Commercial in Confidence

Regional Development Australia – Yorke and Mid North

Gas Lateral Duplication Feasibility Study

December 2013

CQ Partners

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1 Executive Summary

Regional Development Australia, Yorke and Mid North (RDAYMN) have engaged CQ Partners to undertake a study to determine the financial viability of duplicating the natural gas lateral from Whyte Yarcowie to Port Pirie and potentially further to Whyalla.

The mid north region of South Australia (SA) has suffered from a lack of electricity infrastructure to support large commercial and industrial (C&I) customers. As a result, a number of C&I expansion projects have either stalled or have not been developed. This study has considered the commercial viability of duplicating the natural gas lateral from Whyte Yarcowie to Port Pirie and potentially further to Whyalla. The purpose of this lateral duplication was analysed primarily on the basis of supporting a new gas fired generation facility in the northern region.

The report clearly notes that a gas lateral is not commercially viable in relation to supporting a gas fired generation facility for the following reasons:

- An existing oversupply of generation supply in SA;
- SA will not require additional supply until at least 2020-21 at the earliest (under an unlikely high growth scenario)
- Current wholesale (pool and contract) electricity prices are too low to support any new investment in gas fired generation;
- The Eastern States gas market is expected to result in gas prices materially above where the market has been for contractual gas, increasing the fuel costs for gas fired generation facilities and reducing the commercial viability of new gas fired generation in the current energy market;

Energy market participants will generally only build new entrant generation facilities if they are able to underwrite the project with a fixed priced revenue contract for a period well in excess of 5 years. This will mean that large industrials will need to make a commitment to purchase electricity at a fixed price (indexed annually) for a long contract term in excess of 5 years in order to drive the construction of any new generation facilities. Further complexity arises in obtaining the commitment from a large industrial up to 2 years prior to the delivery of the electricity (as this is usually the lead-time in developing a gas fired generation facility).

If we look beyond the gas lateral augmentation and the lack of commercial drivers for a new gas fired generation facility in the northern regions, it is our opinion that the existing lack of network infrastructure to support rapid expansion of large C&I customers and mining loads could curtail a timely investment climate in this region. Even though the region is well supplied with a backbone of high voltage 275kV and 132kV transmission lines, large mining loads and C&I customers often have to wait for further network augmentation to ensure that their growing load is accommodated. Augmentation of the network is however complicated and does not occur on the potential of load growth. ElectraNet will require substantial commitment by a customer for an unregulated network augmentation or would need to put forward a net benefits test to allow infrastructure upgrades to be capable of being incorporated into its asset base from which it can receive a regulated return.

ElectraNet will generally not undertake any unregulated work without a connection enquiry to determine the extent of the augmentation and the costing which would be allocated to a customer. Alternatively, ElectraNet will only put forward a Regulatory Investment Test – Transmission (RIT-T) if it was certain that an augmentation would be capable of passing the test and of a cost recovery from the customers that would utilise that infrastructure. To date, ElectraNet has not been in a position to undertake either a regulated or unregulated augmentation to support future loads in the northern region, as there has been little support for such capital expenditure. Effectively, ElectraNet must be able to charge a customer or group of customers for a network component.

As a result, it is our view that most large C&I and mining loads are unable to connect to the network due to lack of infrastructure when needed. Government funding could assist to drive further network augmentation to assist large loads to more easily get access to energy, but this may require a commitment from ElectraNet (who would need to operate and maintain the assets) and customers who ultimately will need to utilise the network to ensure that it doesn't end up being a stranded asset that is not efficiently utilised.

CQ Partners would encourage further work on the potential to augment the electricity network, including funding (government or private equity) and the potential utilisation of such network infrastructure by large customers in the northern regions. Without a strategy to connect large mining loads and large C&I customers to the electricity network, opportunities to expand infrastructure in this region could be significantly delayed.

2 Introduction

Regional Development Australia, Yorke and Mid North (RDAYMN) have engaged CQ Partners to undertake a study to determine the financial viability of duplicating the natural gas lateral from Whyte Yarcowie to Port Pirie and potentially further to Whyalla.

The mid north region of South Australia (SA) has suffered from a lack of electricity infrastructure to support large commercial and industrial (C&I) customers. As a result a number of C&I expansion projects have either stalled or have not been developed. This study will consider the duplication of a natural gas lateral to serve not only a continuing gas requirement for this region but also to facilitate a new gas fired generation power station to underpin electricity supply to large C&I customers.

The Port Pirie Regional Council (PPRC), the Member for Frome Geoff Brock MP and RDAYMN have formed the Port Pirie Planning Group, the primary aim of which is to foster growth and development opportunities within the region. The Port Pirie Planning Group has identified the following key infrastructure projects to assist in the economic prosperity of the region and to ensure that major development opportunities, such as mining exploration and development are not abandoned.

- Duplication of the gas lateral feed line from Whyte Yarcowie
- Upgrading the Port Pirie Airport
- Shipping Port upgrade, and
- Training Hub

The scoping document that has been provided to CQ Partners has suggested the following scope or prime steps to be undertaken as part of this study:

1. Assessing power and gas demand on Eyre Peninsula, North of State and Braemar regions along with the associated locations for that demand;
2. Where will the power generation be located and how will it best be distributed to each location (i.e. one generation source and subsequent transmission/distribution or multiple generation sources);
3. Based on demand and generation (as per 1 and 2 above) what is the viability of duplicating the gas lateral from Whyte Yarcowie to Port Pirie?

Some alternative solutions that have been covered in the tender documentation by RDAYMN are: power generation at Port Pirie (SAMAG site) and then undersea electricity network connection to Whyalla and duplicating the gas lateral all the way to Port Augusta whilst also supplying Port Pirie and Whyalla.

This study will consider whether the duplication of the existing gas lateral is the most economically viable option to meet the regions future energy requirements. There may be a requirement to undertake further costings on the preferred electricity supply option.

3 Background

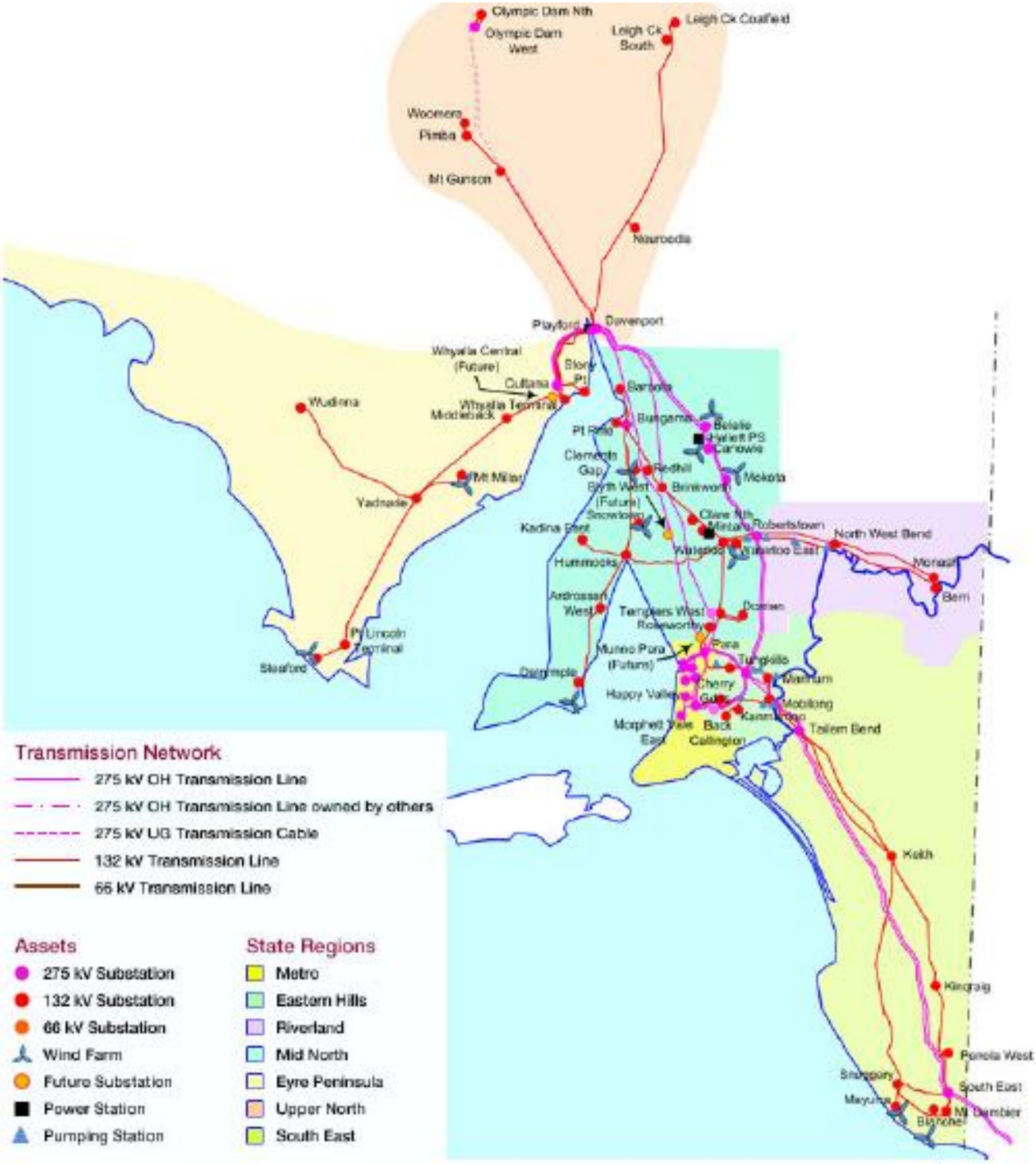
The existing gas lateral spans about 78km from Whyte Yarcowie to Bungama, just outside of Port Pirie. The lateral is 150mm in diameter and increases in size to 200mm between Bungama to Whyalla. The path from Bungama is north past Port Germein then west under the Spencer Gulf and then south to Whyalla via Port Bonython. The lateral from Bungama to Whyalla is approximately 88km.

The lateral is nearly at capacity (without further compression) and currently transports about 7PJ of gas per annum. Nyrstar at Port Pirie consumes about 1 PJ per annum and Arrium (OneSteel) at Whyalla consumes about 5PJ per annum.

3.1 Electricity Network Coverage

RDAYMN covers the Barunga West, Clare and Gilbert Valleys, Copper Coast, Goyder, Mount Remarkable, Northern Areas, Orroroo Carrieton, Peterborough, Port Pirie, Wakefield and Yorke Peninsula local government districts. The following map provides a good illustration of the existing high voltage electricity supply options available to the region.

Figure 1 Electricity Transmission and Supply for Eyre, Northern, Yorke and Mid North Regions



Source: ElectraNet, SA Transmission Annual Planning Report June 2013

The SA transmission network has 4 primary 275kV transmission lines that connect the North and Central regions and 2 by 275kV transmission lines that connect the Central and South East regions. Sitting around this is a meshed 132kV transmission system which as far as practicable connects major loads and generation points to the network. SA also has 2 interconnectors that allow electricity to flow between SA and Victoria. The first of these interconnectors is the Heywood Interconnector which links the South East of SA to Heywood in Victoria. The Heywood Interconnector has a maximum capacity of approximately 460MW. The second interconnector is Murraylink, which connects Monash in SA to Red Cliffs in Victoria. Murraylink has a maximum capacity of approximately 220MW.

The Heywood Interconnector is also expected to have its transfer limit increased from about 460MW to 650MW. The augmentation to deliver this additional transfer limit has received Regulatory Investment Test – Transmission (RIT-T) approval from the Australian Energy Regulator (AER) and will require the installation of a third 275kV transformer at Heywood terminal station and reconfiguration of of the existing 132kV transmission system between Snuggery, Keith and Tailem Bend. The Heywood Interconnector upgrade is expected to be in service by July 2016. The Heywood upgrade is expected to assist wind farm generators to get more generation output to market as the network will be less constrained to export electricity to Victoria. In the longer term this is expected to provide more competition for wholesale electricity in the market.

This network infrastructure along with the distribution network that is owned and operated by SA Power Networks is what currently delivers electricity to load centres across SA from electricity generation facilities and interconnected markets.

A lack of network infrastructure can create significant limitations to parts of the network that are not currently augmented to cope with significant growth in customer loads. ElectraNet uses a process whereby it tracks customer demand for those customers that are directly connected to their network. It also tracks forecasted growth expectations from new loads expecting to be connected to its load. This is usually undertaken through connection enquiries from large customers. The demand forecast is a key input into the planning and development of the transmission network. According to the SA Transmission Annual Planning Report (June 2013), the connection point demand forecasts for 2013 were lower than the 2012 forecasts due to a subdued economy and increasing solar PV impacts. The report also states that the 2013 demand forecast has resulted in significant delays in the timing of emerging network upgrades.

Given the regulatory environment within which ElectraNet operates, it requires firm commitment from interested parties in regards to network connections prior to undertaking any form of network investment. Our discussions with ElectraNet also indicate they have not received any connection enquiries for an increase in customer loads. The exceptions are Rex Minerals, Centrex, Iron Road and Royal Resources who have had discussions with ElectraNet in relation to their existing and future load requirements. However as far as we are aware, none of the large C&I customers have submitted a formal connection enquiry with ElectraNet to expand their electricity consumption requirements in the Upper Spencer Gulf or Braemar regions[1]. This information is consistent with the outcomes as detailed in the ElectraNet SA Transmission Annual Planning Report for 2013.

As a result, even with additional new generation capacity in the Upper Spencer Gulf, the transmission and distribution networks may not be sufficiently augmented to cope of significant C&I load expansions. Further discussion detailing network adequacy is covered later in this report.

3.2 Gas Network Coverage

The duplication of a gas lateral off the Moomba to Adelaide Gas Pipeline System (MAPS) to provide a fuel source for a new gas fired generator will require a number of economic and regulatory hurdles to be overcome, including:

1. Economic return on investment for a gas fired generation either with a long term power purchase agreements (PPA) or in the absence of long term PPA with major C&I customers;

[1] Transmission connection enquiries are usually confidential in nature, but in this instance as ElectraNet have not received any enquiries, they were able to confirm this.

2. The ability to access gas volumes sufficient to run a gas fired generation power station at prices that ensure the power station can be competitive in the NEM;

3. What is the preferred location for a new entrant generation facility – this is largely based on proximity to fuel and transmission network access;

4. What are the network augmentation requirements to connect the generation facility to the NEM and to allow that electricity to be transported to those C&I customers that require energy; and

5. What size generation facility is needed in a market that is currently oversupplied and not expecting any new gas fired generation facilities to be built before 2020.

The following diagram shows the existing gas lateral from Whyte Yarcowie to Port Pirie and then on to Whyalla. The gas lateral is constrained due to its physical size between Whyte Yarcowie and Port Pirie. A study[2] undertaken for RDA in relation to the potential costs to increase gas supply to the Upper Spencer Gulf concluded that the existing lateral capacity could be increased to 11PJ per annum (from 7.7PJ per annum) with additional compression at Whyte Yarcowie. The cost of this compression was evaluated at approximately $5.9m ($2011). With maximum pressure at Port Pirie, the study found that up to 19.6PJ per annum could be made available at Whyalla. Initial discussions with Epic Energy indicate that additional compression is possible, however they have not provided confirmation of additional volume that could be gained from the exercise.

If we assume current gas consumption at Port Pirie does not change (around 7PJ per annum), then there is about 4-5PJ per annum that could be available for gas fired generation at Port Pirie. Assuming a gas fired generator with an installed capacity of 120MW and engine efficiency of 40% (heat rate of 9kJ/kWh) is commissioned at Port Pirie, it would be able to generate at full capacity for about 10 hours per day[3].

It is therefore conceivable that a new gas fired generation power station could be built utilising additional compression on the existing gas lateral. A generation plant of 120MW may not however be an optimal size, given the extent of the infrastructure required and the return on investment required.

Further analysis on demand and existing generation supply is discussed later in this report. It must be noted however that the commissioning of a new gas fired power station at Port Pirie or close to the gas lateral would still require substantial network augmentation to firstly transmit electricity to the SA grid and also separately to connect large C&I customers.

Any upgrade or duplication of the gas lateral will require EPIC Energy to consent to the capital infrastructure connecting into their MAPS infrastructure. The duplication of the gas lateral would ordinarily be built by EPIC and charged back to a user or number of users through a long term tariff structure. This tariff will effectively take into account the cost of the lateral and the operation and maintenance cost of the lateral plus a management fee which would incorporate a profit margin. The total cost (including funding costs) of the lateral are then amortised over a nominal 10 to 15 year period and charged to users of that lateral.

The GPA report has estimated a capital cost in the order of $84m for a 30PJ lateral upgrade. On this basis, the tariff structure over 10 years would be in the order of $0.28/GJ. This however does not incorporate the costs associated with operating and maintaining the lateral, cost of funding and management (profit margin) which we estimate would be in the order of $0.20-$0.30/GJ[4]. As a result, EPIC would look to recover about $0.50/GJ for a 30PJ lateral as noted earlier. The user(s) would effectively be paying for full capacity regardless of whether it was used or not, that is they are paying for pipeline capacity and not utilisation.

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2 GPA Report dated April 2011 – Increased Gas Supply to the Upper Spencer Gulf

3 This assumes 4PJ per annum of gas being available. Plant will require 1,080GJ per hour or 10,800GJ over 10 hours. Across 360 days (availability factor taking into account plant outages), the requirement is about 3.9PJ per annum.

4 The cost of O&M, Management Fee, Profit Margin and Funding cost has been estimated by EPIC Energy.

If the lateral was funded by a gas user or via government funding then EPIC will still most likely retain ownership of the lateral due to the requirement to hold a gas pipeline licence. In this case, EPIC would still pass on the costs associated with O&M, management fee and profit margin (estimated to be around $0.20-$0.30/GJ).

As a result a gas customer would need to enter into a long term agreement with EPIC (usually 10 plus years) at a cost of about $0.50/GJ depending on who funded the capital cost of the lateral. The gas customer is then also responsible for purchasing the gas commodity at a cost of between $7 and $8.50/GJ ($2013).

We have provided further information on the gas market later in this report.

Figure 2 MAPS and Whyte Yarcowie to Port Pirie Lateral

Source: EPIC Energy website

4 SA Energy Market Overview

4.1 Electricity Market Overview

SA joined the National Electricity Market (NEM) in 1998 and at that time had the worst load factor in the NEM[5], largely a result of very hot summers and a large domestic air-conditioning load. The result was that pool prices were extremely volatile in 1999 and 2000 as there was a need for expensive gas fired peaking plant to be dispatched to meet peak day demands with little competition due to a tight generation supply position.

During this period the interconnector between SA and Victoria was often constrained[6]. When this occurs the price is set by the marginal SA generator and not the importing region (Victorian generation), resulting in increased price volatility as SA generators are able to take advantage of the lack of competition on the supply side. This issue was alleviated with the commissioning of the Pelican Point power station (478MW) in 2000.

5 Load factor is the proportion of peak electricity load to average electricity load.

6 When the interconnector between South Australia and Victoria is constrained the maximum amount of energy that can be imported from Victoria through the interconnector has been reached and prices are set by the marginal generator in SA.

Pool prices between 2001 and 2006 were generally flat and suppressed due to cooler summers and increasing generation capacity in the NEM. On many occasions, pool prices in SA were reflecting the low marginal cost of coal based generation across both Victoria and SA.

Drought conditions across the eastern states (particularly Queensland and New South Wales) during 2007 saw hydro and coal fired power stations (reliant on water from dams for cooling purposes) reducing their generation output. This significantly changed the supply and demand balance in the NEM and resulted in an underlying increase in pool prices across all of the NEM jurisdictions.

AGL also acquired the Torrens Island power station (previously owned by TRUenergy now Energy Australia) in mid-2007. At that time AGL already had substantial wholesale (or financial) contracts in place with other generators to cover a large proportion of its retail electricity customer portfolio in SA. The Torrens Island power station was purchased with little or no wholesale contracts in place which allowed AGL to bid the power station aggressively into the market, creating significant price volatility and increasing pool prices in SA for both 2008 and 2009.

Over the past 2-3 years, SA has witnessed a significant change in the supply and demand balance. The first significant impact has been driven through the renewable energy target (RET) which has incentivised the investment in renewable generation facilities (primarily wind farms). SA has benefited from having a strong wind resource as well as having a state government supportive of the renewable industry.

The installation of wind farms across SA (approximately 1,200MW installed to date with the 270MW Snowtown 2 wind farm due for commercial operation in 2014) has had a dampening effect on pool prices as they displace conventional generation when online (as they are bid into the market at $0/MWh or less). This is particularly the case during low demand periods which tend to occur across overnight off peak periods when the wind is strongest. The penetration of wind farms in SA has led to a significant number of negative pool price periods at times, but has also created pool price volatility during higher demand periods when wind farm generation falls quickly due to a lack of wind, requiring conventional generators or imports from Victoria to respond quickly.

The second material change in SA (and across the NEM) has been the uptake of solar PV at a domestic level with an installed capacity of approximately 398MW in SA as at July 2013. This has had the impact of muting peak demand in most states and in SA it contributes approximately 150-240MW or approximately 8% of energy on a peak demand day[7]. Solar PV is also being considered by small to medium enterprises as well as C&I customers to further reduce peak network tariffs and also further reduce their exposure to increasing energy prices. This transition to embedded or on site generation will continue to see a further reduction in peak demand across the NEM.

In SA, the contribution of solar PV during peak summer periods partly explains the flattening of peak demand during extreme hot days over the last 2 years. We have recently witnessed this occurrence on 17 January 2013 which had a maximum of 43^{o}C. The peak demand reached 2,991MW on a day that would previously have resulted in demand of about 3,200 - 3,300MW. On this day the pool price peaked at $95.55/MWh in the half hour ending 17:00 (with peak demand occurring in the half hour ending 18:00). All SA thermal generating plant, including all 8 Torrens Island units were operating[8]. Wind farm generation totalled approximately 600MW during this peak period and imports from Victoria was approximately 300MW. These types of market outcomes reduces the incentive for investors to build fast start gas fired generation plant, as the return on what is regarded as a peak demand day is not producing significant and sustained high pool prices.

7 AEMO – Rooftop PV Information Paper, 2012 & Clean Energy Regulator - List of SGU/SWH installations by postcode, 2013. (This value is not the installed capacity but rather solar's energy contribution based on summer capacity factors and installed capacity.)

8 Playford B is not available until further notice.

The third change across the NEM has been a reduction in total electricity demand in general at both a domestic and commercial/industrial level. This has largely been a result of the global financial crisis and a range of energy efficiency measures introduced by local and federal governments as well as the impact of the carbon tax. This has driven most industry and households to become more aware of the need to reduce their cost of energy through reduced consumption.

In the National Electricity Forecasting Report (NEFR) produced by AEMO, the forecast of annual energy in SA for 2013/14 is expected to be 3.6% lower than the 2012 forecast under a medium economic growth scenario. The forecast over the next 10 year outlook period shows SA's annual energy declining at an average annual rate of 0.1%. This is largely a result of lower than expected population growth, the deferral of the Olympic Dam expansion project and an increase in solar PV installations.

The introduction of a carbon tax on 1 July 2012 has however had the counter effect of inflating pool prices. At a cost of $23/tCO2-e, most generators have been able to build this impost into their short run marginal cost (SRMC) of production, increasing pool prices, with this cost ultimately passed through to end users. As a result, the electricity market experienced a step change in pool prices from July 2012, with nearly 100% of the tax (based on an average emissions intensity in the NEM of 1.0) passed through into the pool price.

This is seen in the graph below, showing pool prices before and after the introduction of the carbon tax. The average pool price for the 12 months prior to the introduction of the carbon tax was $30.27/MWh and for the 12 months after the introduction of the carbon tax it was $69.78/MWh. The carbon price was not the only influence on price but it did have a substantial impact. This pre and post price impact is also noticeable over a shorter time period, with an average pool price of $28.14/MWh for Q2 (April to June 2012) and $65/MWh for Q3 (July to September 2012).

Figure 3 Pool Prices - Pre and Post Carbon

Source: CQ Partners

The market is now expecting a repeal of the carbon tax post 1 July 2014 and as a result has significantly reduced expectations in terms of the need to pass through a carbon impost going forward.

However as the carbon impost is expected to be removed another is expected to take its place, and this is in the form of higher gas fuel costs. This is covered more extensively in later sections of this report. As an overall comment however, the market has started to absorb higher gas costs (in the order of 50 - 80% increases) which will ultimately flow through into the fuel costs of gas fired power plants. Both the removal of a carbon price and an escalation of gas prices should encourage coal fired generation back into the NEM as they will again be the most economic base load plant in the NEM. Those impacted most by the removal of a carbon price and an escalation of natural gas prices will be gas fired plant.

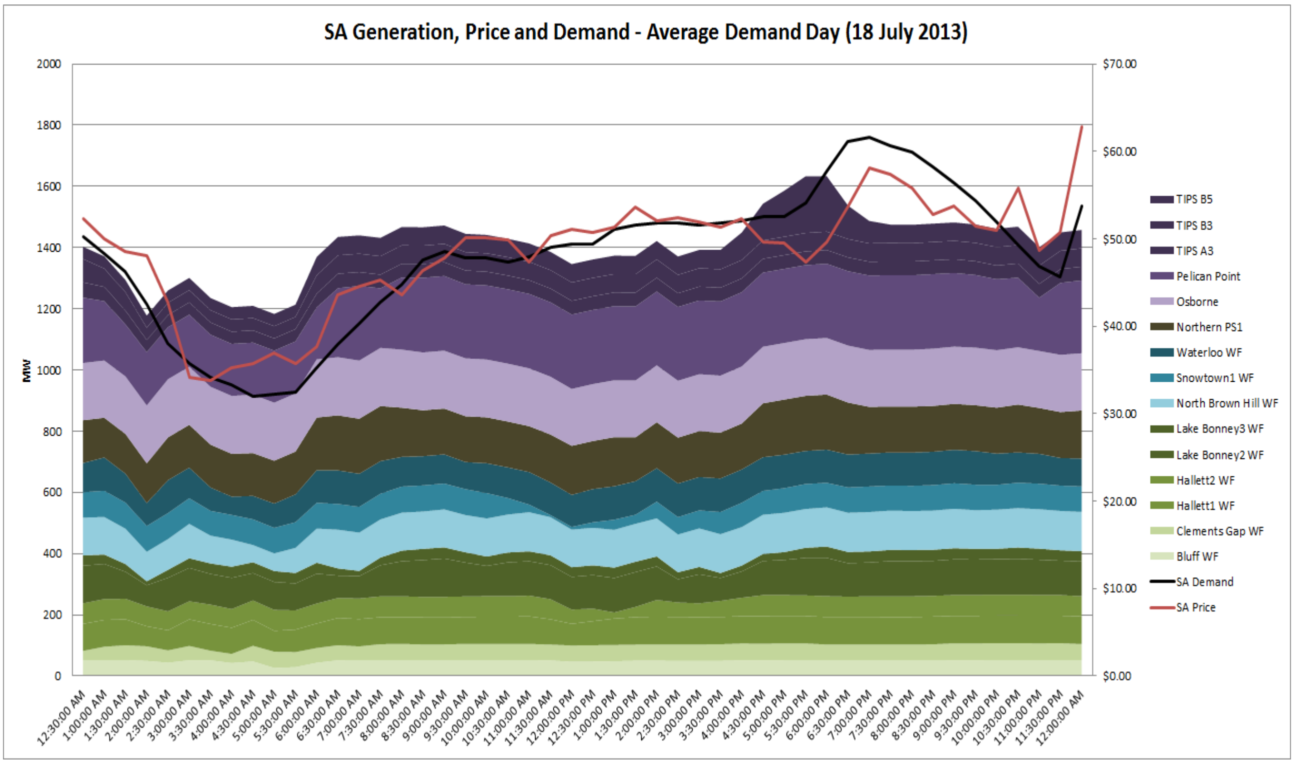
Based on the generation plant mix and their associated marginal costs, the merit order in SA on average and peak demand days is shown below in Figures 4 and Figure 5 (noting that the shortfall between SA generation and demand is being supplied through interconnection with Victoria).

As illustrated in the graphs, wind farms are generally the first to be dispatched as the short-run marginal cost (SRMC) is effectively zero, these are then followed by base load power stations with coal based plants such as Northern power station having lower marginal costs than gas fired plant such as Pelican Point and Torrens Island.

Most new build power stations will look to enter into longer term PPA's with other market participants or with large customers to ensure that they are able to get a suitable return on asset. If a gas fired generator were to take merchant exposure (i.e. receiving largely pool revenue) then it will want to ensure that the average pool price is capable of covering the long run marginal cost (LRMC) of the plant. These costs will include the fixed and variable costs of operating the plant. As a minimum, plants will want to recover their SRMC. If we consider that a peaking plant will have a heat rate of about 7-9 kJ/kWh, then using a conservative fuel cost of say $7.50/GJ, the plant will need to recover in the order of $52.50 - $67.50/MWh just to cover its fuel cost.

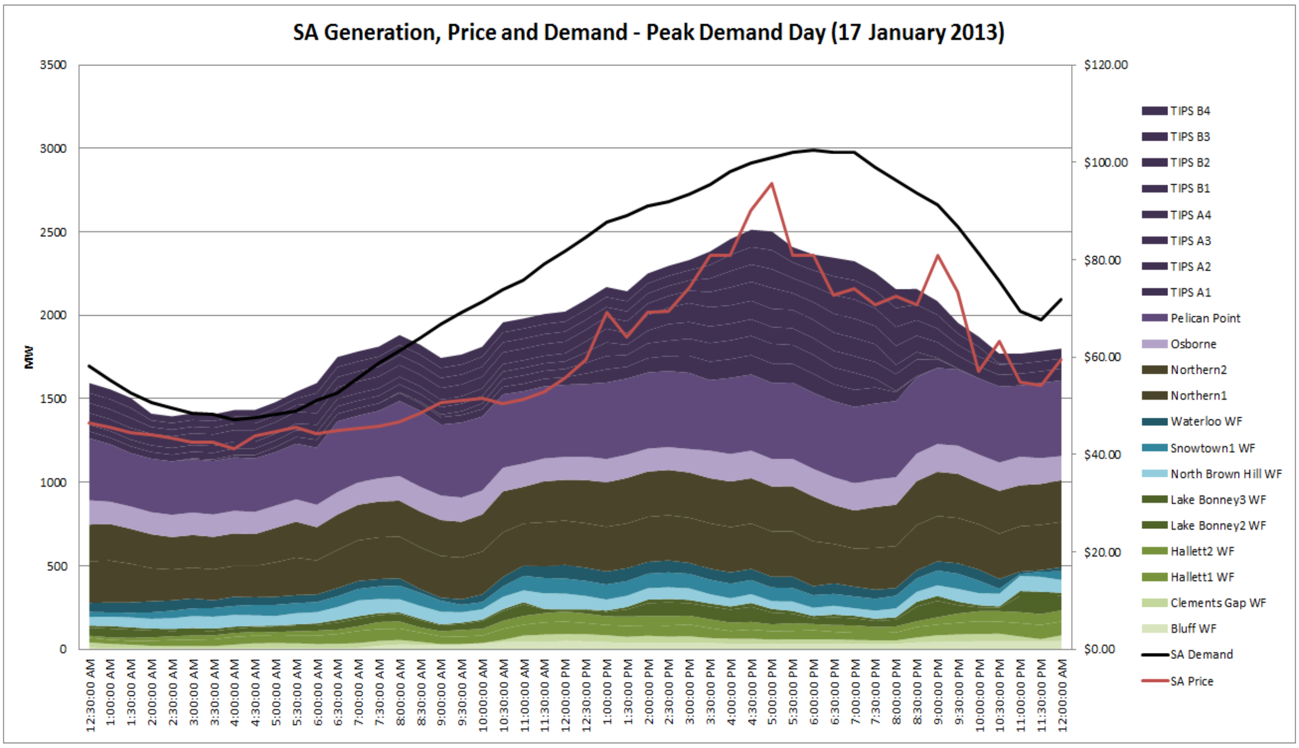
As indicated from the graphs below, on an average demand day, there is little incentive for peaking gas plant to operate as they are not receiving sufficient income to cover their fuel costs. On a peak demand day, there are a number of hours in the day in which peaking plant can recover their fuel costs and most likely their SRMC.

Figure 4 SA Generation, Price & Demand – Average Demand Day



Source: CQ Partners using AEMO data

Figure 5 SA Generation, Price & Demand – Peak Demand Day

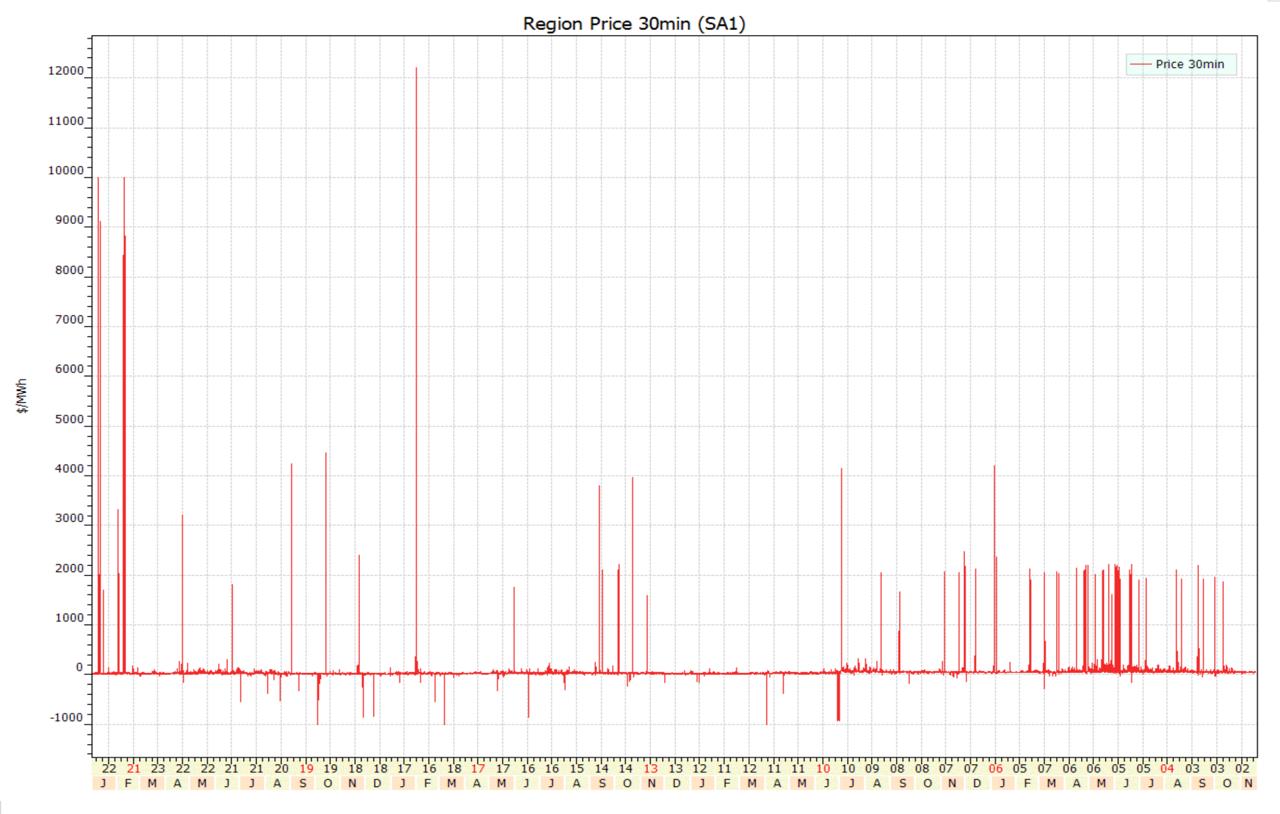


Source: CQ Partners using AEMO data

The number of hours in which a gas fired power station can recover its SRMC is however diminishing, largely due to the dampening of pool prices as a result of increased wind farm penetration, increasing solar PV and a reduction in overall peak demand.

Apart from the carbon tax which created some pool price escalation in July 2012, generation businesses that have significant volumes of generation exposed to the pool price have also tried hard to create pool price volatility in the marketplace. What the graph in figure 6 below indicates is an increase in pool price volatility during 2012 and also during 2013. Even though the number of 5 minute periods where prices are over $100/MWh have increased, these price events are also generally limited to around $2,000/MWh without going up to a maximum of $13,100/MWh, which is the market cap for electricity prices.

Figure 6 SA Half Hour Pool Price Outcomes since 1 January 2010



Source: CQ Partners using AEMO data

The following table shows the annual average pool prices for SA. The primary influence of price volatility over the past 18 months have been:

- The carbon impost on generators from 1 July 2012 which flowed through into the wholesale price of energy;
- The withdrawal of generation supply from the SA market to tighten supply/demand dynamics. This strategy has been largely driven by Alinta Energy (Alinta), in relation to its Port Augusta power station and also GDF Suez with the frequent withdrawal of one Pelican Point power station unit; and
- The increasing cost of natural gas, which is increasing the fuel costs of gas fired generation facilities.

Table 1 SA Average Annual Pool Prices since 2010

Calendar Year	2010	2011	2012	2013 ytd
Average Pool Price ($/MWh)	$40.28	$37.41	$44.21	$71.55

Source: CQ Partners using AEMO data

Alinta's strategy of mothballing the Playford power station (which is uneconomic in a carbon constrained environment) and only operating Northern power station during peak periods (October to March in addition to running one Northern unit during July 2013) is also increase pool price volatility. Alinta has publicly announced that Northern will be returned to full service in the summer of 2014/15. The withdrawal of this generation capacity has meant that the supply/demand balance has tightened, increasing pool prices as compared to the same period last year. Alinta's strategy of mothballing Playford and only running Northern is not totally driven by the carbon price. Other factors including Leigh Creek life of mine considerations, wholesale price outcomes and future contracting strategies all influence the decision as to when to operate the plant.

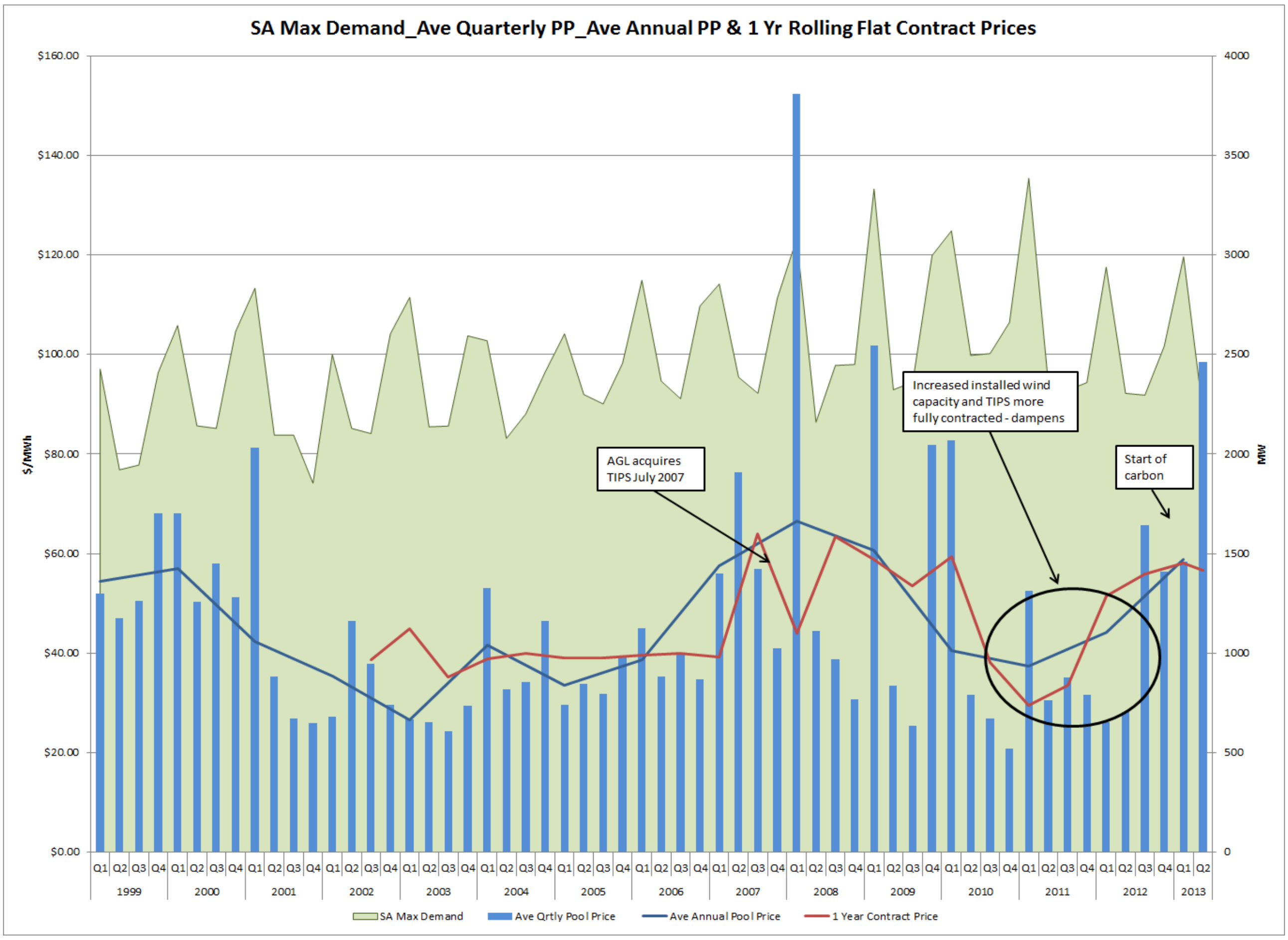
Alinta have considered alternative generation facilities at Port Augusta to replace Playford power station. These have included solar thermal technology and also gas fired generation. To date neither of these technologies have been able to get traction within Alinta because they do not been a sufficient return on investment. Solar thermal technology is expensive and usually is not economic unless it receives significant government funding.

When considering a high level analysis of a gas fired generation option at Port Augusta, we would consider the 30PJ per annum case study from the GPA report which was costed at about $81million for a new gas lateral to Whyalla. If we assume a tariff on that gas lateral of about $0.20/GJ just to recover the capital cost over 15 years (not including cost of funding or any other fees), then the delivered fuel cost would be in the order of $7.20/GJ to $8.70/GJ. Again just to recover the cost of fuel at Port Augusta would require that the gas fired generator earns $65 - $78/MWh depending on the price of gas. In the current market where average annual pool prices have averaged less than $72/MWh over the past 4 years (see table above), investment in gas fired generation would be extremely difficult to finance.

New entrant generators also prefer to contract the output of the generator to either retailers or customers so that they aren't exposed on pool prices which may not meet their SRMC of the plant. As a result, unless a new entrant generator can enter into a PPA structure with a customer or group of customers then it is difficult to foresee a merchant investment in generation.

There is a strong link between pool prices and forward wholesale contract prices which can be seen in Figure 7 below. Forward wholesale contract prices are based on the market's expectations of where pool prices will settle going forward but are also a function of what has happened in the near term (usually over the previous twelve month period). As a result there is generally a convergence of these prices as seen below. Retailers and generators will generally look at the forward contract price to determine what electricity could be sold for over the next 2-3 years. This is another good forward looking indicator for new entrant market participants looking to invest in generation.

Figure 7 SA Demand, Quarterly and Annual Pool Prices and 1 Yr Flat Contract Prices



Source: CQ Partners using AEMO data

Forward 1 year contract prices provides a good indicator as to where the market expects prices to be over the next couple of years. The table below provides both carbon inclusive and carbon exclusive prices for 1 year swap contracts for electricity. There is still a spread in calendar 2014 for carbon inclusive and carbon exclusive pricing as the market is still expecting some carbon exposure to be passed through the wholesale pool price. This spread in prices is however negligible in 2015 as most market participants expect carbon to have been repealed.

What the 1 year flat forward contract prices also indicates however is that the market does not expect much volatility from a pricing perspective. A carbon exclusive price for calendar year 2015 of sub $50/MWh is still well below what a gas fired generator would look to recover from the market.

Table 2 Forward 1 Year Flat and Peak Contract Prices – South Australia

Calendar Year	Flat Carbon Inclusive $/MWh	Flat Carbon Exclusive $/MWh	Peak Carbon Inclusive $/MWh	Peak Carbon Exclusive $/MWh
2014	$59.70	$47.70	$76.79	$64.79
2015	$49.50	$48.20	$63.60	$62.30

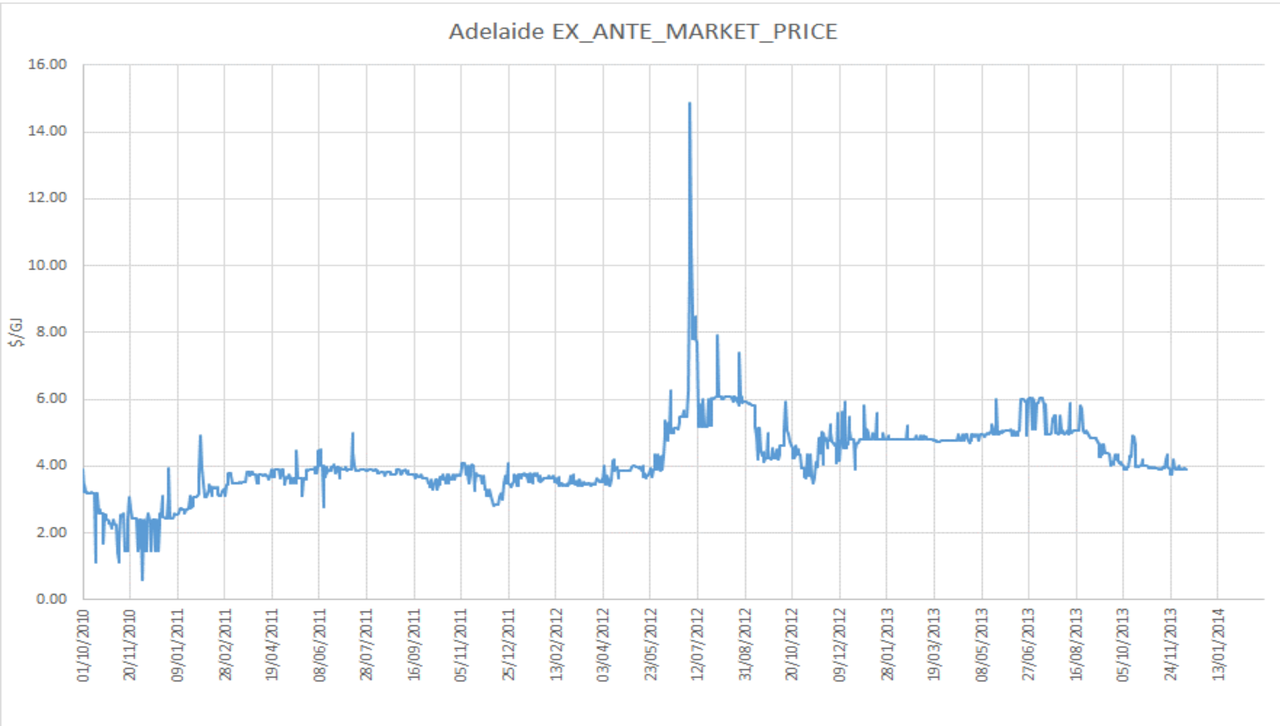
Source: NextGen Solutions

4.2 Gas Market Overview

Gas was discovered in South Australia in 1963 at Moomba in the Cooper basin. This led to the construction of the Moomba to Adelaide Pipeline (MAPS) and the commencement of gas supplies to Adelaide in 1969. In 2001 construction commenced on the SEAGas pipeline connecting Adelaide to the Otway basin gas fields in Victoria. The SEAGas pipeline commenced operations in 2004.

At a wholesale level gas has traditionally been sold under long term bilateral contracts between gas retailers and gas producers at production cost reflective pricing. On 1 September 2010 the Short Term Trading Market (STTM) commenced at the Adelaide hub. The STTM is a day ahead gas market covering the Adelaide gas distribution network. Since its commencement, the STTM price at the Adelaide hub has ranged from $0.59/GJ to $14.89/GJ and averaged $4.16/GJ up to 10 December 2013. The daily STTM price is shown in Figure 8 below.

Figure 8 STTM Ex-Ante Price at the Adelaide Hub



Source: CQ Partners using AEMO data

The STTM is primarily a balancing market in which gas market participants trade their daily unders and overs of gas in the Adelaide metropolitan zone. The STTM does not replace the need for the major gas users to contract gas from upstream gas producers and then haul the gas to Adelaide via either MAPS or SEAGas.

There is a repricing of the value of gas underway in the eastern Australian gas markets. The development of the LNG projects in QLD has significantly changed the landscape in which suppliers will price gas within this market. The first three LNG projects will consume approximately 1,600PJ/a compared to current total gas demand in the eastern Australian gas markets of 675PJ/a (AEMO 2012 SOE). The QLD LNG projects will start producing LNG from early 2015. As a result the pricing of gas in the eastern Australian gas markets is moving from being based on long term gas production costs to a LNG netback pricing basis (i.e. the equivalent cost at the well head of gas exported as LNG with all transport and production costs removed from the purchase price).

Historically wholesale gas prices in SA have been in the range of $4 - $5/GJ. Cooper Basin gas has traded at the higher end of that range and at a premium to Otway Basin gas and QLD coal seam gas. Going forward, gas prices have commenced rising towards LNG netback pricing. The exact pricing and timing of the increase in gas prices can vary significantly between gas suppliers. Currently gas is being offered at $7.00-$8.50/GJ (in $2013) for 2015, which is a significant increase on historical wholesale gas prices in SA. Further, the availability of gas is limited with new gas contracts generally being for much shorter terms and on terms that are less flexible. This rise in gas prices and decrease in flexibility is increasing the marginal cost of gas-fired generators making them less competitive in the merit order against alternative forms of generation (especially wind).

In addition to the step change in pricing and decreased flexibility, there is currently a very limited availability of long term gas supplies. A new entrant gas generator or a large industrial customer will have difficulties in obtaining a long term gas supply particularly from the Cooper Basin. The primary focus of the major producers is to supply sufficient gas to their Queensland LNG projects and they currently have a lukewarm interest in supplying gas to the domestic market. In order to obtain financing, a new entrant gas generator will need to demonstrate it has locked in a long term gas supply with competitive gas pricing. In the current gas market that is near to an impossible outcome to achieve. Once the Queensland LNG projects are commissioned and operating in a steady state and further exploration investment has occurred (as is currently planned) in the Cooper Basin, the current difficult gas market conditions may start to improve towards the later part of the decade (close to 2020).

4.3 New Entrant Generator

The electricity market summary above does not paint a positive picture for capital investment in generation assets. As a rule of thumb, new entrant electricity generation plant will need to recover as a minimum its fuel cost and at best, its long-run marginal cost (LRMC). Based on simple economics of an efficient gas fired generator with a heat rate of 7-9 kJ/kWh and a fuel gas cost of say $7.50/GJ, the wholesale energy price (whether in the form of pool prices or contract prices) would need to be a minimum of $52.50/MWh just to recover its fuel position.

Based on actual pool price outcomes in SA since 2010, only 2013 would have provided sufficient return for a gas fired generator to be cover its fuel position. Based on forward curve data, a gas fired generator could sell peak contracts at a level that is above its fuel recovery position but still shy of its SRMC which would generally be in the order of $75/MWh.

The economic return for gas fired generation new entrants is not supported by current and expected returns in the NEM.

This position is also further supported by an oversupplied generation supply position in SA, with an expectation that further supply is only required by 2020-21 at the earliest to meet system security and reliability parameters.

The economics therefore does not support a new gas fired generator at any location in SA. Having said this, most market participants would look favourably at building a new generation plant that is dedicated for the utilisation by a large customer or group of customers as part of a power purchase agreement (PPA) arrangement. This would remove the merchant risk from the investment as large customers will effectively contract with the generation owner for a period of at least 10 years, underpinning that capital investment.

A long term off take agreement could be structured with a number of existing generation suppliers including Alinta, AGL, EA, Origin and GDF Suez. In order to take advantage of these types of structures, it is imperative that large industrials are in a position to make a long term commitment for electricity, generally at a prices that reflect new entrant gas generation pricing (in excess of $75/MWh, plus network costs and other regulatory pass through costs such as LGCs and STCs).

4.4 South Australian Electricity and Gas Market Participants

The major SA energy market participants are all vertically integrated (electricity and gas retail businesses with power generation in their portfolios). These are AGL Energy (AGL), Origin Energy (Origin), GDF Suez (with their retail subsidiary Simply Energy) and Energy Australia (EA). These companies are also major gas shippers on MAPS. Vertical integration has been a major focus for most electricity participants across the NEM as a means of reducing market risk and extracting additional commercial opportunities. This strategy also provides an internal revenue hedge, for example:

- When electricity pool prices are low the retail business can generally purchase electricity for its customers below the fixed price that it has sold to them, locking in additional margin which assists in offsetting reduced revenue for its generation business which is receiving the same pool price for its generation (assuming other financial products haven't been used to manage price risk);
- When electricity prices are high (or volatile), the generation business will extract additional revenue from the pool price which offsets losses that may be incurred by its retail business which is purchasing electricity above the fixed price tariff it has sold to its customers (assuming other financial products haven't been used to manage price risk).

For example in relation to gas:

- Gas can be purchased contractually for both retail and power generation at the same time providing two channels to market for the one product with the ability to utilise surplus retail customer gas to produce electricity revenue during periods when gas retail customers are not consuming their expected requirements.

The ability to retail both gas and electricity also provides additional marketing opportunities related to other products and services such as renewable energy and solar.

These four vertically integrated MAPS major shippers have substantial energy portfolios in SA and these are summarised below.

4.4.1 AGL

AGL is the largest vertically integrated market participant in SA. AGL owns the 1,280MW gas fired Torrens Island power station (TIPS). TIPS is a base load/mid-merit power station and due to its operational flexibility of 8 units (4 by 200MW and 4 by 120MW) it tends to be the marginal generator (or load following generator) which supplies increases or decreases in demand over a half hour. TIPS is connected to both SEAGas and MAPS. In addition AGL is understood to be the owner/off-taker of 350-400MW of wind farm capacity in the state.

AGL is also the largest electricity retailer in SA. AGL has approximately 55% of customers in the state with a large portion of these being residential customers who tend to have consumption which is peaky over extreme demand periods due to the use of air conditioning during extreme demand periods (residential customers can consume more than double their average daily consumption on these days). AGL's significant customer base in SA is a legacy of their purchase of ETSA Power in 2000, where they acquired the entire SA electricity customer base. In terms of gas, AGL is is understood to have around a 30% market share in SA (~7.45PJ/a excluding Adelaide Brighton).

4.4.2 Origin

Origin owns the 180MW gas fired Osborne power station, the 224MW Quarantine gas fired power station and the 86MW gas fired Ladbroke Grove power station. Osborne and Quarantine are connected to MAPS whilst Ladbroke Grove is not due to its location in the South East of SA.

Osborne is owned 50% by ATCO Australia and 50% by Origin, with Origin the off-taker for all electricity produced through a power purchase agreement (PPA). Osborne provided steam to Penrice and operated in combined cycle mode with some of the steam utilised for Penrice (rather than generating electricity in the steam turbine). The power station is now understood to be operating at its full combined cycle capacity to produce electricity only (base load mode) as required under the PPA following the termination of the Penrice steam agreement. The 224MW Quarantine power station comprises 4 by 24MW units and a 1 by 128MW unit operating in open cycle mode. The Ladbroke Grove power station comprises 2 by 43MW units.

Origin is understood to have around 15% of the electricity retail customers in SA. Origin also purchased the SA Gas Company where it acquired 100% of the SA retail customer base, with Origin's share of gas retail customers in SA understood to be around 60% (~1.4PJ/a excluding Amcor).

4.4.3 GDF Suez

GDF Suez owns the 478MW gas fired Pelican Point power station and Synergen which comprises the open cycle gas fired power stations of Mintaro (90MW) and Dry Creek (156MW) along with the diesel fired power stations of Snuggery (63MW) and Port Lincoln (73.5MW). Pelican point is connected to both SEAgas and MAPS with Mintaro and Dry Creek captive to MAPS supply.

GDF Suez is vertically integrated via its electricity and gas retail business Simply Energy and is understood to have around 10% of the electricity customers and 2.5% of the gas customers in SA (~0.6PJ/a).

4.4.4 Energy Australia

Energy Australia owns the 228.3MW open cycle Hallett power station. Hallett is connected to MAPS and is a duel fuel power station that generates using gas with on-site diesel as a back up fuel supply. Energy Australia have significantly reduced their electricity retailing activities in SA since 2008 following the asset swap with AGL where they sold TIPS and purchased Hallett. It is understood Energy Australia have around 10% of the electricity retail customers and 6% of the gas customers in SA (~1.35PJ/a).

4.4.5 Alinta

Apart from the 4 major MAPS shippers already discussed, Alinta is the another major energy company in SA which has the ability to influence market outcomes and impact the gas demand on MAPS.

Alinta owns the 530MW coal fired Northern and the 240MW coal fired Playford power stations both located at Port Augusta. Through the impact of the carbon tax, the Playford power station has been taken out of service (can be made available during super peak summer periods) with Northern available and operating between October and March but shutdown over the shoulder and winter periods. This strategy is expected to continue until 2014/15. Alinta does not have a requirement for MAPS capacity as it has no gas fired generation in its SA portfolio.

Alinta has adopted an aggressive retail strategy across the NEM in recent years as part of its move to a vertical integration strategy. It is understood Alinta has around 5% of the electricity retail customers in SA and is currently establishing itself as a gas retailer in SA.

4.5 SA Generation Capacity Factors

The following table provides a good picture of how much utilisation the generation mix in SA has had over the past 12 months (Since 1 November 2012). It is clear that the gas peaking plant in SA have quite low capacity factors, which is expected, as they will generally only operate for short periods through the year as required to meet system demand. These peaking plants will also price their generation at high prices to ensure that they received an overall revenue stream across a year that is adequate to cover their return on capital.

What is evident from the capacity factors however is that there is significant supply availability within the current generation mix with plant still capable of increasing their utilisation. Again based on existing and forecast demand and the current oversupply of generation in SA, it is difficult to contemplate a situation that would incentivise the additional of a new gas fired generation facility in the state.

Table 3 SA Generation – Capacity Factors 12 Months from 1 November 2013

SA Generation	Technology Type	Fuel	Total Installed Capacity MW	Capacity Factor
AGL Hallett GT	OCGT	Gas	180	4.38%
DRY Creek GT1	OCGT	Gas	52	0.47%
DRY Creek GT2	OCGT	Gas	52	0.27%
DRY Creek GT3	OCGT	Gas	52	0.73%
LADBROKE Grove 1	OCGT	Gas	40	5.00%
LADBROKE Grove 2	OCGT	Gas	40	22.07%
MINTARO	OCGT	Gas	90	1.83%
NPS1	Sub Critical	Coal	265	52.97%
NPS2	Sub Critical	Coal	265	39.35%
Pelican Point CCGT	CCGT	Gas	478	56.55%
OSBORNE-AG	CCGT	Gas	180	85.74%
Quarantine PS 1	OCGT	Gas	24	5.58%
Quarantine PS 2	OCGT	Gas	24	6.18%
Quarantine PS 3	OCGT	Gas	24	6.76%
Quarantine PS 4	OCGT	Gas	24	4.79%
Quarantine PS 5	OCGT	Gas	128	14.59%
TORRENS Island A1	Steam Sub Critical	Gas	120	11.59%
TORRENS Island A2	Steam Sub Critical	Gas	120	10.49%
TORRENS Island A3	Steam Sub Critical	Gas	120	7.91%
TORRENS Island A4	Steam Sub Critical	Gas	120	12.38%
TORRENS Island B1	Steam Sub Critical	Gas	200	13.58%
TORRENS Island B2	Steam Sub Critical	Gas	200	25.86%
TORRENS Island B3	Steam Sub Critical	Gas	200	26.40%
TORRENS Island B4	Steam Sub Critical	Gas	200	19.54%
Total			3198	

Source: CQ Partners using AEMO data

5 SA Supply and Demand Dynamics

5.1 Electricity Demand

One of the primary sources of information in the NEM when considering whether generation supply is adequate to meet current and forecast demand is AEMO's annual Electricity Statement of Opportunities (ESOO). The ESOO is based on identifying when the network is likely to fall into a Low Reserve Condition (LRC) which is the point at which additional generation investment is required (or demand-side response) to maintain electricity supply reliability with the NEM Reliability Standard.

The following table is taken from the ESOO 2013 and shows when each NEM region is likely to fall into a LRC situation given a low, medium and high demand and growth scenario.

Table 4 Low Reserve Conditions for each NEM Region

Region	Low		Medium		High	
	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)	LRC point	Reserve deficit (MW)
Queensland	Beyond 2022–23	-	2019–20	159	2016–17	69
New South Wales	Beyond 2022–23	-	Beyond 2022–23	-	2021–22	53
Victoria	Beyond 2022–23	-	Beyond 2022–23	-	2021–22	123
South Australia	Beyond 2022–23	-	Beyond 2022–23	-	2020–21	36
Tasmania	Beyond winter 2023	-	Beyond winter 2023	-	Beyond winter 2023	-

Source: AEMO ESOO 2013

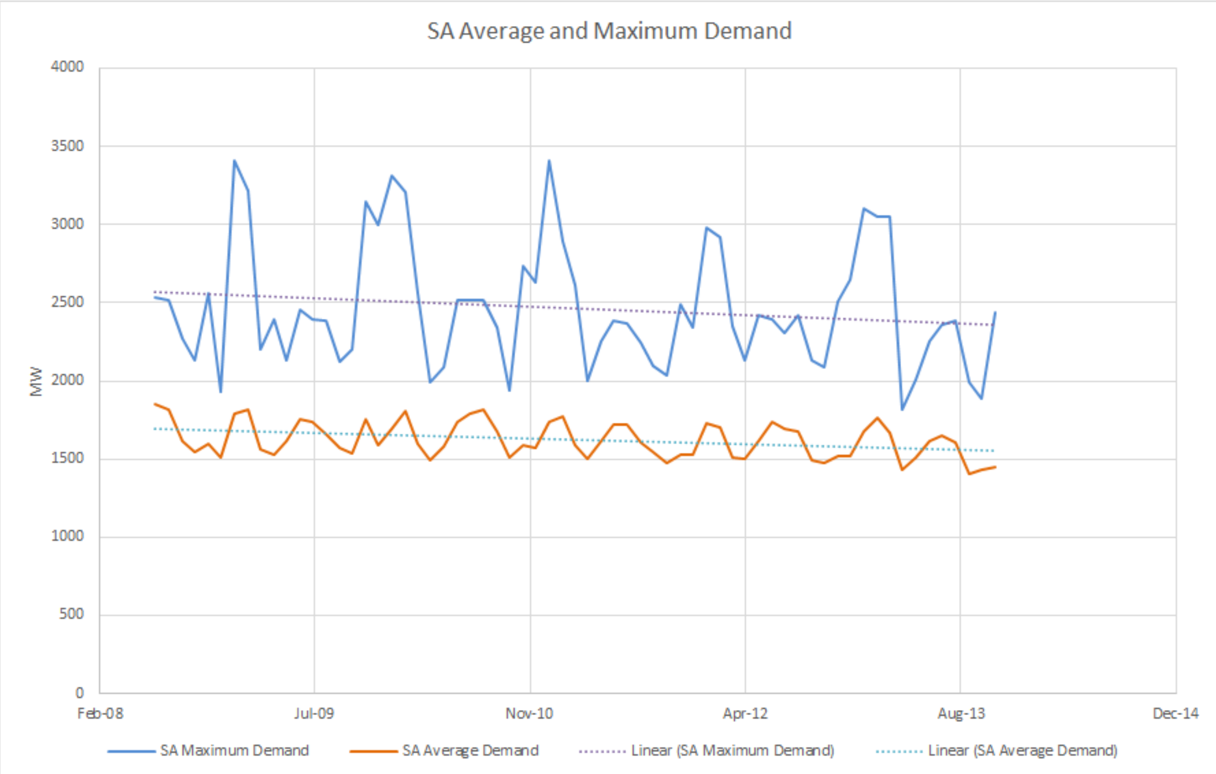
As indicated in the AEMO analysis, SA will only fall into a LRC by 2020-21 based on a high growth demand scenario. If we assume a more realistic growth path as outlined in the medium scenario, then the requirement for additional generation to meet the NEM Reliability Standard is pushed out even further to 2022-23.

Figure 8 below shows average and maximum (peak) SA demand since 2008. What is clear from the graph is that average and peak demand in SA has declined over the past 6 years, again largely a result of slowing economic conditions and an increase in energy efficiency measures and the adoption of rooftop solar PV.

The AEMO National Electricity Forecasting Report (2013) has modelled a total SA demand based on a 10% probability of exceedence (POE) basis at 3,254MW. The 10% POE demand is based on a 1 in 10 year demand scenario and as such is based on a peak demand for an extreme year. Considering this, SA still has sufficient conventional generation to meet peak demand. If all forms of generation are considered (including interconnection between SA and Victoria) then SA has a total supply capacity of around 5,655MW. We note however that wind contribution during peak demand days is often low and as a result we have attributed its average capacity factor of around 8% during peak periods. If we assume this lower generation output from wind and remove Playford Power Station from the capacity mix then SA has about 4,300MW of available capacity (including interconnection). Again this capacity is still more than adequate to meet AEMO's 10% POE demand of 3,254MW.

Please refer to appendix A for a list of generation capacity in SA. We have not included Snowtown 2 in this list as it will be commissioned from 2014.

Figure 9 SA Demand, Quarterly and Annual Pool Prices and 1 Yr Flat Contract Prices



Source: CQ Partners using AEMO data

5.2 Electricity Loads within the Eyre, Mid North, Yorke and Braemar Regions

Large commercial and industrial (C&I) customers, particularly within the mining sector have significant commercial operations within the Upper Spencer Gulf region. The potential customer load from large C&I customers within this region (including Braemar) is approximately an additional 500-750MW depending on the ultimate size of projects such as BHP's Olympic Dam expansion.

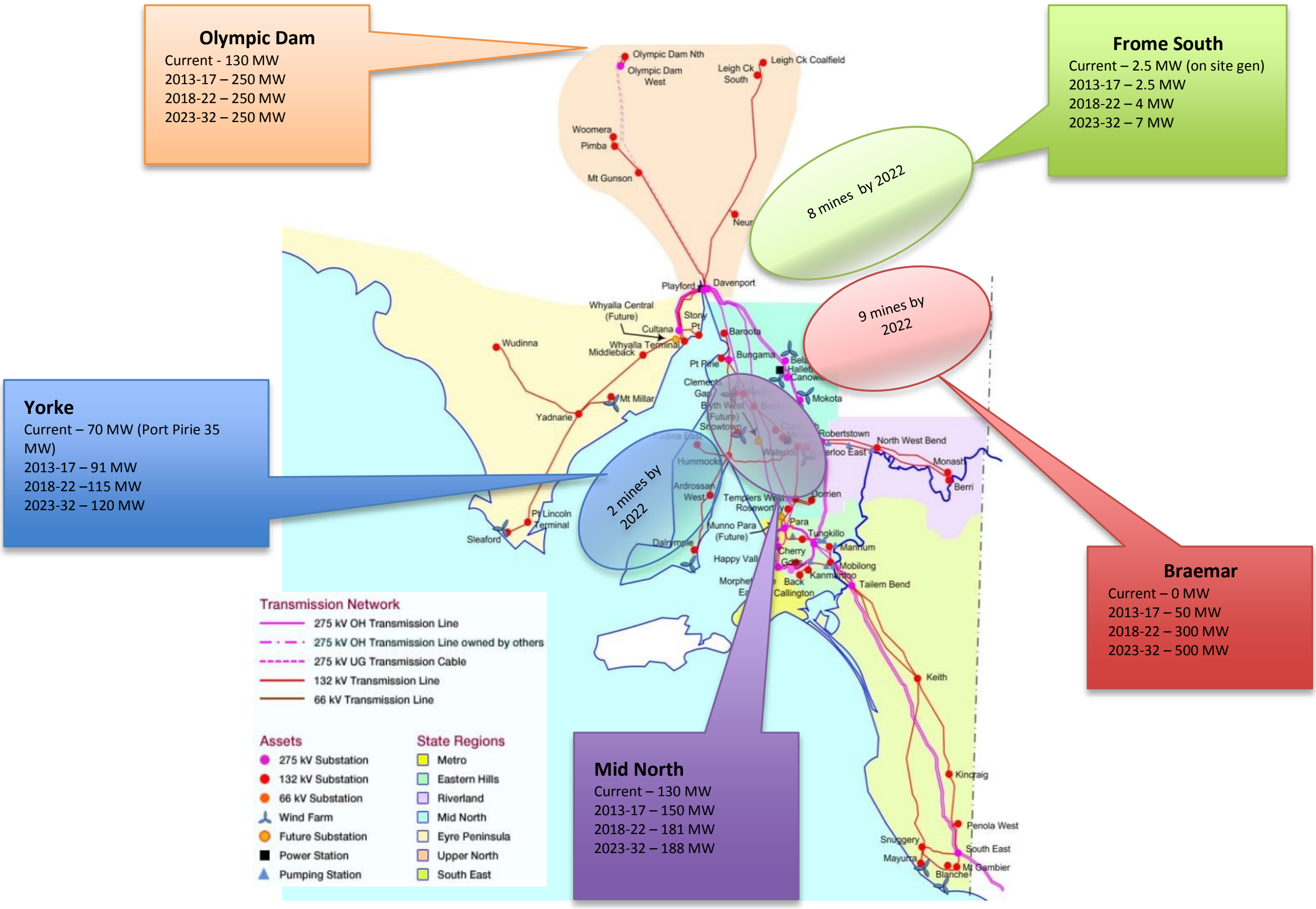
The ability of these large C&I customer loads to expand operations within an unconstrained energy environment has been problematic and will continue to be the case without network augmentation to allow energy to physically flow from generation facilities to large consuming entities.

The figure below shows current and projected demand under a high growth scenario in each demand region relevant to the current electricity transmission network infrastructure.

When considering the energy loads within each of the region we note the following:

- Mining in the Braemar region is predominantly magnetite iron ore which has a high energy intensity in regards to ore extraction and processing;
- Mines in the Frome South region are predominantly uranium and have a much lower energy intensity than those in the Braemar region;
- Mid North demand comprises a mixture of electrical loads including agriculture, grazing, aquaculture and viticulture.

Figure 10 Current & Projected Demand to 2032



Source: SA Government, ElectraNet (2013)

The table below shows projected demand in each region based on low, medium and high growth scenarios using a 10% POE to ascertain maximum potential demand in each sub-region.

Table 5 Projected Demand under Low, Medium & High Growth Scenarios

	Low			Medium			High		
Region	**2013-17**	**2018-22**	**2023-32**	**2013-17**	**2018-22**	**2023-32**	**2013-17**	**2018-22**	**2023-32**
Braemar	1	23.2	74.8	1	33.6	197.4	51	312.4	492.2
Frome South	2.4	4.3	7.2	2.6	4.9	7.2	2.6	4.9	7.2
Yorke	73.3	85.1	88.2	78.4	95.1	99.2	91.6	115.1	120.6
Mid North	124.1	140.5	144.3	131.5	154	160	150.6	181.4	188.3
Eyre	179.4	190	192	185	199	201	201.6	225	232
Total	**380.2**	**443.1**	**506.5**	**398.5**	**486.6**	**664.8**	**497.4**	**838.8**	**1040.3**
Total (Excluding Eyre)	**200.8**	**253.1**	**314.5**	**213.5**	**287.6**	**463.8**	**295.8**	**613.8**	**808.3**

Source: SA Government and ElectraNet

A list of the current and prospective major loads are summarised in Appendix B.

5.3 Current Electricity Network Capacity

Using the high scenario for forecast electricity demand in the Yorke, Mid North and Braemar regions, there is an increase in demand from 295 MW in 2013-17 to over 800 MW by 2023. Given the Braemar region is not presently serviced by any network infrastructure, we need to consider how adequate the present transmission network is when servicing the Yorke and Mid North regions with a combined load of over 300 MW by 2023 under the high scenario. Data obtained from SA Power Networks has shown the Yorke and Mid North region supported peak demand of around 185 MW during 2012/13. ElectraNet have stated this region has limited capability to connect new major demand with network augmentation. Given this region is projecting a 241 to 300 MW potential expansion from 2017 to 2023 from new mining load, substantial investment would be required to ensure this new demand can be met while ensuring system security within the region.

In both our analysis of ElectraNet's 2013 South Australian Transmission Planning Report and direct discussions with ElectraNet we note the following points in relation to the prospective electricity demand discussed in the next section:

- The Mid North & Yorke region 132kV transmission systems have very limited capacity to connect any large scale generation and demand without augmentation;
- Mid North demand locations close to the 275kV substations could be accommodated depending on the location and proximity to adequate generation;
- The existing Upper-North 132kV transmission network could accommodate small generators up to a maximum of 10MW along the Davenport-Leigh Creek 132kV line and up to a maximum of 40MW along the Davenport-Woomera 132 kV line;
- Supporting mining load in the Upper North (i.e. Braemar & Frome South) would require significant augmentation given the distances and existing capacity.

A number of mining projects require the operation of plant that places large loads on the network for intermittent periods such as desalination plants and pumping for slurry lines. These will provide further challenges with regards to network investment required to meet this demand while providing the required levels of network reliability.

As stated earlier in this report, ElectraNet operates within a regulatory framework requiring network investment to meet the AER's Regulatory Investment Test for Transmission (RIT-T). This process from initial connection inquiry, public consultation to final decision can take up to 2 years and needs to be considered in light of project requirements as part of any infrastructure solutions proposed.

In summary, ElectraNet have no current plans for network augmentation to support prospective mining loads in the Yorke, Mid North and Braemar regions. Any network investment in these regions would be dependent upon firm network enquires made to ElectraNet by mining companies wishing to commit in addition to completion of the required RIT-T processes. Alternatively, customers can pay for the network augmentation, but there is always a risk that other loads could piggyback off that augmentation without having to pay for the initial capital. Instead they would get charged a regulated tariff.

5.4 Gas Demand within the Eyre, Mid North, Yorke and Braemar Regions

These regions are serviced by MAPS, the Port Pirie and Whyalla laterals. Major users of natural gas within this region are summarised in the table below.

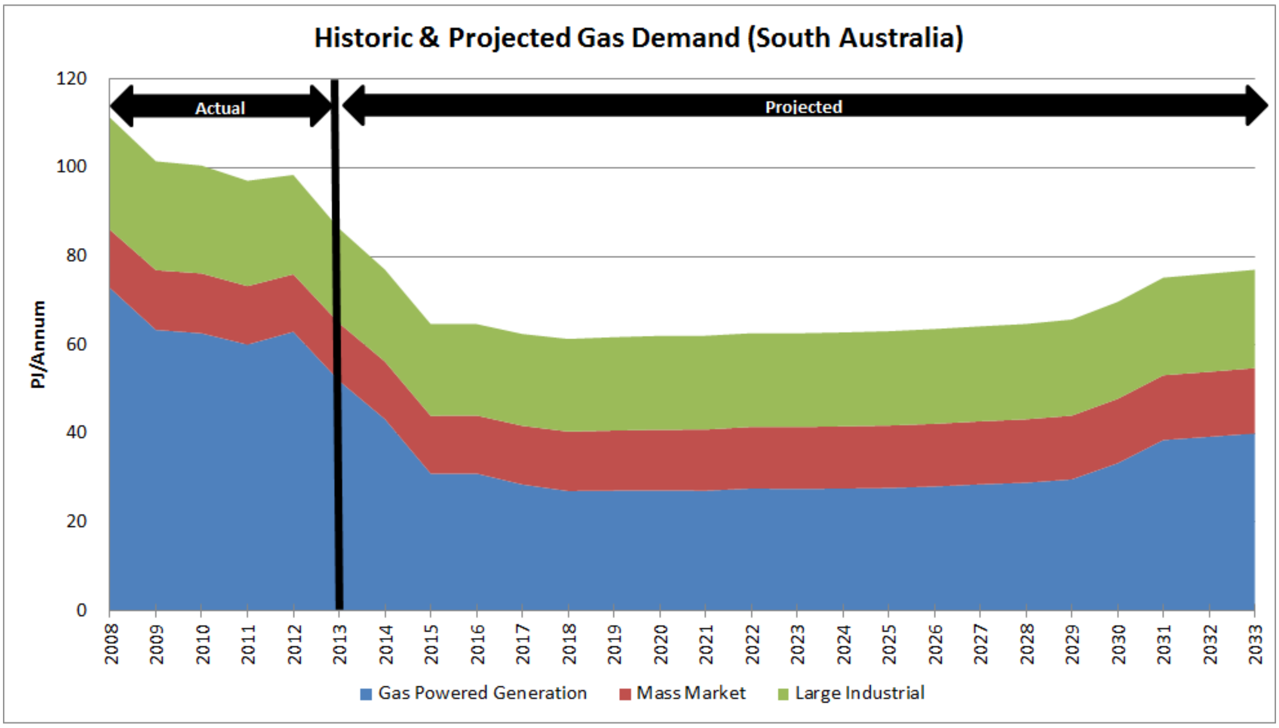
Table 6 Major Gas Users

User	Feed in Location	2012 Consumption (PJ/Annum)	2012 Daily Demand (TJ/day)
Arrium - Whyalla	Whyalla Lateral	6	18
Nyrstar – Port Pirie	Port Pirie Lateral	~1	<1
Hallett Power Station	MAPS	<1	<1
Mintaro Power Station	MAPS	<1	<1

Source: AEMO, Acil Tasman

The graph below shows historic and projected gas demand by end use as modelled by AEMO in the 2013 Gas Statement of Opportunities (GSOO). From the graph it is clear consumption of gas for electricity generation will fall markedly while mass market (i.e. domestic, C&I) and large industrial will remain at current levels. Due to falling electricity demand, increased uptake of solar PV, increased wind generation and imports of cheaper electricity from Victoria due to increased wind generation will further dampen investment in gas fired generation.

Figure 11 Current & Projected SA Gas Demand to 2033



Source: AEMO

5.5 Potential Location for Gas Fired Electricity Generation

The sections above have detailed how the market would generally treat the viability of a new gas fired generation facility. The location at this stage is secondary to the commercial viability, which is largely influenced by the following:

- Current generation supply versus region demand
- The ability for a new generation facility to underpin the investment with either an off take agreement or PPA structure that guarantees a suitable return on investment or sustained high pool prices that would allow a merchant generator to have some confidence that the investment would make a return
- Access to natural gas at volumes that would be able to supply a new gas fired generator and at a price that will sustain the investment

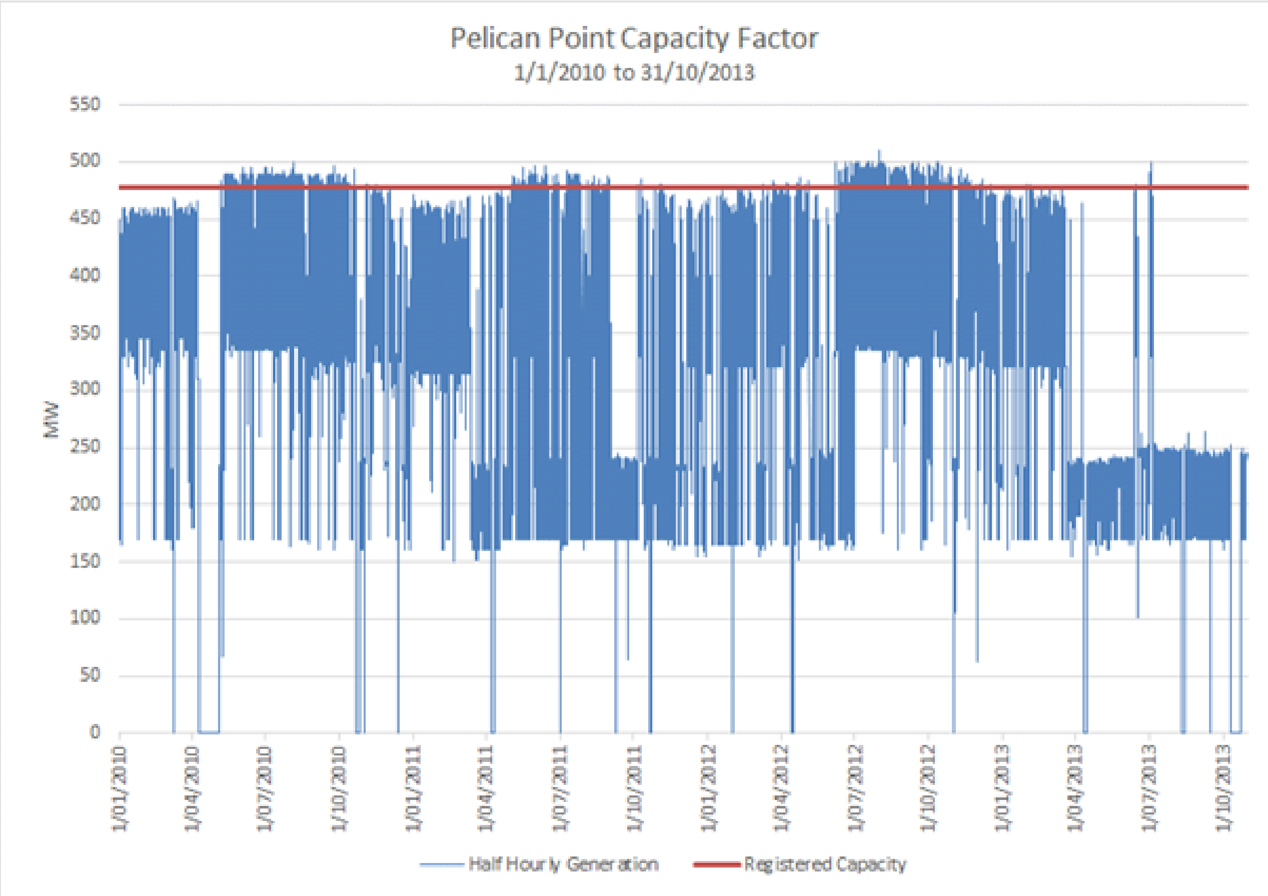
The location would most probably be best served at an existing generation facility such as Port Augusta power station given that the existing infrastructure of transmission connection and substation capability would potentially reduce the costs of commissioning the plant. Port Pirie could also be another logical generator location given that this will have access to gas from the Whyte to Yarcowie gas lateral and it is far enough north to feed into the network. Significant network infrastructure would nevertheless be required.

We have also used Pelican Point as an example of why a new entrant gas fired generator would not be required in the short to medium term.

GDF's long term gas supply arrangements for Pelican Point is understood to be expiring at the end of 2014. GDF has been actively seeking replacement gas supply arrangements. Due to the new Queensland LNG projects, the major gas producers have limited the availability of gas for domestic use from 2015 and the pricing of new gas contracts has risen from the $4-$5/GJ price range to $8-$9/GJ (to reflect the opportunity cost of supplying domestic gas as compared to exporting LNG). At these future gas prices, GDF considers it un-economic to run Pelican Point and it has been considering alternative commercial strategies, which may deliver greater value.

The following graph shows the capacity factor of Pelican Point power station, which is seen to have dramatically reduced since March 2013. Historically Pelican Point has operated with a capacity factor of around 69%. In March 2013 there was a change in the operating regime with Pelican Point generally operating only one of its two gas turbines (plus running the steam turbine). The operating capacity since April 2013 has averaged 210MW (250MW peak periods falling to 170MW overnight). Previously it was averaging 350MW on an annual basis (480MW peak periods falling to 330MW overnight when both gas turbines were operating). This change has resulted in the capacity factor falling to 44% since March 2013.

Figure 12 Change in Pelican Point Capacity Factor



Source: CQ Partners using AEMO data

This change in the operating regime has reduced Pelican Point's gas consumption. Previously Pelican Point would have consumed approximate 60TJ/day on average with a maximum gas demand of 80-85TJ/day (which was the case from 2010 to 2012). Since April 2013 the average gas requirement has fallen by 20TJ/day to around 38TJ/day for its maximum gas demand (excluding outages).

As a combined cycle plant with high efficiency, Pelican Point was designed as a base load power station and not as a peaking power station. The gas turbine is connected to the steam plant. In practical terms this means it takes longer to start up the plant. There may be work required at a plant level to accommodate these types of changes to its operating regime. However taking a broader portfolio perspective, GDF can call on its faster starting generators (Mintaro, Dry Creek, Snuggery and Port Lincoln) to respond to immediate market price (pool price) signals and to provide generation output whilst the slower starting Pelican Point is brought into service.

What this shows is that an existing market participant such as GDF has reassessed its operation of Pelican Point power station, again largely as a result of existing low pool prices (below what is considered to be the LRMC of this type of generation facility), a lack of competitive fuel and a reducing demand. Given that GDF has a vertically integrated position in the market and access to fuel, it is expected that Pelican Point would be the first to be operated at full capacity if the market dynamics change.

6 Conclusion

This report has highlighted a number of issues in relation to duplicating the Whyte to Yarcowie gas lateral to support a new gas fired generation facility to meet the growing energy needs of large C&I customers in the Northern regions.

The primary issues that have been raised include:

- Existing infrastructure limitations in light of system security (Olympic Dam);
- Future cost of gas supplies and high gas prices are likely to diminish the incentive to invest in gas fired generation infrastructure in the short to medium term;
- Current oversupply of generation in SA, particularly generation with very low SRMC such as wind which is significantly dampening pool prices, again reducing the incentive to invest in new generation facilities;
- No investment signals for new gas fired generation in SA – falling demand, oversupply, economic downturn impacting on large customer certainty, a likely removal of the carbon tax which is expected to return coal fired generation into the supply mix;
- Costs and timing of network infrastructure upgrades to support new mining loads means that obtaining PPA or off take structures become difficult due to timing constraints;
- Potential solution for investment in generation is to have direct PPA with mining loads, the issue here is that PPA would serve customers better if customer were combined to fully utilise the output of a generator, but mining projects will come on at different times and augmentation to the network may occur at different times – again timing and consolidation is required.

Even though a single generator that utilises gas as an input may not be the most viable option as the first and most critical issue does appear to be the timing to connect large C&I loads to the network, there are potential solutions for customers.

For large customers to get access to competitively priced electricity they need to have physical connection to the grid which will allow them to fully participate in the market. Participation would mean that customers can access market pricing through various mechanisms including:

- A range of contract structures including retail contracts, PPA structures if the customer prefers to have a dedicated generation facility supply its operation (common for long life mining loads), tolling agreements if customers have access to fuel and in return it get access to competitively priced electricity;
- A customer could also elect to become a market participant in the NEM, whereby it purchases electricity off the grid and utilises swap or cap electricity contracts to mitigate price risk;
- It could enter into a pool price pass through arrangement with a retailer in lieu of becoming a market customer but still get access to pool pricing;
- Creating a cooperative amongst a number of customers in a region to enable timely augmentation of the network to support the growing load;
- Alternative energy solutions that can also provide renewable benefits (including the supply of large generation certificates (LGCs)).

7 Next Steps

This report was aimed at determining the commercial viability of duplicating the gas lateral to Port Pirie and potentially further to Whyalla with the purpose of supporting additional gas fired generation in the northern regions. This was expected to assist large C&I loads to more effectively connect to the network and to be able to obtain electricity for their individual projects.

What this report has determined is that for a range of reasons, predominantly market driven, the commercial viability for a new gas fired generation facility is not evident.

This however does not diminish the need for large C&I customers to obtain electricity at their respective sites. The problem that we see here is not so much a question of additional generation but rather the ability of customer to connect to the transmission or to a lesser extent the distribution network in a timely manner that does not impede on the viability of the customers project.

In order for large C&I customers to get better access to electricity, we would recommend the following work to be undertaken:

1. Determine the physical connection requirements of each large C&I customer given their current and projected load requirements;

2. Discuss with ElectraNet and SA Power Networks how best to facilitate this network augmentation within the timeframes required to meet project load forecasts;

3. Determine how the network augmentations will be funded and if there is a potential for Federal or State funding to assist customers gaining access to electricity;

4. Determine if there is an ability to group large C&I customers as part of an efficient wholesale pricing model.

Some of these elements may not be possible as some large C&I customers may regard other customers as competition and would want to work individually to try to extract maximum benefit from their negotiations with energy participants.

CQ Partners see the need for further work in this area to ensure that large customer in the northern regions are afforded the capability of connecting to the network in a manner that meets their project forecasting expectations.

8 Appendix A – Generation Capacity

	Power Station	Owner	Installed Capacity (MW)	Wind Peak Demand Capacity Factor (%)	Wind Effective Peak Summer Contribution (MW)	AEMO NEFR 2013-14 10% POE	AEMO NEFR 2013-14 50% POE	AEMO NEFR 2013-14 90% POE
Scheduled Generation								
	Dry Creek GT	Synergen Power Pty Ltd	156					
	Hallett GT	EnergyAustralia	228					
	Ladbroke Grove	Origin Energy Power Limited	80					
	Mintaro GT	Synergen Power Pty Ltd	90					
	Northern	Flinders Operating Services Pty Ltd	530					
	Osborne	Osborne Cogeneration Pty Ltd	180					
	Pelican Point	Pelican Point Power Limited	478					
	Playford B	Flinders Operating Services Pty Ltd	240					
	Port Lincoln GT	Synergen Power Pty Ltd	74					
	Quarantine	Origin Energy Power Limited	224					
	Snuggery	Synergen Power Pty Ltd	63					
	Torrens Island A	AGL Energy	480					
	Torrens Island B	AGL Energy	800					
		Total	**3,623**					
Wind Generation								
	Clements Gap	Pacific Hydro Clements Gap Pty Ltd	57	8.6%	5			
	Hallett 4 North Brown Hill	Brown Hill North Pty Ltd	132	8.6%	11			
	Hallett 5 The Bluff WF	Eurus Energy	53	8.6%	5			
	Hallett Stage 1 Brown Hill	Palisade Investment Partner Limited	95	8.6%	8			
	Hallett Stage 2 Hallett Hill	Infrastructure Capital Group Limited	71	8.6%	6			
	Lake Bonney 2 Wind Farm	Lake Bonney Wind Power Pty Ltd	159	8.6%	14			
	Lake Bonney 3 Wind Farm	Lake Bonney Wind Power Pty Ltd	39	8.6%	3			
	Snowtown	Snowtown Wind Farm Pty Ltd	99	8.6%	8			
	Waterloo	Waterloo Windfarm Pty Ltd	111	8.6%	10			
	Canunda	Canunda Power Pty Ltd	46	8.6%	4			
	Cathedral Rocks	JV Cathedral Rock Investments Pty Ltd	66	8.6%	6			
	Lake Bonney 1 Wind Farm	Lake Bonney Wind Power Pty Ltd	81	8.6%	7			
	Mt Millar	Mount Millar Windfarm Pty Ltd	70	8.6%	6			
	Starfish Hill	Ratch Australia	35	8.6%	3			
	Wattle Point	Infrastructure Capital Group	91	8.6%	8			
		Total	**1,203**		**103**			
Non Scheduled Generation								
	Amcor Gawler Glass Bottle	Amcor Packaging Australia Pty Ltd	4		0			
	Angaston	Infratil Energy Australia Pty Ltd	50		0			
	Blue Lake Milling Power Pl	Vibe Energy Pty Ltd	1		0			
	Highbury	EDL LFG SA Pty Ltd	1		0			
	Lonsdale	Infratil Energy Australia Pty Ltd	21		0			
	Pedler Creek	EDL LFG SA Pty Ltd	3		0			
	Pt Stanvac A	Infratil Energy Australia Pty Ltd	29		0			
	Pt Stanvac B	Infratil Energy Australia Pty Ltd	29		0			
	Tatiara Meats	Vibe Energy Pty Ltd	1		0			
	Tea Tree Gully	EDL LFG SA Pty Ltd	1		0			
	Terminal Storage Mini Hyd	Lofty Ranges Power Pty Ltd	3		0			
	Wingfield 1	EDL LFG SA Pty Ltd	4		0			
	Wingfield 2	EDL LFG SA Pty Ltd	4		0			
		Total	**149**		**0**			
Interconnector Capacity								
	Heywood	SP AusNet	460					
	Murraylink	Murraylink Transmission Company	220					
		Total	**680**					
		Grand Total	**5,655**			**3,254**	**2,948**	**2,705**

Source: AEMO

9 Appendix B – Current and Future Major Loads

Table 7 Existing Yorke and Frome South/Braemar Region – Major Loads

Facility	Region	Load (MW)	Comments
Nyrstar – Port Pirie	Yorke	20 MW	
BHP Olympic Dam		130 MW	Included as substantial load currently has impacts on the state's power system security due to size of load.
White Dam (Gold)	Frome South	1 MW	Reduced load as production has ceased. Only processing remaining leach heaps.
Honeymoon (Uranium)	Frome South	1.5 MW	Production around 40,000 tonnes/year. On site electricity generation via gas.

Source: SA Government

Table 8 Future Yorke and Frome South/Braemar Region – Major Loads

Facility	Owner	Production (Mtpa) & Load (MW)	Region	Start Date
Port Pirie Lead Smelter	Nyrstar	+10 MW (on-site co-gen provides 50% of additional 20 MW required) (from 2016)	Yorke	
Hillside	Rex Minerals (Copper, Gold, Iron)	7.5-9 Mtpa (stage 1) 15-18 Mtpa (stage 2) 60 MW	Yorke	2014
Parara	Rex Minerals (Uranium, Copper, Gold, Iron)	Prospective	Yorke	
White Dam (Gold)	Exco Resources	1 MW (4 Mtpa)	Braemar	Operational
Maldorky	Havilah Resources (Iron)	2.4 Mtpa	Braemar	2015
Razorback	Royal Resources (Iron)	8.2 Mtpa	Braemar	
Muster Dam (Mootoroo)	Minotaur Exploration (Iron)		Braemar	
Crocker Well	PepinIni Minerals (Uranium)	1MW	Braemar	
Hawsons (NSW)	Carpentaria Exploration (Iron)		Braemar	
Grants (Maldorky North)	Havilah Resources (Iron)	Prospective	Braemar	
Lilydale	Havilah Resources (Iron)	Prospective	Braemar	
Portia	Havilah Resources (Copper, Gold)	0.5. MW (planning to use diesel gensets)	Frome South	2015
Kalkaroo	Havilah Resources (Copper, Gold)	9 Mtpa	Frome South	
Honeymoon (Uranium) – 40,000 tonnes/year	Uranium One	1.5 MW	Frome South	Operational
Junction Dam	Marmota Energy (Uranium)	20 Mtpa	Frome South	
Becaroo	PepinIni Minerals (Uranium)	Prospective	Frome South	
Goulds Dam (Billeroo)	Uranium One (Uranium)	Prospective	Frome South	
Mount Victoria	PepinIni Minerals (Uranium)	Prospective	Frome South	
Mulyungarie	Marmota Energy (Uranium)	Prospective	Frome South	
Oban	Curnamona Energy (Uranium)	Prospective	Frome South	

Source: SA Government

10 Reference Documents

Regional Development Australia Yorke and Mid North: Infrastructure Audit 2012 (Aurecon, 2012)

Increased Gas Supply to the Upper Spencer Gulf: April 2011 (GPA Engineering, 2011)

South Australia Transmission Annual Planning Report: June 2013 (ElectraNet 2013)

Electricity Statement of Opportunities (AEMO 2013)

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