Electricity spot prices above $5000/MWh

Victoria and South Australia, 13 January 2016

4 March 2016

AUSTRALIAN ENERGY REGULATOR

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1 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.

On 13 January 2016 at 3.30 pm and 4 pm in Victoria and at 4 pm in South Australia, the spot price for energy exceeded $5000/MWh. 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

On 13 January 2016, the spot price in Victoria exceeded $5000/MWh for the 3.30 pm and 4 pm trading intervals and in South Australia for the 4 pm trading interval.

The Victorian dispatch price exceeded $8536/MWh between 3.15 pm and 3.50 pm, inclusive, resulting in the spot prices of $9137/MWh and $7477/MWh for the 3.30 pm and 4 pm trading intervals respectively. Both four and twelve hours ahead, the forecast spot price for these trading intervals was around $300/MWh.

The dispatch price in South Australia reached $10 760/MWh between 3.35 pm and 3.45 pm, inclusive, resulting in a spot price of $5173/MWh for the 4 pm trading interval. Similar to Victoria, the forecast spot price both four and twelve hours ahead was around $300/MWh.

Network outages were the dominant contributing factor to the Victorian price outcomes. Lightning in north eastern Victoria prompted AEMO to invoke constraints to manage the possible loss of transmission lines in those areas. These constraints forced counter-price flows, from Victoria (high priced region) into New South Wales (low priced region), across the Vic-NSW interconnector, constrained down low-priced generation in Victoria and forced flows into Victoria from South Australia. Some Victorian generators rebid capacity from low to high prices and a number, that were directly affected by the constraint managing the possible line losses, rebid to reduce their ramp down rates. These reduced ramp rates prolonged the high price period.

The supply curve in Victoria was very steep with no capacity priced between $300/MWh and $13 000/MWh. This situation was exacerbated by around 800 MW of low-priced capacity not being available for dispatch because of network constraints.

The main contributing factor for the high prices in South Australia was rebidding of capacity at Torrens Island by AGL from low to high prices, at the time when the network was constrained, setting the price.

3 Analysis

The spot price in Victoria exceeded $5000/MWh for the 3.30 pm and 4 pm trading intervals and in South Australia for the 4 pm trading interval. The high prices were not forecast because the impact of lightning on the capacity of the network is unpredictable and the markets response and subsequent high prices cannot be forecast.

Table 1 and Table 2 shows actual and forecast spot price, demand and availability for each high priced trading interval in Victoria and South Australia respectively.

Table 1: Actual and forecast spot price, demand and available capacity for Victoria

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
3.30 pm	9137.03	313.34	247.33	9116	8929	8599	9907	9884	10 075
4 pm	7477.35	332.92	299.90	9141	9068	8734	9993	9889	10 028

Table 2: Actual and forecast spot price, demand and available capacity for South Australia

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
4 pm	5173.04	337.12	292.97	1920	2339	2278	3466	3365	3421

There was a steep supply curve in Victoria (see Figure 2) meaning that small variations in demand or interconnector limits or flows had the potential to lead to large variations in price. This is discussed in greater detail in the following sections.

In Victoria demand was slightly higher than forecast four hours ahead and up to 520 MW higher than forecast 12 hours ahead. However this was only a minor contributor to the high prices. In South Australia demand was around 400 MW lower than that forecast four hours ahead and did not contribute to the high price.

3.1 Network Availability

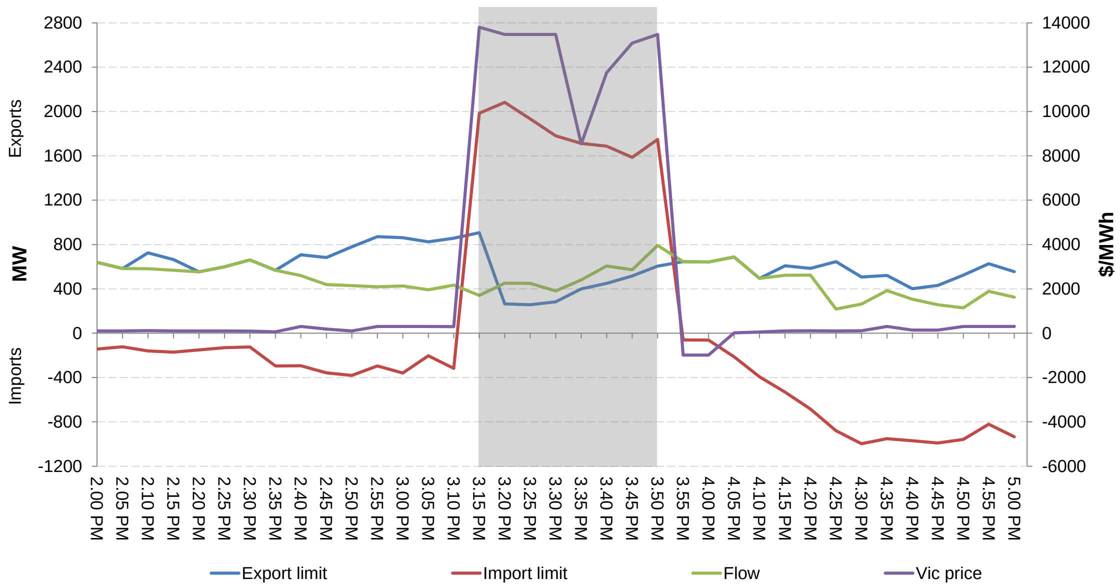
This section examines the change in network capability approaching the event and its contribution to price outcomes.

AEMO issued two market notices at around 3.17 pm reclassifying the loss of Dederang to Glenrowan 220kV lines and the Eildon to Mt Beauty lines as credible contingencies due to lightning[2]. Constraints were invoked at 3.15 pm to manage the possible loss of these lines. A constraint which is designed to prevent overloading the Dederang to Shepparton 220kV line on the trip of the Dederang to Glenrowan 220kV lines effects all interconnectors and around 3700 MW of generation in Victoria.[3] This constraint immediately violated, the dispatch price went to the price cap in Victoria and forced flows into New South Wales across the Vic-NSW interconnector, counter-price. At 3.20 pm the counter-price flows prompted AEMO to invoke a constraint to manage the negative residues which immediately violated. Around $4.3 million of negative settlements were accrued during the 3.30 pm and 4 pm trading intervals.

The ongoing outage of Basslink since December meant that no support was available from Tasmania and both the Murraylink and Heywood interconnectors were exporting into Victoria at their limits.

Figure 1 shows the import and export limit, and target flows of the Vic-NSW while the grey area shows the period for which the constraint was violated. The Victorian dispatch price is also shown. At 3.15 pm the significant drop in the export limit from around 900 MW to around 250 MW as a result of the constraints to manage contingencies for lightening is clearly evident.

Figure 1: Vic-NSW interconnector export/import limits and target flows



The figure shows that flows were being forced out of Victoria and into New South Wales by up to 792 MW, counter-price, during the high priced period. Counter-intuitively, it also shows that the import limit into Victoria was above 2000 MW in the other direction, towards New South Wales and higher than the export limit of 264 MW at the same time. AEMO is satisfied that the constraint was formulated correctly and that it violated as generation could not be scheduled in a way to relieve the violation while maintaining the demand/supply balance in Victoria.

2 See Appendix E for the relevant market notices.

3 This constraint and its effect on generation is detailed in Appendix A.

3.2 Supply and Demand

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

3.2.1 Supply curve

Figure 2 shows the supply curve in Victoria for the 3.25 pm dispatch interval as it is typical of the situation for the period of high prices.

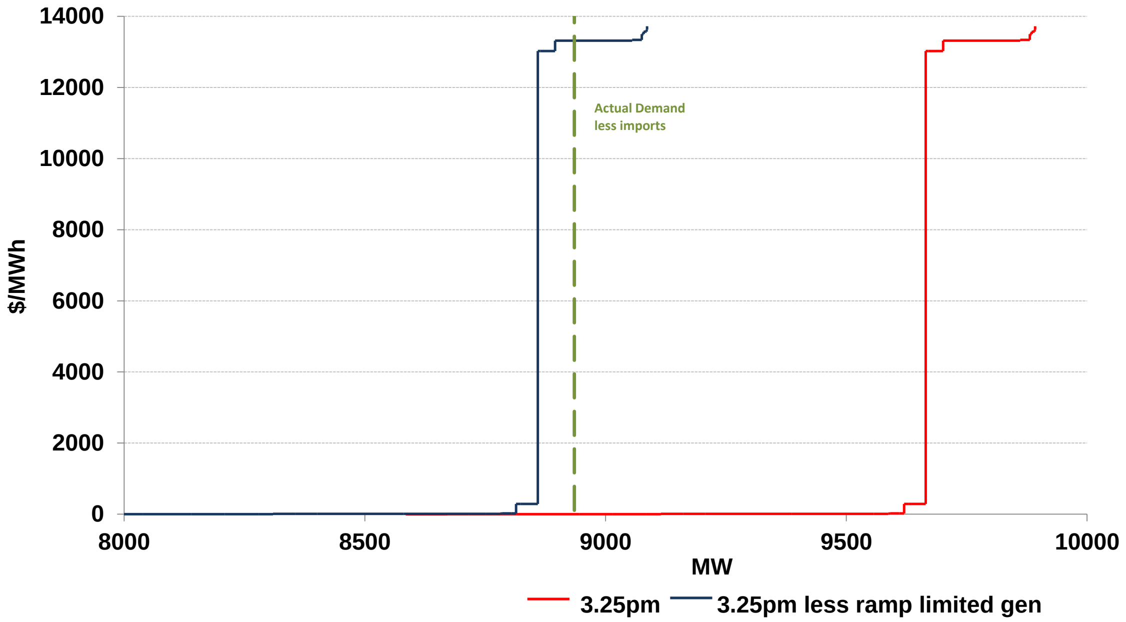
Supply curves illustrate the potential sensitivity of prices to changes in key factors affecting both demand and supply. The supply curve is derived by summing the available capacity in each price band for all generators in Victoria.

The red line in Figure 2 shows the actual supply curve for all generators in Victoria based on their offers. The vertical section of the curve at about 9600 MW shows there was no capacity priced between \$300/MWh and \$13 000/MWh (\$300/MWh was the price forecasts 4 and 12 hours ahead).

As discussed in Section 3.1, network constraints managing the reclassifications constrained low-priced generation in the north of Victoria, reducing the capacity available for dispatch (effective capacity). The 800 MW reduction in effective capacity shifted the supply curve to the left during the period of high prices (shifting the red line down to the blue line).

The dashed green line in Figure 2 represents Victorian demand less imports: that is the effective target for the generators in the region.

Figure 2: Actual and effective supply curves for 3.25 pm dispatch interval in Victoria



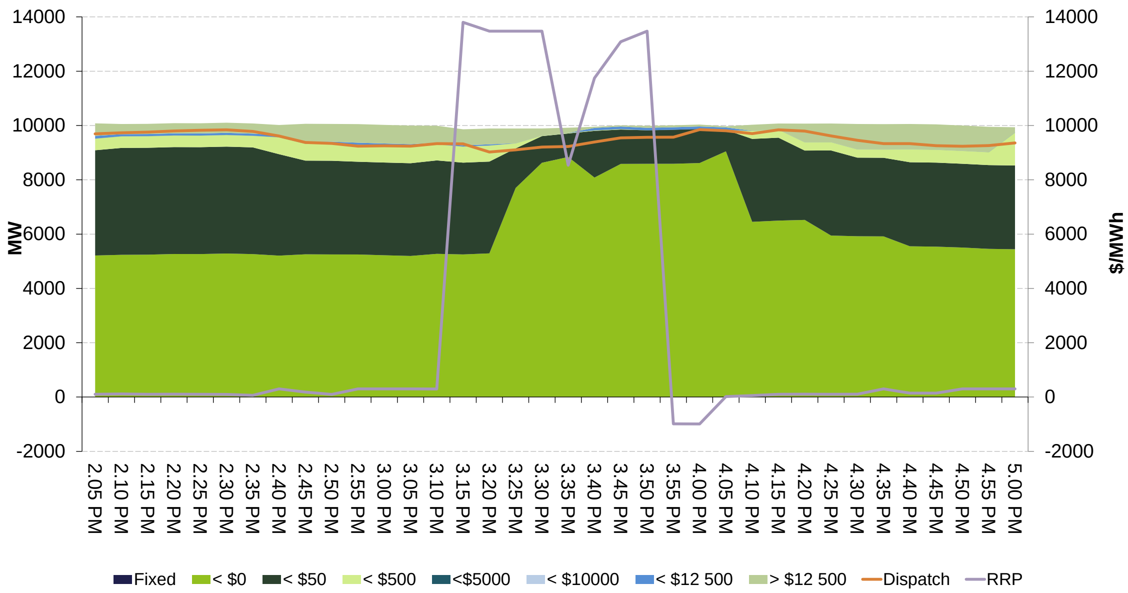
The intersection of the effective demand line and the supply curves provides an indication of the regional price. Had all the capacity offered been available to meet the effective demand the dispatch price would have been much lower. However, with a supply curve with these characteristics small changes in demand, interconnector availability or rebidding may have a large effect on price. Shifting the supply curve to the left increases the probability of a high price outcome, as the demand approached 8800 MW.

3.2.2 Rebidding

There was rebidding of capacity from low to high prices and rebidding of ramp down rates to the minimum allowed without a technical reason[4] that contributed to the high priced outcomes.

Figure 3 and Figure 4 shows the closing bids for participants in Victoria and South Australia as well as the total generation output in the region and the dispatch price.

Figure 3: Closing bids of Victorian generators, output and spot price

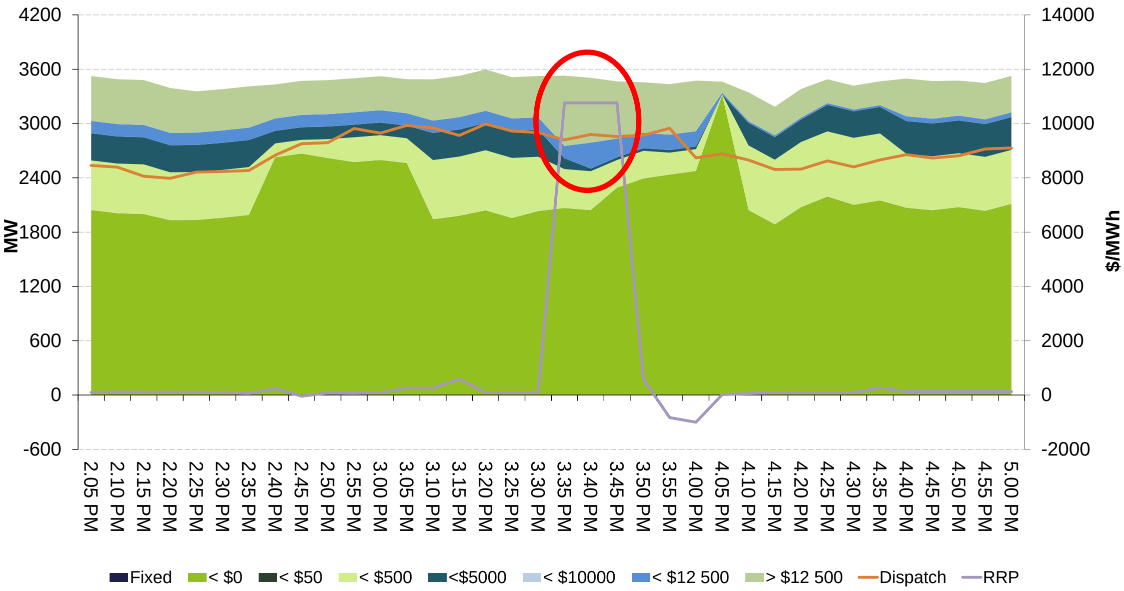


At around 2.30 pm AGL rebid 280 MW of capacity at McKay from low to high prices due to testing at Torrens Island. At around 3 pm EnergyAustralia reduced the available capacity of Yallourn power station by 130 MW, due to mill limitations, all of which was priced at less than $22/MWh.

Around 1800 MW of capacity (by Snowy and AGL) was rebid to the price floor at around 3.30 pm. The constraint was revoked at 3.50 pm and the price went to the price floor.

4 The current requirement under the Electricity Rules that generators specify a ramp rate that is greater than or equal to the lower of three megawatts per minute, or three per cent of maximum capacity, unless there is a physical or safety limitation on their plant.

Figure 4: Closing bids of South Australian generators, output and spot price

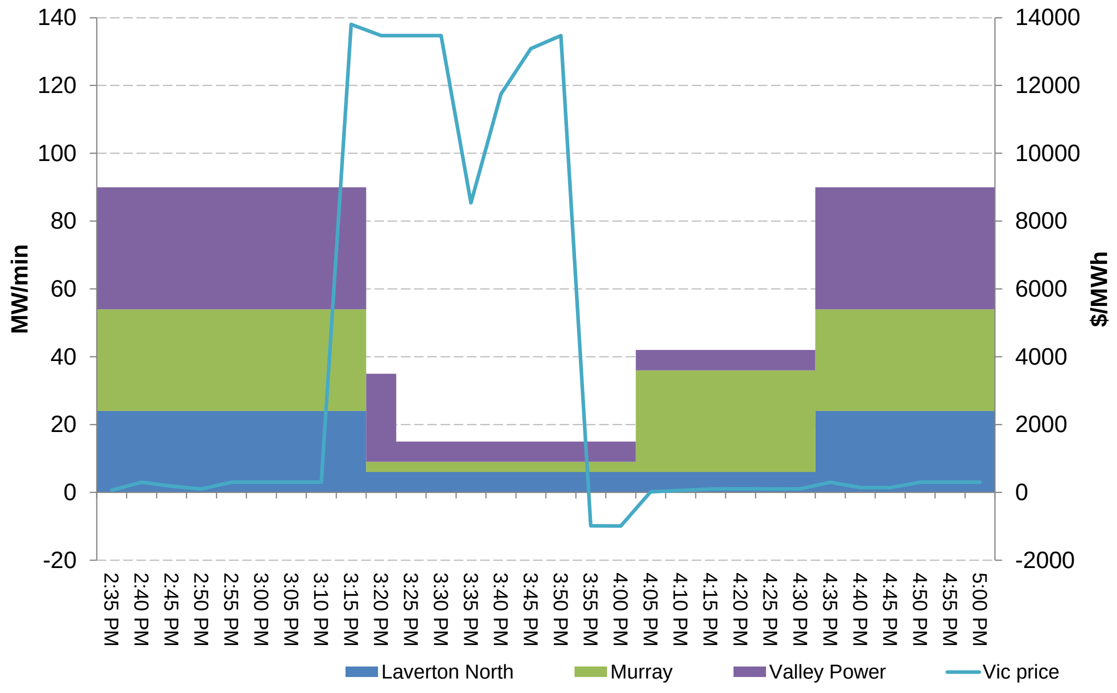


AGL rebid around 400 MW at Torrens Island from low to high prices, shown in the red ellipse. This rebid set the price at $10 760/MWh for three dispatch intervals from 3.35 pm as shown by the grey line. AGL later rebid around 700 MW of capacity to the price floor and the dispatch price followed.

In response to the constraint managing the reclassification of the lines in Northern Victoria, Snowy Hydro rebid the ramp down rates of Laverton North, Murray and Valley Power to the minimum allowable level of 3MW/min.

Figure 5 shows the cumulative ramp down rate in MW/min of Laverton North, Murray and Valley Power. At times these units were being ramped down out of merit order. The reduction in offered ramp rates prolonged the effect of the constraint by taking longer to ramp the units down to the point where the constraint is relieved and prices reduce.

Figure 5: Cumulative ramp down rates for Laverton North, Murray and Valley Power.



Note: Ramp rates as per offer

The rebids considered to have been material to the event are listed in Appendix B.

Appendix C details the generators involved in setting the price during the high-price periods, and how that price was determined by the market systems.

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

Australian Energy Regulator

March 2016

Appendix A: Reclassification and Lightning Constraints

In optimising economic generation dispatch and interconnector flows, the National Electricity Market Dispatch Engine (NEMDE) takes into account the maximum network capability that applies at the time. These network limits are represented as constraint equations that describe the maximum capability of each network element and include generator and interconnector coefficients. The magnitude of a coefficient gives an indication of the significance of the generating unit or interconnector in managing the network limitation (the larger the coefficient the more significant the unit or interconnector). In the formulation of a constraint equation, reducing the output (constrained-off) of a unit or interconnector with a positive coefficient or increasing the output (constrained-on) from a unit or interconnector with a negative coefficient, relieves the constraint.[5] The volume and rate at which a generator is 'constrained-on' or off is, however, limited by the availability and ramp rate offered by those generators.

On 13 January 2016 AEMO issued two market notices reclassifying the loss of Dederang to Glenrowan 220 kV lines and the Eildon to Mt Beauty lines as credible contingencies (blue dashed lines in Figure A1) due to lightning. AEMO invoked a constraint which avoids overloading the Dederang to Shepparton 220 kV line on the trip of both Dederang to Glenrowan lines which affects all interconnectors and around 3700 MW of generation in Victoria.[6] This constraint immediately violated, dispatch price went to the price cap in Victoria and forced flows into New South Wales across the Vic-NSW interconnector, counter-price.

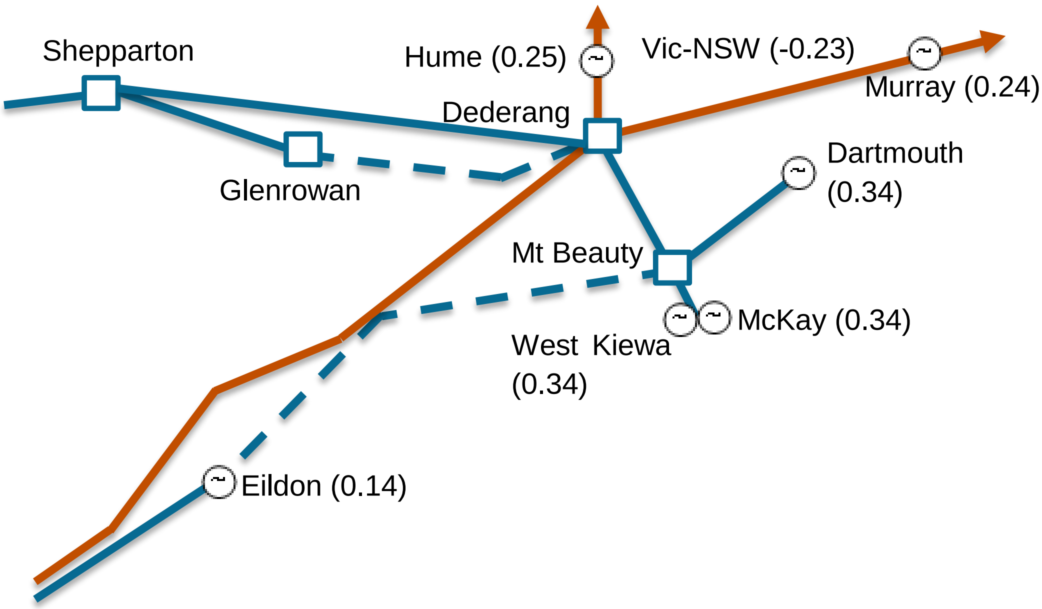
Figure A1 is a simplified representation of the transmission network in Victoria and significant generation stations relevant to the constraint.

The blue lines in Figure A1 represent 220 kV transmission lines and the orange lines represent 330 kV transmission lines. The arrows represent the direction of the inter-regional flows, which were counter price (or from high-priced to low-priced regions) due to the above constraint. The circles indicate the generating stations in the vicinity of this constraint and their coefficient is shown.

5 Network constraints can cause generators to be dispatched at a price that is lower than the offer price (constrained-on) or generators to not be dispatched even though its offer price is lower than the regional price (constrained-off).

6 Constraint equations are mathematical expressions used in the dispatch engine to describe the physical limitations of the power system. 3700 MW includes Murray, West Kiewa, Dartmouth, Eildon, Mortlake, Laverton North, McKay, Oaklands wind farm, Mt Mercer wind farm, Macarthur wind farm

Figure A1: Simplified network in Victoria and counter-price inter-regional flows



Hume, Murray, Dartmouth, McKay West Kiewa and Eildon all have positive coefficients and hence when it was binding or violated the constraint can be relieved by reducing their output. Generators with the largest coefficients have the greatest impact on the constraint. Flow on the Vic-NSW interconnector had a negative coefficient meaning increasing export into New South Wales relieves the constraint. Before the constraint violated, Hume and McKay were not online, Dartmouth, Eildon and one West Kiewa unit were running at close to their maximum offered capacity and Murray was running at around 1300 MW of 1500 MW.

Once the constraint was invoked, it immediately violated. Dartmouth and West Kiewa were given zero targets and were quickly shut down. This left only Murray and Eildon as generators that could be constrained-off to alleviate the constraint. Murray had the larger coefficient and therefore the greatest effect. Snowy Hydro rebid all of Murray's capacity to the price floor and reduced its ramp down rate from 30 MW/min to its minimum allowed (3 MW/min).

Murray is in the Victorian region, north of the Dederang to Glenrowan and the Eildon to Mt Beauty lines and has a positive coefficient of 0.24. When Snowy Hydro rebid the capacity at Murray to the price floor (which was lower than the New South Wales or South Australia region prices), its capacity was dispatched in preference to generators in New South Wales and the network constraint forced power into New South Wales across the Vic-NSW interconnector, counter-price. The changing of ramp rates to the minimum permitted prolonged the effect of the constraint and extended the period of high prices in Victoria.

Appendix B: Significant Rebids

The rebidding tables highlight the relevant rebids submitted by generators that impacted on market outcomes during the time of high prices. It details the time the rebid was submitted and used by the dispatch process, the capacity involved, the change in the price of the capacity was being offered and the rebid reason.

Significant energy rebids for 3.30 pm and 4 pm in Victoria

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.33 pm		AGL	McKay	280	0	13 500	1430~P~010 UNEXPECTED/ PLANT LIMITS~112 REDIST ACROSS PORTFOLIO [TIPS TESTING]
3.01 pm	3.10 pm	EnergyAustralia	Yallourn	-130	<22	N/A	15:01 P CAPACITY ADJ DUE TO MILL ISSUES
3.12 pm	3.20 pm	Snowy Hydro	Murray	1521	>31	-1000	15:15 A VIC: ACT PRICE $13,500.10 HGR THN 5MPD 15:15@15:06
3.17 pm	3.25 pm	AGL Energy	Mckay	280	13 500	-1000	1515~A~040 CHG IN AEMO DISP~45 PRICE INCREASE VS PD +13800
3.19 pm	3.30 pm	EnergyAustralia	Yallourn	70	N/A	-1000	15:19 P CAPACITY ADJ DUE TO IMPROVED MILLING

Significant energy rebids for 4 pm in South Australia

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.28 pm	3.35 pm	AGL	Torrens Island	410	<592	>10 760	1530~A~040 CHG IN AEMO DISP~45 PRICE INCREASE VS PD VIC $13474.65 V $303.69
3.53 pm	4 pm	AGL	Torrens Island	785	>95	-1000	1550~A~040 CHG IN AEMO DISP~44 PRICE DECREASE VS PD SA -$988.09 V $10760

Significant ramp rate rebids for 3.30 pm and 4 pm in Victoria

Submit time	Time effective	Participant	Station	Capacity rebid (MW/min)	Ramp down rate from (MW/min)	Ramp down rate to (MW/min)	Rebid reason
3.12 pm	3.20 pm	Snowy Hydro	Murray	-27	30	3	15:15 A VIC: ACT PRICE $13,500.10 HGR THN 5MPD 15:15@15:06
3.12 pm	3.20 pm	Snowy Hydro	Laverton North	-18	24	6	15:15 A VIC: ACT PRICE $13,500.10 HGR THN 5MPD 15:15@15:06
3.13 pm	3.20 pm	Snowy Hydro	Valley Power	-10	36	26	15:15 A VIC: ACT PRICE $13,500.10 HGR THN 5MPD 15:15@15:06
3.14 pm	3.25 pm	Snowy Hydro	Valley Power	-15	26	11	15:10 A VIC: ACT PRICE $13,500.10 HGR THN 5MPD 15:15@15:06
3.15 pm	3.25 pm	Snowy Hydro	Valley Power	-5	11	6	15:15 A VIC: ACT PRICE $13,500.10 HGR THN 5MPD 15:15@15:06

Appendix C: 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. The dispatch prices that are in italics are capped at the price cap of $13 800/MWh when published by AEMO.

3.30 pm Victoria

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
15:05	$299.90	Snowy Hydro	MURRAY	Energy	$299.90	1.00	$299.90
15:10	$298.35	Delta Electricity	VP5	Energy	$290.00	0.51	$147.90
		Delta Electricity	VP6	Energy	$290.00	0.51	$147.90
15:15	*$34 659.84*	AGL Hydro	EILDON1	Energy	$13 569.83	2.59	$35 145.86
		Snowy Hydro	TUMUT3	Energy	$299.80	-1.67	-$500.67
15:20	$13 474.65	AGL Hydro	AGLSOM	Energy	$13 474.65	1.00	$13 474.65
15:25	$13 474.65	AGL Hydro	AGLSOM	Energy	$13 474.65	1.00	$13 474.65
15:30	$13 474.65	AGL Hydro	AGLSOM	Energy	$13 474.65	1.00	$13 474.65

Spot Price **$9317/MWh**

4 pm Victoria

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
15:35	$8536.43	AGL (SA)	TORRA1	Energy	$10 759.99	0.27	$2905.20
		AGL (SA)	TORRA2	Energy	$10 759.99	0.27	$2905.20
		AGL (SA)	TORRA3	Energy	$10 759.99	0.27	$2905.20
		Snowy Hydro	MURRAY	Energy	-$1000.00	0.32	-$320.00
			ENOF,EILD		$0.00	-13.56	$0.00
			ENOF,EILD		$0.00	-13.56	$0.00
			ENOF,HWP		$0.00	-50.47	$0.00
			ENOF,HWP		$0.00	-69.40	$0.00
			ENOF,HWP		$0.00	-69.40	$0.00
			ENOF,HWP		$0.00	-69.40	$0.00
			ENOF,HWP		$0.00	-69.40	$0.00
			ENOF,HWP		$0.00	-69.40	$0.00
			ENOF,JLA0		$0.00	-12.62	$0.00
			ENOF,JLA0		$0.00	-9.46	$0.00

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

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,JLA0		$0.00	-9.46	$0.00
			ENOF,JLA0		$0.00	-12.62	$0.00
			ENOF,JLB0		$0.00	-22.08	$0.00
			ENOF,JLB0		$0.00	-22.08	$0.00
			ENOF,JLB0		$0.00	-22.08	$0.00
			ENOF,LNG		$0.00	-47.32	$0.00
			ENOF,LNG		$0.00	-47.32	$0.00
			ENOF,LOY		$0.00	-102.52	$0.00
			ENOF,LOY		$0.00	-102.52	$0.00
			ENOF,LYA1		$0.00	-176.65	$0.00
			ENOF,LYA2		$0.00	-94.64	$0.00
			ENOF,LYA4		$0.00	-94.64	$0.00
			ENOF,MOR		$0.00	-92.11	$0.00
			ENOF,MOR		$0.00	-92.11	$0.00
			ENOF,MUR		$0.00	9.46	$0.00
			ENOF,MUR		$0.00	9.46	$0.00
			ENOF,HWP		$0.00	69.40	$0.00
			ENOF,HWP		$0.00	69.40	$0.00
			ENOF,LYA3		$0.00	94.64	$0.00
			ENOF,MUR		$0.00	-160.88	$0.00
			ENOF,MUR		$0.00	-19.87	$0.00
			ENOF,MUR		$0.00	-16.40	$0.00
			ENOF,MUR		$0.00	-16.40	$0.00
			ENOF,MUR		$0.00	-16.09	$0.00
			ENOF,MUR		$0.00	-14.20	$0.00
			ENOF,MUR		$0.00	-14.51	$0.00
			ENOF,MUR		$0.00	-13.25	$0.00
			ENOF,MUR		$0.00	-100.94	$0.00
			ENOF,MUR		$0.00	-69.40	$0.00
			ENOF,MUR		$0.00	-78.86	$0.00
			ENOF,MUR		$0.00	-78.86	$0.00
15:40	$11 746.25	AGL Hydro	AGLSOM	Energy	$11 746.25	1.00	$11 746.25
15:45	$13 085.81	Ecogen Energy	JLA02	Energy	$13 085.81	1.00	$13 085.81
			ENOF,JLA0		$0.00	25.00	$0.00
			ENOF,JLA0		$0.00	5.00	$0.00
			ENOF,JLA0		$0.00	30.00	$0.00
			ENOF,JLA0		$0.00	30.00	$0.00
			ENOF,JLA0		$0.00	5.00	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
15:50	$13 474.65	AGL Hydro	AGLSOM	Energy	$13 474.65	1.00	$13 474.65
15:55	-$988.09	Meridian Energy	MERCER01	Energy	-$996.71	0.99	-$986.74
16:00	-$990.93	Meridian Energy	MERCER01	Energy	-$996.71	1.00	-$996.71
		Origin Energy	QPS2	Energy	-$1000.00	0.00	$0.00
		Origin Energy	QPS3	Energy	-$1000.00	0.00	$0.00
		Origin Energy	QPS4	Energy	-$1000.00	0.00	$0.00
		Origin Energy	QPS5	Energy	-$1000.00	0.00	$0.00
		Pacific Hydro	CLEMGPW	Energy	-$1000.00	0.00	$0.00
		EnergyAustralia	AGLHAL	Energy	-$1000.00	0.00	$0.00
		GDF Suez	PPCCGT	Energy	-$1000.00	0.00	$0.00
		GDF Suez	DRYCGT1	Energy	-$1000.00	0.00	$0.00
		GDF Suez	DRYCGT2	Energy	-$1000.00	0.00	$0.00
		GDF Suez	DRYCGT3	Energy	-$1000.00	0.00	$0.00
		GDF Suez	SNUG1	Energy	-$1000.00	0.00	$0.00
			ENOF,AGL		$0.00	-0.01	$0.00
			ENOF,AGL		$0.00	-0.01	$0.00
			ENOF,AGL		$0.00	-0.04	$0.00
			ENOF,AGL		$0.00	-0.01	$0.00
			ENOF,AGL		$0.00	-0.02	$0.00
			ENOF,AGL		$0.00	-0.06	$0.00
			ENOF,AGL		$0.00	-0.03	$0.00
			ENOF,AGL		$0.00	-0.03	$0.00
			ENOF,AGL		$0.00	-0.03	$0.00
			ENOF,AGL		$0.00	-0.01	$0.00
			ENOF,AGL		$0.00	-0.05	$0.00
			ENOF,AGL		$0.00	-0.05	$0.00
			ENOF,AGL		$0.00	-0.05	$0.00
			ENOF,AGL		$0.00	-0.05	$0.00
			ENOF,CLE		$0.00	-0.01	$0.00
			ENOF,CLE		$0.00	-0.01	$0.00
			ENOF,CLE		$0.00	-0.02	$0.00
			ENOF,CLE		$0.00	0.00	$0.00
			ENOF,CLE		$0.00	-0.01	$0.00
			ENOF,CLE		$0.00	-0.03	$0.00
			ENOF,CLE		$0.00	-0.01	$0.00
			ENOF,CLE		$0.00	-0.01	$0.00
			ENOF,CLE		$0.00	-0.01	$0.00
			ENOF,CLE		$0.00	-0.01	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,CLE		$0.00	-0.02	$0.00
			ENOF,CLE		$0.00	-0.02	$0.00
			ENOF,CLE		$0.00	-0.02	$0.00
			ENOF,CLE		$0.00	-0.02	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.02	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.02	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.02	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	-0.01	$0.00
			ENOF,DRY		$0.00	0.00	$0.00
			ENOF,DRY		$0.00	-0.02	$0.00
			ENOF,DRY		$0.00	-0.02	$0.00
			ENOF,DRY		$0.00	-0.02	$0.00
			ENOF,DRY		$0.00	-0.02	$0.00
			ENOF,NPS		$0.00	0.13	$0.00
			ENOF,NPS		$0.00	0.01	$0.00
			ENOF,NPS		$0.00	0.01	$0.00
			ENOF,NPS		$0.00	0.01	$0.00
			ENOF,NPS		$0.00	0.07	$0.00
			ENOF,NPS		$0.00	0.03	$0.00
			ENOF,OSB-		$0.00	0.10	$0.00
			ENOF,OSB-		$0.00	0.01	$0.00
			ENOF,OSB-		$0.00	0.01	$0.00
			ENOF,OSB-		$0.00	0.01	$0.00
			ENOF,OSB-		$0.00	0.05	$0.00
			ENOF,OSB-		$0.00	0.02	$0.00
			ENOF,PPC		$0.00	-0.06	$0.00
			ENOF,PPC		$0.00	-0.06	$0.00
			ENOF,PPC		$0.00	-0.06	$0.00
			ENOF,PPC		$0.00	-0.02	$0.00
			ENOF,PPC		$0.00	-0.10	$0.00
			ENOF,PPC		$0.00	-0.10	$0.00
			ENOF,PPC		$0.00	-0.10	$0.00
			ENOF,PPC		$0.00	-0.10	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	0.00	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	0.00	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	0.00	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.03	$0.00
			ENOF,QPS		$0.00	-0.03	$0.00
			ENOF,QPS		$0.00	-0.03	$0.00
			ENOF,QPS		$0.00	-0.01	$0.00
			ENOF,QPS		$0.00	-0.05	$0.00
			ENOF,QPS		$0.00	-0.05	$0.00
			ENOF,QPS		$0.00	-0.05	$0.00
			ENOF,QPS		$0.00	-0.05	$0.00
			ENOF,SNU		$0.00	-0.01	$0.00
			ENOF,SNU		$0.00	-0.01	$0.00
			ENOF,SNU		$0.00	-0.01	$0.00
			ENOF,SNU		$0.00	0.00	$0.00
			ENOF,SNU		$0.00	-0.02	$0.00
			ENOF,SNU		$0.00	-0.02	$0.00
			ENOF,SNU		$0.00	-0.02	$0.00
			ENOF,SNU		$0.00	-0.02	$0.00
			ENOF,AGL		$0.00	0.06	$0.00
			ENOF,AGL		$0.00	0.05	$0.00
			ENOF,CLE		$0.00	0.03	$0.00
			ENOF,CLE		$0.00	0.02	$0.00
			ENOF,DRY		$0.00	0.02	$0.00
			ENOF,DRY		$0.00	0.02	$0.00
			ENOF,DRY		$0.00	0.02	$0.00
			ENOF,DRY		$0.00	0.02	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,DRY		$0.00	0.02	$0.00
			ENOF,DRY		$0.00	0.02	$0.00
			ENOF,LAD		$0.00	-0.02	$0.00
			ENOF,LAD		$0.00	0.00	$0.00
			ENOF,LAD		$0.00	0.00	$0.00
			ENOF,LAD		$0.00	0.00	$0.00
			ENOF,LAD		$0.00	-0.01	$0.00
			ENOF,LAD		$0.00	-0.01	$0.00
			ENOF,LAD		$0.00	-0.02	$0.00
			ENOF,LAD		$0.00	0.00	$0.00
			ENOF,LAD		$0.00	0.00	$0.00
			ENOF,LAD		$0.00	0.00	$0.00
			ENOF,LAD		$0.00	-0.01	$0.00
			ENOF,LAD		$0.00	-0.01	$0.00
			ENOF,LKB		$0.00	-0.08	$0.00
			ENOF,LKB		$0.00	-0.01	$0.00
			ENOF,LKB		$0.00	-0.01	$0.00
			ENOF,LKB		$0.00	-0.01	$0.00
			ENOF,LKB		$0.00	-0.04	$0.00
			ENOF,LKB		$0.00	-0.02	$0.00
			ENOF,LKB		$0.00	-0.02	$0.00
			ENOF,LKB		$0.00	0.00	$0.00
			ENOF,LKB		$0.00	0.00	$0.00
			ENOF,LKB		$0.00	0.00	$0.00
			ENOF,LKB		$0.00	-0.01	$0.00
			ENOF,LKB		$0.00	0.00	$0.00
			ENOF,MINT		$0.00	-0.04	$0.00
			ENOF,MINT		$0.00	0.00	$0.00
			ENOF,MINT		$0.00	0.00	$0.00
			ENOF,MINT		$0.00	-0.02	$0.00
			ENOF,MINT		$0.00	-0.01	$0.00
			ENOF,NPS		$0.00	-0.12	$0.00
			ENOF,NPS		$0.00	-0.01	$0.00
			ENOF,NPS		$0.00	-0.01	$0.00
			ENOF,NPS		$0.00	-0.01	$0.00
			ENOF,NPS		$0.00	-0.06	$0.00
			ENOF,NPS		$0.00	-0.03	$0.00

Spot Price **$7477/MWh**

4 pm South Australia

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
15:35	$10 759.99	AGL (SA)	TORRA1	Energy	$10 759.99	0.33	$3550.80
		AGL (SA)	TORRA2	Energy	$10 759.99	0.33	$3550.80
		AGL (SA)	TORRA3	Energy	$10 759.99	0.33	$3550.80
15:40	$10 759.99	AGL (SA)	TORRA1	Energy	$10 759.99	0.33	$3550.80
		AGL (SA)	TORRA2	Energy	$10 759.99	0.33	$3550.80
		AGL (SA)	TORRA3	Energy	$10 759.99	0.33	$3550.80
		CS Energy	GSTONE6	Raise 6 sec	$0.50	0.33	$0.17
		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
15:45	$10 759.99	AGL (SA)	TORRA1	Energy	$10 759.99	0.33	$3550.80
		AGL (SA)	TORRA2	Energy	$10 759.99	0.33	$3550.80
		AGL (SA)	TORRA3	Energy	$10 759.99	0.33	$3550.80
15:50	$590.07	EnergyAustralia	AGLHAL	Energy	$590.07	1.00	$590.07
15:55	-$831.83	Meridian Energy	MERCER01	Energy	-$996.71	0.83	-$827.27
16:00	-$1000.00	Origin Energy	QPS2	Energy	-$1000.00	0.03	-$30.00
		Origin Energy	QPS3	Energy	-$1000.00	0.03	-$30.00
		Origin Energy	QPS4	Energy	-$1000.00	0.03	-$30.00
		Origin Energy	QPS5	Energy	-$1000.00	0.16	-$160.00
		Pacific Hydro	CLEMGPWF	Energy	-$1000.00	0.07	-$70.00
		EnergyAustralia	AGLHAL	Energy	-$1000.00	0.16	-$160.00
		GDF Suez	PPCCGT	Energy	-$1000.00	0.31	-$310.00
		GDF Suez	DRYCGT1	Energy	-$1000.00	0.05	-$50.00
		GDF Suez	DRYCGT2	Energy	-$1000.00	0.05	-$50.00
		GDF Suez	DRYCGT3	Energy	-$1000.00	0.05	-$50.00
		GDF Suez	SNUG1	Energy	-$1000.00	0.07	-$70.00
			ENOF,AGLHA		$0.00	7.77	$0.00
			ENOF,AGLHA		$0.00	7.77	$0.00
			ENOF,AGLHA		$0.00	24.72	$0.00
			ENOF,AGLHA		$0.00	6.06	$0.00
			ENOF,AGLHA		$0.00	11.50	$0.00
			ENOF,AGLHA		$0.00	38.87	$0.00
			ENOF,AGLHA		$0.00	18.66	$0.00
			ENOF,AGLHA		$0.00	18.66	$0.00
			ENOF,AGLHA		$0.00	18.66	$0.00
			ENOF,AGLHA		$0.00	7.00	$0.00
			ENOF,AGLHA		$0.00	31.09	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,AGLHA		$0.00	31.09	$0.00
			ENOF,AGLHA		$0.00	31.09	$0.00
			ENOF,AGLHA		$0.00	31.09	$0.00
			ENOF,CLEMG		$0.00	3.54	$0.00
			ENOF,CLEMG		$0.00	3.54	$0.00
			ENOF,CLEMG		$0.00	11.27	$0.00
			ENOF,CLEMG		$0.00	2.76	$0.00
			ENOF,CLEMG		$0.00	5.25	$0.00
			ENOF,CLEMG		$0.00	17.72	$0.00
			ENOF,CLEMG		$0.00	8.51	$0.00
			ENOF,CLEMG		$0.00	8.51	$0.00
			ENOF,CLEMG		$0.00	8.51	$0.00
			ENOF,CLEMG		$0.00	3.19	$0.00
			ENOF,CLEMG		$0.00	14.18	$0.00
			ENOF,CLEMG		$0.00	14.18	$0.00
			ENOF,CLEMG		$0.00	14.18	$0.00
			ENOF,CLEMG		$0.00	14.18	$0.00
			ENOF,DRYC		$0.00	2.36	$0.00
			ENOF,DRYC		$0.00	2.36	$0.00
			ENOF,DRYC		$0.00	7.51	$0.00
			ENOF,DRYC		$0.00	1.84	$0.00
			ENOF,DRYC		$0.00	3.50	$0.00
			ENOF,DRYC		$0.00	11.82	$0.00
			ENOF,DRYC		$0.00	5.67	$0.00
			ENOF,DRYC		$0.00	5.67	$0.00
			ENOF,DRYC		$0.00	5.67	$0.00
			ENOF,DRYC		$0.00	2.13	$0.00
			ENOF,DRYC		$0.00	9.45	$0.00
			ENOF,DRYC		$0.00	9.45	$0.00
			ENOF,DRYC		$0.00	9.45	$0.00
			ENOF,DRYC		$0.00	9.45	$0.00
			ENOF,DRYC		$0.00	2.36	$0.00
			ENOF,DRYC		$0.00	2.36	$0.00
			ENOF,DRYC		$0.00	7.51	$0.00
			ENOF,DRYC		$0.00	1.84	$0.00
			ENOF,DRYC		$0.00	3.50	$0.00
			ENOF,DRYC		$0.00	11.82	$0.00
			ENOF,DRYC		$0.00	5.67	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,DRYC		$0.00	5.67	$0.00
			ENOF,DRYC		$0.00	5.67	$0.00
			ENOF,DRYC		$0.00	2.13	$0.00
			ENOF,DRYC		$0.00	9.45	$0.00
			ENOF,DRYC		$0.00	9.45	$0.00
			ENOF,DRYC		$0.00	9.45	$0.00
			ENOF,DRYC		$0.00	9.45	$0.00
			ENOF,DRYC		$0.00	2.55	$0.00
			ENOF,DRYC		$0.00	2.55	$0.00
			ENOF,DRYC		$0.00	8.11	$0.00
			ENOF,DRYC		$0.00	1.99	$0.00
			ENOF,DRYC		$0.00	3.77	$0.00
			ENOF,DRYC		$0.00	12.75	$0.00
			ENOF,DRYC		$0.00	6.12	$0.00
			ENOF,DRYC		$0.00	6.12	$0.00
			ENOF,DRYC		$0.00	6.12	$0.00
			ENOF,DRYC		$0.00	2.29	$0.00
			ENOF,DRYC		$0.00	10.20	$0.00
			ENOF,DRYC		$0.00	10.20	$0.00
			ENOF,DRYC		$0.00	10.20	$0.00
			ENOF,DRYC		$0.00	10.20	$0.00
			ENOF,NPS1,1		$0.00	-82.40	$0.00
			ENOF,NPS1,1		$0.00	-8.24	$0.00
			ENOF,NPS1,1		$0.00	-7.91	$0.00
			ENOF,NPS1,1		$0.00	-7.91	$0.00
			ENOF,NPS1,1		$0.00	-42.19	$0.00
			ENOF,NPS1,1		$0.00	-17.80	$0.00
			ENOF,OSB-		$0.00	-63.43	$0.00
			ENOF,OSB-		$0.00	-6.34	$0.00
			ENOF,OSB-		$0.00	-6.09	$0.00
			ENOF,OSB-		$0.00	-6.09	$0.00
			ENOF,OSB-		$0.00	-32.48	$0.00
			ENOF,OSB-		$0.00	-13.70	$0.00
			ENOF,PPCCG		$0.00	37.31	$0.00
			ENOF,PPCCG		$0.00	37.31	$0.00
			ENOF,PPCCG		$0.00	37.31	$0.00
			ENOF,PPCCG		$0.00	13.99	$0.00
			ENOF,PPCCG		$0.00	62.19	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,PPCCG		$0.00	62.19	$0.00
			ENOF,PPCCG		$0.00	62.19	$0.00
			ENOF,PPCCG		$0.00	62.19	$0.00
			ENOF,QPS2,1		$0.00	3.73	$0.00
			ENOF,QPS2,1		$0.00	3.73	$0.00
			ENOF,QPS2,1		$0.00	3.73	$0.00
			ENOF,QPS2,1		$0.00	1.40	$0.00
			ENOF,QPS2,1		$0.00	6.22	$0.00
			ENOF,QPS2,1		$0.00	6.22	$0.00
			ENOF,QPS2,1		$0.00	6.22	$0.00
			ENOF,QPS2,1		$0.00	6.22	$0.00
			ENOF,QPS3,1		$0.00	3.58	$0.00
			ENOF,QPS3,1		$0.00	3.58	$0.00
			ENOF,QPS3,1		$0.00	3.58	$0.00
			ENOF,QPS3,1		$0.00	1.34	$0.00
			ENOF,QPS3,1		$0.00	5.97	$0.00
			ENOF,QPS3,1		$0.00	5.97	$0.00
			ENOF,QPS3,1		$0.00	5.97	$0.00
			ENOF,QPS3,1		$0.00	5.97	$0.00
			ENOF,QPS4,1		$0.00	3.58	$0.00
			ENOF,QPS4,1		$0.00	3.58	$0.00
			ENOF,QPS4,1		$0.00	3.58	$0.00
			ENOF,QPS4,1		$0.00	1.34	$0.00
			ENOF,QPS4,1		$0.00	5.97	$0.00
			ENOF,QPS4,1		$0.00	5.97	$0.00
			ENOF,QPS4,1		$0.00	5.97	$0.00
			ENOF,QPS4,1		$0.00	5.97	$0.00
			ENOF,QPS5,1		$0.00	19.10	$0.00
			ENOF,QPS5,1		$0.00	19.10	$0.00
			ENOF,QPS5,1		$0.00	19.10	$0.00
			ENOF,QPS5,1		$0.00	7.16	$0.00
			ENOF,QPS5,1		$0.00	31.84	$0.00
			ENOF,QPS5,1		$0.00	31.84	$0.00
			ENOF,QPS5,1		$0.00	31.84	$0.00
			ENOF,QPS5,1		$0.00	31.84	$0.00
			ENOF,SNUG1		$0.00	8.06	$0.00
			ENOF,SNUG1		$0.00	8.06	$0.00
			ENOF,SNUG1		$0.00	8.06	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,SNUG1		$0.00	3.02	$0.00
			ENOF,SNUG1		$0.00	13.43	$0.00
			ENOF,SNUG1		$0.00	13.43	$0.00
			ENOF,SNUG1		$0.00	13.43	$0.00
			ENOF,SNUG1		$0.00	13.43	$0.00
			ENOF,AGLHA		$0.00	-41.20	$0.00
			ENOF,AGLHA		$0.00	-31.72	$0.00
			ENOF,CLEMG		$0.00	-18.79	$0.00
			ENOF,CLEMG		$0.00	-14.46	$0.00
			ENOF,DRYC		$0.00	-12.52	$0.00
			ENOF,DRYC		$0.00	-9.64	$0.00
			ENOF,DRYC		$0.00	-12.52	$0.00
			ENOF,DRYC		$0.00	-9.64	$0.00
			ENOF,DRYC		$0.00	-13.51	$0.00
			ENOF,DRYC		$0.00	-10.40	$0.00
			ENOF,LADBR		$0.00	15.55	$0.00
			ENOF,LADBR		$0.00	1.55	$0.00
			ENOF,LADBR		$0.00	1.49	$0.00
			ENOF,LADBR		$0.00	1.49	$0.00
			ENOF,LADBR		$0.00	7.96	$0.00
			ENOF,LADBR		$0.00	3.36	$0.00
			ENOF,LADBR		$0.00	15.55	$0.00
			ENOF,LADBR		$0.00	1.55	$0.00
			ENOF,LADBR		$0.00	1.49	$0.00
			ENOF,LADBR		$0.00	1.49	$0.00
			ENOF,LADBR		$0.00	7.96	$0.00
			ENOF,LADBR		$0.00	3.36	$0.00
			ENOF,LKBON		$0.00	49.44	$0.00
			ENOF,LKBON		$0.00	4.94	$0.00
			ENOF,LKBON		$0.00	4.75	$0.00
			ENOF,LKBON		$0.00	4.75	$0.00
			ENOF,LKBON		$0.00	25.31	$0.00
			ENOF,LKBON		$0.00	10.68	$0.00
			ENOF,LKBON		$0.00	12.13	$0.00
			ENOF,LKBON		$0.00	1.21	$0.00
			ENOF,LKBON		$0.00	1.16	$0.00
			ENOF,LKBON		$0.00	1.16	$0.00
			ENOF,LKBON		$0.00	6.21	$0.00

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
			ENOF,LKBON		$0.00	2.62	$0.00
			ENOF,MINTA		$0.00	23.01	$0.00
			ENOF,MINTA		$0.00	2.30	$0.00
			ENOF,MINTA		$0.00	2.21	$0.00
			ENOF,MINTA		$0.00	2.21	$0.00
			ENOF,MINTA		$0.00	11.78	$0.00
			ENOF,MINTA		$0.00	4.97	$0.00
			ENOF,NPS2,1		$0.00	77.74	$0.00
			ENOF,NPS2,1		$0.00	7.77	$0.00
			ENOF,NPS2,1		$0.00	7.46	$0.00
			ENOF,NPS2,1		$0.00	7.46	$0.00
			ENOF,NPS2,1		$0.00	39.80	$0.00
			ENOF,NPS2,1		$0.00	16.79	$0.00

Spot Price **$5173/MWh**

Appendix D: Closing bids

Figures D1 to D4 highlight the half hour closing bids for participants in Victoria and South Australia with 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 D1 - AGL (Loy Yang A, Macarthur, Oaklands Hill, Somerton, Dartmouth, Eildon, McKay and West Kiewa) closing bid prices, dispatch and spot price - Victoria

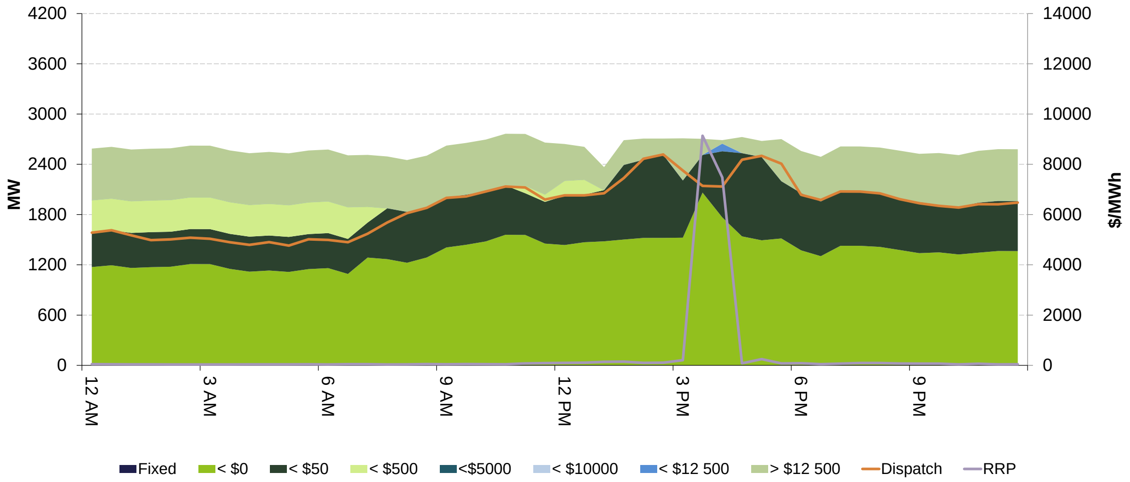


Figure D2 - AGL (Torrens Island, The Bluff, Hallett and North Brown Hill,) closing bid prices, dispatch and spot price – South Australia

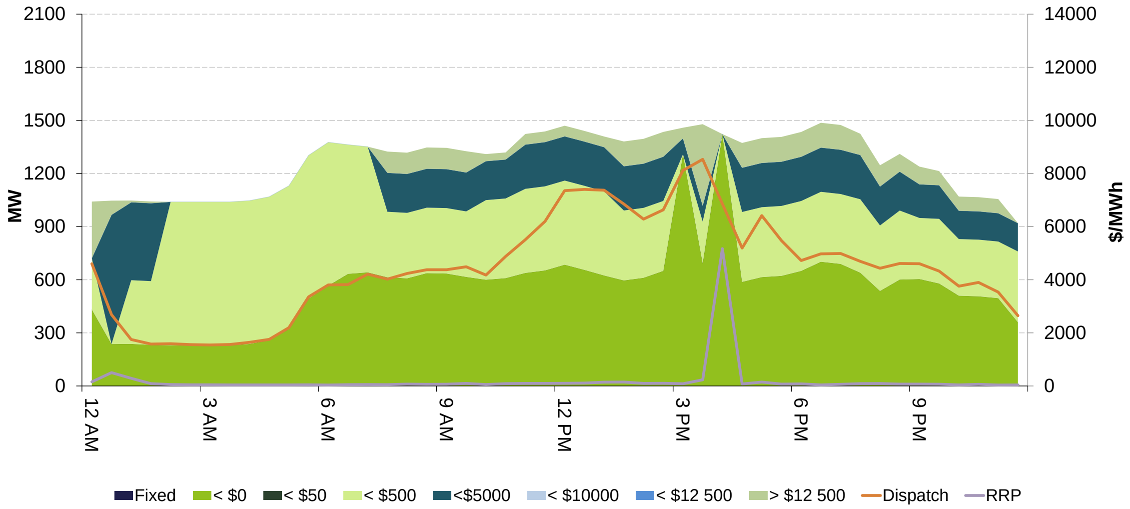


Figure D3 – GDF Suez (Pelican Point, Dry Creek, Mintaro, Port Lincoln and Snuggery) closing bid prices, dispatch and spot price – South Australia

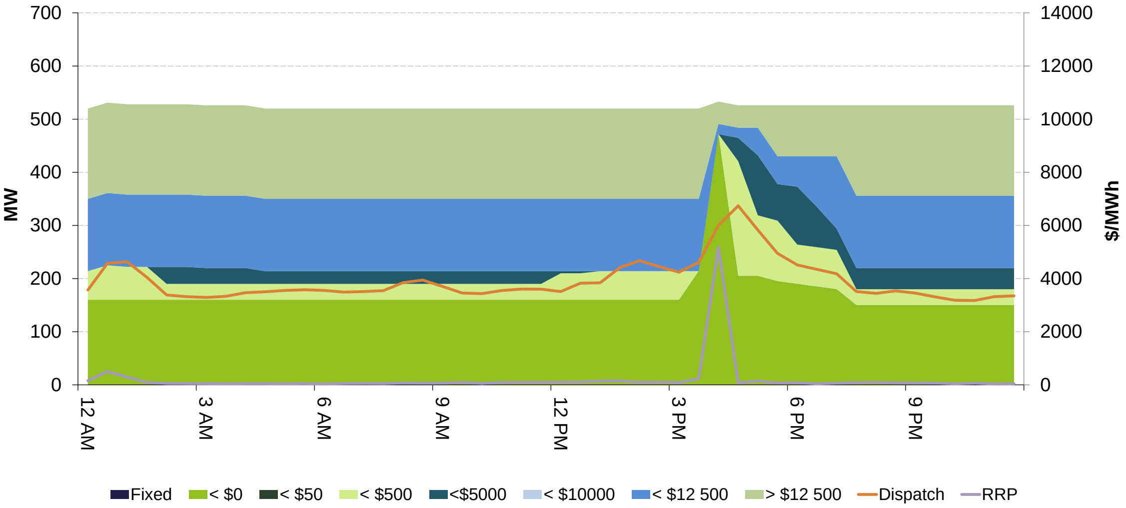
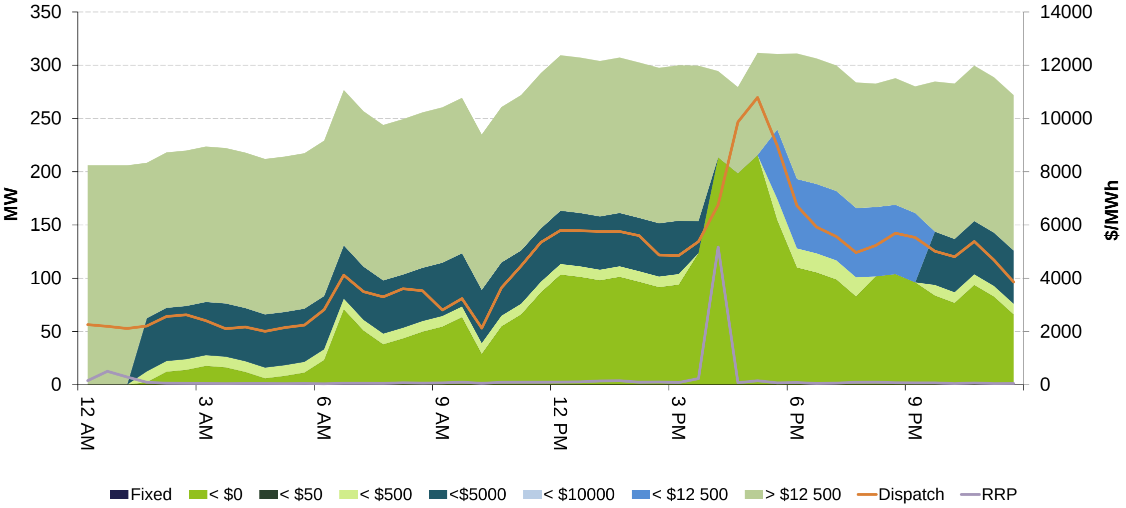


Figure D4 – EnergyAustralia (Hallett and Waterloo) closing bid prices, dispatch and spot price – South Australia



Appendix E: Relevant Market Notices

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

Market Notice	Type	Date of issue	Last Changed
51316	Reclassify contingency	13/01/2016 15:16:45	13/01/2016 15:16:45

External Reference

Reclassification of a Non-Credible Contingency Event: Dederang - Glenrowan No.1 and No.3 220 kV Lines in Victoria due to Lightning

Reason

Reclassification of a Non-Credible Contingency Event: Dederang - Glenrowan No.1 and No.3 220 kV Lines in Victoria due to Lightning.

Lightning is occurring near the Dederang - Glenrowan No.1 and No.3 220 kV Lines.

AEMO considers the simultaneous trip of those circuits to now be more likely.

Therefore AEMO has reclassified this as a credible contingency event from 1510 hrs Wednesday, 13 January 2016 until further notice.

Constraint Set V-DDGN_N-2 invoked.

This Constraint Set contains equations with the following interconnectors on the LHS:

V-S-MNSP1

V-SA

VIC1-NSW1

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
51318	Reclassify contingency	13/01/2016 15:17:01	13/01/2016 15:17:01

External Reference

Reclassification of a Non-Credible Contingency Event: Eildon - Mt. Beauty No.1 and No.2 220 kV Lines in Victoria due to Lightning

Reason

AEMO ELECTRICITY MARKET NOTICE

Reclassification of a Non-Credible Contingency Event: Eildon - Mt. Beauty No.1 and No.2 220 kV Lines in Victoria due to Lightning.

Lightning is occurring near the Eildon - Mt. Beauty No.1 and No.2 220 kV Lines.

AEMO considers the simultaneous trip of those circuits to now be more likely.

Therefore AEMO has reclassified this as a credible contingency event from 5100 hrs Wednesday, 13 January 2016 until further notice.

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
51319	Reclassify contingency	13/01/2016 15:34:27	13/01/2016 15:34:27

External Reference

Reclassification of a Non-Credible Contingency Event: Eildon - Mt. Beauty No.1 and No.2 220 kV Lines in Victoria due to Lightning

Reason

AEMO ELECTRICITY MARKET NOTICE

Update :Reclassification of a Non-Credible Contingency Event: Eildon - Mt. Beauty No.1 and No.2 220 kV Lines in Victoria due to Lightning.

Lightning is occurring near the Eildon - Mt. Beauty No.1 and No.2 220 kV Lines.

AEMO considers the simultaneous trip of those circuits to now be more likely.

Therefore AEMO has reclassified this as a credible contingency event from 1510 hrs Wednesday, 13 January 2016 until further notice.

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
51323	Reclassify contingency	13/01/2016 15:52:22	13/01/2016 15:52:22

External Reference

Cancellation of the Reclassification of a Non-Credible Contingency Event: Dederang - Glenrowan No.1 and No.3 220 kV Lines in Victoria due to Lightning

Reason

AEMO ELECTRICITY MARKET NOTICE

Cancellation of the Reclassification of a Non-Credible Contingency Event: Dederang - Glenrowan No.1 and No.3 220 kV Lines in Victoria due to Lightning.

Refer to AEMO Electricity Market Notice No. 51316

There is no longer any lightning activity in the vicinity of the Dederang - Glenrowan No.1 and No.3 220 kV Lines.

AEMO has cancelled the reclassification of the simultaneous trip of those circuits as a credible contingency event at 1550 hrs. Wednesday, 13 January 2016

Constraint Set V-DDGN_N-2 revoked.

Manager NEM Real Time Operations

Market Notice	Type	Date of issue	Last Changed
51330	Reclassify contingency	13/01/2016 18:03:26	13/01/2016 18:03:26

External Reference

Cancellation of the Reclassification of a Non-Credible Contingency Event: Eildon - Mt. Beauty No. 1 and No. 2 220 kV Lines in Victoria due to Lightning.

Reason

AEMO ELECTRICITY MARKET NOTICE

Cancellation of the Reclassification of a Non-Credible Contingency Event: Eildon - Mt. Beauty No. 1 and No. 2 220 kV Lines in Victoria due to Lightning.

Refer AEMO Electricity Market Notice 51319

There is no longer any lightning activity in the vicinity of the Eildon - Mt. Beauty No. 1 and No. 2 220 kV Lines.

AEMO has cancelled the reclassification of the simultaneous trip of those circuits as a credible contingency event at 1745 hrs. Wednesday, 13 January 2016

Manager NEM Real Time Operations
