SFS ECONOMICS

Barriers to entry in the South Australian region of the NEM

FINAL REPORT

June 2010

SFS Economics Pty Ltd

ACN 141 898 491

Contents

Executive summary

High spot prices have been observed in the South Australian region of NEM over the past three years. The Australian Energy Regulator (AER) is concerned that these high prices may reflect the persistent exercise of generator market power in that region. A central question is therefore whether entry by new market participants is likely to occur that would erode the ability of incumbent generators to raise prices. This paper investigates the factors that determine new generation investment, and whether there are structural or policy related barriers to entry in South Australia that would prevent such investment from taking place.

South Australian region of the NEM

South Australia is one of the smallest regions of the NEM, and is characterised by a high degree of concentration in the generation sector. AGL Energy (AGL), NRG Flinders (NRG) and International Power (IP) control 86.4 per cent of installed (summer) thermal capacity, and AGL alone accounts for 37.6 per cent. The sector is also vertically integrated, with each of the generating portfolios having downstream retail interests. AGL is the declared standing contract retailer in South Australia and has a market share of around 55 per cent of retail customers and 69 of business customers.

South Australia currently has around 3,400MW of installed (summer) thermal capacity. The Australian Energy Market Operator (AEMO)'s most recent Statement of Opportunities (2009) projects that additional firm capacity of 68MW will be required in 2012-13. In addition to conventional thermal (scheduled) generation capacity, South Australia has significant intermittent renewable generation, overwhelmingly from wind. South Australia has the highest installed wind capacity in Australia, and the highest proportional contribution from wind energy to meet the region's electricity demand. Significantly more wind generation is expected to be commissioned in South Australia in future. This is driven by the Federal Government's Renewable Energy Target (RET) that is set to achieve a 20 per cent share of renewables (45,000 GWh) in Australia's electricity mix by 2020. However, generation from wind resources is typically not available during peak demand periods, so that South Australia will continue to require thermal generation capacity to reliably meet demand.

While drought affected regional wholesale market prices across all regions in the NEM in recent years, South Australia has seen a relatively greater number of high price events. Spot prices at the South Australian regional reference node (RRN) have also become more volatile with the number of very high (above $5,000/MWh) and very low (zero or negative) prices increasing.

There has been some recent investment in thermal generation capacity in South Australia by incumbent generators. Origin Energy (Origin) expanded its Quarantine Power Station (PS) by 128MW in 2008-09, while International Power (IP) commissioned a 25MW open cycle gas turbine (OCGT) in Port Lincoln in 2009-10.

Although not firm in status, additional thermal generation projects are ‘proposed’ going forward. These are a planned expansion by AGL of its Torrens Island PS (TIPS) by a 700MW OCGT some time after 2012, a proposal by Altona Resources to commission 560MW of gas-fired capacity in the North of the state in 2014, a proposal by Strike Oil to commission a 40MW gas-fired plant in Kingston in 2015, and a plan by IP to expand its Pelican Point PS by 300MW at an as yet unknown point in time. Given that AEMO has classed these projects as ‘proposed’ (and makes no reference to AGL’s TIPS expansion), there is no certainty that any of these projects will reach the ‘committed’ stage and will eventually be commissioned.

It is also notable that the two key projects that would likely serve loads around Adelaide if they are commissioned – AGL’s TIPS expansion and IP’s Pelican Point PS expansion – would be undertaken by incumbents. In particular, AGL’s proposed expansion of TIPS by 700MW, would represent a very significant increase in generation capacity in a comparatively small region like South Australia. To the extent that AGL is currently able to set spot prices in the South Australian region in some circumstances, the TIPS expansion would likely enable it to do so in future.

Determinants of generation investment

The fact that key thermal investment projects proposals currently planned in South Australia would be undertaken by incumbents (if they indeed materialise) raises the question whether there are factors that prevent (non-incumbent) new entrants from commissioning new generation capacity in South Australia. There are two aspects to this question:

- Whether commissioning new generation would be profitable in the first place; and
- Whether there are specific ‘barriers to entry’ that particularly discourage entrants from undertaking new investment.

In an energy-only electricity wholesale market such as the NEM, market-based generation investment relies on the profile of expected wholesale market prices post entry. Essentially prices must be high enough for sufficient periods of time to enable a generator of a particular size and technology to recover variable and fixed operating costs over a foreseeable timeframe. In general, therefore, high prices would be expected to encourage generation investment, including investment by new entrants. If prices are sufficiently high to support (profitable) new entry, the fact that no new participants have entered or are expected to enter may then suggest that there are barriers to entry, which prevent an investment from being undertaken by a third party.

There are different opinions as to what constitutes a barrier to entry. Broadly speaking, however, these are structural, institutional and behavioural conditions that allow established firms to earn economic profits for a significant length of time. Structural barriers to entry prevent new entry into a market, for instance if incumbents have absolute cost advantages relative to entrants. Dynamic or antitrust barriers to entry are factors that will delay investment relative to what would maximise social welfare. Dynamic entry barriers arise if there are significant sunk costs in combination with uncertainty about future market outcomes, but also take the form of various strategic ‘games’ whereby incumbents can exploit the existence of sunk costs to delay or entirely prevent entry.

Commercial incentives for generation investment in South Australia

A highly simplified analysis of spot prices as they occurred in 2007, 2008 and 2009 suggests that a (hypothetical) market-based investment of a 100MW gas-fired plant would have been profitable in each of those years. This calculation only represents a snapshot of a few years, and assumes that the advent of a new generator would not affect spot prices. Nonetheless, the results seem reasonably robust in the sense that it would take a significant fall in spot market revenues to have made such an investment uneconomic.

However, power stations represent long-lived (30 year) investment so that short-term price outcomes are not sufficient to assess whether a given project will be viable over the life of the asset. Particularly over a longer term time horizon, there are a number of factors that may make generation investment in South Australia commercially unattractive or, at a minimum restrict the range and location of options that would be feasible.

The most material of these is likely to be the expected advent of significant levels of wind generation, which will depress spot prices and also have negative knock-on effects on the power system. The growing share of wind generation in South Australia has been accompanied by an increasing number of negative price events as renewable generators have submitted very low or negative offers in order to be dispatched and earn revenues from renewable energy certificates (RECs). Such pricing outcomes are expected to become more frequent as new wind generation (on some forecasts, around 5,000 MW) are expected to locate in this region.

At the same time, additional investment in renewables is expected to lead to significant intra- and inter-regional network congestion, so that thermal and other generators cannot rely on being dispatched and thereby earn wholesale market revenues. Of the ten most significant system constraints, four are expected to originate in South Australia, including on the existing interconnectors between South Australia and Victoria. An increase in curtailment of imports/exports from/to other regions of the NEM will lead to prices in South Australia separating from prices in other NEM regions more frequently.

There are also indications that demand in South Australia is becoming ‘peakier’ since overall energy consumption is only growing slowly, while peak demand is growing rapidly and concentrated in few hours of the year.

Overall, the implications for new generation investment is that wholesale market prices will evolve in a manner that will, at a minimum, tend to limit the range of investment options to flexible gas-fired generating technologies. Over the longer term it is expected that thermal generation plant will only operate intermittently, during high and shoulder demand periods:

- Demand is expected to be relatively low for the majority of the time with occasional very high spikes in demand, so that prices would also be low most of the time with occasional very high prices;
- With the advent of intermittent wind generation, prices are additionally expected to tend to zero or negative, at least during off-peak periods; and
- The combination of a shift to a peakier demand curve and significant intermittent wind investment is expected to result in more volatile wholesale market prices.

Barriers to entry to generation investment in South Australia

The South Australian region of the NEM has a number of characteristics that can be viewed as structural barriers to entry, in the sense that entrants would have to incur additional costs that incumbents do not face (or have not had to incur in the past).

According to the South Australian Electricity Supply Industry Planning Council (ESIPC), and irrespective of whether additional new wind generation locates in that region, the South Australian transmission network is already congested and requires significant new investment to accommodate additional generation. While currently planning is directed at ensuring that network investment is sufficient to supply customers in a reliable manner, congestion will remain a feature of the South Australian network over the longer term. Depending on the location, network congestion creates dispatch risks for generators that may undermine the commercial case for new investment and/or the ability of new generators to enter into contractual agreements to finance the investment. Financing issues may additionally arise because the large incumbent retailers are vertically integrated, and would be unlikely to enter into long term contracts to finance new entry that would compete with their upstream generation affiliates.

ESIPC has identified a number of sites that are suitable for new generation investment, although in some cases the cost of gas for new entrants would be higher than for incumbents. It is also notable that the expansions proposed by incumbents would take place on existing sites where generation plant are already located, which would likely facilitate planning and approvals processes relative to those required for greenfield sites. Additionally, and given that there is a requirement for flexible gas peaking capacity to cope with volatile demand, it is relevant that there is very limited storage capability in the gas transmission network to support such peaking operations, at least for larger gas-fire generators. However, given that AGL’s proposed TIPS expansion also includes new storage and gasification facilities, the lack of storage may better be viewed as a factor that will raise (sunk) investment costs for all potential investors, incumbents as well as new entrants.

Barriers to entry also arise when investment requires substantial expenditures that are subsequently sunk (so that they have little or no value when market conditions turn adverse), and when there is significant uncertainty about future market conditions. This combination magnifies the risk of an investment and make its financing difficult, so that new entry is postponed or eliminated altogether.

It can be argued that uncertainty in the South Australian region of the NEM – as measured by the volatility of spot prices – has increased significantly in recent years. According to ESIPC, this trend is expected to continue. In combination, significant sunk cost requirements for investment in generation capacity (perhaps with associated gas storage and gasification facilities) and uncertainty about future spot prices therefore likely constitute a barrier for new entrants. Very volatile prices make forecasting future revenue streams more difficult and may therefore also undermine project financing, while extended periods of low or negative prices will further increase the riskiness of a generation investment.

To the extent that volatility is in part 'created' by incumbent generators, the resulting investment risks would be more material, at least for smaller entrants. Larger incumbents would be in a better position to predict future spot prices, if they are able to manipulate them. Spot prices that at certain times reflect the ability of incumbents to set prices high (but presumably also low) may also signal the possibility of punishment strategies, which may deter new entrants.

AGL's announcement of its proposed extension of its TIPS facility can be interpreted as a (unilateral) strategic commitment that will discourage entry. An investment of this size in as small a region as South Australia would significantly add to AGL's existing market share of generation, and would likely make any other (thermal) generation investment uneconomic for some years to come. Given existing demand forecasts, it seems plausible that a (perhaps significant) proportion of this announced new capacity may stand idle for some years. On the face of it, therefore, AGL's announcement would seem to be consistent with a form of behaviour whereby the incumbent sacrifices some profits (by investing in excess capacity) to achieve an overriding strategic purpose (to discourage investment by other parties). This is because a new generation investor will base their revenue analysis on post-entry prices, and the existence (or threat) of a large new generation investment would be expected to lead to significantly lower spot prices at some point in time. However, these effects could only be confirmed by undertaking detailed spot market modelling.

Overall, and while current spot prices appear to be such that they would support profitable new entry, there are a number of factors at play in the South Australian region that may undermine incentives to undertake generation investment generally, but particularly investment on the part of new entrants:

- An expectation that future spot prices will trend to zero, at least during off-peak periods, given significant projected wind investment, which is in turn driven by the RET policy;
- Ongoing intra- and inter-regional network constraints, which create dispatch and risks for generators in many parts of the network;
- The vertically integrated structure of the industry, which would make it unlikely that a new entrant could enter into long-term financing arrangements with an incumbent retailer;
- The combination of significant sunk investment costs and ongoing price volatility, which increase investment risks and would also make it harder to attract financing, particularly for new entrants; and
- Given AGL's recent announcements, the expectation of excess capacity in the South Australian region over the foreseeable future.

Individually and in combination, these factors would likely prevent (third party) new entrants from commissioning new generation in South Australia and thereby encourage more competitive market outcomes.

1 Introduction

High spot prices have been observed in the South Australian region of NEM over the past three years. The AER is concerned that these high prices may reflect the persistent exercise of generator market power in that region. A central question is therefore whether entry by new market participants is likely to occur that would erode the ability of incumbent generators to raise prices. This paper investigates the factors that determine new generation investment, and whether there are structural or policy related barriers to entry in South Australia that would prevent such investment from taking place.

2.2 Terms of reference

SFS Economics has been commissioned by the AER to prepare a paper discussing the apparent lack of a material supply side response in the South Australian region of the NEM, in particular:

- Whether low levels of new investment indicate that there are structural or policy related barriers to entry; and
- The nature of potential barriers, and their relative influence on the decision to invest in new generation in South Australia, including their importance relative to market-based investment signals.

Relevant barriers that may have emerged over the past three to five years and that should be considered in the analysis include, but are not limited to:

- Market structure, including trends in vertical integration and market concentration;
- The strategic exercise of market power on the part of incumbent generators;
- Trends in generation mix, including wind generation;
- Government or regulatory policies that may also influence the above factors or may otherwise create barriers to entry.

2.2 Structure of this report

This report is structured as follows:

- Section 2 provides an overview of the South Australian electricity wholesale market, in terms of the generation and retailing sector, price trends, and recent and projected investment;
- Section 3 describes the determinants of generation investment, as well as the nature of barriers to entry, which may prevent (timely) investment from taking place; and
- Section 4 considers the factors limiting generation investment in the South Australian region, including key structural and market characteristics, and barriers to entry.

2 The South Australian electricity wholesale market

This section provides a brief overview of the South Australian electricity wholesale market, focusing on the structure of the generation sector, price outcomes in the spot market, and recent and proposed generation investment. Its purpose is to set the context for the discussion of commercial, structural and dynamic barrier to entry that exist in South Australia, and that are discussed in Section 4.

2.2 Generation

South Australia is one of the smallest regions in the NEM.[1] Over the summer 2009-10, South Australia had an installed summer scheduled (conventional thermal) generation capacity of 3,402MW, and an additional 871 MW of installed semi scheduled and non scheduled generation capacity (Table 1), most of which was wind generation. Appendix 1 shows more detail on installed generation capacity.

Table 1

INSTALLED SCHEDULED, SEMI SCHEDULED AND UNSCHEDULED GENERATION CAPACITY IN SOUTH AUSTRALIA (SUMMER 2009-10)

Technology / NEM participant	Installed capacity (MW)	Market share (Per cent)
Scheduled/thermal capacity	3,402	79.6
of which:		
AGL Energy (AGL)	1,280	37.6
NRG Flinders (NRG)	917	27.0
International Power	744	21.9
Origin Energy	261	7.7
TRUenergy	151	4.4
Infratil	49	1.4
Semi scheduled (wind) capacity	445	10.4
Non scheduled (wind and other renewable) capacity	426	10.0
Total installed capacity	4,273	100.0

Notes: A scheduled generating has its output controlled through the central dispatch process. Scheduled generators are generally thermal (in South Australia coal and gas) generators. A semi scheduled generating unit has intermittent output, a capacity of 30 MW or greater and may have its output limited to prevent the violation of network constraints. In South Australia these are large wind farms. A non scheduled generating unit is not scheduled through the central dispatch process. In South Australia these are small renewables projects, such as wind or landfill gas.

Source: AEMO 2010.

[1] Installed summer generation capacity in 2009-10 Queensland was 12,068 MW, that in New South Wales was 15,887 MW, and that in Victoria 9,867 MW. Only Tasmania (scheduled summer installed capacity of 2,341 MW) has a smaller generation sector than South Australia (AEMO 2010).

Compared to other NEM regions:

- A significant amount of South Australia's generation capacity, around 7.5 per cent, is downrated in summer when demand peaks typically occur. In combination with the relatively small stock of installed generation in South Australia (so that even a relatively small reduction in capacity may have a significant effect on prices) this may make the region prone to price spikes.
- A large proportion of installed capacity (19.5 per cent) is wind generation, and this proportion is projected to increase. As such, South Australia has the highest installed capacity of wind generation in Australia, one of the highest in the world, and the highest proportional contribution from wind energy to meet the state's electricity demand (ESIPC 2009).
- The generation sector is concentrated, with the top three generating portfolios (AGL, NRG and IP) controlling 86.4 per cent of installed (summer) thermal capacity. AGL alone accounts for 37.6 per cent of thermal capacity.

2.2 Industry structure

The South Australian electricity supply industry (ESI) is characterised by a high degree of vertical integration. As is the case in Victoria, the main generation portfolios have significant downstream positions in the electricity (and gas) retailing sector (Table 2). As of 2008-09, AGL supplied 55 per cent of residential customers and 69 per cent of small business customers. For large customers, AGL's market share was estimated to be around 36 per cent based on sales volume in 2007-08 (AER 2009).

The trend toward vertical integration of generation and electricity retailing in South Australia (as in other regions of the NEM) appears to be continuing (AER 2009):

- In 2007 AGL acquired TIPS (1,260 MW) from TRUenergy, in exchange for the Hallett power station (150 MW) and a cash sum;
- Origin expanded its Quarantine plant by 130 MW in 2008–09; and
- As noted in Table 5 below, AGL and IP plan to expand their TIPS and Pelican Point PS facilities, respectively.

Table 2

RETAIL ELECTRICITY MARKET SHARES (2008-09)

Retailer	Market share (per cent)
Residential customers	
AGL (standing contract)	28
AGL (market contract)	24
Powerdirect (owned by AGL)	3
Total market share AGL	55
Origin Energy	17
TRUenergy	13
Simply Energy (owned by IP)	8
All others	7
Total residential	100
Small business customers	
AGL (standing contract)	46
AGL (market contract)	15
Powerdirect (owned by AGL)	8
Total market share AGL	69
Origin Energy	16
TRUenergy	8
Simply Energy (owned by IP)	4
All others	3
Total small business	100

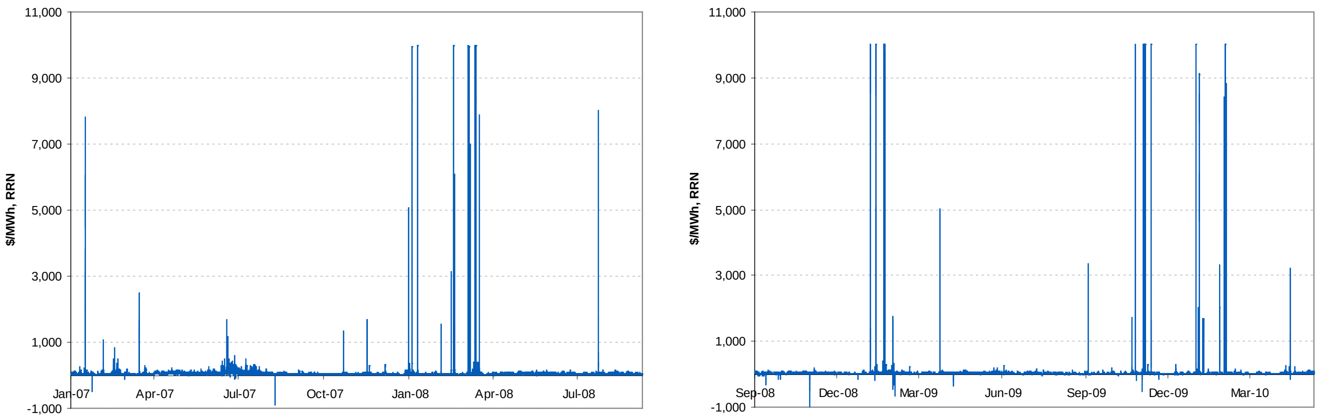
Source: ESCOSA 2009.

2.3 Price outcomes

In recent years there has been a marked increase in the number of high price events in South Australia (Figure 1). The Electricity Supply Industry Planning Council of South Australia (ESIPC 2009) has commented that high price outcomes in South Australia from about early 2007 to 2008 coincided with the drought in those years in all Eastern Seaboard states. During those years, high priced South Australian gas capacity replaced drought affected imports from interstate and contributed to high prices.

Figure 1

PRICES AT THE SOUTH AUSTRALIAN RRN – JANUARY 2007 – MAY 2010



Source: AER data.

Table 3 considers prices to date with reference to specific price bands. Ignoring 2010, for which information is not yet complete, Table 3 suggests that:

- The number of half hours in which prices at the RRN exceeded $5,000/MWh was significantly higher in calendar years (CYs) 2008 and 2009 than in previous years;
- At the same time, the number of half-hours with prices in the range from $200/MWh to $1,000/MWh was noticeably less in CYs 2008 and 2009 than in previous years;
- Half-hourly intervals with prices below $0/MWh have become increasingly frequent since 2006.

Table 3

DISTRIBUTION OF HALF-HOURLY PRICES AT THE SOUTH AUSTRALIAN RRN (CY 2005 TO MAY 2010)

Prices ($/MWh)	2005	2006	2007	2008	2009	2010*
Less than 0	0	1	10	51	93	18
0 – 50	16,432	15,819	10,723	14,707	16,106	6,291
50 – 100	751	1,302	5,345	2,495	993	146
100 - 200	256	244	1,147	174	135	35
200 - 500	40	92	217	15	65	21
500 - 1,000	13	16	9	2	1	4
1,000 - 3,000	10	23	13	5	19	11
3,000 - 5,000	5	9	5	2	8	4
5,000 - 10,000	2	1	3	80	79	32
VOLL	0	0	0	28	29	8

Notes: 2010 price counts are up to 17/05/2010 16:30, corresponding to 6562 half-hours.

Source: AER data.

A comparison with price outcomes in other NEM regions shows that, with the exception of Tasmania, over the last five years, South Australia has frequently seen the highest number of high price events compared to other regions of the NEM (Table 4). 2006-07 was an exception, and high prices occurred in all NEM regions due to drought effects.

Table 4

NUMBER OF HOURS WHEN HIGH SPOT PRICES OCCURRED ACROSS NEM REGIONS (COUNT)

		2004-05	2005-06	2006-07	2007-08	2008-09
SA	>$100/MWh	141	207	547	364.5	146
	>$300/MWh	14	40.5	35.5	49.5	33
	>$1,000/MWh	9.5	18	13.5	31	22.5
QLD	>$100/MWh	61	88.5	581.5	276	111
	>$300/MWh	21	20.5	66	38.5	17.5
	>$1,000/MWh	12	12	23	28.5	11
NSW	>$100/MWh	77.5	123	635	206	117
	>$300/MWh	46	35	94.5	22	18.5
	>$1,000/MWh	21	18	23	2.5	12
VIC	>$100/MWh	31.5	119	509	336	110.5
	>$300/MWh	7.5	29.5	53	27.5	17
	>$1,000/MWh	5	15	22	8	13.5
TAS	>$100/MWh	45	782.5	350.5	423.5	353
	>$300/MWh	2.5	29.5	17.5	8	51
	>$1,000/MWh	0.5	16	8	3	31.5

Source: AEMO 2009.

2.4 Historical and proposed generation investment

2.4.1 Investment in thermal generation

There has been some recent generation investment in South Australia, including in thermal generation capacity (Table 5). Additional thermal generation is ‘proposed’ from 2014 onward, although this is inherently uncertain, since proposed investment do not meet all the criteria considered necessary for a project to be classed as ‘committed’. A generation project is committed if:

- The project proponent is in the process of or has acquired a site;
- Contracts for the supply and construction of major plant or equipment have been executed;
- The project proponent has obtained all required planning and construction approvals;
- Financing arrangements have been finalised and contracts executed; and

- Construction has either commenced or a firm date has been set for it to commence.

Generation projects which do not meet the above five criteria are classed as ‘proposed’. Such projects must still overcome a number of hurdles before construction can begin. Table 5 lists the proposed projects in South Australia identified by AEMO. Table 5 also includes AGL’s planned TIPS expansion, which is not referenced on AEMO’s website, but has nonetheless been announced by AGL.

Table 5

RECENTLY COMPLETED AND PROPOSED THERMAL GENERATION PROJECTS IN SOUTH AUSTRALIA

Timing	Generation project	Capacity (MW)	Technology	Developer
Recently completed generation projects				
2007-08	-	-	-	-
2008-09	Quarantine expansion	128	OCGT	Origin
2009-10	Port Lincoln	25	OCGT	IP
Proposed generation projects (AEMO)				
Post 2012	TIPS expansion[1]	700	OCGT	AGL
2014	Arckaringa	560	IGCC	Altona Resources
2015	Kingston	40	Coal	Strike Oil
unknown	Pelican Point (Stage 2)	300	Gas	IP

Notes: 1) Announced by AGL but not by AEMO.

Source: AER 2007, 2008, 2009. AEMO 2010. AGL 2010a.

Specifically where the proposed projects listed in Table 5 are concerned:

- As noted, and although AEMO does not refer to the expansion of TIPS among its list of proposed projects for South Australia, AGL has announced plans to commission an open cycle gas turbine (OCGT) peaking plant with an installed capacity of 700MW at the TIPS site, as well as a gas storage facility and associated liquefied natural gas (LNG) production and re-gasification facilities (AGL 2010a). The timing of the projects is uncertain, although AGL refers to a timetable of 2-3 years. AGL is currently seeking environmental approvals.
- The Arckaringa project is part of a large integrated coal mining and conversion project in the Arckaringa Basin in South Australia (Altona Resources 2010). This project is being undertaken as a joint venture with the China National Offshore Oil Corporation (CNOOC). According to the developers, this project is proceeding with support from the South Australian and Australian governments. Given its remote location in the north of the state and proximity to existing and potential mining loads (Prominent Hill and Olympic Dam), however, it is tempting to speculate that a project of this size would only go ahead if these loads also materialise.

- Beyond the broad project outlines as described by AEMO, there is little additional information in the public domain about the Pelican Point PS extension.
- The Kingston project in south-eastern South Australia is a coal-to-liquids gasification facility with an associated electricity generation plant. This project does not yet have an investment partner (strike.oil.com.au 2010).

Given that currently planned projects are uncertain, AEMO's most recent Statement of Opportunities (SOO 2009) projects that a low reserve condition will occur in South Australia in 2012-13, when an additional capacity of 68MW will be required.

2.4.2 Investment in wind generation

AEMO lists a number of wind generation projects with a combined capacity of 994 MW that are proposed for South Australia (Table 6). Wind development is driven by the Federal Government's expanded RET that is set to achieve a 20 per cent share of renewables (45,000 GWh) in Australia's electricity mix by 2020. Under the scheme power stations using renewable energy can create and trade RECs for each MWh of renewable electricity generated.

Table 6

PROPOSED WIND GENERATION PROJECTS IN SOUTH AUSTRALIA

Developer	Capacity (MW)	Planned commissioning date
NP Power	118	June 2011
Transfield Services	130	Sep 2011
AGL	90	1 October 2011
TrustPower	206	By 2011
Acciona Energy	71	Winter 2015
Transfield Services	109	Dec 2018
Transfield Services	80	Dec 2019
IP	50	Not Identified
Pacific Hydro	140	Not Identified
Total	**994**	

Notes: A proposed generation project must meet at least three of the following criteria - site has been acquired, contracts entered into for major components, planning consents have been obtained, financing arrangements are finalised, construction has commenced or a date has been set.
Source: AEMO 2010.

Table 7 shows a comparison of proposed investment in South Australia versus that in other NEM states. South Australia (but also Victoria and Tasmania) differ from other NEM regions in that a considerable proportion of proposed investment (as a proportion of existing scheduled and semi-schedule capacity) is in renewables.

Table 7

PROPOSED WIND GENERATION PROJECTS IN SOUTH AUSTRALIA

	Installed capacity,* summer 2009-10 (MW)	Proposed thermal capacity (MW)	Proposed renewable capacity (MW)	Proposed renewable / thermal capacity (per cent)	Total proposed generation capacity (MW)
SA	3,847	900	1,022**	26.6	1,922
QLD	12,068	2,276	244	2.0	2,520
NSW	15,887	7,034	2,225	14.0	9,259
VIC	9,867	1,973	2,695	27.3	4,668
Tasmania	2,341	0	601	25.7	601

Notes: * Refers to existing & committed scheduled & semi-scheduled generation capacity.
** includes 994MW of wind capacity and 28MW of biodiesel.

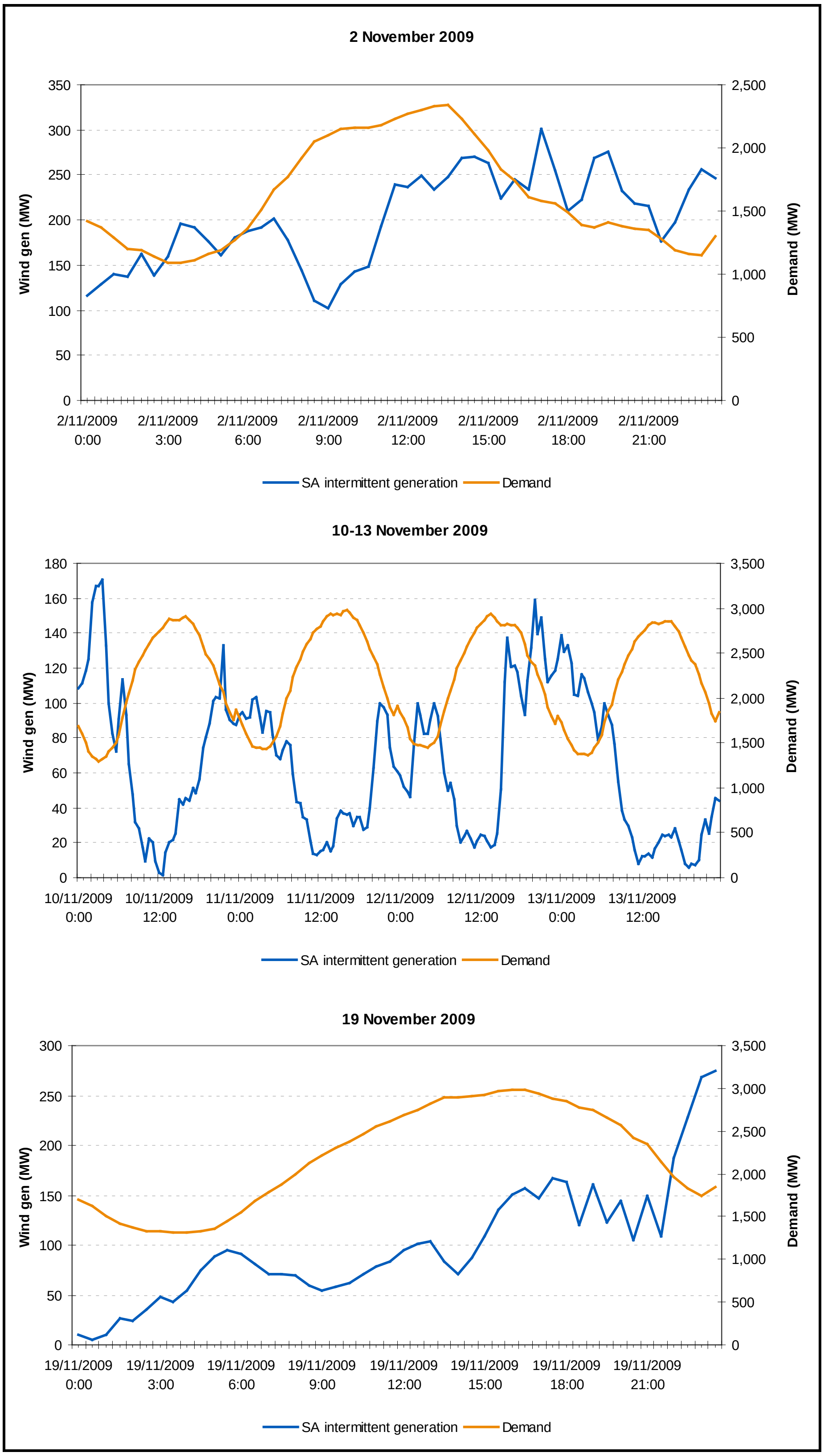
Source: AEMO 2010.

A key characteristic of generation from wind (and from other forms of renewable energy) is that it is intermittent and therefore unpredictable. The experience in South Australia to date has shown that, while that region has significant wind capacity (and significantly more is planned), this is of relatively little value – in terms of mitigating against high price outcomes – in circumstances when temperatures are high and demand peaks. Analysis undertaken by ESIPC of the contribution of wind to meeting peak demand during the 2009 heat wave (27 January 2009 to 8 February 2009) suggested that output from wind generation was negatively correlated with demand, so that wind generation tended to be at its lowest when demand peaked and vice versa. This pattern appears to hold more generally, so that ESIPC assumes for (reliability) planning purposes that wind generation will contribute no more than 3 per cent to summer peak demand (ESIPC 2009).

Figure 2 and Figure 3 consider this effect in more detail for those days from November 2009 onwards and in 2010 to date when prices at the South Australian RRN exceeded $5,000/MWh. The inverse relationship between output from wind generation and demand is most apparent in those instances where successive high temperature days occurred. In other instances, for instance on November 2 and 19, wind output increased with generation, at least temporarily. However, overall, it seems clear that during extended heat waves South Australian customers can only be supplied reliably with thermal generation or from imports.

Figure 2

WIND GENERATION VS TOTAL DEMAND (DAYS WITH PRICES > $5,000/MWH, FROM NOVEMBER 2009)

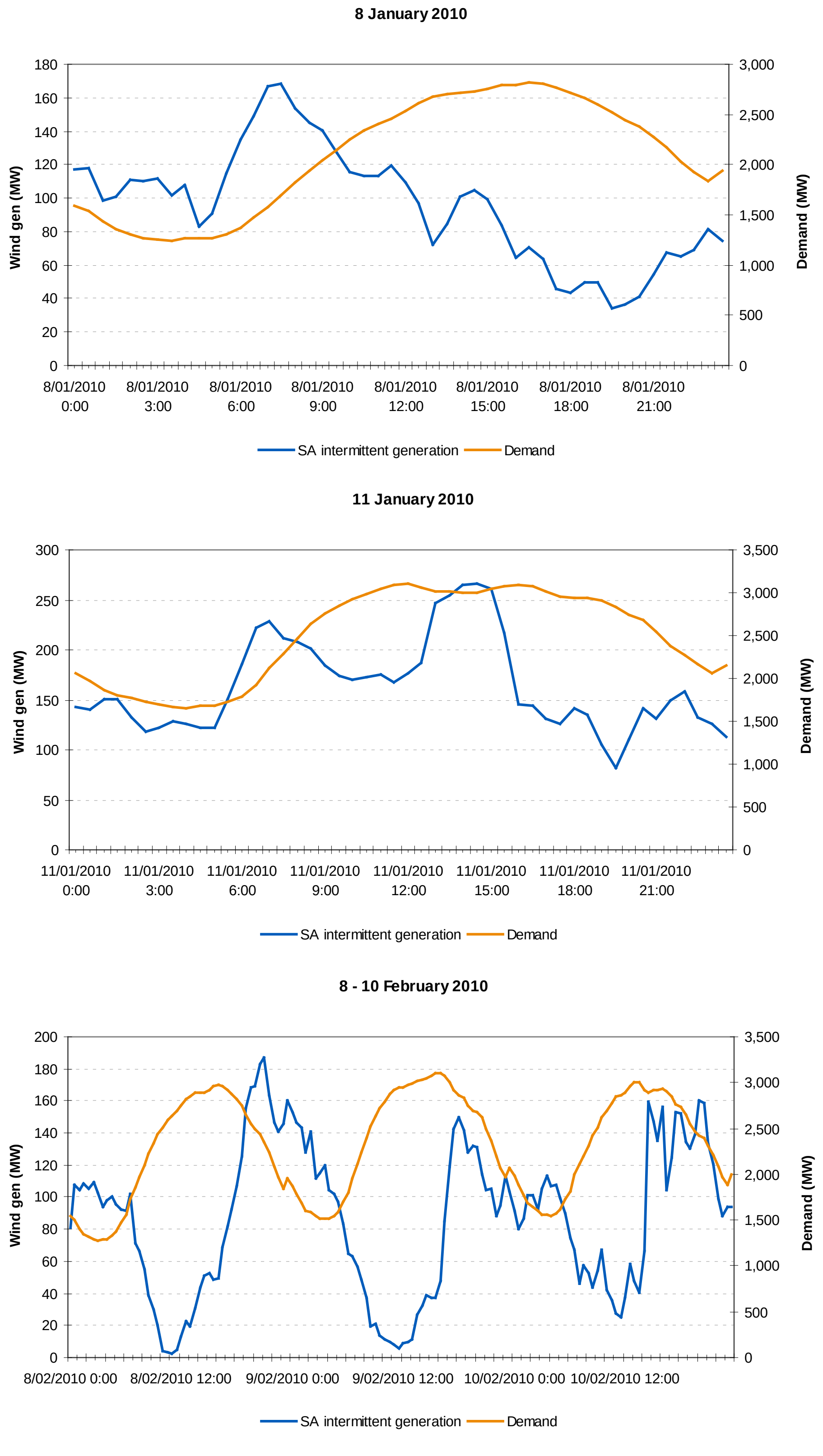


Notes: Correlation coefficient between demand and intermittent generation on 2 November is 0.1254, on 10-13 November (-)0.8335, on 19 November 0.3512.

Source: AER data.

Figure 3

WIND GENERATION VS TOTAL DEMAND (DAYS WITH PRICES > $5,000/MWH, 2010)



Notes: Correlation coefficient between demand and intermittent generation on 8 January 2010 is (-) 0.5010, on 11 January 2010 0.3508, on 8-10 February 2010 (-)0.3253.

Source: AER data.

3 Generation investment and barrier to entry

While new generation investment is planned in South Australia over the medium-term, whether this capacity will materialise and its timing is uncertain. It is notable, however, that two key proposed projects, which could serve future loads would be undertaken by two incumbents (AGL and IP). Given the AER's concerns about the exercise of market power by incumbent generators, this raises the question whether there are barriers to entry that would prevent (third party) new entrants from commissioning new generation in South Australia, which may in turn lead to more competitive market outcomes. This section then reviews the commercial factors that an investor would consider prior to undertaking an investment in generation capacity and the factors that would constitute a barrier to entry to such an investment.

3.1 Generation investment in energy-only markets

The NEM is an 'energy-only' market in which generators submit $/MWh supply offers and are paid the market clearing price for their output. The NEM market design does not incorporate payments for generation capacity or availability, and generators must recover their fixed (capital) and variable costs through energy sales. For most generators, most revenues come from electricity sales in the spot market and/or under forward contracts with NEM retailers or large customers.[2] Generators must therefore recover the fixed (capital) costs of plant from differences between the market clearing price and their variable generating costs.

3.1.1 Price duration curve

Turning to the drivers of generation investment, commercial investors would not invest in additional generation capacity unless they expected prices and revenues *post investment* to be sufficient to recover the cost of the investment. The central question for investors is therefore whether prices in a region such as South Australia support generation of a particular technology or size.

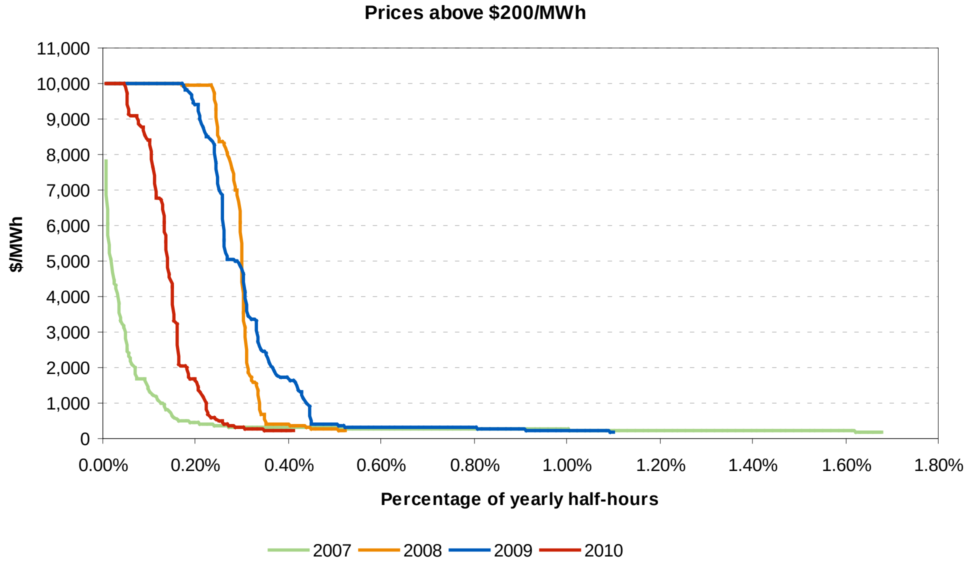
Figure 4 illustrates how expected price outcomes determine the incentive to invest in one or another form of generation technology with reference to the South Australian 'price duration curve' (PDC), shown here separately for prices below and above $200/MWh. The PDC shows the probability of price at or above a certain level occurring in a given year. For instance, in 2009, spot prices in South Australia were at or above $50/MWh for 7.5 per cent of the time, and at or above $100/MWh for 1.9 per cent of the time. The significance of this PDC is that, for a given choice of technology, a generator recovers some proportion of its fixed cost only when market prices are above the plant's variable cost.[3]

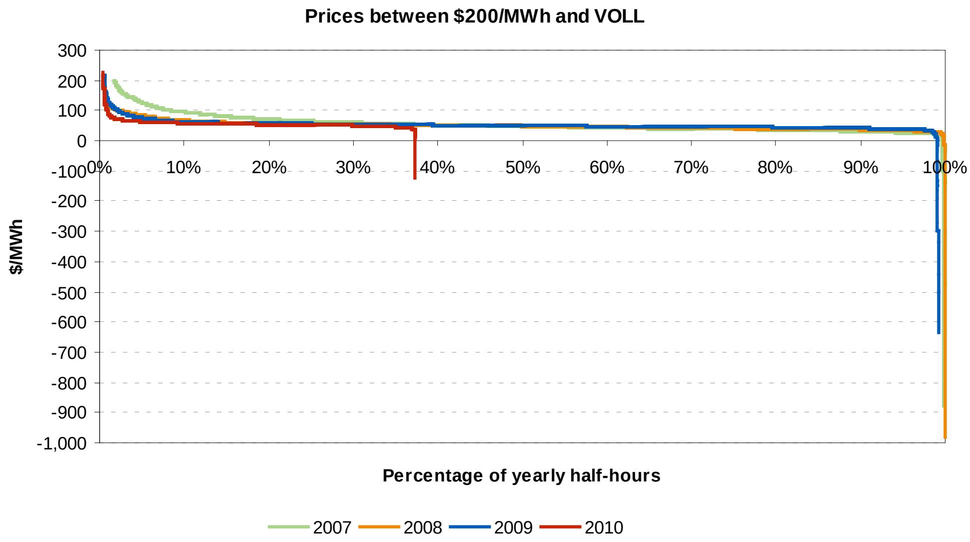
[2] The NEM has separate markets for a range of ancillary services exist, which are an additional source of revenues for generators.

[3] The PDC shows price outcomes in the spot market. In reality, generators earn revenues from the spot market and from sales of contracts for differences. For the purpose of this type of analysis it is generally assumed that contract market prices broadly speaking reflect spot market prices.

Figure 4

PRICE DURATION CURVES FOR SOUTH AUSTRALIA 1999-2000 TO 2007-08 ($ 2008-09)





Notes: The PDC has been separated into prices above and below $200/MWh to show the frequency of high prices.

Source: ESIPC 2009).

Price duration curves of the type shown above are the central starting point for an investor assessing whether prices will be sufficient to recover the cost of different types of generation technologies of a particular size. What type of generation investment is commercially viable will depend on its operating and fixed costs.[4] In the absence of ramping and other physical constraints, a generator would not be expected to run when prices are below its short run marginal costs (SRMC). Additionally, prices must be above SRMC for a sufficient length of time for an investor to recover the fixed costs of a plant.

Two other considerations are also relevant in the South Australian context. First, what matters is not the current shape of the PDC, but its shape post entry. In a small region such as South Australia where interconnection capacity is frequently constrained, the arrival of a relatively large power station (such as AGL's 700MW TIPS extension) will lower market clearing prices, and a rational investor would take this into account. This type of effect will, in general, favour incremental (smaller) generation projects over larger ones.

Second, Figure 4 shows that for spot prices below $200/MWh, the South Australian PDC has moved towards the origin. While peak summer loads have grown rapidly over the past three years (with year-on-year increases of almost 9 per cent), this demand growth has largely translated into growth only in peak demand. Energy consumption overall has remained about the same (ESIPC 2009). Hence the load duration (and therefore the price duration) curve has shifted towards a 'peakier' profile.

Barring other factors (such as the arrival of a substantial new industrial load), the effect of this shift is to increasingly make certain types of (baseload and perhaps also mid-merit) generation investment that must run at a high capacity factor to recover their fixed costs uneconomic. This is because South Australia has more than sufficient capacity to meet demand during off-peak periods (1,100 MW), in particular if the contribution of wind is taken into account. As is set out in more detail in Section 4 below, the proportion of energy generation from wind is expected to increase significantly and to depress prices (at a minimum) during off-peak periods.

Individually and in combination, the shift towards a peakier load profile and very low prices for significant parts of the time imply that operationally flexible peaking capacity – effectively running at the very left hand side of the LDC when prices are high – would likely be the only technology that is commercially viable.

[4] Additionally, a number of other factors will also affect the relative cost-effectiveness of different types of generation technologies, and therefore investment. In the current context, the most important of these are Federal and state government environmental policies, such as the RET and the carbon pollution reduction scheme (CPRS).

3.1.2 Risk

In addition to assessing the revenues that a power station will earn in the wholesale market, investors will factor risk into their assessment. In an energy-only market, mid-merit and peaking generators must rely on (infrequent) high price spikes to recover their fixed costs. In the absence of market power and short of a serious supply shortfall, the frequency of price spikes depends on events such as high temperatures, as well as generation and transmission outages, which are uncertain and difficult to predict. Generator revenues and profits may therefore be quite variable from year to year, and this may limit the ability of projects to obtain financing.

At the same time, frequent price spikes will encourage greater intervention on the part of policy makers and regulators. The height and duration of price spikes are determined by regulatory policies (such as the $10,000/MWh VOLL limit and the $150,000 cumulative price threshold). Frequent high price events may therefore trigger changes to these key design elements of a wholesale market.

3.2 Barriers to entry

Generation investment that would seem to be profitable (with reference to the PDC) may not occur if there is some form of ‘barrier to entry’ that prevents (new entrant) competitors from commissioning additional capacity. The existence of barriers to entry can also explain high spot market prices more generally. There are a range of theoretical economic models of electricity wholesale markets, which show that in (oligopolistic) power markets, incumbent firms can maintain higher than competitive prices in the presence of such barriers to entry.

What exactly constitutes a barrier to entry, however, has been controversial in the economic and antitrust literature over the years. All definitions of barrier to entry relate to different opportunities facing market ‘insiders’ and ‘outsiders’ (such as incumbent generators versus new entrant generators). The definition that probably best reflects current thinking is that barrier to entry are structural, institutional and behavioural conditions that allow established firms to earn economic profits for a significant length of time (Cabral 2008).

3.2.1 Structural (static) barriers to entry

The literature on barrier to entry initially focused on relatively narrowly defined structural entry conditions, such as economies of scale or absolute cost advantages on the part of incumbents.[5] These are structural characteristics of a market that protect the market power of incumbents by making entry unprofitable (McAfee et al. 2004).

5 Another ‘class’ of barriers to entry that are not discussed here relate to regulatory barriers, such as licensing requirements or the existence of statutory monopolies.

Absolute cost advantages

Barrier to entry from absolute cost advantages refer to costs that must be incurred by a new entrant and that incumbents do not or have not had to bear. These types of barriers relate to cost trade-offs that are faced by a new entrant, and that are less favourable to the entrant than they were to incumbents when they entered the market. They occur when incumbents have already established their operations in the most favourable locations, so that entrants cannot access sites or must pay more for key inputs, such as fuel. As discussed in Section 4 below, these types of effects are also relevant in South Australia.

Economies of scale

Barriers to entry from economies of scale arise if a firm must add significantly to industry output in order to be efficient, and if incumbent firms are committed to maintaining their output levels in the event of entry. If a firm enters this market at less than the efficient scale, it enters at a significant cost disadvantage relative to incumbent firms. If the firm enters at or above the efficient scale, then the combined industry output would exceed industry demand causing selling prices to fall and dissipating all profits for the entrant. In industries where the efficient scale is large relative to the market, incumbents may therefore be able to earn supernormal profits without inducing entry.

It is, however, doubtful whether scale economies of this type play a role in preventing generation investment in South Australia. In particular gas generation technologies (which is the only thermal technology relevant for the South Australian region) are available in a wide range of size increments, ranging from single (or less) MW units to very large units of many 100s of MW. A priori it is not generally the case that entry in generation can only take place in very large increments.

Absolute capital requirements

Barrier to entry from absolute capital requirements arise if capital requirements are so large that relatively few firms could secure it, or only on terms that place them at an important cost disadvantage relative to incumbents. Absolute capital requirements have generally been discounted as a barriers to entry in their own right, on the grounds that many firms are capable of paying large capital costs if entry is worthwhile, and that raising money for large projects is not necessarily more difficult than raising money for small projects. Large capital requirements can, however, reinforce other entry barriers, particularly if a significant proportion of them are sunk.

3.2.2 Dynamic (antitrust) barriers to entry

Early definitions of barriers to entry (such as the structural conditions described above) focused on the long run and ignored adjustment costs. In reality, the timing of entry is also important. There is now a recognition that while these might not be insurmountable over the longer term, there are ‘antitrust’ barriers to entry that, at a minimum, delay entry and thereby reduce social welfare.

Adjustment costs, together with other industry characteristics, influence the speed at which industries and markets adjust over time. As a practical matter, taking into account adjustment costs changes the question from whether prices will eventually be competitive, to how long it will take before prices reach a competitive level. The analysis of barrier to entry must then be cast more broadly to assess not just factors that will eliminate entry in the long run, but also those that prevent an industry from moving, within a reasonable timeframe, from one (current) equilibrium to another, more competitive one (Carlton 2004). Relevant dynamic barriers to entry are discussed in the following.

Sunk costs

Sunk costs play a central role in a dynamic analysis of barrier to entry. A sunk cost is a lump sum expenditure that must be made up front before the firm has any significant sales and that cannot be recovered, even if the firm should go out of business (Pindyck 2005).[6] Investment expenditures are sunk when they are firm- or industry-specific. Typical examples of sunk cost investments are specialised production facilities, such as for steel or copper production where investments must be made in large scale facilities and the future price of steel or copper (and thus the return on the investment) is highly uncertain. That expenditure is sunk because if market conditions turn bad, the value of, say the investment will fall, and no company will be willing to pay the original purchase price.

Similarly, the cost of a power station investment is sunk since, once installed, the value of that power station is low if wholesale market prices turn out to be low. Power stations are long-lived assets that require significant capital investment, which vary by type of technology, and of which a significant proportion is typically sunk. Key cost components include:

- Engineering, procurement and construction costs;
- The costs of obtaining environmental and siting approvals;
- Land acquisition costs;
- Infrastructure costs, including water, wastewater and waste disposal facilities;
- The costs of connections to the electricity network; and
- Fuel connection, handling and storage costs.

Commissioning new generation capacity also takes time. Table 8 shows lead times and capital costs for generation technologies that are feasible in the three NEM zones that make up the South Australian region.

6 If there are no sunk costs, and if any fixed costs can be immediately eliminated by shutting down, the industry is ‘contestable’ in the sense that there are no entry (or exit) barriers, and ‘hit-and-run’ entry is possible. Industries can then adjust rapidly.

Table 8

ECONOMIC CHARACTERISTICS OF FEASIBLE SOUTH AUSTRALIAN POWER STATION TECHNOLOGIES

Technology	Economic life (years)	Development lead time (years)	Capital costs (2009-10, $/kW)
CCGT (WC, all zones)	30	3	1,314
CCGT (AC, all zones)	30	3	1,368
OCGT (all zones)	30	2	985
Geothermal (NSA and ADE)	30	4	5,330
Nuclear (NSA)	50	5	5,207

Notes: CCGT is combined cycle gas turbine. WC denotes water cooled. AC denotes air cooled. OCGT denotes open cycle gas turbine. Geothermal technology is at the R&D stage. ADE denotes Adelaide, NSA denotes Northern South Australia.

Source: ACIL Tasman 2009.

Where different power station technologies are concerned, coal-fired stations (which are not contemplated in South Australia) represent the largest investments – they have the largest capital costs and can generally only be commissioned in substantial size increments. In contrast, intermediate or peaking gas-fired plant required in South Australia can be built in smaller increments and can operate more flexibly to take account of short term market opportunities.

Taken on their own, sunk costs are not a barrier to entry (McAfee et al. 2004). Many firms are capable of paying large capital costs if entry is expected to be profitable, particularly in industries where potential entrants are large diversified firms. Indeed it is difficult to think of industries that do not require firm- or industry-specific investment. Nonetheless, significant sunk costs can discourage entry.[7] If entry requires large sunk costs to be incurred and entry is unsuccessful, the entrant's losses are large. Instead of being entry barriers in their own right, therefore, sunk costs tend to reinforce other barriers by magnifying entry risks.

Uncertainty

Sunk costs in combination with material uncertainty about future market conditions constitute a dynamic barrier to entry, because the combination of the two factors will tend to delay entry, possibly indefinitely.

[7] The same logic applies to 'exit' costs. If it is costly to exit a market, then the incentives to enter are reduced.

When future prices are uncertain and/or volatile, there is an opportunity cost of investing today, rather than investing at some unspecified point in time in the future. In the future, uncertainty about market conditions may be resolved and there may be better information about the likely returns from the investment. In this sense, uncertainty creates a 'real option' for a potential entrant (Pindyck 2005).[8] When a firm makes an irreversible investment expenditure, it gives up the associated option value, because the investment cannot be undone if market conditions change adversely. Put in another way, if a substantial investment is required and future market conditions are uncertain, firms have an incentive to 'wait and see', rather than immediately entering a market.

How this plays out depends on different factors, such as whether prices today are informative about prices tomorrow, how uncertainty gets resolved, and the length of time that a sunk investment lasts. These factors differ across industries, and hence the process of entry in different industries depends on the fundamentals of the underlying uncertainty and the nature of the irreversible investment. As set out in more detail in Section 4, uncertainty in the form of volatile spot market prices has increased significantly in the South Australian region in recent years.

Pre-emptive investment

Sunk costs play another role in the context of a dynamic view of barriers to entry, in that they can form part of a larger strategic 'game' being played out in the market. In an intertemporal setting there can be a range of strategic behaviours that advantage one firm over another (Carlton 2004). The source of successful strategic behavior ultimately depends on some kind of asymmetry between incumbent and new firm, but if investments are sunk, there are various games that allow established firms to make credible commitments that discourage new entry.

Most strategic behavior involves some sacrifice of profits by incumbents in order to inflict losses on entrants, but they all require the existence of sunk costs to make these strategies successful. The standard example of such strategic commitments is that of building a plant with substantial excess capacity as a way of making a credible commitment to producing an output that is so large so as to not leave enough room for profitable entry. This type of action effectively commits the incumbent to a high output, and lowers the post-entry price and profits for prospective entrants. If profits are low enough, there will be no entry. This type of strategic behaviour is thought to have occurred is in the Spanish electricity market. In that market, entry was been dissuaded by the incumbent firms, mainly by strategically announcing new investment (although this was never carried out, Crampes and Fabra 2005).

[8] Formally, suppose an entry can occur in a first or a second period and requires the payment of a sunk cost S. Payments in period 1 are known, but payments in period 2 can be 'high' or 'low', each with probability of 1/2 . If the potential entrant waits until period 2 before deciding whether to enter, the net present value (NPV) of the investment will be higher than if the entrant enters in period 1, so it is better for the entrant to wait until period 2 before deciding whether to enter. In this case, the possibility of waiting represents a real option, and by entering, the firm gives up that option. If the firm enters in period 1, it gives up this option value (the value of waiting for information about prices in period 2). The lost option value from investing at a point in time then becomes a sunk cost that must be included as part of the total cost of the investment in an ex ante evaluation.

Sunk investments in capacity are then strategic commitment devices through which first-mover incumbents can deter entry (Cabral 2008).[9] Sunk costs play a role both on the part of the incumbent, as well as for the entrant:

- Sunk costs increase an entrant's losses if entry fails. This makes the incumbent's threats of aggressive post-entry behavior more frightening.
- For the incumbent firm, sunk costs become exit costs. Sunk costs generate earnings that would be lost if a firm exits the market. If incumbents cannot exit without considerable losses, then their threats of aggressive post-entry behavior are more credible, which deters entry and earns them higher profit. Thus, exit barriers for incumbents create entry barriers.

There is also an alternative view to this theory, however. Cabral and Ross (2006) argue that commitment games of this type can also work in reverse. If an entrant, who would otherwise anticipate an aggressive response by the incumbent (in an effort to chase the entrant from the market), can commit itself irreversibly to entry, it can defeat the purpose of the incumbent's retaliation. In this view, high levels of sunk investment may facilitate entry if they serve to commit entrants to staying in the market and thereby induce the incumbent to adopt a more accommodating strategy.

[9] Entry deterrence strategies rely on 'threats' and 'commitments'. Both are designed to influence a competitor by impressing him with the consequences of his actions, along the lines of: "If you take action X, I shall take action Y, which will make you regret X." The distinguishing characteristic is that under a threat, the actor has no incentive to carry out action Y either before or after action X, while under a commitment, X having occurred, it is in the actor's self-interest to take action Y.

4 Barriers to generation investment in South Australia

This section draws on the discussion in Section 3 to identify the key factors that will have a bearing on generation investment, specifically investment by new entrants, in South Australia. That section highlighted a key precondition for commercial generation investment, namely that there must be an expectation that prices will be sufficiently high for a sufficient length of time to enable a generator to be dispatched and recover some portion of its fixed costs.

As is set out in the following, South Australian wholesale market prices in 2007 through 2009 would likely have supported new generation investment. Going forward, this may change, since wholesale prices (at least during off-peak periods) are expected to be significantly lower. There are also commercial and other risks that may affect generation investment due to limited intra- and inter-regional network capacity. In addition, there are a number of potential barriers that may prevent new entry.

4.1 Commercial factors

The following reviews commercial factors that will likely be important for determining the attractiveness of new generation investment in South Australia.

4.1.1 Investment incentives in 2009

Section 3 outlined that in an energy-only market such as the NEM, expected regional spot outcomes are key to determining whether generation investment is economic. Table 9 shows a very simplified calculation to assess, as a first approximation, whether spot prices in South Australia (as they occurred in 2009) would support investment.

Table 9 suggests that a flexible 100MW generator could have earned significant gross profits in 2009. For instance, if a hypothetical 100MW CCGT (AC) generator had been dispatched at all times when the spot price was at or exceeded $50/MWh (661 hours in 2009), it would have incurred fuel costs of around $2.6 million and would have earned spot market revenues of $63.8 million. The annualised fixed cost of a 100MW CCGT (AC) generator is $17.4 million, which would have left a gross profit (net of fuel and fixed costs) of $43.9 million. On the face of it, therefore, investment in 100MW of gas-fired generation would have been economic in 2009. A similar calculation for 2007 and 2008 (shown in Appendix 2) also suggests that investment would have been economic in those years.

Table 9

GROSS PROFIT CALCULATION FOR A 100MW GAS-FIRED GENERATION UNIT (2009 PRICES)

	CCGT (AC) SRMC = $38.58/MWh	CCGT (WC) SRMC = $38/MWh	OCGT SRMC = $85.74/MWh
Number of hours in which spot prices exceeded:			
$50/MWh	661	661	661
$100/MWh	164	164	164
Spot market revenues earned if unit had been dispatched at prices above:			
$50/MWh	$63,828,083	$63,828,083	n/a
$100/MWh	$57,351,975	$57,351,975	$57,351,975
Fuel costs, if unit had been dispatched at prices above:			
$50/MWh	$2,548,209	$2,516,505	n/a
$100/MWh	$632,712	$624,840	$1,406,136
Annual fixed costs	$17,400,000	$16,800,000	$11,300,000
Gross profit if unit had been dispatched at prices above:			
$50/MWh	$43,879,874	$44,511,578	n/a
$100/MWh	$39,319,263	$39,927,135	$44,645,839

Notes: CCGT is combined cycle gas turbine. WC denotes water cooled. AC denotes air cooled. OCGT denotes open cycle gas turbine.
Annualised capital, fixed O&M and tax costs (2009-10) for a CCGT (AC) are $174/kW/annum, for a CCGT (WC) are $168/kW/annum, for an OCGT are $113/kW/annum.
SRMC costs, including carbon costs for ADE (2009-10) for a CCGT (AC) are $38.58/MWh, for a CCGT (WC) are $38/MWh, for an OCGT are $85.74/MWh.
Gross profits are defined as spot market revenues net of fuel costs and annual fixed costs.

Source: ACIL Tasman 2009, AER data.

The calculation in Table 9 is a highly simplified one, since it just takes historical prices as a ‘given’, and calculates gross profits on that basis. Implicit is therefore a key assumption, namely that the operation of a hypothetical generator with a capacity of 100MW would not have affected price outcomes in 2009. In reality this is unlikely to have been the case; the addition of a peaking generator would be expected to have lowered prices, at least in some dispatch intervals. The most that can perhaps be said is therefore that a small stand-alone generator:

- Would not bid to be dispatched at prices below SRMC, since this would entail running at a loss, and in particular, would not offer to run at a price at or around zero (which might have a marked effect on market clearing prices); and
- May instead – as appears to be the pattern in some of the high price scenarios analysed by the AER – submit broadly cost-reflective bids, be dispatched in full, and thereby benefit from high spot prices that are determined by other generators’ (for instance, AGL’s) bids.

Overall, therefore, the arrival of a 100MW generator would be expected to reduce prices, and the estimates of gross profits in Table 9 are therefore overestimates. However, even if there had been a (downward) price impact, it is unclear whether this would have been sufficient to make the (hypothetical) investment uneconomic. For instance, given prices at the RRN in 2009, it would have taken a 70 per cent fall in spot market revenues to make a CCGT investment uneconomic in that year, and an 80 per cent fall to make an OCGT investment uneconomic.

4.1.2 The advent of wind generation

While price outcomes in 2009 would likely have supported new gas-fired generation investment, going forward, the projected increase in renewables (mainly wind) generation in South Australia may create an impediment to new generation investment because it is expected to depress prices.

Low and negative prices

Renewable technologies such as wind power have low operating costs but need relatively high revenues to cover high financing charges. This is typically achieved by a combination of power purchase agreements and REC payments. However, in order to be eligible for REC payments, these generators must operate. Hence South Australian semi scheduled (wind) generators frequently offer their output at zero or negative prices (as low as the market price floor of (-)$1,000/MWh). In addition to an unusually high number of price spikes, South Australia has then also experienced an increasing number of low and negative prices (ESIPC 2009). This effect can also be seen in Figure 1 and Table 3 in Section 2.

NEMMCO/AEMO (2008) analysed the causes of these negative prices following recurrent negative spot market prices between mid September and mid October 2008.[10] The analysis concluded that the key factors contributing to these outcomes are essentially the same as those that make wind generation relatively ineffective when demand is high. That is, negative energy prices in South Australia coincided with periods when regional demand was low, and wind generation was high, particularly in the Southeast of the state. In most cases, a lack of interconnector capacity prevented energy exports to other regions of the NEM and resulted in prices in the South Australian or the combined South Australian/Victorian region separating from the remainder of the NEM.

Future wind developments

As yet the total installed wind capacity of wind in South Australia is less than the minimum demand in the region, which is in order of 1,100 MW. However, zero and negative price events are projected to become more pronounced as more wind capacity (relative to off-peak demand) is installed.

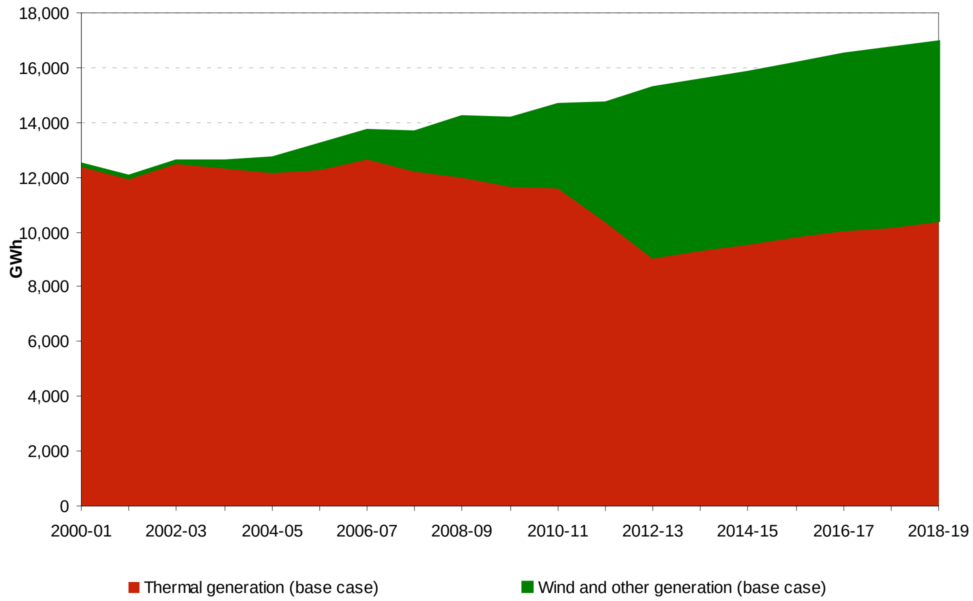
ESIPC (2009) states that is currently tracking in the order of 5,000 MW of proposed projects, and comments that levels of wind generation forecast within South Australia are without precedent in any power system. The expected predominance of wind generation in South Australia is expected to have a significant impact on existing and future thermal generation in that region:

[10] The spot price for a region is negative when an increase in regional demand by 1 MW would be met by scheduled generation offered from a negative price band. This can occur even if some positively priced generation capacity is dispatched. In these cases the positively priced capacity is ineligible to set the regional price because it cannot be reduced any further due to either generator ramp down rates or network constraints.

- At least during off-peak times, wind generation will crowd out thermal generation. ESPIC (2009) predicts that, in its 'base case' scenario (Figure 5), the share of energy supplied by wind farms is projected to rise from 14 per cent in 2008-09 to 15.7 per cent in 2009-10, and to 34.1 per cent by 2018-19.
- Wholesale prices will become significantly more volatile. ESIPC's analysis for the 2012-13 financial year (when the Council expects 1,500MW of wind to operate in South Australia) suggests that during periods of low demand and high wind production, the spot price will drop to the market floor price of (-) $1,000/MWh).

Figure 5

PROJECTED FUTURE SOUTH AUSTRALIAN ENERGY SOURCES



Source: ESIPC 2009.

AEMO's forecasts are very similar to those of ESPIC. For the purpose of planning future network augmentations as part of its National Transmission Statement (NTS) process, AEMO models generation dispatch and flows across the NEM, including the South Australian region for a Lower Carbon Price Scenario (LCPS) and a Higher Carbon Price Scenario (HCPS).[11] In the LCPS, the modelling suggests the following implications for South Australia:

- Wind will account for one-third of installed capacity in South Australia by 2017-18;
- Wind generation will contribute to the increasingly constrained operation of interconnectors in both directions between South Australia and Victoria; and

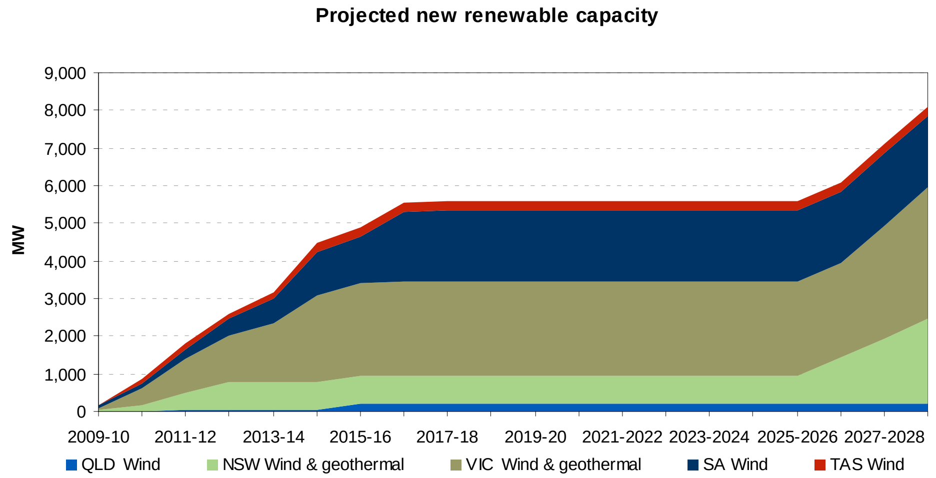
[11] The LCPS entails a 5 per cent reduction in CO2-e emissions below 2000 levels by 2020 (CPRS-5), and corresponding to a carbon price of around $20 (per tonne of CO2-e emissions in real 2007 dollars) on 1 July 2010, increasing to approximately $35 by 2020, and increasing to between $50 and $60 by 2030. The HCPS assumes a 15 per cent reduction in CO2-e emissions below 2000 levels by 2020 (CPRS-15), requiring a carbon permit price trajectorycommencing at $25 (per tonne of CO2 -e emissions) on 1 July 2010,increasing to $45 by 2020, and to $70 and $80 by 2030.

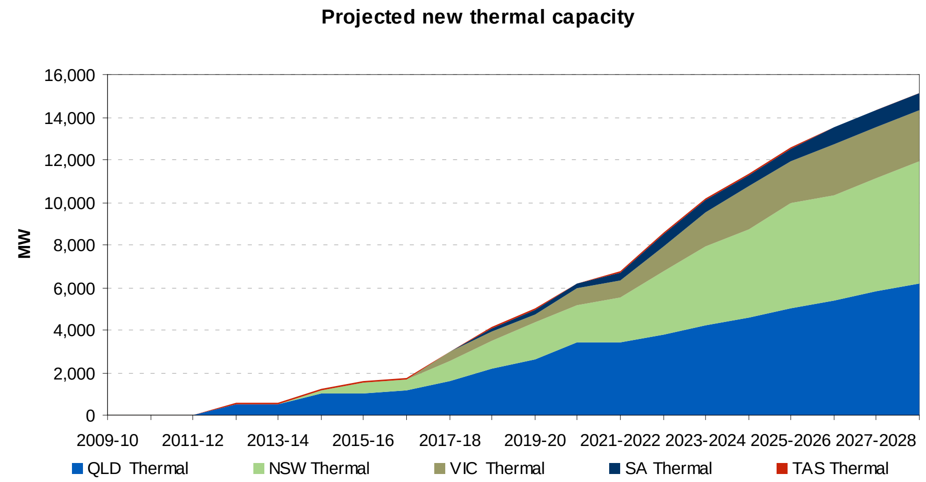
- South Australian spot prices are expected to fall to the market simulation floor price of $0/MWh (in reality, the NEM floor price is -$1,000/MWh).[12]

Figure 6 shows AEMO's projections for new renewable (most of which is wind) and thermal capacity for the various NEM regions. While the MW axes are on different scales, they nonetheless highlight the relative proportions of renewable versus thermal capacity in each region. The proportion of renewable to thermal capacity is significantly greater for South Australia than it is for any of the other regions (although it is also high for Victoria).

Figure 6

Projected future South Australian energy sources (2009-10 to 2028-39, LCPS)





Source: AEMO 2009.

In addition, significant network limits are likely to emerge as a result of the increasing penetration of wind energy, and will reinforce existing network limitations. Of the 10 most significant (frequently binding) system constraints, four are expected to originate in South Australia, namely:

12 The simulation methodology does not account for Renewable Energy Certificates (RECs), which allow wind generators to bid in negative price bands.

- The South East transformer thermal limit;
- The Heywood and Murraylink interconnector oscillatory stability limits;
- The Snuggery-Keith thermal limit; and
- The Bungama-Redhill thermal limit, which is located in NSW, but reflects the impact of additional wind generation connected in the Mid North of South Australia.

Specifically where pricing outcomes are concerned, AEMO predict an increasing incidence of zero price events in South Australia up to 2017-18, as energy exports reach their limits in response to increasing amounts of available wind generation in South Australia.[13] As available wind capacity in South Australia increases, the dispatch process will approach a situation where:

- All conventional generation is operating at minimum levels;
- All wind generation is operating at a level defined by the assumed wind conditions; and
- Generation, with no bids above $0/MWh being accepted, is adequate for meeting both South Australian load and the export capability of the Victoria-South Australia interconnectors.

The results in the HCPSR are very similar. In this scenario, wind capacity is expected to account for one-third of installed capacity in South Australia by 2017-18, contributing to increasingly constrained operation of interconnectors in both directions between South Australia and Victoria. The constrained operation of these interconnectors results in South Australian spot prices falling to the market simulation floor price of $0/MWh. In this scenario even more significant network limits will emerge in South Australia.

4.1.3 Network access

There is uncertainty about whether the South Australian network can accommodate the output of additional generators. The NEM provides no predetermined rights of access to the market. In the normal course of system operations, generators are dispatched in accordance with their offer prices and in order of least cost, but also consistent with the ability of the network to deliver electricity to customers in a reliable and secure manner. When the network is congested, the output of some generators is ‘constrained down’ or ‘constrained off’, so that these generators earn less or no revenues in these circumstances.

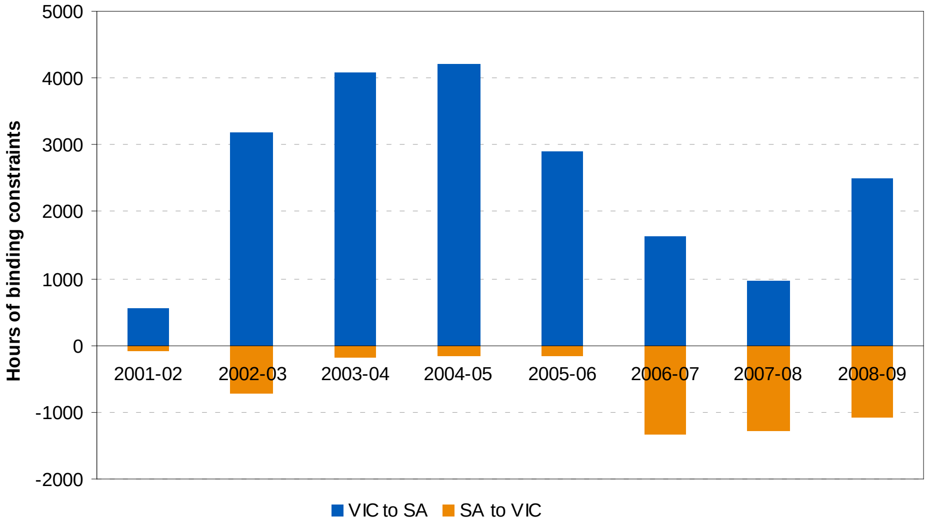
13 The market simulations model wind generation at low cost, the majority being offered at $0/MWh. In addition, the 'must run' component of conventional generation is also offered at $0/MWh. The simulation methodology sets a floor price of $0/MWh to calculate clearing prices.

A number of sections of the existing transmission network in South Australia are strained, certainly during high demand conditions (ESIPC 2009).[14] The extent of network congestion will affect the number of new generators that can be accommodated in the network, and whether they will be able to export their output. In particular, congestion limiting power station dispatch is expected to significantly increase as more wind turbines (but also geothermal plant) are connected on the northern corridor (between Northern PS and Angaston PS) and on the southeast corridor around Adelaide (ESIPC 2009). One of the expected consequences is that thermal power stations will increasingly be constrained off.

Inter-regional constraints have also increased recently, which reduces the opportunity for South Australian generators to export excess power to Victoria. Figure 3 shows the number of hours when the two interconnectors between South Australia and Victoria (Heywood and Murraylink) were constrained (predominantly during times when South Australia imported power from Victoria). Figure 3 shows that although the number of constrained hours declined in 2007-08, imports from Victoria were constrained for more than 2,500 hours (28.6 per cent of the time) and exports for around 1,100 hours (12.4 per cent of the time). As discussed above, congestion on these interconnectors is projected to increase significantly with the advent of additional wind generation.

Figure 7

SOUTH AUSTRALIA – VICTORIA: HOURS OF CONSTRAINED INTERCONNECTOR FLOW DUE TO BINDING CONSTRAINTS



Notes: Includes both constraints during system normal conditions and constraints during outages. Hours refer to total hours on the Heywood and Murraylink interconnectors.

Source: AEMO, 2009. Statement of Opportunities.

The AER's analyses of events when spot prices in South Australia exceeded $5,000/MWh also show that network weaknesses – limits on interconnector transfers and/or intra-regional network congestion – consistently contributed to these high price events.

[14] Both ElectraNet and ETSA Utilities face significant investment programs over the next five to ten years; the scale of these programs is additionally increased, because a significant number of assets are 40 to 50 years old and need to be replaced or refurbished.

Broadly speaking, and depending on the location of a generation investment, an expected increase in intra- and (to a lesser extent) inter-regional congestion will tend to have two effects:

- It will directly reduce the projected earnings of (new) generators if there is an increased likelihood that they will be constrained off or will otherwise only be able to export a lesser proportion of their output; and
- It will reduce their ability to enter into contracts for differences, since these generators will be exposed to unfunded difference payments when there are network constraints. In turn, this may affect their ability to obtain financing for the project.

4.2 Structural barriers to entry

Structural entry barriers are those characteristic of a market that protect the market power of incumbents by making entry unprofitable. Of the potential structural barriers identified in Section 3, the most likely candidates in the South Australian context relate to absolute cost advantages that incumbents may have over new entrants. As is the case in other Australian states, the South Australian ESI was initially built, financed, and operated by the government. These investment were undertaken over time as the most suitable locations and fuel sources were gradually exploited. Today, the range of locations and fuel sources are limited, the transmission network is congested, and entrants can therefore expect to incur higher costs than incumbents did historically.

4.2.1 Sites

There are available sites to connect new generators, but with strict limitations (ESIPC 2009):

- South Australia’s 132 kV network is already congested and will become more so, so that new generation can only be accommodated at the 275 kV level. The effect of this is to increase the costs of commissioning a power station, since additional connection at higher voltages requires additional expenditures for transformers.
- Given that this would require very significant network upgrades, new generation cannot be accommodated in the Mid North and the Southeast of the State.

It is also the case that any type of power station investment requires that the proponents go through extensive planning and development approval processes prior to commissioning the station. This likely represents a greater obstacle for entrants who would need to gain approvals for greenfield sites, for instance relative to AGL/IP whose expansion plans relate to their existing power station sites. It is also relevant that IP holds planning and development approvals for augmentations to Pelican Point PS (up to 300 MW), Dry Creek PS (40 MW), Mintaro PS (40 MW), and Snuggery PS (25 MW, ESIPC 2009).

4.2.2 Fuel

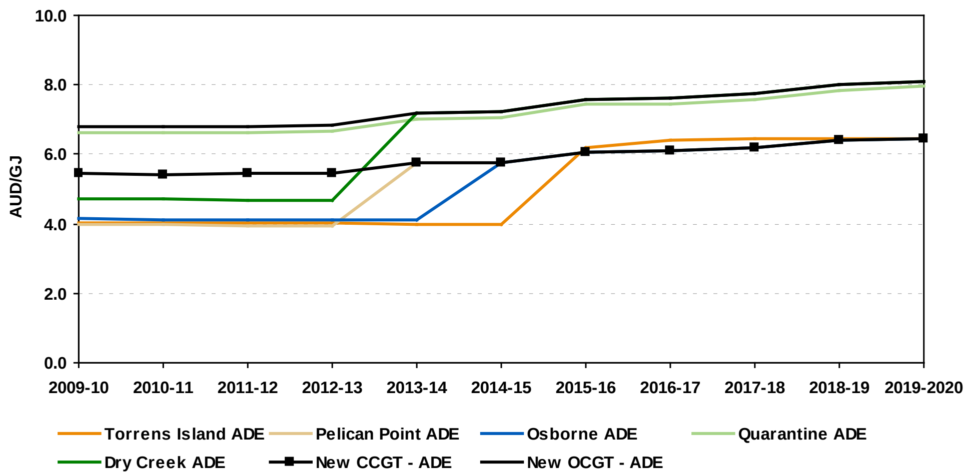
One of the consequences of the expected increase in intermittent wind generation is that generation from thermal power stations will also become more volatile. Thermal generation plant must then operate in a very flexible manner, and would need to be gas-fired.

In general, there is no shortage of gas from South Australian and Queensland gas reserves, and there are feasible locations that are close to a gas pipeline and the transmission network. South Australia also has sufficient physical access to pipeline and processing capacity to meet base-load generation. There are, however, limitations that will affect the operations of new intermittent and peaking gas-fired generation. Other than line pack in pipelines, there is currently no significant gas storage close to the main load centre (Adelaide). Unless a new generation project is combined with a gas storage project (as it the case for AGL's TIPS extension), a lack of storage will limit generation from gas-fired power stations, at least for larger units. Small generators may be able to access line pack, although this would depend on the capacity and the physical capability of the gas network to deliver significant quantities of gas over several hours.

Additionally, and in the Adelaide (ADE) zone of South Australia, new entrant generators would face higher delivered gas costs than incumbent generators in the near term (Figure 8). Open cycle gas turbines (OCGT) would similarly face higher fuel costs in the North South Australia (NSA) zone.

Figure 8

ESTIMATED DELIVERED GAS COSTS TO EXISTING AND NEW ENTRANT CCGT AND OCGT (REAL AUD 2009-10/GJ)



Notes: OCGT denotes open cycle gas turbine. IGCC denotes combined cycle gas turbine. OCGT costs are higher because of higher auxiliary power consumption and a lower thermal efficiency.

Source: ACIL Tasman 2009.

4.2.3 Financing

New power station projects are financed through corporate borrowing on the back of existing balanced sheets and/or via long term contracts with one or more large customers and/or existing retailers. Given that the established South Australian retailers are vertically integrated with upstream generators (Table 2), the ability of entrants to enter into contractual agreement with existing retailers is likely to be very limited. As discussed above revenue risks such those arising from price volatility may also restrict the ability of projects to attract financing.

It is possible, however, that significant new minerals projects developments, which may materialise in the North of South Australia may underwrite new generation investment. ESIPC (2009) has identified the following major industrial developments that might fall into this category:

- The expansion of the Olympic Dam mine by BHP Billiton in the far North of the state;
- The commissioning of a large new pulp mill in the South East; and
- The commissioning of a new 100 GL desalination plant in Adelaide.

4.3 Strategic barriers to entry

Dynamic (or antitrust) barrier to entry arise in circumstances where investments require significant sunk costs, and have the potential to delay – for a time or permanently – investment that would otherwise be efficient.

4.3.1 Sunk costs and uncertainty

While sunk costs, taken on their own, are not considered to constitute barriers to entry, the combination of sunk costs and significant uncertainty about future market conditions is. In the context of the South Australian electricity wholesale market, for instance, the value of a power station will depend on a number of variables that evolve over time such as fuel costs or wages, which are relatively predictable. But the most important determinant of the value of the power station are electricity wholesale market prices.

Significant volatility of electricity wholesale prices in the South Australian region will magnify the risk of a sunk power station investment for an entrant. Spot price volatility has increased and will continue to do so with the advent of new intermittent wind generation (ESIPC 2009). This effect can be seen in Figure 1, and is also reflected in the increase in the annual standard deviation of spot prices, in particularly from 2008 onwards (Table 10). Additionally, to the extent to which volatility is ‘created’ by incumbent generators through the exercise of market power, investment risks for entrants may also increase.

Table 10

VOLATILITY OF PRICES AT THE SOUTH AUSTRALIAN RRN

Year	Standard deviation
2005	101
2006	131
2007	123
2008	523
2009	504
2010	543

Notes: The standard deviation measures the variation from average prices.

Source: ESIPC 2009.

4.3.2 Strategic games

Pre-emptive investment

As discussed in Section 3, one form of a (unilateral) strategic commitment on the part of incumbents that is designed to discourage entry is to build sufficient excess capacity so as to make entry unprofitable.

On current plans, two incumbent generating portfolios plan to install significant additional new capacity in South Australia. AGL has announced plans to commission 700MW of OCGT capacity, and in addition AEMO lists a proposal by IP to commission 300MW of gas-fired capacity (Table 5).

Very little detail is available in relation to IP's planned investment at Pelican Point; the company has made no announcements on its website or annual reports, and AEMO has not identified a commissioning date or other details about this project. In addition, and while noting that IP has development approvals for a number of sites including Pelican Point, ESIPC states that (2009, P.75):

> International Power indicated that, while planning and development approvals will remain in force for generation expansions at these sites, it considers that market conditions and system constraints are not favourable for further investment in merchant generation in South Australia at this time.

Where AGL's announced expansion plans are concerned, there are some reasons to think that such an investment may constitute a pre-emptive move that would create barriers, not just for new entrants, but for other thermal investment that might be undertaken by existing market participants. The addition of 700MW would take installed thermal capacity in South Australia from around 3,400 MW to 4,100MW, an increase of more than 20 per cent. It would also increase AGL's market share of installed generation capacity from currently 37.6 per cent to 48.3 per cent.

AEMO's most recent (2009) summer peak demand projections for a medium economic growth case and assuming a 10 per cent probability of exceedance (POE) suggest that peak demand will not exceed 4,100MW until 2017-18.[15] As a general matter, if AGL's investment goes ahead this would make it very unlikely that any other (thermal) generation investment would be economic before this time. This would be reinforced by price effects, since an additional generation increment of 700MW would be expected to depress spot prices over a significant time horizon, which would in turn discourage (other) investment. Additionally, given existing demand forecasts, it seems plausible that a (significant) proportion of AGL's new capacity may stand idle for some years. This would seem to be consistent with a form of behaviour whereby the incumbent sacrifices some profits to achieve an overriding strategic purpose.

Without detailed spot market modelling, however, it is difficult to tell whether AGL's investment would be economic in its own right, or whether it represents a loss-making strategy aimed at pre-empting investment by other parties. This depends, among other things, on future load growth and therefore what proportion of the new capacity would be required, and on the effect on spot market prices of the investment, taking account AGL's future bidding behaviour.

Collusive strategies

Other types of strategic games assume some form of collusion between generators. In circumstances where there are barriers to entry, sustained collusive games are possible in which incumbent generators persistently maintain higher prices. In these types of models, generators choose production to maximise joint profits subject to the constraint that no generator has an incentive to deviate in order to earn higher one-off profits at the risk of starting a price war (Puller 2001). If demand and prices are observed ex post (as they are in the NEM), generators can always sustain the collusive regime, although the level of collusion depends on current and expected future demand and whether generators face capacity constraints:

- If demand is expected to rise in the near future, the future collusive profits are higher and generators have less incentive to deviate from collusive pricing; and
- Generators also have less incentive to deviate from collusive pricing if there are capacity constraints, because such constraints will affect both the likely profits from deviation and the severity of price wars.

Identifying this type of collusive conduct (or rather, the structure of the underlying game) requires a formal model and detailed data to estimate key response parameters. This is an inter-temporal optimisation problem in which generators optimise supply, subject to contemporary, but also future supply and demand conditions. Such an analysis, which would, by extension also point to the existence of barriers to entry in the South Australian region is not available.

15 In the low economic growth case, peak demand will not exceed 4,100MW until at least 2019-20. In the high economic growth case, peak demand will not exceed 4,100MW until 2013-14.

The analysis undertaken by the AER of high price events is also a source of some (albeit, anecdotal) insights into the nature of any games being played out in the South Australian spot market. The AER's analysis of circumstances where South Australian wholesale market prices exceeded $5,000/MWh is summarised in Appendix 2. These reports suggest that a lack of effective competition combined with other factors (such as network limitations) play a key role in explaining high price events in South Australia:

- In the great majority, but not all instances, AGL took the lead in bidding or rebidding a significant proportion of its capacity at high prices. On 31 March 2009, Infratil submitted very high bids, during 8-10 Feb 2010, AGL, but also other South Australian generators submitted very high bids.
- Other South Australian generators have not followed a consistent pattern in their bidding responses. In some cases, other generators have followed suit and bid capacity at high prices; in others they have left bids unchanged, or submitted low or zero price bids to reduce prices, for instance:
  - On 31 March 2009 IP rebid capacity to zero, supporting a fall in market clearing prices; and
  - On 8 January 2010, Origin rebid capacity to zero.
- All of these events were accompanied by other factors, including significant intra- and inter-regional network limitations that resulted in imports/exports being constrained, as well as frequent instances when demand was under-forecast so that in some cases generation capacity was not available.

Overall, this suggests an underlying market dynamic whereby AGL's competitors are content to benefit from or contribute to high prices in some circumstances, but have a commercial interest in lowering prices in others. There were two events where competitors rebid capacity at lower prices,[16] but there is no evidence of punishment or similar strategies that are required in formal models of collusion in wholesale electricity markets. Intuitively the reason is that, absent such punishments, competitors have an incentive to simply undercut high priced offers by making capacity available, and the (repeated) collusive game could not be sustained. A lack of observed 'punishments' may, however, be inherent in the terms of reference of the reports published by the AER, which focus on high price events, rather than on market dynamics after prices have returned to lower levels.

[16] AGL also rebid prices in spite of ongoing high demand on 10-13 November 2009.

Appendix 1 Installed generation capacity in South Australia

Table 11

SCHEDULED, SEMI SCHEDULED AND UNSCHEDULED GENERATION CAPACITY IN SOUTH AUSTRALIA (SUMMER)

	Owner/Operator	Plant type	Capacity (MW)
	Scheduled generation		
Torrens Island A	AGL Energy	Conventional steam	480
Torrens Island B	AGL Energy	Conventional steam	800
Angaston	Infratil	Reciprocating diesel	49
Dry Creek	International Power	Gas turbine	115
Mintaro GT	International Power	Gas turbine	67
Pelican Point	International Power	Combined	448
Snuggery	International Power	Gas turbine	51
Port Lincoln	International Power	Gas turbine	63
Northern	NRG Flinders	Conventional steam	542
Osborne	NRG Flinders	Cogeneration	175
Playford	NRG Flinders	Conventional steam	200
Ladbroke Grove	Origin Energy	Gas turbine	70
Quarantine	Origin Energy	Gas turbine	191
Hallett GT	TRUenergy	Gas turbine	151
Total scheduled generation			**3,402**
	Semi scheduled generation		
Clements Gap	Pacific Hydro	Wind	57
Hallett I	AGL Energy	Wind	59
Hallett II	AGL Energy	Wind	71
Lake Bonney	Infigen Energy	Wind	159
Snowtown	Trustpower	Wind	99
Total semi scheduled generation			**445**
	Non-scheduled generation		
Lonsdale	Infratil Energy	Diesel	20
TS Mini Hydro	Hydro Tasmania	Hydro	3
Canunda	International Power	Wind	46
Cathedral Rocks	Roaring 40s	Wind	66
Lake Bonney	Infigen Energy	Wind	81
Mount Millar	Transfield Services	Wind	70
Starfish Hill	Transfield Services	Wind	35
Wattle Point	AGL Energy	Wind	91
Wingfield I and II	EDL	Landfill Gas	8
Amcor Gawler	Energy Response	Diesel	3
Pedler Creek	EDL	Landfill Gas	3
Total non-scheduled generation			**426**
Total generation			**4,273**

Notes: A scheduled generating has its output controlled through the central dispatch process. Scheduled generators are generally thermal (in South Australia coal and gas) generators. A semi scheduled generating unit has intermittent output, a capacity of 30 MW or greater and may have its output limited to prevent the violation of network constraints. In South Australia these are large wind farms. A non scheduled generating unit is not scheduled through the central dispatch process. In South Australia these are small renewables projects, such as wind or landfill gas.

Source: AEMO

Appendix 2 New entry profitability calculation for 2007 and 2008

Table 12

GROSS PROFIT CALCULATION FOR A 100MW GAS-FIRED GENERATION UNIT (2007 PRICES)

	CCGT (AC) SRMC = $38.58/MWh	CCGT (WC) SRMC = $38/MWh	OCGT SRMC = $85.74/MWh
Number of hours in which spot prices exceeded:			
$50/MWh	1,381	1,381	1,381
$100/MWh	134	134	134
Spot market revenues earned if unit had been dispatched at prices above:			
$50/MWh	$706,884	$706,884	n/a
$100/MWh	$544,246	$544,246	$544,246
Fuel costs, if unit had been dispatched at prices above:			
$50/MWh	$5,327,898	$5,261,610	n/a
$100/MWh	$515,043	$508,635	$1,144,629
Annual fixed costs	$17,400,000	$16,800,000	$11,300,000
Gross profit if unit had been dispatched at prices above:			
$50/MWh	$47,960,548	$48,626,836	n/a
$100/MWh	$36,509,550	$37,115,958	$41,979,964

Notes: CCGT is combined cycle gas turbine. WC denotes water cooled. AC denotes air cooled. OCGT denotes open cycle gas turbine.
Annualised capital, fixed O&M and tax costs (2009-10) for a CCGT (AC) are $174/kW/annum, for a CCGT (WC) are $168/kW/annum, for an OCGT are $113/kW/annum.
SRMC costs, including carbon costs for ADE (2009-10) for a CCGT (AC) are $38.58/MWh, for a CCGT (WC) are $38/MWh, for an OCGT are $85.74/MWh.
Gross profits are defined as spot market revenues net of fuel costs and annual fixed costs.

Source: ACIL Tasman 2009, AER data.

Table 13

GROSS PROFIT CALCULATION FOR A 100MW GAS-FIRED GENERATION UNIT (2007 PRICES)

	CCGT (AC) **SRMC = $38.58/MWh**	**CCGT (WC)** **SRMC = $38/MWh**	**OCGT** **SRMC = $85.74/MWh**
Number of hours in which spot prices exceeded:			
$50/MWh	3,394	3,394	3,394
$100/MWh	721	721	721
Spot market revenues earned if unit had been dispatched at prices above:			
$50/MWh	$651,230	$651,230	n/a
$100/MWh	$288,196	$288,196	$288,196
Fuel costs, if unit had been dispatched at prices above:			
$50/MWh	$52,030,877	$52,193,765	n/a
$100/MWh	$26,038,015	$26,072,623	$22,637,779
Annual fixed costs	$17,400,000	$16,800,000	$11,300,000
Gross profit if unit had been dispatched at prices above (spot market revenues net of fuel costs and annual fixed costs):			
$50/MWh	$34,630,877	$35,393,765	n/a
$100/MWh	$8,638,015	$9,272,623	$11,337,779

Notes: CCGT is combined cycle gas turbine. WC denotes water cooled. AC denotes air cooled. OCGT denotes open cycle gas turbine.
Annualised capital, fixed O&M and tax costs (2009-10) for a CCGT (AC) are $174/kW/annum, for a CCGT (WC) are $168/kW/annum, for an OCGT are $113/kW/annum.
SRMC costs, including carbon costs for ADE (2009-10) for a CCGT (AC) are $38.58/MWh, for a CCGT (WC) are $38/MWh, for an OCGT are $85.74/MWh.

Source: ACIL Tasman 2009, AER data.

Appendix 3 High price events in 2009 and 2010

Table 14

EVENTS SURROUNDING PRICES HIGHER THAN $5,000/MWH IN SOUTH AUSTRALIA

Date	Circumstances	Market participants actions
31 March 2009	Factors only affecting SA region: • Unplanned outage at Northern PS • No wind • Restrictions on import capability	• High priced offers from Infratil • IP rebid 85 MW of capacity to zero • No rebidding
2 Nov 2009	Factors only affecting SA region: • Under forecast of demand • Lower than forecast import limits on interconnectors • Low cost generation not available on the day	• Day-ahead high priced offers from AGL • No rebidding
10-13 November 2009	Factors only affecting SA region: • High demand as forecast • Lower than forecast import limits from Victoria • Planned interconnector outage	• Day-ahead high priced offers from AGL • Subsequently low bids by AGL (with continued very high demand) reduced prices
19 November 2009	Factors only affecting SA region: • Under forecast of demand • Lower than forecast import limits on interconnectors • Low cost generation not available on the day	• Day-ahead high priced offers from AGL • Rebidding by AGL
8 January 2010	Factors only affecting SA region: • Low priced generation constrained off due to network limits • Import constrained do to additional low cost generation • Generation constraints as a result of network outages	• Day-ahead high priced offers from AGL • Rebidding by Origin of 180 MW of capacity to zero reduced prices
8-10 Feb 2010	Inter-regional factors: • Under-forecast of demand in SA and Vic • Downrated generation capacity in Vic • Lower than forecast import/export limits in both regions • Low cost generation in Vic and SA not available	• High priced offers in SA, most from AGL, but also from TRUenergy, IP, Flinders Power, Origin, Infratil and Synergen • Day ahead rebidding in SA and in Victoria • On the day rebidding (one day) by AGL

Date	Circumstances	Market participants actions
11 January 2010	Inter-regional factors: • Unexpectedly high demand in Victoria • Significantly downrated import limits into Vic and SA	• Day-ahead bidding by AGL • No rebidding

Source: AER market events reports 2009 – 2010.

References

ACIL Tasman, 2009. “Fuel resource, new entry and generation costs in the NEM”, April.

AGL, 2010a. http://www.agl.com.au/about/EnergySources/indevelopment/Pages/TorrensIslandEnergyPark.aspx, accessed on 12 June 2010.

AGL, 2010b. “Regulated Pricing Proposal 1 January 2011 to 30 June 2014”, AGL Proposal to Essential Services Commission of South Australia - Public Version, 19 May.

Australian Energy Market Operator, 2010. http://www.aemo.com.au/data/gendata.shtml, accessed on 20 May 2010.

Australian Energy Market Operator, 2009. “Statement of Opportunities”.

Australian Energy Market Operator, 2009. “National Transmission Statement for the National Electricity Market”.

Australian Energy Regulator, 2007, 2008, 2009. “State of the energy market”.

Australian Energy Regulator, “Electricity spot prices above $5000/MWh”, South Australia: 31 March 2009, South Australia: 2 November 2009, South Australia: 10-13 November 2009, South Australia: 19 November 2009, 8 January 2010, South Australia, 11 January 2010, 8-10 February 2010, South Australia and Victoria

Altona Energy Plc, 2010. “South Australia’s Energy Bank”, Investor Presentation, February.

Bergman, Lars, 2002. “The Nordic electricity market—continued success or emerging problems?”, Swedish Economic Policy Review 9.

Borenstein, Severin, James Bushnell, Edward Kahn, and Steven Stoft, 1996. “Market Power in California Electricity Markets”, PWP-036, March.

W.H. Brock and J.A. Scheinkman. Price Setting Supergames with Capacity Constraints. Review of Economic Studies, 1985.

Cabral, Luís M. B. “barriers to entry.” The New Palgrave Dictionary of Economics. Second Edition. Eds. Steven N. Durlauf and Lawrence E. Blume. Palgrave Macmillan, 2008.

Cabral, Luís M. B., and Thomas W. Ross, 2008. “Are Sunk Costs a Barrier to Entry?,” Journal of Economics & Management Strategy, Blackwell Publishing, vol. 17(1).

Carlton, Dennis W., 2004. “Why Barriers to Entry Are Barriers to Understanding”, The American Economic Review, Vol. 94, No. 2, Papers and Proceedings of the One Hundred Sixteenth Annual Meeting of the American Economic Association, May.

Carlton, Dennis W., 2005. “Barriers to Entry”, NBER Working Paper Series, Working Paper 11645.

Carlton, Dennis and Perloff, Jeffrey. Modern industrial organization. New York: HarperCollins College Publishers, 1994.

Eaton, B. Curtis and Richard G. Lipsey, 1980. “Exit Barriers are Entry Barriers: The Durability of Capital as a Barrier to Entry,” Bell Journal of Economics, The Rand Corporation, vol. 11(2), pages 721-729, Autumn.

Electricity Supply Industry Planning Council, 2009. “Annual Planning Report”, June.

ESCOSA, 08/09 Annual Performance Report, South Australian Energy Supply Industry, November 2009.

Crampes , C. & Fabra , N., 2005. “The Spanish Electricity Industry: Plus ça change …,” Cambridge Working Papers in Economics 0502, Faculty of Economics, University of Cambridge.

McAfee, R. Preston, Hugo M. Mialon and Michael A. Williams, 2004. “What Is a Barrier to Entry?”, The American Economic Review, Vol. 94, No. 2, Papers and Proceedings of the One Hundred Sixteenth Annual Meeting of the American Economic Association, May.

Puller, Steven L., 2001. “Pricing and Firm Conduct in California’s Deregulated Electricity Market”, November, PWP-080.

Pindyck, Robert S., 2005. “Sunk Costs and Real Options in Antitrust”, MIT Sloan Working Paper 4545-05, June.

Strikeoil, 2010. http://www.strikeoil.com.au/operations/otwayBasin.php; accessed on 1 July 2010.