


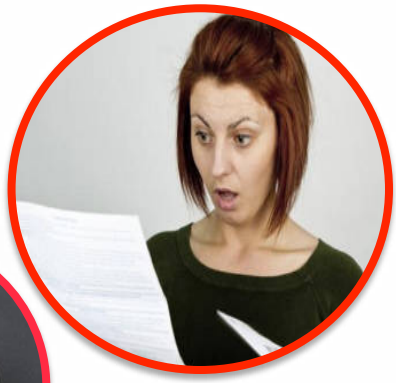

# High SA Electricity Prices: A Market Power Play?

The Final Report for

**South Australian Council for Social Services**

Capstone Project

**MS in Public Policy & Management**

Carnegie Mellon University – Australia

6 December 2013

Carnegie Mellon University Australia

SACOSS South Australian Council of Social Service

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## EXECUTIVE SUMMARY

South Australia has a small and relatively isolated electricity market. In April, May and early June of 2013, that market was subject to a prolonged period of chronic supply shortage as some major generators were off line in the winter period and one of the major interconnectors to the eastern states was constrained. There were no supply interruptions but the tight supply conditions were occasionally overlaid with acute periods of very short supply when low cost sources of electricity were few. On 18 such occasions generators offered electricity to the system at prices above $5000/MWh, that is two orders of magnitude above the normal price. The questions are how to interpret that behaviour and what might be done about it.

This report examines three of those 18 occasions in detail and characterises the price spikes as ultimately due to the chronic tightness of supply (here we agree with the analysis of the regulator) but as proximately due to the aggressive bidding behaviour of some generators which offered normally low priced electricity at prices in excess of $12000/MWh whenever it seemed likely such a bid would succeed (here we disagree with the regulator).

There are some partial solutions to this problem: expand the capacity of the interconnectors, insist on divestiture by the dominant generator and expose consumers to the variable market price (small users are currently on fixed price contracts). Each will help, although each comes at considerable cost. However, they will not solve the problem and so recommendations are made to deal with a recurrence of the problem. We have provided materials and estimation methods for SACOSS to respond quickly to a recurrence. We also propose that, in circumstances where a generator profits from very high prices and that generator cannot show it was due to other than its own aggressive bidding, 0.5% of the revenue generated be set aside in a Vulnerable Users Compensation Fund. Finally, we propose that SACOSS publicly support proposals to extend the powers of the regulator, the AER, to discourage and deal with any recurrence.

# 1. INTRODUCTION

## 1.1 Background

This interim report has been prepared for the South Australian Council of Social Services (SACOSS) by seven students from Carnegie Mellon University - Australia (CMU-A) as part of the Master of Science in Public Policy and Management (MSPPM) program. Our names and those of the client and Advisory Board are listed in Appendix. SACOSS is the peak non-government representative body for community services in SA with more than 300 member organisations. It works to influence public policy in a way that promotes fair and just access to the goods and services required to live a decent life. "A successful society is one that enables all its members to enjoy its benefits, not just some" (SACOSS 2007).

The report concerns a series of unusually high, un-forecasted increases in the wholesale price of electricity, the so-called spot price, which occurred during April, May and early June 2013. It promoted the Australian Energy Regulator (AER) to prepare a Special Report and SACOSS to raise the possibility that the spikes in wholesale prices demonstrated the use of "market power". "(E)lectricity generators were making strategic decisions about when they made capacity available" (Womerseley, 2013). In other words, the price spikes might have been the result of a strategic withholding of supply and the result of purposeful decisions by generators.

## 1.2 Aims

The primary aim of this work is to add to the research base underlying SACOSS' stated position regarding the potential for generators to misuse market power to manipulate electricity prices.

As stated at the inaugural Board meeting, our initial aims have been to provide an interim report advising SACOSS regarding:

1. The international experience – other instances and successful responses
2. The potential impact of vertical integration of retailers and generators
3. The account by the AER for this particular instance
4. The suggestion that relieving congestion on the interstate interconnector will ensure no repeat instance.

Over the course of the weeks since then we have deepened our understanding of these matters and report on most of them here. We also add recommendations.

## 1.3 Scope

The scope of work for this report includes all the matters related to the price spikes of April, May and June 2013, the subject of the special report by the AER (2013a).

The initial point of focus has been on generators' behaviour and particularly their abilities and incentives to cause increases in the wholesale price: under what conditions can generators gain by forcing up prices? We then focus on the question most relevant to SACOSS: how to protect vulnerable consumers from these price spikes?

## 1.4 Outline

This report begins by describing the events themselves. Firstly, in section 2.1, we describe some salient features of the South Australian electricity market. Then we overview the events before focussing on detailed analysis of just three of the price spikes. This allows us to characterise the behaviour of generators and we contrast our conclusion with the position set out in the regulator's Special Report.

Having characterised the behaviour of generators we then consider how this event can be interpreted. We look at it from theoretical and practical points of view and then from legal and regulatory perspectives. The final section makes recommendations to SACOSS based on the understanding, which emerges, and emphasising the importance of protecting vulnerable users from the impact of any recurrence of these events.

## 2. WHAT HAPPENED?

### 2.1 The South Australia Electricity Market

Before describing the events themselves, it is important to understand some of the salient feature of the South Australia Electricity Market (SAEM), some of which are unusual.

The SAEM is one region within the Australian Electricity Market (AEM) and as such is subject to the national regulatory regime. We will not describe the regime in detail but at the heart of the system is the AEMO's National Electricity Market Dispatch Engine (NEMDE). This is a piece of software containing a model built from linear equations which seeks to satisfy demand by determining which of the available generators can dispatch the cheapest electricity, authorising them to do so and then arranging payment for that electricity at the so-called pool price (AEMO, 2010, 11). The pool price is established once every 30 minutes (referred to as trading interval) and is based on the prices of electricity that was chosen by the NEMDE for dispatch in each of the six 5 minute intervals (referred to as dispatch interval) in the period.

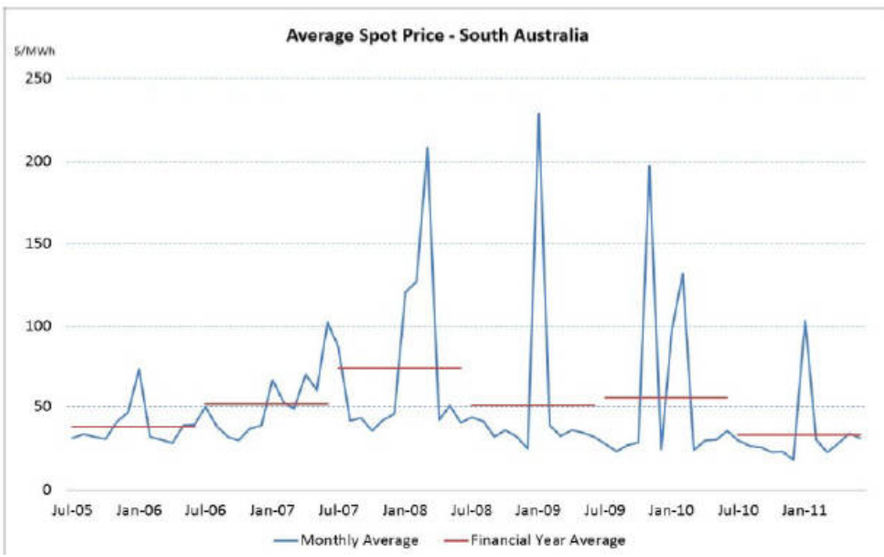
All electricity must be sold through the NEMDE so Australia has what is called a universal pool system. (While all electricity is sold only through the pool at pool prices the generator's net revenue can be different because it can have already committed to supplying customers at a pre-determined price. This is called a forward or futures contract.) The system has been described as creating a Cournot equilibrium i.e. it is a so-called reverse price auction, where rivals compete by underbidding each other and the lowest bids are accepted.

That is the national picture. The SAEM is unusual in a number of respects. Firstly, Australia has the world's longest and thinnest grid and the SAEM is located at the far edge of it, making Adelaide a very isolated demand location. SA has two interconnectors with the rest of the national network, namely the Murraylink (the world's longest underground cable) and the Heywood interconnectors, which connect to the Victorian network (and thereby onto the rest of the east coast states). Note also that the longer the distance that the electricity needs to travel, the greater is the loss of power in transmission so often the NEMDE will choose local generators when they are able to meet local demand but not always and demand in the SAEM is frequently met only by augmentation from interstate across the interconnectors.

Secondly, while the demand in South Australia is relatively small compared with the other mainland states, it is very peaky i.e. maximum demand is many times average demand and maximum demand occurs only for a few hours per year. That is because

demand in the SAEM varies widely over the four seasons. For example, in low demand days in 2011 – 12, during spring, South Australia needed just 1,100 MW but the demand increased to close to 3,000 MW for a short period in one summer day (ESCOSA 2012, p 29). This pattern of increasing demand in summer, accounts for the fact that the monthly average price of electricity in summer was three or four times higher than the annual average price. The price influence of seasons is clear in the following chart.

**Figure 1. Average Spot Price in South Australia**




*Source: Australian Energy Market Commission*

Thirdly, South Australia has a high proportion of generation in the form of wind power, which is economical but unreliable, unpredictable and difficult to control. With the installed capacity of 1,203 MW, wind generation is the second largest source of electricity power in SA. In 2011 – 12, wind farms in SA generated 3,349/GWh of electricity, which is equal to approximate 25% of total electricity generated (ESCOSA 2012, p 29).

Fourthly, the South Australian electricity market was once in government hands but has been successively and now thoroughly deregulated. The generation of electricity has been completely privatised and made subject to the pool for more than a decade and, in February 2013, the reforms culminated in the deregulation of retailing. Previously retail prices were determined by regulation, now retailers can vary the price without recourse to the regulator's approval. After February 2013, ESCOSA (the Essential Services Commission of SA) lost the power to set SAEM retail prices (SACOSS, 2013, p 1). The only constraint is the discipline created by the potential for users to switch to another retailer. This competitive pressure is muted because of the high switching costs for consumers, including that some retail contracts contain exit fees and those that do not have relatively higher prices or longer lock-in terms (SACOSS 2013, p1).

Finally, the SAEM is dominated by AGL, both in generation where AGL makes up 34% of installed capacity and in retailing where it holds nearly 55% of small customers (ESCOSA, 2012a, p 2).

All this suggests that the SAEM will have more volatile and higher prices over the long term as well as being more than usually vulnerable to manipulation, which can lead to more frequent price spikes. That prices are higher than elsewhere is indisputable.

According to CME, a private energy economics consultancy group based in Melbourne, elecriticity price in South Australia was the highest in Australia and the third highest among the 91 studied countries/regions in 2011. The electricity price in South Australia stood at nearly 30c/kWh compared to nearly 35 cents for Denmark (CME, 2013, p 11).

## 2.2 Events of 15 April to 7 June 2013

This section provides an overview of the price spikes and establishes that it was large in scale and unusual in its timing and characteristics.

In April 2013, South Australian volume weighted average (VWA) electricity spot prices were almost 165% of the mean price of all other states in the NEM. In May, the price differential increased to 215% (AER, 2013, p 5). These were the highest sustained prices for these months since the inception of the NEM. The price spikes causing these high averages continued into early June. There were eighteen spikes in the period when spot prices greater than $1,500/MWh.

The Australian Electricity Market Operator (AEMO) is concerned primarily with the engineering stability of the system and particularly the prospects of a lack of reserves (LOR) which lead to outages and blackouts. The gap between demand and available generation was small through much of the period and the AEMO forecast LOR1 conditions on thirty-four days and LOR2 conditions for seven days (AER, 2013, p 6).[1] Most of these circumstances did not eventuate but that frequency of notices is unusual. Conditions intensified and reached a near crisis on the 31st May, as we describe in detail below.

These price spikes and tight network conditions "occurred frequently during this period … such market outcomes are unusual for this time of year" (AER, 2012, p 4). They are more typical in summer when electricity demand peaks (AER, 2013, p 4). They had

[1] The Australian Electricity Market Operator (AEMO) measures available supply in a number of ways. Lack of reserve level 1 (LOR1) events mean insufficient reserves to meet demand in the event of the loss of the two largest generating units. LOR2 means insufficient reserves to manage the loss of the largest generating unit.

never occurred in April and May before, when demand is and was this time far below its peak.

To establish the scale of the event we have calculated the revenue that could have been generated by price spikes above $300/MWh and expressed that as a proportion of total revenue for the period. The $300/MWh figure is used because it is understood to be the price at which so-called peaking plants (i.e. plants that operate only when the price is high) are able to dispatch electricity. It is also the Administered Price Cap (APC), the price imposed on the market by AEMO if the Cumulative Price Threshold (CPT) is exceeded (AEMO, 2010, p 1).

We have calculated the revenue that is generated by these peak prices and compared that to the revenue generated by the more common summer price spikes over the last 3 years and the results are shown in Table 1 below. Note that the method for calculating revenue is described in detail in Appendix 2.

**Table 1: Potential Revenue from Price Spikes in South Australia, December 2010 to June 2013**

| | Dec 2010 – March 2011 $m | Dec 2011 – March 2012 $m | Dec 2012 – March 2013 $m | 15 April – 7 June 2013 $m |
|---|---|---|---|---|
| Spike Revenue (*where trading interval price exceeds $300)* | 176.2 | 0 | 29.9 | 56.9 |
| Total Revenue | 305.2 | 118.1 | 280.4 | 215.6 |
| Revenue from spikes as % of total revenue for the period | 58% | 0% | 11% | 26% |
| Revenue from spikes as % of total revenue for the fiscal year | 31% | 0% | 3% | 6% |

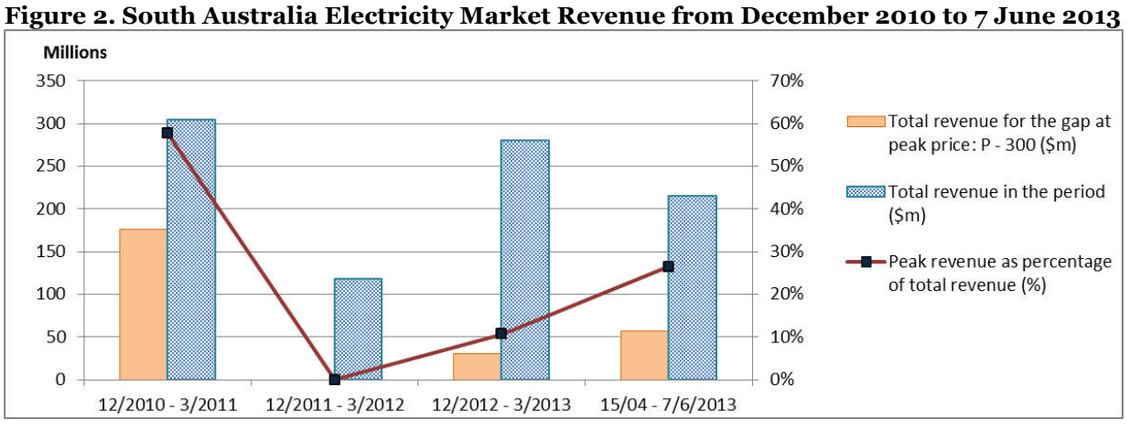
*Source: CMU estimates (see Appendix 2 for method)*

Note that we are estimating the potential revenue that could be derived from the price spikes, based on actual prices paid and dispatches determined by the AEMO. This is not necessarily the actual net revenue earned by generators, many of which have sold significant amounts under futures contracts and so at other prices. So we describe this as the potential revenue.

In 2010-11, the summer price spikes contributed more than half of the generators' potential summer revenue and 6% of the annual total. That was during the drought and heat waves of that year (the immediately preceding years also had major summer spikes) when South Australian electricity demand reached its record peak of 3,399 MW (AEMO, 2013d, p 9). Since then the available capacity relative has increased and demand has decreased so those summer spikes have declined. There were none in 2011-12 and those in 2012-13 were more moderate. The price events considered here is the

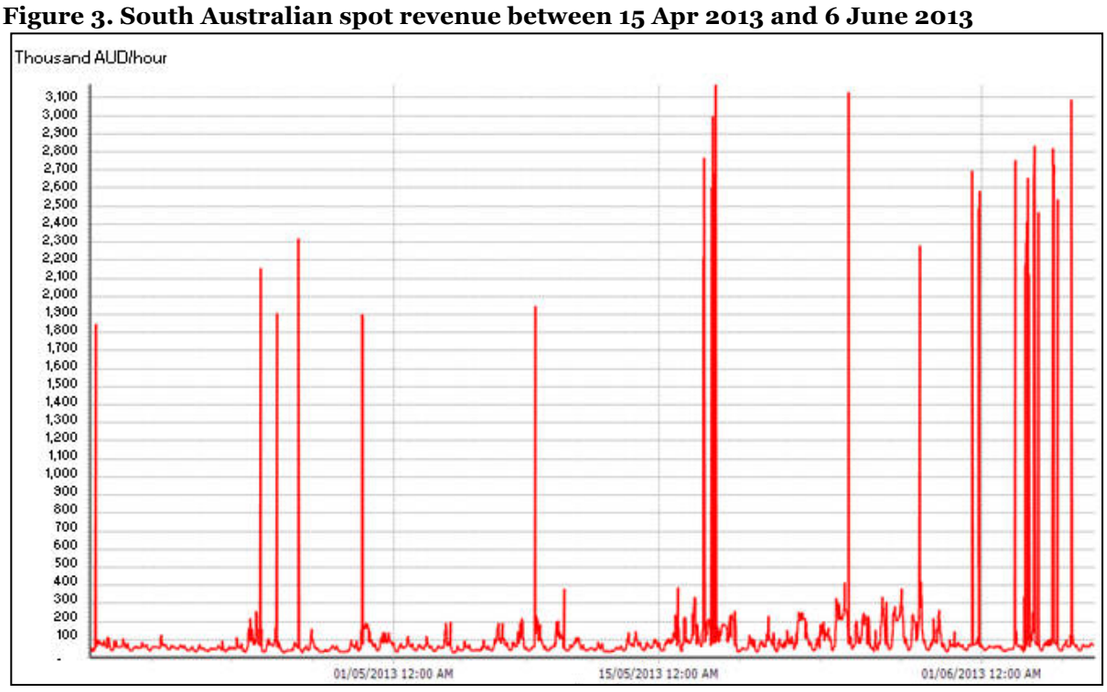
greatest cluster of non-summer spikes and occurred at times when demand was not at its peak. Clearly, these spikes had different causes than those in summer. They certainly created a considerable increase in potential revenue. In dollar terms it was the second biggest event since 2010 and was twice as big as the effects of last summer's spikes. Figure 2 illustrates the situation and shows that more than one quarter of generators' potential revenue in the May – June period could have come from the event.

**Figure 2. South Australia Electricity Market Revenue from December 2010 to 7 June 2013**




Another way of seeing how extreme was this set of price spikes is to show them against the normal spot prices as in Figure 3 below. While the spikes were only occasional they were extreme. And remember that these are averages of the 5-minute prices across a 30-minute interval. While the averages peak at over $3,000/MWh, the actual 5-minute prices were many times higher, as we discuss in the next section.

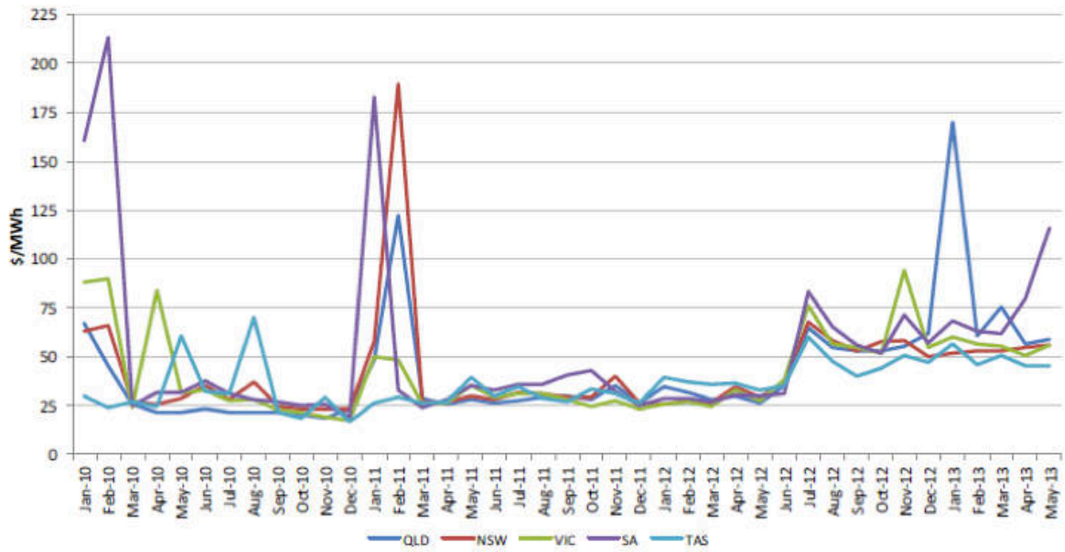
**Figure 3. South Australian spot revenue between 15 Apr 2013 and 6 June 2013**




*Source: 30-minute spot revenue, www.aemo.gov.au, modelled with NEM Review dedicated interpretative software.*

Having established its unusually significant scale, we can now show how unusual was this cluster of price spikes, as seen in Figure 4 below.

**Figure 4. VWA Monthly Spot Prices from January 2010 to May 2013**

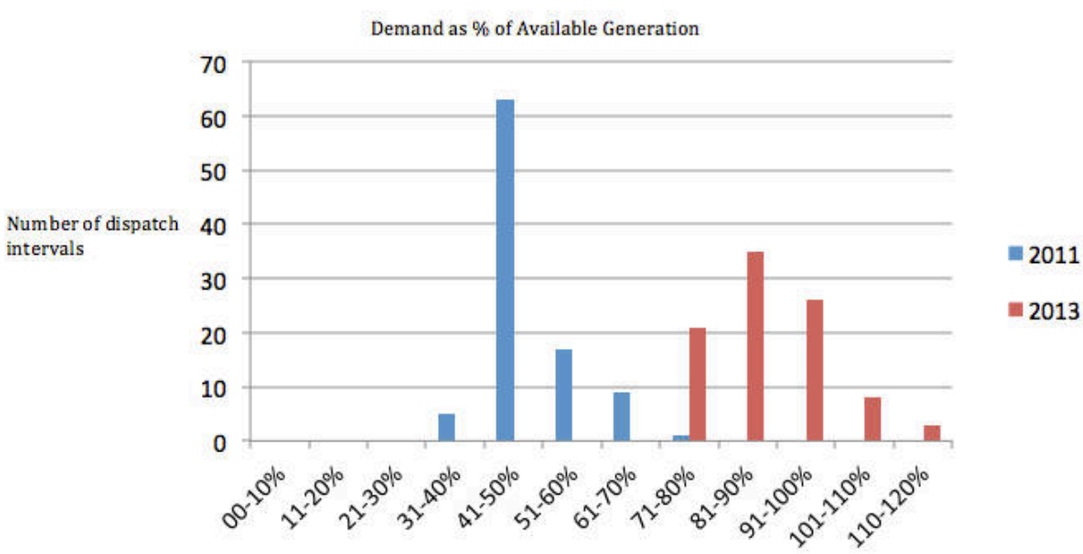



*Source: AER Special Report 92013, Figure 1, p. 5*

The figure shows average spot prices in each regional market since January 2010, with SA in purple. The major summer peaks are readily seen and occur in other regions as well. The point of interest is on the far right end with the significant South Australian price spikes occurring not in summer but in autumn. This is a unique pattern.

The same point can be seen in the following analysis, which compares SAEM demand and available capacity in 2011 and 2013.

**Figure 5. Demand as a % of Available Generation in 2011 and 2013**




*Source: http://www.nemweb.com.au/REPORTS/ARCHIVE/DispatchIS_Reports/*

In 2011, the most common situation, shown by the modal decile of demand relative to available generation, was that local supply exceeded demand by nearly double. By contrast, the modal decile in 2013 was 81 – 90%. In other words, the SAEM was in a chronic situation of having much less local capacity available in 2013 than previously. It

was not the peaky demand in the SAEM that was the problem but the lack of available capacity.

**Table 2. Maximum and Available Generation in South Australia in April and May 2013 (Thermal and Renewable Sources)**

| Generation Type | Maximum Winter Availability (MW) | Amount Withdrawn (MW) | Actual Winter Availability (MW) |
|---|---|---|---|
| Base Load | 736 (15.5%) | 546 (Northern Power Station) | 190 (6.7%) |
| Intermediate | 1,838 (38.5%) | 225 (20% of Torrens Island) + 240 (50% of Pelican Point) | 1,373 (48.2%) |
| Peaking Plant | 821 (17.3%) | 0 | 821 (28.8%) |
| Renewable (Wind) | 1,205 (25.4%) | 892 | 313 (11%) |
| Non wind, Non-Scheduled | 152 (3.2%) | 0 | 152 (5.3%) |
| **Total** | **4,752 (100%)** | **1,903** | **2,849 (100%)** |

*Source: Australian Energy Regulator (2013, pp. 7-8)*

Note Northern Power Station is owned by Alinta Energy, Torrens Island by AGL and Pelican Point GDF Suez.

The Special Report from the AER does not assess the reasons that generation capacity was withdrawn but, notes that the large Northern Power Station was off line because its owner, Alinta, considered that it because it is not competitive to generate electricity with brown coal at times of low, non-summer demand and that the absence of gas fired generation at Pelican Point and Torrens Island was for similar reasons (AER, 2013, p 8). The Special Report follows the in-principle argument that price spikes can result from tight supply/demand conditions and the strategic behaviour by generators. In other words, at times when there are low reserves of generation capacity, prices might rise for one of two reasons:

a) Because generators can increase output only at high cost or
b) Because they choose to price their offered electricity at greater than the cost of supply i.e. they act 'strategically'. It is just as accurate to say they act opportunistically. In an energy only market like the NEM, prices must be above SRMC at times in order to ensure the recovery of fixed costs. LRMC is subject to the number of hours available to recover these costs.

The AER ruled out a possible third, lack of <u>installed</u> capacity, which is reasonable given that demand was not at its peak – that occurs only in the summer months.

So, the AER listed the following contributing factors:

- Significant amount of local generation capacity did not participate – they had made commercial decisions not to generate;
- Inconsistent output of wind generation during peak demand periods – making it hard for other generators to schedule production;

- Interconnector limits – the price spikes began on 15 April, shortly after the Murraylink interconnector was limited by scheduled outages, and continued until early June when the interconnector was again fully operational;
- Off-peak hot water load caused changes in demand of 15 – 20% at exactly 2330 each day; and,
- Generators changed their pricing strategies.

In concluding our analysis of three particular episodes below we will offer some analysis of these contributing factors.

## 2.3 Detailed Analysis of Three Price Spikes

Detailed analysis is required to characterise these price spikes and reach a conclusion about them. It has been beyond the resources of the project to analyse all 18 spikes, so we have focussed on just three, making use of the so-called Price Event Reports, prepared by AEMO whenever prices exceed $5,000/MWh in any 5 minute trading interval. These Reports detail the technical situation at each spike and record the log entries required to be kept by generators. We have used these reports to focus on the three considered indicative of the cluster and have combined the analysis in those reports with our own detailed examination of the behaviour of the dominant generator, AGL. The combination is important: the AEMO and, subsequently the Special Report by the AER, suggest that these events were not caused by generators. We are considering the subsequent question of how the dominant generator responded to the circumstances. The selected trading intervals are those ending at 7:30 am on 15th May, between 7:30 am and pm on 3rd June and midnight on 24th May.

### 15th April, Scarce Supply and Forecasting Limitations

Spot prices reached $2,148.91 for the trading interval ending 07:30 am (AEMO, 2013a, p 3). At 7:05 am, a binding constraint on the Murraylink interconnector was invoked due to the risk of its being overloaded (this link remained constrained throughout the whole April – June period). This reduced the amount of electricity flowing into the state by 122 MW, 8.4% of total available generation at the time (available generation is the sum of electricity generated in South Australia and imported via the interconnectors). In addition wind generation was very low at 37 MW (AEMO, 2013a, p 3). Then, the Heywood interconnector also became constrained. The South Australian Electricity Market was isolated and supply was falling: how did the dominant generator respond?

AGL changed the offer price for some of its Torrens Island electricity. It had offered 100 MW to the market at $70.80 MWh but increased this to $12,599.80 MWh. This behaviour is called re-bidding. Because SA was isolated by constraints on the

interconnector and because the wind had dropped, AEMO's National Electricity Market Demand Engine (NEMDE) needed to accept AGL's bid for the 7:10 am dispatch interval. It is important to understand that AGL would have been aware of the constraints and made the high bid because it believed the probability of it being accepted was high.

After 7:15 am, prices eased dramatically (to $53.34 MWh) as the constraints on the interconnectors were relaxed. The behaviour of AGL changed immediately and they rebid 280 MW to that market floor price.

In summary, supply was constrained by an 8% drop and AGL opportunistically chose to increase its offer price by 1,790%. Such a price does not reflect costs of supply, neither the average cost and certainly not the socially optimal marginal cost.

### 3rd June, Lack of Reserve Conditions and Interconnector Constraints

This event occurred at the end of the period and illustrates the circumstances leading to the culmination of the price spikes. It can be characterised by its being an unforseen and unusual conjunction of events. Again, our focus is not primarily on the causes but on AGL's behaviour.

Supply conditions were already tight on 3rd June and AEMO was anticipating mandatory customer interruptions (AER, 2013, pp 13-14). Then, the wind dropped and three of AGL's four Torrens Island B power station turbines, owned by AGL and Osborne, owned by Origin, tripped i.e. they stopped generating because of technical problems. Reserve conditions were now on a 'knife edge' (AER, 2013, p 14).

Murraylink remained on a planned outage, as it had been since 15th May, but on this day an additional constraint was activated on the Heywood interconnector which had been operating at near capacity and hence, under the rules that govern its use, its was purposely constrained in the subsequent period. In essence, this caused losses of around 45 MW, equivalent to 2.3 – 3% of peak demand on the day. AEMO declared LOR1 conditions from 7:10 am on (i.e. insufficient supply to meet demand in the event of the loss of the two largest generation units).

This situation illustrates how the South Australian market can become volatile when it is isolated. Not only did we have reduced generation but also the interconnectors were constrained. At approximately midday, AGL advised of the additional loss of a turbine at Torrens Island A power station. The AER note that the loss of four generating units is a very rare event (2013, p 14). AEMO responded by advising of mandatory customer interruptions (LOR3 conditions) for the 6:30 and 7:00 pm trading intervals. AEMO was also predicting LOR2 conditions (insufficient reserves to manage the loss of the largest

generating unit) for the morning and evening. AEMO was able to cancel the LOR2 notice when Osborne returned to service in the afternoon and the event LOR3 conditions were avoided because Alinta had made a strategic decision to return Northern Power Station in Port Augusta to service earlier than planned, and because non-scheduled generators (i.e. electricity generators that are not a routine part of the market to be dispatched by NEMDE) were prepared to sell electricity to the market.

In summary, this day was the worst of the period. In these circumstances, available generators were in a position to increase prices and they did so, not occasionally but on 12 trading intervals for that day spot prices were around $2000/MWh (AEMO, 2013b, p 6). In this case, AGL was not involved as all of its major generators were off line. Table 3 below shows instances of re-bidding on 3rd June (there were also trading intervals on 3rd June where spot prices spiked to over $2,000 without rebidding).

**Table 3. Maximum spot prices, rebids, demand and interconnector constraints on 3rd June 2013**

| Trading interval | Maximum Spot Price $ | Rebids Name of generator, time lodged and time effective | Demand change Increase, in MW | Interconnector Constraints Decrease, in MW |
|---|---|---|---|---|
| 7:30 am | $12,199 | Alinta, 7:42 for 7:50<br>30MW from $49/MWh to $11,753 | 40 | 45 |
| 8:30 am | $12,300 | Origin, 8:21 for 8:25<br>37MW from $200 to $12,300 | 38 | 48 |
| 9:00 am | $12,190 | Alinta, 8:45 for 8:55<br>30MW from $49 to $11,573 | 19 | 0 |
| 11:00 am | $11,700 | Alinta, 10:49 for 10:55<br>60MW from $50 to $11,700 | 23 | 29 |
| 6:00 pm | $11,048 | Origin, 5:43 for 5:50<br>51 MW from less than $0 to $11,000 | 35 | 0 |
| 7:00 pm | $12,190 | Origin, 6:40 for 6:50<br>40MW from less than -$950 to $12,000 | 43 | 33 |
| 7:30 pm | $11,048 | Alinta, 7:18 for 7:25<br>60MW from less than $2180 to $11,753 | 60 | 0 |

*Source: AER (2013b, pp 6 - 14)*

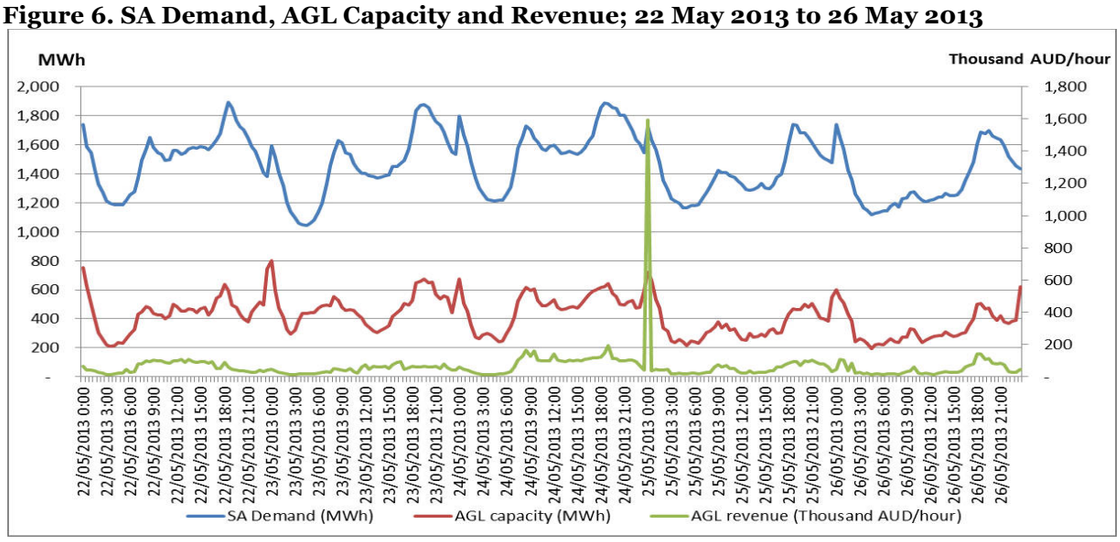
It is important also to add that there were five occasions on this day when regenerators rebid their capacity at negative prices, a circumstance where generators pay to stay online when the cost of staying online is lower than the cost of shutting down and re-starting their plants.

## 24th May, Demand Increases

The previous two episodes were associated with a conjunction of unusual events from which generators profited opportunistically. That suggests that the prices spikes result from short-term tactics where generators respond to unanticipated opportunities to push prices above costs. This last event is different and suggests more complicated factors at play. In this case, the increase in demand was highly predictable but the price spikes were just as severe and the regulatory system did not respond in any different way. Generators continued with their pricing behaviour, in the same way they did when the tightening was unanticipated: they pushed up prices dramatically. It suggests that it is not the unlikely conjunction of events but the preparedness of the generators to profit that is the cause of the problem.

Figure 6 below shows the situation. The top, blue line shows SA electricity demand at various times across 5 days. The important points are small on the figure; they are the spikes in demand (blue line) that occur each day at 23:30. These demand spikes are caused because many off-peak hot water systems turn on at that time. The problem has only recently emerged since more accurate, electronic timers have been retrofitted: 36,000 (of 79,000 in total) electronic timers were installed on hot water systems in 2011 – 12. The greater accuracy of these over the previous mechanical timers meant that nearly all of the off peak hot water heaters now turn on at the same time. As a result, the proportion of demand caused by hot water systems has increased, from 8% in 2009 to 13% in 2013 (AER, 2013, p 23) and each day, at 23:30, demand increases by 15 – 20%. This can be seen in the blue line on the figure. The figure also shows the electricity dispatched by AGL (the red line) and the revenue that created (the green line).

**Figure 6. SA Demand, AGL Capacity and Revenue; 22 May 2013 to 26 May 2013**




We are focussing on 24th May (the interval just before 0000 on 25 May) when demand increased by 16% from 11:30 to 11:45 associated with this known and scheduled off peak hot water. The corresponding flow on the Heywood interconnector increased from 167 MW to 449 MW but that was its limit and with low cost generators limited by their ramp

rate (i.e. the rate at which they can ramp up output), high priced generation had to be dispatched to meet demand (AER, 2013c, p 6). Prices over the 15 minutes increased from $70/MWh at 23:30, to $200 at 23:35 and $12,880 at 23:45 as AGL increased the price of its offers. As a result the spot price reached $2,216.57 MWh for the 30 minute trading interval ending midnight on 24th May as can be seen by the sharp increase in the green line showing the revenue of AGL (AEMO, 2013c, p 2). There was no rebidding in this trading interval.

The 24th May was not the only evening when prices spiked in the 2330 to 0000 period. Four of the eighteen trading intervals with price spikes in April – May 2013 were at these times but we have chosen it to illustrate the behaviour (AER, 2013, p 20).

## 2.4 Conclusions

Having provided an overview and then reviewed the details of three of the events, we are now in a position to characterise them. Firstly, there is no direct evidence that any generator, including AGL, sought to push up the price by constraining the system by, for example, withholding supply or congesting the interconnector. We have seen that a significant amount of generation was unavailable and there were constraints on the interconnectors. These created a chronic state of tight supply conditions and established the overall context in which acute periods of very tight supply emerged. And whenever the system was acutely constrained, generators took the opportunity to push up prices. Secondly, the bids made were not just high but were often made at the maximum permitted. Generators would have been aware of the tight situations and sought maximum advantage from every one of them. So generators might not have created the situations that were the proximate causes of the price spikes but they made use of them: when it was possible they invariably sought to profit from them to the greatest degree possible.

This characterisation is not inconsistent with the conclusions of the AER Special Report. In that report, the AER pointed to the overall conditions that created tight supply conditions. In particular, that "supply conditions were largely due to three major generation owners … making commercial decisions to reduce the amount of available capacity" by which they mean not at particular moments to push up prices but as a medium term decision to last through the winter season. This created a chronic situation of tight supply, which was exacerbated at times by the capacity constraints on the interconnectors, the variability of wind and the demand increases caused by off-peak hot water services.

However, our view departs from that of the AER when they make the next and last step in their report. The AER went on to say "it did not appear that the merchant generators

were seeking to capitalise on the tight supply conditions" (AER, 2013, p 32). We disagree. Generators might not have withdrawn capacity intending to create the tight supply conditions but they did not hesitate to bid greatly in excess of costs of supply when those chronic supply conditions tightened further. And they did that consistently. We do not see how the AER could reach that conclusion. We characterise it as the generators watching for anything that would make the chronic tight supply into an acute position and when that happened they sought to maximise their profit.

# 3. How is It Understood?

## 3.1 Introduction

It is uncontroversial to conclude that the price spikes were unusual and involved offers that did not reflect costs and likely generated super-normal profits. But our conclusion to the last section includes some controversial interpretations and so this section looks at how to understand the events conceptually rather than in their detail. Was this egregious behaviour on the part of the generators or is it understood as part of the normal functioning of the electricity market? Should regulators expect and accept this kind of bidding or should such behaviour be regulated or banned?

To answer those questions, we look at the event from the theoretical and then practical points of view. We find this is a case of imperfect competition and so a kind of market failure. But that raises questions about how a firm could profit in this way and we spell out the feasible and infeasible routes. Then, this section considers the legal and regulatory positions. We describe the positions and assess their adequacy as preparation for the final section where we make our recommendations.

## 3.2 Economic Theory

The theoretical position is straightforward: whenever a firm has market power it is in a position to make so-called super-normal profits. This means that prices exceed the average costs of production. The situation can persist and recur if there are some barriers to the entry of other firms who would otherwise enter and compete away the profits. The efficient outcome occurs when prices equal the marginal cost of supply: then the decision of the retailer to buy one more or one fewer unit of electricity is based on weighing the benefits or one more or fewer against the price to be paid for one more or fewer. When a firm has market power, there is said to be a situation of imperfect competition and this reduces efficiency and imposes a loss, a so-called dead weight loss, on the system. It also redistributes the gains away from buyers of electricity and towards the producers. This redistribution is unimportant in theory (which is only concerned with the issue of efficiency) but has important ethical and political implications.

However, there are two important, additional points, both related to the idea that electricity generation is subject to economies of scale i.e. that average costs will decline as output increases across the range of relevant levels. Firstly, that means that marginal costs will be below average costs (if average costs are falling, it means that the cost of one more – the marginal cost – is less than the average of all previously produced units).

In economists' jargon this is a natural monopoly. The socially optimal price (equal to the marginal cost) is therefore below average costs and if regulators require that generators charge that price they will impose losses on the firm. This would deter investment. In short, to provide the incentives to invest in and expand capacity, prices must exceed marginal cost at some times.

Secondly, the theoretical considerations must be weighed against the practical. In particular, the presence of scale economies means that if there were new entrants and more competition, each generator would be subject to higher costs. In other words, creating more competition would reduce the profit margin of generators but add to their costs and so not necessarily give the improvement suggested by the theory.

Nonetheless, the concept of market power can be analysed more deeply to reveal its sources and hence potential solutions. We do so using a set of diagrams created by Professor Frank Wolak of Stanford University, replicated here with additional explanation. We illustrate the central concept of a residual demand curve facing the dominant generator in the market and show that when a dominant generator's rivals face increasing costs in supplying demand, that dominant generator can profit when capacity is constrained. This makes use of the so-called Inverse Elasticity Rule and is also known as Ramsey pricing i.e. if demand for a firm's output is relatively unresponsive to price, the firm can profit when others' output responses are restricted.

In Figure 7 below, is the level of market demand for a given hour. Consumers face a retail price, which does not vary with the spot market in the short term, and so demand does not vary with changes in the spot price, shown on the vertical axis. SO(p) is the aggregate willingness to supply of all suppliers other than the dominant generator and is a function of the market price.

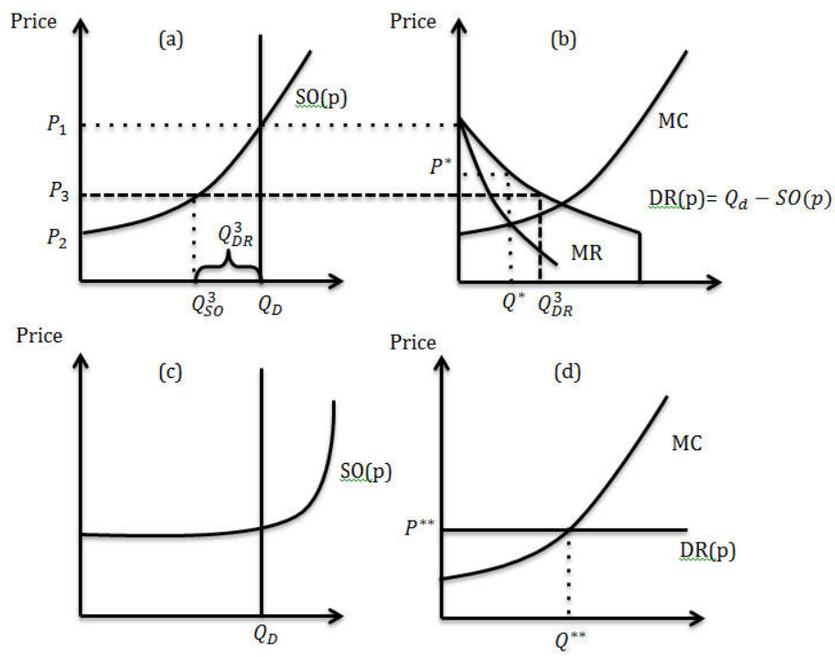
For Figure (b) and (d), DR(p), the residual demand curve facing the dominant firm, is determined by subtracting from the market demand, the amounts supplied by other firms at various prices. Consider price = $P_2$. At that price, no other supplier is willing to supply, so at that price all market demand is met by the dominant firm. For price = $P_1$, other firms offer enough to supply the whole market, so the dominant firm would supply none; at $P_3$, other firms supply $Q_{SO3}$ and the dominant firm $Q_{DR3}$ (=$Q_D$ – $Q_{SO3}$).

The graph also shows an indicative marginal cost curve (MC), as well as the marginal revenue curve (MR) for the dominant supplier. The intersection of MR and MC is the profit-maximising level of output (for this supplier given the bids submitted by all other market participants). The generator can sell that quantity at a market price.

The critical distinction to be made is between the pairing of (a) and (b) on the one hand where the dominant generator can exert market power and (c) and (d) where they

cannot. In both cases the supplier produces profit-maximising level of output at the intersection of DR(p) and MC: so Q** when it cannot exert market power and the smaller amount Q* when it can. The market price with market power is P* which is greater than without, P**. And P = MC when there is no market power; P > MC when there is not.

**Figure 7. Residual Demand Elasticity and Profit-Maximising Behaviour**




*Source: Wolak (2013, p 108)*

In Figures (c) and (d) the market is being supplied by other firms, which are competing with each other and offering their capacity at its marginal cost, which is (near) constant until each generator faces their capacity constraint. Hence SO(p) in the bottom pairing is flat across the section to at least $Q_D$ meaning that the other firms are able to service the whole market. The dominant generator can sell only at the price determined by others' marginal costs and, as a consequence, the demand curve facing the dominant generator is perfectly elastic, meaning that if they tried to raise prices they would sell nothing.

By contrast, in the top pairing, firms are offering capacity in a situation of rising marginal cost. This means that there can be significant residual demand at any price but that the amount will decline as prices rise. This gives the downward sloping residual demand curve in figure (b) and it means that the dominant generator can set a price above its own marginal cost. In effect, competition among the other generators is now muted by their rising marginal costs and so the dominant generator has some ability to set price by withdrawing capacity. This is exercising so-called "unilateral market power" (*ibid*, *passim*).

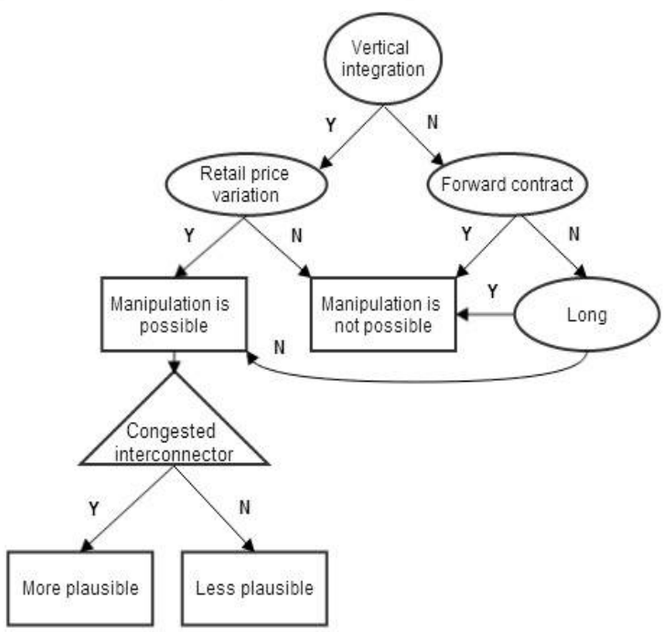
Wolak's use of economic theory provides further insights. It shows us that anything that will constrain others' ability to supply the market will increase the market power of the

dominant generator. Hence, if the system is subject to engineering constraints, the market power is enhanced. This is particularly relevant with regard to congestion or outages on the interconnectors, including the tightness of the rules that seek to ensure stability of the connections. It also emphasises the importance of wind power: when the wind stops, the market power of the dominant generator is enhanced. Finally, Wolak's diagrams indicate the importance of invariant demand, owing to the fact that users are protected from variations in the wholesale price. If consumers faced the variable wholesale price, they would reduce their demand when the system was constrained and that would limit the increase in the pool price, constraining the market power of the dominant generator. We return to these matters in section 4.1 below.

## 3.3 Using Market Power in Practice

Given that theory points out how market failure exists in the energy markets and can give rise to opportunities for super-normal profits, we have developed the logic to reveal the scenarios under which electricity price manipulation is both possible and plausible. The situation is summarised in the following figure:

**Figure 8: Plausibility of Price Manipulation**




The diagram begins with the question of whether the generator is vertically integrated with a retailing operation. That is critical: if they are vertically integrated <u>and</u> retail price variation is not allowed (so higher spot prices cannot justify higher retail prices – at least not without a major overall review) then there can be no gain in manipulation. This situation is the case for some users, including some vulnerable users who remain subject to the so-called standing contract price, which is set by regulation and may not be varied by retailers. Such customers are a small and declining part of the SAEM.

Where retail price variation is possible, and that is the case for many South Australians since deregulation of retail prices three months before this event, generators can benefit, even if they are vertically integrated with retailing, as is AGL. And, of course, the likelihood of being able to manipulate the price is greater the more isolated is the price pool.

The situation is more complicated if the generator sells electricity in the forward market i.e. it commits to supply a user a given amount at a given time at a given price. This means a situation where, in effect, the generator receives the spot price (as determined by the market conditions under AEMO rules) but also a different price from a user who takes electricity from the grid with the generator needing to pay for that electricity from the grid. If the generator provides more to the spot market than it has committed to supply in its forward contracts it does not need to pay for more electricity from the grid than it supplies to the grid. It is said that the generator has gone long on the spot market. In those circumstances the generator will receive a net benefit if the spot price increases. In other words, then price manipulation possible. (By contrast if the generator goes short it has a net deficit at the time – it has committed to supply more than it generates at that moment.)

This says that a possible and plausible scenario is where a vertically integrated gen-tailer, in a deregulated retail market, could benefit when capacity is constrained e.g. by a reduction in wind and the interconnector is congested. This possibility is further enhanced when a generator (vertically integrated or not) has gone long in the forward market and has excess capacity still to sell. This conjunction of features aptly describes the situation of AGL when it benefited in the three particular instances reviewed in section 2.3 above.

Now that theory and practice conclude that the SAEM has a market design where generators could exercise market power, what is then the acceptable behaviour under the law? The next section clarifies what is legal and illegal given imperfectly competitive supply. It mentions of cases where generators have been accused of crossing the line in misusing its market power. But we will see that is difficult to prove.

## 3.4 Legal Considerations

The Australian Competition and Consumer Commission has carriage of laws governing market power. This section outlines those laws and assesses the possibility that some of the behaviour of some of the generators might have been illegal. It also provides some case law, drawn from Australia and other jurisdictions, as illustrations.

Section 46 of the Competition and Consumer Act of 2010 defines market power as the ability of a business to insulate itself from competition. It states further that possessing market power becomes illegal when it is used "for the purpose of eliminating or substantially damaging a competitor or to prevent a business from entering the market" (Australian Government, 2010, S 46). The Act declares such behaviour a misuse of market power, which is illegal in Australia. However, the existence of market power is not illegal, nor is supply at prices above those that would exist with full competition. So there is no *prima facie* case against the generators under competition law.

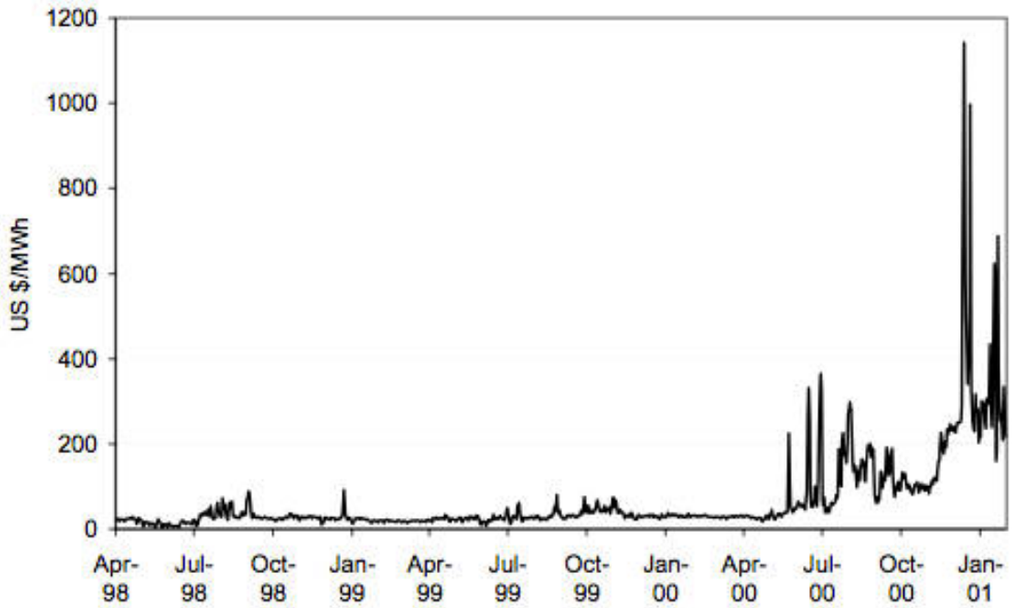
It is also possible to apply other tests to indicate legal culpability. Firstly, there is the test of intentions: if a firm has market power, was it acquired intentionally i.e. did it arise because of conscious action by the imperfectly competitive firm? Intentions are difficult to gauge but, in the cases we are examining, the firm's market power arises only temporarily, when other parts of the system become constrained. This suggests that it is not the result of conscious manipulation by the temporary removal of capacity. The existence of market power acquired unintentionally is not illegal.

A second indicative test is that of behaviour: has the firm acted in ways that were possible only because it had market power? Here the evidence seems implicate the generators. We saw in section 2.3 bidding and re-bidding behaviour clearly designed to profit from short periods when a generator possessed market power and which would have been impossible without the market power. AGL and others fail that test but failing that test alone is unlikely to make their behaviour illegal.

This suggests there is no legal remedy for the behaviour of generators. We can check that conclusion against the experience in other electricity markets. There are multiple instances when the exercise of market power by generators has led to considerable short-term price spikes, sometimes accompanied by electricity blackouts but only in the most egregious instances have cases been successfully prosecuted.

For example, in 2000, California experienced an electricity crisis leading to massive blackouts throughout the state. During this time, wholesale prices rose to extreme heights.

**Figure 9. Daily Average Wholesale Prices in California, 1998-2001**




*Source: Devries, 2004, Based upon data from the University of California Energy Institute*

The market experienced a shortage in generation capacity due to the drought, which limited the available hydropower, and the summer season, which increased the demand. Because consumers were charged a fixed retail price, they did not respond to the high wholesale prices, meaning demand was unconstrained (De Vries, 2004, p 52). There was a near-complete absence of forward contracts in this market and retailers purchased all their electricity in the wholesale market. We have seen these are ideal conditions to profit from pricing above cost: retailers must buy at volatile, sometimes high, market-based wholesale prices while charging regulated fixed retail prices which reflect costs of supply. This led to losses and financial difficulties for the firms, resulting in the collapse of the market (ibid).

The supply situation tightened further when the generators withheld capacity, which drove prices up further. Firms had market power and were in a position and had the incentive to abuse it. The California Public Utilities Commission found that majority of the outages was caused by strategic withholding involving all of the major independent electricity generators. Yet, the generators were losing income since retail prices were fixed. By February 2001, as wholesale prices remained high, the two largest generators lost USD 12 billion (ibid).

Another instance was in New Zealand where there was a period in March 26, 2011 when the wholesale price for electricity exceeded the $20,000/MWh price band. The high prices were a result of several factors—scheduled maintenance of transmission lines, underestimation of demand by the System Operator and the so-called spring washer effect. (The 'spring washer effect' is a situation where there is a constraint in a transmission loop. The generator can overload a weak link so that high priced

generation is used.) Genesis, a New Zealand operator, was believed to be in a net pivotal position to influence the price (Electricity Authority of New Zealand, 2012).

The Electricity Authority of New Zealand found the price hike to be an undesirable trading situation (UTS), where buyer confidence is seriously undermined due to high prices and lack of awareness. In this case, Genesis was in a position to determine prices and the parties involved had no time to seek supplies from other sources. It rejected however the allegation of price manipulation by the generator (ibid, 2012). In other words, this behaviour contravened the regulatory rules but not competition law.

An instance occurred on 22 and 23 February 2008 in Australia when Queensland spot prices exceeded $5,000 MWh on 14 occasions, "peaking at $9,561 MWh and $9,153 MWh respectively" (AER, 2008, p 1). Three factors were said to have contributed to the spot price spike: change in demand, generator offers and rebidding and changes to network availability.

The context of these price spikes was different from those considered here. Temperatures reached 33 degrees in Brisbane on the 22nd, driving demand to 8,100 MW, its highest level for the summer. Demand varied between 7,865 MW and 8,055 MW at the time of high prices and was up to 280 MW above the forecast (ibid, p 2). Around 2,200 MW available generating capacity was offered at prices exceeding $5,000/MWh. Then, Stanwell Corporation presented an average 426 MW of capacity at prices above $5,000/MWh with a further 420 MW of capacity not presented to the market (ibid, p 4). These rebids were short in duration and extended a number of times during the day.

Then on the 23rd, temperatures reached 39 degrees resulting to the highest weekend demand ever. Actual demand on the day peaked at 7,978 MW and was up to 486 MW higher than forecast (ibid, p 2). In addition to the circumstances, imports into Queensland across the Queensland to New South Wales (QNI) and Terranora interconnectors were restricted to a combined total of less than 200 MW (ibid, p 3). This time, 2,470 MW of capacity was priced above $5,000/MW. Again, Stanwell Corporation presented an average of 780 MW of capacity at prices above $5,000/MWh, with a further 296 MW of capacity not presented to the market (ibid, p 4). Rebidding from 12.11 pm shifted 420 MW of capacity from prices of less than $100/MWh to above $5,000/MWh.

In response, the AER alleged Stanwell Corporation did not make several offers of electricity in good faith based on the National Electricity Rules (NER). The rule states that a "Scheduled Generator, Semi-Scheduled Generator or Market Participant must make a dispatch offer, dispatch bid or rebid in relation to available capacity and daily energy constraints in good faith" (NER, 3.8.22A1). Furthermore, the rule asserts that at

the time of offer, either bidding or rebidding, the said generator has a "genuine intention to honour that offer, bid or rebid if the material conditions and circumstances upon which the offer was based remain unchanged until the relevant dispatch interval (NER, 3.8.22A2).

AER sought orders, which included declarations, civil penalties, a compliance program and costs (AER, 2009a). The case went to the Federal Court and lasted two years. In the end, the Court did not rule there had been a breach in the good faith provisions of the NER (AER, 2011a).

This review of the legal situation suggests there is unlikely to be a legal remedy for the behaviour seen in South Australia. Economic theory and an understanding of practice provide for the possibility and plausibility of market power being obtained and then misused by generators but there has been no clear evidence of misuse of market power, either in international or local instances. If a legal remedy is unavailable, is it possible that the regulatory rules of the market can provide a means to redress the outcomes and deter any recurrence?

## 3.5 Regulatory Responses

The attitude of the regulator has been made clear in its submissions to the AEMC. The AER points out that there are no specific provisions in Electricity Law or Rules relating to the exercise of market power. Only one clause (3.8.22A) requires that generators must make offers and rebid in good faith.

The position of the AEMC, consistent with the view from theory, places considerable emphasis on the notion of barriers to entry: "only in the presence of significant barriers to entry can substantial market power be sustained" (AEMC, 2013a, p ii). The idea is that if the exercise of market power is profitable it will induce new entrants. In other words, only if market power persists does it become a problem that would do significant harm and it can only persist if there are identifiable barriers to new entrants who otherwise would necessarily add to competition and reduce the ability of dominant generators to exercise market power. In short, barriers to entry are associated with the misuse of market power and so if a case is to be made it must be possible to identify significant barriers to entry. The existence of barriers to entry is the primary evidence needed for a regulatory response.

There are obvious long-term barriers to entry in electricity generation. These relate to the cost, time and regulation surrounding bringing new generating capacity on line. Such barriers reduce competition and can lead to high prices. They are part of the bigger picture of the electricity market. However, they are not central to explaining the

price spikes that are the subject of this report. That requires a focus on more acute, short-term barriers to entry such as would restrict the ability of existing generators to respond to and hence attenuate price spikes in the short-term.

The key is that only suppliers operating their units in real-time with unloaded capacity or quick-start combustion turbines at the right locations in the transmission network can compete to provide electricity to the real-time energy market. This situation can allow for the temporary curtailment of competition. If a generator knows that there are constraints on other generators and on interconnectors, it can recognise it has transitory market power and bid or re-bid accordingly to make super-normal profits. This is how we characterise AGL's behaviour. And we see it as dependent on short term but repeated barriers to entry.

The position of the regulator when assessing the potential for the exercise of market power focuses on both the scale and frequency of any price spikes that result. The question is whether the price spikes "occur frequently enough and to a significant enough magnitude … to change average price to greater than long-run marginal cost" (AEMC, 2013, p I, emphasis added). The AEMC actually goes further than that and acknowledges that market power may be (i.e. is allowed to be) exercised "through occasional spot price hikes, as it is an inherent feature of a workably competitive wholesale market" (ibid). Furthermore, there is an expectation, as stated above in discussing marginal cost pricing in the electricity industry that "high prices are expected at times … and are not necessarily evidence of the exercise of market power (AER, 2011, p 4)." This is reflected in the guidelines the AER prepares for rebidding. We saw that rebidding played a major role in the events of April to June 2013. The AER states that it "allows participants to adjust their commercial position (i.e. their bids) in response to changing events or market conditions" (AER, 2009b, p 11). In other words, rebidding to make use of temporary market power is permitted.

By adopting this focus, the AER is conceiving of the problem not in legal but in practical terms. It moves the debate from argument by counsels in court to one focussed on the broad phenomenon of so-called commercial or market bidding i.e. when "generators bid or rebid capacity which is normally at low prices into much higher price bands" (ibid, p 6). So the process is for the AER to look to cases where a generator bids or rebids capacity at high prices when that capacity is usually low priced. These "indicate that economic withholding clearly does take place" (AER, 2011b, p 8). Again, to stress, if an isolated incident, this is not illegal nor does it contravene regulatory rules.

The stated, final position of the regulator is based not on the events of April to June 2013 but on a longer term view, cited by the AEMC, that because average pool prices have been declining (AER, 2011, p 6), the system must be working. Average pool prices

are moving towards long-run marginal cost and that implies that if there is manipulation of the market, there is no manipulation of concern.

The AEMC has gone further to the view that substantial market power does not exist in Queensland, NSW and Victoria. However, in relation to South Australia, the picture is less clear. While it has insufficient evidence of "the likely exercise of market power" the AEMC also "considers it is not clear as to whether substantial market power existed" in South Australia (AEMC, op cit, p iii). So, in the case of a price spike event such as this, action might be considered. Substantial, retrospective action is unlikely but it should be noted that the AEMC is considering "making a rule which would put in place … a monitoring regime … to regularly report on whether the wholesale electricity market is workably competitive" (paraphrase, pp v – vi). We take up that point in section 4.3 below.

In conclusion, the lack of specific legal and regulatory provisions and the failure to succeed at prosecution have resulted in the AER focussing not on what might be illegal but on action which might lead to higher average spot prices. In other words it is taking up the suggestion of the AEMC that this behaviour is a problem only if it leads to a so-called SSNIP i.e. a small but significant non-transitory increase in price. The event we are considering was sustained over an eight-week process and has added about 6% to the annual average pool price and so in itself is a small but significant increment. However, it might not be thought of as transitory and that is the central point: if price spikes are ad-hoc and infrequent they are less of a concern but if they recur frequently they would constitute an SSNIP and that should trigger a regulatory response. Our recommendations to SACOSS are informed fundamentally by that point.

# 4. WHAT DO WE RECOMMEND?

## 4.1 Partial Remedies

This section considers possible responses to the price events guided by the logic and principles underlying them. Subsequent sections consider how to respond to any recurrence of the price spikes. This section considers whether it is possible to change the regulatory or market environment to make it more difficult to exercise substantial market power. The central proposition is that if these partial remedies were in place, the probability of a recurrence is reduced and the need for direct action is lessened.

Again, we rely on the reasoning provided by Professor Wolak who has identified several strategies to reduce the incentive for suppliers to exercise unilateral market power (op cit, pp 39 – 54).

The first option is to require that the dominant generator divest itself of generation capacity. A firm is in a pivotal position when its generation capacity is needed to serve the market demand. Then, the firm maximizes its revenues by bidding all of its capacity at the highest bid price possible. Hence it is proposed that dominant generators give up existing capacity to new entrants or small existing firms. Then it loses its capacity to be pivotal and the residual demand curve it faces becomes more elastic. However, by divesting one's capacity, firms lose economies of scale. As a result, production costs will be higher and that can lead to higher prices. A judgement is needed to determine if the enhanced competition provides greater benefits than the reduced enterprise scale.

A second option is to extend the use of forward contracts. The more of available generation that is sold at a fixed price, the less is the incentive to bid or rebid at high prices. Since the price has been agreed upon already, there is no incentive for suppliers to drive up the market price. In addition, forward contracts can create incentives to avoid pushing up prices: if a supplier does not have sufficient capacity to meet its forward contract obligations (in the jargon it has gone short in the forward market), it has an incentive to bid below its marginal cost in order to drive the market price down. By bidding more aggressively, other suppliers will follow suit in bidding aggressively as an incentive, facing a more elastic residual demand curve. Again, there are costs associated with this option: managing forward contracts can be expensive, as firms must have access to market information to be able to properly manage the associated risks.

The third option is to enhance the participation of retail consumers in wholesale market. If retail prices reflected changes in the wholesale prices, then consumers would adjust their consumption accordingly. They would increase demand at low prices but would reduce demand if generators created price spikes. A dominant supplier would then face

a more elastic residual demand curve. This outcome can be achieved by installing so-called smart meters, which record hourly consumption and allow the retailer to charge the customer according to the variable spot price. However, smart meters are expensive and this option also requires a change in behaviour from consumers. They must be educated to understand the new pricing scheme and so they can adjust their consumption.

The final option is to expand the interconnectors. Currently, the AEMO focuses on the engineering reliability of the transmission network and constrains interconnectors if there is any threat to their stability. This approach can be sub-optimal because it can constrain interstate transmission too greatly. The operation of the market could be improved by also considering the economically reliability of interconnection: ideally interconnectors will have sufficient capacity so that distant generation units provide sufficient competition with local units. The greater the economic reliability, the less the ability of any single generator to be dominant. A strong interconnection increases the number of suppliers who are able to compete in a certain area and prevents suppliers from congesting the network, avoiding a local monopoly. This is an attractive solution and efforts are currently underway to expand capacity on SA's interconnectors (AER, 2013). However, this is a requirement on the network in addition to that needed for stability and reliability and it will come at a high cost.

Given that these are all partial solutions and all have associated costs, it is likely that they will not be comprehensively pursued. That raises the question of what else might be done.

## 4.2 Preparing for Possible Recurrences

As argued above, it is unlikely that any action will be taken with regard to these incidents. To pass the threshold of the SSNIP test will require a recurrence and this section prepares our client for such a possibility. We provide a set of three tools SACOSS can use to respond.

Firstly, we detail the significant events leading up to the price spikes and immediately after in order to consolidate a substantial chronology which we attach as Appendix 3. This provides detail about the context of any future event by discussing information on the technical, market and regulatory conditions which in the past have elicited comment. In particular, it summarises the assessments of the AER and other regulators and details the corresponding action taken, including by SACOSS.

Secondly, it is important to determine quickly the scale of a future event and particularly whether it is sufficient to cause an increase in the average pool price. We have made

such estimates in preparing this report and we have consolidated the method used into an instruction manual, attached at Appendix 3, which shows how data can be obtained and collated in a spreadsheet to make the relevant calculations. This tool can be used to assess whether high pool prices during a certain period will significantly increase the average price for a longer period (normally at least a year). This will aid in determining whether the price events constitute an SSNIP and provide a piece of information that is likely to be used in media reporting.

Thirdly, a press release template has been prepared. This document summarizes main points that can be communicated to the public in case of a recurrence and is included in Appendix 4.

### 4.3 Assistance for Vulnerable Users

This final section turns the attention to the people who are the focus for SACOSS, the vulnerable users, especially true of those customers who suffer disconnection because of non-payment of bills (AER, 2013, p 5). We propose measures designed to protect then from the impact of a recurrence of these price events. This section reasons that a very small part of the additional revenue created by these price spikes be retained in a fund to assist people in these circumstances.

This idea was implied in SACOSS' submission to the AEMC inquiry into market power where the Council recommended the Commission address not the question of proving that market power has been misused but the "null hypothesis": what is the set of plausible conditions that would need to be met so that end consumers are insulated from the impacts of behaviour by the dominant generator (AEMC, 2013, p 85)? The idea is also found in Professor Wolak's work when he states the view that a generator who wants to sell at "market-determined prices, rather than at cost-of-service prices" must "demonstrate that it has no ability to exercise unilateral market power" (Wolak, 2013, p 16).

Our reasoning is that when generators make large windfall gains from pricing electricity beyond its marginal cost, the onus of proof is shifted to them to demonstrate that this is not a commercial decision but the result of technical or other factors over which they have no control. If they cannot demonstrate this and instead have simply made a commercial decision to profit when the system is constrained a penalty, amounting to 0.5% of revenue generated, should be paid to a Vulnerable Users Compensation Fund. This Fund shall be used primarily to reconnect electricity for vulnerable consumers who are unable to pay their bills resulting from the high electricity prices.

This proposal has strong theoretical support. The regulators are arguing that the current regime is efficient. In economists' jargon, the regime is said to provide Pareto improvements by supplying electricity at lower average cost. The regulator is unconcerned about who gains, only that there be a net gain. Related to this, the Kaldor-Hicks compensation principle states that an outcome will be more efficient if those who are made better off could in theory compensate those that are made worse off (Hicks, 1939, Kaldor, 1939). We are not arguing that all users be compensated but rather that vulnerable users be protected from the extreme outcome of disconnection and so we propose that electricity generators should compensate small users through this fund.

This proposal does give rise to the so-called moral hazard problem. A moral hazard arises when a party is willing to take more risks because the potential costs would be borne by others. In this case, the intended beneficiaries of the fund will have an incentive not to pay their electricity bill because the fund will bail them out.

To address this issue, the following measures need to be incorporated into the Vulnerable Users Compensation Fund:

- It is recommended that management of the fund be under ESCOSA.
- There should be a clear criteria and verification process regarding who would be eligible to avail of the fund so that only those who need the assistance are able to avail of it.
- A consumer can avail of this assistance only once.
- Those who avail of the fund must go through a consumer education program. This is intended to increase awareness on the benefits of energy efficiency and to provide information on practices that can be adapted to support this, including monthly monitoring of electricity bills.

These measures are intended to prevent abuse of the Fund and to provide a comprehensive approach towards assisting low-income households.

### 4.4 Regulatory Reforms

In our discussions with SACOSS we have become aware of many instances where the Council is seeking improvements to the regime, which are also sought by or are related to the work of the AER. We recommend that SACOSS provides public statements of support for these policy and operational changes. These include:

- AEMC call for AER to have a greater role in monitoring the exercise of market power. In the Final Rule Determination on Potential Generator Market Power in the NEM, the AEMC explored the possibility of making a rule that would give the AER a role in monitoring the wholesale electricity market. However, it is yet to

be established if this function is aligned with the current functions of AER. (AEMC, 2013, p i)

- In response to the Proposed Rule Change on Potential Market Power in the NEM, the AER suggested the following alternatives to address the problem:
  (1) "Structural reform of the generation sector - while challenging to implement, structural reform of the generation sector would be the best solution to any market power problem."
  (2) "Alternative behavioural solutions - the MEU has presented one form of behavioural solution seeking to address market power, but other approaches should be considered, particularly drawing upon international experience." and
  (3) "Changes to the Administrative Price Period (APP) mechanism in rule 3.14.2 of the National Electricity Rules such changes may assist in lessening the potential harm to the market when market power is exercised" (AER, 2011b).
- The AER has called on the AEMO to review the treatment of interconnectors in the Network Constraint Formulation Guideline (AER, 2012a). This relates to the way in which AEMO limits the capacity of the interconnectors to ensure a high minimum level of engineering stability. These decisions do not take account of the market power they can create in South Australia and need to be modified.
- Review bidding rules and arrangements for settlement of generators to limit practice of disorderly biddings in NEM (AER, 2012a). This is a complicated matter but its relevance to the price events discussed here is obvious. Generators need to be more closely constrained in making their bids in good faith.

## APPENDIX 1 THE PROJECT TEAM

**Board Membership**

| | |
|---|---|
| **Mr Ross Womersley** | Chief Executive for SACOSS |
| **Ms Jo De Silva** | Senior Policy Analyst for SACOSS |
| **Mr Andrew Nance** | PhD candidate at UCL and Consultant for SACOSS |
| **Ms Aditi Varma** | Senior Analyst for Independent Market Operator (WA) and CMU-Alumni |
| **Mr Colin Underwood** | Director for Programs for CMU-A |

| | |
|---|---|
| **Project Team** | MS Public Policy and Management |
| **Dr Paul Chapman** | Capstone Adviser & Adjunct Faculty for CMU-A |
| **David Cripps** | |
| **Laila Deles** | |
| **Boom Enriquez** | |
| **Hieu Ngo** | |
| **Marlon Obligado** | |
| **Hiroki Seki** | |
| **Nga Tran** | |

## APPENDIX 2 METHOD FOR COMPARING AVERAGE POOL PRICES WITH AND WITHOUT PRICE SPIKES

### Background

This document serves as a tool for users to analyse wholesale spot prices in the NEM. Specifically, it is a step-by-step guide to estimate the revenue earned by generators and to determine whether the revenue earned would constitute a Small but Significant Non-transitory Increase in Prices (SSNIP). The occurrence of an SSNIP implies a firm's misuse of its market power.

To do this, an estimate is made of the average wholesale spot price with and without price spikes for a given observation period. There is no actual value for a SSNIP but if the average spot price for a year increased by 5% with the price spikes, then this would imply significant pressure on retail prices and is likely to signify an SSNIP.

To perform this analysis, data on wholesale spot prices are needed. These can be downloaded from the AEMO website. Basic proficiency in various Microsoft Excel functions, such as copy, paste and use of arithmetic formulas is also essential.

### Steps

1. Obtain AEMO Data on Average Daily Prices for South Australia for the desired period of observation. The Average Daily Prices are the 30 minute averages of the five-minute dispatch intervals Regional Reference Prices (RRP) for every 30 minutes starting from first 30 minutes of the day at 0:30. See Figure 1a:

Figure 1a:

| REGION | SETTLEMENTDAT | TOTALDEMAND | RRP | PERIODTY |
|---|---|---|---|---|
| SA1 | 4/1/2013 0:30 | 1446.44 | 57.62 | TRADE |
| SA1 | 4/1/2013 1:00 | 1387.34 | 59.11 | TRADE |
| SA1 | 4/1/2013 1:30 | 1296.87 | 53.38 | TRADE |
| SA1 | 4/1/2013 2:00 | 1239.25 | 51.79 | TRADE |
| SA1 | 4/1/2013 2:30 | 1182.94 | 48.83 | TRADE |
| SA1 | 4/1/2013 3:00 | 1142.08 | 47.83 | TRADE |
| SA1 | 4/1/2013 3:30 | 1097.34 | 47.11 | TRADE |
| SA1 | 4/1/2013 4:00 | 1081.33 | 46.44 | TRADE |
| SA1 | 4/1/2013 4:30 | 1088.84 | 47.31 | TRADE |
| SA1 | 4/1/2013 5:00 | 1101.19 | 47.86 | TRADE |

To illustrate, let us assume that we are concerned with knowing how the price spikes in March 2013 (period of observation) affected the average pool price for a period of three months from March to May 2013 (period of comparison). Note that the recommended period of comparison is at least one year. We are interested to know whether the Average Pool Price (APP) has increased and whether the increase constitutes a case of an SSNIP.

To begin, go to http://www.aemo.com.au/Electricity/Data/Price-and-Demand/Aggregated-Price-and-Demand-Data-Files/Aggregated-Price-and-Demand-2011-to-2015. Click on March 2013 for South Australia (SA) as shown below. (Figure 1b) This will download the data for said period in .csv format. (Figure 1c)

Figure 1b:

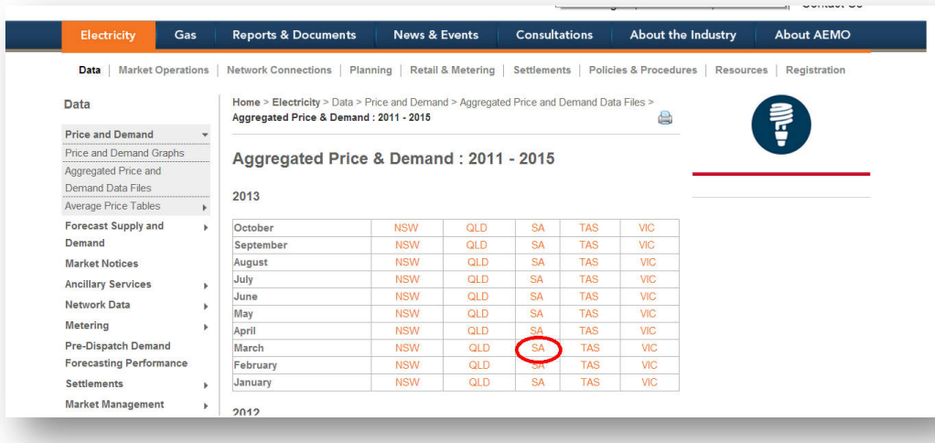
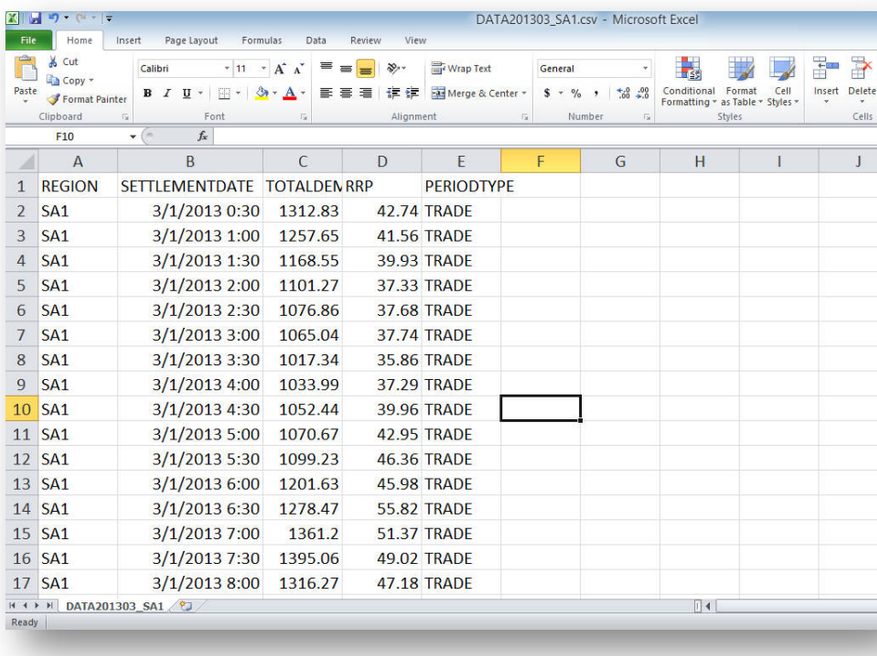



Figure 1c:

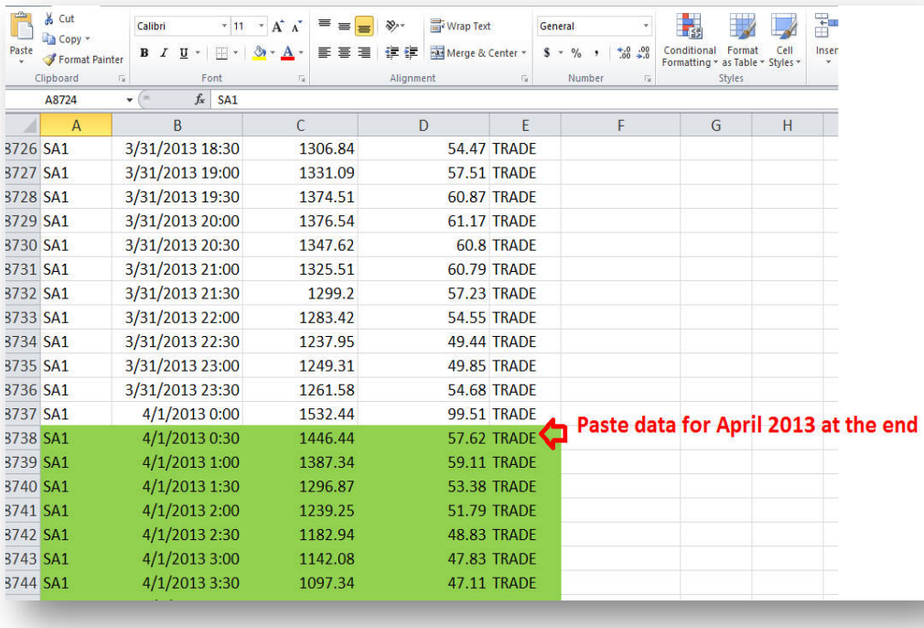



| | A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | REGION | SETTLEMENTDATE | TOTALDEM | RRP | PERIODTYPE | | | | | |
| 2 | SA1 | 3/1/2013 0:30 | 1312.83 | 42.74 | TRADE | | | | | |
| 3 | SA1 | 3/1/2013 1:00 | 1257.65 | 41.56 | TRADE | | | | | |
| 4 | SA1 | 3/1/2013 1:30 | 1168.55 | 39.93 | TRADE | | | | | |
| 5 | SA1 | 3/1/2013 2:00 | 1101.27 | 37.33 | TRADE | | | | | |
| 6 | SA1 | 3/1/2013 2:30 | 1076.86 | 37.68 | TRADE | | | | | |
| 7 | SA1 | 3/1/2013 3:00 | 1065.04 | 37.74 | TRADE | | | | | |
| 8 | SA1 | 3/1/2013 3:30 | 1017.34 | 35.86 | TRADE | | | | | |
| 9 | SA1 | 3/1/2013 4:00 | 1033.99 | 37.29 | TRADE | | | | | |
| 10 | SA1 | 3/1/2013 4:30 | 1052.44 | 39.96 | TRADE | | | | | |
| 11 | SA1 | 3/1/2013 5:00 | 1070.67 | 42.95 | TRADE | | | | | |
| 12 | SA1 | 3/1/2013 5:30 | 1099.23 | 46.36 | TRADE | | | | | |
| 13 | SA1 | 3/1/2013 6:00 | 1201.63 | 45.98 | TRADE | | | | | |
| 14 | SA1 | 3/1/2013 6:30 | 1278.47 | 55.82 | TRADE | | | | | |
| 15 | SA1 | 3/1/2013 7:00 | 1361.2 | 51.37 | TRADE | | | | | |
| 16 | SA1 | 3/1/2013 7:30 | 1395.06 | 49.02 | TRADE | | | | | |
| 17 | SA1 | 3/1/2013 8:00 | 1316.27 | 47.18 | TRADE | | | | | |

The data needed for the analysis are in the TOTALDEMAND and RRP columns. TOTALDEMAND measured in MW hour is the total demand in South Australia for the given 30 minute intervals. RRP, measured in $/MW hour, is the dispatch price for the 30-minute interval.

2. Save the data in excel format (.xlsx or .xls). Next, download the data for the other months (April and May 2013). Copy the data for the given months and paste them at the end of the March data. Remove the label for the subsequent data to be pasted. All the data for the three month period, i.e. March to May should be contained in one worksheet. (Figure 2a)

Figure 2a:

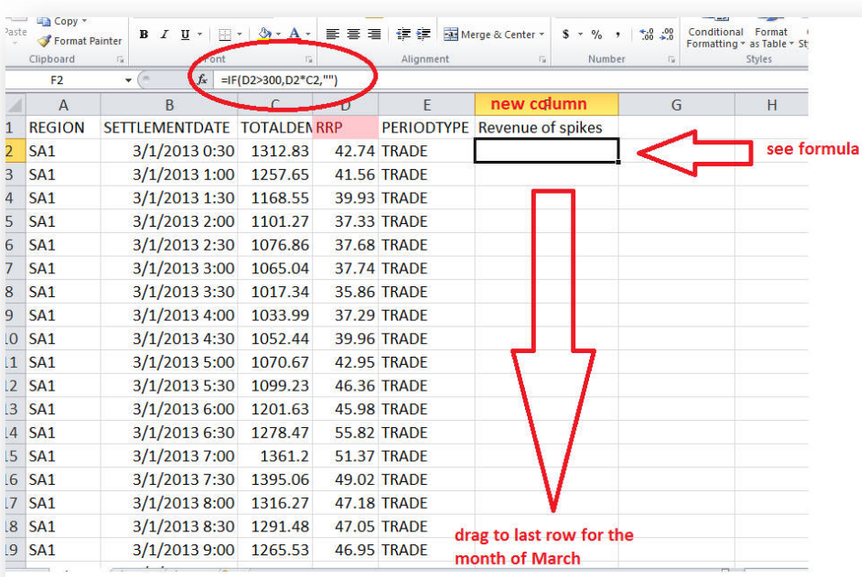



| | A | B | C | D | E |
|---|---|---|---|---|---|
| 8726 | SA1 | 3/31/2013 18:30 | 1306.84 | 54.47 | TRADE |
| 8727 | SA1 | 3/31/2013 19:00 | 1331.09 | 57.51 | TRADE |
| 8728 | SA1 | 3/31/2013 19:30 | 1374.51 | 60.87 | TRADE |
| 8729 | SA1 | 3/31/2013 20:00 | 1376.54 | 61.17 | TRADE |
| 8730 | SA1 | 3/31/2013 20:30 | 1347.62 | 60.8 | TRADE |
| 8731 | SA1 | 3/31/2013 21:00 | 1325.51 | 60.79 | TRADE |
| 8732 | SA1 | 3/31/2013 21:30 | 1299.2 | 57.23 | TRADE |
| 8733 | SA1 | 3/31/2013 22:00 | 1283.42 | 54.55 | TRADE |
| 8734 | SA1 | 3/31/2013 22:30 | 1237.95 | 49.44 | TRADE |
| 8735 | SA1 | 3/31/2013 23:00 | 1249.31 | 49.85 | TRADE |
| 8736 | SA1 | 3/31/2013 23:30 | 1261.58 | 54.68 | TRADE |
| 8737 | SA1 | 4/1/2013 0:00 | 1532.44 | 99.51 | TRADE |
| 8738 | SA1 | 4/1/2013 0:30 | 1446.44 | 57.62 | TRADE |
| 8739 | SA1 | 4/1/2013 1:00 | 1387.34 | 59.11 | TRADE |
| 8740 | SA1 | 4/1/2013 1:30 | 1296.87 | 53.38 | TRADE |
| 8741 | SA1 | 4/1/2013 2:00 | 1239.25 | 51.79 | TRADE |
| 8742 | SA1 | 4/1/2013 2:30 | 1182.94 | 48.83 | TRADE |
| 8743 | SA1 | 4/1/2013 3:00 | 1142.08 | 47.83 | TRADE |
| 8744 | SA1 | 4/1/2013 3:30 | 1097.34 | 47.11 | TRADE |

To compute the revenue we must multiply each RRP above a predetermined limit (in this example we use 300 dollars per MW hour) by the amount of electricity dispatched. We will calculate revenue firstly from the spikes alone, secondly total revenue for the period without the spikes and thirdly total revenue for the period with the spikes.

3. In your excel worksheet, create a new column after PERIODTYPE and label it "Revenue of Spikes" and use the function "=IF(RRP>300,RRP*Total Demand,"")" which will multiply the RRP with the Total Demand in the same row. Drag the formula up to the last day of March at "4/1/2013 0:00" to cover only the observation period. (See Figure 3a). Only data for prices above $300 per mw/h will appear in the new column. A blank means the price was not above $300

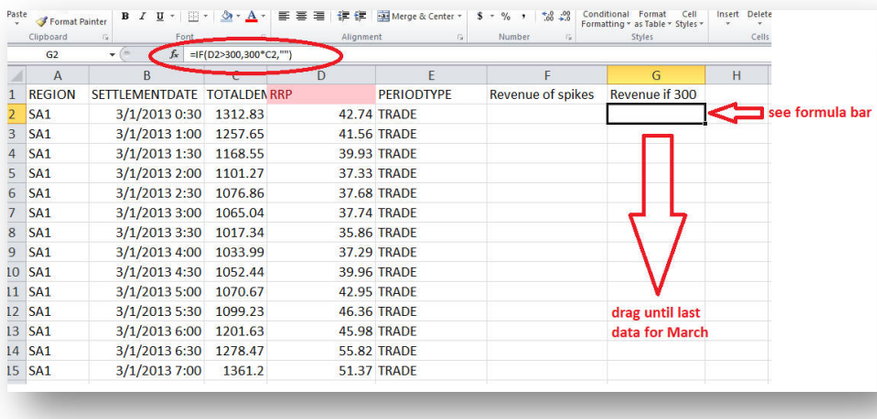
Figure 3a:




| | A | B | C | D | E | G |
|---|---|---|---|---|---|---|
| 1 | REGION | SETTLEMENTDATE | TOTALDEM | RRP | PERIODTYPE | Revenue of spikes |
| 2 | SA1 | 3/1/2013 0:30 | 1312.83 | 42.74 | TRADE | |
| 3 | SA1 | 3/1/2013 1:00 | 1257.65 | 41.56 | TRADE | |
| 4 | SA1 | 3/1/2013 1:30 | 1168.55 | 39.93 | TRADE | |
| 5 | SA1 | 3/1/2013 2:00 | 1101.27 | 37.33 | TRADE | |
| 6 | SA1 | 3/1/2013 2:30 | 1076.86 | 37.68 | TRADE | |
| 7 | SA1 | 3/1/2013 3:00 | 1065.04 | 37.74 | TRADE | |
| 8 | SA1 | 3/1/2013 3:30 | 1017.34 | 35.86 | TRADE | |
| 9 | SA1 | 3/1/2013 4:00 | 1033.99 | 37.29 | TRADE | |
| 10 | SA1 | 3/1/2013 4:30 | 1052.44 | 39.96 | TRADE | |
| 11 | SA1 | 3/1/2013 5:00 | 1070.67 | 42.95 | TRADE | |
| 12 | SA1 | 3/1/2013 5:30 | 1099.23 | 46.36 | TRADE | |
| 13 | SA1 | 3/1/2013 6:00 | 1201.63 | 45.98 | TRADE | |
| 14 | SA1 | 3/1/2013 6:30 | 1278.47 | 55.82 | TRADE | |
| 15 | SA1 | 3/1/2013 7:00 | 1361.2 | 51.37 | TRADE | |
| 16 | SA1 | 3/1/2013 7:30 | 1395.06 | 49.02 | TRADE | |
| 17 | SA1 | 3/1/2013 8:00 | 1316.27 | 47.18 | TRADE | |
| 18 | SA1 | 3/1/2013 8:30 | 1291.48 | 47.05 | TRADE | |
| 19 | SA1 | 3/1/2013 9:00 | 1265.53 | 46.95 | TRADE | |

4. Create another column next to “Revenue of spikes” and label it “Revenue of 300”. This will compute the total revenue created by valuing price spikes at a maximum of $300/MW hour. In excel, use the function “=IF(D2>300,300*C2,"")” which will multiply the corresponding Total Demand to 300. Drag this formula up to the last day of March at “4/1/2013 0:00” to cover only the observation period. (See Figure 4a)

Figure 4a:

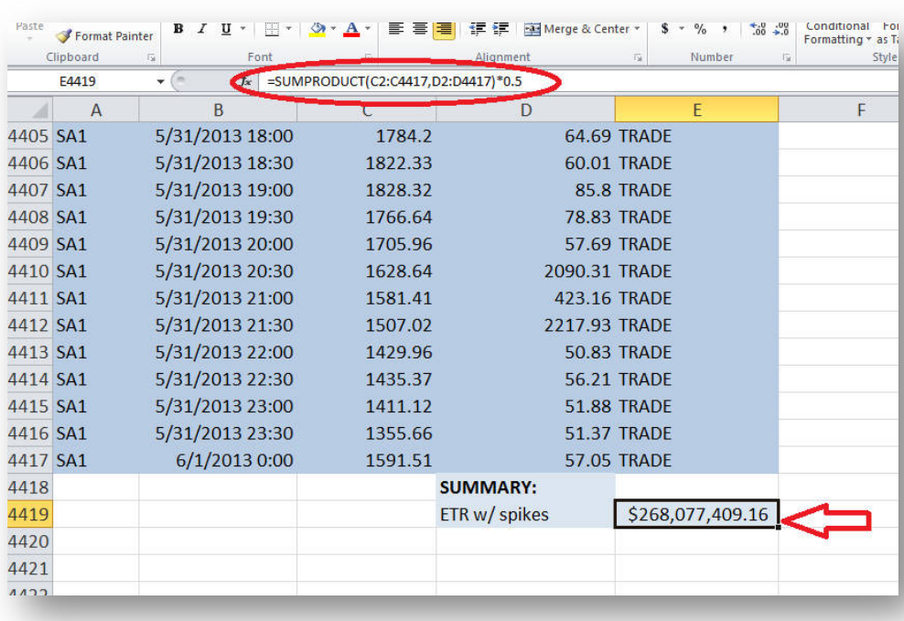



| | A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| 1 | REGION | SETTLEMENTDATE | TOTALDEM | RRP | PERIODTYPE | Revenue of spikes | Revenue if 300 | |
| 2 | SA1 | 3/1/2013 0:30 | 1312.83 | 42.74 | TRADE | | | |
| 3 | SA1 | 3/1/2013 1:00 | 1257.65 | 41.56 | TRADE | | | |
| 4 | SA1 | 3/1/2013 1:30 | 1168.55 | 39.93 | TRADE | | | |
| 5 | SA1 | 3/1/2013 2:00 | 1101.27 | 37.33 | TRADE | | | |
| 6 | SA1 | 3/1/2013 2:30 | 1076.86 | 37.68 | TRADE | | | |
| 7 | SA1 | 3/1/2013 3:00 | 1065.04 | 37.74 | TRADE | | | |
| 8 | SA1 | 3/1/2013 3:30 | 1017.34 | 35.86 | TRADE | | | |
| 9 | SA1 | 3/1/2013 4:00 | 1033.99 | 37.29 | TRADE | | | |
| 10 | SA1 | 3/1/2013 4:30 | 1052.44 | 39.96 | TRADE | | | |
| 11 | SA1 | 3/1/2013 5:00 | 1070.67 | 42.95 | TRADE | | | |
| 12 | SA1 | 3/1/2013 5:30 | 1099.23 | 46.36 | TRADE | | | |
| 13 | SA1 | 3/1/2013 6:00 | 1201.63 | 45.98 | TRADE | | | |
| 14 | SA1 | 3/1/2013 6:30 | 1278.47 | 55.82 | TRADE | | | |
| 15 | SA1 | 3/1/2013 7:00 | 1361.2 | 51.37 | TRADE | | | |

5. It is also useful to create a Summary of the data at the end of the list which will contain revenue data for spikes, without spikes and with spikes and calculate how much average pool prices rose because of the spikes.
Start with the computation of estimated total revenue with the price spikes (ETRwS) by summing the products of total demand and RRP columns. The ETRwS is the estimated revenue that wholesale energy suppliers can expect to obtain if all demand is satisfied at their respective RRP. However, each MW of our demand is only sustained for half an hour at each price so our revenue should only be one half of the multiple of demand and price.

On excel, use the SUMPRODUCT function to multiply total demand with RRP for the entire three month period and multiply the result by 0.5 as shown in Figure 5a. We multiply by 0.5 because the unit of Total Demand is MW hour, but each row corresponds only to a 30 minute interval. Therefore, only half of Total Demand should be considered. To avoid errors, it is important to ensure that the correct cells are referenced.

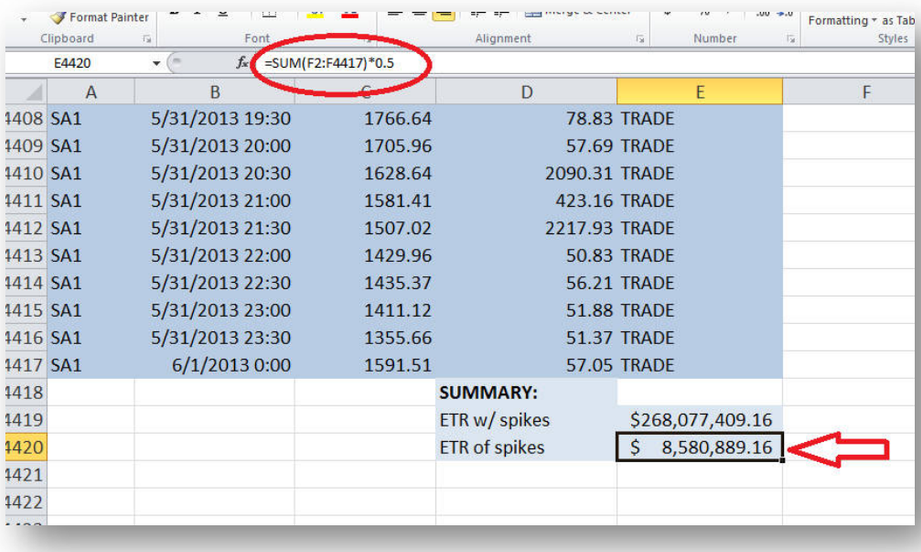
Figure 5a:




| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 4405 | SA1 | 5/31/2013 18:00 | 1784.2 | 64.69 | TRADE | |
| 4406 | SA1 | 5/31/2013 18:30 | 1822.33 | 60.01 | TRADE | |
| 4407 | SA1 | 5/31/2013 19:00 | 1828.32 | 85.8 | TRADE | |
| 4408 | SA1 | 5/31/2013 19:30 | 1766.64 | 78.83 | TRADE | |
| 4409 | SA1 | 5/31/2013 20:00 | 1705.96 | 57.69 | TRADE | |
| 4410 | SA1 | 5/31/2013 20:30 | 1628.64 | 2090.31 | TRADE | |
| 4411 | SA1 | 5/31/2013 21:00 | 1581.41 | 423.16 | TRADE | |
| 4412 | SA1 | 5/31/2013 21:30 | 1507.02 | 2217.93 | TRADE | |
| 4413 | SA1 | 5/31/2013 22:00 | 1429.96 | 50.83 | TRADE | |
| 4414 | SA1 | 5/31/2013 22:30 | 1435.37 | 56.21 | TRADE | |
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | |
| 4418 | | | | SUMMARY: | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | |
| 4420 | | | | | | |
| 4421 | | | | | | |

6. Get the estimated ETR of the price spikes (ETR of spikes). Use the SUM function to get total value of Revenue of Spikes column (column F) and multiply the result to 0.5. (Figure 6a).

Figure 6a:

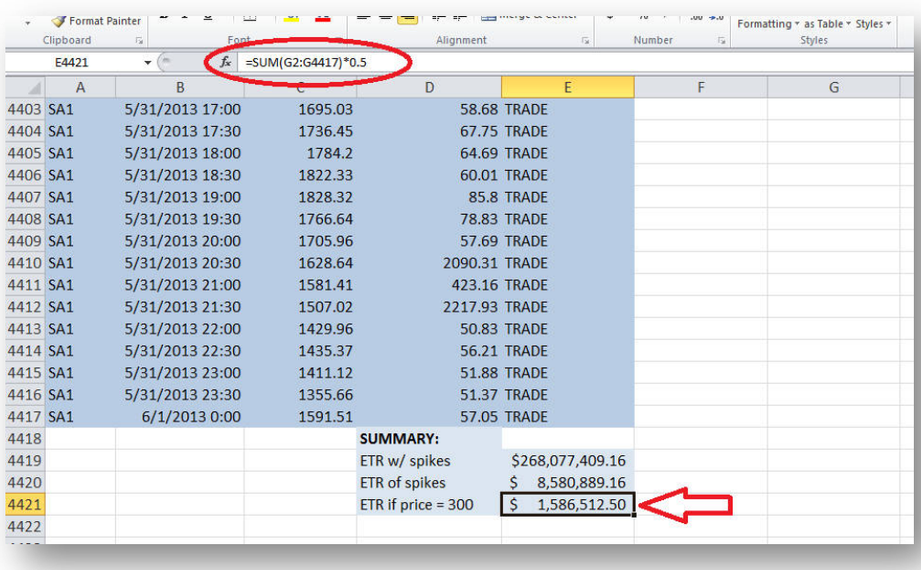


E4420 =SUM(F2:F4417)*0.5

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 4408 | SA1 | 5/31/2013 19:30 | 1766.64 | 78.83 | TRADE | |
| 4409 | SA1 | 5/31/2013 20:00 | 1705.96 | 57.69 | TRADE | |
| 4410 | SA1 | 5/31/2013 20:30 | 1628.64 | 2090.31 | TRADE | |
| 4411 | SA1 | 5/31/2013 21:00 | 1581.41 | 423.16 | TRADE | |
| 4412 | SA1 | 5/31/2013 21:30 | 1507.02 | 2217.93 | TRADE | |
| 4413 | SA1 | 5/31/2013 22:00 | 1429.96 | 50.83 | TRADE | |
| 4414 | SA1 | 5/31/2013 22:30 | 1435.37 | 56.21 | TRADE | |
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | |
| 4418 | | | | SUMMARY: | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | |
| 4420 | | | | ETR of spikes | $ 8,580,889.16 | |
| 4421 | | | | | | |
| 4422 | | | | | | |

7. Compute the ETR for the $300 of the price spikes (ETR if price=300) for the period by getting sum (using SUM function) of column G or "Revenue if 300" column and multiplying the result by 0.5. (Figure 7a)

Figure 7a:

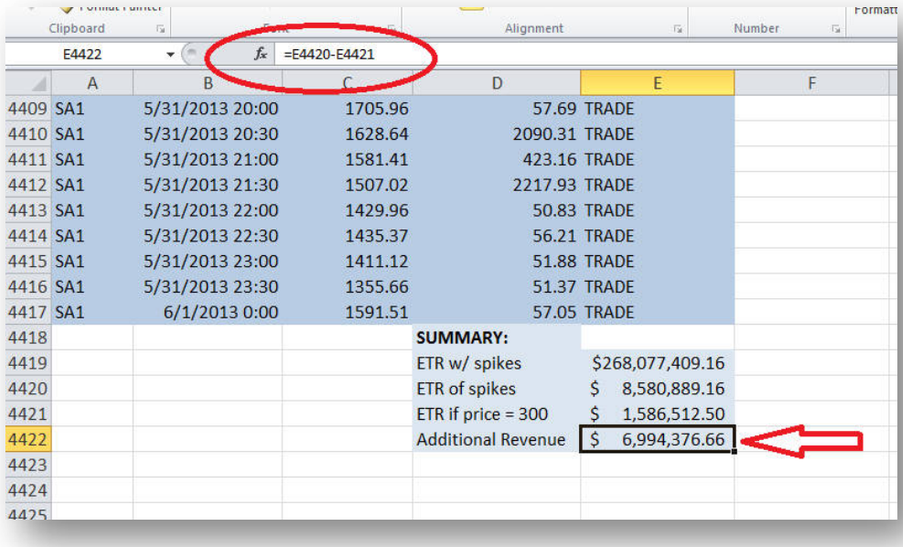


E4421 =SUM(G2:G4417)*0.5

| | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| 4403 | SA1 | 5/31/2013 17:00 | 1695.03 | 58.68 | TRADE | | |
| 4404 | SA1 | 5/31/2013 17:30 | 1736.45 | 67.75 | TRADE | | |
| 4405 | SA1 | 5/31/2013 18:00 | 1784.2 | 64.69 | TRADE | | |
| 4406 | SA1 | 5/31/2013 18:30 | 1822.33 | 60.01 | TRADE | | |
| 4407 | SA1 | 5/31/2013 19:00 | 1828.32 | 85.8 | TRADE | | |
| 4408 | SA1 | 5/31/2013 19:30 | 1766.64 | 78.83 | TRADE | | |
| 4409 | SA1 | 5/31/2013 20:00 | 1705.96 | 57.69 | TRADE | | |
| 4410 | SA1 | 5/31/2013 20:30 | 1628.64 | 2090.31 | TRADE | | |
| 4411 | SA1 | 5/31/2013 21:00 | 1581.41 | 423.16 | TRADE | | |
| 4412 | SA1 | 5/31/2013 21:30 | 1507.02 | 2217.93 | TRADE | | |
| 4413 | SA1 | 5/31/2013 22:00 | 1429.96 | 50.83 | TRADE | | |
| 4414 | SA1 | 5/31/2013 22:30 | 1435.37 | 56.21 | TRADE | | |
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | | |
| 4418 | | | | SUMMARY: | | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | | |
| 4420 | | | | ETR of spikes | $ 8,580,889.16 | | |
| 4421 | | | | ETR if price = 300 | $ 1,586,512.50 | | |
| 4422 | | | | | | | |

8. Compute for the Additional Revenue by deducting ETR if price=300 from ETR of spikes. (Figure 8a)

Figure 8a:

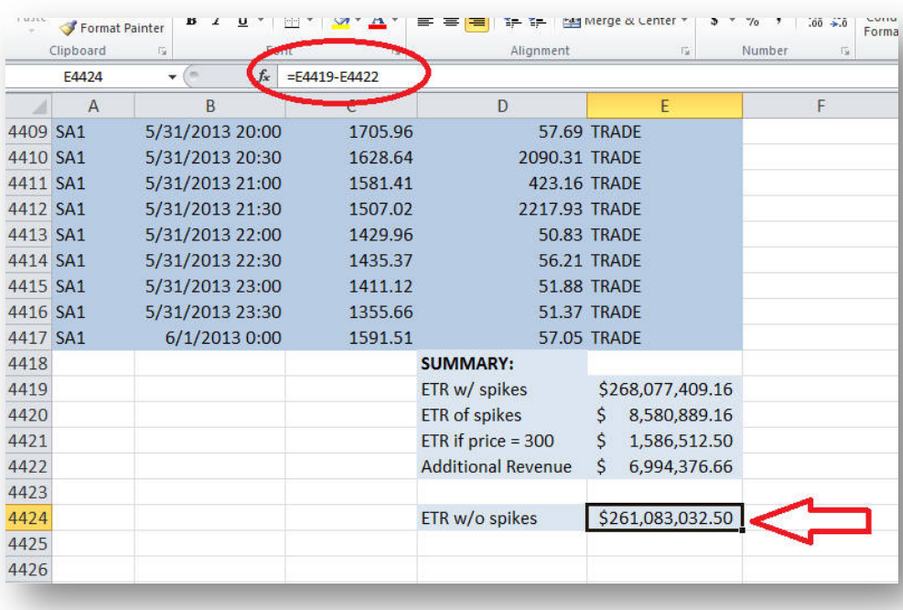


E4422 =E4420-E4421

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 4409 | SA1 | 5/31/2013 20:00 | 1705.96 | 57.69 | TRADE | |
| 4410 | SA1 | 5/31/2013 20:30 | 1628.64 | 2090.31 | TRADE | |
| 4411 | SA1 | 5/31/2013 21:00 | 1581.41 | 423.16 | TRADE | |
| 4412 | SA1 | 5/31/2013 21:30 | 1507.02 | 2217.93 | TRADE | |
| 4413 | SA1 | 5/31/2013 22:00 | 1429.96 | 50.83 | TRADE | |
| 4414 | SA1 | 5/31/2013 22:30 | 1435.37 | 56.21 | TRADE | |
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | |
| 4418 | | | | SUMMARY: | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | |
| 4420 | | | | ETR of spikes | $ 8,580,889.16 | |
| 4421 | | | | ETR if price = 300 | $ 1,586,512.50 | |
| 4422 | | | | Additional Revenue | $ 6,994,376.66 | |
| 4423 | | | | | | |
| 4424 | | | | | | |
| 4425 | | | | | | |

9. To get the ETR without the price spike, deduct the Additional Revenue from ETR w/ spikes (see Figure 9a).

Figure 9a:

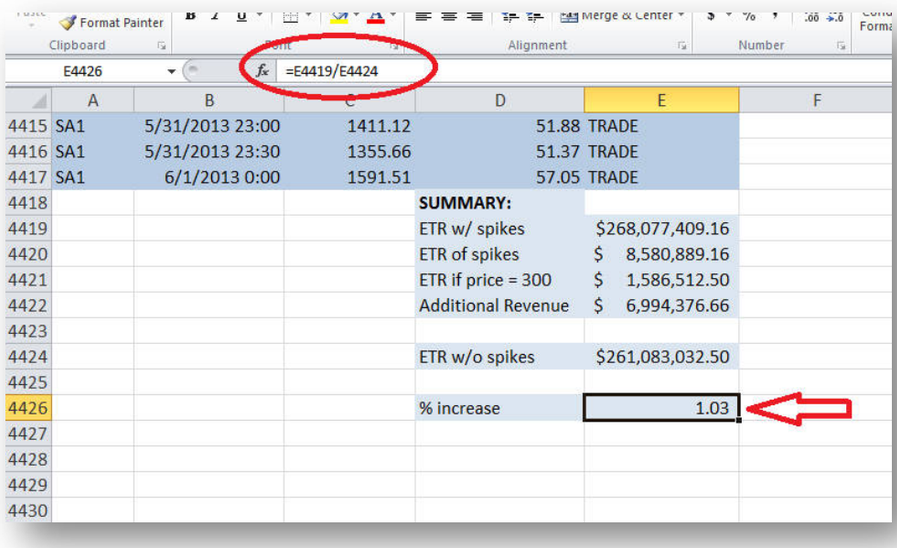


E4424 =E4419-E4422

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 4409 | SA1 | 5/31/2013 20:00 | 1705.96 | 57.69 | TRADE | |
| 4410 | SA1 | 5/31/2013 20:30 | 1628.64 | 2090.31 | TRADE | |
| 4411 | SA1 | 5/31/2013 21:00 | 1581.41 | 423.16 | TRADE | |
| 4412 | SA1 | 5/31/2013 21:30 | 1507.02 | 2217.93 | TRADE | |
| 4413 | SA1 | 5/31/2013 22:00 | 1429.96 | 50.83 | TRADE | |
| 4414 | SA1 | 5/31/2013 22:30 | 1435.37 | 56.21 | TRADE | |
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | |
| 4418 | | | | SUMMARY: | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | |
| 4420 | | | | ETR of spikes | $ 8,580,889.16 | |
| 4421 | | | | ETR if price = 300 | $ 1,586,512.50 | |
| 4422 | | | | Additional Revenue | $ 6,994,376.66 | |
| 4423 | | | | | | |
| 4424 | | | | ETR w/o spikes | $261,083,032.50 | |
| 4425 | | | | | | |
| 4426 | | | | | | |

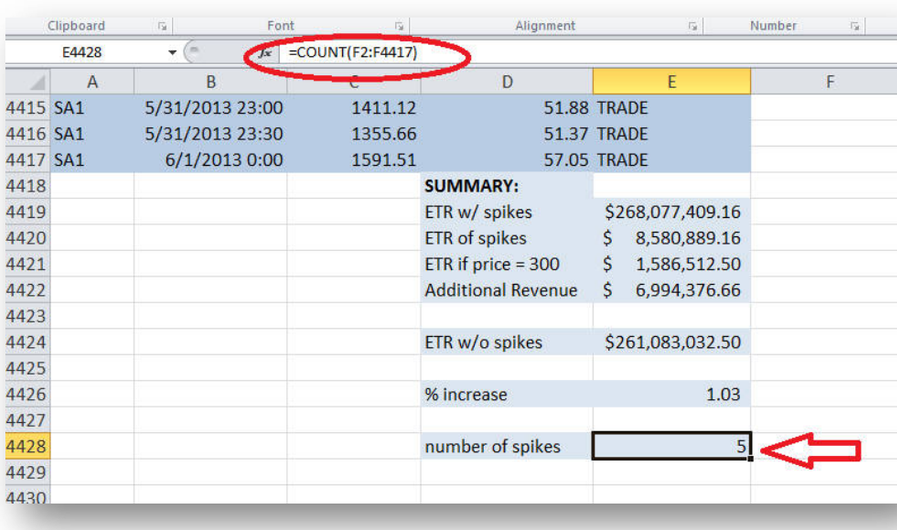
10. Divide ETR w/ spike with ETR w/o spike to obtain the percentage increase the two (see Figure 11a). At this point, we can already infer that since the increase between ETR w/ spike and ETR w/o spike is only 3% (less than 5%) then we can say that the price spikes in March 2013 was not sufficient to make a case for an SSNIP for the period of March to May 2013.

Figure 10a:



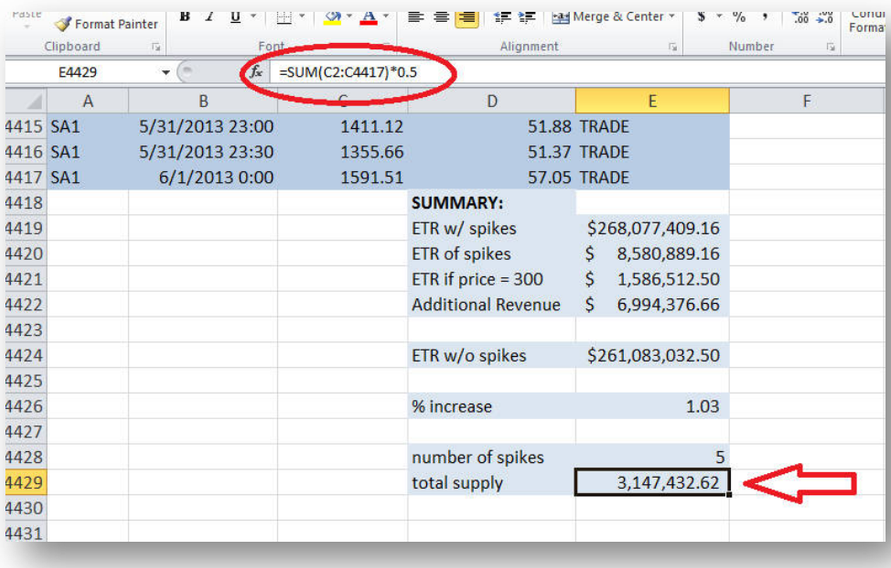

11. In addition, the total number of price spikes within the observation period can be obtained by using the count function in excel to count the entry in column F or G. (See Figure 11a). We can see that there are 5 price spikes for the period of March 2013.

Figure 11a:



12. Compute the Total Energy Supplied for the entire period by getting the sum of column C or Total Demand column and multiplying the result by 0.5 as seen in Figure 12a.

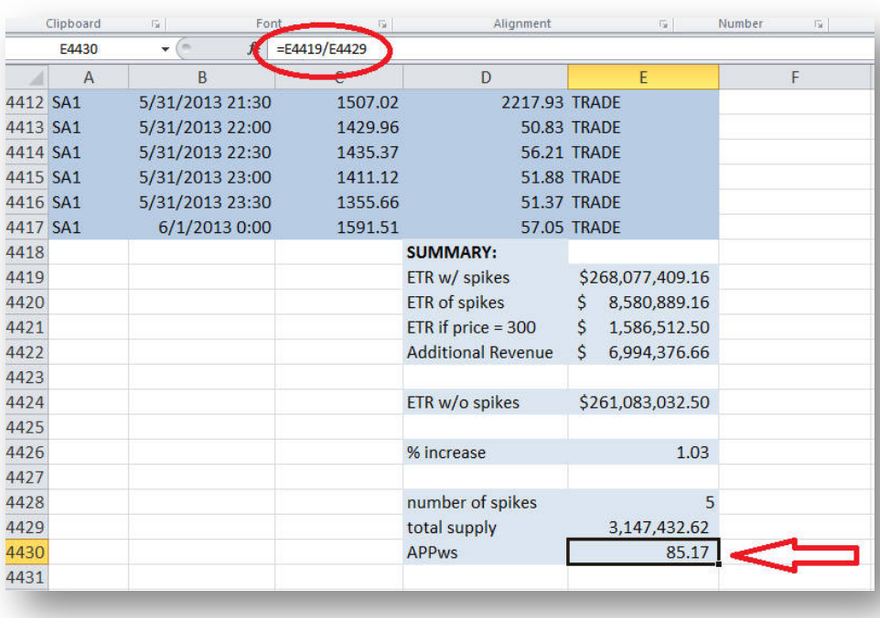
Figure 12a:




| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | |
| 4418 | | | | **SUMMARY:** | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | |
| 4420 | | | | ETR of spikes | $ 8,580,889.16 | |
| 4421 | | | | ETR if price = 300 | $ 1,586,512.50 | |
| 4422 | | | | Additional Revenue | $ 6,994,376.66 | |
| 4423 | | | | | | |
| 4424 | | | | ETR w/o spikes | $261,083,032.50 | |
| 4425 | | | | | | |
| 4426 | | | | % increase | 1.03 | |
| 4427 | | | | | | |
| 4428 | | | | number of spikes | 5 | |
| 4429 | | | | total supply | 3,147,432.62 | |
| 4430 | | | | | | |
| 4431 | | | | | | |

13. Compute the Average Pool Price with Price Spike (APPwS) by dividing the value of ETR w/ spikes by the value of total supply as seen in Figure 13a.

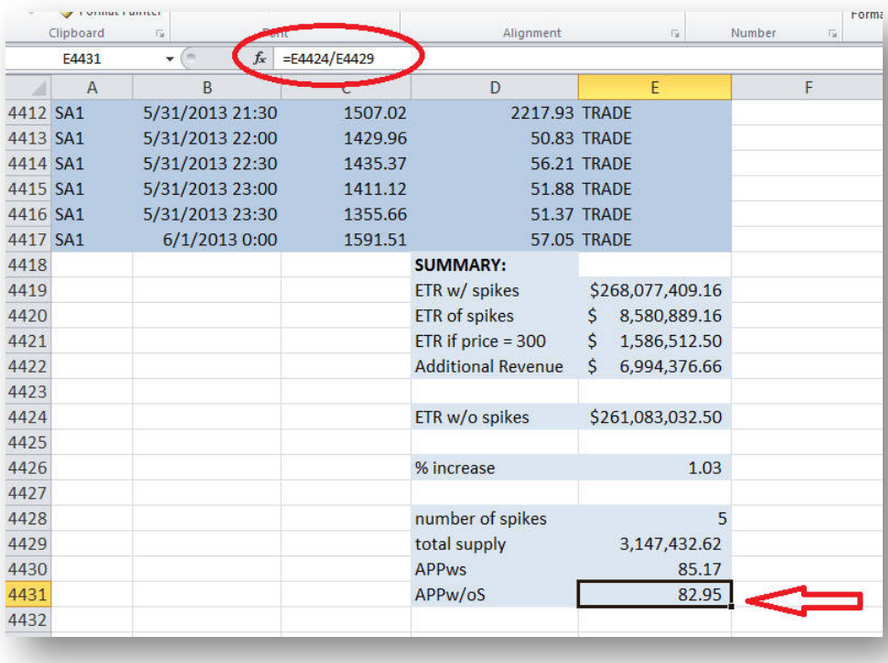
Figure 13a:




| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 4412 | SA1 | 5/31/2013 21:30 | 1507.02 | 2217.93 | TRADE | |
| 4413 | SA1 | 5/31/2013 22:00 | 1429.96 | 50.83 | TRADE | |
| 4414 | SA1 | 5/31/2013 22:30 | 1435.37 | 56.21 | TRADE | |
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | |
| 4418 | | | | **SUMMARY:** | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | |
| 4420 | | | | ETR of spikes | $ 8,580,889.16 | |
| 4421 | | | | ETR if price = 300 | $ 1,586,512.50 | |
| 4422 | | | | Additional Revenue | $ 6,994,376.66 | |
| 4423 | | | | | | |
| 4424 | | | | ETR w/o spikes | $261,083,032.50 | |
| 4425 | | | | | | |
| 4426 | | | | % increase | 1.03 | |
| 4427 | | | | | | |
| 4428 | | | | number of spikes | 5 | |
| 4429 | | | | total supply | 3,147,432.62 | |
| 4430 | | | | APPws | 85.17 | |
| 4431 | | | | | | |

14. Compute for the Average Pool Price without the price spikes by dividing ETR w/o spikes with total supply as seen in Figure 14a. The APPw/oS will serve as a baseline for computing increases in APP.

Figure 14a:



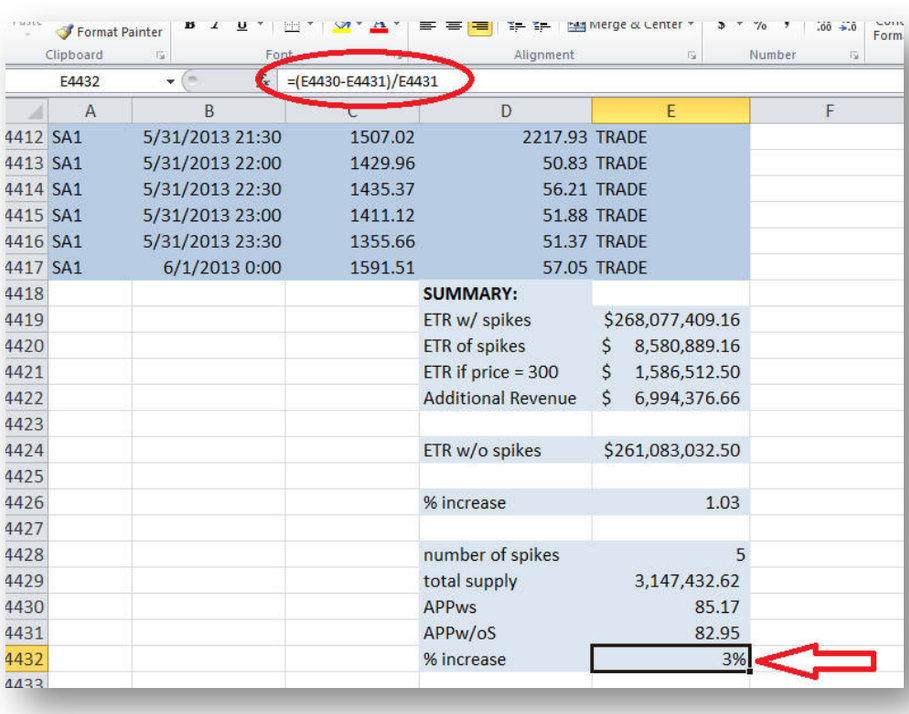
E4431 =E4424/E4429

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 4412 | SA1 | 5/31/2013 21:30 | 1507.02 | 2217.93 | TRADE | |
| 4413 | SA1 | 5/31/2013 22:00 | 1429.96 | 50.83 | TRADE | |
| 4414 | SA1 | 5/31/2013 22:30 | 1435.37 | 56.21 | TRADE | |
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | |
| 4418 | | | | SUMMARY: | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | |
| 4420 | | | | ETR of spikes | $ 8,580,889.16 | |
| 4421 | | | | ETR if price = 300 | $ 1,586,512.50 | |
| 4422 | | | | Additional Revenue | $ 6,994,376.66 | |
| 4423 | | | | | | |
| 4424 | | | | ETR w/o spikes | $261,083,032.50 | |
| 4425 | | | | | | |
| 4426 | | | | % increase | 1.03 | |
| 4427 | | | | | | |
| 4428 | | | | number of spikes | 5 | |
| 4429 | | | | total supply | 3,147,432.62 | |
| 4430 | | | | APPws | 85.17 | |
| 4431 | | | | APPw/oS | 82.95 | |
| 4432 | | | | | | |

15. To calculate the increase of prices between APPw/oS and APPwS with the former as baseline, subtract the value of the APPw/oS from the APPwS and then divide the difference by the value of APPw/oS as seen in Figure 15a.

$$\%\ increase\ (decrease) = \frac{(APP\ w/\ price\ spikes - APP\ w/o\ price\ spikes)}{APP\ w/o\ price\ spikes} \times 100\%$$

Figure 15a:



E4432 =(E4430-E4431)/E4431

| | A | B | C | D | E | F |
|---|---|---|---|---|---|---|
| 4412 | SA1 | 5/31/2013 21:30 | 1507.02 | 2217.93 | TRADE | |
| 4413 | SA1 | 5/31/2013 22:00 | 1429.96 | 50.83 | TRADE | |
| 4414 | SA1 | 5/31/2013 22:30 | 1435.37 | 56.21 | TRADE | |
| 4415 | SA1 | 5/31/2013 23:00 | 1411.12 | 51.88 | TRADE | |
| 4416 | SA1 | 5/31/2013 23:30 | 1355.66 | 51.37 | TRADE | |
| 4417 | SA1 | 6/1/2013 0:00 | 1591.51 | 57.05 | TRADE | |
| 4418 | | | | SUMMARY: | | |
| 4419 | | | | ETR w/ spikes | $268,077,409.16 | |
| 4420 | | | | ETR of spikes | $ 8,580,889.16 | |
| 4421 | | | | ETR if price = 300 | $ 1,586,512.50 | |
| 4422 | | | | Additional Revenue | $ 6,994,376.66 | |
| 4423 | | | | | | |
| 4424 | | | | ETR w/o spikes | $261,083,032.50 | |
| 4425 | | | | | | |
| 4426 | | | | % increase | 1.03 | |
| 4427 | | | | | | |
| 4428 | | | | number of spikes | 5 | |
| 4429 | | | | total supply | 3,147,432.62 | |
| 4430 | | | | APPws | 85.17 | |
| 4431 | | | | APPw/oS | 82.95 | |
| 4432 | | | | % increase | 3% | |

As a conclusion, our sample data does not provide us a prima facie case of an SSNIP since the five (5) price spikes in March 2013 only increased the APP for the period of March to May 2013 by 3%.

## APPENDIX 3 CHRONOLOGY OF EVENTS

### Background

- Always understood that cost reflective pricing principle would mean prices above marginal cost at some times
- This is because the industry has high fixed costs – in the jargon, generation is a natural monopoly
- So high prices alone do not necessarily indicate that generators are acting illegally
- The ACCC defines misuse of market power as "behaviour eliminating or substantially damaging a competitor" or "preventing the entry of a person into that or any other market" (Competition and Consumer Act 2010)
- In relation to the NEM, the AEMC defines substantial market power as "the ability of a generator to increase annual average wholesale prices to a level that exceeds long run marginal cost (LRMC), and sustain prices at that level due to the presence of significant barriers to entry" (AEMC, 2011a, p i)
- Price spikes may constitute evidence of substantial market power if they occur to such an extent and with sufficient frequency that they cause annual average wholesale spot or contract prices to exceed LRMC.

| **Prior to 2011** | |
|---|---|
| | • Summer price spikes in SA: very high average spot prices in South Australia, from 2007 – 08 to 2009 – 10<br>• Supply-demand tight because demand at maximum<br>• The situation was similar in other states, but prices were higher in South Australia (AER, 2011a) |
| November 2010 | • Major Energy Users seek rule change arguing that some large generators have the ability and incentive to use market power to increase wholesale electricity prices during periods of high demand.<br>• They proposed Rule change would require 'dominant' generators, as determined by the AER, to offer their entire capacity at times of high demand at a price of no more than $300 per MWh (MEU, 2010). |
| **2011** | |
| Jan – Feb | • No summer spikes were experienced. The average spot price was falling by almost 50%. |
| January | • South Australian retail prices rose by 12 per cent on 2011, and by a further 17.4 per cent on 1 August 2011, mainly due to higher wholesale energy costs (AER, 2011a) |
| April | • AEMC starts public consultation on Rule change request in relation to exercise of market power by generators in the NEM (AEMC, 2011b) |
| May | With regard to the proposed rule change by the MEU, the AER submitted the following comments to the AEMC:<br>• Market power has been a concern of the AER for several years now and it recognises that high prices resulting from supply and demand conditions are necessary for a functioning market. However, it becomes a concern when it is due to systemic economic withholding by generators with market power. |

| | |
|---|---|
| | • Caution must be exercised when making fundamental changes to the market design to ensure that it does not result in more harm and that it is commensurate with the size of the problem being fixed.<br>• In case it is found that existing mechanisms cannot solve the problem, alternatives to the rule change were presented, particularly (1) structural reform of the generator sectors; (2) alternative behavioural solutions drawn upon international experience; and (3) changes to the Administrative Price Period mechanism in rule 3.14.2 of the National Electricity Rules<br>(AER, 2011b). |
| | • In the *State of the Energy Market 2011* report, the AER characterised the SA energy market as having "(s)ignificant vertical integration, poor liquidity in the market for electricity futures, and strategic bidding by the leading regional generator (which) makes SA a challenging market for potential new entrants" (AER 2011a, p. 13).<br>• In the preface it also commented that "the regulatory framework … has led to some price increases that are difficult to justify" (AER 2011a, p.4) |
| **2012** | |
| July 2012 | • SACOSS submission: argued that the inability to prove the existence of substantial market power does not necessarily mean it has not been exercised<br>• Argued further regulators should ask whether conditions could plausibly exist where end consumers were insulated from the impacts of dominant generator behaviour (SACOSS, 2012). |
| July 2012 | • The standing contract price increased 18% largely due to the solar feed-in tariff scheme, increases in network charges and the introduction of a price on carbon emissions (ESCOSA, 2012b). |
| October | • ESCOSA made a Special Circumstances Determination and a Draft Price Determination that would have resulted in an 8.1 per cent price reduction for electricity standing contract customers, as part of its Wholesale Electricity Cost (WEC) review.<br>• AGL then launched a Supreme Court challenge, which sought to prevent the ESCOSA from making a Final Price Determination.<br>(Hawker Britain Group Pty Ltd [HBG Ltd]. 2012) |
| December | • COAG approved deregulation in SA and AGL dropped legal action against the commission.<br>• Deregulation also involves changing the role of ESCOSA from an independent price setter for standing contracts to a price monitor to guard against any anticompetitive behaviour by retailers.<br>(HBG Ltd., 2012) |
| | • In the *State of Energy Market 2012* report, the AER indicates an emerging concern over increase in disorderly bidding in the wholesale market (that is, generators making bids without reference to their underlying generation costs)<br>• The AER's weekly market reports noted evidence of the periodic exercise of market power in several NEM regions.<br>(AER, 2012) |

| 2013 | |
|---|---|
| February | • Deregulation of SA retail market takes effect (HBG Ltd., 2012) |
| April | • AEMC *Final Rule Determination* states that, unlike all other regions, it is not clear whether substantial market power has existed in that region but there is insufficient evidence to support the likely exercise of substantial market power.<br>- The Commission stated that substantial market power might have been exercised in South Australia in the period from 2007-08 to 2009-10 but that the following years have demonstrated the response to these price outcomes that is consistent with what would be expected of a well-functioning market.<br>- The Commission notes that, should industry structure or conditions substantially change, the possibility of the future exercise of substantial market power cannot be ruled out. (AEMC, 2013) |
| April – June | • From 14th April to 6th Jun, South Australia experienced 43 spot prices in excess 300/MWh, 39 spot prices in excess of $1500/MWh and 26 spot prices in excess of $2000/MWh.<br>• This generated estimated spot price revenue of $110 million and has added 6.2% to the average wholesale price. |
| July | AER Special Report on market outcomes in April and May<br>• "Such market outcomes are unusual for this time of year" (AER 2013a, p 4)<br>• AER suggested that high price outcome is because of supply condition was tight, including:<br>- Reduced capacity because of challenging conditions in SA<br>- Inconsistent level of output from wind generator during peak time.<br>- Interconnector and its limit.<br>- The hot water system automatically turns on in off-peak time, creating a significant increase in demand.<br>- Change in generator's pricing strategies.<br>• AER pointed out that:<br>"It did not appear that merchant generators were seeking to capitalise on the tight supply conditions to spike the pool price to high levels through strategic behaviour. Instead, the general withdrawal of capacity by generators over the period created tight supply conditions that made the market susceptible to spikes caused by a range of different factors" (AER 2013a, p 49 - 50). |
| August | • In response to the report, SACOSS issued a press released that the misuse of market power is present in South Australia electricity market power. Incredibly high power price should worry us? "It appears, however that in these cases [these high spot price outcomes in April and May], the electricity generators were making strategic decisions about when they made capacity available to the retail market and as a result, wholesale prices spiked dramatically" (Womersley, 2013, p 2). |

## APPENDIX 4 PRESS RELEASE TEMPLATE

**Here We Go Again: Yet Another Electricity Price Spike**

SACOSS has repeatedly drawn attention to the behaviour of electricity generators in pushing up electricity prices whenever they think they can profit. It has happened again. On (date here), during dispatch intervals (insert the 30 min dispatch intervals affected), the wholesale price spiked at $(insert peak offer price for any 5 min trading interval in that 30 mins) causing the average pool price for that trading interval to rise to $ (insert average price for that 30 min interval = $y). This is (y/$64)% of the average wholesale price and is yet another instance of reprehensible behaviour.

Quote from Ross

The regulator will issue a report pointing to some technical problems, as they always do (AER must be report if trading interval price exceeds $5000/MWhr). We appreciate that these conditions created circumstances where some price rise was inevitable but y/$64% is obviously excessive.

This is the most recent in a very long list of cases where generators have let their greed get away from them. Because this is happening in the wholesale market, they hope no one will notice. But we are calling them to account.

We have estimated that generators created extra potential revenue of $ z million (insert figure from CMU-A spreadsheet calculation) – details of the calculation are appended. That will add to the $ j00 million in profits they made last year and it will translate into higher prices for South Australian consumers.

We want the regulators finally to address this problem. When we review the chronology of events leading up to this latest price spike (attached) it shows this is a recurring problem and promises have been made to do something about it. We now call on governments to immediately:

1. Establish a Vulnerable Users Compensation Fund by requiring that the generators which profit set aside 0.5% of the additional revenue created by price spikes to assist vulnerable people who are unable to pay their electricity bills because of high prices. The SA government should empower ESCOSA to administer the fund;
2. Join us in supporting calls for the AEMC to extend the role of the AER in monitoring the exercise of market power in SA.

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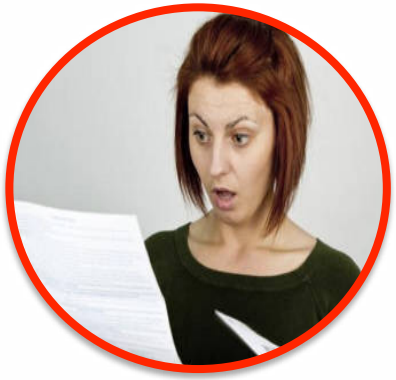


# High SA Electricity Prices: A Market Power Play?

The Final Report to

## South Australian Council for Social Services

Capstone Project
**MS in Public Policy & Management**
Carnegie Mellon University – Australia

10 December 2013

Carnegie Mellon University Australia

SACOSS
South Australian Council of Social Service

# Outline of Presentation

- What happened?
- How is it understood?
- What do we recommend
- Feed back and final comments

# What Happened?

18 price spikes from 15 April to 7 June > $1500/MWh

- Unusual when demand < maximum
  - Usually a summer phenomenon
- Highest sustained prices in the NEM for non-summer months
- Very tight supply conditions
- We estimate a 6% increase in average pool prices for 2012-13

# 15 April

- SAEM isolated and supply falling
  - Murray Link interconnector
  - Low wind generation
  - Heywood interconnector
- AGL responds by:
  - Rebidding at $12599 up from $70
  - So a 1,790% when supply dropped 8%

# 3rd June

- Tight supply and risk of mandatory interruption
  - Wind dropped
  - AGL's Torrens Island B Power Station and Origin's Osborne tripped
  - Murray Link was out
  - Heywood interconnector constrained
- Generators respond by:
  - Increase prices at around 2,000/MWh on 12 trading intervals
  - AGL not involved

# 24th May

- Predictable increase in demand
  - Increased by 16% due to off-peak hot water systems
  - Interconnector at limit
  - High priced generator dispatched
- AGL responds by:
  - Offered prices to $12,880/MWh at 23:45
  - Spot price reached $2,216.57

# Our assessment

- We agree with AER: price spikes result of commercial decisions to reduce available capacity throughout the period
- Generators did not constrain the system to push prices up
- We disagree with AER that generators did not seek to capitalise on the tight supply conditions
- Generators made use of price spikes by bidding at maximum

# Theoretical considerations

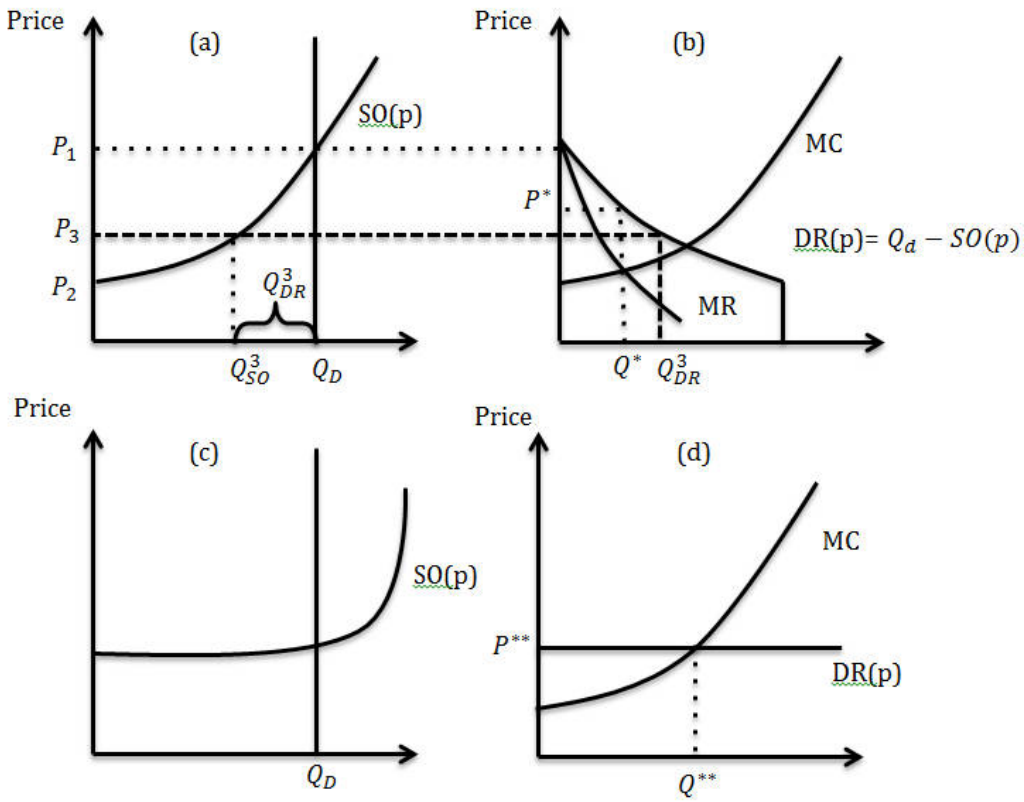
- market power based on barriers to entry
- A case of natural monopoly

  p = MC is loss-making
- p > AC and S/M profits required at times
- Provides incentives to invest
- Price behaviour applies Ramsey's inverse elasticity rule

So what determines when a firm can increase prices – and how much?

# Plausible and Possible in Theory

***Figure 3: Residual Demand Elasticity and Profit-Maximising Behaviour***



# Legal Considerations

- Fact of market power is not illegal
- Market power in SA seems temporary (so not acquired by removing capacity)
- Bidding and rebidding behaviour by generators unlikely to be illegal
- Overseas experience is consistent with this picture.

# Regulatory Responses

- AER opinion, AEMC view
- Instead, focus on short term barriers
- Ad hoc and infrequent vs. recurring
- SSNIP

# Partial remedies

- Require the dominant generator divest itself of generation capacity
- Extend the use of forward contracts
- Enhance the participation of retail consumers in wholesale market
- Expand the interconnectors

# Preparing for Possible Recurrences

3 tools for SACOSS

1. Consolidated chronology
2. Spreadsheet for calculating whether the price events constitute an SSNIP
3. Press release preparation

# Assistance for Vulnerable Users

- Change the onus of proof
- Create Vulnerable Users Compensation Fund
- But problem of moral hazard
- Deal with by
  - Management of the fund via ESCOSA
  - Eligibility criteria
  - Conditions on multiple use: education and awareness

# Regulatory reforms

- Greater role for AER in monitoring market power
- Support for AER's suggestion re
  - Treatment of interconnectors
  - Review bidding rules
- A SACOSS – AER alliance

# In Summary

- Chronic vs acute periods of tight supply
- Partial solutions
- Prepare for Recurrences
- Vulnerable Users Compensation Fund
- Extended Powers of AER

# Feed Back and Final Comments