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Winds of change

An analysis of recent changes
in the South Australian
electricity market

McConnell & Sandiford

August 2016



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Winds of change

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Dylan McConnell and Mike Sandiford
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'When the wind of change blows some build walls while others build windmills'
Chinese Proverb

South Australia has one of the highest penetration intermittent renewable generation portfolios in a liberalised energy-only market. In the year to the end of June 30th, 2016 (FY16) wind generation contributed 37.6% to the total grid dispatch in South Australia, while domestic solar PV contributed an estimated 6% of total electricity production. The rise of renewable generation in South Australia over the last decade has been accompanied by the progressive withdrawal of baseload coal generation, and a changing role for gas generation and reliance on exchanges with the neighboring state of Victoria. Along with the opening up of the interlinked Australian east-coast gas market to international gas pricing, the dynamics of the South Australian electricity market has shifted accordingly, making it a test case for understanding how to manage the transition to a high penetration renewable energy system in liberalised energy-only markets. In the winter months of 2016, South Australian wholesale electricity prices rose steeply, generating intense interest in its causes and the consequences of the South Australian energy transition.

Executive Summary

At around 38% of annual market dispatch, South Australia currently has one of the highest penetrations of wind generation in any liberalised energy-only market, and therefore provides important lessons for other jurisdictions contemplating similar transitions. South Australia set new records set for extreme wholesale electricity pricing in June and July 2016. These events are of particular pertinence to understanding transitional issues associated with decarbonisation of the electricity sector with renewable technologies.

The context for the developments in the South Australian energy market can be understood in terms of several intersecting factors, including the increasing penetration of renewable energy generation, the rapid and unprecedented changes in the gas market, the level of market concentration, and the degree of system-scale planning.

Key findings of this report are as follows:

- The rise in **renewable energy generation** in South Australia since 2006 has impacted in several ways. The addition of renewable generation capacity and its heightened impact on merit order dispatch system has contributed to downward pressure on wholesale prices, which have declined in real terms since FY08, while also generating net Large-scale Renewable Energy Target certificates to the annual value of about \$120 million. In so doing, it has contributed to decisions to close brown coal generators, and increased South Australian dependence on imports and, in times of low wind output, gas. As one of the largest stations on the National Electricity Market (NEM) in terms of its capacity relative to regional demand, the closure of Northern Power Station in May, 2016, has tightened the demand-supply settings with consequent increases in wholesale prices.
- The eastern Australian **gas market** has undergone rapid changes as it adapts to issues associated with a three-fold increase in production to fulfill international export contracts. Because of its high proportion of gas generation, South Australian wholesale electricity prices are particularly sensitive to price movements in the gas market. The closing of Northern has increased its reliance on gas, especially in times of low wind.
- Concerns about the exercise of **market power** in South Australia have been evident in relatively low levels of liquidity in its market, and there is demonstrable evidence for the extraction of monopoly rents by some generators, arguably through physical and economic withholding of capacity. On top of pressure from rising gas market prices, electricity price increases were exacerbated by an unprecedented rise in gas generation margins as revealed by record high spark spread values. Since the closure of Northern, South Australia is the most concentrated region in the NEM, and this was further exacerbated by the earlier decision taken by Engie to effectively mothball its Pelican Point Power Station and on-sell its contracted supply into the gas market. We estimate the Herfindahl–Hirschman Index of the South Australia market at 3000–3400 (depending on the status of Pelican Point) making it *severely concentrated*, and well above the value of 2000 that the ACCC uses to flag competition issues.
- A **disorderly sequence** of station withdrawals and mothballing and interconnector upgrades in South Australia has clearly impacted the way the prices have unfolded. In particular, the closure of Northern, in May, prior to completion of interconnector upgrades has severely accentuated the price impacts, and enhanced the conditions for the exercise of market power. At a broader level, the policies that have opened up of the east coast gas market to international gas pricing have had disproportionate impact in South Australia, and flag tensions between national gas market developments and the Renewable Energy Target.

The interdependence of these issues suggests remedies that can be used to avert future crises in South Australia and elsewhere. For example, new investment in alternatives to gas-peaking designed to alleviate pressure on gas demand in times of low-wind output, such

as storage, concentrating solar thermal or enhanced interchange capacity, can be used to address price volatility concerns, and, with appropriate regulation, competition issues.

Further, we note that the South Australian experience provides a salutary forewarning of the havoc that can ensue from lack of coordinated system planning in times of transition. It bears on the question of disorderly exit that will be faced in all markets requiring substantial decarbonisation, in part because of the scale of the fossil power stations that are displaced. We note there are already calls for fundamentally new market design rules, including the introduction of a parallel capacity market, which we argue is not yet warranted, although attention to details such as the level of the market cap price, or even the need for one, should remain open.

While we don't make specific recommendations in this report, we note that in order to avert future crises in South Australia, as well as other Australian jurisdictions on their pathway to decarbonisation, particular attention should be given to the:

- potential for market power to be concentrated as a consequence of transitional arrangements,
- diversification of low emission generation and storage portfolios,
- alignment of national energy policy across related sectors, specifically the intersection of gas export markets and the Renewable Energy Target, and
- coordinated system planning of transitional arrangements.

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1 Introduction

Over the past decade, the South Australian electricity market has undergone a dramatic change in supply mix. Prior to 2005, energy generation needs were predominantly sourced from gas and brown coal power stations. Since then, over 1500 MW of wind capacity and 680 MW of rooftop solar has been installed. At the same time, 770 MW of brown coal capacity has exited the market. These developments have substantially reduced the greenhouse gas emissions from South Australian electrical power generation¹.

Recent steep increases, especially in the winter of 2016, has seen record high prices set, in what some have called the *South Australian “energy crisis”*. Recent media attention has focused on the relationship between the high level of penetration of renewable energy and the energy crisis. Much of the reporting has been framed in ideological terms - renewables are either ‘good’ or ‘bad’ - with little reference to quantitative analysis of the dynamics of the wholesale electricity market or movements in associated markets such as gas.

This report explores the evolving dynamics in the electricity market in South Australia and how it is impacting wholesale prices. In particular, the report focuses on the growth in renewable energy generation, the impact of a changing gas market and market power concentration and competition issues.

This report is structured as follows: firstly, we describe the physical characteristics of the South Australian energy market and how participants manage financial risks associated with the wholesale market. In the second section we explore the current dynamics that set wholesale prices. The third section looks at options that may help mitigate the issues identified in part two. A summary and discussion follows.

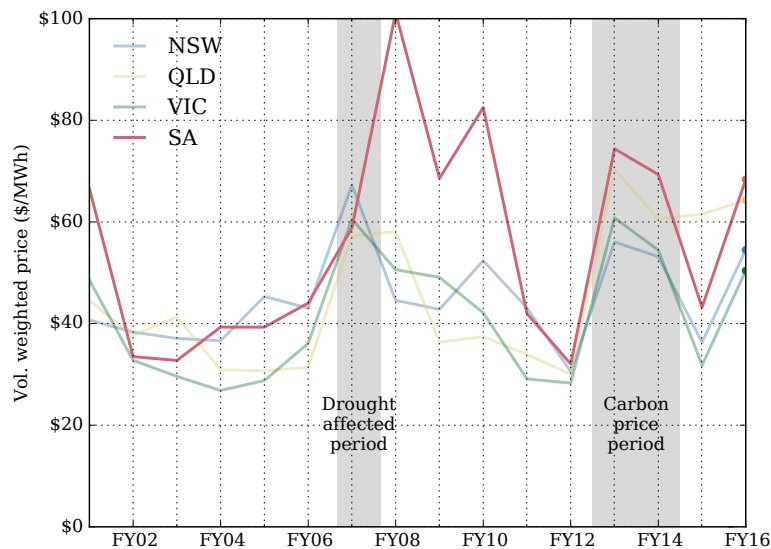


Figure 1: Annual volume weighted prices by financial year across the four mainland regions that form part of the National Electricity Market (NEM). Note that prices vary by region and across time, with South Australia typically at the upper end of the regional range, especially in the period between FY08 and FY10². In FY13 and FY14, carbon pricing applied at the generation level elevated wholesale prices by an average of about \$20/MWh³. Prices across all regions were elevated in FY07, at the height of the Millennium Drought, due to constrained output from hydro power and some thermal plant.

¹The extent to which the reduction in the emissions intensity production has been matched by consumption remains somewhat unclear, as South Australian power imports have increased over the last decade (see Figure 2). The emissions intensity of generation in the NEM is 0.8 tonnes CO₂/MWh compared to the current average of about 0.5 tonnes CO₂/MWh for South Australia (as of mid 2016). The outsourcing of supply to other generators in the NEM has therefore offset some of the reductions from local supply.

²FY10 refers to the financial year ending June 30th, 2010

³The relatively low carbon intensity of South Australia generation means carbon pricing only added around \$14/MWh to wholesale prices.

2 The South Australian electricity market

2.1 Demand

South Australia is part of Australia's National Electricity Market (NEM) that supplies electricity to the four eastern seaboard states of Australia and to South Australia, all of which are interconnected⁴. Over 300 generators are physically linked across the NEM and dispatched 194 TWh of energy to almost 10 million customers in the FY15^{5,6}.

South Australia is the smallest of the four mainland NEM regions. Its annual electrical energy consumption for FY15 was 13,006 GWh⁷ and increased to 13,421 GWh in FY16. The median annual demand in South Australia is typically between 1300 and 1400 MW.

Across all four mainland NEM regions the demand for electricity varies significantly on daily, weekly and seasonal time-frames. Across the NEM the annual peak in demand typically occurs in the afternoon or early evening in summer. The highest demand recorded in South Australia was 3402.06 MW on January 31st, 2011⁸.

Of all the NEM regions, South Australia has the 'peakiest' demand profile, and suffers the greatest seasonal variability, reflecting the relatively high proportion of load from domestic customers. In FY14 the ratio of maximum demand to minimum demand was 4.54. This compares with 2.72 for New South Wales, 2.22 for Queensland and 3.16 for Victoria. Similarly daily fluctuations in South Australian demand can be as large as 250%⁹.

In the years prior to 2011, South Australian peak demand grew at an average annual rate of about 3.5%¹⁰, but has not grown since. The peak in the summer of FY16 was some

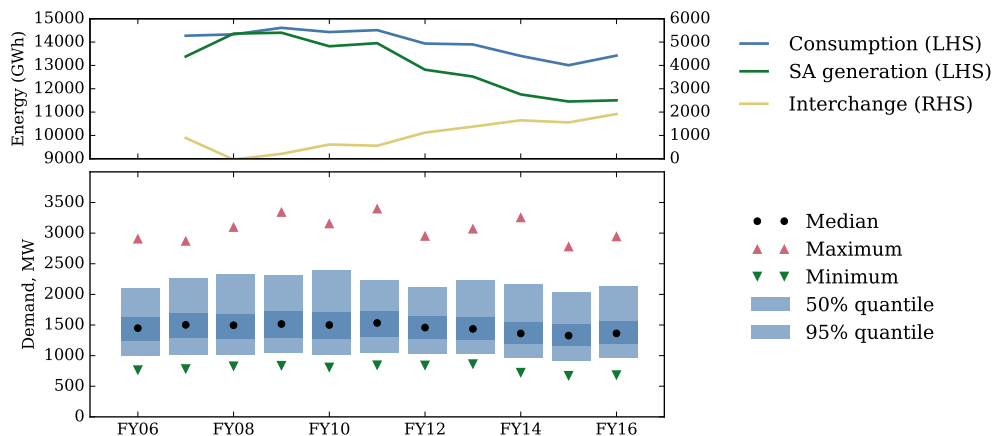


Figure 2: Annual consumption and demand in South Australia, FY06-FY16. Top panel shows the South Australian electrical energy consumption, local generation and net imports via the interconnectors (Heywood and Murraylink) into Victoria in GWh, with imports referenced by units on the right hand side. The bottom panel shows key characteristics of demand in terms of the annual minimum, median and maximum, all in MW by financial year.

⁴The NEM comprises five interconnected regions including the mainland states of South Australia (SA1), Victoria (VIC1), New South Wales (NSW1) and Queensland (QLD1) as well as the island state of Tasmania (TAS1).

⁵In Australia, the financial year ends on the 30th June. Here we refer to financial years using the two last digits of the year in which it ends. Thus FY16 refers to the period 2015/07/01 through 2016/06/30. Because this report was prepared in early August of 2016, the financial year provides the most up-to date basis for annual trend comparisons. Unless otherwise noted, annual comparisons on a financial year basis are implied.

⁶AER 2015, page 24,

⁷AEMO 2015, Table 13.

⁸On January 31st, 2011, the total of demand and non-scheduled generation in South Australia reached 3429.76 MW

⁹For example, on December 20th, 2009 demand increased from 1072 MW at 3am to 2674.77 MW at 5pm.

¹⁰Peak demand in FY02 was 2499 MW compared to 3402 MW in FY11.

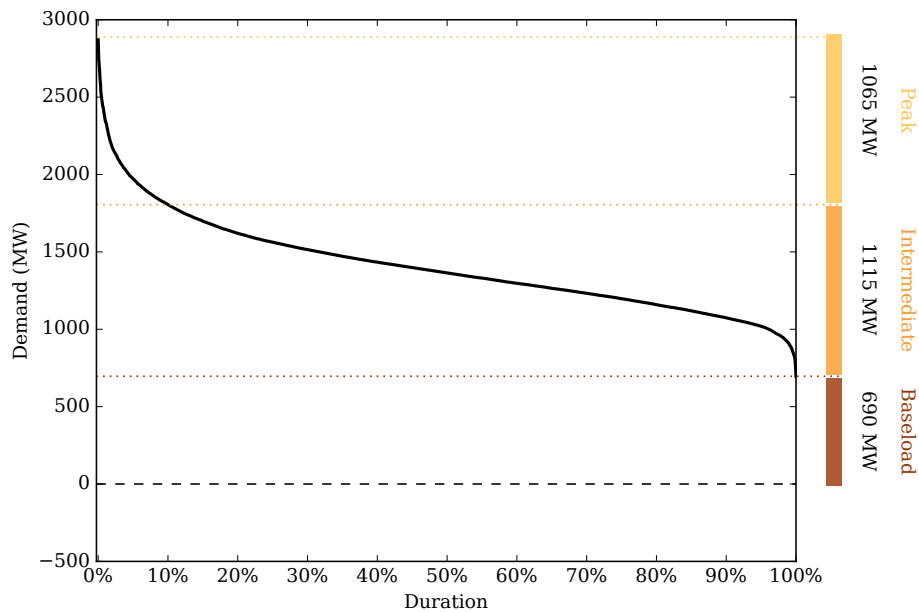


Figure 3: Load duration curve for South Australia in FY16. In this Figure the ‘baseload’ is the permanent minimum load that system is required to deliver, in this case at 690MW. For illustrative purposes we set the peaking capacity at the 10% duration level somewhat arbitrarily. As illustrated in Figure 4, for systems with significant renewable generation the *net load duration curve* is arguably a better guide to the estimating the ‘baseload’.

13.3% below the record 2011 peak¹¹. Figure 2 illustrates the annual demand characteristics for South Australia since FY06.

Load duration curves are used to characterize electricity system demand. By ranking system demand in descending order, load duration curves illustrate the proportion of time that demand exceeds a certain level. Load duration curves can be used to estimate the generation mix in terms of the peaking, intermediate or mid-merit and baseload plant required to meet demand. Figure 3 shows the load duration curve for South Australia for FY16, showing that about 1065 MW of capacity was required to serve the top 10% demand periods¹².

The *net load duration curve* is a variant of the load duration curve that accounts for the impact of renewable energy generation. Subtracting generation types such as wind that are classified as either *semi-scheduled* or *non-scheduled* from the load curve sets the amount of required *scheduled* capacity. For South Australia this is essentially the load duration curve net of wind generation (Figure 4). Note that net of wind, the additional capacity required to meet the top 10% demand periods in South Australia for FY16 was 1215 MW. The net load duration curve shows that for about 33 hours (or 0.4%) in FY16 wind supplied in excess of South Australian demand. An important consequence is that South Australia now has no real need for conventional *baseload* generation. It does however require some 3000 MW of flexible capacity, including intermediate, peaking and interchange, to ensure demand is served in times of low wind output.

2.2 Generation and interconnection

Historically, South Australian energy supply has been dominated by a roughly equal mix of gas- and brown coal-fired power, but that has changed dramatically over the last decade

¹¹The FY16 peak at 2948.38 MW, occurred on December 17th, 2015 just after 5pm. Then the total of demand and non-scheduled generation reached 3006.36 MW

¹²The load duration curves for all mainland NEM regions for FY16 are shown in Appendix A

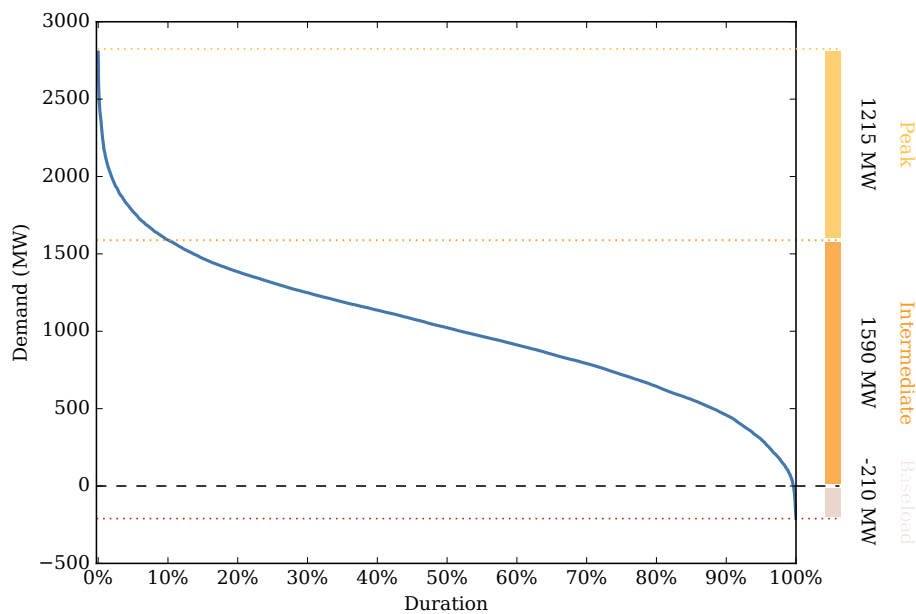


Figure 4: *Net load duration curve for South Australia for FY16.* The net load duration curve uses demand less wind generation. Note that the curve intersects 0 demand at about 99.6% duration, implying total wind dispatch exceeded total demand for 33 hours of the year. Also note that the the highest net load increment (2805 MW) is only 65 MW lower than the highest load increment (2870 MW) and the greater intermediate and peaking (and/or interchange) capacity than implied by the load duration curve shown in Figure 3

(Figure 6). The high proportion of gas has long distinguished South Australia from the other mainland regions which are much more dominated by coal¹³. The generation capacity in South Australia currently includes approximately 660 MW of Combined Cycle Gas Turbine (CCGT) and 1280 MW of thermal (steam) gas. A further 770 MW of Open Cycle Gas Turbine (OCGT) capacity and diesel generation provides for peak power requirements. As outlined below (Section 2.3), South Australian brown coal capacity declined in 2012 from 770 MW to 530 MW then to 0 in May 2016 (see Figure 5).

Some 1575 MW of wind capacity will soon have been added to the South Australian generation system, largely in response to the national Renewable Energy Target (RET)¹⁴. Consequently, in times of high wind dispatch and low regional demand, wind can exceed South Australian demand, with excess production exported to Victoria. The *capacity factor* for South Australian wind output in FY16 was 33.5%. Recent years have also seen the installation of an estimated 680 MW of rooftop solar systems to July 2016¹⁵. For FY16, some 41.3% of South Australia's electricity generation came from wind and solar.

South Australia is connected to the NEM via two transmissions links into Victoria. The Heywood interconnector has a rated capacity of 460 MW, and is currently being upgraded to 650 MW¹⁶. The Murraylink interconnector has a rated capacity of 220 MW. As indicated in Figure 6, South Australia is a net-importer of energy.

¹³In FY16, coal supplied 86.4% of New South Wales, 83.9% of Queensland and 86.3% of Victorian grid generation.

¹⁴At the time of writing, the Hornsdale Wind Farm with a 270 MW capacity was still under construction

¹⁵Clean Energy Regulator 2016.

¹⁶ElectraNet expected upgrades to the Heywood interconnector are expected to be complete in July 2016, see Electranet Factsheet:Heywood Interconnector

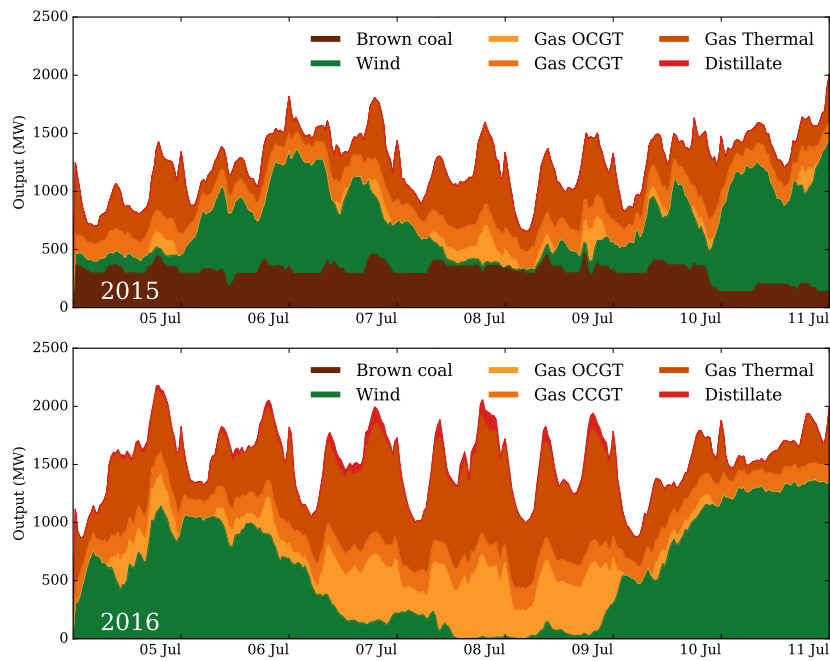


Figure 5: Illustrative South Australian dispatch profiles for the week 4th through 11th July, in 2015 (top panel) and 2016 (bottom panel). Brown is coal dispatch, red is liquid fuels, orange is gas and green is wind, in MW. The events of July 7th, 2016, are discussed in further detail in Section 3.3.2. Then wind output was very low, interchange with Victoria was constrained, and the combination of gas dispatch (1970 MW) and liquids fuels (150 MW) exceed 2000 MW. The impact of the combination of the removal of brown coal, constrained interconnection and low wind output is particularly evident in terms of the differences in gas dispatch at around 3:00 am on July 8th across the two years (around 1000 MW in 2016 as opposed to 350 MW for the corresponding time in 2015).

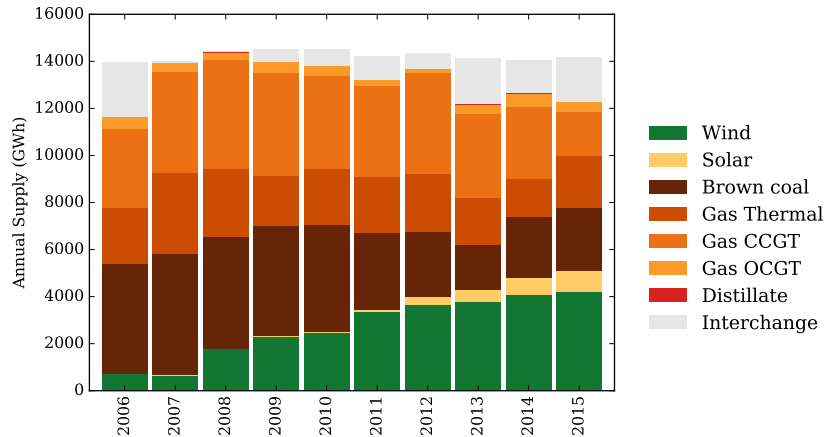


Figure 6: South Australian annual electricity supply by generation type in GWh by calendar year from 2006 to 2015. Interchange refers to the net energy import via exchange with Victoria.

2.3 Brown coal withdrawal

As of May 2016, South Australia has had no remaining local coal generation. The 240 MW Playford B Power Station was mothballed in 2012. For a few years prior to mothballing it was primarily operated in the summer. Along with the 530 MW Northern Power Station, Playford B was permanently closed on May 9th 2016. Prior to closure, Northern’s capacity was equal to approximately 15% of South Australian peak demand, and 40% of median demand, although in the last few years of its operation, Northern was generating at capacity factor around only 56%. In terms of a *regional basis size*, expressed as the ratio of power plant capacity to regional demand, Northern was one of the largest stations dispatching in the NEM, comparable on a regional basis size to the 2200 MW Loy Yang A Power Station in Victoria¹⁷ Figures 6 and 8 show the change in capacity and supply in South Australia as a result the progressive withdrawal of brown coal generators.

Of particular relevance to the discussion in this paper are the changes in supply mix that followed the closure of Northern. With under three months of data at hand at the time of preparation of this report, it is clearly too early for a comprehensive statement. Moreover, the supply mix through the winter months following closure of Northern have been impacted by constraints on the Heywood interconnector into Victoria, due to upgrade work. Nevertheless, as shown in Figures 9 and 10, the short term trends are illuminating, with the June–July period of 2016 characterised by a significant increase in gas and wind output, some distillate and a reduction in interchange, compared to the equivalent period in the previous year. Without the interruptions due to the interconnector upgrade it would be expected that 2016 winter interchange imports would have been higher, mitigating some of the increased demand for gas, and likely all of demand for distillate.

¹⁷See table 4 in Appendix A for a comparison of different coal generators in the NEM

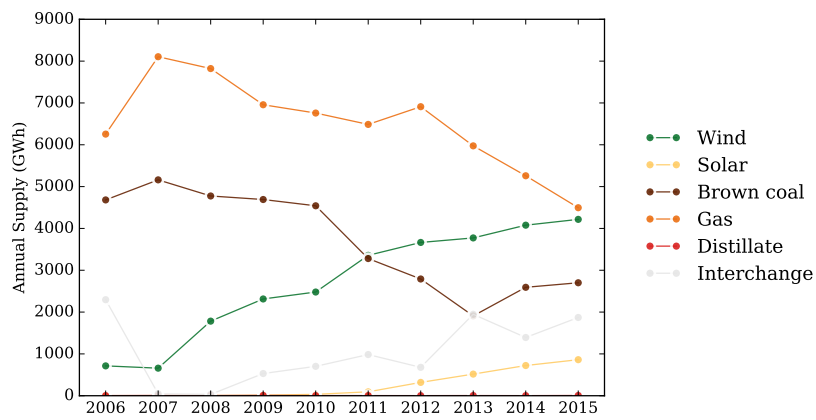


Figure 7: South Australian supply trends by generation fuel type in GWh by calendar year from 2006 to 2016. The three gas generation types are aggregated in this figure.

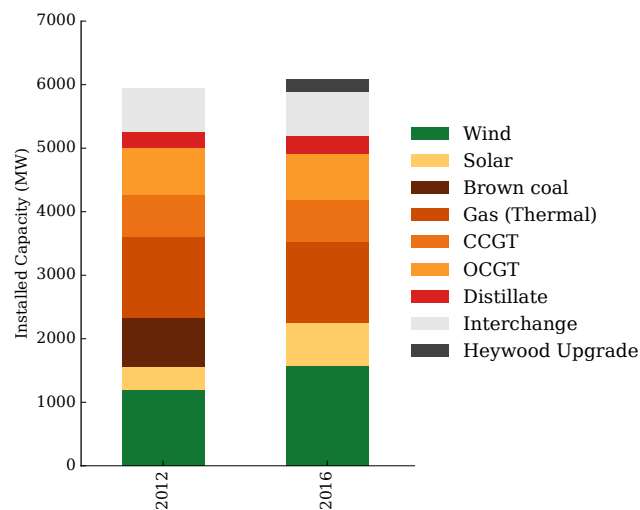


Figure 8: South Australian capacity by generation type in MW, as of January 2012 (left) and July 2016 (right). Note that the Heywood interconnector upgrade was scheduled for completion in July 2016¹⁶.

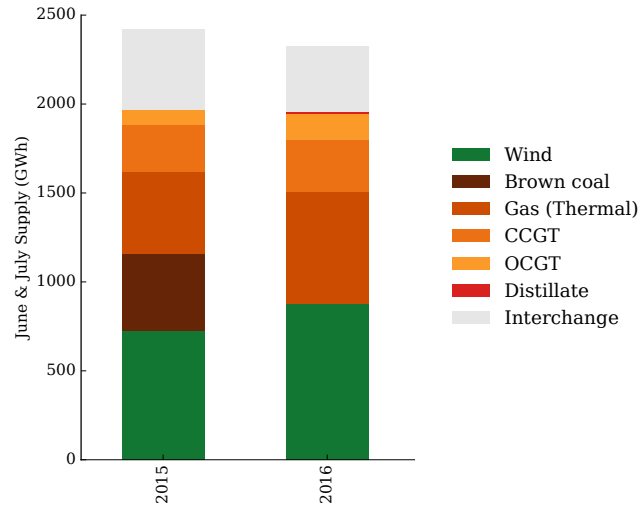


Figure 9: Comparison of South Australian annual electricity supply in GWh by generation type for June & July in both 2015 and 2016. For 2016 this period corresponds to the first nine weeks following closure of South Australia’s then only remaining brown coal generator, the Northern Power Station. The absence of brown coal in the 2016 period has been accommodated by an increase in wind and thermal gas output and, to a lesser extent, OCGT and distillate. Imports were down slightly in the 2016 period, largely because ongoing upgrade work on the Heywood interconnector significantly limited interchange capacity in the 2016 period.

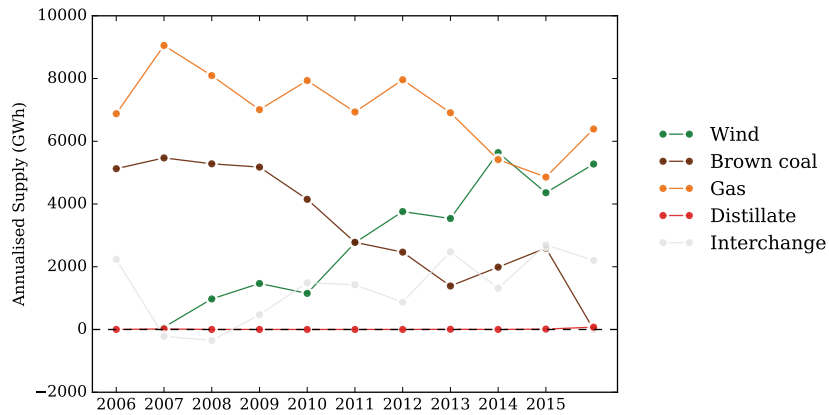


Figure 10: Combined June and July supply trends for South Australia by generation fuel type, from 2006 to 2016. The values have been annualised to yearly GWh equivalents, and the three gas generation types aggregated. This period illustrates the changes in the makeup of the energy supply during 2016, following the closure of the Northern Power Station on May 9th 2016, namely an increase in gas and wind output, some distillate and a reduction in interchange forced by the interconnector upgrades.

2.4 Wholesale prices

Across the NEM, electricity wholesale prices are set on a regional basis¹⁸. Prices vary between regions and over time in response to a range of factors. For example, as shown in Figure 1, wholesale prices in FY13 and FY14 were elevated because carbon pricing was implemented at the generation level. In FY07, during the later stages of the Millennium Drought, prices rose steeply as reduced output from hydro and some thermal power stations tightened supply.

Historically, South Australian wholesale prices have tended to be at the upper end of the regional price range. In the period FY08 through FY10 South Australian prices were significantly above other regions. Since then, South Australian prices have been similar to those in Queensland but higher than New South Wales and Victoria (e.g. Figure 1). Somewhat elevated prices in South Australia in comparison to other states are to be expected given its high proportion of gas powered generation, and the relative *peakiness* of its demand¹⁹, as described earlier.

2.4.1 Energy, capacity and volatility

The NEM is a gross pool, *energy-only market*. As such, generators only receive revenue for the electricity output sent to market, as typically measured in units of megawatt hours (MWh). This is distinct from other market designs, such as parallel markets that include both energy and *capacity payments* in their design, such as operates in Western Australia.

In energy-only markets, both variable costs, such as fuel, and fixed costs, such as capacity, need to be recovered in revenue based on energy output only. To allow generators to recover fixed capital costs energy-only markets allow prices to rise to extreme values during periods of scarcity. Extreme pricing during such *scarcity events* incentivises investment in peak generation, such as OCGT and distillate capacity. In addition to ensuring capacity is available for dispatch during rare high-demand occasions and that generators can recover fixed costs, scarcity events also signal large consumers to contract supply.

In most energy-only markets the prices are capped at the *market price cap*²⁰, set at a value many times higher than the short-run marginal cost of production of even the most expensive generators. At \$14,000/MWh, the NEM's price cap is currently one of the highest in the world²¹, about 300 times the volume weighted price average of around \$50/MWh. The market also has a floor price of -\$1000/MWh. With prices frequently reaching the price cap during periods of scarcity, the NEM is one of the most volatile commodity markets in the world²². As discussed in Section 2.4.3, while price volatility in South Australia is significantly than in both Victoria and New South Wales, it is similar to Queensland.

Figure 11 shows the wholesale price for South Australia over FY16, while Figure 12 shows the number of scarcity and negative price events on an annualised basis since FY05. In FY16, price spikes occurred throughout the year and were responsible for a significant proportion of value traded through the market, with the top-priced 5% trading intervals responsible for over 30% of market turnover in South Australia.

2.4.2 Hedging and contracting

The extreme range in wholesale pricing and the consequent price volatility exposes market participants to significant risk. Persistent low prices reduce generator earnings, potentially to levels below the long-run marginal cost of production. In contrast, frequent scarcity events can drive energy costs for exposed customers to unsustainable levels. Consequently, market participants use a variety of strategies to manage wholesale pricing risks, including vertical integration, hedging on the *Exchange Traded Future* (ETF) markets and *Over-The-Counter* (OTC) bi-lateral contracts.

¹⁸Wholesale or *spot* prices, are set on a 30-minute settlement period basis as the average of six 5-minute dispatch interval prices. They are distinct from the contract prices discussed in a subsequent section.

¹⁹AER 2015.

²⁰also known as the Value of Loss Load (VoLL)

²¹The NEM price cap has increased over time, from \$10,000 prior to 2010, to \$14,000 today

²²Simshauser 2010a.

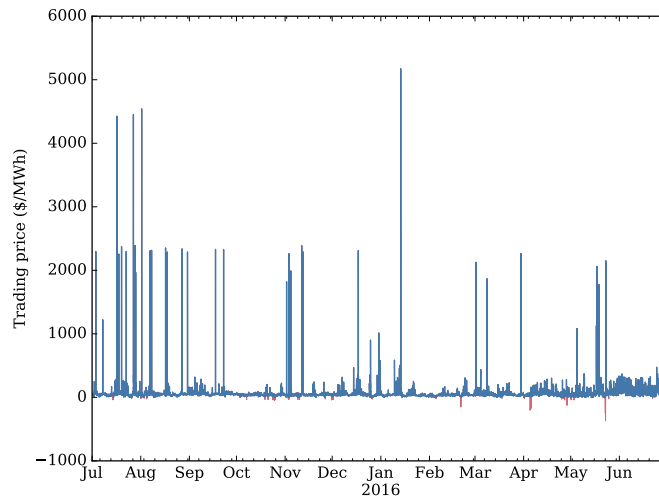


Figure 11: Wholesale settlement prices for South Australia in FY16, with negative prices shown in red. Note the anomalous number of scarcity events with prices in the range \$2300-2400/MWh. As described in Section 3.3.2 such prices typically indicate one 5-minute dispatch price spike to the market cap in the corresponding 30-minute *settlement period*.

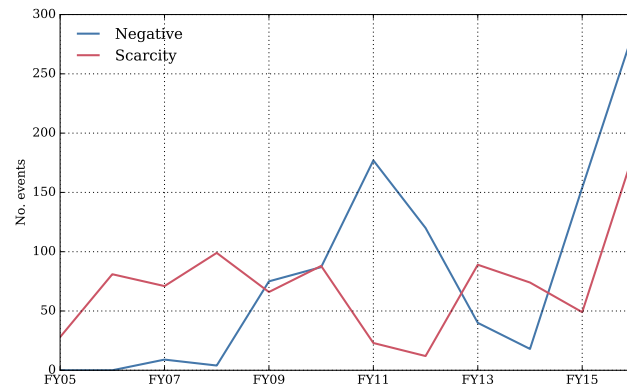


Figure 12: Number of scarcity or high-price (red) and negative (blue) settlement period (30-minute) events in South Australia since FY05, on a financial year basis. *Scarcity events* are defined here as settlement periods yielding prices greater than the standard cap contract price of \$300/MWh. In FY16, there were 288 negative price settlement events and 185 scarcity events, reflecting a recent increase in the volatility in the South Australian market. Not shown is the first month of FY17, July 2016, when there were 14 negative and 236 scarcity events, implying volatility is continuing to track at record high levels.

In FY15, on a NEM-wide basis, 84% of hedging contracts were traded as futures (ETFs) through the Australian Stock Exchange (ASX) with the remainder traded as bilateral OTCs²³. The volume of trades is a measure of *market liquidity*, and was 3.0 times the native demand in FY15, down from 3.6 in FY14²⁴. The liquidity varies across regions. In FY15, the most actively traded state in the ETF market was Queensland at 37% of volume, followed by New South Wales at 35%, Victoria at 26% and South Australia at 2%²⁵. The volume of futures trading in South Australia is the lowest relative to underlying demand and wholesale market turnover²⁶.

As described in detail by AEMC²⁷ and the Productivity Commission²⁸, there are three standard contract types²⁹:

- *Base load futures* covering a full 24 hour period on each day over a specified calendar quarter.
- *Peak load futures* covering the period from 7:00am to 10:00pm on working weekdays in a quarter.
- *\$300 cap futures* that allow retailers and other consumers to manage the risk of high wholesale prices in a similar manner to an OTC cap with a strike price of \$300/MWh.

Figure 13 illustrates how a retailer might manage the risk associated with their customer load using a variety of these products.

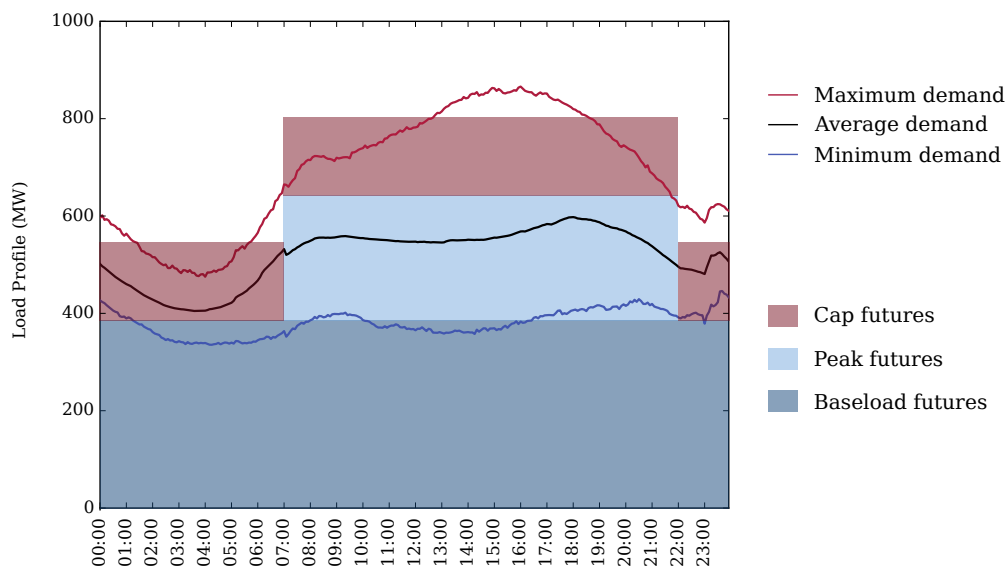


Figure 13: Illustrative risk management approach, using a combination of contract types. The lines represent a hypothetical load profile, and the shaded areas represent the coverage provided by different hedging products in a hypothetical contract scenario. By combining the three standard contract types generators can ensure a more certain revenue stream while retailers can hedge exposure to extreme price spikes.

²³ AER 2015.

²⁴ AFMA 2015.

²⁵ AFMA 2015.

²⁶ The illiquid nature of the futures markets is reflective of the fact the underlying markets are not perfectly competitive (See Anderson, Hu, and Winchester 2007)

²⁷ AEMC 2012; Productivity Commission 2013.

²⁸ Productivity Commission 2013, Appendix C.

²⁹ The baseload and peak contracts are 'swap contracts', while the \$300 'cap' are effectively 'options contracts' as applied in other commodity markets.

Typically, retailers might contract 90-100% of their load one year in advance, declining to 60%-70% two years out³⁰. As such, exposure to wholesale market prices is typically limited. However, wholesale prices affect contract prices, and the extent of coverage varies over time. Recent media reports suggest some large electricity consumers in South Australia including Arrium are either currently under-contracted or un-contracted, and therefore have significant exposure to the wholesale market³¹.

Swap contracts

Baseload and peak futures allow both generators and consumers to manage wholesale price volatility in a similar manner to swap contracts. With swap contracts, the counter-parties effectively 'swap' the payment/receipt of the NEM spot price for the payment/receipt of the contracted strike price³². Swaps are also known as *contracts for differences*.

Cap contracts

Retailers ordinarily enter into *cap contracts* to mitigate exposure to high wholesale electricity price events. The standard cap contract price offering limits exposure to a strike price of \$300/MWh, for which the purchaser makes a contract payment. As such, cap contracts are a form of insurance, where the excess is the strike price and the premium is the cap contract payment. The AEMC describes cap contracts as follows³³:

The parties agree on a strike price for the cap. If the spot price exceeds this strike price, the seller of the cap (usually a generator) must pay the difference to the buyer of the cap (usually a retailer). A common strike price for a cap contract is \$300/MWh. In return, the buyer of the cap will pay the seller a fee, which provides the generator with an extra source of revenue. Buying such a cap helps protect the retailer from high spot prices.

Figure 14 illustrates how cap contracts operate, and the financial transfers that result. In effect, payments are made to the contracted generator for all trading intervals of the year, even if the generator is not dispatching. Such hedging arrangements, and the associated payments, effectively signal the value of capacity in an energy-only market. In July 2016, the price of South Australian Q1 2017 cap contracts was about \$30/MWh³⁴, effectively valuing capacity in South Australia at approximately \$260,000 per MW per year.

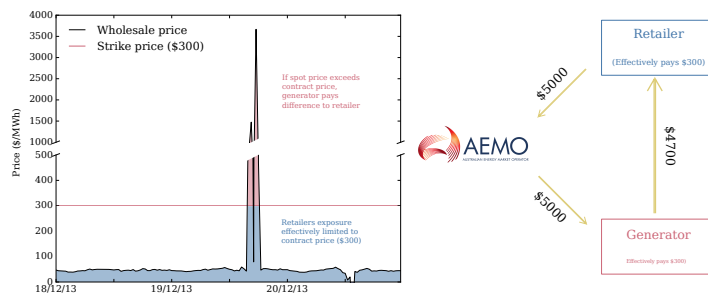


Figure 14: Illustrative cap contract (right), with a strike price of \$300. The contract payment limits exposure of the buyer (typically a retailer, or large energy consumer), to price spikes exceeding the strike price. The financial transfers (right) for a cap contract with a strike price of \$300 and a wholesale spot price of \$5000/MWh are shown at the right.

³⁰see Appendix C from more details on contract coverage

³¹Potter 2016.

³²AEMC 2012, page 11.

³³AEMC 2012, Table 2.1, page 10.

³⁴see the 'Electricity Report 19-25 June', from the Australian Energy Regulator (AER)

2.4.3 Regional comparison

The way participants use these hedging strategies provides an insight into the way the market values *capacity* as opposed to *energy*. For a fully hedged participant, the cost of energy is expressed as the volume weighted price subject to a price ceiling at the strike price, which we term the *hedged volume weighted price*. Contrawise, the cost of capacity can be expressed in terms of the number of scarcity events or price increments in excess of the strike price³⁵.

Figure 15 compares, in the top panel, the number of scarcity events (i.e., a measure of the way the market values capacity) and, in the bottom panel, the hedged volume weighted price with a ceiling of \$300/MWh, across the four mainland NEM regions. The bottom panel shows that while the market has tended to value energy in South Australia slightly higher than in other regions, the values broadly align across all regions. This contrasts significantly with Figure 1 which shows more dramatic price divergence between the regions when scarcity events are included in the price, especially in FY08 through FY10. The top panel in Figure 15 illustrates that since FY12 the way the market values capacity in South Australia has been comparable to, and sometimes lower than, Queensland, but much higher than either New South Wales and Victoria. Note that FY11 and FY12 were characterized by very low scarcity across all regions, especially in comparison to the preceding drought-affected period.

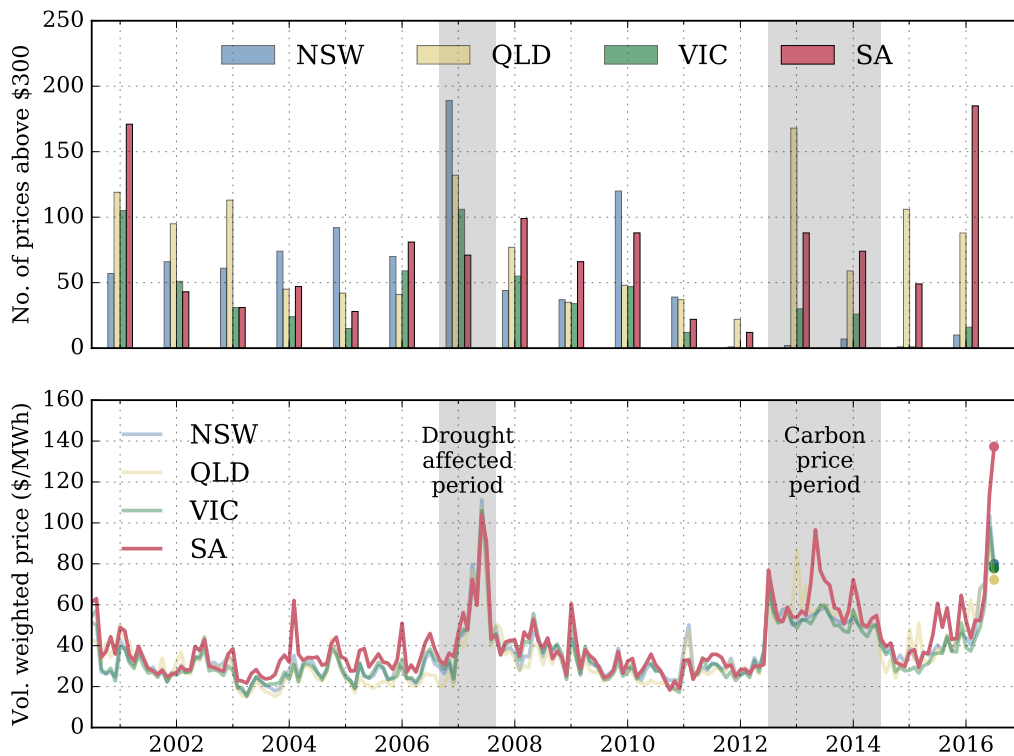


Figure 15: Wholesale prices for the four main NEM regions since the beginning of FY01 financial year. Top panel shows the number of settlement price events above \$300/MWh by financial year. Bottom panel shows the monthly *hedged volume weighted price* with prices capped at \$300/MWh. Refer to Figure 1 for a comparison with the *unhedged volume weighted prices*

³⁵In practice, the cost of cap contracts will track the frequency or expected frequency of scarcity events.

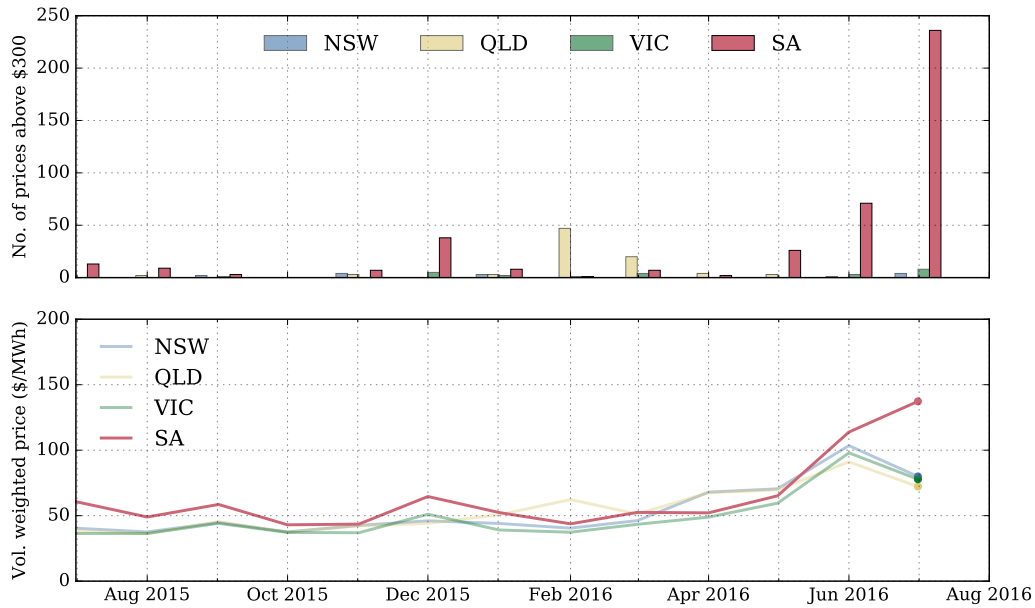


Figure 16: Monthly averaged prices for the four main NEM regions since the start of FY16. Top panel shows the number of scarcity events above \$300/MWh per month. Bottom panel shows the monthly volume weighted price, for prices below \$300/MWh. Note that the scarcity events are tallied by settlement periods (i.e. on the half hour trading period basis), and include many more 5-minute dispatch period scarcity events. For example, along with the 236 settlement scarcity events in South Australia in July 2016, there were also 1315 dispatch scarcity events.

Figure 16 shows both the number of scarcity events (prices at \$300/MWh or higher) and the *hedged volume weighted price* in South Australia has diverged significantly from the other regions since May, 2016. The 236 settlement period scarcity events in July 2016 in South Australia set an all-time monthly record for the NEM³⁶. The divergence followed the closure of the Northern Power Station on May 9th. The scale of the divergence is made apparent by the fact that the number of scarcity events in South Australia in July 2016 exceeded the total of 185 for the entire FY16 (Table 1).

Table 1: Number of high price settlement period events in each of the four mainland NEM regions for financial years FY10 through FY16, and July 2016.

	>\$300 events				>\$1000 events			
	NSW	QLD	SA	VIC	NSW	QLD	SA	VIC
2010	120	48	88	47	69	42	73	39
2011	39	37	23	13	31	22	16	10
2012	1	22	12	0	1	5	11	0
2013	2	168	89	30	0	47	71	18
2014	7	59	74	26	4	43	33	13
2015	1	106	49	1	1	90	37	0
2016	10	88	185	16	6	64	48	8
July 2016	4	0	236	8	0	0	53	0
Total	184	528	756	141	112	313	342	88

³⁶Other notable tallies for monthly settlement scarcity events include, in order: 228 in Tasmania in April 2016, 136 in Queensland in January 2013, 71 in South Australia in June 2016, 55 in South Australia in January 2009, and 47 in Queensland in February 2016

3 Current drivers of wholesale power price dynamics

In the 2015 *State of the Energy Market*³⁷, the Australian Energy Regulator identified a range of factors that contribute to the elevated prices and price volatility in South Australia, including:

- high reliance of gas
- concentrated generator ownership
- anomalous generator rebidding behaviour
- thermal plant withdrawals
- limited import capability
- high levels of wind capacity

The *State of the Energy Market*³⁸ report emphasised the particular role of wind in contributing to price swings. In this section, we detail how these factors have impacted South Australian wholesale prices in recent times, focusing on the role of the renewable energy dispatch, gas pricing, competition and the “*missing money problem*”.

3.1 Renewable energy generation

Renewable Energy Certificates and Feed-in Tariffs

In Australia, large-scale renewable energy is supported by the Large-scale Renewable Energy Target (LRET). Under the LRET scheme, retailers and other energy users are required to purchase Large-scale Generation Certificates (LGC) based on their energy consumption. LGC’s are purchased from eligible generators, such as wind farms. LGC’s provide eligible projects with a revenue stream additional to the market value of the dispatched power, thereby facilitating with their financing. The cost of the LGC’s are passed on the consumers. Some large energy users are exempt, or partially exempt, from the LRET due to trade exposure³⁹.

Small-scale renewable energy systems such as rooftop solar photovoltaics (PV) are supported by the Small-scale Renewable Energy Scheme (SRES) and state based feed-in tariffs (FiT). The SRES is similar to the LRET in that retailers are obliged to purchase certificates. However unlike the LRET, the SRES payments are deemed upfront and function as a *capital cost subsidy*. In contrast, FiTs provide a revenue stream based on energy generated or exported to the grid.

For FY16 the total pass-through cost for the South Australian feed-in tariff schemes was approximately \$127 million⁴⁰. As a result of the closure of the 16 c/kWh scheme in 2016, this annual cost is forecast to decrease by nearly \$30 million to \$98 million for FY17. The SRES and LRET scheme add approximately \$80 million to the aggregate cost of electricity in South Australia.

Due to both excellent wind resources and supportive planning policy, South Australia has received a disproportionately large share of the new wind capacity installed to meet the LRET. In calendar year 2015, South Australia generated over a quarter of the certificates produced nationally, despite contributing only 6% of national electricity consumption. With demand for the certificates based on consumption across all jurisdictions, South Australia effectively exported approximately 3 million LGCs in 2015, worth around \$120 million at historic certificate prices⁴¹. The LRET scheme means that in effect the other mainland

³⁷AER 2015, page 51.

³⁸AER 2015, page 51.

³⁹This includes the South Australian operations of Arrium Steel, in Port Pirie, which is reportedly exposed to the increasing energy prices, Potter (2016)

⁴⁰SA Power Networks 2016, page 99.

⁴¹While the LGC price is currently about \$86, most of LGCs will have been contracted at much lower prices.

Table 2: Contribution of renewable energy support schemes to retail electricity tariffs

	Cost (c/kWh)
LRET	0.59
SRES	0.48
FiT	1.71
TOTAL	2.78

states are subsidizing South Australia’s renewable energy portfolio, to the value of more than \$1 billion per decade.

In total, in 2015 the renewable energy support schemes added 2.78 c/kWh to the cost of electricity⁴² (see table 2). This compares with a typical retail cost of 29 c/kWh, of which about 13 c/kWh is estimated to be from competitive components of the bill such as wholesale and retail costs.

Renewables and merit-order dispatch pricing

It is now well documented that the addition of significant renewable energy capacity into liberalised electricity markets puts downward pressure on wholesale market prices. This phenomenon, known as the *merit order effect*, is demonstrably impacting electricity wholesale prices in Australia and abroad.

There are several reasons such an effect might manifest. The addition of both supply and competition will naturally put downward pressure on wholesale prices. Without compensating withdrawals, the addition of more capacity into market will increase the *capacity overhang*, or the amount of capacity available above peak demand. Indeed this phenomenon is not particular to renewable energy - adding any new fossil or nuclear generation capacity will affect the market in a similar way, and is one of the reasons *power purchase agreements* (PPAs) are needed to finance new capacity build. Conversely, as supply is reduced (for example, with the closure of a coal plant), prices would be expected to increase. Appendix D provides a further discussion on this dynamic, known as the *capacity cycle*. In part because of the long lead times for new build, energy-only markets are specifically designed with high sensitivity to the supply-demand balance as implemented by *merit order dispatch pricing* (see Figure 17).

As first described by Jensen and Skytte (2002)⁴⁴, because of its negligible short-run marginal cost, the impact of renewable energy generation on energy-only markets prices can be particularly acute and can lead to wholesale prices of zero or lower⁴⁵. Figure 17

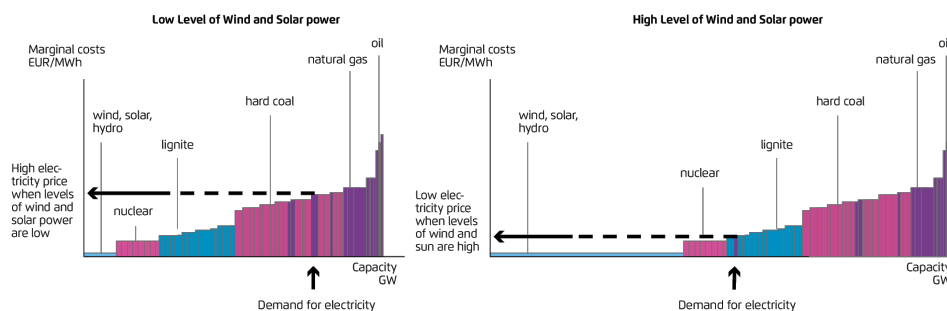


Figure 17: Impact of wind and solar, both low short-run marginal cost technology, on a hypothetical supply curve⁴³. In merit order dispatch pricing participants generally offer capacity at the short-run marginal cost, resulting in a supply curve like the ones shown here. Prices are set by the least cost supply needed to meet demand.

⁴²AEMC 2015a, page 161.

⁴³Agora Energiewende 2013.

⁴⁴Jensen and Skytte 2002.

⁴⁵Edenhofer et al. 2013.

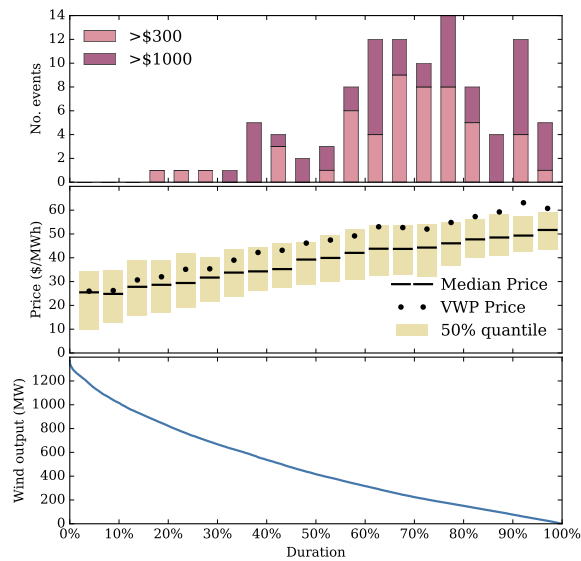


Figure 18: Relationship between wind generation, wholesale prices and volatility for South Australia for calendar year 2015. Top panel shows the scarcity events as a function of duration of wind duration. Middle panel shows hedged volume weighted prices as a function of wind duration. Bottom panel shows the wind duration curve. Note the absence of scarcity events when wind generation exceeded about 900 MW.

coal dispatch⁵⁵. The net price impacts of generator dispatch in 2015 therefore depended primarily on the balance of wind and gas dispatch as well as interchange with Victoria.

The case seems compelling that up until 2016, increasing wind penetration did suppress wholesale prices in South Australia, especially on a real (or inflation-adjusted) basis. For example, factoring out the effects of carbon pricing, which added about \$14/MWh to FY13 and FY14 prices in South Australia, nominal wholesale prices in the period FY11-FY15 were significantly lower than in the period FY07-FY10 (see Figure 1)⁵⁶.

Any significant ongoing reduction in wholesale prices due to increasing penetration of renewables, through either the merit order effect and/or increased capacity overhang, necessarily has implications for the profitability of the existing generation fleet. As much was tacitly acknowledged by Alinta Energy⁵⁷ in announcing the closure its Flinders Operations including the Northern Power Station⁵⁸:

The decline in demand for energy, as households have become more efficient and the number of industrial customers has declined, combined with policy settings designed to support significant growth in renewable energy generation have together had the effect of causing a significant oversupply of power available to South Australia. We now believe that there can be no expectation that the Flinders business can return to profitability.

⁵⁵For the months of June and July in 2015, we find a correlation between wholesale price and coal dispatch of -\$5/100 MW only slightly less so than wind at -\$6/100 MW, whereas gas and imports were positively correlated (at \$19 and \$12/100 MW, respectively). For the corresponding period in 2016, following the closure of Northern, the correlations for wind and gas steepened significantly (to -\$17 and \$33/100 MW, respectively). In 2016, interconnector constraints meant high price events were not well correlated with interconnector flow.

⁵⁶It should be also noted that factors other than wind, such as the Millennium Drought, have also significantly impacted price trends over the period FY07 through FY10.

⁵⁷<https://alintaenergy.com.au/about-us/news/flinders-operations-announcement>

⁵⁸Alinta Energy's Flinders Operations included the Northern and Playford B Power Stations in Port Augusta and the Leigh Creek Coal Mine. In their announcement on 11/06/2015, Alinta indicated the operation would not continue beyond March 2018 and may terminate earlier but not before March 2016. As it transpired, Northern was closed on May 9th, 2016.

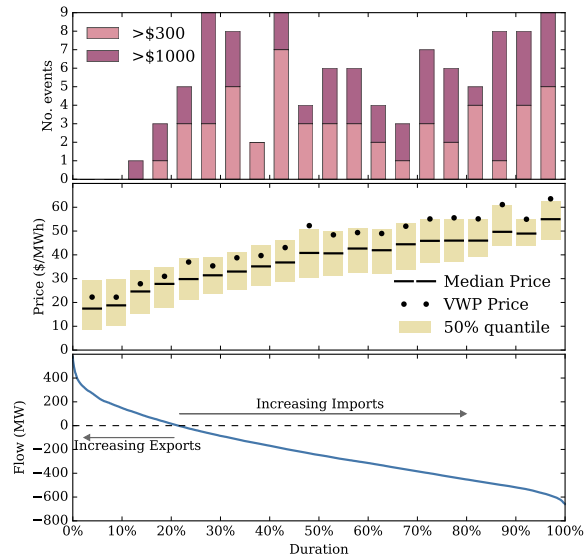


Figure 19: Relationship between interconnector flow, prices and scarcity events for South Australia for the 2015 calendar year. Top panel shows the scarcity events as a function of flow duration. Middle panel shows hedged volume weighted prices as a function of flow duration. Bottom panel shows the *flow duration curve* with positive flows for exports, and negative flows for imports. Note the lack of scarcity events for export greater than about 100 MW which correlate with periods when wind dispatch was close to or exceeding South Australian demand.

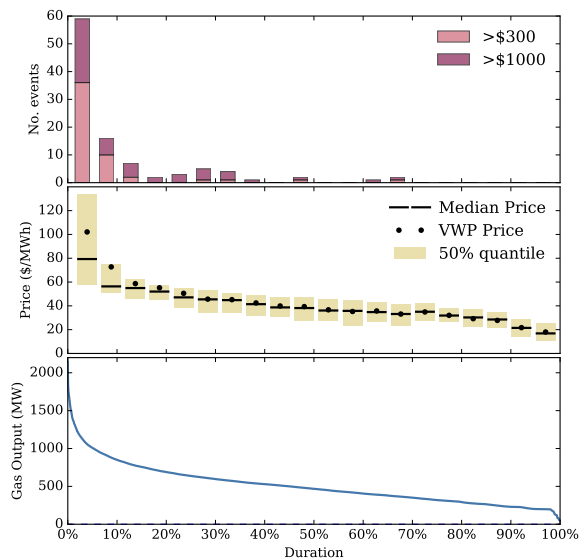


Figure 20: Relationship between gas generation, wholesale prices and volatility for South Australia for calendar year 2015. Top panel shows the scarcity events as a function of duration of gas duration. Middle panel shows hedged volume weighted prices as a function of gas duration. Bottom panel shows the gas duration curve. Note that scarcity events are highly skewed to gas flow durations less than about 15%, corresponding to dispatch of greater than about 1800 MW.

The issues for the profitability of the remaining generation following such closure is discussed further in Section 3.3.2, *Resource adequacy and the “missing money” problem*.

One factor clearly contributing to price rises in South Australia following the closure of Northern has been the increased demand for gas in times of low wind dispatch⁵⁹. The long-term price consequence of wind generation in South Australia must factor in the extent it has impacted the decision to close Northern, and the associated contribution to price increases.

However, as part of any transition in the electricity sector, driven by imperatives such as decarbonisation, abrupt shifts in generation will necessarily accompany closure of power stations. When stations with large regional basis size close, like Northern, the tightening of the demand-supply balance will inevitably create significant upward pressure on price, as is consistent with the notion of the *capacity cycle* alluded to earlier, and discussed in further detail in the Appendix. As discussed later, the price impacts of such closure can be mitigated to some extent by more coordinated transitional arrangements than evidenced during the winter 2016 “energy crisis” in South Australia.

Reliability and Forecasting Issues

Demand forecasting is an important component of electricity system operation. The Australian Energy Market Operator (AEMO) produces forecasts of demand on various time scales, ranging from five minutes ahead, to years ahead, to facilitate optimal scheduling of resources, and planning for shortfalls or new capacity requirements that may occur in the future.

Similar to demand, the reliability of renewable energy forecasting is an important part of system operation. Forecasting allows capacity requirements to be prepared hours in advance, for times of low renewable dispatch. AEMO’s forecasts for wind generation in South Australia are particularly reliable. For example at the half-hour ahead, they are more slightly more accurate than its demand forecasts (see Figure 21). The key point is that while renewable generation varies through time, the variation can be forecast to a standard that does not impose undue risk, at least relative to other forecasts AEMO necessarily undertakes.

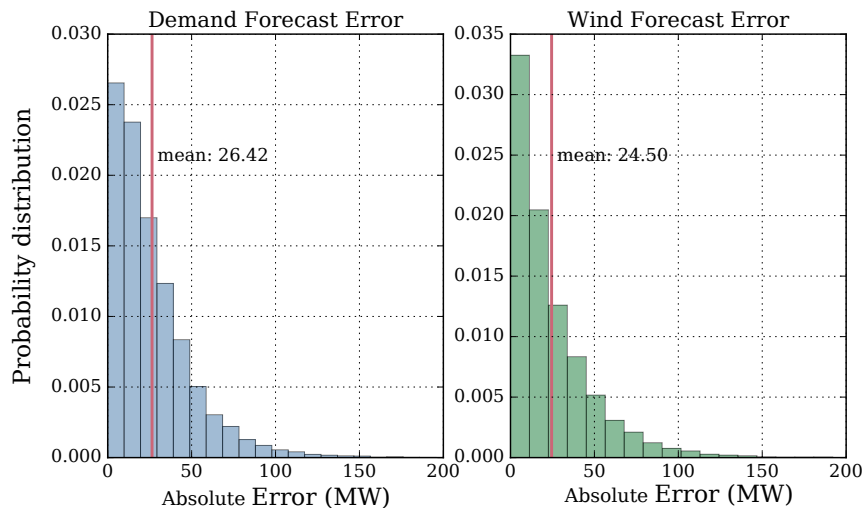


Figure 21: Normalised density distribution of absolute error, measured in MW, of AEMO forecasts at the half hour interval into the future for calendar year 2015. The South Australian demand forecast error is shown on the left and wind dispatch forecast error is on the right.

⁵⁹Another factors is the limited interchange capacity due to ongoing interconnector upgrades that have also meant significantly more gas and distillate have been dispatched in the winter of 2016 than would have been expected under normal interchange operating conditions

Very large unanticipated changes in both supply and demand do occur occasionally (see Figure 22), and the implications of a trip of a large coal generator is much greater than that of the maximum likely forecast error for either demand or wind generation. Managing such large unexpected deviations is challenging, however the system is designed to deal with it and the availability of supply during such unpredictable events is managed through reliability provisions.

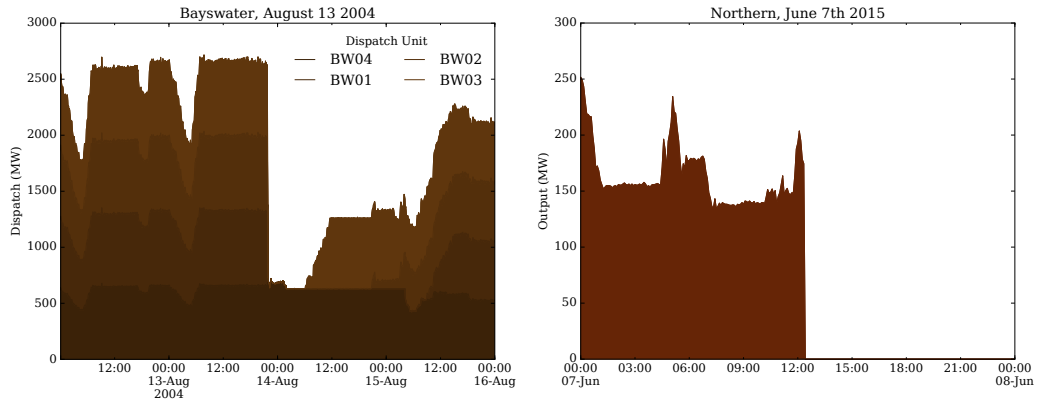


Figure 22: Examples of large unexpected changes in generation output. The left shows an incident when three units at Bayswater (New South Wales) tripped off on the 13th August, 2004, dropping almost 2000 MW in 10 minutes. The right shows a tripping event at Northern on June 7th June, 2015, dropping almost 170 MW.

3.2 Gas prices

In early 2015, exports of Liquid Natural Gas (LNG) commenced in Queensland, for the first time exposing the east-coast gas market to international pricing. The linkage to exports markets has transformed Australia's gas industry, dramatically increasing demand for gas across eastern and south-eastern Australia⁶⁰.

AEMO has forecast that the development of LNG export capacity will almost triple the total demand for gas, with consumption from the export terminals projected to be over 1,400 petajoules (PJ) per annum by 2020. Consumption is forecast to grow at the average annual rate of 32.5% to 2020 and then remain flat⁶¹ (see fig 23).

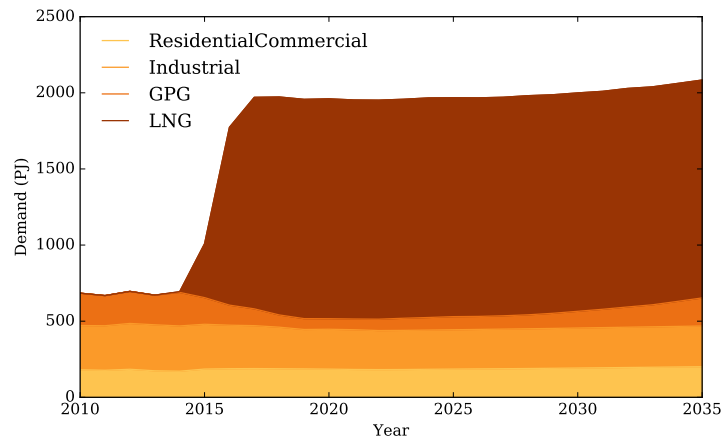


Figure 23: Historical and projected gas demand, data from AEMO, data from AEMO 2016a

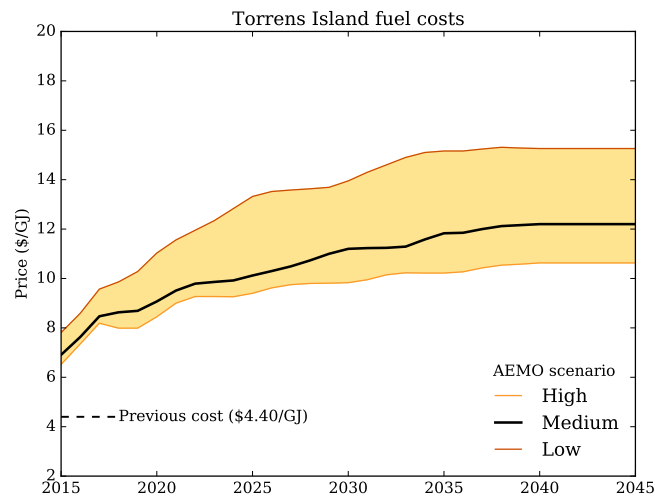


Figure 24: Fuel cost projections for Torrens Island, compared with previous years. Data from AEMO National Transmission Network Development Plan (NTNPD) 2015 and NTNPD 2013

⁶⁰ AEMO 2016a, page 17.

⁶¹ AEMO 2016a, page 14.

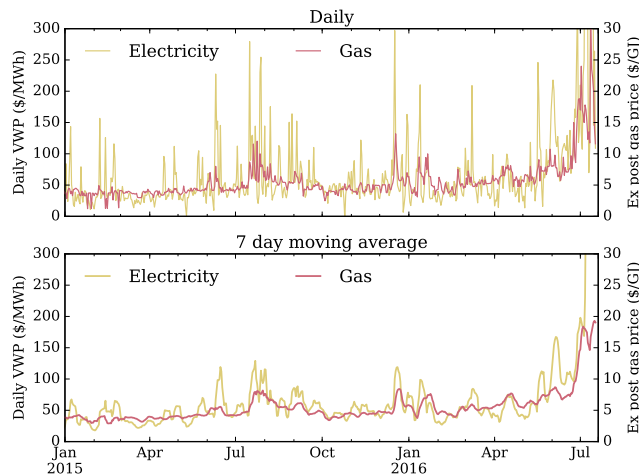


Figure 25: Relationship between South Australian electricity prices (daily volume weighted prices) and daily gas spot prices (ex-post acrshortsttm prices)

Impact on Gas Powered Generation

The dramatic increase in demand has increased prices across eastern Australia. This is reflected in both the Short Term Trading Market⁶² (STTM) and contract prices and impacts the cost of gas powered generation (GPG) in two ways.

Firstly, in the short term, expiry of existing gas supply agreements exposes new contracts to rising domestic gas prices.⁶³ This is reflected in the reported fuel costs for Torrens Island. AEMO's 2013 National Transmission Network Development Plan (NTNDP) indicated Torrens Island fuel costs at approximately \$4.40/GJ⁶⁴. By 2015 the NTNDP⁶⁵ was projecting 2016 prices for Torrens Island would be in the range \$7.35–\$8.59/GJ for 2016, an increase of more than 70% over three years.

Secondly, because electricity consumption and production is typically not 100% contracted, gas generators will normally source some small fraction of their supply at the STTM spot price, which also represents the opportunity cost of selling the gas on the STTM. Given that gas generation generally sets the wholesale electricity price in South Australia, and the strong market linkages, it is unsurprising that price movements on the two markets is strongly correlated as shown in Figure 25⁶⁶.

For the 2015 calendar year, South Australian generators burned approximately 47.5 PJ of gas⁶⁷. This is relatively low, compared with the previous five years. At these consumption rates, the increases in gas price reported by the NTNDP are estimated to have added \$140–\$200 million to the annual cost of electricity supply in South Australia, between 2013 and 2016⁶⁸.

As noted earlier, gas generation in South Australia has increased since the closure of the Northern Power Station. It is worth noting that the scale of increase is small compared to other factors driving demand in the gas market. To date, the output of Northern has only partially been replaced by gas-fired generation. Should all of Northern's output be replaced by gas, the additional demand would be approximately 13 PJ, which represents less than 1% of annual demand projected from gas export contracts.

⁶²The STTM is an 'overs and unders' market (sometimes called balancing market), where non contracted gas is traded

⁶³AEMO 2016a, page 10.

⁶⁴<http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions>

⁶⁵<http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions>

⁶⁶The correlation coefficient for the 7 day moving average is 0.86

⁶⁷see Table 5 in Appendix E for outputs, heat rates and gas consumption by generator

⁶⁸See Appendix E for heat rates and production assumed

3.3 Competition

Competition has long been identified as an issue in the South Australian electricity sector, with a number of studies commenting on it. Carbon and Energy Markets has prepared reports on both market power in the South Australian electricity market⁶⁹ and the interaction of generation of renewable energy and market power⁷⁰.

The first of these reports discussed evidence for the exercise of market power in South Australia, and its implications for prices, concluding that the prices in the period analysed (2008 – 2011) reflected exercise of market power, rather than just scarcity. The second report concluded that the extent to which wind reduced market prices in South Australia was mitigated due to the exercise of market power. A report prepared for the South Australian Council of Social Services⁷¹ in 2013 also examined 18 different high priced events in detail, concluding that generators deliberately sought to maximise profit in times tight supply.

In 2013, the AEMC's review on generator market power in the NEM more broadly AEMC 2013 reported that South Australia was potentially '*prone to inhibiting efficient investment and promoting the likelihood of substantial market power*'. The Commission accepted that there are some circumstances in which substantial market power could be exercised in the NEM, and specifically identified the potential for substantial market power to be exercised in South Australia.

Since the AEMC review in 2013, the closure of brown coal generation make the question of competition in South Australia worth revisiting. This section of the report builds on previous analysis of competition in South Australia. We begin by describing measures of market concentration and the potential for exercise of market power, including the *Herfindahl–Hirschman Index* and the *Pivotal Supplier Index*. We then discuss evidence for the exercise of market power in South Australia in terms of both cost price margins and specific instances where there is a *prima facie* case that supply has been either withheld or withdrawn with intent to impact market price.

3.3.1 Measures of concentration

Herfindahl–Hirschman Index (HHI)

The Herfindahl-Hirschman index (HHI) is a commonly used measure of market concentration reported and is reported annually by the AER in the 'State of the Energy' market report⁷². The HHI is a static metric, calculated by summing the squares of the percentage market shares for all firms participating in a market.

An HHI value of 10,000 is equivalent to a 100% share, and represents complete monopoly. An HHI value of 2000 is used by the Australian Competition and Consumer Commission (ACCC) to flag competition concerns⁷³, while the U.S Department of Justice considers markets to *unconcentrated* at below 1500, *moderately concentrated* at 1500-2500 and *highly concentrated* at 2500⁷⁴.

Perhaps more apposite to energy markets are the UK's Office of Gas and Electricity Markets (OFGEM) guidelines. The OFGEM regards an HHI exceeding 1000 as *concentrated* and above 2000 as *very concentrated*⁷⁵. With a current HHI value of 1243⁷⁶, the OFGEM considers the UK wholesale electricity market *somewhat concentrated*.

The most recent AER 'State of the Energy' market report shows annual HHI trends for each of the four mainland states from FY09 through FY15⁷⁷. AER's HHI estimates lie in the range 1700-2450. In the three years FY12 through FY15, the estimates for South Australia, New South Wales and Victoria have all been in the range 1700-2000, while Queensland has been in the range 2300-2450.

Based on the trading rights indicated in the latest AER report⁷⁸, we estimate the HHI for South

⁶⁹Bruce Mountain 2012.

⁷⁰Mountain 2013.

⁷¹Carnegie Mellon University 2016.

⁷²AER 2015, page 60.

⁷³ACCC 2008, page 37.

⁷⁴U.S. Department of Justice and Federal Trade Commission 2010, pages 18 and 19.

⁷⁵OFGEM 2015, page 37.

⁷⁶OFGEM 2015, page 64.

⁷⁷AER 2015, Figure 1.29.

⁷⁸AER 2015, pages 40 to 41.

Australia at the end of FY2016 was about 2900-3000 with all registered plants available⁷⁹. The value is substantially higher than AER has reported in the previous years reflecting the concentration of market share that followed the closure of Northern Power Station.

Of further relevance to current state of market concentration in South Australia has been the effective *mothballing* of Engie’s 480 MW Pelican Point CCGT station for much of 2016⁸⁰. With Pelican Point effectively mothballed, we estimate South Australia’s HHI at of the end of FY16 to have been 3300-3400, making it an *exceedingly concentrated* market.

Pivotal Supply Index (PSI)

Indices such as the HHI based on static measures such as installed capacity do not fully account for system dynamics through the exercise of transient market power. Several alternative measures have been proposed to capture such transients, including the ‘*Pivotal Supplier Index*’ (PSI) used here⁸¹. The PSI calculates the frequency that some quantity from a given supplier is *required* to serve market demand. Under such conditions, the required participant becomes a *monopoly supplier* of the portion of demand that cannot otherwise be served⁸².

The PSI is calculated by subtracting the total amount of generation made available by other generators and interconnector import limits from the total demand. If a generator is required to meet to the remaining demand, it is said to be ‘pivotal’⁸³. When operating in pivotal mode, a market participant is in a position to extract *monopoly rents*⁸⁴, as distinct from scarcity rents (see Section 3.3.2 for further discussion).

Figure 26 below illustrates the pivotal supplier index for the four mainland NEM regions. This is based on the dynamic available generation and available import capacity, and the largest firm capacity controlled by a single participant. In South Australia, Victoria, and New South Wales, the pivotal supplier is AGL, while in Queensland it is Stanwell Corporation. As shown in Figure 26, the PSI index for South Australia is typically much higher than for Queensland and Victoria, and mostly higher than New South Wales. Increases in New South Wales PSI in early 2016 are attributed to scheduled plant outages of non-AGL coal plants, combined with the AGL’s relatively large capacity holdings⁸⁵.

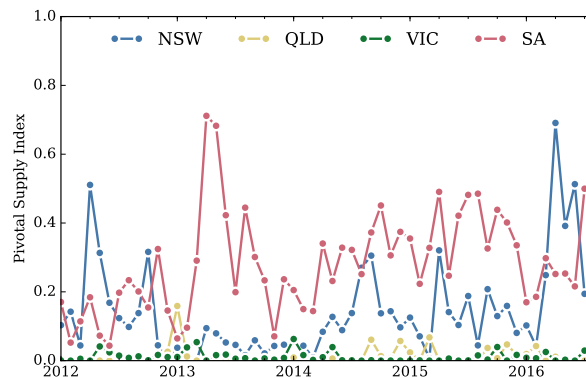


Figure 26: Monthly Pivotal Supply Index for the mainland NEM regions since the beginning of 2012

⁷⁹Note that in our calculation of the current HHI we follow AER’s methodology of de-rating the wind capacity, based on it’s contribution to peak demand

⁸⁰Pelican Point has been offline for much of the 2016 winter because Engie is believed to have on-sold its contracted gas to the LNG export market. At the request of the South Australia’s Energy Minister Engie was bought back online in July to help avert the ongoing *energy crisis*. Pelican Point is one of the most efficient CCGT gas stations on the NEM, with a thermal efficiency of 48%, much higher than AGL’s Torrens Island A (30%) and Torrens Island B (32%), that have continued to provide by far the largest proportion of gas output in South Australia

⁸¹The AER also uses the related ‘Residual Supply Index’.

⁸²Bushnell, Knittel, and Wolak 1999, p. 7.

⁸³A pivotal participant is *essential* to serving market demand, even considering all demand and imports available from the rest of the market.

⁸⁴Profits earned that result from the monopolist restricting supply to raise price without fear of entry by rivals

⁸⁵AGL’s New South Wales holdings include Liddell and Bayswater, which have a combined capacity of 4640 MW

3.3.2 Evidence of exercise of market power

Price-Cost Margins

The fundamental measure of the degree of market power exercised is the price-cost margin⁸⁶. In this Section we look at the price-cost margin for gas generation in South Australia. An important metric for gas generator margins is the ‘spark spread’ - the theoretical margin that a generator receives for a unit of power after deducting fuel costs. All other costs including operation and maintenance, as well as financing and capital costs, must be recovered from the spark spread margin.

The top panel in Figure 27 illustrates the spark spread for gas generation in South Australia using standard assumptions⁸⁷. The theoretical margins for Queensland, New South Wales and South Australia are compared in the bottom panel, since February 2015. Prior to June 2016, the spark spread was relative constant and broadly consistent across the three regions, with the exception of the late summer and early autumn period when Queensland spark spread was elevated by a factor of about four. Prior to June 2016, the South Australian spark spread averaged \$17.34. That value is comparable to the spark spread in other, completely unrelated jurisdictions such as the United Kingdom⁸⁸

Since mid June 2016, there has been significant increase in the South Australian spark spread. On an individual generator basis, accounting for differences in their thermal efficiencies, the margins are estimated to have increased by between \$40/MWh (Torrens Island) and \$60/MWh (Quarantine)⁸⁹. During this period, volume of sales also increased. Such behaviour contrasts with typical price volume trade-offs expected in efficient markets.

This is broadly consistent with an exercise of market power and extraction of monopoly rents. Monopoly rents are distinctly different to scarcity rents, which is discussed further in Section 3.3.2. Assuming difference in margins is indeed a result of market power, approximately \$40–\$60 million of turnover since the beginning of June can be attributed to monopolistic behaviour.

The disparities between input costs of generation, including capital recovery requirements, and prices documented above shares remarkably similarities to an example described in the U.S. Federal Energy Regulation Commission investigation into Enron and the Californian power crisis⁹⁰. The U.S. investigation found that high prices during the Californian power crisis were more due to economic withholding by a pivotal generator than to market fundamentals⁹¹.

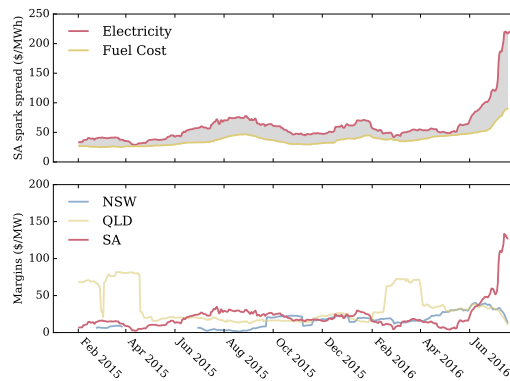


Figure 27: Spark spread for a typical Combined Cycle Gas Turbine with an assumed thermal efficiency of 50%, and a comparison of margins between regions

⁸⁶Bushnell, Knittel, and Wolak 1999.

⁸⁷As is standard, we use a thermal efficiency of 50% to calculate the spark spread. This allows comparison across jurisdictions and is *not* intended to represent the spark spread for a particular generator. A 50% efficiency is relatively high for gas generation stations in the NEM. For example, In South Australia thermal efficiencies range from 30% for Torrens Island to 48% for Pelican Point. At % Tallawarra in New South Wales has the best efficiency of any gas plant on the NEM.

⁸⁸See UK’s spark spread at <https://www.ofgem.gov.uk/chart/spark-and-dark-spreads-gb>

⁸⁹While Pelican Point was not generating during this period, the theoretical margins of the higher efficiency plant would have been approximately \$70/MWh)

⁹⁰Federal Energy Regulatory Commission 2003b, See Economic Withholding of Generation and Inflated Bidding During May to October 2000, Chapter VI page 45.

⁹¹Similar to both the UK and South Australian margins above, the FERC determined capital recovery requirement for a hypothetical new power project is between \$16 and \$19/MWh

Anomalous market behavior and ‘Gaming’

In 2003, the U.S. Federal Energy Regulatory Commission (FERC) investigated the trading strategies employed by Enron and companies in a report on *Price manipulation in western markets*⁹² investigating the Californian energy crisis in 2000 and 2001. In Part II of its report, the Commission specifically looked into two particular practices of concern: ‘gaming’ and ‘anomalous market behavior’⁹³ defining them as:

‘Gaming’ is taking unfair advantage of the rules and procedures .. to the detriment of the efficiency of, and consumers in .. the markets. ‘Gaming’ may also include taking undue advantage of other conditions that may affect the availability of transmission and generation capacity.

‘Anomalous market behavior’ is behavior that departs significantly from the normal behavior in competitive markets that do not require continuing regulation or as behavior leading to unusual or unexplained market outcomes.

FERC, 2003

The Federal Energy Regulatory Commission cites evidence for such behaviour include:

- withholding of generation capacity under circumstances in which it would normally be offered in a competitive market;
- unexplained or unusual redeclarations of availability by generators;
- unusual trades or transactions;
- pricing and bidding patterns that are inconsistent with prevailing supply and demand conditions, e.g., prices and bids that appear consistently excessive for or otherwise inconsistent with such conditions; and
- unusual activity or circumstances relating to imports from or exports to other markets or exchanges.

In this section we investigate instances of ‘gaming’ and ‘anomalous market behavior’. Firstly, we look at the Angaston Power Station which physically withheld generation, taking advantage of rules around the calculation of settlement prices. Secondly, we look at evidence for the Torrens Island Power Station economically withholding generation capacity, and rebidding behaviour.

Physical withholding of generation

The Angaston power station is a 50 MW diesel power plant located in the Barossa Valley in South Australia. Snowy Hydro owns the plant and has the trading rights for its output⁹⁴.

Until recently, Angaston was a *non-scheduled* generator⁹⁵. Non-scheduled generators do not directly participate in the co-ordinated central dispatch process operated by AEMO. As such they are treated as *price takers*, receiving the market price for production. While non-scheduled generators do not directly participate in the central dispatch process that results in price setting, they can influence price outcomes, because they impact the amount of scheduled generation needed to meet demand.

Importantly, because non-scheduled generators operate outside the market dispatch process, scheduled participants can’t necessarily react to rapid changes in non-scheduled output⁹⁶. When the supply-demand balance is tight, rapid and unanticipated reductions in non-scheduled output can force prices to the market price cap. This issue has been identified by the AER⁹⁷ who stated ‘strategic changes to the output of non-scheduled plant [can trigger] a series of high prices.’

Due to a quirk of the market settlement process, extreme prices can be used by generators to increase revenues. There are two relevant prices for NEM dispatch and settlement - the *dispatch price* calculated on a 5-minute basis and the *settlement price* calculated on a 30-minute basis. The 5-minute dispatch prices are determined by the dispatch process, and the half hourly settlement prices are the simple average of the dispatch prices. Settlement prices are the prices that are paid by

⁹²Federal Energy Regulatory Commission 2003a.

⁹³Federal Energy Regulatory Commission 2003b.

⁹⁴AER 2015, page 41 in.

⁹⁵Angaston was re-classified as a *scheduled* generator at the end of May 2016

⁹⁶AER 2015, page 51 in.

⁹⁷AER 2015, page 51 in.

customers to generators. Note that the Australian Energy Market Commission (AEMC) is currently reviewing the rules around 5-minute dispatch and 30-minute settlement pricing⁹⁸.

One 5-minute price spike to \$14,000 substantially increases the price for the entire trading interval to above \$2,000 even if prices are negligible for all other dispatch intervals in the settlement period. Generators can take advantage of this by withdrawing capacity for a single interval, and then boosting output for the remainder of the half hour trading interval. Indications of strategic and systematic withdrawal by Angaston in such a manner is illustrated in Figures 28 and 29. For the morning period between 7.30 am and 10:00 am on September 4th, 2015, the withdrawal Angaston's output for one dispatch interval in each of five successive settlement intervals corresponded to increases in the dispatch price by about \$170/MWh.

We have identified 41 separate occasions in 2015 when withdrawal of Angaston's output corresponded to increases in dispatch prices, with some driving the price to the market price cap (Figure 29). Without those price spikes, the value of settlement price turnover would have been reduced by \$30.3 million⁹⁹.

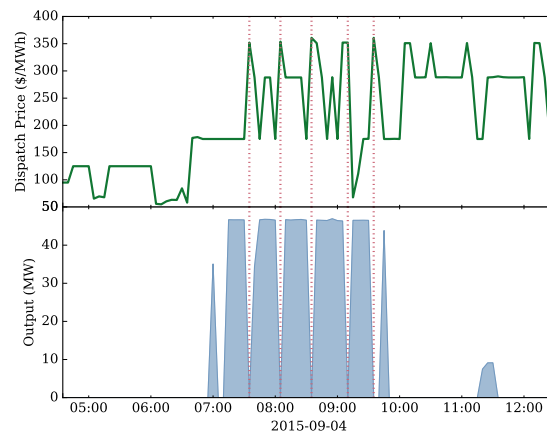


Figure 28: Example of systematic withdrawal of supply by Angaston Power Station impacting prices. The pattern of dispatch between 7:30 and 10:00 am on the morning of 4th September 2015, was characterised by a withdrawal for one dispatch interval in each of five successive settlement periods (bottom panel), each of which corresponded to a price spike of about \$170/MWh (top panel).

Economic withholding and rebidding

Rebidding has been flagged as a potential issue by the AER. Generators can revise their offer up until the start of a dispatch interval through 'rebids' that shift the quantity of electricity they offer at particular prices¹⁰⁰. Rebids that occur close to dispatch time can also trigger extreme prices, if the market is unable to respond adequately. In response to this issue, the AEMC has introduced '*bidding in good faith*' rules, with additional requirements to record information for rebids close to dispatch.

We analysed the extent to which AGL bid capacity to high price bands (typically the market cap price) for the Torrens Island A Power Station. We also looked at the proportion of capacity that was available below and above \$300/MWh. In aggregate, Torrens Island A offered its entire capacity to the market at less than \$300/MWh 96.5% of time in 2015. For the remaining 3.5% of the year (or about 300 hours) some capacity was pushed into high price bands.

Our analysis shows a correlation between periods of high scheduled demand¹⁰¹ and Torrens Island A's bidding of capacity into high price bands. The proportion of time when some capacity was priced above \$300/MWh is clearly skewed to times of high scheduled demand. In 2015, for the top 10% of scheduled demand periods, the amount of time some capacity was bid into these high price bands was 16.7%. For the top 1% of scheduled demand periods it increased to 35%.

⁹⁸See AEMC 2016a.

⁹⁹Price turnover was calculated assuming the settlement prices as the average of the remaining five minute period in the corresponding intervals

¹⁰⁰AEMC 2015b, page 2.

¹⁰¹*Scheduled demand* refers to demand that must be met by *scheduled* generation capacity. Generation types such as wind that are classified as either *semi-scheduled* or *non-scheduled*.

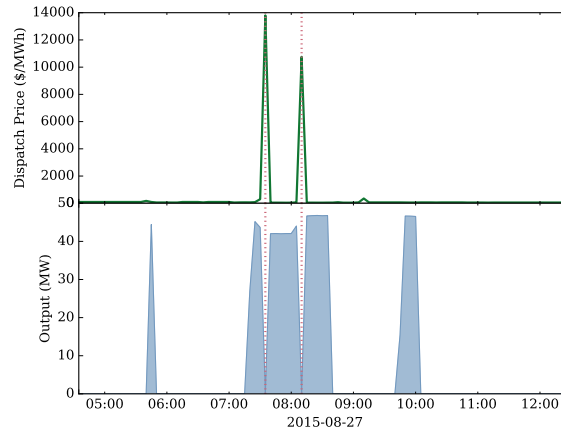


Figure 29: Example of withdrawal of supply by Angaston Power Station corresponding with extreme scarcity pricing events. Between 7:30 and 9:00 am on the morning of 27th August, 2015, on two separate occasions the withdrawal of dispatch (bottom panel) correlated with price spikes exceeding \$14,000 MWh (top panel).

High scheduled demand periods coincide with low availability of wind generation. Whilst not necessarily indicative of abuse of market power, this behaviour is consistent with a ‘pivotal’ generator aware that some proportion of its capacity is required to meet demand.

July 7th and the South Australian “energy crisis”

The events of July the 7th 2016 excited substantial media attention, much of it paying little attention to the factual details¹⁰². On that day, wind output was very low (see Figure 5), averaging about 100 MW, and exchange on the Heywood interconnector into Victoria was constrained due to upgrading. Across the day, dispatch prices exceeded \$10,000 per MWh on 24 occasions, and the unhedged volume weighted price for the day was just above \$1400/MWh. The peak settlement price of almost \$8897.80 occurred for the trading interval between 7:00pm and 7:30pm. Settlement prices were above \$2000/ MWh for most of the afternoon and evening.

In the extreme trading interval between 7:00pm and 7:30pm wind was dispatching only 13.5 MW and other generation capacity displayed erratic dispatch patterns. The output from the AGL Torrens Island plants oscillated, reducing by 91.6 MW while the prices remained at the price cap (Figure 30).

Uncertainties in the role of the interconnector make it difficult to be clear on what the cause of this generation pattern is. However, what is clear is that Torrens Island had bid an unusually high volume of capacity at the market price cap (see Figure 31)¹⁰³. That is what may be expected if Torrens Island was engaging in *economic withholding*, consistent with it exercising market power as a ‘pivotal’ generator. We note that the oscillations may be due to the interconnector becoming intermittently available, due to interconnector upgrade works, and thus intermittently displacing the capacity bid in at the market price cap.

Despite some uncertainties introduced by the interconnector behaviour during this critical time period, the analysis presented here provides a *prima facie* case for economic withholding on July 7th in South Australia. As in the U.S investigation into withholding supply¹⁰⁴ the Torrens Island example is suggestive of market power abuse.

¹⁰²For example, (Owen 2016) claimed that wind generation was drawing 50MW of demand from the grid at the time of the peak period, when in fact it was dispatching about 13.5 MW.

¹⁰³Other generators displayed similar patterns with the exception of some diesel generators, which indicates that their bids were higher than that of the diesel generators

¹⁰⁴Federal Energy Regulatory Commission 2003b, See Economic Withholding of Generation and Inflated Bidding During May to October 2000, Chapter VI page 45.

¹⁰⁵The registered capacity of Torrens Island is 1280 MW, while the maximum capacity is 40 MW higher at 1320 MW

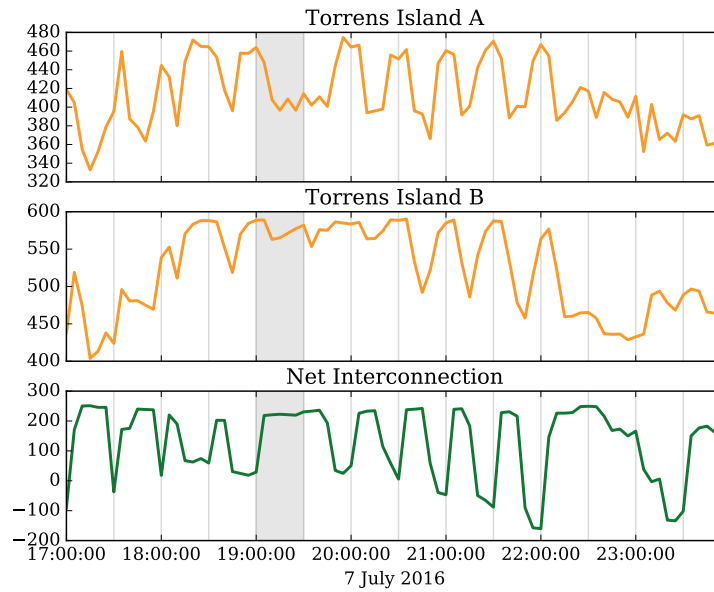


Figure 30: 5-minute dispatch interval output of Torrens Island A and B Power Stations in MW, on the evening of 7th July, 2016. In the peak price settlement period between 7:00 and 7:30 pm (shaded), prices exceeded \$10,000/MWh for five of the six dispatch intervals. Note that Torrens Island A reduced output during the peak pricing period. Dispatch output oscillations later in the evening have a distinctive 30-minute period, that also correlates with a succession of isolated extreme pricing events. While the output peaks on the half-hour, the prices peaked at the 5- and/or 10-minute dispatch interval in each 30-minute settlement period. The oscillations in gas dispatch were antithetic to oscillations in flow across the Victorian interconnectors. A more detailed diagram can be found in

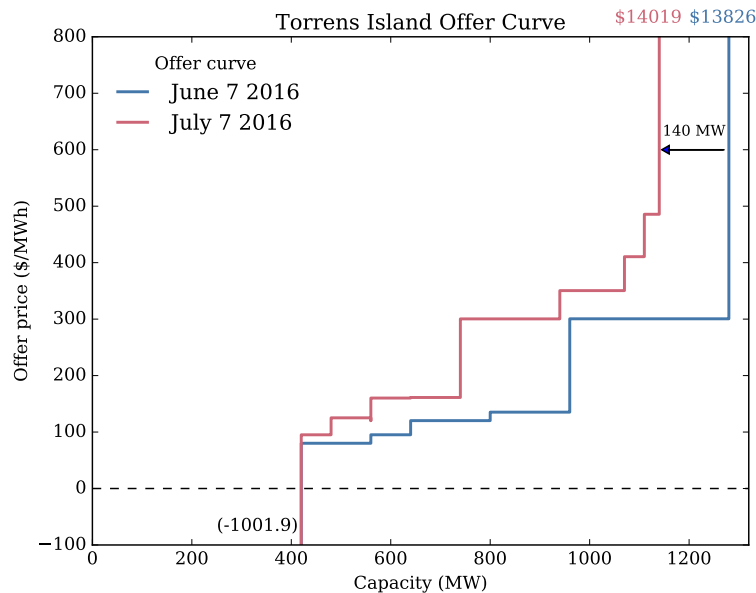


Figure 31: Combined final offer curve for AGL’s Torrens Island A and B for the 7:00-7:30 pm trading interval. The curves show the price at which AGL is willing to dispatch a certain amount of capacity. Torrens Island regularly has 40 MW¹⁰⁵ in the highest price band, typically at the market price cap (as illustrated in the blue line). On July 7th a total 180 MW was rebid to the market price cap. The last bid for the 7:00-7:30 interval on July 7 occurred at 6:35 pm after a series of at least 9 rebids for that interval during the afternoon. A more detailed figure with additional information can be found in Appendix F

Resource adequacy and the “missing money” problem

The ‘Resource adequacy problem’ is a term used to describe the potential for insufficient generating capacity relative to system demand¹⁰⁶. It is directly related to the ‘*missing money*’ problem, first identified by¹⁰⁷:

‘The central problem, labeled “missing money”, is that, when generating capacity is adequate, electricity prices are too low to pay for adequate capacity.’

The key argument¹⁰⁸ is that for long periods, energy-only market markets may set prices that are insufficient to compensate asset owners for both fixed (capital) and variable (predominantly fuel) costs. In turn, generation capacity is inadequate and the market risks reliability. The reality and importance of the issue is the subject of ongoing debate and is not specific to the expansion of renewable generation. Some authors doubt whether the *missing money problem* does in fact exist in current energy-only markets¹⁰⁹.

Energy-only markets are predicated on the need scarcity events and extreme prices to incentivize capital investment. In an efficient equilibrium, the resulting scarcity rents earned in such events are needed to, and would, cover the fixed capital and operating costs of all resources, which is consistent with perfect competition and marginal cost pricing¹¹⁰. Scarcity events do however exacerbate the conditions for exercise of market power and create the potential conditions for extraction of monopoly rents. The extreme increase in price-cost margins relative to both historical averages and other regions, as discussed in Section 3.3.2 and Figure 27, suggest that the recent price increases in South Australia go beyond the *efficient equilibrium* and are indicative of exercise of market power.

¹⁰⁶Simshauser 2010a.

¹⁰⁷Cramton and Stoft 2006, page 8.

¹⁰⁸Cramton and Ockenfels 2012.

¹⁰⁹Edenhofer et al. 2013.

¹¹⁰Cramton and Ockenfels 2012, page 118.

4 Options for South Australia

The previous section identified gas prices and competition issues as significant contributing factors to the recent increases in electricity prices and volatility in South Australia. Our analysis begs the question of the options available to address these issues.

On the supply side, it is noted there appears no current substantive risk to meeting demand in South Australia, as the installed capacity of gas and distillate generation amounts to 2950 MW, and the interconnection capacity will soon be 850 MW. A recent ‘Energy Adequacy Assessment’ analysis from AEMO confirmed no breaches of the reliability standard in any NEM region over the next year, provided gas production facilities remain available¹¹¹.

However, the dependence on gas in times of low wind output, combined with the rising price of domestic gas and limited competition has added a significant cost penalty to South Australian electricity supply. The high prices have opened the opportunity for new supply specifically targeted on low wind output periods. One obvious option for increasing supply in such times is to increase interconnection to other regions. Others include a raft of storage types, including battery, pumped hydro energy storage (PHES), and concentrating solar thermal with storage (CST). Note that all of these approaches could help improve competition¹¹².

In this section we analyse the non-network solutions. While transmission upgrades maybe worthwhile, detailed analysis is beyond the scope of this study. The South Australian government recently announced a major study into transmission upgrade options¹¹³ that should provide a detailed insight into the value of additional interconnection capacity.

Storage in an energy-only markets typically can exploit arbitrage, but also provide capacity and are competitors to traditional peaking technologies. In what follows we discuss the potential, and limitations, for arbitrage opportunities in the South Australian market, building on the findings of our earlier work on the subject¹¹⁴.

4.1 Beyond the Levelised Cost of Energy

A standard metric used by many studies in assessing the cost of competing generation technologies is the Levelised Cost of Energy (LCOE). The LCOE represents the average cost of producing electricity from a particular technology over its life, given assumptions about how the power station will operate¹¹⁵. This measure is useful for comparing the cost of *energy* provision by different technologies. However, the LCOE metric does not necessarily capture the *value* of energy provide, or the value of flexible *capacity*.

OCGT’s provide a good example of the limitations of using the LCOE metric. According the recent Australian Power Generation Technology Study, the LCOE of OCGT is reported to be in the range of \$158-\$269¹¹⁶, with further exposure to rising gas prices. This is a high LCOE¹¹⁷ relative to technologies such as wind, and exceeds the average volume weighted wholesale price of electricity on the NEM by 300-500%. Yet OCGT stations do get built for the simple reason that their primary value is not the amount of energy they provide, but rather the provision of *capacity* and flexible supply.

In this section, we compare the cost of capacity of a range of different technologies. We use a modified LCOE calculation to determine the Levelised Cost of Capacity (LCOC) based on the long-run marginal cost of supplying additional capacity (rather than energy). The LCOC represents the price of capacity required for a project to have a net present value of zero. There are many studies that analyse the LCOC, including one of our own¹¹⁸ that specifically looked at the value of storage in the South Australian electricity market.

Following McConnell et al¹¹⁹, we analyse the value relative to expected hedging contracts. We assume the various technologies have sold cap contracts at \$300/MWh (see Section 2.4.2 for details on cap contracting). Thus for prices at and above \$300, the technology only receives \$300/MWh in exchange for cap contract revenue). A penalty of the spot price minus \$300/MWh is assumed

¹¹¹AEMO 2016b.

¹¹²See Section on Pivotal Supply Index. Both new capacity and increased interconnection decrease the frequency of a generator becoming ‘Pivotal’

¹¹³With costs reported in the \$300-\$700 million range

¹¹⁴McConnell, Forcey, and Sandiford 2015.

¹¹⁵Bongers 2015.

¹¹⁶Bongers 2015, page 131 in.

¹¹⁷The LCOE for OCGT is comparable for example to current estimates for solar thermal that to date has not been competitive even with financing incentives such as the RET

¹¹⁸McConnell, Forcey, and Sandiford 2015.

¹¹⁹McConnell, Forcey, and Sandiford 2015.

for any periods where the price is above \$300/MWh but the technology is not available as may occur, for example, where storage levels have been exhausted. A gas generator is assumed to be inexhaustible and able to respond to any price event.

For prices below \$300/MWh, the storage technologies can either arbitrage in the case of PHEs and battery storage, or sell electricity at the spot price, in the case of CST. This is an additional revenue stream that is not available to an OCGT gas *peaker* that would not normally be expected to generate at prices below \$300/MWh. In determining the LCOC, the arbitrage or energy value for these technologies is also taken into account¹²⁰.

4.2 Storage only technologies: PHEs and Battery Storage

This analysis draws on results from our previous study¹²¹ which specifically looked at the arbitrage and capacity value of storage. In particular, this includes an estimation of the the arbitrage value, as distinct from the capacity value, for arbitrage below \$300/MWh. In addition we only consider up to 6 hours of storage, as our analysis suggested there was not much additional value beyond that (see Figure 32). Only lithium ion battery technology is analysed, and cost data for both PHEs and lithium ion technologies is used from Lazard’s Levelized Cost of Storage Analysis^{122,123}. Two configurations for lithium ion technology were selected (2 hours and 6 hours).

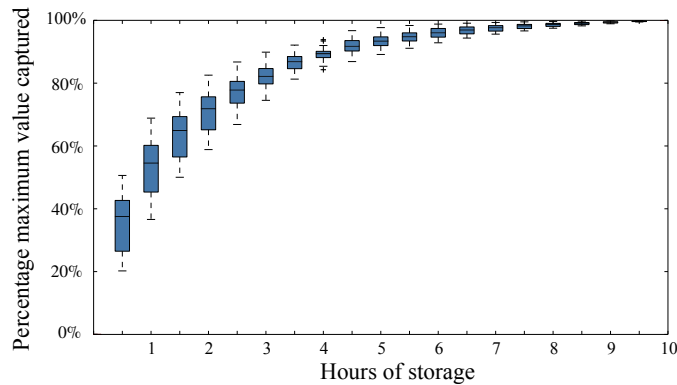


Figure 32: Illustration of the the diminishing marginal returns of the arbitrage opportunity for increasing hours of storage, from our previous study McConnell, Forcey, and Sandiford 2015. Based on the South Australian market analysis, that study showed that six hours of storage provides over 95% of the total realizable arbitrage opportunity.

4.3 Energy technologies: OCGT and CST

Technology costs for OCGT and CST were drawn from the 2015 Australian Power Generation Technology Report¹²⁴. Similar to storage options, we consider CST with 6 hours of storage. This differs markedly from a configuration with 15 hours of storage, and 50 MW dispatch capacity, recently determined by Alinta to be uneconomical. CST also produces energy. We value the energy based on the futures price of peak energy in South Australia¹²⁵, albeit with the capacity value deducted to avoid double counting extreme price events.

Figure 33 illustrates the LCOC for the technologies considered. The current value of capacity based on South Australian futures cap of \$20¹²⁶ is illustrated by a red line, suggesting at these prices several technologies are economically viable. The wide range of costs largely reflects the uncertainty in the capital cost for the technologies.

¹²⁰McConnell, Forcey, and Sandiford 2015.

¹²¹McConnell, Forcey, and Sandiford 2015.

¹²²Lazard 2015.

¹²³A USD to AUD exchange rate of 1.33 (July 2016) was used for this analysis

¹²⁴Bongers 2015.

¹²⁵Current peak futures strip prices for South Australia currently range between \$110 and \$120 out to FY19 (see https://www.asxenergy.com.au/futures_au). Note that the Q1 2017 price was \$130 at the time of writing.

¹²⁶Current cap strip prices range between \$14 and \$26. Q1 2017 cap prices are as high as \$33 (see https://www.asxenergy.com.au/futures_au)

One important consideration is missing from this analysis: only CST is producing significant volumes of additional energy¹²⁷. Both pumped hydro and batteries will draw additional energy from the grid, since their round trip efficiencies are less than 100%. As such, CST would further displace gas or other generation in the NEM, as well as contributing to emissions reductions. OCGT and other storage technologies will increase emissions, based on the current energy mix. In addition, both CST and storage technologies will have help alleviate competitive pressures. Peak generation such as OCGT would only offer competitive supply at high prices, where as CST and storage technologies can increase competition in periods less \$300 (though arbitrage and energy supply respectively).

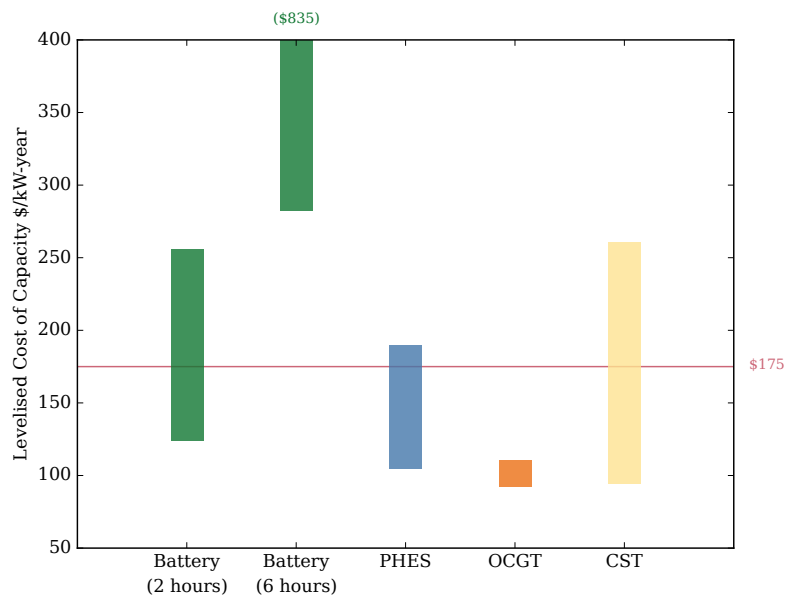


Figure 33: This figure compares the Levelised cost of Capacity (LCOC) for the technologies considered. The LCOC value represents the annual revenue required per kW of capacity for the technology to be economically viable (the data and assumptions can be found in Appendix G). The red line shows the value of a \$20 cap contract (in \$/kW-year). Technologies that fall below this line would be economically viable at this price.

¹²⁷The OCGT will produce small volumes of energy

5 Discussion

Any analysis of South Australian electricity market developments needs framing in terms of the requirement to decarbonise the electricity sector.

Australia’s electricity sector has an historical emission intensity of about 0.8 t/MWh¹²⁸, and accounts for approximately one third of the national emissions. The need to dramatically reduce electricity sector emissions is highlighted by the global climate agreement under the United Nations Framework Convention on Climate Change at the 21st Conference of the Parties in Paris, which set a goal to hold average temperature increase to well below 2°C and pursue efforts to keep warming below 1.5°C above pre-industrial levels. According to the IEA¹²⁹, this goal requires a reduction in the average CO₂ intensity of electricity production from 0.411 t/MWh in 2015 to 0.015 t/MWh by 2050.

Prior to the Paris agreement, Australia had already committed reduce emissions to 26–28% of 2005 levels by 2030¹³⁰. With such targets ‘*substantially weaker*’ than those recommended by many authorities, such as the Climate Change Authority¹³¹, there will be pressure to strengthen them over time.

Whatever the case, in order to meet any of the proposed targets it is necessary to significantly reduce Australian electricity sector emissions. Of all the regions in the NEM, South Australia has made the most significant progress on decarbonisation in the last decade, effectively reducing its electricity generation emissions (see Figure 34) by around 40% since 2008. The imperative to drive reductions in line with, or exceeding, the South Australian experience makes it of particular relevance to broader Australian ambitions.

Counter-factual scenario

During 2015, over 5000 GWh of energy were supplied to South Australian by renewable sources. This is more than can be produced by either Pelican Point or Northern power station running at 100% capacity factor.

It is impossible to determine what would occur in a counterfactual scenario, should no renewable energy have been installed. Here we present two simplistic scenarios without renewable generation and similar interconnector patterns: one with Northern, and without Northern¹³². In scenario one, the renewable is replaced first by Northern and then by gas, as might be expected in the absence of carbon pricing. In the second scenario, the output is replace by gas only. Pelican Point is used as the gas plant in both scenarios. Even though this plant has been mothballed, it has the highest

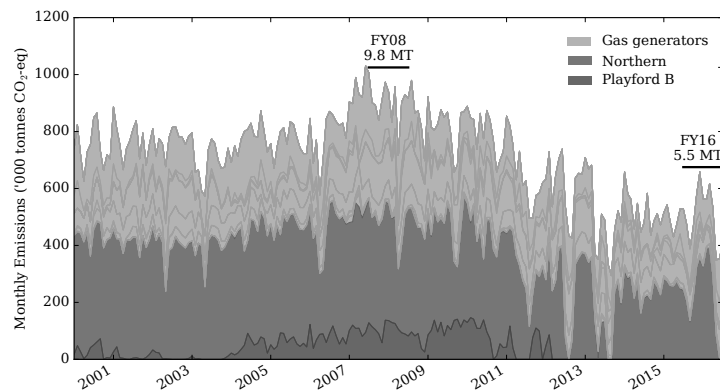


Figure 34: Monthly electricity sector emissions for South Australia since 2000. Annual emissions peaked in FY08, and have declined steadily since with emission intensity falling from about 0.72 t/MWh to 0.45 t/MWh in FY16.

¹²⁸Vivid Economics 2013.

¹²⁹IEA 2016.

¹³⁰Australian Government 2015.

¹³¹Bernie Fraser 2015.

¹³²Most likely, Northern would not have shut down. Until relatively recently, it was expected to keep operating until 2030

Table 3: Counter-factual Scenarios, with and without Northern

	Increased Emissions (MTpa)	Increased Fuel Costs (million pa)
With Northern	4.38	\$32
Without Northern	1.72	\$133

efficiency (and thus lowest fuel costs) and would be expected to be utilized in a high gas cost environment.

5.1 National energy transition and the capacity cycle

Markets requiring substantial decarbonisation will inevitably face the exit of emissions intensive generation. In energy-only markets, this will necessarily reduce the capacity overhang, and increase prices, as described by the capacity cycle (see Appendix A). As alluded to in Section 3.1, these dynamics should occur regardless of the mechanism by which capacity exits or enters the market.

The South Australian experience illustrates how this may unfold through the addition of renewable energy capacity, supported by policies such as the RET. Under a carbon pricing regime, the cost of fossil generation would rise to reflect the externalised costs of emissions. Under this scenario, the dynamics might play out in two different ways. Firstly, an emission intensive generator may become economically unviable and exit the market, as a result of the increase in costs resulting from carbon pricing. Alternatively, the increase in prices of fossil generation would give renewable energy a competitive advantage. In this situation, renewable energy may enter the market and displace fossil generation to the point that a generator exits that market, similar to the South Australian experience.

In all cases electricity prices would be expected to rebound after the exit of a generator. As the capacity overhang decreases, prices would rise and thereby encourage new generation, or new technologies such as storage. The extent of this rebound may be significant, in part because of the relative scale of the fossil power stations that are displaced. In Victoria, the size of Loy Yang A is similar to Northern, relative to local demand and may have similar rebound effects. Hazelwood, by comparison is about 30% smaller and would be expected to have smaller impacts on the capacity cycle and prices.

Competition

There have been long running concerns over market power issues in South Australia. The evidence suggests that recent price spikes may in part be due to market power issues, rather than the underlying economic fundamentals. The recent withdrawal of Northern, combined with interconnector limits increased market concentration to the point where economic withholding of supply would have been profitable for some generators. The conditions that allow for this exercise of market power point to a lack of coordinated system planning in times of transition. The potential also exists for market power to be concentrated as a consequence of transitional arrangements in other jurisdictions.

It's worth noting that competition and market behaviour can also be an issue independent of transitional arrangements and the exit of capacity. As can be seen in Figure 15 volatility is not constrained to South Australia. Queensland has experienced some of the greatest volatility in the past four years, albeit with virtually no renewable energy generation and excess generation capacity. The volatility in Queensland has also been linked to late 're-bidding' practices, that take advantage of the market rules for calculating the settlement price¹³³, and Queensland has historically had high HHI values, relative to the other mainland states (see Section 3.3).

5.2 Market design considerations

Electricity market design has a significant impact on the efficient scheduling and operation of power systems. As penetrations of variable generation increase, market structure and generation scheduling rules become even more important to ensure efficient utilisation of the generation fleet. Importantly, most market design characteristics that facilitate the integration of variable generation also improve the efficiency and operation of the market *without* variable generation¹³⁴.

¹³³AEMC 2016a.

¹³⁴Riesz, Gilmore, and Hindsberger 2013.

The AEMC is currently assessing various rule change proposals to improve market design, including one to address the mismatch between the time intervals for operational dispatch and financial settlement in the NEM¹³⁵, in part to address the some of the issues discussed in Section 3.3.2. Additionally, the AEMC has recently announced a review of System Security in the NEM¹³⁶, in collaboration with AEMO.

Resource Adequacy

The evidence from Section 3.3.2 suggests that recent margins are not reflective of the ‘efficient equilibrium’ and are above scarcity value. While generators need to recover fixed and other costs through scarcity events through increased margins, recent prices go above and beyond this requirement.

Notwithstanding this, in the future high proportions of renewable generation may exacerbate the ‘missing money’ and ‘resource adequacy’ problems (see see Edenhofer et al for a detailed review of this issue). A number of approaches have been suggested to deal with this problem, including the introduction of capacity markets or capacity payments¹³⁷. Capacity markets remain controversial, in part because of a history of flawed capacity market design, resulting in large inefficiencies and high costs¹³⁸.

The main argument for the implementation of capacity markets is that energy-only markets are not able to incentivise sufficient investment in generation to ensure resource adequacy¹³⁹. In the context of a need to dramatically decarbonize electricity system, others are arguing for a wholesale pricing model that reflects the high-fixed cost nature of technologies required, compared with carbon-intensive technologies¹⁴⁰.

The argument for a capacity market is often predicated on the absence of demand side response, and demand side participation. The absence of a robust demand side is the most prominent market failure that drives the need for a capacity market¹⁴¹. In theory, an energy-only market with scarcity pricing, market design with sufficient demand response is likely to be sufficient¹⁴². Additionally, in 2012 AECOM, in a report on this issue¹⁴³, argued that capacity markets are more complex than energy-only markets and relied on centralised decision to much greater extent. They suggested that less disruptive reforms, including raising the market price cap, should be considered in preference to capacity markets.

Indeed with a strong demand side market, the necessity for any market price cap is arguable. Whilst Australia has a high price cap, some energy-only markets seem to operate effectively without one¹⁴⁴. Arguably, the price caps provides a focal point for tacit collusion¹⁴⁵. A strong demand side market and more competitive scarcity prices and no price cap may result in a more efficient outcomes for participants on the NEM.

In addition, capacity markets are supposedly prone to distortion because of pressure from politics and lobbyists¹⁴⁶. There is a precedent for this, with respect to the “*missing money problem*” and resource adequacy. As noted earlier, it has been suggested that average wholesale prices in the NEM have been insufficient for many plants to recover long-run marginal costs¹⁴⁷. In support of this Nelson et al suggest that many gas generators commissioned after 2005 would have been bankrupted had they not been vertically integrated¹⁴⁸. Haines and McConnell¹⁴⁹ has noted the threat of potential bankruptcies has been used by generators to lobby for the vertical integration:

‘Together, private generators and economic commentators exerted leverage over the federal and state governments’ anxieties around reliability of supply to undermine [competition]’

¹³⁵For more details on the importance of ‘fast markets’ and a move to 5 minute settlement, see the Melbourne Energy Institutes submission to the rule change proposal here: <http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement>

¹³⁶AEMC 2016b.

¹³⁷Nelson and Orton 2016.

¹³⁸Cramton and Ockenfels 2012, page 132.

¹³⁹IEA 2016.

¹⁴⁰Nelson and Orton 2016.

¹⁴¹Cramton and Ockenfels 2012, page 113.

¹⁴²IEA 2016.

¹⁴³Riesz 2012.

¹⁴⁴Sioshansi 2008.

¹⁴⁵Knittel and Stango 2003.

¹⁴⁶Cramton and Ockenfels 2012, page 132.

¹⁴⁷Simshauser 2010b.

¹⁴⁸Nelson, Reid, and McNeill 2015.

¹⁴⁹Haines and McConnell 2016.

5.3 Final Comments

Clearly, a number of interdependent factors are playing out in the evolving South Australian electricity sector. The aggregate effect manifest dramatically in winter 2016 reflects a complex interplay between legacy issues, increasing renewable energy generation, competing developments in the gas market, and the absence of coordination of transitional arrangements.

The recent increases in gas prices driven by dynamics in the export market have added at least \$140-\$200 million to the annual cost of South Australian electricity supply. However, due to its historic reliance on gas generation, South Australia has always been exposed to movements in gas prices even without the investment in wind. In pure energy terms, gas generation has been declining over the last decade, due in significant part to the addition of wind to the generation mix.

Despite the closure of the Northern Power station, gas dispatch has remained at near record low levels in seasonally-adjusted terms. What has changed dramatically since Northern's closure is the concentration of market power. While there are legitimate reasons for power station owners to increase prices to reflect scarcity value, our analysis suggests that recent increases in wholesale prices have been well in excess of the reasonable market response, and reflect the extraction of monopoly rents. Such 'opportunism' has been encouraged by poor coordination of the system adjustments, such as mid-winter upgrades to Heywood interconnector.

Multiple options exist that address both of these issues to greater or lesser extent. OCGT is a cheap option to increase capacity and supply in peak periods, but does not improve competition or supply outside these periods and is still partially dependent on gas prices. Storage options can both increase capacity in peak periods, and increase competition through daily arbitrage opportunities. CST further reduces the consumption and reliance on gas, while providing capacity. Additional interconnection (above and beyond the current 190 MW expansion of Heywood) may also prove to be a viable solution.

In the longer term, South Australian experience points to the need to diversify low emissions generation and storage portfolios. As we necessarily decarbonise the national electricity system and increase renewable energy penetration, technologies such as storage and solar thermal will become increasingly necessary to provide for both peak capacity and reliability of supply.

Finally, South Australia highlights the potential benefits for system wide oversight of transitional arrangements to avoid market power issues. The recent price rises in South Australia would have been much less extreme had Northern's closure not occurred prior to completion of the upgrade to the Heywood interconnector at a time when Pelican Point was effectively mothballed, and demand was rising to meet the winter peak. As it transpired, the coincidence of all these factors contributed to a rapid and unprecedented rise in the concentration of market power.

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Appendix A Load Duration Curves

Figure 35 shows the Load Duration Curves (black) and Net Load Duration Curves (blue) for the mainland NEM regions. As is can been seen, the difference between the curves is greatest in South Australia as would be expected for the region with the highest penetration of wind. As there is virtually no non-scheduled or semi-scheduled generation in QLD, the two curves fall on top of each other.

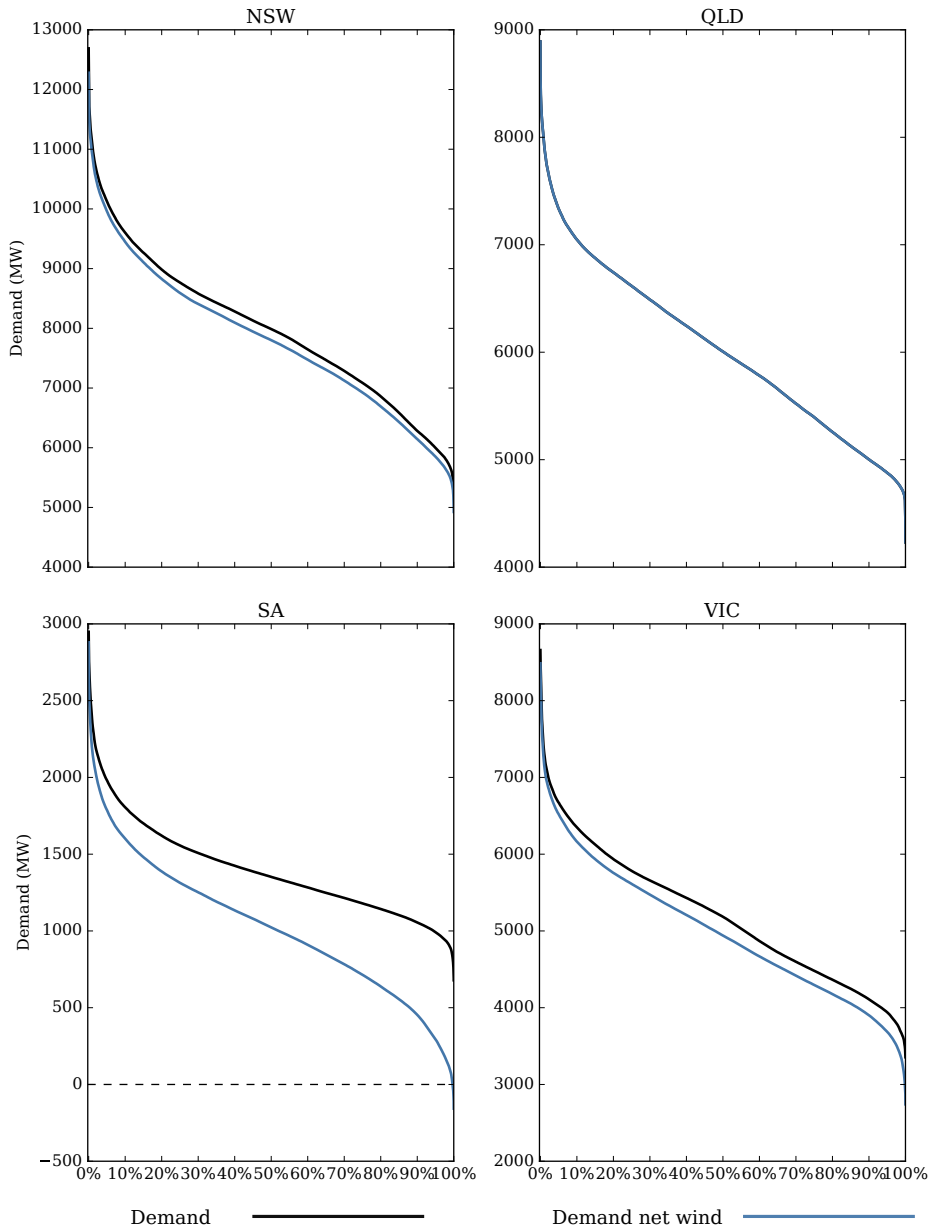


Figure 35: Load duration curves for the main NEM regions in 2015.

Appendix B Power stations by regional basis size, FY16

We define the regional basis size of a power station to be the size of its registered capacity as a percentage of median regional demand. In terms of its regional basis Northern, at 39% was the second largest in the NEM, in FY16 demand terms, behind Loy Yang A in Victoria at 43%. Hazelwood and Yallourn in Victoria are stations commonly discussed as a candidate for closure because of a range of factors including emission intensity, design life and mine stability issues. At 31% and 29% respectively, their regional basis sizes are considerably lower below that of Northern. The regional basis size provides a useful metric for assessing the impact of station closure on market dynamics, though other factors such as ownership distribution amongst remaining plant are clearly important.

Table 4: Size of NEM coal generators in the relative to median regional demand

State (median demand)	Station Name	Trading rights	Registered Capacity (MW)	Regional basis size
NSW (7966.585)	Eraring	Origin	2880	36.15%
	Bayswater	AGL	2640	33.14%
	Liddell	AGL	2000	25.10%
	Mt Piper	EnergyAustralia	1400	17.57%
	Vales Point B	Sunset Power Int'l	1320	16.57%
QLD (6138.17)	Gladstone	CS Energy	1680	27.37%
	Stanwell	Stanwell Corp.	1460	23.79%
	Tarong	Stanwell Corp.	1400	22.81%
	Millmerran	InterGen	852	13.88%
	Callide	CS Energy / Intergen	840	13.68%
	Kogan Creek Callide B	CS Energy CS Energy	744 700	12.12% 11.40%
Vic (5150.325)	Loy Yang A	AGL	2210	42.91%
	Hazelwood	GDF Suez (Engie)	1600	31.07%
	Yallourn	EnergyAustralia	1480	28.74%
	Loy Yang B	GDF Suez (Engie)	1000	19.42%
SA (1363.215)	Northern		530	38.88%

Appendix C Typical contract coverage for a retailer

Figure 36 sets out a typical forward contract position of a retailer, which mirrors that of the generator¹⁵⁰. Similarly, as described in *Forward contracts in electricity markets: The Australian experience*¹⁵¹:

‘... at one year out, [retailers] may want to be fully contracted (100% of final contract cover in volume), two years out 60–70% contracted, three years out 20–30% contracted, and at four years out 5–10% contracted.’

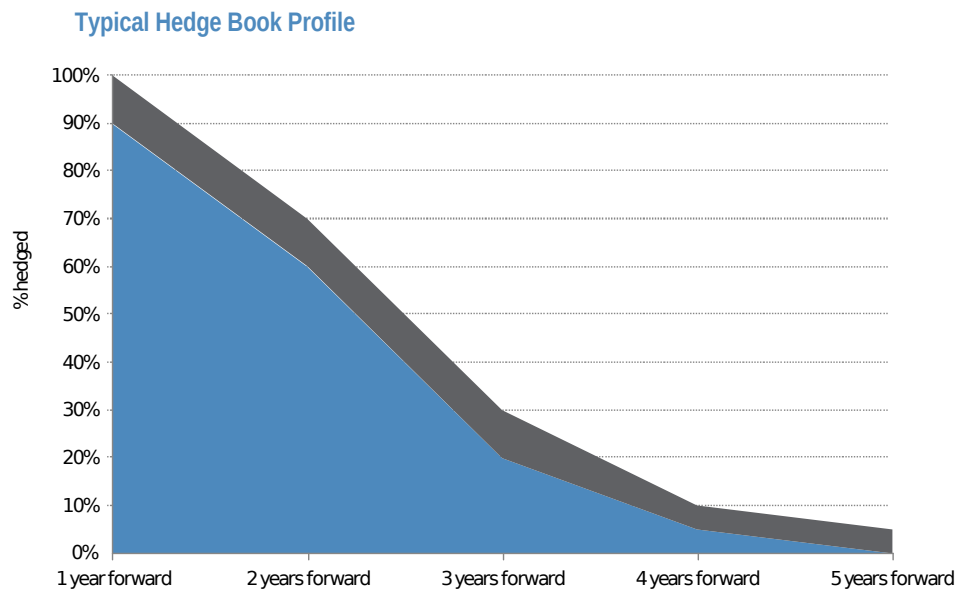


Figure 36: Typical forward contract position, [J.P. Morgan estimates, Company data]

¹⁵⁰Steed and Laybutt 2011.

¹⁵¹Anderson, Hu, and Winchester 2007.

Appendix D Capacity Cycle

Short-to-medium term hedging strategies expose power station owners, (and retailers) to the ‘capacity cycle’. This cycle is driven by the ‘reserve margin’, which represents the difference between the available (firm) capacity and the peak demand.

The cycle functions as follows and is illustrated in Figure 37

1. Excess capacity drives up reserve margins, prices start falling
2. Under-investment leads to tightening reserve margins, prices start rising
3. Firms rush to add new capacity as prices rise

Historically a reserve margin or capacity overhang of around 15% is associated with ensuring adequate system security, and a balanced system¹⁵². Reserve margins above this represent a situation of oversupply, and market prices are well below the long run marginal costs (LRMC) of production, discourage new entry of generation. Margins below this level suggest under supply, and prices theoretically rise above the LRMC, creating the appropriate price signal.

Reserve margins in the NEM have been consistently higher than 15%, and are currently well above this at approximately 37%. This is reflected in the current low wholesale prices, and is a function of increasing renewable generation supported by a certificate scheme (the Renewable Energy Target) and declining demand.

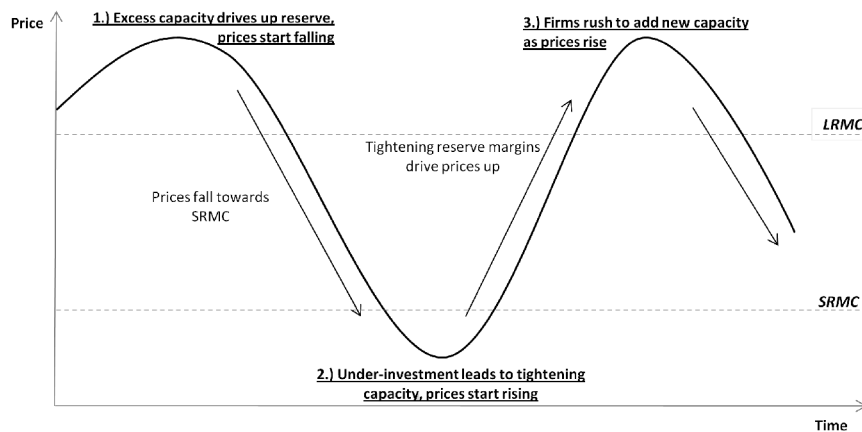


Figure 37: Conceptual illustration of the capacity cycle, source: Steed and Laybutt (2011)

¹⁵²Steed and Laybutt 2011.

Appendix E Gas generation SA

This table shows gas generation in South Australia for the last calendar year. Using the thermal efficiencies of each plant, the heat rate and approximate gas consumption can be determined¹⁵³.

Table 5: Energy output and gas consumption for gas generators in SA, 2015

Station Name	Output (GWh)	Thermal Efficiency	Heat Rate	Gas (PJ)
Dry Creek Gas	6.34	26%	13846	0.09
Hallett	33	24%	15000	0.49
Ladbroke Grove	206.55	30%	12000	2.48
Mintaro	13.39	28%	12857	0.17
Osborne	1220.82	42%	8571	10.46
Pelican Point	293.55	48%	7500	2.2
Quarantine	137.11	32%	11250	1.54
Torrens Island A	657.6	30%	12000	7.89
Torrens Island B	1967.73	32%	11250	22.14
Total	4536	-	-	47.47

¹⁵³Thermal efficiency data from AEMO National Transmission Development Plan (NTNPD) 2015.

Appendix F July 7th 2016

The events of July 7th 2016 are central to understanding the South Australian energy crisis. Here we show the dispatch prices and energy supplies including interchange for the critical afternoon and evening periods over which prices averaged \$2,232/MWh.

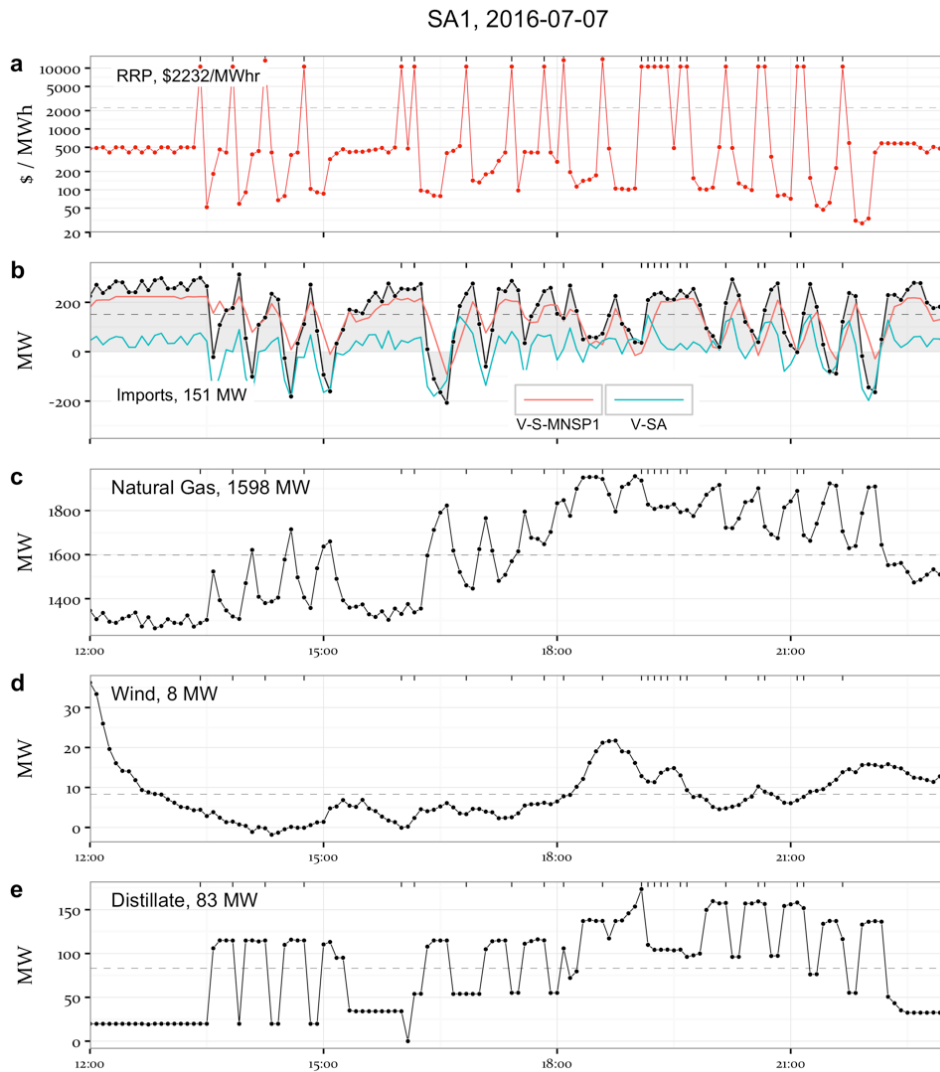


Figure 38: The top panel shows shows the 5-minute dispatch price for South Australia on July 7th 2016 from midday onwards. Panel b show interconnector flows, with V-SA representing Heywood and V-S-MNSP1 representing Murraylink. The dark line and shaded region shows the net imports, which averaged 151 MW over the period. Panels c,d and e show the out put of gas-fired generators, wind and distillate generation during this period. In all panels, vertical tick marks at the top of each panel show period where the 5-minute price exceeded \$9,000/MWh

Appendix G LCOC assumptions

A basic¹⁵⁴ levelised cost of energy calculation was modified to determine the Levelised Cost of Capacity (LCOC). In this calculation the long-run marginal cost of supplying additional capacity (rather than energy) is determined. Alternatively, the LCOC represents the price (of capacity) required for a project to have a net present value of zero. The same Weighted Average Cost of Capital (WACC) and economic life were used in all calculations. Technology specific input assumptions and sensitivities can be found below:

Global assumptions

Table 6: Global economic assumptions

WACC	8%
Economic lifetime	20 years
US/AU exchange rate	1.33

Storage technologies

This input data comes from the ‘Lazards Levelized Cost of Storage Analysis’¹⁵⁵.

Table 7: Capital and O&M cost assumptions for storage technologies

	Lithium		Pumped Hydro	
	High	Low	High	Low
Total Installed Cost (\$/kWh)	\$1,236	\$486	\$359	\$244
Replacement cost (10 years) (\$/kWh)	\$209	\$304	\$0	\$0
O&M Costs (\$/kWh)	\$13	\$7	\$11	\$2

Generation technologies

This input data comes from the ‘Australian Power Generation Technology Report’¹⁵⁶.

Table 8: Capital, O&M costs and fuel cost assumption for generation technologies

	Open Cycle Gas Turbine		Concentrating Solar Thermal	
	High	Low	High	Low
Capital costs (\$/kW)	\$1,200	\$1,000	\$8,500	\$6,700
Fixed O&M (\$/kW-year)	\$10	\$7	\$16	\$16
Variable O&M (\$/Mwh)	\$15	\$12	\$4	\$4
Fuel costs (\$/GJ)	\$8	\$8	\$0	\$0

¹⁵⁴A basic levelised cost of energy (LCOE) calculation does not include financial factors such as depreciation and taxation

¹⁵⁵Lazard 2015.

¹⁵⁶Bongers 2015.

Acronyms and abbreviations

ACCC Australian Competition and Consumer Commission.

AEMC Australian Energy Market Commission.

AEMO Australian Energy Market Operator.

AER Australian Energy Regulator.

ASX Australian Stock Exchange.

CCGT Combined Cycle Gas Turbine.

CST Concentrating Solar Thermal.

ETF Exchange Traded Future.

FiT Feed-in Tariff.

FY Financial Year.

GJ gigajoule.

GPG Gas Power Generation.

GWh gigaawatt hour.

HHI HerfindahlHirschman Index.

IEA International Energy Agency.

LCOC Levelised Cost of Capacity.

LCOE Levelised Cost of Energy.

LGC Large-scale Generation Certificates.

LNG Liquid Natural Gas.

LRET Large-scale Renewable Energy Target.

MTpa million tonnes per annum.

MW megawatt.

MWh megawatt hour.

NEM National Electricity Market.

NTNPD National Transmission Network Development Plan.

OCGT Open Cycle Gas Turbine.

OFGEM Office of Gas and Electricity Markets.

OTC Over-The-Counter.

PHES Pumped Hydro Energy Storage.

PJ petajoule.

PSI Pivotal Supply Index.

PV Photovoltaic.

RET Renewable Energy Target.

SRES Small-scale Renewable Energy Scheme.

STTM Term Trading Market.

TWh terawatt hour.

VoLL Value of Loss Load.