Gas prices in Western Australia

Review of inputs to the WA Wholesale Energy Market

Prepared for the Independent Market Operator

May 2010

ACIL Tasman

Economics Policy Strategy

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ACIL Tasman Pty Ltd

ABN 68 102 652 148
Internet www.aciltasman.com.au

Melbourne (Head Office)
Level 6, 224-236 Queen Street
Melbourne VIC 3000

Telephone (+61 3) 9604 4400
Facsimile (+61 3) 9600 3155
Email melbourne@aciltasman.com.au

Darwin
Suite G1, Paspalis Centrepoint
48-50 Smith Street
Darwin NT 0800
GPO Box 908
Darwin NT 0801

Telephone (+61 8) 8943 0643
Facsimile (+61 8) 8941 0848
Email darwin@aciltasman.com.au

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000
GPO Box 32
Brisbane QLD 4001

Telephone (+61 7) 3009 8700
Facsimile (+61 7) 3009 8799
Email brisbane@aciltasman.com.au

Perth
Centa Building C2, 118 Railway Street
West Perth WA 6005

Telephone (+61 8) 9449 9600
Facsimile (+61 8) 9322 3955
Email perth@aciltasman.com.au

Canberra
Level 1, 33 Ainslie Place
Canberra City ACT 2600
GPO Box 1322
Canberra ACT 2601

Telephone (+61 2) 6103 8200
Facsimile (+61 2) 6103 8233
Email canberra@aciltasman.com.au

Sydney
PO Box 1554
Double Bay NSW 1360

Telephone (+61 2) 9389 7842
Facsimile (+61 2) 8080 8142
Email sydney@aciltasman.com.au

For information on this report

Please contact:

Richard Begley

Telephone (08) 6262 9411
Mobile 0402 113 483
Email rbegley@aciltasman.com.au

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Executive summary and conclusion

ACIL Tasman was engaged by the Independent Market Operator (IMO) to:

- investigate further sources of information on current gas prices in the Western Australian Wholesale Electricity Market (WEM)
- develop a methodology setting out the basis for the determination of the gas price range and load factor to be included in the 2010-11 Energy Price Limits calculation
- recommend a gas price range to apply for the 2010 Energy Price Limits review and propose any additional initiatives to improve the gas price estimate in future years.

A Draft Report was released by the IMO for public comment. This Final Report has benefited from a number of submissions on the Draft Report.

Clause 6.20.7 of the Market Rules determines that the Maximum STEM price must be set for:

- the estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas, where among things
- the Fuel Cost is the unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station expressed in $/GJ.

A number of generators closely approximate this potential requirement for the 2010-11 period, and include:

- Pinjar GTs – six dual fuel open cycle gas turbines (OCGTs) of 37 MW each operated by Verve Energy
- Mungarra GTs – three 37 MW gas-fired OCGTs operated by Verve Energy
- Kwinana Swift GTs – four by 30 MW duel fuel OCGTs at Kwinana operated by Perth Energy, expected to be commissioned in the second half of 2010
- Parkeston GTs – three by 27 MW dual fuel units operated by Goldfields Power.

Gas commodity pricing

There is considerable variation in the commodity price of gas in Western Australia:

- historic prices from existing supplies that are associated with legacy contracts have ranged up to $3.50 per GJ in the early part of the past decade, ex-delivery basis, and were not linked to the oil price
- more recently, it is estimated that new contracts from existing sources, such as from the North West Shelf and Varanus Island, have been around $7.50 to $8.80 per GJ excluding delivery, with oil price linkage

- new greenfields gas, such as from the Devil Creek operation, is estimated to be priced at up to $10.40 per GJ in 2010-11, excluding delivery, with oil price linkage
- LNG netback prices, including Domgas processing costs, could approach $8 per GJ, depending on the oil price and the LNG pricing formula for the particular supply contract.

Overall, we infer that the major portfolio gas commodity costs could range from $3.50 through to $10.50 per GJ, centred around a normally distributed mean of $7 per GJ.

Spot prices tend to have a premium to large portfolio gas costs – although this depends on the degree to which the market is long or short on any particular day. An 80 per cent confidence interval for spot market commodity cost ranges from $5 to $12 per GJ, with a skew-normal distribution mode of $8 per GJ.

Transmission costs

Gas transport reference tariff costs for the 2010-11 period are expected to be around $1.54 per GJ into the South West, and $4.10 per GJ into the Goldfields via the Goldfields Gas Pipeline (GGP).

Spot transport costs for 2010-11 are anticipated to range from standard rates through to much higher tariff rates:

- For the South-West in 2010-11, $1.54 per GJ to $2.50 per GJ provides an estimate of the 80 per cent confidence interval range for full or part haul spot transport on the Dampier to Bunbury Pipeline (DBP). The range has a skew-normal distribution mode of $1.78 per GJ, which reflects the 15 per cent premium to the standard tariff.
- For the Goldfields, a single price of $4.15 per GJ provides an estimate of spot transport costs for 2010-11 on the GGP, into Kalgoorlie, when available.

Load factors

The gas supply daily capacity factors for a major portfolio peaking generator may be consistent with last year's values of between 70 and 85 per cent, centred on a triangular mode of 75 per cent. We have been unable to assemble any further public information shedding light on this requirement.

Spot gas supply daily capacities could be expected to be close to 100 per cent. A load factor of between 80 and 100 per cent – centred on a skew-normal distribution mode of 95 per cent – would take some account of the probability that purchased gas did not get dispatched.

Relevant gas supply for the marginal gas peaking generator

We consider that the spot gas price provides the best indication of the value of gas being used in the marginal gas peaker – it is effectively the opportunity cost for use of that gas.

At the margin, if the price of gas on the secondary spot market exceeds the average portfolio cost of gas, then that is the value in its next best use, and the price at which the portfolio use of that gas should be valued. This is economically efficient.

The corollary of this is that the secondary spot market for gas can be used opportunistically to replace distillate at the margin, for those gas peakers without access to the flexibility provided by a deep portfolio.

Ensuring that the Maximum STEM price could cover this eventuality could serve to increase the number of gas fired peaking days on the WEM – lowering the average STEM price on those days, and delivering benefits for electricity consumers.

The highest cost opportunity to achieve this is likely to involve a gas peaker in the Goldfields. This result is driven by the higher transport costs down the GGP.

Recommendations

We recommend that spot prices for gas for a generator in the Goldfields be used to determine the Maximum STEM price:

- The 80 per cent confidence interval for spot market commodity cost would range from $5 to $12 per GJ, with a skew-normal mode of $8 per GJ.
- For the Goldfields, a single price of $4.15 per GJ provides an estimate of spot transport costs for 2010-11. As gas may be sourced from the DBP, the additional transport cost for the DBP should be added – which ranges from $1.54 per GJ to $2.50 per GJ, with a skew-normal distribution mode of $1.78 per GJ.
- Spot gas supply daily capacities could be expected to be close to 100 per cent. A load factor of between 80 and 100 per cent, with a skew-normal mode of 95 per cent, would take some account of the risk that purchased gas did not get dispatched.

Combining these distributions using Monte Carlo analysis, the effective cost of gas supplied to a marginal peaker on the SWIS is estimated to lie in the 80 per cent confidence interval range of $11.20 per GJ to $18.90 per GJ, with a skew-normal mode at $13.50 per GJ.

1 Introduction

ACIL Tasman was engaged by the Independent Market Operator (IMO) to:

- investigate further sources of information on current gas prices in the Western Australian Wholesale Electricity Market (WEM)
- develop a methodology setting out the basis for the determination of the gas price range and load factor to be included in the 2010-11 Energy Price Limits calculation
- recommend a gas price range to apply for the 2010 Energy Price Limits
- propose any additional initiatives to improve the gas price estimate in future years.

1.1 The Energy Price Limits review

The Energy Price Limits review is undertaken by IMO annually.

The Energy Price Limits are set for the Wholesale Electricity Market (WEM) and include the Maximum Short Term Energy Market (STEM) price, which applies when non-liquid fuel is used by the highest cost peaking plant on the WEM. The Maximum STEM price must be determined for the highest cost peaking plant fuelled by gas. Accordingly, the gas fuel cost faced by the highest cost peaking plant is a crucial input to the determination of the Maximum STEM price.

Clause 6.20.7 of the Market Rules determine that the Maximum STEM price must be set for:

- the estimate of the short run marginal cost of the highest cost generating works in the SWIS fuelled by natural gas, where among things
- the Heat Rate is based on a 40MW open cycle gas turbine generation station's heat rate at minimum capacity, expressed in GJ/MWh
- the Fuel Cost is the unit fixed and variable fuel cost for a 40 MW open cycle gas turbine generating station expressed in $/GJ.

In turn, the current formulation of the Maximum Stem Price determines the Fuel Cost inputs through:

- the variable fuel cost in $/GJ
- the fixed fuel transport cost in $/GJ
- the gas supply daily capacity factor as modelled as a probability distribution.

In 2009, the Energy Price Limits modelling assumed:

- a gas price range of $6 to $10 per GJ, centred on $8 per GJ, with a normal distribution and a standard deviation of $1 per GJ, and[1]
- a gas load factor range of 70 to 85 per cent, centred on a mode of 75 per cent, modelled as a triangular distribution.[2]

1.2 Draft report

ACIL Tasman provided a Draft Report to the IMO in April 2010, which was made public for comments. Written submissions were received from:

- Landfill Gas and Power
- Synergy
- Perth Energy.

ACIL Tasman provided a comprehensive response to the IMO on the points raised in the submissions. Generally, the points raised did not require any changes for this Final Report.

However, there were two notable exceptions:

- In response to comments from Synergy, ACIL Tasman undertook a further review of and consultation on the spot gas commodity cost distribution. This led to a change in the recommended spot gas commodity cost distribution for 2010-11.
- Perth Energy noted that the cost of transporting gas to Kalgoorlie may need to include a component for transport on the Dampier to Bunbury Pipeline (DBP). ACIL Tasman accepted this point, and amended the transmission cost component to include the cost of transport on the DBP.

1.3 This report

In what follows:

- Chapter 2 provides a brief summary of the WA gas market
- Chapter 3 considers gas commodity costs
- Chapter 4 considers gas transport costs
- Chapter 5 considers load factors
- Chapter 6 discusses what the relevant gas price for a marginal peaker might be.

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1 MMA 2009, *Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2009*, www.IMO.com.au, pp 21.

2 Ibid, pp 22.

2 The Western Australian Gas Market

Despite the abundant natural gas resources off the Western Australian coast, the availability of domestic gas supply in the State is currently constrained.

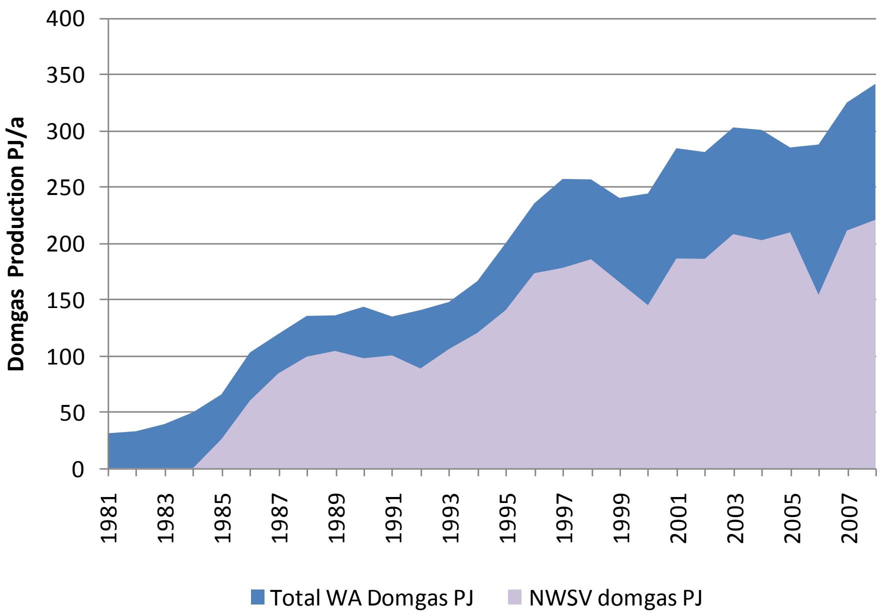
2.1 Structure of demand and supply

The main elements of the Western Australian gas industry are discussed briefly in the following sections.

2.1.1 Western Australia gas supply

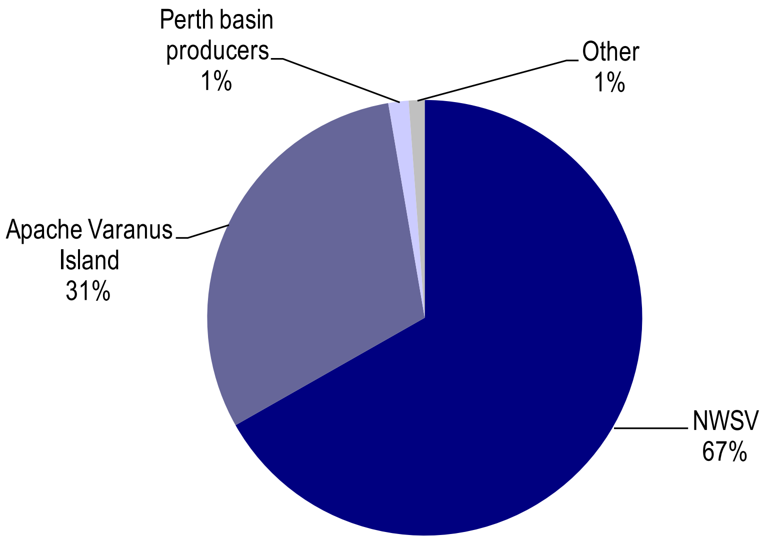
Natural gas supply in Western Australia has grown by 7 per cent in compound average growth terms since the mid-1980s, with the great majority of supply provided by the North West Shelf Venture (Figure 1).

Figure 1 **Western Australian domgas production 1980 - 2008**



Data source: *Western Australia Department of Industry and Resources and ACIL Tasman estimates*

Figure 2 **Shares of Domgas supply in 2007**



Data source: *Western Australia Department of Industry and Resources and ACIL Tasman estimates*

Total gas processing capacity in Western Australia is currently 1,400 TJ per day (or around 510 PJ per annum), however much of this capacity is underutilised. This is particularly the case in the Perth Basin where aggregate processing capacity is around 50 PJ per annum while annual production is currently only 7.5 PJ. Figure 2 shows the breakdown of Domgas production by field for 2007 (calendar year).

LNG exports for 2008-09 totalled 14.0 million tonnes (770 PJ)[3]. Annual production capacity at the NWS LNG Project is now 16.3 mtpa (870 PJ) following the commissioning of Train 5 in late 2008.

2.1.2 Western Australian gas demand

The vast majority of natural gas in Western Australia is utilised for industrial purposes and power generation. Five large customers, Alcoa, Alinta Sales, BHP Billiton, Burrup Fertilisers and Verve Energy, account for 90 per cent of gas consumption in Western Australia.[4] Power generation, alumina refining, and

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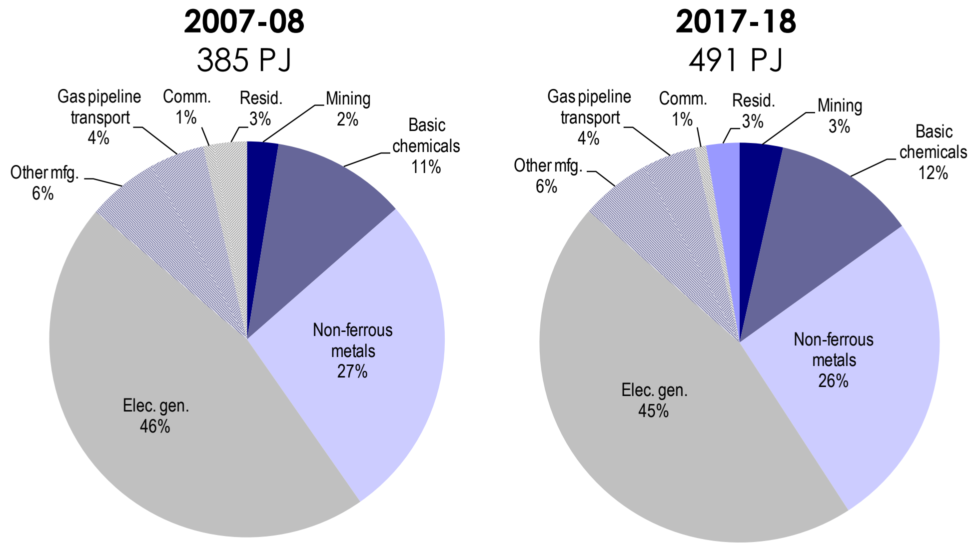
3 Department of Mines & Petroleum, 2009: *"Western Australian Mineral & Petroleum Statistics Digest 2008-09"*.

4 Office of Energy 2009, *Gas Supply and Emergency Management Review: Public consultation package*, www.energy.wa.gov.au, pp 3.

resource processing and manufacturing in the South West accounts for over 80 per cent of existing gas demand.[5]

Figure 3 **Western Australia natural gas consumption (non-LNG), by sector (PJ per annum)**



Note: ABARE classify cogeneration facilities to electricity generation, rather than to the industry sector which utilises the offtake heat.

Data source: ABARE 2007, *Energy Projections to 2029-30*, www.abare.gov.au.

The Western Australia gas market is characterised by (Figure 3):

- A high proportion of gas sales in the industrial sector, predominantly for minerals processing and basic chemicals
- A high level of use of gas in power generation, particularly when compared to the eastern States, and
- A relatively small utility (commercial/residential) sector reflecting the State's small population.

The following section briefly outlines the role of gas in the electricity generation sector.

2.1.3 Demand for gas in electricity generation

In the South West region, most of the base load electricity generation requirement is supplied by coal-fired power stations, with a smaller quantity coming from cogeneration facilities. Stand alone gas-fired generators (CCGT, OCGT) are used for intermediate and peaking service.

[5] Domgas Alliance 2009, *Western Australia's Domestic Gas Security*, Submission to the Gas Supply and Emergency Management Review, www.energy.wa.gov.au, pp 46.

There is a range of gas cogeneration, combined cycle and open cycle gas turbines contributing to energy supply on the WEM. There is considerable variation in the Short Run Marginal Cost (SRMC) of plant. ACIL Tasman estimates that the SRMC of gas-fired plant in the SWIS ranges from about $50 to $80/MWh for combined cycle gas turbine (CCGT) intermediate plant and from $100 to as much as $300/MWh for open cycle gas turbine (OCGT) peaking plant.

Power stations that potentially meet the test of 'the highest cost peaking plant fuelled by gas' will be typically be small open cycle gas turbine plants operating in the South West Interconnected System (SWIS) market that have high Short Run Marginal Costs. The Market Rules are specific that the Energy Price Limits Review consider a 40MW plant.[6]

A number of generators closely approximate this potential requirement for the 2010-11 period, and include:

- Pinjar GTs – six dual fuel OCGTs of 37 MW each operated by Verve Energy
- Mungarra GT – three 37 MW gas fired OCGTs operated by Verve Energy
- Kwinana Swift GT – four by 30 MW duel fuel OCGTs at Kwinana operated by Perth Energy, expected to commissioned in the second half of 2010.
- Parkeston GT – three by 27 MW dual fuel units operated by Goldfields Power.

[6] The rationale for this is that these smaller units are likely to have higher average costs than larger units, such the smaller unit can inform the maximum bound on costs.

3 Gas commodity prices

According to the WA Department of Mines and Petroleum the price of gas sold in Western Australia 'continues to climb, with an average price [excluding gas transmission costs] of $3.81 per gigajoule recorded for 2008–09'.[7] This price presumably reflects a combination of supply under old, long-term contracts with low reference prices, and more recent contracts struck at much higher prices.

The Western Australia gas market has experienced very tight supply conditions in recent times with gas supply contracts difficult to secure. Some companies operating in Western Australia have reported producers are not interested in small contracts.

Recent tightness in the Western Australian gas market may be attributed to a number of factors:

- The high net back value for LNG in the current and expected future high oil price environment, as a result of which producers are currently focused on LNG developments and seeking domestic prices that reflect export parity.
- Higher international oil prices and consequently higher values for gas sold on the international market as LNG have led to a widening gap between domestic gas prices and LNG netback value in recent years. Consequently gas producers have preferred to target the international LNG market, while also seeking higher prices for Domgas supplies.
- High oil prices have also resulted in high prices for petroleum products including diesel and fuel oil, which represent the competitive alternative for many of the more remote mining and industrial sites in Western Australia. Gas producers have therefore been able to command high prices in these locations.
- Rapidly rising capital costs for offshore development and construction, particularly through the period 2005 to 2008, led to significantly higher production costs for new gas supply sources. While there was some relief on the cost front as a result of the global financial crisis (for example, the price of steel fell sharply), development costs remain high.
- Developing large, higher-cost offshore gas deposits may require economies of scale that can only be achieved through LNG or other export-focussed value-adding processes, with incremental supply to domestic markets not providing an economic basis for standalone development.

[7] Department of Mines & Petroleum, 2009: *"Western Australian Mineral & Petroleum Statistics Digest 2008-09" p.26.*

3.1 Existing Domgas supplies

The major Domgas supplies of relevance to this exercise are those from the North West Shelf (NWS) Joint Venture and from Apache/Santos's Varanus Island operations. Significant new gas supplies are also soon to come on stream from the Apache/Santos Devil Creek Domgas plant.

3.1.1 NWS Joint Venture gas supply

The NWS supplies approximately 70 per cent of Western Australia's annual domestic gas demand.

NWS domestic gas historically has been supplied at very low cost – based on long term take or pay contracts that reflected the initial development arrangements. However, with the recent increases in greenfields gas costs, and the increasing opportunity costs associated with LNG production, there has been upward movement in the price demanded for NWS supplies. Importantly, virtually all available production capacity in the NWS Domgas facility has been contracted, with the result that the NWS JV has had no capacity to meet new gas demand.

Gas prices under long-term contracts have come under upward pressure through contractual price resetting mechanisms. So, for example, the NWS supply to Alinta under its take or pay contract was subject to price arbitration in 2009. ACIL Tasman understands that the reported November 2009 decision will lead to an increase in the gas price. However the outcome is not public, nor is it likely to become public. That said, recent JP Morgan analysis has concluded that the new arbitrated gas price for Alinta from the NWS is around $7.50 per GJ on an ex-delivery basis, escalating at CPI.[8] This compares to the old price which was estimated at $3.50 per GJ.[9] With an estimated delivery price into the South-West of around $1.50 per GJ, this would take delivered prices to around $9.00 per GJ.

3.1.2 Apache Corporation / Santos Varanus Island

The Harriet Joint Venture and John Brookes Joint Venture gas supplies are processed on Apache's Varanus Island facility. Gas production was severely disrupted following a gas pipeline explosion, but was restored to full capacity of about 365 TJ per day during 2009.

8 J.P.Morgan 2010, Australia Equity Research.

9 With a transport cost of around $1.50 per GJ into the South-West, the old delivered price approaches $5.00 per GJ. Prior to 2005, gas commodity costs and transport costs were lower again, implying gas prices delivered into the South-West were around $3 per GJ.

There is some evidence of recent gas supply availability and pricing from these sources through public information on a gas sales agreement between Santos and Moly Metals Australia for supply of gas from the John Brookes field to the Spinifex Ridge molybdenum and copper mine in the Pilbara region.[10]

According to an ASX release issued by Santos on 8 October 2008, the agreement involves supply of approximately 33 PJ of gas over six years commencing in mid-2010. It is understood that the gas price includes transportation to the Spinifex Hill site, located off the Pilbara Energy Pipe Line (PEPL). The gas price is linked to international traded crude oil and is denominated in US dollars. According to the announcement by Santos, at a future oil price of US$90 per barrel, the expected revenue derived from the contract would be approximately US$380 million. Assuming full linkage to oil price, and adopting an oil price of US$75 per barrel on average over the next year to reflect recent market conditions, would reduce the expected revenue to US$ 317 million. On this basis, and assuming a US$/A$ exchange rate of 0.90, the implied average delivered price of gas under this arrangement would be A$10.66 per GJ.

Applying this as the real price at mid-2012 (being the mid-point of the contract period) and de-escalating to mid-2010/11 implies a delivered price of around A$10.27 per GJ for that period. Adjustments need to be made for the cost of transportation of gas via part backhaul on the DBNGP, forward haul on PEPL and a dedicated spur line to the Spinifex Ridge site. Again there is no publicly available data on which to accurately assess these transmission cost components, but making what we consider a reasonable estimate of $1.50 per GJ in total, the implied commodity cost of gas under this arrangement is about $8.80 per GJ in mid 2010-11.

3.2 New greenfields gas prices

For the future, current reserves and increasing LNG supply commitments suggest that Domgas prices could continue to climb in real terms in the absence of new Domgas supply. That said, new LNG processing operations bring the prospect of new Domgas supplies – particularly given the Western Australia Government's domestic gas reservation requirement of 15 per cent of LNG production and the recent changes to gas quality specifications. Higher gas prices also provide encouragement for a range of new exploration plays

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[10] While we acknowledge that some projects were deferred due to the global financial crisis and depressed markets for some commodities, we consider that publicly announced gas sales agreements provide a useful indication of gas pricing in Western Australia, even in circumstances where subsequent market conditions resulted in project deferral.

that are targeting gas sources previously regarded as uneconomic to pursue, such as Canning Basin onshore gas, coal seam gas and shale gas in the Perth Basin, and tight gas in conventional reservoirs. The development of a range of new Domgas supplies over the next decade could see the emergence of a more competitive Domgas market that will stem the upward pressure on prices. However, a return to the low prices that prevailed in the past seems highly unlikely.

3.2.1 The Reindeer project

The sale of gas by Santos from the new Devil Creek facility to CITIC Pacific's Sino Iron project – a world scale magnetite mining project – provides evidence for recent pricing from greenfields Domgas operations.[11] According to Santos (media release dated 7 January 2009), the gas will be supplied from the new offshore Reindeer gas project, which is connected via a new 105 kilometre offshore pipeline to the new onshore sales gas processing facility at Devil Creek. The Devil Creek Domgas facility is located approximately 45 kilometres southwest of Dampier, adjacent to the Dampier – Bunbury Natural Gas Pipeline (DBNGP).

Under the contract, Santos will supply 75PJ of gas over seven years commencing in the second half of 2011. The contract price is on a delivered (transport inclusive) basis and is fixed for the first three years with periodic adjustments for changes in CPI. From the beginning of the fourth year the price is indexed to international oil prices. The revenue will be denominated in US dollars. Assuming an oil price of US$50 per barrel, Santos estimates that its net share of the expected revenue over the seven years of the contract will be approximately US$585 million. On this basis, and assuming a US$/A$ exchange rate of 0.90 and an oil price of US$75 per barrel, the implied average delivered price of gas under this arrangement would be A$13.00 per GJ.

Applying this as the real price at mid-2014 (being the mid-point of the contract period) and de-escalating to mid-2010-11 implies a delivered price of around A$11.92 per GJ for that period. Once again, adjustments need to be made for transport of gas from the Devil Creek processing plant to the mine site, including the tie-in from Devil Creek to DBNGP and from DBNGP to the Sino Iron site. Assuming these transport costs amount to $1.50 per GJ in total,

[11] Gas will tend to be supplied to those entities that value it more highly. To the extent that new gas contracts for peaking generators need to compete with other uses for gas, then they will need to pay higher prices. The evidence of gas prices being paid by minerals processing plants is used to illustrate the overall trend in Western Australian gas prices rather than as a direct basis for determining the prices faced by peaking electricity generators.

the implied commodity cost under this agreement would be around A$10.40 per GJ in 2010-11.

3.2.2 Other greenfields operations

In terms of potential developments, BHP's Macedon field appears closest to development, with the changes to Western Australia's gas quality laws in 2009 opening up prospect for Domgas supplies from this source. Construction of the Macedon plant is expected to start in late 2010, for first gas in 2013. Macedon contains reserves of approximately 1.2 tcf, sufficient for production of 200 TJ per day for up to 20 years. No information has been published on Macedon gas prices.

3.2.3 LNG netback pricing

Our estimates for a typical two train LNG facility – built onshore with tieback to an offshore gas field, and a hurdle rate around 12 per cent (post tax nominal) – suggest required netback pricing for the commodity downstream (into the LNG processing plant) of around A$5.50 per GJ.

An alternative approach to establishing the netback price can be based on the delivered cost of LNG adjusted to take account of supply chain costs. Using current oil prices – at around US$80 per barrel – and an assumption of an LNG/oil price parity factor of 0.14 which is around 80 per cent of full oil parity gives an LNG price of around US$11.50 per MMBtu.[12] Subtracting re-gassing and shipping costs of around US$2 per MMBtu, and LNG liquefaction costs of around US$3 per MMbtu gives a netback price into the LNG processing plant of US$6.50. This is equivalent to around A$6.85 per GJ, assuming conversion to $A based on an exchange rate of 0.9 $US/$A, and energy units conversion factor of 1.055 GJ per MMbtu.

Taking this price of A$6.85 per GJ, adding Domgas processing costs estimated around A$1.00 per GJ, gives a netback commodity cost of $7.85 per GJ.

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12 That is, assuming an LNG price formula of $P = AX + B$

where

P = LNG price (US$/mmbtu)

A = the slope of the price curve (0.17 = full oil parity)

X = oil price in US$/barrel

B = a constant.

3.3 Spot prices

Since the Varanus Island incident and the operation of the Gas Bulletin Board there has been an increasing use of secondary spot trading arrangements. As noted by the Domgas Alliance:[13]

> Trades in gas transmission capacity and physical gas are regularly being conducted on a short and long term basis.
>
> While no formal market has been established, given the relatively small number of major players, large gas consumers and pipeline shippers commonly trade amongst themselves either independently, or with the assistance of brokers.
>
> Smaller industrial gas consumers also trade either independently or with the assistance of brokers.
>
> There is now a high level of sophistication in trading arrangements between gas users.
>
> DBP, the owners of the Dampier to Bunbury Natural Gas Pipeline (DBNGP), posts spot transmission capacity, subject to availability.
>
> A gas trading exchange (gasTrading) already facilitates trades of both gas and pipeline capacity, with trades accounting for up to 10 per cent of the gas delivered into the DBNGP on some days.

The secondary market is likely to become an increasingly important part of the market, given:

- the moves by upstream suppliers to ask for 100 per cent take or pay contracts with limited flexibility and no banking
- the flattening of the winter retail gas peak as more consumers install reverse cycle air conditioning allowing winter heating with electricity, albeit offset to a degree by an associated peak winter electricity demand.

Our understanding is that the price of spot gas varies day to day according to:

- whether the market is long or short for that day, which in turn is influenced by
  - seasonal factors
  - the individual situations of the major gas contract holders - including Verve, Synergy, BHP, Alinta, and Alcoa

    … plant outages
- counter-party delivery terms – for example payment terms and the financial surety of counterparty can have a significant influence on the price.

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[13] Ibid, pp 17.

3.3.1 The spot price range

Based on discussions with parties active in the spot market, we understand the spot price of gas in the secondary market in January 2010 was around $5 per GJ. December 2009 spot gas prices were lower, while February and March 2010 spot gas prices were higher.

A typical 80 per cent interval range is understood to be $5 to $12 per GJ.

- Prices are distributed around a skew-normal mode of around $8 per GJ - which reflects the centre of the mid-range and reflects equilibrium between a short and a long market.
- Extremes of the tails could be anywhere $1 per GJ up to the $26 per GJ distillate equivalent (excluding fuel tax) - which is where gas spot prices went during the Varanus crisis.

3.4 Conclusions on gas pricing

There is considerable variation in the commodity price of gas in Western Australia:

- historic prices from existing supplies that are associated with legacy contracts have ranged up to $3.50 per GJ, excluding delivery basis, and were not linked to oil price
- more recently, it is estimated that new contracts from existing sources, such as from the NWS and Varanus Island, have been around the $7.50 to 8.80 per GJ excluding delivery, with oil price linkage
- new greenfields gas, such as from the Devil Creek operation, is estimated to be priced at around $10.40 per GJ in 2010-11, excluding delivery, with oil price linkage
- LNG netback prices, with allowance for Domgas processing costs, could approach $8 per GJ, depending on oil price and the LNG pricing formula for the particular supply contract.

Overall, we infer from the analysis that the major portfolio gas commodity costs could range from $3.50 through to $10.50 per GJ, centred around a normally distributed mean of $7 per GJ.

Spot prices tend to have a premium to large portfolio gas costs – although this depends on the degree to which the market is long or short. An 80 per cent confidence interval for spot market commodity cost would range from $5 to $12 per GJ, with a skew-normal distribution mode of around $8 per GJ.

4 Transmission costs

Transmission costs on both the Dampier to Bunbury Natural Gas Pipeline (DBNGP) and the Goldfields Gas Pipeline (GGP) are regulated by the Economic Regulation Authority under the National Gas Law. However, all contracts on the DBNGP are bi-lateral contracts negotiated outside the regulatory regime with tariffs agreed between DBP Transmission, the operator of the DBNGP, and shippers. In addition, most contracts on the GGP relate to 'uncovered' expansions of the pipeline, and hence are at rates different to the reference tariffs.

4.1 Standard tariffs

The following sections discuss the standard tariffs on each of the DBNGP and the GGP.

4.1.1 DBP standard shipper tariff

Firm full haul capacity ("T1") on the DBNGP is contracted under the terms of the Standard Shipper Contract ("SSC") published on Dampier Bunbury Pipeline's (DBP) website. The 2010 SSC T1 tariff was $1.49/GJ at 100 per cent load factor, with the tariff structured approximately 80 per cent reservation charge and 20 per cent commodity charge.[14]

The T1 tariff escalates at CPI until 1 January 2011 and at CPI-2.5 per cent from 1 January 2011 to1 January 2016. From 1 January 2016, the 100 per cent load factor T1 tariff under the SSC's will be set at the 100 per cent load factor tariff for the nearest equivalent Reference Service approved by the ERA. However, the terms and conditions of the SSC continue for the term of those contracts.

Escalating the 2010 tariff by 2.5 per cent to give an approximate estimate for 1 April 2011 would give a tariff of $1.54 per GJ.

[14] DBP 2010, personal communication, 27 April 2010. This $1.49 per GJ price for 2010 includes the 'Tariff Adjustment Factor' (TAF) applied to all shippers on the SSC. The TAF for a tariff adjustment to reflect the difference in any pipeline expansion costs between the actual costs incurred and budget figures agreed between DBP Transmission and shippers at the time the SSC's were written in 2004.

4.1.2 GGP tariff

While the ERA publish rates for the GGP on its website, these are for the covered portion of the pipeline, and do not apply to the uncovered parts, which relate to subsequent expansions.

In the April quarter 2010, a typical 'A4' contract for six to ten years on the GGP was subject to the following charges:[15]

- toll charge of 0.348227 $/GJ
- capacity reservation charge of 0.002012 $/GJ/day/km
- throughput charge of 0.000639 $/GJ/km.

With a GGP pipeline distance of 1378 kilometres to Kalgoorlie, a 100 per cent capacity tariff to Kalgoorlie would cost around $4.00 per GJ in April 2010.

Inflating this by an assumed 2.5 per cent would take the tariff to $4.10 per GJ for April 2011.

4.2 Spot tariffs

Spot gas will require spot transport – as it is often sourced from the Goldfields or points north of the South-West.

4.2.1 DBP

Some spot gas transport comes bundled with the spot gas. Other spot transport may need to be purchased separately. Our discussions with industry sources indicate that:

- DBNGP often has up to 25 TJ of spot capacity available each day.
- Alternatively, other parties, for example Verve or Alinta, may offer their contracted capacity to third parties on a spot basis during periods when their utilization is low.
  - However, Verve's portfolio is becoming less flexible as the winter peak heating gas demand declines and shifts to an electricity peak with split system heat pumps.
  - As a result, spot capacity from Verve is becoming much harder to get on a warm or cold day, but is more available in the shoulders.

[15] APA 2010, personal communication with Ian Yen, 27 April.

The price for full haul and part haul spot capacity on the DBNGP from DBP is set by an auction process.[16] In summary the process is as follows:

- Each day DBP Transmission publishes, for shippers, the amount of spot capacity available for the following day and the minimum price at which DBP Transmission is willing to provide that capacity.
- Typically the minimum price is 115 per cent of the 100 per cent load factor T1 tariff with charges applied to the actual amount of capacity used on the day.
- Shippers then bid price/volume pairs.
- Spot capacity is then allocated to the highest priced bid, then the next highest, etc until the published quantity is allocated.

Currently there is little bidding activity and spot capacity is generally sold at the minimum price. However, in a constrained market, such as existed from 2004 to 2006, spot capacity was regularly purchased at up to 500 per cent of the T1 tariff and occasionally at higher prices. The highest prices bid were in the range of 1,000 per cent of the T1 tariff.[17]

4.2.2 GGP

GGP does not currently have any arrangements for spot transport in place. However, GGP advises that it would be possible for an existing shipper to gain access to spot capacity for up to 5 to 8 TJ/d for a small premium of 5 cents per GJ over and above the existing A4 tariff.[18]

4.3 Conclusions on gas transport costs

Gas transport reference tariff costs for the 2010-11 period are expected to be around $1.54 per GJ into the South West, and $4.10 per GJ to Kalgoorlie.

Spot transport costs for the South-West for 2010-11 are anticipated to range from less than the 15 per cent premium, through to much higher tariff rates:

- For the South-West in 2010-11, $1.55 per GJ to $2.50 per GJ provides a reasonable 80 per cent range for both full haul and part haul, centred on a skew normal distribution mode of $1.78 per GJ which reflects the 15 per cent premium to the standard tariff.

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16 We note that DBP only operates one market for spot capacity. There is no provision for any pro-rating of price by distance or any other factor – such a mechanism would allow part haul shippers to game the system by making artificially high price bids in the knowledge that their bid would be pro-rated to distance to the disadvantage of full haul shippers. Therefore, the same price applies for spot capacity at every location on the DBP.

17 DBP 2010, personal communication with Mark Cooper, 27 April.

18 APA 2010, personal communication with Ian Yen, 27 April.

For the Goldfields, a single price of $4.15 per GJ provides an estimate of spot transport costs for 2010-11 for up to 5 TJ/d, into Kalgoorlie, when available.

5 Load factors

Load factors have the potential to significantly influence the gas price faced by the marginal generator, both in terms of the effective gas price, and also transport costs. MMA noted as part of the 2009 review that the DBNGP and GGP operate at high load factors – as high as 96 per cent in 2005.[19]

Potential gas load factors will be markedly different for those gas generators which are part of a major gas portfolio with diversity and depth, as compared to a smaller, thinner operation with only one or two aggregated gas demands. Gas load factors associated with spot sales will be different again.

5.1 Major portfolio load factors

Major gas and electricity portfolios provide depth and flexibility with regard to load factors.

A key peaking generator in this context is Verve Energy. Verve has significant depth in terms of its base-load gas generation portfolio. Verve also benefits from large legacy contracts for gas and for transport, which provide significant flexibility in their contractual terms. Further flexibility in managing gas availability can be provided by their coal generation assets, which allow for potential gas banking overnight in order to feed gas peaking units during the day. This allows Verve to manage the peaking gas supply within a smaller gas profile, allowing a higher overall load factor.

However, in recent times there has been generation overcapacity on the SWIS of up to 10 per cent above the IMO's capacity target. It has been argued that this results in the displacement of Verve generation by the new IPPs to further up the merit order. As noted by the Oates Review:[20]

> When Bluewaters 2 comes online and combines with base load supply from Bluewaters 1 and NewGen, Verve expects to have its Cockburn power station on reserve shutdown for most of the year and at least one unit of Muja C cycling down or off. These new displacing plants are expected to represent a significant contribution to the SWIS overnight load which is approximately 1,500MW.

The result is that Verve likely has an excess of transport capacity and gas in the near term.[21] The corollary is that Verve's gas load factor may not be as

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19 MMA 2009, *Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2009*, www.IMO.com.au, pp 24.

20 Deloitte and Oakley Greenwood 2009, *Verve Energy Review*, www.energy.wa.gov.au, pp 33.

21 These conditions in part explain the general availability of spot gas in recent times.

favourable as previously was the case – where it was able to fully utilise all its purchased gas within the bounds of its take or pay contractual arrangements, and to manage its transport with a high load factor.

The current methodology used in the Maximum STEM price calculation uses the average portfolio *daily* capacity factor for the marginal peaker's gas supply.[22] We have been unable to assemble any better information on a typical portfolio average load factor than was gleaned in the 2009 process – the portfolio value applied in 2009 was between 70 and 85 per cent, centred on a triangular mode of 75 per cent.

However, the marginal generator will not necessarily be an operator with a deep gas portfolio such as Verve. The marginal generator may be a new entrant with arrangements to overcome load factor penalty. There are a number of ways to do this, including:

- drawing on the services of a deeper portfolio – in effect tolling spare gas into electricity
- developing arrangements for storage and intraday substitution to reduce the penalty associated with a small load factor.

A good example in this context is Neerabup – which is a peaking operation that operates solely on gas. It manages its very low load factor by drawing on the flexibility provided by:

- the depth in gas supply and transport provided by its gas supplier and augmented by the flexibility its own operations
- the 20 TJ of gas it is able to store in the spur pipeline servicing the plant.

However, the large size of the Neerabup OCGTs (two by 165 MW) means that it is not relevant to this exercise. Nevertheless, it is an example of how arrangements that combine storage and overnight displacement of gas, combined with an element of portfolio depth, can manage a low load factor.

5.2 Spot gas load factors

The development of the spot gas secondary market raises the intriguing possibility that spot gas and transport could be used opportunistically in the marginal gas peaks, as a substitute for distillate in the dual fuel peakers. Perth Energy's Kwinana Swift OCGTs or Goldfield Power's Parkeston OCGTs potentially could utilise this approach.

22 MMA 2009, *Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2009*, www.IMO.com.au, pp 52.

In this case, the higher spot gas price could set the Maximum STEM price, inducing more gas peaking onto the system, which would avoid a distillate generation price that was significantly higher again. This could yield benefits for electricity consumers, and so should be considered. We discuss this possibility in greater detail in the next Chapter. For now, we consider the load factor penalties associated with spot gas peaking supply at the margin.

The spot gas commodity itself would be 100 per cent take or pay, presumably for a short period – such as during the next day.[23] Firm spot transport would also need to be arranged.

However, there would be some risk that the marginal gas peaker using spot gas did not get dispatched in accordance with expectations, given the need to make arrangements to purchase spot gas a day ahead. In this case, the load factor may not be 100 per cent. A load factor of between 80 and 100 per cent, centred on a skew-normal distribution mode of 95 per cent, would reflect this small but significant probability.

5.3 Conclusion

The gas supply daily capacity factors for a major portfolio peaking generator may be consistent with last year's values of between 70 and 85 per cent, centred on a triangular mode of 75 per cent. We have been unable to assemble any further public information shedding light on this requirement.

Spot gas supply daily capacities could be expected to be close to 100 per cent. A load factor of between 80 and 100 per cent, centred on a skew-normal distribution mode of 95 per cent, would reflect the probability that the purchased spot gas did not get dispatched.

[23] We note that the STEM is a day ahead market, with half hourly prices established by auction for the subsequent day.

6 Relevant gas supply for the marginal gas peaking generator

The final question that needs to be answered is: what is the relevant gas supply for the highest cost generating works on the SWIS. In this context, we may choose between:

- a gas supply backed by deep a portfolio – for example available to Verve
- a spot gas supply that might be used opportunistically by a dual fuel unit – for example the plant run by Perth Energy or by Goldfields Power.

Previous reviews conducted by MMA have considered the first approach as being relevant. As noted by MMA:[24]

> Below a certain capacity factor it therefore becomes cheaper to run a gas turbine on distillate than on gas and for peaking duty it is unlikely that a stand alone gas turbine plant in the SWIS would rely on a gas supply. It would be uncompetitive against distillate fuelled units. Indeed, it would be unwise to commit to a long-term gas supply contract for such duty and it would be expected to rely on spot gas with distillate back-up when there is a market for trading in surplus gas.
>
> For this reason, it is only meaningful to apply a gas price in the calculation of the Maximum STEM Price if it is assumed that the supply of gas comes from a portfolio of gas supplies to power stations when there is a temporary surplus. In such a case it would be more relevant to the commercial reality to apply an average cost of gas, based on the usage by the portfolio.

However, we consider that the spot gas price provides a reasonable indication of the value of surplus gas in this instance – it is effectively the opportunity cost for use of that gas within the portfolio, and in this case, within the peak generation unit. At the margin, if the price of gas on the secondary market exceeds the average portfolio cost of gas, then that is the value in its next best use, and the price at which it should be valued. This is economically efficient.

The corollary of this is that the secondary spot market for gas could be used opportunistically to replace distillate at the margin for those peakers without access to portfolio depth.[25] This would potentially increase the number of gas

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[24] MMA 2009, *Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2009*, www.IMO.com.au, pp 52.

[25] The WEM is a day-ahead market. Our understanding is that it is feasible to source spot gas on a day-ahead basis consistent with this requirement. We have included a load factor for spot gas that reflects that there will be some risk associated with sourcing firm spot gas – and that there is a potential misalignment in the timing of the sourcing of the spot gas and the securing of generation dispatch.

fired peaking days, lowering the average STEM price, and delivering benefits for electricity consumers.

The rise of the secondary spot market therefore provides a powerful insight into the true value of gas at the margin during peaks. The secondary market effectively arbitrages flexibility among the various market participants. Large gas contracts are tending to have less flexibility than those of the past – even to the extent of requiring 100 per cent take or pay terms, with as little as 10 per cent daily swing. As a result, the depth of the secondary market is likely to increase in the future. This provides a market based alternative to portfolio depth, and we expect, increasing transparency for the price of gas for the marginal gas peaker.