Eastern Australian Gas Market

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1. Summary and Recommendations

Australia has three distinct and unconnected gas markets as shown in Figure 7. This report focuses on the largest of these, the East Coast Gas Market, and addresses the implications of the the new Liquefied Natural Gas (LNG) projects in Queenland and changing demand/ supply dynamics that have led to higher domestic gas prices. Our key conclusions include:

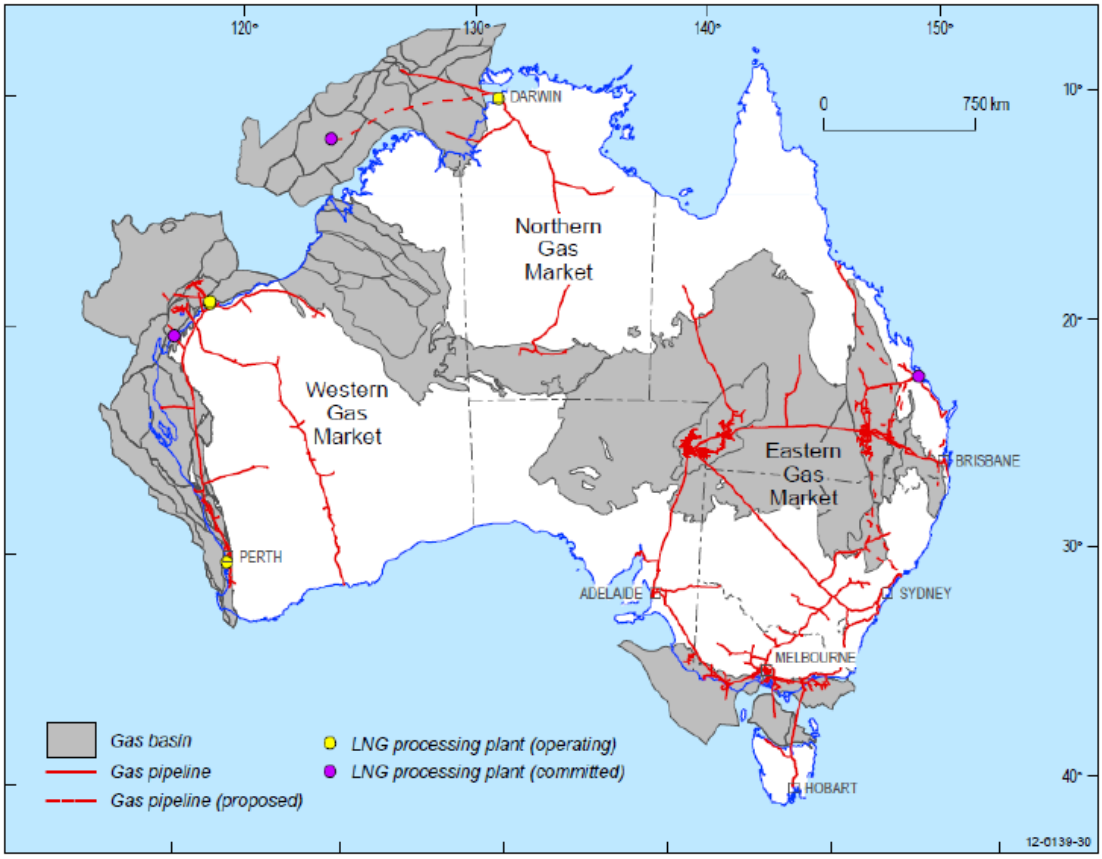
- The sanctioning of three large LNG projects at Gladstone has increased the demand for gas by a factor of three and connected the East Coast Gas market with the international export market. Domestic pricing has already begun to move toward export netback pricing (price of international LNG less the costs of transport and liquefaction) which is oil linked.
- Even with lower oil prices and hence lower export netback prices, and even assuming adequate supply to meet the demand, the quantum of new demand has pushed marginal new gas higher up the cost curve. This will put upward pressure on gas prices.
- A key factor is that there is ***not*** adequate supply to meet the higher demand. The Gladstone LNG projects were originally expected to commercialise Queensland's coal seam gas (CSG) reserves and that adequate gas was in place to fill the projects and provide surplus gas into the domestic market. Resources have not converted to reserves as expected and two of the projects have bought third party gas to supplement their project equity gas. Not only has additional gas not entered the domestic market, but existing gas supply has been removed from the domestic market to fill the export shortfall. This has both left a supply shortfall for domestic gas users as well as push up prices.
- Even if the proposed New South Wales CSG projects (Gloucestor and Narribri) are approved and additional supply brought on, the new volumes are higher up the cost curve and there will still be upward pressure on pricing. There are considerable political, regulatory and community hurdles to these projects and there is a high probability they will not proceed regardless.
- We expect domestic gas prices to continue to increase to the $7-9/GJ range, and are already seeing a few long-term contracts being signed up around these levels. If oil prices recover back to around US$100/bbl, domestic prices could get to A$10-12/GJ.
- At these higher wholesale gas prices, the winners will be the upstream gas producers with lower cost production, and the end user energy retailers that have equity gas and low-priced long-term supply contracts.
- At >A$7.00/GJ, gas generation can not compete with coal-fired generation (even with a carbon price) for electricity. We expect a material reduction in gas-fired generation and increase in coal-fired generation
- Higher domestic gas prices will increase input costs into manufacturing, particularly gas intensive processes like fertiliser. The fertiliser/ explosives/ petrochemical industries are the most intensive gas users.

2. East Coast Gas Market – Background

2.1. Three Distinct Gas Markets

Australia has three distinct and unconnected gas markets as shown in Figure 1. This report focuses on the largest of these, the East Coast Gas Market.

Figure 1: Australia's Regional Gas Markets



Source: Haylen and Montoya, 2013 (Figure 3)

The purpose of this report is to address the changing dynamics, including demand, supply and price, and look at who may be the winners and losers from this. We shall address all industry groups across the supply chain. There has been a lot of talk about increased prices and the implications for the manufacturing industry and industrial gas users, as well as for the oil and gas exploration and production companies themselves.

Australian produced gas is either sold into the domestic market or exported. For a number of years international pricing has been considerably higher than domestic pricing (Jericho, 2014). Up until now, there were no Liquefied Natural Gas (LNG) terminals on the east coast gas and so producers could not sell into international markets to 'arbitrage' export pricing. New LNG projects in Queensland, however,

have changed this and is the key driver of the new dynamic in domestic gas markets including higher contract prices in recent years.

2.2. Coal Seam Gas (CSG) on the East Coast

Once focus of this report is Coal Seam Gas (CSG) as it was the desire to commercialise CSG resources in Queensland that led to the development of three separate LNG projects in Gladstone, QLD. All of Australia's CSG reserves are part of the Eastern Gas Market.

Table 1: Key Statistics – Australian Gas Markets

Gas Reserves	NSW	Eastern Market	Australia
Conventional Gas Reserves (2P)(PJ)	17	8,784	97,656
Coal Seam Gas Reserves (2P)(PJ)	2,266	41,156	41,156
Gas Reserves (2P)(PJ)	**2,283**	**49,940**	**138,812**
Gas Reserves (Total)	95,003	422,478	912,166

Source: Haylen and Montoya, 2013 (Table 1)

The key takeaways from Table 1 above are that, (i) over 80% of total East Coast 2P gas reserves are coal seam gas (CSG) and, (ii) almost all of NSW 2P gas reserves are CSG.

According to Haylen and Montoya (2013) about 95% of all Australian CSG reserves are either contracted to, or earmarked for, LNG export. An important point to note is that the CSG reserves that these three projects ***expected*** to have when the LNG facilities started up is more than what they ***actually*** have at this stage. Credit Suisse estimate that total 2P+2C (reserves + resources) have declined by about 12% since these projects were initially sanctioned. The key driver of this has been GLNG, as shown in Table 2.

Table 2: Key Statistics – Australian Gas Markets

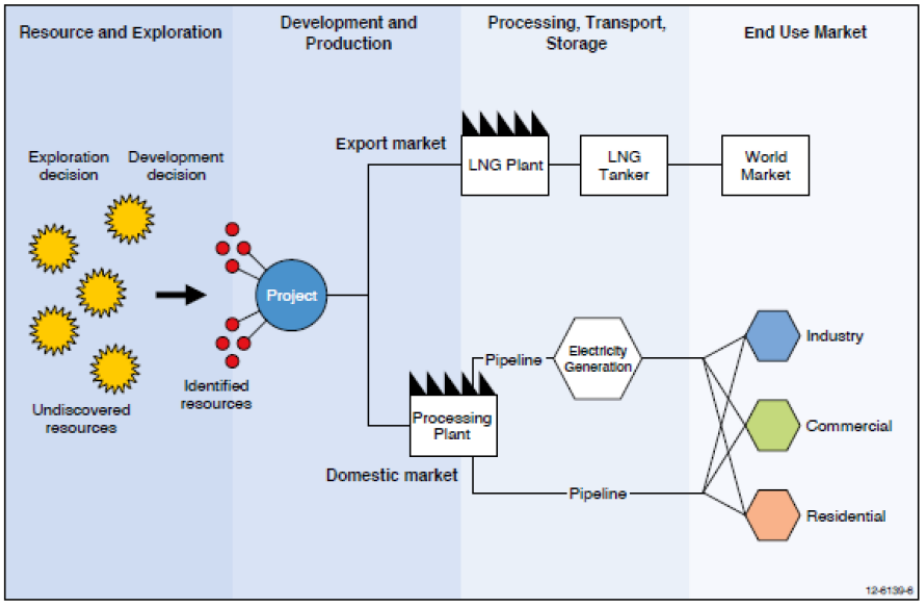
GLNG	2010	2014		APLNG	2010	2014		Combined	2010	2014	
2P	5,009	5,603	12%	2P	10,143	14,091	39%	2P	15,152	19,694	30%
2C	3,732	1,202	-68%	2C	4,844	2,679	-45%	2C	8,576	3,881	-55%
2P+2C	**8,741**	**6,805**	**-22%**	2P+2C	**14,987**	**16,770**	**12%**	2P+2C	**23,728**	**23,575**	**-1%**

Source: Haylen and Montoya, 2013 (Table 1)

APLNG has converted 2C resources to 2P reserves and increased it's total by about 12%. Unfortunately, the data on QCLNG is unclear. Although QCLNG reports that its 2P reserves has increased from about 7,000PJ in 2010 to 10,000PJ currently, its reporting of 'resources' is ambiguous. What it reports as 'resources' isn't comparable to the other players, ie. 2C, but also includes risked exploration upside. The fact since FID QCLNG has entered into an agreement to buy 640PJ of gas from Origin Energy, implies that it now doesn't believe it has sufficient gas of its own to meet its LNG commitments.

Whereas commercialisation of the CSG reserves in Queensand were originally expected to supply the export volumes as well as delivering surplus volumes into the domestic gas market, what has actually eventuated is a ***shortfall for export***. These export volumes have been pre-sold and so need to be supplied and, as a result volumes that were previously earmarked for domestic supply have been redirected to LNG.

Figure 2 – Australia's Gas Supply Chain

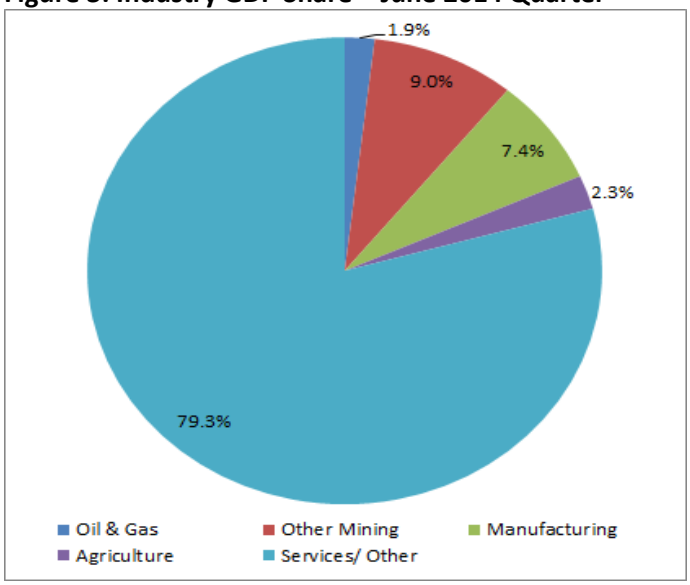


Source: Haylen and Montoya, 2013 (Figure 4)

2.3. The Gas Industry and the Australian Economy

Australia is primarily a services driven economy with total mining (including oil and gas) only accounting for about 11% of total GDP according to the Australian Bureau of Statistics (Figure 3). Oil and gas extraction currently represents about 2% of Australian GDP and, despite strong growth as a result of current projects that are under construction, will still only account for about 3.5% of GDP by 2020 (Byers, 2014).

Figure 3: Industry GDP Share – June 2014 Quarter



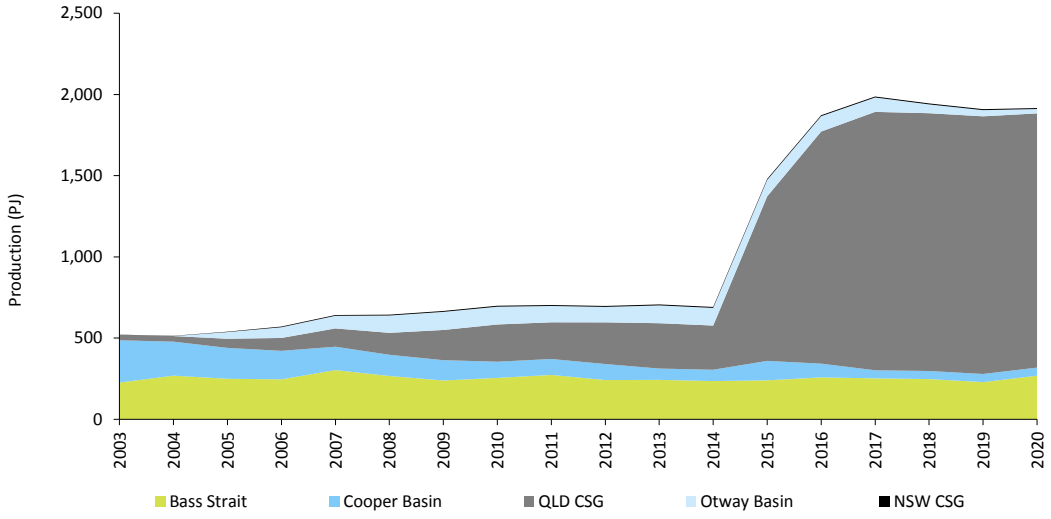
Source: Australian Bureau of Statistics, Series 5206.0 - Australian National Accounts

Total mining (including oil and gas) is higher as a proportion of ***state*** production for some – about 30% for WA, 20% of NT and 10% of Queensland.

3. Exploration and Production – Supply

The following figure shows Australian east coast gas production and consumption by state. Note that the Cooper Basin is largely South Australia, but also partially Queensland.

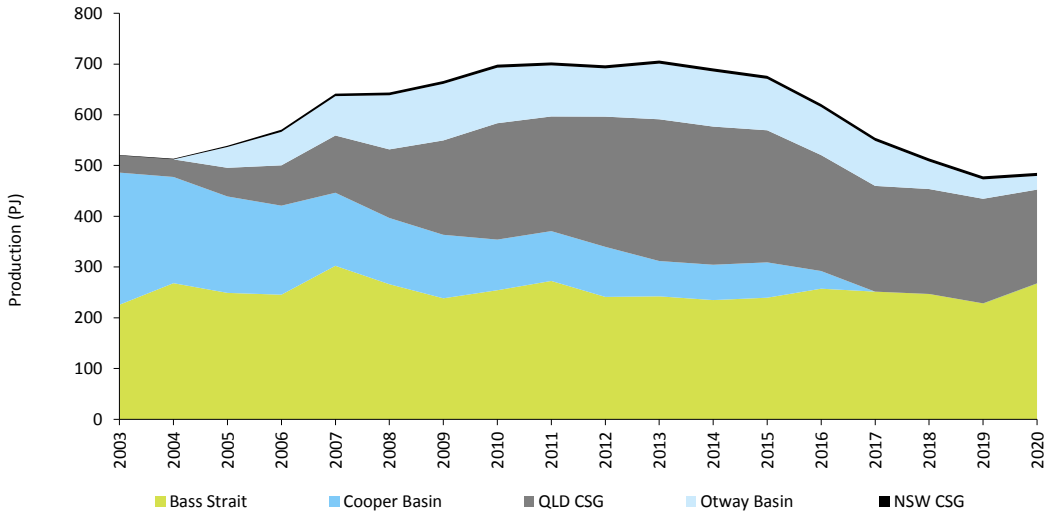
Figure 3: Australian East Coast Gas Contracted Production by Basin/ State – *Including* LNG



Source: Deutsche Bank

The figure above includes gas production for LNG export, whereas the figure below looks at production for domestic use only. The strong forecast growth in gas production is mostly driven by QLD CSG and, as mentioned, is almost entirely for export as LNG. If we exclude LNG, Deutsche Bank estimates the following production for domestic use.

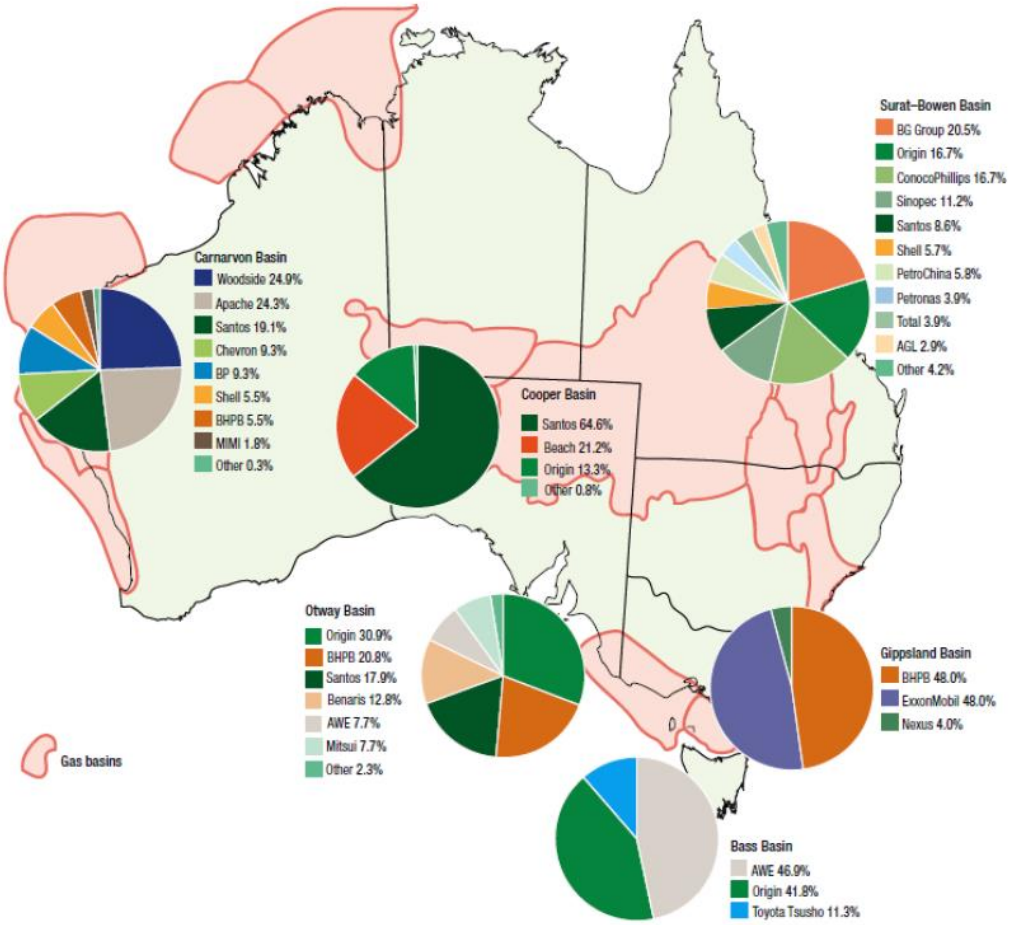
Figure 4: Australian East Coast Gas Contracted Production by Basin/ State – *Excluding* LNG



Source: Deutsche Bank

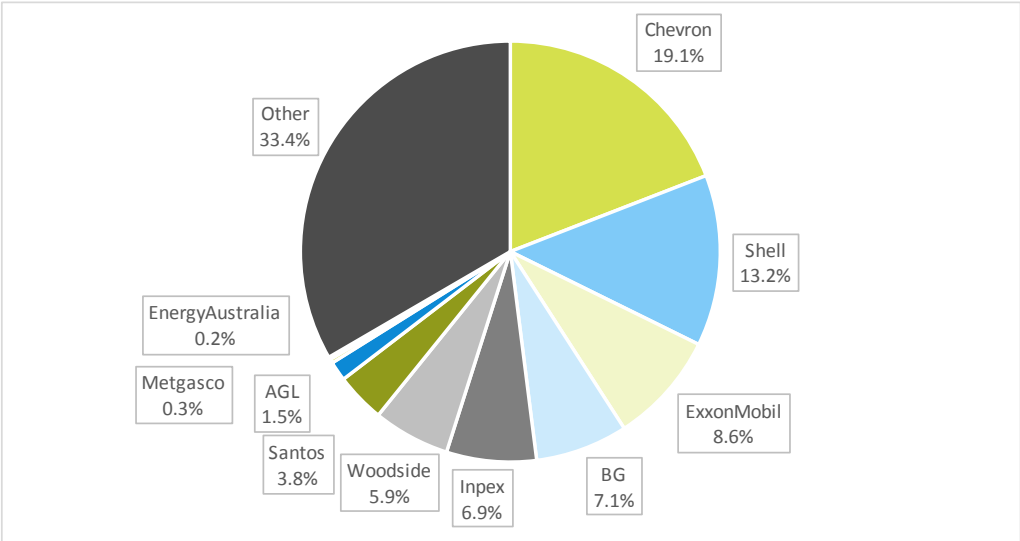
Previous charts showed the region of production, whereas the following charts at the companies that hold the reserves.

Figure 5: Market Shares in Domestic Gas Production, by Basin, 2012-13



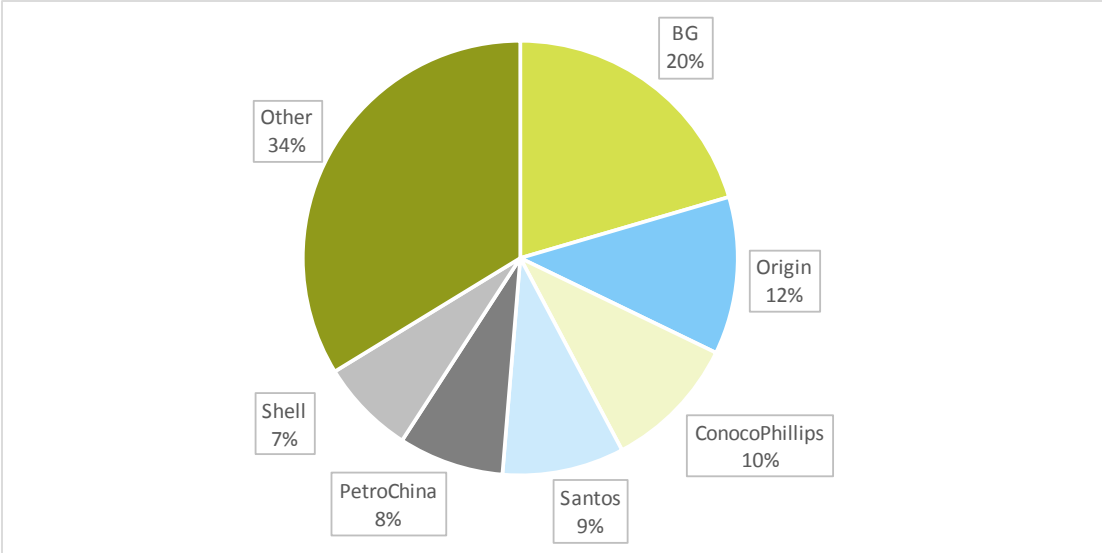
Source: Haylen and Montoya, 2014

Figure 6: Shares in 2P Reserves at August 2012 – Total Australia



Source: Australian Energy Regulator, State of the Energy Market 2014

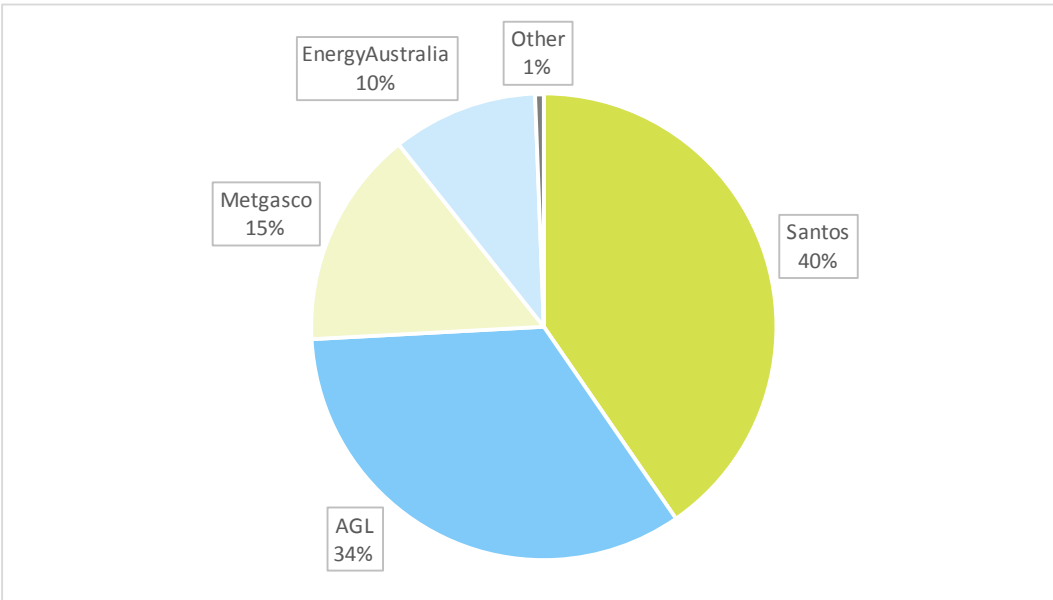
Figure 7: Shares in 2P Reserves at August 2012 – Eastern Australia



Source: Australian Energy Regulator, State of the Energy Market 2014

2P Reserves in Eastern Australia are dominated by the CSG LNG project players: BG, Origin, ConocoPhilips, Santos, Petrochina and Shell. Looking at NSW in isolation (see Figure 8 below), Santos and AGL have the bulk of gas reserves, all CSG, with AGL at Camden and Gloucester and Santos at Narribri.

Figure 8: Shares in 2P Reserves – NSW Coal Seam Gas



Source: Australian Energy Regulator, State of the Energy Market 2014

Importantly, despite having reserves in NSW, the CSG projects are struggling to turn that into production. NSW has a moratorium on CSG development, which has been in place now since 2011 (Emerson, 2014), so only Camden is producing, and Stage 1 of Gloucester has approval to produce –

although it is currently halted due to an environmental investigation. So NSW currently cannot increase its own supply despite consuming a lot of gas, as shall be discussed later.

4. Wholesale Gas Market

Historically, the wholesale gas market has been characterised by long-term contracts of 10 years or more between producer and buyer. However, currently the predominant form of contracting is a mix of medium (1 to 3 year) term contracts and long-term contracts, largely due to the uncertainty around supply and pricing brought on by the Gladstone LNG projects. This has made it increasingly difficult for gas consumers to lock in security of supply for extended periods at reasonable prices. Unlike some markets such as the United States, there is a limited spot market in Australia.

Two Trading Markets in Eastern Australia

Long-term contracts – Typically 10 years, and including volume and price plus other conditions, although more recently a lot of contracts done on 1 to 3 years. The following table shows recent contracts and, for a market that has long had wholesale gas contract prices around A$3-4/GJ, it shows that contract prices have increased materially.

Table 3: Recent Eastern Market Domestic Gas Contracts

Seller	Buyer	Source	Start Date	Term - years	Annual Volume (PJ)	Term Average Price ($/GJ)
AGL	Xstrata	Surat CSG	1/05/2013	10.5	13.1	6
Origin	MMG	OE Portfolio	1/01/2013	7	3	8.29
Santos	Unknown	STO Portfolio	Unknown	Short	Low	8
Beach Petroleum	Origin	Cooper	1/01/2015	8	17	8.5
BHPB-Esso	Lumo	Gippsland JV	1/01/2016	3	7	7.29
BHPB-Esso	Origin	Gippsland JV	1/01/2014	9	48	6.76
BHPB-Esso	Orica	Gippsland JV	1/01/2017	3	14	5.86
Nexus	Santos	Gippsland Longtom	1/07/2013	5.5	15.1	5.95
AGL	Incitec Pivot	Surat CSG	1/02/2015	1.9	8.5	10.02

Source: Jacobs SKM

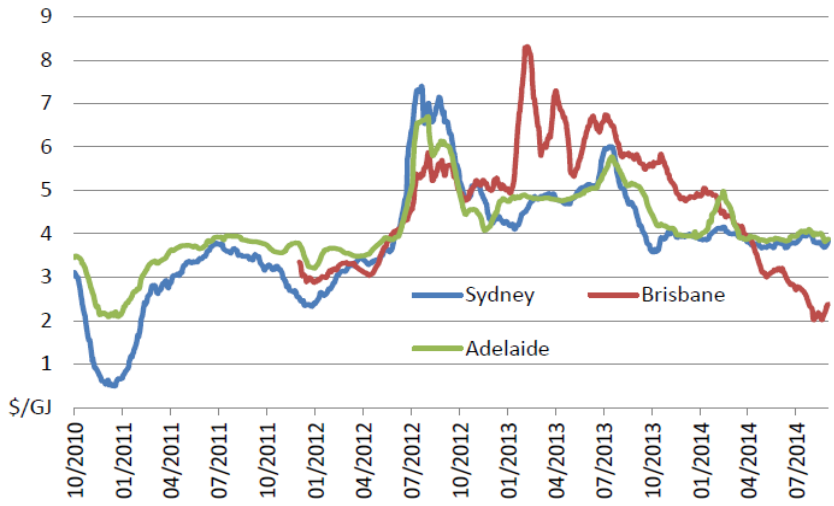
Short-term trading market:

There is also a spot market (Short Term Trading Market), with the newest brokerage hub opening at Wallumbilla, Queensland in 2014 as a result of the growing CSG/ LNG industry. The spot market primarily exists to enable participants to trade gas supply imbalances that arise because their actual demand is different to their contracted supply.

- Sydney, Brisbane and Adelaide – Short Term Trading Market (STTM) – established in Sep 2010 (BNE and SYD) and Dec 2011 for ADL.
- Victoria – Declared Wholesale Gas Market (DWGM) – established in 1999
- Wallumbilla, QLD – Voluntary hub established in 2014

Figure 9 shows recent trends in short term prices. The lower prices in 2014, particularly at the Brisbane hub, have resulted from excess gas as the LNG projects ramp up production ready to fill the LNG liquefaction plants. Figure 10 shows that Brisbane prices, and Eastern Australian prices overall, are expected to trend upward, particularly once all the LNG projects are operating.

Figure 9: Ex Ante Short Term Trading Market Spot Prices

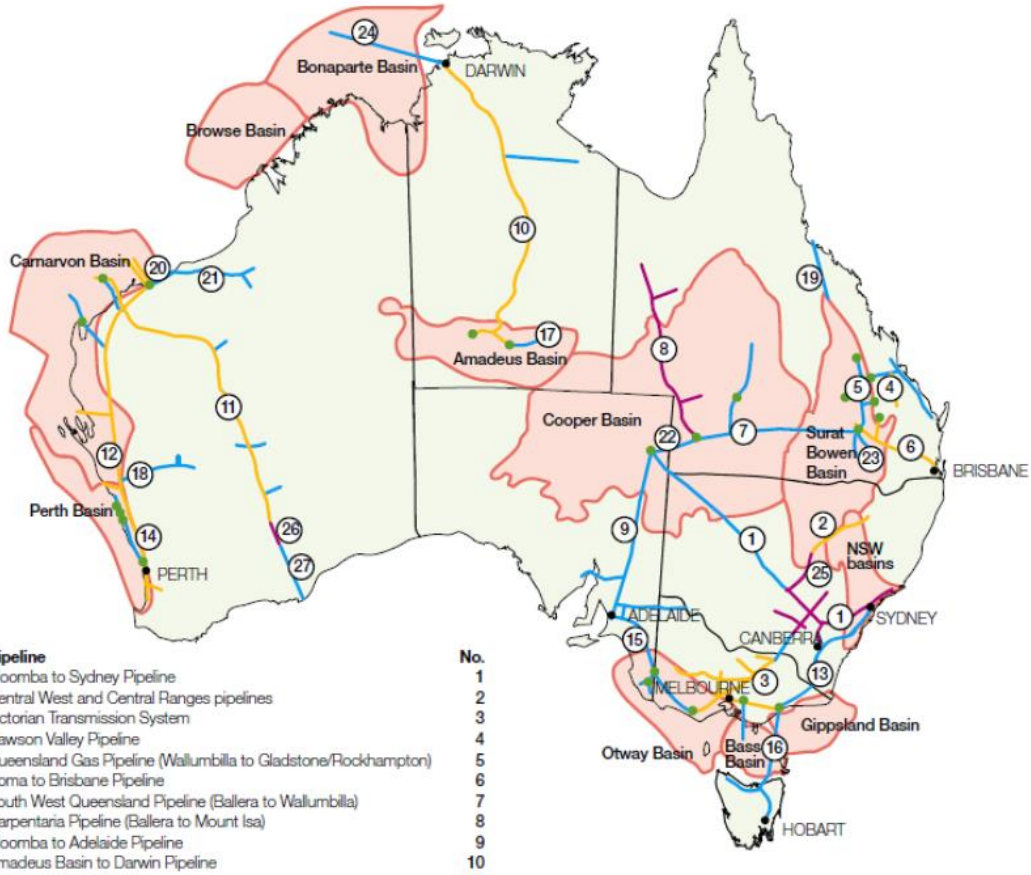


Source: AEMO Short Term Trading Market Data, 2014

5. Gas Transmission System

Transmission pipelines take gas from the production gathering facilities to the entry point of the distribution systems, or directly to some end users like power stations and industrial users. Although there is a huge network of transmission pipelines across Australia, the three distinct gas markets (Eastern Australia, Northern Territory and Western Australia) are not connected.

Figure 10: Australian Gas Basins and Transmission Pipelines



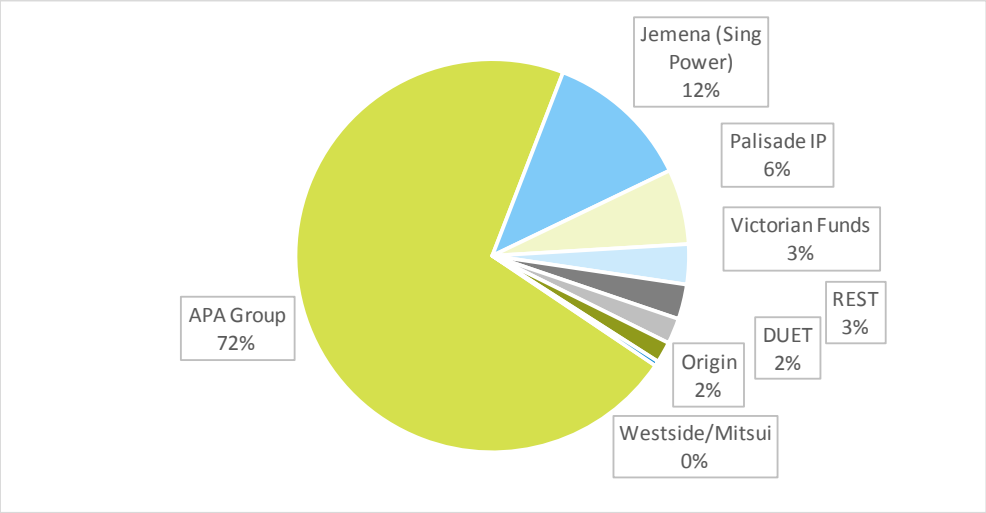
Pipeline	No.
Moomba to Sydney Pipeline	1
Central West and Central Ranges pipelines	2
Victorian Transmission System	3
Dawson Valley Pipeline	4
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Carpentaria Pipeline (Ballera to Mount Isa)	8
Moomba to Adelaide Pipeline	9
Amadeus Basin to Darwin Pipeline	10
Goldfields Gas Pipeline	11
Dampier to Bunbury Natural Gas Pipeline	12
Eastern Gas Pipeline (Longford to Horsley Park)	13
Parmelia Pipeline	14
SEA Gas Pipeline	15
Tasmanian Gas Pipeline	16
Palm Valley to Alice Springs Pipeline	17
Midwest Pipeline	18
North Queensland Gas Pipeline	19
Pilbara Pipeline	20
Telfer Pipeline	21
QSN Link	22
Berwyndale to Wallumbilla Pipeline	23
Bonaparte Pipeline	24
Central West Pipeline	25
Kalgoorlie to Kambalda Pipeline	26
Kambalda to Esperence Pipeline	27

Source: Haylen and Montaya, 2014

In Victoria, gas shippers bid daily for pipeline capacity through the Victorian Declared Wholesale Gas Market. In all other states, transmission services are through bilateral contracts between shippers and pipeline owners. Some pipelines are regulated, whereas most have capacity negotiated between

pipeline owner and shipper. Many pipelines are bi-directional, to allow for changing demand/ supply patterns. For example, the Moomba to Sydney pipeline has historically flowed in this direction, moving Moomba produced gas to the Sydney market. With the increased demand for gas in Queensland, Moomba gas now mostly flows to Wallumbilla and the pipeline has net movements from Sydney to Moomba. For a pipeline owner, it can grow its revenue by having contracts going both ways, as it gets paid by contract regardless of what the net movement is.

Figure 11: Gas Transmission Pipeline Ownership – Eastern Australia

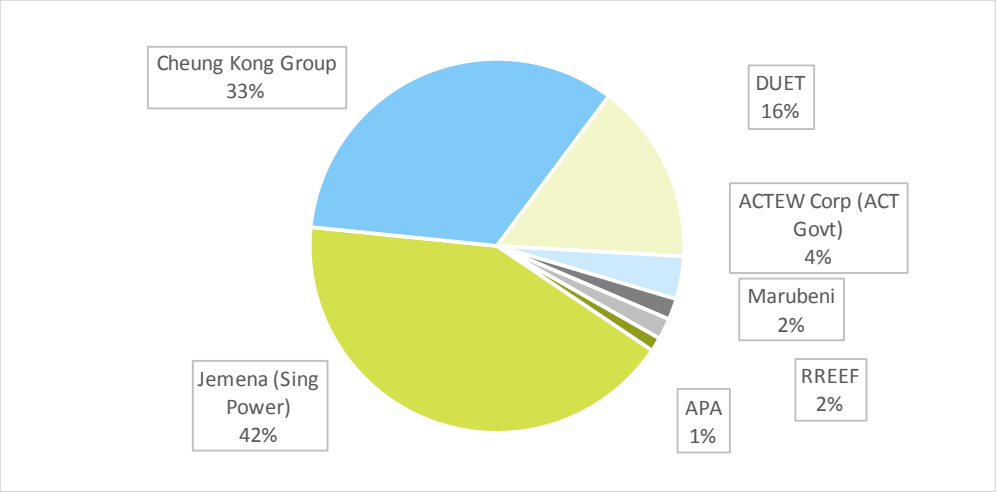


Source: Australian Energy Regulator, State of the Energy Market 2014

APA is by far the largest transmission pipeline operator and has achieved strong growth through expansion of existing pipeline capacity (guides to $300-400m of capital expenditure per annum) under long-term take-or-pay arrangements with gas shippers.

6. Gas Distribution System

Figure 12: Gas Distribution Pipeline Ownership – Eastern Australia



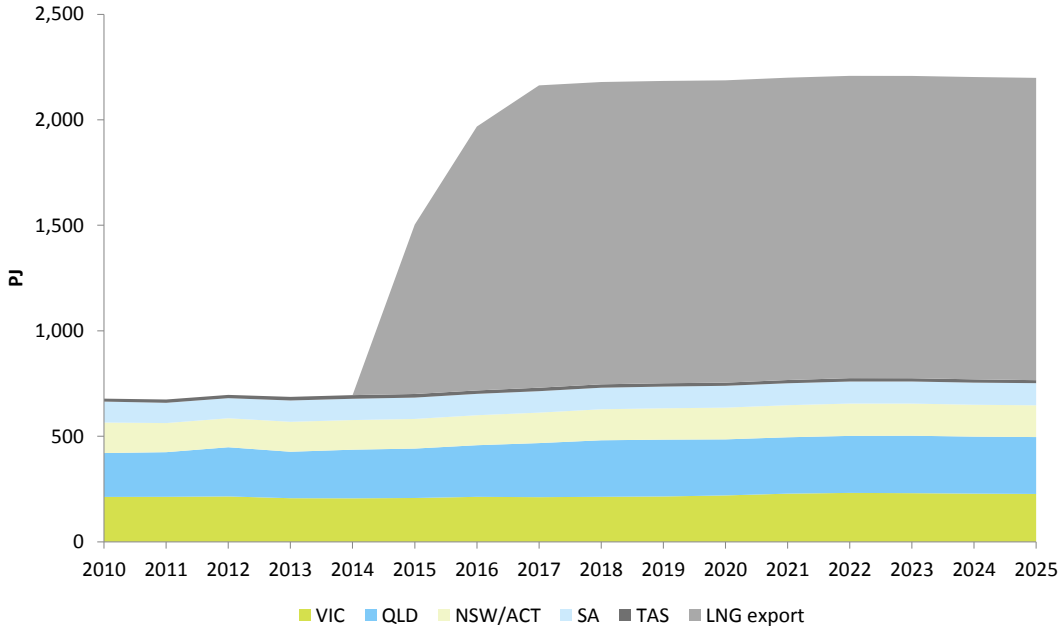
Source: Australian Energy Regulator, State of the Energy Market 2014

Distribution networks are lower pressure systems for distribution of gas to the end user. Many industrial and generation customers don't use the distribution networks as they take gas straight from transmission pipelines. Distribution networks are mostly regulated and, almost counterintuitively, make up a considerable proportion of the cost of getting gas to end users. This shall be addressed in a later section.

7. Gas Consumers – Demand

Eastern market gas consumption has only grown by about 4% p.a. over the past decade, whereas in Western Australia consumption has grown at an average annual rate of 6% driven by demand from mining, manufacturing and gas-fired electricity generation. Figure 14 shows historical actual gas demand by state, as well as Deutsche Bank forecasts out to 2025.

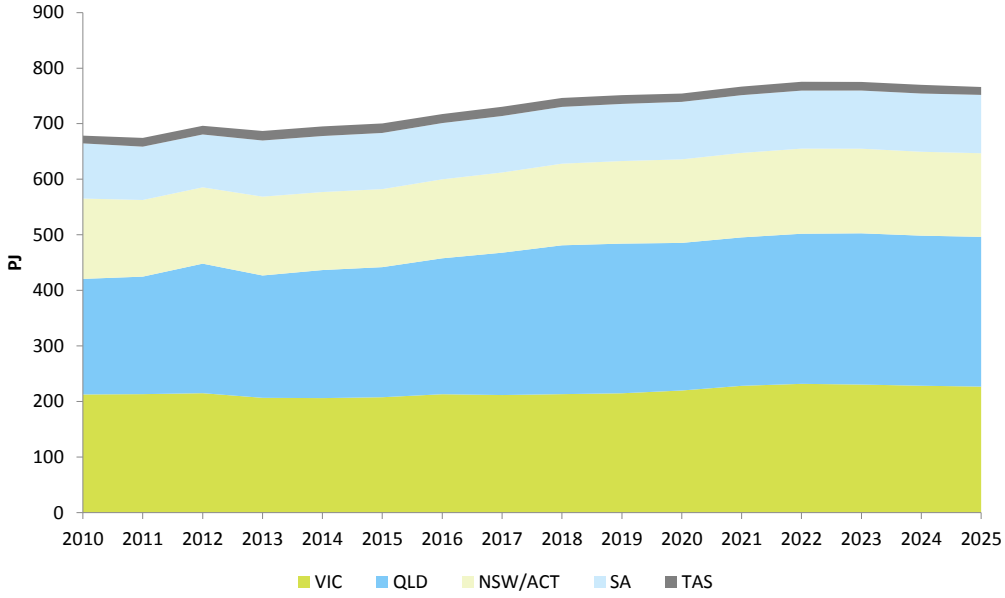
Figure 13: Australian Gas Consumption by State – *Including* LNG



Source: Deutsche Bank

The above figure includes the new demand from the three Gladstone LNG projects. QCLNG commenced shipping in December 2014 and will ramp up over 2015, and the other two projects are expected to commence shipping around the middle of 2015 and will ramp up over a couple of years.

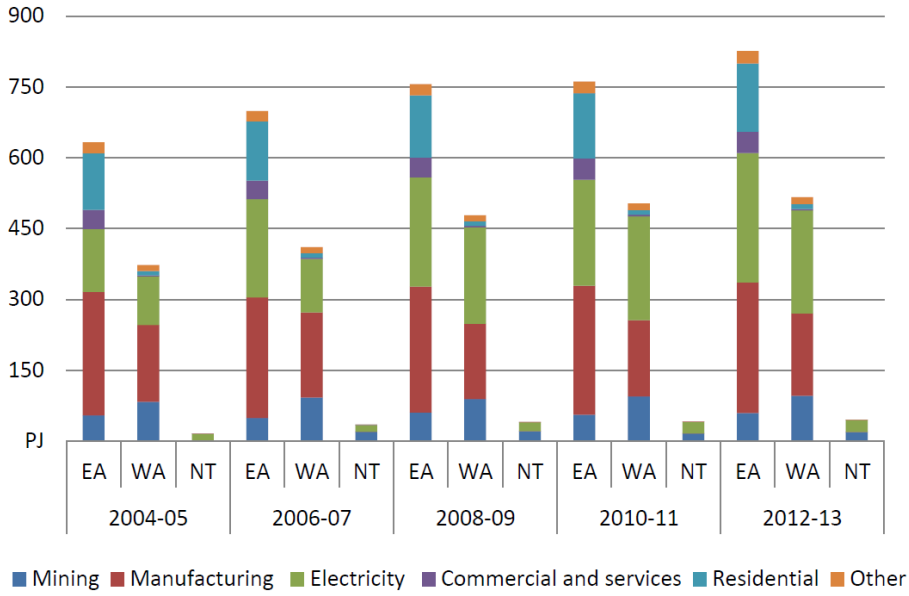
Figure 14: Australian Gas Consumption by State – *Excluding* LNG



Source: Deutsche Bank

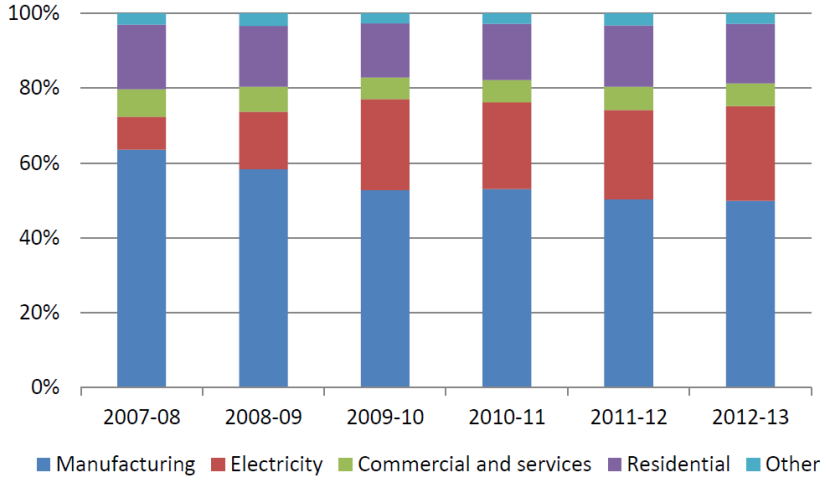
NSW differs to other states in a couple of other ways. Firstly, it produces only about 4% of what it consumes, so has to import most of its gas from other states. In 2011-12 NSW produced 6 petajoules (PJ) of gas but consumed 165PJ (Haylen and Montoya, 2013). Secondly, it has a moratorium on CSG development, which has been in place now since 2011 (Emerson, 2014), so cannot increase its own supply. The Victorian government also recently extended its ban on fracking and onshore exploration for CSG until at least 2016, at which time a parliamentary enquiry will report back.

Figure 15: Australian Gas Consumption by Market and Sector



Source: Bureau of Resources and Energy Economics – 2014 Australian Energy Statistics Data – Table F

Figure 16: Distribution of Gas Consumption by Sector in NSW



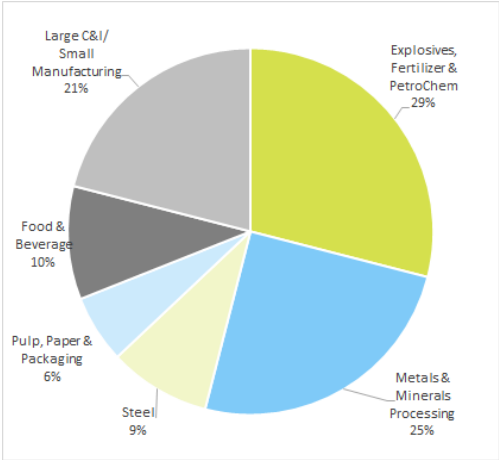
Source: Bureau of Resources and Energy Economics – 2014 Australian Energy Statistics Data – Table F

Overall, residential usage has been broadly flat and manufacturing use of gas has decreased consistently year to year. Gas use for electricity generation has been a big driver of demand over the past 5-7 years, driven by the carbon tax and availability of relatively cheap domestic gas. This is expected to reverse in the coming years given the removal of the carbon tax and the higher price of gas.

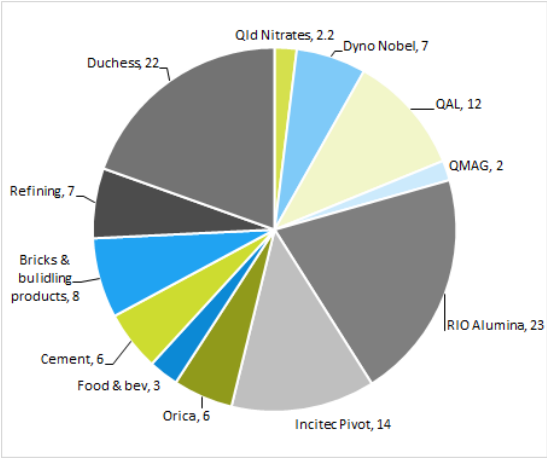
Figure 17 shows broad gas usage by the industrial and manufacturing sectors. Queensland is the largest user by State and there is more transparency arund specific company contracts compared to other states. The fertilizer, explosives and petrochemicals industries are the largest users of gas across the East Coast. A doubling of the wholesale gas price will result in a very significant increase in input costs for some of these companies. Natural gas represents 90% of the inputs into fertilizer.

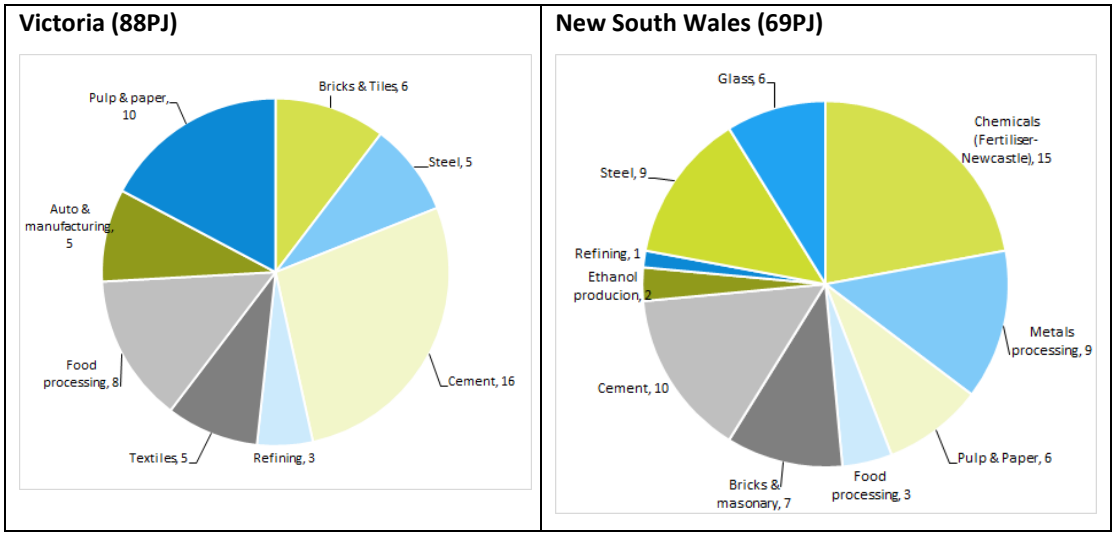
Figure 17: Industrial/ Manufacturing Gas Users - 2013

East Coast Market (298PJ)



Queensland (113PJ)





Source: Morgan Stanley Estimates

AEMO (2013) expects domestic gas demand to grow at about 0.9% p.a. to 750PJ by 2033.

Table 4: Average Annual Domestic Gas Demand Growth – 2014 to 2033

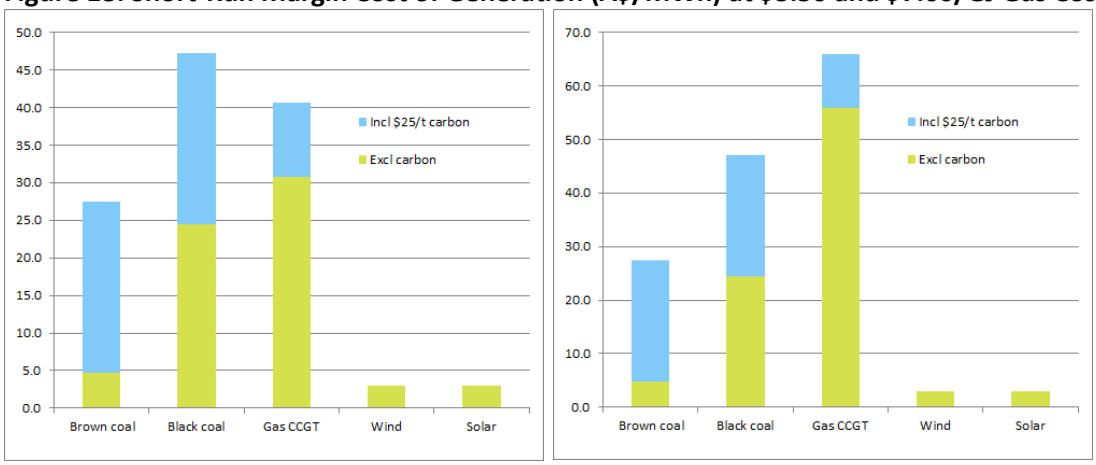
	SA	VIC	TAS	NSW/ACT	QLD	Total
Gas generation	-0.4%	12.6%	3.5%	-2.3%	-0.7%	-0.4%
Mass market	0.7%	1.1%	2.7%	1.6%	2.4%	1.2%
Large industrial	0.4%	0.2%	1.3%	1.3%	1.7%	1.2%
Total	0.0%	1.0%	1.9%	0.8%	1.1%	0.9%

Source: Australian Energy market Operator (AEMO), Gas Statement of Opportunities, 2013

AMEO expects gas use for generation to decline at 0.4% CAGR, driven largely by the higher gas price which makes the economics less attractive. There has been an increase in coal-fired generation over the past couple of years anyway, due to the removal of the carbon tax and hence more attractive economics for coal.

Figure 18 shows the short-run margin cost (SRMC) of different fuel types for generation.

Figure 18: Short-Run Margin Cost of Generation (A$/MWh) at $3.50 and $7.00/GJ Gas Cost



Source: CBA and Arnhem Estimates

The key points to note are:

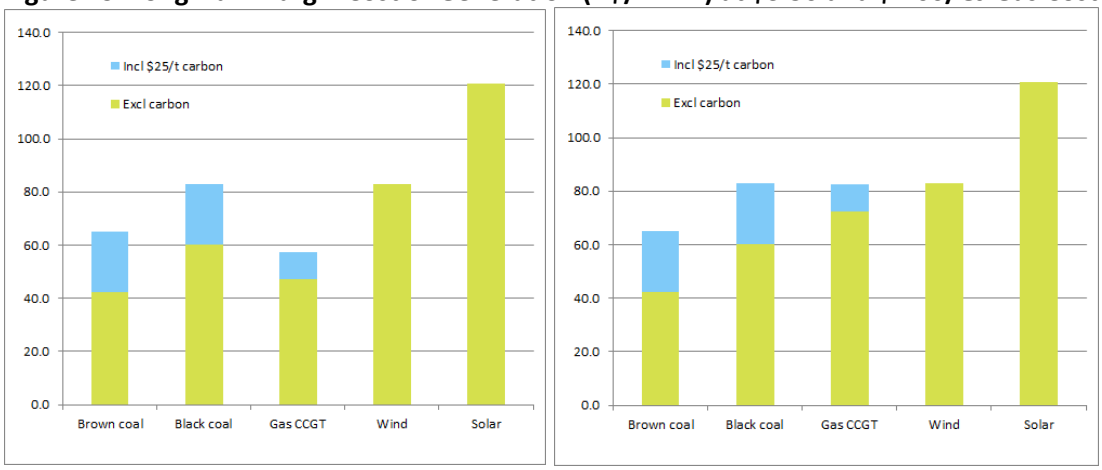
(i) Below ~$2.60/GJ the SMRC of gas-fired generation is lower than that of black coal, maing combined cycle gas generation more economic assuming ***no carbon price***,

(ii) Below ~$4.40/GJ the SRMC of gas-fired generation is lower than that of black coal, assuming ***a $25/tonne carbon price,***

(iii) At currently expected medium- to long-term contract gas prices of >$7.00/GJ, gas-fired generation is unattractive and will only be used intermittently for peaking electricity supply.

Figure 19 shows the long-run margin cost (LRMC) of different fuel types for generation, which includes the capital cost of building new generators.

Figure 19: Long-Run Margin Cost of Generation (A$/MWh) at $3.50 and $7.00/GJ Gas Cost



Source: CBA and Arnhem Estimates

The key points to note are:

(iv) At ~$5.50/GJ the LRMC of gas is roughly equal to that of black coal, assuming no carbon tax,

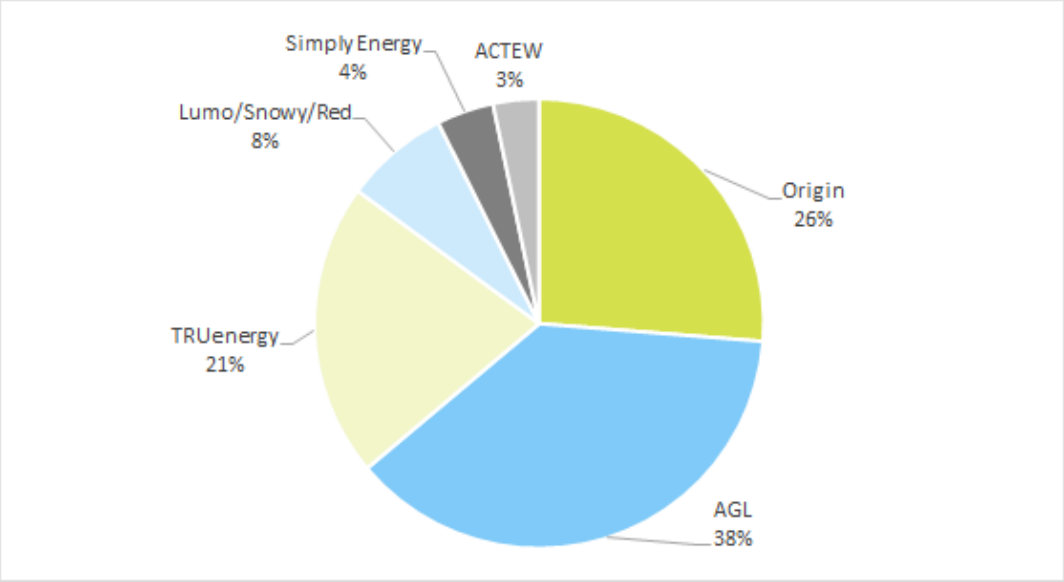
(v) At ~$7.00/GJ the LRMC of gas is roughly equal to that of black coal, assuming a carbon tax of $25/tonne,

Ultimately, these data mean that at current contract prices of about $7-8/GJ, it is unlikely that any new gas generation will be built even if its believed that a carbon tax will be reintroduced. Given the movement globally toward carbon abatement, it does seems likely that Australia will reintroduce a carbon tax at some stage.

8. Retail Energy – Demand

Gas retailers buy wholesale gas, typically through long-term contracts, and package it with network services for sale to customers. Figure 18 shows Gas Retail Energy market shares in Eastern Australia.

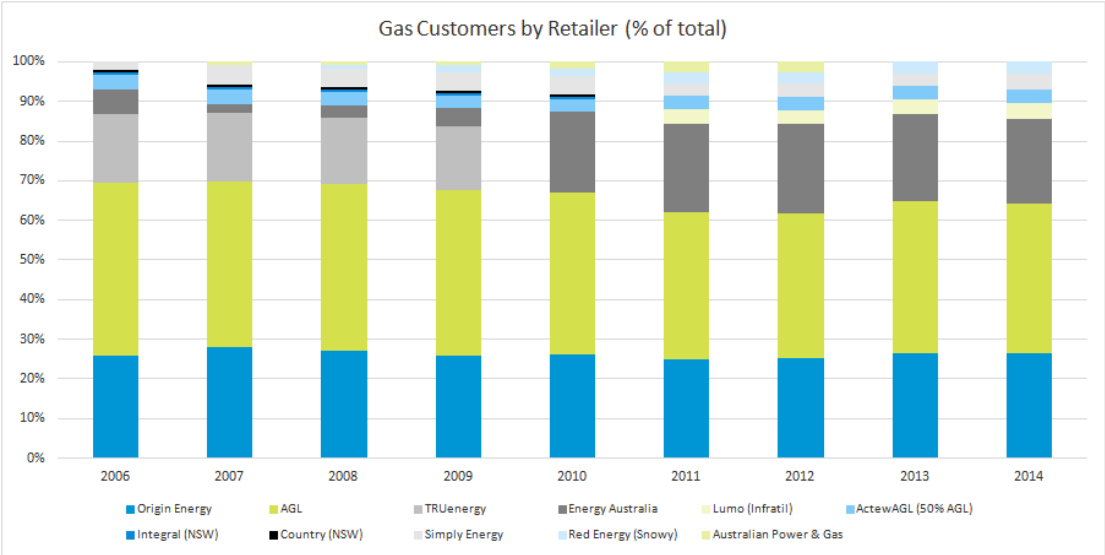
Figure 20: Total Eastern Australia Retail Gas – Market Shares



Source: Commonwealth Bank of Australia

More than 80% of Eastern Australian retail gas market share is between just three players, (i) Origin Energy, (ii) AGL Limited, and (iii) Energy Australia (formerly TRUenergy). Figure 19 shows that these market shares have only changed a little over the past 7 years. AGL's dominance has been slightly reduced, but largely through new entrants rather than losing share to Origin and Energy Australia.

Figure 21: Eastern Australia Retail Gas – Market Shares between 2007 and 2014

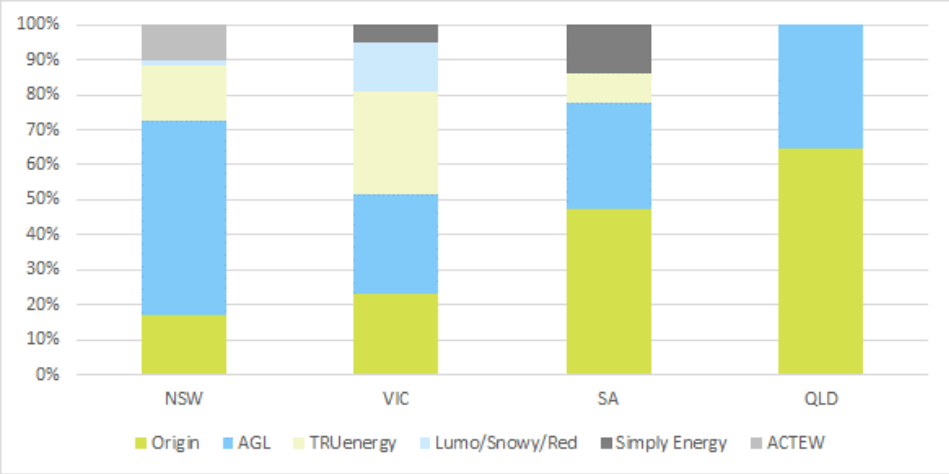


Source: Companies, UBS estimates, CBA estimates, Arnhem estimates

Market concentration, measured by the Herfindahl-Hirshman Index (HHI), has actually fallen from an ***HHI of 2,935 in 2007*** to an ***HHI of 2,642 in 2014***. In 2010, TRUenergy bought Energy Australia from the NSW government, which resulted in a small improvement in HHI, but consistent growth of smaller new entrants has been strong and seen HHI fall again. Competition has been particularly strong in Victoria, although more so in electricity than gas. It is a lot easier for a new retailer to get a hedge contract for its wholesale electricity exposure than it is to get a long-term gas supply contract at a reasonable price – particularly in the current environment. As such, the HHI of electricity retailing is only 1,888 versus gas retailing of 2,642.

Victoria has the highest margins for electricity retailers and as such has the most retail gas competition as well, as reflected in Figure 20. There are strong synergies in offering customers "dual-fuel" accounts/ contracts, whereby a customer gives there business for both to a single retailer.

Figure 22: Eastern Australia Retail Gas – Market Shares – By State

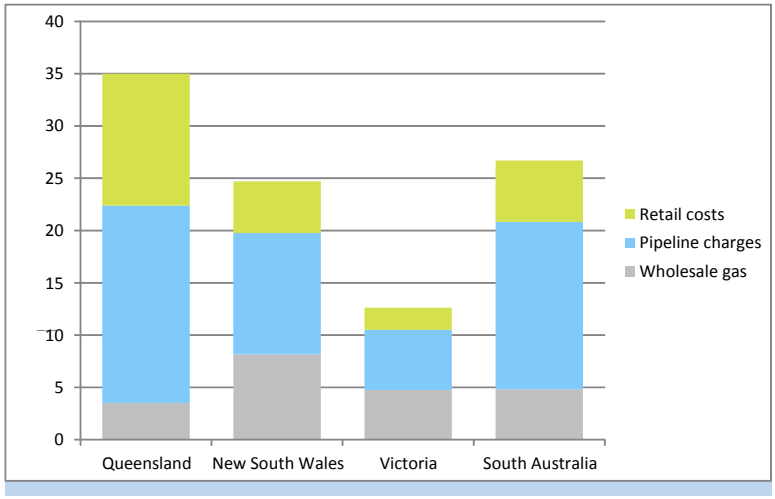


Source: Commonwealth Bank of Australia

9. Eastern Australian Gas – Value Chain

Figure 24 shows that there is a large different in gas price to the end retail customer within different states. Victoria has the lowest wholesale price, given the lower cost gas from the Otway and Bass Basins, as well as the lowest network costs

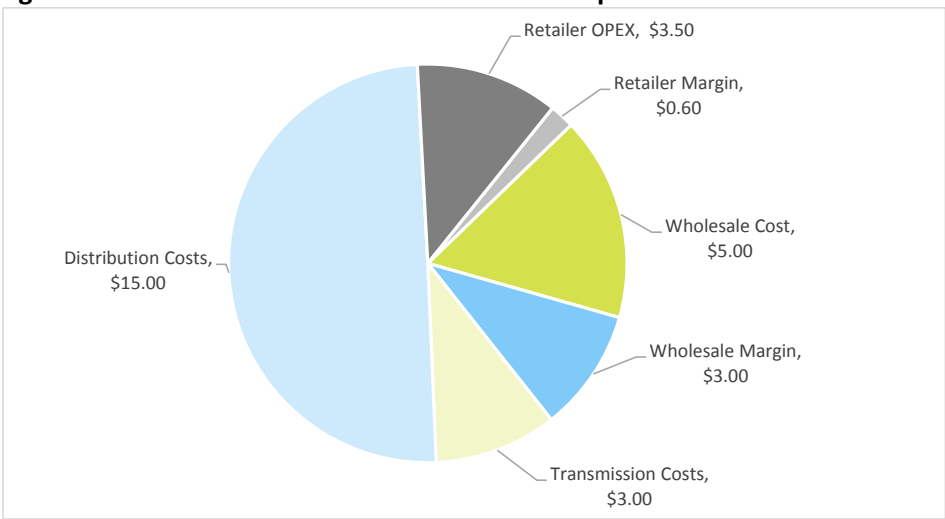
Figure 23: Eastern Australia Retail Gas Prices – By State



Source: Victorian Gas Market Taskforce Supplementary Report, 2013

Figure 24 takes the price in NSW and breaks it down further into its components.

Figure 24: New South Wales Retail Gas Price Components



Source: Deutsche Bank, Arnhem Estimates

Looking at the players involved, amd considering where the value is gained for each GJ of gas:

- **Wholesale gas producer** – Although increased production volumes are moving higher on the cost curve, the price is rising faster. As such, there is an additional margin being captured (and to be

captured) by the producers – particularly those with low cost production (conventional gas in Southern Victoria etc) and close to market.

- **Transmission / Pipeline owner** – Although some pipelines are regulated, a major operator like APA Group has only about 25% of its revenues regulated. A lot of gas transmission is negotiated through long-term Gas Sale Agreements between shipper and pipline operator. Through bi-directional functionality and managing large volumes of gas as a 'network', transmission pipeline operators should be able to achieve above regulated returns.
- **Distribution network owner** – Figure 24 shows that distribution network costs are about half the entire cost to the end consumer and this is despite the distribution networks being regulated. A lot of the value is lost in the capital required just to provide the service. Because the distribution networks are regulated the return is limited. In addition, with lower interest rates, we have seen recent regulatory decisions at materially lower WACC allowances, which suggests there is probably downside risk to returns in the short- to medium-term.
- **Retail energy provider** – The energy retailers, such as Origin Energy and AGL Limited, are currently making ~7-9% EBIT margins. Although energy retail is competitive, it is harder for the smaller 'tier 2' retailers to compete in gas given the difficulties in obtaining long-term gas supply contracts. On the flipside, competition is particularly strong in electricity retailing as it is comparatively easier to get an electricity hedge contract to underwrite wholesale electricity volumes.

Overall, although they have higher risks, the most value is likely to be extracted from upstream gas producers and downstream end retailers, particularly if they are vertically integrated with equity gas or have cost competitive gas supply arrangements.

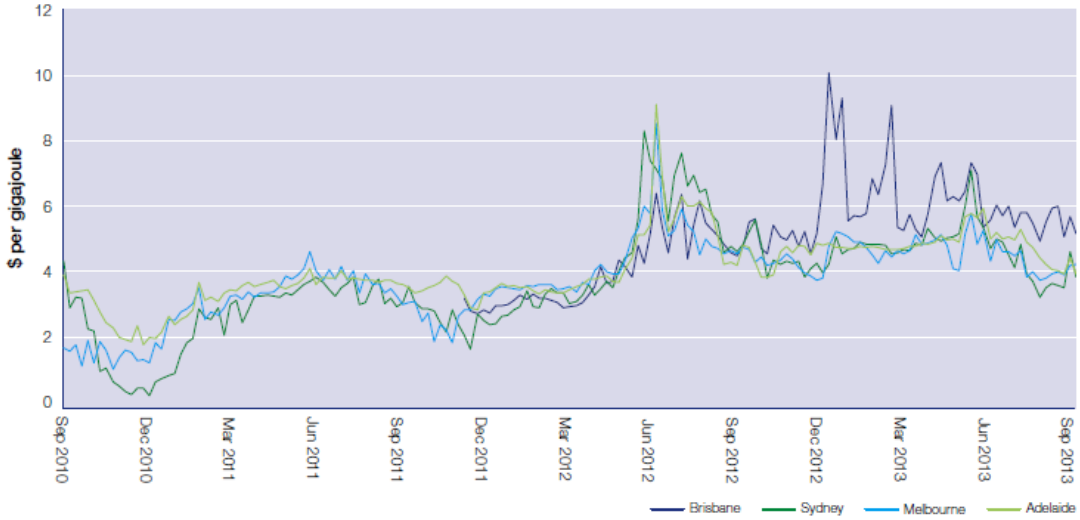
10. East Australian Gas Pricing

10.1. History

The huge increase in demand for gas due to export Liquefied Natural Gas (LNG) projects that is expected from 2015/16 is expected to have a significant impact on domestic gas prices. In Western Australia (WA), which has been exporting gas as LNG since 1989, gas prices have risen from $2-$3 per gigajoule (GJ) in the early 1990's to $8-$9/GJ for contracts in 2013 (Haylen and Montoya, 2013). We have already seen prices increase in Queensland move from about $3-4/GJ to about $7/GJ over the past couple of years as we move closer to first exports (Haylen and Montoya, 2013).

Figure 25 shows the trend in spot gas prices between 2010, when the Gladstone LNG projects were sanctioned, and late 2013. Refer back to Table 2 on page 11 for details on recent long-term contracts. The recent trend has definitely been toward higher prices.

Figure 25: East Coast Spot Gas Prices – Weekly Averages

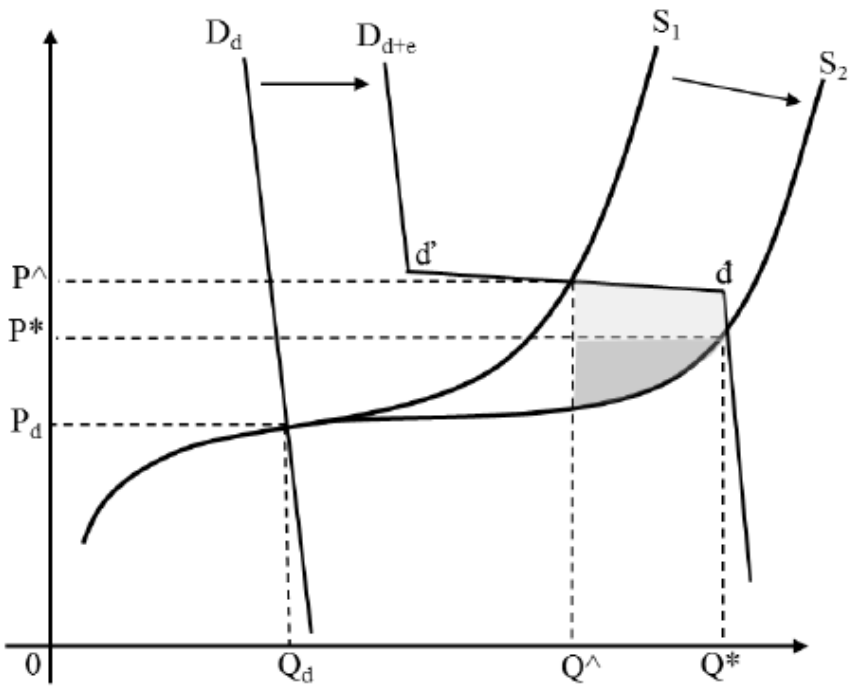


Source: AEMO, AER

10.2 Pricing Expectations

Simshauser and Nelson, as part of a detailed study conducted by AGL Limited, examined the supply/ demand impact of the East Coast gas market tapping the international market. Figure 26 shows the demand supply dynamics and impact of entering the export market. S_1 represents east coast supply and D_d east coast demand. The domestic market settles at price P_d, which has been around $2-$3/GJ, and quantity Q_d.

Figure 26: Supply/ Demand Curve – Domestic versus Export Gas



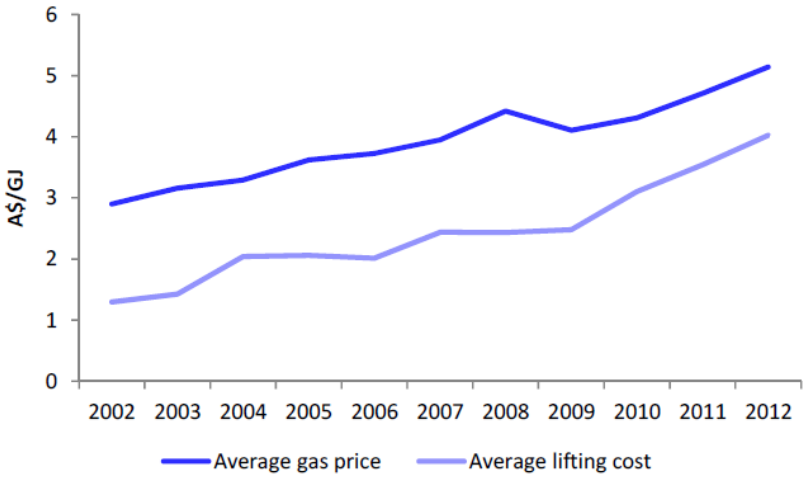
Source: Simshauser and Nelson, 2013. Figure 29, Page 33

Once the international market is entered, the demand curve changes to D_{d+e}. The relatively flat section d'd represents the large quantity demanded at the going international price and ability for LNG producers to substitute some of their own output with purchased spot cargos (Simshauser and Nelson, 2013). The new equilibrium price is P^, which is the net back price of about $9-10/GJ, at quantity Q^. If additional supply is brought online, pushing the supply curve to S_2, it's argued that price will reduce to P* at quantity Q*, which is estimated to be about $7-8/GJ (Simshauser and Nelson, 2013). Prices are therefore still materially higher than before exports, but settle below export parity, and is what happened in Western Australia (Jericho, 2014).

Once they have access to international markets, gas producers will only sell into the domestic market if the price achieved is equal to what they can get in the export market (King, 2013; Jericho, 2014). Australia's gas exports have minimal effect on international supply as it represents only 4% of Asia/ Pacific gas consumption (Jericho, 2014), whereas previously east coast gas production represented 100% of domestic consumption. This has been seen previously in Western Australia (WA) where, once LNG exports started, gas prices rose from $2.50/GJ to $8/GJ (King, 2013). Simshauser and Nelson (2013) identify a difference between a short-run net back price and a long-run net back price, and expect an initial spike in pricing to export parity or above while there is a supply shortfall, but for prices to settle back at net back or below once all projects are fully ramped up.

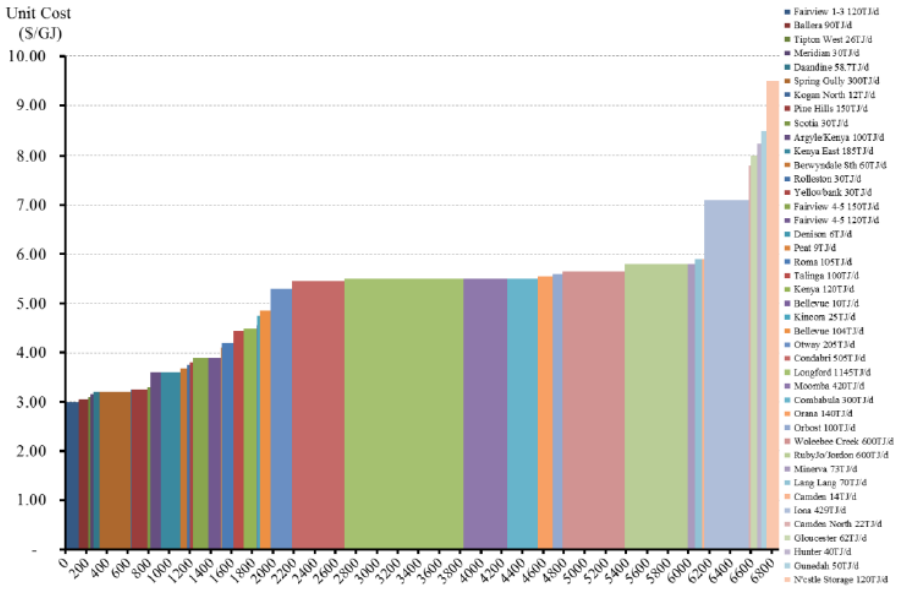
It is important to note that, even without LNG exports, domestic gas prices are expected to increase over time (Emerson, 2014; Wood, 2014). According to APPEA (Byers, 2014) gas prices are also rising because low cost sources are becoming depleted and new supply is more costly to extract. This is supported by data from Santos Limited and Deutsche Bank, shown in figure 14, that shows average production costs have tripled for Santos over the past decade, and figure 15 shows the cost curve for the Australian gas market.

Figure 27: Santos Limited Historical Gas Price and Production Cost



Source: Santos Limited, Deutsche Bank

Figure 28: Aggregate Gas Supply Cost Curve for East Coast for 2018F



Source: Simshauser and Nelson, 2014. Figure 12, Page 17

Even though a fall in oil price will reduce LNG prices and domestic netback gas prices, the volume required to meet contracts will mean additional volumes will move up the cost curve. So falling oil prices certainly help domestic prices, but they will still creep upward.

11. Key Issues Impacting the Eastern Gas Market

11.1. Domestic gas reservation policy

There is a view that introducing a gas reservation policy on the East Coast will keep prices down. Currently only WA and Queensland have gas reservation policies in place, although the provisions of the Queensland policy have not effectively been implemented. Other States and Territories, as well as the Commonwealth, have not established reservation policies.

WA has a policy that reserves 15% of gas for domestic use. A formal policy was adopted in Western Australia, *WA Government Policy on Securing Domestic Gas Supplies*. The Pluto LNG project was approved subject to this policy. This has not, however, kept prices down to where east coast prices have been, althugh prices have settled below export parity (Jericho, 2014).

In Queensland, the Gas Security Amendment Act 2011 was passed, which amended the Petroleum and Gas (Production an Safety) Act 2004 to enable implementation of the Prospective Gas Production Land Reserve (PGPLR) policy. Under this policy the State may, when granting a production license, require that gas produced from an area be supplied domestically. No gas field has yet been set aside for domestic supply.

There are many arguments for and against domestic reservation policies. Ultimately, assuming there remains a different between international and domestic pricing, such a policy is a form of subsidy and economic theory suggests it is ultimately a form of inefficient protectionism – an effective 'tax' on the producer and an effective 'subsidy' for the user. Importantly, King (2013) points out that the only way a domestic reservation policy can keep gas prices materially below export parity is if the domestic supply is greater than demand to drive down prices.

11.2. Coal Seam Gas as a Solution

A major dilemma facing State governments in Australia is how to deal with the rising east coast gas price and CSG production approvals. On one hand governments are being told that they must immediately remove the moratoria against CSG drilling, 'fracking' and production as there is an impending supply shortfall (Jericho, 2014) that will see prices rise further and will cripple gas-intensive manufacturing in Australia. Further, governments can see the benefits to the economy in terms of royalties and tax income, as well as investment and employment. On the other hand, governments are being told that rising prices are *not* the result of a supply shortage and that CSG production is harmful to the environment and must be permanently banned.

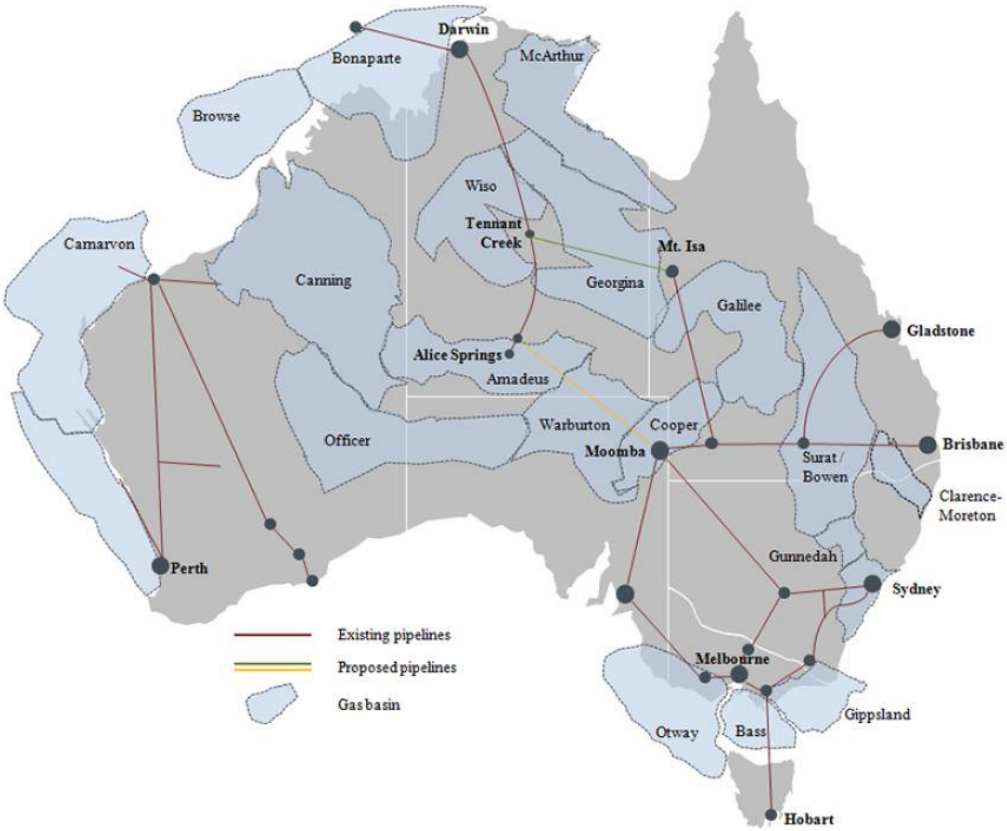
There is an argument that economic analysis of CSG production does not take into account externalities such as carbon emissions and any impact on ground water. There has been considerable opposition from activists, the community and landowners to CSG production. 75% of submissions to the independent review into CSG related to risks to groundwater (O'Kane, 2013) and although landowners suffer negatives like noise, disruption, impact on landscape and local roads, they do not get adequately compensated (Wood, 2014). The public doesn't trust the 'experts' as there has been evidence of corruption (Keane, 2013). Independent, science-based research is vital, such as the NSW chief scientists report into CSG which found that, (i) CSG is not materially different to other extraction industries, and (ii) the environmental risks can be adequately managed (O'Kane, 2014). The other impact on the environment is that, as gas becomes more expensive, the use of coal for electricity generation has increased, which increases the carbon footprint. This is expected to continue with significant gas fired generation being replaced by coal (Wood, 2014).

According to the Grattan Institute (Wood, 2014), the economic benefits of nurturing an LNG export industry far outweigh the negatives for manufacturing and gas-intensive sectors from higher gas prices. Once the Gladstone LNG projects start up, QLD expects to have the highest growth in the country of about 6% (APPEA, 2014) and will see petroleum royalties increase from $70m to more than $500m (Whop, 2014). Research indicates that higher gas prices will have a significant negative impact on the manufacturing industry as well as the transport, agricultural and mining industries (O'Donoghue, 2014), and The Australia Institute (2013) claims that the oil and gas industry employs only about 0.2% of the workforce.

11.3. Connecting Domestic Markets

A potential new source of supply to the East Coast market would be the proposed new pipeline connecting it with the Northern Territory gas market via Moomba. There appears to be a reasonable amount of interest in the idea of building a 1,000km pipeline that would run from either Alice Springs to Moomba pipeline or Tennant Creek to Mount Isa. In fact, the Northern Territory granted it "major project" priority status late in 2014 and signed a memorandum of understanding with NSW.

Figure 29: Proposed Northern Teritory to East Coast Gas Pipeline



Source: ***http://www.abc.net.au/news/2014-10-13/map-of-gas-pipelinesjpg/5810362***

The theory is that a pipeline would help commercial gas in a number of basins in central and northen Australia that are currently 'stranded', while providing NSW with new gas supplies to keep costs down. The key questions are how much 'stranded' gas could actually be extracted in the Northern Territory and at what price would it be delivered to NSW consumers.

According to gas transmission pipeline operator APA Group (Daly, 2014), the cost of the pipeline would be between $900m to $1.3 billion. Research by Credit Suisse concluded that it doesn't stack up unless unsanctioned resources in Eastern Australia are extremely expensive to develop ($10+). There are two main issues:

1) **Where does gas come from?** There are currently no reserves available and Rio Tinto shut down its Gove alumina refinery because there's wasn't enough gas. Commercialisation of unconventional gas in central/ northern Australia remains unproven and a 'wildcard'. It is unlikely a $1.0 billion pipeline will be sanctioned without clear gas reserves and long-term contracts to underpin it. Bringing offshore gas down from Darwin (if feasible at all) would probably get better economics via LNG, particularly as Darwin LNG will require additional gas in about 5 years and has potential for expansion. The Ichthys LNG project also has expansion opportunities.

2) **It adds a lot of cost**. The proposed APA pipelines would add about $1.50-$2.00/GJ to get to Moomba. But if gas has to come from Darwin, the existing pipline from Darwin to Alice Springs needs to be upgraded or rebuilt (according to Santos), which would add another $2.00/ GJ to the transport cost. Ultimately, gas would need to be sourced that is $3-4/GJ cheaper to produce than it is in Eastern Australia and, if that exists, would be more likely to go to LNG.

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