Electricity spot prices above $5000/MWh

South Australia, 14 July 2016

11 October 2016

AUSTRALIAN ENERGY REGULATOR

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1 Introduction

The AER is required to publish a report whenever the wholesale price for electricity in the National Electricity Market exceeds $5000/MWh.[1] The wholesale (or spot) price is the price that generators receive and retailers pay for electricity in the wholesale market and is one component that makes up the price ultimately seen by consumers. The wholesale price for electricity can vary between -$1000/MWh and $14 000/MWh. The National Electricity Rules require the AER to report whenever the spot price for electricity exceeds the $5000/MWh threshold. The report must examine the conditions in the wholesale market and:

- describe the significant factors contributing to the spot price exceeding $5000/MWh, including withdrawal of generation capacity and network availability;
- assess whether rebidding contributed to the spot price exceeding $5000/MWh;
- identify the marginal scheduled generating units; and
- identify all units with offers for the trading interval equal to or greater than $5000/MWh and compares these dispatch offers to relevant dispatch offers in previous trading intervals.

On 14 July 2016 at 6.30 pm, the spot price for electricity reached $6918/MWh in South Australia. This report presents our analysis of the events in accordance with this obligation.

1 This requirement is set out in clause 3.13.7 (d) of the National Electricity Rules.

2 Summary

Forecasts for 14 July 2016 prepared by AEMO the day before, predicted the spot price would be above $5000/MWh most of the day. However, on the day the spot price in South Australia exceeded $5000/MWh only once, reaching $6918/MWh during the 6.30 pm trading interval. Prices exceeded $4500/MWh on two other occasions during the morning demand rise but did not exceed the reporting threshold. The factors contributing to these events were discussed in the 10-16 July weekly report.

Prices in the 6.30 pm trading interval would have been close to the $14 000/MWh forecast had it not been for generation at Port Stanvac being dispatched “out of merit order” due to operational parameters included in its offer, suppressing the price for the first three dispatch intervals. When Port Stanvac shut-down at 6.20 pm prices returned to the forecast above $13 000/MWh for the remainder of the trading interval.

The following factors contributed to the high price for the 6.30 pm trading interval:

- Planned network outages, at Tailem Bend to complete augmentation works on the Heywood Interconnector between Victoria and South Australia, materially reduced its capacity. While this major upgrade was flagged to the market in late 2015 its likely impact on Heywood’s operating capability was not always clear until the previous days forecast.
    - The change in the generation mix following the closure of Northern Power station (coal fuelled) in May 2016 means that South Australia electricity supply is dependent on two primary fuel sources: gas and wind.
        - While there is in the order of 1600 MW of wind capacity installed in South Australia, on the day it was generating around 240 MW, as forecast.
        - Two gas fired generators (Torrens Island B4, Dry Creek 3) were on planned outages and the return to service of Pelican Point power station was delayed by start-up issues which decreased the available capacity in South Australia.

Rebidding of capacity did not contribute to the price exceeding $5000/MWh. Demand was at similar levels to previous days and to average demand levels of last winter.

3 Analysis

Table 1 shows the actual and forecast spot price, demand and generator availability for the 6.30 pm and 7 pm trading intervals.

Table 1: Actual and forecast spot price, demand and availability

Trading interval	Price ($/MWh)			Demand (MW)			Availability (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6.30 pm	**6918**	**14 000**	**13 299**	**2061**	**2158**	**2094**	**2381**	**2529**	**2531**
7 pm	2463	434	350	2115	2206	2163	2410	2537	2536

Table 1 shows that the price for the 6.30 pm trading interval was forecast to be at the market price cap. The actual price for that trading interval was below the forecast but still greater than $5000/MWh. The high price for 7 pm was not forecast.

Demand was slightly lower than forecast and generator availability was around 148 MW lower than forecast mainly due to Engie reducing the availability of Pelican Point power station. Pelican point was on “48-hour recall” and had not operated since 28 April 2016 and experienced issues during its return to service.

3.1 Network Availability

This section examines the change in network capability approaching the event and its contribution to price outcomes.

Network constraints were invoked to manage a planned network outage on equipment at Tailem Bend in South Australia as part of the Heywood interconnector upgrade.[2] The outage reduced the network capability between the south east of South Australia and Adelaide. Consequently generation in the South East in excess of that network capability to Adelaide is exported to Victoria.[3] Appendix A provides a description of the constraint and network configuration. While this major upgrade was flagged to the market as early as November 2015, its likely impact on Heywood’s operating capability was not entirely clear, until it was included in forecasts prepared the day before.

Flows into South Australia on the Murraylink interconnector during the 6.30 pm trading interval were close to the 190 MW limit in the first three dispatch intervals and at that limit during the high price period. The MurrayLink interconnector was operating at its limit into South Australia around 190 MW (its nominal limit is 220 MW).[4]

2 At 7 am on 4 July, a planned network outage commenced on equipment at Tailem Bend in South Australia as part of the Heywood interconnector upgrade. This outage continued until the evening of 14 July.

3 In this instance, wind generation in the South East was significantly greater than the capacity of the remaining network to Adelaide and that excess generation could be either exported to Victoria or if the export limits had been reached, curtailed.

4 Limits were reduced by a constraint managing the outage of the New South Wales MurrayLink runback scheme.

Table 2 shows actual and forecast net import limit into South Australia (MurrayLink and Heywood) for the 6.30 pm and 7 pm trading intervals.

Table 2: Actual and forecast net network capability

Trading interval	Flows into South Australia (MW)			Net Import limit (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6.30 pm	**41**	**96**	**90**	**45**	**96**	**90**
7 pm	43	515	479	59	546	593

Table 2 shows that flows into South Australia for the 6.30 pm trading interval were 55 MW lower than forecast four hours ahead. This was due mainly to higher than forecast wind generation in the South East that could not be delivered to Adelaide (past the network outage) and was forced into Victoria via the Heywood Interconnector.

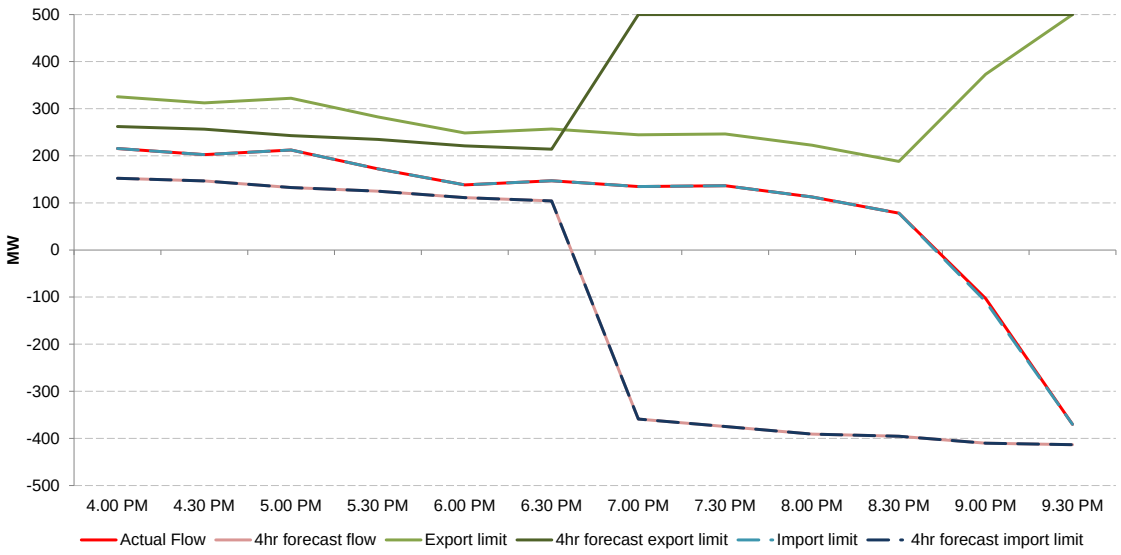
While, the outage of the network equipment at Tailem Bend was originally forecast to finish at the end of the 6.30 pm trading interval, at 5.41 pm AEMO issued a market notice announcing that the return to service of the equipment was delayed until 8.30 pm[5]. For the 7 pm trading interval, the extension of the outage meant that constraints on Heywood remained and imports into South Australia were significantly (around 470 MW) lower than forecast four hours ahead.

Figure 1 shows the actual and forecast import and export limit, and target flows across the Heywood interconnector. Despite the Victorian price being lower South Australia's counter-price flows occurred on Heywood into Victoria because there was more generation in the South East (conventional and wind) than could be delivered to Adelaide[6]. When the constraint managing the outage was revoked at around 8.30 pm, the transfer limit and flow returned to what was forecast four hours ahead.

5 See Appendix D, market notice 54506 for further information.

6 On this occasion the import limit was in the same direction as what would normally be considered as export.

Figure 1: Heywood export and import limits and target flows



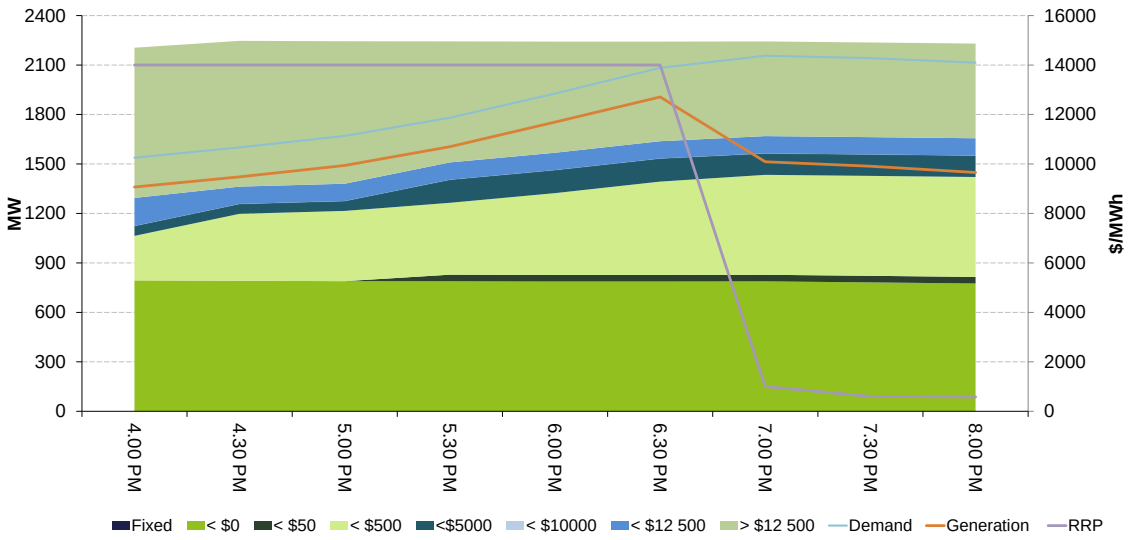
3.2 Supply and Demand

This section discusses changes to the price and capacity offered by generators, and demand conditions relevant to the pricing event.

3.2.1 Offers and rebidding

Figure 2 shows the initial price and volume offers of generators in South Australia as well as initial forecast demand (light blue), forecast dispatched generation (orange) and forecast spot price (grey). Initial offers for 14 July 2016 created a situation where there was no capacity priced between $1000/MWh and $10 000/MWh. The forecast price was expected to be around $14 000/MWh until work on the Heywood interconnector was complete. For the 6.30 pm trading interval, there was around 1400 MW of capacity priced below $500/MWh.

Figure 2: Initial bids of South Australia generators and forecast price

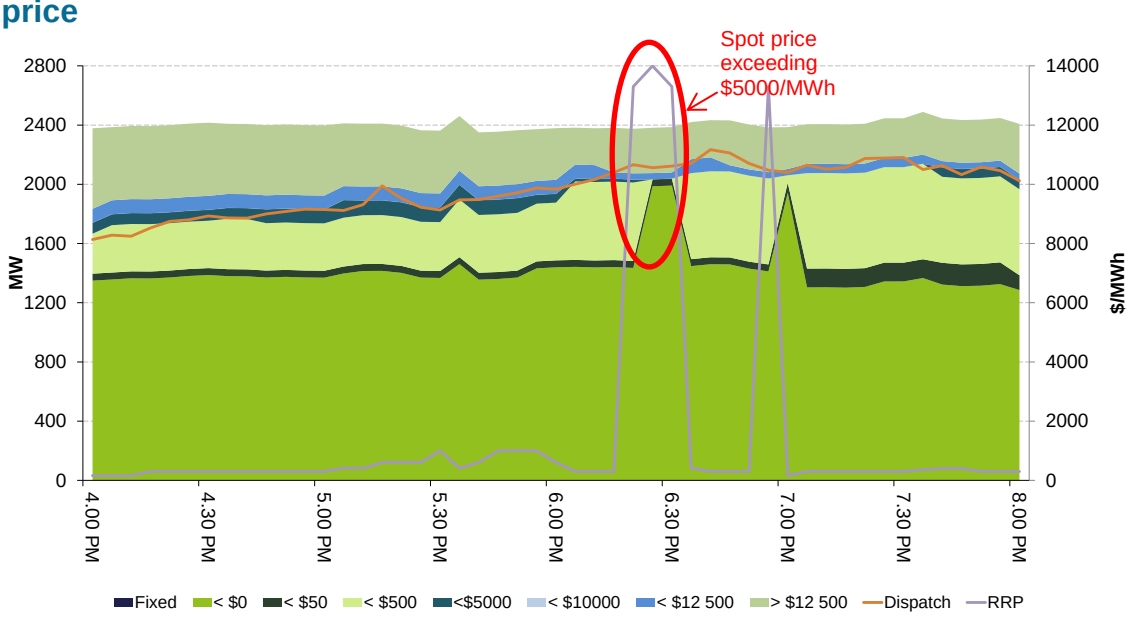


Forecasts produced at around 7.30 pm on 13 July indicated that Engie would be restarting its Pelican Point power station from around 3 pm the following day. This was the first time the station had run since the end of April. Engie expected Pelican Point to be available for at least 240 MW by 6.30 pm. However, due to delays in the return to service, a series of rebids between 4.49 pm and 5.56 pm withdrew 180 MW of capacity, leaving 60 MW available at the price floor. Engie offset most of this reduction by rebidding its peaking plant to the price floor. These rebids can be seen in Appendix E.

There was no significant rebidding of capacity from low to high prices that contributed to the 6.30 pm spot price.

Figure 3 shows closing bids for participants in South Australia, total regional generation dispatched (orange) and the 5 minute dispatch price (grey). After high dispatch prices occurred at the end of the 6.30 pm trading interval, participants in South Australia rebid capacity from high to low prices.

Figure 3: Closing bids of South Australia generators, output and dispatch price



The increase in capacity priced below $0 MWh around the time of the high price was a result of Torrens Island rebidding 530 MW priced between $0/MWh and $500/MWh (light green band) to the price floor (dark green band). This had no impact on price as the original offer was below the forecast and eventual dispatch price.

Rebidding had no effect on the high price for the 7 pm trading interval.

Appendix B details the generators involved in setting the price during the high-price periods, and how that price was determined.

The closing bids for all participants in South Australia with capacity priced at or above $5000/MWh for the high-price periods are set out in Appendix C.

A summary of significant rebids can be found in Appendix E.

3.2.2 Port Stanvac FSIP

Prices in the 6.30 pm trading interval would have been close to forecast had it not been for the offer parameters of Snowy Hydro's generator at Port Stanvac.

Port Stanvac, located just south of Adelaide, is a 60 MW fast start diesel generator, comprising 36 units. Fast start generators offers comprise certain technical dispatch parameters that define their start performance. These technical parameters are classified as a generators fast start inflexibility profile (FSIP). Port Stanvac's FSIP is detailed in Appendix F.

Port Stanvac's FSIP specifies that they can start-up and reach their minimum load within five minutes, then once they have reached their minimum load, they must remain at that level for 15 minutes before being able to be targeted down.

From 6 pm:

- The dispatch engine (NEMDE) determined that 28 MW of capacity from Port Stanvac was needed to meet demand. Port Stanvac's FSIP dictated that it had to be dispatched to its minimum load of 52 MW and remain there for 15 minutes.
- Since Port Stanvac had to produce more than was required to meet demand, dispatch targets for other cheaper priced generators were reduced. Consequently Port Stanvac was dispatched "out of merit order" and could not set price.
- The dispatch price was set by capacity priced at around $300/MWh for the first three dispatch intervals, while Port Stanvac was at minimum load.
- After 15 minutes the minimum run time specified in Port Stanvac's FSIP had been satisfied. Its capacity, priced around $14 000/MWh, was not needed to meet demand and NEMDE targeted them off.
- The 52 MW of generation at Port Stanvac was replaced by capacity, which was only slightly lower in price than Port Stanvac's bid, at around $13 000/MWh.
- The dispatch price remained high for the remainder of the trading interval.

3.2.3 Generator Availability

Generator availability and low wind generation affected outcomes on the day.

At 11 am AEMO published a forecast Lack of Reserve 1 (LOR1) condition for the 6.30 pm trading interval. The Lack of Reserve flag is the first in a series of escalating notices and indicates that AEMO considers that there is insufficient short term capacity available to maintain the necessary reserves in an operational timeframe in the event of a credible contingency occurring. The LOR is a trigger for the market to respond. There was very limited response and an actual LOR1 was declared at 5.45 pm until 8.30 pm.

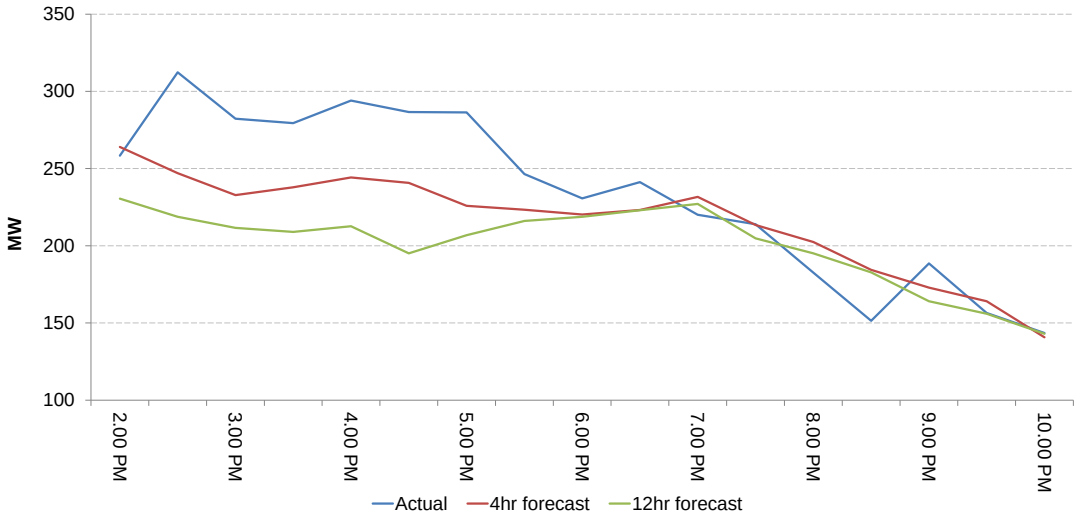
Unit 4 at Torrens Island B Station (200 MW) was on a planned outage while Dry Creek 3 (46 MW) did not offer any capacity into the market for the 6.30 pm trading

interval. The return to service of 240 MW at Pelican Point, which has commenced at around 3 pm, was delayed and only 60 MW was available.

Out of approximately 1600 MW of wind capacity installed in South Australia there was only around 240 MW of generation, which was slightly above forecast. The majority of this generation (around 210 MW) was coming from wind farms located in South East, which, because of the Tailem Bend constraint, could not be delivered to the main load centre around Adelaide (see Appendix A for more detail).

Figure 4 shows the actual and forecast wind generation, four and 12 hours ahead, for the afternoon of 14 July.

Figure 4: Actual and forecast wind generation



Australian Energy Regulator

October 2016

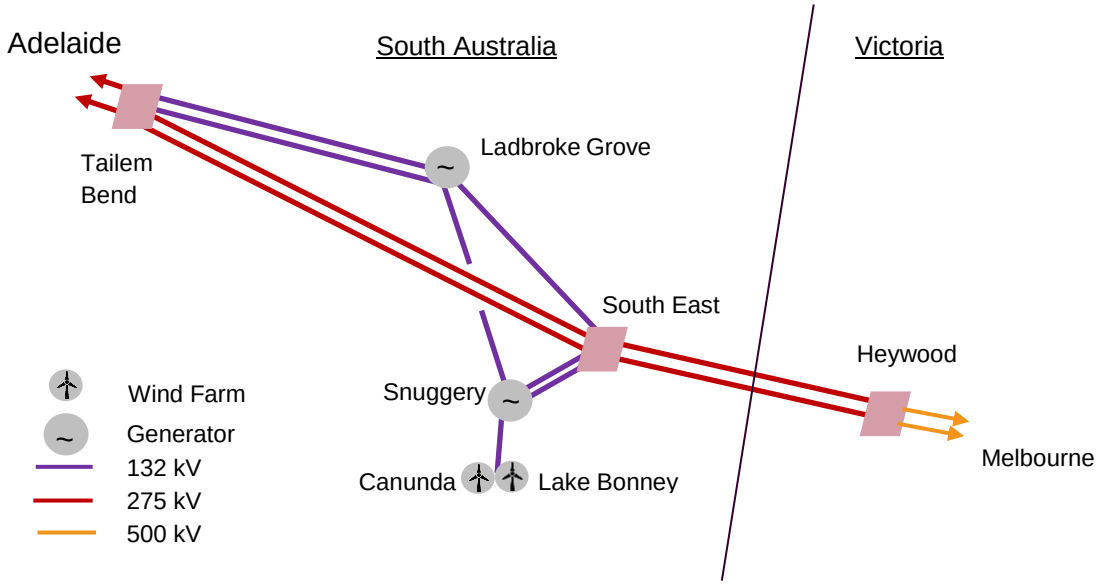
Appendix A: Network Diagram

In March 2014 the Heywood augmentation project to increase the capacity of the transmission system between South Australia and Victoria to 650 MW satisfied the Regulatory Investment Test (transmission). Until the completion of the augmentation, Heywood has a nominal capacity of 460 MW. While the Heywood interconnector is notionally only the lines between South East Substation and the Heywood Terminal Station it effectively comprised:

- four parallel circuits (two circuits operating at 275 kV and two circuits operating at 132 kV) between Tailem Bend (near Adelaide) and South East Substation (close to the border). These lines also deliver power to the load centres at Keith, Kincraig; Penola, Blanche and Mount Gambier; and
- two parallel 275 kV circuits between South East Substation to Heywood Terminal Station in south-west Victoria and two parallel 500 kV circuits from the Heywood Terminal Station to Moorabool Terminal Stations and on to the Sydenham Terminal Station in the 29 kms north west of Melbourne.

The upgrade works:

- reduce the number of parallel circuits in South Australia between Tailem Bend and South East Substation to three; and
- installs an additional transformer and associated switchgear at Heywood terminal station and compensation equipment along the transmission path.



The V::S_TB_275kV_W_B1 constraint was invoked to manage the outage of the Tailem Bend West bus. The constraint contains six variables, all of which have a factor of one:

- Ladbroke units 1 and 2
- Lake Bonney units 2 and 3
- Snuggery unit 1 and
- the Heywood interconnector.

This means that an increase in generation from these units or an increase in flow into South Australia across Heywood will reduce the headroom of the constraint, until it binds. Conversely reduced generation from the units or flows into Victoria increases the headroom. If the constraint is binding, flows on Heywood are optimised with local generation in the South East. For example a MW increase in generation in the South East must be balanced against either a MW reduction in flow into South Australia or a MW increase in flow into Victoria across Heywood.

Appendix B: Price setter

The following table identifies for the trading interval in which the spot price exceeded $5000/MWh, each five minute dispatch interval price and the generating units involved in setting the energy price. This information is published by AEMO.[7] The 30-minute spot price is the average of the six dispatch interval prices.

Table 3: price setter for the 6.30 pm trading interval

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
18:05	$300.99	AGL (SA)	TORRB1	Energy	$300.99	0.50	$150.50
		AGL (SA)	TORRB2	Energy	$300.99	0.50	$150.50
18:10	$300.99	AGL (SA)	TORRA1	Energy	$300.99	0.25	$75.25
		AGL (SA)	TORRA2	Energy	$300.99	0.25	$75.25
		AGL (SA)	TORRA3	Energy	$300.99	0.25	$75.25
		AGL (SA)	TORRA4	Energy	$300.99	0.25	$75.25
		AGL (SA)	TORRB1	Raise 6 sec	$2.60	0.33	$0.86
		AGL (SA)	TORRA1	Raise 6 sec	$0.50	-0.08	-$0.04
		AGL (SA)	TORRA2	Raise 6 sec	$0.50	-0.08	-$0.04
		AGL (SA)	TORRA3	Raise 6 sec	$0.50	-0.08	-$0.04
		AGL (SA)	TORRA4	Raise 6 sec	$0.50	-0.08	-$0.04
18:15	$303.22	AGL (SA)	TORRA1	Energy	$300.99	0.33	$99.33
		AGL (SA)	TORRA2	Energy	$300.99	0.33	$99.33
		AGL (SA)	TORRA3	Energy	$300.99	0.33	$99.33
		Hydro Tasmania	TRIBUTE	Raise 60 sec	$1.80	0.83	$1.49
		AGL (SA)	TORRA1	Raise 60 sec	$0.04	-0.28	-$0.01
		AGL (SA)	TORRA2	Raise 60 sec	$0.04	-0.28	-$0.01
		AGL (SA)	TORRA3	Raise 60 sec	$0.04	-0.28	-$0.01
		AGL Energy	BW03	Raise 6 sec	$2.80	0.33	$0.92
		AGL (SA)	TORRA1	Raise 6 sec	$0.50	-0.11	-$0.06
		AGL (SA)	TORRA2	Raise 6 sec	$0.50	-0.11	-$0.06
		AGL (SA)	TORRA3	Raise 6 sec	$0.50	-0.11	-$0.06
18:20	$13 300.20	Engie	DRYCGT2	Energy	$13 300.20	1.00	$13 300.20
18:25	$13 998.99	Energy Australia	AGLHAL	Energy	$13 998.99	1.00	$13 998.99
18:30	$13 300.20	Engie	DRYCGT2	Energy	$13 300.20	1.00	$13 300.20
Spot Price		**$6918/MWh**					

[7] Details on how the price is determined can be found at www.aemo.com.au

Appendix C: Closing bids

Figures C1 to C4 highlight the half hour closing bids for participants in South Australia with significant capacity priced at or above $5000/MWh during the periods in which the spot price exceeded $5000/MWh. They also show generation output and the spot price.

Figure C1 - AGL (Torrens Island, The Bluff, Hallett Wind Farm, North Brown Hill) closing bid prices, dispatch and spot price

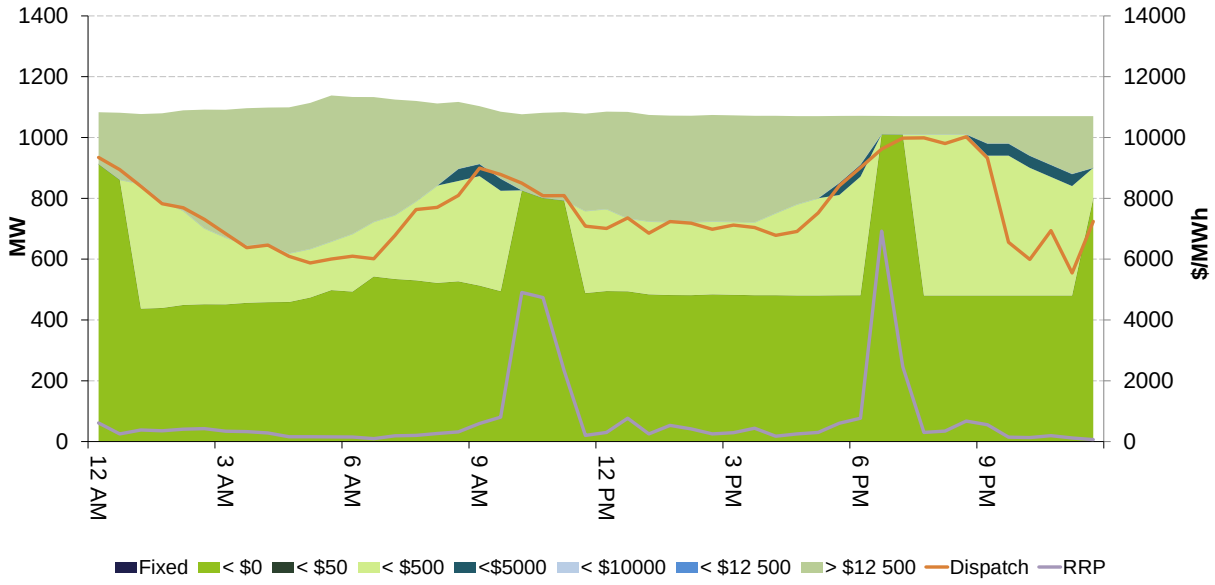


Figure C2 - EnergyAustralia (Hallett, Waterloo) closing bid prices, dispatch and spot price

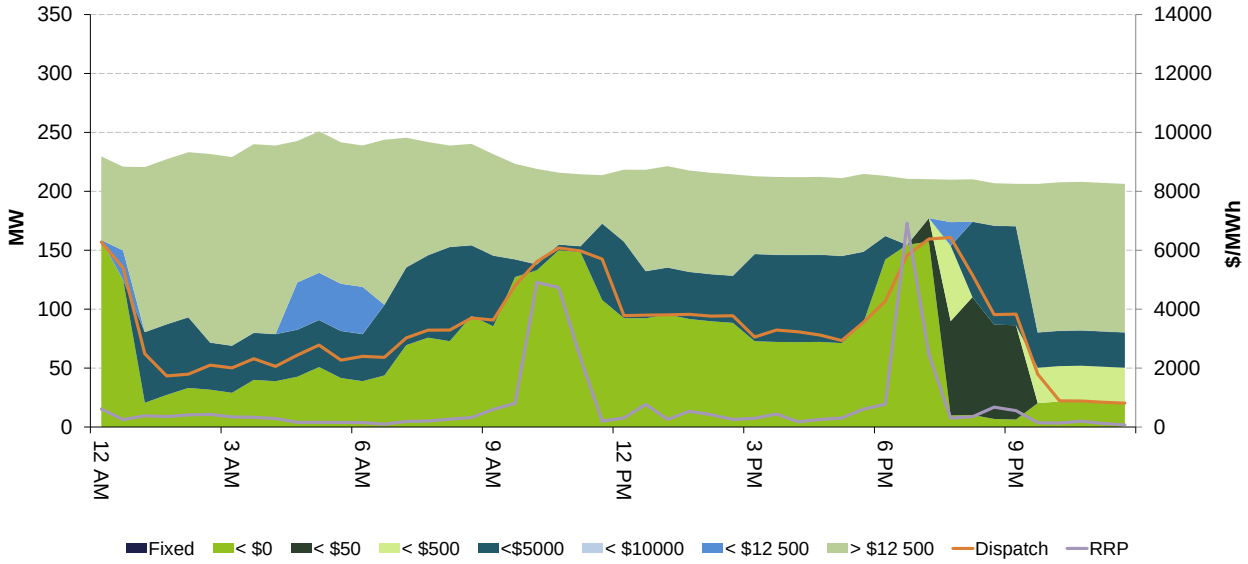


Figure C3 - Engie (Dry Creek, Mintaro, Port Lincoln, Snuggery) closing bid prices, dispatch and spot price

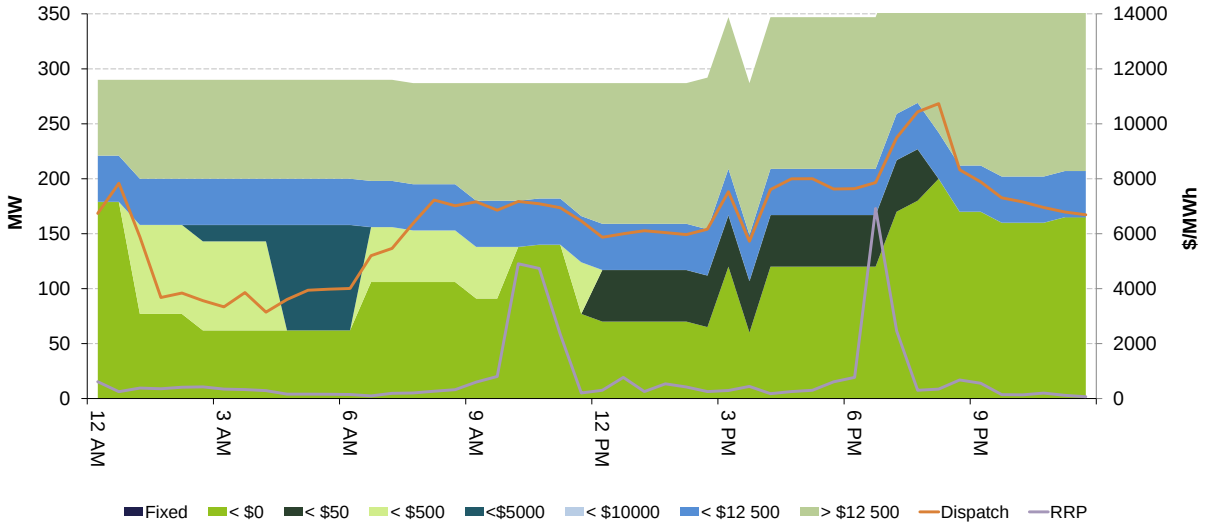
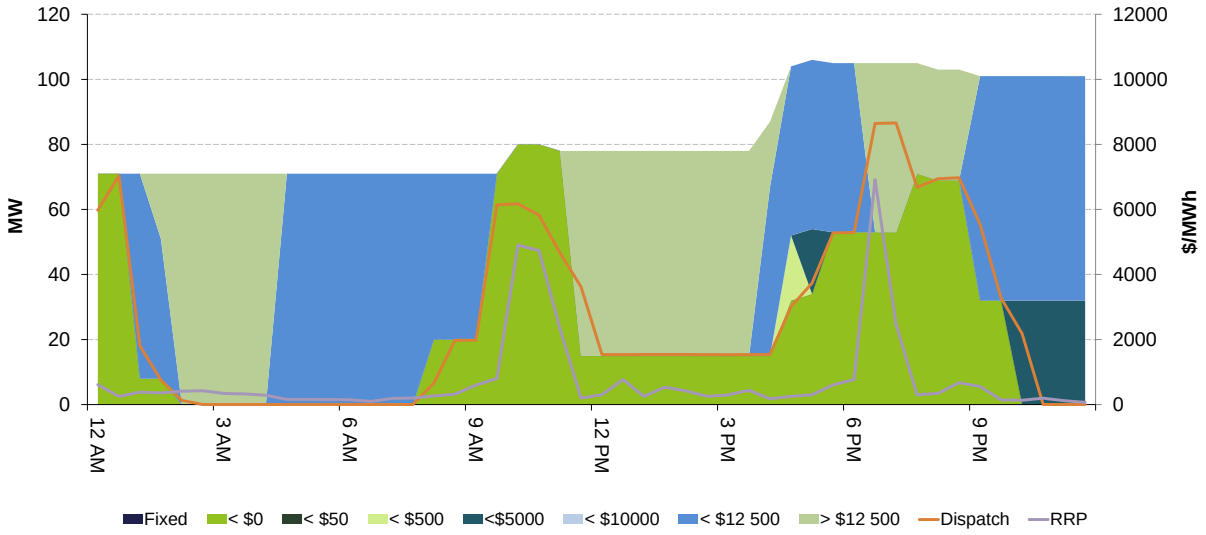


Figure C4 – Snowy Hydro (Lonsdale, Pt Stanvac and Angaston) closing bid prices, dispatch and spot price



Appendix D: Relevant Market Notices

The following market notices either were notifying the market of the network issues in South Australia.

Market Notice	Type	Date of issue	Last Changed
54504	RESERVE NOTICE	14/07/2016 11:11:31 AM	14/07/2016 11:11:31 AM

External Reference

Forecast Lack Of Reserve Level 1 (LOR1) in the SA Region - PDPASA - 14/07/16

Reason

AEMO ELECTRICITY MARKET NOTICE

Forecast Lack Of Reserve Level 1 (LOR1) in the SA Region - PDPASA - 14/07/16

AEMO declares a Forecast LOR1 condition for the SA Region.

From 1800 hrs to 1830 hrs 14/07/16

The contingency capacity reserve required is 440 MW

The minimum reserve available is 390 MW

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
54506	INTER-REGIONAL TRANSFER	14/07/2016 5:41:28 PM	14/07/2016 5:41:28 PM

External Reference

Inter-regional transfer limit variation SA region - 14 July 2016

Reason

AEMO ELECTRICITY MARKET NOTICE

Inter-regional transfer limit variation SA region - 14/07/16

The return to service of the Tailem Bend 275 kV West Bus and the Tailem Bend - South East No. 1 275 kV Line has been delayed to 2030 hrs.

The following constraint set is invoked for these outages

S-TB_275KV_W_BUS

The constraint set contains equations the following interconnectors on the LHS

NSW1-QLD1

V-S-MNSP1

V-SA

Refer to AEMO Network Outage Scheduler (NOS) for further details.

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
54507	Reserve Notice	14/07/2016 5:46:03 PM	14/07/2016 5:46:03 PM

External Reference

Actual Lack Of Reserve Level 1 (LOR1) in the South Australia Region. 14/07/16

Reason

AEMO ELECTRICITY MARKET NOTICE

Actual Lack Of Reserve Level 1 (LOR1) in the South Australia Region. 14/07/16.

An Actual LOR1 condition has been declared for the SA Region from 1745 hrs.

The Actual LOR1 condition is forecast to exist until 2030 hrs

The contingency capacity reserve required is 440 MW

The minimum reserve available is 342 MW

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
54508	Reserve Notice	14/07/2016 8:33:32 PM	14/07/2016 8:33:32 PM

External Reference

Cancellation of Actual (LOR1) condition in the South Australia region - 14/07/16

Reason

AEMO ELECTRICITY MARKET NOTICE

Cancellation of Actual (LOR1) condition in the South Australia region - 14/07/16

The Actual LOR1 Condition in the South Australia Region advised in AEMO Electricity Market Notice 54507 is cancelled at 2030 hrs 14/07/16

Manager NEM Real Time Operations

Appendix E: Rebid summary

Table 4 below shows significant rebids by South Australian participants for the 6.30 pm trading interval. A negative number refers to the MW capacity being withdrawn and a positive means additional capacity.

Table 4: rebids for South Australia 6.30 pm

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.49 pm		GDF Suez	Pelican Point	-40	13 999	N/A	1649P UPDATE PPCCGT RTS PROFILE - STEAM TURBINE DELAYS SL
5.29 pm		GDF Suez	Pelican Point	-35	13 999	N/A	1729P UPDATE PPCCGT RTS PROFILE - STEAM TURNINE SYNCH DELAY
5.29 pm		GDF Suez	Dry Creek	20	13 990	-999	1729P UPDATE PPCCGT RTS PROFILE - STEAM TURNINE SYNCH DELAY
5.29 pm		GDF Suez	Mintaro	87	14 220	<0	1729P UPDATE PPCCGT RTS PROFILE - STEAM TURNINE SYNCH DELAY
5.40 pm		GDF Suez	Pelican Point	-40	-1000	N/A	1739P UPDATE RTS PROFILE - SLOWER RAMP AFTER ST SYNC SL
5.40 pm		GDF Suez	Pelican Point	-5	13 999	N/A	1739P UPDATE RTS PROFILE - SLOWER RAMP AFTER ST SYNC SL
5.56 pm	6.05 pm	GDF Suez	Pelican Point	-60	-1000	N/A	1756P PPCCGT UPDATE RTS PROFILE - TURBINE TEMP
6.07 pm	6.15 pm	Snowy Hydro	Port Stanvac	52	10 687	14 000	18:05 A SA: ACT PRICE $10,368.30 LWR THN 30MPD 18:10@18:02

Appendix F Fast start inflexibility profile (FSIP)

Fast Start units are units that can synchronise and reach minimum loading within 30 minutes. A Fast Start unit's inflexibility profile defines its start-up and shut-down performance. These values are used by the NEM Dispatch Engine (NEMDE) to determine whether the unit should be dispatched.

Rule 3.8.19 (e) states the inflexibility profile for a generating unit must contain the following parameters:

1. The time, T1, in minutes, following the issue of a dispatch instruction by AEMO to increase its loading from 0 MW, which is required for the plant to begin to vary its dispatch level from 0 MW in accordance with the instruction;
2. The time, T2, in minutes, that the plant requires after T1 to reach a specified minimum MW loading level;
3. The time, T3, in minutes, that the plant requires to be operated at or above its minimum loading level before it can be reduced below that level;
4. The time, T4, in minutes, following the issue of a dispatch instruction by AEMO to reduce loading from the minimum loading level to zero, that the plant requires to completely comply with that instruction;

Table 5 shows Port Stanvac's FSIP at 6.30 pm on 14 July 2016.

Table 5 – Port Stanvac's FSIP

T1 (Min)	T2 (Min)	T3 (Min)	T4 (Min)	Minimum load (MW)
1	4	15	0	52