Electricity spot prices above $5000/MWh

New South Wales, 23 September 2015

24 November 2015

AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
MELBOURNE VIC 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au
AER Reference: 58425-D15/153101

Amendment Record

Version	Date	Pages
1 version for publication	23/11/2015	19

Contents

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.

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

2 Summary

On 23 September 2015, the spot price in New South Wales exceeded $5000/MWh for the 6.30 pm and 7 pm trading intervals. Spot prices in the region had been between $40/MWh and $60/MWh for the majority of the day, with the exception of a short period during the morning demand rise when spot prices reached $180/MWh. Demand and available capacity were what would be expected for this time of year.

The spot price in New South Wales reached $13 420/MWh and $6717/MWh for the 6.30 pm and 7 pm trading intervals respectively. The dispatch price exceeded $13 400/MWh between 6.05 pm and 6.45 pm, inclusive. Both four and twelve hours ahead, the forecast spot price for these trading intervals was around $300/MWh.

Network outages contributed to the outcomes during the day. A planned outage on the Canberra to Upper Tumut line forced flows from New South Wales into Victoria across the Vic-NSW interconnector and constrained down low-priced generation. This outage commenced the day before. During the afternoon of 23 September, a short notice outage was required on an Armidale to Bulli Creek transmission line limiting transfers into New South Wales from Queensland across the QNI. The ongoing partial outage of the Terranora interconnector set its capability to around 100 MW of imports from Queensland to New South Wales. Together these network outages limited imports into New South Wales.

The rebidding of capacity from low prices to high prices did not contribute to the high prices but rebidding of generator ramp rates did prolong high prices. The supply curve in New South Wales was very steep with no capacity priced between $300/MWh and $13 100/MWh. This situation was exacerbated by around 900 MW of low-priced capacity not being available for dispatch because of either ramp rate limits or network constraints.

At the same time as the high energy prices in New South Wales, local 6 Second Lower Frequency Control Ancillary Service (FCAS) prices in Queensland exceeded $5000/MW.

3 Analysis

Table 1 shows actual and forecast spot price, demand and availability for each high priced trading interval. The spot price in New South Wales exceeded $5000/MWh for the 6.30 pm and 7 pm trading intervals, however the high prices were not forecast four or twelve hours ahead of dispatch.

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

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	13 420	317	314	9963	9736	9723	11 956	11 960	12 010
7 pm	6717	338	321	10 169	9885	9861	11 952	11 948	11 993

Network availability and supply-demand conditions were such 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.

The difference between forecast and actual demand was a contributing factor to the high prices. The contribution of demand is discussed in greater detail in Section 3.2.

3.1 Network Availability

This section examines the change in network capability approaching the event and its contribution to price outcomes. Table 2 shows the net import limit into New South Wales was up to 823 MW lower than that forecast four hours ahead, while Net imports were up to 438 MW lower than those forecast four hours ahead.

Table 2: Actual and forecast network capability

Trading interval	Net Imports (MW)			Net Import limit (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6.30 pm	112	550	606	112	935	981
7 pm	308	715	660	377	980	923

There were network constraints which limited flows into New South Wales on each of the three interconnectors connecting the region to Victoria and Queensland.

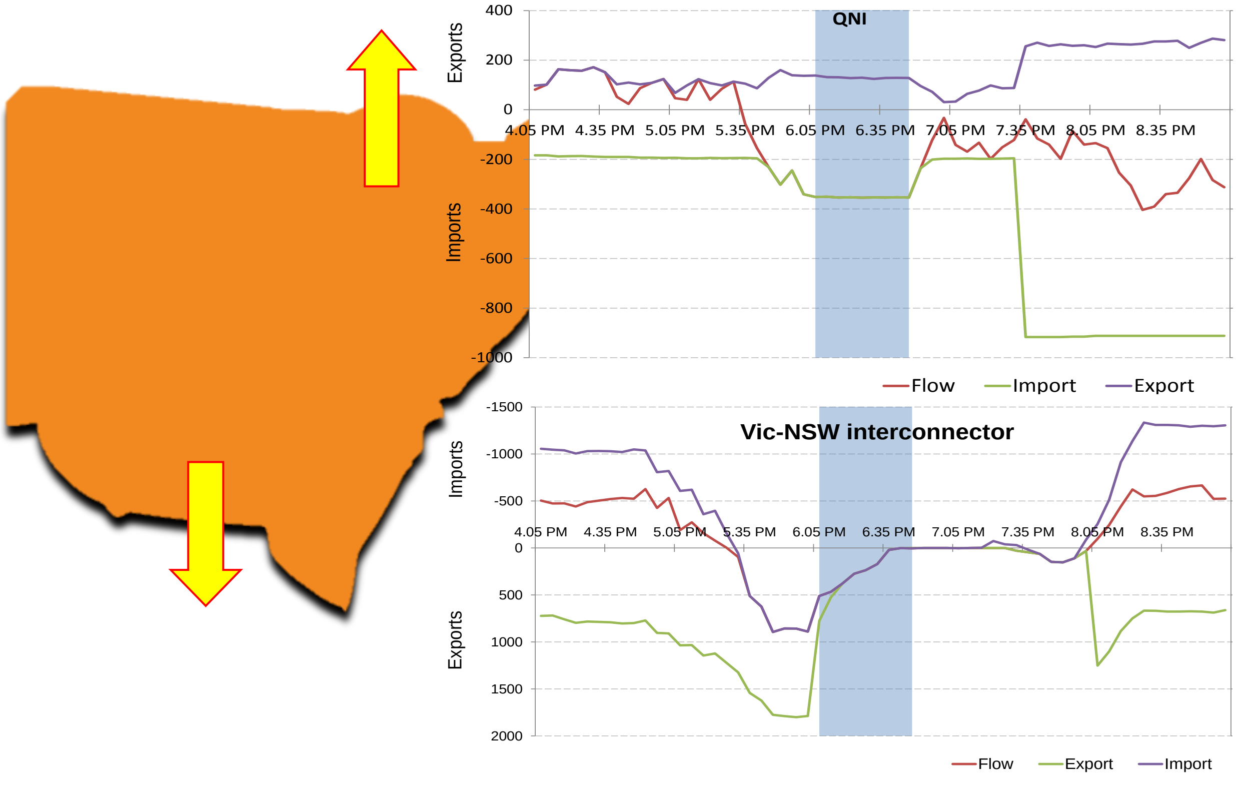
On the previous day, a planned outage of the Upper Tumut to Canberra No.1 line prompted AEMO to invoke a constraint on the Vic-NSW interconnector. This constraint optimises over 3000 MW of generation in New South Wales against flows on the Vic-NSW interconnector. When the high prices occurred, this constraint forced flows, counter-price, out of New South Wales into Victoria by up to 512 MW. The subsequent accrual of negative settlement residues (from the counter price flows) led to AEMO invoking a negative residue management constraint which bound from 6.15 pm. These two constraints together reduced the output of lower priced generation in New South Wales despite the high prices. Flows across the Vic-NSW interconnector were held to around zero from 6.40 pm until 8 pm. A total negative settlement of approximately $3.5 million accrued for the 6.30 pm and 7 pm trading intervals.

A constraint invoked by AEMO at around 4 pm to manage a short notice outage of one of the Armidale to Bulli Creek lines reduced the import limit on QNI into New South Wales by 555 MW. Consequently flows on QNI were 186 MW lower than forecast four hours ahead. This outage also resulted in the high FCAS prices in Queensland.

Flows on the Terranora interconnector between Queensland and New South Wales have been limited for some time as a result of damage to two of the three cables that comprise the interconnector. This constraint limited imports into New South Wales by two thirds to around 100 MW at the time of high prices, which was as forecast.

Figure 1 shows the import and export limit, and target flows of the Vic-NSW and QNI interconnectors which connect NSW to neighbouring regions. New South Wales was importing around 370 MW at the time of high prices across QNI.

Figure 1: New South Wales export/import limits and target flows



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

Supply curves illustrate any potential sensitivity 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 New South Wales.

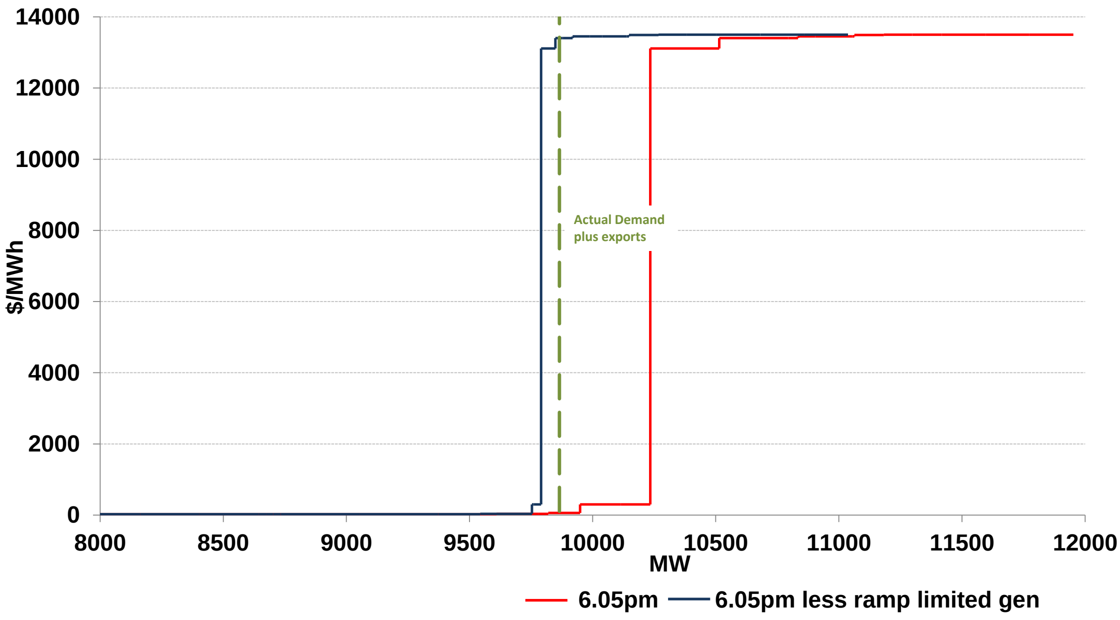
We have examined in detail the supply curve for the 6.05 pm dispatch interval (shown in Figure 2) as it is typical of the situation for the period of high prices.

The red line in Figure 2 shows the actual supply curve for all generators in New South Wales based on their offers. The vertical section of the curve at about 10 250 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 above, constraints managing the Canberra to Tumut outage and the accrual of negative residues constrained low-priced generation in the south of New South Wales reducing the capacity available for dispatch (effective capacity). Furthermore other generation at Mount Piper and Tallawarra priced below the dispatch price had limited “ramp up” capability. These reductions in effective capacity shift the supply curve to the left by around 900 MW during the period of high prices (represented by the blue line in Figure 2).

The third line on the graph in Figure 2, represents New South Wales demand plus exports (denoted by the dashed green line), that is the effective target output from the generators in the region.

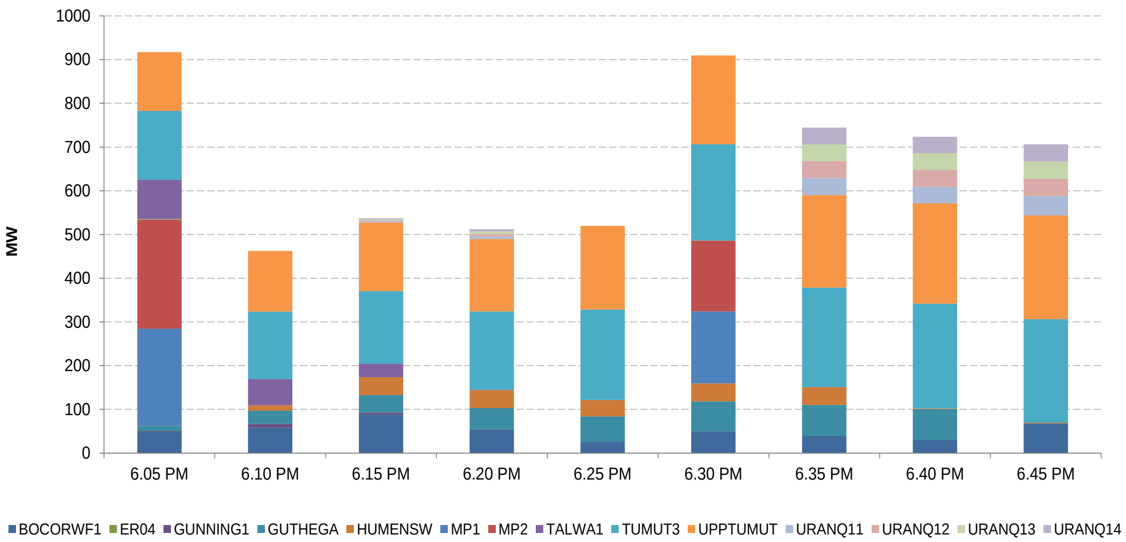
Figure 2: Actual and effective supply curves for 6.05 pm dispatch interval



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 (around $35/MWh). 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 9800 MW.

Figure 3 shows capacity, by unit, that was priced less than the dispatch price that was either constrained down by network or negative residue management constraints or was ramp up limited. Tumut 3, Upper Tumut and Guthega were constrained down for the entire time of high prices by as much as 540 MW in total. The Boco Rock and Gunning wind farms were also constrained down for a majority of the high price period.

Figure 3: Unit capacity unable to be accessed by the market



3.2.2 Rebidding

There was no significant rebidding of capacity from low to high prices that contributed to the high priced outcomes. The significant rebidding that affected the high prices was the rebidding of ramp down rates to the minimum allowed without a technical reason.[2]

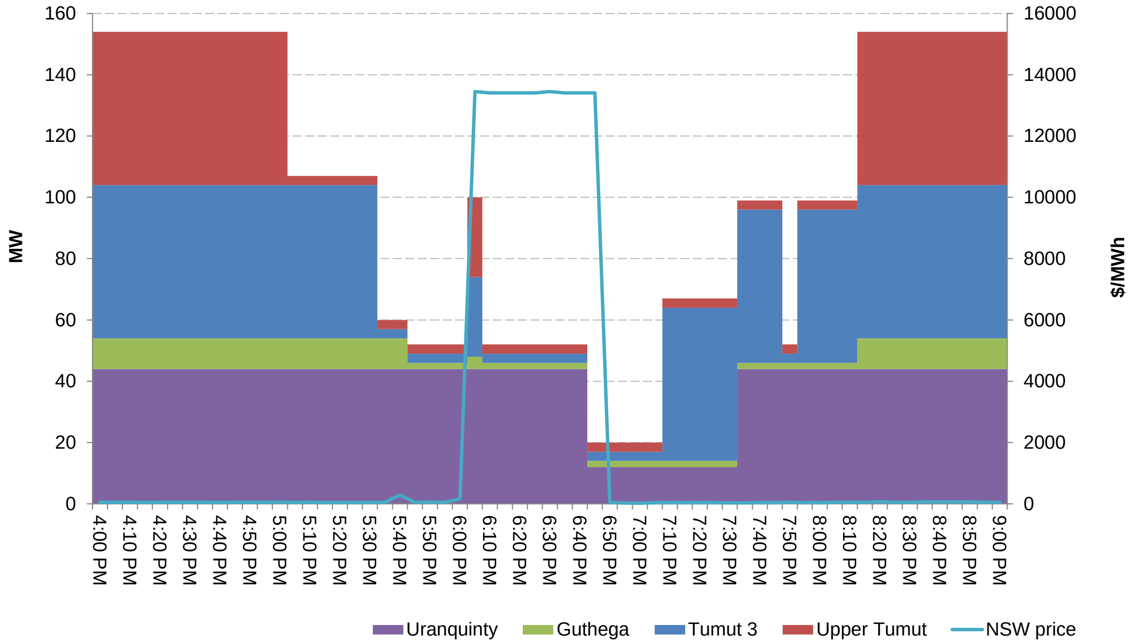
In response to the constraint managing the Canberra to Upper Tumut line outage, just before the high prices occurred, Snowy Hydro rebid the ramp down rates of Tumut 3, Upper Tumut and Guthega down to the minimum allowable. Similarly, towards the end of the high price event, when the constraint managing negative residues across the Vic-NSW interconnector was invoked, Origin reduced the ramp down rates of its Uranquinty units.

Figure 4 shows the cumulative ramp down rate in MW/min of Tumut 3, Upper Tumut, Guthega and Uranquinty. At times these units were being ramped down out of merit

[2] 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.

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.

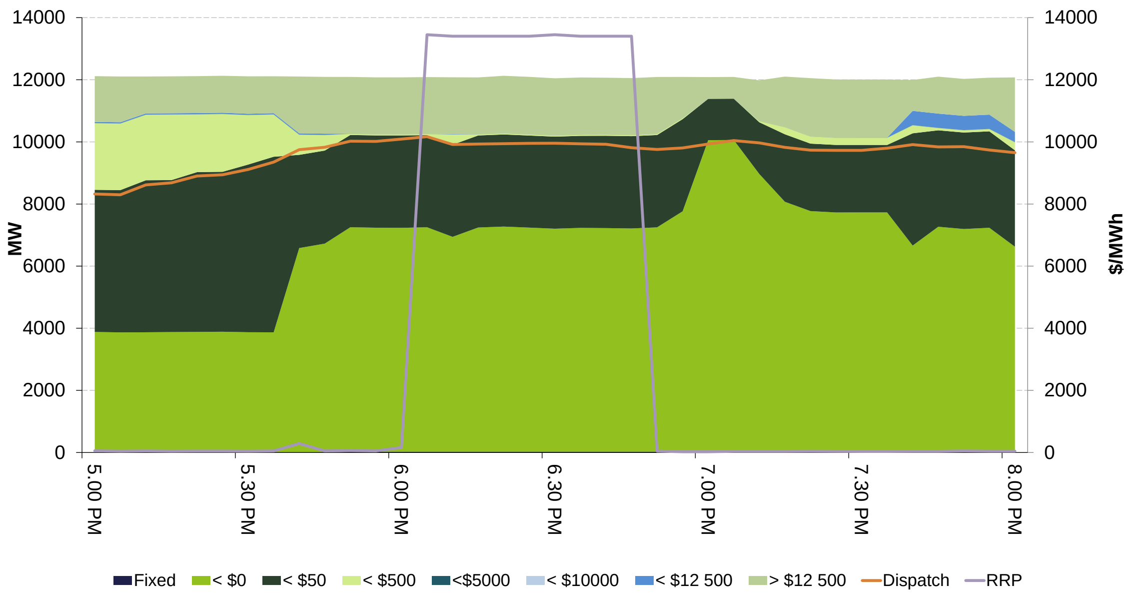
Figure 4: Cumulative ramp down rates for Tumut 3, Upper Tumut, Guthega and Uranquinty.



Note: Ramp rates as per offer

Figure 5 shows the closing bids for participants in New South Wales as well as the total generation output in the region and the dispatch price.

Figure 5: Closing bids of New South Wales generators, output and spot price



There were two rebids made by Snowy Hydro and Origin which repositioned capacity from high prices down to the price floor. These rebids caused a reduction in spot price back to around $40/MWh as shown in Figure 5.

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

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

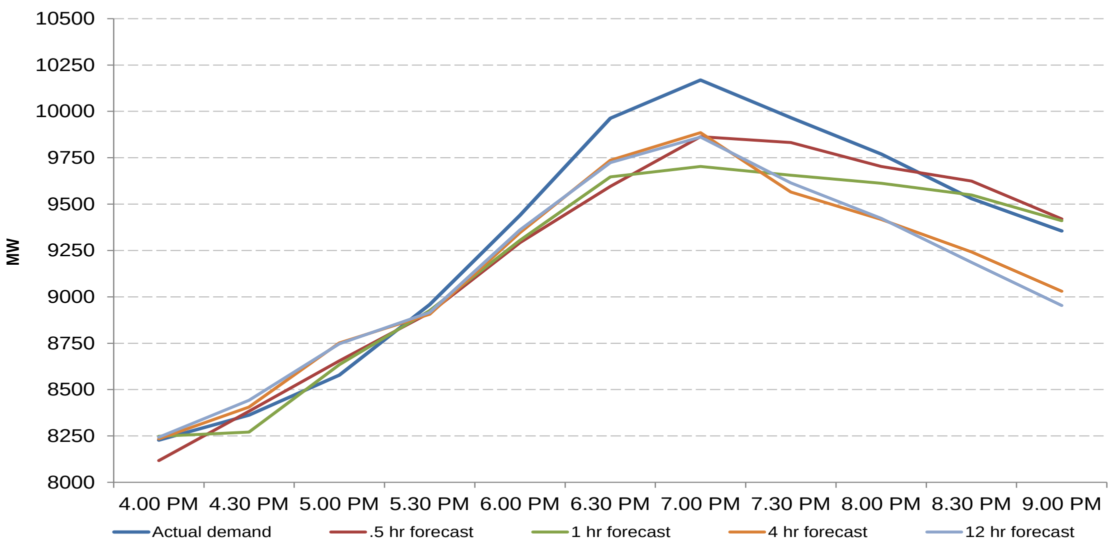
The closing bids for all participants in New South Wales with capacity priced at or above $5000/MWh for the high-price periods are set out in Appendix C.

3.2.3 Forecast demand

Actual New South Wales demand had been trending close to that which had been forecast by AEMO for the two hours preceding 5.30 pm but then started to deviate more markedly from forecast. During the high price trading intervals, actual demand was between 220 MW and 280 MW higher than forecast four hours ahead.

As illustrated by Figure 2, a steep supply curve combined with demand forecast errors could materially impact the accuracy of price forecasts. Figure 6 shows actual demand and forecast demand over several time frames. It shows that actual demand was higher than what was forecast in all timeframes and the demand error increased in forecasts made closer to the actual time. For example, the demand error one hour ahead was 316 MW and 466 MW for the 6.30 pm and 7 pm trading intervals while 12 hours ahead the demand errors were 240 MW and 308 MW respectively.

Figure 6: Actual and forecast demand



For the 6.05 pm dispatch interval, small changes in forecast demand between 5 minute pre-dispatch runs resulted in only minor changes in forecast price. Once forecast demand exceeded 9800 MW in the 6 pm pre-dispatch run, a demand level which coincides with the large step change in the adjusted supply curve in Figure 2, the forecast price spiked to $13 450/MWh (reflecting actual dispatch price).

Table 3 lists the demand forecasts made by AEMO for the 6.05 pm dispatch interval in the previous 5 minute pre-dispatch runs. The table shows that even as close as 10 minutes prior to the 6.05 pm dispatch interval the AEMO forecast was almost 110 MW below what actually occurred.

Table 3: Actual and forecast dispatch price and demand for the 6.05 pm dispatch interval

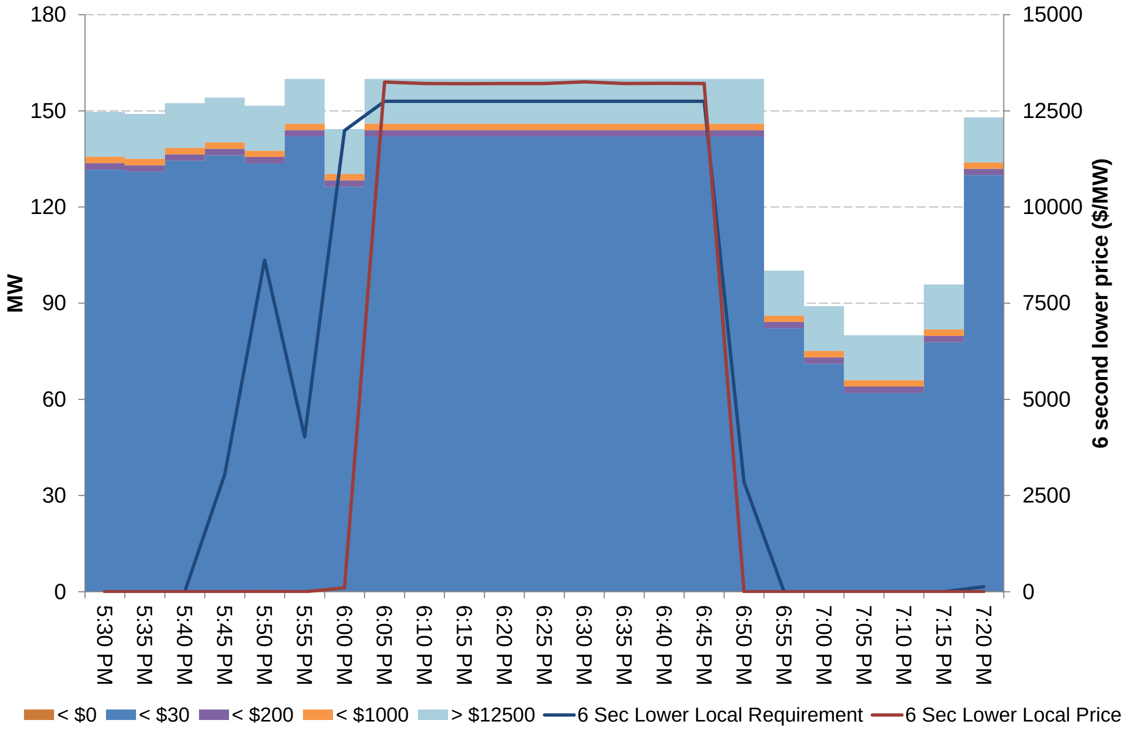
Time	Forecast time	Price ($/MWh)	Demand (MW)
6.05 pm	Actual	13 450	9802
6.05 pm	Published at 18:00:37	13 450	9803
6.00 pm	Published at 17:55:30	61.88	9694
5.55 pm	Published at 17:50:29	49.00	9639
5.50 pm	Published at 17:45:31	84.09	9692
5.45 pm	Published at 17:40:31	61.88	9663

4 FCAS in Queensland

While prices in New South Wales were high, the price in Queensland for the 6 Second Lower service exceeded $5000/MW. The short notice outage on QNI took one circuit of the interconnector out of service. A single contingency would then result in Queensland being islanded and, as is the normal approach, local frequency control ancillary services are required to support the region depending on the direction of flow on QNI. When the high price occurred in New South Wales, Queensland was exporting into New South Wales and consequently contingency FCAS lower services were required in Queensland. While there was sufficient capacity to meet the local requirements, there was only 4 MW of capacity priced between $10/MW and $13 000/MW. As a result of an increase in requirement for 6 Second Lower services and co-optimisation of local services and interconnector flows, the ancillary service price reached $13 251/MW at 6.05 pm and stayed around that price until 6.45 pm.

Figure 7 shows the local FCAS requirement, price and effective availability of 6 Second Lower services for Queensland during the high price period in New South Wales.

Figure 7: Queensland 6 Second Lower requirement, price and availability



Australian Energy Regulator

November 2015

Appendix A: 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 6.30 pm and 7 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6.42 pm	6.50 pm	Snowy Hydro	Colongra	510	13 500	-1000	18:41:A MANAGE CONSTRAINT: NRM_NSW1_VIC1
6.47 pm	6.55 pm	AGL	Liddell	615	13 800	-1000	1847A CONSTRAINT MANAGEMENT - N::V_CNUT_2 SL

Significant ramp rate rebids for 6.30 pm and 7 pm

Submit time	Time effective	Participant	Station	Capacity rebid (MW/min)	Ramp down rate from (MW/min)	Ramp down rate to (MW/min)	Rebid reason
3.23 pm		Snowy Hydro	Tumut 3 Upper Tumut	-47	50	3	15:22:P PLANT TEST RUN: GUTH U1 DELAYED
5.38 pm		Snowy Hydro	Guthega	-8	10	2	17:36 A NSW: 5MPD PRICE $10,918.81 HGR THN 5MPD 17:50@17:31
5.53 pm	6.05 pm	Snowy Hydro	Tumut 3 Upper Tumut	23	3	26	17:51 A NSW: 5MPD PRICE $10,408.05 LWR THN 30MPD 18:05@17:32
5.53 pm	6.05 pm	Snowy Hydro	Guthega	2	2	4	17:51 A NSW: 5MPD PRICE $10,408.05 LWR THN 30MPD 18:05@17:32
6.02 pm	6.10 pm	Snowy Hydro	Tumut 3 Upper Tumut	-23	26	3	18:05 A NSW: ACT PRICE $13,388.12 HGR THN 5MPD 18:05@17:56

Submit time	Time effective	Participant	Station	Capacity rebid (MW/min)	Ramp down rate from (MW/min)	Ramp down rate to (MW/min)	Rebid reason
6.02 pm	6.10 pm	Snowy Hydro	Guthega	-2	4	2	18:05 A NSW: ACT PRICE $13,388.12 HGR THN 5MPD 18:05@17:56
6.34 pm	6.45 pm	Origin	Uranquinty	-8	11	3	1834A CONSTRAINT MANAGEMENT - N::V_CNUT_2 SL

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

6.30 pm

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
18:05	$13 450.00	AGL	BW01	Energy	$13 450.00	0.34	$4573.00
		AGL	BW02	Energy	$13 450.00	0.22	$2959.00
		AGL	BW03	Energy	$13 450.00	0.22	$2959.00
		AGL	BW04	Energy	$13 450.00	0.22	$2959.00
18:10	$13 404.83	EnergyAustralia	MP1	Energy	$13 404.83	0.50	$6702.42
		EnergyAustralia	MP2	Energy	$13 404.83	0.50	$6702.42
18:15	$13 404.83	EnergyAustralia	MP2	Energy	$13 404.83	1.00	$13 404.83
			ENOF,MP1, 10,MP2,10		$0.00	280.00	$0.00
18:20	$13 404.83	EnergyAustralia	MP1	Energy	$13 404.83	0.50	$6702.42
		EnergyAustralia	MP2	Energy	$13 404.83	0.50	$6702.42
18:25	$13 404.83	EnergyAustralia	MP1	Energy	$13 404.83	0.50	$6702.42
		EnergyAustralia	MP2	Energy	$13 404.83	0.50	$6702.42
18:30	$13 450.00	AGL	BW01	Energy	$13 450.00	0.34	$4573.00
		AGL	BW02	Energy	$13 450.00	0.22	$2959.00
		AGL	BW03	Energy	$13 450.00	0.22	$2959.00
		AGL	BW04	Energy	$13 450.00	0.22	$2959.00
Spot Price		**$13 420/MWh**					

7 pm

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
18:35	$13 404.83	EnergyAustralia	MP1	Energy	$13 404.83	0.50	$6702.42
		EnergyAustralia	MP2	Energy	$13 404.83	0.50	$6702.42
18:40	$13 404.83	EnergyAustralia	MP1	Energy	$13 404.83	0.50	$6702.42
		EnergyAustralia	MP2	Energy	$13 404.83	0.50	$6702.42
18:45	$13 404.83	EnergyAustralia	MP1	Energy	$13 404.83	0.50	$6702.42
		EnergyAustralia	MP2	Energy	$13 404.83	0.50	$6702.42
18:50	$43.79	Origin Energy	DDPS1	Energy	$41.91	1.04	$43.59

[3] 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
18:55	$23.17	Braemar Power Projects	BRAEMAR1	Energy	$23.98	0.34	$8.15
		Braemar Power Projects	BRAEMAR2	Energy	$23.98	0.32	$7.67
		Braemar Power Projects	BRAEMAR3	Energy	$23.98	0.32	$7.67
19:00	$22.84	Braemar Power Projects	BRAEMAR1	Energy	$23.98	0.33	$7.91
		Braemar Power Projects	BRAEMAR2	Energy	$23.98	0.31	$7.43
		Braemar Power Projects	BRAEMAR3	Energy	$23.98	0.31	$7.43
Spot Price		**$6717/MWh**					

Appendix C: Closing bids

Figures C1 to C4 highlight the half hour closing bids for participants in New South Wales 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 (Bayswater, Liddell, Hunter Valley) closing bid prices, dispatch and spot price

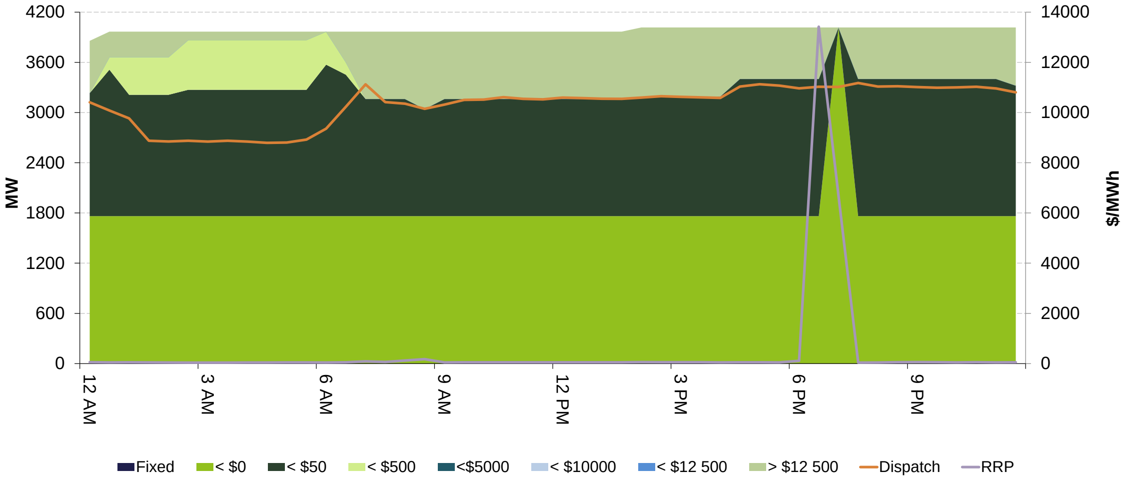


Figure C2 - EnergyAustralia (Mt Piper, Tallawarra) closing bid prices, dispatch and spot price

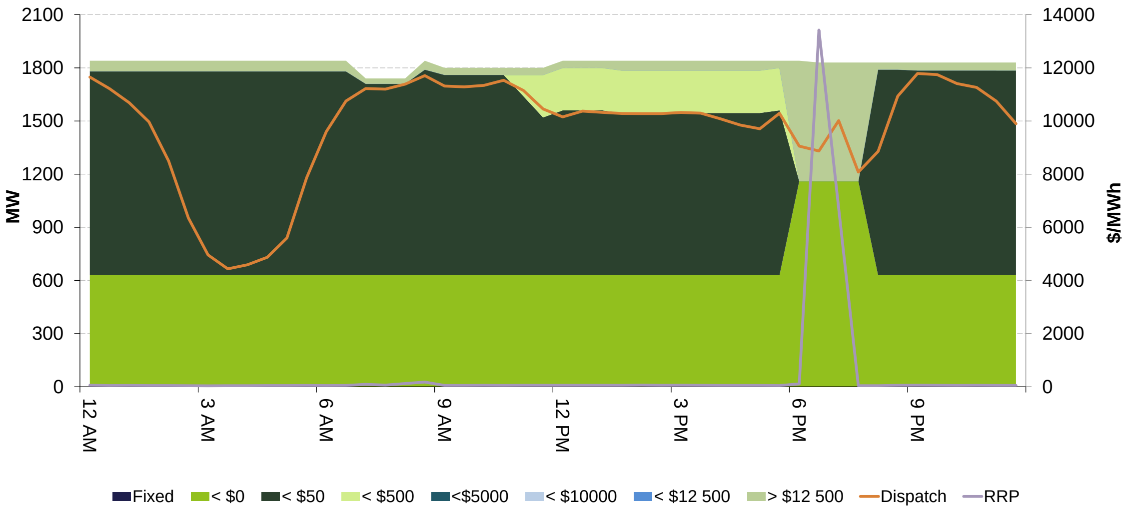


Figure C3 - Origin (Eraring, Shoalhaven, Uranquinty) closing bid prices, dispatch and spot price

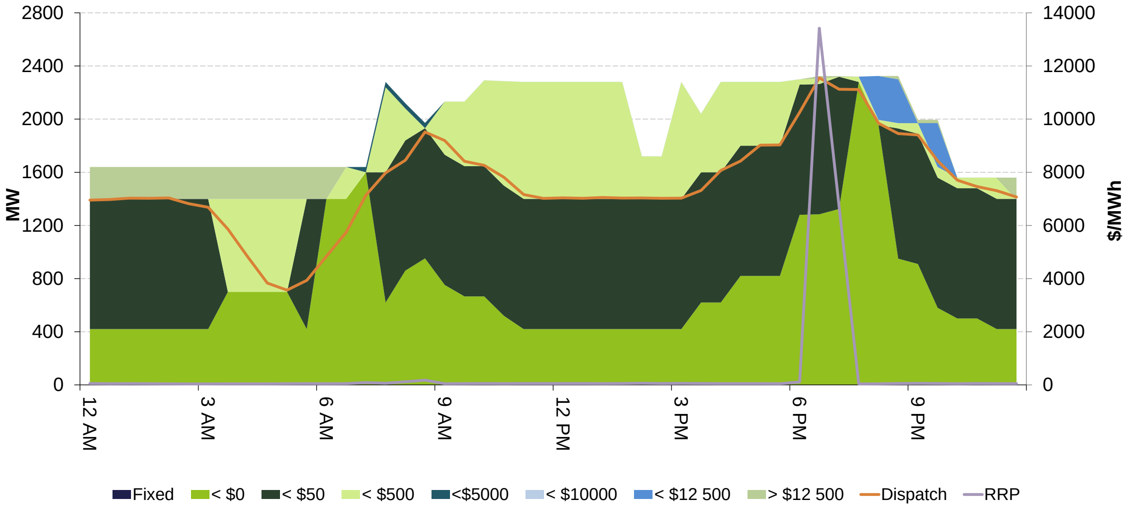


Figure C4 – Snowy Hydro (Colongra, Tumut, Upper Tumut, Guthega, Blowering) closing bid prices, dispatch and spot price