Final Public Version

Cost of gas for the 2013 to 2016 regulatory period

A report on the wholesale cost of gas for the review for Standard Retailers in New South Wales

Prepared for IPART

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ACIL Tasman

Economics Policy Strategy

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1 Introduction

1.1 Background

IPART is responsible for regulating retail gas prices charged by AGL, Origin Energy and ActewAGL (the Standard Retailers) to small gas customers in New South Wales (consuming annually less than 1 TJ) who have not chosen to enter into a negotiated customer supply contract. The form of regulation is based on Voluntary Transitional Pricing Arrangements (VTPAs) agreed with each of the Standard Retailers.

The Standard Retailers supply gas to small customers in the following areas:

- AGL supplies gas to most of the small regulated retail customers in NSW, covering Sydney, Wollongong, Newcastle, Dubbo, Orange, Parkes, and parts of the Riverina region
- ActewAGL supplies the regions around the NSW/ACT border (including Young, Goulburn, and Yass) and South East NSW (including Shoalhaven)
- Origin Energy (Wagga Wagga) supplies the South Western regions of NSW including Wagga Wagga and Gundagai and inland cities such as Tamworth
- Origin Energy supplies customers on the NSW - Victorian border, including Albury and the Murray Valley towns.

The Standard Retailers have proposed a one year price path for 2013/14 and a mechanism to update prices for the following years.

IPART intends to evaluate the wholesale gas costs proposed for 2013/14 and the level of uncertainty in wholesale gas costs in 2014/15 to 2015/16.

1.2 Scope

IPART provided ACIL Tasman with the following scope of work:

- Establish a methodology for estimating a range of benchmark wholesale gas costs for each Standard Retailer over the period 1 July 2013 to 30 June 2016; and
- Forecast a range of benchmark wholesale gas costs for each Standard Retailer over the period 1 July 2013 to 30 June 2016.
- The benchmark range should reflect costs incurred by a prudent and efficient retailer supplying gas to small retail customers in each supply area. In doing so, the consultant should:
  - advise IPART on the uncertainties associated with these estimates and the risks of putting in place a fixed price path; and
  - advise on whether the methodology and assumptions used to establish the benchmark gas costs for IPART's 2010 review are still relevant for the period 1 July 2013 to 30 June 2016.

In specifying a methodology for establishing a set of wholesale gas costs, the consultant must consider a number of issues including how it proposes

- to establish benchmarks for gas commodity and transmission costs and to assess the uncertainty associated with forecasting these costs; and
- to establish an efficient and prudent contracting strategy (including the approach to reserving transmission capacity).

1.3 Draft and Final Report

ACIL Tasman's draft report was provided to IPART on 22 April 2013 and made available for consultation along with IPART's own draft report. There were no issues raised in submissions in relation to ACIL Tasman's gas price estimates or modelling. However we did provide IPART with additional explanation of the use of the gas supply curve in our gas price modelling, our views on the issue of ramp-up gas and its likely impact on gas prices, and further justification of our assumption that gas reserves designated for export would be unlikely to be made available to the domestic market.

We also note that following the completion of our draft report, AGL provided IPART with a revised price proposal. For avoidance of doubt, all references in this final report are to the original price proposal.

1.4 Structure of Retailers' Price Proposals

In November 2012, the Standard Retailers provided IPART with public versions of their proposed VTPAs. The Standard Retailers have continued with the "R + N +C" approach where R is the retail component, N is the network component, and C is the carbon component. The retail component includes wholesale gas costs which include commodity costs, transportation charges (from supply point to demand hub), peak demand costs (also referred to as "additional deliverability" costs), market charges, and other relevant costs.

The retail component also includes retail operating costs and retail margin. These, together with the network and carbon components, are not considered as part of this wholesale gas cost review.

In the public versions of their proposals, the Standard Retailers have proposed real increases (increases in excess of CPI) in the retail component of their costs. AGL (AGL, 2012) proposes an increase in wholesale gas costs from $7.85 per GJ in 2012-13 to $8.26 per GJ in 2013-14; ActewAGL (ActewAGL, 2012) states that the retail component of their 2013-14 default tariff in NSW will be required to increase by around 1.5% above CPI; and Origin Energy (Origin Energy, 2012) proposes an increase for the retail component of CPI + 5.3% for the Murray Valley / Albury districts and CPI + 4.2% for the South Western region.

Table 1 shows the public price proposals of each Standard Retailer.

Table 1 **Standard Retailers' proposals for 2013-14**

AGL	ActewAGL	Origin Energy Murray Valley / Wodonga	Origin Energy Wagga Wagga
Increase wholesale gas costs from \$7.85 per GJ in 2012-13 to \$8.26 per GJ in 2013-14	Increase retail component by CPI plus 1.5%	Increase retail component by CPI plus 5.3%	Increase retail component by CPI plus 4.2%

Referring to the fact that a number of its long term gas supply agreements (GSAs) are subject to price reviews over the 2013-2016 period, AGL states that "not only is AGL uncertain what its costs of supply will be over the period of the proposed VTPA, AGL is not able to include in public or confidential submissions any indications as to the expected outcomes of their GSA price reviews". Later in its public proposal, AGL adds "due to the risk of setting a 'benchmark' prior to the review being completed, AGL proposes a specific price path for 2013/14 with the price path for 2014/15 and 2015/16 to be finalised at a later date". Likewise, ActewAGL did not propose a price for the later years of the review period explaining that AGL is its wholesale gas provider and is in price review proceedings. Origin Energy states that "wholesale gas costs will significantly increase over FY15 and FY16". It adds that it is "now negotiating supply contracts for the VTPA period with contract prices that reflect the development of the LNG export market". Origin Energy also proposes to submit proposed prices for other than the initial year of the forthcoming VTPA period later and on an annual basis.

1.5 Key Findings

In this section we set out our key findings.

1.5.1 Projected wholesale gas costs for 2013-14

In Table 2 we show our estimates of wholesale gas costs for each of the Standard Retailers' supply areas for the financial year 2013-14.

Please note that the costs of transportation to the relevant areas includes haulage, odorisation and the cost of system use gas and are in respect of delivery to Sydney, Canberra, Wodonga, and Wagga Wagga respectively. Further note that while we provide a range for additional deliverability and transportation costs, we show total cost as a point value. The calculation of this total cost value makes use of confidential data provided by the Standard Retailers which we have assessed as being reasonable. As we did not receive confidential data from ActewAGL for our review, we show a total cost value for ActewAGL calculated assuming a load factor of 32.5% being the midpoint of our assessed range for customer load factor.

Table 2 **Wholesale gas cost projections (2013-14$/GJ) for 2013-14**

Item	AGL	ActewAGL	Origin Energy Murray Valley	Origin Energy Wagga Wagga
Commodity Gas	$5.13	$5.13	$4.69	$5.58
Additional Deliverability	$0.74 - $1.10	$0.95 - $1.38	$0.95 - $1.38	$0.95 - $1.38
Market Charges	$0.08	N/A	$0.10	N/A
SubTotal	$5.95 - $6.31	$6.08 - $6.51	$5.74 - $6.17	$6.53 - $6.96
Transportation	$2.69 - $3.07	$2.53 - $2.95	$2.10	$2.34 – $2.72
Total	$8.85	$9.01	$8.09	$9.26

The Standard Retailers' proposed total costs are lower than our estimates based on the long-run marginal cost of production at relevant supply points. This is evident in the case of AGL by comparison with Table 1.

From 2014-15 we consider it likely that LNG netback pricing rather than the long-run marginal cost of production will be the principal factor affecting the price of commodity gas. This is projected to result in a step increase in wholesale gas costs from the beginning of 2014-15.

1.5.2 Methodology

We consider the methodology employed in the previous gas price review to be appropriate for the present review and have retained its key elements.

1.5.3 Sources of supply

With respect to the issue of identifying the sources of supply, we note that customers in New South Wales can be supplied generally from the Gippsland Basin via the Eastern Gas Pipeline (EGP) and the Cooper Basin via the Moomba to Sydney Gas Pipeline (MSP). We agree it would be prudent for a retailer to establish a portfolio of supply contracts. In the case of AGL, we consider it reasonable to assume an equal share of gas is sourced from Longford and Moomba, and in the case of Origin Energy to assume supply is sourced from Longford to supply customers in Murray Valley / Wodonga and from Moomba to supply customers in the South Western regions.

1.5.4 Price uncertainty

We consider there is significant uncertainty with respect to future gas commodity costs. For this reason we developed three scenarios upon which to model gas prices over the 2013-2016 VTPA period. These scenarios gave rise to low, medium and high gas price outcomes respectively. On balance we consider that, for the initial year of the period, gas prices are likely to reflect marginal supply costs (the low price scenario) before transitioning subsequently to netback prices (the medium price scenario). In our view, the medium price scenario represents the most likely future price path over the medium term, albeit with a high level of risk attaching to that estimate given the current market uncertainties.

This uncertainty is created largely by the development of a number of LNG projects in Central Queensland and the opportunities this provides for producers to move prices for domestic gas contracts to export parity pricing based on LNG netback arguments. While the feedstock for these LNG projects is intended to be sourced from coal seam methane production in Queensland, the sheer size of the feedstock requirements and potential for delays or problems in bringing on this production puts upward pressure on prices for conventional gas from existing production facilities.

These considerations appear to have had minimal influence on the gas commodity costs proposed by Standard Retailers for 2013-2014 as prices during this period are covered under legacy supply contracts. Their proposed costs (after allowing for transmission charges) are lower than our modelled prices based on our view of marginal supply costs in 2013-14 (our low price scenario) for the relevant gas basins - $5.58 per GJ for Moomba and $4.69 per GJ at Longford, and considerably below our estimates of LNG netback prices (our medium price scenario) - $10.16 per GJ at Moomba and $8.02 per GJ at Longford. However supply costs particularly for 2014-2015 and 2015-2016 remain highly uncertain.

1.5.5 Cost of additional deliverability

In relation to additional deliverability, we retain from the previous review the assumption that a prudent and efficient retailer would contract for MDQ up to the requirements of a 1 in 25 peak day standard under a planning basis. We also retain the cost of additional deliverability formula employed in the previous review which relates this cost to MDQ cost (MDQC), customer load factor (CLF) assessed according to the adopted planning basis, and supply load factor (SLF).

In the matter of MDQ cost, as previously, the Standard Retailers have proposed costs based on the previously published rates for storage services provided by the Iona gas storage facility in Victoria. We establish a number of benchmarks which result in a wide range of values. Of these we consider the most relevant to be an estimated range of between $188 and $229 per GJ MDQ/year based on the reported project cost, and withdrawal capacity of AGL's Newcastle Gas Storage Facility which is currently under development. On this basis we consider the retailers' proposed MDQ costs to be reasonable. We investigated a number of non-storage benchmarks based on either interrupting gas-fired power generators, or selling them excess gas at a discount. MDQ cost estimates developed in this way are generally higher than those based on the cost and capability of storage facilities.

1.5.6 Supply load factor

With respect to supply load factor, we have not reviewed the Standard Retailers' actual supply contracts. We do however consider that future supply contracts are likely to be less flexible than they have been in the past.

1.5.7 Customer load factor

We have reviewed the proposed customer load factors and while we have not had access to the data required to perform our own detailed calculations, consider them to be appropriate. In the case of AGL, we have estimated a range of load factor for small customers based on information published by AEMO in its Gas Statement of Opportunities publication (AEMO, 2012), and Jemena in information provided for its access arrangement (Jemena, 2010). In the case of the South Western regions supplied by Origin Energy (Wagga Wagga), we obtained an estimate based on information published in relation to Country Energy's access arrangement (Country Energy Gas Networks, 2010). In the case of ActewAGL we obtained an estimate based on the projections of small customer average and maximum daily consumption as published in their access arrangement information (ActewAGL, June 2009, p.91). We also note that previously, MMA undertook considerable analysis based on regional differences in heating degree days and the application of its own gas appliance level modelling. No factors have been identified that would be expected to result in a significant shift in small customer load factors. Consequently, we are of the view that the load factors of small customer demand in the relevant gas networks can be expected to have changed little since the last review.

1.5.8 Transmission and other costs

With respect to transmission costs, we have reviewed the proposed costs with reference to the relevant published tariffs. In general our calculations agree reasonably closely with those of the Standard Retailers.

1.5.9 Recommended periodicity of review

ACIL Tasman's analysis of gas commodity cost drivers revealed a potentially wide range of price outcomes over the regulatory period. The Standard Retailers have put forward commodity costs for 2013-14 which are below the modelled price outcomes under our low case and below what we consider to be efficient costs faced by new-entrant retailers. This is not surprising given that the commodity costs to the Standard Retailers for 2013-14 will reflect prices from legacy contracts entered into a number of years ago. This contrasts with the price outcomes from the modelling which are designed to be more representative of prices for *new* contracts which factor in the effects on the Eastern Australian gas market of the LNG export developments.

Given the nature of the price drivers involved and the high level of uncertainty as to how these price drivers will play out during this period of fundamental transition in the Eastern Australian gas market, it is not possible to settle on specific price outcomes for the subsequent two years of the regulatory period. Therefore, ACIL Tasman agrees with the proposition put forward by the Standard Retailers that commodity costs should be subject to annual review by IPART.

1.6 Costs and Prices

Unless stated otherwise, ACIL Tasman estimates of costs and projected prices are expressed in real 2013-14 Australian dollars. For the purpose of adjusting costs and prices forward we assume an annual inflation rate of 2.5%.

Our projections of gas prices are developed on a calendar year basis. We obtain gas prices for financial years by averaging the prices of successive calendar years. For example we obtain a gas price for 2013-14 by averaging the 2013 and 2014 calendar year gas prices.

2 Methodology

2.1 Previous Review

Previously McLennan Magasanik Associates (MMA) was retained by IPART to assist in reviewing wholesale gas costs for the period 1 July 2010 to 30 June 2013. MMA's final report is "Public version of final report to Independent Pricing and Regulatory Tribunal of NSW – Gas Retail Price Review – Wholesale Gas Costs" (MMA, June 2010).

Here we reproduce a number of the statements that appear in this report for the purpose of providing a summary of what we consider to be the main methodological features of the previous review. We consider these features to be still appropriate and they are largely retained for the current review.

MMA "…broadly assumed that the costs assessed should be those of a Standard Retailer, supplying not just regulated small customers but also other customers, and that while the quantum of the requirements should be those required by the regulated small customer segment, the costs need to be calculated against the requirements of the market as a whole." "IPART has confirmed that the appropriate costs for analysis are for the small market as a whole, rather than separately for the residential and small business markets."

"MMA considered it prudent and efficient for a retailer to have a portfolio of supply, and to estimate as the price to the small customer market the average of the costs of supply across NSW as a whole. MMA assessed the proposed base gas supply costs of each Standard Retailer by comparing them against the costs submitted by the other retailers, recent regulatory decisions and other publicly available benchmarks."

Other price reviews noted by MMA included ESCOSA's 2008 price review and to a lesser extent QCA's 2008 work on estimating gas costs for second-tier retailers.

The additional cost of MDQ refers to the difference between the MDQ requirement of the customer load and supply MDQ. The following formula was adopted previously to calculate this cost.

AC_MDQ = MDQC/365 x (1/CLF – 1/SLF) where:

AC_MDQ is additional cost of MDQ

MDQC (MDQ cost) is $ per GJ/MDQ/year

CLF is customer load factor, SLF is supply load factor

CLF, SLF (load factor) is (AQ / 365) / MDQ; and

AQ is annual quantity.

MDQ is assessed for a 25 year recurrence interval. The recurrence interval chosen constitutes the particular planning basis.

MMA states that "As the customer load factor is very important in setting both additional deliverability and transmission costs a significant amount of effort has been spent in reviewing this value and the basis on which it has been derived."

With respect to the "planning basis" of the load factor, "MMA considered it reasonable to accept a load factor for the 1 in 25 year requirement however, notes that this likely to be a little conservative."

"To assess the customer load factor, where appropriate MMA reviewed the methodology used and tested its sensitivity to varying key parameters and underlying assumptions. In addition, MMA compared customer load factors to evidence from other sources".

"MMA has reviewed the information provided by the Standard Retailers to assess the supply load factors. Where supply load factors under individual or aggregated contracts have been provided they have generally been accepted at face value."

"The range of underground storage prices currently quoted by TRUenergy on its website is $160 to $240 per GJ MDQ." MMA stated that "it considers it unlikely that an efficient retailer would contract full additional deliverability requirements for its small market at the published price of underground storage", and that "it considers it reasonable for the price used for additional deliverability to be estimated at $160 per GJ MDQ – the bottom end of the range provided by TRUenergy for storage."

MMA says that "In general the retailers have used published transmission prices on the MSP and EGP and the Principal Transmission System, multiplied by the customer load factor to determine proposed transmission costs for the small customer market. MMA considered this a reasonable approach to use, on the basis that the small customer market should pay its stand-alone costs within the overall coincident demand. MMA also considered it reasonable that the retailers propose to use the published tariffs along the pipelines."

MMA adds that "As well as the costs of gas commodity, additional deliverability and transmission, retailers also face additional risk or market-related costs associated with procuring wholesale gas supply. For example, AGL has estimated the additional costs of participating in the Short Term Trading Market (STTM) which will … impact all gas supplied into the Sydney hub."

2.2 Issues for the Current Review

In its final report for the 2010-2013 review, IPART noted that gas retailers procure wholesale gas and transmission services to city gates through long-term bilateral contracts with gas producers and transmission asset owners. The retailers hold a portfolio of gas supply contracts with varying terms and conditions and expiry dates depending on geographic location. The report concluded that Standard Retailers may face different wholesale gas costs for which there is little publically available information on which a benchmark could be made.

Previously MMA examined forecasts of wholesale gas costs submitted by each Standard Retailer. MMA also included an indicator of commodity costs based on a 50:50 split between gas supplied from Moomba via the Moomba to Sydney Pipeline and from Longford via either the Eastern Gas Pipeline or the Albury to Wagga interconnector. This estimate was then combined with transmission charges to establish one indicator of wholesale city gate price for each Standard Retailer.

MMA also compared the Standard Retailers' price forecasts for wholesale gas costs with publicly available benchmarks based on gas price reviews by the Queensland Competition Authority (QCA) in November 2008 and the Essential Services Commission of South Australia (ESCOSA) in June 2008.

On this basis, IPART approved wholesale gas costs for each year in the 2010-2013 regulatory period. However for the current review, the Standard Retailers have argued that there is too much uncertainty associated with regulatory and market changes for a fixed price path to be determined over the 2013 to 2016 regulatory period. The position of the Standard Retailers is encapsulated in the Issues Paper released by IPART in November 2012:

> "In this context, the Standard Retailers consider that the objectives of the Act will be best met by providing flexibility in the pricing agreements. While they have proposed average regulated prices for 2013/14, they proposed that these prices for 2014/15 and 2015/16 be agreed through a periodic review, when additional information is available to update their wholesale gas cost estimates." (IPART, November 2012).

The following sections outline a methodology for addressing these issues and suggestions for an initial benchmark for commodity costs and base city gate wholesale prices to assist in assessment of what might represent an efficient wholesale price for each Standard Retailer.

Previously MMA explained that:

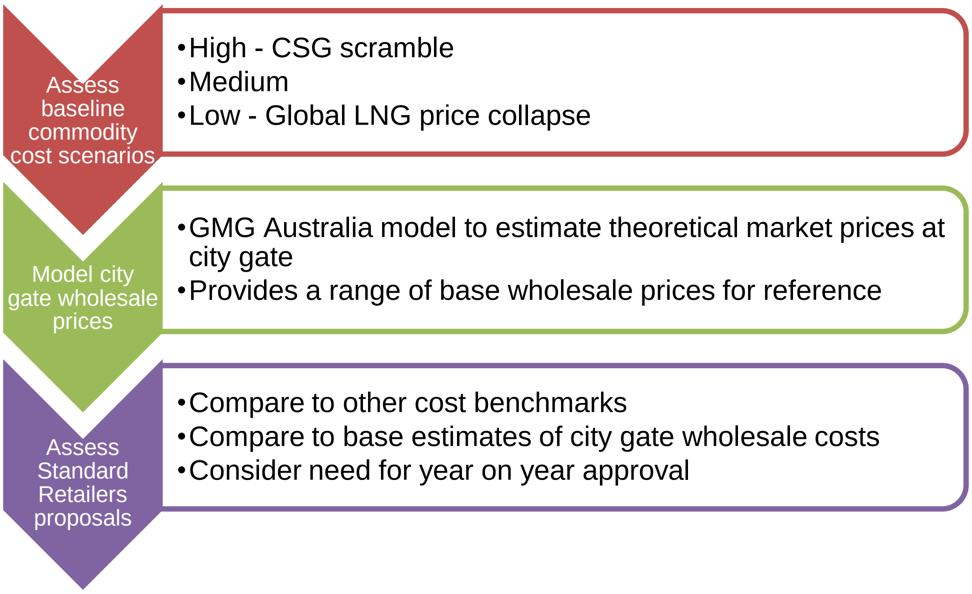
- Longford and Moomba are the only material sources of supply for AGL's NSW market over the period.
- It would be prudent for AGL to have a portfolio of supply (obtain gas from both sources) and to estimate as the price to the small customer market the average of the costs of supply across its whole market in New South Wales.

We consider the portfolio approach to purchasing gas to be still valid.

2.3 Commodity Cost of Gas for the 2013-2016 regulatory period

The approach we have taken in addressing the uncertainties and issues for determination of the commodity cost of gas is summarised in Figure 1.

Figure 1 **Approach to consideration of base wholesale costs**



The first step in the analysis is to develop projections of wholesale gas prices for three scenarios –

- a high price scenario driven by constraints and higher costs in production of CSG in Queensland leading to a scramble for gas resources to meet the needs of the currently planned 6 LNG trains due to commence production from 2014 onwards;
- a central scenario based on 8 LNG trains being developed in the near future; and
- a low price scenario wherein price outcomes are reflective of marginal supply costs.

The results of this analysis provide the basis for assessing the risks associated with projecting gas commodity prices forward. The second step is to use ACIL Tasman's Eastern Australian gas market model – *GMG Australia* – to establish city gate prices for each Standard Retailer for each of the scenarios. These will provide reference points against which the wholesale price proposals put forward by the Standard Retailers will be assessed. Our city gate prices include transmission which needs to be taken into account when making comparisons.

The third step is to benchmark the Standard Retailers proposals against other publicly available evidence. In this case the main reference point is the ESCOSA determination of 2012.

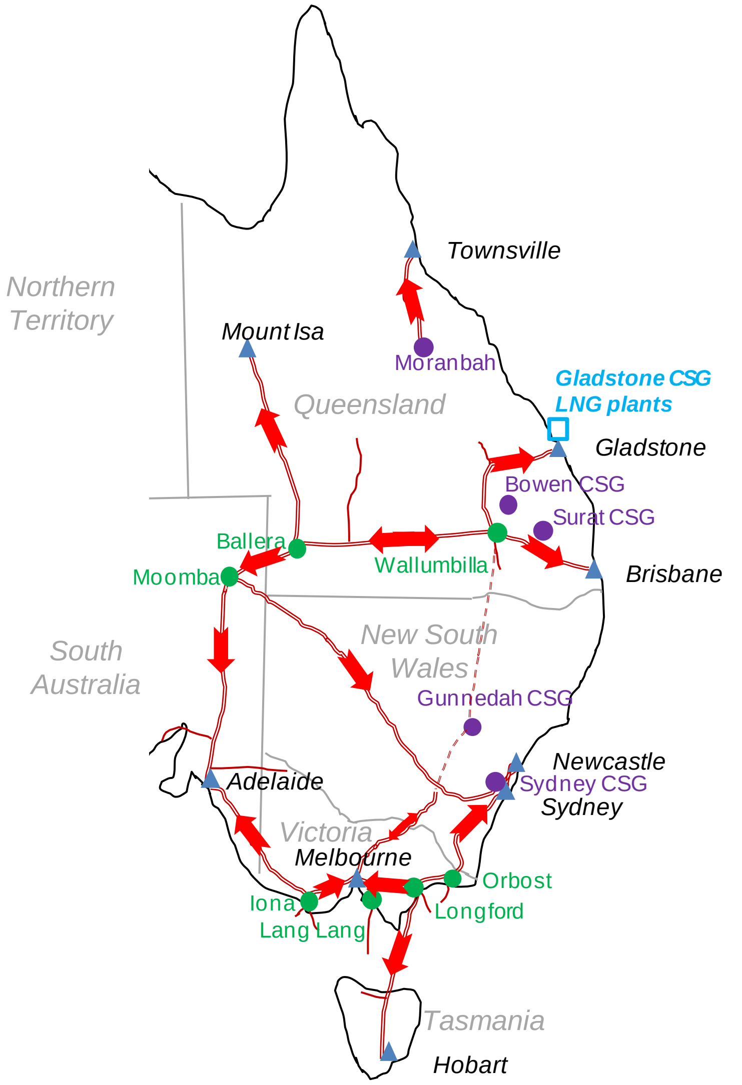
The three strands of analysis are then used to provide an assessment of the proposals for base wholesale costs submitted by the Standard Retailers.

3 Commodity cost of gas

3.1 Eastern Australian Gas Market Overview

The Eastern Australian Gas Market has evolved over the last 40 years from a number of discrete "single source to single market" systems into an interconnected network in which most regional markets have access to multiple sources of gas. In total the Eastern Australian market currently consumes around 700 PJ of gas per year (Figure 2).

Figure 2 **Eastern Australian Gas Market**



Source: ACIL Tasman

The main sources of gas supply have historically been conventional gas fields in Central Australia (Cooper Basin) and in the Bass Strait region of Southern Australia (Gippsland, Otway and Bass Basins). The past 10 years have seen the rapid emergence of coal seam gas (CSG) production in

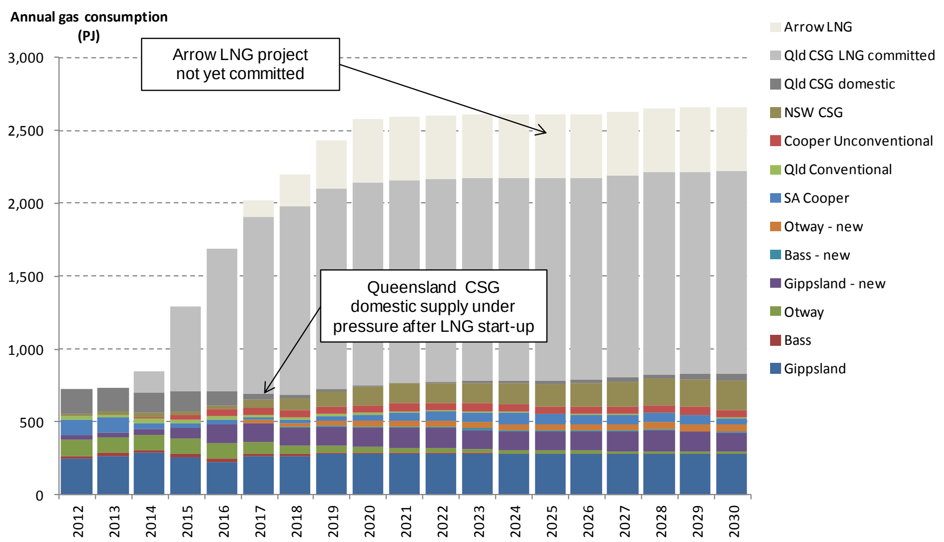
Queensland and to a lesser extent New South Wales. CSG now accounts for around 30% of Eastern Australia's gas production. To date all gas produced in Eastern Australia has been used locally in the domestic market. However that situation is changing with three LNG projects based on CSG feed currently under construction at Gladstone, in central Queensland. By 2020, it is expected that LNG production will account for at least two-thirds of total gas production in Eastern Australia. Gas prices in Eastern Australia are facing strong upward pressure, largely as a result of the rapid expansion of the CSG LNG industry.

Domestic gas demand for Eastern Australia is currently 700PJ per year with low growth prospects to 2020. With the introduction of carbon pricing, power generation had been considered to be a sector with strong growth prospects. However with declining electricity demand, strong investment in renewable energy and uncertainty associated with the future level of carbon pricing, the outlook has changed considerably. Little growth in gas demand for electricity generation is now expected before 2020.

There are three committed LNG projects – QCLNG (BG) 8.5Mtpa, GLNG (Santos / Petronas / Total / Kogas) 7.8Mtpa, and APLNG (Origin / ConocoPhillips / Sinopec) 9Mtpa. A project proposed by Arrow Energy (a subsidiary of Shell) for 16Mtpa is under consideration. The first LNG exports from QCLNG are due to commence late in 2014 with the other projects to follow soon thereafter.

A typical LNG train produces around 4Mt annually which translates into a demand of about 240PJ of CSG (including gas use in liquefaction). LNG export volumes are projected to rise rapidly, dwarfing volumes required for domestic consumption as shown in Chart 1.

Chart 1 **East coast demand by market segment**



Source: ACIL Tasman

3.2 Ramp-Up Gas

In the context of LNG projects supplied from CSG reserves, an issue arises as a result of

- the large amount of gas used in these projects,
- the large number of CSG wells required to supply this amount of gas, and
- the fact that it is generally desirable to produce CSG wells at a steady rate, rather than turning production rates up and down.

This is referred to as the "ramp-up gas issue". Previously the view has been expressed that in the lead up to the LNG projects commencing operations, domestic gas prices would be suppressed as a result of significant quantities of ramp-up gas being made available to the domestic market. For example (EnergyQuest, 2009) -

"…substantial volumes of 'ramp up' gas are likely to be produced in the lead-up to the commissioning of Queensland's CSG-LNG projects. In the short to medium term, this is likely to mean that increased supplies of gas will be available at relatively low prices for domestic purposes such as power generation."

However significant quantities of ramp-up gas are yet to materialise. The ramp-up gas issue is being managed through a number of strategies including

- pre-drilling wells and deferring production,
- placing gas in underground storage and depleted gas fields, and
- gas swaps within LNG proponents supply portfolios and between LNG project proponents.

It is noted further that the LNG projects themselves will have large storage tanks, and upon completion, the projects will not necessarily have to run at full capacity immediately. Recently, the LNG proponents have confirmed that they are making arrangements to allow transfer of gas between the projects, thereby helping to manage commissioning and production ramp up. The ramp-up gas issue appears to be less significant than originally foreshadowed. Indeed we are not aware of any transactions that would point to ramp-up gas putting downward pressure on long-term gas supply contracts. Meanwhile, prices in the Brisbane Short Term Trading Market (which one might have expected to be most strongly affected by excess ramp-up gas) have been rising strongly since early 2012 despite ongoing CSG development in advance of LNG plant commissioning.

3.3 Wholesale Gas Price Uncertainty

Compared to electricity, there has always been less transparency around wholesale gas costs and prices. This is because gas supply contracts have been longer term and subject to confidentiality around price and other conditions. Furthermore, despite the relatively early establishment of the formalised gas spot market arrangement in Victoria (a declared wholesale gas market) and the later commencement of Short Term Trading Markets (STTM) operated by AEMO and providing prices at Sydney, Brisbane and Adelaide, there are fewer sources of publically available relevant price information. Forward pricing of gas is even more problematic as unlike for electricity, financial contract markets in gas have not developed. This may not have mattered in the past as wholesale prices were relatively static in real terms, with pricing arrangements under long-term bilateral contracts generally formed around a base price with annual CPI adjustments. However, with the development of a gas export industry, a new pricing dynamic can be expected to operate.

One view is that gas in the domestic market will henceforth be priced at international LNG prices ("net-backed" by subtracting liquefaction costs such that producers are indifferent between supplying domestic and international customers). Another view is that these prices will serve as a price ceiling and that the "net-backed" international price can be expected to be further discounted to reflect the fact that once gas has been sourced for the initial LNG trains, incremental export will be capacity constrained and it will be a number of years before additional capacity is provided to enable further export opportunities.

To explore the implications on price of these developments, ACIL Tasman used its model of the East Coast Gas Market to develop projections of the future delivered prices (at the city gate) for each area under different scenarios.

3.4 Gas market model - GMG Australia

GasMark Global (GMG) is a generic gas modelling platform, developed by ACIL Tasman, which has the flexibility to represent the unique characteristics of gas markets across the globe. Its potential applications cover a broad scope— from global LNG trade, through to intra-country and regional market analysis. The Australian version of the model is known as *GMG Australia*. A more detailed discussion of *GMG Australia* is provided in Appendix B. The main inputs to *GMG Australia* are discussed below.

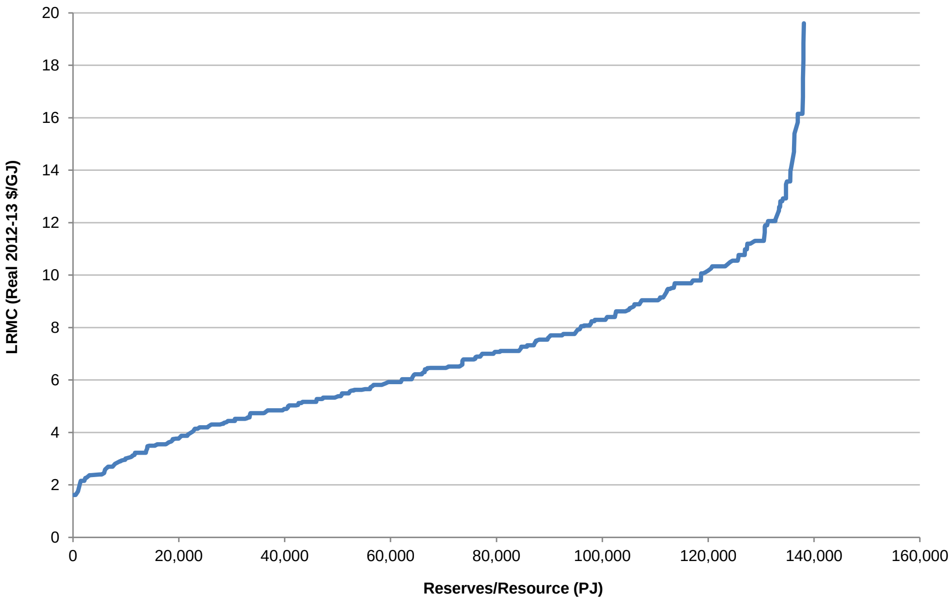
3.4.1 Existing and potential new sources of gas supply

Sources of gas supply are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices.

The assumptions embedded in the model have been built up over nearly 20 years of modelling the gas market by ACIL Tasman. The data base draws on official documents, releases by petroleum companies to the ASX and information placed in the public domain from time to time in the course of commercial due diligence and company reporting. While commercial in confidence information is not included in the general *GMG Australia* database, the assumptions reflect the accumulated knowledge and understanding of ACIL Tasman's consultants.

If we were to take all of the existing and potential gas supplies in the east coast natural gas market we could theoretically produce a supply curve of gas since commencement of production from the Gippsland Basin in the 1960s. Such a curve is provided in Chart 2 for illustration.

Chart 2 **Supply curve for natural gas in the East Coast market (PJ)**



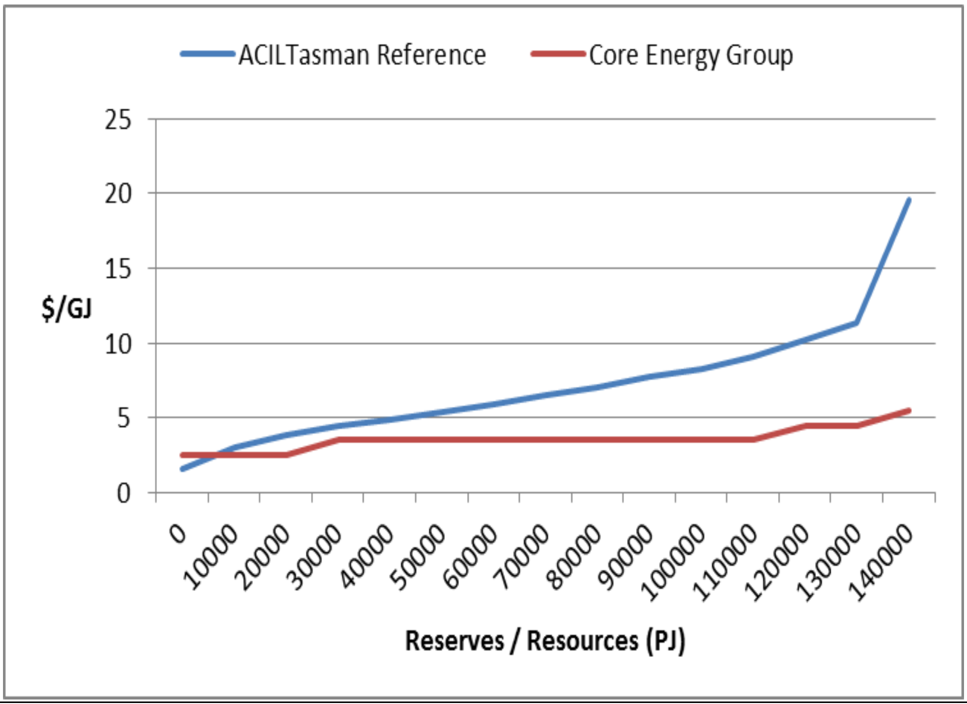
Note: Currently around 15,000 PJ has been drawn down by consumers in the east coast gas market
Source: ACIL Tasman

This curve suggests that supply is moving though the $4 per GJ range and it will require higher prices in future to bring new gas supplies to market.

Other parties have released estimates of supply curves. The Core Energy Group prepared estimates of production and supply costs in a report prepared for AEMO in 2012 (Core Energy Group, August 2012).

The ACIL Tasman and Core Energy Group projections are compared in Chart 3.

Chart 3 **Comparison of ACIL Tasman and Core Energy Group supply curves for natural gas**



Source: ACIL Tasman, Core Energy Group

It is ACIL Tasman's professional view that the ACIL Tasman curve is more indicative of the supply curve going forward. In particular, our understanding based on emerging results of CSG development activities in Queensland is that the extensive flat area of the Core Energy Group cost curve at about $3.50 per GJ (which we infer to relate to cost of production of Queensland CSG) is unlikely to be realised in practice. Wide variations in average well performance across different CSG fields in the Bowen and Surat Basins suggest a much broader distribution of LRMC for Queensland CSG.

3.4.2 Existing and potential new gas demand

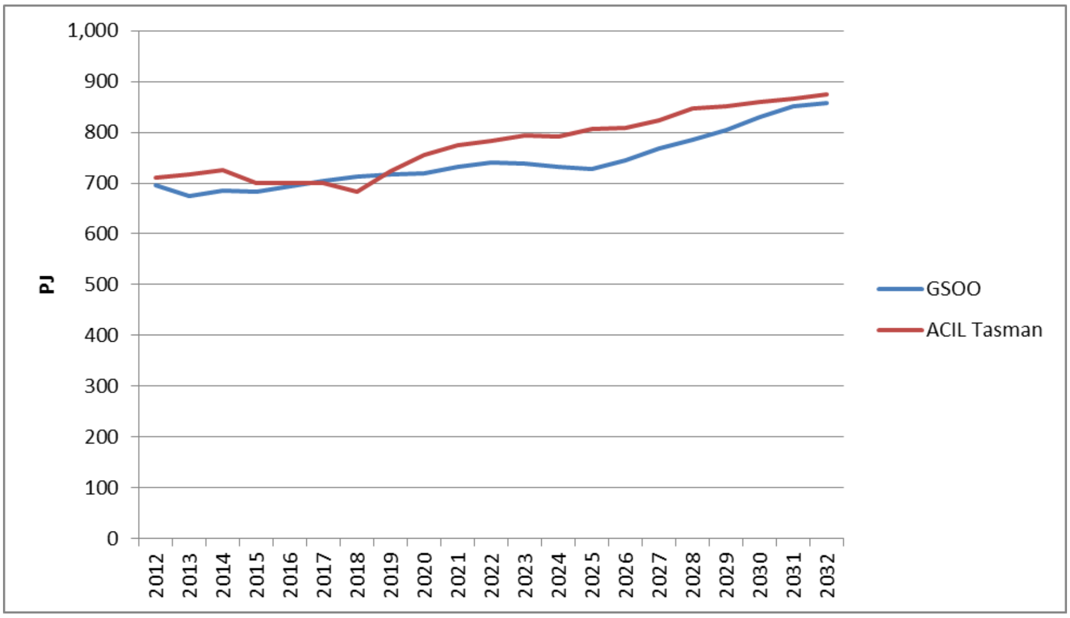
Demand may relate to a specific load such as a power station or fertiliser plant, or to a group or aggregation of customers such as the residential or commercial markets in particular locations.

Loads are defined in terms of their location, annual gas demand, price tolerance and price elasticity of demand (that is, the amount by which demand will increase or decrease depending on the price at which gas can be delivered).

The price tolerance and elasticities of demand have been developed based on published studies, internal research and other public sources.

In Chart 4 we compare our projected Eastern Australian Gas demand with that published by AEMO in its GSOO. From the point of view of projecting prices, the demand projections are not materially different.

Chart 4 **Gas demand projections – GSOO and ACIL Tasman**



3.4.3 Existing, new and expanded transmission pipeline capacity

Pipelines are represented in terms of their geographic location, physical capacity, system average load factor (which is relevant to determination of the effective annual throughput capability given assumptions regarding short-term [daily] capacity limits) and tariffs.

3.4.4 Existing and potential new LNG facilities

LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and costs of conversion.

3.4.5 Solving the model

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. This is described in more detail in Appendix B.

The equilibrium solution produces projections of wholesale prices at various nodes in the market. These nodes may represent the exit valve at gas processing plants or the "city gate" facilities where the transmission pipelines terminate and gas is transferred to lower pressure distribution systems. For example the city gate at Sydney is represented by the node at Wilton[1]. The nodal prices include transmission charges.

The nodal prices produced at equilibrium reflect the interaction of supply and demand in each year. As such they reflect the price that a new entrant retailer would need to pay to obtain gas at each node. **The equilibrium nodal prices therefore represent efficient prices in each year** based on the assumed supply and demand characteristics included in the model's data bases**. These efficient prices will not necessarily reflect the cost of production for particular fields nor the price tolerance of various domestic loads or retailers. They reflect the market equilibrium price which may also be influenced by factors such as LNG export demand and prevailing LNG export prices.**

3.4.6 Use of the supply curve

Simplistically, an annual market clearing price could be obtained for each year of a projection period by calculating the cumulative market demand for gas and reading the marginal supply cost directly off the supply curve shown as Chart 2. However this use of the supply curve would ignore time constraints associated with the development of the various reserves including development lead times and annual production constraints, and implicitly assume that reserves committed to large demand increments (the LNG projects) are available to the domestic market at the marginal cost of supply until the demand for which they are committed actually materialises. It would also ignore the spatial distribution of the various fields comprising the demand curve, and the cost of transport differentials between them.

It is well attested that large future demand increments (LNG projects) are already impacting gas contract prices. The question arises as to whether these future demand increments should impact modelled annual gas prices prior to the start-up of these projects. If it is assumed that reserves are committed to these projects (as ACIL Tasman does), the marginal supply cost for the first year of the projection period will be the marginal price *after* effectively removing the committed reserves from the supply curve by quarantining them from the domestic market. Alternatively if it is not assumed that reserves are committed to these projects, the marginal supply cost for the first year of the projection period will be the marginal supply cost *prior to* removing the committed reserves from the supply curve.

We believe our assumption that the reserves committed to the LNG projects are not available to the domestic market is consistent with the commercial realities of gas supply. As justification we cite the largely separate infrastructure associated with the development of export designated CSG fields, LNG project financier and LNG customer requirements regarding project resource adequacy and priority access, and consideration of the relevant opportunity cost of gas.

[1] The Eastern Gas Pipeline (EGP) from Longford in Victoria connects into the Sydney distribution ring main at a point east of Wilton. However for modelling purposes the node is taken to include both the Wilton and the EGP line.

Separate infrastructure

The infrastructure for supplying the domestic and export markets is distinct. The LNG pipelines connecting export designated CSG fields to the liquefaction facilities will be exempt from third party access and will not be set up to supply gas to the domestic market. This is not to say the LNG projects will be unconnected with the domestic market. There will be provision to supply the projects from the domestic market, but not routinely to supply the domestic market with gas from the LNG pipelines.

Insistence on resource adequacy

The financiers of the LNG projects will insist on resources being dedicated for use in the projects with lending agreements generally restricting the on-sale of gas to the domestic market. We note further that LNG customers would not enter long term contracts with these projects without assurance that the gas resources are committed and dedicated to the contracts.

Opportunity cost of gas

With LNG projects acquiring large volumes of gas at prices up to net back price, we would not expect them to make gas available in the short term to the domestic market at a time-discounted price. By selling even a relatively small quantity of this gas, they are potentially exposing themselves to having to purchase back the gas at an unknown price in the future. Furthermore, while there are multiple LNG projects still seeking sufficient gas to operate their projects long term, the present opportunity to use the gas, is not to sell it to the domestic market at a time-discount to a likely future price at which it would have to be bought back, but to sell it to another LNG project at net back price. There is clear market evidence of such behaviour. For example, Origin Energy (a participant in the APLNG project) in May 2012 entered into a contract with GLNG to sell 365 PJ of gas over a ten year period commencing 2015. While detailed pricing terms were not disclosed, Origin stated at the time that pricing was "in line with international oil-linked pricing."

3.5 Scenario Development

3.5.1 Introduction

As discussed previously, there is considerable uncertainty around future wholesale gas price paths, particularly over the next three years. The actual costs of supplying small customers in NSW will depend on the gas supply contracts held by the Standard Retailers. Prices under these contracts are already set, and escalate annually typically at inflation (that is, as a function of the Consumer Price Index). Periodic price resets (typically every 5 years) can result in step changes. Price review processes are currently underway on resets for major gas supply contracts into NSW. In particular, AGL's gas supply contracts with both the Cooper Basin producers and the Gippsland Basin joint venture are currently the subject of price arbitration proceedings

(Chambers, Report in the Australian newspaper, 2013) that will determine the actual wholesale cost of gas faced by AGL over the next 3 years.

We obtain a range of benchmark prices by modelling the Eastern Australian gas market. We have developed three scenarios that give rise to high, medium and low price outcomes. These scenarios are designed to provide a reasonable range within which prices under new contracts (or price resets under existing contracts) may fall.

3.5.2 Key Drivers

The key driver for scenario outcomes is the influence of the CSG-LNG projects due to their sheer size. This has fundamentally altered producer price expectations for producers with direct involvement in the projects. It also alters views for producers without direct involvement due to the potential for third-party feedstock gas sales to supplement CSG feedstock.

That these expectations are already influencing gas prices for new supply contracts in advance of LNG start up is certainly the case for the recent long term supply contracts which we review in section 3.7.2. While in our view this does not preclude the existence of opportunities for retailers to obtain shorter term, smaller quantity contracts at more favourable prices, with respect to producer pricing, there is an important and fundamental difference between the electricity and gas markets in Australia. For an electricity generator, a decision whether or not to generate at any particular point in time does not usually alter in any way its capacity to generate at a future point in time. For a gas producer the situation is quite different. The producer can sell each gigajoule of its gas reserves once only: a decision to sell a gigajoule of gas today means that it cannot be sold at some later date. The producer must therefore constantly weigh up whether the gas reserves it has available for sale would be better sold now or at some later date when, after allowing for the time value of money, they will be more valuable. As a result, long term gas supply contracts entered into today will be priced taking into account the expectations of the producer and consumer regarding the likely price at which the gas could be sold in the future.

In the current market environment, key drivers of commercial gas prices are the level of east coast LNG development, the gas prices that those LNG facilities can support, and the future performance of the CSG fields that supply the LNG plants.

The level of CSG-LNG development is dependent on:

- Asia-Pacific LNG market and propensity of LNG buyers to continue to sign JCC-linked LNG contracts and oil price expectations; and
- domestic gas production costs and LNG development costs.

Other issues which we consider to be second-order include:

- domestic demand including demand for gas-fired power generation driven by carbon pricing; and
- supply side developments such as the level of emerging CSG production in NSW.

For this report three scenarios have been developed to test the possible range of commodity costs that might arise with different LNG and domestic supply developments over the medium term. The scenarios chosen are summarised in Table 3.

The principle differences between the scenarios lie in:

- future assumed levels of international LNG prices;
- the rate of progress and the number of LNG trains that are assumed to come on stream in the near term; and
- the availability and cost of gas produced from Queensland CSG fields.

The **high price scenario** is driven by a netback price being the price that LNG producers and developers are willing to pay for gas delivered at the inlet valve to the LNG plants (6 trains) now under construction. This is a short run pricing strategy driven by the assumed production constraints from CSG projects in Queensland and the short run export parity price.

The **medium price scenario** is driven by the netback price of LNG over the longer term, again delivered at the inlet valve to the LNG plants including the currently committed plus medium term prospect plants (8 trains in total). This is a medium term export parity price.

The **low price scenario** is driven by the long run marginal cost of domestic gas supplies as the price of LNG assumed for this scenario, combined with the commissioning of only 6 trains, is not sufficient to drive domestic gas prices to LNG export parity.

Table 3 **Scenarios**

	High price scenario	Medium price scenario	Low price scenario
Scenario title	"LNG feedstock scramble"	"All goes to plan"	"LNG price collapse"
International oil prices	IEA Current Policies assumption (~US$130/bbl by 2020)	IEA Current Policies assumption (~US$130/bbl by 2020)	ACIL Tasman low price assumption of US$80/bbl by 2020
Asia Pacific LNG prices	As per Japan import prices within IEA World Energy Outlook 2012 Current Policies scenario (US$15-16/mmbtu in 2020)	As per Japan import prices within IEA World Energy Outlook 2012 Current Policies scenario (US$15-16/mmbtu in 2020)	ACIL Tasman low price assumption declining to ~US$10/mmbtu by 2020
LNG East Coast Production	6 LNG trains by 2020 (no further commitments due to poor CSG performance)	8 LNG trains by 2020 (i.e. Shell/Arrow project proceeds with 2 train project either independently or in conjunction with existing projects)	6 LNG trains by 2020 (no further commitments due to low international price outlook)
Conventional gas outlook	As per ACIL Tasman Base case	As per ACIL Tasman Base case	As per ACIL Tasman Base case
QLD CSG assumptions	Well performance is below expectations and completion costs are significantly higher	As per ACIL Tasman Base case	As per ACIL Tasman Base case
Unconventional tight gas/shale assumptions	As per ACIL Tasman Base case	As per ACIL Tasman Base case	As per ACIL Tasman Base case

Data source: ACIL Tasman

For the **high** and **medium** price scenarios ACIL Tasman's modelling and analysis indicates that pricing would be based on netback of LNG prices into the LNG plant. This assumes that LNG developers will be willing to pay up to the netback LNG price and will seek to buy gas at that price in order to secure supplies. Furthermore, they will not sell gas from their CSG fields into the domestic market for less than LNG netback prices, which effectively represent the opportunity cost of supply. Other domestic producers, mainly those producing at Longford and the Cooper Basin, will sell into the market at the price that a retailer would have to pay in order to compete with LNG producers. It is noted that this requires the Ballera to Wallumbilla or the Moomba to Ballera pipelines to have spare capacity for flows from west to east in Queensland. At the present time the flow on the Ballera to Wallumbilla pipeline is east to west to bring CSG contracted in southern states to market. However this should not pose a significant problem for central and southern Australian producers seeking to sell gas into the Gladstone LNG plants. Santos has already entered into an agreement with GLNG to supply 750 PJ of gas over 15 years from the Cooper Basin, and has signed a gas transportation agreement with the South West Queensland Pipeline (SWQP) for 147 TJ/d of firm capacity (the so-called "Easternhaul Agreement") to facilitate that supply. According to Epic Energy (ASX release dated 25 October 2010) that agreement underpinned the capital investment required to convert the SWQP into a bi-directional pipeline. Alternatively, a producer in South Australia, New South Wales or Victoria could arrange a swap with a Queensland producer or retailer, circumventing any constraint on eastward flows in the Moomba to Wallumbilla pipeline system, and indeed any need for physical delivery of gas across that system. It would only be in extreme circumstances the west to east capacity on the Ballera to Wallumbilla pipeline would restrain a netback price in New South Wales.[2] Such circumstances are not likely to arise over the 2013 to 2016 regulatory period.

3.6 LNG Netback Calculations

Table 4 sets out our calculations to arrive at netback prices. These calculations are undertaken on a calendar year basis.

Table 4 **LNG netback calculations**

Item	2013	2014	2015	2016
Exchange rate $US/$AUD	0.94	0.93	0.95	0.96
Implied JCC price based on LNG slope (Real 2013 US$/bbl)	$131.25	$132.34	$133.43	$132.39
Asia-pacific LNG prices delivered (Real 2013 US$/mmbtu)	$15.75	$15.88	$16.01	$15.89
Asia-pacific LNG prices FOB Gladstone (Real 2013 US$/mmbtu)	$14.95	$15.08	$15.21	$15.09
Asia-pacific LNG prices FOB Gladstone (Real 2013 A$/GJ)	$15.02	$15.43	$15.24	$14.84
Effective netback for domestic producers Real 2013 A$/GJ	$11.02	$11.43	$11.24	$10.84

2 In any case, over the longer-term such a pipeline capacity constraint can be overcome through additional compression or looping if the parties are willing to enter a long-term shipper contract with the pipeline owner.

We have also used the following assumptions –

- mmbtu/GJ = 1.055
- Japan shipping cost (US$/mmbtu) = $0.80
- Liquefaction capex/risk premium (Real 2013 A$/GJ) = $4.00
- JCC linkage = 0.12

3.7 Modelling Results

ACIL Tasman has modelled prices at selected nodes in the east coast gas market. The nodes correspond to the Standard Retailers' areas and include:

- Cooper Basin – supply node;
- Longford – supply node;
- Sydney (Wilton) – AGL;
- Newcastle – AGL;
- Canberra region – ActewAGL;
- Wagga Wagga - Origin Energy (Wagga Wagga);
- Dubbo - Origin Energy (Wagga Wagga);
- Tamworth - Origin Energy (Wagga Wagga); and
- Wodonga (Origin Energy).

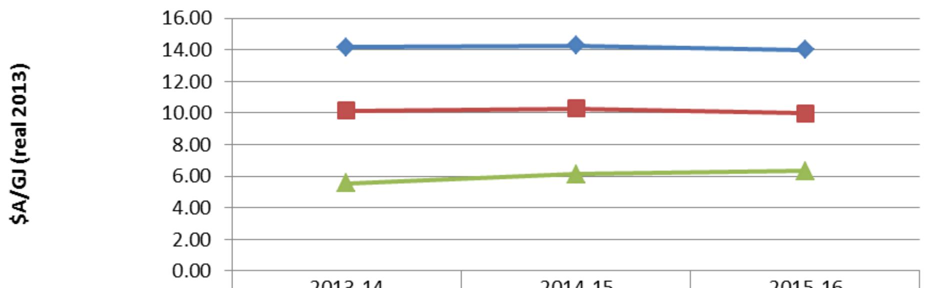
The results for the Cooper Basin and Longford nodes are shown in Chart 5 and Chart 6 respectively. The other nodes are discussed later in this report.

These results represent the prices at each node that would be arrived at in an efficient, rational gas market in the absence of existing contracts. They are based on annual quantities with transmission tariffs based on either 70% or 80% load factor depending on the typical system average load factor for the relevant system. They represent reference points against which consideration of each Standard Retailers proposals can occur.

Please note that prices at Cooper Basin and Longford for the high and medium price scenarios are based on LNG netback prices at Gladstone less the cost of transporting gas from Cooper Basin and Longford respectively to Gladstone. For the low price scenario the prices are the long run marginal cost of production at each of these supply nodes. Prices cited at supply nodes do not include transmission costs.

Chart 5 shows that potential prices at the Cooper Basin node could range from nearly $5.60 per GJ for the low price scenario to around $10 per GJ for the medium price scenario. The price for the high price scenario could be over $14 per GJ.

Chart 5 **Projected prices - Cooper Basin node**



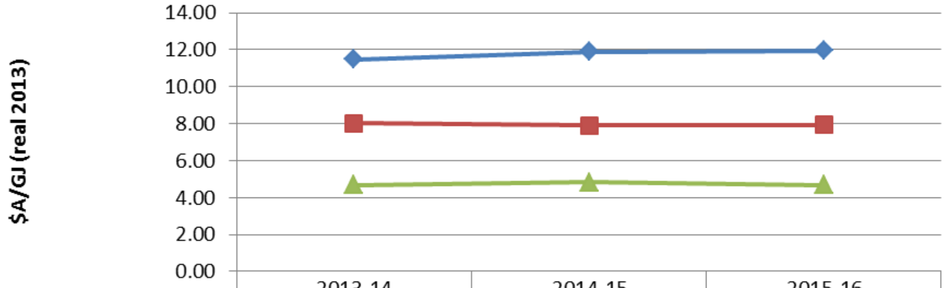
	2013-14	2014-15	2015-16
High price scenario	14.17	14.28	13.99
Medium price scenario	10.16	10.27	9.99
Low price scenario	5.57	6.13	6.35

High price scenario   Medium price scenario   Low price scenario

Source: ACIL Tasman GMG Australia modelling

Chart 6 shows that potential prices at the Longford node could range from around $4.70 per GJ for the low price scenario to around $8 per GJ for the medium price scenario. The price for the high price scenario could be up to $12 per GJ.

Chart 6 **Projected Prices - Longford node**



	2013-14	2014-15	2015-16
High price scenario	11.48	11.91	11.94
Medium price scenario	8.02	7.90	7.94
Low price scenario	4.68	4.85	4.68

High price scenario   Medium price scenario   Low price scenario

Source: ACIL Tasman GMG Australia modelling

3.8 Other Commodity Cost Benchmarks

Deriving benchmark wholesale energy costs in the gas market is more problematic than in the electricity market. This is because gas supply contracts are longer term and prices may not be disclosed. Also such spot markets for gas as have been established serve as balancing markets wherein relatively small quantities of gas are traded rather than wholesale pools through which all the gas supplied to a regional market might be transacted. An actively quoted financial contract market, such as that which exists in electricity, has not developed.

Sources of commodity cost benchmarks include the prices of gas contracts to the extent to which these are disclosed, recent projections of gas market consultants, prices referred to in other regulatory determinations, and gas spot prices.

3.8.1 Recent Projections of Gas Market Consultants

Recent projections of gas market consultants include those prepared by ACIL Tasman for AEMO in 2012, and those prepared by Intelligent Energy Systems (IES) as part of the annual Queensland Gas Market Review also in 2012.

ACIL Tasman fuel cost projections for AEMO

In June 2012, ACIL Tasman prepared an update of fuel cost projections for AEMO modelling. Gas price projections were provided for five scenarios and for each scenario a number of sensitivities around gas-fired power generation (ACIL Tasman, 2012). Prices were cited at Moomba. Depending on scenario, over the period 2013 to 2016, long run LNG netback prices ranged from $6-8 per GJ and short run LNG netback prices from $10-12 per GJ. Our current price projections are generally higher being around $10 per GJ for long run netback and $14 per GJ for short run. The principal reason that our projected prices have increased is that the report for AEMO was based on Asia Pacific LNG price projections reported in the 2011 IEA World Energy Outlook. Projected Asia Pacific LNG prices are higher in the IEA's 2012 Outlook.

Queensland Gas Market Review 2012

Intelligent Energy Systems (IES) discussed the gas price outlook in a report for the Queensland Government (IES, June 2012).

The IES report noted

> "Cost of supply will increase in line with development of new reserves, setting the floor price. The cap will be set by LNG export parity. The likely [domestic gas] price range is wide, $6 per GJ to $12 per GJ, delivered to large customers".
>
> "The modelled gas prices, reflecting the marginal cost of supply plus pipeline costs, are in the order of $4.50-6 per GJ increasing to $5.50-6.50 per GJ delivered by 2020 (January 2012$). These costs reflect a move to higher cost CSG fields".
>
> "A bullish LNG development trajectory accompanied by high oil prices would likely lead to gas scarcity for domestic contracts and domestic gas prices in the order of $10 per GJ by 2015. Conversely, a modest oil price and LNG development outlook could see prices at a much lower level of AUD6-7 per GJ by 2015".
>
> The prices cited are January 2012 Australian dollars real.

3.8.2 Contract pricing

There have been few domestic gas supply contracts written over the last two years. Examples of publicly announced contracts and their reported pricing include:

- Santos sale to GLNG (October 2010) - 750 PJ of gas over 15 years from 2014 to be used to augment CSG feedstock for the GLNG export project at a price reportedly around $6 per GJ ex-Moomba with some price linkage with international oil prices;
- AGL sale to Xstrata Mt Isa (November 2011) - AGL (on-selling gas entitlements) is believed to have secured a price of about $6 per GJ (excluding transport) for gas that will be used to supply electricity generation at Mount Isa for 10 years from 2013 (the previous contract price was around $3.50 per GJ);
- Origin Energy sale to GLNG (May 2012) - 365 PJ over a period of 10 years commencing in 2015 with pricing based on an oil-linked formula with base price reportedly around $8 per per GJ;
- Origin Energy sale to MMG (December 2012) – 22 PJ over 7 years for use in the Mount Isa region (Century, Dugald River mines) commencing 2013. It was reported at the time that "... the price is not linked to oil prices, instead rising to a flat price of close to $9 during the seven-year contract".; and
- Beach Energy sale of Cooper Basin gas to Origin Energy (April 2013) – 139PJ over 8 years to supply Origin Energy's domestic gas business and reportedly priced between $6 and $9 per GJ and oil price linked.

As these contracts demonstrate, prices have been rising significantly over the past two years. There has been a move toward linkages with oil price—never previously a feature of long term gas contracts in eastern Australia—reflecting the pricing basis for LNG export projects.

3.8.3 Other regulatory determinations

A recent relevant gas price determination is that undertaken by ESCOSA for small gas consumers in South Australia in 2011 (ESCOSA, June 2011). This has implications for MDQ costs as well as commodity costs. For convenience we deal with both here. As part of this determination, Origin Energy proposed "a significant increase in Annual Contract Quantity (ACQ) costs in 2013/14, reflecting its expectation that wholesale gas prices will move to export LNG netback price parity from 1 January 2014"; and also significant increases to MDQ costs arguing

- reduced flexibility in gas supply contracts has increased the need for peak contracts;
- overall gas demand volatility and peakiness has increased, driven by increased gas-fired generation in Queensland, South Australia and Victoria;
- reduced flexibility in transmission line pack rights has led to further reductions in the flexibility of the Origin Energy peak supply portfolio; and
- the cost of disposal of non-peak/excess gas on the STTM, Victorian gas market and non-peak generation pool.

Origin Energy's proposed wholesale gas costs are shown in Table 5.

Table 5 **Origin Energy's Proposed Wholesale Gas Costs – South Australia ($2011)**

Customer	2011-12	2012-13	2013-14
	$ per GJ	$ per GJ	$ per GJ
Residential	5.13	5.21	6.44
SME	4.61	4.64	5.87

Data source: *(ESCOSA, June 2011)*

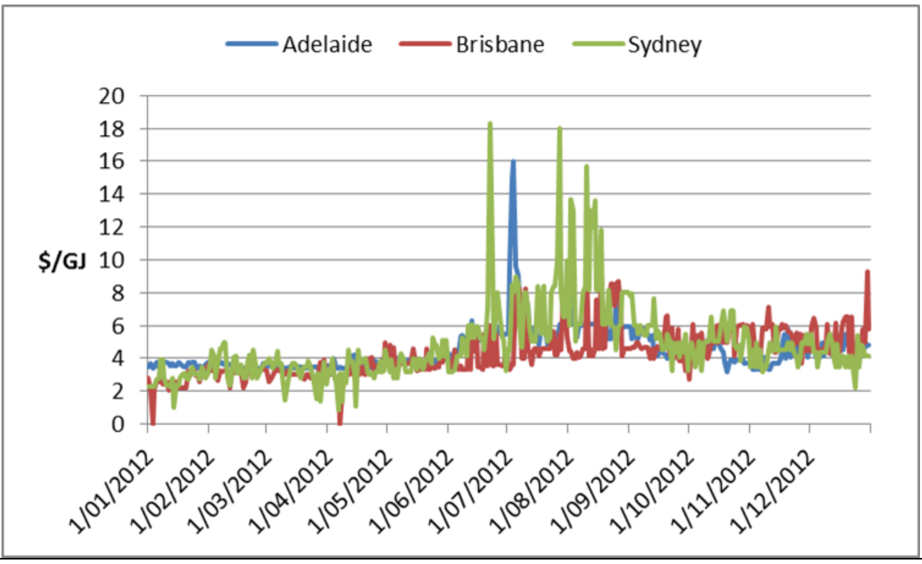
According to ESCOSA

> "The Commission elected to address any claimed increase in wholesale gas costs in 2013/14 in the subsequent price path (should regulation of standing contract prices continue), with any under-recovery of costs from that final 6 month period to be recovered in the subsequent price path, or, to the extent that wholesale gas costs increase so significantly during the price path period that it is not feasible to defer the recovery of the increased costs to the next period, the Commission would consider a special circumstances review, and re-open the price path."
>
> "The Commission's Draft Determination was to establish a wellhead gas cost (ACQ) of $4.16 per GJ in 2011/12, falling to $4.14 per GJ in 2012/13 and 2013/14."
>
> "The Commission accepted the load factors proposed by Origin Energy and, consistent with the approach used in the Commission's 2008 Gas Standing Contract Price Determination, the Commission concluded that the MDQ price should be based on the published underground storage (UGS) price, currently $175 per GJ MDQ. The Commission's Draft Determination set an MDQ price that remains constant throughout the price path period as follows:
>
> – $0.87 per GJ for residential customers, and
>
> – $0.37 per GJ for SME customers."

3.8.4 Gas spot prices

Gas spot prices are published by AEMO for the Declared Wholesale Gas Market (DWGM) which has been operating in Victoria since 1999 and the Short Term Trading Market (STTM) which commenced operating at the Adelaide and Sydney hubs on 1 September 2010, and at the Brisbane hub on 1 December 2011. The STTM operating at the Sydney hub serves as a balancing arrangement to support retail competition in gas supply at AGLGN's Wilton network section (AEMO, 19 April 2012). The STTM gives rise to a daily spot price providing a cash basis for trading imbalances. In other network sections, participants are required presently to maintain their cumulative imbalance amounts within a specified tolerance by varying injections in the future or trading with other participants (AEMO, 3 September 2012). For the 2012 calendar year, daily gas spot prices, which include the cost of transmission to the hub, averaged $4.52 per GJ for Adelaide, $4.25 per GJ for Brisbane, and $4.77 per GJ for Sydney (see Chart 7). Spot prices exhibited significant volatility during the winter period at all hubs.

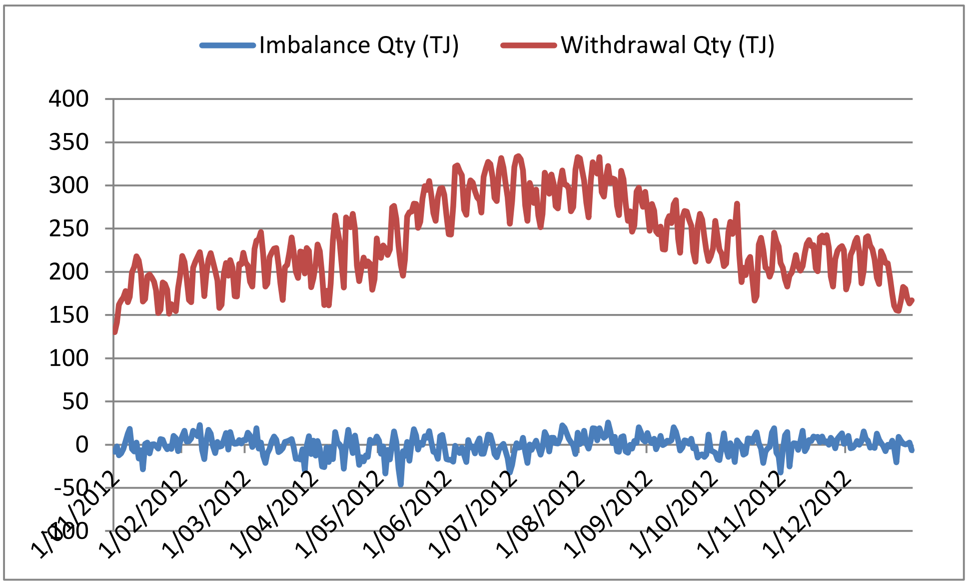
Chart 7 **STTM Prices 2012**



Source: AEMO

Unlike the NEM's electricity spot prices which arise from a gross pool arrangement in which, market customers including electricity retailers, and with few exceptions generators are required to participate, gas spot prices apply only to imbalance quantities. These imbalance quantities are the difference between the gas injected into the network by or on behalf of the retailer, and the gas withdrawn by the retailer to supply its customers. These quantities can be positive or negative and are generally small compared to total system withdrawals. This is shown in the case of the Sydney hub in Chart 8. Over the period shown, the average of the ratio of the absolute imbalance quantity to system withdrawal is 3.72%. The value of this ratio which was exceeded 90% of the time is 7.61%. The maximum value of the ratio is 22.31%.

Chart 8 **Sydney Hub – Imbalance and Withdrawal Quantities**



Over this period the daily gas spot price at the Sydney hub averaged $4.77 per GJ. The average spot price weighted according to system withdrawal was $5.06 per GJ. The spot price averaged $5.45 per GJ across days of positive imbalance and $4.02 per GJ across days of negative imbalance. Across days on which the system withdrawal exceeded the average withdrawal for the year, weighted according to the size of the excess, the spot price averaged $6.91 per GJ.

We do not consider that spot prices are a relevant benchmark for the supply costs of gas retailers. In electricity, most of the energy is traded through the NEM's mandatory gross pool, and regional spot prices serve as reference prices for the financial contracts retailers purchase to hedge the spot electricity purchases they are required to make in respect of their customer load. It should also be kept in mind that whereas in the supply of electricity, demand and supply must be instantaneously balanced, there is substantial stored gas (linepack) in gas transmission pipelines. In general, as injections of gas from production facilities are scheduled ahead of time, mismatches between the amount of gas injected into a network and the amount of gas withdrawn from the network by users, is managed by drawing down, or adding to linepack. Production facilities do not, and are not capable of responding to variations in demand and supply as power generators do in electricity supply systems.

In gas, spot prices apply to imbalance quantities which are relatively small compared to total system withdrawals. As yet, a financial contract market has not, and in fact may not, develop around these spot prices. Antecedent spot price outcomes do not inform price negotiations for gas, in the way they do for electricity. There is in gas at present, no evident linkage between contract prices and spot prices.

Origin Energy has contended previously that assessing benchmark gas purchase costs by reference to the gas spot market prices is inappropriate. According to Origin Energy,

> "No major gas retailer would rely on the gas spot market to cover their gas portfolio and, for instance, only around 8% of gas is "traded" in the Victorian gas spot market" (Origin Energy, 2003).

Further while AEMO states that

"The STTM is a wholesale market designed to facilitate short term gas trading using market-driven, short term (daily) prices", and adds that

"it allows retailers and other large customers to purchase gas from the market without having to enter into long-term contracts with pipeline providers or gas producers",

it further explains (AEMO, 2011) that

> "Long-term investment in gas production and distribution infrastructure is, in general, reliant on the ability of the investor to secure a matching long-term return. This is typically achieved by setting up long-term contractual arrangements with shippers and users. Long-term contracts are also advantageous to shippers and users because this usually means that the gas is acquired on more attractive terms. Although a user is able to acquire its entire gas requirements solely by bidding in the STTM, there are countervailing forces that will always encourage users and shippers to seek longer-term arrangements. Firstly, a user who

purchases gas solely on the short-term market can expect to pay a higher average price and is more likely to experience higher volatility with day-to-day pricing, with a consequentially lower profit margin and higher commercial risk. And secondly, because of scheduling priorities, a user who relies heavily on uncontracted or as-available gas is also likely to deviate from the market schedule more frequently, and so incur higher costs through deviation charges and payments. This creates clear commercial drivers for users to contract for a substantial portion of their expected gas supply with firm capacity."

3.9 ACIL Tasman's view on efficient prices

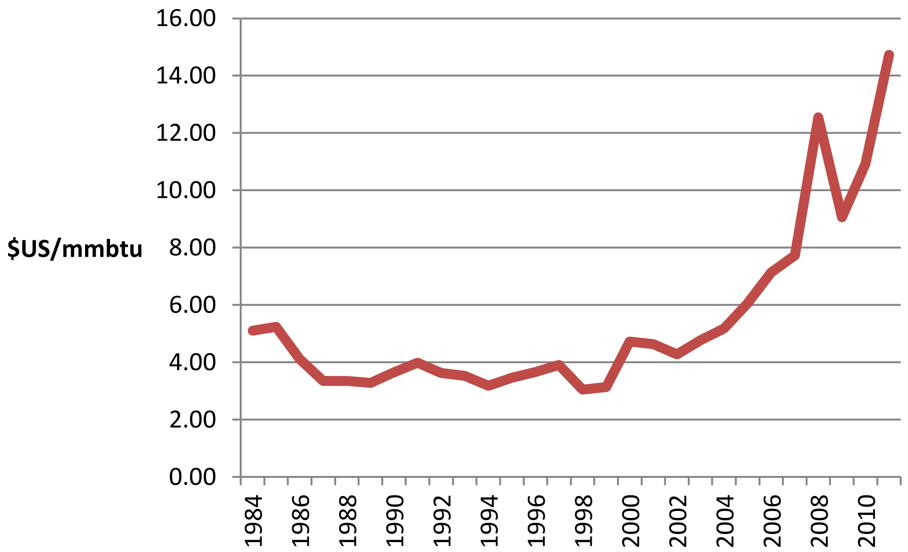
The nodal prices produced from our GasMark modelling represent the prices that a retailer is likely to have to pay for gas delivered to the node. There may be short term opportunities that arise from time to time to purchase gas off the spot market at different prices but if these prices are not sustainable they would not be a reasonable reflection of the efficient price for a retailer to contract gas over the longer term. ACIL Tasman considers that these nodal prices produced from the modelling therefore represent a reasonable assessment of an efficient price for the purpose of establishing an estimate of an efficient wholesale gas price in each market.

The modelling revealed a wide range of potential price outcomes depending on the scenario chosen. The key variables distinguishing each scenario are:

- the cost and production available from CSG projects in Queensland;
- the rate of progress in the Queensland LNG plants and their associated CSG supply fields;
- and international LNG prices.

LNG prices in the Asia Pacific region have been steadily rising towards $15 per mmbtu over the past ten years or so (see Chart 9).

Chart 9 **LNG prices cif Japan**



Data source: (Chambers, 2013)

However some analysts are predicting a longer term decline in existing oil linked LNG prices relevant to markets of interest to Australian LNG exporters. This view was expressed most recently by the Chief Economist of BP (Chambers, 2013). On balance, ACIL Tasman considers that for the period from 2013-14 to 2015-16, LNG prices are likely to remain at elevated levels. In the current climate it appears that plans for development of the three committed LNG export projects at Gladstone are proceeding more or less on schedule, with first shipments beginning late 2014. However, a number of analysts have noted that the rate of growth of Queensland CSG reserves appears to have been slowing, and that average well performance has not lived up to initial expectations. So, for example, Citi Research in a recent note observed that:

> "Overall, however, we think the appraisal of the QLD CSM fields has identified the geology to be more variable than initially envisaged back in 2008 and 2009, and we think the estimated ultimate recovery from the CSM acreage is less than the original estimates. We think this is evident across all four projects." (Citi Research, March 2013)

Already GLNG has procured more than 1,000 PJ of third party gas supply, and is understood to be still active in the market for supplies to meet its contractual commitments.

If this apparent under-performance of the CSG resource base persists, it could put significant upward pressure on prices, at least temporarily. Faced with an initial feedstock shortfall, LNG proponents would be reluctant to commit any supply into the domestic market at less than replacement cost—which in these circumstances could be as high as LNG spot price less avoidable costs of production (that is, short-run LNG netback).

However, on balance we consider that, for the initial year of the projection period, gas prices are likely to reflect marginal supply costs (the low price scenario) before transitioning subsequently to netback prices (the medium price scenario). The medium price scenario represents the most likely future price path, albeit with a high level of risk attaching to that estimate given the current market uncertainties.

In forming this view, we have taken into account the following:

- There is no reason presently to expect a collapse in either oil or LNG spot prices. The U.S. Energy Information Administration in its Annual Energy Outlook 2013 Early Release Overview has adopted a reference case in which oil prices continue to rise in real terms from current levels. Despite moves by some Asian buyers (particularly in Japan) to decouple oil and LNG prices it is unlikely in our view that there will be a widespread separation of oil and LNG prices within the next five years. On the supply side, while unconventional/tight gas may have a significant role to play in the longer term it is unlikely to provide a large source of low cost gas at least in the short to medium term. While this implies that LNG netback prices are likely to remain higher than long run marginal production costs at the principal supply points over the three year period, we recognise that the market is presently in a transitionary phase, and for this reason, we think prices under the low price scenario to be more reflective of gas commodity costs for 2013-14.
- The apparent under-performance of the CSG resource base could result in a period of tight supply in the period leading up to, and for some time after, LNG start up and this could push prices toward the high case outcomes, at least temporarily. However, the high price

scenario would be expected to arise only if there was clear evidence of a pervasive supply shortfall problem across all the LNG projects (such that the problem could not be dealt with by trades/swaps between the projects). This would be unlikely to become apparent until after commissioning of all six currently committed LNG trains which is unlikely to happen until 2016 at the earliest. Furthermore, prices at the levels of the high price scenario would be likely to lead to significant demand destruction if maintained for any period of time and in that sense would be essentially self-correcting.

3.9.1 Constructing a price path

One possibility to determine a price path would be to apply probabilities to each of the three modelled price scenarios, and to use these probabilities to derive a single "probability weighted" price path. We do not support such an approach, because it effectively involves conflating scenarios that are mutually exclusive and in so doing obscures the true level of uncertainty around the estimated price path. For example, a situation in which world oil prices and/or LNG prices collapse leading to an outcome similar to the low price scenario would be mutually exclusive with a situation of high LNG netback and feedstock shortfall into the Queensland LNG plants, leading to the high price scenario.

We consider that the better approach is to accept the medium price scenario as the *most likely* beyond 2013–14 based on current information, but note that the actual price path could move either up toward the high price scenario, or down toward the low price scenario, depending on how the key price drivers play out over the next four years.

4 Cost of Additional Deliverability

4.1 Introduction

Additional Deliverability refers to the difference between the peak day requirement of a retailer's customer load and the maximum daily quantity it can access on its supply contracts. Consistent with the previous review, the Standard Retailers have proposed the cost of additional deliverability be calculated according to the following formula:

$$AC\_MDQ = MDQC/365 \times (1/CLF - 1/SLF)$$

We consider this an appropriate methodology for the current review.

4.2 MDQ Cost Benchmarks

We consider a number of MDQ cost benchmarks based on gas storage, and then develop additional non-storage benchmarks based on the prospects of interrupting and alternatively providing excess gas at a discounted price to gas-fired power generation. For comparative purposes, we also estimate an MDQ cost based on daily gas spot prices at the Sydney Hub observed during 2012.

4.2.1 Underground Gas Storage (Iona)

This storage facility was previously referred to as Western Underground Storage (WUGS). According to EnergyAustralia (EnergyAustralia), "the Iona site is located above a depleted gas field that was originally used to supply the Western System. Gas is stored in three underground storage reservoirs – Iona and the remote reservoirs of North Paaratte and Wallaby Creek. The plant includes two gas processing trains and compression equipment to process gas from the storage reservoirs and the offshore Casino development. Compressed gas can be injected into the South West Pipeline to supply Melbourne, the SEA Gas Pipeline to supply Adelaide, or into the storage reservoirs for later withdrawal."

EnergyAustralia explains further that "Iona provides energy retailers and wholesalers the ability to shape supply contracts to meet peak requirements and provides a hedge against spikes in the spot market price. Storage might also appeal to gas producers because it allows production to remain flat whilst allowing deliverability to match demand."

According to EnergyAustralia, "gas storage fees consist of a fixed capacity charge for MHQ and storage volume, and variable charges per gigajoule of plant throughput. Storage contracts are available until 30 September for the following reservoir year (1 October to 30 September). The minimum contracting level is typically 10TJ per day of storage withdrawal capacity."

Previously, when operated by TXU, WUGS rates were published and constituted a publicly available source of information on the market cost of MDQ. We understand that EnergyAustralia, the current owners and operators of the gas storage, no longer publish rates publicly but invite commercial enquiries. Origin Energy (submission 2002) refers to a rate of $150 per GJ/MDQ from October 2003. For the previous review a range of MDQ costs based on WUGS published rates was $160 to $240 per GJ MDQ /year. In the previous review MMA expressed its view that the cost of MDQ for retailers was at the lower end of this range.

4.2.2 Newcastle Gas Storage Facility

According to an AGL media release of 11 May 2012, AGL is constructing the Newcastle Gas Storage Facility at Tomago. The total project investment cost is cited by AGL to be around $310 million. It is expected to be completed in 2015 and will incorporate a processing plant to treat and liquefy natural gas, LNG storage tank capable of 1.5PJ capacity and a re-gasification unit to convert the LNG back into natural gas. According to AGL it will have peaking capacity of 120 TJ/day (AGL, 27 February 2013). Ignoring any operating costs, estimates for the cost of providing MDQ at this facility can be made on the basis of its cited project development cost and peaking capacity. Assuming a thirty year asset life, annual capital recovery factors corresponding to post-tax real weighted average costs of capital of 6% and 8% are 7.26% and 8.88% respectively. Multiplying the project development cost by the annual capital recovery factor and dividing by the peak capacity expressed in GJ, gives an MDQ cost in the range of $188 to $229 GJ MDQ/year.

4.2.3 Dandenong LNG Storage Facility

According to APA Group, with a fully contracted capacity of approximately 12,000 tonnes (or 0.7 PJ), the Dandenong LNG storage facility provides peak shaving and security of supply services for the Victorian Principal Transmission System (PTS). This facility injects gas into the PTS to meet peak winter demands as well as providing a truck loading station for LNG tankers. The Dandenong LNG Facility is not subject to regulation under the National Gas Code. We understand that APA Group makes the associated peak shaving services available through a tender process, the details of which, including outcomes are not generally disclosed.

4.2.4 Mondarra Gas Storage Facility

In a media release of 26 May 2011, APA Group cited a cost of $140M to expand its Mondarra gas storage facility located on the Parmelia Gas Pipeline near Dongara in Western Australia. According to the Australian Pipeliner, October 2011, "a significant increase in the daily injection and withdrawal rates into and out of the facility will be another result of the expansion, with the current 15 TJ/d injection and withdrawal rates to increase to rates of 70 TJ/d for injection and 150 TJ/d for withdrawal." This information suggests that an additional 135TJ/day withdrawal capacity is achieved at a cost of $140M. Amortising the project development cost at 10% provides an MDQ cost estimate for this facility of $104 per GJ MDQ per year.

4.2.5 Non Storage Benchmarks

Electricity spot prices are typically more volatile is summer than in winter. This suggests that there might be a case for sourcing MDQ by interrupting gas-fired power generators in the winter season (quarters 2 and 3) when retail gas demand is higher. Assuming a heat rate of 11 GJ/MWh, and valuing the MDQ at the cost of an electricity cap contract, the equivalent value would be $200 per GJ MDQ/year for a $1/MWh cap premium. Winter season caps are currently traded at around $3/MWh, implying a potentially very high MDQ cost of $600 per GJ MDQ/year. This assumes that the generator is unable to produce electricity if its gas supply is interrupted.

If the gas-fired power generator has the ability to switch from gas to liquid fuel it will retain its ability to generate against potentially high electricity prices. SKM MMA has estimated recently for Western Australia's Independent Market Operator (IMO), the capital cost of providing a 160MW open cycle gas turbine installation with liquid fuel capability (SKM MMA, January 2013). The cost is around $6.5M or $650,000 annually if amortised at 10%. Assuming that the use of liquid fuel results in a variable generation cost of $300/MWh (SKM MMA cites an estimated cost of diesel fuel of $23.62 per GJ), and that the generator is interrupted 1% of the time, the annual cost of interruption (in fuel terms) will be 0.01 x 8760 x 160 x $300 = $4.2M. The total cost of the interrupt service would be $4.85M. If the interruption is for 12 hours and the heat rate of the OCGT is assumed to be 11 GJ/MWh, the available MDQ is 12 x 160 x 11 = 21,120GJ. The cost is then $230 per GJ MDQ/year. It will be noted that this estimate is highly sensitive to assumptions, particularly the assumption regarding the time the generator is to be interrupted. As a result the cost estimate has a potentially wide range.

Another approach is for the retailer to contract additional annual quantity and to sell excess gas at a discount to gas-fired power generators. For example if a retailer has a customer load factor of 33% and contracts for an annual quantity three times its demand, and it is assumed that it sells excess gas at a $1 per GJ discount, it will make a loss of $2 per GJ for every GJ sold to its customers. This "additional deliverability" cost of $2 per GJ corresponds to an MDQ cost of $360 per GJ MDQ/year. In this approach it is assumed that there is adequate spare gas-fired generation capacity to make use of the retailer's excess gas. This is likely to be problematic for a retailer with a relatively large customer demand.

Finally, it possible to arrive at an estimate of MDQ cost from gas spot price and system withdrawal data published by AEMO. We base our estimate on daily data published for 2012 for the Sydney hub. This estimate can be regarded as an implied MDQ cost.

Analysis of daily system withdrawals gives an average withdrawal of 236TJ and a maximum withdrawal of 334TJ – a load factor of 71%. The difference between the system withdrawal weighted spot price and the time-weighted spot price ($5.06 - $4.77 = $0.29 per GJ) represents the cost of additional deliverability. This is the additional cost of supplying a 71% load factor demand over a 100% load factor demand. Rearranging the formula used previously to calculate the additional cost of MDQ, we have

MDQC = 365 x AC_MDQ x CLF = $75.15 per GJ MDQ/year.

The cited range of MDQ costs of $160 to $240 per GJ MDQ/year represents a multiple of 2 to 3 of this value. However this is not dissimilar to the electricity market where cap contracts trade at similar or even higher multiples to value based on spot prices.

4.3 Conclusions

There are a number of approaches to estimating the cost of MDQ. The application of these gives rise to a large range in estimated value from less than $100 per GJ/MDQ/year based on analysis of daily gas spot prices to possibly in excess of $300 per GJ/MDQ based on opportunities to interrupt gas-fired power generators or provide them with additional gas at a discounted price. We consider the most relevant benchmark cost to be that based on AGL's Newcastle gas storage facility. Our reasoning is that this is a facility currently under construction in New South Wales which is well suited to providing the additional deliverability service and for which the estimated cost and delivery capacity are known. We note further that our estimate of the MDQ cost at this facility ($188 to $229/ GJ MDQ/year) is within the range previously quoted for the underground storage facility in Victoria ($160 to $240 GJ MDQ /year). Finally we note that our estimate of MDQ cost of $230 per GJ MDQ/year based on interrupting a gas-fired power generator fitted with the capability to switch to liquid fuel is also within this range. However we note that this particular estimate depends on a number of assumptions.

5 Wholesale Cost of Gas Projections

5.1 Introduction

In this chapter, we develop wholesale cost of gas projections for the Standard Retailers' supply areas by considering the commodity cost of gas at relevant supply points, the cost of additional deliverability to meet peak day demand requirements, the cost of hauling gas from supply points to the relevant supply areas, and other relevant costs.

We also show prices projected by our GasMark model at nodes relevant to the particular retailer supply areas of interest. These prices should be interpreted as the marginal cost of supplying the nodal demand. The haulage cost component of these prices is based on the typically higher nodal demand load factor rather than the small customer load factor and they do not include any additional deliverability cost component. These prices are lower therefore than the wholesale cost of gas calculated by applying the "prudent retailer" methodology adopted for this review. Indeed they may be more representative of the actual costs incurred by Standard Retailers supplying a large diversified customer demand (of which the small customer load is a part) than the costs incurred by hypothetical new-entrant retailers supplying a small proportion of the small customer loads and contracting in accordance with the "prudent retailer" methodology.

Reference transmission tariffs are published by the relevant pipeline businesses. In general they include both throughput ($ per GJ) and MDQ ($ per GJ MDQ) charges. In the case of MDQ charges, proposed load factors are relevant to transmission costs. We review the proposed transmission costs on this basis.

Most gas customers in NSW can be supplied either from Moomba by means of the MSP or Longford via the EGP. In general it will be cheaper for a retailer to supply from a single source. However, as has been noted, a prudent retailer might be expected to contract at multiple sources. Based on the long-run marginal cost of production, our modelling suggests that the gas commodity is cheaper at Longford than at Moomba. However the cost of hauling gas to Canberra or Sydney is lower from Moomba than from Longford.

Table 6 shows the current tariffs for the MSP and EGP (source APA Group and Jemena).

Table 6 **MSP and EGP pipeline tariffs as at 1 January 2013**

Item	Cost
MSP	
Capacity $/km/GJ MDQ	0.000662
Throughput $/km/GJ	0.0000369
EGP	
Capacity $/GJ MDQ Zone 2	0.8959
Capacity $/GJ MDQ Zone 3	1.1854

The MSP tariff has distance based capacity and throughput charges. The EGP tariff has a zonal based capacity charge. Zone 2 includes Canberra and Zone 3 includes Sydney.

Table 7 sets out the cost of haulage on these pipelines for delivery to Canberra and Sydney. The distance from Moomba to Canberra and Moomba to Sydney is 1,189 and 1,299km respectively. It is evident that it is more expensive to haul gas from Longford to these destinations than from Moomba and that the difference in the cost increases with reducing load factor. For example to supply Canberra, the EGP is $0.09 per GJ more expensive than the MSP at an 80% load factor and $0.32 per GJ more expensive than the MSP at a 30% load factor. To supply Sydney the extra cost using the EGP is $0.36 per GJ for an 80% load factor and $1.04 per GJ for a 30% load factor.

Table 7 **Estimated haulage costs for various load factors (1 January 2013)**

	30%	40%	50%	80%
Longford to Canberra	$2.99	$2.24	$1.79	$1.12
Moomba to Canberra	$2.67	$2.01	$1.62	$1.03
Longford to Sydney	$3.95	$2.96	$2.37	$1.48
Moomba to Sydney	$2.91	$2.20	$1.77	$1.12

Other relevant costs include fees for participating in markets operated by AEMO (STTM and DWGM[33]). In Table 8 we set out what we consider to be the appropriate range of assumptions for assessing the costs and prices proposed by the Standard Retailers.

Table 8 **Assumptions for assessing price proposals**

Item	AGL	ActewAGL	Origin Energy Murray Valley	Origin Energy Wagga Wagga
Sources of Supply	Longford, Moomba	Longford, Moomba	Longford	Moomba
Supply Load Factor	80%-100%	80%-100%	80%-100%	80%-100%
Customer Load Factor	35%-40%	30%-35%	30%-35%	30%-35%
MDQ Cost $/GJ / year	$216	$216	$216	$216
Market Charges	STTM	N/A	DWGM	N/A

Our adopted ranges for customer load factors are based on what we can establish from publicly available sources of relevant information. The higher range for the AGL supply area reflects the higher winter temperatures in that area compared to the others. While our investigations give rise to a wide range of MDQ cost, we settle on the current value of the midpoint of the range of $160 to $240/GJ MDQ /year originally quoted in respect of the Victorian underground gas

[33] Short Term Trading Market and Declared Wholesale Gas Market

storage (AGL, 2010). Where multiple supply points are assumed (Longford and Moomba), it is assumed gas is taken from each in equal proportions (i.e 50:50).

On this basis, we develop estimates of wholesale gas costs for the 2013-14, 2014-15 and 2015-16 financial years. These are shown in Tables 9 to 11 respectively. Commodity costs are based on our modelled low price scenario for 2013-14 and our modelled medium price scenario for 2014-15 and 2015-16. This results in a step-change from prices reflective of long run marginal production costs in 2013-14 to prices based on LNG netback calculations from 2014-15. All other costs are assumed to remain constant in real terms. Please note that the costs of transportation to the relevant areas includes haulage, odorisation and the cost of system use gas and are in respect of delivery to Sydney, Canberra, Wodonga, and Wagga Wagga respectively. Further note that while we provide a range for additional deliverability and transportation costs, we show total cost as a point value. The calculation of this total cost value makes use of confidential data provided by the Standard Retailers which we have assessed as being reasonable. As we did not receive confidential data from ActewAGL for our review, we show a total cost value for ActewAGL calculated using a load factor of 32.5% being the mid-point of our assessed range for customer load factor.

Table 9 **Wholesale gas cost projections (2013-14$/GJ) 2013-14**

Item	AGL	ActewAGL	Origin Energy Murray Valley	Origin Energy Wagga Wagga
Commodity Gas	$5.13	$5.13	$4.69	$5.58
Additional Deliverability	$0.74 - $1.10	$0.95 - $1.38	$0.95 - $1.38	$0.95 - $1.38
Market Charges	$0.08	N/A	$0.10	N/A
Sub Total	$5.95 - $6.31	$6.08 - $6.51	$5.74 - $6.17	$6.53 - $6.96
Transportation	$2.69 - $3.07	$2.53 - $2.95	$2.10	$2.34 – $2.72
Total	$8.85	$9.01	$8.09	$9.26

Table 10 **Wholesale gas cost projections (2013-14$/GJ) 2014-15**

Item	AGL	ActewAGL	Origin Energy Murray Valley	Origin Energy Wagga Wagga
Commodity Gas	$9.09	$9.09	$7.90	$10.28
Additional Deliverability	$0.74 - $1.10	$0.95 - $1.38	$0.95 - $1.38	$0.95 - $1.38
Market Charges	$0.08	N/A	$0.10	N/A
Sub Total	$9.91 - $10.27	$10.04 - $10.47	$8.95 - $9.38	$11.24 - $11.66
Transportation	$2.69 - $3.07	$2.53 - $2.95	$2.10	$2.34 – $2.72
Total	$12.81	$12.96	$11.30	$13.96

Table 11 **Wholesale gas cost projections (2013-14$/GJ) 2015-16**

Item	AGL	ActewAGL	Origin Energy Murray Valley	Origin Energy Wagga Wagga
Commodity Gas	$8.97	$8.97	$7.94	$9.99
Additional Deliverability	$0.74 - $1.10	$0.95 - $1.38	$0.95 - $1.38	$0.95 - $1.38
Market Charges	$0.08	N/A	$0.10	N/A
Sub Total	$9.79 - $10.15	$9.92 - $10.35	$8.99 - $9.42	$10.94 - $11.37
Transportation	$2.69 - $3.07	$2.53 - $2.95	$2.10	$2.34 – $2.72
Total	$12.68	$12.84	$11.34	$13.67

5.2 AGL – Sydney Region

Table 12 sets out our estimate of AGL's wholesale gas costs for the Sydney region for 2013-14.

Table 12 **AGL wholesale gas cost ($/GJ) 2013-14**

Item	AT estimate
Commodity Gas	5.13
Additional Deliverability	0.74 – 1.10
Average Haulage (MSP, EGP)	2.69 - 3.07
Other	
STTM Fees	0.08
Total (Excluding TUOS)	5.95 – 6.31
Total	8.64 - 9.38

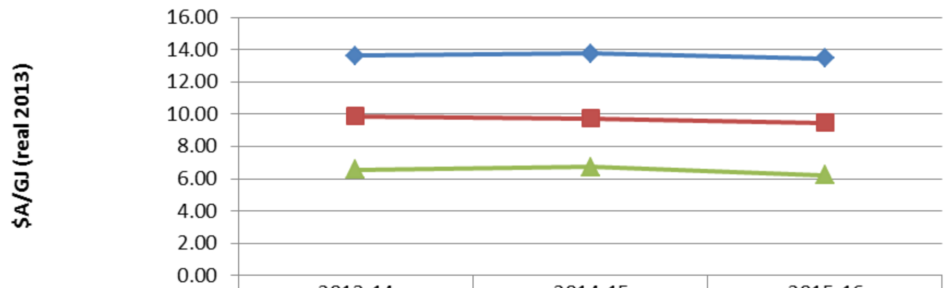
5.2.1 Commodity Cost of Gas

Our modelled commodity price under the low price scenario of $5.13 per GJ is calculated as the average of the Moomba price ($5.58 per GJ) and the Longford price ($4.69 per GJ). The modelled Longford price is lower than the modelled Moomba price (by $0.89 per GJ). However haulage from Longford is $0.70 to $0.80 per GJ higher than from Moomba. On this basis the difference in delivered cost between the two sources is therefore between $0.10 and $0.20 per GJ.

5.2.2 GasMark Nodal Prices

In the charts below we show GasMark projected prices for our three scenarios at the Sydney and Newcastle nodes. Please note that these prices do not include additional deliverability costs and the transmission charges included in these prices have respect to the load factor of the nodal demand in aggregate and not the small customer component of this load.

Chart 10 **GasMark Projected prices - Sydney (Wilton)**



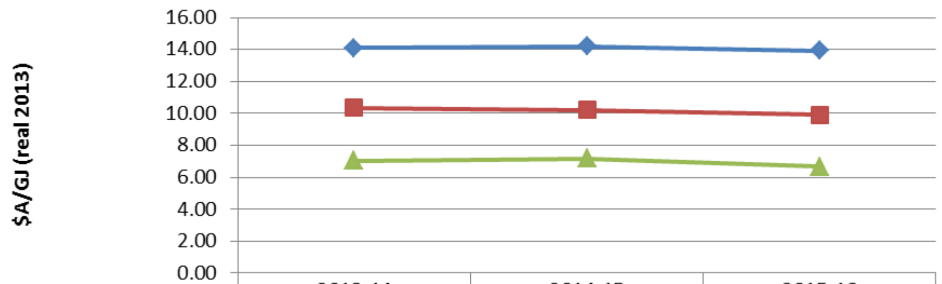
	2013-14	2014-15	2015-16
High price scenario	13.64	13.75	13.47
Medium price scenario	9.88	9.75	9.47
Low price scenario	6.58	6.73	6.21

High price scenario   Medium price scenario   Low price scenario

Note: Prices include transmission charges

Source: ACIL Tasman GMG Australia modelling

Chart 11 **GasMark Projected prices - Newcastle**



	2013-14	2014-15	2015-16
High price scenario	14.10	14.21	13.93
Medium price scenario	10.34	10.21	9.92
Low price scenario	7.04	7.19	6.67

High price scenario   Medium price scenario   Low price scenario

Note: Prices include transmission charges

Source: ACIL Tasman GMG modelling

Based on our low price scenario, a price of between $6.50 and $7 per GJ would reflect our best estimate of an efficient commodity price for gas delivered to Sydney and Newcastle in 2013-14.

5.2.3 Additional Deliverability

AEMO in its GSOO (AEMO, 2012) provides actual demand for New South Wales and the ACT in aggregate and by market segment (2011). AEMO cites aggregate annual demand of 138PJ made up of 42PJ mass market, 68PJ large industrial, and 28PJ power generation. AEMO also cites peak day demand of 682TJ giving a load factor for the whole market of 55%. Jemena's access arrangement (Jemena, 2010) cites 287TJ/day as the MDQ for large industrial customers (load factor 65%). We are not sure what the contribution of gas-fired power generation is to peak day demand, however we have analysed electricity generation dispatch data for New South Wales' gas-fired power generators over the period June to September 2012. The median daily gas usage was 85TJ and maximum 135TJ. This suggests a load factor for the mass market of between 37% and 44%. The 90th percentile daily gas usage by power generators of 111TJ corresponds to a load factor for the mass market of 40.5%. In reviewing AGL's proposed costs we adopt a customer load factor range of 35% to 40%. Using an MDQ cost of $216 per GJ MDQ / year, and allowing the supply load factor to be in the range 80% to 100%, we estimate the cost of additional deliverability to be in the range of $0.74 to $1.10 per GJ.

5.2.4 Transmission

Our estimate of transmission cost is in the range of $2.69 to $3.07 per GJ.

5.2.5 Other Costs

STTM Fees

AEMO charges an activity fee of $0.07572 per GJ withdrawn (AEMO Final Budget 2012-13).

5.2.6 Conclusions

We estimate a wholesale cost of gas (delivered to Sydney) for 2013-14 of between $8.64 and $9.38 per GJ.

5.3 ActewAGL

ActewAGL supplies gas to customers in the ACT and neighbouring regions of NSW including Young, Goulburn, and Yass and South East NSW (including Shoalhaven). Gas prices in the ACT are not subject to regulation.

We present our estimates of efficient prices for the supply of gas to the ACT border / Canberra in 2013-14 in Table 13.

Table 13 **ActewAGL wholesale gas cost 2013-14**

Item	AT estimate
Commodity Gas	5.13
Additional Deliverability	0.95 – 1.38
Average Haulage (MSP, EGP)	2.53 – 2.95
Total (Excluding TUOS)	6.08 – 6.51
Total	8.61 - 9.46

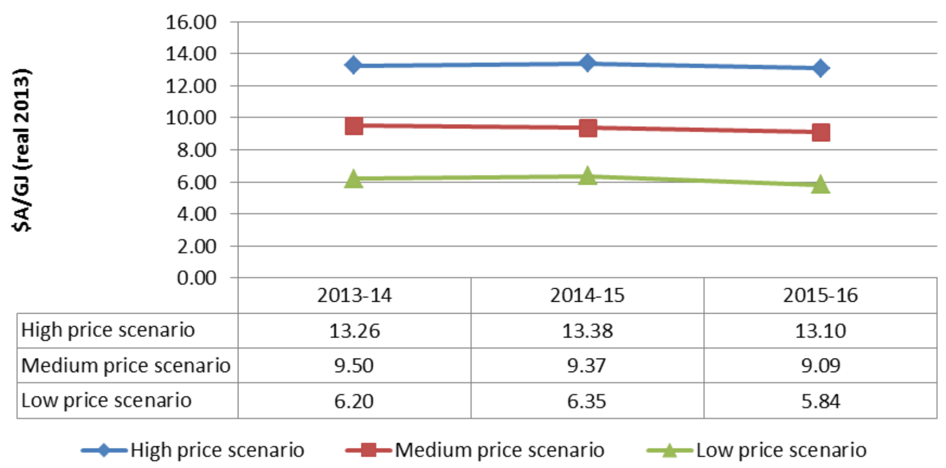
5.3.1 Commodity Cost of Gas

Gas for supply to Canberra can be sourced from Longford or Moomba and delivered by means of the EGP or MSP respectively. Our modelled estimates of marginal gas supply costs for 2013-14 are $4.69 per GJ at Longford and $5.58 per GJ at Moomba. The average of these prices is $5.13 per GJ.

5.3.2 GasMark Nodal Prices

GasMark projected prices for Canberra under our three scenarios are shown in Chart 12. Please note that these prices do not include additional deliverability costs and the transmission charges included in these prices have respect to the load factor of the nodal demand in aggregate and not the small customer component of this load.

Chart 12 **GasMark Projected prices - Canberra**



	2013-14	2014-15	2015-16
High price scenario	13.26	13.38	13.10
Medium price scenario	9.50	9.37	9.09
Low price scenario	6.20	6.35	5.84

Note: Prices include transmission charges

Source: ACIL Tasman GMG Australia modelling

Based on our low price scenario, a price of around $6.20 per GJ would reflect our best estimate of an efficient commodity price for gas delivered to markets in the Canberra region in 2013-14.

5.3.3 Additional Deliverability

In 2009, as part of information provided for its access arrangement (ActewAGL, June 2009, p.91), ActewAGL included projections of maximum daily and average daily consumption for its tariff (small) customers for the period 2010-2011 to 2014-2015. These projections suggest a load factor for this market of around 29% remaining constant over the period. The relatively low value of this load factor compared to other areas of NSW is likely to be the result of the use of gas for space heating in Canberra. The load factor of customers in the South-East regions could be higher than this owing to the relatively milder climate. We adopt a range of customer load factor of 30% to 35% for the purpose of estimating wholesale gas costs for ActewAGL's supply areas.

In estimating the cost of additional deliverability, we use an MDQ cost of $216 per GJ (the current value of the mid-point of the range of $160 to $240 per GJ). We estimate this cost as a range calculating it using supply load factors of 100% and 80%. On this basis, our calculated range for the cost of additional deliverability is $0.95 to $1.38 per GJ.

5.3.4 Transmission

Based on current reference tariffs, we estimate the cost of hauling gas to Canberra from Longford and Moomba to be between $2.53 per GJ and $2.95 per GJ depending on load factor.

5.3.5 Other Costs

We are not aware of other relevant costs.

5.3.6 Conclusions

We estimate a wholesale cost of gas (delivered to Canberra) for 2013-14 of between $8.61 and $9.46 per GJ.

5.4 Origin Energy – Murray Valley / Wodonga

Table 14 shows our cost estimates for supplying gas to Murray Valley / Wodonga in 2013-14.

Table 14 **Origin Energy Wodonga wholesale gas cost 2013-14**

Item	AT estimate
Commodity Gas	4.69
Additional Deliverability	0.95 – 1.38
TUOS Wodonga	2.10
Other	
AEMO Costs	0.1
Total (Exclusive TUOS)	5.74 – 6.17
Total	7.84 – 8.27

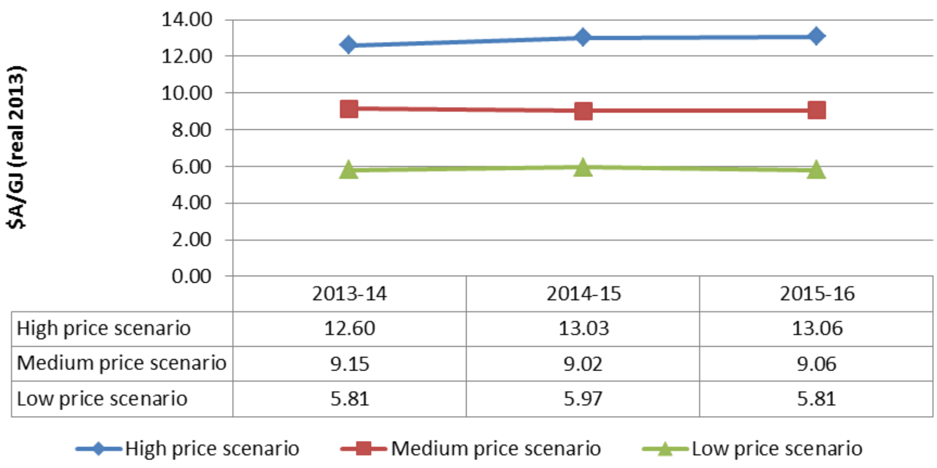
5.4.1 Commodity Cost of Gas

Gas supplied to the Murray Valley is assumed to be sourced from Longford. The commodity cost of gas according to our modelled low price scenario for 2013-14 is $4.69 per GJ.

5.4.2 GasMark Nodal Prices

The prices for the three scenarios projected by GasMark for the Wodonga node that represents Origin Energy's Victorian and New South Wales areas as a Standard Retailer are shown in Chart 13. Please note that the prices do not include additional deliverability costs and the transmission charges included in these prices have respect to the load factor of this nodal demand in aggregate and not the small customer component of this load.

Chart 13 **GasMark Projected prices - Wodonga**



	2013-14	2014-15	2015-16
High price scenario	12.60	13.03	13.06
Medium price scenario	9.15	9.02	9.06
Low price scenario	5.81	5.97	5.81

Note: Prices include transmission charges

Source: ACIL Tasman GMG Australia modelling

Under the low price scenario, a price of around $5.80 per GJ would reflect our best estimate of an efficient commodity price for gas delivered to the Wodonga region in 2013-14.

5.4.3 Additional Deliverability

We would expect small customer usage characteristics in the Murray Valley to be similar to Wagga Wagga, which is geographically close and for which we have adopted a customer load factor range of 30% to 35% based on available data. Adopting this range, and assessing the cost using supply load factors of 80% and 100%, the cost of additional deliverability is estimated to be between $0.95 per GJ and $1.38 per GJ.

5.4.4 Transmission

TUOS for Murray Valley and Wodonga are based on APA Gasnet's proposed 2012 tariffs for Victoria's Principal Transmission System (PTS). These tariffs consist of a throughput charge ($ per GJ). APA Gasnet also applies a peak day injection charge (APA Gasnet) which is currently $2.4866 per GJ or $2.6125 per GJ in 2013-2014$. This is applied to injections on the ten highest injection days at the Longford injection point. AEMO publishes daily injections at Longford and other injections points and also total system withdrawals. APA Group publishes the ten peak injection days (APA Gasnet). For 2012, the ratio of the average withdrawal on the ten peak injection days to the maximum daily withdrawal was 90%. This suggests that the peak day injection charge will be overestimated if it is calculated by simply assuming that the peak day withdrawal occurs on each of the ten peak injection days. We base our estimate on an average daily injection equal to 90% of the peak day demand.

5.4.5 Other Costs

Market charges of $0.1 per GJ arise in relation to AEMO's Victorian wholesale gas fees (p.17 AEMO Final Budget 2012-13).

5.4.6 Conclusions

We estimate a wholesale cost of gas (delivered to Wodonga) for 2013-14 of between $7.84 and $8.27 per GJ.

5.5 Origin Energy – South Western Regions

Table 15 sets out our estimate of the wholesale gas cost for supplying Wagga Wagga in 2013-14.

Table 15 **Origin Energy Wagga Wagga wholesale gas cost 2013-14**

ITEM	AT estimate
Commodity Gas	5.58
Additional Deliverability	0.95 – 1.38
TUOS Wagga Wagga	2.34 - 2.72
Total (Exclusive of TUOS)	6.53 - 6.96
Total	8.87 – 9.68

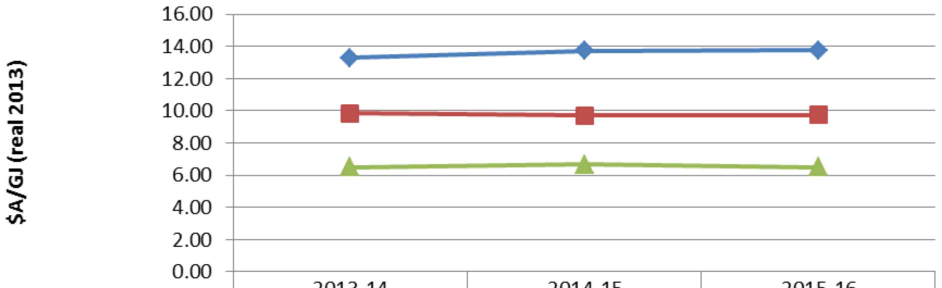
5.5.1 Commodity Cost of Gas

Gas supplied to the South Western regions is assumed to be sourced from Moomba at which our projected price in 2013-14 according to the low price scenario is $5.58 per GJ.

5.5.2 GasMark Nodal Prices

GasMark projected prices for nodes relevant to Origin Energy's (Wagga Wagga) supply areas are provided in Charts 14 to 16. Please note that the prices do not include additional deliverability costs and the transmission charges included in these prices have respect to the load factor of the nodal demand in aggregate and not the small customer component of this load.

Chart 14 **GasMark Projected prices – Wagga Wagga**



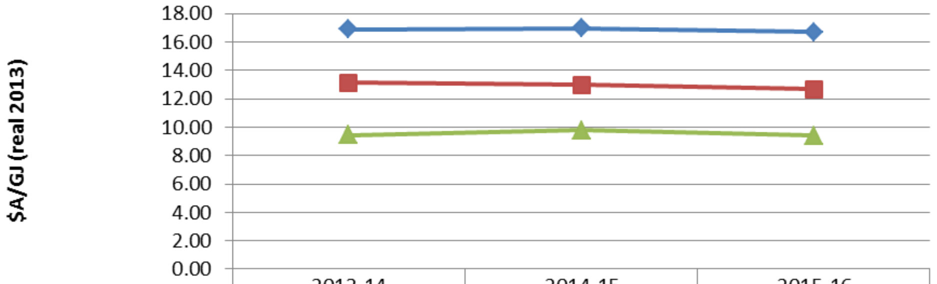
	2013-14	2014-15	2015-16
High price scenario	13.31	13.73	13.76
Medium price scenario	9.85	9.72	9.76
Low price scenario	6.49	6.67	6.50

High price scenario   Medium price scenario   Low price scenario

Note: Prices include transmission charges

Source: ACIL Tasman GMG Australia modelling

Chart 15 **GasMark Projected prices - Dubbo**



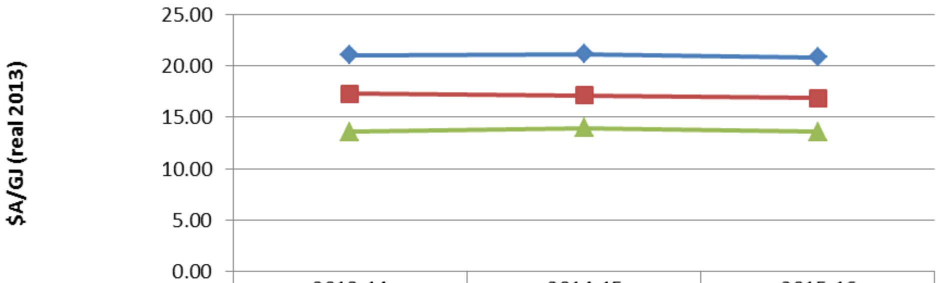
	2013-14	2014-15	2015-16
High price scenario	16.88	16.98	16.68
Medium price scenario	13.12	12.97	12.67
Low price scenario	9.43	9.79	9.42

High price scenario   Medium price scenario   Low price scenario

Note: Prices include transmission charges

Source: *ACIL Tasman GMG Australia modelling*

Chart 16 **GasMark Projected prices - Tamworth**



	2013-14	2014-15	2015-16
High price scenario	21.04	21.14	20.84
Medium price scenario	17.28	17.13	16.83
Low price scenario	13.59	13.95	13.58

Note: Prices include transmission charges

Source: ACIL Tasman GMG Australia modelling

Under our low price scenario, a price of between $6.50 per GJ and $13.60 per GJ would reflect our best estimate of an efficient commodity price for gas delivered to these regions in 2013-14.

5.5.3 Additional Deliverability

In its access arrangement information for the Wagga Wagga Natural Gas Distribution Network, 1 July 2010, Country Energy provided forecasts of total volume load (small customer load) and total contract load (large customer load). Also provided are forecasts of contract MDQ and maximum demand (for all customers). The forecasts suggest load factors for the contract customers and the total market of 45% and 40% respectively. By difference, the small customer load factor can be estimated to be 36%. As Country Energy's peak day was likely to have been based on a 1 in 2 criterion rather than a 1 in 25 criterion, we adopt a range of customer load factor of 30% to 35% upon which to base our estimate of the cost of additional deliverability. Accordingly we obtain a cost in the range of $0.95 per GJ to $1.38 per GJ.

5.5.4 Transmission

Our estimated range for delivery of gas from Moomba to Wagga Wagga is $2.34 to $2.72 per GJ depending on load factor. We estimate the tariff for delivery to Marsden (the off-take point for the Central West Pipeline to Dubbo) to be around $2.12 per GJ. The reference tariff for delivery from Marsden to Dubbo is $3.18 per GJ giving around $5.30 per GJ for the delivery of gas from Moomba to Dubbo. The reference tariff for the Central Ranges Pipelines which carries gas from Dubbo to Tamworth is $8.25 per GJ giving around $13.60 per GJ delivered from Moomba to Dubbo.

5.5.5 Other Costs

We do not consider there to be any relevant additional costs.

5.5.6 Conclusions

We estimate a wholesale cost of gas (delivered to Wagga Wagga) for 2013-14 of between $8.87 and $9.68 per GJ.

Appendix A Glossary of terms

Term	Description
ACQ	Annual Contract Quantity
AEMO	Australian Energy Market Operator
AQ	Annual Quantity
CLF	Customer Load Factor
CRP	Central Ranges Pipeline
CSG	Coal Seam Gas
CWP	Central Western Pipeline
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
ESCOSA	Essential Services Commission of South Australia
GSA	Gas Supply Agreements
GSOO	Gas Statement of Opportunities
JCC	Japan Customs-Cleared Crude
JGN	Jemena Gas Networks
LNG	Liquid Natural Gas
LRMC	Long Run Marginal Cost
MHQ	Maximum Hourly Quantity
MDQ	Maximum Daily Quantity
MMA	McLennan Magasanik Associates
MSP	Moomba to Sydney Pipeline
NEM	National Electricity Market
PTS	Principal Transmission System (Victoria)
QCA	Queensland Competition Authority
SLF	Supply Load Factor
STTM	Short Term Trading Market
SUG	System Use Gas
SWQP	South West Queensland Pipeline
TUOS	Transmission Use of System
UAFG	Unaccounted for Gas
UGS	Underground Gas Storage
VTPA	Voluntary Transitional Pricing Arrangement
WUGS	Western Underground Gas Storage

ACIL Tasman
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Appendix B The *GasMark* model

GasMark Global (GMG) is a generic gas modelling platform, developed by ACIL Tasman, which has the flexibility to represent the unique characteristics of gas markets across the globe. Its potential applications cover a broad scope— from global LNG trade, through to intra-country and regional market analysis. The Australian version of the model is known as *GMG Australia*.

B.1 Data inputs

The user can establish the level of detail by defining a set of supply regions, customers, demand regions, pipelines and LNG facilities. These sets of basic entities in the model can be very detailed or aggregated as best suits the objectives of the user. A 'pipeline' could represent an actual pipeline or a pipeline corridor between a supply and a demand region. A supplier could be a whole gas production basin aggregating the output of many individual fields, or could be a specific producer in a smaller region. Similarly a demand point could be a single industrial user or an aggregation of small consumers such as the residential and commercial users typically serviced by energy utility companies.

The inputs to *GMG Australia* can be categorised as follows:

- **Existing and potential new sources of gas supply**: these are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices.
- **Existing and potential new gas demand**: demand may relate to a specific load such as a power station, or fertiliser plant. Alternatively it may relate to a group or aggregation of customers, such as the residential or commercial utility load in a particular region or location. Loads are defined in terms of their location, annual gas demand, price tolerance and price elasticity of demand (that is, the amount by which demand will increase or decrease depending on the price at which gas can be delivered), and load factor (defined as the ratio between average and maximum daily quantity requirements).
- **Existing, new and expanded transmission pipeline capacity**: pipelines are represented in terms of their geographic location, physical capacity, system average load factor (which is relevant to determination of the effective annual throughput capability given assumptions regarding short-term [daily] capacity limits) and tariffs.
- **Existing and potential new LNG facilities**: LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and tariffs for conversion.

B.2 Solving the model: the market settlement process

At its core, GMG is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements.

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory[4], consists of three terms:

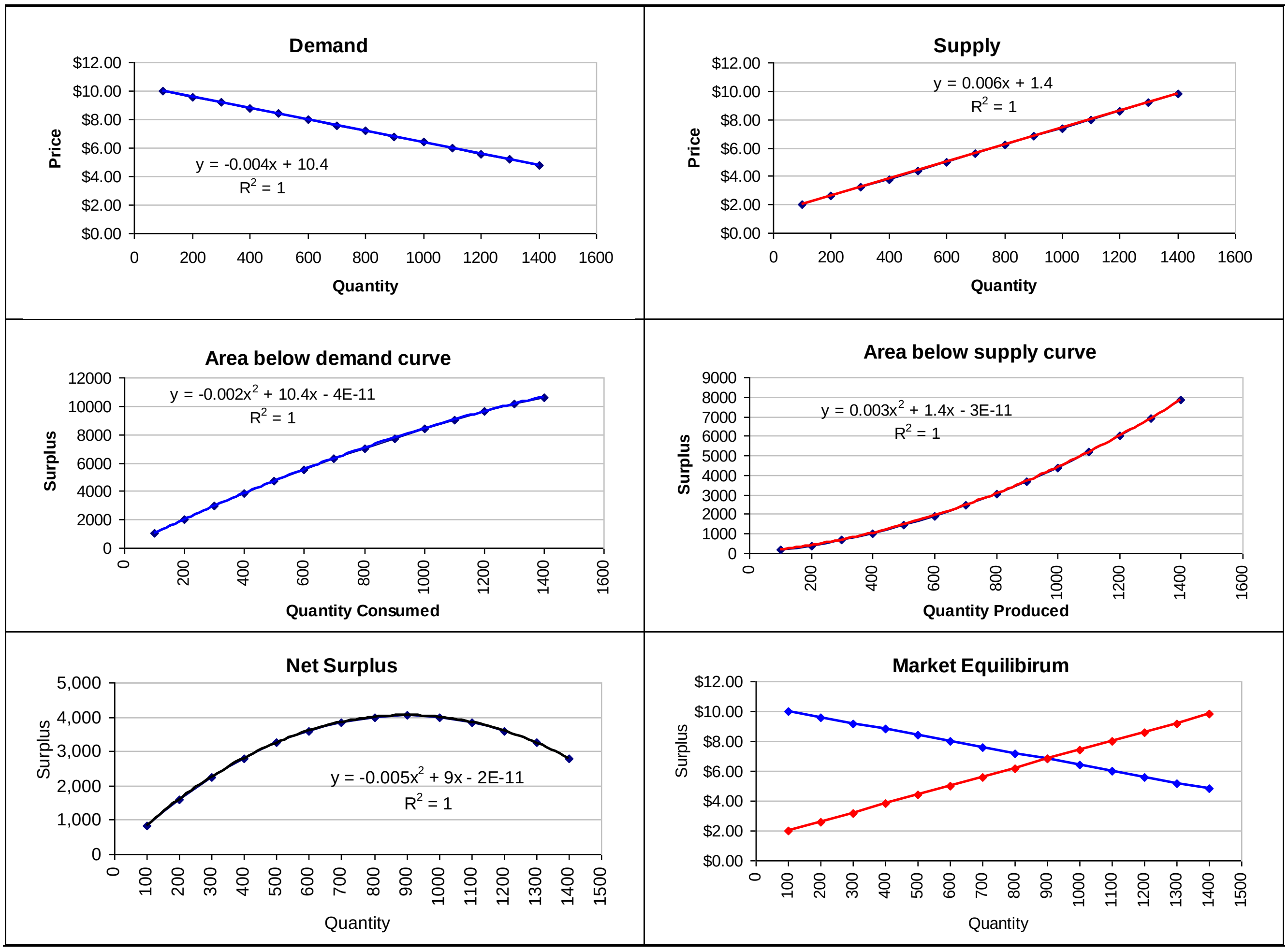
- the integral of the demand price function over demand; minus
- the integral of the supply price function over supply; minus
- the sum of the transportation, conversion and storage costs.

The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

Figure B1 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of Figure B1 show simple linear demand and supply functions for a particular market. The figures in the middle of Figure B1 show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum clearly evident at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

[4] The theoretical framework for the market solution used in GMG is attributed to Nobel Prize winning economist Paul Samuelson.

Figure B1 **Simplified example of market equilibrium and settlement process**



Data source: ACIL Tasman

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world. Examples include:

- Gas Pipeline Competition Model (GPCM®) developed by RBAC Inc energy industry forecasting systems in the USA; and
- Market Builder from Altos Partners, another US-based energy market analysis company.

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