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# Wholesale Gas Price for AGL's VPA Proposal for 2014–16 (public version)

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PREPARED FOR

AGL

PREPARED BY

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We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

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## Executive Summary

AGL Energy has asked us to estimate the wholesale price of natural gas at which new supplies would be available at Moomba and at Longford which a retailer entering the NSW market could use to supply small customers.<sup>1</sup> We understand that our estimate, together with other information, will be used by AGL Energy in proposing the Retail Component for the July 2014 to June 2016 period, under the Voluntary Pricing Arrangements (VPA) with IPART.

We understand that AGL Energy's proposal to IPART will cover the July 2014 to June 2016 period, and we have estimated the relevant wholesale price for that period.

In preparing this report we have relied on a report prepared by MDQ Consulting for AGL Energy.<sup>2</sup>

### Eastern gas market dynamics

The stand-out feature of current market conditions is the extraordinary growth in demand for new gas production forecast to begin in mid-2014, production which is being required by LNG export projects in Queensland. In 2012, total demand in Eastern and South-eastern Australia was 687 PJ. Demand is forecast to rise to 745 PJ in 2014 and to over 1,700 PJ in 2016. LNG exports were zero in 2013 and by 2015 are forecast to be approximately equal to total demand in 2012.<sup>3</sup>

The ramp-up of the LNG export projects is bringing new pressures to bear on Eastern Australian gas markets which have important implications for market prices in Australia's eastern seaboard. The market in the north is currently tight: the Queensland LNG exporters are dedicating their own reserves to their export projects rather than to customers in the domestic market, and the exporters have been active in buying what third party gas is available. Recent contracts in the north have reportedly been struck at higher prices than previously experienced in the eastern

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<sup>1</sup> "Small customers" means customers that consume less than 1 terajoule (TJ) per year. These customers are eligible for supply at a capped regulated price, and about one third of such customers are supplied in this way.

<sup>2</sup> *NSW Wholesale Gas Market Report*, MDQ Consulting, February 2014.

<sup>3</sup> All figures are taken from the 2013 GSOO. See Workpapers (2013 GSOO – Forecasts).

states. In the south, there are transportation constraints on the Eastern Gas Pipeline (EGP) and the Victoria–NSW Interconnect which, in the short term, prevent new or additional supplies from accessing the NSW market from Longford.

Relieving transportation constraints and/or bringing on new production requires investment which takes time to come on stream and is likely to require backing with long-term contracts. Projects requiring investment and/or long-term contracts are therefore not relevant to the remainder of the VPA period, because the new production and/or transportation capacity takes time to build, so the gas would not be available until the end of the VPA period. As a result, the only short-term option for new supplies that could be made available to a retailer for onward supply to small customers in NSW is gas at Moomba which would have to be “bid away” from the LNG exporters. That gas would therefore be priced at an LNG netback (the price at which an exporter would be indifferent between re-selling gas in the domestic market, or exporting it as LNG). It has been reported that recent contracts have been signed at prices significantly higher than historical levels, closer to LNG netback levels.

The MDQ Consulting report describes how GLNG is short of gas reserves and deliverability relative to its contractual commitments, and that the LNG exporters are short supply in aggregate. There are also substantial spot LNG sales opportunities, particularly in the near term over the “ramp” period in the export contracts. If these spot LNG sales opportunities are taken into account, the gap between the supplies of gas in the exporters’ current portfolios and their potential needs is even greater. The MDQ Consulting report indicates that the shortage of gas production relative to demand in the north is likely to persist at least to 2020.

### **Evidence relevant for estimating the wholesale price**

In estimating prices in this report, we rely primarily on an analysis of LNG netbacks and reports of prices in recent GSAs. The evidence on prices in recent GSAs supports our assessment that the wholesale price at Moomba is at LNG netback levels. We have reviewed estimates from other analysts that are based on estimates of production costs, either directly or in conjunction with an optimization model. In our view, production costs are not relevant to estimating prices over the VPA period because the market is tight. With new supplies scarce relative to the quantity of gas demanded by the LNG export projects, and with competition between buyers for scarce supplies, estimates of production cost are not a relevant benchmark in determining price. In a tight market, all producers have the economic incentive and the ability to receive prices above costs. Production costs might be one relevant benchmark over the longer term, with market

participants having sufficient time to respond to scarcity and high prices by bringing on new sources of supply. However, between now and June 2016 there is insufficient time for investment in new production to come on stream.<sup>4</sup> We also note that estimates of production costs are highly uncertain.<sup>5</sup>

## **Estimate of the wholesale price: 1 July 2014 to 30 June 2016**

### *Wholesale price at Moomba*

For the VPA period (July 2014 to June 2016), our view is that new supplies at Moomba which a NSW retailer could use to supply small customers will be at an LNG netback price. On the basis of the information provided in the MDQ Consulting report, the market will remain short due to the LNG exporters needing to purchase additional gas to meet their contractual commitments. Since the exporters' LNG sales contracts ramp up over a period of time, it is possible that during the early part of the ramping up phase the exporters will have significant spot LNG sales opportunities. Such spot sales opportunities increase the exporters' willingness to pay high prices for significant volumes of gas.

A netback price is appropriate because a retailer seeking new supplies now is in a market where it has to compete with LNG exporters for available supplies, and in which recent contracts have been at relatively high prices. A retailer wishing to supply small customers in NSW using new supplies at Moomba would need to "bid away" gas from the competing alternative of export as LNG. We have estimated an LNG netback price of \$9.73/GJ at Moomba. This corresponds to a price of \$10.83/GJ at Wallumbilla or \$11.38/GJ at Gladstone, and US\$13.50/GJ ex plant as LNG. This price is in line with estimates of netback prices we have seen from other analysts in recent reports.<sup>6</sup>

The netback price of \$9.73/GJ is the price that an LNG exporter would be able to pay while covering all transport and liquefaction costs and earning a normal return of and on its capital investment in the export project. However, since the LNG exporters are in aggregate short of gas

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<sup>4</sup> *NSW Wholesale Gas Market Report*, MDQ Consulting, February 2014, chapter 8.

<sup>5</sup> See discussion below in chapter VII.

<sup>6</sup> For example, both IES and ACIL have similar netback prices. See below, chapter III.

(as documented in the MDQ Consulting report), it is possible that they would be prepared to pay a price above \$9.73/GJ. Even at higher prices, the incremental profit to be earned on additional export volumes is positive because much of the cost of the liquefaction plants is fixed and has already been sunk. We therefore consider \$9.73/GJ to be a conservative estimate of the price at which new supplies would be available to a retailer at Moomba over the VPA period.

We note that reports of recent GSA prices are close to the netback price we have estimated. For example, IES reports<sup>7</sup> a price of “closer to \$8-9/GJ” for Origin Energy’s purchase of Cooper basin gas from Beach Energy (announced April 10 2013), and industrial buyers are reported to have paid \$9.00/GJ or more for long-term supplies.<sup>8</sup>

### *Wholesale price at Longford*

The MDQ Consulting report suggests that prices at Longford relevant to the VPA period are in the range of \$6.25/GJ to \$6.50/GJ. We have also seen reports of prices around \$7.00/GJ.<sup>9</sup> On this basis, we assume a price of \$6.50/GJ at Longford during the VPA period. Pipeline transportation constraints currently prevent Longford producers from accessing higher prices that might be available in NSW. The EGP is full, and announced plans to expand the Interconnect will not see any new capacity until winter 2015. Furthermore, expanding either route to Sydney would require a transportation commitment significantly longer than two years, and the announced expansions to the Interconnect are backed by long-term contracts, so the new capacity will not be available in the VPA period. We therefore do not consider that a shorter-term Longford price is relevant to the VPA proposal because a NSW retailer would have to make a commitment beyond the VPA period in order to obtain the necessary transportation capacity, and because the new capacity would not be available until part way through the VPA period at the earliest.

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<sup>7</sup> *Study on the Australian Domestic Gas Market*, IES, November 28 2013, p. 69.

<sup>8</sup> See discussion in the MDQ Consulting report of the contracts signed by MMG and Incitec Pivot.

<sup>9</sup> IES reports a price of \$7.00/GJ for Esso/BHP’s GSA with Lumo for supplies starting in 2015 (*Op. Cit.*, p. 69).



# I. Introduction and Approach

## A. CONTEXT

AGL Energy has asked us to estimate the wholesale price of natural gas at which new supplies would be available at Moomba and at Longford which a retailer entering the NSW market could use to supply small customers.<sup>10</sup> We understand that our estimate, together with other information, will be used by AGL Energy in proposing the Retail Component for the July 2014 to June 2016 period, under the Voluntary Pricing Arrangements (VPA) with IPART.

We understand that AGL Energy's proposal to IPART will cover the July 2014 to June 2016 period. This follows from IPART's decision in its most recent three-year review of regulated retail prices to wait to set price caps for these last two years of the review given the significant uncertainties prevailing in the wholesale market, and the absence of transparent price signals from a forward market.<sup>11</sup> We have therefore estimated a price for the July 2014 to June 2016 period.

The price we have estimated is the price at which we think new supplies of gas might be made available to a retailer wishing to enter the NSW market to supply small customers for the VPA period. This is the approach IPART took in its last review. In the course of that review, IPART requested its consultant ACIL Tasman to "forecast a range of benchmark wholesale costs faced by a prudent and efficient retailer over the regulatory period". ACIL's estimates "reflect the increasing prices that may be available to retailers under new long term contracts in supplying gas to customers".<sup>12</sup>

The approach we have taken is forward-looking, in the sense that we do not have regard to the gas supply costs of the incumbent retailers that are embodied in long-term contracts entered into

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<sup>10</sup> "Small customers" means customers that consume less than 1 terajoule (TJ) per year. These customers are eligible for supply at a capped regulated price, and about one third of such customers are supplied in this way.

<sup>11</sup> IPART, *Review of regulated retail prices and charges for gas: From 1 July 2013 to 30 June 2016, Gas – Final Report*, June 2013, p.8.

<sup>12</sup> *Ibid.*, p.35.

historically (sometimes referred to as “legacy contracts”). Legacy contract costs are not relevant to the principles we have described above because they do not reflect the efficient costs that could be achieved by a new entrant (or incremental purchase costs by an existing incumbent) under current and future market conditions.

The forward-looking approach is consistent with the approach IPART took in its last review and also with the principles enunciated by the AEMC in its recent report on best regulatory practice with respect to setting price caps for retail electricity service. In respect of the energy purchase cost component of the retail price, “setting this cost component involves estimating future energy purchase costs for an efficient retailer. The Commission considers that the method used to estimate energy purchase costs should have the following efficiency characteristics: be forward-looking in approach; reflect, and be responsive to, the current supply/demand balance; and include a time dimension”.<sup>13</sup>

We agree with these principles and incorporate them in this report.

It may be that a retailer looking for incremental volumes to supply small customers in the NSW market would prefer a supply contract with a term longer than two years. Entering the retail market is a long-term investment, for example because of the importance of branding, so the retailer might prefer an upstream contract with a longer term. In our analysis we have not found any reasons to expect the term of a contract to influence price, and in our experience it is common for long-term contracts to contain mechanisms such as indexation or price reviews designed to keep the prices under long-term contracts in line with market prices.

## **B. EAST AUSTRALIAN GAS MARKET**

AGL Energy has commissioned a report from MDQ Consulting on the prevailing wholesale gas market conditions in NSW. The MDQ Consulting report<sup>14</sup> describes the East Australia gas market from a commercial perspective. It summarises the status of the three Queensland LNG export projects, the pricing pressures currently being experienced in the market, and provides insight on recent GSA prices.

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<sup>13</sup> AEMC, *Advice on best practice retail price methodology: Final Report*, 27 September 2013, p. iii.

<sup>14</sup> *NSW Wholesale Gas Market Report*, MDQ Consulting, February 2014.

The gas market in East Australia is undergoing dramatic change. Multi-billion dollar projects are under construction in Queensland which will result in LNG exports from East Australia for the first time. First LNG is expected in mid-2014, at the start of the VPA period, and by the end of the VPA period gas demand for LNG export in Queensland is forecast to be more than double the combined demand for all other gas use in Eastern and South-eastern Australia.<sup>15</sup> Not only is this extraordinary increase in overall gas demand taking place over the VPA period, but the LNG exporters are short of gas to supply their liquefaction plants. The MDQ Consulting report details that the GLNG project in particular is short of gas, and has been active in the market purchasing third-party gas from the Cooper basin. On an aggregate basis, the three projects under construction are short supply.<sup>16</sup>

Since in aggregate the LNG exporters are short of gas relative to their contractual export commitments, there has been and will continue to be demand for large volumes of third party gas. The GLNG project has been the largest purchaser of gas in the Queensland market over the last three years,<sup>17</sup> yet even with these purchases the project is short of gas. These facts have important consequences for the domestic Queensland and NSW markets. In Queensland, the LNG exporters used to be suppliers of significant volumes to the market. This is no longer the case. Instead, the LNG exporters are themselves buying gas from the Cooper basin, which would otherwise have been available to retailers in NSW. The SWQP pipeline from Moomba to Wallumbilla currently flows in an East-West direction, but is likely to reverse flow by mid-2014 as Origin's Cooper basin gas begins to be supplied to GLNG.<sup>18</sup> The MDQ Consulting report describes the consequences for the NSW market as a transition from a period in which new supplies are available both at Moomba and at Longford for onward transport to NSW, to one in which, at Moomba, domestic demand is competing with LNG exporters for incremental volumes.

A retailer in NSW needing new supplies of gas for sale to small customers would therefore have two choices: purchase gas from producers at Longford, or buy gas at Moomba in competition

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<sup>15</sup> Based on data from the 2013 GSOO (see Workpapers, 2013 GSOO - Forecasts). 2016 LNG export is forecast to be 1,137 PJ and 2016 domestic demand is forecast to be 570 PJ (covering Queensland, VIC, NSW, ACT, SA and TAS).

<sup>16</sup> MDQ Consulting report, chapter 5.

<sup>17</sup> MDQ Consulting report, p. 2.

<sup>18</sup> MDQ Consulting report, p. 24.

with the LNG exporters. Because purchases at Moomba would be competing with the LNG exporters, the NSW retailer would effectively have to “bid away” the gas from the exporter, and would therefore have to pay an LNG netback price. Recent GSAs at Longford are at lower prices than GSAs at Moomba.<sup>19</sup> This reflects the lack of transportation capacity between Longford and NSW: both the EGP and the NSW–Victoria Interconnect are fully subscribed (and fully utilised in the key winter peak demand periods). The transport constraints mean that sellers at Longford are currently unable to seek higher prices. Therefore, until the pipeline transportation constraints can be relieved, new entrant NSW retailers will have to rely on purchases at Moomba.

### C. EVIDENCE WE RELY ON

In preparing this report we have reviewed publicly-available reports<sup>20</sup> in which the Eastern Australia gas markets are analysed. These reports contain four kinds of evidence relevant to an estimate of the wholesale price:

- recent market prices (i.e., prices at which new GSAs have been signed);
- estimates of the value (opportunity cost) of gas exported as LNG, based on the fundamentals of the export market;
- the cost of new production (long run marginal cost); and
- the results of optimization models, which in turn depend on other inputs including production cost estimates.

All four kinds of evidence are relevant only to the extent they help in estimating the price at which new supplies, which a NSW retailer could use to supply small customers, might be made available. Evidence must be relevant given the market circumstances prevailing over the VPA period.

The prices at which new supply is being contracted should be given considerable weight, because this is direct evidence as to the alternative sale opportunities that a NSW retailer supplying small customers would be competing with. However, the Australian gas market is not transparent—

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<sup>19</sup> See Table 2 below.

<sup>20</sup> For example: *Study on the Australian Domestic Gas Market*, IES, November 28 2013 and *Cost of Gas for the 2013-2016 Regulatory Period*, ACIL Tasman report for IPART, 13 June 2013.

prices are in general not published—and transactions are infrequent, so there may be large changes in reported price between one transaction and the next, and the prices may be influenced by the non-price terms of the transactions.

Estimates of the value of gas exported as LNG are relevant because, with the construction of liquefaction plant in Queensland, domestic demand may compete with exports.

Estimates of production cost could be relevant to a long-term price forecast because new supplies will not usually be made available at a price below production cost (although in our view it is difficult to obtain reliable estimates of production cost). However, production cost will in any case not influence prices over the July 2014 to June 2016 period because the market is tight: there is excess demand for gas from the LNG export projects, and it takes time to develop new supply. In a tight market, all producers have the economic incentive and the ability to price above costs, so costs cease to be a relevant benchmark for estimating price.

We have reviewed some reports<sup>21</sup> which use optimization models to estimate price. Optimization models can produce somewhat more sophisticated price forecasts than simple basin-by-basin production cost estimates because they allow for competition between basins, given pipeline transport constraints. Nevertheless, optimization models frequently rely on assumptions or constraints which tend to drive the results to a significant degree, and they have the disadvantage of being “black box”: the relationship between input data and assumptions and the model results can be obscure. The MDQ Consulting report explains that the market is tight. There is excess demand from the LNG exporters, and these market circumstances are likely to continue out to 2020. Any optimization model needs to be structured to reflect the prevailing market circumstances. The optimization modelling we have seen does not always do this.

In line with other analysts,<sup>22</sup> we do not consider prices in the spot markets (for example, the Sydney STTM) to provide a benchmark price relevant to estimating the price at which gas might

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<sup>21</sup> ACIL and IES reports already cited, and *Input assumptions for modelling wholesale electricity costs*, Frontier, June 2013.

<sup>22</sup> For example, see the Lowe report for AEMC (*Gas Market Scoping Study*, K Lowe Consulting, July 2013) and the ACIL report. The ACIL report states (p. 26): “We do not consider that spot prices are a relevant benchmark for the supply costs of gas retailers”.

be available to a retailer entering the NSW market to supply small customers. The STTM trades only daily imbalance volumes. It could not be relied upon as a reliable source of supply.

#### **D. LAYOUT OF THE REPORT**

Chapter II contains our estimates of the wholesale price for the period 1 July 2014 to 30 June 2016, on an ex-plant basis at both Moomba and Longford. Chapter III reviews estimates in reports from other analysts. In Chapter IV we explain our approach to calculating the additional cost associated with supplying the seasonal demand profile of mass market customers in NSW, and chapter V contains our conclusions on prices. The detailed assumptions and calculations on which these assessments are based are in background chapters on LNG netbacks (chapter VI), production costs (chapter VII), and pipeline flows (chapter VIII).

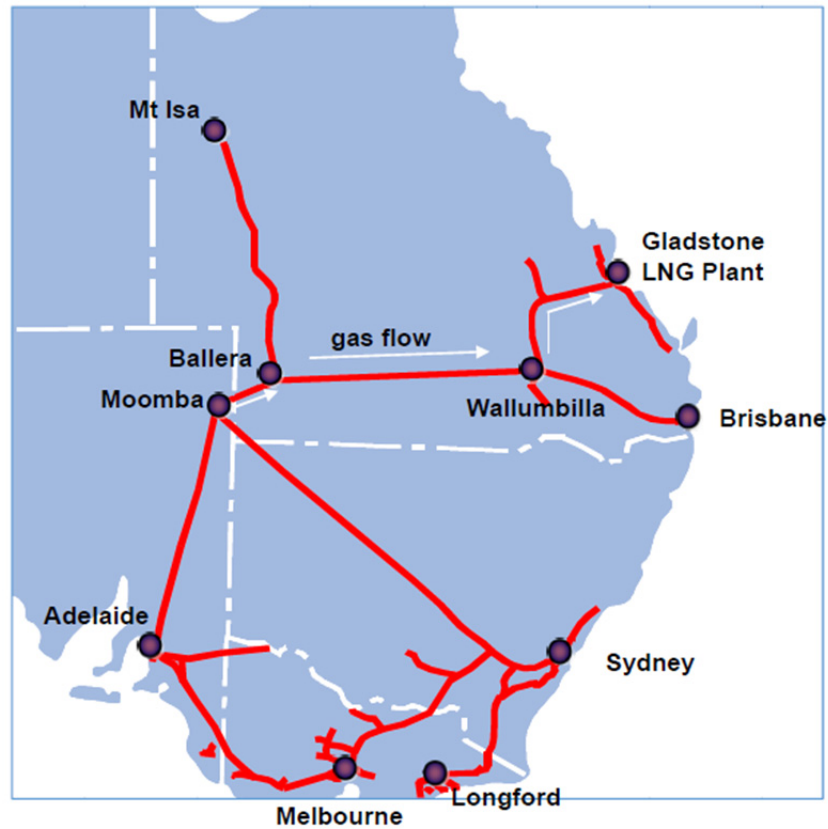
## II. Estimated Wholesale Price: 1 July 2014 to 30 June 2016

### A. LNG NETBACKS

For the reasons given above, and as explained in the MDQ Consulting report, a retailer seeking incremental gas supply at Moomba in order to enter the NSW market to supply small customers has to compete with other buyers prepared to pay high prices. Across the three LNG export projects currently under construction, in aggregate the exporters are short of gas relative to their contractual commitments. The shortage of gas is even greater if spot LNG sales opportunities, particularly in the ramp phase of the export projects, are taken into account. Therefore a retailer seeking new supplies for NSW would have to compete for the gas with the exporters, and one way to think about this is that the retailer would have to “bid away” the gas from the exporter, paying an LNG netback price as a result.

LNG netbacks represent the price that an exporter is willing to pay to obtain feedstock. The netback is the expected export price for the gas as LNG (which is related to the price of oil), minus pipeline transportation, liquefaction and other costs. Netback prices are different at different locations, because of pipeline transportation costs. Figure 1 shows the key locations at which we have estimated netback prices, and Figure 2 illustrates how netback prices at various locations are derived from an LNG price at Gladstone and estimates of liquefaction and transportation costs.

Figure 1



**Notes:**

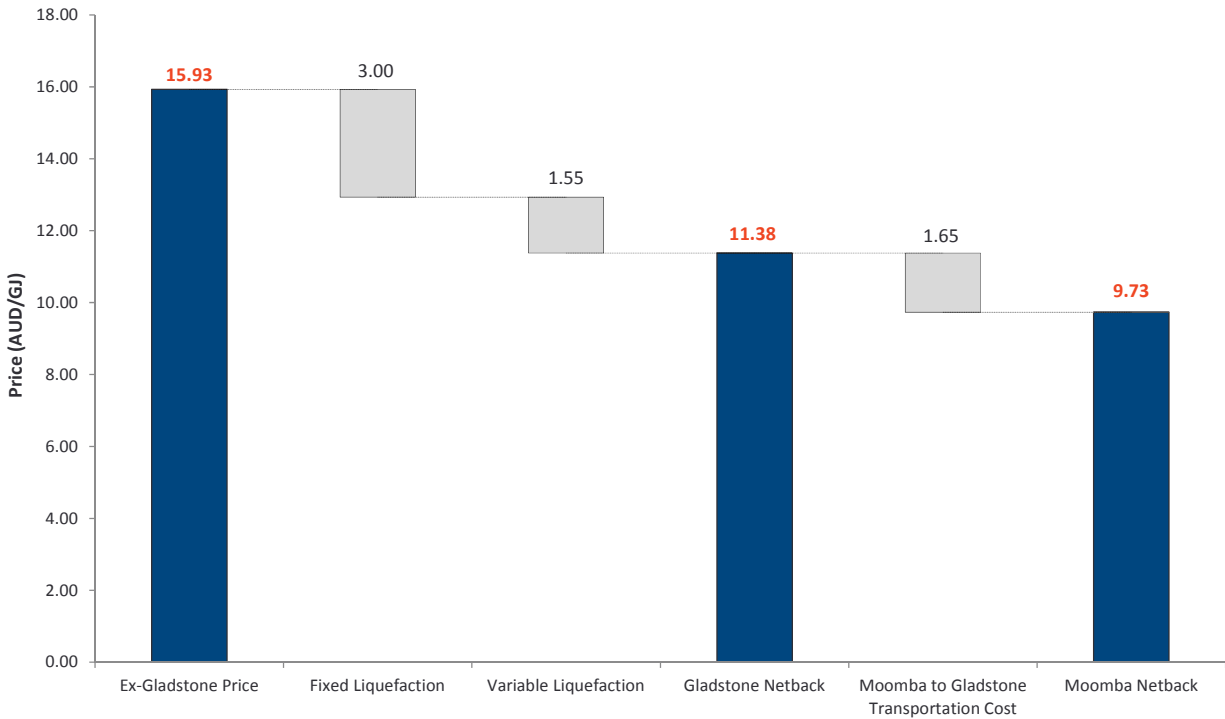
- 1) Wallumbilla net back price = Gladstone LNG sales price – Gladstone LNG plant costs – Wallumbilla to Gladstone pipeline costs.
- 2) Moomba net back price = Wallumbilla net back price – Moomba to Wallumbilla pipeline costs.

Note that in Figure 2 the netback prices decrease from left to right: gas at Moomba is cheaper than gas at Gladstone, because gas at Moomba has to be transported to Gladstone and liquefied before it can be exported, whereas gas at Gladstone just has to be liquefied. Figure 2 assumes that there are no pipeline capacity constraints.



Figure 2

Build up of Australian LNG Netback Prices & Ex-Gladstone LNG Price (AUD/GJ)



Sources & Notes: Brattle Analysis. Netback prices are highlighted in bold red. See Workpapers, Data for Figure 2 Tab.

We have estimated LNG netbacks on the basis of oil at US\$100/bbl,<sup>23</sup> an exchange rate of 0.85 USD/AUD, a “slope” of 13.5%, and liquefaction costs of \$4.55/bbl. These assumptions are explained in detail in chapter VI, and in chapter III we compare our netback prices with those of other analysts. Table 1 shows LNG netback prices at various locations. The difference between the Gladstone netback and Wallumbilla and Moomba netbacks reflects pipeline transportation tariffs.

<sup>23</sup> Unless otherwise specified, all prices in this report are in Australian dollars.

**Table 1**  
**LNG Netback Prices**

[a] Ex-Gladstone LNG (USD/GJ)	13.50
[b] Gladstone (AUD/GJ)	11.38
[c] Wallumbilla (AUD/GJ)	10.83
[d] Moomba (AUD/GJ)	9.73

Sources & Notes:

[a] - [d]: See Table 6.

In common with other analysts, we assume that LNG netbacks are a function of the US dollar oil price (and therefore also a function of the USD/AUD exchange rate). However, over the VPA period, both oil and exchange rates can be “locked in” in forward markets. A buyer that commits to pay a price for gas that will be a function of oil prices and the exchange rate over the VPA period can remove all the uncertainty over oil and exchange rate movements during that period by hedging in forward markets. We therefore base our netbacks on forward market prices for oil and the exchange rate.<sup>24</sup>

Because there is currently no pipeline capacity available between Longford and Sydney (particularly in the peak winter periods), we do not believe that a Longford producer is currently able to achieve LNG netback prices. Prices in recent GSAs are consistent with this view. A second consequence of pipeline constraints between Longford and Sydney is that a retailer entering the NSW market would not be able to access new supplies at Longford during the VPA period. For the VPA period, prices at Longford are insulated from the scarcity pricing prevalent at Moomba because of pipeline constraints.

The prices in Table 1 are prices which an LNG exporter could pay for feed gas and sell the LNG profitably after paying for all transportation and liquefaction costs. The MDQ Consulting report documents that the exporters are short gas relative to their contractual commitments and/or spot LNG sale opportunities.<sup>25</sup> In such a situation, because a significant part of the exporter’s costs are

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<sup>24</sup> See chapter VI.

<sup>25</sup> The opportunity for spot LNG sales arises when less than the full output of the liquefaction plant has sold under long-term contract.

sunk, incremental profits can be earned even if the exporter has to pay more than the netback prices shown in Table 1.

## B. PRICES IN RECENT CONTRACTS

The East Australian gas market is not transparent: prices paid under long term GSAs are usually not directly disclosed (although the size and term of the contracts typically are directly reported by the parties). However, in many cases industry analysts are able to report estimates of GSA prices. In Table 2 we summarize the terms of all recent GSAs of which we are aware. The prices in Table 2 are taken either from IES<sup>26</sup> or from ACIL,<sup>27</sup> with the exception of the most recent GSAs which are not mentioned in those reports. For the prices in these GSAs we rely on the MDQ Consulting report. Note that we have not made any attempt to adjust the prices in Table 2 and Figure 3 for non-price terms (such as flexibility) as such terms are not publically available.

**Table 2**  
Recent GSAs

	Seller	Buyer	Date Announced	Total Volume (PJ)	Start	End	Reported Price (\$/GJ)	Priced At	Source for Price
[a]	Santos	GLNG	Oct-10	750	2014	2029	\$7.00 to \$8.00	Wallumbilla	IES
[b]	Origin Energy	GLNG	May-12	365	2015	2025	\$8.00	Wallumbilla	ACIL
[c]	Origin Energy	GLNG	Dec-13	100	2016	2021	\$9.40 - \$10.60	Wallumbilla	MDQ Consulting
[d]	AGL	Xstrata	Oct-11	138	2013	2023	\$6.00	Ballera	ACIL
[e]	Origin Energy	MMG	Dec-12	22	2013	2020	\$9.00	Ballera	ACIL
[f]	AGL or Origin	Incitec Pivot	Dec-13	18	2015	2016	\$10.00	Ballera	MDQ Consulting
[g]	Beach Energy	Origin Energy	Apr-13	up to 173	mid-2014	2022-2023	\$8.00 to \$9.00	Moomba	IES
[h]	BHP-Esso	Lumo Energy	May-13	22	2015	2018	\$7.00	Longford	IES
[i]	BHP-Esso	Origin Energy	Sep-13	432	2014	2023	\$6.00 - \$6.42	Longford	MDQ Consulting

Sources & Notes:

[a], [g] - [h]: See Study on the Australian Domestic Gas Market, IES, November 2013, p. 69.

[b], [d] - [e]: See Cost of gas for the 2013 to 2016 regulatory period, ACIL, June 2013, p. 27.

[c], [f], [i]: See MDQ Consulting Report. Note that the MDQ Report shows the Origin GLNG GSA in USD/GJ. This has been converted to AUD using the 0.85 USD/AUD exchange rate.

Notes:

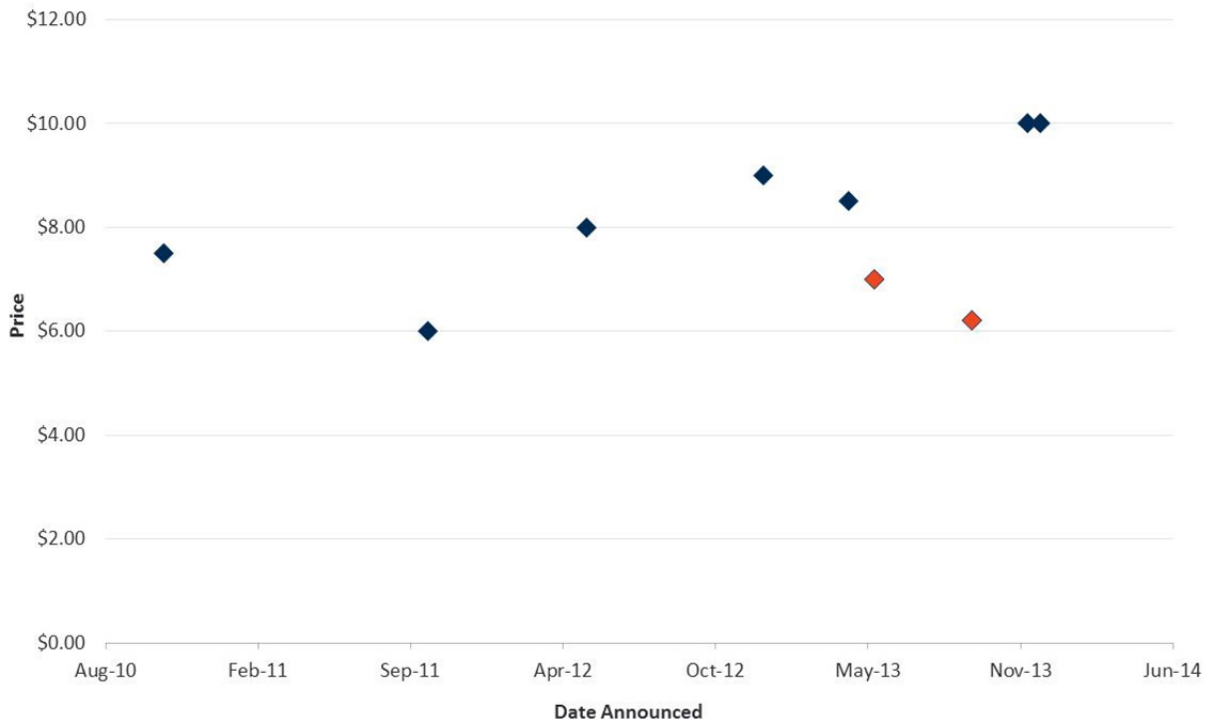
Some of these contracts are reported by both ACIL and IES, in which case we take the IES price because the IES report is more recent.

We note that more recent GSAs at Moomba have been at the highest prices. Older GSAs and GSAs at Longford are at lower prices, as shown in Figure 3.

<sup>26</sup> Study on the Australian Domestic Gas Market, IES report for Department of Industry, and Bureau of Resources and Energy Economics, 28 November 2013.

<sup>27</sup> Cost of Gas for the 2013-2016 Regulatory Period, ACIL Tasman report for IPART, 13 June 2013.

**Figure 3**  
**Recent Gas Supply Agreement Prices**  
**(\$/GJ)**



Sources & Notes: See Table 2. Red markers are priced at Longford.

Based on Table 2 and Figure 3, we conclude that recent GSAs at Moomba suggest prices in the range \$8.00–10.00/GJ, and a rising trend over time. In contrast, recent prices at Longford are lower, in the range \$6.00–7.00/GJ.

We note that the MDQ Consulting report suggests Longford prices of \$6.25–6.50/GJ for the VPA period, and indicates that prices are expected to step up over time.

### C. PIPELINE CAPACITY CONSTRAINTS

Over the VPA period to June 2016, there is limited capacity to bring gas from Longford to Sydney. Historical flow data<sup>28</sup> shows that both the EGP and the NSW–Victoria interconnect (in contrast to the Moomba-to-Sydney pipeline) are at or close to capacity, particularly in the

<sup>28</sup> See chapter VIII.

winter. Both pipelines have proposed expansions, and the interconnect expansion is going ahead, having already received support from market participants in the form of long-term contracts. Chapter VIII documents this in detail.

While expansion of either or both of the EGP and Victoria–NSW Interconnector is possible, either option would take time and would require shippers to make much longer commitments than the two-year period of the VPA. A retailer wishing to source new supplies for the NSW market at Longford would have to make a contractual commitment for longer than two years. It is not unreasonable to suppose that a retailer entering the NSW might seek a longer-term GSA. However, if that GSA supplied gas at Longford, the gas could not reach NSW before winter 2015/16 at the earliest. We therefore consider that prices at Longford are not accessible to NSW retailers before the middle of the VPA period at the earliest, and then only on a longer-term basis.

Nevertheless, we recognize that NSW tariff reviews have traditionally relied on a weighted average of Longford and Moomba prices. We therefore provide an estimate of an ex-plant price at Longford, although we consider it to be of limited relevance to NSW retailers seeking new supplies for the VPA period.

## D. EX-PLANT PRICE ASSESSMENT

### 1. Moomba

We have estimated an LNG netback price of \$9.73/GJ at Moomba.<sup>29</sup> This is a conservative estimate of the price at which gas might be available: because some liquefaction costs are sunk, exporters could earn incremental profits even while paying more than this amount.

Evidence from recent GSAs is consistent with netback pricing. Over the past year, new GSAs from the Cooper basin have reportedly been signed at prices in the range of \$8.00–\$10.00/GJ. Since the LNG exporters continue to be short gas, we have based our ex-plant price assessment at Moomba on our estimate of the LNG netback price (\$9.73/GJ). It is possible that prices during the VPA period could rise above this level because a price of \$9.73/GJ includes liquefaction costs which are sunk. We therefore consider this price to be a conservative assessment.

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<sup>29</sup> See chapter VI.

## 2. Longford

If Longford production were competing with Cooper production to supply NSW over the VPA period, the Longford price would have to be equivalent to the netbacks discussed above, after taking into account transportation. If a retailer entering the NSW market to supply smaller customers over the VPA period had the choice between obtaining gas at Moomba or at Longford, we would expect LNG netback prices at both locations. At Moomba the price is a netback for the reasons given above. At Longford the producers would have the economic incentive and ability to seek prices up to the netback level from retailers supplying small customers in NSW, since the retailers' alternative would be a netback price at Moomba. However, pipeline transportation constraints mean that new supplies from Longford could not be supplied to NSW until winter 2015 at the earliest, so Longford producers are not currently able to seek netback prices.<sup>30</sup> Recent GSA prices at Longford are significantly below LNG netback prices, and are in the range \$6.00–\$7.00/GJ. Our assessment of the ex-plant price at Longford is therefore based on recent GSA prices. Relying on the price range in the MDQ Consulting report, which is slightly lower than the GSA prices reported above, our assessment of the ex-plant price at Longford is \$6.50/GJ.

The existence of transportation constraints means that, after adjusting for pipeline tariffs, prices at Moomba and Longford should not be the same. Producers at Moomba are able to access LNG netbacks, but producers at Longford are not. Reports of prices in recently-signed GSAs are consistent with this picture.

However, for the same reason that Longford prices are below Moomba prices, a retailer wishing to enter the NSW market to supply smaller customers would not be able to use gas from Longford. As transportation constraints are relieved and pipeline capacity becomes available, the retailer would be able to use gas from Longford to supply the NSW market, but the Longford price would be expected to rise under those circumstances.

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<sup>30</sup> See chapter VIII.

### III. Estimates from Other Analysts

#### A. LNG NETBACKS

We have estimated an LNG netback price of \$9.73/GJ at Moomba. This is similar to, but slightly higher than, netbacks we have seen in recent reports from ACIL and from IES. Table 3 shows all three estimates.

**Table 3**  
**LNG Netbacks at Moomba**  
**(2014/15)**

Analyst	Price (\$/GJ)
[a] ACIL	9.09
[b] IES	9.35
[c] Brattle	9.73

Sources & Notes:

[a]: See Cost of Gas for the 2013 to 2016 Regulatory Period, ACIL, June 2013, Table 10, p. 40.

[b]: The IES netback is quoted as \$11.00/GJ at Gladstone, which has been netted back to Moomba (subtracted \$1.65 transport costs). See Study on the Australian Domestic Gas Market, IES, Table 10-2 and Figure 10-2, pp. 78 & 81. For transport costs, see Table 6.

[c]: See Table 6.

The basis of our netback calculations and underlying assumptions is explained in detail in chapter VI. Neither IES nor ACIL report all of the assumptions<sup>31</sup> underlying their netback calculations, so the reasons for the differences shown in Table 3 are not clear. One possible explanation is that the AUD/USD exchange rate has been falling (making the US dollar more

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<sup>31</sup> In the case of IES, the assumptions are reported but it is not clear that the assumptions detailed in the report are consistent with the netback prices reported. Also, IES netbacks appear to fall over time (the figure we give is for 2013/14). It is not clear why this should happen.

expensive). Other things equal, this has the effect of increasing netbacks expressed in Australian dollars, because the LNG netback price is derived from an oil price expressed in US dollars. Given the sensitivity of netback prices to various assumptions, including oil price and exchange rates, we consider the estimates in Table 3 to be reasonably close.

Over the VPA period, forward markets allow oil price and exchange rate risks to be hedged. We therefore do not consider oil prices and exchange rates to be a significant source of uncertainty in the netback prices we estimate for the VPA period. Our netback price estimates are based on current forward oil prices and exchange rates.<sup>32</sup>

## B. OPTIMIZATION MODELLING

Optimization models are usually designed to produce results consistent with perfectly competitive markets. As such, they are of limited relevance when, as here, there is excess demand and a relatively small number of suppliers. IES acknowledges that its model assumes that the market is perfectly competitive.<sup>33</sup>

Optimization models take data on production costs, transportation and demand, and find the combination of production and flows that meets demand at least cost. The models produce a set of prices that represent the long-run marginal cost of production delivered at each location in the network. Optimization models are useful when production costs can be estimated accurately and when flow patterns can be complex, because in these situations the modelling may produce insights not apparent from inspecting the underlying data. However, a disadvantage of optimization models is that their workings are not transparent. We have not relied on optimization models in this study because the data available as inputs to such models is imprecise and network flows are relatively simple. As a result, we consider that model results are unlikely to add insights. Furthermore, comparing the published results of different optimization models applied recently to the Eastern Australian gas market suggests that model results are driven to a significant extent (if not entirely) by assumptions.

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<sup>32</sup> See chapter VI.

<sup>33</sup> IES report, p. 76.



In various studies of the gas market, network optimization modelling has been employed to attempt to estimate the long-run marginal cost (LRMC) of gas at particular supply and demand nodes as a proxy for the wholesale market value of gas at those locations. Typically, these models are designed to “dispatch” gas from supply to demand locations in the optimally least cost way, taking into account pipeline capacity constraints (and the costs to expand such capacity if the model determines it is economic to do so in order to balance supply and demand). They usually do not take into account contractual constraints in that they assume no gas is “pre-committed” under legacy contracts. All supply is assumed to be available to serve all demand subject only to pipeline flow constraints. Obviously, critical to these models is the specification of the supply and demand curves at each node, and none of the model results that we have reviewed make these input assumptions public.

While these models have their appropriate uses (particularly in analysing pipeline network constraints and expansion projects), in our view they are of limited usefulness in the current exercise for at least three reasons. First, by not accounting for contractual constraints these models are somewhat divorced from the commercial reality one observes in the market. In particular, there is limited trading of gas or pipeline capacity in Eastern Australian markets that would contribute to the price arbitrage these models assume. Second, in the current uncertain market environment we are not confident that there is information of sufficient richness to populate these models. Finally, as mentioned, they are a “black box” in the sense that the internal supply and demand curve assumptions that dictate the models’ results are not revealed for evaluation. In this context, the AEMO has said: “The gas supply-demand outlook model does not contain cost-related information in sufficient detail to form a reliable view on transmission and production augmentation based on cost efficiency. Instead, AEMO reviews and models publicly-announced and generic augmentation projects and uses model outcomes to aid assessment of reserves adequacy.”<sup>34</sup>

In section IIIA we showed that the netback prices of IES and ACIL are similar at Moomba.<sup>35</sup> However, they are very different netted back to Sydney. IES estimates Sydney prices of around

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<sup>34</sup> *2013 Planning Consultation Methodology and Input Assumptions*, AEMO, May 30<sup>th</sup> 2013, p. 11.

<sup>35</sup> IES does not report a netback at Moomba. IES reports a Gladstone netback which we have further netted back to Moomba, using pipeline tariffs, and find a price similar to our estimate and to ACIL’s (as shown in Table 3).

\$7.00/GJ, based on an optimization model, whereas ACIL has a Sydney delivered price of over \$10.00/GJ.<sup>36</sup> This large difference demonstrates that caution needs to be exercised in interpreting the results of optimization modelling.

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<sup>36</sup> The ACIL report gives a Moomba price of \$9.09/GJ and additional transport costs of over \$1.00/GJ.

## IV. Flexibility and Deliverability

### A. APPROACH

Small users demand more gas in the winter than in the summer because many homes and businesses use gas for space heating. In estimating the cost of gas to a prudent and efficient retailer it is necessary to take this factor into account because it costs more to obtain a “flexible” supply of gas on the wholesale market than a “flat” gas supply. A flat gas supply is one where the same quantity is taken every day throughout the year, whereas a flexible supply allows for more gas to be taken in periods of high demand than in periods of low demand.

Consistent with the approach taken in previous IPART reviews, we have based our assessment of the costs of additional deliverability on the cost of using Iona storage.

### B. ADDITIONAL DELIVERABILITY REQUIRED TO SUPPLY SMALL CUSTOMERS

We assume that, in line with the approach taken in prior IPART reviews, the prudent and efficient retailer would need to make arrangements for sufficient deliverability to supply the forecast demand of its customers in a cold winter. In prior reviews, a 1 in 25 standard has been applied. Under this standard, peak demand is estimated as the demand in a cold winter which is likely to be exceeded only one winter in 25 years (or, equivalently, a demand forecast for which there is only a 4% probability that actual demand will exceed it). Forecast average demand is then divided by forecast 1 in 25 peak demand to give a 1 in 25 load factor.

We use a load factor of 38.7%, based on AGL calculations using a 1 in 25 standard.<sup>37</sup> We understand that the load factor of 38.7% represents an average annual consumption in the small user segment, divided by a forecast peak daily consumption. The forecast peak daily consumption is modelled using historical weather data and correlations between weather and demand.

In chapter II above we estimated the ex-plant costs of wholesale gas. Typically producers are willing to supply some flexibility “bundled” in with the commodity gas. To put it another way, a GSA under which the buyer is obliged to pay for 3.65 PJ per year might allow it the right to take

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<sup>37</sup> Load factor means the ratio of average to peak load. The smaller the load factor, the less gas is delivered over the course of a year for a given peak day deliverability. We use a load factor of 38.7%, which was applied in prior IPART reviews.

up to 11 TJ of gas per day. This is equivalent to a swing of 110% (the peak deliverability is 11 TJ per day but the average taken is 10 TJ/day) or a load factor of 91%. The more deliverability that is bundled in with the commodity cost of gas, the less additional deliverability needs to be purchased.

In Table 4 we calculate the additional deliverability required to supply a demand load factor of 38.7%, depending on whether the supply load factor is 80%, 90% or 100%. Table 4 shows that for an illustrative supply of 1 PJ/yr at 90% load factor, the retailer needs just over 7 TJ/d MDQ, of which around 3 TJ/d comes from the gas producer, leaving an approximate 4 TJ/d storage requirement.

**Table 4**  
**Additional Deliverability Requirement**

[a]	Total Supply (PJ/year)	1.00		
[b]	Average daily supply (TJ/d)	2.74		
[c]	Demand Load Factor	38.7%		
[d]	Peak Daily Demand (TJ/d)	7.08		
		80% Supply Load Factor	90% Supply Load Factor	100% Supply Load Factor
[e]	Peak Supply Available (TJ/d)	3.42	3.04	2.74
[f]	Additional Deliverability Requirement (TJ/d)	3.65	4.04	4.34

Sources & Notes:

[a]: Assumed.

[b] = ([a]/365) x 1,000.

[c]: Assumed, consistent with prior IPART determinations.

[d] = [b]/[c].

[e] = [b]/ (Supply Load Factor).

[f] = [d] - [e].

### C. COST OF ADDITIONAL DELIVERABILITY BASED ON STORAGE

Consistent with prior IPART reviews, we have based our assessment of the cost of additional deliverability that a retailer supplying small customers in NSW requires on the cost of storage services at Iona. We assume a price of \$221/GJ/day MDQ per year, based on the cost ACIL

Tasman used in its work for IPART connected with the 2013/14 determination.<sup>38</sup> Table 5 shows the corresponding calculations, assuming a supply load factor of 90%. The additional cost of deliverability is about \$0.89/GJ.

**Table 5**  
**Cost of Additional Deliverability for a**  
**1 PJ/year Supply**

	90% Supply Load Factor
[a] Additional Deliverability Requirement (TJ/d)	4.04
[b] Cost of Deliverability (\$/GJ MDQ per Year)	216
[c] Inflation Rate	2.5%
[d] Inflation-Adjusted Cost of Deliverability (\$/GJ MDQ per Year)	221
[e] Cost of Incremental MDQ (\$/PJ)	893,406
[f] Cost of Incremental MDQ (\$/GJ)	0.89

Sources & Notes:

[a]: See Table 4.

[b]: Assumed cost of deliverability from Cost of gas for the 2013 to 2016 regulatory period, ACIL, June 2013, p. 43.

[c]: See Reserve Bank of Australia, Statement on Monetary Policy, August 2013, Table 6.1, p. 55.

[d] = [b] x (1 + [c]).

[e] = [a] x [d] x 1,000.

[f] = [e] / 1,000,000.

<sup>38</sup> We understand that ACIL used the mid-point of the range \$160–240/GJ MDQ/yr, based on the cost of Iona storage quoted in AGL’s 2010 submission, adjusted for inflation.

## V. Conclusions on Wholesale Prices

### A. MOOMBA

We estimate an ex-plant price of \$9.73/GJ at Moomba for supplies to a retailer wishing to enter the NSW market to supply small customers for the remaining duration of the VPA period. This estimate is based on an LNG netback price at Moomba. Together with an uplift of \$0.89/GJ for supplying additional deliverability required for a load factor corresponding to the residential customer retail market, the resulting cost is \$10.62/GJ.

### B. LONGFORD

Based on recent GSA prices and the views expressed in the MDQ Consulting report, we estimate an ex-plant price at Longford of \$6.50/GJ for the VPA period. Together with an uplift of \$0.89/GJ for additional deliverability, the resulting cost is \$7.39/GJ (as noted above, our view is this price is not available to NSW retailers seeking new supplies during the VPA period, because of transport constraints).

## VI. Background: LNG Export and Netbacks

### A. QUEENSLAND LNG EXPORT PROJECTS

LNG exports from Queensland are expected to begin in 2014, and to ramp up quickly. While there remains significant uncertainty over the pace and ultimate size of the export projects over the longer term, three projects are under construction and are expected to be completed within the 2014/16 period. All three projects are expected to have first trains commissioned in 2014-15.

#### 1. QCLNG

The QCLNG project is a US\$20.4 billion venture between BG Group, CNOOC (50% Train 1) and Tokyo Gas (2.5% Train 2). The project involves the expansion of “QGC’s natural gas production in the Surat Basin,”<sup>39</sup> the “construction of a 200 kilometre...export pipeline to Gladstone”<sup>40</sup> and a “two-train 8.5 mtpa LNG plant”.<sup>41</sup> First gas was delivered to the liquefaction plant on Curtis Island at the end of 2013, and the project is currently “on-track... ..to deliver first LNG in the second half of 2014.”<sup>42</sup>

#### 2. GLNG

The GLNG project is a US\$18.5 billion joint-venture between Santos (30%), PETRONAS (27.5%), Total (27.5%) and KOGAS (15%). The project involves “the development of gas fields in the Bowen and Surat Basins, the construction of a 420 kilometre underground gas transmission pipeline to Gladstone and a two-train LNG processing facility on Curtis Island in Gladstone.”<sup>43</sup> The two-train facility will have a 7.8 mtpa capacity with 7.2 mtpa contracted to PETRONAS and KOGAS.<sup>44</sup> The project has “passed the 65 per cent completion mark... ..[and is] on track for first LNG in 2015.”<sup>45</sup>

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<sup>39</sup> See QCLNG newsletter “the energy”, BG Group, November 2013, Issue 31, p. 4.

<sup>40</sup> *Ibid.*

<sup>41</sup> QCLNG website, <http://www.bgggroup.com/OurBusiness/WhereWeOperate/Pages/Australia.aspx>, as of November 11, 2013.

<sup>42</sup> BG Group 2013 Third Quarter Results conference call transcript, October 31, 2013, p. 3.

<sup>43</sup> GLNG website, <http://www.santosglng.com/the-project.aspx>, as of November 11, 2013.

<sup>44</sup> See “Citi Australia Conference” presentation, Santos, October 29-30, 2013.

<sup>45</sup> See “Santos GLNG continues to pass milestones” press release, October 29, 2013.

### 3. APLNG

The A\$24.7 billion APLNG project is a joint-venture between Origin (37.5%), ConocoPhillips (37.5%) and Sinopec (25%).<sup>46</sup> The project consists of the further development of gas fields in the Surat and Bowen Basins, and the construction of a 530 kilometre gas transmission pipeline and a two-train LNG facility with 9 mtpa processing capacity.<sup>47</sup> Currently, there is about 8.6 mtpa of contracted exports with first LNG on track for mid-2015.<sup>48</sup>

### 4. Other Projects

There are currently two additional proposed LNG projects in Queensland,<sup>49</sup> however there is uncertainty regarding the timing and actual scope of the projects.

- The approximately \$17 billion<sup>50</sup> Arrow LNG project includes construction of up to 4 trains, with the first stage including two trains with about 4 mtpa capacity each and first LNG commencing in 2017.<sup>51</sup> However, a recent article stated that Shell, one of the two project partners,<sup>52</sup> “planned to boost divestments” and the Arrow LNG project “is a potential asset for sale.”<sup>53,54</sup>
- The A\$1.7 billion, two-train 3.8 mtpa-planned Fisherman’s Landing project<sup>55</sup> had already begun construction and is looking to recommence Stage 1 construction in 2013.<sup>56</sup> It is unclear whether construction has in fact recommenced, as LNG Ltd. notes that achievement of FID will be dependent upon a number of key

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<sup>46</sup> See “The Australia Pacific LNG Project” fact sheet, available at [http://www.aplng.com.au/pdf/factsheets/APLNG012\\_Fact\\_Sheet\\_The\\_APL\\_Project\\_FINAL.PDF](http://www.aplng.com.au/pdf/factsheets/APLNG012_Fact_Sheet_The_APL_Project_FINAL.PDF).

<sup>47</sup> *Ibid.*

<sup>48</sup> APLNG website and “A new class of E&P Investment Company Overview,” ConocoPhillips investor presentation, November 1, 2013.

<sup>49</sup> These include the Arrow LNG and Fisherman’s Landing LNG projects.

<sup>50</sup> See “Struggling Shell defers Arrow LNG project again” *The AGE*, February 1, 2014.

<sup>51</sup> See “Gas Demand Study: An assessment of demand for Coal Seam Gas and pipeline services in Central Queensland”, ACIL Tasman, March 1, 2013, p. 53.

<sup>52</sup> The other partner is PetroChina.

<sup>53</sup> See “Arrow likely for Shell sale list”, *The Australian*, November 2, 2013.

<sup>54</sup> See also discussion in MDQ Consulting report, chapter 5.

<sup>55</sup> This project is a venture of Liquefied Natural Gas Limited.

<sup>56</sup> Fisherman’s Landing website, <http://www.lnglimited.com.au/irm/content/australia1.aspx?RID=262>, as of November 11, 2013.



requirements including access to gas supplies, a tolling agreement, engineering procurement and construction and project financing.<sup>57</sup>

The MDQ Consulting report documents how GLNG in particular, and the three LNG export projects in aggregate, are short of gas to meet their contractual commitments. There is an even bigger shortfall if spot market opportunities are taken into account. As a result, the exporters are therefore buying significant volumes of third-party gas.

## B. NETBACKS

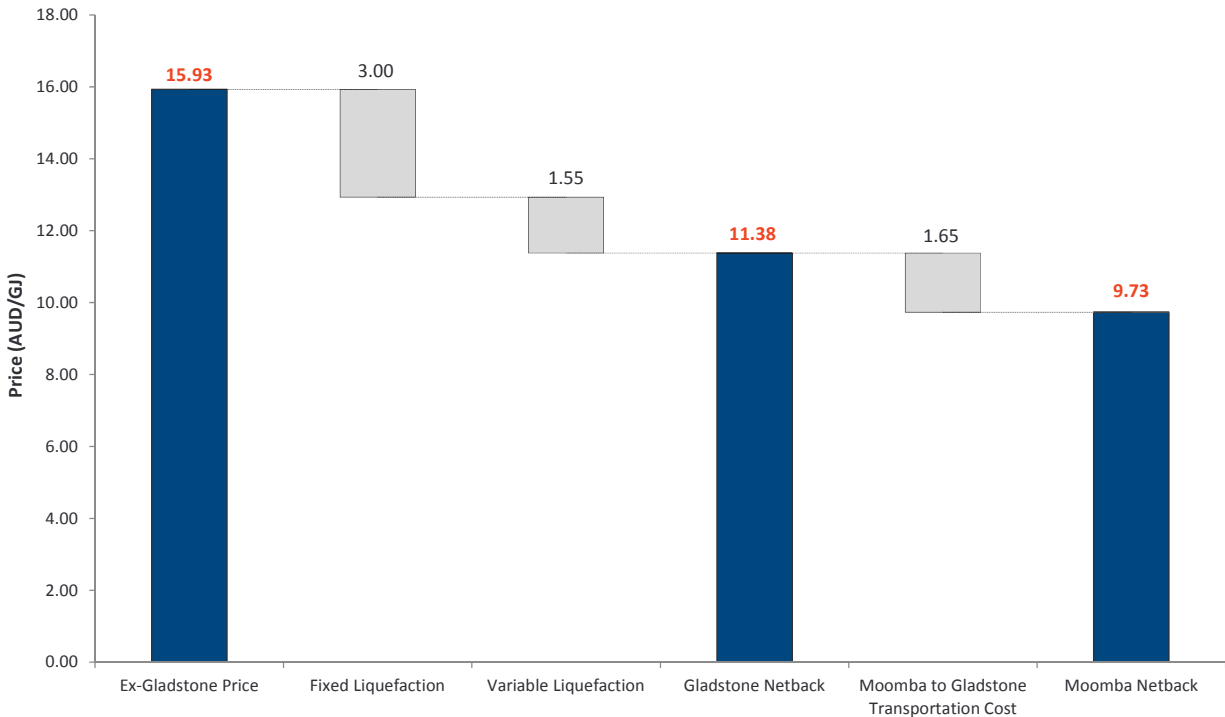
In this chapter we calculate “netback” prices, starting from estimates of the value of gas exported as LNG. Starting from an LNG price, we can work backwards to find a price for the gas at various points in the supply chain. At each step, the costs associated with moving and/or processing the gas are subtracted. Thus, for example, the netback price at the inlet to the LNG plant is the price for LNG on the ship as it leaves the plant minus the costs of liquefying the gas. This is illustrated in Figure 4.

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<sup>57</sup> *Ibid.*

Figure 4

Build up of Australian LNG Netback Prices & Ex-Gladstone LNG Price (AUD/GJ)



Sources & Notes: Brattle Analysis. Netback prices are highlighted in bold red. See Workpapers, Data for Figure 2 Tab.

## 1. Background

The netback price is an estimate of the price that an LNG exporter would be willing to pay for feedstock gas. This price is a relevant benchmark because LNG export and domestic consumption may compete for the same gas supplies.

The LNG netback price represents the commercial value that an exporter in Queensland can obtain by exporting the gas to the Asian market. It is an estimate of the maximum amount that the exporter might be prepared to pay to obtain feedstock gas, taking into account the costs of transporting, liquefying and shipping<sup>58</sup> the gas to market. The netback is thus a function of the

<sup>58</sup> Some LNG contracts are priced “FOB”, meaning that the buyer pays for shipping from the plant to the destination port, while others are priced “DES”, meaning that the seller pays for shipping (and thus the cost of shipping is included in the contract price). In this report we assume all LNG prices are FOB, so the cost of shipping does not enter our netback calculations.

price at which the LNG will ultimately be sold, and the costs of transporting and liquefying the gas. A number of different analysts have reported netback costs (see Table 8 below). However, we have found that published reports generally do not provide full details of how the netbacks have been calculated. For example, one report might specify a cost for liquefaction alone, and a second report might specify a cost for liquefaction together with the cost of pipeline transportation to Gladstone. Furthermore, liquefaction costs depend on the feedstock gas price (because some of the gas delivered to the plant is used to power the liquefaction process). We have used a set of assumptions on costs which appear to us reasonable and which produce similar netback estimates to those we have seen in other reports.<sup>59</sup> We explain our assumptions and compare them with assumptions we have seen other analysts make in the sub-sections which follow.

## 2. Netback Prices and Sunk Costs

We have calculated netback prices allowing for all of the costs associated with exporting LNG. In assessing the economics of a potential new project, this netback is the feedstock price which would make the project just economic, given forecasts of costs and the price at which the LNG will be sold. At this price, the project sponsor expects to recover all investment and to make a normal profit on the project.

The three LNG projects currently under construction have already made a significant fraction of the investment that will underpin their projects. A large part of the project cost is sunk, and is independent of the volumes exported by the project. As a result, the exporter can potentially pay a price higher than the netback we estimate, and still make incremental profits. For this reason, we (and other analysts)<sup>60</sup> consider that prices could be higher than the netbacks we have estimated during the VPA period. In the short-run the exporter may be willing to pay a netback that excludes some of the fixed costs associated with the dedicated pipeline to Gladstone and the fixed costs associated with the liquefaction plant.

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<sup>59</sup> See Table 8 below.

<sup>60</sup> See, for example, Commonwealth Bank of Australia's *14 Predictions for 2014*, 24 January 2014: "This suggests through this ramp-up phase, with LNG prices remaining strong, projects could potentially purchase volumes at \$13-15/GJ in the east coast market and still add to the overall profitability of the project".

### 3. Netback Calculations

In this sub-section we present our LNG netback calculations. We explain our assumptions and choice of parameters in later sub-sections.

Table 6 shows our netback calculations, which start from an estimate of the LNG price, and work backwards to an estimate of the feedstock price at various locations by subtracting costs. The oil price and Australian dollar / US dollar exchange rates are key inputs because LNG prices are typically expressed as a function of the oil price in US dollars.<sup>61</sup> The calculations in Table 6 use the current forward oil price and the current forward exchange rate, and an assumed slope (ratio of LNG price to oil price) of 13.5%, which is consistent with reports on recently-signed LNG contracts.<sup>62</sup>

In Table 6:

- The ex-Gladstone price is the FOB price paid by the buyer;
- We assume liquefaction costs of \$3.00/GJ (fixed) and 12% of feed gas used in liquefaction (these assumptions are further explained below);
- Under the assumptions in rows [a] through [d] of the table, 12% corresponds to a variable liquefaction cost of \$1.55/GJ;
- On this basis, we calculate a Gladstone netback corresponding to the price of the gas at the inlet to the plant of \$11.38/GJ;
- The cost of transporting the gas from Wallumbilla to Gladstone is \$0.55/GJ (see Table 11);
- Subtracting this pipeline transportation charge gives a Wallumbilla netback (row [k]); and
- Similarly, subtracting pipeline costs of \$1.10/GJ gives the Moomba netback (row [m]).

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<sup>61</sup> Unless otherwise stated, all prices and costs are in Australian dollars.

<sup>62</sup> These assumptions are explained below.

**Table 6**  
**LNG Netback Calculations**

[a]	USD/AUD Exchange Rate	0.85
[b]	Liquefaction %	12.0%
[c]	Oil Price (\$/barrel)	100.00
[d]	Slope	13.5%
[e]	Ex-Gladstone price (USD/GJ)	13.50
[f]	Ex-Gladstone price (AUD/GJ)	15.93
[g]	Fixed liquefaction (AUD/GJ)	3.00
[h]	Variable liquefaction (AUD/GJ)	1.55
[i]	Gladstone netback (AUD/GJ)	11.38
[j]	Wallumbilla to Gladstone pipeline (AUD/GJ)	0.55
[k]	Wallumbilla netback (AUD/GJ)	10.83
[l]	Moomba to Wallumbilla pipeline (AUD/GJ)	1.10
[m]	Moomba netback (AUD/GJ)	9.73
[n]	Liquefaction (AUD/GJ)	4.55
[o]	Pipeline plus liquefaction (AUD/GJ)	5.10

Sources & Notes:

[a]: Assumed exchange rate. Equivalent to 0.85 USD = 1 AUD. See Table 16 for exchange rates.

[b]: Assumed, based on Table 12.

[c] - [d]: Assumed. See text of report.

[e] = [c] x [d].

[f] = [e] / [a].

[g]: Assumed, based on Table 10.

[h] = [i]/(1 - [b]) x [b].

[i] = ([f] - [g]) x (1 - [b]).

[j]: See Table 11.

[k] = [i] - [j].

[l]: See workpapers, Pipeline Tariffs Table.

[m] = [k] - [l].

[n] = [g] + [h].

[o] = [n] + [j].

The assumptions we used in Table 6 are similar to assumptions we have seen other analysts make, and produce netbacks similar to those we have seen reported by other analysts. We show comparisons with other analysts in the sub-sections which follow.

#### 4. Comparison with Other Analysts' Netback Calculations

We have estimated an LNG netback price of \$9.73/GJ at Moomba. This is similar to, but slightly higher than, netbacks we have seen in recent reports from ACIL and from IES. Table 7 shows all three estimates.

**Table 7**  
**LNG Netbacks at Moomba**  
**(2014/15)**

Analyst	Price (\$/GJ)
[a] ACIL	9.09
[b] IES	9.35
[c] Brattle	9.73

Sources & Notes:

[a]: See Cost of Gas for the 2013 to 2016 Regulatory Period, ACIL, June 2013, Table 10, p. 40.

[b]: The IES netback is quoted as \$11.00/GJ at Gladstone, which has been netted back to Moomba (subtracted \$1.65 transport costs). See Study on the Australian Domestic Gas Market, IES, Table 10-2 and Figure 10-2, pp. 78 & 81. For transport costs, see Table 6.

[c]: See Table 6.

Neither IES nor ACIL report all of the assumptions<sup>63</sup> underlying their netback calculations, so the reasons for the differences shown in Table 7 are not clear. We attempt to back out these differences in Table 8.

In Table 8 we also show estimates from EnergyQuest and Credit Suisse. Since LNG netback prices depend strongly on oil price and exchange rate assumptions, in order to compare methods for calculating a netback price given certain assumptions about the oil price and exchange rates, we re-calculated our figures shown in Table 6 to match the various oil price and exchange rate assumptions from which other analysts derived their netbacks. In this way we can compare our netback calculations on a consistent basis. These adjusted calculations are shown in column [5] of Table 8, with the corresponding netbacks reported by other analysts in column [4].

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<sup>63</sup> In the case of IES, the assumptions are reported but it is not clear that the assumptions detailed in the report are consistent with the netback prices reported. Also, IES netbacks appear to fall over time (the figure we give is for 2013/14). It is not clear why this should happen, as discussed further below.

**Table 8**  
**LNG Netback Comparisons (at Gladstone / Plant Inlet)**  
**(\$/GJ)**

Report	Exchange Rate (USD/AUD)	Oil Price (USD/Barrel)	Netback	Brattle Netback
[1]	[2]	[3]	[4]	[5]
[a] IES, "Study on the Australian Domestic Gas Market" (November 2013) - Gladstone Netback	0.90	110	11.00	11.88
[b] EnergyQuest, EnergyQuarterly (August 2013) - Gladstone Netback	0.90	100	10.46	10.56
[c] Credit Suisse, "Eastern Australia Gas Prices" (June 2013)	0.85	90	10.70	9.94
[d] ACIL Tasman, "Cost of gas for the 2013 to 2016 regulatory period" (June 2013) - Gladstone Netback	0.93	132	11.43	14.27
[e] EnergyQuest, "Australian Coal Seam Gas 2013: All Aboard the LNG Train" (May 2013) - GLNG Netback	0.95	95	8.75	9.24

Sources & Notes:

[a]: IES, "Study on the Australian Domestic Gas Market" (November 2013) - Gladstone Netback, pp. 78, 81 and 82. The oil price assumption is approximated based on the chart presented in the report.

[b]: EnergyQuest, EnergyQuarterly (August 2013) - Gladstone Netback, pp. 102-103.

[c]: Credit Suisse, "Eastern Australia Gas Prices" (June 2013), p. 11.

[d]: ACIL Tasman, "Cost of gas for the 2013 to 2016 regulatory period" (June 2013) - Gladstone Netback, p. 23.

[e]: EnergyQuest, "Australian Coal Seam Gas 2013: All Aboard the LNG Train" (May 2013) - GLNG Netback, p. 89.

Note: Brattle netbacks calculated in accordance with the methodology in Table 6.

Exchange rates are interpreted as USD per AUD. For example, an exchange rate of 0.90 is equivalent to 0.90 USD = 1 AUD.

Table 8 shows that we are assuming a similar relationship between the oil price, the exchange rate, and netbacks (although ACIL assumes a high oil price but a low “slope”, thereby obtaining a similar overall relationship).<sup>64</sup>

Table 9 shows the assumptions we made to calculate LNG netbacks compared to those reported by other analysts. In general we have found that it is not always clear what assumptions other analysts have used, although the netback methodology is the same. Reported netbacks are not always consistent with reported cost assumptions. We have used the same netback methodology that other analysts use, and we have also set out the details of our assumptions and calculations.

<sup>64</sup> A slope of 11.4% can be backed out of ACIL’s figures (see *Cost of gas for the 2013-16 regulatory period*, ACIL, June 2013, Table 4). See Workpapers, ACIL Slope Calculation.

**Table 9**  
**Pipeline Transportation and Liquefaction Long-run Cost Estimates (\$/GJ)**

Report	Pipeline Transportation	Liquefaction
[a] Brattle Assumptions	0.55	4.55
[b] IES, "Study on the Australian Domestic Gas Market" (November 2013)		\$6.00
[c] EnergyQuest, EnergyQuarterly (August 2013)	0.92	4.20 - 5.10
[d] ACIL Tasman, "Cost of gas for the 2013 to 2016 regulatory period" (June 2013)	N/A	4.00
[e] Credit Suisse, "Eastern Australia Gas Prices" (June 2013)	N/A	4.50
[f] ACIL Tasman, "Fuel Cost Projections for AEMO Modelling" (June 2012)		4.00

Sources & Notes:

[a]: See Table 6.

[b]: IES, "Study on the Australian Domestic Gas Market" (November 2013), p. 81.

[c]: EnergyQuest, EnergyQuarterly (August 2013), pp. 103 and 111. Figures for Liquefaction costs are calculated using values from Figure 40. See Workpapers, EnergyQuest Liquefaction Costs Tab. Pipeline transportation figures are for Wallumbilla to Gladstone transportation.

[d]: ACIL Tasman, "Cost of gas for the 2013 to 2016 regulatory period" (June 2013), p. 24.

[e]: Credit Suisse, "Eastern Australia Gas Prices" (June 2013), p. 3.

[f]: ACIL Tasman, "Fuel Cost Projections for AEMO Modelling" (June 2012), pp. 5-6. This figure is the estimated "tolling charge on pipeline and liquefaction...with an additional A\$1/GJ added to account for risk premium."

Note that in Table 9 EnergyQuest appears to have used the published QGC tariff to netback from plant inlet to Wallumbilla, whereas we have used an estimate of the cost of the dedicated pipelines used by the export projects (see Table 11). We think that the cost of the dedicated pipelines is likely to be a better proxy for the long-run cost.

A key assumption in calculating a LNG netback is the assumed investment in liquefaction plant. In Table 10 we show that our assumption of \$3.00/GJ for liquefaction cost is in line with reported investments by the three LNG exporters.



**Table 10**  
**Liquefaction Capital Costs**

	QCLNG	GLNG	APLNG	Average
[a] Capital Cost of Liquefaction Plant (AUD billions)	10.20	10.40	10.80	
[b] Plant Capacity (mtpa)	8.50	7.80	9.00	
[c] Capital Cost per ton (AUD/ton)	1,200	1,333	1,200	
[d] Plant Capacity (GJ/year)	470,900,000	432,120,000	498,600,000	
[e] Cost of Capital	12.0%	12.0%	12.0%	
[f] Recovery Period (years)	20.00	20.00	20.00	
[g] Yearly Cost (\$ billions)	1.37	1.39	1.45	
[h] Liquefaction Cost (\$/GJ/year)	2.90	3.22	2.90	3.01

Sources & Notes:

[a] - [b]: See Australian Coal Seam Gas 2013: All Aboard the LNG Train, EnergyQuest, May 2013, pp. 59, 63 for QCLNG, pp. 86, 88 for GLNG, pp. 109, 111 for APLNG.

[c] =  $([a] \times 1,000) / [b]$ .

[d] =  $([b] \times \text{GJ/ton conversion factor of } 55.4) \times 10^6$ . See Table 15 for conversion factor.

[e]: Assumed cost of capital in EnergyQuest's Coal Seam Gas report. See pp. 64, 88 and 112.

[f]: Assumed capital recovery time period.

[g] = yearly cost assuming 12% cost of capital, ammortized over 20 years.

[h] =  $([g] \times 10^9) / [b]$ .

Similarly, in Table 11 we show how our assumed pipeline transportation cost of \$0.55/GJ from Wallumbilla to Gladstone relates to the reported cost of the pipelines.

**Table 11**  
**Pipeline Capital Costs**

	QCLNG	GLNG	APLNG	Average
[a] Capital Cost of Pipeline (AUD billions)	2.25	1.30	2.25	
[b] Plant Capacity (mtpa)	8.50	7.80	9.00	
[c] Plant Capacity (GJ/year)	470,900,000	432,120,000	498,600,000	
[d] Cost of Capital	12.0%	12.0%	12.0%	
[e] Recovery Period (years)	20.00	20.00	20.00	
[f] Yearly Cost (\$ billions)	0.30	0.17	0.30	
[g] Pipeline Cost (\$/GJ/year)	0.64	0.40	0.60	0.55

Sources & Notes:

[a] - [b]: See Australian Coal Seam Gas 2013: All Aboard the LNG Train, EnergyQuest, May 2013, p. 63 for QCLNG, p. 88 for GLNG, and p. 111 for APLNG.

[c] =  $([b] \times \text{GJ/ton conversion factor of } 55.4) \times 10^6$ . See Table 15 for conversion factor.

[d]: Assumed cost of capital in EnergyQuest's Coal Seam Gas report. See pp. 64, 88 and 112.

[e]: Assumed capital recovery period.

[f] = annual capital charge assuming 12% cost of capital, ammortized over 20 years.

[g] =  $([f] \times 10^9) / [b]$ .

In Table 12 we show the basis of our assumption that 12% of feed gas is used in the liquefaction process (based on figures from the GLNG environmental impact statement).

**Table 12**  
**Process Losses as a Percent of Total LNG**

	Assumes OCP and 3 Mtpa			Process Losses as a Percent of Total Feedstock
	Process Losses		Total Feedstock	
	<i>CO<sub>2</sub> (tonnes)</i>	<i>Methane (tonnes)</i>	<i>Feed (tonnes)</i>	
[a] Fuel consumption in process equipment	825,764	300,278		
[b] Power generation	102,735	37,358		
[c] Fugitive emissions	653	237		
[d] Flaring and venting	233,570	84,935		
[e] <b>Total</b>	<b>1,162,722</b>	<b>422,808</b>	<b>3,422,808</b>	<b>12.4%</b>

Sources & Notes:

GLNG Environmental Impact Statement - Greenhouse Gases, Santos, 23 March 2009, Table 4.3, p. 16.

The process losses used are for the facility project section only (excludes CSG fields).

These calculations assume that all carbon dioxide came from burning methane.

Methane losses are calculated as CO<sub>2</sub> emissions multiplied by 16/44.

Process Losses as a Percent of Total Feedstock calculated as Methane Losses / Total Feedstock.

We note that “brownfield” expansions of an existing project might be expected to have lower capital costs than shown in Table 6 above. If capital costs are reduced for future projects, the netback prices would be higher, other things equal, because a smaller cost would be subtracted from the LNG price in calculating the netback. We have not seen any estimates of the cost saving that might be associated with a brownfield expansion. For illustrative purposes, we show in Table 13 that a 40% reduction in capital costs would increase the netback by approximately \$1.10/GJ.

**Table 13****LNG Netback with Capital Cost Reduction**

[a]	USD/AUD Exchange Rate	0.85
[b]	Liquefaction %	12.0%
[c]	Oil Price (\$/barrel)	100.00
[d]	Slope	13.5%
[e]	Ex-Gladstone price (USD/GJ)	13.50
[f]	Ex-Gladstone price (AUD/GJ)	15.93
[g]	Fixed liquefaction (AUD/GJ)	3.00
[h]	Gladstone netback (AUD/GJ)	11.38
[i]	Capital Cost Reduction	40%
[j]	New Capital Cost (AUD/GJ)	1.80
[k]	New Gladstone netback (AUD/GJ)	12.44
[l]	Netback Difference (AUD/GJ)	1.06

## Sources &amp; Notes:

[a] - [d], [g]: Assumptions. See Table 6.

[e] = [c] x [d].

[f] = [e] / [a].

[h] = ([f] - [g]) x (1 - [b]).

[i]: Assumed.

[j] = [g] x (1 - [i]).

[k] = ([f] - [j]) x (1 - [b]).

[l] = [k] - [h].

We explained above that an exporter which is short gas relative to its contractual commitments and/or spot LNG sales opportunities could profitably buy feed gas above the netback price we have calculated, because much of the liquefaction cost is sunk.

## 5. LNG Export Price Assumptions

LNG export contracts to the Asian market are generally written against the Japanese Crude Cocktail oil price (JCC price), and it is common to assume a linear relationship between the LNG price and the oil price. We have estimated netbacks against the Brent price because derivative contracts that can be used to hedge the Brent price are widely available, and Brent prices are more widely quoted. We assume that the spread between Brent and JCC is zero.<sup>65</sup>

<sup>65</sup> Analysts commonly assume that the Brent price forecast is a reasonable proxy for JCC. See, for example, *All aboard the LNG Train*, EnergyQuest, May 2013, p. 230.

The precise nature of the relationship between the JCC price and the delivered LNG price in any given contract is not typically divulged. The relationship is often described as an “S-curve”, with the sensitivity of the LNG price to changes in the oil price being smaller outside a central range. However, we have seen very little evidence as to the parameters of the curve. In practice, it is common to assume that the LNG price is a simple linear function of the Brent oil price, at least over some central range of oil prices. We have reviewed analyst reports that suggest a “slope” of over 15% or as low as 12%.<sup>66</sup> Some analyst estimates are shown in Table 14.

**Table 14**  
**Analyst Estimates of "Slope" in LNG Contracts**

	Source	Date	Slope	DES or FOB
[a]	IES "Study on the Australian Domestic Gas Market" (November 2013)	Nov-13	14.00%	FOB
[b]	EnergyQuest, EnergyQuarterly (August 2013)	Aug-13	14.50%	FOB
[c]	ACIL Tasman "Cost of gas for the 2013 to 2016 regulatory period" (June 2013)	Jun-13	12.00%	DES
[d]	Credit Suisse "Eastern Australia Gas Prices" (June 2013)	Jun-13	15.10%	DES
[e]	EnergyQuest, "Australian Coal Seam Gas 2013: All aboard the LNG train" (May 2013)	May-13	14.50%	FOB
[f]	EnergyQuest, "ESAA Domestic gas study phase 2" (March 2011)	Mar-11	14.85%	FOB

Sources & Notes:

[a]: IES "Study on the Australian Domestic Gas Market" (November 2013), pp. 81-82. Note that the slope includes an MMBtu to GJ conversion.

[b]: EnergyQuest, EnergyQuarterly (August 2013), pp. 102-103.

[c]: ACIL Tasman "Cost of gas for the 2013 to 2016 regulatory period" (June 2013), p. 24.

[d]: Credit Suisse "Eastern Australia Gas Prices" (June 2013), p. 11.

[e]: EnergyQuest, "Australian Coal Seam Gas 2013: All aboard the LNG train" (May 2013), p. 230.

[f]: EnergyQuest, "ESAA Domestic gas study phase 2" (March 2011), p. 64.

Notes:

FOB means priced at the origin with buyer to pay for shipping.

DES means priced at the destination, seller having paid for shipping.

The only primary-source evidence we have seen as to the relationship comes from Santos describing the revenue it expected associated with one of the off-take agreements from its Queensland LNG project. We have calculated an oil price range that would be consistent with the Santos revenue projection on the assumption that the slope is 13.5%. The calculations in Table 15 show that an assumed slope of 13.5% implies a “market consensus” oil price range of

<sup>66</sup> For example, a recent article in World Gas Intelligence (December 4<sup>th</sup> 2013) stated that Australian sellers had offered slopes of 13.8% to 16% in recent years, and that Kogas had agreed a new contract with Malaysia LNG at 13.5%. In principle, slopes could be as high as 17% (the point at which gas and oil are at price parity on an energy content basis).

\$90/bbl to \$130/bbl, which we consider to be reasonable. Our 13.5% assumption is therefore consistent with the Santos revenue projection, and it is also within the range shown in Table 14.

**Table 15**  
**Santos GLNG Oil Price Calculation**

[a]	Contract Volume (mtpa)	7.00	
[b]	LNG tons to GJ conversion factor (GJ per ton LNG)	55.4	
[c]	Contract Volume (million GJ/year)	388	
[d]	Assumed JCC-linkage	13.5%	
[e]	MMBtu to GJ Conversion factor (GJ/MMBtu)	1.05506	
[f]	Revenue (US\$ billions)	4.50	6.50
[g]	Implied Oil Price (US\$/Barrel)	90.69	130.99

Sources & Notes:

[a]: See "GLNG signs binding LNG off-take agreement with KOGAS for 3.5 mtpa" press release, December 17, 2010.

[b]: Assumed conversion factor. See <http://www.santos.com/UserControls/ConversionCalculators/ConversionCalculator.html>.

[c] = [a] x [b].

[d]: Assumed oil linkage slope.

[e]: Assumed conversion factor. See <http://www.transcanada.com/conversiontool/>.

[f]: Estimated. See "GLNG Project FID" investor presentation, January 13, 2011, p. 9.

[g] = ([f] x [e])/([c]/1,000 x [d]).

## 6. Oil Price and Exchange Rate Assumptions

As discussed above, netbacks are sensitive to assumptions about the exchange rate and oil prices. However, over the July 2014 to June 2016 period, both exchange rates and oil prices can largely be hedged ("locked in") by entering into transactions in the forward market. If a gas buyer were to enter into a GSA where the gas price was indexed to the oil price in US dollars, the buyer would be able to convert that GSA price to a fixed Australian dollar price, at least for the period of the VPA, by trading in forward oil and exchange markets. On the basis of current forwards, we think it is reasonable to assume a Brent price of \$100/bbl. The current spot price is around

\$110/bbl, with the forward curve sloping downwards. The current forward price for the period July 2014-June 2016 is around \$103/bbl.<sup>67</sup>

We show current exchange rates in Table 16. We use the two-year forward rate in our calculations.

**Table 16**  
**USD/AUD Exchange Rates**  
**As of December 17, 2013**

[a] Spot	0.89
[b] One year forward	0.87
[c] Two year forward	0.85

Sources & Notes:

[a] = Average of Bid and Ask Spot Price.

[b] = Average of Bid and Ask Spot Price + the average Bid and Ask for one-year forward exchange rate.

[c] = Average of Bid and Ask Spot Price + the average Bid and Ask for two-year forward exchange rate.

Notes:

See workpapers, Exchange Rates Table.

Equivalent to 0.85 USD = 1 AUD.

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<sup>67</sup> Based on forward prices from Bloomberg for December 16<sup>th</sup> 2013 and spot prices from EIA.

## VII. Background: Production Costs and Modelling

### A. MODELLING

A number of analysts have developed models of the eastern Australia gas market. For example, ACIL describes using its “GasMark” model, and Frontier describes its “WHIRLYGAS” model.<sup>68</sup> IES also presents modelling results. These are “optimization” models – they produce prices which reflect a “least cost” or optimal mix of supply.

In our view, these models are of limited relevance in a tight market characterised by an excess of demand. In this chapter, we explain in more detail why we would in any case have concerns about relying on a model that uses production costs as inputs. We have not seen any reliable source for information on production costs in Australia.

As inputs, optimization models require information about the shape of the demand and supply curve at each geographic location in the system, together with the cost of transporting gas from one location to another. The models may (or may not) also take into account constraints such as pipeline capacity or the rate and cost at which new pipeline or production capacity can be brought on line. The output of these models is a prediction of the quantity of gas that will be produced and consumed at each location, and the price of gas at each location. The models work by “dispatching” different sources of gas, starting with the cheapest, satisfying each unit of demand in descending order of price, until the next most expensive source of gas would cost more than the next unit of demand is willing to pay (taking into account pipeline transport costs). The models typically do not account for contractual constraints on the supply or demand for gas. This process is equivalent to maximizing a utility function equal to the sum of consumer surplus and producer surplus. Equivalently, it maximizes the area under the assumed demand curve in each consumption location, less the area under the assumed supply curve in each supply location, less transport costs between them.<sup>69</sup>

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<sup>68</sup> See ACIL’s *Cost of gas for the 2013 to 2016 regulatory period*, June 2013, and Frontier’s *Input assumptions for modelling wholesale electricity costs*, June 2013. Both reports were prepared for IPART.

<sup>69</sup> This approach is a standard one. See, for example, Appendix B to *Cost of gas for the 2013 to 2016 regulatory period*, ACIL, June 2013.

In the sections below we discuss specific difficulties associated with estimating the production costs (supply curves) which are a key input to these models. In addition to these difficulties, there are other features of the models, particularly as applied to the eastern Australia gas market, which may make the results of limited value for the IPART determination at issue here.

The models produce prices based on what is called “Long-run Marginal Cost” or LRMC. One interpretation of LRMC is an average price for *new* supplies over a period long enough that new supplies are brought on. It is an equilibrium price, meaning that it is relevant to a situation in which supply (and demand) have sufficient time to come to equilibrium, including through investment in new production. In the short term, prices can in theory be higher or lower than LRMC because it takes time for new supplies to be brought on (or for new demand to appear in response to lower prices).

The eastern Australia gas market is characterized by long-term contracts, non-transparent prices, and relatively little short term trading of gas or transportation capacity. These features make it less likely that the market will reach an equilibrium around an LRMC price.

Estimates of production cost are only half of the model: the other half are the demand curves at each consuming location, and estimates of the willingness of various customers to buy gas at different price levels. While there is some discussion of the demand curves in the description of the ACIL modelling,<sup>70</sup> it is not clear how, or even if, Frontier models gas demand. Frontier states “We have adopted the domestic gas demand forecasts from the planning case of the AEMO 2012 GSOO for the purposes of this modelling.”<sup>71</sup> If the volume of demand is treated as given, the modelling results are much less meaningful: this is equivalent to assuming that demand is completely unresponsive to changes in prices—a zero price elasticity of demand. IES similarly provides few details of its model.

Pipeline transportation costs are almost entirely fixed (independent of the volume of gas transported), and should therefore be treated as sunk costs in an optimization model, unless the model is running over a timescale long enough to require pipeline expansion, in which case the relevant cost would be the incremental cost of the expansion. Frontier includes sunk

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<sup>70</sup> *Cost of gas for the 2013 to 2016 regulatory period*, ACIL, June 2013, section 3.4.2.

<sup>71</sup> *Input assumptions for modelling wholesale electricity costs*, Frontier, June 2013, p. 114.



transportation costs in its model, for reasons that appear to be pragmatic and not theoretically sound based on its discussion of the assumption.<sup>72</sup>

Both the ACIL and Frontier models are “black box” in the sense that the model inputs and assumptions are not completely specified, and the model itself is not disclosed. As a result, it is not possible to investigate the sensitivity of model results to changing inputs.

## B. PRODUCTION COSTS

Typically, production costs are estimated for each field or processing plant and are used to generate the supply curves to be used by the model. For example, Frontier lists 20 existing processing plants and 14 new processing plants (with the Queensland CSM plants currently under construction included as “new”).<sup>73</sup> If, as is usually done, production costs are expressed in \$/GJ terms, the cost is “levelised”, such that the total cost of producing gas over the life of the plant is divided by the total volume of gas to be produced. Thus, behind the production cost figure quoted for each field or plant is a calculation which in turn requires as inputs estimates of various costs associated with the plant over its life, and assumptions about the profile of production over time. We have reviewed gas market modelling results published by Frontier and by ACIL, and production cost estimates published by Core Energy.<sup>74</sup> However, none of these

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<sup>72</sup> Frontier states: “Strictly speaking, when calculating the LRMC of gas, the cost information that we require for gas transmission pipelines should depend on whether the gas transmission pipeline is an existing gas pipeline or a new gas pipeline. As with gas production plant, the fixed costs for existing gas transmission pipelines are sunk and, therefore, irrelevant to economic decisions. However, since almost all pipeline costs are fixed costs, and since the capacities of existing gas transmission pipelines are in most instances sufficient to meet forecast demand over the full modelling period, taking this approach to transmission pipelines would mean that the LRMC of gas would, in most instances, not reflect any pipeline costs. [f/n: In contrast, there is a requirement for ongoing investment in gas production plant during the modelling period so that the fixed costs of gas production plant are reflected in the LRMC of gas.] For this reason, we incorporate fixed pipeline costs in our modelling for both existing and new pipelines. We also note that this is consistent with the way that tariffs for regulated pipelines are established.”. See *Input assumptions for modelling wholesale electricity costs*, Frontier, June 2013, pp. 111–2.

<sup>73</sup> *Input assumptions for modelling wholesale electricity costs*, Frontier, June 2013, Figure 30 and Figure 31.

<sup>74</sup> *Gas Production Costs*, Core Energy, April 2012 and an updated version published in August 2012. These reports were prepared on behalf of AEMO for use in the 2012 GSOO and were also used in the 2013 GSOO.

reports shows the detailed calculations and assumptions underlying the field-by-field cost estimates (the ACIL report does not show the field-by-field cost estimates). Core Energy published some of the underlying data behind its production cost estimates, but did not show how production cost estimates were calculated from this data.<sup>75</sup>

## 1. Liquids

Many fields (not including CSM) produce both gas and liquids. A fundamental difficulty in estimating a levelised cost of producing gas is thus how to deal with the value of the associated liquids production. One alternative is to include the expected value of the liquids as an offset to the costs of (jointly) producing gas and liquids. This option has the advantage of more accurately reflecting the actual economics of a decision to produce or not produce, since production would occur if the revenues from liquids and gas exceed the combined costs. A disadvantage is that the resulting levelised gas price can be very sensitive to the assumed liquids price, which itself is very uncertain. In its work for the 2012 GSOO, Core Energy quoted a US example in which the value of liquids was more than ten times the value of gas, implying that the gas would be produced irrespective of demand, and that the calculated levelised gas price would be much less than zero.<sup>76</sup> An alternative approach is to “allocate” some production costs to gas and some to liquids. For example, Core Energy also shows “standalone prices by allocating shared production costs in proportion to the volume of the gas and liquids streams. Core Energy said “This allocation facilitated the calculation of a standalone breakeven price for the gas component of the basin’s product stream... . . . Although oil and gas investment decisions practically involve an analysis of overall project economics, it is useful to illustrate the cost of gas production from fields / basins exclusive of the influence of liquids pricing so a meaningful comparison with dry gas supply sources can be made”.<sup>77</sup>

For the purposes of modelling the gas market, it is clear that the value of liquids needs to be taken into account (the first of the two options described above). Unfortunately, analysts typically do not specify how that has been done, indicating neither the liquids price assumption used nor the sensitivity of the resulting levelised gas cost to changes in the liquids price. For

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<sup>75</sup> See spreadsheet inputs published as part of the 2012 GSOO.

<sup>76</sup> *Gas Production Costs*, Core Energy, August 2012, pp. 3-4.

<sup>77</sup> *Gas Production Costs*, Core Energy, August 2012, pp. 4-5.

some fields, the quantity of associated liquids is large enough to have a very significant impact on the economics of the production decision. For example, Core Energy reports a levelised gas production cost for the Yolla field of \$0.41/GJ, rising to \$5.29/GJ if the value of liquids is ignored.<sup>78</sup> For the GBJV, Core Energy estimates that the value of liquids is enough to cover all production costs (such that the levelised gas price is zero or less).

In the eastern Australia gas market, the existence of associated liquids production raises an interesting dynamic: as the price of oil increases, the value of associated liquids increases, and as a result the levelised cost of gas production falls. However, at the same time, as oil prices rise the LNG netback price also rises. Arguably a high oil price is more likely to result in LNG netback pricing in the domestic market, whereas a low oil price is more likely to result in other factors, such as production costs, influencing domestic prices. Therefore, for the purposes of estimating levelised gas production costs, an “unbiased” oil price forecast may not be appropriate. It might be better to use a low oil price (therefore higher gas production costs) because under circumstances where gas production costs are more likely to be relevant, oil prices are more likely to be low than high.

None of the cost modelling we have seen discusses this point.

## 2. Well Production Profiles

A second key factor in calculating levelised gas production costs is the assumed production profile over the life of the well. This is particularly important for CSM where, because the producing regions are new, there is little experience of how wells will perform over time.

## 3. Comparing Production Cost Estimates

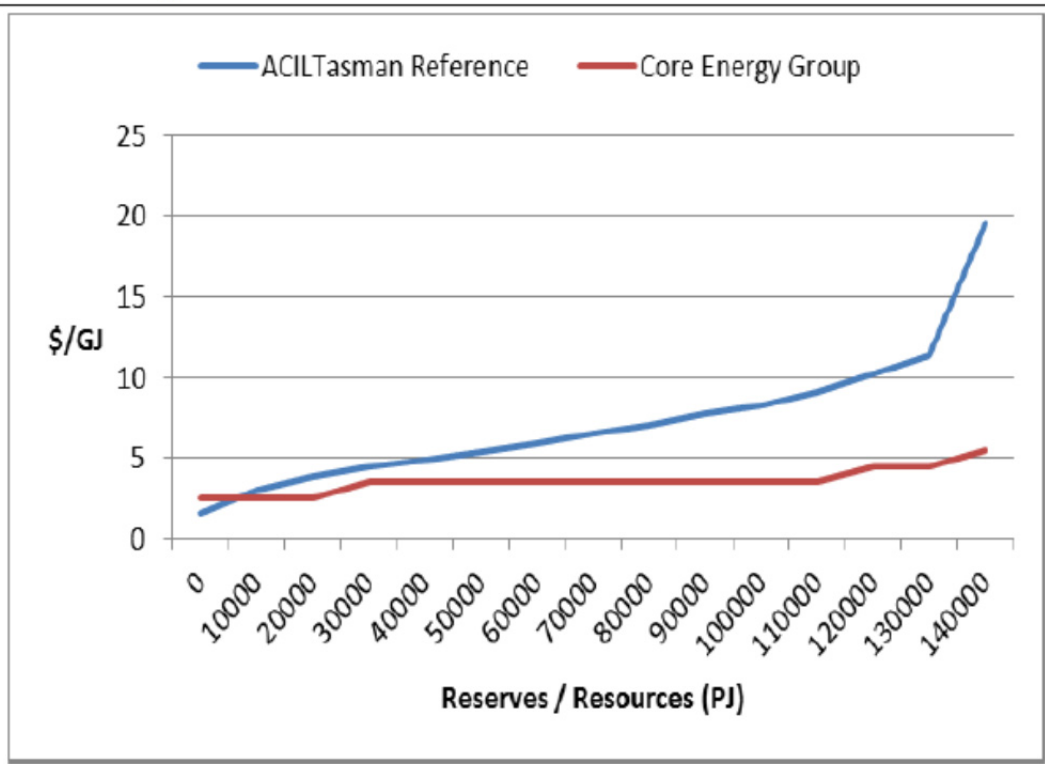
Both ACIL and Frontier compared their production cost estimates to those of Core Energy. The charts below, taken from the ACIL and Frontier reports, show these comparisons.

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<sup>78</sup> *Gas Production Costs*, Core Energy, August 2012, p. 7.

Figure 5

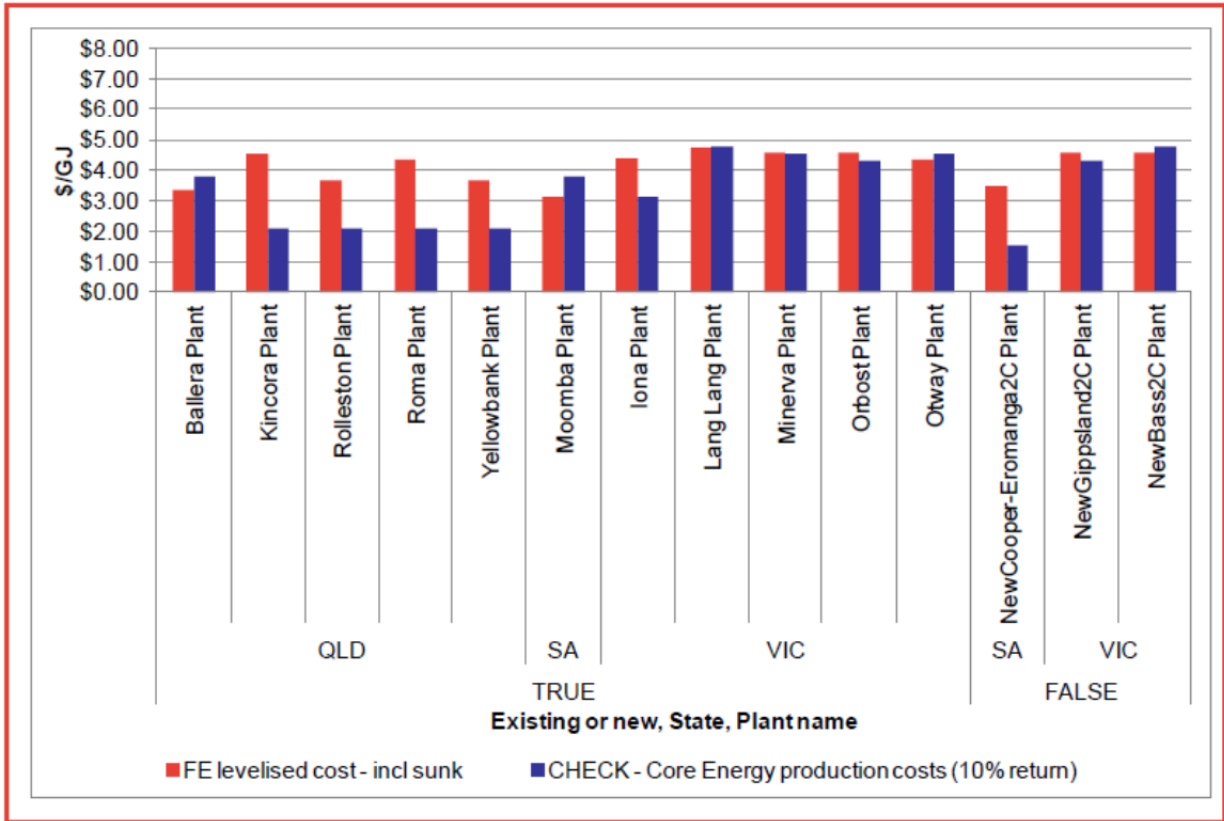
Chart 3 Comparison of ACIL Tasman and Core Energy Group supply curves for natural gas



Source: ACIL Tasman, Core Energy Group

Figure 6

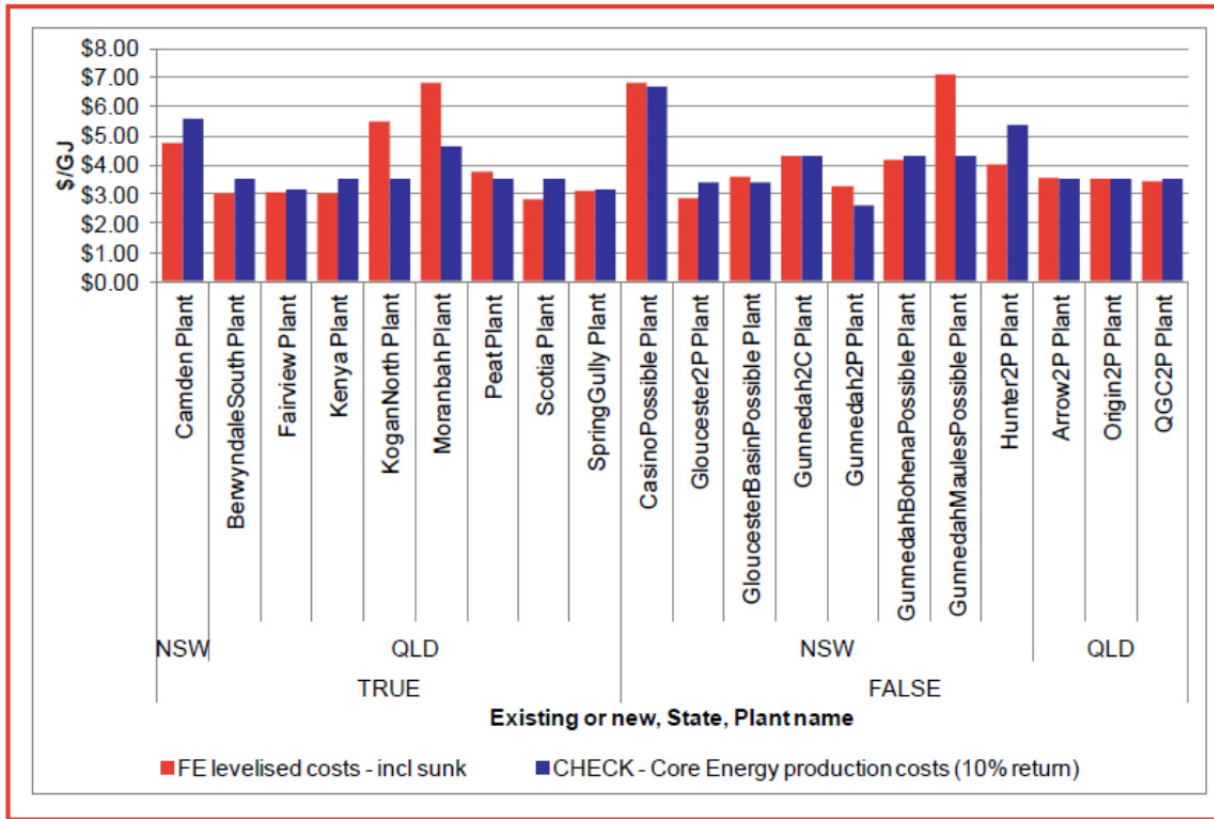
Figure 30: Comparison of current levelised cost of conventional gas plant (\$2012/13)



Source: Frontier Economics

Figure 7

Figure 31: Comparison of current levelised cost of CSM plant (\$2012/13)



Source: Frontier Economics

### C. RESULTS AND ASSUMPTIONS

Frontier’s WHIRLYGAS model has produced prices for the 2013-14 financial year of less than \$5.00/GJ, and around \$5.00/GJ for 2014-15 (delivered to NSW).<sup>79</sup> ACIL’s GasMark model has 2013-14 prices of \$5.13/GJ and 2014-15 prices of \$9.09/GJ (excluding transport to NSW).<sup>80</sup> While these prices may not be exactly comparable since ACIL’s prices are ex-plant and Frontier’s prices are power-station delivered, the 2013-14 prices are similar whereas the 2014-15 prices are very different. Since the Frontier and ACIL models are ostensibly similar, and seem to be using similar

<sup>79</sup> See *Input assumptions for modelling wholesale electricity costs*, Frontier, June 2013, Figure 37.

<sup>80</sup> See *Cost of gas for the 2013 to 2016 regulatory period*, ACIL, June 2013, Table 9 and Table 10.

inputs on production costs,<sup>81</sup> it is at first sight surprising that the ACIL model should produce a much higher price for 2014–15. One possible explanation is that Frontier may be assuming that the Queensland CSM producers will have spare capacity that can supply the domestic market in the early years of LNG export, whereas ACIL assumes that CSM production will be dedicated to export demand such that there is no spare CSM production available below netback prices.

The IES model produces results which are similar to the Frontier results under the “production cost” run, and results (at Sydney) part way between the ACIL and Frontier results under the “netback” run. This is presumably because of the assumptions, discussed above, that Moomba production is priced at LNG netback whereas Longford production is priced at production cost.

The fact that apparently similar models can produce very different results indicates that the models are of limited use, particularly if the workings of the model and the impact of various assumptions made are not transparent. The modelling results seem to be driven in large part by the model setup and high level assumptions.

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<sup>81</sup> Both ACIL and Frontier compare their input costs to those reported by Core Energy, and both seem to view their input costs as similar but somewhat above the Core Energy values.

## VIII. Background: pipeline flows into NSW

### A. PIPELINE EXPANSIONS

Both of the pipelines connecting Victoria and NSW markets have announced expansion plans. It appears that the EGP is hoping to expand, but has not yet announced the firm commitments from shippers that would allow it to proceed.<sup>82</sup> The Victoria–NSW Interconnect has announced that it will expand, with new capacity available for winter 2015.

The expansion of the Victoria–NSW Interconnect is underpinned by new or renewed transportation agreements with three shippers, as well as (in part) by regulated revenues,<sup>83</sup> and will allow increased winter gas flow from the Victorian DTS to Sydney (via the connection with the MSP). The new contracts are for terms of around 5 years.<sup>84</sup> Peak winter capacity into the MSP will increase by 145%, and the expansion will be completed by winter 2015.<sup>85</sup>

We are not aware of any current plans to expand the MSP (upstream of the connection with the Interconnect).

### B. HISTORICAL FLOWS

Sydney, the main load centre in NSW, is served by the Moomba–Sydney pipeline (MSP) and the Eastern Gas Pipeline (EGP). The MSP brings gas from the Cooper basin via Moomba southeast into NSW, and the EGP brings Gippsland basin gas via Longford northeast into NSW. In addition, the NSW–Victoria Interconnect, which connects the Victorian PTS with the MSP, can transport Cooper basin gas from the MSP to Victoria or gas from Victoria into the MSP and on to

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<sup>82</sup> “Talking at an Australian Pipeline Industry Association (APIA) dinner, Mr Adams said that while the timing of commissioning would rely on early commitment, the company is planning the expansion of EGP with FEED currently underway and a final investment decision expected later this year. [2013]” (“Jemena plans Eastern Gas Pipeline Expansion”, *Gas Today*, October 10<sup>th</sup> 2013.) We are not aware of any progress towards expansion having been made since then.

<sup>83</sup> See *Victorian Transmission System - Gas to Culcairn Project Revised*, APA Group, November 7, 2012, p. 2.

<sup>84</sup> The three contracts supporting the expansion have terms of 4.5, 5.5 and 6 years (APA press releases of September 24<sup>th</sup>, October 26<sup>th</sup> and November 4<sup>th</sup> 2013).

<sup>85</sup> *APA to proceed with additional expansion of the Victorian New South Wales interconnect*, APA press release, November 4<sup>th</sup> 2013.



Sydney. Both the Interconnect and the EGP have delivery points serving Canberra, and all three pipes have various delivery points along their lengths at which gas is dropped upstream of Sydney.<sup>86</sup>

**Figure 8: Extract of AEMO pipeline map<sup>87</sup>**



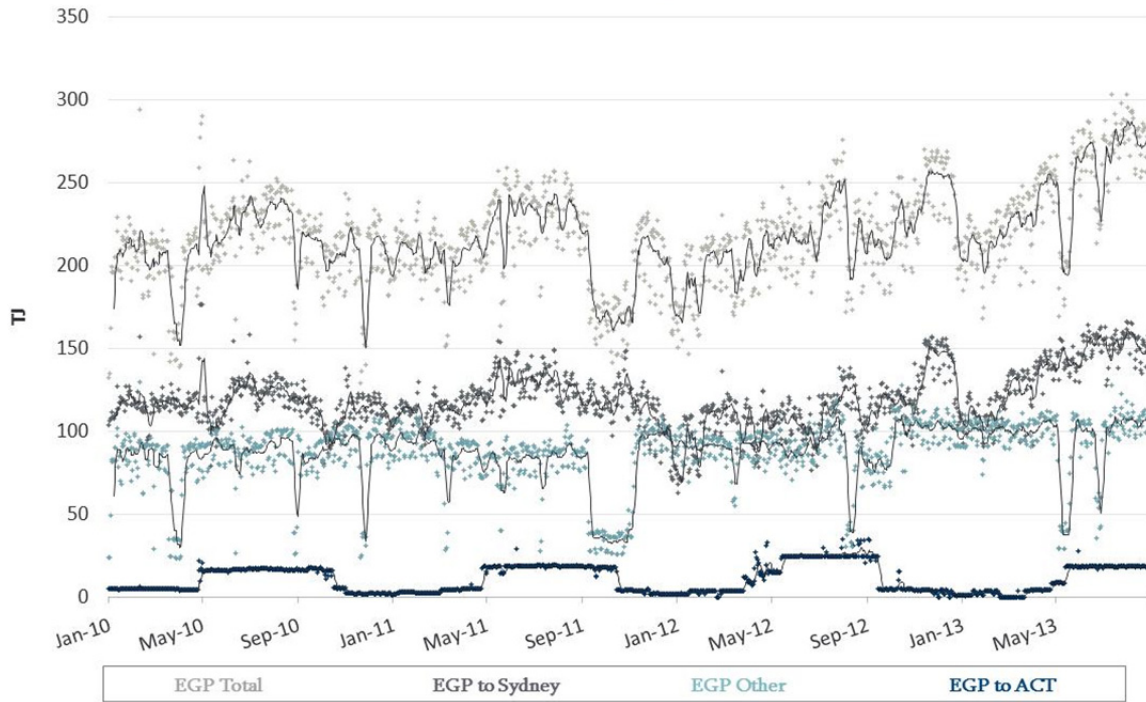
The patterns of flow on the three pipes supplying NSW are different. The EGP tends to run at about the same rate all the time; deliveries to the ACT are seasonal (but small), deliveries to Sydney are only slightly seasonal, and other deliveries are more or less flat (see Figure 9).

<sup>86</sup> For example, the EGP supplies significant demand in the Wollongong area.

<sup>87</sup> Taken from the 2012 GSOO published by AEMO, p. 2-2.

Figure 9

Daily Gas Flow on the EGP  
January 2010 - August 2013



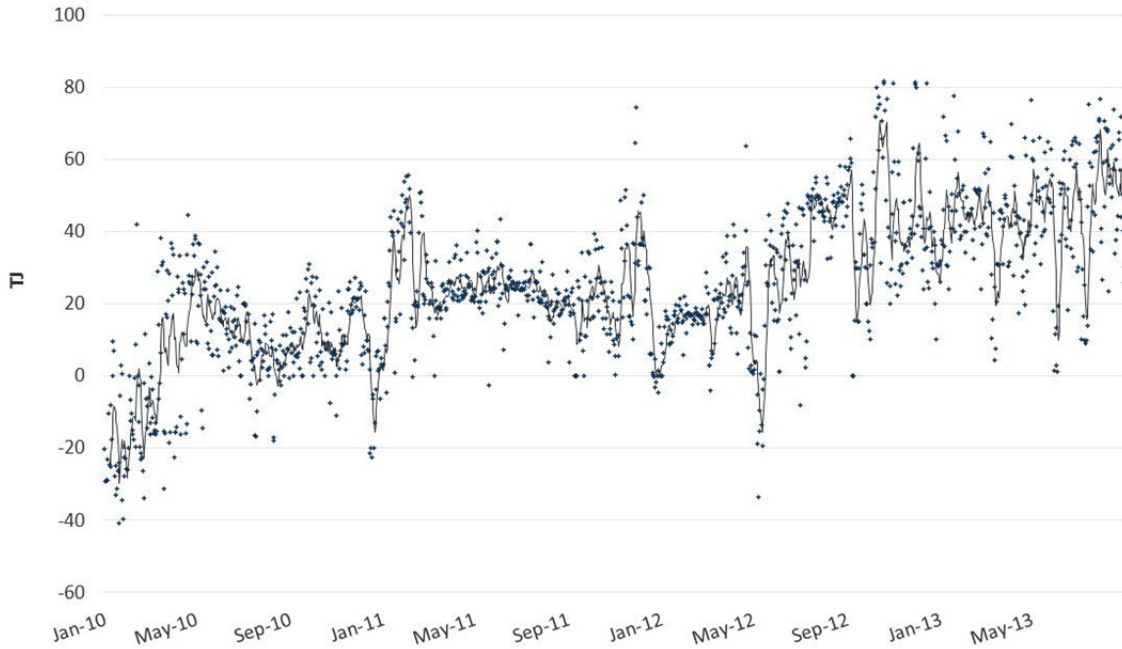
Source: National Gas Market Bulletin Board. The solid lines represent the 7-day moving average for each series.

In 2012 the EGP had a load factor (maximum daily flow divided by average daily flow) of about 79%.

Flows from Victoria into NSW on the Interconnect also do not show a clear seasonal pattern (see Figure 10).

**Figure 10**

**Daily Gas Flow on the Victoria-NSW Interconnect  
January 2010 - August 2013**

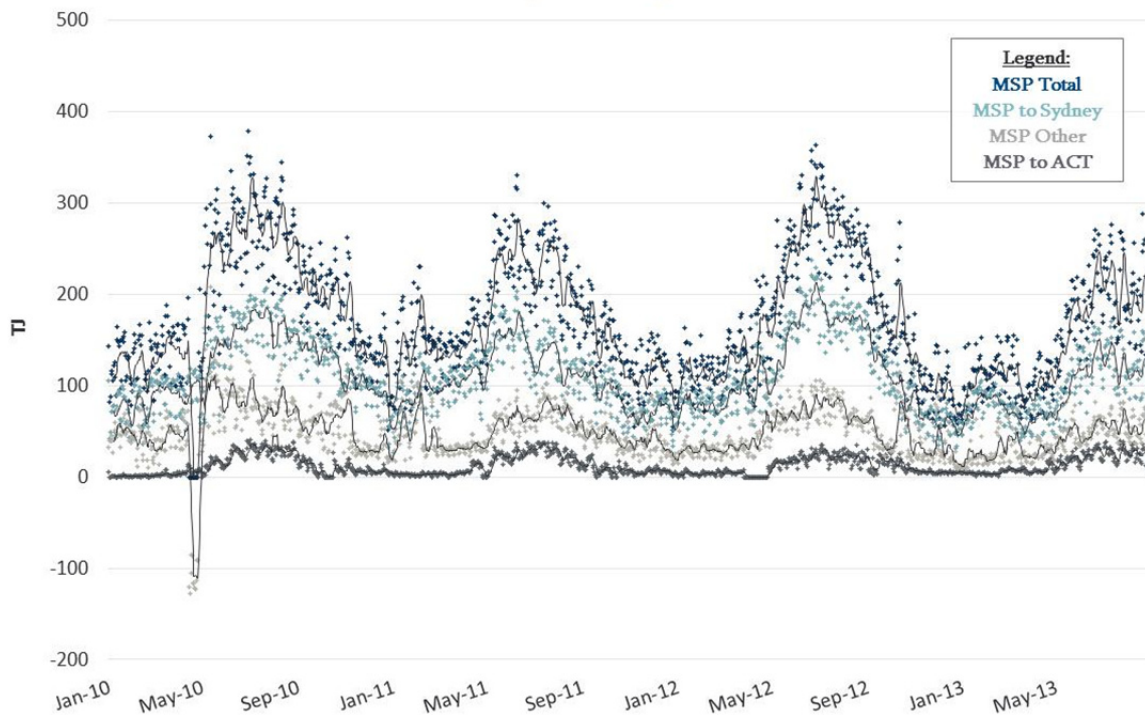


Source: National Gas Market Bulletin Board. The solid lines represent the 7-day moving average.

In contrast, flows on the MSP are highly seasonal. Figure 11 shows that total flows, as well as flows to Sydney, the ACT, and other delivery points on the MSP are all seasonal.

Figure 11

Daily Gas Flow on the MSP  
January 2010 - August 2013



Source: National Gas Market Bulletin Board. The solid lines represent the 7-day moving average for each series.

The load factor on the MSP is low, reflecting the seasonal flow pattern, at about 48%.

The current capacity of the MSP is over 400 Tj/day.<sup>88</sup> The flows shown in Figure 11 suggest that the MSP has spare capacity in the winter, and we note that flows in winter 2013 were lower than in previous years.

In contrast, flows on the Victoria-NSW Interconnect were higher in winter 2013 than in previous years. Similarly, recent flows on the EGP are higher than at any time in the past. EGP flows in winter 2013 were at or close to the pipeline's capacity of 289 Tj/day.<sup>89</sup>

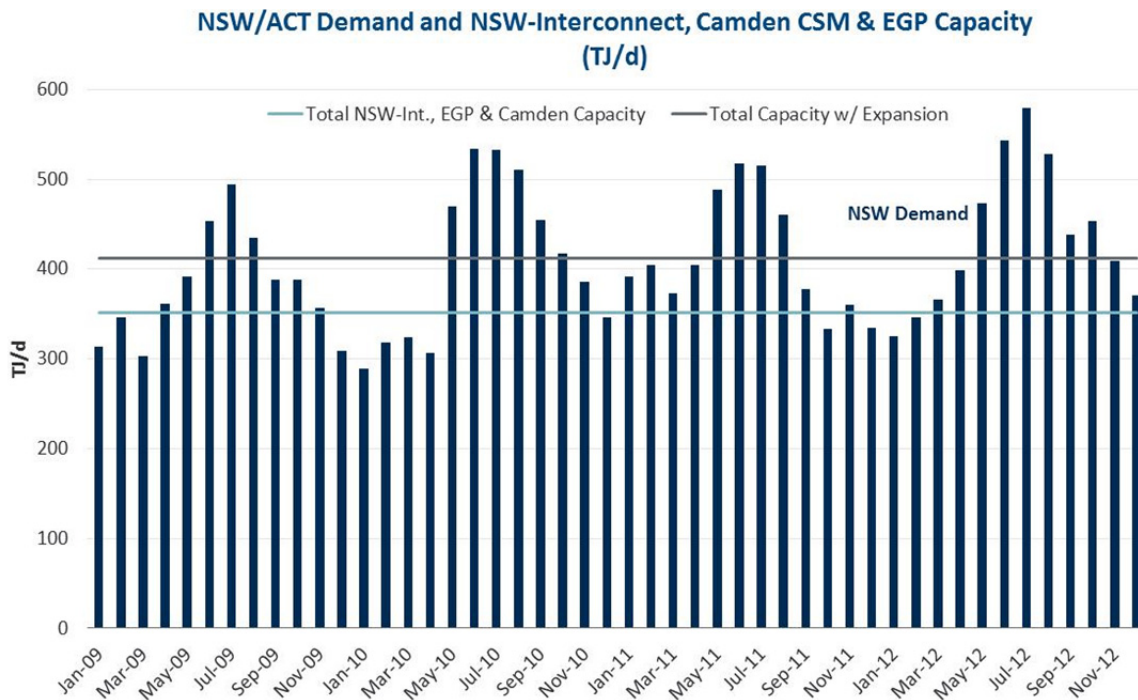
<sup>88</sup> The GBB currently reports the MSP capacity to be 439 Tj/day. See also *MSP light regulation submission*, September 5 2008, paragraph 2.24, and APA press release, May 6<sup>th</sup> 2008 (139 PJ/year plus 20% expansion is equivalent to 457 Tj/day).

<sup>89</sup> This is the figure for winter capacity reported on the GBB. Jemena's website shows 106 PJ/year, which is equivalent to 290 Tj/day.

These flow patterns show that in winter 2013 relatively more gas flowed on the Interconnect and the EGP, and relatively less on the MSP. They are consistent with the announced expansion plans on the pipelines from Victoria, and suggest that for winter 2014 any new supplies to Sydney would have to come from Moomba.

In Figure 12 we show historical NSW demand relative to the capacity of supply sources excluding the MSP. The horizontal line represents the capacity of Camden CSM production, the EGP and the interconnect (our capacity assumptions are shown in Table 17). Figure 12 shows that the NSW market relies on supply from the MSP for much of the year with current Interconnect capacity, and that it will still rely on the MSP after the interconnect is upgraded in winter months. Incremental supply for the NSW market therefore has to come from Moomba. Figure 12 also shows that the capacity needed to supply the winter peak can vary significantly from year to year (due to the sensitivity of peak demand to weather conditions).

**Figure 12**



Source: Gas Bulletin Board per AEMO GSOO 2013. NSW/ACT demand includes flows from the MSP, EGP, NSW-Interconnect and Camden CSM. Total Capacity with Expansion includes three expansions on the NSW-Interconnect that will increase pipeline capacity by 145% (from 42 TJ/d to 103 TJ/d). See *APA to proceed with additional expansion of the Victorian New South Wales Interconnect*, APA Group Press Release, November 4, 2013 and *Victorian Transmission System - Gas to Culcairn Project Revised*, APA Group, November 7, 2012, p. 2.

**Table 17**

**EGP, NSW-Interconnect and Camden CSM  
Capacity Assumptions**

	TJ/d
[a] Eastern Gas Pipeline	289
[b] NSW-Interconnect	42
[c] Camden CSM	20
[d] NSW-Interconnect after Expansion	103
[e] Current Total	351
[f] Total with Expansion	412

Sources & Notes:

[a], [c]: Gas Bulletin Board, Standing Capacities Report, as of January 27, 2014.

[b]: See *Victorian Transmission System - Gas to Culcairn Project Revised*, APA Group, November 7, 2012, p. 2.

[d] = 42 TJ/d x (1 + 145%). After expansion, NSW-Interconnect peak capacity is said to increase by 145%. See *APA to proceed with additional expansion of the Victorian New South Wales Interconnect*, APA Group Press Release, November 4, 2013. For pre-expansion capacity of 42 TJ/d, see *Victorian Transmission System - Gas to Culcairn Project Revised*, APA Group, November 7, 2012, p. 2.

[e] = [a] + [b] + [c].

[f] = [a] + [c] + [d].



## About the Authors

### Dr. Toby Brown

Dr. Toby Brown specializes in the regulation and economics of the gas and electricity sectors. He has consulted for pipelines, utilities, and regulators in the U.S., Canada, Europe, and Australia, and he has particular expertise in incentive-based regulation in the energy sector.

Dr. Brown's project experience at The Brattle Group includes analyzing business risk in pipeline rate cases, assessing the economic impacts of alternative regulatory frameworks and competitive structures in the energy sector, and advising on regulatory best practices based experience in different jurisdictions worldwide. Dr. Brown also provides litigation support in a wide range of areas, including damages estimations, valuation and gas contract arbitrations.

Dr. Brown was previously part of Brattle's European practice before relocating to San Francisco to join the firm's energy practice. Prior to joining Brattle he worked at the UK energy regulator, Ofgem. He holds a D.Phil. in chemistry from the University of Oxford.

### Dr. Paul Carpenter

Dr. Carpenter specializes in the fields of energy economics, regulation, corporate planning, pricing policy, and antitrust. He is an expert in the economics and regulation of the natural gas, oil, and electric utility industries. He holds a Ph.D. in Applied Economics from the Massachusetts Institute of Technology.

Dr. Carpenter has provided expert testimony before the British Monopolies and Merger Commission, the Australian Competition Tribunal, various U.S. and Canadian regulatory authorities, and U.S. federal and state courts. In addition, he has testified before the U.S. Congress on issues surrounding the transition of network industries from strict regulation to increased competition and in high-stakes commercial disputes involving the energy industries. These issues have included: stranded investments and contracts; asset valuation and cost of capital; pricing in long-term supply agreements; evaluation of supply, demand, and price forecasting models; the competitive effects of capacity expansions; and the design of innovative regulatory regimes including performance-based regulation.

Dr. Carpenter has worked extensively with clients throughout Europe, Australia, and New Zealand to help apply lessons on restructuring and regulation from North American experience. He co-founded Incentives Research, Inc. in 1983 and is chairman of The Brattle Group.



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