Public Version of Final Report to

Independent Pricing and Regulatory Tribunal of NSW

Gas Retail Price Review - Wholesale Gas Costs

June 2010

McLennan Magasanik Associates

Ref: J1842

Project Team

Michael Goldman

Richard Lewis

Albert Suyanto

Esteban Gil

Melbourne Office
PO Box 825
South Melbourne Vic 3205

242 Ferrars Street
South Melbourne Vic 3205

Tel: +61 3 9699 3977
Fax: +61 3 9690 9881

Brisbane Office
GPO Box 2421
Brisbane Qld 4001

Level 2, 200 Mary Street
Brisbane Qld 4000

Tel: +61 7 3100 8064
Fax: +61 7 3100 8067

Canberra Office
GPO Box 443
Canberra City ACT 2601

Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

ACN: 004 765 235
ABN: 33 579 847 254

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

VERSION

Version	Date	Comment	Approved
1	June 2010	Conversion of final report to public methodology report	MG

EXECUTIVE SUMMARY

Introduction

The current arrangements for regulating retail gas tariffs for small customers in NSW are due to expire on 30 June 2010. The NSW government has decided to retain the option of regulated tariffs until at least 2013 and has asked IPART to put in place new arrangements for the 2010 regulatory period with the Standard Retailers for different parts of NSW; AGL, ActewAGL, Country Energy and Origin Energy.

The Standard Retailers have submitted their proposals to IPART. Tariffs charged under the proposals can be divided into the sum of the Retail (R), Network (N) and (yet to be calculated) climate (C) costs. As the Standard Retailers have all proposed automatic pass-through of network costs and pass-through of climate costs, both of which are largely out of the control of retailers, the focus of the IPART review is on the "R" cost of supplying the regulated small customers market. According to IPART, the R cost is estimated to make up around 50% of a small gas customer's overall bill.

The R cost can be considered to have a number of sub-components:

- The cost of the underlying gas commodity which is required to supply the market (referred to as commodity gas).
- The cost of any "additional deliverability" beyond that available under the standard commodity contracts required to supply the market during peak periods
- the "transmission" cost of hauling gas through major transmission pipelines to the small customers as required
- the "retail operating costs" which are costs incurred by the retailer for activities such as billing, marketing, attaining and servicing customers
- the "retail margin" which compensates retailers for the risk and capital involved in supplying the market
- "other" costs (apart from network and climate costs which are considered separate to the above.

The commodity, additional deliverability, transmission, climate and any "other" costs related to supply of gas are collectively referred to as "wholesale gas costs".

IPART has engaged McLennan Magasanik Associates (MMA) to assist it in reviewing the wholesale gas costs proposed by the Standard Retailers.

It should be noted that the MMA reviews of wholesale gas costs differ according to information and cost substantiation provided by each of the Standard Retailers.

Review process

MMA has been asked to review the proposals and cost information related to the wholesale gas costs submitted by the Standard Retailer against costs which would be incurred by a prudent and efficient retailer. The nature of this information is generally considered to be commercially sensitive and confidential. In our review we have taken into account information provided by the Standard Retailers as well as recent pertinent regulatory determinations and other available information.

Components of wholesale gas costs

As part of its assessment of wholesale gas costs, MMA examined the information submitted by each Standard Retailer on the individual components of its proposed costs – commodity gas cost, cost of additional deliverability (to service peak demand), transmission costs and other costs.

Commodity gas cost

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

Additional deliverability

If the peak day requirements of small customers are greater than are provided for under the commodity gas supply contracts, then there will be an extra cost of supply to meet the additional deliverability requirement.

The cost of additional deliverability can be calculated from the following formula:

> Additional deliverability cost ($/GJ) = price of additional deliverability ($/GJ MDQ/year)/365 x (1/(Customer load factor) – 1/(Supply load factor))

It can be seen that this $/GJ amount is independent of the size of the load but depends only on the customer load factor, supply load factor and price of MDQ. This cost is calculated in two parts; firstly the amount of additional deliverability required is calculated then the price of providing this deliverability is assessed.

Calculation of the customer load factor

The peak capacity requirement is generally expressed in terms of maximum daily quantity (MDQ). The customer load factor is the average daily requirement divided by the peak day requirement or MDQ.

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

Calculation of the supply load factor

Base gas supply contracts generally specify the volume of gas to be supplied, the level of flexibility around this contracted amount (defined by the supply load factor) and the take-or-pay level. The supply load factor is the average daily contract quantity divided by the MDQ available under each contract.

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

Price of additional deliverability

Additional deliverability is likely to be available from a number of sources, not just storage or additional contracts with producers. A prudent and efficient retailer is likely to adopt a portfolio approach, using cheaper sources such as take or pay agreements and park and loan to the extent possible and then topping this up with the more expensive options.

The range of underground storage prices currently quoted by TRUenergy on its website is $160 to $240/GJ MDQ. The website suggests that the lower prices would be those contracted for a longer term.

However, the published price range for storage provides nothing more than an indication of the price paid. The ESCOSA report in 2008 stated that, at the time, Origin Energy was paying less then the bottom of the range then quoted.

In addition MMA considers it likely that the <u>average</u> price of MDQ available across a portfolio to efficient and prudent retailers may be below published prices of underground storage. Some of the additional deliverability might be available, for example, from park and loan tariffs on pipelines.

MMA considers it unlikely that an efficient retailer would contract full additional deliverability requirements for its small market at the published price of underground storage. Although MMA considers it reasonable that the small market should pay for its stand-alone contribution to the peak day requirement, it does not consider it reasonable for the price used to be assessed at what is likely to be the highest price available for MDQ. MMA considers it reasonable for the price used for additional deliverability to be estimated at $160/GJ MDQ – the bottom end of the range provided by TRUenergy for storage.

Conclusion on additional deliverability

MMA examined the additional deliverability required by the small customer market on a very cold day, the sources of such additional deliverability and the likely price of additional deliverability. As part of this analysis, MMA considered each retailer's assumption about customer load factor, which is central to the calculation of both additional deliverability costs and transmission costs.

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

In assessing the source and price of additional deliverability, and deriving its own assessment of this cost component, MMA compared proposed costs to those submitted by the other Standard Retailers, recent regulatory decisions and other publicly available benchmarks. MMA also tested the sensitivity of the overall cost of additional deliverability to varying the assumed price of additional deliverability.

Transmission costs

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

In examining proposed transmission costs, and deriving its own assessment of this cost component, MMA compared each retailer's forecast transmission costs to those it estimated using the published transmission tariffs and MMA estimates of customer load factors and proportion of peak load supplied through each pipeline.

Other costs

As well as the costs of gas commodity, additional deliverability and transmission, retailers also face additional risk or market-related costs associated with procuring wholesale gas supply. For example, AGL has estimated the additional costs of participating in the Short Term Trading Market (STTM) which will from September 2010 impact all gas supplied into the Sydney hub.

The STTM has not yet commenced, so there are significant uncertainties related to how it will operate and what costs will be incurred. However, MMA expects that introduction of the STTM may result in costs being incurred for:

- market fees of the order of $0.05/GJ. MMA considers it reasonable for these costs to be passed through, although care must be taken that these costs are not also included in retailer operating costs.
- increased IT expenditure and operational staff.
- re-nomination costs - because of the structure and incentives of the STTM, a prudent and efficient retailer will aim to minimise the difference between its daily forecasts and actual deliveries. One method to achieve this is through pipeline re-nominations or "premium park" services. The estimated cost of re-nominations

will depend on a retailer's estimates of forecasting error, average impact and time and price of re-nomination.

- costs associated with Market Operator Service (MOS) provision and contingency gas provision.

MMA has assessed the forecast other costs of each Standard Retailer by comparing them to the costs submitted by the other retailers and against information gathered from discussions with other industry participants.

Climate costs

As the future nature and timing of any such regulation is currently unclear, none of the Standard Retailers has included a specific cost for the impact of climate regulation; however, any climate costs incurred will be passed through.

MMA has indicatively assessed that CO2-e prices of \$10/t, \$20/t and \$30/t would add about \$0.62/GJ, \$1.24/GJ and \$1.85/GJ respectively to the price of natural gas to small customers.

Conclusion

MMA has reviewed the retailers' proposals for wholesale gas costs to its regulated small customer market. MMA's final assessments are provided in Exec Table 1. Note that in some cases MMA provided a range of potential outcomes. In this instance, the value provided in the table below has been selected by IPART from within this range.

Exec Table 1: Wholesale cost of gas supply, average \$/GJ \$2009/10

	AGL	ActewAGL	Country Energy	Origin Energy
\$/GJ	7.26	7.11	6.17	6.81

1 INTRODUCTION

1.1 Regulatory context

Since 2002 all gas customers in New South Wales have been able to choose their retailer supplier and negotiate a retail supply contract. Small retail gas customers, defined as those consuming less than 1000 gigajoules (GJ) or 1 terajoule (TJ) per annum (pa), have also had the option of remaining on a regulated retail tariff.

The Independent Pricing and Regulatory Tribunal (IPART) is responsible for setting the regulated retail gas prices charged by AGL, Country Energy, Origin Energy and ActewAGL (the Standard Retailers – each with a specified area of supply) to small gas customers in NSW who have not chosen to enter into a negotiated customer supply contract.

The current arrangements for setting regulated retail gas tariffs and charges are due to expire on 30 June 2010. The NSW Government has decided to retain the option of regulated retail tariffs at least until 2013 and the Minister for Energy[1] has asked IPART to put new arrangements in place for the period 1 July 2010 to 30 June 2013 (2010 regulatory period).

Under section 27 of the *Gas Supply Act 1996*, IPART has the option of establishing a Gas Pricing Order (GPO) that regulates tariffs, fees and other charges for small retail customers under standard form customer supply contracts.

IPART has not previously exercised this power, preferring a more light-handed form of regulation. Between 1997 and 2004, IPART regulated prices by establishing voluntary pricing principles (VPPs). Since 1 July 2004, IPART has agreed Voluntary Transitional Pricing Arrangements (VTPAs) with each of the Standard Retailers.

IPART has stated its intention to continue using a light-handed approach to regulating gas tariffs by reaching a new VTPA with each of the Standard Retailers unless a mutually satisfactory arrangement cannot be reached[2].

1.2 Proposals from Standard Retailers

The Standard Retailers have each prepared proposals for changes to gas pricing for the 2010 Regulatory Period. These are summarised in the IPART Draft Report[3].

---

1 Minister for Energy letter to Dr Keating, Chairman of IPART dated 19 August 2009 provided in Independent Pricing and Regulatory Tribunal of NSW, "Review of regulated retail tariffs and charges for gas 2010 – 2013, Gas – Issues Paper", November 2009, page 41.

2 Independent Pricing and Regulatory Tribunal of NSW, "Review of regulated retail tariffs and charges for gas 2010 -2013, Gas – DraftReport", April 2010, Chapter 2.

3 Independent Pricing and Regulatory Tribunal of NSW, "Review of regulated retail tariffs and charges for gas 2010-2013, Gas – Draft Report", April 2010, page 8 and Appendix A.

All retailers propose to continue to use a Weighted Average Price Cap (WAPC) form of price control. However, whereas under the current VTPAs this control applies to the total bundled retail tariff, for the 2010 regulatory period the retailers have proposed to separate out and control differently the Retail (R) and the Network (N) parts of the tariffs.

The Retail costs are the costs of purchasing gas and transmission for the small customers, the costs of retailing to these customers and the profit margin. These costs are essentially controllable by the retailers. The Network costs are the costs of transporting gas through the gas distribution networks and are essentially not controllable by the retailers.

The retailers have proposed that the N component should be an automatic pass-through and the R component increase at a maximum of either the rate of increase in the consumer price index (CPI) (AGL and Country Energy) or, for ActewAGL at CPI-0.3% or, for Origin Energy, at CPI+10% in 2010/11 for the Albury district (then CPI+1% thereafter) and at CPI+1% for the Murray Valley district.

In addition, the four retailers have all proposed that the "Climate" (C) component of costs – the cost of meeting carbon pricing under either the Government's proposed Carbon Pollution Reduction Scheme (CPRS) or an alternative – be an automatic pass-through.

1.3 Review of R cost and Wholesale Gas Cost

The tariffs charged by all of the Standard Retailers over the 2010 regulatory period can be considered to be the sum of the Retail (R), Network (N) and climate (C) costs.

All the Standard Retailers have proposed automatic pass-through of network costs, which are generally regulated and beyond their control, and the automatic pass-through of Climate costs, for which the timetable, underpinning regulatory mechanism and quantum are very uncertain.

As a result, the cost component currently of most concern to this review by IPART is the "R" component, comprising all the costs of supplying gas to small customers apart from network and climate related.

According to IPART, the R cost is estimated to make up around 50% of a small gas customer's overall bill, with the remainder being the network cost.

The R cost for supplying small customers can be considered to have a number of sub-components:

- the cost of the underlying gas commodity which is required to supply the market (commodity gas)
- the cost of any "additional deliverability[4]" beyond that available under the standard commodity contracts required to supply the market during peak periods

[4] Sometimes also referred to as capacity or maximum daily quantity (MDQ) cost.

- the "transmission" cost of hauling gas through major transmission pipelines to the small customers as required
- the "retail operating costs" which are costs incurred by the retailer for activities such as billing, marketing, attaining and servicing customers
- the "retail margin" which compensates retailers for the risk and capital involved in supplying the market
- "other" costs (apart from network and climate costs which are considered separate to the above[5].

The commodity, additional deliverability, transmission, climate and any "other" costs related to supply of gas are collectively referred to as "wholesale gas costs" by IPART in its Draft Report[6] and throughout this report.

IPART has engaged McLennan Magasanik Associates (MMA) to assist it in reviewing the wholesale gas costs proposed by the Standard Retailers. The other components of the R cost, which are the retail operating cost and retail margin and any other cost not associated with wholesale gas, are excluded from the MMA review. As no climate regulation is in place, MMA has only outlined the cost that such regulation might produce.

1.4 Approach - costs incurred by an efficient and prudent retailer

The approach taken by MMA to the review of wholesale gas costs has been derived after consideration of the IPART Issues Paper and following discussions with IPART. According to the IPART Issues Paper:

"We will also review the costs of gas supply as it has been some time since we conducted such a review and the Minister has specifically requested it. In addition, this may be the last time we review regulated retail gas tariffs before regulation is phased out completely. In our view, it is important that regulated tariffs reflect the efficient costs of service provision"

…

"In reviewing costs, we will analyse the Standard Retailers' proposed VTPAs to determine whether the underlying costs are consistent with those an efficient and prudent retailer would incur in supplying small retail customers on regulated tariffs over the regulatory period. Unlike the approach to regulating electricity prices, we will not be setting revenue allowances for these costs. Instead, we will assess the Standard Retailers' proposals to determine whether the total level of costs (to be recovered through the proposed retail tariffs) is consistent with efficient levels"[7].

"..Whether the forecast costs that underlie the proposed regulated retail tariffs are consistent with those an efficient and prudent retailer would incur in supplying small retail customers on regulated tariffs over the regulatory period"[8].

5 These might, for example, include charges applied by a central market operator if this has not been considered elsewhere.

6 Independent Pricing and Regulatory Tribunal of NSW, "Review of regulated retail tariffs and charges for gas 2010-2013, Gas – Draft Report", April 2010, Chapter 3.

7 Independent Pricing and Regulatory Tribunal of NSW, "Review of regulated retail tariffs and charges for gas 2010 -2013, Gas – Issues Paper", November 2009, page 11.

8 Independent Pricing and Regulatory Tribunal of NSW, "Review of regulated retail tariffs and charges for gas 2010-2013, Gas – Issues Paper", November 2009, page 3.

"We have engaged McLennan Magasanik Associates (MMA) to assist us in assessing the pricing proposals of the Standard Retailers in relation to wholesale gas costs, including the overall level of these costs, the allocation of costs between customers on regulated tariffs and market contracts, and the likely increase in wholesale gas costs due to the CPRS. The contracts that determine wholesale gas costs may be negotiated or arbitrated. We do not propose to review the efficiency of arbitrated prices. However, we will have regard to available benchmarking data in assessing the reasonableness of wholesale costs"[9].

We have understood the IPART requirement to be for MMA to review the wholesale gas costs proposed by each of the Standard Retailers against those that would be incurred by an "efficient and prudent retailer" in supplying small retail customers on regulated tariffs as well as other customers.

This interpretation has meant that we have had to make decisions in a number of areas including.

- whether the costs to be assessed are those faced by the Standard Retailer or for a new, generic, second tier retailer
- whether the costs assessed should be based on stand-alone requirements for the regulated customers, or should also consider other customers that would normally be served by the retailer
- if the latter, whether and how costs should be allocated between other customers served by the retailer
- whether the highest or average costs should be allocated to regulated customers
- the relevance of cited "benchmark costs" such as published tariffs.

Although MMA's interpretations vary according to the cost component, we have broadly assumed that the costs assessed should be those of a Standard Retailer, supplying not just regulated small customers but also other customers, and that while the quantum of the requirements should be those required by the regulated small customer segment, the costs need to be calculated against the requirements of the market as a whole.

In addition, IPART has confirmed that the appropriate costs for analysis are for the small market as a whole, rather than separately for the residential and small business markets.

1.5 Key definitions, units and conventions

Unless otherwise stated the analysis is all carried out in real terms in dollars of 2009/10 $2009/10). We have taken this to mean the average price across the period 2009/10. We note that this is not the same as the prices on 1 January 2010. When a CPI adjustment is made, we have taken the September to September index as the rate of inflation.

All years referred to are financial years unless otherwise indicated.

9 Independent Pricing and Regulatory Tribunal of NSW, "Review of regulated retail tariffs and charges for gas 2010-2013, Gas – Issues Paper", November 2009, page 30.

Average annual gas consumption at the small customer level is typically measured in terms of gigajoules (1 GJ = 10^9 J). This is generally also the unit used for pricing in gas contracts ($/GJ).

Larger quantities are generally measured in terajoules (1 TJ = 10^{12} J or 1000 GJ) or petajoules (1 PJ = 10^{15} J or a million GJ).

Capacity, whether maximum daily supply available from a supplier or the quantity reserved for storage or on transmission pipelines is generally measured in terms of GJ or TJ of maximum daily quantity (MDQ) across a year or peak season and is often priced in $/GJ MDQ or $/TJ MDQ.

The load factor is a measure of the ratio of average to peak requirements. In this report the term "load factor" is calculated as the average daily quantity (ADQ) divided by the maximum daily quantity (MDQ).

1.6 Similar reviews

Reviews of the cost of providing gas to small customers have been undertaken over recent years by several regulators including:

- IPART in 2007[10]. While the review did not look in detail at the costs of supply it considered that regulated gas prices, apart from in the Murray Valley, were broadly cost-reflective. In 2008 under special circumstances IPART allowed AGL to increase its regulated prices by $0.75/GJ from 1 April of that year (in place of the CPI increase that would have otherwise occurred on 1 July 2008) [11]. In this review IPART reviewed costs on an incremental basis which included some auditing and data verification.

- The Essential Services Commission of South Australia (ESCOSA) whose draft[12] and final[13] determinations of standing contract prices for small gas customers are available from the ESCOSA website (www.escosa.sa.gov.au). This review, and the previous one in 2005, used a bottom-up approach to review the costs of Origin Energy, the retailer responsible for standing contract prices.

- The Queensland Competition Authority (QCA) in late 2008 reviewed pricing to small gas customers. A report by MMA which assessed the costs for a second tier

10 Independent Pricing and Regulatory Tribunal of NSW, "Promoting retail competition and investment in the NSW gas industry – Regulated gas retail tariffs and charges for small customers, 2007 to 2010, Gas – Final report and Voluntary Transitional Pricing Arrangements", June 2007 available at http://www.ipart.nsw.gov.au/files/Gas%20Retail%20Review%20-%20Final%20report%20and%20voluntary%20arrangements%20VTPAs%20-%20Web%20version%20-%20June%202007.PDF

11 Independent Pricing and Regulatory Tribunal of NSW, "Regulated gas retail tariffs: Decision and statement of reasons – AGL's 2008 application for a special cirumstances price increase", March 2008 available at http://www.ipart.nsw.gov.au/documents/DecisionandStatementofReasons-AGLapplicationforpriceincreaseunderspecialcircumstancesprovisi.PDF

12 Essential Services Commisssion of South Australia, "2008 gas standing contract price path inquiry – draft inquiry report and draft price determination", April 2008.

13 Essential Services Commisssion of South Australia, "2008 gas standing contract price path inquiry – final inquiry report and final price determination", June 2008.

retailer to supply gas to small customers in Queensland was commissioned for the review.[14]

- The Western Australian Office of Energy in June 2009 reviewed pricing for small customers in WA, including a "cost stack" analysis of the costs to supply plus the costs of the Varanus Island supply disruptions[15].
- The Essential Services Commission (ESC) of Victoria in late 2002 and 2003 investigated proposed increases to retail gas tariffs of more than CPI[16]. The investigation determined that both commodity and peak day capacity components were important in the wholesale gas cost.

In this report we refer extensively to the ESCOSA review which was recently conducted and assessed in detail the costs faced by an incumbent retailer.

1.7 Layout of the report

The various cost components of the wholesale gas costs are reviewed in the following chapters:

- Chapter 2 considers the sources and prices of the underlying gas commodity contracts under which gas, generally at high supply load factors[17], is sold by producers to retailers.
- Chapter 3 evaluates the additional deliverability requirement of the small customer market on a very cold day, the sources of such additional deliverability and the likely costs. As part of this it looks in detail at the calculation of customer load factor which is central to the calculation of both additional deliverability costs and transmission costs.
- Chapter 4 looks at the transmission costs of getting the gas to market.
- The final Chapter outlines additional costs which are claimed by the retailers and indicative climate costs which might apply over the 2010 regulatory period.

---

14 McLennan Magasanik Associates, final report to the Queensland Competition Authority, "Costs of gas supply for a second tier retailer supplying small customers in Queensland", November 2008, available at http://www.qca.org.au/files/GR-RSCSPComp-MMA-FinalRep-1208.PDF.PDF .

15 Government of Western Australia, Office of Energy, report to the Minister for Energy "Gas tariffs review Interim report" June 2009 available at http://www.energy.wa.gov.au/cproot/1557/14580/Gas%20Tariffs%20Review%20-%20Interim%20Report%202009%20-%20FINAL%20(2).pdf

16 Essential Services Commission of Victoria[16],Final report, "Special investigation: Proposed retail tariff amendments", December 2003 available athttp://www.esc.vic.gov.au/NR/rdonlyres/C6695E9E-2CF2-41BF-83DA-DB7A475A857D/0/FinalReportProposedRetailTariffAmendDec03.pdf.

17 In this report high supply load factors refer to load factors of over 80% - that is where the average daily quantity is 80% or more of the maximum daily quantity contracted.

2 COMMODITY GAS COST

2.1 Introduction

The commodity gas cost, sometimes also known as the cost of ACQ (Annual Contract Quantity) is the underlying cost of the base gas supply contracts used to supply the market served by the Standard Retailer.

While retailers can conceivably source gas supply from the Victorian spot market[18], and this can be transmitted into NSW, it has been argued that a prudent retailer would not rely mainly on such supply and MMA accepts this position. Many retailers also take a portfolio approach to the supply requirements of their markets, allowing gas supply from different producers and gas basins transported along the corresponding transmission pipelines. Again, MMA considers such a portfolio approach, where possible and efficient, to be prudent.

Commodity gas contracts with retailers are generally of relatively long duration, from three to ten years, allow for a supply load factor ((ACQ/365)/MDQ) which is typically around the 80% to 90% level, include take or pay (ToP) requirements set at 80% or more and stipulate price reviews to market every few years.

Details of individual contracts are normally highly confidential. While MMA has sought information about individual contracts from Standard Retailers it has often either not been provided or responses have been in a form which does not allow MMA to check the veracity of the details. Where this has been the case MMA has checked information for reasonableness against benchmark data available in public arena and information supplied in confidence by the other Standard Retailers.

Allocation of the commodity gas costs between customer classes may be an issue. In other jurisdictions it has been argued, and generally accepted, that the commodity cost of gas paid by the retailer should not differ significantly between customer classes – that is, that the average commodity cost should be applied across all customer classes as the retailer uses these contracts to serve the entire state market. This is also the approach adopted by the Standard Retailers.

2.2 Sources of gas which supply retailers in NSW

Figure 2-1 shows the sources of supply and key transmission routes for the supply of gas to NSW and southern and eastern Australia.

Historically gas supply into the bulk of NSW was sourced from the Cooper Basin (centred around Moomba) through the Moomba to Sydney Pipeline (MSP)[19]. However, since the

18 A new trading market is also expected to start operating in the Sydney and Adelaide markets from September 2010.

19 With gas to supply Albury and the Murray Valley towns traditionally supplied from the Gippsland Basin.

commissioning of the Eastern Gas Pipeline (EGP) in 2000 there has been increasing supply to NSW from Gippsland Basin gas offshore Victoria (treatment plant at Longford).

More recently gas has been supplied to southern Australia and NSW from coal seam gas (CSG) fields centred around Wallumbilla in south east Queensland, either under a swap arrangement between producers or through the South West Queensland Pipeline (SWQP) and the QSN link via Moomba. Finally, relatively small quantities of gas into NSW are also supplied from CSG fields around Camden near Sydney directly into the Jemena distribution network. These fields were originally owned by Sydney Gas Company (SGC); however, this company was acquired by AGL in 2009. While gas is also supplied into southern Australia from the Otway Basin (centred around Iona) and the Bass Basin (near the Gippsland Basin), the great bulk of this gas is supplied to Victoria and South Australia.

Figure 2-1: Supply centres and pipelines in eastern and southern Australia

Source: AGL submission to IPART NSW Gas Tariffs, 1 July 2010 – 30 June 2013 October 2009, page 26[20].

The largest gas centres in NSW, Sydney, Newcastle and Wollongong as well as the central coast region and some country regions around the ACT are generally supplied through either the MSP or the EGP. Gas to many country areas of NSW is often sourced via laterals

[20] This submission is included in the Independent Pricing and Regulatory Tribunal of NSW, "Review of regulated retail tariffs and charges for gas 2010 – 2013, Gas – Issues Paper", November 2009.

to the MSP or from Longford via the GasNet Principal Transmission System and laterals to the MSP if required.

2.3 Other regulatory decisions

The 2008 price review in South Australia for standing contract prices for the period of 2008/09 to 2010/11 undertaken by ESCOSA[21] largely accepted the price path proposed by Origin Energy. Origin Energy proposed prices of commodity gas cost of $3.78/GJ in 2008/09, $3.79 in 2009/10 and $3.87 in 2010/11, all in $December2008 (which is understood to be $2008/09). Assuming an increase of about 1.26% in CPI[22] this means an average price of about $3.88/GJ in $2009/10 for the 2009/10 and 2010/11 years.

In 2008, QCA undertook studies to estimate costs of gas supply for a second tier retailer supplying small customers in Queensland[23]. The estimated gas cost coming out of that report was $4/GJ in 2008/09 and $6/GJ for a new contract in 2012/13, in real $2008/09. However, the latter prices relate to relatively small quantities for a new second tier retailer at a time of great uncertainty about availability of gas because of plans to export very large quantities of liquefied natural gas (LNG) from Queensland.

2.4 Conclusion

MMA considers it prudent and efficient for a retailer to have a portfolio of supply and to estimate as the price to the small customer market the average of the costs of supply across its whole market in NSW.

MMA examined the forecast base gas supply costs of each Standard Retailer, and derived its own assessment of this cost component, by comparing the forecasts to the costs submitted by the other retailers, recent regulatory decisions and other publicly available benchmarks.

---

21 http://www.escosa.sa.gov.au/library/080624-GasStandingContractPrice_2008-FinalDetermination-PartAB.pdf

22 Based on an increase in the all groups eight capital cities index between September 2008 and September 2009.

23 http://www.qca.org.au/files/GR-RSCSPComp-MMA-FinalRep-1208.PDF.PDF

3 ADDITIONAL DELIVERABILITY

3.1 Introduction

If the peak day requirements of small customers are greater than are provided for under the commodity gas supply contracts, then there will be an extra cost of supply to meet the additional deliverability requirement. This chapter considers this extra cost in two parts. Firstly, the additional deliverability required is calculated. Secondly, the means and costs of providing this deliverability are assessed.

3.2 The additional deliverability requirement

The main uses of natural gas among small customers in NSW (and southern Australia) are for hot water heating, cooking and space heating, In March 2008, according to the Australian Bureau of Statistics (ABS), the penetration of gas appliances among customers who had mains gas was 64% hot water, 73% cooktops, 40% ovens and 43% space heaters[24].

Gas usage for space heating is clearly weather dependent with almost all gas used for this purpose being in winter. The amount of energy required to heat hot water also varies according to the temperature of the feed-water which is generally also related to ambient temperature. As a result, in cold, cool and even moderate climates gas usage in winter will be significantly higher than across the year as a whole. In such climates customer load factors of the order of 30% to 50% are not uncommon. This means that the peak day requirement for such customers is between 3.33 and 2 times the average daily quantity. Invariably the peak day requirement rises during cold weather.

Given that most current gas commodity supply contracts have high supply load factors (say between 80% and 90%)[25] this allows for only limited supply on peak days to meet the customer requirements. The difference, the additional deliverability requirement, needs to be met from other sources.

An example calculation of the amount of additional deliverability required and how the cost is calculated on a $/GJ basis is provided in Exhibit 1.

Exhibit 1: Sample calculation of additional deliverability requirement

Let us assume a retailer has a contract to supply small customers who consume an average daily quantity of 10 TJ/d (3.65 PJ/year) but who have a customer load factor of 40%. This means the customers require 25 TJ to be supplied on the peak day. Let us further assume that the retailer has a gas supply agreement which also has an average daily quantity of 10 TJ/d (ACQ of 3.65 PJ) but a supply load factor of 85%. Under this contract only 11.76 TJ/d can be supplied. The **additional deliverability** required to serve this small customer market on the peak day is 13.24 TJ/d. This calculation is illustrated in Table 3-1

[24] Australian Bureau of Statistics, *4602.0.55.001 - Environmental Issues: Energy Use and Conservation, Mar 2008.*

[25] Meaning that the MDQ for supply is between 1.25 and 1.11 times the average daily quantity.

Table 3-1 Sample MDQ calculation

ACQ	3650	TJ/year
ADQ	10	TJ/day
Customer load factor	40%	ADQ/MDQ
Customer MDQ requirement	25	TJ/d
Supply ADQ	10	TJ/day
Supply LF	85%	ADQ/MDQ
Supply MDQ	11.76	TJ/d
Additional MDQ required	13.24	TJ/d
$/MDQ	200	$/GJ MDQ
$'000 pa for additional MDQ	2647	$'000 pa
$/GJ for additional MDQ	0.725	$/GJ

Finally, let us assume that the price of the additional deliverability capacity is $200/GJ. To meet the additional deliverability requirement would cost $2.65 M which, divided over the entire annual load, results in a cost of $0.725/GJ. Ways to meet additional MDQ and their prices are discussed in Section 3.4.

The cost of additional MDQ ($/GJ) can be calculated using the following formula:

> Additional deliverability cost ($/GJ) = price of additional deliverability ($/GJ MDQ/year)/365 x (1/(Customer load factor) – 1/(Supply load factor))

It can be seen that this $/GJ amount is independent of the size of the load but depends only on the customer load factor, supply load factor and price of MDQ.

3.3 Calculation of the customer load factor

A key variable is the calculation or estimation of the customer load factor. This is also very important in the calculation of the cost of transmission as seen in Section 4.2.1.

3.3.1 Planning basis

According to the ESCOSA decision in 2005,

"While there may be some debate about whether the planning basis should be a 1 in 20 year winter day (as in the Victorian system) or a 1 in 25 year day (as proposed by Origin Energy on the basis that it has historically been the South Australian planning requirement) it is not significant. Based on analysis of weather in Adelaide over the past 50 and 100 years, the difference in heating degree days (HDD) between a 1 in 2 winter maximum and a 1 in 20 winter maximum is about 11% and that the difference between a 1 in 2 winter and a 1 in 25 winter is about 12%. Given that the increase in consumption on these days is less than proportional to HDDs (because of a base non-

temperature sensitive load) the Commission considers the difference between the two to be insignificant"[26].

MMA considers it reasonable to assume that, even without a strict regulatory requirement to do so, a prudent retailer will act to ensure it can meet demand on a peak day which sees more demand than the average. It is unclear whether a prudent retailer actually sets in place contracts and other arrangements for a 1 in 25 year peak demand, or whether planning for a 1 in 10 or 1 in 20 year demand is considered adequate. Given that the difference in estimated load factor between a 1 in 10 and a 1 in 25 year is relatively small, MMA considers it reasonable to accept a load factor for the 1 in 25 year requirement – however, notes that this likely to be a little conservative.

3.3.2 Stand alone or contribution to coincident peak load

In calculating the cost-reflectivity of the regulated small market customers it is important to consider whether the costs assessed are for the stand-alone regulated market or whether they should take into account the characteristics of the Standard Retailer's other (non-regulated) customers and load.

For example, when evaluating the costs of supplying additional deliverability and transmission pipeline capacity a large, incumbent retailer that is efficient would optimise its purchasing based not on the characteristics of one market segment, but on the characteristics of the market as a whole. Thus, for example, the purchase of storage to provide peak day deliverability might benefit not only the small customer market in winter but might also benefit (say) a large customer which used significant quantities in summer.

It is clear that a second tier retailer which services only small customers would have to provide the additional deliverability and transmission capacity to service only this market – and the costs of this capacity would be allocated entirely to this market. However, it is not clear that a prudent and efficient retailer would enter into gas arrangements purely with such customers. Certainly the Standard Retailers provide gas to a market significantly larger and more diverse than to the small customers alone.

In South Australia the approach adopted by ESCOSA appears to have been that the small customer market should pay for its contribution to the retailer's total coincident peak day and that the small customer market there could be assumed to peak on the same day as the market as a whole – that is not on a weekend[27]. While such an approach approaches the stand-alone cost of supplying the small customer market, it does take into account the entire market as well. MMA considers this to be a reasonable position to adopt.

---

[26] Essential Services Commisssion of South Australia, "Gas standing contract price path – final inquiry report and final price determination", June 2005 page A-39..

[27] Essential Services Commisssion of South Australia, "Gas standing contract price path – final inquiry report and final price determination", June 2008, page A-33

MMA considers it reasonable to assume that, as the system peak day will in reality never occur on a weekend, the load factor attributable to the market should be that on weekdays only.

3.3.3 Other regulatory decisions

The 2003 ESC review in Victoria took into account a capacity as well as commodity cost component however the details of load factors were not provided.

The 2008 ESCOSA draft and final reports provide approximate details about the load factors applied to the residential and small business customers. The final ESCOSA report states that Origin Energy initially proposed a peak daily demand of around three times average daily demand for the residential market and around twice average daily demand for the SME (small business < 1 TJ) class[28]. This translates into approximate load factors of 33% for the residential market and 50% for the small business customers. In its final report ESCOSA determined that load factors used in calculations should be higher than those proposed by Origin Energy. The 33% to 50% range initially proposed by Origin Energy provides indicative guidelines for reasonable assumptions for the NSW market.

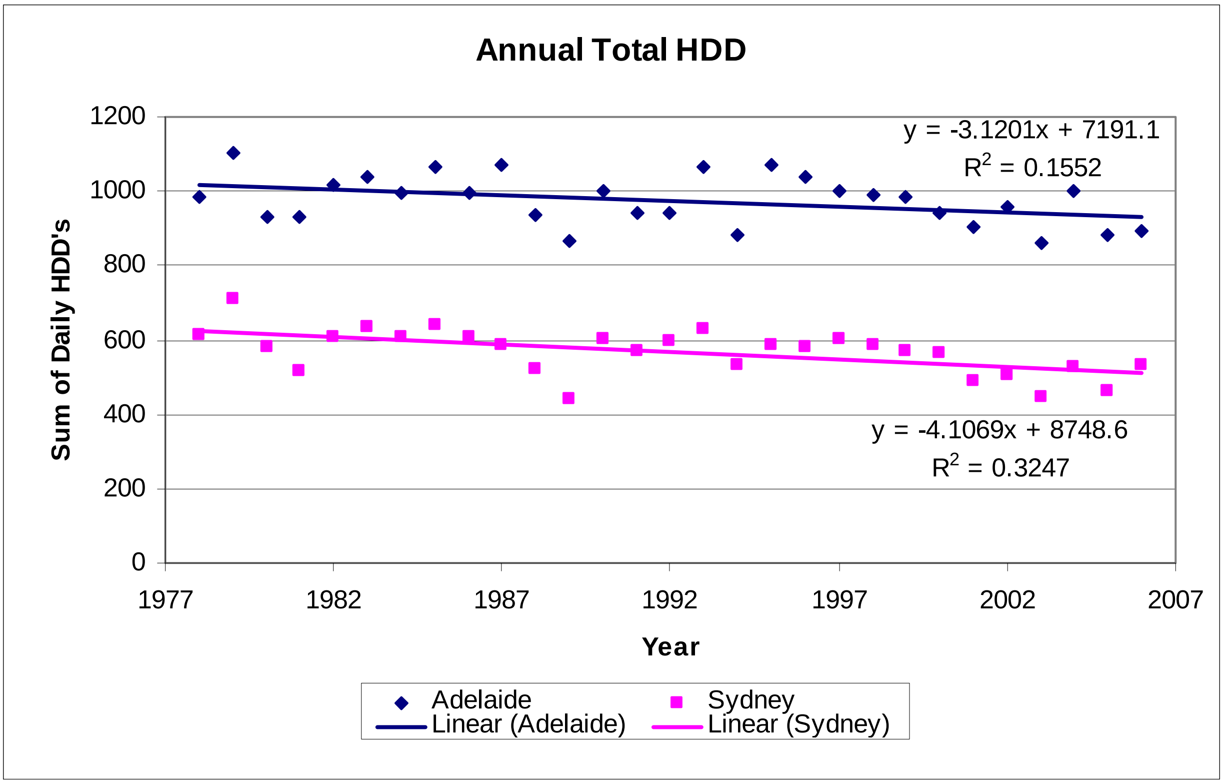
3.3.4 Heating degree day analysis

MMA has analysed weather data for Sydney, Wagga Wagga and Albury compared to Adelaide over the period 1978 to 2006[29] to calculate the HDDs (heating degree days) in these cities. Figure 3-1 charts the annual sum of HDD (for Sydney and Adelaide) and Figure 3-2 the annual peak HDD (for Sydney and Adelaide).

[28] Essential Services Commisssion of South Australia, "2008 gas standing contract price path inquiry – final inquiry report and final price determination", June 2008, page A-33.

[29] Obtained from the Australian Bureau of Meteorology.

Figure 3-1 Sydney and Adelaide sum of HDD per year



Sydney has a lower annual sum of HDD across the entire period meaning that Adelaide has a higher overall heating requirement (is colder in winter) than Sydney. Adelaide has on average about 1.7 times the HDD of Sydney. We can see that the annual sum of HDD for both Sydney and Adelaide has a downward trend (ie the winters appear on the whole to be getting milder).

Despite Adelaide being the colder city as a whole, the graph of annual peak days shows that the difference between the two is much narrower than that of Annual HDDs and that there is some overlap of annual peaks. Based on this it is reasonable to expect that while Sydney as a whole has less heating requirement than Adelaide, its requirement may be peakier – having an influence on load factors.

Figure 3-2 Sydney and Adelaide annual peak day HDD

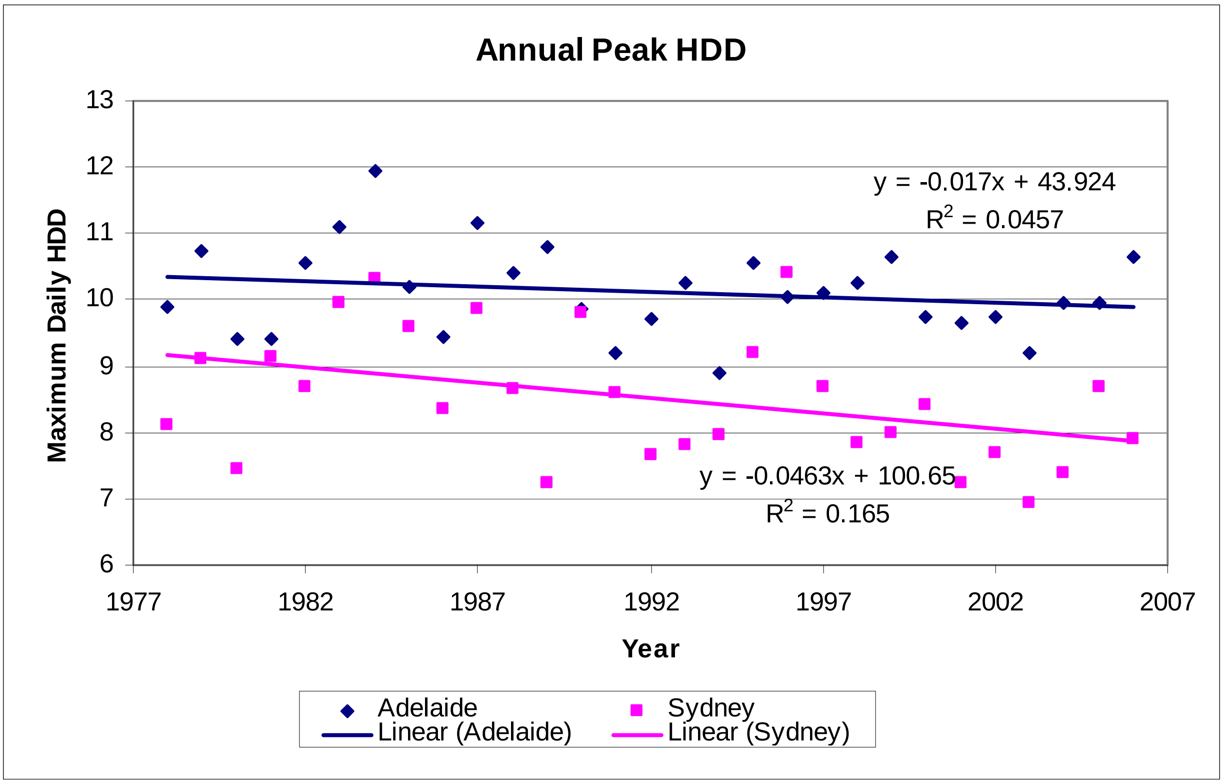


Figure 3-2 also indicates that the peak annual HDDs for both Sydney and Adelaide are reducing over time. While this may have an impact on the 1 in 25 year peak day planning requirement, MMA considers that there is as yet insufficient evidence to confirm this.

3.3.5 Check through MMA appliance model

In order to provide an initial assessment of the reasonableness of load factors, MMA has screened possible load factors through a model utilising weather data, estimated appliance usage data and appliance penetration data to indicatively estimate the residential customer load factors for various locations.

The model indicates that it is plausible that the residential load factors in NSW may well be lower than in South Australia, despite South Australia having a colder climate, and that Victorian residential load factors are likely to be lower than they are in NSW.

3.4 Price of additional deliverability

3.4.1 Sources of additional deliverability

Having calculated the required additional deliverability the next step is to estimate the sources and prices payable for additional MDQ.

Additional deliverability can be provided from a number of different sources, some of the most common being:

- the portfolio of supply contracts including taking into account take or pay requirements and make-up gas availability[30].
- the diversity of a retailer's supply and demand portfolio across states and regions. Typically peak day demand does not coincide in all connected states and regions at the same time.
- linepack available on pipelines – although this used to come at no cost, increasingly it is being charged for by pipelines through overrun and imbalance payments and under park and loan tariffs
- additional contracted gas supply – for example, a contract for additional "winter" MDQ above that provided for in the base contract
- spot market purchases – currently in Victoria but soon to be introduced in NSW as well
- underground storage – although this is located in Victoria it can be used as part of a portfolio of supply to provide gas into other states as well. Again the costs of storage can also be shared between customer classes and states.
- overruns and imbalance payments for rare events
- LNG storage, again in Victoria
- customer interruptibility.

A prudent and efficient retailer would typically use a combination of these and would secure the cheapest sources first. The detail of contracts for additional MDQ is highly confidential and the Standard Retailers provided very limited detail about either the cost of its additional storage or the quantity they actually have contracted.

3.4.2 Regulatory Decisions

The ESCOSA review of Standing Contract Prices for small gas customers in 2008 determined that the cost of additional deliverability should be $0.28/GJ for small business customers and $0.62/GJ (in $2008/09) for residential customers[31].

In its draft determination ESCOSA noted that the price submitted by Origin Energy was lower than the $140 to $190/GJ MDQ price range quoted on the TRUenergy website for underground storage and therefore assessed the benchmark price submitted by Origin

30 Take or Pay clauses require that a customer take or pay for a proportion (typically 80% or more) of the ACQ. Many contracts also have make-up gas provisions which allow gas paid for but not taken to be taken at a later stage (within limits) at a reduced additional cost.

31 Essential Services Commisssion of South Australia, "2008 gas standing contract price path inquiry – final inquiry report and final price determination", June 2008 page A-57..

Energy to be reasonable[32] although it appears to have further reduced it by subtracting most of the cost of a lateral used to supply the MDQ.

3.4.3 Discussion about price of additional deliverability

Additional deliverability is likely to be available from a number of sources, not just storage or additional contracts with producers. A prudent and efficient retailer is likely to adopt a portfolio approach, using cheaper sources such as ToP agreements and park and loan to the extent possible and then topping this up with the more expensive options.

The range of storage prices currently quoted by TRUenergy on its website is $160 to $240/GJ MDQ[33]. The website suggests that the lower prices would be those contracted for a longer term.

However, the published price range for storage provides nothing more than an indication of price for Iona. The ESCOSA report in 2008 stated that, at the time, Origin Energy was paying less then the bottom of the range then quoted

Although MMA considers it reasonable that the small market should pay for its stand-alone contribution to the peak day requirement, it does not consider it reasonable for the price used to be assessed at what is likely to be the highest available for MDQ. MMA considers it reasonable for the price used for additional deliverability to be $160/GJ MDQ – the bottom end of the range provided by TRUenergy for storage[34].

3.5 Conclusion about additional deliverability

Three components need to be considered in determining the cost of additional deliverability:

- customer load factor
- supply load factor
- source and price of additional deliverability.

MMA examined the additional deliverability required by the small customer market on a very cold day, the sources of such additional deliverability and the likely costs. As part of this analysis, MMA considered each retailer's assumption about customer load factor, which is central to the calculation of both additional deliverability costs and transmission costs.

To assess the customer load factor, where appropriate MMA reviewed the methodology used and tested its sensitivity to varying key parameters and underlying assumptions. In

---

32 Essential Services Commisssion of South Australia, "2008 gas standing contract price path inquiry – draft inquiry report and draft price determination", April 2008 page A-47.

33 http://www.TRUenergy.com.au/Production/Iona/index.xhtml.

34 The wording on the website suggests that the lower end is for longer-term contracts.

addition, MMA compared proposed customer load factors against evidence from other sources. MMA has generally accepted supply load factors at face value.

In assessing the source and price of additional deliverability, and deriving its own assessment of this cost component, MMA compared proposed costs against those submitted by the other Standard Retailers, recent regulatory decisions and other publicly available benchmarks. MMA also tested the sensitivity of the overall cost of additional deliverability to varying the assumed price of MDQ.

4 TRANSMISSION

4.1 Introduction

As discussed in Section 2.2, gas for customers in NSW is supplied predominantly through two pipelines, the Moomba to Sydney Pipeline (MSP) and the Eastern Gas Pipeline (EGP). Gas from the Cooper Basin and Queensland CSG supplies are delivered at Moomba and then through the MSP to ACT, Sydney, Newcastle and Wollongong and to other locations through laterals to the MSP. Gas from the Gippsland Basin is delivered mainly at Longford and transported through the EGP to the ACT, Sydney and to users along the route. Some parts of NSW are also supplied through the GasNet Principal Transmission System (PTS).

Gas is transported through transmission pipeline to the required delivery point, either through the mainline or the laterals. Transmission through the pipelines attracts tariffs payable which are based largely on capacity reservation payments ($/GJ MDQ) which vary according to load factors, with relatively little relying on throughput. Additional costs relating to throughput may include for system use gas (for use in compressors or lost during transmission), odorisation and unaccounted for gas where appropriate.

4.2 Key issues

Two key issues related to the transmission pricing proposed are:

- Use of stand-alone transmission requirements and customer load factor
- Use of published tariffs

4.2.1 Stand-alone transmission and load factor

As discussed in Section 3.3.2, MMA considers it reasonable to calculate additional deliverability and transmission requirements based on the stand-alone requirements of the regulated market within the coincident peak day load. While this approach ignores the effect of customer diversity, this is very difficult to calculate and allocate to different customer classes and will vary significantly between retailers. The stand-alone requirement on a coincident peak day approach was also applied in its 2008 review by ESCOSA.

4.2.2 Use of published tariffs

The published tariff for the MSP includes a throughput charge of $0.0000337 / km per GJ and a capacity charge of $0.0005740 / km per GJ of MDQ as at 1 July 2009, increasing to

$0.0005817 / km per GJ of MDQ at 1 January 2010[35]. Standard Retailers have added estimated costs for odorisation, system use gas and for unaccounted for gas where appropriate. The published tariff for the EGP as of 1st January 2009 includes a capacity charge of $1.0933/GJ for delivery to zone 3 (Sydney and Wollongong) and $0.8264/GJ for zone 2 (ACT and surrounding) Injection and delivery tariffs for the PTS are also published.

MMA considers it reasonable to use the published tariffs on the EGP, MSP and PTS in the calculations.

4.3 Conclusions

In general the retailers have used published transmission prices on the MSP, EGP and PTS multiplied by the customer load factor and estimated or assumed proportion of load using each of the pipelines to determine proposed transmission costs for the small customer market. MMA considers this a reasonable approach to use, on the basis that the small customer market should pay its stand-alone costs within the overall coincident demand. MMA also considers it reasonable that the retailers propose to use the published tariffs along the pipelines.

[35] http://www.apa.com.au/our-business/gas-transmission-and-distribution/new-south-wales.aspx

5 OTHER COSTS

This Chapter of the report considers "other" costs which have been proposed by the retailers.

5.1 Costs and risks of the STTM

The Australian Energy Market Operator (AEMO) is establishing the Short Term Trading Market (STTM) and will operate that market upon its anticipated commencement in June 2010. Under the National Gas Law (NGL) and the National Gas Rules (NGR) AEMO may determine, charge for and recover fees in respect of the costs of establishment and operation of the STTM. The STTM will initially operate in Sydney and Adelaide.

The STTM is materially different to the Victorian gas market and a market trial of the STTM has only recently commenced. As a result, the actual impact of the STTM on operations, risks and costs are highly uncertain.

5.1.1 Costs

On 19 November 2009 AEMO published an issues paper[36] which outlined expected fee structures and provided indicative fees for use of the STTM in 2010/11[37].

- $10,000 per market participant
- $0.04059/GJ withdrawn as an activity payment
- $0.00353/GJ withdrawn as a Participant Compensation Fund (PCF) fee.

MMA considers it reasonable to assume a cost of about $0.05/GJ for the Market fees cost of the STTM. MMA cautions that there is a possibility that this cost may be included also in retailer operating costs. Care must be taken to avoid double-counting.

As well as market fees, costs may be incurred for:

- increased IT expenditure and operational staff.
- re-nomination costs - because of the structure and incentives of the STTM, a prudent and efficient retailer will aim to minimise the difference between its daily forecasts and actual deliveries. One method to achieve this is through pipeline re-nominations or "premium park" services. The estimated cost of re-nominations will depend on a retailer's estimates of forecasting error, average impact and time and price of re-nomination.

[36] Australian Energy Market Operator, "STTM participants fee structure and major gas project determination – Issues Paper", 18 November 2009.

[37] Australian Energy Market Operator, "STTM participants fee structure and major gas project determination – Issues Paper", 18 November 2009, page 23.

- costs associated with Market Operator Service (MOS) provision and contingency gas provision.

5.1.2 Conclusion

MMA has assessed the forecast other costs of each Standard Retailer by comparing them to the costs submitted by the other retailers and against information gathered from discussions with other industry participants.

While there are likely to be costs and risks associated with the STTM, there is also the potential for rewards from which market participants might well benefit.

5.2 Climate costs

None of the Standard Retailers has included a specific cost for the impact of climate regulation and the future nature and timing of any such regulation is currently unclear as the Carbon Pollution Reduction Scheme (CPRS) regulation has not been passed.

MMA sets out below an indicative consideration of what climate regulation costs might entail at different cost levels for carbon dioxide equivalent (CO_2-e) emissions.

5.2.1 Additional costs faced by retailers

Retailers are likely to face material additional carbon costs in five areas when a price of carbon is imposed:

- As the responsible party for emissions by small customers, retailers are likely to be responsible for emissions related to the combustion of natural gas in the home.
- Producers of natural gas emit greenhouse gases in the production and treatment of natural gas. Some or all of the costs faced by producers may be passed through to retailers under gas supply agreements.
- Transmission pipelines will face additional costs associated with emission of greenhouse gases during operation (typically as compressors) and from losses. Some or all of the costs faced by transmitters may be passed through to retailers through increased tariffs under gas transportation agreements.
- Distribution networks will face additional costs associated with emission of greenhouse gases from network losses and during operations. These are likely to be passed through to retailers through regulated tariffs.
- There may also be a cost to retailers of operating in a carbon market and in managing risks (Carbon market). We have not taken such costs into account.

5.2.2 Indicative cost calculations

We have estimated indicative additional costs faced by retailers at three carbon prices, \$10/t CO_2-e, \$20/t CO_2-e and \$30/t CO_2-e.

We have assumed that retailers will be initially responsible for the permits related to the combustion of natural gas by customers. We assume the costs of the permits are passed on in full to customers.

We have assumed that while large emitters such as gas producers, transmitters and distributors will be initially responsible for paying for, or providing permits for, their emissions, these costs will be passed through to retailers. In reality, the ability to pass through such costs, and the timing, may be constrained by clauses within agreements, by competition in gas supply and transmission and by timing of regulatory reviews.

We have indicatively calculated the additional cost to retailers for small customers at the three carbon cost levels by using the combined Scope 1 (combustion) and Scope 3 (indirect emissions associated with extraction, production and transport of fuels) as the full fuel cycle emission factors applicable to use of gas by small customers. The emission factors we have used are sourced from the Department of Climate Change NGA Factors publication[38]. Tables 2 and 37 of that publication lists the Scope 1 and Scope 3 emission factors for a small gas user. Combined for NSW these add to 67.73 kg CO_2-e/GJ consumed. At CO_2 prices of $10/t, $20/t and $30/t this would add $0.68/GJ, $1.35/GJ and $2.03/GJ to the price of natural gas.

However, the combined emission factors for Victoria are significantly lower, some 55.83 kg CO_2-e/GJ consumed. At CO_2 prices of $10/t, $20/t and $30/t this would add $0.56/GJ, $1.12/GJ and $1.57/GJ to the price of natural gas.

As, according to the publication, the losses in distribution networks for NSW and Victoria are similar[39], the difference appears to be due to the source of the gas. Given that perhaps half of the gas used in NSW is sourced from Longford, we consider an average value of emission factor, 61.78 kg CO_2-e/GJ consumed to be reasonable to use. At CO_2 prices of $10/t, $20/t and $30/t this would add $0.62/GJ, $1.24/GJ and $1.85/GJ to the price of natural gas.

---

38 Australian Government Department of Climate Change, "National Greenhouse Accounts (NGA) Factors", June 2009.

39 Australian Government Department of Climate Change, "National Greenhouse Accounts (NGA) Factors", June 2009 Table 17.