Electricity spot prices above $5000/MWh

19 December 2013

South Australia

AUSTRALIAN ENERGY REGULATOR

Introduction

The AER is required to publish a report whenever the electricity spot price exceeds $5000/MWh.[1] The report:

- describes the significant factors contributing to the spot price exceeding $5000/MWh, including withdrawal of generation capacity and network availability;
- assesses whether rebidding contributed to the spot price exceeding $5000/MWh;
- identifies the marginal scheduled generating units; and
- identifies 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.

Summary

On Thursday 19 December 2013 the spot price in South Australia reached $10 627/MWh at 4 pm and $5640/MWh at 4.30 pm. These prices were not forecast. These were the highest spot prices in the high-price period from 2.30 pm to 6 pm inclusive, during which time the (five-minute) dispatch price exceeded $10 000/MWh on 17 occasions.

One of the main contributors to the high prices was high demand due to extreme heat. The maximum temperature was 43.4C in the city at 2.48 pm, making it the hottest December day since the temperature reached 43.9C on 29 December 1931, and the third hottest December day on record. Maximum demand for the day reached 2728 MW at 7 pm[2]. At 4 pm demand was 2621 MW. A plant outage at Northern Power Station, lower than forecast contribution from wind and interconnector import flows also contributed to tight supply conditions.

Rebidding by participants was also an important factor. Rebidding during the afternoon, particularly by AGL and GDF Suez, shifted significant capacity that was priced under $300/MWh to prices at or near the price cap.

The analysis also highlights how critical accurate demand forecasting is to an efficiently functioning market. Demand forecasting is arguably more challenging in recent years given: the growth in embedded generation (particularly solar photovoltaic systems); reductions in demand from customers pursuing energy efficiency initiatives; and customers electing to reduce their output in response to price (i.e. demand side response). However, the impacts of these factors, although uncertain, are arguably largely predictable. The AER considers that the transparency and dependability of forecasts of demand/supply and market outcomes during peak periods would be enhanced by AEMO developing and publishing more data on these sources.

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

2 Record demand for South Australia is 3381 MW and occurred on 31 January 2011.

Analysis

Demand

Temperatures in Adelaide reached 43 degrees relatively uniformly across the suburbs. This was the second day in a row where the temperature reached the low 40s, constituting the first spell of very hot weather for the 2013-14 summer. Total Demand[3] was generally above 2500 MW for the majority of the afternoon, with the maximum for the day of 2728 MW occurring at 7 pm. With the Christmas break still several days away, most industrial loads were still on-line.

Impact of non-centrally controlled energy sources

The Australian Energy Market Operator (AEMO) forecasts demand across a range of time frames, from 5-minute pre-dispatch and dispatch, to long term planning time frames spanning over many years. More non-centrally controlled energy sources are available now than at market start, which has increased the difficulties associated with producing accurate short-term demand forecasts. Examples of non-centrally controlled energy sources include embedded generation such as rooftop solar photovoltaic (PV) systems, demand curtailment through embedded generation and energy efficiency or significant non-scheduled generation installations in the network.

For example: South Australia has 468 MW of solar photovoltaic (PV) generation, approximately 9 per cent of installed capacity in the region[4]. The prevalence of solar PV in the region has grown significantly in recent years, up by 250 MW from December 2011. There is also significant other non-centrally controlled energy sources.

Extreme demand events only occur infrequently as they depend on the alignment of a number of environmental and customer behaviours, so there is only limited historical demand data available for these events. It has been difficult to accurately benchmark the performance of the forecasting models to account for the increase in these non-centrally controlled energy sources during high temperature events.

Figure 1 shows total demand and sources of supply in linear form. Figure 2 shows the contribution of various sources of supply on the day (including estimates of PV and demand side response) in a stacked chart.

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[3] All calculations and discussions in this document refer to Total Demand which is the underlying forecast demand at the Regional Reference Node (RRN) that is met by local scheduled and semi-scheduled generation and interconnector imports after excluding the demand of local scheduled loads and that allocated to interconnector losses.

[4] Solar PV is in addition to installed capacity.

Figure 1: Demand and sources of supply for 19 December 2013

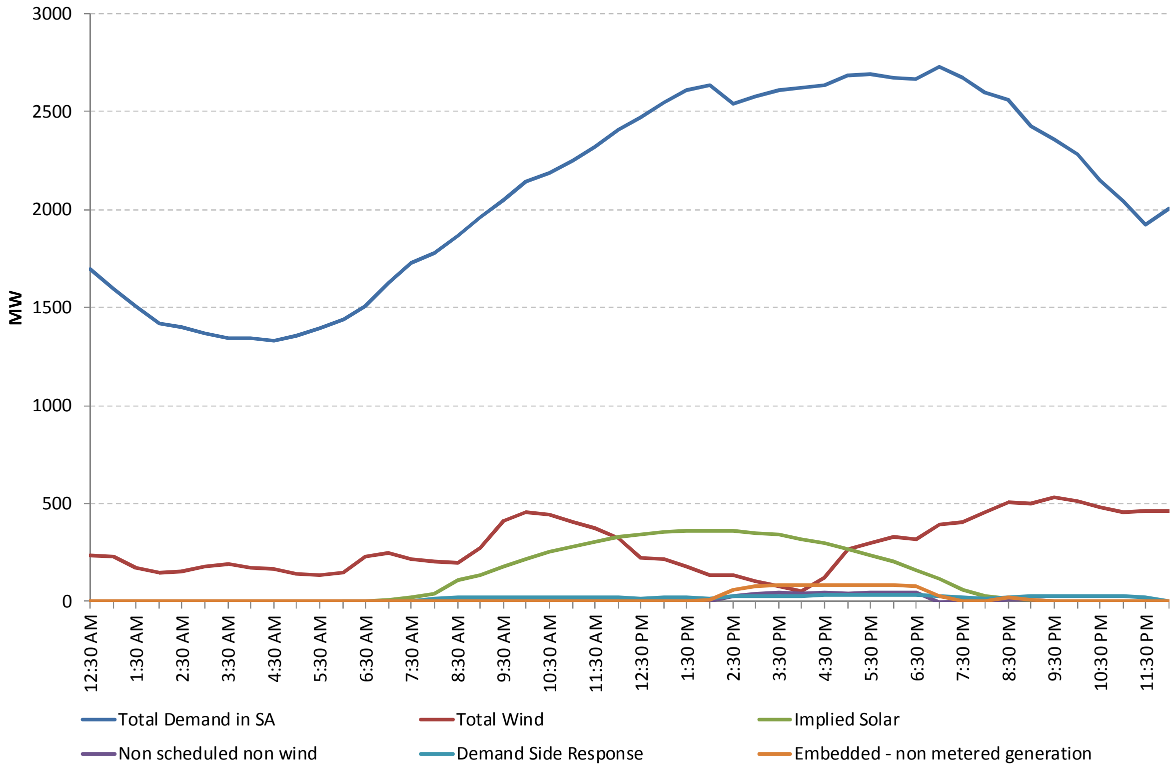


Figure 1 clearly shows that maximum demand for the day of 2728 MW occurred at 7 pm. It is interesting to note that demand reduced from about 1 pm, and gradually started to increase again from about 2.30 pm (shown by the dark blue line). This is reflected in figure 2 by the increase in embedded non-metered generation (such as the Lonsdale and Port Stanvac reciprocating engine sets and Mini hydro), non-scheduled non-wind (such as the Angaston reciprocating engine sets), and non-scheduled wind generation. All of these sources of generation are treated as reductions in demand. The demand side response, shown in purple, also assisted in the reduction in total demand. Had solar, embedded non-metered, non-scheduled non-wind generation and demand-side response not been available, we estimate that maximum demand for the day would have been around 3160 MW[5] and occurred at around 5 pm, which is more typical of the time that peak customer demand has historically occurred (around 4.30 and 5.00pm).

Figure 1 also shows the contribution from solar PV started at around 7.30 am and ended at about 8 pm. The contribution from wind generation varied across the day but fell away for the 4 pm and 4.30 pm trading intervals.

We note that the solar PV data used in figures 1 and 2 is based on broad approximations of the performance of a small sample of output data from actual solar systems operating on that day[6]. The sample was not a statistically significant portion of the approximately 170 000 systems in South Australia.

[5] This figure does not include distribution loss factor (DLF).

[6] The data is sourced from PVOutput.org from around 20 systems with capacity between 3 and 10 kW distributed around Adelaide with 5 minute recording of PV output.

Non-scheduled non wind output is derived from meter data for a number of embedded reciprocating engine sites in the region (for example, Lonsdale and the Port Stanvac engines). Total capacity from this energy source is approaching 85 MW.

Our estimate of demand-side response has been calculated from the meter data for nine major customers in the region. These customers exhibited noticeably lower demand on this day than on days before and after the event. These sources made a significant contribution, offsetting generation from scheduled sources, from about 2.00 pm until around 6.30 pm.

Figure 2 presents the data in a different way, highlighting how these other sources fill in the "notch" in the total demand line and how, but for these other sources, we estimate that maximum demand would have been higher (around 3160 MW) and occurred earlier (at around 5.00 pm).

Figure 2: Sources of supply and spot price and for 19 December 2013

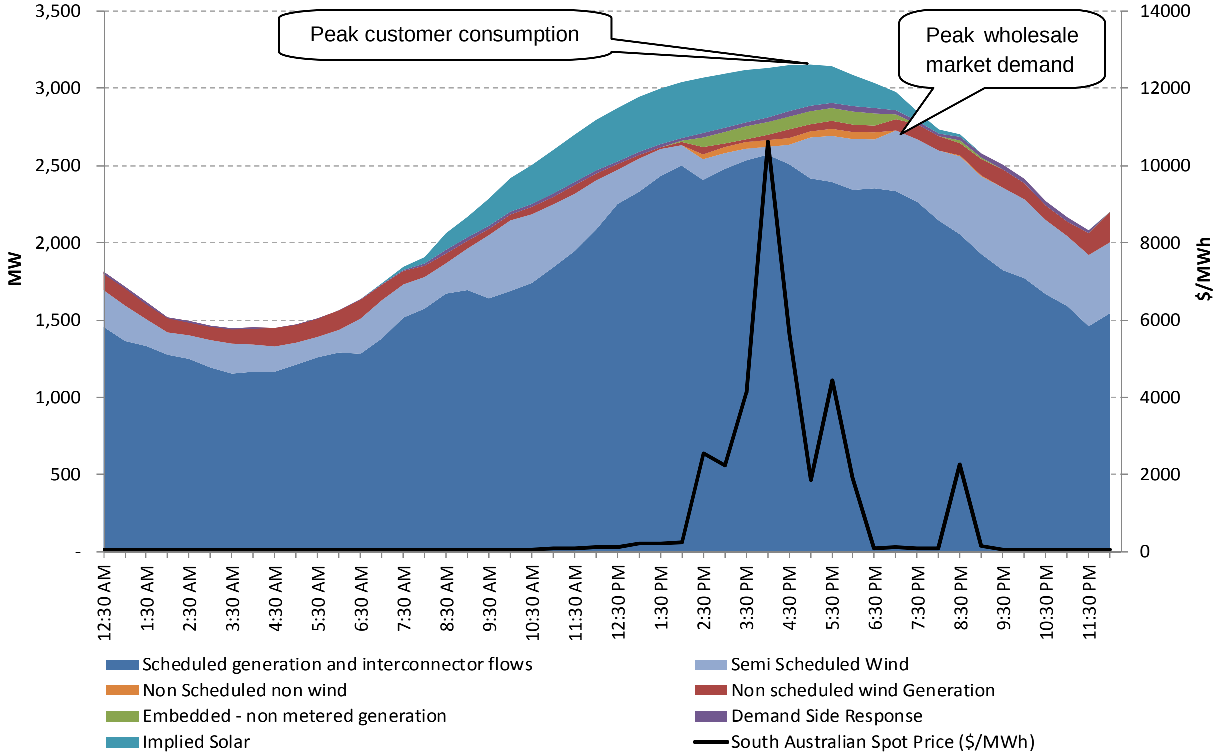


Table 1 shows actual and forecast price, demand and available capacity for the eight trading intervals between 2.30 pm and 6 pm (inclusive) compared to forecast four and twelve hours from dispatch.[7]

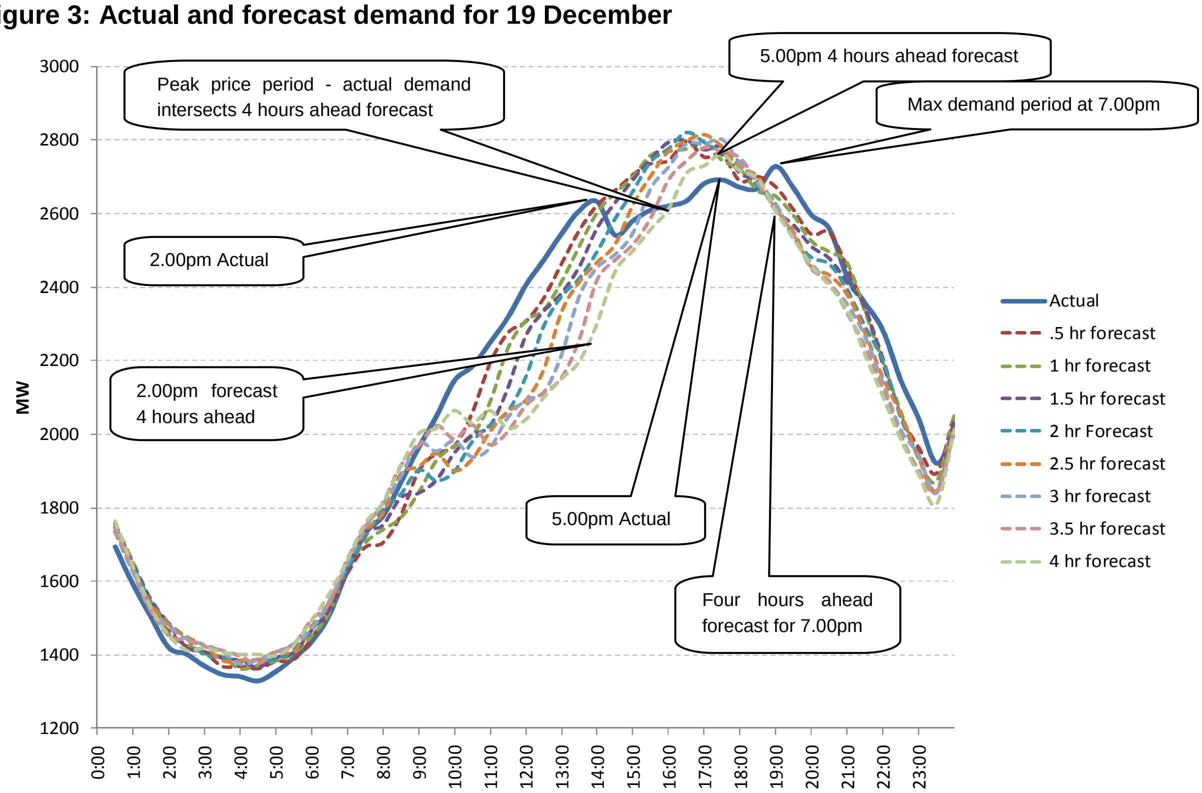
[7] The weekly report from 15 to 21 December 2013 stated that we would investigate all of these prices as part of this report.

Table 1: Actual and forecast demand, spot price and available capacity in South Australia

Time	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
2:30 PM	2539.54	90.80	109.8	2542	2448	2555	3091	3050	3100
3:00 PM	2241.20	110.05	118.93	2580	2503	2573	3064	3029	3086
3:30 PM	4125.81	199.99	199.99	2610	2562	2601	3031	3087	3068
4:00 PM	10 627.00	299.81	199.99	2621	2614	2620	3026	3077	3054
4:30 PM	5639.52	299.81	199.99	2634	2712	2643	3079	3079	3059
5:00 PM	1868.20	199.99	199.99	2682	2734	2627	3212	3054	3042
5:30 PM	4427.20	299.81	199.99	2692	2765	2579	3257	3051	3057
6:00 PM	1928.80	199.99	197.32	2671	2721	2546	3219	3063	3064

A more granular inspection of the variations between forecast and actual demand across the day are shown in figure 3. Figure 3 shows actual demand and forecast demands in half hour increments from half an hour to four hours prior to dispatch. This chart shows that while the demand forecasts reasonably predicted the peak demand on the day, the anticipated shape of demand on the day was different to that forecast even a relatively shorty period before dispatch. The forecasts were not tracking the progression of demand well, indeed 12 hours ahead was closer than four hours.

Figure 3: Actual and forecast demand for 19 December



The four and 12 hours ahead price forecasts for the 4.00 pm and 4.30 pm trading intervals were $300/MWh and $200/MWh respectively. However, rebidding removed capacity from the $200/MWh to $300/MWh range to prices close to the cap.

Every half hour, AEMO publishes demand sensitivities that show forecast spot prices on the basis of adjusted regional demand forecasts. Table 2 shows the effect that changes in forecast demand had on forecast spot prices in South Australia for the 4.00 pm trading interval four hours ahead. The inclusion of this table is designed to show how tight the supply conditions were at the time of high prices and how rebidding changed forecast conditions.

Table 2: Demand and price sensitivities in South Australia for 4 pm as published by AEMO

	Demand change (MW)							
	-200	-100	-50	Actual forecast	50	100	200	500
Published	Spot Price for 4 PM ($/MWh)							
3.35 pm	200	10 627	13 090	13 098	13 098	13 099	13 100	13 100
3.04 pm	245	11 067	11 925	13 098	13 098	13 099	13 099	13 100
2.35 pm	200	1116	10 627	12 098	13 098	13 098	13 099	13 100
2.05 pm	200	9993	10 627	13 090	13 098	13 098	13 099	13 100
1.35 pm	200	203	10 627	13 090	13 090	13 098	13 099	13 100
1.05 pm	200	300	300	1409	13 090	13 098	13 099	13 100
12.35 pm	200	200	200	300	300	1108	13 098	13 100
12.00 pm	292	300	300	481	521	524	13 098	13 100

Table 2 shows that from 3.00pm, conditions were predicted to be sufficiently tight, that even a 100 MW *reduction* in demand above forecast would not have been sufficient to reduce the forecast price to below $10 000/MWh. However, at the time of the 12.00pm forecast, it was predicted that only a 200 MW increase in demand above forecast would have increased prices above $10,000/MWh. The change in conditions occurred as a result of a number of rebids during the afternoon which shifted capacity from low prices to prices above $10 000/MWh, as shown in Table 3 below.

Generator Availability, Offers and Rebidding

Table 3 shows the significant rebids on the day.

Table 3: Rebids by SA plant

Time		Participant	Plant	Move			Reason	Comment
Submitted	Effective			MW	From $/MWh	To $/MWh		
12.54 pm	1.05 pm	AGL	Torrens Island	80	200	13 100	13:00F chg in contract pos	forecast spot price increased from $300 to $1409
1.17 pm	1.25 pm	GDF Suez	SA portfolio	53	300	10 627	1316A SA dem 5m 2613MW > 30MPD 2570MW HHE 13:30 SL	forecast spot price increased from $1409 to $13 090
2.47 pm	2.55 pm	AGL	Torrens Island	40	200	13 100	14:48F chg in contract pos	
3.22 pm	3.30 pm	AGL	Torrens Island	40	200	13 100	15:01A chg in 30pd forecast::price increase SA +$1471 at 15:30	
4.43 pm	4.50 pm	AGL	Torrens Island	130	200	13 100	16:31A chg in forecast::30PD price decrease SA -$11720 at 17:30	

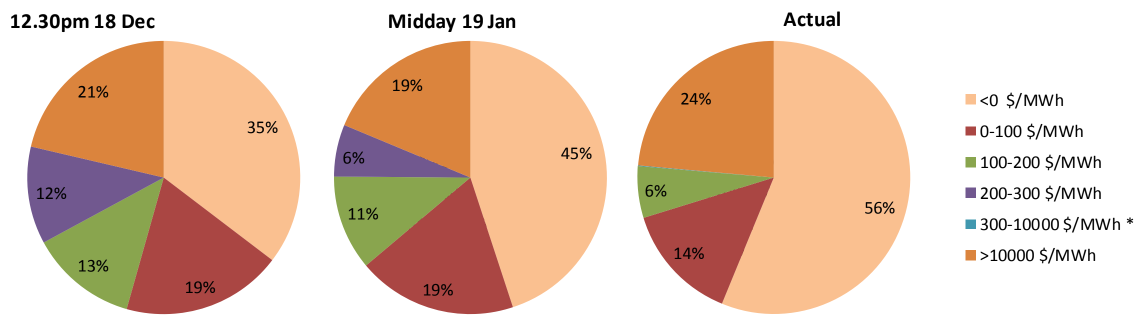
Figure 4 shows how the rebids affected available capacity in a range of price bands.

Starting from the left, the pie charts show three snapshots of the percentage of capacity available in various price bands as at: the first pre-dispatch[8] run for 19 December; four hours ahead; and as at the time of dispatch. These charts show that day ahead there was no capacity priced between $300/MWh and $10 000/MWh. The charts also show that, through rebidding, participants gradually: removed all capacity priced between $200/MWh to $300/MWh; reduced the percentage of capacity priced between $0/MWh to $100/MWh and $100/MWh to $200/MWh; and increased the percentage of capacity priced below $0/MWh and above $10 000/MWh.

While the increase in capacity at low prices is material, at the time of dispatch, there was no capacity priced between $200/MWh and $10 000/MWh.

[8] First predispatch for the 19th of December was published ad 12.30 PM on the 18th of December 2013.

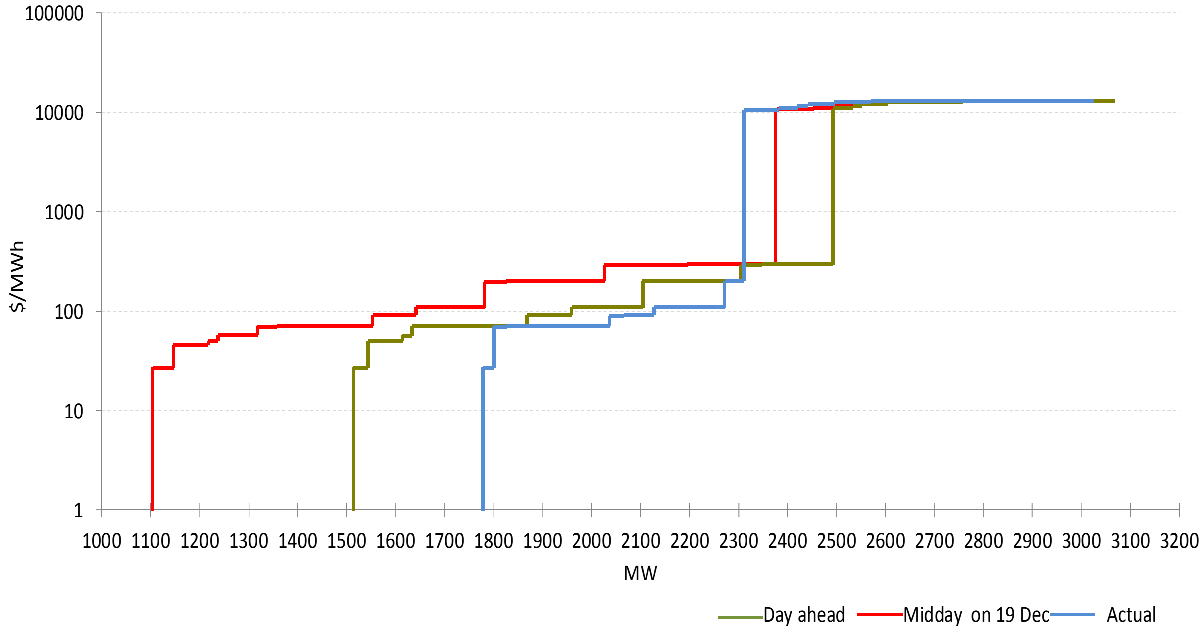
Figure 4: Forecast and actual supply volume by price for generation in SA at 4 pm



*there was no capacity priced between $300/MWh and $10 000/MWh.

Figure 5 shows the supply curve for the 4 pm trading interval over the same time frames as figure 4. Together the charts demonstrate that despite there being more low priced capacity available at dispatch than was forecast, the rebidding of capacity to high prices was sufficient to require the dispatch of high priced generation and set high prices.

Figure 5: Forecast and actual supply curves and generation output in South Australia for 4 pm (log-scale)



Due to a boiler tube leak, Alinta Energy's 272 MW Northern Power Station Unit 1 was withdrawn from service several days prior to the day of high prices. Given the unplanned nature and close proximity to the high-price event, it would have shown as being available in the market systems in the medium to longer term timeframes (such as MTPASA – Medium Term Projected Assessment of System Adequacy) but been unavailable in the shorter term timeframes (i.e. Short Term PASA and Pre-Dispatch).

GDF Suez's Pelican Point power station was the marginal generator for the majority of the period between 3.35 pm and 4.30 pm, setting high prices for nine dispatch intervals.

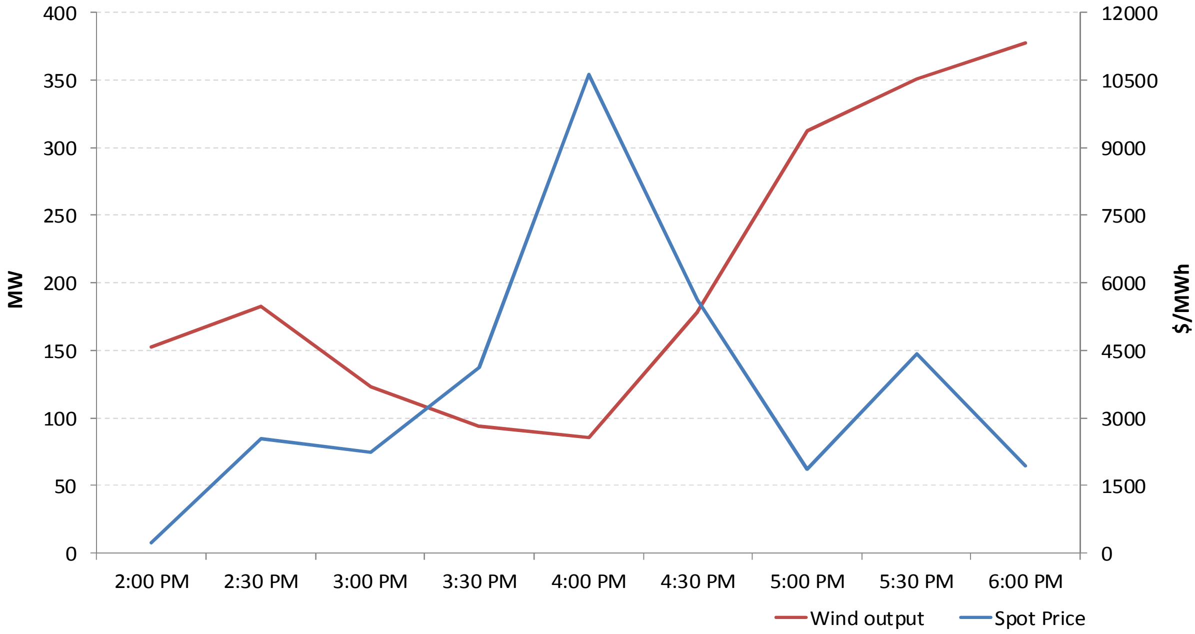
The generators involved in setting the price during the high-price periods, and how that price was determined by the market systems is detailed in **Appendix A.** The closing bids for all participants in

South Australia with capacity priced at or above $5000/MWh for the high-price periods are set out in **Appendix B**.

Wind generation

The contribution of wind generation on 19 December 2013 varied considerably across the course of the day as shown in Figure 1 above. Figure 6 shows the wind generation and spot price from 2 pm to 6 pm and highlights that during the afternoon hours when wind output reached its lowest contribution the spot price peaked. At 4 pm wind generation was around 85 MW[9], half that forecast four hours ahead. The reduced output from wind generation exacerbated the supply situation and contributed to the high prices at 4 pm and 4.30 pm.

Figure 6: Wind output and spot prices in South Australia



Network Availability

Flows into South Australia and combined limits for the Heywood and Murraylink interconnectors are shown in Table 4. Similar to the situation with wind generation, reduced output and capability of the interconnectors into South Australia contributed to the high prices.

Both the Heywood and Murraylink interconnectors were constrained at their import limits for much of the afternoon. When the price was above $5000/MWh, the import limit into South Australia across Heywood was around 300 MW, lower than forecast four and twelve hours ahead. Imports across Heywood were limited due to system normal transmission constraints that manage the potential overload of the Snuggery to Keith 132 kV line on the trip of the Penola West to Kincraig 132 kV or the South East to Tailem Bend No.1 275 kV lines. Constraints associated with these 132 kV lines will be resolved as part of the Heywood interconnector upgrade[10]. The import limit across Murraylink was close to forecast but limited to around 5 MW due to the outage of the Murraylink runback scheme[11]

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9 Installed wind generation capacity in South Australia is 1475 MW.

10 http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission/Heywood-Interconnector-RIT-T

11 The Murraylink Runback scheme is designed to reduce the flows on Murraylink in the event of the loss of one of the supporting network lines. Without this scheme in operation flows on the interconnector are reduced significantly.

and a system normal constraint managing the overload of the Ballart to Bendigo 220 kV line on the loss of the Shepparton to Bendigo 220 kV line.

Table 4: Actual and forecast limits and flow across Heywood and Murraylink

Time	Export Limit			Import Limit			Flows into SA		
	Actual	4 hr Forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
2:30 PM	508	502	379	-143	-461	-593	-143	-461	-593
3:00 PM	466	385	344	-217	-369	-623	-217	-369	-623
3:30 PM	384	379	343	-294	-362	-616	-294	-362	-616
4:00 PM	369	379	342	-311	-319	-603	-311	-187	-603
4:30 PM	444	369	341	-277	-361	-602	-277	-250	-602
5:00 PM	400	366	341	-353	-360	-610	-335	-360	-610
5:30 PM	419	364	344	-238	-366	-609	-238	-366	-609
6:00 PM	431	315	305	-242	-421	-618	-242	-421	-618

Australian Energy Regulator
February 2014

A Price setters for 19 December 2013

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.[12] The 30-minute spot price is the average of the six dispatch interval prices.

South Australia – 4 pm

Time	Dispatch Price	Participant	Unit	Service	Offer price	Marginal Change	Contribution
15:35	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
15:40	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
15:45	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
15:50	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
15:55	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
16:00	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
Spot Price		**$10 627/MWh**					

South Australia – 4.30 pm

Time	Dispatch Price	Participant	Unit	Service	Offer price	Marginal Change	Contribution
16:05	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
16:10	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
16:15	$10627.00	GDF Suez	PPCCGT	Energy	$10627.00	1.00	$10627.00
16:20	$958.82	Snowy Hydro	LAVNORTH	Energy	$0.00	2.14	$0.00
		ENOF,AGLHAL,1,LKBONNY2,1			$0.00	191.76	$0.00
		ENOF,DRYCGT3,1,LKBONNY2,1			$0.00	4.79	$0.00
		ENOF,HWPS1,2,LAVNORTH,2			$0.00	-21.44	$0.00
		ENOF,HWPS2,2,LAVNORTH,2			$0.00	-21.44	$0.00
		ENOF,HWPS3,2,LAVNORTH,2			$0.00	-171.51	$0.00
		ENOF,HWPS4,2,LAVNORTH,2			$0.00	171.51	$0.00
		ENOF,HWPS5,2,LAVNORTH,2			$0.00	-21.44	$0.00
		ENOF,HWPS6,2,LAVNORTH,2			$0.00	-128.63	$0.00
		ENOF,HWPS7,2,LAVNORTH,2			$0.00	-128.63	$0.00
		ENOF,HWPS8,2,LAVNORTH,2			$0.00	-128.63	$0.00
		ENOF,LADBROK1,1,LKBONNY2,1			$0.00	47.94	$0.00
		ENOF,LADBROK2,1,LKBONNY2,1			$0.00	47.94	$0.00
		ENOF,LAVNORTH,2,LOYYB1,2			$0.00	-267.99	$0.00
		ENOF,LAVNORTH,2,LOYYB2,2			$0.00	-267.99	$0.00
		ENOF,LAVNORTH,2,VPGS,2			$0.00	-321.58	$0.00
		ENOF,LKBONNY2,1,NPS1,1			$0.00	-143.82	$0.00
		ENOF,LKBONNY2,1,NPS2,1			$0.00	268.47	$0.00
		ENOF,LKBONNY2,1,OSB-AG,1			$0.00	133.28	$0.00
		ENOF,LKBONNY2,1,PPCCGT,1			$0.00	306.82	$0.00
		ENOF,LKBONNY2,1,TORRA1,1			$0.00	52.74	$0.00
		ENOF,LKBONNY2,1,TORRA2,1			$0.00	43.15	$0.00
		ENOF,LKBONNY2,1,TORRA3,1			$0.00	43.15	$0.00
		ENOF,LKBONNY2,1,TORRA4,1			$0.00	43.15	$0.00
		ENOF,LKBONNY2,1,TORRB1,1			$0.00	57.53	$0.00
		ENOF,LKBONNY2,1,TORRB2,1			$0.00	57.53	$0.00
		ENOF,LKBONNY2,1,TORRB3,1			$0.00	57.53	$0.00
		ENOF,LKBONNY2,1,TORRB4,1			$0.00	57.53	$0.00
		Infigen	LKBONNY2	Energy	-$1000.00	-0.96	$960.00
16:25	$887.48	Snowy Hydro	UPPTUMUT	Energy	$47.01	1.88	$88.38

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

Time	Dispatch Price	Participant	Unit	Service	Offer price	Marginal Change	Contribution
		ENOF,AGLHAL,1,LKBONNY2,1			$0.00	159.81	$0.00
		ENOF,DRYCGT3,1,LKBONNY2,1			$0.00	4.00	$0.00
		ENOF,LADBROK1,1,LKBONNY2,1			$0.00	39.95	$0.00
		ENOF,LADBROK2,1,LKBONNY2,1			$0.00	39.95	$0.00
		ENOF,LKBONNY2,1,NPS1,1			$0.00	-119.86	$0.00
		ENOF,LKBONNY2,1,NPS2,1			$0.00	223.73	$0.00
		ENOF,LKBONNY2,1,OSB-AG,1			$0.00	111.07	$0.00
		ENOF,LKBONNY2,1,PPCCGT,1			$0.00	255.70	$0.00
		ENOF,LKBONNY2,1,TORRA1,1			$0.00	43.95	$0.00
		ENOF,LKBONNY2,1,TORRA2,1			$0.00	35.96	$0.00
		ENOF,LKBONNY2,1,TORRA3,1			$0.00	35.96	$0.00
		ENOF,LKBONNY2,1,TORRA4,1			$0.00	35.96	$0.00
		ENOF,LKBONNY2,1,TORRB1,1			$0.00	47.94	$0.00
		ENOF,LKBONNY2,1,TORRB2,1			$0.00	47.94	$0.00
		ENOF,LKBONNY2,1,TORRB3,1			$0.00	47.94	$0.00
		ENOF,LKBONNY2,1,TORRB4,1			$0.00	47.94	$0.00
		Infigen	LKBONNY2	Energy	-$1000.00	-0.80	$800.00
16:30	$109.80	AGL (SA)	TORRA1	Energy	$109.80	0.05	$5.49
		AGL (SA)	TORRA3	Energy	$109.80	0.19	$20.86
		AGL (SA)	TORRB1	Energy	$109.80	0.19	$20.86
		AGL (SA)	TORRB2	Energy	$109.80	0.19	$20.86
		AGL (SA)	TORRB3	Energy	$109.80	0.19	$20.86
		AGL (SA)	TORRB4	Energy	$109.80	0.19	$20.86
		ENOF,TORRA1,6,TORRA2,6			$0.00	0.95	$0.00
		ENOF,TORRA1,6,TORRA4,6			$0.00	0.95	$0.00
		ENOF,TORRA2,6,TORRA3,6			$0.00	3.81	$0.00
		ENOF,TORRA2,6,TORRB1,6			$0.00	3.81	$0.00
		ENOF,TORRA2,6,TORRB2,6			$0.00	3.81	$0.00
		ENOF,TORRA2,6,TORRB3,6			$0.00	3.81	$0.00
		ENOF,TORRA2,6,TORRB4,6			$0.00	3.81	$0.00
		ENOF,TORRA3,6,TORRA4,6			$0.00	3.81	$0.00
		ENOF,TORRA4,6,TORRB1,6			$0.00	3.81	$0.00
		ENOF,TORRA4,6,TORRB2,6			$0.00	3.81	$0.00
		ENOF,TORRA4,6,TORRB3,6			$0.00	3.81	$0.00
		ENOF,TORRA4,6,TORRB4,6			$0.00	3.81	$0.00
Spot Price		**$5639.52/MWh**					

B Closing bids for 19 December 2013

Figures B1 to B2 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 B.1 AGL Energy (Torrens Island, Bluff, Hallett and North Brown Hill) closing bid prices, dispatch and spot price

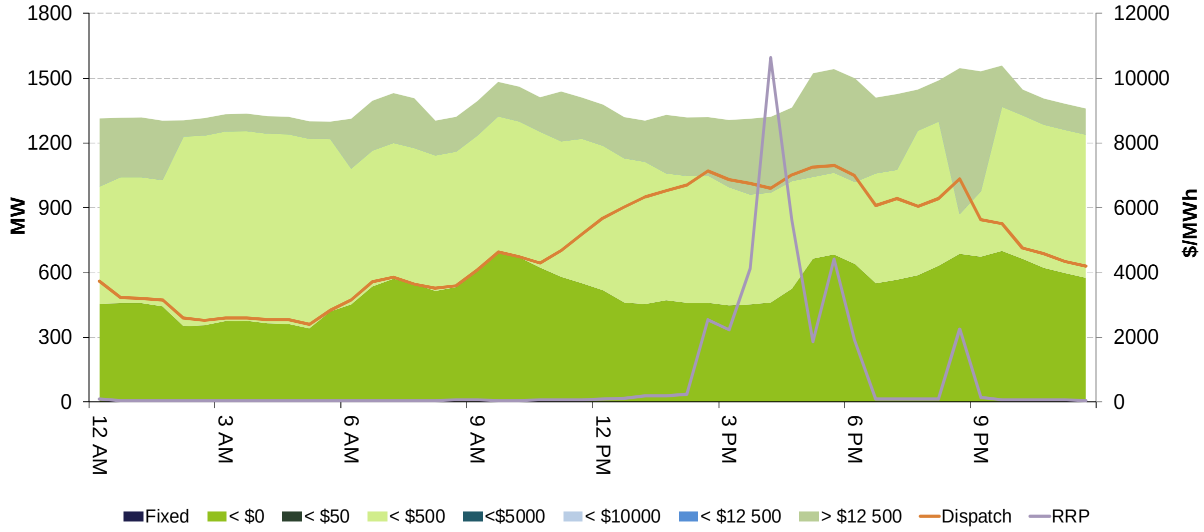

Figure B.2 GDF Suez (Pelican Point, Dry Creek, Mintaro, Port Lincoln, Snuggery) closing bid prices, dispatch and spot price