Electricity prices above $5,000 per MWh

January to March 2025

June 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 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]

30-minute prices rarely reach $5,000 per MWh, but with a market price cap of $17,500 per MWh, prices can occasionally exceed this reporting threshold.[3] This reporting framework is intended to pick up these outlier 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.

[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 11 times, across 7 days, in January to March 2025 – 4 times in New South Wales (NSW), 3 times in Queensland, 3 times in South Australia and 1 time in Victoria. This compares to 23 high prices in the previous quarter and 26 high prices over the same period last year. There were many periods when demand was high, but prices remained low due to sufficient low-priced supply. Low-priced wind and solar generation were, on average, higher this quarter than the same period last year, as observed in the Wholesale Markets Quarterly Q1 2025.[4]

The high prices were mostly forecast. In many cases we observed market dynamics functioning as designed, with participants rebidding significant amounts of capacity from high to lower prices preventing high prices from eventuating. For example, on 3 February, 10 30-minute high prices were forecast across South Australia and Victoria, but participants shifted around 900 MW of capacity to lower prices and only one high price in each region eventuated (section 7.4).

Despite improved supply conditions and helpful rebidding, there were still 40 unique 5-minute prices above $5,000 per MWh during 30-minute high prices across the regions this quarter.

The high prices occurred due to a combination of contributing factors rather than one single driver, including high demand, low wind output and network limitations (Table 1). Participant rebidding, mostly for technical reasons, also contributed to many of the high prices.

Table 1 Common drivers on high energy price days

Date	High prices forecast	Network limitations	High demand	Baseload outages*	Low wind	Low solar	Rebidding
15 January, NSW	✓	✓	✓	×	✓	✓	×
22 January, Qld	✓	✓	✓	✓	✓	×	✓
1 February, SA	×	✓	×	×	✓	×	✓
3 February, SA + Vic	✓	✓	✓	×	✓	×	✓
5 February, NSW	×	✓	×	✓	×	×	×
12 February, SA	×	✓	✓	×	✓	×	✓
15 March, NSW	✓	✓	✓	×	✓	×	✓

Note: *Baseload outages refer to planned or unplanned outages of coal-fired generators.
Source: AER analysis using NEM data.

Demand was high this quarter due to unusually warm temperatures across most of Australia, with it being the second warmest summer on record since 1910.[5] All mainland regions experienced higher-than-average minimum and maximum temperatures for January and February, which affected 6 of the 7 high price days. Hot temperatures drove high demand due to increased air conditioner use. At times, a combination of network limitations, low wind output and small amounts of rebidding meant there was not enough low-priced capacity to

[4] AER, Wholesale markets quarterly Q1 2025, 7 May 2025.

[5] Bureau of Meteorology, Australia in Summer 2024-2025, 3 March 2025.

meet this increased demand, resulting in high prices. The high demand levels led AEMO to forecast reserve shortfalls on 4 of the 7 high price days, with reserve shortfall conditions eventuating on three of these.

Network limitations resulting from planned and unplanned outages, and system normal constraints meant that at times low-priced capacity was unable to make it to market. Between 28 MW and 2,862 MW of low-priced capacity was unable to be dispatched during the high price periods and high-priced capacity was needed to meet demand. The planned outage of the Collector to Marulan line in southern NSW had the biggest impact, limiting network flows during 3 of the 7 high price days.

3 High temperatures coinciding with low wind

3.1 High demand driven by hot temperatures

High temperatures driving high demand is a common occurrence in the early parts of the year during summer. Average minimum and maximum temperatures were above historical averages for the quarter in all mainland regions.[6] Almost all of the high prices this quarter saw very high demand driven by warm temperatures and associated air conditioner use, including all-time record demand in Queensland (Figure 1) and demand levels very close to the record in South Australia (Figure 2).

High prices occurred in Queensland only in January, where the region saw its highest average maximum temperature for any January since 1947.[7] High prices occurred in South Australia only in February, which had its highest average maximum temperature on record for any February since 1910.[8]

Queensland demand has been increasing as the growing population and high temperatures drive higher energy usage.[9] The previous all-time record demand in the region was from the same day the year prior. The high demand in South Australia this quarter was out of the ordinary, as demand had been trending down for the past several years, with demand levels very close to records set back in 2011 due to unusually high temperatures.[10]

At other times, increases in demand were a result of cloud cover reducing rooftop solar output.[11] On 15 January in NSW, rooftop solar output dropped from over 5,000 MW at midday to around 3,000 MW at 2.30 pm when the high prices occurred (section 7.1).

[6] Bureau of Meteorology, Monthly Climate Summaries

[7] Bureau of Meteorology, Queensland in January, 2 February 2025.

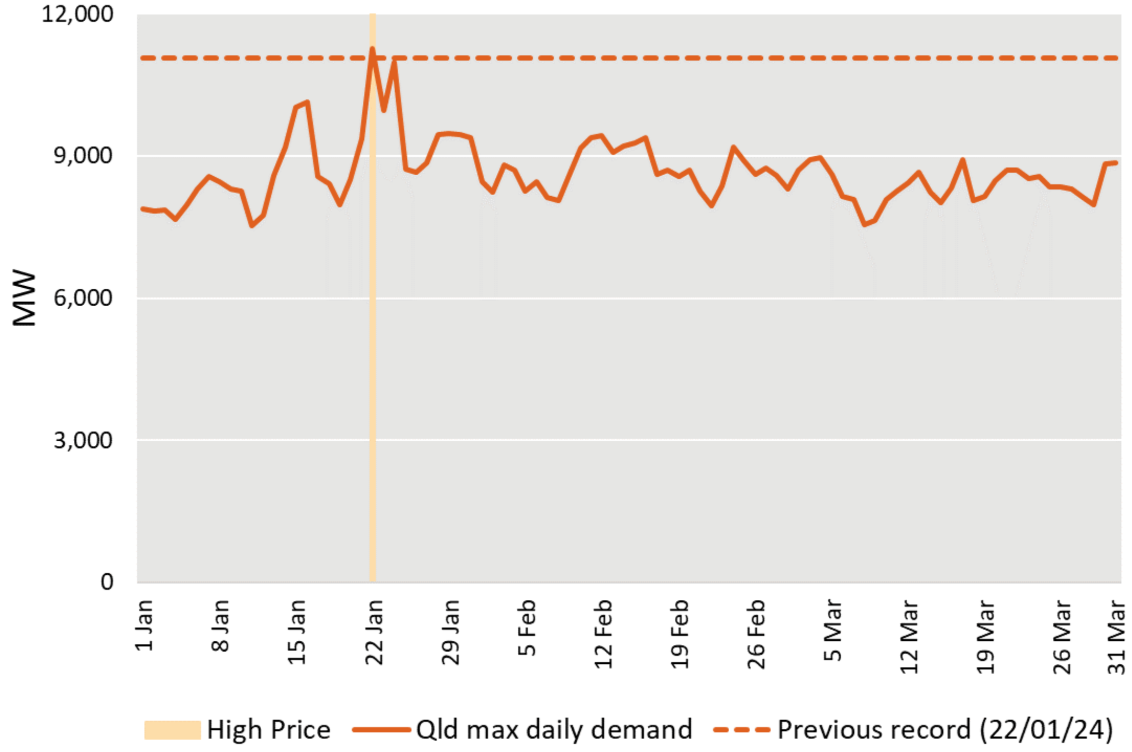
[8] Bureau of Meteorology, South Australia in February, 2 March 2025.

[9] Bureau of Meteorology indicates Queensland temperatures in January to March were higher than recent years. Queensland has seen recent annual population growth rates of around 2.5%, according to Queensland Treasury.

[10] Bureau of Meteorology reports, SA saw the fourth- highest area-averaged mean maximum temperature on record for January, the highest on record for February, and the fourth highest on record for March.

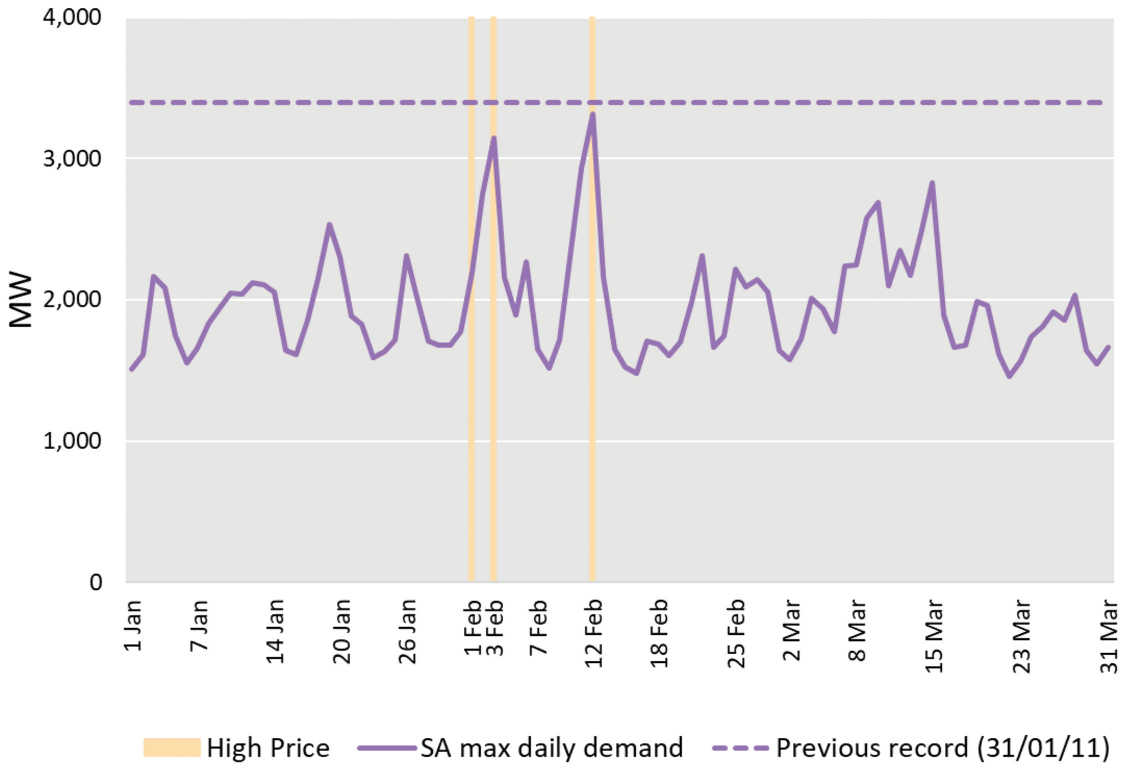
[11] Note: rooftop solar output reduces NEM demand.

Figure 1 Record high demand in Queensland



Source: AER analysis using NEM data.

Figure 2 High demand in South Australia

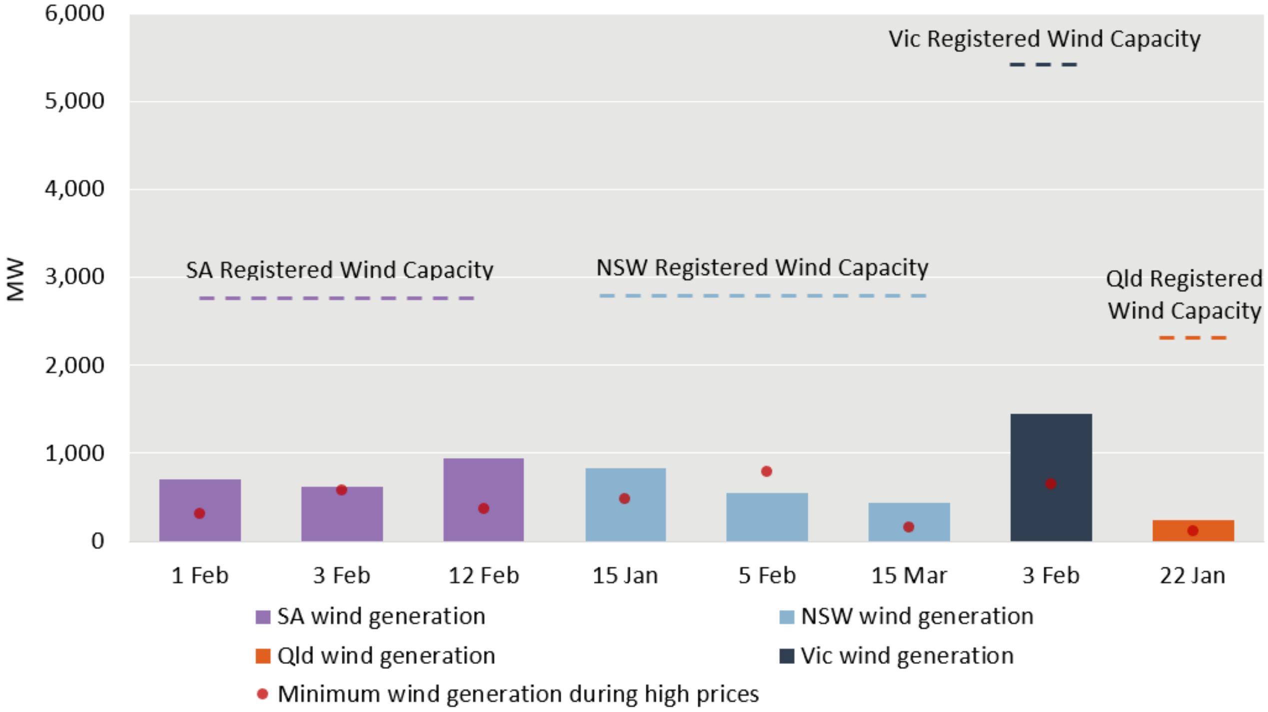


Source: AER analysis using NEM data.

3.2 Low wind output

Wind output was variable throughout the quarter, and during the high prices wind output was well below registered capacity for the region (Figure 3). On most of the high price days, wind output was significantly lower than surrounding days. For example, on 15 March in NSW, average wind generation for the day was less than half the average of the week before and the week after (section 7.7). Wind-generated capacity is generally offered at low prices, so low wind output means less low-priced capacity is available to meet demand.

Figure 3 Low levels of wind generation on high price days



Note: Wind generation (column) refers to average wind dispatched for the day.
Source: AER analysis using NEM data.

3.3 Reserve shortfalls

When there is a forecast tightening of supply and demand conditions, the Australian Energy Market Operator (AEMO) manages reserve shortfalls by issuing market notices to seek a response from market participants. High demand levels contributed to AEMO forecasting reserve shortfalls on several occasions this quarter. Reserve shortfalls were forecast for 4 of the 7 high price days. Actual reserve shortfalls eventuated in NSW on 15 January and 15 March, and in Queensland on 22 January, but none were severe enough to lead to any market interventions.

4 Network limitations

4.1 Network outages limited access to cheaper generation

A combination of planned and unplanned network outages meant some interconnectors were flowing well below their nominal capacity to maintain system security and prevent overloading (Table 2). This limited access to low-priced capacity from neighbouring regions.

Table 2 Network outages

Network outage	Date impacted	High price region	Planned/unplanned
Collector to Marulan line	3 Feb 5 Feb 15 Mar	South Australia & Vic. NSW NSW	Planned
Lower Tumut to Yass line	15 Jan	NSW	Unplanned
Muswellbrook to Tamworth line	15 Jan	NSW	Unplanned
Terranora Directlink cables	15 Jan 5 Feb 15 Mar	NSW NSW NSW	Unplanned* Unplanned* Planned
Lismore Static Var Compensator	22 Jan	Queensland	Planned

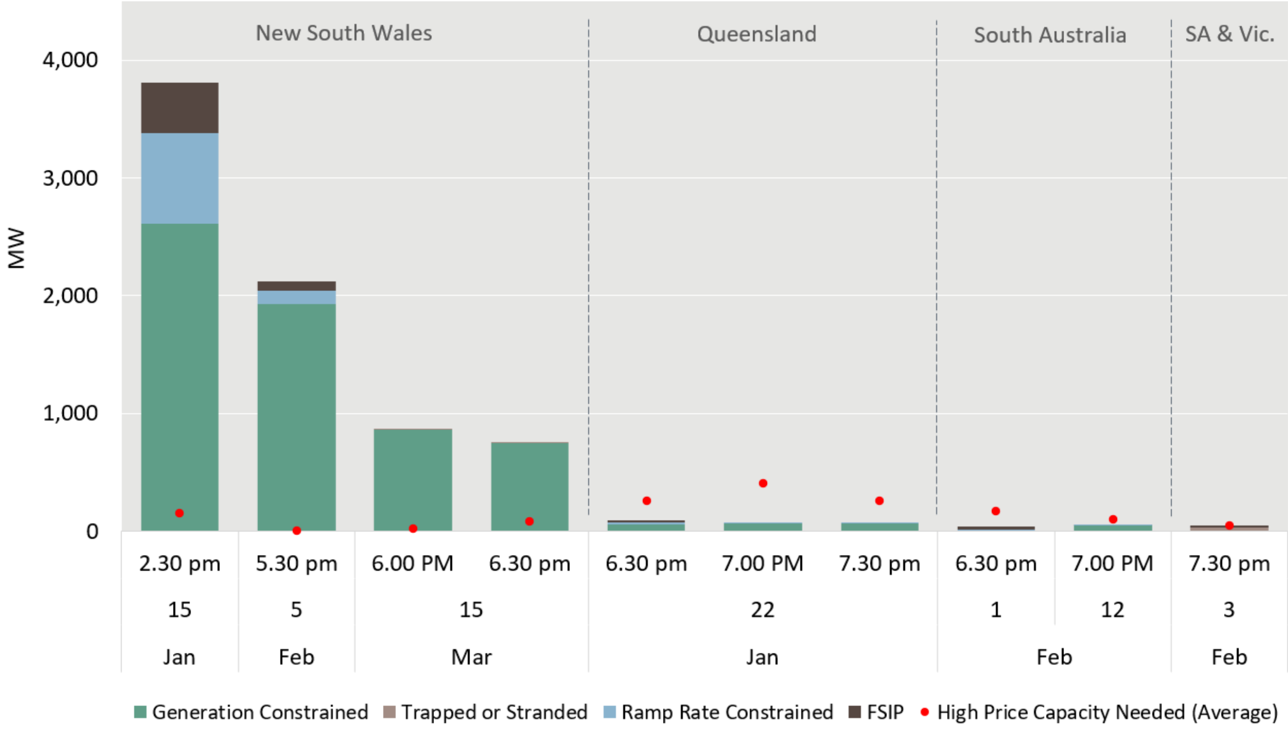
Source: AER analysis using NEM data.
*Note the outage of 2 and 3 of Terranora's Directlink cables in January and February were unplanned when they occurred. However, at the time of the high prices on 15 January and 5 February, the outage had been ongoing for at least five days in each case, so the market was aware in advance.

Constraints in place to manage these outages prevented up to 2,659 MW of low-priced capacity in the region from making it to market during the high price periods, which was more than 5 times the largest amount of high-priced capacity needed to meet demand (Figure 4).

The AER administers the service target performance incentive scheme (STPIS) which includes incentivising transmission network service providers to reduce the number and duration of outages. There was a recent review of this scheme, with the decision to suspend the Market Impact Component and explore alternatives more suitable for the energy transition.[12]

[12] AER, AER publishes final decision on the Transmission STPIS Review, 17 April 2025.

Figure 4 Low-priced capacity unable to be dispatched due to network constraints, ramp rates and start up limitations



Note: High price capacity needed refers to the average capacity priced over $5,000 per MWh dispatched (MW) during intervals when a high-priced offer set the price. Fast start inflexibility profile (FSIP) relates to how quickly a unit can start up.[13]
Source: AER analysis using NEM data.

4.1.1 Network outages in southern NSW

Similar to Q4 2024, most of the network outages contributing to high prices were in the southern NSW area (Figure 5).[14] A planned outage of the Collector to Marulan line contributed to high prices in NSW, Victoria and South Australia. This outage constrained up to 1,944 MW of low-priced capacity in NSW during high prices on 5 February (section 7.5) and up to 896 MW on 15 March (section 7.7) by preventing cheap capacity from Victoria and southern NSW from making it to the Sydney load centre.

During high prices in South Australia and Victoria on 3 February, this outage limited Victoria's ability to import from NSW, reducing flows on the Victoria to NSW interconnector to around 570 MW out of its nominal capacity of up to 1,540 MW (section 7.4).

An unplanned outage of the Lower Tumut to Yass line also contributed to high prices in NSW, preventing up to 2,371 MW of low-priced capacity from making it to market on 15 January (section 7.1).

We note that HumeLink, a 500 kV transmission line connecting Maragle, Wagga Wagga and Bannaby in southern NSW, is scheduled to begin construction in 2025. It includes around

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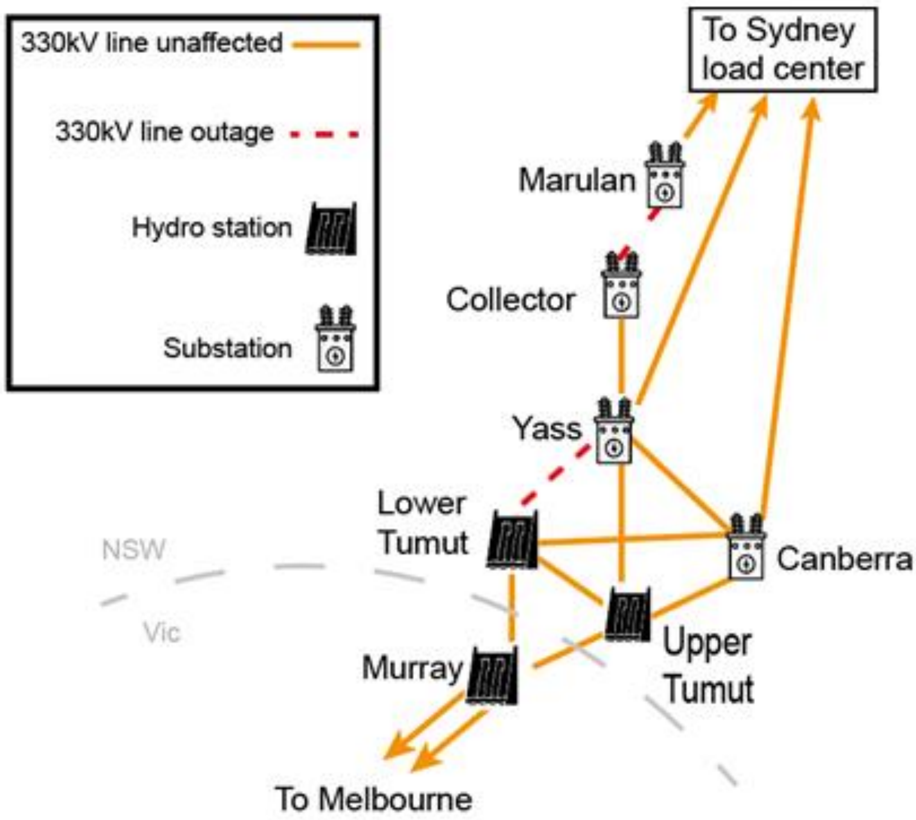
[13] AEMO, Fast Start Inflexibility Profile, June 2021.

[14] AER, Prices above $5,000/MWh - October to December 2024, 28 February 2025

365 km of new transmission lines and, once complete, it is expected to help alleviate some of the network congestion seen in this southern NSW area.[15]

Figure 5 Network diagram for southern NSW



Source: AER analysis using NEM data.

4.1.2 Network outages in north-eastern NSW

Outages in north-eastern NSW, including an unplanned outage of the Muswellbrook to Tamworth line, a planned outage of the Lismore static var compensator (SVC), and planned and unplanned outages of the Terranora interconnector's Directlink cables contributed to high prices in NSW and Queensland on 15 January, 22 January and 5 February.

The Muswellbrook to Tamworth line outage constrained up to 200 MW of low-priced capacity during high prices in NSW on 15 January (section 7.1). An outage of the Lismore SVC caused flows to be forced out of Queensland on the Terranora interconnector during high prices in Queensland on 22 January (section 7.2). The planned outage of the Terranora interconnector's Directlink cables limited flows into NSW to around 18 MW on 15 January (section 7.1), to around 100 MW on 5 February (section 7.5) and to around 130 MW on 15 March (section 7.7), compared its nominal capacity of 210 MW.

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[15] Transgrid, HumeLink energy infrastructure project.

4.2 System normal constraints contributed to high prices

During some of the high prices this quarter, system normal network constraints also contributed to the high prices.[16] For example, during high prices in Queensland on 22 January, a constraint to avoid overloading network equipment in northeast Queensland prevented around 70 MW of cheap generation from being dispatched (section 7.2). On 5 February, during high prices in NSW, a constraint managing transient stability reduced flows on the Queensland-NSW interconnector (QNI) to around 70% of its capacity (section 7.5).

On 1 February, there was a system normal constraint in place to avoid overloading a line in northwest Victoria. This led to flows being forced, counter-price (from a higher price region to a lower price region), out of Victoria and into South Australia. When a threshold of counter-price flows is reached, AEMO invokes a constraint to minimise those flows. This reduction of flows into South Australia in turn contributed to the high prices that occurred in the region (section 7.3).

4.3 Backing off negatively-priced generation set high prices

Network limitations and resulting congestion can lead to system security risks. For example, if a large amount of generation attempts to flow through a congested area, there is a risk of overloading the network. On three of the high price days, network limitations led AEMO to determine that the best solution was to back-off negatively-priced generation (mostly hydro) to maintain system security. There was one dispatch interval on 15 January (section 7.1), two on 5 February (section 7.5) and three on 12 February (section 7.6) when negatively-priced generation was backed off causing high prices.

[16] “System normal” constraints do not relate to outages, but are in place to protect system security, e.g. reducing generation to prevent overloading a line.

5 Rebidding contributed to the high prices

While large amounts of rebidding from high to low prices prevented some forecast high prices from occurring, this was not enough to alleviate all high prices. There were 40 high price 5-minute intervals during the 30-minute high price periods. Of the 40, around a third were impacted by participants rebidding capacity from low to high prices or withdrawing low-priced capacity. Of these rebids that did contribute to high prices, around 90% were for technical reasons related to a unit's operational capabilities, such as milling limits or changes in state of charge. Other rebids were for commercial reasons which are financial in nature, such as changes in forecast prices.

Details of participant rebidding are included in the individual high price day sections in Chapter 7 and the appendices.

6 High prices impacted average spot and futures prices in mainland regions

6.1 Impact on average spot prices

Prices in all mainland regions were affected by the 11 30-minute high prices this quarter. These high prices drove up the quarterly volume-weighted average (VWA) price by:

- $16 per MWh in South Australia
- $14 per MWh in Queensland
- $8 per MWh in NSW
- $3 per MWh in Victoria.

Compared to Q1 2024, there were 30% more negative 30-minute prices in the NEM. The number of negative prices in NSW and Queensland was a record for Q1.[17] Despite more negative prices, their impact on the quarterly VWA price was minimal due to the negative prices being closer to zero than in previous quarters (e.g. -$50 prices compared to -$300). The impact of negative prices was largest in South Australia and Victoria, reducing the quarterly VWA price by $8 per MWh and $6 per MWh, respectively. In Victoria, negative prices had a bigger impact on the quarterly price than high prices. That is, they subtracted more (-$6) from the quarterly VWA price of $72 per MWh than high prices added (+$3).

6.2 Impact on futures contract prices

Except for the significant market events of winter 2022 and their immediate aftermath, Q1 2025 base futures contracts reached their highest prices in December 2024. The large number of high price events in Q4 2024 created an expectation of continuing high prices into Q1 2025.

These expectations did not materialise, with only 11 high prices occurring in the NEM in Q1 2025, compared to 23 in the previous quarter. Futures prices were relatively moderate compared to Q4 2024, with only a limited number of spot prices above $300, reflected in the reduced prices in the caps market (Figure 6).

The largest movements in daily settled base futures prices throughout the quarter (Figure 7) were as follows:

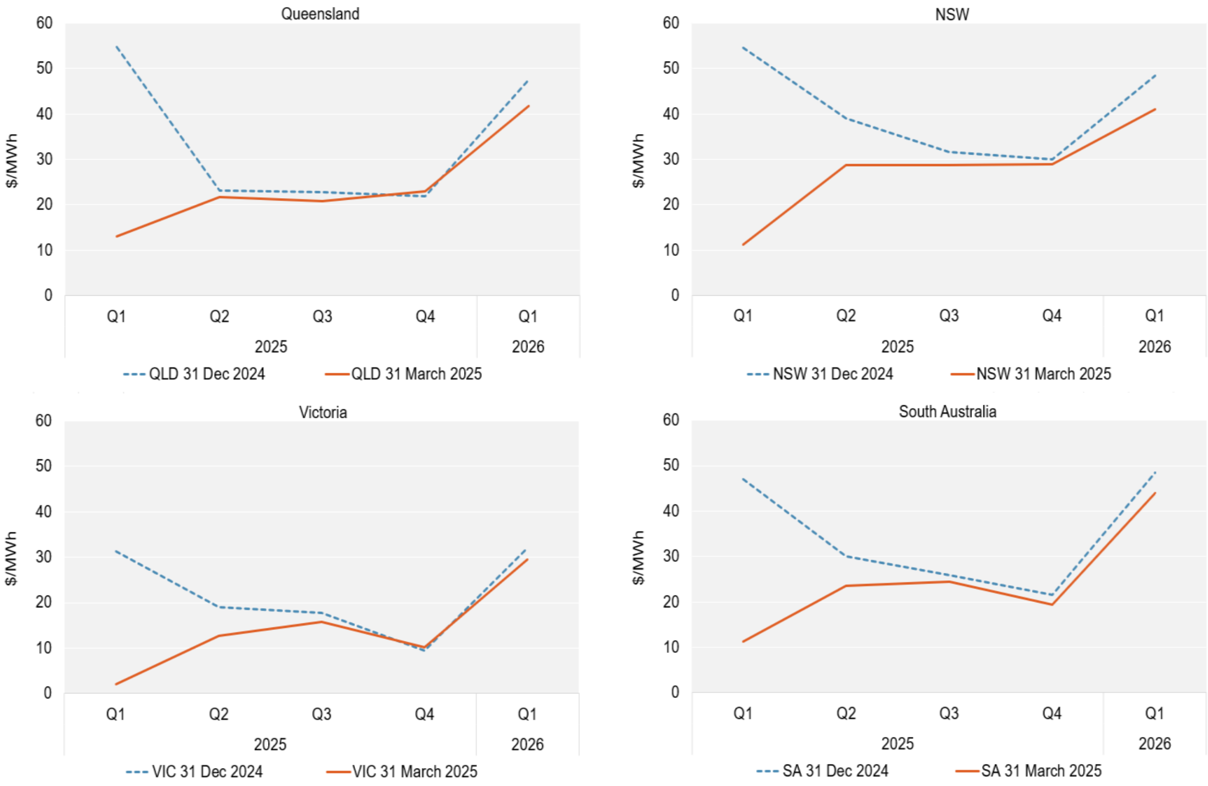
- $14 increase in Victoria on 28 January appears related to an AEMO market notice forecasting low reserve conditions, and unserved energy exceeding the reliability standard, for February 2026 to February 2027.[18]
- $12 increase in Queensland on 23 January in response to three 30-minute high prices the day prior.

[17] AER, Wholesale markets quarterly Q1 2025, 7 May 2025.

[18] See AEMO market notice 123772.

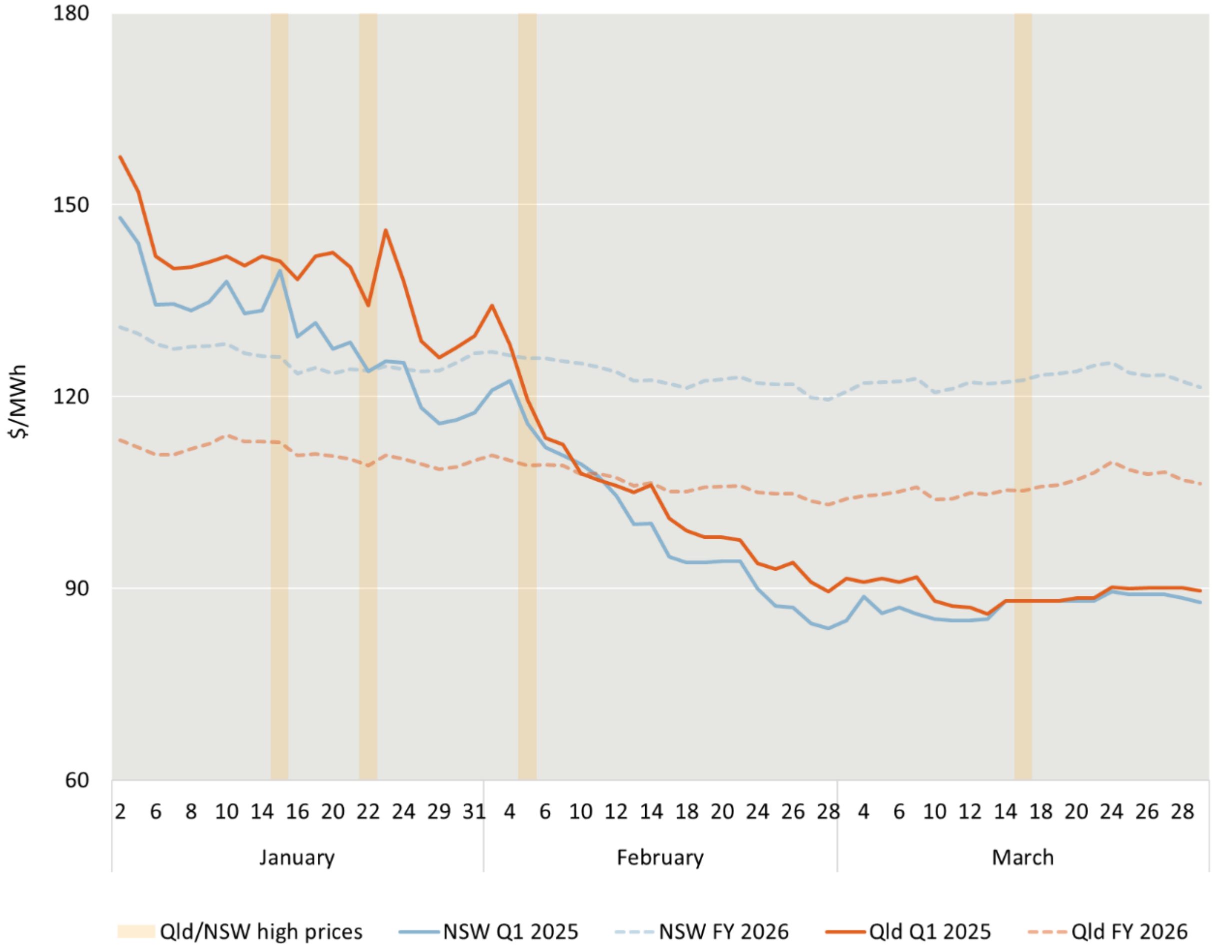
- $10 decrease in NSW on 16 January after only one 30-minute high price occurred on 15 January, despite seven 30-minute high prices forecast the day prior.

Figure 6 Caps contract prices at 31 March compared to 31 December



Source: AER analysis using ASX Energy data.

Figure 7 Queensland and NSW base futures prices



Note: Base futures contracts are only traded on business days. For high prices that occurred on weekends or public holidays (e.g. 15 March), the high price indicator has been assigned to the next business day.
FY 2026 refers to the average price of the four quarterly base futures products for the financial year 2025-26.
Source: AER analysis using ASX Energy and NEM data.

7 High energy price events

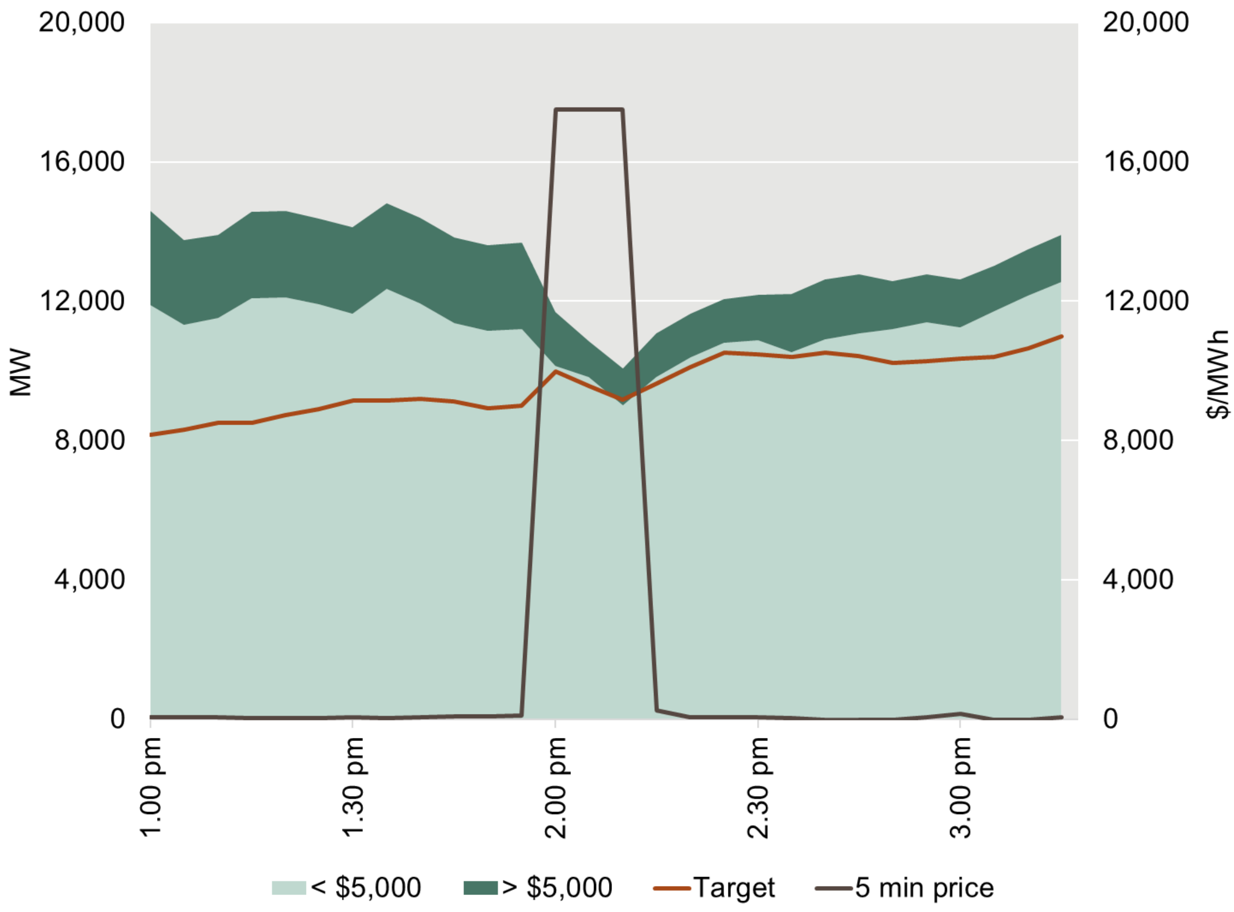
7.1 15 January, NSW

On 15 January, the 30-minute price in NSW reached $5,906 per MWh at 2.30 pm. The high price was not forecast. Around 89% of capacity was offered below $5,000 per MWh (Figure 8). There was no capacity offered between $2,500 per MWh and the market price cap meaning that any high-priced capacity needed to meet demand would be at the price cap.

AEMO forecast multiple low-level reserve shortfalls in NSW for 13 to 15 January. Actual low-level shortfalls eventuated on earlier days and shortly after the high prices on 15 January.[19]

There was also a lower 6 and lower 60 second Frequency Control Ancillary Service (FCAS) high price for one 30-minute period in Queensland but these did not breach our reporting threshold (section 7.1.5).

Figure 8 Capacity offered above and below $5,000 per MWh, 15 January



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

[19] See AEMO market notices 123289, 123323.

7.1.1 High demand

Demand at 2.30 pm was 10,323 MW which was 695 MW higher than forecast one hour prior. Demand was also significantly higher than the monthly average for 2.30 pm in NSW of 7,013 MW. This higher demand was mostly due to a reduction in solar output (section 7.1.2).

7.1.2 Limited output from wind and solar generation

In the lead up to the high price period, there was a significant reduction in solar generation due to cloudy conditions. Rooftop solar output dropped from over 5,000 MW at midday to around 3,000 MW at 2.30 pm when the high prices occurred.

Calm conditions saw relatively low levels of wind output with an average of around 800 MW on the day. Wind output was even lower at the time of the high prices, averaging 587 MW during the high price period, which equates to around 20% of the installed capacity in NSW.

7.1.3 Network limitations

An unplanned network outage on the Lower Tumut to Yass line in southern NSW also contributed to the high prices by limiting access to low-priced generation from southern NSW and Victoria. This outage prevented between 1,890 MW and 2,462 MW of low-priced capacity from reaching the Sydney load centre during the high prices. For the 2.05 pm interval, this outage meant AEMO needed to back off negatively-priced generation at Snowy Hydro's Tumut Power Station, resulting in a high price (section 4.3).

There was also an unplanned outage on the Muswellbrook to Tamworth line in northern NSW which prevented around 200 MW of low-priced solar generation from being dispatched.

The Muswellbrook to Tamworth line outage also set high local FCAS requirements in lower 6 and 60 second services in Queensland[20] and caused high FCAS prices in Queensland which flowed through to the NSW energy price (section 7.1.5). This was due to the outage creating a credible risk of losing QNI. Terranora, the remaining interconnector into Queensland, cannot transfer FCAS. To allow for this, AEMO made Queensland supply its own FCAS (section 7.1.5).

An unplanned outage of all three Directlink cables on the Terranora interconnector since 26 December also limited flows on the interconnector to around 18 MW into NSW.

7.1.4 Generation start up and ramp up constrained

During the high prices, around 800 MW of gas units could not start up quickly enough, and a further 800 MW from units already running could not ramp up quickly enough to mitigate the high prices.

For both high price intervals, the amount of low-priced capacity that was unable to be dispatched due to stations not starting up quickly enough was likely more than the amount of high-priced capacity needed to meet demand. These were peaking gas generators in the Snowy region. This includes 137 MW at Origin Energy's Uranquinty Power Station at

[20] The requirement for lower 60 services in Queensland reached a record 623 MW at 2.10 pm.

2.05 pm, 618 MW at Snowy Hydro's Colongra Power Station and 91 MW at Origin Energy's Uranquinty Power Station at 2.10 pm.

Up to 364 MW at Delta Electricity's Vales Point Power Station, 248 MW at Origin Energy's Eraring Power Station and 218 MW at Energy Australia's Mount Piper Power Station, could not ramp up quickly enough to prevent high prices. For two dispatch intervals, the amount of low-priced capacity unable to be dispatched due to ramp up limitations was likely enough to avoid high prices from occurring and was not impacted by network constraints.

7.1.5 Energy FCAS trade-off sets the price

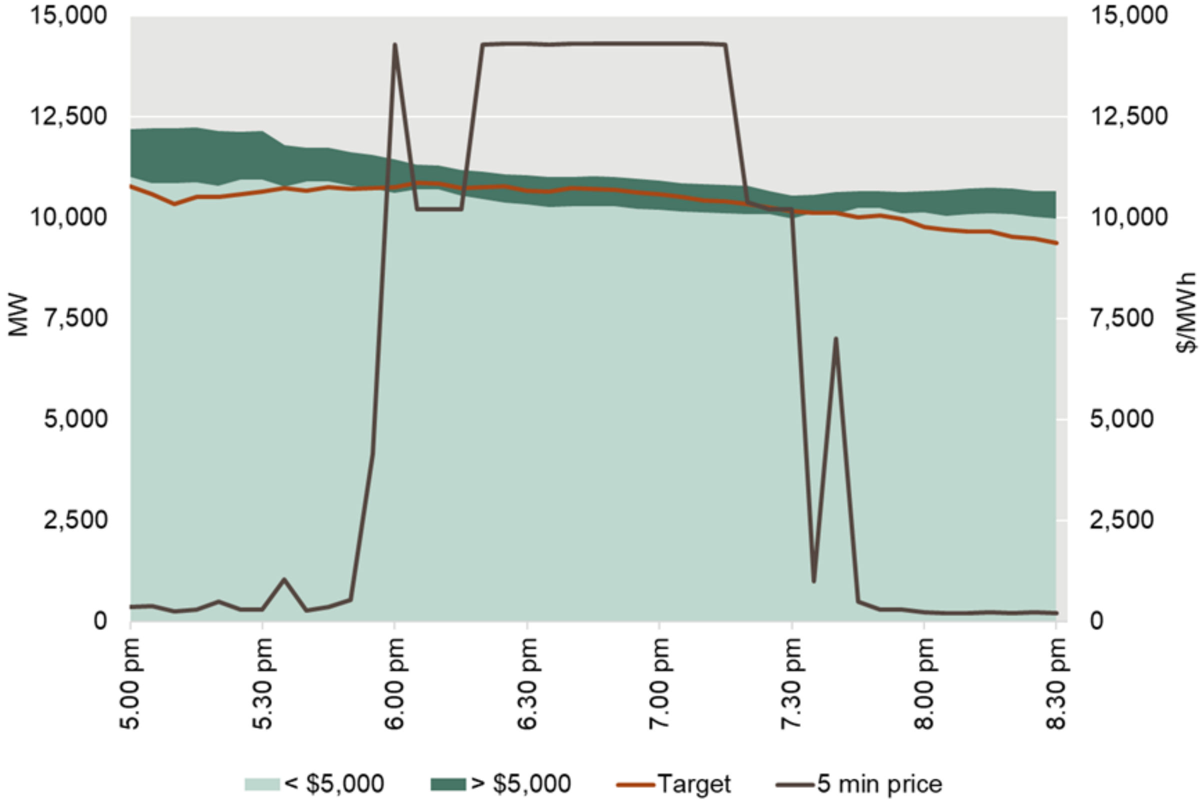
The market operator's dispatch engine simultaneously optimises the FCAS and energy markets, every dispatch interval, to determine the least cost outcome. This can lead to a trade-off between the FCAS and energy markets. For example, a generator may be reduced in providing raise ancillary services so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

On this day, for one of the two high-priced 5-minute intervals, at 2.10 pm, offers of around $17,500 per MW in lower FCAS contributed to setting the energy price in NSW.

7.2 22 January, Queensland

On 22 January, the 30-minute price in Queensland exceeded $5,000 per MWh three times in the evening. The price reached $12,261 per MWh at 6.30 pm, $14,319 per MWh at 7 pm and $12,291 per MWh at 7.30 pm. The high prices were forecast. Around 94% of capacity was offered below $5,000 per MWh (Figure 9).

Figure 9 Capacity offered above and below $5,000 per MWh, 22 January



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

7.2.1 High demand

Due to continuing high temperatures, demand was very high. Average demand during the high price periods was around 10,950 MW, compared to the quarterly average demand for this time of day of around 8,550 MW. Queensland's record demand was broken by more than 200 MW at 6 pm (30-minutes prior to high prices), when demand reached 11,258 MW.

High demand in combination with other drivers meant AEMO issued a forecast Lack of Reserve level 1 (LOR1) and a forecast Lack of Reserve level 2 (LOR2) notices in the evening. Actual LOR1 conditions eventuated from 5.30 pm to 8.15 pm and LOR2 conditions from 6.30 pm to 7.45 pm, but no market intervention was required.[21]

[21] See AEMO market notices 123540, 123545, 123593, 123589, 123594, 123598.

7.2.2 Limited output from wind generation

Calm conditions saw low levels of wind output. Average wind generation for the day was relatively low at just 240 MW, compared to an average of around 350 MW across the week. During the high prices, wind output averaged 154 MW, which equates to only 7% of installed capacity in Queensland.

7.2.3 Network limitations

Network limitations and a planned outage reduced Queensland's ability to access cheap generation from New South Wales.

During the high prices, QNI was flowing around 381 MW on average into Queensland, compared to its nominal capacity of 850 MW, due to a constraint in place to manage negative settlement residues (section 4.2).[22] AEMO published a market notice at 6 pm explaining that, due to forecasts, negative settlement residues would breach the threshold in the NSW to Queensland direction.[23] This constraint began binding on QNI from 6.05 pm, reducing imports into Queensland by around 200 MW. At 6.40 pm, there were actual accruals of negative settlement residues above the threshold and the constraint managing these was extended until 7.30 pm.

Terranora was constrained by an ongoing planned outage of the Lismore SVC in NSW. To maintain system security, flows were forced into NSW, at an average of 139 MW, during the high-priced periods. Lismore SVC returned to service by 24 January.

A system normal constraint to avoid overloading network equipment in northeast Queensland also prevented an average of around 70 MW of cheap generation from being dispatched during the high prices.

7.2.4 Baseload outages

Two coal units were unavailable at the time of the high prices. One of six 280 MW units at Gladstone Power Station was on an unplanned outage since the morning of 20 January, and one 443 MW unit at Tarong North Power Station was on a planned outage since 19 January. These outages meant around 700 MW of baseload capacity, most of which is typically offered at low prices, was unavailable during the high prices.

7.2.5 Rebidding

Rebidding for commercial and technical reasons contributed to some of the high prices. Between 145 MW and 454 MW of high price capacity was needed to meet demand (Appendix A).

CS Energy removed 338 MW of low-priced capacity for technical reasons including mill limits and control system issues, mostly at Gladstone Power Station. These rebids impacted the high prices at 7.20 pm, 7.25 pm and 7.30 pm.

Genuity withdrew around 180 MW of low-priced capacity at Millmerran Power Station due to milling and temperature issues, impacting the 7.25 pm and 7.30 pm intervals.

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[22] AEMO, Automation of Negative Residue Management, July 2021

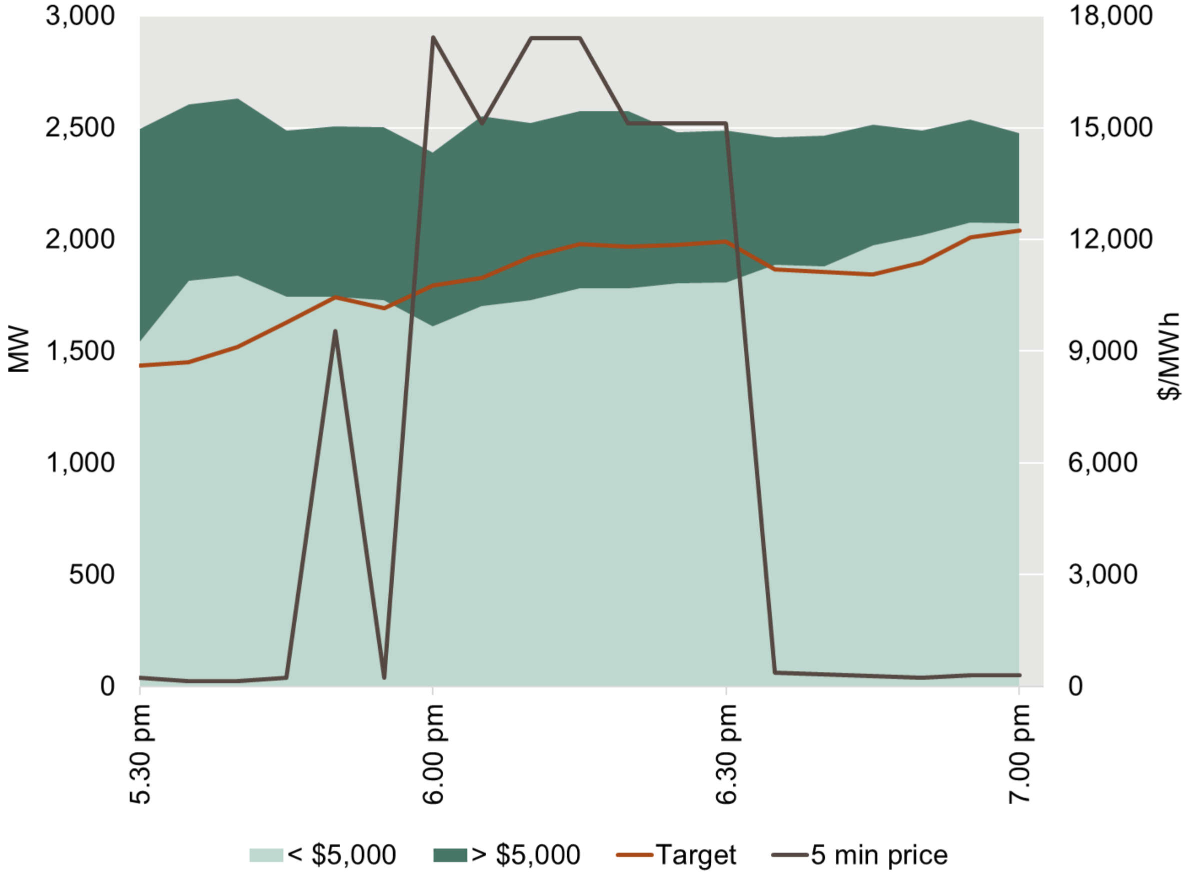
[23] See AEMO market notices 123591, 123596.

Neoen shifted 192 MW of capacity from low to high prices at its Western Downs battery due to changes in its state of charge, setting the price from 6.05 pm to 6.15 pm and 7.25 pm to 7.30 pm.

7.3 1 February, South Australia

On 1 February, the 30-minute price in South Australia reached $15,874 per MWh at 6.30 pm. The high price was not forecast. Around 70% of capacity was offered below $5,000 per MWh which is better than other comparable weekends (Figure 10).

Figure 10 Capacity offered above and below $5,000 per MWh, 1 February



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

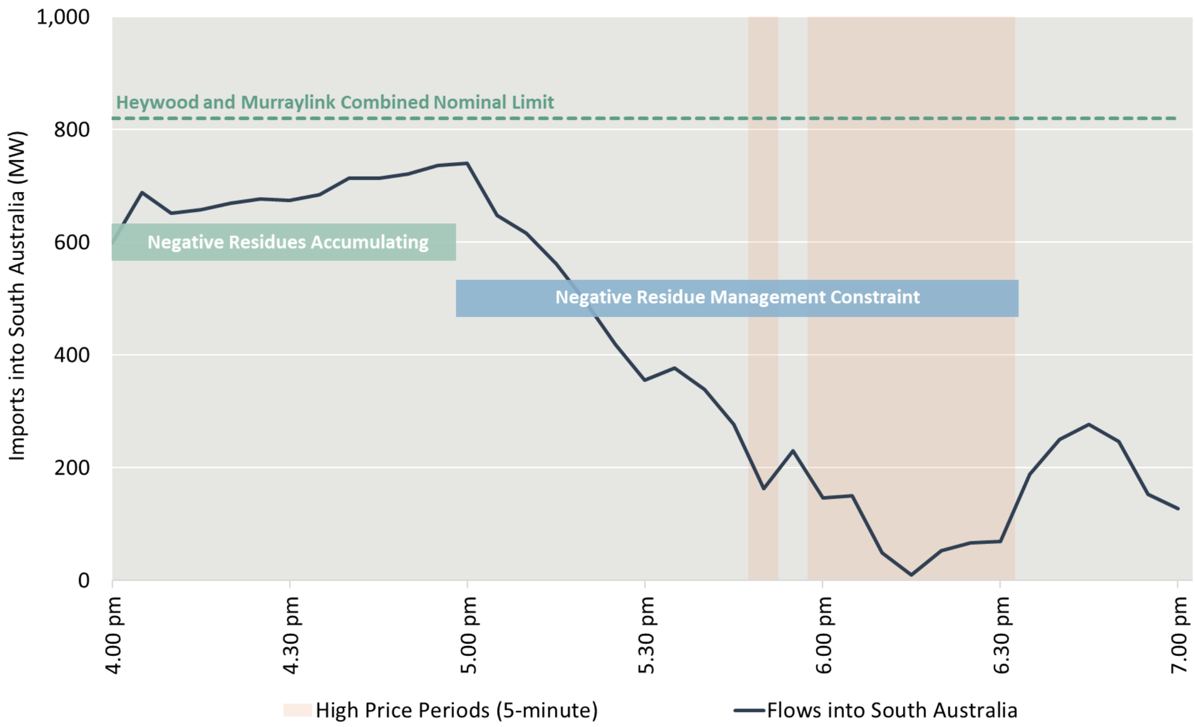
7.3.1 Limited output from wind generation

Average wind output on 1 February was 704 MW, compared to 841 MW across the week prior. During the high prices, average wind output was 357 MW, which equates to around 13% of installed capacity in South Australia.

7.3.2 Network limitations

During the afternoon on 1 February (from around midday to 5.30 pm), prices were higher in Victoria than in South Australia, though both remained under $250 per MWh. Due to a network constraint to avoid overloading a line in northwest Victoria, flows were being forced out of Victoria (higher price region) and into South Australia (lower price region). As a result, negative settlement residues accrued (green bar in Figure 11).[24] To manage these negative settlement residues, AEMO invoked a constraint that limited flows into South Australia (blue bar in Figure 11). At around 6 pm, prices then increased to over $5,000 per MWh in South Australia. This constraint, intended to reduce the accumulation of negative settlement residues, continued to limit flows into South Australia (now the high price region), preventing it from accessing more low-priced capacity from Victoria (section 4.2).

Figure 11 Interconnector flows into South Australia



Source: AER analysis using NEM data.

7.3.3 Rebidding

Between 130 MW and 199 MW of high price capacity was needed to meet demand. Rebidding for commercial reasons contributed to the high price (Appendix B).

Just prior to 6 pm, and effective from 6.05 pm, AGL Energy shifted a combined total of 155 MW of capacity from low to high prices. 90 MW was shifted from $138 per MWh to $17,500 per MWh at Torrens Island Power Station, and 65 MW was shifted from under $215 per MWh to above $9,625 per MWh at the Torrens Island Battery, both due to changes in forecast prices. Torrens Island Battery set the price for all six high-priced intervals.

[24] Negative settlement residue is the product of the difference in the regional reference price between two regions in the NEM and the quantity of electricity flowing over an interconnector between those two regions. A negative settlements residue arises where there are counter-price flows; that is, electricity flows from a high-priced region to a low-priced region. When the accumulated value of negative settlement residues reaches $100,000, AEMO intervenes to reduce the counter-price flow of electricity in the affected direction of an interconnector.

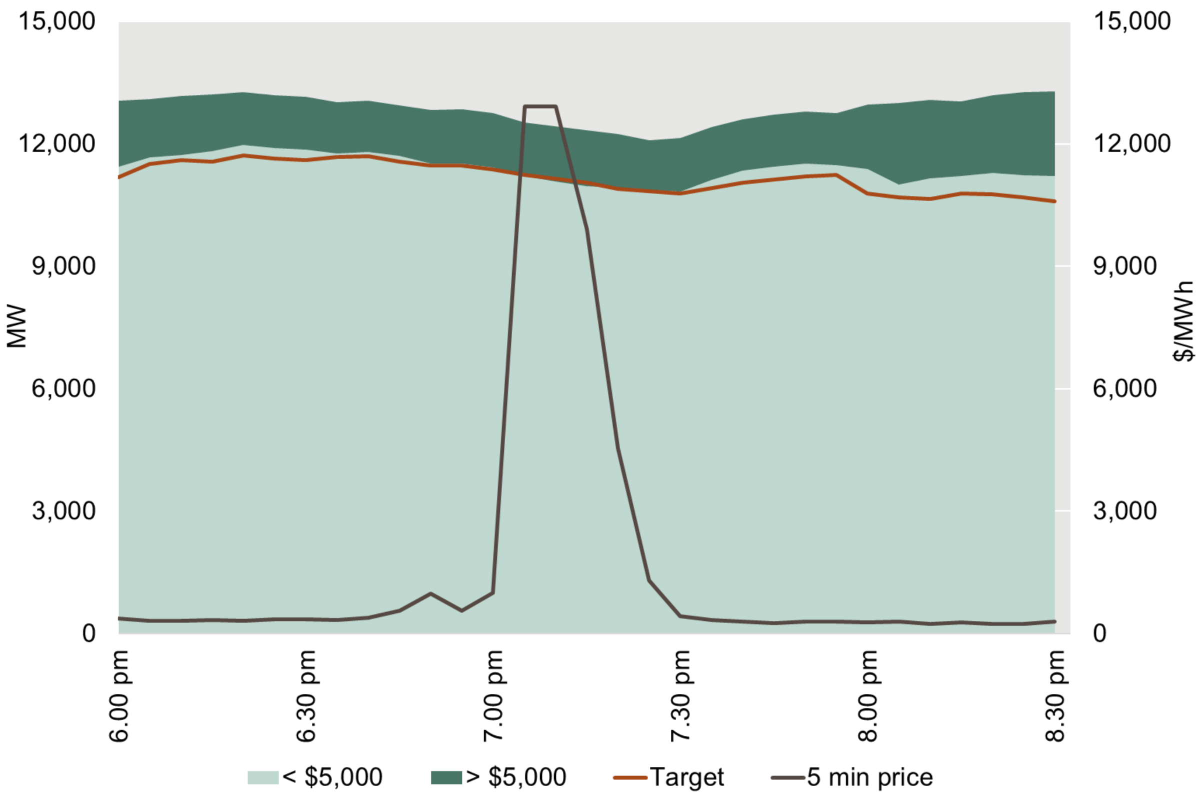
7.4 3 February, South Australia and Victoria

On 3 February, the 30-minute price exceeded $5,000 per MWh in South Australia and Victoria at 7.30 pm. The price was $6,034 per MWh in Victoria and $7,003 per MWh in South Australia. Around 90% of capacity was offered below $5,000 per MWh (Figure 12). The high prices were forecast.

In this event South Australia and Victoria were price aligned and for the purpose of analysis were treated as one combined region.

Both regions had reserve shortfall forecasts in the days leading up to 3 February, however no actual reserve shortfalls eventuated.[25]

Figure 12 Capacity offered above and below $5,000 per MWh, 3 February



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

[25] See AEMO market notices 124025, 124042.

7.4.1 High demand

Demand was very high, driven by heatwave conditions in Victoria and South Australia.

Combined demand for the regions at 7.30 pm was 12,347 MW which was the third highest for the quarter, with the highest, 12,650 MW, occurring in the preceding 7 pm interval. This is more than 1,000 MW below the combined record for the two regions.

7.4.2 Network limitations

A planned outage of the Collector to Marulan line limited flows from New South Wales to Victoria. Flows on the Victoria to NSW interconnector were limited to 574 MW of its nominal capacity of up to 1,540 MW.

7.4.3 Limited output from wind generation

Wind output in the regions was relatively low on the day, with an average of 1,966 MW across South Australia and Victoria, compared to an average of around 2,550 MW across the following week. At the time of the high prices, wind output averaged 1,267 MW, which equates to around 15% of installed capacity in South Australia and Victoria.

7.4.4 Generation start up constrained and trapped in FCAS

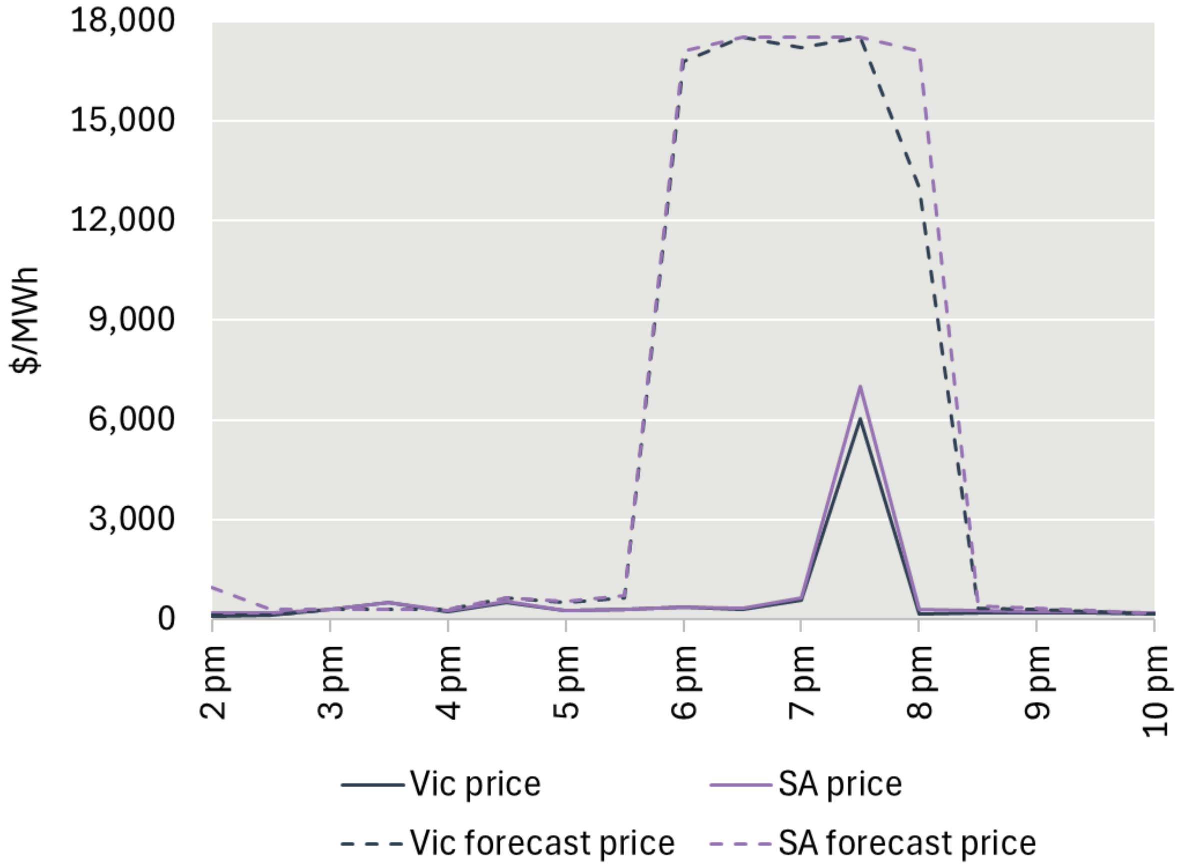
For the 7.15 pm high price, 78 MW of high-priced capacity was needed to meet demand. At Snowy Hydro’s Valley Power station, 47 MW was unable to be dispatched due to start-up limitations.

At Loy Yang A Power Station, 29 MW was unable to be dispatched due to the interactions between the FCAS and energy markets (section 7.1.5). For one interval, the amount of low-priced capacity unable to be dispatched was more than the high-priced capacity needed to meet demand.

7.4.5 Rebidding prevented more high prices from occurring

Around 900 MW of capacity was shifted from high to lower prices within four hours of dispatch in Victoria, while in South Australia, around 40 MW was removed from low prices. This rebidding resulted in lower than forecast prices, and fewer high prices in total than forecast (Figure 13).

Figure 13 Actual and 4 hour ahead forecast prices for Victoria and South Australia



Source. AER analysis using NEM data.

7.4.6 Other rebidding contributed to the high prices

Despite most of the forecast high prices being prevented by helpful rebidding (section 7.4.5), in the 30 minutes leading up to the high price, the following rebids contributed to the one 30 minute high price that did eventuate. (Appendix C).

Between 24 MW and 78 MW of high price capacity was needed to meet demand during the high prices at 7.05 pm, 7.10 pm and 7.15 pm.

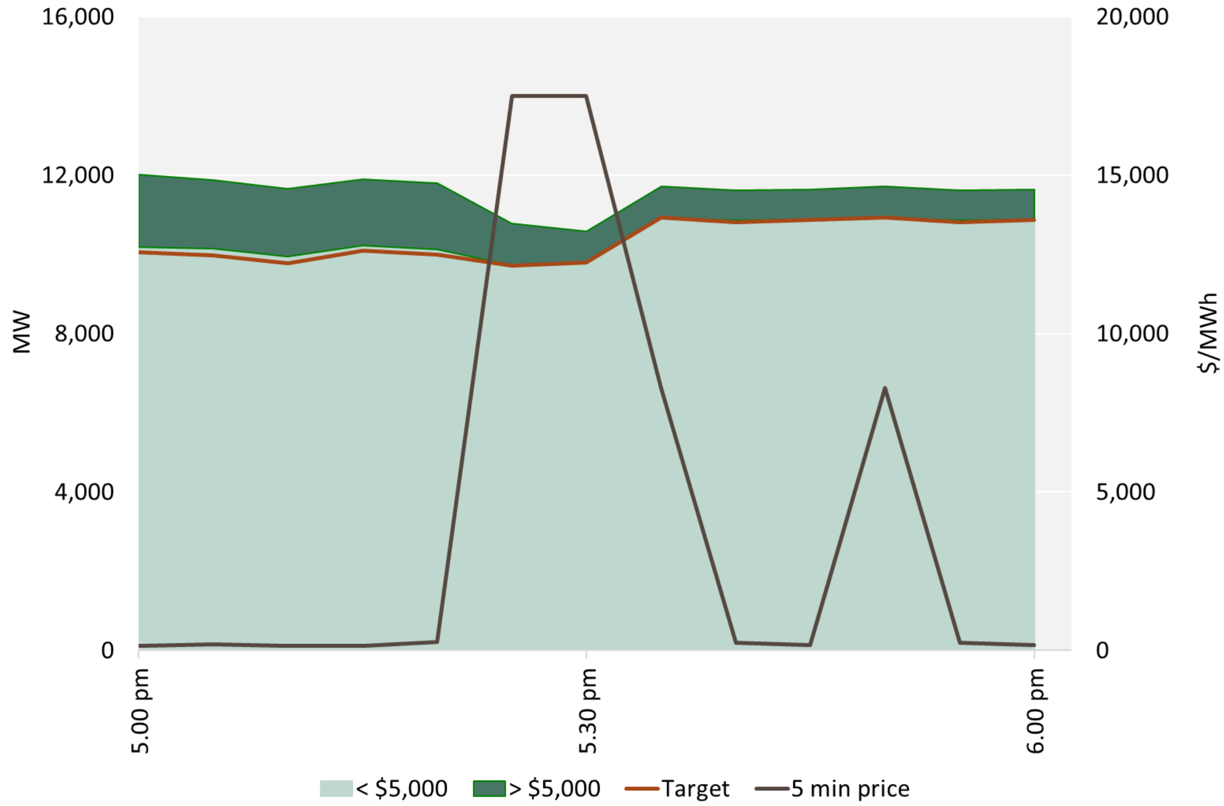
Between 6.38 pm and 6.58 pm, AGL Energy removed 65 MW of low-priced capacity at Torrens Island B Power Station, Dalrymple North battery and Mckay power station due to plant failure, and shifted 142 MW of capacity from low to high prices at Barker Inlet and Torrens Island B power stations due to a change in forecast prices. These rebids contributed to the high prices at 7.05 pm and 7.10 pm, and includes a rebid of 92 MW from low to high prices at Barker Inlet Power station which set the price for both intervals.

At 7.07 pm, Neoen shifted 80 MW from low to high prices in a late rebid at the Hornsdale Battery due to updated state of charge, which set the price for 7.15 pm.

7.5 5 February, NSW

On 5 February, the 30-minute price in NSW reached $5,958 per MWh at 5.30 pm. Around 92% of capacity was offered below $5,000 per MWh (Figure 14). The high price was not forecast on the day.

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



Source: AER analysis using NEM data.

7.5.1 Network congestion

A planned outage on the Collector to Marulan line limited nearly 2,000 MW of cheap generation in southern NSW, contributing to the high prices (section 4.1.1). One of these units being backed off set the price at the market price cap (section 4.3).

On the other side of Sydney, a system normal constraint managing transient stability on QNI for a trip of either lines from Armidale to Dumaresq or to Sapphire set the import limit on the interconnector during high-priced dispatch intervals, limiting flows into NSW to around 920 MW, compared to its nominal capacity of 1,300 MW.

An unplanned outage of two of the three Directlink cables since 30 January limited flows into NSW on the Terranora interconnector to 100 MW out of its 210 MW nominal capacity during both high-priced dispatch intervals.

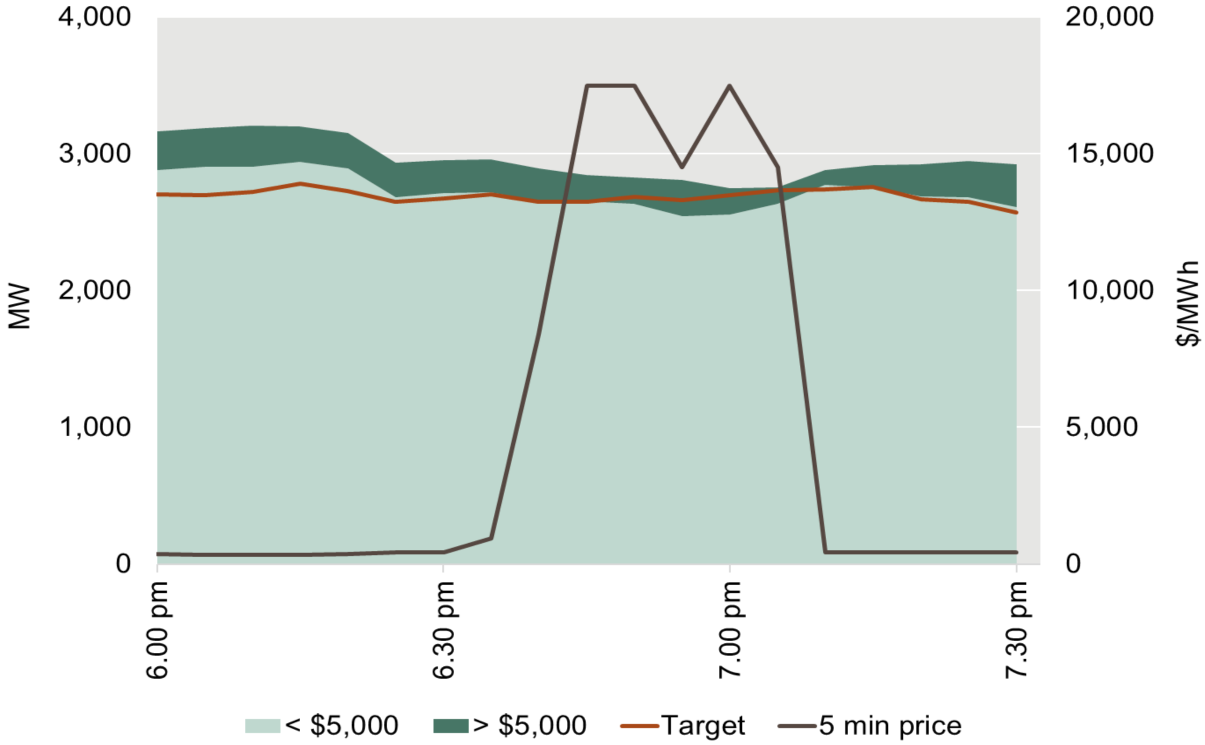
7.5.2 Baseload outages

Two coal units were unavailable at the time of the high prices. One unit at Baywater Power Station and one unit at Eraring Power Station were on unplanned outages since 21 January and 3 February, respectively. These outages meant around 1,400 MW of baseload capacity, most of which is typically offered at low prices, was unavailable during the high prices.

7.6 12 February, South Australia

On 12 February, the 30-minute price in South Australia reached $12,723 per MWh at 7 pm. The high price was not forecast. Around 92% of capacity was offered below $5,000 per MWh (Figure 15).

Figure 15 Capacity offered above and below $5,000 per MWh, 12 February



Source: AER analysis using NEM data.

7.6.1 High demand

Due to consecutive days of high daytime and evening temperatures, demand remained elevated as there was continued need for cooling. Demand during the high price period was 3,315 MW, which was the highest for the quarter and only 82 MW below the record for South Australia, set in January 2011.

7.6.2 Limited output from wind generation

Wind output was low, and lower than forecast, averaging 434 MW out of 2,763 MW of installed capacity during the high prices. This equates to around 16% of installed wind capacity in South Australia.

7.6.3 Network limitations

Flows into South Australia were limited from Victoria due to system normal constraints invoked to prevent overloading lines and maintain system security.

Murraylink flows were 70 MW out of its 220 MW nominal limit to manage an outage of the New South Wales Murraylink runback scheme, a special protection scheme. Heywood flows were around 590 MW out of its 650 MW capability[26] to avoid overloading the Tailem Bend to Tungkillo line.

For the 6.50 pm high price, a system normal constraint to avoid overloading Tailem Bend to Tungkillo line also meant that 45 MW of low-priced capacity at Iberdrola's Lake Bonney battery and wind farm was unable to make it to market. This was less than the high-priced capacity needed but, when combined with 28 MW ramp rate limited at Engie's Dry Creek, it exceeded the amount of high-priced capacity that was needed to meet demand.

AEMO's dispatch engine when considering the formulation of these constraints, determined that the least cost outcome was to back-off low-priced generation instead of dispatching higher high-priced capacity. There were three dispatch intervals where low-priced generation set a high price.

7.6.4 Rebidding

Between 48 MW and 120 MW of high price capacity was needed to meet demand during the high prices. Rebidding for technical reasons contributed to both dispatch intervals where high-priced offers set the price (Appendix D).

AGL Energy removed 150 MW of low-priced capacity at Torrens Island Battery due to a change in unit capabilities.

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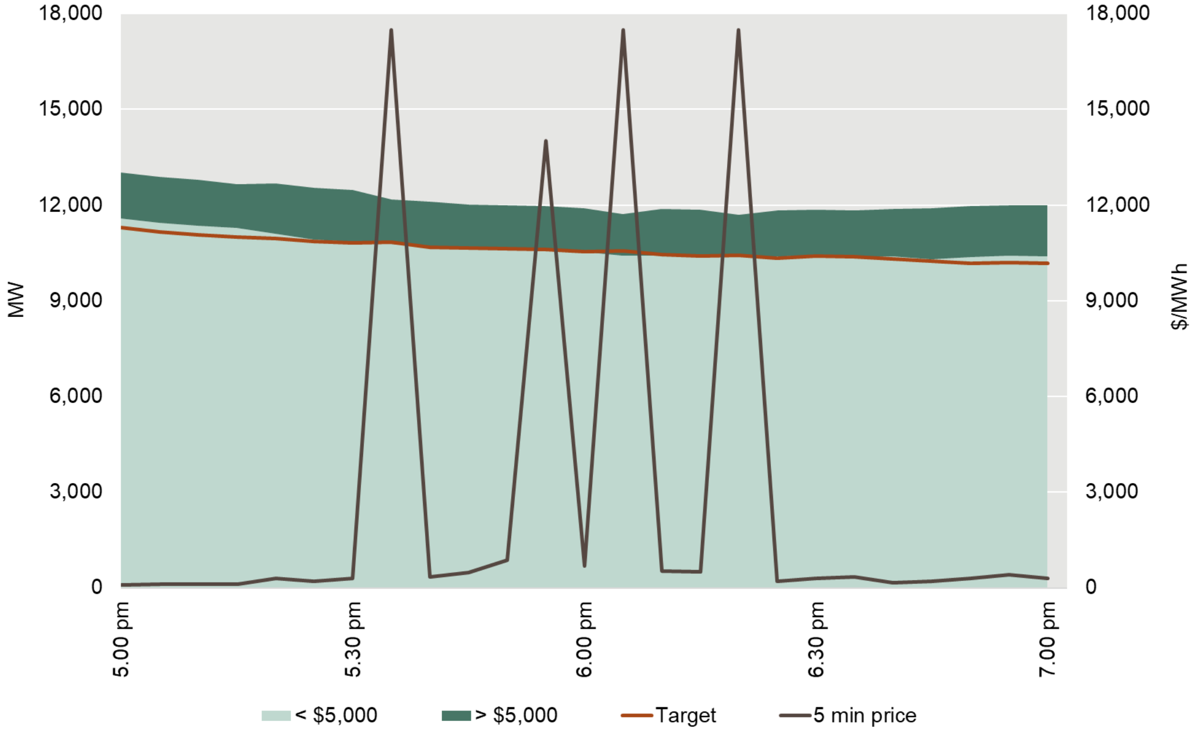
[26] The nominal limit is 600 MW but the export limit has consistently reached 650 MW throughout February 2025 due to Project Energy Connect stage 1.

7.7 15 March, NSW

On 15 March, the 30-minute price in NSW exceeded $5,000 per MWh twice in the evening. The price reached $5,648 per MWh at 6 pm and $6,086 per MWh at 6.30 pm. The high prices were forecast. AEMO forecast multiple low-level reserve shortfalls in NSW throughout the day, with actual low-level shortfalls occurring from 5.30 pm to 6.45 pm.[27] Around 89% of capacity was offered below $5,000 per MWh (Figure 16).

Figure 16 Capacity offered above and below $5,000 per MWh, 15 March



Source: AER analysis using NEM data.

7.7.1 High demand

High demand was driven by very warm temperatures in NSW.[28] Demand was 12,109 MW at 6 pm and 11,903 MW at 6.30 pm. The maximum daily demand was 12,147 MW, which was the fourth highest for the quarter.

7.7.2 Limited output from wind generation

Average wind generation in NSW on 15 March was 419 MW compared to 858 MW across the week prior and 877 MW the following week.

At the time of the high prices, wind generation was 176 MW, which equates to around 9% of installed capacity in NSW.

[27] See AEMO market notice 125678.

[28] ABC News, Sydney swelters through hot March night, 16 March 2025.

7.7.3 Network limitations

Network limitations prevented NSW from accessing cheaper generation, contributing to the high prices.

The Terranora interconnector was limited to around 134 MW on average into NSW compared to its nominal capacity of 210 MW due to a system normal constraint relating to rate of change on the interconnector and a planned outage of one Directlink cable.

QNI was flowing around 1,246 MW on average into NSW out of its capacity of 1,300 MW.

Similar to 5 February, the continuing planned network outage on the Collector to Marulan line meant 700 MW and 895 MW of low-priced capacity from Victoria and southern NSW was unable to reach the Sydney load centre (section 4.1.1).

7.7.4 Rebidding

Between 5 MW and 133 MW of high-priced capacity was needed to meet demand. The requirement for high-priced capacity was mostly driven by tight supply conditions and the substantial amount of low-priced capacity that was constrained. Rebidding for technical reasons also contributed to some of the high price intervals (Appendix E).

AGL Energy withdrew between 65 MW and 123 MW of low-priced capacity, impacting the 5.35 pm, 5.55 pm and 6.20 pm high prices. Most of this rebidding occurred at Bayswater power station due to milling and feeder issues. 13 MW was withdrawn at Broken Hill battery due to a capability change, which impacted the 6.20 pm high price.

8 Appendix A – Significant rebids 22 January, Queensland

6.05 pm (172 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.06 pm		Neoen	Western Downs Battery	122	343	16,939	Updated SOC close to limit
4.11 pm		Neoen	Western Downs Battery	1	16,939	343	Updated SOC close to limit
4.36 pm		Neoen	Western Downs Battery	69	343	16,939	Updated SOC close to limit
4.41 pm		Neoen	Western Downs Battery	2	343	16,939	Updated SOC close to limit

6.10 pm (145 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.06 pm		Neoen	Western Downs Battery	123	343	16,939	Updated SOC close to limit
4.16 pm		Neoen	Western Downs Battery	1	16,939	343	Updated SOC close to limit
4.36 pm		Neoen	Western Downs Battery	70	343	16,939	Updated SOC close to limit

6.15 pm (184 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
4.06 pm		Neoen	Western Downs Battery	124	343	16,939	Updated SOC close to limit
4.31 pm		Neoen	Western Downs Battery	1	16,939	343	Updated SOC close to limit
4.36 pm		Neoen	Western Downs Battery	69	343	16,939	Updated SOC close to limit

7.20 (266 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.44 pm		CS Energy	Callide B	70	<500	N/A	Emissions - Precip/TR set -SL
4.33 pm		CS Energy	Kogan Creek	30	87	N/A	Ambient Temperature--SL
6.00 pm		CS Energy	Kogan Creek	5	N/A	87	Ambient Temperature--SL
6.11 pm		CS Energy	Kogan Creek	5	N/A	87	Ambient Temperature--SL
6.19 pm		CS Energy	Kogan Creek	5	N/A	500	Ambient Temperature--SL
6.23 pm		CS Energy	Callide B	30	<500	N/A	Mill -Mill Limit-SL
6.31 pm		CS Energy	Callide B	10	N/A	140	Emissions - Coal quality-SL
6.31 pm		CS Energy	Callide C	12	17,500	3,000	Market Condition Changed - QLD1 TI 22-01-2025 18:35:00 P5 RRP $14936.02 vs P5 RRP $14319.88 @ P5 RUN 22-01-2025 18:16:31 - RRP CHANGE OF $616.14 - SL
6.46 pm	6.55 pm	CS Energy	Gladstone	50	154	N/A	Control System-Other-SL
6.51 pm	7.00 pm	CS Energy	Kogan Creek	5	N/A	500	Ambient Temperature--SL
6.53 pm	7.00 pm	CS Energy	Gladstone	90	<154	N/A	Control System-Other-SL
7.13 pm	7.20 pm	CS Energy	Gladstone	110	-1,000	N/A	Control System-Other-SL

7.25 (171 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.44 pm		CS Energy	Callide B	70	<500	N/A	Emissions - Precip/TR set -SL
4.13 pm		Genuity	Millmerran	1	-1,000	N/A	Condensate Polisher Inlet Temperature Limitation
4.27 pm		Genuity	Millmerran	18	-1,000	N/A	Condensate Polisher Inlet

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
							Temperature Limitation
4.33 pm		CS Energy	Kogan Creek	30	87	N/A	Ambient Temperature--SL
4.36 pm		Neoen	Western Downs Battery	50	343	16,939	Updated SOC close to limit
4.38 pm		Genuity	Millmerran	163	-1,000	N/A	Fuel/Mill/CV Limitation
4.43 pm		Genuity	Millmerran	13	-1,000	N/A	Condensate Polisher Inlet Temperature Limitation
4.46 pm		Neoen	Western Downs Battery	53	343	16,939	Updated SOC close to limit
4.51 pm		Neoen	Western Downs Battery	21	343	16,939	Updated SOC close to limit
4.56 pm		Neoen	Western Downs Battery	76	16,939	343	Updated SOC close to limit
5.06 pm		Neoen	Western Downs Battery	144	343	9,993	Updated SOC close to limit
5.16 pm		Genuity	Millmerran	3	N/A	-1,000	Condensate Polisher Inlet Temperature Limitation
5.22 pm		Genuity	Millmerran	3	N/A	-1,000	Condensate Polisher Inlet Temperature Limitation
5.29 pm		Genuity	Millmerran	16	N/A	-1,000	Condensate Polisher Inlet Temperature Limitation
5.30 pm		Genuity	Millmerran	20	N/A	-1,000	Mill or Feeder Limitation
6.00 pm		CS Energy	Kogan Creek	5	N/A	87	Ambient Temperature--SL
6.11 pm		CS Energy	Kogan Creek	5	N/A	87	Ambient Temperature--SL
6.14 pm		Genuity	Millmerran	35	-1,000	N/A	Backpressure Limitation
6.19 pm		CS Energy	Kogan Creek	5	N/A	500	Ambient Temperature--SL
6.23 pm		CS Energy	Callide B	30	<500	N/A	Mill -Mill Limit-SL
6.31 pm		CS Energy	Callide B	10	N/A	140	Emissions - Coal quality-SL
6.31 pm		CS Energy	Callide C	12	17,500	3,000	Market Condition Changed - QLD1 TI 22-01-2025 18:35:00 P5 RRP $14936.02 vs P5 RRP

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
							$14319.88 @ P5 RUN 22-01-2025 18:16:31 - RRP CHANGE OF $616.14 - SL
6.46 pm	6.55 pm	CS Energy	Gladstone	50	154	N/A	Control System-Other-SL
6.51 pm	7.00 pm	CS Energy	Kogan Creek	5	N/A	500	Ambient Temperature--SL
6.53 pm	7.00 pm	CS Energy	Gladstone	90	<154	N/A	Control System-Other-SL
6.55 pm	7.05 pm	Genuity	Millmerran	10	N/A	-1,000	Condensate Polisher Inlet Temperature Limitation
7.13 pm	7.20 pm	CS Energy	Gladstone	110	-1,000	N/A	Control System-Other-SL

7.30 pm (178 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.44 pm		CS Energy	Callide B	70	<500	N/A	Emissions - Precip/TR set -SL
4.27 pm		Genuity	Millmerran	16	-1,000	N/A	Condensate Polisher Inlet Temperature Limitation
4.33 pm		CS Energy	Kogan Creek	30	87	N/A	Ambient Temperature--SL
4.36 pm		Neoen	Western Downs Battery	52	343	16,939	Updated SOC close to limit
4.38 pm		Genuity	Millmerran	165	-1,000	N/A	Fuel/Mill/CV Limitation
4.43 pm		Genuity	Millmerran	15	-1,000	N/A	Condensate Polisher Inlet Temperature Limitation
4.46 pm		Neoen	Western Downs Battery	52	343	16,939	Updated SOC close to limit
4.51 pm		Neoen	Western Downs Battery	21	343	16,939	Updated SOC close to limit
4.56 pm		Neoen	Western Downs Battery	75	16,939	343	Updated SOC close to limit

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.01 pm		Neoen	Western Downs Battery	1	16,939	343	Updated SOC close to limit
5.06 pm		Neoen	Western Downs Battery	143	343	9,993	Updated SOC close to limit
5.16 pm		Genuity	Millmerran	3	N/A	-1,000	Condensate Polisher Inlet Temperature Limitation
5.22 pm		Genuity	Millmerran	3	N/A	-1,000	Condensate Polisher Inlet Temperature Limitation
5.29 pm		Genuity	Millmerran	18	N/A	-1,000	Condensate Polisher Inlet Temperature Limitation
5.30 pm		Genuity	Millmerran	20	N/A	-1,000	Mill or Feeder Limitation
6.00 pm		CS Energy	Kogan Creek	5	N/A	87	Ambient Temperature--SL
6.11 pm		CS Energy	Kogan Creek	5	N/A	87	Ambient Temperature--SL
6.14 pm		Genuity	Millmerran	38	-1,000	N/A	Backpressure Limitation
6.19 pm		CS Energy	Kogan Creek	5	N/A	500	Ambient Temperature--SL
6.23 pm		CS Energy	Callide B	30	<500	N/A	Mill -Mill Limit-SL
6.31 pm		CS Energy	Callide B	10	N/A	140	Emissions - Coal quality-SL
6.31 pm		CS Energy	Callide C	12	17,500	3,000	Market Condition Changed - QLD1 TI 22-01-2025 18:35:00 P5 RRP $14936.02 vs P5 RRP $14319.88 @ P5 RUN 22-01-2025 18:16:31 - RRP CHANGE OF $616.14 - SL
6.46 pm	6.55 pm	CS Energy	Gladstone	50	154	N/A	Control System-Other-SL
6.51 pm	7.00 pm	CS Energy	Kogan Creek	5	N/A	500	Ambient Temperature--SL
6.53 pm	7.00 pm	CS Energy	Gladstone	90	<154	N/A	Control System-Other-SL
6.55 pm	7.05 pm	Genuity	Millmerran	10	N/A	-1,000	Condensate Polisher Inlet Temperature Limitation
7.13 pm	7.20 pm	CS Energy	Gladstone	110	-1,000	N/A	Control System-Other-SL

9 Appendix B – Significant rebids 1 February, South Australia

6:05 pm (130 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
5.59 pm	6.05 pm	AGL Energy	Torrens Island B Power Station	90	138	17,500	050 Chg in AEMO PD~56 Price increase [SA] [8059.81 5MPD vs $138.00 PD PE 1830
6 pm	6.05 pm	AGL Energy	Torrens Island Battery	65	<215	>9,625	050 Chg in AEMO PD~56 Price increase [sa] [8059.81 5MPD vs $ 138.00 PD PE 1830

10 Appendix C – Significant rebids 3 February, South Australia and Victoria

7.05 pm (24 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
6:38 pm		AGL Energy	Torrens Island B Power Station	5	-1000	N/A	010 Unexpected/plant limits~106 Aux/Plant failure
6:42 pm		AGL Energy	Torrens Island B Power Station	15	-1000	N/A	010 Unexpected/plant limits~106 Aux/Plant failure
6:49 pm		AGL Energy	Torrens Island B Power Station	25	-1000	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$985.35]
6:49 pm		AGL Energy	Torrens Island B Power Station	25	-1000	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$985.35]
6:43 pm		AGL Energy	Barker Inlet Power Station	92	138	12,922	Chg in AEMO DISP~45 Price change vs PD [SA] [$555.55]
6:58 pm		AGL Energy	Dalrymple North Battery	5	242	N/A	Local Limit Change RR Change RR Changed
6:58 pm		AGL Energy	Mckay	40	-1000	N/A	Reduction in avail cap~203 plant failure

7.10 pm (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
6:42 pm		AGL Energy	Torrens Island B Power Station	15	-1000	N/A	010 Unexpected/plant limits~106 Aux/Plant failure
6:49 pm		AGL Energy	Torrens Island B Power Station	25	-1000	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$985.35]
6:49 pm		AGL Energy	Torrens Island B Power Station	25	-1000	17,500	040 Chg in AEMO DISP~44 Price change vs PD [SA] [$985.35]
6:43 pm		AGL Energy	Barker Inlet Power Station	92	138	12,922	Chg in AEMO DISP~45

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
							Price change vs PD [SA] [$555.55]
6:58 pm		AGL Energy	Dalrymple North Battery	5	242	N/A	Local Limit Change RR Change RR Changed
6:58 pm		AGL Energy	Mckay	40	-1000	N/A	Reduction in avail cap~203 plant failure

7.15 pm (78 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
7.07 pm		Neoen	Hornsdale Battery	80	362	9,932	Updated SOC close to limit

11 Appendix D – Significant rebids 12 February, South Australia

For 6.50 pm (48 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
5.15 pm		AGL Energy	Torrens Island Battery	100	17,409	985	040 Chg in AEMO DISP~45 Price change vs PD [sa] [$286.89 disp v pe 1730 170.44]
5.53 pm		AGL Energy	Torrens Island Battery	250	<985	N/A	Capability Change (PD) ENERGY, LOWER1SEC, LOWER5MIN, LOWER60SEC, LOWER6SEC, LOWERREG, RAISE1SEC, RAISE5MIN, RAISE60SEC, RAISE6SEC, RAISEREG
6.03 pm		AGL Energy	Torrens Island Battery	171	N/A	<985	Capability Change (PD) ENERGY, LOWER1SEC, LOWER5MIN, LOWER60SEC, LOWER6SEC, LOWERREG, RAISE1SEC, RAISE5MIN, RAISE60SEC, RAISE6SEC, RAISEREG
6.08 pm		AGL Energy	Torrens Island Battery	171	<985	N/A	Capability Change (PD) ENERGY, LOWER1SEC, LOWER5MIN, LOWER60SEC, LOWER6SEC, LOWERREG, RAISE1SEC, RAISE5MIN, RAISE60SEC, RAISE6SEC, RAISEREG

For 6.55 pm high prices (120 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
5.15 pm		AGL Energy	Torrens Island Battery	100	17,409	985	040 Chg in AEMO DISP~45 Price change vs PD [sa] [$286.89 disp v pe 1730 170.44]
5.53 pm		AGL Energy	Torrens Island Battery	250	<985	N/A	Capability Change (PD) ENERGY, LOWER1SEC, LOWER5MIN, LOWER60SEC, LOWER6SEC, LOWERREG, RAISE1SEC, RAISE5MIN, RAISE60SEC, RAISE6SEC, RAISEREG
6.03 pm		AGL Energy	Torrens Island Battery	169	N/A	<985	Capability Change (PD) ENERGY, LOWER1SEC, LOWER5MIN, LOWER60SEC, LOWER6SEC, LOWERREG, RAISE1SEC, RAISE5MIN, RAISE60SEC, RAISE6SEC, RAISEREG
6.08 pm		AGL Energy	Torrens Island Battery	169	<985	N/A	Capability Change (PD) ENERGY, LOWER1SEC, LOWER5MIN, LOWER60SEC, LOWER6SEC, LOWERREG, RAISE1SEC, RAISE5MIN, RAISE60SEC, RAISE6SEC, RAISEREG

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5.35 pm (52 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
3.21 pm		AGL Energy	Bayswater	35	-1,000	N/A	Reduction in avail cap-feeder issues ongoing
4.30 pm		AGL Energy	Bayswater	10	-1,000	N/A	Reduction in avail cap – Milling limits
5.27 pm		AGL Energy	Bayswater	45	-1,000	N/A	Availability change

5.55 pm (5 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MW)	Price to ($/MW)	Rebid reason
3.21 pm		AGL Energy	Bayswater	35	-1,000	N/A	Reduction in avail cap-feeder issues ongoing
4.30 pm		AGL Energy	Bayswater	10	-1,000	N/A	Reduction in avail cap – Milling limits
5.27 pm		AGL Energy	Bayswater	45	-1,000	N/A	Availability change
5.33 pm		AGL Energy	Broken Hill Battery	25	17,500	-1,000	060 Unfcast network constraint~constraint management: N::N_CTMN_2

6.20 pm (36 MW of high-priced capacity was needed)

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
3.21 pm		AGL Energy	Bayswater	35	-1,000	N/A	Reduction in avail cap-feeder issues ongoing
5.33 pm		AGL Energy	Broken Hill Battery	25	17,500	-1,000	060 Unfcast network constraint~constraint management: N::N_CTMN_2
5.43 pm		AGL Energy	Broken Hill Battery	6	-1,000	N/A	Capability change ENERGY
5.48 pm		AGL Energy	Broken Hill Battery	8	-1,000	N/A	Capability change ENERGY
4.30 pm		AGL Energy	Bayswater	10	-1,000	N/A	Reduction in avail cap – Milling limits

Submitted time	Time effective	Participant	Station	Capacity rebid (MW)	Price from ($/MWh)	Price to ($/MWh)	Rebid reason
5.52 pm		AGL Energy	Bayswater	65	-1,000	N/A	Availability change
5.53 pm		AGL Energy	Broken Hill Battery	7	-1,000	N/A	Capability change ENERGY
5.58 pm		AGL Energy	Broken Hill Battery	8	-1,000	N/A	Capability change ENERGY
6.03 pm		AGL Energy	Broken Hill Battery	7	-1,000	N/A	Capability change ENERGY
6.08 pm		AGL Energy	Broken Hill Battery	3	-1,000	N/A	Capability change ENERGY
6.13 pm		AGL Energy	Broken Hill Battery	1	N/A	-1,017	Capability change ENERGY