Oakley Greenwood

Gas Price Trends Review 2017

Version 2.1 March 2018

Disclaimer

Acknowledgements

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Revisions

Number	Date	Description
2.1	February 2018	Further updates to ACT residential based on information provided by Evoenergy 21 Feb 2018.

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Abbreviations and acronyms

Acronym	Description
2P	Proved and Probable gas reserves (typically in PJ)
ACQ	Annual Contract Quantity (typically in PJ per year)
ADQ	Average Daily Quantity (typically in TJ per day)
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGN	Australian Gas Networks
CGP	Carpentaria Gas Pipeline
CLF	Customer Load Factor
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CSG	Coal Seam Gas
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DWGM	Declared Wholesale Gas Market – the Victorian gas market operated by AEMO
EDD	Effective Degree Days
EGP	Eastern Gas Pipeline – the gas transmission pipeline from Longford to Sydney
ERAWA	Economic Regulation Authority Western Australia
ESC(V)	Essential Services Commission of Victoria
ESCOSA	Essential Services Commission of South Australia
ESS	NSW Energy Savings Scheme
GGP	Goldfields Gas Pipeline

Acronym	Description
GLNG	Gladstone Liquefied Natural Gas
GPG	Gas Power Generation
GSA	Gas Supply Agreement – sometimes also called a Gas Sales Agreement
GSH	Gas Supply Hub – the Wallumbilla and/or Moomba GSH operated by AEMO
GTA	Gas Transport Agreement
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal (NSW)
JV	Joint Venture
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MAPS	Moomba to Adelaide Pipeline System
MDQ	Maximum Daily Quantity (typically in TJ per day)
MSP	Moomba to Sydney Pipeline
NCC	National Competition Council
NECF	National Energy Customer Framework
NGER	National Greenhouse Emissions Reporting
NEM	National Electricity Market
NGA	(Australian) National Greenhouse Accounts
OTTER	Office of the Tasmanian Economic Regulator
PPS	Pilbara Pipeline System
QCLNG	Queensland Curtis LNG
QGP	Queensland Gas Pipeline
RBP	Roma to Brisbane Gas Pipeline

Acronym	Description
RMS	Retail Market Scheme
SLF	Supply Load Factor
SRES	Small Scale Renewable Energy Scheme
STTM	Short Term Trading Market
SWQP	South West Queensland Gas Pipeline
TGP	Tasmanian Gas Pipeline
ToP	Take or Pay
UAG	Unaccounted for Gas
VEET	Victorian Energy Efficiency Target
VTS	Victorian Transmission System
WACC	Weighted Average Cost of Capital

Units

Unit	Description
MJ	Megajoules
GJ	Gigajoules (1GJ = 1000 MJ)
TJ	Terajoules (1TJ = 1000 GJ)
PJ	Petajoules (1PJ = 1000 TJ)
¢/MJ 2017	Australian cents per MJ - in year 2017 real terms
$/GJ 2017	Australian dollars per GJ - in year 2017 real terms

Glossary of specific gas terms used in the report

Term	Description
Capacity Trading	*Capacity Trading* is a secondary market for buying and selling acquired rights to transport gas through transmission pipelines.
Delivered gas	*Delivered gas* is inclusive of wholesale gas, transport and (in the context of large industrial consumer gas price) carbon impost.
Effective degree days	*Effective degree days* is a weather variable set out by AEMO that is created from a number of climate variables which include temperatures, wind speeds and daily sun hours as well as seasonal impacts to produce a linear relationship between temperature and gas demand. It provides a means of simplifying demand models and an improvement of the fit of weather demand models.
Gas distribution zone	A *gas distribution zone* in the retail analysis is an area that correlates to the area of a regulated or monopoly gas distribution network provider. It often defines the region that retail standing and market offers are based on.
Gas shipper	A *gas shipper* is a customer of a transmission pipeline(s) - typically a retailer or a large industrial customer, but can also be a producer - that has a contract to haul gas.
Gas swaps	The underlying concept of a *gas swap* as used in this report is the exchange of gas at one physical location for an amount delivered at another physical location – effectively payments are based on the exchange of some fixed amount of gas volume between regions or market participants which never physically changes hands – they are effectively “swapped”. This can be used to overcome physical gas transmission limitations on the wholesale gas market.
Illiquid market	An *illiquid market* is defined as one without many transactions (annually) and is typified by either a small number of sellers or buyers, or both – the wholesale gas markets in Australia are typified as being illiquid for this reason and some jurisdictional (state) locations may only have one or two major gas transactions annually.

Term	Description
In-Pipe Trading	*In-Pipe Trading* is a physical gas trade that is between two shippers to transfer gas volumes bilaterally received or stored on the pipeline traded at virtual receipt and delivery points.
LNG netback	*LNG netback* gas pricing is the cost of gas at the wellhead for gas supplied to LNG facilities, and is worked out by deducting gas shipping (sea freight) costs, liquefaction costs and pipeline transportation costs from delivered LNG export prices.
Load factor	The ratio (e.g. 1.2) of the Maximum Daily Quantity (MDQ) to the Average Daily Quantity (ADQ) that a customer's gas supply agreement and/or gas transportation agreement specifies. It gives an indication of the flexibility of a customer's contracted supply.
Market offer	A contract offered by a gas retailer to a customer where gas tariffs are set by the retailer and which may have terms and conditions in addition to those in a standing offer. Market offers tend to be cheaper than standing offers. See B.1 for details.
Multi Asset Services	A type of service offered by pipeline owners with multiple interconnected pipelines that allows the shipper to receipt gas on one pipeline and take delivery of the gas from another interconnected pipeline owned by the same pipeline owner.
Price maker	In this report the term *price maker* has been used where it is considered that a specific market location or producer sets the price for the wholesale market as a whole - the price being limited only by the highest priced alternative opportunity cost for the gas (e.g. LNG netback) and thus can set (or make) the price for all supply in that wholesale market. Occurs typically where wholesale gas markets are not oversupplied relative to demand.
Ramp gas	*Ramp gas* is CSG that is produced by an LNG project prior to their LNG plant's commissioning.

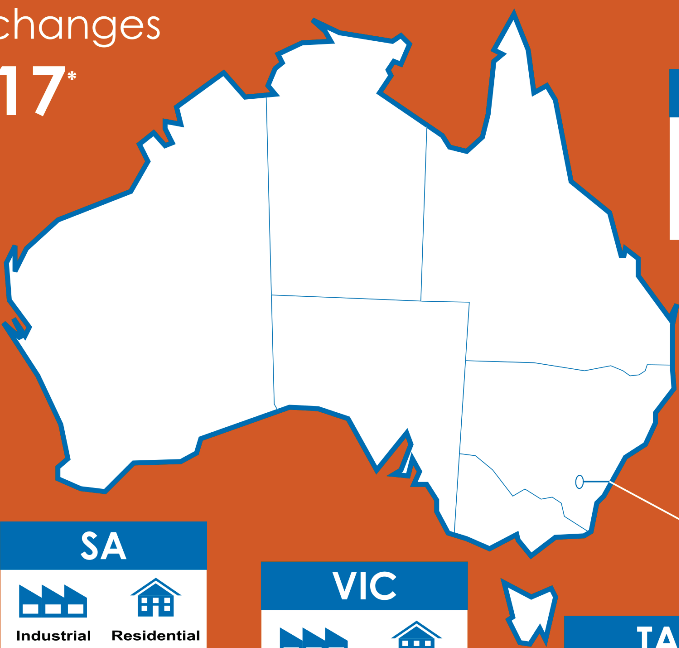
Term	Description
Reference Year	Due to the different regulatory determinations in the different jurisdictions, data provided for a certain year can be either calendar year or financial year. For example, Queensland year 2017 refers to financial year 2016-17 and Victoria year 2017 refers to calendar year 2017.
Retail gas market	The *retail gas market* is defined in this report as being the supply and sale of gas to residential, small business and commercial customers.
Short or long (on gas)	Gas producers, retailers and major industrial gas users can be *short* or *long* on gas over any given supply period. This means they may have under or over contracted for supply to meet their anticipated demand and could need to buy additional gas or sell excess gas in order to avoid financial penalties and therefore manage potential financial impacts.
Standing (or Standard) Offer	This is a basic contract offered by a gas retailer to a customer where terms and conditions and, where prices are regulated, tariffs are set by set by state Governments or jurisdictional regulators. See B.1 for details.
Take or Pay	*Take or Pay* is a gas contract term that denotes the minimum amount of gas that must be either taken or paid for – typically quoted as a percentage of the ACQ
Transmission system use gas	*Transmission system use gas* is gas provided to operators of the transmission pipelines to cover compressor fuel, metering errors, unaccounted for gas and venting during maintenance and expansion activities (generally less than 1-2% of transmission pipeline annual throughput).
Unaccounted for gas	*Unaccounted for gas* is a measure of the amount of gas lost in transport systems either directly emitted or through metering errors
Wholesale gas	The price of gas at the point of transfer, be it ex-field or at a gas hub, without consideration of transportation charges to the final point of consumption.

Term	Description
Wholesale gas market	The *wholesale gas market* is defined in this report to be where gas producers, retailers, and large gas consuming (industrial) customers buy and sell gas – the two key areas are the east and west coast markets as these are not physically interconnected.

Executive Summary

Large Industrial Customers	>1 PJ pa
Small Industrial Customers	<1 PJ pa
Residential Customers	<100 GJ pa

Gas price trend changes
2015 to 2017*

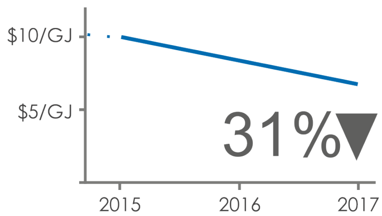


	Industrial	Residential
WA	31%▼	5%▲
QLD	11%▼	4%▲
NSW	21%▲	17%▼
ACT	21%▲	7%▼
SA	17%▲	12%▼
VIC	78%▲	16%▲
TAS	60%▲	13%▲

* percentage change is difference between delivered gas prices year 2015 and year 2017 only.

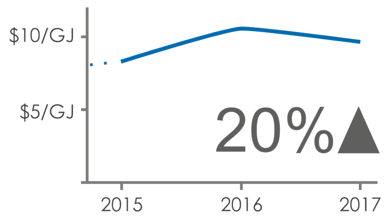
DELIVERED WHOLESALE GAS PRICES

WEST COAST



Prices continue to decline from high prices in 2009.

EAST COAST



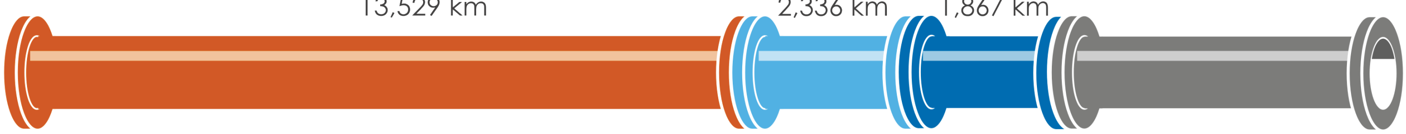
Prices have increased (particularly in VIC), peaking in 2016 and easing in 2017 with a downward trend in all jurisdictions.

TOP 3 Transmission Pipeline Owners by Length

APA Group 13,529 km

Jemena 2,336 km

AGIG 1,867 km



Australian Pipeline Industry 22,534 km

1 Executive Summary

Gas price trends in Australia have transformed in the last three years.

This report, Gas Price Trends Review 2017, is a backcast of the gas price trends for a consumer of the types (i) large industrial, (ii) small industrial and (iii) residential, contracting for gas in a given year (including data from Gas Price Trends Review 2015) in Australia since 2006. The report extends the analysis performed in Gas Price Trends Review 2015 and is augmented by key definition and analysis of the evolutionary trends of the gas transmission pipeline industry.

1.1 Wholesale gas price trends

The average east coast's wholesale gas price has shown an increasing trend from 2015 to 2016, with Victoria almost doubling and peaking in 2016 at $10.67/GJ. Since then the east coast wholesale gas pricing has shown a consistent downward trend in 2017 in all states.

Victoria is experiencing the highest wholesale gas prices on the east coast in 2017 and Gladstone is the lowest. This is a reversal from 2015 when Victoria was experiencing the lowest gas prices on the east coast and Gladstone was experiencing the second highest gas prices (second only to North West Queensland).

Table 1 below shows the divergent trends of wholesale gas prices in Australia.

Table 1: Wholesale gas price (excluding transmission costs) trend 2015 to 2017 by region ($2017)

Region	2015[1]	2016	2017
East coast high	$10.60 NWQ	$10.67 Victoria	$10.00 Victoria
East coast low	$5.45 Victoria	$7.36 Gladstone	$7.00 Gladstone
East coast average	$7.60	$9.78	$9.19
Western Australia	$8.17	$6.09	$5.00
Australia	$7.82	$8.40	$7.63

The analysis of this trend indicates the high gas prices experienced in Queensland up until 2015 have migrated south to all states south of Queensland. The most affected states in terms of price escalation are Victoria and Tasmania.

Where up to 2015 and 2016, cheaper gas was migrating north to Queensland from Victoria, it is more the case in 2017, the gas supply dynamic seems to have matured and gas price escalation has moderated somewhat from the peaks of 2016 (consistent with the spot market trend). This appears partly due to the commencement of relatively stable operations

1 Data for 2015 is from the previous Gas Price Trends Review 2015 report.

of the LNG plants compared to the hyper activity and disruptive uncertainty leading up to the commissioning and start up operations of three major gas consumers in Gladstone. Other key factors affecting price are further discussed in this report.

Western Australia's industrial consumer gas prices, on the other hand, have declined over 30% since 2015 and wholesale gas can be secured for under $5/GJ in 2017.

The Northern Territory has a very thin wholesale gas market therefore gas price trends are not analysed in this report but an overview of the supply and demand for gas is discussed.

1.1.1 Delivered gas prices – large industrial consumers

The gas trends for large industrial consumers are defined to include the cost of transport of the wholesale gas to the respective consumer types.

For large industrial consumers (greater than 1PJ/a), the gas prices are the wholesale gas price with the additional cost of gas transport incorporated. Generally, this type of gas consumer secures its own gas supply direct from producers with or without transport and may manage any short-term supply or demand imbalance from the trading hubs or short-term trading markets.

In 2017, delivered gas prices to large industrial consumers range from the highest of $12.21/GJ (including transport) in Tasmania to the lowest on the east coast of $8.15/GJ (including transport) in Gladstone (ironically, the epicentre of the major price influencing LNG developments) to the west coast of $6.97/GJ (including transport) delivered to Perth.

1.1.2 Delivered gas prices – small industrial consumers

For small industrial consumers (between 0.1PJ/a and 1PJ/a), gas is predominantly secured through retailers. The data of 120 contracts of consumers in NSW and Victoria has been analysed.

In 2015, Victoria's small industrial consumers' delivered gas prices were $5.55/GJ ($2017) compared to $13.35/GJ in 2017. In 2015, NSW's small industrial consumers' gas prices were $8.92/GJ ($2017) compared to $15.07/GJ in 2017.

The upward small industrial consumer gas price trend is consistent with the upward wholesale gas price trend with the exception there is no evident dip from peak wholesale gas prices in 2016 moderating in 2017. The small industrial gas price in 2017 continues in an upward trend.

1.1.3 Delivered gas prices – residential consumers

The retail offers, be they standing or market offers, in all major jurisdictions with residential natural gas supply tariffs have been used to understand the component costs. The components of residential gas prices are built up from wholesale gas costs, transport costs (including transmission and distribution), environmental costs (if applicable) and the retail cost components. Note the calculation methodology is specified in Appendix B. In 2017, residential gas prices (per unit) are highest in Queensland and lowest in Victoria. This is despite the highest wholesale gas prices in Victoria. The high wholesale gas price is countered by the consumer critical mass in Victoria which has the largest residential consumer base, the largest state residential consumption and a relatively high gas distribution system energy density (GJ delivery per km of network).

Table 2 below summarises the extremities of the residential gas prices in Australia.

Table 2: Residential gas price 2017 sorted by price

Region	Gas price (¢/MJ)	Household consumption estimate[2] (GJ p/a)
Victoria	2.35	50.1
ACT	3.00	38.7
NSW	3.45	21.5
Tasmania	3.91	30
WA	4.12	14.5
SA	4.53	17.7
QLD	6.40	11.4
National[3]	2.90	39.8

Analysis of the component trends from 2015 to 2017 of each region shows a national average increase in residential gas price of 2% over that period. ACT, NSW and SA have declined over the same period while the other states' residential gas prices have increased since 2015. The bigger movements in components are in the distribution and wholesale gas cost components which are buffered by the retailer component which in turn moderates the risk of price changes to the end consumer.

1.2 Gas transmission pipeline industry trends

Approximately 22,500km of onshore gas transmission pipelines, including the Northern Gas Pipeline currently under construction, are installed in Australia. The first three pipelines, Roma to Brisbane Pipeline, the Moomba to Adelaide Pipeline and (what is now called) the Victorian Transmission System, commenced operations 48 years ago in 1969. The Dampier to Bunbury Pipeline and Goldfields Gas Pipeline are the main transmission pipelines in Western Australia, each approximately 1,400km long. In the Northern Territory, the

2 The household consumption estimate is the average of the last three years consumption. See Appendix B for further details.

3 The national average is calculated based on the volume-weighted average.

Amadeus Gas Pipeline and Bonaparte Gas Pipelines are the main pipelines predominantly supplying gas for electricity generation. These latter two pipelines are soon to be joined by the Northern Gas Pipeline, currently under construction from Tennant Creek to Mount Isa, which will connect the north and east gas transmission pipeline systems.

Almost 13% (or 2,867km) of the total has been commissioned or is under construction since 2014 with over half of the total gas transmission pipeline system owned by APA (13,529km – this includes pipelines that APA Group has 100% and partial interests in).

Cost comparison between pipelines and tariffs are proportional to distance transported and potential tariff combinations analysed ranging from (an Australian context) relative low of 0.06 cents/GJ/km (or $0.73/GJ) from the Cooper Basin to Adelaide via the Moomba to Adelaide Pipeline to a relative high of 0.23 cents/GJ/km (or $3.91/GJ) from the Bonaparte Basin to Mount Isa via the Bonaparte Gas Pipeline-Amadeus Gas Pipeline-Northern Gas Pipeline.

The key trends that have stemmed from the changes in the gas market include:

- Flow reversal or bi-directional flow is reshaping the pipeline industry and its ability to respond to the shifting supply and demand relationship between Queensland and south-eastern Australia;
- The introduction of Generator Reliability Obligation and the National Energy Guarantee will create opportunities for the gas market to link up with renewable generation through the use of gas in power generation to provide firming capacity;
- Innovation in the services offered by pipeline companies including Operational Capacity Transfers, In-Pipe Trades and Multi-Asset services;
- There has been a noticeable trend towards shorter term gas supply agreements for several years, which has been highlighted in 2017 with the six domestic gas supply agreements publicly announced having terms of three years or less;
- Gas fired generators are taking advantage of the spot market to source gas in combination with non-firm transportation services in a more sophisticated way;
- Over the last 12 months, there has not been a general trend in the changes to published tariffs. Some of the changes include a reduction in the prices for reference services for a fully regulated pipeline, increases in line with CPI on un-regulated or light regulation pipelines and significant increases in tariffs on a light regulation pipeline (23%); and
- Innovation in the management of gas portfolios with the use of gas location swaps and gas time swaps by market participants.

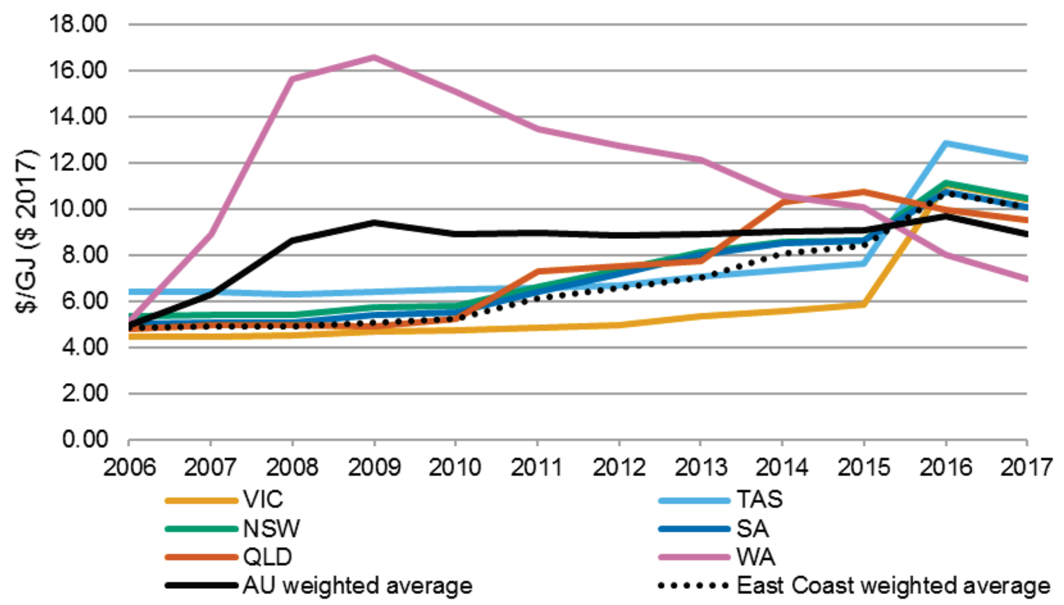
2 Key findings

2.1 Large and small industrial price trends

2.1.1 Wholesale gas prices have peaked

- The wholesale gas prices, on average, appear to have peaked on the east coast in 2016 and come back down in 2017 with gas prices starting to recede as can be seen in Figure 1.

Figure 1: Delivered gas price ($2017) trends for large industrial customers on new gas supply agreements.



- There was a lot of scatter in the wholesale gas prices for 2017 which was not seen in the previous report. This was understandable in a supply constrained market as sellers explored pricing in what is also a very opaque market for price discovery – even for the sellers.

- Timing of execution of contracts was a big factor in pricing. Based on a limited dataset it appears that prices rose sharply in 2016 through to about July 2017 when they started to come back down. This coincided with more gas and offers coming into the market from supplies in Queensland (or swaps with Queensland gas from sources south and from Moomba possibly).

- Western Australia wholesale gas prices continued to reduce to relatively low levels as new wholesale gas supply and sellers entered the market, enhancing competition. This continued the deflation of the pricing bubble that was seen in WA in the 2015 report, probably close to cost of supply levels. Gas in WA is generally sourced from reservoirs rather than coal seam gas – it is cheaper to produce reservoir gas.

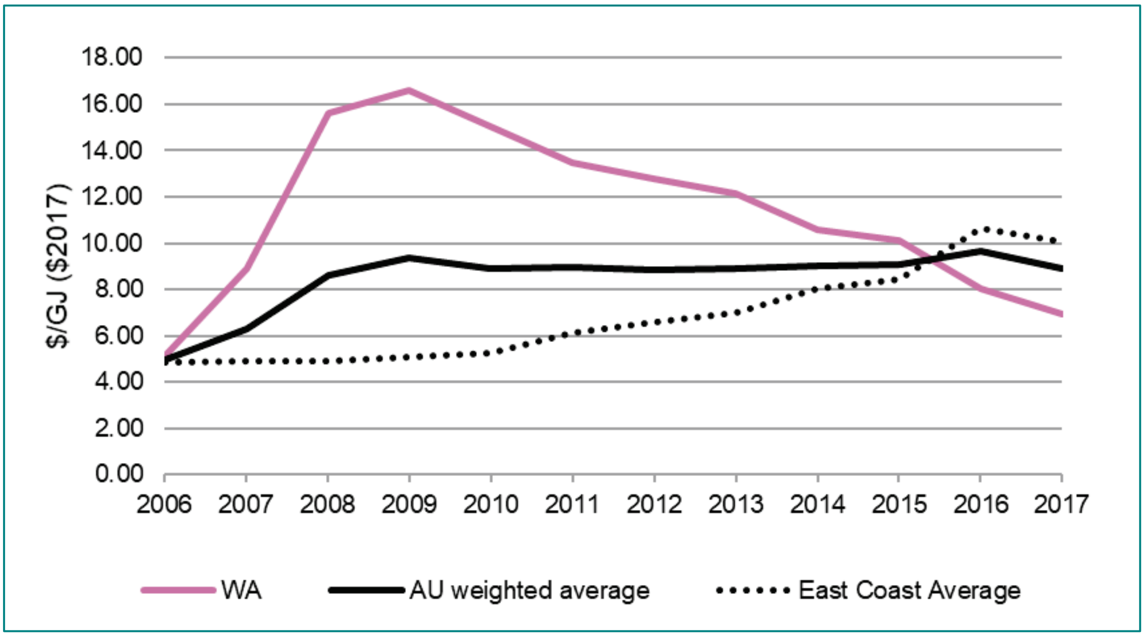
- This reinforced the conclusions from the 2015 report that gas prices reflect the supply and demand balance, albeit within an inefficient market for price discovery.

2.1.2 National average gas price trends

The average large industrial customer gas price for Australia has been developed by volume weighting[4] the average prices of all the state jurisdictions (Queensland, NSW, Victoria, SA, WA and Tasmania). In 2017, the weightings were 11% NSW, 20% Victoria, 22% Queensland, 8% SA, 37% WA and 1% Tasmania. Northern Territory is excluded from the price analysis for reasons in section 1.1.

Figure 2 shows the large industrial gas pricing for the National average and the East and West regions from 2006 to 2017.

Figure 2: Australian weighted average large industrial gas price (including transmission) for National weighted average, East Coast weighted average and the West Coast.



2.1.3 East coast wholesale gas price trend

- There has been a major reversal of pricing trends demonstrated since the Gas Price Trends Review 2015. In that report it was observed that the further away from Queensland customers were located, gas prices decreased – this has now reversed. Wholesale gas prices increase with distance from Queensland as can be seen in Figure 3. This most likely reflects changes in the sources of marginal wholesale gas supply.

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4 This weighting has been based on the Australian Energy Statistics 2016, Chief Economists Office (Table Q1) that provides gas consumption by state up to 2015-2016. For the following years the 2015-16 ratios have been used as a proxy.

Figure 3: Average delivered gas price comparison 2015, 2016 and 2017 for large industrial users on new gas supply agreements (price includes wholesale gas and transport).

- When the LNG facilities in Queensland were competing for domestic gas reserves (above their own CSG developments) it meant southern gas buyers were paying prices reflecting the value of gas to those northern buyers, and
- In 2017 this trend reversed, and more gas has been made available from the northern gas fields into the southern market – it is now notable that wholesale gas in Victoria is more expensive than NSW, and NSW is more expensive than Queensland,
- In late 2017 Gladstone wholesale gas prices are reported to be $7/GJ. This east coast reversal of this pricing trend may also indicate a timing issue as the market adjusts. As we noted, the scatter is very high in 2017 prices, and we may see more equalisation in 2018 and after.
- This trend has some logic:
  - The prices in NSW and Victoria may reflect the marginal costs of Queensland gas plus the haulage charges to transport it to those southern hubs,
  - The previous Gas Price Trends Review 2015 report observed that the Sydney wholesale gas market seems to be the price setting market on the east coast as it is almost entirely reliant on imported gas for what is a large gas market at some 150 PJ.
  - This report appears to continue to support that observation with the reversal of wholesale gas pricing along the east coast, however two notable outcomes are:
    - The delivered prices in Victoria and NSW are almost the same when transport and network charges are added back in (NSW transport and network charges are

a lot more expensive than Victoria, due to much larger transmission distances) potentially indicating some pricing strategy at work.

- Victorian prices may be more a reflection of supply and demand balance and timing of market adjustments on the east coast rather than reflective of localised production costs.

2.1.4 East coast average vs west coast – large industrial consumers

Table 3: Summary of differential factors comparing east coast and west coast

Factor	East coast 2017	Western Australia 2017
Delivered average gas price	$10.08	$6.97 (Perth)
Wholesale gas component	$9.19	$5.00
Transport component	$0.89	$1.97 (Perth)
Total consumption 2015-16[5]	887 PJ	563 PJ
Total production 2015-16[6]	1,606 PJ	1,754 PJ
Major consumers	Mining 15% Manufacturing 28% Electrical 33% Residential 18% Others 7%	Mining 20% Manufacturing 29% Electrical 47% Residential 2% Others 2%
Gas source[7]	Conventional 41% Coal seam gas 59%	Conventional 100%
Policy settings	QLD Prospective Gas Production Land Reserve (PGPLR) NSW CSG exploration exclusion zones	WA Gas Reservation Policy 15% WA onshore fracking moratorium

5 Source: Department of the Environment and Energy, Australian Energy Statistics, Table Q, August 2017
6 Source: Department of the Environment and Energy, Australian Energy Statistics, Table Q, August 2017
7 Source: Department of the Environment and Energy, Australian Energy Statistics, Table R, August 2017

Factor	East coast 2017	Western Australia 2017
	Victoria Resources Amendment Legislation (Fracking Ban) Act 2017	
Spot markets	<0.1% through GSH	1%[8]
Bilateral markets	>99.9%	99%

2.1.5 Small industrial gas prices

- Small industrial consumer gas prices escalated markedly in 2016 as the effect of tighter supply impacted and drove up the underlying wholesale gas prices. Prices in Sydney did not see the major increase in 2016 as was seen in Melbourne, but escalated markedly in 2017 and are set to decline in 2018 based on a limited set of forward pricing in some contracts.
- NSW wholesale gas prices are lower than in Victoria (as it was for larger industrial customers) with delivered prices being about the same once transport and networks charges are added.
- There are noticeable lags in pricing changes in rural Victoria and in Sydney which were like the observed lags in various regions in the 2015 report. However, major scatter occurred in the wholesale prices embedded in offers to this customer sector in 2017 which was not observed in the 2015 report.

8 Calculated from Gas Trading Australia volumes

Figure 4: Small industrial price scatter, New South Wales. Average wholesale gas price is the delivered large industrial wholesale gas price in NSW.

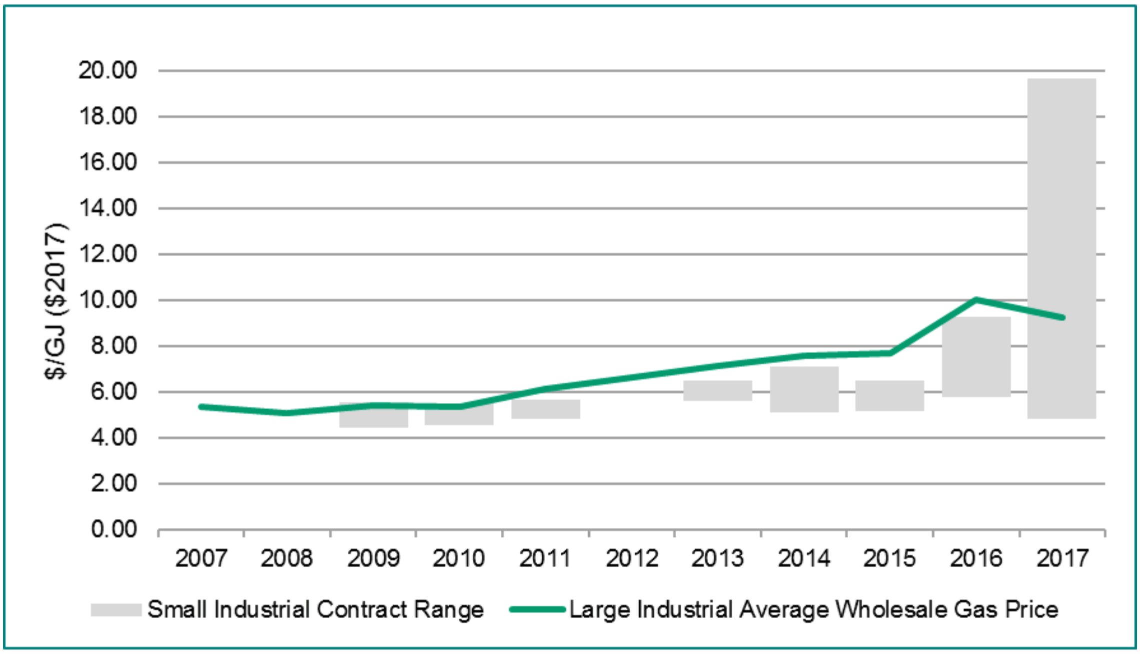
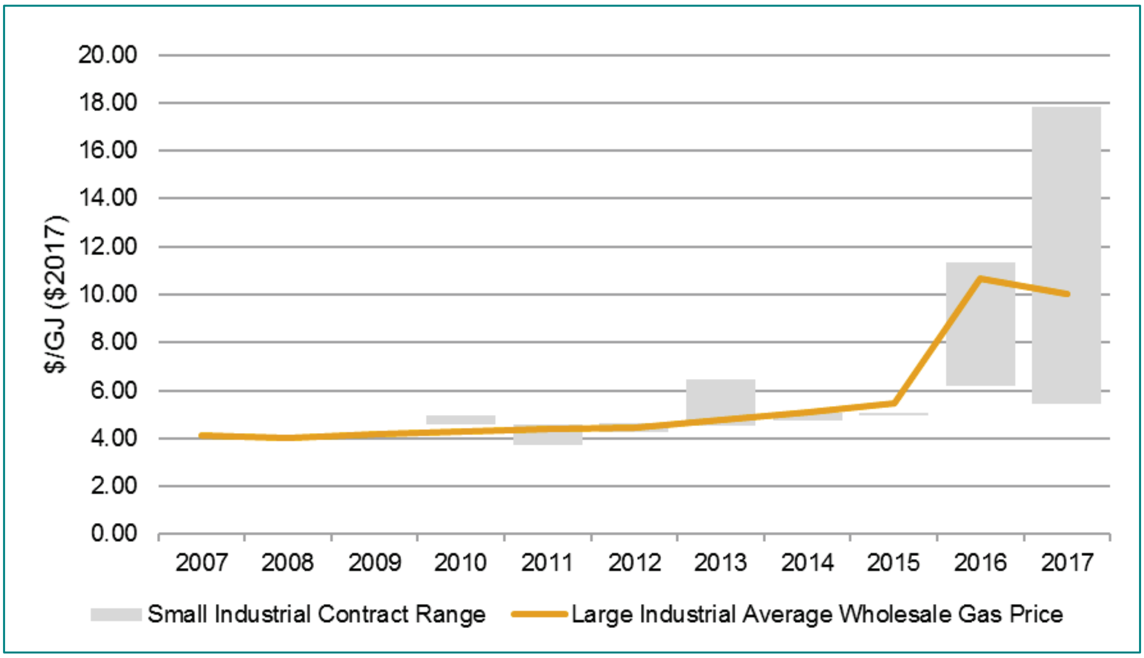


Figure 5: Small industrial price scatter, Victoria. Average wholesale gas price is the delivered large industrial wholesale gas price in Victoria.



- Looking at the VIC and NSW data (as it can be compared with the local STTM prices) it does become apparent that the timing of entering into contracts was an important factor for the price secured by the customer as the prices rose and fell.

- There is some correlation with the STTM prices. Generally, when prices offered have been high for small industrials on the contract market, there has been some higher levels of price in the STTM, with less correlation when prices are of a higher volatility, but it is not a consistent pattern (as expected due to the nature of STTM trades being a day before, unders/overs balancing market).

- But, it is noticeable that from the start of 2017 prices started to climb in this market sector for wholesale gas (including the retail component) and seem to have peaked at about the start of July 2017 – and since then have declined – and the 2018 data sees it smoothing off.

Figure 6: Small industrial contract signing timing, New South Wales ($ nominal)

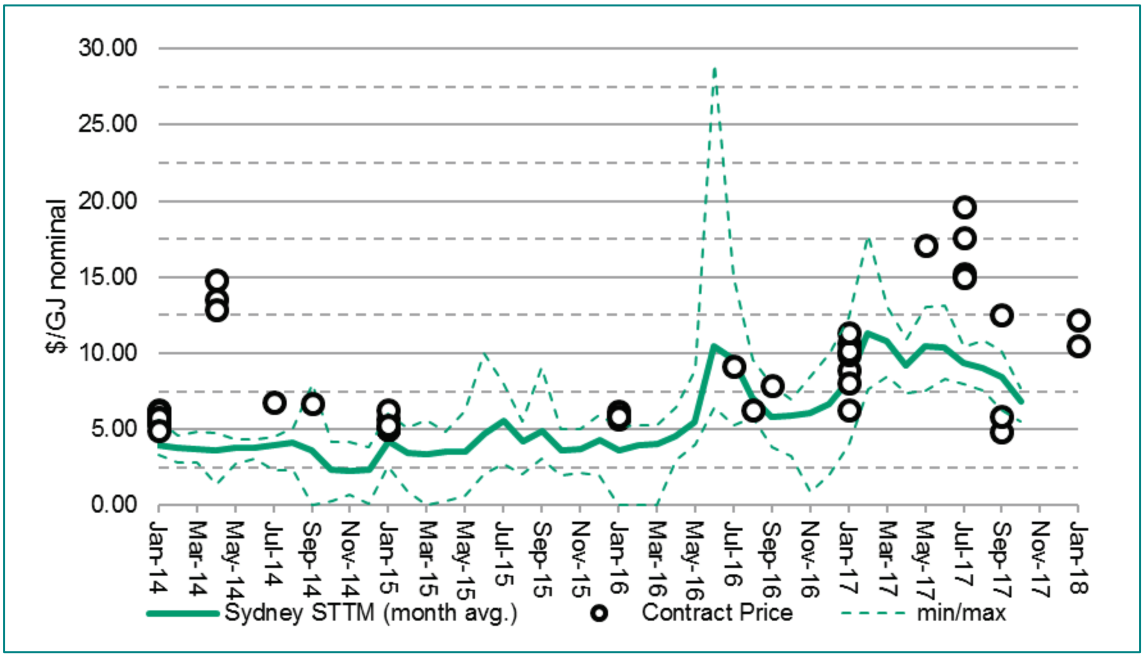
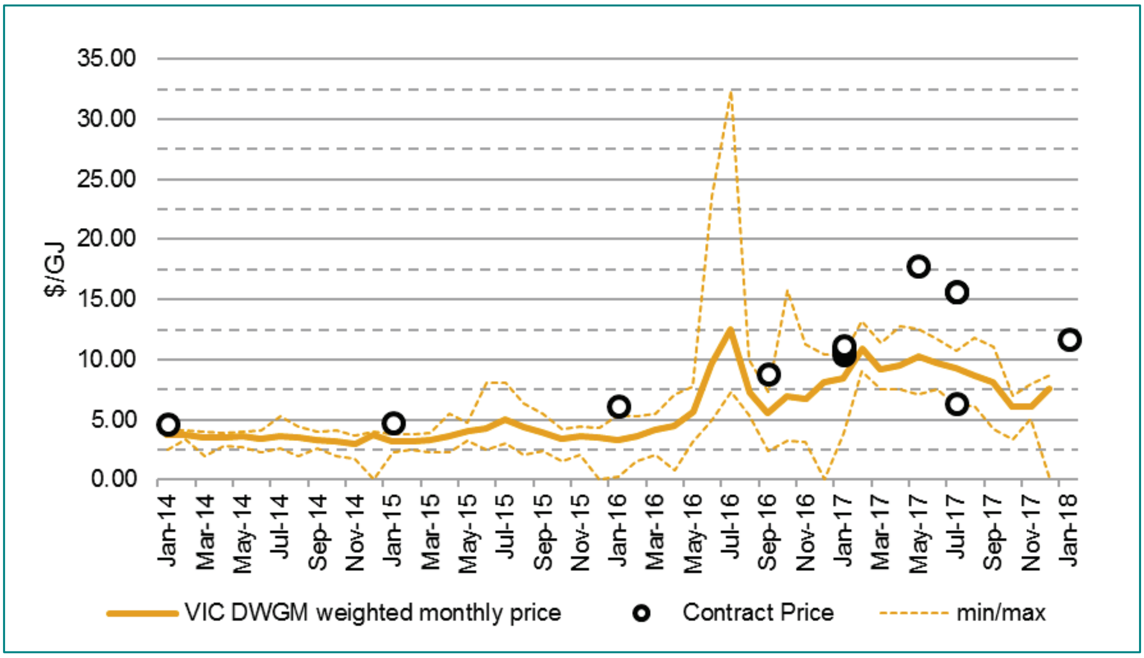


Figure 7: Small industrial contract signing timing, Victoria ($ nominal)



2.2 Gas supply and demand

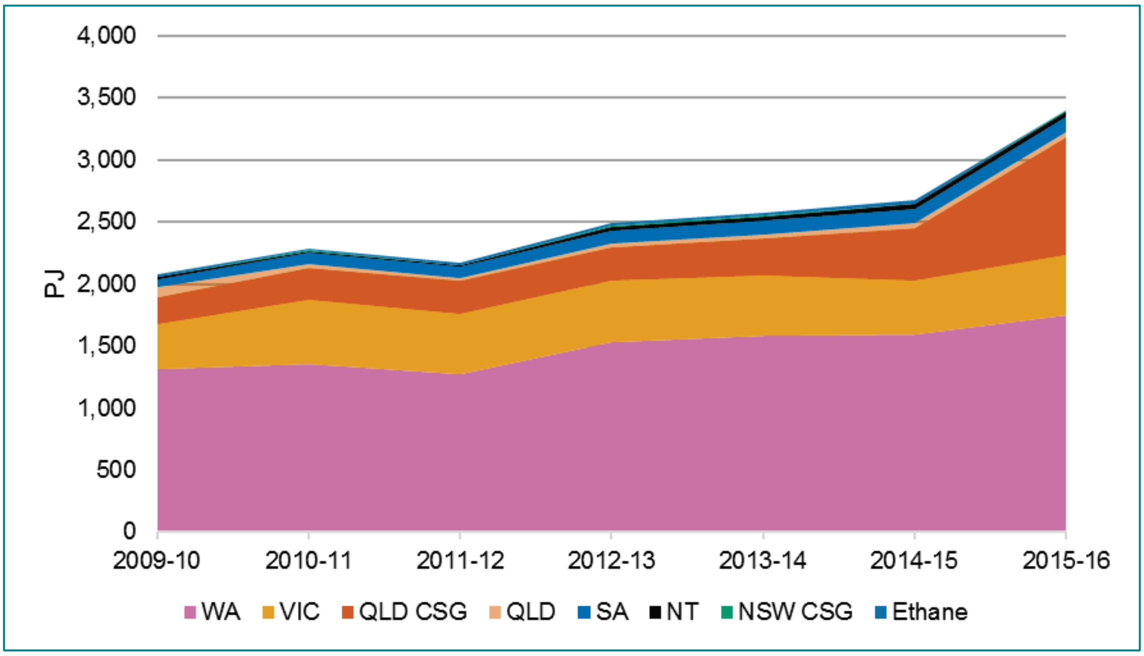
2.2.1 Gas supply

- The largest gas producers are now Western Australia and Queensland. Western Australia is predominantly an offshore producer and Queensland is an onshore producer of predominantly coal seam gas.

- The offshore Gippsland, Otway and Bass Basins supply into Victoria's onshore infrastructure gas processing plants, 80% of which is produced from the Gippsland Basin Joint Venture[9] (GBJV). Victoria is the third major source of supply into the Australian gas market. New South Wales is the second largest consumer of gas and produces a negligible amount of gas from coal seams hence it must 'import' its gas from Queensland or South Australia Cooper Basin producers through Moomba via the Moomba to Sydney Pipeline (MSP) or from Victoria the Eastern Gas Pipeline (EGP).

- Figure 8 illustrates the state by state gas production identifying the coal seam gas sectors (CSG) for Queensland (QLD) and New South Wales (NSW).

Figure 8: Australian historic production identifying gas source. Where gas type is not mentioned it is conventional gas.



Source: Department of the Environment and Energy, Australian Energy Statistics, Table R, August 2017

- Demand for gas for LNG export is the key driver for increasing supply. Australia exported some 52 million tons (Mt) of LNG in the 2016/2017 financial year[10] which is equivalent to

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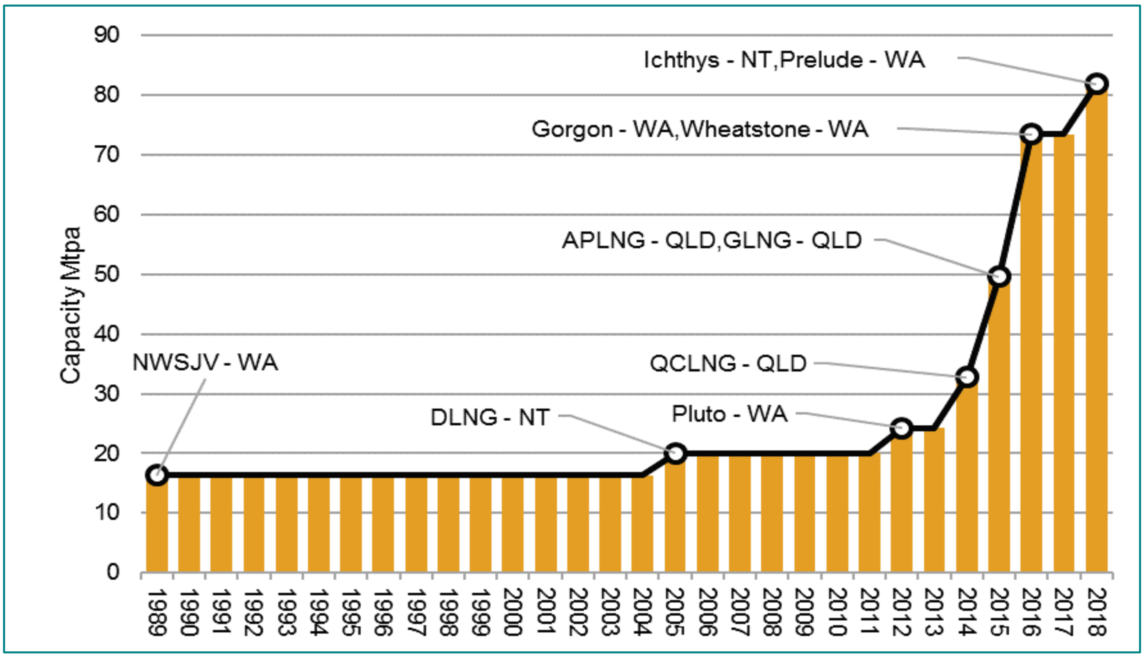
9 Department of Innovation, Industry and Science (November 2017) Offshore South East Australia Future Gas Supply Study.

10 DEE (2017) Australian Petroleum Statistics LNG exports by rural 2016-17.

approximately 2,830 PJ, more than doubling the export volumes in the 2014/2015 financial year of 25 Mt or approximately 1,360 PJ[11]. Export LNG is from three main production zones - North West Shelf in WA (56% production), Gladstone in QLD (30% production) and Darwin in the NT (14% production).

- Figure 9 shows Australia's LNG development since the North West Shelf Joint Venture in WA started operations in 1989. In the period from 2014 to 2016, there has been rapid investment and commencement of operations of LNG plants in Queensland and Western Australia increasing output capacity by 200% in three years on top of the previous three decades of development. This increase will be further augmented by the completion of Ichthys in the Northern Territory and Prelude in Western Australia, both in 2018.

Figure 9: Australia's LNG capacity development from 1989 to 2018



Source: APPEA website, Australian LNG Projects.

2.2.2 Gas demand

- Total Australian domestic gas consumption, which excludes LNG exports but not gas used for LNG production, was approximately 1,506 petajoules[12] (PJ) in 2015-16, an increase of 6% from the 1,416[13] petajoules (PJ) in 2013-2014.

- Natural gas is consumed in every state and territory and is used by various sectors including industry, power generation and residential and commercial customers as shown in Figure 10.

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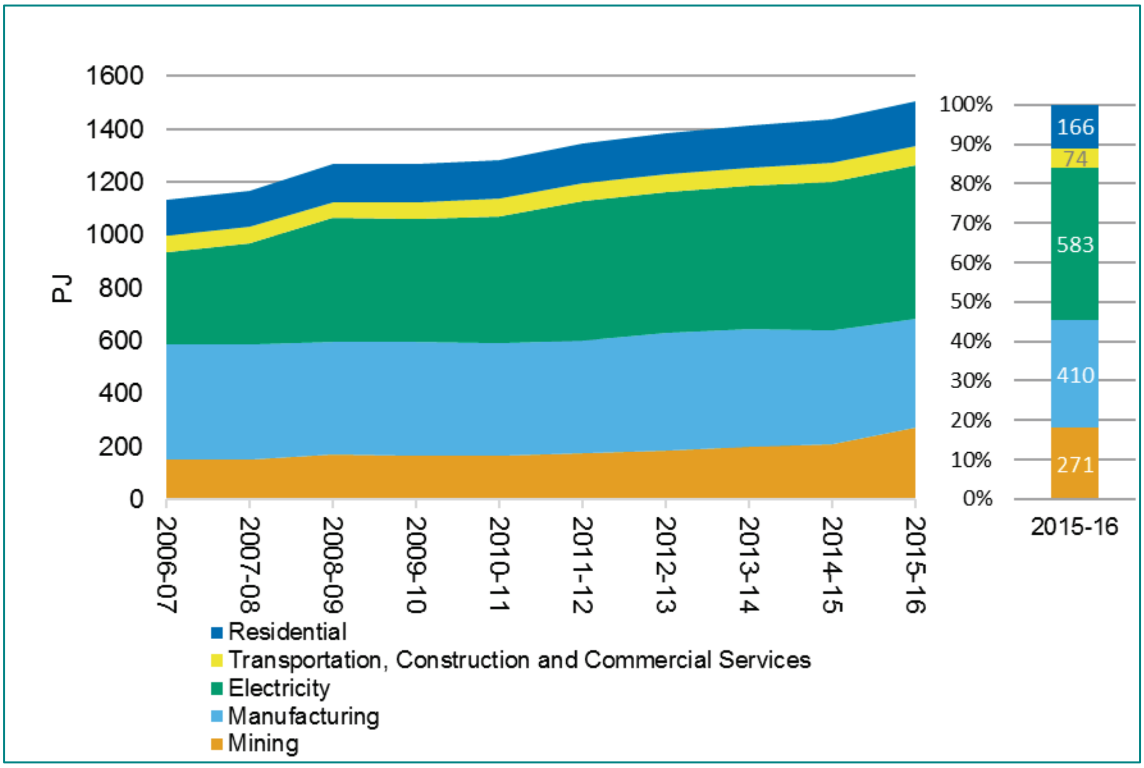
11 Department of Industry, Innovation and Science - Office of the Chief Economist, Resources and Energy Quarterly, September 2015. PJ values have been converted from Mt using 1 Mt = 54.4 PJ.

12 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

13 Consumption updated from Gas Price Trends Review 2015 (1,402 PJ) using latest data available.

Figure 10: Annual gas consumption in Australia by sector for financial year 2006-2016. Mining includes gas consumption for LNG production.



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

- LNG increases in overall gas demand in the domestic market dominate the recent trends on the east coast with growth from virtually zero to 1,292 PJ in 2017, some 68% of total east coast demand – a huge uplift in demand.

- The most notable trend in gas consumption, that seems to demonstrate some of the marginal demand price elasticity issues with gas, was in the gas power generation (GPG) sector on the east coast:

  - It had been declining until 2016 as gas prices escalated (and supply tightened) and electricity prices reduced, when it seems to have bottomed out at 196 PJ/a, but

  - In 2017 there was some recovery to 223 PJ based on actual AEMO data. This means GPG is competing for new wholesale gas supplies as these power stations come back on-line.

- The combined residential and industrial loads on the east coast have overall been decreasing. This has been driven largely by the industrial load consistently reducing annually (some 13% over the last 5 years, 45 PJ/a reduction) as manufacturing is declining.

- The residential load has flattened off over the last 3 years – any organic growth is being undermined by lost load as average consumption across the jurisdictions per households decrease. The number of connections is generally increasing across different distribution zones, but new connections are in general lower consumption due to better building standards and better energy efficient appliances. Also with the installation of efficient reverse cycle air conditioners in most homes, electricity is being used more and more as a source of heating.

2.3 Gas transmission industry trends

- The development of the new gas fields has led to significant changes in the gas pipeline industry, initially through the development of new pipelines, in particular in Queensland, and then in the services that pipeline owners are now offering.
- The network of pipelines on the east coast has changed significantly from a model of point to point pipelines connecting gas fields with a single demand centre. From 2018 there will be an interconnected grid across the Northern Territory (NT) and the east coast allowing the potential for gas to flow between the extremities of the grid being gas fields in the NT, Gladstone, Brisbane, Mt Isa, Adelaide, Melbourne, Sydney and Hobart. The growth of the coal seam gas industry in Queensland has also led to the investment in the development of almost 3,000 kilometres of new pipelines.

2.3.1 Transmission and gas supply innovations

- There has been innovation in some areas with services being offered by pipeline owners that do not of themselves generate significant additional revenue, but do support the development of the gas market as it evolves. These services include:
  - The In-Pipe Trade service on APA Group's pipelines and similar services offered by Epic Energy and AGIG (Dampier to Bunbury Pipeline) have been identified by shippers as services that are contributing to the development of the gas market – stakeholder comments received included, for example, "a huge step forward". Services that facilitate secondary pipeline capacity trading are offered by some pipeline companies, although trading activity has been limited.
  - The AEMO gas trading platform offered with the Gas Supply Hub(s) appears to have had some success with participants, but maybe somewhat limited with the offers on the platform appearing to be pro-forma with tariffs at a substantial premium to tariffs published by the owners of the pipeline. However, the platforms created by the pipeline companies to facilitate Operational Capacity Transfers, and the support for them by participants interviewed in this analysis, may well point to the way forward for implementing capacity transfers once the Day-Ahead Auction being developed by the COAG Energy Council's Gas Market Reform Group is implemented.
- One of the most marked findings from our extensive stakeholder discussions was that the changing gas market is leading to innovation in how market participants manage their gas portfolios, with transmission a key positive or negative factor.
  - Contractual constraints on some pipelines limits access to contracted but unutilised capacity other than through development of new capacity. This has led to the use of

gas trading instruments such as gas location swaps to overcome some of these barriers and create more flexibility for a wider range of participants to supply gas to the market beyond points directly connected via pipelines to their gas fields.

  - Some gas buyers (traders) are operating gas power stations without any long (or even short) term gas supply and transmission arrangements. They are largely depending on their ability to buy spot gas and contract non-firm transmission capacity to be able to run their power stations when opportune, and it was noticeable that these gas “traders” often were electricity traders. Some also expressed the desire for more compulsory gas trading arrangements (not voluntary hubs) as this would be more efficient, transparent and lower costs for trades. The parties who put forward this position did not suggest a preferred alternative approach.

  - This group of “traders” is almost a club or group that know each other and because of this can execute off market trades, especially when supply is tight, resulting in the prices becoming very opaque publicly (trading platforms at the Gas Hubs are not used so openly then).

- A growing level of sophistication in gas trading and support for further market reforms and products would increase efficiency in these processes. It also points to the short-term contracting market being predominant for some period of time while the current level of uncertainty of the direction of the gas market remains, due to moratoria or bans on onshore gas development in some states.

2.3.2 Transmission Tariffs

- Not all tariff information has been made available for this report; however, tariffs under existing services typically escalate with CPI. In some cases, tariffs have dropped slightly due to the implementation of new Access Arrangements. There have been in the last 12 months reductions in the published indicative tariffs for some services, most notably tariffs for compression services offered by APA Group at Wallumbilla and Moomba.

- A key outlier for tariffs has been the 23 percent increase from $1.32/GJ to 1.62/GJ from 2016 to 2017 in APA Group’s Carpentaria Gas Pipeline tariff.

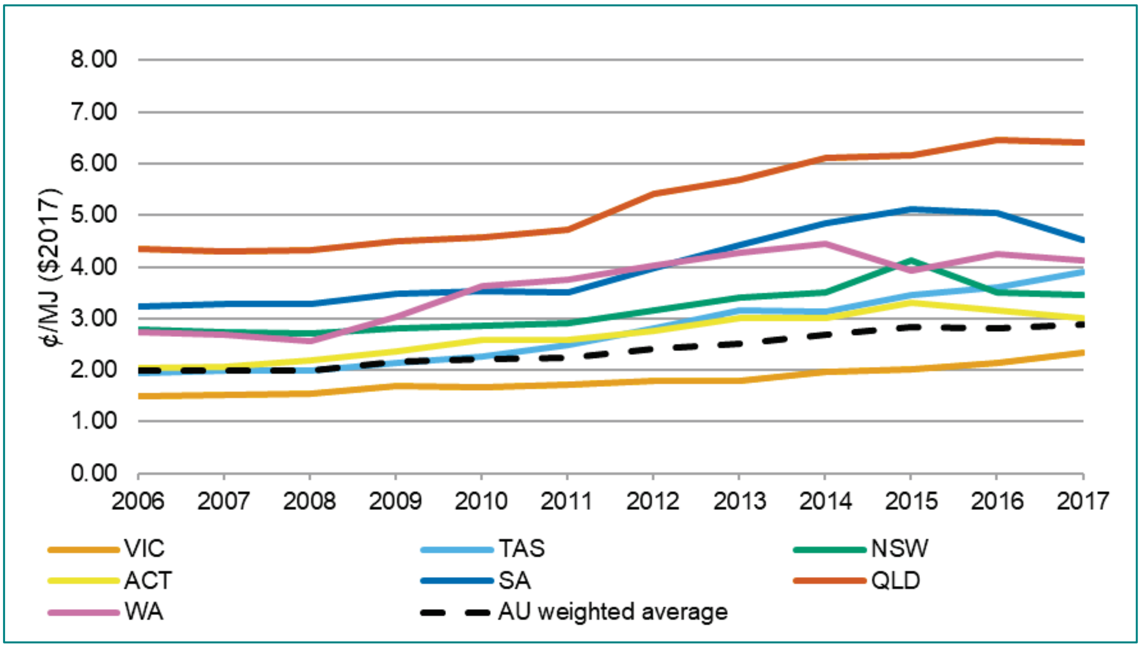
- APA Group unsuccessfully attempted to gain approval in the 2017-2022 Roma to Brisbane Pipeline Access Arrangement process, from the Australian Energy Regulator for charging a premium for short term Reference Services (less than a three-year term) relative to long term services. There might be some merit to this price premium as a short-term service may prevent long term contracting of capacity. However, this may not be a durable position given gas market dynamics. Recent gas supply arrangements have been for terms that are generally less than three years as the gas market has evolved. Given this trend, APA Group’s proposal for a premium for terms of less than 3 years for an existing pipeline would have had the potential to effectively escalate prices where parties attempt to align the term of the transport agreement with the term of their gas supply agreement.

- With the recent gas pricing and debate over lack of supply there has also been renewed focus on the costs and charges for each component of the gas value chain including transmission. Comparison of total gas transmission costs to deliver gas from Karratha to Perth and to deliver gas from the Surat Basin to major south-eastern coast demand centres, could be interpreted that the charges on the east coast are double that on the west coast. A simple comparison of transmission costs does not reflect the fact that gas is transported from the Surat Basin west to Moomba and then either south to Adelaide or south east to Sydney, over significantly longer distances using multiple pipelines than a direct single pipeline from Karratha to Perth. It also does not take account of the fact that what were originally developed as point to point pipelines on the east coast are now being utilised for a different purpose to when they were first commissioned.

2.4 Residential trends

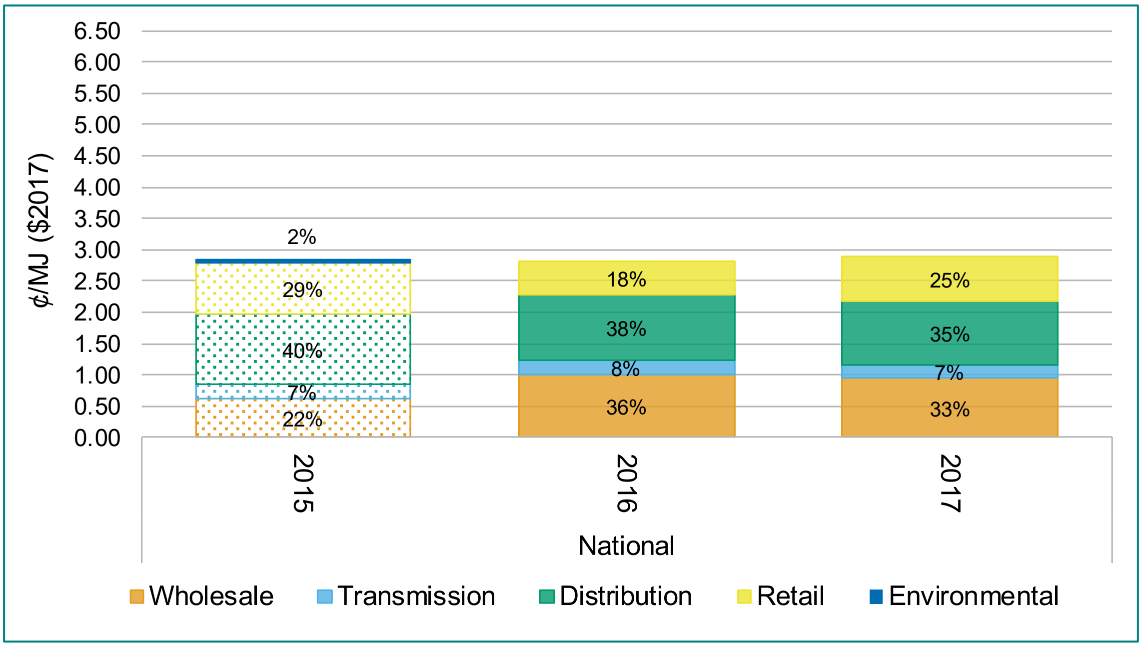
The chart in Figure 11 is the summary of the total retail residential gas prices on a ¢/MJ basis.

Figure 11: Residential retail gas price 2006 - 2017 in ¢/MJ ($2017)



2.4.1 National

Figure 12: National average residential gas price trend 2015 to 2017

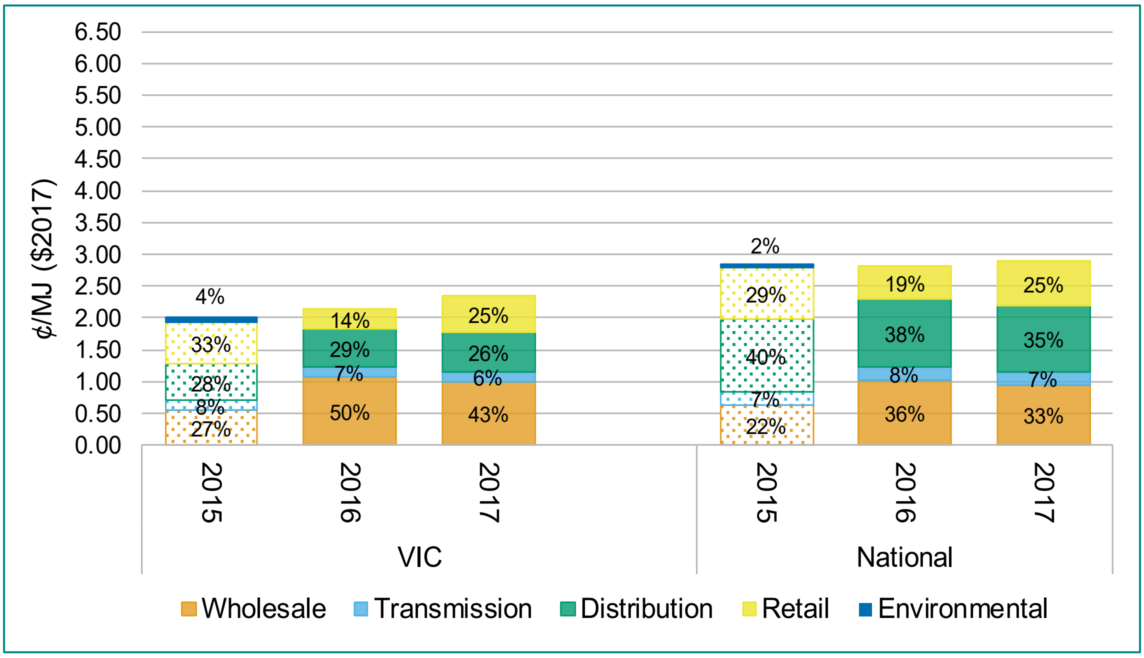


- The national average residential retail gas price has increased by some 2% since 2015. The largest component shift is in the wholesale gas component, increasing approximately 50% over the 2015 to 2017 period, and retail costs/margins seem to have moved to smooth prices to the end consumer.

- While this trend is consistent in the east coast markets, the opposite is reflected in the Western Australia market where the wholesale gas component of the average delivered residential retail price has declined by approximately 40% over the 2015 to 2017 period, and is not fully reflected in the prices.

2.4.2 Victoria

Figure 13: Victoria residential gas price trend 2015 to 2017



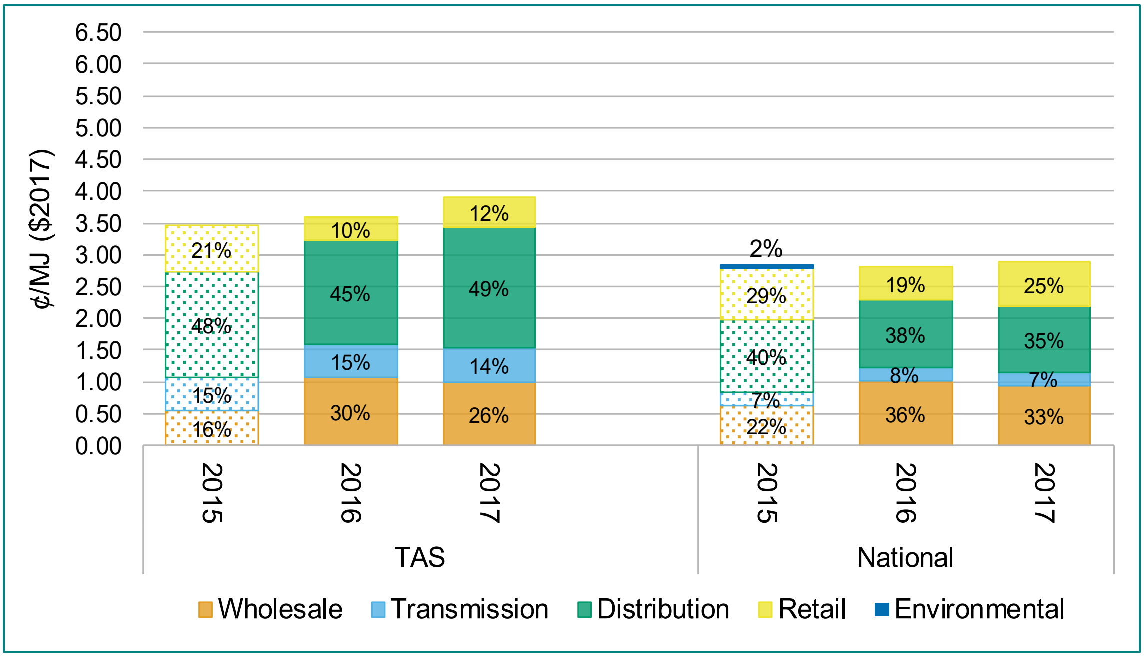
- Victoria is the largest residential gas market by volume, and delivered residential retail gas prices have increased some 16% from 2015 to 2017 but remain the cheapest in Australia by quite a margin due to the high volume and connection penetration. The apparent Retailer cost component dipped in 2016 as wholesale gas prices rose and were not fully reflected in retail prices but has since recovered somewhat as overall retail prices increased. There may have been a lag effect between wholesale gas prices increasing and being more fully passed through to residential customer delivered prices.

- The overall price increase has though been influenced mainly by the increase in wholesale gas prices being experienced in Victoria (from 27% in 2015 to 50% and 43% in 2016 and 2017 respectively) and combined with a moderate increase over the period in distribution charges (per GJ).

- The environmental costs of the Victorian Energy Efficiency Target (VEET) is estimated to be 0.003 ¢/GJ in 2017 and is a result of the traded price of the certificates with a price of approximately $11 in 2017.

2.4.3 Tasmania

Figure 14: Tasmania residential gas price trend 2015 to 2017



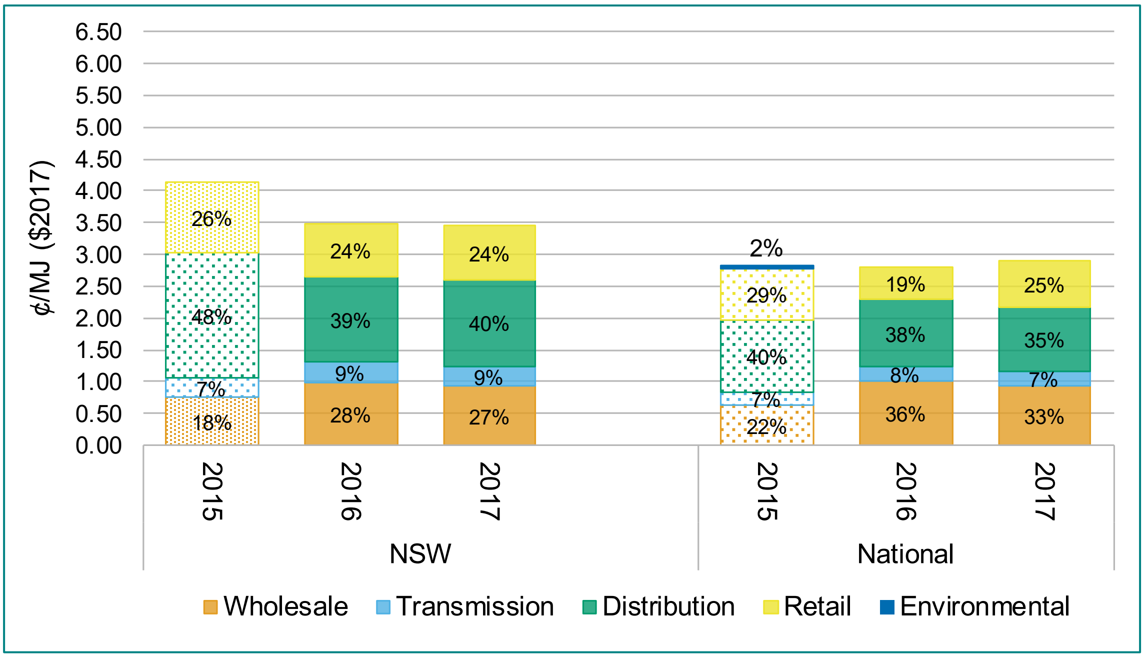
- The cost component analysis is difficult due to there being only two retailers, a relatively very small residential demand base and an unregulated gas distribution system with opaque charges. The application of the standard methodology for determining the cost components used for the other states would yield extraneous results. Therefore, for Tasmania, the wholesale gas component of the residential gas price analysis references the Victoria wholesale gas price providing a more consistent underlying wholesale gas component and a more likely reflection of actual retail procurement positions.

- Delivered residential retail gas prices have increased since 2015 by 13%. This appears to be a combination of realised increases in distribution charges of 13% and increased wholesale gas prices of 83% - and as a result tempering the retail component significantly to adjust.

- The challenge for Tasmania is the relatively large infrastructure investment to supply a small load but its delivered gas cost is quite competitive on a national scale e.g. similar delivered prices to NSW.

2.4.4 New South Wales

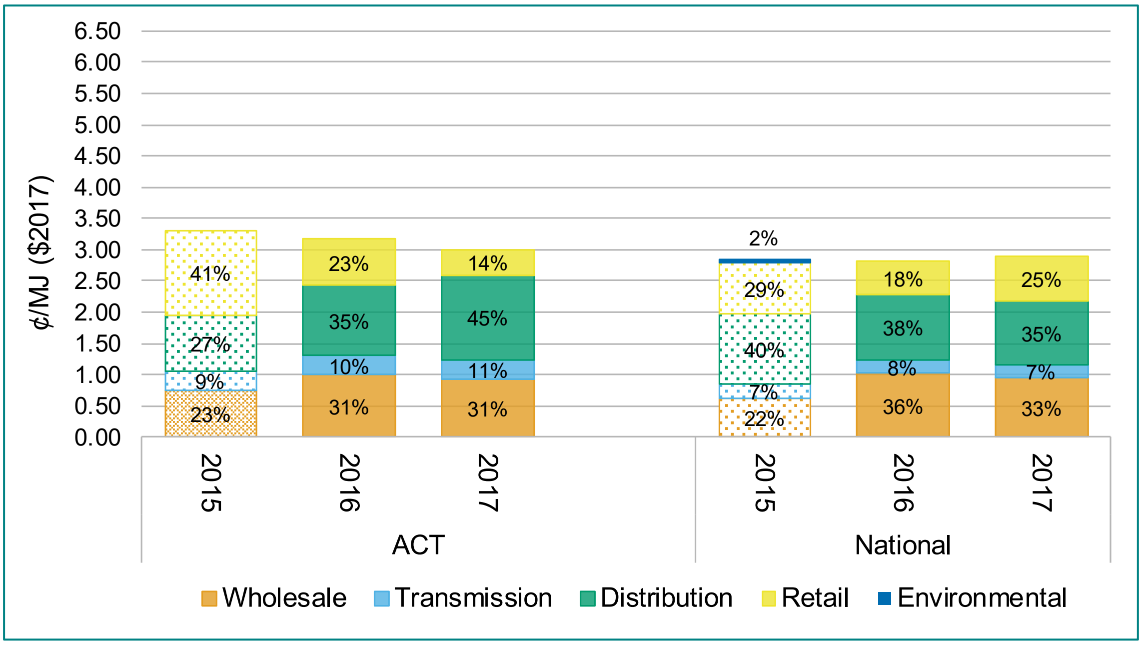
Figure 15: New South Wales residential gas price trend 2015 to 2017



- New South Wales data in this report includes both the rural and metropolitan gas pricing. More than 95% of gas in the state is supplied to Sydney but those in rural areas have double the consumption per connection.
- The average delivered residential gas price in NSW has eased somewhat since 2015, by around 17%. A relatively significant decrease in the distribution charges of 32% and a squeeze on the retail component of some 23% has largely offset an increase in the wholesale gas price of some 23% (or 0.83 ¢/MJ) delivering this overall reduction.
- Natural gas has now become eligible for the NSW Energy Savings Scheme in 2016. However, no certificates have been generated for the calendar year 2016.

2.4.5 Australian Capital Territory

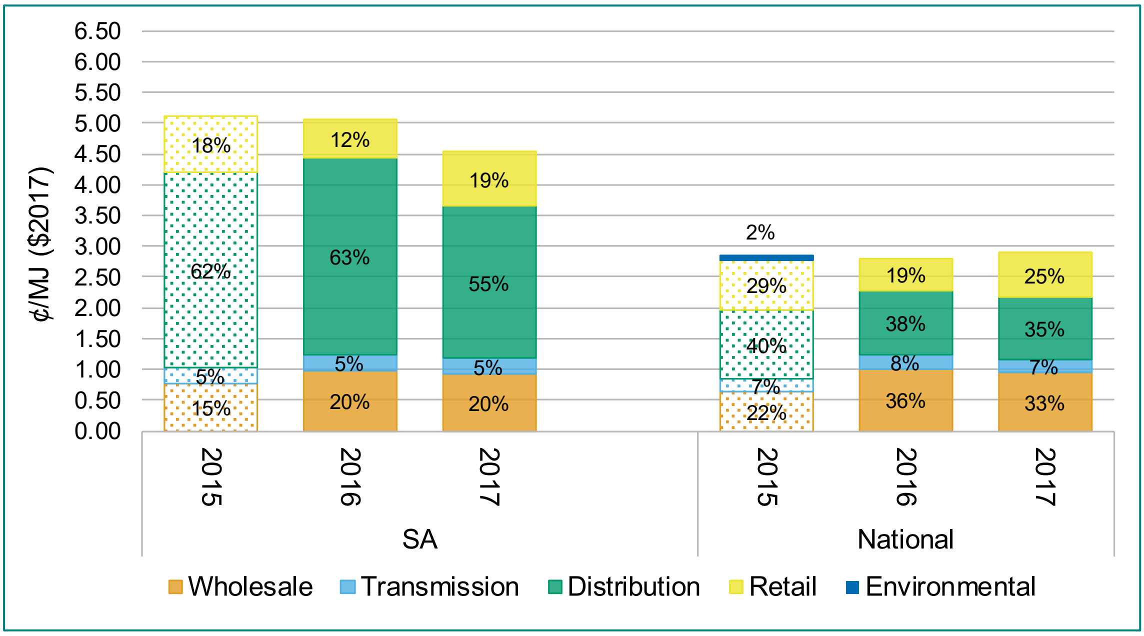
Figure 16: Australian Capital Territory residential gas price trend 2015 to 2017



- The Australian Capital Territory (ACT) delivered average residential gas price has had a moderate decrease from 2015 to 2017 of 7%. This is interesting as there has actually been an increase in the distribution charges component from 27% to 45% and an increase in the wholesale gas price component from 23% to 31%.
- Additional competition has entered into the ACT space with Origin and Energy Australia providing market offers with better discounts compared to the incumbent ActewAGL. This seems to have reduced the retail component which was very high in 2015 (41%) and is now lower than the national average at 14%.
- The ACT shows a long term declining trend in average residential consumption, similar to other jurisdictions. One possibility is due to a shift from gas to electricity for heating, which is a big household load in the ACT due to cold temperatures over winter as noted in the 2015 Gas Price Trends Report.

2.4.6 South Australia

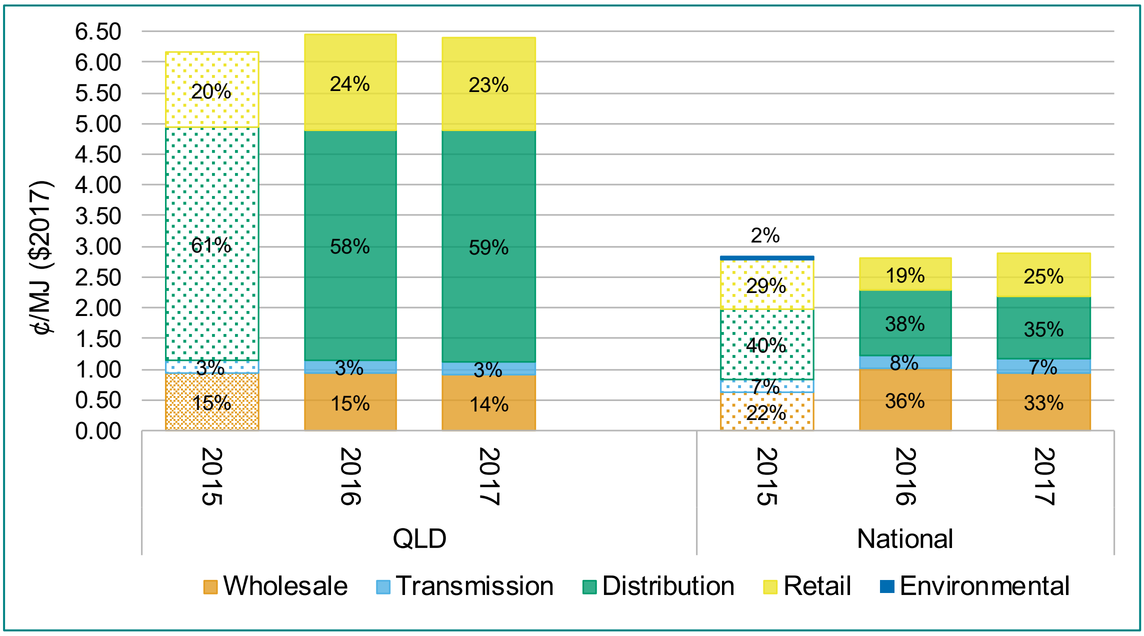
Figure 17: South Australia residential gas price trend 2015 to 2017



- The average delivered residential gas price rose in 2016 and has moved downward in 2017, with an overall reduction in residential delivered prices of some 12% from 2015.
- An increase in the retail component of costs (23%) and an underlying increase in wholesale gas costs (19%) has been more than offset by a significant drop in distribution costs driven by regulatory determinations in 2016.
- South Australia's consumption per household has been consistently declining, again as the use of electricity for space heating has been increasing (and gas decreasing).

2.4.7 Queensland

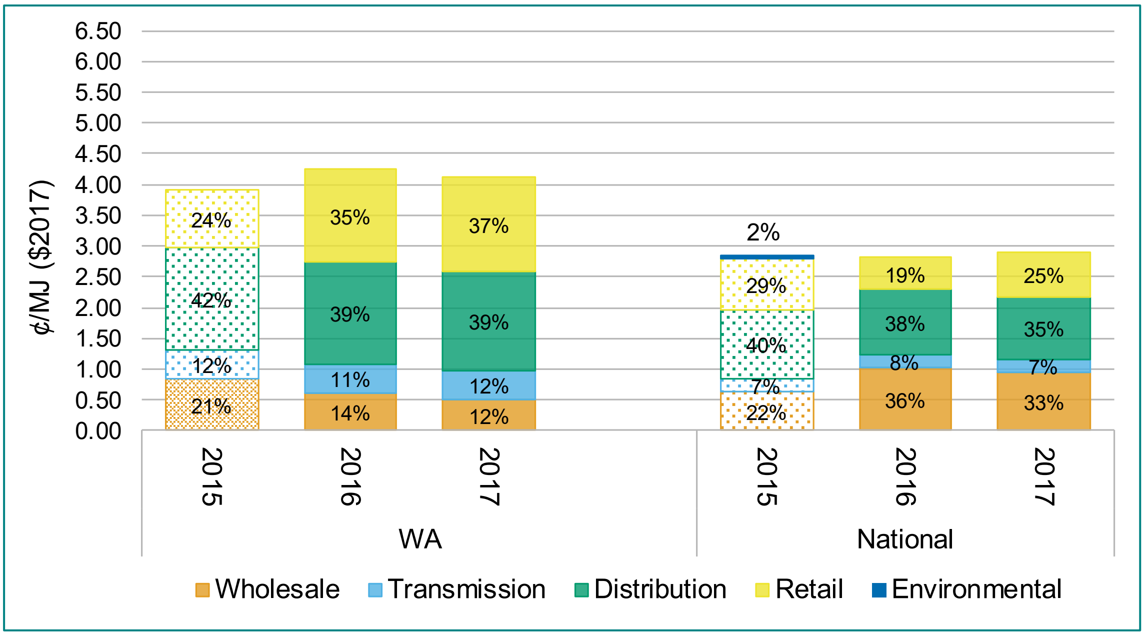
Figure 18: Queensland residential gas price trend 2015 to 2017



- Queensland has the lowest average gas consumption per household and low penetration resulting in the highest gas prices (driven by the highest average distribution prices).
- The average residential gas price rose in 2016 (4%) and is consistent from 2016 to 2017. The movement from 2015 to 2016 is mainly in the retail component, the other components remained fairly flat with a small decrease in wholesale gas costs and increase in transmission charges.

2.4.8 Western Australia

Figure 19: Western Australia residential gas price trend 2015 to 2017



- The retail residential gas price is a capped price regime with retailers offering various discount packages pegged to that published price.
- Western Australia's delivered residential gas price average edged upward in 2016 and dropped in 2017 to still be some 5% higher than 2015. There appears to be a combination of slightly easing of distribution charges and a major drop in wholesale gas price, offset by a major increase in the retail cost component (61% since 2015).
- It is feasible this apparent head room seems to have been an impetus for increased competition entering the market at the retail level in recent times - AGL and recently Origin have announced their intentions to enter the WA retail gas market. The market-offer discounts applied (e.g. AGL) are influencing the total price to trend downward a little from 2016 to 2017, but the wholesale gas price decreases seem to have not been fully passed through to the market yet and there may be timing issues with these wholesale price reductions in retailer portfolios.

2.5 Future price drivers

The key issue in nearly all the jurisdictional markets that will impact future wholesale gas prices is the supply and demand balance. This has been a consistent and well proven pattern in the Australian wholesale gas market – as we reported in 2015. Therefore, price drivers are heavily related to the supply of gas that is available to a market and the relative demand for it at the prices being charged.

It is also arguable that the wholesale price of electricity in the (east coast) NEM has also been heavily influenced in recent times by the price of gas as structural changes occur in the electricity generation market that start to see the underlying value of dispatchable gas plant being realised and used more. This is a complete reversal from 2015 when gas plant was not required for its dispatch capabilities except in extreme circumstances and could not compete on price in the NEM for any appreciable dispatch.

These structural changes in the electricity sector are also being heavily influenced by changing Government policy on reliability (and emissions) and therefore the major changes that could occur (and have been occurring) is greater demand for GPG gas supplies.

This comes on top of new policies and regulation related to the supply of gas back into the domestic gas market rather than being dedicated solely to LNG export, and various other changes that have seen more gas flow to the domestic market (such as excess supply and removal of joint venture sale arrangements) and clearly mitigate pricing.

If this continues and the electricity sector demand increases the relevant balance of the two (supply and GPG demand) will be critical and a serious consideration for policy makers and regulators. The current outcome of relatively high gas prices and electricity prices is not sustainable and yet is likely to continue if gas becomes the main marginal generation plant in the NEM for example.

This report does not seek to comment on state or federal government policy but it is clear that energy policy is a major issue related to the potential supply and demand for gas in the east coast market.

The marginal cost of gas on the east coast (supplying the NEM generators) is driven largely by the costs of supply of coal seam gas and already the cost at Gladstone may well be representative of that price. It is hard to see where cheap(er) gas can be sourced and delivered to the main NEM markets on the east coast.

There is some movement still to come on gas price reductions on the east coast, but they are likely to be marginal and not sufficient to lower GPG costs into the NEM.

This competition for domestic gas supply by the GPG market also creates problems for the other gas users – particularly industrial and manufacturing users. When GPG comes back on line the movements in demand can be very high as they are major consumers – they are effectively the “swinging” demand in the domestic market. It is also likely GPG will be looking for short term supply and transport agreements or buying on market/trading – again a trend we have seen in this report.

If the GPG market once again recedes within the NEM dispatch reducing demand for gas and also gas supply remains robust, the gas prices should recede to be more reflective of the cost of CSG production (as the marginal gas available) delivered to the various hubs – continuing the price reversal we have seen on the east coast.

The opportunity for gas price relief beyond the marginal cost of CSG production will come if there is more competition from reservoir based gas production (such as from Bass Strait, NT) or more localised CSG in NSW and Victoria that would bypass the effective transmission cost mark-ups.

Other options that might assist to reduce delivered gas costs, or potentially curb major gas price rises in the future include:

- Removal of transmission constraints to move gas, or new transmission pipelines that may haul gas at lower costs (e.g. Wallumbilla to Sydney).
  - The Gas Market Reform Group (GMRG) as part of the COAG Energy Council are undertaking a number of activities for reforms for pipeline commercial arbitration framework, number of transportation capacity trading reforms and wholesale gas market related reforms to develop greater transparency on pricing and markets.
- Maturing spot markets and gas trading platforms and arrangements with an improved level of price discovery and increased volumes and liquidity – a participant trading market may assist on the east coast as well.
- Lower cost of production for CSG fields – technical focus has been strong on this issue in the sector and it is reported to be improving.
- Floating LNG facilities at ports like Sydney and Melbourne (or even Adelaide and Hobart)
  - While LNG regasification may not reduce prices directly, the effect of storage at peak times being available may mitigate peak domestic gas pricing and deliver longer term domestic gas pricing caps.
- More exploration activity focused on domestic supply.

A high oil price may also have a major impact on supply as there is a correlation with gas developments for LNG – so if international demand (and price) for LNG was to escalate we may see once again major exploration programs. This may lead to some gas flow into the domestic market at attractive prices. However, if this is not well managed, LNG netback pricing may once again dominate the domestic market.

Large and Small Industrial Price Trends

3 Australia's gas markets

3.1 Introduction

There have been major movements in gas prices and underlying gas price drivers since the Gas Price Trends Review 2015. The net result is a far greater awareness in the community of the impact and role of (i) gas supply and (ii) price sensitivity.

The underlying gas price drivers include:

- Supply/demand balance.
- LNG development and new capacity becoming operational in Western Australia and Queensland.
- Liquidity and transparency in spot markets.
- Policy statements such as the
  - Australian Domestic Gas Security Mechanism, and the
  - National Energy Guarantee.
- Electricity market response to security issues.
- Incidents such as the Basslink outage in December 2015, SA blackouts ('SA region Black System event' in September 2016) and SA's load shedding events in February 2017 and how these have augmented the importance of gas in Australia's energy mix.

Matters relating to gas transport, accessibility and the development of that sector are addressed in the Transmission Industry Trends chapter.

3.2 Gas Price Trends Review 2015

The Gas Price Trends Review 2015 noted with regard to key drivers for industrial gas prices:

The key issue in nearly all the jurisdictional markets that will impact future wholesale gas prices is the supply and demand balance, including the ability to transport (haul) gas without undue transmission constraints. The simple economic models of supply and demand balances and clearing prices are always at play in the gas market.

Scarcity of supply has seen gas prices rise, which in turn has seen demand reduced and new supply enter the various jurisdictional markets. Price increases may seem to be a windfall for those sellers with market power, but it can be seen from this report that price increases are an essential component in the development of new supply.

3.3 Australia's wholesale gas markets

The definition and components of the wholesale gas market have not changed in the last two years and neither has these underlying drivers - rather it is the increase in gas supply and competition, amongst other matters, which have changed and driven change. The Gas Price Trends Review 2015 stated:

A wholesale gas market is defined in this report to be where gas producers, retailers, and large gas consuming (industrial) customers buy and sell gas – the two key areas are the east and west coast markets, which are not physically interconnected.

Most participants in the wholesale gas market purchase gas under firm gas supply agreements (GSAs). That is, buyers enter into a bilateral GSA with wholesale suppliers to satisfy their gas requirements at an agreed price, with limited rights of interruption and for an agreed term. In the case of retailers, they have multiple GSAs that provide an aggregate gas supply that satisfies the demand of their customers.

While there are exceptions to this type of GSA arrangement, and parties may also seek to purchase gas from spot markets, a firm GSA is the dominant type of contract for wholesale gas market participants.

The wholesale gas market in Australia is a relatively illiquid market[14] in that there are only a few sellers and buyers at any one time and the market does not have an accessible and managed market place or exchange. It is contractually driven and contractual confidentiality is a cornerstone of the market. As a result, there is little wholesale gas price transparency.

Australia also has several spot wholesale gas markets where buyers and sellers trade gas on a daily basis. These are the Short Term Trading Markets (STTMs) that operate in Brisbane, Sydney and Adelaide and also the Declared Wholesale Gas Market (DWGM) operating in Victoria (operated by AEMO).

The eastern gas market also has the Wallumbilla Gas Supply Hub (GSH), which is an exchange for the voluntary trade of wholesale gas at an upstream location in southern Queensland.[15] It allows participants to trade gas over longer terms than just a daily imbalance including weekly, monthly and three monthly, using standardised contracts. It also provides a mechanism to list an interest to trade transmission pipeline capacity.

This definition is maintained in this Gas Price Trends Review 2017, although another GSH has been developed at Moomba since the 2015 report (June 2016).

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14 Compared to the National Electricity Market (NEM), for example.

15 At Wallumbilla, three gas transmission pipelines converge, namely the: Queensland Gas Pipeline (QGP); Roma to Brisbane Pipeline (RBP); and the South West Queensland Pipeline (SWQP). In addition, pipelines from several CSG fields meet at Wallumbilla. It is therefore a convenient place to trade wholesale gas at an upstream location.

3.4 Supply side

The largest gas producers are now Western Australia and Queensland. Western Australia is predominantly an offshore producer and Queensland is an onshore producer of predominantly coal seam gas as opposed to the traditional conventional gas.

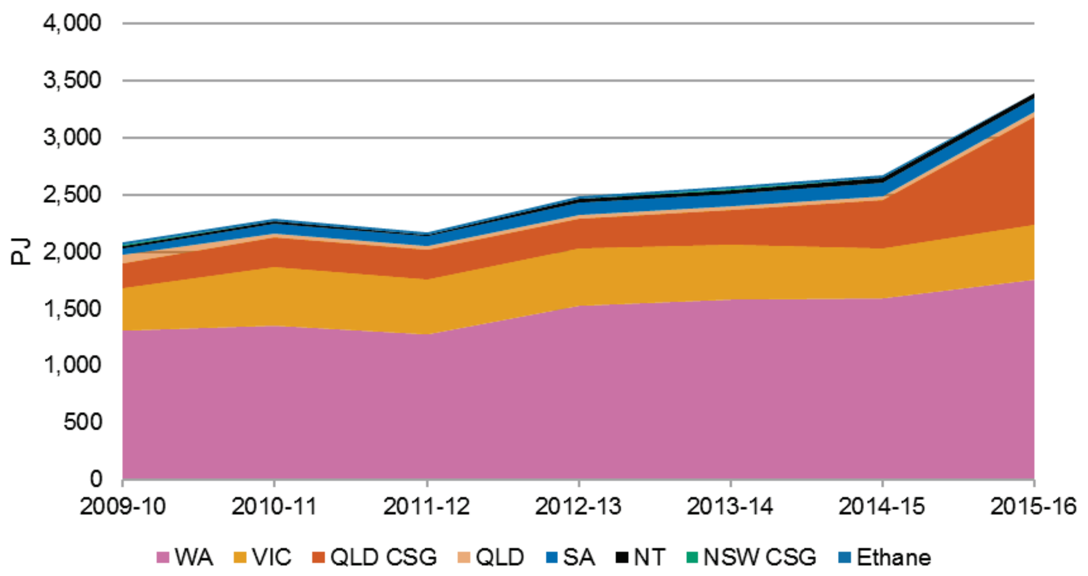
The Gippsland, Otway and Bass Basins supplying into Victoria's onshore infrastructure gas processing plants, 80% of which is produced from the Gippsland Basin Joint Venture[16] (GBJV). These basins are technically offshore producers. Victoria is the third major source of supply into the Australian gas market. New South Wales is the second largest consumer of gas and produces a negligible amount of gas from coal seams hence it must 'import' its gas from Queensland or South Australia Cooper Basin producers through Moomba via the Moomba to Sydney Pipeline (MSP)or from Victoria the Eastern Gas Pipeline (EGP).

Coal seam gas production accelerated within the period 2014 to 2017 to meet demand from the new LNG export plants in Queensland.

The major difference is the gas supply from coal seam gas is onshore and the method of production is more distributed across wide areas and into coal seam geological structures.

Figure 20 illustrates the state by state gas production with separate coal seam gas sectors (CSG) for Queensland (QLD) and New South Wales (NSW).

Figure 20: Total gas production in Australia including ethane 2009 - 2016



Source: Department of the Environment and Energy, Australian Energy Statistics, Table R, August 2017

16 Department of Innovation, Industry and Science (November 2017) Offshore South East Australia Future Gas Supply Study.

The largest increase in production has been from QLD CSG since 2014 aligning with the commissioning and commencement of operations of the three LNG projects located in Gladstone.

Table 4: Main drivers of QLD CSG production from LNG plant operations

Plant	Year of operation[17]	Capacity (Mtpa)	Equivalent PJ/a
APLNG	2015	9	499
GLNG	2015	7.8	432
QCLNG	2014	8.5	471

3.4.1 LNG development

Australia exported some 52 million tons (Mt) of LNG in the 2016/17 financial year[18] which is equivalent to approximately 2,830 PJ, more than doubling the export volumes in the 2014/15 financial year of 25 Mt or approximately 1,360 PJ.[19]

Figure 21 illustrates the location and relative percentage production of LNG plants in the three main production zones:

- North West Shelf, WA.
- Darwin, NT.
- Gladstone, QLD.

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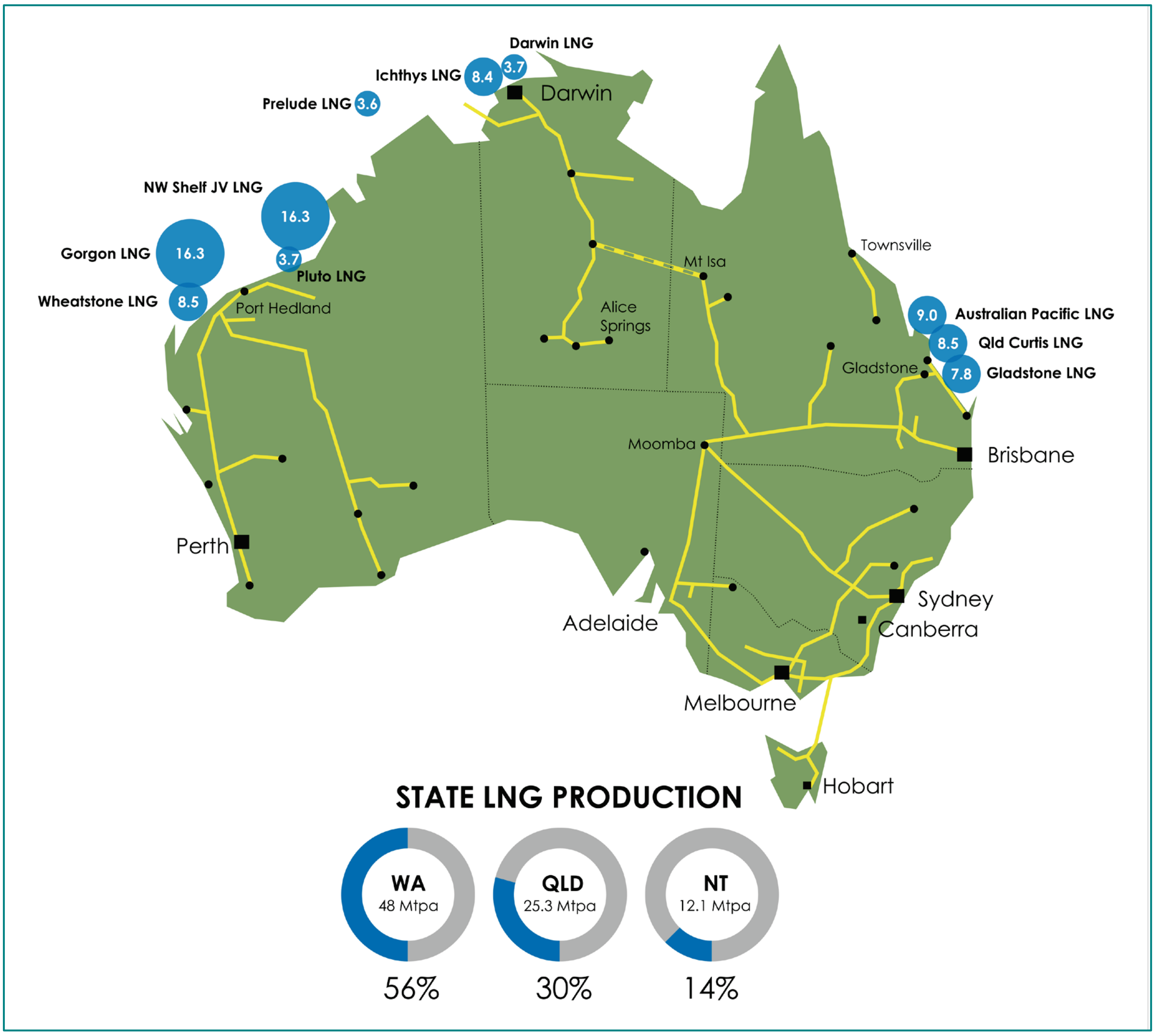
17 APPEA, Australian LNG Projects. APPEA website

18 DEE (2017) Australian Petroleum Statistics LNG exports by rural 2016-17.

19 Department of Industry, Innovation and Science - Office of the Chief Economist, Resources and Energy Quarterly, September 2015. PJ values have been converted from Mt using 1 Mt = 54.4 PJ.

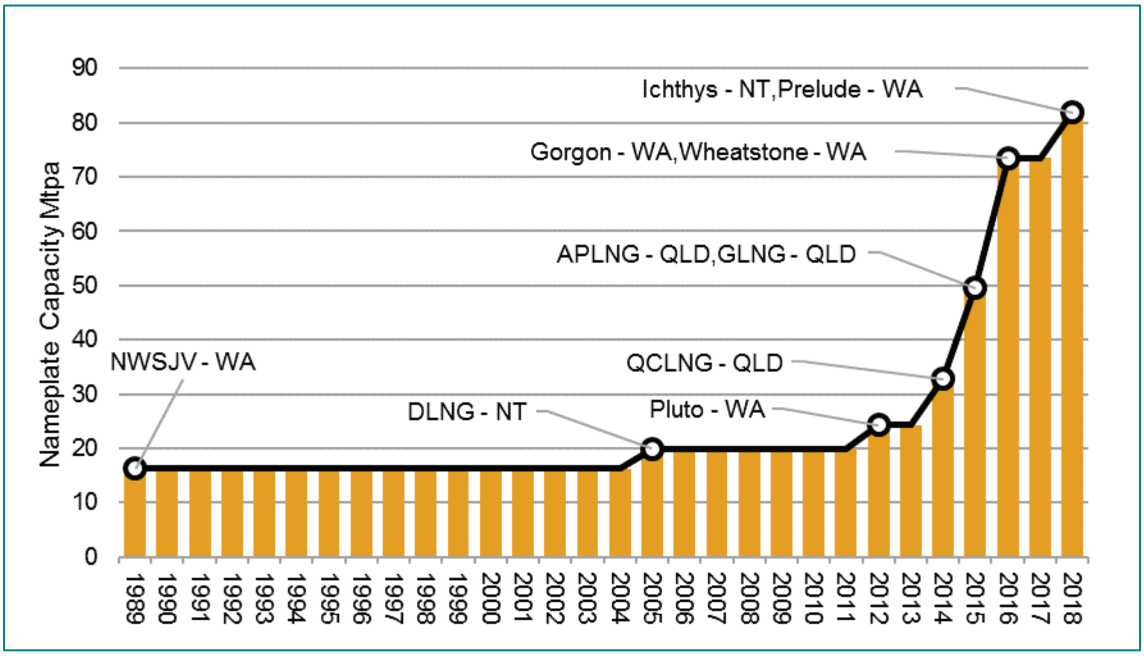
Figure 21: Summary of Australian LNG plant operations and production



Source: APPEA, Australian LNG Plants, [APPEA website](#).

Figure 22 shows Australia's LNG development since the North West Shelf Joint Venture in WA started operations in 1989. Darwin LNG and Pluto commenced operations in 2005 and 2012 respectively. In the period from 2014 to 2016, there has been rapid investment and commencement of operations of LNG plants in Queensland and Western Australia increasing output capacity by 200% in three years on top of the previous three decades of development. This increase will be further augmented by the completion of Ichthys in the Northern Territory and Prelude in Western Australia, both in 2018.

Figure 22: Australia's LNG capacity development from 1989 to 2018



Source: APPEA, Australian LNG Plants, APPEA website.

In the 2014 to 2016 period, a total of 25.3 million tons per annum (Mtpa) of LNG capacity became operational in Queensland and almost the same amount (23.9 Mtpa) became operational in Western Australia.

3.5 Demand side

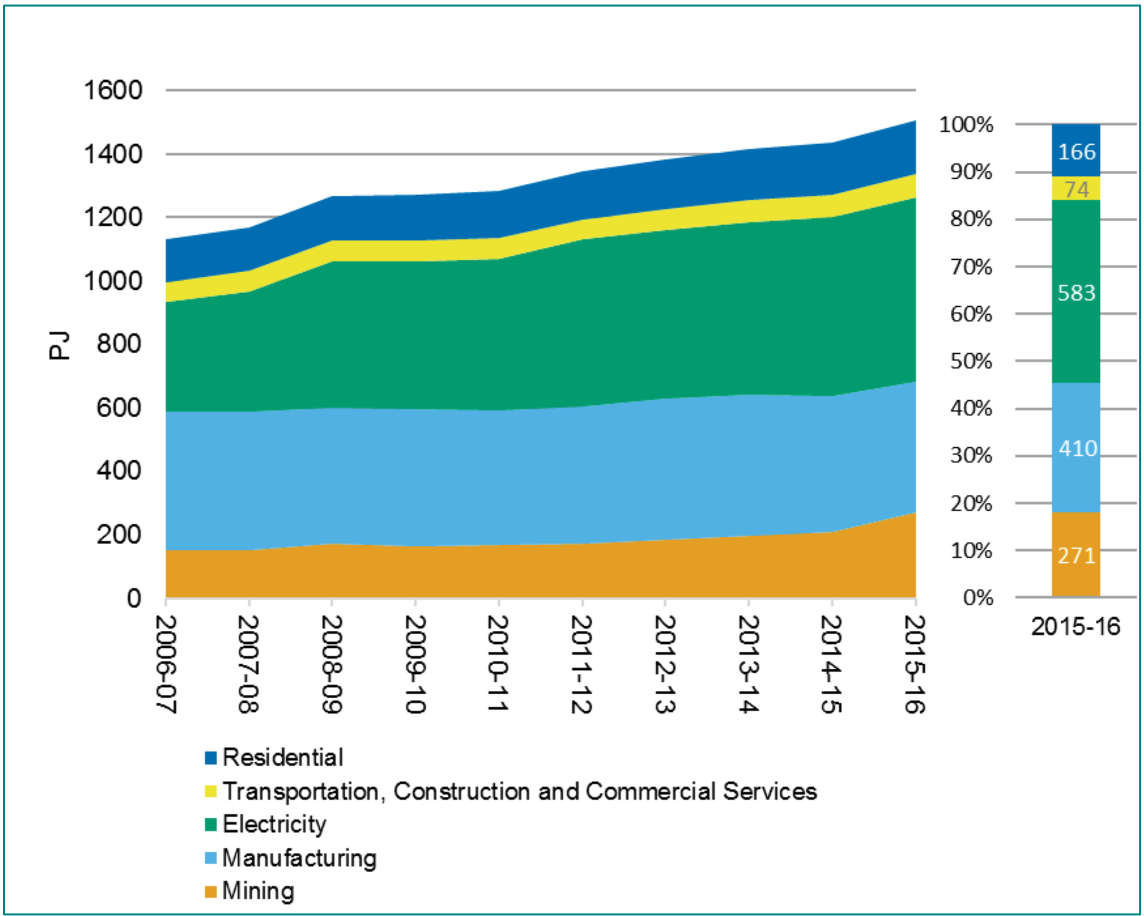
3.5.1 Domestic gas consumption

Total Australian domestic gas consumption was approximately 1,506 petajoules[20] (PJ) in 2015-16, an increase of 6% from the 1,416[21] petajoules (PJ) in 2013-2014. Natural gas is consumed in every state and territory and is used by various sectors including industry, power generation and residential and commercial customers as shown in Figure 23. Note that Mining includes gas consumption used in the liquefaction process for converting natural gas to LNG (but not gas exported as LNG).

20 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

21 Consumption updated from Gas Price Trends Review 2015 (1,402 PJ) using latest data available.

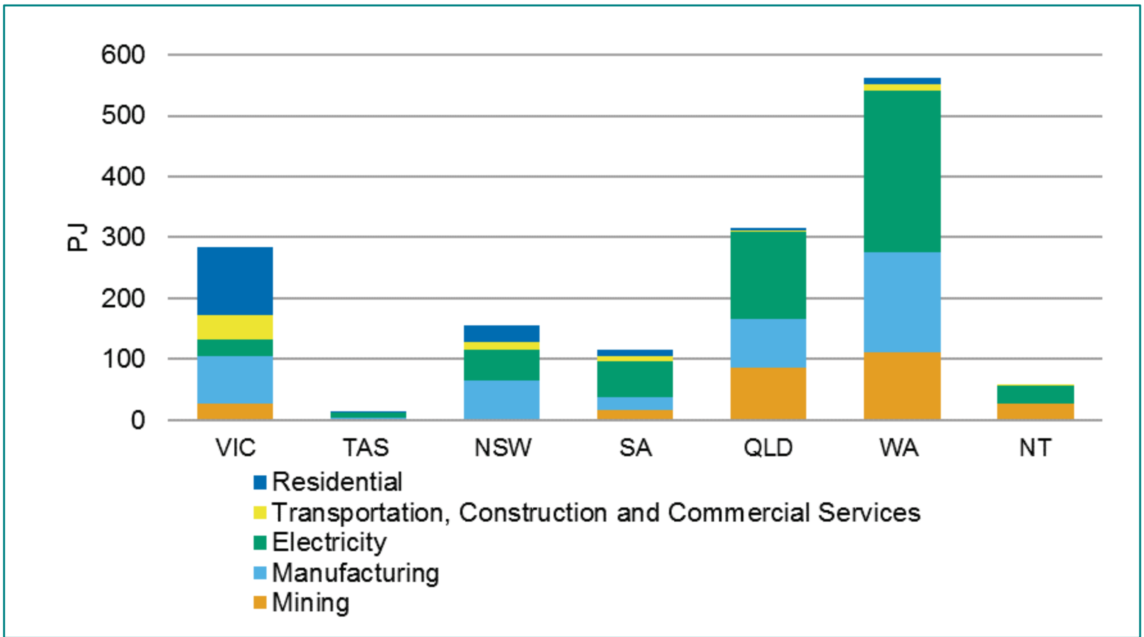
Figure 23 : Annual gas consumption in Australia by sector for financial year 2006-2016.



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Consumption across sectors and across the states varies as can be seen in Figure 24.

Figure 24: Annual gas consumption by sector and jurisdiction for financial year 2015-2016.



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

3.6 Gas commodity spot markets

The gas spot markets have become increasingly liquid over the last three years – in both number of trades and volumes traded. This has presented some additional transparency in traded prices, but the market in Australia is still predominantly a bilateral market with little visibility on contracted prices.

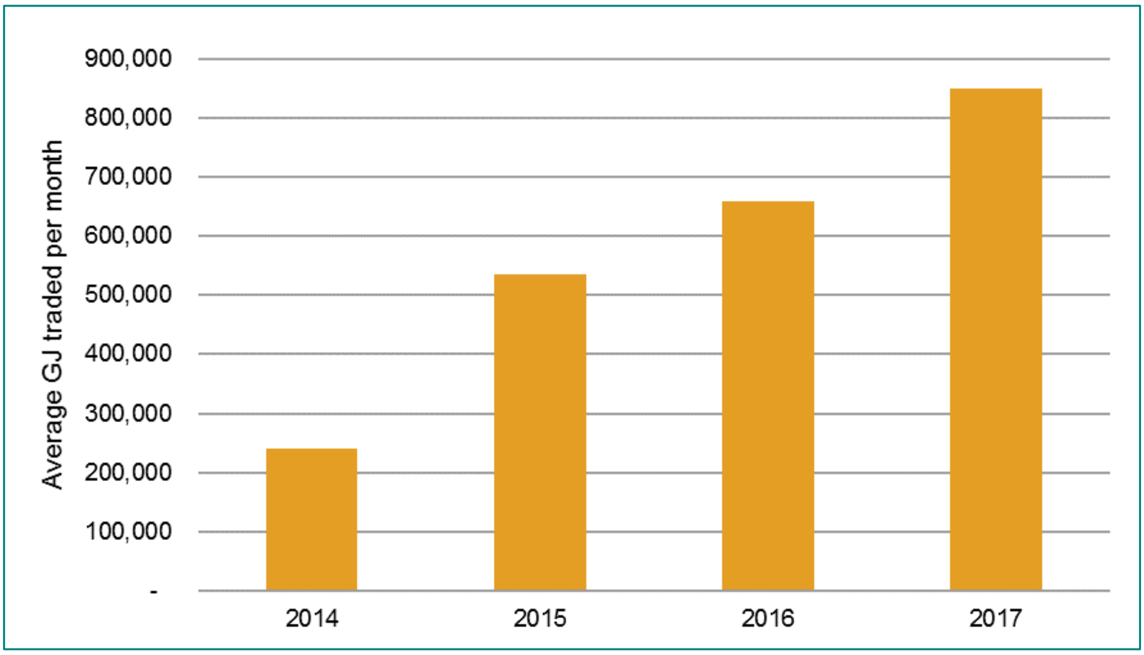
The short-term gas trading markets in Australia include:

- Wallumbilla and Moomba gas supply hubs.
- The Short Term Trading Markets in Sydney, Adelaide and Brisbane.
- The Declared Wholesale Gas Market in Victoria.
- The Gas Trading Australia bulletin board in Western Australia.

3.6.1 East coast spot markets

Data obtained and illustrated in Figure 25 for the Wallumbilla gas supply hub's trend in trading volumes suggests the volume of trades is steadily increasing. While the volume of trades is a small percentage of the traditional bilateral markets, the increasing volumes will provide a more credible source of price discovery for buyers and sellers.

Figure 25: Wallumbilla Hub average trading volumes per month



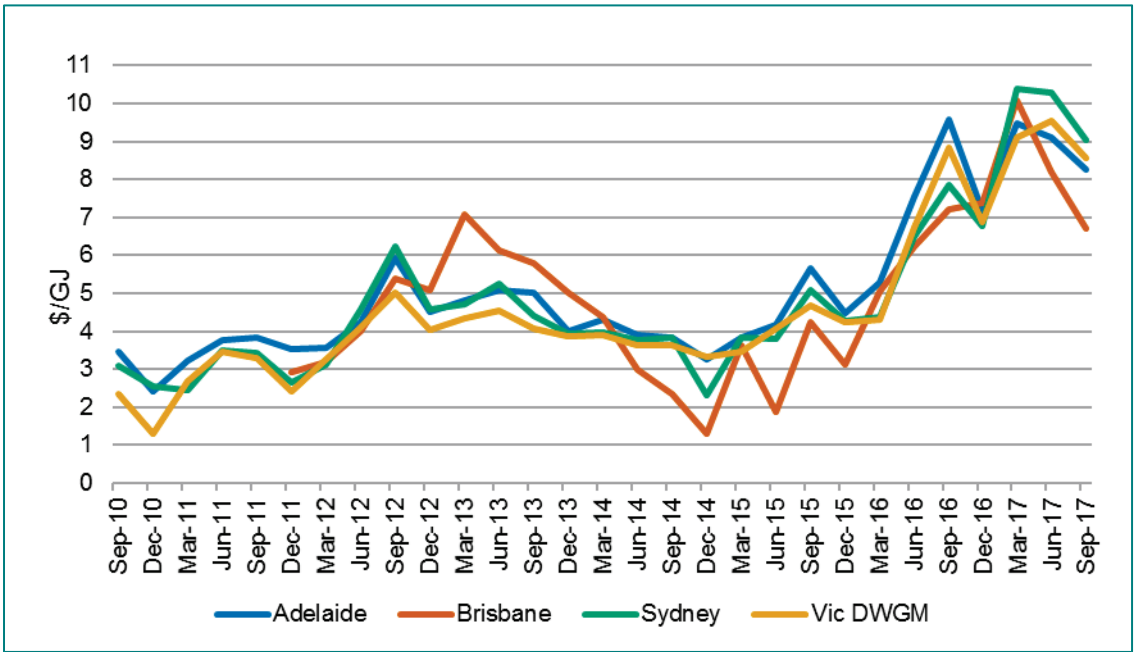
Source: AER wholesale statistics - Wallumbilla Gas Supply Hub - trade volume and volume weighted average prices by pipeline.

Figure 26 is a plot of data from four of the short-term trading markets in Adelaide, Sydney, Brisbane and the Victoria Declared Wholesale Gas Market. Prices trends for the four markets have been largely consistent since 2010. The key points to note are:

- All markets have a consistent trend upward post 2014.

- All markets peak in 2016/17.
- All markets have a downward price trend in 2017.
- Brisbane/SEQ decline May to Sep 2017 is down to below $7/GJ.
- All trends are consistent with the large industrial (>1 PJ/a) gas prices.

Figure 26: East coast short term trading market gas price trend



Source: AER wholesale statistics – (i) STTM quarterly prices and (ii) Victorian gas market average daily weighted prices by quarter.

3.6.2 WA spot markets

The gas spot market in Western Australia is a self-regulated system owned and operated by Gas Trading Australia Pty Ltd. Spot gas trades have been transacted since 2012. The spot gas platform provides a transparent trading mechanism for market participants to buy or sell gas if they need to.

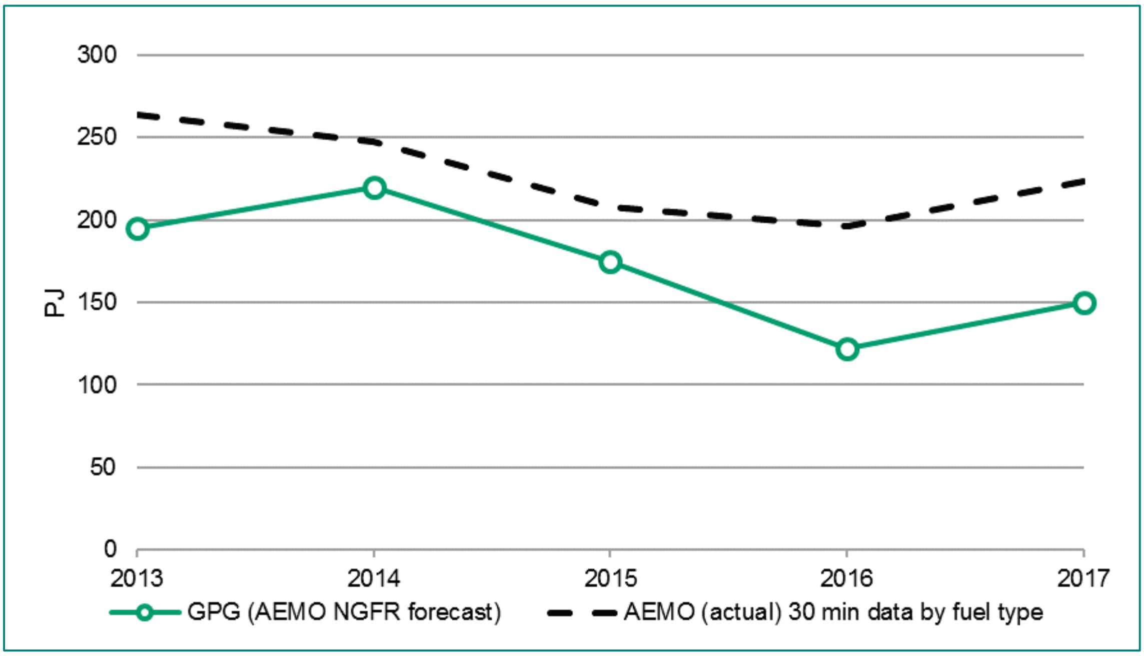
3.7 National Energy Guarantee

In October 2017, the Australian Government announced a proposal to establish the National Energy Guarantee (Guarantee). The Guarantee includes: (i) the reliability guarantee and (ii) the emissions guarantee.

The reliability guarantee establishes a level of dispatchable generation in each state. Gas generation plant is generally dispatchable and as the penetration of intermittent renewable generation increases, it can reasonably be expected gas generation will be called for this purpose (along with coal, batteries, etc.) depending on response times required.

Figure 27 shows the forecast and actual gas power generation consumption trend and a 14% uplift in actual consumption from 2016 to 2017. While the single cause of this uplift cannot be ascertained from this data, contributions would come from the shutdowns of Hazelwood (VIC) and Northern (SA) coal power stations and electricity system security requirements in the wake of the SA blackouts in September 2016, the SA load shedding event of February 2017.

Figure 27: East coast market gas power generation gas consumption trend 2013 to 2017



Source: AEMO National Gas Forecasting Report (Version 23/12/2016) and AEMO 30 minute generation data

The emissions guarantee is set by the Australian Government and administered by the AER. Where gas fuelled generation can contribute to the emissions guarantee, one might expect an influence on the total gas consumption.

3.8 Electricity price movement

The link to electricity price is via dispatch of gas-fuelled generation as the marginal unit in the operation of the NEM. The marginal price of the marginal unit sets the electricity market price and when the marginal generating unit is gas-fuelled, there is a direct link to the price of gas.

4 Industrial customer price trends

4.1 Introduction

This section is a state–by-state roundup of gas price trends for small and large industrial customers followed by a national summary and discussion on trends, drivers and short-term expectations.

The trends are shown from years 2006 to 2017 and the gas prices are represented as those for which a buyer is entering into a new supply contract in that year and is represented in real and nominal terms.

Transport costs are also provided for each state and priced at assumed injection and supply points as noted in the respective jurisdictional analysis.

Large industrial customers are defined as consuming over 1 PJ/a.

Small industrial customers are defined as consuming between 0.1 PJ/a and 1 PJ/a.

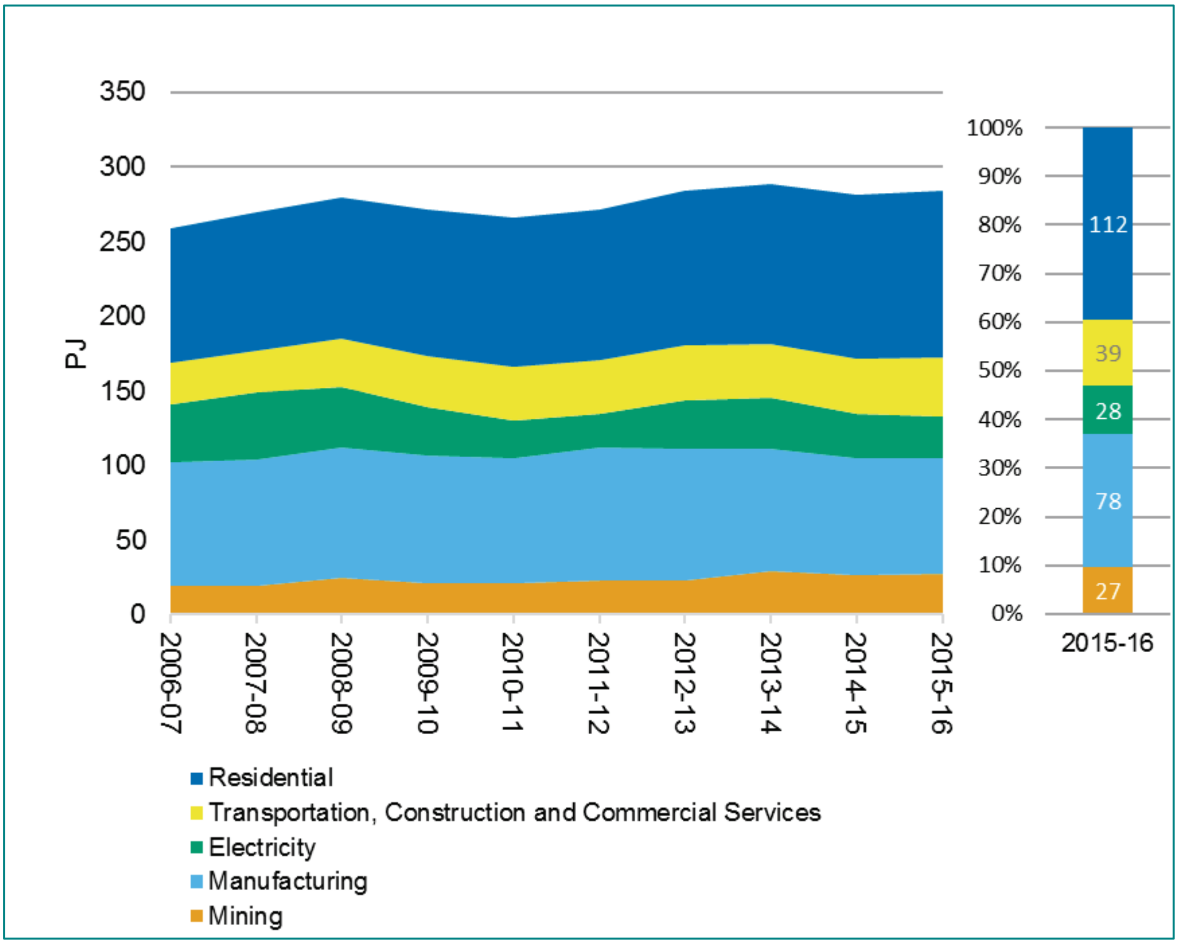
For detailed methodology and definition, refer Appendix B.

4.2 Victoria industrial gas prices

4.2.1 Victoria gas consumption trends

Figure 28 illustrates the gas consumption trends by sector and percentage contribution of each sector. There is a slight trend downward in total from 2014 to 2016.

Figure 28: Victoria gas consumption by sector (PJ)



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Table 5 indicates total gas consumption in Victoria was 284 PJ in 2015-2016 with Manufacturing and Mining consuming a combined 37% (105 PJ) and residential consumption accounting for the largest sector at 39% (112 PJ). Other major consumers were Commercial and Electricity. Total consumption has decreased 1% from 288 PJ in 2013-14.

Table 5: Victoria sectoral consumption volume trends 2013-14 to 2015-16.[22]

	2013-14	2015-16	Trend %
Mining	29	27	-7%
Manufacturing	81	78	-5%
Electricity	34	28	-18%

22 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

	2013-14	2015-16	Trend %
Transportation, Construction and Commercial Services	36	39	7%
Residential	107	112	5%
Total	288	284	-1%

4.2.2 Victoria large industrial customer gas price trends

The average prices paid by Victorian large industrial customers entering into a new supply contract on a year-by-year basis is shown in Figure 29 below. The large industrial customer gas price is the sum of the prevailing average Victorian wholesale gas price and gas transportation costs to Melbourne. Transportation costs assume an injection point at Longford and a supply point at Metro South East. Transportation costs will vary depending on whether a large industrial customer's facility is outside the Melbourne metro region.

In 2017, the average gas price delivered to Victorian large industrial customers was $10.39/GJ, of which $10.00/GJ (96%) was the wholesale gas cost and $0.39/GJ (4%) was pipeline transportation costs.

Table 6 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The increase in gas price is 78% on the 2015 gas price.

Table 6: Victoria gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	5.45	10.67	10.00	96%	83%
Transport	0.39	0.39	0.39	4%	-1%
Total	5.85	11.06	10.39	100%	78%

Figure 29 shows a peak in delivered gas price in 2016 of $11.06/GJ ($2017) and a tempering to $10.39/GJ in 2017.

Figure 29: Victorian real and nominal large industrial delivered gas prices (Melbourne)

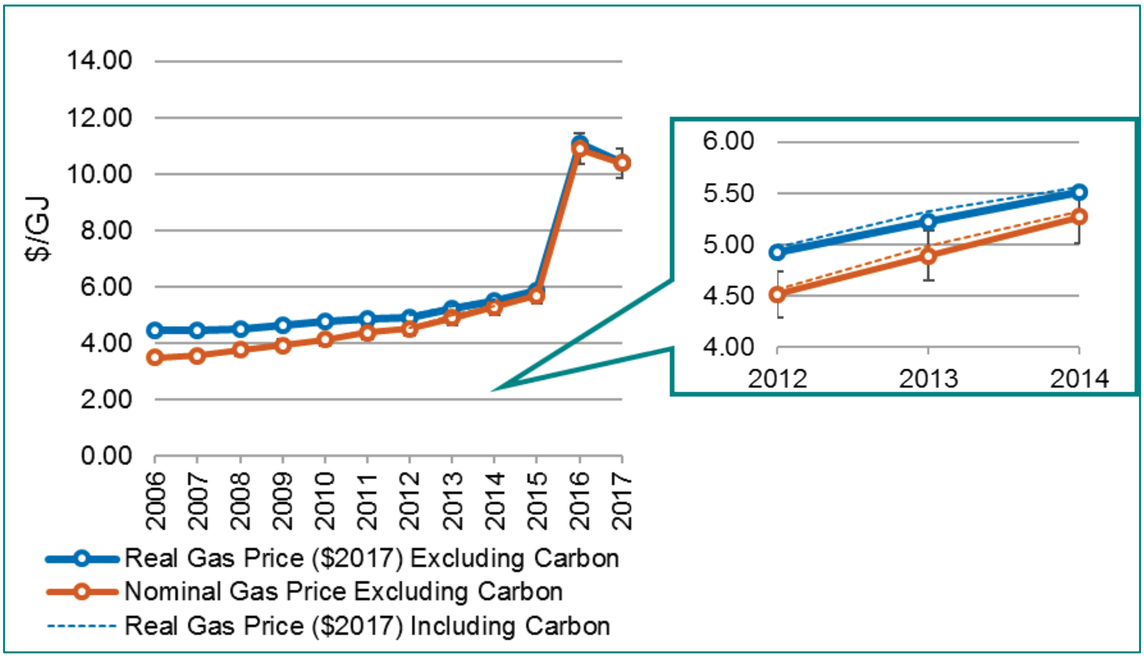


Figure 30 below shows the average cost of different components making up the large industrial gas price in Victoria from 2006 to 2017. It can be seen that:

- The impost of the Scope 3 emissions for Victoria under the carbon tax had a minor impact on the effective price customers paid for gas during that period.
- The real delivered price of gas up to about 2012 was reasonably flat.
- Moderate increases started in the period from 2013 to 2015.
- From 2015 to 2016 the gas price has almost doubled, and prices have trended down a little in 2017.

Figure 30: Victorian large industrial customer gas price components (Melbourne)

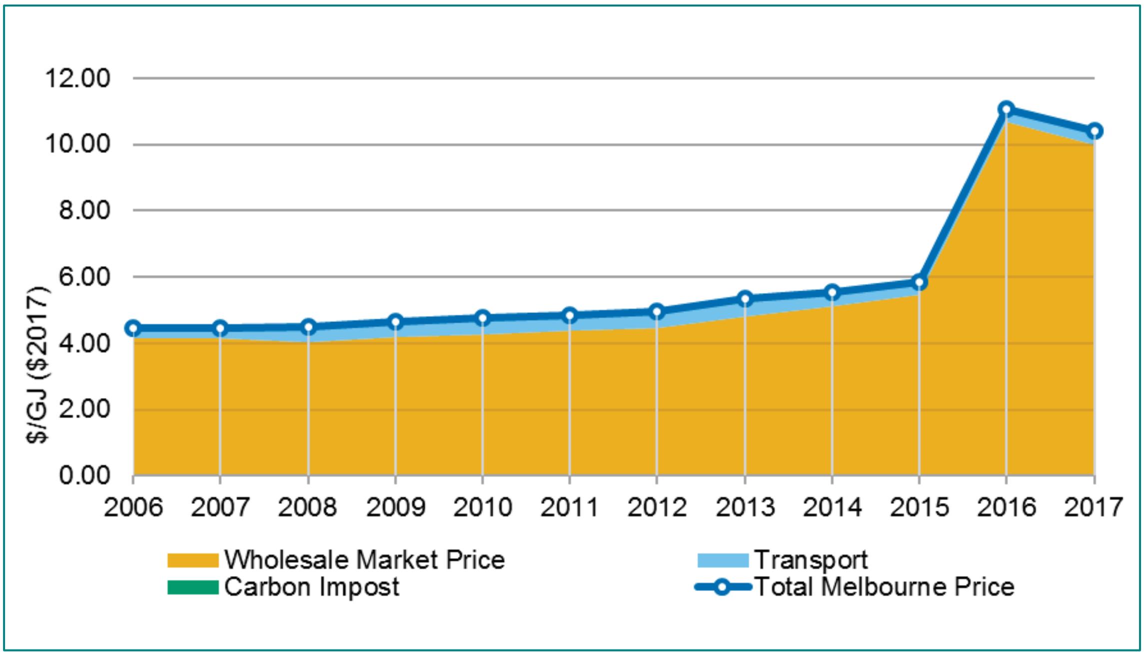
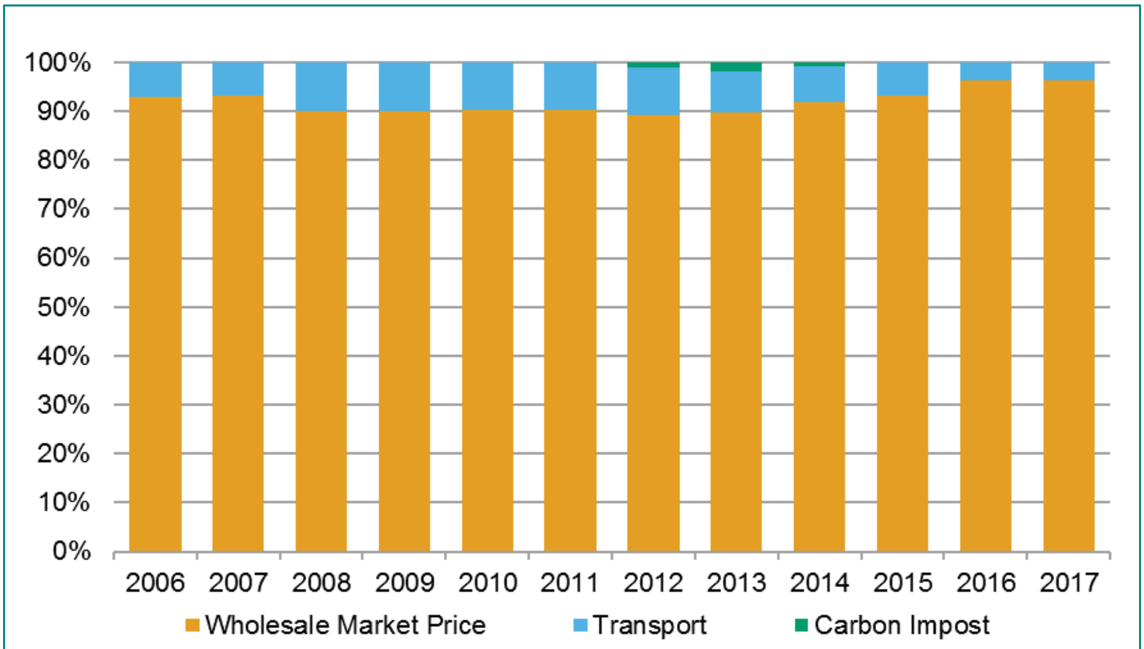


Figure 31 shows the percentage breakdown of different components making up the large industrial gas price in Victoria from 2006 to 2017. Unlike most other markets in Australia, transportation costs are relatively low as gas supply is very close to the market. This is a unique advantage for Victorian large industrial customers. As the gas price has increased the relative percentage of transport cost has decreased.

Figure 31: Victorian large industrial gas price components by %



4.2.3 Victorian large industrial customer gas price analysis

The key findings from analysing gas prices paid by large industrial customers in Victoria between 2015 and 2017 are:

- Large industrial customers have been impacted by the supply/demand imbalance that occurs when the dynamics of the interconnected east coast market are subjected to a fundamental shift in locational demand and supply shortages.
- Long standing legacy gas contracts supplied from the Gippsland Basin producers have expired or are expiring, and prices being secured in the last two years reflect the inflation in gas cost and price discovery by producers under different market conditions of tight supply.
- On 16 March 2017, the Victorian State Government brought into operation the Resources Amendment Legislation (Fracking Ban) Act 2017. The Act provides for amendment of existing legislation and imposes (i) a ban on hydraulic fracturing, (ii) prevents exploration and mining of coal seam gas and (iii) imposes a moratorium on onshore petroleum exploration and production until 30 June 2020[23].
- In 2015, the Victoria gas price for large industrials was the lowest on the east coast.
- Now in 2017, the Victoria gas price for large industrial customers is one of the highest on the east coast – a major reversal, yet in isolation, the supply demand balance in Victoria hasn't changed. It appears the high prices experienced by Queensland in 2015 have migrated down to Victoria due to the commencement of flows of gas from Victoria/Bass Strait to Queensland in the absence of sufficient localised gas supply to the LNG plants in Gladstone.
- Demand from the Queensland LNG plant operations for domestic gas (above Queensland's own production from CSG) effectively drew gas supply from Victoria in order to directly or indirectly supply the Queensland demand, competing on price as supply tightened, but
- This appears now to be changing in late 2017 as gas from the north flows south.

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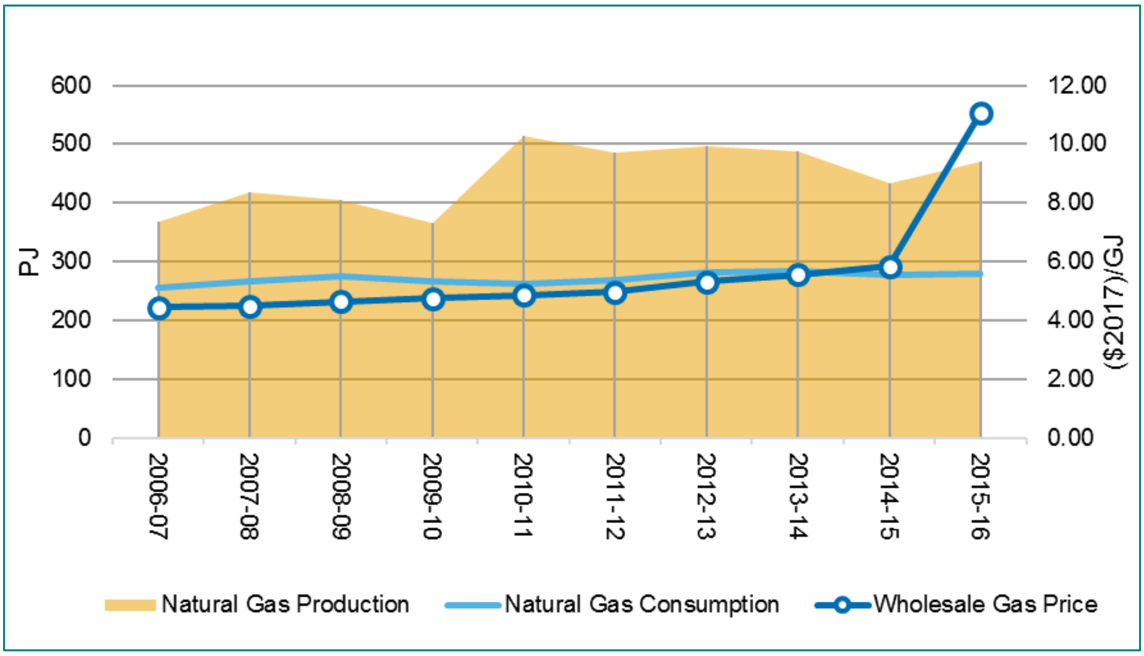
23 Victoria Government, Onshore Gas Community Information, on shore gas website accessed 5 December 2017.

Figure 32: Victoria native gas supply/demand



4.2.4 Victorian small industrial customer price trends

A set of actual contract data was available for small industrial customers for Melbourne and for rural Victoria.

The prices in Figure 33 are for delivered gas in Melbourne, including transmission and network charges (mostly transmission) and charges for the gas commodity, primarily by Retailers to small industrial customers.

As can be seen in the price components in Figure 34, the carbon tax between 2012 and 2014, did have a major influence on gas price rises and falls as Retailers were largely liable for the Scope 1 emissions from use of the gas which covers fugitive emissions from distribution networks and the combustion of gas, among other things. The impact of the carbon tax was not as significant on large industrial customers which only included Scope 3 emissions.

Sharp price rises were experienced as the wholesale gas prices rose. What is noticeable is the impact of the price pressure caused by the LNG plants competing in the domestic market for gas supply were slightly delayed compared to the large industrial user prices, and the turn down in prices in 2017 was also slightly delayed (based again on a limited number of forward contract prices in the data set). This noticeable lag in pricing was also reported in the 2015 report, so appears to be a consistent trend.

Gas prices in $2017 terms more than doubled from 2015 to 2017 for small industrial customers – some 142% increase.

Figure 33: Victorian real and nominal small industrial gas prices (metro)

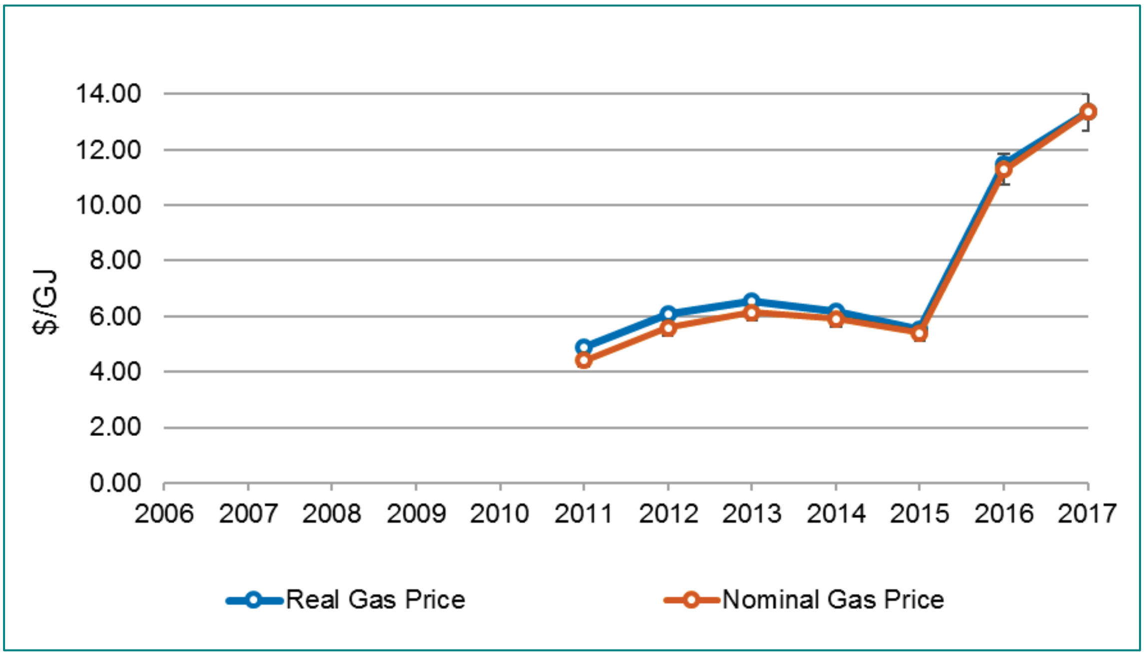
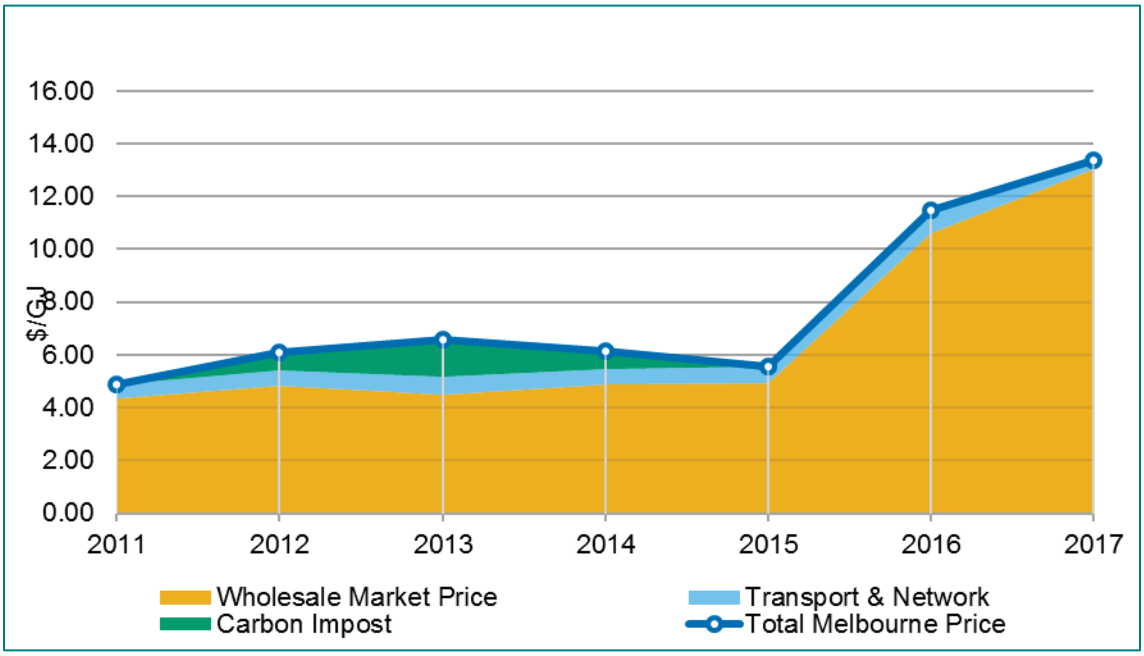
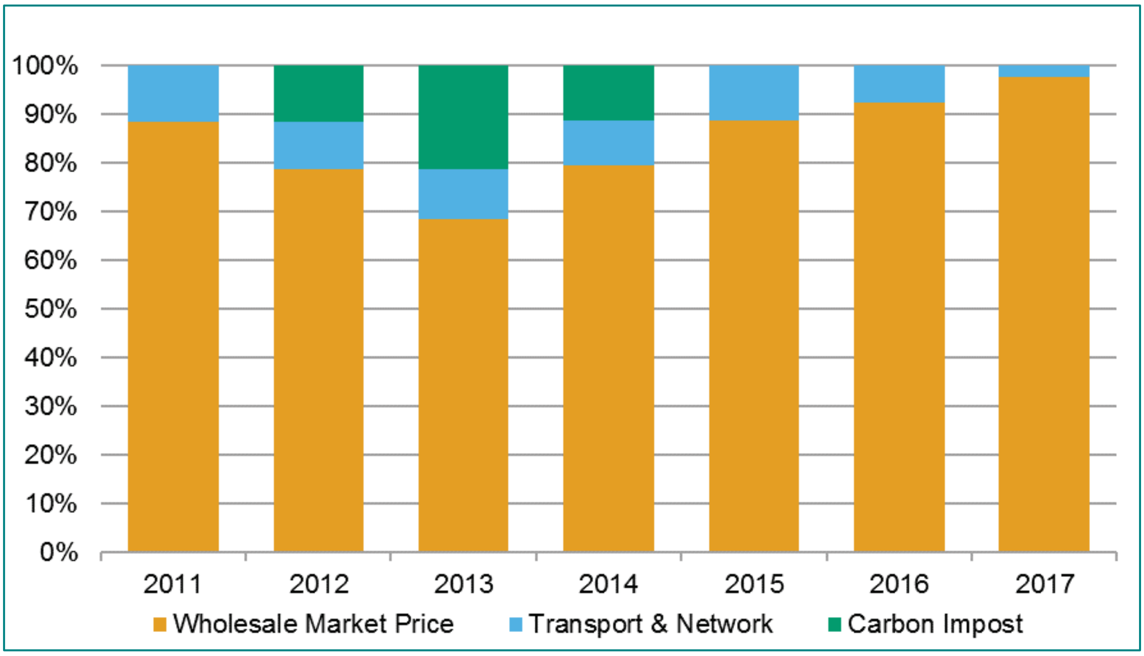


Figure 34: Victorian small industrial customer gas price components (metro)



The transport charges look slightly anomalous for 2016 as they increase from 2015 and then seemly decreased substantially in 2017. This may have something to do with the carbon tax roll off or the costs of sourcing gas from outside Victoria or even contract timing issues as gas prices escalated quickly. But overall the price trend has been quite markedly driven by the gas commodity charges to this customer class as can be seen in Figure 35.

Figure 35: Victorian small industrial customer gas price component by % (metro)



For small industrial customers in rural Victoria, the price trends are very similar, including the carbon tax imposts, but as can be seen from Figure 36 they went only marginally higher ($13.35/GJ Melbourne, $13.50/GJ Rural) in 2017. This was still a 107% increased on the 2015 prices but it appears in the data that there was even a slightly longer lag in underlying gas commodity price pass through for Rural small industrial customers as opposed to their Melbourne counterparts.

The Transport and Network charges are understandably higher for rural Victoria (a consistent reality) and again we saw this difference in these charges as they increased in 2016 and decreased in 2017.

Figure 36: Victorian small industrial customer gas price components (rural)

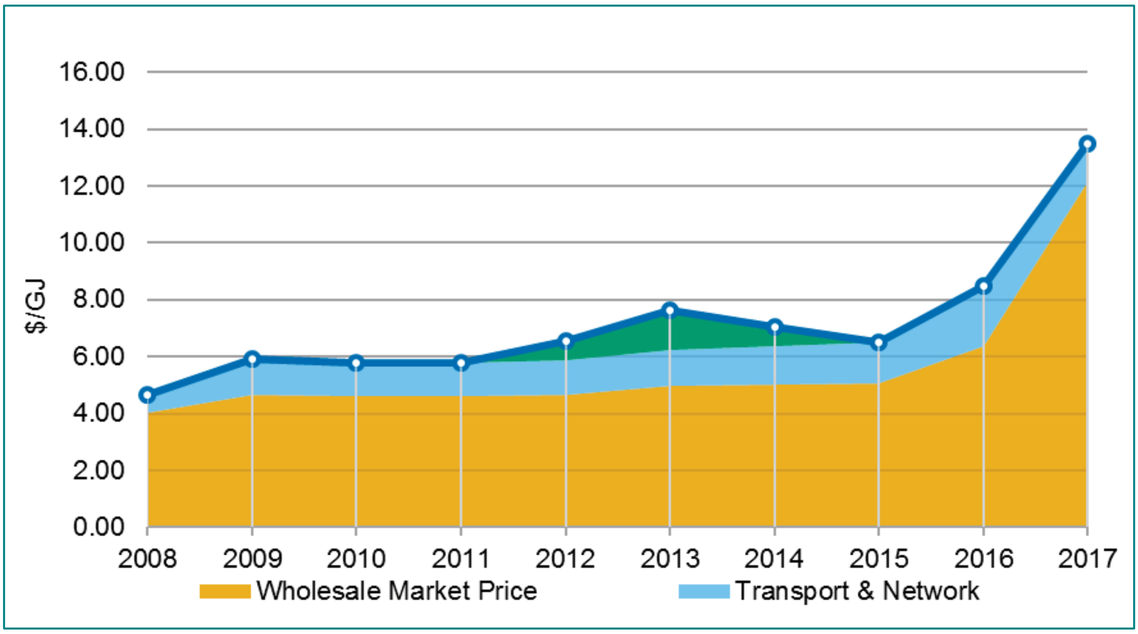
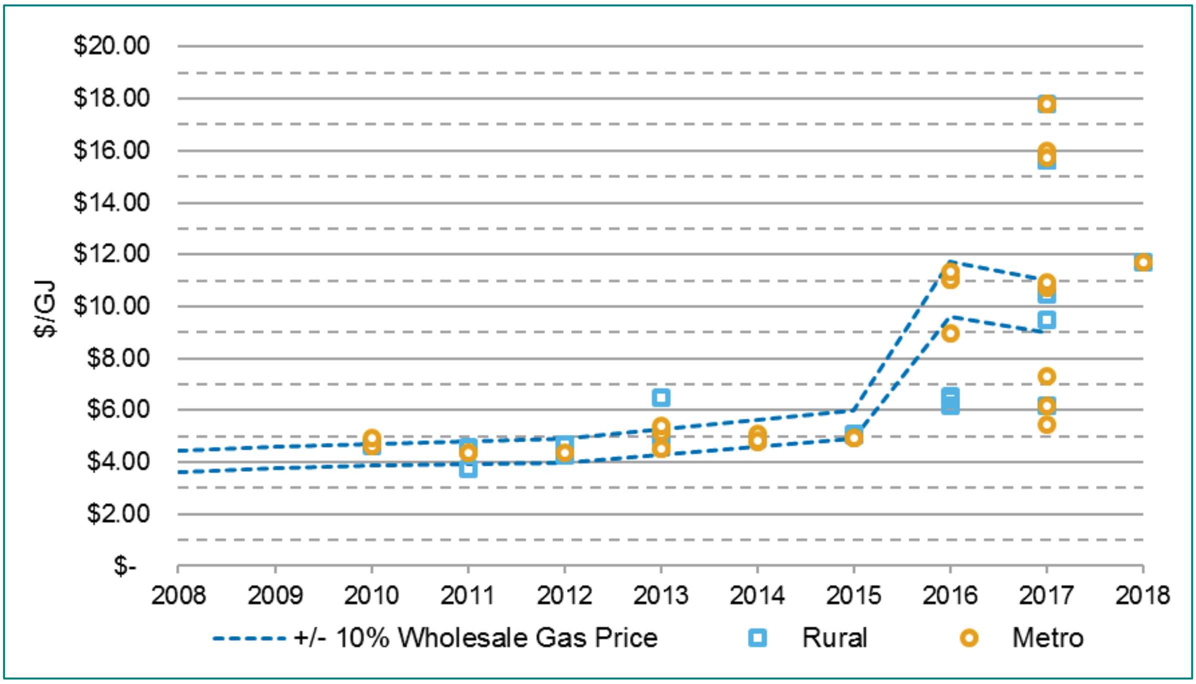


Figure 37 below shows the relative wholesale gas prices for rural and metro customers (excluding network and carbon tax prices) overlayed on the average wholesale prices seen for large industrial customers (Melbourne) including the price range. The customer wholesale contract prices vary by location (rural and metro) and other factors such as load factors and retail margin uplift.

Figure 37: Victorian small industrial wholesale price comparison.



From Figure 37 it can be seen:

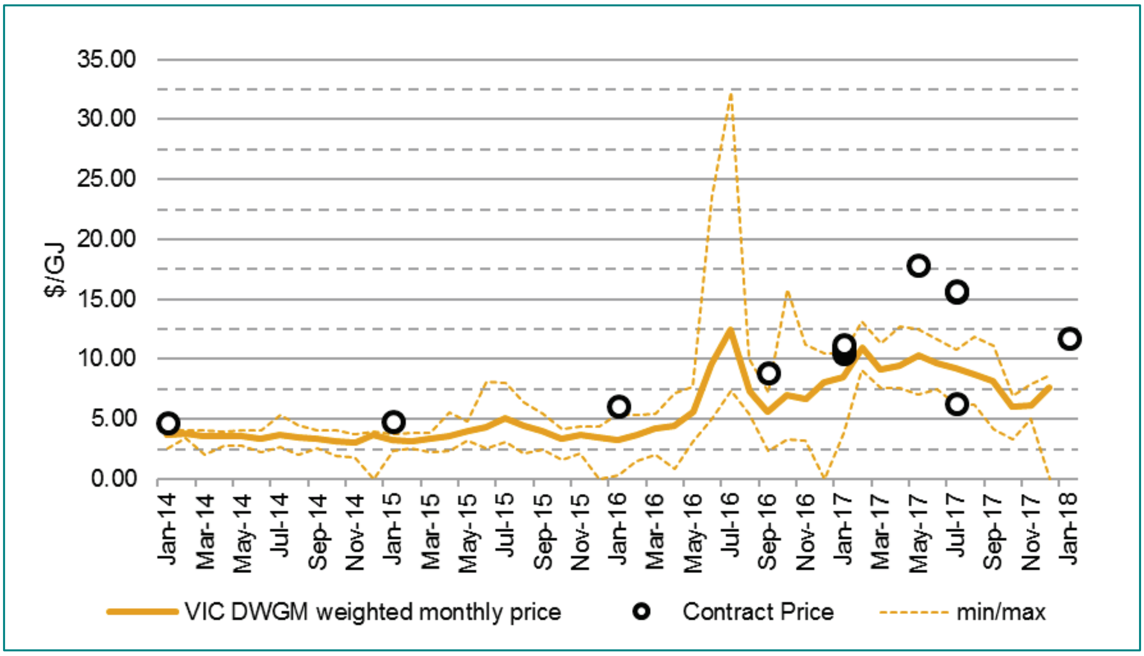
- As in the 2015 report, the general price trend is indicative of the historical charts for the large industrial customers, and
- There is an appreciable lag effect relative to large industrial customers and that contract prices should trend down in 2018 based on a small number of forward contract prices in the dataset;
- The data seems to show that there is considerable variance in the prices small industrial customers saw for wholesale gas in 2017 – a very large spread not seen in the 2015 report;
- This relates to issues such as:
  - Sellers seeking to explore prices in a very tight supply market – i.e. trying to find a new supply and demand balance clearing price
  - The relative size and sophistication of the buyer’s load – smaller loads did seem to see higher prices

– The timing of new contracts though seems to be the critical element (see Figure 38) - it appears that the peak for retail pricing was up to 1 July 2017 and after that prices seem to have dropped as new supply and offers flowed into the market, and

– Customers have tended to go for short term deals as prices were rising

– To our mind these are all logical responses to a market that has inefficient price discovery.

Figure 38: Contract Timing for VIC compared to the Victoria's DWGM[24]



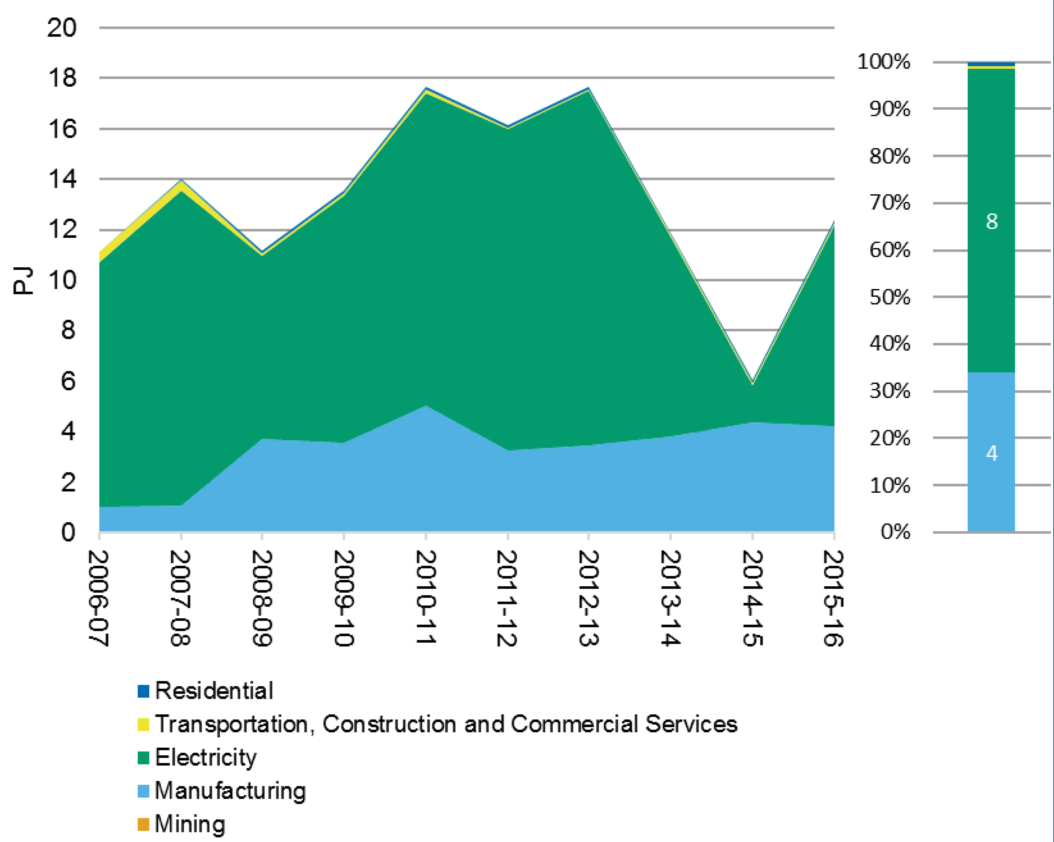
4.3 Tasmania industrial gas prices

4.3.1 Tasmania gas consumption trends

Figure 28 illustrates the gas consumption trends by sector and percentage contribution of each sector. There is a defined downward trend from 2012 to 2014 and a spike from 2015 to 2016 due largely to additional electricity generation fuelled by gas.

24 Contract price time is the contract commencement date. Contract signing dates are on average 30 to 60 days prior providing a lag with price and timing compared to the DWGM.

Figure 39: Tasmania gas consumption by sector (PJ)

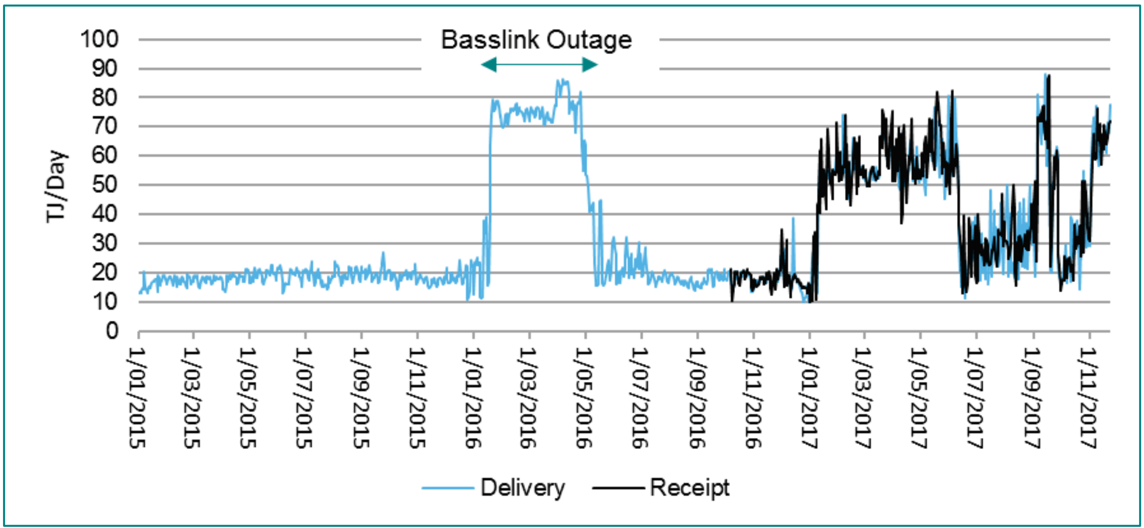


Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

In 2015, the Tamar Valley Power Station (TVPS) had been effectively mothballed until the Basslink outage between December 2015 and June 2016. Combined with drought conditions and low hydro dam levels, this situation necessitated the recommissioning and operation of TVPS.

The Tasmania Energy Security Taskforce has since completed its review and recommended the TVPS be kept in the near term, and with changed electricity market conditions the TVPS has since operated on a more regular basis. Up-to-date data from AEMO's Gas Bulletin Board shown in Figure 40 confirm the continued operation of TVPS subsequent to the Basslink outage.

Figure 40: Tasmania Gas Pipeline actual throughput



Source: AEMO Gas Bulletin Board.

Table 7 indicates total gas consumption in Tasmania was 12.4 PJ in 2015-2016 with manufacturing and electricity generation consuming a 4.2 PJ (34%) and 8.0 PJ (64%) of the state's gas respectively. Total consumption has increased 4% up from 11.9 PJ in 2013-14.

Table 7: Tasmania sectoral consumption volume trends 2013-14 to 2015-16.[25]

	2013-14	2015-16	Trend %
Mining	0	0	0%
Manufacturing	3.8	4.2	10%
Electricity	7.9	8.0	1%
Transportation, Construction and Commercial Services	0.09	0.07	-25%
Residential	0.100	0.105	5%
Total	11.9	12.4	4%

4.3.2 Tasmanian large industrial gas price trends

The historical trend of relatively high Tasmanian industrial gas prices is based on the Victorian wholesale price of gas, as the gas is sourced at Longford, plus the transmission costs to Tasmania.

25 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Table 8 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The increase in gas price is 60% on the 2015 gas price.

Table 8: Tasmania gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	5.45	10.67	10.00	82%	83%
Transport	2.18	2.19	2.21	18%	1%
Total	7.64	12.85	12.21	100%	60%

The price paid by large industrial customers in Tasmania (delivered to Hobart, ex-Tasmanian Gas Pipeline) entering into a new supply agreement on a year-by-year basis is detailed below in Figure 41.

Figure 41 shows a peak in delivered gas price in 2016 of $12.25/GJ ($2017) and a tempering to $12.21/GJ in 2017.

In 2017, the average gas price delivered to Tasmanian large industrial customers was $12.21/GJ of which $10.00/GJ (82%) was the wholesale gas cost and $2.21/GJ (18%) was pipeline transportation costs. The relatively high delivered gas price in Tasmania compared to Victoria is due to high transmission costs.

Figure 41: Tasmania real and nominal large industrial customer delivered gas prices (Hobart)

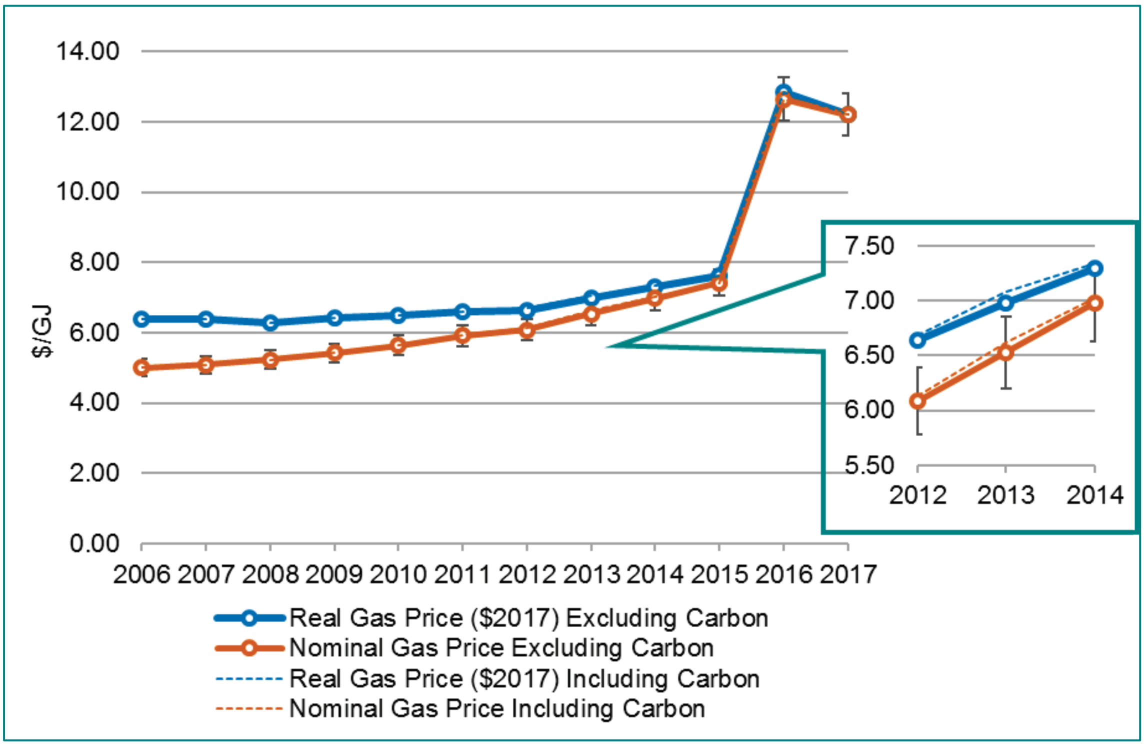


Figure 42 shows the average cost of different components making up the large industrial gas price in Tasmania from 2006 to 2017.

Figure 42: Tasmanian large industrial customer gas price components

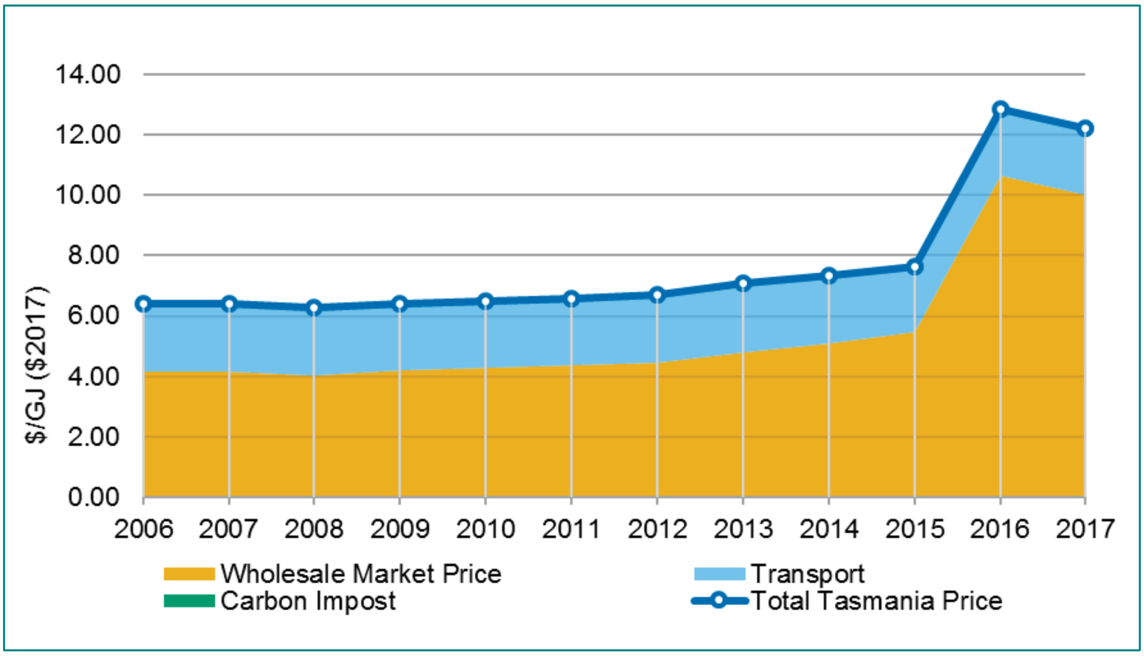
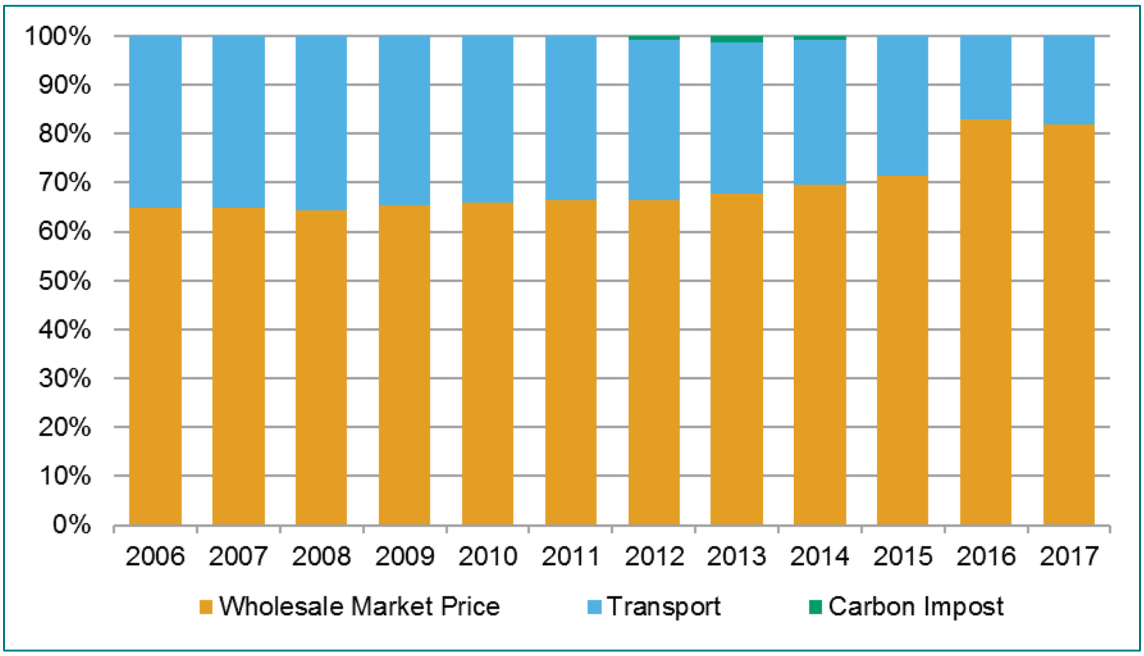


Figure 43 shows the percentage breakdown of different components making up the large industrial gas price in Tasmania from 2006 to 2017, and clearly highlights the much higher impact of the Tasmanian Gas Pipeline charges compared to Victoria. This relates to the long distance from the Victorian supply hub, most of which is a subsea pipeline, as well as significant pipeline costs on land in Tasmania and very low pipeline utilisation. As the delivered gas price has increased by almost double from a touch above $5/GJ to circa $10/GJ, the percentage component of transport has decreased, similar to the Victoria trend.

Figure 43: Tasmanian large industrial gas price components by %

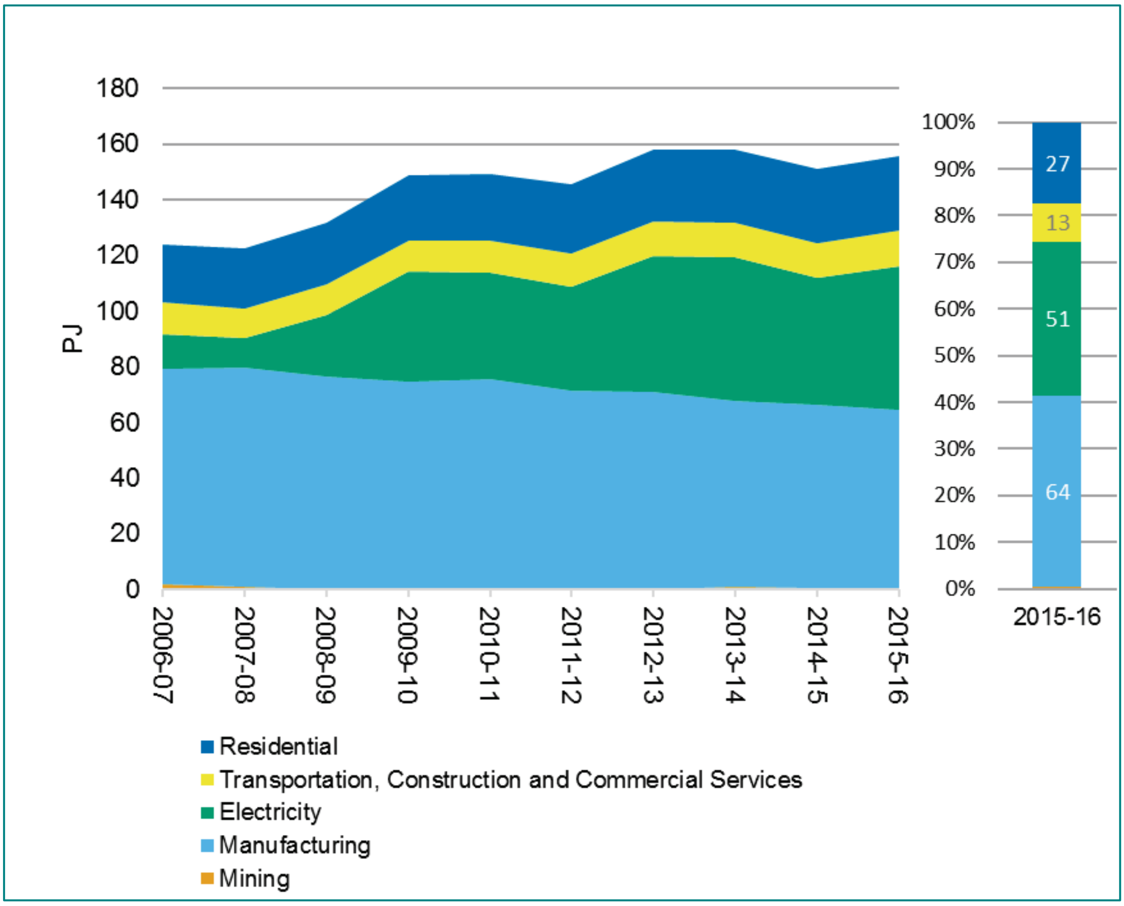


4.4 New South Wales and Australian Capital Territory industrial gas prices

4.4.1 New South Wales and Australian Capital Territory gas consumption

Figure 28 illustrates the gas consumption trends by sector and percentage contribution of each sector. There is a reasonably steady increase from 2006 to 2012 and flat consumption from 2012 to 2016 with a dip on the 2014-15 year. the data suggests the dip is due to a reduction in gas-fuelled electricity generation. The chart shows a steady decline in manufacturing gas use across the whole period from 2006 to 2016.

Figure 44: New South Wales gas consumption by sector (PJ)



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Table 9 indicates total gas consumption in New South Wales was 158 PJ in 2015-2016 with manufacturing 64 PJ (41%) and electricity generation 51 PJ (33%) the state's largest consumers followed by residential 27 PJ (17%).

Total gas consumption in 2015-16 was 157.5 PJ - down by 1% from 2013-14.

Table 9: New South Wales sectoral consumption volume trends 2013-14 to 2015-16.[26]

	2013-14	2015-16	Trend %
Mining	0.9	0.6	-34%
Manufacturing	67.0	64.0	-4%
Electricity	51.4	51.3	0%
Transportation, Construction and Commercial Services	12.4	12.9	3%
Residential	26.3	27.0	3%
Total	158.1	155.7	-1%

Australian Energy Statistics includes the ACT natural gas consumption in NSW statistics.

Total gas consumption in ACT is approximately 4% of the total combined NSW/ACT gas consumption, with the residential component forming the majority 73% of the ACT's natural gas consumption[27].

4.4.2 Gas prices for large industrial customers

Table 10 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The increase in gas price is 21% on the 2015 gas price.

Table 10: New South Wales gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	7.51	9.90	9.25	88%	23%
Transport	1.14	1.21	1.21	12%	6%
Total	8.65	11.11	10.46	100%	21%

The price paid by large industrial customers in NSW and ACT (delivered to Sydney at Wilton/Horsley Park or the ACT) entering into a new GSA on a year-by-year basis is shown in Figure 45 below.

26 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

27 ACT consumption estimated for 2015-2016 based on demand forecast in the ActewAGL Access Arrangement for the ACT, Queanbeyan and Palerang gas distribution network, June 2015.

In 2017 the average gas price delivered to NSW and ACT large industrial customers was $10.46/GJ of which $9.25/GJ (88%) was the wholesale gas cost and $1.21/GJ (12%) was pipeline transportation costs.

Figure 45: NSW & ACT real and nominal large industrial customer delivered gas prices

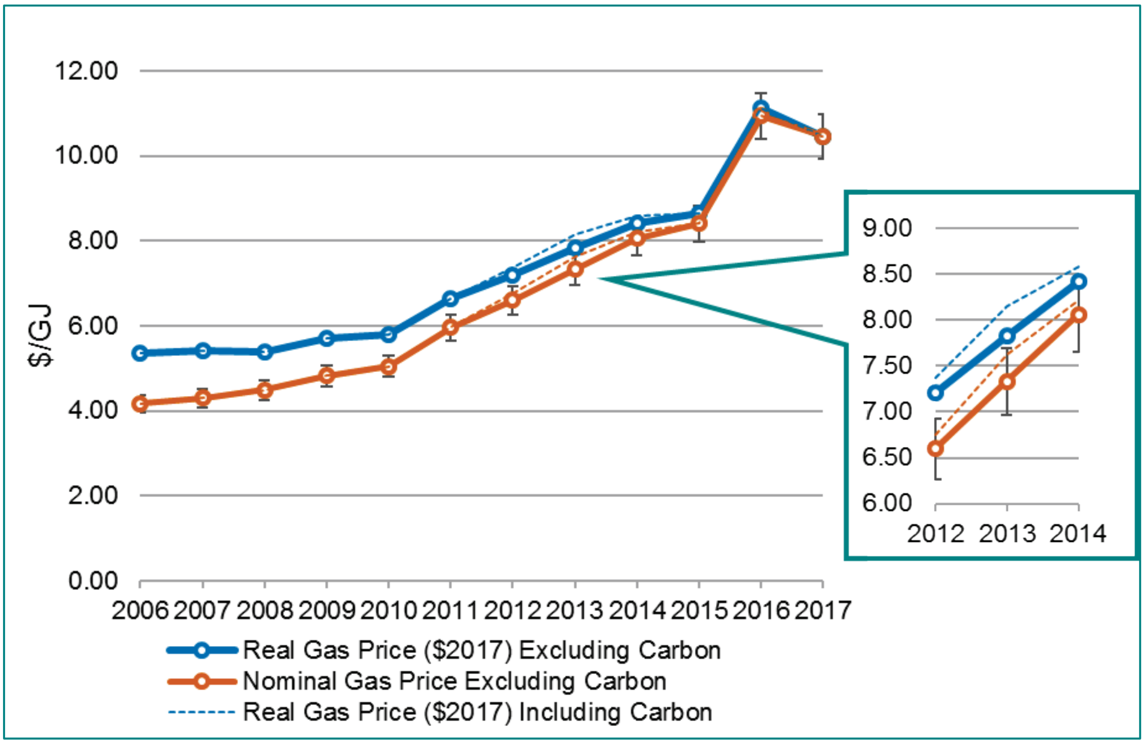


Figure 46 shows the average cost of different components making up the large industrial gas price in NSW and ACT from 2006 to 2017.

Figure 46: NSW & ACT large industrial customer gas price components

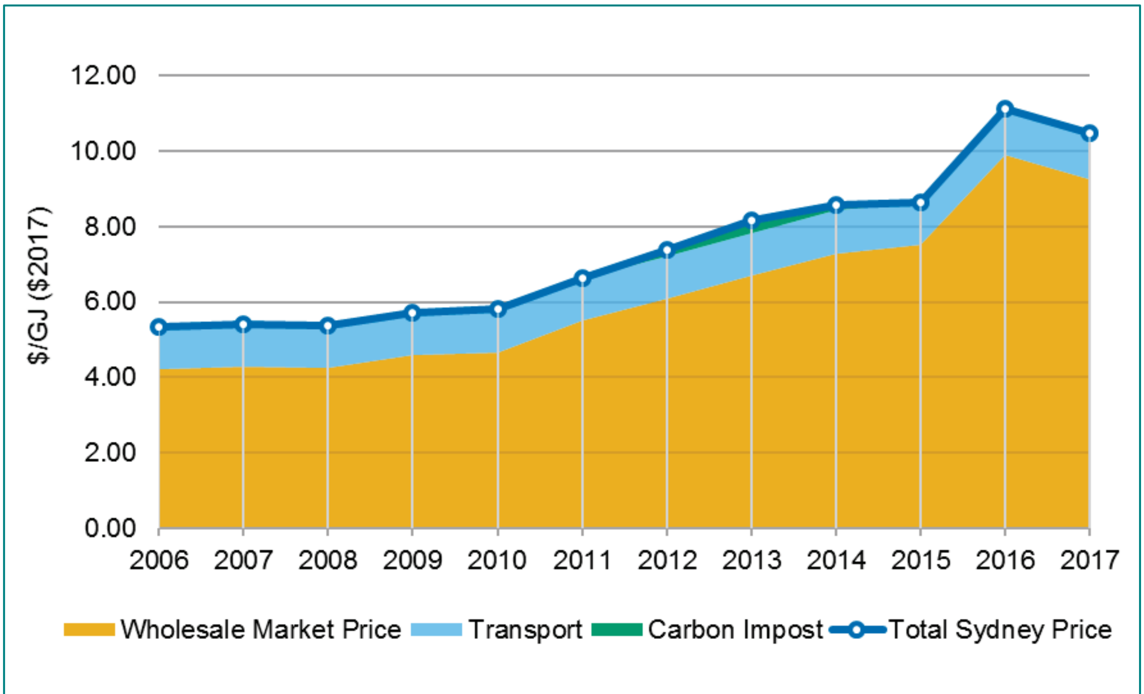
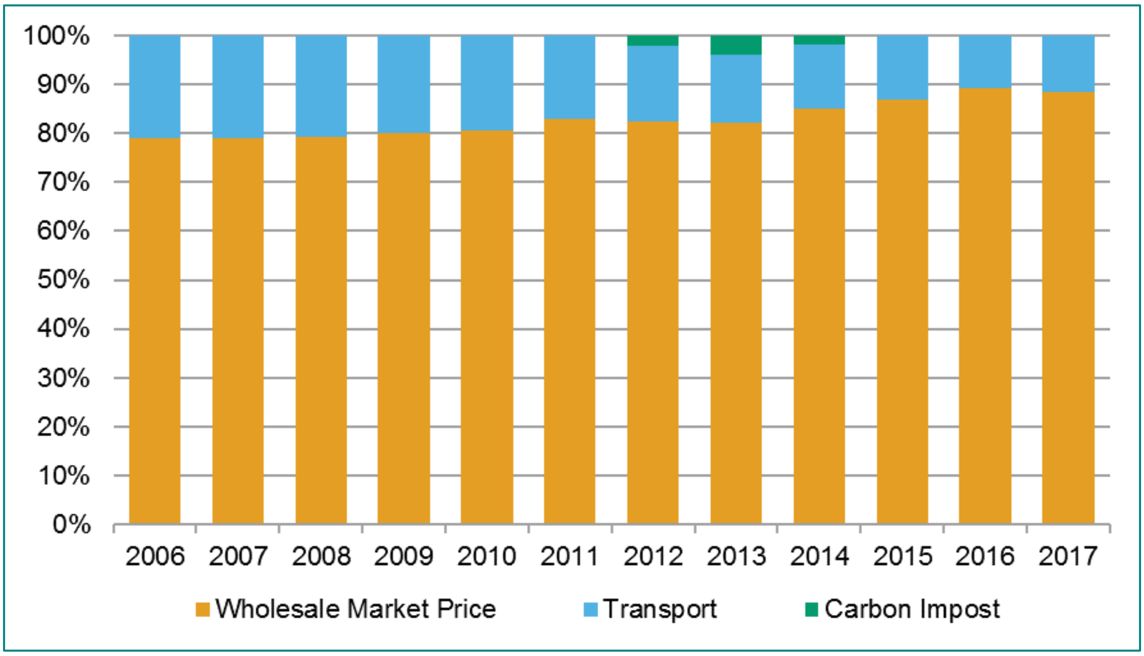


Figure 47 shows the percentage breakdown of different components making up the large industrial gas price in NSW and ACT from 2006 to 2017.

Figure 47: NSW & ACT large industrial gas price components by %.



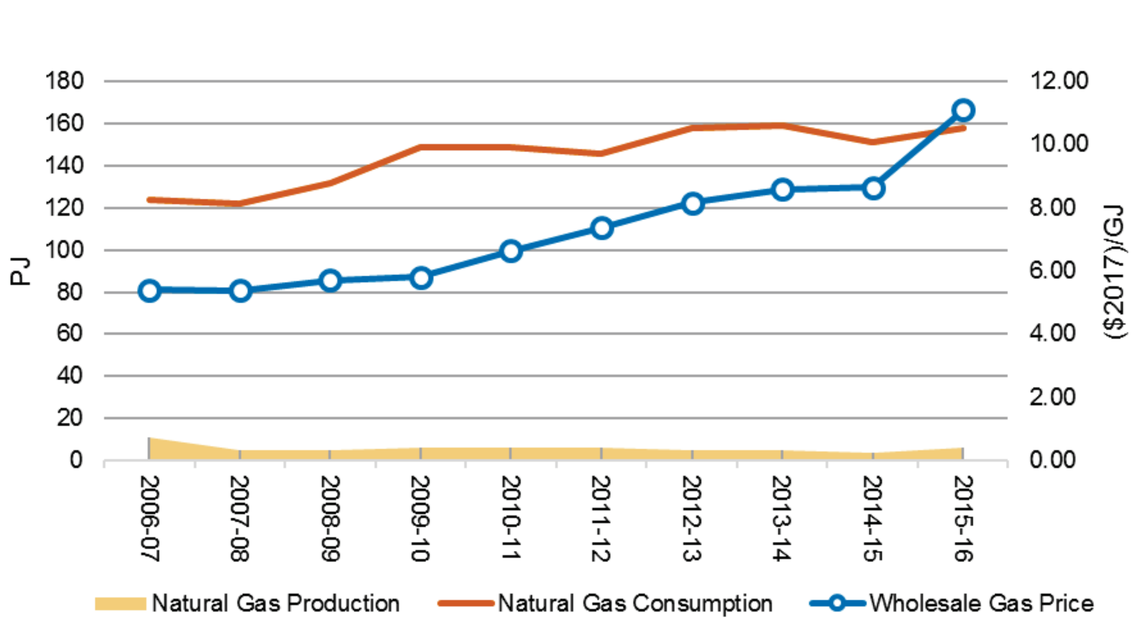
4.4.3 New South Wales large industrial customer gas price analysis

The major factors influencing NSW and ACT large industrial gas prices between 2015 and 2017 were:

- The competition for gas supply destined for Queensland LNG plants – as in Victoria.
- The imbalance of supply and demand in NSW is far more prevalent than any other state – see Figure 48.
- NSW must source its gas from the Moomba Hub or Victoria, therefore as those locational prices increase, NSW's price will increase.
- The indigenous gas sources in NSW are under strict exploration rules and ranging exclusion zones for coal seam gas exploration[28]. It is hard to see additional production from within the state in the near term.
- Gas prices did decrease in the last half of 2017 as gas flows started to come south from Queensland – more gas becoming available and more sellers in the market, and this reversal effect is discussed in more detail in the Victorian section.

28 NSW Government website, Resources and Energy, The facts on CSG, Protection and Controls. Accessed 6 December 2017.

Figure 48 NSW native gas supply/demand



4.4.4 NSW small industrial gas price trends

A set of actual contract data was also available for small industrial customers for Sydney and for Rural NSW.

The prices in Figure 49 are for delivered gas in Sydney, including transmission and network charges, and similar to Victoria charges for the gas commodity primarily by Retailers to small industrial customers.

As can be seen in Figure 50 the carbon tax between 2012 and 2014, did have a major influence on gas price rises and falls as Retailers were largely liable for the Scope 1 emissions from use of the gas which covers fugitive emissions from distribution networks and the combustion of gas, among other things. The impact of the carbon tax was not as significant on large industrial customers which only included Scope 3 emissions.

Sharp price rises started in 2016 which is a major lag between rises in NSW large industrial prices and even those of the small industrial customers in Victoria, and this is discussed below.

Sydney delivered prices for small industrial customers also were higher on average in 2017 than in Melbourne ($15.07/GJ Sydney, $13.35/GJ Melbourne), largely driven by higher Sydney transport and network charges even though the gas commodity prices were distinctly lower in Sydney in Retail contracts ($11.75/GJ Sydney, $13.05/GJ Melbourne).

This seems to indicate that although Melbourne small industrial customers benefited from lower haulage costs (closer to nominal gas source at Longford) they have been paying more for the gas commodity from Retailers, and paid it a bit earlier in the upward cycle. This may be due to gas being priced at Longford as derived from the north (more inherent haulage to Longford) or simply timing, or thin supply pricing issues.

Again the scatter in gas prices in 2017 for Sydney small industrials had a huge variation as can be seen in Figure 53 and is probably skewing any 2017 price comparison, as contract timing was one of the key determinants to actual outturn prices for a small industrial customer in both states.

For Sydney small industrial customers average delivered gas prices in $2017 terms did increase significantly by some 74% from 2015 to 2017.

Figure 49: NSW real and nominal small industrial delivered gas prices (metro)

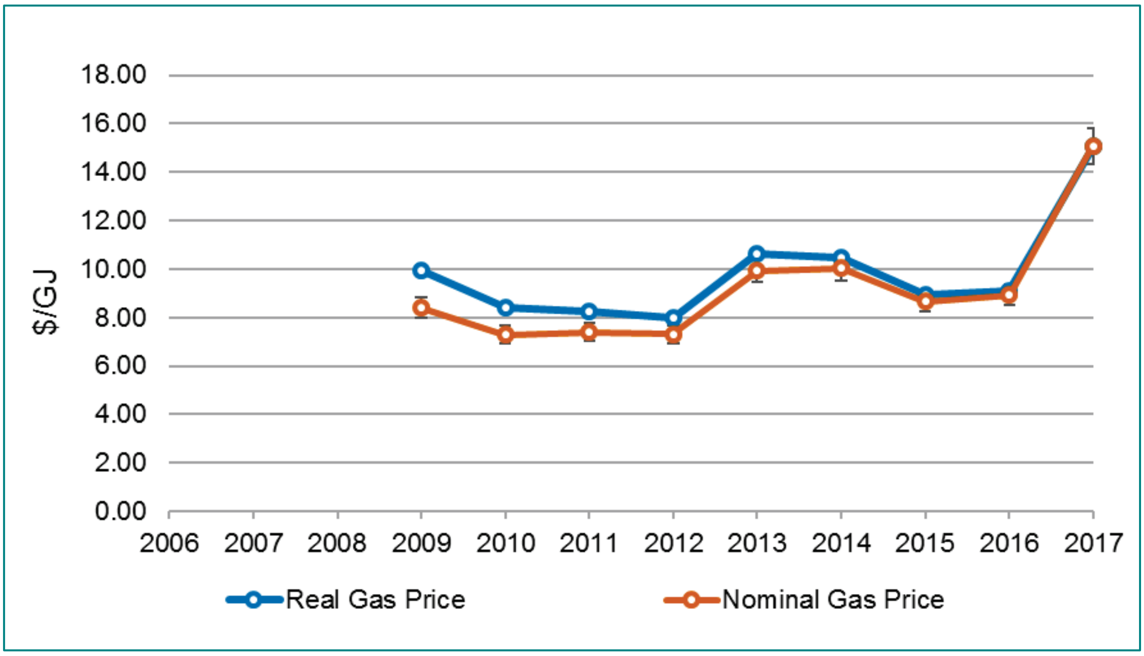


Figure 50: NSW small industrial customer gas price components (metro)

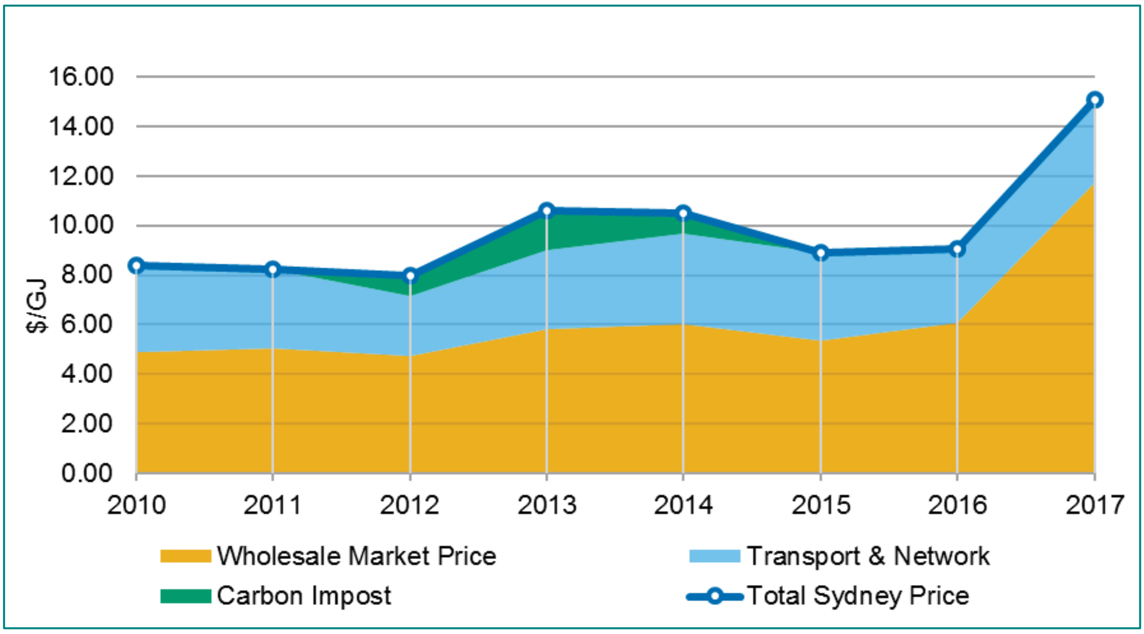
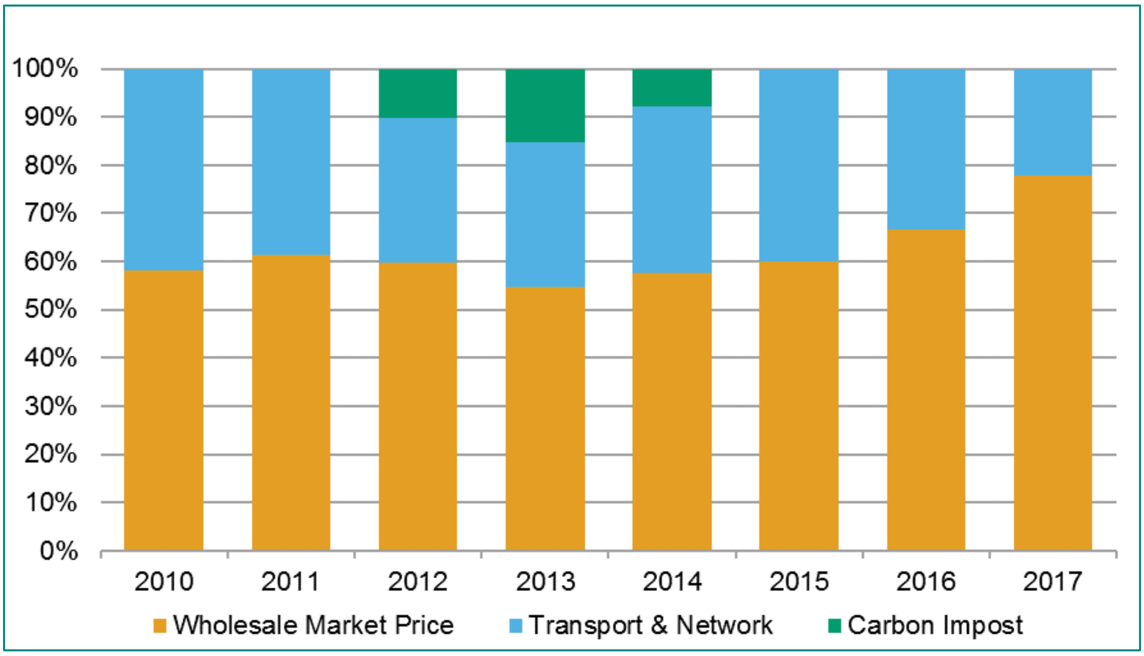


Figure 51: NSW small industrial customer gas price component by % (metro)



For small industrial customers in rural NSW the price trends are very similar, including the carbon tax imposts, but as can be seen from Figure 52 the overall delivered gas price was significantly higher on average in 2017 than metro prices ($15.07/GJ metro, $19.83/GJ rural). Removing the higher transport and network charges for rural NSW (some $3.25/GJ higher than metro) then rural NSW wholesale gas prices were some $1.81/GJ (or 15%) higher than metro which could be due to lower load factor undertakings in the rural (as was found in 2015), gas sourcing issues or simply an averaging issue across such a wide spread of prices as can be seen for 2017 in Figure 53 – it is not possible to determine a prime driver from the data.

What is informative is the rural small industrial contract dataset has a range of 2018 contracted gas prices which we have charted here, and it shows a downturn in pricing. This downturn occurred in the large industrial data in 2017, again indicating the lag effects in the sector or the market.

Figure 52: NSW small industrial customer gas price components (rural)

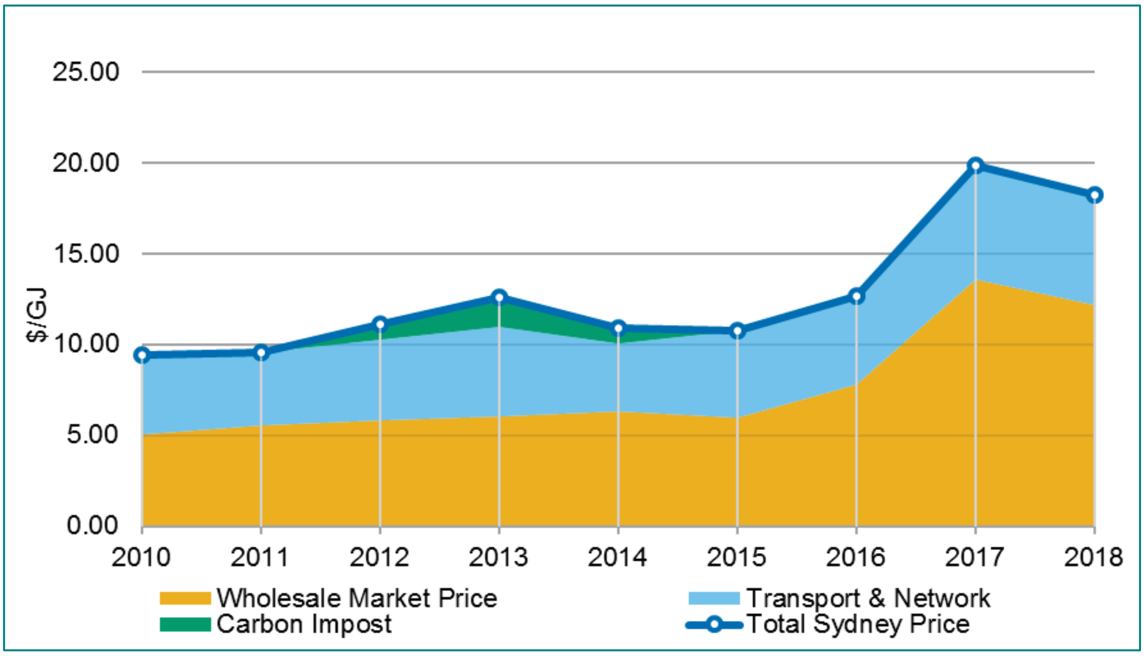
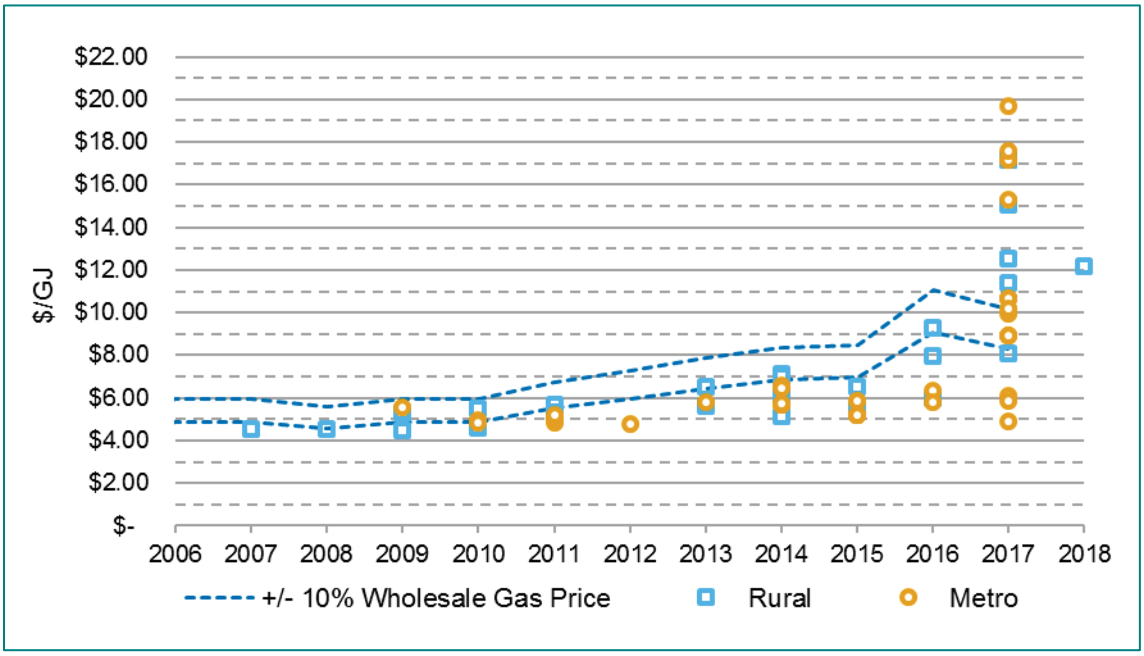


Figure 53 below shows the relative wholesale gas prices for rural and metro customers (excluding network and carbon tax prices) overlayed on the average wholesale prices seen for NSW large industrial customers including the price range. This should indicate any variance by location (rural and metro) and other factors that may impact such as load factors and retail margin uplift.

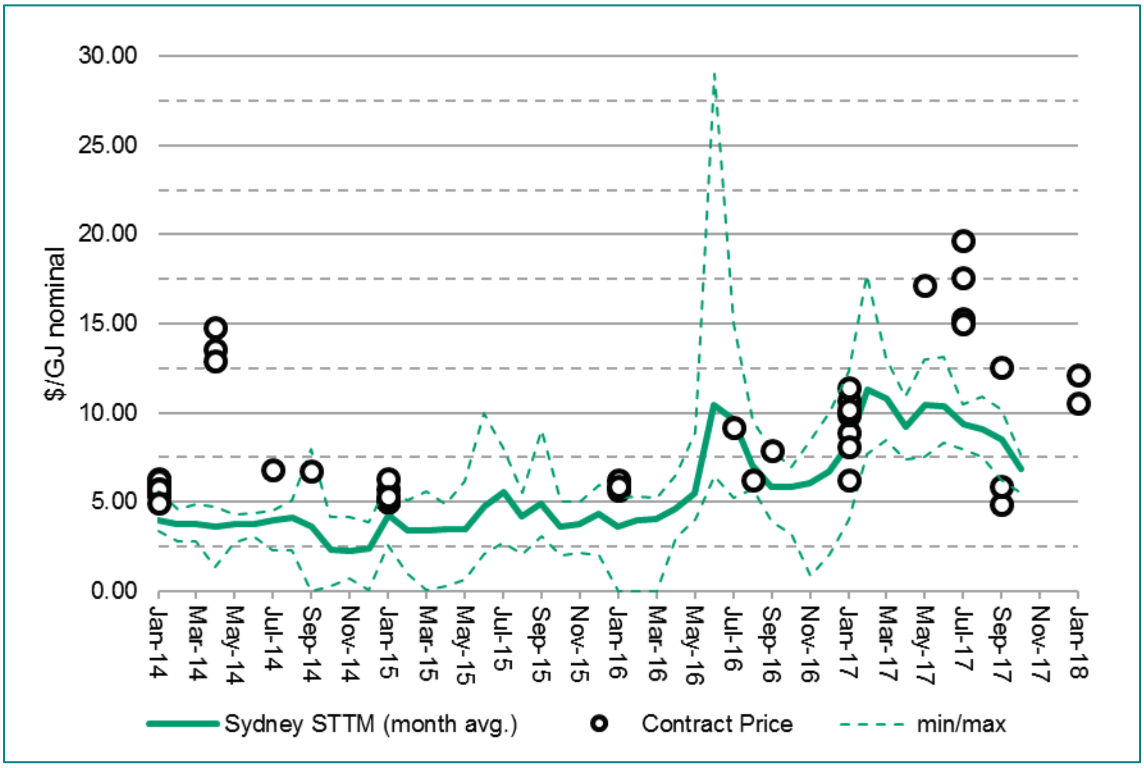
Figure 53: NSW small industrial wholesale price comparison.



From Figure 53 it can be seen:

- As in the 2015 report, the general price trend is indicative of the historical charts for the large industrial customers, and
- There is an appreciable lag effect relative to large industrial customers - therefore prices should trend down in 2018 based on a small number of forward contract prices in the dataset (for rural customers).
- The data shows, as in Victorian small industrial contract data, that there is considerable variance in the prices small industrial customers saw for wholesale gas in 2017 – a very large spread not seen in the 2015 report.
- This relates to issues such as:
  - Sellers seeking to explore prices in a very tight supply market – trying to find a new supply demand balance clearing price.
  - The relative size and sophistication of the buyer’s load – smaller loads did seem to see higher prices.
  - It also seems that rural gas users have more consistently seen high gas prices than metropolitan users in recent escalating years.
  - The timing of new contracts though seems to be the critical element. Looking at the NSW data (see Figure 54 - as it can be compared with the local STTM prices) it does become apparent that contract timing was critical as the prices rose and fell.
  - There is little discernable correlation with the STTM prices – generally when prices offered have been high there has been some higher levels of price in the STTM, but it is not a consistent pattern (as we expected due to the nature of STTM trades).
  - But, it is noticeable that from the start of 2017 prices started to climb in this market sector for wholesale gas (including the retail component) and seem to have peaked at about the start of July 2017 – and since then have declined – and the 2018 data sees it smoothing off.

Figure 54: Contract Timing for NSW compared to the Sydney STTM[29]



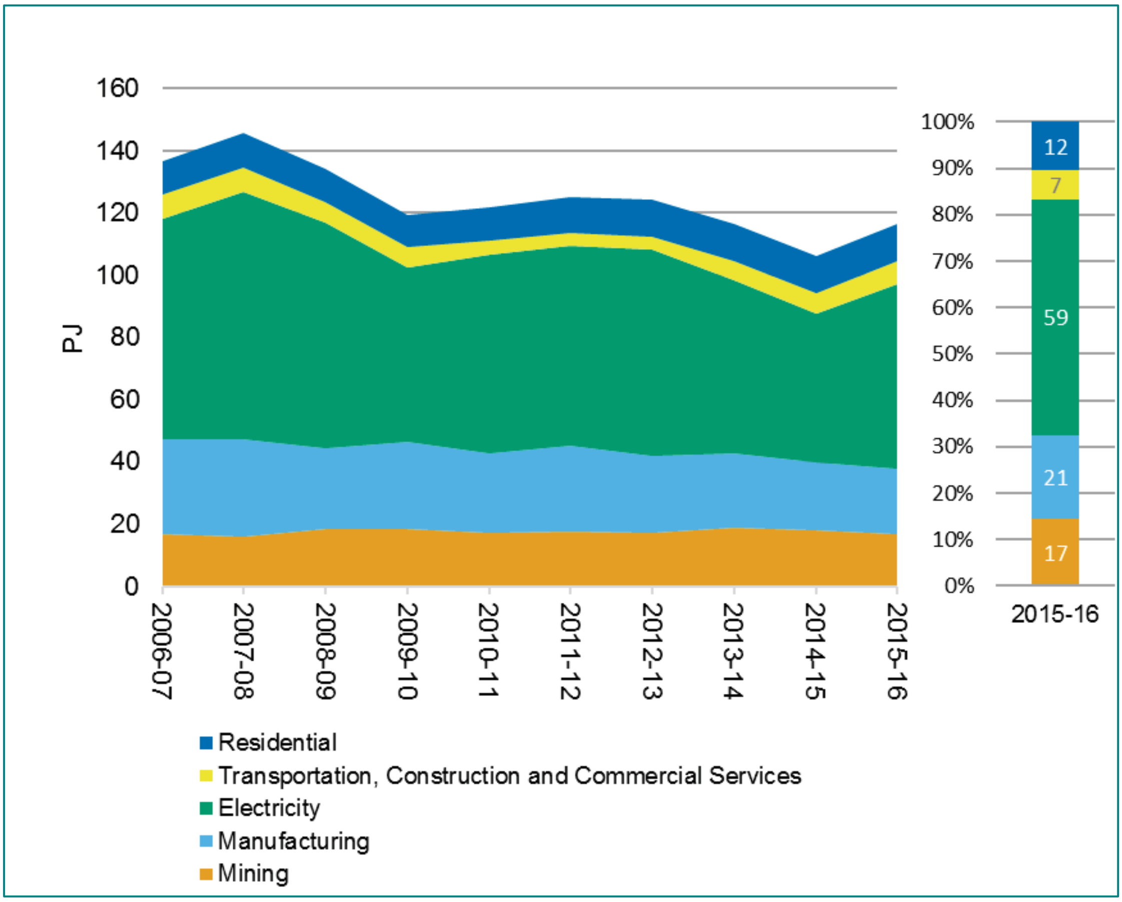
29 Contract price time is the contract commencement date. Contract signing dates are on average 30 to 60 days prior providing a lag with price and timing compared to the STTM.

4.5 South Australia industrial gas prices

4.5.1 South Australia gas consumption

Figure 55 illustrates the gas consumption trends by sector and percentage contribution of each sector. Total gas use has declined from 2007-08 until 2014-15 with an uplift in 2015-16.

Figure 55: South Australia gas consumption by sector (PJ)



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Table 11 indicates total gas consumption in South Australia was 117 PJ in 2015-2016 with manufacturing 21.1 PJ (18%) and electricity generation 59.3 PJ (51%) the state's largest consumers followed by mining 16.8 PJ (14%) and residential 12.2 PJ (10%). The total gas consumption in 2015-16 had negligible change from 2013-14 despite a reduction in 2014-15. The data suggests the drop and rise between 2013 and 2016 is due to variation in gas-fuelled electricity generation.

Table 11: South Australia sectoral consumption volume trends 2013-14 to 2015-16.[30]

	2013-14	2015-16	Trend %
Mining	18.8	16.8	-11%
Manufacturing	24.0	21.1	-12%
Electricity	55.5	59.3	7%
Transportation, Construction and Commercial Services	6.3	7.2	14%
Residential	11.9	12.2	2%
Total	116.5	116.6	0%

SA region Black System event

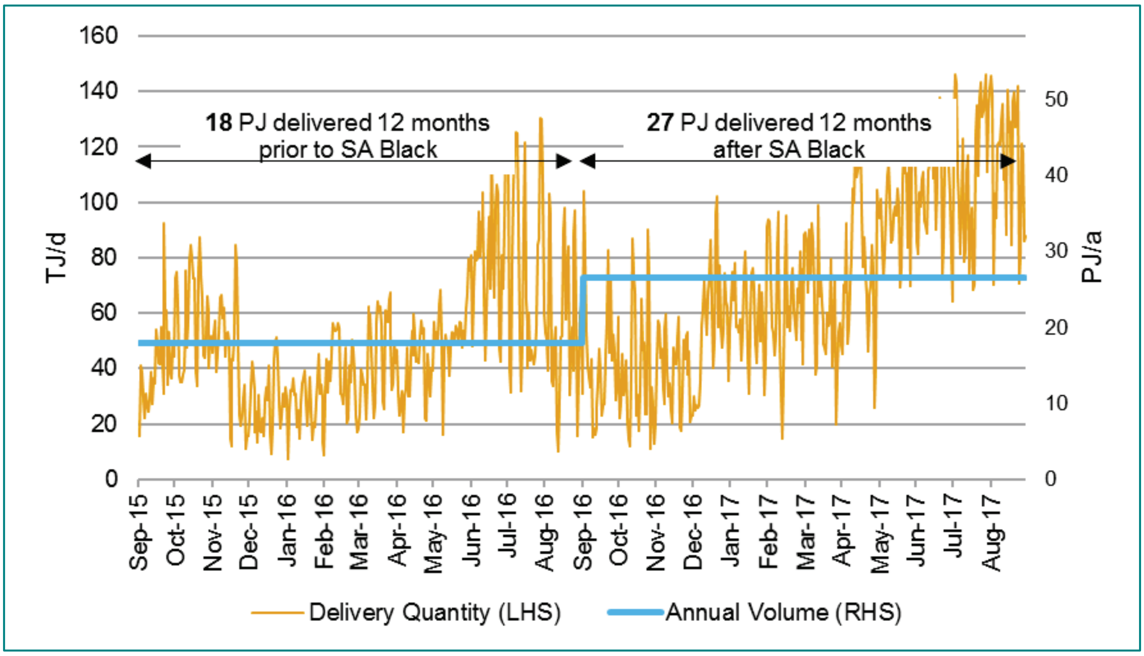
On 28 September 2016, for a number of reasons, the South Australia electricity system blacked out ('SA region Black System event'). AEMO issued its final findings in March 2017[31]. In the end a far greater awareness of electrical networks system security has resulted and in part has driven awareness of the interplay between intermittent renewable generation, its penetration percentages in to network systems and enabling dispatchable generation (or demand response) to maintain system security at larger scales than has been experienced before in the NEM. This has driven some of the thinking in the development of the National Energy Guarantee.

In gas market terms, it means gas-powered generation of electricity, which is dispatchable, along with coal, hydro, battery, etc., may become more prevalent in the market if it ran as a contingency to mitigate foreseeable intermittency and insecurity in the system.

As an example, Figure 56 illustrates the increased gas consumption through the Moomba to Adelaide Pipeline (MAPS) before and after the 'SA region Black System event' on 28 September 2016. The volume of gas 12 months prior is 18 PJ and 12 months subsequent is 27 PJ, an increase of 47%.

30 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.
31 Black system South Australia 28 September 2016 (March 2017) AEMO.

Figure 56: Gas delivered to Adelaide through MAPS 12 months pre and post the 'SA region Black System event'



Source: AEMO Gas Bulletin Board.

4.5.2 Gas prices for large industrial customers

Table 12 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The increase in gas price is 17% on the 2015 gas price.

Table 12: South Australia gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	7.77	9.90	9.25	92%	19%
Transport	0.85	0.85	0.85	8%	0%
Total	8.62	10.76	10.10	100%	17%

The price paid by large industrial customers in SA (delivered Adelaide, ex-MAP/SEA Gas pipelines) entering into a new supply agreement on a year by year basis is set out in Figure 57.

In 2017, the average gas price delivered to Adelaide/SA large industrial customers was $10.10/GJ of which $9.25/GJ (92%) was the wholesale gas cost and $0.85/GJ (8%) was pipeline transportation costs.

Figure 57 and Figure 58 show that SA large industrial customer price trends were similar to NSW due to the Moomba/Cooper Basin gas supply link to both NSW and SA. Prior to 2010, large industrial prices remained reasonably constant in real terms. The uplift from 2015 to

2016 and the moderation from 2016 to 2017 follows a very similar profile to NSW probably for the same reason.

Figure 57: SA real and nominal large industrial delivered gas price trends (Adelaide)

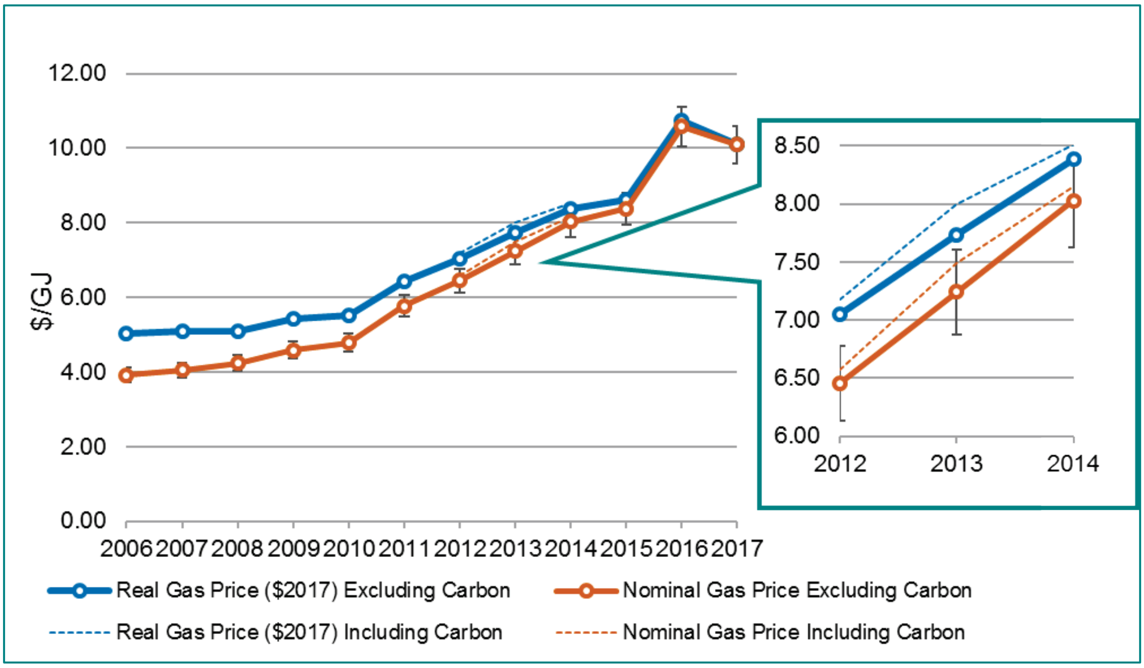


Figure 58 shows the average cost of different components making up the large industrial gas price in South Australia from 2006 to 2017.

Figure 58: SA large industrial customer gas prices components (Adelaide)

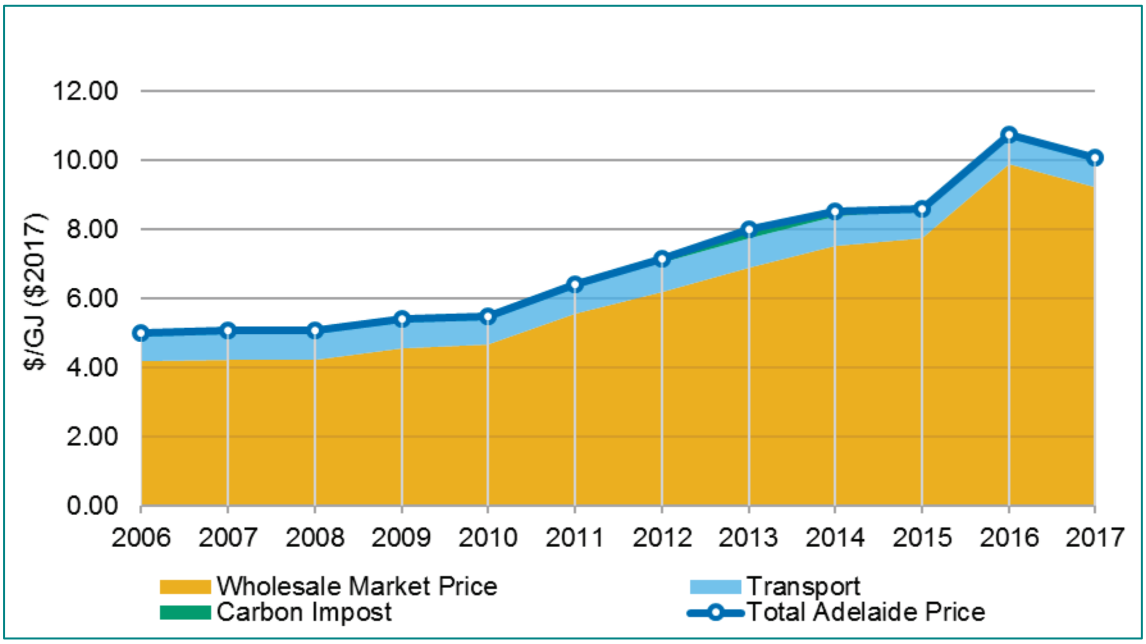
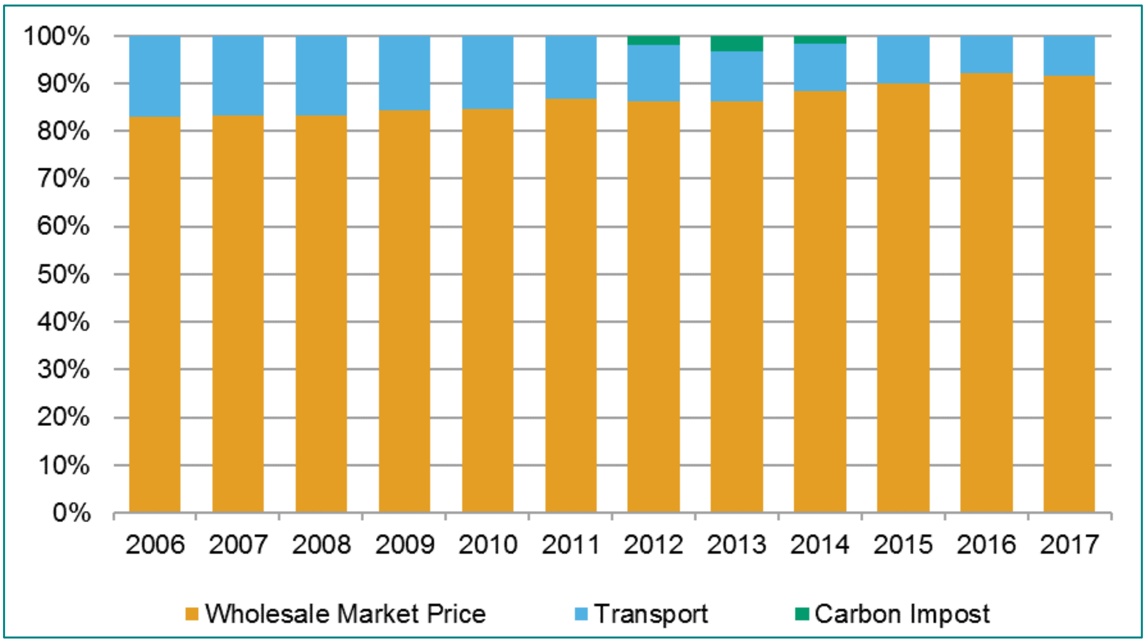


Figure 59 shows the percentage breakdown of the different components making up the large industrial gas price in SA from 2006 to 2017.

Figure 59: SA large industrial customer gas price components by %



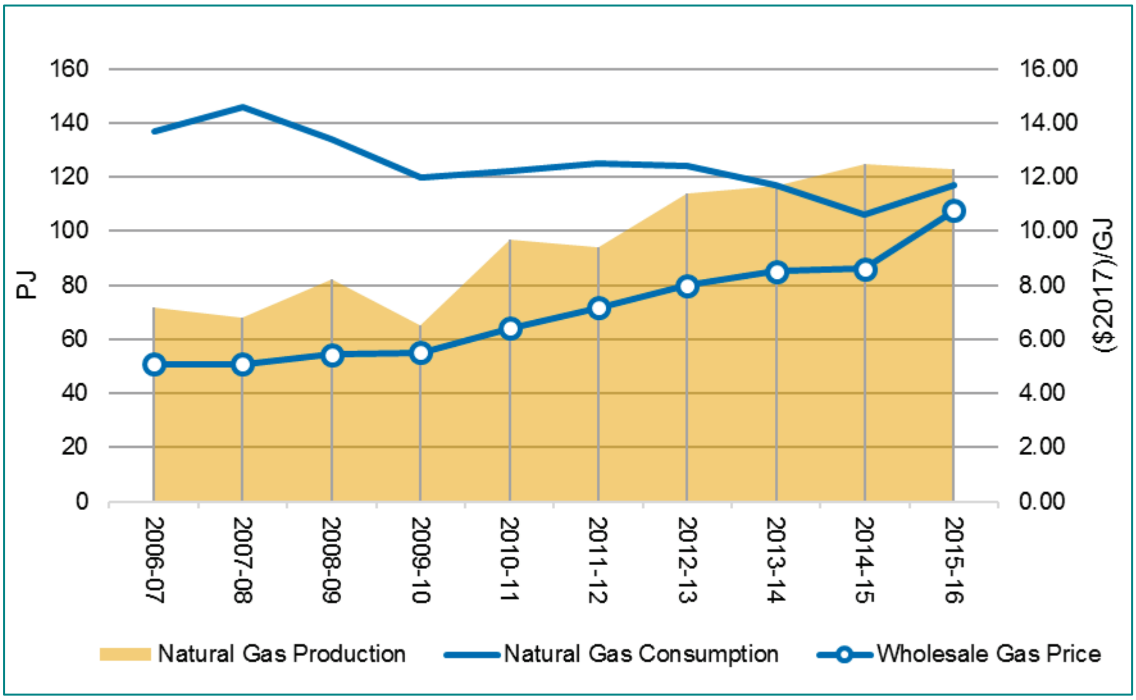
4.5.3 Large SA industrial customer price analysis

Between 2015 and 2017, the major factors influencing SA large industrial prices were:

- Gladstone LNG projects materially impacted Moomba wholesale prices from 2010.
- The pricing profile is similar to NSW and Victoria, which is consistent with connectivity through the Moomba Adelaide Pipeline and the SEA gas pipelines.

Figure 60 shows the relationship between gas supply, demand and price trends of South Australia.

Figure 60: South Australia gas production, consumption and price trend

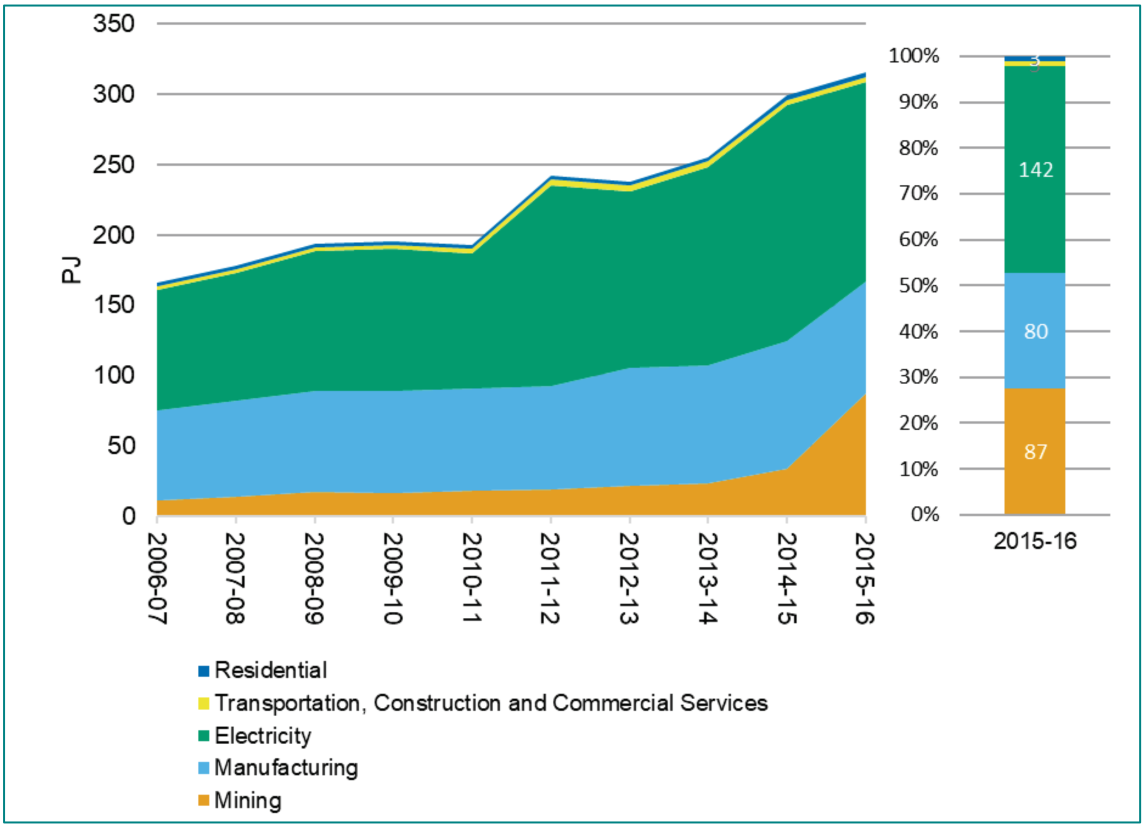


4.6 Queensland industrial gas prices

4.6.1 Queensland gas consumption

Figure 61 illustrates the gas consumption trends by sector and percentage contribution of each sector. There is a steady uplift in gas consumption from 2006 with a definite spike in 2014 to 2016 due to the LNG developments in Gladstone.

Figure 61: Queensland gas consumption by sector (PJ)



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017

Table 13 indicates total gas consumption in Queensland was 316 PJ in 2015-2016 with manufacturing, electricity generation and mining consuming 79.8 PJ (25%), 141.8 PJ (45%) and 86.9 PJ (28%) of the state's gas respectively. The Departmental data classifies LNG under mining consumption, hence its increase in terms of volume trend. Volume trend is the contribution of that sector in percentage terms to the increase (or decrease) in the total gas consumption from 2013-14. Total consumption has increased 24% up from 255 PJ in 2013-14. All of that increase was due to mining (LNG) consumption increase tempered by a slight decrease in manufacturing gas use.

Table 13: Queensland sectoral consumption volume trends 2013-14 to 2015-16.[32]

	2013-14	2015-16	Trend %
Mining	23.7	86.9	266%
Manufacturing	83.8	79.8	-5%
Electricity	140.7	141.8	1%

32 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

	2013-14	2015-16	Trend %
Transportation, Construction and Commercial Services	3.9	3.4	-12%
Residential	3.2	3.4	9%
Total	255.3	315.4	24%

4.6.2 Brisbane/South East Queensland large industrial customer gas prices

Table 14 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The decrease in gas price is 4% on the 2015 gas price and is now lower than Sydney, Melbourne and Adelaide prices – a major reversal.

Table 14: Brisbane/South East Queensland gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	9.43	9.40	9.00	93%	-5%
Transport	0.65	0.68	0.69	7%	7%
Total	10.08	10.08	9.69	100%	-4%

In 2017, the average gas price delivered to Brisbane/South East Queensland large industrial customers was $9.69/GJ of which $9.00/GJ (93%) was the wholesale gas cost and $0.69/GJ (7%) was pipeline transportation costs.

Figure 62 shows the average gas price paid by large industrial customers (delivered to Brisbane & SEQ, ex-Roma Brisbane Pipeline) entering into a new supply agreement on a year-by-year basis.

Figure 62: Brisbane & SEQ large industrial customer delivered gas price history

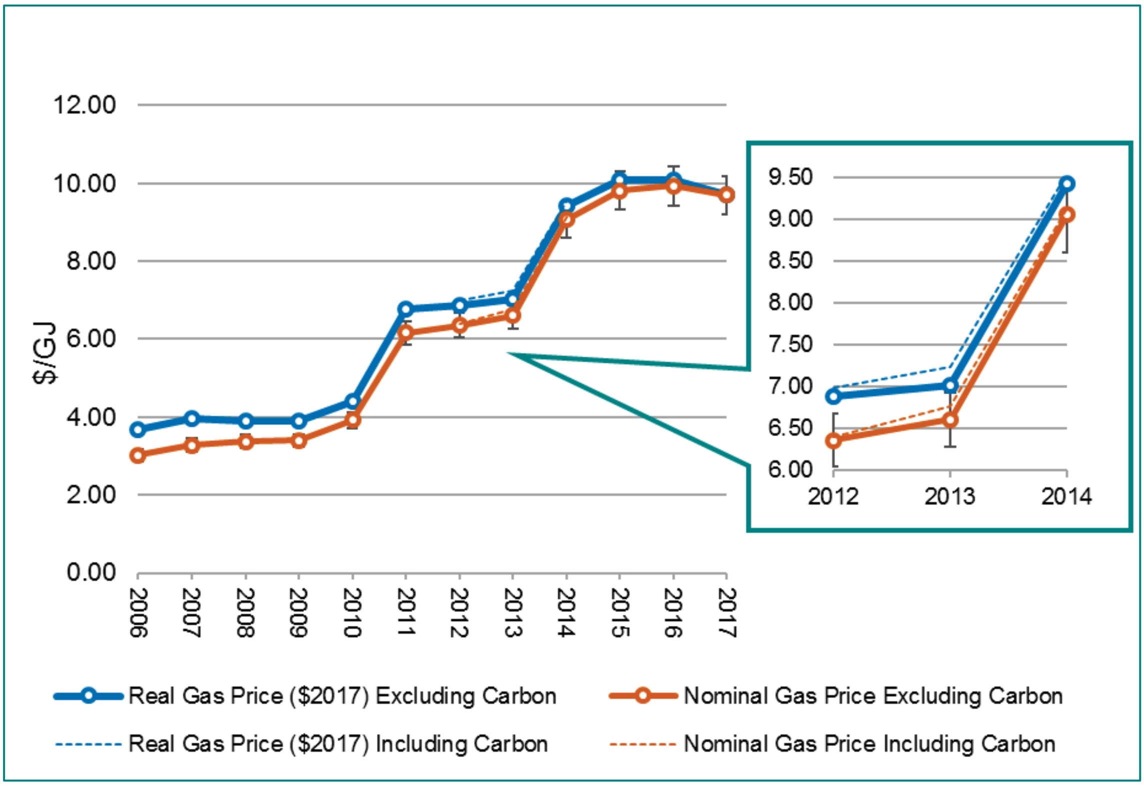


Figure 63 shows the breakdown of the different components making up the large industrial gas price in Brisbane/SEQ from 2006 to 2017.

Figure 63: Brisbane and SEQ large industrial customer gas prices components

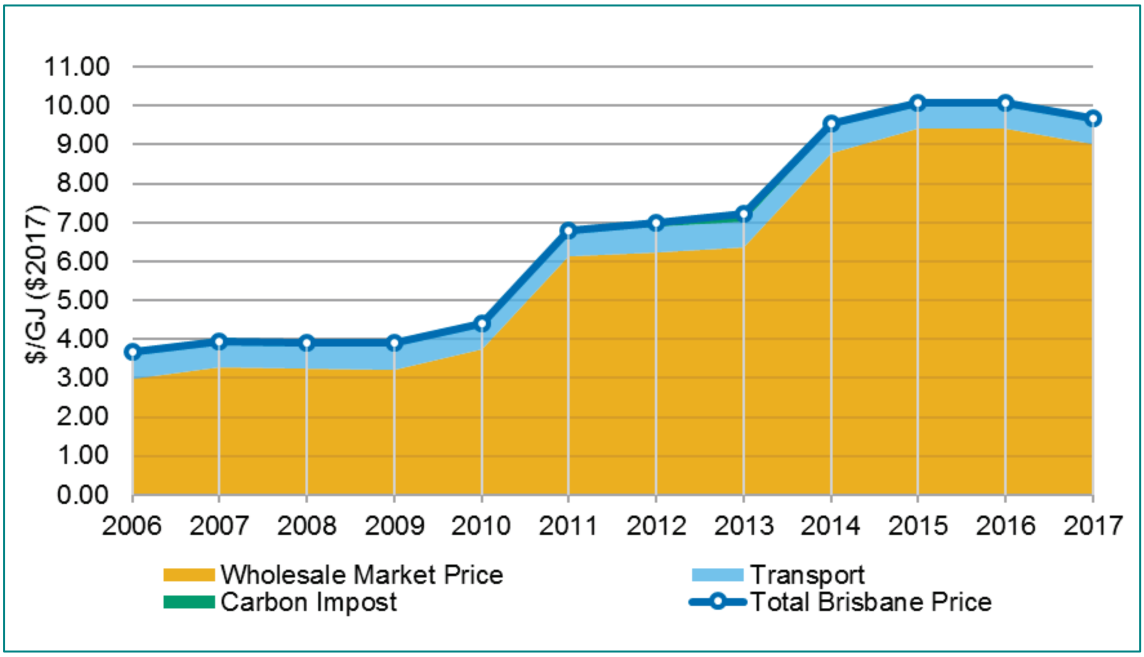
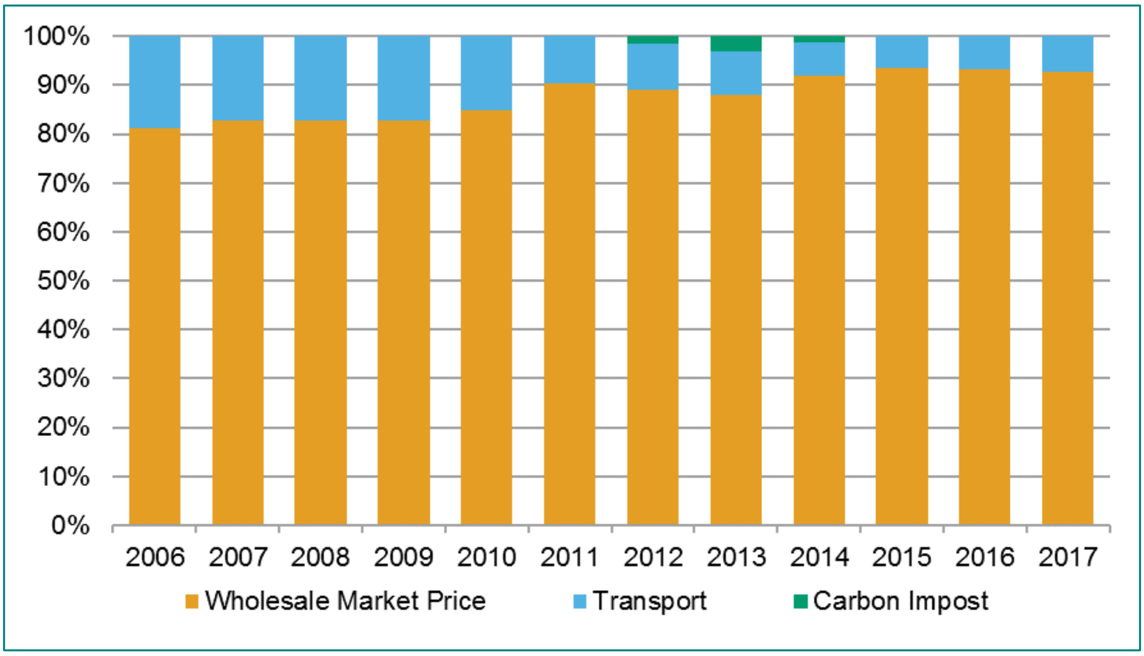


Figure 64 shows the percentage breakdown of the different components making up the large industrial gas price in Brisbane/SEQ from 2006 to 2017.

Figure 64: Brisbane and SEQ large industrial customer gas price components by %



4.6.3 Gladstone large industrial gas customers

Table 15 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The decrease in gas price is 24% on the 2015 gas price, which is a major change and likely the cheapest wholesale gas on the east coast.

Table 15: Gladstone gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	9.53	7.36	7.00	86%	-27%
Transport	1.15	1.15	1.15	14%	0%
Total	10.68	8.51	8.15	100%	-24%

In 2017, the average gas price delivered to large industrial customers in the Gladstone region was $8.15/GJ of which $7.00/GJ (86%) was the wholesale gas cost and $1.15/GJ (14%) was pipeline transportation costs.

The average gas price paid by large industrial customers in the Gladstone region (delivered ex-Queensland Gas Pipeline) entering into a new GSA on a year-by-year basis is shown in Figure 65.

Figure 65: Gladstone large industrial customer delivered gas price history

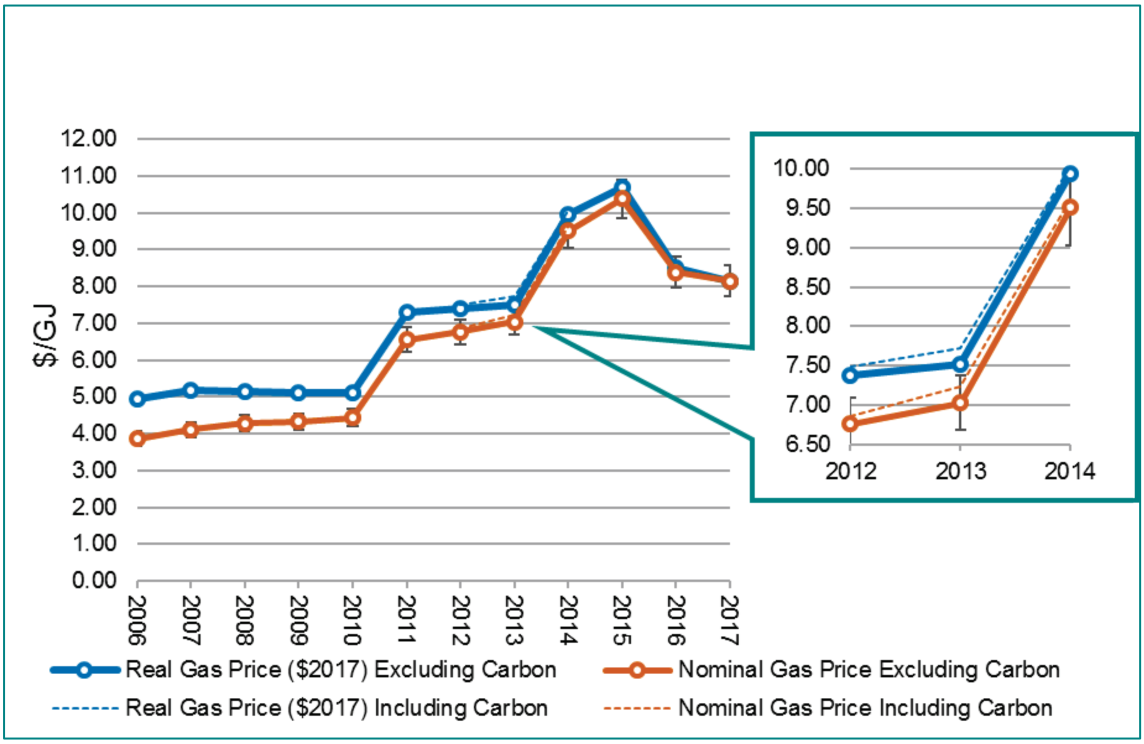


Figure 66 shows the breakdown of the different components making up the large industrial gas price in Gladstone from 2006 to 2017.

Figure 66: Gladstone large industrial customer gas price components

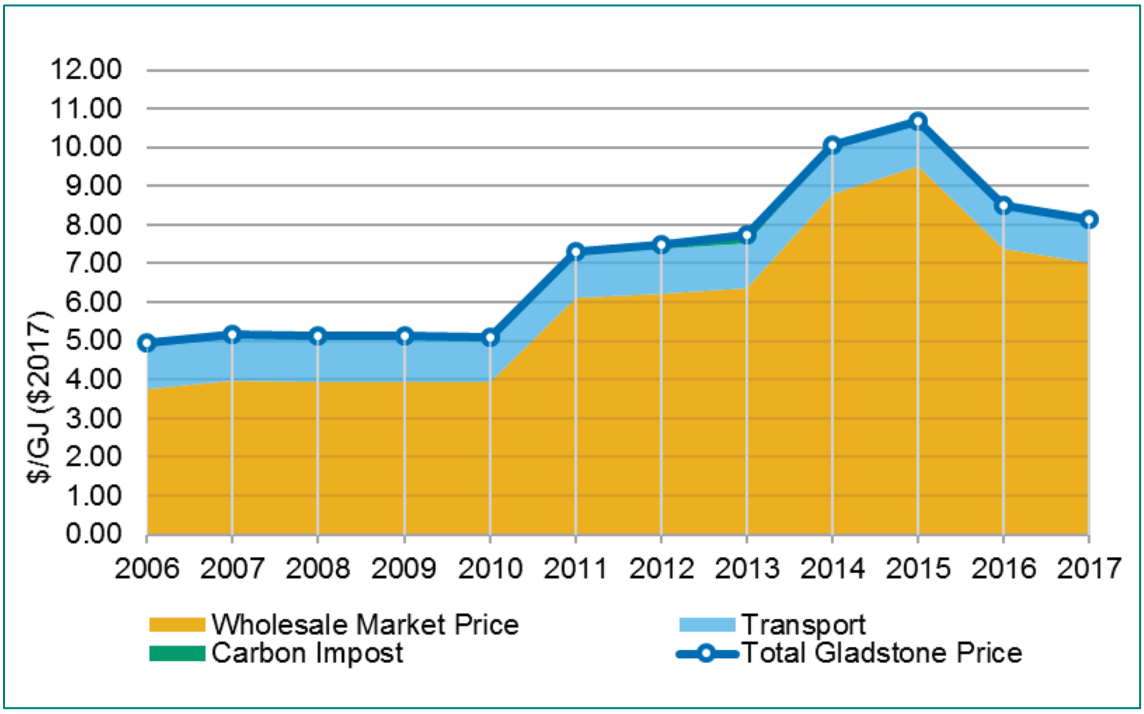
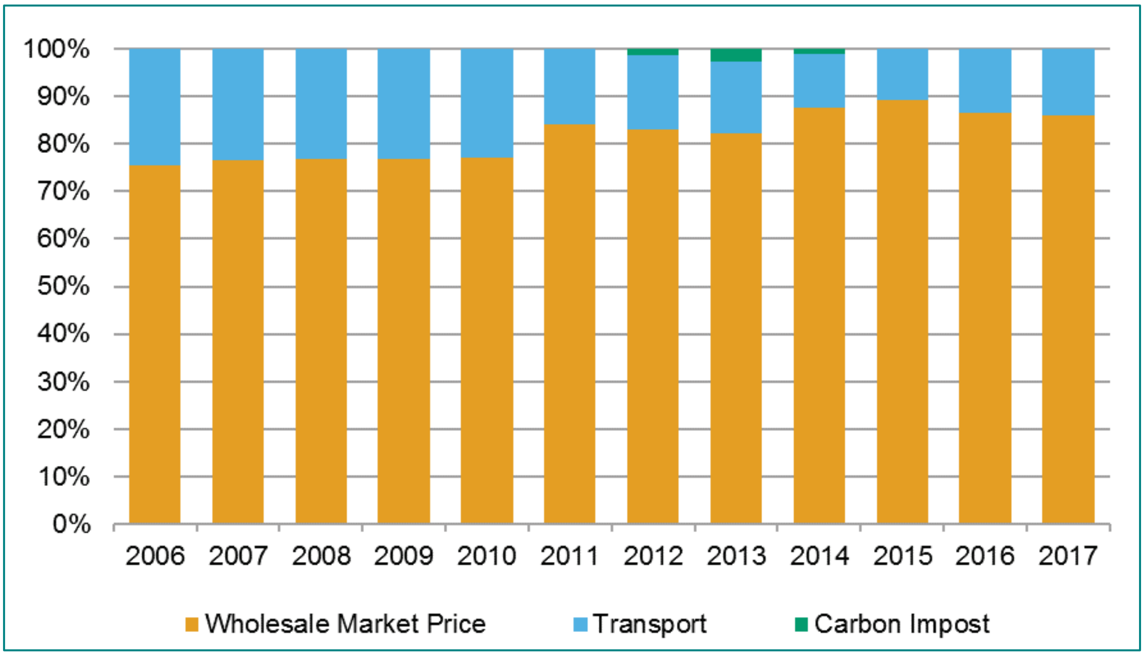


Figure 67 shows the percentage breakdown of the different components making up the large industrial gas price in Gladstone from 2006 to 2017.

Figure 67: Gladstone large industrial customer gas price components by %



4.6.4 North West Queensland large industrial customer gas prices

Table 16 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The decrease in gas price is 5% on the 2015 gas price, continuing the trend of price reductions in Queensland.

Table 16: North West Queensland gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	10.60	10.41	10.00	85%	-6%
Transport	1.72	1.72	1.72	15%	0%
Total	12.32	12.13	11.72	100%	-5%

In 2017 the average gas price delivered to North West Queensland (NWQ) large industrial customers was $11.72/GJ of which $10.00/GJ (85%) was the wholesale gas cost and $1.72/GJ (15%) was pipeline transportation costs.

The gas price paid by NWQ large industrial customers (delivered ex-Carpentaria Gas Pipeline - Mt Isa) entering into a new supply agreement on a year-by-year basis is shown in Figure 68.

Figure 68: NWQ large industrial customer delivered gas price history

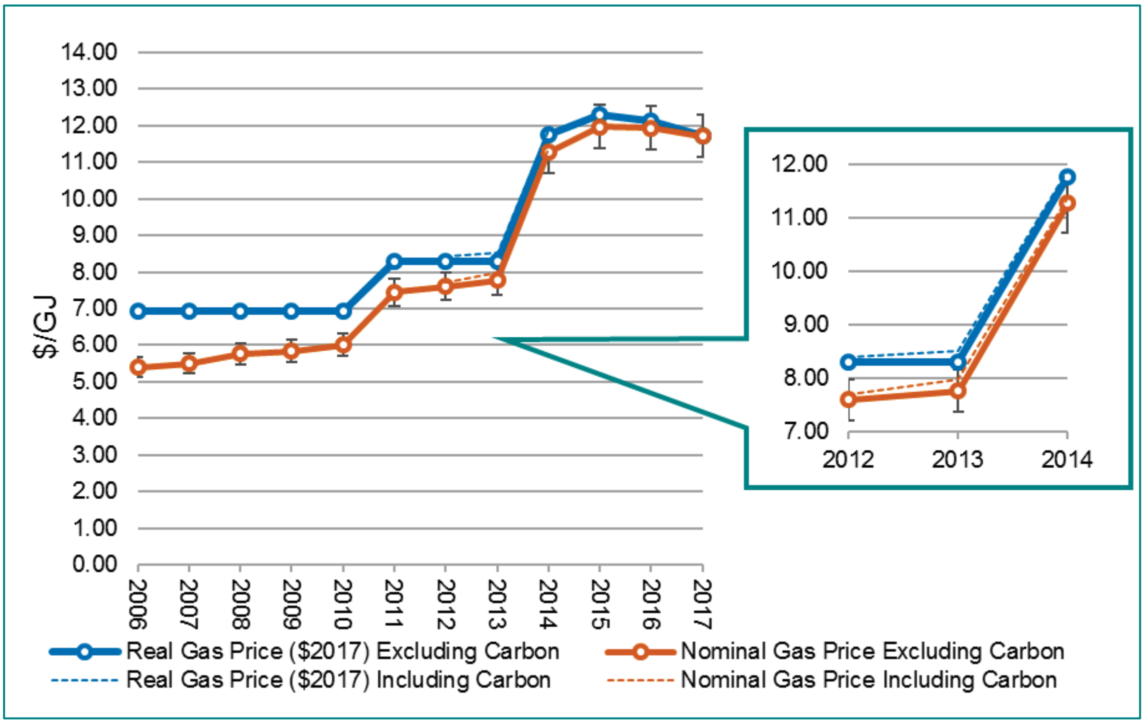


Figure 69 shows the breakdown of the different components making up the NWQ large industrial gas price from 2006 to 2017.

Figure 69: NWQ large industrial customer gas price components

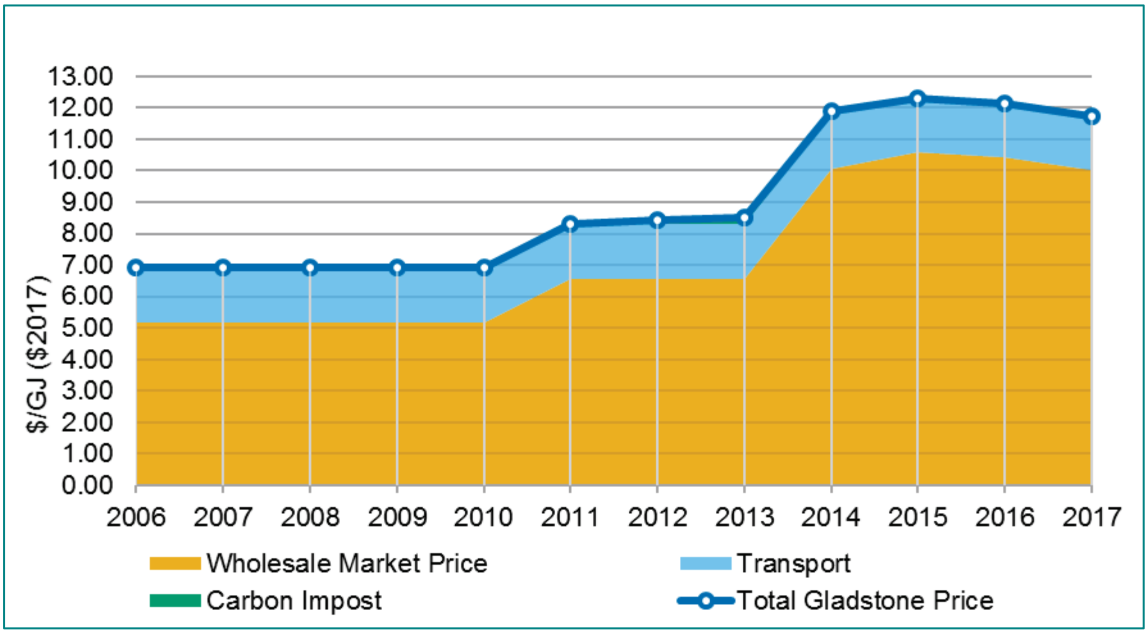
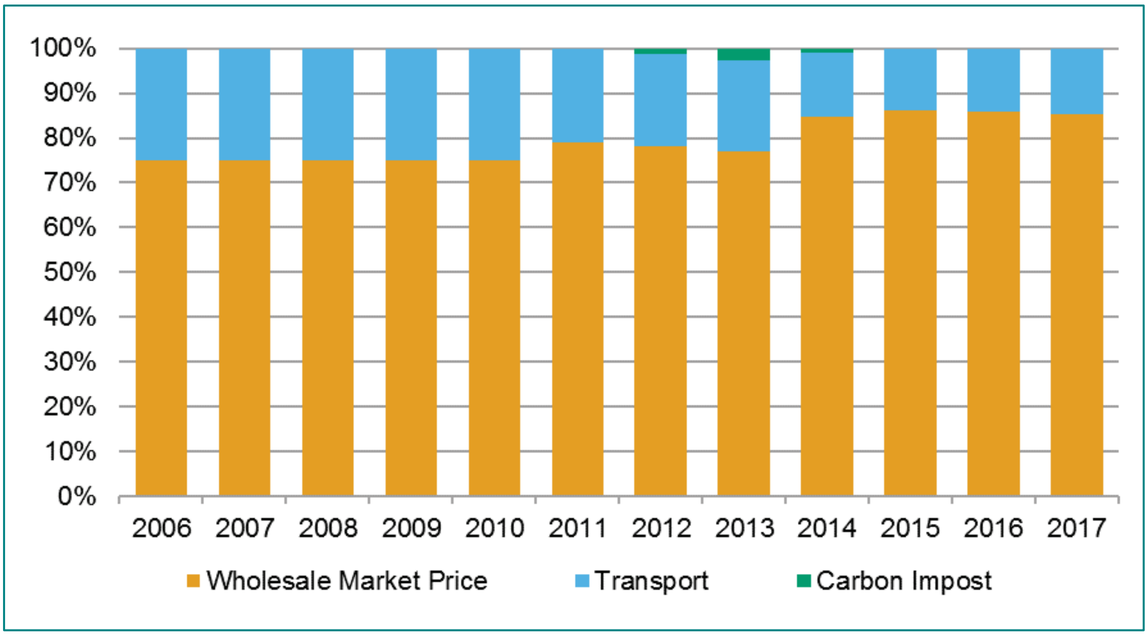


Figure 70 shows the percentage breakdown of the different components making up the NWQ large industrial customer gas price from 2006 to 2017.

Figure 70: NWQ large industrial customer gas price components by %



4.6.5 Queensland large industrial customer gas price averages

The average large industrial customer gas price for Queensland has been developed by volume weighting the prices for the three demand nodes based on transmission flow data from the AEMO National Gas Bulletin Board[33] for the specific feed pipelines – Roma to Brisbane Pipeline (RBP – Brisbane and SEQ), Queensland Gas Pipeline (QGP - Gladstone) and the Carpentaria Gas Pipeline (CGP - NWQ). This data was available back to 2008 and prior to that the 2008 data has been used as a proxy.

In 2017, the weightings were 33% Brisbane/SEQ, 43% Gladstone and 24% NWQ.

Table 17 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The decrease in gas price is 14% on the 2015 gas price.

Table 17: Queensland gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	9.70	8.86	8.40	88%	-13%
Transport	1.04	1.13	1.14	12%	10%
Total	10.74	9.99	9.54	100%	-11%

33 AEMO's National Gas Bulletin Board at the National Gas Bulletin Board website.

Based on the weighting described above, in 2017, the average gas price delivered to Queensland large industrial customers was $9.54/GJ of which $8.40/GJ (88%) was the average wholesale gas cost and $1.14/GJ (12%) was average pipeline transportation costs.

The average gas price paid by Queensland large industrial customers between 2006 and 2017 is shown in Figure 71.

Figure 71: Weighted average large industrial customer delivered gas price trend Queensland

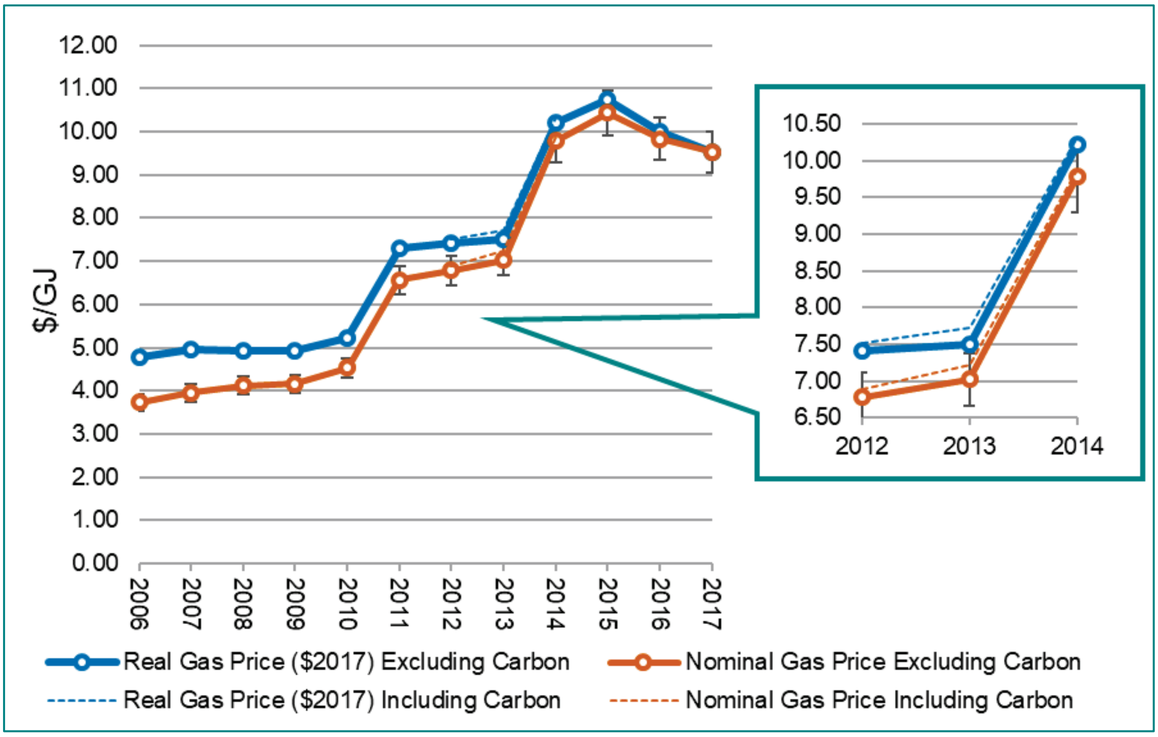


Figure 72 shows the breakdown of the different components making up the average Queensland large industrial customer gas price from 2006 to 2017.

Prices have clearly peaked and now are in decline in Queensland, much as we saw in the WA pricing cycle.

Figure 72: Weighted average large industrial customer gas price components Queensland

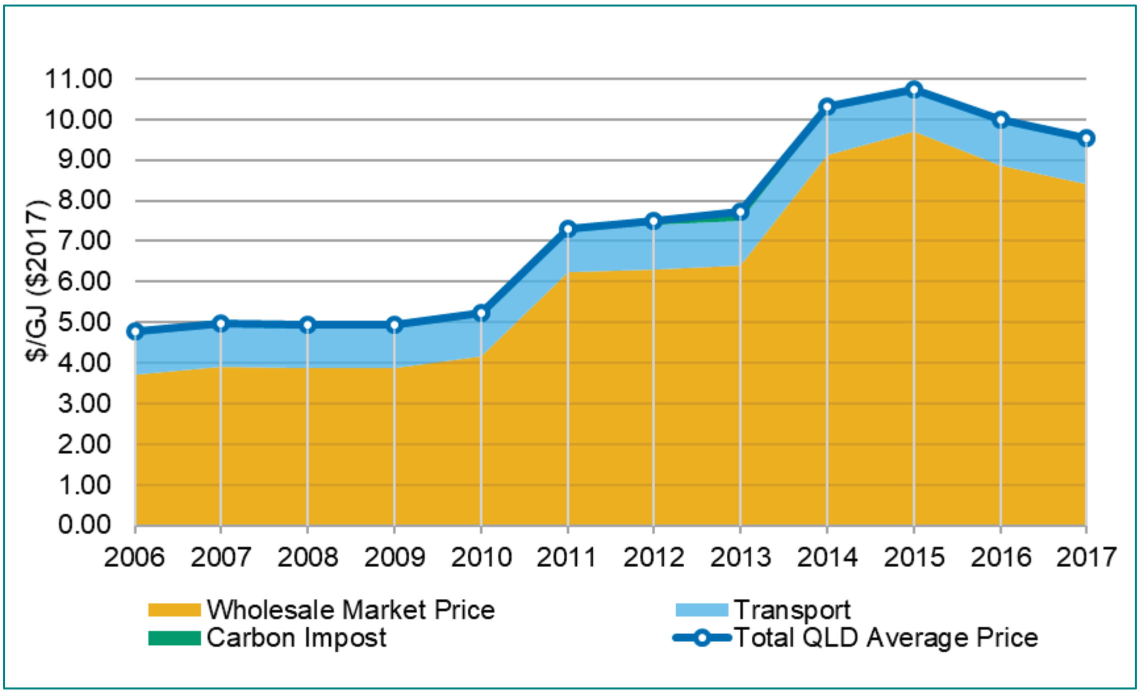
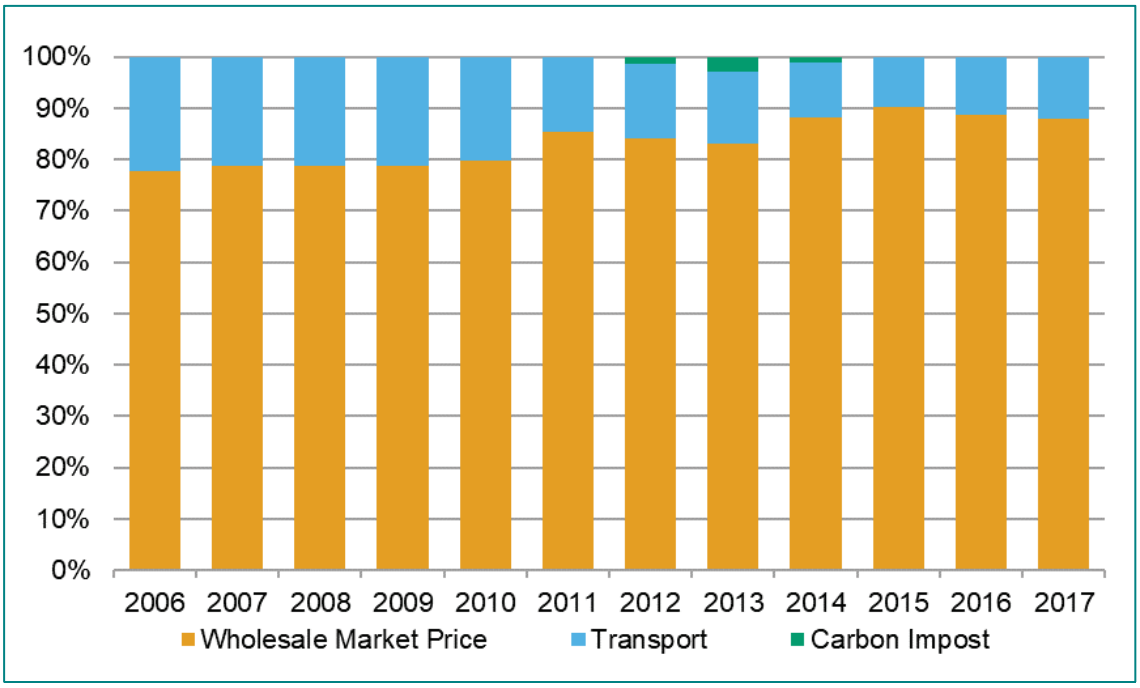


Figure 73 shows the percentage breakdown of the different components making up the average Queensland large industrial customer gas price from 2006 to 2017.

Figure 73: Weighted average large industrial gas customer price components Queensland by %.



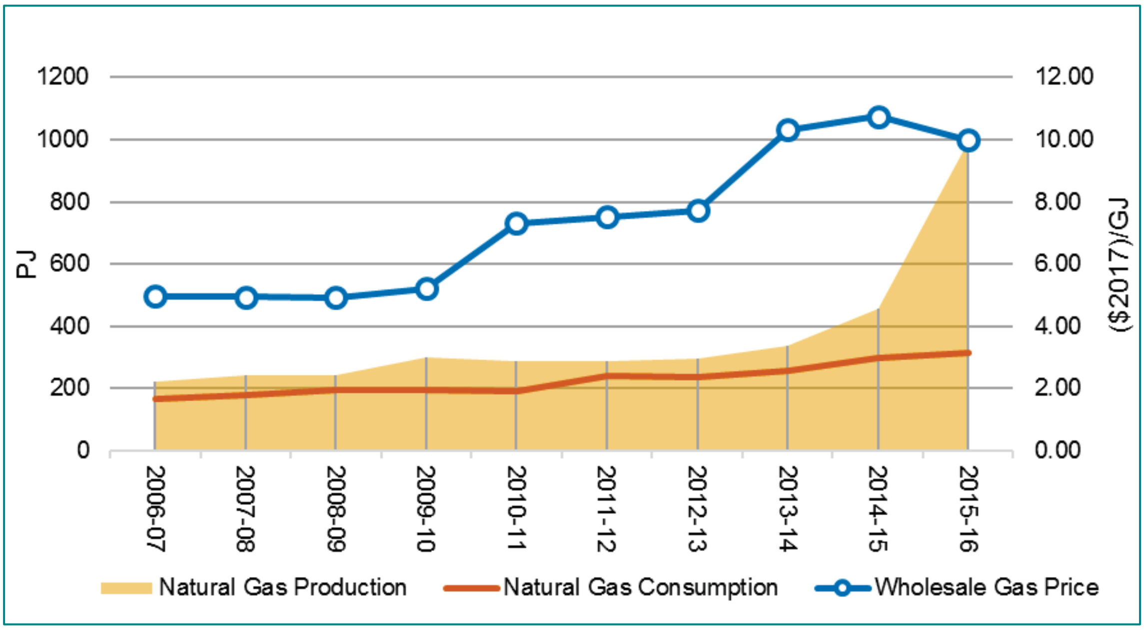
4.6.6 Queensland large industrial gas price analysis

Between 2015 and 2017, the major factors influencing Queensland large industrial prices were:

- A material change in the supply/demand balance. See Figure 74.

- Despite the moving balance, the average price in Queensland has moderated, peaking in 2015 and tempering to approximately $9.50/GJ (delivered including transport) in 2017.
- It's probably premature to suggest the price decrease will continue trending down but as:
  - The LNG plant operations stabilise,
  - The underlying longer term contracts are recontracted,
  - The spot markets mature, and
  - Coal seam gas field upstream operations, methodology and production matures
- The price may stabilise at least down to the cost of production, and Gladstone may already be at that level for wholesale gas.

Figure 74: Queensland gas supply/demand balance



4.7 East coast industrial gas price average

The average large industrial customer gas price for the east coast of Australia has been developed by volume weighting the average price for each of the state jurisdictions (Qld, NSW, Vic, SA and Tasmania).[34] In 2017, the weightings were 18% NSW, 32% Vic, 36% Qld, 13% SA and 1% Tasmania.

Table 18 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The increase in gas price is 20% on the 2015 gas price.

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[34] This weighting has been based on the Australian Energy Statistics 2016, Chief Economists Office (Table Q1) that provides gas consumption by state up to 2015-2016. For the following years the 2015-16 ratios have been used as a proxy.

Table 18: East coast (volume weighted) average gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	7.60	9.78	9.19	91%	21%
Transport	0.82	0.89	0.89	9%	8%
Total	8.43	10.67	10.08	100%	20%

Based on the weighting described above, in 2017, the average delivered gas price for the large industrial customers on the east coast of Australia was $10.08/GJ of which $9.19/GJ (91%) was the average wholesale gas cost and $0.89/GJ (9%) was average pipeline transportation costs.

The average east coast Australian gas price gas price paid by large industrial customers between 2006 and 2017 is shown in Figure 75. Again, as can be seen the peak of pricing was in 2016 and there has been a reduction related to 2017 (but as we note timing of contracts is an issue as the prices turned).

Figure 75: East Coast weighted average large industrial delivered gas price trend

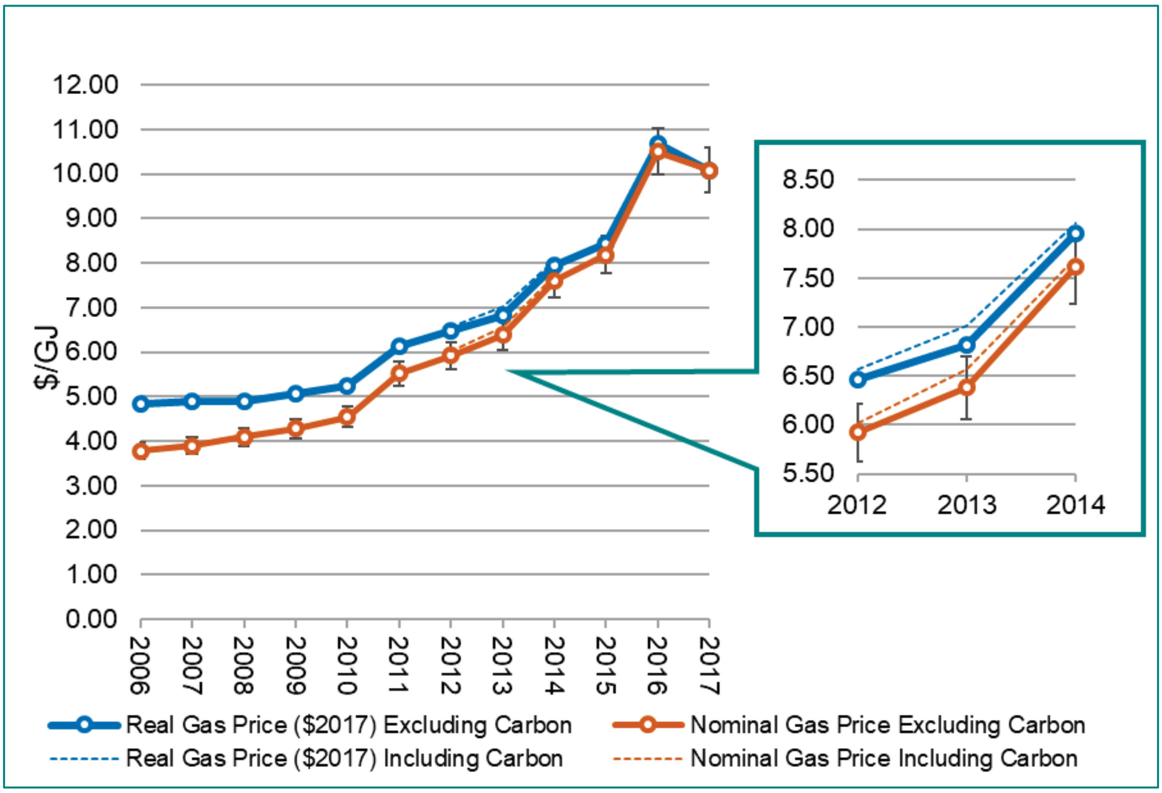


Figure 76 shows the breakdown of the different components making up the average east coast large industrial customer gas price from 2006 to 2017.

Figure 76: East Coast weighted average large industrial customer gas price components

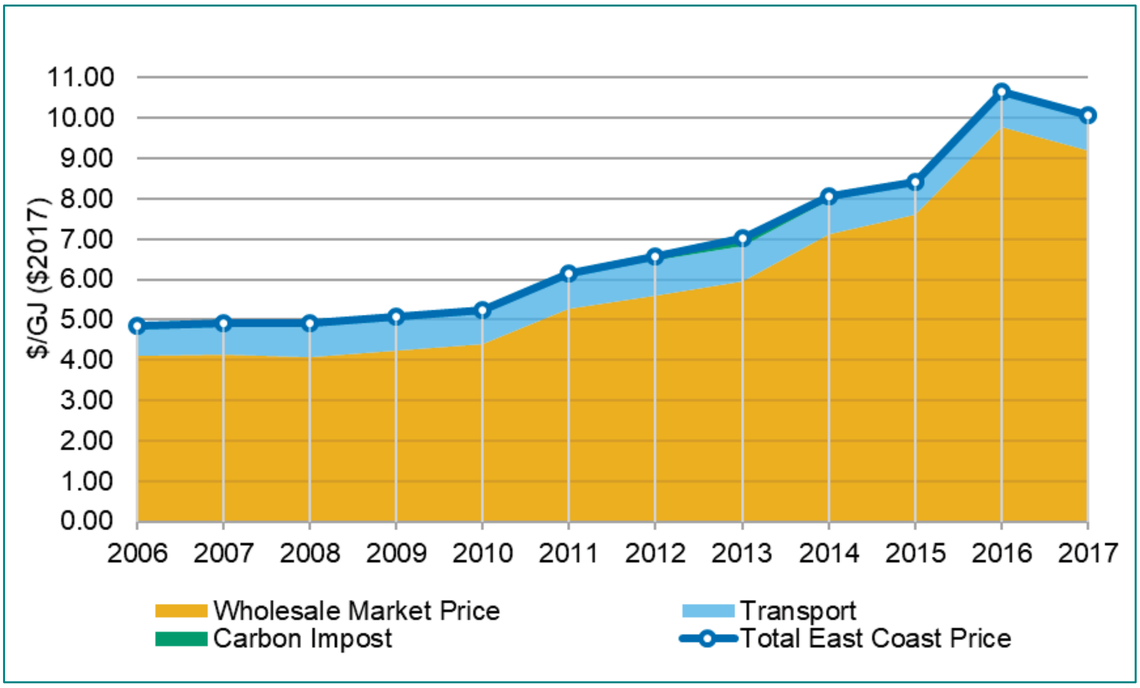


Figure 77 shows the different components making up the average east coast Australian large industrial gas price from 2006 to 2017.

Figure 77 : East Coast weighted average large industrial customer gas price components %

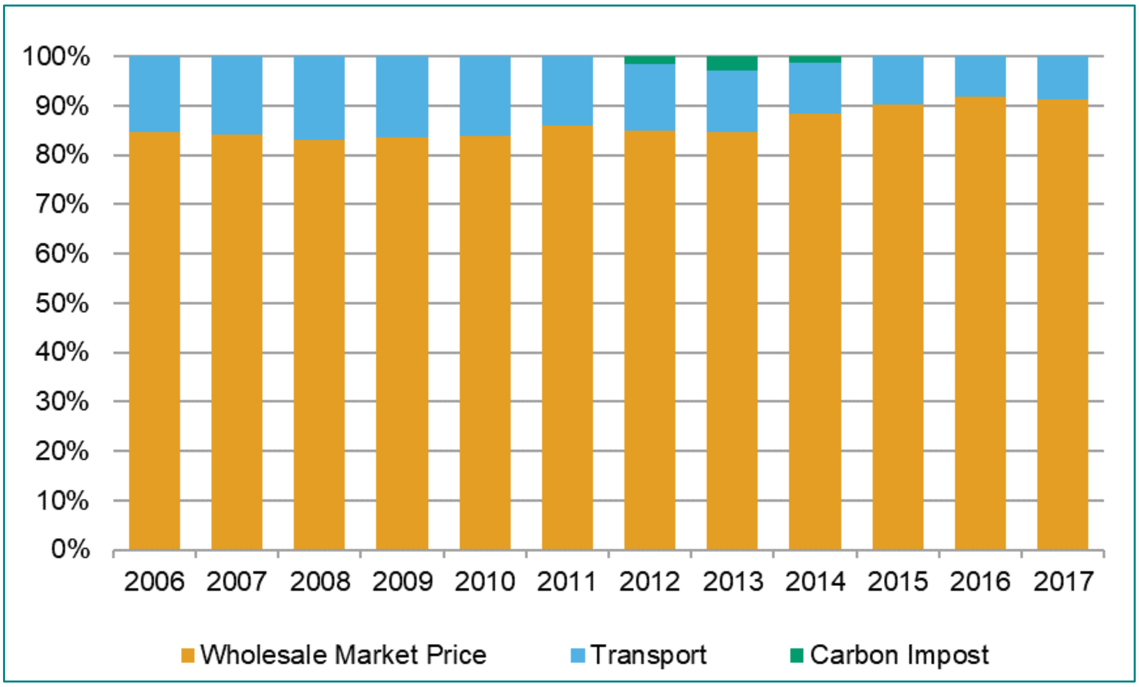
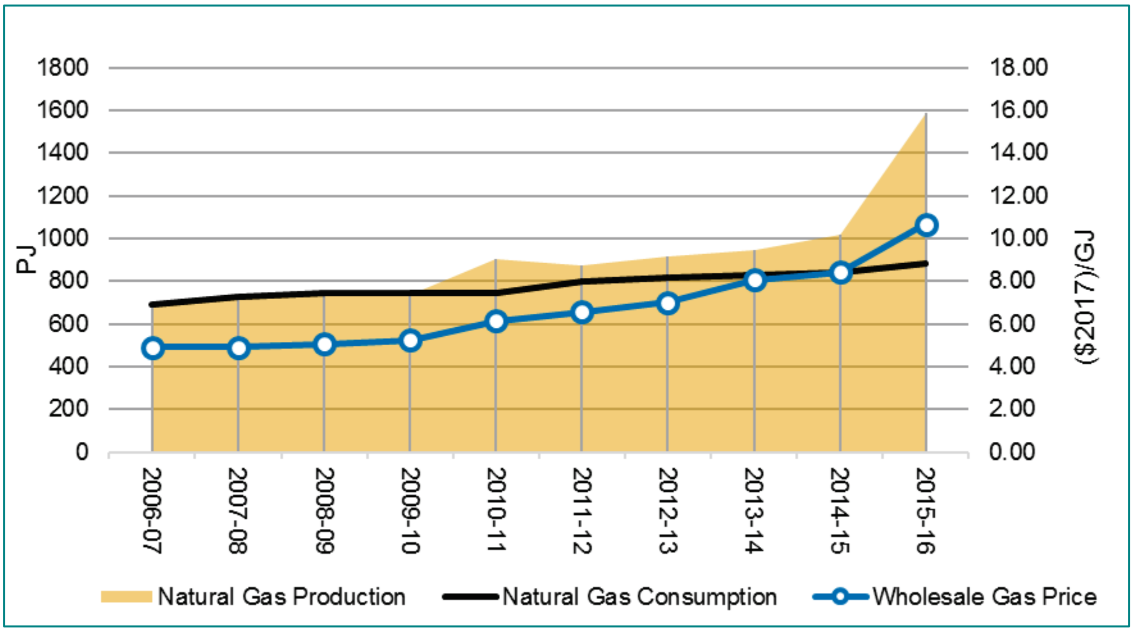


Figure 78 shows the relationship between gas supply, demand and price trends of the combined (volume-weighted) average gas price on the east coast of Australia.

Figure 78: Combined east coast gas production, consumption and (volume-weighted) price trend



4.8 Northern Territory industrial gas prices

Industrial (and residential) gas in the Northern Territory has historically been supplied by the Power and Water Corporation (PWC) via the Amadeus Gas Pipeline to its own power generation facilities located in the major load centres embedded in the Darwin-Katherine, Tennant Creek and the Alice Springs electricity networks.

Gas producer, Santos, had its long-term gas supply contracts with PWC replaced with gas from ENI's offshore Blacktip field in the Bonaparte Gulf.

Central Petroleum (CTP) has a scheme of arrangement with Santos to operate and market its gas reserves in the Mereenie, Palm Valley and Dingo gas fields and in 2017, CTP announced it has contracted approximately 2 PJ/a over a 5 year period with Energy Developments to supply its Pine Creek Power Station[35].

The Northern Gas Pipeline (NGP) connecting Tennant Creek and Mount Isa is scheduled for completion in 2018. PWC has been reported to have contracted gas supply transport through the NGP of some 11 PJ/a out of a pipeline capacity of approximately 36 PJ/a. The supply agreement is a 10 year contract with Incitec Pivot[36] who has operations in the Mount Isa region (Phosphate Hill).

In the majority case, in accordance with bilateral arrangements, PWC supplies gas to third parties and continues to supply gas to Territory Generation post disaggregation of the electricity retail and generation groups into Jacana and Territory Generation respectively.

35 Central Petroleum (26 April 2017) ASX release: Central signs 9.85PJ Gas Supply Agreement.

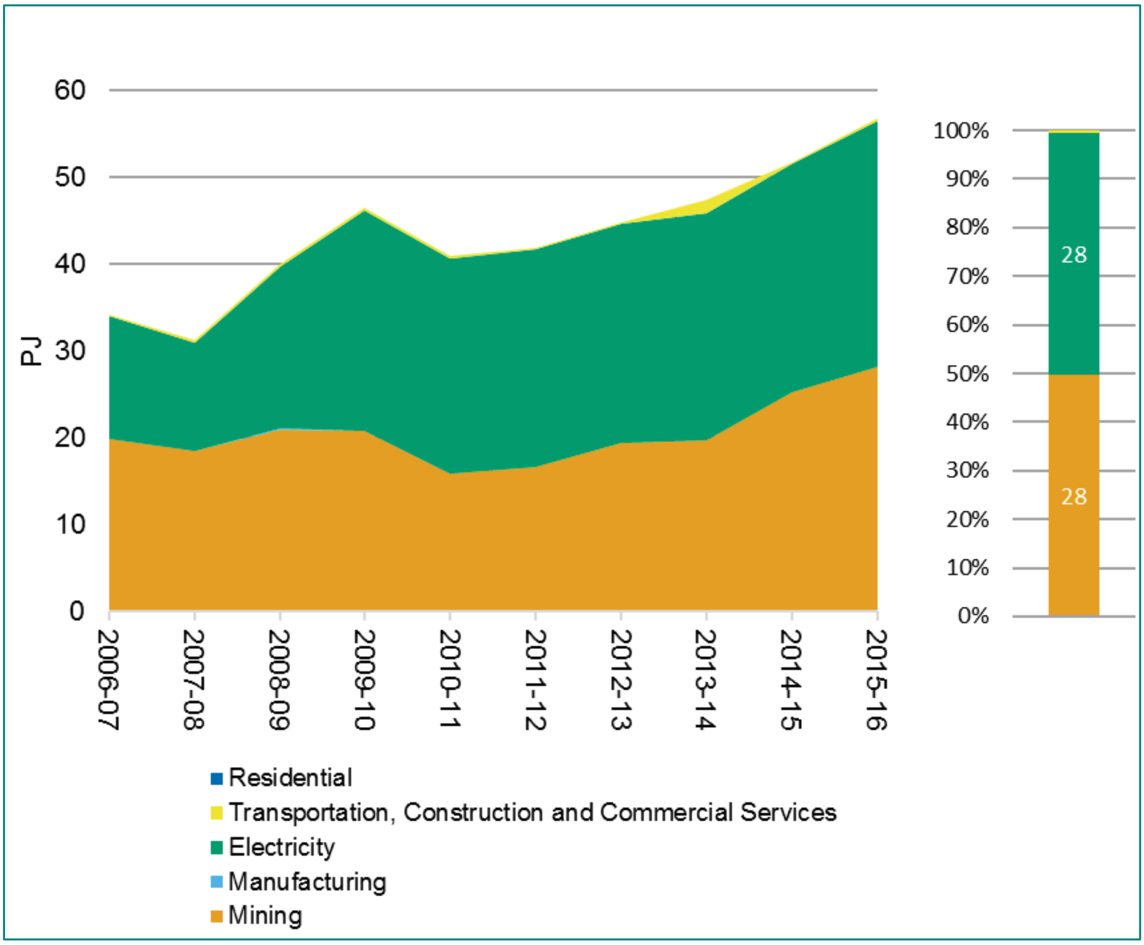
36 PWC (18 November 2015) Power and Water Board Chair signs NEGI gas deal.

Because of this majority utility-style structure, gas prices are confidential and no data is available to present in this report. This section does, however, summarise the demand and supply infrastructure and background.

4.8.1 Northern Territory gas consumption

Figure 79 illustrates the gas consumption trends by sector and percentage contribution of each sector. There is a steady uplift in gas consumption from 2010 to 2016.

Figure 79: Northern Territory gas consumption by sector (PJ)



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Table 19 indicates total gas consumption in Northern Territory was 57 PJ in 2015-2016 with electricity generation and mining consuming 28.3 PJ (50%) and 28.2 PJ (50%) of the territory's gas respectively. The Departmental data classifies LNG under mining consumption, hence any increase in terms of volume trend is opaque in this data set. Volume trend is the contribution of that sector in percentage terms to the increase (or decrease) in the total gas consumption from 2013-14. Total consumption has increased 20% up from 47 PJ in 2013-14. Most of that increase was due to mining (18%) consumption and electricity generation (2%).

Table 19: Northern Territory sectoral consumption volume trends 2013-14 to 2015-16.[37]

	2013-14	2015-16	Trend %
Mining	19.7	28.2	43%
Manufacturing	0.0	0.0	8%
Electricity	26.1	28.3	8%
Transportation, Construction and Commercial Services	1.5	0.2	-84%
Residential	0.0	0.0	0%
Total	47.4	56.7	20%

Gas demand for electricity generation in the Northern Territory (NT) for 2015-16 was about 28 PJ (excludes LNG production by Darwin LNG and the soon to be completed Inpex project) and this is almost exclusively for supply to gas power generation in the three zones of Alice Springs, Tennant Creek and the main Darwin-Katherine electricity networks.

There is a small industrial load in Darwin serviced by a distribution system owned and operated by APA Group which supplies approximately 0.01 PJ/a.

For the NGP, there will be additional gas supply requirements for compression facilities[38] (either through electric or gas compressors that will be gas-fuelled presumably) at the Tennant Creek end of the NGP but this has yet to materialise in this dataset.

PWC supplied gas to the McArthur River Mine (MRM) for power generation up until 2014. MRM expanded the power station to a total of 68 MW capacity and is now supplied with gas from Santos and its Mereenie gas field. It is estimated the gas demand for the expanded mining operation is 3 PJ/a.

There is a small (0.25 PJ/a) compressed natural gas (CNG) operation owned and operated by Energy Developments located in the Alice Springs Brewer Estate which transports CNG via road trains to the Yulara Power Station to supply electricity to the Yulara township and resort.

4.8.2 Northern Territory gas supply

There is a small retail residential natural gas distribution network in Alice Springs owned and operated by Australian Gas Networks (previously known as Envestra). There is also a reticulated liquefied petroleum gas (LPG) supply system in Darwin.

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37 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.
38 PWC (17 July 2017) Power and Water positioned to enter the Australian gas market.

The NT's gas supply was sourced from the Mereenie and Palm Valley gas fields west of Alice Springs to 2010 and supplied to PWC by a Santos-Magellan joint venture. Post 2010, due to a forecast decline of reserves in Mereenie and Palm Valley, a GSA was signed with Italian gas major Eni to supply gas from the Blacktip gas reserve offshore from Wadeye south west of Darwin.

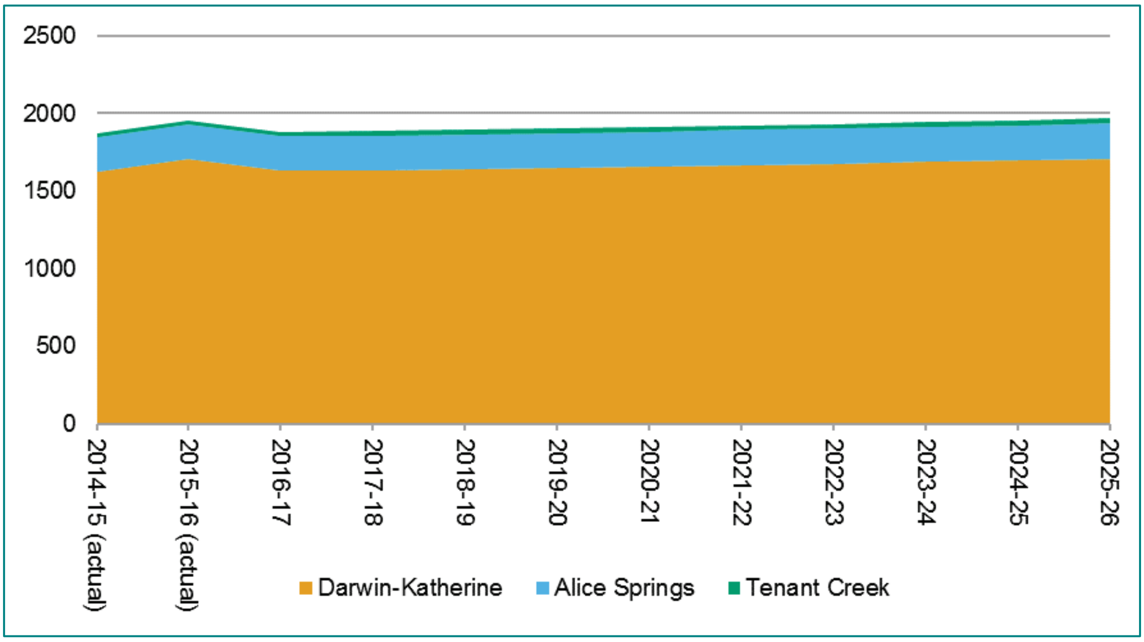
Up until 2013, when McArthur River exited its Power Purchase Agreement (PPA) with PWC, the only gas buyer in NT was PWC Generation (now called Territory Generation), apart from the small distribution network supplying some industrial sales in Darwin. In 2013, the McArthur River mine signed a GSA directly with Santos.

On 14 September 2016, the Northern Territory Government announced a moratorium on hydraulic fracturing on onshore unconventional petroleum reservoirs[39]. In December 2016, the NT Government announced an independent "Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory". The moratorium will remain in place during the inquiry. The interim inquiry report was released in July 2017[40] and at the time of writing the inquiry is ongoing.

4.8.3 Forecast demand

The electricity forecast in the Northern Territory is expected to remain largely flat and, on the basis that it is really a single fuel source for generation (gas), it can be expected that the forward gas supply requirement will also be largely flat.

Figure 80: Northern Territory electricity consumption forecast



Source: Data sourced from Utilities Commission Power System Review 2015-16, Appendix B.

39 NT Government website (28 November 2017) Hydraulic fracture stimulation: moratorium and public inquiry.

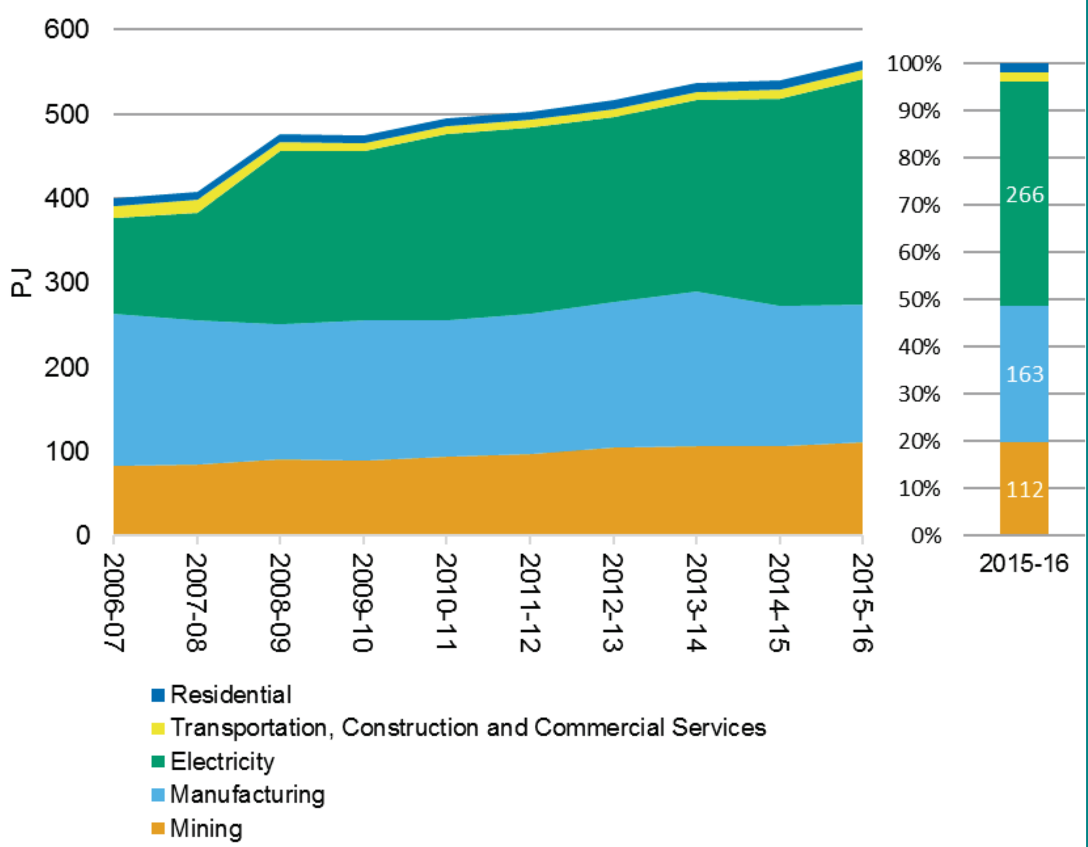
40 Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory, Fracking Enquiry website .

4.9 Western Australia industrial gas prices

4.9.1 Western Australia gas consumption

Figure 81 illustrates the gas consumption trends by sector and percentage contribution of each sector. Total gas use has risen steadily from 2006 with the largest increases experienced in the electricity generation and mining sector of which the latter includes (as specified in the Department's datasets) mining operations and LNG both of which are very prevalent in the WA gas market.

Figure 81: Western Australia gas consumption by sector (PJ)



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Table 20 indicates total gas consumption in Western Australia was 563 PJ in 2015-2016 with mining 111.7 PJ (20%), manufacturing 163.2 PJ (29%) and electricity generation 266.5 PJ (47%) the state's largest consumers of gas.

Total gas consumption increased 5% from the 2013-14 financial year but there has been a significant decline in Manufacturing gas use.

Table 20: Western Australia sectoral consumption volume trends 2013-14 to 2015-16.[41]

	2013-14	2015-16	Trend %
Mining	105.9	111.7	5%
Manufacturing	183.7	163.2	-11%
Electricity	226.4	266.5	18%
Transportation, Construction and Commercial Services	10.4	10.8	4%
Residential	10.5	10.9	4%
Total	537.0	563.2	5%

4.9.2 Large industrial customer price trends

Table 21 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The decrease in gas price is 31% on the 2015 gas price, after a prolonged period of gas price reductions as the supply constrained "pricing bubble" burst with new supply and sellers entering the market.

Table 21: Western Australia gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	8.17	6.09	5.00	72%	-39%
Transport (Perth)	1.93	1.95	1.97	28%	2%
Total	10.10	8.04	6.97	100%	-31%

In 2017, the average gas price delivered to Perth large industrial customers was $6.97/GJ of which $5.00/GJ (72%) was the wholesale gas cost and $1.97/GJ (28%) was pipeline transportation costs.

The average gas price paid by WA large industrial customers, delivered to Perth ex-Dampier to Bunbury Pipeline (DBNGP), who entered into a new GSA on a year-by-year basis is shown in Figure 82.

41 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Figure 82: WA real and nominal large industrial customer delivered gas price history (Perth)

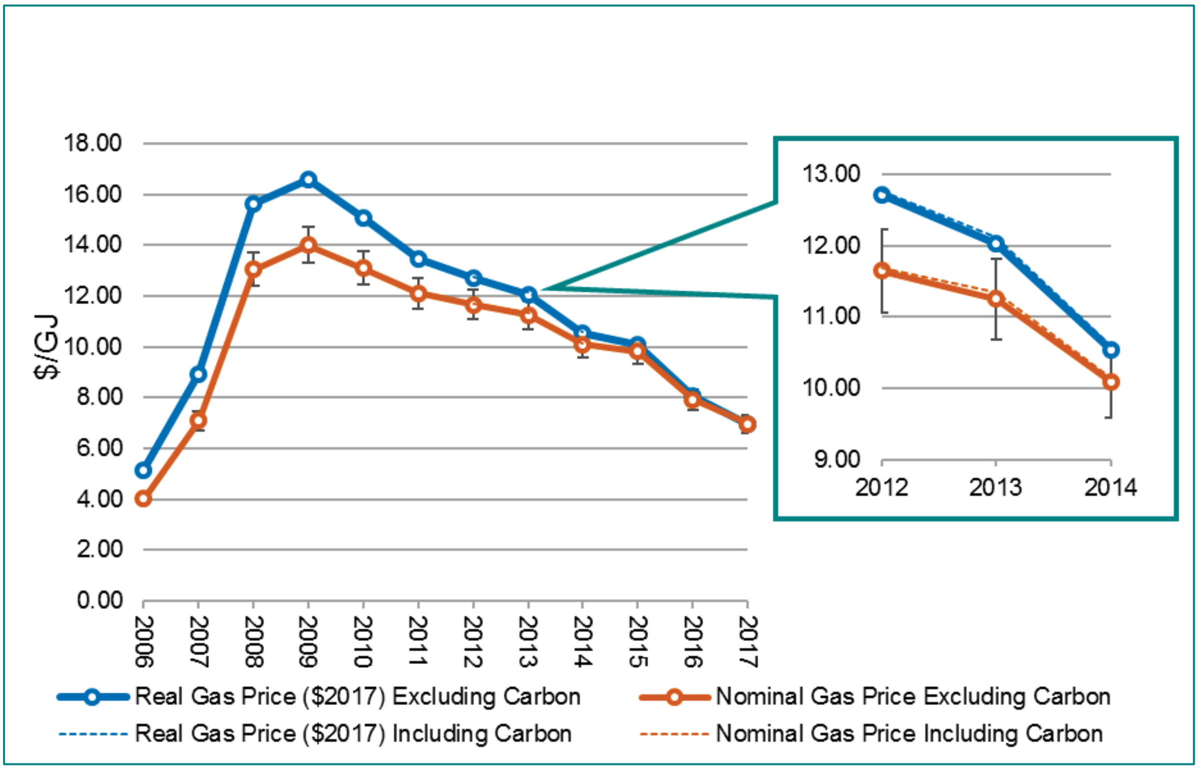


Figure 83 shows the breakdown of the different components making up the large industrial customer gas price in WA from 2006 to 2017.

Figure 83: WA large industrial customer gas price components

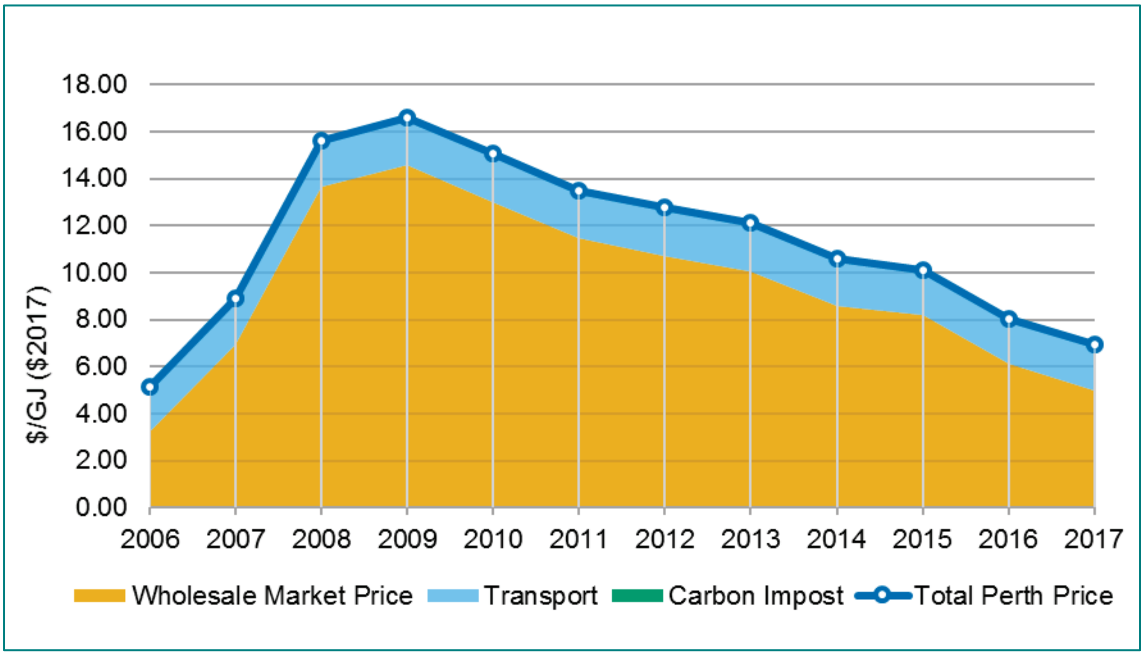
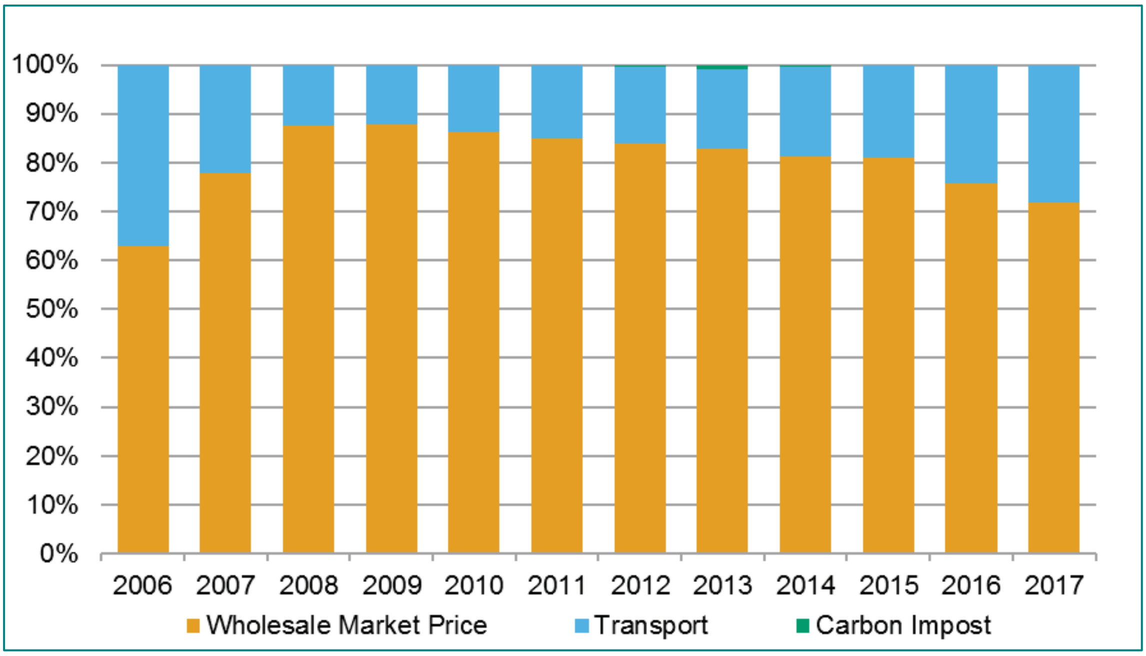


Figure 84 shows the percentage breakdown of the different components making up the large industrial customer gas price in WA from 2006 to 2017.

Figure 84: WA large industrial customer gas price components %

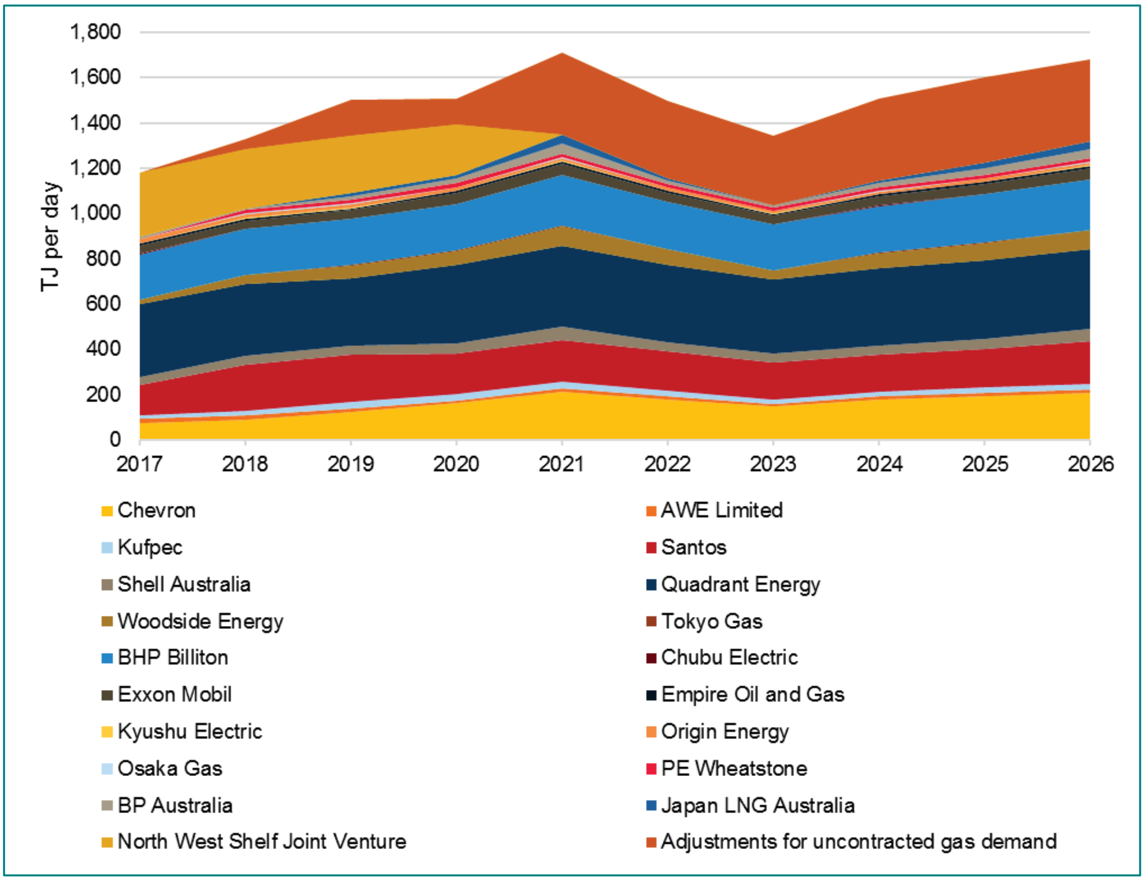


4.9.3 WA large industrial gas price analysis

Between 2015 and 2017, the major factors influencing WA large industrial prices were:

- Expiry of the North West Shelf joint marketing arrangements therefore more 'suppliers' in the market with gas to sell. The NWS JV partners and Gorgon JV partners have declined to renew their respective joint marketing agreements which allows each party to market their gas individually (equity marketing). Including new gas supplies into the market there will be some 20-odd producers (excluding resellers) which can sell gas. Figure 85 (extracted from the WA GSOO 2016) illustrates the build-up of gas producers to the domestic gas market from 2017 onward.

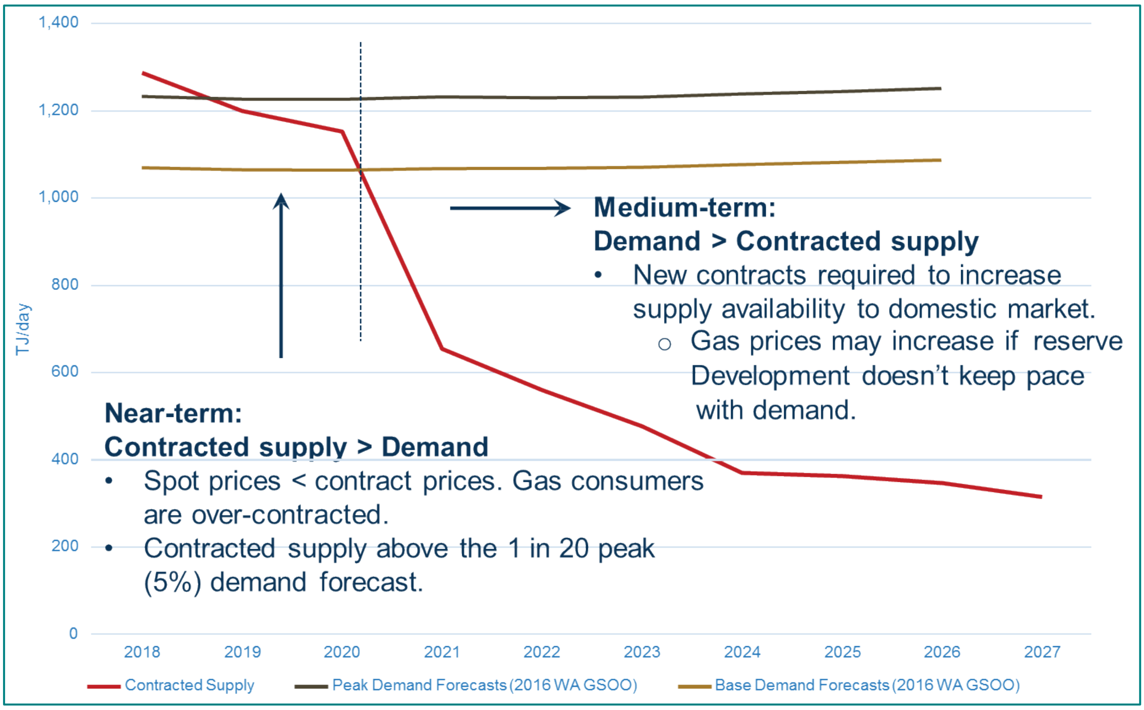
Figure 85: 2016 Base scenario potential domestic gas supply forecasts



Source: WA AEMO GSOO 2016, Figure 21.

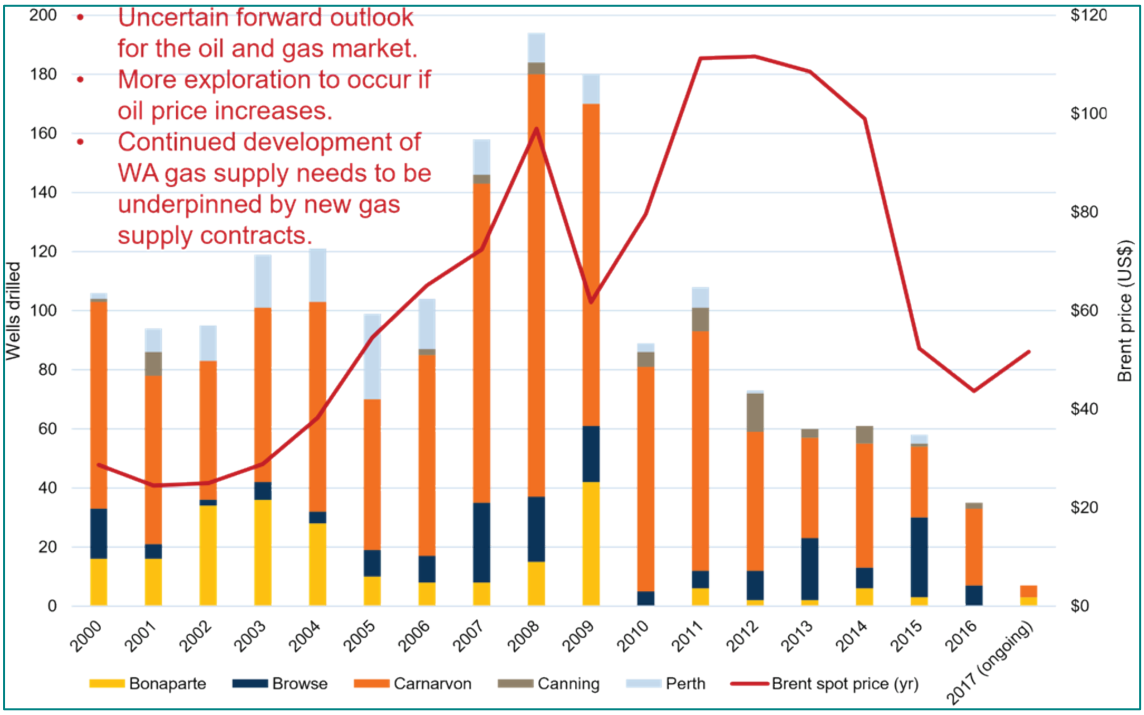
- Multiple fields producing more gas for sale on the domestic market. Excess gas available to the market relative to demand and intercompany trades (anecdotally) are quite common – see Figure 86. Note the potential tightening of supply in 2020 which in combination with limited exploration activity (See Figure 87) may place upward pressure on gas prices.

Figure 86: WA contracted gas supply and demand



Source: WA AEMO GSOO 2017 update (20 September 2017) – presentation to ERAWA Gas Advisory Board.

Figure 87: Exploration versus oil price index.



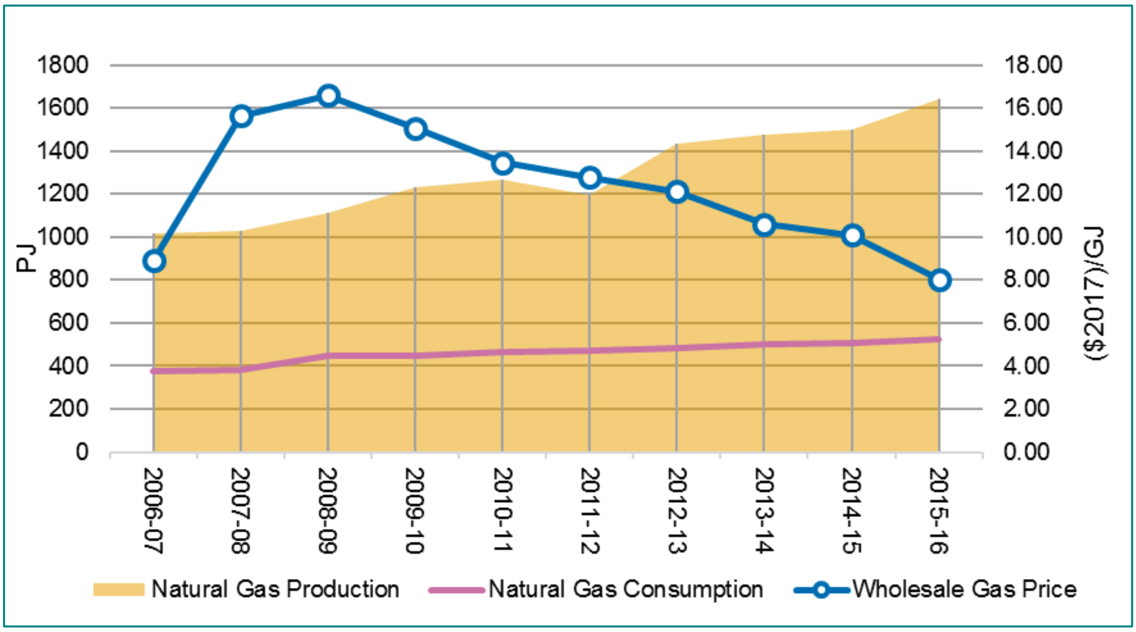
Source: WA AEMO GSOO 2017 update (20 September 2017) - presentation to ERAWA Gas Advisory Board.

- Domestic reservation policy. Western Australia's domestic gas policy requires LNG exporters to provide 15% of LNG exports available for sale in the domestic market. In July 2014, the Economic Regulation Authority of WA (ERAWA) recommended to rescind the gas reservation policy[42] which was presented to parliament but not enacted as far as can be determined. The detailed recommendations and reasons can be found at ERAWA's website[43].

- Maturing spot and intercompany trading market. The spot market operated by Gas Trading Australia has been functioning since 2012 and anecdotally intercompany trades are becoming more readily available between participants with standard term sheets and contracts developed.

- Figure 88 shows the relationship between gas supply, demand and price trends in Western Australia.

Figure 88: WA gas production, consumption and price trend



On 5 September 2017, the Western Australia Government announced a ban on existing and future hydraulic fracturing in the South-West, Peel and Perth metropolitan regions combined with a state-wide moratorium on hydraulic fracturing[44]. These apply to both exploration and production.

The ban and moratorium are subject to and in place until the review of the recommendation in (and implementation of) the "Independent Scientific Panel Inquiry into Hydraulic Fracture Stimulation in Western Australia 2017" announced on the same day.

42 Inquiry into Microeconomic Reform in Western Australia (2014) ERAWA.

43 Microeconomic Reform 2014 ERAWA website

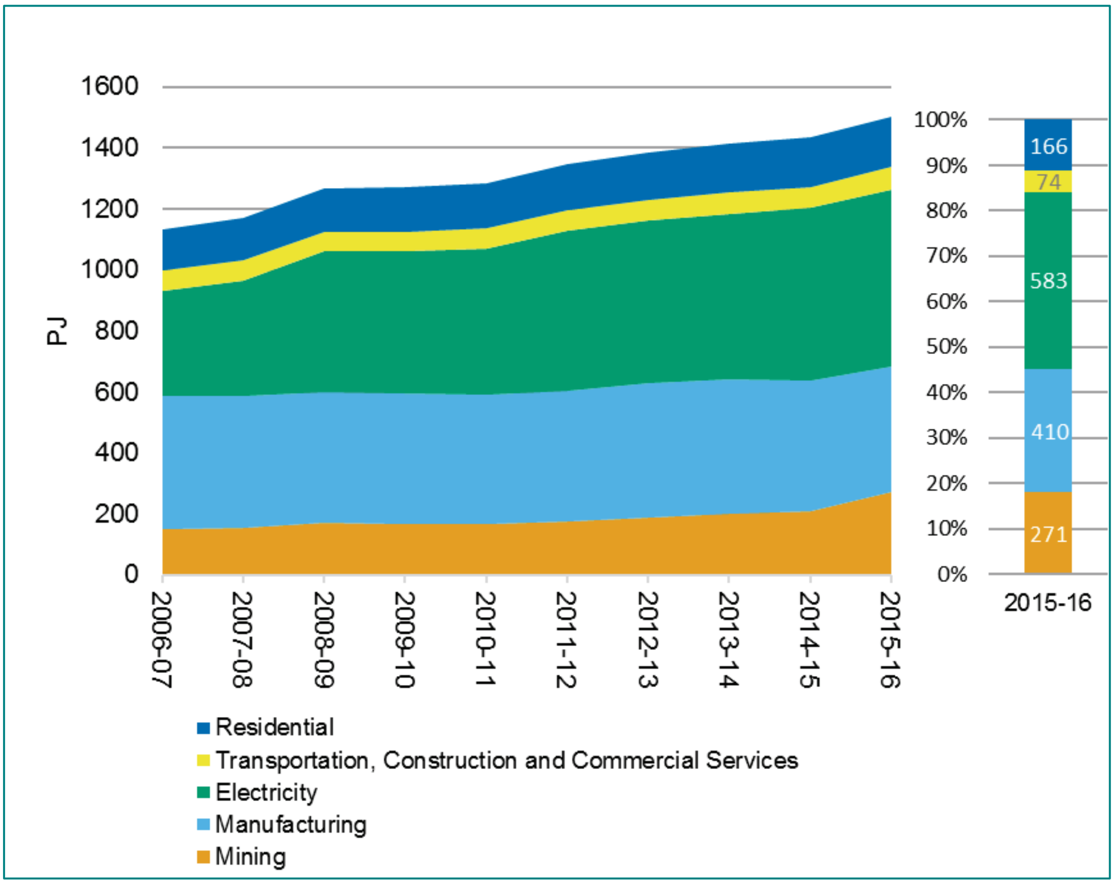
44 Government of Western Australia (5 September 2017) McGowan Government implements fracking commitment.

4.10 National summary of large industrial customer gas prices

4.10.1 National gas consumption

Figure 89 illustrates the gas consumption trends by sector and percentage contribution of each sector. Total gas use has risen steadily from 2006 with the largest increases experienced in the electricity generation sector and a noticeable upward movement in mining (which includes gas used for LNG production) in the 2014-15 to 2015-16 period.

Figure 89: National gas consumption by sector (PJ)



Source: Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

Table 22 indicates total gas consumption in Australia was 1,506 PJ in 2015-2016 with mining 271 PJ (18%), manufacturing 410 PJ (27%) and electricity generation 583 PJ (39%) the nation's largest consumers of gas. Total gas consumption increased 6% from the 2013-14 financial year.

Table 22: National sectoral consumption volume trends 2013-14 to 2015-16.[45]

	2013-14	2015-16	Trend %
Mining	198	271	37%
Manufacturing	444	410	-8%
Electricity	543	583	8%
Transportation, Construction and Commercial Services	71	74	4%
Residential	159	166	4%
Total	1415	1504	6%

4.10.2 Large industrial customer price trends

Table 23 compares the 2017 gas prices to the 2015 gas prices reported in the Gas Price Trends Review 2015 (in $2017). The decrease nationally in gas price is 4% on the 2015 gas price – driven mainly by results in Queensland and Western Australia.

The average large industrial customer gas price for Australia has been developed by volume weighting[46] the average prices of all the state jurisdictions (Queensland, NSW, Victoria, SA, WA and Tasmania). In 2017, the weightings were 11% NSW, 20% Victoria, 22% Queensland, 8% SA, 37% WA and 1% Tasmania.

Table 23: National gas price trends 2015 to 2017 ($2017/GJ)

	2015	2016	2017	2017 % component	2015 to 2017 % trend
Wholesale	7.82	8.40	7.63	86%	-3%
Transport	1.25	1.28	1.29	14%	4%
Total	9.07	9.69	8.92	100%	-2%

Based on the weighting described above, in 2017, the average gas price delivered to large industrial customers in Australia was $8.92/GJ of which $7.47/GJ (86%) was the average wholesale gas cost and $1.29/GJ (14%) was average pipeline transportation costs.

45 Department of the Environment and Energy, Australian Energy Statistics, Table F, August 2017.

46 This weighting has been based on the Australian Energy Statistics 2016, Chief Economists Office (Table Q1) that provides gas consumption by state up to 2015-2016. For the following years the 2015-16 ratios have been used as a proxy.

Figure 90 shows the average gas price paid by large industrial customers in Australia from 2006 to 2017.

Figure 90: Australian weighted average large industrial delivered gas price trend

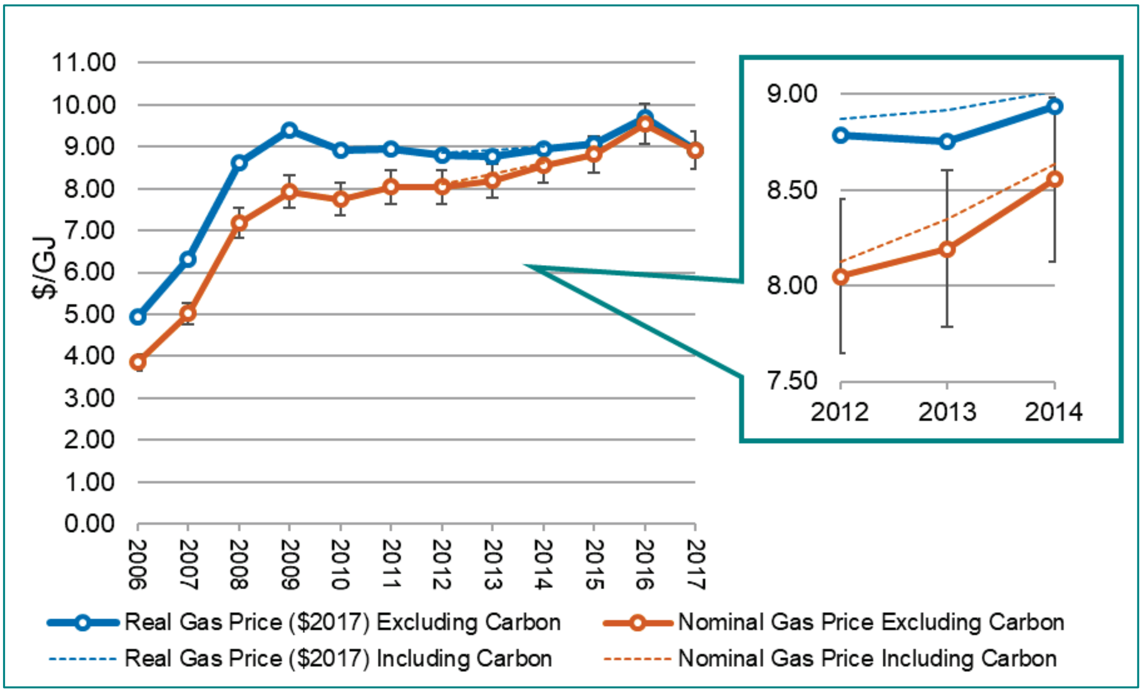


Figure 91 shows the breakdown of the components making up the average Australian large industrial gas price from 2006 to 2017.

Figure 91: Australian weighted average large industrial gas price components

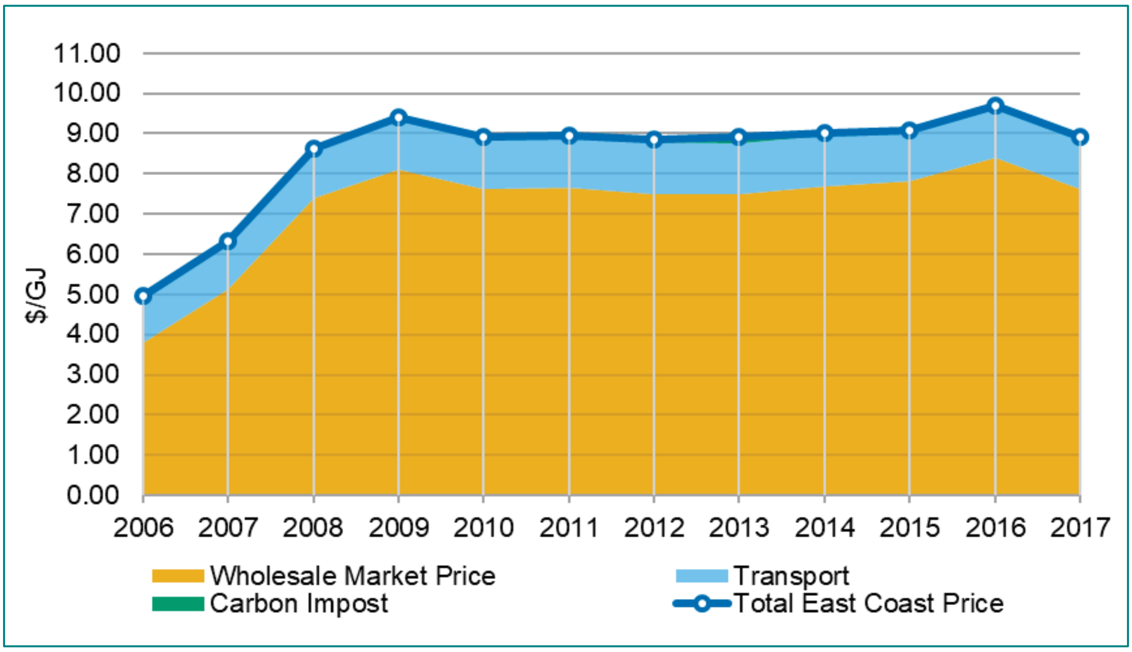
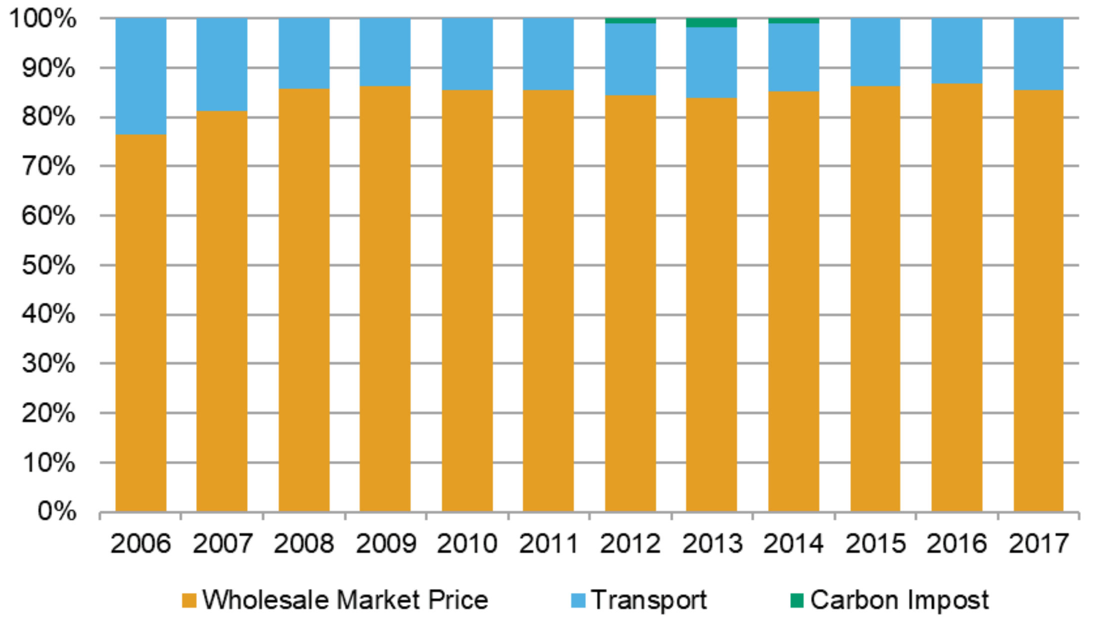


Figure 92 shows the percentage breakdown of the different components making up the average Australian large industrial gas price from 2006 to 2017.

Figure 92: Australian weighted average large industrial gas price components %



4.11 National large industrial gas price comparison

Figure 93 shows the large industrial customer gas price trend for each state, the east coast and nationally. Industrial gas prices have been steadily rising in all states except WA, where prices peaked in 2009 and have been declining since. A comparison of the national trend with the east coast trend, which excludes WA, highlights WA's impact on the national average.

Figure 93: Gas price trends (delivered $/GJ) for large industrial customers on new gas supply agreements.

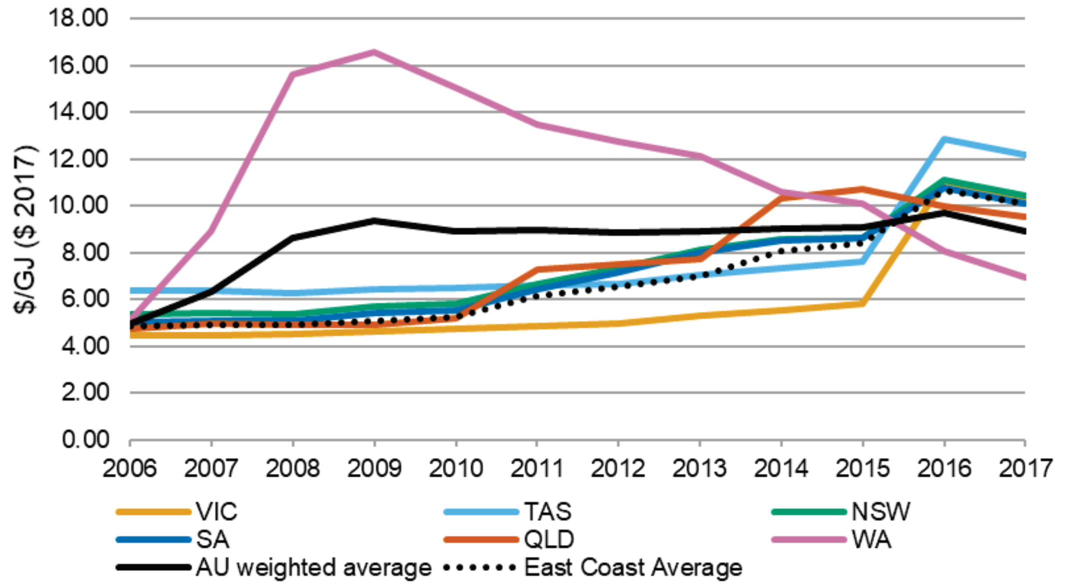
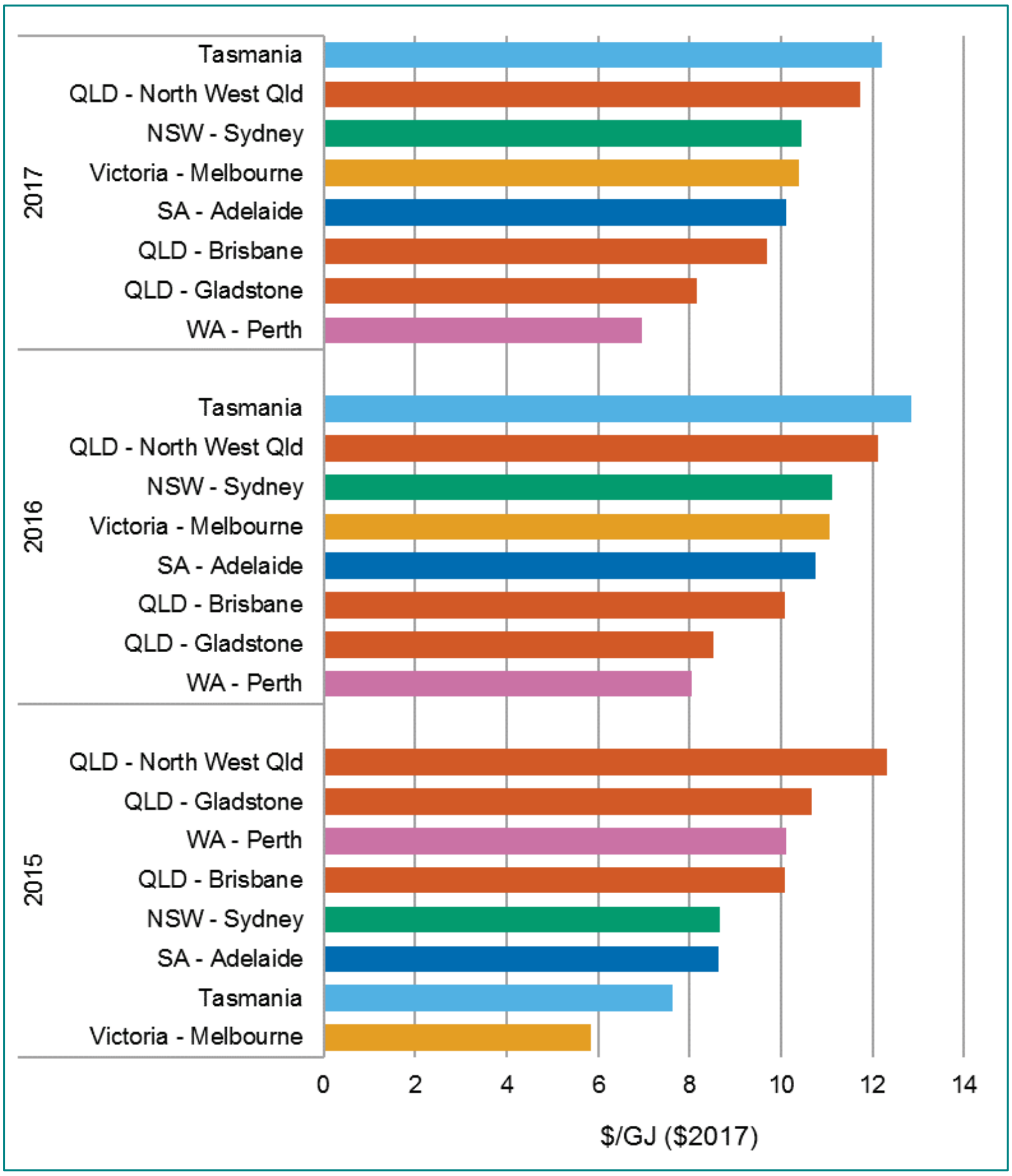


Figure 94 and Table 24 summarises the average delivered gas price in each state, east coast and nationally in 2015 and 2017 with relative rankings.

In 2015, Victoria had the cheapest delivered gas in Australia followed by Tasmania. In 2017, Victoria's delivered gas price has risen 78% from 2015 and now has one of the highest delivered gas prices.

Western Australia (Perth) has the lowest delivered gas price in 2017 of all state capitals. Delivered gas prices in the north west of Western Australia would be even lower by virtue of the transport cost would be lower. Prices in Western Australia have reduced 31% since 2015.

Figure 94 Average delivered gas price and ranking comparison 2015, 2016 and 2017 for large industrial users on new gas supply agreements. Prices are expressed in $2017.



Note: Environmental charges are zero for every state since carbon tax repeal in 2014.

Table 24: 2015, 2016 and 2017 average delivered gas price ($/GJ) and ranking (1 = lowest price)

Location	2015 ($/GJ)	2015 rank	2016 ($/GJ)	2016 rank	2017 ($/GJ)	2017	2015-17 Price change ($/GJ)	2015-17 % price change
VIC - Melbourne	5.85	1	11.06	5	10.39	5	4.54	78%
TAS	7.64	2	12.85	8	12.21	8	4.57	60%
NSW - Sydney	8.65	4	11.11	6	10.46	6	1.81	21%
SA - Adelaide	8.62	3	10.76	4	10.10	4	1.48	17%
QLD - Brisbane	10.08	5	10.08	3	9.69	3	-0.38	-4%
QLD - Gladstone	10.68	7	8.51	2	8.15	2	-2.53	-24%
QLD - NWQ	12.32	8	12.13	7	11.72	7	-0.60	-5%
WA - Perth	10.10	6	8.04	1	6.97	1	-3.13	-31%

4.11.1 East coast average vs west coast

Table 25 summarises the different factors of major influence between the east coast and west coast large industrial gas markets.

The wholesale gas price in WA is some 40% lower than the east coast average recorded in 2017.

Table 25: Summary of differential factors comparing east coast and Western Australia

Factor	East coast 2017	Western Australia 2017
Delivered average gas price	10.08	6.97
Wholesale gas component	9.19	5.00
Transport component	0.89	1.97
Total consumption 2015-16[47]	887 PJ	563 PJ
Total production 2015-16[48]	1,606 PJ	1,754 PJ
Major consumers	Mining 15% Manufacturing 28% Electrical 33% Residential 18% Others 7%	Mining 20% Manufacturing 29% Electrical 47% Residential 2% Others 2%
Gas source[49]	Conventional 41% Coal seam gas 59%	Conventional 100%
Policy settings	QLD Prospective Gas Production Land Reserve (PGPLR) NSW CSG exploration exclusion zones Resources Amendment Legislation (Fracking Ban) Act 2017	WA Gas Reservation Policy 15% WA onshore fracking moratorium

There is a temptation to look at the Western Australian gas price landscape and identify one or two factors which drive the continued price de-escalation found, compared to the east coast gas prices. In reality, it is a combination of factors and these are discussed as follows:

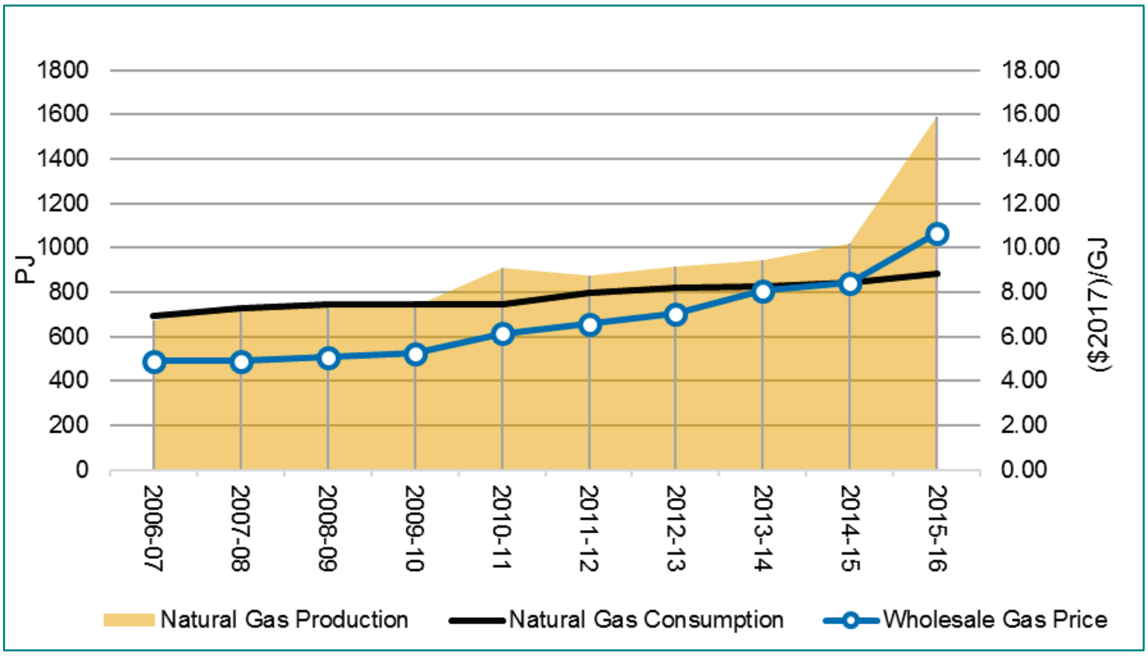
- Supply demand balance

47 Source: Department of the Environment and Energy, Australian Energy Statistics, Table Q, August 2017
48 Source: Department of the Environment and Energy, Australian Energy Statistics, Table Q, August 2017
49 Source: Department of the Environment and Energy, Australian Energy Statistics, Table R, August 2017

– Until the 2015-16 period, east coast production expanded exponentially to supply the LNG plants in Gladstone relative to domestic consumption whereas in Western Australia there has long been production above domestic consumption because of the LNG production from offshore gas.

– Figure 95 is the east coast production and consumption overlaid with the price curve. While production has expanded in 2015/16, the domestic consumption has remained flat and the price has escalated. Underneath those counterintuitive optics, it is important to note the additional production is largely from coal seam gas destined for LNG export and where insufficient supplies of coal seam gas were available in the market, gas was directed from primarily domestic gas reserves at Moomba and Victoria to Gladstone which tightened the domestic gas availability, hence the higher gas prices 'travelled' to Victoria. There is an easing of gas price in 2017 which is reflective of gas availability[50].

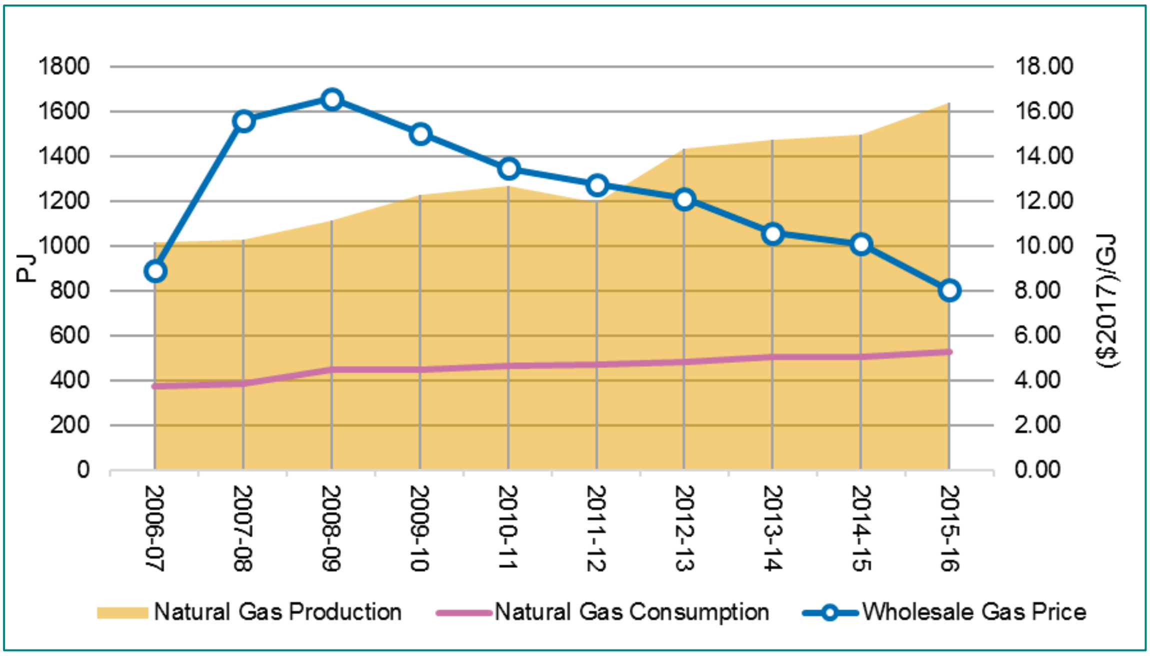
Figure 95: East coast production, consumption and price trends



– Figure 96 is the west coast production and consumption overlaid with the price curve for WA. It shows increasing production and a decline in price which follows a more intuitive reaction in supply/demand balance. Other factors involved include the number of gas sellers competing in the domestic market and the amount of gas available in the domestic market.

50 Data for supply and consumption statics only available to 2015-2016. Table Q, Energy statistics

Figure 96: WA production, consumption and price trends



- Gas source
  - The gas source on the east coast from which the LNG plants are committed is coal seam gas. Wells from coal seam gas have a top and tail effect where there is high production in early years with a peak and then gas volumes per well tail off. As production in each well tails off, more wells are drilled and commissioned to maintain a total flat production profile across tenements and basins. There are thousands of coal seam gas wells to be drilled to support the LNG plant's production requirements and where gas supply is short, the interconnected gas pipeline system on the east coast will (and has) drawn gas from conventional basins, the Cooper and Gippsland Basins.
  - The gas source on the west coast is predominantly and traditionally offshore North West Shelf conventional gas which has less uncertainty in production levels and geological formation compared to coal seams. Therefore, ongoing sustained production from WA's offshore conventional gas has less variables and better understood sustained cost of production resulting in far less stay in business capital expenditure than seen for CSG production. This difference will be reflected in the evolution of the cost of production in the respective gas basins and subsequent gas prices.
- Major consumer types
  - Western Australia's major gas consumers are dominated by large industrial users (manufacturing, mining and electricity generation).
  - The east coast is also dominated by the same sectors but has a much larger proportion of residential consumers (18% compared to 2% in WA).

- Number of sellers
  - The number of sellers in the Western Australian market has increased markedly since the introduction of Gorgon sellers and the non-extension of joint marketing arrangements between the North West Shelf equity partners.
  - This combined with excess gas in the market means consumers are able to receive multiple offers for gas.
- Policy settings
  - Queensland Petroleum Gas Production Land Reserve (PGPLR) policy was released in consultation in 2009[51] with a choice between a percentage domestic reservation similar to Western Australia and parcels of land being reserved for domestic use only. The policy was never enacted until recent land releases by the Queensland Government.
  - Several east coast states and the Northern Territory have moratoriums or exclusion zones relating to coal seam and unconventional gas exploration and hydraulic fracturing, the most affected of which is probably New South Wales which has the most prospective resources in ground. Buyback of some leases and newly promulgated requirements for CSG production in NSW have reduced the likelihood of major gas production expansion and delay of existing proponents' production timetables. The Western Australia Government has imposed a moratorium on hydraulic fracturing in the state subject to a scientific inquiry announced in September 2017, though this will only apply to onshore gas developments which are not the primary source of gas in Western Australia. The primary source of gas in Western Australia is offshore.

4.11.2 Specific small industrial customers characteristics

There is a separate group of small industrial customers that has a wide spread of usage from 0.1 PJ/a to 1 PJ/a. Customers in this group:

- Source competitively priced wholesale gas when benchmarked against the wholesale price trends for large industrial customers, which indicates there is significant competition in this sector (except in some remote rural areas as outlined above), and
- Are often characterised as a single entity that owns a number of smaller industrial sites, and
- Across the east coast market, these customers appear to experience a discernible lag of price rises at the wholesale gas price level.

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51 Consultation Paper: Domestic Gas Market Security of Supply (September 2009) QLD Government.

- Have higher (peakier) load factors than the large industrial customers and tend to have had these serviced without impost. There was little evidence that producers or retailers had been charging for this service although it is possible that, due to this cost being relatively small (for higher load factor), it may have been embedded in the error range associated with averaging.[52]
- Be subject to much higher network charges than large industrial customers as they tend to be connected via lower pressure gas distribution systems and therefore incur both transmission and distribution network costs, and
- May use several transmission pipelines to receive supply and accordingly pay more, if their sites are located in more remotely serviced rural areas.
- Have disaggregated pricing agreements (rather than bundled tariffs), representing the level of historical competition in the sector and again pointing to more competitive prices over simple application of bundled tariffs.

52 On an anecdotal level, this issue has been known to exist with large sales agreements for a few years now. Using available data, it was found that in large contracts, the variance is minimal (possibly $0.10 to $0.20/GJ) so falls within a 10% error band generated through averaging market data.

Transmission Industry Trends

5 Gas pipeline industry

5.1 Development of the industry

5.1.1 Point to point pipelines servicing capital cities

The Australian gas pipeline industry has developed over a 60 year period with the first natural gas pipeline, the Roma to Brisbane Pipeline, commissioned in 1969. The Roma to Brisbane Pipeline was constructed to initially transport gas from gas fields in the Roma area of south west Queensland to supply gas to Brisbane for the fertiliser plant constructed by Austral Pacific Fertilisers (one of the antecedent companies to Incitec Pivot) at Gibson Island and at locations where the pipeline connected to what is now the Allgas distribution network. This point to point configuration for a pipeline has been typical of pipelines developed in Australia.

The Roma to Brisbane Pipeline has been expanded since its original construction. Additional receipt and delivery points were added as new gas fields were developed along the route of the Roma to Brisbane Pipeline and new network connections added and three gas fired power stations were built adjacent to the Roma to Brisbane Pipeline. The pipeline has ceased to be a point to point pipeline with mid-line receipt points added as the coal seam gas industry developed and recently the Roma to Brisbane Pipeline was reconfigured to allow west flow from the mid-line receipt points in addition to the traditional easterly flow.

Within a decade of the commissioning of the Roma to Brisbane Pipeline the following pipelines had been constructed:

- The Moomba to Adelaide Pipeline, transporting gas from the Moomba gas fields to Adelaide.
- The Moomba to Sydney Pipeline, transporting gas from the Moomba gas fields to Sydney.
- The Parmelia Gas Pipeline, transporting gas from Perth Basin gas fields near Geraldton to Perth.
- The Dutson to Dandenong Pipeline (the first pipeline that formed what is now the Victorian Transmission System) to transport Bass Strait gas from Longford to the Melbourne City Gate.

The Amadeus Gas Pipeline was completed in 1986 to transport gas from the Amadeus Basin in the southern area of the Northern Territory to Darwin.

Like the Roma to Brisbane Pipeline, the above pipelines were initially constructed as point to point pipelines with gas sourced from a single gas basin and delivered to a single capital city or region.

It was in 1984 that the first pipeline, the Dampier to Bunbury Pipeline, was constructed to deliver gas to a demand centre, in this case Perth, already served by an existing pipeline and with gas from a new gas basin, the Carnarvon Basin (North West Shelf). A small pipeline from Wagga Wagga to Wodonga connecting the Moomba to Sydney Pipeline and the Victorian Transmission System was also completed in the same year providing Melbourne with limited alternative supplies during the gas supply crisis that occurred following the Longford gas explosion in 1998.

Since then, pipelines have been constructed to provide competing gas supply to Sydney (the Eastern Gas Pipeline in 2000), Adelaide (SEAGas in 2005) and Darwin (Bonaparte Gas Pipeline in 2008). Gas from the Black Tip field transported on the Bonaparte Gas Pipeline is transported on the Amadeus Gas Pipeline to Darwin for 123 kilometres, from where the Bonaparte Gas Pipeline interconnects with the Amadeus Gas Pipeline.

The Tasmanian Gas Pipeline was completed in 2003 to supply gas for power generation in Tasmania and the small commercial and industrial market in Hobart and regional Tasmania.

Hobart and Brisbane remain the only capital cities served by a single pipeline, noting that the Roma to Brisbane Pipeline consists of two pipelines in a common easement. This was critical to supply being maintained to Brisbane when flooding in 2011 caused damage to a section of one of the pipelines, which required the affected section to be taken out of service.

5.1.2 Supplying gas for power generation in the resources sector

The 1990s saw several pipelines developed largely to supply gas to mines or industrial centres in regional Australia:

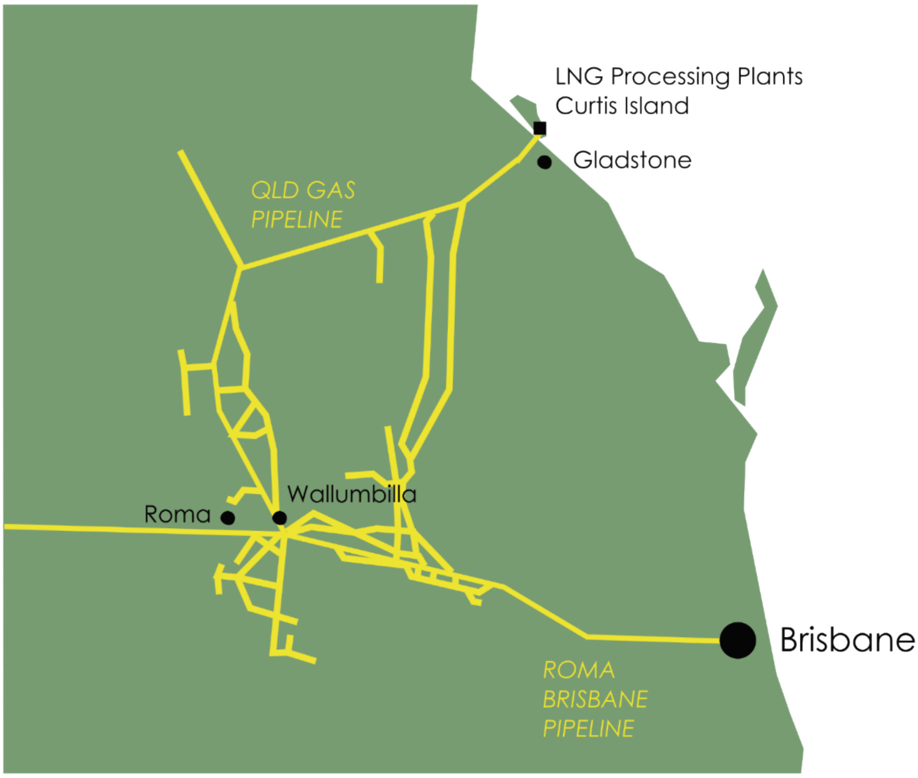
- The Queensland Gas Pipeline, transporting gas from the Roma area to primarily industrial customers in Gladstone and Rockhampton.
- The Goldfields Gas Pipeline transporting gas from the Dampier to Bunbury Gas Pipeline to mining sites on the pipelines route primarily for power generation.
- The Carpentaria Gas Pipeline transporting gas from Ballera to Mt Isa and mines adjacent to the pipeline route primarily for power generation.

5.1.3 Coal seam gas in Queensland driving pipeline development

The east coast pipeline industry and the east coast gas market more generally has been reshaped by the lobbying efforts of the proponents of the PNG Gas Project. The original development concept for the PNG Gas Project was based on a gas pipeline to transport gas to demand centres on the east coast of Australia. Lobbying by the proponents resulted in the Queensland government introducing the Gas Electricity Certificate Scheme. This initially required that 13 percent (later increased to 15 percent) of electricity sold in Queensland be generated from gas. Generating 15 percent of electricity from gas, in the end, was not sufficient to support the PNG Gas Project, however it provided support for the fledgling coal seam gas industry.

The development of the coal seam gas industry in Queensland (refer Figure 97) led to un-precedented gas pipeline development by Australian standards over two decades with 2,700 kilometres of pipeline and 6,700 TJs of pipeline capacity being developed (the combined capacity of all pipelines listed A.1 Pipelines is 12,700 TJ).

Figure 97: Pipelines developed for the CSG and LNG industry in Queensland



The developments included the:

- Peat and Scotia Lateral Pipeline, connecting the Peat and Scotia gas fields to the Roma to Brisbane Pipeline.
- Partial looping of the Roma to Brisbane Pipeline to increase the capacity of the pipeline to deliver coal seam gas to the Swanbank E power station.
- North Queensland Gas Pipeline connecting Moranbah gas fields to Townsville.
- Spring Gully Pipeline connecting the Spring Gully field to Wallumbilla.
- Darling Downs Pipeline connecting Wallumbilla to the Darling Downs Pipeline.
- Braemar 1 Gas Pipeline connecting the Braemar I Power Station to the Roma to Brisbane Pipeline and Arrow Energy's Tipton West Gas field.
- Braemar 2 Gas Pipeline connecting the Braemar 2 Power Station to Arrow Energy's Daandine Gas field.
- Comet Ridge to Wallumbilla Pipeline connecting the Fairview gas field and the Wallumbilla Hub.

- Berwyndale to Wallumbilla Pipeline connecting QGC's Berwyndale gas field to the Wallumbilla Hub.
- Looping of the Comet Ridge to Wallumbilla Pipeline.
- GLNG Pipeline connecting Fairview gas field to Curtis Island.
- Wallumbilla Gladstone Pipeline connecting QGC's gas fields to Curtis Island.
- APLNG Pipeline connecting APLNG gas fields to Curtis Island.
- Reedy Creek to Wallumbilla Pipeline connecting APLNG Gas fields and Wallumbilla.

5.1.4 Establishing an integrated East Coast grid

The South West Queensland Gas Pipeline was developed in the 1990s. The South West Queensland Gas Pipeline was a departure from the rationale for earlier pipeline development. It was built to transport gas from Ballera to where it interconnected with the Roma to Brisbane Pipeline and Queensland Gas Pipeline near Roma, or what is now referred to as the Wallumbilla Hub, rather than to a demand centre. Gas delivered to Wallumbilla on the South West Queensland Gas Pipeline was then transported on those pipelines to industrial customers and retailers in Brisbane and Gladstone. The construction of the South West Queensland Gas Pipeline was a key building block in transitioning the east coast pipeline industry from a number of standalone point to point pipelines to the integrated gas grid that is in place today.

Arguably, the development of the LNG plants on Curtis Island to monetise the Queensland coal seam gas resource has led to other pipeline developments which allow gas from southern Australia to be delivered into markets no longer supplied from the producers participating in the LNG projects on Curtis Island. This includes the expansions or flow reversal of the:

- South West Queensland Gas Pipeline.
- Moomba to Sydney Pipeline.
- Compression facilities at Moomba and Wallumbilla.

Flow reversal, or more typically bi-directional flow, on gas pipelines and investments in compression facilities are re-shaping the pipeline industry and its ability to respond to the shifting supply/demand relationship between Queensland and south-eastern Australia.

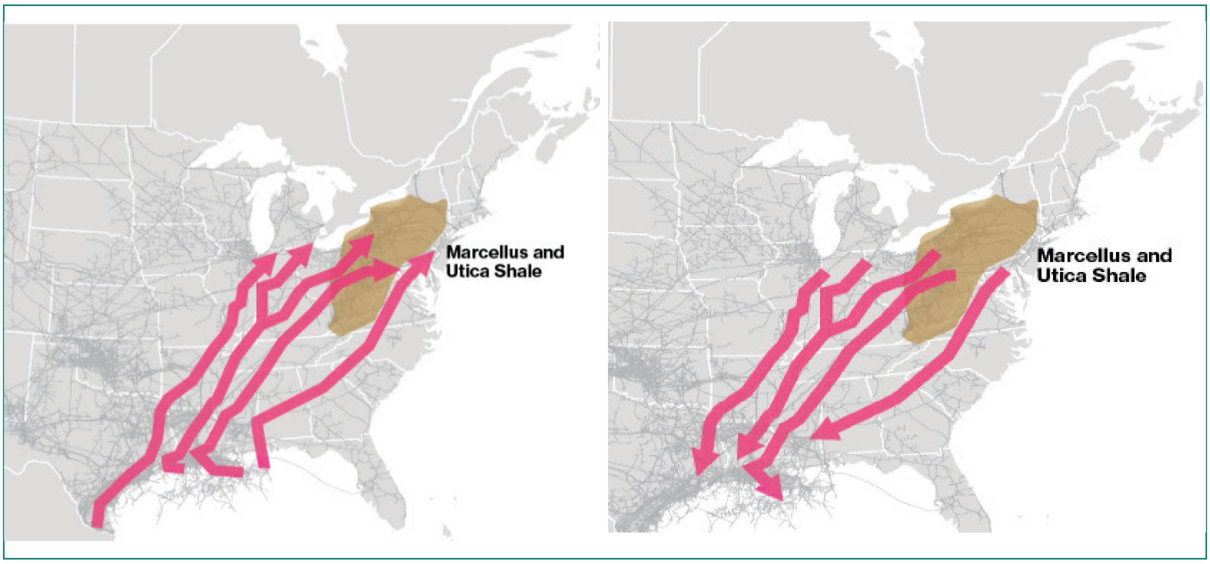
The following pipelines on the east coast are bi-directional:

- Amadeus Gas Pipeline.
- Berwyndale to Wallumbilla Pipeline.
- Comet Ridge to Wallumbilla Pipeline.
- Moomba to Adelaide Pipeline.
- Moomba to Sydney Pipeline.
- Queensland Gas Pipeline.
- Reedy Creek to Wallumbilla Pipeline (under construction).
- Roma to Brisbane Pipeline.
- QSN Link.
- Silver Springs Pipeline.
- South West Queensland Gas Pipeline.
- Victorian Northern Interconnect.

Where bi-directional flow is available on a pipeline it is most effective in supporting improved connectivity across pipelines where the pressure at the delivery point on the bi-directional pipelines is permanently greater than the inlet pressure on the connected pipelines, if this is not the case then there is still the constraint of the services being non-firm. The installation of compression facilities enables firm services to be made available in both directions. Compression facilities have been installed at Wallumbilla and Moomba by APA Group to provide firm services across interconnected pipelines.

This change in the pipeline industry is similar to that in North America (refer Figure 98) where the shale gas revolution initially resulted in gas delivered to the north-eastern markets from traditional sources, such as the Gulf of Mexico, being displaced by gas from the Marcellus shale gas region. Long distance pipelines that cross the Marcellus shale gas region initially backhauled gas and then were converted to bi-directional configuration. Marcellus shale gas is now being shipped south for export as LNG from the Gulf coast.

Figure 98 North American Gas Pipeline flows



Source: Bloomberg (November 2016) Can the U.S. Become an Energy Superpower in 2017?

Analysts in the United States have observed that "*It is going to be a lot more difficult to understand Northeast gas flows in the future. We also think that this sets up the market for some very strange price behaviour as pipeliners learn to operate their long-line systems like web based systems,*" …… "*Get ready for more exciting times in Northeast natural gas markets*"[53].

5.1.5 Gas storage

Storage is an important component of the gas value chain. Storage can be provided from pipeline linepack and dedicated storage facilities, which in the Australian context is usually depleted gas fields. The key storage facilities are listed in Table 26.

Table 26 Gas Storage Facilities

Facility	Type	Location	Owner
Braemar Line Pack Connection	Pipeline	QLD	Alinta Energy
Chookoo (Ballera) storage facility	Underground	QLD	Santos
Colongra Gas Transmission and Storage Pipeline	Pipeline	NSW	Jemena

53 Understanding Northeast gas flows getting harder as pipelines grow more flexible, S&P Global (previously SNL Financial), Oct 2013.

Facility	Type	Location	Owner
Dandenong LNG Storage Facility	LNG Tank	VIC	APA Group
Iona Gas Plant	Underground	VIC	Lochard Energy (QIC)
Kincora Gas Storage	Underground	QLD	Armour Energy
Mondara Gas Storage	Underground	WA	APA Group
Moomba Gas Storage	Underground	SA	Santos
Newcastle LNG Gas Storage Facility	LNG Tank	NSW	AGL
Roma Underground Gas Storage	Underground	QLD	Santos GLNG
Silver Springs Gas Storage	Underground	QLD	AGL
Tubridgi Gas Storage	Underground	WA	Australian Gas Infrastructure Group

Source: Company web sites

Storage is also provided on transmission pipelines, although this has the effect of sterilising, or making unavailable an amount of transportation capacity. The offering of storage services on transmission pipelines has increased in recent years. Several pipelines have experienced significant reductions in contracted capacity for transportation services and in actual throughput. Therefore, storage services which can now be offered due to the lower levels of contracted transportation services, are being marketed by effected pipeline owners to offset some of the loss of revenue due to reduced capacity contracted under transportation services. The availability of storage services on pipelines where other forms of storage are not available provides shippers with increased flexibility to manage their portfolios.

Storage is used for a range of purposes, including for:

- Supply of gas to meet peak demand in highly seasonal markets (e.g. Victoria).
- Security of supply in the event of supply disruptions.
- Supply to peaking power stations (the Braemar Linepack Connection is a 90 km pipeline built to connect the Braemar 1 power station to the Roma to Brisbane Pipeline and provide storage).
- Trading opportunities to purchase gas when prices are low and sell during higher price periods.

- The procurement of gas supply contracts with flat load profiles which can be attractively priced or even required by some producers.
- Managing ramp gas from new gas fields (the Silver Springs Gas Storage facility was developed to store ramp gas produced by QGC as part of the QGC LNG Project[54]).

5.1.6 Ownership of gas infrastructure

There are 56 onshore pipelines in Australia (see A.1 Pipelines) and of these 10 are subject to some form of regulation, either heavy or light. The Moomba to Sydney Pipeline is subject to partial regulation with the section from Moomba to the offtake point of the Central West Pipeline unregulated and the remaining section subject to light regulation.

Some of the pipelines listed are laterals that connect a single end user to a mainline, or a gas field to a mainline.

There are five companies, or groups of companies, that own multiple pipelines or gas storage facilities. These are:

- APA Group.
- Australian Gas Infrastructure Group (AGIG).
- Jemena.
- Palisade Investment Partners.
- Queensland Investment Corporation (QIC).

The above companies have varying interests across the gas value chain beyond pipelines, including gas distribution, gas processing and gas fired power generation. Some of the companies have diversified into renewable generation. The Finkel Review[55] recommends the establishment of a Generator Reliability Obligation for variable renewable energy generators and recognises that this obligation could result in an increased role for gas generation. This may represent an opportunity for pipeline companies that have investments that extend into gas and renewable generation, or even have significant supply to generators.

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54 Silver Springs Gas Storage Facility - Environmental Management Plan, RPS prepared for AGL, 2010

55 Independent Review into the Future Security of the National Electricity Market, page 99, June 2017

Table 27 identifies the range of industries in which the major pipeline owners have investments.

Table 27 Infrastructure ownership

Company	Gas Trans-mission	Gas Distribution	Gas Storage	Gas Processing	Gas Generation	Renewable Generation
APA Group	✓	✓	✓	✓	✓	✓
AGIG	✓	✓	✓			
Jemena	✓	✓	✓			
Palisade	✓					✓
QIC	✓		✓			✓

Source: Company websites

APA Group is the largest investor in pipelines in Australia with 27 of the 56 pipelines (listed in A.1 Pipelines) either wholly or partially owned by APA Group. APA Group also typically operates the pipelines owned by joint ventures that APA Group has an interest in.

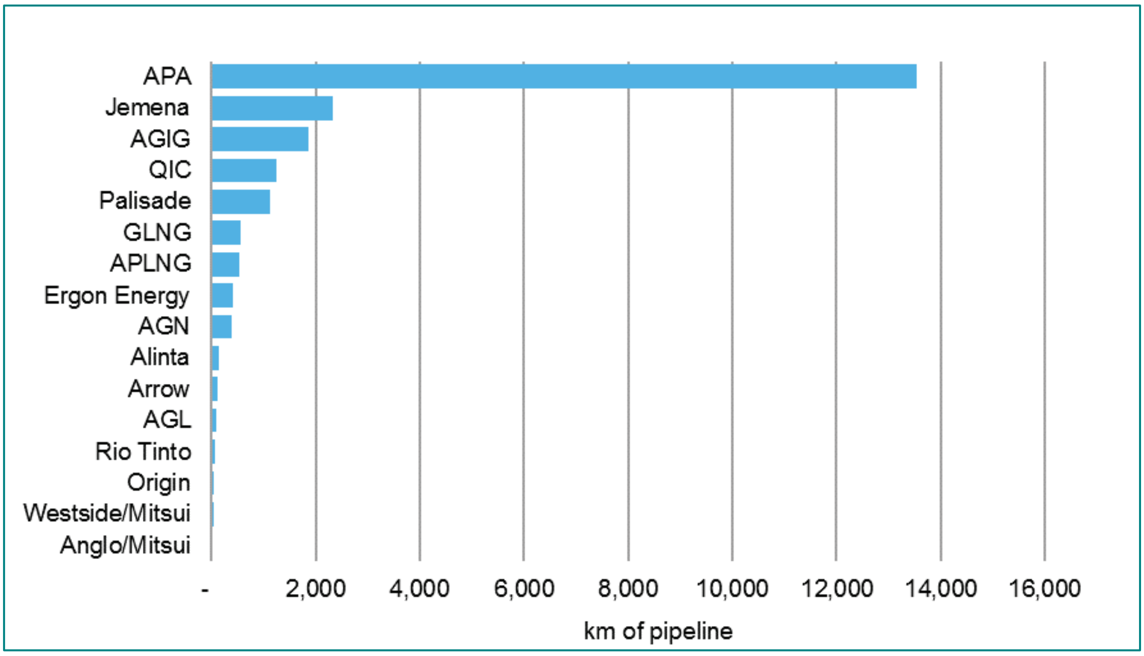
Jemena is the next largest investor in pipelines with five pipelines. This includes the Northern Gas Pipeline which is due to be commissioned in late 2018.

A measure sometimes used to compare the size of pipeline companies is the total length of pipelines owned (either wholly or in joint ventures) by a company. Figure 99 illustrates this metric.

This is not an ideal approach to comparing companies in this industry as some pipelines may be long with only small revenue due to their level of contracted capacity. Revenue information is not typically published by owners of pipelines.

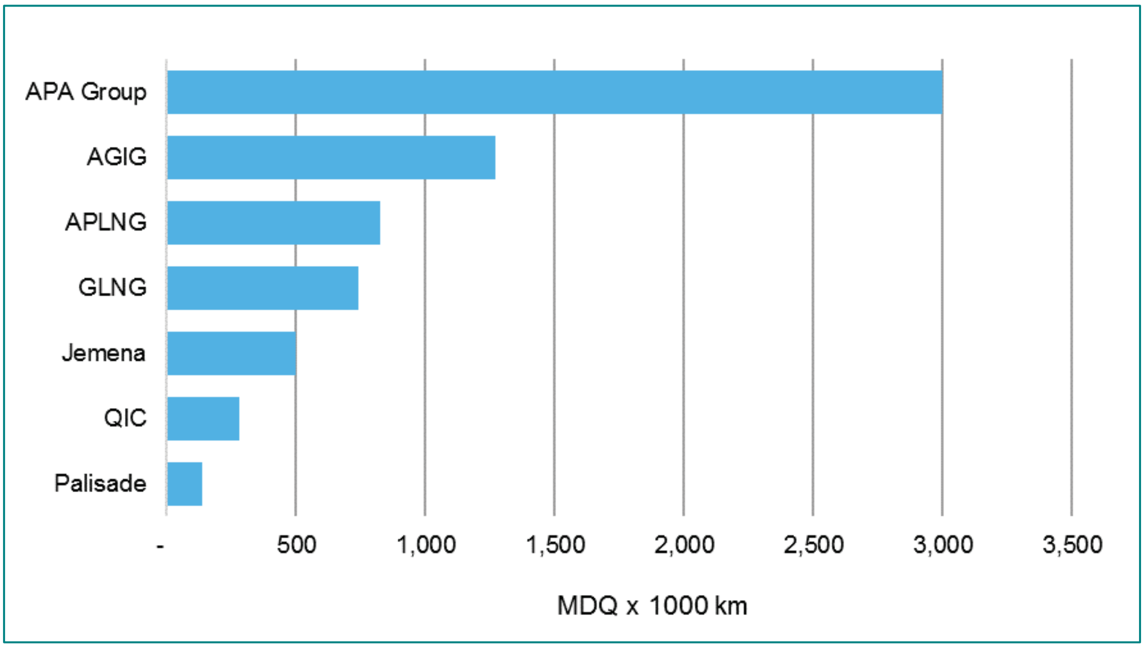
Figure 100 presents another metric which is the capacity (MDQ) by kilometre length of a pipeline. Again, this is not ideal as capacity on pipelines with receipt and delivery points along the length of the pipeline results in pipeline capacity being a complicated metric with which to draw comparisons.

Figure 99: Pipeline companies by total length of pipelines



Source: AER and Company web sites

Figure 100 Pipelines Companies by length of pipelines by capacity



Source: AER and Company web sites

5.2 Analysis of change in service offerings on pipelines

Historically the services offered by pipeline owners consisted of what are now by comparison relatively vanilla services. The main service offered on most pipelines was firm forward haul plus in some cases Authorised Overrun Services (tied to Firm forward haul services), and Interruptible Services either tied to firm forward haul services or as standalone services under a gas transport agreement.

The tariff structures for firm forward haul services included postage stamp tariffs and distance based tariffs. These structures are explained in section 3.3.1.

The tariffs included in this section are generally “rack” rates that pipeline owners publish or were willing to make available for the report. Some of the pipeline owners Oakley Greenwood consulted indicated a willingness to negotiate on price for longer terms or larger capacity services. APA Group has publicly stated[56] in respect of its tariffs “*For customers prepared to commit larger volumes on a longer basis then the tariff is obviously lower*”.

5.2.1 Storage services

Storage services are provided from dedicated storage facilities and on pipelines. This section discusses storage services on pipelines.

The types of services available include:

- AGIG’s Park & Loan service on the Dampier to Bunbury Pipeline.
- APA Group’s Firm Park & Loan service.
- Jemena’s Firm Park Services on the Eastern Gas Pipeline.
- Palisade Investment Partners High Priority Storage Service on the Tasmanian Gas Pipeline[57].

A Park Service is a storage service offered by pipeline owners that allows shippers to storage gas in a pipeline. This type of service utilises capacity of the pipeline that would otherwise be used to transport gas. A Park and Loan Service is a type of service which in addition to providing storage allows the shipper to borrow gas from the pipeline and then “repay” the volume of gas that has been borrowed within a prescribed period.

Table 28 sets out tariffs for park and loan services on APA Group and Jemena pipelines.

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[56] APA explodes over Shell price claims, Australian Financial Review, March 29 2017.

[57] TGP High Priority Storage Opportunity, March 13, 2014 [Tasmanian Gas Pipeline website](#).

Table 28: Pipeline Storage Tariffs

Company	Service	Tariffs ($/GJ/Day)
APA Group	Firm Park and Loan less than 1 Year	$0.3000
	Firm Park and Loan greater than 1 Year	$0.2000
Jemena – EGP	Premium Park Service	$0.5029
	Firm Park Service	$0.2000
	As Available Park and Lend Service	$0.2600

Source: APA Group tariffs are as at 1 July 2017 and Jemena tariffs are as at 1 January 2017. Tariffs sourced from Jemena web site and an APA Group presentation for this report.

The charge for these services (except for Jemena's 'As Available Park and Lend' Service) is determined by multiplying the tariff by the capacity (in GJ) by the number of days that the service is contracted for in a billing period.

Jemena's 'As Available Park and Lend' service is a service that is an Imbalance Charge on other pipelines. Under most gas transport agreements shippers have an obligation to balance their receipts and deliveries on a day. If receipts and deliveries do not balance, then pipeline companies may charge the shipper an Imbalance Charge. The Jemena 'As Available Park and Lend' service charge is determined by multiplying the tariff by the cumulative imbalance on a day.

There is limited publicly available history of storage service tariffs, so it is difficult to comment on movement in tariffs. In 2015, Core Energy analysed storage costs for AEMO[58] and concluded that tariffs for storage at QIC's Iona Gas Plant were likely to be in the range of $0.50/GJ/day to $0.65/GJ/day. The lower rates referenced in the above table may reflect either:

- Competitive pressure resulting in a reduction in storage charges e.g. both APA Group's Moomba to Sydney Pipeline and Jemena's Eastern Gas Pipeline are able to offer storage services and AGL owns the Newcastle LNG Storage facility; or
- The services from an underground gas storage facility, such as Iona, are more flexible than the storage services that can be offered on pipelines, and are therefore more valuable to the market.

58 Gas Storage Facilities – Eastern and South Eastern Australia, Core Energy Group, February 2015. Prepared for AEMO, 2015 Gas Statement of Opportunities Supporting Information.

APA Group's ability to offer its 'Firm Park and Loan' service at a lower tariff than Jemena offers for the 'Eastern Gas Pipeline Park Service' may reflect APA Group's ability to take advantage of being able to store gas on its interconnected grid of east coast gas pipelines rather than only on the pipeline that the customer utilising the service is connected to.

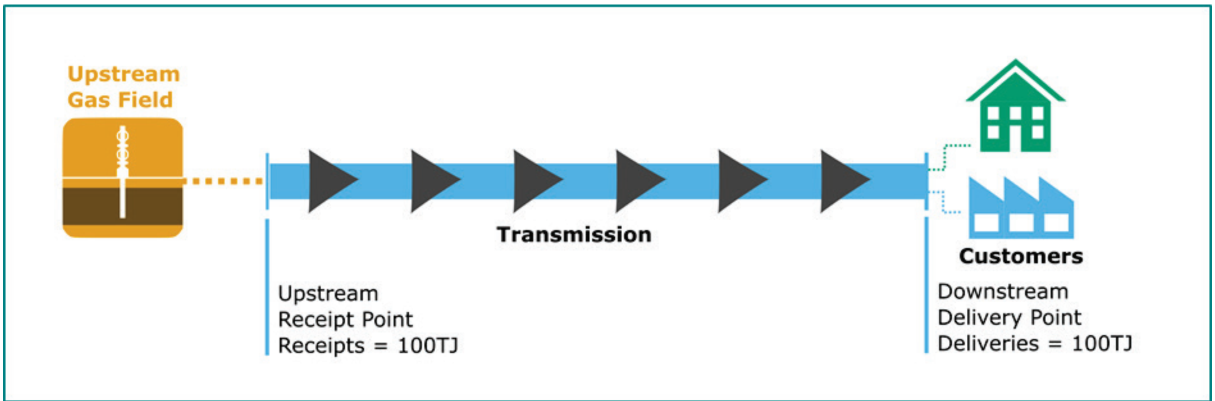
5.2.2 Backhaul and bi-directional flow

As discussed above the changes in where gas is produced in Australia has seen the emergence of backhaul services on pipelines and the re-configuration of some pipelines as bi-directional pipelines. Where pipelines have been re-configured as bi-directional pipelines then the term backhaul service is typically no longer in use in respect of those pipelines.

Backhaul services are more likely to be utilised where there is demand for gas at both the downstream and upstream ends of a pipeline and with sources of gas other than at the upstream end of a pipeline, such as midstream receipt points.

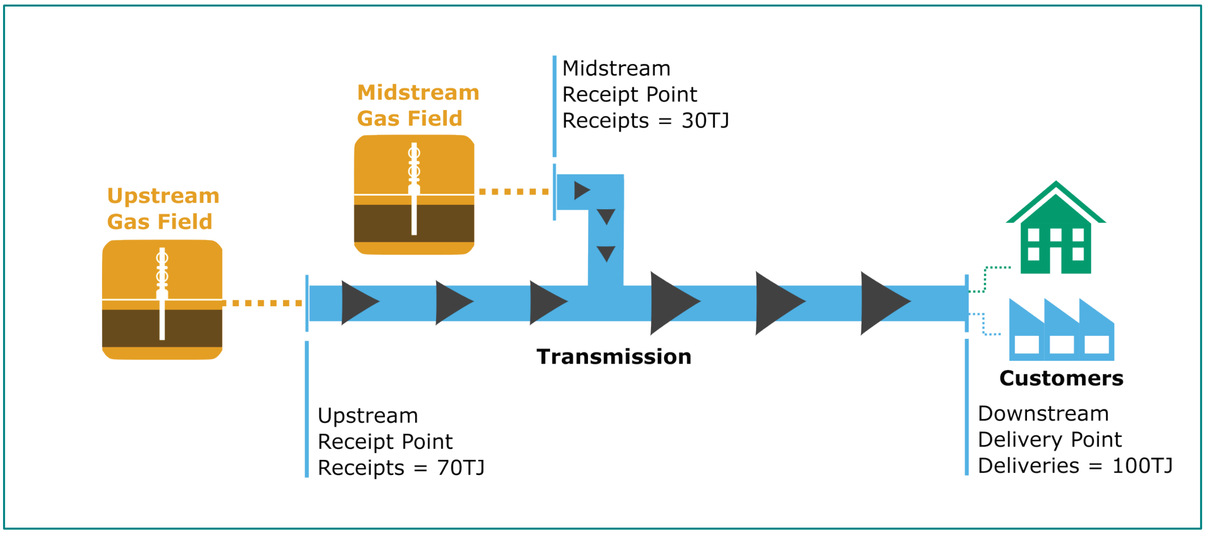
Pipelines were traditionally designed to flow gas in one direction e.g. west to east on the Roma to Brisbane Pipeline and north to south on the Moomba to Sydney, Moomba to Adelaide and Dampier to Bunbury Gas Pipelines. Figure 101 illustrates forward flow only on a pipeline.

Figure 101: Upstream receipts only with forward flow



New sources of gas supply were connected into some pipelines at midstream locations, e.g. the coal seam gas fields that are connected to the Roma to Brisbane Pipeline and the Macedon field that is connected to the Dampier to Bunbury Pipeline. Figure 102 illustrates the introduction of midstream receipts. These reduce the quantity that flows between the upstream receipt point to the midstream receipt point by the quantity receipted at the midstream receipt point for forward contract flow (30 TJ).

Figure 102 Upstream and midstream receipts with forward flow

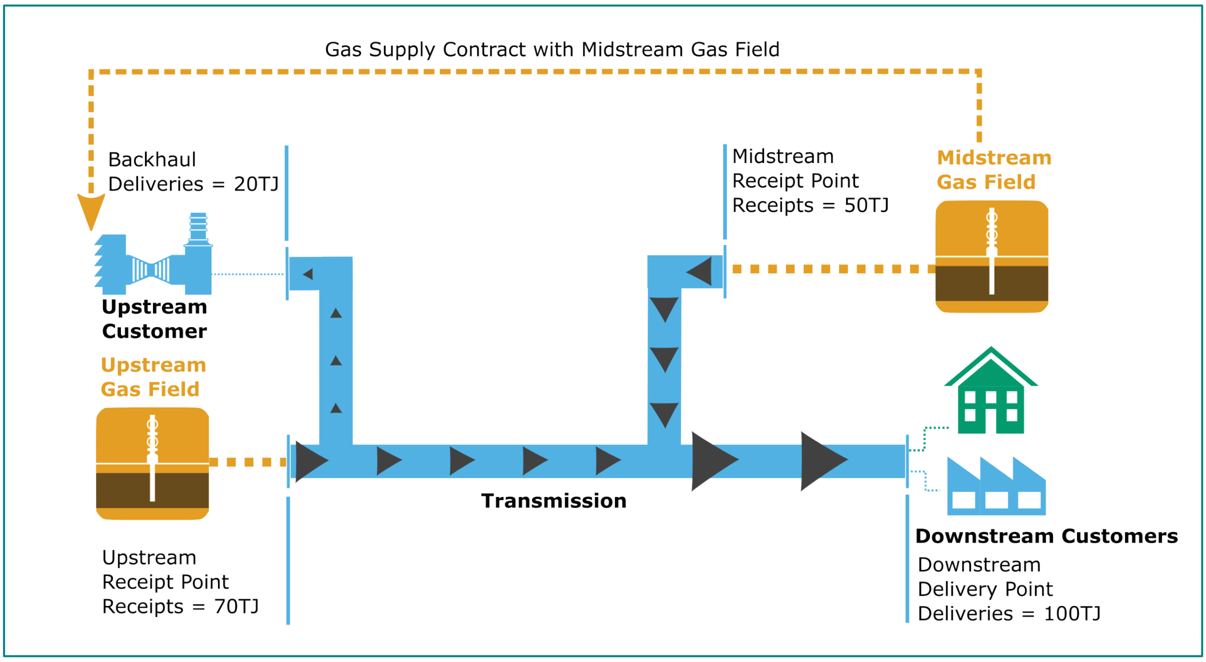


These shifts in natural gas market dynamics started to create a need for additional options for gas “flow” so pipeline companies started to offer backhaul services. These backhaul services allowed a customer to contract for the receipt of gas at a point downstream of the traditional location of receipt points and for the gas to contractually “flow” in the opposite direction of traditional flows.

Under a backhaul service, gas does not physically flow in the reverse direction. This service is facilitated via a physical swap of gas within the pipeline with gas being delivered upstream of the point at which it is receipted into the pipeline. The volume of gas that can be contracted under a backhaul service is limited by the physical forward flow from the upstream receipt points and the receipt points located downstream. On pipelines with multiple upstream receipt points the backhaul service is also limited by the forward flow into the pipeline at the relevant receipt point where the customer is seeking to have gas delivered. Given the constraints on these services with the need for sufficient forward flow to be displaced by the backhaul service they are marketed as non-firm services.

Figure 103 illustrates the introduction of backhaul, which reduces the quantity that flows between the upstream receipt point to the midstream receipt point by the quantity receipted at the midstream receipt point for forward contract flow (30 TJ) and the backhaul quantity (20 TJ).

Figure 103 Upstream and midstream receipts with forward flow and backhaul



Gas was initially produced from fields in Bass Strait, Cooper Basin, the Roma area of the Surat Basin and the Perth Basin. However significant changes in the market have taken place:

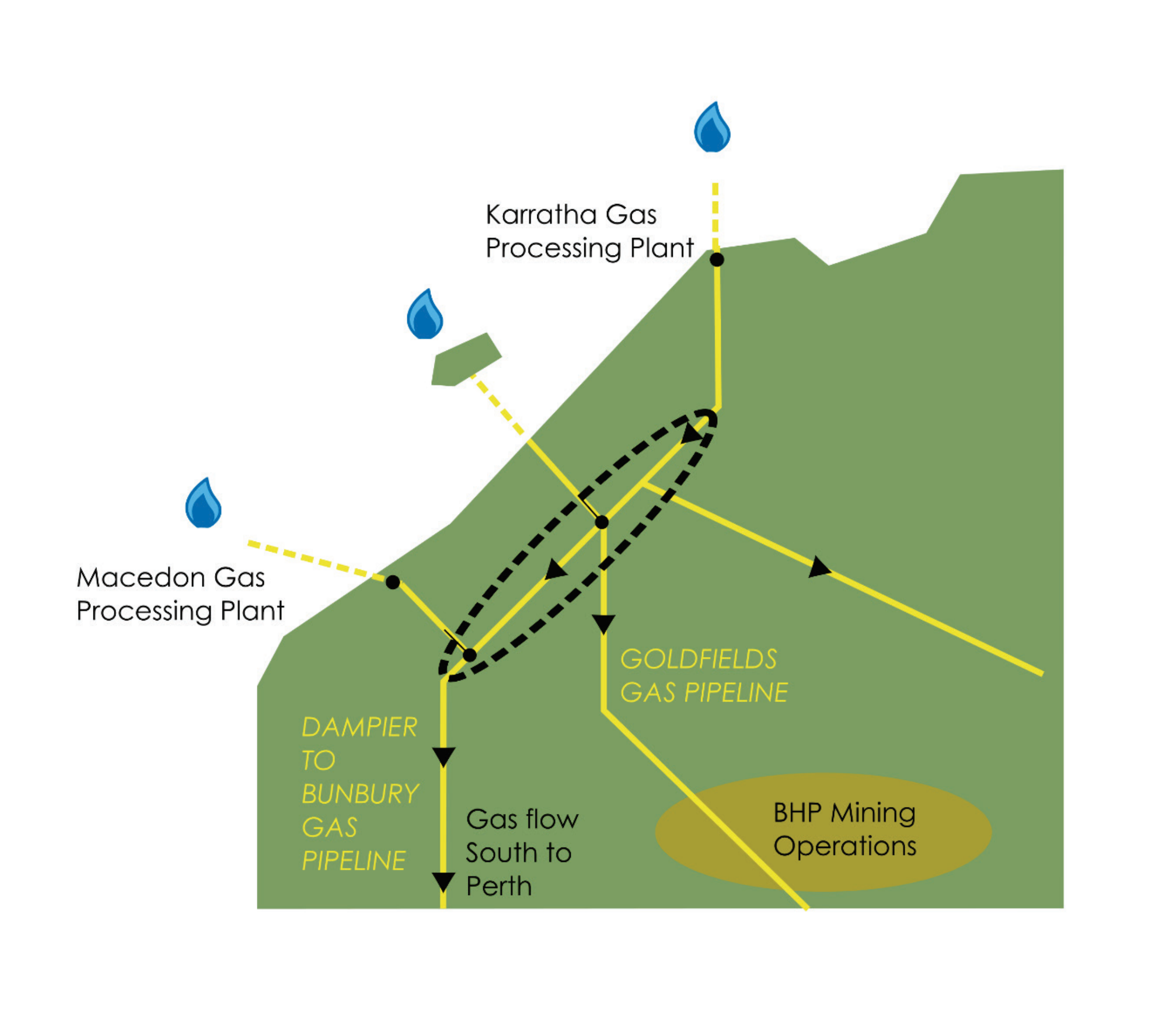
- Some conventional fields have either been depleted or are in decline.
- Gas users needing to contract for gas from sources of supply beyond their traditional sources.
- The development of the Queensland coal seam gas fields.
- The development of the Gladstone LNG plants.

This has led to the need for more flexible arrangements for the transport of gas across the east coast and in particular has led to the need for more secure gas transport arrangements than that offered by backhaul services. This has been achieved with a number of existing pipelines re-configured as bi-directional pipelines and new pipelines configured as bi-directional pipelines in their initial design.

The significance of gas supply for the domestic market from gas fields in northern Western Australia compared to supply from the Perth Basin has not led to the same type of dynamics driving the type of arrangements seen on the east coast.

BHP Billiton operates mines on the Goldfields Gas Pipeline which is supplied with gas from the Dampier to Bunbury Pipeline and has also developed the Macedon gas field. The receipt point for the Macedon gas field is on the Dampier to Bunbury Pipeline downstream of the Goldfields Gas Pipeline interconnect. The development of the Macedon gas field provided a supply of gas for these power stations. It is in this situation that a backhaul service could be used to notionally transport gas from the Macedon receipt point to the Goldfields Gas Pipeline interconnect (refer Figure 104).

Figure 104: Gas grid in Dampier region of Western Australia



On the APA Group website[59] what has been historically referred to as a Forward Haul[60] service on the Roma to Brisbane Pipeline is now referred to as Eastbound service. Under the Roma to Brisbane Pipeline Access Arrangement for 2012 to 2017 one Reference Service was offered this was described as "*The Firm Service is a service for the receipt, transportation and delivery of Gas through any length of the Covered Pipeline in the direction from Wallumbilla or Peat to Brisbane*" which APA Group described in the Access Arrangement Information submission as a "*forward haul*" service. APA Group previously offered a backhaul service, as a negotiated service, and this has now been replaced by a Westbound service. The Roma to Brisbane Pipeline has been re-configured to allow Westbound services to be offered on a firm basis. APA Group's standard terms and

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59 APA indicative transmission tariffs, APA website accessed 03 November 2017.

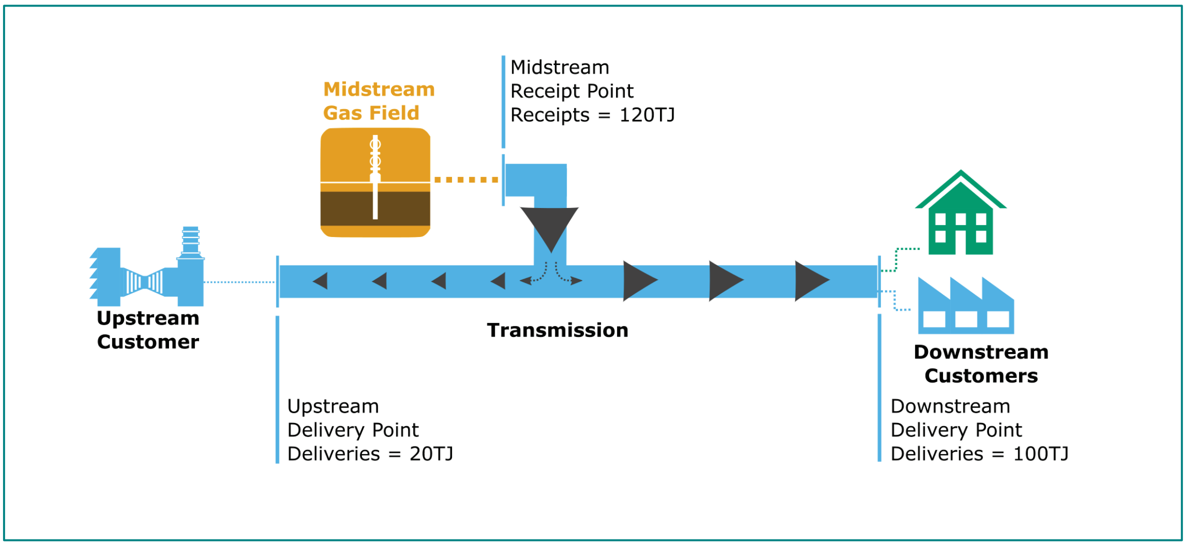
60 Roma (Wallumbilla) to Brisbane Pipeline – Access arrangement 2012-2017, AER.

conditions[61] refer to backhaul services, however APA Group does not publicly identify on the relevant pipelines offering these services.

Epic Energy no longer offers backhaul services on the Moomba to Adelaide Pipeline, instead it offers firm services that can be north or south bound. Where a shipper seeks the flexibility to have gas transported in a north or south bound direction under the one service by having the flexibility to receipt gas at either end, then Epic Energy includes a Bi-directional Charge on either a firm or interruptible basis[62].

Figure 103 above illustrated the situation where there was backhaul on a pipeline due to the introduction of midstream receipts and the emergence of demand at the upstream end of the pipeline. Figure 105 illustrates the situation where daily demand can be fully met at the downstream end (100 TJ) of the pipeline and what was traditionally the upstream end (20 TJ) of the pipeline is by midstream receipts (120 TJ). This is facilitated by re-configuring the pipeline for bi-directional flow.

Figure 105: Midstream receipts on a bi-directional pipeline



5.2.3 Hub services

The principal gas trading hubs on the east coast of Australia are at Wallumbilla and Moomba where AEMO has established its Gas Supply Hubs as an exchange for trading of gas. There is also the Declared Wholesale Gas Market in Victoria. The Gas Supply Hubs are voluntary markets and as such Hub Services that facilitate trading are more relevant to building liquidity. An alternative to the Gas Supply Hub that is offered by some pipeline companies is described below in Section 5.2.5.

61 APA Group Pipeline Assets – Capacity Trading Standard Gas Transport Agreement, APA Capacity Trading website accessed 22 Nov 2017.

62 Email from Epic Energy General Manager, Strategy & Commercial on 3 November 2017.

Hub Services include:

- AGIG offers a form of Hub Service on the Dampier to Bunbury Pipeline known as a Pilbara Service, albeit over a 140km section of the pipeline.
- The Hub Services offered by APA Group include Re-direction and Compression services.

The AGIG Pilbara Service applies to a section of the Dampier to Bunbury Pipeline between the North West Shelf receipt point and the Wheatstone receipt point. The service provides shippers with full flexibility on receipt and delivery point combinations in what AGIG describes as a "*Hub style approach to receipts and deliveries*"[63]. This service includes deliveries in and out of AGIG's Tubridgi Gas Storage Facility. The tariff for transport is a postage stamp tariff of a total of $0.29/GJ, of which 10% is a capacity component and 90% is throughput.

APA Group offers compression services and pressure reduction services at the Moomba and Wallumbilla Hubs[64] that allow for the transfer of gas between various pipelines that interconnect at these hubs.

In 2015 APA Group[65] stated that it was developing the following additional services:

- Firm day ahead hub service.
- Trade point establishment.
- Compression trading service.

5.2.4 Secondary capacity trading

Capacity trading is in area that has been slowly evolving in the Australian pipeline industry. As there is already considerable work being undertaken by the Gas Market Reform Group in relation to capacity auctions and standardisation of contracts this future direction for capacity trading is not discussed in this report. This section discusses the back ground to capacity trading.

Shippers have had the ability to trade capacity under some legacy transport agreements either through the assignment of capacity or through a bare transfer. Primary capacity is capacity sold by a pipeline owner to a shipper and secondary capacity is capacity held by a shipper under an agreement with a pipeline owner that is sold to another shipper.

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63 The Dampier to Bunbury Pipeline for Dummies, AGIG. Accessed by email.

64 APA Group Queensland site tour Wallumbilla Gas Hub and Integrated Operations Centre presentation, 19 Nov 2015.

65 See footnote 64.

In 2014 the Australian Pipelines and Gas Association (formerly APIA) published Guidelines for the Provision of Operational Capacity Transfer Services by Pipeline Operators[66] (Guidelines) that were developed by pipeline owners. The Guidelines describes an assignment as being "*where the seller is entitled to assign part or all of its capacity to another party. This approach requires the negotiation of agreements between the seller, the buyer and pipeline operator. Under an assignment the buyer assumes all the rights and obligations of the seller.*"

A bare transfer is also a form of assignment of capacity however unlike the assignment described above an agreement is only negotiated between the seller of capacity and the buyer of capacity. The pipeline operator may be notified that an assignment of capacity has taken place however as stated in the Guidelines "*Under the bare transfer model the seller of capacity remains responsible for all contractual obligations and daily interaction with pipeliners".*

There appears to have been limited trading activity using the above mechanisms. The Guidelines state that "*Assignments of capacity occur infrequently*" and that in respect of bare transfers "*Based on feedback from customers we believe bare transfers are occurring, although the number of transfers is limited."*

The Guidelines proposed a new approach to implement capacity trades called Operational Capacity Transfers. This mechanism was based on a widely adopted model for pipeline capacity trading in the United States.

The Guidelines describe an Operational Capacity Transfer in these terms:

"*the seller of capacity does not retain any operational rights or obligations in respect of the sold capacity for the period that it is sold, other than to pay the pipeline operator the tariff under the original Gas Transport Agreement (GTA). To enable an operational transfer to proceed there needs to be a GTA in place between the buyer of capacity and the pipeliner so that the rights and obligations associated with the capacity can be transferred to the buyer*.**"**

The Guidelines noted that pipeline owners were proposing to develop their customer management systems to allow buyers of traded capacity to be able to nominate their daily gas transport requirements directly into the customer management systems and receive reports directly. The Guidelines state "*This will likely significantly alleviate the administrative burden on the existing capacity holder (seller) and provide the buyer of capacity with confidentiality around nominations and allocations. Industry discussions have highlighted the importance of these criteria.*"

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66 Capacity trading – Guidelines for the provision of operational capacity transfer services by pipeline operators, Australian Pipeline Industry Association, March 2014.

The Gas Market Reform Group has identified that trades through the proposed capacity exchange and day-ahead auction "*will be given effect through an operational transfer*". [67] The purchase and sale of capacity will be transacted (i.e. bids and offers published and then matched) on a platform to be developed by AEMO and the implementation of the trades (i.e. the transfer of capacity entitlements from the seller to the buyer) will be undertaken in the pipeline companies customer management systems using Operational Capacity Transfers.

In addition to offering Operational Capacity Transfers in their customer management systems APA Group[68] and Jemena[69] have developed their customer management systems to offer capacity trading services. This is the type of functionality that the AEMO platform referred to above will provide.

Sellers and buyers of capacity are currently able to post offers and bids for capacity on the APA Group and Jemena web sites. APA Group currently offers its capacity trading service on the Roma to Brisbane Pipeline and the South West Queensland Pipeline. Jemena currently offers the capacity trading service on the Queensland Gas Pipeline.

At the time this report was written there were no bids published on the APA Group and Jemena capacity trading web sites and the only offers were presumably for capacity held by the two pipeline owners (the contact people for each of the offers were employees of the companies). The APA Group offers were for 7 days ahead and the Jemena offers were for approximately 6 months ahead. APA group advised that there had only been a small number of capacity trades transacted through its customer management system in the three years that it has been available. Therefore, APA Group has not extended the service beyond the Roma to Brisbane Pipeline that the service was originally offered on[70].

The APA Group site includes an offer of capacity on an East Coast Gas Grid service from Wallumbilla to Wilton (Sydney). This is across the South West Queensland Pipeline, one of the pipelines on which capacity trading is offered, and the Moomba to Sydney Pipelines a pipeline on which capacity trading is not separately offered.

AEMO introduced a capacity bid and offer listing facility on its web site in April 2014 as part of the Gas Supply Hub. This service allows shippers to post bids or offers for capacity with contact details. Transactions are negotiated bilaterally and settled outside the Gas Supply Hub.

Since AEMO introduced the capacity bid and offer listing facility on the Gas Supply Hub in April 2014, there have been approximately 1,900 bids or offers posted. Of these approximately 1,600 have been offers of 2 TJ of capacity by one retailer on the Roma to

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67 Gas Market Reform Group Public Forum: Standardisation and capacity trading platform reforms, 14 September 2017

68 Capacity trading factsheet, APA Group, May 2016.

69 Capacity trading factsheet, Jemena.

70 Email from APA Group General Manager Commercial on 7 November 2017.

Brisbane Pipeline at prices between $1.00/GJ and $2.00/GJ, i.e. pro-forma offers at a price which is at a premium to the published negotiated service tariff.

APA Group's negotiated service on the Roma to Brisbane Pipelines is $0.9577/GJ. The retailer has been posting offers since the listing facility was introduced. Approximately 250 postings have been bids for capacity by a gas producer on various pipelines, although these bids were submitted in 2014 and 2015.

As trades in secondary capacity are bi-lateral transactions with no reporting of the outcome of trades, there is limited information on margins. In our consultation a pipeline owner indicated that some shippers were selling secondary capacity at a discount to the primary capacity tariff.

In discussions with shippers, secondary capacity trading was not highlighted as a product that played a significant role in managing commodity or transport positions. Bare transfers were identified as preferable as well as alternatives to capacity trading (refer to discussion below on location swaps in Section 5.4). Some stakeholders indicated that an alternative to secondary capacity trading is using a gas transport agreement to transport another party's gas. This is through a transaction where the primary capacity holder purchases the other party's gas at a receipt point and sells it to the same party at a specified delivery point. The difference in the sale and purchase price was the transportation cost component that the primary capacity holder recovered.

5.2.5 Services that facilitate physical gas trading

A recent innovation is the availability from pipeline owners of services that facilitate physical gas trading. These include:

- Inlet Sales offered by AGIG on the Dampier to Bunbury Pipeline.
- In-Pipe Trade service offered by APA Group on some pipelines.
- In-Pipe Trade Point offered by Epic Energy on the Moomba to Adelaide Pipeline.

AGIG describes Inlet Sales[71] as an agreement that allow shippers and marketers to trade at receipt points. These are trades across the meter at a physical receipt point.

APA Group's In-Pipe Trade[72] service enables shippers to trade gas receipted into a pipeline at a virtual point in the pipeline rather than across the meter at a receipt as is the case with AGIG's Inlet Sales. The trading of gas at a virtual receipt point provides shippers with greater flexibility as gas can be receipted at any physical receipt point on a pipeline and then traded at the virtual point.

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71 The Dampier to Bunbury Pipeline for Dummies, AGIG. Accessed by email.

72 In-pipe trade factsheet, APA Group, May 2016.

To utilise the In-Pipe Trade service shippers need to have a gas transport agreement with APA Group to be able to utilise this service. Shippers are able to manage their gas position through the APA Group customer portal by nominating for receipt (the gas buyer) or delivery (the gas seller) of gas at the virtual point in the pipeline.

APA Group's fee for the In-Pipe Trade service is $0.01/GJ of gas that is traded using In-Pipe Trades. APA Group advised that the majority of trades have been in and around the Wallumbilla Hub[73].

The Epic Energy's In-Pipe Trade Point is a notional delivery and receipt point located immediately downstream of the Moomba Receipt Point and "*The IPT Service enables shippers to receipt gas at Moomba, QSN or the IPT Point and deliver gas to a secondary shipper at the IPT Point*"[74].

A significant outcome of these services is the transfer of risk and title in gas that is traded as described by Epic Energy, "*The service enables the simple allocation of gas between users of the pipeline to ensure custody and risk of gas can be efficiently transferred between shippers*"[75].

Shippers were generally positive about the use of In-Pipe Trades with comments that included:

- "*A huge step forward making it easier to trade*"
- "*Increased interest in IPTs from other parties*"
- "*The In-Pipe Trades service is less complicated trading tool than the Declared Wholesale Gas Market*"
- "*In-Pipe Trades useful for facilitating trades and shippers operationally prepared to use the service*"

APA Group has advised that the utilisation of the In-Pipe Trade service across APA Group's East Coast Grid has increased from 1,300 TJ in July 2016 to 2,500 TJ in June 2017[76]. The volume in June 2017 is about 10% of total deliveries on the East Coast Grid in that month.

5.2.6 Multi-Asset services

APA Group's ownership of multiple interconnected pipelines on the east coast allows it to offer Multi-Asset services for gas transport across its East Coast Grid (Refer Figure 106).

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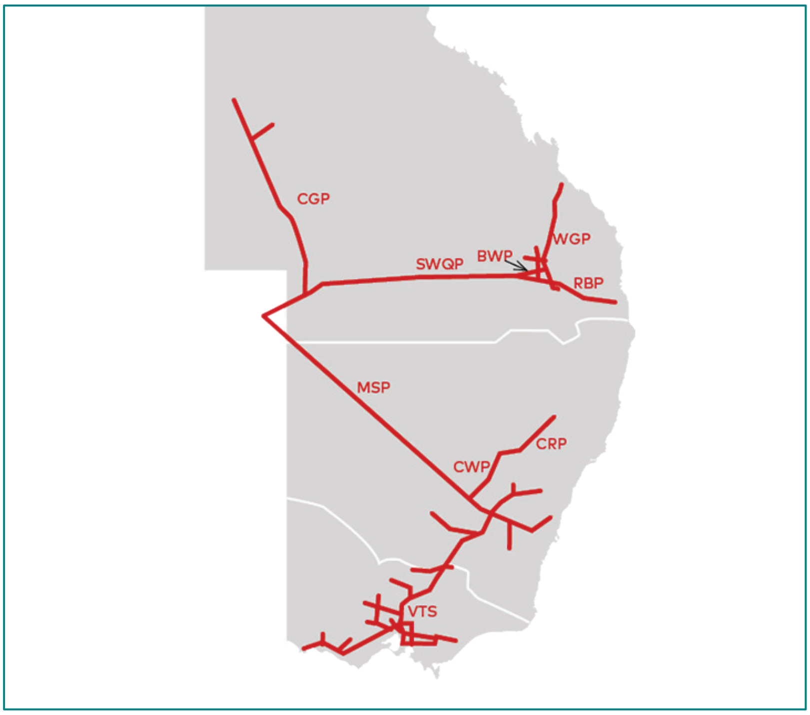
73 Email from APA Group General Manager Commercial on 7 November 2017.

74 Email from Epic Energy General Manager, Strategy & Commercial on 1 November 2017.

75 Email from Epic Energy General Manager, Strategy & Commercial on 1 November 2017.

76 Email from APA Group General Manager Commercial on 7 November 2017.

Figure 106: APA Group East Coast Grid



Source: APA Group website accessed 22 November 2017.

A Multi-Asset service is a service under which gas is transported across multiple pipelines owned by APA Group under one service. Historically shippers have submitted to pipeline owner's nominations for transport of gas on individual pipelines. Where gas is transported across multiple interconnected pipelines owned by different companies then it is necessary to submit nominations to each pipeline owner.

An example of a Multi-Asset service is a service entered into by Incitec Pivot with APA Group for the transport of gas from the Surat Basin (west of Brisbane) to Phosphate Hill (south of Mt Isa)[77]. The gas is transported using the Roma to Brisbane Pipeline, the Wallumbilla Gas Hub, the South West Queensland Pipeline and the Carpentaria Gas Pipeline. Under a Multi-Asset service, a shipper can submit a single nomination for receipt of gas from a gas field connected to the Roma to Brisbane Pipeline and delivery at Phosphate Hill. This provides a shipper with the convenience of only needing to manage a single nomination, with APA Group managing the nominations on the individual pipelines across which the service is provided.

5.3 Pricing trends on pipelines

5.3.1 Structure of tariffs

Pipeline tariffs in Australia are typically structured as one of the following:

77 APA signs a multi-asset gas transport agreement, ASX announcement, 31 March 2016.

- Postage stamp – a single tariff applies irrespective of the length along a pipeline that gas is transported and is typically expressed as \$/GJ; or
- Distance based – the tariff varies depending on the length between points where gas is injected into a pipeline and delivered out of it and is typically expressed as cents per kilometre per GJ.

In some limited cases the charging mechanism for a pipeline is not a tariff, but is a "cost-plus" mechanism, where the pipeline owner charges the customer based on the actual cost of providing the service on the pipeline.

Postage stamp tariffs are generally structured in one of two ways. One tariff structure includes two components:

- A fixed component expressed as cents per GJ of pipeline capacity contracted by a customer (referred to as a Capacity Charge).
- A variable component expressed as cents per GJ of throughput i.e. gas transported during the billing period (referred to as a Throughput Charge).

An alternative approach is to structure the tariff as cents per GJ of throughput in combination with a minimum bill (referred to as a 'take or pay' obligation in gas supply agreements). The minimum bill for a billing period is calculated by multiplying the tariff by the capacity (GJ) contracted by the number of days in the billing period by the minimum bill %. If the actual throughput in the billing period is greater than the capacity (GJ) contracted by the number of days in the billing period by the minimum bill % then this component of the calculation is replaced with the actual throughput.

A trend has emerged in recent years where tariffs are being structured as Capacity only tariffs, without either the variable component or minimum bill component outlined above. This includes the tariffs on the:

- Eastern Gas Pipeline.
- Roma to Brisbane Pipeline - Reference Service Tariff.

In its submission to the AER concerning the proposed 'capacity only' structure of the proposed Reference Service Tariff on the Roma to Brisbane Pipeline Origin Energy stated, "*A throughput charge is generally applied to account for the incremental and variable costs of transporting gas.*"[78] However the variable costs of transporting gas are relatively low.

Capacity charges are likely to account for the largest share of revenue on pipelines as the capacity tariff typically accounts for 80 to 90% (e.g. the Dampier to Bunbury Pipeline tariff is structured as 90% capacity and 10% throughput) of revenue. Information concerning the

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78 Origin Energy - Submission Roma (Wallumbilla) to Brisbane Pipeline – Access Arrangement 2017-22, 21 October 2016.

share of revenue from different tariff types is not available by pipeline. APA Group is a listed entity, and therefore publishes more information than other non-listed pipeline owners. APA Group's 2017 Annual Report reported that the split of revenue[79] from its energy infrastructure was:

- 76.2% from capacity charges.
- 9.4% from regulated revenue.
- 7.8% from throughput charges and other variable revenue.
- 4.7% from contracted fixed revenue.
- 1.7% from flexible short term services.
- 0.2% from Other.

Analysing the above percentage splits published by APA Group for capacity charges and throughput charges and other variable revenue put the ratio at 90% for capacity and 10% for throughput and other variable charges.

5.3.2 Backhaul and Bi-Directional Tariffs

EnergyQuest has stated that "*Moving NT sourced gas to markets in eastern Queensland south of the delivery point of the NGP in Mt Isa may require some wins for gas shippers against the current transmission pricing methodologies, particularly in the area of back-haul*".[80] Such "*wins*" may be difficult to achieve with the:

- Pricing of firm backhaul at the same level as firm forward haul on some pipelines.
- A precedent for the removal of forward haul as a reference service and replacement of it with eastern haul (traditionally forward haul on the Roma to Brisbane Pipeline) and the introduction of western haul (traditionally backhaul on the Roma to Brisbane Pipeline), both priced at the same level, under the 2017-2022 Roma to Brisbane Pipeline Access Arrangement.

Table 29 lists pipelines on which backhaul tariffs, or in the case of the Moomba to Adelaide, Moomba to Sydney and Roma to Brisbane pipelines – tariffs that are applicable in both directions, are publicly available, and the forward haul tariffs on those pipelines. These rates are sometimes referred to as indicative tariffs or rack rates.

Several pipeline companies described their backhaul services as Firm. Where this capacity is traditional backhaul, the services will only be firm to the extent that there is forward flow on the pipeline to offset the nominated backhaul quantity.

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79 Financial results, year ended 30 June 2017 presentation, APA Group, 23 August 2017, slide 15.

80 Energy Quarterly, EnergyQuest, September 2017, page 21.

The re-configuration of the Roma to Brisbane Pipeline as a bi-directional pipeline allows APA to offer a firm Western Haul service without the need for offsetting flow in an easterly direction.

The re-configuration of the Moomba to Adelaide Pipeline as a bi-directional pipeline allows Epic Energy to offer a firm Northern Haul service without the need for offsetting flow in a southerly direction. As noted above if a shipper seeks the flexibility to receive gas at both ends of the Moomba to Adelaide Pipeline under one service then a Bi-Directional Charge applies.

Table 29: Tariffs

Company	Pipeline	Forward Haul Tariff ($/GJ)	Backhaul Tariff ($/GJ)	Backhaul Service Type
AGIG[81]	Dampier to Bunbury Gas Pipeline	Full Haul ($/GJ) $1.1891 and $0.1304 Partial ($/GJ/km) $0.000850 $0.000093	($/GJ/km) $0.000850 $0.000093	Firm
Epic Energy[82]	Moomba to Adelaide Pipeline	$0.73	$0.73	Firm
Jemena[83]	Eastern Gas Pipeline	Zone 1 - $0.44 Zone 3 - $1.2615	Zone 1 - $0.1692 Zone 3 - $0.1692	Firm
	Queensland Gas Pipeline	$0.9857	$0.5703	
APA Group	Moomba to Sydney Pipeline	$1.02 and $0.05		Firm
APA Group	Roma to Brisbane Pipeline – 2017-2022 Reference Service	$0.7195	$0.7195	Firm

81 AGIG tariffs are Capacity and Throughput.

82 Postage stamp tariffs.

83 Jemena tariffs are capacity only.

Company	Pipeline	Forward Haul Tariff ($/GJ)	Backhaul Tariff ($/GJ)	Backhaul Service Type
	Roma to Brisbane Pipeline – Negotiated Service	$0.9577	$0.5773	Firm
	Roma to Brisbane Pipeline – 2012-2017 Reference Service	$0.6413 and $0.0430	N/a	Firm

Source: Company web sites, AER and ERA web sites. Tariffs are as at 1 July 2017, except for the Roma to Brisbane Pipeline 2017-2022 Reference Service which is at 1 January 2018. The Roma to Brisbane Pipeline 2012-2017 Reference Service and the DBP Reference Services tariffs are capacity ($/GJ/MDQ) / throughput tariffs ($/GJ). The other tariffs are capacity only. The tariffs quoted above are Zonal for the Eastern Gas Pipeline, postage stamp for the Roma to Brisbane and Queensland Gas Pipelines, and full haul ($/GJ/day) and part haul ($/GJ/day/km) for the Dampier to Bunbury Gas Pipeline.

In eastern Australia where backhaul tariffs are offered this has been at a discount to forward haul tariffs. APA Group's proposal in its 2017-2022 Roma to Brisbane Pipeline Revised Access Arrangement Submission (AA Submission) was to redefine backhaul as Western Haul and apply the same tariff for Eastern Haul and Western Haul. APA Group defines its reference service as "*The Firm Service is a service for the receipt, transportation and delivery of Gas through any length of the Covered Pipeline.*" This definition captures both west bound (backhaul) and east bound (forward haul) services as Reference Services.[84] APA group's proposal was accepted by the Australian Energy Regulator.

APA Group is forecasting a decline in the capacity that can be contracted under Eastern Haul services and in order to maintain its revenue during the 2017-2022 Access Arrangement period it is necessary to price the Western Haul Reference Service at the same level as the Eastern Haul Reference service.

5.3.3 Tariffs for Short Term versus Long term services

The differentiation between tariffs for long term and short term pipeline services is particularly relevant given the current gas market dynamics where offers of gas supply, when available, are typically for short terms of less than three years. Gas buyers can manage the risk of committing to take or pay obligations under gas transport agreements by matching the term of gas transport agreements with the term of their gas purchase agreements with producers.

Domestic gas sale agreements with terms of 10 years were typical of transactions in the early years of this decade. However, in recent years longer dated GSAs have been typically from new producers such as Cooper Energy and portfolio sales such as the sale of surplus

84 2017-22 Roma to Brisbane Pipeline, Access Arrangement Submission, September 2016, p 21.

gas by PowerWater Corporation to Incitec Pivot. Recent domestic gas sales have been for terms of typically less than three years, a trend we outlined in our 2015 report. Gas sales in 2017 include:

- Shell's sale of gas to Engie's Pelican Point for a five month term[85].
- Shell's sale of gas to Orica's Yarwun facility for an eighteen month term[86].
- Origin's sale of gas to Engie for its customer portfolio for a two year term[87].
- Origin's sale of gas to Engie Pelican Point for a three year term[88].
- Santos's sale of gas to Engie's pelican Point has been reported to be for a two year term[89].
- APLNG's sale of gas to Origin Energy for a fourteen month term[90].

The limited amount of publicly available information concerning pipeline tariffs makes it difficult to address the topic of tariff setting for short term agreements in detail. However, the recent process to determine the 2017-22 Roma to Brisbane Pipeline Access Arrangement has provided an opportunity to better understand this aspect of tariff setting.

Before discussing the 2017-22 Roma to Brisbane Pipeline Access Arrangement process, this section will consider precedents for premiums tariffs for short term services.

APA Group's Carpentaria Gas Pipeline was commissioned in 1998. The Access Arrangement set a tariff for the Reference Service, which was defined as having a fifteen year term[91]. For gas transport agreements with a term of less than fifteen years the Access Arrangement included a formula to adjust the tariff applicable to a fifteen year term to arrive at a tariff for shorter terms.

The Goldfields Gas Pipeline 2000 Access Arrangement Submission[92] proposed a Reference Service tariff structure on a sliding scale with five year steps for terms and tariff. A gas transport agreement term of 1-5 years was set at a premium of 20% above an agreement

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85 Shell Seals More East Coast Domestic Gas Deals, Shell Media Release, 06 April 2017.

86 Refer footnote 85.

87 Origin works with ENGIE to help boost energy security in South Australia, Origin Energy Media Release, 29 March 2017.

88 Refer footnote 87.

89 EnergyQuarterly, EnergyQuest 20 September 2017, page 27.

90 Origin secures 41PJ of gas for Australian customers, Origin Energy Media Release, 26 Oct 2017.

91 Access Arrangement for Carpentaria Gas Pipeline, September 2002, page 14.

92 Goldfields Gas Pipeline Access Arrangement Information, 15 Dec 1999, page 9.

term of 15-20 years. It has not been possible to determine whether this proposed structure was approved.

A review of publicly available information concerning current pipeline tariffs identified the Northern Gas Pipeline which is currently under construction as having a different tariff for differing terms for the nitrogen removal service that is offered separate to transport services. The tariff for a 10 year term is $0.7430/GJ of capacity[93.] The tariff for 15 year term is $0.5572/GJ, i.e. contracting for longer secures a discount on the price of the service.

The 2012-17 Roma to Brisbane Pipeline Access Arrangement includes a single tariff for the Reference Service. The Reference Service is for a minimum Term of three years[94] and therefore agreements for a term of less than three years are negotiated services. The tariff structure for the Reference Service[95] consists of a:

- Capacity Tariff of $0.5289 per GJ of MDQ/Day at 1/09/2012.
- Throughput Tariff of $0.0354 per GJ at 1/09/2012.

In its 2017-22 Roma to Brisbane Pipeline Access Arrangement submission, APA Group proposed two reference services - a Long Term Firm Service and a Short Term Firm Service. The term of the of the Long Term Firm Service is defined as three years or more as agreed between the parties. APA Group proposed that the Short Term Firm Service be for a term of up to three years[96].

APA Group has proposed that the Short Term Firm Service should be priced at a premium to the Long Term Firm Service. APA Group proposed that the tariff for the Short Term Firm Service be set with reference to the load factor on the Roma to Brisbane Pipeline.

APA Group stated in support of its proposal to set the Short Term Firm Service at a premium that "*Long Term Firm capacity is sold subject to a take-or-pay arrangement; the shipper must pay for reserved capacity over a longer term, even if it is unutilised on a particular day. In the case of Short Term Firm services, the shipper pays only for that capacity over the short term contracted (as little as one day)*"[97]. APA Group argued that a shipper with a low load factor is incentivised to enter into shorter term agreements "*so it is not required to pay*

93 Jemena Northern Gas Pipeline tariffs, Jemena website accessed 22 Nov 2017.

94 2012-17 Roma to Brisbane Pipeline Access Arrangement, Access Arrangement Submission, September 2016, page 8.

95 2012-17 Roma to Brisbane Pipeline Access Arrangement, Access Arrangement Submission, September 2016, page 8

96 2017-22 Roma to Brisbane Pipeline, Access Arrangement Submission, September 2016, pages 21 and 22.

97 2017-22 Roma to Brisbane Pipeline, Access Arrangement Submission, September 2016 page 47.

for extended periods of unutilised capacity"[98]. A peaking power station owner is an example of such a shipper.

APA Group[99] states that "*large industrial and retail customers with load factors in the order of 80% will tend to book their full requirements as Long Term Firm capacity. At the other end of the scale, peaking power plants and commodity traders, with a very low load factor, are unlikely to reserve any Long Term Firm capacity at all, and rely entirely on the availability of the Short Term Firm service*".

APA Group argued that the tariff for the Short Term Firm Service should be charged at a multiplier of 166% and this is linked to the load factor on the Roma to Brisbane Pipeline. APA Group's argument appears to have been that shippers who contract firm for less than three years will have low load factors.

A position that shippers contracting for a short term service will prevent other shippers during the term of the short term service contracting long term may have some merit. However, on a pipeline such as the Roma to Brisbane Pipeline that is set to experience a reduction in Eastern Haul demand[100] to approximately 50% of capacity, this is not a particularly robust position.

As outlined, APA Group's position appears to have been that shippers who contract for a term of less than three years will have a low load factor and that shippers who contract for longer than three years will have higher load factors. This may not be a durable position given the dynamics in the market. In Oakley Greenwood's consultation with market participants they generally referred to being able to source gas for the following calendar year, only in a small number of cases did participants state that they could or had secured offers for terms of two or three years.

Had the Australian Energy Regulator accepted APA Group's proposed Short Term Firm Service as a reference service, then the combination of APA Group's proposed tariff structure and the current gas market dynamics would have created the potential to see new shippers, irrespective of their load factor, paying a premium for transport services on the Roma to Brisbane Pipeline. Assuming that such a shipper would seek to manage the risks in purchasing gas by contracting for transport for the same term that they are able to contract for gas supply.

If the proposed tariff structure for the Roma to Brisbane Pipeline Access Arrangement had been approved, then it would have created a precedent endorsed by the regulatory process for pipeline owners to charge a premium for shorter term negotiated services.

The Australian Energy Regulator's stated that it was "*not satisfied that defining a Short Term Firm Service (STFS) as a reference service as proposed by APTPPL is consistent with the*

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98 2017-22 Roma to Brisbane Pipeline, Access Arrangement Submission, September 2016 page 48.

99 2017-22 Roma to Brisbane Pipeline, Access Arrangement Submission, September 2016 page 48.

100 2017-22 Roma to Brisbane Pipeline, Access Arrangement Submission, September 2016 page 53.

Revenue and Pricing Principles (RPPs) or will promote the NGO". The Australian Energy Regulator concluded that defining the Short Term Firm Service as a reference service "*appears unnecessary given reforms underway to facilitate more trade and competition between pipeline operators and users for provision of short-term transportation services*".[101]

5.3.4 Tariffs on regulated and unregulated pipelines

Tariffs for Reference Services on pipelines that are subject to full (heavy handed) regulation are developed under a 5 yearly access arrangement process. These pipelines set tariffs for negotiated services without reference to the access arrangement process.

A key difference between regulated pipelines for which there are access arrangements and pipelines where there are no access arrangements, i.e. pipelines that are either unregulated pipelines or subject to light handed regulation, is the ability of owners of the latter group of pipelines to change tariffs without submission of the tariffs to a regulatory body for approval.

The regulatory status of light regulation pipelines is explained on the AER web site. In the case of the Carpentaria Gas Pipeline the AER web site states that:

"*The National Gas Law (NGL) and National Gas Rules (NGR) commenced on 1 July 2008 and replaced the Gas Pipeline Access Law and the gas code. The National Gas (Queensland) Regulation 2008 (the Regulation), which is subordinate legislation to the National Gas (Queensland) Act 2008, provides for transitional arrangements under the NGL and NGR for the South West Queensland Pipeline, the Queensland Gas Pipeline and the Carpentaria Gas Pipeline (CGP).*

The Regulation stipulated that the access arrangement for the CGP ceases to apply, effective 2008. It also stipulates that the services provided by the CGP will be subject to light regulation and the pipeline cannot be made the subject of a full access arrangement."

Table 30 lists tariffs on major pipelines in 2016 and 2017. These tariffs include a combination of tariffs for Reference Services under Access Arrangements and indicative tariffs that companies publish for either negotiated services on regulated pipelines or tariffs on unregulated pipelines.

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101 DRAFT DECISION, Roma to Brisbane Gas Pipeline Access Arrangement 2017–22, Australian Energy Regulator, June 2017, page 17.

Table 30: Pipeline tariffs

Pipeline	Pipeline Regulatory Status	Tariff	
		2016 ($/GJ)	2017 ($/GJ)
Amadeus Gas Pipeline	Heavy	0.5959	0.5835
Carpentaria Gas Pipeline	Light	1.3200	1.6200
Dampier to Bunbury Pipeline[102]	Heavy	1.2945	1.3195
Eastern Gas Pipeline[103]	Unregulated	N/A	1.2615
Goldfields Gas Pipeline	Heavy	See comment below	
Moomba to Sydney Pipeline[104]	Partial	1.0300	1.0700
Moomba to Adelaide Pipeline	Unregulated	N/a	0.7300
Northern Gas Pipeline - Transport	Unregulated	N/a	1.4447
Northern Gas Pipeline - Processing[105]	Unregulated	N/a	0.7430
Parmelia Gas Pipeline[106]	Unregulated	0.6000	0.6000
QLD Gas Pipeline	Unregulated		0.9857
RBP – reference service[107]	Heavy	0.6743	0.6843
RBP – negotiated service	Heavy	0.9500	0.9577
South West QLD Pipeline	Unregulated	1.1600	1.1700

102 The tariffs are Capacity / Throughput tariffs for full forward haul Karratha to Perth.

103 The tariff is for Zone 3 (which includes the Sydney delivery point).

104 Full forward haul tariff (Capacity ($0.98/GJ) plus Throughput ($0.05/GJ) in 2016) Moomba to Wilton. Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden. The covered portion became a light regulation pipeline in 2008.

105 This is a tariff for a 10-year term. The tariff for a 15-year term is $0.5572/GJ.

106 Tariff in 2016 Capacity ($0.54/GJ) plus Throughput ($0.06/GJ)

107 Tariff is the sum of the Capacity and Throughput components which as at 1 July 2017 were $0.6413 and $0.0430/GJ respectively.

Pipeline	Pipeline Regulatory Status	Tariff	
		2016 ($/GJ)	2017 ($/GJ)
Moomba Compression	Unregulated	0.2700	0.2000
Wallumbilla Compression	Unregulated	0.1600	0.095

Source: Tariffs are sourced from company web sites and communications with companies.

The Roma to Brisbane Pipeline Reference Service quoted above are the tariffs under the 2012-2017 Roma to Brisbane Pipeline Access Arrangement. In November 2017 the Australian Energy Regulator released its final decision for the 2017-2022 Roma to Brisbane Pipeline Access Arrangement. The Reference Service tariff under this Access Arrangement is a Capacity only tariff of $0.7195/GJ as at 1 January 2018[108], compared to a Capacity and Throughput tariff of $0.6413/GJ and $0.0430/GJ as at 1 January 2017 under the prior Access Arrangement.

In its Final Decision Fact Sheet for the 2017-2022 Roma to Brisbane Pipeline Access Arrangement the Australian Energy Regulator states "*We estimate reductions in annual gas bills of around $3 for residential customers and $31 for small business customers in 2017–18.*" and "*Our decision impacts only the transmission charge component of customers' gas bills.*".

OGW reviewed the Australian Energy Regulator's above statement that it estimated that the change in the transmission component of gas bills is a reduction of $3 per annum in annual gas bills. With Queensland's average household consumption being 11.4 GJ/a, a reduction of $3 in annual gas bills would require a tariff reduction of approximately $0.26/GJ.

The AER advised that "*the change in reference tariffs between 2016–17 to 2017–18 appears to represent a tariff increase. However, there are a number of moving parts between access arrangement periods, including redefining the reference service tariff from a two part tariff to a single capacity only tariff, as outlined in our final decision.*"[109]. The AER noted that by adjusting the analysis of the bill impact to allow for a comparison that reflected the change in the type of tariff from 2016–17 to 2017–18 then this indicates "*a negligible bill impact in 2017–18*".

Further, on the Roma to Brisbane Pipeline a negotiated service is any service other than a Reference Service, this includes a service other than from the existing capacity of the pipeline. Tariffs on regulated pipelines can therefore include two types of tariffs, negotiated service tariffs and Reference Service tariffs.

The above statement by the Australian Energy Regulator could be interpreted as meaning that changes to Reference Service tariffs will flow through to residential customers generally.

108 AER - Approved access arrangement for the RBP 2017-22 - final decision - November 2017, page 46.
109 Email from AER Analyst on 21 December 2017.

This may not be the case as gas prices in the Queensland context are not regulated and there is no requirement for retailers to pass on changes in pipeline tariffs to customers.

Furthermore, the ACCC's Inquiry into the east coast gas market highlighted that there is a range of tariffs paid by shippers[110] on the Roma to Brisbane Pipeline. These varied from $0.43/GJ to $0.95/GJ in 2015 with the Reference Service tariff at that time being approximately $0.65/GJ. A change in the Reference Service tariff from one access arrangement period to the next would not impact on a retailer's transportation costs where the retailer has a gas transport agreement with a negotiated service tariff.

The Goldfields Gas Pipeline Reference Service tariff in 2016 (July) was:

- $0.116369/GJ toll charge; plus
- $0.00062/GJ/km capacity; plus
- $0.000228/GJ/km throughput.

The Reference Service tariff in 2017 (July) increased slightly and was:

- $0.117555/GJ toll charge; plus
- $0.000627/GJ/km capacity; plus
- $0.00023/GJ/km throughput.

The Goldfields Pipeline non-Reference Service tariff in 2017 (July) was:

- $0.37/GJ toll charge; plus
- $0.0022/GJ/km capacity; plus
- $0.0007/GJ/km throughput.

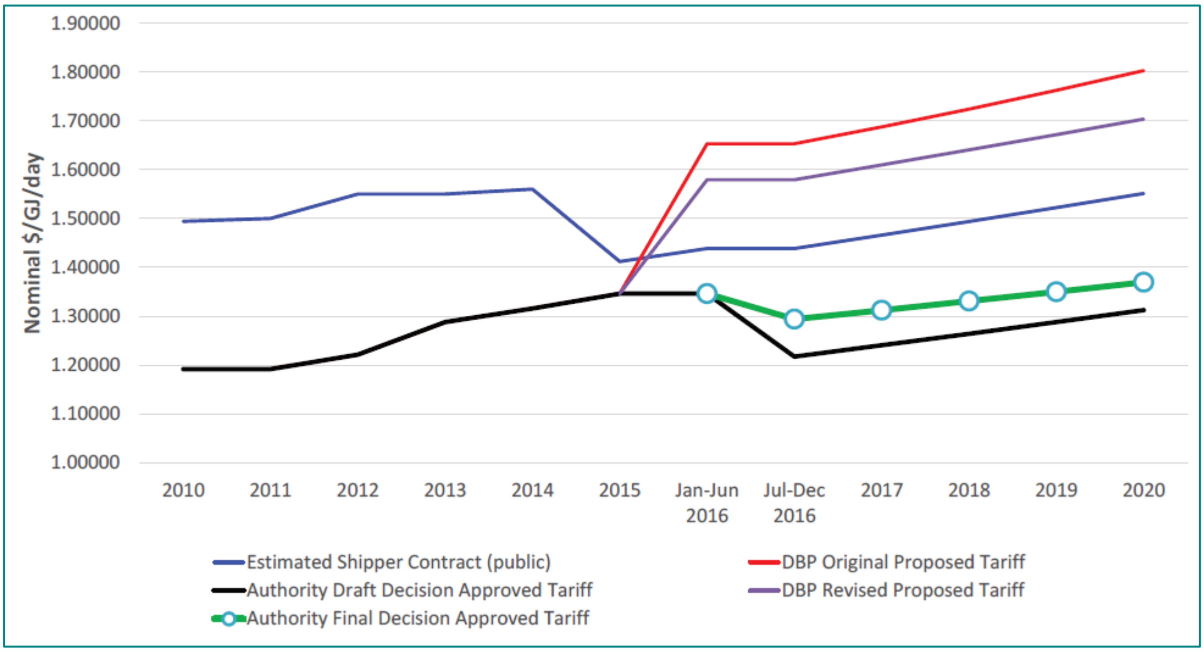
The most notable change in a tariff is APA Group's Carpentaria Gas Pipeline. The indicative tariff on this pipeline in July 2016 was $1.32/GJ[111] to October 2017[112]. In November, the tariff changed to $1.62/GJ - a 23% increase. The application of CPI escalation to the July 2016 tariff would have seen an increase in the order of 2%. APA Group's explanation for the change is that "*There was an inconsistency in the way we presented our tariffs*" and that the change "*reflects the regulated tariffs, which more accurately reflects the objective of and the rest of the numbers on the indicative tariff table*"[113].

APA Group has marginally reduced the Amadeus Gas Pipeline tariff. The Amadeus Gas Pipeline tariff has been reduced in accordance with the adjustment mechanism in the Access Arrangement. The tariff on the Parmelia Gas Pipeline is unchanged from 2016 to 2017.

110 Inquiry into the east coast gas market, ACCC, April 2016, page 17.
111 Accessed via Internet Archive Wayback Machine on 27 October 2017.
112 APA Group website, accessed 6 October 2017.
113 Email from APA Group General Manager Commercial on 15 November 2017.

The Dampier to Bunbury Pipeline tariff in the above table is from the Economic Regulation Authority of Western Australia's Final Decision on Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 – 2020 (Decision) that was published in June 2016. Industry sources estimate that 85% of capacity is contracted under negotiated services. Figure 107 is an extract from the Decision and indicates that these negotiated services are at a higher level than the approved tariff under the Decision. The Australian Competition Tribunal held a hearing in February 2017 in response to a Dampier to Bunbury Pipeline challenge of the Decision. A decision is expected later this year.

Figure 107: Dampier to Bunbury Pipeline tariffs



Source: Final Decision on Proposed Revisions to Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline 2016 – 2020, Final Decision, ERAWA, 30 June 2016.

The tariffs discussed in this section are tariffs that are publicly available, either tariffs under access arrangements or 'rack rates' published by pipeline owners. Figure 107 highlights a situation where shippers are understood to have entered into negotiated services at a rate higher than an access arrangement tariff. The ACCC's Inquiry into the east coast gas market highlighted that the range of actual tariffs paid by shippers[114] varies from the tariffs, including access arrangements tariffs, published by pipeline owners. The ACCC published details of tariffs based on pipeline company invoices in Q1 2015. The tariffs from the ACCC report have been escalated by CPI for comparison in this section.

APA Group publishes an indicative tariff for the Carpentaria Gas Pipeline of $1.62/GJ (July 2017). The range of tariffs that was included in the ACCC report for the Carpentaria Gas Pipeline was $1.18/GJ to $1.70/GJ.

[114] Inquiry into the east coast gas market, ACCC, April 2016, page 17.

Jemena publishes an indicative tariff for the Queensland Gas Pipeline of $0.9857/GJ (January 2017). The range of tariffs that was included in the ACCC report for the Queensland Gas Pipeline was $0.73/GJ to $1.27/GJ.

5.3.5 Impact of Lower Interest Rates on Transmission Costs

In this section we discuss at a high level the impact that the decline in interest rates has had on pipeline tariffs.

Tariffs in gas transport agreements typically escalate over time through a linkage to CPI, therefore where there are longer dated agreements in place the tariffs charged will not be impacted by lower (or higher) interest rates.

Where a pipeline owner is borrowing now to fund a new pipeline or pipeline expansion then the current lower interest rate environment may help to reduce the level at which that tariffs need to be set. However, it is difficult to draw a direct link as there are other factors driving tariffs such as the capital cost of a new project and customer ability or willingness to pay as in the end market forces do predominate in such investments decisions. Having lower cost debt at this point of decision making may become more of an issue of investment approval than margin maximisation. The answer lies somewhere between the appetite for investor returns and the markets willingness to pay based on firm and often longer term gas transport agreements.

With regard to existing pipelines where gas transport agreements are ending, and replacement agreements are being put in place for that capacity, then the debt profile of pipeline owners may have an impact on the level that pipeline companies set tariffs, again with the caveats above on market forces and investor expectations.

Where pipeline owners entered into relatively fixed debt facilities when interest rates were higher, then current interest rates will have less of an impact on the pipeline owner's ability to reflect current interest rates in its tariffs.

The Australian Energy Regulator's view on funding costs for pipelines is reflected in its Amadeus Gas Pipeline Access Arrangement decision where it applied a lower "*allowed rate of return (or 'cost of capital')*" (6.18%) than proposed by APA Group (8.58%) in determining the revenue that APA Group could recover from Reference Services and therefore the Reference Tariff. This setting cost of capital or Weighted Average Cost of Capital by Regulators lower when interest rates are low is consistent across regulated entities.

The Australian Energy Regulator states "*The investment environment has improved since our previous decision, which was made during the period of uncertainty surrounding the global financial crisis. This improved investment environment translates to lower financing costs necessary to attract efficient investment.*"[115]

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115 Final decision: Amadeus Gas Pipeline access arrangement 2016–21, Australian Energy Regulator, May 2016.

This tends to provide an incentive for heavily regulated entities to manage cost of debt to ensure changes are managed but new pipelines have been granted extended regulatory holidays in Australia to recognise the market effects and need most times for foundation agreements, and many pipelines are not heavily regulated for similar reasons – they are reacting to market forces rather than monopoly assets. This is an issue currently under detailed review, but it is not easily discernible in the current more dynamic market that unregulated or lightly regulated assets that have been in service for some period react to these underlying cost changes, except at the margin where new capacity or capital upgrades may be required.

5.3.6 Pipeline charges between major gas basins and demand centres

The tariffs on pipelines on the east coast is a central component of the debate concerning gas prices on the east coast. Shell has made the statement that "*East coast customers are paying more than twice as much to get the gas from where it is produced to where it is used as customers on the west coast*"[116]. In this section Oakley Greenwood compares tariffs on gas pipelines connecting major demand centres and gas basins in Australia.

A range of factors are involved in determining the tariff on a gas pipeline, including operating cost, capital cost, configuration (free flow, compressed or looped) contracted quantities, capacity and competitive tension where more than one pipeline services a market. Therefore, it is difficult to draw comparisons of tariffs across pipelines with the information available for this report.

It should also be noted that history of pipeline development on the east coast is different in such a way to make comparisons between the cost of transport between gas basins and demand centres on the east coast versus west coast more problematic. The Dampier to Bunbury Pipeline was initially constructed to transport gas from the North West Shelf gas plant to Perth. The pipeline has evolved over time with new gas fields connected to it and connections to new pipelines. However, these are predominately in the northern region of the pipeline.

By contrast, the grid of pipelines on the east coast connecting the Surat Basin gas fields to Sydney and Adelaide consist of three pipelines (the Roma to Brisbane Pipeline, the South West Queensland Pipeline and either the Moomba to Sydney Pipeline or the Moomba to Adelaide Pipeline respectively). The Roma to Brisbane Pipeline was originally developed to flow gas east. It is now configured to also flow gas west from the Surat Basin, potentially to Sydney, which has required modification to the configuration to meet this new purpose. Similarly, the South West Queensland Pipeline was built to flow gas from west to east and at smaller volumes than it is currently configured to flow west.

116 Statement on East Coast Domestic Gas media release, Shell, 20 September 2017.

The capacity of the DBP at 845 TJs (per day) is double the capacity of the largest capacity pipeline in the grid of pipelines connecting the Surat Basin to Sydney and Adelaide:

- Roma to Brisbane Pipeline of 125 TJ (West flow).
- South West Queensland Pipeline of 384 TJ.
- Moomba to Sydney Pipeline of 392 TJ.
- Moomba to Adelaide Pipeline of 250 TJ.

The Dampier to Bunbury Pipeline follows a relatively logical route north to south over a distance of 1,400 km.

The distance from the southern Surat Basin near the Roma to Brisbane Pipeline to Sydney is 800 kilometres. However, the pipeline distance between these two points using the three interconnected pipelines is 2,190 km, as the route the pipelines follow is west from the Surat Basin to Moomba and then south east from there to Sydney.

The headline total tariff from the Surat Basin to Sydney is approximately $3.40/GJ. This is more than double the tariff on the DBP from the North West Shelf gas plant to Perth of approximately $1.30/GJ.

However, to provide an order of magnitude comparison the total transport costs between demand centres and gas basins have been converted to distance based costs. In the case of the Dampier to Bunbury tariff this is 0.09¢/GJ/km. The total tariff on the pipelines connecting the Surat Basin to:

- Sydney is 0.15¢/GJ/km.
- Adelaide is of a similar order at 0.14¢/GJ/km.

While the cost of transport in ¢/GJ/km terms from the Surat Basin to Sydney is greater than from the North West Shelf to Perth, this may relate to how the east coast grid has developed compared to the purpose built Dampier to Bunbury Pipeline. It may also relate to the separable nature of the pipelines in the east coast grid that transport gas from the Surat Basin to the above cities and the stacking of prices to arrive at a total transport cost.

Table 31 lists the total cost of transport from gas basins to major demand centres across Australia. The pipeline distances in Appendix A.1, tariffs in Section 5.3.4, a Core Energy estimate of the SEAGas Pipeline tariff[117] (escalated at CPI) and an Oakley Greenwood estimate of $1.13/GJ for the Bonaparte Gas Pipeline have been used to determine the total tariffs in the table. There is no quoted tariff for the Victorian Transmission System, Victoria to Moomba Interconnector and Moomba to Sydney combination, based on a statement by APA Group it is assumed that the tariff for a service across these pipelines is competitive with the Eastern Gas Pipeline.

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117 AEMO – Gas Price Consultancy, Core Energy Group, August 2015.

The tariffs on the Moomba to Sydney Pipeline and the Moomba to Adelaide Pipeline are lower than the Dampier to Bunbury Pipeline on a cents per GJ basis. The Moomba to Sydney Pipeline (1,300 km) and the Moomba to Adelaide Pipeline (1,185 km) are of a similar length to the Dampier to Bunbury Pipeline (1,400 km)

Table 31: Cost of transport from major gas basins to major demand centers

Gas Basin	Demand Centre	Pipelines[118]	Total Pipeline Distance (km)	Total Tariff ($/GJ)	Total Tariff (¢/GJ/km)
Surat[119]	Adelaide	RBP/WC/SWQP/MC/MAP	2,075	2.89	0.14
	Brisbane	RBP	305	0.69	0.23
	Sydney	RBP/WC/SWQP/MC/MSP	2,190	3.23	0.15
	Mt Isa	RBP/WC/SWQP/BC/CGP	1,730	3.78	0.22
Cooper	Adelaide	MAP	1,185	0.73	0.06
	Sydney	MSP	1,300	1.07	0.08
	Mt Isa[120]	QSN/CGP	1,022	2.05	0.20
Gippsland / Otway	Adelaide	SEAGas	680	0.83	0.12
	Sydney	EGP	795	1.26	0.16
	Sydney	VTS/VNI/MSP	-	1.26	
Bonaparte	Mt Isa	BGP/AGP/NGP	1,676	3.91	0.23
	Adelaide	BGP/AGP/NGP/CGP/QNI /MAP	3,883	6.89	0.18

118 MC is Moomba Compression, BC is Ballera Compression (assumed to be the same cost as quoted by APA Group for Moomba Compression) and WC is Wallumbilla Compression. The tariff used for the Bonaparte Gas Pipeline is an Oakley Greenwood estimate.

119 Distance on Roma to Brisbane Pipeline assumed to be Argyle Receipt point at KP135 and tariff used is proposed Access Arrangement Tariff

120 This assume that the QSN component is a prorate amount of the published South West Queensland Pipeline tariff.

Gas Basin	Demand Centre	Pipelines[118]	Total Pipeline Distance (km)	Total Tariff ($/GJ)	Total Tariff (¢/GJ/km)
	Sydney	BGP/AGP/NGP/CGP/QNI /MSP	3,998	7.23	0.18
NT Onshore	Brisbane	NGP/CGP/BC/SWQP/WC /RBP	2,657	5.74	0.22
	Mt Isa	NGP	622	2.19	0.35
	Adelaide	NGP/CGP/BC/QNI/MC/RBP	2,829	5.17	0.18
	Sydney	NGP/CGP/BC/QNI/MC/MSP	2,944	5.51	0.19
North West Shelf	Perth	DBP	1,400	1.32	0.09

The Northern Gas Pipeline currently being constructed by Jemena has a tariff of $1.4447/GJ which includes a nitrogen removal service from NT gas to meet the east coast gas specification. The pipeline is 622km in length. This is equivalent to a distance based tariff of ¢0.23/GJ/km.

5.3.7 Other service considerations

A key differentiation between services is the level of priority of a service. The priority determines how a shipper's nominations (a notice given daily by shippers advising the pipeline owner of how much capacity they require the following day) to utilise its service are treated in the event that there is insufficient pipeline capacity on a day to meet the total nominations of all shippers. Table 32 includes a description of the types of services typically offered on pipelines.

Table 32 Pipeline services

Service	Description
Firm	Typically, the highest priority service. This service includes a firm obligation to receive and deliver gas up to the shippers contracted capacity (referred to as Maximum Daily Quantity or MDQ) on a day, subject to force majeure and maintenance provisions. This type of service is typically used by shippers who have a predictable and stable demand e.g. industrial customers and base load power stations.

Service	Description
As Available	A lesser priority service. Capacity for this type of service is provided on a day from spare firm capacity (either uncontracted capacity or contracted but unutilised capacity). Therefore, pipeline owner is not obliged to have capacity available. However, once the pipeline owner has accepted a nomination for As Available capacity it has a firm obligation to receive and deliver gas up to the capacity the shipper was notified was available, subject to force majeure provisions
Interruptible	The lowest priority service. Capacity for this type of service is provided on a day from spare firm capacity (either uncontracted capacity or contracted but unutilised capacity). The pipeline owner has no obligation to make capacity available on a day and has the right after notifying the shipper that capacity is available on a day to interrupt the provision of the service.
Park	A storage service offered by pipeline owners that allows shippers to storage gas in a pipeline. This type of service utilises capacity of the pipeline that would otherwise be used to transport gas.
Park and Loan	A service which in addition to providing storage allows the shipper to borrow gas from the pipeline and then “repay” the volume of gas that has been borrowed within a prescribed period.
Backhaul	A service for the receipt and delivery of gas up to the shippers contracted backhaul capacity. The direction of “flow” is in the opposite direction to flows under firm services. This type of service is offered on both a firm and non-firm basis. The ability of a pipeline owner to offer this service is conditional on there being sufficient forward flow between the relevant receipt and delivery points to offset the amount of the nominated for the backhaul service.
Multi asset service	A type of service offered by pipeline owners with multiple interconnected pipelines that allows the shipper to receipt gas on one pipeline and take delivery of the gas from another interconnected pipeline owned by the same pipeline owner.

The above are the main types of services offered by pipeline owners. Pipeline companies also offer bespoke services, some of which are discussed in the sections above on Services that facilitate physical gas trading, Hub services and Secondary Capacity Trading.

In addition to charging for services pipeline owners apply ancillary charges under gas transport agreements. These include charges such as imbalance charges, a charge applied when the quantity of gas receipted by a shipper does not match the quantity that the shipper tables delivery of on a day. Given the difficulty for shippers in balancing receipts and deliveries, pipeline owners often include an imbalance tolerance to give shippers some leeway.

Another charge that is often included in gas transport agreements is an overrun charge that the pipeline owner charges when the quantity of capacity used by a shipper on a day exceeds the quantity they have contracted or the amount that they have nominated to use on a day.

It was noted by one shipper that some pipeline owners have been eliminating small “annoying” ancillary charges.

APA Group and Epic Energy stated that they had recently reviewed their charges and had removed some ancillary charges. Ancillary charges are generally low value charges.

Jemena’s tariff structure for the Eastern Gas Pipeline[121] includes a Minimum Monthly Service Charge for each of its transport and storage service types. The amount of the charge is a fixed dollar amount per month per delivery point. Although Jemena has stated that the Minimum Monthly Service Charge is waived if the revenue under the applicable service for the month under the transport or storage charge exceeds the amount of the Minimum Monthly Service Charges.

5.4 Pipelines and innovation in gas trading

In section 4.11 the changes in the gas market on the east and west coasts are discussed. These changes have resulted in a more dynamic market with the potential for greater variability in gas flows. This is especially the case on the east coast where the existence of gas supply in both the north and the south, and demand in both the north and the south is driving uncertainty in the market.

As noted above shippers indicated that the In-Pipe Trades service provided by APA Group and the similar service offered by Epic Energy were services that were contributing to streamlining gas trading. One user of this service noted that the number of parties that had access to the In-Pipe Trade service was increasing.

The capacity trading service offered by APA Group and the AEMO capacity listing service are being utilised to a very limited extent by shippers in the case of the AEMO service and negligibly in the case if the APA Group service.

Several shippers indicated that there has been increased activity with gas swaps. Two types of swaps were referred to, time swaps and location swaps.

Time swaps allow Party A that has surplus gas available in a future period and a need for gas in the shorter term to take gas from Party B that has gas available in the shorter term. Party A then makes a corresponding amount of gas available to Party B in the future period.

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121 Jemena, Eastern Gas Pipeline, transportation tariffs effective 1 January 2017.

Depending on the location of the gas there may be no impacts of this type of transaction on pipeline owners.

Time swaps were entered into during the lead up to the commissioning of the Curtis Island LNG plants. This could be achieved where a domestic gas user had a need for gas prior to the commissioning of an LNG plant and the LNG project had surplus gas that was being produced as coal seam gas wells were being brought into production (referred to as ramp gas). The LNG project supplied the ramp gas to the domestic gas user. After the LNG project was commissioned the domestic gas user supplied gas back to the LNG project.

Location swaps allow Party A that has gas available at Wallumbilla, as an example, but requires gas at Moomba to swap gas with Party B that has gas available at Moomba but requires gas at Wallumbilla. Based on recent media reports this is the basis of the recent swap agreement between Santos[122] and Shell.

The implication for a pipeline of a transaction of this structure, in this example the South West Queensland Pipeline, is that Party B does not need to enter into a transport agreement on the pipeline for an Eastern Haul service and Party A does not need to enter into a transport agreement for Western Haul on the South West Queensland Pipeline.

A driver for location swaps is therefore to avoid paying transportation charges and minimise the cost of delivering gas to customers, or getting around fully contracted pipeline arrangements.

Feedback from shippers that were consulted was that the use of location swaps is increasing, however a lack of transparent information concerning gas flows makes it difficult to translate information concerning production from a production facility into information about where that gas is being shipped. It was suggested (hoped) that upcoming changes to the Gas Bulletin Board may improve the availability of information to assist with this type of analysis by market participants.

In Oakley Greenwood's consultations one shipper stated that transitioning to compulsory trading of gas through Gas Hubs would be beneficial as in that companies experience when supply is tight the level of transparency is reduced as producers offer less gas through the Gas Supply Hubs and rely on bi-lateral trading with offers being confidential. An implication of the convergence of gas and electricity markets is that more experienced traders from the electricity sector are now involved in the gas market and it is noticeable that the influx of skills has had an impact on the trading of gas.

122 Santos facilitates delivery of gas into southern domestic market, Santos media release, 30 Aug 2017.

5.5 Cost comparison between transmission and distribution pipelines

5.5.1 Transmission pipelines and distribution networks compared

While transmission pipelines and gas distribution networks perform similar functions in that they transport gas, the two types of infrastructure have quite different characteristics which impact on the cost of construction, operation and expansion. Transmission pipelines are typically very high pressure rated and approved pipes, where-as distribution networks can include both low and medium to high-pressure pipes. Medium to high pressure pipes within distribution networks transport gas from transmission pipelines to areas of the distribution network where it is then delivered to customers in low pressure pipes. Table 33 compares the characteristics of transmission pipelines and the pipelines of distribution networks.

Table 33: Characteristics of transmission pipelines and distribution networks

Characteristic	Transmission Pipeline	Distribution Network
Operating Pressure	High	Medium or Low
Construction material	High Grade Steel	Steel, Cast iron, nylon, polyethylene
Environment	Rural Easements	Urban Easements
Compression facilities	Yes	No
Risk profile	Low	High[123]
Connection points	High capital cost. Small number, gas fields, large customers e.g. power stations and networks	Low capital cost. Many, industrial, commercial and residential properties

123 This is largely due to the potential for third party interference causing damage

5.5.2 Operating cost comparison

Table 34 includes operating cost information and technical information for the Roma to Brisbane Pipeline[124] in 2012/13 and the Victorian Transmission System forecast in 2012[125].

Table 34 Roma to Brisbane Pipeline operating costs

Company	Roma to Brisbane Pipeline	Victorian Transmission System
Operating Expenses ($m)	$13.4	$30.5
Gas Throughput (TJ)	61,100	239,075
Length of pipeline (km)[126]	975	1,990

The operating cost per unit of gas delivered is a metric that was used in a report[127] prepared by Economic Insights on the efficiency performance of the three Victorian gas distribution businesses – AusNet Services, Multinet Gas and Australian Gas Networks' (formerly Envestra) Victorian operations, that was prepared in preparation for their access arrangement processes.

Table 35 compares the operating cost per terajoule of gas delivered on the Roma to Brisbane Pipeline in 2012/13, and the 2012 Victorian Transmission System forecast operating cost per terajoule[128], to the operating cost per terajoule of gas delivered included in the Economic Insights report. These operating costs per terajoule were based on average operating costs and deliveries for the period 2011 to 2015.

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124 2017-2022 Roma to Brisbane Pipeline Access Arrangement revision submission, APA Group, pages 27 and 173.

125 APA GasNet – Access arrangement 2013-2017, 2 April 2012, Australian Energy Regulator.

126 The Roma to Brisbane Pipeline is typically described as being 440 km long. This is the length of the pipeline route from Wallumbilla to Gibson Island in Brisbane. The distance quoted above is the length of the original pipeline, the loop and the Peat/Scotia lateral.

127 Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs using Partial Productivity Indicators, Economic Insights, June 2016.

128 APA GasNet 2013-2017 Victorian Transmission System Access Arrangement Information, November 2013.

Table 35: Transmission pipeline and distribution network costs

Company	Throughput (TJ)	Operating cost ($/TJ)	Length of pipe (km)	Operating Cost ($/km)
Roma to Brisbane Pipeline	61,100	219	995	13,814
Victorian Transmission System	239,075	121	1,990	15,344
Envestra Victoria	55,608	999	10,618	5,171
Envestra Queensland	5,996	3,568	2,591	8,532
Envestra South Australia	22,055	2,125	8,043	6,371
Allgas	10,216	1,695	3,189	5,547
Multinet	58,233	1,080	10,141	6,043

Of the metrics presented above it is Operating Cost/Terajoule of gas delivered that is the most instructive. Even though the Envestra Victoria and Multinet distribution networks deliver similar volumes of gas to that delivered on the Roma to Brisbane Pipeline the costs per Terajoule delivered on the networks are approximately five times that of the Roma to Brisbane Pipeline. The economies of scale on transmission pipelines compared to distribution networks are reflected in the high multiples of the network operating costs per Terajoule compared to transmission pipelines.

The differences between distribution networks and transmission pipelines are significant and as such comparisons between the costs of the two types of infrastructure are not informative.

Residential Price Trends

6 Introduction

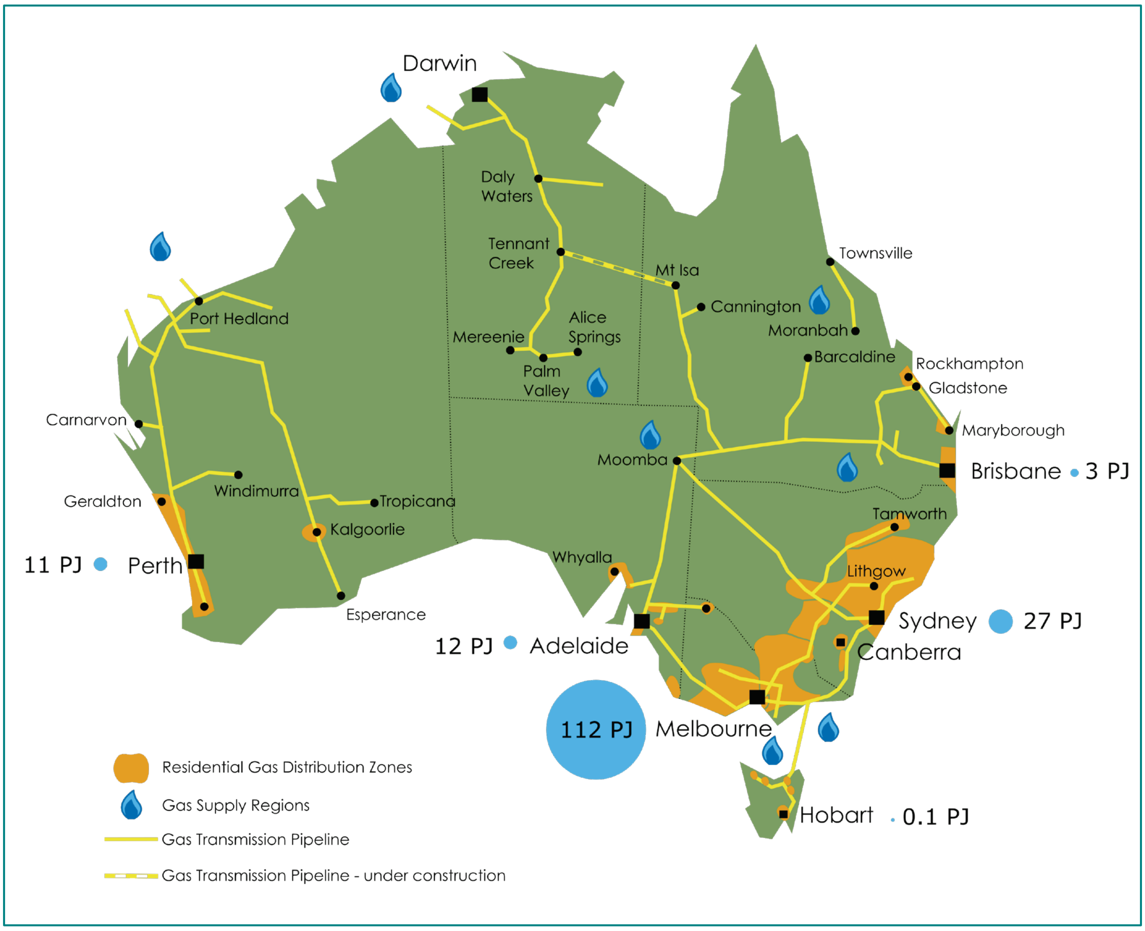
The total Australian residential gas consumption was approximately 171 Petajoules (PJ) in 2017 with a majority of the consumption in the states of NSW and Victoria. Victoria has the highest residential gas consumption of 112 PJ which dominates at 65% of the overall national consumption. Residential gas consumption is approximately 11% of the national's total gas consumption.

The residential gas pricing is dependent on the four major cost components of the gas supply chain –

- Wholesale gas,
- Transmission pipelines,
- Distribution networks and
- Retailers.

Wholesale gas fields tend to be located some distance from residential customers requiring the gas to be transported via transmission pipelines where it is reduced in pressure to be distributed by the gas distribution network to residences and commercial properties in the towns and cities. Licenced retailers bundle these components in the supply chain to sell gas to residential customers using market or standing offers.

Figure 108 Map of the gas transmission and gas distribution areas and retail demand in Australia



7 Key factors influencing residential gas prices

The residential gas prices are broken into the following components:

- Wholesale gas costs - the wholesale cost of gas supplied from a gas field
- Transmission pipeline costs - charges to transport of gas from gas fields to the distribution network
- Distribution network costs – charges to supply gas to homes and businesses through a distribution network.
- Environmental Policy costs - this covers the Clean Energy Act (carbon pricing – now withdrawn) and any energy efficiency schemes. The only energy efficient scheme that has direct impact on gas pricing is the VEET scheme. The NSW Energy Savings Scheme (ESS) introduced gas as an eligible source in 2016 for creation of Energy Saving Certificates (ESC) but no ESCs were recorded at the time of writing the report.
- Retail costs - the direct costs and margins for retailers to supply customers

There are a number of overriding factors that have impacted residential gas consumption and costs to consumers which are markedly different to factors which impacted industrial gas prices. Some of these factors are unique to the gas industry and some are similar trends observed in the residential electricity sector.

The key drivers which impacted residential gas markets in Australia included:

- Distribution charges and recovery of long run marginal costs
- Declining average household gas consumption
- Wholesale gas price escalation
- Retailer costs
- Pricing and tariff structures
- Carbon pricing

These key drivers are discussed in Section 7.2.

7.1 Retail price regulation

Only two states currently retain regulation of residential retail gas prices in some form.

NSW has both standing offers, where gas prices are regulated by that state's Independent Pricing and Regulatory Tribunal (IPART), and unregulated market offers. Standing offers are the default for customers who have not moved to a market offer or are on a network where there is no retail competition. According to IPART, 18% of NSW customers are on standing offers[129].

In WA the WA Government regulates gas prices to small users and, under the Energy Coordination (Gas Tariffs) Regulations 2000, sets gas price caps each year. All retailers must offer a standard contract at these rates and they have the option to offer rates (discounts) below the regulated price caps. Retailers may charge additional fees (for example market fees) other than the tariff caps and these are not regulated by the WA Government.[130]

7.2 Key drivers

7.2.1 Distribution charges

Distribution charges represent the largest component of the typical residential gas bill in most states (the national average is 35%). The main driver of distribution charges is the cost of installing and maintaining the network of pipes and connections. Distribution networks seek to recover these costs through the use of two-part tariffs with a variable component, which charges per MJ of gas consumed, and a fixed component. These tariffs are charged by distribution networks to retailers, who pass them through to residential customers and the structure of distribution charges usually determines a retailer's pricing structure.

Distribution networks rely on economies of scale and volume throughput to minimise prices and make gas use attractive. This is a function of the number of customers connected to a network and the consumption of each customer.

Economies of scale are a function of:

- Penetration rates – the percentage of customers that are eligible to connect to a gas network that have connected; and
- Density of connections - in terms of the number of customers connected per length of network – often this is affected by things like size of house blocks and number of units with gas connected - making construction costs more efficient.

However, the average volume consumed by each household can have a dominant effect as high average household consumption means higher asset utilisation and lower average costs per unit of gas throughput.

High fixed or sunk asset businesses like gas distribution are more return on capital (WACC, depreciation) driven (fixed costs) than throughput driven (variable or operational costs) and pricing that relies heavily on throughput returns does give rise to revenue recovery risks.

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129 AER Industry Statistics NSW small contracts.

130 Retail Energy Market Company, 2015, *Fees and Revenue*, Retail Energy Market Company fees and revenue web page.

Higher fixed components of pricing are more cost reflective of the higher capital proportion of distribution networks as we see in transmission pricing as an example.

In Australia though, for gas distribution, throughput volumes of gas are the main method of recovering the capital invested. Revenue recovery is generally through variable charges (¢/MJ) and, to a lesser extent, using the fixed charges.

As a result, the higher the consumption of a household and higher number of connections, the lower the cost is per unit of gas consumed.

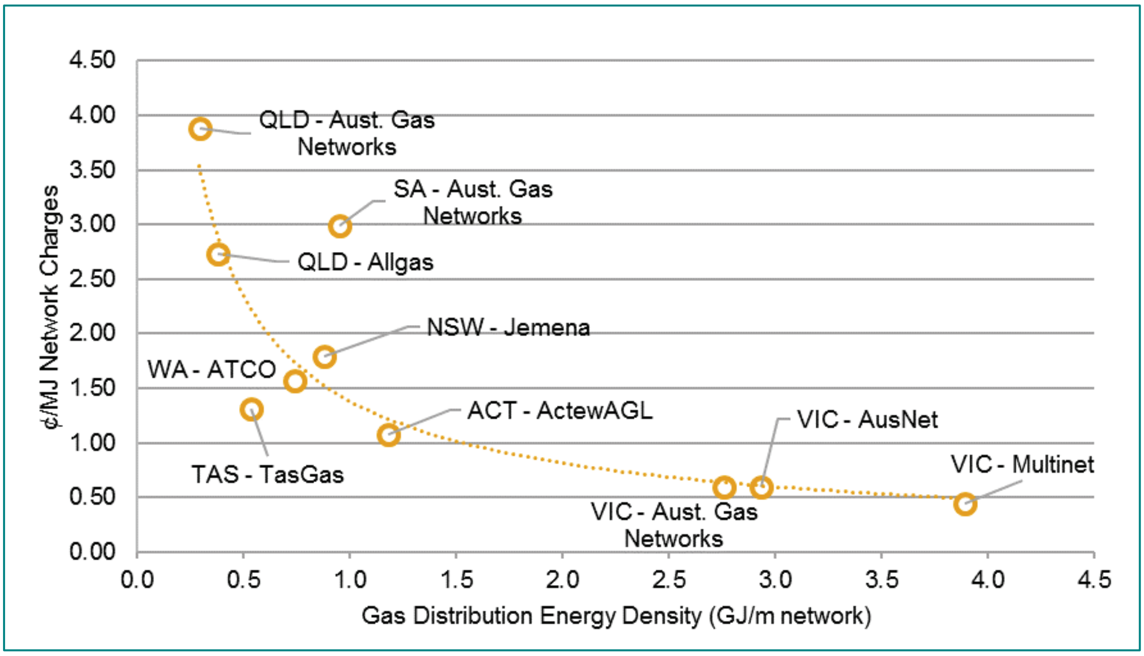
Figure 109 shows the impact of low and high-density throughput of energy per metre of installed distribution network for Australia's largest distribution networks. In essence, the average marginal cost required to serve a customer is unlikely to be materially different between distribution networks (regardless of jurisdiction), therefore those customers that have much greater consumption of gas (i.e. Victoria) are paying much less per unit of gas for the distribution network's largely fixed costs. This represents the value of economies of scale and high average household consumption within a distribution network.

Figure 109 also highlights the point of diminishing returns where increasing the number of connections or gas use per connection would not provide a material decrease to the cost to consumers.

For example, for the period 2013/2014, in Queensland the penetration rate of gas to households is 10% and average household consumption is low at 11.4 GJ/a. As a result, the two Queensland networks (Allgas and Australian Gas Networks) have high gas distribution charges (the Qld average in 2017 is 3.78 ¢/MJ) which is reflected in the gas price of consumers.

Compare this to Victoria which has a household gas connection penetration rate of 80% and high average household consumption (50.1 GJ/a) resulting in relatively high throughput of gas per metre of installed gas distribution network. In this case distributors Multinet, Ausnet and Australian Gas Networks offer the most competitive network charges (in the Victorian average in 2017 is 0.62 ¢/MJ) out of all jurisdictions.

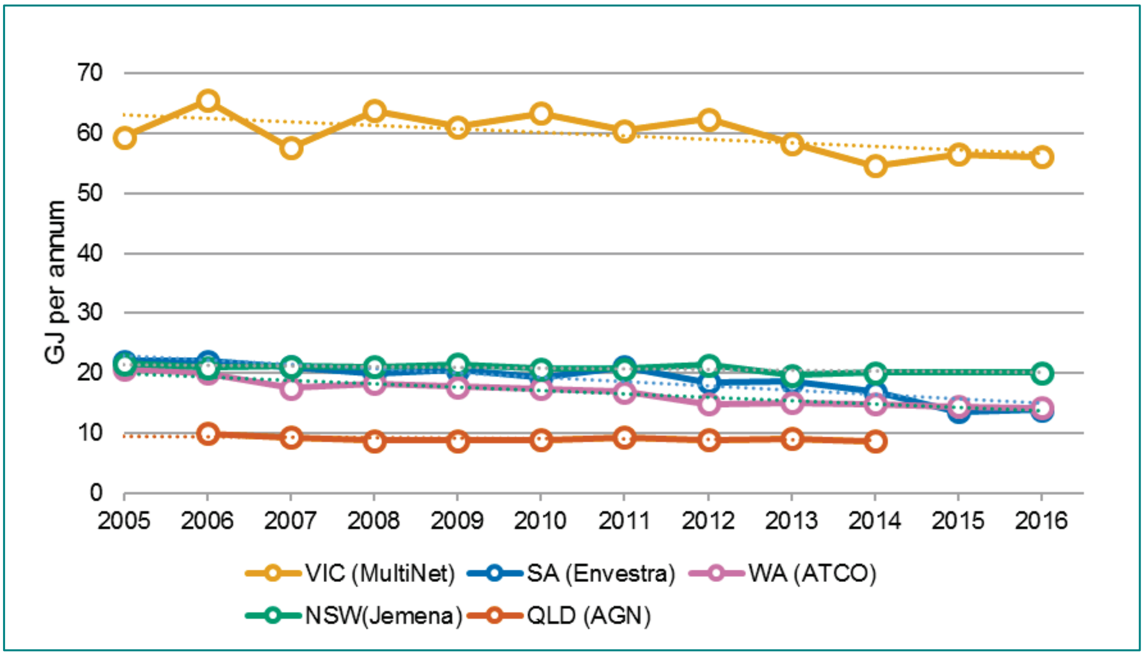
Figure 109 2013/2014 Benchmark network charges (¢/MJ) vs. distribution energy density (GJ/m network)



7.2.2 Declining average consumption

There is a general trend across all jurisdictions of declining average household consumption as shown in Figure 110. This is despite an increase in the number of residential connections in most jurisdictions in the past decade.

Figure 110 Typical consumption trends of average household gas use.



Decreases in average household consumption can be due to a combination of several factors in each jurisdiction and one may contribute more than others. For example, in Victoria the average consumption has been trending with milder weather and therefore less demand for gas for heating. The decline in consumption could also be driven at the margins by households switching to another fuel or simply conserving their gas use to reduce energy bills.

Factors which have influenced average consumption include:

- Gas appliance efficiency – and to some degree technology developments with competing electric appliances e.g. induction cooktops.
- Household conservation – being more conservative with heating appliances to save money.
- Socio-demographic changes – reduced number of persons per household.
- Fuel substitution – increasing penetration of competitively priced reverse cycle air conditioning, especially for households that have solar PV fitted as the marginal cost often for use of reverse cycle air conditioning heating is zero or at least very low during the day, or
- The potential for wood use in Tasmania (and even around Canberra, and other rural areas). However, the smoke and emissions will contribute to air pollution.
- More energy efficient building construction – better insulating properties of construction materials, designing for "green" building ratings and reduced energy reliance.
- Federal or state government energy policies – for example the Small Scale Renewable Energy Scheme (SRES), eligibility for solar hot water/heat pump installations incentivising alternative water heating substitutes.

7.2.3 Wholesale gas price

In the residential sector, wholesale gas prices have typically accounted for about 10-15% of the retail price of gas but this has increased significantly in the last 2 years (33% is the national average). As a result, the wholesale gas price has become more of a driver in the residential market, but the impacts of retail and network costs components still remain a substantial portion of residential customers' bills. These are significant issues for prospective new entrants in retail gas markets to consider and hence a factor in competitive gas supply to customers.

The viability of entry into retail gas markets depends on access to wholesale gas supply at a reasonably competitive price. Where an incumbent retailer has access to low wholesale gas prices, it may compete on better terms than a new entrant that is unable to secure access to low wholesale gas prices. Alternatively, they may elect to take a greater retail margin and use this margin to market more effectively for new customers.

There are retailers with access to low priced gas under legacy gas contract arrangements that can use this marginal advantage at times. Many are facing the end of their gas contracts and need to renegotiate gas prices in an escalating market – so this is partly a market timing issue.

It should be noted that, in the absence of information on each retailer's gas portfolio, the wholesale cost identified for large industrial customers is assumed to be the wholesale gas component of the residential price. This is discussed further in section B.1.3.1 of the residential methodology.

7.2.4 Retail cost component and role of the retailer

Traditionally, retailers buy gas in wholesale markets and package it with transportation services for sale to customers under a retail contract. The customer pays charges based on the rates set out in the contract and is not exposed to the short-term movements in the wholesale market prices. Retailers use a range of portfolio and hedging arrangements to manage risks of the price volatility in the wholesale market. In some states, retailers also arrange connections with distributors and participate in compulsory gas trading markets.

The retail cost component of a consumer's residential bill covers a retailer's operation and marketing costs and their profit margin. A retailer's profit margin depends on the retailer's ability to operate efficiently, the level of competition in the market and whether there is a regulated ceiling on the tariffs consumers can be charged.

For example, in WA's mid-west to south-west gas supply area the WA Government sets a tariff cap for small use customers. If new entrants in that market are unable to access wholesale gas at a price that enables them to sell gas below the retail tariff cap, they would not be competitive and, so it would be difficult to enter the market. Alinta is the dominant retailer in WA with potentially long-term legacy gas contracts that are lower-priced than the tariff price determination that would enable it to price at or below the tariff cap[131].

7.2.5 Pricing structures

As outlined, the standard pricing approach for gas retailers is to offer a two-part tariff with a fixed and variable component, which largely follows the tariff structure applied by gas distribution businesses. This is the standard approach for utilities across Australia, where the variable component is nominally set with reference to variable costs for the business while the fixed price is to ensure some level of revenue sufficiency for the business or recovery of nominal fixed costs.

The majority of gas retailers apply declining block tariffs for gas consumption. This means that a higher level of consumption will be charged at a lower price per MJ. In contrast, the water industry tends to apply an inclining block tariff where higher usage gets charged at a higher rate per kilolitre. The theory behind declining block tariffs includes:

- That the network has a declining marginal cost to supply over some average usage threshold and is therefore seeking to encourage higher consumption (in contrast to inclining block tariffs that are designed to encourage restricting excess consumption);

131 Parliamentary Inquiry – Domestic Gas Price, 29 June 2010, Government of WA, Office of Energy.

- That the marginal cost of gas must be competitive for energy use that can be easily transferred to electricity – mostly of concern are hot water and heating loads; and
- The bock structure means that smaller average gas use provides more of the revenue recovery as these customers may be less likely to move or transfer load at the margins to electricity the gas distributors revenue is far less effected overall.

The impact of providing more competitive gas supply at the margin is becoming an important, if not overriding, pricing signal for the supply industry as customers consider switching between electricity and gas consumption. An example is space heating where, if the consumer has a reverse cycle air conditioner and gas heating, switching costs then relate to the marginal cost of the fuel as there is no capital expenditure involved.

Victoria has an added complexity with its tariff structure with the use of seasonal-based pricing. Given the significant fluctuation in gas consumption between winter months and non-winter months in Victoria, the majority of Victorian retailers apply a peak price for usage in winter months (reflecting cost of supply dynamics) which lessens the competitiveness of gas at that time with electricity. Notably though, given the average household usage trends, some retailers have recently stopped this approach after one of the distribution networks stopped applying peak charges.

Several retailers offer a dual fuel account which provides gas and electricity accounts rolled into one and can allow the retailer to offer a better gas or electricity deal/price due to increased returns per customer. If a customer is on a dual fuel account, the impact of any subsequent fuel switching decision on the retailer is also lessened.

7.2.6 Environmental policies

The only remaining environmental policies which has a direct cost impost on gas tariffs for the review period is the energy efficiency policies of Victoria and NSW.

The Victorian Government introduced the Victorian Energy Efficiency Target (VEET) scheme in 2009 and it is legislated to continue in three-year phases until 2030. The scheme requires large energy retailers to surrender a specified number of certificates each year and is designed to reduce the greenhouse gas emissions across both the electricity and gas industry sectors. During the review period, the impact that this scheme has had on residential gas prices was minimal (less than 1 ¢/MJ).

The NSW Energy Savings Scheme (ESS), which is predominantly based on electrical energy efficiency, was amended to incorporate gas savings by providing methods for households and businesses to create Energy Savings Certificates for end-use gas efficiency from 15 April 2016. No uptake has been recorded in the 2016 calendar year.

8 Residential price history

This section discusses each jurisdiction's historical gas price trend, the market's structure, cost components of prices and future price drivers. All prices exclude GST unless otherwise stated.

8.1 Victoria

Figure 111 shows the breakdown of the average cost per MJ of gas residential prices for Victoria since 2011 (in real terms). It can be seen that the average price shows a steady increase year-on-year for the period, driven largely by the increasing retailer component and the wholesale gas component in the 2016-2017 time frame.

In 2017, the average gas price delivered to Victorian households was 2.35 ¢/MJ of which 0.58 ¢/MJ (25%) was the retailer component, 0.62 ¢/MJ (26%) was the distribution component, 1.00 ¢/MJ (43%) was the wholesale gas component, 0.15 ¢/MJ (6%) was the transmission component and less than 0.01 ¢/MJ) (<1%) was the environmental policy component. Fixed charges made up 0.42 ¢/MJ (21%) of the gas price and variable charges made up 1.60 ¢/MJ (79%)

Figure 111 Victorian average gas price components

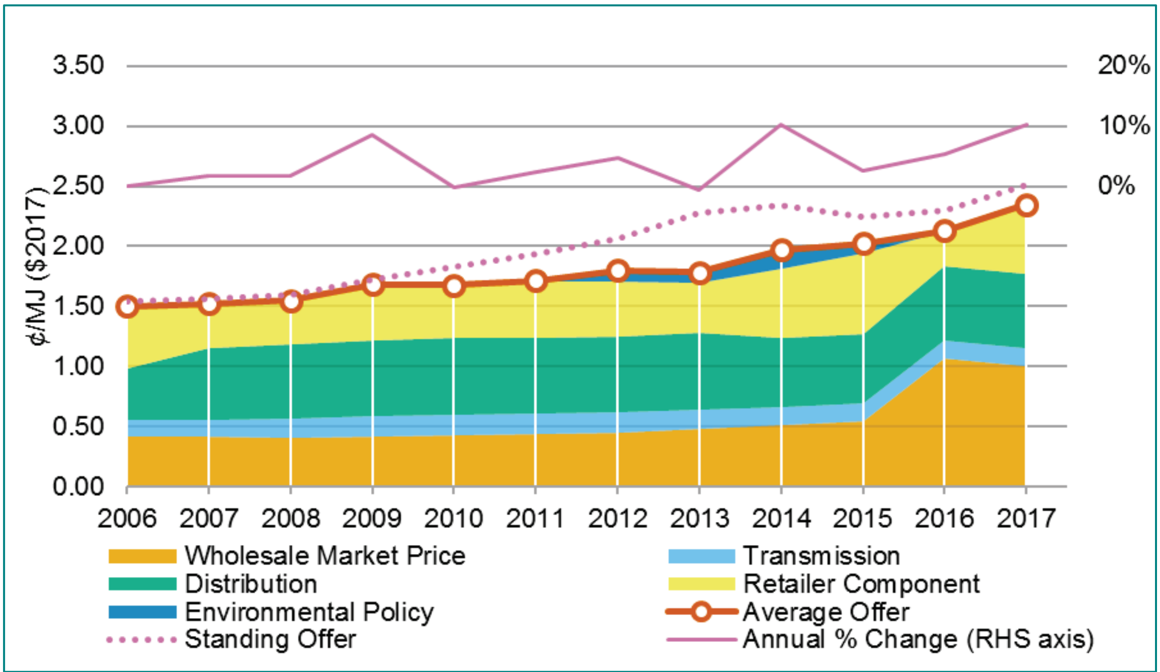


Figure 112 shows the proportions of the average retail price across the different components. It can be seen from this that while the wholesale gas price and transmission costs have remained at a relatively consistent proportion until 2015, the changes in wholesale percentage has increased by 83% on 2015 prices and is now a major contributor to retail gas prices. The distribution and retail proportions have fluctuated over the period (this is discussed Section 8.1.5).

Figure 112: Victorian average residential gas price components by %

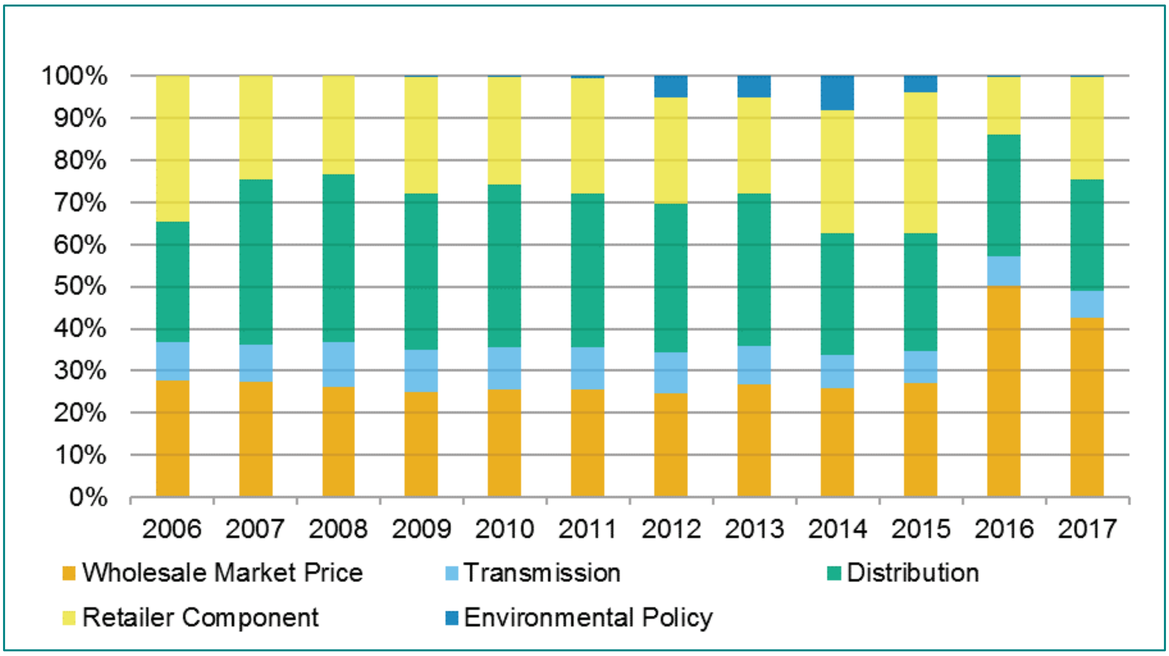


Figure 113, Figure 114, and Figure 115 show the difference between the average annual bill for standing offers and market offers for each of Victoria's three major distribution networks – AusNet Services, Australian Gas Networks and Multinet Gas - based on the average household consumption for that network. Between 2011 and 2017, each of the networks follow a similar pattern with small increases early in the period, followed by larger increases in the middle with a tailing off and reduction/flat lining in bills to 2016. The average offer price in 2017 has started to increase – presumably in response to upward pressure from wholesale gas costs to maintain retail margins.

The average cost per MJ is influenced by the average usage within the distribution zone. The Multinet distribution zone, which has the highest average household consumption, has the lowest average cost per MJ of the three distribution zones. This emphasises the benefits that economies of scale for large network capital costs can deliver to end customers through pricing.

Apart from the AusNet Services network area, the range in market offers does not provide a significant degree of variability in the average household bills. Even the AusNet Services variation in market offers is not that significant, with the variation being $69.10 in 2017 calendar.

Figure 113: Typical Household Gas Bill – AusNet Services, Vic

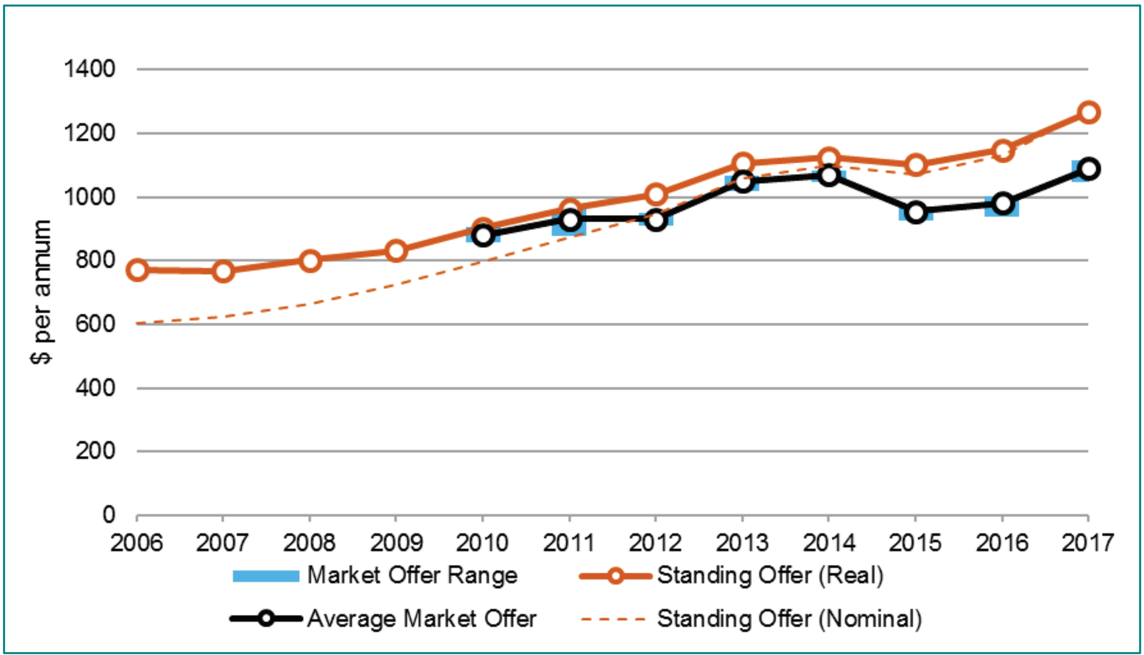


Figure 114: Typical Household Gas Bill ($2017) – Multinet, Vic

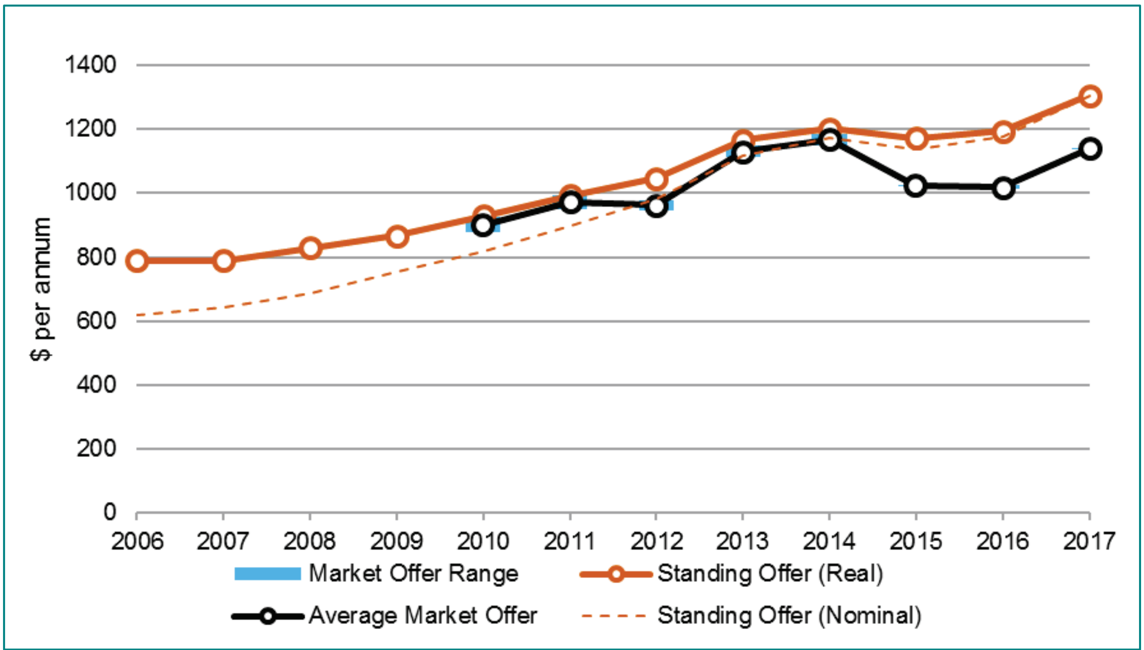
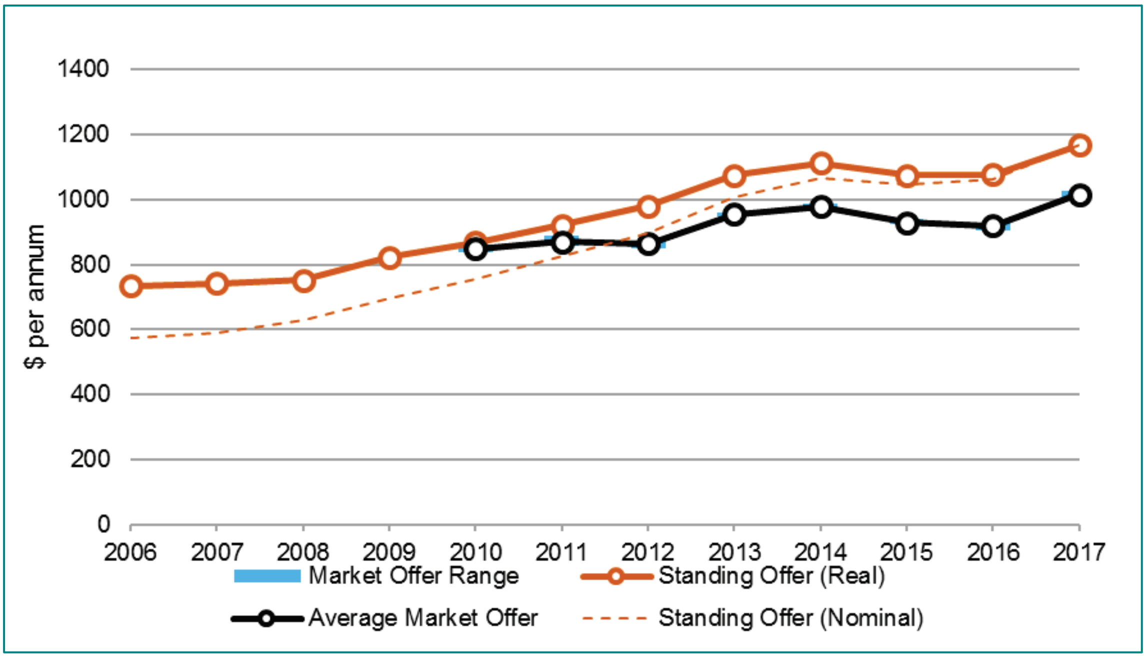


Figure 115: Typical Household Gas Bill ($2017) – Australian Gas Networks, Vic



8.1.1 Market overview

The majority of gas supplied to Victoria is processed at the Longford gas facility in the Gippsland Basin, with storage facilities that help meet demand during peak demand periods. The gas is transported through the Victorian Transmission System (VTS)[132] which is owned by GasNet and operated by the Australian Energy Market Operator (AEMO) under a market-based centrally coordinated carriage system. Further downstream there are three distribution businesses broken up into a number of smaller distribution zones. The distribution tariffs are based on these smaller distribution zones. The main distribution zones are:

- Australian Gas Networks (formerly Envestra): Central and North;
- Multinet: Main; and
- AusNet Services (formerly SP Ausnet): Central and West.

There are a number of smaller distribution zones that have their own distinct charges. However, these zones were disregarded from this analysis due to their small size (the largest of which has approximately 8,500 customers).[133]

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132 The VTS, sometimes known as the principal transmission system (PTS) or Gasnet, was constructed between 1969-2008. It consists of approximately 1,993 km of high pressure pipelines which transport gas from various supply points to load centres throughout Victoria.

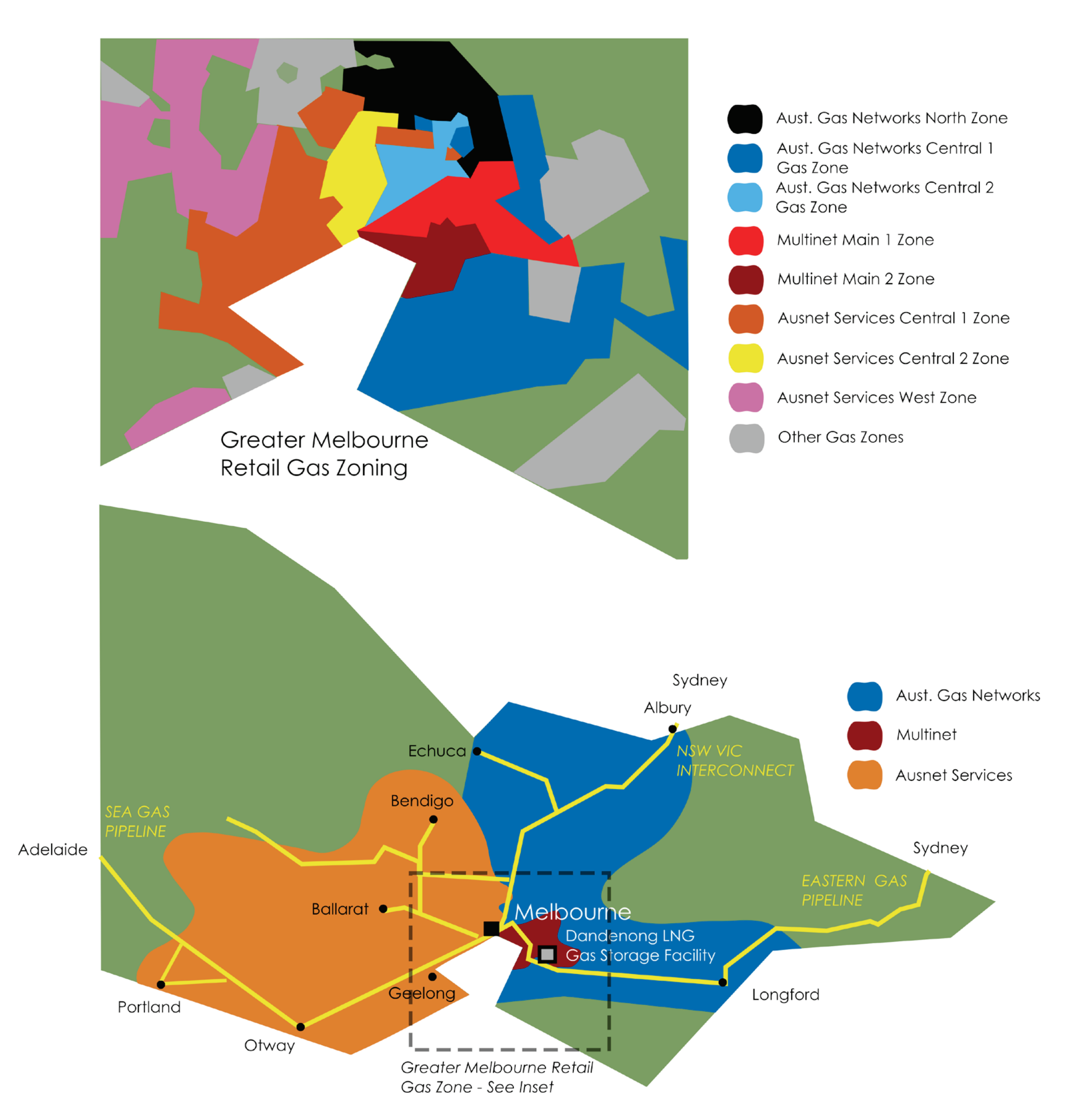
133 These zones include Australian Gas Networks Murray Valley, Australian Gas Networks Bairnsdale, Multinet Yarra Valley, Multinet South Gippsland, AusNet Services Adjoining Central and AusNet Services Adjoining West.

End customers are then charged based on retail franchise zones. These zones were established when the retail market was opened to contestability and they do not exactly line up with the physical distribution zones. The following retail zones align to the main distribution zones outlined above. Some of the naming conventions reflect the ownership structure at the time of deregulation and Envestra zones are part of the Australia Gas Networks distribution network.

- Envestra Central 1 (also referred to as Origin South-East);
- Envestra Central 2 (also referred to as TRU East);
- Envestra North (also referred to as Origin North);
- Multinet Main 1 (also referred to as Origin Metro);
- Multinet Main 2 (also referred to as AGL South);
- AusNet Services Central 1 (also referred to as TRU Central);
- AusNet Services Central 2 (also referred to as AGL North); and
- AusNet Services West (also referred to as TRU West).

Figure 116 shows the different zones. It should be noted that some retailers that have entered the market in recent years have begun charging on the distribution zones rather than the retail franchise zones.

Figure 116: Map of Victorian distribution networks



Victoria has extensive gas network coverage and the majority of households (including most of Melbourne) can connect to this network. Table 36 shows the proportion of Victorian households that are connected to natural gas distribution. It can be seen from this that Victoria has a very high penetration rate, increasing from 81% in 2005 to 83% in 2014. Breaking this down further, Melbourne had a penetration rate over 91% in 2014, while the remainder of Victoria was nearly 62%.

Table 36: Household gas penetration in Victoria (%)

	2005	2008	2011	2014
Penetration Rate	81.0	81.1	81.6	83.0

Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

Full retail competition was introduced to the Victorian gas industry in October 2002 and in January 2009 retail pricing was deregulated.

Victorian residential gas usage is the highest in Australia and there are a number of very active retailers fighting for market share:

- The incumbent retailers are AGL, EnergyAustralia (previously TRUenergy and TXU) and Origin Energy. These retailers procured retail franchise zones during the privatisation of the Victorian gas market (breakup of the Victorian Government owned Gas and Fuel Corporation monopoly) and saw the establishment of full retail contestability. They have remained the major retailers for the state.
- Since full retail contestability, a number of new retailers have entered the Victorian gas market, creating a range of consumer choice within the market.

Table 37 provides a list of the retailers operating in Victoria in 2016 and the percentage market share that each had at the time. The three incumbent retailers service nearly 69% of the residential gas customers in Victoria, a decline from over 77% in 2011-12.

Table 37 List of Victorian gas retailers and proportion of market share in 2016.

Retailer	Residential customers	Market Share (%)
AGL	517,856	27
Origin Energy	378,709	20
EnergyAustralia	420.435	22
Red Energy	140,748	7
Simply Energy	160,001	8
Lumo Energy	153,426	8
Alinta Energy	42,187	2
Momentum	20,726	1
M2 Energy	38,601	2
Click Energy	12,114	1
Total	1,884,803	100

Source: Essential Services Commission, 2016, Victorian Energy Market Report 2015-16, November 2016.

8.1.2 Regulatory environment

The prices for standing offer contracts and market offer contracts are determined by the retailer and monitored by the Essential Services Commission of Victoria (ESCV).

Both the distribution and transmission components are regulated by the Australian Energy Regulator (AER), and the VTS acts as the basis for a market carriage model for transport and gas settlements.[134]

8.1.3 Victorian seasonal tariffs

Unlike other state jurisdictions Victoria has a seasonal pricing structure, fundamentally a peak/off-peak season approach, with the peak based on the winter months of June to September.

This is effectively driven by the distribution network tariff structure and is passed on to end customers by the retailers. While the peak period is reasonably consistent across distributors, Multinet applies “Shoulder Period” charges which effectively extend the peak period to 6 months (although with a slightly lower charge for the shoulder period than the peak 4-month period).

Australian Gas Networks stopped applying the seasonal pricing structure from 2013 and this has flowed through to some of the retail offers, however the majority of retailers still apply a peak/off-peak tariff structure in these distribution zones.

The theory behind applying a seasonal peak tariff structure can be driven by two factors: it is more cost reflective given the increased capacity required to service the higher consumption during peak periods, or a Ramsey pricing approach whereby prices are higher during times when customers’ gas consumption is more inelastic. Notwithstanding this, with the increased use of electricity for heating, networks need to be conscious of the threat of fuel switching if they miscalculate the elasticity of their customers during those peak times (and as seen in average household consumption trends) - this could for example be a factor behind Australian Gas Networks’ (Envestra) decision to discontinue its seasonal-based charging.

Given the significant usage of gas during the peak periods the load profile has been adjusted accordingly. Based on information in a report undertaken by the Energy Rating Program’s Residential Energy Metering Program, 65% of the average annual usage has been applied to the peak period for those zones that have a 4-month peak period and 85% of the average annual usage for those zones that have a 6-month peak period (including shoulder periods).[135]

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134 For the market carriage model adopted for the Victorian gas network, large end users secure rights to pipeline capacity and these rights are tradable. If an end user has surplus capacity, this surplus can be sold, or alternatively end users with insufficient capacity can purchase their additional capacity requirements through a daily capacity ‘auction’ operated by AEMO.

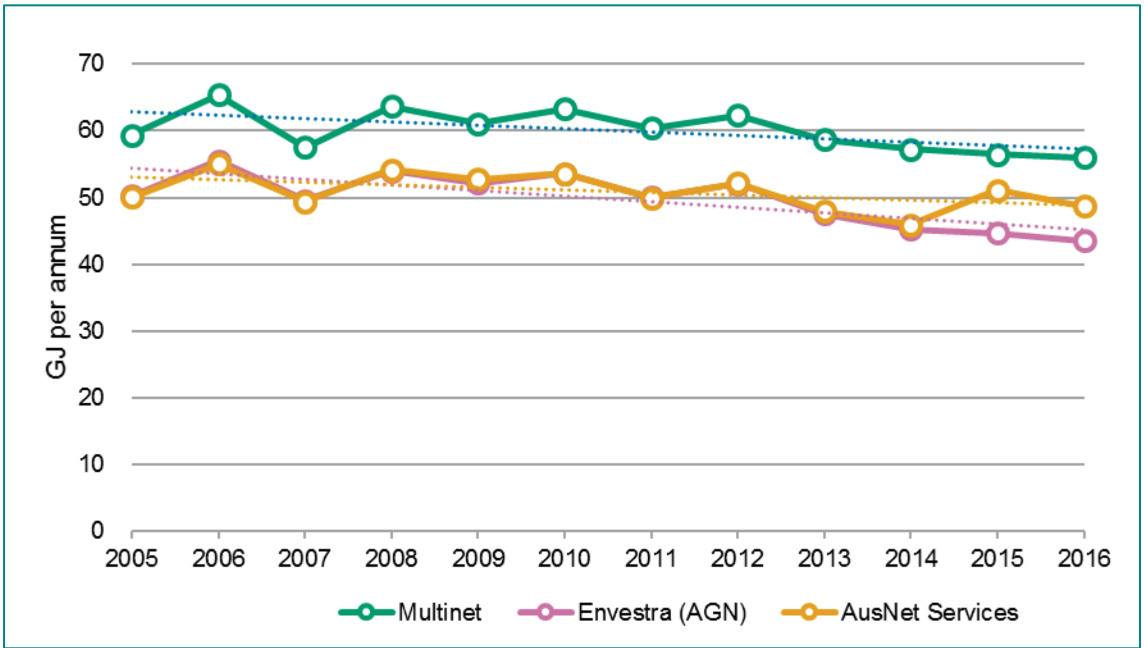
135 Proof of Concept Residential Energy Monitoring Program – Final Report, March 2012.

8.1.4 Victorian household consumption

As discussed, Victoria has a relatively high level of average household gas consumption compared to the other jurisdictions. This is predominantly due to the winter weather conditions in Victoria with the widespread use of natural gas for space heating, particularly ducted heating systems. The average household consumption each year is heavily dependent on how cold the winter has been with much higher usage in a severe year than a mild winter.

Figure 117 shows the average household consumption Victoria from 2011 to 2017. The average household consumption shows a long term declining trend.

Figure 117: Victorian average household gas consumption levels



Source: Information provided by businesses and AER

It can be seen in Figure 118 that Victorian residential gas usage is closely tied to weather conditions, where changes in the average household gas consumption peaks and troughs closely align with changes in the Effective Degree Days (EDD) measurement each year. The data has been adjusted from the 2015 Gas Price Trends Report to correlate with the aggregate EDD for the winter period 1 June to 30 September. While there has been a general trending down in EDDs to 2014 indicating warmer winters, 2015 shows a major correction correlating to the coldest winter experienced by Victoria in 26 years[136]. This seems to indicate that the average consumption no longer has a good correlation with EDD variation (EDD is explained in the Glossary) – this is contrary to the analysis of the 2015 Gas Price Trends Report and could indicate much higher household elasticity now to gas prices, explored in section 8.1.6.

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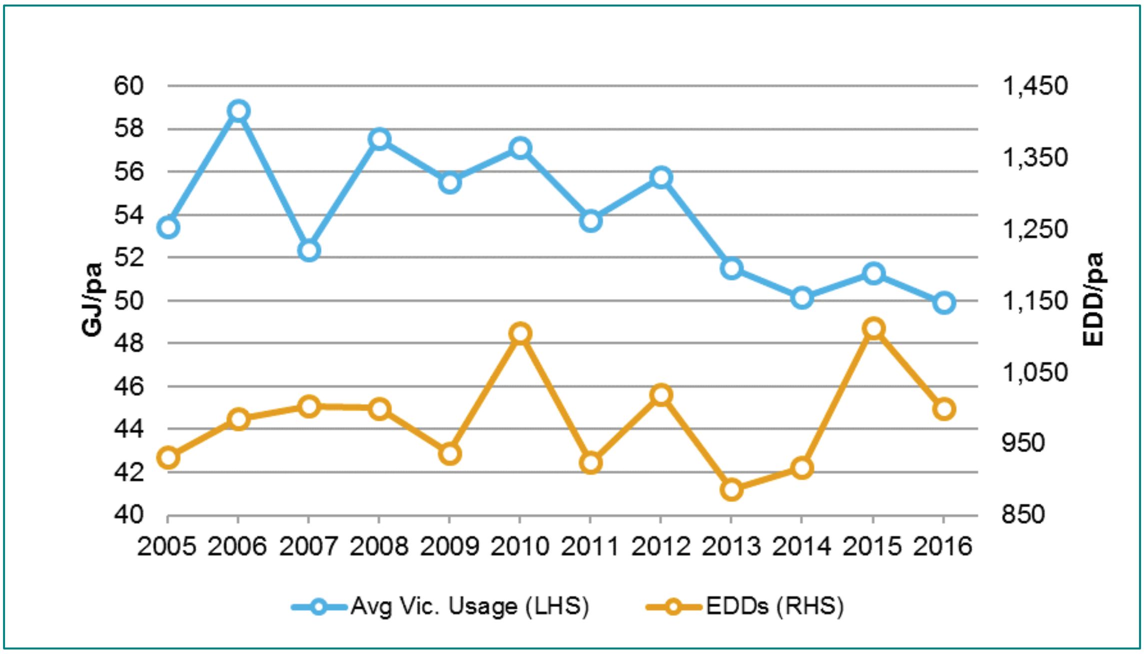
136 AEMO, 2016 Victorian Gas Planning Report.

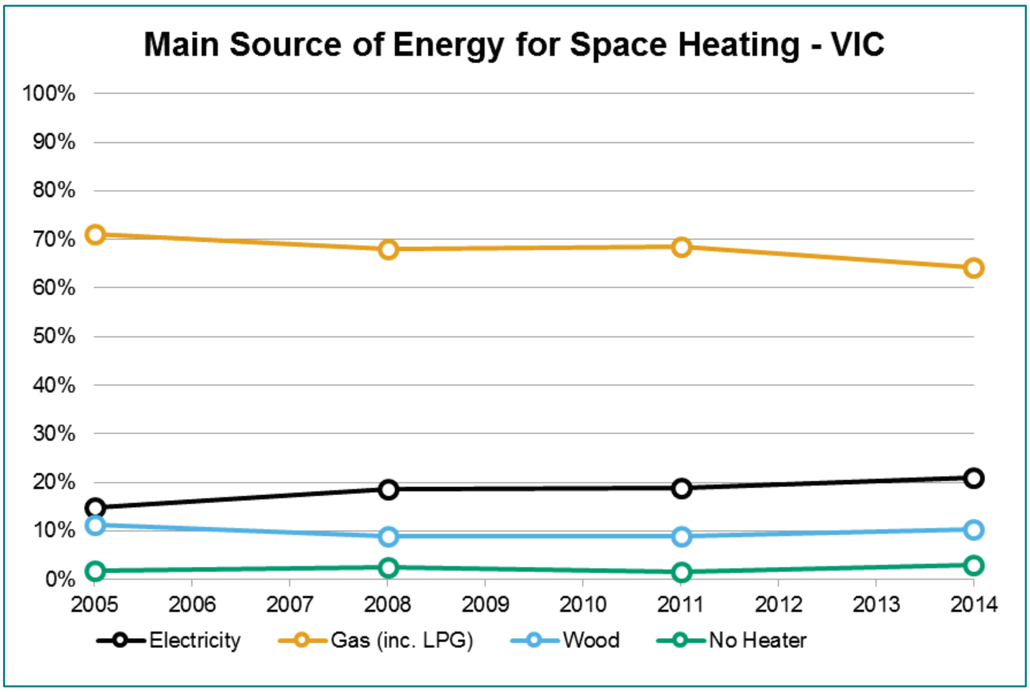
Figure 118: Average Victorian average household consumption and effective degree days (EDDs)



Source: Information provided by businesses; AEMO, EDD Historical data and Victorian Gas Planning Reports.

In contrast, Figure 119 shows the main fuel sources for household space heating across Victoria from 2005 to 2014[137]. This indicates that the percentage of households using gas as the main fuel source for space heating has declined slightly while electricity has increased.

Figure 119: Main source of space heating for Victorian households



137 2014 is the last update by ABS Energy Use and Conservation Statistics.

Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

Table 38 shows that the proportion of households that have reverse-cycle air-conditioning has increased from 36% in 2005 to 48% in 2014. This increasing penetration of reverse-cycle air-conditioning provides households with an easier switch away from gas to electricity for their space heating. This may provide some support to why the consumption per household didn't see a high increase correlating to the high EDD in 2015 which was the coldest winter period in 26 years. Refer Figure 118.

Table 38: Proportion of Victorian households that have reverse-cycle air-conditioning as their choice of cooling (%)

	2005	2008	2011	2014
Reverse-cycle air-conditioning cooling	36.3	41.9	43.7	48.0

Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

8.1.5 Victorian gas price components and trends

Victoria's average retail gas price of 2.35 ¢/MJ in 2017 is lowest of Australia's states and territories and it had the lowest distribution (0.62 ¢/MJ), despite wholesale gas almost doubling to (1.00 ¢/MJ) and transmission (0.15 ¢/MJ) cost components. The retail gas price has increased 26% in real terms from 2006 to 2017 and a 16% change from the previous Gas Price Trends Review 2015. Wholesale costs are now the major contributor at 43% of the 2017 average offer with distribution costs forming 26% and retail costs at 25% making up the remainder.

The retailer component of the average standing offer price in Victoria has shown a reduction in the retailer component from the Gas Price Trends Review 2015 from 32% to 25%.

Victorian energy efficient target (VEET)

The VEET scheme started in 2009 as a market-based approach to encourage energy efficiency in households and workplaces throughout Victoria. The scheme operates through earning Victorian Energy Efficiency certificates when eligible energy efficiency measures are implemented. Every certificate represents one tonne of carbon emissions saved over the lifetime of the measure.

These certificates can then be sold to energy retailers who are required to meet an emission savings target each year. These certificates are subsequently traded on a market to allow the development of a market-based value.

The energy retailers' costs of either undertaking the energy efficiency activity or purchasing certificates to meet their required target each year is passed on to customers through the retail price.

In determining the cost of meeting these targets for the gas retailers, the value of the traded certificates has been used. It is assumed that a retailer would not undertake an energy efficiency (gas-related) activity[138] to meet its target that cost more than the value of the certificates in the market. Therefore, the use of the certificates to quantify the cost of the scheme would be a conservative approach and represent an estimate at the upper bounds of the likely cost of the scheme on customers.

The estimated impact on retail gas bills is minor with a maximum impact of 0.01 ¢/MJ in 2012 and a 0.003 ¢/MJ impact in 2017. The estimated impact on customer bills is mainly influenced by the traded price of the certificates which peaked in 2012 with an average of $23.04 and a price of approximately $11 in 2017.

8.1.6 Further developments

In the Gas Price Trends Review 2015, it was identified that the retailer percentage component for Victoria was one of the highest despite having a deregulated and “competitive” market. This finding is consistent with a review undertaken by the Essential Services Commission of Victoria into retailer margins in Victoria’s electricity market. This review found that, since deregulation of electricity prices in 2009, the retailer component built into those tariffs appear to have increased considerably, even despite active competition - although as noted earlier, 72% of the market is still held by the original incumbents.[139]

The high retailer component could be due to the high concentration of the market between a few retailers or that these dominant retailers may well be more concerned about maintaining retail margins than which fuel the customer uses and not incentivised to offer discounts to maintain customer numbers.

While not a focus of the analysis in this report, customer switching between gas and electricity may well be less of a driver in the Victorian market than profit margins. It is also possible customer switching is aligned to the high average gas use, and corresponding relatively low electricity use in the Victorian market in some way, or the relatively low domestic gas price in Victoria and likely elasticity from pushing prices up toward other states.

The increase in wholesale price component over the last two years, which has been the largest change in a price component in Victoria, will make it harder for new entrants to enter the market when large incumbents and other competitors are likely to have existing legacy contracts at lower wholesale cost.

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138 Gas-related energy efficiency activities include decommissioning electric hot water and installing gas hot water, installing high efficiency ducted gas space heating, replacement of gas heating ducts, etc.

139 Essential Services Commission 2013, Retailer Margins in Victoria’s Electricity Market – Discussion Paper, May, p. 14. And “*If the retail energy market is competitive then is Lara Bingle a Russian cosmonaut*?” Dr Ron Ben-David, Chairperson, Essential Services Commission, June 2015

In November 2016, the Victorian Government announced an independent bi-partisan review of Victoria's electricity and gas retail markets[140]. The review examined the operation of the Victorian electricity and gas retail markets and provided options to improve outcomes for consumers. The final report was delivered to the Victorian Government in August 2017. While heavily focussed on the electricity retailers, the review found that there is no constant trend to explain the increase in retail prices given the trends of wholesale, transmission, distribution and environmental costs. The key recommendations were to:

- Abolish the requirement for retailers to offer standing offer contracts;
- Require retailers to provide a Basic Service Offer that is not greater than a regulated price determined by the ESC;
- Market information on prices to be easily comparable and contracts are clear and fair;
- Promoting access to smart meter data to assist customers to manage bills and increase energy efficiency;
- Protect low income and vulnerable customers, including brokerage and group purchasing;
- The ESC to monitor and report on the competitiveness and efficiency of the Victorian retail energy market;
- The ESC to review regulatory codes to focus on customer outcomes;
- Expansion of the powers of the Energy Water Ombudsman Victoria to cover emerging energy business, products and services; and
- Request the COAG Energy Council to review the energy market to deliver long-term interests to consumers.

8.2 Tasmania

The gas retail prices shown in Figure 120 range from 2006 to 2017 and show a steady increase in delivered prices. The average retail gas price in Tasmania increased by almost 1.5 ¢/MJ between 2011 and 2017, an increase of 60%.

In 2017, the average gas price delivered to Tasmanian households was 3.91 ¢/MJ, of which 1.91 ¢/MJ (49%) was the distribution component, 0.47 ¢/MJ (12%) was the retailer component, 1.00 ¢/MJ (26%) was the wholesale gas component and 0.53 ¢/MJ (14%) was the transmission component. There was no environmental policy component.

The share of fixed and variable tariff components of the average gas price is calculated in Table 39 Fixed and variable tariff components ($2017) based on average market offers. Of

140 Independent Review into the Electricity & Gas Retail Markets in Victoria Final Report, August 2017.

the 2017 average market offer delivered gas price, fixed charges made up 0.59 ¢/MJ (15%) and variable charges made up 3.32 ¢/MJ (85 %).

Table 39 Fixed and variable tariff components ($2017) based on average market offers

	Equivalent ¢/MJ	% of total
Fixed	0.59	15
Variable	3.32	85
Total	3.91	100

Figure 120 Tasmania residential gas price components

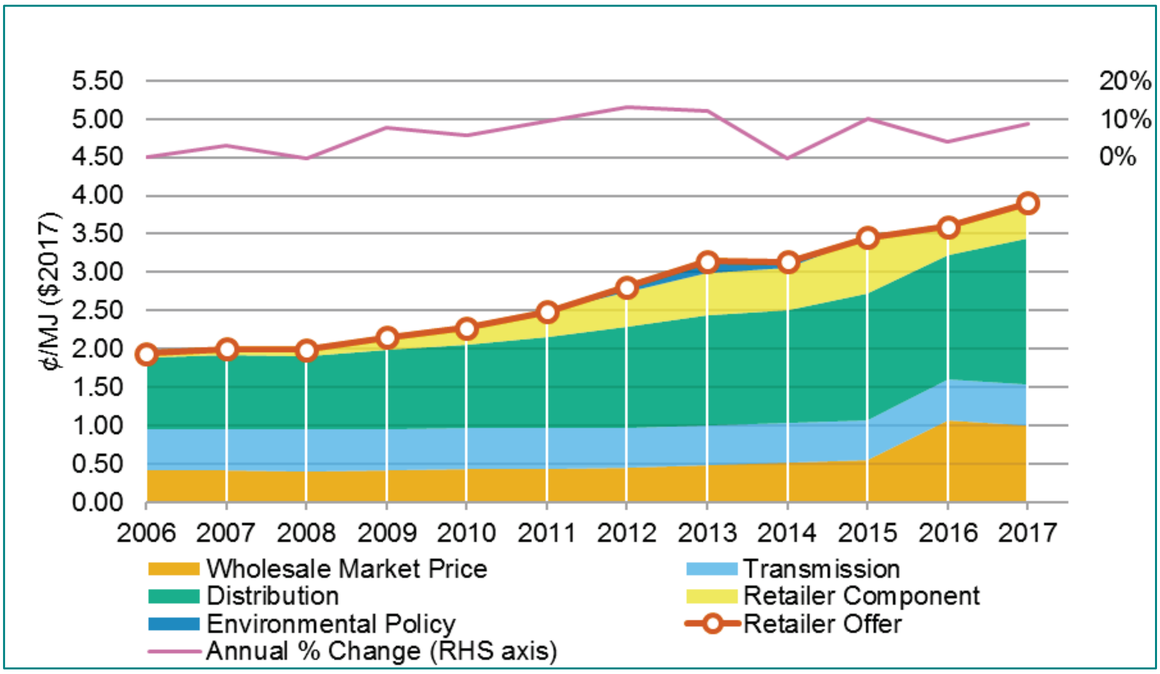


Figure 120 shows the proportions of the average retail price across the different components.

Figure 121 Tasmania average gas price supply component proportions

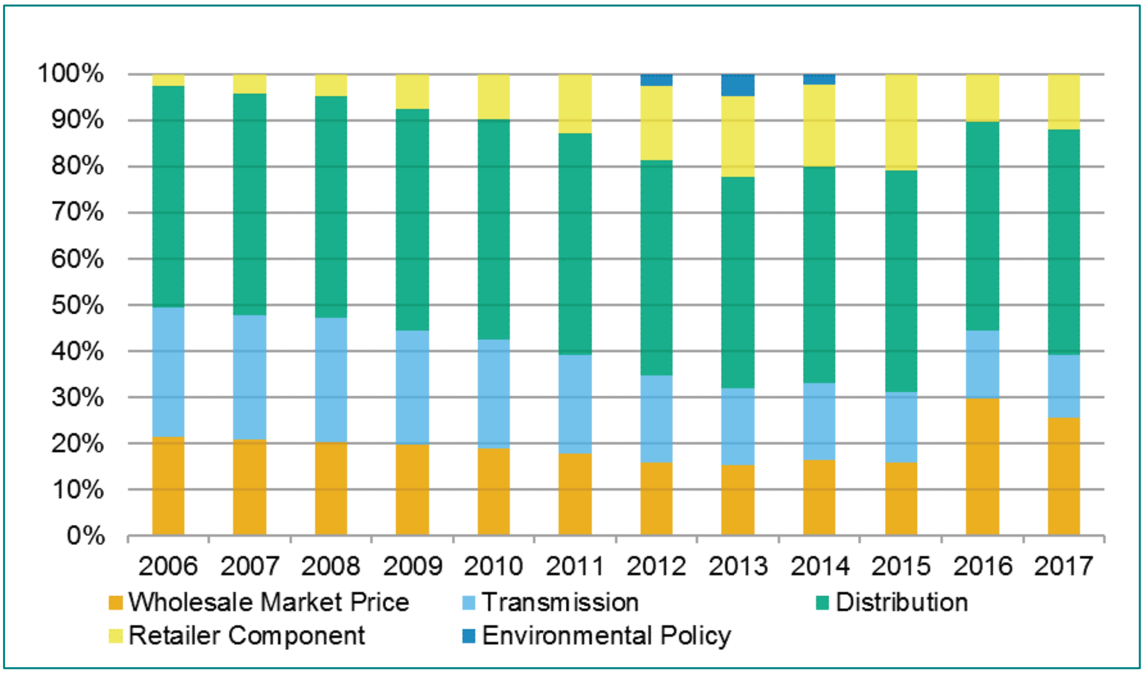
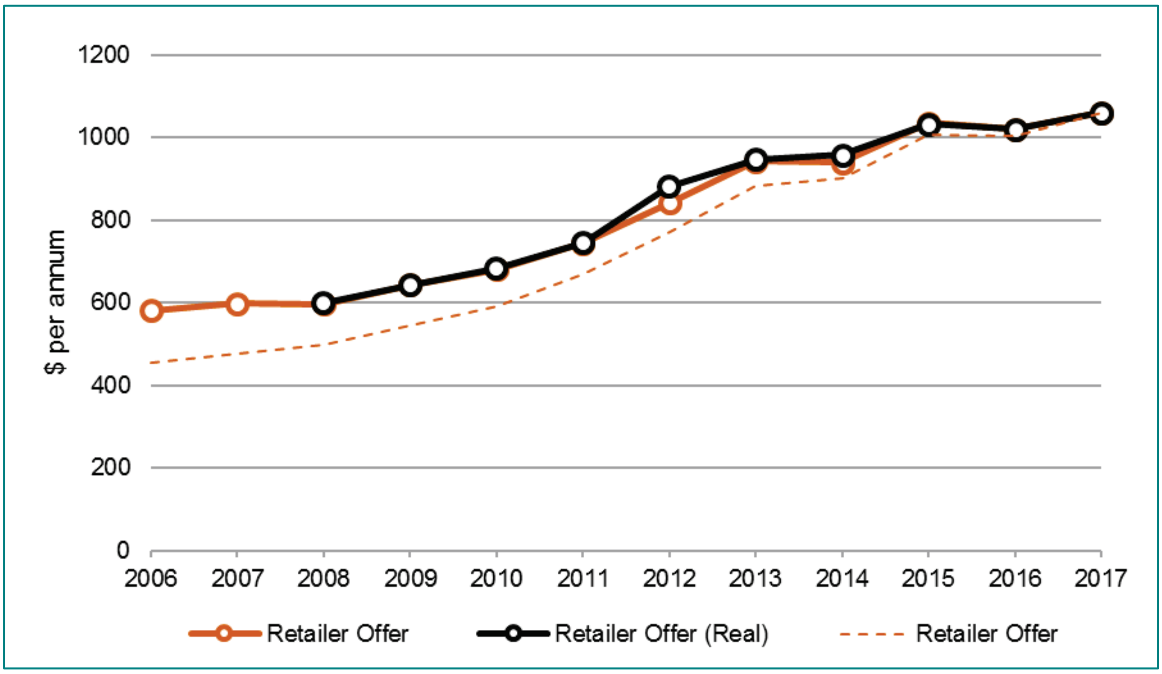


Figure 121 shows the different gas retail offers available in Tasmania.

Figure 122 Tasmania typical household gas bill

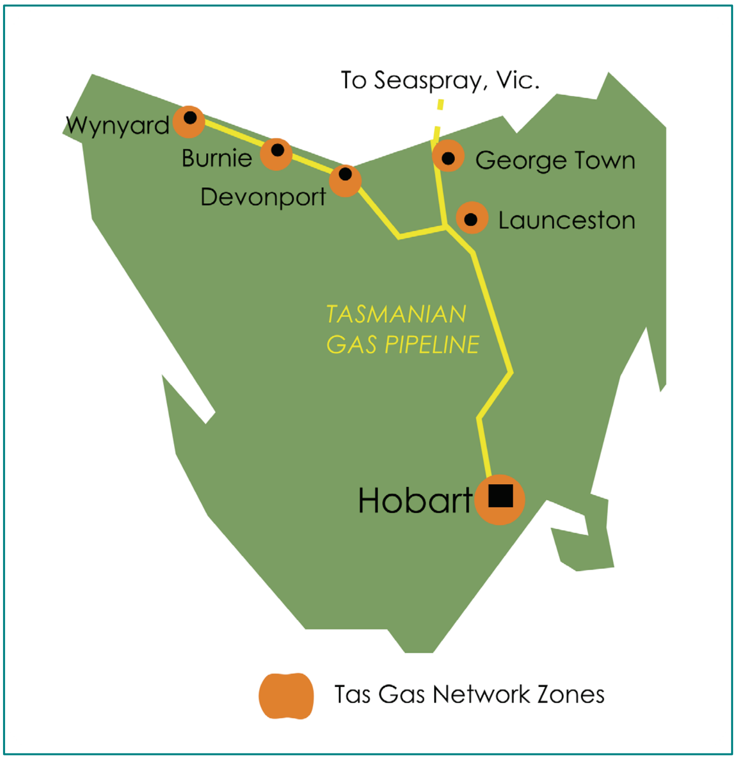


8.2.1 Market Overview

Gas is supplied to Tasmania from Longford, Victoria across Bass Strait via the Tasmanian Gas Pipeline (TGP) and into the main distribution centres in Hobart, Launceston, Devonport and Burnie and across to Wynyard and Port Latta.

Figure 123 shows the TGP and the locations of distribution network and network zones in Tasmania. The TGP was completed in 2002. The distribution network is operated by Tas Gas Networks and was completed in 2007.

Figure 123 Tasmanian gas distribution networks



The two active gas retailers are Tas Gas Retail (owned by the same company as Tas Gas Networks) and Aurora Energy who hold approximately 68% and 32% market shares respectively of residential customers.[141] Rural Energy and TRUenergy (now EnergyAustralia) were licenced to retail gas but have since surrendered their licences. The Office of the Tasmanian Economic Regulator (OTTER) is responsible for the regulation of gas licences and codes in Tasmania.

There are 241,744 private dwellings in Tasmania according to 2016 Census[142] data. Data received from industry participants indicates the total number of residential connections is (in 2016) 11,359. That is, 4.7% of households in Tasmania are connected to the gas distribution system.

Table 40 shows the proportion of households connected to natural gas has been slowly increasing since the distribution network was completed in 2007 and was just below 5% in 2014. This is consistent with ABS data retrieved for previous years showing negligible movement in the number of households connected to gas.

141 Office of the Tasmanian Economic Regulator (Dec 2016) Energy in Tasmania Report 2015-2016

142 2016 Census Quick Stats Tasmania, http://www.censusdata.abs.gov.au

Table 40 Household gas penetration rate in Tasmania (%)

	2005	2008	2011	2014
Total state	0.7	2.8	4.4	4.8

Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

8.2.2 Tasmanian household consumption

The TGP and Tas Gas Networks are not regulated and do not release information on residential gas volumes and quantities or details of distribution network pricing. In the absence of this data, connection and consumption data has been sourced from market participants.

The number of connected residential gas customers has been steadily increasing since 2009 from just under 8,000 to approximately 10,000 in 2013[143] to 11,700 in 2017[144].

Household consumption data is reasonably consistent, the household consumption from 2014 (sourced from OTTER's Performance Report) is some 30GJ/a and data sourced form market participants suggests in 2016 and 2017, consumption is 32GJ/a and 31GJ/a respectively. A marginal trend down in the last two years and not relatable to the 2014 data because it's from a different source.

Tasmania has competitive alternatives to gas for space and water heating, specifically:

- Wood heating for households – wood accounts for approximately half the energy use in households in Tasmania.[145] It is used mainly for space heating and some cooking and heating water. There is some evidence of switching from wood to electricity for households but no indication of large scale switching from wood to gas for heating.

- Electricity for heating – there are attractive off-peak heating electricity tariffs offered in Tasmania which is consistent with the switch from wood to electricity for space heating. There is a history of residents using cheap off-peak electricity for storing heat using systems such as underfloor heating. Table 41 provides a comparison of different space heating costs.[146] The comparison shows the economic benefit of switching away from gas as a fuel for heating. Wood is cheaper than gas but can be a less attractive option for some households in terms of handling and sourcing.

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143 OTTER (Mar 2015) Energy in Tasmania – Performance Report

144 Market source

145 OTTER (2014) Energy in Tasmania – Performance Report, s16.1

146 Aurora, Prices/heating cost comparison, Aurora Energy's heating cost comparison web page accessed 8 June 2015

Since 2014, the cost of off-peak electric heating and gas heating (according to the data Table 41) has increased by 29% and 13% respectively but the cost of wood heating has decreased by 6%. There is no up to date data available to suggest the difference in cost is (or is not) causing a change of fuel source for heating.

Table 41 Space heating comparison

Heater	Capacity	Max/hour 2014	Max/hour 2017	Percent change in cost 2014 to 2017
Heat pump	6kW	29.8¢	33.6¢	13%
Wood	6kW	39.5¢	37.2¢	-6%
Off-peak electric heating	6kW	39.5¢	50.8¢	29%
Gas	6kW	80.9¢	91.7¢	13%

Source: Aurora, Aurora Energy's heating cost comparison web page, accessed on 2 June 2015 and 27 October 2017. Note there are conditional footnotes on the accessed web page which are not reflected here.

8.2.3 Residential price components and trends

Given the low number of customers and the fact that the network was not completed until 2007, it would be expected that the retail component would be quite low early in the period (between 3% and 7%). After the completion of the network, the retailer component has increased to around 12% in 2017.

The network component daily connection[147] charge more than doubled from 19.78 ¢/day in 2014 to 42 ¢/day in 2015 which caused an increase in the overall average energy cost (year-on-year) of approximately 10% from 3.00 ¢/MJ to 3.36 ¢/MJ.

OTTER’s comparison of the increased charges in 2015 posits the supply charges in Tasmania are “*still low compared to most offerings by mainland retailers*”.[148]

As noted above, there is only a 4.8% penetration of gas into Tasmanian residential households. Combined with the likely trend of reducing gas demand, there is the potential that the pipeline network has limited ability to recover its investment. This may explain an increased cost pass-through but without the transparency in distribution pricing, it cannot be demonstrated.

The estimated impact of the distribution network on the gas retail offer is between 46% and 48% throughout the period.

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147 The network component consists of a fixed ¢/day charge and a variable ¢/ MJ charge.

148 OTTER (Mar 2015) Comparison of Australian Standing Offer Energy Prices, p14

8.2.4 Change since 2015 report

Table 42 summarises the residential gas price component changes from the base year 2006 to both 2015 and 2017. The biggest change is in the wholesale gas price component increasing by 83% on 2015 prices. Notwithstanding a retailer's ability to manage its gas purchasing arrangements and risk beyond a year on year re-contracting, the data suggests a retailer's component becomes squeezed as a result when the tariff does not increase by the same amount as the wholesale gas price, which is the case here. In reality, a retailer will manage its gas purchasing strategy to an extent and in parallel is able to manage or buffer the consumer's exposure to escalating wholesale gas prices.

Table 42: Summary component price changes from 2006-2015 & 2006-2017

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribution to change	¢/MJ change ($2017)	% contribution to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Total increase from 2006	1.51	44%	1.97	50%	0.45	13%
Wholesale change	0.13	9%	0.59	30%	0.45	83%
Transmission change	-0.02	-1%	-0.01	-1%	0.00	1%
Distribution change	0.73	48%	0.97	50%	0.25	15%
Retail change	0.67	44%	0.42	21%	-0.25	-35%
Totals	1.51	100%	1.97	100%		

8.2.5 Further developments

Wholesale gas prices are expected to hold toward or closely align with Victoria wholesale gas prices with possibly a low volume premium to be incurred due to limited relative bargaining power. Retailers' current underlying gas contracts will roll off eventually and if positions are not hedged now, will be exposed in future to the market price at the time of renegotiation.

If consumption per household remains flat or falls, the distribution system may need to increase its fixed residential gas charges to recover investment return expectations.

These are the two largest components of the delivered retail gas price (total 75%) therefore the influence on the retail gas price will largely be subordinate to movements in either the wholesale gas price and/or the distribution charges.

8.3 New South Wales

In this report, NSW residential gas prices are broken into two regions due to the significantly different levels of household consumption. The two regions are NSW metro and NSW regional.

8.3.1 NSW metro gas pricing

Figure 124 shows the breakdown of the average cost per MJ of gas retail prices for metropolitan NSW from 2011 (in real terms). There was a considerable increase year-on-year for the period from 2011 to 2015 (Gas Price Trends Review 2015), driven largely by increasing distribution costs. In the period of 2016 to 2017, there has been a downward trend in the average cost per MJ despite increasing wholesale costs in the same period.

In 2017, the average gas price delivered to NSW metropolitan households was 3.52 ¢/MJ, of which 1.39 ¢/MJ (40%) was the distribution component, 1.19 ¢/MJ (25%) was the retailer component, 0.73 ¢/MJ (26%) was the wholesale gas component and 0.30 ¢/MJ (9%) was the transmission component. There was no environmental policy component.

Of the 2017 average residential gas price, fixed charges made up 1.13 ¢/MJ (27%) and variable charges made up 3.12 ¢/MJ (73%).

Figure 124: NSW metro average household gas price ($2017) components

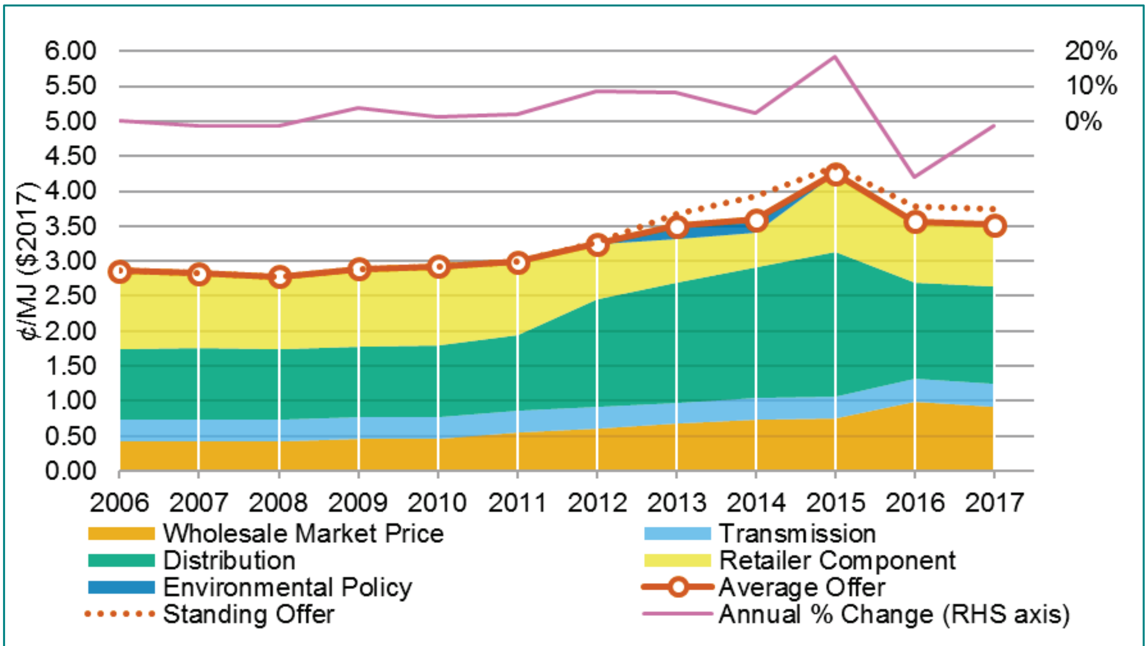


Figure 125 shows the percentage breakdown of the average retail price across the different components. It can be seen from this that while the wholesale gas price and transmission component have remained a relatively consistent proportion to 2015, The wholesale component has shown an increase in cost proportion in the timeframe of this report (this is discussed in more detail in Large and Small Industrial Price Trends). The distribution and retail proportions have fluctuated over the period with distribution costs making less of a contribution to the residential pricing in 2016 and 2017 (this is discussed in more detail in 8.3.6).

Figure 125: NSW household gas price component %

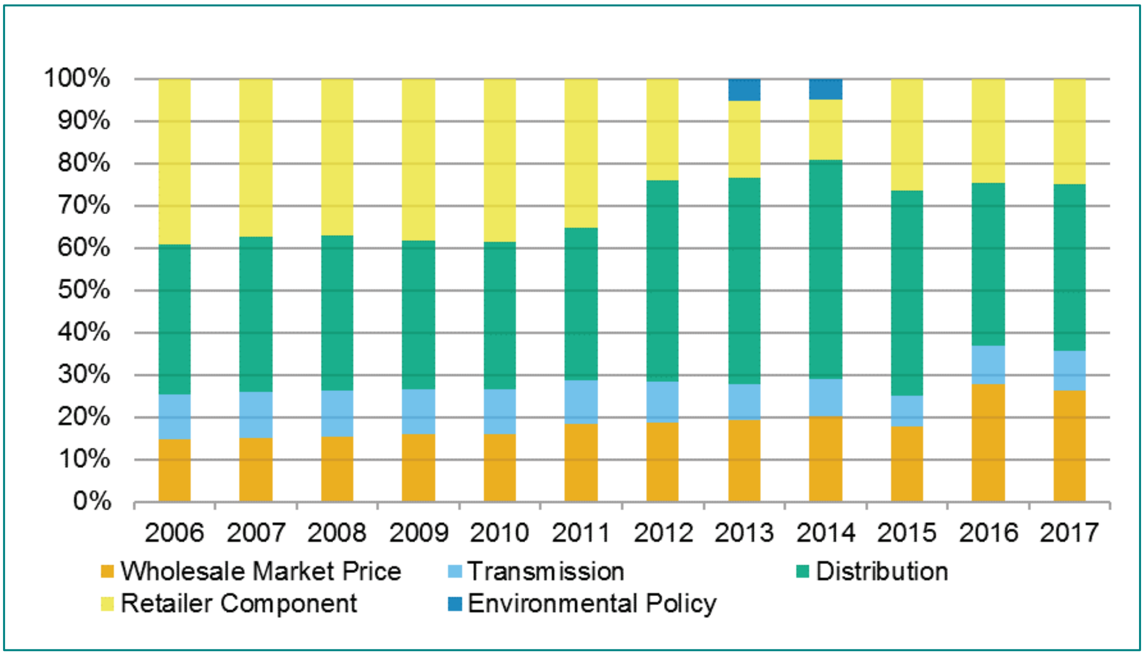
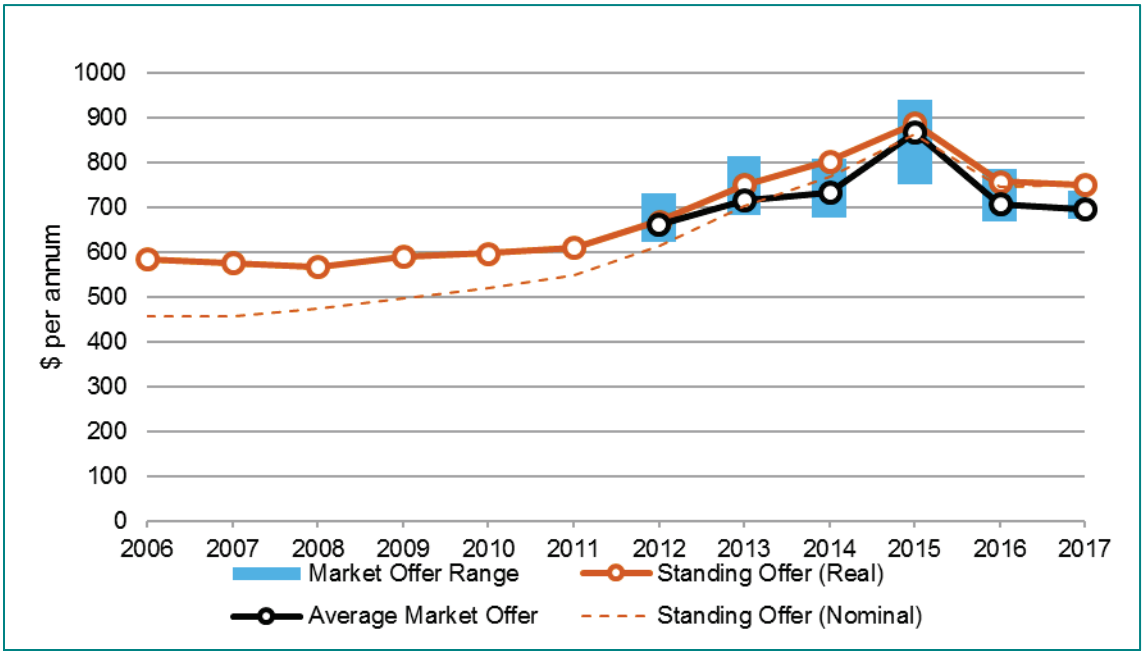


Figure 126 shows the market and standing offers in the NSW metropolitan area. There are relatively few market offers available in NSW, with the metropolitan zone (Jemena distribution network/AGL host retailer zone) the only area with more than two offers. Most regional areas only have one standing offer. Only the metropolitan zone has been analysed for market-based offers. The number of small customers on standing offers has reduced from 28% at 2013 to 18% as of the end of 2016 (compared to 23% of electricity customers) with the remainder on market contracts.

Market offers were tracked back to the 2011-2012 financial year. The market offer for a typical household account assumes the bill is paid on time and the maximum discount is obtained. Discounts for direct debit and electronic billing has been excluded. The market offers tend to straddle the standing offer and some discounts can be achieved by shopping around. No analysis of contractual terms or exit fees was undertaken.

Figure 126: NSW metro typical household gas bill



8.3.2 Rural NSW residential gas pricing

As outlined in Table 46, there is a considerable difference (approximately twice) in the average gas consumption between metropolitan NSW (20 GJ/a) and rural NSW (~41 GJ/a). The zones used for rural NSW include Albury and Wagga Wagga. Smaller zones, such as Murray Valley and Tamworth, were not included because of their size (and lack of data) and the fact that Murray Valley customers are generally captured by the Murray Valley zone in Victoria.

The penetration of natural gas in rural areas is also different to the metropolitan zone, largely reflecting that the distribution networks do not cover the whole state. While 51% of households in Sydney were connected to natural gas in 2014, only 31% of rural NSW was connected. However, there are some regions in rural NSW with high gas penetration rates. For example, Wagga Wagga has a penetration rate of approximately 90%.[149]

As shown in Figure 127, in 2017 the average gas price delivered to NSW rural households was 2.54 ¢/MJ, considerably lower than the average price in Sydney of 3.52 ¢/MJ and marginally lower than the 2015 average price of 2.63 ¢/MJ. Of this 0.97 ¢/MJ (38%) was the distribution component, 0.93 ¢/MJ (36%) was the wholesale gas component, 0.33 ¢/MJ (13%) was the retailer component and 0.32 ¢/MJ (13%) was the transmission component. There was no environmental policy component. Figure 128 shows the proportion of each price component.

Of the 2017 average residential gas price, fixed charges made up 0.64 ¢/MJ (25%) and variable charges made up 1.97 ¢/MJ (75%).

149 Origin Energy, Application of revocation of coverage of Wagga Wagga natural gas distribution network, 2013.

Figure 127: NSW average household gas price ($2017) components (rural)

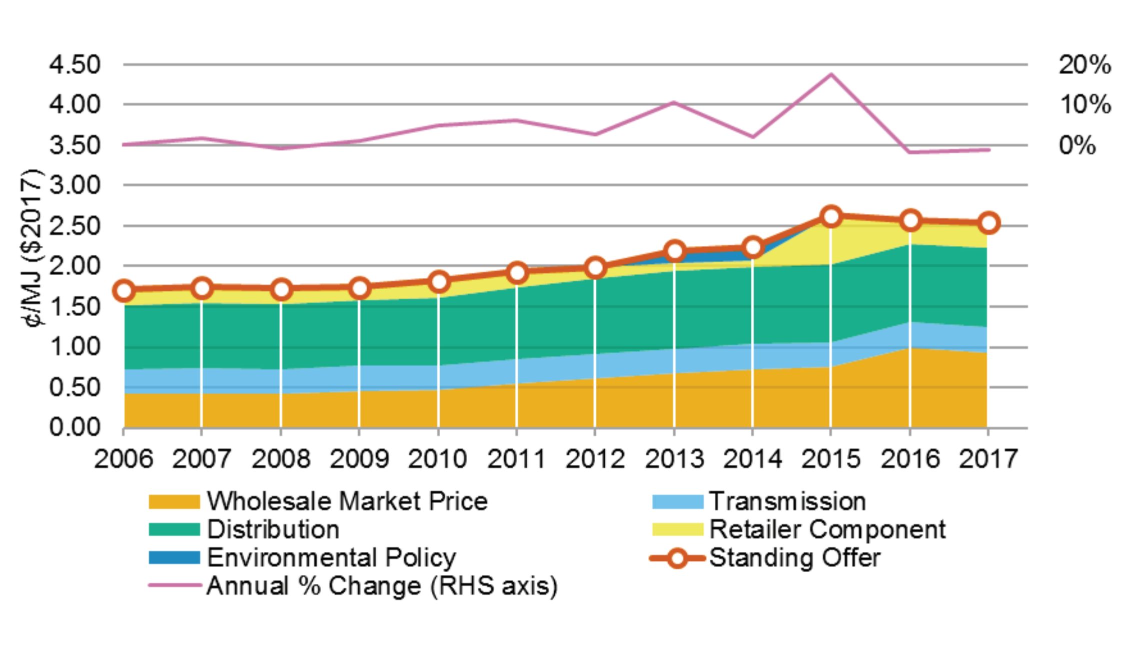


Figure 128: NSW average household gas price component % (rural)

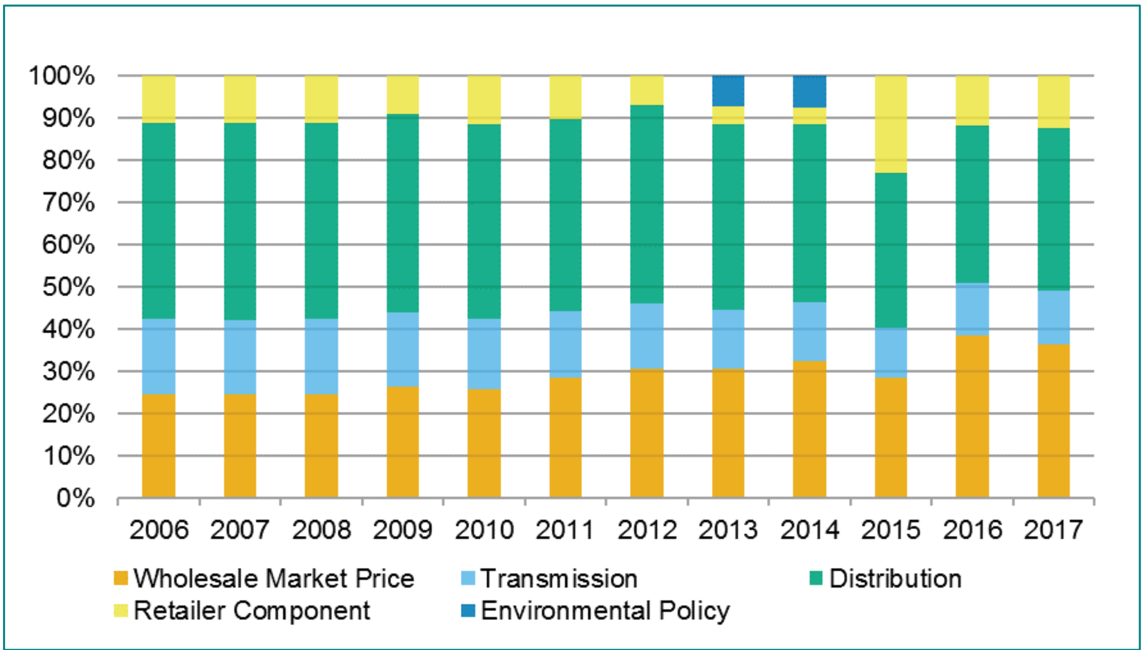
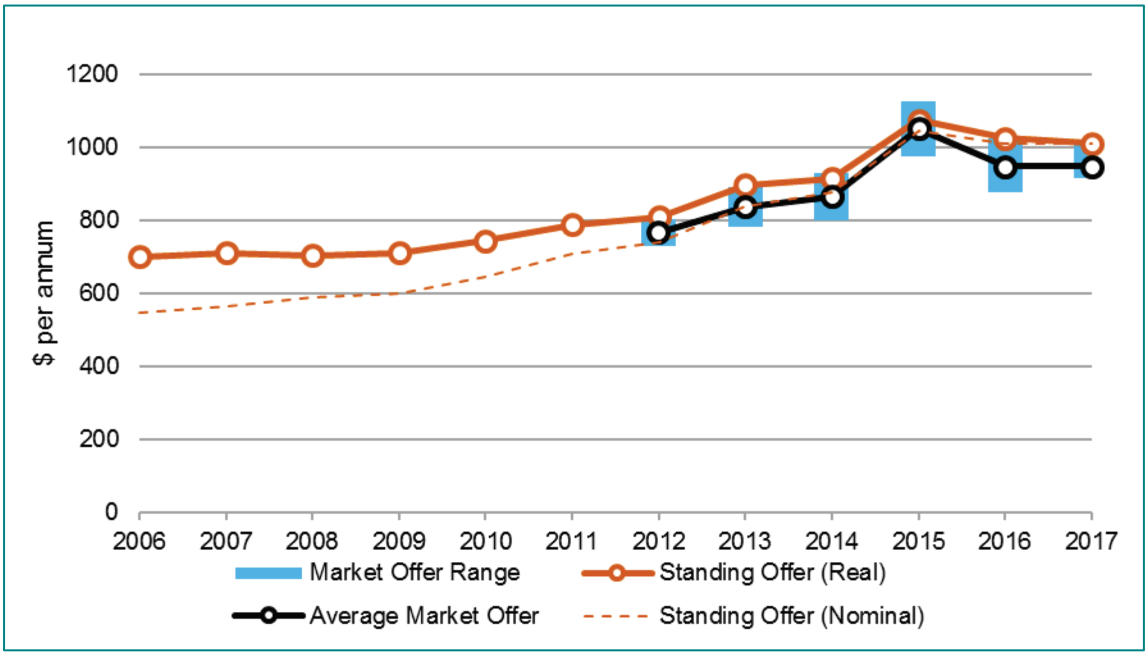


Figure 129 shows the overall impact of the rural gas prices and average consumption on a rural household customer's gas bill.

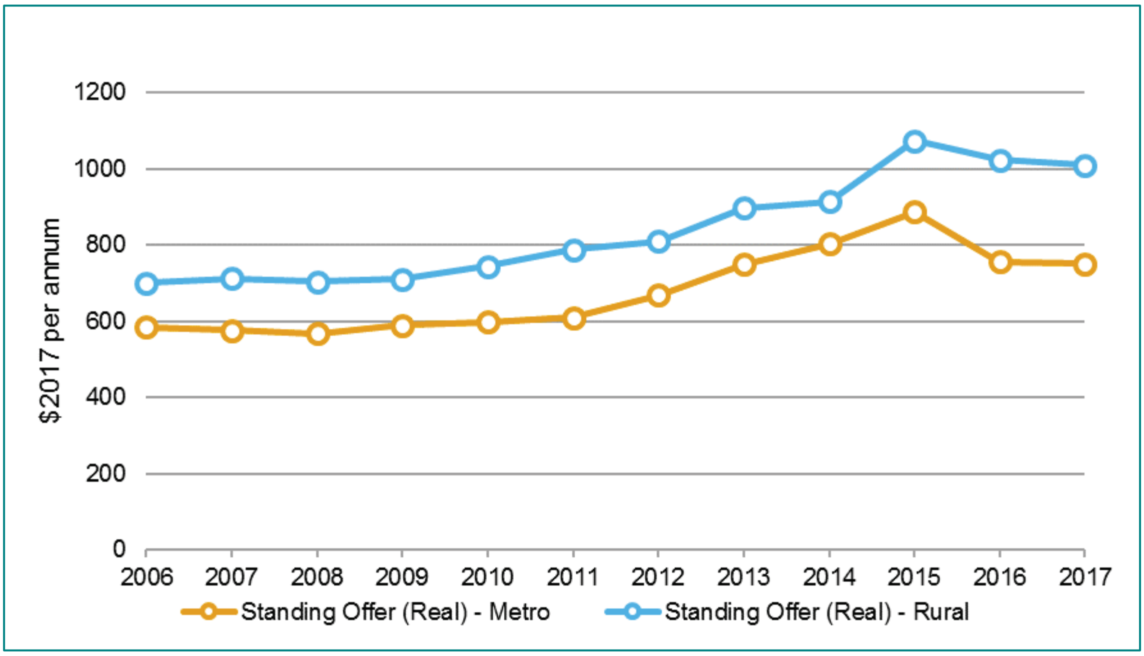
Figure 129: NSW typical household gas bill (Rural)



While a market range is shown in the graph it is only between the host retailer offer (Origin Energy) and another market offer (EnergyAustralia) for the Albury zone.

It should be noted that the overall rural price is lower on a price per MJ basis compared to metropolitan NSW. As a result, despite the rural zone having approximately double the typical household consumption of a metro household, the overall bill is approximately 34% more than the typical bill in the metropolitan zone compared to 15% in the previous Gas Price Trends Review 2015. Most of this change is attributed to the differences in distribution cost contribution for the different regions. Figure 130 compares the two regions based on an indicative bill.

Figure 130: NSW typical household gas bill compared (Rural and Metro)



8.3.3 NSW average residential gas prices

Figure 131 shows the NSW weighted average residential gas price. In 2017 the price was 3.54 ¢/MJ of which 0.93 ¢/MJ (27%) was the wholesale gas component, 0.32 ¢/MJ (9%) was the transmission component, 1.36 ¢/MJ (40%) was the distribution component and 0.84 ¢/MJ (24%) was the retail component. There was no environmental policy component.

The pricing for NSW is dominated by the Sydney Jemena region which represents more than 80% of the consumption for the NSW retail load.

Figure 131: NSW residential weighted average residential gas price ($2017)

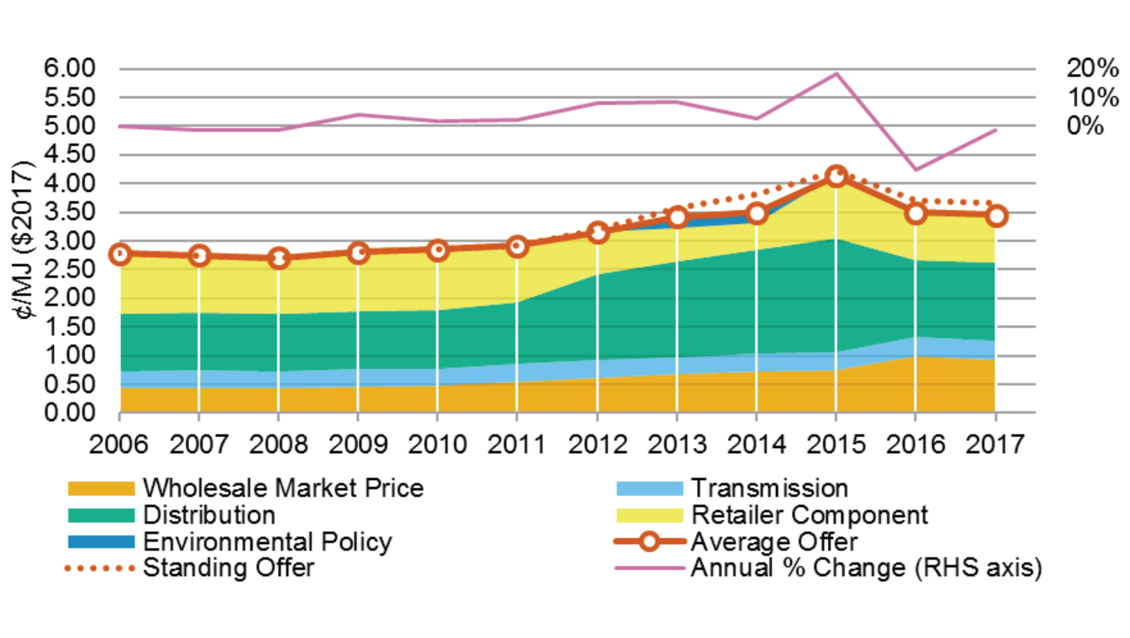
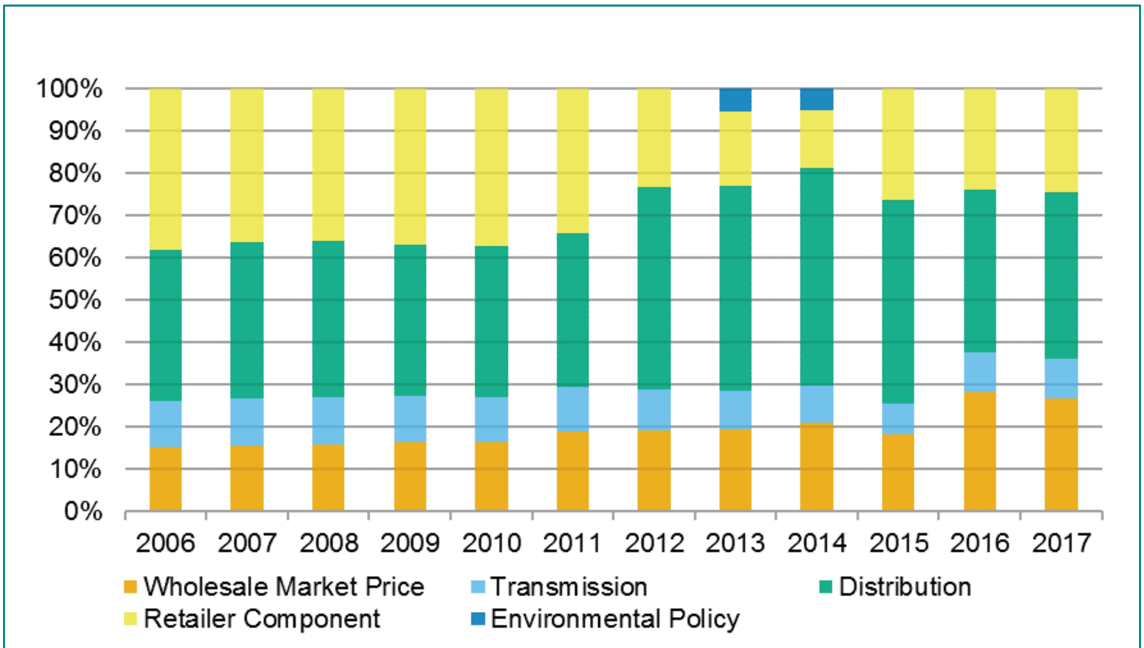


Figure 132: NSW weighted average residential gas price supply component proportions



8.3.4 Market overview

The NSW retail gas market is supplied predominantly from the upstream basins at Moomba, SA and Longford, Victoria. Wholesale gas is transmitted to the distribution networks using the unregulated Eastern Gas Pipeline (EGP) owned by Jemena and the lightly regulated Moomba to Sydney Pipeline (MSP) owned by APA Group.

The overwhelming majority of the retail load is in the Sydney region. This region has been supplied by AGL since1841 - AGL was formed in 1837, who used town gas produced from coal in order to fuel street lighting.

Historically each distribution zone had a single, host retailer. Natural gas retail competition was introduced for NSW residential customers in 2002. With the opening up of the industry to market offers, competitors have entered into the different zones. The Sydney/Jemena zone is the most competitive and has expanded from four retailers to six retailers over the last two years providing services with AGL as the host retailer.

Retail gas pricing continued to be regulated by the Independent Pricing and Regulatory Tribunal (IPART) until July 2017 when gas prices were deregulated. What this means is IPART will now monitor gas prices and report annually on gas prices and competition. According to the NSW Government, sufficient competition exists in the NSW gas market and deregulation will encourage greater competition which may bring gas prices down further. More than 80% of retail customers in NSW are on already on market contracts[150].

Figure 133 shows distribution areas/zones in NSW and ACT.

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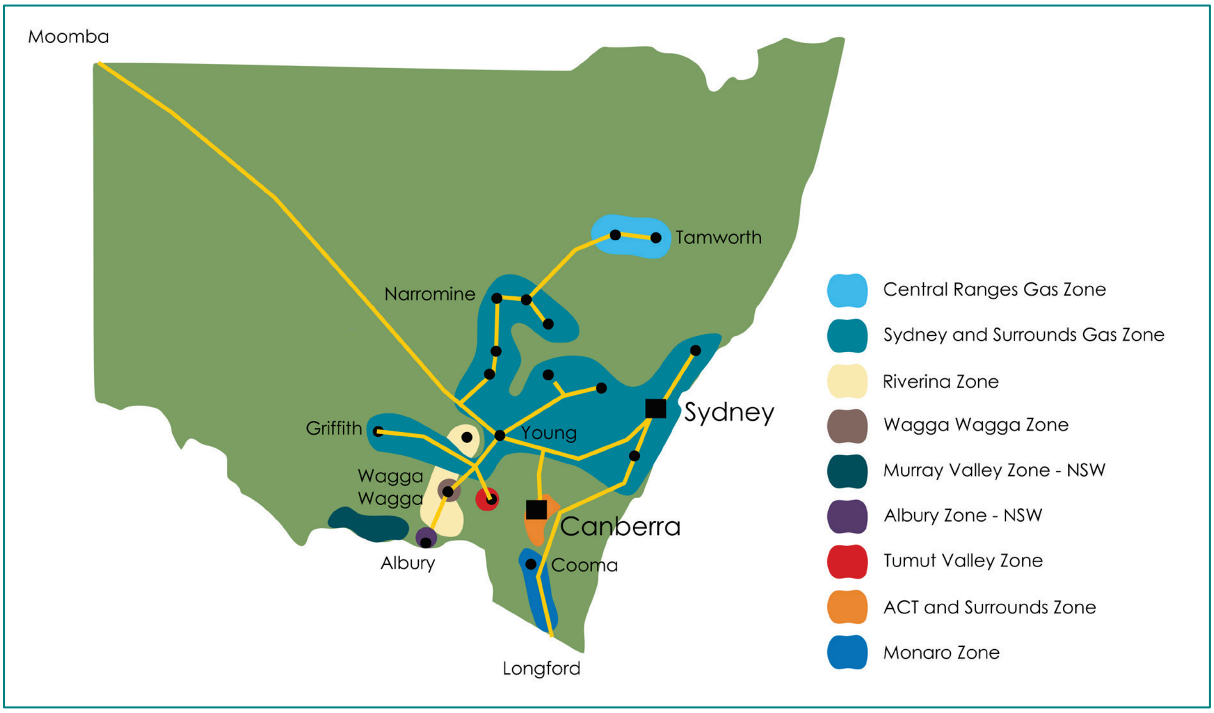
150 NSW Department of Environment Resources and Energy, Removal of gas price regulation, Resources and Energy website, accessed 20/12/2017.

Figure 133: NSW distribution network and zoning



Most of the distribution networks are currently regulated by the AER with Access Arrangements determined every five years.

The exception is the Wagga Wagga distribution network. Envestra (now Australian Gas Networks) applied to the National Competition Council (NCC) for revocation of regulated coverage of the distribution network in May 2013. The Regulation of the Wagga Wagga distribution network was revoked in April 2014 by the NSW Minster for Resources and Energy, contrary to the NCC's recommendations to maintain coverage, due to the continuing retail price regulation by IPART and lack of retail competition. Envestra stated that regulatory costs would be reduced by more than $1 million the following year and that distribution charge increases will be limited to the rate of inflation over the following five years commencing 1 July 2014.[151] AGN makes the Wagga Wagga tariff publicly available and the distribution cost component has remained steady and only shown a 2% increase in nominal terms since deregulation.

One of the biggest impacts on decreasing gas pricing in NSW, despite increasing wholesale costs, was AER's determination of the Jemena access arrangement for 2015-2020. The final decision saw the AER reject Jemena's methodology for determining a rate of return of 7.06% and saw the application of a lower rate of return of 5.41% being applied due to better global

151 Envestra media statement, "Consumers to benefit from deregulation of Wagga Wagga gas network.", 9 April 2014.

financial conditions[152]. This has implications for other regulated distribution gas and electricity networks.

The NSW Energy Savings Scheme has been expanded to include gas and create a financial incentive for gas efficiency. The amendments to the ESS Rule came into effect on 15 April 2016 to incorporate gas savings by providing methods for households and businesses to create Energy Savings Certificates for end-use gas efficiency.

The scheme is predominantly electricity focussed and to end of 2016 only ESCs have been created from electrical activities; however, it does include gas heating and gas hot water assessments. Data was not available for the 2017 calendar year at the time of writing of this report.

Table 43 shows the projected number of connections and approximate gas consumption by major distribution zone. The data has come from a number of sources but primarily from submissions to the AER concerning the networks' Access Arrangements.

Table 43: NSW Distribution network ownership and connections

Major Distribution Network	Ownership	Number of Connections	Approx. Gas Consumption (PJ p/a)
Sydney and Surrounds	Jemena	1,260,000	25
Wagga Wagga and Riverina	Australian Gas Networks (Envestra)	23,800	1
Albury	Australian Gas Networks (Envestra)	20,000	0.85
Central Ranges	APA Group	7000	~0.3
Monaro, Tumut Valley	Australian Gas Networks (Envestra)	NA	NA

Source: Data provided from various Access Arrangement submissions to the AER

For the analysis of this report, the focus has been on the regions of the largest consumption with Sydney and surrounds forming over 80% on a consumption basis for ACT and NSW. The smaller consumption regions such as the Central Ranges, Monaro and Tumut Valley have not been used to calculate the weighted average calculations for the NSW total

152 AER Final decision: Jemena Gas Networks (NSW) 2015-2020.

indicative tariff as they will have minimal impact. This assumption is in line with IPART's review of the typical annual retail gas costs as part of their 3-yearly retail price review.

Any NSW connections to the ActewAGL distribution network have been included as part of the ACT/Canberra consumption due to the majority of the network being concentrated in ACT. Refer to Section 8.4.

It can be seen from Table 44 that the retail gas market is still heavily concentrated with AGL, EnergyAustralia and Origin Energy controlling 95% of the residential retail market.

Table 44: List of New South Wales gas retailers and proportion of market share

Retailer	Small customers	Market Share (%)
AGL	660,097	49
EnergyAustralia	338,681	25
Origin Energy	274,382	21
Other Retailers	65,647	5

Source: Australian Energy Regulator, Aust. Energy Regulator industry statistics web page (accessed 13 Nov 2017).

Contrary to other jurisdictions, Table 45 shows that the penetration rate of natural gas to households in NSW has actually been increasing between 2005 and 2014. Penetration estimates as part of AEMO's 2016 NGFR estimate the penetration at 45%. This may be due to the location of growth corridors in NSW and new houses being built in cooler climates that may consider natural gas as a preferable energy source for heating.

Table 45: Household gas penetration in NSW (%)

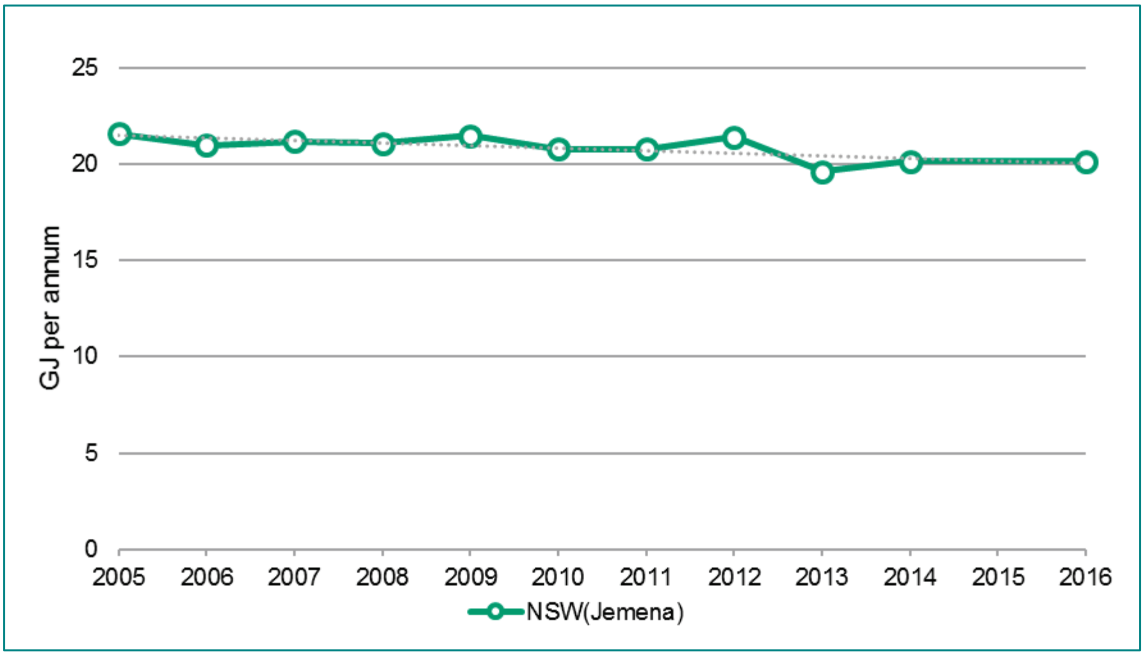
	2005	2008	2011	2014
Penetration Rate	35.1	37.5	38.9	42.9

Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

8.3.5 NSW household consumption

Figure 134 shows that, as with most households in other states, average gas consumption has declined over time.

Figure 134: NSW household average gas consumption (Sydney)



Source: Gas consumption forecast for JGN's Tariff V customers as part of Jemena's Access Agreement 2015-2020 submission to the AER.

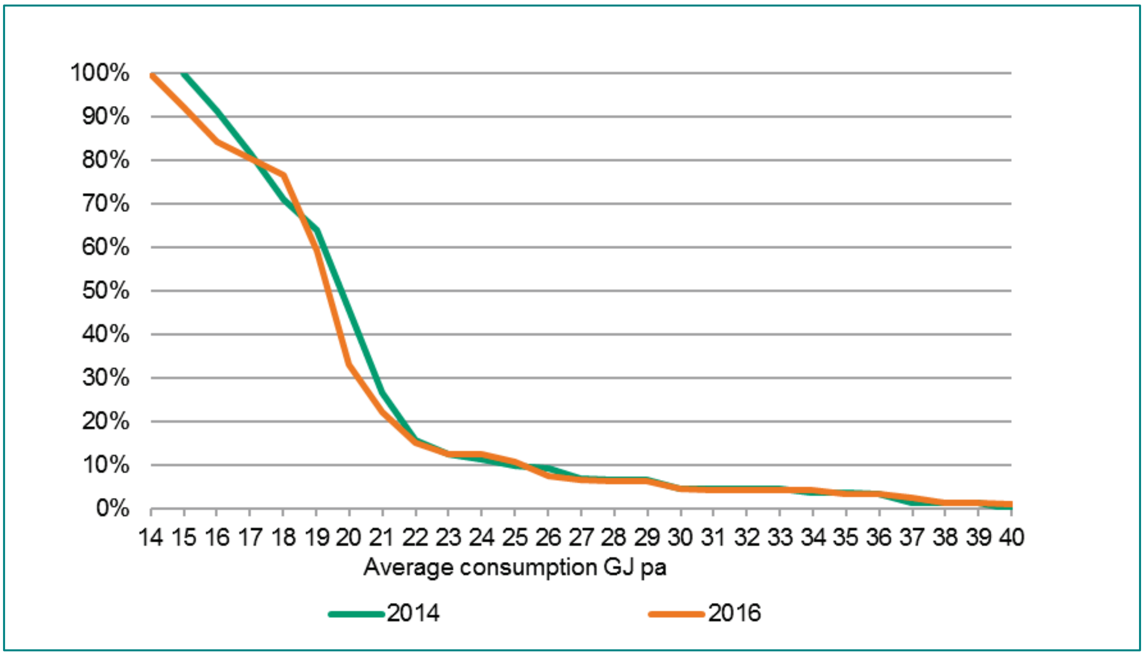
Jemena is unique among distribution networks in that it publishes the yearly statistics of average consumption and number of connections for residential and small business customers for each council region in Sydney and surrounds. The average household consumption used for metro household bill calculations was taken for 2014-2016. The same consumption was assumed for each previous year to remove additional variables to allow clearer analysis of the pricing components.

For the rural regions, where data was unavailable from a year-to-year basis, the IPART-assumed consumption for each zone was used.

The Jemena network is large and covers a region that has colder climatic zones up beyond the Blue Mountains and coastal temperate regions. The colder areas have approximately double the consumption per household compared to the entire average across the region; however, they form only a small percentage of the total number of connections.

Figure 135 shows that about 90% of customers connected to the Jemena gas distribution system in Sydney have an average consumption less than 25 GJ/a and 50% of customers use less than 20 GJ/a, or close to the system average. This could well be due to smaller homes and units being connected as the city infills, or a range of other factors such as appliance usage, appliance efficiency and competing fuel use.

Figure 135: Sydney Jemena network connection consumption distribution



Source: Distribution of customer consumption derived from JGN 2016 calendar year LGA average gas consumption data.

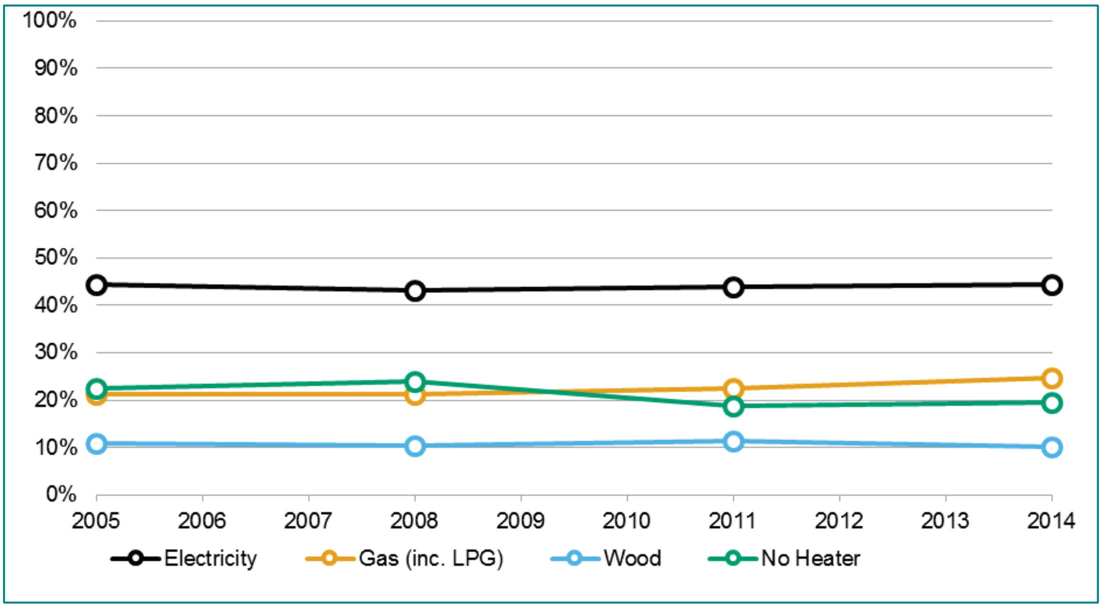
As can be seen from Table 46, the cooler climatic zones in NSW and ACT have much higher average consumptions, more in line with places like Victoria.

Table 46: 2017 NSW average household consumption

Gas Zone	Typical Household Consumption (GJ p/a)
Sydney/Jemena	20.0
Wagga Wagga	37
Albury	45
Canberra and surrounds/ ActewAGL	45

Figure 136 highlights a similar trend with the gas penetration rate and there has been a slight increase in the use of gas as the main source of energy for household space heating. While the use of gas has increased slightly, it is considerably behind electricity.

Figure 136: Main sources of energy for space heating – New South Wales



Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

8.3.6 Change since 2015 report

Table 47 summarises the residential gas price component changes from the base year 2006 to both 2015 and 2017. The major movement is in the distribution component and the retail component down 31% and 23% respectively from 2015. Across the averages, the tariffs have decreased, and the retail component has returned to long term average despite significant wholesale price increase. The wholesale gas price component has moved upward 23% from 2015 consistent with upward movement in the south-eastern states.

Table 47: Summary component price changes from 2006-2015 & 2006-2017

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Total increase from 2006	1.36	33%	0.67	19%	-0.69	-17%
Wholesale change	0.33	24%	0.50	75%	0.17	23%
Transmission change	0.00	0%	0.02	3%	0.01	5%
Distribution change	0.99	73%	0.36	55%	-0.62	-31%
Retail change	0.03	3%	-0.22	-33%	-0.25	-23%
Totals	1.36	100%	0.67	100%		

8.3.7 Further developments

As of 1 July 2017 (outside of the scope of this report), retail gas prices in NSW were deregulated and retailers are no longer required to agree a regulated offer with IPART. IPART will assume a monitoring role of retail gas prices alongside retail electricity prices which were deregulated a number of years ago.

The Australian Energy Market Commission (AEMC) determined that "*there is sufficient competition in the New South Wales retail gas market for customers to benefit from the removal of retail price regulation from 1 July 2017*".

8.4 Australian Capital Territory

8.4.1 Residential gas prices

In 2017, the average gas price delivered to ACT households was 3.00 ¢/MJ, of which 0.41 ¢/MJ (14%) was the retailer component, 1.35 ¢/MJ (45%) was the distribution component, 0.93 ¢/MJ (31%) was the wholesale gas component and 0.32 ¢/MJ (11%) was the transmission component. There was no environmental policy component.

Of the 2017 average market offer delivered gas price, fixed charges made up 0.66 ¢/MJ (20%) and variable charges made up 2.65 ¢/MJ (80%).

Figure 137: ACT average residential gas price components

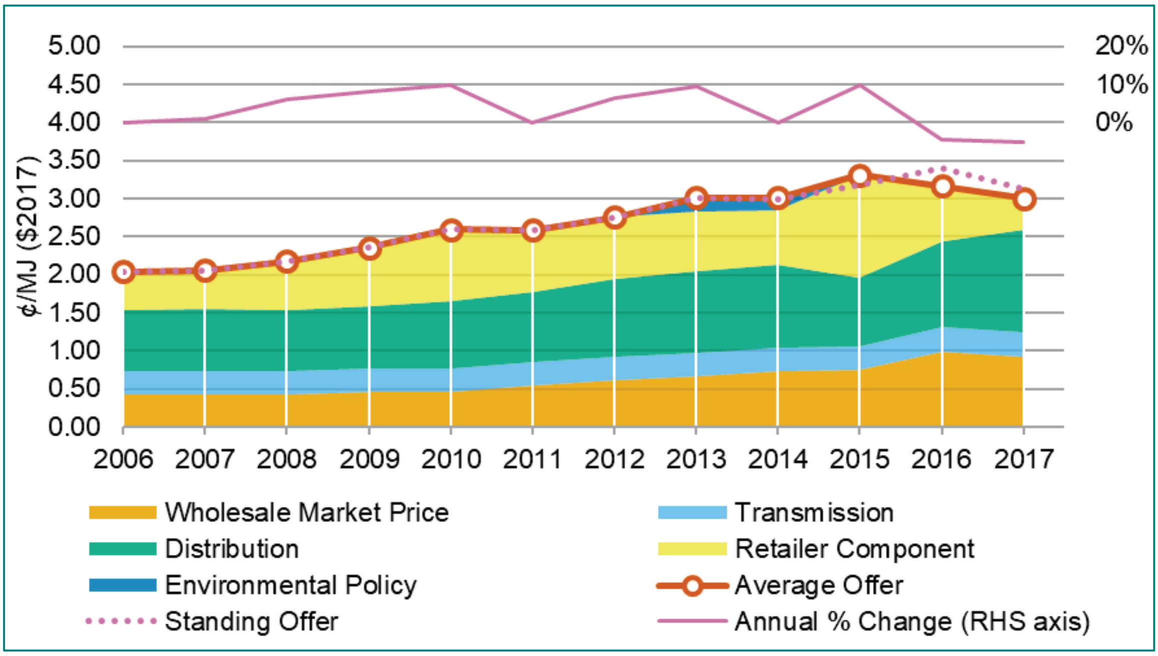
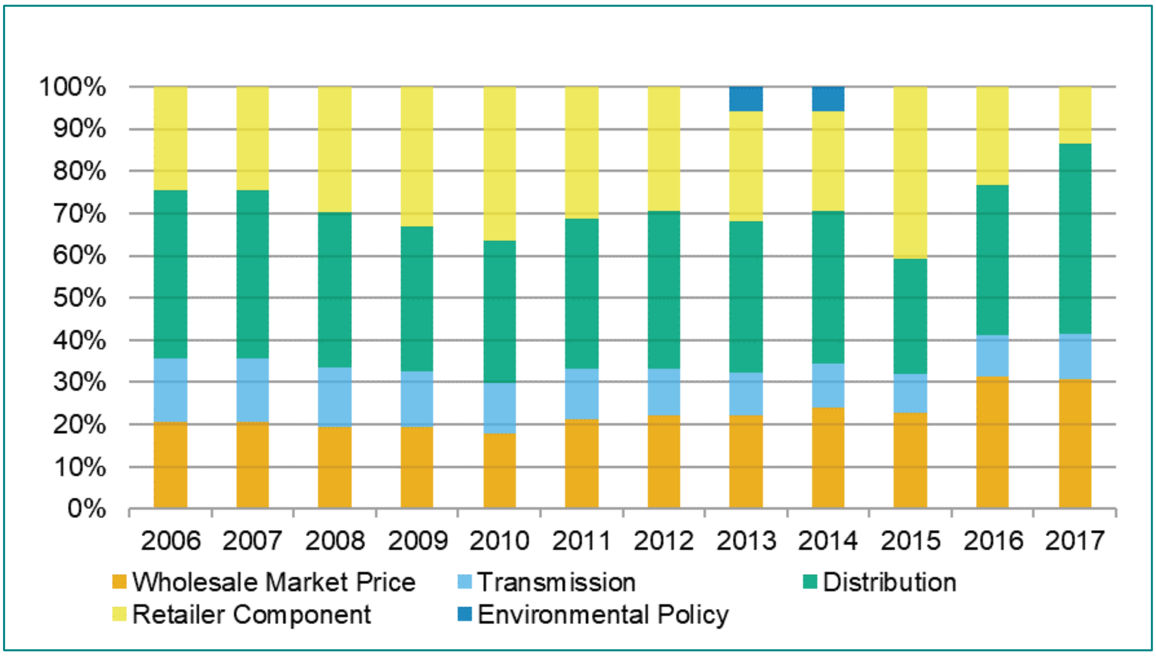


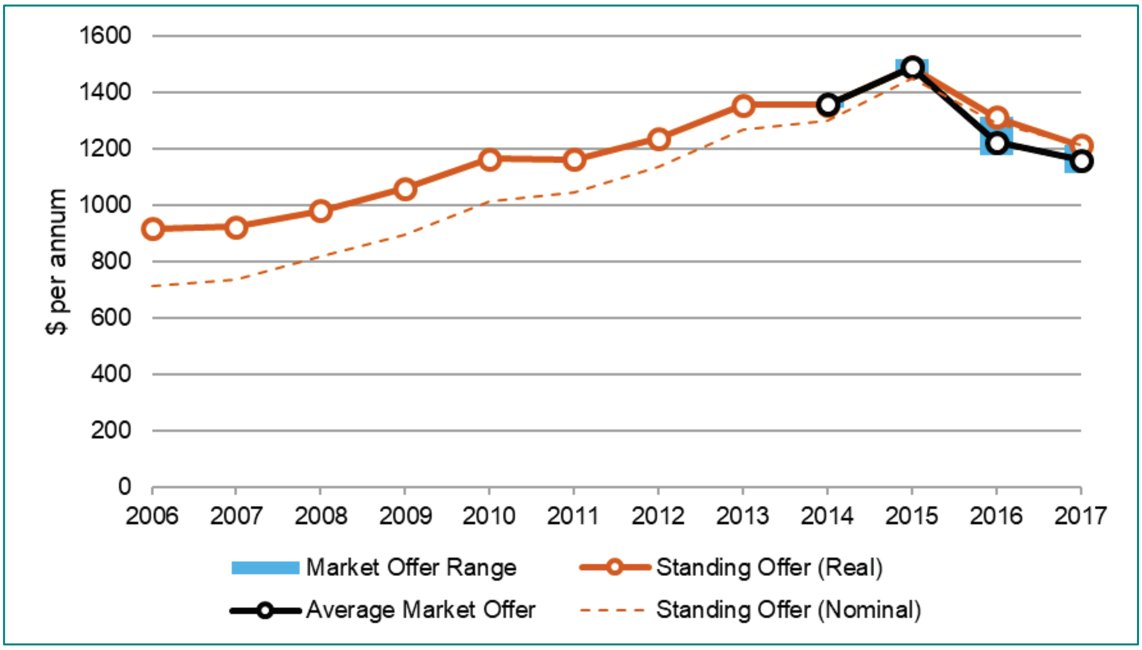
Figure 138 shows the percentage breakdown of the average retail gas price in the ACT.

Figure 138: ACT average residential gas price component %



It should be noted that while the overall pricing is lower on a price per MJ basis compared to metropolitan NSW, the overall average household bill is greater due to double the typical household consumption of metropolitan NSW. Figure 139 shows a decreasing typical household gas bill in the ACT between 2016 and 2017 in real terms.

Figure 139: ACT typical household gas bill ($2017)



8.4.2 Overview

The ACT energy retail market has operated with full retail competition since 2003. According to the Independent Competition and Regulatory Commission (ICRC) there are nine licenced gas retailers but only the host retailer ActewAGL and Energy Australia offer a market contract for gas.

The Queanbeyan and Bungendore networks in NSW are part of the ACT network (ActewAGL) and are included in ACT figures. Figure 140 shows the areas across the two jurisdictions that the ActewAGL distribution network covers.

Figure 140: ActewAGL Distribution network map

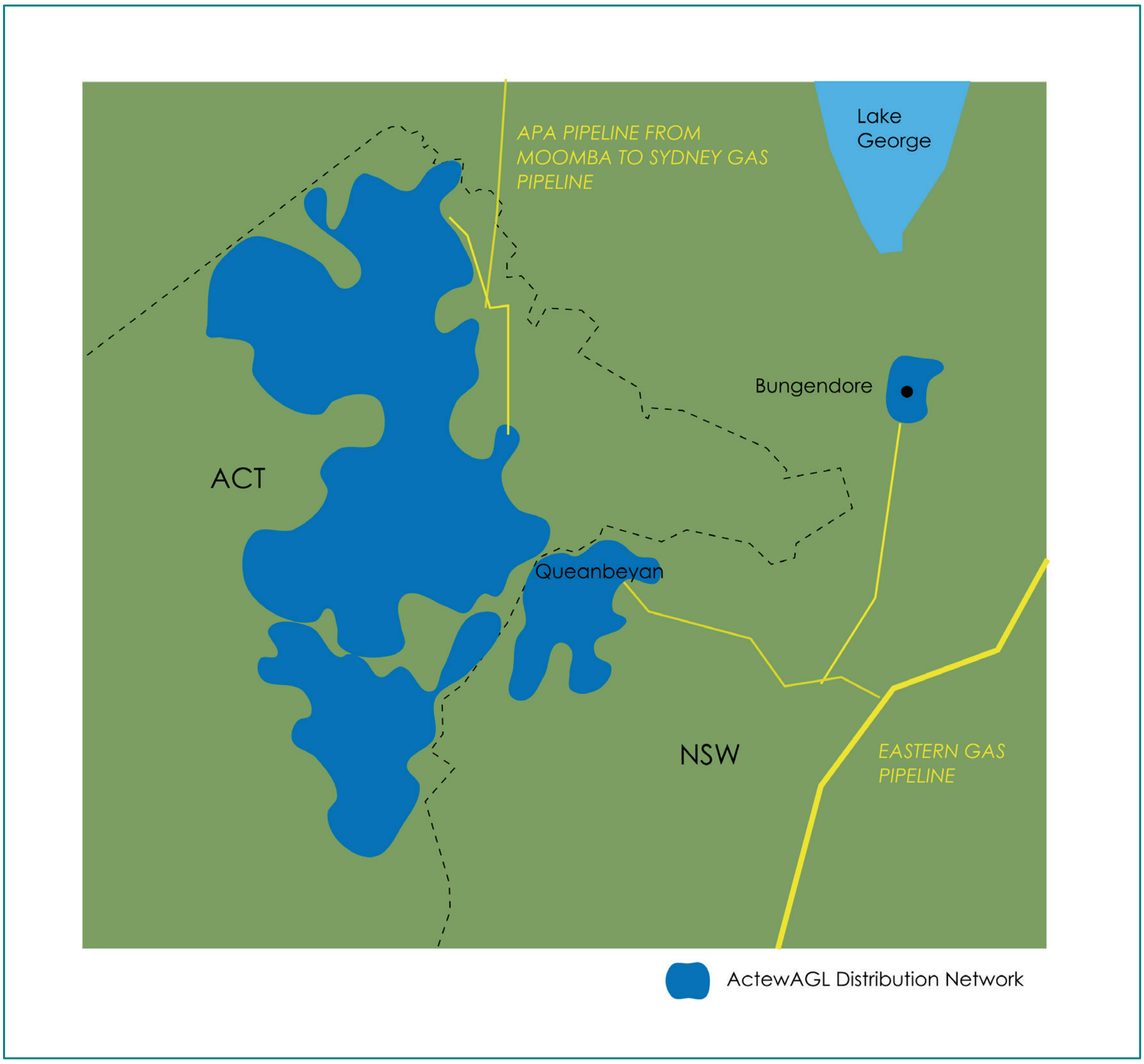


Table 48 shows that ActewAGL has more than 91% of the market share which is a decrease from 95% in the 2015 Gas Price Trends Report. Origin Energy entered the ACT market in 2016 to provide further competition and a third market offer.

Table 48: List of Australian Capital Territory gas retailers and proportion of market share

Retailer	Small customers	Market Share (%)
ActewAGL	110,366	91
Other Retailers	10,687	9

Source: Australian Energy Regulator, [Aust. Energy Regulator industry statistics web page] (accessed 13 Nov 2017).

The addition of the Origin Energy offer into the calculations may skew the average offer in a downward direction shown in Figure 139 as the average offer is not weighted by customer numbers.

Table 49 shows the reasonably high penetration rate of natural gas throughout the ACT, which has increased to 74.2% in 2017. This level of penetration is typical of what could be expected in areas with cooler climates and the levels of network access available for residential customers (annual variations are likely to be within statistical error range).

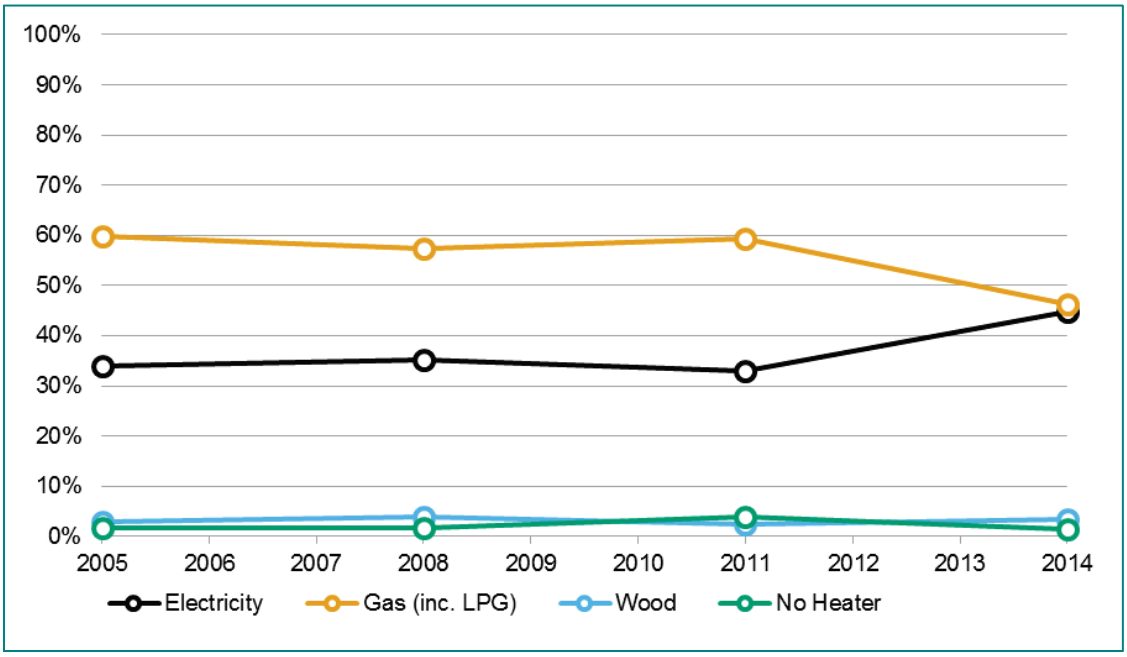
Table 49: Household gas penetration in the ACT (%)

	2005	2008	2011	2014
Penetration Rate	70.0	68.4	68.6	72.2

Source: Australian Bureau of Statistics 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Data provided by Evoenergy, email/letter 21 February 2018 for 2011 and 2014.

As with each of the other jurisdictions, the average household consumption for ACT residential customers has been declining. Figure 141 outlines the main source of energy for space heating in the ACT. It can be seen from this that electricity has been increasing to the point that, in 2014, electricity is close to overtaking gas as the main source of energy for space heating for residential households.

Figure 141: Main sources of energy for space heating – ACT



Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

8.4.3 Change since 2015 report

Table 50 summarises the residential gas price component changes from the base year 2006 to both 2015 and 2017. The major movement is in the distribution component, increasing by 56% from 2015 to 2017. ActewAGL exercised its power to extend its submission for Access Arrangement revision proposal from 2014 to 2015. As a result of the extension, the National Gas Rules (NGR) provide that the same distribution tariffs remain in force. The new 2016-2021 Access Arrangement saw a significant increase in distribution tariff with a restructure resulting in 2.6 times increase in the daily charge. The retail component also sees a downwards change of 68% based on the methodology of this report. This due to an additional market offer provided by Origin Energy contributing to a downward outcome with the averaging process of the calculation. Across the averages, the total tariffs have decreased.

Table 50: Summary component price changes from 2006-2015 & 2006-2017

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Total increase from 2006	1.27	38%	0.96	32%	-0.31	-9%
Wholesale change	0.33	26%	0.50	52%	0.17	23%
Transmission change	0.00	0%	0.01	1%	0.01	3%
Distribution change	0.09	7%	0.55	57%	0.45	50%
Retail change	0.85	67%	-0.10	-10%	-0.95	-70%
Totals	1.27	100%	0.96	100%		

8.5 South Australia

In 2017, the average gas price delivered to SA households was 4.53 ¢/MJ, of which 2.48 ¢/MJ (55%) was the distribution component, 0.93 ¢/MJ (20%) was the wholesale gas component, 0.88 ¢/MJ (19%) was the retailer component and 0.25 ¢/MJ (5%) was the transmission component. There was no environmental policy component.

Of the 2017 average delivered gas price, fixed charges made up 1.49 ¢/MJ (33%) and variable charges made up 3.03 ¢/MJ (67%).

Figure 142 shows that market offers (represented by average offers in the figure) are continuing to be discounted to standing offers. Where there is a slight increase in 2016 there is a marked decrease in 2017. This is due largely to the distribution component reducing in 2017 and all other components remain flat. The increase in wholesale gas price was experienced from 2015 (15% of the total) to 2016 (18% of the total).

Figure 142 SA average residential gas price

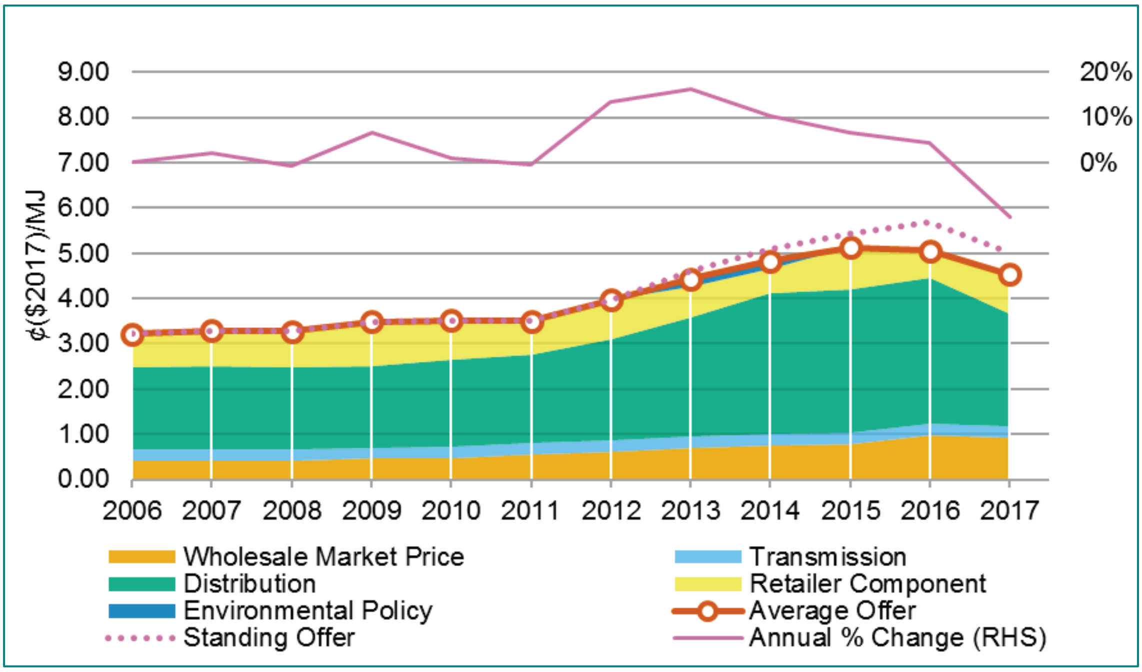
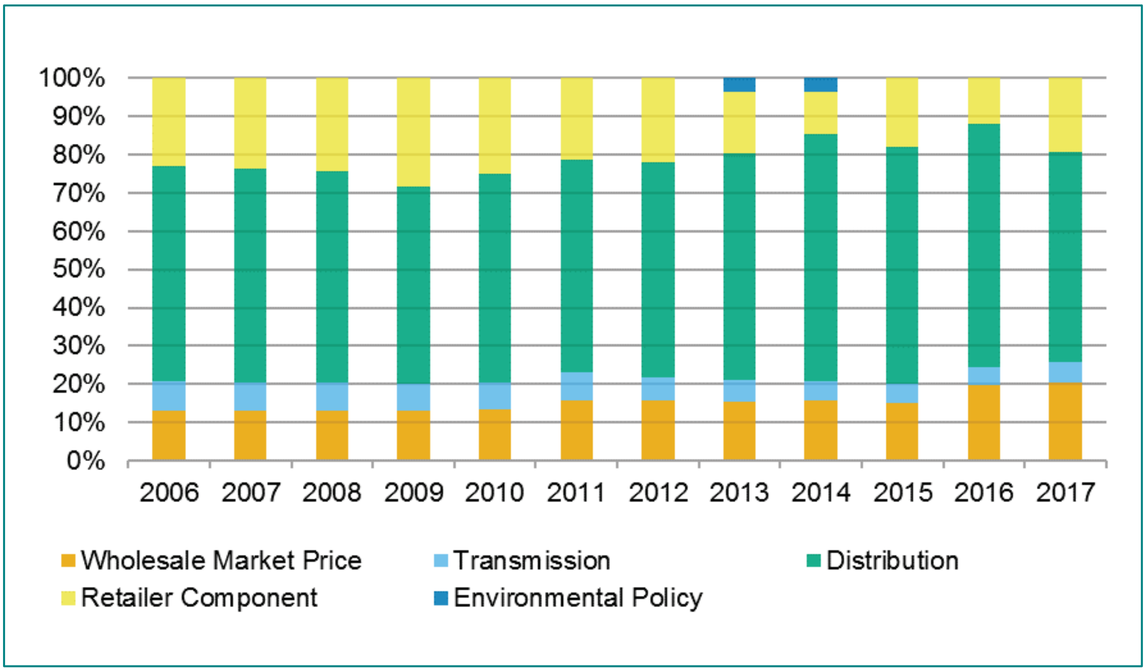


Figure 143 highlights the significant contribution that the distribution component makes to the average gas retail price.

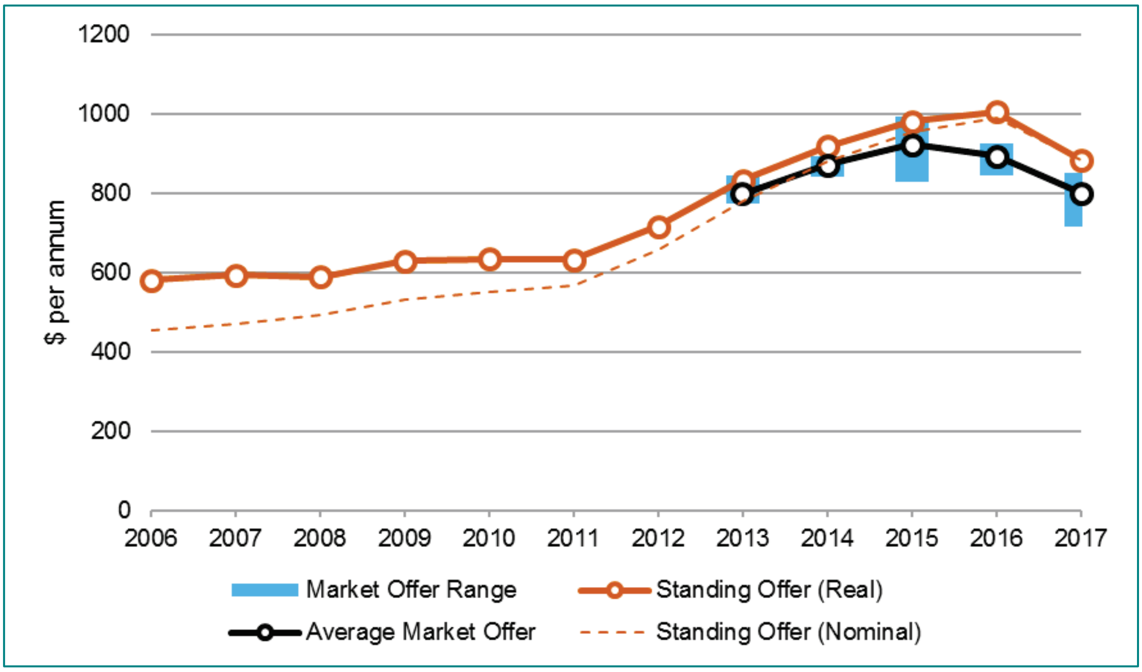
Figure 143 SA average residential gas price component percentage



Residential gas tariffs in SA use a two-tiered pricing approach (fixed and variable components) with the variable component having declining blocks based on the volume of gas consumed. The typical household bill (real and nominal) is shown in Figure 144

The gas retail market became contestable in 2013. Figure 144 indicates average market offers are consistently lower than traditional standing offers.

Figure 144 SA typical household gas bill (Adelaide)



The blue band represents the range of maximum to minimum market offers normalised in $ per annum. The market offers include the retailer's incentives or pay on time discounts to consumers. As a result, the minimum market offer is the lower end of the blue band which is almost $170 per annum lower than the standing offer benchmark which does not offer discounts or incentives to consumers. This suggests that contestability incentivises retailers to attract new customers with discounts and therefore improves the price outcome for consumers.

8.5.1 Market overview

Gas is supplied to the gas distribution network in SA from two transmission pipelines, namely the South-East Australia Gas (SEA Gas) pipeline and the Moomba to Adelaide Pipeline System (MAPS).

The gas distribution network is owned by Australian Gas Networks (formerly Envestra) and supplies five retail zones. The five retail gas regions in SA are:

- Adelaide
- Mount Gambier
- Port Pirie
- Riverland and
- Whyalla.

The residential gas demand in Adelaide consumed 96% of the SA's total residential demand in 2017[153].

The gas distribution system has been extended to the town of Tanunda approximately 75 km north east of Adelaide in the Barossa Valley district. The Tanunda gas distribution system is owned by Australian Gas Networks and supplied from a high-pressure spur off the MAPS. The system was completed in May 2015 and is expected to supply up to 2,000 households.[154] Tanunda has a different set of distribution network tariffs to the rest of South Australia[155] and, due to its small size, is not considered in this report.

AGN is in the process of replacing its old cast iron gas mains. Some 900km of pipeline will be replaced in the next two years and the project is expected to be completed in 2021.[156]

Figure 145 SA gas distribution network

153 NIEIR (Sep 2010) Natural gas forecasts for the Envestra South Australian distribution region to 2019/20, Table B1-B6

154 AGN website, Natural gas in Tanunda web page (accessed 7 August 2015)

155 AGN website, Aust. Gas Networks tariff publication web page

156 AGN website, Aust. Gas Networks major projects web page (accessed 7 August 2015)

Table 51 shows the market share of the major retailers in SA. Origin Energy was the incumbent retailer in SA before retail contestability started in 2003. AGL has since entered the market (along with EnergyAustralia, Simply Energy and Alinta Energy) and together with Origin has 75% of the market.

Outside of the Adelaide region, Origin Energy is the dominant supplier to residential consumers.

Since 2015 there has been a 2.5% increase in the number of small customers (residential and small business) and the market shares of the respective retailers has not changed in any material manner.

Table 51 List of SA gas retailers and proportion of market share of "small customers" as at March 2017

Retailer	June 2015	Market Share (%)	March 2017	Market Share (%)
AGL	130,130	31.2%	131,675	30.8%
Energy Australia	54,105	13.0%	55,589	13.0%
Origin Energy	184,060	44.2%	185,750	43.5%
Other Retailers	48,373	11.6%	53,918	12.6%
Total	416,668	100%	426,932	100%

Source: Australian Energy Regulator, Aust. Energy Regulator industry statistics web page (accessed 30 October 2017).

Table 52 shows that the penetration rate in SA is reasonably high compared to a number of other jurisdictions. Adelaide's penetration rate is significantly higher than the rest of the state. Adelaide has a penetration rate of 71% and the remainder of the state averages 18%. This is reflective of the distribution networks location outlined earlier.

Table 52 Household gas penetration rate in SA (%)

	2005	2008	2011	2014
Adelaide	NA	72.1	75.2	71.1
Balance of state	NA	9.8	13.7	18
South Australia	56.8	55.9	58.4	56.7

Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

8.5.2 Regulatory environment

Full gas retail contestability came into effect in SA on 1 February 2013 and the economic regulation of the gas distribution network was transferred to the AER from 1 July 2008.

8.5.3 SA household consumption

Figure 146 illustrates the typical household consumption in SA. It can be seen from this that the typical household consumption showed a steady decline from 22.1 GJ/a in 2005 to 15.5 GJ/a in 2017. The further forecasts out to 2021 show a continuing trend downward in household consumption to 13 GJ/household[157].

Figure 146 SA typical household gas consumption

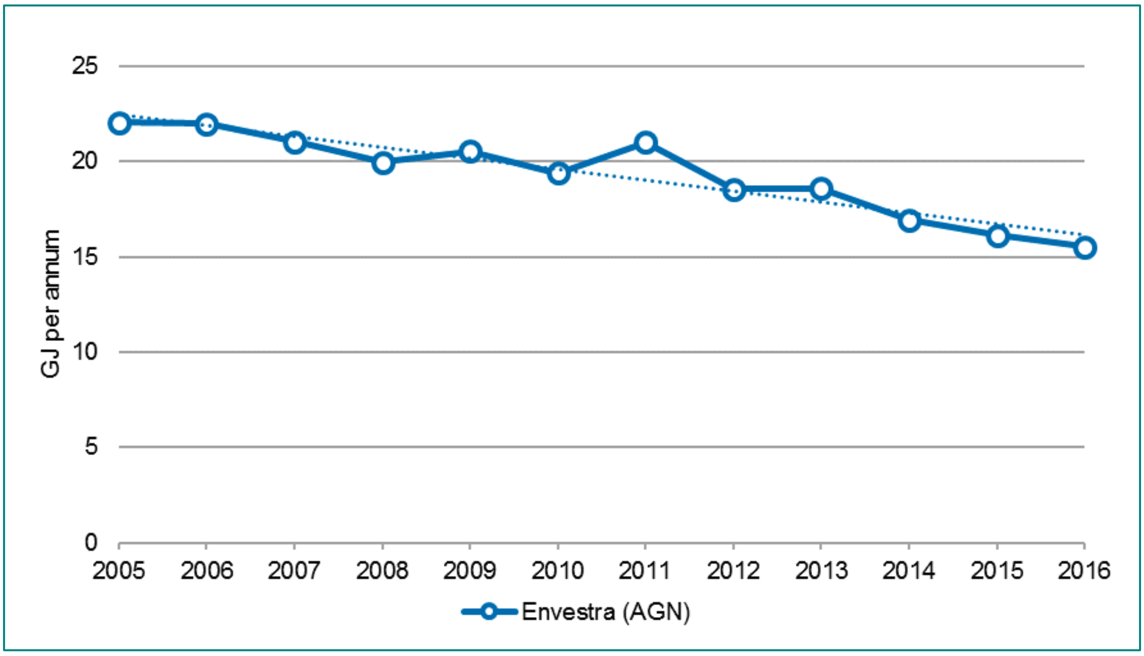


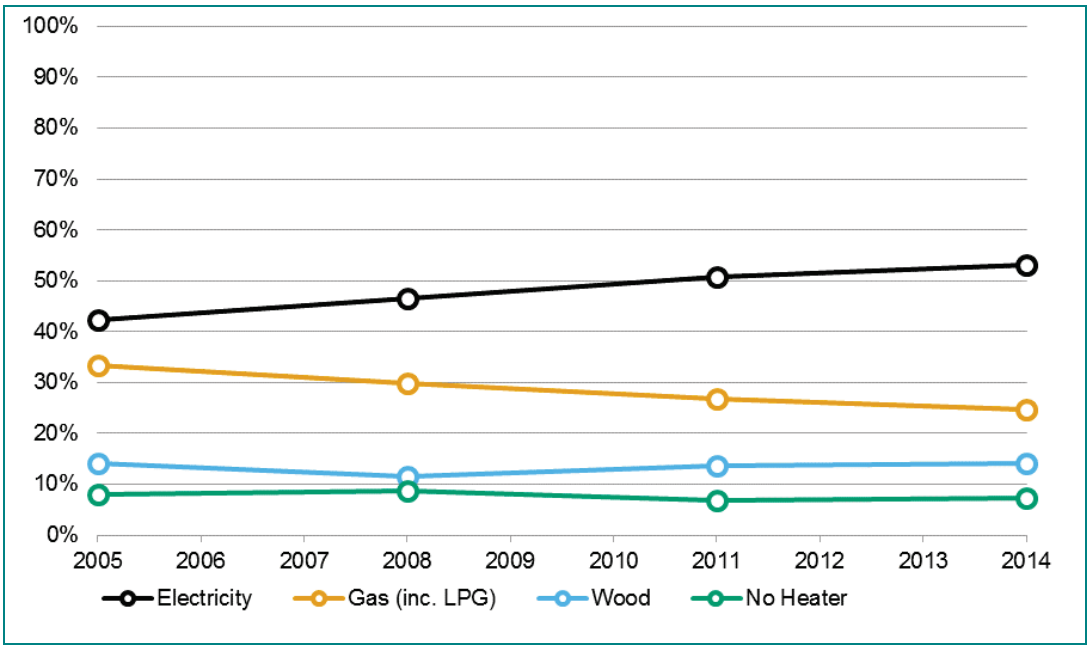
Figure 147 shows the trend in increasing electricity use as the energy source for household space heating, while gas has been in decline from the start of the period. This demonstrates that one of the key drivers of gas consumption is the fuel substitution decision and it could potentially have a significant impact on the overall use of the network if this trend continues.

While the source data has not been updated by ABS, it is expected this trend would continue unless significantly impacted by electricity price changes in SA.

Gas prices in SA are high compared to Victoria and this would suggest an increasing incentive for consumers to switch from gas heating to electricity and exacerbate the price elasticity issue that currently prevails whereby increasing price decreased demand This may be mitigated in the next couple of years if the gas price decreases (resulting in increasing demand for gas) and electricity prices trend upward (resulting in decreasing demand for electricity) and reversion to gas heating.

157 Australian Gas Networks 2016-2021 Access Arrangement.

Figure 147 Main sources of energy for space heating – SA



Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

8.5.4 Change since 2015 report

Table 53 summarises the residential gas price component changes from the base year 2006 to both 2015 and 2017. The major movement is in the distribution component down 22% from 2015. Across the averages, the tariffs have decreased and so has the distribution component and therefore a widening of the retail component is possible where the tariff moves downward lesser than the distribution component. The wholesale gas price component has moved upward 19% from 2015 consistent with upward movement in the south eastern states.

Table 53: Summary component price changes from 2006-2015 & 2006-2017

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Total increase from 2006	1.90	37%	1.31	29%	-0.59	-12%
Wholesale change	0.36	19%	0.51	39%	0.15	19%
Transmission change	0.00	0%	0.00	0%	0.00	0%

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Distribution change	1.36	71%	0.66	51%	-0.70	-22%
Retail change	0.18	10%	0.14	11%	-0.04	-5%
Totals	1.90	100%	1.31	100%		

8.5.5 Further developments

It can be expected the increasing penetration of rooftop solar and reverse cycle air conditioning will encourage fuel switching for heating from gas to electricity.

The reduction in distribution charges forecast in the 2015 report have emerged and it appears the retailers have passed through the reduction in charges to the consumer and maintained their retail component margins. This may further evolve in the next couple of years.

8.6 Queensland

In 2017 the average gas price delivered to Queensland households was 6.40 ¢/MJ the highest of all states. Average consumption per household in Queensland is the lowest which explains the high cost to serve a small base of customers with low usage. Of the total delivered average gas price, 3.78 ¢/MJ (59%) was the distribution component, 1.50 ¢/MJ (23%) was the retailer component, 0.90 ¢/MJ (14%) was the wholesale gas component and 0.22 ¢/MJ (3%) was the transmission component. There was no environmental policy component.

Of the 2017 average delivered gas price, fixed charges made up 3.09 ¢/MJ (48%) and variable charges made up 3.31 ¢/MJ (52%).

Figure 148 shows the real increase in average residential gas prices in Queensland.

Figure 148: Queensland residential gas price components

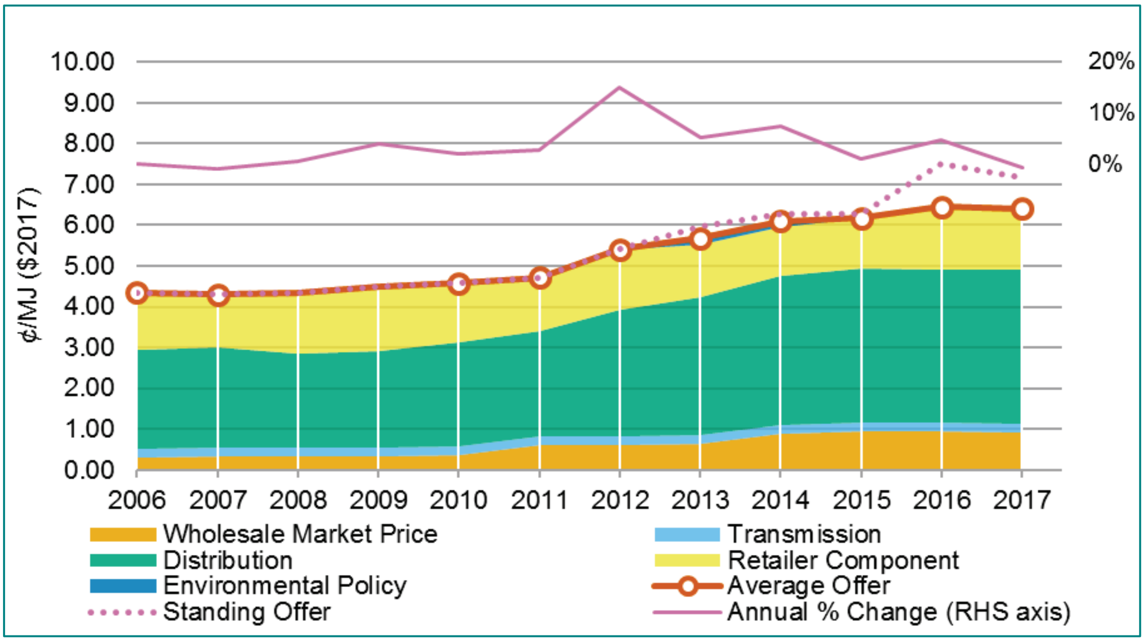


Figure 149 shows the proportion each component contributes to the average gas price.

Figure 149 Proportion of Queensland residential gas price components

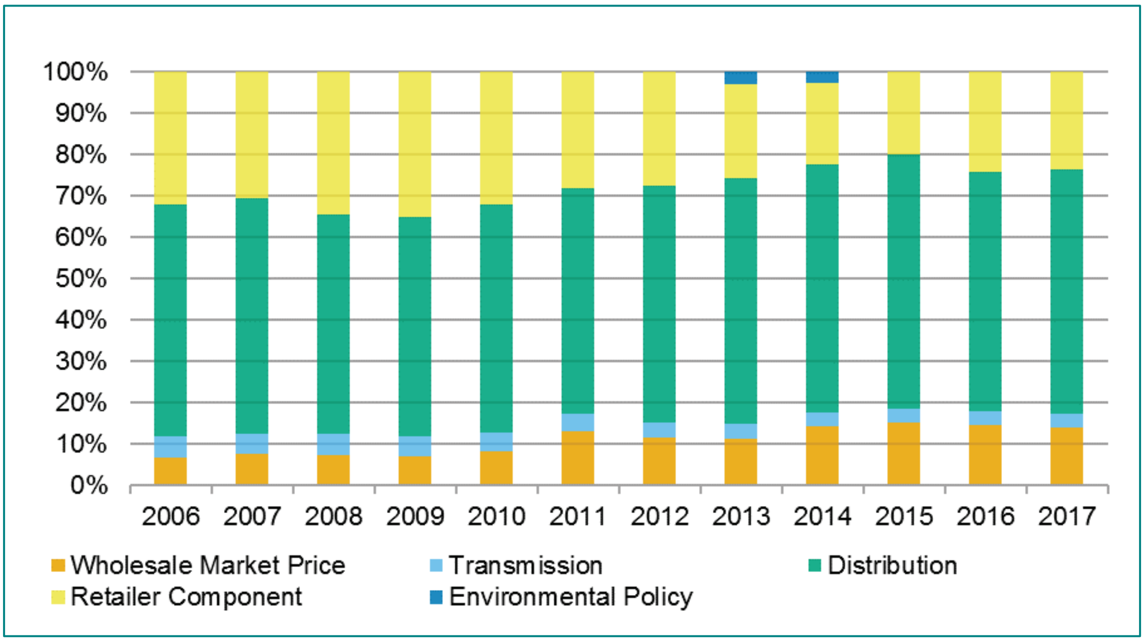


Figure 150 and Figure 151 show the difference between the average standing offers and market offers for each distribution network using the average household consumption for that network.

Figure 150 Typical Household Gas Bill – Australian Gas Networks, Queensland

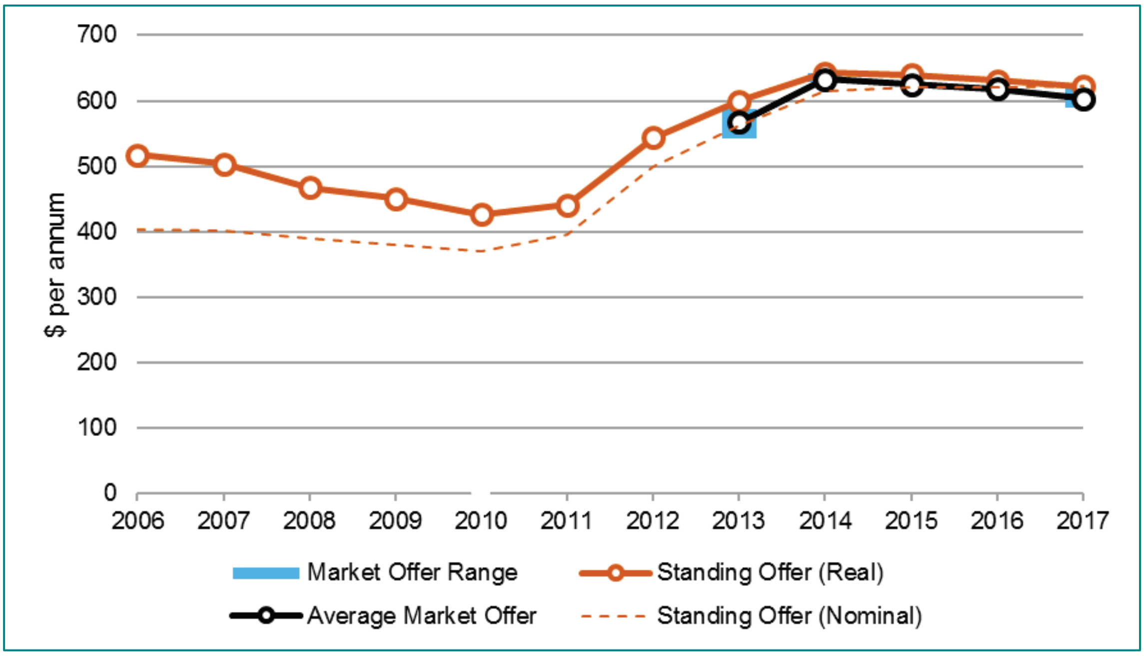
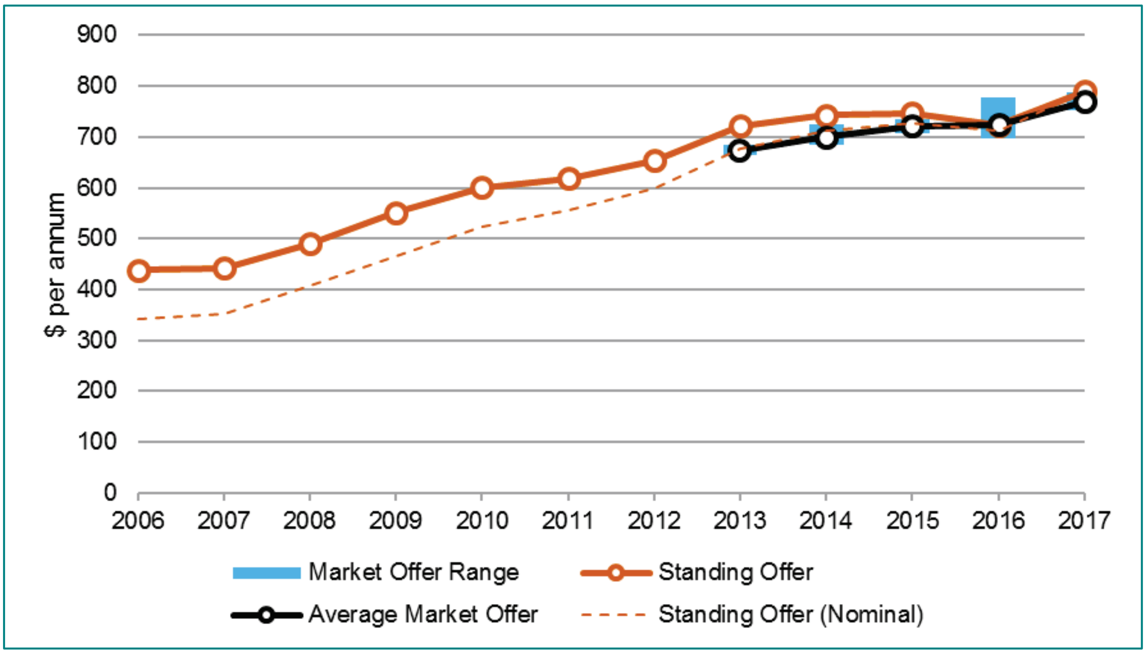


Figure 151 Typical Household Gas Bill – Allgas network, Queensland



8.6.1 Market overview

There are two primary distribution zones in Queensland – Brisbane North and Ipswich (Australia Gas Networks network) and South-East Queensland (Allgas network). South East Queensland extends from south of Brisbane own to the Gold Coast.

The Allgas network is subject to light regulation from 2015 and the AGN network has been subject to light regulation since late 2014 both as a result of decisions by the National Competition Council[158].

The reasons for transition to light regulation are broadly due to:

- Low penetration rates in Queensland;
- Low/negligible switching costs from gas to electric heating (reverse cycle air conditioning);
- Relatively low heating demand in winter due to favourable weather conditions generally;
- Cost to serve per household are relatively high incentivising gas networks to be efficient and competitive without full regulatory oversight; and
- Improbable new market entrants.

Figure 152 Map of Queensland's gas distribution networks

Gas prices for residential customers were deregulated in Queensland on 1 July 2007.

158 National Competition Council (2014) Light Regulation of Envestra's Queensland Gas Distribution Network

Given the relatively small size of the Queensland residential gas market and difficulties acquiring competitively priced new GSAs, few new retailers have entered the market.

AGL and Origin Energy are the only incumbent retailers for the jurisdiction and continue to provide retail standing and market offers. Australian Power and Gas was also providing offers for the region until it was acquired by AGL in 2013.

Table 54 highlights the low level of natural gas penetration with households in Queensland. This reflects the relatively smaller distribution networks in Queensland and the warm climate. The penetration rate is higher for Brisbane (20%) than the remainder of the state (7%).

Table 54 Household gas penetration in Queensland (%)

	2005	2008	2011	2014
Penetration Rate	12.4	12.5	10.9	11.8

Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

8.6.2 Queensland household consumption

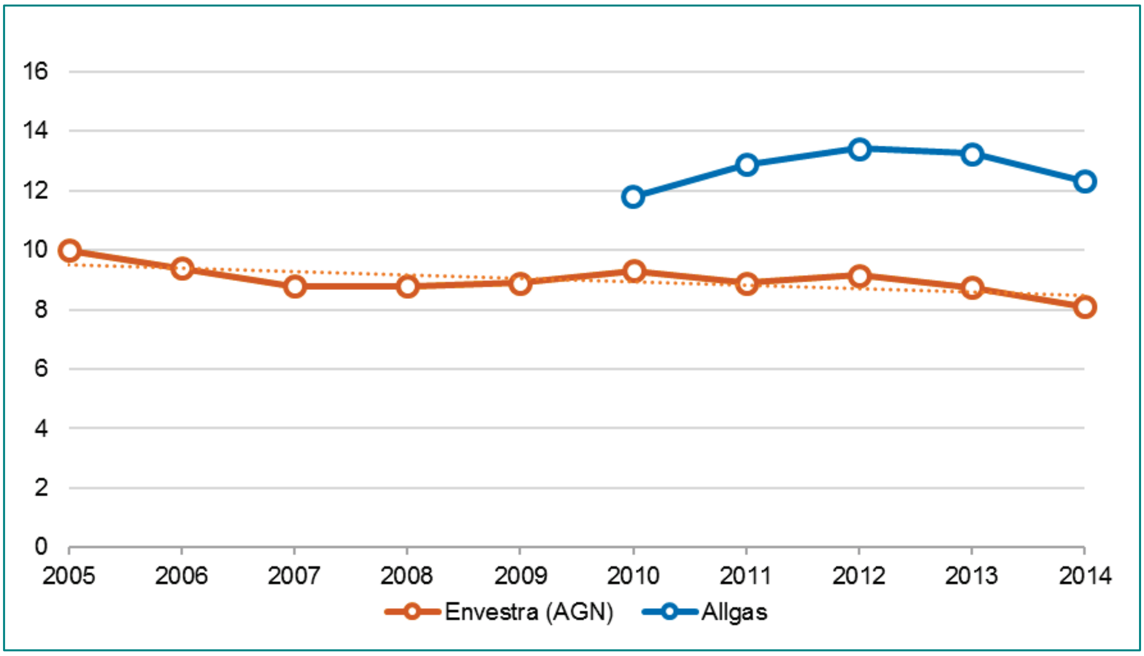
Queensland's average household consumption is 11.4 GJ/a, the lowest of all the states. In 2014, Australian Gas Networks distribution zone had an average consumption of approximately 8 GJ/a and the Allgas distribution zone has an average consumption of approximately 13 GJ/a (most likely reflecting colder weather overall in their zone). There has been no update to this data since, but it is expected to remain a flat demand profile or declining.

This low usage reflects how the gas is used by Queensland households – primarily for cooking, and hot water and space heating quite uncommon.

Figure 153 outlines the recent decline in average household consumption across the two distribution zones.[159]

[159] Allgas submission to National Competition Council; Australian Gas Networks (Envestra) submission to National Competition Council.

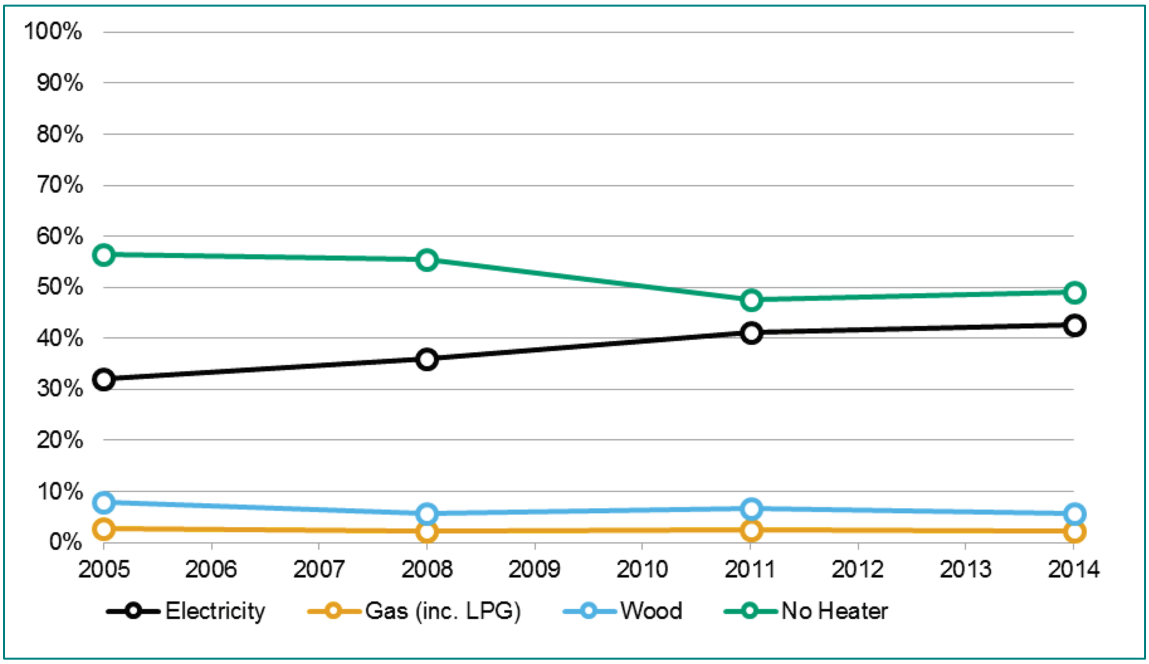
Figure 153 QLD average household gas consumption



Source: Allgas submission to National Competition Council; Australian Gas Networks (Envestra) submission to National Competition Council.

As outlined in 8.6.2, gas is not a common source of energy for space heating in Queensland. This is due to the general warmer climates of Queensland and limit network coverage. This means that changes in the weather do not have a significant impact on the average household usage of gas in Queensland year on year.

Figure 154 Main sources of energy for space heating – Queensland



Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011;

8.6.3 Change since 2015 report

Table 55 summarises the residential gas price component changes from the base year 2006 to both 2015 and 2017. Component changes are minimal, reduced wholesale gas component is offset by increased transmission charges. The retail component acts as the buffer to changes in the other underlying components.

Table 55: Summary component price changes from 2006-2015 & 2006-2017

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Total increase from 2006	1.82	30%	2.05	32%	0.23	4%
Wholesale change	0.64	35%	0.60	29%	-0.04	-5%
Transmission change	-0.01	0%	0.00	0%	0.01	5%
Distribution change	1.35	74%	1.34	65%	-0.01	0%
Retail change	-0.16	-9%	0.11	5%	0.27	22%
Totals	1.82	100%	2.05	100%		

8.6.4 Further developments

The residential gas use patterns and overall trends of marginal decline or limited/no growth in consumption per household in Queensland are not expected to change materially in the short to medium term.

8.7 Western Australia

In 2017, the average gas price delivered to WA households was 4.12 ¢/MJ, of which 1.60 ¢/MJ (39%) was the distribution component, 1.54 ¢/MJ (37%) was the retailer component, 0.50 ¢/MJ (12%) was the wholesale gas component and 0.48 ¢/MJ (12%) was the transmission component. There was no environmental policy component.

Of the 2017 average market offer delivered gas price, fixed charges made up 0.49 ¢/MJ (12%) and variable charges made up 3.62 ¢/MJ (88 %).

Figure 155 shows the trends and components of the average residential gas price.

Figure 155 WA residential gas price components

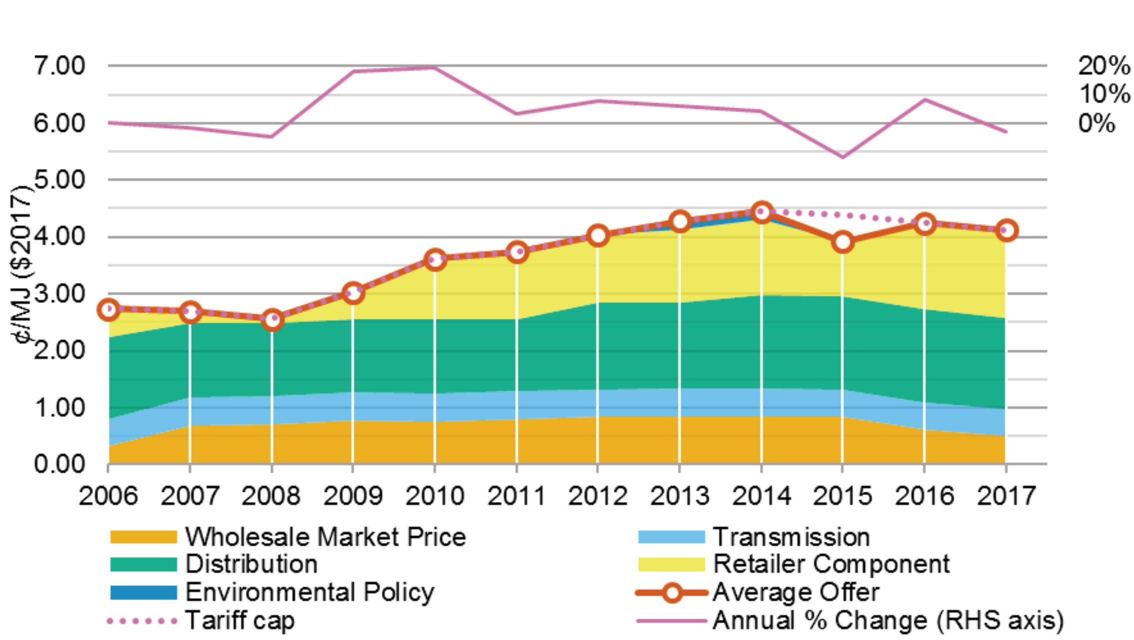
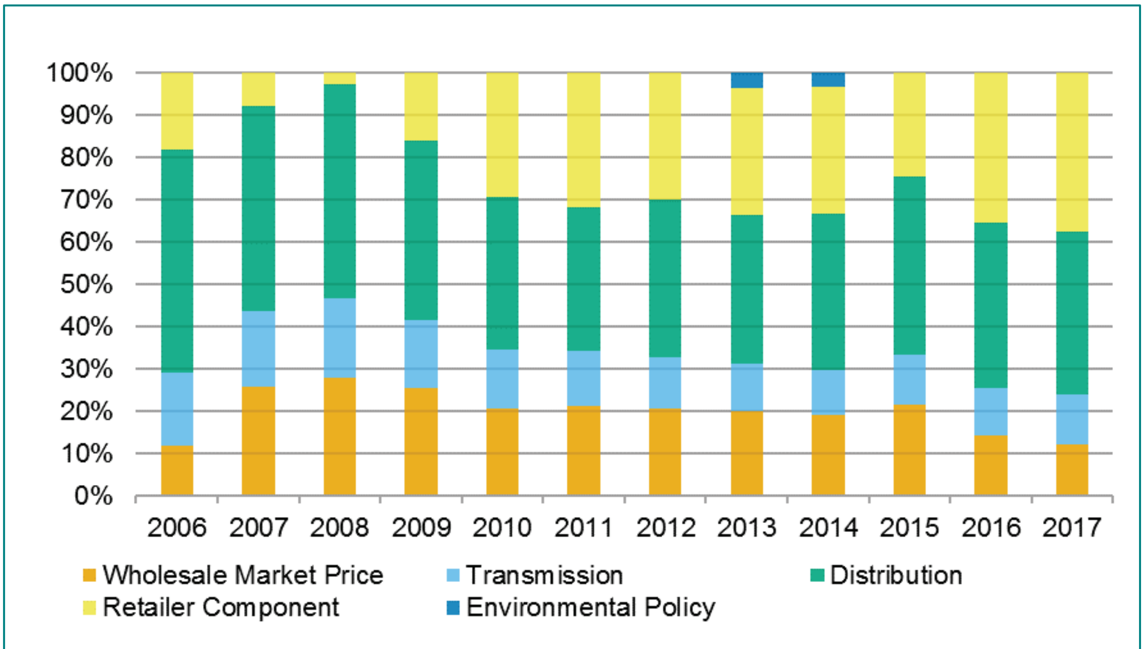


Figure 156 shows significant fluctuation between the proportions of the different components throughout the period.

Figure 156 Proportion of Western Australia residential gas price components



The typical household bill is shown in below in Figure 157.

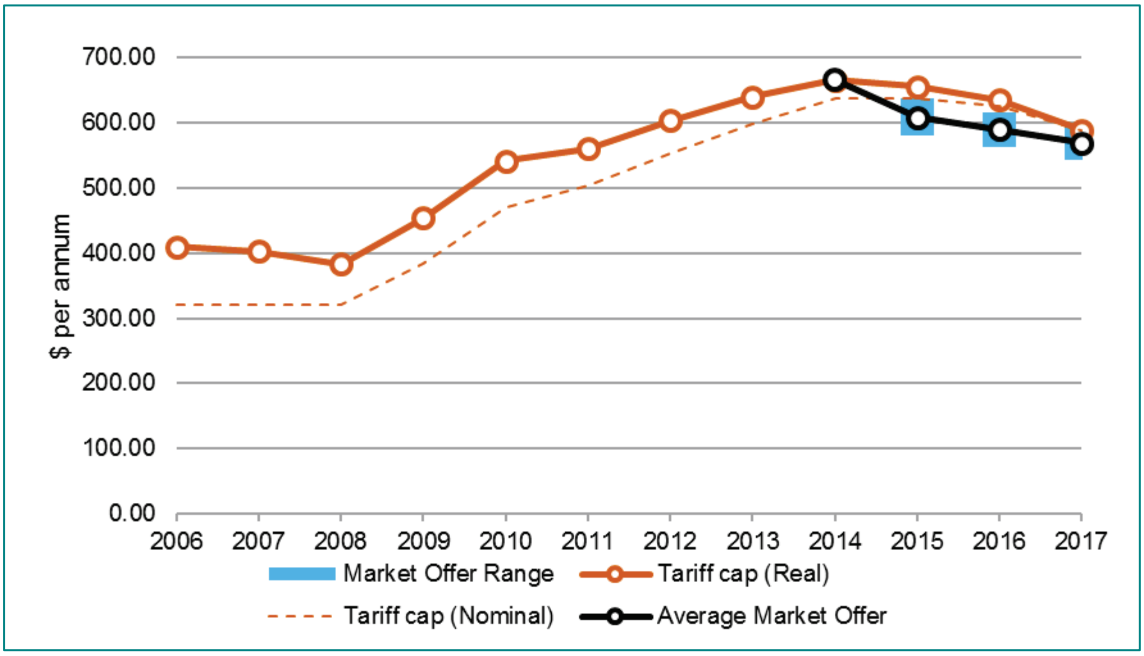
The Western Australian Government sets the price cap (maximum tariff) a retailer can charge a residential customer. Notably, Alinta's standard market offers are not appreciably different to the price cap; though, it is understood they actively pursue customers considering switching retailers with competitive counter offers. Kleenheat offers a 10% discount on gas use. New residential gas retailers AGL, Perth Energy and Origin have entered the market since 2015.

Gas tariffs in WA have a declining block structure where the price per unit decreases with increasing usage.

Residential tariffs are split into a supply charge (cents per day) and a usage charge for tranches of usage with lower charges per unit[160] as more is used above a threshold. In the mid-west to south-west (MWSW), it is the first 12 units are the first tranche, the next 24 units are the next tranche and above 36 units is the next tranche.

The Kalgoorlie-Boulder, Esperance and Albany[161] regions have flat tariff structures with a fixed charge component and a single usage charge.

Figure 157 WA typical household gas bill



8.7.1 Market overview

The main natural gas distribution zones in Western Australia (WA) are shown in Figure 158.

The mid-west to south-west (MWSW) region stretching from Geraldton down to Busselton in the south west corner (regulated);

- Kalgoorlie-Boulder (regulated); and
- Esperance (unregulated).

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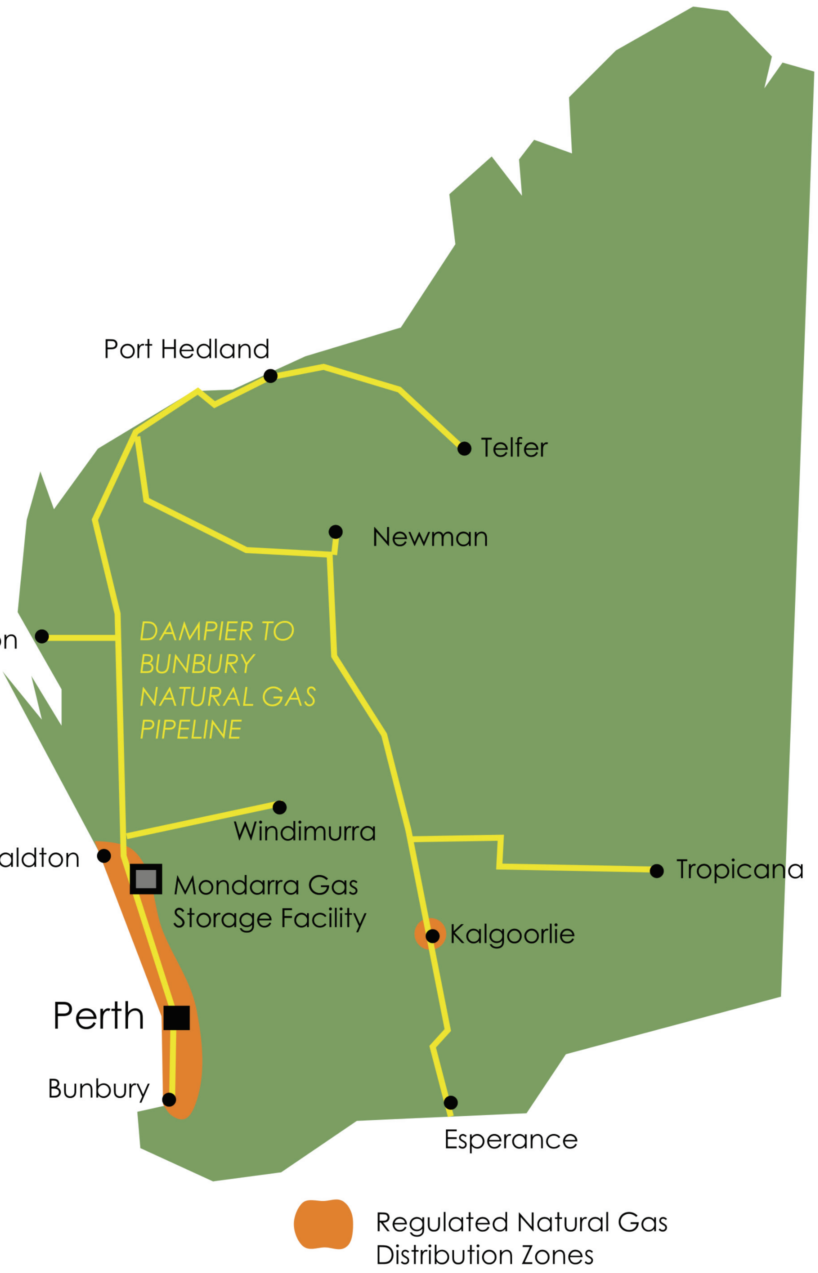
160 In WA, by definition, 1 unit is equal to 3.6 MJ

161 Albany is supplied by the Albany Gas Distribution System (Albany GDS) which is a liquefied petroleum gas (LPG) gas distribution network.

Figure 158 WA residential natural gas regions



There are a number of other gas distribution systems in WA (both regulated and unregulated) that distribute LPG. The Albany gas distribution system is the largest with smaller systems located in Leinster, Margaret River and Hopetoun. These zones have not been included in this report.

Only the larger, regulated mid-west to south-west natural gas distribution zones are included in this report.

The gas retail market in WA became contestable in 2004 and there are now four or five active gas retailers. They are the incumbent Alinta Energy, Kleenheat Gas (part of Wesfarmers), AGL, Origin and Perth Energy.

WA's dominant gas consumption zone is the MWSW region and the distribution network servicing this region is owned by ATCO Australia Pty Ltd.

Table 56 indicates that the gas penetration for Western Australia is reasonably high, with nearly 70% of the state connected to natural gas. There is a considerable difference between gas usage between metro and regional WA. The gas penetration rate in Perth is 83% (one of the highest for a capital city in Australia) while the remainder of the state averages only 25%, probably due to lack of access in those regions.

Table 56 Household gas penetration rate in Western Australia (%)

	2005	2008	2011	2014
Perth	Not available	80.7	83.9	82.6
Balance of state	Not available	29.4	24.5	24.9
Total state	67.2	68.1	68.3	69.0

Source: Australian Bureau of Statistics (2014) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2014; Australian Bureau of Statistics (2011) 4602.0.55.001 Environmental Issues: Energy Use and Conservation, March 2011.

Synergy is also a market participant and retail gas licence holder. However, a WA Government moratorium prevents Synergy from servicing small customers that consume 180 GJ/a or less, hence they do not supply the residential market which sits below this threshold. This moratorium on gas supply for Synergy was set in 2007. The Public Utilities Office states:

"*The purpose of the Moratorium is to provide competitive neutrality for participants in the small use electricity and gas markets. The Moratorium achieves this by preventing Synergy from fully accessing the gas market while gas retailers are denied full access to the electricity market.*"[162]

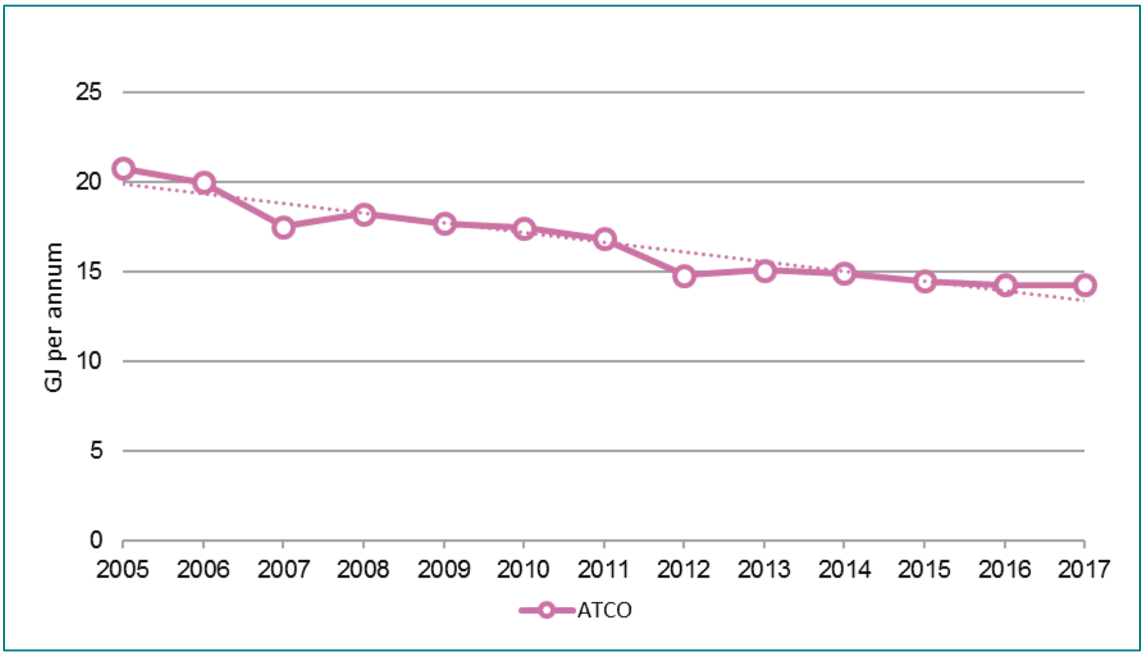
This moratorium applies to electricity retailers with gas portfolios and protects gas only retailers supplying the residential market.

162 WA Department of Finance, WA Dept. of Finance gas market moratorium web page accessed 30 May 2015

8.7.2 WA household consumption

Figure 159 shows the typical household consumption in WA. As with most other jurisdictions, the typical household consumption has been steadily declining throughout the period – from 20.8 GJ/a in 2005 to 14.9 GJ/a in 2014 and is assumed to continue to moderate to 14.25 GJ/a in 2017[163].

Figure 159 WA typical household gas consumption



8.7.3 Change since 2015 report

Table 57 summarises the residential gas price component changes from the base year 2006 to both 2015 and 2017. The largest movement is in the downward wholesale gas price component which presents the opportunity for a higher retail component depending on when retailers contract their gas.

Table 57: Summary component price changes from 2006-2015 & 2006-2017

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Total increase from 2006	1.18	30%	1.38	33%	0.20	5%

163 ERAWA (2015) Review of ATCO Gas Australia's gas demand forecasts

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Wholesale change	0.51	44%	0.17	13%	-0.34	-41%
Transmission change	0.00	0%	0.01	1%	0.01	2%
Distribution change	0.20	17%	0.15	11%	-0.06	-3%
Retail change	0.46	39%	1.04	76%	0.58	61%
Totals	1.18	100%	1.38	100%		

8.7.4 Further developments

New entrant retailers who could challenge Alinta's dominance (without a legacy GSA pricing gas at least similar to Alinta's gas price) may not be able to compete if the regulator maintains a tariff cap level to counter any extra headroom in the WA retailer component. The fact Kleenheat only entered the market in 2014 and that there were no new entrants before then demonstrates this challenge.

Synergy might be able to compete in the residential retail gas sector presuming it has a legacy GSA, but it is constrained by the current moratorium imposed by the WA Government on its entry into the residential gas retail sector for various reasons[164].

Given Alinta's dominant market position, there is also an opportunity for new entrants to capture market share by virtue of natural attrition away from the incumbent market share holder. Kleenheat for example could steadily increase its market share and provide a competitive offering to consumers.

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164 The WA Government imposed a 0.18TJ/a contestability threshold on Synergy in 2007 to align with electricity and provide competitive neutrality in the small consumer gas and electricity markets, where Synergy's access to gas and electricity data and demand base could disadvantage other retailers. The Electricity Market Review recommends removing the gas moratorium subject to full retail contestability in the electricity market (WA Electricity Market Review webpage).

With the widening of the retail margin due to reducing wholesale gas prices available in the market, the evidence suggests it is attractive for new entrant retailers to enter, hence AGL and Origin and Perth Energy have entered the market since 2015.

9 National summary of residential gas prices

Residential gas prices in each state and territory overall rose to varying degrees over the past ten years. Figure 160 shows the national weighted average residential gas price in real dollars ($2017) from 2006 to 2017.[165]

In 2017 the national average retail gas price was 2.91 ¢/MJ, of which 1.02 ¢/MJ (35%) was the distribution component, 0.73 ¢/MJ (25%) was the retailer component, 0.95 ¢/MJ (33%) was the wholesale gas component and 0.21 ¢/MJ (7%) was the transmission component. The environmental policy component was insignificant.

Of the 2017 average market offer delivered gas price, fixed charges made up 0.66 ¢/MJ (23%) and variable charges made up 2.25 ¢/MJ (77 %).

Figure 160 All jurisdictions average residential gas retail prices ($2017)

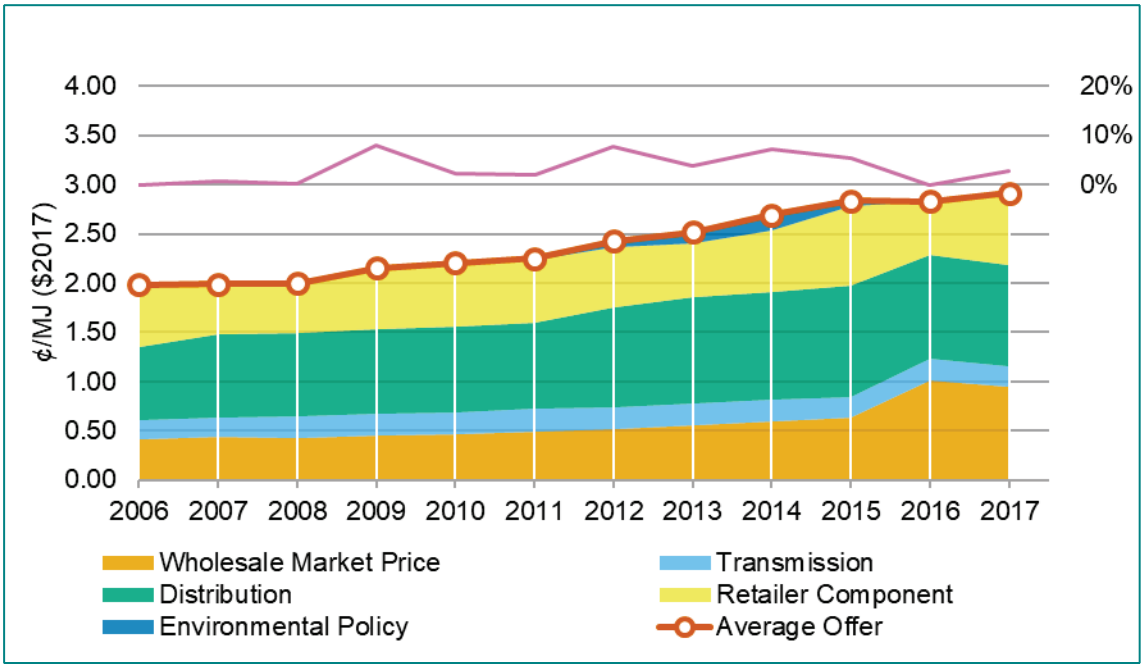

Figure 161 shows the percentage breakdown of the average residential gas price. The percentage breakdown of the average residential gas price has been reasonably consistent up to 2015 then the wholesale gas price impact moves around the retailer component in 2016 and 2017. The retail component is about 25%, distribution 35%, wholesale gas price at 33%, and transmission 7% in 2017. The recent analysis shows that the wholesale component has become more dominant in the last two years forming 33%-36% of the Australian average residential price.

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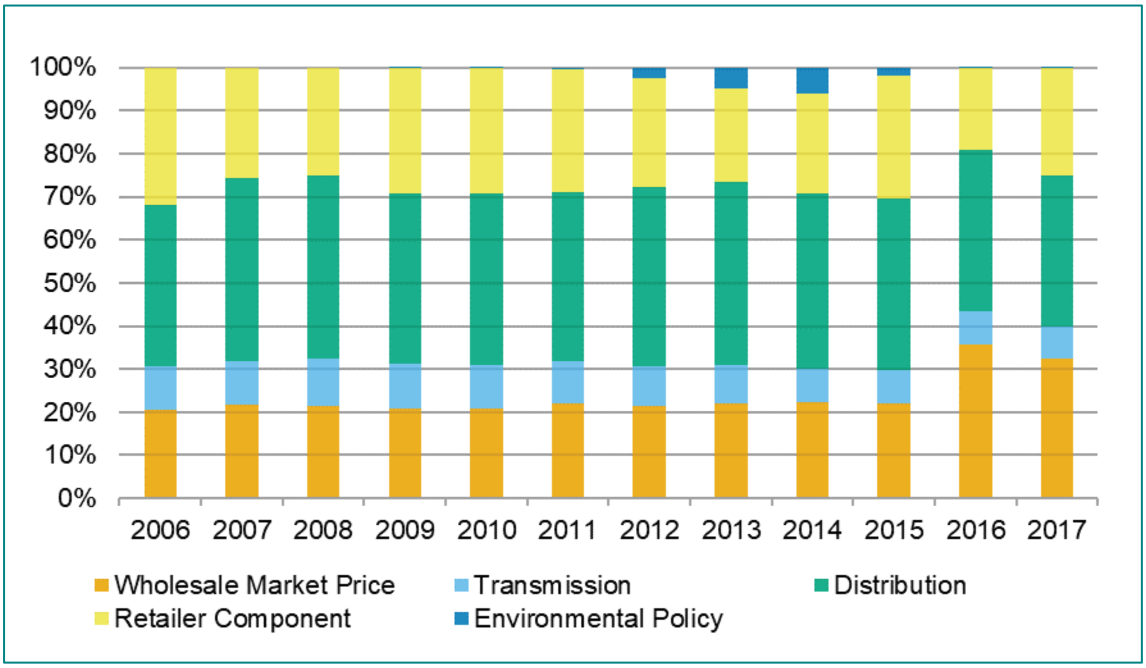
165 Financial year reference

Figure 161 Proportion of national average residential gas price components



9.1 Change since 2015 report

Table 57 summarises the residential gas price component changes from the base year 2006 to both 2015 and 2017. The largest movement is in the increase wholesale gas price component which presents the opportunity for a higher retail component depending on when retailers have contracted their gas.

Table 58: Summary component price changes from 2006-2015 & 2006-2017

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Total increase from 2006	0.86	30%	0.91	32%	0.06	2%
Wholesale change	0.22	26%	0.54	59%	0.32	50%
Transmission change	0.01	1%	0.01	1%	0.00	1%
Distribution change	0.39	46%	0.28	30%	-0.11	-10%
Retail change	0.18	21%	0.08	9%	-0.10	-10%

	2015 Report		2017 Report		Change	
	¢/MJ change ($2017)	% contribu-tion to change	¢/MJ change ($2017)	% contribu-tion to change	2015 to 2017 ¢/MJ change	2015 to 2017 % change
Totals	0.80	94%	0.91	100%		

The wholesale price component has increased by 50% compared to the 2015 Gas Price Trends Report and is one of the largest contributions to residential gas pricing. Despite the large increase in gas pricing the overall residential gas cost has seen modest gains of only 2% since 2015. Some of the price increase has been offset by a lower distribution component (-10%) with lower regulated tariffs and a reduction to the retailer component, absorbing the resent wholesale component increase.

9.2 National retail price comparison

While residential gas prices rose over the time frame of the report in all states, prices in all states except Tasmania and Victoria have plateaued and some states have peaked and started to decline.

Figure 162 shows the weighted average Australian gas price and the average gas price of each state and territory.

Figure 162 Residential gas price trends by state ($2017)

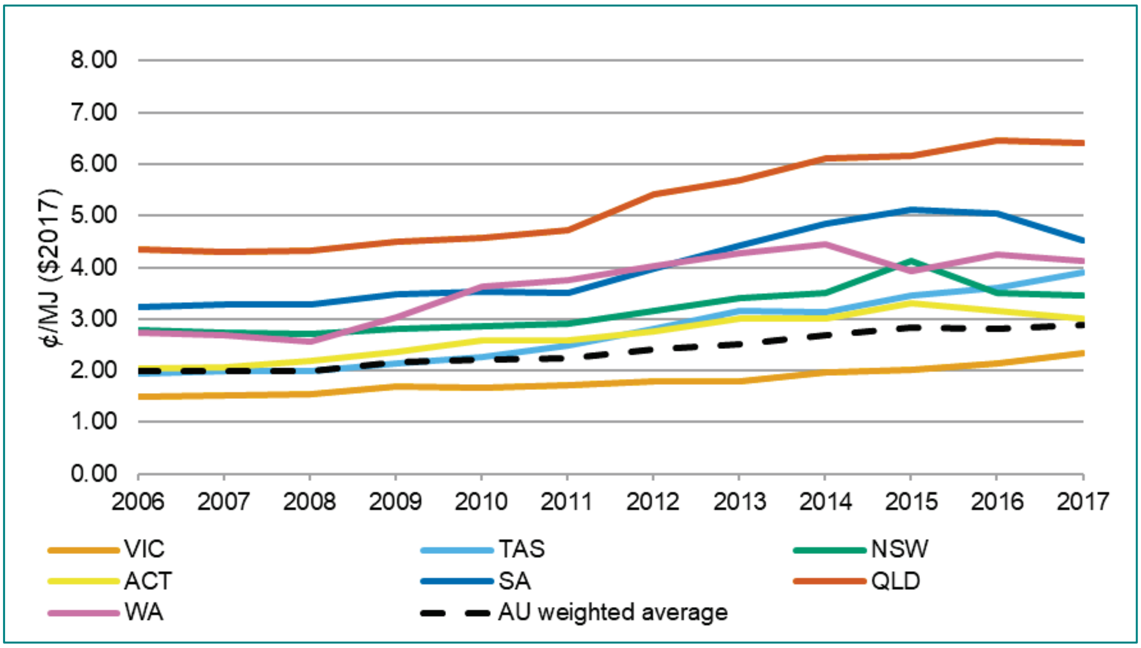


Table 59 shows average residential prices in 2017 for a typical household, and its four cost components in terms of ¢/MJ and as a percentage of the total average price.

In 2017 (which represents either the calendar year 2017 or the financial year 2016/17, depending on the various regulatory cycles of each state), the average gas price ranged from 2.35 ¢/MJ in Victoria to 6.40 ¢/MJ in Queensland.

In all states except Victoria, distribution network charges still were the largest cost component (from 26% of the average price in Victoria to 59% in Queensland (QLD) and ranged from 0.62 ¢/MJ in Victoria to 3.78 ¢/MJ in Queensland.

Increases in wholesale costs over last few years now see these costs form the second highest proportion of the total costs (from 0.50 ¢/MJ in WA to 1.00 ¢/MJ in TAS and VIC).

For most states retail costs were the next biggest component (from 0.32 ¢/MJ in NSW Rural to 1.54 ¢/MJ in WA).

Transmission costs were the smallest component for all states and ranged from 0.15 ¢/MJ in Victoria to 0.48 ¢/MJ in WA.

Victoria is the only state with an environmental policy that directly affects residential gas prices, the cost of which is estimated to be less than 0.01 ¢/MJ.

Table 59 Average delivered gas price and cost components for a typical household in 2017[166]

	Typical household consumption estimate (GJ p/a)	Average gas price, typical household (¢/MJ)	Wholesale gas (¢/MJ and % of gas price)		Transmission (¢/MJ and % of gas price)		Distribution (¢/MJ and % of gas price)		Retail (¢/MJ and % of gas price)	
ACT	38.7	3.00	0.93	31%	0.32	11%	1.35	45%	0.41	14%
NSW avg.	21.5	3.45	0.93	27%	0.32	9%	1.36	40%	0.84	24%
NSW metro	20	3.52	0.93	26%	0.32	9%	1.39	40%	0.88	25%
NSW rural	41	2.54	0.93	36%	0.32	13%	0.98	38%	0.32	12%
QLD	11.4	6.40	0.90	14%	0.22	3%	3.78	59%	1.50	23%
SA	17.7	4.53	0.93	20%	0.25	5%	2.48	55%	0.88	19%
TAS	30	3.91	1.00	26%	0.53	14%	1.91	49%	0.47	12%
VIC	50.1	2.35	1.00	43%	0.15	6%	0.62	26%	0.58	25%
WA	14.5	4.12	0.50	12%	0.48	12%	1.60	39%	1.54	37%

166 The total average gas price may not equal the sum of the components due to rounding errors.

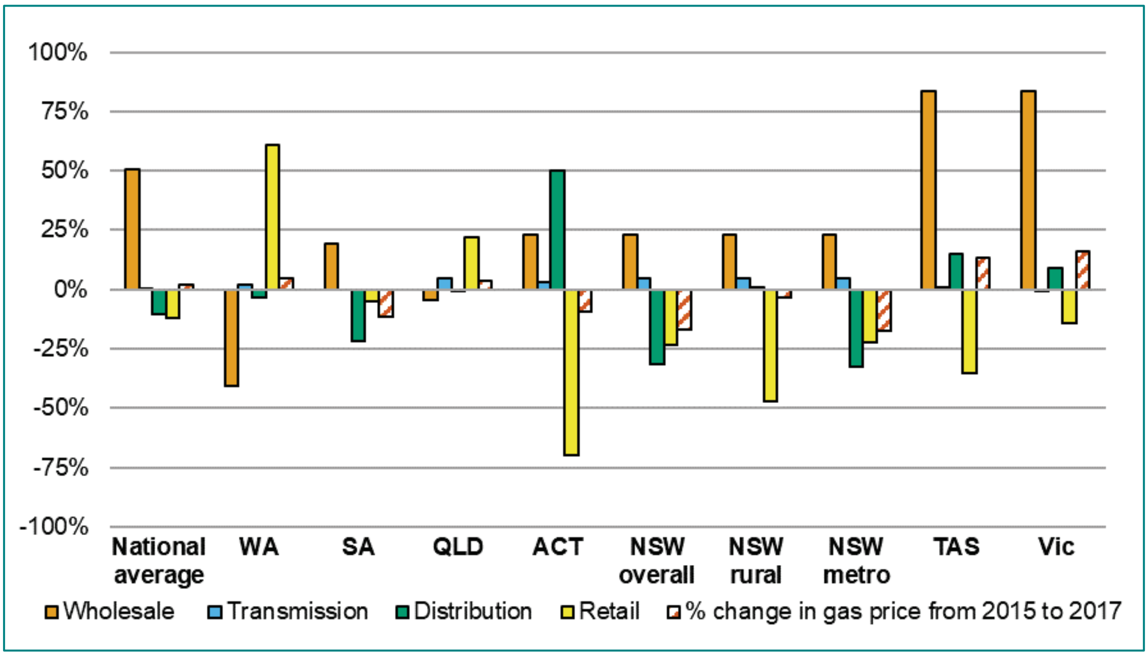
	Typical house-hold consump-tion estimate (GJ p/a)	Average gas price, typical house-hold (¢/MJ)	Wholesale gas (¢/MJ and % of gas price)	Transmis-sion (¢/MJ and % of gas price)	Distribu-tion (¢/MJ and % of gas price)	Retail (¢/MJ and % of gas price)
National	39.9	2.89	0.95 33%	0.21 7%	1.02 35%	0.71 25%

Figure 163 shows the real increases in residential gas prices over the study period and the contribution of each cost component to these increases. Price changes ranged from -17% in NSW to 20% in WA.

Rising wholesale costs were responsible for more than 83% of price increases in VIC and TAS. Despite the increase in wholesale costs in most jurisdictions. The reduction in retail cost components and distribution cost components, the overall percentage were negative for all jurisdictions except WA, TAS and VIC.

The contribution of transmission costs to rising prices was negligible in most states and even made a slight negative contribution in some.

Figure 163 Percent contribution of each cost component to change in real residential gas prices from 2015 to 2017

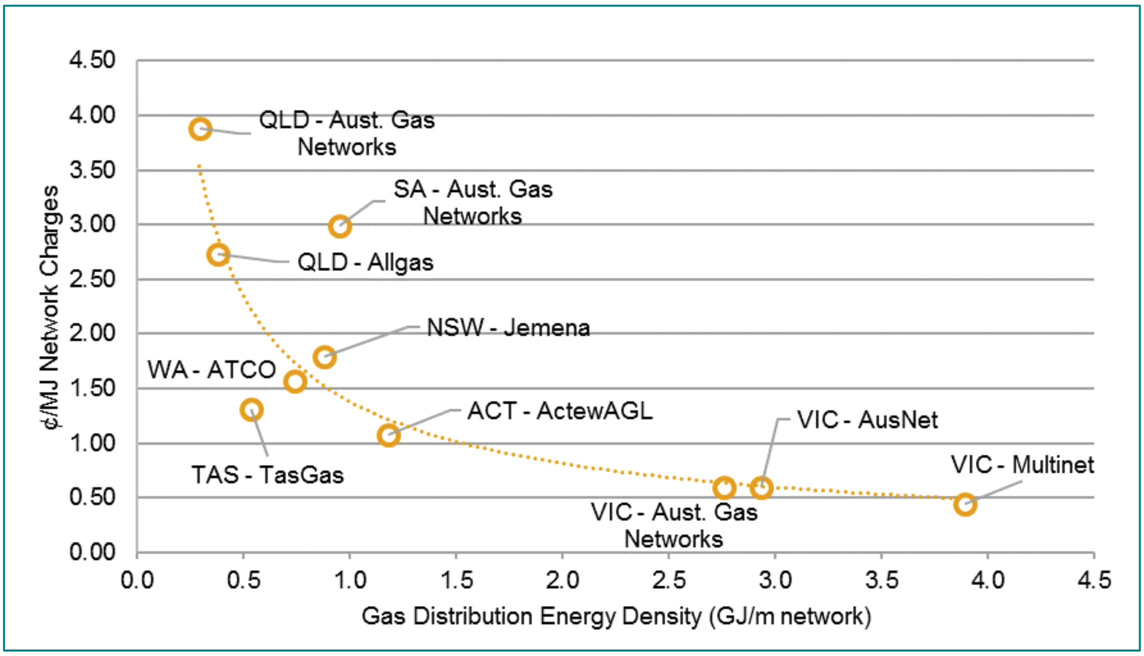


9.3 Distribution network charges

Distribution network charges are a function of the amount of gas consumed on a network relative to a network's size (total length of pipe), known as the network's energy density. Networks with a relatively large number of customers and high average consumption per customer have lower distribution charges.

This correlation is shown in Figure 164 which benchmarks energy density against network costs based on residential consumption for Australia's largest distribution networks. This illustrates the influence of economies of scale on the cost of distribution, which in turn impacts on the overall residential gas price.

Figure 164 Benchmark network charges ($/GJ) versus distribution energy density (GJ/m network) 2013/2014

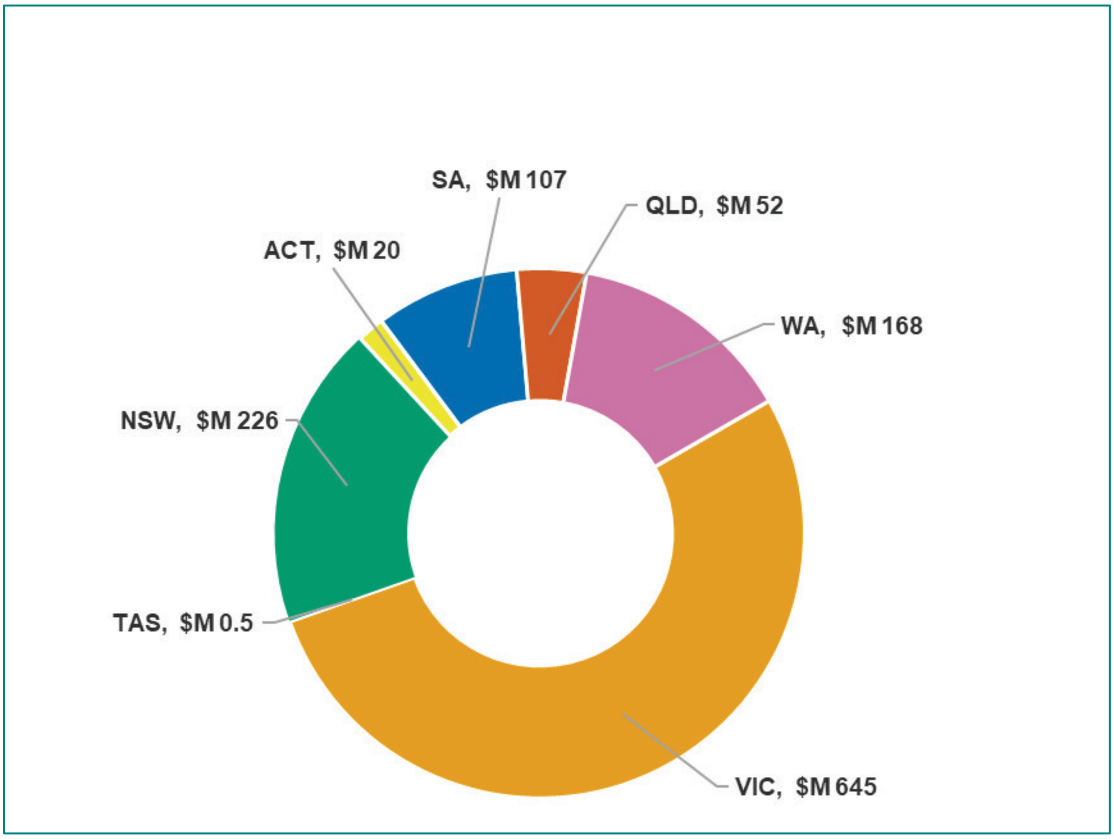


Source: AER State of the Energy Markets and various companies' websites and access arrangements

9.4 National retailer component

Figure 165 shows an estimation of retailer component revenue for each jurisdiction. Revenue is calculated by multiplying the retailer component (¢/MJ) by the total residential gas consumption per jurisdiction.

Figure 165 Retailer component revenue estimate for each state jurisdiction



Appendix A Transmission Industry Pipeline Schedule and Consultations

A.1 Pipelines

Pipeline	MDQ Forward (TJ)	State	Length (km)	Year Commissioned
Amadeus Gas Pipeline	120	NT	1512	1986
APLNG Pipeline	1560	QLD	530	2015
Beharra Springs Pipeline	37	WA	1.6	-
Berwyndale to Wallumbilla Pipeline	160	QLD	112	2008
Bonaparte Pipeline	80	NT	286	2008
Braemar Gas Pipeline I	80	QLD	150	2005
Braemar Gas Pipeline II	-	QLD	110	2009
Bundaberg Port Gas Pipeline	-	QLD	28	2017
Cheepie to Barcaldine Pipeline	-	QLD	404	1995
Comet Ridge to Wallumbilla	950	QLD	127	2007
Carpentaria Gas Pipeline	119	QLD	840	1998
Cannington Lateral Pipeline	13	QLD	98	1998
Central Ranges Pipeline	-	NSW	300	2006
Central West Pipeline	-	NSW	255	2006
Dampier to Bunbury Pipeline	845	WA	1400	1984
Darling Downs Pipeline	270	QLD	200	2004
Darwin City Gate to Berrimah Pipeline	-	NT	19	1996
Dawson Valley Pipeline	30	QLD	47	1996
Eastern Gas Pipeline	351	NSW	795	2000
Eastern Goldfields Pipeline	-	WA	293	2015

Pipeline	MDQ Forward (TJ)	State	Length (km)	Year Commissioned
Fortescue River Gas Pipeline	26	WA	270	2015
GLNG Pipeline	1430	QLD	435	2014
Goldfields Gas Pipeline	202	WA	1378	1996
GGP to Kalgoorlie Power Station Lateral	-	WA	8	1996
Kalgoorlie to Kambalda Pipeline	-	WA	44	N/a
Karratha to Cape Lambert Pipeline	-	WA	57	N/a
Kincora to Wallumbilla Pipeline	-	QLD	53	N/a
Mid-West Pipeline	10	WA	353	N/a
Moomba to Adelaide Pipeline	250	SA	1185	1969
Moomba to Sydney Pipeline	392	NSW	2001	1974
North QLD Gas Pipeline	108	QLD	391	2004
Northern Gas Pipeline	90	NT	622	2018
Palm Valley to Alice Springs Pipeline	-	NT	146	1983
Parmelia Gas Pipeline	65	WA	416	1971
Peabody Mitsui Gas Pipeline	-	QLD	23	1996
Pilbara Pipeline System	166	WA	240	1995
QSN Link	404	NSW/QLD	182	2009
Queensland Gas Pipeline	149	QLD	629	1991
Reedy Creek Wallumbilla Pipeline	300	QLD	50	2017
Riverland Pipeline System	-	SA	237	1995
Roma to Brisbane Pipeline	233	QLD	440	1969
Peat and Scotia Lateral Pipeline	74	QLD	121	2001

Pipeline	MDQ Forward (TJ)	State	Length (km)	Year Commissioned
SEA Gas Pipeline	314	SA	680	2004
Silver Springs Pipeline	-	QLD	101	1978
South East Pipeline System	-	SA	70	1991
South East South Australia Pipeline	-	SA	45	2005
South West Queensland Pipeline	340	QLD	755	1996
South Gippsland Pipeline	-	VIC	60	2006
Spring Gully Pipeline	142	QLD	90	2004
Tasmanian Gas Pipeline	129	Tas	734	2003
Telfer Gas Pipeline	29	WA	374	2005
Victorian Transmission System	-	VIC	2035	1969
Wallumbilla Gladstone Pipeline	1588	QLD	530	2014
Wheatstone Ashburton West Pipeline	-	WA	109	2015
Wickham Point Pipeline	-	NT	12	2009
VIC-NSW Interconnect	138	VIC	150	1998

A.2 Consultation Process

The following pipeline owners were consulted for the preparation of this section of the report:

- APA Group;
- Australian Gas Infrastructure Group;
- Epic Energy;
- Jemena; and
- Palisade Investment Partners.

The following government agencies were consulted:

- AEMO;
- AEMC;
- Gas Market Reform Group;
- Office of the Tasmanian Economic Regulator;
- Tasmanian Government State Development; and
- Western Australian Public Utilities Office.

Oakley Greenwood consulted with fourteen shippers. These included shippers on the east and west coasts, end users, generators and retailers. The shippers we consulted had gas transport agreements on one or more of the following pipelines:

- Carpentaria Gas Pipeline;
- Dampier to Bunbury Pipeline;
- Eastern Gas Pipeline;
- Moomba to Adelaide Pipeline;
- Moomba to Sydney Pipeline;
- Parmelia Gas Pipeline;
- Roma to Brisbane Pipeline;
- SEAGas Pipeline;
- South West Queensland Pipeline;
- Tasmanian Gas Pipeline; and
- other smaller pipelines.

Appendix B Residential Price Trends - Methodology

B.1 Residential methodology

This section outlines the approach used to estimate the trends in gas pricing for residential gas for each state and territory, excluding the Northern Territory, from 2002-2003 to 2014-2015 on a yearly basis. The data is processed on a ¢/MJ basis to understand the component costs for each jurisdiction and also was processed to develop a representative household bill per annum. All prices and costings are GST exclusive and are in real dollars (2014-2015), unless noted otherwise.

Data are based on a calendar year for some jurisdictions and financial year for others. For comparison purposes, any data that is based on a calendar year was assumed to be equivalent to the previous financial year. For example, 2015 calendar year data is assumed to align with data provided for the 2014-2015 financial year from another jurisdiction.

Estimations were produced for the following components of the retail price:

- Wholesale gas
- Transmission
- Distribution
- Environmental policies
- Retailer

Through the research process it became apparent that the archiving and transparency of tariffs and changes in tariffs (and some environmental policies) was dependent upon each individual regulating body and, as a result, details and quality of the data were variable between states and territories particularly in the earlier years. Where prices were not regulated, details were not always available with even some retailers not carrying records back more than four to five years.

As a result, for some states a small number of data points were not available for some years and in these cases the data were interpolated. Where data were unavailable at the beginning, the data were extrapolated for the rate of change in previous or subsequent years. Queensland is the only state where retail tariff data were incomplete in the years 2008 and 2009. Where a year has been estimated no marker appears on the average retail offer trend line for that year.

B.1.1 How average household gas prices are calculated

An effective average gas price was calculated for residential customers in each state. This price is an average ¢/MJ price a customer with the average gas consumption for a particular state would pay. The basic approach used to calculate an effective average gas price for a state, in a particular year, was:

- Research the retail and distribution tariffs in the market offers and/or, if applicable, standing offers in a state for each distribution zone or region, for each year;

- Establish the jurisdiction’s average household consumption or where there are multiple distribution zones, the average consumption per zone;
- Using the average household consumption calculate the annual retail bill and distribution charges from the market or standing offer tariffs for each year;
- Divide the annual bill by the average household consumption to get a ¢/MJ equivalent gas price for the retail and distribution charges;
- Where there are multiple market offers in a given year, calculate the average ¢/MJ equivalent gas price for each offer and then average these values to get an overall average ¢/MJ equivalent gas price; and
- Where there were multiple distribution zones in a jurisdiction, use a weighted average based on distribution zone consumption to derive an average jurisdiction ¢/MJ for the retail and distribution charges.

This approach, including the various considerations and assumptions that have been used, is explained as follows.

In 2015, in each state the majority of consumers were on market offers (see section B.1.2 for an explanation of market and standing offers). In competitive markets, there are often a number of market offers available from a range of retailers. To determine the equivalent gas price, the straight mean of the ¢/MJ equivalent gas price for each market offer for a given year in a distribution zone was used as the average gas price for that zone.

At the beginning of the data series in 2006, some jurisdictions did not have retail contestability and/or there was limited competition. In these cases, the majority of customers were on standing offers and so standing offers were used to calculate gas prices in the initial years.

Tariffs and data were calculated for each state based on a consumption weighted average from each gas zone. The consumption weighted average of these zones is used to calculate the consumption weighted average for the state.

A gas distribution zone is the area covered by a particular distribution network or part of a distribution network that has market and/or standing offers particular to that area. These distribution zones have traditionally been operated by a single distribution company with a regulated distribution tariff, which forms the underlying cost basis for the retail tariff. In regions that have high penetration, competition and consumption, such as Victoria, the major distribution networks are each divided into a number of distribution zones, based on historical retail franchise zones, and retailers have market offers for each of these zones. Each of these distribution zones is considered a gas zone for the purposes of this analysis (see 8.1.1 for details of Victoria’s gas zones). By contrast, in Queensland the analysis considers two gas zones, which are the state’s two distribution networks.

For most gas zones, the tariff is flat year round. For these states bills and costs have been calculated by assuming average household gas consumption is constant across the year (see section B.1.2.1 for information on average consumption and consumption profiles).

Some of the colder regions, such as Victoria, have a seasonal pricing structure, fundamentally a peak/off-peak season approach, with the peak based on the winter months of June to September. This is effectively driven by distribution network tariff structures and is passed on to end customers by the retailers. While the peak period is reasonably consistent across distributors, Multinet applies “shoulder period” charges which effectively extend the peak period to 6 months (although with a slightly lower charge for the shoulder period than the peak 4 month period).

Given the significant usage of gas during the peak periods, the load profile for Victoria has been adjusted. Based on information in a report undertaken by the Energy Rating Program’s Residential Energy Metering Program, 65% of the average annual usage has been applied to the peak period for those zones that have a 4-month peak period and 85% of the average annual usage for those zones that have a 6-month peak period (including shoulder periods).[167]

The annual bill was calculated by the addition of the fixed charge over the year plus multiplying the variable charge by the average annual household consumption in the year. Most gas tariffs are based on a tiered charging structure based on consumption tranches. Generally, the tranche ¢/MJ charge reduces with increased consumption. For uniformity of calculations for all the data for the different zones, all tariff structures have been reduced to a daily charge structure for the average daily consumption.

An average residential gas price (the indicative tariff) in ¢/MJ was then calculated by taking the total bill and dividing by the average annual household consumption.

The general formula for the calculations are:

Daily charge for period (¢/day) = fixed cost per day + ∑ (variable rate/day/tranche (¢/MJ) x MJ/tranche/day)

Annual bill ($ pa) = ∑ (Daily charge (¢/day) x days in tariff period[168])

Indicative tariff (¢/MJ) = annual bill ($ pa) / annual consumption (MJ)

Box 1 provides a complete worked example for 2014-2015 for the ACT region.

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167 Proof of Concept Residential Energy Monitoring Program – Final Report, March 2012.

168 The tariff period is 365 days for a flat rate contract.

Box 1 Worked Example for ACT

ActewAGL retail offer for ACT for 2014-2015:

Our ACT natural gas prices

The following rates apply from 1 July 2014. Accounts issued on or after that date will be charged on a pro-rata basis. The carbon price has been removed from usage rates (item 1 to 2).

1 Residential

Plan	Unit	2014-15 GST exclusive	2014-15 GST inclusive
Home			
Supply charge	¢ per day	66.66	73.326
Usage rates:			
• first 41.0959 MJ/day	¢/MJ	2.685	2.9535
• next 2,704.1096 MJ/day	¢/MJ	2.484	2.7324
• next 10,964.3836 MJ/day	¢/MJ	2.429	2.6719
• thereafter	¢/MJ	2.224	2.4464

(Source: archived ActewAGL website)

Assumed average annual household consumption for ACT = 45 GJ/annum.

Daily consumption 45/365 = 0.1233 GJ/day or 123.3 MJ/day.

Retail tariff calculation (GST exclusive) from above:

Tariffs	Calculation	Totals (¢/day)
Tranche 1 =< 41.0959 MJ/day	41.0959MJ x 2.685¢/MJ	110.34
Tranche 2 next 2704.1096 MJ/day	82.1917MJ x 2.484 ¢/MJ	204.16
Daily charge	66.66 ¢/day	66.66
Daily totals	~123.3 MJ	381.17

Typical household yearly bill = 381.17/100 x 365 = $1,391.26

B.1.2 Residential tariffs: Market and Standing Offers

In most states and territories two categories of gas supply offers are available to consumers. These are market offers and standing offers. These offers give, among other things, the tariff a customer would pay for using gas. In all states and territories in recent years, the majority of residential customers are on market offers, which are generally cheaper and offer discounts such as for on time payment, and so market offers have been used to determine the annual average tariff for a state. At the beginning of the data series in 2006, some jurisdictions did not have retail contestability and/or there was limited competition. In these cases, the majority of customers were on standing offers and so standing offers were used to calculate gas prices in the initial years.

The tariff structure in market and standing offers has two components: a fixed component and a variable component. The fixed component or "daily supply charge" is independent of the amount of gas a customer uses. It is a fee to service the property and covers costs such as meter reading and the distribution network operator's capital cost recovery. The variable charge or "consumption charge" is a charge per MJ of gas the customer consumes. The variable charge typically has a sliding scale (in consumption tranches) where the charge changes, typically reduces, depending on how much gas a customer uses over a billing cycle, averaged per day.

Residential retail market offers and their tariffs were obtained from a number of sources including regulator data bases and archives, the AER's energy made easy comparison web site, discussions with retailers, St Vincent de Paul Society's Tariff Tracking Project, and research using web archive retrieval tools.[169]

One of the key resources was the research that St Vincent De Paul Society has undertaken every year since 2009 with their Tariff Tracking Project.[170] This work provides a centralised historical resource for all standing and market retail tariffs for gas and electricity across all zones (with exception of WA) in Australia. The research is in spreadsheet form and was used for verifying a significant portion of the inputs in the analysis.

Prices under market retail contracts are set by the retailers. Market retail contracts are gas contracts that include minimum terms and conditions prescribed by law. The terms and conditions of market retail contracts generally vary from standing offer contracts. For example, market retail contracts may also include:

- Discounted prices
- Non-price incentives
- Different billing periods

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169 Internet archive wayback machine website

170 Energy reports from St Vincent De Pauls website.

- Different payment options
- Fixed term durations
- Fees and charges, such as establishment fees or exit fees.

The discount can be on a bill or usage basis. For the analysis it has been assumed that the typical bill is paid on time and receives the additional discount. These discounts can range from a 2-3% to around 11%.

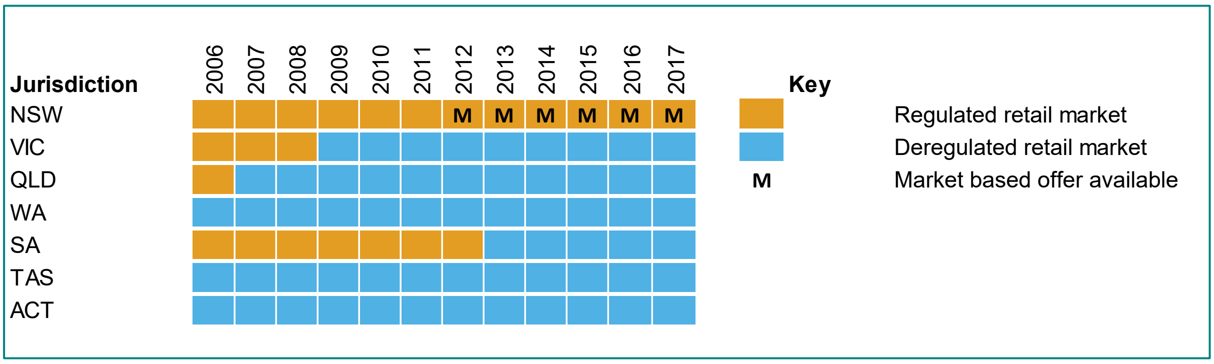
No value has been assigned to any non-monetary incentives (e.g. gift vouchers).

Standing offer contracts are basic gas contracts with the terms and conditions set by state governments or jurisdictional regulators. In jurisdictions that have adopted the National Energy Customer Framework (NECF), which aims to move state-based regulation to national regulation, the applicable terms and conditions are set out in the National Energy Retail Rules.

Only in NSW[171] and WA is the standing offer price regulated by the state regulator. In all other states the standing offer price is set by the gas retailers. Under the NECF, retailers are required to publish their standing offers on their websites.

Figure 166 shows the regulation for the retail gas market in different jurisdictions.

Figure 166 Gas Market Regulation in Different Jurisdictions



Prices on standing offer contracts should change no more than once every six months.

B.1.2.1 Typical household consumption

To develop the typical household consumption estimate for a distribution zone a number of approaches were used. Where data were available from the distribution network provider directly or from Access Arrangements submitted to the AER, the typical consumption for each zone has been estimated by averaging the last three years of actual or forecast data. The three year average was considered sufficient to account for any seasonal variance and

171 NSW gas market has been deregulated from 2017/2018 financial year

is reflective of the methodology that some distributors apply to their consumption trends[172]. Data was typically available for the larger zones, such as Victoria, Sydney metro, Adelaide and Brisbane. Where this data was not available, another approach was to use typical household gas consumption figures published by the state regulator.

For each jurisdiction, an average gas price and its components are calculated on a gas volume weighted average of each distribution gas zone to derive a state-based average gas price.

Consumption data in each distribution gas zone in each state were reviewed to see if consumption varies significantly. Only NSW was found to have significant variation in consumption between zones. Household consumption in rural NSW is approximately twice the metro household consumption due to the colder climate conditions encountered inland in some rural areas. As a result, NSW has been separated into rural and metropolitan zones for analysis.

B.1.3 Retail gas supply chain components

Average residential gas prices were broken down into five major cost components:

- Wholesale gas
- Transmission
- Distribution
- Environmental policy
- Retailer

B.1.3.1 Wholesale component

Most retailers maintain a portfolio of wholesale gas supply contracts that usually includes legacy contracts that provide gas at a relatively low price. In the absence of information on each retailer's gas portfolio, for each state the wholesale cost identified in the large industrials analysis is assumed to be the wholesale gas component. This cost is for new industrial contracts struck in the year in question and, as a result, it is likely the actual average wholesale gas component for some retailers is less than what is estimated in this report.

These wholesale gas costs have also been compared with analysis undertaken by some of the jurisdictional regulators when determining residential gas prices (where they were regulated within the jurisdiction). Regulators typically undertook this analysis using wholesale gas price forecasts provided by third-party forecasters and then worked through a retailer cost and margin exercise to arrive at final determined prices or to check the prices

172 Jemena 2012-2014 Calendar Year LGA Rolling Average Gas Consumption Data refer Jemena's 2012 to 2014 rolling average gas consumption data documentation

and disaggregation of costs provided by retailers submitting new prices for determination. This type of analysis had the benefit of being open to public scrutiny.

B.1.3.2 Transmission component

Transmission pricing for each jurisdiction was adapted from the large industrial analysis to estimate the transmission costs. The load factor assumption for the large industrial analysis was 1.2 where the load factor is the maximum daily quantity or peak demand divided by the average demand. Large industrial loads tend to be fairly constant with small or limited peaks. The customer load factor for retail load tends to have larger peaks.

The customer load factor for retail supply has been assumed as 2.5 for all gas zones. This is based on a review of a number of public sources and a number of distribution network access arrangements which identify peak daily flow and average daily flow. [173]

To confirm that this number was reasonable, information available from AEMO's Gas Statement of Opportunities was reviewed.[174] Detailed information is available for the Victorian network, of which it was considered that Melbourne would be the best zone to use in confirming the use of 2.5 for the load factor. In considering the Melbourne usage, the maximum daily usage of 853 TJ/day and an average daily usage of 340 TJ/day equates to a customer load factor of 2.51 which aligns with the other sources cited for customer load factors of 2.5.

Estimation of the cost of transportation of the wholesale gas supply has been calculated by multiplying the transmission costs in the large industrials by the residential customer load factor (CLF) divided by the large industrial supply load factor (SLF).

Residential transmission cost estimate = transmission cost (large industrials) x 2.5/1.2

As wholesale contracts are offered on a supply load factor of 1.2 to 1.05, the retailer also needs to ensure that their GSAs are capable of covering the peaks and diversity of their load factor. They can do this using a number of means such as additional GSAs, specific gas storage contracts etc. For the estimation of the deliverability cost estimate is 5.5 cents per GJ for each 0.1 difference between the customer load factor (assumed to be 2.5 for residential) and the supply load factor (assumed to be 1.2).

Deliverability estimate = (SLF-CLF)/0.1 x 5.5 cents/GJ ($2014)

The total transmission cost estimate in ¢/MJ for each year is the sum of the pipeline transmission cost estimate and the delivery cost estimate.

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173 AGL's Voluntary Price Agreement proposed price path for NSW regulated gas price from 1 July to 30 June 2016 – public submission and ACIL Tasman report, Cost of gas for the 2013 to 2016 regulatory period for IPART's review of regulated retail prices.

174 Australian Energy Market Operator, Gas Statement of Opportunities – Attachment B: Victorian Gas Planning Review 2015, April 2015.

B.1.3.3 Distribution component

As the majority of Australia's distribution networks were regulated by the AER from 2009, or state based regulators before then, detailed distribution network tariffs are readily available. Distribution tariffs have a fixed and variable charge, which is usually reflected in retailer tariffs, which have the same structure.

Every five years distribution networks submit a proposed access arrangement to the regulator, who determines the tariffs and associated charges. Each year the variation to the tariff is approved by the regulator and published by the distributor.

The distribution component on a ¢/MJ basis was calculated using the same process as the retailer tariffs. The annual distribution charge is calculated from the regulated tariff using the annual household consumption assumption. The resulting cost is then divided by the average household consumption to determine a distribution charge based on ¢/MJ for the zone. If multiple zones exist in the jurisdiction, then an indicative tariff is calculated using the consumption weighted average for each zone.

In most cases, the distribution gas zone also aligned with the retail gas zone. Some exceptions have been where the network crosses jurisdictional boundaries. For example, where ActewAGL operates in both the ACT and NSW, then it has been assumed that the analysis for the ACT gas prices, which forms a majority of the consumption, also apply to the NSW regions on the same distribution network. In Victoria, retail franchise zones were established when the retail market was opened to contestability and they do not exactly line up with the physical distribution zones.

For the Tasmanian gas distribution network no publicly available data exists to determine the bottom up distribution cost component. The only information published is by the regulator which identifies the distribution is approximately 48% of the retail cost.[175] The distribution cost component has been estimated using this percentage to determine the ¢/MJ for all of the Tasmanian data.

175 Office of the Tasmanian Economic Regulator, Comparison of Australian standing offer energy prices, March 2015.

B.1.3.4 Environmental Policy

The two environmental policy costs that were analysed and estimated were:

- *Clean Energy Act 2011* – Carbon Price for the years 2012-2013 and 2013-2014; and
- The *VEET* scheme.

NSW also has the *Energy Savings Scheme* (ESS) but it has only been focussed at reducing electricity consumption at present. A recent decision was made to expand the scheme to gas efficiency however this is not expected to commence until 2016.

1. Clean Energy Act

The difference between the large industrial carbon cost estimate and the residential carbon cost estimate is that the retailer is also responsible for the customer's carbon emissions when the gas is combusted. The carbon cost estimate recovered from the customer consists of:

- Upstream costs resulting from direct and indirect emissions from production and transmission (Scope 1 emissions);
- Downstream costs resulting from combustion by end users (Scope 3); and
- Any retail costs associated in processing and managing costs.[176]

Where retailers have been transparent on their determination of the carbon cost impact on a $/MJ basis, these costs have been used directly in estimating the environmental policy cost. The determination of the carbon tax cost used the publicly available National Greenhouse Accounts (NGA) intensity factors for determining their Scope 3 emissions and applied these to the distribution of their customer base. Other vertically integrated retailers have used their own emission intensity factors from their gas fields to determine the Scope 3 emissions.

Under the *Clean Energy Act 2011*, liability is imposed on a natural gas supplier for the potential greenhouse gas emissions embodied in the natural gas it supplies.[177] Scope 1 emissions have been calculated using the emission intensity factor of 51.33 kgCO2-e/GJ for natural gas distributed by a pipeline.

Publicly available proposals by retailers for the carbon tax showed a variety of different additional costs which have been identified - from operating cost to bad debt increases. In addition, proposals for an uplift adjustment for retail margin has also been considered and

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176 ESCOSA rejected the inclusion of a retail margin on the basis that there is no evidence that the carbon price will materially increase those costs intended to be recovered by Origin Energy's retail margin. IPART accepted retail costs and margins on the carbon tax. For this report has been assumed that retailers have recovered additional costs incurred from administering the carbon tax.

177 *Clean Energy Act 2011*, Section 33

allowed in some jurisdictions. AGL included an 8% retail margin adjustment on the pass through costs of the carbon tax.[178]

Where all the details of each retailer's carbon tax impost are not publicly available or as transparent as the applications made to regulators (e.g. IPART), the carbon tax impost has been estimated using the NGA factors for the metro and rural areas for Scope 3 emissions. [179] Scope 1 emissions form a majority of the carbon tax impost being 79%-93% of the carbon emissions. Table 60 shows a summary of the calculated carbon cost imposts.

Table 60: Summary of carbon tax impost on retail customers

	NSW and ACT (¢/MJ)	VIC (¢/MJ)	QLD (¢/MJ)	SA (¢/MJ)	WA (¢/MJ)
Metro					
2012-2013	0.16	0.14	0.15	0.15	0.14
2013-2014	0.17	0.14	0.16	0.16	0.14
Rural					
2012-2013	0.16	0.14	0.15	0.15	0.14
2013-2014	0.17	0.14	0.15	0.16	0.14

Note: Cost estimates include Scope 1, Scope 3 and retail margin/costs.

As the carbon tax was applied across financial years, wherever tariffs have been based on calendar years, the carbon tax impost has been weighted across each calendar year.

The emissions from the gas distribution system are comparatively low and the liability for these fugitive emissions only impacted when they were greater than 25,000 tonnes of CO2-e under the Act. Where distribution networks have been liable, it has been in the order of 5-10 cents/GJ and this cost has been passed through in the distribution tariff charges. For the analysis in this report, the distribution fugitive emissions have not been included in the carbon cost component but assumed to be embedded in the distribution charges, if relevant. This approach has been adopted due to either the cost not being calculated and discoverable or because it is a relatively small percentage of the carbon tax impost.

178 AGL's submission to IPART, Carbon component of default prices from 1 July 2012. The margin is in line with IPART's range of retail margin of 7.3% to 8.3% in its regulated price review for 2012-2013.

179 Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education, National Greenhouse Accounts Factors 2013.

In general, the methodology involved identifying the number of gas-related activities undertaken through the scheme and using an average price for the certificates to determine an assumed value of the activity. This information was collected from the ESCV.

Discussion on the methodology for determining the environmental policy costs for the VEET is detailed in the discussion of the Victorian retail costs (Section 8.1.5).

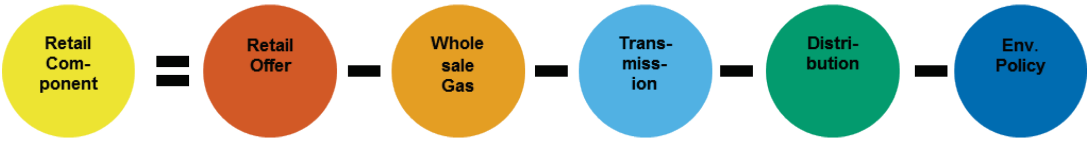
B.1.3.5 Retail component

The retail component includes:

- Retail operating costs;
- Customer acquisition and retention costs; and
- Retail margin.

For most jurisdictions, the retail component is not directly observable and it has been calculated as the residual when all the non-retail cost components have been subtracted from the total retail cost per MJ.

As a result, the retail component also includes any errors (positive or negative) from any of the estimates from the other supply chain components. Importantly, the retail component is not the profit that any retailer would realise.



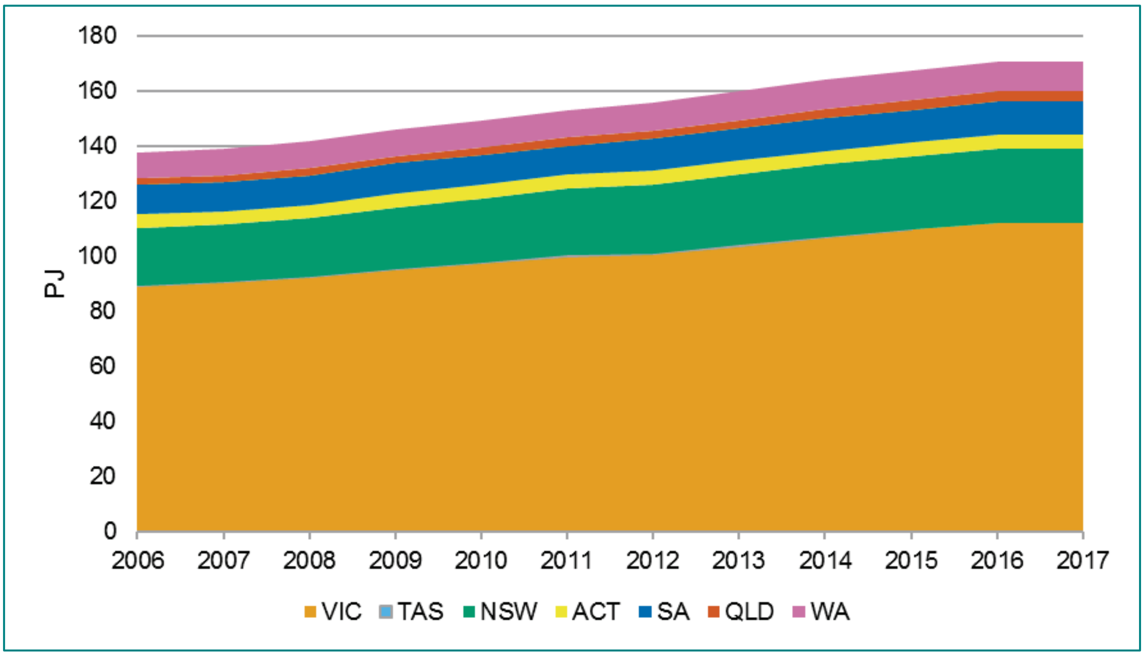
B.1.4 National average

The indicative average gas price for Australia was calculated using a weighted average residential gas consumption for each jurisdiction multiplied by each cost component to determine an indicative cost component. The weightings for each year were determined from Department of Environment and Energy's Australian energy statistics data – Table F Residential Natural Gas Consumption.[180]

180 Department of Environment and Energy, Australian energy consumption, by fuel type, Table F.

Figure 167 shows the total gas consumption by state from 2011 to 2017.

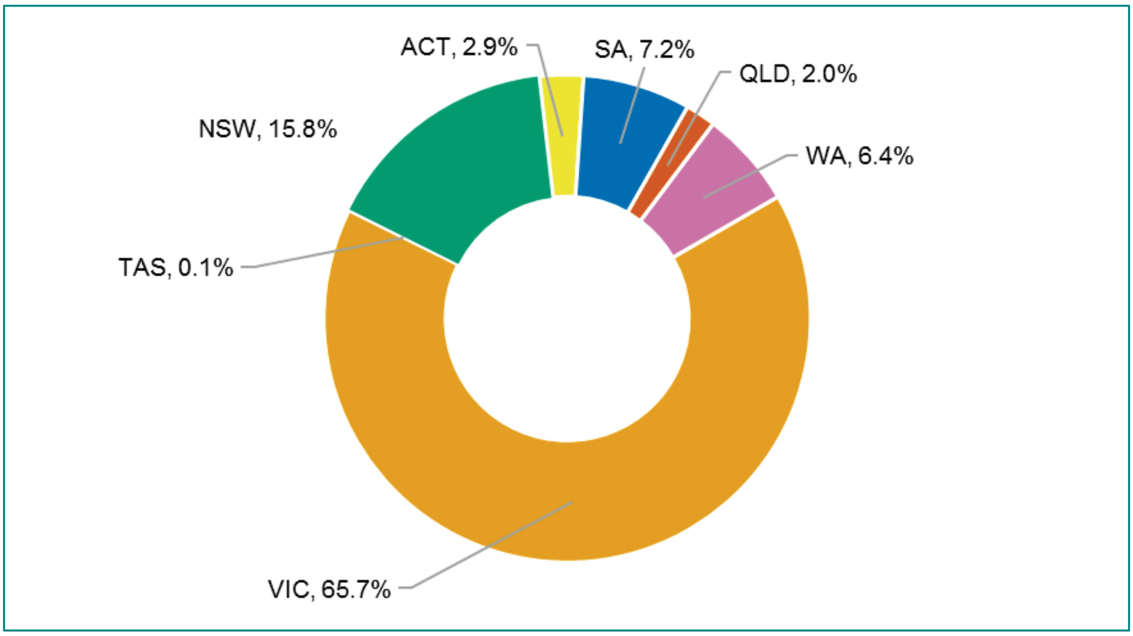
Figure 167 : National natural gas consumption by State



Source: Department of Environment and Energy, Australian Energy Statistics, by fuel type, Table F.

Figure 168 shows the percentage breakdown of Australia's residential gas consumption by state in 2017.

Figure 168: Residential gas consumption percentages by state in 2017



Source: Department of Environment and Energy, Australian Energy Statistics, by fuel type, Table F.

The ratios of consumption have remained stable through the last ten years with Victoria consuming approximately 65% of residential natural gas and Tasmania only consuming approximately 0.2%.