Confidential Note

on

Price Spikes in South Australia

On 18 and 19 February 2008

by

The Major Energy Users Inc

February 2008

Assistance in preparing this submission by the Major Energy Users Inc was provided by Headberry Partners Pty Ltd and Bob Lim & Co Pty Ltd.

The MEU acknowledges the contribution made by the NEM Advocacy Panel in providing funds to assist in this work.

The content and conclusions reached are entirely the work of the Major Energy Users Inc and its consultants

Throughout this paper, there are many charts and graphs. Where these are uniquely provided, attribution is noted. All charts and graphs that do not have an attribution have been sourced from NEM-Review which uses data sourced from NEMMCo.

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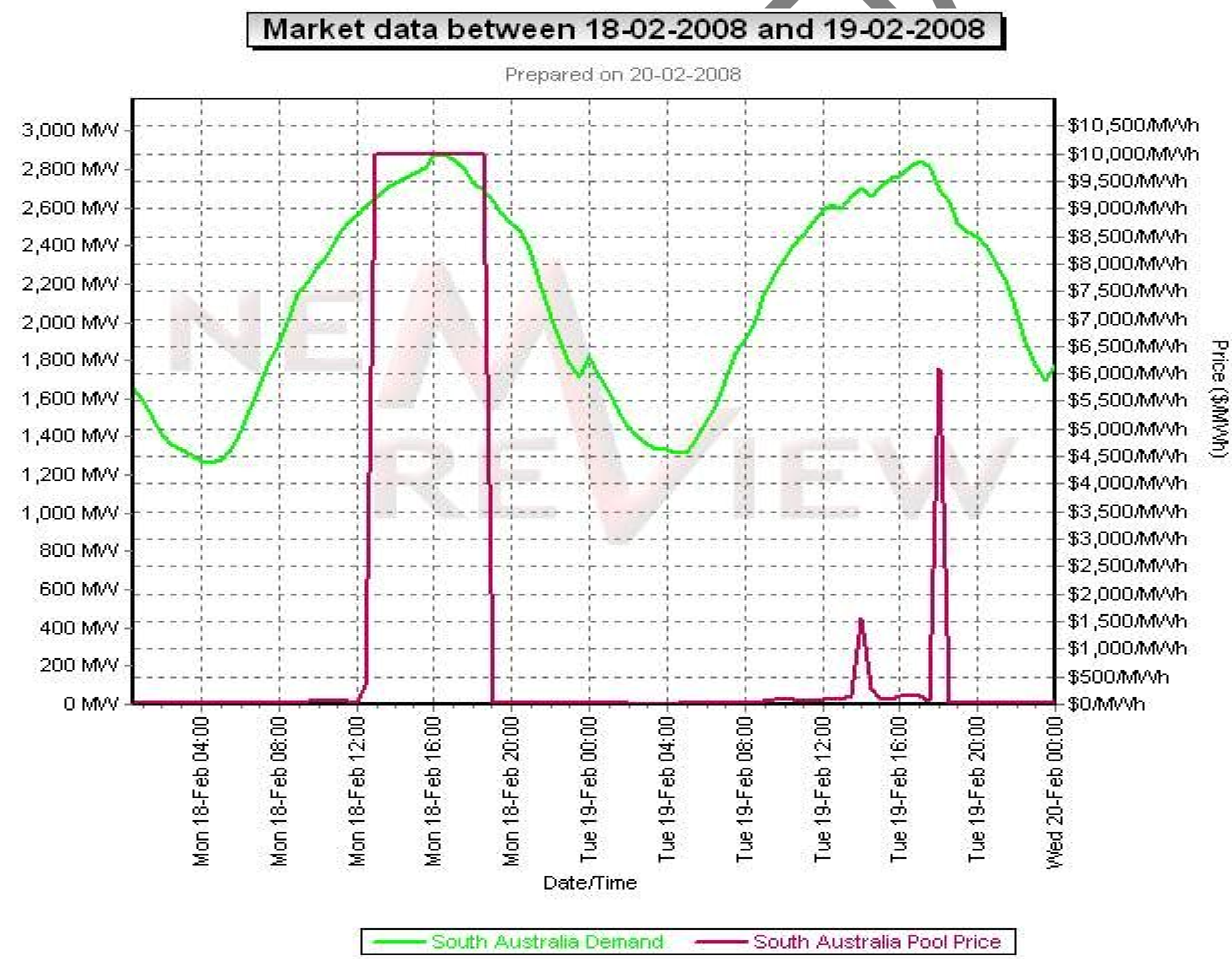
Price Spikes in SA, 18 and 19 February 2008

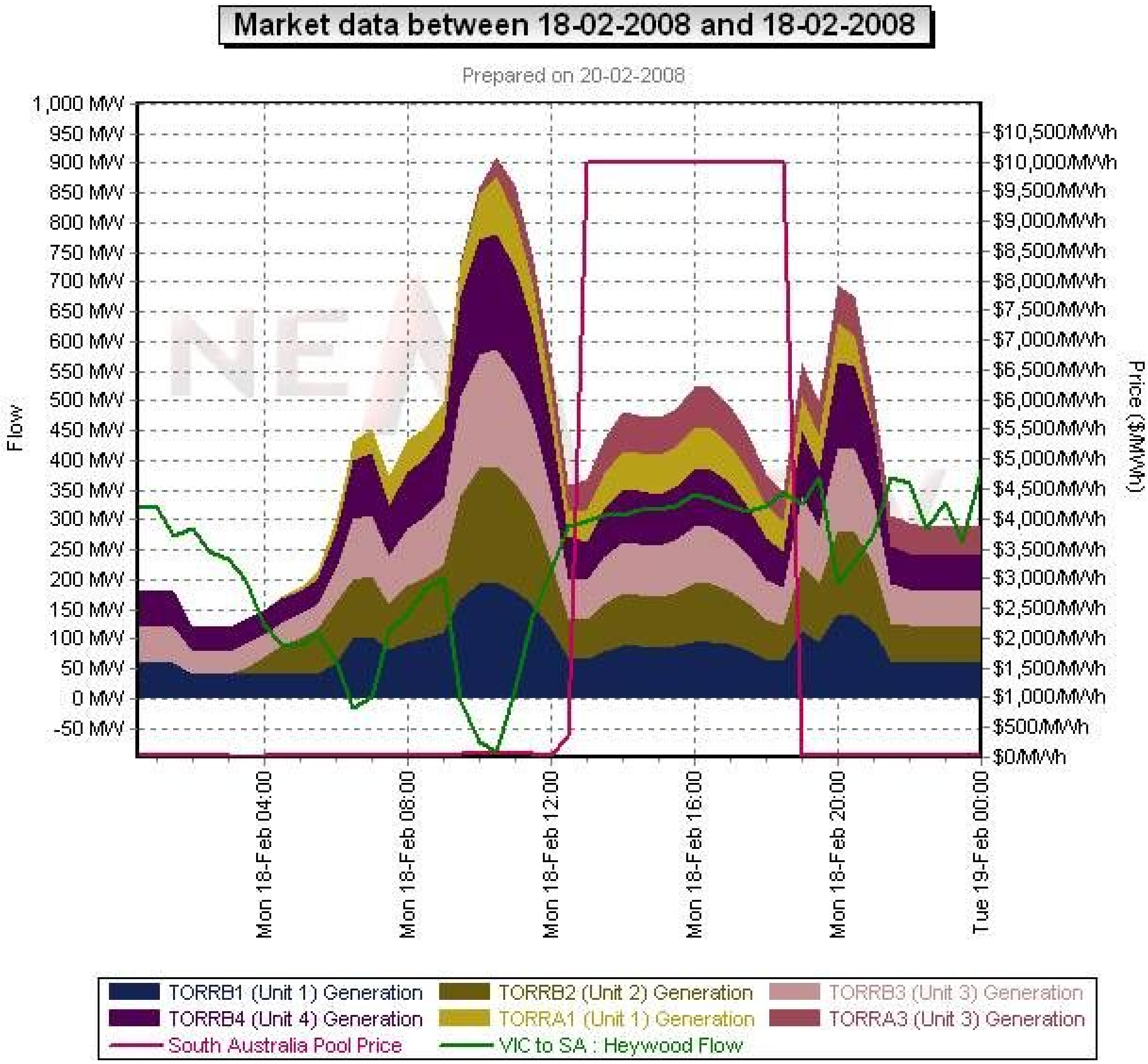
Price spikes were repeated on 18 and 19 February 2008 in the South Australian electricity market, following on from the earlier price spikes on 4 and 10 January 2008.

Analysis of the generation and demand curves reveals that TIPS used its market power to great effect on 18 February. Although demand on 19 February was almost identical to that on the previous day, the price outcomes were quite different.

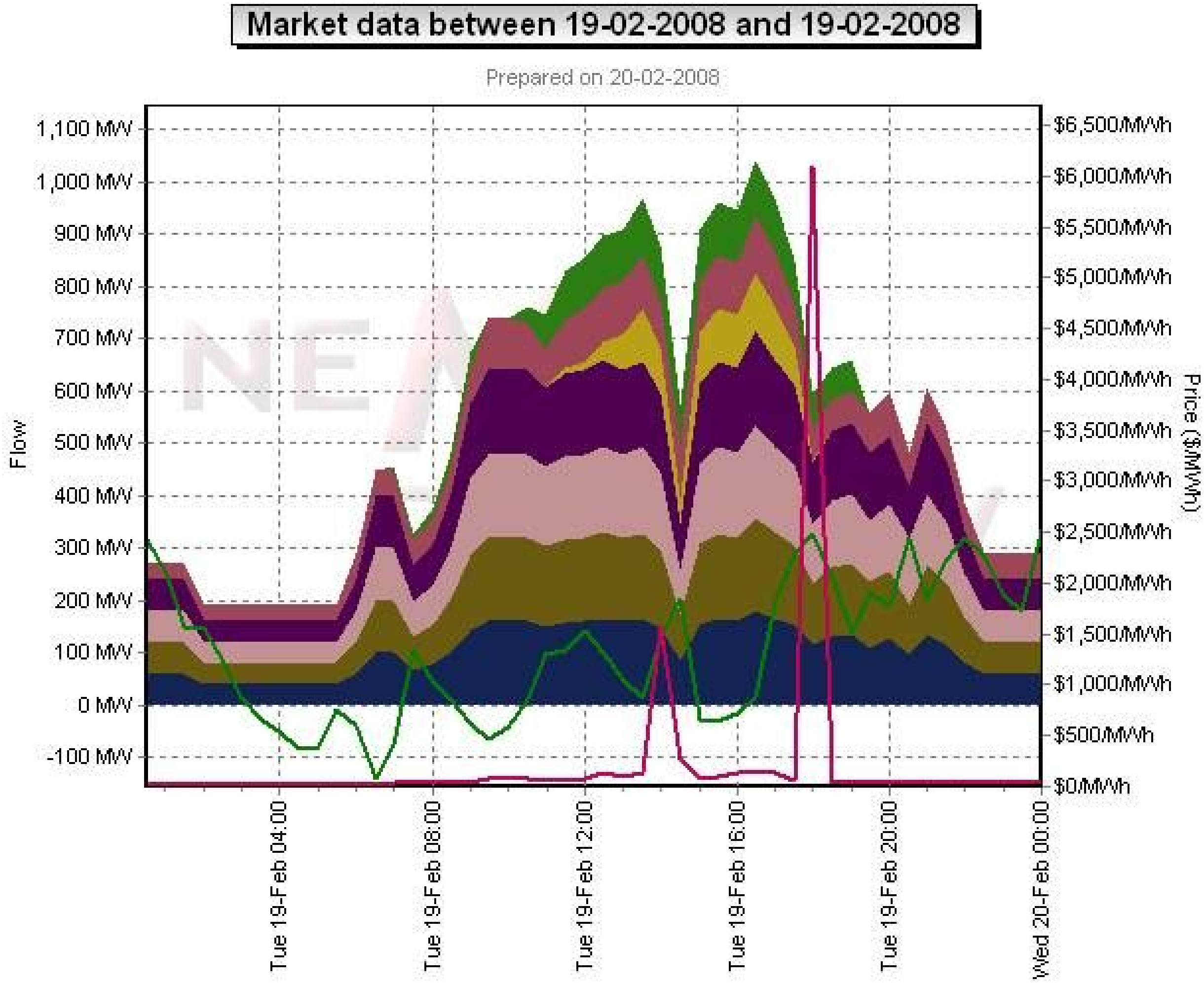


On 18 February TIPS successfully used its market power to spike the spot price and hold it at VoLL for an extended period. It effectively withdrew (by bidding in at a higher price range) at least 550 MW at the time Heywood was constrained. As demand increased so did output from TIPS. TIPS output then followed down demand until it lost market power due to the separate dispatch of all of the other

peaking stations, at which point TIPS increased output again. This was a successful use of market power resulting in 5.5 hours at VoLL, and clearly shows that TIPS as the generator with market power was able to set the spot price by its dispatch and bidding processes, without any effective constraints from market forces or by the regulatory regime.



On 19 February, TIPS again sought to increase prices but with apparent less vigour as it would have quickly identified that if it did follow the previous day's approach, there was the likelihood that the cumulative price would breach the permitted threshold and trigger an administered price regime by NEMMCo. The fact the TIPS could act to prevent a breach of the CPT is a separate, but just as clear, example of how TIPS has the requisite market power in the SA power market to maximize revenue.



The latest February price events demonstrate (again) the ease at which TIPS is able to exercise market power, and coming so soon after the January price events, shows that it intends to aggressively maximize its revenue opportunities.

Consumers are powerless in the face of such aggressive market behaviour by the dominant, vertically-integrated business (AGL). Worst of all, such predatory behaviour raises fundamental questions about:-

- the effectiveness of the NEM institutions and the National Electricity Rules to adequately regulate a market which by its very nature allows an extraordinary increase in market power with modestly increasing system demand;
- the efficiency of the electricity market which is increasingly demonstrating minimal retail competition, absence of retail and hedge contracts at reasonable prices (that bear a relationship to the cost of generating electricity and to the economics of using electricity to manufacture products) and the ineffectiveness of substantial demand side responses.

The February 2008 price events have had significant adverse effects on consumers:-

- those that are exposed to the pool have experienced massive financial losses
- those that are able to effect substantial demand side responses have had to cease manufacturing production
- excessively higher average pool prices and excessive market volatility lead to the setting of higher domestic tariffs and excessively high priced contracts, reflecting the increased risks faced by retailers

Overall, this highly volatile market in South Australia coupled with regulatory failure will lead to a review of the economics of manufacturing in South Australia, as to continue operations in such a volatile and expensive environment is unsustainable.

Attention is drawn to the substantial transfer of wealth from consumers to AGL in such a short time frame.

The average volume weighted spot price for 2007 in SA was $64.89/MWh. If this amount was applied to TIPS total output for the four days (4 and 10 Jan and 18 and 19 Feb) then TIPS would have received revenue of $5.4m. This implies that a reasonable revenue reward for providing power on these days would be of this magnitude.

In 2007, TIPS generated some 13.4TWh of electricity, which provided TIPS with a gross revenue of $510m for the year, giving it a volume weighted average spot price for 2007 of $38.04/MWh. This provides an indication of the LRMC of production for TIPS.

On the four days being examined, TIPS would have had a gross revenue of $114.8m, of which $110m was derived from just 30 half hour periods. Thus in fifteen hours TIPS achieved more than 22% of its gross revenue for the entire 2007 period.

In comparison, on the 30 highest price periods in 2007, TIPS achieved a gross revenue of $62.4m (about half what was earned on the four days in 2008) yet these high price periods were spread over 13 mostly non-consecutive different days in eight different months. This implies that consumers can expect over the rest of the year a number of additional periods where the spot price is very high.

MEU members observe that if any other business had used its market power in such a fashion as TIPS has in the first two months of 2008, this would be investigated in detail by the appropriate regulator with a view to preventing a recurrence.

Generators contacted by MEU are equally concerned that TIPS is prepared to act in the way it does because it increases their risk exposure. Most generators see that the volatility caused by such activity increases their risk and creates an environment where generators are loath to provide long term contracts.

Retailers contacted by MEU are also very concerned, as the actions of TIPS has increased their risk exposure, causing them to consider how to manage such a massive risk and whether they can afford to provide long term contracts to consumers. This is made even more difficult as these retailers are not able to source hedges with generators, yet at the same time these same retailers have a significant exposure for all of their small consumer customers because they are provided with a retail price cap, replicating the same conditions that existed in California in 2000. The result has been a move away from the small end market where retailers (other than AGL which controls TIPS) are being squeezed between increasing hedge costs and a fixed retail price cap. This trend will increase AGL's dominance of the small consumer retail market.

We note that the AER considers that AGL contracts with base load generators (such as Flinders and International Power) will conclude in due course and that AGL will not then be able to use the market power held by TIPS. Advice available to MEU indicates that it is quite possible that AGL could secure new or renew such contracts with these generators, allowing TIPS an untrammeled ability to repeat its exercise of market power in the future. To rely purely on the assumption that an AGL entity will not be able to secure well priced contracts with the base load generators to prevent a repeat of its exercise of its market power in the future, could well be a vain hope.

Investigation Into the

Price Spikes in South Australia

On 4 and 10 January 2008

by

The Major Energy Users Inc

February 2008

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EXECUTIVE SUMMARY

The Major Energy Users Inc. (MEU) provides its review of the South Australian electricity price spikes on 4 and 10 January 2008.

The MEU's review demonstrates that AGL, which owns an integrated business combining AGL Retail and Torrens Island Power Station, is the dominant electricity supplier in South Australia and has substantial market power.

TIPS is the dominant generator with a capacity to supply over 80% of the average demand in SA and nearly 50% of the peak demand and AGL Retail is estimated to have some 70% of the retail market in SA. In other words, AGL represents a combination of the largest (and most dominant) generator and the largest (and most dominant) retailer in SA.

The 4 and 10 January 2008 price events demonstrate an easy ability on the part of TIPS to exercise market power in the spot market and substantially raise pool prices.

In the experience of MEU members, TIPS's dominant position has led to a lack of retail competition, and difficulties in obtaining retail contracts at reasonable prices.

TIPS's ability to set prices at both ends of the supply chain, gives AGL an exceptionally dominant position. This allows the raising of pool prices above competitive levels to maximize revenue. It also allows the raising of retail price contracts and the costs of hedge contracts with competing retailers and large customers.

This means that in the SA region:-

- the market is highly concentrated and competition is decreasing
- the current market institutions and Rules have been ineffective in preventing the increase in market concentration and market behaviour
- retail competition and hedging contracts are not effective at restraining market power
- retail contract prices have been rising and profit maximization motives will ensure even higher pool and contract prices as AGL purchases new hedging contracts
- relatively inelastic demand, daily bidding 24 hours before dispatch, and readily available information on generators' bids ahead, demand conditions and interconnector constraints, are ideal for encouraging strategic market behaviour.

Consumers in SA are totally exposed to the strategic behaviour seen on 4 and 10 January 2008, both directly and indirectly when retail contracts are subsequently written.

In its decision to permit AGL to acquire Torrens Island Power Station from TRUenergy, the ACCC observes that AGL will be able to exercise market power in setting prices in the spot market. This is turn influences contract prices. The MEU demonstrates that AGL has exercised its market power as foreshadowed by the ACCC.

The NEM institutions and the Rules are in operation to ensure that the SA electricity market delivers competitive outcomes. However, it has been demonstrated that when demand is high and exceeds a certain level in SA, TIPS is able to spike the pool price, with many adverse implications for consumers. SA's market structure also provides AGL with an unfair advantage over competitors and consumers, given the absence of constraints on bidding behaviour.

The MEU considers that the AER/ACCC must now implement actions to prevent AGL/TIPS from repeating its use of this undoubted market power in the future.

1. The proposition

In assessing the circumstances surrounding the market behaviour of AGL's Torrens Island Power Station (TIPS), it is important to first analyse the make up of the South Australian (SA) electricity supply arrangements. This is particularly important in order to demonstrate that the market behaviour on 4 and 10 February by TIPS was typical of what might be expected of a power station that has substantial market power..

TIPS is now, and has always been, a critical part of the SA base and intermediate load supply, and because of the size of its installed capacity (its 1280 MW being nearly twice the size of the next largest power station – Northern plus Playford at 740 MW) TIPS was, and still is, a critical element of the SA generation supply. TIPS has the installed capacity to provide over 80% of the average demand in SA and nearly 50 % of peak demand in the State.

TIPS is owned by AGL, which is also the largest electricity retailer in SA, estimated by Bardak[1] at controlling some 70% of the retail supply of electricity. According to the Essential Services Commission of South Australia[2], AGL serviced 68.7% of residential customers, as at 30 June 2006. A combination of the largest generator and the largest retailer in the SA region, provides the incentive for the integrated business to use its market power to maximise its revenue from its SA operations. This behaviour raises pool prices above competitive levels, thereby maximizing generator revenue, and by so doing, raises the prices that the integrated business could negotiate with their customers and/or obtain in new retail contracts and hedging contracts.

The ACCC[3] had assessed in its Public Competition Assessment of the AGL TRUenergy swap of generation assets (which allowed AGL to acquire TIPS) in April 2007, that:-

> *"Economic analysis undertaken by the ACCC suggested that, when demand in South Australia is high and the Vic-SA interconnector is constrained, TIPS appears to have the ability to bid strategically to increase average SA pool prices by at least 5%."* (para. 45)

In that assessment, the ACCC also stated that:-

> *"Regarding AGL's incentives, market participants raised concerns that AGL would have a greater incentive to raise SA pool prices than TRUenergy possessed. The ACCC's assessment of this issue is given below; however, the ACCC notes that this overview is in*

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[1] The Effect of Industry Structure on Generation Competition and End-User Prices in the National Electricity Market, by Bardak Ventures Pty Ltd, May 2nd 2005, page 26
[2] Annual Performance Report – Report Performance of South Australia Energy Retail Market 2005/06, November 2006, page 72
[3] Public competition Assessment, AGL Energy Limited and TRUenergy Pty Ltd – proposed swap of South Australian electricity generation assets, 20 April 2007

> *part restricted by the ACCC's obligation to maintain confidentiality of certain information provided to it."* (para.47).

The clear import of the ACCC assessment was that the acquisition would allow AGL to exercise market power. It is not surprising that this outcome has occurred. The issue is that now the AER/ACCC has to take action to prevent the continuation of this exercise of the market power that was identified.

2. A review of the SA generation and power supply facilities

2.1 Base and intermediate load providers

There are 6 **base and intermediate load** power stations in SA with a combined peak capacity of 2700 MW. These are:-

- **Pelican Point** is a **gas fired** combined cycle gas turbine (CCGT) power station with a peak output of 500MW
- **Northern power** station is a **coal fired** steam plant comprising 2 units each with a combined peak capacity of 520 MW
- **Playford B** is a **coal fired steam** plant and has been refurbished after being planned for retirement. It has 4 units and a combined maximum output of 220 MW
- **Osborne** is a **gas fired cogeneration** plant with two power trains and an historic output of 190 MW output
- **TIPS A** was originally an **oil fired** steam plant but converted later to **gas fired steam**. It has 4 units each with a combined peak output of 480 MW
- **TIPS B** was built as a **gas fired steam** plant with 4 units each with a combined peak output of 800 MW

2.2 Peaking generators

SA has a large number of **peaking** generators, applying gas fired open cycle gas turbine (OCGT) technology, using natural gas or oil as fuel, with a combined capacity of 740 MW. Peaking stations in SA are:-

- Dry Creek (150 MW)
- Mintaro (100 MW)
- Port Lincoln (45 MW)
- Snuggery (65 MW)
- Ladbroke Grove (which uses substandard gas as a fuel supply (95 MW)
- Quarantine (95 MW)
- Hallett (190 MW)

The reason for the large proportion of peaking plants in SA is historical and is largely due to the need for retailers to have a physical hedge against spot price spikes, and the extent of “peakiness” of the SA demand, caused in the main by a high penetration of refrigerative air conditioners to match the relatively high ambient temperatures in the state.

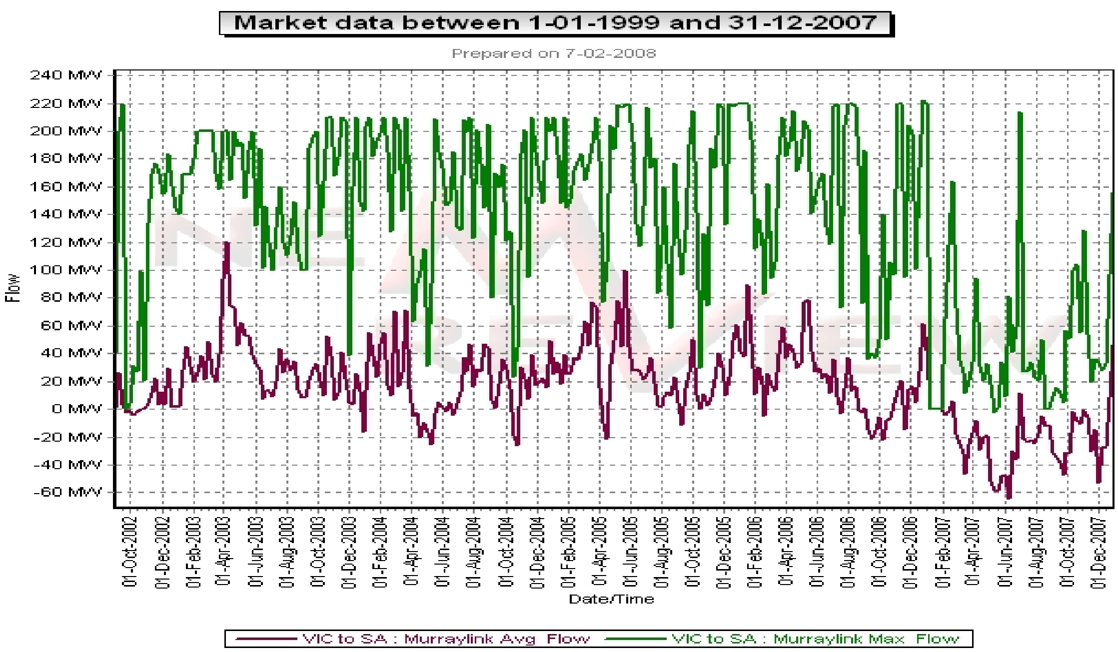
2.3 Interconnections and other supplies

SA has a significant (relative to its demand) amount of wind powered generation. This generation is intermittent due to its motive force and cannot be completely relied on. Traditionally, NEMMCo assesses that 25-30% of wind generation installed should be used for inclusion in any projection of adequacy of supply. Thus only about **100 MW of wind generation** currently installed in SA is considered to be "firm" supply.

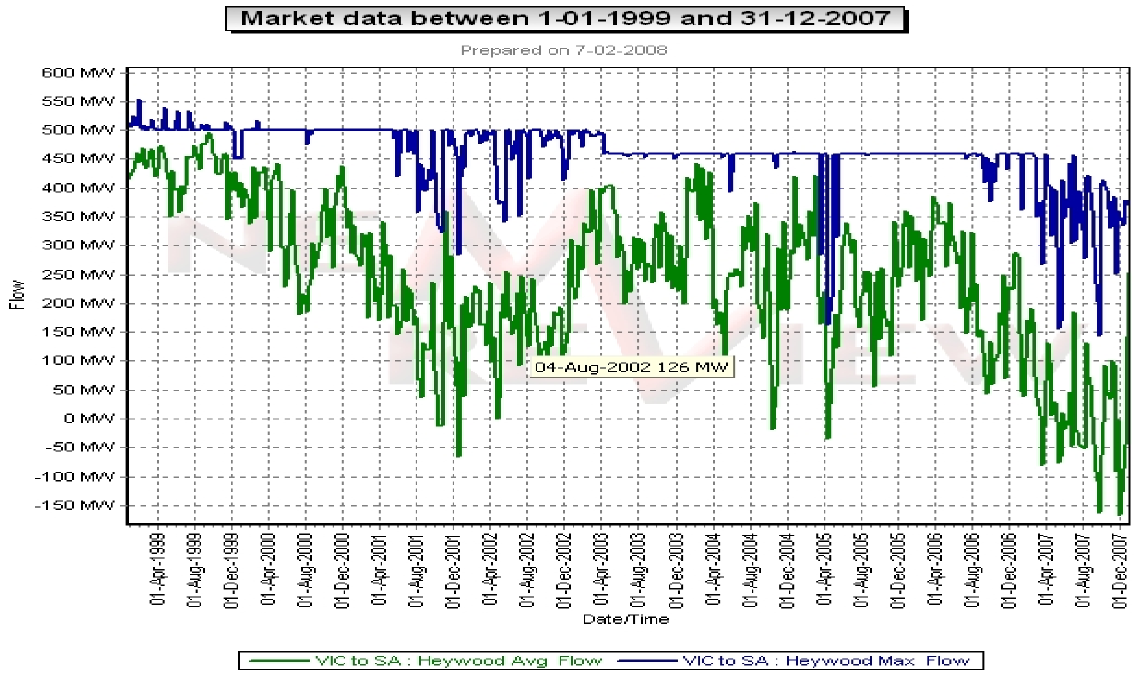
New wind farms are being constructed, which will increase this amount, but at the same time there is concern that the continuing growth of intermittent generation might cause increasing instability in the SA supply arrangements, limiting the benefit of these additional sources of supply as far as security of supply is concerned. This concern has been investigated by SA's Electricity Supply Industry Planning Council (ESIPC).

To these other forms of generation could be added the **Heywood** interconnector nominally rated at 460 MW and **Murraylink** interconnector nominally rated at 220 MW. It is arguable whether an interconnector should be rated as base load or peaking.

Murraylink operations can be seen in the following chart. The average flow is from Victoria to SA and is about 30MW, although peak flows were as much as 220MW to SA.



Heywood operates a little differently.



At the start of the NEM, Heywood operated much as a base load station but in recent times it acts more as a peaking provider for both SA and Victoria needs. **Murraylink** has always operated as a peaking provider.

Just as importantly, due to the increase in wind generation in the lower south east of SA, the capacity of **Heywood** has been significantly reduced when these wind farms are operating at high outputs. For example, Heywood had consistently provided SA with a maximum 460 MW from Victoria. In recent time this maximum has fallen to about 360 MW, and this is expected to fall further as more wind generation is brought on line at Snuggery substation. More generation at this point constrains the amount of power that can flow between the SE substation and Adelaide.

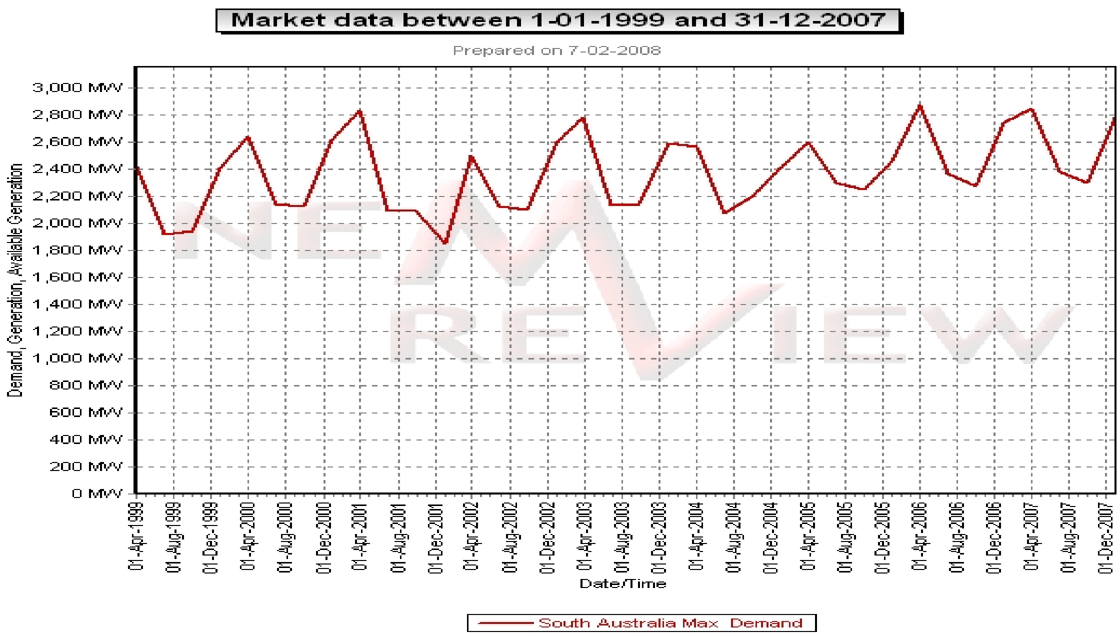
It should be noted that some of the peaking power stations serve a dual purpose of supporting demand at the end of very long supply lines, such as at Port Lincoln and Snuggery.

2.4 Fuel supplies

SA is very dependent on the supply of gas for power generation. Over the Christmas2007/NewYear 2008, **gas supplies** from Moomba ceased as it underwent major refurbishment over a period of 13 days from 21 December 2007. Gas was stored in the Moomba Adelaide Pipeline System (MAPS) gas supply system and additional gas was made available from Victoria via SEAGas pipeline. However, the cause of the electricity spot price spikes (on 4 and 10 January 2008) was not caused by a lack of gas, as the two pipelines (SEAGas and MAPS) report that there was no constraint on gas supplies[4]. This observation was corroborated by the fact that it was the gas fired "peakers" that made up any shortfall in electricity supplies during this time.

2.5 SA demand characteristics

The SA peak demand since NEM start shows that summer peaks are normally about 2800 MW, but that winter peaks are also high, requiring in recent times, some 2300 MW, only 20% below the summer peaks.



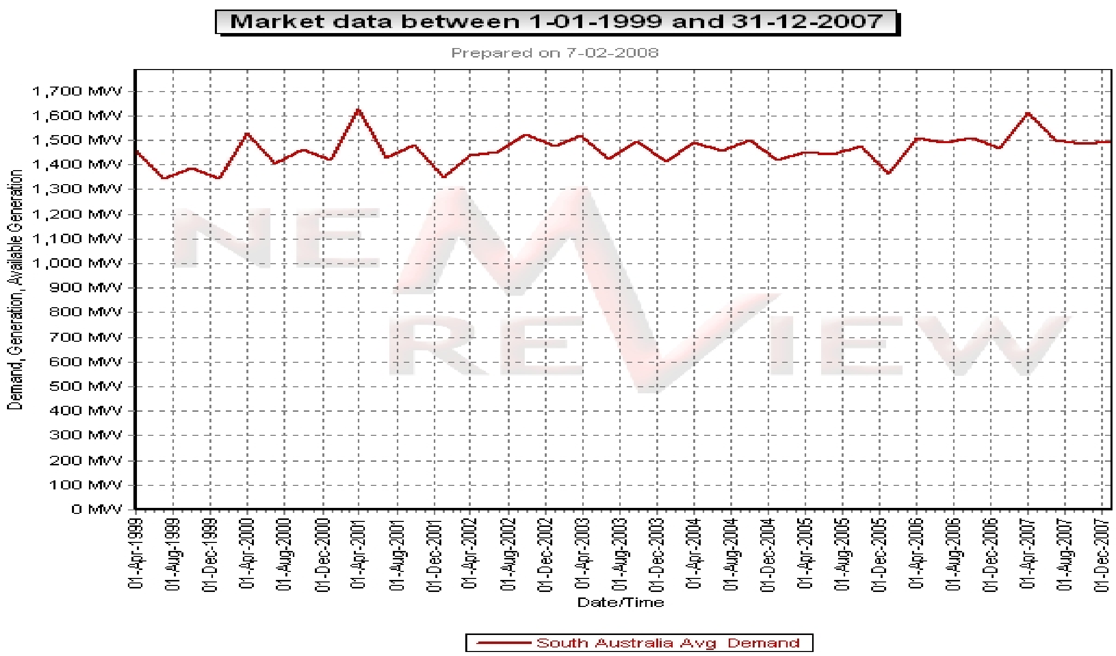
To provide the 0.002% USE, NEMMCo considers that ~10% above the forecast peak demand is required for security of supply. This implies that the entire SA system needs some 3100 MW of supply, as a minimum. In fact, overseas power supply authorities consider a 20% margin is required on current supplies, implying that the current installed capacity needs to be nearly 3400 MW.

The NEMMCo 2007 SoO requires that in addition to the augmentations already in train (Quarantine and Hallett augmentations), loss of Snuggery, and increases in wind farms, **SA requires another 50 MW by summer 2010/11**. This clearly supports the view that supply in SA is relatively tight.

SA average demand (against which there is a need for base load supply) hovers around the 1500 MW level. The implication is that this sets the level of base and intermediate load supplies. For reliability reasons, this amount needs to be augmented by an additional ~25% of base load supplies, implying a need for installed base load generation of ~2000MW or higher. Excluding TIPS there is

[4] Advice provided to MEU by Epic Energy and SEAGas pipeline owners in January 2008.

only 1420 MW of base load generation in SA, implying that TIPS must, in part at least, provide some of this base/intermediate power need.



3. The importance of TIPS and its role as a base/intermediate load generator

To provide for the **base and intermediate load** in SA to be met requires a minimum of some 2000 MW installed. If, as is alleged that, TIPS is considered to be a peak load station then the installed base/intermediate load would be 1400MW, well below the needs of the region.

TIPS comprises two basic elements – **TIPS A** the older part of the power station complex. TIPS A was designed and originally operated as an oil fired power station although it was later converted to using gas as a fuel. The later addition of **TIPS B** coincided with the delivery of gas from the Cooper Basin. It was the demand for gas at TIPS, that was the main reason why the gas supply to Adelaide was initially implemented during the 1970s

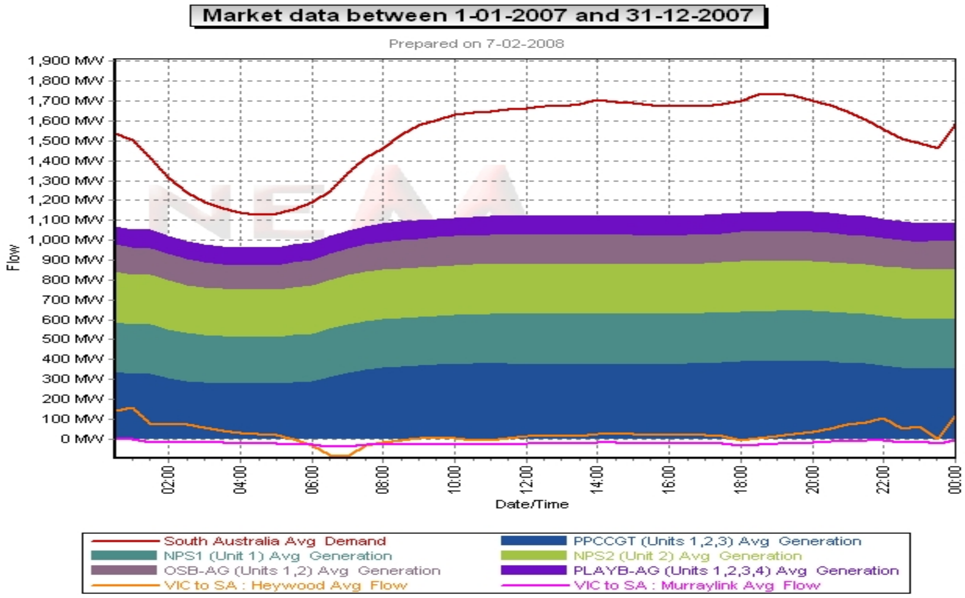
Prior to the building of Pelican Point in the late 1990s, TIPS B provided base load supply for the SA electricity market, along with Northern Station. Playford B was scarcely used and was due for retirement. The building of Pelican Point was at the instigation of the SA government as part of its program of privatization and entry to the NEM. The privatization of Northern Station resulted in Playford B being refurbished, as Playford was sold as part of the SA government package.

3.1 The base load supply (excluding TIPS)

To assess the importance of TIPS it is necessary to examine the SA market in the absence of TIPS. The following chart shows the annual average supply of power in SA for 2007, including the base and intermediate stations and the interconnectors, but excluding TIPS.

The chart shows that:-

- The base load stations (excluding TIPS) could only provide about 65% of the average demand. Any demand above this level had to be supplied from TIPS or the interconnectors
- On average the base load stations (excluding TIPS) were dispatched to 80% of their installed capacity. This is consistent with the expectation that over time there is a need on average to have about 20% excess installed capacity to maintain security of supply.

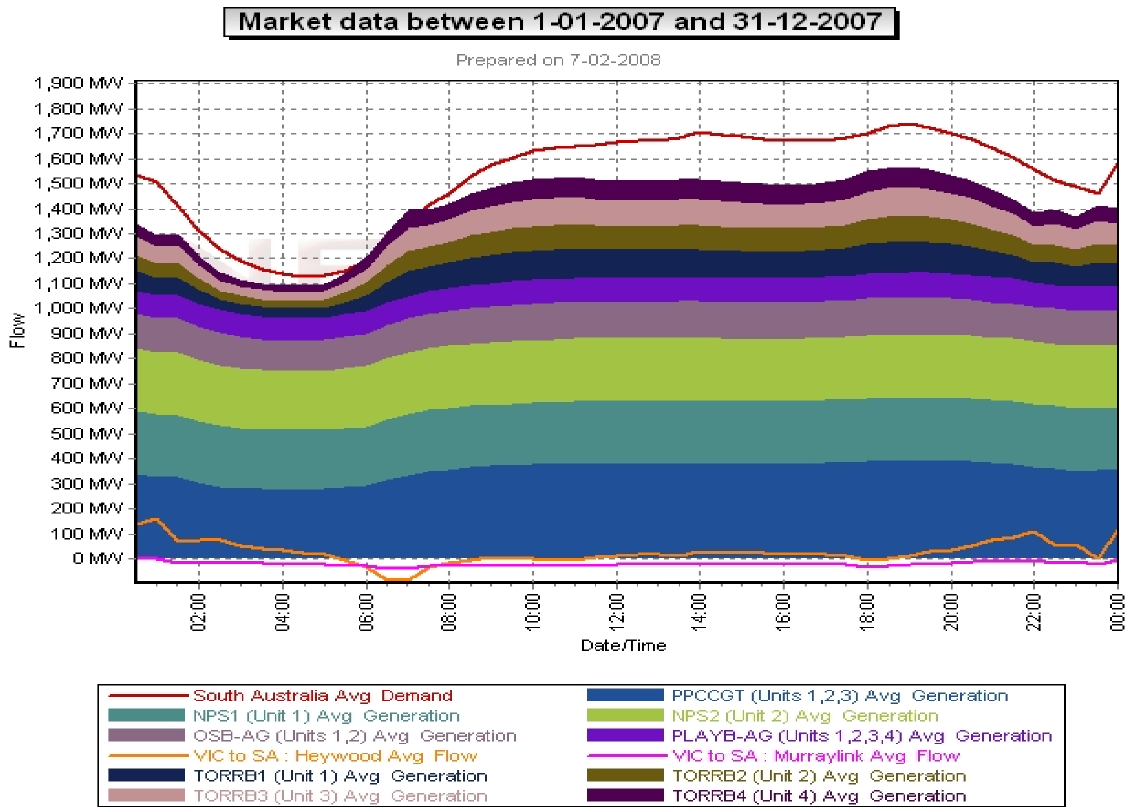


Whilst the base load stations provided about 65% of the demand during the day, they provide a greater proportion during the early morning, but still not all. It is noted that the kick up in demand starting at 11 pm is the off peak electric water storage systems coming on stream, which are not supplied by the base load stations.

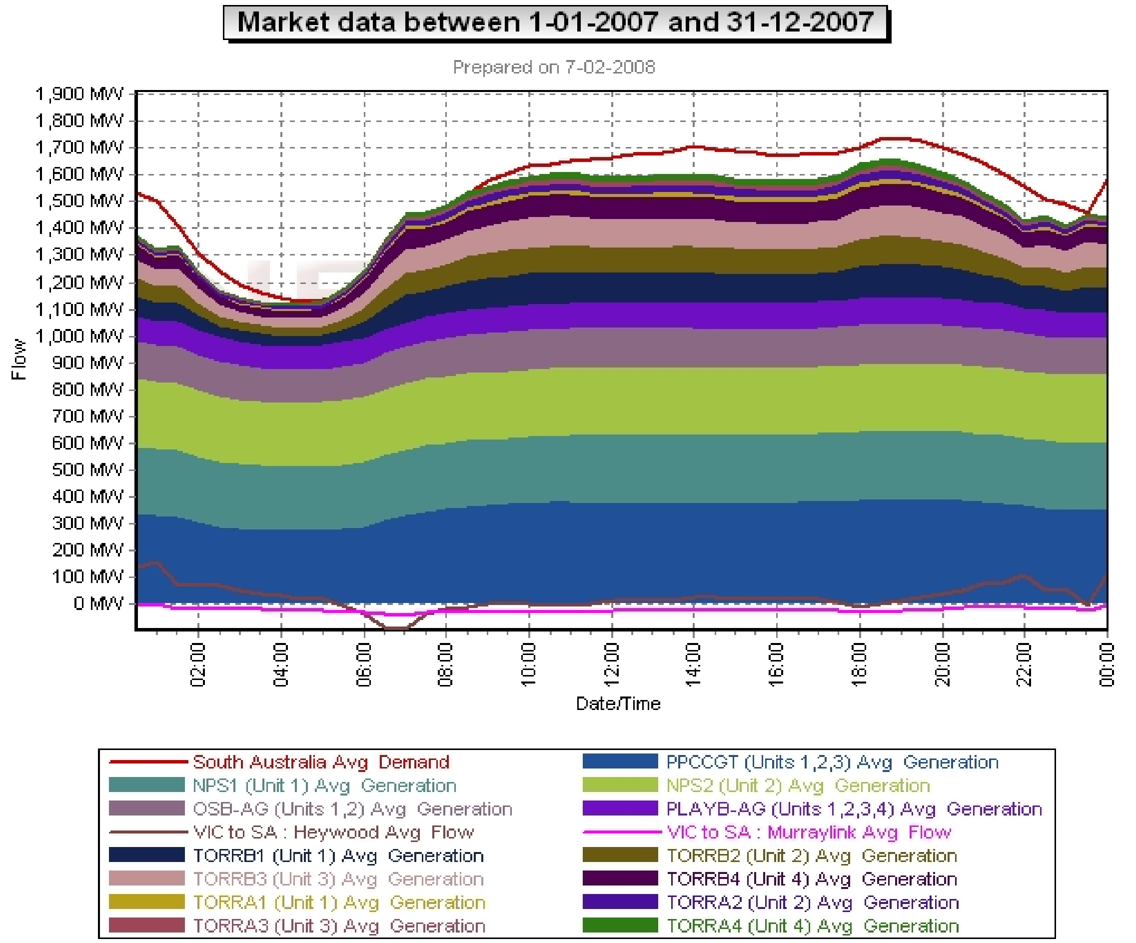
Between them, the interconnectors added little to the overall supply except during the night.

The shortfall of base load supply peaks at about 600 MW. In theory, this could be provided by all of the OCGT peaking plants of which, there is installed, some 740 MW. Allowing for the need for 20% over supply to maintain security, this leaves the average peaking supply at less than 590 MW. Thus in theory over the long term, there is insufficient peaking generation to eliminate the need for TIPS.

When TIPS B is added to the average daily supply chart, this shows that it provided part of the base load and the majority of the intermediate load, as TIPS B adds some 400 MW to the system. As TIPS B has 800 MW of installed capacity this relates to a “secure” capacity of 640 MW (allowing for the 20% average need for security). This implies that TIPS B still has some 30-40% of its installed capacity available for dispatch on a secure basis.



Adding TIPS A average output provides just under another 100 MW, leaving some 100 MW still needed. This additional 100 MW is 20% of the TIPS A installed capacity, leaving some 300 MW (firm after allowing for a 20% security allowance) available for dispatch on average.



The clear implication of the above is that TIPS B is an essential element of the base/intermediate capacity for the SA market. TIPS A provides a significant amount of intermediate capacity as well.

If neither TIPS A nor TIPS B is dispatched, there will be a likely shortfall of supply in the market. Further, the type of generation both TIPS A and B have is one suited to base or intermediate supply, and as the following sections demonstrate, TIPS has always provided this base/intermediate supply and continues to do so even now.

3.2 TIPS A

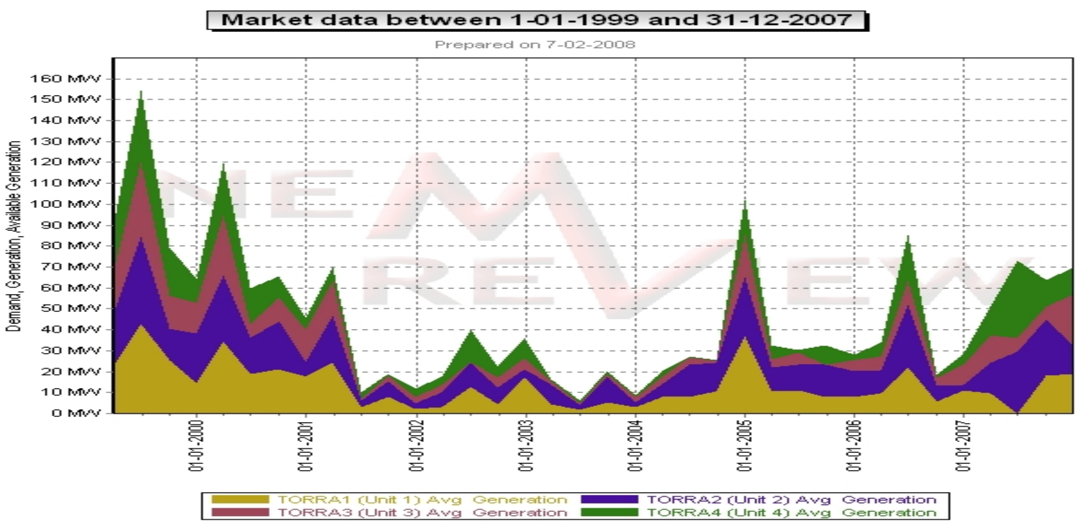
The following two graphs show that over the period since the NEM commenced, TIPS A generation has effectively fallen in average terms but picked up in the later years. When the average output is compared to the peak output, TIPS A was operating at a load factor of ~30% in the early years moving to a load factor of ~15% in more recent times.

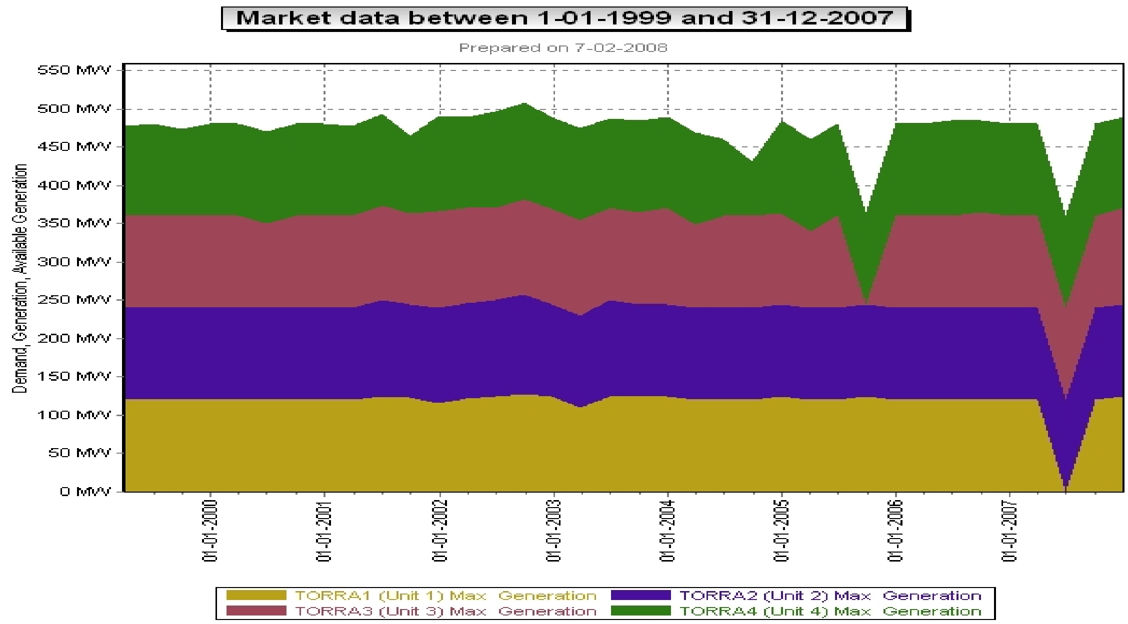
The question then becomes: is TIPS A operating in this mode due to its low efficiency (using steam raised in a boiler designed for oil firing) and therefore being relegated on a cost merit basis?

What is important is that TIPS A cannot compete with OCGT fired plant for peaking power supply due to its operating characteristics (an OCGT can come on line within minutes, whereas a steam boiler takes hours to start generating from cold).

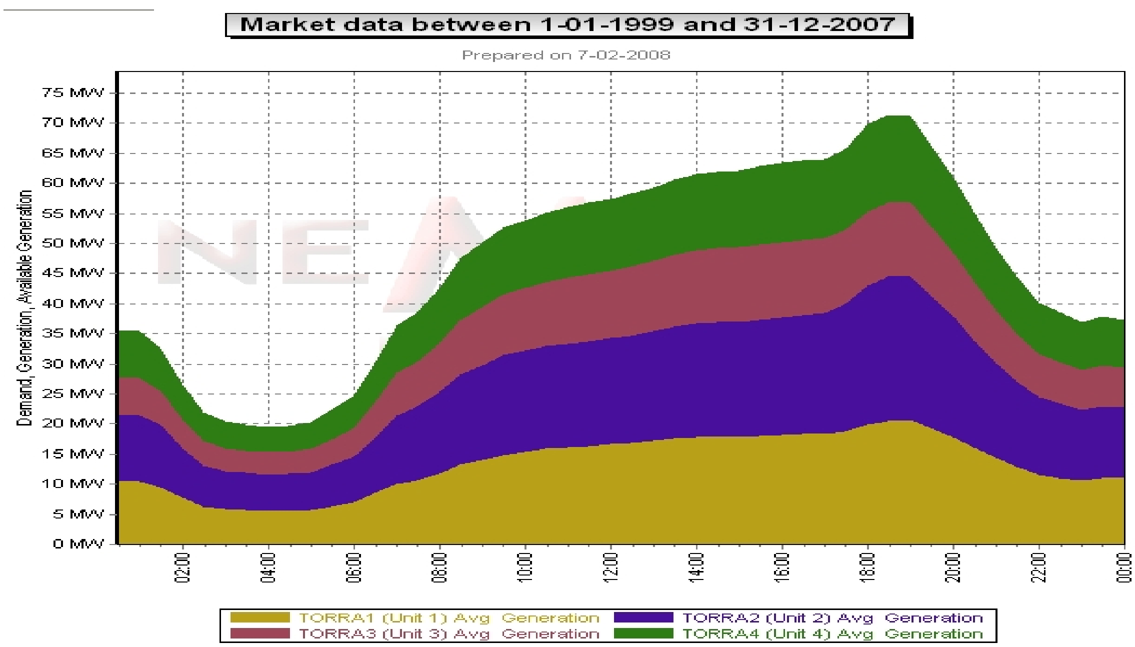
The quarterly average dispatch of TIPS A shows that in recent years it has been increasing its average supply to the SA region.

In fact, on a quarterly average time basis, TIPS A is consistently being dispatched and in each quarter has been dispatched to its maximum capacity, and (as the next two charts show), TIPS A's average load factor ranges between 33% and 5%, but recently has been averaging at over 15%.

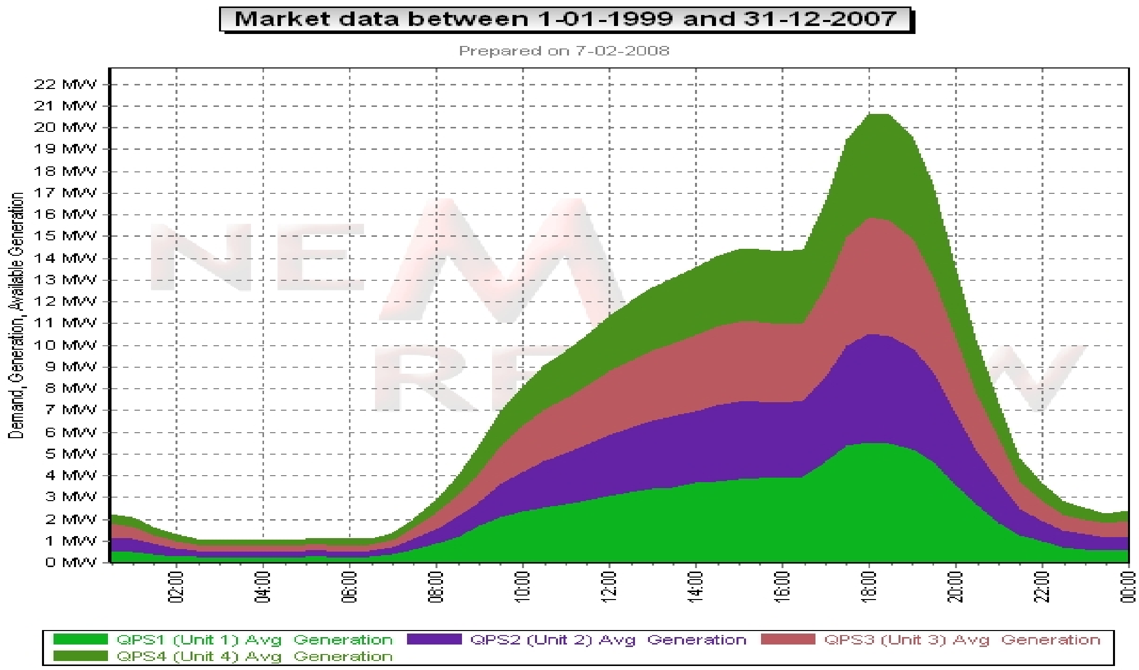




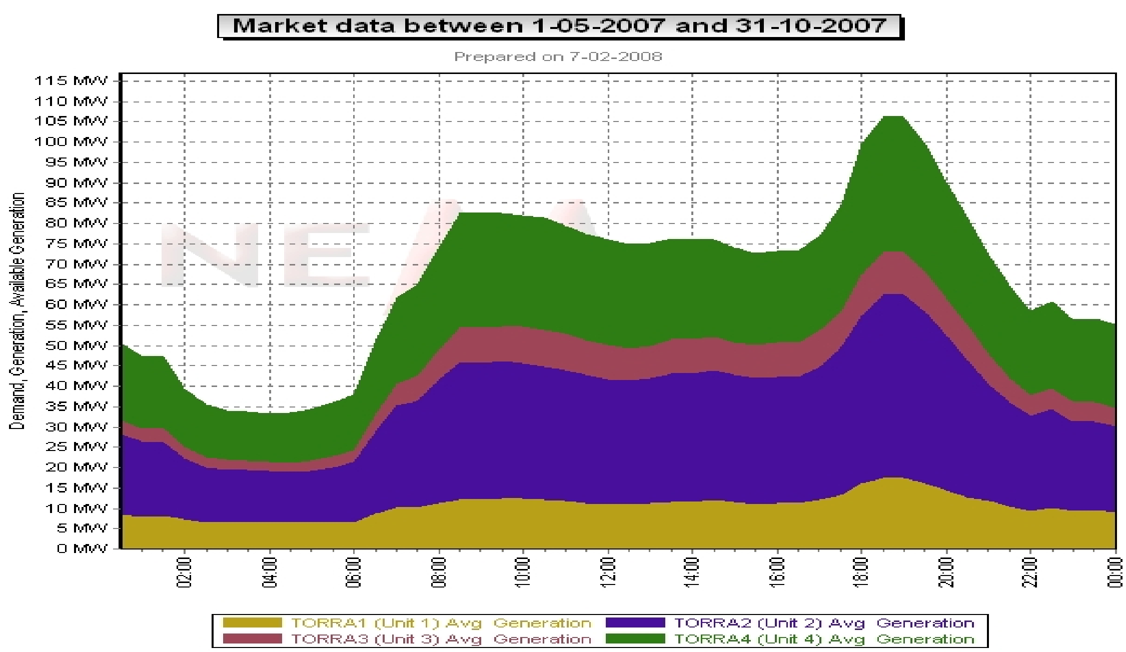
If TIPS A is operating as an intermediate load supply source, it would have its boilers near steaming on a near continuous basis, and so could manage faster responses to incremental demand changes. The following chart shows that an average day for TIPS A follows this pattern, having its daily peak 3.5 times its daily minimum



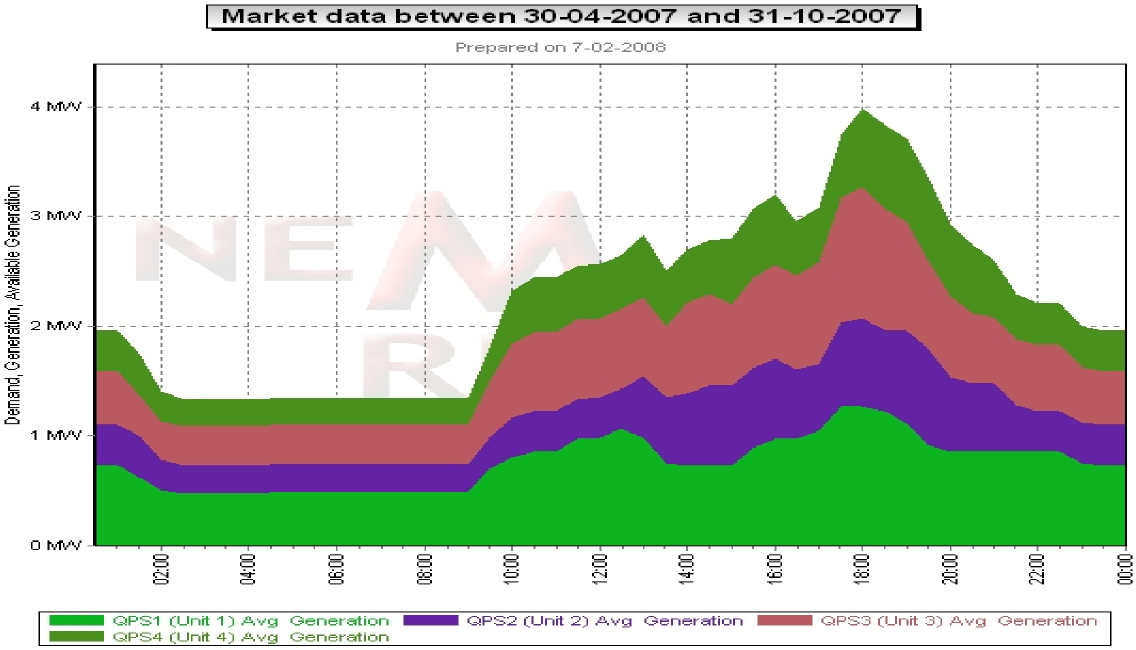
In contrast, comparing the operation of Quarantine (peaking OCGT plant) on an average day shows that a peaking station typically has its daily peak some 20 times its daily minimum.



This trend is even more pronounced when viewing a typical day in the colder months when demand is more predictable and TIPS A is operating like an intermediate station which would have a peak load factor of ~25%.



Compared to Quarantine, which is a peaking plant, it has operated at a peak load factor of 4% during the colder months.



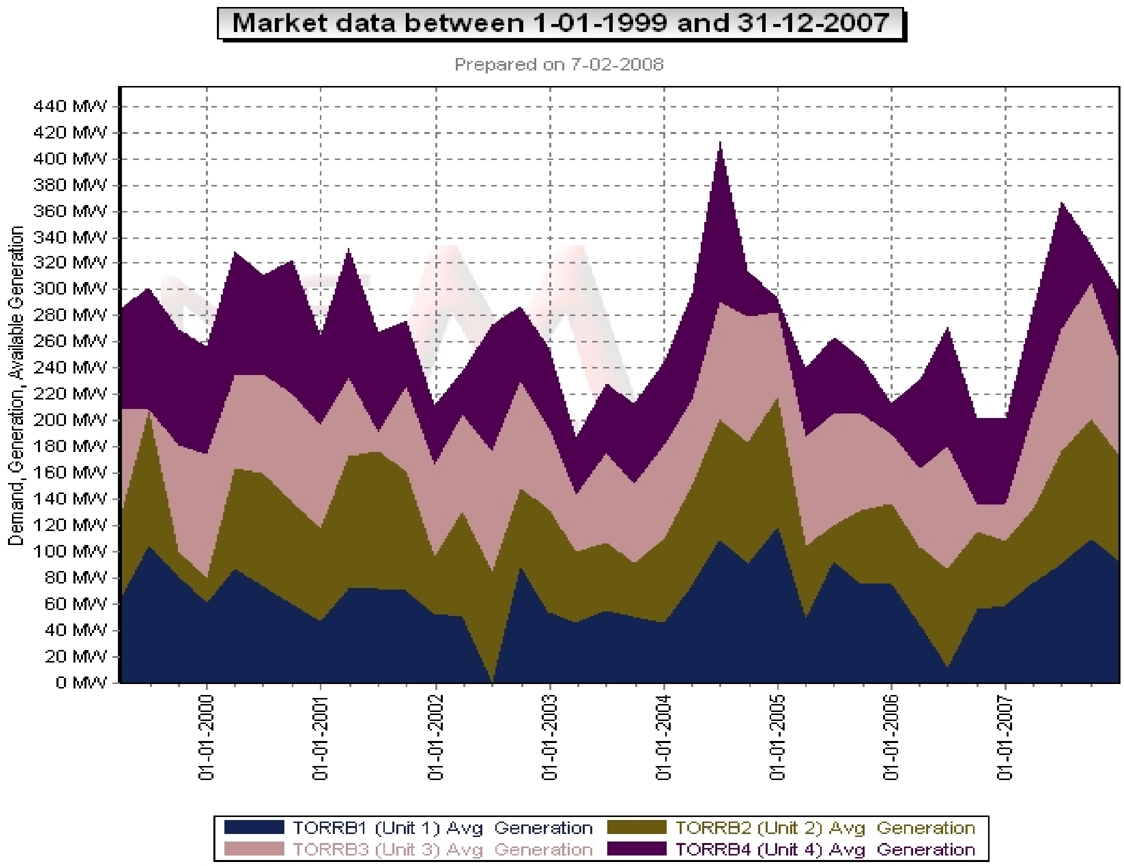
This analysis shows that TIPS A not only is designed to operate as a base to intermediate load power station, but that it does operate as an intermediate station, and when analysing its pricing strategy this must be kept in mind.

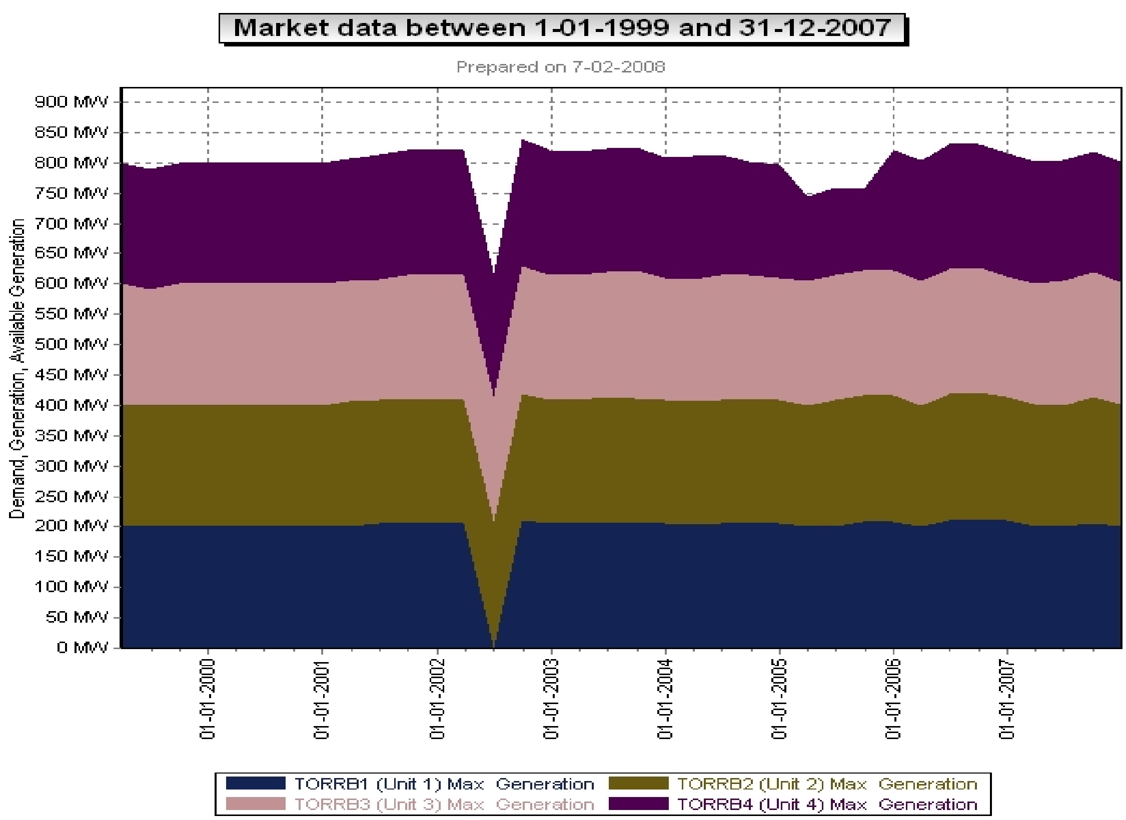
3.3 TIPS B

The following two graphs show that over the period since the NEM commenced, TIPS B generation has provided basically consistent output in average terms. When the average output is compared to the peak output, TIPS B was operating at a load factor of 30-50% for most of the time and in the last year at ~45%.

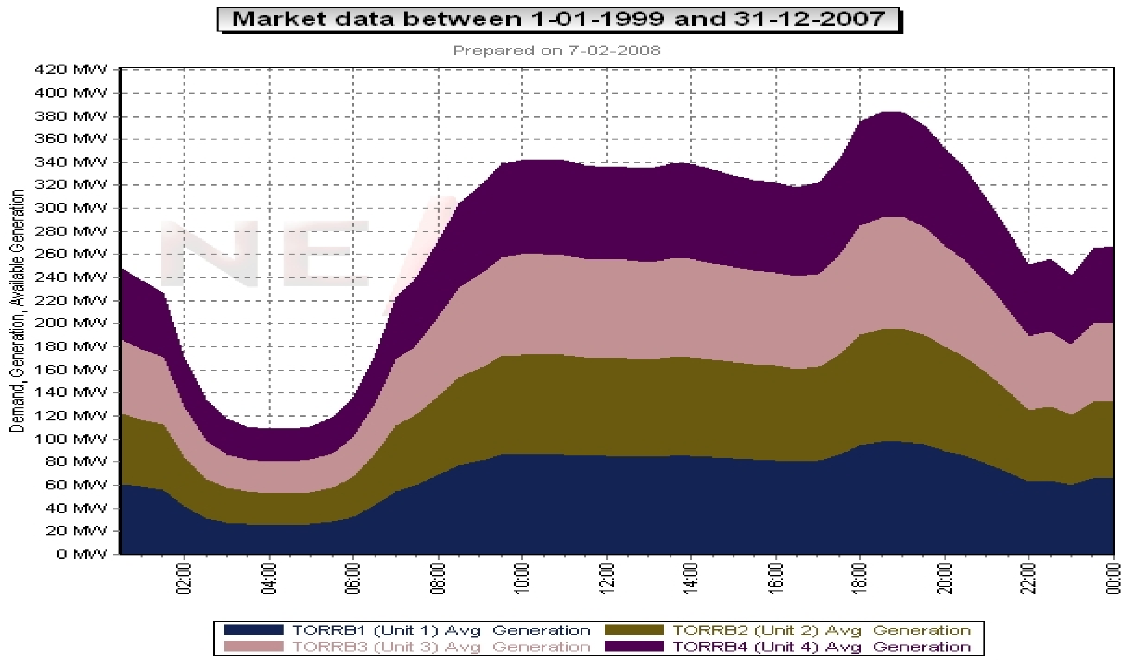
The question then becomes: is TIPS B operating in this mode due to its low efficiency (using a steam cycle) compared to a higher efficiency plant, such as Pelican Point, which operates at higher efficiencies using the same fuel, or compared to lower cost fuel plants such as Northern Station using coal, and therefore being relegated on a cost merit basis?

In fact on a quarterly average time basis, TIPS B is consistently being dispatched and in each quarter has been dispatched to its maximum capacity, (as the next two charts show), demonstrating that the TIPS B average load factor ranges between 53% and 25%, and averaging over 40%.

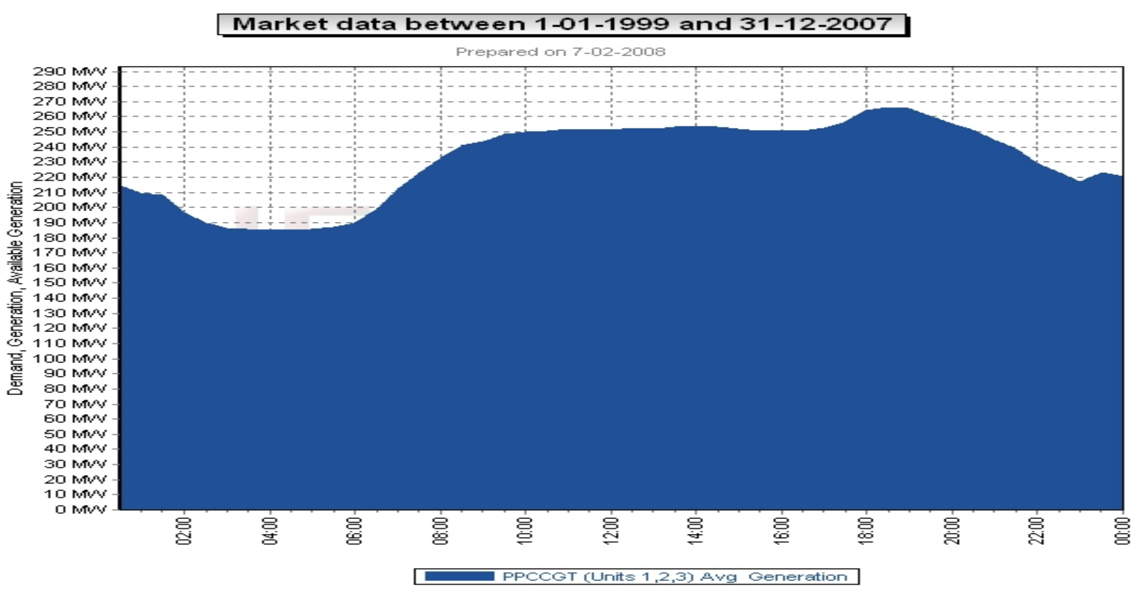

Market data between 1-01-1999 and 31-12-2007
Prepared on 7-02-2008
Demand, Generation, Available Generation
440 MW
420 MW
400 MW
380 MW
360 MW
340 MW
320 MW
300 MW
280 MW
260 MW
240 MW
220 MW
200 MW
180 MW
160 MW
140 MW
120 MW
100 MW
80 MW
60 MW
40 MW
20 MW
0 MW
01-01-2000
01-01-2001
01-01-2002
01-01-2003
01-01-2004
01-01-2005
01-01-2006
01-01-2007
TORRB1 (Unit 1) Avg Generation
TORRB2 (Unit 2) Avg Generation
TORRB3 (Unit 3) Avg Generation
TORRB4 (Unit 4) Avg Generation


Market data between 1-01-1999 and 31-12-2007
Prepared on 7-02-2008
Demand, Generation, Available Generation
900 MW
850 MW
800 MW
750 MW
700 MW
650 MW
600 MW
550 MW
500 MW
450 MW
400 MW
350 MW
300 MW
250 MW
200 MW
150 MW
100 MW
50 MW
0 MW
01-01-2000
01-01-2001
01-01-2002
01-01-2003
01-01-2004
01-01-2005
01-01-2006
01-01-2007
TORRB1 (Unit 1) Max Generation
TORRB2 (Unit 2) Max Generation
TORRB3 (Unit 3) Max Generation
TORRB4 (Unit 4) Max Generation

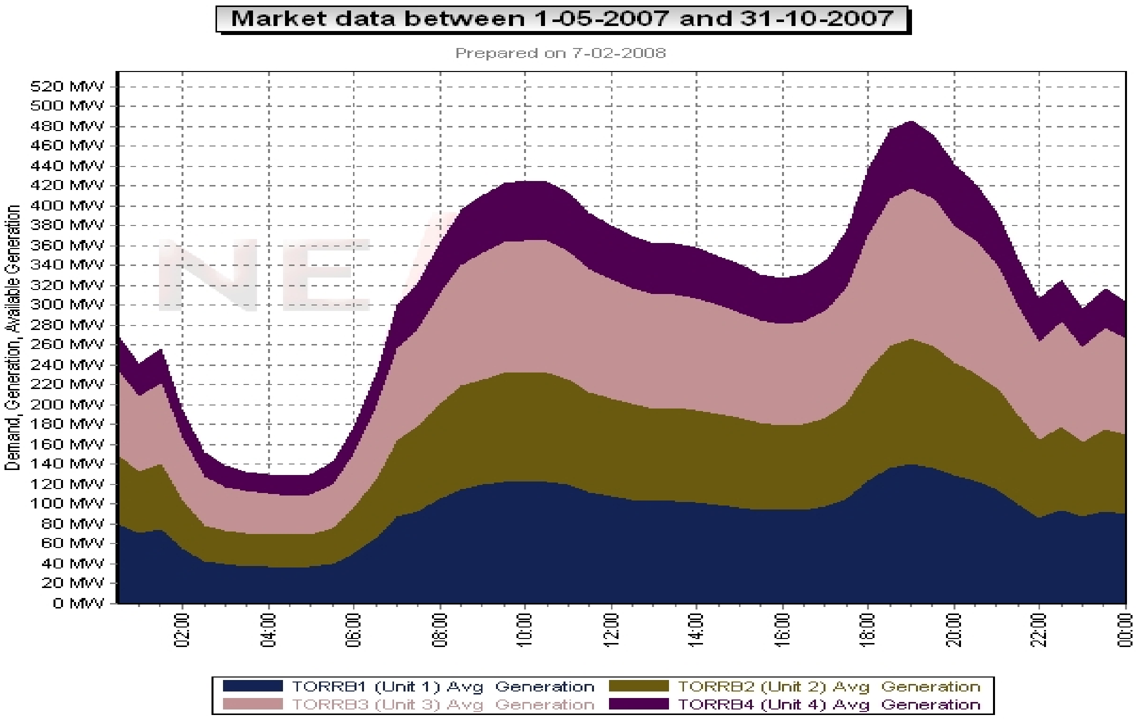
If TIPS B is operating as a base or intermediate load supply source, it would have its boilers near steaming on a continuous basis, and so could manage faster responses to incremental demand changes. The following chart shows that an average day for TIPS B follows this pattern, having its daily peak 3.5 times its daily minimum.



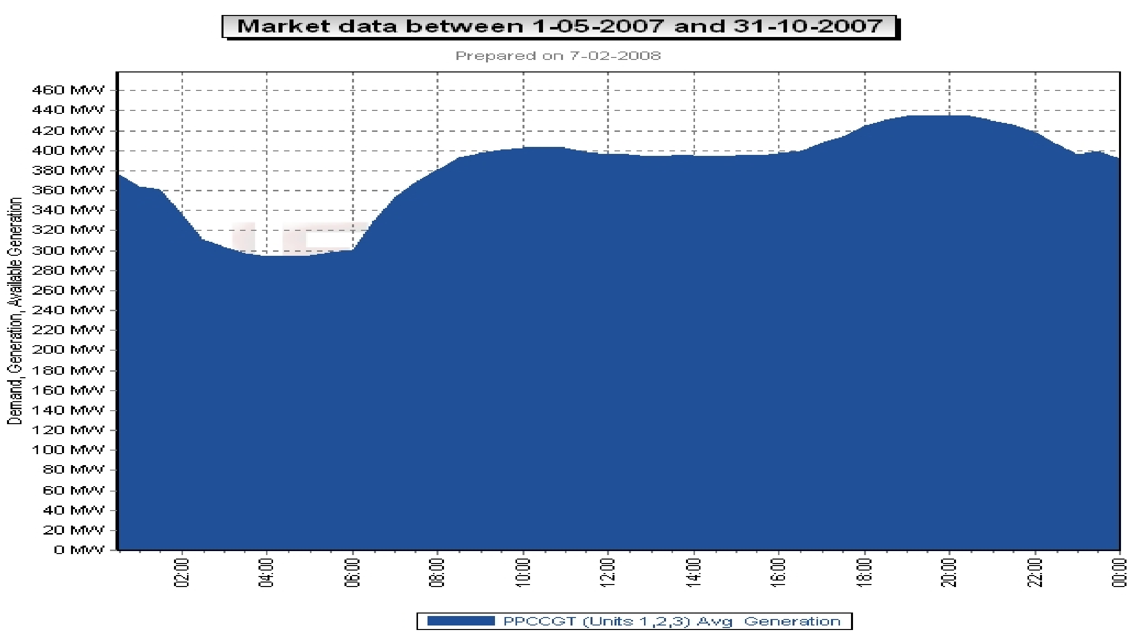
In contrast, comparing the operation of Pelican Point (gas fired CCGT plant) on an average day shows that a base load station typically has its daily peak some 1.5 times its daily minimum.



This trend is even more pronounced when viewing a typical day in the colder months when demand is more predictable and TIPS B is operating like an intermediate station which would have a peak load factor of ~50%.

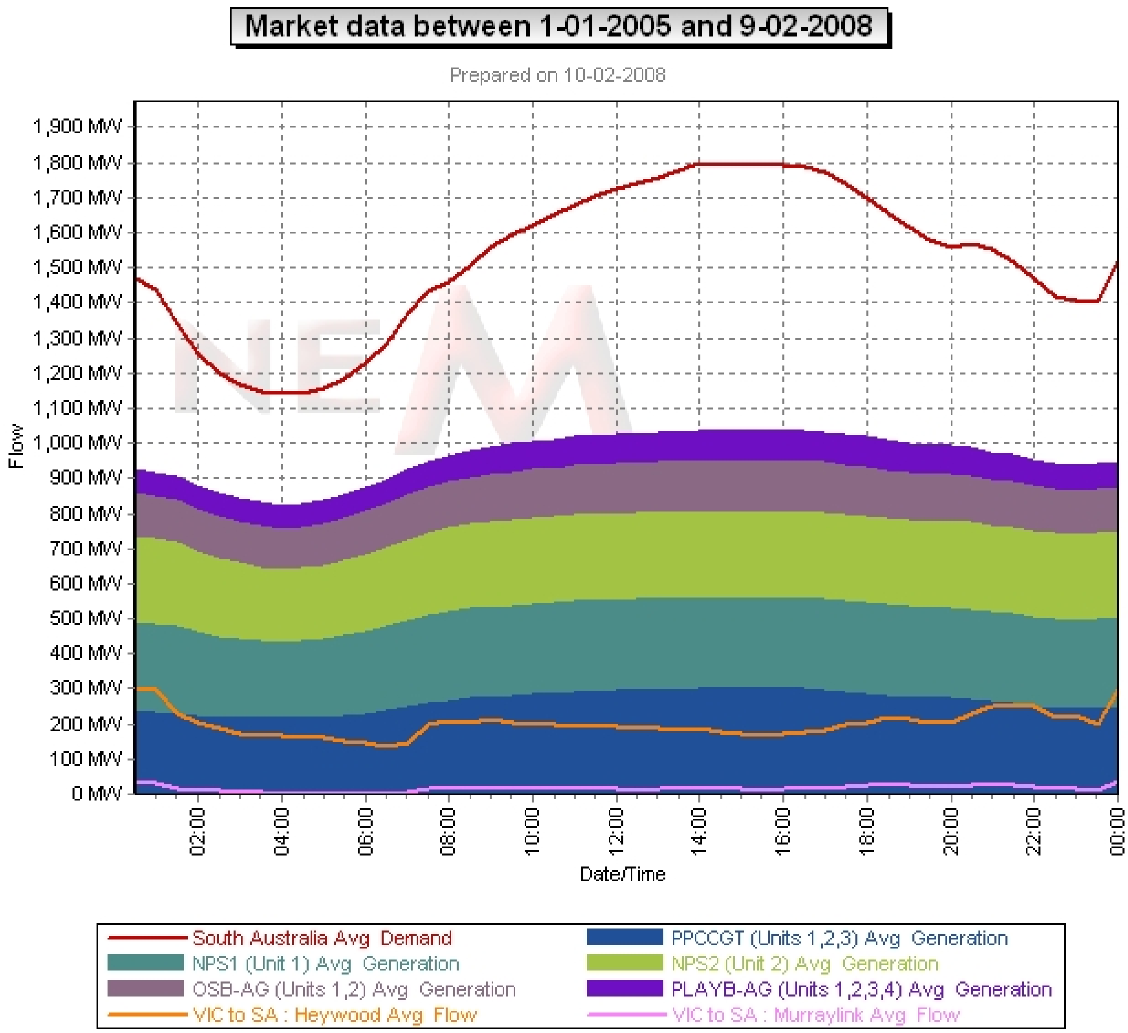


Compared to Pelican Point which is a base load plant, Pelican Point operated at a peak load factor of nearly 90% during the colder months.



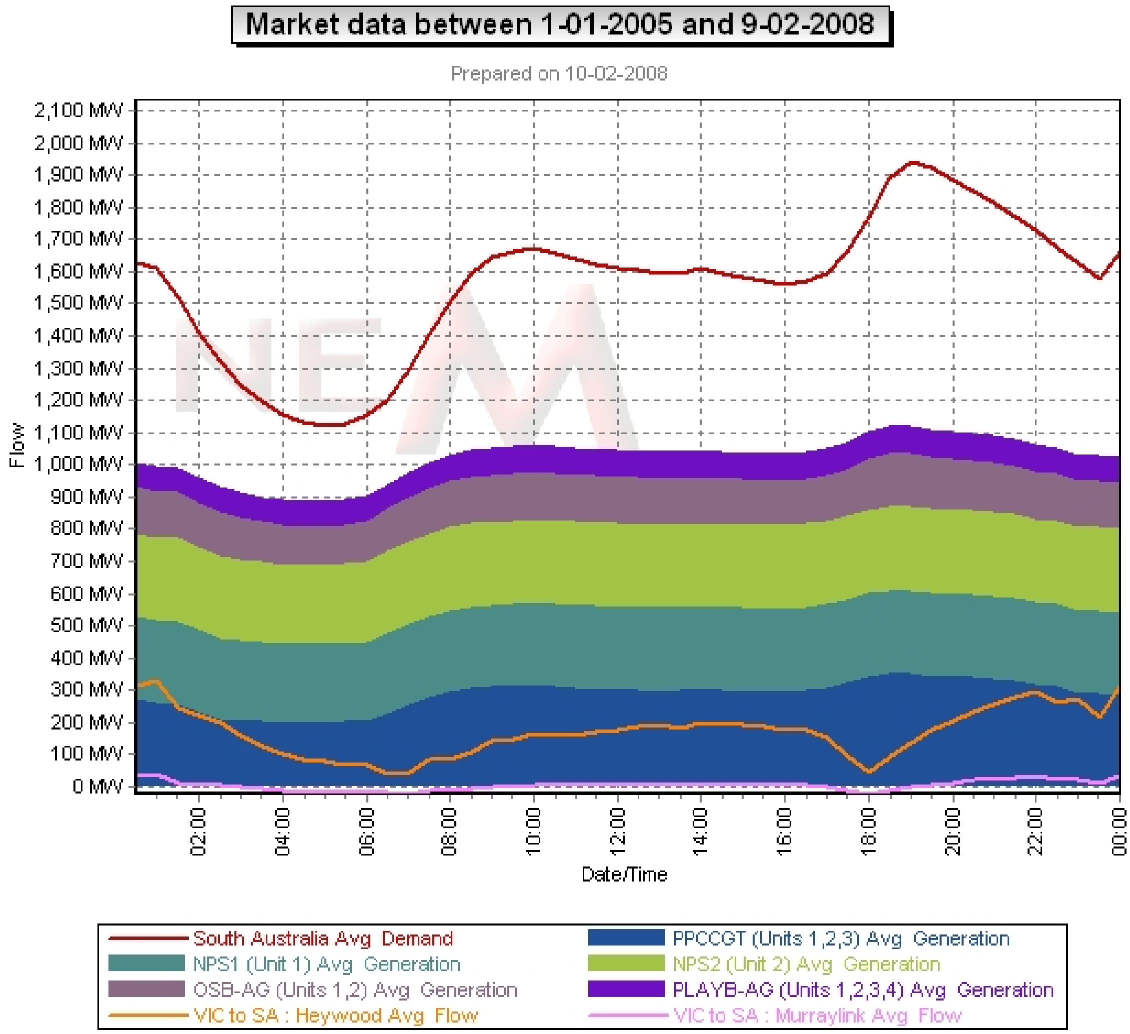
3.4 An alternative approach

In the summer months (December, January and February), the SA demand has the following average characteristics as applying from 2005 to current. To this has been added the average output of the base load stations Pelican Point, Northern, Playford B and Osborne.



This shows Heywood and Murraylink operating at maximum capacity (Murraylink hardly ever does and Heywood is now constrained to ~360 MW when the wind farms at Snuggery are operating). Further, if all the base load stations were operating at maximum capacity (i.e. 1430 MW), there is still a short fall of base load/intermediate supply for some 16 hours of the day.

A similar occurrence applies in winter (June, July and August) and although the average demand is slightly less the average peak demand in the winter months is even higher than in summer.



In winter, the average shortfall of baseload is even greater and for longer. Even if all base load units were operating at maximum output (i.e. 1430 MW) there is a shortfall of supply for 6 hours of the day. Adding Heywood at the rated 460 MW and all base load stations working at maximum output, would just cover most of a winter's day.

It is not realistic, however, to assume continuous operation at maximum. In fact, the average actual output of the base load stations is about 80% of rated output – this 20% loss is consistent with normal operating parameters. Examination of the flows on the interconnectors shows that Murraylink does little to provide any support and Heywood adds at most ~300MW.

Thus a realistic evaluation shows that in the absence of TIPS, there is a short fall of base load supplies for much of an average day in winter and summer.

Assuming TIPS was a peaking station, then for most of summer and winter, consumers would have to be exposed to peak generation prices for 16-18 hours per day. The fact that this does not occur supports the contention that TIPS was designed for base/intermediate supply and that the actual operation of TIPS supports this contention.

3.5 Conclusion

This analysis shows that TIPS B not only is designed to operate as a base or intermediate load power station, but that it does operate as such (perhaps with "more base" than TIPS A), and when analysing its pricing strategy this must be kept in mind.

Bardak[5] has offered a quantification for the terms **base, intermediate and peaking** generation.

> "The term base load is usually used for plants operating down to about 60% load factor (which is the ratio of actual energy production to the maximum possible energy production in a period), intermediate load factors range from 60% down to about 15%, and peaking load factors are below 15%."

Analysis of the different stations against these criteria supports the view that Pelican Point, Northern, Playford and Osborne are all base load stations. The operation of TIPS B with its average load factor of over 40% sits near the base/intermediate interface. TIPS A with its recent average load factor of ~15% sits at the interface of intermediate/peak, although it has operated at higher load factors in the past.

The logic of such nomenclature is obvious. A **base load** station needs time to fire up and has limited ability to make large and fast adjustments to its output. Base load plant offset its high capital cost with low fuel costs using fuels such as coal. Classically coal fired boiler plant fits this operating regime.

A **peaking** station can quickly start using fuels which can be quickly ramped up (such as gas) and tends to operate for short periods. OCGT plant fits this operating regime. Because of its limited operating times, the plant tends to be low capital cost.

Intermediate plant tends to use a flexible fuel (such as gas) and needs to balance the higher cost of fuel with a higher thermal efficiency than lower capital cost plant can provide. This drive for higher thermal efficiency reduces the ability for faster changes in output. Gas fired steam plant falls into the category of intermediate plant.

[5] ibid page 28

This assessment of Bardak, which is consistent with world wide observations, supports the view that TIPS is at most an intermediate load station based on its actual operating characteristics, and could well be considered for at least part of its output as a base load station.

TIPS certainly is not a peaking station, and operates primarily as an intermediate supply. Therefore any analysis of its market activities must reflect this ranking.

4. The impact of assessing TIPS as intermediate

Having established that TIPS is in reality an intermediate ranking power station, should its pricing strategy reflect this, and if so can it effectively use its capacity to exercise market power?

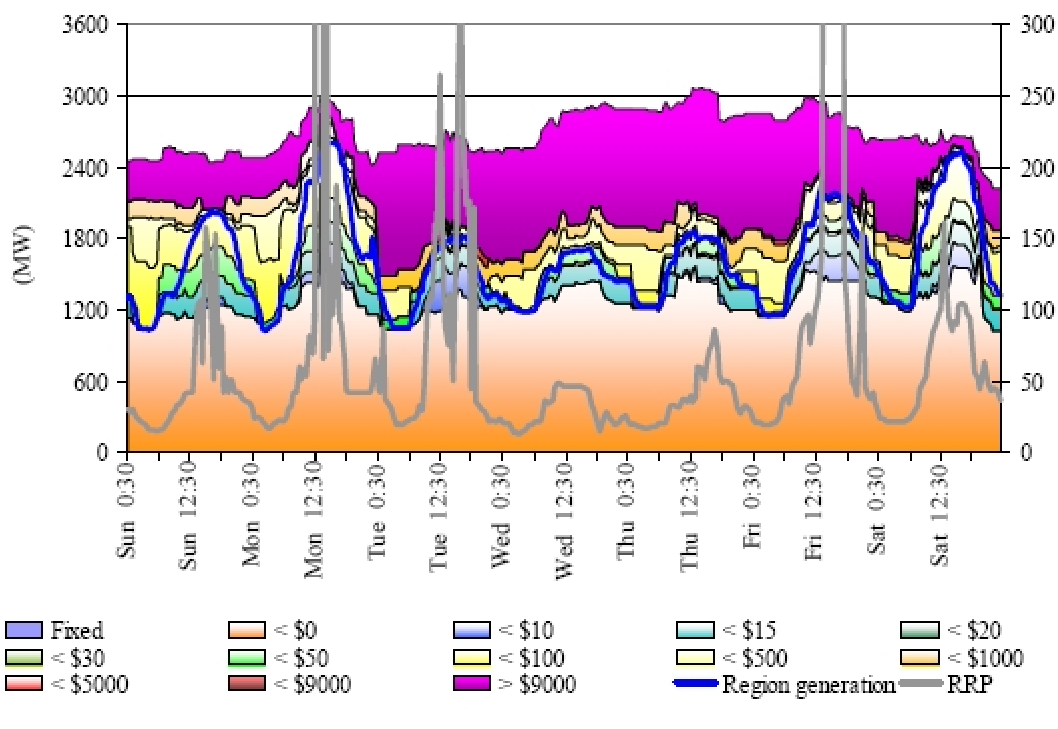
The MEU contention is that TIPS's actions must be seen in light of its ranking as a base/intermediate power station, that it does have market power, and it has used this market power to set the spot market price.

The following examples support this contention.

4.1 Friday January 4, 2008

The AER market analysis[6] shows that there appeared to be no rebidding by TIPS on this day.

Figure 60: South Australia closing bid prices, dispatched generation and spot price



[6] AER Market analysis 30 December 2007 – 5 January 2008, AER website

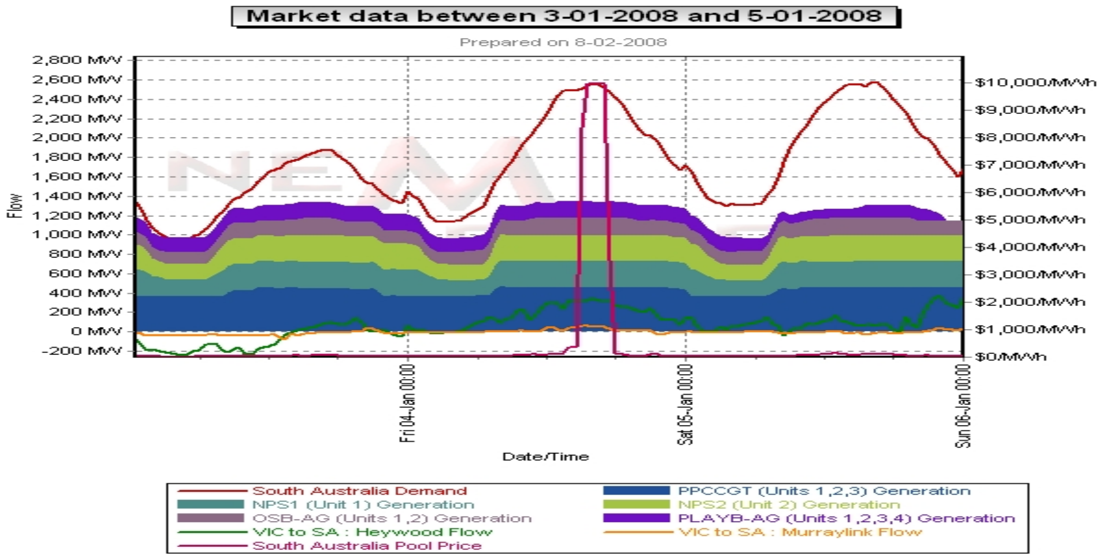
Friday, 4 January

3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	8353.99	9946.82	9999.32
Demand (MW)	2509	2537	2601
Available capacity (MW)	2820	2899	2958
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9950.37	9949.51	9999.72
Demand (MW)	2539	2565	2630
Available capacity (MW)	2829	2899	2958
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9950.32	9949.45	9999.72
Demand (MW)	2564	2574	2632
Available capacity (MW)	2849	2934	2958
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9949.94	9949.51	9999.72
Demand (MW)	2555	2585	2642
Available capacity (MW)	2849	2931	2954
5:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9948.25	9947.48	9999.72
Demand (MW)	2535	2554	2609
Available capacity (MW)	2853	2920	2946
5:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3526.58	145	9950.77
Demand (MW)	2499	2488	2542
Available capacity (MW)	2856	2918	2946

Conditions at the time saw demand at close to record levels. Prices were generally close to forecast. In accordance with clause 3.13.7 of the Rules, the AER will be issuing a report into the circumstances that led to the spot price exceeding $5000/MWh.

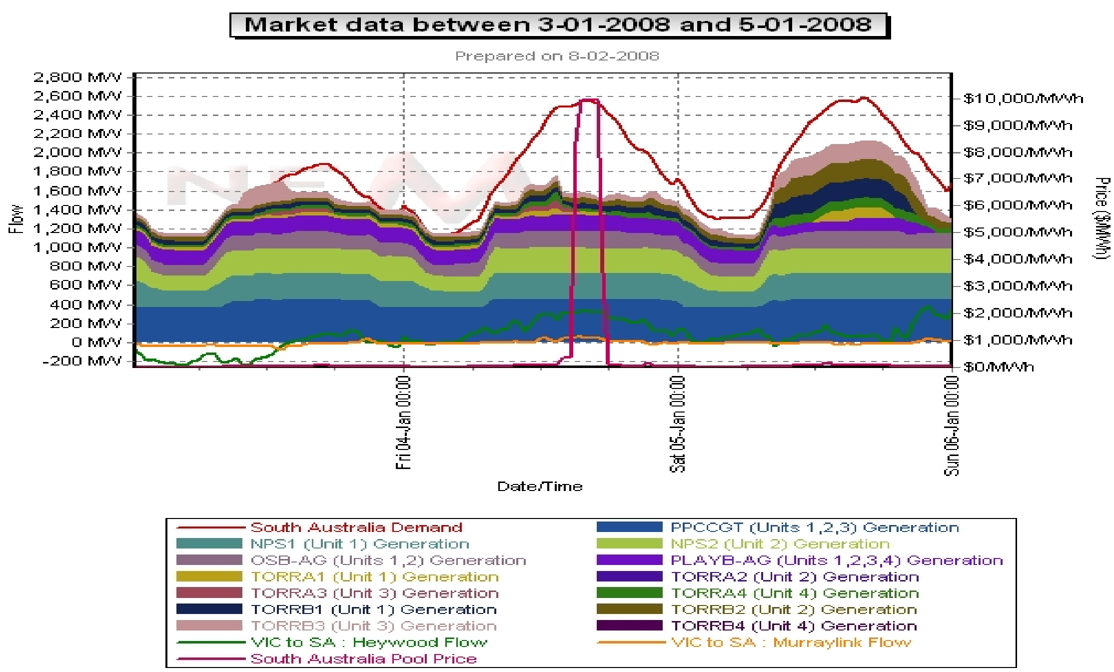
On 4 January 2008, TIPS was instrumental in spiking the spot price to VoLL through its actions and pricing policy. The following chart shows that the base load stations were all operating as appropriate for base load dispatch, and had been for the days before and after January 4.

Murraylink provides little support to the SA demand and Heywood is constrained to ~360MW due to the constraining influence of the wind farm generation.

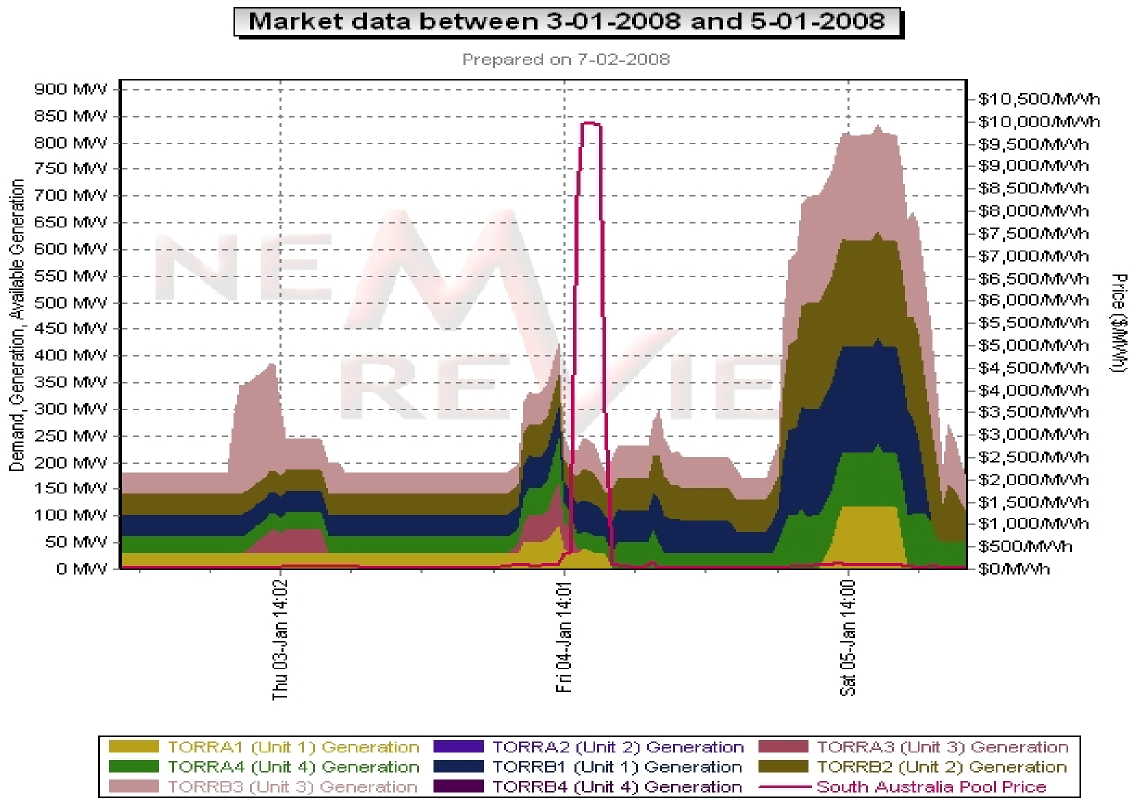


When TIPS output is added to the chart, it shows that TIPS actively used its market power to spike the spot price by the effective withdrawal of a critical element of its capacity by bidding the same capacity into the top price band. This caused peaking stations to be dispatched.

On Saturday 5 January, the system demand was much as on the Friday, and if the market operated consistently (i.e. prices rising as demand increases) then a price spike would also have eventuated if TIPS was what it professes to be. But no price spike occurred. What did happen as the following chart shows is that TIPS was dispatched as an intermediate station, more than doubling its output.

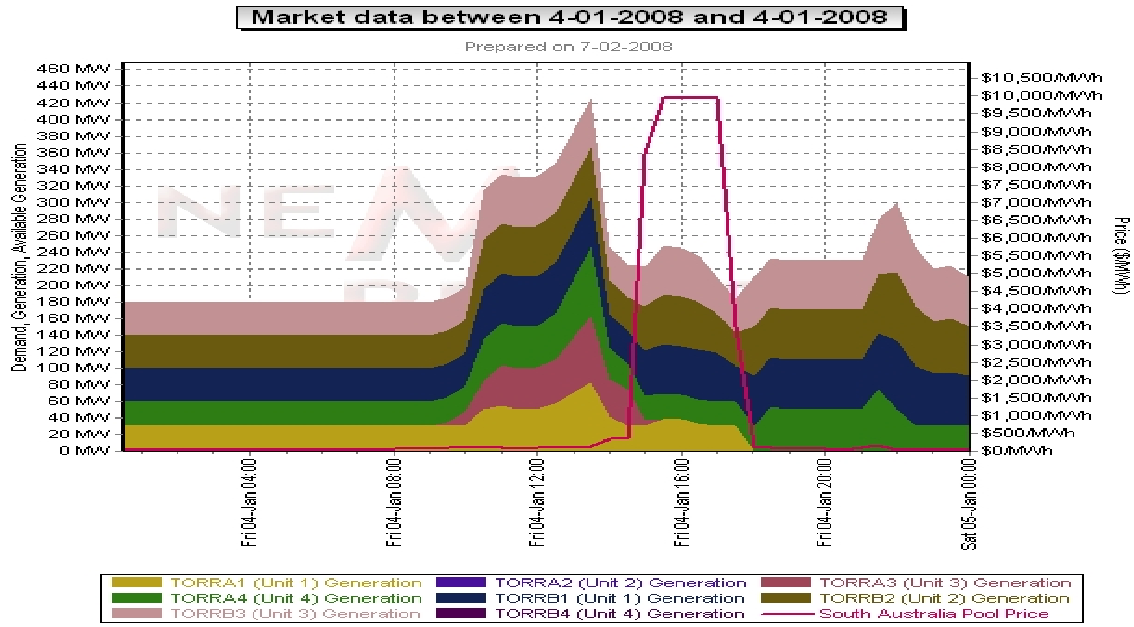


Examining the actual dispatch pattern in closer detail, shows that TIPS saw an opportunity and reduced a critical part of its capacity (i.e. bid sufficient capacity into the top price band to cause the spike) knowing that there would be a shortfall in supply, and high priced peaking stations (the only power plant left in the market) were dispatched to make up supply.



As can be seen, TIPS attempted to hold the price at VoLL, and even further reduced output towards 6 pm to hold the price high, but falling system demand made TIPS no longer the critical source of supply.

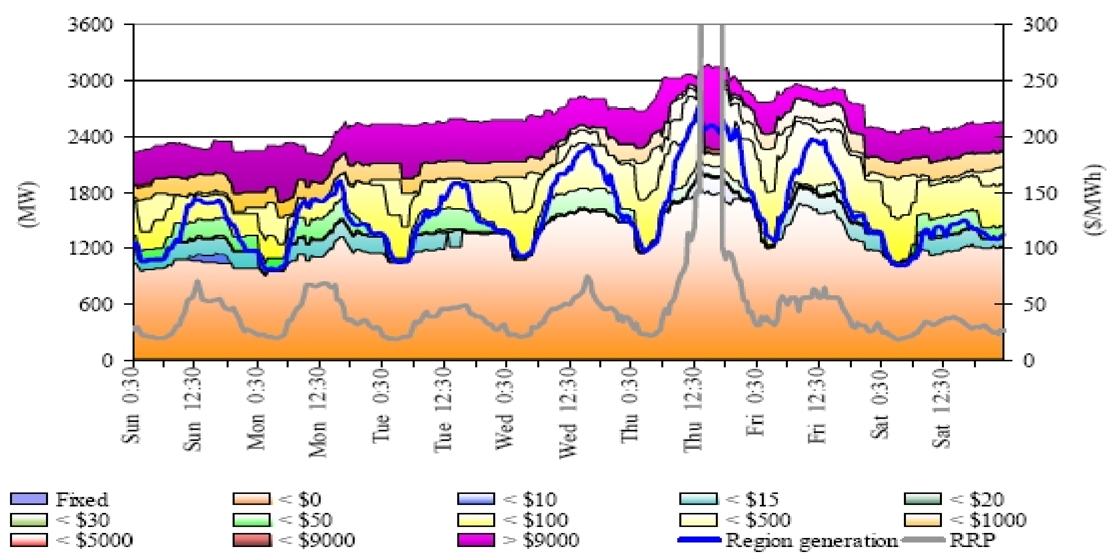
Just as MacQuarie Generation used its market position and bidding approach (by “repricing”)to spike the NSW market in mid 2007, TIPS did exactly the same thing, as its capacity is critical to meet demand in SA.



4.2 Thursday January 10, 2008

The AER market analysis[7] shows that there appeared to be no rebidding by TIPS on this day, but extremely "strategic" bidding when compared to the previous and following days relative to the demand

Figure 60: South Australia closing bid prices, dispatched generation and spot price



7 AER Market analysis 6 January – 12 January 2008, AER website

There were seven occasions where the spot price in South Australia was greater than three times the South Australia weekly average price of $416/MWh.

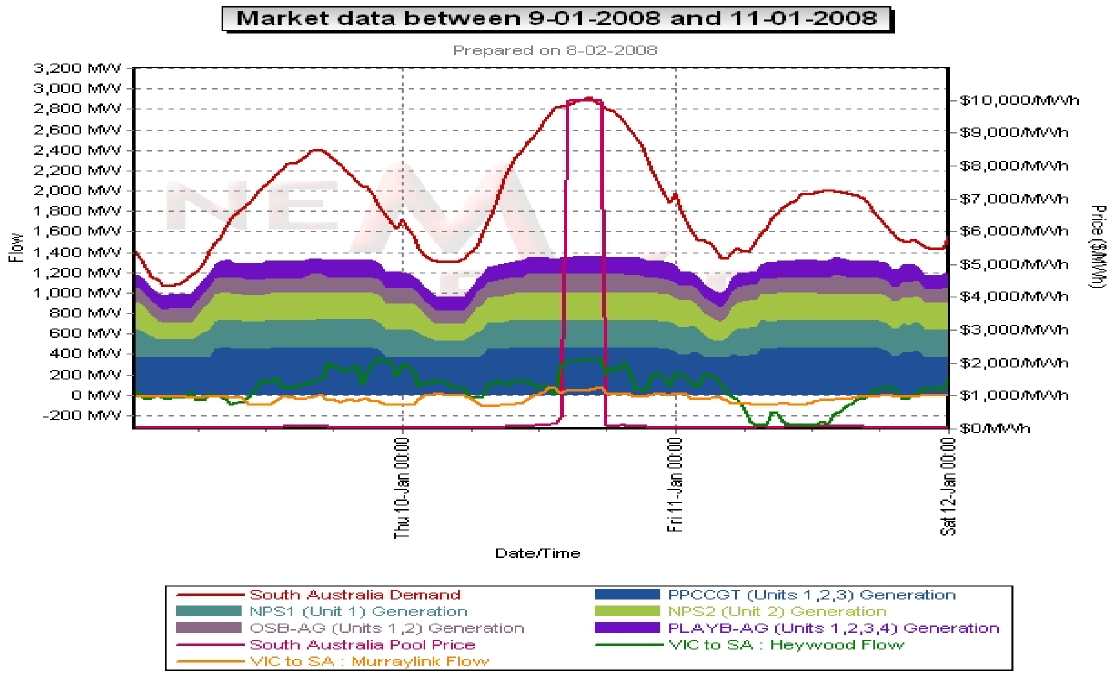
Thursday, 10 January

2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.72	9999.72	9999.72
Demand (MW)	2835	2817	2817
Available capacity (MW)	3146	3152	3045
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.72	9999.72	9999.72
Demand (MW)	2859	2883	2855
Available capacity (MW)	3171	3152	3045
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.72	9950.71	9999.72
Demand (MW)	2879	2895	2869
Available capacity (MW)	3174	3152	3046
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.72	9999.72	9999.72
Demand (MW)	2891	2906	2884
Available capacity (MW)	3155	3155	3037
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.72	9999.72	9999.72
Demand (MW)	2916	2912	2889
Available capacity (MW)	3144	3155	3035
5:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.72	9999.72	9999.72
Demand (MW)	2879	2891	2868
Available capacity (MW)	3148	3153	3035
5:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9999.72	8999.72	9999.72
Demand (MW)	2852	2837	2819
Available capacity (MW)	3146	3128	3035

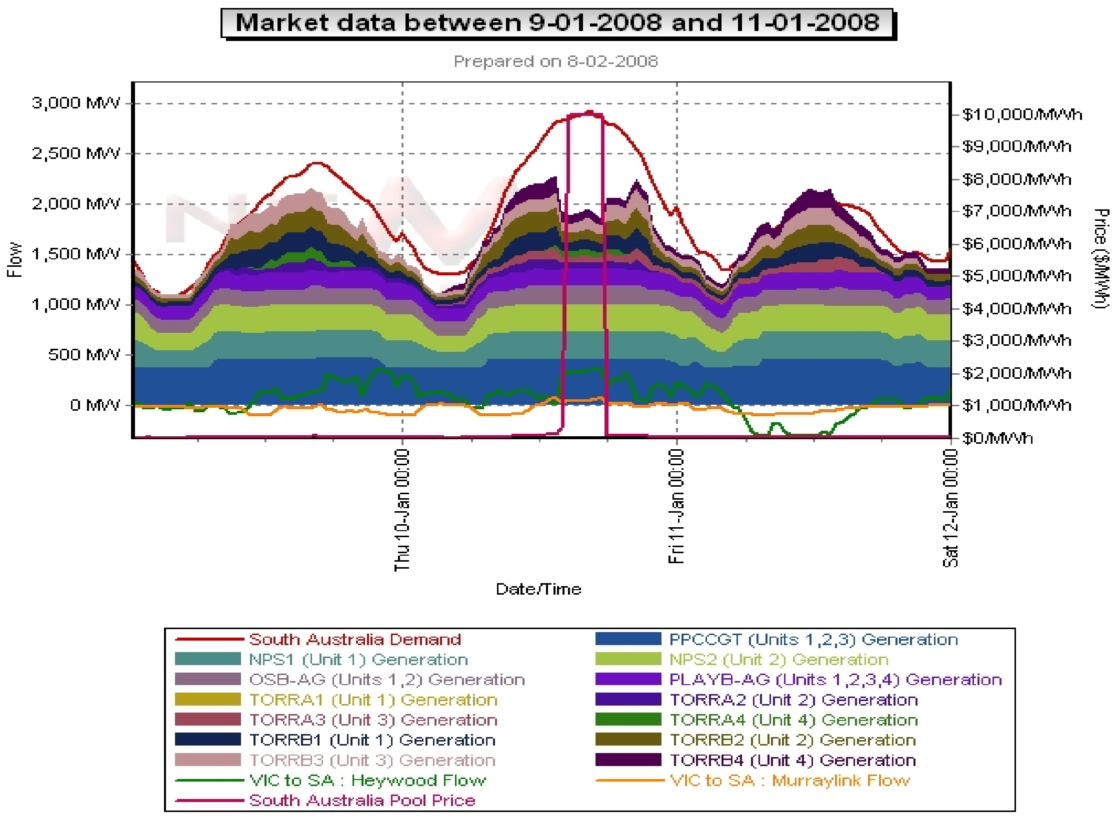
Conditions at the time saw demand, price and available capacity close to that forecast four and twelve hours ahead.

As on 4 January, 10 January saw the base load generators operating in standard fashion, operating at maximum output without any gaming. This practice was observed on both the preceding and proceeding days which were “work” days,.

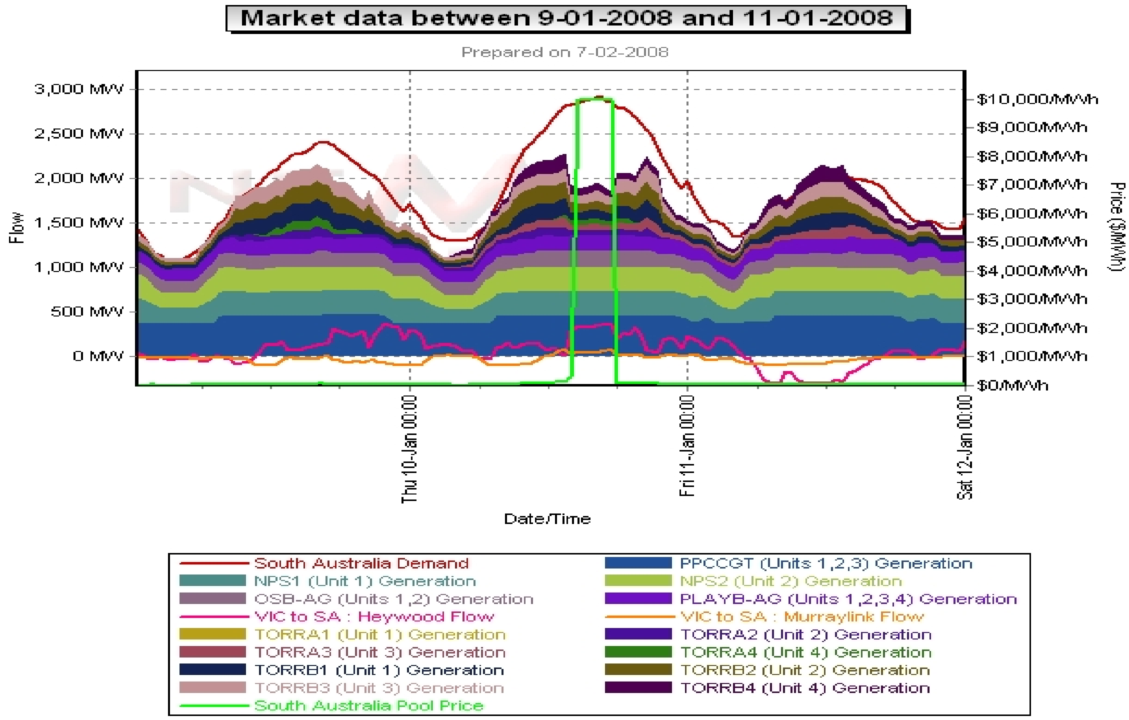
Murraylink provided little support to the SA demand and Heywood was constrained to ~360MW due to the constraining influence of the wind farm generation.



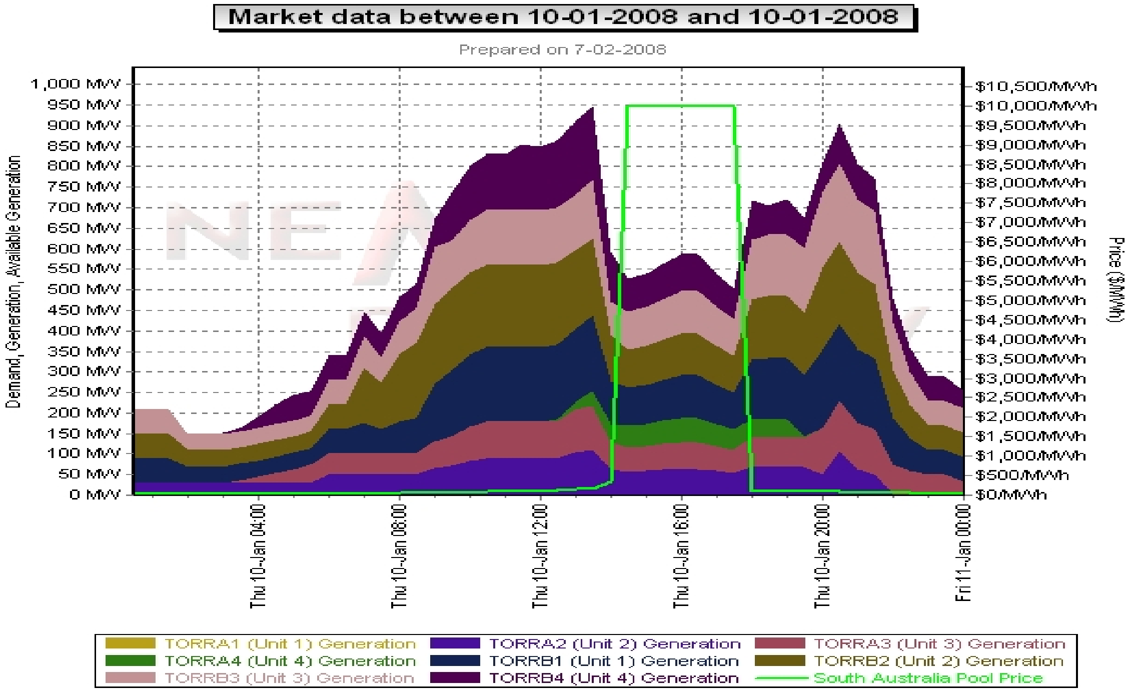
When the supply from TIPS is added, it provides an interesting view. TIPS provided supply of about the same amount on each of the three days, yet on 10 January, it effectively withdraws capacity (or bids the same capacity into the top price band) and due to its importance in the ranking of generation, it caused the price to spike.



When a more detailed examination is made of the TIPS practices, it shows that when the interconnector was identified to be constrained, that all base load supply had been committed, and at what prices peaking plant would be dispatched, it withdrew sufficient capacity (i.e. bid the same capacity into the top band width) so that higher priced peaking plant was dispatched.

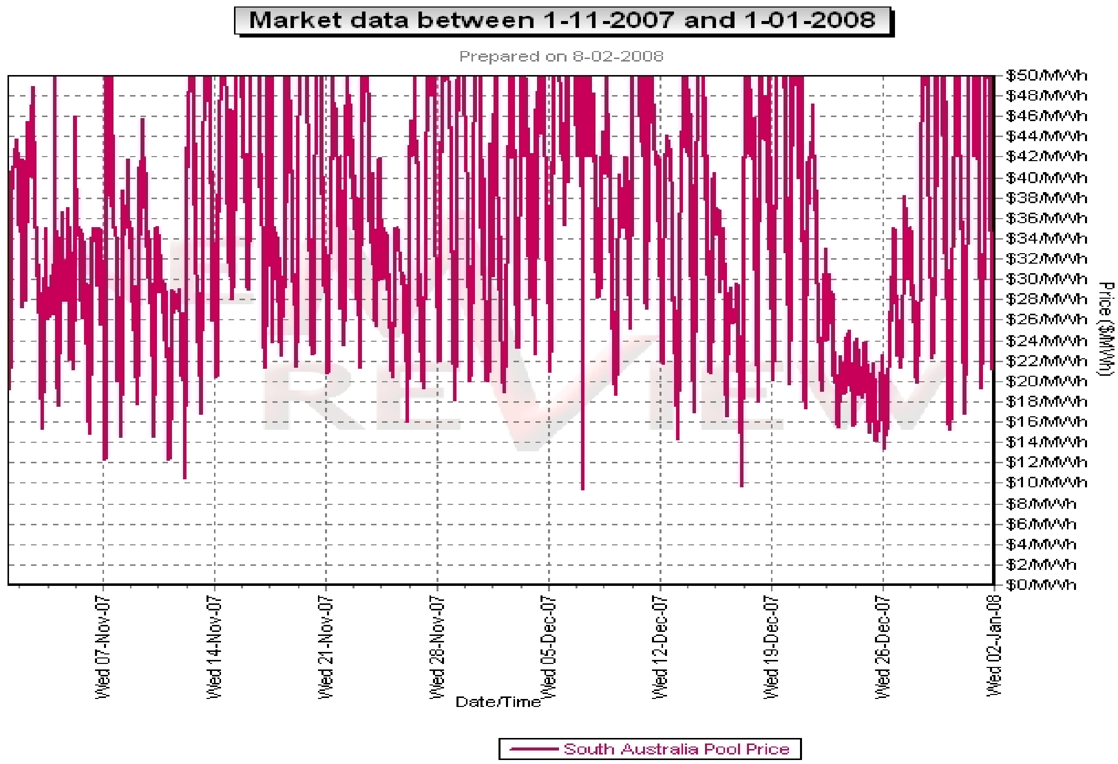


Through its bidding strategy, TIPS then increased output sufficient to keep peaking plant dispatched (i.e. to hold the price at VoLL) until the system demand commenced to fall at about 4.30 pm. TIPS then withdrew capacity again until the system demand had reduced sufficiently (i.e. by 6 pm) that TIPS could no longer exercise market power. At this stage it increased its supply (i.e. by bidding the same capacity into a lower band width) to reflect the more appropriate use of an intermediate power station.

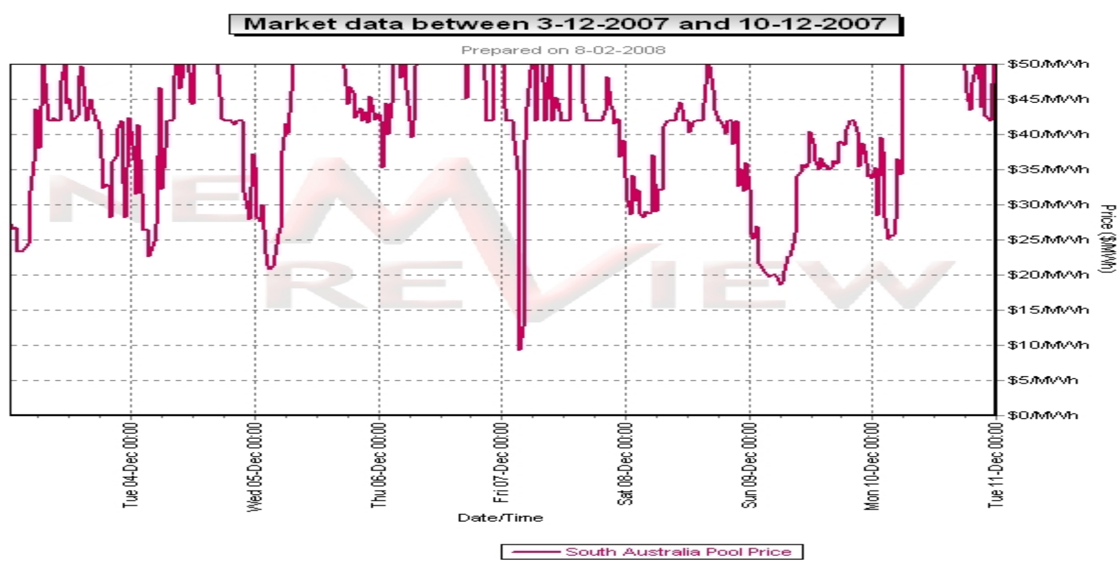


4.3 Floor price setting

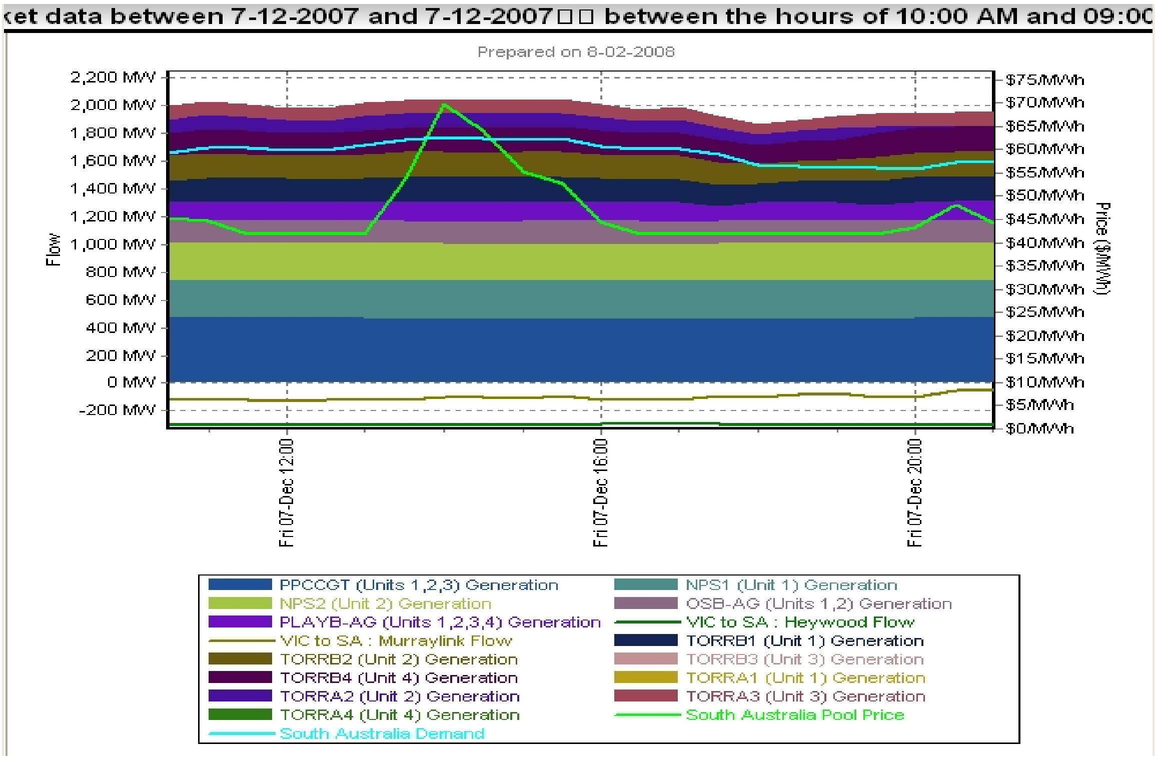
In addition to the spot prices in early January 2008, it has been observed that there was an attempt to set a floor price on SA of $42/MWh during November and December 2007. This can be observed in the following chart.



A review of the first week in December 2007 shows this more clearly, and was well pronounced on Friday 7 December.



The supply chart for Friday 7 December shows that output from TIPS has a close relationship to the SA demand curve and flows to Victoria. As the demand curve falls, so does the output of TIPS such that the price does not fall below $42/MWh.



This floor price is probably a reflection of the LRMC for TIPS to provide power and therefore this is an understandable market pricing approach. From a consumer viewpoint it is not so much that there is a floor price at this level, but that TIPS can set the market price to ensure that it occurs.

5. The ACCC decision[8] allowing the sale of TIPS to AGL

The ACCC assessed in April 2007 whether the sale of TIPS to AGL considering its dominance as a retailer in SA, contravened the competition laws and whether it would give AGL greater power to raise prices in SA, and/or if it would lessen competition in electricity supply in SA.

5.1 The likelihood that the proposed transaction would give AGL the ability and incentive to raise prices in the wholesale market

In this regard the ACCC commented (paragraph 45):

> "Economic analysis undertaken by the ACCC suggested that, when demand in South Australia is high and the Vic-SA interconnector is constrained, TIPS appears to have the ability to bid strategically to increase average SA pool prices by at least 5%"

The ACCC has determined that AGL can increase the SA spot price by 5% when demand is great. This clearly accepts that AGL ownership of TIPS does imply that AGL has a position of market power.

In fact, one half hour at VoLL, increases the average annual spot price by 1%. The implication of the ACCC comment is that it would expect that AGL will use its market power for no more than 5 half hour periods in any one year.

The recent efforts by AGL during January 2008 (i.e. in the first month of 2008) show that AGL used TIPS to increase the spot price at or near VoLL, for 8 half hour periods on 4 January and for 8 half hour periods on 10 January – a total of 16 half hour periods, some 18% in one week. In this regard, it must be noted that the demand on the first of these days was 10% below the peak reached on 20 January 2006 where the price averaged ~$2500/MWh for only 3 half hour periods.

The new SA peak of 2920 MW was reached on 10 January and this lasted for 10 half hour periods above 2800 MW, with only 4 half hour periods above the previous system peak 2873 MW on 20 January 2006. However, on 10 January the price was at VoLL for 8 half hour periods, including 4 periods which were less than the previous system peak.

Thus at most the ACCC observation has validity for perhaps 4 of the half hour periods where VoLL or near VoLL prices were incurred for 16 half hour periods.

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[8] Public Competition Assessment, AGL Energy Limited and TRUenergy Pty Ltd – proposed swap of South Australian electricity generation assets, 20 April 2007

5.1.1 (a) Potential incentive to influence ESCOSA's forthcoming review of the regulated electricity retail tariff

The ACCC considered that AGL did have the ability to influence the ESCoSA determination for retail price caps as in paragraph 52 it noted

> "Notwithstanding the processes undertaken and things taken into account by ESCOSA when determining regulated tariffs, the ACCC also considered that there were already possible strategies open to AGL to attempt to influence the tariff review, if it wished. Finally, the ACCC considered that TRUenergy may have already had the incentive to influence ESCOSA's review process, because, as a provider of market contracts, it would presumably also benefit from an increase in regulated retail tariffs, as outlined above."

The ACCC considered that AGL had as much incentive to increase the retail cap prices as much as TRUenergy. This is inadequate reasoning. Firstly, TRUenergy has only some 20%[9] of the total market in SA, compared to AGL's 70%. Secondly, the bulk of the TRUenergy market share is in the contestable market rather than the "protected" small user market. AGL has the bulk of its market share in the "protected" small user market (with Origin Energy using its position as dominant gas retailer to access the balance of the "protected" small user market) giving it a much greater incentive to influence any retail price cap assessment by ESCoSA.

For the ACCC to assume that TRUenergy had as much at stake in influencing the ESCoSA assessment shows that the ACCC investigation into this aspect was inadequate.

AGL has a strong incentive to use its position as operator of the largest power station in SA to increase the spot price as ESCoSA will use actual market data on which to base its assessment of the retail price cap in SA. In this regard, it is poignant to note the large numbers of references to AGL's needs in the last ESCoSA retail price cap assessment.,.

In its report to ESCoSA on the 2007 price cap review[10], ACG noted that AGL had secured ownership of TIPS and noted on page 10 that:

> "This change could have two impacts on AGL's wholesale electricity cost, as follows:

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[9] The Effect of Industry Structure on Generation Competition and End-User Prices in the National Electricity Market, by Bardak Ventures Pty Ltd, May 2nd 2005, page 26

[10] Wholesale Electricity Costs for Standing Contract Customers in South Australia, Report for Publication, August 2007, Report to Essential Services Commission of South Australia

> Firstly, the actual cost of hedging AGL's customer load could change, depending on the cost claimed by AGL's retail business for hedging provided by AGL's generation business. According to AGL "*the purchase of TIPS* [Torrens Island Power Station] *adds 80% energy increase and 63% capacity increase to* [their] *portfolio. It reduces exposure to extreme price events and reduces need to purchase expensive derivative products*"[11]
> Secondly, the dynamics of the electricity market in South Australia could change, depending on how AGL bids and operates Torrens Island Power Station after it takes control from 1 July 2007. Torrens Island comprises a significant proportion of the peak generation capacity in South Australia, so strategic bidding of Torrens Island could affect the average pool price in South Australia. AGL's strategy for bidding Torrens Island into the NEM will depend on whether its generation capacity exceeds its customer load. Specifically:
>
> - if generation is greater than load, then AGL would appear to have an incentive to increase the spot price; but
> - if generation is less than load, then AGL would appear to have an incentive to decrease the spot price.
>
> These incentives could change over time — possibly even during one day. They may also change depending on AGL's over-arching corporate objectives."

It appears that the ACCC has underestimated this possible impact of the AGL acquisition

5.1.2 (b) Increase revenues for AGL's wholesale business.

The ACCC notes that AGL incentive to increase prices was no different to that of TRUenergy:

> "Finally, the ACCC noted that, given the capacity of TIPS relative to the size of TRUenergy's South Australian retail load, TRUenergy already had the incentive to raise pool prices to increase its wholesale revenues. On this basis TRUenergy would also not have faced a corresponding increase in its retail costs.
> Therefore, the ACCC considered that AGL may actually have less incentive than TRUenergy in this regard."

This seems contrary to the views of ACG and others. Certainly the actions of AGL on 4 and 10 January 2008 seem to run counter to the views of the ACCC when the historic performance of TIPS under TRUenergy show that TIPS was not used to set prices

[11] Presentation by Paul Anthony, Managing Director and CEO of AGL Energy, to UBS energy and utilities conference July 2007.

5.1.3 (c) Increase the costs of AGL's retail competitors

The ACCC was of the view that the use of TIPS under AGL was likely to be no different than that under TRUenergy, as it observed in paragraph 60:

> Therefore, while the ACCC accepted that AGL may have an incentive to raise prices in the wholesale market post-transaction, it was not clear that these were substantially greater than TRUenergy's existing incentives, and AGL's ability to do so was not enhanced by the proposed transaction."

The performance of TIPS under AGL highlights that the ACCC was wrong. In fact the impact of AGL to increase the annual average price in SA by some 18% as a result of its actions on 4 and 10 January 2008, shows that AGL must have had its retail custom well hedged for itself.

What has not been highlighted is that a number of large (contestable) consumers have not been able to secure contracts, even when AGL was their previous retailer. The members of MEU[12] operating in SA have observed that they are having increasing difficulty In securing retail contracts at prices which reflect the LRMC of supplying electricity. Some customers have not been able to obtain retailer responses to calls for tenders during the 6 months ended December 2007..Some customer operations have been driven into the spot market, and therefore were directly exposed to the spot prices on 4 and 10 January, thereby incurring substantial monetary losses.,

It is important to note that the prices on 4 and 10 January will have a double impact on consumers. Firstly, there will be the direct increase in average spot prices which will result in higher contract prices. Secondly, the impact of the price spikes will increase the price volatility in the market as well as the severity of the volatility. This double impact of more spikes and more severity will increase the risk margin that retailers will have to add to their contract prices. In fact, it can be observed that SA wholesale contract prices have been rising since October 2007, from about $67/MWh (flat CAL08) to about $83/MWh (flat CAL 08) toward end December 2007.

5.2 The likelihood the proposed transaction would raise barriers to entry into the retail market

The ACCC was of the view that overall the acquisition by AGL was unlikely to provide a barrier to entry, as in paragraph 64 it notes:-

> "The ACCC also accepted that, in the short term, there was a possibility that the liquidity of hedge products referenced against the SA node may decrease as a

[12] All large electricity users ranging in demand up to ~100 MW

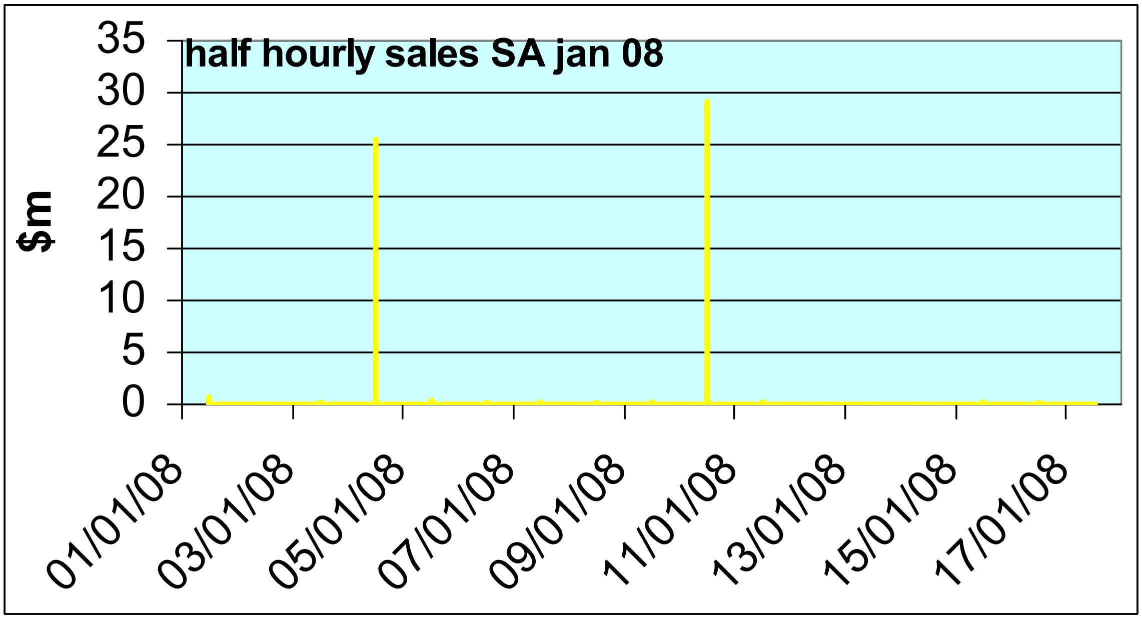
> result of this transaction. However, market inquiries, including confidential information provided to the ACCC by a number of relevant market participants, indicated that it was unlikely that this transaction would lead to a material long term decrease in the availability of hedge products in South Australia.
> Therefore it did not appear that this transaction significantly raised barriers to entry for retailing in South Australia when compared to the likely scenario were the transaction not to proceed, and it appeared unlikely there would be a substantial lessening of existing competition in the South Australian retail market."

The MEU cannot comment on the "confidential information" made available to the ACCC on this issue. It is also noted that the ACCC referred to "confidentiality of certain information" provided to it to allow it to ignore market participants' "concerns that AGL would have a greater incentive to raise SA pool prices than TRUenergy possessed".[13] Despite this the MEU can point out that price spikes such as seen on 4 and 10 January, will result in an increase in the financial requirements for new entrants to gain access to the NEM. It is not transparent to the MEU what "confidential" material or undertaking was provided to the ACCC. But in examining the 4 and 10 January 2008 price events, the AER must seek to revisit this "confidential" material to test the veracity of any "commitments" or "undertakings" provided by AGL or any other participants. This is important as the ACCC[14] had stated when it issued its April 2007 assessment on the AGL-TIPS swap that:-

> *"By issuing Public Competition Assessments, the ACCC aims to provide the market with a better understanding of the ACCC's analysis of various markets and the associated merger and competition issues.* ***It also alerts the market to the circumstances where the ACCC's assessment of the competition conditions in particular markets is changing, or likely to change, because of developments."*** (emphasis added)

It is important to see the risks stemming from the actions of a single party which can lead to such financial exposure as resulted on these two days. The following graph shows the impact of these 16 half hour price excursions

[13] Ibid, para 47
[14] Ibid, para 4



Source: Calculated by MEU

The average half hour price for all of January was ~$300k. Compared to this, the half hour prices at the peak times was $25-30m per half hour. The severity of a risk of this magnitude must have an impact on new entrant retailers, especially when it is considered that such new entrant retailers would have to seek hedges from TIPS, as there is insufficient capacity in all the other base load stations (Pelican Point, Northern, Playford and Osborne to cover the demand likely to occur in SA.

As discussed in sections above, almost all retailers seeking a hedge in the market must go to TIPS for a hedge, especially as hedges from base load stations are insufficient for the market.

Thus almost all retailers would have to seek a hedge from their competitor to operate in the SA market. This is clearly an example of a barrier to entry.

5.3 Conclusion

The ACCC sums up its decision not to oppose the acquisition in paragraphs 65 and 66.

> "The proposed transaction is unlikely to give AGL any increased incentive or ability to increase prices in the wholesale market, over and above those held by the current owner of TIPS, TRUenergy. As such, the proposed acquisition was considered unlikely to result in a substantial lessening of competition in the wholesale market.
>
> Similarly, while noting concerns about the current liquidity of financial markets in South Australia, the ACCC concluded that the present transaction was unlikely to

> materially decrease the availability of hedge products, particularly in the long term. Therefore, the ACCC concluded that the transaction was unlikely to significantly raise barriers to entry into the retail market and unlikely to result in a substantial lessening of competition."

The ACCC decision is clearly wrong as events have demonstrated. A retailer must seek a hedge from AGL as TIPS controls such a large element of the supply of power in SA. When TIPS was owned by TRUenergy, TRUenergy's retail market was at most 20% of the SA market or about an average of 300 MW (20% of the average SA demand of 1500 MW). Even allowing for some short term higher demand, TRUenergy would not be supplying more than ~600 MW. This is well less than the output of TIPS and so there was an incentive on TIPS to offer its surplus capacity to the market.

AGL has a higher small user retail demand and control of the largest power station in SA. It can provide its own hedge against TIPS generated price spikes, but there is no incentive for it to provide hedges to others. (c-in-c)

Overall the ACCC decision to allow the acquisition to proceed was made based on assessments which were either based on incorrect data or inadequate analysis.

Events have shown that SA contract prices have been rising in the 3 months to end 2007; retail competitors to AGL have not been responding to large users' tenders; any contract prices quoted have been at unreasonable price levels; and some large customer operations have had to take pool exposure.

6. Conclusions

A number of observations can be made from the foregoing:-

- TIPS is in reality an intermediate ranked power station, and based on the assessment above, is the only intermediate load supplier in SA.
- TIPS is by far the largest power station in SA, nearly twice the capacity of the next largest (Northern + Playford).
- TIPS dispatch capacity output is more that 80% of the average demand in SA
- AGL owns TIPS and is also the largest retailer of electricity in SA
- Flows from Victoria to SA are being constrained by wind farm outputs at Snuggery, in the lower SE of SA, and this is going to get worse as Lake Bonney Stage 2 wind farm is complete, because this will effectively double the intermittent generation connected at Snuggery and constrain Heywood even more
- TIPS has set the spot price in SA, both by spiking the price and creating a floor price.

Effectively, TIPS used its undoubted position of market power in the supply arrangements and the Rules to their maximum benefit, in order to create an apparent shortage of supply. Whether this was done through strategic bidding, or even rebidding, the TIPS approach is unique to it, due to its dominance as the largest generator in the SA region.

This approach by TIPS is analogous to any supplier in the market attempting to drive up prices. If the supplier can effectively create an artificial shortage of a needed product with no scope for demand responses then by doing so, it can drive prices up.

The issue of TIPS being able to set the spot price revolves around a number of decisions made previously:-

- The NEM market design, being an energy only market, creates a need for a high level of VoLL, which in turn causes excessive volatility in prices.
- The bidding Rules allow generators to revise their prices and bidding patterns so that economic withdrawal of capacity (bidding and rebidding the same capacity into higher price bands) is permitted
- The SA government sold TIPS as an integrated power station, despite knowing that it has market power due to its size relative to the SA market
- The ACCC permitted the sale of TIPS to the retailer with the largest retail market share, thus combining the largest power station with the largest retail base in the region, creating a “gentailer” with market power at both ends of the industry in the region

- The advent of wind power and the increasingly likelihood of more constraints on the Heywood interconnector, makes the SA market even more susceptible to strategic market behaviour by dominant players.
- AGL has demonstrated that it can set the spot price and knowing this can adjust its retail activities to reflect this.
- Contract prices have been rising since October 2007. The January event would have certainly demonstrated the ease at which prices can be spiked. Even if AGL's hedge contracts expire over time and new contracts need to be arranged (at higher prices) strategic-behaviour due to profit maximization motives will push pool and retail contract prices to even higher levels.

From a consumer viewpoint these decisions have led to a number of unacceptable outcomes.

Floor price maintenance prevents the balancing of high prices at higher demands against lower prices at lower demands. As such, it prevents the market from sending signals to consumers to modify their needs to reflect prices. Floor price maintenance increases the average spot price and so ultimately this price pressure flows into contract prices.

Price spikes result in retailers and those consumers exposed to the market to incur significant costs, and as a result contract prices for consumers not exposed to the market suffer a consequential rise.

However, just as importantly, retailers can see that certain generators can set the spot price, creating a concern that greater volatility in prices will result. To manage the potential for increased volatility retailers must increase their risk margins either directly or by employing another party to take this risk (e.g. hedging the risk with a counterparty). Regardless of how the risk is managed, it becomes a cost for consumers to pay. It can also discourage retail competition if retailers cannot buy hedge contracts from generators, particularly when, in SA, TIPS and AGL Retail are the dominant players.

If a dominant generator has the power to set the spot price, whether it does so or not, this creates a risk for consumers, which is not a desirable outcome of a 'competitive' market.

In its decision to permit AGL to acquire Torrens Island Power Station from TRUenergy, the ACCC observes that AGL will be able to exercise market power in setting prices in the spot market. This is turn influences contract prices. The MEU demonstrates that AGL has exercised its market power as foreshadowed by the ACCC.

The NEM institutions and the Rules are in operation to ensure that the SA electricity market delivers competitive outcomes. However, it has been demonstrated that when demand is high and exceeds a certain level in SA, TIPS is able to spike the pool price, with many adverse implications for consumers. SA's market structure also provides AGL with an unfair advantage over competitors and consumers, given the absence of constraints on bidding behaviour.

The MEU considers that the AER/ACCC must now implement actions to prevent AGL/TIPS from repeating its use of this undoubted market power in the future.