New Contract Gas Price Projections

IPART

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Contents

Executive summary

Terms of reference

The Independent Pricing and Review Tribunal (IPART) has appointed Jacobs SKM[1] to provide advice in relation to the wholesale gas prices that are likely to apply in New South Wales in 2014/15 and 2015/16. Specifically, IPART has requested advice covering:

1) A forecast of the potential range of wholesale gas costs faced by an efficient new entrant gas retailer serving the small customer market in NSW The forecasts are to be for the price of a new long term contract delivered at each zonal hub relevant to the gas standard retailers in NSW, as well as an average NSW forecast. (The standard retailers serve customers in Sydney, Albury, Wagga, Tamworth and near Canberra.)
2) Given these forecasts, advice on the reasonableness of the retailers' proposed wholesale gas costs for 2014/15 and indicative costs for 2015/16. It is not intended to re-examine the individual components of the retailers' proposed wholesale gas costs in the same level of detail as in the 2010 and 2013 price reviews. However, IPART needs to be satisfied that the proposed wholesale costs are reasonable and reflect efficient costs, in particular whether it's appropriate to add additional deliverability and market related costs to the forecast delivered price and compare that to the retailers' proposals.

Summary of findings

Background

Eastern Australia (New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT) has a well-developed gas market and infrastructure. Total demand was approximately 676 PJ in 2013, spread among the capital cities and sites of major industry and power generation. Supply is spread across seven basins concentrated in Queensland, South Australia and offshore Victoria and linked by an almost[2] fully interconnected transmission network. Total proved and probable (2P) reserves are estimated at 46,170 PJ at the end of 2013, equivalent to 68 years supply, though most of these reserves have been proved up to support LNG exports from Gladstone, which will triple gas demand and reduce supply to 22 years.

Gas sales and purchases in eastern Australia take place under bi-lateral term contracts at both wholesale and retail levels, with organised spot markets used to manage network imbalances. Spot markets provide for price discovery – contract prices are confidential – but do not provide any forward price indication and effective financial forwards markets have yet to be established. New contract prices, or rather estimates of them, therefore provide the best guide to future gas prices.

LNG impacts

The LNG projects under construction in Gladstone are scheduled to start exporting CSG-based LNG in late-2014. The projects will triple eastern Australian gas demand by connecting gas supplies with the high volume, high value East Asian market. From the domestic gas market perspective this has created:

a) The expectation that all eastern Australian gas can be sold at "export parity" prices considerably higher than legacy domestic gas prices

[1] **Jacobs® and Sinclair Knight Merz (SKM) have combined to form one of the world's largest and most diverse providers of technical, professional and construction services across multiple markets and geographies.**

[2] Only Townsville remains isolated.

b) An apparent shortfall in gas supply as the three LNG developers prioritise supply from their own acreage to their projects and have also pre-purchased significant volumes of gas from third parties.

Since the projects were first proposed in 2007 and 2008 a growing number of studies have advanced the view that the prices of new domestic gas contracts would rise because of LNG. A wide range of price levels has been predicted, from \$6/GJ to \$12/GJ, because of uncertainty in key drivers such as future oil prices, export volumes and costs of gas production, as well as differences in study methodology. The studies also showed wide variations in the speed at which prices would escalate after LNG start-up.

With the first exports now only 6 months away, some uncertainties have reduced, particularly regarding the next 2 to 3 years. Moreover, since 2011 new domestic gas contracts have been entered for supply in the period from 2014 onwards, under the above influences, and these contracts provide a clearer indication of future pricing. While these two factors create more certainty about the immediate future, other elements continue to reinforce uncertainty, most significantly the ability of the LNG projects to ramp up production to meet export targets and their continuing purchases of third party gas.

Gas price factors

Jacobs SKM has made the following assessment of the key factors impacting the price of gas:

1. Costs of gas production

   Estimates of the cost of gas production, including capital and operating costs, applicable to new gas supply, that is, ignoring potentially lower cost sources already dedicated to contracts, has been assessed to be \$4.50/GJ. This sets the lowest price at which a gas producer would sell gas in a new contract, in a very competitive market.

2. LNG pricing and netback

   East Asian LNG prices are linked to the JCC (Japan Customs Cleared Crude) index, a crude price closely related to Brent Crude. The strength of the linkage varies from time-to-time and for the Gladstone LNG projects is estimated to yield an FOB price in the range \$US14.00-14.50/mmbtu in 2014/15 and 2015/16, corresponding to EIA median oil price projections.

   The LNG netback value is the above FOB value translated back to a value at Gladstone or at the wellhead by subtracting liquefaction and transmission costs. As these costs are capital intensive long- and short-run costs are materially different. Using IMF \$US/\$A exchange rate forecasts, netbacks for 2014/15 and 2015/16 are projected in the ranges: long-run, \$8.50-8.75/GJ; and short-run, \$12.00-12.50/GJ. Actual values for each of the Gladstone LNG projects could be outside these ranges.

These values define the <u>maximum</u> values that an export project would pay for third party gas delivered to their wellhead (effectively, to Wallumbilla). The actual price at which any contract between a third party supplier and an LNG project is negotiated will lie between the suppliers cost of production and the project's netback value, How the difference between these values, the "pure profit" component of LNG, is shared between them will be determined by the parties relative negotiating powers. As there are only three export projects, their market power relative to gas producers may be considerable in which case the prices paid would be below the full netback value.

The LNG netback value is one factor among many that now determine the level of domestic prices, since it represents the value in a competing market for gas supply that has become restricted. Given the quantum of exports relative to the domestic market, namely about 2x, it is an important factor. However Jacobs SKM does not subscribe to the widely expressed view that the domestic prices must inevitably equal the netback value, or export parity value, for reasons including the above and because there is no unique netback value, due to variations in LNG pricing formulas and liquefaction and shipping costs between different LNG projects.

Recent new domestic contract prices

Nine new domestic contracts are known to have been entered since 2011. Price data for the contracts is based on detailed reviews of statements by the seller and/or buyer as to whether the pricing formula is oil linked, related to market etc and correlated with other media statements including those by financial analysts who may have received briefings from contract participants. The price estimates are uncertain and it is difficult to draw definitive conclusions apart from averages but the following trends seem clear:

- Prices have escalated since before 2010 and cover a wide range from approximately $5.50/GJ to $10.00/GJ
- Prices in Queensland appear to have escalated further in 2013 relative to 2010-2012 as more third party gas has been purchased by LNG projects. The most recent price in Queensland is $10/GJ for a 23 month contract starting in February 2015, compared to the first contract signed in 2011 at $6/GJ. It is also noted that the price in this first contract may have been influenced by the negotiating power of the buyer, which had a viable alternative source of electrical energy via the Copperstring project.
- Prices for gas in southern states, sourced from the Gippsland JV, are lower than those in Queensland but are evidently set by contract to escalate to higher levels over a short period. The aggregate estimates for southern states rely heavily upon the large volume contract between BHPB-Esso and Origin Energy.
- Some domestic contracts are oil-linked but others are not.

Table E 1 shows the estimated average prices in the new contracts by region. Escalation of the average prices from year to year are due to a combination of: timing of new contracts starting; staged increases in each contract; and oil indexation impacts.

In terms of supply to NSW, Jacobs SKM considers that these prices are reasonable midpoint estimates of new contract prices that might be paid by a new entrant for Cooper and Gippsland gas respectively, subject to the observation that very limited Cooper Basin gas would be available.

Table E 1 Estimated recent domestic wholesale contract average prices by region

	2014/15	2015/16
Surat & Cooper Basin	$7.86/GJ	$8.01/GJ
Gippsland Basin	$5.50/GJ	$6.06/GJ

Price projections derived by modelling

Jacobs SKM has used its “Market Model Australia – Gas” (MMAGas) modelling tool and associated data to estimate gas prices in all market zones and well heads in the short-term. Key assumptions, detailed in the text of the report, cover: gas reserves; gas demand projections, including LNG; gas production costs; existing domestic & LNG contract volumes, prices and durations; transmission network structure and costs; and LNG netback values.

Modelling has focussed on six scenarios: short and long-run netback values, each for three modes of operation, referred to as: Base Case; Victorian-constrained, in which transmission constraints are assumed to prevent Victorian gas supplying new contacts into NSW; and LNG-advanced, in which further LNG contracts are negotiated before domestic contracts.

In the Base Case projected prices at Longford are broadly consistent with those estimated from recent contracts, though about $0.50/GJ higher which is within the uncertainty of the estimates. The Base Case prices at Moomba are very similar to recent contracts except in 2014/15, where we note that the low Moomba price calculated is due to Moomba not supplying any new contracts in that year. Prices are not much different between the short- and long-run netback cases, which suggests that prices are being determined by market power rather than direct reference to netback.

In the scenario where further Victorian supply is constrained out of NSW, the Moomba prices are up to $2/GJ higher than in the Base Case because of the tightness of supply at Moomba.

In the scenario where further LNG contracts are negotiated before domestic contracts, prices are approximately $2/GJ higher in the SR netback case but only $1/GJ higher in the LR netback case.

Jacobs SKM estimates of new gas contract prices in NSW

Jacobs SKM considers that a new gas retailer (or end-user) should be able to negotiate a new gas contract at Longford in Gippsland on the following basis: in 2014/15 in the range $6.00-$6.50/GJ and in 2015/16 in the range $6.50-$7.00/GJ which represent premiums of $0.50-$1.00/GJ over prices in other recent contracts, due to further tightening of the gas market since these were negotiated.

We are less confident that a new gas retailer (or end-user) will be able to negotiate a new gas contract at Moomba at all. Although our modelling indicates that small volumes should be available, there are no recent contracts to support this and key participants in the Cooper Basin JV, Origin and Santos, are strongly aligned with LNG projects. If a retailer negotiates with a Moomba producer without the benefit of competition from Gippsland, the price will be high, in the range $8.00-$10.00/GJ, lower for small volumes of 2-3 PJ pa and higher for larger volumes of 5-10 PJ pa.

We note that a new retailer will have a strong preference for obtaining supply from Gippsland but will not be able to negotiate new transmission capacity from Victoria to NSW until 2015/16. However we consider that it may be possible for a new retailer to obtain existing capacity from another shipper in 2014/15, based on the peak day projections in the AEMO 2013 GSOO, which show a reduced total requirement from 2013.

Comparison of Jacobs SKM new entrant price estimates and retailer wholesale prices

AGL's proposed gas commodity costs are compared with Jacobs SKM estimates of new entrant gas contract prices in Table E 2. AGL's proposed aggregate commodity cost sits towards the low end of the estimated new entrant price range in 2014/15 and towards the high end in 2015/16.

ActewAGL's and Origin Energy's price proposals provide insufficient information regarding their commodity cost assumptions to permit a direct comparison with Jacobs SKM's estimates.

Table E 2 Comparison of AGL gas commodity costs and Jacobs SKM estimates of new entrant gas contract prices ($/GJ)

		2014/15	2015/16
Moomba	AGL	$8.65	$9.73
	Jacobs SKM	$8.00-$10.00	$8.00-$10.00
Gippsland	AGL	$5.59	$6.50
	Jacobs SKM	$6.00-$6.50	$6.50-$7.00

		2014/15	2015/16
Weighted Average	AGL Proposed	$7.12	$8.12
	Jacobs SKM	$7.00-$8.25	$7.25-$8.50

1. Introduction

For some time it has been predicted that domestic market wholesale gas prices in eastern Australia would rise in the period 2014 to 2017, in parallel with the new LNG export projects in Queensland ramping up to full production. Details of a number of studies which address this are provided in section 6.2.1.

The LNG export projects, which are expected to triple gas demand in eastern Australia, have had and will continue to have the effect of:

- Enabling gas producers to sell gas into export markets that pay a price premium relative to historical domestic market prices
- Creating an apparent gas supply shortfall, resulting in domestic gas buyers reporting difficulty securing additional gas at the end of their existing supply arrangements

A wide range of future domestic wholesale gas price scenarios have been presented by analysts, though typically in the range $6/GJ to $12/GJ, compared to historical prices at $4/GJ to $4.50/GJ. Key scenario drivers have been:

- Oil prices, to which East Asian LNG export values are linked
- The volumes of LNG projected to be exported, and their relationship to gas supply availability
- Costs of gas production, which have been increasing owing to exploitation of more costly resources and project cost escalation

Progressively since 2011 but mostly in 2013, nine new domestic contracts have been concluded for the period from 2014 through to 2017 and beyond. These are contracts negotiated since the LNG projects entered their construction phases and their pricing would therefore be expected to fully reflect LNG influences. Though details of such contracts are generally held in confidence, it has been revealed that many have pricing arrangements involving a link to oil prices and that price levels are substantially above historical prices. During the same period nine supply arrangements have also been concluded between the LNG projects and third party suppliers, also with oil-indexed pricing. This represents direct competition between LNG and domestic buyers and directly influences domestic pricing.

To the extent that the new contract prices are known they provide both a direct indication of the price likely to be paid by an efficient new entrant gas retailer and a guide for the fine tuning of pricing models, which can be used to investigate prices that may be paid by new entrants under a range of different circumstances.

1.1 Study structure

The following sections of this report provide:

2. Back ground information on eastern Australian gas demand-supply and market operation
3. Features of gas contracts relevant to pricing
4. A description of the study methodology
5. An assessment of pricing factors
6. Estimates of new contract prices in 2014/15 and 2015/16 based upon recent new contracts (actual) and Jacobs SKM modelling under three scenarios

7. Jacobs SKM's conclusions regarding contract prices faced by a new entrant retailer for supply in NSW in 2014/15 and 2015/16.

1.2 Report update

This report is an update of the final report issued to IPART on 4th April 1014, which incorporated data with a cut-off date set at 20th March 2014. Relevant information that became available after this date includes:

- A 20 year contract for sale of gas by Westside to GLNG from Bowen Basin CSG reserves, announced on 27th March 2014. The price of gas in this contract, of which more details have been published than for other recent contracts, is discussed in section 6.1. Jacobs SKM's conclusions regarding gas prices published in the 4th April report are consistent with this information and have not changed.
- A very large gas supply agreement between Russia and China, which may disrupt LNG markets, announced on 21st May 2014. A discussion of the potential impacts, which are difficult to quantify, is provided in section 6.2.3.2.

1.3 Abbreviations

Table 1-1 Abbreviations

2P	Proved and probable reserves (50 percentile estimate of commercial reserves)
ADQ	Average daily quantity of gas available under contract
AEMO	Australian Energy Market Operator
APA	Australian Pipeline Trust
APLNG	Australia Pacific LNG
AQ	Annual quantity of gas available under contract
ASX	Australian Stock Exchange
AVI	Argus Victorian Index (gas price index based on Victorian spot market price)
bbl	Barrel (of oil)
BREE	Bureau of Resource and Energy Economics
CSG	Coal seam gas (natural gas released from coal seams after drilling)
EIA	Energy Information Administration
FOB	Free on-board

GJ, PJ	Giga-, Petajoule (10^9, 10^{15} joules)
GLNG	Gladstone LNG
GSOO	Gas statement of opportunities
IMF	International Monetary Fund
IRR	Internal rate of return
JCC	Japan Customs Cleared Crude (an oil price index used to price LNG)
LNG	Liquefied natural gas (gas cooled to -160C)
LR, SR	Long-run, short-run
MDQ	Maximum daily quantity of gas available under contract
mmbtu	Millions of British thermal units
MTPA	Million tonnes per annum (of LNG)
QCLNG	Queensland Curtis LNG
STO	Santos

2. The eastern Australian Gas Market

2.1 Introduction

The prices of most products reflect the balance of supply and demand for the product. Gas in NSW is such a product and this section presents details of the market within which NSW gas is priced.

The gas resources and delivery infrastructure in eastern Australia (New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT) are illustrated in Figure 2-1. All gas producing and consuming regions with the exception of the northern Bowen basin and Townsville in Northern Queensland are interconnected by a transmission grid and gas currently flows across many of the state boundaries, including from Queensland to NSW and SA and from Victoria to Tasmania, NSW and SA.

Eastern Australia has a domestic market estimated at 676 PJ in 2013, supported by substantial conventional and coal seam gas (CSG) reserves – total 2P reserves at 31/12/2013 are estimated at 46,170 PJ. Total reserves declined for the first time during 2013, principally in New South Wales owing to development projects being put on hold. Regional breakdowns are shown in Table 2-1.

Table 2-1 Gas demand and 2P reserves by state, 2013 (PJ)

	NSW	Victoria	SA	Tasmania	Queensland	Total
Demand	160	215	95	13	193	676
2P Reserves	1,928	4,652	1,889	257	37,444	46,170

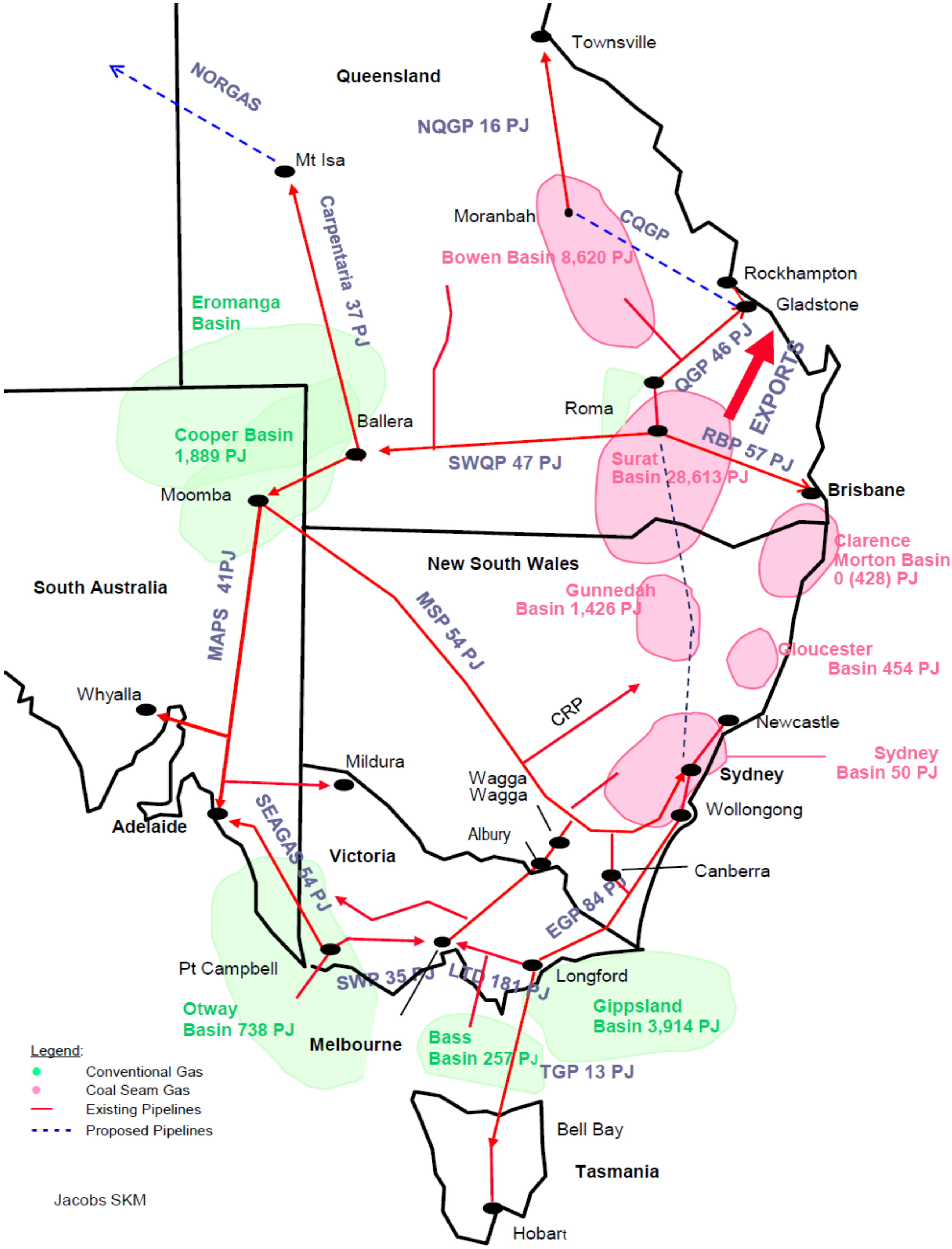
Sources: Demand: AEMO Gas Bulletin Board; Reserves: Oil and Gas Resources Australia; Queensland Department of Natural Resources and Mines; and Producer Estimates

Demand and supply patterns in this market have operated in isolation from other gas markets in Australia and overseas because to date there have been no gas exports from or imports to the region. In the period since 2007 growth of CSG reserves, to levels in excess of foreseeable domestic demand, has led to construction of a number of LNG export projects which are scheduled to start exporting from late 2014. These projects have already begun to change the domestic market, both in terms of the demand-supply dynamics and the nature of the participants, who now include global energy companies such as BG Group, Conoco Phillips, Petronas and Shell, and large offshore gas purchasers such as China Petroleum Corporation, Kogas and PetroChina.

The prospect of exports emerged relatively quickly and unexpectedly, following a long history of perceived excess of demand over local supply and a corresponding history of proposals to import gas from the North West Shelf in Western Australia, from Papua New Guinea and from the Timor Sea. All of these proposals have been deferred because of unforeseen growth in eastern Australian gas reserves and supply, most recently the CSG reserves in Queensland.

All eastern States sub-markets except Northern Queensland are now served by multiple basins and/or pipelines. Plans for a pipeline between Moranbah and Gladstone, which would link Townsville to other supplies, have been advanced but construction appears to be contingent upon LNG development in Gladstone using gas from the Moranbah area. Armour Energy and APA have also recently floated the NORGAS project concept of linking Mt Isa to the NT Pipeline to exploit gas in the Carpentaria, Georgina and McArthur Basins.

Figure 2-1 Gas reserves at 31/12/2013 and pipeline flows in 2013, eastern Australia



2.2 Market transactions

Gas sales and purchases in eastern Australia take place at a number of levels depicted in Table 2-2.

Table 2-2 Gas market transactions

Market Level	Sellers	Buyers	Form of sale
Wholesale - Wellhead	Gas Producers	Trader/Retailers or Large End Users	Bi-lateral term contract
Wholesale - General	Trader/Retailers or Large End Users	Traders/Retailers or Large End Users	Bi-lateral term contract
Retail	Trader/Retailers	End Users	Bi-lateral agreement or default terms
Spot	Trader/Retailers or Large End Users	Traders/Retailers or Large End Users	Bids and offers in organised markets

Note: a number of parties participate as vertically integrated producers, trader/retailers and large end users (power generators).

2.2.1 Term contracts

New gas supply is introduced to the market only by Wholesale-Wellhead transactions and these therefore tend to introduce price changes related to higher production costs and the value of gas in alternative markets. However buyers in the majority (by gas volume) of these transactions are traders who buy long and sell short and their secondary Wholesale-General transactions are beginning to have an important impact on price perceptions.

The duration of term contracts has covered a wide range, running from 3 years to 20 years in contracts entered over the last decade. There is limited public information on gas contracts but the basic details such as term and average volumes are known for the majority of the significant contracts because they are material to company performance and are therefore reported to the ASX. Contract prices are less well known but can often be estimated – most contract prices have until recently been CPI indexed and undergo periodic reviews to ensure they remain at “market” levels, though without a recognised market price, reviews can be protracted.

Shorter-term bi-lateral contracts are also used but there is almost no public information about them because they are insufficiently material to warrant reporting. In particular, short-term markets have had insufficient depth to support a price index, though we note the very recent start-up of the Argus Victorian Index (AVI), a month-ahead index linked to the Victorian spot price discussed below. The AVI hopes to replicate short-term markets in the US and Europe, where many trading hubs have associated benchmark prices, the best known being the Henry Hub in Louisiana. Many longer term contracts in the US are now indexed to the Henry Hub price, overcoming the difficulty of setting long-term prices that remain in line with the market.

2.2.2 Retail and spot markets

The gas being traded in retail and spot markets gets its commodity value to the seller from the wholesale markets. In the past it has been assumed that it would trade at approximately this value, for example retail prices would incorporate the average wellhead value of gas plus network and other components. However it is now inevitable that in the near future the wholesale market will be made up of a mix of old contracts at lower prices and new contracts at higher prices and it will be important to determine which of these values should influence retail and spot prices.

Organised spot markets are operated by the Australian Energy Market Operator (AEMO) in Victoria, Adelaide, Brisbane and Sydney for the primary purpose of balancing the transmission/distribution system – the pool price is used to settle injection/withdrawal imbalances. Bidding into the pool is compulsory for all transmission/distribution system users in the pool area, most of whom are retailers buying gas from producers under contracts. AEMO in conjunction with the gas industry has recently established a trading hub at Wallumbilla (near Roma), which is likely to see a rapid increase in volumes associated with LNG developments.

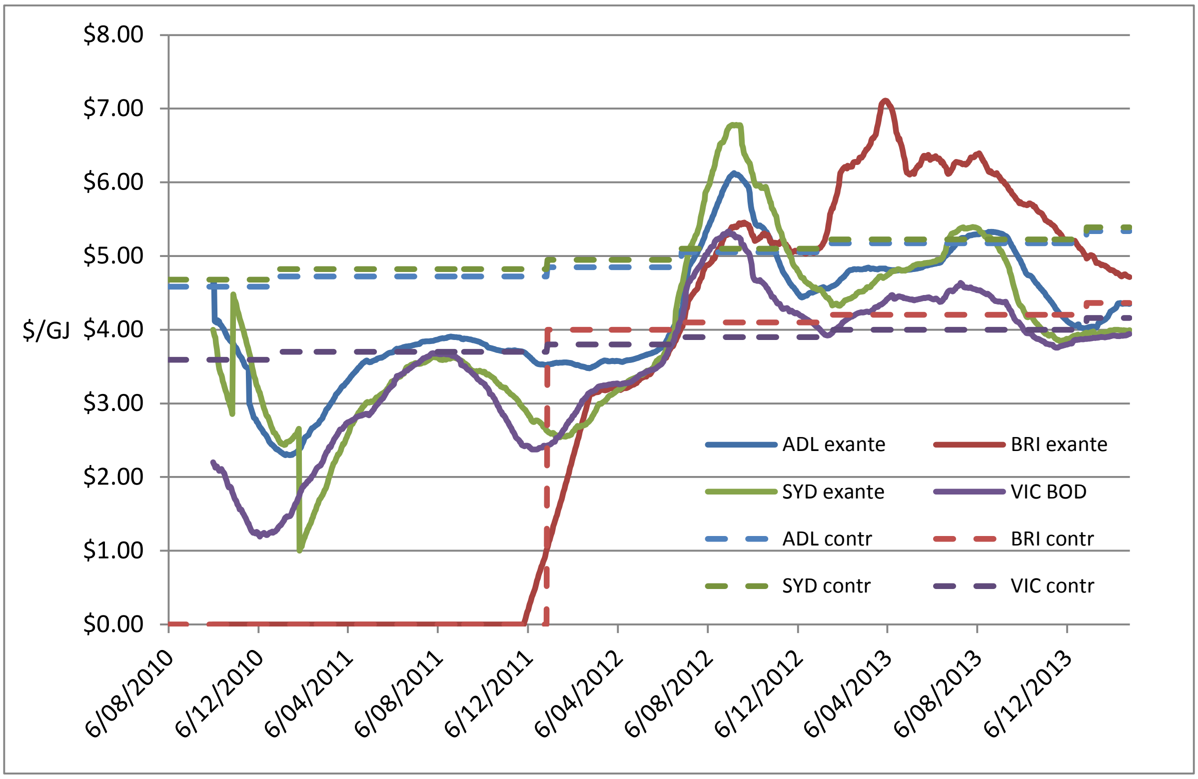
In general the pool bids and prices are determined by the prices set in the contracts rather than vice versa, though in recent years this has become less clear cut. Figure 2-2 compares spot market and contract prices from 2010 to the present, during which time there has been a material increase in spot prices which has led some commentators to suggest that the spot markets are signalling future increases in the value of gas. While this may be the case, the signals have recently weakened, with spot prices falling back to current average contract price levels and Jacobs SKM considers that the explanation of the price rise and fall lies in the following:

1) From 2010 to mid-2012 spot prices were generally below the comparable contract prices, due to excess contracted supply capacity, which in turn lead to low bidding to ensure dispatch and avoid paying for gas not taken under take-or-pay terms in contracts. If there is no prospect of using the gas over the next 2-3 years then discounting bids by 20% to 30% of the contract price is rational.
2) From mid-2012 spot prices rose to well above comparable contracts. Not only was the supply excess used up by higher winter demand in 2012, the take-or-pay problem also disappeared because accumulating banked gas (the gas paid for but not taken) became an asset rather than a liability because of the prospect of higher gas prices in future. For example if gas was purchased in 2012 for $4/GJ and banked until 2016, at a 10% holding cost per year the banking cost would be $1.60/GJ and banking would be a worthwhile strategy if the value of gas in 2016 was believed to be more than $5.60/GJ. The concept of creating a gas bank asset in this way was aired by analysts at JP Morgan, who estimated that AGL already had a bank of 204 PJ at June 2012 and that it could grow to 450 PJ by 2017, equivalent to 2 years supply[3].This is a considerable volume, given that many contracts limit the period at the end of contract during which banked gas can be used and provide lower priorities of delivery for banked gas.
3) Since early 2013 spot prices in Adelaide, Sydney and Victoria have fallen back to be approximately equal to comparable contracts but spot prices in Brisbane continued at high levels for another 12 months. A milder winter in 2013 is partly responsible.

Broadly, it appears that spot prices track contract prices and respond in the short term to whether supply capacity is long or short. With respect to the impact of LNG exports on spot prices, supply will progressively switch to higher priced new contracts which will most likely have a progressive impact. More importantly, as the export projects ramp up to full production, gas supply capacity across eastern Australia will be stretched, possibly to the extent that material load curtailment occurs from 2016 onwards[4] and this will be accompanied by persistent high spot prices in most market areas.

[3] Australian Financial Review June 12, 2013.
[4] AGL Working Paper No 40 Solving for x. March 2014.

Figure 2-2 Spot market prices (90d moving average) vs contract prices



Sources: AEMO (spot prices); Jacobs SKM (contract prices)

3. Gas contract structure and negotiation

3.1 Contract structure

The following typical features of a gas supply contract are discussed in more detail in Appendix A.

1. Term
2. Gas volumes
    a. Annual quantity (AQ), Maximum annual quantity (MAQ)
    b. Average daily quantity (ADQ), Maximum daily quantity (MDQ)
    c. Total volume over term
    d. Take-or-pay, banking and make-up gas
    e. Reserve/field dedication
3. Pricing
    a. Price
    b. Price indexation
    c. MDQ payment
    d. Price review

The relationships among these features, particularly gas volumes, can materially influence contract prices. Offtake flexibility, in the form of high MDQ relative to ADQ and low take-or-pay relative to AQ, would generally be expected to be related to higher prices. A number of factors however prevent us from estimating what this relationship is in practice:

- Details of these aspects of contracts are not generally publicly released
- The factors employed in contracts are understood to have converged eg to high take-or-pay
- Recent material increases in contract prices will tend to obscure the impacts of other factors

Consequently in estimating the price of a new long term contract delivered at each zonal hub relevant to the gas standard retailers in NSW we assume standard conditions, namely high take-or-pay and high load factor (ratio of ADQ to MDQ). This is consistent with the inclusion in the price review of separate costs for deliverability.

3.2 Contract negotiation

In relation to this study, the key issue about contract negotiation is timing. Negotiations are typically completed well in advance of first gas supply, with times in advance ranging to more than four years. This is because new gas supply is very rarely introduced on a develop-first sell-later basis, instead commercial terms are drawn up before construction of new plant, which then takes up to four years after negotiation. Consequently any contract that introduces a new supply source, of which there must always be some, must be negotiated well in advance. Buyers able to negotiate on this basis will be able to negotiate with any producer that has uncontracted gas reserves that are developable within four years, or a trader that has gas contracted but not sold to an end user.

This yields the widest range of supply options and competitive supply tensions and correspondingly lower prices for such buyers.

If a buyer is unable to negotiate this far in advance because of its own business uncertainties, such as uncertainties regarding its volume requirements, it will only be able to buy from a limited number of producers who have spare capacity already in the ground, owing to the termination of earlier contracts, or from traders who have gas contracted from producers but not sold to an end user. This limits the number of producers that such a buyer can deal with and this limited competitive tension can result in higher prices.

Some contract examples are given in section 6. Typically, traders, who have diverse buy and sell portfolios, are able to negotiate further in advance than end users. Consequently end users are more likely to buy from traders and traders from producers, though there are end users that purchase directly from producers.

This study requires estimates of the potential range of wholesale gas costs faced by an efficient new entrant gas retailer serving the small customer market in NSW. The forecasts are to be for the price of a new long term contract delivered at each zonal hub relevant to the gas standard retailers in NSW, as well as an average NSW forecast. For the years of relevance to the study, 2014/15 and 2015/16, the majority of relevant "new" contracts may have already been negotiated over the past three to four years or be currently under negotiation. Based on the above discussion it is possible that contracts for this period negotiated at different times will have different prices due to the different negotiation timing and to changing perceptions of the market in 2014/15 and 2015/16.

Details of the timing of seventeen recent new domestic and LNG contracts are provided in section 6. The ranges and averages of the times between contract announcement and first gas are tabled below. The times range from just over one month for traders selling to any type of buyer to over 4 years for a producer selling to an LNG buyer. This data confirms that producers, who may have to develop new reserves or capacity, negotiate further in advance than traders, who are selling spare gas from a contract portfolio.

Table 3-1 Time between contract announcement and first gas supply (years)

	Minimum	Maximum	Average
Producer sellers	1.7	4.6	3.6
Trader[5] sellers	0.1	2.7	1.9
LNG buyers	0.1	4.6	4.1
Domestic buyers	0.3	3.2	0.9
All contracts	0.1	4.6	2.5

[5] Parties that are both producers and traders have been classified as traders in calculating this table

4. Methodology

Previous assessments of future domestic prices have relied heavily upon gas pricing models that estimate one or more of the price drivers and the balance between them. Now that more domestic contracts have been entered for the period affected by LNG export developments, the actual new contract prices must be used to benchmark the models and/or be used directly to infer future domestic prices. In particular they can be used to assess the linkage between LNG netback prices (the value of LNG exports net of shipping, liquefaction and transmission costs) and domestic prices.

4.1 Factors influencing the setting of gas prices

A range of factors that influence the prices agreed in long-term contracts are discussed below.

4.1.1 Gas production costs (seller's economics)

The long-run cost of gas production including returns of and to capital and operating expenses sets a floor to the price that a gas producer is likely to agree to sell gas on a long-term contract.

4.1.2 Buyer's economics

Buyers economics are established either by the price of using an alternative fuel, such as coal in power generation, or by the maximum fuel cost that their product market will support, such as in chemicals or refining industries.

The difference between the value to the buyer and the cost to the seller is shared between them subject to their negotiating power, which is influenced by the following.

4.1.3 Level of sales and purchasing competition

Having alternative sellers increases the buyer's negotiating power and vice versa. On the sales side, in a competitive market pricing is set just above the marginal cost, whereas in a monopoly market the single supplier sells at a profit maximising price determined by the buyers' alternatives.

4.1.4 Demand-supply balance

If reserves are sufficient to meet the desired contract terms for the whole demand side of the market, this factor will not impinge on gas prices. However if reserves are insufficient, it may constrain contract availability to the lower value demand side sectors, such as power generation and energy intensive industry, in order to redress the imbalance.

4.2 Context

Until approximately 2010 new gas contracts were available in eastern Australia at price levels that had remained steady in real terms over the previous decade or longer. In south eastern markets supply was augmented by new reserves and developments in the Otway and Bass basins (first production in 2004) and in Queensland supply was augmented by CSG, which captured market share at lower prices in some Queensland sub-markets from the early 2000s. CSG growth increased the number of competing gas producers and rendered the supply of gas to eastern Australia from Papua New Guinea unnecessary.

By 2007 however the estimated CSG resource had outgrown the requirements of the domestic market and CSG developers sought monetisation of the resource in new, larger markets, the most accessible of which is the Asian LNG market. This market is also a high value market, with oil-linked prices that at the oil prices prevailing since 2005 yield a considerably higher value per GJ of gas sold than the eastern Australian domestic market, albeit with a very high investment per GJ.

A number of export projects were proposed between 2007 and 2008 and following marketing, CSG resource appraisal, including absorption of smaller CSG producers, and detailed design studies, three projects commenced construction in 2011 and 2012, Queensland Curtis LNG (QCLNG), Gladstone LNG (GLNG) and Australia Pacific LNG (APLNG). This development, which will increase gas demand in eastern Australia by 200% by 2017, has led to promotion of the view that all wholesale gas prices in eastern Australia will be set by reference to “export parity”, meaning the netback value of LNG exports. Further details regarding the export projects and background information about the global LNG market can be found in the 2013 Gas Statement of Opportunities and supporting documents, published by AEMO.

At a more detailed level, pricing perceptions have also been changed by the following:

- Although CSG resources are large, commercial proved and probable (2P) reserves were initially insufficient for standard 20 year LNG export contracts.
    - The LNG projects therefore focussed on proving up more reserves and refrained from selling any gas to the domestic market.
    - Reports of domestic buyers having difficulty securing new gas contracts emerged as early as 2011 in the Queensland Gas Market Review.
    - Two of the LNG projects also backed-up their reserves with volumes of gas purchased from third parties at relatively high, oil-indexed prices.
    - This created the impression that all uncontracted reserves could be sold at elevated prices and producers became reluctant to sell for less.
    - There was also an expectation that further LNG projects would absorb more gas
- Reports of lack of domestic supply intensified through 2012 and 2013 and have been countered by gas producer statements that gas is available at the right price.
    - A number of parties have put forward suggestions to help resolve matters[6] [7]
    - Since late 2011 and particularly during 2013 a growing number of new domestic contracts have been entered, all apparently at higher price levels than previous contracts (details in section 6.1).
    - In May 2013 the Federal Minister for Energy commissioned the Department of Industry and the Bureau of Resources and Energy Economics to report on the status of the gas market, gas price projections and future policy options. Their report was published in January 2014, followed by a large list of submissions.
- Further recent developments adding to the complexity include:
    - It has been questioned whether gas supply capacity is developing fast enough to meet demand in 2016 and 2017 when exports are expected to reach full production.
    - Public opposition to CSG and further regulation of CSG in NSW have halted development there for 3 years and may continue to do so. Two companies have curtailed development of advanced NSW CSG projects: AGL (Camden area and Hunter Valley); and Metgasco (Clarence Morton Basin).

[6] Getting Gas Right - Australia’s Energy Challenge. Grattan Institute, June 2013
[7] Securing Australia’s Gas Future. Australian Pipeline Industry Association, July 2013

- Export project cost blow-outs have had the two-fold effect of:
  - Making further east coast LNG commitments less likely in the face of new competition from North America and East Africa
  - Reducing the value of exports relative to domestic sales

5. Assessment of pricing factors

This section presents an assessment of the factors influencing future gas prices.

5.1 Costs of gas production

Information regarding gas production costs is not widely disseminated by the production sector in Australia. A number of alternative approaches to estimating production costs are discussed below.

5.1.1 Costs implied in reserve declarations

The production cost for declared reserves can be inferred from the fact that they are commercial, provided that the market price at which the reserves test for commerciality has been conducted is known. For the large majority of reserve estimates this market price is not stated however.

For gas in eastern Australia, where the wellhead market price has been low in world terms, in the range $3/GJ to $4.50/GJ in real 2014 dollar values, it has until recently been reasonable to assume that commerciality meant profitable at that price level or perhaps slightly above if a price rise was anticipated by the developer. The advent of LNG exports which can sustain higher gas input prices raises the possibility of higher price assumptions and in recent presentations[8] Santos has stated that it has booked its first shale reserves, for which the estimated costs of production are $6/GJ to $9/GJ.

5.1.2 Estimates based on LNG project costs

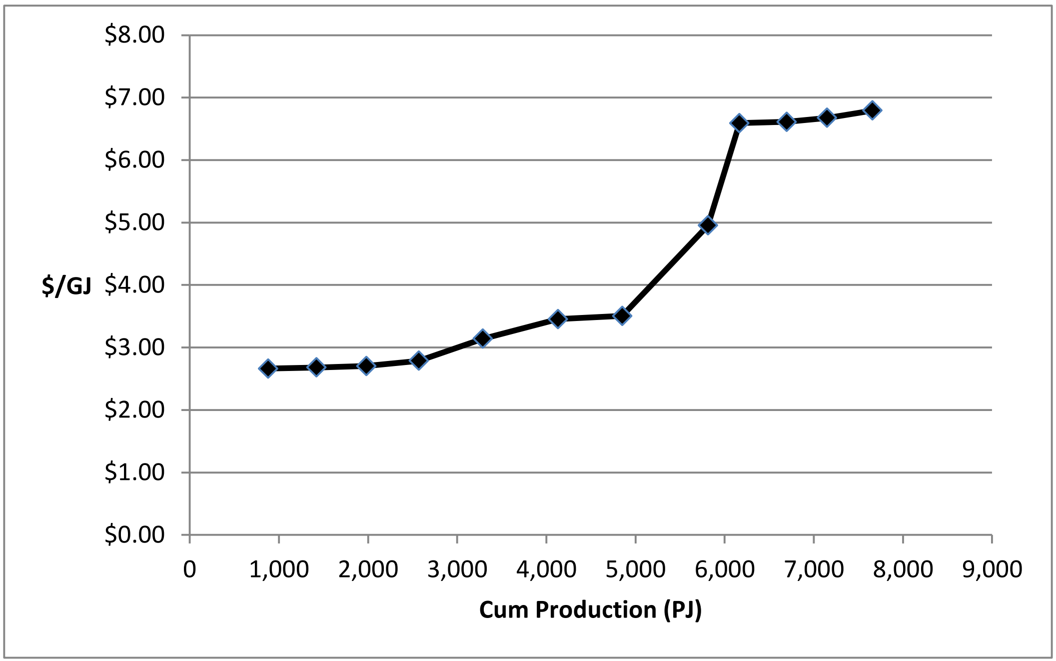
McKinsey and Company have recently released a detailed study of LNG costs in Australia and elsewhere[9]. Their estimate of CSG production costs is $4.35/GJ, for a typical LNG project. It is noted that costs for LNG supply may be higher than for domestic supply owing to the need to drill wells over a period of 2-3 years in advance of first production of LNG, possibly offset by economies of scale.

5.1.3 ESG production costs

Eastern Star Gas produced a “Scheme Booklet” to advise shareholders in relation to Santos’ and TRUEnergy’s offers to purchase 80% of ESG. The Booklet provides details of capital and operating costs estimated by MHA Petroleum Consultants for various tranches of gas. Our analysis of this data, assuming a 12% breakeven IRR, has yielded the cumulative production cost curve in Figure 5-1. This covers all of ESG’s current reserves and resources and shows that up to 5,000 PJ could be produced profitably for less than $3.50/GJ in 2011 dollar terms. These costs would be somewhat higher if re-estimated today and expressed in 2014 dollars, especially taking into account the increased constraints on CSG production in NSW. The volume of gas producible at $3.50/GJ is likely to increase in future with further resource appraisal and the more expensive gas, which is mostly in higher CO_2 fields, is likely to remain undeveloped.

[8] Cooper Basin Unconventional Gas Opportunities & Commercialisation, November 2012, available at www.Santos.com .
[9] Extending the LNG Boom. Improving Australian LNG productivity and competitiveness. McKinsey & Co, May 2013.

Figure 5-1 ESG Production Costs ($2011)



5.1.4 Well productivity

A key factor in determining CSG costs is the rate of production per well. The above costs are typical of wells that produce 0.6 TJ/day to 1.0 TJ/day. Table 5-1, based on CSG production data released by Queensland Department of Resources and Mines, shows that the three producers committed to LNG exports, APLNG, GLNG and QCLNG, have the most productive wells, with others operating at lower rates. It is noted that APLNG has stated[10] that some of its fields are operating below capacity and their outputs could be increased by 50%. SKM believes this could also apply to GLNG and QCLNG because they do not currently need all of the output from wells drilled for their LNG projects.

We use this information to fine tune our estimates of relative production costs.

Table 5-1 CSG well productivity (TJ/day/well)

Producer	2008	2009	2010	2011	2012
Arrow Energy	0.25	0.24	0.29	0.26	0.26
Molopo	0.07	0.14	0.20	0.17	0.08
APLNG (Origin)	0.73	0.73	0.80	0.90	0.93
QCLNG (QGC)	0.65	0.80	0.84	0.73	0.76
GLNG (Santos)	0.75	0.75	0.94	0.87	1.00
Westside	0.18	0.15	0.15	0.14	0.17

5.1.5 Jacobs SKM Production cost assumptions

For the purposes of this study we have assumed gas production costs excluding carbon costs as listed in Table 5-2. These costs are assumed to be constant in real terms. Costs of production will increase when more costly resources are brought into production.

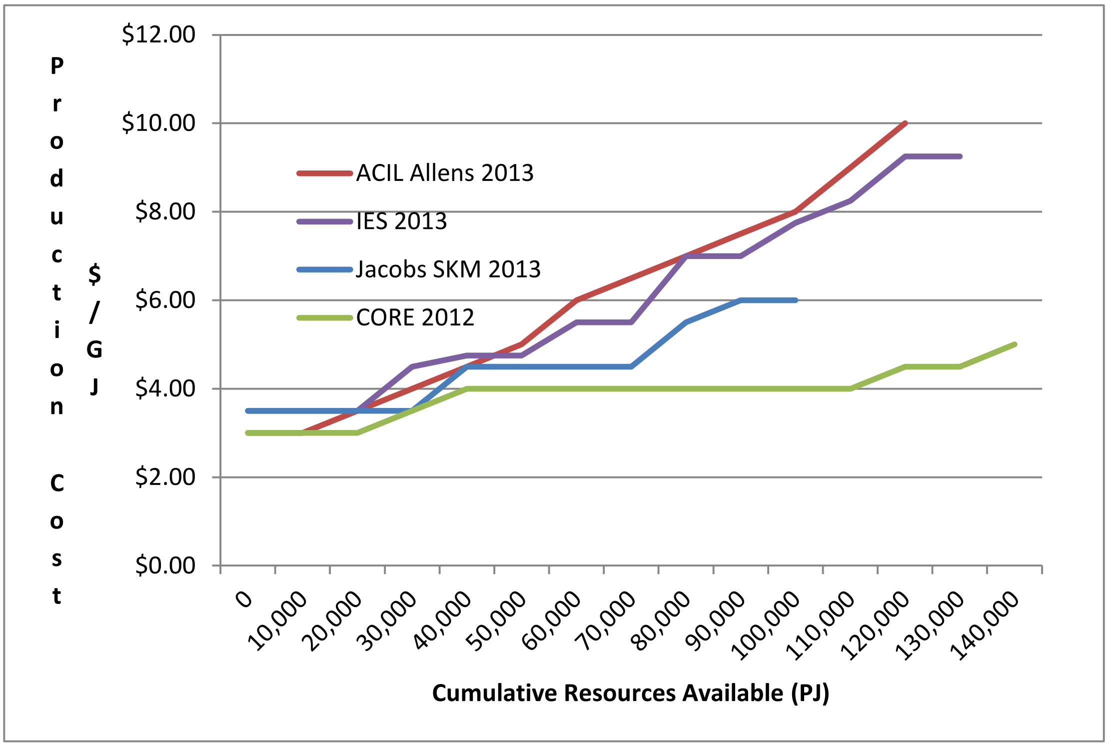
[10] APLNG CSG Production, May 2013. www.originenergy.com.au

Table 5-2 Jacobs SKM estimates of gas production breakeven costs

Basin	Joint Venture	2P Reserves	3P + 2C Resources
Gippsland, Longford	BHPB, Exxon	$3.50	$4.50
Gippsland, Orbost	Nexus	$4.00	$5.00
Bass	Origin, AWE	$4.00	$5.00
Otways, Minerva	BHPB, Santos	$4.00	$5.00
Otways, Geographe	Origin, Others	$4.00	$5.00
Otways, Casino	Santos, Others	$4.00	$5.00
Cooper Eromanga	Santos, Beach, Origin	$4.00	$5.00
Cooper Eromanga	Others	$6.00	$6.00
Sydney	AGL	$5.50	$6.50
Gloucester	AGL	$3.50	$4.50
Gunnedah	Santos/TRU	$3.50	$4.50
Clarence Morton	Metgasco	$6.00	$8.00
Bowen	AGL/Arrow	$4.50	$5.50
Surat	APLNG	$3.50	$4.50
Surat	QCLNG	$3.50	$4.50
Surat/Bowen	GLNG	$3.50	$4.50
Surat	Arrow Energy	$4.50	$5.50
Surat/Bowen	Second Tier	$5.00	$6.00

These figures, together with the related reserves and resources estimates, translate into a cumulative gas supply curve as depicted in Figure 5-2, where it is compared with supply curves prepared by other consultants[11],[12].

Figure 5-2 Cumulative gas resource availability vs cost of production



[11] ACIL Tasman. Cost of Gas for the 2013-2016 Regulatory Period. Prepared for IPART, 13 June 2013. (This source also documents the CORE estimates, which were published by AEMO in the 2012 GSOO).
[12] IES, Study on the Australian Domestic Gas Market, prepared for DoI and BREE, November 2013.

5.1.6 Conclusion

The wide gap between the estimates prepared by different consultants illustrates the degree of uncertainty in gas costs, particularly for resources beyond the first 50,000 PJ. Since the latter resources are not yet in the 2P category even the producers concerned would not have accurate estimates of production costs and access to better information would probably not reduce the uncertainty. However what is of most relevance to this study is the cost of gas applicable to recent new contracts, which is determined by how far along the curves the gas already committed to the LNG projects takes the next contracts.

Each LNG train will produce approximately 4 Mtpa of LNG per year, equivalent to 220 PJ per year. Liquefaction will consume a further 8% to power compressors and other plant so the reserves consumed by 6 trains over 20 year contract periods will be approximately 28,800 PJ. Allowing for ramp down gas (gas remaining in fields at the end of the 20 year contracts) and approximately 6,000 PJ contracted to domestic buyers, the total volume of reserves that is already committed is between 35,000 PJ and 40,000 PJ. In this range on the curves the cost estimates are in reasonable agreement, in the range $4.00/GJ to $4.75/GJ and for the purposes of this study we propose to use the median estimate of $4.50/GJ.

Note: Many study methodologies result in orderly development of resources, that is from lowest to highest cost. However this is not how the real world works, because cheaper resources can be discovered later, as with CSG in Queensland and shale gas in the US. Jacobs SKM modelling allows for this to occur.

5.2 LNG pricing and netback

5.2.1 LNG pricing

LNG exports are competing with domestic sales for eastern Australian gas resources. LNG pricing in the East Asia region is oil inked, which at current oil prices creates netback prices significantly higher than contract prices prevailing before 2010.

The LNG price is expressed in $US/mmbtu as:

$LNG = \alpha * JCC + \beta$

α and β are constants and JCC is the Japan Customs Cleared Crude price, also nicknamed the Japan Crude Cocktail, expressed in $US/bbl and linked to the Brent Crude price. The formula would also typically have a cap and a floor to protect buyer and seller from extreme oil price variations, though in the case of some earlier contracts the cap is now well below current oil prices.

A value of the slope parameter α of 0.172 indicates full energy equivalence of LNG with oil. It is understood that the Gladstone LNG projects have contracted at values in the range 0.12 to 0.155 and correspondingly low values of β. During the timeframe of interest we expect these parameters to remain unchanged by any application of a price review. Similarly, in this timeframe these contracts are not expected to be impacted by competition from US or Canadian exports[13].

A slope parameter value of 0.14 together with JCC price projections based on Energy Information Administration median projections of Brent crude prices result in base case LNG export value projections as in Table 5-3. The projected decline in JCC leads to a parallel decline in export value in $US/mmbtu terms.

[13] Some US exports are already contracted on a Henry Hub (US spot price) plus margin basis. With margins of $US 7/mmbtu and Henry Hub prices below $5/mmbtu, these are very competitive with Gladstone exports.

Table 5-3 Base Case LNG Export Value Projections (FOB)

	2013/14	2014/15	2015/16
JCC ($US/bbl)	$106.66	$102.80	$101.39
LNG ($US/mmbtu)	$14.93	$14.39	$14.19

5.2.2 LNG Netback

The LNG netback value is the above FOB value translated back to a value at Gladstone or a wellhead. Based on recent estimates[14], including escalation, SKM estimates that:

- Long-run liquefaction costs are approximately $US5.50/mmbtu for brownfield projects (additional trains at existing projects, which is the most likely basis of further expansion at Gladstone).
- Short-run liquefaction costs are approximately $US2.50/mmbtu for all projects

The actual costs applicable to the projects currently under construction may differ from these estimates.

The transmission cost from the Surat Basin (Wallumbilla) to Gladstone via large diameter pipelines is estimated to be $A0.50/GJ in the long-run and negligible in the short-run. Incremental transmission costs from other wellheads to Wallumbilla are estimated to be: from Moomba, $1.31/GJ; and from Longford, Gippsland, $3.04/GJ. These are assumed to be the same in both the long- and short-run.

The resulting $A/GJ wellhead netback values at Wallumbilla, Moomba and Longford, incorporating IMF $US/$A exchange rate projections, are presented in Table 5-4. The projected decline in the exchange rate from almost parity in 2013/14 to $US0.89/$A in 2015/16 more than offsets the decline in oil prices and leads to increasing netback values. However minor variations in the JCC and exchange rate projections could reverse this trend.

Table 5-4 Estimated Wellhead LNG Netback Values ($A/GJ)

	2013/14	2014/15	2015/16
Wallumbilla Short-run	$11.81	$12.14	$12.44
Wallumbilla Long-run	$8.46	$8.58	$8.75
Moomba Short-run	$10.49	$10.82	$11.13
Moomba Long-run	$7.14	$7.26	$7.44
Gippsland Short-run	$8.77	$9.10	$9.40
Gippsland Long-run	$5.42	$5.54	$5.71

[14] Extending the LNG Boom: Improving Australian LNG Productivity & Competitiveness, McKinsey & Co, May 2013.

The Wallumbilla values are slightly higher than the netback values recently estimated by AGL[15], namely $7.95/GJ long-run and $11.20/GJ short run. AGL has assumed a lower JCC index and lower Brent price offset by a lower exchange rate.

These values define the maximum values that an export project would pay for third party gas delivered at each of the wellheads concerned, unless it was in some form of penalty situation for non-delivery of LNG, in which case it may pay more.

The long-run value applies to projects in the pre-commitment phase before the liquefaction capital is a sunk cost and the short-run value applies to projects under construction or already operating, when the liquefaction capital is a sunk cost. In the current context the short-run value applies to gas sold to the three committed projects, QCLNG, GLNG and APLNG, to fill up their six existing trains and the long-run value applies to gas sold to the these projects for expansion trains or to other potential projects, such as that of Arrow Energy.

The actual price at which any contract between a third party supplier and an LNG project is negotiated will lie between the suppliers cost of production and the project's netback value, i.e. between $4.50/GJ plus transmission costs to Wallumbilla for a typical producer and the above netback values. How the difference between these values, the "pure profit" component of LNG, is shared will be determined by the parties relative negotiating powers as discussed in section 4.1. As there are only three export projects their market power relative to gas producers may be considerable, which means that prices paid would be below the full netback value.

It is also noted that because the netback value is indexed to the JCC price it is to be expected that the contract price may also be indexed to the JCC or oil more generally.

5.2.3 Impact of LNG netback on domestic prices

The LNG netback value is one factor among many that now determines the level of domestic prices, since it represents a competing market for gas supply that has become restricted. Given the quantum of exports relative to the domestic market, namely about 2x, it is an important factor. However Jacobs SKM does not subscribe to the widely expressed[16] view that the domestic price must inevitably equal the netback value, or export parity value, for the following reasons:

1) There is no unique netback value, due to variations in LNG pricing formulas and liquefaction and shipping costs between different LNG projects.

2) It is possible for the domestic price to rise above the netback value if:

    a) A seller or sellers has a high level of market power because of high demand from LNG projects and the domestic buyer(s) can afford it

    b) The oil price trends down

3) It is also possible for the domestic price to fall below the netback value if:

    a) Demand from LNG projects falls because no new projects are committed in eastern Australia due to competition from other locations[17]

    b) Additional gas reserves are appraised and developed faster than demand grows.

15 AGL Working Paper No 40 Solving for x. March 2014.

16 Frequently without any supporting argument

17 AGL expresses this as: "increasing aggregate supply will eventually place sufficient downward pressure on unit prices so that they fall below long run LNG netback prices – that is, once export volumes are fully subscribed. And to be perfectly clear on this, gas demand from LNG terminals on the east coast is bounded". AGL Working Paper No 40 Solving for x. March 2014

4) A gas trader/retailer may pay above Gippsland netback for gas that can be supplied to NSW and SA in place of Surat-Cooper basin gas that can be sold at higher prices in Queensland. This arbitrage will act to equalise prices in different eastern Australian sub-markets.

We note that in the US approval of exports is conditional on the assessment that the exports will not lead to a material increase in domestic prices and that the pricing of exports is based on the market price (Henry Hub) plus a liquefaction and shipping margin, which would cease to be competitive if the domestic price increased.

Clearly this is due to the size of the US market, which at 20,000 PJ/year is approximately twice the size of the global LNG market and thirty times the size of the eastern Australian domestic market. Nevertheless it illustrates that the impact of exports on the domestic market must be assessed more subtly than has often been the case in Australia.

5.2.4 Oil price indexation of domestic gas prices

For the past forty years prices in almost all eastern Australian gas contracts have been indexed either fully or partly to CPI, with price reviews every three to five years, which adjust the base price to market. This has resulted in price predictability that has benefitted both buyers and sellers.

Exports of LNG to East Asia create a market for eastern Australia gas in which the price is indexed to a $US denominated oil price and sales into this market are exposed to both oil price and exchange rate fluctuation. Supply contracts between gas producers and LNG suppliers share the risks and exposure by also using oil price indexation. If the export price has a slope parameter of 0.14, then equal sharing of the risk between producer and exporter would yield a gas supply price formula with a slope of 0.07, with a constant reflecting the point of supply and other factors. Use of such indexation is known from third party supply agreements with LNG projects (refer to section 6.1) but it is also reasonable to assume that it applies to upstream-downstream agreement within projects, because the project Joint Ventures have different upstream and downstream membership.

The netback value of LNG is also indexed to oil and with the current importance of netback value to domestic prices, it is not surprising that prices in a number of recent domestic contracts are oil indexed (refer to section 6.1). While this indexation is welcomed by gas producers, for buyers it creates a potentially unwelcome exposure to oil prices and exchange rates, though it is noted that they can reduce or remove the price volatility in the medium term by using the appropriate hedging instruments.

6. New contract price estimates

6.1 Recent new domestic and export contract prices

A summary of nine new domestic contracts is provided in Table 6-2. Our definition of a domestic contract is that the buyer is not an LNG project, though it is clear that some gas purchased by traders, which we count as domestic, is onsold to LNG projects. Data on third party contracts with LNG projects is provided in Table 6-4. The domestic and LNG contract data has been derived entirely from public sources and is in general though not precise agreement with that in similar lists presented by other parties[18] [19] [20].

The price data is based on detailed reviews of statements by the seller and/or buyer as to whether the pricing formula is oil linked, related to market etc and correlated with other media statements including those by financial analysts who may have received briefings from contract participants. Key statements about domestic contract prices are summarised in Table 6-3 and statements about LNG contract prices are summarised in Table 6-5. Jacobs SKM has not relied upon estimates prepared by other consultants or AGL.

The quality of timing and volume data is reasonable but price estimates are in many cases more speculative, relying upon statements by equity market analysts and energy journalists. It is difficult to draw definitive conclusions about contract prices but the following trends seem clear:

- Prices have escalated since before 2010 and cover a wide range from approximately $5.50/GJ to $10.00/GJ
- Prices in Queensland appear to have escalated further in 2013 relative to 2010-2012 as more third party gas has been purchased by LNG projects. The most recent price in Queensland is $10/GJ for a 23 month contract starting in February 2015, compared to the first contract at $6/GJ. It is also noted that the price in this first contract may have been held down by the negotiating power of the buyer, which had a viable alternative source of electrical energy via the Copperstring project.
- Prices for gas in southern states, sourced from the Gippsland JV, are lower than those in Queensland but the contracts may specify escalation to parity with Queensland over time. The aggregate estimates for southern states rely heavily upon the large volume contract between BHPB-Esso and Origin Energy.
- All LNG contracts are oil linked
- Some domestic contracts are oil-linked but others are not.

In two domestic cases, those of Orica and Incitec Pivot, the buyers have stated the incremental gas costs in dollar terms, from which the contract gas prices have been derived using estimates of volumes purchased. The resulting price estimates sit at opposite ends of the range encountered, with Orica, located in NSW, at $5.86/GJ, and Incitec Pivot, in Mt Isa Queensland, at $10.02/GJ.

The pricing applicable to the most recent LNG contract has been stated explicitly by the producer, Westside, in a takeover defence document[21] and is reproduced in Table 6-1. From this we can deduce that the underlying formula has a slope of 0.068 and a constant of 1.5825 in US$/mmbtu terms, close to our expectations.

Table 6-1 Westside-GLNG Oil linked pricing from 2017

JCC Oil Price (US$/bbl)	100	110	120
Gas Price (US$/GJ)	$7.95	$8.60	$9.24
Gas Price (A$/GJ)	$8.58	$9.28	$9.98

[18] NSW Wholesale Gas Market Report. MDQ Consulting, February 2014
[19] Wholesale Gas Price for AGL's VPA Proposal for 2014-16, the Brattle Group, February 2014
[20] Study on the Australian Gas Market. Intelligent Energy Systems, November 2013
[21] Westside Target's Statement. Available on www.westsidecorporation.com

In terms of supply to NSW Jacobs SKM notes that:

- None of the new domestic contracts known to be destined for NSW are sourced from CSG (the Surat Basin)
- Only one new domestic contract (between Beach Energy and Origin Energy) is known to be sourced from the Cooper Basin and its destination is not known. However Jacobs SKM considers it reasonable to assume that this contract, plus Origin's equity Cooper Basin gas that will be produced in parallel, will be used to support Origin's third party contracts with LNG projects and substitute for CSG supply in South Australia, with its new Gippsland contract performing the same role in NSW. We find it unlikely that any of this Cooper Basin gas will enter the NSW market.

Regarding further contracts to supply NSW, Jacobs SKM agrees with conclusions reached by MDQ Consulting[22]: "there is no new Queensland CSM available to supply the NSW gas market for an extended period of time, at least until after the end of this decade at best" and "during the VPA Period there is unlikely to be large quantities of new Cooper gas available for the NSW market". Our modelling further supports these conclusions (Table 6-9).

[22] MDQ Consulting, as above.

Table 6-2 Recent domestic contracts

Seller	Seller Business Type	Buyer	Buyer Business Type	Source	Destination	Date Announced	Start Date	End Date	Term (Years)	Annual Volume (PJ)	Term Average Price ($/GJ)
AGL	Trader	Xstrata	End User	Surat CSG	Mt Isa	6/10/2011	1/05/2013	30/10/2023	10.5	13.1	$6.00
Origin	Producer/ Trader	MMG	End User	OE Portfolio	Mt Isa	20/12/2012	1/01/2013	31/12/2019	7	3.0	$8.29
Santos	Producer	Unknown	Unknown	STO Portfolio	Unknown	23/02/2013	Unknown	Unknown	Short	Low	$8.00
Beach Petroleum	Producer	Origin	Producer/ Trader	Cooper	OE Portfolio	10/04/2013	1/01/2015	31/12/2022	8	17.0	$8.50
BHPB-Esso	Producer	Lumo	Trader	Gippsland JV	Victoria & NSW	1/05/2013	1/01/2016	30/12/2018	3	7.0	$7.29
BHPB-Esso	Producer	Origin	Producer/ Trader	Gippsland JV	Victoria & NSW	19/09/2013	1/01/2014	31/12/2022	9	48.0	$6.76
BHPB-Esso	Producer	Orica	End User	Gippsland JV	NSW	1/11/2013	1/01/2017	31/12/2019	3	14.0	$5.86
Nexus	Producer	Santos	Producer	Gippsland Longtom	Victoria & NSW	31/10/2013	1/07/2013	29/12/2018	5.5	15.1	$5.95
AGL?	Trader	Incitec Pivot	End User	Surat CSG?	Mt Isa	18/12/2013	1/02/2015	31/12/2016	1.9	8.5	$10.02

Table 6-3 Recent domestic contracts – pricing comments

Seller	Buyer	Pricing comments
AGL	Xstrata	$6/GJ (Press speculation, CBA 22/11/11)
Origin	MMG	Substantially less than $9/GJ (MMG Spokeswoman - Australian 23/2/13)
Santos	Unknown	Higher end of $6-9/GJ range (D Knox, CEO Santos quoted in Australian, 23/2/13
Beach Petroleum	Origin	$7-9/GJ (Australian, 24/9/13) Oil linked curve and other parameters (Origin 10/4/13)
BHPB-Esso	Lumo	Incorporates oil-linkage mechanism (Lumo 14/5/13)
BHPB-Esso	Origin	Price indexation initially reflects current pricing arrangements in the market and transitions to incorporate an oil link (OE 19/9/13). Deal priced at $5.50/GJ rising to $7/GJ by 2017 (Leitch, UBS in Australian 24/9/13)
BHPB-Esso	Orica	Price adds $12m pa to costs (AFR 12/11/13) Consumption is estimated to be 14P PJpa and current contract $5.00/GJ
Nexus	Santos	
AGL?	Incitec Pivot	Price adds $50m pa to costs (The Australian, 20/12/13). Consumption is estimated to be 9PJpa and current contract $4.50/GJ. AGL reports a domestic sale at $10.00/GJ in its FY14 Interim Results (26/2/14), which is understood to be Incitec Pivot.

Table 6-4 Recent third party contracts with LNG projects

Seller	Seller Business Type	Buyer	Source	Destination	Date Announced	Start Date	End Date	Term (Years)	Annual Volume (PJ)	Term Average Price ($/GJ)
APLNG	Producer	QCLNG	Surat CSG	Field	25/02/2010	1/10/2014	2/10/2034	20	95 falling to 25	$7.50
Santos	Producer	GLNG	Cooper primarily	Wallumbilla?	26/10/2010	1/01/2015	31/12/2029	15	50	$7.73
AGL	Trader	QCLNG	Surat CSG	Field	25/08/2011	1/01/2014	31/12/2016	3	25	$5.72
Origin	Producer/ Trader	GLNG	OE Portfolio	Wallumbilla	2/05/2012	1/01/2015	31/12/2024	10	36.5	$9.05
Origin	Producer/ Trader	QCLNG	OE Portfolio	Wallumbilla	28/11/2013	1/01/2014	31/12/2015	2	15	$8.34
Origin	Producer/ Trader	GLNG	OE Portfolio	Wallumbilla	19/12/2013	1/01/2016	31/12/2020	5	20	$8.80
Stanwell	Trader	Unknown	Wallumbilla?	Wallumbilla?	5/02/2014	1/10/2014	30/09/2017	3	10	N/a
AGL	Trader	Unknown	Wallumbilla?	Wallumbilla?	26/02/2014	1/07/2014	Unknown	Unknown	15	$10.00
Westside	Producer	GLNG	Bowen CSG	Field	27/03/2014	1/01/2015	31/12/2034	20	23	$9.95

Table 6-5 Recent third party contracts with LNG projects – pricing comments

Seller	Buyer	Pricing comments
APLNG	QCLNG	N/a
Santos, Origin?	GLNG	Oil-linked pricing formula (STO) $5.30/GJ @ $80/bbl & Nov 11 $A/US (CBA 22/11/11)
AGL	QCLNG	Attractive oil-linked selling price (AGL)
Origin	GLNG	Pricing based on an oil-linked formula (STO)
Origin	QCLNG	At oil-linked pricing (OE 28/11/13)
Origin	GLNG	In line with international oil- pricing (OE 19/12/13)
Stanwell	Unknown	N/a. Selling contracted gas for more than it would return in the electricity market
AGL	Unknown	$10.00/GJ (AGL FY14 Interim Results, 26/2/14)
Westside	GLNG	Oil-linked formula provided (refer to Table 6-1)

Table 6-6 shows the estimated total volumes and average prices in the new contracts by region. The first second, third, fourth and last contracts above are included in Surat & Cooper though the sources are not all precisely known and the first contract is excluded because of its timing and atypical buyer power. Escalations of the average prices are due to a combination of: timing of new contracts starting; staged increases in each contract; and oil indexation impacts.

The Gippsland value is heavily influenced by the price estimated for the BHPB-Exxon Origin contract which MDQ Consulting has estimated to be $0.50/GJ to $0.75/GJ higher, though the data presented by MDQ Consulting suggests this overstates the value by $0.25/GJ.

Table 6-6 Estimated recent new domestic contract volumes and average prices by region

	2013/14	2014/15	2015/16
Surat & Cooper PJ	3.0	20.5	39.5
Gippsland PJ	26.6	50.1	66.6
Surat & Cooper $/GJ	$7.00	$7.86	$8.01
Gippsland $/GJ	$4.75	$5.50	$6.06

Figure 6-1 and Figure 6-2 compare the above estimates with relevant short- and long-run netbacks and costs of production. The Surat Cooper actual is approximately $0.60/GJ above the Moomba long-run netback in both 2014/15 and 2015/16. The Gippsland actual is approximately equal to Gippsland long-run netback in 2014/15 and $0.30/GJ above it in 2015/16.

Figure 6-1 Surat-Cooper Estimated Actual vs Moomba Netback and Cost of Production

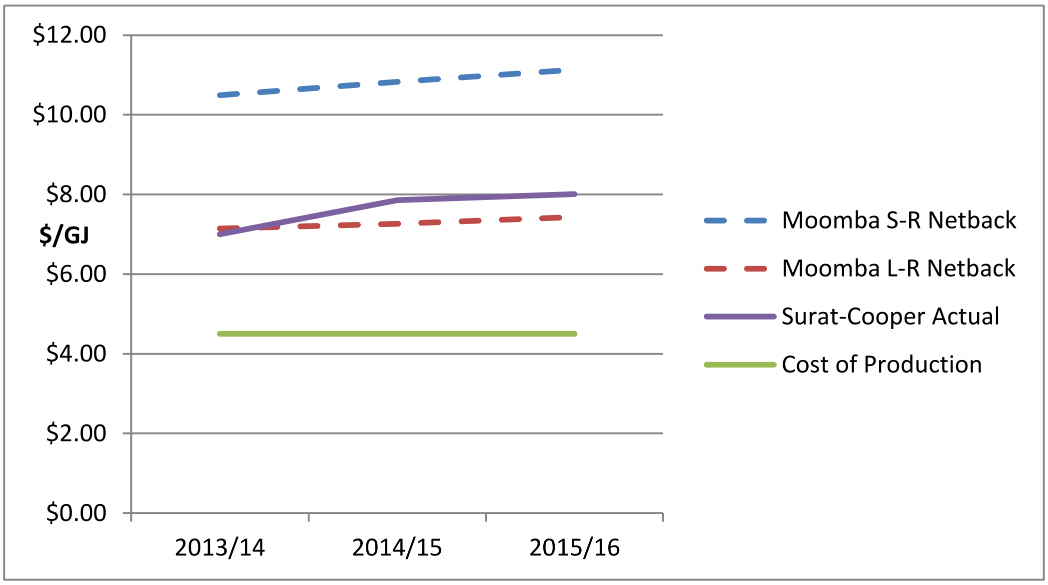
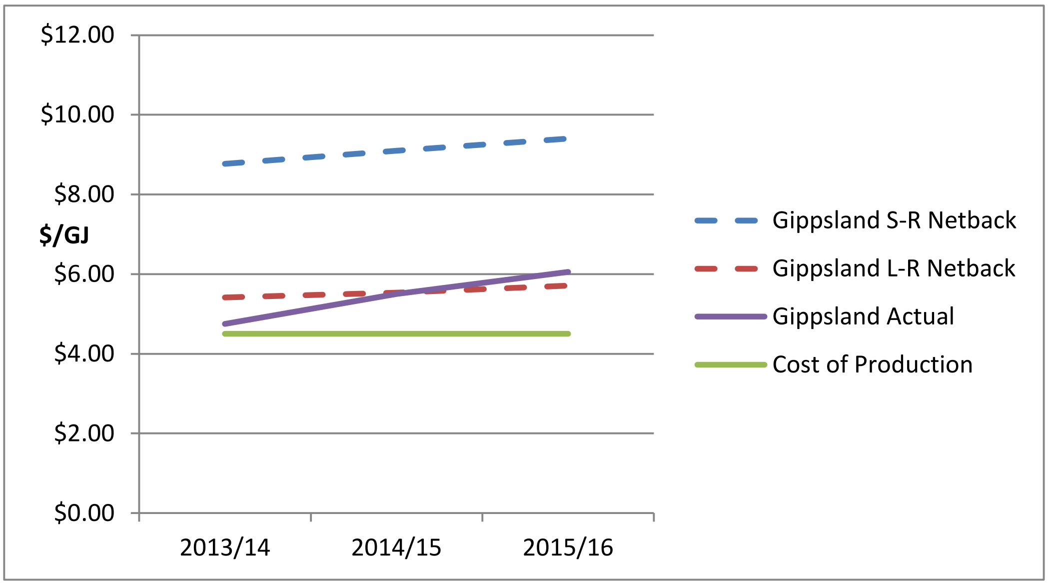


Figure 6-2 Gippsland Estimated Actual vs Gippsland Netback and Cost of Production



6.2 Price projections derived by modelling

6.2.1 Introduction

A growing number of publicly available studies have investigated the impact of Queensland LNG exports on eastern Australian domestic gas supply and prices. The studies, including only those which presented independent price projections, include in reverse order of publication:

1) Eastern Australian Domestic Gas Market Study. Department of Industry and Bureau of Resources and Energy Economics, January 2014

2) Securing Australia's Gas Future. Australian Pipeline Industry Association, July 2013

3) Cost of gas for the 2013-16 regulatory period. ACIL Tasman June 2013

4) 2012 Gas Market Review Queensland. Department of Energy and Water Supply, Queensland, July 2012

5) Fuel cost projections – updated natural gas and coal outlook for AEMO modelling. ACIL Tasman, June 2012

6) 2011 Gas Market Review Queensland. Department of Employment, Economic Development and Innovation, Queensland, August 2011

The prices presented in these studies were undertaken by a number of consultants, using their proprietary models:

- ACIL Allens (formerly ACIL Tasman) – studies 2, 3 and 5
- Intelligent Energy Systems – studies 1 and 4
- Jacobs SKM (formerly Sinclair Knight Merz) – studies 1 and 6

All of these studies have concluded that gas prices will rise, however there is no consensus on how fast they will rise or what level they will peak at. The key reasons for this are the wide ranges of scenarios employed and differing modelling technologies which emphasise different aspects of the gas market.

Ultimate domestic price levels depend primarily upon the following parameters:

1) Projected number of LNG trains compared to gas resource availability

2) Oil prices and exchange rates

3) Gas production cost projections

4) Long-term versus short-term netback consideration

5) Modelling of the interaction of 1 to 4

For a near term projection such as for this study, parameters 1 to 3 are more predictable than in the longer term and the focus is on the impacts of different versions of netback.

Timing of price rises depends upon:

1) Ramp up of LNG production
2) Gas contracting details, including the relative timing of when new LNG and domestic contracts are entered
3) Gas trader roles, in particular whether traders sell further “domestic” portfolio gas to the LNG projects (gas in their portfolios that has not been contracted to domestic end users), thereby advancing the requirement for new domestic contracts.

Timing is critical to near term projections. Timing of LNG ramp-up is scheduled for the period Q4 2014 to 2017. Delays due to slower downstream (liquefaction plant) commissioning could slow down domestic price rises but delays due to slower upstream (gas production plant) commissioning could accelerate domestic price rises. Jacobs SKM has no reliable information regarding the likelihood of delays and has adopted the schedules suggested by the LNG project proponents.

To date it appears that LNG projects have negotiated their third party gas requirements progressively (refer to Table 6-4), possibly because their exact requirements are uncertain and conditional upon progress with their own plant. However we consider it important to investigate the impact on domestic contract prices of LNG negotiations being accelerated.

Item 3 was not considered in pricing studies until Jacobs SKM drew attention to its potential impact in a recent study for DoI/BREE[23], and this is largely because supply-demand models do not capture the traders’ roles (including the Jacobs SKM model). Using the latest contract data, the current version of Jacobs SKM’s standard model captures much of this effect and we do not consider it necessary to repeat the earlier analysis.

With the rapid evolution of the market over the past three years and particularly the last 12 months, Jacobs SKM considers that there is limited value in discussing the results of previous studies, and this section therefore focusses on modelling based on most recently available data and the factors that are key to near-term new contract prices.

6.2.2 Gas market methodology

Gas market modelling has been conducted using Jacobs SKM’s “Market Model Australia – Gas” (MMAGas) modelling tool and associated data. MMAGas represents the market for new long-term gas contracts as a competitive game between producers with uncommitted 2P gas reserves. The Nash-Cournot game basis of the model enables it to capture both competitive outcomes and outcomes reflecting market power due to limited

[23] Gas market modelling. SKM, October 2013.

supply or suppliers. Competition between producers is based on maximising profits after accounting for production costs and transmission network costs.

Key data includes:

- Gas reserves (2P) and resources available for development
- Gas demand projections in each market zone, including LNG
- Estimated gas production costs, specified in 2 tranches for each producer
- Existing gas contract volumes, prices and terms
- Gas transmission network structure and costs

Nine domestic market zones are specified plus one LNG export zone. Exports have a critical influence on domestic outcomes because: a) their scale is projected to be at least twice that of domestic demand by 2017, hence they can reduce domestic supply; and b) their value is higher than historical domestic gas prices.

6.2.3 Assumptions

6.2.3.1 Gas reserves and resources available for development

For this study 2P reserves assumptions are several thousand PJ lower than those presented in the Eastern Australian Domestic Gas Market Study and the 2013 Gas Statement of Opportunities. A small part of this is due to recent downward reserve revisions by AGL but the larger part is due to discrepancies between Queensland CSG reserves reported in these studies and by the Queensland Department of Natural Resources and Mines. Jacobs SKM has adopted values consistent with the latter.

Consistent with CSG reserves additions during 2013, it is assumed that there are no Queensland CSG reserves additions in 2014 or 2015.

The following assumptions have been made regarding availability/development timing:

1) Consistent with assumptions regarding Arrow LNG (below), no Arrow Surat Basin reserves are available until after 2017. There is some pressure on Arrow to sell gas domestically, since it has the largest uncommitted reserves, but as yet this has not occurred. If Arrow does enter new domestic contracts over the next year, even though supply will be after 2017 this could have an immediate effect by reducing expectations of other producers. This effect cannot be modelled however.

2) Queensland CSG reserves controlled by producers independent of LNG projects are not able to increase capacity until 2016 at the earliest and will have very limited impact in the study time frame. Further, Westside, the largest of these producers, has sold a significant proportion of its gas to GLNG.

3) Cooper Basin unconventional gas is available from 2017 in increments of 20PJ per year

6.2.3.2 Gas demand projections in each market zone, including LNG

Domestic demand projections are based upon 2013 GSOO projections, with allocation to Queensland sub-zones consistent with demand structure in each zone. Aggregate demand is illustrated in Figure 6-3.

LNG demand projections are based on the six committed trains only, with ramp-up and plateau levels consistent with the proponents most recent media statements. Arrow LNG has indicated it is unlikely to commit during 2014, with the result that its train(s) cannot become operational until 2018 at the earliest, which is outside the study timeframe.

The recent large scale gas pipeline supply deal between Russia and China (for 38 Bcm/yr, equivalent to 26 Mt/yr, fractionally larger than the 6 Gladstone trains combined) will be priced approximately 30% below LNG. Together with other competitors this may make it difficult to sell further Australian LNG in Asia unless Australian cost and prices reduce[24], though the view that it simply expanded the Chinese gas market has also been advanced. A negative impact on further trains of Gladstone LNG could bring forward domestic sales of Arrow's uncommitted reserves, which has the potential to reduce contract prices within the study period, as discussed above.

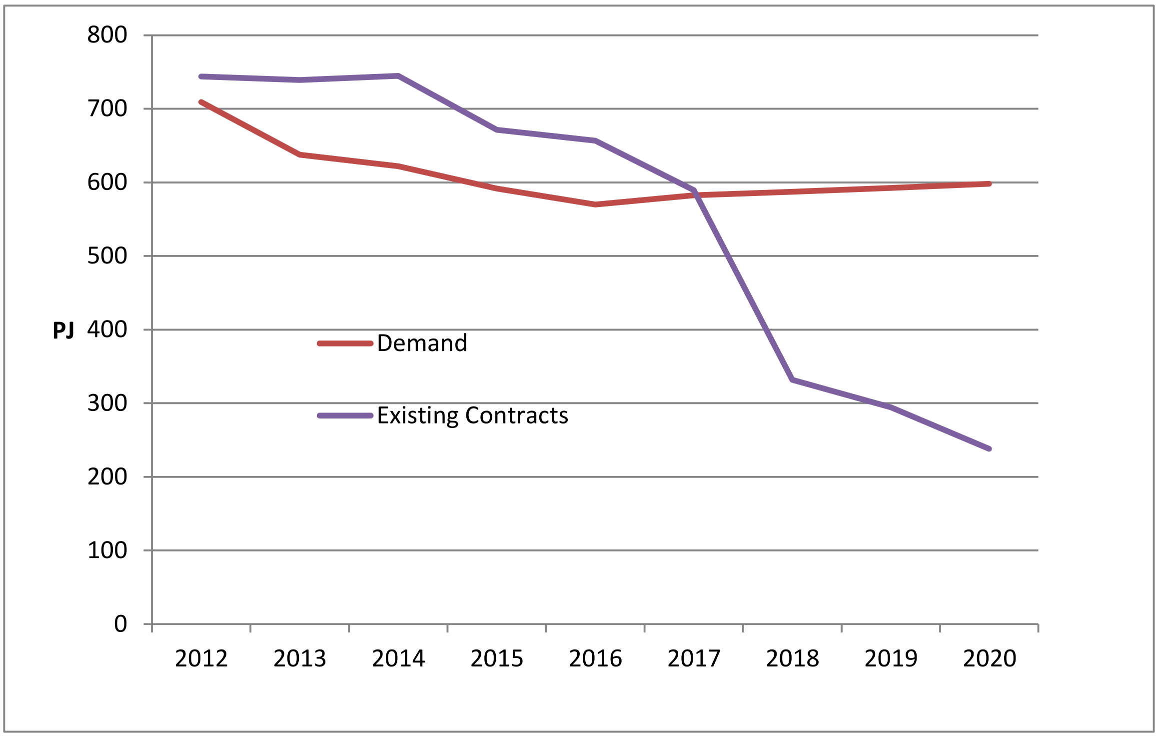
6.2.3.3 Estimated gas production costs, specified in 2 tranches for each producer

Jacobs SKM's production cost estimates are discussed in section 5.1 and presented in Table 5-2.

6.2.3.4 Existing gas contract volumes, prices and terms

Existing contract volumes are compared with demand in Figure 6-3. It is noted that the downward revision of demand in the 2013 GSOO plus the recent addition of new contracts appears to defer the aggregate need for further new contracts until 2018, subject to no further gas in these contracts being onsold to LNG projects. In the absence of a requirement for new contracts the MMAGas model does not calculate a realistic new contract price; consequently further demand has been added to generate a requirement for new contracts.

Figure 6-3 Existing contract volumes vs domestic demand, Eastern Australia



[24] Russia's LNG game cruncher. Energy News Premium, 26 May 2014.

6.2.3.5 Gas transmission network structure and costs

The eastern Australian gas transmission network is illustrated in Figure 2-1. Transmission costs are based on pipeline tariffs converted to a single $/GJ figure and assume a load factor of 85%. The resulting costs are very similar to those in the 2013 GSOO.

It is possible that transmission between Victoria and New South Wales on the APA and Jemena pipelines will be constrained during 2014/15, with the result that new contracts for NSW cannot be sourced from Victoria. APA has recently entered three new five to seven year transportation contracts, with Energy Australia, Origin Energy and Lumo, as a result of which it is expanding capacity of the Interconnect pipeline by 145%. The expansion will be completed by winter 2015, that is, available for 2015/16 but not 2014/15. A new entrant retailer wishing to use the pipeline may be able to access residual capacity in 2015/16, if available, but otherwise may require further capacity to be constructed. Given that the pipe sections for the expansion have been delivered to Australia, it seems unlikely further expansion could be accommodated in the current plan.

Jemena is understood to be marketing a further expansion of the Eastern Gas Pipeline, construction of which is likely to take 12-18 months after contracts are entered. It appears unlikely this capacity would be available in time for winter 2015 i.e. during the study period.

Our modelling therefore considers a scenario in which no newly contracted Victorian gas can enter NSW during 2014/15 and 2015/16. The MMAGas model operates on an annual basis and does not directly estimate pipeline capacity; however it can replicate constrained behaviour in regard to new contracts.

6.2.3.6 LNG Netback values

Prices have been projected using both the short-run and long-run netback values discussed in section 5.2.2.

6.2.3.7 Other modelling assumptions

In its standard mode of operation MMAGas calculates the demand-supply-pricing for new contracts a year at a time. With the current set of assumptions LNG demand is met by its current contracts in 2015 but requires further third party gas to meet 2016 and 2017 demand. Thus domestic new contracts don’t compete with LNG in 2015. The mode of operation of MMAGas can be adjusted to bring forward the pricing of new LNG contracts to 2015 to determine the impact of this on domestic contract prices.

6.2.3.8 Scenarios

Six scenarios have been modelled, short and long-run netback values each for three modes of operation, referred to as Base Case, Victorian-constrained (for both years) and LNG-advanced.

6.2.4 Jacobs SKM new contract gas price projections

The following tables present the new contract prices relevant to new contracts for NSW supply, estimated for each scenario. Prices are presented for an additional year after the study period to show whether prices continue to rise or not.

Table 6-7 Estimated new contract prices at Longford, Gippsland

	Base		Vic Constrained		LNG Advanced	
	SR Netback	LR Netback	SR Netback	LR Netback	SR Netback	LR Netback
2014/15	$6.04	$6.52	N/a	N/a	$8.36	$7.21
2015/16	$6.57	$7.01	N/a	N/a	$9.53	$8.12
2016/17	$7.93	$8.03	$8.31	$8.36	$9.48	$8.64

Table 6-8 Estimated new contract prices at Moomba

	Base		Vic Constrained		LNG Advanced	
	SR Netback	LR Netback	SR Netback	LR Netback	SR Netback	LR Netback
2014/15	$5.32	$5.56	$8.39	$9.38	$7.63	$6.15
2015/16	$7.60	$7.76	$9.74	$8.60	$9.91	$8.63
2016/17	$8.10	$8.40	$9.39	$8.46	$9.61	$9.15

Table 6-9 Estimated percent of new NSW Contracts sourced at Longford

	Base		Vic Constrained		LNG Advanced	
	SR Netback	LR Netback	SR Netback	LR Netback	SR Netback	LR Netback
2014/15	100%	100%	0%	0%	100%	100%
2015/16	85%	89%	0%	0%	75%	96%
2016/17	60%	62%	45%	35%	46%	62%

Table 6-10 Weighted average wellhead price for new NSW contracts

	Base		Vic Constrained		LNG Advanced	
	SR Netback	LR Netback	SR Netback	LR Netback	SR Netback	LR Netback
2014/15	$6.04	$6.52	$8.39	$9.38	$8.36	$7.21
2015/16	$6.72	$7.09	$9.74	$8.60	$9.62	$8.14
2016/17	$8.00	$8.17	$8.91	$8.43	$9.55	$8.83

In the Base Case projected prices at Longford are consistent with those estimated from recent contracts, though about $0.50/GJ higher. The Base Case prices at Moomba are very similar to recent contracts except in 2014/15, where we note that the low Moomba price calculated is due to Moomba not supplying any new contracts in that year. Prices differ little between the SR and LR netback cases, which suggests that prices are being determined by market power rather than direct reference to netback.

In the scenario where further Victorian supply is constrained out of NSW, the Moomba prices are up to $2/GJ higher than in the Base Case because of the tightness of supply at Moomba.

In the scenario where further LNG contracts are negotiated before domestic contracts, prices are approximately $2/GJ higher in the SR netback case but only $1/GJ higher in the LR netback case.

Figure 6-4 and Figure 6-5 compare modelled prices from the short-run scenarios with the relevant short-run netback values. The Moomba prices are all below the Moomba short-run netback but the Gippsland price reaches the Gippsland short-run netback in the scenario where LNG contracts are negotiated before domestic ones.

Figure 6-4 Moomba modelled prices vs Moomba Short-run Netback

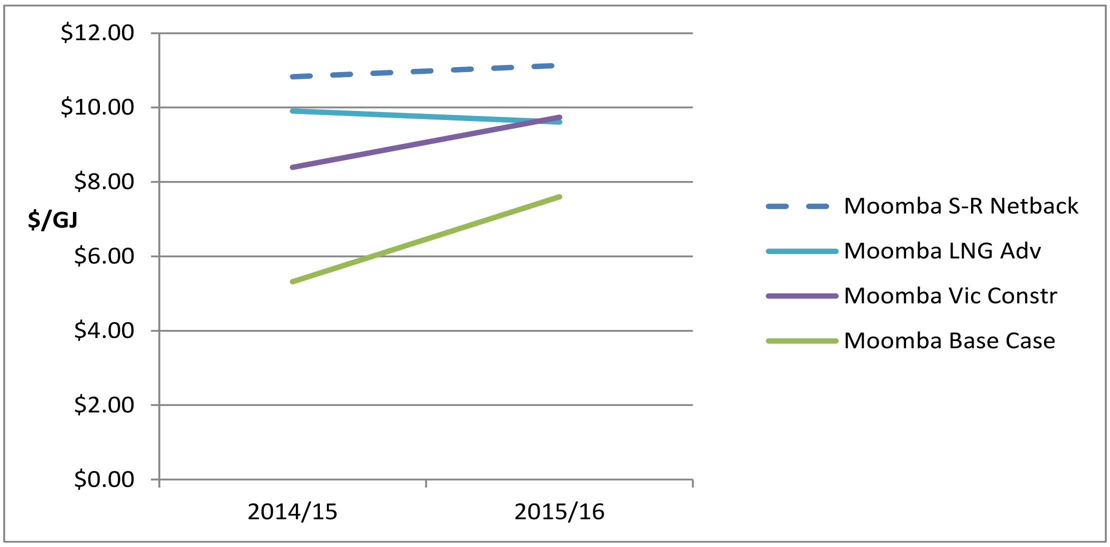
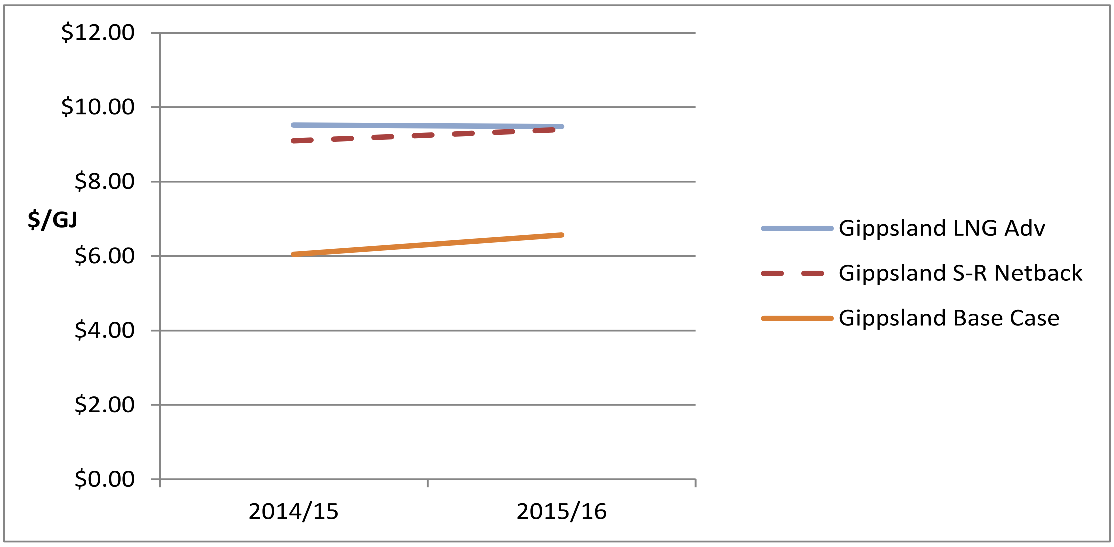


Figure 6-5 Gippsland modelled prices vs Gippsland Short-run Netback



7. Jacobs SKM estimates of new gas contract prices in NSW

Jacobs SKM considers that a new gas retailer (or end-user) should be able to negotiate a new gas contract at Longford on the following basis: in 2014/15 in the range $6.00-$6.50/GJ and in 2015/16 in the range $6.50-$7.00/GJ which represent premiums of $0.50-$1.00/GJ over prices in other recent contracts, due to further tightening of the gas market since these were negotiated.

We are less confident that a new gas retailer (or end-user) will be able to negotiate a new gas contract at Moomba at all. Although our modelling indicates that small volumes should be available, there are no recent contracts to support this and key participants in the Cooper Basin JV, Origin and Santos, are strongly aligned with LNG projects. If a retailer negotiates with a Moomba producer without the benefit of competition from Gippsland, the price will be high, in the range $8.00-$10.00/GJ, towards the lower end of this range for small volumes of 2-3 PJ pa and towards the higher end for larger volumes of 5-10 PJ pa.

We note that a new retailer will have a strong preference for obtaining supply from Gippsland but will not be able to negotiate new transmission capacity from Victoria to NSW until 2015/16. However we consider that it may be possible for a new retailer to obtain existing capacity from another shipper in 2014/15, based on the peak day projections in the AEMO 2013 GSOO, which show a reduced total requirement from 2013.

7.1 Comparison of Jacobs SKM new entrant price estimates and retailer wholesale prices

7.1.1 AGL

Table 7-1 compares AGL's proposed gas commodity costs[25] with Jacobs SKM estimates of new entrant gas contract prices, for gas sourced from Moomba (Cooper Basin) and Gippsland and the aggregate proposal. AGL's proposed commodity cost sits towards the low end of the estimated new entrant price range in 2014/15 and towards the high end in 2015/16.

Table 7-1 Comparison of AGL gas commodity costs and Jacobs SKM estimates of new entrant gas contract prices ($/GJ)

		2014/15	2015/16
Moomba	AGL	$8.65	$9.73
	Jacobs SKM	$8.00-$10.00	$8.00-$10.00
Gippsland	AGL	$5.59	$6.50
	Jacobs SKM	$6.00-$6.50	$6.50-$7.00
Weighted Average	AGL Proposed	$7.12	$8.12
	Jacobs SKM	$7.00-$8.25	$7.25-$8.50

25 VPA - Proposed price path for NSW regulated gas prices from 1 July 2014 to 30 June 2016 – public submission. AGL, 11 February 2014

7.1.2 Other retailers

ActewAGL's and Origin Energy's public price proposals provide insufficient information regarding their commodity costs assumptions to permit a direct comparison with Jacobs SKM's estimates.

Appendix A. Contract Structure and Negotiation

A.1 Contract structure

The following elements are common to most gas supply contracts.

A.1.1 Term

The term of a contract may be defined by:

- A fixed period of time
- A period until a fixed volume of gas is purchased
- A period until a field (with uncertain reserves) is depleted

A.1.2 Gas volumes

A.1.2.1 AQ, MAQ

The annual quantity AQ is often just a number used to define other volumes, such as maximum annual quantity MAQ. AQ may vary from year to year and may be reset in response to field performance if the contract is based on defined fields.

Seller has no or limited obligation to supply more than MAQ per year. MAQ is usually set at 100% to 110% of AQ.

A.1.2.2 ADQ, MDQ

Average daily quantity ADQ is usually AQ/365.

Maximum daily quantity MDQ is typically set at 110% to 130% of ADQ. Seller has no or limited obligation to supply more than MDQ per day. The more MDQ is set above ADQ, the more flexibility the buyer has in meeting seasonal demand variations from within the contract.

Peak hourly delivery may also be defined, frequently at MDQ/24.

A.1.2.3 Total Volume

Total contract volume may be a defined quantity such as a number of years times AQ. Seller has no or limited obligation to supply more than total volume over the contract period.

A.1.2.4 Reserve/field dedication

Many contracts are backed by dedication of reserves in a specific field or area (for CSG mainly). Seller will have no or limited obligation to sell buyer gas from other reserves. Reserve backing is usually with 2P (proved and probable) reserves for the total volume. Contracts may be conditional on proving up of reserves greater than total volume or may allow the producer to maintain reserves at say 10 * AQ in a 10+year contract.

Independent reserves certification and annual reporting are essential to the buyer.

In CSG contracts 1P reserves are used to back short-term producibliity of gas.

If there is a reserves shortfall the producer may declare reserves force majeure.

A.1.2.5 Allocation

Producers supply more than one buyer from a single steam of gas at each processing plant. The single stream is measured (each hour or day) and allocated to the buyers according to agreed allocation rules. Some buyers may have priority if production falls significantly below buyer orders.

A.1.3 Pricing

A.1.3.1 Price

Gas is usually priced on a per GJ basis. In a contact the price will typically be varied using an index such as CPI (or another energy price) and therefore a base price and index will be established with reference to a defined period. For example for a contract starting on 1/1/2011 the price in calendar 2011 may be set at $5.00/GJ with escalation relative to Perth CPI in the September quarter (December CPI isn't available on 1st January). The 2012 price would then be: $5*CPI Sep 2011/CPI Sep 2010.

A.1.3.2 MDQ payment

In some contracts there may be a separate payment for MDQ, priced per GJ/d capacity. This would be fixed (independent of volume purchased) for whatever periods MDQ is fixed for.

A.1.3.3 Price review

Most contracts have a price review clause that enables buyer or seller to seek renegotiation of the price every 3 to 5 years. The review is guided by principles set in the contract which may include references to gas prices in other contracts (however difficult to obtain), references to other fuel prices or other value references. If the parties fail to agree on a new price the matter is usually referred to arbitration.

A.1.4 Resource tax pass-on

Prices are usually agreed in a given resource tax regime such a state royalties and a change to another regime may significantly change the producers cost structure. Consequently many contracts allow for pass-on of tax changes or a price review. This doesn't generally apply to changes in income tax.

A.1.5 Take-or-pay, banking and make-up gas

Take-or-Pay (ToP) is basically a means of setting a minimum annual payment by the buyer. ToP is a quantity (usually annual but can be monthly) which the buyer must pay for even if they haven't taken it from the producer. ToP is typically set at 80% to 90% of AQ.

When a buyer makes a ToP payment, the gas paid for but not taken is normally “banked” and becomes available to the buyer the following year after the buyer has exceeded Top in that year. The banked gas that is used is called make-up-gas (MUG). In some contracts MUG is free but in others there is a charge, such as the escalation in prices between banking and MUG being taken.