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Gas Statement of Opportunities

November 2015

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[1] Gas referred to throughout this report refers to natural gas.

Executive summary

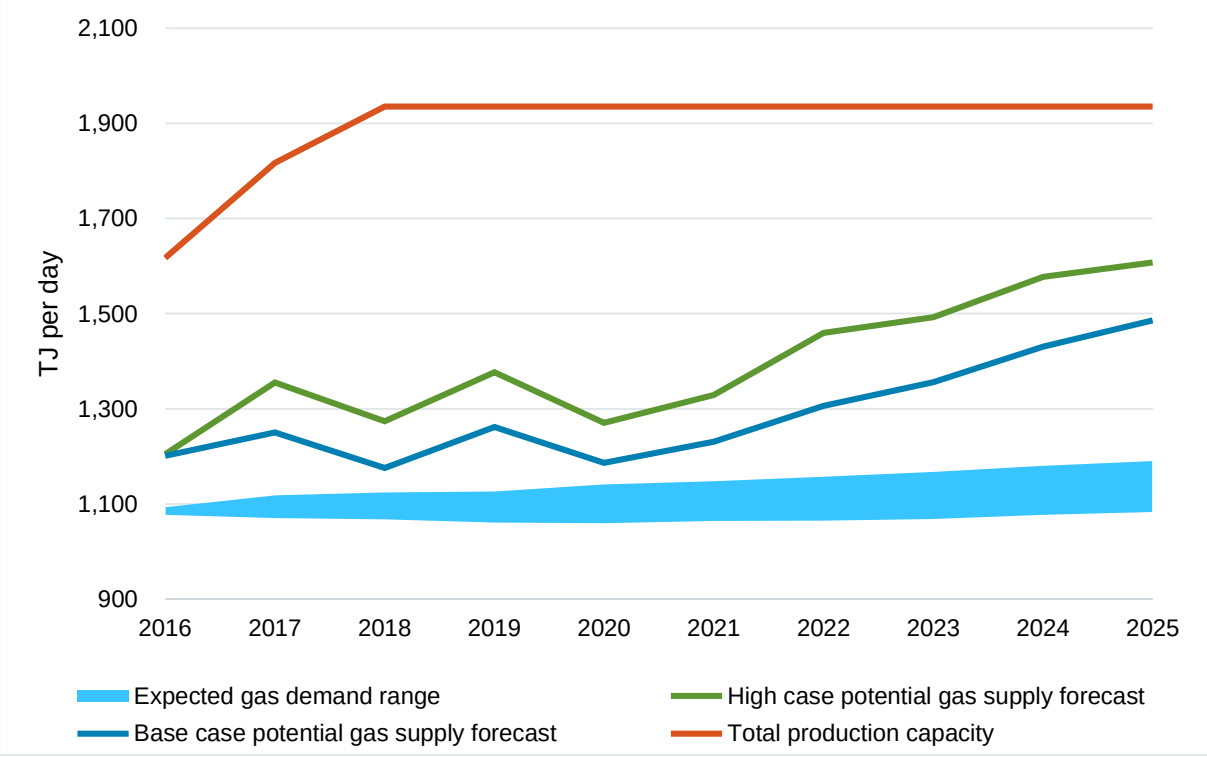
This Gas Statement of Opportunities (GSOO) provides the Independent Market Operator's (IMO) independent assessment of the Western Australian (WA) domestic gas market over the calendar years 2016 to 2025 (the forecast period). This GSOO includes forecasts of gas demand and supply, an overview of gas infrastructure in the state, and emerging issues affecting the gas industry. It is designed to assist Gas Market Participants and other energy industry stakeholders to identify any potential shortfalls, constraints and opportunities in the WA gas sector.

Key findings

- **The domestic gas market remains in excess supply**

The potential gas supply for the forecast period remains significantly higher than forecast demand. Potential gas supply is at least 107 TJ per day greater than demand over the next four years in the base forecast scenario (see Figure ES.1). This excess supply is forecast to rise to more than 400 TJ per day by the end of the forecast period as several large domestic gas production facilities commence operation[2].

Figure ES.1: Domestic gas market balance, 2016 to 2025



Source: NIEIR and IMO forecasts, 2015

[2] Gorgon and Wheatstone domestic facilities are expected to have commenced production by 2018. This will be followed by an expansion to the Gorgon domestic facility in 2020.

- **Domestic gas supply has been affected by falling oil prices but is forecast to grow over the forecast period**

Potential gas supply over the forecast period (see Table ES.1) is lower than was presented in the 2014 GSOO. This is due to the recent fall in international oil prices, which has reduced domestic gas prices and caused uncertainty in the market. Gas producers will likely be less willing to supply the domestic market in the short-term, at least until prices increase (or stabilise) or additional production capacity comes online.

Table ES.1: Forecast potential supply (TJ per day), 2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Ave. growth p.a. (%)
Base	1,201	1,251	1,175	1,262	1,187	1,231	1,306	1,356	1,431	1,486	2.4
High	1,205	1,355	1,274	1,377	1,271	1,329	1,460	1,492	1,578	1,608	3.3

Source: IMO forecasts 2016 to 2025

However, the IMO expects potential supply to increase towards the end of the period as international oil prices recover[3], which should lead to a higher domestic gas price and a more attractive domestic market. The commencement of the Gorgon and Wheatstone domestic gas projects in 2016 and 2018 will also increase production capacity and the availability of gas supply.

- **Domestic gas demand is forecast to grow very slowly**

The IMO expects domestic gas consumption to increase by less than 1 per cent per annum over the forecast period, remaining almost flat in the base scenario forecast (see Table ES.2).

Table ES.2: Forecast demand (TJ per day), 2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Ave. growth p.a. (%)
Base	1,077	1,070	1,068	1,061	1,059	1,064	1,065	1,068	1,077	1,083	0.1
High	1,093	1,118	1,124	1,126	1,141	1,148	1,157	1,167	1,180	1,190	0.9

Source: NIEIR forecasts 2016 to 2025

This slow growth is due to the expected decrease in gas-fired electricity generation in the South West Interconnected System (SWIS), partially offset by increased gas consumption by the following projects:

- connection of the Sunrise Dam and Tropicana gold mines to the Eastern Goldfields Gas Pipeline;
- restart of Newman Power Station, which will supply electricity to the Roy Hill iron ore mine;
- operation of the South Hedland Power Station;

[3] The Organisation of Petroleum Exporting Countries expects oil prices to recover by 2020. See Bloomberg (2015).

- operation of the Pilbara Temporary Power Station; and
- expansion of the Sino Iron magnetite mine.

Overall demand is lower than forecast in the 2014 GSOO, largely due to scheduled decommissioning of the South-West Joint Venture Co-generation facility in 2016, which consumes about 30 TJ per day.

- **The end of joint marketing will bring greater competition to the supply market and may provide Gas Market Participants the opportunity to rebalance their gas requirements**

On 31 December 2015, the joint marketing authorisation for the North West Shelf Joint Venture (NWS JV) and the Gorgon Joint Venture (Gorgon JV) will expire. The IMO understands that participants of both JVs have not applied for an extension of their joint marketing authorisations. From 1 January 2016, the IMO expects each participant to market its share of gas production individually (commonly known as equity marketing).

The end of joint marketing authorisation for the NWS and Gorgon JVs is a significant change to the dynamics of the WA domestic gas market. This is because it will increase the number of individual gas suppliers, which is likely to increase competition. Greater competition will provide opportunities for customers to renegotiate their gas requirements, or secure a more competitive price.

The move to equity marketing has also eased concerns that the Karratha Gas Plant (KGP), WA's largest gas production facility, may be retired. Domestic gas customers were uncertain whether the KGP would continue to produce gas beyond 2020, when all the NWS JV's domestic gas supply contracts are known to expire[4]. However, in October 2015 several NWS JV partners confirmed they will market their uncontracted portion of KGP domestic capacity separately, meaning it is unlikely any of KGP's capacity will be retired in the near future.

- **There is greater opportunity for gas suppliers in the north of WA than in the South West**

Forecast demand growth is greater in areas that are not covered by the SWIS than those that are connected to the SWIS. Table ES.3 shows demand forecasts for the base and high scenarios in the SWIS and non-SWIS.

Table ES.3: Domestic gas forecasts for SWIS and non-SWIS (TJ per day), 2016 to 2025

Scenario		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Non-SWIS	Base	379	382	379	377	378	383	383	382	387	389
	High	389	416	426	432	448	453	458	461	468	472
SWIS	Base	698	689	689	684	681	681	682	686	690	694
	High	704	702	698	694	693	695	699	706	712	718

Source: NIEIR forecasts 2016 to 2025

[4] See IMO (2014a) for a list of known NWS gas supply contracts.

Though around two-thirds of domestic gas is consumed in the Metropolitan and South West regions, the bulk of this is by a small number of large industrial users and electricity generators. Electricity demand is not forecast to increase significantly in the SWIS and excess capacity in the electricity network (1,061 MW for the 2016-17 capacity year) suggests no new gas-fired generation capacity will be required to meet demand in the near future.

The IMO is not aware of any new large industrial projects commencing operations in the South West and Metropolitan regions during the forecast period. If any large industrial users do commence operation, they are likely to connect to the SWIS for their energy needs rather than require independent gas-fired electricity generation.

In regional WA the situation is different. Mines and industrial facilities tend to be located too far from the SWIS to be able to draw on any of its spare electricity capacity. As a result, any new major mining or processing facility would likely require its own on-site electricity generation, with gas as a potential fuel source.

Several resources projects in regional WA are expected to commence operation or increase gas consumption during the forecast period. The high forecast demand scenario includes a further six prospective resources projects, all of which are located outside the SWIS. It is likely some or all of these projects will require domestic gas supply.

- **The domestic gas market will benefit from greater transparency**

As discussed, the end of joint marketing is expected to increase competition in the domestic gas market. New production facilities such as Wheatstone, Gorgon and Pluto will increase WA's production capacity. Further, gas infrastructure development such as the new Eastern Goldfields Gas Pipeline (EGGP) and the recent upgrade of the Goldfields Gas Pipeline (GGP)[5] brings greater shipping capacity to WA. These are fundamental changes to the domestic gas market, which create the potential for greater opportunity and efficiencies in the gas sector.

The IMO considers improved data sharing, greater visibility of domestic gas flows, and more transparent sales information will maximise the potential efficiencies that can be achieved. Greater transparency provides Gas Market Participants with more information on how to identify potential investment opportunities, which ultimately leads to more competitive pricing.

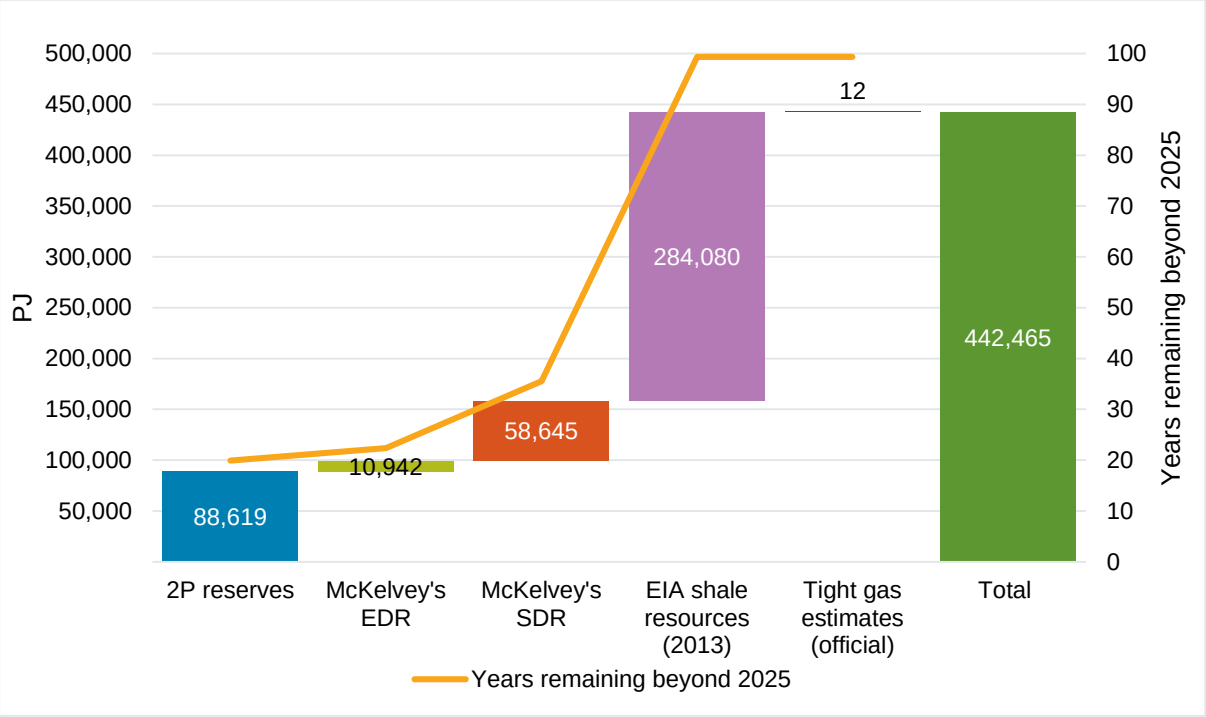
While the IMO understands a degree of confidentiality must be retained, the recent introduction of WA's Gas Bulletin Board and the IMO's data visualisations have demonstrated that the domestic gas sector can increase transparency without adversely affecting the market. Changes to the domestic gas sector over the forecast period present a unique opportunity to establish a more efficient market through the provision of information, with the potential for gas trading.

[5] The upgrade of the GGP was competed in September 2014, however utilisation rates have not yet increased.

Gas resources and reserves

Approximately 92 per cent (158,373 PJ) of Australia's total conventional gas resources are located in WA and the waters around it[6]. WA is also estimated to hold at least 284,092 PJ[7] of unconventional resources in the form of tight and shale gas. Based on total estimates of conventional and unconventional gas, WA's reserves may last up to 99 years beyond the forecast period (see Figure ES.2).

Figure ES.2: Estimated WA gas resources and reserves, 2014



Source: *EnergyQuest (2015), Geoscience Australia (2014), DMP (2013b) and DMP (2014)*

Note: McKelvey provides two estimates of reserves. Economic demonstrated resources (EDR) is a measure of the resources that are established, analytically demonstrated or assumed with reasonable certainty to be profitable for extraction or production under defined investment assumptions that are set by Geoscience Australia. Sub-economic demonstrated resources (SDR) are similar to EDR in terms of certainty of occurrence but are considered to be potentially economic only in the foreseeable future.

It should be noted that the estimates of conventional gas reserves are based on official 2P (proven and probable) assessments, which are typically conservative. The Chevron-led Gorgon and Wheatstone liquefied natural gas (LNG) projects, both of which are in the Carnarvon Basin, are expected to commence production within the next two years. Each project has an expected operating life of around 30 years, which takes these conventional reserves beyond 2045.

6 Geoscience Australia (2014), gas basins in Australia (offshore and onshore).
7 Ibid.

Gas transmission capacity

WA has nine transmission pipeline systems shipping gas to customers (see Figure ES.3). The two largest systems are the Dampier to Bunbury Natural Gas Pipeline (DBNGP) and the GGP. These account for almost 80 per cent of gas shipping capacity, and 90 per cent of total domestic gas shipped throughout WA.

Figure ES.3: Gas transmission pipelines in WA

Source: GBB data

In July 2014, APA Group announced it will construct the 292 km EGGP to ship gas to AngloGold Ashanti's Sunrise Dam JV and Tropicana JV gold mines[8]. The EGGP will connect to the end of the existing gas lateral at the Murrin Murrin mine and will be registered as part of the GGP. The extension is currently under construction and is anticipated to be completed late 2015 and be in service in 2016.

Peak utilisation rates indicate the Telfer Gas Pipeline is fully contracted. The DBNGP is not fully contracted but is fully utilised at peak periods. Substantial shipping capacity appears to be available on all other pipelines. This indicates that greater opportunity for major gas customers exists in regional WA than the South West and Metropolitan areas.

[8] APA Group (2014).

Forecast assumptions

The IMO's domestic gas supply and demand forecasts are calculated using input assumptions including:

- forecast WA economic growth;
- resources sector outlook;
- LNG outlook;
- domestic gas prices;
- WA electricity consumption; and
- production efficiency assumptions (in the resources sector).

These inputs are detailed in chapter 3 of this GSOO, and are provided to complement Gas Market Participants' assumptions when forming their own view of the domestic gas market.

The IMO's assumptions are based on the latest available information and subject to internal scrutiny and annual refinement. Key changes to assumptions compared with the 2014 GSOO include an adjustment to account for the introduction of equity marketing and a relaxation of efficiency assumptions in the resources sector. Previous forecasts assumed that businesses in the resources sector would seek production efficiencies (such as switching to alternative fuel sources) as a result of the high domestic gas prices. However, as the domestic gas price has fallen during 2015, a move away from gas is less likely.

Other issues

This GSOO also considers other emerging issues that are likely to impact the WA gas sector in the near future. The most pertinent issues include:

- the introduction of full retail contestability in the WA retail electricity market, which carries the potential for major energy retailers to enter the retail gas market;
- the Australian Energy Market Commission's proposal to introduce a wholesale gas price index for Australia, which would increase pricing transparency including in WA;
- the use of domestic LNG and compressed natural gas facilities, which has the potential to make gas supply accessible to remote areas of the state, while increasing gas demand as a substitute for diesel; and
- changes to the pricing of the LNG in the international gas market which are likely to have an impact on domestic gas prices.

These issues are discussed further in chapter 6, and will be carefully monitored over the forecast period.

Contents

List of tables

List of figures

1. Introduction and acknowledgements

The Gas Statement of Opportunities (GSOO) is published annually under the Gas Services Information (GSI) Rules made under the *Gas Services Information Act 2012* (GSI Act).

The GSOO contains information and assessments relating to long-term natural gas supply and demand, and transmission and storage capacity in Western Australia (WA). This is the fourth GSOO published in accordance with Part 6 of the GSI Rules, and contains forecasts for the 10-year period from 1 January 2016 to 31 December 2025 (forecast period).

1.1 Structure of this report

The structure of the report is as follows:

- **this chapter** outlines relevant legislation and lists parties that have contributed to the production of this GSOO;
- **chapter 2** provides a description of the size and structure of the WA gas market, production capacity and infrastructure. It also reviews pipeline utilisation and provides a historical overview of gas demand and supply;
- **chapter 3** describes the methodology used to forecast domestic gas demand and potential gas supply for the forecast period. It includes an outlook of the WA economy and key commodities;
- **chapter 4** provides forecasts of domestic and total demand and potential supply for the WA domestic gas market for the forecast period. It also provides an estimate of total gas demand, a projection of production capacity, and a view of the domestic gas balance over the same period;
- **chapter 5** provides an overview of key hydrocarbon basins in WA and an estimate of developed and undeveloped gas resources. It also contains an assessment of how long these resources are expected to satisfy domestic gas consumption and liquefied natural gas (LNG) production; and
- **chapter 6** presents other issues that may be relevant to the medium to long-term demand and supply of natural gas in WA.

1.2 Acknowledgements

The Independent Market Operator (IMO) acknowledges the following industry stakeholders for their assistance in the development of this GSOO:

- Alcoa of Australia (Alcoa);
- APA Group;
- Argus Media;
- Australian Petroleum Production and Exploration Association (APPEA);
- AWE Limited;

- BHP Billiton;
- Chevron;
- CITIC Pacific;
- DBNGP (WA) Transmission Pty Ltd (DBNGP Transmission);
- Department of Mines and Petroleum (DMP);
- Department of State Development (DSD);
- EnergyQuest;
- EVOL LNG;
- Horizon Power;
- Japan Australia LNG (MIMI);
- Mobile LNG;
- North West Shelf Joint Venture (NWS JV);
- PE Wheatstone;
- Quadrant Energy;
- Rio Tinto;
- Santos;
- Shell Australia;
- South32;
- Synergy;
- Wesfarmers;
- Wood Mackenzie;
- Woodside; and
- other participants who have provided feedback during the development of this GSOO, including current and previous members of the Gas Advisory Board (GAB).

2. WA gas market overview and infrastructure

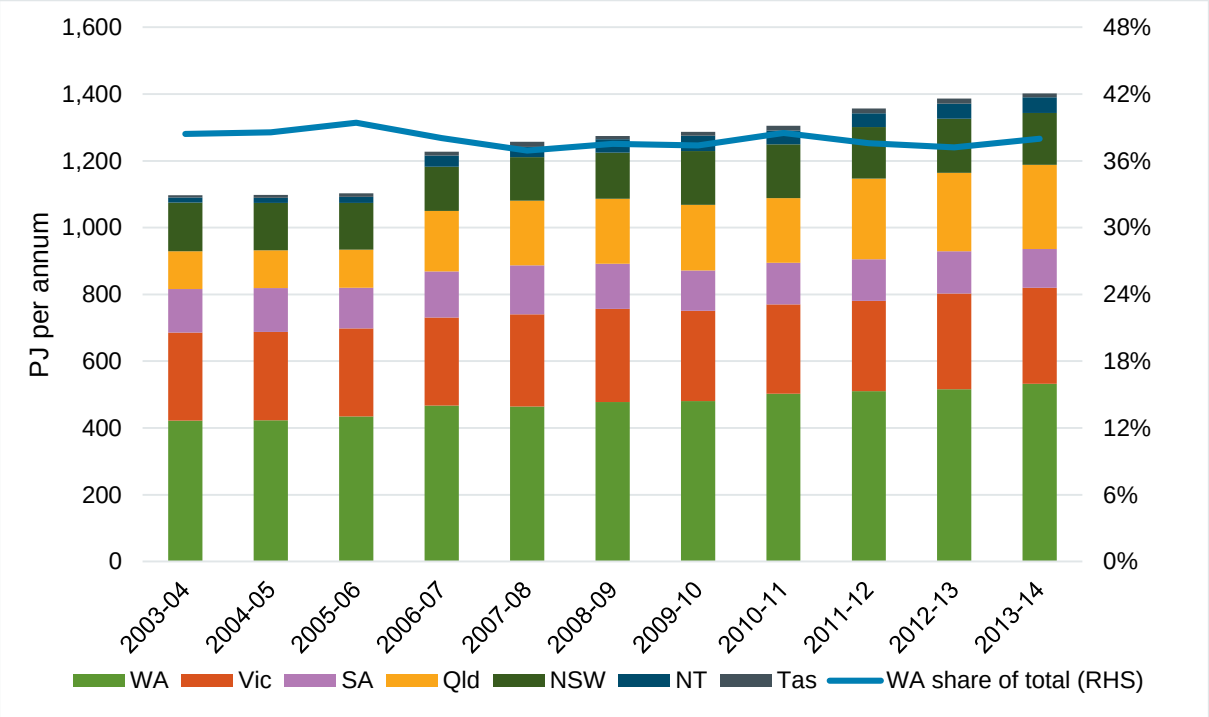
This chapter provides an overview of the historical gas demand and supply in the WA market. It also provides information on gas infrastructure, production capacity and pipeline utilisation.

2.1 Overview of domestic gas demand

Despite its relatively small population, WA is Australia's largest gas consumer. The majority of WA's consumption is driven by the resources sector and heavy industry. Residential consumption is a relatively small component of total gas demand.

Figure 2.1 shows each state's share of total gas consumption from 2003-04 to 2013-14.

Figure 2.1: Australia's gas consumption, 2003-04 to 2013-14



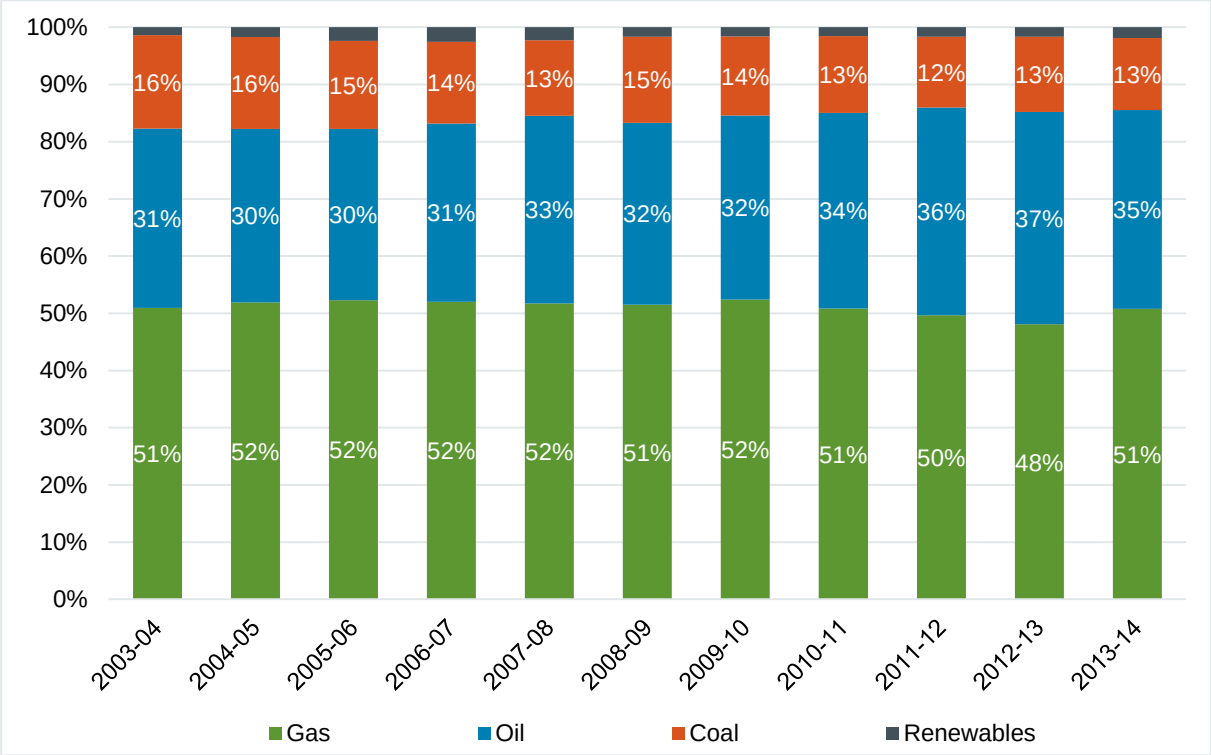
Source: Office of the Chief Economist (OCE) (2015a)

WA consumed approximately 533 PJ of gas in 2013-14, accounting for 38 per cent of all domestic gas consumption in Australia. In WA, large volumes of gas are consumed by a relatively small number of users. Major customers include LNG processing facilities (whose gas consumption is not visible to the IMO[9]), mines, mineral processing facilities, gas processing facilities, electricity generators, and large industrial plants. Most major customers are connected to gas transmission pipelines. The gas distribution network accounts for less than 10 per cent of natural gas consumption.

[9] These major customers are either LNG or oil processing facilities that are situated before domestic gas production facilities and are classified as "behind the fence".

Figure 2.2 shows WA's fuel consumption by energy source from 2003-04 to 2013-14.

Figure 2.2: WA's primary fuel consumption by energy source, 2003-04 to 2013-14



Source: OCE (2015a)

Natural gas accounts for more than half the state's energy consumption[10]. The majority of WA's gas consumption occurs in areas located outside of the South West Interconnected System (SWIS). This is due to natural gas being more competitive for many consumers located in the Goldfields, Mid-West, Pilbara and Kimberley regions.

2.1.1 Wholesale customers

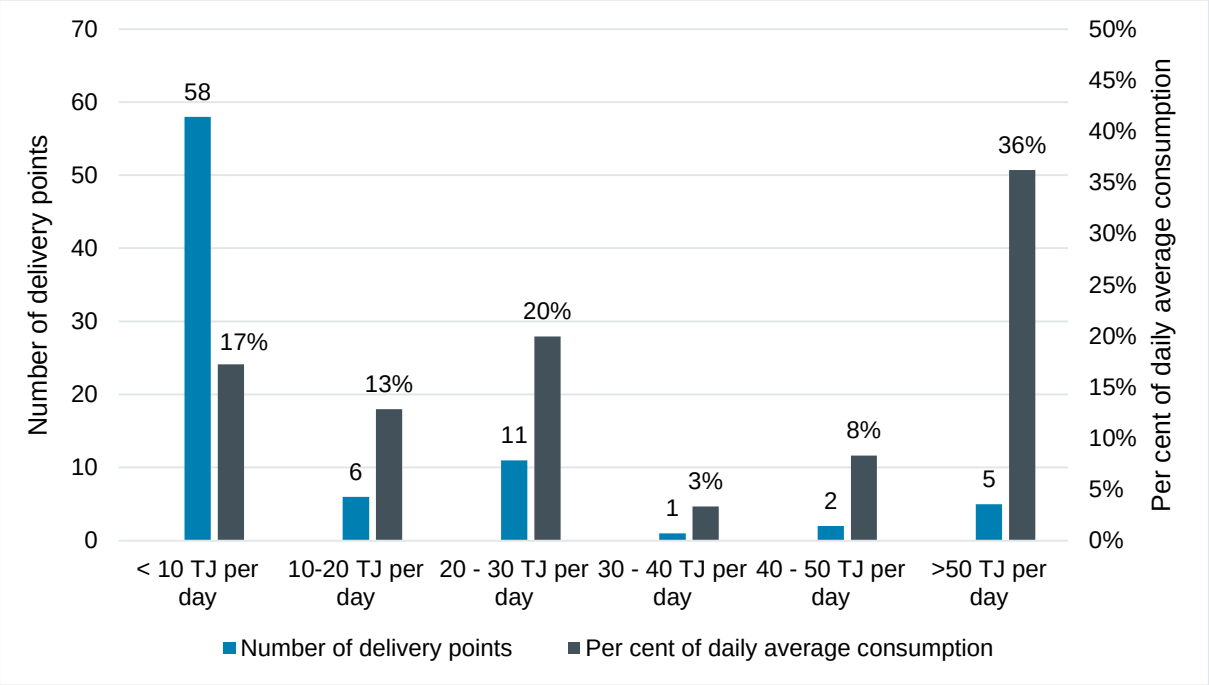
2.1.1.1 Wholesale market structure

Wholesale customers are connected to gas transmission infrastructure. There are more than 80 industrial, manufacturing, electricity generation, domestic LNG and transport-related facilities using gas in the domestic market. The average wholesale customer uses 11.7 TJ per day. As such, a single new wholesale customer is likely to increase aggregate gas consumption in WA significantly.

[10] OCE (2015a).

Figure 2.3 shows the distribution of the average daily consumption for gas delivery points (each delivery point is typically an individual gas consuming facility) between July 2014 and June 2015.

Figure 2.3: Distribution of facility consumption by average daily consumption, July 2014 to June 2015



Source: *GBB data*

Note: These delivery points do not include transmission pipeline interconnections, but do include connections to the distribution network.

Figure 2.3 highlights that:

- over two thirds of facilities consume less than 10 TJ per day, but account for less than 20 per cent of total domestic gas usage; and
- five large facilities, using more than 50 TJ per day, account for more than one third of total gas consumption.

2.1.2 The WA gas market structure

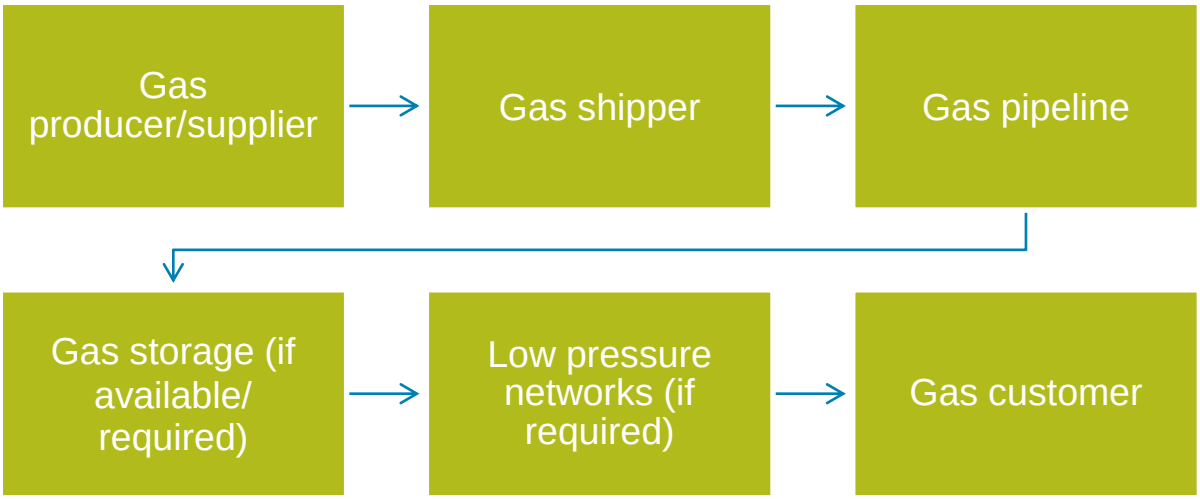
Domestic gas is supplied to wholesale gas market customers either:

- jointly from a specific joint venture;
- directly by a single gas producer from its portfolio of gas production (equity marketing);
- through an intermediary third party; or
- through secondary gas trading platforms.

Short-term gas sales are increasing but remain a small part of the domestic market.

Figure 2.4 shows how gas reaches the final customer in the WA domestic market.

Figure 2.4: Gas market structure



Natural gas is extracted from petroleum wells (mostly located in the Carnarvon and Perth basins) and processed into a specification acceptable to the pipeline operator by the gas producer/supplier. The processed gas is then transferred to the gas shipper (who acts on behalf of the gas customer) who then works with the pipeline operator to ship the gas via high or low pressure pipelines to the customer. Sometimes gas is stored to accommodate seasonal variations in demand.

In WA, most domestic gas producers own gas reserves and operate gas production facilities[11]. Producers sign gas supply agreements with gas shippers or gas customers directly.

The WA gas market operates predominantly under a contract carriage model[12], where about 97 per cent of all domestic gas sales are made through long-term bilateral contracts[13]. Where consumption is lower than maximum contracted quantities, secondary gas may be available for short-term trading.

WA does not have a legislated exchange to trade short-term gas. Gas is traded through gas swaps or via short-term agreements in an over-the-counter market. Short-term gas requirements are typically filled by obtaining additional gas through:

- existing gas supply agreements with gas suppliers;
- short-term master sales agreement with gas suppliers;
- bilateral trades with other market participants or third party gas suppliers;
- pre-determined flexible commercial arrangements with existing gas retailers;

11 Only Tap Oil does not operate gas production facilities or produce its own gas.

12 A contract carriage model for the domestic gas market is where a shipping contract exists between the pipeline owners and the gas shipper. The contract between these two parties typically defines the terms (which includes the quantity of capacity, conditions relating to capacity, cost per GJ of capacity and quantity shipped etc.), rights, duties and liabilities of all parties to the contract. Other market structures include common carriage, market carriage, network carriage and hybrids.

13 Contracted gas prices and quantities are generally not made public unless required by legislation, legal disputes, stock market regulation or energy market rules.

- brokers; or
- energy trading platforms.

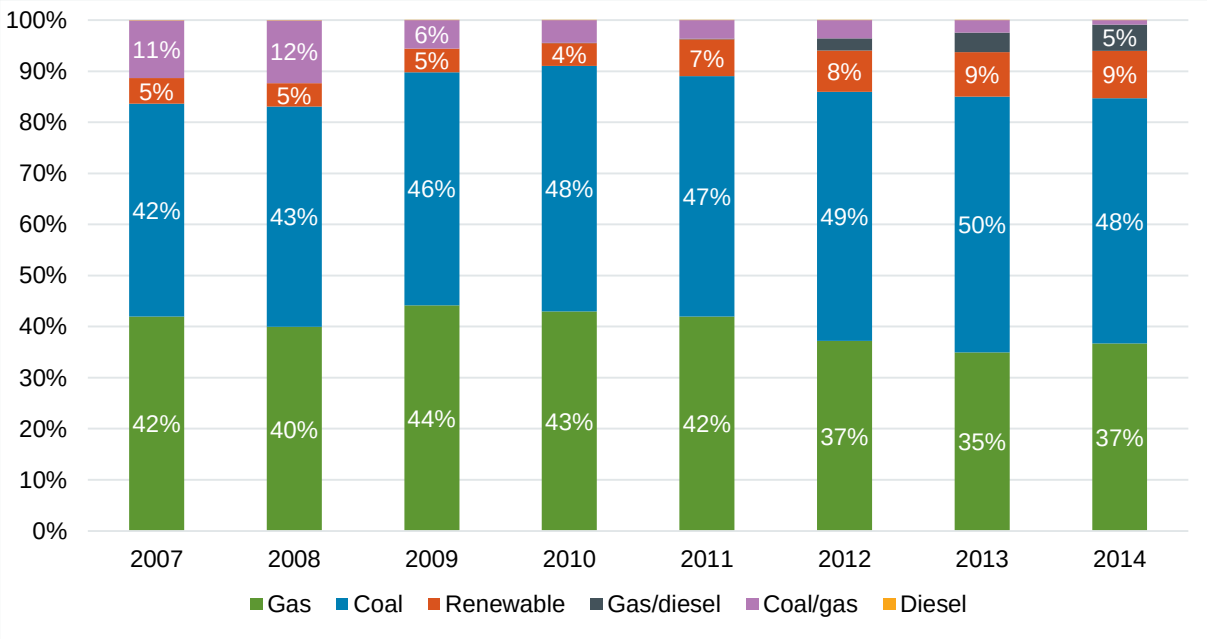
The short-term market remains fragmented across multiple trading platforms, with little transparency of gas prices or quantities being traded.

2.1.2.1 Gas demand from electricity generation in the SWIS

Historical gas consumption reported in the 2014 GSOO shows electricity generation accounts for just over one quarter of total gas demand in WA[14]. The majority of gas consumption for electricity generation occurs in the region served by the SWIS.

Figure 2.5 shows the proportion of electricity generated by fuel type in the SWIS between 2007 and 2014.

Figure 2.5: Electricity generation in the SWIS by fuel type, 2007 to 2014



Source: IMO (2015)

The share of gas-fired generation has decreased from 42 per cent in 2007 to 37 per cent in 2014. The amount of electricity generated from gas in the SWIS has decreased 1 per cent from 6,873 GWh in 2007 to 6,778 GWh in 2014. Over the same period, coal-fired electricity generation has grown by 30 per cent, while generation from renewable sources more than doubled.

In June 2015, the Australian Renewable Energy Target was revised[15], requiring 23.5 per cent of Australia's energy to be derived from renewable sources by 2020. In the SWIS, 9.3 per cent of sent-out generation was produced by renewable facilities in 2014. Given coal remains a lower cost fuel source, new renewable generation sources will likely compete for the market share of gas-fired generation. This will contribute to the decline of gas-fired electricity generation in the South West.

14 IMO (2014a), Figure 6.3.
15 Minister for the Environment (2015).

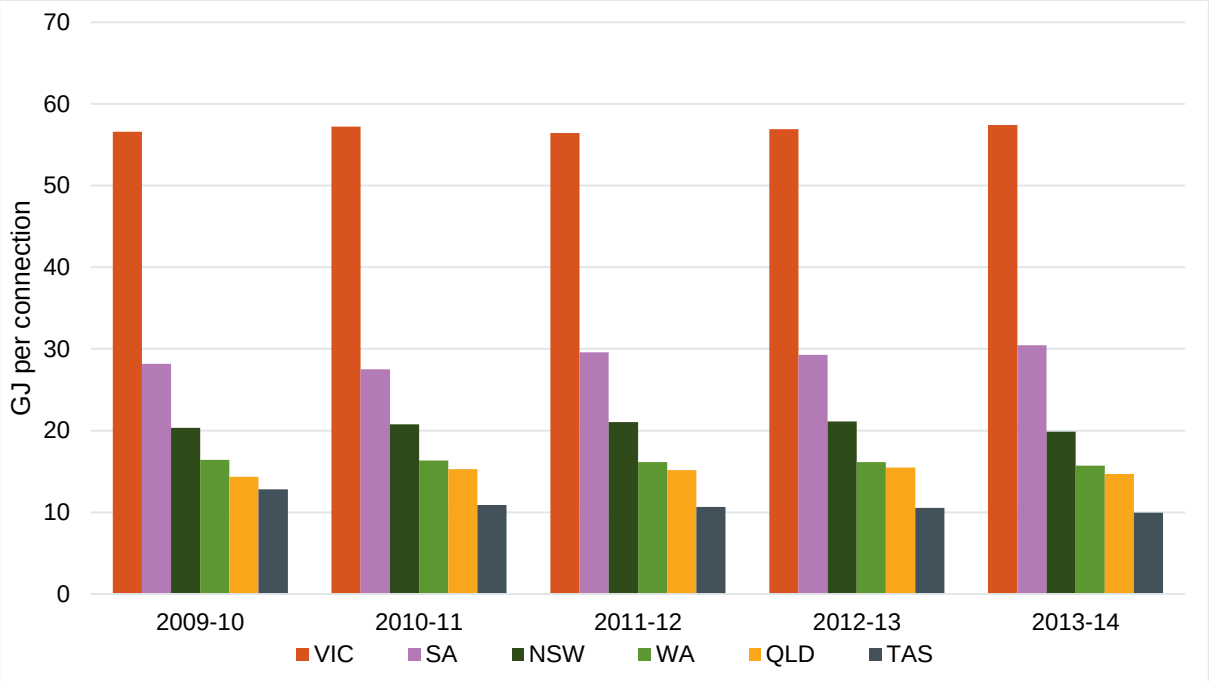
2.1.3 Customers supplied through the low pressure gas distribution network

2.1.3.1 Residential market

WA's residential gas demand is relatively low compared to other states. This is because WA has a small population and a warm climate, meaning less gas is needed for heating than in states with cooler climates such as Victoria and New South Wales. Distribution network coverage is also lower. WA's network covers around 80 per cent of households in the Perth Metropolitan area[16] whereas Victoria's network delivers gas to more than 90 per cent of the Melbourne Metropolitan area[17].

Figure 2.6 shows residential gas consumption per connection by state between 2009-10 and 2013-14.

Figure 2.6: Residential gas consumption per connection by state, 2009-10 to 2013-14



Source: IMO estimates based on Australian Bureau of Statistics (ABS) (2014b) and OCE (2015a)

WA's residential use per connection is around 16 GJ per annum, roughly a third of the average Victorian household's usage. While the introduction of full retail contestability led to a new participant entering the WA domestic gas market (Wesfarmers Kleenheat Gas) in 2013, it has not resulted in significant increases in residential gas consumption.

Prior to Kleenheat's entry, Alinta Energy was the only retailer supplying gas to residential customers. In the twelve months to September 2015, 5.6 per cent of residential customers changed retailers, an increase from 4.0 per cent in the previous year[18]. Despite the levels of customer churn driven by price competition, aggregate residential demand has not changed significantly.

16 ATCO (2012).
17 AER (2014).
18 REMCo (2015).

2.1.3.2 Commercial and industrial market

Gas demand from commercial and industrial gas customers is relatively stable. As shown in Table 2.1, there has been a shift in the relative market share of each retailer, although low overall growth in the number of connections.

Table 2.1: Number of non-residential gas customers by retailer, 2009 to 2014

Retailer	2009	2010	2011	2012	2013	2014
Alinta Energy	8,024	8,191	8,359	8,468	8,355	8,282
Synergy	98	112	119	112	141	79
Wesfarmers (Kleenheat Gas)	19	2	1	1	20	232
WorleyParsons	31	33	34	31	36	33
Total	**8,172**	**8,338**	**8,513**	**8,612**	**8,552**	**8,626**
Change from previous year (%)		**2.0**	**2.1**	**1.2**	**-0.7**	**0.9**

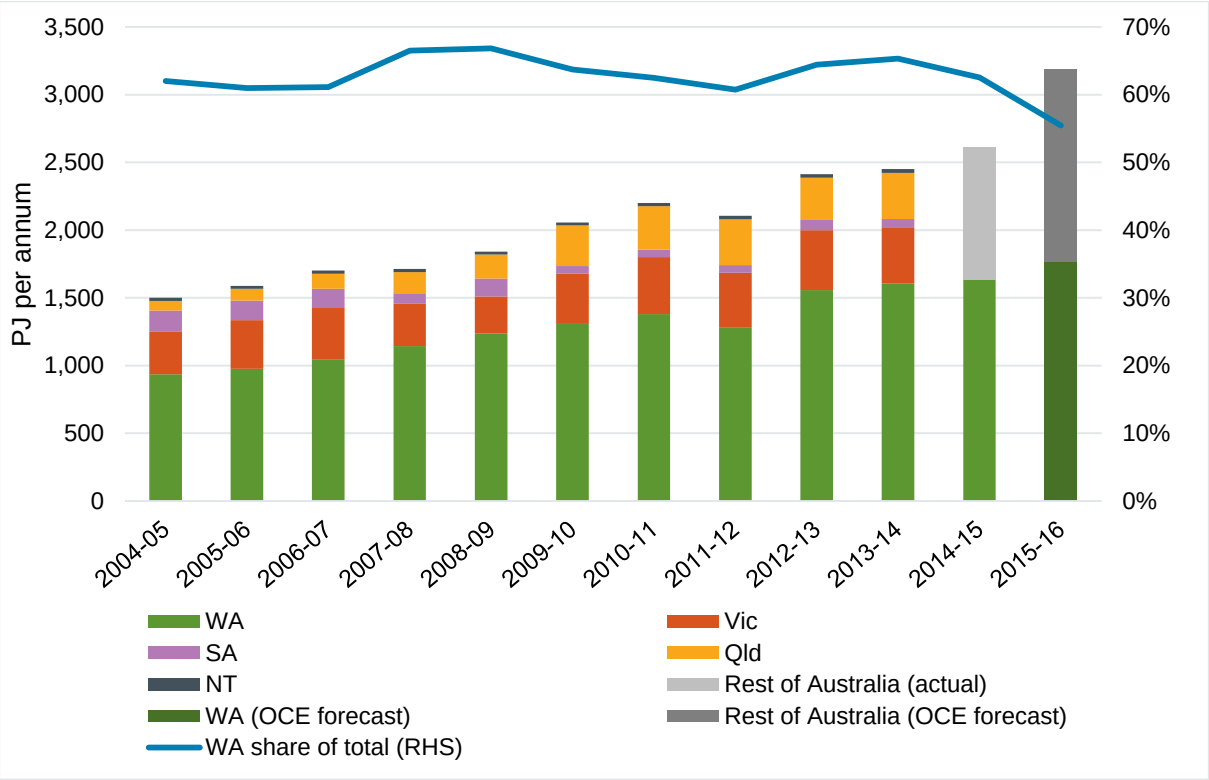
Source: Economic Regulation Authority (ERA) (2014)

Commercial and industrial customers on the low pressure distribution network account for 7 per cent, or 25 PJ, of total WA gas consumption. Even if the number of commercial and industrial customers on the low pressure network was to increase more quickly over the forecast period than it has over the last five years, it is unlikely to have a significant impact on demand.

2.2 Overview of domestic gas supply

WA is the largest supplier of natural gas in Australia, accounting for approximately 63 per cent[19] of gas production in 2014-15. Figure 2.7 shows the share of Australian gas supply by state since 2004-05.

Figure 2.7: Australia's gas market supply (includes domestic gas, LNG and petroleum processing), 2004-05 to 2015-16



Source: OCE (2015a), OCE (2015b) and OCE (2015c)

While total state production continues to increase, WA's share of national gas production has declined. The decline is due to commencement of three LNG export projects in Queensland[20].

[19] OCE (2015a).
[20] Asia Pacific LNG, Gladstone LNG and Queensland Curtis LNG.

Table 2.2 lists companies that supplied the domestic gas market in the third quarter of 2015.

Table 2.2: Domestic gas suppliers, Q3 2015

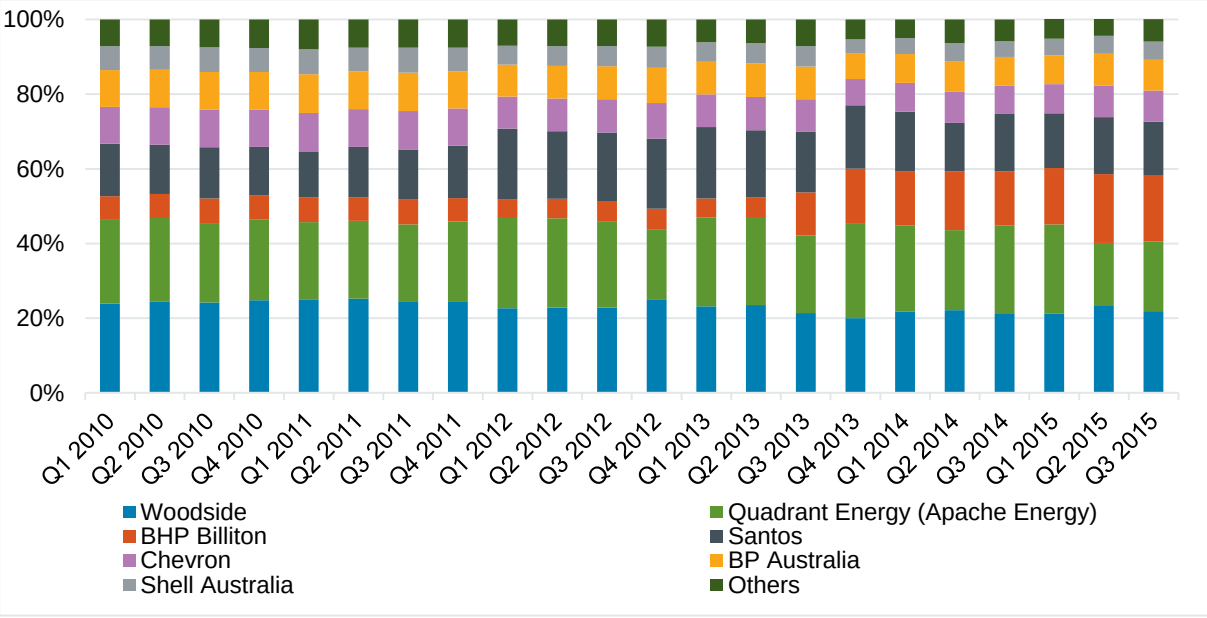
Company	Estimated average supply to WA domestic market (TJ per day)
AWE Limited	7.1
BHP Billiton	179.8
Empire Oil and Gas	6.1
Kufpec	12.4
NWS JV	501.6
Origin Energy	12.0
Quadrant Energy	189.2
Santos	146.7
Tap Oil	7.9
Total	**1062.88**

Source: *IMO estimates based on GBB data and respective company quarterly production reports*

Note: ERM sold its share of the Red Gully gas production facility and is no longer a WA gas supplier.

Figure 2.8 shows how the market share has varied for each domestic gas supplier between 2010 and 2015.

Figure 2.8: Estimated market share of all WA domestic gas suppliers, Q1 2010 to Q3 2015



Source: *IMO estimates from quarterly production reports and GBB data*

Note: Respective shares of the domestic market are estimated using gas production from quarterly reports and applying several assumptions. NWS JV partners supplying the domestic market are estimated using NWS JVs (Domestic Gas JV (DGJV) and Incremental Pipeline Gas JV) shares outlined in Woodside (2012) and assumes the DGJV retains all NWS JV legacy contracts.

The NWS JV partners[21], Quadrant Energy (formerly Apache Energy), Santos and BHP Billiton account for more than 94 per cent of total gas production. Ten other entities account for the remaining 6 per cent.

Each company's market share has been fairly stable over the last five years as the majority of domestic gas was jointly marketed and sold. BHP Billiton has seen the biggest movement, with its share increasing from 6 per cent in 2010 to around 18 per cent in 2015, due to commissioning of its Macedon and Red Gully facilities in 2013.

The expiry of joint marketing authorisation for the NWS and Gorgon JVs, and the commencement of the Wheatstone domestic gas facility, will mean the following additional suppliers are likely to begin selling gas individually to domestic customers during the forecast period:

- BP Australia;
- Chevron Australia;
- Chubu Electric;
- ExxonMobil;
- Kyushu Electric;
- MIMI;
- Osaka Gas;
- PE Wheatstone; and
- Tokyo Gas.

Greater competition in the domestic gas supply market will create opportunities for major gas customers to renegotiate their supply arrangements, and for producers to adjust their position in the market.

[21] BHP Billiton, BP Australia, Chevron, MIMI, Shell Australia and Woodside.

2.3 Overview of WA gas infrastructure

2.3.1 Gas production facilities

Eight gas production facilities supply gas to the WA domestic market. These facilities have a total gas production capacity of 1,477 TJ per day. Ninety-eight per cent of total domestic gas production capacity is connected to the Carnarvon Basin. Table 2.3 shows production statistics for WA's eight domestic gas production facilities.

Table 2.3: Domestic gas production facility average production, Q4 2014 to Q3 2015

Facility	Owner	Nameplate capacity (TJ per day)	Peak production Oct 2014 to Sept 2015	Average production			
				Q4 2014 (TJ per day)	Q1 2015 (TJ per day)	Q2 2015 (TJ per day)	Q3 2015 (TJ per day)
Beharra Springs	AWE Limited and Origin Energy	19.6	18.9	17.3	18.5	10.6	17.9
Dongara	AWE Limited	7	1.5	1.5	1.5	1.3	1.3
Devil Creek	Quadrant Energy and Santos	220	240.2	78.2	101.1	80.6	77.0
KGP	BHP Billiton, BP Australia, Chevron, MIMI, Shell Australia and Woodside	630	619.9	466.8	480.0	477.2	501.6
Macedon	BHP Billiton and Quadrant Energy	200	216.0	148.0	153.6	178.4	179.8
Red Gully	Empire Oil and Gas	10	9.9	7.4	8.3	8.1	7.6
Varanus Island (2 facilities)	Quadrant Energy and Kufpec (Harriet) Quadrant Energy and Santos (East Spar)	390	344.9	284.3	264.7	268.4	276.2
Total		**1,477**	**1,451.3**	**1,003.5**	**1,027.7**	**1,024.6**	**1061.4**

Source: GBB data

Table 2.3 shows that the Karratha Gas Plant (KGP) remained WA's most productive facility during 2015. There were concerns among domestic gas customers that some of KGP's production capacity would be retired when the NWS JV domestic supply contracts expire[22]. However, in November 2014 the NWS JV committed to supplying at least 100 TJ per day to the WA domestic market[23].

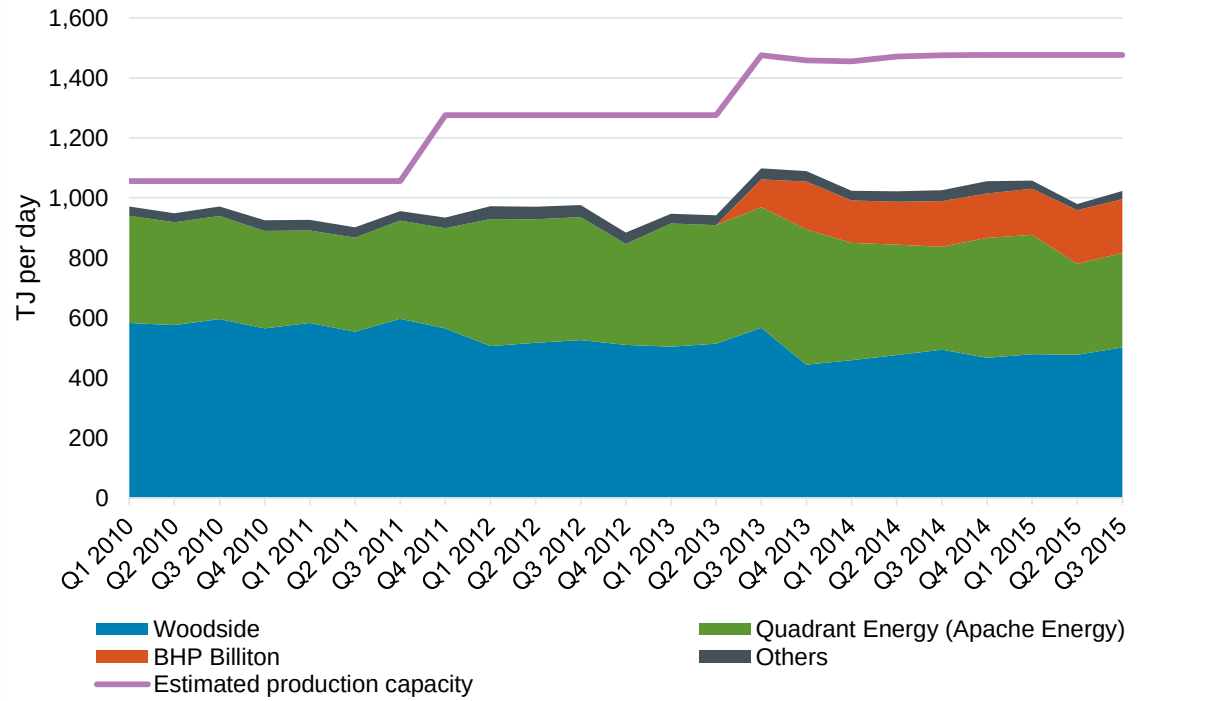
In October 2015, several NWS JV partners confirmed they will market their uncontracted portions of domestic supply from the KGP separately (equity marketing) once joint marketing expires on 1 January 2016. This means it is unlikely any of the KGP's production capacity will be retired in the near future.

Two new large domestic gas production facilities, Gorgon and Wheatstone (both located in the Carnarvon Basin), are expected to commence production in 2016 and 2018 respectively. An expansion to the Gorgon domestic gas facility is also anticipated for 2020. When these facilities are completed, they will add a combined production capacity of approximately 500 TJ per day, increasing total domestic gas production capacity to 1,977 TJ per day by the end of 2024.

2.3.2 Spare production capacity

WA has a large amount of spare gas production capacity. Figure 2.9 shows the estimated production capacity in WA, and the amount of gas actually produced between 2010 and 2015.

Figure 2.9 Domestic gas production capacity and actual gas production by operator, Q1 2010 to Q3 2015



Source: Quarterly production reports from respective corporate websites and GBB data

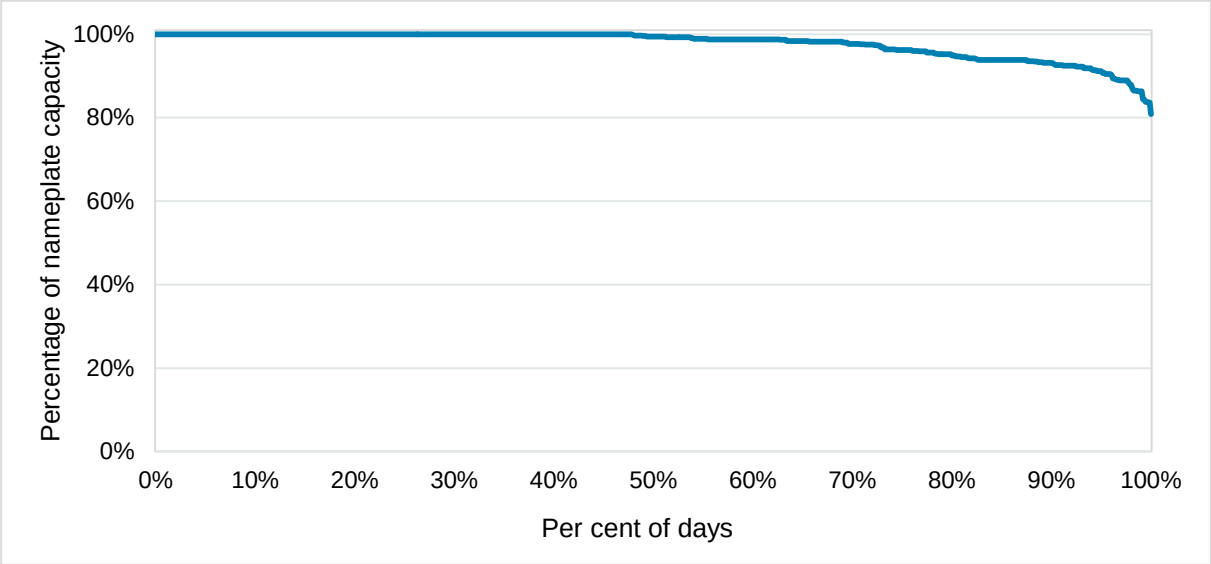
Growth in domestic gas demand has not kept pace with increases in gas production capacity. Despite the introduction of the Devil Creek gas production facility in 2011, and the Macedon and Red Gully facilities in 2013, domestic gas production since 2010 has remained relatively

22 IMO (2013) provides a list of known NWS gas supply contracts.
23 Government of Western Australia (2014).

flat. As a result, there is now substantial spare production capacity in the WA domestic market that is able to support new gas demand.

Figure 2.10 shows the availability of domestic gas production capacity since 1 August 2013.

Figure 2.10: Production capacity availability, 1 August 2013 to 31 August 2015



Source: GBB data

This shows that more than 80 per cent of total gas production capacity, or approximately 1,182 TJ per day is available almost all the time.

The highest peak gas consumption day recorded on the GBB was 1,188 TJ. This suggests the maximum production capacity of 1,477 TJ per day is unlikely to be reached, meaning there is sufficient available capacity to allow new gas customers to enter the WA market.

2.3.3 Gas transmission pipelines

All gas pipelines in WA are privately owned and operated. They are not interconnected with gas pipelines in the east of Australia. The three principal operators of WA gas pipeline infrastructure are:

- APA Group;
- DBNGP Transmission; and
- DDG Operations Pty Ltd.

Figure 2.11 illustrates the major gas transmission pipelines in WA.

Figure 2.11: Gas transmission pipelines in WA

Source: GBB data

There are nine transmission pipeline systems shipping gas to customers. The two largest systems are the Dampier to Bunbury Natural Gas Pipeline (DBNGP) and the Goldfields Gas Pipeline (GGP). These account for almost 80 per cent of gas shipping capacity, and 90 per cent of total domestic gas shipped throughout WA.

In July 2014, APA Group announced it will construct the 292 km Eastern Goldfields Gas Pipeline (EGGP) to ship gas to AngloGold Ashanti's Sunrise Dam JV and Tropicana JV gold mines[24]. This new pipeline will connect to the end of the existing gas lateral at the Murrin Murrin mine and will be registered as part of the GGP. The extension is currently under construction and is anticipated to be completed late 2015 and be in service in 2016.

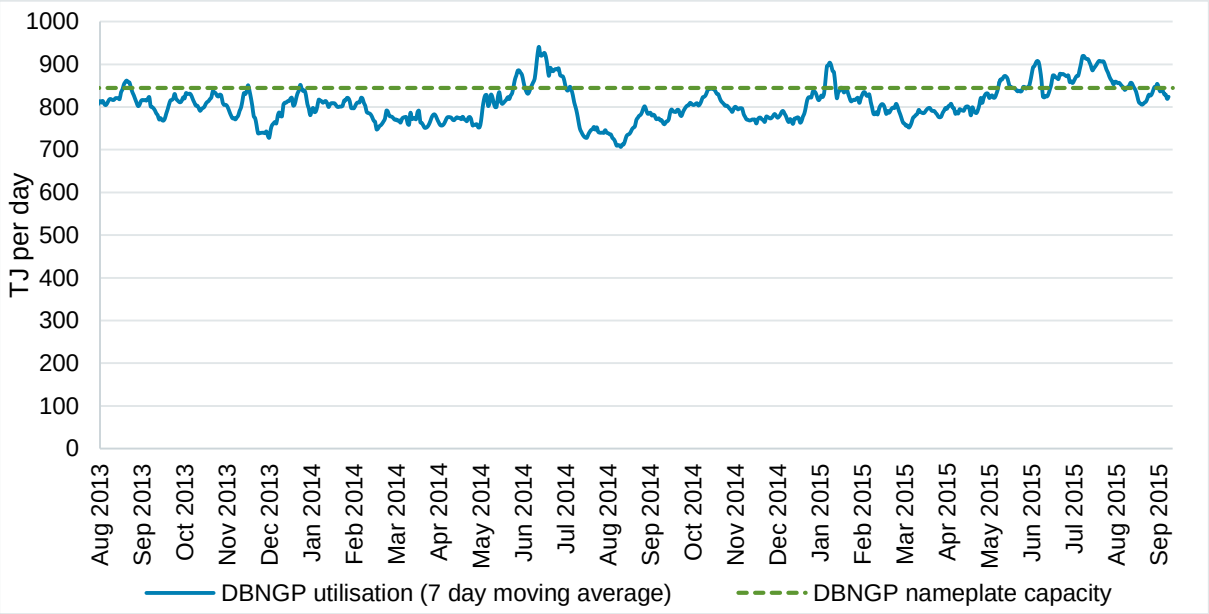
Peak utilisation rates indicate the Telfer Gas Pipeline is fully contracted. The DBNGP is not fully contracted but is fully utilised at peak periods. The Fortescue River Gas Pipeline (FRGP), which commenced operation at the end of the first quarter of 2015, has 40 per cent of its capacity contracted out. The majority of this demand is from Transalta's 125 MW dual-fuelled power station located at Fortescue Metals Group's (FMG) Solomon Hub.

[24] APA Group (2014).

2.3.3.1 The Dampier to Bunbury Natural Gas Pipeline

Figure 2.12 presents the DBNGP's average gas flow against nameplate capacity for 1 August 2013 to 30 September 2015.

Figure 2.12: DBNGP pipeline utilisation, 1 August 2013 to 30 September 2015



Source: GBB data

Figure 2.12 shows:

- the DBNGP shipped more than its nameplate capacity during winter 2014 and summer 2015. This suggests non-firm shipping capacity over the year is not constant and more information could be made available to the market;
- there was a sharp drop in gas flow during August 2014 (this was due to Yara Pilbara's fertiliser facility reducing its gas consumption); and
- the DBNGP ships at least 750 TJ per day in any given day and the utilisation and available capacity varies with the changes in temperature.

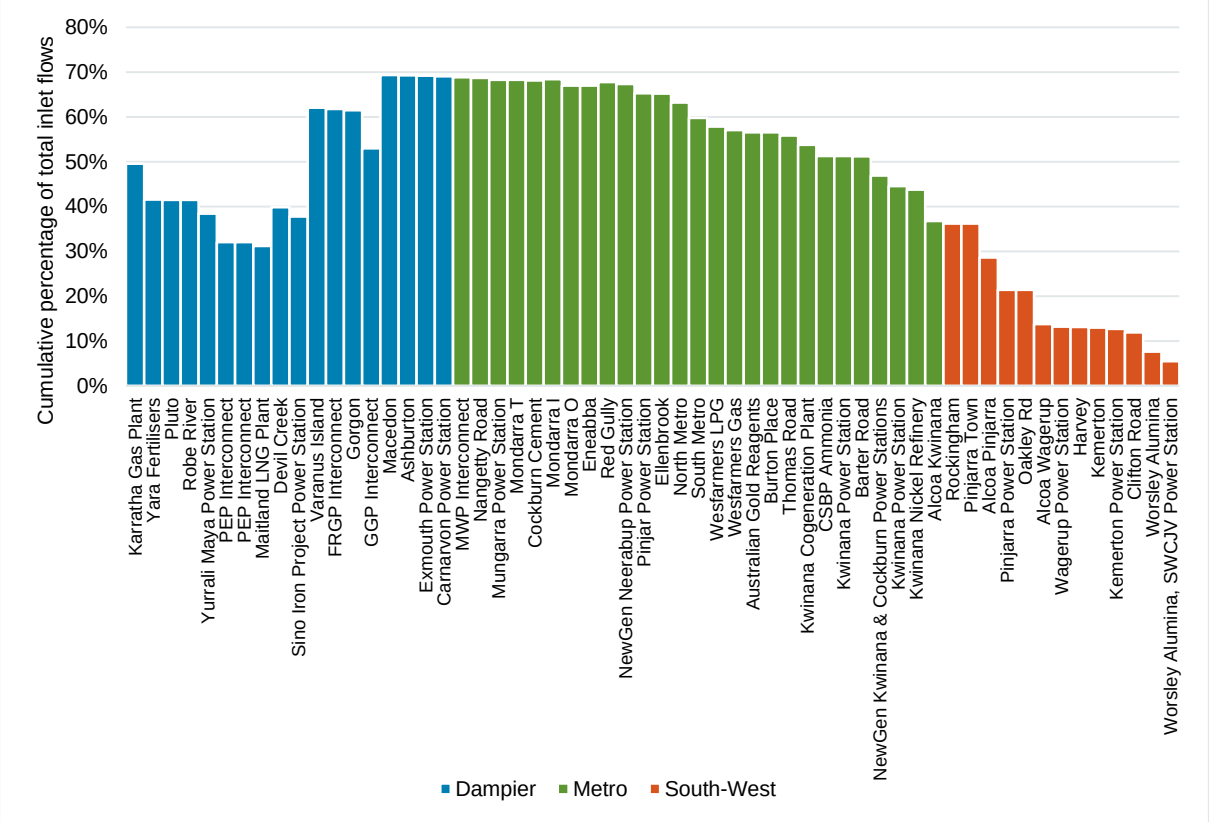
DBNGP Transmission, which operates the pipeline, provides multiple shipping services under standard form contracts. It also offers spot capacity, park and loan services, and seasonal capacity services[25].

Full haul shipping is the most commonly used service on the DBNGP, transporting gas from the major fields off the Dampier Coast in the north to WA's South West and Metropolitan regions, where the majority of gas customers are located.

[25] Non-standard capacity services are highly customised. More information can be obtained by contacting DBNGP directly.

Figure 2.13 illustrates the relative magnitude of gas flows into and out of the DBNGP by each injection and delivery point. It represents an estimate of the average utilisation of the nameplate capacity for the DBNGP and also highlights which portions of the DBNGP are more utilised. For example, Figure 2.13 shows there may be opportunities for the injection of gas into the pipeline around the Red Gully gas production facility (where the Perth Basin is located) where the average utilisation is 68 per cent.

Figure 2.13: Pipeline flows on the DBNGP by connection point and Zone, July 2014 to June 2015

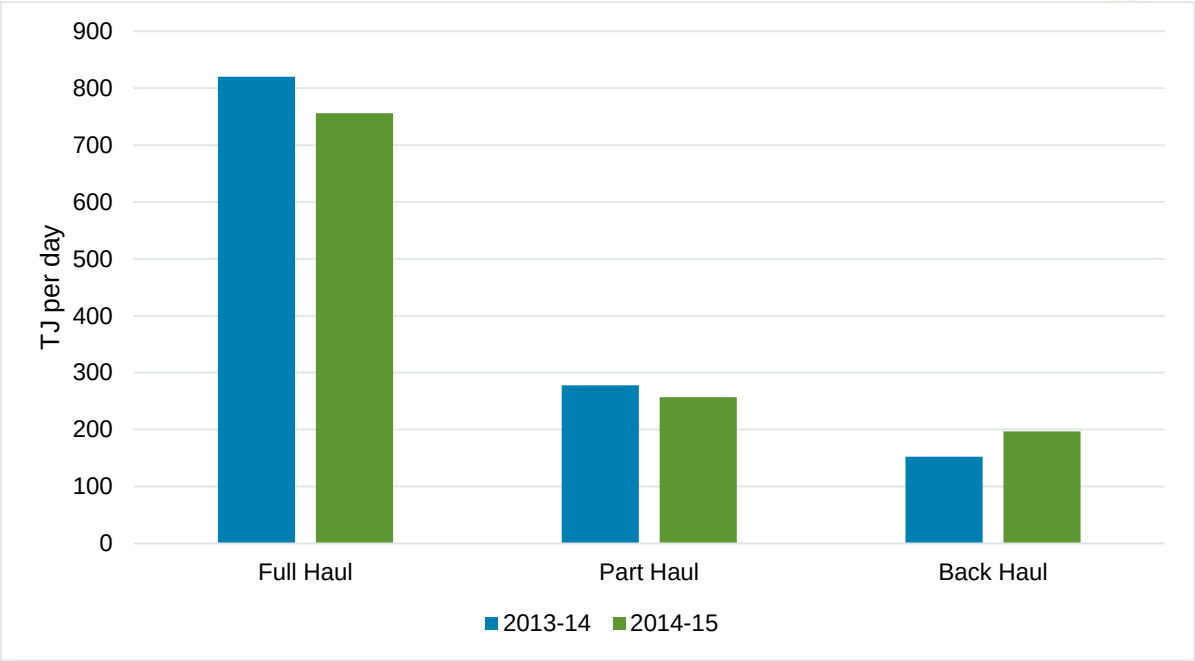


Source: Calculated from GBB data

The largest three net inflow points are at the KGP, Varanus Island and Macedon, which together equal 90 per cent of total inlet flows. The largest three net outflow points are located at the GGP interconnect, Alcoa Pinjarra and Alcoa Wagerup.

Figure 2.14 shows contracted capacity by service type on the DBNGP.

Figure 2.14: DBNGP contracted capacity by type of service



Source: DUET Group (2015)

As at 1 May 2015, 88.5 TJ per day of firm full haul capacity is available on the DBNGP[26]. This presents an opportunity for additional gas shipping, which could supply new gas customers or allow existing facilities to expand.

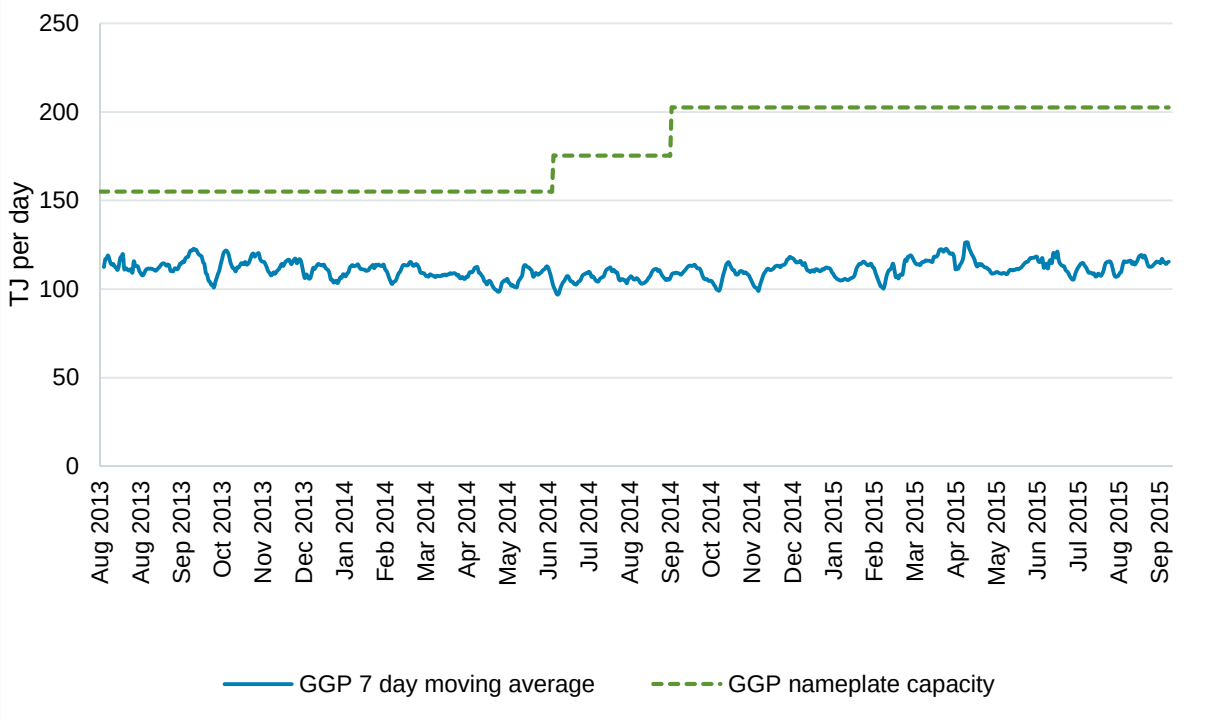
The fall in the contracted capacity for full-haul and part-haul services shows gas consumption in the SWIS region has fallen, while consumption in outside of the SWIS has increased.

[26] DBNGP Transmission (2015).

2.3.3.2 The Goldfields Gas Pipeline

The GGP is WA's second-largest gas pipeline by capacity and throughput. Figure 2.15 shows the GGP's average gas flow against the nameplate capacity for 1 August 2013 to 30 September 2015.

Figure 2.15: GGP pipeline utilisation, 1 August 2013 to 30 September 2015



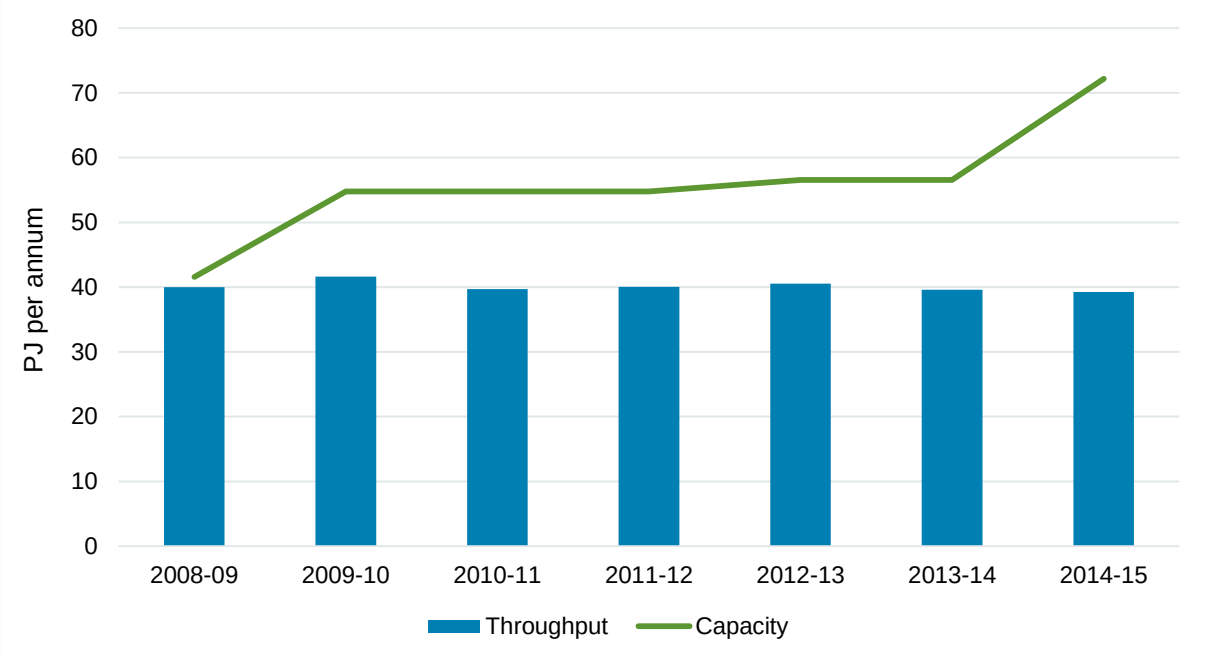
Source: GBB data

Figure 2.15 shows:

- the GGP's utilisation rate is significantly lower than nameplate capacity, indicating there is a significant amount of spare shipping capacity; and
- seasonal variation is minimal, indicating utilisation is largely unaffected by temperature change and consists mainly of shipments for mining loads.

The September 2014 upgrade of the GGP system has increased capacity from about 42 PJ to 72 PJ (see Figure 2.16). Although capacity has increased, throughput has not changed because new gas customers have not yet commenced operations. In the coming year, the IMO expects GGP utilisation to increase due to the start of the Roy Hill mining operations, from the connection of AngloGold Ashanti's Sunrise Dam and Tropicana gold mines to the GGP.

Figure 2.16: GGP capacity and quantity of gas shipped, 2008-09 to 2014-15



Source: GGP's capacity is estimated from AER (2007 to 2014), APA Group's public announcements, submissions to the ERA, GBB data and shipping quantities provided by APA Group

Only a portion of the GGP's capacity is covered by regulated access arrangements (109 TJ per day). The remainder of the GGP's capacity is uncovered. Capacity and throughput on the covered portion of the GGP is charged on a dollar per GJ per kilometre basis. The ERA is currently reviewing the access arrangements for the covered portion of the GGP, and is expected to finalise a decision by the end of 2015.

Table 2.4 shows the amount of spare capacity on the GGP as at July 2015.

Table 2.4: Covered and uncovered capacity on the GBB

	March 2014	July 2015
Spare covered capacity (TJ per day)	3.5	0.0
Total covered capacity (TJ per day)	108.9	109.0
Total uncovered capacity (TJ per day)	46.1	93.5

Source: APA Group (2015) and IMO (2014b)

While the data in Table 2.4 suggests there is no firm capacity available on the covered portion of the GGP, throughput and total pipeline capacity data indicates there remains significant uncovered capacity available. This presents opportunities to gas customers in the Pilbara and Goldfields regions who may seek to utilise this spare capacity.

2.3.3.3 The Eastern Goldfields Gas Pipeline

APA Group expects the EGGP to be operational early 2016. APA Group has applied to register the EGGP as part of the GGP system, therefore the EGGP's capacity is unspecified.

Although the pipeline has been constructed to ship gas to the Sunrise Dam and Tropicana gold mines, the IMO estimates the EGGP will have sufficient spare capacity to meet demand from other mines in the vicinity. Table 2.5 presents a non-exhaustive list of potential projects that lie within 30 km of the EGGP.

Table 2.5: Potential projects situated in the vicinity of the EGGP

Site name	Project type	Estimated distance from the EGGP
Granny Smith	Gold	< 1 km
Mount Morgans	Gold	< 2 km
NiWest	Nickel	10 km
Mt Weld	Phosphate/Rare Earths	10 km
Red October	Gold	15 km
Laverton	Gold/Town	20 km
Fortitude	Gold	25 km
Windarra	Nickel	25 km
Second Fortune	Gold	30 km
Brightstar Alpha	Gold	30 km

Source: APA Group and DMP (2015c)

Note: The majority of the outlined projects are new projects and are not connected to existing gas pipelines.

2.3.3.4 Prospective pipeline developments

There are two new pipelines currently under consideration; the Bunbury to Albany Pipeline and the Great Northern Pipeline.

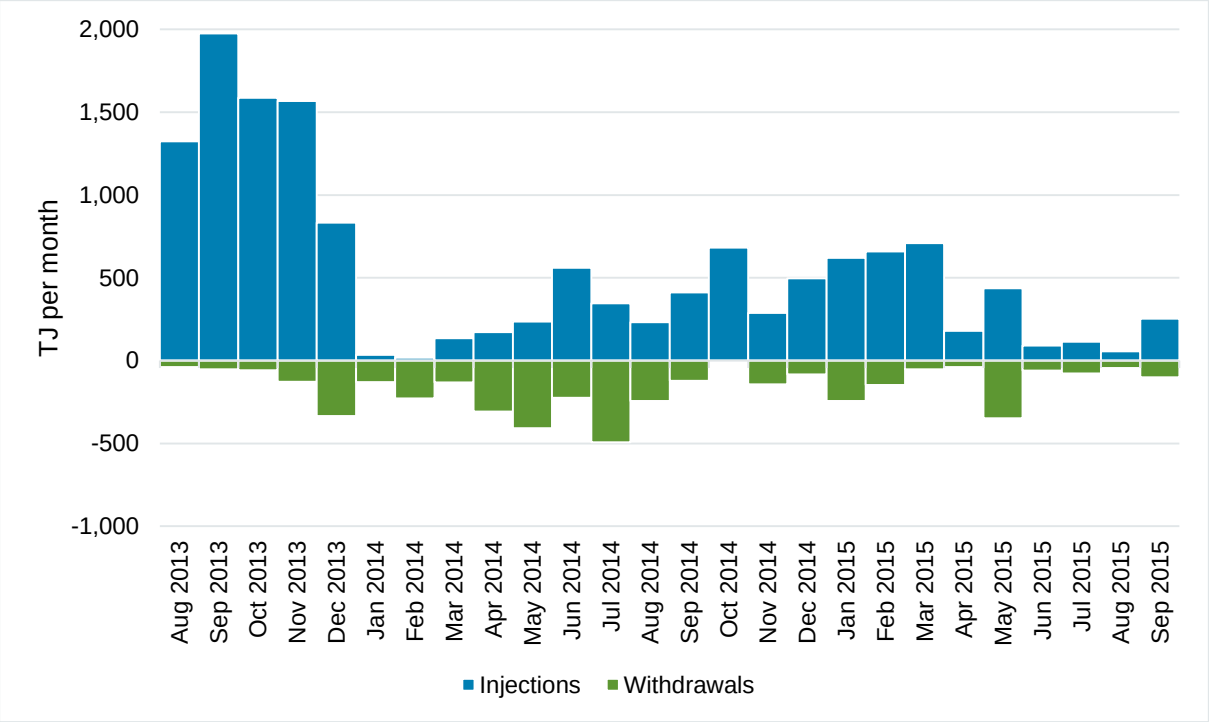
The Bunbury to Albany Pipeline is expected to be 350 km long and have a nameplate capacity of around 12 TJ per day. No planned completion date has been confirmed for this prospective pipeline. The Great Northern Pipeline will be between 550 km and 630 km long, and is anticipated to be completed after 2020.

Due to the uncertainty surrounding these two prospective projects, neither have been considered in the potential supply forecasts.

2.3.4 *Multi-user gas storage facilities*

APA Group's Mondarra Gas Storage Facility (MGSF) is currently the only operational multi-user storage facility in WA[27]. Figure 2.17 shows the volume of gas injected into and withdrawn from the MGSF aggregated by month.

Figure 2.17: MGSF injections and withdrawals, 1 August 2013 to 30 September 2015



Source: GBB data

The large injections in late 2013 were due to the initial fill of gas required to operate the MGSF, and a contractual agreement with Synergy[28] to inject gas into the facility.

The quantities of gas transferred rarely reach the MGSF's maximum injection capacity of 70 TJ per day and maximum withdrawal capacity of 150 TJ per day. This suggests there is scope for market participants to use this facility to manage their gas requirements and/or contractual obligations to a greater extent.

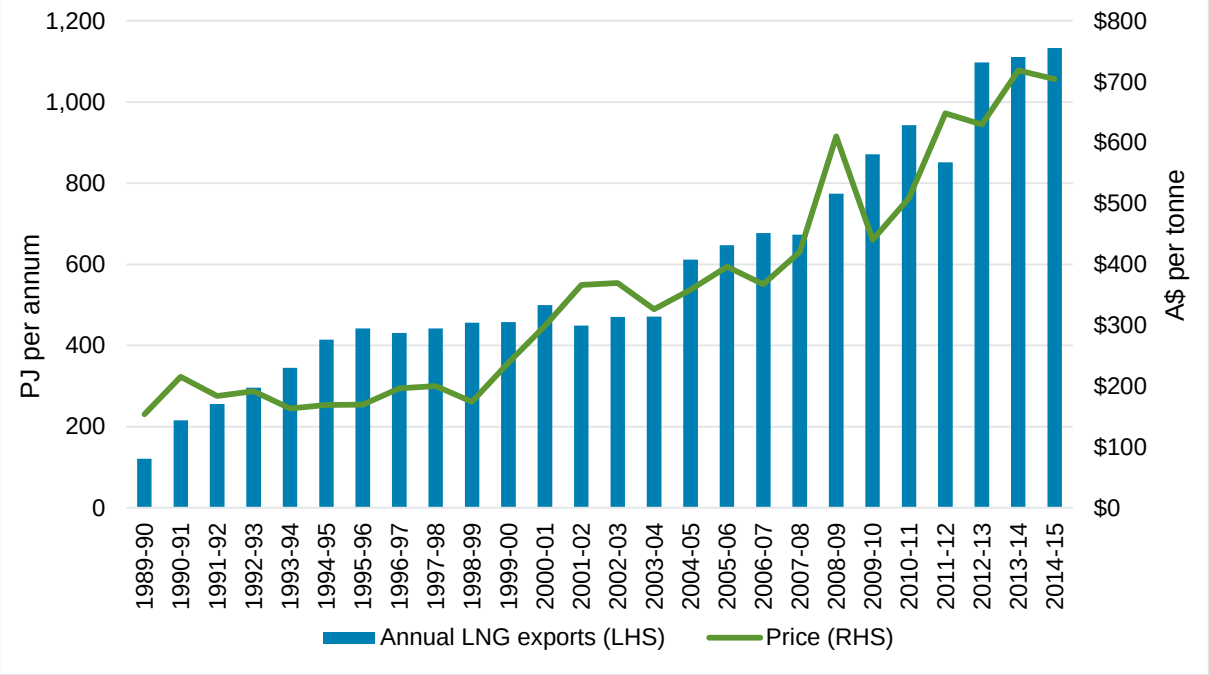
[27] IMO (2013) provides further information about other prospective gas storage facilities.

[28] According to the WA Minister for Energy Media Statement (2011), MGSF has been contracted by Synergy (formerly Verve Energy) to provide up to 90 TJ per day for up to 60 days should WA face a gas supply disruption. This reduces the availability of firm storage capacity for other gas market participants to adequately balance their gas usage when there is a gas supply disruption.

2.4 The WA LNG export market

Figure 2.18 shows the historical quantities and price of WA LNG exports from 1989-90 to 2014-15.

Figure 2.18: WA LNG export volume and prices, 1989-90 to 2014-15



Source: DMP (2015b)

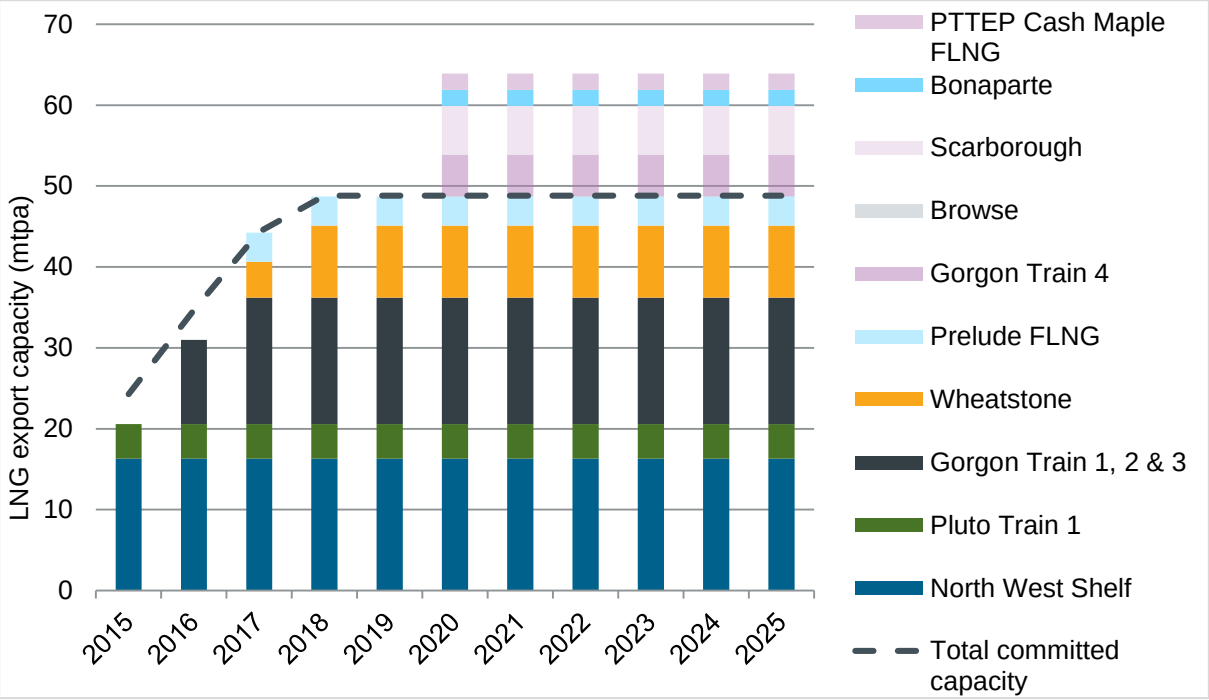
In summary:

- large increases in LNG exports are related to the commencement of new LNG facilities;
- WA's LNG exports only increased by 2 per cent from 2013-14 to 2014-15 when there were no new LNG export facilities;
- while the quantity of LNG exports continues to increase, average export prices have fallen from A$719 to A$705 per tonne in 2014-15, a 2 per cent decrease from 2013-14;
- WA's nominal LNG export prices remained relatively stable from 1989-90 to 1998-99 before rising from 1999-2000 until 2008-09; and
- in 2009-10, LNG prices fell due to a drop in international oil prices during the global financial crisis. Since then average LNG prices have steadily recovered, exceeding A$700 per tonne from 2013-14.

According to OCE forecasts, nominal LNG prices are expected to decrease in 2015-16 due to lower oil prices.

Figure 2.19 shows WA's existing, upcoming and prospective LNG facilities.

Figure 2.19: Total estimated LNG export capacity in WA, 2015 to 2025



Source: *Respective corporate websites, Wood Mackenzie and government publications*

Note: Projects above the committed capacity line are prospective (pre-final investment decision) and may not be realised in the 2016 to 2025 period. Other potential LNG projects, including Caldita-Barossa, Crux, Equus, Poseidon, Thebe and Crown, are not reflected in this figure as there are no known indicative dates and/or export capacities. The Equus project does alter the export capacity as it is likely to be tolled through the NWS. PTTEP refers to PTT Exploration and Production Public Company Limited.

Table 2.6 presents the nameplate capacity of the existing and committed WA LNG export facilities.

Table 2.6: Existing and committed LNG export facilities in WA as at 2015

LNG Facility	Nominal capacity (mtpa)	Commissioned date/ expected commissioning	Status
NWS Train 1	2.5	1989	Operational
NWS Train 2	2.5	1989	Operational
NWS Train 3	2.5	1992	Operational
NWS Train 4	4.4	2004	Operational
NWS Train 5	4.4	2008	Operational
Pluto Train 1	4.3	2012	Operational
Gorgon Train 1	5.2	Anticipated to be operational in early 2016*	Under construction
Gorgon Train 2	5.2	Anticipated to be operational in second half of 2016*	Under construction

LNG Facility	Nominal capacity (mtpa)	Commissioned date/ expected commissioning	Status
Gorgon Train 3	5.2	Anticipated to be operational in in the first half of 2017*	Under construction
Wheatstone Train 1	8.9	Anticipated to be operational in mid-2017**	Under construction
Wheatstone Train 2		Anticipated to be operational in early 2018**	Under construction
Prelude FLNG	3.6	Anticipated to be operational in 2017	Under construction
Total LNG export capacity (by 2025)	48.7		

Source: *North West Shelf corporate, Chevron Australia, Wood Mackenzie and APPEA websites*

Note: *Chevron's 2Q and 3Q earnings announcements. **Wood Mackenzie estimates.

In summary:

- WA's current LNG export production capacity is 20.6 mtpa;
- the NWS JV's LNG facility is currently the largest operational LNG export facility in Australia, with almost twice the export capacity of the next largest facility, the Queensland Curtis LNG facility; and
- when the Gorgon, Wheatstone and Prelude facilities are complete, WA's LNG export capacity will increase by approximately 28.1 mtpa by the end of 2025, to a total of 48.7 mtpa[29]. This will increase WA's share of international LNG capacity to between 12 and 15 per cent.

[29] Woodside (2012). While the nominal LNG capacities are often reported, these capacities are almost never reached. Typical utilisation rates for WA LNG facilities for 2008 to 2012 have ranged from more than 90 per cent to 97.6 per cent of maximum capacity.

2.4.1.1 LNG capacity under consideration in WA

Approximately 40 mtpa of additional LNG projects in WA are under consideration, but yet to attain a favourable final investment decision. Table 2.7 lists the projects under consideration.

Table 2.7: Prospective LNG export facilities under consideration in WA

LNG export facility	Expected operator	Expected capacity (mtpa)	Type	Expected final investment decision
Bonaparte	Engie (formerly GDF Suez) or Santos	2	Likely to be offshore, under consideration*	Unknown*
Browse	Woodside	12**	Three FLNG facilities, FEED phase	FID Anticipated to be 2H-2016**
Equus	Hess	Not applicable. However, gas is likely to be tolled through NWS LNG facility***	Onshore, LNG is likely to be tolled through NWS Karratha gas plant	Hess signed a non-binding letter of intent with NWS to toll gas through the NWS LNG facility*** Expected to be in 2017 or later
Gorgon Train 4	Chevron	5.2	Onshore	Anticipated to be after the completion of Gorgon Train 3^^^
Pluto Train 2	Woodside	4.3	Onshore	Unknown
PTTEP Cash Maple	PTTEP	2^	Potentially FLNG^	Unknown
Scarborough^^	ExxonMobil	6 or 7	Single FLNG facility with five trains and 7 production wells initially	Pre-FEED phase, Anticipated to be 2017 or later
Total WA LNG export capacity under consideration	**~40.1 mtpa**			

Source: *Respective corporate websites*

Notes: *SMH (2015). **Woodside (2015). *** Hess (2014). ^Wood Mackenzie estimates. ^^According to Australian Mining (2014a) the Scarborough project has obtained environmental approval from the Commonwealth Government for an FLNG project. ^^^According to Australian Mining (2014b), the fourth LNG train for the Gorgon project will not be decided until Chevron has gained a better understanding of costs in Australia.

3. Forecast methodology and assumptions

This chapter describes the IMO's methodology for producing the gas demand and supply forecasts in this GSOO. It includes a summary of the inputs used to create each forecast, and a description of the economic assumptions and domestic price forecasts that underpin them.

The forecasting methodology is largely unchanged from previous GSOOs, however, forecasting assumptions have been updated to reflect the most recent information available.

3.1 Gas demand forecast methodology

The IMO presents **domestic** and **total** gas demand forecasts for WA.

- The **domestic demand forecast** considers expected gas consumption by domestic users. This includes all major industrial and commercial loads, electricity generators and customers connected to the gas distribution network.
- The **total gas demand forecast** comprises the domestic demand forecast, plus an estimate of the gas required for LNG export. The total gas demand forecast presents an overall assessment of demand for natural gas produced by WA, as required by section 104(2)(b) of the *Gas Services Information Regulations 2012*.

Sections 3.1.1 and 3.1.2 describe the IMO's methodology for producing each of these forecasts.

3.1.1 Domestic gas demand forecast methodology

The IMO appointed the National Institute of Economic and Industry Research (NIEIR) to produce forecasts of domestic gas demand for each year of the forecast period (2016 to 2025). NIEIR's forecasts have been tested and challenged by the IMO, and were developed using the following inputs:

- gas-fired electricity generation in the SWIS;
- consumption by customers connected to the gas distribution system;
- consumption by transmission-connected customers;
- gas-consuming projects expected to come online during the forecast period;
- domestic gas price outlook;
- forecast WA economic growth;
- forecast international economic growth; and
- outlook for prices of key WA export commodities (including iron ore, alumina, gold and LNG).

NIEIR produced two forecast scenarios of domestic gas demand; a **base** and a **high** scenario:

- the **base scenario** only includes gas-consuming projects that are certain to be in operation during the forecast period. This includes established loads and future projects that have attained a favourable final investment decision[30]. The base scenario does not include prospective gas projects; and
- the **high scenario** includes prospective gas-consuming projects with a sufficient degree of likelihood that they will operate during the forecast period. Prospective projects are assessed against criteria detailed in section 3.1.1.4.

The base and high scenarios represent the lower and upper bounds of a reasonable gas demand range for the forecast period. Gas market participants may wish to consider this range when assessing market opportunities and investment decisions.

Figure 3.1 shows NIEIR's domestic gas demand forecast model.

Figure 3.1: Domestic gas demand forecast model

The following sections summarise how NIEIR applies this model to generate the forecasts.

3.1.1.1 SWIS electricity generation and gas distribution network use

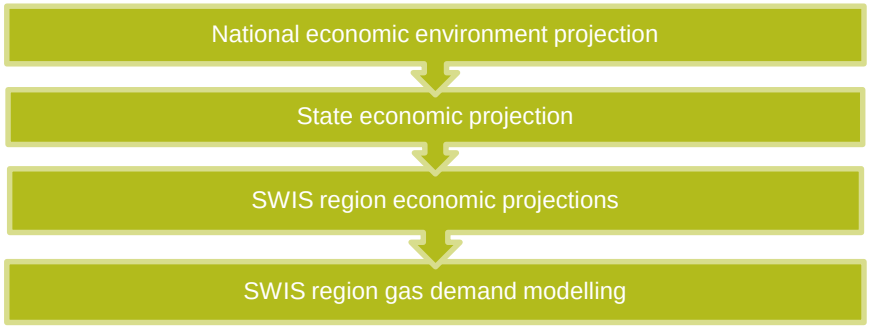
The first step is to consider gas consumption in the South West region, where the majority of the state's population is located. Gas demand in this region is driven by electricity generation and gas consumption by users connected to the gas distribution network.

Gas required to generate electricity in the SWIS is estimated using the electricity forecasts published in the 2014 Electricity Statement of Opportunities. NIEIR applies assumptions regarding the type (for example, peaking or mid-merit) and efficiency of gas-fired generators, as well as the impact of alternative fuel sources.

[30] Either publicly announced by the proponents, reported by DSD or OCE by the end of September 2015.

Gas distribution network demand is estimated using the top-down econometric model summarised in Figure 3.2.

Figure 3.2: NIEIR's top-down forecast methodology



NIEIR's model incorporates economic indicators such as state final demand, gross state product, government investment, private consumption spending, and population. NIEIR considers economic growth forecasts at a national, state and regional level, which are then disaggregated into economic projections for the SWIS region.

An overview of the economic assumptions used in the forecast is provided in section 3.3.

3.1.1.2 Transmission connected customers

NIEIR's model then considers customers connected to the gas transmission network. These customers are typically large mining or processing facilities, many of which are located in the Goldfields, Mid-West and Pilbara regions of WA.

Transmission customers account for around 60 per cent of WA gas demand. These large loads are forecast using historical data drawn from the GBB and from pipeline operators, combined with economic assumptions and international commodity prices. The IMO also meets with major customers to ascertain the latest information about each facility and the customer's corresponding forward plans.

3.1.1.3 Gas price adjustments

Demand forecasts are then adjusted to account for medium to long-term average domestic gas price forecasts. This includes applying an estimate of the demand elasticity to the price-sensitive portion of the gas demand forecast (typically electricity generation and distribution-connected customers).

3.1.1.4 Prospective gas demand

The high demand scenario includes an estimate of gas consumption from prospective projects. Prospective projects are those which are likely to:

- switch from diesel to gas; or
- be developed and consume gas during the forecast period.

These projects are then shortlisted, with each project required to meet at least two of the following criteria to be considered for inclusion in the high scenario demand forecast:

- The project will potentially consume more than 10 TJ per day.
- The project is within 20 km of gas transmission pipelines that are under construction, pipelines that have spare shipping capacity, or new pipelines that have attained a favourable final investment decision.
- The project proponent has a commercial arrangement with a gas pipeline/gas storage company to connect physical infrastructure to withdraw gas.
- It has been reported that the project will use or potentially use existing domestic compressed natural gas (CNG) or LNG facilities.
- The project proponent has applied to the IMO to receive Capacity Credits, either as an electricity generator using gas, or as a dual-fuelled facility that can operate on natural gas.
- The project has a value of greater than A$1 billion.
- The project proponent has attained its required funding for the project.
- The project proponent has announced its intention to consume gas.
- The project proponent has completed investigations into converting from diesel to gas for its operations.
- The project has been identified by existing pipeline operators as a potential gas project.

The shortlisted projects then are assessed further to ascertain the likelihood they will consume gas during the forecast period. Only those projects with a high degree of certainty to proceed are included in the high demand forecast.

For this GSOO the initial project list was reduced from around 200 to 51 projects using the above criteria. From there, the 51 eligible projects were revised down to six prospective projects that are included in the high forecast. The remaining shortlisted projects were excluded for one or more of the following reasons:

- The project relied on the construction of other infrastructure to transport its minerals (for example, Oakajee, Ashburton, Esperance Ports, common user rail system in the Pilbara).
- The project relied on improved commodity prices in the future (for example, uranium, magnetite iron).
- The project relied on the availability of financing.
- The project is located in the SWIS where there is significant spare capacity for electricity generation.
- The project proponent had not conducted any environmental studies.
- The project proponent did not appear to have committed to a project commencement date.

Table 3.1 presents an estimate of the cumulative impact of the six prospective gas demand projects included in the high gas demand forecast.

Table 3.1: Prospective gas demand projects included in the high gas demand forecasts, 2016 to 2025

	2016	2017	2018	2019	2020 and beyond (for each year)
Prospective project consumption (TJ per day)	4.0	24.5	35.1	40.1	51.2
Number of prospective projects	1	4	6	6	6

Source: IMO estimates

3.1.2 Total gas demand forecast methodology

To develop the total gas demand forecast, the IMO estimates the amount of gas required for WA's LNG sector and adds it to NIEIR's domestic gas demand forecast (see Figure 3.3).

Figure 3.3: Total gas demand forecast model

The IMO develops two scenarios for total gas demand – base and high. LNG forecasts are developed using historical data from existing LNG facilities and publicly-available information on the proposed consumption and commencement date of new LNG facilities.

It is important to note that unlike the domestic demand forecast, the base scenario for total gas demand is not restricted to projects that have reached a favourable final investment decision. For example, Chevron's Gorgon LNG expansion is included in the base scenario because Chevron has already commenced marketing LNG from Gorgon Train 4[31]. This indicates the project is likely to proceed within the forecast period.

[31] Argus Media (2014).

Table 3.2 outlines the assumptions applied in each total gas demand scenario.

Table 3.2: Total gas demand scenarios, 2016 to 2025

Parameter	Base scenario	High scenario
Domestic gas demand forecasts	Base	High
Gas feedstock for LNG exports	• NWS (16.3 mtpa) • Pluto LNG (4.3 mtpa) • Gorgon LNG (15.6 mtpa in 2015), • Wheatstone LNG (4.45 mtpa in 2016, and 4.45 mtpa in 2017) • Prelude FLNG (3.6 mtpa in 2017) • Gorgon LNG expansion (5.2 mtpa in 2020)	• Includes assumptions in Base scenario (but assumes a 2019 start for the Gorgon LNG expansion) • Bonaparte (2.0 mtpa in 2019) • Wheatstone LNG expansion (4.45 mtpa in 2020) • Pluto LNG expansion (2.2 mtpa in 2021) • Equus (2 mtpa in 2023)
Gas used for processing LNG	8 per cent of total LNG feedstock	8 per cent of total LNG feedstock

Source: *IMO*

Note: Processing estimates are assumed by taking the low range of processing estimates outlined in Tusiani, Michael D. and Shearer, Gordon (2007).

LNG feedstock requirements are adjusted by the average utilisation rate of LNG facilities operating in WA from Q1 2010 to Q3 2015 outlined in Table 3.3.

Table 3.3: LNG utilisation rates (operational facilities only – percentage of nameplate), 2010 to 2015

Facility	2010	2011	2012	2013	2014	2015 (to end Q3)	Average
KGP	101.4	98.4	95.5	93.5	100.8	96.3	97.9
Pluto	NA	NA	93.6	93.4	108.2	96.1	95.9

Source: *Woodside (2010 to 2015)*

Note: Utilisation is calculated using nameplate capacity, as the IMO does not have access to LNG facility outage data, the utilisation data may periodically exceed 100 per cent.

A 98 per cent utilisation rate applicable from when they commence production is assumed for LNG facilities that are still under construction (Gorgon and Wheatstone).

3.2 Potential gas supply forecast methodology

The IMO's potential gas supply forecast considers two important factors:

1. gas production capacity; and
2. an estimate of gas producers' willingness to supply.

While gas production capacity is an indicator of supply, to base the supply forecast solely on capacity would overstate the amount of gas available to the market. This is because the bulk of gas for the WA domestic market is supplied via confidential supply agreements between wholesale gas suppliers and customers.

Gas producers are not required to provide additional supply to the domestic market on top of these existing agreements. Any decision to do so is entirely discretionary and is influenced by commercial, economic and operational factors. Therefore, while gas producers may have spare capacity, the availability of this potential supply to the domestic market is determined by the prices that can be negotiated and the timing of the requirement.

The IMO forecasts potential gas supply by:

1. estimating the production capacity of each gas producer;
2. estimating the quantity of gas already contracted to the WA domestic market (after considering outages);
3. estimating the quantity of additional (uncontracted) supply that can be made available from each gas producer at the forecast domestic gas price; and
4. aggregating these values to create the overall estimate.

The IMO's forecast model assumes a gas producer will only supply to the domestic market if it is commercially viable, and is managing its operations as a portfolio[32]. Inputs to the supply forecast model include:

- the availability of uncontracted gas production capacity;
- remaining reserves;
- minimum operational requirements of gas production plants;
- estimated production costs[33];
- availability of production capacity[34];
- estimated contracted level[35];
- the required rate of return on investment (LNG-linked or domestic only)[36];
- the share of gas reserves available to the gas producer;
- cost of alternative fuels;
- the opportunity cost of selling the gas;
- prevailing and projected exchange rates; and
- government regulation.

[32] The model also allows the consideration of joint and equity marketing by different entities.
[33] The production costs for facilities applied in this study are estimated by the IMO using the latest Wood Mackenzie cost estimates.
[34] This is calculated using an annualised average of capacity for each facility using GBB data for 1 August 2014 to 30 September 2015.
[35] These are IMO estimates.
[36] Assumed to be a minimum of 10 per cent.

The potential gas supply model assumes there are no constraints to pipeline capacity.

The model also assumes a linear relationship between additional (uncontracted) supply and the domestic gas price. This assumption is applied as follows:

- zero uncontracted supply is assumed if the forecast domestic gas price does not exceed the cost of gas production plus the assumed rate of return;
- for LNG-linked facilities, all spare capacity (subject to the availability rate for the facility) is assumed available for uncontracted supply if the domestic gas price reaches or exceeds the LNG netback price; and
- for domestic gas only facilities, all spare capacity (subject to the availability rate for the facility) is assumed available for uncontracted supply if the domestic gas price reaches an assumed rate of return[37] on top of the cost of production.

With the current joint marketing arrangements for domestic gas set to expire from 1 January 2016, the IMO has updated its assumptions from the 2014 GSOO by allowing for separate marketing of uncontracted gas supply by the NWS and Gorgon JVs until the end of the forecast period.

3.2.1 The end of joint marketing of domestic gas for NWS and Gorgon JVs

Gas from the NWS JV has been jointly supplied since 1984. Joint marketing for the Gorgon JV was approved in 2009[38]. On 31 December 2015, the joint marketing authorisation for both JVs will expire.

The IMO understands that participants of the NWS and Gorgon JVs have not applied for an extension of their respective joint marketing authorisations. This means from 1 January 2016, each market participant is expected to market its share of gas production from their respective JVs individually. The IMO has factored this change into the potential gas supply forecast methodology.

The end of joint marketing authorisation for the NWS and Gorgon JVs is a significant change to the dynamics of the WA domestic gas market. This is because it will increase the number of individual gas suppliers, which will increase competition. Greater competition may provide opportunities for customers to renegotiate their gas requirements, or secure a more competitive price. However, this does not influence all the existing NWS gas contracts.

The end of joint marketing will also influence how domestic gas is managed from the suppliers' perspective. Market participants are more likely to adopt a portfolio approach to managing domestic gas contracts and supply risks. The majority of NWS and Gorgon JV partners also own rights to gas supply from other WA domestic gas production facilities (for example, BHP Billiton also owns a portion of production from the Macedon project).

There is also potential for new domestic joint supply arrangements. Some NWS or Gorgon JV partners may consider entering into new joint marketing agreements (subject to their share of the domestic market and/or authorisation from the Australian Competition and Consumer Commission).

[37] Estimated to be 25 per cent.
[38] Australian Competition and Consumer Commission (2009).

Table 3.4 lists the NWS and Gorgon JV partners. Only BHP Billiton currently supplies gas to the domestic market via the Macedon gas production facility. The expiry of the joint marketing authorisation, coupled with the commencement of the Gorgon facility will likely increase the number of domestic gas suppliers from 6 to 15.

Table 3.4: Joint venture partners in the NWS and Gorgon projects

Company	Current JV	Equity share
BHP Billiton	NWS (DGJV, IPJV)	8.33%, 16.67%
BP	NWS (DGJV, IPJV)	16.67%, 16.67%
Chevron	NWS (DGJV, IPJV) and Gorgon	16.67%, 47.3% (Gorgon)
Chubu Electric Power	Gorgon	0.417%
ExxonMobil	Gorgon	25%
MIMI	NWS (IPJV)	16.67%
Osaka Gas	Gorgon	1.25%
Shell	NWS (DGJV, IPJV) and Gorgon	8.33%, 16.67% (NWS) 25% (Gorgon)
Tokyo Gas	Gorgon	1%
Woodside	NWS (DGJV, IPJV)	50%, 16.67%

Source: Corporate websites and public reports

Note: DGJV – Domestic Gas JV, IPJV – Incremental Gas JV. Totals may not add to 100 per cent due to rounding.

3.3 Input assumptions

There is a direct relationship between the economic environment and gas supply and demand in the WA market. Historically, gas supply and demand has been influenced by:

- productivity of large commercial and industrial loads, whose gas consumption typically increases or decreases in line with the changes in the level of economic activity in the South West region of WA;
- the level of discretionary spending by small gas users;
- increased electricity consumption, which in turn drives investment in new gas-fired generation. Note the influence of this factor has declined as renewable electricity generation technology becomes an attractive alternative to gas and demand side response has an effect;
- the outlook for export-based commodities in the resources sector. Strong growth in commodity prices tends to stimulate investment in new mining operations and minerals processing facilities. Such investment has historically driven demand for gas in regional and remote WA; and

- LNG export pricing and demand, which affects the domestic gas price and WA gas producers' willingness to supply the domestic market.

Over the past decade WA's growth has been driven by investment in the resources sector, which peaked at $85 billion in 2013-14. The rate of economic growth has slowed in the past year as international commodity markets have softened and several large resources projects have transitioned from construction to production phases.

This section provides an overview of WA's historical and forecast economic growth, as well as an outlook of the resources and LNG sector. It also provides an overview of the IMO's domestic price forecasts and methodology. These economic assumptions are key inputs into the domestic demand and supply forecasts.

3.3.1 WA's historical economic growth

Table 3.5 shows growth rates of several key economic indicators between 2009-10 and 2013-14. National gross domestic product growth is provided for comparison.

Table 3.5: Growth in key economic indicators, 2009-10 to 2013-14

	2009-10 (%)	2010-11 (%)	2011-12 (%)	2012-13 (%)	2013-14 (%)
WA					
State final demand	2.3	5.8	15.8	3.6	-1.8
Net exports	15.8	5.9	-1.3	14.0	9.6
Gross state product	4.1	4.7	7.6	4.6	5.5
Industry gross value added	4.5	4.7	7.7	4.8	5.8
Agriculture	-6.4	-30.8	37.1	-8.2	58.6
Mining	10.2	8.50	7.3	10.5	11.2
Manufacturing	-0.7	6.8	7.4	-4.2	-3.2
Electricity, gas, water and waste services	5.0	10.1	9.2	0.5	0.9
Construction	1.0	1.1	18.1	0.2	3.6
Services	3.2	4.9	4.4	3.6	2.3
Australia					
Gross domestic product	2.0	2.3	3.7	2.5	2.5

Source: ABS (2014a) and ABS (2015)

In summary:

- state final demand, a measure of all domestic consumption, grew at an average annual rate of 5.7 per cent between 2009-10 and 2013-14. This was mainly associated with strong growth in business investment in the mining sector; and

- gross state product (GSP), a measure of all state output (taking into account net exports), grew at an average annual rate of 5.6 per cent during the same period.

3.3.2 WA's forecast economic growth

The IMO engaged NIEIR to develop projections of the WA economy. Table 3.6 shows NIEIR's base forecast of major economic indicators for WA for 2015-16 to 2019-20.

Table 3.6: Forecast growth in key economic indicators, 2015-16 to 2019-20

	2015-16	2016-17	2017-18	2018-19	2019-20
	(%)	(%)	(%)	(%)	(%)
Private consumption	2.53	2.18	2.27	2.69	2.43
Private dwelling investment	4.86	4.10	1.66	0.78	-0.73
Business investment	-16.17	-8.10	-3.30	-4.49	2.47
Government consumption	2.79	3.12	2.66	2.84	2.12
Government investment	2.69	-2.49	-3.54	3.47	6.78
State final demand	-3.11	-0.52	0.74	1.01	2.43
Gross state product	2.81	3.55	3.35	2.13	2.01
Population	2.19	2.02	1.91	1.90	1.89
Unemployment	5.87	6.12	6.29	6.48	6.38

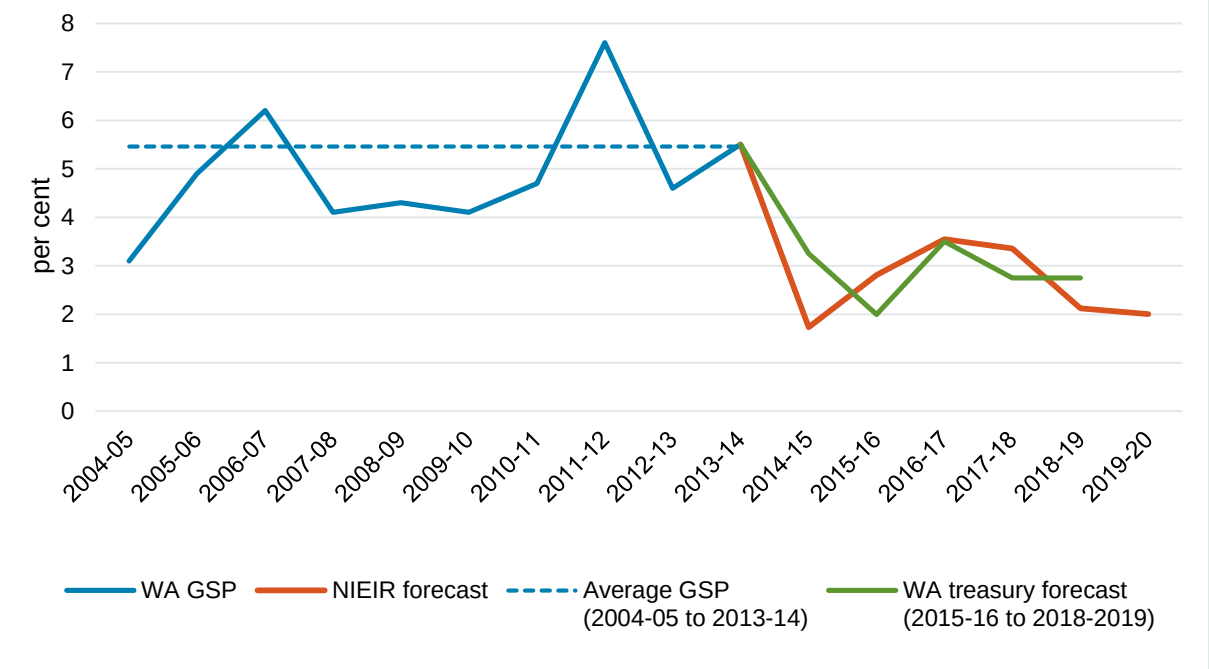
Source: NIEIR forecasts

In summary:

- NIEIR suggests that the softening of the WA economy observed in 2014-15 will continue into 2015-16. Economic activity will not return to levels higher than 3 per cent until 2016-17;
- NIEIR expects GSP growth to remain well below the long-term average of 4.5 per cent, driven in the short-term by falls in private business investment as several major iron ore and natural gas projects move from construction to production; and
- domestic WA consumption, as measured by state final demand, is forecast to recover over the forecast period from the 2015-16 low of -3.1 per cent, improving to 2.4 per cent by 2019-20.

Figure 3.4 shows actual growth in WA's GSP between 2004-05 and 2013-14, and compares NIEIR's base GSP forecasts with WA Treasury forecasts (published in the 2015-16 State Budget).

Figure 3.4: Comparison of GSP forecasts, NIEIR and WA Treasury, 2004-05 to 2019-20



Source: ABS (2015), WA Department of Treasury (2015) and NIEIR

See Appendix B for NIEIR's high economic forecast scenario values.

3.3.3 Resources sector outlook

The following sections summarise the impact of the economic outlook for the iron ore, gold, alumina and other base metals sectors on gas consumption. LNG projects are discussed in section 3.3.4.

3.3.3.1 Iron ore

Iron ore remains the state's most valuable mineral commodity, accounting for 54 per cent of WA's mineral and petroleum exports by value in 2014-15[39], or $53.8 billion.

Iron ore prices have fallen over the past five years. As illustrated in Figure 3.5, the average monthly price in calendar year 2015 was A$75 per tonne, a sharp fall from the high of A$163 in 2011.

Figure 3.5: Iron ore prices per dry metric tonne ($A/62 per cent iron content), January 2011 to June 2015

Source: DMP (2015b)

The decline in price has caused iron ore producers to change focus from expansion to productivity and cost optimisation. For example in June 2015, BHP Billiton announced the deferral of capacity expansion at Port Hedland[40], while continuing with efforts to reduce unit costs by 25 per cent[41].

While the lack of investment to support capacity growth will limit the need for new gas supplies, productivity and cost optimisation programs may see higher cost fuel sources substituted for gas. FMG, the third-largest producer of iron ore in Australia, has switched electricity generation at its Solomon Hub from diesel to gas[42]. Rio Tinto and BHP Billiton are also reported to be considering greater use of gas in their mining operations[43].

39 DMP (2015a).
40 BHP Billiton (2015).
41 BHP Billiton (2014).
42 FMG (2014).
43 AFR (2014).

3.3.3.2 Gold

Gold is WA's second most valuable mineral commodity, accounting for approximately 9 per cent of mineral and petroleum exports in 2014-15[44]. Currently, the four gold mines in WA use natural gas to generate electricity. The Sunrise Dam and Tropicana gold mines are also expected to use gas when the EGGP is completed (expected to be January 2016[45]).

Without any prospect of increases in the gold price, the gold sector (similar to the iron ore sector) is focusing on efficiency measures to remain profitable. As there are no new major gold projects at an advanced stage of development, the IMO considers the gold sector will not make a significant contribution to gas consumption growth in the forecast period.

3.3.3.3 Alumina

Though not a large export commodity for WA (only accounting for 5.1 per cent of mineral and petroleum exports in 2014-15[46]), the production of alumina is energy intensive, making it the largest gas-consuming sector in WA. This industry accounts for approximately one third of total domestic gas consumption.

Production from Alcoa's WA refineries – Kwinana and Wagerup – is expected to remain unchanged over the forecast period, while production from Pinjarra is expected to expand from 4.2 mtpa to 5 mtpa over the forecast period[47]. Alcoa has indicated the majority of production increases are related to increases in facility efficiency. As a result, the IMO does not consider that gas consumption related to alumina production will change materially over the forecast period.

3.3.3.4 Other base metals

Other base metals mined in WA include copper, nickel and lead. These commodities accounted for approximately 2 per cent of WA mineral and petroleum exports in 2014-15[48].

Domestic gas consumption relating to these commodities mostly occurs in nickel mines, with the Murrin Murrin nickel-cobalt mine being the largest gas customer in this sector. While the outlook for the base metals sector is considered in the gas demand forecasts, the IMO does not expect it to be a key driver of gas demand during the forecast period.

3.3.4 LNG outlook

The WA domestic gas market is directly linked to the international gas market. The strength of the international market, LNG netback prices, global demand and LNG production capacity all influence domestic gas prices, which ultimately affect potential domestic supply.

By the end of 2025, there will be at least five LNG export facilities in WA:

- Gorgon;
- NWS;

44 DMP (2015a).
45 APA Group (2014).
46 DMP (2015a).
47 The West Australian (2015).
48 DMP (2015a).

- Pluto;
- Prelude; and
- Wheatstone.

The WA Government's domestic gas reservation policy means that some or all of these production facilities will be required to reserve some supply for domestic consumption. Further, the domestic gas price and competition in the LNG export market will directly impact gas producers' willingness to supply the domestic market. As a result, the outlook for the LNG market is a key input into WA's domestic supply and demand forecasts.

3.3.4.1 LNG prices

The recent fall in oil prices has had a sharp impact on the international price of gas, particularly in the Asia Pacific region, where most of WA's LNG is exported. Currently, more than half of all gas contracts in the Asia Pacific region are oil price escalated[49].

The rapid fall in oil prices has created an uncertain environment in the international LNG market. Asia Pacific LNG customers are no longer willing to pay premium LNG prices relative to other regions and are looking to negotiate flexible LNG supply contracts that are not based on oil price escalation.

For example, Anadarko signed Asia Pacific sales contracts using a hybrid pricing model for Mozambique's gas in 2014[50]. Tokyo Electric Power Company (TEPCO) recently signed a 17-year LNG agreement with BP Singapore that indexes its LNG prices to Henry Hub prices[51]. Spot and short-term LNG trading is also increasing, accounting for 29 per cent of LNG contracts traded in 2014 (compared to 25 per cent in 2012).

LNG producers also face a changing LNG supply market. The United States of America (US) is forecast to become a net exporter of LNG, with a number of new suppliers expected to come on line at the end of 2015[52]. These new suppliers are able to offer different LNG pricing models (such as hub linked pricing, tolling, hybrids and others) and terms (a lack of destination clauses[53]) that compete with existing LNG contracts.

3.3.4.2 LNG demand

LNG demand impacts international LNG prices, which are an input into the WA domestic gas forecasts. LNG demand is expected to be weak over the next few years because:

- South Korea and Japan, the world's largest LNG customers, are likely to reduce LNG consumption in the short-term as they restart their nuclear reactors to generate electricity; and
- Chinese gas market reforms between 2013 and 2015 have increased its wholesale gas prices.

49 IGU (2015b).
50 Forbes (2014).
51 Tokyo Electric Power Company (2014).
52 Fuel Fix (2015).
53 This was outlined by Bakers at the Gastech 2015 Singapore Conference.

However, the medium to long-term demand outlook for the Asia Pacific LNG market remains positive. This is because:

- Indonesia is expected to start importing LNG around 2018[54];
- India is expected to increase LNG imports[55];
- despite switching on several of its nuclear reactors during 2015, industry experts consider Japan will continue to use LNG[56] to meet its energy requirements over the long-term;
- gas demand in South East Asia continues to grow. Rapid urbanisation and economic development through government reforms are encouraging greater use of gas in industrial and residential sectors, and power generation[57];
- China has committed to reduce carbon emissions at the 2015 United Nations Climate Change Conference in Paris[58] and is likely to consider gas as a substitute for fuels such as coal, which release more carbon;
- the G7 countries have pledged to phase out the use of fossil fuels[59] by the end of the century[60] and are likely to use gas as a transition fuel towards cleaner energy sources; and
- an LNG trading and transhipment hub is being developed in Singapore[61].

3.3.4.3 LNG supply

The international LNG supply outlook directly impacts WA LNG producers' willingness to supply the WA domestic gas market. Though the export market remains the primary focus for WA gas producers, low international prices and increased competition from other LNG-exporting countries may mean the domestic market becomes more attractive.

Australia is currently the third largest LNG exporter in the world, after Qatar and Malaysia[62]. In 2014, Australia supplied 23.3 mt of LNG, accounting for approximately 10 per cent of international LNG supply. By the end of 2018, the Gorgon, Wheatstone and Prelude LNG projects in WA will increase Australia's LNG export capacity to 86.6 mtpa. Australia will have sufficient capacity to meet 20 to 25 percent of international LNG demand[63].

Despite this strong position, Australia will face intense competition from other countries supplying LNG into the Asia Pacific market. Key competitors are:

- **Qatar** – while Australia is expected to surpass Qatar as the world's largest LNG exporter in 2018, Qatar has the capability to increase LNG supply. In June 2015, the Qatari Government announced it had sufficient gas reserves to last for another 138 years at current rates of gas production[64];

54 Bloomberg (2013a).
55 Wood Mackenzie estimates.
56 Reuters (2015a).
57 IEA (2015b).
58 Whitehouse (2015).
59 ABC News (2015).
60 Natural gas is a transitional fuel in this process.
61 HFW (2013).
62 IGU (2015a), Qatar and Malaysia accounted for about 31.9 and 10.4 per cent, respectively, of international LNG exports in 2014.
63 Innovative Energy Consulting (2012), assuming existing LNG export capacity that has approvals remains unchanged.
64 Arabian Business (2015).

- **US** – gas production in the US increased significantly between January 2014 and May 2015. The US is likely to export these excess quantities of gas into the international market, and is expected to switch from being a net importer to a net exporter of natural gas by 2020[65];

- **Canada** – the passing of the LNG Projects Agreements Act in British Columbia (July 2015) has reduced uncertainty and improved the prospects of LNG projects in Canada; and

- **Russia** – gas supply from Russia to the international LNG market continues to be an unknown. Ongoing international trade sanctions and counter-sanctions have limited normal commercial relations with the EU[66]. However, gas exports from Russia to China appear unaffected, as demonstrated by commencement of the Power of Siberia gas pipeline to China[67] and the introduction of China National Petroleum Corporation as a stakeholder in the Yamal LNG project[68].

Competition from these and other countries is likely to influence the LNG export price WA producers can achieve, thereby impacting the domestic gas price and potential gas supply.

3.3.5 Domestic gas price forecasts

A key input to the gas supply and demand forecasts is the domestic gas price. As previously discussed, uncontracted gas supply and gas demand in the SWIS region is price-sensitive. Therefore, the IMO produces a domestic gas forecast to test the robustness of supply and demand projections.

The IMO considers the following variables when developing the domestic price forecasts:

- future oil prices;
- future LNG prices;
- LNG netback prices;
- projected exchange rates; and
- recoverable WA gas reserves.

65 OCE (2015d).
66 This was outlined by Professor Jonathan Stern in his presentation on Russia at the Gastech 2015 conference Singapore, 28 October 2015.
67 Russian Times (2015).
68 Bloomberg (2013b).

These scenarios represent the likely range of average medium to long-term[69] contract prices for the forecast period.

Table 3.7: Forecast gas price parameters, 2016 to 2025

Parameter		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
International oil prices (US$/barrel)	Base	50.8	54.4	59.1	62.3	55.6	54.3	63.9	67.5	71.5	76.6
	High	53.9	63.6	68.3	72.4	67.5	66.3	75.7	81.2	83.5	87.6
LNG prices-real (US$/MMBtu)	Base	7.1	7.6	8.3	8.7	7.8	7.6	8.9	9.5	10.2	10.7
	High	7.5	8.9	9.6	10.1	9.5	9.3	10.6	10.9	11.4	11.6
Shipping and liquefaction costs (US$/MMBtu)	All	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Exchange rates (A$/US$)	All	0.72	0.71	0.73	0.71	0.66	0.63	0.63	0.65	0.66	0.66
Recoverable reserves (bcm)	Base	4407	4390	4350	4308	4250	4188	4120	4048	3975	3899
	High	4407	4391	4355	4310	4256	4195	4119	4041	3958	3874

Source: *NIEIR forecasts 2015 to 2025*

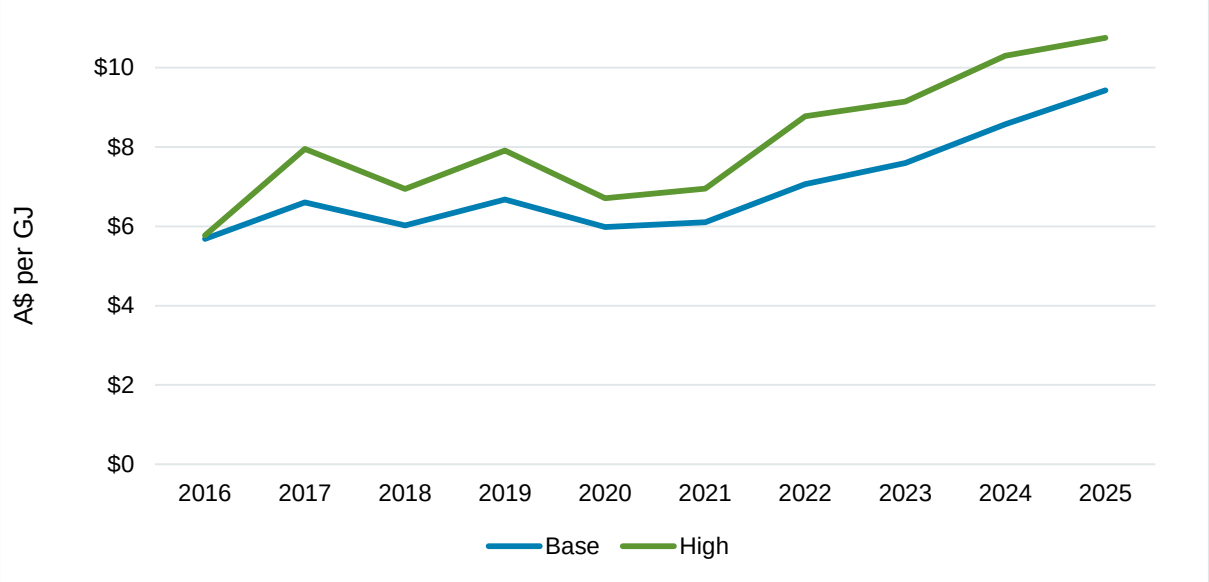
Note: Scenarios outlined in this table are developed by the IMO and NIEIR and do not represent any information provided by existing market participants. International oil prices are an average of Brent, Light Sweet Crude and West Texas Intermediate.

As shown in Table 3.7, over the forecast period, international oil prices, and consequently LNG prices, will trend back to a long-run average from the recent historic lows. However, in 2020 and 2021, NIEIR forecasts oil prices to temporarily decrease on the basis of a supply-side augmentation to production capacity in previous years. The supply-side augmentation is triggered by increasing economic activity in OECD countries, which drives oil demand. Generally speaking, oil price variability is driven by the lag between demand growth increasing prices and new supply coming online.

[69] A medium to long-term gas contract is a gas supply agreement that has a term of four years or longer.

Figure 3.6 shows the IMO's forecast of medium to long-term average (ex-plant) new contract gas prices for 2016 to 2025.

Figure 3.6: Forecast medium to long-term average (ex-plant) new domestic contract gas prices (real), 2016 to 2025



Source: IMO forecasts 2016 to 2025

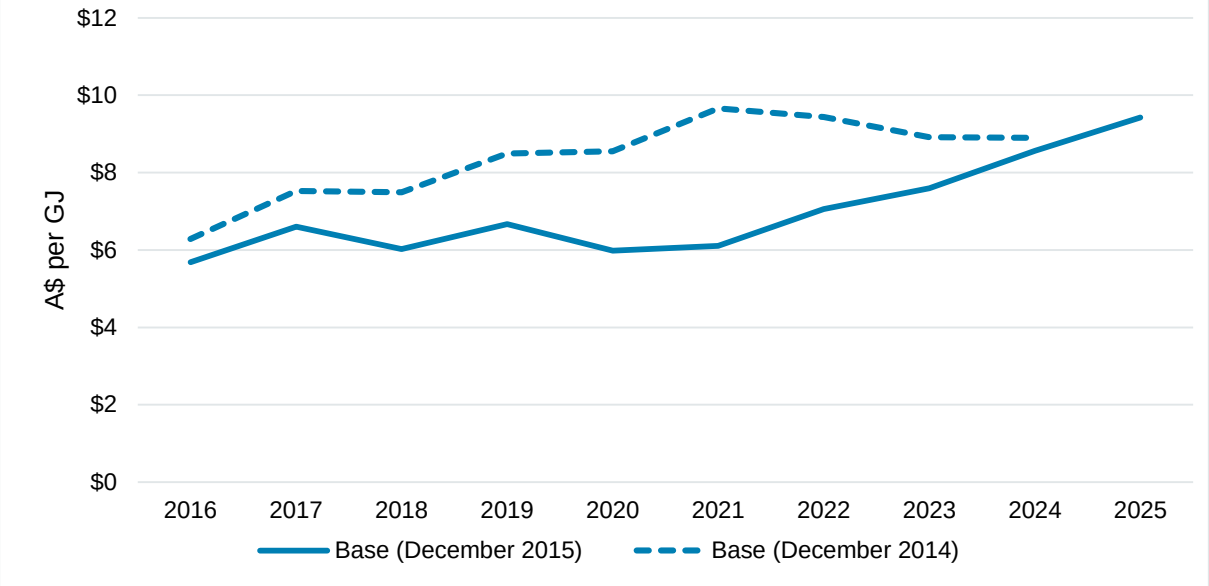
In summary, the IMO considers that:

- domestic gas prices will rise between 2016 and 2025 due to the expected recovery of international oil prices and the continued weakening of the Australian dollar; and
- anticipated improvement in the US economy and likely increases in US interest rates, will increase LNG netback prices in Australian dollar terms. This should drive an increase in domestic gas prices despite lower forecasts for Asia Pacific LNG prices.

The IMO's price forecasts are indicative only. Actual prices negotiated between any two contracting parties are influenced by a range of commercial and competitive factors specific to the contracting parties. It is also important to note that short-term gas contracts are not considered in the forecasts due to the relatively small scale of the short-term market.

Figure 3.7 compares the average new medium to long-term contract gas price projections developed for the 2014 GSOO and this GSOO. The main driver for the sharp decrease in forecast gas prices since the 2014 GSOO is the sharp fall in international oil prices observed recently.

Figure 3.7: Comparison of the medium to long-term forecast contract prices (real), December 2014 and 2015 GSOOs, 2016 to 2025



Source: NIEIR forecasts 2015 to 2024 and 2016 to 2025

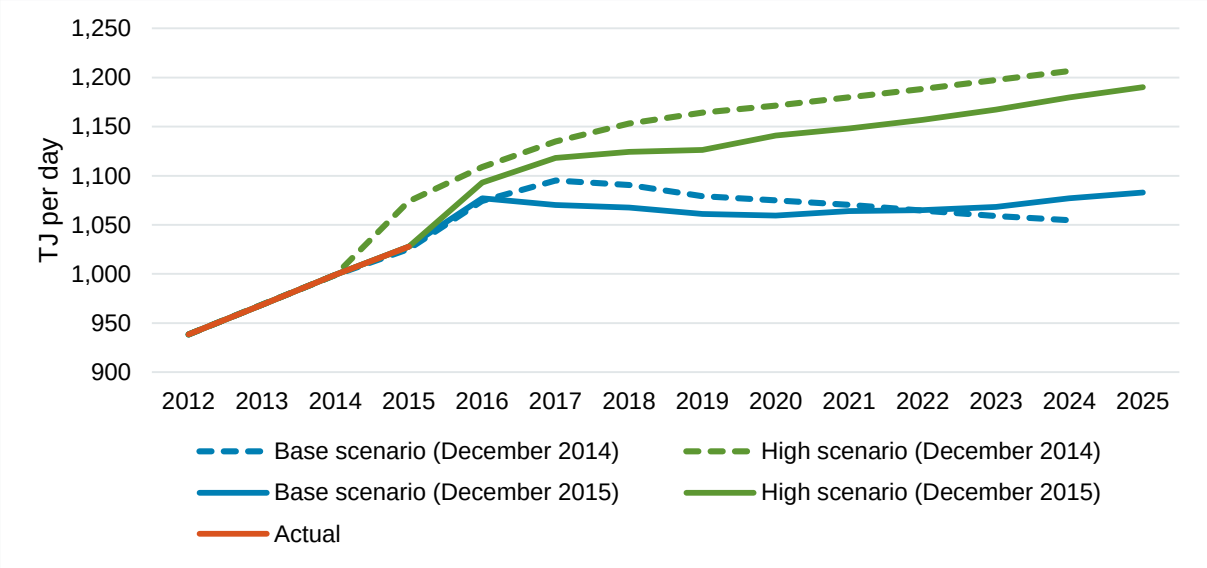
4. Forecasts

This chapter presents forecasts of WA domestic gas demand and supply for 2016 to 2025, and the supply-demand balance. It includes projections of total gas demand[70], production capacity and available supply. The IMO also provides commentary on potential opportunities for participants in the WA domestic gas market.

4.1 Domestic demand forecast

The IMO publishes two forecast demand scenarios; **base** and **high**. Only the high scenario includes prospective gas demand. Figure 4.1 and Table 4.1 show the base and high domestic gas demand forecasts for 2016 to 2025.

Figure 4.1: Domestic gas demand forecasts, 2016 to 2025



Source: NIEIR forecasts 2016 to 2025

Table 4.1: Forecast gas demand (TJ per day), 2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base	1,077	1,070	1,068	1,061	1,059	1,064	1,065	1,068	1,077	1,083
High	1,093	1,118	1,124	1,126	1,141	1,148	1,157	1,167	1,180	1,190

Source: NIEIR forecasts 2016 to 2025

Domestic gas consumption is forecast to grow very slowly in both the base and high scenarios over the forecast period (average annual growth of 0.1 per cent and 0.9 per cent respectively). The forecasts are lower than those in the 2014 GSOO due to:

- the scheduled decommissioning of the South-West Joint Venture Co-generation facility in 2016, which consumes about 30 TJ per day; and
- the closure of the Windimurra vanadium mine (due to fire damage in late 2014).

[70] Total gas demand is the sum of domestic demand, LNG export and LNG processing.

However, this decrease compared to the 2014 forecasts is partially offset by the commencement of the following projects between 2014 and 2017:

- connection of the Sunrise Dam and Tropicana gold mines to the EGGP;
- restart of Newman Power Station, which will supply electricity to the Roy Hill iron ore mine;
- operation of the South Hedland Power Station;
- operation of the Pilbara Temporary Power Station; and
- expansion of the Sino Iron magnetite mine.

These changes in gas consumption result in the base scenario forecast staying relatively flat, remaining below the 2014 forecast until towards the end of the forecast period.

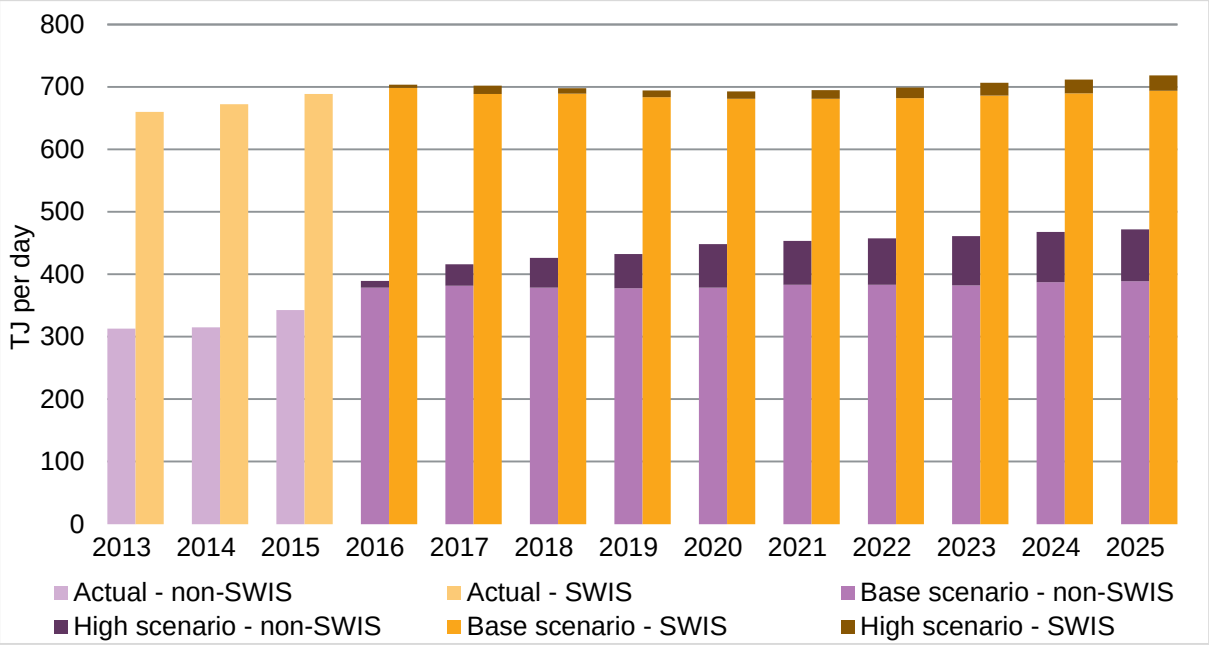
The 2014 forecast included efficiency assumptions relating to the mining and minerals processing sectors that were expected to decrease gas demand from 2017 onwards. The IMO had assumed average gas consumption per tonne of output from key minerals projects (such as iron ore and alumina) would decrease as a result of rising domestic gas prices. The IMO has relaxed these efficiency assumptions in the 2015 forecast. As domestic gas prices have fallen. As a result, despite its flat trajectory, base scenario demand is expected to exceed the 2014 base forecast by 2022.

While the 2015 high scenario is lower than the 2014 high demand forecast, growth is expected due to six major prospective demand projects that will likely come into operation during the forecast period.

4.1.1 Gas demand by area, 2016 to 2025

Forecast data indicates gas demand growth will be greater in areas that are not covered by the SWIS than those that are connected to the SWIS. Figure 4.2 and Table 4.2 shows demand forecasts for the base and high scenarios in the SWIS and non-SWIS.

Figure 4.2: Actual gas demand and forecasts for SWIS and non-SWIS, 2013 to 2025



Source: NIEIR forecasts 2016 to 2025

Table 4.2: Domestic gas forecasts for SWIS and non-SWIS (TJ per day), 2016 to 2025

Scenario		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Non-SWIS	Base	379	382	379	377	378	383	383	382	387	389
	High	389	416	426	432	448	453	458	461	468	472
SWIS	Base	698	689	689	684	681	681	682	686	690	694
	High	704	702	698	694	693	695	699	706	712	718

Source: NIEIR forecasts 2016 to 2025

The decrease in gas demand for the SWIS region is due to an expected decrease in gas-fired electricity generation over the forecast period, as the move towards coal-fired and renewable generation in the SWIS region continues.

Growth outside of the SWIS is driven by the new transmission-connected projects listed in section 4.1. The high non-SWIS scenario includes the six prospective projects, all of which are located outside of the SWIS region.

4.1.1.1 Opportunities in the SWIS and non-SWIS

Overall, the domestic gas demand forecasts suggest there is greater opportunity for gas producers outside of the SWIS than in the SWIS.

Though around two-thirds of domestic gas is consumed in the Metropolitan and South West regions, the bulk of this consumption is driven by a handful of large industrial users (such as Alcoa's Kwinana, Wagerup and Pinjarra alumina refineries) and electricity generators connected to the SWIS (such as the Kwinana and Cockburn power stations). Electricity demand is not forecast to increase significantly and the current level of excess capacity in the electricity network (1,061 MW for the 2016-17 capacity year) suggests no new gas-fired generation capacity will be required to meet demand in the near future.

The IMO is not aware of any new large industrial projects commencing operations in the South West and Metropolitan regions during the forecast period. If any large industrial users do commence operation, they are likely to connect to the SWIS for their energy needs rather than require independent gas-fired electricity generation.

Outside of the SWIS region the situation is different. Mines and industrial facilities in regional WA tend to be located too far from the SWIS to be able to draw on any of its spare capacity. Though there is 3,519 MW of gas-fired electricity generation located outside of the SWIS, most of this capacity is located at remote sites and/or isolated networks. As a result, any new major mining or processing facility would likely require its own on-site electricity generation.

In many cases, the choice of fuel type for on-site generation outside of the SWIS region is restricted to diesel or gas. The cost of transporting coal to remote locations means it is not a commercially viable option, while renewable generation alone is often insufficient to meet a facility's energy needs. As diesel is currently more expensive than gas, growth in regional WA provides greater opportunity for gas producers.

There is also 444 MW of diesel-fuelled generation capacity outside the SWIS. Some of this generating capacity may be converted to consume gas. In particular, the IMO expects FMG's power stations at its Chichester Hub (including Christmas Creek and Cloudbreak mines) are likely to convert to gas (total capacity of 88 MW).

Further diesel to gas conversions will depend on the cost of constructing pipeline infrastructure or the availability of mobile CNG or LNG technology, as well as the cost of diesel compared to natural gas.

4.1.2 Total gas demand (domestic and LNG exports)

Figure 4.3 shows the base and high scenario for total gas demand for 2016 to 2025. Total gas demand is the sum of WA's domestic gas demand and LNG export requirements (used as feedstock and in electricity generation for the production of LNG).

Figure 4.3: Total gas demand forecasts, 2016 to 2025

Source: IMO forecasts 2016 to 2025

In summary:

- in the base scenario, total gas demand is forecast to grow at an average annual rate of 7.8 per cent, from 1,870 PJ per year in 2016 to 3,667 PJ per year in 2025;
- in the high scenario, total gas demand is projected to grow at an annual rate of 10.1 per cent per year to about 4,454 PJ in 2025;
- an increase in LNG export is driving growth in total demand. By the end of 2017, the Gorgon LNG, Wheatstone LNG and Prelude FLNG export projects are all expected to have commenced gas production;
- the base scenario includes the planned expansion to the Gorgon LNG project from 2021; and
- the high scenario includes the base scenario assumptions, plus planned expansions to the Wheatstone and Pluto LNG facilities by 2021. The high scenario also includes the Bonaparte and Equus projects which are expected to commence production during the forecast period.

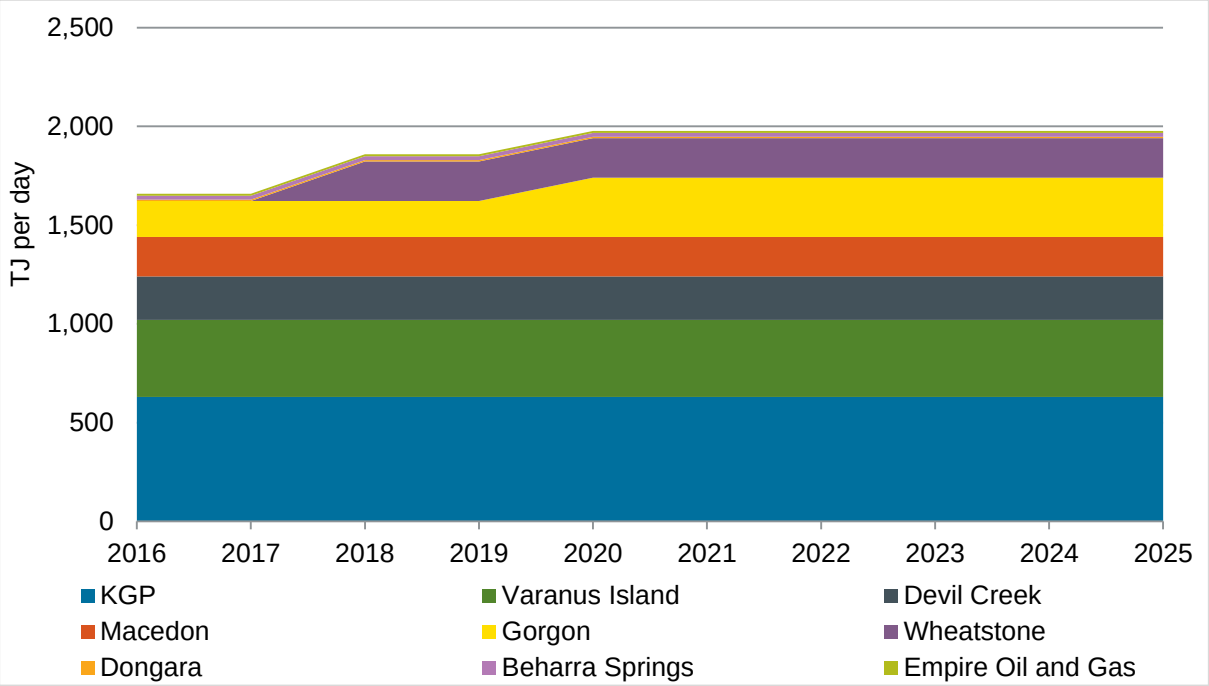
4.2 Domestic supply forecast

The domestic supply forecast has two key components: production capacity and potential supply. The way in which gas is owned and marketed in WA means the amount of gas production capacity does not necessarily equal total available gas supply. Factors including the domestic gas price, LNG export demand and contractual arrangements influence potential supply. Therefore, this section presents an overview of project production capacity, followed by the IMO's forecast of how this translates into potential supply.

4.2.1 Projected gas production capacity

Figure 4.4 illustrates projected domestic gas production capacity for the forecast period.

Figure 4.4: Projected gas production capacity in the WA domestic gas market, 2016 to 2025



Source: *GBB standing data and various corporate websites*

Note: Start-up dates represented in this chart are Gorgon domestic Phases 1 and 2 (2016 and 2020) and Wheatstone domestic (2018).

In summary:

- domestic gas production capacity is estimated to increase from 1,659 TJ per day at the end of 2016 to 1,977 TJ per day by the end of 2025[71]; and
- the KGP is expected to remain the largest domestic gas production facility in WA, retaining almost one-third of the total gas production capacity at the end of 2025.

[71] Potential domestic facilities such as Woodside's Pluto, Buru Energy's Yulleroo and Transerv Energy's Warro and other expansions are not considered in the supply forecasts for this GSOO, due to a lack of certainty regarding completion timeframes associated with their potential contribution to domestic gas supply.

Although production capacity remains well above forecast demand, new domestic gas production facilities have been proposed. The new facilities are summarised in the following sections.

4.2.1.1 The Browse FLNG project

The Browse FLNG project has the potential to contribute to domestic gas supply shortly after the forecast period if it attains a favourable final investment decision. On 22 June 2015, the JV partners of this project executed the 'Browse FLNG Development Domestic Gas and Supply Chain Key Principle Agreement' with the WA Government[72]. Under this agreement, Woodside has committed to reserve 15 per cent of the State's share of LNG production from the Torosa field (that equates to approximately 0.8 tcf of gas) for the domestic market. The IMO understands gas will be offered to the domestic market coinciding with the commencement of Torosa's production.

There is no transmission infrastructure in place to ship gas from the Browse Basin to the domestic market in the South West and Goldfields regions. The IMO expects any domestic gas that is supplied from this project would be through a third party provider via the domestic gas offset provisions allowed by the WA Government.

The IMO understands that a separate full-termed agreement (called the Development Agreement) between the Browse JV partners, which outlines the exact domestic reservation commitments for all parties, will be discussed after the front-end engineering and design phase (FEED) of the project is complete. On 1 July 2015, Woodside announced the Browse FLNG project has entered into FEED phase[73] with an expected final investment decision during the second half of 2016. Wood Mackenzie suggests the project is likely to commence in 2028, therefore the Browse FLNG project is not included in the high scenario supply forecast.

4.2.1.2 The Equus LNG project

The Equus project may contribute to domestic gas supply towards the end of the forecast period. Hess, the owner of this project, has signed a non-binding letter of intent with the NWS JV partners[74]. Subject to execution of binding agreements in the future, Hess intends to use the LNG facilities at the KGP to process and liquefy gas in the Equus fields for export. As the Equus project is subject to the WA domestic gas policy[75], 15 per cent of the gas reserves for this project must be set aside for the domestic market[76].

Hess is expected to consider its final investment decision in 2017. Wood Mackenzie expects the project to commence production in 2023.

4.2.1.3 The Pluto domestic gas facility

When the Pluto LNG project was approved for development by the WA Government in July 2007, a confidential agreement was signed between the WA Government and the Pluto JV partners to ensure the Pluto JV will adhere to the WA domestic gas reservation policy.

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72 WA Parliament (2015).
73 Woodside (2015).
74 Hess (2014).
75 This was outlined in the new Subclause (4) that replaces clause 46(1A) in the principal agreement between the NWS JV and the WA Government.
76 The Equus project holds permits WA-390-P and WA-474-P for the Equus project. According to Wood Mackenzie, contains approximately 2.5 tcf of gas in WA-390-P, while there is no information on WA-474-P. 15 per cent of 2.5 tcf is about 0.38 tcf.

According to the 2010 WA Parliamentary inquiry on domestic gas, under the terms of the agreement the Pluto JV must commence delivering gas to the domestic market within five years of exporting LNG **or** after 30 million tonnes of LNG has been exported[77], whichever is earlier[78].

The Pluto JV started exporting LNG in May 2012. Lead-time for environmental approvals, construction of a domestic gas supply facility and an excess production capacity of gas production supply suggests it is unlikely any domestic gas from the Pluto LNG project will be available by May 2017. Instead, an excess gas supply production capacity in WA means the IMO expects the Pluto JV will supply domestic gas through an offset arrangement with an existing gas production facility, most likely the neighbouring KGP.

The IMO understands Woodside is in discussion with the Department of State Development. The IMO has not received further advice on the timing of any domestic gas supply from Pluto LNG.

4.2.1.4 Other potential gas production facilities

Table 4.3 shows other potential gas production facilities currently under consideration.

Table 4.3: New domestic gas production facilities that may be operational or upgraded by 2025

Production facility	Operator	Basin	Existing and proposed pipeline connection	Is gas production capacity contracted?
Dongara	AWE Limited	Perth	Parmelia/DBNGP	Information not publicly available
Warro	Transerv Energy	Perth	Parmelia/DBNGP	Conditional gas supply agreement with Alcoa
Xyris	AWE Limited	Perth	Parmelia/DBNGP	Information not publicly available
Yulleroo/ Valhalla	Buru Energy	Canning	Proposed Great Northern Pipeline	Information not publicly available

Source: Respective corporate websites

AWE Limited is considering expanding its Dongara facility[79] and refurbishing its Xyris facility[80]. Transerv Energy's Warro facility and Buru Energy's Yulleroo/Valhalla facility are both greenfield projects.

While the potential facilities appear to be well supported by their respective companies, it is unlikely any of these potential facilities will commence until commercial gas supply agreements have been secured.

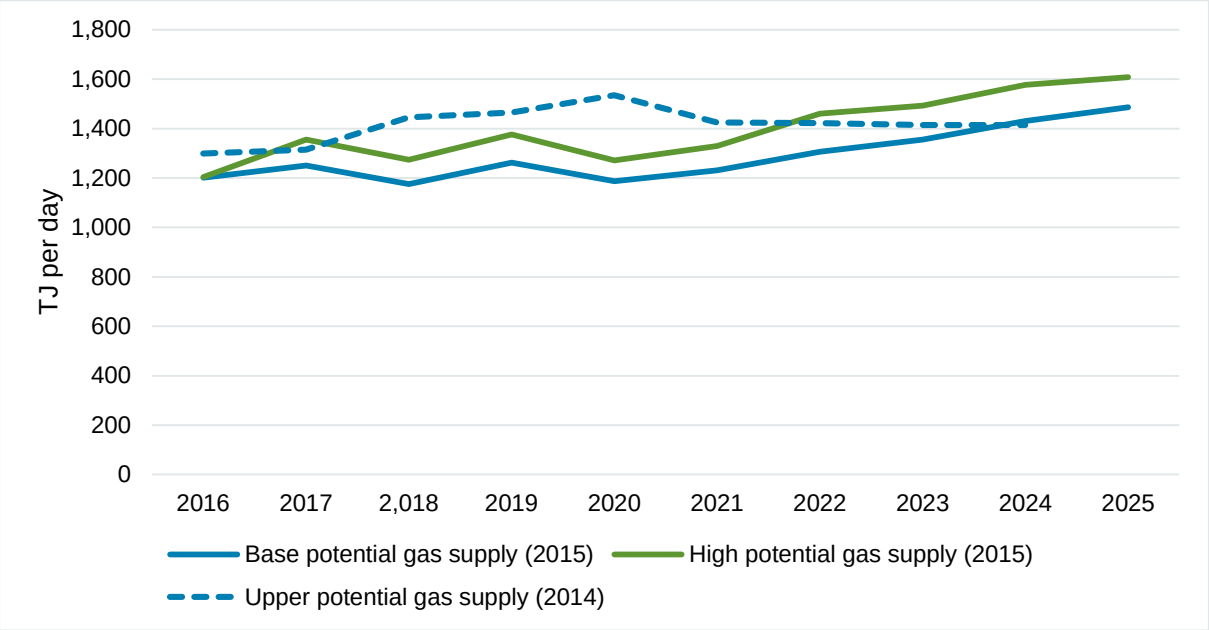
77 WA Parliament (2011), page 79.
78 Woodside (2007), page 12.
79 AWE Limited (2013). Resources from the Senecio gas field may be used to backfill the expanded Dongara domestic gas production facility.
80 AWE Limited (2015b).

4.2.2 Potential gas supply forecast

The IMO publishes two potential supply forecast scenarios; **base** and **high**. The difference between the base and high scenarios is driven by the average gas price assumptions for medium to long-term domestic gas contracts.

Figure 4.5 illustrates the price-adjusted potential supply forecast for 2016 to 2025 compared with the upper potential gas supply scenario forecast produced in the 2014 GSOO.

Figure 4.5: Potential domestic gas supply forecasts, 2016 to 2025



Source: IMO 2014 and 2015 forecasts

Table 4.4 shows the volume of potential domestic gas supply for each year of the forecast period.

Table 4.4: Potential domestic supply forecasts (TJ per day), 2016 to 2025

Scenario	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Base	1,201	1,251	1,175	1,262	1,187	1,231	1,306	1,356	1,431	1,486
High	1,205	1,355	1,274	1,377	1,271	1,329	1,460	1,492	1,578	1,608

Source: IMO forecasts 2016 to 2025

Over the forecast period potential gas supply:

- in the base scenario is forecast to grow on average by 2.4 per cent per annum; and
- in the high scenario is forecast to grow on average by 3.3 per cent per annum.

The base and high potential supply forecasts are considerably lower than those presented in the 2014 GSOO. This is driven by the fall in international oil prices from 2014 to 2015 (from $110 per barrel to around $50 per barrel). The falling oil price has reduced international gas prices by about US$4.50 per GJ, which has a flow-on effect for domestic gas prices.

The lower forecast domestic gas price means gas producers' willingness to supply is likely to be diminished. Even though production capacity is expected to increase during the forecast period, low prices mean gas producers may consider it uneconomic to supply the domestic market in the short-term.

However, potential gas supply is expected to increase towards the end of the forecast period because:

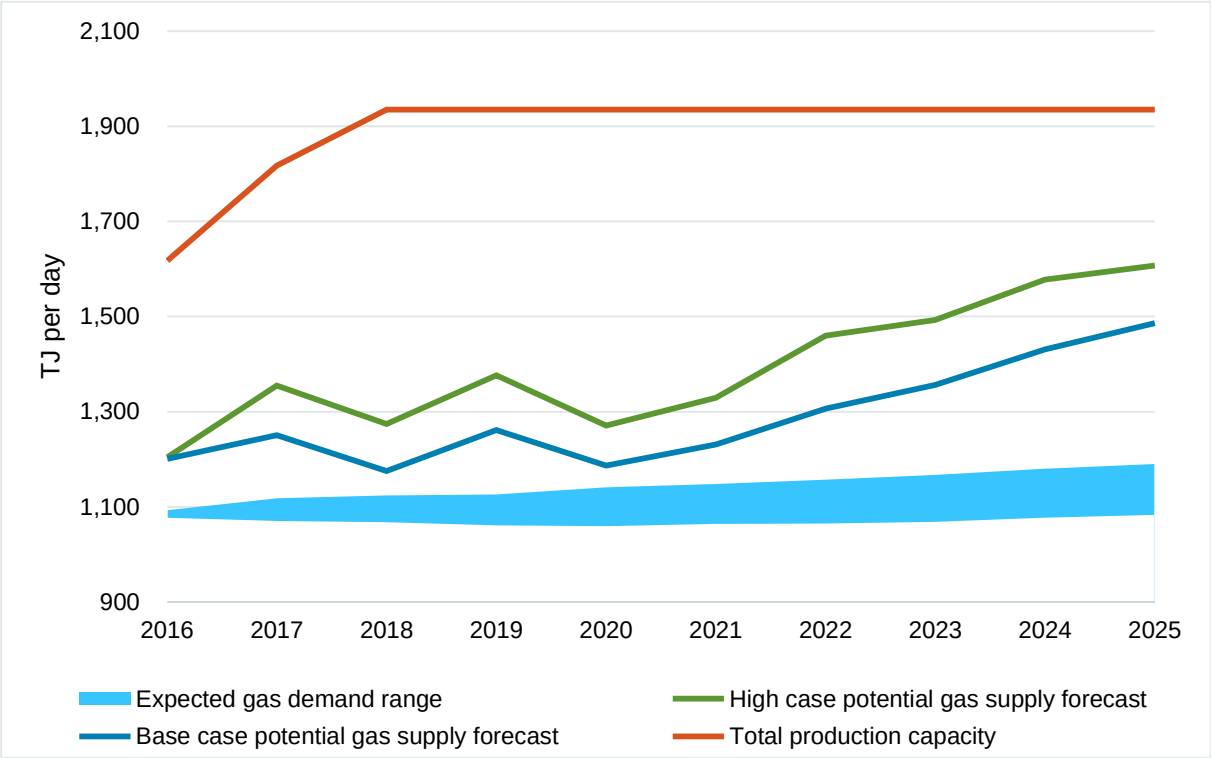
- the Organisation of Petroleum Exporting Countries (OPEC) expects international oil prices to recover[81] which should lead to a higher domestic gas price and a more attractive domestic market; and
- gas production capacity will increase due to the commencement of Gorgon and Wheatstone.

[81] Bloomberg (2015).

4.3 Domestic gas market supply-demand balance

Despite the decrease in potential gas supply compared to the 2014 forecast, the domestic gas market remains in excess supply for the forecast period. Figure 4.6 illustrates the gas market balance for the base supply and demand scenarios from 2016 to 2025.

Figure 4.6: Gas market balance, 2016 to 2025



Source: NIEIR and IMO forecasts 2015

5. Gas reserves and resources

This chapter provides an overview of hydrocarbon basins in WA. It provides an estimate of conventional and unconventional gas resources that lie within each basin, and projects how long these resources will continue to satisfy demand.

5.1 Gas resources in WA

Approximately 92 per cent (158,373 PJ) of Australia's total conventional gas resources are located in WA and the waters around it[82]. WA is also estimated to hold at least 284,092 PJ[83] of unconventional resources in the form of tight and shale gas.

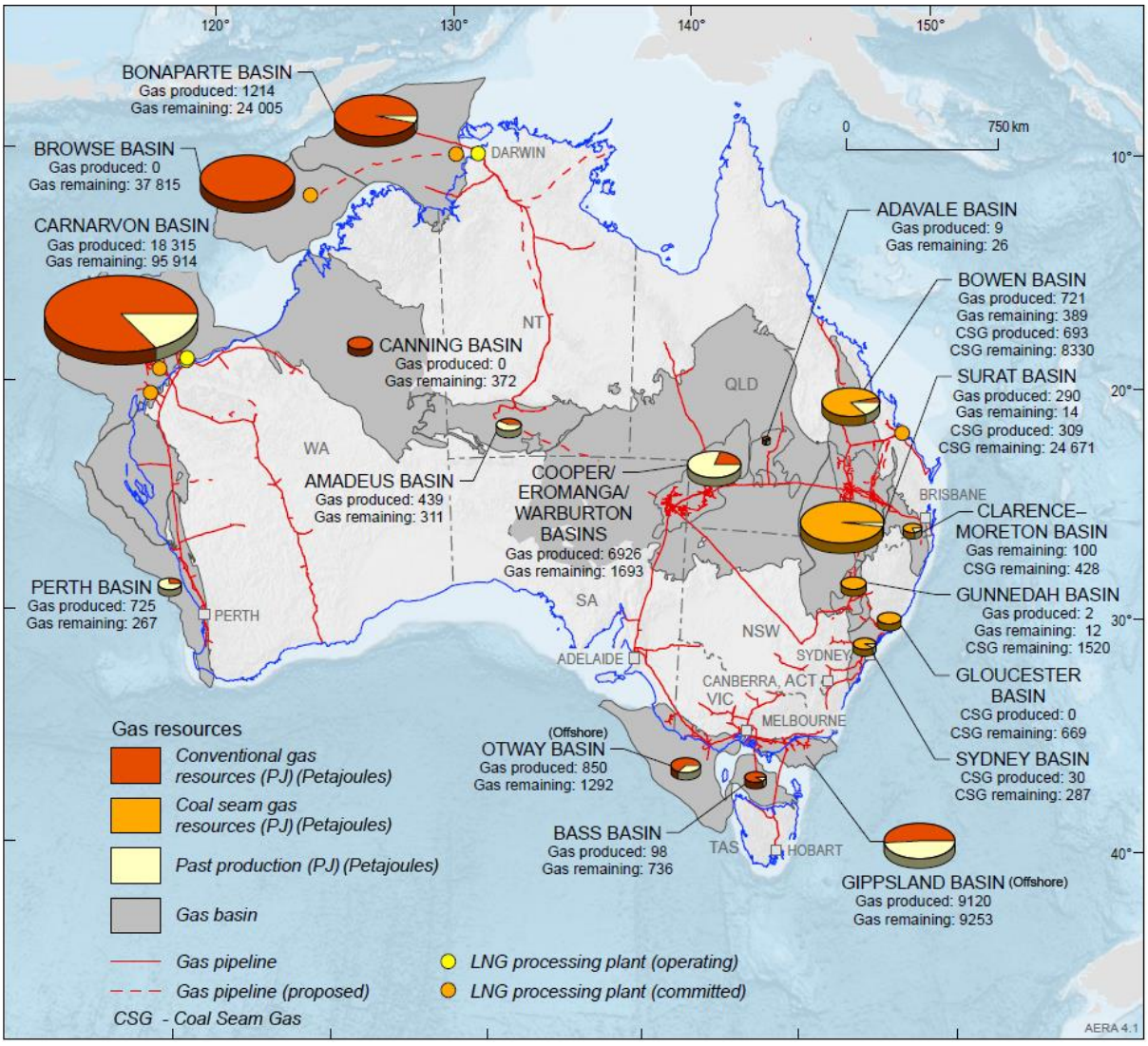
WA has five active gas basins:

- Bonaparte;
- Browse;
- Canning;
- Carnarvon; and
- Perth.

[82] Geoscience Australia (2014), gas basins in Australia (offshore and onshore).
[83] Ibid.

Figure 5.1 shows the relative size and location of these WA basins and other basins in Australia.

Figure 5.1: Australian gas basins



Source: *Geoscience Australia (2014), gas basins in Australia (offshore and onshore)*

Note: The Roebuck Basin is considered part of the Canning Basin.

The majority of conventional resources in WA lie in the Bonaparte, Browse and Carnarvon Basins, while the majority of WA's unconventional gas resources lie in the Canning and Perth Basins[84].

[84] Geoscience Australia (2014).

5.2 Gas resources and reserves

Of WA's estimated 158,373 PJ of conventional gas resources, approximately 88,619 PJ is categorised as 2P (proven and probable) reserves by oil and gas companies[85].

There is currently no commercial production of unconventional gas in WA. The amount of WA unconventional gas resources is unverified.

Table 5.1 summarises the current attributes of WA's active basins, and includes an estimate of unconventional gas reserves provided by the US Energy Information Association (EIA) in 2013.

[85] This is a conservative estimate that relates to the amount of gas that producers are confident they can recover. The actual volume of gas reserves is likely to be much larger. A 2P rating means there is at least a 50 per cent confidence level that these gas reserves can be recovered.

Table 5.1: Attributes of WA's gas basins

Attribute	Bonaparte	Browse	Canning	Carnarvon	Perth
Supplies LNG export market*	✔	X	X	✔	✔
Supplies WA domestic market*	X	X	X	✔	✔
Transmission infrastructure in place	X	X	X	✔	✔
Total area offshore, km^2 (approximate)*	250,000	140,000	76,000	535,000	122,500
Total area, onshore, km^2 (approximate)*	20,000	0	430,000	115,000	50,000
Gas produced to date (PJ)*	1,214	0	0	18,315	725
Conventional 2P gas reserves (PJ)*	981	17,384	Not reported	70,386	35
Estimated remaining conventional resources (McKelvey's EDR + SDR) (PJ)*	24,005	37,815	372	95,914	267
Contains unconventional gas reserves	X	X	✔	✔	✔
Estimated shale reserves (tcf)^	NA	NA	235	NA	33
Estimated tight gas reserves (tcf)+	NA	NA	14.1	NA	29.21

*Sources: *Geoscience Australia (2014), EnergyQuest (2015) and IMO (2014b). ^ EIA (2013). + DMP (2013b), Buru Energy (2014).*

Note: Economic demonstrated resources (EDR) is a measure of the resources that are established, analytically demonstrated or assumed with reasonable certainty to be profitable for extraction or production under defined investment assumptions (that are set by Geoscience Australia). Sub-economic demonstrated resources (SDR) are similar to EDR in terms of certainty of occurrence but are considered to be potentially economic only in the foreseeable future.

5.2.1 Conventional gas resources

As of December 2015, gas has only been produced from the Bonaparte, Carnarvon and Perth basins. The Browse Basin is currently being developed by Shell and INPEX for LNG export, while the Canning Basin is still being appraised. The WA domestic market is only supplied with gas from the Carnarvon and Perth basins.

It is unlikely the WA domestic market will be supplied with gas from basins other than Perth and Carnarvon in the near future. The relatively small domestic demand is already more than adequately supplied, with the Carnarvon Basin accounting for 98 per cent of domestic supply.

Domestic gas may be supplied from the Browse Basin after the forecast period. On 3 December 2014, the WA Parliament passed the *Petroleum Titles (Browse Basin) Bill 2014,* recognising new marine boundaries relating to Scott and Seringapatam reefs located the Browse Basin. The new boundaries mean substantial portions of the hydrocarbon fields in the Woodside-led Browse and ConocoPhilips-led Poseidon projects fall within WA waters, making them subject to WA Government royalties and domestic gas reservation policies.

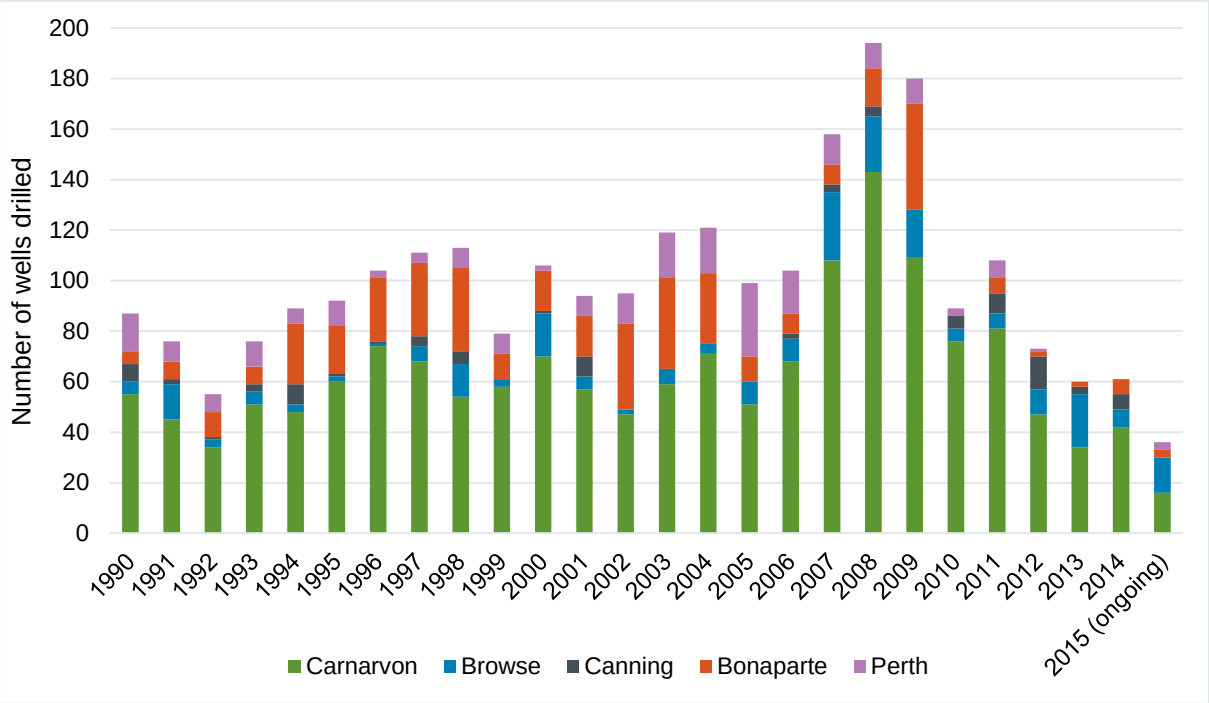
However, there is no transmission infrastructure in place to ship gas from the Browse Basin to the domestic market in the South West and Goldfields regions. The Browse JV partners will likely provide gas through a third party provider via the domestic gas offset provisions allowed by the WA Government.

There is also no gas infrastructure in place to transport gas from the Canning and Bonaparte basins to the South West and Goldfields. The vast distances involved means the cost of building the necessary infrastructure is prohibitive.

5.2.1.1 Exploration

Between 1990 and September 2015 a total of 2,579 hydrocarbon wells were drilled in WA (shown in Figure 5.2), of which around 63 per cent were in the Carnarvon Basin.

Figure 5.2: Number of exploration wells drilled, 1990 to 2015



Source: Compiled using APPEA (2014b) and National Offshore Petroleum Titles Administrator (2015)

Note: The same well may be counted twice if it is redrilled.

The number of wells being drilled has fallen in recent years compared to the peaks in 2007 to 2009. Cost is likely a factor in this reduction, as the total cost of drilling offshore wells has increased five-fold in Australia since 2003[86]. EnergyQuest[87] estimates the average cost of offshore exploration in WA is US$90 million per well, although other sources report higher figures[88]. Rising costs can be attributed to exploration moving further offshore, with wells located in deeper water.

5.2.2 Unconventional gas resources

Unconventional gas (shale and tight gas) reserves in WA remain largely unverified, with only the Perth and Canning basins having been appraised to any significant extent. However, it is widely accepted that WA has substantial unconventional gas reserves.

The EIA estimates there are 268 tcf of recoverable shale gas resources within the onshore Canning and Perth Basins, almost twice the amount of WA's conventional gas resources[89]. A 2013 Australian Council of Learned Academies report[90] provides a higher estimate (475 tcf), again with the majority located in the Canning Basin.

86 APPEA (2014a).
87 EnergyQuest (2014).
88 Thomson Reuters Zaywa (2014) reports up to US$170 million.
89 EIA (2013).
90 ACOLA (2015).

Geoscience Australia estimates there are approximately 22,052 PJ (20 tcf) of tight gas reserves in Australia. Department of Mines and Petroleum (DMP) considers WA has the majority of this volume, with most of WA's tight gas reserves located in the Perth Basin. DMP estimates the Perth Basin contains approximately 12 tcf of tight gas. However, an estimate based on public announcements from a sample of WA tight gas explorers suggest tight gas reserves in WA may be as high as 29 tcf.

5.2.2.1 Exploration

Currently, all shale and tight gas exploration activities in WA are confined to onshore exploration[91]. Exploration activities in each basin are summarised below.

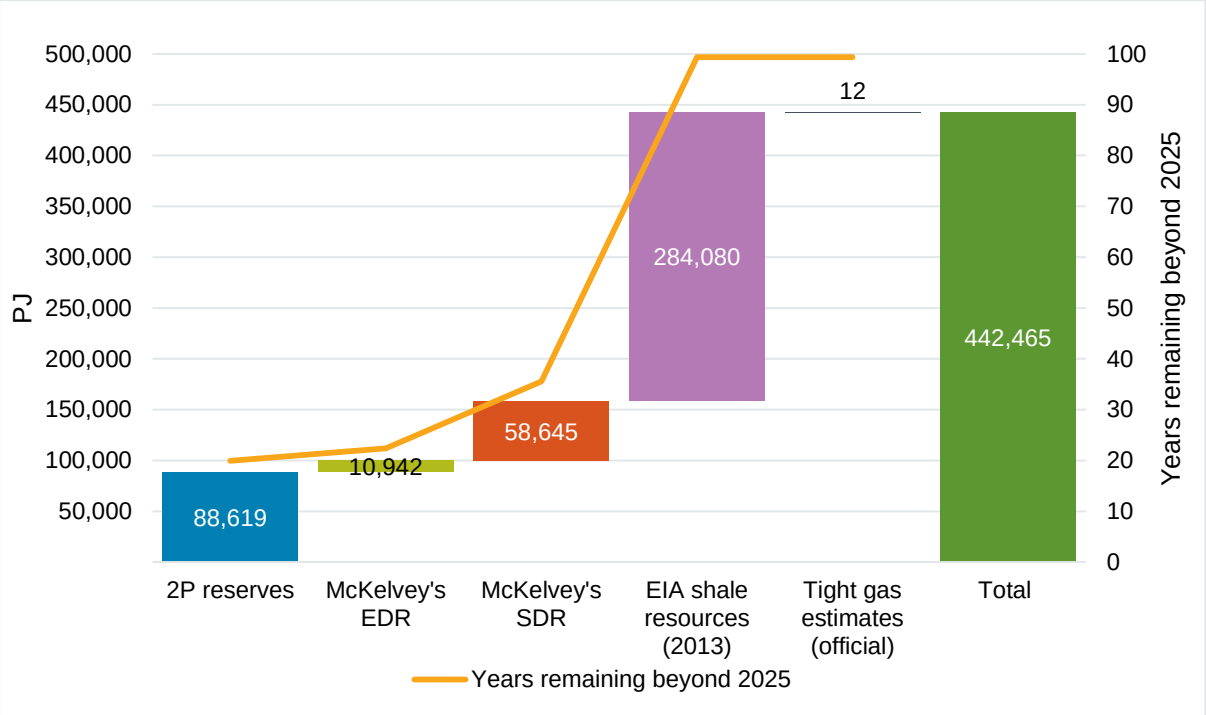
- **Bonaparte Basin** – Advent Energy is known to be exploring for shale resources at its Waggon Creek field[92].
- **Canning Basin** – Several exploration companies, JV partners and/or JV interests have permits in the Canning Basin. Buru Energy and New Standard Energy are drilling in the Canning Basin with their respective JV partners (Mitsubishi Corporation and Quadrant Energy with Buru, ConocoPhilips and PetroChina with New Standard).
- **Carnarvon Basin** – Rusa Resources and Tap Oil are exploring for shale resources in two special prospecting license areas covering a total of 38,000 square km[93].
- **Perth Basin** – A number of companies are exploring for shale and/or tight gas. AWE Limited and Transerv Energy have made the most progress in the Perth Basin, as they have been drilling and testing the gas flows of their various exploration projects[94].

91 DMP (2014).
92 DMP (2013a).
93 According to Tap Oil's corporate website, it has entered into a binding agreement with Rusa Resources to farm into Rusa's special prospective areas.
94 AWE Limited (2013) and Transerv Energy (2012).

5.2.3 Remaining resources and reserves

Based on the total estimates of conventional and unconventional resources, Figure 5.3 shows how long WA's resources are expected to last at the current and projected rate of domestic gas and LNG sales.

Figure 5.3: Estimated WA resources and reserves, 2014



Source: *EnergyQuest (2015), Geoscience Australia (2014), DMP (2013b) and DMP (2014)*

Note: McKelvey provides two estimates of reserves. Economic demonstrated resources (EDR) is a measure of the resources that are established, analytically demonstrated or assumed with reasonable certainty to be profitable for extraction or production under defined investment assumptions that are set by Geoscience Australia. Sub-economic demonstrated resources (SDR) are similar to EDR in terms of certainty of occurrence but are considered to be potentially economic only in the foreseeable future.

In summary:

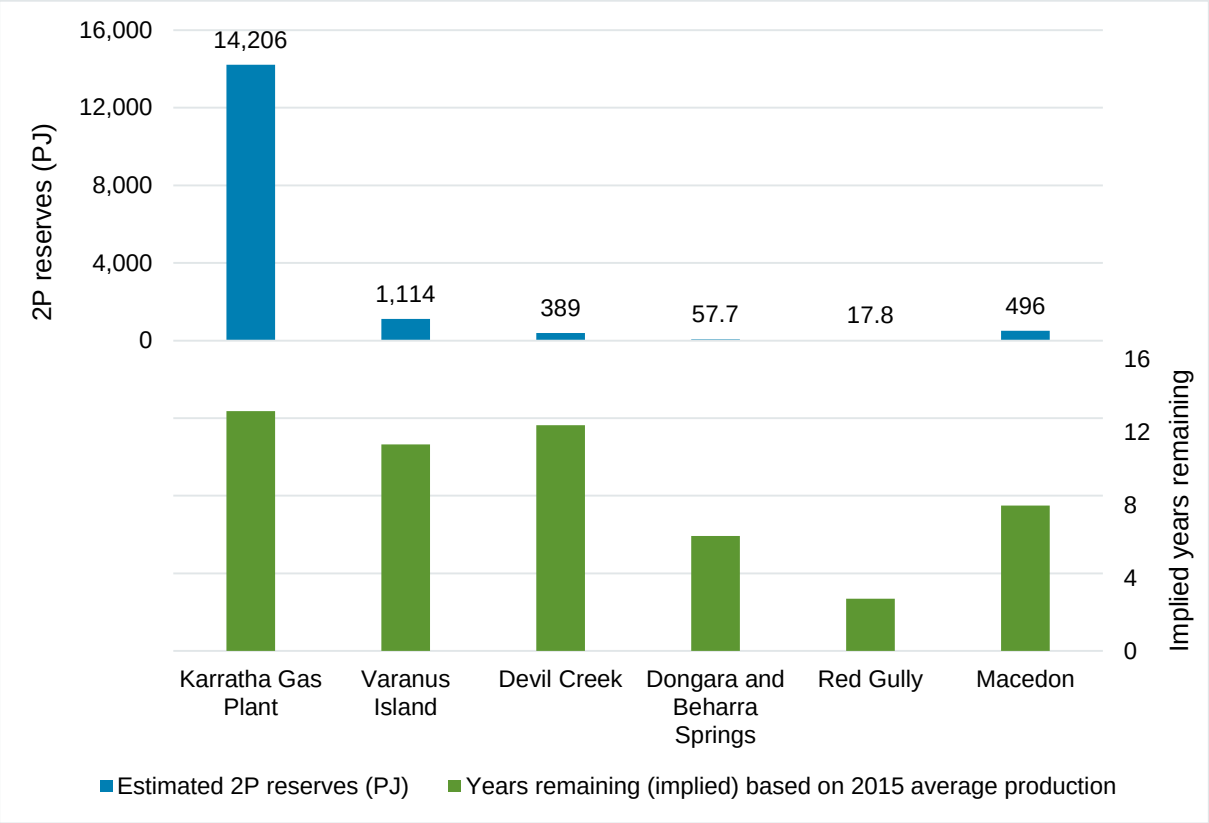
- based on the 2P assessments and McKelvey's assessment of economic resources, conventional gas reserves will last approximately 19 to 22 years from 2025 (to 2047);
- if improvements in technology, reduction in production costs and higher gas prices allow resources that are currently uneconomic to be developed in the future, there may be sufficient conventional resources in WA to last until 2060; and
- if unconventional gas is also taken into account, WA's resources may be expected to last up to 99 years beyond 2025.

It should be noted that the estimates of conventional gas reserves are based on official 2P assessments, which are typically conservative. The Chevron-led Gorgon and Wheatstone LNG projects, both of which are in the Carnarvon Basin, are expected to commence production within the next two years. Each project has an expected operating life of around 30 years, which takes these conventional reserves beyond 2045.

5.2.3.1 Estimated reserves by domestic production facility

Figure 5.4 shows the estimated gas reserves supporting WA's major domestic gas production facilities for the forecast period.

Figure 5.4: Estimated gas reserves linked to domestic production facilities, August 2015



Source: Estimates based on EnergyQuest (2015) and AWE Limited (2015a)

Only the production facilities located in the Perth Basin (Dongara, Beharra Springs and Red Gully) appear to have insufficient gas reserves to maintain current production levels until 2025. While supply from any of these three facilities may cease prior to the end of 2025, any disruption to domestic gas supply would be minimal as their contribution to the domestic market is small and can be replaced by other providers' spare production capacity.

6. Other issues

This chapter summarises the most pertinent other issues that are likely to impact the domestic gas industry in the medium to long-term.

6.1 WA Government Electricity Market Review

In March 2014, the Minister for Energy launched the WA Government's Electricity Market Review (EMR)[95]. Although the EMR is mostly focused on the Wholesale Electricity Market, its proposal to introduce full contestability to the retail electricity market will also affect the retail gas market.

There are currently two retailers (Alinta Energy and Kleenheat) that supply gas to residential and small-use commercial customers via the gas distribution network. When full retail contestability is introduced to the electricity market, it is likely to attract new retailers to the electricity sector. These retailers may also enter the retail gas market. The WA Government intends to introduce full retail contestability to the retail electricity market by mid-2018.

The EMR also proposes to transition some gas and electricity economic regulatory functions from the WA-based ERA to the national Australian Energy Regulator (AER)[96]. A draft timeline published by the Public Utilities Office suggests legislative amendments to the regulatory framework will be made in September 2016 to apply from 1 July 2018.

As gas transmission and distribution infrastructure in WA is already regulated under the National Gas Law, the regulatory mechanism will not change. However, the transfer of functions may impact the timing of when future regulatory reviews are performed, which can impact the timing of investment decisions by regulated entities.

6.2 Wholesale gas price indices

6.2.1 Australian index

As part of the Commonwealth Government's Domestic Gas Strategy[97], the Australian Energy Market Commission (AEMC) is working with the ABS and the gas industry to establish a wholesale gas price index to measure average price movements in bilateral gas contracts. The price index follows the gas market development plan[98] endorsed by all State and Territory Energy Ministers at the Council of Australian Governments on 23 July 2015 in Perth[99].

The AEMC considers a wholesale gas price index for the whole of Australia will enable the development of:

- a robust and credible spot market reference price;
- a forward derivative curve;

95 See the website of the Public Utilities Office for more information on the EMR.
96 Department of Finance (2015).
97 Department of Industry and Science (2015).
98 COAG (2015a).
99 COAG (2015b).

- a measure of movements in bilateral contracts; and
- cost of production and LNG netback estimates.

This data can then be used to:

- measure the trend in wholesale gas prices in the Australian economy;
- increase transparency around pricing structures in bilateral gas contracts; and
- as a price escalation factor in wholesale gas contracts.

On 14 September 2015[100], the AEMC and the ABS outlined the purpose of the index and how they intend to proceed with its development. The AEMC and ABS said they intend to establish an Australian (including WA/NT) and eastern Australian (excluding WA/NT) index due to the different supply and demand fundamentals of each market. This will be done by surveying large gas users operating in each state.

Prices would be weighted according to a methodology to be developed by the ABS. Data would be collected and the index published quarterly (lagged by approximately one month) in line with the existing Producer Price Index.

The IMO expects the index to be made up of a basket of gas contracts with different pricing structures. The index will allow users to measure the direction and magnitude of movements in wholesale prices across a sample of bilateral gas contracts. The AEMC has indicated it will return to WA to consult market participants further.

6.2.2 Asia Pacific index

There are currently moves to establish an LNG pricing index in the Asia Pacific region. For example, Singapore unveiled its LNG price index on 11 June 2015 (see section 6.4.1).

While the Asia Pacific hub will not be directly linked to an Australian domestic price hub, it will provide greater transparency of spot trading and provide valuable data to help calibrate domestic prices and improve the quality of LNG netback estimates.

[100] Representatives from the AEMC and ABS held a presentation to WA stakeholders at the IMO's offices.

6.3 Domestic LNG and CNG

Domestic LNG and CNG consumption is a growing subsection of WA's wholesale gas market. There are now two domestic LNG facilities and one CNG facility operating in WA, with a further LNG facility proposed in Port Hedland (see Table 6.1).

Table 6.1: Current and potential domestic LNG and CNG facilities

Owner and Operator	Location	Facility Type	Gas production capacity (estimates) – TJ per day	Status
EVOL (Wesfarmers)	Kwinana	LNG	~9.7	Operational
EDL	Maitland (Karratha)	LNG	~11.1	Operational
Sub161°	Port Hedland	CNG	~12.5	Operational
Mobile LNG	Port Hedland	LNG	~6	Proposed

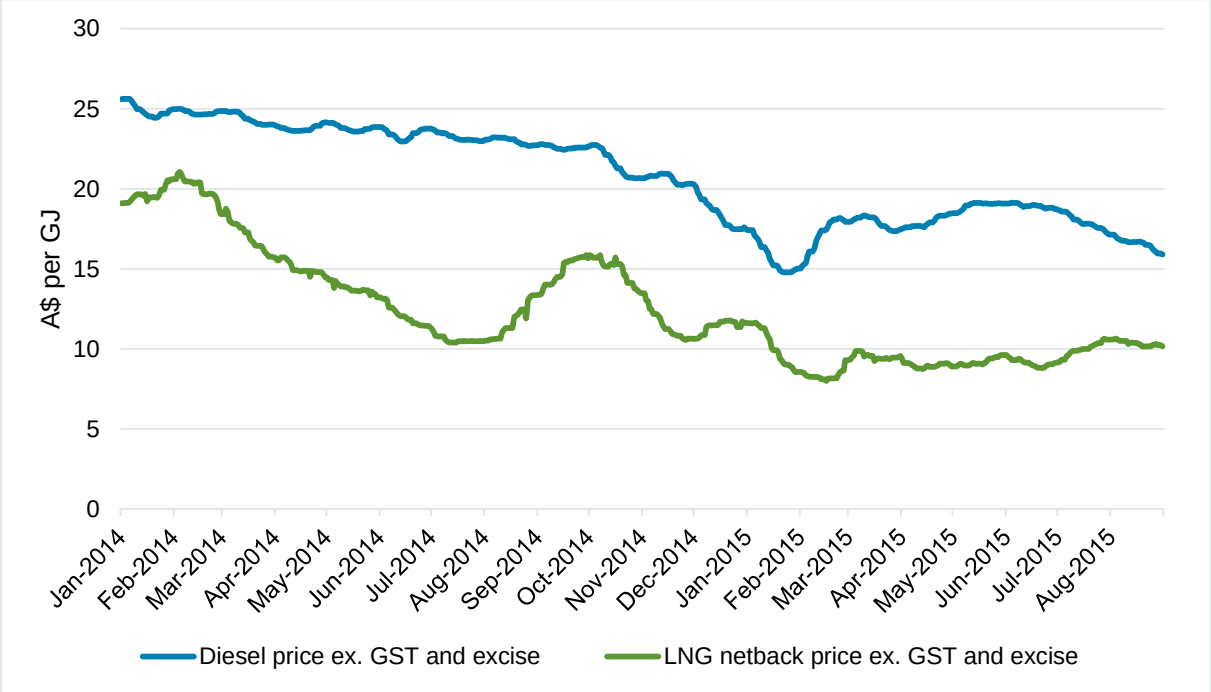
Source: Respective corporate websites and IMO estimates

Domestic LNG and CNG facilities allow natural gas to service areas of WA that are not connected to the gas pipeline network. The current facilities are primarily being used to supply remote power generation facilities and LNG-fuelled transport. For example, EDL's Maitland facility supplies domestic LNG to the West Kimberley Power Project for remote generation sites, and EVOL LNG supplies several remote power generation sites in the Goldfields[101].

[101] EVOL LNG (2015).

Average utilisation for the EDL and EVOL facilities is approximately 75 per cent[102]. This suggests there is spare capacity at these facilities, which may be utilised by companies considering switching from diesel to gas. Figure 6.1 compares the prices of diesel and LNG net of GST and excise from January 2014 to August 2015. The average difference between diesel and LNG prices was $8.38 per GJ. Depending on project life, LNG transport costs, and the capital cost of switching, significant savings are possible if a diesel operated facility switches to LNG.

Figure 6.1: Diesel and LNG netback prices, January 2014 to August 2015



Source: *Argus Media (2015) and Australian Institute of Petroleum (2015)*

Note: Prices do not include transport costs.

The consistently lower price per GJ of LNG relative to diesel in WA will be attractive to potential customers who cannot economically connect to existing or upcoming pipeline infrastructure.

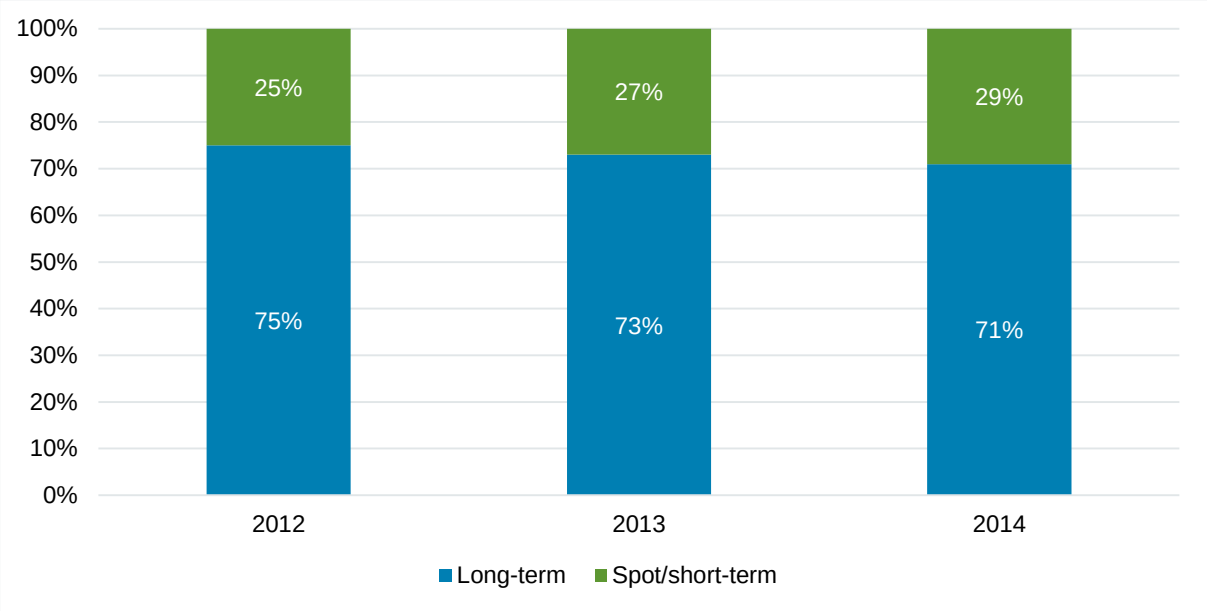
[102] GBB data.

6.4 Other developments in the LNG market

6.4.1 The potential rise of an Asia Pacific LNG trading hub

Spot and short-term LNG trading continues to increase as a proportion of total LNG exports internationally (see Figure 6.2). This means establishing a pricing reference for short-term trading in each region is important.

Figure 6.2: Type of LNG contracts traded, 2012 to 2014



Source: GIIGNL (2013 to 2015)

North America and Europe have already established pricing references through existing trading hubs, such as the Henry Hub in the US, National Balancing Point in the United Kingdom, Zeebrugge hub, Central European Trading hub and the Title Transfer Facility in Europe. Currently, there is no price reference for LNG in the Asia Pacific region (other than the international oil price).

China, Singapore and Japan are vying to become the authoritative trading and pricing hub for the entire Asia Pacific region:

- Japan was the first to develop LNG trading in the Asia Pacific region, allowing trade of non-deliverable forward products[103] on the Japan OTC Exchange in September 2014;
- Singapore unveiled its LNG price index in June 2015, called the Free on Board Singapore SGX LNG Index Group; and
- China commenced trading natural gas through its Shanghai Petroleum and Natural Gas Exchange[104] in July 2015.

While it is unclear which of these proposed hubs will develop into the definitive pricing reference for the Asia Pacific, Singapore potentially has the strongest case.

[103] A non-deliverable forward is a type of futures contract that is settled financially without any physical exchange.
[104] Reuters (2015b).

Singapore possesses LNG, fuel bunkering[105], oil and gas trading and shipping expertise, strong legal frameworks, an efficient port, independence (not a significant buyer or seller), large multi-user LNG storage facility that can accept multiple LNG carriers and has close economic relationship with the majority of LNG selling and purchasing countries[106].

Singapore also possesses political stability and unique geography. Several international oil and gas companies have located their LNG and oil marketing and/or shipping divisions in Singapore. In addition, Singapore has potential to support LNG redistribution in the South East Asian region, another area expected to be short of gas supply over the forecast period[107].

6.4.2 Potential displacement of Australian LNG production

OCE reports WA has some of the highest long-run marginal costs of gas production and liquefaction when compared to a sample of LNG export locations in the US, East Africa and Asia Pacific[108]. As a high cost producer of LNG[109], WA faces the highest risk of displacement in the LNG supply chain when several long-term LNG export contracts start to expire from 2016.

Reports from Accenture[110] and Oxford University[111] also highlight that Australia's ability to compete internationally may be severely undermined by high operating costs. This is despite Australia's advantages in terms of geographic location, gas reserves and domestic expertise for LNG. However, the reports suggest brownfield developments remain economically viable.

The high cost of LNG production in Australia was recently supported by estimates calculated by Carbon Tracker[112]. The report estimates all prospective Australian LNG projects require LNG international prices to be higher than US$12 to US$16 per MMBtu.

6.4.3 Availability of unconventional gas to international gas supply

The availability of unconventional gas to the international gas market has the potential to significantly influence the availability of gas and LNG. Currently, only Australia and the US have successfully developed unconventional gas for their domestic and export markets which may be replicated in other countries.

In addition, low oil prices have impacted the exploration budgets of the oil and gas industry, leading to greater consideration.

105 Singapore is already the largest fuel bunkering location internationally and already commands 17 per cent of the total bunkering market share in 2010.
106 See Tan, J (2015) for other reasons on why Singapore is likely to succeed.
107 IEA (2015a).
108 OCE (2015d).
109 Macquarie Equity Research (2012), Credit Suisse Global Equity Research (2012), Deloitte (2013) and McKinsey (2013) also provide a breakdown of cost estimates for LNG projects in Australia.
110 Accenture (2015).
111 Oxford University (2014).
112 Carbon Tracker (2015).

Appendix A. Abbreviations

2P – proven and probable

A$ – Australian dollar

ABS – Australian Bureau of Statistics

ACCC – Australian Competition and Consumer Commission

ACOLA – Australian Council of Learned Academies

AEMC – Australian Energy Market Commission

AER – Australian Energy Regulator

AFR – Australian Financial Review

APPEA – Australian Petroleum Production and Exploration Association

bcm – billion cubic metres

CCIWA – Chamber of Commerce and Industry Western Australia

CNG – compressed natural gas

COAG – Council of Australian Governments

CSG – coal seam gas

DAE – Deloitte Access Economics

DBNGP – Dampier to Bunbury Natural Gas Pipeline

DBNGP Transmission – DBNGP (WA) Transmission Pty Ltd

DMP – Department of Mines and Petroleum

DSD – Department of State Development

EDR – economic demonstrated resources

EGGP – Eastern Goldfields Gas Pipeline

EIA – (United States) Energy Information Administration

EMR – Electricity Market Review

ERA – Economic Regulation Authority of WA

F&D – finding and developing

FLNG – floating liquefied natural gas

FMG – Fortescue Metals Group

FRGP – Fortescue River Gas Pipeline

GAB – Gas Advisory Board

GBB – Gas Bulletin Board

GDP – gross domestic product

GGP – Goldfields Gas Pipeline

GIIGNL – International Group of Liquefied Natural Gas Importers

GJ – gigajoule

GSI – Gas Services Information

GSOO – Gas Statement of Opportunities

GSP – gross state product

GWh – gigawatt hour

IEA – International Energy Agency

IGU – International Gas Union

IMO – Independent Market Operator

IPJV – Incremental Pipeline JV

KGP – Karratha Gas Plant

JV – joint venture

LNG – liquefied natural gas

LPG – liquefied petroleum gas

MGSF – Mondarra Gas Storage Facility

MMbtu – million British thermal units

mt – million tonnes

mtpa – million tonnes per annum

MW – megawatt

NIEIR – National Institute of Economic and Industry Research

NSW – New South Wales

NT – Northern Territory

NWS – North West Shelf

OCE – Office of the Chief Economist

OPEC – Organization of the Petroleum Exporting Countries

PC – Productivity Commission

PEP – Pilbara Energy Pipeline

PJ – petajoule

Q – quarter

Qld – Queensland

SA – South Australia

SDR – sub-economic demonstrated resources

SWIS – South West Interconnected System

Tas – Tasmania

TEPCO – Tokyo Electric Power Company

tcf – trillion cubic feet

TJ – terajoule

US – United States

US$ – US dollar

Vic – Victoria

WA – Western Australia

WA Treasury – WA Department of Treasury

WEM – Wholesale Electricity Market

Appendix B. Forecasts of economic growth

Table B.1: Growth in Australian gross domestic product (per cent per year)

Year	Actual	Base	High
2006-07	3.8		
2007-08	3.7		
2008-09	1.7		
2009-10	2.0		
2010-11	2.2		
2011-12	3.6		
2012-13	2.7		
2013-14	2.5		
2014-15	2.3		
2015-16		2.4	3.3
2016-17		3.0	3.8
2017-18		3.3	4.0
2018-19		2.4	3.4
2019-20		1.6	2.4
2020-21		2.4	3.1
2021-22		2.7	3.5
2022-23		2.8	3.6
2023-24		2.7	3.6
2024-25		2.6	3.6
2025-26		2.7	3.4
Average growth		**2.6**	**3.4**

Source: NIEIR forecasts 2016 to 2025

Table B.2: Growth in WA gross state product (per cent per year)

Year	Actual	Base	High
2006-07	6.2		
2007-08	4.1		
2008-09	4.3		
2009-10	4.1		
2010-11	4.7		
2011-12	7.7		
2012-13	4.6		
2013-14	5.5		
2014-15	1.7		
2015-16		2.8	3.8
2016-17		3.6	4.6
2017-18		3.4	4.0
2018-19		2.1	3.0
2019-20		2.0	3.0
2020-21		2.7	3.7
2021-22		3.0	3.9
2022-23		3.0	3.9
2023-24		2.9	4.0
2024-25		3.4	4.4
2025-26		3.2	4.1
Average growth		**2.9**	**3.9**

Source: NIEIR forecasts 2016 to 2025

Appendix C. Facilities included in potential supply, 2016 to 2025

Table C.1: Production facilities included in potential supply forecasts

Production facility	Operator/ expected operator	Basin	Estimated gas production capacity (TJ per day)	Estimated start-up	Comments
Karratha Gas Plant (NWS)	NWS JVs	Carnarvon	630	NA	
Varanus Island – East Spar	Quadrant Energy	Carnarvon	270	NA	
Varanus Island – Harriet	Quadrant Energy	Carnarvon	120	NA	
Devil Creek	Quadrant Energy	Carnarvon	220	NA	
Macedon	BHP Billiton	Carnarvon	200	NA	
Gorgon Domestic	Chevron	Carnarvon	300	early 2016 (182 TJ per day)	Capacity is anticipated to be 182 TJ per day until 2020
Wheatstone Domestic	Chevron	Carnarvon	200	2018	
Dongara	AWE Limited	Perth	7	NA	Facility may be expanded due with the commercialisation of Senecio fields.
Beharra Springs	Origin Energy	Perth	19.6	NA	
Red Gully	Empire Oil and Gas	Perth	10	NA	Facility has provisions to expand capacity to approximately 20 TJ/day
Total gas production capacity			**1976.6 TJ per day by the end of 2025**		

Source: Public announcements and respective corporate websites

Appendix D. Medium to long-term average (ex-plant) new gas contract price forecasts

Table D.1: Average medium to long-term gas price forecasts (ex-plant) (real, $ per GJ)

Year	Base	High
2016	$5.68	$5.77
2017	$6.60	$7.95
2018	$6.02	$6.94
2019	$6.67	$7.91
2020	$5.98	$6.70
2021	$6.10	$6.95
2022	$7.06	$8.77
2023	$7.60	$9.14
2024	$8.57	$10.30
2025	$9.43	$10.75

Source: NIEIR forecasts 2016 to 2025

Appendix E. LNG requirement forecasts, 2016 to 2025

Table E.1: LNG feedstock estimates (PJ per year)

Year	Base	High
2016	1,367	1,367
2017	2,064	2,064
2018	2,591	2,591
2019	2,640	2,640
2020	2,640	2,688
2021	2,781	3,194
2022	2,922	3,506
2023	2,922	3,560
2024	2,922	3,615
2025	3,029	3,722

Source: IMO forecasts 2016 to 2025

Table E.2: LNG processing estimates (8 per cent of feedstock) (PJ per year)

Year	Base	High
2016	109	109
2017	165	165
2018	207	207
2019	211	211
2020	211	215
2021	222	255
2022	234	280
2023	234	285
2024	234	289
2025	242	298

Source: IMO forecasts 2016 to 2025

Table E.3: Total LNG requirement estimates (PJ per year)

Year	Base	High
2016	1,477	1,477
2017	2,229	2,229
2018	2,798	2,798
2019	2,851	2,851
2020	2,851	2,903
2021	3,003	3,449
2022	3,156	3,786
2023	3,156	3,845
2024	3,156	3,904
2025	3,272	4,020

Source: IMO forecasts 2016 to 2025

Appendix F. Conversion factors

The following conversion factors have been applied when preparing this GSOO.

Table F.1: Conversion factors

	To						
Natural gas and LNG	Billion cubic meters NG	Billion cubic feet NG	Million tonnes of oil equivalent	Million tonnes LNG	Trillion British thermal units	Million barrels oil equivalent	Petajoule
From	**Multiply by**						
Billion cubic meters NG	1	35.3	0.9	0.74	35.7	6.6	37.45
Billion cubic feet NG	0.028	1	0.025	0.0216	1.01	0.19	1.06
Million tonnes oil equivalent	1.11	39.2	1	0.82	39.7	7.33	-
Million tonnes LNG	1.36	48	1.22	1	48.6	8.97	55.43
Trillion British thermal units	0.028	0.99	0.025	0.021	1	0.18	1.06
Million barrels oil equivalent	0.15	5.35	0.14	0.11	5.41	1	5.82
Petajoule	0.027	0.943	-	0.018	0.943	0.172	1

Note: NG is natural gas.

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