Electricity and ancillary service prices above $5,000/MW(h)

Queensland, 21 July 2021

17 September 2021

AUSTRALIAN ENERGY REGULATOR

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1 Obligation

The Australian Energy Regulator (AER) regulates energy markets and networks under national legislation and rules in eastern and southern Australia (known as the National Energy Market), as well as networks in the Northern Territory. Its functions include:

- monitoring wholesale electricity and gas markets to ensure energy businesses comply with the legislation and rules, and taking enforcement action where necessary;
- setting the amount of revenue that network businesses can recover from customers for using networks (electricity poles and wires and gas pipelines) that transport energy;
- regulating retail energy markets in Queensland, New South Wales, South Australia, Tasmania (electricity only), and the ACT;
- operating the Energy Made Easy website, which provides a retail price comparator and other information for energy consumers;
- publishing information on the performance of energy markets, including the annual State of the energy market report and biennial effective competition report, to assist stakeholders and the wider community.

The AER is required to publish a report whenever the electricity spot price exceeds $5,000 per megawatt hour ($/MWh) and when prices for a market ancillary service over a period significantly exceed the relevant spot price for energy and exceed $5000/MW for a number of trading intervals.

In accordance with clause 3.13.7 (d) of the National Electricity Rules the report for energy must:

- describe the significant factors contributing to the spot price exceeding $5,000/MWh, including withdrawal of generation capacity and network availability;
- assess whether rebidding contributed to the spot price exceeding $5,000/MWh;
- identify the marginal scheduled generating units; and
- identify all units with offers for the trading interval equal to or greater than $5,000/MWh and compares these dispatch offers to relevant dispatch offers in previous trading intervals.

In accordance with the clause 3.13.7(e) of the National Electricity Rules, the ancillary services report must:

- describe the significant factors that contributed to the ancillary service prices exceeding $5,000/MW;
- identify any linkages between spot prices in the energy market and ancillary service prices contributing to the occurrence; and
- assess whether rebidding pursuant to clause 3.8.22 contributed to prices exceeding $5,000/MW.

These reports are designed to examine market events and circumstances that contributed to wholesale market price outcomes and are not an indicator of potential compliance issues or enforcement action.

2 Summary

On 21 July 2021 energy and Frequency Control Ancillary Services (FCAS) prices exceeded $5,000/MWh and $5,000/MW, respectively. This report covers both markets as the main drivers of the high prices are the same.

The spot price in Queensland reached $5,434/MWh and $6,564/MWh for the 6 pm and 6.30 pm trading intervals, respectively. Raise FCAS prices exceeded $5,000/MW in Queensland between 6 pm and 8 pm.

The main drivers were:

- Generator outages and reduced generator availability.
- Highest winter demand recorded in Queensland since the start of the NEM.
- There was limited access to low-priced capacity from New South Wales.
    - Upgrades to the Queensland-New South Wales interconnector (QNI) required Queensland to provide its own FCAS and forced exports from Queensland into New South Wales.
    - Line outages associated with the upgrade were extended on numerous occasions through the evening peak.
- Co-optimisation between the Energy and FCAS markets.
- Rebidding capacity to high prices and removing capacity contributed to the high prices.

These reports are designed to examine market events and circumstances that contributed to wholesale market price outcomes and are not an indicator of potential compliance issues or enforcement action.

We are separately making enquiries around participant behaviour on the day.

3 Analysis

On 21 July 2021 the energy spot price in Queensland reached $5,434/MWh and $6,564/MWh for the 6 pm and 6.30 pm trading intervals respectively. Raise FCAS prices exceeded $5,000/MW in Queensland between 6 pm and 8 pm.

3.1 Overview of actual and expected conditions

Table 1 compares actual and forecast energy prices, demand and availability:

- High prices were forecast for most of the evening from at least 12 hours out, and ended up lower than forecast both 4 and 12 hours prior for most of the evening.
- Only the 6 pm and 6.30 pm trading intervals saw prices breach our reporting thresholds.
- Demand and availability were close to forecast both 4 and 12 hours prior.

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 pm	**5,434**	**11,580**	**15,100**	**8,160**	**8,077**	**8,185**	**9,264**	**9,212**	**9,273**
6.30 pm	**6,564**	**15,100**	**15,100**	**8,154**	**8,208**	**8,283**	**9,258**	**9,205**	**9,272**
7 pm	4,364	15,100	15,100	8,179	8,252	8,316	9,212	9,192	9,233
7.30 pm	4,608	14,215	15,100	8,038	8,171	8,224	9,142	9,152	9,237
8 pm	1,416	549	15,100	7,951	8,080	8,121	9,136	9,167	9,212
8.30 pm	1,590	294	514	7,846	8,018	8,061	9,135	9,183	9,200

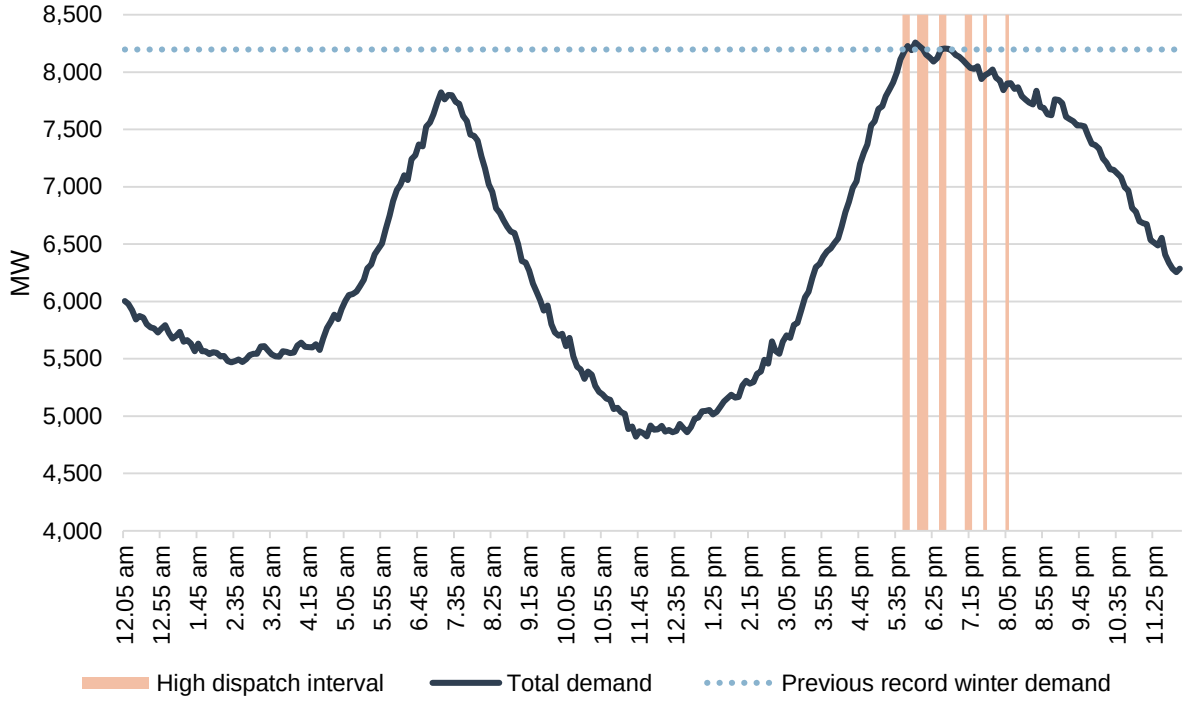
3.2 Demand was historically high

It was cooler than usual across most of Queensland from 18 – 22 July 2021, with the coldest day being 21 July.[1]

The high price intervals coincided with peak demand that evening (Figure 1). Though demand was close to forecast, demand reached 8,257 MW at the 6 pm dispatch interval[2]. This is the highest winter demand on record exceeding the previous record of 8,197 MW set in 2008.

[1] http://www.bom.gov.au/climate/current/month/qld/archive/202107.summary.shtml
[2] Total demand is used in setting price

Figure 1: Queensland total demand



3.3 There was reduced access to low-priced capacity

3.3.1 A large amount of baseload capacity in Queensland was not available

Almost 2,400 MW of baseload capacity in Queensland was not offered to the market for the 6 pm and 6.30 pm trading intervals. Almost 1,500 MW of this capacity was on unplanned outages that occurred at least 2 days prior, about half of which was the Callide C units that had yet to return to service from events on 25 May.[3] The remaining 900 MW of capacity was on planned outages. This limited the amount of low-priced capacity available (Table 2).

Table 2: Unavailable generation

Participant	Station	Unit	Registered capacity (MW)	Max Avail (MW)	Unavailable (MW)	Reason
Callide Power Trading	Callide C	CPP_3	420	0	-420	Offline since failure of Callide C unit 4 on 25 May
		CPP_4	420	0	-420	Offline since significant failure on 25 May
CS Energy	Gladstone	GSTONE1	280	0	-280	Unplanned outage since 15 July
		GSTONE5	280	0	-280	Planned outage since 23 June
		GSTONE6	280	0	-280	Planned outage since 25 June

[3] https://www.aer.gov.au/wholesale-markets/performance-reporting/prices-above-5000-mwh-25-may-2021-queensland-and-nsw

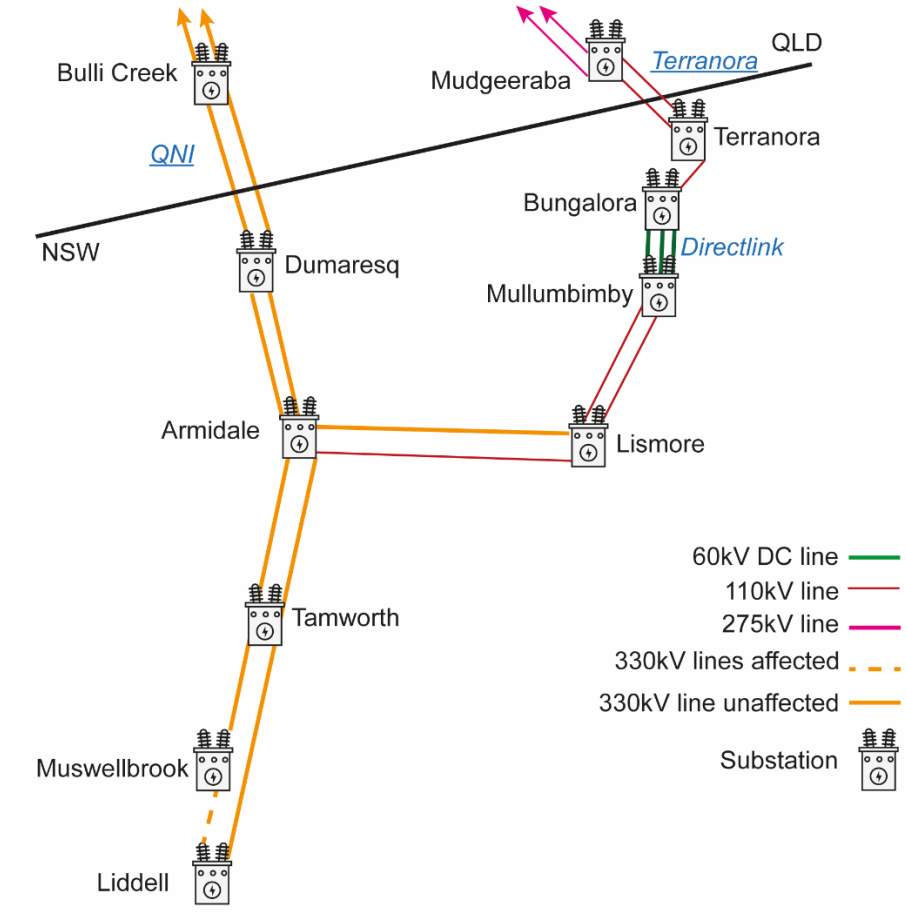
Participant	Station	Unit	Registered capacity (MW)	Max Avail (MW)	Unavailable (MW)	Reason
Stanwell	Stanwell	STAN-2	365	0	-365	Planned outage since 19 May
	Tarong	TARONG#1	350	0	-350	Unplanned outage since 17 July
				Total	**-2,395**	

3.3.2 Planned network outages reduced access to low-priced capacity from other regions

There were planned outages in New South Wales due to the upgrade of the QNI which limited access to cheap generation from New South Wales.

In northern New South Wales there was a planned outage of the Liddell to Muswellbrook 330 kV line as part of the upgrade to the QNI (Figure 2). The line outage meant that Queensland was at risk of becoming electrically isolated from the rest of the NEM, as Directlink cannot transfer FCAS. To manage this possibility AEMO required Queensland to supply its own FCAS. The constraints to manage the line outage forced exports out of Queensland into New South Wales across both the QNI and Terranora interconnectors for the duration of the outage to maintain local FCAS requirements in Queensland.

Figure 2: Simplified network diagram of affected lines



Source: AER

The planned line outage was scheduled to finish at 4.30 pm that afternoon, but lasted longer than originally planned. The outage was extended 9 times from 1.30 pm onwards and was returned to service at 8.15 pm.

The outage extension resulted in continued forced exports from Queensland into New South Wales for longer than forecast (Table 3). This contributed to both energy and FCAS high price outcomes (discussed in sections below).

Table 3: Actual and forecast Queensland net flows

Trading interval	Flows (MW)			Import limit (MW)			Export limit (MW)		
	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast	Actual	4 hr forecast	12 hr forecast
6 pm	411	23	317	411	-170	-179	507	1,014	1,039
6.30 pm	395	313	317	395	-167	-163	292	1,018	1,054
7 pm	404	317	317	404	-167	-164	316	1,024	1,068
7.30 pm	433	27	317	433	-161	-173	255	1,037	1,072
8 pm	396	-58	317	396	-167	-182	307	1,040	1,080
8.30 pm	321	103	51	128	-174	-198	224	1,103	1,087

Note – a positive value in imports indicates forced exports from Queensland into New South Wales.

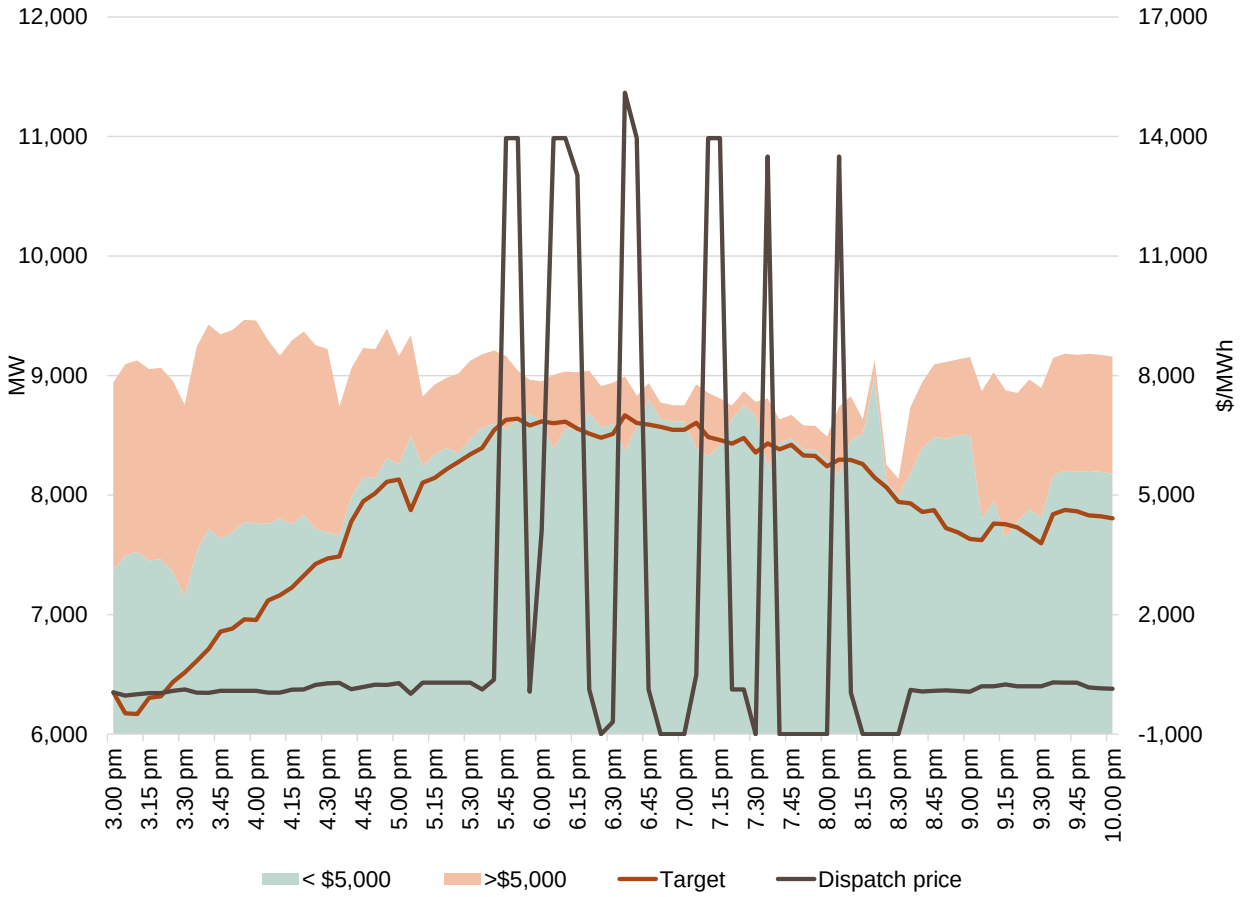
The forced exports also resulted in counter-price flows that resulted in negative inter-regional settlement residues.[4] AEMO invoked a financial constraint used to limit the accrual of negative residues from Queensland to New South Wales from 5.45 pm through to 9.30 pm. This reduced the amount of forced exports from Queensland to a small degree, but exports above the allowable limit set by the constraint continued for system security. As this constraint could not be satisfied it violated and when this occurs a violation penalty applies. In this case it was twice the price cap ($15,100/MWh) and contributed to setting the price in energy and FCAS.

3.4 During the 6 pm and 6.30 pm trading intervals

Around 94% of capacity was offered below $5,000/MWh during the high priced intervals, a majority of which was priced below $0/MWh. Despite this, during the evening demand peak between 1 MW to 218 MW of high-priced capacity was still required to meet demand (Figure 1).

[4] In the normal course of events, electricity will flow from low priced regions across interconnectors into higher price regions. Counter-price flows occur when electricity is exported from a high price region into a lower priced region in order to manage congestion. See https://www.aer.gov.au/system/files/Special%20Report%20-%20The%20impact%20of%20congestion%20on%20bidding%20and%20inter-regional%20trade%20in%20the%20NEM.pdf

Figure 3: Queensland capacity above and below $5,000/MWh



Participants with capacity priced above $5,000/MWh were Arrow Energy, CS Energy, ERM Power, Origin Energy, and Stanwell Corporation (Table 4). The offers for these participants are set out in *Appendix A: Offers greater than $5,000/MWh*.

Table 4: Capacity offered above $5,000/MWh

Participant	Station	Registered capacity (MW)	Fuel type	Capacity offered >$5,000/MWh				
				5.45 pm (MW)	5.50 pm (MW)	6.05 pm (MW)	6.10pm (MW)	6.15 pm (MW)
Arrow Energy	Braemar 2	519	Gas	299	299	299	299	299
CS Energy	Gladstone	1,680	Black coal	25	25	60	60	60
ERM Power	Oakey	288	Gas	196		151		
Origin Energy	Roma	80	Gas	37	37	38	38	38
Stanwell Corporation	Stanwell	1,460	Black coal	25	15	45	45	45
	Tarong	1,400	Black coal	30	30	30	30	30
			Total	**612**	**406**	**623**	**472**	**472**

During the high priced intervals, there was very little capacity offered between $400/MWh and $13,900/MWh so small changes in demand, availability or network flows could cause large fluctuations in price. This resulted in prices above $13,900/MWh during a number of dispatch intervals.

Minor rebidding and removal of low-priced capacity contributed to the high 5.50 pm and 6.10 pm prices. At 2.44 pm, Stanwell removed 43 MW of capacity priced at the floor at Tarong North due to technical issues. Stanwell and CS Energy also rebid a total of 55 MW of capacity from prices below $401/MWh to prices above $13,499/MWh due to forecast prices and in response to concurrent conditions in the FCAS markets. Further detail on the significant rebids are contained in *Appendix B: Significant rebids*.

There were 5 occasions where the dispatch price was above $13,000/MWh and once where the price was $4,127/MWh. These contributed to the 6 pm and 6.30 pm trading intervals exceeding $5,000/MWh. There were 3 drivers of the high dispatch prices (Table 5):

- Co-optimisation with FCAS markets (See the FCAS section below)
- Constraints violating
- High priced capacity required

At 6.15 pm, price was set by the negative residue management constraint being violated to maintain system security and the co-optimisation of Energy and FCAS. With just the negative residue management constraint, price would have been capped at $15,100/MWh, but the co-optimisation led to a lower dispatch price.

The generators involved in setting the price during the high-price periods and how that price was determined by the market systems are detailed in *Appendix C: Price Setter*.

Table 5: High priced dispatch intervals and what set price

Dispatch Interval	Price ($/MWh)	Price set by	Capacity priced above $5,000/MWh dispatched (MW)
5.45 pm	13,959	Energy – almost 100 MW of capacity priced below $5,000/MWh constrained off and increase in demand	77
5.50 pm	13,959	Energy – over 215 MW capacity priced below $5,000/MWh constrained off, increase in demand, and rebidding removing capacity	5
6 pm	4,127	Co-optimisation between Energy and FCAS	
6.05 pm	13,959	Energy – almost 250 MW of capacity priced below $5,000/MWh constrained off	218
6.10 pm	13,959	Energy – almost 225 MW of capacity priced below $5,000/MWh constrained off and rebidding of capacity to higher prices	53
6.15 pm	13,034	Negative residue management constraint violated and co-optimisation between the Energy and FCAS markets	

3.5 FCAS

The price of raise services in Queensland exceeded $5,000/MW for several trading intervals between 6 pm and 8 pm (Table 6) reaching $12,954/MW at 6.30 pm. This was due to:

- the extension of the line outage as part of the QNI upgrade
- reduced FCAS availability

- FCAS providers on outages
- the interaction between the energy and FCAS markets

- rebidding of capacity from low to high prices
- constraint violations.

Table 6: Local Queensland FCAS prices

	R5 Min ($/MW)	R60 Sec ($/MW)	R6 Sec ($/MW)	R Reg ($/MW)
6 pm	4,552	4,425	6,713	4,706
6.30 pm	10,549	7,528	12,954	10,589
7 pm	6,453	5,229	6,683	6,471
7.30 pm	5,663	3,061	6,195	5,688
8 pm	2,370	2,382	8,351	2,398

3.5.1 Network outage extension

There was no local FCAS requirement or high prices forecast for between 6 pm and 8 pm as the Liddell to Muswellbrook 330 kV line outage was supposed to finish at 4.30 pm (see section 3.3.2). The line outage was extended which meant the requirement for local FCAS was extended throughout the evening peak where energy was needed to meet peak demand limiting the amount of raise services available.

3.5.2 Reduced availability

The interactions of the energy and FCAS means that there is a trade-off between providing energy and FCAS. For example, a generator that is operating at its maximum capacity cannot provide raise services so their “effective” available capacity for raise services would be zero. On this day there was record winter demand for energy and high FCAS requirements competing against each other.

There was reduced FCAS capacity available as 5 of the 7 units unavailable on the day (Table 2) normally offer raise FCAS. Requirements on the day were up to 262 MW for raise 6 and 60 second services.

Due to the high demand for energy during the evening peak and generator outages, the remaining units that can provide FCAS had reduced capacity to provide raise services.

3.5.3 Rebidding of raise services

There was rebidding that contributed to some of the high FCAS prices.

At 5.52 pm, effective from 6 pm, Origin Energy made 20 MW of raise 6 second services available at Mt Stuart, 5 MW priced at $0.01/MW and 15 MW at $15,000/MW. The reason given was due to a material change in Queensland demand. As a result the 6 pm, 6.05 pm and 6.15 pm price for raise 6 second services was set by Mt Stuart at $15,000/MW. It was also co-optimised with the energy market and contributed to the energy price exceeding $4,000/MWh at 6 pm. Origin rebid the 15 MW of high priced capacity down to $0.01/MW effective 6.20 pm and no longer set price.

3.5.4 Constraint violations

As discussed above the negative residue management constraint violated on several occasions. As a result it contributed to prices above $5,000/MW for each of the raise services between 6.10 pm and 6.25 pm.

Table 7 shows that most of the high raise service prices were a result of the Energy and FCAS markets interacting leading to the price being co-optimised. Raise 6 second service prices were mainly set by high priced capacity. Except for the 20 minutes that Mt Stuart's rebid was effective there was only 4 MW of high priced raise 6 second capacity offered. Due to the reduced availability of low-priced capacity the high priced capacity was required and set price.

Table 7: High price intervals and what set price

Dispatch interval	Raise 5min	Raise Reg	Raise 60 sec	Raise 6 sec
5.45 pm				co-op
5.50 pm	co-op	co-op	co-op	
5.55 pm				co-op
6.00 pm	co-op	co-op	co-op	Mt Stuart
6.05 pm	co-op	co-op	co-op	Mt Stuart
6.10 pm	co-op	co-op	co-op	Constraint
6.15 pm	Constraint	Constraint	Constraint	Mt Stuart
6.20 pm				Tarong
6.25 pm	co-op	Gladstone		Constraint
6.30 pm				Tarong
6.35 pm	co-op	co-op	co-op	
6.40 pm	co-op	co-op	co-op	Stanwell
6.45 pm				Stanwell
6.50 pm				Tarong
6.55 pm				Stanwell
7.10 pm	co-op	co-op		co-op
7.15 pm	co-op	co-op	co-op	Stanwell
7.20 pm				Tarong
7.35 pm	co-op	co-op	co-op	
7.40 pm				Stanwell
7.45 pm				Tarong
7.50 pm				Tarong
7.55 pm				Tarong
8.00 pm				Tarong

3.6 Lack of Reserve

A Lack of Reserve (LOR) 1 was forecast for the evening of 21 July from as early as 15 July, with a LOR 2 forecast from as early 16 July. Both were cancelled and re-forecast a number of times. When an Actual LOR 1 was declared at 5.30 pm, it was not forecast. An Actual LOR 2 was declared from 6 pm. Both lasted until 8.30 pm.

When demand and supply conditions are tight AEMO notifies the market, through LOR notices, to elicit a market response to increase generation or reduce demand. LORs have three levels – LOR 1, 2 and 3 with LOR 1 being the least severe and LOR 3 meaning there is not enough supply to meet demand. An actual LOR 3 requires AEMO to shed load in order to maintain power system security.

Appendix A: Closing bids

Figures A1 to A6 highlight the 5 minute offers for participants in Queensland with capacity priced at or above $5,000/MWh during the periods in which the spot price exceeded $5,000/MWh. They also show generation output and the dispatch price.

Figure A1: Alinta Energy (Braemar A, Collinsville Solar PV, Rugby Run Solar Farm) offers, dispatch and dispatch price

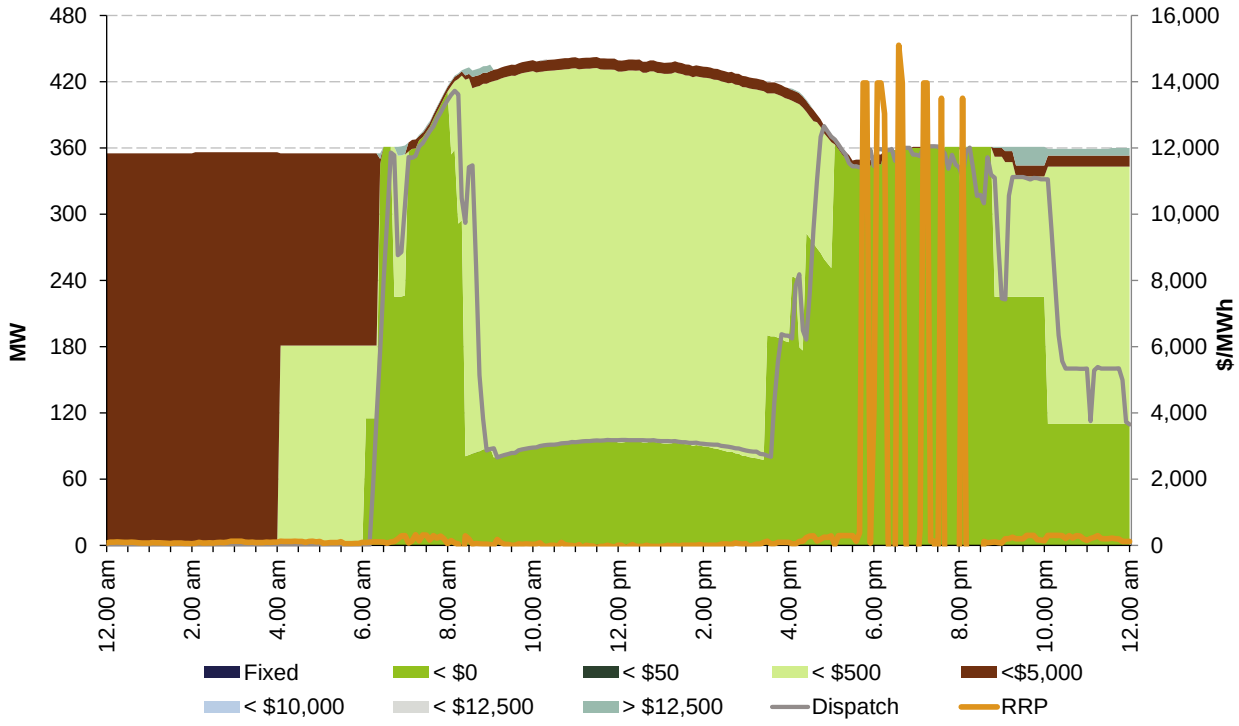


Figure A2: Arrow Energy (Braemar 2) offers, dispatch and dispatch price

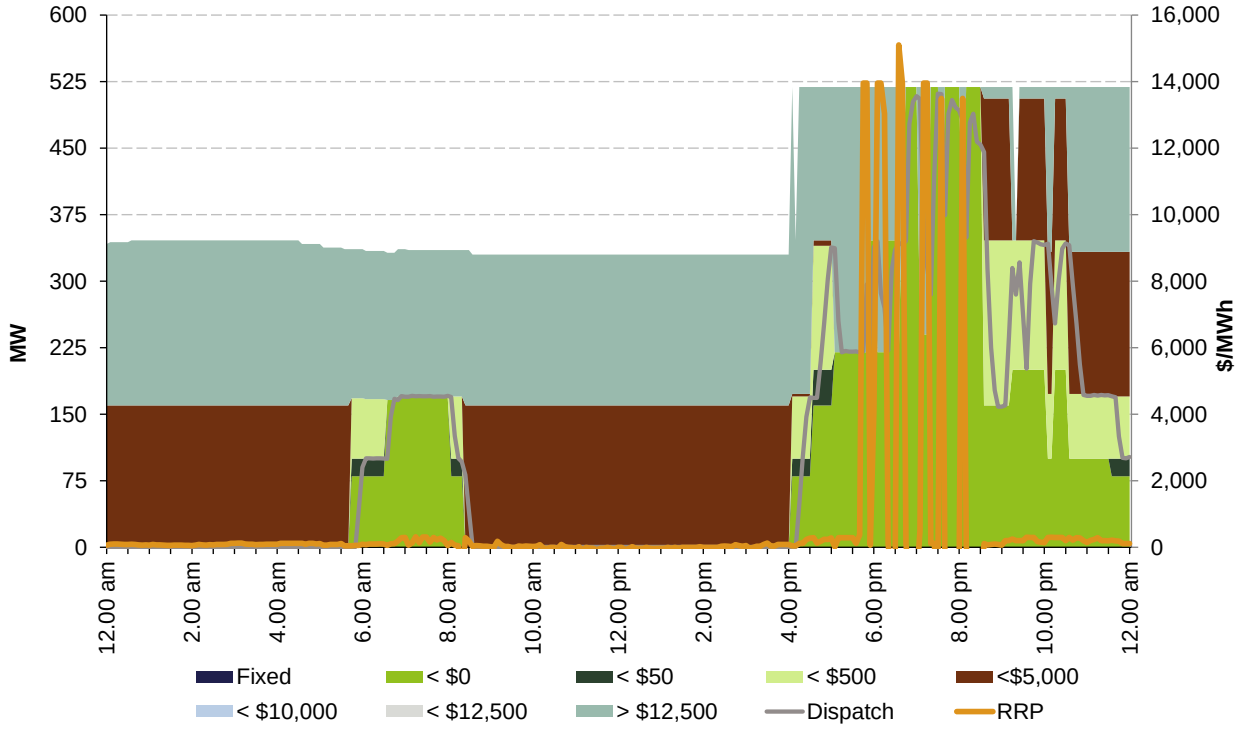


Figure A3: CS Energy (Callide B, Gladstone, Kogan Creek) offers, dispatch and dispatch price

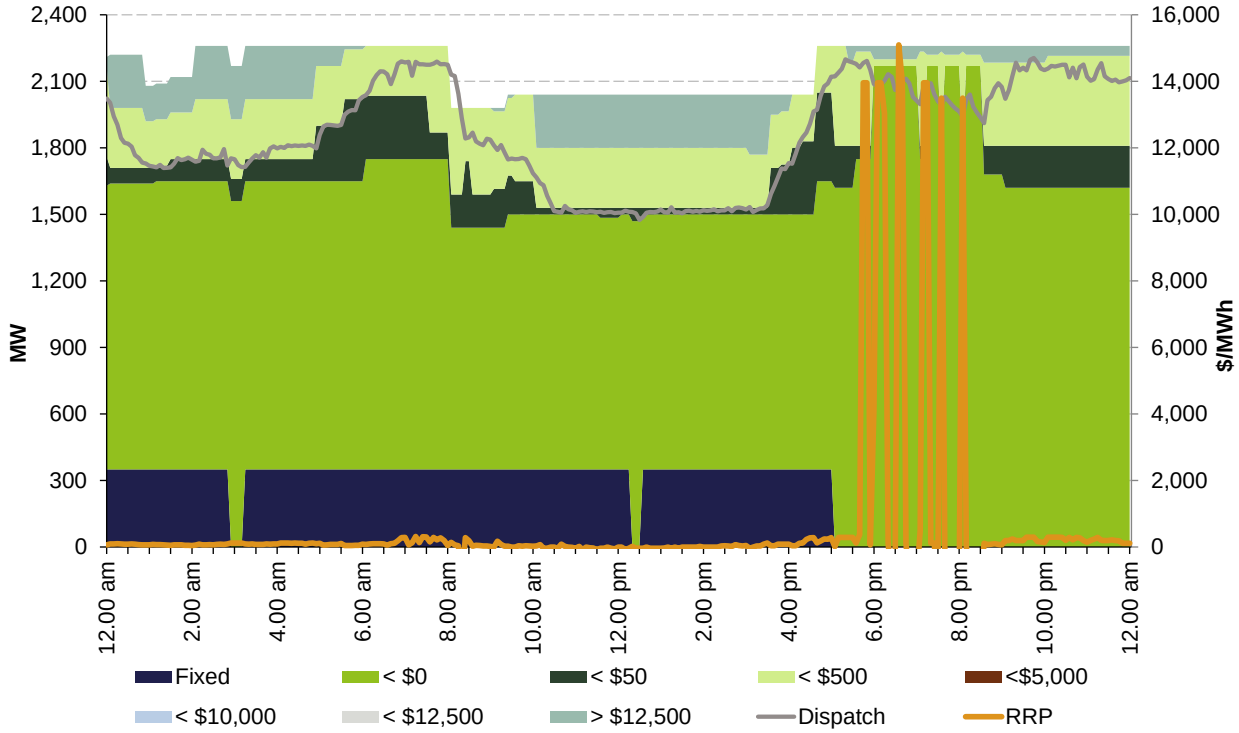


Figure A4: ERM Power (Oakey) offers, dispatch and dispatch price

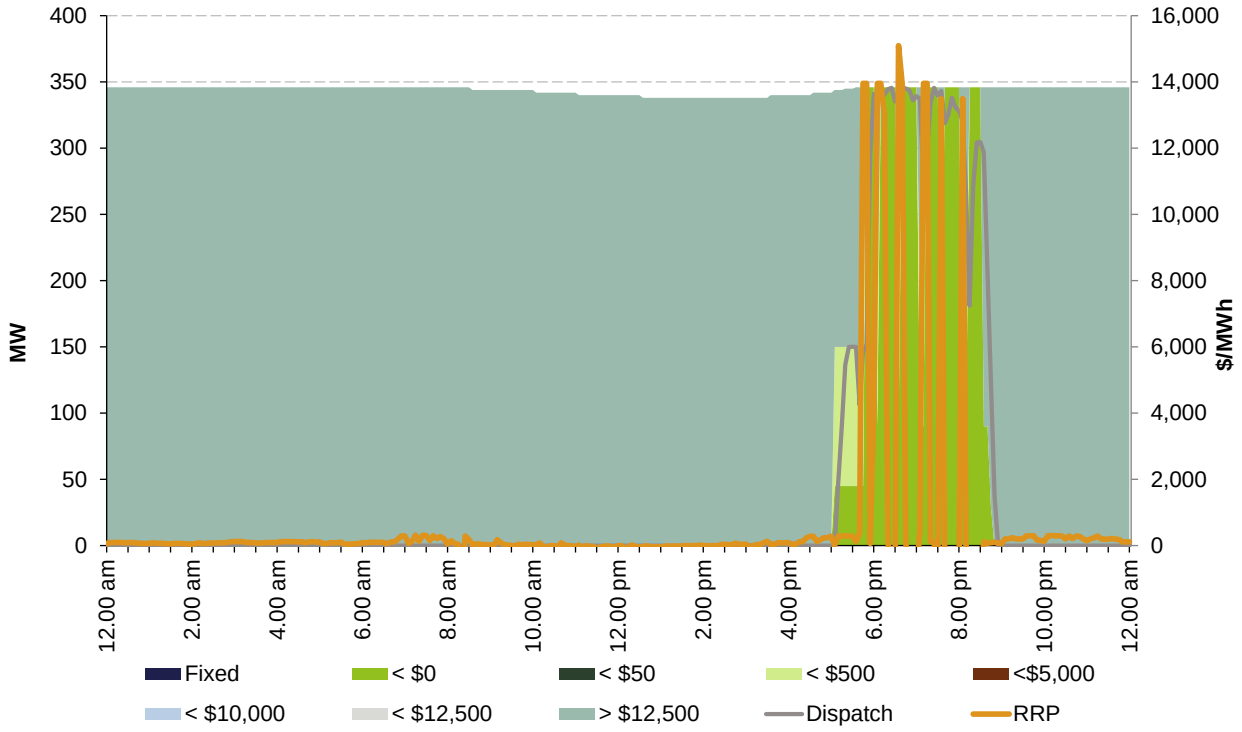


Figure A5: Origin Energy (Darling Downs Power Station, Mt Stuart, Roma) offers, dispatch and dispatch price

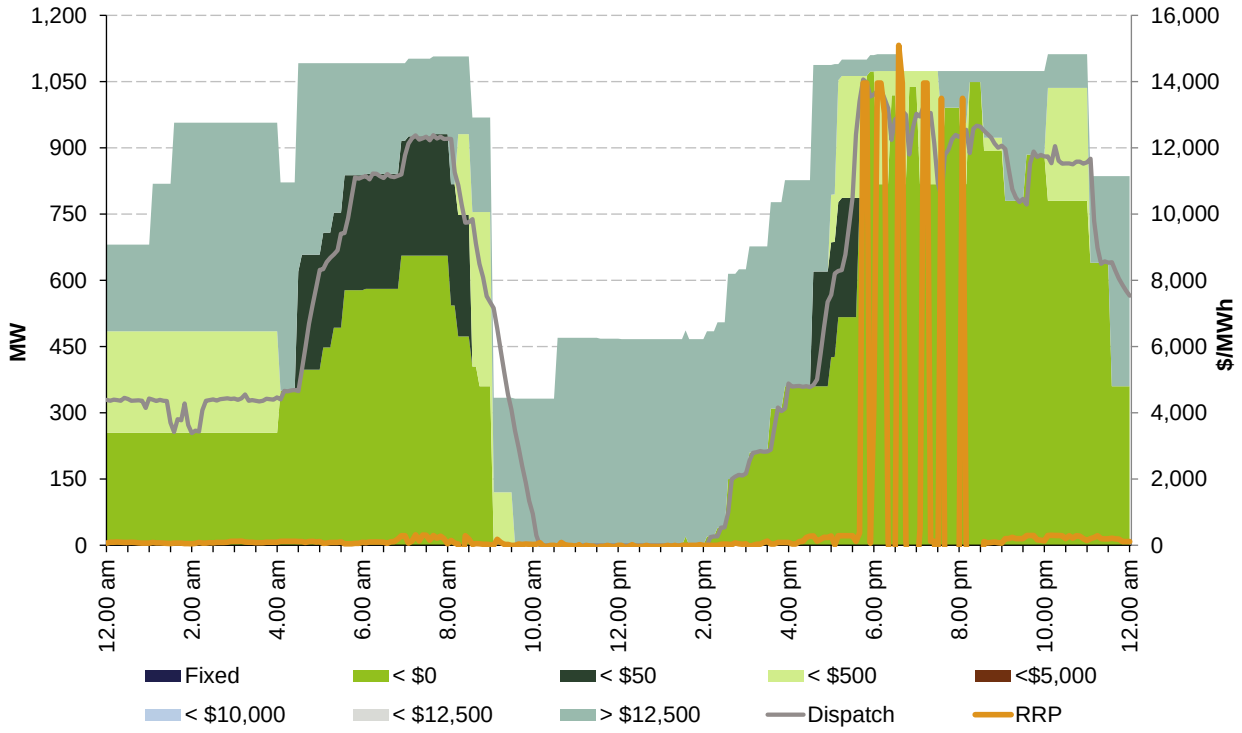
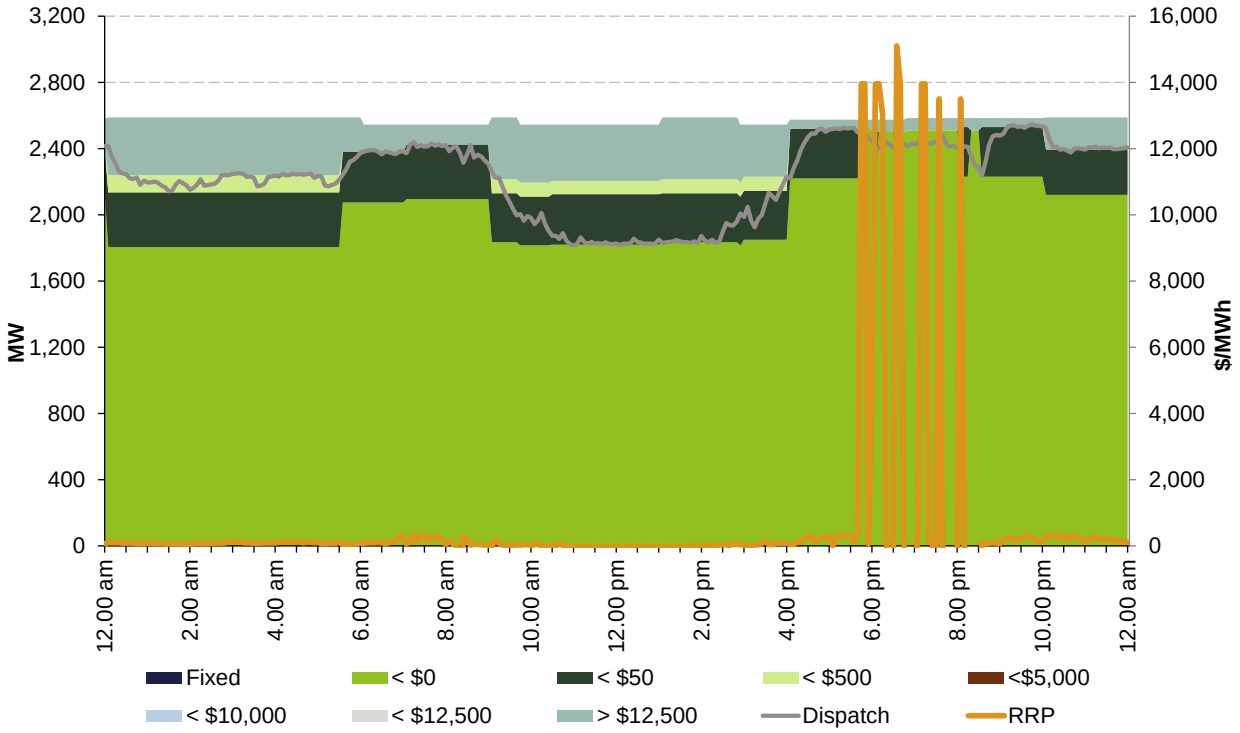


Figure A6: Stanwell (Stanwell, Tarong, Tarong North) offers, dispatch and dispatch price



Appendix B: Significant energy rebids

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

Table 8: significant rebids for 6 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.44 pm		Stanwell Corporation	Tarong North	-43	-1,000	N/A	1443P high air heater motor amps

Table 9: significant rebids for 6.30 pm trading interval

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.44 pm		Stanwell Corporation	Tarong North	-43	-1,000	N/A	1443P high air heater motor amps
5.57 pm	6.05 pm	Stanwell Corporation	Stanwell	20	-1,000	15,100	1757A avoid unit stranded
5.58 pm	6.05 pm	CS Energy	Gladstone	35	<401	15,100	1758A qld1 di 21-07-2021 18:00:00 rrp $4126.68 vs p5 rrp $-999.99 @ p5 run 21-07-2021 17:55:00 - rrp change of $5126.68-sl

Appendix C: Price setter

The following tables identifies for the trading interval in which the spot price exceeded $5,000/MWh, each 5 minute dispatch interval price and the generating units involved in setting the energy price. This information is published by AEMO.[5] The 30-minute spot price is the average of the 6 dispatch interval prices. The dispatch prices that are in italics are capped at the price cap of $15,100/MWh when published by AEMO.

Table 10: Queensland price setter 6 pm

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
17:35	$122.28	Origin Energy	MSTUART2	Energy	$122.28	1.00	$122.28
17:40	$369.89	Origin Energy	MORTLK12	Energy	$86.72	-1.06	-$91.92
		CS Energy	GSTONE2	Energy	$85.73	0.34	$29.15
		CS Energy	GSTONE2	Raise 60 sec	$0.73	-0.34	-$0.25
		CS Energy	GSTONE2	Raise 6 sec	$0.73	-0.34	-$0.25
		CS Energy	GSTONE3	Energy	$85.73	0.34	$29.15
		CS Energy	GSTONE3	Raise 60 sec	$0.73	-0.34	-$0.25
		CS Energy	GSTONE3	Raise 6 sec	$0.73	-0.34	-$0.25
		CS Energy	GSTONE4	Energy	$85.73	0.34	$29.15
		CS Energy	GSTONE4	Raise 60 sec	$0.73	-0.34	-$0.25
		CS Energy	GSTONE4	Raise 6 sec	$0.73	-0.34	-$0.25
		ERM Power	OAKEY1	Energy	$286.00	1.01	$288.86
		ERM Power	OAKEY1	Raise reg	$89.69	-1.01	-$90.59
		AGL Hydro	MCKAY1	Raise reg	$90.00	1.01	$90.90
		EnergyAustralia	MP2	Raise 6 sec	$46.50	1.01	$46.97
		EnergyAustralia	YWPS1	Raise 60 sec	$39.00	1.01	$39.39
17:45	$13,958.95	Arrow	BRAEMAR6	Energy	$13,958.95	0.50	$6,979.48
		Arrow	BRAEMAR7	Energy	$13,958.95	0.50	$6,979.48
17:50	$13,958.95	Arrow	BRAEMAR6	Energy	$13,958.95	0.50	$6,979.48
		Arrow	BRAEMAR7	Energy	$13,958.95	0.50	$6,979.48
17:55	$65.56	CS Energy	GSTONE2	Energy	$85.73	0.33	$28.29
		CS Energy	GSTONE2	Lower reg	$0.73	0.33	$0.24
		CS Energy	GSTONE3	Energy	$85.73	0.33	$28.29
		CS Energy	GSTONE3	Lower reg	$0.73	0.33	$0.24
		CS Energy	GSTONE4	Energy	$85.73	0.33	$28.29
		CS Energy	GSTONE4	Lower reg	$0.73	0.33	$0.24
		AGL Energy	LYA1	Lower reg	$20.90	-1.00	-$20.90
18:00	$4,126.68	Origin Energy	MSTUART3	Raise 6 sec	$15,000	0.35	$5,250
		CleanCo	W/HOE#2	Energy	-$1,000	1.00	-$1,000
		CleanCo	W/HOE#2	Raise 5 min	$100.00	-0.56	-$56.00
		CS Energy	CALL_B_1	Raise reg	$2.62	0.91	$2.38
		CS Energy	CALL_B_1	Raise 60 sec	$0.62	-0.35	-$0.22

[5] 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
		CS Energy	CALL_B_1	Raise 6 sec	$0.62	-0.35	-$0.22
		Snowy Hydro	TUMUT3	Raise 5 min	$0.88	0.56	$0.49
		AGL Hydro	MCKAY1	Raise reg	$150.00	-0.56	-$84.00
		Stanwell	STAN-1	Raise reg	$20.68	-0.35	-$7.24
		Stanwell	STAN-1	Raise 60 sec	$100.68	0.35	$35.24
Spot Price		**$5,434/MWh**					

Table 11: Queensland price setter 6.30 pm

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
18:05	$13,958.9	Arrow	BRAEMAR6	Energy	$13,958.95	0.50	$6,979.48
		Arrow	BRAEMAR7	Energy	$13,958.95	0.50	$6,979.48
18:10	$13,958.9	Arrow	BRAEMAR6	Energy	$13,958.95	0.50	$6,979.48
		Arrow	BRAEMAR7	Energy	$13,958.95	0.50	$6,979.48
18:15	$13,033.8	Origin	MSTUART3	Raise 6 sec	$15,000	-1.01	-$15,150
		NEON	HPRG1	Raise 6 sec	$20.00	1.01	$20.20
		Engie	PPCCGT	Energy	$132.44	-1.04	-$137.74
		Engie	PPCCGT	Raise reg	$32.99	1.01	$33.32
		Engie	PPCCGT	Raise 60 sec	$4.88	1.01	$4.93
		Stanwell	STAN-1	Energy	-$1,000	0.50	-$500
		Stanwell	STAN-1	Raise 60 sec	$100.68	-0.50	-$50.34
		Stanwell	STAN-3	Energy	-$1,000	0.50	-$500
		Stanwell	STAN-3	Raise 60 sec	$100.68	-0.50	-$50.34
		Stanwell	TARONG#2	Energy	-$1,000	0.50	-$500
		Stanwell	TARONG#2	Raise reg	$100.68	-1.01	-$101.69
		Stanwell	TARONG#2	Raise 60 sec	$100.68	0.50	$50.34
		Stanwell	TARONG#4	Energy	-$1,000	0.50	-$500
		Stanwell	TARONG#4	Raise 60 sec	$100.68	-0.50	-$50.34
			NRM_QLD1_NSW1	Negative residue management constraint	$30,200	1.01	$30,502
18:20	$122.28	Origin	MSTUART1	Energy	$122.28	0.50	$61.14
		Origin	MSTUART2	Energy	$122.28	0.50	$61.14
18:25	-$1,000	Arrow	BRAEMAR6	Energy	-$1,000	0.08	-$80
		Arrow	BRAEMAR7	Energy	-$1,000	0.08	-$80
		CleanCo	BARRON-1	Energy	-$1,000	0.01	-$10
		CleanCo	BARRON-2	Energy	-$1,000	0.01	-$10
		CleanCo	KAREEYA1	Energy	-$1,000	0.01	-$10
		CleanCo	KAREEYA2	Energy	-$1,000	0.01	-$10
		CleanCo	KAREEYA3	Energy	-$1,000	0.01	-$10
		CleanCo	KAREEYA4	Energy	-$1,000	0.01	-$10

DI	Dispatch Price ($/MWh)	Participant	Unit	Service	Offer price ($/MWh)	Marginal change	Contribution
		CleanCo	W/HOE#2	Energy	-$1,000	0.13	-$130
		CS Energy	GSTONE2	Energy	-$1,000	0.11	-$110
		CS Energy	GSTONE3	Energy	-$1,000	0.11	-$110
		CS Energy	GSTONE4	Energy	-$1,000	0.11	-$110
		Ergon	BARCALDN	Energy	-$1,000	0.02	-$20
		ERM Power	OAKEY1	Energy	-$1,000	0.08	-$80
		ERM Power	OAKEY2	Energy	-$1,000	0.08	-$80
		Braemar	BRAEMAR1	Energy	-$1,000	0.07	-$70
		Braemar	BRAEMAR2	Energy	-$1,000	0.08	-$80
18:30	-$690.65	CleanCo	W/HOE#2	Energy	-$1,000	2.28	-$2,280
		CleanCo	W/HOE#2	Raise 5 min	$0.87	-1.28	-$1.11
		NEON	HPRG1	Raise reg	$59.00	-1.28	-$75.52
		Snowy Hydro	TUMUT3	Raise 5 min	$0.88	1.28	$1.13
		Stanwell	STAN-1	Energy	-$1,000	-0.32	$320
		Stanwell	STAN-1	Raise 60 sec	$150.68	0.32	$48.22
		Stanwell	STAN-3	Energy	-$1,000	-0.32	$320
		Stanwell	STAN-3	Raise reg	$300.68	0.96	$288.65
		Stanwell	STAN-3	Raise 60 sec	$150.68	-0.64	-$96.44
		Stanwell	TARONG#2	Energy	-$1,000	-0.32	$320
		Stanwell	TARONG#2	Raise 60 sec	$150.68	0.32	$48.22
		Stanwell	TARONG#4	Energy	-$1,000	-0.32	$320
		Stanwell	TARONG#4	Raise reg	$300.68	0.32	$96.22
Spot Price		**$6,564/MWh**					