Electricity prices above $5,000 per MWh

October to December 2024

February 2025

AUSTRALIAN ENERGY REGULATOR

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1 Obligation

The Australian Energy Regulator (AER) has an obligation under the National Electricity Rules (energy rules) to monitor and report on significant price outcomes in the National Energy Market (NEM). The energy rules require us to produce a guideline for how we report significant price events.[1] Our guideline commits us to reporting whenever the 30-minute energy price exceeds $5,000 per megawatt hour (MWh); or 2 consecutive 30-minute Frequency Control Ancillary Service (FCAS) prices exceed $5,000 per MW.[2]

With a market price cap over $17,500 per MWh prices can occasionally exceed this 30-minute reporting threshold.[3] This reporting framework is intended to pick up these events.

This report describes the significant factors contributing to 30-minute prices exceeding $5,000 per MWh, considering market conditions, available generation capacity, network availability, as well as offer and rebidding behaviour.

The AER also analyses trends in prices and other market events through our quarterly wholesale markets report, available from www.aer.gov.au/wholesale-markets/performance-reporting.

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1 AER, Significant price reporting guidelines, September 2022.

2 A trading interval is a 5-minute period, and the spot price is the price for a trading interval. The 30-minute price is the average of 6 trading intervals.

3 The market price cap in 2024/25 is $17,500 per MWh.

2 Summary

The wholesale 30-minute price of electricity exceeded $5,000 per MWh 23 times in October to December 2024 – 13 times in New South Wales (NSW), 7 times in Queensland and 3 times in South Australia. This compares to 54 high prices in the previous quarter and 5 high prices over the same period last year. There were also 15 high raise 6 (R6) second service prices in Queensland on 10 and 11 October, and 12 November – the most since Q4 2021.

Common drivers across most of the high price periods included network limitations and increased demand (Table 1 and Figure 1). These conditions were compounded by significant baseload outages (most of which was planned in Queensland and unplanned in NSW) and periods of low wind or solar output which meant tight supply.

Table 1 Common drivers of high energy prices

Date	High prices forecast*	Network	Demand	Baseload outages**	Low wind	Low solar	Rebidding
22 October, SA	×	✓	✓	×	✓	✓	✓
23 October, SA	×	✓	×	×	✓	×	✓
7 November, NSW + Qld	✓	✓	✓	✓	✓	×	✓
26 November, NSW	✓	✓	✓	✓	✓	×	✓
27 November, NSW	✓	✓	✓	✓	×	×	✓
2 December, NSW + Qld	✓	✓	✓	✓	✓	×	✓
3 December, NSW	×	✓	✓	×	×	✓	✓
5 December, SA	×	✓	✓	×	✓	✓	✓
6 December, NSW	×	✓	✓	×	✓	✓	×

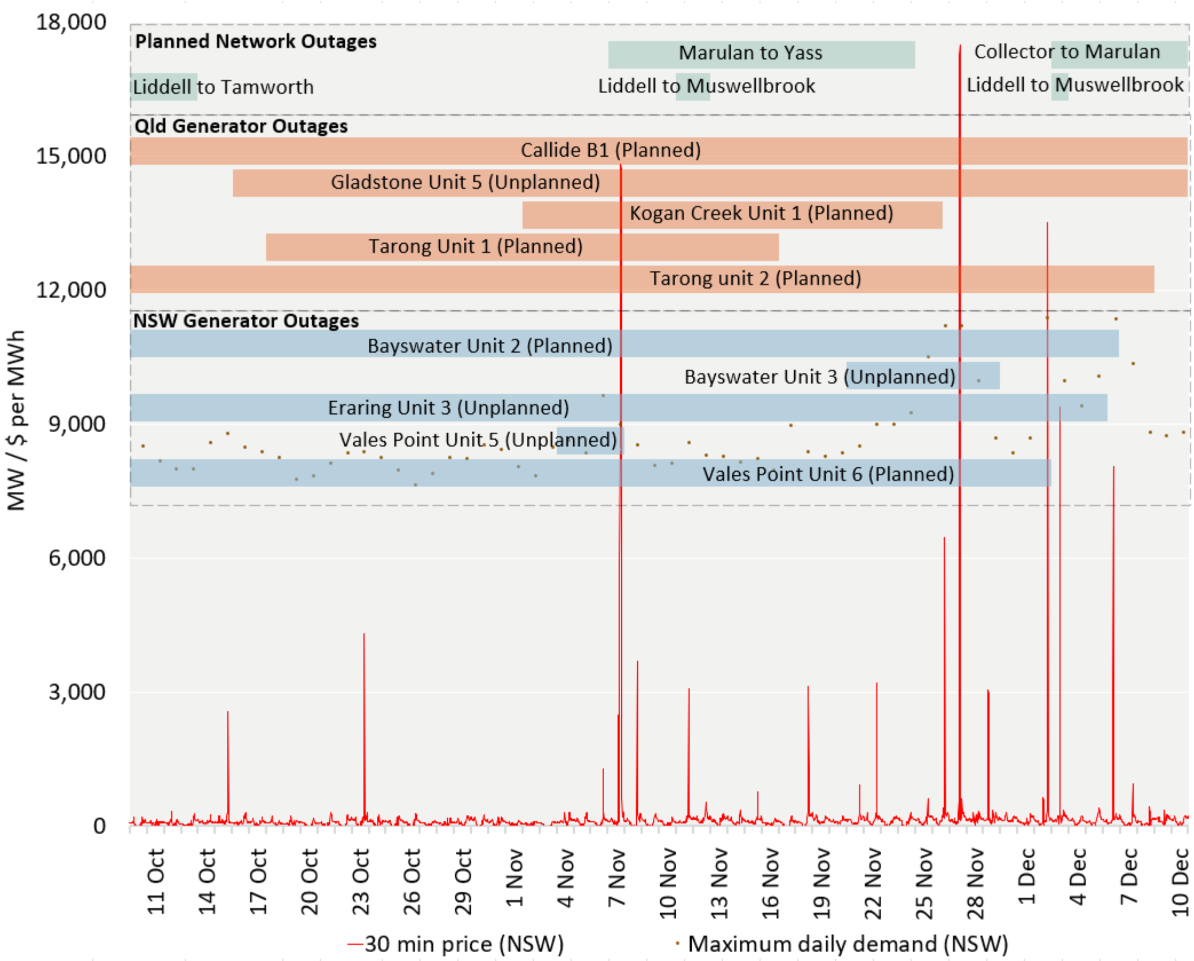
Source: AER analysis using NEM data.
Note: *High prices were forecast at least 4 hours before the 30-minute dispatch interval.
**Baseload outages refer to planned or unplanned outages of coal-fired or gas generators. There are no coal-fired generators in South Australia.

Table 2 Common drivers of high R6 second service prices

Date	High prices forecast	Network	Energy vs FCAS trade-off	Rebidding
10 October, Qld FCAS	×	✓	×	×
11 October, Qld FCAS	✓	✓	×	✓
12 November, Qld FCAS	×	✓	✓	✓

Source: AER analysis using NEM data.

Figure 1 Significant coinciding drivers contributing to high prices



Source: AER analysis using NEM data.
Note: Using 30-minute price in NSW to demonstrate the relationship between network and generator outages.

Unusually warm temperatures occurred across most of Australia, with it being the fifth warmest on record since 1910.[4] Queensland had its warmest spring on record, surpassing the previous record set in 2020.[5] Maximum temperatures were above average for the remaining states, including NSW. These conditions drove up demand due to an increased need for cooling and was a common driver for most of the high price events in Queensland and NSW, with forecast or actual shortfalls in reserve supply occurring on most days in November.

Network limitations due to planned outages on the Collector to Marulan and Marulan to Yass lines and associated system normal constraints meant that at times low-priced capacity from Victoria and southern NSW was unable to reach key load centres including Sydney. Between 550 MW and 1,550 MW of low-priced capacity was unable to make it to market during the high price periods and more high-priced capacity was needed to meet demand.

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[4] Bureau of Meteorology, Australia in spring 2024, 1 December 2024.
[5] Bureau of Meteorology, Australia in spring 2024, 1 December 2024.

The tight supply conditions were compounded by significant baseload outages which led to AEMO implementing the Reliability and Emergency Reserve Trader (RERT) on 27 November - the first time since Q1 2023 (section 5.1). Up to 4,700 MW of capacity was unavailable due to baseload outages during some of the high-priced periods. In addition, four of Origin Energy's gas and hydro power stations (Uranquinty and Shoalhaven) tripped due to technical issues on 26 and 27 November – these were the only unexpected generator outages that occurred on a high-priced day which would not have been included in initial forecasts.

Lots of high prices were forecast. In many cases we observed market dynamics functioning as designed, with participants rebidding significant amounts of capacity from high to low prices preventing high prices from eventuating. However, there were 67 unique 5-minute prices above $5,000 per MWh when the 30-minute prices were high. Around 40% of these 5-minute prices were a result of participants rebidding small amounts of capacity from low to high or withdrawing low-priced capacity due to technical reasons (section 7).

In South Australia, the high prices were not forecast and occurred mostly due to a reduced supply of low-priced capacity from periods of low wind or solar output. Planned network outages which impacted the Heywood or Murraylink interconnectors also limited South Australia's ability to import cheaper generation from Victoria during the high price periods.

Queensland also needed to provide local R6 second services over three days in October and November (Table 2). This was due to a planned outage on the Liddell to Tamworth/Muswellbrook lines which created a credible risk of losing the Queensland-NSW Interconnector (QNI) which could electrically island Queensland from the NEM. The remaining interconnector into Queensland, Terranora, cannot transfer FCAS. To allow for this contingency, Queensland was required to provide its own local R6 second service on these days. While there was a large portion of capacity available below $5,000 per MW, there were times when high-priced R6 second were needed resulting in prices above $5,000 per MW.

3 Warm temperatures and calm conditions contributed to high price periods

3.1 High demand driven by hot temperatures

Hot days and warm nights occurred regularly in parts of southern Australia in October and November, with daily maximum temperatures in the high 30s and low 40s.[6] There were also extended periods with low to severe intensity heatwaves across much of Australia in both October and November. The warmer conditions also continued into December.

The unusually warm temperatures saw an increase in demand for cooling during four of the high-priced days. In particular, NSW recorded the third, fourth, fifth and seventh highest maximum daily demand for Q4 2024 on 2 December at 11,466 MW, 6 December at 11,381 MW, 27 November at 11,325 MW, and 26 November at 11,301 MW.[7]

Queensland also recorded the fourth and fifth highest maximum daily demand for Q4 2024 on 7 November at 9,192 MW and 2 December at 9,160 MW.

3.2 Low wind output

Wind output was variable and well below registered capacity in NSW, Queensland and South Australia. Wind output was lower than forecast for most of the high price periods. Wind generated capacity is generally offered at low prices, so relatively low wind generation reduced the amount of low-priced capacity available in the regions.

For the high prices in NSW, the lowest minimum wind output during the high-priced periods was 157 MW out of 2,762 MW, which equates to around 6% of total installed capacity (Figure 2).

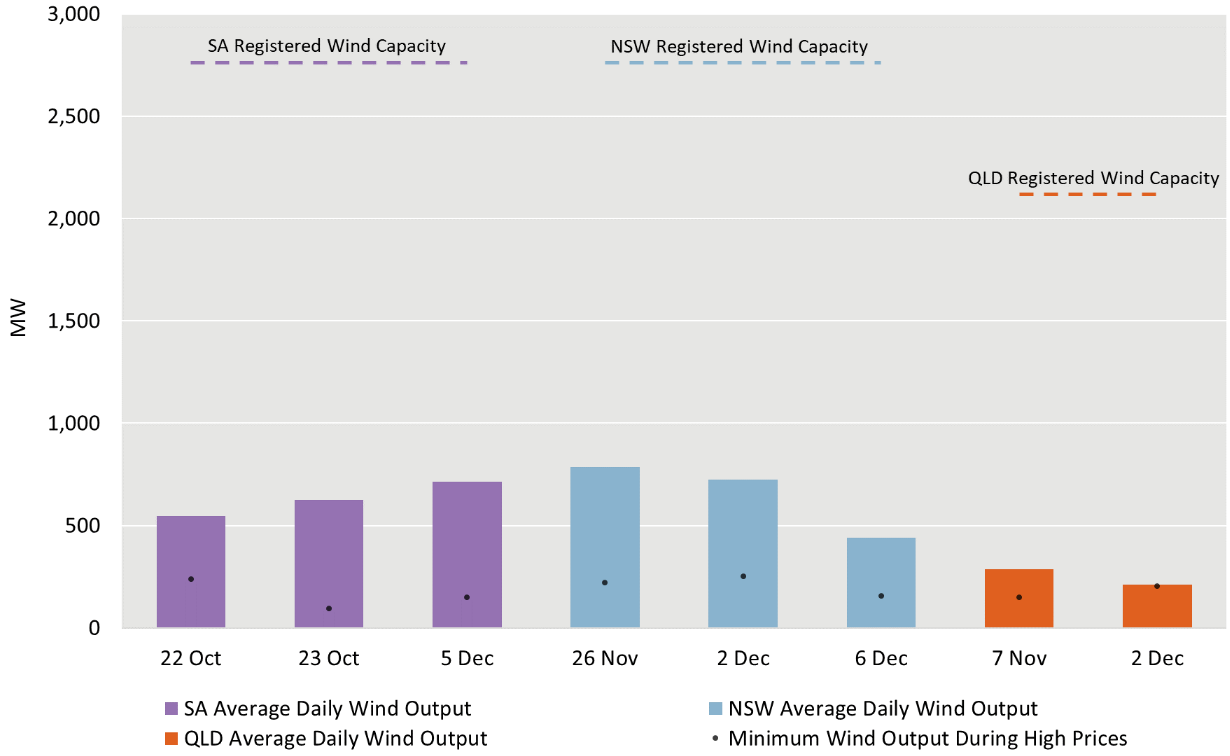
In Queensland, the highest average wind output during the high-priced periods was 220 MW out of 2,117 MW of installed capacity, which equates to around 10% of total installed capacity. The lowest minimum wind output was 149 MW, which equates to around 7% of total installed capacity.

In South Australia, the highest average wind output during the high-priced periods was 263 MW out of 2,763 MW of installed capacity, which equates to around 10% of total installed capacity. The lowest minimum wind output was 94 MW, which equates to around 3% of total installed capacity.

[6] Bureau of Meteorology, Australia in spring 2024, 1 December 2024.

[7] Based on 30-minute native demand. The AER defines native demand which is met by local scheduled, semi-scheduled and non-scheduled generation. It does not include demand met by rooftop solar PV systems.

Figure 2 Average daily and minimum wind output during high prices in South Australia, NSW and Queensland



Source: AER analysis using NEM data.

4 Network limitations

Planned network outages meant some interconnectors were flowing well below their nominal capacity to prevent overloading and to maintain system security. This limited some regions' ability to access low-priced capacity from neighbouring regions. Constraints used to manage these outages also prevented up to 1,550 MW of low-priced capacity from making it to market during the high-price periods which was twice the amount of high-priced capacity that was needed to be dispatched.

4.1 Queensland and NSW limitations

Multiple planned network outages impacted Queensland and NSW's ability to access low-priced capacity during the high-priced periods.

4.1.1 Marulan to Yass and Collector to Marulan lines

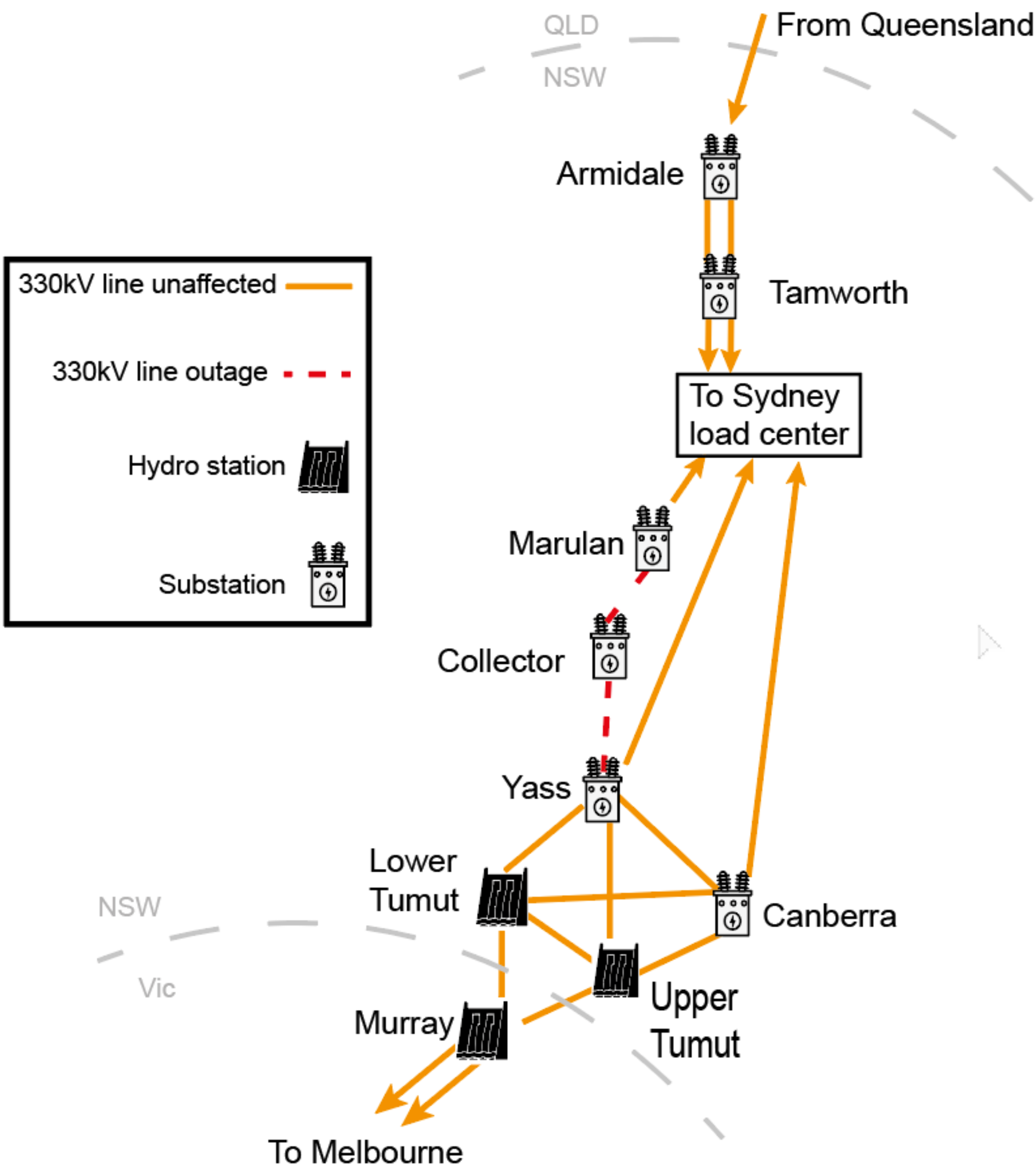
Planned network outages on the Collector to Marulan and Marulan to Yass lines meant low-priced capacity from Victoria and southern NSW was unable to reach key load centres including Sydney (Figure 3).

While these network outages did not occur simultaneously, they impacted the high-priced periods on 7 November, 3 and 6 December (Figure 1).

The Marulan to Yass outage started on 7 November and was originally scheduled to end on 8 November but was extended multiple times. The line returned to service on 25 November.

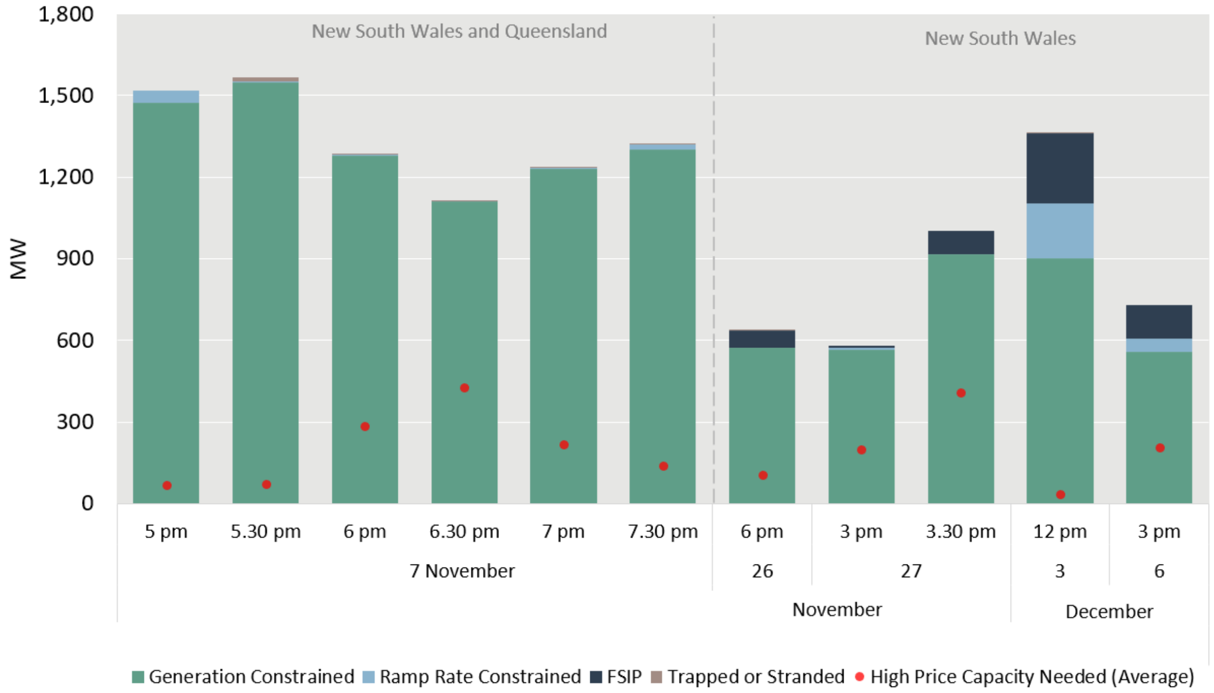
The Collector to Marulan outage started on 3 December and was originally scheduled to end on 14 December. The line returned to service on 13 December.

Figure 3 Network diagram



The location of the outages also meant that up to 1,550 MW of low-priced capacity in southern NSW was unable to make it to market. This included generation from hydro powered power stations (Tumut and Upper Tumut), gas fired power stations (Uranquinty), as well as wind farms (Bango and Gunning) and batteries (Riverina, Darlington Point, Broken Hill). For most of the high-priced intervals, the amount of low-priced capacity behind the constraint (green bar in Figure 4) was more than the high-priced capacity that was ultimately needed to meet demand (red dots in Figure 4).

Figure 4 Low-priced capacity unable to be dispatched



Source: AER analysis using NEM data.

4.1.2 Liddell to Tamworth/Muswellbrook lines

A planned network outage on the Liddell to Tamworth line in northern NSW from 9 October to 13 October, and the Liddell to Muswellbrook line from 11 November to 12 November, created a credible risk of the loss of QNI and Queensland being electrically islanded from the NEM (section 9).

To allow for this contingency, Queensland had to source its own R6 second services locally as the remaining interconnector into Queensland, Terranora, cannot transfer FCAS. On 10 and 11 October, it had requirements of 354 MW on average in R6 second services while on 12 November, it had requirements of between 176 MW and 343 MW in R6 second services.

While there was a large portion of capacity available below $5,000 per MW, there were times when high-priced R6 second was needed resulting prices above $5,000 per MW.

The Liddell to Muswellbrook line also had a short-term planned outage which caused flows on the QNI and Terranora interconnectors to be limited well below their nominal capacities during the high-priced periods on 3 December.

4.2 South Australia limitations

There are two interconnectors between South Australia and Victoria, Heywood and Murraylink. The nominal capacity of flows into South Australia on Heywood is 600 MW while on Murraylink it is 220 MW.[8]

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[8] AEMO, Interconnector Capabilities, April 2024.

During the high price periods on 22 October, flows over the Heywood interconnector were limited due to a planned network outage on the Cressy to Moorabool line in Victoria. Network constraints managing the outage limited imports on Heywood to around 54 MW during the high-price periods.

During the high price periods on 5 December, an outage of the Bundey to Buronga line (which is part of Project EnergyConnect, a new interconnector being built between South Australia and NSW) impacted the surrounding network and interconnectors.[9] Network constraints managing the outage limited imports on Heywood to around 228 MW.

On 23 October, to manage system security in the Victorian region, AEMO invoked a constraint which forced flows on Heywood from South Australia into Victoria during the high price periods. Murraylink was also impacted by a planned network outage on the Bendigo to Shepparton line in Victoria which saw flows into South Australia reduced to an average of 123 MW.

[9] Project EnergyConnect, Construction complete on South Australian side of new electricity interconnector, 21 December 2023.

5 Less generation due to increased baseload outages

A significant amount of generally low-priced baseload capacity was unavailable in Queensland and NSW mostly due to planned outages and unplanned plant issues (Table 3). Up to 4,700 MW of capacity was unavailable due to the baseload outages during the high-priced periods on 7, 26 and 27 November and 2 December.[10]

Table 3 Black coal baseload outages during high-priced periods

Participant	Station	Region	Registered Capacity (MW)	Outage type*	Outage period
CS Energy	Callide B Unit 1	Qld	350	Planned	18/07/24 to 15/12/24
CS Energy	Gladstone Unit 5	Qld	280	Unplanned	16/10/24 to 23/12/24
CS Energy	Kogan Creek unit 1	Qld	744	Planned	02/11/24 to 26/11/24
Stanwell Corporation	Tarong Unit 1	Qld	350	Planned	18/10/24 to 17/11/24
Stanwell Corporation	Tarong Unit 2	Qld	350	Planned	13/09/24 to 09/12/24
AGL Energy	Bayswater Unit 2	NSW	660	Planned	08/09/24 to 06/12/24
AGL Energy	Bayswater Unit 3	NSW	660	Unplanned	21/11/24 to 30/11/24
Origin Energy	Eraring Unit 3	NSW	720	Unplanned	25/08/24 to 06/12/24
Delta Electricity	Vales Point Unit 5	NSW	660	Unplanned	04/11/24 to 08/11/24
Delta Electricity	Vales Point Unit 6	NSW	660	Planned	25/09/24 to 03/12/24

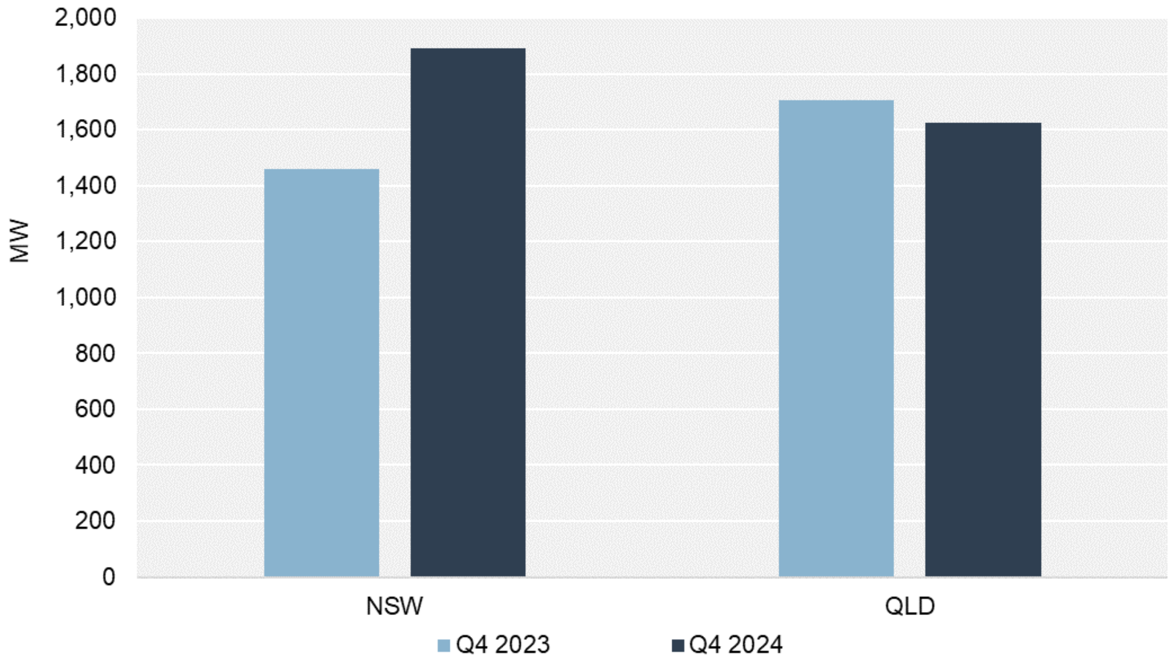
Source. AER analysis using NEM data.

Note: *An outage is regarded as planned if the MT PASA availability for the day was 0 MW. If MT PASA anticipated the unit being online, the outage is regarded as unplanned. MT PASA is updated weekly, and outages that being as unplanned may be reclassified if the generator submits updated availability information to AEMO. AEMO uses a different method in its reporting of outage data.

While it is common for coal-fired generators to schedule maintenance during shoulder periods (i.e. spring and autumn), the outages this quarter have increased on average, in NSW (Figure 5).

[10] The total baseload outage on 7 November was 4,700 MW for Queensland and New South Wales combined.

Figure 5 Average capacity unavailable due to black coal baseload outages, Q4 2023 and Q4 2024



Note: This chart illustrates the average capacity unavailable due to coal outages. Unavailability is only counted if the unit is completely offline for the whole day (AEMO uses a different method in its reporting of outage data). An outage is regarded as planned if the MT PASA availability for the day was 0 MW. If MT PASA anticipated the unit being online, the outage is regarded as unplanned. MT PASA is updated weekly, and outages that being as unplanned may be reclassified if the generator submits updated availability information to AEMO.
Source: AER analysis using NEM data

The impact of these outages was exacerbated by the network limitations described above in chapter 4.

5.1 Reserve shortfalls

The baseload outages contributed to the Australian Energy Market Operator (AEMO) forecasting low-level reserve shortfalls on several instances in November and December, with actual reserve shortfalls occurring on 7, 26, 27 November and 2 December. When there is a forecast tightening of supply and demand conditions, AEMO manages reserve shortfalls by issuing market notices to seek a response from market participants. If the market response is not adequate, a reserve shortfall notice is issued.

On 27 November, AEMO implemented the Reliability and Emergency Reserve Trader (RERT) from 3.45 pm to 4.45 pm and called upon a list of non-market generators or demand response to maintain system reliability and security - the first time since Q1 2023.[11]

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[11] Market notices 121038 and 121110. Reliability and Emergency Reserve Trader (RERT) Intention to negotiate for additional reserve – NSW Region.

AEMO, Reliability and Emergency Reserve Trader (RERT), February 2025.

AEMO, RERT Contracted Report for 27 November 2024, 23 December 2024.

6 High price events impacted average spot and forward prices in Queensland and NSW

6.1 Impact on average spot prices

Prices in Queensland and NSW were heavily affected by the 23 high price events this quarter. These periods drove up the quarterly price by.

- $46 per MWh in NSW
- $26 per MWh in Queensland
- $5 per MWh in South Australia.[12]

Despite the high average prices this quarter, there was an all-time record number of negative price 30-minute periods in the NEM. Victoria and South Australia had the largest number of negative price intervals, with both regions setting records. The negative prices led to the quarterly volume-weighted average price being $11 per MWh lower in Victoria and $9 per MWh lower in South Australia.[13]

6.2 Impact on forward contract prices

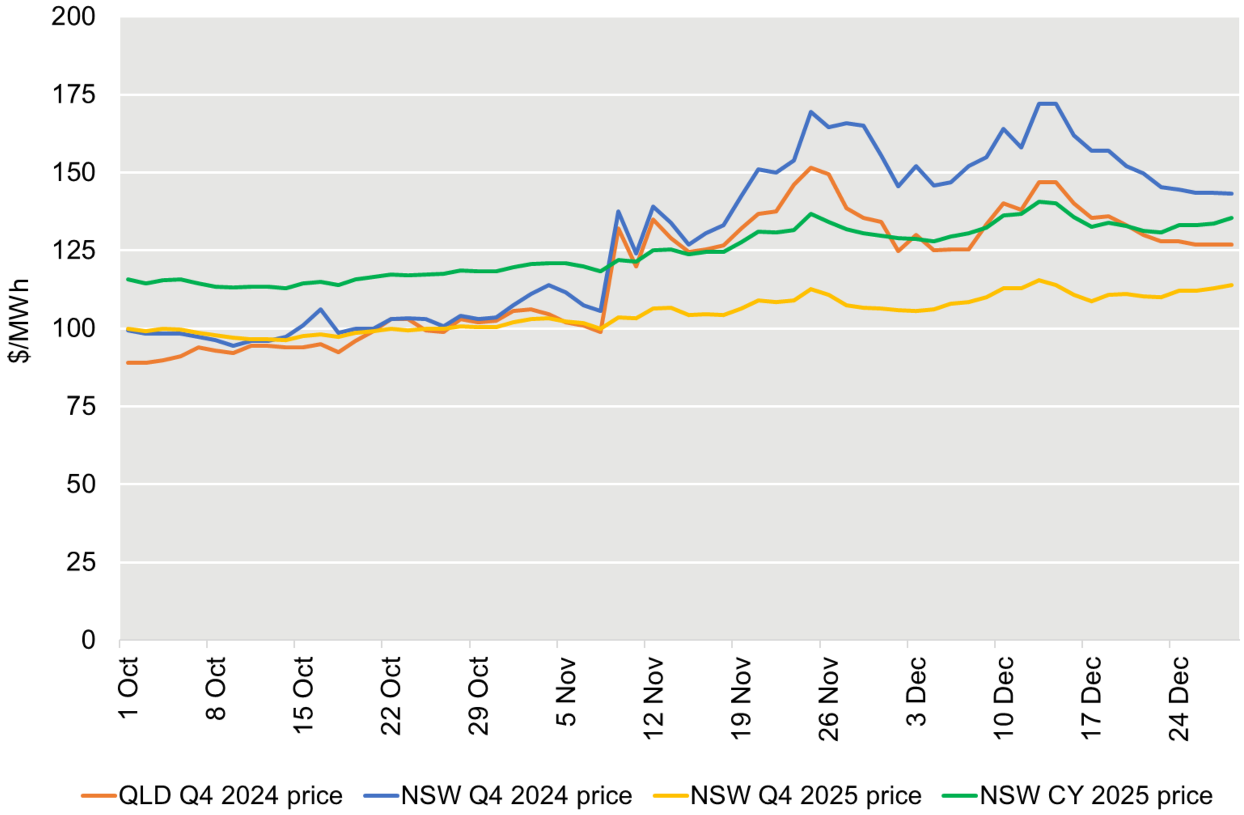
During the quarter, forward prices were relatively stable in October but increased sharply in November (by 34% and 30%, respectively), largely due to hot weather early in the season (Figure 6). Q4 2024 prices in Queensland and NSW increased by $34 per MWh and $32 per MWh, respectively, following the high price event on 7 November.

Very tight supply/demand conditions in NSW in the week beginning 25 November saw high forecast spot prices occurring on most days and either forecast or actual reserve shortfalls on several occasions. The sharp Q4 2024 November contract price increases reflected high spot prices expectations continuing into December.

[12] Australian Energy Regulator, Wholesale Quarterly Report Q4 2024, 30 January 2025.

[13] Australian Energy Regulator, Wholesale Quarterly Report Q4 2024, 30 January 2025.

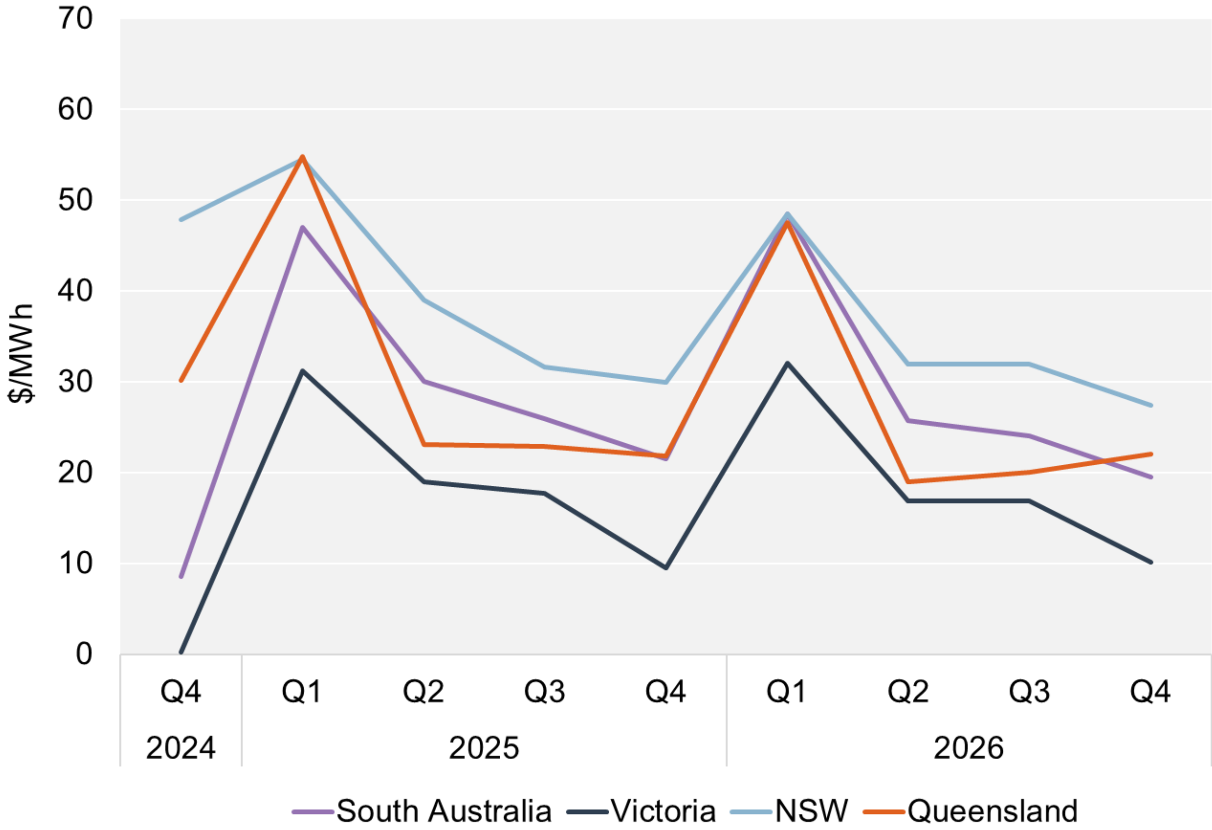
Figure 6 High spot prices in November drove higher futures prices in Queensland and NSW



Source. AER analysis using ASX Energy data.
Note. Settled base future prices for Q4 2024, Q4 2025 and Calendar Year 2025.

Like the base futures market, Q4 2024 caps prices increased in November by $15 per MWh (or 60%) in Queensland and $27 per MWh (or 89%) in NSW in response to November's spot high price events, with smaller increases seen in the Q1 2025 and Q2 2024 caps prices (Figure 7). In contrast, December Q4 2024 caps prices fell slightly in Queensland and NSW by around $10 per MWh. Q1 2025 caps prices in both Queensland and NSW (both $58 per MWh at 31 December) reflected a market expectation of high cooling demand and consequently a heightened risk of above $300 per MWh spot market intervals in those states for summer.

Figure 7 Caps prices at 31 December 2024



Source. AER analysis using ASX Energy data.

7 Rebidding contributed to some of the high prices

While over 1,000 MW of capacity was rebid from high to low prices, which stopped some forecast high prices from occurring, this was not enough to alleviate all high prices. There were 102 5-minute prices above $5,000 per MWh when the 30-minute prices were high across the three regions. As NSW and Queensland were treated as one region for two high price days, there were 67 unique 5-minute prices above $5,000 per MWh. Of the 67, around 40% were a result of participants rebidding small amounts of capacity from low to high or withdrawing low-priced capacity for technical reasons.

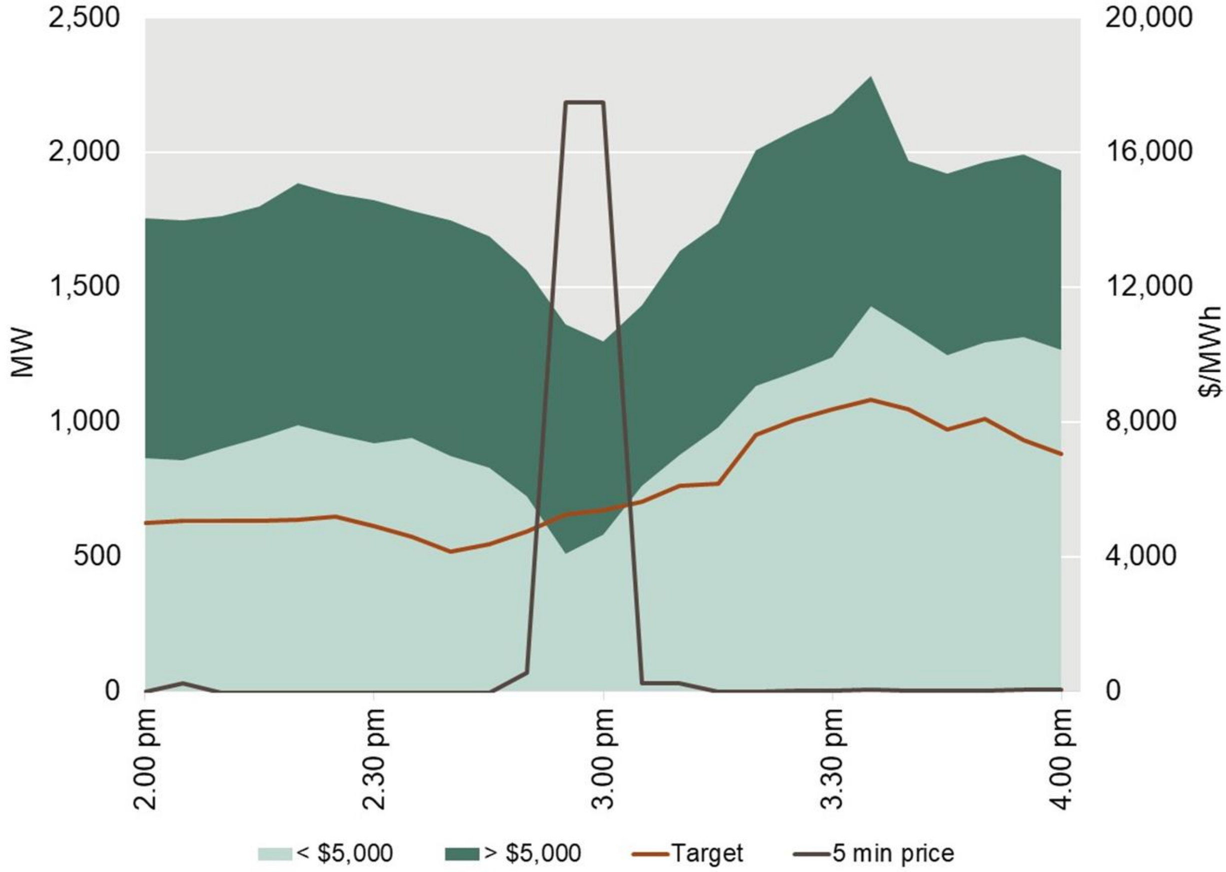
Details of participant rebidding are included in the individual high priced day sections in Chapter 8 and the appendices.

8 High energy price events

8.1 22 October, South Australia

On 22 October, the 30-minute price in South Australia reached $5,910 per MWh at 3 pm. The high price was not forecast. Around 47% of capacity was offered below $5,000 per MWh which is similar to the October average for this time of day (Figure 8).

Figure 8 Capacity offered above and below $5,000 per MWh, 22 October



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity.

8.1.1.1 Demand was higher than average

Demand at 3 pm was 798 MW. Demand was also higher than average with the 30-minute average for the quarter at 3 pm of 584 MW.

8.1.1.2 Network limitations

A planned outage of network equipment near Moorabool meant flows on Heywood were limited to 58 MW into South Australia and South Australia was unable to import more low-priced capacity during the high prices.

8.1.1.3 Limited output from wind and solar generation

Wind output averaged 263 MW during the high prices out of around 2,763 MW installed, which equates to around 10% of installed capacity in South Australia.

Average solar output was 134 MW out of around 600 MW of maximum capacity due to cloudy conditions. The cloudy conditions also meant rooftop solar output was low. Rooftop solar output was 855 MW during the high prices which was 381 MW lower than the daily peak a few hours earlier.

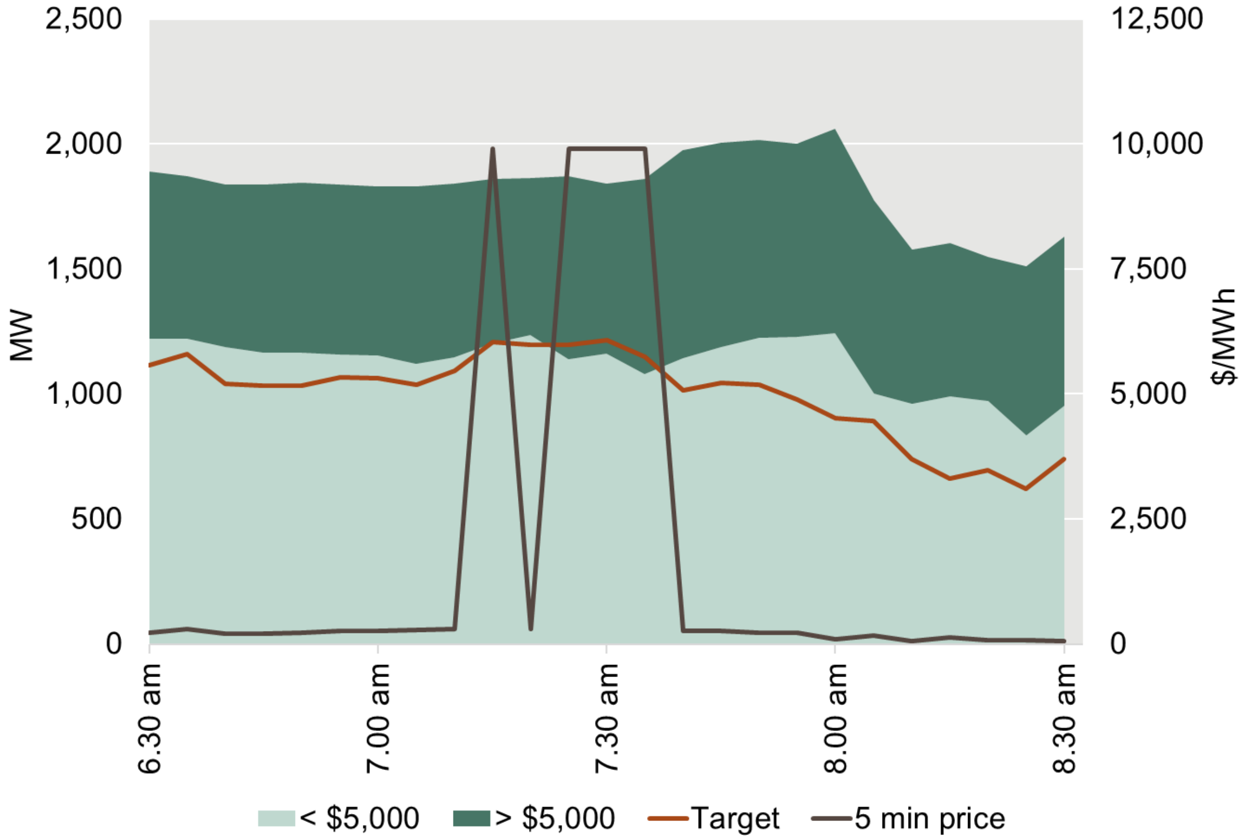
8.1.1.4 Rebidding for commercial reasons

Between 89 MW and 147 MW of high-priced capacity was needed to meet demand. At 2.49 pm, effective from 2.55 pm, AGL Energy shifted 176 MW of capacity at Barker Inlet from $561 per MWh to $17,500 per MWh due to a change in forecast price and contributed to setting the price at 2.55 pm and 3 pm (Appendix A).

8.2 23 October, South Australia

On 23 October, the 30-minute price in South Australia reached $5,096 per MWh at 7.30 am. The high price was not forecast. Around 63% of capacity was offered below $5,000 per MWh (Figure 9).

Figure 9 Capacity offered above and below $5,000 per MWh, 23 October 2024



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity.

8.2.1.1 Network limitations

To manage system security in the Victorian region, AEMO invoked a constraint which forced flows on Heywood from South Australia into Victoria while South Australia had high prices from 7.15 am. Flows went from 185 MW into South Australia at 7.05 am to flows out of South Australia at 245 MW by 7.30 am.

Murraylink was impacted by a planned outage on the Bendigo to Shepparton line in Victoria, with flows into South Australia reduced to an average of 123 MW during the high price periods.

The network limitations meant South Australia was unable to import more low-priced capacity during the high price periods.

8.2.1.2 Limited output from wind generation

Wind output was lower than forecast, averaging 104 MW out of 2,763 MW of installed capacity during the high prices. This equates to 4% of installed wind capacity in South Australia.

8.2.1.3 Rebidding

Between 5 MW and 58 MW of high price capacity was needed to meet demand. Rebidding for commercial reasons contributed to the high price (Appendix B).

At 7.18 am, effective from 7.25 am, AGL Energy shifted 56 MW of capacity at Barker Inlet and 30 MW of capacity at Torrens Island from $138 per MWh to $17,500 per MWh due to a change in forecast prices.

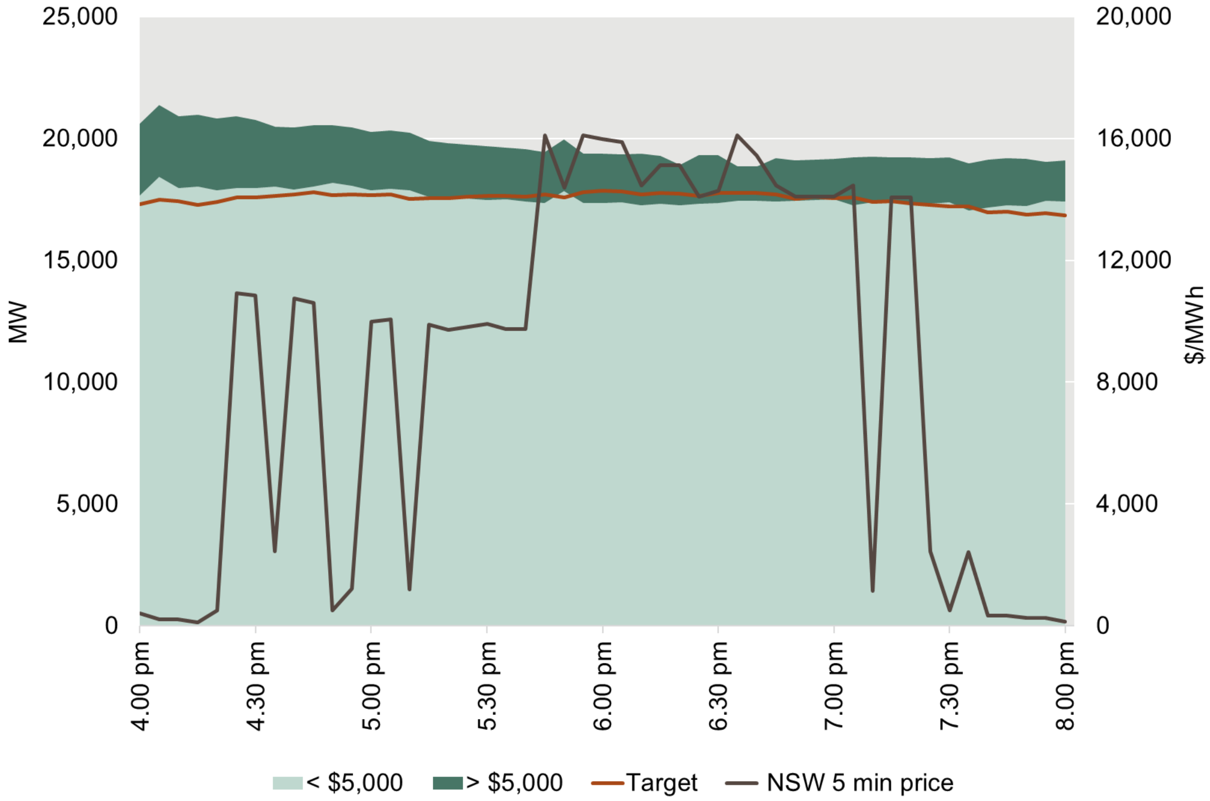
8.3 7 November, NSW and Queensland

On 7 November, the 30-minute prices exceeded $5,000 per MWh six times in NSW and five times in Queensland (Figure 10) from 5 pm to 7.30 pm. The prices ranged from $5,915 per MWh to $15,637 per MWh. The high prices were forecast.

In this event Queensland and NSW were price aligned. When regions are price aligned they function more like a single market than a collection of regional markets as generators are exposed to competition from generators in other regions.

Both regions had multiple reserve shortfall forecasts in the days leading up to 7 November with an actual reserve shortfall (lowest level) occurring in both regions at around 5.45 pm until 7.45 pm.[14]

Figure 10 Capacity offered above and below $5,000 per MWh, 7 November



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity. The capacity for NSW and QLD has been combined as they are treated as one region. NSW is used as the proxy in this chart as prices were aligned across the regions.

8.3.1.1 High Demand

Demand during the high price periods in NSW was 8,937 MW and 9,192 MW for Queensland at its peak. While demand in NSW was not remarkably high compared to the highest

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[14] Market notices 120112 and 120113 - actual LOR1 in Queensland and New South Wales. AEMO, "LOR Factsheet", AEMO, December 2022.

maximum daily demand for the quarter (12,611 MW), Queensland still recorded the fourth highest maximum daily demand for the quarter on this day at 9,192 MW.

8.3.1.2 Network limitations

A planned network outage on the Marulan to Yass line meant low-priced capacity from Victoria and southern NSW was unable to reach key load centres including Sydney. This meant NSW was unable to access low-priced capacity from southern NSW or Victoria to alleviate the high prices. There were also two system normal constraints in Queensland which constrained low-priced capacity during the high-priced periods.

Between 1,000 MW and 1,800 MW of low-priced capacity was constrained for both regions and could not make it to market during the high price periods.

8.3.1.3 Baseload outages

Around 4,700 MW capacity of baseload units were on mostly planned outages in NSW and Queensland.

8.3.1.4 Limited output from wind in Queensland

In Queensland, wind output averaged 205 MW out of around 2,117 MW installed capacity during the high prices, which equates to around 10% of installed capacity in Queensland.

8.3.1.5 Rebidding

High prices in both regions were forecast to be above $5,000 between 5 pm and 9 pm, four hours ahead. Due to participants rebidding significant amounts of capacity from high to low prices, only six eventuated in NSW and five in Queensland.

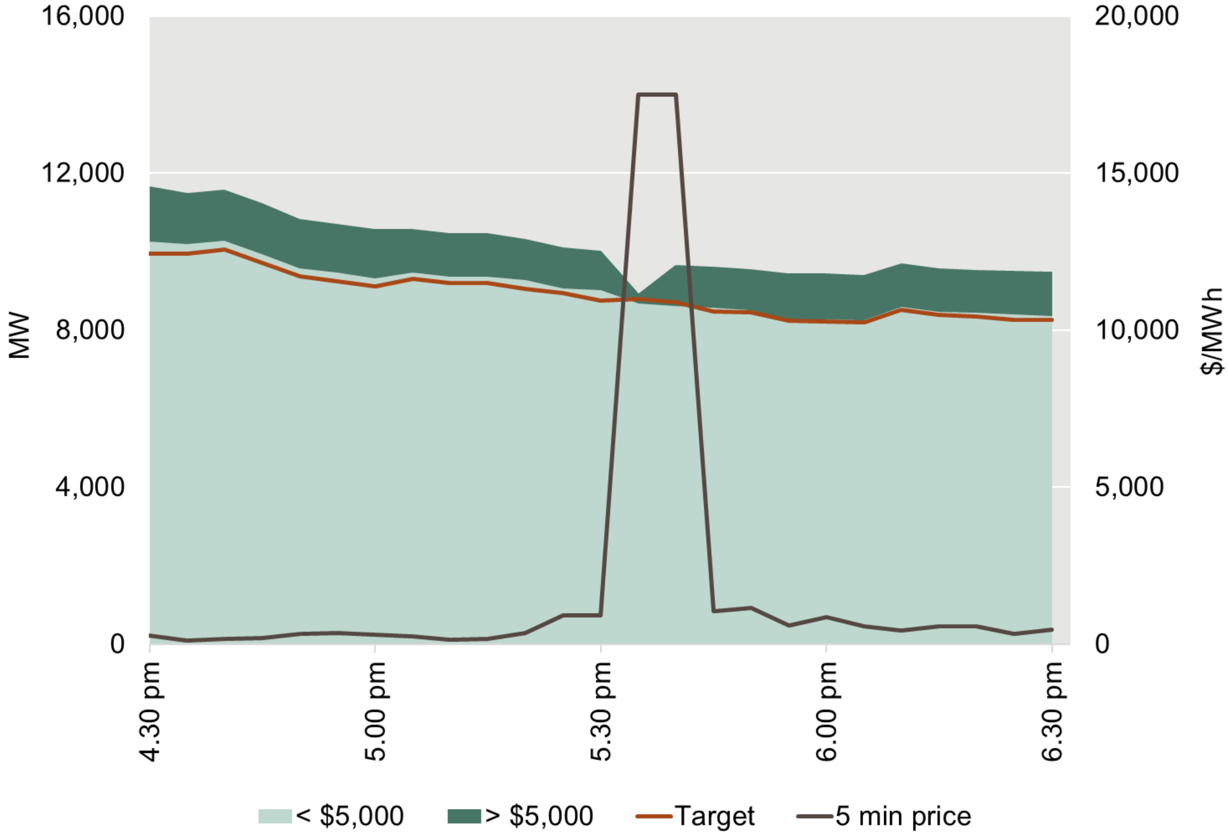
Rebidding for commercial and technical reasons contributed to some of the high prices. Between 7 MW and 490 MW of capacity above $5,000 per MWh was dispatched during high-priced dispatch intervals.

In the four hours leading up to the event, participants shifted a combined total of over 1,000 MW of high-priced capacity to low prices, but this was not enough to meet demand on occasions. Some participants rebid small amounts of capacity from low to high prices (most significantly AGL and CleanCo) for commercial reasons or withdrew low-priced capacity (CS Energy) due to ashing system issues (Appendix C).

8.4 26 November, NSW

On 26 November, the 30-minute price in NSW reached $6,448 per MWh at 6 pm. The high price was forecast. Around 93% of capacity was offered below $5,000 per MWh (Figure 11).

Figure 11 Capacity offered above and below $5,000 per MWh, 26 November



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity.

8.4.1.1 High demand

Demand during the high price periods was around 11,197 MW driven by mid-30 temperatures during a week of heatwave conditions in NSW. The maximum daily demand peaked at 11,301 MW and was the seventh highest for the quarter.

8.4.1.2 Network limitations

Flows into NSW were limited from Queensland and Victoria due to system normal constraints invoked to prevent overloading and to maintain system security.

Flows into NSW across QNI were around 1,300 MW, which is its nominal limit, while Terranora was at around 120 MW, out of its 210 MW nominal limit. VNI was flowing at around 1,189 MW into NSW out of its nominal limit of 1,700 MW.

Due to various system normal constraints, between 504 MW and 643 MW of low-priced capacity was constrained and unable to make it to market during the high price periods.

Around 306 MW of capacity below $1,000 per MWh was being backed off from solar generators at 5.35 pm to maintain system security.

The network limitations meant NSW was unable to access low-priced capacity to alleviate the high prices.

8.4.1.3 Less generation in NSW due to baseload outages

Planned baseload outages meant that 2,700 MW of generally low-priced capacity was unavailable in NSW. This capacity was spread between Origin Energy's Eraring Power Station, AGL Energy's Bayswater Power Station and Delta Electricity's Vales Point Power Station.

In addition, three of Origin Energy's Uranquinty Power Station's gas units tripped around 4.40 pm (generating around 450 MW at the time). This caused AEMO to declare a reserve shortfall for NSW from 4.30 pm until 8.15 pm.

8.4.1.4 Limited output from wind generation

Wind generation was around 253 MW out of around 2,762 MW at the time of high prices, which equates to around 9% of installed capacity in NSW.

8.4.1.5 Generation start up constrained

125 MW of low-priced capacity at Snowy Hydro's Colongra Power Station could not start up fast enough to prevent high prices. For one high-priced interval, the amount of low-priced capacity unable to be dispatched was more than the high-priced capacity needed to meet demand.

8.4.1.6 Rebidding

Between 91 MW and 116 MW of high-priced capacity was needed to meet demand. Rebidding for technical reasons contributed to the high price (Appendix D).

Over three rebids from 4.40 pm, Origin Energy removed 534 MW of capacity from the price floor (-$1,000 per MWh) at Uranquinty due to its gas turbine tripping during the high price periods.

8.5 27 November, NSW

On 27 November, the 30-minute price in NSW exceeded $5,000 per MWh twice in the afternoon. The price reached $17,250 per MWh at 3 pm and $17,500 per MWh at 3.30 pm. The high prices were forecast.

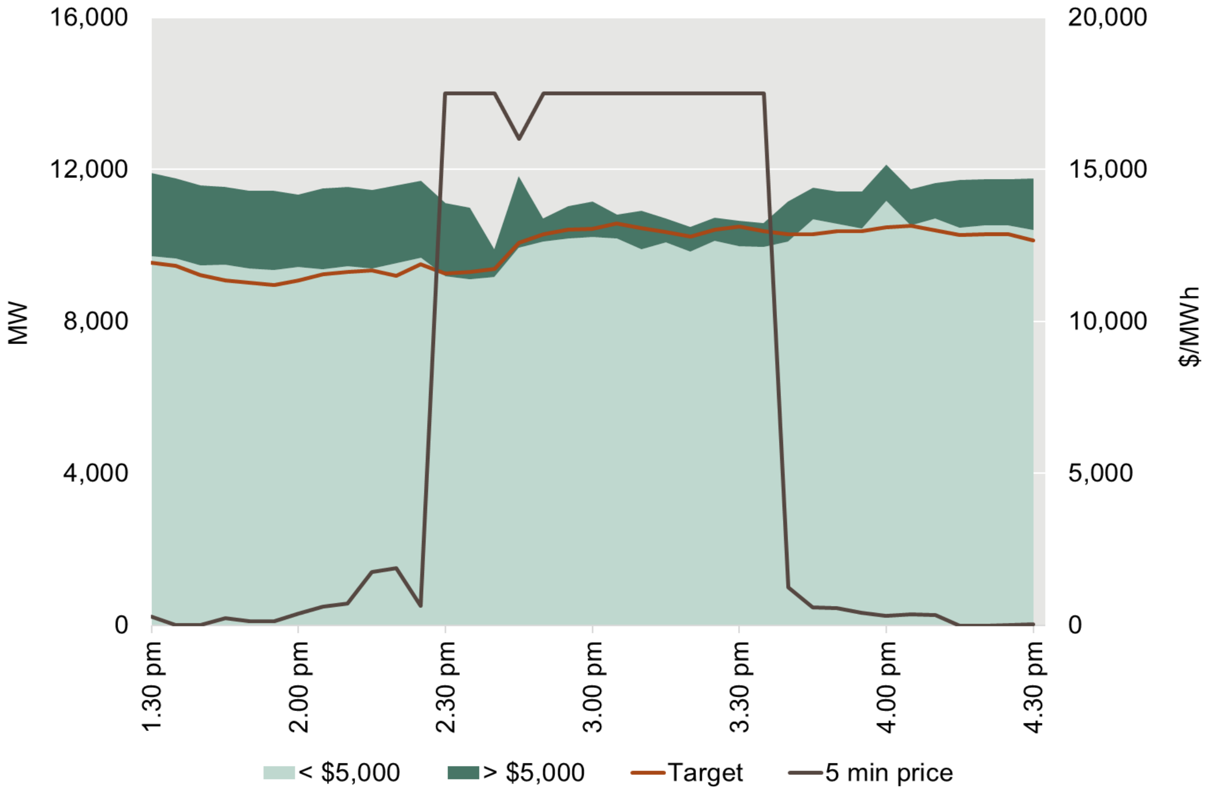
Like the previous day of 26 November, the same dynamic of hot temperatures, high demand, network constraints and baseload unit outages meant there was not enough low-priced capacity below $5,000 per MWh to meet demand in NSW.

AEMO forecast multiple low-level reserve shortfalls in NSW throughout the day, with actual level 1 and level 2 shortfalls occurring from 2.30 pm to 8 pm and 3.30 pm to 4.45 pm, respectively.[15]

Due to the low-level reserve shortfalls, AEMO implemented the Reliability and Emergency Reserve Trader (RERT) from 3.45 pm to 4.45 pm so that it could call upon non-market generation or demand response to maintain system reliability and security.

Around 92% of capacity was offered below $5,000 per MWh (Figure 12).

Figure 12 Capacity offered above and below $5,000 per MWh, 27 November



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity.

[15] Market notices 120974, 120975, 120988, 120989, 121014, 121015, 121017, 121021, 121023, 121024, 121040, 121049, 121057, 121060, 121066, 121069, 121084, 121088, 121095, 121104 - forecast LOR1, LOR2 and LOR3 for New South Wales. Market notices 121089, 121101 and 121106 - actual LOR1 and LOR2 in New South Wales. AEMO, "LOR Factsheet", AEMO, December 2022.

8.5.1.1 High demand

Demand during the high price periods reached around 11,325 MW driven by heatwave conditions. The maximum daily demand was 11,325 MW which was the fifth highest for the quarter.

8.5.1.2 Network limitations

Flows into NSW were limited from Queensland and Victoria due to system normal constraints invoked to prevent overloading and to maintain system security.

Terranora was flowing around 10 MW on average into NSW compared to its nominal capacity of 210 MW.

QNI was flowing around 867 MW on average into NSW, limited below is capacity of 1,300 MW.

Flows on the VNI averaged around 68 MW and subsequently reduced to 0 MW shortly before 3.30 pm. This was well below its nominal capacity of up to 1,700 MW.

Due to various system normal constraints, between 292 MW and 1,520 MW of low-priced capacity was constrained and could not make it to market during the high price periods.

The network limitations meant NSW was unable to access cheaper generation to alleviate the high prices.

8.5.1.3 Less generation in NSW due to baseload outages

Like the previous day on 26 November, around 2,700 MW of generally low-priced baseload capacity was unavailable in NSW.

8.5.1.4 Rebidding

Between 146 MW and 544 MW of high-priced capacity was needed to meet demand. Most high-priced capacity needed was driven by the tight supply conditions and the large number low-priced capacity that was constrained. Rebidding for technical reasons partly contributed to some of high price intervals (Appendix E).

The most significant rebids during the high-priced periods were from Origin Energy. At 1.01 pm, Origin Energy removed 120 MW of capacity at Shoalhaven from the price floor (-$1,000 per MWh) due to plant issues leaving 40 MW of capacity available.

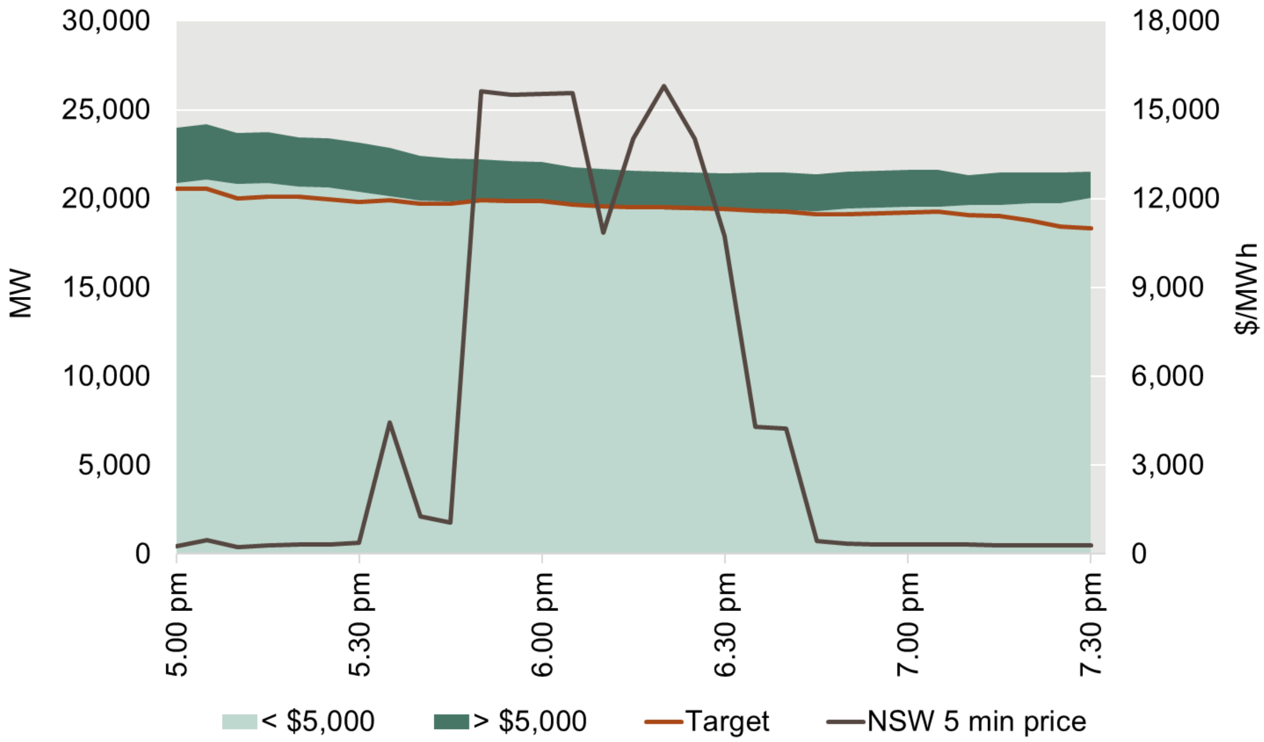
Over two rebids at 2.17 pm and 2.24 pm, effective for 2.25 pm and 2.30 pm, respectively, Origin Energy's Eraring unit 1 removed a total of 40 MW of capacity from $1 per MWh due to a fan limitation.

8.6 2 December, Queensland and NSW

On 2 December, the 30-minute prices in NSW and Queensland exceeded $5,000 per MWh twice in the evening (Figure 13). The price reached $8,903 per MWh at 6 pm and $13,502 per MWh at 6.30 pm in NSW and $8,261 per MWh at 6 pm and $12,360 per MWh at 6.30 pm in Queensland. The high prices were forecast very early. AEMO forecast low-level reserve shortfalls in NSW early in the day, with actual level 1 shortfalls occurring from 5 pm to 7.20 pm.[16]

In this event Queensland and NSW were price aligned. When regions are price aligned they function more like a single market than a collection of regional markets as generators are exposed to competition from generators in other regions.

Figure 13 Capacity offered above and below $5,000 per MWh, 2 December



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity. The capacity for NSW and QLD has been combined as they are treated as one region. NSW is used as the proxy in this chart as prices were aligned across the regions.

8.6.1.1 High demand

Due to continuing warm temperatures, demand during the high price periods for NSW was 11,466 MW which was the maximum daily demand in NSW and the third highest for Q4 2024. Queensland's demand during the high prices reached 9,160 MW and was the fifth highest for the quarter.

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[16] Market notices 121382 Forecast LOR1 for New South Wales. Market notices 131384 Actual LOR1 in New South Wales.
AEMO, "LOR Factsheet", AEMO, December 2022.

8.6.1.2 Network limitations

System normal constraints to avoid overloading on the Upper Tumut to Stockdill and Wagga to Lower Tumut lines limited flows from southern NSW and Victoria.

Flows on VNI were averaging 592 MW into NSW out of its nominal capacity of between 400 MW and 1,700 MW.

8.6.1.3 Baseload outages

Four units were offline due to planned outages while two units were offline due to unplanned outages. Around 3,020 MW of baseload capacity was unavailable. The reduction in baseload capacity unavailable was likely due to units returning to service for summer.

8.6.1.4 Limited output from wind generation

Calm conditions saw very low levels of wind output in both regions.

In NSW, wind output averaged 314 MW out of around 2,762 MW installed capacity during the high prices, which equates to around 11% of installed capacity in NSW.

In Queensland, wind output averaged 220 MW out of around 2,117 MW installed capacity during the high prices, which equates to around 10% of installed capacity in Queensland.

8.6.1.5 Generation start up and ramp up constrained

At 6.05 pm, 110 MW of low-priced capacity at Alinta's Braemar Power Station could not start up quickly enough to prevent high prices. For one interval, the amount of low-priced capacity unable to be dispatched was more than the high-priced capacity needed to meet demand.

At 6.10 pm, 60 MW of low-priced capacity at Braemar Power Station could not ramp up quickly enough to prevent high prices. For one interval, the amount of low-priced capacity unable to be dispatched was more than the high-priced capacity needed to meet demand.

8.6.1.6 Rebidding

High prices in both regions were forecast to be above $5,000 between 5 pm and 8 pm, four hours ahead. Due to participants rebidding significant amounts of capacity from high to low prices, only two eventuated at 6 pm and 6.30 pm.

Between 16 MW and 207 MW of combined high-price capacity was needed to meet demand in both regions. Rebidding for commercial and technical reasons contributed to the high price (Appendix F).

In the four hours leading up to the event, participants shifted a combined total of between 1,341 MW to 2,128 MW of high-priced capacity to low prices but this was not enough to meet demand for 6 pm and 6.30 pm. Some participants rebid capacity from low to high prices for commercial reasons or withdrew low-priced capacity for technical reasons. The biggest being Snowy Hydro which moved a total of 160 MW from below $500 per MWh to the price cap due to a change in forecast prices/sensitivities. Delta Electricity removed between 45 MW and 70 MW of capacity under $218 per MWh across all 5-minute intervals due to a fabric filter limit issue.

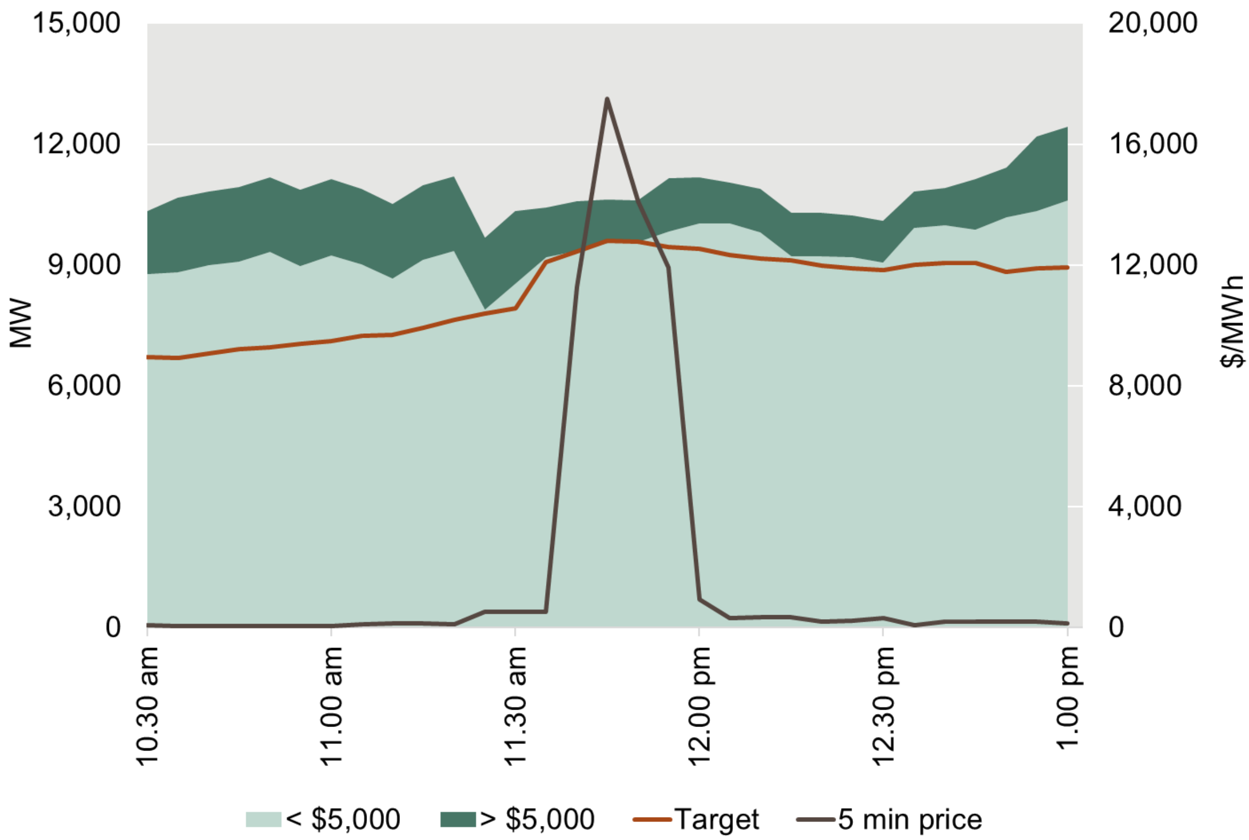
On occasion, small amounts of rebidding by several participants such as Iberdrola, Arrow Energy and Stanwell, which combined, contributed to the high price capacity needed

(Appendix F). Stanwell had offered 365 MW of fixed load as part of their tuning process. From 5.50 pm to 6 pm, Stanwell removed 365 MW of fixed load (fixed load is treated as the lowest offer in the bid stack) as they completed their tuning process. Their offers reverted to the ten price bands with 45 MW of capacity at market cap, having the same effect as rebidding 45 MW from the price floor to the price cap.

8.7 3 December, NSW

On 3 December 2024, the 30-minute price in NSW reached $9,371 per MWh at 12 pm. The high price was not forecast. Around 89% of capacity was offered below $5,000 per MWh (Figure 14).

Figure 14 Capacity offered above and below $5,000 per MWh, 3 December



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity.

8.7.1.1 Demand was higher than average

Demand at 12 pm was 9,457 MW and was 632 MW higher than forecast one hour prior. Demand was also higher than average with the 30-minute average for 12 pm for the quarter of 6,211 MW.

8.7.1.2 Network limitations

A planned network outage on the Collector to Marulan line in southern NSW resulted in between around 180 MW and 1,020 MW of low-priced capacity unable to reach key load centres including Sydney.

There was also a short term planned outage on the Liddell to Muswellbrook line which caused flows on the QNI to be limited to around 570 MW out of its 1,300 MW nominal capacity, and Terranora to be limited to around 17 MW out of its 210 MW nominal capacity.

8.7.1.3 Limited output from solar generation

There was a significant reduction in rooftop solar generation during the high price periods due to cloudy conditions. Between 11.30 am and 12 pm, rooftop solar output was 2,484 MW. This is almost half the output generated the day prior of 4,837 MW.

8.7.1.4 Generation start up and ramp up constrained

Up to 270 MW at Snowy Hydro’s Colongra Power Station could not start up quickly enough to prevent high prices. The amount of low-priced capacity unable to be dispatched was more than the high-priced capacity needed to meet demand for two high priced intervals.

Up to 173 MW at Delta Electricity’s Vales Point Power Station could not ramp up quickly enough to prevent high prices. The amount of low-priced capacity unable to be dispatched was more than the high-priced capacity needed to meet demand for two high priced intervals.

8.7.1.5 Energy FCAS trade-off sets the price

The market operator’s dispatch engine simultaneously optimises the FCAS and energy markets, every dispatch interval, to determine the least cost outcome. This can lead to a trade-off between the FCAS and energy markets. For example, a generator may be reduced in providing raise ancillary services so it can provide additional energy or vice versa. This can impact prices in both the energy and FCAS markets.

On this day, for two of the four high-priced 5-minute intervals at 11.40 am and 11.55 am, offers of around $10,000 per MW in lower FCAS contributed to setting the energy price in NSW.

8.7.1.6 Rebidding for commercial and technical reasons

Between 5 MW and 57 MW of high-price capacity was needed to meet demand. Rebidding for commercial and technical reasons contributed to the high price (Appendix G).

Delta Electricity withdrew a total of 225 MW of low-priced capacity at Vales Point during the high-priced periods due to technical issues including milling limits and fabric filter limits.

At 10.53 am, AGL Energy removed 45 MW of low-priced capacity at Bayswater due to unexpected plant limits.

At 11.24 am, AGL Energy shifted 65 MW of capacity at Bayswater from $36 per MWh to the price cap due to a change in forecast prices.

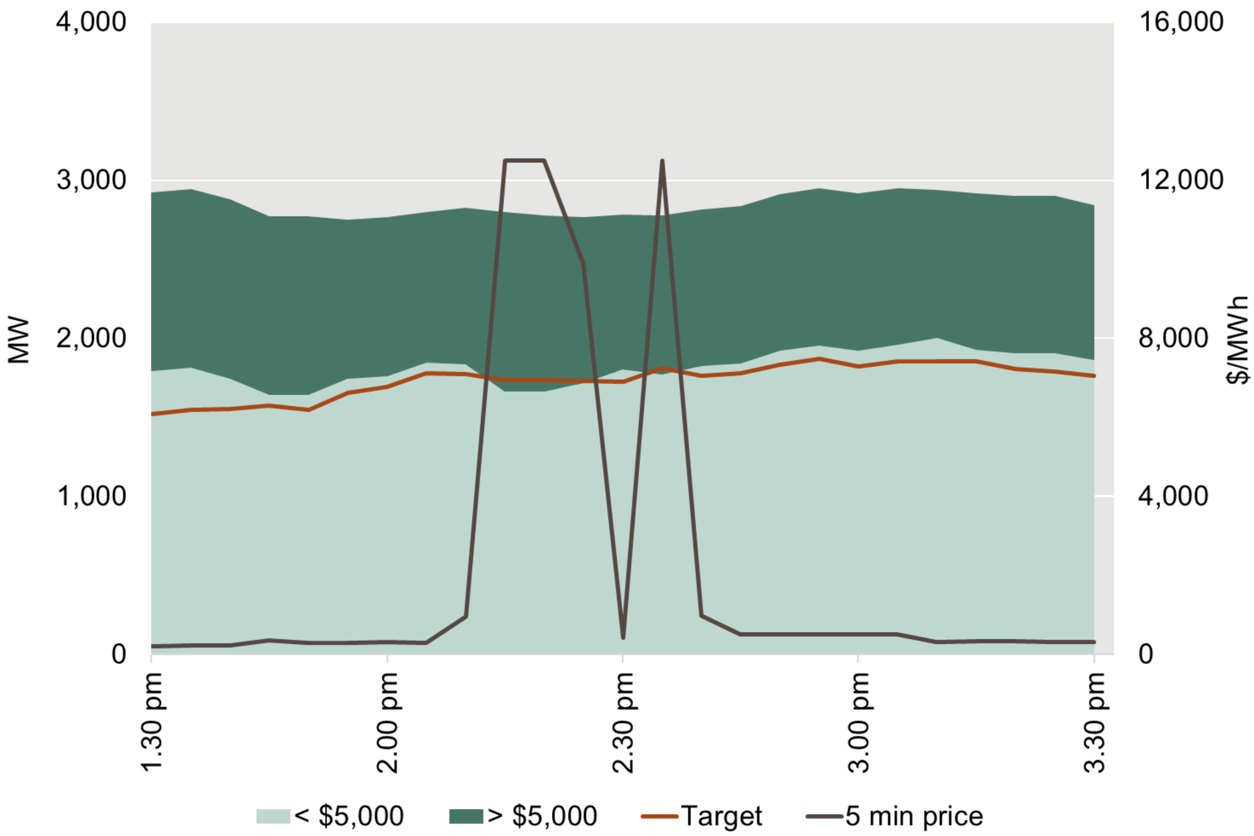
At 11.36 am, effective for 11.45 am and 11.50 am, it offered 20 MW of capacity, 5 MW was low-priced while 15 MW was high priced, as the plant limit had been lifted.

The combined effect of the three rebids by AGL Energy contributed to the high-priced periods at 11.45 am and 11.50 am.

8.8 5 December, South Australia

On 5 December, the 30-minute price in South Australia reached $6,096 per MWh at 2.30 pm. The high price was not forecast. Around 63% of capacity was offered below $5,000 per MWh (Figure 15).

Figure 15 Capacity offered above and below $5,000 per MWh, 5 December



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity.

8.8.1.1 Demand was higher than average

Demand at 2.30 pm was 2,101 MW compared to 1,530 MW forecast four hours prior. Demand was also higher than average with the 30-minute average for 2.30 pm for the quarter of 540 MW.

While demand was significantly impacted by a fall in rooftop solar generation, high temperatures in Adelaide of around 37°C meant that demand on the day was already high.

8.8.1.2 Network limitations

A planned outage of the Bundey to Buronga line meant constraints managing the outage limited flows on Heywood and South Australia was unable to import more low-priced capacity during the high prices.

This outage also meant that up to 68 MW of low-priced capacity was unable to make it to market. This included generation from the Tailem Bend Solar Farm and Canunda Wind

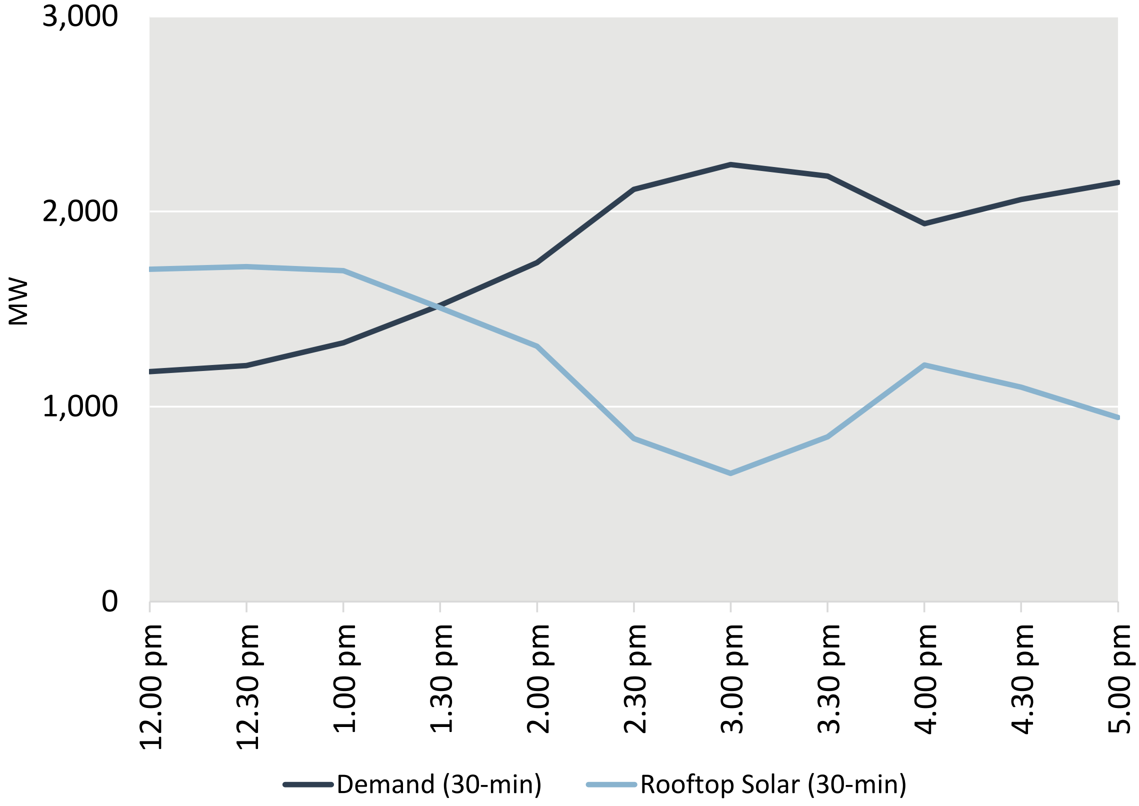
Farm. For only one high-priced interval, the amount of low-priced capacity behind the constraint was more than the high-priced capacity that was needed to meet demand.

8.8.1.3 Limited output from wind and solar generation

Wind output averaged 179 MW out of around 2,763 MW installed capacity during the high prices, which equates to around 6% of installed capacity in South Australia.

Average solar output was 349 MW out of around 600 MW of maximum capacity due to cloudy conditions. The cloudy conditions also meant rooftop solar output was low. Rooftop solar output was 836 MW during the high prices which was 881 MW lower than the daily peak a few hours earlier. A drop in rooftop top solar means an increase in demand to be met by market generators (Figure 16).

Figure 16 Correlation between demand and rooftop solar generation



Source. AER analysis using NEM data.

8.8.1.4 Generation ramp up and start up constrained

Up to 81 MW of low-priced capacity at Origin Energy's Osborne could not ramp up quickly enough to avoid high prices. For all high-priced intervals, the amount of low-priced capacity that could not be dispatched was more than the high-priced capacity that was needed to meet demand.

Up to 19 MW of low-priced capacity at Origin Energy's Quarantine could not start fast enough to avoid high prices. For only 1 high-priced interval, the amount of low-priced capacity unable to be dispatched was more than the high-priced capacity that was needed to meet demand.

8.8.1.5 Rebids

Between 11 MW and 74 MW of high-priced capacity was needed to meet demand. Rebidding for commercial and technical reasons contributed to the high price (Appendix H).

At 2.04 pm, effective from 2.10 pm, Engie shifted 25 MW of capacity at Pelican Point from $299 per MWh to $12,500 per MWh due to fuel management and contributed to setting price for two of the three high-priced intervals.

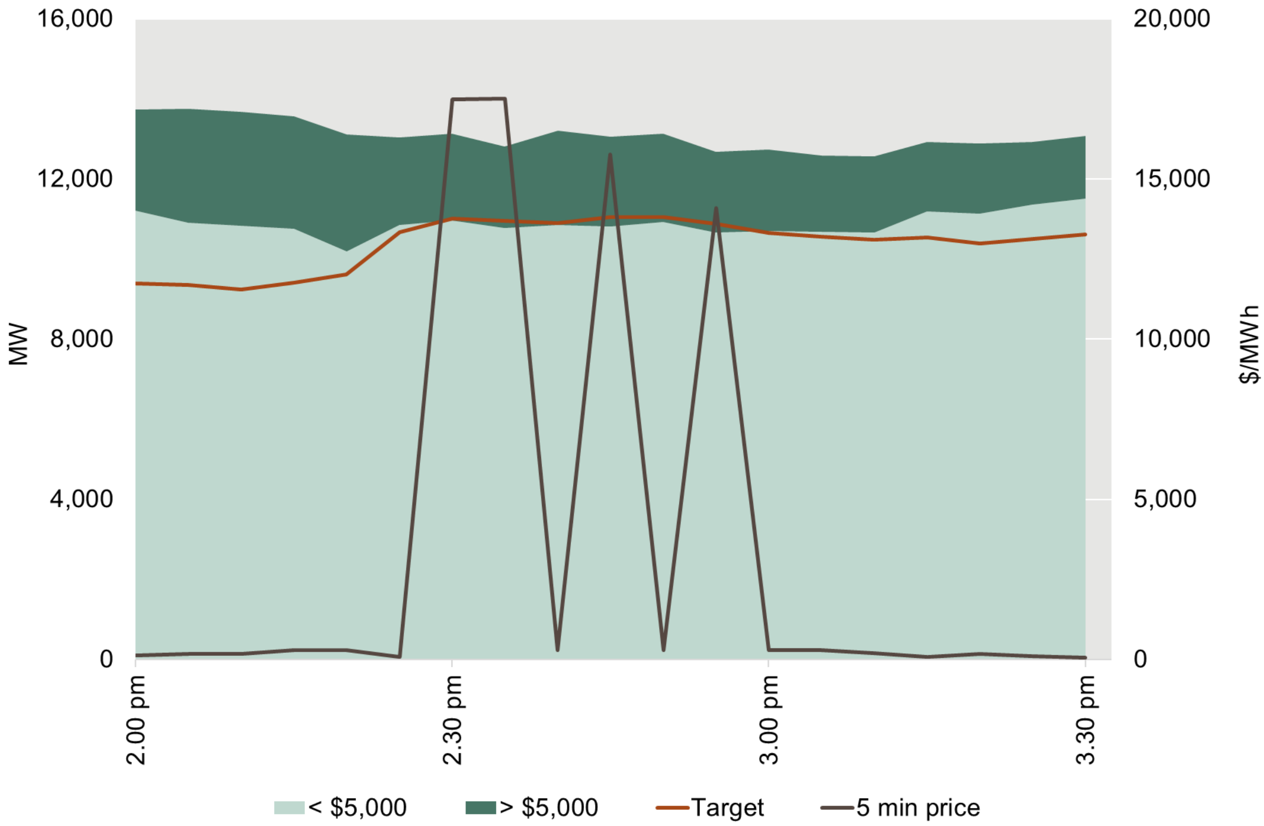
For all high-priced intervals, AGL Energy rebid 72 MW of capacity to high prices across Torrens Island and Barker Inlet. This was mainly a result of AGL shifting 120 MW of capacity at Torrens Island from $138 per MWh to $17,500 per MWh at 2.08 pm due to a change in forecast prices. There were other rebids where they shifted capacity to both low and high prices for changes in forecast prices.

At 2.13 pm, effective from 2.20 pm, Neoen shifted 25 MW of capacity at Hornsdale Power Reserve from $3,911 per MWh to $9,932 per MWh due to a change in forecast prices and contributed to setting price for one of the three high-priced intervals.

8.9 6 December, NSW

On 6 December, the 30-minute price in NSW reached $8,044 per MWh at 3 pm. The high prices were not forecast. Around 84% of capacity was offered below $5,000 per MWh (Figure 17).

Figure 17 Capacity offered above and below $5,000 per MWh, 6 December



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MWh refers to effective capacity.

8.9.1.1 Demand was higher than average

Demand at 3 pm was 11,377 MW. Demand was also higher than average with the 30-minute average for 3 pm for the quarter of 6,959 MW.

8.9.1.2 Network limitations

A planned outage of the Collector to Marulan line limited flows from southern NSW and Victoria from reaching the load centre in Sydney, with between 344 MW and 719 MW of low-priced capacity being unable to make it to market.

Flows on the VNI was limited to an average of 481 MW out of its nominal limit of 1,700 MW.

The QNI and Terranora had flows of around 1,000 MW of their combined nominal capacity (1,510 MW), due to system normal constraints.

The network constraints meant NSW was unable to access cheaper generation from Victoria to alleviate the high prices.

8.9.1.3 Low wind and solar generation

Wind output averaged around 182 MW out of 2,762 MW installed capacity during the high prices, which equates to around 7% of installed capacity in NSW.

From 2.30 pm to 3 pm, cloudy conditions caused grid scale solar generation to drop by 550 MW, with the average output at 2,013 MW. The cloudy conditions also meant rooftop solar output dropped 860 MW which resulted in higher demand.

8.9.1.4 Generation start up constrained

Up to 238 MW at Snowy Hydro’s Colongra Power Station could not start up quickly enough to prevent the high prices. For one high-priced interval, the amount of low-priced capacity unable to be dispatched was more than the amount of high-priced capacity needed to meet demand.

9 Three days of high raise 6 second service prices in Queensland

The 30-minute price for raise 6 second services exceeded $5,000 per MW on 15 occasions over three days in Queensland.

Table 4 Breakdown of the 30-minute high R6 second service price

Date	Time	Price per MW ($/MW)
10 October	10.30 pm	5,051
	11 pm	9,750
11 October	1 am	5,083
	1.30 am	14,750
	8.30 pm	14,844
	9 pm	15,220
	9.30 pm	11,326
	10 pm	11,070
	10.30 pm	6,066
	11 pm	17,500
	11.30 pm	11,351
12 November	2 am	11,709
	2.30 am	9,067
	3 am	11,250
	4 am	13,579

9.1.1 Frequency control ancillary services (FCAS)

FCAS is used to maintain the frequency of the power system within set frequency operating standards by increasing the frequency (raise services) or lowering the frequency (lower services). If a region is or is at risk of being electrically islanded, unable to transfer FCAS from neighbouring regions, then it must provide its own local FCAS.

For all three days, a planned network outage around Liddell in NSW created a credible risk of losing QNI which could electrically island Queensland from the NEM. The remaining interconnector into Queensland, Terranora, cannot transfer FCAS. To allow for this contingency, Queensland was required to provide its own local R6 second service. Queensland was required to provide up to 400 MW of R6 second services on these days.

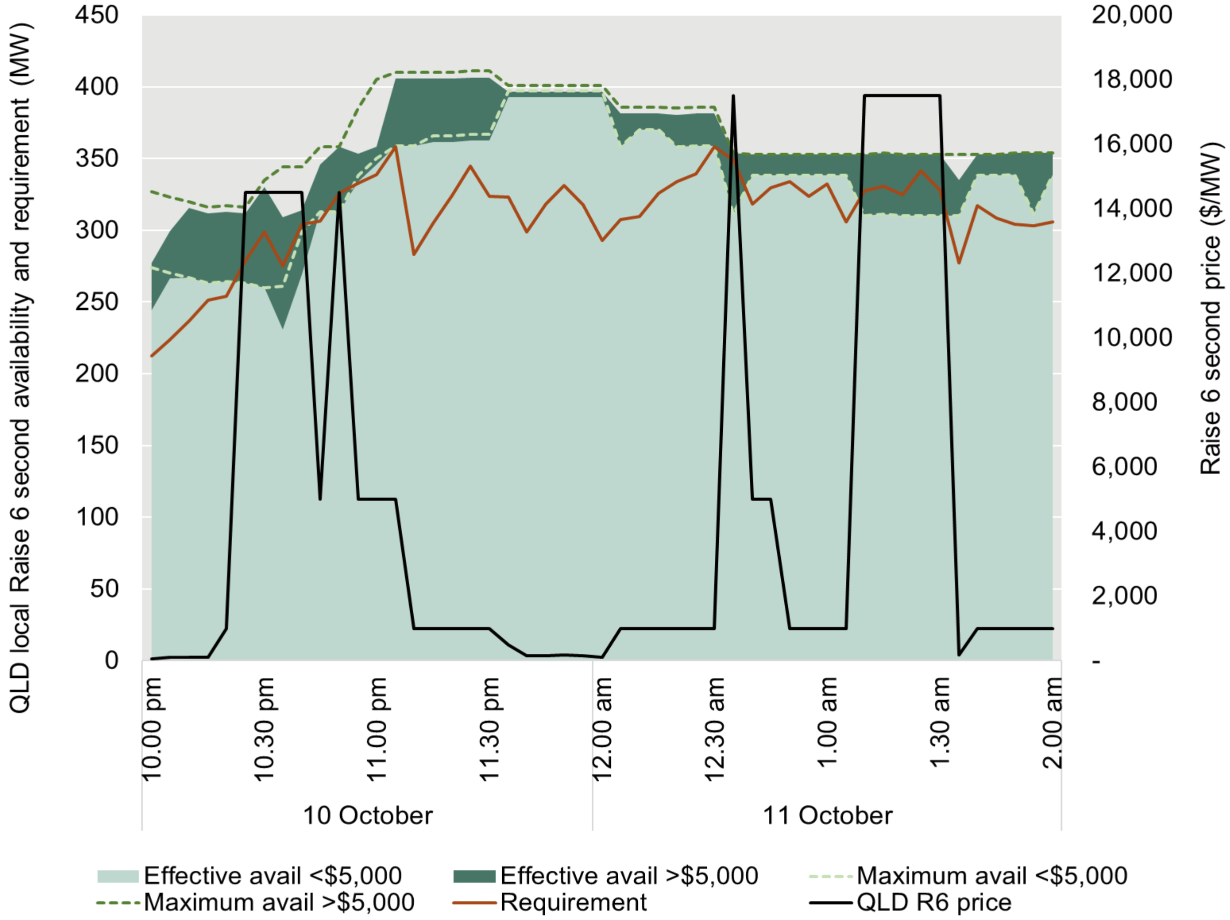
The cost of enabling local R6 second services in Queensland on 11 October was $20 million, which was the highest since Q4 2021.

9.2 10 October and 11 October

On 10 and 11 October, the local price for R6 second services in Queensland exceeded $5,000 per MW for eleven 30-minute periods. Four high price periods occurred between 10.30 pm on 10 October and 1.30 am on 11 October. Then seven consecutive high price periods occurred in the evening on 11 October from 8.30 pm to 11.30 pm. The prices ranged from $5,051 per MW to $17,500 per MW. The high FCAS prices were not forecast for 10 October but were forecast from around 7 pm on 11 October.

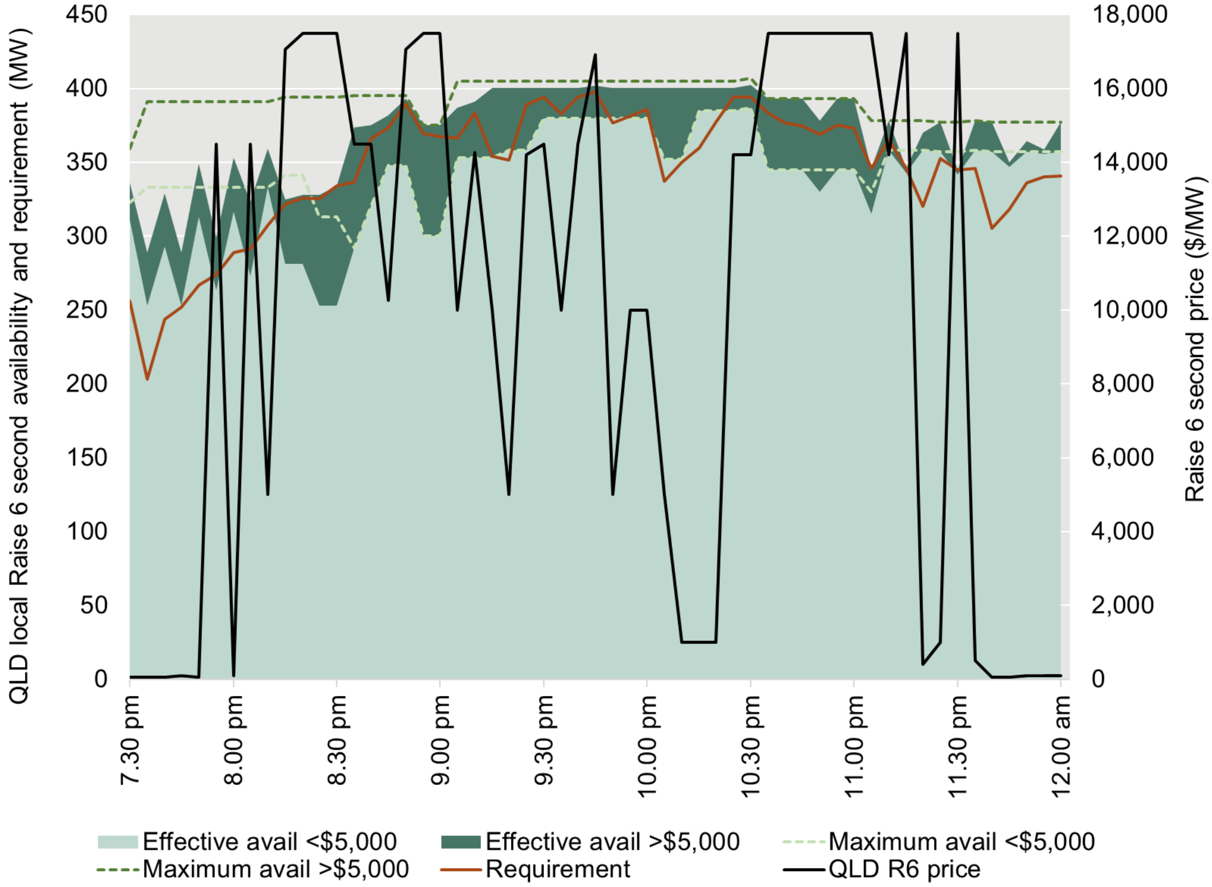
Most of the capacity for R6 second service was offered below $5,000 per MW (Figure 18 and Figure 19) but due to the high requirement, high priced R6 second service capacity was needed to be dispatched.

Figure 18 Capacity above and below $5,000 per MW, 10 October and 11 October



Source. AER analysis using NEM data.
Note. Capacity available below $5,000/MW refers to effective capacity.

Figure 19 Capacity above and below $5,000 per MW, 11 October



Source. AER analysis using NEM data.
Note: Capacity available below $5,000/MW refers to effective capacity.

9.2.1.1 Planned network outage drove R6 requirement in Queensland

A planned network outage on the Liddell to Tamworth line in NSW created a credible risk that Queensland could be electrically islanded from the NEM. To provide for this contingency, Queensland was required to provide its own local R6 second service.

For several 5-minute intervals, the amount of R6 second service required in Queensland was higher than was effectively available capacity priced below $5,000 per MW. As a result, between 1 MW and 69 MW of capacity priced above $5,000 per MW was required.

9.2.1.2 Rebidding contributed to the high prices

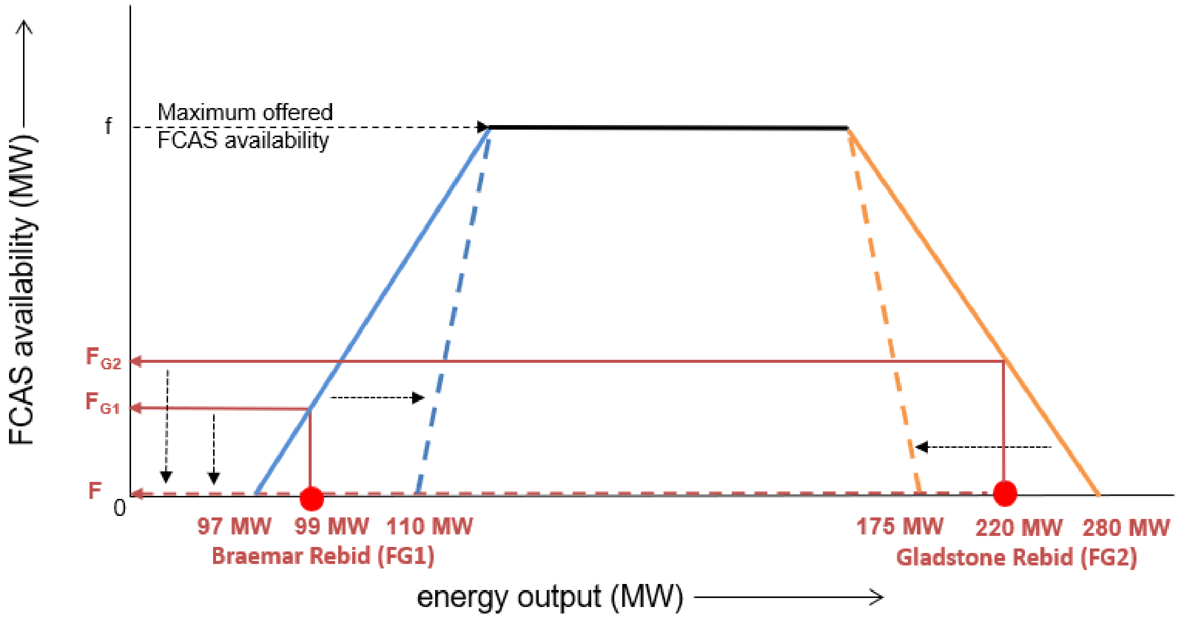
While the planned network outages drove the requirement for R6 second service, participant rebidding also contributed to the high prices (Appendix I).

Around 1 am on 11 October, Genex Power rebid to shift 28 MW of capacity from low to high prices. These rebids contributed to the high prices for four intervals between 1.10 am and 1.30 am. The rebids impacting the first three intervals were due to a change in forecast state of charge, and the final rebid was due an increase in price.

On 11 October, CS energy rebid its FCAS trapezium at Gladstone Power Station to manage its mill schedule, reducing the enablement maximum at three of its units from 280 MW down to 175 MW (Figure 20). As their target in energy was greater than 175 MW, they were unable to provide FCAS. This resulted in 60 MW of low-priced capacity becoming unavailable and high-priced capacity was needed to meet requirements, contributing to the high prices for three intervals around 8.15 pm.

At around 11 pm on 11 October, Alinta Energy rebid its minimum enablement point at Braemar Power Station from 97 MW to 110 MW. The rebid reason given was “adjust min enablement values”. As it was unclear why the rebid was made, we wrote to Alinta seeking their contemporaneous records given it was a late rebid and are satisfied the rebid was for a technical reason.[17] For two intervals between 11.15 pm and 11.30 pm, this unit was dispatched for between 99 MW and 109 MW. As this was below its new enablement minimum, it could not provide FCAS. This resulted in 15 MW of low-priced capacity becoming unavailable and high-priced capacity was needed to meet requirements.

Figure 20 FCAS trapezium



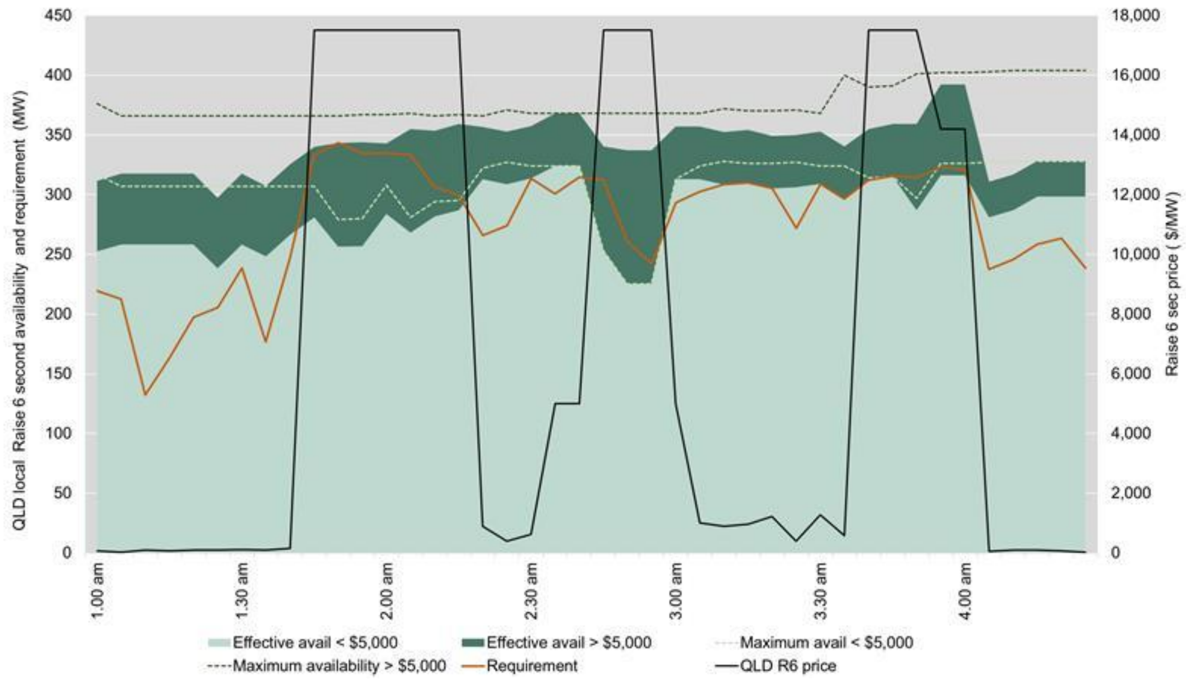
Source. AER analysis using NEM data.

[17] Australian Energy Regulator, Rebidding and Technical Parameters Guidelines, October 2024.

9.3 12 November

On 12 November 2024, the local raise 6 second FCAS in Queensland exceeded $5,000 per MW for four 30-minute periods from 2 am to 4 am. The high FCAS prices were not forecast. The prices ranged from $9,067 per MWh to $13,579 per MWh. Most of the capacity for R6 second service was offered below $5,000 per MW (Figure 21) but due to the high requirement, high priced R6 second service capacity was needed to be dispatched.

Figure 21 Capacity above and below $5,000 per MW, 12 November



Source. AER analysis using NEM data.
Note: Capacity available below $5,000/MW refers to effective capacity.

9.3.1.1 Planned network outage

Similar to the previous FCAS events on 10 and 11 October, a planned network outage on the Liddell to Muswellbrook line created a credible risk that Queensland could be electrically islanded from the NEM. This outage meant that Queensland had to provide contingency FCAS locally, with the requirement for the R6 second FCAS between 176 MW and 343 MW. At times, not enough capacity offered under $5,000 per MW was available to meet this requirement, so between 1 MW to 87 MW of high-priced R6 second capacity was enabled.

9.3.1.2 Effective FCAS availability

Due to the trade-off in energy and FCAS (section 8.7.1.5), CS Energy's Gladstone unit 6 which had offered 20 MW of R6 second service effectively could only provide 6 MW to 12 MW from 1.45 am to 2.15 am.

9.3.1.3 Rebidding contributed to the high prices

Participant rebidding also contributed to the high prices (Appendix J).

Between 1.40 am and 3.45 am, Genex Power rebid 28 MW of capacity from low to high prices at its Bouldercombe battery due to its state of charge being close to the limit. This exceeded the amount of high-priced capacity required and contributed to the high prices at 2.10 am, 2.15 am, 2.55 am and 3.50 am.

At 2.36 am, CS Energy rebid 60 MW of capacity from low to high prices at Gladstone due to a change in market conditions. This contributed to the high prices at 2.45 am, 2.50 am and 2.55 am when less than 60 MW of high-priced capacity was required.

At 3.33 am, effective from 3.40 am, Origin Energy rebid their maximum availability from 10 MW to 0 MW at Darling Downs due to a duct burner issue. This contributed to the high prices at 3.40 am and 3.45 am when less than 10 MW of high-priced capacity was required.

10 Appendix A – Significant rebids 22 October, South Australia

2.55 pm (147 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.49 pm	2.55 pm	AGL Energy	Barker Inlet	176	561	17,500	040 Chg in AEMO DISP~44 Price change vs PD SA $560.98 DISP PE 14.50 vs -$25.78 30MPD PE 15.00

3 pm (89 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.49 pm	2.55 pm	AGL Energy	Barker Inlet	176	561	17,500	040 Chg in AEMO DISP~44 Price change vs PD SA $560.98 DISP PE 14.50 vs -$25.78 30MPD PE 15.00

11 Appendix B – Significant rebids 23 October, South Australia

7.25 am (58 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.18 am	7.25 am	AGL Energy	Barker Inlet	56	138	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] $299.99 07.20 vs $17,457.52 30minPD 07.30 – SL
7.18 am	7.25 am	AGL Energy	Torrens Island	30	138	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] $299.99 07.20 vs $17,457.52 30minPD 07.30 - SL

7.30 am (55 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.18 am	7.25 am	AGL Energy	Barker Inlet	56	138	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] $299.99 07.20 vs $17,457.52 30minPD 07.30 – SL
7.18 am	7.25 am	AGL Energy	Torrens Island	30	138	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] $299.99 07.20 vs $17,457.52 30minPD 07.30 - SL

12 Appendix C – Significant rebids 7 November, Queensland & NSW

For the 4.45 pm and 5 pm high prices (Between 48 MW and 54 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.57 pm		CleanCo	Wivenhoe	60	<155	14,928	Manage SYC; Rebalance portfolio - SL

For the 5.05 pm, 5.15 pm, 5.20 pm and 5.25 pm high prices (Between 7 MW and 61 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.52 pm		AGL Energy	Bayswater	240	36	>16,100	050 Chg in AEMO PD~51 PD (15:33) Demand change [NSW] 151MW avg for PE 17:00 - 20:00 - SL
3.20 pm		AGL Energy	Yabulu	60	N/A	-1,000	Availability adj due to pd
4.03 pm		AGL Energy	Yabulu	25	N/A	-1,000	Availability adj due to pd
4.14 pm		AGL Energy	Yabulu	51	N/A	-1,000	Availability adj due to pd
4.14 pm		AGL Energy	Yabulu	15	N/A	-1,000	Availability adj due to pd
4.37 pm	4.45 pm	AGL Energy	Yabulu	3	N/A	-1,000	Availability adj due to pd
4.38 pm	4.45 pm	AGL Energy	Yabulu	3	N/A	-1,000	Availability adj due to pd

5.35 pm (130 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.52 pm		AGL Energy	Bayswater	310	36	>16,100	050 Chg in AEMO PD~51 PD (15:33) Demand change [NSW] 151MW avg for PE 17:00 - 20:00 - SL
3.20 pm		AGL Energy	Yabulu	60	N/A	-1,000	Availability adj due to pd
4.03 pm		AGL Energy	Yabulu	25	N/A	-1,000	Availability adj due to pd
4.14 pm		AGL Energy	Yabulu	51	N/A	-1,000	Availability adj due to pd
4.14 pm		AGL Energy	Yabulu	15	N/A	-1,000	Availability adj due to pd
4.37 pm	4.45 pm	AGL Energy	Yabulu	3	N/A	-1,000	Availability adj due to pd
4.38 pm	4.45 pm	AGL Energy	Yabulu	3	N/A	-1,000	Availability adj due to pd

For the high prices at 7 pm, 7.15 pm and 7.20 pm (Between 42 and 63 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.37 pm		CS Energy	Callide B	-60	-1,000	N/A	Ashing System-Other-SL
6.23 pm	6.30 pm	CS Energy	Callide B	-30	-1,000	N/A	Ashing System-Other-SL

13 Appendix D – Significant rebids 26 November, NSW

5.35 pm (116 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.40 pm		Origin Energy	Uranquinty	-172	-1,000	N/A	Change in avail - Unit trip SL
4.43 pm		Origin Energy	Uranquinty	-344	-1,000	N/A	Change in avail - Unit trip SL
4.45 pm		Origin Energy	Uranquinty	-18	-1,000	N/A	Change in avail - PAG unavail SL

5.40 pm (93 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.40 pm		Origin Energy	Uranquinty	-172	-1,000	N/A	Change in avail - Unit trip SL
4.43 pm		Origin Energy	Uranquinty	-344	-1,000	N/A	Change in avail - Unit trip SL
4.45 pm		Origin Energy	Uranquinty	-18	-1,000	N/A	Change in avail - PAG unavail SL

14 Appendix E – Significant rebids 27 November, NSW

2.45 pm (146 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.01 pm		Origin Energy	Shoalhaven	-120	-1,000	N/A	Change in avail - Unit trip SL
2.17 pm	2.25 pm	Origin Energy	Eraring	-20	1.00	N/A	Change in avail – ID fan limitation SL
2.24 pm	2.30 pm	Origin Energy	Eraring	-20	1.00	N/A	Change in avail – ID fan limitation SL

15 Appendix F – Significant rebids 2 December, Queensland & NSW

5.50 pm (102 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.23 pm		Delta Electricity	Vales Point	-70	<218	N/A	FF DP limits SL
*4.28 pm		Stanwell	Stanwell	45	-1,000	17,500	Process Tuning complete - SL

Note: *Stanwell came off being fixed which had the same effect as rebidding 45 MW from the price floor to the cap.

5.55 pm (55 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.18 pm		Arrow Energy	Braemar	-17	116	N/A	1518P ambient conditions: adjust bid for prevailing conditions - SL
4.23 pm		Delta Electricity	Vales Point	-70	<218	N/A	FF DP limits SL
*4.28 pm		Stanwell	Stanwell	45	-1,000	17,500	Process Tuning complete - SL
4.32 pm		Arrow Energy	Braemar	3	N/A	116	1632P ambient conditions: adjust bid for prevailing conditions - SL
5.38 pm	5.45 pm	Delta Electricity	Vales Point	15	N/A	-1,000	FF DP limits revised SL

Note: *Stanwell came off being fixed which had the same effect as rebidding 45 MW from the price floor to the cap.

6.15 pm (103 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.50 pm		Snowy Hydro	Hunter Economic Zone	20	500	17,500	14:39:00 A NSW 30MIN PD -500 Sensitivity $13,597.81 lower than 30MIN PD 17:30@14:09 ($370.77)
3.11 pm		Snowy Hydro	Tumut	50	-1,000	17,500	15:06:00 A NSW 5MIN PD Price $133.68 lower than 30MIN PD 16:05@15:03 (-$26.52)
4.23 pm		Delta Electricity	Vales Point	-70	<218	N/A	FF DP limits SL
5.38 pm		Delta Electricity	Vales Point	15	N/A	-1,000	FF DP limits revised SL
5.43 pm	5.50 pm	Snowy Hydro	Tumut	50	-1,000	17,500	17:41:00 A NSW 5MIN PD +350 Sensitivity $16,194.45 lower than 5MIN PD 17:45@17:37 ($1,305.55) - SL
5.58 pm	6.05 pm	Delta Electricity	Vales Point	5	N/A	-1,000	FF DP limits revised
6.07 pm	6.15 pm	Snowy Hydro	Tumut	40	-1,000	17,500	18:07:00 A NSW 5MIN PD -200 Sensitivity $5,120.69 lower than 5MIN PD 18:10@18:02 ($360.05) - SL

6.20 pm (141 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.50 pm		Snowy Hydro	Hunter Economic Zone	20	500	17,500	14:39:00 A NSW 30MIN PD -500 Sensitivity $13,597.81 lower than 30MIN PD 17:30@14:09 ($370.77)
3.11 pm		Snowy Hydro	Tumut	50	-1,000	17,500	15:06:00 A NSW 5MIN PD Price $133.68 lower than 30MIN PD 16:05@15:03 (-$26.52)
4.23 pm		Delta Electricity	Vales Point	-70	<218	N/A	FF DP limits SL
5.38 pm		Delta Electricity	Vales Point	15	N/A	-1,000	FF DP limits revised SL
5.43 pm		Snowy Hydro	Tumut	50	-1,000	17,500	17:41:00 A NSW 5MIN PD +350 Sensitivity $16,194.45 lower than 5MIN PD 17:45@17:37 ($1,305.55) - SL
5.58 pm	6.05 pm	Delta Electricity	Vales Point	5	N/A	-1,000	FF DP limits revised
6.07 pm	6.15 pm	Snowy Hydro	Tumut	40	-1,000	17,500	18:07:00 A NSW 5MIN PD -200 Sensitivity $5,120.69 lower than 5MIN PD 18:10@18:02 ($360.05) - SL
6.13 pm	6.20 pm	Delta Electricity	Vales Point	5	N/A	-1,000	FF DP limit revised SL

6.25 pm (90 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.40 pm		Snowy Hydro	Tumut	25	17,500	450	14:39:00 A VIC 30MIN PD +1000 Sensitivity $488.12 higher than 30MIN PD 20:00@14:09 ($11,552.07) - SL
2.50 pm		Snowy Hydro	Hunter Economic Zone	20	500	17,500	14:39:00 A NSW 30MIN PD -500 Sensitivity $13,597.81 lower than 30MIN PD 17:30@14:09 ($370.77)
3.11 pm		Snowy Hydro	Tumut	75	<450	17,500	15:06:00 A NSW 5MIN PD Price $133.68 lower than 30MIN PD 16:05@15:03 (-$26.52)
4.23 pm		Delta Electricity	Vales Point	-70	<218	N/A	FF DP limits SL
5.38 pm		Delta Electricity	Vales Point	15	N/A	-1,000	FF DP limits revised SL
5.43 pm		Snowy Hydro	Tumut	50	-1,000	17,500	17:41:00 A NSW 5MIN PD +350 Sensitivity $16,194.45 lower than 5MIN PD 17:45@17:37 ($1,305.55) - SL
5.58 pm	6.05 pm	Delta Electricity	Vales Point	5	N/A	-1,000	FF DP limits revised
6.07 pm	6.15 pm	Snowy Hydro	Tumut	40	-1,000	17,500	18:07:00 A NSW 5MIN PD -200 Sensitivity $5,120.69 lower than 5MIN PD 18:10@18:02 ($360.05) - SL
6.13 pm	6.20 pm	Delta Electricity	Vales Point	5	N/A	-1,000	FF DP limit revised SL

6.30 pm (17 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.50 pm		Snowy Hydro	Hunter Economic Zone	20	500	17,500	14:39:00 A NSW 30min PD -500 Sensitivity $13,597.81 lower than 30min pd 17:30@14:09 ($370.77)
3.11 pm		Snowy Hydro	Tumut	50	-1,000	17,500	15:06:00 A NSW 5MIN PD Price $133.68 lower than 30min pd 16:05@15:03 (-$26.52)
4.23 pm		Delta Electricity	Vales Point	-70	<218	N/A	FF DP limits SL
5.38 pm		Delta Electricity	Vales Point	15	N/A	-1,000	FF DP limits revised SL
5.43 pm		Snowy Hydro	Tumut	50	-1,000	17,500	17:41:00 A NSW 5MIN PD +350 Sensitivity $16,194.45 lower than 5MIN PD 17:45@17:37 ($1,305.55) - SL
5.58 pm	6.05 pm	Delta Electricity	Vales Point	5	N/A	-1,000	FF DP limits revised
6.07 pm	6.15 pm	Snowy Hydro	Tumut	40	-1,000	17,500	18:07:00 A NSW 5MIN PD -200 Sensitivity $5,120.69 lower than 5MIN PD 18:10@18:02 ($360.05) - SL
6.13 pm	6.20 pm	Delta Electricity	Vales Point	5	N/A	-1,000	FF DP limit revised SL
6.23 pm	6.30 pm	Snowy Hydro	Tumut	15	-1,000	17,500	18:21:00 A NSW 5MIN PD -200 Sensitivity $10,300.60 lower than 5MIN PD 18:25@18:16 ($4,228.63) - SL

16 Appendix G – Significant rebids 3 December, NSW

11.45 am (57 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.40 am		Delta Electricity	Vales Point	-10	76	N/A	Fabric Filter Limit revised SL
8.03 am		Delta Electricity	Vales Point	-280	<14,027	N/A	RTS profile revised
9.39 am		Delta Electricity	Vales Point	250	N/A	<145	Fabric Filter limit revised SL
10.19 am		Delta Electricity	Vales Point	-165	<76	N/A	Milling/Feeder limit SL
10.53 am		AGL Energy	Bayswater	-45	<106	N/A	010 Unexpected/plant limits~105 Emission Limits
10.55 am		Delta Electricity	Vales Point	-65	-1,000	N/A	Milling/Feeder limit SL
11.05 am		Delta Electricity	Vales Point	15	N/A	-1,000	Milling/Feeder limit SL
11.24 am	11.30 am	AGL Energy	Bayswater	65	36	17,500	040 Chg in AEMO DISP~45 Price change vs PD [nsw] $515 v $57.01 pe 1130
11.36 am	11.45 am	AGL Energy	Bayswater	20	N/A	<14,100	030 Increase in avail cap~301 plant limit lifted

11.50 am (13 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
8.03 am		Delta Electricity	Vales Point	-280	<14,027	N/A	RTS profile revised
9.39 am		Delta Electricity	Vales Point	250	N/A	<145	Fabric Filter limit revised SL
10.19 am		Delta Electricity	Vales Point	-165	<76	N/A	Milling/Feeder limit SL
10.53 am		AGL Energy	Bayswater	-45	<106	N/A	010 Unexpected/plant limits~105 Emission Limits
10.55 am		Delta Electricity	Vales Point	-65	-1,000	N/A	Milling/Feeder limit SL
11.05 am		Delta Electricity	Vales Point	15	N/A	-1,000	Milling/Feeder limit SL
11.24 am	11.30 am	AGL Energy	Bayswater	65	36	17,500	040 Chg in AEMO DISP~45 Price change vs PD [nsw] $515 v $57.01 pe 1130
11.36 am	11.45 am	AGL Energy	Bayswater	20	N/A	<14,100	030 Increase in avail cap~301 plant limit lifted

17 Appendix H – Significant rebids 5 December, SA

For the 2.15 pm and 2.20 pm high prices (Between 72 MW to 74 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.49 pm	1.55 pm	AGL Energy	Barker Inlet	80	17,500	0	A 040 Chg in AEMO DISP~45 Price change vs PD [SA] [$299.44]
2.08 pm	2.15 pm	AGL Energy	Barker Inlet	32	0	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$952.67]
2.08 pm	2.15 pm	AGL Energy	Torrens Island	120	138	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$952.67]

2.25 pm (11 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.49 pm	1.55 pm	AGL Energy	Barker Inlet	80	17,500	0	A 040 Chg in AEMO DISP~45 Price change vs PD [SA] [$299.44]
2.04 pm	2.10 pm	Engie	Pelican Point	25	299	12,500	Fuel Management. EOD Linepack - SL
2.08 pm	2.15 pm	AGL Energy	Barker Inlet	32	0	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$952.67]
2.08 pm	2.15 pm	AGL Energy	Torrens Island	120	138	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$952.67]
2.13 pm	2.20 pm	Neoen	Hornsdale Power	25	3,911	9,932	SA1 energy 5PD@2024-12-05 14.15.00 AEST for 2024-12-05 15.10.00 AEST is 12500.44 vs 5PD@2024-12-05 14.10.00 AEST for 2024-12-05 15.10.00 AEST is 228.44

18 Appendix I – Significant rebids 11 October, Queensland

1.10 am (17 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
1.02 am		Bouldercombe Battery	Bouldercombe Battery	28	4,999	17,500	Change in forecast SOC

1.15 am (20 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
1.02 am		Bouldercombe Battery	Bouldercombe Battery	28	4,999	17,500	Change in forecast SOC

1.20 am (15 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
1.02 am		Bouldercombe Battery	Bouldercombe Battery	28	4,999	17,500	Change in forecast SOC

1.30 am (18 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
1.02 am		Bouldercombe Battery	Bouldercombe Battery	28	4,999	17,500	Change in forecast SOC

19 Appendix J – Significant rebids 12 November, Queensland

2.10 am (25 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.42 am		Genex Power	Bouldercombe Battery	28	98	17,500	Updated SOC close to limit

2.15 am (12 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
1.42 am		Genex Power	Bouldercombe Battery	28	98	17,500	Updated SOC close to limit

2.45 am (59 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.36 am	2.45 am	CS Energy	Gladstone	60	<371	17,500	Market condition changed--SL QLD1 DI 12-11-2024 02.35.00 forecast R6SEC RRP $14500 vs actual R6SEC RRP $4999 @ DI RUN 12-11-2024 02.30.03 - DELTA OF $-9501.

2.50 am (35 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
2.36 am	2.45 am	CS Energy	Gladstone	60	<371	17,500	Market condition changed--SL QLD1 DI 12-11-2024 02.35.00 forecast R6SEC RRP $14500 vs actual R6SEC RRP $4999 @ DI RUN 12-11-2024 02.30.03 - DELTA OF $-9501.

2.55 am (17 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
2.27 am		Genex Power	Bouldercombe Battery	28	98	4,999	Updated SOC close to limit
2.36 am	2.45 am	CS Energy	Gladstone	60	<371	17,500	Market condition changed--SL QLD1 DI 12-11-2024 02.35.00 forecast R6SEC RRP $14500 vs actual R6SEC RRP $4999 @ DI RUN 12-11-2024 02.30.03 - DELTA OF $-9501."
2.42 am	2.50 am	Genex Power	Bouldercombe Battery	28	4,999	17,500	Updated SOC close to limit

3.40 am (1 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
3.33 am	3.40 am	Origin Energy	Darling Downs	10	10	N/A	Change in avail - duct burner transfer SL

3.45 am (1 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
3.33 am	3.40 am	Origin Energy	Darling Downs	10	10	N/A	Change in avail - duct burner transfer SL

3.50 am (27 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
3.42 am	3.50 am	Genex Power	Bouldercombe Battery	28	498	17,500	Updated SOC close to limit