further information (section 38A(3) of the *Petroleum (Submerged Lands) Act 1967 (Cth)*), where the application is either within two years of the relevant blocks having become a location or having been extended out to no more than four years at the discretion of the Designated Authority (section 38A(4)(b) *Petroleum (Submerged Lands) Act 1967 (Cth)*).

Under section 38D of the *Petroleum (Submerged Lands) Act 1967 (Cth)*, the initial term of the retention lease is 5 years. Leases can be renewed for further 5 year periods if the tests provided by section 38B continue to be met and previous lease conditions have been met.

This is the case except in a situation where section 38BC of the *Petroleum (Submerged Lands) Act 1967 (Cth)* applies and a production licence reverts to a retention lease. In this situation, the retention lease blocks are excised from the exploration permit and the work program commitments applicable to the residual permit will not be reduced after excision of lease blocks.[41] The application period in respect of an application for the block or blocks which constitute the unused area (and which are excised from the exploration permit) is either 5 years from the day on which the licence began (where no operations ever commenced) or from the last day on which commenced recovery operations ceased (section 38BB(4)(a) and (b)).

Retention leases may be the subject of suchconditions as the Joint Authority sees fit (section 38H(1)). Generally, the types of conditions that are attached to retention leases are designed to promote the lessee to enhance the commerciality of a field in a lease area (section 38H(2)).

In assessing whether a discovery meets the criteria for a retention lease the Joint Authority has regard to the following statutory criteria:

- the area comprised in the block, or any one or more of the blocks, specified in the application contains petroleum (section 38B(1)(c)(i)); and
- 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 (section 38B(1)(c)(ii)).

The critical aspect of these criteria is then when will a retention lease be considered "*likely to become commercially viable"*.

For the purposes of section 38B *likely* should be interpreted to mean a "*substantial or real chance as distinct from what is a mere possibility*"; and commercially viable petroleum should be interpreted to mean that the petroleum could be developed:

- given existing knowledge of the field (this includes mapping and resource estimates at proved, probable and possible probability levels); and
- having regard to prevailing market conditions; and
- using proven technology readily available within the industry.

The Offshore Petroleum Guidelines provide some detail as to the standard interpretations that are applied by the Joint Authority in these matters. Within the formulation set out above:

- Consideration is given to the commercial rates of return from recovery of the petroleum in question (including recovery of all operating and capital costs and taxes, royalties and other charges). Consideration is then given to whether the petroleum in question demonstrates an acceptable rate of return. That is to say, whether, the commercial rate of return exceeds 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.
- 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.
- Where commercial viability is dependent on combining a development with other potential third party developments or access to third party facilities or technology, the petroleum will not be considered commercially viable if the titleholder is unable to complete an agreement for joint development or complete an access agreement for use of facilities or technology which provides an acceptable rate of return.[42]
- 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 the terms 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 (e.g. 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 can demonstrate 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 where this is necessary to demonstrate supply capability to potential buyers.

The Offshore Petroleum Guidelines also provide some indication as to the appropriate and therefore usual form of applications for retention leases. The Offshore Petroleum Guidelines state that an application for a retention lease should:

- identify the circumstances which would commercialise the discovery and address their likelihood of occurrence;

- include an analysis of the commercial viability of a prospective development including the assumptions, the methodology and the conclusions reached by the applicant; and

- provide sufficient information to demonstrate that the assumptions and methodology are realistic and lead to a likely outcome (and, if appropriate, a range of outcomes). The impact of alternative reasonable assumptions should also be identified and assessed.

The Offshore Petroleum Guidelines then go on to state that the Government will analyse the extent to which there are reasonable grounds for adopting alternative assumptions and methodologies.

It can be noted that the process established by section 38B of the *Petroleum (Submerged Lands) Act 1967 (Cth)* is not adversarial. Applications by the holder of an exploration permit made pursuant to section 38A are made to the government in the form of the Joint Authority and the Designated Authority. The

decision as to whether the application satisfies the relevant criteria is made by Government. As the system is not adversarial, there are no other parties to the proceedings other than the applicant and the Government. The application is therefore not disclosed to any other party.

Further, the *Petroleum (Submerged Lands) Act 1967 (Cth)* does not provide for any gazetting system which would make public the substance of a retention lease application. This was one of the changes suggested by Alinta, that is a gazetting process that:

> *"…would allow other players to submit development options with an associated absolute undertaking to develop the field."*

This suggestion does not appear to go so far as to require that the details of an applicant's submissions be made publicly available or available to other potential applicants. Doubtless, a variety of objections may be raised to such a suggestion, most centring on the fact that such a process would involve disclosure of commercially confidential information to competitors regarding an applicant's cost structures and business practices.

The Alinta proposal appears to suggest an option for interested parties other than the applicant (who under section 38A is the exploration permit holder for the location) to put a proposal to develop the field. The Alinta proposal is not accompanied by further detail as to what might constitute an 'absolute undertaking to develop the field'. Indeed, some difficulties may exist in such a process. Aside from interpreting the term 'absolute undertaking' and devising a scheme for enforcing such an undertaking, one obvious problem relates to the practical timing of development.

Presumably, even if such an undertaking could be meaningfully given and accepted, the undertaking would come from a party that previously had no proprietal rights to the location. That party, even if it considered itself willing and able to develop the location, would be unlikely to be ready to commence that development immediately. Inherent in such an undertaking would be the fact that some time lag, and perhaps a significant one, would exist between the allocation of the lease to the new lessee and the commencement of development. Depending on the extent of the time lag practically involved, it may be that such a system may not contribute a great deal towards the desired end of significantly expediting the development of gas fields.

That said, the *Petroleum (Submerged Lands) Act 1967 (Cth)* does require gazettal in numerous circumstances. Some even involve competitive purposes broadly analogous to that contemplated by Alinta. One example is where, pursuant to section 87A(2) of the *Petroleum (Submerged Lands) Act 1967 (Cth)*, the Designated Authority corrects the register to accurately record the rights and

interests in relation to a title. Where this occurs, pursuant to section 87A(3)(a) and (b), the Designated Authority publish in the Gazette a notice:

(a) setting out the terms of the entry that the Designated Authority proposes to make in the Register; and

(b) inviting interested persons to give to the Designated Authority, by such day as is specified in the notice, being a day not earlier than 45 days after the publication of the notice, submissions in writing relating to the making of the entry.

Where submissions are received, the Designated Authority, pursuant to section 87A(4)(a), shall take those submissions into account before making an entry in the Register.

As well as being an example of a gazetting process, section 87A also provides an example of government taking into account submissions of third parties.

Alinta suggests a process to apply where a retention lease is sought by the holder of an exploration permit, where the holder maintains that the field is not yet commercially viable. Alinta suggests a gazetting process as a trigger to allow another party to give an absolute undertaking to develop. In such circumstances, the Alinta suggestion implies that the existing holder of the exploration permit should lose its interest in the location and the government should transfer the interest in the location to the third party that has given the absolute undertaking.

As such, the Alinta suggestion goes beyond the process set out, for example, by section 87A, which gives third parties an opportunity to put submissions to the government relevant to an impending decision. In the case of retention leases, a middle approach might be to use the gazetting process to allow third parties to make submissions to the government with respect whether and when a field might be commercially viable. The government could be required, as in the section 87A situation, to take those submissions into account in making its decision – without the process allowing for an automatic shift in proprietal interests from the exploration permit holder/applicant to a third party that has given an absolute undertaking.

The above analysis is not to suggest that either or any reform is warranted. It merely explains both the mechanics of the Alinta proposal and at least one other possible option. As has been noted, because of the history and co-operative nature of the relevant legislation, substantive legislative change (which the Atlanta suggestion would involve) would require such a level of interstate and Commonwealth co-operation as to render such amendment extremely difficult.

Ultimately, whether any legislative change to the process relevant to the grant and administration of retention leases is warranted depends upon an assessment of whether the criteria relevant to the grant or the practical application of those criteria to factual applications are striking an appropriate balance so as to prevent what Alinta refers to as 'hoarding', whilst also protecting property rights and minimising sovereign risk.

It was not in relation to the criteria established by section 38B that concern was raised, but rather that in some way these criteria were not being stringently enough applied, or, as expressed in the Alinta submission:

> *"…the government should seek to better understand the commercial viability of the discovery".*

It is difficult to assess the Government's application of the criteria established by section 38B. As was noted above, the section 38A and 38B process is not adversarial and does not produce written reasons for decision. Further, it has been noted that obvious explanations exist (relating to the sensitive commercial nature of applications), which explain why these applications are not gazetted or otherwise published as public record.

The obvious difficulty is that assessment of the Government's application of the criteria is hampered by an inability to consider the detail of applications and decisions that might be considered as contentious. In the course of the interview process for this analysis, CCI was given the opportunity to examine the submissions made in support of a recent successful WA retention lease application.

In addition, CCI was shown further commercial in confidence information regarding how such submissions are formulated, as well as, information setting out the procedural history of engagement between an applicant for a retention lease and the relevant State/Territory and Federal Government during the course of the application process. Whilst CCI cannot duplicate here the specific details of the application and ancillary information, two general observations can be made:

First, the written submissions which form the basis of a retention lease application are lengthy and detailed documents. The submission examined by CCI was in excess of 50 pages and might be described as being separated into two parts.

- The first part of the submission, amongst other matters, considered: the relevant retention lease application criteria; a summary of the domestic market for natural gas (consisting of both a historical and predictive analysis); and detailed geological information on the gas field. The applicant advised CCI that the information in the first half of the submission was generally available and could be reconstructed from information which was a matter of public record

(including information pertaining to the geology of the gas field rather than the domestic gas market generally).

- The second half of the submission contained information which might be described as 'commercial in confidence'. This part of the analysis mapped the conclusions from part 1 regarding the WA gas market and geophysics of the field to a supply side analysis of the applicant's prevailing costs structures. This section also contained a demand analysis regarding the availability of customers and likely prevailing prices which would determine whether, in the applicant's view, the field was commercially viable. The availability to government decision makers of estimates as to unit price at which the applicant asserts the relevant field would become commercially viable is significant. This is because it places government decision makers in the position where they may seek information from potential customers or groupings of customers to test assertions that sufficient demand at a stated unit price is or is not existent.

To some extent, the procedural mechanics set out in the Act do not adequately describe the actual application process which is in reality lengthy and interactive. The applicant explained to CCI that the report and recommendation complied by the Joint Authority was not merely based on the applicant's written submissions.

Rather, the report and recommendation of the Joint Authority were based on the original submission, various presentations to that submission as well as the applicant's responses to a series of written and oral questions which often focussed on technical issues regarding the size and the geology of the field and the basis and accuracy of economic assumptions, conclusions and costings. The applicant advised that these questions were multiple, often complex and were directed to the applicant by the Joint Authority over a period of months or longer. In this sense it appears that the Joint Authority already embarks on a process of testing the assertions made in the original application.

Secondly, there is already a role for third parties in the retention lease application system. As noted above, Alinta proposed:

> "*A gazetting process that allows other players to submit development options with an associated absolute undertaking to develop the field. "*[43].

Examination of the history of the Gorgon field retention lease illustrates the extent to which a role for third parties already exists in the process. The following exchange from the, albeit informal, Senate Economics Legislation Committee sets out the role played by a third party, Multiplex, in the government's consideration of the Gorgon gas field retention lease.[44]

> ***Senator GEORGE CAMPBELL****—I have some questions on resources. Mr Hartwell, can you tell us on what date the department received the*

application from Chevron Texaco to renew the retention lease for the Gorgon gas field?

***Mr Hartwell**—Certainly. At the moment there is an application from the operator of the Gorgon gas fields—that is, Chevron Texaco—for a retention lease in relation to those leases. That is presently under consideration between us, being a part of the joint authority which considers such matters under the Petroleum (Submerged Lands) Act, and the relevant minister from Western Australia.*

***Senator GEORGE CAMPBELL**—When did you receive the application?*

***Mr Hartwell**—I cannot remember the precise date, but it was probably late last year.*

***Senator GEORGE CAMPBELL**—When is the retention lease due to expire?*

***Mr Hartwell**—I cannot provide that precise date, but it is sometime this year.*

***Senator GEORGE CAMPBELL**—Can you take both those questions on notice?*

***Mr Hartwell**—Certainly.*

***Senator GEORGE CAMPBELL**—When did the department receive an objection from Multiplex to the renewal of this retention lease?*

***Mr Hartwell**—Again, there has been communication from Multiplex but I cannot recall the precise date. The communication was along the lines that they believed that they did have a viable project which could use the gas from the Gorgon leases, and that is a factor that will obviously be taken into consideration in deliberations between the two governments.*

***Senator GEORGE CAMPBELL**—Is there a legislative process which dictates the process the department has to follow for both the retention lease renewal and the objections?*

***Mr Hartwell**—Yes. The process is set out under the Petroleum (Submerged Lands) Act. There are a number of guidelines which cascade down from the Petroleum (Submerged Lands) Act in consideration of retention leases.*

***Senator GEORGE CAMPBELL**—I presume that you have not made a decision yet on the objection by Multiplex.*

***Mr Hartwell**—That is correct.*

***Senator GEORGE CAMPBELL**—When is that likely to be made?*

***Mr Hartwell**—That is in the hands of the two ministers involved, but there is a date that we will advise you of by which that retention lease would have to be renewed or not renewed.*

***Senator GEORGE CAMPBELL**—Has the department been advised by the Western Australian government regarding their decision on both the retention licence renewal and the objection?*

***Mr Hartwell**—The relevant Western Australian minister has written to the Minister for Industry, Tourism and Resources.*

***Senator GEORGE CAMPBELL**—If the objection was lodged in June last year, has an inordinate amount of time been taken to deal with it?*

***Mr Hartwell**—You portray it as an objection. I think it is more to the point that they have made a submission on whether the retention lease should be maintained. The decision period relates to when the existing release expires.*

***Senator GEORGE CAMPBELL**—Is it your view or the department's view that the objector has a valid case?*

***Mr Hartwell**—We are making no judgment on that at this point in time. That will ultimately be a decision of the ministers involved. The process is that the Western Australian minister will make a recommendation to the federal minister and the decision will be made accordingly.*

***Senator GEORGE CAMPBELL**—And that will relate to both the renewal for ChevronTexaco and the objection by Multiplex.*

***Mr Hartwell**—It will relate to the renewal application by Chevron Texaco, but the views of Multiplex will be taken into account in that decision.*

This exchange suggests that third parties do already contribute, at least informally, to the Government's decision making in the grant of retention leases.

Ultimately, the participation might be best described as a form of lobbying in which the third party submits that the Government should exercise its power under to the Act to refuse the relevant retention lease.[45]

It is not clear how effective this lobbying is. Relevant Ministers have stated on the public record that they take third party submissions into account.

According to reports in the Australian Financial Review, in the case of Gorgon, State and Federal Ministers confirmed that the Multiplex submission was seriously considered.

- Those decisions rest with WA's state development minister, Clive Brown, and the federal Industry, Tourism and Resources Minister, Ian Macfarlane. Brown confirms that the arguments put forward by Roberts meant the issue of renewing the Gorgon retention leases was elevated form a departmental to a ministerial level. Given the issues raised by Multiplex, it could well be "*a couple more months*" before final decisions are made. "*It's going to be a high-level decision because it is such an important issue*," Brown says. Asked how forceful Roberts had been in putting Multiplex's position, Brown replies: "*John Roberts is a very successful businessman, and you don't run a very successful business without a lot of vigour*."[46]

- A spokesperson for Mr Macfarlane said the delays in renewing the Gorgon retention leases were a direct result of the matters raised by Mr. Roberts, which has elevated the issue from the departmental to ministerial level. "*The timeframe was extended somewhat because of Multiplex"*, the spokesperson said. "*Both ministers took carriage of it at a personal level. They decided to make the decisions themselves, as opposed to taking advice, because it was such an unusual case*."[47]

Notwithstanding any opportunity for informal participation in the retention lease approval process, there may be opportunity for Government to seek more routinely input or information from third parties to assist them in their determinations.

Considering the majority of the State's gas is consumed by only a small number of consumers, it is surprising that they have never been approached by any government decision makers in respect of an impending Western Australian retention lease decision or asked to provide any information on whether they would be ready, willing and able to purchase certain volumes of gas at certain nominated prices.

Given the nature of the analysis invariably being undertaken by government decision makers on retention lease applications, this may suggest some room for either a more robust lobbying effort on the part of third parties with a view on any specific retention lease application process (along the lines of that engaged in by Multiplex and detailed above), or it may suggest room for a more proactive approach on the part of government in seeking information from potential gas purchasers as a means of testing evidence given by applicants about the unavailability or otherwise of purchaser(s) at suggested volumes and prices.

Several organisations noted that they view retention lease applications as serious matters where outcomes are not guaranteed, pointing to examples of the refusal of retention leases as evidence of this fact.

One such example of a retention lease application being refused that was provided during the interview process, was in relation to the Victorian 'Kipper' gas field. On 9 June 2004, the Kipper Joint Venture Participants (Esso Australia Pty Ltd, BHP Billiton Ltd, Woodside Petroleum Ltd and Santos Ltd) were advised by the Victorian Department of Primary Industries that the Department considered production from the Kipper field to be commercially viable and that the Department had rejected the participants' application to renew Retention Lease VIC/RL2.

The Kipper field is a significant one with proven and probable reserves of approximately 620 billion cubic feet of recoverable gas and 30 million barrels of condensate/LPG and where development of the field is likely to cost up to $300 million. In this instance, following refusal for a further retention lease, an application for a production licence was made in 2005 and, subject to corporate funding and approvals, production is expected to commence in 2009.[48]

Infrastructure Support

An issue that was raised in a number of submissions was the possibility for the WA Government to provide some form of infrastructure support, in order to assist development of smaller domestic-only gas projects.

High quality economic infrastructure, appropriately-placed suitable land and efficient planning processes are key enablers for industry growth and the attraction of business investment to Western Australia, particularly for industries where the investment location is flexible. Access to appropriate infrastructure is also fundamental to ensuring that the whole community can contribute to, and share in, the State's wealth and quality of life.

Overall, economic development in Western Australia continues to be driven by a dominant resources sector. The continued development in the State has meant that there are significant infrastructure demands faced in Western Australia. This need is further exacerbated by the fact that industry is located across the vast expanse of the State and in some of the most inhospitable and remote environments, which means that the cost of providing and maintaining infrastructure is high.

In most circumstances, CCI is sceptical of the benefits of government subsidies to particular projects. By and large, projects should proceed only if commercially viable. Government subsidies tend too often to take money from efficient businesses and give it to inefficient ones, to the detriment of overall economic efficiency. Where the government exercises discretion in the allocation of funds,

there is a risk that political considerations and patronage will influence the distribution of funds.

The WA Government's business support programs, which focus on the provision of common user infrastructure to assist a number of businesses and is generally supportable on the basis of market failure, is supported. It also leaves the state with some residual benefit in the event that a project fails.

In contrast, the Commonwealth's approach to industry assistance is notoriously secretive – it focuses on providing financial benefits to individual businesses and is discretionary (and therefore open to accusations of political patronage). Its efforts to pick winners have resulted in the picking of losers.

CCI supports the views expressed in the Department of Treasury and Finance's submission to the Consultation Paper:

> *The Government should not view infrastructure support or other forms of subsidy as an appropriate compensation or inducement to encourage proponents to supply gas into the domestic market.* [49]

In the case of the gas industry, the privatisations of the Dampier to Bunbury Natural Gas Pipeline and Alinta mean that the only involvement the Government has relates to the regulatory environment it which the industry operates.[iii] Rather than provide direct infrastructure support to assist in the development of smaller domestic-only gas projects, the WA Government should look to create the right environment to support the development of such projects.

Infrastructure Access

Another policy response raised in the submissions to the Consultation Paper was for gas gathering and processing infrastructure to be subject to the same open access principles that apply to other essential infrastructure. This was highlighted by Alcoa in its submission:

> *Open access principles, such as those applied to gas pipeline infrastructure, should be extended to include gas gathering and processing infrastructure. For example, expansion of existing facilities (such as NWS project's domgas plant) or use for processing third-party gas as the owner's reserves are*

[iii] However, the Government, through Horizon Power, owns the small Onslow gas pipeline and 50 per cent of the Mid West Pipeline (along with Australian Pipeline Trust) that connects the Dampier-Bunbury pipeline with Mt Magnet and the Windimurra mine.

depleted may reduce the cost of delivering gas for domestic use and facilitate development of new sources of supply.[50]

Part IIIA of the *Trade Practices Act 1974 (Cth)* (TPA) establishes the legal rights for third parties to share the use of certain infrastructure services of national significance on reasonable terms and conditions. In essence, the Part IIIA framework covers nationally significant infrastructure services where such infrastructure has natural monopoly characteristics, and where it is deemed that access to such infrastructure is necessary to promote competition in an upstream and downstream market.

Part IIIA also requires that access be economically feasible and not be allowed to compromise the system integrity of infrastructure, and the benefits of access regulation must not outweigh the costs.

The National Competition Council (NCC) is responsible for administering the Part IIIA framework, and there are essentially three avenues for a party to seek access to an infrastructure service – through declaration; by using an effective access regime; or under the terms and conditions set out in a voluntary undertaking approved by the Australian Competition and Consumer Commission.

The declaration pathway is the common way in which a business will try to gain access to a particular infrastructure service, with the NCC in making its deliberation taking into consideration a number of criteria to establish whether the relevant service is provided by a nationally significant facility that has natural monopoly characteristics and that occupies a bottleneck position in an industry. In addition, a public interest assessment is undertaken to weigh the costs and benefits of imposing access regulation.

If an infrastructure service is declared, it does not provide the access seeker with an automatic right to use that service; rather, it establishes a right for any party to negotiate terms and conditions of access with the service provider.

The NCC cannot recommend that a service be declared unless it is satisfied that all of the following criteria (set out in section 44G(2) of the TPA) are met:

(a) that access (or increased access) to the service would promote competition in at least one market (whether or not in Australia), other than the market for the service;

(b) that it would be uneconomical for anyone to develop another facility to provide the service;

(c) that the facility is of national significance, having regard to:

(i) the size of the facility; or

(ii) the importance of the facility to constitutional trade or commerce; or

(iii) the importance of the facility to the national economy;

(d) that access to the service can be provided without undue risk to human health or safety;

(e) that access to the service is not already the subject of an effective access regime; and

(f) that access (or increased access) to the service would not be contrary to the public interest.

The NCC must also consider whether it would be economical for anyone to develop another facility that could provide part of the service (section 44F(4)).

The NCC must be affirmatively satisfied that all of the declaration criteria in section 44G(2) are met before it can recommend declaration. If the NCC is not satisfied that one or more of the criteria are met, then it must recommend that the service not be declared.

Part IIIA therefore provides a regime by which businesses can obtain access to major infrastructure provided that the application is made in good faith (section 44F(3)), and whether it would be economical for anyone to develop another facility that could provide part of the service (section 44F(4)).

In the case of major infrastructure, businesses should have legal avenues to pursue the use of nationally significant infrastructure services owned and operated by others on commercially negotiated terms.

Where commercially negotiated terms and conditions are not possible, implementing authorities must be sensitive to the implications of their decisions including possible disincentives to future investment that may result from mandated access and it is important that where access is given it is on 'reasonable' terms and conditions and at 'fair' prices.

In the case of gas gathering and processing infrastructure, it is unclear whether such infrastructure would be declared under Part IIIA, although this has never been tested.

It should be noted, however, that the producers supplying gas to the domestic market found it to be commercially viable to build domestic gas processing facilities, even for relatively small gas fields, and in an economic environment that is far less supportive than it is today.

That said, it is possible that commercial opportunities may exist for gas producers to negotiate access to gas processing facilities.

Codes of Practice

In the United Kingdom, there exists a voluntary code of practice on access to upstream oil and gas infrastructure on the UK continental shelf. This non-statutory Code sets out the principles and procedures to guide all those involved in negotiating third party access to oil and gas infrastructure, with the aim of facilitating the utilisation of infrastructure for the development of fields through timely agreements for access on fair and reasonable terms.

This Code was developed by the UK Offshore Operators Association in consultation with the UK Department of Trade and Industry and a wide range of other parties.

Under the Code, companies seeking access to infrastructure must apply in the first instance to the relevant owner of the infrastructure in question. If the parties are unable to agree satisfactory terms of access to that infrastructure, the applicant for access may make an application to the Secretary of State to resolve the dispute. Importantly, the Secretary of State's discretion in exercising his powers cannot be fettered.

Such an approach is certainly more streamlined that the access framework that exists in Australia due to the fact that producers agreed in the first instance to be subject to the Code. However, it also confers significant power upon the Secretary of State for dispute settlement where an agreement for access cannot be reached.

It is certainly possible for such an approach to be adopted in Australia. In June 1999, the Australian Petroleum Production and Exploration Association (APPEA) adopted a statement of best practice principles for the commercial negotiation of third party access to upstream facilities. However, the principles do not address compulsory arbitration or other deadlock breaking techniques.

It may be worthwhile exploring the possibility of expanding the Code to include compulsory dispute resolution when negotiations become deadlocked, and possibly amending the *Petroleum (Submerged Lands) Act* to provide for ministerial intervention as a last resort where access negotiations have failed.[51]

Taxation

A key policy issue at each stage of the gas supply chain is the taxation environment. In relation to production, a number of submissions suggested that the taxation rules which apply could be reviewed in order to accelerate the development of gas fields – particularly smaller gas developments that would supply the domestic market.

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The Commonwealth's Petroleum Resource Rent Tax (PRRT) and company tax regimes are the primary mechanisms that tax income and profits associated with oil and gas production in Australia.

While the WA Government's taxation system also imposes royalties, most gas projects are located outside Western Australia's territorial boundaries, with the result that WA's royalty regime does not generally apply.

The WA Government also imposes a Petroleum Titles Transfer Fee for the registration of a transfer of an interest in a petroleum title (on account that a transfer of a interest in petroleum titles is exempt from stamp duty). This fee is levied at a rate of 1.5 per cent, and does not raise a significant amount of revenue, so is unlikely to represent a significant burden on the industry.

Other state taxes which are applicable to gas projects are applied across all industries, such as payroll tax.

Further discussion on some of the key taxation issues detailed below.

Petroleum Taxation

The Commonwealth's principal royalty regime is the Petroleum Resource Rent Tax (PRRT), although it also imposes the Offshore Petroleum Royalty and Crude Oil Excise, both of which do not overlay with the PRRT.[52]

The PRRT is a tax charged by the Australian Government for the sole right given to producers to extract petroleum from deposits offshore. PRRT is a profits-based tax levied at 40 percent of net revenues (sales receipts less eligible expenditures) from a project.

- Eligible expenditures include exploration and all project development and operating expenditures.

- A 'project' consists of facilities in the project title area, and any facilities outside that area necessary for the production and initial storage of marketable petroleum commodities such as stabilised crude oil, condensate, natural gas, liquefied petroleum gas, and ethane. Value added products, such as LNG, are excluded.

In its 2004-05 Budget, the Australian Government announced a taxation incentive designed to encourage petroleum exploration in Australia's remote offshore areas. The measure allows an immediate uplift to 150 per cent on PRRT deductions for exploration expenditure incurred in designated offshore frontier areas. That is, for every $1.00 of exploration expenditure there is a $1.50 tax deduction for PRRT.

Such a taxation regime is unlikely to provide a disincentive to producers.

Company Taxation

A crucial element of the company tax system is the framework over which capital expenditures can be claimed as deductions in the calculation of taxable income. Despite the introduction of effective life caps, depreciation deductions available to gas projects are generally not competitive with the 5–10 year writeoff periods (and similar or lower tax rates) available to most LNG competitors overseas. An ability to commence depreciation upon acquisition of the asset would also be of particular value to gas projects with long construction lead times (of three to four years in many cases).

As part of the 1999 Review of Business Taxation, the Commonwealth abolished accelerated depreciation, with the savings from this reform used to fund the lower company tax rate.

Companies now determine their depreciation allowance based on the effective life of the plant and equipment. However, a number of additional deductions are available for companies involved in petroleum exploration and development activities, including the immediate deduction of petroleum exploration and prospecting expenditures, operating costs and environmental protection expenditure.

In the Commonwealth's 2002-03 Budget, further reforms were introduced to reduce the impact of accelerated depreciation tax reforms on large capital intensive, long life petroleum projects, with a 15 year cap imposed on oil and gas production assets (except offshore platform assets with the current 20 year life remains), and a 15 year cap for LNG assets.

While these recent reforms have no doubt been important, more needs to be done to ensure that Australia's depreciation regime becomes at least comparable with competitor countries which allow for a significantly faster write-off of plant and equipment costs. In this regard, APPEA has recommended that a five to seven year write-off period be targeted for depreciation purposes.

Flow through Shares

A flow through share scheme essentially enables the transfer of tax deductions of individual exploration companies to individual investors. In this, the tax deduction of the exploration expenditure is leveraged in the capital markets in the subject year, attracting external investors rather than being accumulated tax losses, which will only be realisable if the company earns taxable income. This mechanism has been used with considerable success in Canada where investment in bona fide exploration has increased substantially.

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It has been suggested that such a reform, if implemented, would make it easier for junior exploration companies without taxable income to raise exploration capital on fields on which they have a licence.

Active junior exploration companies are crucial to the overall health of the Australian petroleum industry, but they can be limited in capital. As a result, they are often required to focus on marginally prospective acreage with consequent lower success rates.

One of the reasons for such a situation is via the impact of the income tax system. For companies that have a tax liability, the ability to deduct such costs immediately against other income provides an important form of cost relief. Entities that do not have (or have insufficient) income are therefore required to carry forward potential tax benefits for exploration expenditure which may never be used. As a direct consequence, this inability to obtain a tax deduction significantly reduces the after tax value of exploration activity undertaken by these companies.

This could be considered a tax related market failure that should be remedied.

APPEA's submission to the 2006-07 Commonwealth Budget noted that industry bodies representing companies engaged in petroleum and mining exploration activities across the Australian resources sector have developed a flow through share mechanism that will have the same impact on Australian exploration as it has done in Canada. The proposal has been developed as a result of stakeholder consultations (including with government agencies) and via dialogue through the Minerals Exploration Action Agenda. Features of the proposal include:

- tax rate for subscribers equal to the prevailing company tax rate;
- 150 per cent investment uplift to reflect the nature of the expenditure (and the offsetting CGT impact);
- relinquishment of the deductibility of the expense by the company following the pass through to the eligible investor;
- a capping on individual raisings;
- no limitation on the number of raisings by an entity;
- transferability of the credit upon the sale of the flow through share;
- eligibility extending to all publicly registered entities (listed or unlisted); and
- appropriate penalties for misuse of the mechanism.

Approvals Processes

Difficulties with project approvals are the most often cited impediments to timely project development. Approvals are complex, and often lengthy and uncertain. Duplication between levels of government adds to these problems.

The Commonwealth and State Governments have recognised the complexity of project approvals processes, the time taken to gain approvals and the effect on investment. They have taken steps both individually and together to reform approvals processes, enhance inter- and intra-government coordination and shorten timelines.

At the Federal level, regulatory efficiency for business has become a policy priority. The Commonwealth Government established a taskforce to make recommendations to reduce the regulatory burden on business, which was delivered to the Prime Minister and Treasurer on 31 January 2006.

On 15 August 2006, the Treasurer announced the Australian Government's final response to the report, agreeing in full or in part to 158 of the 178 recommendations.

The Commonwealth has also completed a review of the processes to resolve native title claims, with legislation introduced into Parliament on 7 December 2006. The reforms are primarily aimed towards identifying and implementing improvements to the processes for the recognition of native title and the resolution of disputes over land which may be subject to native title.

In Western Australia, the creation of the Office of Development Approvals Coordination (ODAC) and the associated package of initiatives are intended to go further than the recommendations of the Keating Review.

However, there is considerable work still required to improve approvals processes, particularly coordination within and between governments. Moreover, even though governments have initiated processes to streamline approvals, additional land access and approvals requirements in recent years have actually added to the burden on project developers. This is highlighted by the fact that a major project such as a greenfields LNG facility can require more than 70 approvals at Commonwealth, state and local government levels.

An example of unnecessary duplication is the protection of places or objects of significance to indigenous Australians. This is currently provided through Commonwealth and state legislation including the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (Cth), the Environmental Protection* and *Biodiversity Conservation Act 1999 (Cth)* and, the *Aboriginal Heritage Act 1972 (WA)*. Within Western Australian processes there is also further duplication

including Environmental Protection Authority heritage assessment during the environmental approval of proposed projects. This duplication has not resulted in better heritage protection, but has increased development delays and costs.

The uncertainties created by the opening of new avenues of intervention by the Commonwealth, such as through new National Heritage listings, also threaten to reverse the commitment of government to simplify and rationalise approval processes.

In addition, local governments have been extending their reach into planning approvals and building licensing for some projects under State Agreements, adding to complexity at a time when the objective of the State Government and industry is to reduce project approval complications.

Commonwealth Government approvals

The Commonwealth Government has two key powers of approval that are particularly relevant to the gas industry – environment and heritage, and petroleum approval and regulation in Commonwealth waters.

The triggers for requirements for Commonwealth approval under the *Environment Protection and Biodiversity Conservation Act 1999 (Cth)* (EPBC Act) include matters that are the subject of international agreements (e.g. migratory species) and matters of national environmental significance (e.g. threatened species and sites that are on the National Heritage list).

Other matters which may require Commonwealth approvals include:

- installation of structures in Commonwealth waters;
- disposal of dredge spoil in Commonwealth waters;
- foreign investment;
- taxation treatment of certain assets;
- Petroleum Resources Rent Tax arrangements;
- customs tariff concessions on imported plant and equipment; and
- cultural heritage approval under EPBC Act and *Indigenous Heritage Act*.

While the EPBC Act and petroleum approvals and regulation have coordination mechanisms in place with States, none of these other processes have formal links to State Government approvals processes. In addition, there is the Commonwealth reporting mechanism of the National Greenhouse Gas Inventory.

Approvals by the Government of Western Australia

Principal approvals required under State legislation are planning and environmental approvals. Other State approvals typically required by major projects include:

- petroleum approvals;
- approvals under the *Mining Act* and *Mines Inspection Act*;
- leases and licences for pipelines and other infrastructure;
- dangerous goods approvals;
- port approvals, licences and leases;
- water licences;
- native title agreements; and
- cultural heritage approvals.

The 2002 Review of the Project Development Approvals System (the "Keating Review") made 56 recommendations for improvement to the mechanism by which major projects (i.e. projects that fall within the State Development portfolio) are approved[53]. The recommendations, if fully implemented, should result in improved timeliness, coordination and transparency and reduce duplication of effort for both project proponents and government agencies alike.

While project approvals have improved, they are still unacceptably complex. They are often too lengthy – extending beyond investment decision timelines and therefore threatening investment.

In November 2005, the Government of Western Australia created a special unit, known as the Office of Development Approvals Co-ordination (ODAC). The head of ODAC reports directly to the Premier.

The package of initiatives goes beyond those recommended by the Keating Review. Under the new changes:

- relevant directors general will be held directly accountable for approval outcomes;
- relevant agencies will be required to report on approvals process timelines in their annual budgets, and account for approvals-process expenditure;

- agencies will be required to meet firm deadlines for commenting on resource projects, or will be deemed to have no comment to make; and
- agencies will be able to hire-in special expertise when necessary to keep projects moving.

In addition, the Department of Industry and Resources will investigate the creation of an across-Government information database to help prospective resource projects identify planning, environmental, heritage and other matters relevant to their projects.

As well as coordinating approval processes, ODAC has a remit to prepare a Strategic Regional Planning Framework for industrial development sites in regional areas to simplify site access and pre-approvals for major resource developers. This entails a review of local government, environmental, planning and regional development initiatives to improve the State's capacity for undertaking strategic industrial planning and preparing a pre-approvals environment for future project developments.

The major issues with approvals processes identified by project proponents and industry associations – and required improvements – are:

- the implementation of the Keating recommendations has taken too long and is still incomplete, particularly in relation to inter-agency coordination and timeliness. It is vital that the State Government's approvals initiative brings about more rapid and far-reaching change;
- the need for leadership at political and agency level to make the Government's policy objectives clear to all agencies and their staff and to ensure that agencies are committed to meeting these objectives. The mechanisms within the State Government's approvals initiative should drive greater accountability;
- a "silo" culture between agencies remains strong in Western Australia and whole-of-government, and coordinated approaches to project facilitation (not just approvals) compares poorly with other States and nations;
- ODAC should have authority to drive assessment and approvals processes for major projects;
- the need for timelines and performance indicators to measure agencies' performance and hold them accountable;
- overlap and duplication between legislation, and between levels of government;

- recent and threatened additions to approvals and compliance requirements, including:
  - extension by some local governments of planning approvals and building licence requirements;
  - proposed State greenhouse gas emission reporting requirements; and
  - overlap between State and Commonwealth Aboriginal heritage requirements that could extend with proposed listing of the Burrup on the Commonwealth heritage register.

Clearly, further substantial improvements are required to approvals processes in Western Australia if investment is to be encouraged and facilitated.

Approvals under State Agreements

State Agreements are contracts between the State and major project developers that are ratified by Parliament. Most major projects in WA operate under State Agreements, which were established to provide long term certainty, security of land tenure, facilitation of complex approvals and reduction of sovereign risk.

State Agreements differ from other primary approvals in that they are a facilitating mechanism for development of specific projects. Agreements specify the rights, obligations, terms and conditions for development of the project, and establish a framework for ongoing relations and cooperation between of the State and the project proponent.

The development proposals clause in a State Agreement requires the proponent to submit detailed proposals on its overall development. Detailed information is required on operational plans, plant and equipment, workforce, workforce accommodation, project specific infrastructure, social infrastructure, impact on public infrastructure and services, land requirements and environmental management. The development proposal is submitted to the Minister for State Development for final go-ahead approval of a project.

Before the Minister approves proposals, all primary approvals must be finalised, such as environmental approval, native title agreements, and heritage clearances.

It has been suggested by some proponents that the operation of the development proposals clause is unduly complex and onerous. A major mining expansion, for example, can require more than 200 separate approvals, each with their own application, assessment and decision steps. Some approvals fall outside the State Agreement process, most are inside it.

Proponents have commented that the process of approval usually cannot accommodate options for development. That is, in a situation of business decision uncertainty, where options for technical approaches may need to await analysis, the approval process cannot deal with say two options for, say infrastructure provision or energy supply. It requires a company to put forward one firm proposal. In this way, the process does not take account of business realities.

On the other hand, the State Agreements approvals process can be used to "second guess" or interfere in purely commercial decisions. The Government has the policy objectives to facilitate the efficient and effective development of the State's natural resources consistent with State policies and for the economic and social benefit of the community. These are appropriate objectives. However, proponents report that the Government has at times stepped over the boundary between these policy objectives and becoming involved in commercial decision-making that should be the sole prerogative of the project proponent.

Local government approvals

While the State Government has been making efforts to streamline approvals processes, the growing involvement of local government in approval of major projects threatens to make some of the processes more rather than less complex.

In particular, some local governments have recently determined that building licences and planning approvals must be obtained from the local government for all development, regardless of any State Agreement Act provisions that may apply to a project.

There are questions about the physical and technical capacity of some local governments to undertake the required assessments for such approvals. As well, such approvals are tending to come at the end of the overall approval process.

This situation is leading to uncertainty and may potentially cause complications for both State Agreement projects and governments.

Other local government powers are provided under the Building Code (structural, fire, safety etc for ancillary buildings) and the *Health Act* (approval and periodic inspection of messing and accommodation facilities).

While local government needs to fulfil its responsibilities to local communities, its involvement in approvals of major projects needs to be tempered by:

- the capacity of local government to undertake assessments and approvals;
- the value added by local government involvement; and

- the cost of local government involvement to local governments themselves, to project developers and to communities.

This emerging issue is one that needs to be considered carefully by the State Government within the current framework of the implementation of the Keating recommendations.

Coordination between governments

The Commonwealth has, over several years, moved to cooperate more closely with the States and Territories in project assessment and approvals. This cooperation ranges from formalised processes where State agencies have delegated powers to more informal inter-agency communication, information-sharing and cooperation.

In two key areas of approval – environment and petroleum regulation – the Commonwealth and WA Governments have agreements or understandings in place to coordinate assessment and approvals, and to accredit the State agencies to undertake assessment on behalf of the Commonwealth. Specifically:

- for grant of petroleum production licences in Commonwealth waters, the State Minister acts as the Designated Authority under Commonwealth legislation;

- the National Offshore Petroleum Safety Authority (NOPSA) is a joint Commonwealth-State body established to oversee the safe operation of offshore petroleum operations in both State and Commonwealth waters; and

- for assessment of environmental matters under the Commonwealth EPBC Act, the Commonwealth may accredit the State Environmental Impact Assessment process for assessment, but the Commonwealth Minister must still make a decision on approval.

There are numerous other approvals mechanisms and reporting requirements, most of which relate only to one level of government. Where they intersect or duplicate (e.g. heritage and local government regulation for projects under State Agreements) there is a need to seek to reduce duplication and reporting.

Joint Marketing

The issue of the joint marketing arrangements that are undertaken by the NWS Venture for the purposes of supplying gas to the domestic market was raised in a number of the submissions to the Consultation Paper.

On 29 July 1998, the ACCC granted an authorisation (subject to certain conditions) to the participants in the NWS Venture to jointly market their gas to the domestic market.[54] Such an authorisation was required under Part VII of the

Trade Practices Act 1974 (Cth) (TPA), where such contracts or arrangements might include exclusionary provisions or substantial lessening of competition, both of which are prohibited by section 45 of the TPA. The authorisation enabled each of the applicants to jointly market and sell natural gas with protection under the TPA.

As part of their application for authorisation, the NWS Venture noted that the joint marketing and sale of natural gas would not substantially lessen competition in the relevant market, and would be a means of establishing certainty with respect to anticipated future contractual arrangements.

The ultimate and often important consideration in judging the appropriateness of joint marketing arrangements is the effect they may have on competition.

A view which emerged from some submissions in relation to the joint marketing arrangements of the NWS Venture was that it had an ongoing anti-competitive effect, particularly with respect to gas prices, and that there was no public benefit to be gained from such arrangements.

In assessing the validity of such a view it is necessary to:

- set out the legislative framework pursuant to which authorisations for joint marketing are granted; and

- examine those aspects of gas markets, particularly the WA gas market, which has a direct bearing upon determinations to grant or not grant an authorisation pursuant to the TPA.

It should be noted that the TPA does not mandate that all joint marketing ventures are required to seek an authorisation pursuant to section 88(1). In many instances authorisation may not be sought by joint marketing ventures because the view of the joint marketing venture is that the effect of the relevant arrangements are not anti-competitive and do not, therefore, require authorisation.

This is relevant to the NWS Venture. The NWS Venture continues to market domestic gas to new and existing customers on behalf of the Incremental Pipeline Gas Joint Venture (IPGJV) participants. However, the IPGJV participants did not seek a new authorisation from the ACCC for their coordinated marketing beyond August 2005 based on their belief that their gas marketing practices meet the requirements of the TPA.

The ACCC's 1998 NWS Determination which lapsed in August 2005 is analysed in this section to provide background to the present joint marketing arrangements existent in WA, as well as to provide a summary of the issues generally considered by the ACCC in granting authorisations for joint marketing of gas. Similarly, the

following examination of the review mechanism for authorisations provided for by section 91(4) of the TPA is not to assert that there is presently in existence any NWS authorisation which would be subject to such a review, but again it is discussed to provide a fulsome analysis of the mechanisms relevant to situations where authorisations under the TPA are in effect.

The Legislative Framework for Authorisations

Section 88(1) of the TPA allows that the ACCC may, upon application, grant an authorisation:

> (a) to make a contract or arrangement, or arrive at an understanding, where a provision of the proposed contract, arrangement or understanding would be, or might be, an exclusionary provision or would have the purpose, or might have the effect, of substantially lessening competition within the meaning of section 45; or
>
> (b) to give effect to a provision or a contract, arrangement or understanding where the provision is, or may be, an exclusionary provision or has the purpose, or may have the effect, of substantially lessening competition within the meaning of section 45.

Joint marketing conduct which is determined to fall within paragraph (a) or (b), and which is not covered by an authorisation, constitutes a contravention of the TPA.

The TPA does not mandate that all joint marketing ventures are required to make an application to seek an authorisation. In the absence of an authorisation, the onus is upon the ACCC to initiate any review if it believes that the arrangement might be likely to result in a substantial lessening of competition. Otherwise, a joint marketing venture may form its own opinion as to whether its joint marketing behaviour is or is not likely to substantially lessen competition.

Under section 90 of the TPA, the ACCC will only grant an authorisation under section 88(1) of the TPA if satisfied:

- in all the circumstances that the provision of the proposed contract, arrangement or understanding would result, or be likely to result, in a benefit to the public; and
- that benefit would outweigh the detriment to the public constituted by any lessening of competition that would result, or likely to result, if those proposed contract, arrangements or understandings were made and their provisions were given effect to by the parties.

Applicable case law reveals several key features of assessing applications for authorisation under section 88 of the TPA:

- the onus of establishing public benefit rests with the applicant;[55]
- the concept of public benefit is a broad term entailing anything of value to the community generally and any contributions to the aims pursued by the relevant society;[56]
- the applicant must be able to show a cause or link between the relevant contract, arrangement or understanding and the public benefit claimed;[57]
- public detriment is considered to be a similarly broad term which refers to any impairment to the community generally; any harm or damage to the aims pursued by the society including as one of its principal elements the achievement of the goal of economic efficiency[58]; and
- the ACCC must define the market for purposes of identifying benefit and detriment to a community.[59] By way of definition, the market has been relevantly described in case law as follows, "*a market is the field of actual and potential transactions between buyers and sellers amongst whom there can be strong substitution, at least in the long run, if given sufficient price incentives.*"[60] Importantly, as will be discussed below, the authorities demonstrate that the correct approach to assessing the definition of the relevant market is to use an expanding market definition, that is, to consider a market as expanding over time.[61]

The perceived public benefit in joint marketing

Applicants often argue that public benefit lies in the fact that a project would not proceed at all but for joint marketing.

For instance, in *Re Alliance Petroleum Australia Pty Ltd* the applicant claimed that:

- the introduction of gas into NSW would only become possible if the capital to build the pipeline was underwritten by long-term gas supply contract;
- long-term gas supply could not be assured in the absence of large capital expenditure on exploration and development of the gas fields and on processing facilities which would not be undertaken in the absence of a long-term supply contract; and
- field development and conversion to enable distribution in NSW could not be undertaken in the absence of assured long-term supply.[62]

In this sense it was argued by the applicants that the potentially anti-competitive agreement (which involved joint marketing as well as other features determined to be anti-competitive) created a mechanism for sharing and apportioning risks and protecting each side from opportunistic behaviour by the other. Thus, the central public benefit that was argued was, in effect, to make possible the development of a project itself.

In its decision, the Australian Competition Tribunal reviewed the historical development of natural gas supply in Australia. This was because the Tribunal considered that in assessing public benefit and detriment it was necessary to understand the particular structure that had developed in the Australian gas supply industry.

The Tribunal considered natural gas supply in Australia as having developed as a series of regional business systems, in each of which a single joint venture typically produced gas that passed through a single transmission pipeline to one buyer that then reticulated gas to end-users. The Tribunal at the time considered that gas supply systems to the major centres of demand in Australia were not so interconnected that trade in gas between them could readily occur and that consequently separate business systems largely persisted. The Tribunal considered that it was this form of the Australian gas industry that led to producers favouring the vehicle of joint ventures as a means of dealing with a number of central characteristics of the industry, particularly the high risks and large capital expenditure are associated with exploration, production and transmission.

The Tribunal considered that the common use of joint venture structures and thereby the common application for joint marketing authorisation was a response to such factors. Particularly, because long-term contracts which often involved joint marketing and 'take or pay' provisions by the joint venture producers were considered a favoured vehicle for underwriting significant capital expenditure in production, exploration and transportation infrastructure.

More recently, in May 2006 the ACCC authorised joint marketing by the PNG Gas Project.[63] In that determination, the ACCC agreed with the applicants' submission that joint marketing was integral to the success of the project and, whilst noting that separate marketing can add value, also agreed that separate marketing should not be seen as the whole solution for promoting upstream competition.

Joint marketing and the WA Gas Market

In their submissions supporting the NWS Project 1998 joint marketing authorisation, which lapsed in August 2005, the applicants argued that the relevant expansion would not proceed without the joint marketing of natural gas. In their submission to the ACCC, the applicants said that:

> *"Unless the joint venture participants are permitted to coordinate the marketing and sale of natural gas produced under the Project, development of the Project (in particular the proposed expansion currently under consideration by the joint venture participants of approximately $1,040 million) will be jeopardised (as will other major resource projects in Western Australia which depend on large volumes of competitively priced gas from the North West Shelf). Accordingly, the Australian public might be deprived of the benefits which would accrue from natural gas fired or assisted projects that might not proceed because of an unwillingness on the part of the Joint Venture Participants to undertake the expansion."*[64]

In assessing public benefit, the applicants said the ACCC should compare the future with the relevant conduct and the future without the relevant conduct. The applicants asserted that the future without the relevant joint marketing conduct was a future in which the project expansion would not occur. The applicants relied on reasoning similar to that in *Re Alliance Petroleum Australia Pty Ltd*, namely, that joint marketing was a necessary contractual tool which allows for the underwriting of significant capital expenditure in production, exploration and transportation infrastructure.

As summarised above, the question of public detriment, as it relates to the joint marketing of natural gas, requires that the ACCC consider whether joint marketing arrangements (as compared to separate marketing) substantially lessen competition.

In the NWS Determination, the ACCC appeared to take the starting view that separate marketing is to be generally preferred to joint marketing because:

> *"By creating price competition between as many suppliers of gas as possible, separate marketing should generate a number of benefits for consumers and users of gas".*[65]

However, the ACCC accepted that separate marketing for the NWS joint venture was impractical or unachievable. The applicants cited several reasons why separate marketing was impractical at the time including that it would have significantly reduced incentives for substantial infrastructure investment such as the type then being proposed. Further, it was argued by the applicants that separate marketing at the relevant time would have had the effect of less reliable supply to customers, greater time and costs associated with negotiations with customers, fewer economies of scale and higher transportation and storage costs. These considerations were generally adopted by the ACCC, which concluded that:

> *"…no-one has been able to substantively counter the applicant's proposal that separate marketing of gas by the NWSJV is not currently viable".*[66]

Looking forward to the gas market today, the central question becomes whether or not the ACCC would accept the proposal that separate marketing gas by the NWS Venture remains unviable in Western Australia. However, this question is not easily answered.

The TPA provides specifically for the review of decisions relating to joint marketing. Section 91(4) of the TPA provides:

> *"If, at any time after the Commission has granted an authorization, it appears to the Commission that the authorization was granted on the basis of evidence or information that was false or misleading in a material particular, that a condition to which the authorization was expressed to be subject has not been complied with or that there has been a material change of circumstances since the authorisation was granted*
>
> > *(a) the Commission shall give notice accordingly to the corporation to which the authorization was given and any other persons who appear to the Commission to be interested and afford them a reasonable opportunity of making submissions to the Commission in the matter; and*
> >
> > *(b) where, after so notifying the corporation and other persons (if any) and considering any submissions made by those persons, the Commission is satisfied that the authorization was granted on the basis of evidence or information that was false or misleading in a material particular, that the condition has not been complied with or that there has been such a material change of circumstances, the Commission may make a determination revoking the authorization and, if it considers it appropriate to do so, granting a further authorization in substitution for the authorization so revoked."*

The Australian Competition Tribunal has jurisdiction to review a determination of the ACCC revoking or varying a previous authorisation.[67] Section 101 of the TPA requires the Tribunal to review the determination by the ACCC in relation to an application for, or in relation to the ratification of, an authorisation. Importantly, the person seeking review can be either the applicant for the authorisation or a person with a "sufficient interest".

The decision to revoke or vary an authorisation has been characterised as a three-stage process where the Tribunal considers:

- whether there has been a material change in circumstances since the authorisation was granted;
- if so, whether the authorisation should be revoked;

- if so, whether there should be granted a further authorisation in substitution for the revoked authorisation.[68]

A material change of circumstances refers to circumstances that have an impact or likely impact upon public benefit and/or detriment occasioned by the conduct originally the subject of the determination.[69] The case of *Re Alliance Petroleum Australia Pty Ltd* stands as authority for the proposition that the correct approach to assess market definition is by using the expanding market definition, that is, to consider a market as expanding over time. And in consequence, that there may be a material change in circumstances as market opportunity and market vulnerability shift.

Indeed, at the time of the NWS determination, the ACCC accepted the applicants' submissions, but also raised the possibility that the relevant marketing environment in WA could develop into one which would sustain separate marketing in the future and specifically noted several developments which might increase the likelihood that separate marketing would be viable including:

- a significant increase in the number of customers; the interim and new competitive supply;
- the additional transportation options;
- storage;
- the entry of brokers/aggregation;
- the creation of gas related financial markets; and
- the development of significant short term and spot markets.

These characteristics, which have been endorsed by subsequent reviews, including the Upstream Issues Working Group and the Parer Committee, are relevant not only to an authorisation application, but also to the fundamental question of whether particular joint marketing has the purpose or effect of substantially lessening competition in a market. If, having regard to the relevant criteria, separate marketing is neither feasible nor realistic, then seeking to require separate marketing will likely reduce rather than increase competition.

In its determination, the ACCC also indicated that it would monitor the development of the gas market in WA and that where it believed that the separate marketing of gas had become viable, it might review its previous authorisation under the provisions of the TPA that allow for replication of authorisation on the basis of changed circumstances.[70]

As has been described above, the centrally important consideration in ACCC joint marketing determinations is whether it is practically feasible at the time of the application for separate marketing rather than joint marketing to occur in the relevant market. At present there appears to be a substantial variance in views regarding whether the WA gas market has made separate marketing a more feasible opportunity since the ACCC determination in 1998.

Transmission

There are four major gas pipeline transmission systems in Western Australia through which gas is supplied to the domestic market - the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the Goldfields Gas Pipeline (GGP), the Parmelia Pipeline and the Pilbara Energy Pipeline (PEPL).

Other major downstream transmission pipelines in WA include the Kambalda to Esperance Gas Pipeline (6TJ/day), the Mid West Pipeline (20TJ/day), the Kalgoorlie to Kambalda lateral (20TJ/day) and the Telfer Gas Pipeline (25TJ/day).

Western Australia's gas pipeline infrastructure currently has an average total capacity of 1,089TJ/day, excluding smaller laterals and trunklines.

Ownership of the state's pipeline networks is fairly disbursed. The main DBNGP line is operated by DBNGP (WA) Transmission Pty Limited (DBP), which is ultimately owned by a consortium consisting of Diversified Utilities and Energy Trusts (60 per cent), Alcoa (20 per cent) and Alinta (20 per cent).

The Goldfields line is owned by the Australian Pipeline Trust (88 per cent) and Alinta (12 per cent) and is operated and maintained by Agility Services Pty Ltd. Meanwhile, the Parmelia Pipeline is wholly owned by Australian Pipeline Trust, while the Pilbara Energy line is owned and operated by Epic Energy, which is itself wholly owned by Hastings Diversified Utilities Fund (an investment fund operated by Hastings Funds Management).

There are a number of external environmental factors that must be taken into consideration when making an assessment of the gas transmission sector. These include:

- *Natural Environment* – including the varying characteristics of gas fields such as location of the field, gas quality and distance from shore, as well as physical location on the pipeline (particularly with regard to licence grants) – all of which impact on demand for pipeline services and the costs and economic viability associated with a pipeline project. The geography of Western Australia is also unique in that the distance between the major suppliers and consumers has necessitated the construction of lengthy and costly pipelines,

meaning the cost of shipping gas (although generally regulated) is disproportionate to the cost of the physical gas in a total bundled sense;

- *Economic* – including the significant initial investment outlay which includes considerations regarding pipeline diameter, the number of compressor stations and their location versus looping, and the establishment of 'foundation contracts' which help to underpin a project given the significant capital costs associated with a pipeline infrastructure;

- *Technological* – including technological advances which make the transmission of gas through pipeline infrastructure more efficient and profitable; and

- *Government* – including the stability of legal and political systems, the impact of access regimes, licensing processes, gas specifications and other government laws and regulations pertinent to the pipeline sector, particularly those pertaining to investment in pipeline expansion.

In addition to these external environmental factors, there are also industry-related factors which can impact on firms in the transmission sector.

Analysing the transmission sector with reference to Porter's Five Forces Model, it can be concluded that there is a relatively low degree of competition among participants to the extent that:

- *significant barriers to entry exist* with respect to the transmission of gas due to the high capital investment requirements, the long-term contracts of incumbent service providers (that 'lock in' users or suppliers), as well as the licensing requirements related to developing or expanding new pipelines;

- there is a *high degree of market power*, given there are only four major lines in WA, each with different capacity and most of which service separate geographical areas of the state, giving each significant market power in the particular region they service;

- the *degree of bargaining power on the part of domestic customers differs according to size*, given that five large customers consume 90 per cent of total domestic supplies, meaning they have the potential to lock-in large volumes of supply for a long period of time, potentially crowding out smaller users from pipeline infrastructure; and

- the *threat of substitutes is dependent upon the nature of the gas use among end customers to which the pipeline is supplying gas*. For example, in some regions (such as the Goldfields) the threat of substituting gas with diesel or electricity is high, while in other areas (e.g. gas use in the South West by Alcoa), the threat of substitution is low given the importance of gas as a feedstock. In this

context, the threat of substitution of gas pipeline services may be seen to vary with the nature of the end-use.

Based on the above analysis, it can be concluded that the transmission sector has natural monopoly characteristics given the high barriers to entry, as well as the captivation of markets in the particular regions the pipelines service. However, the cost of alternative energy sources provides some competitive pressures in regard to pipeline tariffs.

The external environmental assessment shows that the success or otherwise of a pipeline operator is significantly affected by regulatory issues, particularly with regard to gas quality specifications, investment and price controls via access regimes. Economic considerations are also crucial, as pipelines entail significant sunk costs.[71]

In all of this, government policy and economic considerations appear to be the key factors which can have a large bearing on the industry, and are the focus of this analysis.

Pipeline Capacity

An issue raised by some entities interviewed as part of the consultation process related to the lack of gas transmission capacity in Western Australia, particularly on the DBNGP.

As outlined above, Western Australia's gas pipeline infrastructure had an average installed capacity of 1,093TJ/day (as at August 2006) according to the Office of Energy (excluding smaller laterals and trunklines).

There are large differences in contracted capacity across the four major pipelines. For example, the existing 'full haul' capacity of the DBNGP is currently fully contracted to shippers under contracts which are outside of the regulated access regime.[72]

Similarly, there is currently little spare capacity available for firm transportation services on the GGP, although there is scope for expansion with the operators estimating that the expandable capacity of the pipeline using compression is around 167 TJ/d.

Contracted capacity on PEPL is also close to full, with capacity usage expected to increase to over 98 per cent in 2006 as a result of new shipping contracts signed in September 2005.[73] The PEPL is a free-flow pipeline, and its capacity can also be increased with compression.

In contrast to the DBNGP, GGP and PEPL, the Parmelia pipeline is currently at less than half of its capacity on long term contracts.[74]

The current state of the transmission sector in WA, where contracted capacity on the major lines is currently full or close to full, highlights the need for investment into additional capacity.

Although the joint owners of the DBNGP are currently undertaking a major expansion of the system, it is the manner in which regulation impinges on investment decisions in terms of timeliness and the level of investment that is of most concern.

The level and timeliness of investment in pipeline capacity are vital for the development of both the downstream and upstream gas sectors in WA. Indeed, the interviews conducted as part of this consultation process found that many small producers and consumers were 'locked out' of the market, being unable to transport gas on the fully contracted larger pipelines.

Hence, greater investment in pipeline capacity would help to encourage field development for domestic supply, while also helping to satisfy growing industrial demand for natural gas in WA, particularly for lower volume producers and consumers.

The importance of timely and adequate investment in pipeline capacity for industry is illustrated by Alcoa's strategic outlay on a 20 per cent ownership stake in the DBNGP, and its subsequent spending to increase capacity on the line.

However, capital investment in gas pipeline infrastructure is not straightforward as in other sectors. Indeed, the decision to invest in additional pipeline capacity is heavily influenced by regulatory settings.

Western Australia's two major lines, the DBNGP and the GGP are both 'covered' under the provisions of the National Third Party Access Code for Natural Gas Pipelines (the Gas Access Regime).

This is an industry-specific regime that is given legislative effect in a *Gas Pipelines Access Act* in each State and Territory. The legislation implements the National Third Party Access Code for Natural Gas Pipeline Systems. In WA, it is the *Gas Pipeline Access (Western Australia) Act 1998* which incorporates as its Schedule 2 the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code).

These regulations exist to promote competition in the Australian economy by enabling third parties, in particular circumstances, to gain access to pipelines which are often considered essential infrastructure.

Not all gas pipelines in Australia are covered by the Gas Code. Currently, there are four means by which a pipeline may come to be covered by the Gas Code:

- it may originally have been listed in Schedule A of the Gas Code, which was approved by the Council of Australian Governments in 1997;
- a service provider may request coverage, and has an access arrangement approved by the relevant regulator;
- the relevant Minister might decide to cover a line, following a recommendation from the NCC and a request for coverage by any person; and
- where the outcome of a competitive tender process for a new pipeline is approved by the relevant regulator.

The NCC makes the initial assessment as to whether coverage is applicable to a particular line once a request for coverage has been made. This process involves public consultation, with assessments made according to set criteria.

The NCC provides a recommendation to the relevant Minister in each jurisdiction with regard to the suitability of coverage, and if the Minister agrees to coverage, the pipeline owner then submits an 'access arrangement' to the ACCC or the relevant state-based regulator for approval.

The conduct of this regime has important implications for investment, particularly with regard to the way in which it regulates the price of access.

An access arrangement for a covered pipeline must include a reference tariff based on the 'estimated efficient costs of supply'. With this in mind, service providers and access seekers are free to negotiate access prices on commercial terms that differ from the reference tariff policy approved by the regulator.

It is only if access can not be agreed to after commercial negotiation that the access arrangement then becomes relevant.

However, in its 2004 review of the Gas Access Code, the Productivity Commission noted that the interpretation of reference tariffs by regulators can serve to create a psychological barrier in the minds of access seekers such that any agreement negotiated at a price higher than the reference tariff is perceived as being too high.[75]

Hence, the access regime often impinges on commercial negotiation, and on many occasions, access agreements tend to take place at a price equal to, or near the regulated access price. This led the Productivity Commission to conclude that:

> *"The Gas Access Regime is a form of price regulation based on a cost-of-service model. It is, therefore, at the more intrusive end of regulation."*[75]

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It could be argued that the regulated rates of return on pipelines provide an attractive investment vehicle for fund managers/investors seeking security as part of a balanced investment portfolio, especially considering many such pipelines tend to have long term contracts in place.

However, there are few current examples of such investment in pipelines, with most expenditure undertaken by industry participants. In this context, such implicit price regulation has significant flow-on effects for investment into pipeline infrastructure. The Productivity Commission identified three ways in which the Gas Access Regime's form of cost-based price regulation leads to inefficient investment decisions:

- regulatory error - where mistakes are made in applying regulation;
- regulatory risk – which involves uncertainty about how regulation is applied, thus increasing the riskiness of investment; and
- asymmetric truncation - where profit is curtailed if it is better than expected.[76]

The Productivity Commission goes on to outline the potential costs of such actions on investment decisions:

> *"If regulatory risk, asymmetric truncation or regulatory error reduce expected profits and/or increase risk, then some riskier projects might no longer have an expected profit that investors consider is sufficient to compensate for the associated risk. Investors could respond by abandoning such projects.*
>
> *Alternatively, investors could modify projects so they are unlikely to be regulated (enabling a higher expected rate of return than allowed by regulators) or are lower risk (to match the low expected rate of return allowed by regulators). Relative to the intended outcome under cost-based price regulation, this might involve greater emphasis on:*
>
> - *building capacity that is essentially fully contracted — pipelines are smaller in diameter than otherwise because capacity is essentially built exclusively for clients that enter a long-term contract before construction;*
> - *incremental expansion — greater reliance than otherwise on expanding capacity incrementally to meet demand growth as it arises, rather than building a larger pipeline initially based on forecasts of realisable demand; and*

- *delaying investment — new projects are delayed for longer than otherwise while investors wait until demand is more certain."*[77]

It could therefore be argued that the access regime discourages investment into additional pipeline capacity by delaying and distorting investment decisions, particularly with regard to building new capacity speculatively to cater for future demand growth.

With coverage under the Gas Code entailing such negative elements with regard to implicit price regulation, then the likelihood of coverage under the Gas Code itself serves as a disincentive to invest in greenfield pipeline projects.

Some entities interviewed as part of this consultation process highlighted this lack of incentive to invest in additional pipeline capacity in WA, with investment generally carried out only when potential new capacity is fully contracted.

For example, the stage 4 expansion of the DBNGP currently under construction proceeded with the additional 100 TJ/day of capacity fully contracted to shippers.[78]

Some entities interviewed suggested that the incentive to build additional capacity only when it is fully contracted is not purely borne out of regulatory effects, but is also driven by commercial forces, particularly in relation to securing financing for a proposed expansion.

However, this reluctance on the part of credit providers to lend unless additional capacity is contracted might reflect the nature of the cost-based price regulation regime currently in place, which effectively constrains the ability of service providers to vary tariffs and recoup higher capital costs stemming from speculative expansion in the event that some capacity is left uncontracted.

Reforms to the Code are currently underway, with the Ministerial Council on Energy releasing a proposed national *Gas Legislative Framework* in November 2006.

The Framework consists of a new *National Gas Law*, supplemented by a set of *National Gas Rules*. Together, this Framework constitutes a new gas pipeline regulatory regime replacing (in WA) the *Gas Pipeline Access (WA) Act 1998* (which incorporated as its Schedule 2, the National Third Party Access Code for Natural Gas Pipeline Systems).

The proposed changes are a result of the Australian Energy Market Agreement, which commits Australian governments to implement a series of reforms to deliver fairer, more effective access regimes for both gas and electricity.

This reform process involves two key stages, of which the proposed national *Gas Legislative Framework* is the first step. While this 2006 legislative package has a primary focus on the economic regulation of network access, the 2007 legislative package will focus on non-price retail regulation.

While the aims of the reforms are commendable in that they seek to provide more effective access regimes and focus on economically efficient outcomes, it is debatable whether the Framework will actually deliver such outcomes.

In many instances, broadly positive reforms which promise to spur investment by reducing the disincentives that currently exist in regulation, are tainted by forceful and prescriptive requirements.

Perhaps the two most significant reforms which aim to encourage investment in pipeline infrastructure relate to the introduction of 'light regulation', and incentives for greenfield pipelines.

The 'light regulation' concept was introduced by the Productivity Commission in its 2004 report as a means of avoiding the upfront setting of reference tariffs through the access arrangement approval process. This allows a service provider operating a covered pipeline to apply for the services offered by means of that pipeline to be 'light regulation' services.

Among other things, this status means service providers are not required to, but may, submit a 'limited access arrangement' to the appropriate regulator (the Australian Energy Regulator for all states except WA, where it will be the ERA) for approval.

A limited access arrangement is one in which no explicit provision for price or revenue regulation of the pipeline is made. Further, a limited access arrangement also means the regulator, in resolving an access dispute, must apply the limited access arrangement terms and conditions.

However, some of the terms of the light regulation option proposed under the new framework are heavy handed compared to that proposed by the Productivity Commission, and do not achieve the overarching objective of encouraging investment by reducing the upfront setting of tariffs.

For example, a pipeline operator that provides services subject to 'light regulation' is nonetheless forced to confirm with onerous requirements, including:

- to publish the prices of those services regardless of whether or not a limited access arrangement applies to the services (section 140); and

- to provide information to the regulator regarding access negotiations as and when requested (section 141), and compulsorily on an annual basis (section 142), which the regulator is then permitted to release publicly (section 143).

Additionally, there is no guaranteed term under which light regulation coverage would apply. Indeed, any person may apply (to the regulator) for a covered pipeline to be revoked of its light regulation status (section 145).

Such requirements built around the otherwise positive light regulation option defeat the initial purpose of the reform.

Meanwhile, the introduction of greenfield incentives aims to create an appropriate climate for investment in greenfield pipeline projects by removing the disincentives that currently exist due to the risk that new pipelines may be covered under the regulatory regime.

The incentive allows the relevant Minister to make, following a recommendation by the NCC, a no-coverage determination over a greenfield pipeline that is binding for a period of 15 years.

However, the proposed 15-year regulatory exemption only applies if a new pipeline does not meet the pipeline coverage criteria. Coverage of pipelines is a process for determining whether or not regulation should or should not be applied to the services provided by a particular pipeline. This decision is made by the relevant State or Commonwealth Minister, on the recommendation of the NCC.

The decision of whether or not to regulate or cover is based upon all of the following conditions being satisfied (the coverage criteria):

- access to the service would promote a material increase in competition in upstream or downstream markets;
- that the pipeline is uneconomic to duplicate;
- that access can be provided safely; and
- that regulation is in the public interest.

It is evident from the above criteria that most major greenfield gas pipeline projects are likely to meet the requirements for coverage, and therefore be disqualified from the beneficial 15-year regulatory exemption.

Only minor greenfield pipelines are likely to qualify for the 15-year exemption, and while this is better than the current regime, it is not likely to have a material impact in terms of bringing new pipeline capacity into the market.

In addition to these issues, there are other broader concerns which limit the value of the proposed reforms in terms of encouraging investment into pipeline capacity. These include:

- broader information gathering powers bestowed to the regulator (section 41), including powers to request information from any person or entity (i.e. potentially impacting producers, shippers and consumers); and

- wider ring-fencing provisions through 'additional ring-fencing requirements' (section 120), which give the regulator the ability to dictate a pipeline owner's business processes (section 120, 4a), and the ability to disclose those processes publicly (section 120, 4b).

The changes included in the 2006 legislative package released by the Ministerial Council on Energy are intended to commence on 1 July 2007, following a period of public consultation.

While this window of opportunity for reform exists, it is hoped that the regulatory regime governing pipelines is further amended to account for the issues highlighted above (and others raised by industry) during the consultation period to ensure adequate incentives are created for investment in pipeline capacity.

While it is anticipated that further reforms would encourage more efficient investment in gas transmission pipelines, the State Government also has a role to play in facilitating investment by way of streamlining project approvals processes (see Approvals Processes on page 101) and ensuring the wider policy settings are conducive to a positive investment climate in Western Australia.

Maximum Allowable Operating Pressure

Pipeline capacity can also be increased by varying the pressure limitations on natural gas pipelines. However, such variances are limited by industry standards applying to pipeline construction.

In Australia, the overarching Standard that applies to the pipeline industry is AS 2885, 'SAA Pipelines - Gas and Liquid Petroleum' – a standard developed by a working group from both industry and government.

Standards Australia is the peak non-government development body operating in Australia and is responsible for assisting in the development and maintenance of industry standards, such as AS 2885. The AS 2885 sets out guidelines pertaining to design, construction, testing, operations and maintenance of gas and petroleum pipelines that operate at pressures in excess of 1,050kpa.

The standard stipulates the determination of a 'Maximum Allowable Operating Pressure' (MAOP) for pipelines, which describes the maximum pressure at which a pipeline may be operated in order to ensure safety.

MAOP is a function of the 'design factor' of the pipeline, which is defined as the ratio between the operating (hoop) stress in the pipeline and its yield stress. The design factor is important in the selection of appropriate pipe wall thicknesses, and its value changes depending on location to allow differing risk situations.

AS 2885 currently specifies that pipes should be constructed to a maximum 'design factor' of 72 per cent of the specified minimum yield strength (SMYS) of the pipe.

The design factor (and hence the MAOP) of a pipeline is important, as it has an influence on the carrying capacity of a pipeline. Under AS 2885, the DBNGP is currently subject to pressure limitations of 8.48 mega Pascals (MPa).

Recently, the Australian Pipeline Industry Association (APIA) requested that the Petroleum Pipelines Committee of Standards Australia (known as 'ME-038') and the Design Subcommittee ('ME-038-01') consider whether the current design factor used in determining the design wall thickness of transmission pipelines can be raised from 72 per cent of SMYS to 80 per cent, or some other value higher than the current 72 per cent level.

Significant benefits may be construed to the transmission pipeline industry from such a change. Specifically, it is argued that raising the design factor would result in a reduction in the capital cost of new pipelines, while existing pipelines that are capable of satisfying requirements for an MAOP upgrade would be capable of a capacity increase (of up to 15 per cent), provided it is permitted to operate at higher stress levels[79].

In the case of the DBNGP, these proposed changes should, if implemented in Western Australia, allow the DBNGP to be operated at a pressure higher than the current MAOP of 8.48 MPa.

With relatively minor modifications to existing compression and metering facilities, DBP expects that it would be able to increase the MAOP to 9.3 MPa, which would provide additional capacity which could be used to provide a firm service at a lower tariff than would otherwise be the case for shippers.

Debate on the proposed change continues today, with some parties opposed to the amendments on grounds of safety. Although the Director of the DOIR Petroleum Division is the WA Safety and Technical Regulator for the DBNGP and all pipelines regulated under the Petroleum Pipelines Act, the technical capability to support the Director has been transferred to the Resources Safety Division of the

Department of Consumer and Employment Protection, due to government restructuring.

The WA Safety and Technical Regulator has opposed the proposed modifications to AS 2885, and a further draft of AS 2885 is set to be released in the near future for comment.

It is believed that the draft will contain provisions for new pipelines to operate at up 80 per cent of SMYS, conditional on necessary testing and certification during construction. However, the revised draft is not expected to contain any provision for existing pipelines to use the 80 per cent design factor available for new pipelines, even if existing pipelines have been safety tested to a standard which would satisfy the requirements of the draft AS 2885 (i.e. the 80 per cent limit).

In its submission to the initial Consultation Paper, DBP outlined the problem this creates for it in light of its current expansion:

> *"A change to the relevant standard* [AS 2885] *is currently under consideration, which would increase the allowable pressure by approximately 10%, with significant capacity benefits. While the new Stage 4 and Stage 5 looping construction will probably be entitled to take advantage of the higher limit, the Western Australian Technical Regulator (DOIR) has yet to be persuaded to extend the proposed new standard to the existing pipeline, notwithstanding the fact that it was originally tested to the higher level. This means that in order to take advantage of the new standard, the DBNGP would need to be completely looped and the new pipeline operated at the higher pressure entirely separately from the original pipeline. Clearly the inability of DBP to take advantage of the proposed new standard for the entire DBNGP system will result in a sub-optimal outcome as far as the potential capability of the pipeline is concerned, and the inability to deliver lower costs to users. DBP would encourage further analysis of this issue."*

Given the current state of the gas transmission sector in WA (where capacity on major lines, particularly the DBNGP is near to full capacity), allowing for an increase in the MAOP may be a viable short-term solution to raising capacity, and hence satisfying any unmet demand for gas from industrial consumers.

Pipeline Specifications

In addition to the lack of physical capacity in the gas transmission network in WA, the gas quality specification on the DBNGP has also been raised as being an impediment to the development of gas reserves in Western Australia.

Gas quality is measured by a number of different variables, one of which is its higher heating value (HHV). The HHV is a measure of the energy content of gas

transmitted in a pipeline and is normally measured in mega joules per cubic metre (MJ/m^3). In specifying the gas quality transmitted in a pipeline, the HHV is set with a maximum and minimum level to ensure safety and efficiency reasons. In its 1995 review of the gas specifications on the DBNGP, the Office of Energy said:

> *"The maximum HHV limit is important for the safe operation of domestic appliances. Gas with a high HHV has a higher propensity to form soot which over time can build up and lead to partial blockages, reducing secondary air. If this occurs, increased potentially dangerous carbon monoxide can be produced exposing occupants to these higher emissions."*[80]

In relation to the minimum HHV specification, the Office of Energy said:

> *"It does not impact on safety considerations for residential gas appliances, which are sufficiently protected by the lower Wobbe Index limit, but is used by some manufacturers of commercial/industrial gas using equipment to indicate the safe, reliable and efficient operation of their equipment."*

The minimum HHV on the DNGP is the main area of contention. Currently, the minimum HHV on the DBNGP is set at 37.0 MJ/m^3, however, the quality of gas can vary markedly from one field to another and quality from existing producing fields can itself vary over the life of the field. This means that any field (undeveloped and developed) which falls below the minimum HHV can not be transmitted along the DBNGP without being adjusted or spiked with LPG to raise its heating value up to the required setting.

In its submission to the Consultation Paper, BHP Billiton suggested that the Government consider the importance of the gas specification requirements of the DBNGP, to the extent that current specification requirements are not sufficient to allow gas from either the Macedon or Scarborough gas fields to enter the pipeline without first being 'spiked' with LPG to increase the heating value of the gas up to the required minimum specification.

BHP Billiton noted that:

> *"Such requirements can create a strong disincentive to supply the domestic market, and may be an unnecessary constraint on expanding the supply base."*

However, broadening the specification or composition of gas to allow a wider range of gas into the pipeline is easier said than done. Varying the composition of the gas that enters the pipeline can have an impact on pipeline capacity, which then affects the bottom line of pipeline operators given that transmission is priced on an energy basis as opposed to a volume basis. According to M.J. Kimber Consultants:

"Capacity risk is irrevocably linked to gas composition – if composition changes, so does capacity. Hence those stakeholders that determine gas composition also determine capacity and thus have a major influence on the operating and capital costs associated with operating and expanding the DBNGP. Producers and Shippers determine composition through their gas supply agreements; the pipeline has no part of this process and is required to accept the gas that meets a very broad specification which implies a highly variable gas composition. Hence Producers and Shippers determine capacity.

In simple terms, if the Producers and the Shippers manage capacity risk, then the transport price will be lower than if they did not; if the pipeline is required to manage capacity risk, the transport price will inevitably be higher since the pipeline has no means of managing gas composition, and has to adopt a conservative approach in choosing a design gas composition."[81]

DBP further elaborated on this issue as part of its submission to the Consultation Paper:

"Given that DBP (like other gas transmission systems) is contracted to deliver energy not volume, the broadening of the gas quality specification, and producer response in the form of a lowering of the energy content of the gas delivered into the DBNGP, has reduced the transportation capacity of the pipeline. This has required additional investment by DBP to ensure that it can continue to meet its gas transportation obligations. To the extent that gas quality continues to decline, more investment will be required, and as a result, costs to users will increase.

In addition to the capacity loss suffered as gas quality declines, DBP faces increased operating costs through higher fuel and compressor maintenance costs.

Any further change in gas quality has the potential to not only expose DBP to liability under its commercial arrangements, but also to change the efficiency of facilities (such as electricity generating plant, and minerals processing operations) which use gas. Any action by the State which resulted in reservation of lower quality gas for the domestic market would diminish the capacity, and increase the costs of the State's pipeline infrastructure. It would also diminish the efficiency and the value of major investments in downstream industry."

Despite these issues, the gas quality specification for the DBNGP was broadened in transportation contracts negotiated by DBP with shippers at the time of its acquisition of the DBNGP.

Subsequently, the ERA set an even broader specification (the current 37.0 MJ/m^3) in the (revised) Access Arrangement for the DBNGP prepared and approved in accordance with the requirements of the National Third Party Access Code for Natural Gas Pipeline Systems in December 2005.

While the ERA's proposal to introduce a wider gas quality specification as part of the Access Arrangement was initially framed in terms of the 'Broadest Specification' of the *Dampier to Bunbury Pipeline Regulations 1998* (which stipulated a minimum HHV of 35.1 MJ/m^3), the introduction of the *Gas Standards Regulations 2000* (stipulating a minimum HHV of 37.0 MJ/m^3) subsequently imposed more stringent limits to gas quality for some quality parameters on the Mid-West and South-West Gas Distribution Systems.

Taking these regulations into account, the ERA considered that there was no practical reason why a wider gas quality specification contemplated for the DBNGP should be any narrower than the more stringent of the standards established by either the Broadest Specification of the *Dampier to Bunbury Pipeline Regulations 1998* or the *Gas Standards Regulations 2000*. Hence, the specification for the DBNGP was amended to reflect the minimum HHV stipulated in the Gas Standards Regulations 2000.

However, the ERA's preliminary investigations into the application of the Broadest Specification favoured its introduction. The Broadest Specification is a quality specification which sets out operating specifications for gas quality at receipt points and delivery points along the pipeline.

Under provisions of the 1998 regulations, the Broadest Specification comprised limits on the extent to which the operating specification for the DBNGP could be widened, except in certain special circumstances.

Notably, the minimum HHV of 35.1 MJ/m^3 set out in the Broadest Specification of the 1998 regulations would allow gas from the Macedon field to enter into the DBNGP (the HHV of Macedon Gas[82] is 35.68 MJ/m^3).

The GGP, Parmelia Pipeline and the AlintaGas distribution systems all currently operate according to the Broadest Specification. However, there is no requirement for the DBNGP to conform to the provisions of the 1998 regulations, which ceased to have effect when an approved Access Arrangement for the DBNGP commenced in January 2004.

At that time, regulatory oversight of the gas quality specification for the DBNGP fell to the ERA as part of its role in approving Access Arrangements and any revisions to Access Arrangements in that gas quality specifications form part of the terms and conditions for a Reference Service.

The ERA made several determinations in favour of adopting the Broadest Specification as part of the 2005 (revised) Access Arrangement for the DBNGP, including that:

- it was clear from the 1995 report of the Office of Energy, and from the provisions of the *Dampier to Bunbury Pipeline Regulations 1998*, that there has been a clear policy intention of the Government for the gas quality specification to be widened. However, recognising that there were a number of pre-existing contracts that prevented a widening of the gas quality specification without renegotiation of these contracts, the regulations did not impose a wider gas quality specification but rather foreshadowed a widening of the specification that should have been heeded by pipeline operators and users;

- no party should oppose the broadening of the gas quality specification for reason of an erosion of current contractual rights, as the Gas Access Code does not permit a revised Access Arrangement to deprive a party of certain pre-existing rights, regardless of whether it was reasonable or not for the parties to enter into those agreements;

- the broadening of the gas quality specification in the DBNGP to the Broadest Specification would not be reason for concern over operation or safety in the use of domestic gas appliances, following advice from the Director of Energy Safety and the Director of Gas and Emergency Management of the Department of Consumer and Employment Protection of WA;

- an alignment of gas quality specifications across pipelines would be desirable in principle on the grounds that manufacturers of gas-using appliances would be able to produce appliances suitable for a known and widely applied gas standard, and that there were benefits of consistent gas quality specifications [between the Parmelia Pipeline and DBNGP in particular[iv]], as it would allow the interchange of gas between these pipelines, and to and from the Mondarra gas storage facility;

- a broadening of the gas quality specification was unlikely to have a substantial effect on the capacity of the DBNGP, given that the minimum HHV specification is substantially affected by the required minimum LPG content for gas received into the DBNGP – a specification which was not required after 1 July 2005; and

[iv] Note that the Parmelia Gas Pipeline has received gas from the DBNGP since 1995. This is an example of the benefits of interchange that could be achieved by aligning specification among pipelines.

- a widening of the gas quality specification would give rise to substantial benefits to gas producers and a majority of end users of gas, and these benefits would be likely to outweigh the costs to the owners of the DBNGP and those end-users of gas, in particular those that use gas as a feedstock, that would be disadvantaged by a wider specification;

While the current Access Arrangement for the DBNGP applies until 2010, the above determinations give some scope for a further broadening in specifications for the DBNGP in future.

However, the benefits of any further broadening would again need to be weighed against the potential cost to pipeline operators and end-users (particularly those that use gas for feed-stock).

In this context, one option in further widening the gas specification could involve permitting DBP to a fair tariff adjustment, whereby it could recoup any losses incurred as a result of lower transportation capacity and increased operating costs (through higher fuel and compressor maintenance costs).

In its final decision on the proposed revisions to the Access Arrangement for the DBNGP in November 2005, the ERA accepted that DBP may incur increases in costs due to the proposed changes in gas quality, but noted that the Code allowed a service provider to recover any such additional costs to the extent they are justified by the Access Arrangement Information.

By how much this might require tariffs to be adjusted upwards remains to be seen however. It is not inconceivable that Shippers and consumers would accept a tariff variation, given the benefit this may bring to the domestic gas market in terms of encouraging upstream supply competition.

Indeed, this could work to reduce domestic gas prices in the long term as new supply comes on stream, helping to offset some proportion of the higher tariff. Clearly, such a step would require further analysis and consultation with industry.

Nationally, the Australian gas industry, through the National Competition Policy (NCP), has been developing a national gas quality standard with a view to allowing processed gas to move through all interlinked pipeline networks in Australia without adversely affecting pipelines or gas appliances.

This aim was considered important in the context of NCP in that such a standard would be important to achieving a national gas market by removing a potential barrier to interstate gas trade.

As part of this process, the Natural Gas Quality Specification Committee was formed to write a new gas quality standard specification for general purpose natural gas.

The standard, known as AS 4564/AG 864, defines the requirements for providing natural gas suitable for transportation in transmission and distribution systems within or across state borders, and provides the range of gas properties consistent with the safe operation of natural gas appliances supplied to the Australian market.

However, the standard does not specify a minimum and maximum HHV for Australian pipelines[83]. Generally, gas qualities on major pipelines outside of Western Australia are assessed individually, with no guidance given as to the HHV.

The standard was endorsed in January 2003, and all governments other than Western Australia and the Northern Territory have stated their intention to implement the standard. New South Wales, Queensland, South Australia and Tasmania have completed this reform, while Victoria and the ACT were assessed by the NCC in 2005 as having demonstrated a commitment to doing so.

As stated above, Western Australia's *Gas Standards Regulations 2000* include a gas quality specification that applies to gas entering a gas distribution system. The specification has similarities to the national standard, but specifies a HHV range and a different hydrocarbon dewpoint.

The HHV range was considered important in Western Australia because it forms the basis for billing customers on an energy basis, and a number of contracts reflect higher heating value. Although legislation does not specify gas quality in transmission pipelines, as discussed above, pipelines covered by an access arrangement include a gas quality specification in the arrangement.

Following discussions with industry in 2004, the State Government decided not to adopt the national standard. Rather, the Government agreed to review and, where appropriate, amend its standards to reflect the national standard if interconnection with interstate pipelines occurred.

Importantly, in making this decision, the Government considered that the adoption of the national standard would not have a material effect on the performance of gas appliances but could, in the longer term, restrict some of the state's producers in shipping their gas.

While a broadening in the specifications of the DBNGP has been assessed as being of potential benefit to gas producers and a majority of end users, there are other options to address the HHV disconnect in the absence of a further broadening in the specifications.

One option is for producers whose fields fall below the minimum HHV specification to install a cryogenic plant to improve the quality of the raw natural gas extracted from the field (this is normally adopted for removing nitrogen and/or helium).

This process involves substantially reducing the temperature of the gas stream, which condenses the ethane and other hydrocarbons in the stream, while maintaining the methane in gaseous form. This process allows for the recovery of about 90 to 95 percent of the ethane originally in the gas stream while stripping out unwanted elements, particularly nitrogen. The gas can then be spiked with LPG or condensate and supplied into the DBNGP.

However, the cost of developing a cryogenic plant and spiking the gas is high. Other treatment options also exist (such as solvent extraction and membranes) to remove other acid gases such as carbon dioxide, but like cryogenic treatment, these also entail extra costs.

The characteristics of each gas field is different, meaning some fields, particularly those that contain associated deposits of oil and condensate, might be able to support the cost of additional infrastructure to process associated gas deposits, however, where this is not the case (i.e. dry gas), such costs can prohibit the development of fields.

Anecdotally, the cost of spiking natural gas with LPG is estimated to add approximately $0.50 per GJ to the end price of domestic natural gas, meaning it would be uncompetitive compared to other sources of domestic gas.

Another option is for the producer to feed the raw gas into a pipeline with a lower minimum HHV. As mentioned previously, the minimum HHV on the GGT and Parmelia pipelines are in line with the Broadest Specifications of the Dampier to Bunbury Pipeline Regulations 1998, which specifies a lower minimum HHV (35.1 GJ/m^3) than the current DBNGP Access Arrangement (37.0 GJ/m^3).

However, the feasibility of feeding gas into an alternative pipeline depends on the location of the field, and the location of the end customer.

For example, the Macedon field is located 40 kilometres north of Exmouth in the Carnarvon Basin. If gas from this field were not below the specification of the DBNGP, it could be supplied into the domestic market via the existing Griffin/Tubridgi pipeline, which carries gas from the Griffin field (also operated by BHP Billiton) into the DBNGP.

However, in order for BHP Billiton to transmit Macedon gas into the alternative GGP, a new purpose built pipeline would need to be constructed at significant

cost. Indeed, this line would need to cross over the existing DBNGP line to access the GGP.

In the case of the Macedon field, which has dry gas, it is unlikely that such costs could be accommodated.

In addition to the cost of the physical infrastructure, BHP Billiton would be limited to potential customers on the GGP as opposed to the DBNGP, which services a wider area.

The final option which exists for producers in the absence of a further broadening in the gas specifications of the DBNGP is to enter a blending arrangement with the pipeline operator.

Blending adjusts the quality of the natural gas transmitted along the line by blending heavier hydrocarbons (often higher energy content natural gas) into the gas stream in order to bring it to the acceptable energy level.

However, in injecting a volume of off-specification gas into the pipeline, the producer is limited to a volume that will not bring the total volume of gas already in the line below the specification threshold.

Therefore, the opportunity to blend requires gas already being transported in the pipeline to be a reasonable level above specification to avoid the blended gas falling below the specification threshold.

Because the supply of gas from the off-specification field is dependent on the quality of the gas upstream, the supply of that gas is flagged as 'interruptible' (i.e. supply halts if the blend is below specification). The customer base for interruptible gas is significantly narrower than for firm gas, as only large customers with diverse portfolios of gas supply contracts are able to accommodate an interruption in supplies.

Therefore, for a producer sitting on an off-specification gas field and looking to enter a blending arrangement, the decision to develop that field is made much more difficult given the interruptability attached to blended supplies.

Consumption

Western Australia is the single largest natural gas consumer in Australia. The state's share of national consumption of natural gas has risen from less than 20 per cent in the mid-1980s to around one-third of national consumption currently.

A more detailed analysis of supply and demand dynamics is provided on page 34.

Although Western Australia is a significant gas consumer, much of that demand is concentrated among just a handful of consumers.

Specifically, there are five large consumers of gas in Western Australia which account for around 90 per cent of total demand – namely, Alcoa (mineral manufacturing), BHP Billiton (mining), Alinta (utilities), Verve Energy (electricity generation) and Burrup Fertilisers (chemical manufacturing).

The remaining ten per cent of supply is accounted for by smaller users who also operate in industries such as power generation, manufacturing and mining.

Because natural gas users in WA operate in such distinct industries and use the gas for different purposes, analysing the key external factors that impact on gas consumers can only be done in a generic fashion.

However, broadly speaking, the ability to secure adequate supplies at the appropriate quality, in a reliable fashion, and at a competitive price is perhaps the key external factor facing most consumers in WA at present.

Many consumers, particularly in the mining and manufacturing sectors, operate in global markets, meaning the availability and cost of gas (as a key input in the production processes of many large gas consumers in WA) is a crucial element in ensuring the business remains competitive.

In addition, the nature of the business conducted by some consumers necessitates that gas supplies be secured on a long-term basis. For example, when dealing with a mining operation where resources tend to be sold on a long-term fixed price basis, the operator needs to ensure that any variability in production costs are kept to a minimum.

In this context, the availability and cost of gas might also dictate investment flows, as any failure to secure appropriate volumes of gas as an input into the production process is a potential deterrent to Greenfield and Brownfield investment in heavy industry in Western Australia.

In this regard, consumers have raised concerns about the ongoing availability of gas to domestic users, and at what price natural gas can be supplied into the domestic market in future.

In addition to these broad external factors, a number of industry-related factors also exist which contribute to concerns over supply adequacy. In this context, the key issue concerns the competitive positioning of gas consumers relative to each other, and relative to suppliers.

In the case of the former, it has been argued that the five largest customers, by virtue of their size, maintain a strong bargaining position relative to other consumers and suppliers (provided adequate supplies of gas exist to meet market demand).

In terms of competition with other gas users, it has been argued that smaller users are virtually crowded out of supply from the North West Shelf given the fact it is mostly contracted to large producers.

As noted by BHP Billiton (which is both a gas producer and consumer) in its submission to the Consultation Paper:

> *"The large size of these customers means that each customer in its own right would be in a position to take action to ensure the future reliability of its gas supply including, where necessary, contracting in such a manner to support any necessary investment in infrastructure"*

The issue of joint marketing of domestic gas by the North West Shelf Partners has also been raised in the submissions to the Consultation paper.

However, joint marketing is a more pertinent issue for larger buyers, where gas tends to be a much more critical input into the production process and is therefore not easily substituted for other energy sources (and in the case of Alinta and Burrup Fertilisers, an energy switch is not possible).

In addition, large gas consumers are also more dependent on supply from the North West Shelf, given their requirement for larger volumes of natural gas, which can not be satisfied by smaller producers.

The joint marketing arrangement employed by the project partners eliminates any supply competition between the partners, increasing their bargaining position in the market.

These issues do not necessarily mean that the WA gas market is uncompetitive. Rather, the issue lies in identifying what factors are impacting on further supplies of gas coming to the domestic market.

The supply chain analysis employed above has identified a number of issues which potentially impact on the efficient supply of gas to the domestic market, from taxation and infrastructure to pipeline capacity and retention leases.

Notably, every consumer interviewed as part of this consultancy project expressed a preference for the free market to determine the supply and price of natural gas in Western Australia. However, there is uncertainty among some as to whether

market mechanisms can guarantee continued security of gas supply at a price which does not reduce their competitiveness.

The view expressed by many consumers is that a reservation policy should be an option of last resort, and only serve as a stop-gap measure while other reforms to the supply chain are implemented to increase supply competition.

Aggregation

The Consultation Paper indicated that government intervention in the Western Australian gas market as a "demand aggregator" may be an alterative or complementary intervention to the use of gas reservations for the purposes of facilitating investment in infrastructure necessary to support the supply of gas to the domestic market.

Aggregation allows a group of consumers to combine their demand to form a buying group. The buying group, with its greater bargaining power, may then be able to secure lower or more stable natural gas prices, as well as greater certainty of supply.

This is a particularly pertinent issue for smaller industrial gas users in Western Australia, some of whom have reported difficulty in securing gas supply due to the small scale of their purchasing contracts.

Some small consumers suggest that large scale gas producers seek the security of large volume, long-term contracts due to the stringent credit support conditions required by pipeline operators.

Credit support is required by pipeline operators to reduce counterparty risk in the contract to ship gas. This is a legitimate commercial incentive whereby operators need to be satisfied that the shipper is capable of meeting the obligations imposed under any relevant contract for gas transmission capacity.

However, the more onerous these requirements are on the shipper, the greater the likelihood that shippers will seek further surety from their customers in the form of their own stringent credit requirements.

This has the effect of pushing smaller users out of the market, while contracts move towards large-scale gas users, who are typically better able to satisfy robust credit support conditions by way of their size and the longevity of their supply contracts. In contrast, smaller users tend to prefer shorter, more flexible contracts for supply.

In this context, it is believed that demand aggregation would increase the availability of gas to smaller customers by aggregating smaller loads, and

transferring the counterparty risk to the aggregator (i.e. aggregator provides credit support).

It has also been suggested that while smaller users on their own are unable to underpin new gas development projects, an aggregated load could prove a catalyst for new developments, therefore bringing extra supplies onto the market in a more timely fashion.

In Western Australia's gas market, demand aggregation is already undertaken by gas retail companies, including AlintaAGL and Origin. However, these entities currently do not aggregate on a scale necessary to meet the demands of some industrial users.

The Office of Energy defines 'large' gas users as those that consume more than one tera joule of gas per year – a small volume compared to the usage of many small to middle tier gas users interviewed as part of this project. The Office of Energy requires retailers to obtain an authorisation from it should the retailer wishes to sell gas to customers consuming more than this amount.

While the aggregators currently operating in WA could purchase gas on a larger scale and take on a bigger role in aggregating demand, questions remain over whether any would be willing to assume the greater credit risk attached to greater load aggregation.

In the case of Alinta, there is also an issue with regard to competition in that it should not compromise competitive neutrality principles in taking on a larger role as an aggregator and on-selling gas to downstream buyers in greater volume while also having an interest in downstream activities such as distribution.

For these reasons, it has been suggested that a new aggregating entity could be established as a State purchasing entity.

However, this option raises further uncertainties. In the case of a State purchasing entity, the question is whether there is an identifiable market failure in the activities of existing retail businesses which would justify the government intervening in the market to become a demand aggregator.

In many respects, this may be viewed as a retrograde step in that it mirrors the situation which prevailed prior to the break up of SECWA in 1995 when the State Government controlled the gas supply industry through SECWA by way of its ability to contract for significant long-term gas purchases.

Overall, the idea that the WA Government intervene in the gas market and become a demand aggregator did not receive much support in the submissions to the Consultation Paper.

It is questionable as to whether there is a requirement for the WA Government to intervene in the gas market in such a manner. Demand aggregation is a core function of gas retail companies, but it is also a strategy that can be employed by other organisations. In this regard, BHP Billiton has noted that it is now looking at trying to aggregate its demand for gas across all of its operations in order to achieve the benefits of economies of scale.

It could also be possible for gas consumers to establish strategic alliances, with the aim of aggregating their gas needs and potentially underpinning new developments. On this basis, it is unlikely that government intervention is warranted, although aggregation in some form and scale could be undertaken by government trading enterprises.

Perth Energy has suggested that a demand aggregator could be undertaken by an independent private sector infrastructure business. Such an entity would act as an on-seller of gas to smaller downstream buyers unable to secure gas supplies on a stand-alone basis due to the relatively small supplies that are needed. According to Perth Energy:

> *This aggregator would likely be welcomed by suppliers because it would help facilitate underwriting of large gas field developments by offering 1) economies of scale in purchasing contracts and 2) credit support and for all gas loads regardless of size.*
>
> *It would also act as a defacto "wholesale market" whereby it would use a simple daily bulletin board to facilitate gas trading between downstream buyers for a fee, with the money used to provide commercial services such as blanket credit support for all gas buyers.*
>
> *The flexibility in trading arrangement would benefit even traditional large scale buyers like Alcoa, which up until now could only negotiate flexible timing of gas uptake or unexpected disruption events into purchase contracts with NWS suppliers rather than being able to trade such demand uncertainties with other gas users.*
>
> *The "trading desk" function would benefit smaller gas users by allowing them to access gas released by large users or sell gas to large users when the latter need it for timing or other reasons, enabling small and large gas users to trade on an opportunistic basis to minimise standby cost or stranded contract cost.*
>
> *This framework would expand the small wholesale gas market and diversify this customer base, in turn improving the demand security for gas and therefore the business of the aggregator.*

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The concept of aggregation is also something that the ACCC noted as a sign of any future development of the WA gas market when it provided the NWS Venture with authorisation to jointly market their gas to the domestic market in 1998.

However, it remains to be seen whether a private purchasing entity would initially have the capacity to assume significant credit support requirements on behalf of its buyers while maintaining a margin on on-selling that does not price some buyers out of the market.

While a defacto 'wholesale market' which facilitates gas trading between downstream buyers for a fee could help to cover the cost of blanket credit support for all gas buyers, such a system of trade would take some time to establish.

Even then, it remains to be seen whether the fees for trading could be set at a level which provides an incentive for buyers to use the system, particularly given the fact that some significant but smaller buyers have established relationships with niche gas producers for their supply needs and already deal directly with these entities at a lower cost than transacting through a central buying entity.

While some buyers may be prepared to transact through a purchasing entity in order to secure supplies and achieve flexibility in their contracts, there are still concerns as to the impact on price to final consumers.

This is because a purchasing entity represents an additional link in the supply chain, and although it may have a more powerful price bargaining position by way of aggregating loads, there is no guarantee that the discounts achieved in this respect could subsidise the operating cost of the entity to any significant degree. Indeed, it may be for these reasons that such an aggregation entity does not yet exist.

An Overall Energy Policy

This report has been focussed primarily on the gas industry. In reality, however, the gas industry must be viewed more broadly in the context of all energy sources, not just gas.

A concern that emerged as part of this report is the implications of the WA Government's policy to reserve gas supplies for domestic use – both within the gas industry and on other energy sources, such as coal and renewable energy sources.

Issues associated with the impact of a reservation policy within the gas industry have been articulated in the discussion on the policy on page 66. However, the policy may also impact on the viability of alternative sources of energy, such as coal and renewable energy sources.

As a key producer of coal and renewable energy sources, Griffin Energy noted that the gas reservation policy should be considered within a broader energy policy framework. These sentiments were also articulated by other organisations in their submissions to the WA Government's Consultation Paper.

To be effective, overall energy policy would also need to be agreed nationally, ensuring that those dimensions of energy policy (such as the taxation policy framework) are addressed by the relevant level of government.

Policy Framework

In 2001, the Council of Australian Governments (COAG) established the Ministerial Council of Energy to coordinate interjurisdictional cooperation. As part of this, a national energy policy framework was established to guide future energy policy decision making by jurisdictions and to provide the necessary policy certainty for energy users and the energy sector. This was set out in the 2004 publication, *Securing Australia's Energy Future*.

The agreed objectives included:

- encouraging efficient provision of reliable, competitively priced energy services to Australians, underpinning wealth and job creation and improved quality of life, taking into account the needs of regional, rural and remote areas;
- encouraging responsible development of Australia's energy resources, technology and expertise, their efficient use by industries and households, and their exploitation in export markets;
- mitigating local and global environmental impacts, notably greenhouse impacts, of energy production, transformation, supply and use.

Consistent with these agreed objectives, and in light of their responsibilities under the constitution, all Australian Governments agreed that their energy policies will:

- recognise the importance of competitive and sustainable energy markets in achieving these objectives;
- continuously improve Australia's national energy markets, in particular between and among jurisdictions and—recognising growing convergence between energy markets—between energy sources, and supply and demand side opportunities;
- enhance the security and reliability of energy supply, encompassing resource availability, conversion, transportation and distribution, and recognising the impact of government policy and the regulatory environment on private sector investment and operation;
- stimulate sustained energy efficiency improvements to technologies, systems and management proficiency across production, conversion, transmission, distribution and use;
- encourage the efficient economic development and increased application of less carbon-intensive (including renewable) energy sources and technologies, including exploring opportunities for appropriate inter-fuel substitution;
- recognise that Australia's energy markets operate in the context of world energy markets and seek to enhance Australia's international competitiveness in these markets;
- in view of the importance of long-term investment in the energy sector, provide the degree of transparency and clarity in government decision making required to achieve confidence in current and future investment decisions;
- carefully consider the social and economic impacts on regional and remote areas, with particular regard to businesses, industries and communities; and
- facilitate constructive, effective interjurisdictional cooperation and productive international collaboration on energy matters.

The objectives and issues set out above represent a useful starting point towards the development of an overall energy policy.

Findings

The key findings of this research report are summarised below.

Natural Gas Reserves

1. There is no lack of gas reserves in Western Australia. WA currently holds the largest reserves of natural gas in the country, with a total endowment of 112.1 trillion cubic feet (Tcf) (including all fields that are either developed or undeveloped).

2. The key challenge for the state lies in developing its vast reserves of gas. Of the 112.1 Tcf of gas reserves in Western Australia, only 18 per cent (or 20.5 Tcf) relates to developed or producing fields. Within this portion, around 90 per cent (or 18.6 Tcf) of the deposits belong to the North West Shelf Venture alone.

3. The remaining 82 per cent (or 91.8 Tcf) of the state's gas resources are located in undeveloped fields. Of this, retention lease resources account for the bulk of this (63.2 Tcf), and make up 56 per cent of the state's total endowment of gas resources.

4. A large proportion of WA's gas deposits currently under retention lease relate to two projects in particular, with 46 per cent of resources under lease relating to the Greater Gorgon area, while approximately one-third relates to the Browse LNG project.

5. The remaining 28.6 Tcf of undeveloped gas resources relate to deposits which are viewed as having some scope to be developed.

Field Economics

6. There are a number of key issues which have a significant effect on the commercial viability of any one gas field. Every field development requires special purpose design, which is generally matched to the resource's characteristics in order to optimise the recovery of the resource relative to its development costs.

7. The matching of the optimal development to the market is important to understanding the potential viability of gas projects in Western Australia. It should be noted that all of the large undeveloped gas resources currently planned for development in WA suffer from a number of factors that increase the development cost, and therefore the scale required to achieve a commercial development.

8. Supply into the domestic market provides proponents with an opportunity to earn immediate revenues from the field given the typically long lead times to developing LNG facilities, as well as the high cost of liquefaction and storage of LNG.

9. This means that for any significant project, the supply of a proportion of gas from the field into the domestic market is to a large extent contingent upon the timing and viability of the export project, which provides the foundation for the overall development of the resource. Therefore, any factors that delay the export part of the project in effect risks making less gas available for the domestic market.

Gas Supply and Consumption

10. Natural gas supply to the WA domestic market has risen by an average of 5.6 per cent per annum over the past 20 years to 2005-06. However, supply growth has eased in the past five years, growing by just 0.3 per cent per annum. This is primarily as a result of lower supply from non-North West Shelf suppliers, whose output has fallen by an average of 5.3 per cent each year over the past five years, while gas supply from the North West Shelf have risen by an average of 3.6 per cent per annum during this period.

11. Western Australia is the single largest natural gas consumer in Australia, accounting for one-third of national consumption currently. Consumption of natural gas here increased by an average of 6.2 per cent per annum between 1986-87 to 2004-05, which compares to an average rate of consumption growth across Australia of 3.2 per cent per annum over the same period.

12. The strength of gas consumption growth here lies in the state's reliance on gas as a fuel source, with natural gas currently accounting for around 41 per cent of total net fuel consumption in Western Australia. Across Australia, natural gas currently makes up less than 20 per cent of the nation's energy source.

13. The state's reliance on natural gas as a fuel source is due to its base in manufacturing, electricity generation and mining, which together consume up to 90 per cent of the state's natural gas supplies each year. In turn, this volume of consumption by industry is concentrated among only five major users.

Exploration

14. Western Australia is the lead state in terms of petroleum exploration, with over $5.4 billion expended on exploration in the past decade, which accounts for almost 60 per cent of expenditure nationwide in the past ten years.

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15. WA has a rich history of gas exploration success, with major discoveries made at regular intervals over the past 40 years.

16. Despite the low price of gas in the domestic market, exploration activity is still high, and it is not just concentrated in locating larger deposits more suitable to LNG. In fact, spudding in the Perth Basin (where field sizes are more suited to servicing the domestic market) has risen in the past four years, with a record number of wells spudded in this basin during 2005.

Gas Prices and Market Characteristics

17. Domestic gas prices in Western Australia have been low, but a comparison of prices internationally requires an understanding of the different characteristics of gas markets. In 2005-06, it is estimated that domestic wholesale consumers paid an average price of $2.34 per giga joule (GJ) for natural gas in WA. Recent reports have gas prices now in excess of $5.50 per GJ.

18. The consistently low price of natural gas in Western Australia is more likely a function of the characteristics of the WA gas market as opposed to previous government intervention in the market.

19. Several aspects of the WA market stand out as unique compared to markets overseas, including; trading via physical long-term contracts, periodic periods of high supply competition, the price of alternative fuel sources (coal in particular), and the manner in which contract prices are elevated during the terms of the contract.

Production Industry – Policy Issues

20. High barriers to entry mean that a relatively few large companies dominate the production of gas in Western Australia, and also hold a large proportion of undeveloped reserves.

21. The concentration of resource ownership does not necessarily suggest that competitive forces are not at work in the industry. The success or otherwise of a producer (large or small) relies on the ability to obtain exploration permits and then retention leases. The extent to which production eventuates will depend on the characteristics of the field and the demand for gas, all of which underpin the economics of the field.

Gas Reservation

22. In relation to the WA Government's policy on gas reservation, the majority of submissions to the Consultation Paper did not support the introduction of a reservation requirement on gas producers. Instead, there was a strong belief

that market mechanisms would be the most efficient means by which domestic gas supplies could be secured.

23. While the policy contains certain shortcomings, it remains the view of some participants in the domestic gas market that some form of reservation is necessary in order to guarantee continued security of supply. While such participants broadly favour market mechanisms over government intervention, for the most part, their views are based on the fact that there is no fungible market for gas in WA, with domestic supplies concentrated among only two projects.

24. That said, there was a strong belief that wider issues which address infrastructure concerns, approvals processes and taxation would provide greater incentives and ability for field development. Getting these wider settings right would be less distortionary than a direct reservation requirement.

Retention Leases

25. In relation to retention leases, a number of submissions suggested that an improvement could be achieved within the existing legislative scheme applying to retention leases to prevent 'hoarding', whilst also protecting property rights and minimising sovereign risk.

26. In order to open up such a process to competition, the implementation of a gazetting process was suggested. Here, where a retention lease is being sought by the holder of an exploration permit, a gazetting process would be the trigger to allow another party to give an absolute undertaking to develop such a field. In such circumstances, the existing holder of the exploration permit and the applicant for the retention lease should lose their interest in the location and the Government should transfer the interest in the location to the third party that has given the absolute undertaking.

27. Such a reform would involve substantial amendment to a complicated legislative regime (requiring agreement from all States, Territories and the Commonwealth). It would also radically alter the present balance between expediting development and minimising sovereign risk.

28. One further option that could be considered is a gazetting process which would allow third parties to make submissions to the government with respect to the issue of whether and when a field was commercially viable such that the government would be required to take those submissions into account in making its decision – without the process allowing for the automatic shift in proprietal interests from the exploration permit holder/applicant to a third party that has given an absolute undertaking. In some respects, an informal lobbying process of this type can already be seen to exist such that third party scrutiny

and lobbying may already enhance the stringency with which the Government assesses the retention lease applications.

Infrastructure Support

29. Overall, CCI remains of the view that infrastructure support, or other forms of subsidy, are not an appropriate mechanism to encourage proponents to supply gas into the domestic market.

30. By and large, projects should proceed only if commercially viable, government subsidies tend too often to take money from efficient businesses and give it to inefficient ones, to the detriment of overall economic efficiency. Where the government exercises discretion in the allocation of funds, there is a risk that political considerations and patronage will influence the distribution of funds.

31. Rather than provide direct infrastructure support to assist in the development of smaller domestic-only gas projects, the WA Government should look to create the right environment to support the development of such projects.

Infrastructure Access

32. A proposal raised by a number of submissions to the Consultation Paper was for the Government to subject gas gathering and processing infrastructure to the same open access principles that apply to other essential infrastructure.

33. While it has never been tested, it is unclear whether such infrastructure would be declared under Part IIIA of the TPA. This is largely because it would need to be demonstrated that, among other things, the infrastructure is uneconomical to develop and that it has natural monopoly characteristics – both of which are debatable.

34. In this regard, there already exists a high degree of upstream competition, and each of these producers has found it to be commercially viable to build domestic gas processing facilities, even for relatively small gas fields, and in an economic environment that is far less supportive that it is today.

35. That said, it is possible that commercial opportunities may exist for gas producers to share gas processing facilities – in much the same way that the NWS Venture has been doing since it first supplied gas to the domestic market.

Taxation

36. A crucial element of the company tax system is the framework over which capital expenditures can be claimed as deductions in the calculation of taxable income. Despite the introduction of effective life caps, depreciation deductions

available to gas projects are generally not competitive with the 5–10 year write-off periods (and similar or lower tax rates) available to most LNG competitors overseas.

37. A flow through share scheme essentially enables the transfer of tax deductions of individual exploration companies to individual investors. In this, the tax deduction of the exploration expenditure is leveraged in the capital markets in the subject year, attracting external investors rather than being accumulated tax losses, which will only be realisable if the company earns taxable income. Such a reform, it is argued, could assist in the development of domestic-only gas fields held by junior exploration companies.

Approvals Processes

38. Difficulties with project approvals are the most often cited impediments to timely project development. Approvals are complex, and often lengthy and uncertain. Duplication between levels of government adds to these problems.

39. While the Commonwealth and State Governments have taken steps both individually and together to reform approvals processes, there is more that needs to be done, particularly by the State Government. This includes: the more timely implementation of the Keating recommendations; the need for timelines and performance indicators to measure agencies' performance and hold them accountable to achieving regulatory reforms; removing any overlap and duplication between legislation, and between levels of government; and ensuring new regulations are rigorously assessed.

40. The growing involvement of local government in approval of major projects threatens to make some of the processes more rather than less complex. In particular, some local governments have recently determined that building licences and planning approvals must be obtained from the local government for all development, regardless of any State Agreement Act provisions that may apply to a project. There are questions about the physical and technical capacity of some local governments to undertake the required assessments for such approvals. As well, such approvals are tending to come at the end of the overall approval process. This situation is leading to uncertainty and potentially causes complications for both State Agreement projects and governments.

Joint Marketing

41. One of the key issues in relation to the WA gas market cited in a number of submissions was the fact that NWS proponents jointly market their gas to domestic consumers, which was alleged to have the effect of reducing competition in the supply of gas to the domestic market.

42. Against this, proponents of joint marketing arrangements suggest that it provides a suitable mechanism for sharing and apportioning risks and creating certainty in a market where high risks and large capital expenditure are associated with exploration and production.

43. In 1998, the ACCC authorised the joint marketing arrangements of the NWS Venture, accepting the view that separate marketing was impractical or unachievable. While the Authorisation enabled each of the applicants to jointly market and sell natural gas with protection under the *Trade Practices Act 1974* (TPA), the Act itself does not mandate that all joint marketing ventures are required to seek an authorisation. As a result, the NWS Venture did not seek a new authorisation from the ACCC for their coordinated marketing beyond August 2005 based on their belief that their gas marketing practices meet the requirements of the TPA.

44. The centrally important consideration in ACCC joint marketing determinations is whether it is practically feasible at the time of the application for separate marketing rather than joint marketing to occur in the relevant market. At present, there appears to be a substantial variance in views regarding whether the WA gas market has made separate marketing a more feasible opportunity since the ACCC determination in 1998.

Transmission – Policy Issues

Pipeline Capacity

45. There are four major gas pipeline transmission networks in Western Australia through which gas is supplied to the domestic market. The state's pipeline infrastructure currently has an average total capacity of 1,093TJ/day, although capacity on the key transmission lines is currently constrained.

46. Additional investment into pipeline capacity in Western Australia is constrained by the *Gas Pipeline Access (Western Australia) Act 1998* which incorporates the National Third Party Access Code for Natural Gas Pipeline Systems. The manner in which these laws regulate the price of access (through formal access arrangements) is the main obstacle to investment.

47. In particular, the interpretation of reference tariffs by regulators has been found to create a psychological barrier in the minds of access seekers, such that any agreement negotiated at a price higher than the reference tariff is perceived as being too high. Therefore, the access regime often impinges on commercial negotiation, and on many occasions, access agreements tend to take place at a price equal to, or near the regulated access price.

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48. Although reforms to the Code are currently underway in the form of a draft Gas Legislative Framework supplemented by a set of National Gas Rules, it is debatable whether the framework will actually deliver better outcomes in terms of encouraging efficient investment into pipeline capacity. In this regard, further amendments to the new set of regulations are encouraged in order to deliver meaningful reforms to the gas transmission sector, particularly in relation to the proposed 'light' regulation provisions, and incentives for Greenfield developments.

Pressure Limitations on the DBNGP

49. Pipeline capacity can also be increased by varying the pressure limitations on natural gas pipelines. However, such variations are limited by industry standards applying to pipeline construction (AS 2885, 'SAA Pipelines – Gas and Liquid Petroleum'), to which the DBNGP is subject.

50. AS 2885 is currently under review, with a design subcommittee ('ME-038-01') considering whether the current design factor used in determining the design wall thickness of transmission pipelines can be raised from 72 per cent of specified minimum yield strength to 80 per cent, or some other value higher than the current 72 per cent level.

51. Significant benefits may be construed to the transmission pipeline industry from such a change. Specifically, it is argued that raising the design factor would result in a reduction in the capital cost of new pipelines, while existing pipelines that are capable of satisfying requirements for a pressure upgrade would be capable of a capacity increase (of up to 15 per cent), provided it is permitted to operate at higher stress levels.

52. With these standards currently under review, an opportunity exists for current limitations to be amended (provided that it does not compromise safety), which may then provide a viable short-term solution to raising pipeline capacity in WA, and meeting unmet demand for gas.

Gas Quality Specifications

53. In addition to the lack of physical capacity in the gas transmission network in WA, the gas quality specification (minimum higher heating value or HHV) on the DBNGP also serves as an impediment to the development of gas reserves in Western Australia. Currently, the minimum HHV on the DBNGP is set at 37.0 MJ/m^3.

54. However, the quality of gas can vary markedly from one field to another and quality from existing producing fields can itself vary over the life of the field. This means that any field (undeveloped and developed) which falls below the

minimum HHV can not be transmitted along the DBNGP without having its composition amended.

55. Although the required heating value specification has recently been broadened, there remains scope for a further broadening as a means to encouraging further development of gas fields in Western Australia.

56. This being the case, there are valid arguments both for and against a further broadening in the specification, and in this regard, the benefits of any further broadening would need to be carefully weighed against the potential cost to pipeline operators and end-users.

57. In this context, one option in further widening the gas specification could involve permitting pipeline owners to a fair tariff adjustment, whereby it could recoup any losses incurred as a result of lower transportation capacity and increased operating costs.

58. By how much this might require tariffs to be adjusted upwards remains to be seen however. It is not inconceivable that shippers and consumers would accept a tariff variation, given the benefit this may bring to the domestic gas market in terms of encouraging upstream supply competition. This could work to reduce domestic gas prices in the long term as new supply comes on stream, helping to offset some proportion of the higher tariff. Clearly, such a step would require further analysis and consultation with industry.

59. Although there are alternatives to broadening the quality specification on the DBNGP, the viability of each of these varies according to nature of each gas field. In many instances issues such as the cost (i.e. spiking), access to infrastructure (i.e. sub-sea pipelines and location of the customer), and quality of gas upstream in the pipeline (i.e. in relation to the blending envelope) can render these alternatives unviable.

Consumption

60. The ability to secure adequate supplies at the appropriate quality, and at a competitive price, is perhaps the key external factor facing most consumers in WA at present. In addition to these broad external factors, a number of industry-related factors also exist which contribute to concerns over supply adequacy, with the key issue concerning the competitive positioning of gas consumers relative to each other, and relative to suppliers.

61. However, these issues do not necessarily mean that the WA gas market is uncompetitive. Rather, the issue lies in identifying what factors are impacting on further supplies of gas coming to the domestic market. Notably, every consumer interviewed as part of this consultancy project expressed a

preference for the free market to determine the supply and price of natural gas in Western Australia.

62. The view expressed by many consumers is that a reservation policy should be an option of last resort, and only serve as a stop-gap measure while other reforms to the supply chain are implemented to increase supply competition.

Aggregation

63. One option explored to increase the availability of gas to smaller customers is through some form of demand aggregation. Its is argued that an aggregated load could prove a catalyst for new field developments, therefore bringing extra supplies onto the market in a more timely fashion.

64. In Western Australia's gas market, demand aggregation is already undertaken by gas retail companies, including AlintaAGL and Origin. However, these entities currently do not aggregate on a scale necessary to meet the demands of some industrial users.

65. While the aggregators which currently operate in WA could purchase gas on a larger scale and take on a bigger role in aggregating demand, questions remain over whether any would be willing to assume the greater credit risk attached to greater load aggregation.

66. Some gas consumers believe that a State purchasing entity could be established to undertake a demand aggregator role and assume the credit risk. However, it is unclear whether there exists an identifiable market failure in the activities of existing retail businesses which would justify the government intervening in the market to become a demand aggregator. Demand aggregation is a core function of gas retail companies, but is also a strategy that can be employed by other organisations. It could also be possible for gas consumers to establish strategic alliances, with the aim of aggregating their gas needs and potentially underpinning new developments.

67. The prospect of an independent private sector infrastructure business to undertake such a function was also proposed. However, it remains to be seen whether a private purchasing entity would initially have the capacity to assume significant credit support requirements on behalf of its buyers while maintaining a margin on on-selling that does not price some buyers out of the market.

Summary – An Overall Energy Policy

68. The range of issues identified across the whole gas supply chain highlights the need for this issue to be considered in the context of an overall energy policy –

one which looks at energy supply through the entire supply chain, and across different sources of energy.

69. An overall energy policy would allow the development of a coherent and consistent policy framework that would deliver superior outcomes for the State than any ad hoc approaches.

70. To be effective, overall energy policy would also need to be agreed nationally, ensuring that those dimensions of energy policy (such as the taxation policy framework) are addressed by the relevant level of government.

71. The 2004 publication, *Securing Australia's Energy Future*, provides a good starting point from which a state energy policy can be developed, detailing a national energy policy framework to guide future energy policy decision making to provide certainty for energy users and the energy sector. The publication was developed by the Ministerial Council on Energy, a body established by the Council of Australian Governments (COAG) to coordinate inter-jurisdictional cooperation.

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[1] Australian Bureau of Statistics Catalogue 8412.0 - Mineral and Petroleum Exploration.

[2] Spudded is an industry term used to describe the process of initiating drilling operations.

[3] *WA Government Policy on Securing Domestic Gas Supplies*, DBNGP (WA) Transmission Pty Limited submission to Department of Industry and Resources, April 2006. Page 2.

[4] According to the PennWell Corporation, Oil & Gas Journal, Vol. 103, No. 47 (December 19, 2005) estimate of 'proved' world natural gas reserves. Proved reserves refer to quantities that analysis of geologic and engineering data demonstrates with reasonable certainty are recoverable under existing economic and operating conditions.

[5] "Chevron Announces Significant Gas Discovery in Australia", Media Release. http://www.chevron.com/news/press/2006/2006-11-09.asp. Accessed 16 November 2006.

[6] North West Shelf Venture. http://www.nwsg.com.au/sp-frameset.html?industry/conversionfactors.html. Accessed 31 October 2006.

[7] Field production data by DOIR is only available for 2005. Note that the discussion above this paragraph canvasses 2005-06 overall production data.

[8] LNG is often measured in tonnes. The 17.1 billion cubic metres quoted here refers to the approximate natural gas equivalent (i.e. not liquefied).

[9] ABARE data is only available up to 2004-05.

[10] The Australian Bureau of Agriculture and Resource Economics measures total energy consumption in Australia as the sum of total fuels consumed net of derived fuels produced. In WA, the sole derived fuel produced is thermal electricity.

[11] *WA Government Policy on Securing Domestic Gas Supplies*, BHP Billiton Submission, Submission to Department of Industry and Resources, 21 April 2006. Page 15.

[12] Based on estimates provided by CSBP.

[13] *WA Government Policy on Securing Domestic Gas Supplies*, BHP Billiton Submission, Submission to Department of Industry and Resources, 21 April 2006. Page 2.

[14] The Natural Gas Supply Association, United States. http://www.naturalgas.org/naturalgas/marketing.asp. Accessed 22 November 2006.

[15] West Texas Intermediate (WTI) crude oil prices increased by 80 per cent in 1999-00 and by a further 16 per cent in 2000-01. Joutz and Villar (2006) find that a permanent shock of 20 per cent in the WTI leads to a 16 per cent increase in the Henry Hub price, 1 year out ceteris paribus.

[16] *Gas Prices in the UK*, ILEX Consulting Report, October 2004. Page ii.

[17] LNG is often measured in tonnes, however, a conversion to cubic metres can be approximated, which is then comparable to natural gas (i.e. not liquefied). This is termed 'LNG equivalent' in this paper.

[18] This price was recently paid by Newmont Mining for gas from the John Brookes field operated by Apache and Santos ("WA under pressure as gas prices double", The Australian, 27 February 2007).

[19] Department of Industry and Resources (2006), *WA Government Policy on Securing Domestic Gas Supplies Consultation Paper*, p.4.

[20] Department of Industry and Resources (2006), *WA Government Policy on Securing Domestic Gas Supplies Consultation Paper*, p.4.

[21] Alinta, APPEA, ARC Energy, BHP Billiton, BP, Collie Region and Coal Industry Futures Group, Department of Treasury and Finance, Exxon Mobil, ACIL-Tasman, Griffin Group, Inpex, NWS Venture, ResourcesLaw, Santos, Strike Oil, Verve.

[22] Alcoa, Amcor, Dampier Bunbury Pipeline, Horizon Power, Synergy.

[23] Porter, M. E., *Competitive Strategy: Techniques for Analysing Industries and Competitors.*

[24] Department of Industry, Science and Resources (Petroleum and Electricity Division) 'Offshore Petroleum: Guideline for Grant and Administration of a retention Lease' October 1999. Available on 17 October 2006 at: www1.industry.gov.au/library/content_library/Retent_Guide_Final_11.pdf

[25] 'Agreement relating to the Exploration for, and the Exploitation of, the Petroleum Resources, and certain other Resources, of the Continental Shelf of Australia and of certain Territories of the Commonwealth and of certain other Submerged Land.' This Agreement resulted in the *Petroleum (Submerged Lands) Act* 1967 (Cth) and 'mirror' legislation in each State and the NT, notably in WA *The Petroleum (Submerged Lands) Act* 1967 (repealed)(WA).

[26] The agreement is reflected in the recitals to the *Petroleum (Submerged Lands) Act* 1982 (WA). This includes Australia's sovereign rights over the continental shelf to explore and exploit the resources, as recognised by the Convention on the Continental Shelf (Geneva,

29 April 1958; Aust TS 1963 No 12; 499 UNTS 311) in force for Australia and generally, 10 June 1963 and co-operation among the Commonwealth, the Northern Territory and the States with regard to administration of Australia's internal waters, as provided for by Agreement between the Commonwealth and the States on 16 October 1967.

[27] *Coastal Waters (State Powers) Act* 1980 (Cth); *Coastal Waters (State Title) Act* 1980 (Cth); *Coastal Waters (Northern Territory Powers) Act* 1980 (Cth); *Coastal Waters (Northern Territory Title) Act 1980* (Cth); *Constitutional Powers (Coastal Waters) Act 1979* (WA) and *Off-shore (Application of Laws) Act* 1982 (WA).

[28] The current statutes are: *Petroleum (Submerged Lands) Act* 1981 (NT); *Petroleum (Submerged Lands) Act* 1982 (NSW); Petroleum *(Submerged Lands) Act* 1982 (QLD); *Petroleum (Submerged Lands) Act* 1982(SA); *Petroleum (Submerged Lands) Act 1982* (TAS); *Petroleum (Submerged Lands) Act* 1982 (VIC); *Petroleum (Submerged Lands) Act* 1982 (WA).

[29] *Coastal Waters (Northern Territory Powers) Act* 1980 (Cth) s.4(2); *Coastal Waters (State Powers) Act* 1980 (Cth)

[30] *Constitutional Powers (Coastal Waters) Act* 1979 (WA) Sch ss 3, 5; Off-shore (Application of Laws) Act 1982 (WA) ss 3, 3A.

[31] *Seas and Submerged Lands Act* 1973 (Cth) ss 3(1) (definition of 'territorial sea'), 6, Sch (enacting United Nations Convention on the Law of the Sea (Montego Bay, 10 December 1982; UN Doc A/Conf 62/122; 21 ILM 1261 (1982) Pts II, V, VI)). See also ibid arts 3, 4 in relation to 'territorial sea'.

[32] *Seas and Submerged Lands Act 1973* (Cth) ss 3(1) (definition of 'continental shelf'), 11, Sch (enacting United Nations Convention on the Law of the Sea (Montego Bay, 10 December 1982; UN Doc A/Conf 62/122; 21 ILM 1261 (1982) Pts II, V, VI)). See also ibid art 76 para 1 in relation to 'continental shelf'

[33] *Seas and Submerged Lands Act* 1973 (Cth) ss 3(1) (definition of 'exclusive economic zone'), 10A, Sch (enacting United Nations Convention on the Law of the Sea (Montego Bay, 10 December 1982; UN Doc A/Conf 62/122; 21 ILM 1261 (1982) Pts II, V, VI)). See also ibid arts 55, 57 in relation to 'exclusive economic zone'.

[34] The right and extent to which natural resources may be exploited is specified by ibid art 77 (concerning the continental shelf) and ibid art 56 (concerning the 'exclusive economic zone') [both contained in *Seas and Submerged Lands Act* 1973 (Cth)]. The rights to exploit natural resources within the territorial sea are no different to those in respect of onshore mining activities: Convention on the Territorial Sea and the Contiguous Zone (Geneva, 29 April 1958; Aust TS 1963 No 12; 516 UNTS 205) art 2 in force for Australia and generally, 10 September 1964; United Nations Convention on the Law of the Sea (Montego Bay, 10 December 1982; UN Doc A/Conf 62/122; 21 ILM 1261 (1982)) art 2.

See also *New South Wales v Commonwealth (Seas and Submerged Lands Case)* (1975) 135 CLR 337; 8 ALR 1; 50 ALJR 218 [confirmed constitutional validity of *Seas and Submerged Lands Act* 1973 (Cth)].

[35] *Seas and Submerged Lands Act* 1973 (Cth) ss 3(1), 6, 10A, 11.

[36] Offshore Constitutional Settlement adopted at the Premiers' Conference on 29 June 1979. See also Reid P C, 'Commonwealth-State Relations Offshore Mining and Petroleum Legislation; Recent Developments: An Historic Milestone or Millstone?' [1980] 2(2) *Australian Mining and Petroleum Law Journal*, 58.

[37] The coastal waters of a State consist of those parts of the territorial sea of Australia which are adjacent to the State**:** *Coastal Waters (State Title) Act* 1980 s 3. A similar position applies in the Northern Territory: *Coastal Waters (Northern Territory Title) Act* 1980 (Cth) s.3; *Coastal Waters (Northern Territory Powers) Act* 1980 (Cth) s.4(2).

[38] See: *Seas and Submerged Lands Act* 1973 (Cth) s.16, *Coastal Waters (Northern Territory Powers) Act* 1980 (Cth) s.5, *Coastal Waters (Northern Territory Title) Act* 1980(Cth), *Coastal Waters (State Title) Act* 1980 (Cth) s.4, *Coastal Waters (State Powers) Act* 1980 (Cth) s.5.

[39] Commonwealth Department of Industry, Science and Resources (Petroleum and Electricity Division) 'Offshore Petroleum Guideline for Grant and Administration of a Retention lease' ("Offshore Petroleum Guideline") October 1999 at page 3. Available on 31 October 2006 at:

www1.industry.gov.au/library/content_library/Retent_Guide_Final_11.pdf –

[40] Section 38BC of the P(SL)A ("Cth") also provides for the grant of a Retention Lease over blocks, forming part of a Production Licence, in which recovery of petroleum has ceased, provided petroleum remains in those blocks that is less than commercial. The licensee has 5 years from the date of cessation of production to apply for a lease. However, given the similarity in the relevant criteria this paper will limit its analysis to s.38B.

[41] Op. cit., Offshore Petroleum Guideline at page 4.

[42] On this point it is necessary to note that pursuant to s.73 of the P(SL)A ("Cth"), the Joint Authority may direct that an offshore pipeline licensee be a 'common carrier' of petroleum.

[43] Ibid.

[44] Senate Economics Legislation Committee: Consideration of Additional Estimates Hansard Wednesday 12 February 2003 Canberra at pg E 42

[45] It should be noted that in the Multiplex example that the lobbying process involve both a submission to Government regarding the relevant retention leases but also an offer from Multiplex to the Greater Gorgon partners of $70million for the interest in the fields the subject of the West Tryal Rocks retention lease and that the offer was made on the day before the West Tryal Rocks and the related Spar gas fields came up for the 5 year renewal of their retention leases. See Treadgold T., 'Huge gas projects in doubt', Business Review Weekly 6 March 2003 at 26.

[46] Drummond M., 'Multiplex's dream of fields', Australian Financial Review 28 January 2003 at 6.

[47] Drummond M., 'Roberts' Bold Gas Bid Thwarted', Australian Financial Review 29 April 2003 at 54.

[48] See Department of Primary Industry Victoria, 'Minerals and Petroleum Industry Activity'. Website available on 11 December 2006 at: http://www.dse.vic.gov.au/dpi/nrenmp.nsf/LinkView/4091419D117B5E654A2569B2002022F4C3DB2784730E0A4C4A256A8000122A09

[49] Department of Treasury and Finance (2006), *Government Policy on Securing Domestic Gas Supplies Consultation Paper: Public Submission by the Department of Treasury and Finance.*

[50] Alcoa of Australia (2006), *Submission on WA Domestic Gas Policy*, p.25.

[51] Thompson, A, *Access to Upstream/Midstream Oil and Gas Infrastructure in Australia – Fair game or not?* AustralAsian Oil and Gas Conference, 23 February 2005.

[52] Offshore petroleum royalties currently apply only to the North West Shelf (NWS) production area and State and Territory waters. Royalties do not overlap with the PRRT or Resource Rent Royalty (RRR) regimes. Crude oil excise does not overlap with the profits-based PRRT or RRR regimes and currently only applies to the NWS production area and State and Territory waters. The rate of excise applied depends on the annual rate of production of crude oil, the date of discovery of the petroleum reservoir and the date on which production commenced.

[53] Independent Review Committee, 2002, *Review of the Project Development Approvals System.*

[54] Australian Competition and Consumer Commission, *Application for Authorisation No.A90624, North West Shelf Project*, Determination 29.07.1998.

[55] Re Queensland Cooperative Milling Association [1976] ATPR 40-012 at 17,247 ("Re Queensland Cooperative Milling Association").

[56] Re QCNA and Defence Holdings (1976) ATPR 40-012 at 17,242 and see Re 7-Eleven Stores Pty Ltd, Australian Association of Convenience Stores Inc and Queensland Newsagents Federation (1994) ATPR 41-357 at 42,677 ("Re 7-Eleven Stores Pty Ltd").

[57] Broken Hill Associated Smelters Pty Ltd (1984) ATPR (Com) 50,071.

[58] Re 7-Eleven Stores Pty Ltd at 42,683 and see re Queensland Independent Wholesalers Ltd (1995) ATPR 41-438 at 40,960.

[59] Re Media Council of Australia (1996) ATPR 41-497 at 42,261 ("Re Media Council of Australia").

[60] Re Queensland Cooperative Milling Association Ltd at 17,247.

[61] Re Alliance Petroleum Australia Pty Ltd (unreported) Australian Competition Tribunal per Lockhart J, Dr. Brunt and Dr. Aldrich M, 14 October 1997 BC9705137 ("Re Alliance Petroleum Australia Pty Ltd").

[62] Re Alliance Petroleum Australia Pty Ltd at page 54

[63] Australian Competition and Consumer Commission, *Application for Authorisation No.A40081, PNG Gas Joint Venture Project*, Determination 3.5.2006.

[64] See the NWS Determination at page 22 referring to the applicants' submission at para. 9.11. See also Rose P. and Grave D., "Authorisation of Joint Venture Marketing: North West Shelf Project Authorisation" (1998) 17 AMPLJ at 382.

[65] The NWS Determination at 32.

[66] The NWS Determination at 34; see Rose P. and Grave D., at 384 and 385.

[67] It is also been noted that to perform its statutory duty to review the Tribunal must have the same powers as those specifically vested in the ACCC by s.91(4)(b) of the TPA, they being to revoke the authorisation; and if the Tribunal considers it appropriate to do so, grant a further authorisation in substitution for the authorisation so revoked: see Re Media Council of Australia at 42,238 and see Alliance Petroleum Australia Pty Ltd.

[68] Re Media Council of Australia at 42,239, 42,240 and 42,261.

[69] Alliance Petroleum Australia Pty Ltd at page 54

[70] NWS Determination at 48: See also Rose P. and Grave D., at 385 and 386.

[71] These are investment costs that cannot be recouped if the project is unsuccessful — that is, the investor cannot salvage the facility or sell it to another party without substantial loss.

[72] DBP offer a Standard Shipper Contract Service, which is used by the majority of existing shippers and is a firm full haul service. However, the DBNGP is a covered pipeline under the Gas Access Code, and if it can not agree terms and conditions of access, the Gas Access Code provides a means available to third parties under the Access Arrangement approved by the Economic Regulation Authority of WA (ERA).

[73] Hastings Funds Management Limited. Company profile. http://www.hfm.com.au/hduf/epic_energy.php. Accessed 27 November, 2006.

[74] Arc Energy, Corporate Presentation, October 2006. http://www.arcenergy.com.au/files/presentations/20061012%20ARC%20Corporate%20%20presn.pdf. Accessed 27 November 2006.

[75] Productivity Commission 2004, *Review of the Gas Access Regime*, Report no. 31, Canberra. Page 82.

[76] Productivity Commission 2004, *Review of the Gas Access Regime*, Report no. 31, Canberra. Page 102.

[77] Productivity Commission 2004, *Review of the Gas Access Regime*, Report no. 31, Canberra. Page 107.

[78] Dampier to Bunbury Pipeline. Media Statement, "$430 million expansion of DBNGP announced". 13 May 2005.

[79] Department of Industry and Resources Petroleum Division, "AS 2885.1 Pipelines – Gas And Liquid Petroleum Revision Of As 2885.1 Upper Limit Of Design Factor", July 2003. Page 9.

[80] Review of the Gas Quality Specification for the Dampier to Bunbury Natural Gas Pipeline, Western Australia. November 1995. Office of Energy, Western Australia.

[81] Review of Gas Specification for The Dampier to Bunbury Pipeline & Determination of an Appropriate Gas Composition For Design of Stage 5 Expansion, Version 5: Final For Public Release, M. J. Kimber Consultants Pty. Ltd. 22 February 2006. Page 5.

[82] Review of Gas Specification for The Dampier to Bunbury Pipeline & Determination of an Appropriate Gas Composition For Design of Stage 5 Expansion, Version 5: Final For Public Release, M. J. Kimber Consultants Pty. Ltd. 22 February 2006. Page 26.

[83] AS 4564 specifies the Wobbe index, oxygen content, hydrogen sulphide content, total sulphur content, water content, hydrocarbon dewpoint, content of total inert gases and other combustion parameters.

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