DomGas Alliance

Western Australia's Domestic Gas Security

REPORT 2010

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The DomGas Alliance

The DomGas Alliance is Western Australia's peak energy user group and represents natural gas users, infrastructure investors and prospective domestic gas producers. The Alliance promotes security and affordability of gas supply for business and households.

Members include: Alcoa of Australia, Alinta, Burrup Fertilisers, DBP, ERM Power / NewGen Power, Fortescue Metals Group, Horizon Power, Murphy Oil, Newmont Australia, Synergy and Verve Energy.

Alliance members represent around 80 percent of Western Australia's domestic gas consumption and transmission capacity, and supply gas and electricity to 200,000 small businesses and 2 million West Australians.

Executive Summary

Australia's largest gas market

Western Australia has the most energy and gas-dependent economy in Australia. Natural gas supplies close to 60 per cent of the State's primary energy and 70 per cent of its electricity generation.

The WA domestic gas market is the largest in Australia and represents 40 per cent of Australia's natural gas consumption. The WA gas market is bigger than NSW, Victoria and the ACT's combined. It is almost as large as NSW, Victoria and Queensland's combined.

The WA gas market is mature. It has over 30 downstream customers, a mix of short and long-term contracts, significant gas trading and substantial transportation and storage capacity.

The gas shortage is expected to worsen

Western Australia is experiencing a serious shortage of domestic gas. Current and prospective gas users are unable to secure gas supplies in substantial quantity.

At the same time, LNG contracts are being entered into on 20 year terms. When gas is locked-up in long term LNG contracts, it is no longer available to meet current or future domestic demand.

The gas shortage is expected to worsen. The State will need at least 1,100 terajoules per day (TJ/day) of new domestic gas production by 2020 to meet demand growth and to replace existing supply as fields decline and contracts expire.

Announced new gas field developments will not meet this demand and the State faces a potential shortfall of up to 600 TJ/day. To put this in perspective, this shortfall is equivalent to half of the State's current domestic gas consumption.

Producers have immense market power to increase prices and withhold supply

Given the State's dependence on affordable energy, natural gas should be supplied at a price that gives WA a competitive advantage.

Western Australia however has one of the most uncompetitive gas markets in the country. It is a duopoly market where just two supplier groups control close to 100 per cent of the market. This gives producers immense market power to control prices and supply.

Producers are able to "keep their foot on the hose" and release only small volumes of gas on very short terms and very high prices. The Gorgon producers have for example indicated they would not meet their obligation to deliver 300 TJ/day of domestic gas until 2021 – some 12 years after the project's final investment decision. It was stated that this was to avoid an "oversupply" of domestic gas.

Major producers, supported by government, are warehousing gas fields for possible LNG development when those fields could be developed for the local market. Some fields have been warehoused for as long as 30 years despite strong interest from potential domestic gas producers and customers.

WA gas prices are up to three times Eastern States prices

As a result, WA gas prices are up to three times the price of gas in the Eastern States. Domestic gas customers are being forced to deliver premium returns to gas producers – in excess of that obtained from overseas LNG customers.

At the $8 per gigajoule prices now being demanded by producers, the State will be forced to spend an extra $2 billion a year on domestic gas. This represents a $2 billion transfer from WA businesses and households to the world's biggest and most profitable oil and gas companies.

Just two domestic gas plants supply almost all of the State's gas

The 2008 North West Shelf Joint Venture and Apache Energy Varanus Island outages highlight the energy security risks of having just two domestic gas processing plants.

Reliability of supply depends on both reliable infrastructure assets and diversity of supply. There needs to be a significant expansion in the number of domestic gas supply sources to the State.

High domestic gas prices means higher greenhouse emissions

Natural gas is no longer competitive with coal for baseload power generation and major manufacturing and resource processing. This is unlikely to change under an emissions trading scheme.

At current prices, natural gas would only be competitive with coal at a $90 per tonne carbon cost. Australia's current policy framework does not encourage the use of natural gas as the most effective and efficient means of reducing greenhouse emissions.

At a time when the rest of the world is shifting to cleaner energy sources, the gas shortage is forcing the state to build new coal-fired stations.

The domestic gas shortage could be the single biggest factor contributing to emissions growth in Western Australia over the next decade.

Urgent action needed on domestic gas supply

Urgent action is needed by the State and Commonwealth to address WA's worsening domestic gas shortage. This must include:

- An improved exploration regime to promote domestic gas exploration;
- Stringent enforcement of retention leases to stop producers warehousing gas that could supply the domestic market;
- Giving teeth to the State's domestic reservation policy;
- Removing anti-competitive joint selling arrangements; and
- Promoting initiatives to lower development costs such as common-use infrastructure.

Promote domestic gas exploration

The current offshore exploration release process is inefficient and discourages gas exploration and development. While companies have nominated areas for exploration work, these have not been released on the basis that the Federal Government must first undertake work to demonstrate that the areas are attractive for prospective explorers.

An improved exploration licence regime should be implemented whereby explorers can reasonably obtain approval to explore any area not already under licence.

Stringently enforce retention leases

Major producers are warehousing gas fields for possible LNG development when those fields could be commercially developed for the local market. Fields have been warehoused for as long as 30 years despite strong interest from potential domestic gas producers and customers.

Retention leases should be stringently enforced and should not be used to indefinitely park gas reserves when those resources could economically supply the domestic market.

The Federal Government however seems determined to give LNG projects precedence over domestic supply in approving the warehousing of reserves under retention leases. This approach appears in conflict with existing legislation and can only lead to higher domestic gas prices for WA.

Enforce competition and eliminate joint selling

Joint selling by gas producers limits competition, leads to higher gas prices, and undermines State Government energy market reforms. ACCC intervention to protect producers remains the single biggest barrier to competition and market development in WA.

Removing joint selling will significantly increase the number of independent sellers and lead to lower prices. These same producers already compete with each other in separately selling to overseas customers.

Give the domestic gas reservation policy teeth

The current reservation policy needs teeth and must ensure:

- **Certainty** – domestic obligations should be made unconditional and not subject to a "commerciality" escape clause;
- **Flexibility** – LNG producers should be given sufficient flexibility in how they can meet their domestic supply obligations;
- **Growth** – the domestic supply commitment should expand with any future growth in project gas reserves, production or LNG exports; and
- **Timeliness** – the reservation commitment should be applied to both reserves and production; domestic gas should be supplied no later than LNG start-up and not unduly delayed.

The State should apply domestic supply obligations on the Browse and Wheatstone projects.

Domestic supply obligations should also be implemented by the Commonwealth in offshore WA waters to support and complement the State's reservation policy. This is vital given domestic gas fields are now being diverted to LNG through retention leases.

Secure additional domestic supply through the North West Shelf State Agreement

The North West Shelf State Agreement provides a powerful mechanism for the State Government to secure additional domestic supply from 2010 through 2025.

The State can ensure domestic supply takes precedence over LNG when the Project renews or rolls-over existing LNG export contracts enters into new LNG contracts or undertakes new LNG developments such as the flagged LNG Train 6.

Even if the NWSJV producers satisfy their original domestic supply obligation by 2014, this does not extinguish the State's power to ensure priority of domestic supply.

Promote common-use infrastructure

Shared-use infrastructure could cut project costs by as much as half. This can facilitate development, reduce costs and promote domestic gas supply.

Concessions under the Commonwealth Petroleum Resource Rent Tax (PRRT) may however act as a disincentive for investment in shared use infrastructure.

Tax, royalty and investment incentives

To overcome WA's domestic gas shortages, Commonwealth and State tax, royalty and investment incentives should be provided to promote domestic gas exploration and development.

Key incentives could include:

- State royalty concessions such as royalty holidays, royalty rate reductions or rebasing the commodity value for royalty assessment;
- increased deductibility for pre-wellhead expenses from Commonwealth taxation;
- Flow Through Share scheme; and
- Commonwealth and State grants to promote domestic gas exploration and development.

Domestic gas production should be exempted from any extension of the PRRT to all offshore and onshore oil and gas projects.

Government responses to date

Initiatives taken by the State include broadening pipeline gas specification, royalty incentives for tight gas projects and the Exploration Incentive Program, the Strategic Energy Initiative and the 15 per cent domestic reservation policy.

These initiatives need to be matched by the Commonwealth. The State and Commonwealth should also act to remove barriers to competition and supply including joint selling of domestic gas and the warehousing of gas resources under retention leases.

Consequences of action vs. inaction

Domestic gas security is the most critical challenge facing Western Australia today. Failure to act will have profound consequences including:

- loss of clean, secure and affordable energy supply for the State;
- sharply rising energy costs for industry, small business and households;
- loss of industry competitiveness and downstream, value-adding industries;
- lost investment, development opportunities and jobs; and
- significantly higher greenhouse emissions and damage to the environment.

Over 40 new resource projects in Western Australia potentially need gas supply. Together, these projects could deliver $46 billion in capital investment, $25 billion a year in economic output, employ 19,000 people and generate billions in tax revenues.

Action needed	Response to date
Stringently enforce retention leases Improve transparency and third party participation	✓ 2007 Joint Working Group recommends stringent enforcement of commerciality test to promote domestic supply; and greater transparency and third party participation ✗ Federal Government takes two years to publish an Options Paper for yet more discussion ✗ Joint Authority now giving LNG projects precedence over domestic supply in managing retention leases ✗ No action taken to improve transparency and third party participation
Remove joint selling and enforce competition	✗ ACCC has been "investigating" the North West Shelf producers for over three years with no outcome ✗ ACCC takes just 5 weeks to authorise Shell, Chevron and ExxonMobil jointly selling Gorgon gas ✗ ACCC intervention in the market to endorse joint remains the biggest barrier to competition and market development in WA ✗ ACCC authorises continued joint selling by the six North West Shelf partners
Domestic supply obligations	✗ LNG producers delaying or avoiding domestic supply obligations ✗ Chevron indicates it would not meet 300 TJ/d Gorgon domestic supply target until 2021 to avoid an "oversupply" in the domestic market ✗ Domestic supply not being pursued in ongoing administration of the North West Shelf State Agreement ✗ State yet to announce domestic supply obligations for Browse and Wheatstone

Action needed	Response to date
Promote domestic gas use to reduce greenhouse emissions	✗ Current policy framework ignores and in fact discourages natural gas use ✗ The proposal CPRS would penalise domestic gas supply by providing free permits to export LNG
Promote more domestic gas exploration by open access	✗ Delays in releasing exploration areas to prospective domestic gas producers
Provide tax and royalty incentives	✓ State Government royalty incentives for tight gas projects ✗ Flow Through Shares Scheme yet to be implemented by the Federal Government
National energy security strategy	✓ Federal Government proposes Energy Security White Paper in Jan 2008 to address gas security ✗ Energy White Paper now focused on maximising Australia's energy exports ✗ Energy exporters made up 10 of 12 industry members of original White Paper committee ✗ Draft Energy Green Paper highly critical of State's domestic gas reservation policy ✗ Energy White Paper suspended until after the 2010 Federal election
Other initiatives to promote domestic gas exploration and development	✓ State Government broadens gas specification ✓ State Government Exploration Incentive Program ✓ State Government launches Strategic Energy Initiative

The West Australian Gas Market

Key Points

- Western Australia has the most energy and gas-dependent economy in Australia.
- Natural gas supplies close to 60 per cent of the State's primary energy and 70 per cent of its electricity generation.
- The WA domestic gas market is the largest in Australia and represents 40 per cent of Australia's natural gas consumption.
- It is bigger than NSW, Victoria and the ACT combined. It is almost as big as NSW, Victoria and Queensland combined.
- It is a mature and developed market with over 30 downstream customers, a mix of short and long-term contracts, significant gas trading and substantial transportation and storage capacity.

1. WA's gas dependent economy

Energy security is a matter of vital importance for Western Australia. Access to secure and affordable gas supply has underpinned the State's growth and development for the past 25 years.

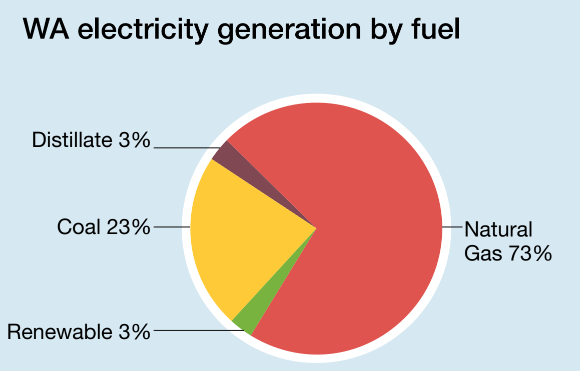
Western Australia is by far the most energy dependent economy in Australia. For every million dollars of Gross State Product generated, around 6.28 terajoules of energy is consumed. This compares to 5.32 terajoules for Australia as a whole.[1]

Western Australia is also the most gas-dependent. Natural gas supplies 56 per cent of the State's primary energy needs.[2] It fuels around 70 per cent of the State's electricity generation.[3] In contrast, natural gas supplies 22 per cent of the primary energy needs of Australia as a whole.[4]

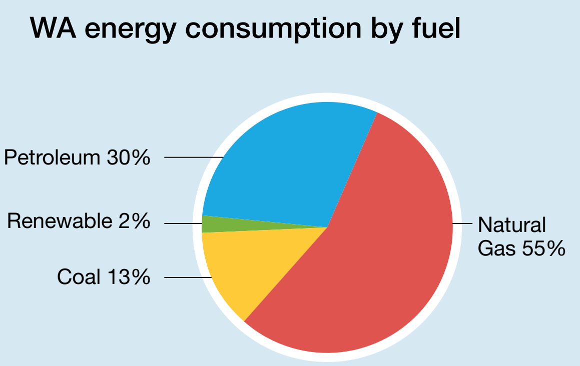
Manufacturing, electricity generation and mining together account for up to 90 per cent of annual domestic gas consumption in Western Australia.

1 Energy Supply Association of Australia, *Western Australian Energy Market Study*, November 2009, p.42, citing ABARE and ABS statistics.
2 ABARE, *Energy Update 2009*.
3 CCIWA, *Meeting the Future Gas Needs of Western Australia*, May 2007, p.41.
4 ABARE, *Energy Update 2009*.

Charts: WA's gas dependence



Source: WA Office of Energy, Energy and Resources Infrastructure 2009



Source: ABARE, Energy in Australia 2010 (Energy consumption, 2007-2008)

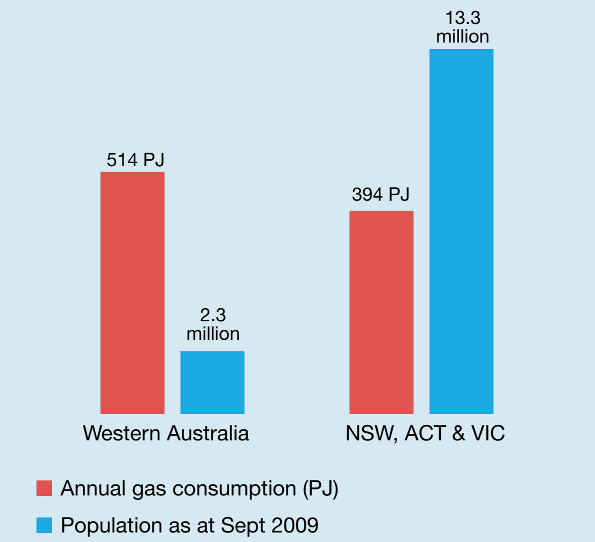
Natural gas supply has enabled the growth of the State's key value-adding industries such as alumina, chemicals, fertiliser, manufacturing and other resource-processing industries. It has underpinned living standards through affordable gas and electricity prices for WA business and households. It is vital to the State's future ability to grow and attract new developments such as the Oakajee Port and magnetite industry.

2. Australia's biggest domestic gas market

The WA domestic gas market is the largest in Australia. According to ABARE, Western Australia accounts for almost 40 per cent of Australia's total natural gas demand.[5]

The State consumes more gas than New South Wales, ACT and Queensland combined; and almost as much as New South Wales, Victoria and Queensland combined.[6]

Chart: Domestic gas consumption



Source: ABARE, Energy in Australia 2010 (Energy consumption, 2007-2008); ABS, Australian Demographic Statistics, September 2009

Natural gas consumption averaged an estimated 1,194 TJ/day in 2006-07 – seven times the volume used in 1983 prior to deliveries from the North West Shelf.[7] Since 1984, domestic demand for gas has been growing at around 8.5 per cent per year.[8]

It is a multi-billion dollar market where more than 30 customers buy directly from just two producer groups. At recent WA domestic gas prices, Western Australia would spend up to $3.5 billion on domestic gas each year.

5 ABARE, *Energy Update 2009*, Table e 'Australian consumption of natural gas by state'.
6 ABARE, *Energy Update 2009*, Table e 'Australian consumption of natural gas by state'.
7 ABARE, *Natural gas consumption by State*, 2008.
8 ABARE, *Natural gas consumption by State*, 2008.

3. Gas production

Western Australia accounts for around 80 per cent of Australia's natural gas resources.[9] The State also accounts for the bulk of Australia's LNG exports through the North West Shelf Project.

Around one-third of WA gas production is supplied to the domestic market, with the remaining two-thirds used as feedstock for LNG production and export.[10]

The North West Shelf Joint Venture, which comprises six participants, supplies almost 70 per cent of the WA domestic gas market. The NWJSV is operated by Woodside (50%), with the other participants being: Shell, Chevron, BP, BHP Billiton, and Mitsui-Mitsubishi.

Apache-led joint ventures supply almost all of the remaining 30 per cent of the WA domestic gas market.

Western Australia currently exports around 16 million tonnes of LNG per year. All LNG is produced by the North West Shelf Joint Venture. The NWSJV operates five LNG processing trains, with Train 5 commissioned in 2008.

In September 2009, Chevron, Shell and ExxonMobil announced final investment approval for the Gorgon Project. The project will construct three LNG processing trains with a total capacity of 15 million tonnes per year, and by 2015 a domestic gas plant.

Woodside is progressing its Pluto LNG Project with first gas expected late 2010. The project involves construction of a 4.3 million tonnes per year LNG train, with Woodside flagging development of a second and third LNG train, and at some stage a domestic gas facility.

4. Natural gas reserves

According to the WA Department of Mines and Petroleum, Western Australia has an estimated 138 trillion cubic feet of natural gas resources.[11] This estimate however refers to "P50" resources with only a minimum 50% or higher probability of economic recovery. Further, the bulk of these gas resources are considered uncommercial. Just 14 per cent of gas resources relate to developed fields.[12]

56 per cent of the State's gas resources are held under retention leases and are currently considered uncommercial for development. 99 per cent of resources held under retention leases were operated by Woodside, Chevron and ExxonMobil.[13]

A 2007 Commonwealth – States Joint Working Group Report on Natural Gas Supply noted that there were significant barriers to easily accessing and commercialising a significant proportion of the State's natural gas reserves.[14]

9 ABARE, *Energy in Australia 2009*, available at: http://www.abareconomics.com/interactive/09_auEnergy/

10 Australian Energy Regulator 2008, *State of the Energy Market 2008*, p.224; Energy Supply Association of Australia, *Western Australian Energy Market Study*, November 2009, p.45

11 WA Department of Mines and Petroleum, *Petroleum in Western Australia 2009*, p.35.

12 WA Department of Mines and Petroleum, *Western Australian Oil and Gas Review 2008*, pp.79-81.

13 WA Department of Mines and Petroleum, *Western Australian Oil and Gas Review 2008,* pp.80-81.

14 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy Joint Working Group on Natural Gas Supply, Final Report, September 2007, p.7.

5. A large and mature domestic gas market

The WA domestic gas market is a large and mature market characterised by:

- a large number of downstream customers that purchase directly from gas producers;
- a mix of short and long-term supply contracts;
- significant short and long-term gas trading; and
- substantial transportation and storage capacity

5.1 Downstream market transformation

At the time the North West Shelf Joint Venture commenced production in 1984, domestic gas supply in WA was characterised by a single monopoly seller (the NWSJV) and a single vertically integrated State monopoly buyer (SECWA) which owned and operated the gas transmission pipeline between Dampier and the South West of the State.

Since the 1990s, Western Australia has undertaken extensive reform of the structure and characteristics of the downstream market. This has increased competition between customers and promoted market maturity.

The disaggregation of SECWA and the single domestic gas contract transformed the domestic gas market from one characterised by a vertically-integrated monopoly buyer to one where there are now around 30 individual customers which purchase directly from gas producers. Downstream reforms gathered momentum with the subsequent deregulation of the gas and electricity markets.

As a result of these reforms, the WA domestic gas market has fundamentally changed – at least with respect to the downstream market. There has been a significant increase in:

- the breadth of the domestic market and the size of domestic demand;
- the number of direct gas customers;
- the number of parties buying through an aggregator, many of whom could also elect to purchase directly from gas producers;
- the entry of brokers providing gas trading services to gas users;
- short and long-term trading in gas transmission capacity and physical gas;
- additional transportation and storage options;
- the flexibility within the Dampier to Bunbury Natural Gas Pipeline system to deal with supply and demand imbalances; and
- connectivity between gas pipelines in Western Australia – gas can now be traded either physically or commercially in any part of the system.

In contrast, the upstream market retains the same high level concentration and lack of competition between suppliers as was the case in the mid-1990s. It is a duopoly market in which just two producer groups control almost 100 per cent of the market.

Major producers exercise immense market power through joint selling arrangements, and through common / overlapping ownership of new developments such as Gorgon, Wheatstone and Pluto.

5.2 Around 30 domestic gas customers

In 1995, the original SECWA contract was disaggregated which led to the emergence of six major independent buyers:

- the Electricity Corporation (South West);
- the Electricity Corporation (Pilbara);
- the Gas Corporation;
- Alcoa of Australia Limited;
- Hamersley Iron Pty Limited; and
- Robe River Mining Co. Pty Ltd.

There were also a number of buyers who purchased their gas from one or other of the Apache joint ventures.

Other key reforms implemented after 1995 to increase downstream competition in the market included:

- the separation of the supply and transmission components of the SECWA domestic gas supply contract as part of the disaggregation;
- the introduction of an open access regime for the Dampier to Bunbury Natural Gas Pipeline;
- the establishment of Alinta Gas and Western Power as separate corporatised businesses (albeit government owned);
- the sale of the Dampier to Bunbury Natural Gas Pipeline to Epic Energy in 1998;
- the staged removal of barriers to competition downstream in the domestic gas market;
- the privatisation and sale of Alinta Gas in 2000; and
- the disaggregation of Western Power to establish four entities (Verve, Synergy, Horizon Power and Western Power) with existing gas supply contracts (the ability to contract with gas suppliers).[15]

The downstream market today comprises over 30 customers buying directly from gas producers. This contrasts to the previous market situation characterised by a single vertically-integrated monopoly buyer.

The Apache-led joint ventures supply the majority of these parties, including most of the NWSJV's customers. These contract sizes range from >80 TJ/d (such as with Burrup Fertilisers, Verve, Alinta and Alcoa) down to approximately 1 TJ/d.

Gas customers are dependent on existing gas producers. They have no reasonable alternatives for supply which limits their bargaining position. In contrast, major gas producers can supply to both the domestic and international markets.

5.3 Aggregators

A large number of customers purchase through aggregators such as Alinta and Synergy. These customers range from light industrial and commercial customers, as well as small businesses and households.

Many of these customers can purchase directly from a producer and arrange their own transmission. However for reasons of convenience, some customers prefer to purchase a delivered service through an aggregator. Perth Energy is also building a presence in the domestic market as an aggregator supplying to gas users.

[15] Western Power (Networks) was created without the ability to purchase power or gas.

5.4 Gas trading and brokers

Trades in gas transmission capacity and physical gas are regularly being conducted on a short and long term basis. There is a high level of sophistication in trading arrangements between gas users.

While no formal market has been established, given the relatively small number of major players, large gas consumers and pipeline shippers commonly trade amongst themselves either independently, or with the assistance of brokers. Smaller industrial gas consumers also trade either independently or with the assistance of brokers.

DBP, the owners of the Dampier to Bunbury Natural Gas Pipeline (DBNGP), posts spot transmission capacity, subject to availability. A gas trading exchange (gasTrading) facilitates trades of both gas and pipeline capacity, with trades accounting for up to 10 per cent of the gas delivered into the DBNGP on some days.

Since 2007 – with the completion of the DBNGP / Goldfields Gas Pipeline interconnect - there has been complete interconnectivity between pipelines in Western Australia.

Customers now have the ability either physically or with swaps to trade gas to most of the market. Gas from the North West Shelf can be traded - either physically or commercially - in any part of the system.

There has been a significant increase in the number of independent brokers providing gas trading services to gas users. Gas users engaging brokers range from large industrial to smaller industrial customers.

To further improve transparency, the State Government has committed to the establishment of a Gas Bulletin Board. A Gas Bulletin Board operated for over three months during the 2008 Apache Energy Varanus Island outage.

Gas consumers are supportive of efforts to improve transparency and short term trading arrangements. However, the volume of trades that took place during the Varanus Island emergency is tiny compared to the volume of day-to-day direct trades already taking place between market participants.

5.5 Gas storage and balancing options

Downstream market participants have undertaken significant investments in gas storage, transportation and demand/ load management. This demonstrates commitment by downstream participants in a more mature gas market.

Australian Pipeline Trust (APA) has expanded the Goldfields Gas Pipeline with two new compressor stations. The expansion increased pipeline capacity by 20 per cent.[16]

APA has completed a major expansion of the Mondarra Gas Storage Facility. The project involved constructing an additional injection and production well drilled into the Mondarra reservoir. The expansion improves peak demand management, especially in power generation. [17]

Expansion of the Mondarra Gas Storage Facility forms part of APA's Mondarra Gas Hub development which straddles the DBNGP and the Parmelia Gas Pipeline. The Mondarra Gas Hub provides interconnected pipeline gas transportation services, load management, storage, compression and processing.

16 APA, Group Annual Meeting: Chairman Address, 30 October 2009, p.4.

17 APA, 'APA to expand the Mondarra Storage Facility', media release, 27 February 2006; APA, Annual Report 2008, p.11.

APA is now working with customers and will further develop the storage facility in line with demand requirements.[18]

DPB has completed a three stage expansion program which has seen $1.8 billion invested in the DBNGP since 2004. Key features of the expansion program include:

- a 50 per cent increase in pipeline capacity to meet gas demand in the South West and Pilbara;
- meeting delivery schedules and supply lead times of gas shippers; and
- increased reliability of services delivered on the DBNGP. [19]

The Stage 5B Expansion Project improved reliability and increased the pipeline's full haul capacity by around 110 terajoules per day. Stage 5B involved installation of 440 km of parallel pipe and upgrade works on the pipeline's compressor station facilities.

As a result of the three stage expansion program, firm full haul capacity has been increased by more than 300 terajoules per day. Around 85 per cent of the DBNGP between the North West Shelf and Bunbury is now duplicated – effectively creating a second pipeline.

The duplicated DBNGP plays an important role in load profile management and storage:

- The DBNGP provides shippers with an unconditional Accumulated Imbalance Limit of +/- 8 per cent of Contracted Capacity and a conditional limit of +/- 20 per cent – which are among the most generous in the world;
- Given that the current Contracted Capacity across all firm services on the DBNGP exceeds 800 TJ/day, the 20 per cent imbalance limit equates to over 160 TJ/day – which is more than the proposed initial production target for the Gorgon Project;
- In addition, DBP offers Park & Loan Storage services on the DBNGP and has entered into Operational Balancing Limits with the operators of production facilities and interconnected pipelines;
- Producers and gas customers therefore have a high degree of flexibility to balance daily, monthly and even yearly variances between contracted sales and actual gas volumes.[20]

DBP is in active discussions with gas shippers on engineering options to further increase the storage capability of the pipeline. This could significantly expand storage by around 150-200 TJ/d.

[18] APA, Group 2009 Annual Meeting: Chairman's Address, 30 October 2009, p.5.

[19] DBP, 'Completion of third pipeline project to meet the energy needs of Western Australia', media statement, 29 April 2010.

[20] DBP submission to the ACCC on the Gorgon Project's application for joint selling authorisation, 4 June 2009.

A recent report commissioned by APPEA does not consider any lack of gas storage options as a significant market barrier:

> "Australia's need for storage facilities is mitigated by the fact that gas production facilities are generally located close to the main demand centres. Gas production matches demand and Australia relies on spare pipeline capacity to deal with the supply / demand mismatch. *This spare capacity acts effectively as gas storage*."

> "Unlike other countries, most of Australia is not exposed to strong seasonal swings in demand. However, Victoria, Tasmania and the ACT experience seasonality in winter demand and the storage facilities do not always solve the problem as they have limited capacity. *Whilst it would be ideal to have additional storage facilities in key locations, an option to increase pipeline capacity will also increase flexibility in the markets*." [21]

Table: WA domestic gas market: 1984 and 2010

Downstream market 1984	Upstream market 1984
✗ Single downstream monopoly buyer (SECWA)	✗ Single upstream monopoly seller (NWSJV)

Downstream market 2010	Upstream market 2010
✓ Disaggregation of SECWA monopoly contract ✓ Over 30 gas customers buying directly from producers ✓ Privatisation of Alinta and the DBNGP ✓ Open access regime for the DBNGP ✓ Alinta, Synergy and Perth Energy operating as aggregators ✓ Short and long-term trading in gas transmission capacity and physical gas ✓ Significant expansion in market breadth and size ✓ Connectivity between gas pipelines in WA ✓ Greater flexibility within the DBNGP to manage supply and demand imbalances	✗ Duopoly sellers ✗ NWSJV participants continue to sell jointly to set prices, terms and conditions

[21] Asia-Pacific Partnership and PriceWaterhouseCoopers, *Asia-Pacific Gas Market Growth*, June 2009, p.31.

Challenges: Security

Key Points

- Western Australia is experiencing a serious shortage of domestic gas. Current and prospective gas users are unable to secure gas supplies in substantial quantity.
- Major producers are limiting domestic gas contracts to a maximum of 6 years, while continuing to sign 20 year contracts with overseas LNG customers. This will not allow the development of major new gas-based projects.
- Major producers are focusing on LNG exports while withholding gas from the domestic market.
- The gas shortage is expected to worsen. The State will need at least 1,100 TJ/day of new gas production by 2020 to meet demand growth, and to replace existing supply as fields decline and contracts expire.
- Announced new gas field developments will not meet this demand and the State faces a potential shortfall of up to 600 TJ/day. This is equivalent to more than half of the State's current domestic gas consumption.

1. Overview

Western Australia is experiencing serious challenges to security, reliability and affordability of supply, and to delivering cleaner energy. Gas users are unable to secure gas supplies in substantial quantity or on long-term contracts that could underpin major capital intensive projects.

Despite having Australia's largest natural gas reserves, WA has among the highest domestic gas prices in the country. Domestic gas prices are among the highest of any gas producing and exporting economy in the world.

The lack of gas availability and affordability is impacting:

- investment, employment and development in the State;
- household living standards through rising gas and electricity bills; and
- the State's response on climate change.

2. Long term contracts needed for project investment

Historically, Western Australia's gas supply market has been characterised by long term contracts. Long term take-or-pay domestic gas contracts underpinned the original development and subsequent expansion of the North West Shelf project.

Long term contracts are necessary to enable capital intensive developments such as mining, resource processing and new power stations. These investments involve significant capital investment with rates of return assessed on a 20-25 year timeframe. Businesses require confidence over energy security.

Gas security also underpins the State's vital energy infrastructure. Regulated infrastructure, such as the Dampier to Bunbury Natural Gas Pipeline, functions in a regulatory environment involving write-off periods of 60 years or more without regard to natural gas availability.

3. WA's serious gas shortage

Western Australia has been experiencing a serious domestic gas shortage and escalating prices since at least 2004. Current and prospective gas users are unable to secure gas supplies in substantial quantity and on long contractual terms.

Major gas producers have been shortening contract terms on a "take it or leave it" basis. This is impacting investment as long term contracts are necessary to underpin capital intensive developments such as manufacturing, minerals processing and power generation.

Table: Impact on investment and jobs in Western Australia

Projects Impacted

- Alcoa suspended a multi-billion dollar expansion of its Wagerup alumina refinery with lack of certainty around long term gas supply a key factor;
- Burrup Fertilisers reported it was unsuccessful in securing competitively-priced gas from the Gorgon Project for a proposed urea plant;
- Prospective gas-based power generators ERM Power and Griffin have been unable to source gas for new power station developments;
- DBP was required to significantly downsize an expansion of the Dampier to Bunbury Natural Gas Pipeline in 2006 as a number of prospective projects were unable to secure gas supply;
- Coogee Chemicals has publicly stated that at current domestic prices of $8 - $15/GJ, it was now uneconomic for any new onshore downstream processing in Western Australia;
- Coogee Chemicals shuts a manufacturing plant in 2009 because of the cost of production.
- DBP tenders for additional pipeline gas failed when the prospective supplier withdrew its offer;
- very high gas prices have forced major construction materials producer Adelaide Brighton to switch to coal and lock-in a long term coal supply agreement;
- gas suppliers were unable to meet existing contracted supply obligations, with Tap Oil for issuing a notice of force majeure in relation to its contract with Burrup Fertilisers.

4. Focus on LNG exports

At a time when the State is experiencing a serious gas shortage, major producers continue to expand LNG exports.

Long term LNG contracts present challenges to the State's energy security. As gas is locked-up in 20 year LNG contracts, it is no longer available to meet demand – regardless of the domestic gas price.

Gas fields ideally suited for domestic gas supply are also being diverted to LNG. In October 2009, Apache Energy and KUFPEC announced an agreement to undertake joint development of the Brunello and Julimar fields with Chevron's Wheatstone LNG project.[22]

The Julimar-Brunello fields were expected to produce 200 million cubic feet of gas per day and were well suited for development as a domestic gas project. A potential source of domestic gas will now be diverted to supplying LNG exports.

In the absence of domestic supply obligations, the State could well see the bulk of Wheatstone production being lost to long term LNG contracts. In December 2009, Chevron announced a 20 year agreement to supply 4.1 million tonnes a year of LNG from Wheatstone to Japan - equivalent to almost half the project's initial production capacity of 8.6 million tonnes a year.[23] The State Government has yet to announce a domestic supply obligation for Wheatstone.

Table: WA domgas and LNG contracts

Recent Domgas contracts	Recent LNG contracts
Oct 2008 – Santos 6 year contract to supply Moly Mines	**Dec 2008** – Shell 20 year Gorgon contract to supply China
Jan 2009 – Santos 7 year contract to supply CITIC Pacific	**Aug 2009** – ExxonMobil 20 year Gorgon contract to supply India
Jul 2009 – Santos 4 year contract to supply Newmont	**Aug 2009** – ExxonMobil 20 year Gorgon contract to supply China
Apr 2010 – Santos 5 year contract to supply Wesfarmers	**Sept 2009** – Chevron 15 year Gorgon contract to supply Korea
	Sept 2009 – Chevron two 20 year Gorgon contracts to supply Japan
WA gas users unable to secure long term contracts.	**Sept 2009** – Chevron 20 year Gorgon contract to supply Korea
Significant unfilled demand.	**Dec 2009** – Chevron 20 year contract to supply half of Wheatstone's initial production to Japan
	Jan 2010 – Chevron 15 year contract to supply Gorgon and Wheatstone gas to Japan
	Jan 2010 – Chevron 15 year contract to supply Gorgon gas to Japan
	Jul 2010 – Chevron 20 year contract to supply Wheatstone gas to Korea

5. WA will need at least 1100 TJ/day of new gas supply

Western Australia will need significant new domestic gas production to meet demand growth, and to replace existing supply as fields decline and supply contracts expire.

Some 150 megawatts of additional electricity generation capacity is required each year in the South West Interconnected System alone, equivalent to building a new 300 MW power station *every two years*. Additional demand growth is expected in the State's North West and Mid West.

A 2010 report by Economics Consulting Services, *Western Australia Natural Gas Demand and Supply Forecast*, assesses the State will need to source at least 1,100 TJ/day of new production by 2020 to meet new and replacement demand.[24]

The report warns that the State faces a shortfall of up to 600 terajoules per day (TJ/day) in the next decade because of the lack of supply. To place this in perspective, this volume is equivalent to half of the State's current gas consumption.

Key findings include:

- Production from existing gas fields supplying the WA market is expected to decline – by as much as two-thirds by 2020.
- The North West Shelf Gas fields have been in production for over 25 years. These fields currently supply around 70 per cent of the WA market. The majority of the largest fields are in decline.
- The State would need to source at least 1,100 TJ/day of new gas to meet new demand growth, and to replace existing supply sources as fields decline and contracts expire.
- Between 500 and 700 TJ/day of new production would be needed just to maintain existing consumption without taking into account any growth in demand.
- New projects such as Reindeer, Macedon and Gorgon would only provide up to 500 TJ/day of new supply. While other projects have been identified, they have yet to be proven commercial or there is uncertainty over domestic supply commitments.
- The State therefore faces a potential shortfall of up to 600 TJ/day between expected supply and demand in the next decade.

The report identified over 40 new resource projects in Western Australia that potentially need gas supply. Together, these projects could deliver $46 billion in new capital investment, $25 billion a year in economic output and employ 19,000 people.

North West Shelf Joint Venture producer BHP Billiton also assesses the State will require 1000 TJ/d of new capacity and reserves backing by 2020 to replace existing supply and meet forecast growth.[25]

In BHP Billiton's view, existing natural gas supply capacity is fully utilised and expected to decline. Replacement of existing supply and supply to meet forecast growth must come from new sources.

[22] Apache Corporation, 'Apache, KUFPEC to join Chevron's Wheatstone LNG Project in Australia', Media Statement, 22 October 2009.

[23] The Australian, 'Tokyo Electric signs $90bn deal to buy west's LNG', 7 December 2009, available at: http://www.theaustralian.com.au/business/mining-energy/tokyo-electric-signs-90bn-deal-to-buy-wests-lng/story-e6frg9df-1225807524628.

[24] Economics Consulting Services, *Western Australia Natural Gas Demand and Supply Forecast*, 2010.

[25] BHP Billiton presentation, *Macedon Domestic Gas Project: Gas Supply (Gas Quality Specification) Bill 2009,* July 2009.

Chart: WA demand and supply forecast to 2020

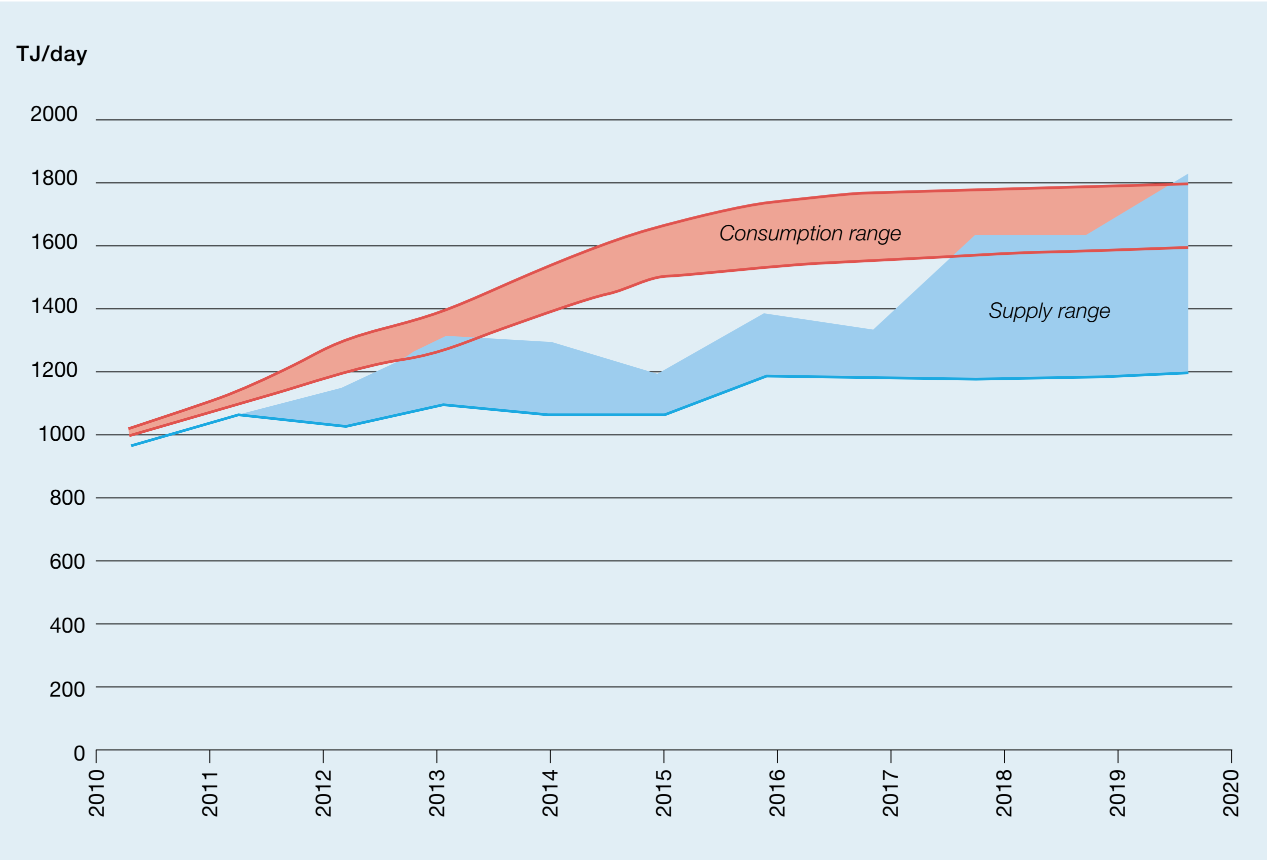
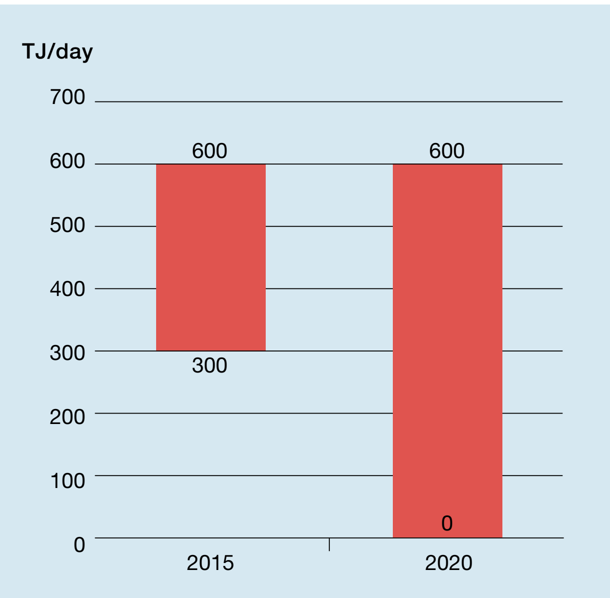


Chart: Potential domestic gas shortfall in 2015 and 2020



6. The gas shortage is expected to worsen

The WA Strategic Energy Initiative Issues Paper considers that "gas supply will remain tight until around 2015 when major new fields, such as the Gorgon gas field are likely to come to market".[26] As the ECS Report points out, this presumption is incorrect. New LNG projects will not solve the State's serious gas shortage by 2015.

Furthermore, the Gorgon Project will delay meeting the 300 TJ/d domestic gas supply commitment. Under the terms of the Gorgon State Agreement, the Gorgon participants are obliged to supply at least 300 TJ/day of gas to the domestic market.

The Gorgon partners however indicate that this supply volume will not be available until 2021 – some 12 years after the project's final investment decision. *The West Australian* quotes Chevron:

> "Chevron says it does not expect to be delivering its full quota of 300 tj/day until 2021 *because of an expected oversupply in the domestic market* … Chevron said a number of competing projects would come on to the market by 2015 *and it needed to be mindful of oversupply*."[27]

Claims about an "oversupply" in the WA gas market are not supported by the evidence. Rather than an oversupply of gas in the WA market, it appears that a deliberate shortfall of gas is more likely.

The WA Government has yet to indicate how it would apply the 15 per cent reservation policy to the Wheatstone and Browse gas projects. In the absence of binding domestic gas supply obligations, there is no certainty that domestic supply will be delivered to gas users.

Table: Prospective domestic gas projects

Project	Domestic gas supply	Start-up
Reindeer	Up to 110 TJ/d	From 2011
Macedon	Up to 220 TJ/d	From late 2012
Gorgon	Up to 150 TJ/d "if commercial"	From 2016, rising to 300 TJ/d by 2021
Julimar	Will now be developed as part of Chevron's Wheatstone LNG project	?
Pluto	5 years after LNG "if commercial"	?
Wheatstone	?	?
Browse	?	?

[26] Office of Energy, *Strategic Energy Initiative: Issues Paper*, December 2009, p.6.
[27] *The West Australian*, 'Barnett opens door to gas reserve changes', 16 June 2009.

7. Why the current market conditions?

Why is Western Australia experiencing a serious gas shortage and gas prices up to three times the price in the Eastern States?

It has been suggested that the relatively small size of Western Australia's domestic gas market (compared to international markets) and the economies of scale that can be achieved by supplying LNG to export markets. This suggests that commercial imperatives tend to favour the development of Western Australia's deep water gas resources for large-scale LNG projects.[28]

It has also been suggested that producers are only interested in securing large contracts on offer in export markets, even in the presence of commercially viable domestic supply options. [29]

It is important not to lose sight of the fact that the WA domestic gas market is a multi-billion dollar market representing 40 per cent of Australia's natural gas demand. The WA market is larger than NSW, ACT and Victoria combined. Victoria, which has a considerably smaller market than Western Australia, is not experiencing a serious gas shortage.

Claims that LNG delivers higher returns to producers do not appear sustainable. LNG involves significantly higher capital and operational costs compared to domestic gas. LNG production is moreover energy-intensive with 26 per cent of the energy consumed by the LNG supply chain representing a significant loss of value.

International LNG sales involve higher risks including sovereign risk, exchange rate risk, jurisdictional and governing law issues, complex negotiations with sovereign government entities or foreign corporations, and commodity price risks where LNG contracts are linked to international oil prices. These risks must be reflected in prices.

8. Barriers to supply and competition

The State's gas shortage and high domestic price can therefore be attributed to barriers to supply and competition. For instance, government appears to have taken a deliberate approach to give LNG priority over domestic supply in managing offshore gas resources.

The ACCC has also intervened in the market to protect major producers from competition. Authorisation for joint selling suppresses competition, distorts the market and prevents efficient market outcomes.

[28] Energy Supply Association of Australia, *Western Australian Energy Market Study*, November 2009, p.45.
[29] Energy Supply Association of Australia, *Western Australian Energy Market Study*, November 2009, p.49.

Table: Barriers to gas supply and competition

Bariers to supply	Barriers to competition
• WA gas industry is characterised by a small number of very large gas producers. • Existing producers control close to 100 per cent of developed reserves and the bulk of undeveloped reserves held under retention leases. • Existing producers target very large projects that maximise Net Present Value over a very long period of time. • In contrast, smaller gas producers target smaller fields with a lower NPV but higher rate of return over a shorter period of time. • Prospective producers face significant barriers to accessing resources locked-up by major producers. • Existing producers are able to "keep their foot on the hose" and release only small volumes of gas on very short terms and very high prices. • The Gorgon producers will not meet their 300 TJ/day domgas supply target until 2021 – so as to avoid an "oversupply" of gas in the domestic market.	• WA has a gas market duopoly – just two producer groups control close to 100 per cent of the market. • Major producers combine together to set prices when selling to WA customers. • This gives them immense market power to increase prices. • There is significant ownership concentration across projects. • The same producers are participants in the NWSJV, Gorgon, Wheatstone, Pluto, Browse and Macedon projects – these projects are unlikely to compete against each other when selling to domestic customers. • Producers have full access to customer information on contract price, volume and expiry across different joint venture projects. • Producers are using their market power to open-up existing domgas contracts and to force significantly higher prices on customers.

Challenges: Competitiveness

Key Points

- Western Australia has one of the most uncompetitive gas markets in the country.
- It is a duopoly market in which just two supplier groups control close to 100 per cent of the market because of joint selling arrangements.
- Producers exercise immense market power and can increase prices or withhold supply.
- This concentration in market power extends to prospective new developments such as Gorgon and Wheatstone which are operated by the same NWSJV producer Chevron.
- Western Australia has among the highest gas prices in Australia, despite having the bulk of Australia's natural gas reserves.
- Major producers continue to press for gas prices upwards of $7-8 per gigajoule (before transport costs) – which equate to two to three times the price of gas in Victoria.
- Government intervention to protect gas producers from competition is the single biggest barrier to competition and market development in WA.

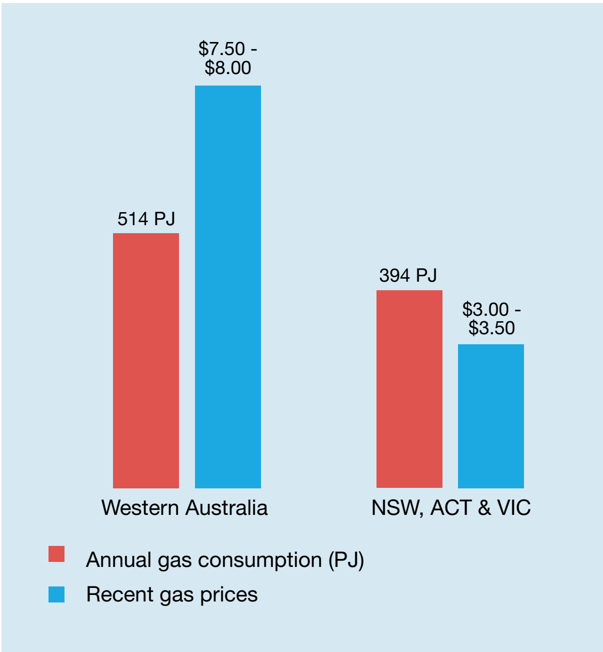
1. Western Australia has among the highest gas prices in Australia

Despite Western Australia holding 80 per cent of Australia's natural gas, WA domestic gas prices are now among the highest in the country. They are also among the highest of any gas producing / exporting economy in the world.

Historically, wholesale gas prices for WA have been around $2.50 - $3.50 per gigajoule. Recent years have however seen a sharp rise in gas prices.

The recent fall in "international" gas prices over the last 12-18 months has not translated to lower WA gas prices. Major producers continue to demand around $8 per gigajoule before transport costs. This equates to gas prices that are up to three times the price for new gas compared to in Victoria.

Chart: Domestic gas prices



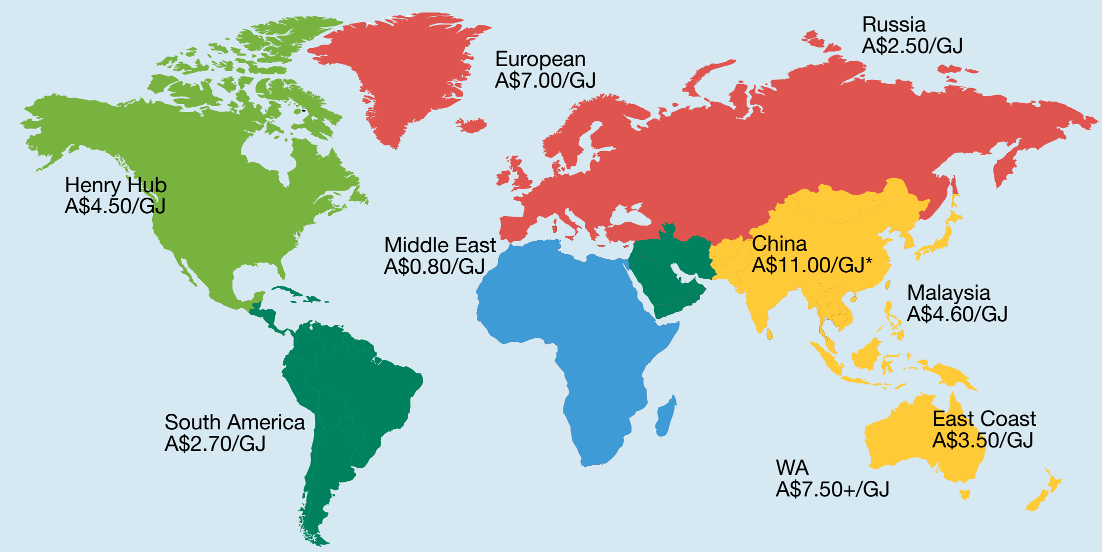
In February 2010, five of the six North West Shelf Joint Venture producers (Shell, Chevron, BP, Woodside, BHP Billiton) combined together to secure significant increases in the price of gas they supply to Alinta under an existing long term contract. Alinta is the State's largest retailer of gas and buys wholesale gas from the North West Shelf to supply to 600,000 homes and businesses. Media reports indicated a price of around $8 per GJ, equating to a 300 per cent price rise.[30]

2. "International" or "LNG-netback" prices?

Producers claim that rising domestic gas price rises reflect "international" gas prices. Producers also refer to "LNG-netback" prices – which could be defined as the price of gas paid by industry in China and Japan, less the cost of processing and shipping gas as LNG.

In fact, there is no international price for gas. Gas prices vary considerably between different countries and regions, reflecting local conditions, national resource endowments and government policies. As the following chart shows, gas prices range from under $1 per gigajoule in the Middle East to $2.50 in Russia, $4.50 in the United States and $11 in China. Even in China, industrial users can pay as low as $4.50 per gigajoule for domestic gas.

Chart: Natural gas is priced regionally



** In China industrial users pay as low as $4.50/GJ*

Source: Alcoa of Australia

[30] *WA Business News*, 'Woodside hails new domgas price mark', 24 February 2010.

There is no rationale for WA domestic gas prices to reflect prices in energy-poor countries such as Japan and China. LNG-netback would lock the State into even higher domestic gas prices and remove the State's competitive advantage in energy. At such prices, much of the State's manufacturing and resource processing industry would be rendered uneconomic. The impact on jobs and local communities would be immense.

Given its strategic importance, domestic gas should to be supplied at a price that maintains the State's competitive advantage in energy, and that reflects the State's energy resource endowment. This has been recognised by successive State Governments. As Premier Barnett emphasised to gas producers:

> "I would very strongly suggest to the industry … [that] as an industry, I would make sure that you are supplying the domestic market and that you're doing it at a price that gives us at least a marginal competitive advantage in energy, and therefore develop the potential to add value to other minerals and other natural resource production in this State…
>
> [T]hat's going to be the long-term policy of the West Australian Government, because we're not about a short-term boom, we're about trying to set this State up for 20 years of strong economic growth so that the benefits can go into health, into education, into regional development and wherever else future generations might decide." [31]

Given the State's natural gas resources belong to all West Australians, there is a public expectation that the State's gas resources are developed in a manner that delivers downstream benefits in terms of investment, development, employment and living standards.

3. LNG involves significantly higher producer costs

LNG plants involve significantly higher capital costs compared to domestic gas plants. These costs must be recouped. Conversely, producers could obtain the same return supplying domestic gas at prices well below LNG or even LNG netback prices.

The concept of LNG netback pricing was rejected by two reports by McLennan Magasanik[32] and EnergyQuest[33] in relation to Queensland. The reports concluded that producers would make an equivalent return to LNG at domestic prices of just $4.23 per gigajoule. This was *substantially lower* than the $10.83/GJ netback price.

In short, LNG netback prices represent significantly higher returns from domestic gas than otherwise obtainable from LNG.

> "MMA expects that gas producers will continue to highlight the higher netback prices whilst being prepared to supply new domestic gas contracts at something closer to the equivalent return price." [34]

In the WA market characterised by a sellers' duopoly and joint selling, producers have immense market power to control prices and supply. In the past, gas producers were quick to point to $US 8 per gigajoule Henry Hub prices to justify domestic price increases. While Henry Hub prices have since halved to around $US 4 per gigajoule, WA gas users have not seen this translate to lower WA domestic gas prices.

LNG netback is simply a formula used by major producers to justify a level of pricing set by them in the absence of real competition.

[31] Premier Colin Barnett, 'Transcript – Speech – Petroleum Club of Western Australia', 8 September 2009.

[32] McLennan Magasanik, *Queensland LNG Industry Viability and Economic Impact Study: Final Report to Queensland Department of Infrastructure and Planning*, May 2009.

[33] EnergyQuest, *Australian Coal Seam Gas 2010: CSG Meets LNG*, May 2010.

[34] McLennan Magasanik, *Queensland LNG Industry Viability and Economic Impact Study: Final Report to Queensland Department of Infrastructure and Planning*, May 2009, page xii.

4. High domgas prices not justified by producer costs

Major producers claim gas is "deeper, dirtier, dryer and more distant", and that higher production and development costs are driving up domestic gas prices.

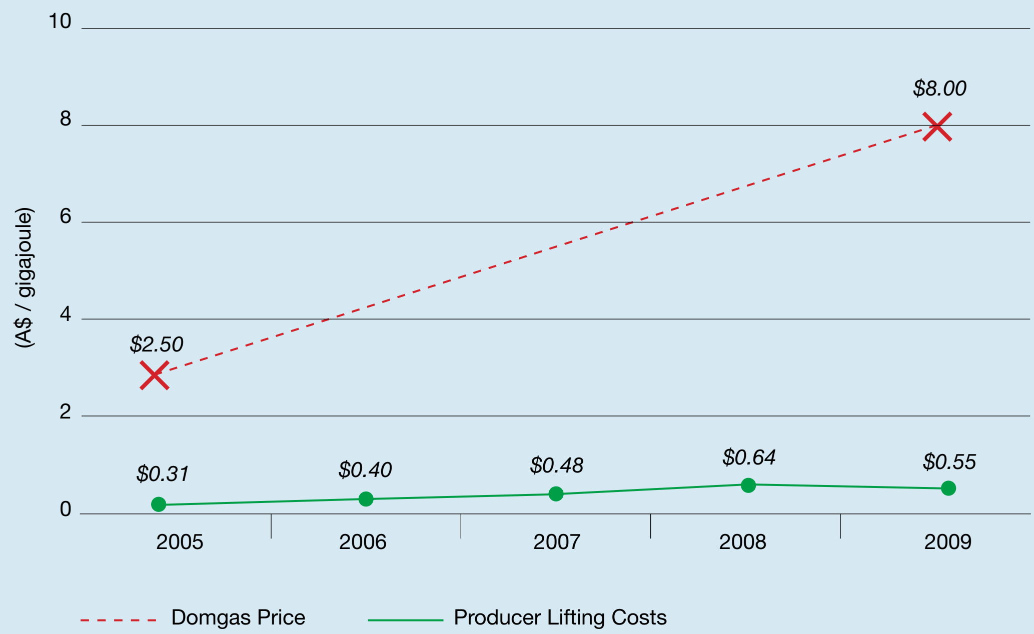
According to Woodside's 2009 company results presentation, gas lifting costs (the cost of extracting gas and delivering into the processing plant) in 2009 was $3.35 per barrel of oil equivalent.[35] This equates to just *55 cents per gigajoule*.

Lifing costs rose from 31 cents in 2005 to 65 cents in 2008, before falling in 2009. Over the same period, Woodside and its North West Shel partners have combined together to hike prices from around $2.50 - $3.00 per gigajoule to around $8.00 per gigjoule.

As Woodside CEO Don Voelte told shareholders:

> "This is a huge new revenue exposure for North West Shelf and Woodside and my expectation is that when other new or existing contracts come up for review, there will now be a new price foundation to work from."[36]

Chart: Producer lifting costs vs. domestic gas prices



Source: Lifting costs from Woodside's 2009 company results presentation

[35] Woodside, 2009 *Full Year Results Briefing*, 24 February 2010.
Conversion factor: 1 barrel of oil equivalent (bue) is approximately 6.1 gigajoules (GJ).

[36] *WA Business News*, 'Woodside hails new domgas price mark', 24 February 2010.

5. No competition means higher prices

Western Australia has one of the most uncompetitive gas markets in Australia. It is a duopoly market in which just two producer groups control close to 100 per cent of supply. Through joint selling arrangements, the six North West Shelf Joint Venture producers combine together to set prices and contract terms that cover almost 70 per cent of the market.

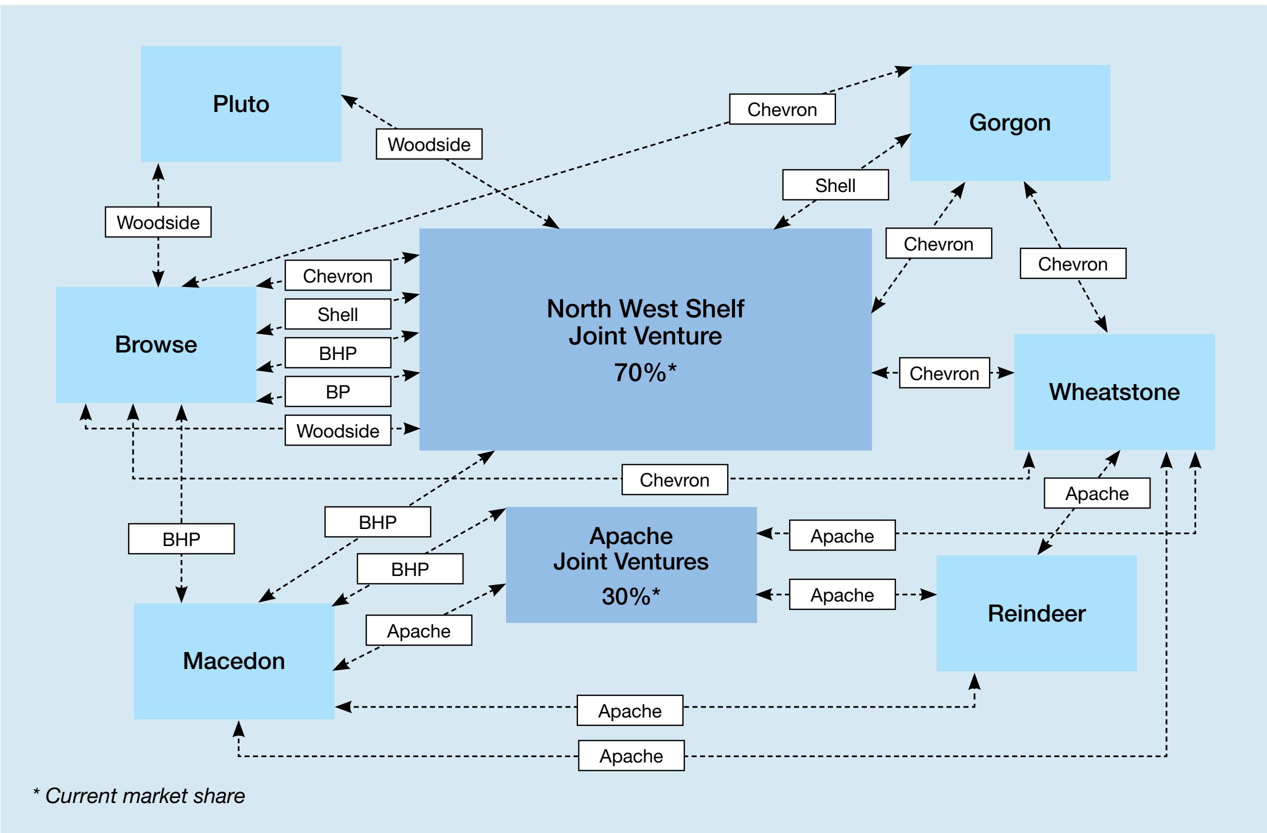
Given the same producers control prospective gas developments in the State, the competitive pressure that new projects could be expected to assert will be minimal. Through joint selling and cross-ownership, gas producers are able to co-ordinate gas marketing across projects including by marketing sequentially.

There is now increased alignment between the North West Shelf/Gorgon producers and the other major supplier into the WA domestic market, Apache. This has been highlighted by Apache and BHP Billiton's joint ownership of Macedon, and by the joint development of Apache's Brunello and Julimar fields with Chevron's Wheatstone project.

Table: WA gas projects and participants

Projects	Participants
NWSJV	Woodside, Chevron, Shell, BP, BHP Billiton, Mitsui-Mitsubishi
Pluto	Woodside
Macedon	BHP Billiton and Apache
Wheatstone	Chevron and Apache
Gorgon	Chevron, Shell and Exxon Mobil
Browse	Woodside, Chevron, Shell, BP, BHP Billiton
Reindeer	Apache, Santos

Chart: Joint selling and cross-ownership suppresses competition between projects



The WA gas market is therefore characterised by a very small grouping of producers with immense market power. The ACCC has entrenched this market power by repeatedly intervening in the market to protect gas producers from competition.

In 2009, the ACCC authorised Gorgon producers Chevron, Shell and ExxonMobil to combine together to set prices for WA customers. This was despite the fact Chevron, Shell and ExxonMobil are separately selling 95 per cent of Gorgon gas to overseas customers.

In 2010, the ACCC authorised the six NWSJV partners to continue to combine together and set prices covering almost 70 percent of the market.

ACCC intervention has suppressed competition, increased prices and limited the effectiveness of successive State Government market reforms. It is the single biggest barrier to competition and market development in the State.

6. Impact of rising gas prices on industry and the competitive fuel mix

Western Australia's power generation, resource processing and manufacturing industries are highly sensitive to gas prices and depend on affordable energy supply. Prospective projects have been suspended or lost overseas or interstate. The DomGas Alliance continues to be approached by major project developers unable to secure affordable gas prices to support projects.

Rising natural gas prices also impact the competitive fuel mix in Western Australia. Coal prices traditionally shadow gas prices which mean higher fuel costs for power generation and higher electricity costs for business and households.

Table: Impact of Tariff Cap Increases on Median Customers (based on Annual Bills) [37]

	Gas Cost increase	Disruption Costs	Total
Mid-West / South-West Residential	$78 (20%)	$11 (2.4%)	$89 (22.9%)
Mid-West / South-West Non-Residential	$78 (4.9%)	$47 (2.8%)	$126 (7.9%)
Kalgoorlie – Boulder Residential	$86 (20%)	$11 (2.2%)	$98 (22.6%)
Kalgoorlie-Boulder Non-Residential	$109 (20%)	$17 (2.6%)	$127 (23.2%)
Albany Residential and Non-Residential	$78 (20%)	-	$78 (20%)

7. Impact of rising gas prices on small business and households

Higher gas prices are impacting small business and households through higher energy bills. In June 2009, the WA Government approved significant increases in business and residential gas tariffs. These new tariffs came into force on 1 July 2009. As a result, the annual gas bill of the average Mid West and South West household has increased by $78 or almost 23 per cent.[38]

A key driver for the gas tariff increases was significantly higher wholesale gas prices. As the WA Office of Energy report noted:

> "Natural gas commodity costs in the Western Australian domestic market have increased dramatically in recent periods, moving sharply away from historical prices in the $2.50 per GJ range earlier this decade." [39]

In March 2010, the State Government announced further gas tariff increases of 7 per cent for residential customers and 6.5 per cent for small business.[40]

It is understood that current gas tariffs have yet to reflect the 300 per cent price rise that the NWSJV producers reportedly secured from gas retailer Alinta. This could only lead to even higher gas and electricity prices for WA business and households.

[37] Premier Colin Barnett and Minister for Energy Peter Collier, *State Government announces increases in tariff arrangements*, Media statement, 8 March 2010.

[38] WA Office of Energy, *Gas Tariffs Review: Interim Report to the Minister for Energy*, June 2009, p.3.

[39] Ibid.

[40] Ibid, pp.14-15.

Challenges: Reliable Energy

Key Points

- With just two supply sources, any outage at one or both domestic gas plants will have profound impacts on the State.
- Reliability of supply depends on having reliable infrastructure assets, as well as diversity of supply and a significant expansion in the number of domestic supply sources.

1. Reliability of upstream supply

In January 2008, an electrical fault at the North West Shelf gas processing plant at Karratha resulted in domestic gas supply being suspended for more than two days. The North West Shelf Joint Venture supplies around 70 per cent of the State's domestic gas requirements.

In June 2008, an outage at Apache Energy's Varanus Island plant shut off 30 per cent of the State's total gas supply and resulted in significant economic damage to gas users.

The Apache Energy outage resulted in severe disruption to operations as well as higher costs as companies. While some gas users were able to switch to diesel, this was at a significant economic cost and unsustainable for the longer term. Other gas users were forced to curtail or shut down operations through inability to secure alternative non-gas supply, or alternative supply at a commercially sustainable cost.

The Apache Energy outage had a compounding impact on industry by disrupting the local production and supply of other essential inputs, such as fertilisers for local agriculture, reagents for the mineral processing industry and industrial gases such as carbon dioxide. The incident had far-reaching economic, employment and investment impacts and also resulted in significant inconvenience to households. Relevant issues include:

- the ability of emergency response arrangements to quickly restore production in the event of supply outages or to provide alternative fuel supplies;
- the extent of redundancy built into the gas supply and delivery systems; and
- the effectiveness of the technical regulation which oversees the design and ongoing operation of domestic gas processing and supply facilities.

These issues have been the subject of detailed inquiry by the State's Gas Supply and Emergency Management Committee. The State has committed to implementing the recommendations of the Committee, including those relating to gas disruption management, mitigation measures and gas market arrangements.

2. Reliability also depends on diversity of supply

With just two supply sources (North West Shelf and Varanus Island) supplying almost 100 per cent of the State's gas needs, an outage at one or both plants will have profound impacts on the State.

The Apache Energy Varanus Island outage highlighted significant practical and economic constraints on the ability of existing users to switch from gas to alternative fuels such as coal.

Reliability of supply depends on having reliable infrastructure assets, as well as diversity of supply. There is a need to significantly expand the number of gas supply sources to the domestic market.

Challenges: Cleaner Energy

Key Points

- Natural gas is the only conventional energy source that can underpin the State's transition to a low carbon economy during the next 20 years.
- Using natural gas to fuel WA industry and households is by far the most greenhouse-and energy-efficient use of the State's natural gas resources.
- At current domestic gas prices, natural gas is no longer competitive with coal for baseload power generation and major manufacturing and resource processing.
- This is unlikely to change under an emissions trading scheme. At a $7 per gigajoule (before transport) wholesale gas price, natural gas would only be competitive with $2 per gigajoule coal at a $90 per tonne carbon cost.
- Australia's current policy framework does not encourage the use of natural gas as the most effective and efficient means of reducing greenhouse emissions.
- The domestic gas shortage could be the single biggest factor contributing to emissions growth in Western Australia over the next decade.

1. Natural gas' vital role in meeting the greenhouse challenge

Energy security and climate change are inseparably linked with efforts to reduce greenhouse emissions dependent on access to cleaner energy.

Natural gas has a vital role in meeting Western Australia's greenhouse challenge. It is the only conventional energy source that can underpin the State's transition to a low carbon economy during the next 20 years.

Natural gas produces less than half the greenhouse emissions compared to coal and uses proven, readily available technology. Combined cycle gas-fired plants and gas-fired cogeneration plants constitute by far the most greenhouse efficient forms of non-renewable power generation.

Over its life, a new 350 megawatt per hour natural gas combined cycle plant will produce 30 million tonnes of carbon dioxide emissions, compared to 70 million tonnes for an equivalent coal power plant.[41] In terms of annual greenhouse gas emissions avoided, the difference is equivalent to removing 325,000 cars off the road.

Natural gas underpins the development of greenhouse-friendly gas fired cogeneration plants. Cogeneration plants at alumina refineries in Western Australia for example generate steam which is used in the alumina refining process, as well as electricity for supply into the grid. Cogeneration plants can achieve at least 75 per cent energy efficiency, compared with 30-50 per cent for comparable coal fired generation.

[41] Simshauser, P. and Wild, P. (2007) 'The WA Power Dilemma', p.23; available at www.bbpower.com/media/299790/25907%20wa%20energy%20summit.pdf.

Natural gas supply also underpins renewable energy. Only natural gas plants can provide the peaking power capacity necessary to support renewable power such as wind and solar, and which makes renewable energy a feasible source of energy for the local market.

2. Domestic gas supply is by far the most greenhouse-and energy-efficient use of the State's gas resources

From a global greenhouse perspective, using natural gas to fuel local industry, power generation, small businesses and households is by far the most greenhouse and energy efficient use of the State's natural gas resources.

Unlike LNG, domestic gas does not need to be liquefied, shipped long distances in tankers and then regasified before it can be used as a fuel – an energy-intensive process.

Domestic gas supply is over 92 per cent energy-efficient, with less than 8 per cent of energy lost in the supply chain. Transport through the Dampier to Bunbury Natural Gas Pipeline, the longest gas transmission system in Australia, only uses less than 3 per cent of the energy transported.[42] In contrast, LNG is only 74 per cent energy efficient, with 26 per cent of the energy consumed by the LNG supply chain.[43]

In terms of lifecycle emissions, LNG produces 20 per cent more greenhouse emissions on a per gigajoule basis compared to domestic pipeline gas.[44]

Table: DomGas Alliance lifecycle study (2009)

For every 100 GJ of energy in the supply chain:

	Energy Delivered	Energy Consumed	Total	Energy efficiency
DomGas	92.3 GJ	7.4 GJ	100 GJ	92.3 %
LNG	73.7 GJ	26.3 GJ	100 GJ	73.7 %

Lifecycle greenhouse emissions for:

1 GJ LNG	67 kg $CO_{2\text{-eq}}$
1 GJ domestic gas	56 kg $CO_{2\text{-eq}}$

1 GJ of LNG generates almost 20% more greenhouse emissions over its lifecycle than domestic pipeline gas.

42 2009 DomGas Alliance study.
43 Ibid.
44 Ibid.

This analysis is consistent with other international studies. A Carnegie Mellon University study found LNG generated almost 25% more greenhouse emissions over its lifecycle compared to domestic natural gas. The study also found that the upper band of emissions associated with LNG approached that of coal.[45]

Table: Carnegie Mellon study (2007)

Lifecycle emissions (lb CO2-e per megawatt hour)			
	DomGas	**LNG**	**Coal**
Midpoint	1250	1600	2100
Upper Band	1600	2400	2550

Western Australian industry and electricity generators are energy efficient compared to their international counterparts. This reinforces the global greenhouse benefits of using the State's gas resources to fuel industry and power generation in the State.

3. Serious threat to WA's response on climate change

With 80 per cent of Australia's natural gas reserves, Western Australia should be well-placed to lead the transition to a lower carbon economy. Escalating prices and domestic gas shortages however present significant risks to the State's response on climate change.

A report by the Energy Supply Association of Australia warned that sustained higher domestic gas prices may have implications for a low-emissions transformation of the State's stationary energy sector. [46]

The Department of Mines and Petroleum also reported that transitioning the stationary energy sector has proved difficult to achieve because the demand for gas resources for export has increased and domestic gas prices have risen in response. [47]

As a result of the gas shortage and escalating prices, a number of resource and energy development projects have had to resort to coal-fired energy. The State's two recent baseload power generator tenders have been coal-fired as opposed to gas-fired (Griffin Bluewaters 1 and 2).

At current prices in Western Australia, natural gas is no longer competitive with coal for baseload power generation and major manufacturing and resource processing. This is unlikely to change under an emissions trading scheme.

At a wholesale gas price as low as $7 per gigajoule (before transport costs), natural gas would only be competitive with $2 per gigajoule coal at the following carbon costs:

- $90 per tonne carbon cost - on a long run marginal cost (LRMC) basis, that is, for new baseload power plant construction;
- $110 per tonne – on a short run marginal cost (SRMC) basis, that is, for plant already built.

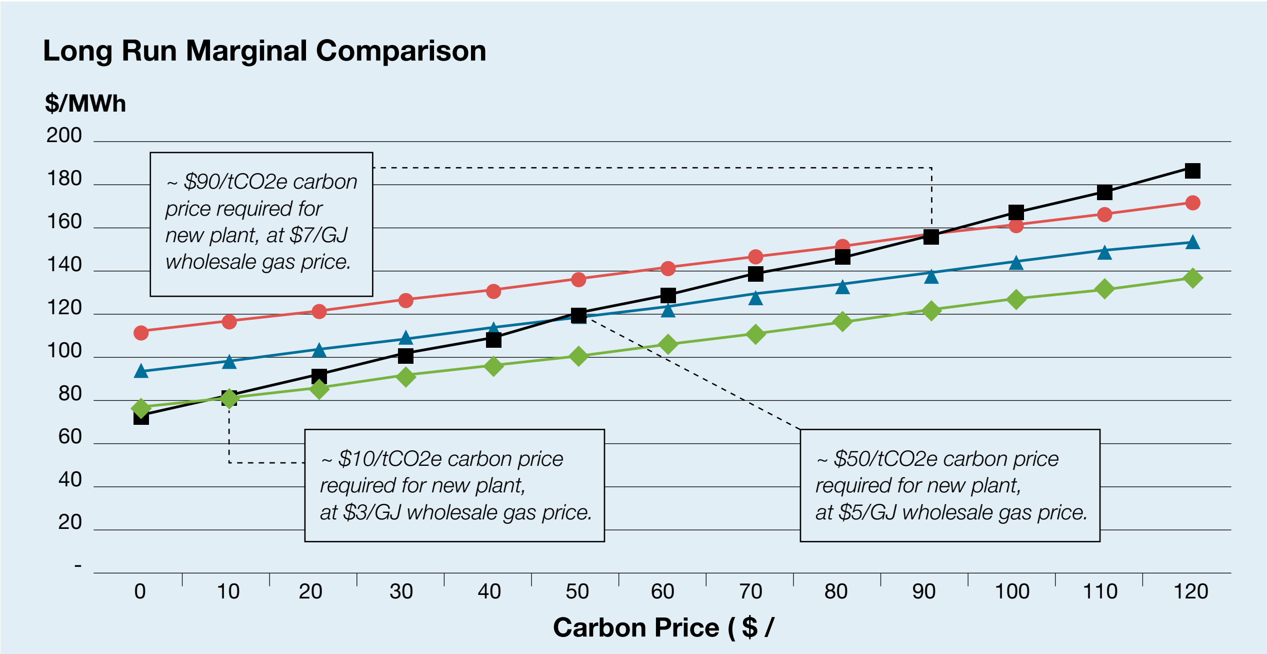
At a time when the rest of the world is shifting to cleaner energy sources, the shortage of gas is leading to WA constructing new coal-fired power plants. The domestic gas shortage could well be the single biggest factor contributing to emissions growth in Western Australia over the next decade.

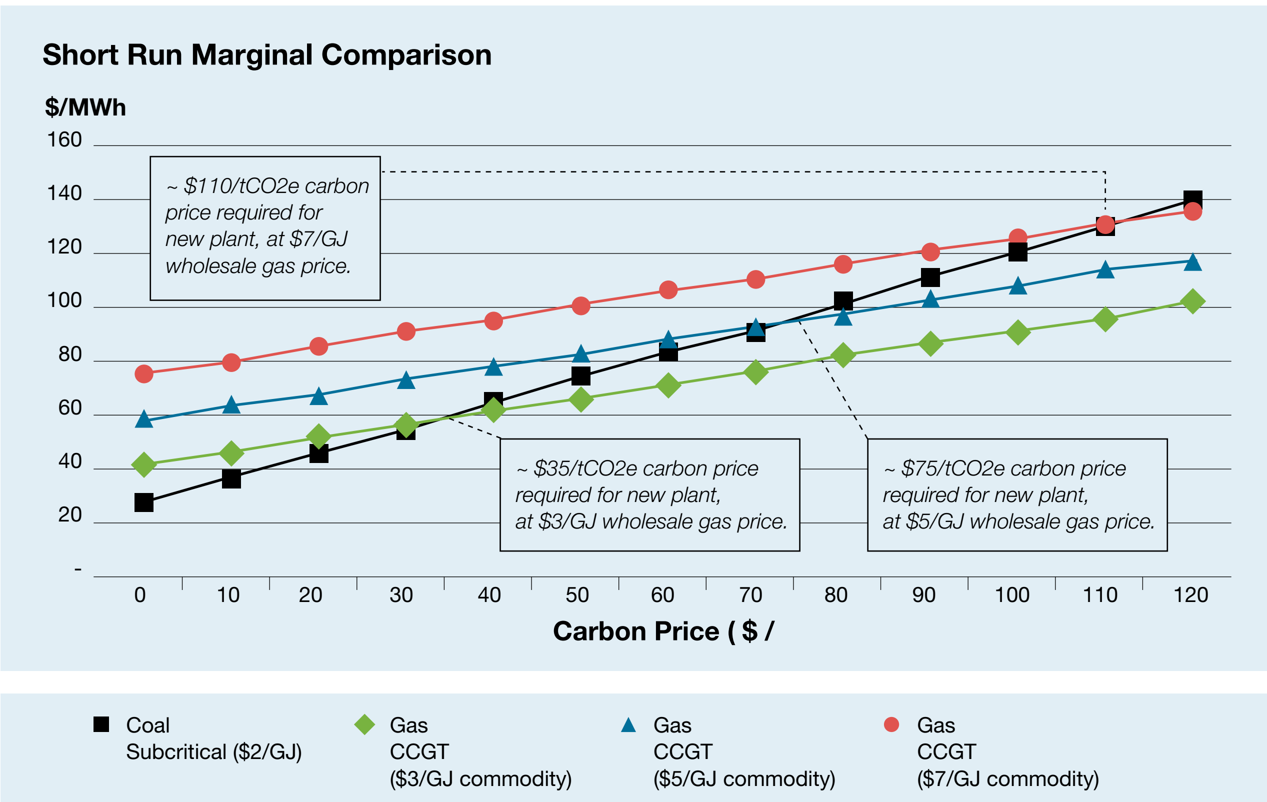
[45] Jaramillo, Griffin and Matthews, 'Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG and SNG for Electricity Generation', *Environ. Sci. Technol. 2007*, 41, 6290-6296.

[46] Energy Supply Association of Australia, *Western Australian Energy Market Study*, November 2009, p.48.

[47] Department of Mines and Petroleum, *Western Australia Oil and Gas Review 2008*, p.10.

Chart: Competitiveness of $7 / GJ gas vs. $2 / GJ coal





Abbreviations: • CCGT: combined cycle gas turbine • tCO2e: tonne of CO2 equivalent • MWh – megawatt hours • kW: kilowatt • WACC: weighted average cost of capital

4. Australia's current policy framework does not encourage domestic gas

Australia's current policy framework does not encourage – and in fact *discourages* – the used of natural gas as the most effective and efficient means of reducing Australia's greenhouse emissions.

The Federal Government's proposed Carbon Pollution Reduction Scheme provides a financial incentive for gas producers to export and discriminates against domestic gas. Under the CPRS, the LNG industry is treated as an Emission Intense Trade Exposed (EITE) industry and will qualify for 60 per cent assistance towards any emissions it produces from LNG production. The production of domestic gas on the other hand qualifies for no assistance meaning that the full cost of a carbon tax will be borne by domestic gas.

To the extent that the gas producer is not able to pass the carbon costs onto its customers, this provides a significant disincentive to invest in domestic gas supply. This could distort investment decisions in favour of LNG and divert gas reserves to exports instead of the already tight domestic gas market. Where gas producers are able to pass on carbon costs to the domestic market, this will further increase the cost of natural gas for downstream industry.

The competitiveness and uptake of natural gas could be further undermined by compensation provided to coal-fired energy for carbon costs and the support to renewable energy through a Mandatory Renewable Energy Target.

The CPRS could have serious unintended consequences and distort investment, discourage domestic gas supply, increase gas and electricity prices and undermine energy security. It could also increase greenhouse emissions and shift investment and energy use from gas to coal.

Consequences of Action vs Inaction

Key Points

- Domestic gas security is the most critical challenge facing Western Australia today. The consequences of inaction include:

  - loss of clean, secure and affordable energy supply for the State;

  - sharply rising energy costs for industry, small business and households;

  - loss of industry competitiveness and downstream, value-adding industries;

  - lost investment, development opportunities and jobs;

  - significantly higher greenhouse emissions and damage to the environment.

1. Urgent action needed on domestic gas supply

Domestic gas security is the most critical challenge facing Western Australia today. Secure and affordable gas supply is vital to the State's ability to grow, attract investment and create employment.

Urgent action is needed by the State and Commonwealth to address WA's worsening domestic gas shortage. This must include:

- An improved exploration regime to promote domestic gas exploration;
- Stringent enforcement of retention leases to maximise supply into the domestic market;
- Giving teeth to the State's domestic reservation policy;
- Removing anti-competitive joint selling arrangements; and
- Promoting initiatives to lower development costs such as common-use infrastructure and open access arrangements.

The consequences of inaction are therefore significant and include:

- loss of clean, secure and affordable energy supply for the State;
- sharply rising energy costs for industry, small business and households;
- loss of WA industry competitiveness and downstream, value-adding processing;
- lost investment, development opportunities and jobs;
- significantly higher greenhouse emissions and damage to the environment.

2. Responses should be driven by fact, not rhetoric

Meeting the gas security challenge will require a strong leadership by government. This requires policy choices being made between the commercial interests of LNG producers, and the economic, social and environmental interests of the WA community.

An evidence-based approach is needed. Concerns by major producers that action on energy security could threaten investment, discourage exploration, increase sovereign risk or constitute unwarranted market intervention by government have been unfounded. Meeting the State's gas security challenge:

- Will not discourage investment and development in Western Australia;
- Will not discourage gas exploration;
- Will not increase the State's sovereign risk or reduce its attractiveness as a place to invest; and
- Will not constitute unwarranted market intervention by government.

2.1 Western Australia's gas resources remain highly sought after by international oil companies

According to a report by Curtin University, only 8 per cent of world reserves are available to international oil companies on an open access basis.[48] 92 per cent of world natural gas reserves are controlled by national governments or national oil companies.

Australia, with under 2 per cent of world reserves, therefore represents a *quarter of the total global opportunity* available to international oil companies on an open access basis. As the WA Department of Mines and Petroleum pointed out:

> "Australia is one of the few nations in the world to have an expanding hydrocarbon resource, predominantly in natural gas, without a national oil and gas company controlling its exploitation." [49]

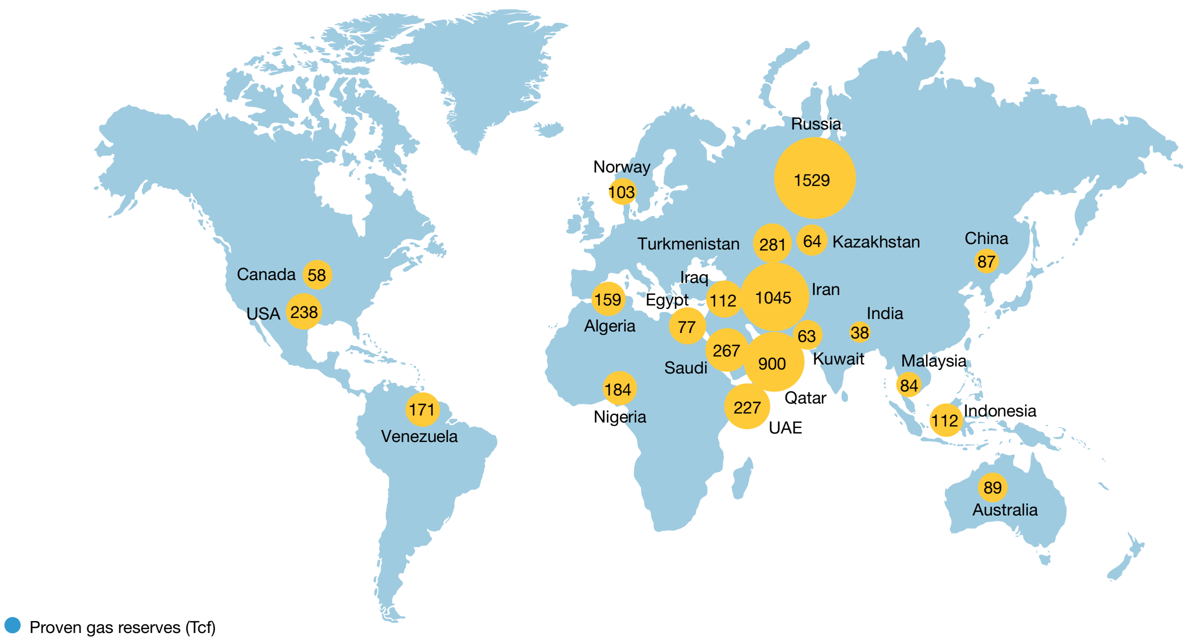
Premier Colin Barnett has also observed:

> "I think the industry is probably going to accept that … [there] is going to be a domestic reservation … I can remember in a previous life in the 1990s when some representative in [the gas] industry came along and complained about issues like that, and said how much easier it was to do projects elsewhere in the world. So I offered them the choice where the State would take 95 per cent of production or 80 per cent whatever the norm is and that was the end of that conversation."

> "[T]he industry gets a good deal in Australia, it's a fantastic deal compared to production sharing arrangement in developing countries ... I don't think the [15 per cent reservation] is a great burden on industry." [50]

[48] Leonard, Manuhutu and West, *Domestic Energy Reservation Policies: An International Comparison*, Curtin University, June 2008.
[49] Department of Mines and Petroleum, *Western Australia Oil and Gas Review 2008*, p.12.
[50] Premier Colin Barnett, 'Transcript – Speech – Petroleum Club of Western Australia', 8 September 2009.

Top 20 World Natural Gas Reserves



Source: BP Statistical Review 2009, Oil & Gas Journal, PFC Energy "Full IOC Access" countries; Santos, Melbourne Mining Club presentation, February 2010. Excludes unconventional gas reserves.

Top 20 Natural Gas Reserves with Full International Oil Company Access

Source: BP Statistical Review 2009, Oil & Gas Journal, PFC Energy "Full IOC Access" countries; Santos, Melbourne Mining Club presentation, February 2010. Excludes unconventional gas reserves.

2.2 *Governments around the world are acting to secure vital energy resources*

Governments around the world are acting to secure vital energy resources. As the State acknowledged in 2006:

> "Domestic market obligations, where a proportion of a project's production entitlements are reserved for local energy markets (and/or state owned energy utilities), are a common feature in many other oil and gas exporting nations."[51]

Egypt

A 15 per cent State reservation policy is in fact modest by world standards. Egypt for example has a national reservation policy that reserves one-third of natural gas for exports, one-third for domestic use and one-third "to save for our children".[52] This is in effect a 68 per cent reservation policy.

That policy has not prevented Egypt from accounting for Apache Energy's largest acreage position and 30 per cent of global production revenue. Apache continues to have an active drilling program in Egypt.[53]

Case Study: Qatar

Qatar is currently the world's largest LNG exporter. In 2006, Qatar imposed a moratorium on further expansion of LNG exports until 2013 in response to uncertainty over gas reserves.

Qatar has around *eight times* Australia's natural gas reserves, despite having one-twentieth Australia's population.

Australia continues to hold ambitions of overtaking Qatar as the world's largest LNG exporter.

Malysia

Malaysia has a national depletion policy which applies domestic production limits for oil and gas.[54] A 1974 Act also placed custody of Malaysia's petroleum resources with the national petroleum corporation Petronas.

Malaysia's policies do not appear to have prevented Shell from expanding petroleum exploration and production in Malaysia, including natural gas in offshore Sabah and Sarawak. Nor has it prevented Shell from expanding operations in Malaysia through production sharing agreements.

Qatar, the world's biggest LNG exporter, has placed a moratorium on further expansion of LNG exports until 2013. The moratorium was in response to uncertainty over gas reserves.[55] Qatar's actions are significant given Australia's ambitions to overtake Qatar as the world's largest LNG exporter – despite having just one-eighth Qatar's natural gas reserves but 20 times its population.

Other countries

Other countries have sought to secure energy supply through the use of export taxes or duties to manage energy exports. China for example has used export taxes to manage the export of coal and natural gas.

51 WA Department of Premier and Cabinet, *WA Government Policy on Securing Domestic Gas Supplies*, October 2006.
52 Leonard, Manuhutu and West, *Domestic Energy Reservation Policies: An International Comparison*, Curtin University, June 2008.
53 Apache Energy website, http://www.apachecorp.com/Operations/Egypt/index.aspx (accessed 30 June 2010).
54 Leonard, Manuhutu and West, *Domestic Energy Reservation Policies: An International Comparison*, Curtin University, June 2008.
55 Australian Financial Review, 'LNG export debate ought to be revisited', 27 October 2009.

2.3 Australia has one of the lowest investor / sovereign risk ratings in the world

In terms of investor and sovereign risk, Australia ranks well other major gas producers. In fact, Australia has one of the lowest investor / sovereign risk ratings in the world.

International risk management group Coface ranks Australia fourth in the world in terms of lowest country risk, after Luxembourg, Sweden and Switzerland.[56] This is well above other major LNG producers Malaysia, Qatar, Saudi Arabia, Egypt, Indonesia and Russia.

Table: Country risk rankings [57]

Country	**Lowest to highest risk**
Australia	4
Malaysia	18
Qatar	23
Saudi Arabia	61
Egypt	67
Indonesia	71
Russia	116

Western Australia's political and fiscal stability, measures to ensure domestic gas supply will have marginal if any impact on the ongoing attractiveness of the State's natural gas resources to international oil companies.

In fact, domestic gas supply would enhance Western Australia's attractiveness as a place to invest by promoting energy security.

2.4 Domestic gas security measures have not discouraged investment and development in Western Australia

Contrary to LNG industry concerns, the State's domestic reservation policy has had little if any impact on gas investment and development in Western Australia.

The policy has not prevented Woodside from developing its Pluto Project. In fact, Woodside has outlined its ambitions to expand the Project from one to five LNG processing trains, to increase production from which will increase production from 4 million tonnes per annum to 21.5 million tonnes per annum. This was despite Woodside CEO claiming that the respuation policy was "crazy" and that it would make Pluto uneconomic.[58]

Nor has the policy prevented Woodside from flagging an extra six LNG processing trains and a potential 77 million tonnes of additional LNG capacity within the next 15 years in Western Australia.[59]

[56] Coface Group, *Country rankings by risk rating*, available at: http://www.trading-safely.com/sitecwp/ceen.nsf/vwCRO/EDDC0F81926049ADC12569D0003A6548

[57] Coface Group, *Country rankings by risk rating*, available at: http://www.trading-safely.com/sitecwp/ceen.nsf/vwCRO/EDDC0F81926049ADC12569D0003A6548

[58] The West Australian, 'Woodside says Pluto will dwarf $50b Gorgon', 19 August 2009, available at: http://au.news.yahoo.com/thewest/a/-/newshome/5840299/woodside-says-pluto-will-dwarf-50b-gorgon/

[59] Woodside CEO address to Annual General Meeting, 1 May 2009, reported by Fairfax Media, 'Woodside's Voelte outlines big vision for LNG', 1 May 2009, available at: http://www.tradingroom.com.au/apps/view_breaking_news_article.ac?page=/data/news_research/published/2009/5/121/catf_090501_164100_1191.html

Similarly, the WA gas reservation policy has not prevented Chevron from flagging growth plans in Western Australia to make it one of its "biggest businesses", with equity production from Gorgon and Wheatstone approaching that in the United States. Chevron Chairman and Chief Executive David O'Reilly has stated:

> "When Gorgon and Wheatstone are up and running our equity production in Australia by the end of the coming decade should be very close to what we're producing in the United States, which would make Australia one of our biggest businesses." [60]

Dow Jones News reported that Australia's stable political environment, substantial gas reserves and proximity to fast-growing Asian economies make it an attractive place to invest in, particularly with US gas prices low due to a flood of domestic gas supply into the US market. [61]

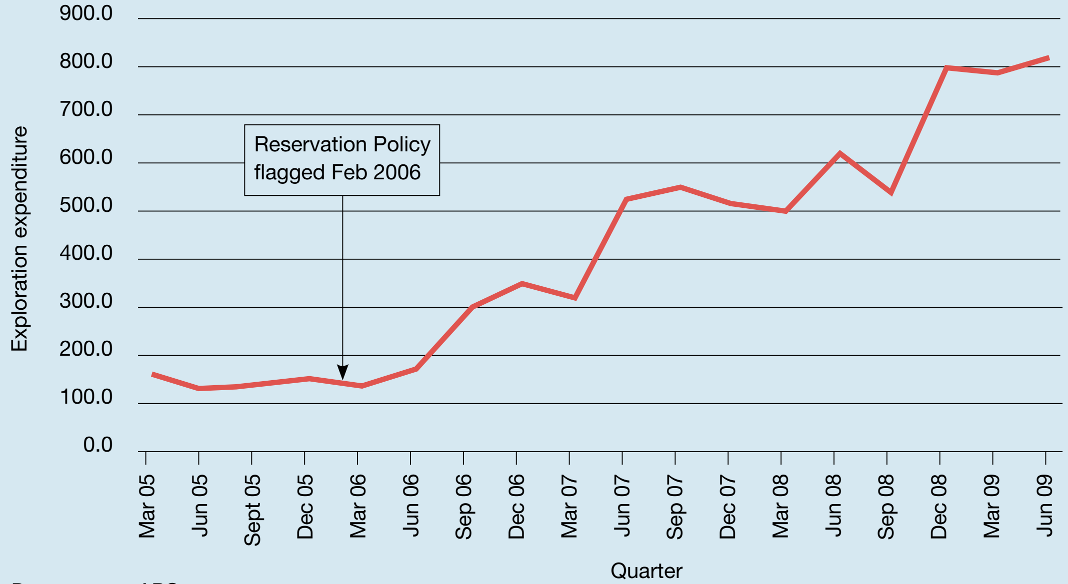
2.5 Domestic gas security measures have not discouraged exploration in Western Australia

Contrary to claims that the domestic reservation policy would discourage exploration,[62] exploration activity in WA has in fact *significantly increased* since the introduction of the policy in 2006. This is confirmed by public data available from the Australian Bureau of Statistics (see earlier chart).

The 2006 reservation policy did not prevent Alcoa and ARC Energy from entering into an agreement to expand ARC's Canning Basin exploration program.

In October 2009, the Federal Government awarded ten offshore exploration permits in Western Australia and the Northern Territory for new investment worth $158 million. Of the ten offshore permits awarded, *eight relate to Western Australia*. [63]

Chart: WA petroleum exploration expenditure ($)



Data source: ABS

[60] Dow Jones Newswires, 'Chevron CEO Flags Australia LNG Deals, Growth Plans', 18 October 2009.
[61] Dow Jones Newswires, 'Chevron CEO Flags Australia LNG Deals, Growth Plans', 18 October 2009.
[62] APPEA, *Submission on WA Government Policy on Securing Domestic Gas Supplies*, April 2006, available at: http://www.appea.com.au/content/pdfs_docs_xls/PolicyIndustryIssues/policysubmissions/WAGasReservationSubmission.pdf
[63] Minister for Resources and Energy, '$158 million investment in offshore exploration', 2 October 2009.

As the Federal Minister for Resources and Energy commented:

> "Despite the global economic downturn, the awarding of these ten new exploration permits indicates that *Australia remains a highly attractive and secure destination for offshore petroleum exploration*." [64]

2.6 Domestic gas security measures do not constitute unwarranted market intervention by government

Elected governments intervene, and are expected to intervene in the market place where there is clear public interest to do so. Accordingly, governments have intervened in the areas of occupational health and safety, greenhouse emissions and renewable energy targets, or to provide tax concessions to oil and gas producers.

Successive WA State Governments have recognised the importance of domestic gas supply and have sought to strike a balance between the commercial interests of gas producers, and the energy needs of the broader community.

In contrast, the Commonwealth remains focused on maximising Australia's LNG exports, at the expense of energy security.

Major gas producers have, to date, not been reluctant to press for government intervention where it is in their commercial interest to do so. Producers continue to secure authorisations from the ACCC to protect producers from competition in the domestic market place. This intervention has delivered producers significant commercial benefits – in the form of higher domestic gas prices.

[64] Minister for Resources and Energy, '$158 million investment in offshore exploration', 2 October 2009.

Table: 2006 APPEA submission on WA Gas Reservation Policy [65]

We'll all be ruined, APPEA claims…

"A Domestic Gas Reservation policy would, if adopted:

- reduce the international competitiveness (for sales and for capital) of one of Australia's largest and most rapidly growing export sectors;
- potentially render some LNG projects uneconomic and unable to be developed for the domestic market without very large increases in gas prices;
- be economically inefficient and divert gas from its highest value use;
- treat LNG projects inequitably and disadvantage dedicated domestic gas producers;
- impact on the viability of WA's existing domestic gas suppliers;
- act as a form of taxation or appropriation of property without just compensation, thereby increasing sovereign risk and reducing Western Australia's attractiveness for petroleum investment;
- distort the WA gas market by creating a large gas overhang which could result in large increments in gas supply being introduced into the WA market at subsidised prices;
- maintain an uncompetitive and unsustainable price cap on domestic gas prices thereby leading to sub-optimal exploration for domestic gas and investment in new domestic gas production infrastructure;
- increase (not reduce) the long term risk of rapidly rising prices and gas shortages as the maintenance of uncompetitive prices leads to reduced investment and less diversity of supply;
- distort field development decisions potentially resulting in reduced resource recovery and reduced returns to governments and the community from the depletion of their gas resources;
- add a significant new risk to WA petroleum investment which does not arise in eastern Australia or in parts of the world which have attractive, vibrant and expanding petroleum industries;
- harm Australia's reputation for security of title and be inconsistent with the rights to petroleum embedded in Australian and West Australian petroleum legislation and the benefits and entitlements that those rights convey;
- be inconsistent with Australian Government policy that petroleum prices be determined by world markets with no consequential price relief or subsidy for domestic industry and consumers affected by increasing international prices; inconsistent with National Competition Policy Agreements made by the Australian and State Governments (including WA) and Australia's free trade agreement commitments (including its WTO commitments)."

[65] APPEA, Submission on WA Government Policy on Securing Domestic Gas Supplies, April 2006, available at: http://www.appea.com.au/content/pdfs_docs_xls/PolicyIndustryIssues/policysubmissions/WAGasReservationSubmission.pdf

Table: The rhetoric vs. the reality

The Rhetoric	The Reality
"[The WA Government] is threatening these national projects in two different ways which will ultimately cost West Australians the most – in lost jobs, exports and income." [66]	Woodside flags the potential for an extra six LNG processing trains and 77 million tonnes of additional LNG capacity within the next few years.
"Firstly, tying up large parcels of gas from major projects would severely damage or destroy the many smaller gas producers that are willing and able to supply gas into the domestic state system. Secondly, this sovereign risk threat is severely damaging Australia's reputation as an investment destination."	Woodside outlines ambition to expand Pluto from one to five LNG trains to increase production from 4 million tonnes per annum to 21.5 mtpa.
"At least three major project proposals are at serious risk of abandonment because of Carpenter's plans. No one wins if proponents walk away from their plans and the gas stays in the seabed."	Woodside announces front-end engineering and design (FEED) for Pluto Project.
"The economics of Pluto … are so fine that an LNG development would not be viable if 15 per cent of field reserves were unavailable for LNG production." [67]	Gas exploration expenditure significantly increases since introduction of the 15 per cent reservation policy in 2006.
"The Pluto project would not go ahead if the gas reservation policy was applied." [68]	Chevron outlines ambitions to develop Wheatstone LNG project.
"[W]e think it's counter productive in the long-term and will not help to promote investments in the long-term large LNG projects." (ExxonMobil) [69]	Apache Energy and KUFPEC enter into agreement with Chevron to undertake joint development of the Brunello and Julimar fields with Chevron's Wheatstone LNG project.
"Two companies who are considering and in fact well into the development of LNG options in Western Australia told me in the last 24 hours that those projects would not go ahead if a reservation scheme of the type being proposed was enforced on them." [70]	Up to 12 new LNG projects at various stages of development with the potential to increase LNG exports to 80 million tonnes per annum.
"Our reputation as one of the world's best LNG exporters and our ability to guarantee no sovereign risk is under real threat." [71]	

[66] Petroleum Exploration Society of Australia, 'WA gas plans threatens projects and won't protect domestic supplies', PESA News, Oct/Nov 2006, available at: http://www.pesa.com.au/publications/pesa_news/oct_06/pesanews_8423.html

[67] The Australian, 'Woodside, WA sort out deal on Pluto', 9 October 2006, reporting comments by Woodside CEO Don Voelte.

[68] The Australian, 'Woodside, WA sort out deal on Pluto', 9 October 2006, reporting comments by Woodside CEO Don Voelte.

[69] ABC News Online, 'ExxonMobil complements Carpenter over gas policy handling', 12 October 2006, quoting ExxonMobil.

[70] The West Australian, 'Opponents go head-to-head in very public stoush', 1 September 2006, quoting former Federal Minister Ian Macfarlane.

[71] The West Australian, 'Opponents go head-to-head in very public stoush', 1 September 2006, quoting former Federal Minister Ian Macfarlane.

Action: Offshore Exploration Management

Key Points

- The current offshore exploration release process is inefficient and discourages gas exploration and development.
- While companies have nominated areas for exploration work, these have not been released on the basis that the Federal Government must first undertake work to demonstrate that the areas are attractive for prospective explorers.
- The existing system should be reformed so that explorers can reasonably obtain approval to explore any area not already under licence.

1. Overview

Australia operates a gazettal system whereby offshore exploration areas are "closed" to prospective explorers until gazetted by the Department of Resources, Energy and Tourism. The Department's website states:

> "Each year, following consultation with stakeholders, the Department releases offshore petroleum exploration acreage for competitive bidding by prospective explorers.
>
> The Offshore Petroleum Exploration Acreage Release remains the key mechanism for the government to encourage offshore petroleum exploration in Australia. The annual release of acreage for petroleum exploration enables long term planning for the industry, access to comprehensive geological and geophysical data on CD-ROM and through the website, and provides high-quality information about issues that may need to be taken into consideration by applicants." [72]

The current gazettal policy is inefficient and impedes exploration. It operates as a significant barrier to the entry of new players and potentially delays the development of domestic gas supply.

2. Current administrative arrangements

The Department of Resources Energy and Tourism (DRET) administers offshore oil and gas policies and procedures, including the Exploration Licence Round Gazettal.

Geoscience Australia provides technical advice to DRET for offshore Commonwealth licences, including Exploration License Round Gazettals. Geoscience Australia is responsible for the basin evaluation, which determines which licenses go into each annual Exploration Licence Gazettal Round.

All oil and gas companies are required by Geoscience Australia to provide data from any well (exploration, appraisal or development well) within 24 months after the drilling rig has moved off location. Companies are also required to provide all proprietary seismic data 24 months after the data has been processed.

Data is classified "open file" as soon as Geoscience Australia receives the data. Any company may purchase any open file data from Geoscience Australia for minimal cost. Service companies also acquire speculative geo-technical surveys (seismic, gravity, magnetic, etc.) in offshore basins. Speculative data is actively marketed to oil and gas companies at a higher cost than open file data. The service companies work closely

[72] Department of Resources, Energy and Tourism, available at: http://www.ret.gov.au/resources/upstream_petroleum/offshore_petroleum_exploration_in_australia/Pages/OffshorePetroleumExplorationinAustralia.aspx

with industry to identify areas, which may require additional data for basin evaluations. Geoscience Australia requires that speculative geo-technical surveys become open file after fifteen years.

Australia's open file oil and gas data policy is one of the most progressive in the world. Open file oil and gas data allows any company to access data in any basin across Australia. In practice, this means hundreds of industry technical professionals are able to evaluate offshore Australian basins and develop new exploration concepts and ideas. New exploration concepts and ideas can lead to the discovery of significant new oil and gas resources, which in turn will generate significant revenue for government.

3. The Exploration License Round Gazettal Process

There is a lack of transparency over DRET's process for determining which areas and how many licenses will be gazetted for an annual Exploration License Round.

While DRET have publicly stated that there is close collaboration with the oil and gas industry on the Exploration License Round process, there have been limited if any open forums for industry collaboration.

Companies are invited to nominate areas for consideration. However, the areas nominated by companies will only be considered for exploration release if DRET has already determined the area is worthy of a basin study and prospective for industry.

Geoscience Australia evaluates basins and identifies new exploration concepts and ideas, which will result in the industry bidding, exploring and finding new oil and gas resources. A basin evaluation study will take six to ten months for provinces with existing production, such as the Carnarvon, Gippsland or Perth basins.

Frontier provinces, such as the Great Australian Bight or Gulf of Carpentaria, may require Geoscience Australia to acquire new data to conduct a basin evaluation. Evaluations of frontier provinces may take three to four years, if new data is acquired.

While companies have nominated areas for exploration work, these have not been released on the basis that the Federal Government must first undertake work to demonstrate that the areas are attractive for prospective explorers.

Chart: Annual exploration licence round

4. The current process discourages exploration

It is ineffective

DRET presumes to know which areas the oil and gas industry will find prospective. A significant number of the open licenses at the 2009 Exploration License Round Gazettal however received zero industry bids. This clearly shows that DRET's assumptions on prospectivity are incorrect. DRET's process does not take advantage of the new exploration concepts and ideas, innovation or new technology that resides in the oil and gas industry.

At the same time, areas nominated by companies willing to invest exploration resources have not been released by DRET, despite strong support from the State Government.

It wastes government resources

Geoscience Australia has a small, but highly educated and talented technical team. Those resources are best used in the evaluation of frontier basins, not on provinces with proven production.

Provinces with proven production have significant open file data, which industry can and does access to develop new exploration concepts and ideas. Government resources are also depleted promoting the annual Exploration License Round Gazettal.

It delays exploration programs

The current process adds one to three years to the exploration process. Successful oil and gas companies are actively recruited to explore and invest by international governments.

Ineffective or opaque exploration license round processes will result in successful oil and gas companies withdrawing from Australia.

5. Solutions

Eliminate the current exploration licence round process

As outlined above, the current process is ineffective, wastes valuable government resources and delays oil and gas exploration. It also lacks transparency. The current process will result in lost exploration investment and delays the discovery of new oil and gas resources.

Institute an annual exploration license round

An annual exploration license could be held on a fixed date, which will allow industry to prepare and plan for the exploration evaluations. This process would also improve the transparency.

Open all areas not under licence to be available for bidding

The oil and gas industry should be permitted to determine what is or is not prospective. This would effectively unleash the hundreds of technical professionals in the oil and gas companies to develop new exploration ideas and concepts.

Under an improved exploration licence regime, access to exploration acreage would no longer be limited to staff resourcing availability within government. Geoscience Australia's technical resources can then be focused on evaluating frontier basins, such as the Great Australian Bight.

Any concerns that the Commonwealth might have on a small number of companies nominating entire areas could be managed by attaching and enforcing appropriate licence conditions, such as appropriate work programs.

Action: Retention Lease Management

Key Points

- Retention leases should not be used to indefinitely park gas reserves for LNG when those resources could economically supply the domestic market.
- The Joint Authority however appears determined to give LNG projects precedence over domestic supply in managing retention leases. This threatens WA's energy security and can only lead to higher energy prices.
- In the longer term, Australia should eliminate retention leases. Companies should be required to develop fields within 8 years or drop the field.

1. Targeting stranded resources will help meet the gas shortage

Currently, 56 per cent of the State's natural gas resources are held under retention leases on the basis that they are currently considered uncommercial for development. 99 per cent of resources held under retention leases were operated by Woodside, Chevron and ExxonMobil. [73]

Given the bulk of WA's identified gas reserves are held under retention leases, targeting development of stranded resources for the domestic market will help meet the State's gas shortage.

The Alliance has identified some 22 stranded gas fields in the Carnarvon, Bonaparte and Browse Basins. Together, these fields hold over 84 trillion cubic feet of gas and 1.4 billion barrels of condensate.

Many of these fields are too small for LNG development, are amenable for domestic gas development, but have been warehoused by existing leaseholders for as long as 30 years.

[73] WA Department of Mines and Petroleum, Western Australian Oil and Gas Review 2008, pp.80-81.

Table: Discovered stranded fields

Field Name	Year Discovered	Water Depth (metres)	Gross Reserves Tcf	Gross Reserves MMbblC
Carnavon Basin				
Jansz	2000	1321	12.9	0.0
Scarborough	1979	923	4.8	0.0
Io	2001	1352	3.4	522.7
West Tryal Rocks	1973	138	2.4	38.0
Geryon	1999	1231	2.2	8.8
Chandon	2006	1201	2.0	11.0
Chrysaor	1994	806	1.7	16.0
Dionysus	1996	1092	1.4	11.6
Iago	2000	118	1.0	10.9
Orthrus	1999	1200	0.8	2.2
Persephone	2006	126	0.7	17.4
Subtotal			**33.3**	**638.7**

Field Name	Year Discovered	Water Depth (metres)	GA Resource Assessment Tcf	GA Resource Assessment MMbblC
Bonaparte Basin				
Evans Shoal	1988	110	8.3	0.0
Sunrise/Troubador	1975	159	7.7	299.0
Caldita/Barossa	2006	150	5.6	0.0
Petrel	1969	100	1.0	5.9
Tern	1971	92	0.4	5.7
Prometheus/Rubicon	2000	69	0.2	0.0
Subtotal			**23.2**	**310.6**
Browse Basin				
Tarosa	1971	50	10.6	121.0
Crux	2000	168	5.1	175.0
Brecknock	1979	543	4.9	109.4
Calliance	2005	575	3.7	86.6
Argus	2000	572	3.6	0.0
Subtotal			**27.9**	**492.3**

Source: Geoscience Australia

2. Major producers are warehousing resources that could supply the domestic market

Under the Commonwealth *Offshore Petroleum and Greenhouse Gas Storage Act 2006*, a retention lease must be converted to a production licence when a reserve is commercial. The Act does not provide an exception for reserves – that might otherwise supply the domestic market – to be set aside for the purpose that they might at some time in the future contribute to an LNG development.

Major producers appear to be using Australia as an international safe haven to warehouse resources. Producers are parking commercially viable gas resources in anticipation of future large-scale LNG developments or holding supply to leverage domestic gas prices above competitive levels. [74]

As a result, offshore gas developments in Australia are taking significantly longer to progress from discovery to first gas compared to other countries. This is impacting project development costs and domestic gas supply.

While LNG producers initially claimed that resources were uneconomic for domgas development, such arguments appear no longer valid given the significant rise in domestic gas prices. As the Commonwealth –States Joint Working Group on Natural Gas Supply recognised as early as 2007, expectations of commercially have substantially improved:

> "[T]he marked environment has changed significantly in recent years. As a result, there is an expectation that the prospects for commercialising many known gas resources have improved substantially." [75]

The Joint Working Group recommended stringent enforcement and greater transparency in retention leases to promote domestic supply:

> "In these circumstances it would appear appropriate for the Joint Authority to review existing gas retention leases, implement a more transparent application of existing gas retention leases, implement a more transparent application of existing guidelines, and where considered appropriate, to request a re-evaluation of commercial viability in accordance with s38H of the Petroleum (Submerged Lands) Act." [76]

3. The Federal Government appears determined to give LNG projects precedence over domestic supply

The Commonwealth has repeatedly affirmed a stringent approach to retention lease management to promote domestic gas supply. Gas users have however yet to see this translate to direct action. The Alliance is not aware of any retention leases that have been revoked in recent years by the Joint Commonwealth – State Authority, on the basis that resources could be developed for the domestic market.

In fact, the Federal Government appears determined to accord LNG priority over domestic supply in managing retention leases. The Joint Authority has approved the warehousing of gas resources even though those resources could economically supply the domestic market.

An example is the West Tryal Rocks field discovered in 1973 which is located in shallow water and close to existing domestic gas infrastructure. The field has attracted strong interest from prospective domestic

[74] Energy Supply Association of Australia, *Western Australian Energy Market Study, November 2009*, p.48-49.

[75] Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy Joint Working Group on Natural Gas Supply, Final Report, September 2007, p.32.

[76] Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy Joint Working Group on Natural Gas Supply, Final Report, September 2007, p.32.

gas producers. WA gas customers have also approached operator Chevron with offers to help underwrite development of the field through long term supply contracts. Despite WA's serious gas shortage, the Joint Authority has agreed to Chevron warehousing the resources for another 5 years.

The Federal Government has justified this decision on the basis that the field can be "developed sequentially to maintain production and extend the economic life of the [Gorgon] project".[77] No timetable has been given as to when the field might be developed.

In June 2009 the Commonwealth released an Options Paper which flagged that gas resources may be warehoused for future LNG development so long as they are considered "essential to meeting contractual commitments and the overall viability of the greater project".[78]

The issue underlines the importance of domestic supply obligations – to ensure some gas is delivered to the WA market from domestic gas fields that have now been diverted by government and producers to LNG production.

Case Study: West Tryal Rocks

- **1973 –** West Tryal Rocks field discovered by WAPET
- **2002 –** Multiplex proposes to develop the field for domestic supply and offers to buy it from Chevron, Shell and ExxonMobil for $70 million
- **2003 –** Multiplex's challenge is rejected by government and the lease rolled-over
- **2007 –** Joint Working Group acknowledges significant rise in domestic gas prices and substantial improvement in prospects for developing stranded gas reserves
- **May 2008 –** retention lease scheduled to expire. No announcement is made by the Federal Government for the next 16 months
- Chevron publicly reported to be targeting West Tryal Rocks for domestic gas development by discussing with potential customers and pursuing contracts for FEED studies
- Oswal Group proposes to buy all of the gas for proposed $1.5 billion Burrup ammonia urea plant
- **Feb 2009 –** Crystal Exploration challenges Chevron's right to the lease on the basis that it is commercial for domestic gas development
- **Sept 2009 –** Federal Government announces it will renew West Tryal Rocks, along with six other gas fields, to be "developed sequentially to maintain production and extend the economic life of the [Gorgon] project

77 Minister for Resources, Energy and Tourism; 'Government Clears Final Hurdle for $50 Billion Gorgon Go-Ahead', Media Statement, 1 September 2009.

78 Department of Resources, Energy and Tourism; *Review of Policy Relating to the Grant and Renewal of Retention Leases – Options Paper*; June 2009; Draft Recommendation 5.8.

4. There is no transparency in retention lease decisions

The West Tryal Rocks lease renewal highlighted significant flaws in the process - there is little transparency in the current retention lease process and little opportunity for third parties to participate.

There is no gazetting system which would make public the substance of a retention lease application, nor is there a formal procedure for third parties to participate. The current process provides for an asymmetry of information that exclusively benefits the small number of existing lease holders. Prospective gas producers continue to express frustration at the current arrangements and their difficulties in being able to access information and engage in the process.

This contrasts with existing State and Commonwealth environmental approval processes for development projects. These processes provide for transparency and significant opportunity for stakeholder input. Greater transparency and third party participation will:

- improve the underlying basis of retention lease decisions;
- encourage third party participation;
- subject applicant claims and assumptions to greater scrutiny and contestability;
- strengthen the application of the commerciality test; and
- promote new field development.

Information should be made available that would allow meaningful engagement by third parties. Opportunity for participation should be provided throughout the process. Measures could include:

- A public, on-line registry of State and Commonwealth Retention Leases should be established.
- The registry should provide clear indication on the current status of individual lease applications or review process, and identify leases coming up for review.
- The Designated Authority should make a public announcement when it begins the process of reviewing an individual retention lease.
- The factors and assumptions used by the Designated Authority to test "commerciality" should be publicly disclosed.
- Publishing an assumptions or data book identifying key factors such as prices, local demand, rate of return, expectations on CAPEX / OPEX.
- Expert reports commissioned by the Designated Authority into matters such as market conditions, construction costs, etc, should be published.
- The Government's Joint Technical Report should be published.
- There should be a review period allowing third parties to submit information in relation to the assessment parameters used by the Designated Authority, the assumptions and development concepts being advanced by the proponent, or to reinforce or challenge the Designated Authority's draft decision.
- Opportunity should be provided to third parties to have input into the establishment of conditions for the grant or renewal of retention leases.

- The reasons and substance of the Designated Authority's decision should be published.
- There should be an independent peer review or third party assessment to review and validate the Joint Technical Report, and to test the assumptions and conclusions made.

The 16 month delay between expiry of the West Tryal retention lease (May 2008) and the Federal Government's announcement that it was renewing the lease (September 2009) also underlines the need for clear decision-making timeframes. Timeframes should be established, including for Ministerial decisions. This will ensure that decisions over lease applications, reviews and renewals are made in a timely manner.

5. Reviews have been ongoing for almost 4 years with no outcome

Government processes to review the retention lease process have been ongoing since 2006. Despite recommendations by the Joint Working Group in 2007, there have been no outcomes on stringent enforcement of retention leases to promote domestic supply, or to improve transparency and third party participation.

Figure: Timeline of reviews to improve the Retention Lease process

Sept 2006	Federal / State Joint Working Group on Natural Gas Supply established in response to domestic supply shortage
July 2007	Consultants' report recommends major reforms
Aug 2007	***Stakeholders provide detailed submission***
Sept 2007	Joint Working Group releases Final Report recommending major reforms.
Nov 2007	***Stakeholders provide detailed submission***
April 2008	Federal Government announces policy review of Retention Lease process
April 2008	***Stakeholders provide detailed submission***
April 2008	Federal Government requests Productivity Commission to undertake review into regulatory Burden on upstream oil and gas sector
May 2008	Federal Government advises it was preparing an options paper
July 2008	***Stakeholders provide detailed submission to Productivity Commission***
Dec 2008	Productivity Commission releases Draft Report which includes recommendations on Retention Lease process
Jan 2009	***Stakeholders provide detailed submission to Productivity Commission Draft Report***
April 2009	Productivity Commission issues Final Report recommending major changes to Retention Lease process

Jun 2009	Federal Government publishes Retention Lease Options Paper which proposes giving LNG projects precedence over domestic supply
Aug 2009	***Stakeholders provide detailed submission strongly opposing LNG projects being given precedence over domestic supply***

6. Longer-term solutions

Current Commonwealth policies for offshore license policies are a result of the significant downturn in the oil and gas industry due to the dramatic drop in oil price from 1981 to 1987. These policies were developed to encourage companies to continue to invest in exploration.

However, these policies have allowed some companies to warehouse or sequence gas discoveries, which could have been rapidly developed by experienced, cost effective and innovative operators.

As an example, the Gorgon Field was only developed after significant pressure was applied by government. License policies should be established to encourage innovative, cost effective and safe operators to expeditiously develop discovered oil and gas resources. The following longer term solutions would provide a strong incentive to operators to expedite development of oil and gas resources.

Do not change current licence terms

Changing the terms of an existing license could raise investment concerns with the oil and gas industry.

Continue work program bid system

Cash bonus bids do not encourage exploration. DRET should continue to award licenses based on the most effective work programs.

Modify exploration licence term

The exploration license term should comprise two three lease terms. The first three year term is the commitment period for the initial work program.

The company has the opportunity to commit to the second three year term, subject to fulfilment of the contingent work program bid.

The license would be relinquished after a maximum of six years, if the company has not found commercial hydrocarbons and is prepared to move forward into a development program.

This approach will encourage companies to either test their exploration ideas and concepts or relinquish the lease and allow another company to come forward with their ideas and concepts. Companies should no longer be permitted to warehouse exploration licenses for decades.

Eliminate retention lease status

Companies that are technical competent and financially strong will ordinarily be in a position to determine after the initial six year exploration whether or not an exploration discovery is commercial.

The current retention lease system allows companies to indefinitely delay or sequence oil and gas developments. It no longer benefits the Commonwealth or the State and should be eliminated.

Modify production license term

Instead of the current arrangements, a company should be given eight years to bring a new field on stream. Woodside has for example demonstrated that a major gas field, such as Pluto can be developed and achieve first production from a new build LNG Plant in just six years. Project delays increase the development cost, which in turn reduces government revenues.

Where the company has failed to develop the field within eight years, it should "drop the field", which could then be released to a company willing and able to develop it.

7. Stringent approach has increased exploration and development in the United Kingdom

Any tightening of the retention lease process would not discourage exploration and development in Australia. Experience in the United Kingdom in fact demonstrates the opposite – it *increases* exploration and development.

Previously, the UK did not have a process to force activity when oil and gas licences were granted. Licences granted between 1964 and 1972 were "multi-block" - if the initial term obligation was fulfilled with a Development somewhere on the licence, companies could retain acreage into the second term for up to 46 years without any further activity.

The UK Government implemented an initiative to facilitate development of fields that were Fallow Discoveries or on Fallow Blocks. Under the new system, both blocks and discoveries are considered Fallow after three years and are classed "Fallow B".

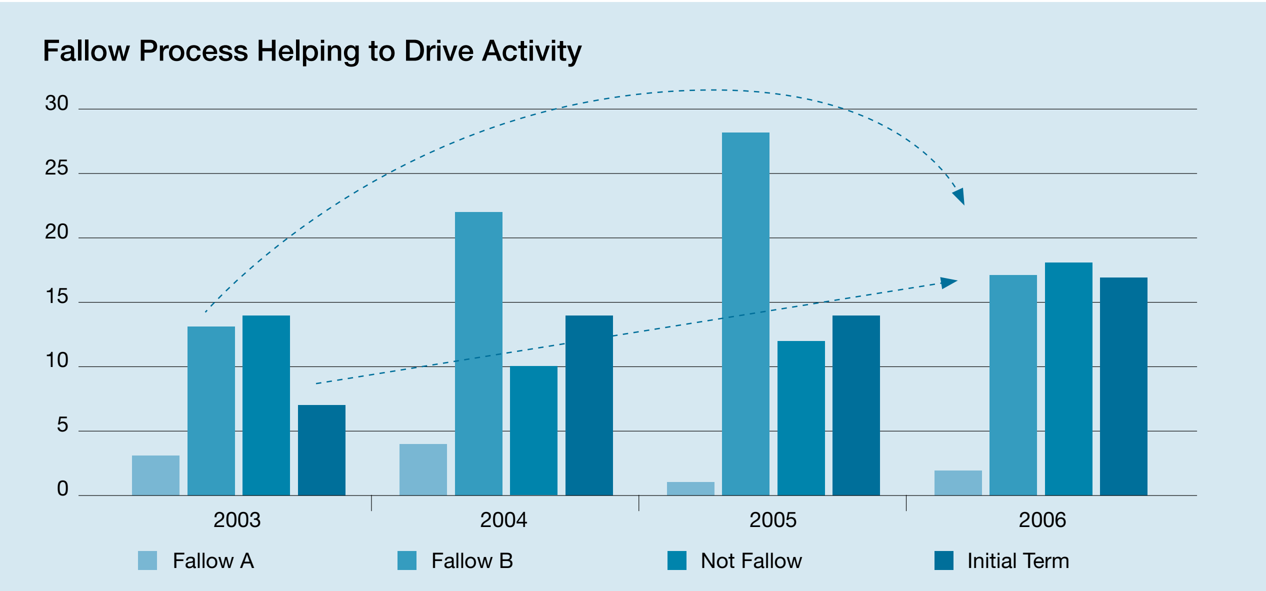
These "Fallow B" Discoveries and Blocks are released on the UK government website if the current licensees were unable to progress activity due to misalignment within the partnership, a failure to meet economic criteria, or other commercial barriers.

Fallow B Discoveries that have been listed on the website for two years or Fallow B Blocks that have been listed on the website for one year will be relinquished if there are no agreed plans for significant activity.

Far from discouraging investment, the UK's efforts to tighten the country's Fallow Field process have in fact significantly increased exploration and production activity by oil and gas companies.

A similar outcome could be expected in Western Australia.

Figure: UK Department of Trade and Industry presentation



UK fields which are now under Development or in Production that were Fallow Discoveries or on Fallow Blocks [79]

• Duart	• Maria	• Gadwell	• Pict	• Chiswick	• Grove
• Wenlock	• Thurne	• Arthur	• Horne	• Davy East	• Seymour
• Saturn Area	• Wren	• Brechin	• Cutter	• Farragon	• Munro
• Broom	• Nuggets N4	• Goldeneye	• Braemar	• Sycamore	• Caledonia
• Madoes	• Mirren	• Scoter	• Carrack	• Playfair	

[79] UK Department of Trade and Industry, Initiatives to Encourage Exploration, presentation, 20 March 2007.

Action: Eliminate Joint Selling

Key Points

- Joint selling by gas producers limits competition, leads to higher gas prices, and undermines State Government energy market reforms.
- ACCC market intervention to endorse joint selling remains the single biggest barrier to greater competition and market development in WA.
- Removing joint selling arrangements will increase competition by increasing the number of independent sellers. These same producers already compete with each other in separately selling to overseas customers.

1. Joint selling has suppressed competition and led to higher prices

While joint selling arrangements might have been appropriate in a market characterised by a single monopoly seller, it is no longer justified in the current market. Over the last decade, joint selling by the North West Shelf Joint Venture has:

- suppressed competition and reduced the number of independent sellers in the WA market;
- increased domestic gas prices;
- reduced customer choice over terms and conditions on offer;
- entrenched the already dominant market power exercised by major producers;
- enabled the coordinated exercise of market power within the NWSJV;
- extended that market power to new projects such as Gorgon, Macedon and Wheatstone;
- entrenched an effective minimum price for domestic gas;
- constrained market development; and
- undermined the effectiveness of State Government market reforms.

In the absence of joint selling:

- major producers would compete against each other for WA domestic gas customers;
- there would be greater competition between projects in the sale of domestic gas;
- consumers would have greater choice over the terms and conditions on offer;
- major producers would not be able to co-ordinate market power in setting price or non-price terms; and
- there would be competitive pressure asserted on existing and prospective suppliers.

A report by the Allen Consulting Group, commissioned by the ACCC, concludes that joint selling will lead to higher prices for consumers. Separate selling would instead force gas producers such as Shell, Chevron and ExxonMobil to compete with each other, resulting in lower prices for consumers. [80]

[80] Allen Consulting Group, 'Gorgon Gas Project Joint Venture Application for Authorisation of Joint Marketing', Final Report to the Australian Competition and Consumer Commission, July 2009, pp.26 and 28.

2. Market features do not prevent separate selling

Separate selling is practical and feasible in the WA gas market, and should be pursued by major gas producers. There is no basis to the argument that the WA gas market is too small, immature or undeveloped to support separate selling.

The Allen Consulting Group report dismissed as "misleading" claims that joint selling was necessary to manage risk or to underpin project investment. The report considered it "difficult to accept the argument … that joint marketing is required as a risk mitigation tool". In the Gorgon Project case, this was because:

- Domestic gas represents less than 5 per cent of the Gorgon gas resources;
- Domestic gas would account for less than 5 per cent of total Gorgon revenue;
- Shell, Chevron and ExxonMobil are three of the largest companies in the world with combined 2008 income of over $US 120 billion;
- The domestic phase post-dates LNG export start-up by three or more years;
- Domestic gas prices will almost certainly have lower price volatility than LNG exports;
- Chevron and Shell are equity partners in the largest domestic gas seller in Western Australia;
- Domestic sales will be subject to take-or-pay contract provisions;
- Chevron and Shell management are familiar with the WA gas market through their investment in the NWS project; and
- ExxonMobil is the world's largest and most profitable oil and gas company with over 40 years experience in the Australian gas market.[81]

The report concluded that the Chevron, Shell and ExxonMobil had failed to demonstrate why joint marketing for domestic should be required following a Final Investment Decision on the Gorgon Project.[82]

If, however, joint selling was permitted, this would enable the Gorgon supply to be locked away, the Project cannot contribute to "competitive tension" in the market place with respect to other gas developments.[83]

[81] Allen Consulting Group, 'Gorgon Gas Project Joint Venture Application for Authorisation of Joint Marketing', Final Report to the Australian Competition and Consumer Commission, July 2009.

[82] ACG Report, p.30.

[83] ACG Report, p.30.

Domestic gas contracts	LNG contracts
• Over 30 gas customers buying directly from producers • Short and long term contracts • Minimal or no sovereign, exchange rate and currency risks • Lower price volatility • WA based businesses • No upstream competition • Producers combine together to set prices and contract terms	• Small number of very large customers • 20 year LNG contracts, very little gas sold on spot market • Significant sovereign, exchange rate and currency risks • Higher price volatility • Sovereign government entities or very large foreign corporations • Globally competitive LNG market • Producers compete with each other in separately selling to international customers

3. WA gas users have been pressing the ACCC to enforce competition

Government intervention to protect major producers has suppressed competition, increased prices and limited the effectiveness of State Government market reforms. It remains the single biggest barrier to competition and the development of a more mature gas market.

WA gas users have been pressing the ACCC since 2007 to enforce competition, remove the NWSJV joint selling arrangements and end the State's gas supply duopoly. No action was taken for over three years

In 2009 however, Chevron, Shell and ExxonMobil applied for authorisation to sell Gorgon gas jointly. Gas users were given just 10 working days to respond. Chevron, Shell and ExxonMobil received interim authorisation from the ACCC within just 5 weeks, and final authorisation within 6 months.

In 2010, the ACCC authorised the six North West Shelf Project partners to continue to combine together and set prices covering 70 per cent of the market. This was despite three WA Government Departments informing the ACCC that requiring producers to compete with each other would not threaten investment in the North West Shelf Project or domestic supply. [84]

[84] ACCC, *NWS Project Applications for Authorisation A91220-A91223: Government of Western Australia Departments – Record of Meeting*, 1 June 2010.

Action: Domestic Gas Reservation

Key Points

- The original North West Shelf Project domestic gas reservation has delivered immense social, economic and environmental benefits to Western Australia for over 25 years.
- Subsequent gas commitments have however failed to keep pace with the State's growing energy needs, or the significant growth in LNG exports.
- The current reservation policy needs teeth and should be strengthened.
- The State Government should apply domestic obligations to the Browse and Wheatstone projects.

1. Key elements of an effective gas reservation policy

The WA gas reservation policy has been effective in establishing expectations on the importance of domestic supply. Recent experience however highlights serious flaws in the policy's application. In particular, the Gorgon partners' intention to delay meeting the 300 TJ/d domestic supply commitment until 2021, on the grounds of an "oversupply" in the WA gas market, underlines the need for a more effective reservation policy.

The reservation policy needs teeth to meet the State's worsening gas shortage, and to ensure domestic supply commitments are not able to be avoided by major LNG producers. Effective domestic supply obligations are particularly important given domestic gas fields are now being diverted to LNG through retention leases.

For a reservation policy to be effective, it must provide for:

- ***Certainty*** – domestic gas obligations should be made unconditional and not subject to "commerciality" escape clause;
- ***Flexibility*** – LNG producers should be given flexibility in how they can meet their domestic supply obligations;
- ***Growth*** – domestic supply should increase with any future expansion in gas reserves or LNG exports; and
- ***Timeliness*** – the reservation commitment should be applied to both reserves and production; domestic gas should be supplied no later than LNG start-up and not unduly delayed.

2. Certainty

The purpose of domestic supply obligations is to ensure domestic supply of gas. This purpose is undermined where the commitment is subject to a commerciality "escape clause". As experience demonstrates, this provides too much scope for producers to delay or avoid meeting domestic supply obligations by claiming that it is not "commercially viable", "economic" or "feasible".

In 2006, the WA Government assessed that 2 trillion cubic feet of gas will be needed from existing and proposed gas projects to meet WA's gas requirements to 2020. Of this, it was assessed that the Gorgon Project would need to supply 1.85 Tcf.[85] It was therefore assumed by the State that *almost all of the entire 2000 petajoule Gorgon reservation volume would be delivered by 2020*.

> ***Case Study: Pluto Project***
>
> Under the Pluto domestic gas arrangement, Woodside is only required to market and sell as domestic gas the equivalent of 15 per cent of the Pluto Project's LNG production provided it is "commercially viable".
>
> Woodside is prioritising construction of the LNG project. There is no certainty what if any volume of domestic gas supply would be delivered.
>
> ***Action:*** *The 15% reservation commitment on Pluto should be made unconditional and not subject to a commerciality escape clause. Domestic gas supply should be given priority over LNG export in the event of any reserves shortfall.*

The Gorgon partners have however indicated that the 300 TJ/d supply volume will not be available until 2021 – some 12 years after the project's final investment decision. This demonstrates the need for any reservation commitment to be *unconditional*.

The ESAA Report considers that uncertainty over the application of the gas reservation policy increases investment risks for LNG producers subject to domestic gas obligations, as well as for domestic gas producers trying to anticipate alternative sources of supply.[86]

The obligation should be unconditional

An *unconditional* obligation would:

- provide certainty to downstream users on future gas availability that would enable investment in mining, minerals processing and power generation;
- provide certainty to gas project developers that the policy would be stringently and consistently applied, which enables them to factor-in the commitment in evaluating and developing projects; and
- align with the policies being adopted in other countries to ensure security of supply.

85 WA Department of Industry and Resources, WA Government Policy on Securing Domestic Gas Supplies: Consultation Paper, February 2006, p.7.

86 Energy Supply Association of Australia, *Western Australian Energy Market Study*, November 2009, p.47.

An unconditional obligation would reduce the opportunity for project proponents seeking preferential treatment or special exemptions.

Commerciality issues could, in any event, be adequately managed by giving producers sufficient flexibility in how they would meet reservation obligations as outlined below.

Obligation to "supply" as opposed to "market"

The obligation should be to supply domestic gas, as opposed to "market", "offer for sale" or "make available" gas to potential customers. This would provide a strong commercial incentive for producers to supply in order to monetise resources as the alternative would be to simply leave resources in the ground.

This would minimise the prospect of LNG producers offering gas at terms that are unrealistic or unfeasible - for example by only offering 3 year contracts to major project developers - in an effort to avoid supplying to the domestic market.

Priority to domgas supply over LNG exports

The commitment should ensure priority of domestic gas supply over LNG export in the event of any reserves shortfall. LNG producers should not be able to avoid meeting domestic gas commitments on the grounds that reserves were needed to meet LNG export contractual obligations or to optimise the LNG project.

This recognises the vital importance of domestic gas supply to the WA economy, and the fact that local industry and households have no reasonable alternatives to domestic supply. By comparison, LNG customers have alternative sources of supply across a number of international suppliers.

Made an express condition in permits, leases and licences

A reservation commitment should be made an express condition in the granting and renewal of all gas exploration permits, retention leases and production licences. This reinforces a clear expectation with prospective gas developers that the domestic gas reservation policy will be applied.

Fields should be set aside for exclusive domgas development

The drive towards increasingly ambitious LNG export developments is placing significant pressure on fields otherwise suitable for domestic gas development. This was demonstrated by Apache's announcement that it will now jointly develop the Julimar-Brunello fields with Chevron's Wheatstone LNG project. The Joint Authority also appears determined to accord LNG priority over the domestic market in managing retention leases.

Specific leases or tenements should be set aside and granted only on the condition of exclusive domgas development. For example acreage tenements located in shallow water are currently being released for prospective explorers and producers.

These fields are suitable for domgas supply and should be designated as such to provide certainty and clear expectation to prospective developers. They should not be diverted to support increasingly ambitious LNG projects, even if those LNG projects were subject to a 15 per cent reservation commitment.

Certainty - Key Recommendations

- Domestic gas obligations should be made unconditional and not subject to a "commerciality" escape clause.
- The policy should be consistently applied to discourage individual projects from claiming "special exemptions" and treatment.
- The obligation should be to "supply" domestic gas, as opposed to "market", "make available" or "offer to sell" domestic gas.
- In the event of any resources shortfall in a project or field, domestic gas supply should be accorded priority over LNG export.
- The reservation policy should be made an express condition in the granting and renewal of all gas exploration permits, retention leases and production licences.
- Specific leases or tenements should be set aside and granted only on the condition of exclusive domgas development.

3. Flexibility

To balance an unconditional commitment, producers should be given sufficient flexibility in how they would meet domestic supply obligations. This could be by permitting producers to:

- trade obligations between different fields – for example by supplying less domgas from Field A and more domgas from Field B;
- trade obligations with other producers;
- meet their obligations by supporting domgas developments in other fields – e.g. where a medium sized field could only support LNG, the producer could seek to bring on a smaller field for the domestic market that could be credited; and
- meet obligations by supporting third party domestic gas developments - e.g. by supporting a smaller producer to develop a domestic gas field that might otherwise not be developed for the domestic market.

This flexibility would encourage producers to adopt the most efficient way of meeting their domgas obligations for a given field – whether by supplying domgas from that field or, where it is not commercially viable to do so, by meeting this commitment from production outside the field.

Flexibility would support application of the State's 15 per cent reservation policy to the prospective Browse Basin development. The Browse participants should be given flexibility in how they meet domestic supply obligations – whether by supplying domestic gas directly from Browse, or if it is not commercially viable to do so, by securing domestic gas supply from other fields.

This means that a domestic gas commitment with respect to Browse Basin gas could involve supplying new processing and power generation activity in the Kimberley, or it could involve a swap arrangement with existing or prospective Carnarvon Basin producers. It is important that in providing producers flexibility, the objective should remain the delivery of additional domgas supply than might otherwise be the case.

Flexibility - Key Recommendations

- Producers should be given sufficient flexibility on how they would meet domestic supply obligations.
- Producers should be encouraged to adopt the most efficient means of meeting domestic supply obligations - whether by supplying domgas from the relevant field or, where it is not commercially viable to do so, by supplying domgas from other fields.
- The 15 per cent reservation policy should be applied to the Browse Project and producers given flexibility in how they meet domestic supply obligations.

4. Growth

The original North West Shelf reservation has failed to keep pace with Western Australia's expanding energy needs or the Project's LNG exports. LNG exports from the Project have increased by over 150 per cent from the originally envisaged 6.5 million tonnes per annum, with further expansions foreshadowed.

> ***Case Study: Julimar – Brunello Fields***
>
> Apache Energy and KUFPEC have agreed to undertake joint development of the Brunello and Julimar fields with Chevron's Wheatstone LNG project.
>
> The Julimar-Brunello fields are expected to produce 200 million cubic feet of gas per day and are otherwise well suited for development as a domestic gas project.
>
> The decision means a potential source of domestic gas will now be diverted to supplying LNG exports.
>
> ***Action:*** *An unconditional 15% reservation commitment should be applied to production from the Wheatstone / Julimar-Brunello Fields to ensure domestic gas supply*.

In contrast, supply to the domestic market by the NWSGJV has increased only marginally.

In October 2009, Chevron announced a significant gas discovery in the Carnarvon Basis which could help support Chevron's ambition for a further two LNG processing trains in the Gorgon Project.

Given the Gorgon Project State Agreement provides for a domestic reservation commitment of 2000 petajoule (2 Tcf) and 300 TJ/d, it is unclear whether this commitment expands with any increase in project reserves or LNG exports.

It is vital that any reservation commitment grow with any future expansion in gas reserves and production. This can be achieved by attaching the commitment as a *percentage* of reserves and production.

Growth - Key Recommendations

- The domestic supply commitment should expand with any future growth in project gas reserves, production or LNG exports.

5. Timeliness

Any reservation commitment should be tied to both reserves and production. Where a reservation commitment is tied only to the reserves of a project or field, there is no certainty that domestic gas would ever be supplied over the life of the project. This could result in long delays with domestic supply being relegated to the tail-end of LNG projects or field life.

Where domestic supply is tied to declining fields and increasingly expensive production, resources may no longer be economic to supply, or supply might only be made available at prices higher than would otherwise have been the case. This encourages producers to monetise the most economic gas as long term LNG contracts while potentially leaving the most expensive (and potentially uneconomic) resources for domestic supply.

The Gorgon Project highlights the need for reservation obligations to be stringently tied to LNG production to avoid undue delays in domestic supply.

Domestic gas is expected to account for just 5 per cent of Gorgon gas production and 5 per cent of expected revenues. It is expected to account for less than 5 per cent of project investment and operating costs given the relatively low cost of processing gas to pipeline specification compared to the high capital and operating costs of producing LNG. There is no justification for the Project delaying meeting its 300 TJ/day domestic supply target.

Case Study: Gorgon Project

The Gorgon State Agreement commits the Gorgon participants to establish a domestic gas plant by end 2012 to progressively deliver at least 300 TJ/d of gas to the WA market.

The Gorgon partners however indicate that this supply volume will not be available until 2021 – some 12 years after the project's final investment decision.

Action: *The Gorgon producers should be required to supply 300 TJ/d of domgas prior to or no later than LNG start-up.*

Similarly, the Pluto domestic gas commitment only requires domestic supply five years after the date LNG is first exported from Pluto. Even then, Woodside could seek to avoid this obligation by claiming it is not "commercially viable" to supply domestic gas, or that the resources need to be allocated to underpin LNG contracts.

Timeliness - Key Recommendations

- The obligation should be applied as a *percentage* of reserves and production, as opposed to a fixed volume.
- Producers should be required to supply domestic gas prior to or at least no later than start-up of LNG production.

6. The need for Commonwealth domestic supply obligations

The 2006 WA Reservation Policy highlighted the importance of Commonwealth policies to promote gas security and support State policies:

> "Most of the gas resources off the coast of Western Australia fall under Commonwealth jurisdiction. The Australian Government therefore has a strong and legitimate interest in the development of these resources."
>
> The State Government is of the view that the issues facing Western Australia regarding the long term security of domestic gas supply are ones that will soon also be facing the eastern states. Given that the majority of the nation's gas resources are located offshore from Western Australia, decisions made concerning the development of these resources have major implications for Australia's energy mix, the international competitiveness of gas consuming energy intensive domestic industries, and the achievement of national greenhouse gas abatement targets."[87]

Shell has announced it will develop its Prelude and Concerto gas fields in the Browse Basin off the WA coast using Floating LNG technology.[88] A floating LNG plant allows producers to develop fields in Commonwealth waters, thereby limiting the ability of State governments to apply a reservation commitment. In addition, gas fields ideally suited for domestic use – such as West Tryal Rocks - are now rolled into LNG projects and warehoused under retention leases.

Domestic supply obligations should be implemented by the Commonwealth in offshore WA areas to support and complement the State's reservation policy. This would send a consistent message to gas producers on the importance of energy security and ensure current and future offshore projects are subject to domestic supply obligations.

It would also avoid potential conflict of laws. The Federal Government has for example been contemplating treaty commitments, as part of Free Trade Agreement negotiations, which would underpin Japan and China's energy security requirements. These include provisions that could commit the Commonwealth and States not to apply export restrictions on energy resources such as domestic reservation obligations.

Commonwealth domestic supply obligations

- Domestic supply obligations should be implemented by the Commonwealth in offshore WA areas to support and complement the State's reservation policy.
- Commonwealth obligations would ensure producers do not avoid domestic supply commitments when developing projects in offshore Commonwealth waters.
- It would also avoid potential conflicts of laws, and send a consistent message to LNG producers on the importance of energy security.

87 WA Department of Premier and Cabinet, *WA Government Policy on Securing Domestic Gas Supplies*, October 2006, p.7.
88 Shell, 'Prelude LNG Development to Deploy Shell's Floating LNG Technology', Media release, 8 October 2009.

Action: North West Shelf State Agreement

Key Points

- The North West Shelf State Agreement provides a powerful mechanism for the State to secure additional domestic supply from 2010 through 2025.
- The State can ensure domestic supply takes precedence over LNG when the Project: renews or rolls-over existing LNG contracts; enters into new LNG contracts; or undertakes new LNG developments.
- The State has yet to apply additional domestic supply commitments under the State Agreement as it is entitled to.

1. Historical background

The North West Shelf Gas Project is governed by the North West Shelf State Agreement which establishes the framework of rights and obligations between the project participants and the State.[89]

When the State Agreement was concluded, the North West Shelf Gas project was envisaged to have three phases:

- **Phase 1:** The domestic gas development, which involved construction of the DomGas processing plant and the Dampier to Bunbury Natural Gas Pipeline (DBNGP). This was underpinned by the 20 year take-or-pay contract entered into with the State Energy Commission of WA (SECWA), which was in turn backed up by a major commitment from Alcoa.
- **Phase 2:** The initial LNG export phase, involving the construction of LNG Trains 1 and 2.
- **Phase 3:** The expansion of capacity to process and export LNG, resulting in the construction of LNG Train 3.

An intent of the State Agreement was to ensure sufficient priority was placed on meeting the requirements of the WA domestic gas market.

2. LNG exports have expanded significantly

Since the original State Agreement and the 1994 amendments, the North West Shelf Joint Venture has committed to a significant expansion in LNG exports. LNG Train 4 was completed in 2005 and LNG Train 5 commissioned in 2008. Completion of LNG Train 5 will bring LNG exports to a level of 16.3 million tones per year.

This represents a 250 per cent increase compared to the originally envisaged 6.5 million tonnes per annum of LNG exports. The operator of the North West Shelf Joint Venture, Woodside, has flagged further expansions through a potential sixth LNG train.

[89] The State Agreement was concluded and ratified by State Parliament in 1979 and scheduled in the North West Shelf Gas Development (Woodside) Act 1979. The Agreement was originally due to expire in 2010, but was extended in 1984 to 2025.

… while domestic supply has increased marginally

In contrast, supply to the domestic market by the Joint Venture has increased only marginally. In 1998, the Shelf Joint Venture advised, as part of its justification for seeking ACCC authorisation for joint selling, that it intended to increase the capacity of the domestic gas processing plant to 1,100 TJ/d through the construction of an additional domestic gas processing train.

That commitment was never met despite the Joint Venture participants receiving authorisation from the ACCC, and continuing to sell jointly to local gas users.

3. The State Agreement provides a mechanism for the State to ensure additional domestic supply

The NWSJV has been committing to the extension of supply contracts from LNG Trains 1 and 2. It is understood that the original 20 year terms for these contracts began to expire from 2009 with long-term extensions being negotiated.

Given the State depends on the North West Shelf Joint Venture for almost 70 per cent of its domestic gas, LNG exports should be matched by additional domestic supply commitments.

The North West Shelf State Agreement provides a powerful mechanism for the State Government to secure additional domestic supply from 2010 through 2025. The State can ensure domestic supply takes precedence over LNG when the Project:

- renews or roll-over existing LNG export contracts;
- enters into new LNG contracts entered into by the NWSJV; or
- undertakes new LNG developments such as the flagged LNG Train 6.

Even if the NWSJV producers satisfy their original domestic supply obligation by 2014, this does not extinguish the State's power to ensure priority of domestic supply. Clause 46(1a) of the Agreement requires the Joint Venture participants and the State to:

> "…*consult and reach agreement on the requirements in the State and the manner on which they will be met*…" before entering into arrangements for the sale, use, supply or export of gas during 2010 to 2025.

The State has yet to apply additional domestic supply commitments under the State Agreement as it is entitled to.

4. Retention leases and permit approvals

The North West Shelf Gas website has previously stated that:

> "*… production licences, retention leases and permits held by the NWSV for [the NWSV fields] expire between 2001 and 2018 …*
>
> *The NWSV expects permits that expire to be renewed in the ordinary course of business*".[90]

The importance of permit renewals to the North West Shelf Joint Venture gives the State an additional mechanism to ensure additional supply to the domestic market.

[90] North West Shelf Gas website, accessed 2008.

Action: Common-Use Infrastructure

Key Points

- Shared-use infrastructure could cut project costs by as much as half. This can facilitate development, reduce costs and promote domestic gas supply.
- Concessions under the Commonwealth Petroleum Resource Rent Tax (PRRT) may however act as a disincentive for investment in shared use infrastructure.
- Under these concessions, companies may obtain a larger financial benefit from building and operating stand-alone infrastructure. The issue merits further examination by the State.

1. Overview

Currently, gas gathering and processing facilities are scaled and built to support individual projects. This has the potential to lead to sub-optimal development with little integration. The likely end result is to increase project costs and make development of some gas fields uneconomic.

A significant component of the total costs of a new offshore development is the cost of gas gathering pipelines – which rise the further gas fields are located from shore - and the associated gas processing facilities.

Common use infrastructure can promote new domestic gas developments by lowering investment barriers and costs. Third party participation in infrastructure investment could also facilitate investment where infrastructure operators have lower hurdle rates of return than upstream producers.

2. Shared-use infrastructure could cut project costs by almost half

A study by international energy consulting firm Wood MacKenzie examined opportunities for common use gas gathering and processing facilities. The study examined two development scenarios concerning the development of gas fields in the Carnarvon Basin with a typical distance of 150 km to shore:

- Scenario One: three independent 100 terajoules / day (TJ/d) developments, each with separate pipelines and processing facilities;
- Scenario Two: one integrated development utilising one common gathering trunkline and a processing plant of 300 TJ/d capacity

The study found potential capital costs could be cut by almost half by consolidating developments into an integrated development with common-use facilities. This could deliver potential savings as high as $1 billion.

Potential benefits included lower barriers to entry, a more economically efficient use of capital leading to lower gas supply chain costs and increased transparency in supply costs.

Figure: Benefits of common-use infrastructure

	Scenerio One Integrated System Capex ($m) 300 TJ/d	Scenario Two Stand Alone Capex ($m) 100 TJ/d x 3 fields	Timing
Pipeline to Shore Costs			
Field A – Initial 100 TJ/d	$555 (150 km x 20”)	$445 (150 km x 16”)	Year 1
Field B – Subsequent 100 TJ/d	$111 (50 km x 12”)	$445 (150 km x 16”)	Year 3
Field C – Subsequent 100 TJ/d	$111 (50 km x 12”)	$445 (150 km x 16”)	Year 5
Gas Processing Costs			
300 TJ/d Plant	$400	$250 x 3	Year 1
100 TJ/d Plant			Years 1, 3, 5
TOTAL CAPEX	**$1, 177**	**$2,085**	

3. Government can promote common-use infrastructure

Government can facilitate discussions between stakeholders, and by

improving transparency and disclosure in the retention lease system. An effective gas reservation policy would also ensure that any consolidation between domestic gas and LNG projects still delivers domestic gas supply.

There is also a need for government to review existing taxation arrangements to ensure that such arrangements promote, or at least not discourage, shared use infrastructure. Concessions under the Commonwealth Petroleum Resource Rent Tax (PRRT) system may act as a disincentive for investment in shared use infrastructure.

PRRT taxes the profits of petroleum production in Commonwealth areas. PRRT is assessed at a rate of 40 per cent of taxable profits of a petroleum project, after allowing for deductions including exploration expenditure, and project development and operating expenses.

Companies can carry forward un-deducted expenses to offset against future PRRT assessable receipts. Additionally, a concession allows for un-deducted exploration expenditure to be transferred to another company under common ownership with a PRRT paying project (or between projects of the same taxpayer) where certain conditions are satisfied.

Under these concessions, companies may obtain a larger financial benefit from building and operating stand-alone infrastructure, as opposed to participating in common-use infrastructure. The issue merits further examination.

Action: Tax, Royalty and Investment Incentives

Key Points

- Commonwealth and State tax, royalty and investment incentives should be provided to promote domestic gas exploration and development. These could include:

  - State royalty concessions such as royalty holidays, royalty rate reductions or rebasing the commodity value for royalty assessment;
  - Increased deductibility for pre-wellhead expenses from Commonwealth taxation;
  - Flow Through Share scheme;
  - Commonwealth and State grants to promote domestic gas exploration and development.

- The Alliance does not support the Commonwealth assuming control of State royalties. Such an outcome could limit the State's ability to provide targeted incentives for domestic gas development.

1. Fiscal incentives needed to promote domestic gas

There may be a number of reasons why gas reserves that could potentially supply the domestic gas market have not been developed. These reasons include:

- the size of the known reserves and potential size of unknown reserves;
- the inability of smaller companies to raise capital to explore and develop marginal fields;
- the difficulties associated with extracting the gas (i.e. tight gas reserves); and
- the economics of exploring and developing the smaller fields under the current royalty regime.

By targeting these factors, tax and royalty incentives can promote development, entice new entrants into the upstream gas market, and lead to a diversification of supply among different competitors and reserves.

Such incentives could promote smaller domestic gas developments, or LNG projects with a domestic gas component. This will help balance the oil and gas industry's current focus on LNG exports, and the incentive under existing tax and royalty arrangements to develop Australia's natural gas resources as large scale LNG projects.

Incentives could also encourage new frontier technical challenges such as onshore "tight gas" fields. Tight gas developments involve additional technology and significant pre-wellhead expenses compared to conventional fields. Increased deductibility of pre-wellhead expenses could for example promote field development.

In the economic downturn, inshore and onshore exploration activities – which are the most likely sources of competitive domestic gas supply - are impacted to a far greater extent than deepwater offshore exploration. This is because the companies involved are reliant on regular injections of risk capital from the local market.

2. Appropriate incentives

Appropriate tax and royalty incentives include:

- State royalty incentives – such as royalty holidays, and rebasing the commodity value of royalty assessment;
- Commonwealth tax incentives – such as reducing the statutory cap on the effective life of upstream gas assets, and targeted incentives for "tight gas" development; and
- Flow Through Share Scheme for domestic gas exploration and development.

In addition, investment incentives such as Commonwealth and State grants can encourage and support companies to explore for and develop gas fields for domestic supply.

Appendix 1 demonstrates that tax and royalty incentives can have a significant impact on the net present value of after-tax cash flows of domestic gas field projects that promotes the commerciality of such projects.

In some instances, it could facilitate the development of projects that might otherwise not be commercial under the existing tax and royalty regime.

Where fiscal incentives enable the development of gas fields, the impact on government budgetary arrangements could be neutral or even positive. This is where incentives deliver tax and royalty streams from gas fields that might otherwise not be developed.

2.1 State royalty concessions

State royalty concessions could provide important encouragement for domestic gas developments. These include royalty holidays, reducing the royalty rate or rebasing the commodity value for royalty assessment. Such concessions can promote the development of domestic gas fields by improving the upfront economics of a project, particularly for tight gas projects.

Any impact on State revenue could be limited, particularly where the concessions allow the development of a field that might otherwise be uneconomic to develop in its initial stages, which would subsequently generate significant royalties for the State over the long term life of the field.

The royalty rate for domestic gas developments could be reduced to 5 per cent to promote development. Alternatively, royalty holidays for the first 6 years of a domestic gas project should be provided.

Where gas fields involve LNG projects with a potential domestic gas leg, royalty concessions can be provided for the domestic gas component to promote domestic supply.

The Alliance welcomes the State Government's recent royalty incentives for tight gas. Royalty incentives should also be extended to all domgas development inshore and onshore.

2.2 Increased Commonwealth deductibility for pre-wellhead expenses

Increased deductibility for pre-wellhead expenses could be provided for domestic gas developments under federal taxation arrangements.

A 175 per cent uplift on expenditure incurred in exploring and developing domestic gas reserves should be provided, particularly for tight gas where development involves significant pre-wellhead expenses.

The uplifted tax deduction would be available to companies once the expenditure is incurred, and the companies would not have to develop gas before they received the tax incentive. The impact of this incentive would be to reduce companies' taxable income and may provide an incentive to companies with an existing tax liability.

2.3 Commonwealth Flow Through Share Scheme

A Flow Through Share scheme would provide significant assistance for smaller petroleum companies engaging in domestic gas exploration and development, and who are reliant on the market for risk capital.

Such a scheme would promote frontier and start-up developments where companies might not otherwise generate a taxable income in the initial project years that would make tax deductions an appropriate incentive.

By implementing an FTS scheme, these companies would be able to pass these losses through to investors who could use the tax deductions, which could in turn create interest and equity funding by investors.

The Federal Government committed to the introduction of a FTS scheme as part of its 2007 election policies. It has yet to do so.

2.4 Investment incentives

Commonwealth and State grants can encourage and support companies to explore for and develop gas fields for domestic supply. Such grants are administratively straight forward to implement, and would support long term energy security by promoting competition and diversity of domestic gas supply.

Grants could also be used to promote new "frontier" developments and technology, such as greenfield tight gas developments. Grants have in the past been provided to support new technology development in the petroleum industry, such as coal seam methane and carbon sequestration.

3. Commonwealth take-over of State royalty arrangements not supported

The Alliance does not support the Commonwealth assuming control of State royalty arrangements. Such an outcome would impact the State's ability to address domestic gas security, by limiting its ability to provide targeted incentives for domestic gas development.

As the State has demonstrated in the case of tight gas, such incentives can provide significant benefits in encouraging and promoting domestic gas development.

4. Domestic gas production should be exempted from the PRRT

The Commonwealth should exempt domestic gas production from any proposal to extend the Petroleum Resource Rent Tax (PRRT) to all offshore and onshore projects.

An exemption would provide a significant incentive to develop further domestic gas supply. Gas producers would enjoy a tax incentive, while business and households would benefit from more domestic supply.

An exemption could have only a modest effect on Commonwealth revenues as domestic gas production accounts for a small proportion of Australia's petroleum production. Any revenues foregone would be more than offset by taxes from existing downstream industries, as well as new projects dependent on domestic gas supply.

An exemption would support recent efforts by the State Government, such as the State's decision to grant royalty relief to tight gas projects.

Government Action to Date

Key Points

- Initiatives taken by the State will help promote domestic gas supply. These initiatives need to be matched by the Commonwealth.
- The State and Commonwealth must act to remove barriers to competition and supply – in particular joint selling of domestic gas and the warehousing of domestic gas fields.

1. The State has supported initiatives to promote gas supply

The State should be commended for its leadership on domestic gas security. Initiatives taken by the State include broadening pipeline gas specification, royalty incentives for tight gas projects, the Exploration Incentive Program and the Strategic Energy Initiative and the 15 per cent domestic gas reservation policy.

These initiatives need to be matched by the Commonwealth. The State and Commonwealth should also act to remove barriers to competition and supply. These joint selling of domestic gas and producer warehousing of domestic gas fields.

2. The national policy framework is focused on maximising LNG exports

The national policy framework remains focused on maximising LNG exports. There also appears to be a limited understanding at the Commonwealth level of the West Australian gas market with assessments reflecting a narrow upstream producers' perspective.

The 2009 National Energy Security Assessment on Gas, prepared by the Department of Resources, Energy and Tourism for the Energy White Paper, for example concluded that:

> "Small domestic demand in WA limit development of reserves for WA domestic supply"
>
> "High production capital costs … in WA limit development of reserves for WA domestic supply"; and
>
> "Domestic prices still low internationally despite being high historically" [91]

[91] Department of Resources, Energy and Tourism; *National Energy Security Assessment 2009*, chapter on gas, pp.14-19.

Similarly, the draft Energy Green Paper repeats producer claims relating to a "small" WA domestic gas market and the impact of long term contracts and domestic reservation obligations on exploration and investment, but provides little evidence to support these claims.

There appears to be a presumption at both the Commonwealth and State level that LNG projects like Gorgon would resolve the State's gas shortage by 2015. As the ECS Report demonstrates, this presumption is misplaced.

In particular, the Gorgon Project's contribution to domestic supply is expected to be modest. It represents only a very modest volume of domestic supply, which is subject to long delays in production ramp-up, and marketed under conditions that provide for no competition between sellers.

3. Commonwealth policy responses have gone backwards

Commonwealth policy responses to domestic gas supply have in fact gone backwards in recent years. In 2006, a Commonwealth-States Joint Working Group on Natural Gas Supply was established in response to Western Australia's serious domestic gas shortage.

In 2007, the Joint Working Group issued its Final Report recommending stringent enforcement of the retention lease commerciality test to promote domestic supply. This was to ensure that major producers do not warehouse gas resources that could supply the domestic market.

The Joint Authority now seems determined to give LNG precedence over domestic gas supply in approving the warehousing of gas resources under retention leases.

The ACCC has also repeatedly intervened to protect major gas producers from competition by authorising joing selling arrangements for Gorgon and the North West Shelf Projects.

Unless action is taken, business and households in Western Australia face even higher gas prices, greenhouse emissions and the potential for significant job losses.

Appendix: Fiscal Incentives

To quantify the impact that fiscal incentives can have on domestic gas field developments, two quantitative models were examined:

- a near-to-shore conventional gas field; and
- an on-shore tight gas field.

The impact of alternative incentives has been calculated in terms of the net present value (NPV) of after tax cash flows which the projects are expected to yield over a 10 and 20 year period. [92]

The base case scenario represents the current fiscal and taxation regime, in which no incentives are offered. These projects forecast marginal returns over a 10 and 20 year period, to reflect the situations often facing potential investors in domestic gas fields.

The impact of the alternative tax, royalty and investor incentives on the NPV of the projects over a 10 and 20 year period are shown in the Table on the following page.

As demonstrated by the results, incentives such as reducing the royalty rate to 5% or providing a royalty holiday for the first 6 years of the projects have the greatest impact on the NPV of these projects over a 10 and 20 year period.

In these models, introducing a resource rent royalty has the effect of reducing the NPV of the projects, due to the significant revenue which the fields generate at the height of their production, relative to their costs.

Other fiscal incentives (such as rebasing commodity value for royalty assessment, providing increased deductions for eligible expenditure, allowing for quicker depreciation of capital assets or providing cash grants) all help to improve the NPV of the expected returns from the project.

[92] A discount rate of 15% was used to calculate the net present value of future after tax cash flows

Figure: Results of Scenario Modelling

Near-shore DomGas Project

Scenario	NPV of 10 years of after tax cash flows ($M)	% impact of incentive on NPV	NPV of 20 years of ofter tax cash flows ($M)	% impact of incentive on NPV
1 Base case (no incentives)	55.96	na	$18.52	na
2 Reduce royalty rate to 5%	89.79	60.46%	$57.14	208.56%
3 Royalty holiday until 2015	101.08	80.64%	$63.64	243.68%
4 Rebase commodity value for OPEX and depreciation	59.70	6.69%	$22.26	20.21%
5 Resource Rent Royalty (40%)	-70.84	-226.60%	-$101.75	-649.45%
6 Uplift in pre-well head expenses 175% allowable tax deduction	79.03	41.23%	$41.59	124.60%
7 Reduce statutory cap on effective life of pipeline to 10 years	60.48	8.07%	$22.63	22.21%
8 Provide 3 year cash grant to offset CAPEX	79.18	41.49%	$41.73	125.37%

Onshore Tight Gas Project

Scenario	NPV of 10 years of after tax cash flows	% impact of incentive on NPV	NPV of 20 years of ofter tax cash flows	% impact of incentive on NPV
1 Base case (no incentives)	$70.31	na	$119.76	na
2 Reduce royalty rate to 5%	$91.48	30.12%	$144.13	20.35%
3 Royalty holiday until 2015	$97.11	38.13%	$146.57	22.38%
4 Rebase commodity value for OPEX and depreciation	$84.50	20.19%	$135.69	13.30%
5 Resource Rent Royalty (40%)	-$0.33	-100.47%	$35.41	-70.43%
6 Uplift in pre-well head expenses 175% allowable tax deduction	$73.60	4.68%	$123.06	2.75%
7 Reduce statutory cap on effective life of pipeline to 10 years	$71.24	1.32%	$120.83	0.97%
8 Provide 3 year cash grant to offset CAPEX	$73.96	5.19%	$123.41	3.05%

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