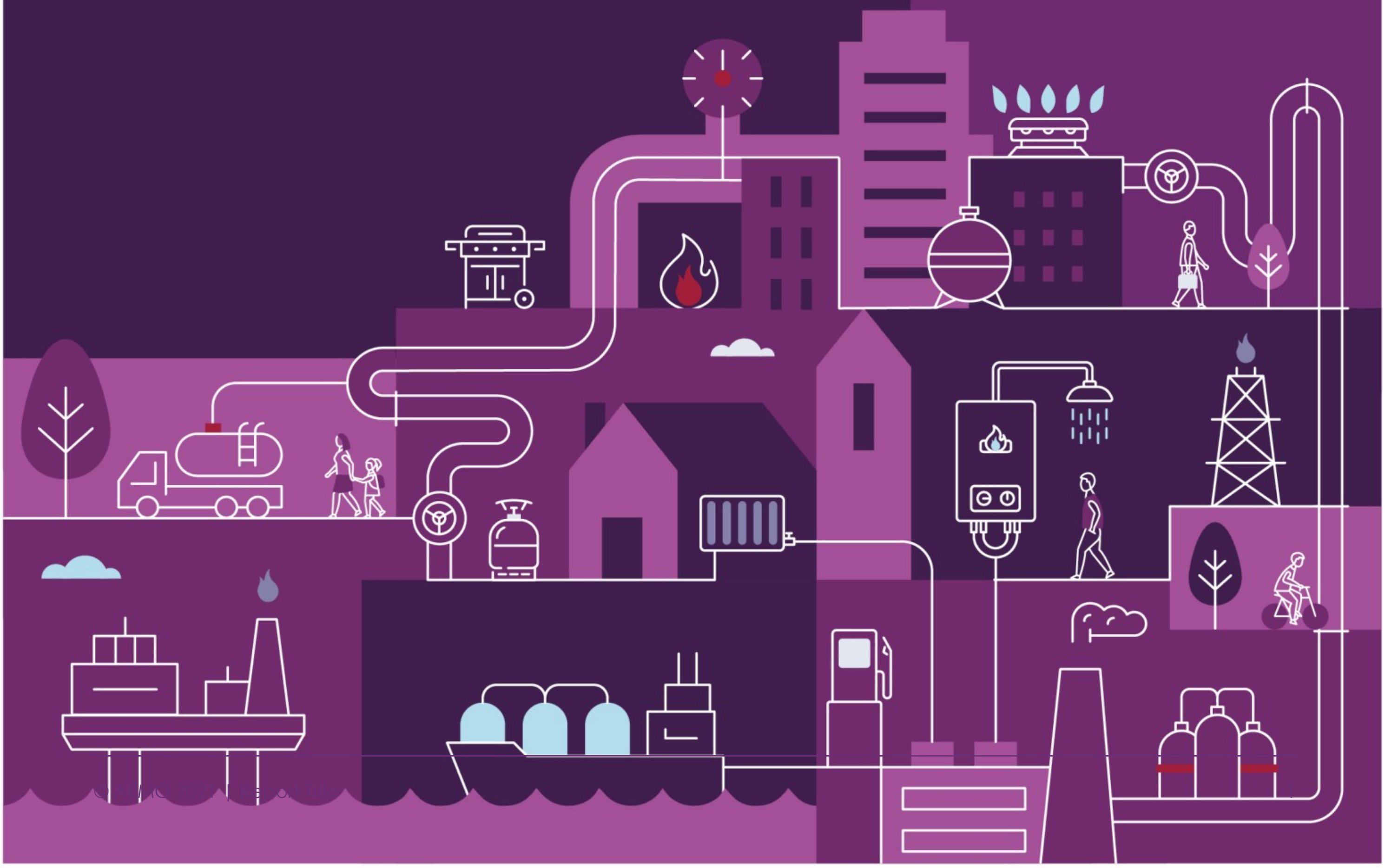
Quarterly Energy Dynamics Q1 2026

April 2026



We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q1 2026 (1 January to 31 March 2026). This quarterly report compares results for the quarter against other recent quarters, focusing on Q1 2025 and Q4 2025. Geographically, the report covers:

- the National Electricity Market (Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania);
- the Wholesale Electricity Market and domestic gas supply arrangements operating in Western Australia; and
- the gas markets operating in Queensland, New South Wales, Victoria and South Australia.

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Executive summary

East coast electricity and gas highlights

Operational demand remained steady, with distributed photovoltaic (PV) growth offsetting underlying demand growth

- Underlying demand across National Electricity Market (NEM) regions averaged 25,496 MW, a new quarterly record, up 302 megawatts (MW) (+1.2%) from Q1 2025, reflecting higher cooling demand during January alongside ongoing electrification, population increase and data centre growth. With record Q1 distributed PV output of 4,090 MW, up 308 MW (+8.1%) year on year, NEM-wide operational demand averaged 21,406 MW, remaining broadly unchanged from Q1 2025.
- NEM-wide maximum operational demand reached 33,645 MW on 7 January, the highest Q1 since 2020, while Victoria set a new all-time maximum of 10,736 MW during the extreme heat on 27 January, exceeding the previous record set in January 2009. NEM-wide minimum operational demand fell to a new Q1 low of 11,058 MW in late March, and all regions except New South Wales recorded new Q1 minimum demands during the quarter.

Renewables supplied a higher share of NEM generation, reaching new Q1 highs

- Grid-scale solar output reached a new quarterly high of 2,706 MW, up 13% from Q1 2025, while wind output reached a new Q1 high, increasing by 9.3% to average 3,845 MW, driven by increased availability at new and commissioning facilities, primarily in Queensland.
- Total coal-fired generation fell to a new Q1 low at 13,102 MW, down 4.4% from Q1 2025, with a small year-on-year increase in brown coal-fired generation (+0.9%), offset by a 6.1% reduction in black coal-fired generation. Gas-fired generation recorded its lowest average for any quarter since Q4 1999, at 712 MW, 24% lower than in Q1 2025.
- These supply changes lifted the renewable share of NEM generation to a new Q1 high of 46.5%, up from 42.5% in Q1 2025. NEM total emissions and emissions intensity reduce to a new Q1 low of 26.0 million tonnes of carbon dioxide equivalent (MtCO2-e), down 4.8% from Q1 2025, and 0.56 tonnes of carbon dioxide equivalent (tCO2-e/MWh), down 4.9%.

Expanded battery capacity reshaped supply patterns across the day

- Battery discharge continued to rise significantly, averaging 359 MW this quarter, more than three times the Q1 2025 level. This new quarterly record was driven by the addition of 4,445 MW / 11,219 MWh of new large-scale battery capacity to the grid since the end of Q1 2025, more than doubling the total installed battery capacity in the NEM.
- Growth in battery capacity reshaped when electricity was supplied, with daytime charging increasing by 872 MW (+300%) and evening peak discharge rising by 818 MW (+275%), shifting energy from daylight hours into periods of higher demand.

Average NEM wholesale electricity prices decreased year-on-year, despite periods of high-priced volatility in South Australia

- NEM-average wholesale spot prices averaged $73/megawatt hour (MWh), down $10/MWh (-12%) from Q1 2025, but up $23/MWh (+47%) compared to Q4 2025. Prices eased through the quarter, averaging $85/MWh in January, $69/MWh in February and $64/MWh in March as temperatures moderated and volatility decreased.
- South Australia was the only NEM region to record a year-on-year increase in wholesale spot prices with a major weather-related volatility event on 26 January contributing $26/MWh to the region's quarterly average of $88/MWh (up 33% from Q1 2025). Tasmania recorded the highest regional quarterly average at $94/MWh (down 15% from Q1 2025) with Basslink's bidding reducing imports into the region from the mainland. Year-on-year reductions were recorded across New South Wales (at $73/MWh, down 16%), Queensland (at $65 MWh, down 27%), and Victoria (at $43/MWh, down 28%).
- The increase in battery capacity was evident in price-setting outcomes, with combined battery charge and discharge setting prices in 32% of intervals, displacing hydro as the most frequent price-setting technology across the NEM this quarter. This was reflected in price outcomes, with evening peak prices falling as battery discharge reduced reliance on gas and hydro generation. This effect was slightly moderated by an increase in daytime prices as battery charge set prices more frequently, reducing the frequency of negative prices in the northern regions.

East coast Q1 2026 gas prices were lower than Q1 2025, driven by lower demand and bidding behaviour

- East coast wholesale gas prices averaged $10.61 per gigajoule (GJ) for the quarter, significantly lower than Q1 2025 which averaged $13.26/GJ (a record high) and lower than Q4 2025 which averaged $12.68/GJ. The average price in March dropped even further to $9.22/GJ, a four-year low. At the same time, international liquefied natural gas (LNG) spot prices were materially higher than prices observed in the east coast gas market, amid heightened supply risks linked to the conflict in the Middle East.
- Gas demand decreased by 1% from Q1 2025, driven by record low demand for gas-fired generation (-5 petajoules (PJ)) and lower demand for Queensland LNG exports (-1.4 PJ). AEMO markets saw a slight increase (+0.6 PJ) mainly reflecting higher industrial demand in the Sydney Short Term Trading Market (STTM) hub.
- There was a large decrease in gas flows from Moomba to Queensland from Q1 2025 (-9.8 PJ), with gas flowing instead from Moomba to the southern markets, with the Moomba Sydney Pipeline (MSP) flowing towards Sydney for the quarter, the opposite of Q1 2025. The flows from Moomba to the southern market, combined with low gas-fired generation demand, were accompanied by a decline in Victorian production (-9.2 PJ).
- After starting Q1 at the lowest level since 2022, Iona underground gas storage (UGS) ended the quarter with an inventory of 23.6 PJ, very similar to Q1 2025 which finished at 23.96 PJ. Iona UGS remains on target to be at full capacity prior to the start of winter.

Western Australia electricity and gas highlights

Wholesale Electricity Market (WEM) supply mix shifted further towards renewables, while battery storage reshaped intraday supply patterns

- Underlying electricity demand in the WEM declined by 2.3% year-on-year, driven by milder weather conditions and reduced cooling demand, while distributed PV output rose by 6.5%, further reducing daytime grid-supplied demand.
- The renewable share of the generation mix increased from 40.8% in Q1 2025 to 46.1% this quarter, supported by higher wind output (+52 MW), increased distributed PV output (+38 MW), and a rise in biomass generation of 28 MW.
- Battery discharge increased by 108 MW (+305%), driven by the commissioning of 1,025 MW/4,100 MWh of new battery capacity since the end of Q1 2025.
- With the increase in renewable contribution and higher battery discharge across peak periods, thermal generation decreased, with average coal fired generation down by 142 MW (-18%) and gas fired generation down by 16 MW (-2%) compared to Q1 2025. These supply mix changes saw WEM total emissions decrease from 2.46 $MtCO_2$-e in Q1 2025 to 2.05 $MtCO_2$-e (-16%) in Q1 2026 as emission intensity decreased by 0.09 tCO_2-e/MWh (-18%).

Average WEM energy prices remained consistent year-on-year, with lower volatility, and Essential System Services costs declined

- The average energy price in Q1 2026 was $88.53/MWh, slightly lower than in Q1 2025 (-0.6%) and less volatile, with a flatter daily profile driven by increased battery charging during the middle of the day, lifting supply requirements, and increased discharging during the evening peak, which displaced higher-priced generation.
- Essential System Services costs fell by 72% from Q1 2025 to $13.9 million in Q1 2026. The largest reduction was in Frequency Co-Optimised Essential System Services (FCESS) enablement costs, which were $5.1 million in Q1 2026, $15.1 million lower than in Q1 2025. The accreditation of two additional batteries since Q1 2025 increased batteries' market share of the contingency and regulation markets to 83% of total volume, with increased competition contributing to these cost reductions.
- Overall, normalised WEM costs increased by $2.10/MWh to $147.03/MWh in Q1 2026. Reductions in FCESS enablement (-$3.07/MWh), Energy Uplift (-$2.37/MWh), FCESS Uplift (-$2.02/MWh), and energy costs (-$0.51/MWh) were offset by increases in Non-Co-Optimised Essential System Services (+$6.14/MWh) and Reserve Capacity (+$4.20/MWh) costs.

Western Australia's domestic gas consumption and production decreased

- Western Australia's domestic gas consumption was 97.4 PJ, a decrease of 4.7 PJ (-4.6%) compared with Q1 2025. Production was 97.3 PJ, which represented a 4.1 PJ (-4.0%) decrease. Net storage withdrawals of 1.2 PJ were recorded, compared to 1.8 PJ in Q1 2025.
- Linepack Capacity Adequacy (LCA) flags were observed late in the quarter, reflecting precautionary operational measures during cyclone conditions. Mondarra Storage Facility was flagged Red on 27 March, indicating reduced operational flexibility under maximum withdrawal conditions, while the Dampier to Bunbury Natural Gas Pipeline was under Amber conditions across the Dampier, Metro and South West zones from 27 March to the end of the quarter.

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1 Weather

This quarter, most parts of Australia experienced warmer than average temperatures, alongside variability in weather conditions across regions (**Figure 1**).

The quarter commenced with above-average temperatures in January, with New South Wales, South Australia and Western Australia recording their fourth-warmest January on record. Warmer conditions were most evident across eastern and southern regions, while rainfall was generally below average across southern states. Parts of the east coast experienced intermittent rainfall and periods of elevated humidity. A late-January heat event between 26 and 30 January resulted in all-time daily maximum temperatures in parts of New South Wales, South Australia and Victoria, with some locations reaching 50°C. Conditions moderated through February, with temperatures near average across most regions and fewer extreme heat events. Rainfall increased in New South Wales and Queensland, accompanied by periods of humidity and cloud cover. March saw near average temperatures, reflecting more moderate conditions across most regions. Tropical cyclone activity in early February and late March also brought periods of heavy rainfall, strong wind gusts and localised disruptions in Western Australia.

Figure 1 Warmer than long-term average temperatures across parts of Australia

Q1 2026 mean temperature deciles for Australia

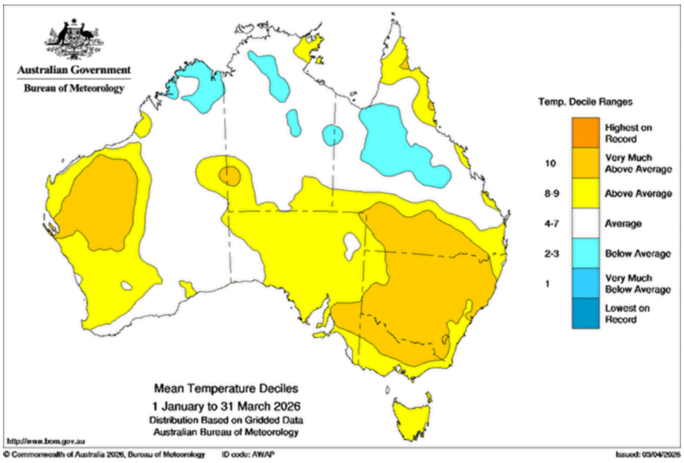
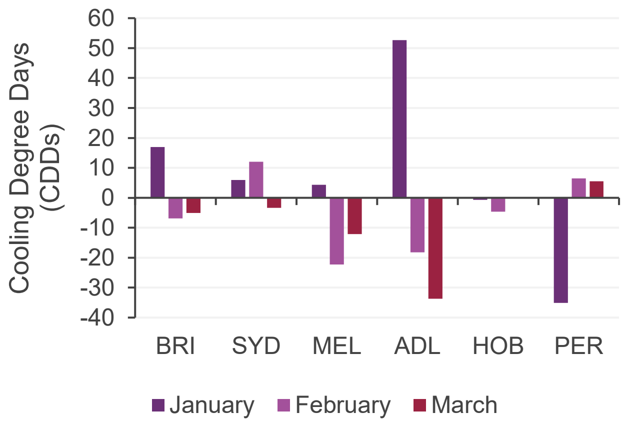


Figure 2 Higher cooling requirements in most capital cities in January, with declines in February and March

Change in monthly CDDs by capital city – Q1 2026 vs Q1 2025



Source: Bureau of Meteorology (BOM)

In Q1 2026, Cooling Degree Day (CDD)[1] trends across major capital cities relative to Q1 2025 diverged between January and the rest of the quarter (**Figure 2**). January recorded higher cooling requirements in most cities, notably in Adelaide with more than double the 2025 levels, and more moderate increases observed in Brisbane, Sydney and Melbourne. In contrast, February and March saw broad declines in cooling demand across the NEM, with the largest reductions in the southern capitals of Melbourne and Adelaide. In contrast to other capitals, Perth exhibited a distinct CDD profile, with significantly lower cooling requirements in January relative to Q1 2025, followed by modest increases in February and March.

[1] A "cooling degree day" (CDD), which is based on the average daily temperature, is a measurement used as an indicator of outside temperature levels above what is considered a comfortable (base) temperature. CDD value is calculated as max (0, average temperature – base temperature)

2 NEM market dynamics

2.1 Electricity demand

In Q1 2026, NEM-wide underlying demand[2] reached a new quarterly record average of 25,496 MW, an increase of 302 MW (+1.2%) compared to previous record from Q1 2025 (**Figure 3**). The increase was primarily driven by January's higher cooling demand across mainland regions, and ongoing impacts from electrification, population increase and data centre growth.

Operational demand[3] averaged 21,406 MW this quarter, comparable to 21,412 MW in Q1 2025. Higher distributed PV output essentially offset increased underlying demand (**Figure 4**), with NEM-wide output reaching a Q1 record average of 4,090 MW, up 308 MW (+8.1%) compared to Q1 2025.

Figure 3 Underlying demand reached a record high

NEM average underlying and operational demand – Q1s

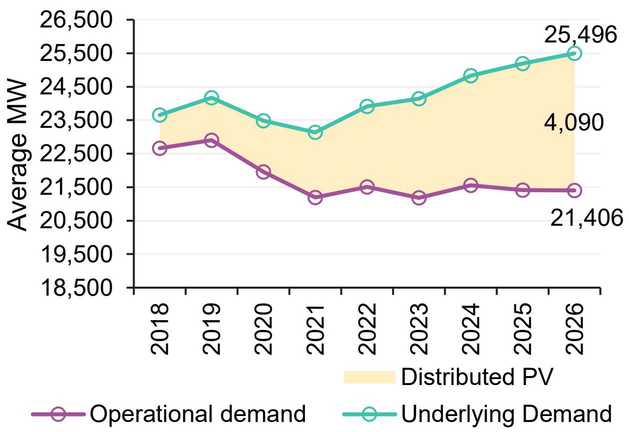
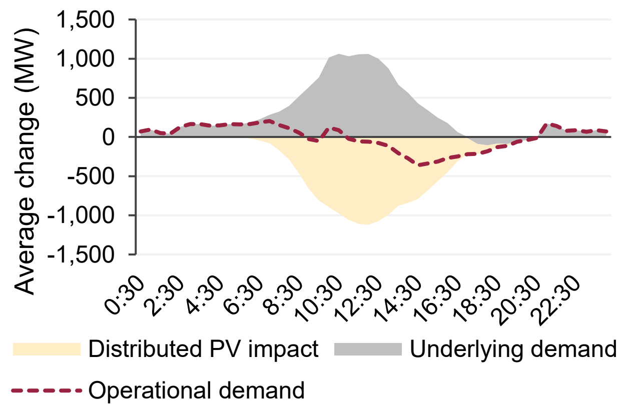


Figure 4 Increased distributed PV output offset underlying demand growth leaving operational demand flat

Average changes in NEM demands and distributed PV output by time of day – Q1 2026 vs Q1 2025



Distributed PV[4] output grew to new Q1 highs in all regions (**Figure 5**). Underlying demand increased in all regions except South Australia and Tasmania, with a notable increase in New South Wales, evident across all hours of the day. New South Wales also experienced the only significant increase in operational demand; there was a slight increase in Victoria, while outcomes in other regions were lower than Q1 2025.

Comparing quarterly average outcomes in Q1 2026 with Q1 2025:

- In **Queensland**, underlying demand rose slightly by 46 MW (+0.6%) to average 7,838 MW amid mild conditions throughout the quarter. Distributed PV output averaged 1,211 MW, up 118 MW (+11%), driven by higher solar

[2] Underlying demand is calculated by adding estimated production from distributed PV to operational demand.

[3] Operational demand in a region is demand that is met by local scheduled generation, semi-scheduled generation, non-scheduled wind and solar generation of aggregate capacity >=30 MW, and by generation imports to the region, excluding the demand of local scheduled loads and including Wholesale Demand Response.

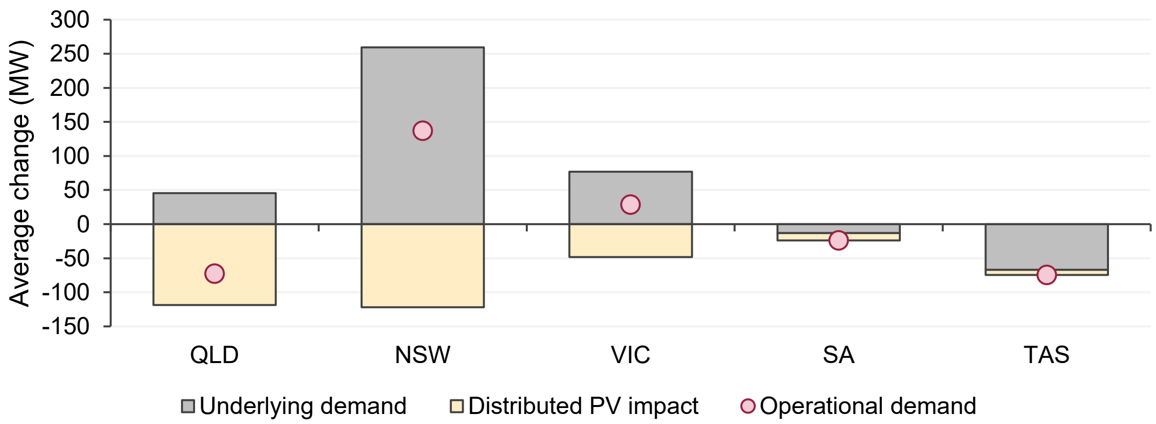
[4] Data from AEMO's Australian Solar Energy Forecasting System (ASEFS) phase 2: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/operational-forecasting/solar-and-wind-energy-forecasting/australian-solar-energy-forecasting-system.

exposure and increased installed PV capacity. This growth more than offset the increase in underlying demand, reducing operational demand to an average of 6,627 MW (-1.1%).

- **New South Wales** was the only region to have a notable increase in underlying demand, up by 259 MW (+3.0%) to average 8,978 MW. This was driven by warmer and humid conditions, particularly during January and February, alongside continued growth in data centre demand, which averaged 398 MW (+18% year-on-year). Distributed PV output also increased to a Q1 record of 1,338 MW, up 122 MW (+10%) supported by higher installed capacity despite broadly similar levels of solar exposure to the same period last year. Operational demand grew 137 MW (+1.8%) to average 7,639 MW.
- **Victoria**'s underlying demand averaged 5,806 MW, up 77 MW (+1.3%), supported by data centre demand, which increased from 96 MW in Q1 2025 to average 187 MW (+94%) this quarter. Distributed PV output increased to a Q1 record of 955 MW, up 48 MW (+5.3%). Operational demand increased only slightly by 29 MW (+0.6%) to average 4,851 MW, with underlying demand growth offset by distributed PV.
- In **South Australia**, underlying demand decreased to average 1,831 MW this quarter, down 13 MW (-0.7%) from Q1 2025 with milder weather conditions through February and March. Distributed PV increased marginally to a record average of 514 MW, up by 11 MW (+2.2%). Operational demand decreased by 24 MW (-1.8%) to average 1,317 MW.
- **Tasmania**'s underlying demand decreased by 67 MW (-6.1%) to average 1,043 MW this quarter, largely due to lower industrial demand. Distributed PV output reached a record high, averaging 71 MW, up 7 MW (+12%) and resulting in reduction of operational demand, which averaged 972 MW, down 75 MW (-7.1%).

Figure 5 Operational demand decreased in all regions except New South Wales and Victoria

Changes in average demand components by region – Q1 2026 vs Q1 2025



2.1.1 Maximum and minimum demands

In this quarter, NEM-wide **maximum operational demand** reached 33,645 MW for the half-hour ending 1830 hrs on Wednesday 7 January, its highest Q1 level since 2020. Victoria was the only NEM region to set a new all-time[5] maximum demand record. This record of 10,736 MW (**Figure 6**) was set in the half-hour ending 1800 hrs on Tuesday 27 January,

[5] NEM-wide all-time records are computed based on demand data starting from May 2005 after Tasmania joined the NEM.

surpassing the previous record of 10,576 MW set on 29 January 2009. This record was set during a period of extreme heat, with temperatures exceeding 43°C in parts of Melbourne, contributing to elevated cooling demand.

NEM-wide **minimum operational demand** reached new Q1 record of 11,058 MW on Sunday 29 March for the half-hour ending 1300 hrs, 646 MW (-5.5%) lower than the previous Q1 record of 11,704 MW set in Q1 2025. All NEM regions except New South Wales set new Q1 records for minimum operational demand (**Figure 7**), with these records occurring during periods of high distributed PV output, mild weather conditions, and relatively low underlying demand during the daytime hours. Queensland's minimum operational demand reached 3,288 MW on Saturday 28 March for the half-hour ending 1100 hrs, a notable reduction of 937 MW (-22%) from the previous record from Q1 2007. Tasmania also recorded a new Q1 minimum operational demand of 715 MW, down 17 MW (2.3%) from 732 MW set in Q1 2013.

Figure 6 New maximum operational demand record in Victoria

Maximum operational demand for mainland regions – Q1s

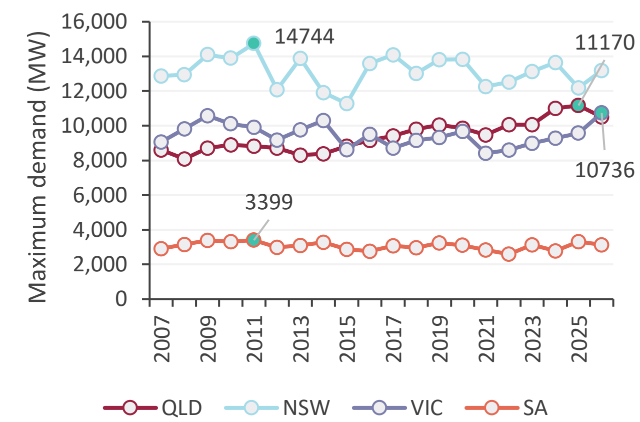
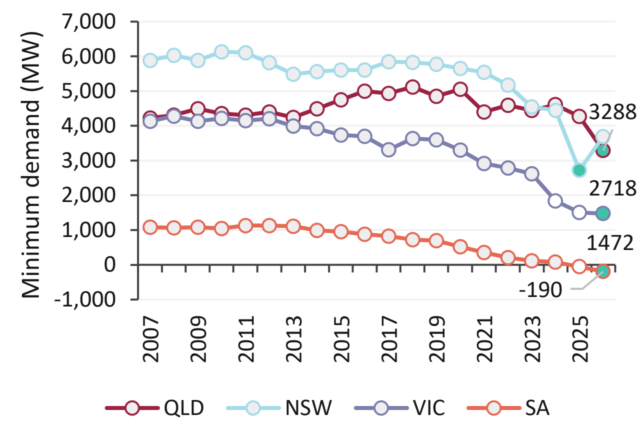


Figure 7 Queensland, Victoria and South Australia set new Q1 lows for minimum operational demand

Minimum operational demand for mainland regions – Q1s



2.1.2 Consumer energy resources (CER)

Cumulative CER solar capacity continued to increase steadily across the NEM, rising from 25 gigawatts (GW) at the end of Q4 2025 to 25.5 GW at the end of this quarter[6] (**Figure 8**). This was supported by growth in CER solar installations that increased by 0.1 million to 3.8 million over the same period. CER solar capacity expanded consistently across all regions, with New South Wales reaching 8.7 GW, followed by Queensland at 7.7 GW. Victoria and South Australia distributed PV capacity reached 5.7 GW and 2.9 GW respectively. Growth in Tasmania remained comparatively smaller and reached 0.4 GW.

The introduction of the Australian Government's Cheaper Home Batteries Program[7] supported a rapid increase in household battery uptake, with cumulative capacity reaching 6,716 MWh at the end of March 2026 and installations rising

[6] Data from Clean Energy Regulator: https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data. Data current as of 31 March 2026, noting that a 12-month creation period for registered persons to create small-scale technology certificates applies, so figures for the previous 12 month period will continue to rise.

[7] See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.

to 251,119[8] (**Figure 9**). By the end of the quarter, New South Wales reached 2,911 MWh, Queensland reached 1,533 MWh, Victoria reached 1,406 MWh, and South Australia and Tasmania reached 812 MWh and 54 MWh respectively.

Figure 8 CER solar capacity increased with sustained growth in installations

Cumulative CER solar capacity and installations by region

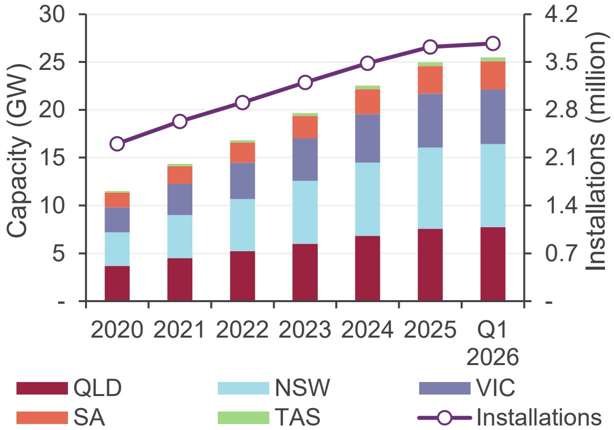
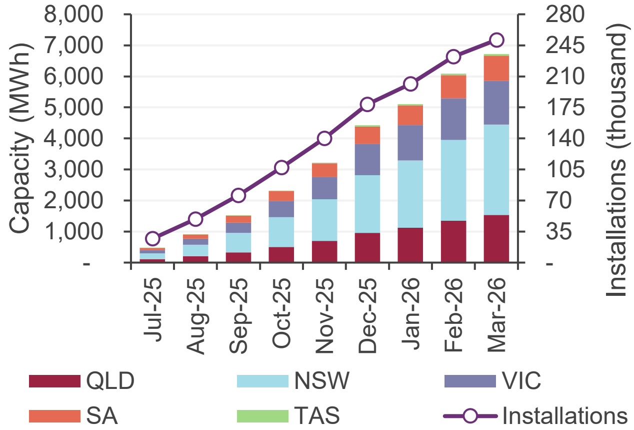


Figure 9 Continued growth in CER battery capacity and installations across the NEM

Cumulative CER battery capacity and installations by region



Source: Clean Energy Regulator

Emerging patterns in household solar and battery behaviour are reflected in intraday demand profiles, based on residential demand data sourced from National Metering Identifier (NMI) sample datasets[9] of households with rooftop solar only and those with both solar and battery systems.

Figure 10 shows average net time-of-day demand profiles for the sampled solar-only households and households with solar and battery systems in New South Wales for Q1 2026, shown alongside year-on-year changes in operational demand, while **Figure 11** illustrates separate import and export behaviour in Victoria on the day when a new all-time maximum demand was recorded. Across both examples, households with batteries transitioned to exports later in the morning and exhibited higher grid imports, consistent with batteries charging using a combination of rooftop solar generation and grid supply, contributing to higher mid-morning operational demand. During the evening peak (1600 hrs to 2100 hrs), households with solar and battery systems continued exporting to the grid for longer and reduced net grid imports relative to solar-only households, reflecting battery discharge to meet household load and support the grid. In New South Wales, this reduced average evening-peak net imports by around 0.9 kilowatts (kW) per household relative to solar-only households across the quarter, moderating weather-driven year-on-year demand growth. In Victoria, households with batteries reduced average evening peak net imports by 1.4 kW relative to solar-only households on the maximum demand day.

[8] Solar battery postcode data is only available from 1 July 2025, when solar batteries became eligible under the Small-scale Renewable Energy Scheme, up until 31 March 2026. Postcode data only includes installations that have had their application for small-scale technology certificates approved. It does not include installations with pending applications.

[9] Households included in the sample are houses/detached dwellings with installed PV system capacity below 20 kilowatts (kW). For battery households, only battery systems installed from 1 July 2025 to 1 October 2025 are included. For sampled households with PV-only, the average PV system size is 6.67 kW in New South Wales and 5.66 kW in Victoria. For sampled households with both PV and battery systems, the average PV system size is 9.54 kW in New South Wales and 9.57 kW in Victoria, and average installed battery size in New South Wales is 24.16 kWh and 21.23 kWh in Victoria. Each sample set includes 1000 households.

Figure 10 Household PV and battery impacts in New South Wales in Q1 2026

Average operational demand change (Q1 26 vs Q1 25), household PV and battery net kW (Q1 26) – New South Wales

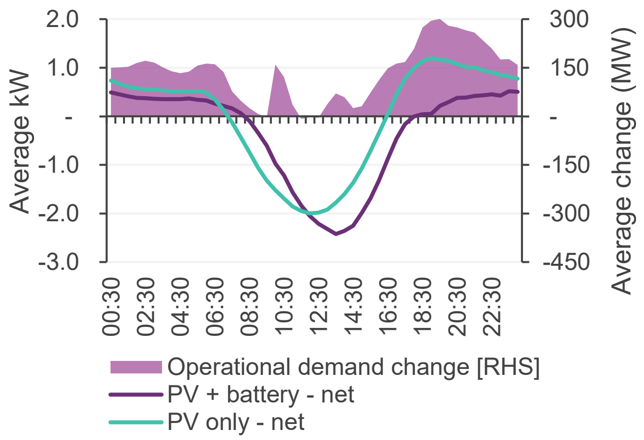
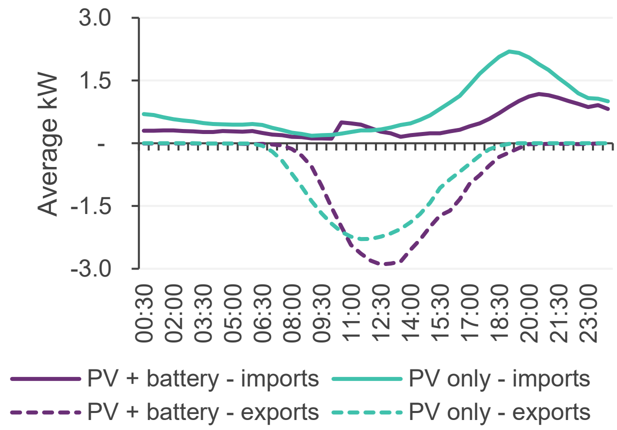


Figure 11 Household PV and battery behaviour on Victorian maximum demand day

Average household PV and battery import and export kW on 27 January – Victoria

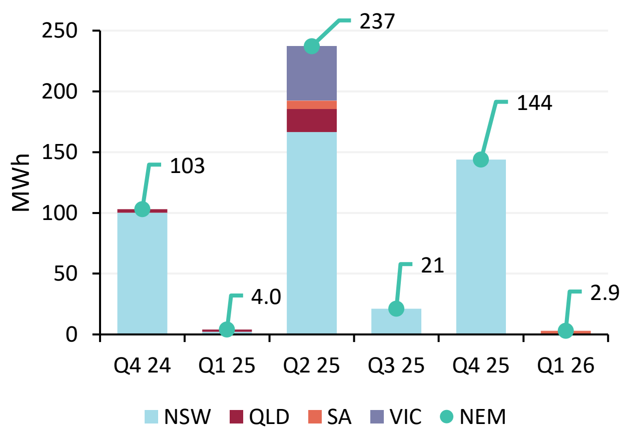


2.1.3 Wholesale demand response (WDR)

WDR activity remained minimal in Q1 2026, totalling just 3 MWh (**Figure 12**). This was 1 MWh lower than in Q1 2025 and represented a sharp decline of 141 MWh compared with Q4 2025.

Figure 12 Drop in WDR dispatch

Total quarterly WDR energy dispatch



All WDR dispatch occurred in South Australia on 26 and 27 January, spanning 35 dispatch intervals, compared with 24 intervals in Q1 2025 and 864 intervals in Q4 2025. On 26 January, a single unit dispatched at 1 MW across 30 intervals, with an average regional reference price of $14,109/MWh. On 27 January, one unit dispatched across five intervals at an average regional reference price of $300/MWh.

Demand flexibility continued to play an important role in FCAS markets, with demand response (DR) supplying 16% of combined contingency raise services in Q1 2026, up slightly from 15% in Q1 2025.

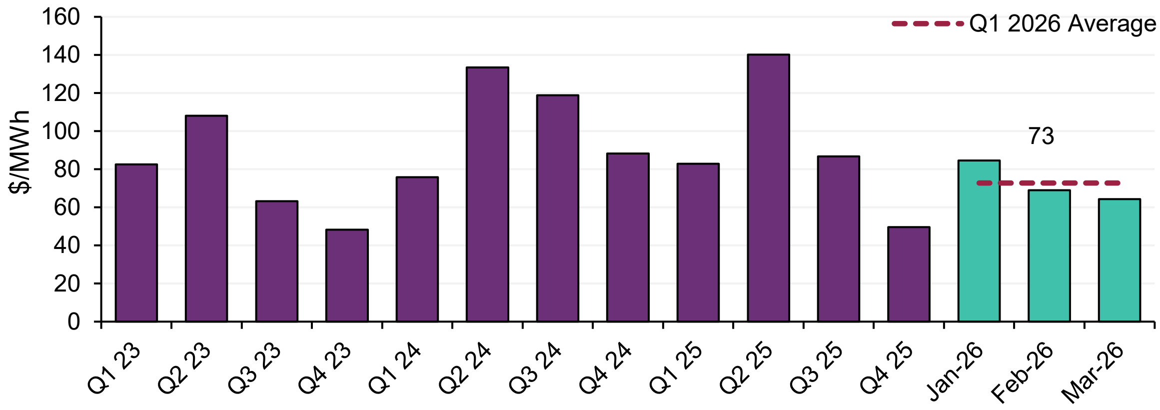
2.2 Wholesale electricity prices

In Q1 2026, wholesale spot prices across the NEM averaged $73/MWh[10], $10/MWh (-12%) lower than Q1 2025 and $23/MWh (+47%) higher compared to Q4 2025 (**Figure 13**). Monthly prices fell through the quarter, averaging $85/MWh in January, $69/MWh in February and $64/MWh in March.

[10] Time-weighted average – simple average of regional wholesale electricity spot prices over each five-minute dispatch period over the quarter.

Figure 13 Average NEM spot prices down 12% year-on-year, but up 47% on Q4 2025

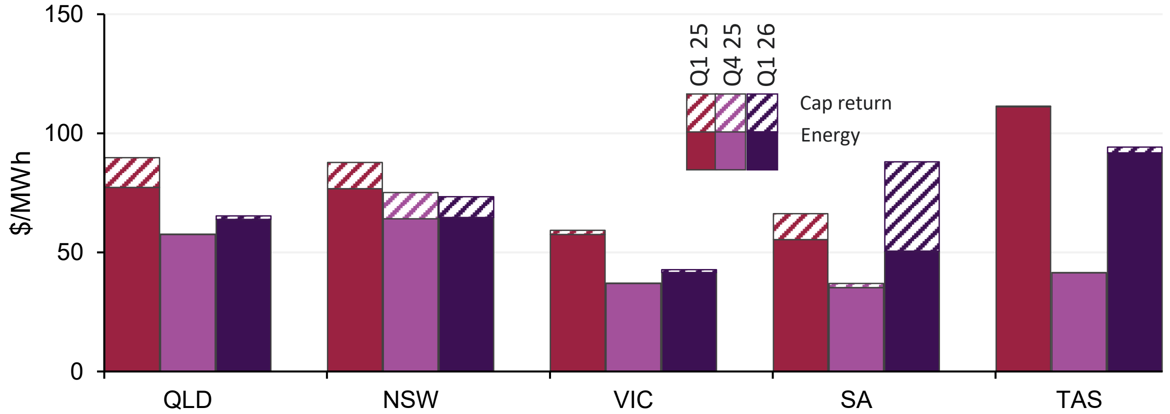
NEM average wholesale electricity spot prices – quarterly since Q1 2023



The cap return[11] component of the NEM average price increased to $10/MWh for the quarter, up 41% from $7/MWh in Q1 2025 (**Figure 14**). This increase was driven by South Australia, which saw several high-priced events in January (see Section 2.2.2). The energy component of average spot prices averaged $62/MWh this quarter, down $13/MWh (-17%) from Q1 2025, and was lower across all NEM regions.

Figure 14 Year-on-year declines in energy prices drove lower spot prices across all regions except South Australia

Average wholesale electricity spot price by region – energy and cap return components for selected quarters



By region:

- **Queensland** recorded the largest year-on-year reduction in wholesale spot prices, averaging $65/MWh in Q1 2026, down $24/MWh (-27%). Increased renewable output and higher battery discharge at peak periods, alongside mild weather conditions and relatively moderate changes in demand year-on-year, resulted in $11/MWh (-88%) reduction in the cap return component and $13/MWh (-17%) lower energy prices.

[11] The price analysis divides the average spot price into two components: the energy component, which is the average spot price capped at $300/MWh, and the cap return component (also referred to as volatility), which reflects the contribution to the quarterly average from any excess spot prices above $300/MWh. Since the introduction of Five-Minute Settlement (5MS) on 1 October 2021, both energy prices and cap returns are calculated on a five-minute basis.

- In **New South Wales**, wholesale spot prices decreased by $14/MWh (-16%) to average $73/MWh this quarter. The cap return component remained broadly similar to Q1 2025 at $9/MWh, down $2/MWh (-20%). Increased battery discharge during peak periods contributed to a $12/MWh (-16%) decrease in energy prices to average $65/MWh.
- **Victoria** had the lowest quarterly average wholesale spot price across the NEM regions at $43/MWh, $17/MWh (-28%) lower than Q1 2025. The cap return component remained at $1/MWh this quarter, broadly similar to $2/MWh in Q1 2025. The energy component averaged $42/MWh, down $16/MWh (-28%) year-on-year, with milder weather conditions contributing to lower prices.
- **South Australia** was the only region to experience a year-on-year increase in wholesale spot prices, averaging $88/MWh this quarter, up $22/MWh (+33%) compared to Q1 2025. The cap return component increased to $38/MWh, up from $11/MWh in Q1 2025. This was driven by high-priced volatility in January, with high temperatures leading to increased cooling demand. The energy component decreased by $5/MWh year-on-year to average $51/MWh this quarter.
- **Tasmania**'s wholesale spot prices decreased to $94/MWh this quarter, down $17/MWh (-15%) compared to the same quarter last year. The cap return component increased from close to zero in Q1 2025 to $2/MWh in Q1 2026. This increase was offset by the decrease in energy prices that reduced by $19/MWh (-17%) compared to previous year to average $92/MWh this quarter.

In Q1 2026, NEM average spot prices increased slightly during the daytime hours, while prices overnight decreased compared to Q1 2025 (**Figure 15**). Increased battery charging activity (see **Figure 56** in Section 2.4) and reduced negative price impact (see Section 2.2.3) lifted daytime prices, while overnight prices decreased due to higher wind output displacing coal generation and more supply being effectively available to meet mainland demand due to lower exports to Tasmania via Basslink (see Section 2.6).

Figure 15 Lower NEM average price during overnight hours

NEM average spot price by time of day – Q1 2026 vs Q1 2025

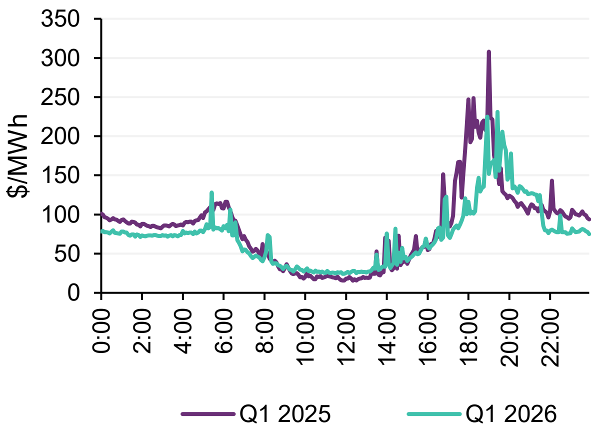
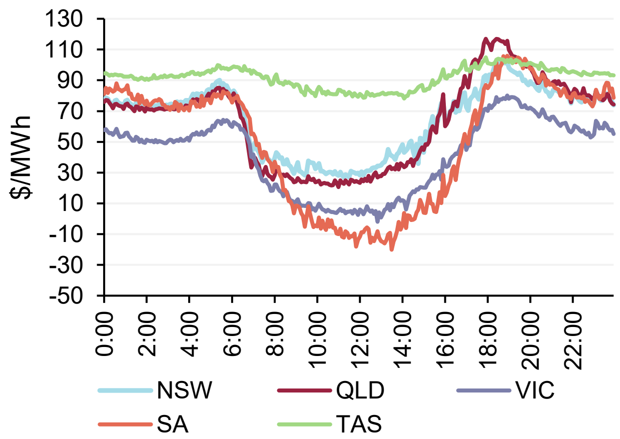


Figure 16 Daytime price spread widened across NEM regions

Average regional energy price by time of day – Q1 2026



This quarter, energy price separation across NEM regions remained evident, consistent with prior quarters, with a divergence between northern and southern regions, particularly during the daylight hours (**Figure 16**). Between 1000 hrs and 1600 hrs in Q1 2026, energy prices in New South Wales and Queensland averaged $40/MWh and $34/MWh respectively, compared to $11/MWh in Victoria and -$4/MWh in South Australia.

Within the southern regions, price separation was observed between Victoria and South Australia, particularly during the overnight period (2200 hrs to 0600 hrs), with the energy price gap increasing from $11/MWh in Q1 2025 to $23/MWh in Q1 2026. Price separation between Tasmania and the mainland regions was evident across all hours of the day, with energy prices between 1000 hrs and 1600 hrs averaging $83/MWh in Tasmania this quarter, $72/MWh higher than energy prices in Victoria. These outcomes reflect the higher-priced Basslink capacity offers that limited inter-regional flows (see Section 2.6).

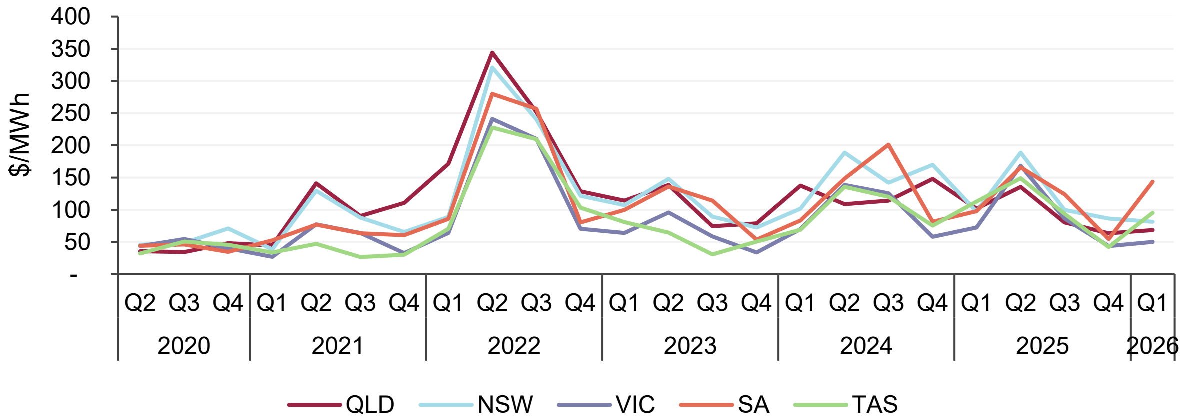
Volume-weighted average price (VWAP)

The VWAP[12] reflects the average value of energy supplied in the spot market, weighted by demand in each region and trading interval. By comparison, the time weighted average price (TWAP) represents the simple average of trading interval prices and does not account for variations in demand or generation. As spot prices generally increase during periods of higher operational demand, particularly during evening peaks, VWAP is typically higher than TWAP. Periods of increased price volatility can further widen the difference between the two measures.

This quarter, VWAP outcomes ranged from $50/MWh in Victoria to $144/MWh in South Australia, with Queensland, New South Wales and Tasmania averaging $69/MWh, $81/MWh and $95/MWh respectively (**Figure 17**). Compared to Q1 2025, VWAP declined in all regions except South Australia. In South Australia, higher price volatility this quarter led to a year-on-year increase of 47% in VWAP, compared to a 33% increase in TWAP.

Figure 17 Volume-weighted average prices below Q1 2025 in all regions except South Australia

Volume-weighted average prices by region – quarterly since Q2 2020



2.2.1 Wholesale electricity price drivers

Table 1 summarises the main drivers of price changes in the NEM during this quarter, with further analysis and discussion referred to relevant sections of this report.

[12] The VWAP is calculated by weighting regional prices by INITIALSUPPLY + TOTALINTERMITTENTGENERATION. INITIAL SUPPLY represents the scheduled demand in a region that is met by local scheduled and semi-scheduled generation, by generation from scheduled bidirectional units, and by generation imports to the region. TOTALINTERMITTENTGENERATION represents metered output of significant non-scheduled generators.

Table 1 Wholesale electricity price drivers in Q1 2026

Increased battery capacity influencing price-setting outcomes	In Q1 2026, combined battery charge and discharge accounted for 32% of price-setting dispatch intervals across the NEM, making batteries the most frequent price-setting technology during the quarter (see Section 2.2.4). In New South Wales and Queensland, batteries set prices in more than 40% of intervals, reflecting increased participation during both charging and discharging periods. This displaced the frequency of price-setting by coal-fired, gas-fired and hydro generation (**Figure 25** in Section 2.2.4). Battery discharge during peak periods contributed to lower peak prices (see **Figure 15** above) and reduced price volatility across most regions, while increased daytime battery charging contributed to higher daytime prices year-on-year and coincided with lower negative price occurrence (see **Figure 22** in Section 2.2.3).
Higher renewable generation	This quarter, average variable renewable generation (VRE) output reached a Q1 high of 6,550 MW, up 648 MW (+11%) from Q1 2025. Grid solar reached a quarterly record of 2,706 MW, up 170 MW (+6.7%) from the previous record set in Q4 2025. Wind also increased year-on-year to average 3,845 MW, up 328 MW (+9.3%) (see Section 2.3.4). This VRE growth contributed to reduction in average spot prices across the NEM, particularly overnight where increased wind output displaced coal generation (see **Figure 34** in Section 2.3) and contributed to lower prices (see **Figure 15**). This was reflected in a shift in price outcomes, with the proportion of intervals with prices below $100/MWh increasing from 59% in Q1 2025 to 80% in Q1 2026.
Price volatility events in South Australia	In Q1 2026, aggregated cap returns (contributions from spot prices exceeding $300/MWh) across the NEM increased to $51/MWh, up $15/MWh from Q1 2025, with South Australia the largest contributor at $38/MWh (see Section 2.2.2). This was primarily driven by a major weather-related volatility event on 26 January that accounted for a significant share of the cap return ($25.7/MWh), with further contributions from other events in January. These events were associated with tight supply-demand conditions, network constraints and higher cooling requirements in Adelaide during January (see **Figure 2** in Section 1), with further details provided below in **Table 2**.

2.2.2 Wholesale electricity price volatility

In Q1 2026, aggregated cap returns across the NEM, representing contributions from spot prices exceeding $300/MWh, rose by $15/MWh from Q1 2025 to $51/MWh (**Figure 18**). South Australia recorded the highest cap return at $38/MWh, largely driven by a weather-driven volatility event on 26 January (**Figure 19**). New South Wales was the next largest contributor, adding $9/MWh to the NEM aggregate cap return, with price volatility spread across the quarter.

Figure 18 Increase in NEM-wide cap returns led by South Australia

Cap returns by region – quarterly

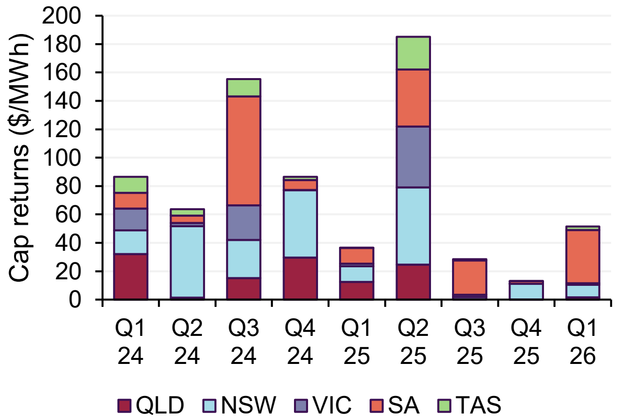


Figure 19 Significant price volatility in South Australia this quarter

Cumulative cap return by region – Q1 2026

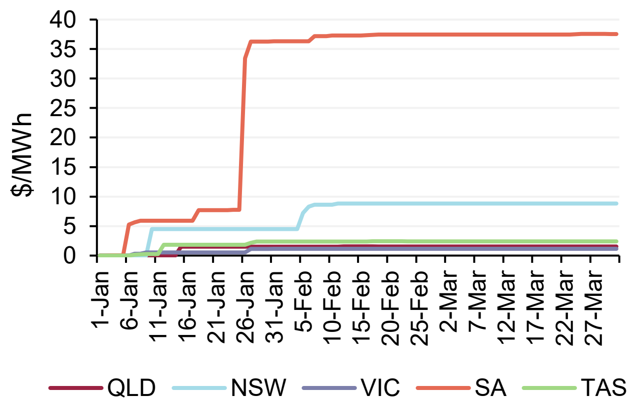


Table 2 summarises events of significant high-priced volatility during Q1 2026.

Table 2 Significant price volatility events in Q1 2026

Date	Region	Contribution to regional cap return ($/MWh)	Drivers
26 January	South Australia	25.7	On this day, South Australian spot prices were highly volatile during the evening peak, with prices exceeding $19,000/MWh in 28 dispatch intervals between 1900 hrs and 2130 hrs. The high price outcomes coincided with extreme heat conditions, with temperatures above 43°C in parts of Adelaide, and total demand[13] rising above 3,000 MW, resulting in tight supply and demand conditions (**Figure 20**). Interconnector support was limited, with temperature-related constraints reducing Murraylink transfer capability and Heywood imports constrained at the transfer limit, restricting flows into the South Australian region. Reflecting reduced reserve margins, an actual Lack of Reserve 1 (LOR1)[14] condition was declared between 2030 hrs and 2145 hrs. During the high-priced intervals, battery discharge contributed to meeting demand and price-setting across more than half of the intervals. As battery state of charge declined, gas-fired generation supported supply and set prices across the remainder of the event (**Figure 21**).
6 January	South Australia	5.2	South Australian spot prices were volatile during the evening peak on this day following the onset of heatwave conditions, which increased cooling demand. Prices exceeded $17,000/MWh for six dispatch intervals between 1930 hrs and 2010 hrs. Interconnector support was limited, with Heywood flows constrained at the transfer limit and network constraints restricting imports via the Murraylink interconnector from Victoria. Battery discharge supported supply during the event, peaking earlier in the high price period as battery state of charge declined. Battery output and gas-fired generation were the primary price-setting technologies during the event.
10 January	New South Wales	4.5	New South Wales spot prices were volatile during the evening peak on 10 January, coinciding with heatwave conditions that saw temperatures exceed 40°C in parts of Sydney. Prices exceeded $10,000/MWh in nine dispatch intervals between 1835 hrs and 1920 hrs, with operational demand above 13,000 MW at the start of the volatile period. Supply conditions tightened as solar generation declined given the time of day, increasing reliance on dispatchable generation. Network conditions reduced transfer capability, with an outage on the Avon to Marulan transmission line limiting flows within the New South Wales network. Interconnector capability was also constrained, with imports from Queensland limited on the Queensland – New South Wales Interconnector (QNI) and flows on the Victoria – New South Wales Interconnector (VNI) constrained, reducing access to lower-cost generation from other regions. Prices were predominantly set by gas-fired generation, with hydro generation also contributing during the volatile period.
27 January	South Australia	2.8	Persistently high temperatures during the late-January heatwave contributed to intermittent spot price volatility in South Australia during the morning period between 0405 hrs and 0820 hrs. Elevated overnight temperatures sustained cooling demand into the trading day, tightening regional supply-demand conditions. During this period, spot prices exceeded $3,000/MWh in eight dispatch intervals, including three intervals above $14,000/MWh. Interconnector flows were constrained, restricting transfers between South Australia and Victoria. The generation mix during the event comprised gas-fired generation, battery discharge and wind generation, with solar output gradually increasing from around 0700 hrs. During the volatile intervals, battery discharge set spot prices, contributing to elevated price outcomes.
5 February	New South Wales	2.7	Daytime conditions contributed to intermittent spot price volatility in New South Wales, with price spikes occurring between 1430 hrs and 1805 hrs, commencing with prices reaching the Market Price Cap of $20,300/MWh at 1430 hrs. The volatility coincided with a reduction in distributed PV output through the afternoon, increasing operational demand and tightening supply-demand conditions. Network capability was reduced due to the ongoing Avon to Marulan transmission line outage, with associated constraints limiting flows within the New South Wales network and on the Victoria – New South Wales Interconnector (VNI). Reduced access to generation from other regions resulted in higher-cost local generation being dispatched, contributing to elevated price outcomes. Battery discharge set prices in most dispatch intervals, with gas and black coal-fired generation also contributing to the price outcomes.

[13] Refers to the five-minute regional total demand, that is met by local scheduled generation and semi-scheduled generation, and by generation imports to the region, excluding the demand of local scheduled loads, and including Wholesale Demand Response.

[14] LOR1 condition exists when reserve levels are lower than the two largest supply resources in a region. See https://www.aemo.com.au/learn/energy-explained/fact-sheets/lack-of-reserve-notices

Figure 20 South Australia's sustained evening price volatility on 26 January

South Australia Regional Reference Price (RRP), total demand, net interconnector flows and generation by fuel type – 26 January

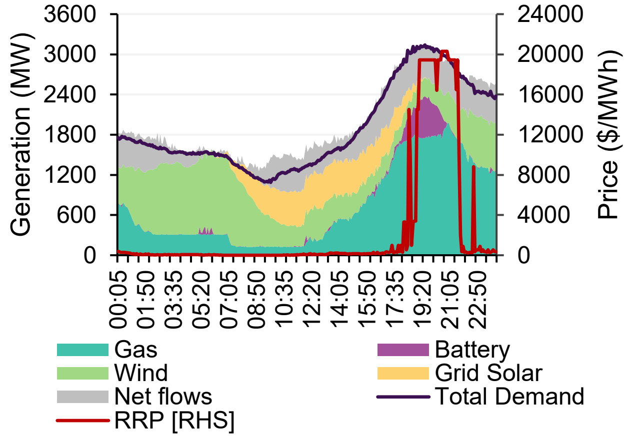
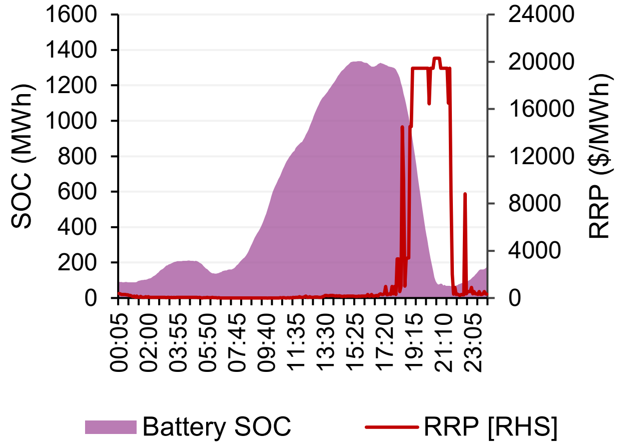


Figure 21 Battery state of charge declined as price volatility persisted

Battery charge, discharge and RRP [RHS] on 26 January – South Australia



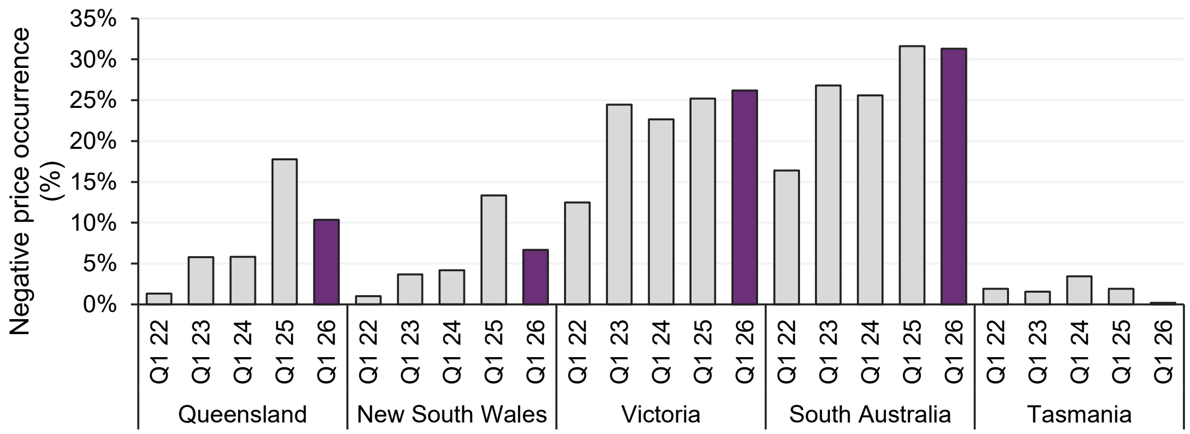
2.2.3 Negative wholesale electricity prices

In Q1 2026, 14.9% of dispatch intervals across the NEM experienced negative or zero prices, 3.0 percentage points (pp) lower than the 18.0% recorded in Q1 2025 (**Figure 22**).

All NEM regions except Victoria experienced a year-on-year reduction in negative price occurrence. Victoria experienced negative prices occurring in 26.2% of intervals, up 1.0 pp year on year. South Australia recorded the highest occurrence of negative prices at 31.3% of intervals, down only slightly by 0.3 pp year-on-year. In contrast, negative price occurrence fell in New South Wales to 6.7% (-6.7 pp) and in Queensland to 10.4% (-7.4 pp), while Tasmania recorded negative prices in 0.2% (-1.7 pp) of intervals.

Figure 22 Negative price occurrence fell across most NEM regions

Negative price occurrence in NEM regions – Q1s



Negative price outcomes are more prevalent during daytime hours, reflecting periods of lower operational demand driven by strong distributed PV output, high large-scale variable renewable generation (VRE) generation, and coal-fired generators operating at minimum stable output levels (**Figure 23**).

Figure 23 Negative price occurrence led by South Australia

Negative price ocuurence by time of day – Q1 2026

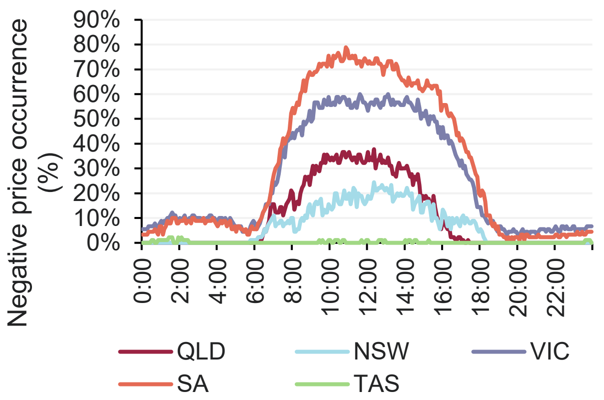
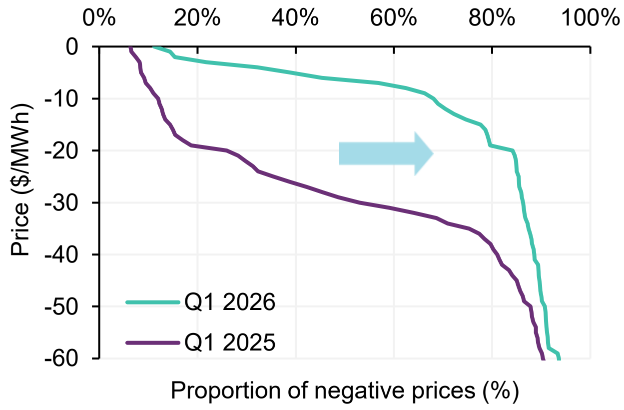


Figure 24 Impact of negative prices decreased in Q1 2026

Cumulative distribution of negative prices – Q1 2026 vs Q1 2025



During the daytime hours (0900 hrs to 1700 hrs), negative prices occurred in 16% of dispatch intervals in New South Wales and 26% in Queensland, representing year-on-year declines of 14 pp and 15 pp respectively compared to Q1 2025. These reductions are consistent with lower year-on-year price-setting frequency by grid solar and wind in these regions (see Section 2.2.4). Over the same daytime period, negative prices occurred in 67% of dispatch intervals in South Australia and 53% in Victoria, both up 1 pp compared to same quarter last year. Victoria was the only region to record a notable increase in overnight negative price occurrence (2200 hrs to 0600 hrs), with negative prices observed in 7.9% of intervals, up 2.4 pp year-on-year.

The proportion of negative prices in the -$10/MWh to $0/MWh range increased to 68% this quarter, up from 12% in Q1 2025 (**Figure 24**). This trend aligned with the decline in large-scale generation certificate (LGC) prices, which averaged $5/certificate in Q1 2026, compared to $29/certificate in Q1 2025. Consequently, the average spot price during negative price intervals increased from -$35.4/MWh to -$17.7/MWh. Negative price impact[15], reflecting the combined effect of negative price levels and frequencies on quarterly average prices, decreased across all NEM regions year-on-year. NEM-wide negative price impact declined to $2.6/MWh this quarter, down from $6.4/MWh in Q1 2025, consistent with lower average negative prices and reduced frequency of negative price intervals.

2.2.4 Price-setting dynamics

This quarter, increased price-setting by batteries reshaped market outcomes, with broader distribution of price-setting across technologies. Batteries and wind set NEM prices more frequently than in Q1 2025, while other energy sources saw a decline or remained broadly stable. Price setting by battery discharge increased 11 pp year-on-year to 15% of intervals, and by battery charge from 6% in Q1 2025 to 17% this Q1. Battery discharge and charge, combined, accounted for 32% of price-setting intervals, with batteries displacing hydro as the most frequent price-setting technology across the NEM this quarter. Wind set prices in 8% of intervals, up 1 pp year-on-year.

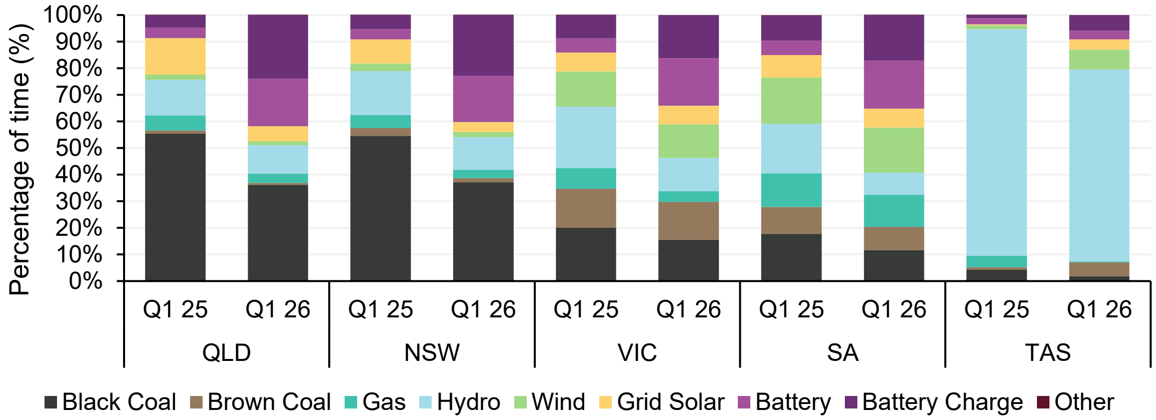
At a regional level, the shift in price-setting dynamics was most notable in New South Wales and Queensland (**Figure 25**). In Queensland, battery charge and discharge set prices in 24% and 18% of intervals respectively this quarter, while in New South Wales battery charge reached 23% and battery discharge reached 18%. Battery charge and discharge, when

[15] Negative price impact is defined as the increase in regional spot price that would result from replacing all negative spot price values with $0/MWh.

combined, accounted for over 40% of price-setting intervals in both regions. This increase coincided with a reduction in price-setting frequency of grid-scale solar and wind, alongside decreased negative price occurrence in both regions (see Section 2.2.3). Combined battery charge and discharge set prices in 34% and 35% of intervals in Victoria and South Australia respectively. Price-setting by thermal and hydro generation reduced year-on-year in both regions, while wind and grid-scale solar remained relatively stable.

Figure 25 Shift in price-setting outcomes across NEM regions

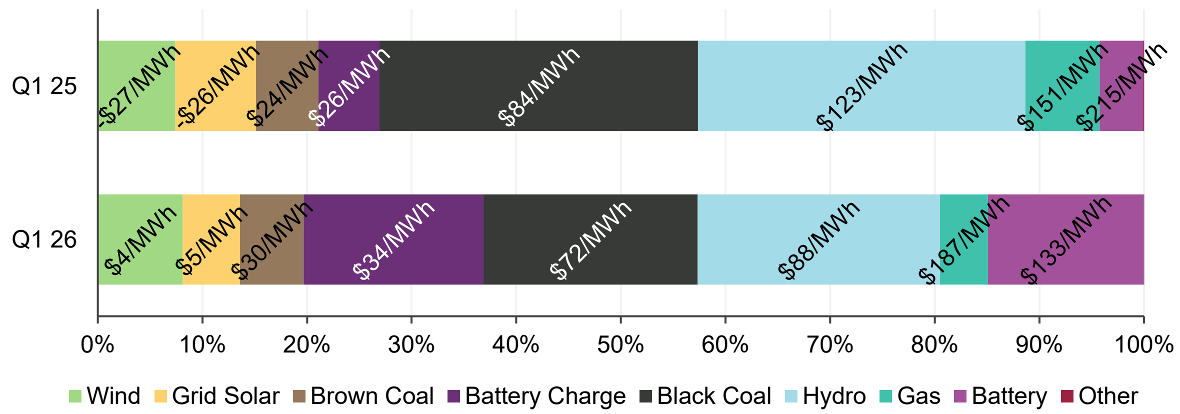
Price-setting frequency by region and fuel type – Q1 2026 vs Q1 2025



Average prices set when marginal declined for black coal, hydro and battery discharge, while other energy sources recorded increases (**Figure 26**). Wind and grid-scale solar experienced year-on-year increases of $31/MWh and $32/MWh respectively, to positive average prices of $4/MWh and $5/MWh. This was largely driven by the higher prices set by these technologies in Tasmania due to Basslink transfer costs, as discussed in the following section. Average prices set by gas rose by $37/MWh from Q1 2025 to $187/MWh, with periods of price volatility in South Australia and New South Wales driving the uplift. In contrast, average prices set by battery discharge declined sharply, falling from $215/MWh in Q1 2025 to $133/MWh in Q1 2026 as this source was marginal across a broader range of intervals. Average prices set by hydro also decreased significantly from $123/MWh to $88/MWh this quarter.

Figure 26 Increased battery price setting reshaped market outcomes in Q1 2026

NEM price-setting frequency and average spot price when price-setter by fuel-type – Q1 2026 vs Q1 2025

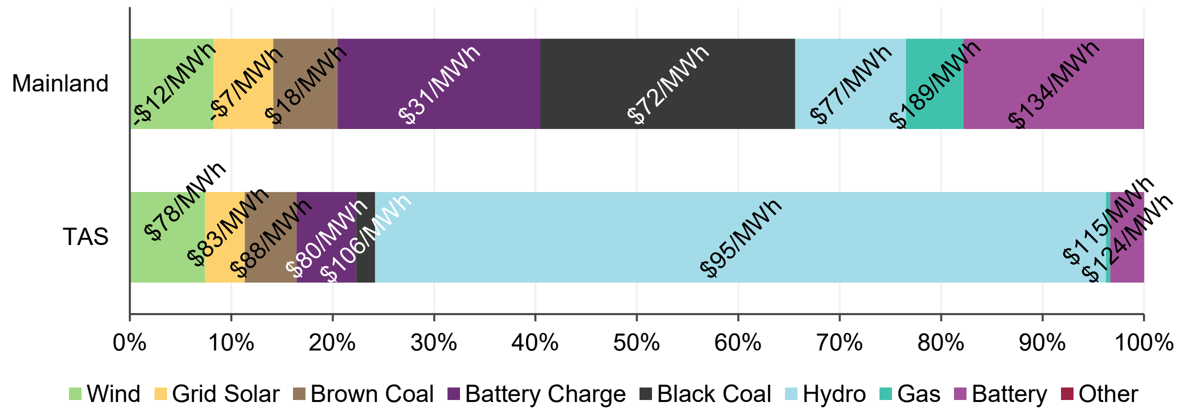


Impact of Basslink on price-setting

Basslink currently operates as a non-regulated Market Network Service Provider (MNSP)[16], with transfer capacity between Victoria and Tasmania scheduled through market offers. These offers are incorporated into dispatch outcomes and influence price-setting dynamics across NEM regions. The large increase in Basslink offer prices since Q1 2025 contributed to higher price-setting outcomes in Tasmania this quarter, in addition to reduced Basslink transfers (see Section 2.6). This quarter, Basslink imports to Tasmania contributed to price setting in 27% of intervals, with an average transfer price of \$80/MWh[17], and contributed \$22/MWh to the region's quarterly average spot prices. As a result, in Q1 2026 average Tasmanian prices set by most fuel types when marginal were higher than on the mainland (**Figure 27**). The differential was most notable for renewable generation, with wind and grid-scale solar setting negative average prices on the mainland, but averages of \$78/MWh and \$83/MWh respectively in Tasmania.

Figure 27 Price-setting outcomes remained higher in Tasmania than on mainland across most fuel types

NEM price-setting frequency and average spot price when price-setter by fuel type – Mainland vs Tasmania in Q1 2026



Price-setting by time of day

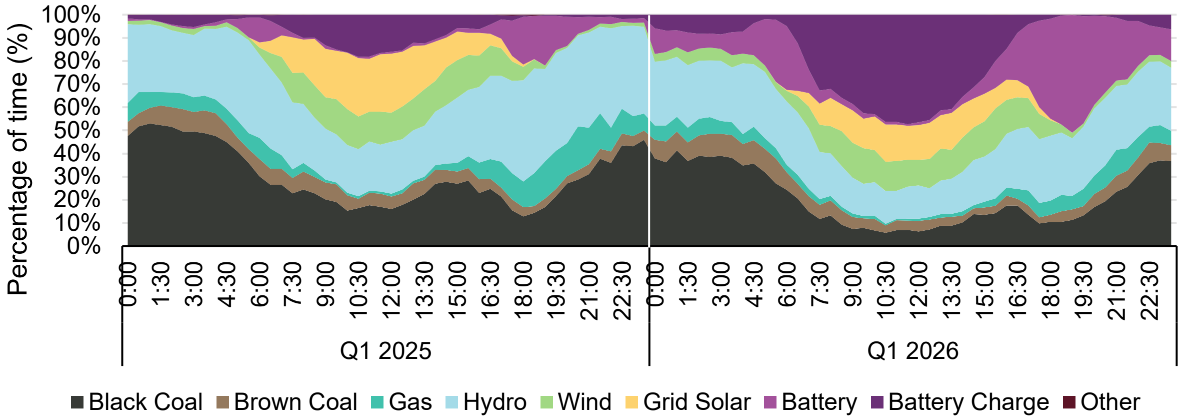
In Q1 2026, price-setting dynamics shifted across all hours of the day, with the increased marginal role of batteries reducing the role of other energy sources (**Figure 28**). Black coal, gas and hydro set prices less frequently across most hours of the day. The most pronounced reductions occurred during the evening peak (1600 hrs to 2100 hrs) where price-setting by hydro declined by 13 pp year-on-year to 27% this quarter. During the same time period, price-setting by both black coal and gas declined by 7 pp to 14% and 6% respectively. These reductions were offset by a significant increase in battery discharge during the evening peak (1600 hrs to 2100 hrs), with its price-setting frequency rising by 23 pp year-on-year to 36% in Q1 2026. During the day, between 1000 hrs and 1600 hrs, price-setting frequency by battery charging rose from 13% in Q1 2025 to 39% this quarter, reducing the frequency of price setting by other energy sources.

[16] Note that AEMO has received a notice from Basslink Pty Ltd (ABN 52 090 996 231) under clause 2.10.1(a) of the National Electricity Rules, stating that Basslink Pty Ltd intends to cease its registration category as an MNSP from 1 July 2026.

[17] This is the average of the marginal "regional reference node (RRN_ band price" (offer price) for Basslink imports when involved in price-setting.

Figure 28 Battery charge and discharge drove time of day price-setting shifts in Q1 2026

NEM price-setting frequency by fuel type and time of day – Q1 2026 and Q1 2025



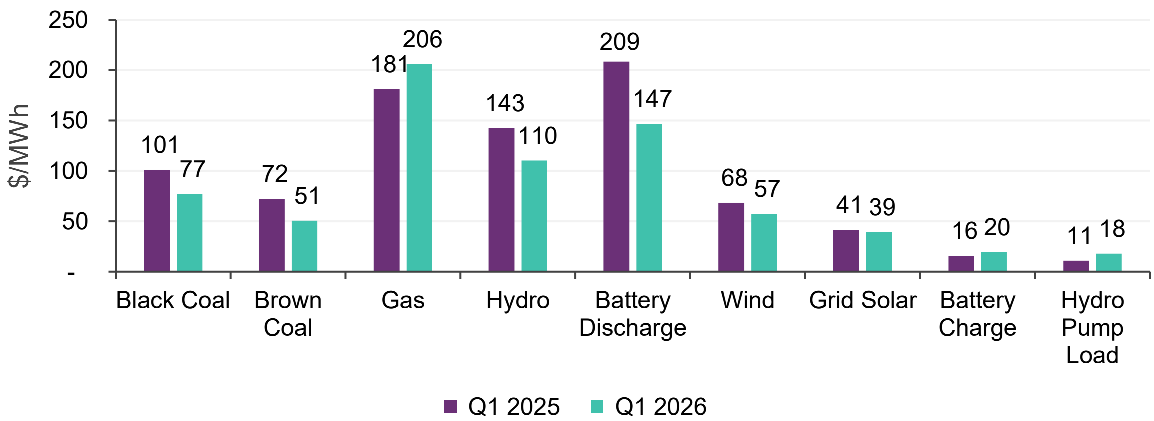
2.2.5 Volume-weighted average prices by fuel type

Figure 29 shows the average spot prices earned[18] or incurred by different fuel types across the NEM, derived as volume-weighted averages based on their generation or load volumes in each dispatch interval. In Q1 2026, volume-weighted average prices declined across most fuel types compared to Q1 2025.

Black coal and brown coal fell to $77/MWh (-$24/MWh) and $51/MWh (-$22/MWh) respectively, while hydro declined to $110/MWh (-$32/MWh) and battery discharge to $147/MWh (-$62/MWh). In contrast, gas was the only generation fuel type to record higher year-on-year VWAP, increasing to $206/MWh, up $25/MWh compared to Q1 2025. This increase in VWAP reflected the smaller share of gas generation this quarter (see Section 2.3), with its output levels concentrated more towards periods of higher demand and volatile prices in New South Wales and South Australia. The decline across most fuel types reflected reduced average pricing outcomes across the NEM, despite periods of volatility in some regions.

Figure 29 All fuel types except gas earned lower average spot prices

Volume weighted average prices by fuel type – Q1 2026 vs Q1 2025



[18] This does not reflect the full revenue earned by generators, which also includes earnings from other sources such as impact of derivative (hedging) contracts or power purchase agreements.

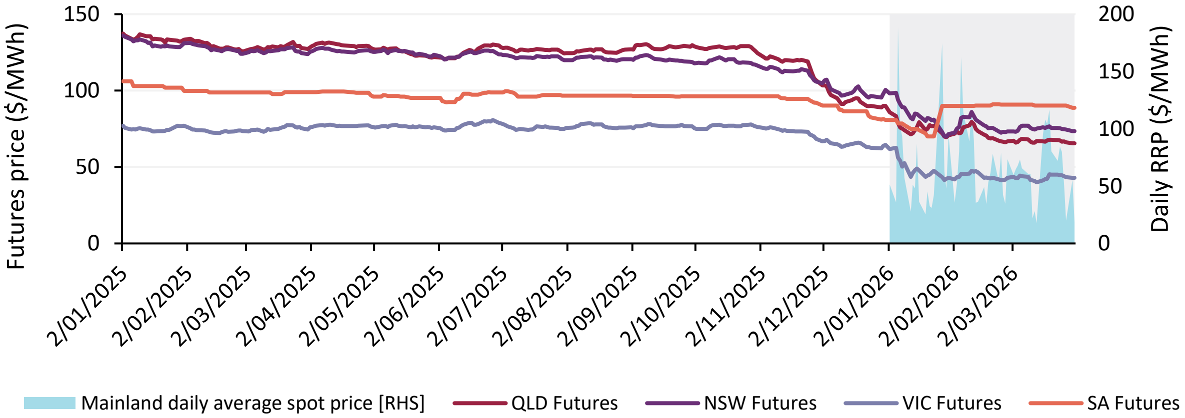
2.2.6 Electricity futures markets

Electricity futures markets are centralised exchanges offering standardised forward financial contracts for electricity. AEMO does not administer these exchanges. Information presented in this section is to allow a holistic view of both spot electricity outcomes and electricity futures pricing. **Figure 30** shows Australian Securities Exchange (ASX) daily prices for Q1 2026 base contracts across mainland regions. Final settlement prices for such current quarter contracts are set at quarter end to the time-weighted quarterly average wholesale price for the relevant region, but prior to this "delivery quarter" their traded prices reflect market expectations. During the delivery quarter, traded prices were influenced by both quarter-to-date wholesale price levels and expectations for the balance of quarter, ultimately converging to the final settlement price.

ASX contract prices for Q1 2026 declined through the quarter except for South Australia, extending the downward trend from Q4 2025 amid lower price volatility in most regions. Contract prices eased steadily in New South Wales, Queensland and Victoria, consistent with lower spot price outcomes during the quarter. In contrast, South Australia had higher variability, with contract prices declining from $81/MWh to $70/MWh early in the quarter before sharply rising to $90/MWh during the price volatility events in January and ending the quarter at $89/MWh.

Figure 30 Q1 2026 base futures declined through the quarter across all regions except South Australia

ASX Energy- Regional daily Q1 2026 base future prices and daily average spot price for mainland regions



ASX base contract prices for the 2026-27 financial year (FY27) averaged $87/MWh across mainland regions in Q1 2026, down $7/MWh (-7%) from Q4 2025 and $12/MWh (-12%) year-on-year (**Figure 31**). In Q1 2026, contract prices declined at the start of the quarter before increasing in March, coinciding with heightened geopolitical tensions in the Middle East and increased volatility in global energy markets. From the end of Q4 2025, New South Wales recorded the largest increase at $113/MWh (+8%), followed by Queensland at $92/MWh (+7%), Victoria at $80/MWh (+6%), and South Australia at $93/MWh (+5%).

By the end of this quarter, FY28 and FY29 forward futures showed a declining trend for Queensland and New South Wales, while Victoria and South Australia trended upward into FY29 (**Figure 32**).

Trading activity in the ASX morning peak electricity futures remained limited in Q1 2026. In contrast, evening peak electricity futures recorded some activity in New South Wales, Queensland and South Australia, while Victoria remained inactive. Prices in New South Wales and Queensland trended lower over the quarter compared to end of Q4 2025. South Australia exhibited variability during the January volatility events and ended the quarter higher compared to end of Q4 2025.

Figure 31 FY27 futures increased towards the end of Q1 2026

ASX Energy – Daily FY27 base futures by region

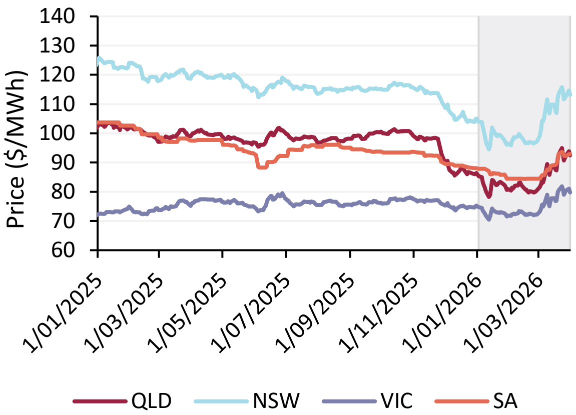
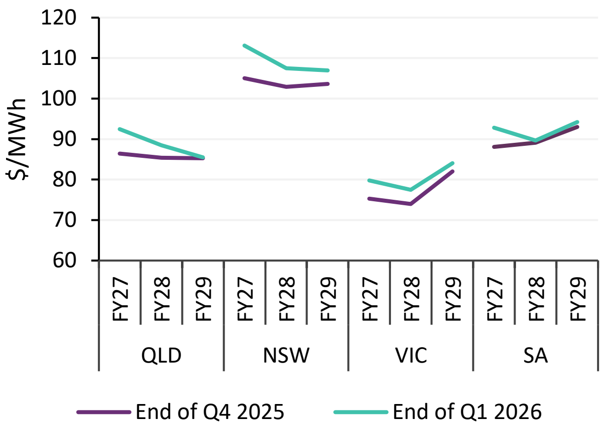


Figure 32 Future financial year contracts higher across all regions at the end of Q1 2026

ASX Energy – Financial year futures contract prices in mainland NEM regions – end of Q4 2025 and end of Q1 2026

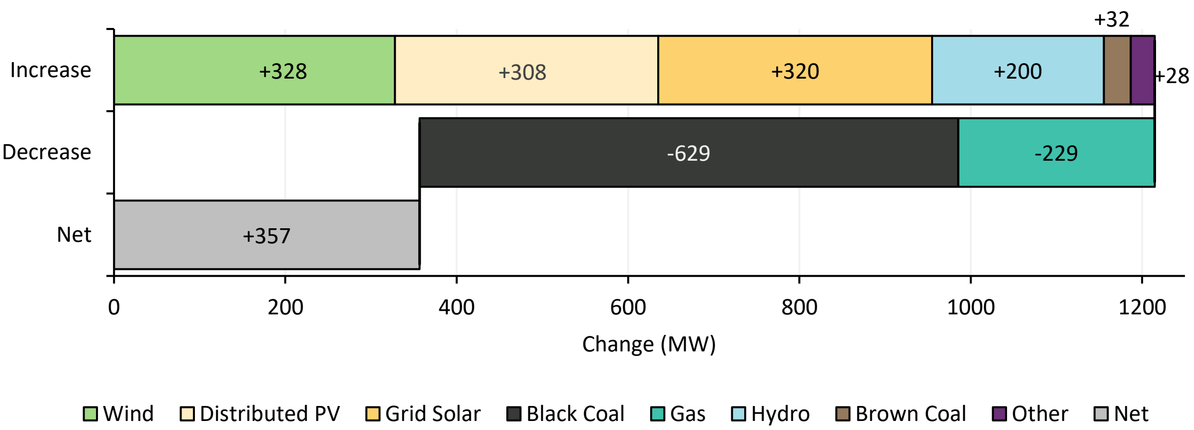


2.3 Electricity generation

This section focuses on changes in electricity generation by fuel type, with batteries and pumped hydro considered separately in Section 2.4 as storage rather than primary generation. Over Q1 2026, total generation[19] across the NEM averaged 25,805 MW, increasing by 357 MW (+1.4%) compared to Q1 2025, broadly reflecting higher underlying demand. Renewable energy share[20], which captures the contribution from primary generation sources, reached a record Q1 high of 46.5%, up from 42.5% in the same period previous year.

Figure 33 Shift in supply mix driven by higher renewable output

Change in NEM supply by fuel type – Q1 2026 vs Q1 2025



[19] Generation calculation is inclusive of AEMO's best estimates of generation from distributed PV. Generation also includes supply from certain non-scheduled generators and supply to large market scheduled loads (such as pumped hydro and batteries) which are excluded from the operational and underlying demand measures discussed in Section 2.1.

[20] Renewable energy share measures the renewable proportion of total generation but excludes battery discharge and pumped hydro production from both renewable and total generation quantities. Pumped hydro production for Tumut 3 was estimated by multiplying its pumping load by round-trip efficiency (78%) while for Wivenhoe and Shoalhaven actual generation was used.

Changes in average NEM generation by fuel type relative to Q1 2025 are shown in **Figure 33**, with corresponding shifts in supply-mix contributions summarised in **Table 3**.

Table 3 NEM supply mix contribution by fuel type

Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Biomass
Q1 25	40.4%	13.5%	3.7%	0.01%	14.9%	13.8%	9.4%	4.3%	0.1%
Q1 26	37.4%	13.4%	2.8%	0.01%	15.8%	14.9%	10.5%	5.0%	0.2%
Change	-3.0%	-0.1%	-0.9%	-0.01%	1.0%	1.1%	1.1%	0.7%	0.1%

Comparing Q1 2026 with Q1 2025:

- VRE generation, comprising wind and grid-scale solar, reached a new Q1 high of 6,550 MW, up 648 MW year-on-year from Q1 2025. Grid-scale solar recorded an all-time quarterly high of 2,706 MW, increasing its share of total generation to 10.5% (up 1.1 pp). Wind generation also increased, with its share rising by 1.1 pp to 14.9% and average output reaching a new Q1 high of 3,845 MW. Across both technologies, growth was largely driven by newly connected projects and facilities progressing through commissioning.
- Distributed PV output reached a new Q1 high of 4,090 MW this quarter (up 8.1% year on year), increasing its share to 15.8% of total supply and remaining the single largest renewable contributor. Higher distributed PV output, alongside increased grid-scale solar and wind generation, continued to suppress daytime thermal generation.
- Hydro generation (excluding pumped hydro) increased by 200 MW (+18%) year-on-year to average 1,292 MW, with most of the uplift coming from Tasmania. As a result, hydro's share of total generation rose by 0.7 pp to 5.0%. Biomass generation also increased, averaging 57 MW, more than double the 28 MW recorded in Q1 2025, lifting its share to 0.2%.
- Coal-fired generation declined to a new Q1 low of 13,102 MW, down 597 MW (-4.4%) from Q1 2025. Black coal generation fell by 629 MW (-6.1%) year on year to average 9,641 MW, with its share of supply declining further to 37.4% (down 3.0 pp). In contrast, brown coal generation increased marginally by 32 MW (+0.9%) to average 3,461 MW, although its share of supply still declined to 13.4% (down 0.1 pp).
- Gas-fired generation continued its long-term decline, falling by 229 MW (-24%) to average 712 MW, its lowest quarterly average since Q4 1999. Reflecting the combined decline in coal and gas generation, the fossil fuel share of total supply fell from 57.5% in Q1 2025 to 53.5% in Q1 2026.

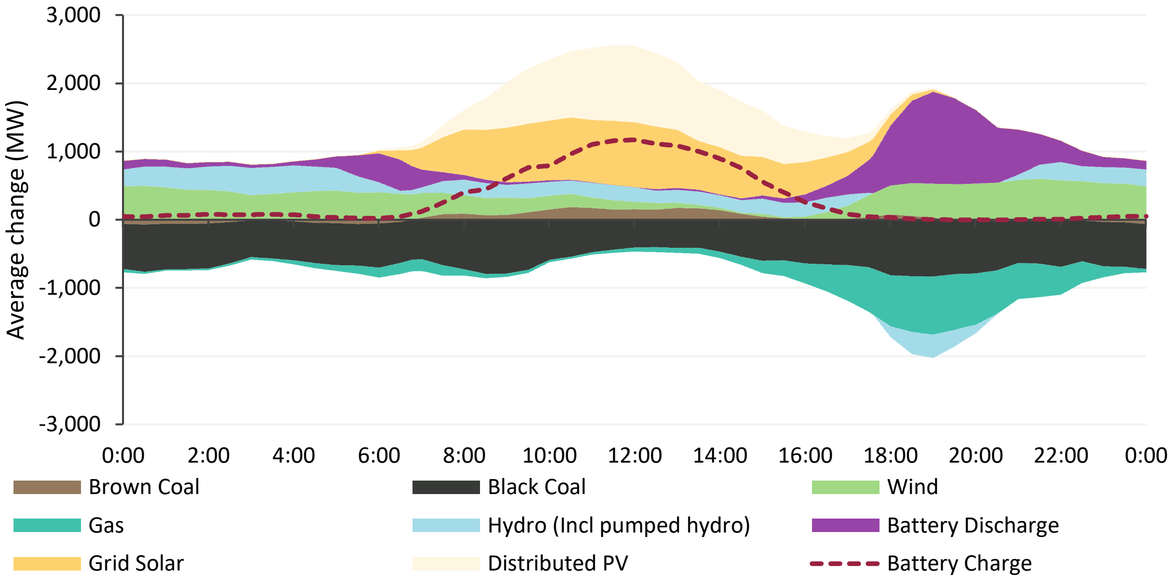
Figure 34 shows how the NEM generation profile changed by time of day. Battery charging and discharging are included to show the storage-driven shifts that underpinned changes in generation across the day.

During the day between 1000 hrs and 1600 hrs, increased battery charging reshaped the intraday generation profile by shifting energy into storage. Battery charging rose by 872 MW (+300%), alongside higher grid-scale solar generation (+755 MW, +14%) and increased distributed PV output (+877 MW, +8.4%).

This shift into storage was reflected later in the day, as batteries returned energy to the grid during periods of higher demand. During the evening peak (1600 hrs to 2100 hrs), battery discharge increased sharply by 818 MW (+275%), to average 1,115 MW, alongside higher wind generation which increased by 420 MW (+10%) to average 4,459 MW. Together, these changes shifted supply into peak periods and displaced thermal generation, with black coal and gas output falling by 742 MW (-6.1%) and 673 MW (-33%), respectively.

Figure 34 Renewables and storage reshaped supply across the day, displacing thermal generation

Change in NEM generation and storage by time of day – Q1 2026 vs Q1 2025



2.3.1 Coal-fired generation

Black coal-fired fleet

Black coal-fired generation declined by 629 MW (-6.1%) year-on-year to a new Q1 low of 9,641 MW this quarter (**Figure 35**). Black coal availability also fell to a Q1 low at 13,407 MW (-111 MW, -0.8%), with a 438 MW increase in capacity fully offline across both Queensland and New South Wales. As shown in **Figure 36**, fully offline capacity is classified into planned and unplanned maintenance/repair outages, or units being offline for market and operational reasons, referred to as economic withdrawals[21].

In New South Wales, black coal-fired generation declined by 198 MW (-3.9%) to a Q1 low of 4,891 MW, despite a 448 MW (+6.6%) increase in available capacity compared with Q1 2025. Generator utilisation declined by 8 pp to 69%, reflecting higher renewable generation during the quarter, which reduced output. Fully offline black coal capacity declined by only 25 MW, with the increase in availability primarily reflecting higher partial outages in Q1 2025. In Q1 2026, planned and unplanned full unit outages declined by 22 MW and 104 MW respectively, largely offset by a 102 MW increase in economic withdrawals.

In Queensland, black coal-fired generation fell by 431 MW (-8.3%) year-on-year to average 4,750 MW, alongside a 559 MW (-8.3%) decline in availability to an average of 6,207 MW. This reflected a 463 MW (+84%) increase in capacity fully offline, driven by higher planned outages and economic withdrawals, which rose by 168 MW and 396 MW respectively, partially offset by a 101 MW reduction in unplanned outages.

[21] Economic withdrawals refer to periods where coal units are offline (generation below 5 MW) but are not undergoing planned or unplanned repair or maintenance work. This includes units classified under the Medium Term Projected Assessment of System Adequacy (MT PASA) as "Inactive Reserve", as well as intervals where a unit's market bid availability is zero, but non-zero PASA availability indicates that it could come online if required.

Figure 35 NEM black coal-fired output reduced to a Q1 low despite increased availability in New South Wales

Quarterly average black coal-fired generation and availability by region – Q1s

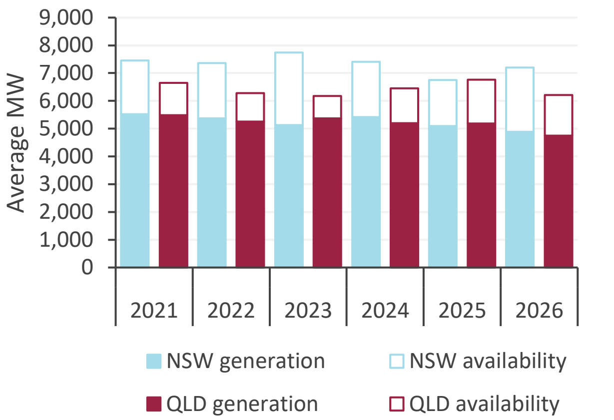


Figure 36 Unplanned outages declined while economic withdrawals increased in both New South Wales and Queensland

Average coal-fired capacity fully offline – Q1 2026 vs Q1 2025

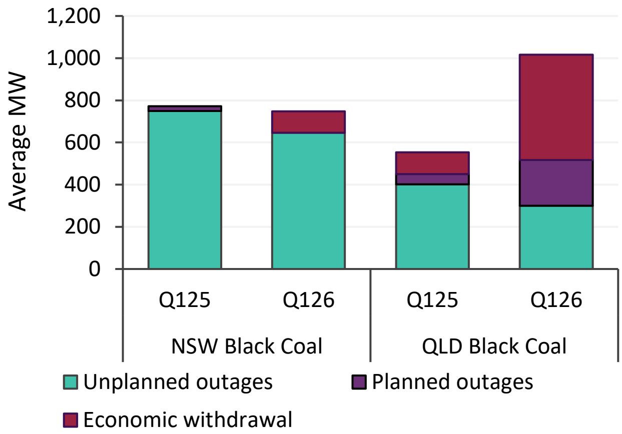
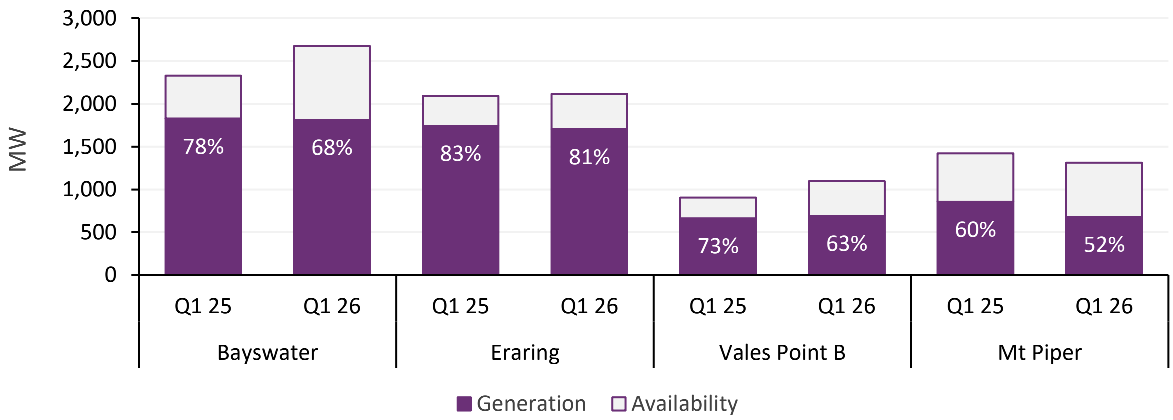


Figure 37 shows availability, generation and utilisation rates for the New South Wales black coal-fired power stations. Bayswater output declined by 12 MW (-0.7%) year-on-year to average 1,815 MW, despite availability increasing by 347 MW (+15%), reflecting a 323 MW reduction in average capacity on full outage. Utilisation reduced from 78% in Q1 2025 to 68% in Q1 2026. Eraring output also declined, down 38 MW (-2.2%) to average 1,704 MW. This occurred despite a 21 MW (+1.0%) increase in availability, with utilisation easing by 3 pp to 81%.

Mount Piper recorded a larger decline in output, averaging 680 MW, down 178 MW (-21%) year-on-year. Availability reduced by 109 MW (-7.7%), driven by a 109 MW increase in capacity on full outage. Utilisation also fell by 9 pp to average 52%. Vales Point B was the only New South Wales station to record higher generation, with output increasing by 30 MW (+4.6%) compared with Q1 2025. Availability rose by 189 MW (+21%); however, utilisation declined to 63%, down from 73% in Q1 2025.

Figure 37 Lower utilisation across New South Wales black coal-fired fleet

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q1 2026 vs Q1 2025

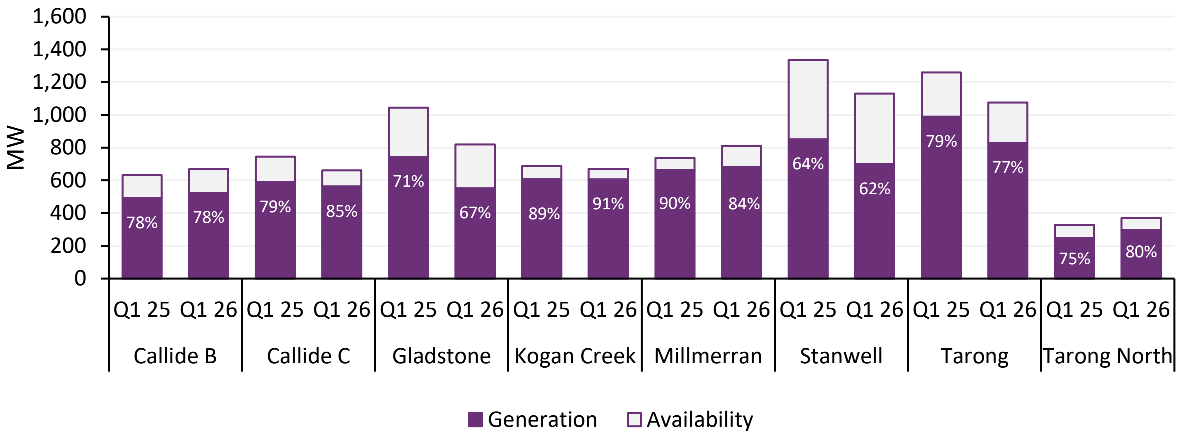


As shown in **Figure 38**, Gladstone, Tarong and Stanwell recorded the largest reductions in average output this quarter, down 191 MW, 160 MW and 150 MW respectively. These declines were primarily driven by higher capacity fully offline, reducing availability by 225 MW at Gladstone, 182 MW at Tarong, and 205 MW at Stanwell. Gladstone's utilisation fell by 4 pp, while utilisation at Tarong and Stanwell each reduced by 2 pp. Output at Callide C and Kogan Creek also declined, by 27 MW and 2 MW respectively, with reduced availability at both stations.

In contrast, generation increased at Tarong North, Callide B and Millmerran, rising by 48 MW (+19%), 35 MW (+7.0%) and 17 MW (+2.6%) respectively, supported by higher availability compared with the same period last year.

Figure 38 Queensland black coal-fired output dropped

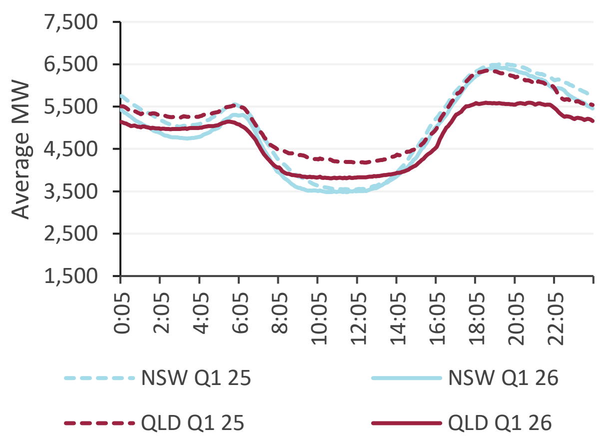
Average quarterly availability and generation for Queensland black coal-fired power stations – Q1 2026 vs Q1 2025



This quarter, the decline in New South Wales black coal-fired generation was observed across most hours of the day, with a more pronounced reduction outside daylight hours (**Figure 39**). During the morning peak period between 0600 hrs and 1000 hrs, average output fell by 242 MW to 4,148 MW.

Figure 39 Black coal-fired generators in Queensland saw lower swing year-on-year

Black coal-fired output by time of day – Q1s



Intraday variation in New South Wales remained broadly unchanged at 2,938 MW, compared with 2,958 MW in the previous year. At the unit level, Bayswater recorded a 186 MW increase in intraday variation, reflecting higher output during the evening peak period. This was largely offset by a 174 MW reduction in intraday variation at Mount Piper, resulting in limited net change across the fleet.

In Queensland, intraday swing declined by 388 MW to 1,786 MW this quarter, reflecting lower generation during both the morning and evening peak periods. Output fell by 444 MW between 0600 hrs and 1000 hrs and by a larger 610 MW between 1600 hrs and 2100 hrs, indicating reduced peak-period responsiveness and lower availability associated with higher fully offline capacity.

Brown coal-fired fleet

In Q1 2026, Victorian brown coal-fired generation was broadly unchanged from the same period last year, increasing marginally by 32 MW to average 3,461 MW (**Figure 40**). Availability also remained relatively stable, also increasing by 32 MW to average 4,031 MW for the quarter, despite fully offline capacity increasing slightly by 28 MW.

Brown coal-fired generation remained broadly stable across most hours of the day in Q1 2026, with the exception of the midday period, when output increased slightly (**Figure 41**). This reduced intraday flexibility by 164 MW, with intraday swing declining from 1,287 MW in Q1 2025 to 1,123 MW in Q1 2026.

Figure 40 Brown coal-fired availability and generation increased slightly

Quarterly average brown coal-fired generation and availability in Victoria (including decommissioned units) – Q1s

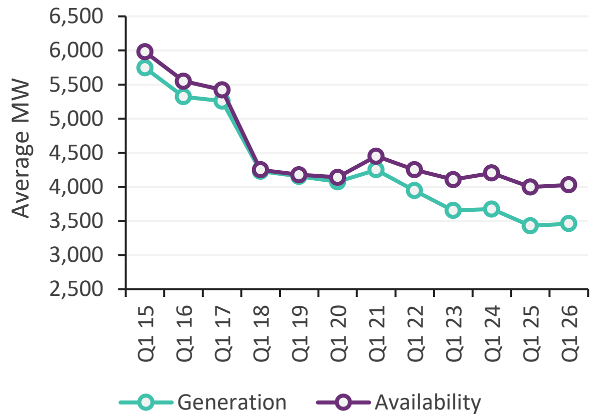
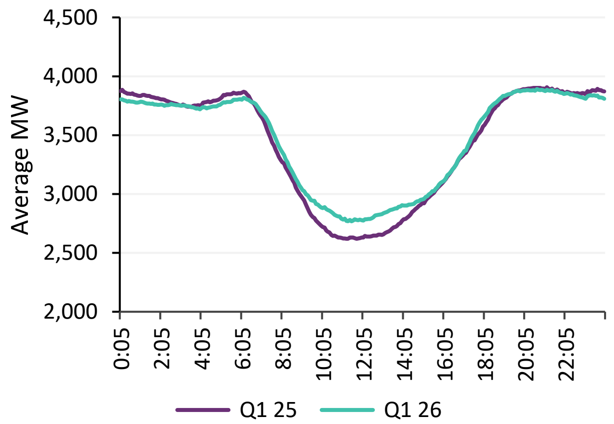


Figure 41 Brown coal-fired output remained largely unchanged except for mid-day period

Brown coal-fired output by time of day – Q1s



At the station level, as shown in **Table 4,** outcomes were mixed. Output rose at Yallourn (+72 MW) and Loy Yang B (+29 MW), supported by higher utilisation (+6.9 pp to 95% and +1.4 pp to 86% respectively) and modest availability increases (+1 MW and +15 MW). This was partly offset by a 69 MW decline at Loy Yang A, where output fell despite availability increasing by 16 MW as utilisation dropped 4.4 pp to 81%. Loy Yang A's intraday swing continued to increase over time, while Loy Yang B and Yallourn showed lower year-on-year variation, reflecting higher daytime generation.

Table 4 Brown coal availability, output, utilisation, offline capacity, and intraday swing – Q1 2026 vs Q1 2025

Generator	Availability (MW)		Output (MW)		Utilisation		Fully Offline Capacity (MW)		Intraday swing (MW)	
	Q1 25	Q1 26	Q1 25	Q1 26	Q1 25	Q1 26	Q1 25	Q1 26	Q1 25	Q1 26
Loy Yang A	1,850	1,866	1,579	1,511	85%	81%	278	302	591	686
Loy Yang B	1,134	1,150	955	983	84%	86%	2	0	423	349
Yallourn W	1,014	1,015	896	967	88%	95%	444	450	286	96

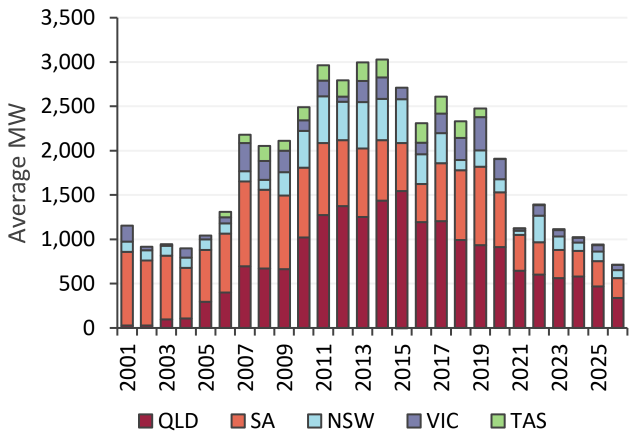
2.3.2 Gas-fired generation

In Q1 2026, gas-fired generation across the NEM averaged 712 MW, down 229 MW (-24%) from Q1 2025, marking its lowest average for any quarter since Q4 1999 (**Figure 42**). Gas-fired output declined in all NEM regions, with the largest reduction occurring in Queensland, where gas-fired generation fell by 131 MW (-28%) year-on-year to its lowest quarterly level since Q1 2005. Lower output was observed across all hours of the day, reflecting persistently lower spot prices. Most generators recorded year-on-year reductions, led by Darling Downs Power Station, where output averaged 104 MW, down 57 MW (-35%) from Q1 2025. Yabulu and Yarwun also reduced output by 27 MW and 16 MW, respectively.

In South Australia, gas-fired generation averaged 222 MW, down 63 MW (-22%) from Q1 2025, marking the second-lowest quarterly average on record, after Q4 2025. The largest reductions were observed at AGL's Torrens Island (-25 MW, -31%) and Origin's Osborne facility (-25 MW, -92%).

Figure 42 NEM-wide gas-fired generation dropped

Average gas-fired generation by region – Q1s



Gas-fired generation in New South Wales declined by 14 MW (-13%) to average 92 MW this quarter, driven primarily by lower output at Tallawarra A (-10 MW, -40%) and Uranquinty Power Station (-12 MW, -44%). This was partially offset by a 14 MW increase at Hunter Power Station following the commencement of commissioning for its second unit in December.

Victorian gas-fired output also declined, falling by 14 MW year-on-year to average 59 MW, with most stations recording lower generation.

2.3.3 Hydro

This section discusses hydro generation, excluding pumped hydro output, which is covered in section 2.4.2.

In Q1 2026, hydro generation[22] across the NEM increased by 200 MW (+18%) year-on-year to average 1,292 MW (**Figure 43**). Tasmania recorded the largest increase, with average hydro output rising by 174 MW (+29%) to 766 MW. This uplift was supported by higher storage water levels and increased generation volumes offered at lower price bands (**Figure 44**). Much lower Basslink imports into Tasmania (see Section 2.6) also required hydro generation to increase output despite lower operational demand. Tasmanian hydro storage levels began the quarter at 52.8%, 5.8 pp higher than at the same time last year, before declining through the quarter to reach 41.6% by the end of March, 3.5 pp higher than previous year.

Queensland's hydro generation also increased, averaging 125 MW, up 48 MW (+62%) from Q1 2025. Higher output at Barron Gorge (+59 MW) more than offset reduction at Kareeya (-11 MW).

New South Wales's output remained largely unchanged from the previous year, averaging 143 MW for Q1 2026. Decreased outputs at Blowering (-14 MW) and Hume (-10 MW) stations were partially offset by higher output at Upper Tumut, which increased by 23 MW to average 94 MW. Snowy Hydro's Lake Eucumbene storage level stood at 41% at the end of Q1 2026, down from 43% at the same time last year.

Victoria also experienced a decline in average hydro generation, with output falling by 23 MW (-8.2%) to 258 MW. Reduced generation at Dartmouth (-11 MW, -23%) and Eildon (-16 MW, -41%), was partially offset by higher output at Murray (+13 MW, +7.8%).

[22] Hydro generation excludes output from hydro pumped storage and does not net off electricity consumed by pumping at these facilities. When excluding pumped hydro generation, the pumped hydro production for Tumut 3 was estimated by multiplying its pumping load by round-trip efficiency (78%) while for Wivenhoe and Shoalhaven actual generation was used.

Figure 43 Hydro generation in Tasmania increased

Average hydro-generation by region – Q1s

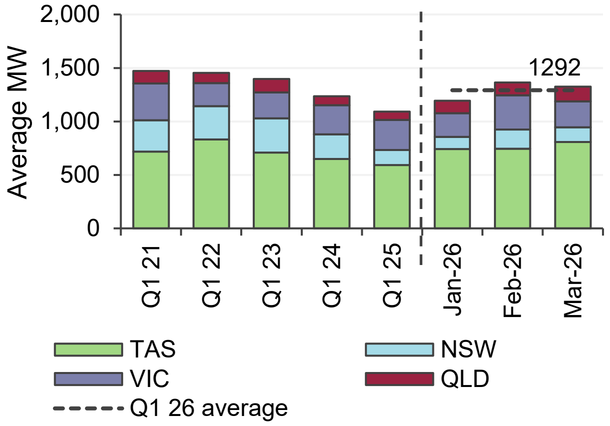
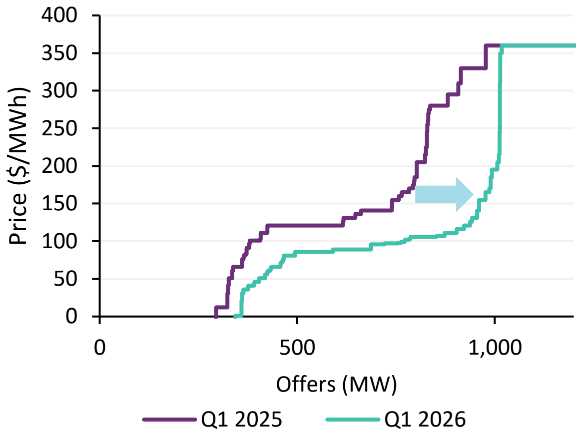


Figure 44 Higher volume offered at lower price bands by hydro generators in Tasmania

Tasmania hydro bid supply curve – Q1 2026 vs Q1 2025



2.3.4 Wind and grid-scale solar

Average VRE generation in the NEM reached its second-highest quarterly average at 6,550 MW, 77 MW below the record high of 6,627 MW in Q4 2025. Compared with Q1 2025, average VRE output increased by 648 MW (+11%), driven by higher wind generation (+328 MW, +9.3%) and grid-scale solar generation (+320 MW, +13%) (**Figure 45**).

Wind generation growth was led by Queensland, where average output more than doubled (+384 MW, +103%) to its highest-ever quarterly average of 759 MW (**Figure 46**). South Australia also recorded growth (+40 MW, +5%), partially offset by declines in New South Wales (-64 MW, -7%), Victoria (-25 MW, -2%) and Tasmania (-7.7 MW, -5%). Grid-scale solar growth was strongest in Queensland (+158 MW, +20%) and New South Wales (+142 MW, +13%) with a more moderate increase in Victoria (+50 MW, +15%). In contrast, South Australia recorded a decline of 31 MW (-25%).

Figure 45 Continued growth in VRE output

Average quarterly VRE generation by fuel type – Q1s

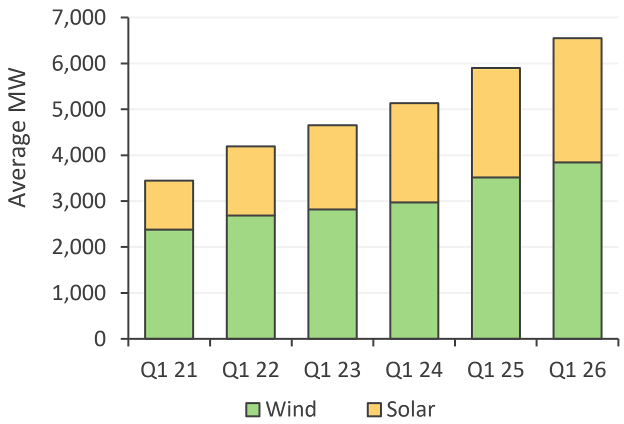
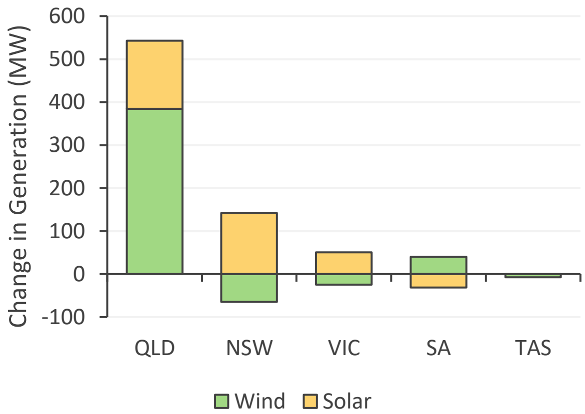


Figure 46 Queensland led renewable increases

Average MW change in output Q1 2026 vs Q1 2025



Grid-scale solar

Grid-scale solar output across the NEM reached an all-time quarterly high of 2,706 MW this quarter, up 320 MW (+13%) from Q1 2025. Higher grid-scale solar availability across the NEM reflected contributions from both newly connected projects and facilities progressing through commissioning, a process that can extend beyond 12 months. Together, these additions lifted average quarterly solar availability by 556 MW relative to Q1 2025 (**Figure 47**). Most of the increase occurred in New South Wales and Queensland. In New South Wales, growth was led by Culcairn (+107 MW), Stubbo (+102 MW) and Wollar (+73 MW), while in Queensland the Aldoga Solar Farm added 114 MW.

However available output from established[23] grid-scale solar facilities fell by 137 MW, as quarterly NEM-wide volume-weighted available capacity factors[24] were 1.1 pp lower this quarter than in Q1 2025, averaging 29%. Victoria recorded the highest available capacity factor at 34% (+1.0 pp), followed by New South Wales at 30% (-1.8 pp) (**Figure 48**). South Australia experienced a notable decline of 5.9 pp to average 28% due to reduced solar irradiance and increase in facilities being outages/offline, while Queensland recorded the lowest available capacity factor at 27% (-0.3 pp).

Network curtailment increased year-on-year, reducing potential growth in grid-scale solar output by 127 MW, while economic offloading declined by 28 MW.

Figure 47 New and commissioning capacity led the year-on-year grid-scale solar growth

Changes in grid-scale solar generation – Q1 2026 vs Q1 2025

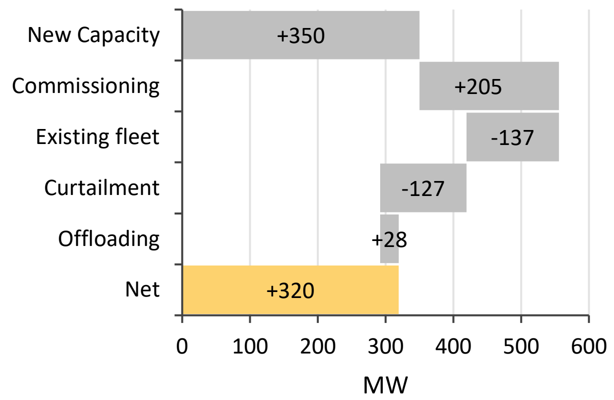
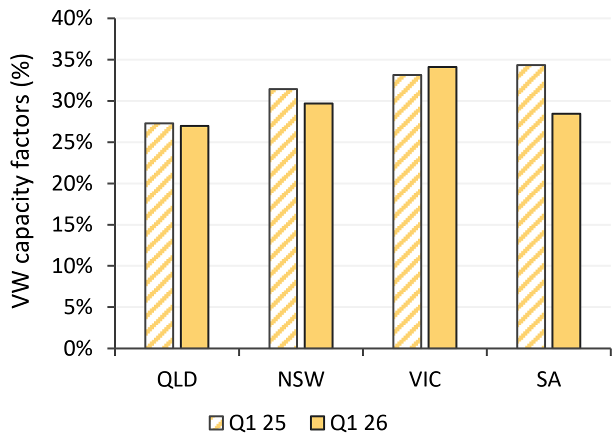


Figure 48 Reduced grid-scale solar availability in all NEM regions except Victoria

Volume-weighted grid-scale solar available capacity factors[25] – Q1s



Wind

In Q1 2026, NEM-wide wind generation averaged 3,845 MW and reached a new Q1 high, exceeding the previous level set in 2025 by 328 MW (+9.3%). Higher availability from new and commissioning wind farms lifted average quarterly availability by 573 MW compared with Q1 2025 (**Figure 49**). Queensland drove much of this growth, with major contributions from Clarke Creek (+174 MW), MacIntyre (+140 MW) and Wambo (+68 MW), alongside Golden Plains in Victoria (+145 MW) and Goyder South in South Australia (+47 MW).

Available output from established wind farms was lower this Q1, down by 143 MW. NEM-wide quarterly volume-weighted available capacity factors for established facilities dropped by 1.8 pp to 31%. Queensland was the only region to record an increase, rising by 0.6 pp to average 33% for the quarter. South Australia also recorded a capacity factor of 33%, down

[23] Existing (or established) capacity here means wind and grid-scale solar facilities that were fully commissioned prior to the start of Q1 2026. These facilities may also appear in the "New Capacity" or "Commissioning" categories in **Figure 47** and **Figure 49** if they were connected or exhibited ramping activity between Q1 2025 and Q1 2026 respectively.

[24] Available capacity factors are calculated using average available energy divided by maximum installed capacity. The use of availability instead of generation output removes the impact of any economic offloading or curtailment and better captures in-service plant capacity and underlying wind or solar resource levels.

[25] Available capacity factors for each established facility are weighted by maximum installed capacity to derive a regional weighted average

0.9 pp year-on-year (**Figure 50**). New South Wales experienced the largest decline, falling by 3.1 pp to 30%, followed by Victoria (-2.0 pp to 29%). Tasmania also recorded a decrease of 1.6 pp year-on-year to average 29%, contrasting with the region's 49% level in Q4 2025.

Network curtailment of wind increased by 20 MW, while economic offloading rose by 83 MW year-on-year, moderating overall growth in wind output.

Figure 49 Increased output from new and commissioning wind farms

Changes in wind generation – Q1 2026 vs Q1 2025

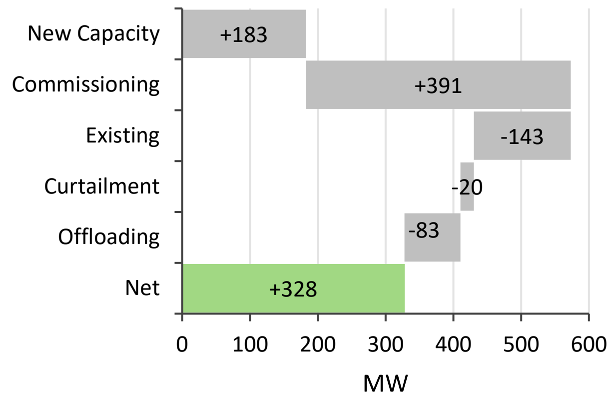


Figure 50 Wind availability down in all NEM regions except South Australia and Tasmania

Volume-weighted wind available capacity factors – Q1s

Economic offloading

During Q1 2026, total economic offloading[26] of grid-scale solar and wind generation averaged 509 MW, an increase of 55 MW (+12%) on Q1 2025 (**Figure 51**). Economic offloading was higher in Victoria and South Australia than in Queensland and New South Wales, driven by more frequent negative price occurrences in the southern regions (see Section 2.2.3).

Grid-scale solar economic offloading averaged 194 MW, down 28 MW (-12%), with offloading as a share of average grid-scale solar availability falling from 8% to 6%. Reductions were concentrated in New South Wales (-32 MW, -59%) and Queensland (-30 MW, -48%), while offloading increased in Victoria (+34 MW, +119%) (**Figure 52**). In South Australia, economic offloading remained largely unchanged year-on-year at 77 MW, however offloading as a proportion of available output reached 46%, reflecting very low daytime spot prices and limited ability to export surplus energy to Victoria.

In contrast, wind economic offloading increased notably, averaging 315 MW in Q1 2026, up 83 MW (+36%) from Q1 2025. As a share of average grid-scale wind availability, offloading increased from 7% to 8%. The largest increase occurred in Victoria (+78 MW), with additional rises in South Australia (+10 MW) and Queensland (+2.6 MW). New South Wales recorded a small reduction (-8 MW), while Tasmania remained near zero. Constraint-driven limitations on transfers northward to New South Wales, together with lower flows on Basslink following changes in bidding behaviour since July 2025, contributed to lower Victorian spot prices. These conditions increased economic offloading during periods of low operational demand and high VRE availability.

[26] Economic offloading refers to a generator being dispatched below its maximum availability, because some or all of its output was bid into price bands greater than the regional reference price (that is, it was undercut by competitors offering their output at a lower price).

Figure 51 Economic offloading increased for wind and decreased at solar farms

Average MW offloading and as percentage of availability by fuel type

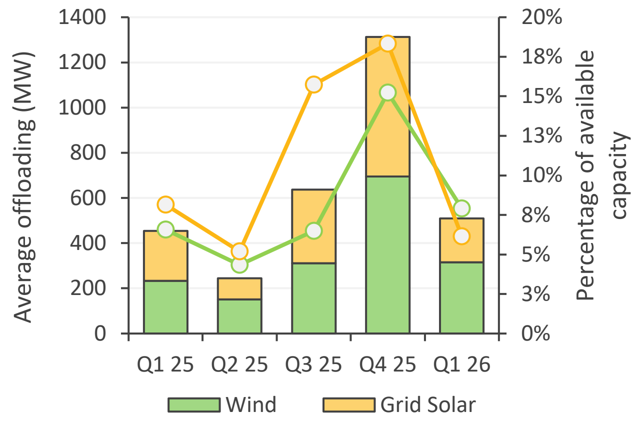
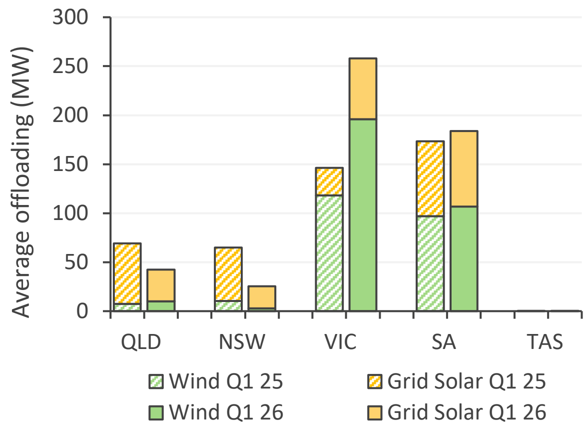


Figure 52 Victoria and South Australia saw higher economic offloading

Average MW offloading by region – Q1s



Network curtailment

Total network curtailment[27] of grid-scale solar and wind generation averaged 296 MW in Q1 2026, nearly doubling the 150 MW in Q1 2025 (**Figure 53**). Grid-scale solar curtailment due to network constraints increased sharply, averaging 246 MW in Q1 2026, an increase of 127 MW (+107%) from Q1 2025. This outcome was driven primarily by New South Wales, where curtailment grew 99 MW (+109%), the increase concentrated at newer facilities in the south of the state, followed by Victoria (+20 MW, +90%) (**Figure 54**). As a result, network curtailment as a share of average grid-scale solar availability rose to 7.8%, up from 4.4% in Q1 2025.

Figure 53 Curtailment increased for both wind and solar farms

Average MW network curtailment and as percentage of availability by fuel type

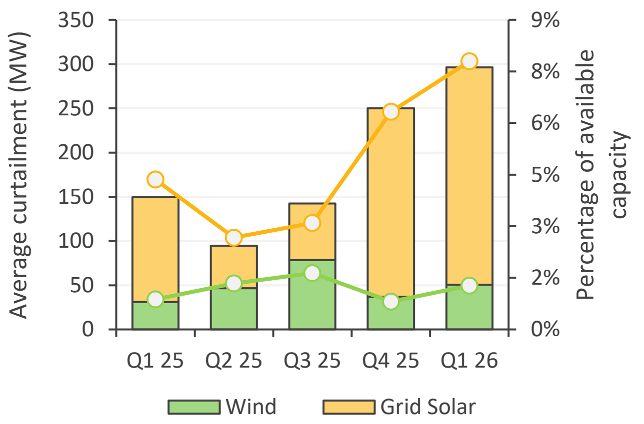
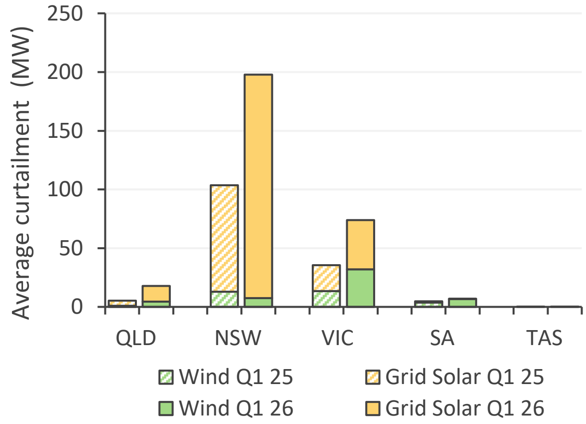


Figure 54 New South Wales saw higher grid solar curtailment

Average MW network curtailment by region – Q1s



Wind curtailment also increased, rising by 20 MW (+63%) to average 51 MW this quarter. As a proportion of average wind availability, curtailment increased marginally by 0.4 pp to 1.3%. The largest increase occurred in Victoria (+18 MW, +136%),

[27] Curtailment refers to a generator being dispatched below its economic availability (output available at offer prices below the regional reference price) due to the operation of network- or security-related constraints.

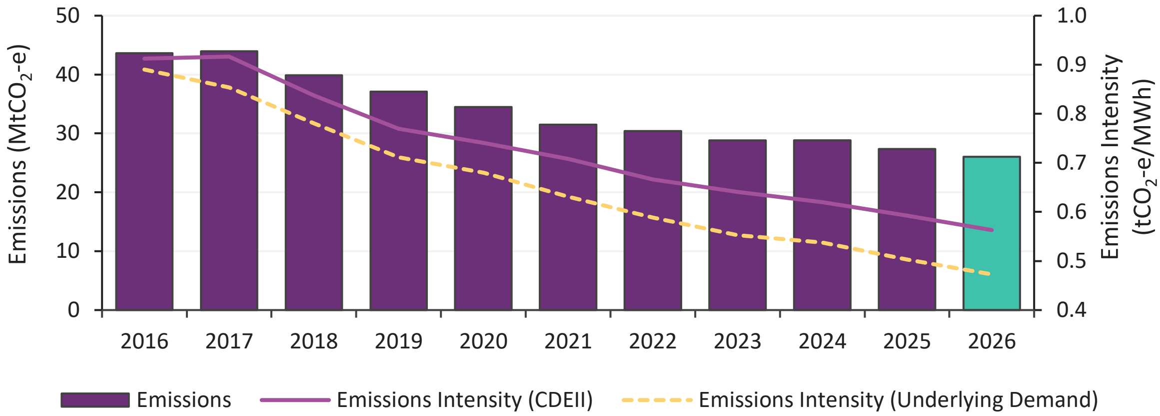
with further increases in South Australia (+3.0 MW, +82%) and Queensland (+3.5 MW, +396%). These rises were partially offset by reductions in New South Wales (-5.4 MW, -42%), while curtailment in Tasmania remained negligible.

2.3.5 NEM emissions

In Q1 2026, total emissions across the NEM fell to a new Q1 low of 26.0 $MtCO_2$-e, a reduction of 1.3 $MtCO_2$-e (-4.8%) compared with Q1 2025 (**Figure 55**). The Carbon Dioxide Equivalent Intensity Index (CDEII) emissions intensity is measured by combining sent out metering data with publicly available generator emission and efficiency data to provide a NEM-wide CDEII[28]. This emissions intensity excludes generation from distributed PV, considering only sent out generation from market generating units.

Figure 55 Emissions and emissions intensity fell to Q1 lows

Quarterly NEM emissions and intensity – Q1s



Average CDEII emissions intensity declined to 0.56 tCO_2-e/MWh in Q1 2026, the lowest Q1 level on record. This represented a year-on-year reduction of 0.03 tCO_2-e/MWh (-4.9%), driven by a lower combined share of coal- and gas-fired generation. Emissions intensity associated with underlying demand[29] also declined, falling by 0.03 tCO_2-e/MWh year-on-year to 0.47 tCO_2-e/MWh, marking a new Q1 low.

2.4 Storage and renewable contribution

2.4.1 Batteries

This quarter saw a substantial expansion in battery capacity that entered commissioning from the end of Q1 2025. Between the end of Q1 2025 and the end of Q1 2026, multiple large battery energy storage systems (BESS), with a combined capacity of 4,445 MW/11,219 MWh, commenced initial commissioning in the NEM. Of this total, 1,504 MW/4,460 MWh came online during Q1 2026 (**Table 5**). These assets are now either fully commissioned or continuing through their commissioning processes, lifting total installed battery capacity (including commissioned and commissioning assets) to more than 8,000 MW by the end of the quarter.

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[28] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/settlements-and-payments/settlements/carbon-dioxide-equivalent-intensity-index.

[29] Total emissions from NEM electricity generation including distributed PV, divided by underlying demand.

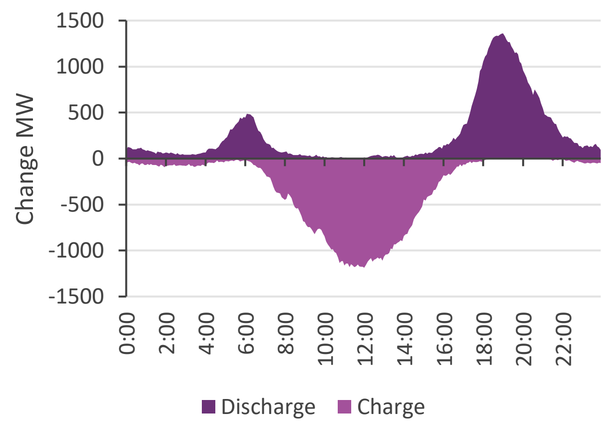
Table 5 New battery systems commenced commissioning in the NEM in Q1 2026

Battery	Region	Maximum Capacity
Supernode BESS unit 2	Queensland	260 MW / 1090 MWh
Orana BESS	New South Wales	415 MW / 1660 MWh
New England BESS	New South Wales	200 MW / 400 MWh
Quorn Park Solar Hybrid BESS	New South Wales	19 MW / 40 MWh
Mortlake BESS	Victoria	300 MW / 650 MWh
Terang BESS	Victoria	100 MW / 200 MWh
Bungama BESS	South Australia	150 MW / 300 MWh
Clements Gap BESS	South Australia	60 MW / 120 MWh

Average battery discharge increased sharply, reaching 359 MW (+262 MW), more than three times the 98 MW recorded in the same period a year earlier, and setting a new quarterly high. Average battery charging also increased by 315 MW year-on-year, with a notable uplift during the daytime. This supported a shift in renewable generation from daytime to evening peaks, with increased daytime charging and stronger evening discharge (**Figure 56**), and contributed to more moderate prices during high-demand periods.

Figure 56 Increased daytime charging and stronger evening discharge

Change in average battery discharge/ charge by time of day – Q1 2026 vs Q1 2025



Batteries also set a new peak discharge record this quarter, reaching 3,556 MW on 7 January 2026 during the half-hour ending 1900 hrs. This was 671 MW (+23%) higher than the previous record of 2,885 MW, which was set in Q4 2025. Peak battery charging reached 2,742 MW this quarter, slightly below the record of 2,833 MW set in Q4 2025.

Battery revenue

In Q1 2026, estimated revenue[30] for NEM grid-scale batteries averaged $96.9 million, more than double the $44.0 million recorded in Q1 2025 (**Figure 57**). This increase was driven primarily by higher energy arbitrage revenue, which rose by $55.1 million (+142%) to $93.9 million.

[30] Battery revenue comprises revenue from energy arbitrage – calculated as revenue from energy discharged (including charging at negative prices) net of charging costs – and revenue earned from frequency control ancillary services (FCAS). This measure excludes FCAS costs incurred by batteries and Frequency Performance Payment (FPP) outcomes for batteries.

In contrast, frequency control ancillary services (FCAS) revenue declined to $3.0 million in Q1 2026, down $2.3 million (-43%) from the previous year. As a result, FCAS accounted for just 3% of total battery revenue this quarter, compared with 12% in Q1 2025. The energy market share increased to 97%, up from 88% a year earlier (**Figure 58**).

Figure 57 Significant increase in battery arbitrage revenue while FCAS revenue declined

Quarterly net revenue from NEM battery systems by revenue stream

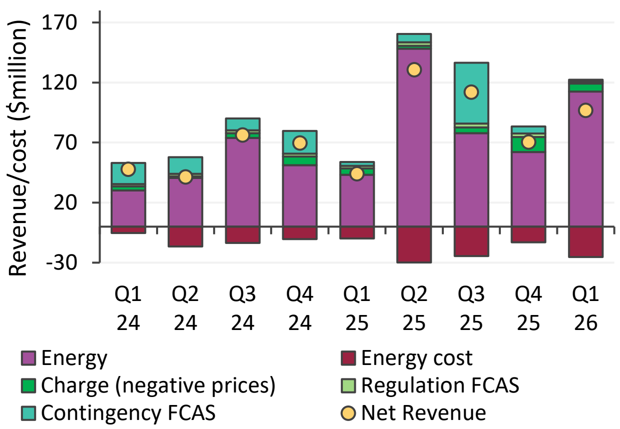
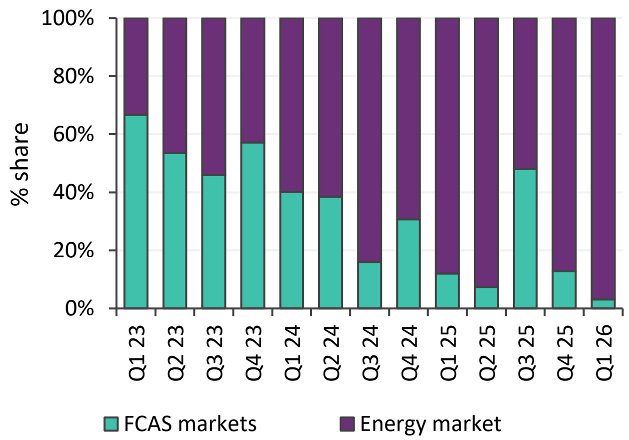


Figure 58 Battery revenue from FCAS markets dropped

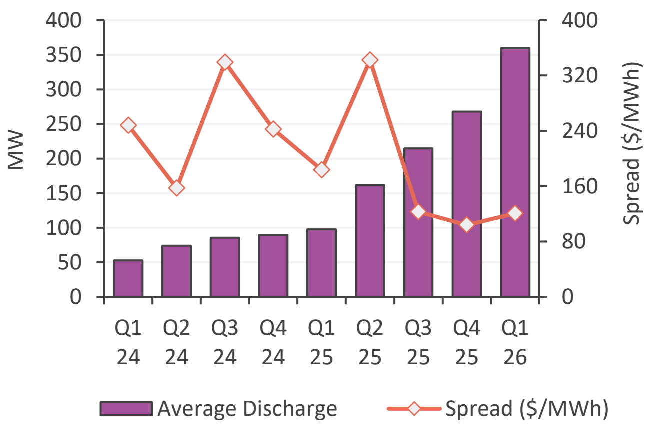
Percentage share of battery net revenue – energy vs FCAS markets



Higher energy arbitrage revenue, including revenue earned from charging at negative prices, reflected an increase in gross energy revenues, which rose by $70.8 million (+146%) to $119.3 million. This was partially offset by higher energy charging costs, which increased by $15.7 million (+161%) to $25.4 million.

Figure 59 Decrease in NEM-wide battery price spread with lower price volatility

Average quarterly battery discharge (MW) and price spread ($/MWh) [RHS]



Energy arbitrage revenue rose across all regions, with the strongest growth in South Australia (+$25.4 million) and New South Wales (+$14.3 million). Queensland and Victoria recorded increases of $8.0 million and $7.4 million respectively.

The increase in arbitrage revenue was largely driven by increased battery discharge while NEM-wide battery price spreads declined from $183/MWh in Q1 2025 to $121/MWh (**Figure 59**), reducing the value of arbitrage opportunities. This reflected lower spot price volatility in Q1 2026, which reduced the average spot prices earned by battery discharge (see Section 2.2.5) alongside higher average charging costs that compressed arbitrage margins across most regions.

Average price spreads declined sharply in Queensland and Victoria, falling by 68% and 41% to $78/MWh and $86/MWh, respectively. New South Wales recorded a more modest decline of 23% to an average of $101/MWh, while South Australia saw an increase of $125/MWh, averaging $328/MWh. Lower price spreads in most regions relative to Q1 2025 were driven by a combination of lower price volatility, higher middle-of-day prices and lower peak prices. In South Australia, volatility events supported wider price spreads and stronger arbitrage outcomes.

2.4.2 Pumped hydro

This section discusses pumped hydro generation, covering the Shoalhaven and Tumut 3 stations in New South Wales and Wivenhoe in Queensland. Revenue calculations include Shoalhaven and Wivenhoe only, with Tumut 3 excluded.

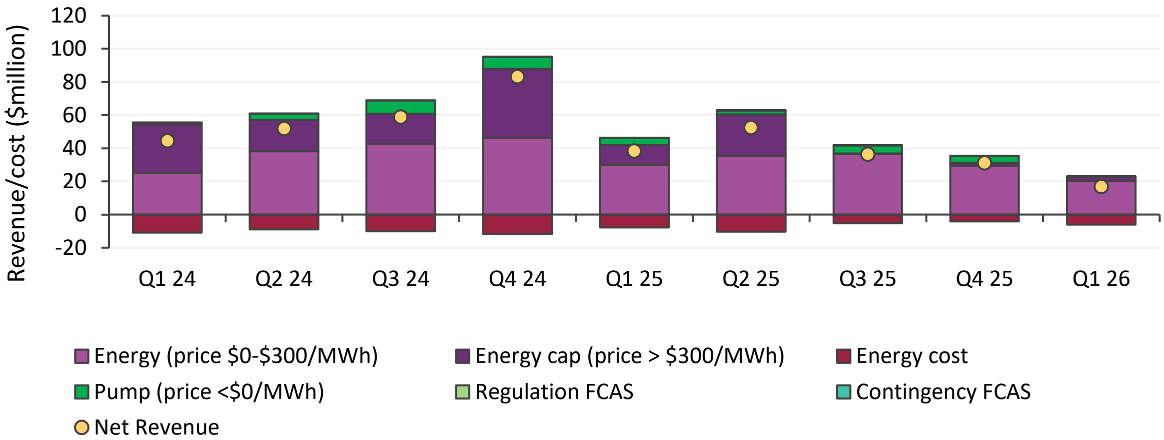
In Q1 2026, pumped hydro generation[31] averaged 130 MW, down 26 MW (-17%) from Q1 2025. This was driven by declines at Tumut 3 (-23 MW) and Wivenhoe (-5 MW), partially offset by a slight increase at Shoalhaven (+2 MW).

Pumped hydro revenue[32]

Estimated net pumped hydro revenue declined to $17.0 million this quarter, down $21.5 million (-56%) from Q1 2025 (**Figure 60**). This reduction was driven primarily by lower wholesale spot prices. In Queensland, reduced price outcomes lowered Wivenhoe's revenue by $20.2 million (-59%) to $14.0 million. In New South Wales, Shoalhaven's revenue fell by $1.2 million (-29%) to $3.0 million, reflecting eased price volatility compared with the same period last year.

Figure 60 Pumped hydro revenue decreased year-on-year

Quarterly revenue from NEM pumped hydro by revenue stream



2.4.3 Peak renewable and storage contribution

This section examines renewable and storage contribution to demand at a 30-minute level, reflecting the combined role of renewable generation and battery discharge in meeting demand at any point in time.

Peak renewable and storage contribution[33] in the NEM reached 76.7% during the half-hour ending 1130 hrs on Wednesday 7 January 2026. This was 4.3 pp higher than the previous Q1 outcome, but 1.9 pp below the all-time high of 78.6% recorded in October 2025 (**Figure 61**). At the time of this quarter's peak, distributed PV accounted for 40.6% of total generation, while grid-scale solar and wind contributed 19.8% and 14.2%, respectively.

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[31] Pumped hydro production for Tumut 3 was estimated by multiplying its pumping load by round-trip efficiency (78%) while for Wivenhoe and Shoalhaven actual generation was used.

[32] Pumped hydro revenue calculations include Shoalhaven and Wivenhoe only, with Tumut 3 excluded.

[33] Peak renewable contribution is calculated using the renewable share of total generation (either NEM-wide or regional). This measure is calculated on a half-hourly basis, because this is the granularity of estimated output data for distributed PV. Renewable generation includes grid-scale wind and solar, hydro generation (including pumped hydro), biomass, battery discharge and distributed PV. Total generation = large-scale generation + estimated PV output.

Maximum renewable potential reached 92.2% in the half-hour ending 1400 hrs on 1 January. This was 2.0 pp lower than the peak potential observed in Q1 2025 and 21.8 pp below the record high of 113.9% set in Q4 2025.

Figure 61 Peak renewable and storage contribution increased from Q1 2025 but was below Q4 2025's record high

Percentage of NEM supply from renewable energy sources and storage at time of peak renewable and storage contribution

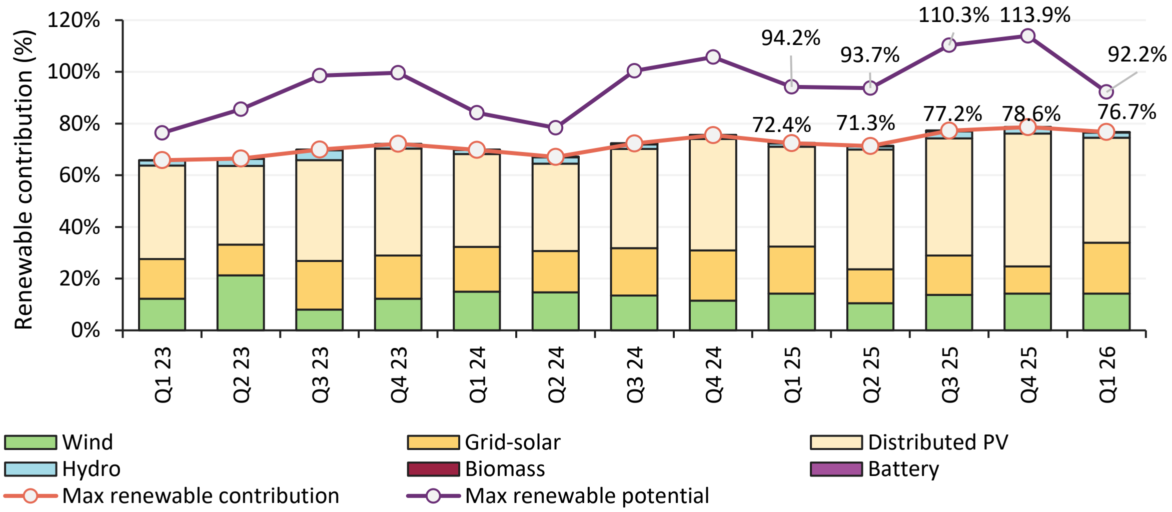


Figure 62 Higher maximum and minimum renewable and storage contribution

Range of NEM supply share from renewable sources and storage – Q1s

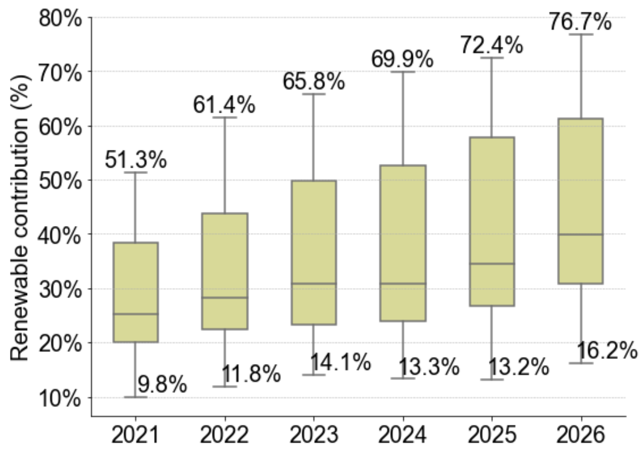


Figure 62 illustrates the quarterly range in renewable generation and storage contribution, which recorded a swing of 60.5 pp, from a high of 76.7% to a quarterly minimum of 16.2%. The minimum occurred in the half-hour ending 0430 hrs on Tuesday 10 March 2026 and was 3.0 pp higher than the Q1 2025 minimum of 13.2%.

By region, South Australia set a record for renewable generation and storage contribution this quarter, reaching 98.8% during the half-hour ending 1500 hrs on 31 January 2026. This was 0.1 pp higher than the previous record set on 10 September 2025.

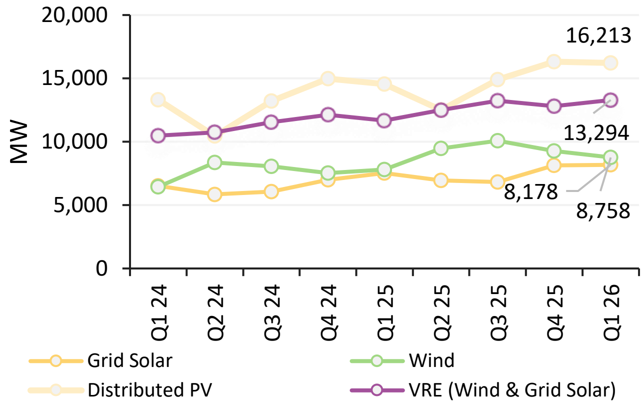
Maximum renewable output

Figure 63 highlights the highest quarterly peak half-hourly generation for grid-scale solar, wind, and distributed PV since Q1 2024. In Q1 2026, grid-scale solar reached a new record output of 8,178 MW in the interval ending 1130 hrs on Tuesday, 6 January 2026. This exceeded the previous peak of 8,148 MW, set in Q4 2025.

Peak VRE output, comprising wind and grid-scale solar, also reached a new record this quarter, at 13,294 MW in the half-hour ending 0930 hrs on Friday, 9 January 2026. This was 63 MW (+0.5%) higher than the previous record set in Q3 2025.

Figure 63 Record highs for grid-scale solar and combined VRE generation

Maximum quarterly peak (half-hourly) generation by fuel type

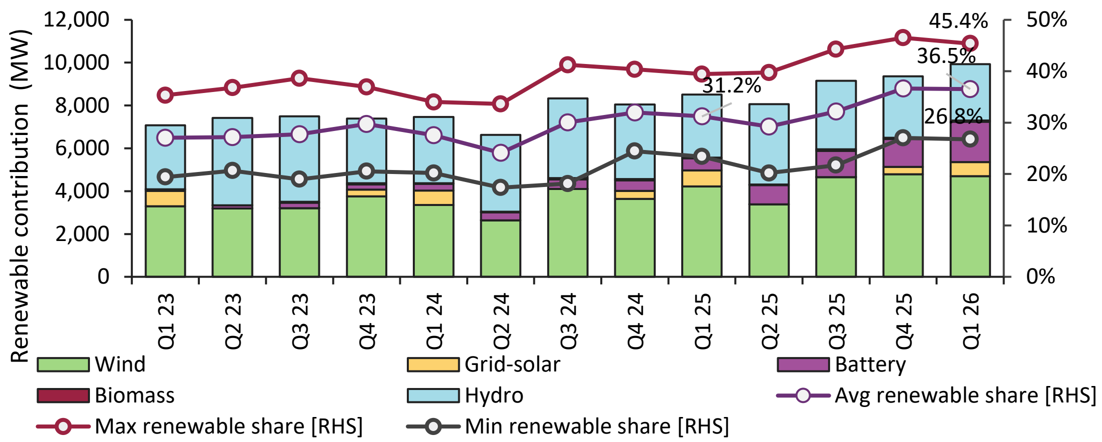


Renewable and storage contribution to maximum demand

Figure 64 shows the average share of large-scale renewable generation and storage in meeting daily maximum NEM operational demand, aggregated across all days in each quarter since Q1 2023[34].

Figure 64 Renewable and storage contribution increased at daily maximum demand

Maximum, minimum and average renewable share (%) and average renewable contributions (MW) at time of daily maximum operational demand – quarterly



In Q1 2026, the average renewable and storage contribution to daily maximum demand increased to 36.5%, up from 31.2% in Q1 2025. This increase was driven primarily by higher wind output, which supplied an average of 17.3% of daily maximum demand (+1.8 pp), and a marked increase in battery discharge, which contributed 7.0% (+4.9 pp). Over the quarter, the renewable and storage contribution to daily maximum demand ranged between 26.8% and 45.4%, reflecting variability in renewable output and demand conditions.

[34] For every day in the quarter, the half-hour of maximum NEM operational demand is found along with the contribution from large-scale renewables and storage to meeting that demand. These quantities are then averaged over all days in the quarter to compute the average renewable and storage contribution to supplying maximum demand.

2.5 New grid connections

New grid connections to the NEM follow a process which involves the applicant, network service provider (NSP) and AEMO. Prior to submission of a connection application with AEMO, the applicant enters the enquiry phase where the connecting NSP is engaged in the process. The key stages[35] monitored by AEMO to track the progress of projects going through the connections process include application, proponent implementation, registration, commissioning, and model validation.

During the past two quarters, the capacity of projects in application stage has grown (**Figure 65**), driven by a higher volume of applications submitted for connection in New South Wales and also larger average capacity for applications submitted across all NEM regions. The average size of applications received during Q1 2026 and Q4 2025 was 315 MW and during the four quarters preceding this it was 215 MW.

During the past year there has been an increase in standalone battery projects. Battery connections during this latest quarter made up 96% of applications approved (**Figure 66**). Batteries comprise 49% of the capacity of projects in the connections pipeline, with around 74% of batteries being grid forming.

Generation and storage project capacity in the pipeline has grown 33% in the past year from 50.5 GW to 67.3 GW. Growth came from batteries (62% increase), wind (17% increase), solar generation (17% increase) and hydro (10% increase).

During Q1 2026:

- 1.4 GW of applications were approved across eight projects.
- 1.8 GW of plant across nine projects were registered and connected to the NEM.
- 1.5 GW of plant across five projects progressed through commissioning to reach full output: Hunter Power Station (660 MW), Clarke Creek Wind Farm (440 MW), Swanbank BESS (250 MW/500 MWh), Limondale BESS (50 MW/400 MWh) and Wangaratta Solar Farm (22 MW).

Please see the Connections Scorecard[36] for further information.

At the end of Q1 2026, AEMO's snapshot of connection activities in progress shows that:

- 67.3 GW of new capacity was progressing through the end-to-end connection process from application to commissioning, 33% more than at the same time last year when 50.5 GW was in-progress. An influx of 18 new applications (5.5 GW) during the last quarter has contributed to this connection pipeline growth.
- Battery project capacity in the end-to-end connection process increased by 62% over the year, from 20.5 GW to 33.2 GW, comprising 25.3 GW grid-forming, 7.7 GW grid-following and 0.2 GW compressed air storage.
- Wind project capacity increased by 1.43 GW (from 8.32 GW to 9.75 GW). Projects with solar generation increased by 17% since last year (from 17.7 GW to 20.7 GW); of this capacity, 68% are hybrid solar plus battery projects. Gas decreased by 74% (from 0.9 GW to 0.2 GW) and hydro (3.0 GW) remained stable.
- The total capacity of in-progress applications increased by 51% from 19.7 GW to 29.8 GW.

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[35] Application stage establishes technical performance and grid integration requirements. In proponent implementation stage, contracts are finalised and the plant is constructed. AEMO is not involved in this stage. Registration stage reviews the constructed plant models for compliance with agreed performance standards. Once the plant is electrically connected to the grid, commissioning confirms alignment between modelled and tested performance.

[36] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard.

- 24.9 GW of generation and storage projects are finalising contracts and/or under construction (proponent implementation), compared with 19.9 GW last year (25% increase).

Figure 65 Increased capacity progressing through application stage driven by recent New South Wales applications

12-month trend [37] of connection capacity in progress

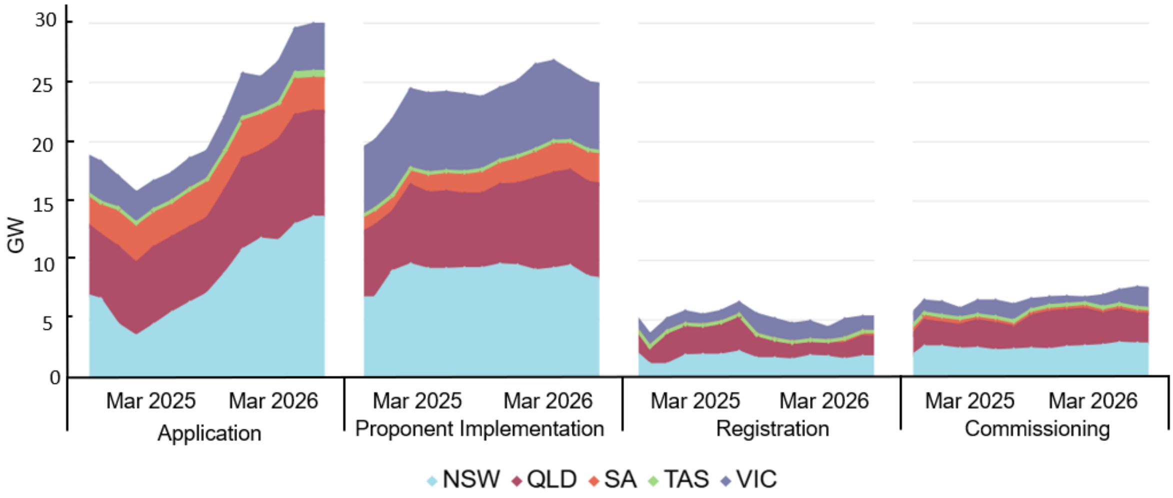
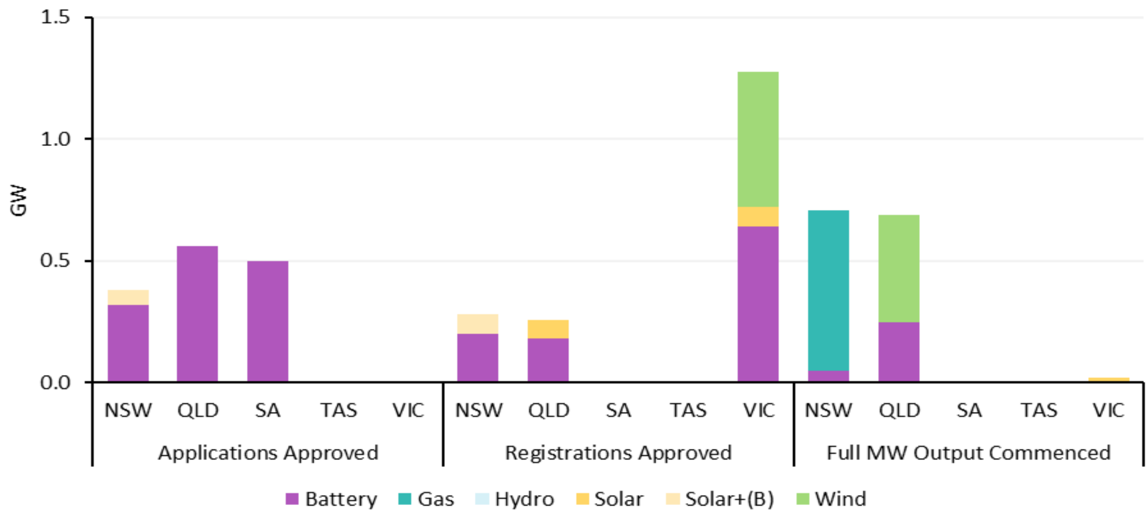


Figure 66 Strong quarter for registration approvals and steady progress for applications and commissioning

Application approved, registrations and plant commissioned to full output during Q1 2026



AEMO does not currently have a formal role in connecting data centre loads that are less than 5 MW and do not demonstrate potential for inverter control instability. However, AEMO does track progress through the connection process, which is managed by NSPs. The key stages monitored by AEMO to track progress of data centre load connections include application[38] , proponent implementation and commissioning.

[37] Charts are based on current data, and therefore some variances may exist compared to previously reported capacity in-progress.

[38] Only projects with an officially submitted connection application package to AEMO are reported. AEMO and NSPs are also supporting multiple proponents across New South Wales, Victoria, South Australia and Tasmania to prepare their project connection applications.

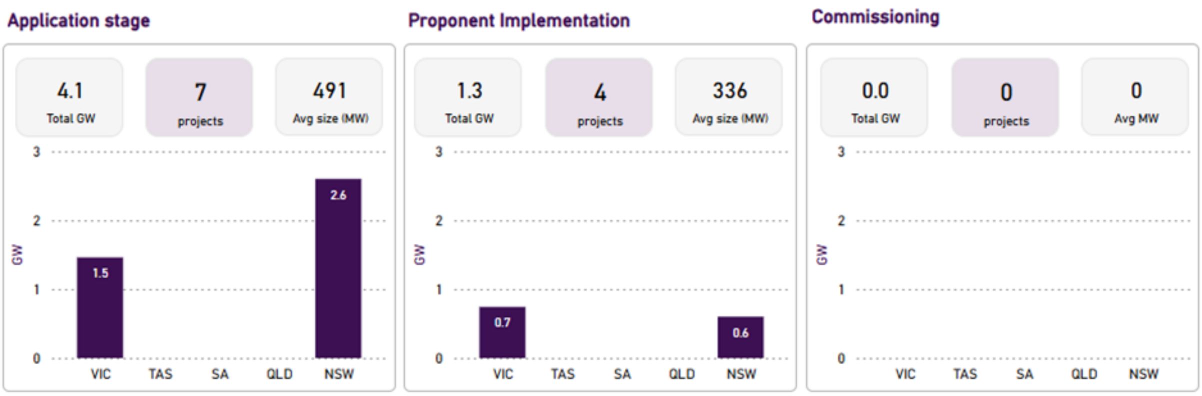
In Q1 2026, there are 11 data centres totalling 5.4 GW of maximum capacity load working through a transmission network connection (**Figure 67**). Of these:

- 60% of the capacity is in New South Wales and 40% in Victoria.
- Seven projects (4.1 GW) are currently in the application stage.
- Four projects (1.3 GW) have already received application approval and are now in proponent implementation stage.

AEMO is currently gathering comprehensive data regarding distribution connections, with the aim of publishing these in future. Given data centres fill up gradually, as customers and computing demand grow, the load for these data centres will ramp-up over a number of years. The outlook for all prospective data centre developments, which considers this ramp-up, is reported in the NEM Electricity Statement of Opportunities (ESOO)[39].

Figure 67 Data centre load connection applications submitted to AEMO

Number and capacity of data centre load connection applications submitted to AEMO



2.6 Inter-regional transfers

Total inter-regional transfers were 2,841 gigawatt hours (GWh) in Q1 2026, equivalent to 6.1% of operational demand, and a reduction of 338 GWh (-11%) from Q1 2025. The decrease was driven by a 613 GWh (-77%) reduction in net transfers between Victoria and Tasmania, partially offset by higher net transfers between mainland regions (**Figure 68**).

[39] Latest NEM ESOO can be found here: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

Figure 68 Reduction in inter-regional transfers between Victoria and Tasmania

Quarterly inter-regional transfers

Compared to Q1 2025, average net transfers on Basslink decreased by 236 MW, with transfers from Victoria to Tasmania reducing from an average of 338 MW to 78 MW (**Figure 69**). This reduction reflected the change in Basslink bidding observed since 1 July 2025. In Q1 2026, the majority of Basslink capacity to Tasmania (83%) was offered at prices between $75 to $150/MWh, with most of the remainder offered between $35 to $75/MWh (**Figure 70**). Almost half of Basslink capacity to Victoria (44%) was offered between $75 to $150/MWh, with the remaining capacity mostly split between offers priced between $15 to $35/MWh and $35 to $75/MWh.

Figure 69 Significant reduction in transfers from Victoria to Tasmania across all hours

Average Basslink flow by time of day

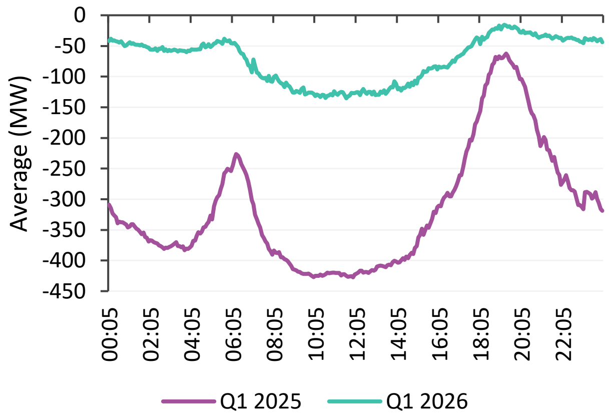
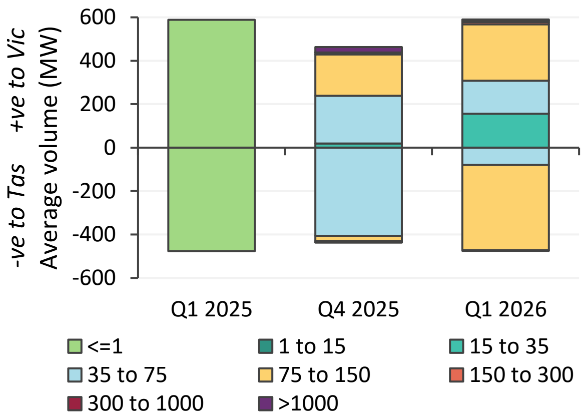


Figure 70 Majority of Basslink capacity offered at prices between $75 to $150/MWh

Basslink MNSP offers, average transfers capacity (MW) offered by price range ($/MWh)



Compared to Q1 2025, transfers into New South Wales increased from both Victoria (+182 MW) and Queensland (+72 MW), and transfers into South Australia from Victoria rose by 33 MW. The increase in transfers from Victoria and Queensland to New South Wales was most evident during overnight hours, consistent with changes in regional demands and price relativities. Higher overnight demands in New South Wales resulted in average spot prices that were $22/MWh above Victoria's and $2/MWh above Queensland's between 2200 hrs and 0600 hrs this quarter, compared to $14/MWh higher and $6/MWh lower respectively over the same period last year.

2.6.1 Inter-regional settlement residue (IRSR)

Positive IRSR totalled $119 million in Q1 2026, up from $84 million in Q1 2025 (**Figure 71**). The largest increase was into South Australia, where residues increased from $14 million to $57 million, with $39 million of this accruing on 6, 26 and 27 January when high priced volatility in South Australia coincided with imports from lower-priced Victoria (see **Table 2** in Section 2.2.2).

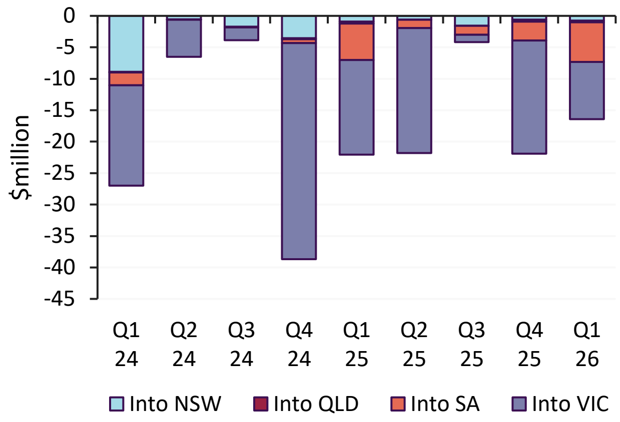
Negative IRSR decreased from -$22 million in Q1 2025 to -$16 million this quarter, with the largest reduction in residues into Victoria from New South Wales (**Figure 72**).

Figure 71 Large increase in positive IRSR into South Australia

Quarterly positive IRSR by region

Figure 72 Negative IRSR reduced year-on-year

Quarterly negative IRSR by region



2.7 Frequency control ancillary services (FCAS) and frequency performance payments (FPP)

Total FCAS costs were $14 million in Q1 2026, equivalent to approximately 0.4% of the cost of consumed energy[40] over the quarter. Compared to Q1 2025, NEM-wide FCAS costs increased by $0.3 million, with a $6.6 million increase in costs in Tasmania largely offset by decreases in all other regions (**Figure 73**). The contingency raise 6-second (R6SE) service contributed the largest proportion of total FCAS costs for the quarter, at $8.4 million (**Figure 74**).

Most of this cost occurred in Tasmania, where R6SE costs increased from $0.7 million in Q1 2025 to $8.2 million in Q1 2026. This outcome reflected an increase in the number of intervals where Basslink was unable to transfer FCAS[41] due to flow levels being within its 'No-Go' zone of approximately -50 MW to 50 MW. The share of these intervals increased from 2% in Q1 2025 to 42% in Q1 2026, consistent with the change in Basslink's bidding behaviour discussed in Section 2.6.

[40] Where the cost for consumed energy is the Adjusted Consumed Energy (ACE) amount which comprises the costs for both the total consumed energy and the unaccounted-for energy allocation.

[41] For additional detail on Basslink's capability to transfer FCAS, see Section 5.8 of AEMO's Constraint Formulation Guidelines: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/cfg-and-scvpf/final/constraint-formulation-guidelines-v12---final_.pdf.

Figure 73 FCAS costs decreased in all regions except Tasmania

Quarterly FCAS costs by region

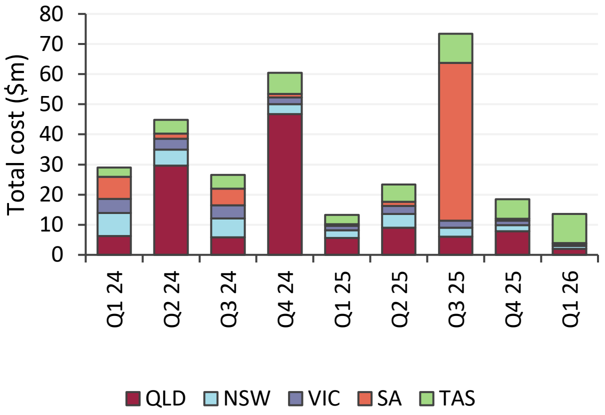
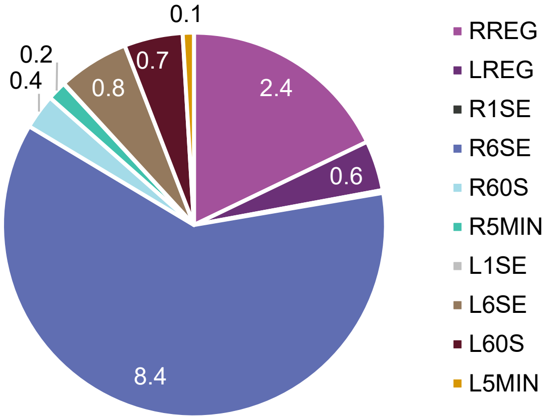


Figure 74 R6SE accounted for 65% of the total FCAS costs

NEM quarterly FCAS costs per service – Q1 2026 ($m)



Battery enablement continued to be the dominant source technology providing FCAS, with volume share rising from 59% in Q1 2025 to 66% this quarter (**Figure 75**). Average enablement of batteries rose by 571 MW from Q1 2025, with the largest enablement increases recorded at new entrants Melbourne Renewable Energy Hub (+430 MW), Tarong (+270 MW), Latrobe Valley (+194 MW), and Smithfield (+192 MW). Hydro increased enablement in the contingency lower services (+92 MW), while DR increased enablement in the contingency raise services (+46 MW). Other fuel types reduced enablement, with the largest decrease in black coal (-138 MW) and followed by virtual power plants (VPPs) with a 33 MW reduction (**Figure 76**).

Figure 75 Battery FCAS market share rose to over 65%

FCAS volume market share by technolology – Q1 2026

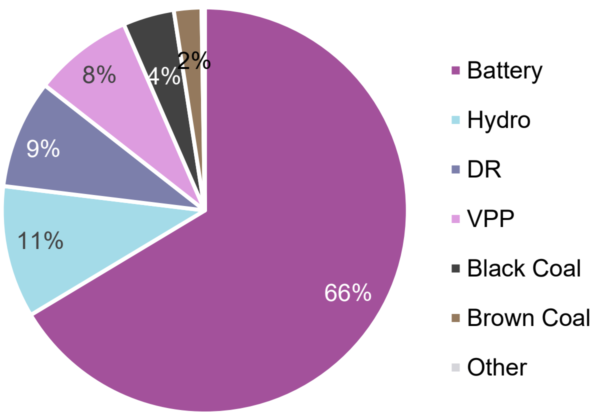
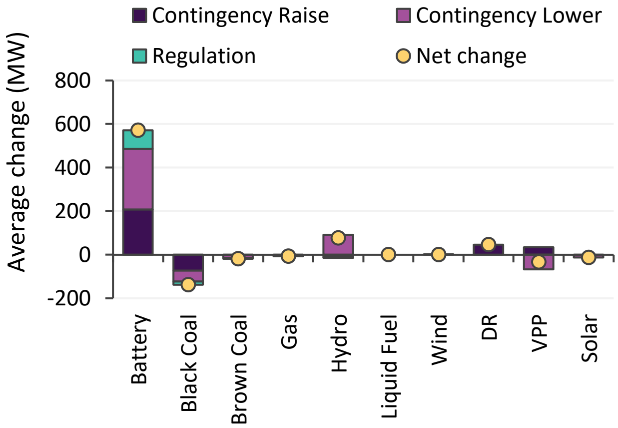


Figure 76 Increase in battery enablement across all FCAS services

Change in FCAS enablement by technology – Q1 2026 vs Q1 2025

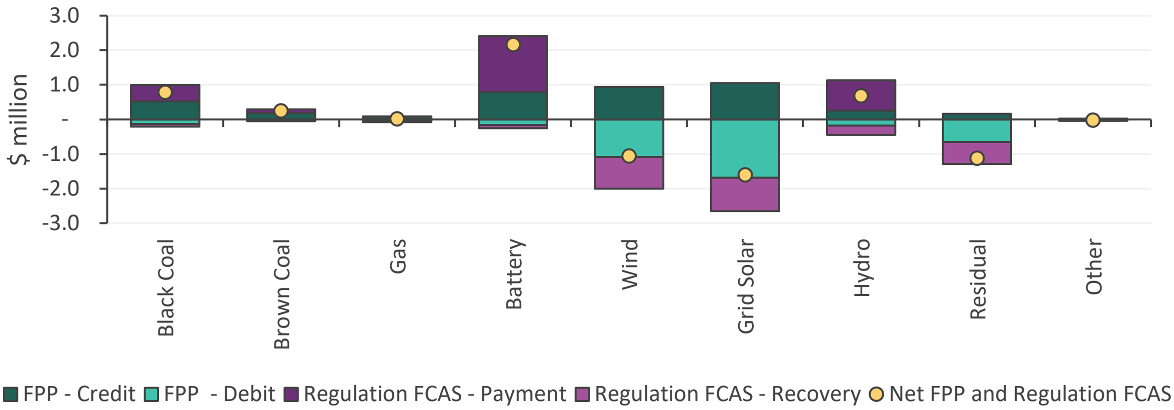


Regulation FCAS and frequency performance payments (FPPs)

In Q1 2026, costs for regulation FCAS were $3.0 million, $2.6 million (-22%) lower than in Q1 2025, and a total of $4.0 million in FPP incentive payments were distributed. **Figure 77** shows the FPP credits and debits, and regulation FCAS payments and cost recovery by fuel type in Q1 2026.

Figure 77 Batteries received highest share of FPP and FCAS net settlements

Sum of Frequency Performance Payments (FPP) and regulation FCAS recovery and payments by fuel type – Q1 2026



For batteries, hydro, black and brown coal-fired and gas-fired units, combined FPP credits and regulation FCAS payments offset the combined FPP debits and regulation FCAS recovery costs, with batteries receiving the large share of overall net settlements at $2.2 million. Grid-scale solar units incurred the largest share of charges, with -$1.6 million in total net FPP and regulation FCAS settlements. Wind units and the residual category (which includes sites without appropriate metering to calculate individual contribution factors, such as small consumers and distributed resources) both recorded -$1.1 million in net charges.

2.8 Power system management

In Q1 2026, directions to registered participants were required for minimum system load (MSL) management and voltage control services in South Australia. Additionally, network support and control ancillary services (NSCAS) agreements were activated for voltage control in South Australia, and Type 1 transitional service contracts were activated for MSL management in Victoria[42].

Estimated power system management costs[43] were $19.4 million in Q1 2026, representing approximately 0.6% of the total cost of consumed energy for the quarter, and a reduction from Q1 2025's costs of $40.8 million (**Figure 78**). No costs were associated with short notice reserve or interim reliability reserve (IRR)[44] under the Reliability and Emergency Reserve Trader (RERT) mechanism this quarter[45], compared to $19.1 million in IRR costs in Q1 2025.

[42] Details on the MSL Type 1 Transitional Service Request for Offer procurement process for Victoria can be found here: AEMO | Minimum System Load Transitional Services for Victoria and South Australia.

[43] 'Power system management costs' are those associated with Reliability and Reserve Trader (RERT), estimated compensation for system security directions for energy services, costs associated with NCSAS for voltage control and costs associated with Type 1 transition contracts. Costs associated with reliability directions (including those to maintain a state of charge) and system security directions for other services (that is, operating as synchronous condenser) are not included because current quarter cost estimates are not available at the time this report is prepared. All direction reports are available on AEMO's website at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/market-event-reports.

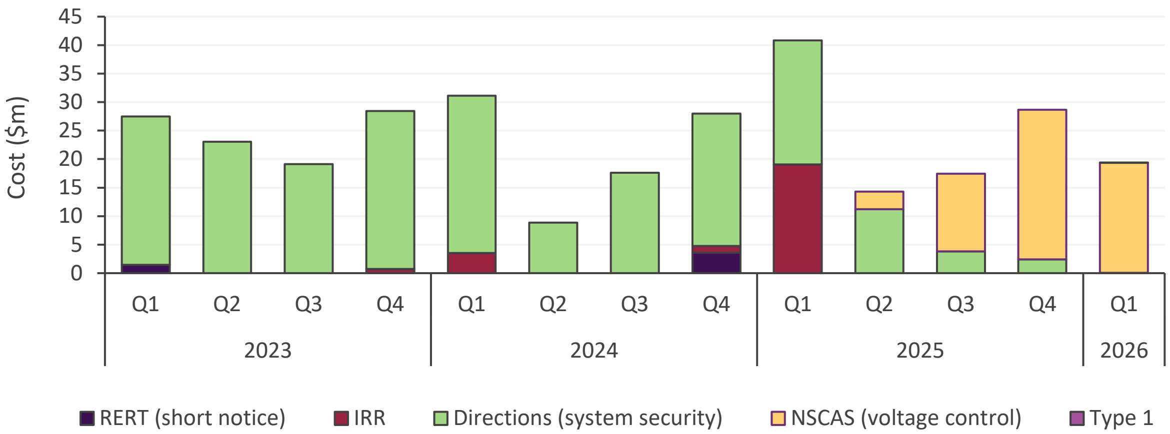
[44] IRR was enabled under National Electricity Rules clause 11.128 which expired on 31 March 2025 after which new IRR contracting is no longer permitted. The QED continues to report IRR costs for periods in which IRR contracts were active prior to the expiry of the mechanism.

[45] AEMO, RERT Reporting, at https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

The Q1 2026 cost shown includes an estimated $19.4 million for voltage control in South Australia (combined costs for system security energy directions[46] and NSCAS costs), along with an estimated $0.01 million for Type 1 transitional services in Victoria to manage MSL. Estimated costs associated with directions to manage MSL in South Australia are not yet available and are not included in the overall cost estimates.

Figure 78 Reduction in estimated power system management costs

Estimated quarterly system security costs by category



2.8.1 South Australian voltage control

NSCAS services are primarily used to manage voltage control in South Australia, with directions issued only as a last resort when contracted services are insufficient. In Q1 2026, the overall percentage of time in which gas-fired generation was dispatched under contract (or directed when necessary) for voltage control reduced from 61% of dispatch intervals in Q1 2025 to 54% this quarter (**Figure 79**). This included just 1% of intervals with directions in place. Additionally, the proportion of time that two or more units were required simultaneously for voltage control decreased from 47% to 29% of dispatch intervals, in-line with the change in South Australian operating condition requirements implemented during Q3 2025[47].

As a result, the overall volume of gas-fired generation required to be online for voltage control, either under contract or via direction, reduced from 45 MW in Q1 2025 to 36 MW this quarter (**Figure 80**). However, with the overall reduction in gas-fired generation in South Australia this quarter in response to market conditions (see Section 2.3.2), the proportion of total output that was dispatched for voltage control increased from 16% in Q1 2025 to 19% this quarter.

[46] Participants directed for energy or market ancillary services receive an initial compensation amount determined using a price calculated as the 90th percentile of the relevant market prices over a trailing 12-month window. Directed participants may also make a claim for additional compensation to cover loss of revenue and net direct costs minus trading amounts for energy and market ancillary services and minus any compensation for directed services that has already been determined by AEMO.

[47] See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/related-resources/reduction-of-minimum-synchronous-generators-in-south-australia.pdf.

Figure 79 Decrease in two-unit requirement for voltage control

Percentage of time units simultaneously used for voltage control

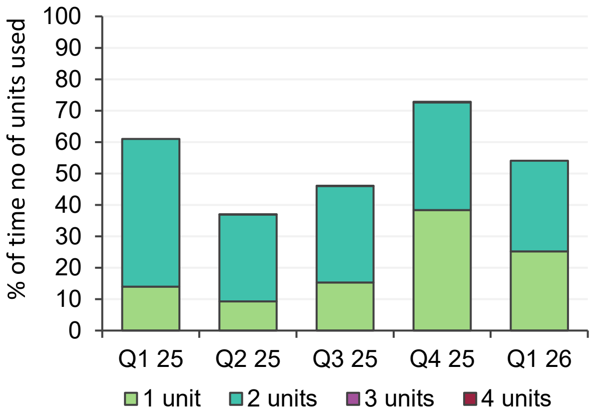
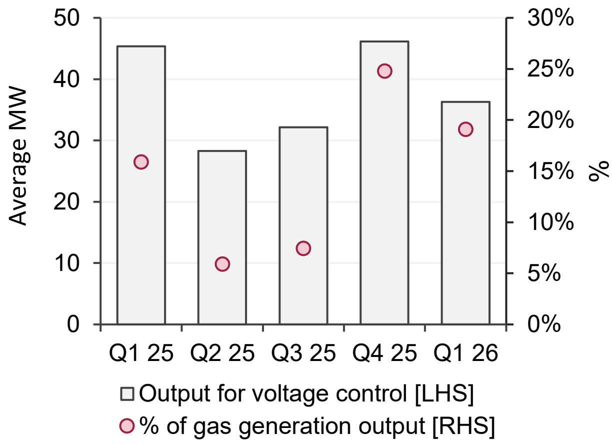


Figure 80 Reduction in South Australian gas generation use for voltage control

South Australian gas-fired generation for voltage control – volume and share



2.8.2 Minimum system load management in South Australia and Victoria

High distributed PV output combined with low underlying demand can significantly reduce operational demand on the transmission system, leading to MSL conditions[48]. Record distributed PV output during the quarter resulted in multiple MSL declarations in South Australia and Victoria[49], including two instances of forecast MSL2[50] and two actual MSL2 conditions in South Australia and one forecast MSL2 in Victoria.

Under MSL2 conditions, grid-scale action such as reducing grid-scale generation, increasing electricity demand by large users or procuring[51] or directing re-secure reserves, are required to ensure the system will remain in a satisfactory state and can return to a secure state within 30 minutes of a credible load contingency.

In Q1 2026, AEMO issued directions on three days to participants in South Australia to provide MSL management services after detecting an elevated risk of insufficient demand to maintain a secure operating state (that is, under actual or active forecast MSL2 conditions). In these instances, grid-scale batteries (Torrens Island on 1 January and 9 March and Blyth on 8 March) first reached and then held a pre-agreed low state of charge, providing sufficient headroom to increase demand in the event of a credible load contingency. Additionally, Type 1 transitional services were used to manage MSL conditions in Victoria on 1 January.

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[48] AEMO, Minimum System Load Factsheet. September 2025: https://www.aemo.com.au/learn/energy-explained/fact-sheets/minimum-system-load.

[49] AEMO's Lack of Reserve Framework Quarterly Reports including reporting on MSL events are at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/power-system-operation/nem-lack-of-reserve-framework-quarterly-reports.

[50] For more information on MSL thresholds see https://www.aemo.com.au/-/media/files/initiatives/der/managing-minimum-system-load/2025-spring-and-summer-minimum-system-load-thresholds-fact-sheet.pdf?rev=dd9ee8c543cb438f8573f04e355b53b5&sc_lang=en.

[51] AEMO published a Statement of Need to acquire MSL transition services in South Australia, Victoria, New South Wales and Queensland in November 2025: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/minimum-system-load---type-1-transitional-service.

3 East coast gas market dynamics

3.1 Wholesale gas prices

Quarterly wholesale gas prices averaged $10.61/GJ across all markets in Q1 2026, down 20% from the Q1 2025 price of $13.26/GJ, which was the highest average Q1 price on record. Prices were also 16% lower than Q4 2025 (**Table 6)**.

Table 6 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q1 2026	Q4 2025	Q1 2025	Change from Q1 2025
Victoria Declared Wholesale Gas Market (DWGM)	10.50	12.02	12.18	-14%
Adelaide	10.61	12.82	13.51	-21%
Brisbane	10.56	12.95	13.64	-23%
Sydney	10.65	12.82	13.33	-20%
Gas Supply Hub (GSH)	10.63	12.76	13.63	-22%

Key factors influencing the movement of prices throughout Q1 2026 are summarised in **Table 7**, with further analysis and discussion in relevant sections elsewhere in this report.

Table 7 Wholesale gas price levels: Q1 2026 drivers

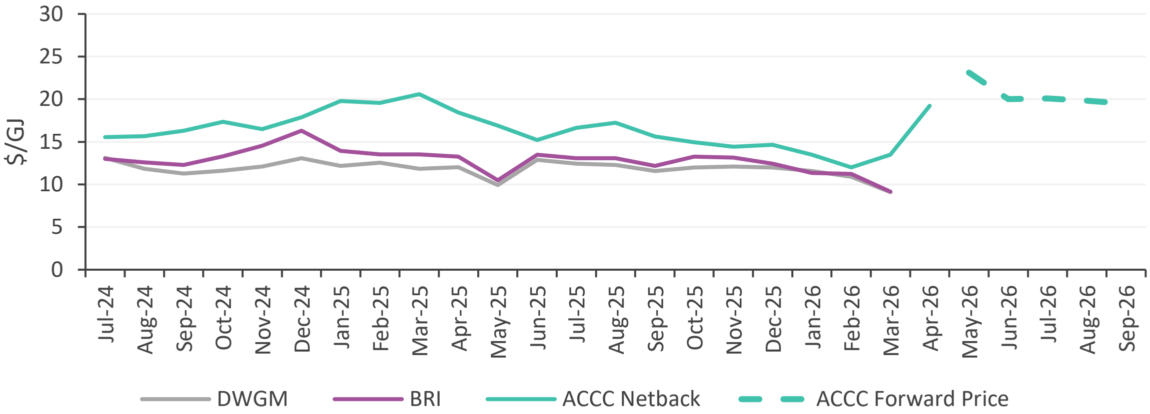
Increase in gas flows to southern markets from Moomba	Moomba's production was similar to Q1 2025, but net northward transfers on the South West Queensland Pipeline (SWQP) dropped significantly. This decline was driven by reduced demand from Gladstone LNG (GLNG) exports and lower flows to Mt Isa via the Carpentaria Gas Pipeline (CGP). This additional southern supply replaced Longford and Otway production in Victoria despite both plants having spare capacity for much of the quarter.
Market participant bidding behaviour change in March	While there was an increase in offers below $12/GJ in January and February compared to 2025, a significant shift in market participant offer prices in AEMO markets occurred from the start of March. A large increase in volume priced below $10/GJ was observed, leading to significantly lower prices across the entire month.
Record low gas-fired generation demand	Similar to Q4 2025, demand from gas-fired generation dropped to record low levels due to increased wind output and battery discharge in the NEM. This put downward pressure on spot prices across all AEMO markets, particularly in March where low gas-fired generation demand combined with a change in market participant bidding behaviour.

International LNG spot prices were at their lowest level since April 2024 during February, reflected in a decrease in the Australian Competition and Consumer Commission (ACCC) netback price to $12/GJ, close to the average AEMO market price of $11.74/GJ. Prices were materially higher than prices observed in the east coast gas market from the start of March, amid heightened global supply risks linked to the conflict in the Middle East. This conflict resulted in a rapid increase in global energy prices, reflected in a sharp increase in the ACCC netback price, with corresponding forward prices ranging from $23.69/GJ to $25.20/GJ over the next six months (**Figure 81**). Drivers for international prices are discussed in Section 3.1.1.

AEMO market prices did not follow international markets, however, and in fact decreased significantly in March across all markets, with the average price across all markets dropping to $9.22/GJ. This was the lowest average price for any month since January 2022. Lower domestic prices reflected increased supply to southern markets from Moomba, combined with continued low demand, particularly from gas-fired generation.

Figure 81 Domestic prices decreased in March while international prices increased sharply

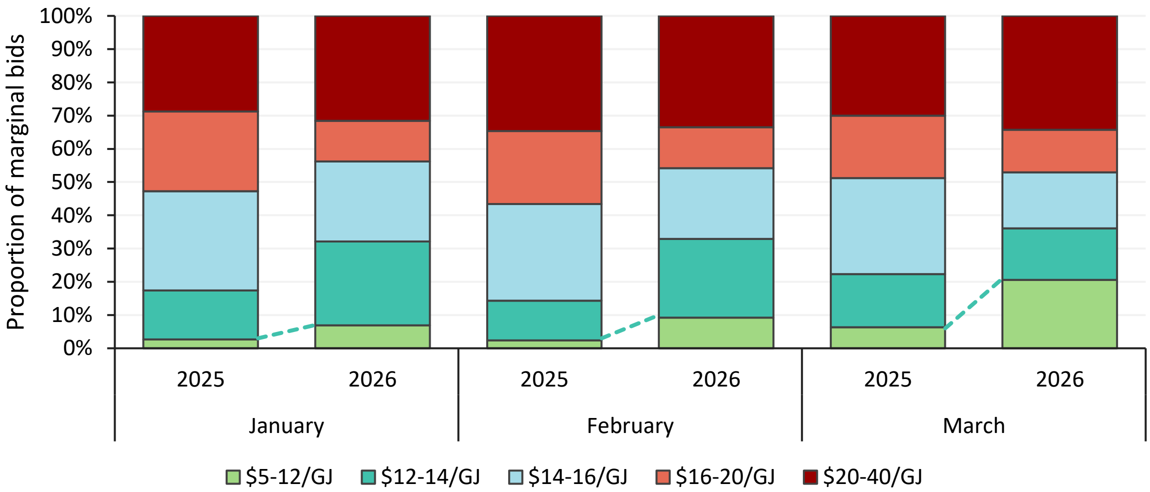
ACCC netback and forward prices[52], DWGM and STTM Brisbane average gas prices by month



Compared to Q1 2025, there was a significant increase in the proportion of DWGM bid volumes below $12/GJ, particularly in March where there was a large increase in offers below $10/GJ (**Figure 82**). Factors contributing to this include decreased exports from Victoria, particularly to New South Wales which saw a large increase in southerly flows from Moomba. Record low gas-fired generation demand across the east coast was also a contributing factor.

Figure 82 Increased proportion of DWGM bids at lower prices compared to 2025, particularly in March

DWGM – proportion of marginal bids by price band – Q1 2026 vs Q1 2025 by month



3.1.1 International energy prices

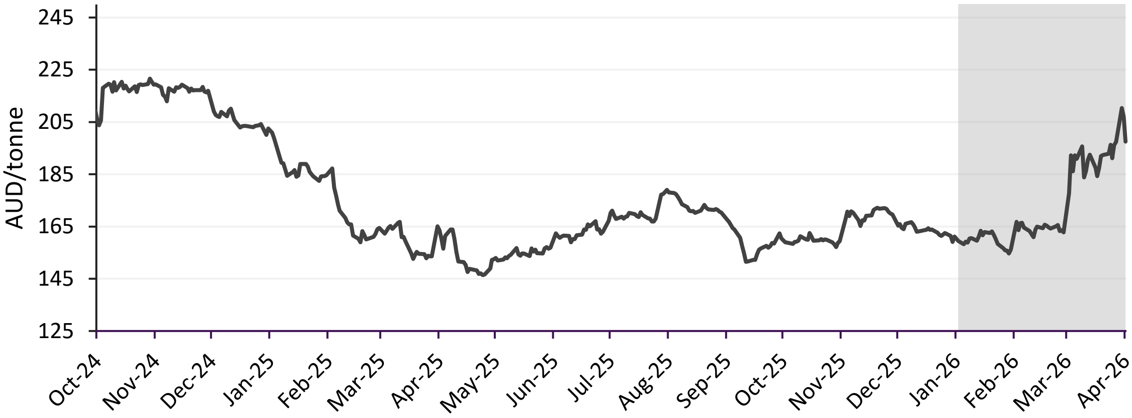
In Q1 2026, Newcastle export coal prices increased sharply, rising from $159/tonne at the start of the quarter, to a peak of at $210/tonne in late March, largely driven by the conflict in the Middle East (**Figure 83**). Disruptions to oil and LNG shipments through the Strait of Hormuz, including the halt of Qatar's major LNG exports, triggered a global energy supply

[52] ACCC, LNG netback price series published on 16 April 2026: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

shock that lifted gas and oil prices. Utilities across Asia responded by increasing coal-fired generation[53], supporting stronger demand for Australian thermal coal. Gas to coal switching and elevated energy security concerns sustained higher coal prices through the quarter.

Figure 83 Traded thermal coal prices rose sharply during the quarter

Newcastle 6,000 kcal/kg thermal coal price in A$/Tonne daily



Source: Bloomberg ICE data

Asian LNG prices (**Figure 84**) rose sharply, peaking at A$29.10/GJ before easing to A$27.10/GJ by the end of the quarter (more than doubling the price at the end of Q4 2025). In mid-January, Asian LNG spot prices recorded a modest increase, driven by a cold snap in the Northern Hemisphere that resulted in short-lived volatility across Asian LNG, U.S. and European gas markets[54]. This price movement was brief, with prices returning to late-Q4 2025 levels relatively quickly.

Figure 84 Asian LNG prices volatile as transit through the Strait of Hormuz is constrained

Asian LNG price in A$/GJ daily

Source: Bloomberg ICE data

[53] Asia pivots to coal as Middle East conflict chokes LNG supply, March 2026: https://www.reuters.com/sustainability/boards-policy-regulation/asia-pivots-coal-middle-east-conflict-chokes-lng-supply-2026-03-17/.

[54] Asia spot prices rise as cold weather forecasts lift demand, January 2026: https://www.reuters.com/business/energy/asia-spot-prices-rise-cold-weather-forecasts-lift-demand-2026-01-16/.

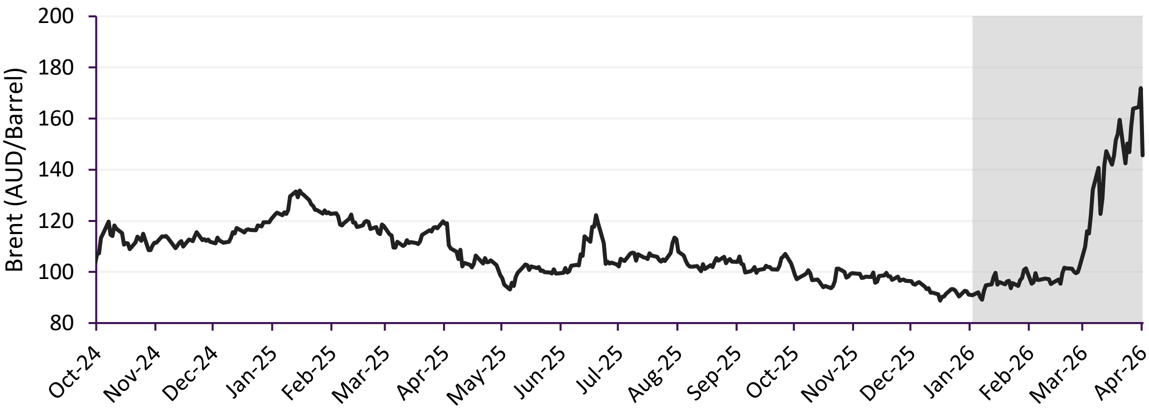
On 1 March, Asian LNG spot prices increased sharply amid a military escalation in the Middle East. The LNG market felt an immediate supply shock as vessel movements were constrained in and out of the Strait of Hormuz. QatarEnergy's Ras Laffan liquefaction facility (which accounts for 20% of global LNG supply in 2025) suspended operations and declared force majeure on some of their LNG sale and purchase agreements. Subsequent escalation included multiple strikes on regional energy infrastructure, including (but not limited to) damage to QatarEnergy's Ras Laffan liquefaction facilities[55]. Spot LNG prices in Asia surged, more than doubling from the end of February, and buyers (particularly in emerging Asian nations) began curtailing gas demand.

Over calendar year 2025, approximately 89% of Qatar's LNG exports were directed to Asia, whereas Europe accounted for around 7-9%. At the end of Q1 2026, European gas storage levels had declined to 27.7% of maximum capacity, near a five-year low. There have already been instances of United States (US) LNG cargoes bound for Europe that have been redirected toward Asia[56] and as Europe enters the storage refill period (alongside the planned suspension of Russian LNG and pipeline gas imports), Asian LNG spot prices may remain subject to increased volatility while constraints on transit through the Strait of Hormuz persist.

Similar to price volatility in Asian LNG spot market, Brent Crude oil followed a near identical trend (**Figure 85**). Roughly 20% of all global crude oil and condensate require the Strait of Hormuz to be open. While some countries (such as Saudi Arabia and the United Arab Emirates [UAE]) have the option to redirect supply via alternative routes (such as the East West Petroline and the Habshan Fujairah pipeline respectively); other nations like Kuwait, Iraq, Bahrain and Iran have little to no alternatives to supply crude oil to the global market[57].

Figure 85 Brent Crude oil prices surge to the largest quarter on quarter increase dating back to 1988

Brent Crude Oil in A$/Barrel daily



Source: Bloomberg ICE data

In response to the supply disruption and price volatility as a result of the events in the middle east, on 11 March International Energy Agency (IEA) member countries (including Australia) agreed to make available emergency reserves to

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[55] Iran attacks wipe out 17% of Qatar's LNG capacity for up to five years, March 2026: https://www.reuters.com/business/energy/iran-attack-damage-wipes-out-17-qatars-lng-capacity-three-five-years-qatarenergy-2026-03-19/.

[56] Fuel tankers divert to Asia in threat to British supplies, March 2026: https://www.telegraph.co.uk/business/2026/03/10/fuel-tankers-divert-to-asia-in-threat-to-british-supplies/.

[57] Strait of Hormuz Factsheet, February 2026: https://www.iea.org/about/oil-security-and-emergency-response/strait-of-hormuz.

the market[58]. Even though this was done early in the month, continued escalation of attacks on energy infrastructure in the region and the remerging risk of Yemen's Houthi rebels targetting commercial and naval vessels in the Red Sea and the Bab-al Mandab Strait led to the largest quarter on quarter price increase in the Brent crude oil market (on an inflation-adjusted basis) dating back to 1988[59].

3.2 Gas demand

Total east coast gas demand decreased by 1% compared to Q1 2025 (**Figure 86** and **Table 8**). Gas-fired generation saw the largest decrease (-5 PJ), falling to record low levels, followed by Queensland LNG production (-1.4 PJ). AEMO markets saw a small increase in overall demand (+0.6 PJ), mainly due to Sydney STTM demand increase (+0.5 PJ) due to an increase in industrial demand.

Figure 86 Large reduction in gas-fired generation

Components of east coast gas demand change – Q1 2026 to Q1 2025

Table 8 Gas demand – quarterly comparison

Demand (PJ)	Q1 2026	Q4 2025	Q1 2025	Change from Q1 2025
AEMO markets *	45.4	57.1	44.8	1 (+1%)
Gas-fired generation **	13.3	14.8	17.8	-5 (-26%)
Queensland LNG	364.6	372.5	366.0	-1 (0%)
Total	423.3	444.4	428.6	-5 (-1%)

* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand decreased slightly compared to Q1 2025 due to a decrease in Gladstone LNG (GLNG) demand, which was offset by increases in Australia Pacific LNG (APLNG) and Queensland Curtis LNG (QCLNG) demand. The combined total of 364.6 PJ is the third highest LNG export demand for Q1, with the record set in Q1 2024 (**Figure 87**).

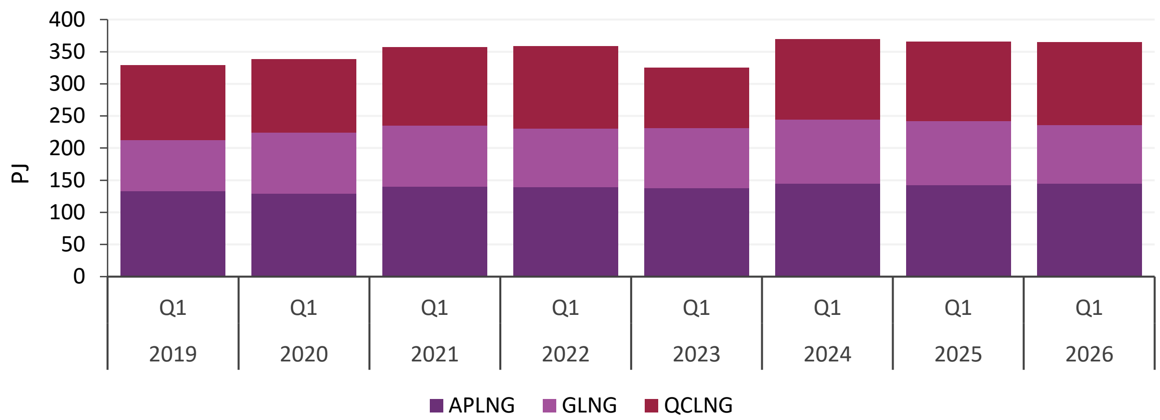
[58] Update on IEA collective action decision of 11 March 2026: https://www.iea.org/news/update-on-iea-collective-action-decision-of-11-march-2026.

[59] Brent eyes record monthly rise; US crude settles for above $100 as Houthis join Iran war: https://www.reuters.com/business/energy/oil-prices-jump-after-yemeni-houthis-attack-israel-widening-iran-conflict-2026-03-29/.

By participant, in comparison to Q1 2025, GLNG decreased by 9.3 PJ, while QCLNG increased by 5.3 PJ and APLNG increased by 2.7 PJ. GLNG's total of 90.8 PJ was its lowest Q1 export demand since 2019.

Figure 87 Lowest Q1 GLNG demand since 2019 leading to slightly lower Queensland LNG production

Total quarterly pipeline flows to Curtis Island – Q1



3.2.1 Gas-fired generation

Gas-fired generation decreased by 26% compared to Q1 2025 (**Figure 88**). The largest declines were in Queensland (-1.9 PJ) and South Australia (-1.4 PJ). Lower demand for gas-fired generation reflected higher wind output and battery discharge in the NEM, particularly during the evening peak (see **Figure 34** in Section 2.3). The significant decreases across all months led to the lowest Q1 demand for gas-fired generation since Q1 1999 (**Figure 89**).

Figure 88 Daily gas-fired generation below 2025 levels

Average daily gas-fired generation by state

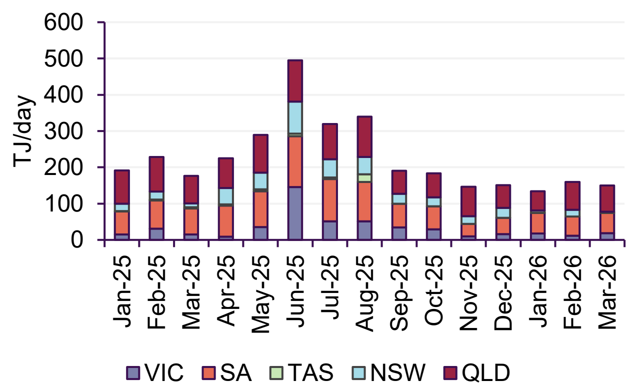
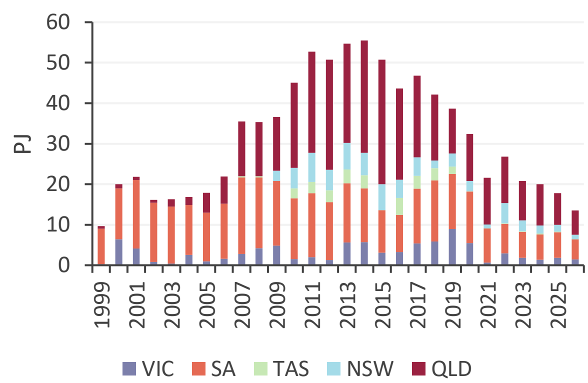


Figure 89 Lowest Q1 gas-fired generation since 1999

Q1 gas-fired generation by state



3.2.2 Victorian Declared Wholesale Gas Market (DWGM) demand

In the Victorian DWGM, Tariff D customers are defined as large commercial and industrial users that consume more than 10 terajoules per year (TJ/y) or more than 10 gigajoules per hour (GJ/h) of gas. These customers typically have flat consumption profiles across a year, with their gas consumption often linked to economic conditions. They are also generally less sensitive to weather conditions than residential and small commercial gas users (known as Tariff V customers).

Q1 2026 saw a continuation of Tariff D demand decrease, with demand decreasing from 11.7 PJ in Q1 2025 to 11.1 PJ in Q1 2026, a 6% decrease (**Figure 90**).

Figure 90 Victorian industrial demand continues to decline year on year

Q1 DWGM Tariff D demand

3.3 Gas supply

3.3.1 Gas production

East coast gas production decreased by 11.2 PJ (-3%) compared to Q1 2025 (**Figure 91**). Key changes included:

- Victorian production decreased by 9.2 PJ, driven by decreases in Longford production (-6.4 PJ) and Otway (-3.3 PJ), and smaller decreases at Athena (-0.2 PJ) and Bass Gas (-0.2 PJ). Orbost was the only Victorian facility to increase (+0.9 PJ).
- Queensland production decreased by 1.9 PJ, with assets operated by APLNG decreasing by 2.7 PJ and GLNG operated assets decreasing by 0.3 PJ, while QCLNG operated assets increased by 1.8 PJ. Gas demand for Queensland LNG exports decreased by 1.4 PJ, resulting in 0.5 PJ less net supply associated with Queensland LNG projects entering the domestic market compared to Q1 2025. This represents the lowest domestic market supply for Q1 since 2017 (**Figure 92**).

Figure 91 Victorian supply decrease mainly due to lower Longford and Otway production

Change in east coast gas supply – Q1 2026 vs Q1 2025

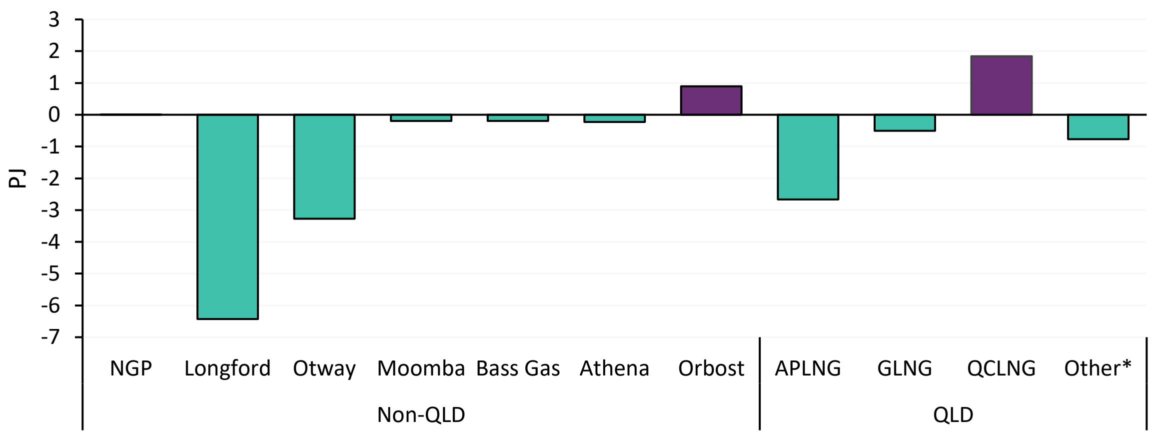
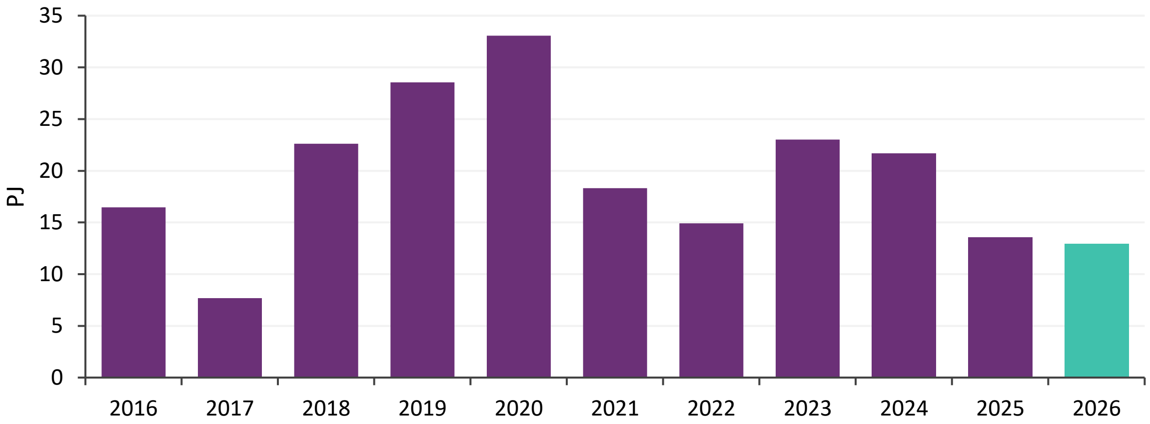


Figure 92 Queensland Q1 2026 net domestic supply slightly lower than Q1 2025 and lowest since 2017

Queensland net domestic supply during Q1



3.3.2 Northern Territory supply

As reported previously, the Northern Territory continues to be supported by emergency gas from the Ichthys LNG facility while the Yelcherr Gas Plant remains shut down due to the offshore Blacktip gas field platform outage caused by Tropical Cyclone Fina in November 2025. Capacity at the Yelcherr Gas Plant is zero for the foreseeable future.

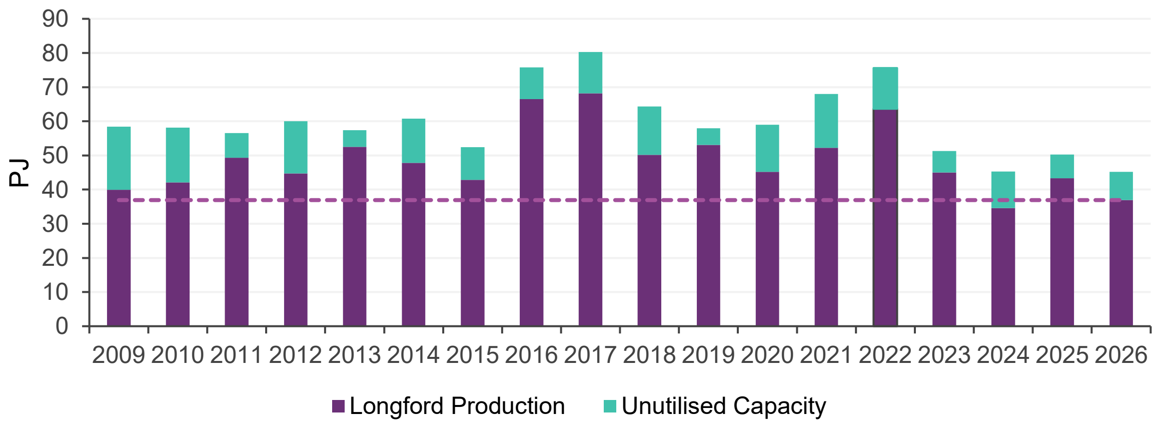
The Northern Gas Pipeline (NGP) is set in western flow mode, with an available capacity of 60 TJ/day from Mt Isa to Tennant Creek (see Section 3.4).

3.3.3 Longford production and capacity

This quarter saw a decrease in Q1 Longford production compared to 2025, reaching 37 PJ, the second lowest Q1 since data commenced on the Gas Bulletin Board (GBB) in 2009 (**Figure 93**), with the lowest level of 34.6 PJ occurring in Q1 2024. Similar to Q1 2024, Longford undertook extensive maintenance during the quarter resulting in available capacity of 45.2 PJ, almost identical to Q1 2024.

Figure 93 Lower Longford Q1 production and capacity due to maintenance

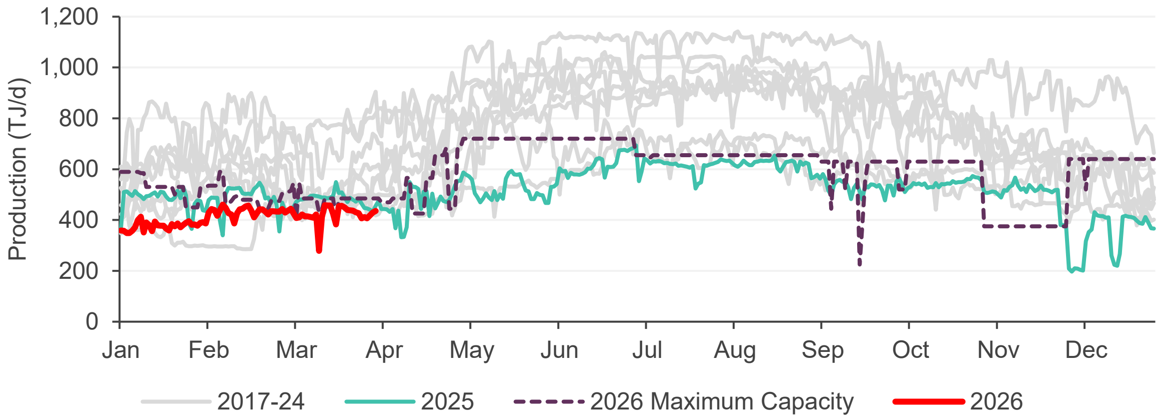
Longford Q1 production and unutilised capacity



As observed throughout much of 2025, daily production through Q1 was usually below available Longford capacity, particularly in January before maintenance reduced that capacity (**Figure 94**), with Longford's capacity factor at 82%. This gap continues to be driven by a continuation of Longford supply offer prices being above the Daily DWGM and Sydney STTM price outcomes, but did narrow in February and March when maintenance lowered Longford's capacity further.

Figure 94 Daily Longford production lower than Q1 2025 but similar to Q1 2024

Daily Longford production 2017-2026, maximum capacity profile 2026



During mid-September 2026, Longford Gas Plant has planned offshore maintenance associated with the demobilisation of the drilling rig for the Turrum Phase 3 development project[60]. This will significantly reduce Longford supply for 2-3 days as shown above, and is necessary to support gas supply during 2027. The activity is currently scheduled to occur between 18 and 20 September 2026, however timing is subject to drilling progress and weather conditions.

AEMO is engaging Esso on the timing of this outage and is seeking engagement with participants on responses to manage supply adequacy during this planned maintenance capacity reduction.

3.3.4 Gas storage

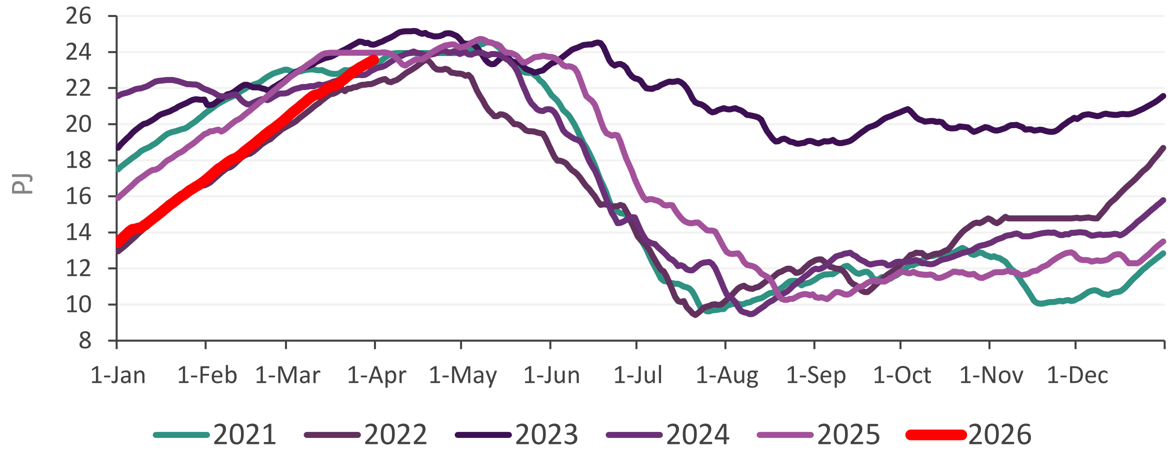
After starting Q1 at the lowest level since 2022, Iona UGS recovered to finish the quarter with an inventory of 23.6 PJ, very similar to Q1 2025 which finished at 23.96 PJ (**Figure 95**).

Storage inventory consistently filled on most days during the quarter, aided by a large reduction in gas flows from Victoria to New South Wales, low gas-fired generation demand and industrial demand which continues its downward trend, as discussed in previous sections.

[60] See https://corporate.exxonmobil.com/-/media/global/files/locations/australia/infobulletin--turrum--phase3-v01.pdf.

Figure 95 Iona storage ended the quarter at a similar level to 2025

Iona storage levels

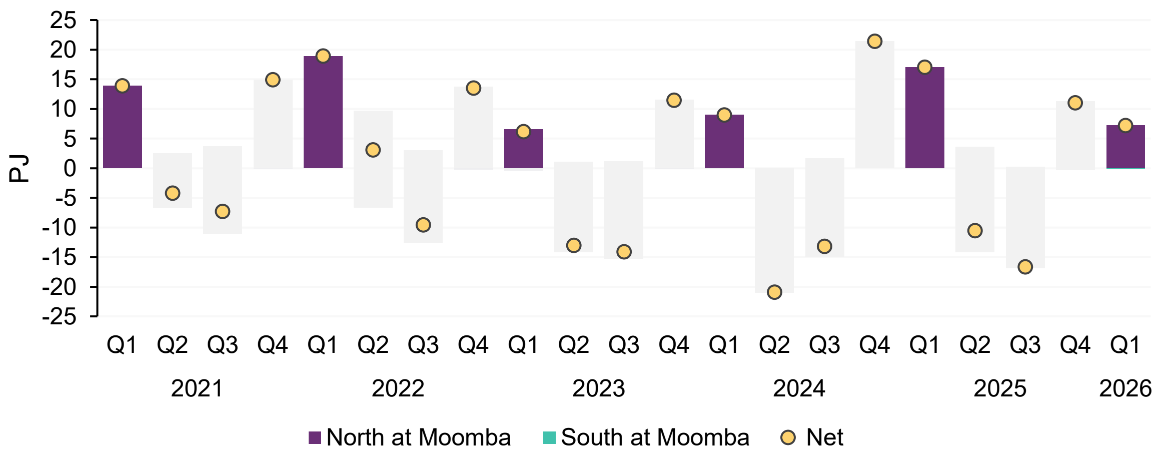


3.4 Pipeline flows

Compared to Q1 2025, there was a 9.8 PJ decrease in net transfers north from Moomba on the South West Queensland Pipeline (SWQP, **Figure 96**) which represents the lowest flow north from Moomba for a Q1 since 2023. This decrease reflects a reduction in flows on the Carpentaria Gas Pipeline (CGP) due to lower demand in the Mt Isa region and a reduction in GLNG demand.

Figure 96 Net Q1 flows north on SWQP decreased to lowest level since 2023

Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states decreased by 10.7 PJ from Q1 2025 levels, due to lower Victorian production, and increased southerly flows from Moomba on the Moomba Sydney Pipeline (MSP). This represents the lowest Q1 net transfers out of Victoria since data reporting on the Gas Bulletin Board began in July 2008, just lower than the previous record of 19.4 PJ in Q1 2020 (**Figure 97**).

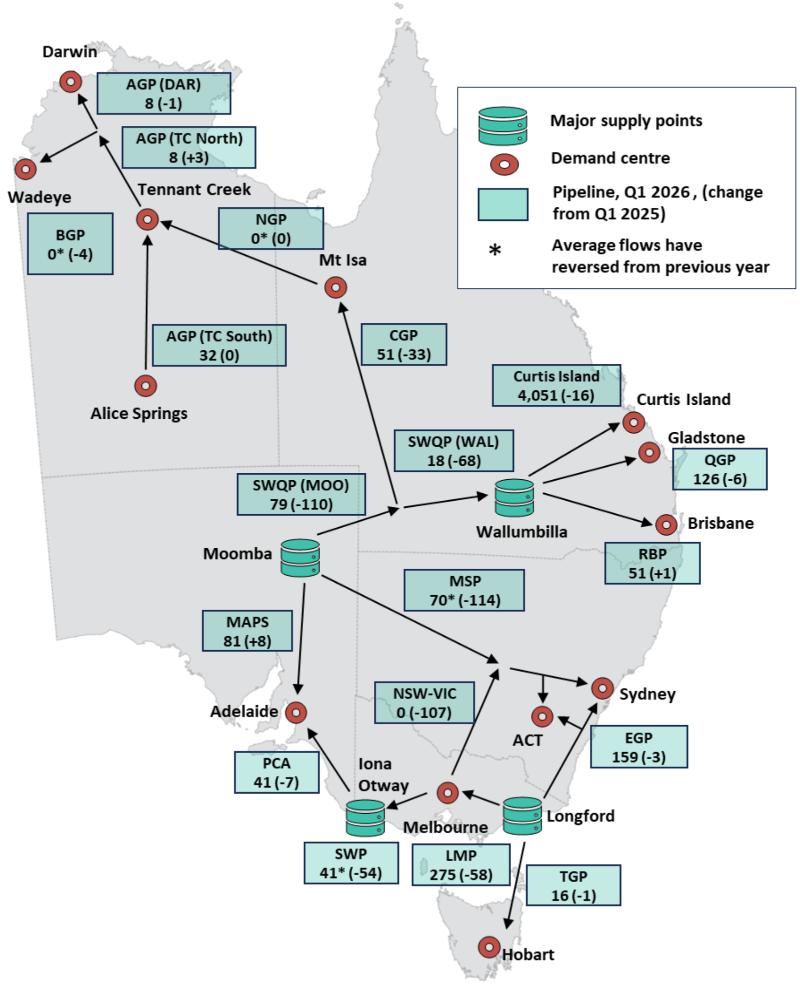
Figure 97 Lowest Q1 net transfers out of Victoria since the Gas Bulletin Board began in July 2008

Victorian net gas transfers to other regions during Q1

Flows on the Victoria to New South Wales Interconnect went from an average of 107 TJ/d from Victoria to New South Wales, to an average of under 0.5 TJ/day (**Figure 98**), reflecting the continuation of a redirection of Moomba gas from Queensland to southern regions, and lower Longford and Otway production observed in Q4 2025.

Figure 98 Reduced Moomba flows to Queensland with increased flow to southern regions continues from Q4 2025

Average daily pipeline flows TJ/day Q1 2026 vs Q1 2025



In Queensland, Mt Isa demand continues to be solely supplied from Queensland, reflecting the continued upstream supply issues experienced in the Northern Territory. Average daily Curtis Island flows in Q4 2025 were slightly lower mostly due to decreased production at GLNG.

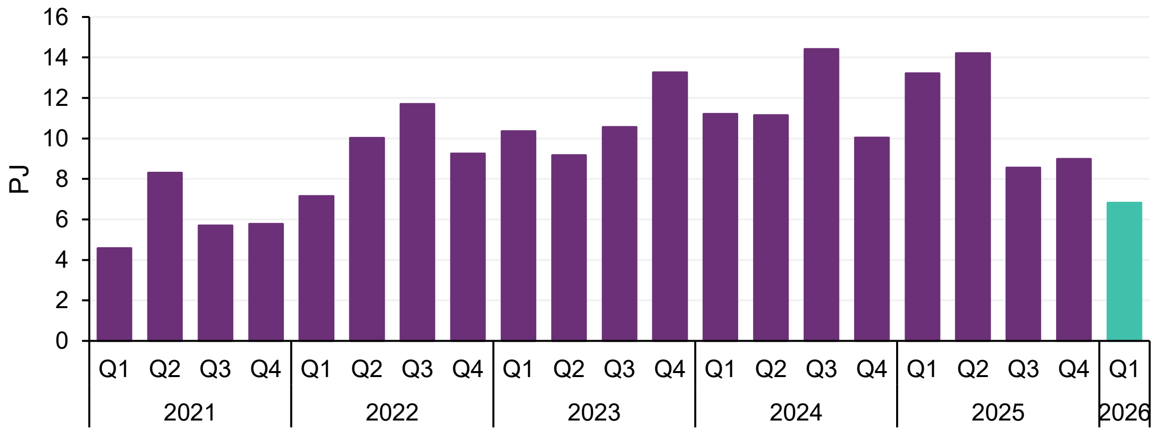
There was a small flow on the Northern Gas Pipeline (NGP) from Queensland to Northern Territory for a few days in January, but for most of the quarter there were no flows observed.

3.5 Gas Supply Hub (GSH)

In Q1 2026, traded volumes on the GSH decreased by 6.4 PJ compared to Q1 2025 (**Figure 99**). The traded volume this quarter was 6.8 PJ, which was the lowest volume for any quarter since Q4 2021. Contributing factors to reduced trading include low gas-fired generation and AEMO market demand.

Figure 99 Lowest volume traded for any quarter since Q4 2021

Gas Supply Hub – quarterly traded volume



3.6 Pipeline capacity trading and Day Ahead Auction

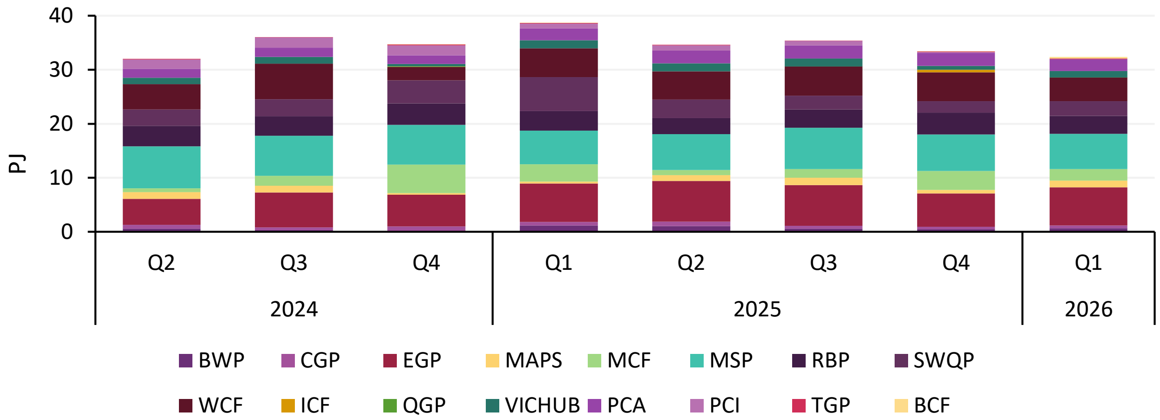
Day Ahead Auction (DAA) volumes decreased by 6.3 PJ in comparison to Q1 2025 (**Figure 100**). Compared to Q1 2025, there were notable decreases on the South West Queensland Pipeline (SWQP, -3.5 PJ), Moomba Compressor (MCF, -1.1 PJ) and Port Campbell to Iona pipeline (PCI, -0.9 PJ).

Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were:

- the Eastern Gas Pipeline (EGP), which averaged $0.10/GJ, and
- the Carpentaria Gas Pipeline (CGP), which averaged $0.07/GJ.

Figure 100 Large decrease in DAA volumes compared to Q1 2025 but only slightly lower than Q4 2025

Day Ahead Auction volumes by quarter



4 WEM market dynamics

4.1 Electricity demand

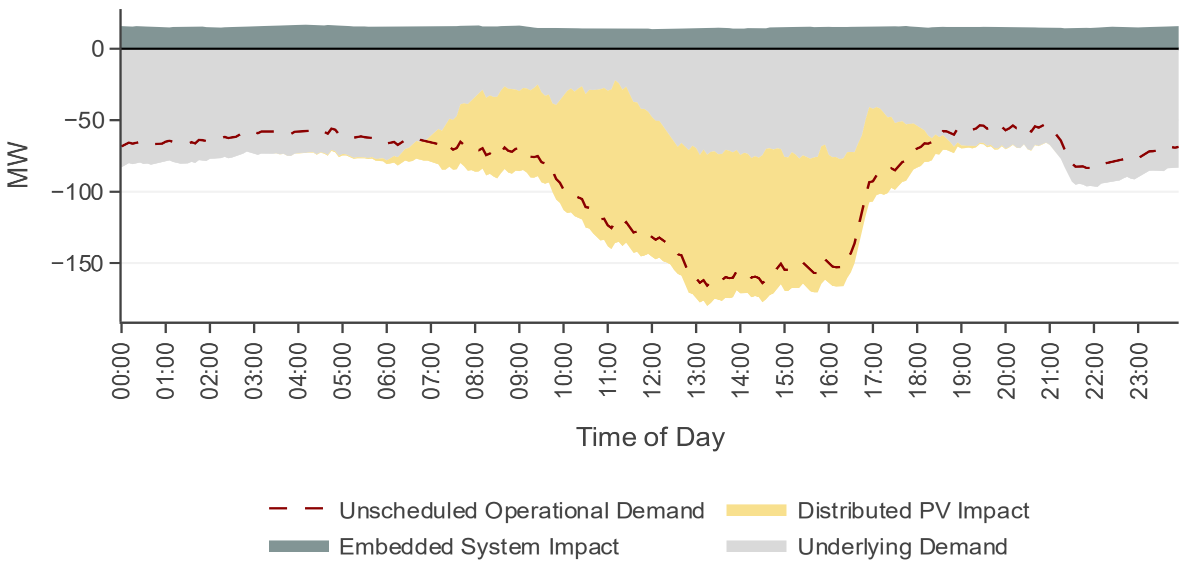
This section focuses on changes in demand, measured as unscheduled operational demand, with battery charging and discharging handled separately, in Section 4.3, where it is treated as storage behaviour rather than a component of underlying demand or as primary generation (covered in Section 4.2).

Average unscheduled operational demand[61] was 2,083 MW in Q1 2026, a decrease of 88 MW (-4.1%) compared to Q1 2025 (**Figure 101**). This was driven by a decrease in average underlying demand[62] of 65 MW (-2.3%) and an increase in average distributed PV[63] generation of 38 MW (+6.5%). A decrease in average embedded system impact[64] of 15 MW (-56%) marginally offset the decrease in average unscheduled operational demand.

The decrease in average underlying demand can be attributed to fewer cooling degree days[65] and cooler maximum and minimum temperatures. The average daily maximum and minimum temperatures were both 0.7°C degrees lower than Q1 2025.

Figure 101 Decreased unscheduled operational demand driven by cooler temperatures and increased distributed PV generation

Change in WEM average unscheduled operational demand components by time of day – Q1 2025 vs Q1 2026



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[61] Unscheduled operational demand sums the injection, in megawatts, from all scheduled facilities, semi-scheduled facilities and non-scheduled facilities that are injecting at the end of the dispatch interval, excluding scheduled demand driven by charging from Electric Storage Resources (batteries).

[62] Underlying demand is calculated by summing distributed PV generation and unscheduled operational demand.

[63] Distributed PV generation is an estimation based on solar irradiance data and installed distributed PV capacity data available to AEMO.

[64] An embedded system is a network connected to the South-West Interconnected System (SWIS) which is owned, controlled or operated by a person who is not a Network Operator or AEMO. Net export into the grid results in a decrease to operational demand as this offsets generation required from registered facilities.

[65] A "cooling degree day" (CDD), which is based on the average daily temperature, is a measurement used as an indicator of outside temperature levels above what is considered a comfortable (base) temperature. CDD value is calculated as max (0, average temperature - base temperature).

4.1.1 Consumer energy resources

Total WEM solar installations increased from 0.4 million at the end of 2020 to 0.6 million at the end of 2025, with capacity increasing from 1.6 GW to 3.0 GW. Consistent with this growth trend, a further 67 MW of CER solar capacity was installed in Q1 2026 (**Figure 102**). Household battery uptake also accelerated following the introduction of the Australian Government's Cheaper Home Batteries Program and the Western Australian Residential Battery Scheme (WARBS)[66]. Clean Energy Regulator data shows that WEM household storage increased by 236 MWh (+57%) over Q1 2026, reaching 651 MWh, with installations surpassing 32,000 (**Figure 103**).

Figure 102 Growth in the WEM's solar capacity and installations since 2020

Cumulative CER solar capacity and installations

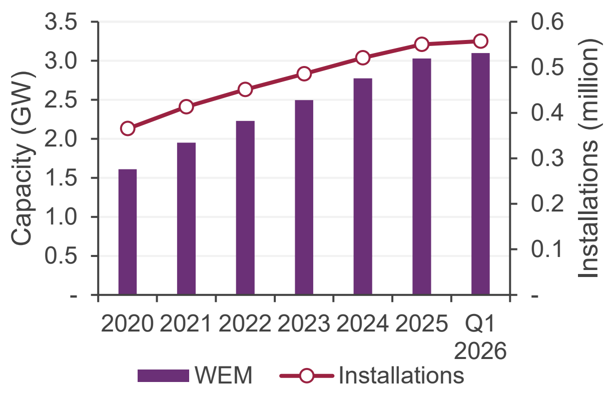
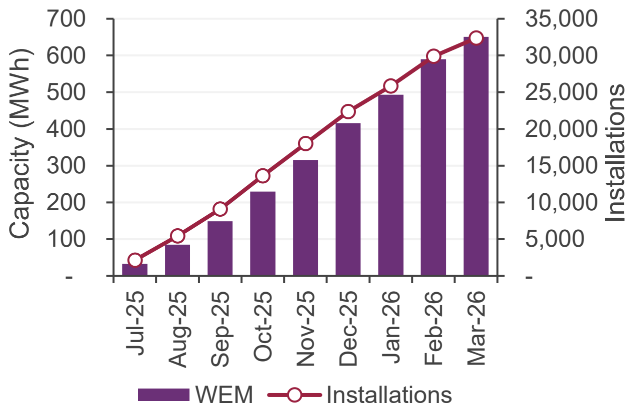


Figure 103 Growth in WEM's CER battery capacity

Cumulative CER battery capacity and installation



Source: Clean Energy Regulator

4.2 Electricity generation

This section focuses on changes in electricity generation by fuel type, with battery charging and discharging considered separately in Section 4.3 as storage rather than primary generation.

Coal-fired generation's share of the fuel mix in Q1 2026 was -4.66 pp lower than it was in Q1 2025. Balancing this change was an increase in renewable generation of +5.26 pp, increasing the average renewable contribution[67] from 40.8% in Q1 2025 to 46.1% in Q1 2026 – a Q1 average renewable contribution record. This was driven by the commissioning of a new biomass facility, increased wind generation and increased distributed PV generation.

Table 9 shows all Q1 2026 contributions, with average generation shown in **Figure 104**. The following key changes were observed since Q1 2025:

- Average coal fired generation decreased by 142 MW (-18%). This was driven by growth in the average renewable contribution and a slight reduction in coal availability, as Muja C Unit 6 was decommissioned in Q2 2025.

[66] See https://www.wa.gov.au/organisation/energy-policy-wa/wa-residential-battery-scheme.

[67] The renewable contribution metric is calculated by dividing total renewable injection by underlying demand. Battery discharge is removed from this calculation to determine battery-adjusted renewable contribution.

- Average gas-fired generation decreased by 16 MW (-2%). This can be attributed to gas-fired generation being displaced by battery discharge during the evening peak (**Figure 105**).
- Average embedded system impact decreased by 15 MW (-56%) due to the permanent retirement of ALCOA_KW_IL.
- Average biomass generation increased 28 MW (+299%). This can be attributed to the commissioning of facility PHOENIX_KWINANA_WTE_G1, with a capacity of 46.1 MW, which commenced Commercial Operation in Q3 2025.

Table 9 WEM supply mix contribution by fuel type

Quarter	Coal	Gas	Distillate	Grid solar	Wind	Biomass	Hybrid	Hydro	Distributed PV	Embedded systems
2025 Q1	28.3%	29.8%	0.1%	2.0%	17.0%	0.3%	0.8%	<0.1%	20.8%	1.0%
2026 Q1	23.6%	29.7%	<0.1%	2.0%	19.2%	1.4%	1.0%	<0.1%	22.5%	0.4%
Change	-4.7%	-0.1%	<0.1%	0.1%	2.2%	1.0%	0.2%	-	1.8%	-0.5%

Figure 104 Decreased coal-fired generation was largely balanced by increased renewable generation

Change in quarterly average generation – Q1 2025 vs Q1 2026

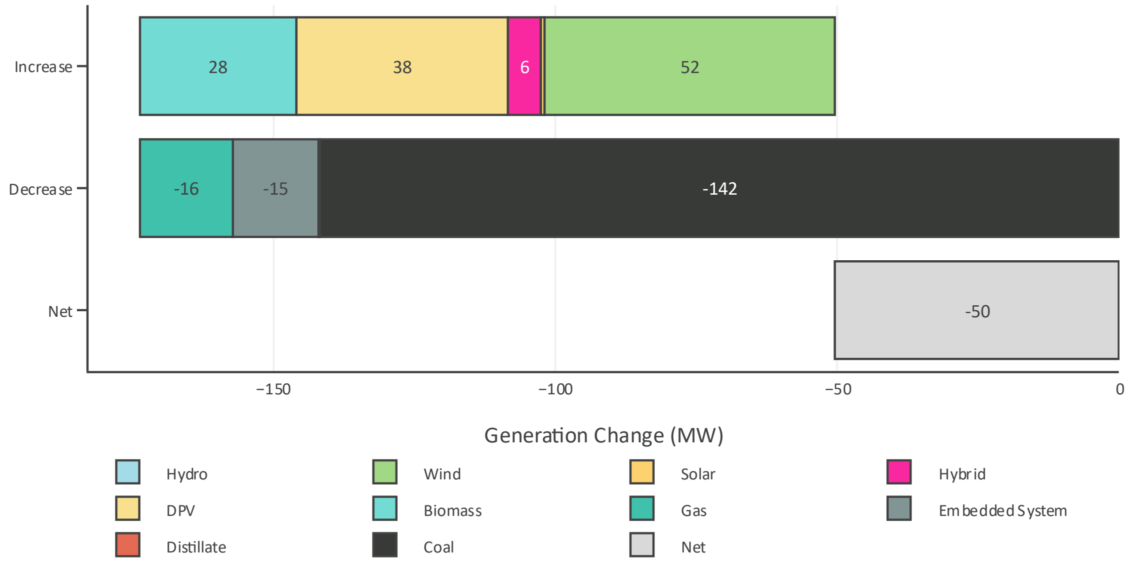
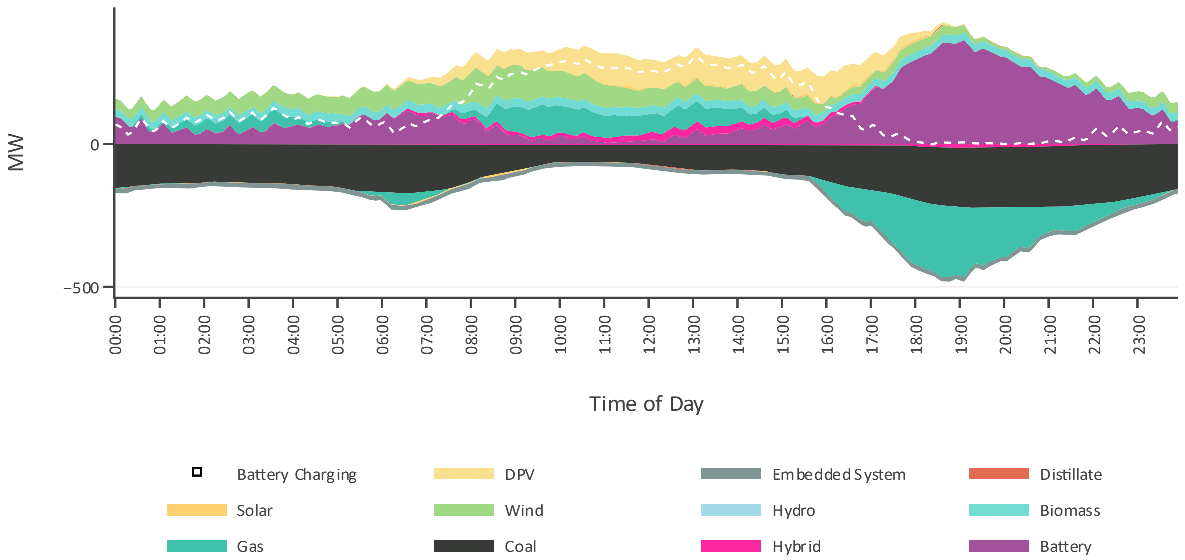


Figure 105 shows how the WEM's generation profile changed by time of day. Battery charging and discharging are included to show the storage-driven shifts that underpinned changes in generation across the day.

Figure 105 Gas and coal-fired generation replaced by batteries at the evening peak, batteries increased charging during the day

Change in average WEM generation and storage by time of day – Q1 2025 vs Q1 2026

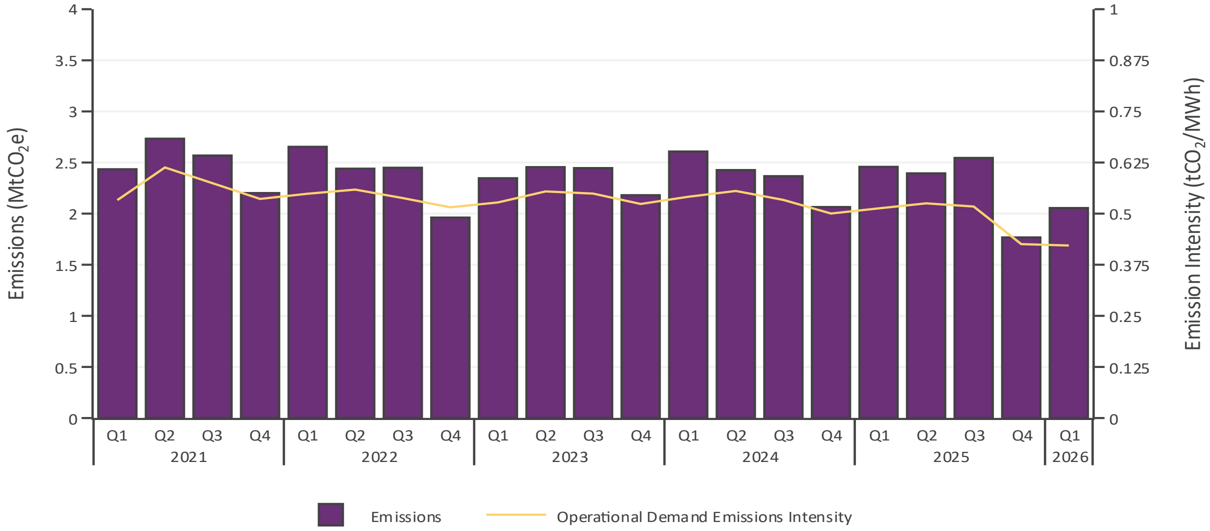


4.2.1 Carbon emissions

Total WEM emissions decreased from 2.46 MtCO2-e in Q1 2025 to 2.05 MtCO2-e (-16%) in Q1 2026 (**Figure 106**). This can be attributed to a reduction in emission intensity of 0.09 tCO2-e/MWh (-18%). The reduction in emission intensity can be attributed to the greater share of the fuel mix taken by renewable generation in lieu of gas and coal.

Figure 106 Emissions deceased as share of renewable generation rose

Quarterly WEM emissions and emission intensity – Q1 2021 to Q1 2026

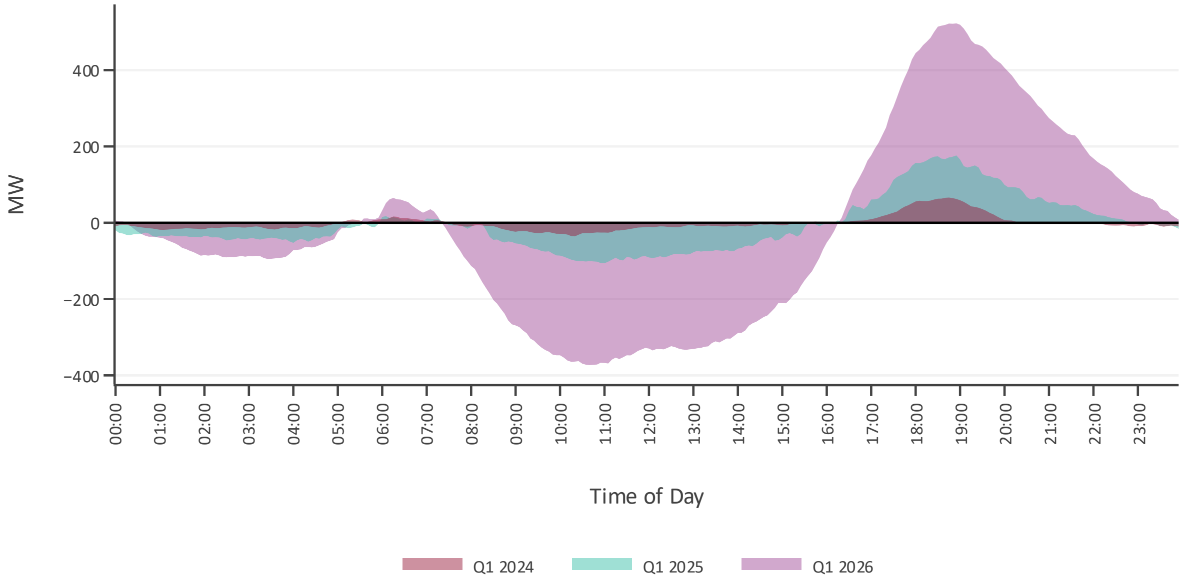


4.3 Electric Storage Resources (ESR)

In Q1 2026 average battery charging and average battery discharging were 122 MW (+290%) and 108 MW (+305%) higher, respectively, than Q1 2025. The increase in battery charging and discharging can both be attributed to an increase in battery capacity (see **Table 10**). Batteries primarily charged during the middle of the day and discharged over the evening peak (**Figure 107**). Battery charging lifted overall supply requirements, leading to a year-on-year increase in average operational demand[68] of 35 MW (+1.6%), while battery discharging later in the day shifted supply into peak demand periods.

Figure 107 Battery discharge and charge profiles have increased year-on-year with increased battery capacity

Average battery energy injection/withdrawal, time of day – Q1s



Batteries set three charging records this quarter, reaching a maximum of -1,000 MW withdrawal on 25 January 2026 during the 16:30 hrs interval (+6.7%). This was 63 MW more than the previous quarter's all-time record of -937 MW on 26 December 2025 during the 12:30 hrs interval. The WEM also saw a record peak battery charging of 1,000 MW in the 16:30 interval on Sunday 25 January 2026.

4.3.1 ESR revenue

In Q1 2026, estimated net Real-Time Market revenue for WEM grid-scale batteries was $8.3 million[69], down $4.3 million (-34%) from Q1 2025 (**Figure 108**). Energy arbitrage revenue increased by $0.2 million (+4.3%) to $4.0 million, compared to the same period in Q1 2025. This increase was eclipsed by a decrease in frequency co-optimised essential system services

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[68] Operational demand sums the injection, in megawatts, from all scheduled facilities, semi-scheduled facilities and non-scheduled facilities that are injecting at the end of the dispatch interval. As such, it includes scheduled demand driven by charging of electric storage resources (batteries).

[69] Battery estimated net Real-Time Market revenue comprises revenue from energy arbitrage – calculated as revenue from energy discharged (including charging at negative prices) net of charging costs – and revenue earned from Frequency Co-optimised Essential System Services (FCESS). It excludes FCESS charges and other payments and charges including those relating to Energy Uplift, FCESS Uplift, Reserve Capacity (including Refunds), and NCESS. Revenue quantities are approximations based on dispatched quantities rather than metered values and do not account for Bilateral Contracts or STEM trading.

(FCESS) revenue, which fell to $4.2 million in Q1 2026, a reduction of $4.4 million (-51%). Consequently, FCESS revenue accounted for 51% of total battery revenue this quarter, down from 69% in Q1 2025 (**Figure 109**).

Figure 108 Increase in battery arbitrage revenue while FCESS revenue reduced

Quarterly net revenue from WEM battery systems by revenue stream

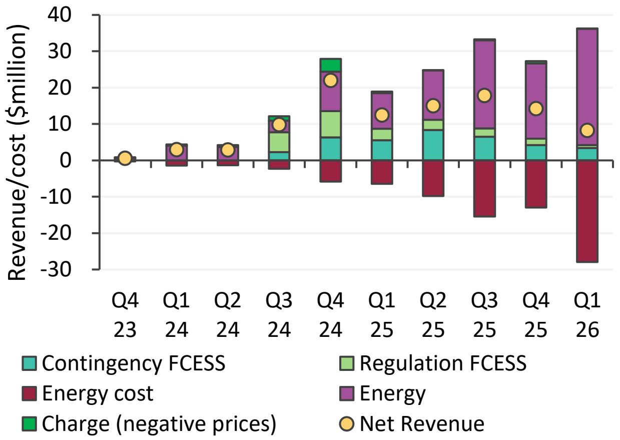
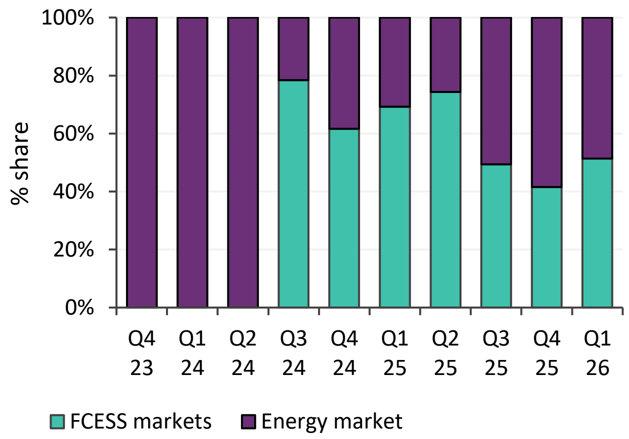


Figure 109 Battery revenue from FCESS markets reduced compared to Q1 2025

Percentage share of battery net revenue – energy vs FCESS markets



The reduction in FCESS revenue from Q1 2025 was driven by a significant increase in battery capacity (including FCESS-accredited battery capacity), with four battery systems having completed commissioning since Q1 2025 (**Table 10**). This led to increased competition in the FCESS markets, which resulted in lower FCESS prices, and therefore lower revenue despite batteries taking a larger share of the FCESS markets.

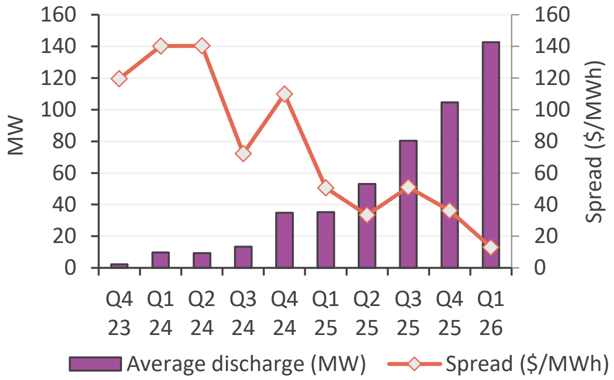
Table 10 New battery systems were commissioned and FCESS-accredited since Q1 2025

Battery	Capacity	Commercial Operation	FCESS accreditation
KWINANA_ESR2	225 MW / 900 MWh	Q2 2025	Q2 2025
COLLIE_BESS2	300 MW / 1,200 MWh	Q3 2025	Q4 2025
COLLIE_ESR4	250 MW / 1,000 MWh	Q4 2025	Not yet accredited
COLLIE_ESR5	250 MW / 1,000 MWh	Q4 2025	Not yet accredited

Between Q1 2025 and Q1 2026, total WEM battery discharge capacity increased by 1,025 MW to 1,275 MW total (5,140 MWh total), a 410% increase. As a result, average battery discharge also increased sharply to 142.6 MW, more than four times greater than the 35.2 MW average recorded in the same period a year earlier, setting a new quarterly high.

Figure 110 WEM battery price spread continued to decrease with lower price volatility

Average quarterly battery discharge (MW) and price spread ($/MWh) [RHS]



However, lower volatility in the energy Market Clearing Price in Q1 2026 reduced the value of arbitrage opportunities for batteries in the WEM. This can be partly attributed to the increased battery capacity, which raises demand, and therefore prices, during midday charging periods, while contributing to lower evening prices due to greater available capacity.

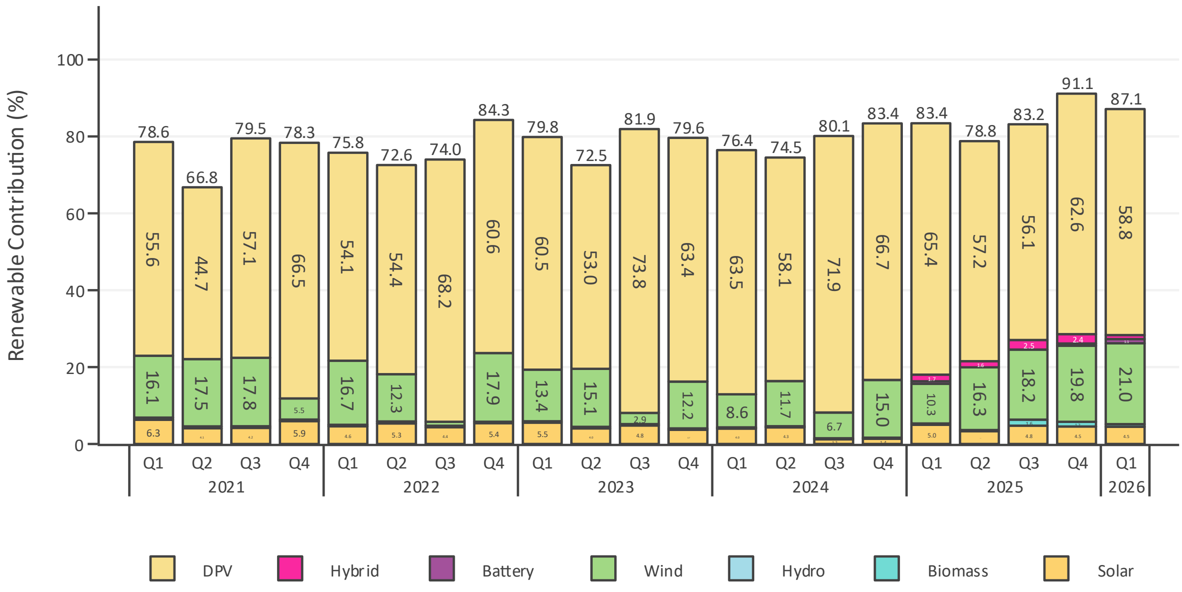
As a result, the WEM price spread earned by batteries declined by 74%, from $51/MWh in Q1 2025 to $13/MWh (**Figure 110**).

4.3.2 Peak renewable and storage contribution

This section examines renewable and storage contribution to demand at a 5-minute level, reflecting the combined role of renewable generation and battery discharge in meeting demand at any point in time. Q1 2026 saw a new Q1 peak renewable and storage contribution record of 87.12% in the 11:10 interval on Thursday 21 February 2026 (**Figure 111)**. At the time of this quarter's peak, distributed PV accounted for 58.8% of total generation and wind accounted for 21.0%.

Figure 111 Peak quarterly renewable and storage share achieves a Q1 record

Percentage of WEM supply from renewable energy sources and storage at time of peak renewable and storage contribution



4.4 Frequency co-optimised essential system services (FCESS)

In Q1 2026, batteries again increased their market share of the contingency and regulation markets, reaching 83% of total volume (**Figure 112**), an increase of 44 pp on Q1 2025 (**Figure 113**) and a decrease of 1 pp compared to Q4 2025. This increase was driven by two additional batteries becoming accredited to provide FCESS since the end of Q1 2025.

The average Contingency Reserve Lower requirement increased by 71.9 MW (+187%), attributed to commissioning of larger battery systems since Q1 2025 (see Section 4.3), and the commencement of regulatory changes in Q4 2025 which facilitated larger credible load contingencies. The average Contingency Reserve Raise requirement increased by 45 MW (+23%) compared to Q1 2025, with a contributing factor being the increase in the allowable contingency size via an increase to the Rate of Change of Frequency (RoCoF) Safe Limit from 26 February 2026.

Figure 112 Batteries took 83% of the contingency and regulation market volume in Q1 2026

FCESS volume market share by market and fuel type, excluding RoCoF control service – Q1 2026

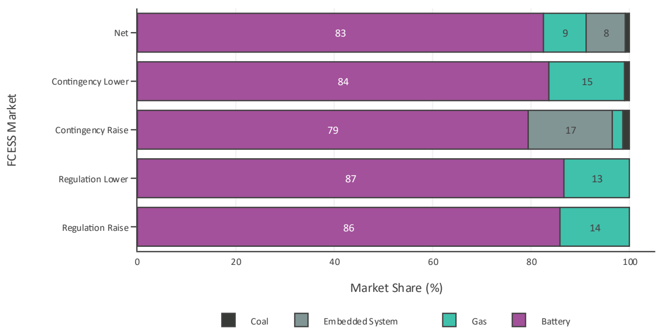
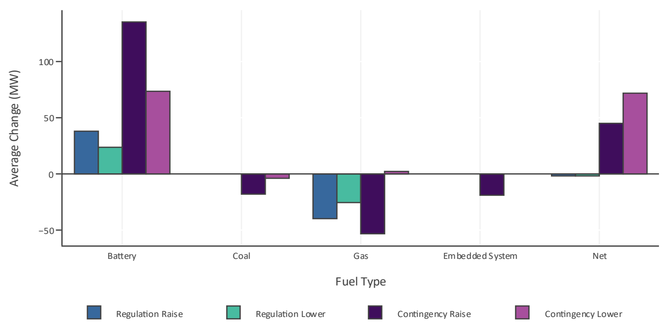


Figure 113 Batteries increased market share and contributed to higher contingency lower requirements

Change in FCESS (regulation and contingency markets) enablement by fuel type – Q1 2025 vs Q1 2026



4.5 WEM price outcomes

4.5.1 Real-Time Market price dynamics

The average energy price in Q1 2026 was $88.53/MWh, a small decrease of $0.51/MWh (-0.58%) from Q1 2025. A comparison of the spread of energy prices in this quarter compared to the same quarter last year reveals lower variability between the first and third quartiles, as well as maximum and minimum values (**Figure 114**). When compared to Q1 2025, the average prices over morning and afternoon peaks were lower in Q1 2026 and the WEM continued to observe a flattening of the daily price profile (**Figure 115**). The quarterly energy price dynamics can be attributed to:

- an increase in renewable generation at all times of the day, putting downward pressure on prices,
- increased battery charging during the middle of the day, which increased operational demand and contributed to higher daytime prices (**Figure 116**), and
- increased battery discharge during the evening peak reduced prices by displacing more expensive generation.

Figure 114 Less variability in Real-Time Energy Prices during Q1 2026

Range of real-time energy prices - Q1 2025 to Q1 2026

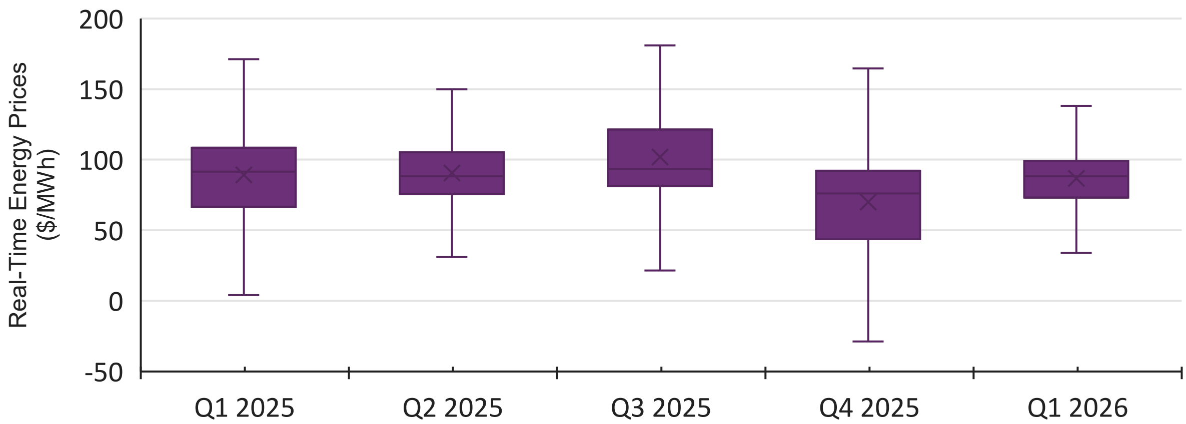


Figure 115 Flattening of the daily price profile

Average energy price by time of day – Q1 2025 vs Q1 2026

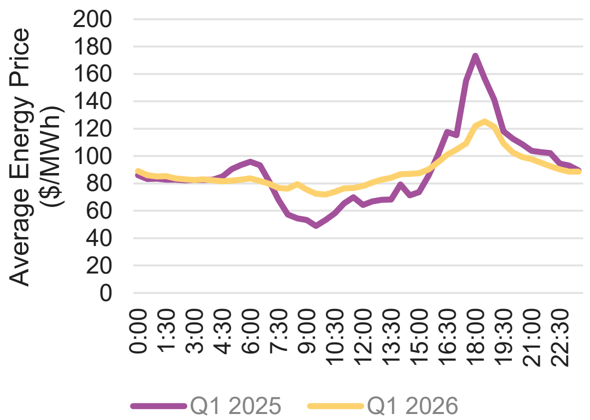
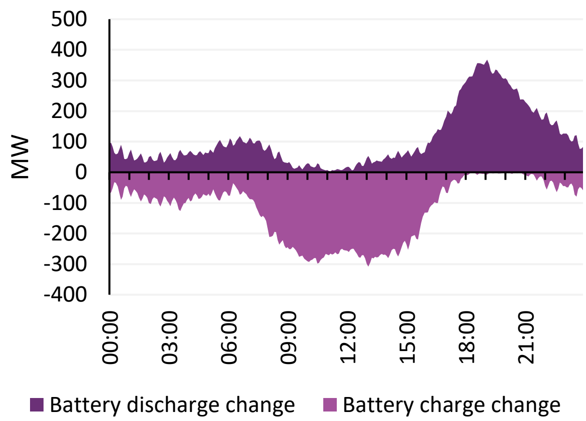


Figure 116 Batteries are a driver of a flatter price profile

Average change in battery charge and discharge – Q1 2025 vs Q1 2026



4.5.2 Essential system services (ESS) costs

Total ESS including Uplift costs fell to $13.9 million in Q1 2026, down $36.7 million (-72%) from Q1 2025 (**Figure 117**). Key observations include:

- FCESS enablement costs, which excludes FCESS Uplift, were $5.1 million in Q1 2026, a total reduction of $15.1 million (-75%) compared to Q1 2025. Costs reduced across all markets, which can be attributed to increased participation from newly registered Facilities accredited for FCESS, notably COLLIE_BESS2 in Q4 2025.
  - Contingency Reserve Raise costs saw a significant decrease to $3.3 million, 73% down from $12.3 million in Q1 2025, but remained the largest contributor to total FCESS enablement costs, accounting for 64% of Q1 2026 FCESS enablement costs.
  - Costs for Regulation Reserve Lower and Regulation Reserve Raise saw significant decreases of $1.7 million (-79%) and $3.2 million (-88%) compared to Q1 2025.

- Contingency Reserve Lower costs decreased by $1.2 million (-58%) compared to Q1 2025 despite an increase in Contingency Reserve Lower Quantities (see Section 4.4). This was driven by lower prices as a result of increased competition from the accreditation of new batteries for FCESS

- FCESS Uplift costs were $1.0 million Q1 2026, a reduction of $10.0 million (-91%) from $10.9 million in Q1 2025, largely driven by increased competition from batteries. This was the second largest decrease observed within any component of the ESS costs. **Figure 118** shows how FCESS Uplift Costs were assigned to the five FCESS Market Services.
- The largest decrease occurred in Energy Uplift costs, which totalled $1.3 million in Q1 2026. This is a decrease of $11.7 million (-90%) compared to Q1 2025.
- Provisional Non-Peak NCESS costs were $6.5 million in Q1 2026 (including estimates[70]), remaining similar to Q4 2025 (+2%).

Figure 117 Total ESS and Uplift cost decrease driven by FCESS Cost Review and battery participant

Total ESS and Uplift cost per quarter – Q1 2025 to Q1 2026

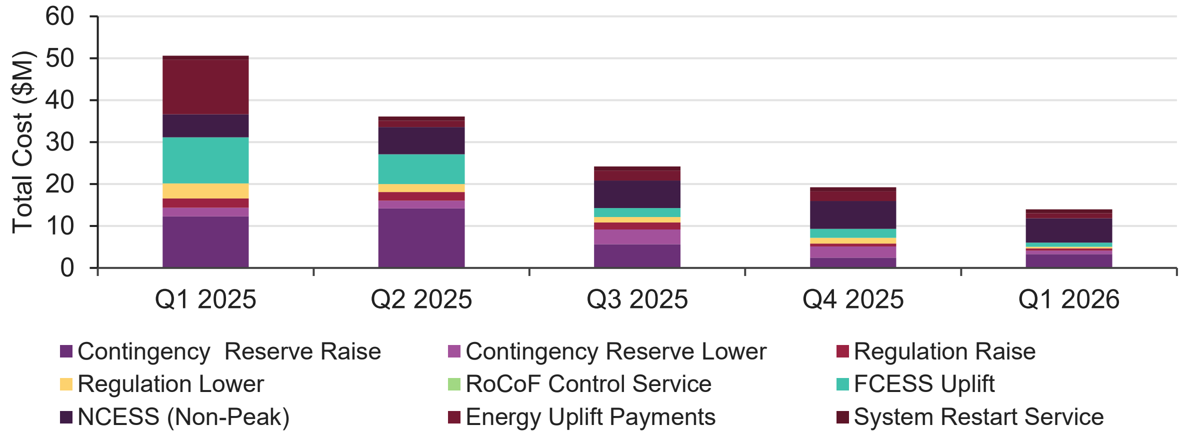
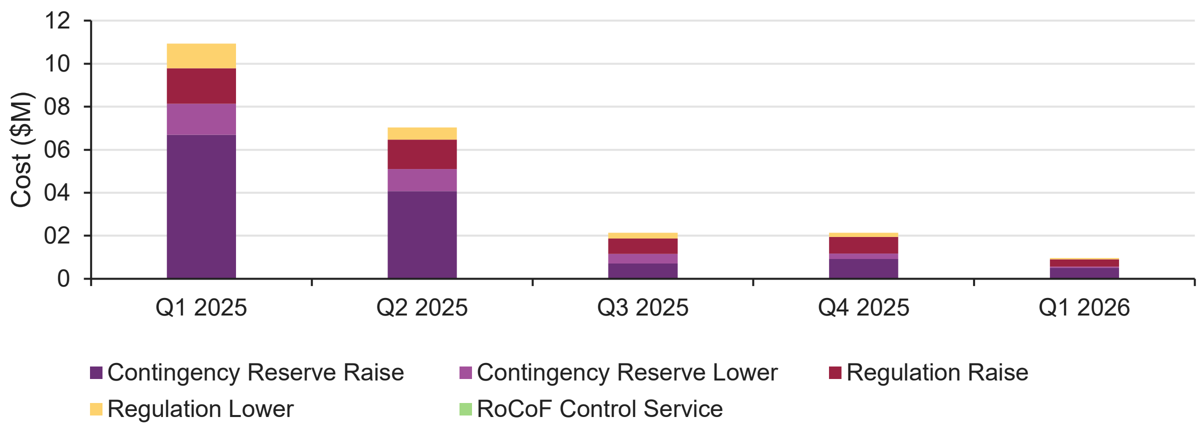


Figure 118 Total FCESS Uplift Share Costs decreased by $10 million (-91%) in Q1 2026 compared to Q1 2025

Distribution of FCESS Uplift Costs across market services per quarter – Q1 2025 to Q1 2026



[70] Actual NCESS costs data in this report are only available up to 21 March 2026 inclusive due to timing discrepancies in payment reconciliation at the time of reporting. Estimates have been included in this total to account for Trading Days 22 March 2026 to 31 March 2026 inclusive. Further details on the estimation are in Section 4.5.3.

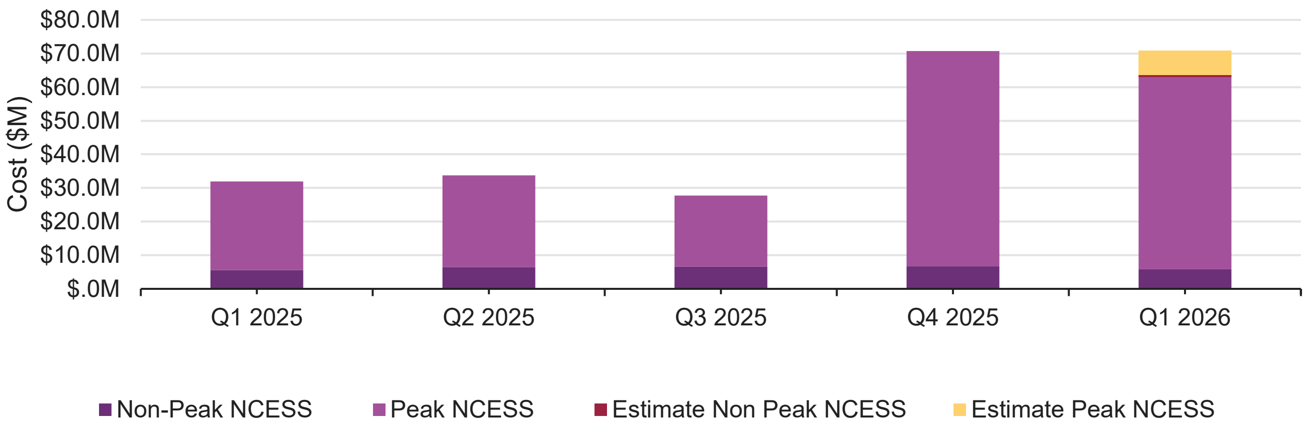
4.5.3 Non-Co-optimised Essential System Services (NCESS)

NCESS costs are divided into two categories, with different cost-recovery mechanisms, based on the nature of the NCESS service. AEMO refers to these as "Peak NCESS" and "Non-Peak NCESS" costs, and groups these with Capacity and ESS costs for reporting purposes.

NCESS costs data in this report are only available up to 21 March 2026 inclusive due to timing discrepancies in payment reconciliation at the time of reporting. For a comparative dataset, Q1 2026 NCESS costs includes an estimation[71] for Trading Days from 22 March 2026 to 31 March 2026 inclusive. In Q1 2026, total NCESS costs, including estimates reached $70.9 million, a $38.9 million (+122%) increase compared to Q1 2025 (**Figure 119**). This increase was driven by the commencement of 11 new Peak NCESS contracts since Q4 2024, with eight of these commencing in Q4 2025. Total Peak NCESS costs increased by $38.0 million (+139 %) compared to Q1 2025, contributing $64.4 million to total NCESS costs and Non-Peak NCESS costs were $6.5 million in Q1 2026.

Figure 119 Total NCESS costs

NCESS cost by cost recovery mechanism (including NCESS costs after 21 March 2026 as an estimate) – Q1 2025 to Q1 2026



4.5.4 Supplementary Capacity

In 2025, AEMO identified a potential capacity shortfall for the 2025-26 Hot Season (defined as the period 1 December 2025 to 31 March 2026). To address this, AEMO contracted 141.15 MW of Activation & Availability (A&A) contracts to meet the Supplementary Capacity procurement target for the 142 MW shortfall. Additionally, AEMO procured 30.5 MW of Activation-Only (AO) contracts for the 2025-26 Hot Season as an extra contingent Supplementary Capacity service

During the 2025-26 Hot Season, AEMO did not activate Supplementary Capacity services as there were no shortfalls in supply. The total cost of Supplementary Capacity contracts was $22.6 million, a $2.3 million (-9%) reduction from the 2024-25 Hot Season.

4.5.5 Total Wholesale Electricity Market costs

Figure 120 represents WEM costs as a price per MWh normalised by total energy consumed, enabling better comparison of costs between periods with different demand.

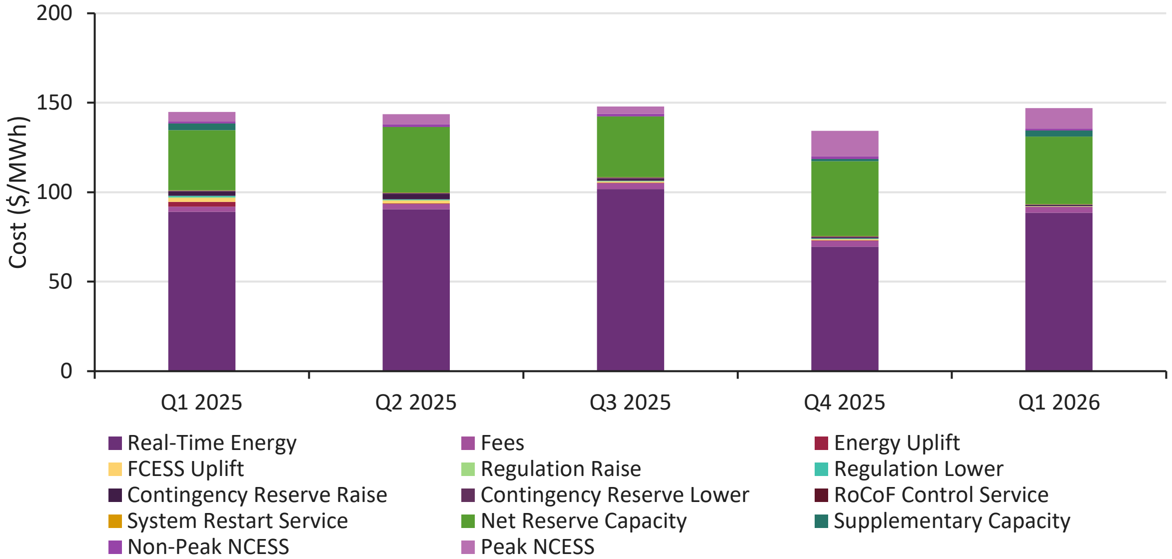
[71] NCESS cost estimation assumes no activation events and no services were unavailable over the impacted Trading Days. Estimation may differ from actual NCESS costs.

The sum of all normalised costs in the WEM was $147.03/MWh in Q1 2026, an increase of $2.10/MWh (+1%) from Q1 2025. Key observations and changes include:

- Normalised energy prices were $88.53/MWh, a decrease of $0.51/MWh (see Section 4.5.1).
- Normalised Energy Uplift costs reduced by $2.37/MWh to $0.25/MWh. This was a result of unusually high Energy Uplift costs in Q1 2025, while Q1 2026 costs are more typical compared to recent quarters.
- Normalised FCESS enablement costs reduced by $3.07/MWh to $1.02/MWh, while normalised FCESS uplift costs decreased by $2.02/MWh to $0.19/MWh (see Section 4.5.2).
- Total normalised NCESS costs were $12.62 per MWh, increasing $6.14/MWh due to the commencement of eight new NCESS contracts (see Section 4.5.3).
- Normalised Reserve Capacity costs, net of Reserve Capacity Refunds, were $37.72/MWh, an increase of $4.20/MWh (+13%), mainly driven by an increase in the Reserve Capacity Price for Capacity Year 2025-26[72].
- Supplementary Capacity costs decreased from $3.82 per MWh to $3.37 per MWh.

Figure 120 Wholesale Energy Market costs increased in Q1 2026 compared to Q1 2025

Normalised Energy, ESS and Capacity costs per MWh consumed in the WEM – Q1 2025 to Q1 2026



4.5.6 Short Term Energy Market (STEM) and Bilateral Trades

The energy traded between participants on the STEM totalled 495 GWh, representing a 171% increase from the Q1 2025 traded volume of 182 GWh, with average traded quantities exceeding 100 MWh across all intervals (see the dark purple line in **Figure 121**). The quarterly average STEM clearing price was $92.62 in Q1 2026 which was an increase of $5.23 (+6%) from $87.38 in Q1 2025.

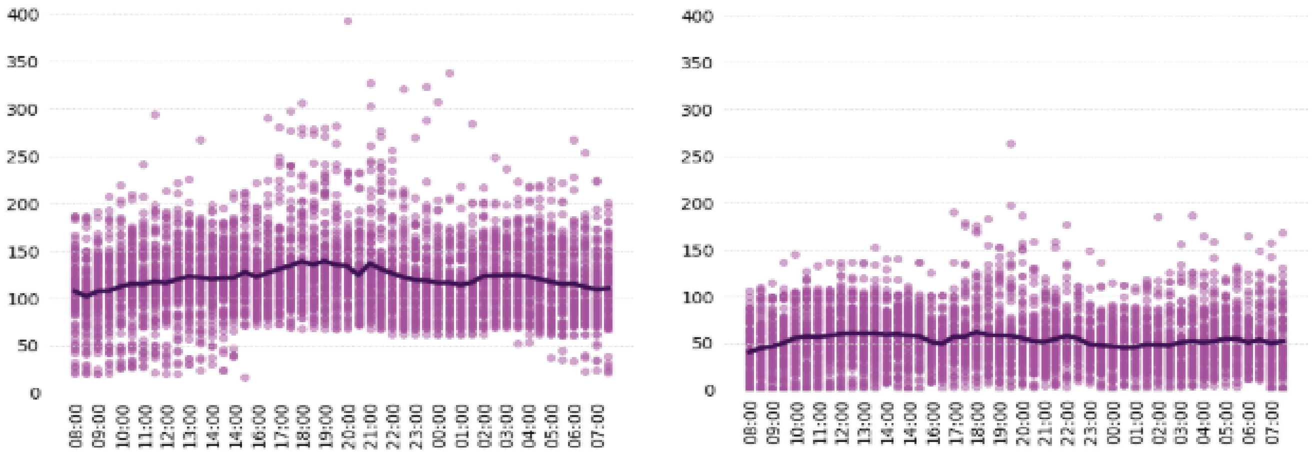
Figure 121 shows the distribution of STEM quantities traded by trading interval for Q1 2026 and Q1 2025. The results indicate a material increase in STEM participation in Q1 2026, with traded quantities consistently higher across most trading

[72] The reserve capacity price for transitional facilities, which is applicable to the majority of facilities, increased from $150,754.81 to $155,418.93/MW/yr, while the reserve capacity price increased from $194,783.54/MW/yr to $251,420.00

intervals compared to the previous year. STEM has been liquid with more quantities clearing in the auction by market participants. Higher traded quantities at times also coincided with outages when the market participants were observed selling/purchasing quantities in STEM to meet their demand and mitigate exposure in the real-time market. In Q1 2025, minimum traded quantities frequently sat at or near zero, whereas in Q1 2026 traded quantities exceeded approximately 50 MWh for a substantial portion of the trading day, with a greater incidence of volumes above 200 MWh.

Figure 121 STEM quantities gross traded were materially higher across trading intervals in Q1 2026

Distribution of STEM Gross Trade Quantities by Trading Interval (MWh) – Q1 2026 (LHS) and Q1 2025 (RHS)



The increase in STEM traded quantities observed in **Figure 121** coincides with a reduction in bilateral trading volumes shown in **Figure 122**. **Figure 122** shows bilateral energy traded between market participants by trading interval for Q1 2026 and Q1 2025, excluding trades between the same participant. Bilateral traded volumes in Q1 2026 were consistently lower across most trading intervals compared to Q1 2025, with the largest year-on-year reductions observed during peak and evening trading intervals. While the daily trading profile remains broadly similar between years, overall bilateral trading volumes were lower in Q1 2026 compared to Q1 2025.

Figure 122 Bilateral trades between market participants decreased between Q1 2026 vs Q1 2025

Average Bilateral Trades Between Participants (MWh) – Q1 2025 vs Q1 2026

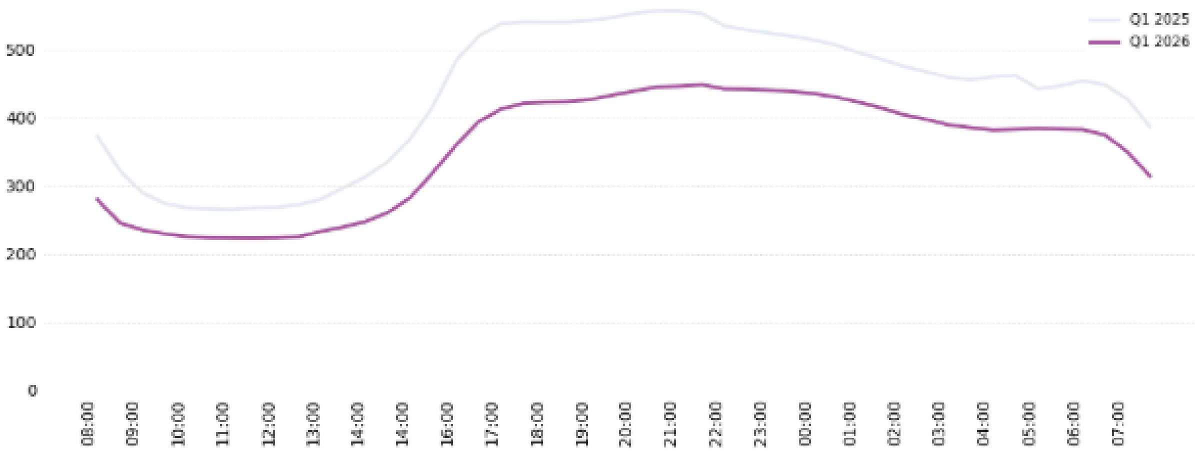


Figure 123 shows the distribution of STEM clearing prices by trading interval for Q1 2026 and Q1 2025, together with the average STEM price profile. The average daily STEM price profile is broadly similar between Q1 2026 and Q1 2025;

however, STEM prices in Q1 2026 are generally higher, with a slight elevation observed through to the evening period. Prices are more tightly clustered during overnight through to early afternoon trading intervals, while a wider dispersion of observed prices occurs during the evening peak. This pattern is evident in both quarters, although Q1 2026 shows a slightly higher average price and a more pronounced spread of prices through the evening period.

Figure 123 The range of observed STEM prices increased during the evening peak in Q1 2026

Distribution of STEM Clearing Prices by Trading Interval ($/MWh) – Q1 2026 (LHS) and Q1 2025 (RHS)

In Q1 2026, the average price difference between the Short-Term Energy Market and Reference Trading Price was $4.09/MWh higher than in Q1 2025. **Figure 124** shows the average price difference across each Trading Interval. The results indicate that the STEM price was generally lower than the Reference Trading Price during the early trading intervals through to the early afternoon, before becoming higher during the evening peak. STEM auction occurs a day ahead for the next Trading Day. STEM Offers and Bids are formed in advance for trading intervals the next day spanning over a horizon of a 24 to 48 hour period. Due to the forecast horizon within a 24-hour period when submitting offers for morning intervals for the next day, offers can be cheaper for morning intervals than the offers submitted for the afternoon and evening peak trading intervals for the next day. When submitting offers for the next day's afternoon and evening peak intervals, the forecast dispatch uncertainty increases for a forecast horizon over 24-hour period. Hence, STEM Offers can be expensive for the peak afternoon and evening trading intervals for the next Trading Day, whereas the real-time market offers submitted closer to afternoon and evening dispatch intervals reflect better forecast and market conditions such as availability of cheaper generation.

Figure 124 STEM was on average priced higher than the Energy price in the evening peak, but less in the morning

Average Daily Variance Between STEM Clearing Price and Energy Reference Trading Price ($/MWh) – Q1 2025 vs Q1 2026

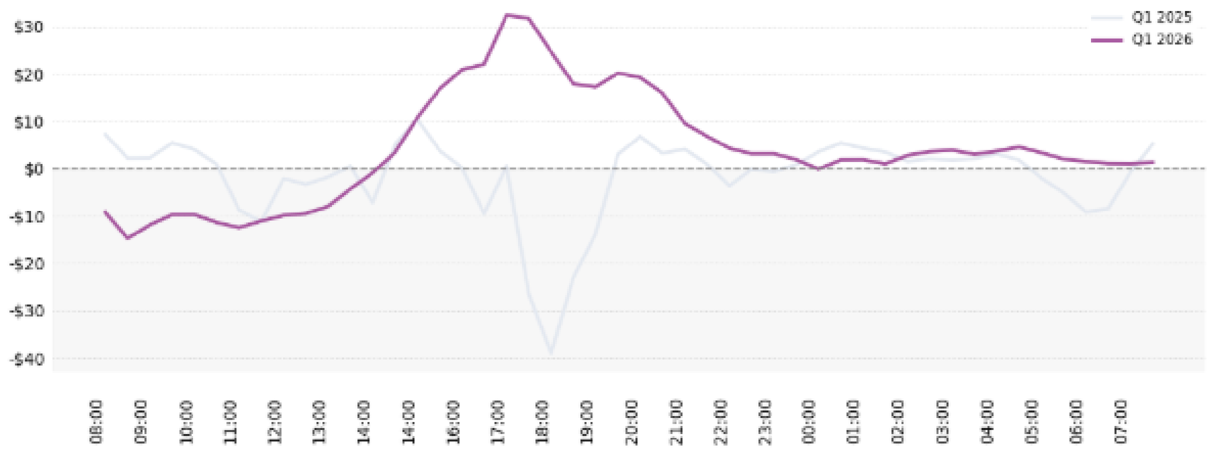
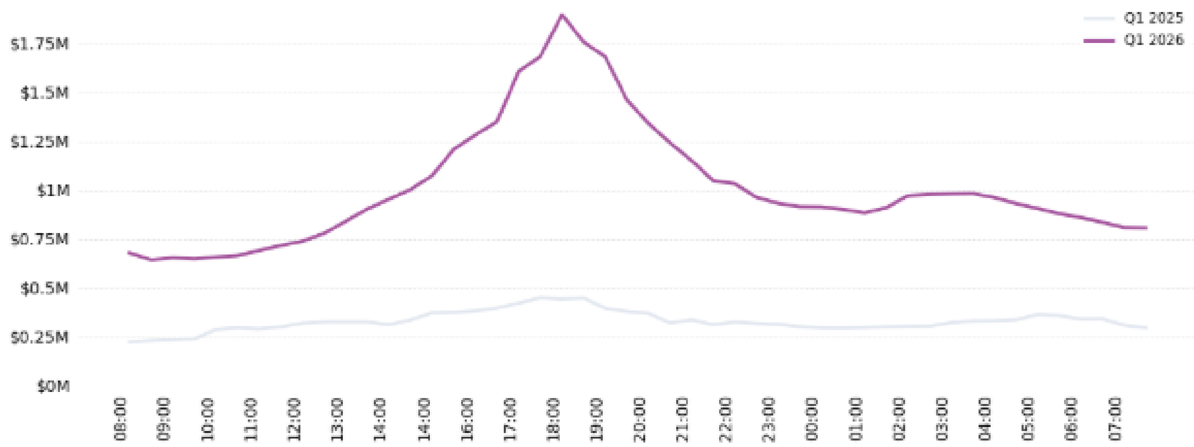


Figure 125 shows the total transaction value of energy traded in the STEM by trading interval for Q1 2026 and Q1 2025, calculated as the product of STEM clearing price and net STEM energy sold. The total transaction value in Q1 2026 is higher than in Q1 2025 across all trading intervals, with a pronounced increase during the evening peak. Elevated transaction values during the evening period coincide with intervals where both STEM prices and traded quantities are higher relative to Q1 2025, as shown above in **Figure 121** and **Figure 123**.

Figure 125 Transaction value of the net STEM traded quantities increased between Q1 2026 vs Q1 2025

Total STEM Transaction Value – Q1 2025 vs Q1 2026



5 Western Australia gas market dynamics

5.1 Gas consumption

A total of 97.4 PJ of gas was consumed across registered pipelines in the Western Australian domestic gas market in Q1 2026, representing a decrease of 4.7 PJ (-4.6%) from the 102.1 PJ consumed in Q1 2025, as shown in **Figure 126**. The reduction in gas consumption compared to Q1 2025 was largely driven by lower demand from other (Non-Large User) categories, which decreased by 10.5 PJ to 7.8 PJ. In contrast, other large user consumption increased substantially to 16.6 PJ in Q1 2026, compared to 3.8 PJ in Q1 2025, offsetting part of the overall decline.

Gas consumption in the Metro zone declined to 18.2 PJ in Q1 2026, down from 23.7 PJ in Q1 2025, as shown in **Figure 127**, reflecting reduced demand from Industrial and Non-Large Users.

In contrast, combined gas consumption across the Dampier and Pilbara zones increased by 2.5 PJ over the same period. Consumption in the Dampier zone rose from 25.1 PJ to 26.3 PJ, while Pilbara consumption increased from 8.0 PJ to 9.2 PJ.

Figure 126 Gas consumption by sector in Western Australia decreased compared to Q1 2025

Quarterly gas consumption by sector (PJ)– Q1 2025 and Q1 2026

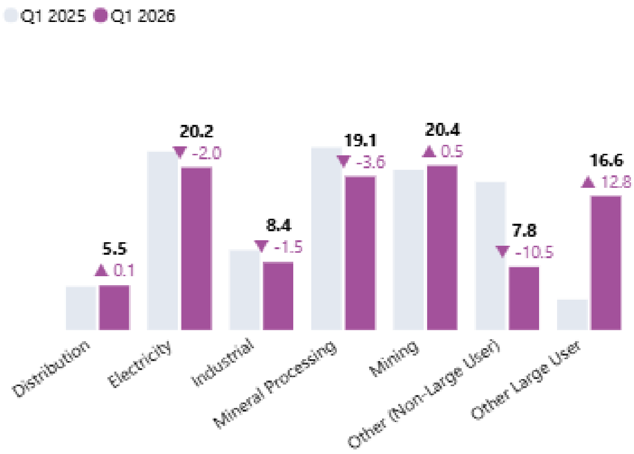
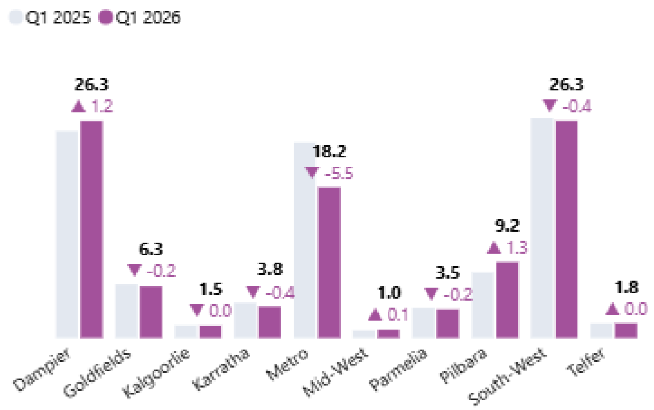


Figure 127 Gas consumption by zone in Western Australia decreased compared to Q1 2025

Quarterly gas consumption by zone (PJ) – Q1 2025 and Q1 2026



5.2 Gas supply and balance

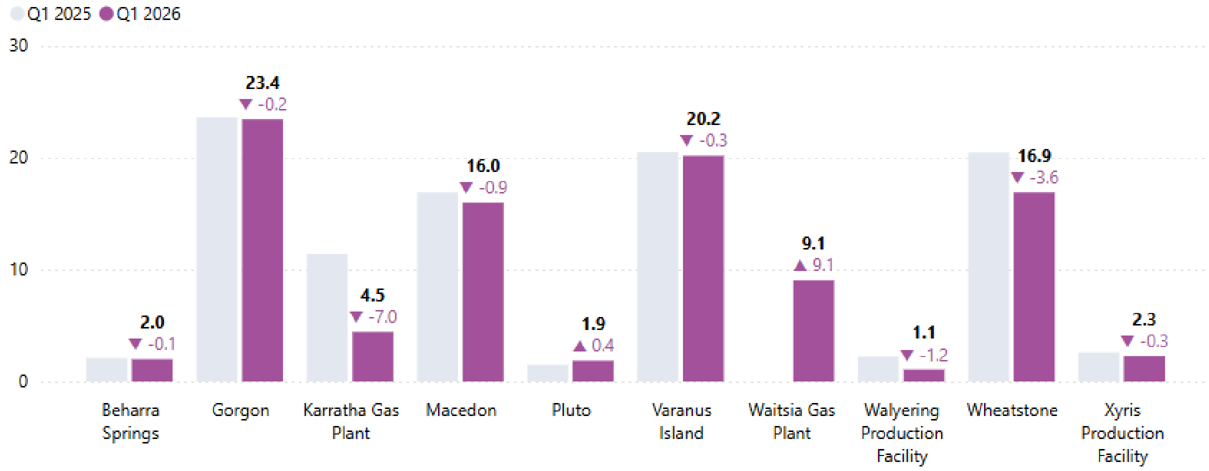
5.2.1 Gas production

Total gas production decreased to 97.3 PJ in Q1 2026, representing a decline of 4.1 PJ (-4.0%) compared to Q1 2025 with 101.4 PJ, as shown in **Figure 128**. The reduction in production was driven primarily by lower output from the Wheatstone and Karratha Gas Plant facilities, with smaller decreases observed across several other facilities. Wheatstone decreased by 3.6 PJ from 20.5 PJ in Q1 2025 to 16.9 PJ in Q1 2026, while Karratha Gas Plant decreased from 11.4 PJ to 4.5 PJ in the same timeframe.

This reduction was partially offset by production at the Waitsia Gas Plant, which produced 9.1 PJ in Q1 2026 and had not commenced production in Q1 2025.

Figure 128 Gas production in Western Australia decreased by 4.1 PJ compared to Q1 2025

Quarterly gas production by production facility (PJ)– Q1 2025 and Q1 2026



5.2.2 Storage facility

Net withdrawals from storage facilities were recorded in Q1 2026, with total net withdrawals of 1.2 PJ, compared to net withdrawals of 1.8 PJ in Q1 2025, as shown in **Figure 129**.

Figure 129 Net withdrawals from storage in Q1 2026

Gas storage facility injections and withdrawals (PJ) – Q1 2025 and Q1 2026

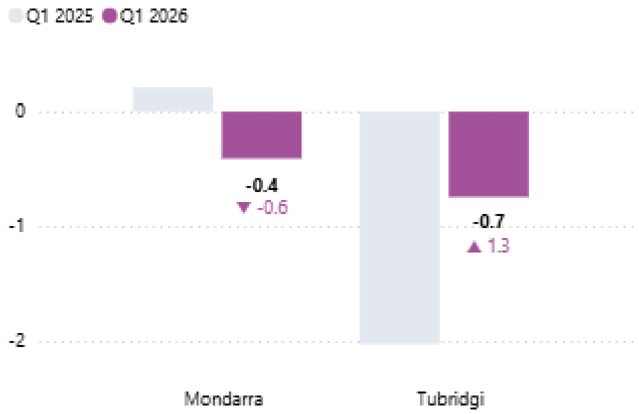
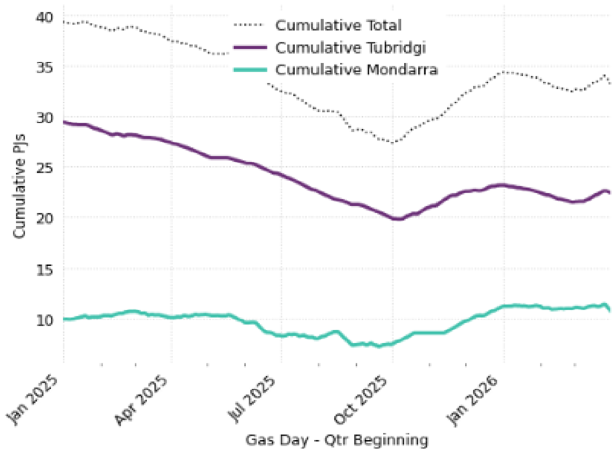


Figure 130 Cumulative storage levels in Q1 2026

Gas storage levels by facility over time



Mondarra recorded net withdrawals of 0.4 PJ in Q1 2026, compared to net injections of 0.2 PJ in Q1 2025. Even though Tubridgi recorded 1.3 PJs more storage than Q1 2025 (2 PJ net withdrawal), this quarter still reflects net withdrawals of 0.7 PJ. In Q1 2026, cumulative gas storage levels were lower than in Q1 2025, as seen in **Figure 130**. This is driven largely by a reduction in storage at Tubridgi.

5.2.3 Linepack Capacity Adequacy (LCA)

LCA is an indication of the actual or expected capability of a pipeline to meet relevant delivery nominations, and, for a storage facility, an indication of the number of days for which supply of natural gas can be maintained at the maximum operational outlet capacity. An Amber flag indicates that while firm demand is expected to be met, interruptible gas flows may be curtailed, and overall system flexibility is reduced.

On 27 March, Mondarra was flagged Red, indicating signals increased operational risk in response to Cyclone Narrelle. During the cyclone period, the Dampier to Bunbury Natural Gas Pipeline was under Amber conditions across the Dampier, Metro and South West zones from 27 March through to the end of the quarter on 31 March. The Amber status can also be seen earlier in the quarter, on 9 and 10 of February, also due to low linepack conditions associated with producer outages and cyclone-related impacts.

6 Reforms delivered

AEMO, with government and industry, continues to deliver energy market reforms across the WEM, NEM and east coast gas markets. These reforms provide for changes to key elements of Australia's electricity and gas market design to facilitate a transition towards a modern energy system, capable of meeting the evolving wants and needs of consumers, as well as enabling the continued provision of the full range of services necessary to deliver a secure, reliable and lower emissions system at least cost. **Table 11** provides a brief description of the reforms implemented over the last quarter.

Table 11 Reforms delivered Q1 2026

Reform initiative	Market	Description	Reform delivered
East coast gas system (ECGS) notice of closure rule change	Gas	AEMO implemented the ECGS notice of closure rule change by making the necessary amendments required to the Gas Statement of Opportunities (GSOO) Procedures. The notice of closure rule change: • Applies to a reportable closure decision, which is the decision of a facility to permanently cease supply of covered gas services. • Requires a reportable closure decision to be reported through the GSOO survey process. The survey is also used for the purposes of the Victorian Gas Planning Report (VGPR). • Requires a GSOO reporting entity to inform AEMO: – about a reportable closure decision, where practicable, at least 36 months prior to the intended date for cessation of supply. On receipt of a reportable closure decision AEMO will be required to publish a notice on its website. In circumstances where the intended date for cessation of supply in within 36 months of the reportable closure decision, a GSOO reporting entity must provide reasons in writing to AEMO for why it has not been able to provide 36 months' notice. These reasons will be published. – as soon as practicable, where the reporting entity identifies new information relating to a reportable closure decision outside a GSOO survey cycle. AEMO will then publish a notice on its website and will consider whether a supplement to the GSOO or VGPR is required. The amended GSOO Procedures took effect on 13 February 2026. More information: https://www.aemo.com.au/consultations/current-and-closed-consultations/implementation-of-the-ecgs-notice-of-gas-infrastructure-closure.	January 2026
Extension of the DWGM Dandenong LNG interim arrangements	Gas	In 2025, amendments to the National Gas Rules extended the interim arrangements for the Dandenong LNG facility within the DWGM to 31 December 2029. The reform also introduced additional transparency and reporting requirements, including obligations for the facility to comply with Gas Bulletin Board reporting and maintenance planning provisions. AEMO has implemented corresponding procedure changes to give effect to these rule amendments. The amended Procedures took effect on 1 April 2026. More information: https://www.aemo.com.au/consultations/current-and-closed-consultations/implementation-of-extension-of-the-dwgm-dandenong-lng-interim-arrangements.	January 2026
Update to Wholesale Market Gas Quality Monitoring Procedures	Gas	On 13 June 2025, Standards Australia published AS4565:2025 General-purpose natural gas and natural gas equivalents. This amendment to AS4565 was implemented to facilitate the incorporation of renewable gas including hydrogen and biomethane. AEMO has implemented amendments to the Wholesale Gas Quality Monitoring Procedures for consistency with AS4564:2025. The amended Procedures took effect on 10 March 2026. More information: https://www.aemo.com.au/consultations/current-and-closed-consultations/update-to-wholesale-market-gas-quality-monitoring-procedures.	February 2026

Reform initiative	Market	Description	Reform delivered
Contingency Reserve Raise and RoCoF cost recovery	WEM	Changes to the recovery of Contingency Reserve Raise (CRR) and RoCoF essential system services in the WEM commenced on 26 February 2026. These changes encompassed modifications to: • the cost allocation methodology for CRR and the Additional RoCoF Control Requirement to achieve the desired cost allocation in the edge cases of loss from network or distributed energy resources (DER) causes; • Energy Uplift Payments to ensure that costs of Energy Uplift Payments arising from AEMO constraining-on a facility to provide RoCoF Control Service (RCS) are appropriately allocated to all Market Participants who cause the RCS requirement; and • introduce a new payment type RCS Uplift Payment where AEMO has facilitate directions to provide RCS. To enable these changes, AEMO has implement changes to its settlement system and supporting applications of the dispatch engine to give effect to the requirements of the Electricity System and Market Rules (ESM Rules). Once settlement occurs for days commencing after 26 February, the cost of procuring CRR and RoCoF will be more fairly allocated to a Market Participant according to the individual risks of their facilities and the contribution of their facilities to any Network Raise Risks that set the Largest Credible Supply Contingency. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/p3109-first-final.pdf.	February 2026

In addition to these reforms, work continues to progress on the next wave of initiatives set for release in 2026. **Table 12** below provides a brief description of initiatives to be delivered in Q2 and Q3 2026.

Table 12 Upcoming implementation of reforms Q2 2026 – Q3 2026

Reform initiative	Market	Description	Reform to be delivered
Relevant Level Method (RLM)	WEM	In September 2023, Energy Policy WA recommended changes to the RLM detailed in the ESM Rules. The RLM is a key component of the Reserve Capacity Mechanism in the Wholesale Electricity Market. It determines how many Capacity Credits a facility, particularly an intermittent generator like wind and solar, can receive based on its contribution to system reliability. The fundamental change is a move toward Effective Load Carrying Capability (ELCC) based modelling, which is a probabilistic measure of reliability contribution, rather than simple historical averages. The new RLM introduces numerical models that simulate system conditions and better evaluate the contribution of different forms of generation and storage under system stress scenarios. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/p03427-relevant-level-method-final-ia.pdf.	Q2 2026
Demand Side Programme Participation – Workstream 1	WEM	In September 2023, Energy Policy WA made several ESM Rule changes to implement the outcomes of its Reserve Capacity Mechanism Review. One of the initiatives within that review proposed amending Rules to simplify the process for facilities participating as a Demand Side Programme (DSP) within the Reserve Capacity Mechanism but increased the obligations for participation. Commencing from the 2024 Reserve Capacity Cycle, DSP Facilities can apply for certification without providing locational information. Workstream 1 of this reform focuses on the obligation that a Market Participant must provide the network locational information when registering a DSP Facility and associating loads to that DSP Facility. AEMO will implement changes to enable the registration of DSP Facility at the network location referred to as Transmission Node Identifier (TNI). Where a Market Participant did not provide the network location as part of the certification process, it must register DSP Facilities at a TNI, associate loads to the DSP from the same TNI, and distribute Capacity Credits from the certified DSP between one or more registered DSPs by 1 July of the relevant Capacity Year.	Q2 2026

Reform initiative	Market	Description	Reform to be delivered
		More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/dsp-participation-draft-ia.pdf.	
Demand Side Programme Participation – Workstream 2	WEM	In September 2023, Energy Policy WA made several ESM Rule changes to implement the outcomes of its Reserve Capacity Mechanism Review. One of the initiatives within that review proposed amending Rules to simplify the process for facilities participating as a Demand Side Programme (DSP) within the Reserve Capacity Mechanism but increased the obligations for participation. Commencing from 1 October 2026 DSP Facilities will subject to more stringent refunds for failure to provide the obligated capacity when dispatched to subject to a reserve capacity test. Workstream 2 of this reform focuses on the dispatch, reserve capacity testing, and settlement obligations of DSP Facilities. AEMO will implement changes to enable: • DSP aggregators to identify in their DSP Profile Submissions where the facility will provide injection or withdrawal; • simplification of AEMOs dispatch process for DSPs to effectively dispatch large numbers of DSP Facilities within the obligations of the ESM Rules; • both summer and winter testing of DSP facilities where they have not already proven their ability to provide their Capacity Credits; • a new dynamic baseline methodology (Relevant Demand) to measure the performance of the DSP following a dispatch or reserve capacity test; and • revised settlement calculations for failure to deliver the expected capacity in line with the Reserve Capacity obligations. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/dsp-participation-draft-ia.pdf.	Q3 2026
Flexible Trading Arrangements (FTA)	NEM	On 15 August 2024, the Australian Energy Market Commission (AEMC) published its final determination on the "Unlocking Consumer Energy Resources (CER) Benefits through Flexible Trading" rule. This rule is designed to enhance the flexibility of how CER are used and traded within the NEM enabling consumers to better manage their energy usage and participate in the market. The rule is optional, and allows: • large customers to engage multiple energy service providers at their premise, • energy service providers for small and large customers to separate and manage 'flexible' CER or active loads (secondary settlement point) from 'passive' loads (connection point), and • minor energy metering flows to be metered to enable the delivery of innovative and essential products and services at lower cost. Further, the final determination introduces new metering types – Type 8 that allows for bespoke requirements to apply for the metering of CER within customers' premises, and Type 9 which is designed to enable the integration of street furniture (such as kerbside electric vehicle chargers, smart street lighting systems) into the NEM metering framework. AEMO is implementing FTA across two releases. • The first release (31 May 2026) gives effect to Type 9 metering arrangements. • A subsequent release in November 2026 will give effect to the remainder of the rule requirements. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/flexible-trading-arrangements.	Q2 2026
Metering Services Review – Package 2	NEM	The Accelerating Smart Meter Deployment (ASMD) rule seeks to achieve universal smart meter deployment in the NEM by 2030. To facilitate the accelerated deployment, the AEMC final determination introduces new obligations for industry coordination between Distribution Network Service Providers (DNSPs), Financially Responsible Market Participants (FRMPs), and Metering Coordinators (MCs) for sites with shared points of isolation. This includes a requirement for MCs to provide DNSPs with a basic power quality data (PQD) service and for AEMO to determine the specifications, formats, and delivery mechanism for this service. The second and final release (1 July 2026) enables better access to PQD for DNSPs.	Q3 2026

Reform initiative	Market	Description	Reform to be delivered
		More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/metering-services-review---accelerating-smart-meter-deployment.	
Shortening the settlement cycle	NEM	On 12 December 2024, the AEMC published its final determination on the "Shortening the settlement cycle" rule change. The final rule shortens the NEM settlement cycle to nine (9) business days following the end of a billing period and introduces a new revision 20 business days following the end of the billing period. The final rule has three major implementation components: • establishing metering and settlement processes that support a new, shorter settlement cycle, • adapting the credit limit procedures (CLP) and supporting process to reflect the shorter settlement cycle, and • transitioning metering, settlement and prudential processes from the current settlement cycle to the shorter settlement cycle. The final rule will commence on 9 August 2026. AEMO will have from 9 August 2026 to 17 October 2026 to complete this transition from a 20-business day to 9 business day settlement period. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/shortening-the-settlement-cycle.	Q3 2026
Project EnergyConnect (PEC) – Market Integration	NEM	When implemented, PEC (Stage 2) will provide approximately 800 MW of transmission capacity between New South Wales and South Australia. This will create a parallel transmission configuration between three adjacent regions which presents new challenges for the NEM, especially for the way negative inter-regional settlement residue is managed. AEMO undertook stakeholder consultation on PEC Market Integration (PEC-MI), with the final recommendations published on 9 February 2024. On 25 September 2025, the AEMC made a final determination and more preferable final rule that will net off inter-regional settlements residue (IRSR) in transmission loops. The final rule commenced on 2 October 2025, noting that the new IRSR arrangements for transmission loops will not take effect until a transmission loop is in operation in the NEM dispatch engine and changes to AEMO's settlement systems have been implemented. The final rule requires project go-live to occur no earlier than 1 October 2026 and no later than 2 November 2026. Integration of PEC Stage 2 into AEMO's systems is designed in 2 phases: • Release 1 August 2026: Integrate a transmission loop into AEMO dispatch systems (price scaling and negative residue management), and • Release 2 November 2026: Integrate PEC into AEMO settlement systems (IRSR, Settlement Residue Auction [SRA]). More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/project-energyconnect-market-integration-project.	Q3 2026

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Abbreviations

Abbreviation	Expanded term
5MS	Five-Minute Settlement
ACCC	Australian Competition and Consumer Commission
ACE	Adjusted Consumed Energy
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APLNG	Australia Pacific LNG
ASMD	Accelerating Smart Meter Deployment
ASX	Australian Securities Exchange
BESS	battery energy storage system
CDD	cooling degree days
CDEII	Carbon Dioxide Equivalent Intensity Index
CER	consumer energy resources
CGP	Carpentaria Gas Pipeline
CLP	credit limit procedures
CRR	Contingency Reserve Raise
DAA	Day Ahead Auction
DER	distributed energy resources
DNSP	distribution network service provider
DR	demand response
DSP	Demand Side Programme
DUID	Dispatchable Unit Identifier
DWGM	Declared Wholesale Gas Market
ECGS	east coast gas system
EDD	effective degree day
EGP	Eastern Gas Pipeline
ELCC	Effective Load Carrying Capability
ERI	Enhancing Reserve Information
ESM	Electricity System and Market (previously WEM Rules)
ESOO	*Electricity Statement of Opportunities*
ESR	electric storage resource
ESS	essential system services
FCAS	frequency control ancillary services
FCESS	frequency co-optimised essential system services
FPP	Frequency Performance Payment
FRMP	Financially Responsible Market Participant
FTA	flexible trading arrangements
GBB	Gas Bulletin Board

Abbreviation	Expanded term
GJ	gigajoule/s
GJ/h	gigajoules per hour
GSOO	*Gas Statement of Opportunities*
GW	gigawatt/s
GWh	gigawatt hour/s
GLNG	Gladstone LNG
GSH	Gas Supply Hub
IEA	International Energy Agency
IRR	interim reliability reserve
IRSR	inter-regional settlement residue
LCA	Linepack Capacity Adequacy
LGC	large-scale generation certificate
LNG	liquefied natural gas
LOR1	Lack of Reserve 1
MC	Metering Coordinator
MCF	Moomba Compression Facility
MNSP	market network service provider
MSL	minimum system load
MSP	Moomba Sydney Pipeline
MT PASA	Medium Term Projected Assessment of System Adequacy
$MtCO_2$-e	million tonnes of carbon dioxide equivalents
MW	megawatt/s
MWh	megawatt hour/s
NEM	National Electricity Market
NCESS	non-co-optimised essential system service
NMI	National Metering Identifier
NSCAS	network support and control and ancillary services
NGP	Northern Gas Pipeline
NO	Network Operator
NSP	network service provider
NT	Northern Territory
PCI	Port Campbell to Iona Pipeline
PEC	Project EnergyConnect
PEC-MI	Project EnergyConnect – Market Integration
pp	percentage points
PJ	petajoule/s
PQD	power quality data
PV	photovoltaic
QED	*Quarterly Energy Dynamics*
QCLNG	Queensland Curtis LNG

Abbreviation	Expanded term
QNI	Queensland – New South Wales Interconnector
R6SE	raise 6-second (FCAS)
RCS	RoCoF control service
RERT	Reliability and Emergency Reserve Trader
RLM	Relevant Level Method
RoCoF	Rate of Change of Frequency
RRP	regional reference price
SOC	state of charge
SRA	Settlement Residue Auction
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
tCO2-e	tonnes of carbon dioxide equivalent
TJ/d	terajoules per day
TJ/y	terajoules per year
TNI	Transmission Node Identifier
TWAP	time-weighted average price
UAE	United Arab Emirates
UGS	Underground Storage Facility
US	United States
VGPR	*Victorian Gas Planning Report*
VWAP	volume-weighted average price
VPP	virtual power plant
VRE	variable renewable energy
VNI	Victoria – New South Wales Interconnector
WA	Western Australia
WARBS	Western Australian Residential Battery Scheme
WEM	Wholesale Electricity Market
WEMDE	WEM dispatch engine
WDR	wholesale demand response