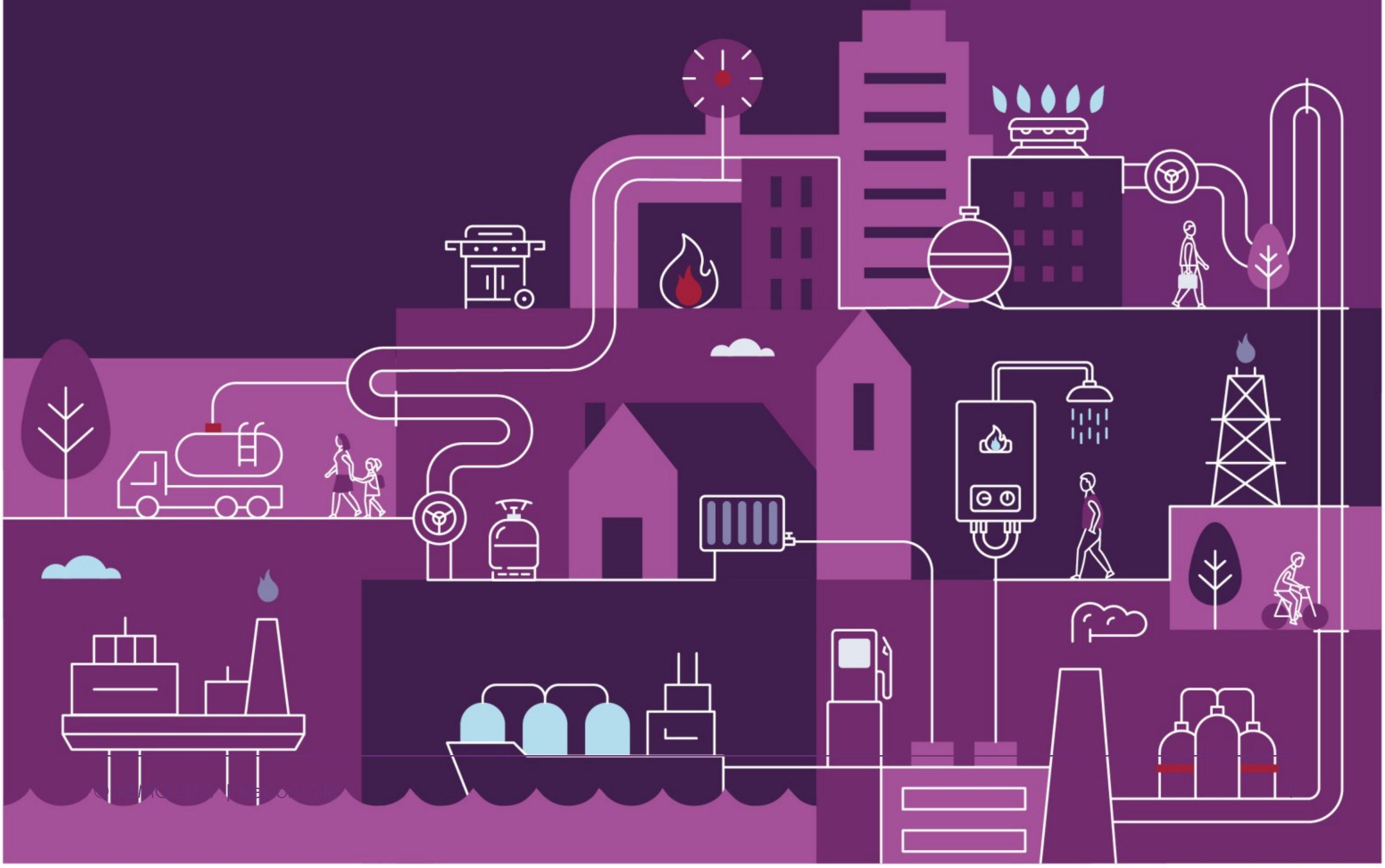
Quarterly Energy Dynamics Q4 2025

January 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 Q4 2025 (1 October to 31 December 2025). This quarterly report compares results for the quarter against other recent quarters, focusing on Q4 2024 and Q3 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.

Disclaimer

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- past, current or future market conditions, prices and outcomes; and
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Executive summary

East coast electricity and gas highlights

National Electricity Market (NEM) underlying demand reached a new Q4 high as consumer energy resources continued to shape the demand profile

- Warmer temperatures in the northern regions and cooler temperatures in the southern regions saw average NEM-wide underlying demand set a new Q4 high at 24,271 megawatts (MW), up 2.2% from Q4 2024. With distributed photovoltaic (PV) output reaching an all-time quarterly high at 4,407 MW (+8.7%) and offsetting daytime demand, operational demand increased only slightly (+0.9%) to 19,864 MW.
- Installations of distributed PV and household battery consumer energy resources (CER) continued to grow. Total distributed PV supply reached 61% of NEM underlying demand in one half-hour interval, and household battery installations surged past 145,000[1], with total storage capacity at 3,398 megawatt hours (MWh).
- Distributed PV output growth drove further reductions in minimum operational demand. Mild and sunny conditions in October led to a record low in NEM-wide demand at 9,666 MW (down 4.0% from the previous record), along with a new Q4 low in Queensland at 2,992 MW, while Tasmania recorded an all-time low demand of 678 MW on 2 November. Later, between 25 December and New Year's Eve, Victoria (1,287 MW) and South Australia (-263 MW) reached new all-time lows, while New South Wales set a new Q4 low of 2,848 MW.

Renewables supplied more than 50% of quarterly NEM energy needs for the first time

- Total NEM generation averaged 25,064 MW (+3.1%), with renewables (including storage) exceeding 50% of the quarterly energy mix for the first time, delivering 51.0% of overall supply, up from 46% in Q4 2024.
- Variable renewable energy (VRE) output set a new quarterly average output record of 6,627 MW, up 23% from Q4 2024. This increase comprised a 29% rise in wind output and a 15% increase in grid-scale solar, reflecting growth in new and commissioning capacity and improved wind conditions. Battery discharge nearly tripled to average 268 MW, with 3,796 MW / 8,602 MWh of new large-scale battery capacity added to the grid since the end of Q4 2024.
- Coal-fired generation fell to an all-time quarterly low at 11,544 MW, down 4.6% from Q4 2024, with both black and brown coal generation at record lows, although black-coal fired availability improved this quarter compared to Q4 last year. Gas-fired generation also recorded its lowest Q4 output since 2000, and overall, the fossil fuel share of the NEM supply mix decreased from 54.0% in Q4 2024 to 49.0% in Q4 2025.
- The increase in renewable output drove NEM total emissions and emissions intensity to new all-time record low levels of 23.4 million tonnes of carbon dioxide equivalent (MtCO2-e) and 0.53 tonnes of carbon dioxide equivalent (tCO2-e/MWh) respectively.

[1] Includes installations in NEM regions from 1 July 2025, when solar batteries became eligible under the Small-scale Renewable Energy Scheme, up to 31 December 2025. Data includes installations that have had their application for small-scale technology certificates approved and does not include installations with pending applications.

Wholesale electricity prices fell across all NEM regions

- Wholesale electricity prices across the NEM averaged $50/MWh[2], a $39/MWh (-44%) reduction from Q4 2024 and a $37/MWh (-43%) decline from Q3 2025. Large reductions were recorded across all regions, with New South Wales at $75/MWh (down 48% from this quarter last year), Queensland at $58/MWh (-55%), Tasmania at $41/MWh (-41%), South Australia at $37/MWh (-30%) and Victoria at $37/MWh (-18%).
- Price volatility (spot prices above $300/MWh) added only $3/MWh to this quarter's NEM average, a significant decrease from $17/MWh in Q4 2024 when an early season heatwave coincided with coal generator and transmission outages.
- Increased wind generation and battery discharge, particularly in the evening peaks, reduced reliance on gas and hydro generation in those periods, contributing to lower average prices and the reduced incidence of high-priced intervals.

System security directions to manage system strength and minimum system load increased, and network limits impacted economic offloading of VRE

- Interventions in the market, via directions to market participants, were required to maintain system strength as the number of synchronous generators online at times dipped below required levels in New South Wales and Victoria. Directions were also issued to manage minimum system load conditions in South Australia on multiple low demand days in November and December.
- Network constraints and interconnector limits continued to shape regional price outcomes and VRE offloading. Transmission constraints between the northern and southern regions, and changed Basslink behaviour reducing exports to Tasmania, contributed to record high occurrence of zero and negative prices in South Australia and Victoria, reaching 48% and 43% of intervals, respectively. Economic offloading of wind and solar capacity reached 15% and 18% of availability.

East Coast Q4 2025 gas prices were lower than Q4 2024 driven by lower demand

- East coast wholesale gas prices averaged $12.68 per gigajoule (GJ) for the quarter, lower than Q4 2024 which averaged $13.60/GJ, and consistent with Q3 2025 which averaged $12.62/GJ.
- Gas demand decreased by 3% from Q4 2024, driven by lower demand for Queensland liquified natural gas (LNG) exports (-10 petajoules [PJ]) and lower demand for gas-fired generation (-6 PJ). AEMO markets saw a slight increase (+3.1 PJ) due to colder weather conditions compared to Q4 2024.
- While gas production declined across all regions, Queensland LNG export demand fell at a faster rate than the associated supply reduction from those projects with an additional 2.3 PJ available for the domestic market. Victorian production for the quarter was lower (-8.9 PJ) due to a combination of higher flows from Queensland to southern markets, decreased gas-fired generation demand and major outages at the Longford and Otway gas plants.
- Iona underground gas storage (UGS) was used to support demand on colder days for much of the quarter, with inventory only increasing from 11.8 PJ to 13.5 PJ, its lowest at the end of Q4 since 2021.

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

Western Australia electricity and gas highlights

Operational demand was steady, with increases in battery charging partially offset by distributed PV in Q4 2025

- Average operational demand was 1,882 MW in Q4 2025, 12 MW (+0.7%) higher than in Q4 2024. The increase was driven by higher average battery charging, up 81 MW (+199%), partially offset by increases of 46 MW (+7.8%) in distributed PV output and 6.5 MW (+42.8%) in average embedded system generation.

Average renewable contribution exceeded 50% for the first time in a quarter

- Average renewable contribution was 52.4% for Q4 2025, a new Wholesale Electricity Market (WEM) quarterly record. This comprised strong distributed PV (24.9%, +1.1 percentage points (pp) from Q4 2024), wind (18.2%, +0.7 pp), battery (4.2%, +2.8 pp), hybrids (1.3%, +1.1 pp) and biomass (1.5%, +1.1 pp).
- The WEM also experienced a new peak renewable contribution of 91.1% during the 11:35 interval on Saturday, 20 December 2025. This followed clear, sunny conditions and mild temperature facilitating a high distributed PV contribution of 62.6%, which combined with a strong wind contribution of 19.8%. Prior to Q4 2025, the peak renewable contribution record was 85.1%, set in Q4 2024.
- Coal and gas generation decreased 33 MW (-5.8%) and 126 MW (-16.4%), respectively. This can be attributed to the increase in renewable contribution, small decreases in facility availability, and changes to the Frequency Co-Optimised Essential System Services (FCESS) Uplift framework which resulted in fewer synchronous facilities committing during low demand periods.
- The increase in renewable contribution and reductions in coal and gas generation resulted in a reduction in emissions by 14.4% on Q4 2024, to 1.77 MtCO2-e.

WEM energy prices and FCESS costs decreased

- The average energy price in Q4 2025 was $69.55/MWh, a decrease of $10.37/MWh (-13%) from Q4 2024 and a decrease of $32.21/MWh (-32%) from Q3 2025. This can be attributed to the increase in renewable generation meeting demand.
- Essential System Services costs fell 82% from Q4 2024, to a total of $17.7 million in Q4 2025. This can be attributed to rule changes which reduced FCESS Uplift costs by $48.8 million (-96%) and the addition of three FCESS-accredited batteries reducing FCESS enablement costs by $34.5 million (-83%).
- Overall, normalised WEM costs reduced by $18.30/MWh to $132.09/MWh (-12%). Offsetting the reduction in energy (-$10.37/MWh), FCESS Uplift (-$12.35/MWh) and FCESS enablement costs (-$7.91/MWh) was an increase in Non-Co-Optimised Essential System Services (+$6.25/MWh) and reserve capacity costs (+$7.80/MWh).

Western Australia domestic gas saw reductions in consumption and production in Q4 2025

- Western Australia's domestic gas consumption was 94.5 PJ, a decrease of 9.7 PJ (-9.3%) on Q4 2024. Production was 102 PJ, a decrease of 1.8 PJ (-1.7%) compared to Q4 2024. Storage recorded a net injection of 6.9 PJ, which broke a consecutive run of seven quarters of withdrawal.

Contents

1 Weather

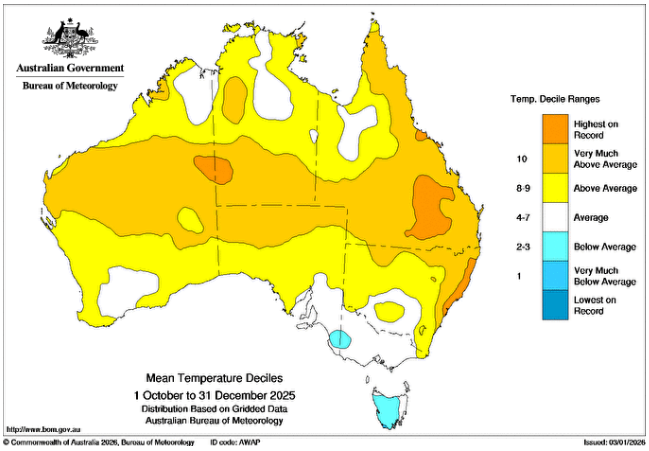
In Q4 2025, Australia generally experienced above-average temperatures, but with varied regional weather conditions through the quarter (Figure 1). Mean temperatures were above average across northern regions, while southern regions recorded average to below-average mean temperatures.

The quarter commenced with hot, dry and predominately sunny conditions in October across large parts of the mainland, with temperatures widely above average. Area-averaged mean temperatures for Queensland and the Northern Territory were the highest on record for October. Low to severe intensity heatwave conditions developed across northern parts of the Northern Territory, parts of Queensland and Western Australia, and persisted throughout the month.

November saw variable weather across the mainland, with above-average mean maximum temperatures through Queensland, New South Wales and parts of Western Australia, while temperatures were below average in the southern states. Increased thunderstorm activity affected New South Wales and Queensland towards the end of the month due to tropical moisture interacting with dry surface conditions. Severe storms on 25 and 26 November developed over parts of New South Wales, including Greater Sydney, with heavy rainfall and damaging winds. In December, mean temperatures were generally average to above-average across much of the mainland, while parts of the southern states and extensive areas of Queensland, the Northern Territory and northern Western Australia experienced average or below average conditions. Periods of rainfall increased during the month of December, particularly in the northern and eastern states.

Figure 1 Warmer than average temperatures across most of Australia

Q4 2025 mean temperature deciles for Australia



Source: Bureau of Meteorology (BOM)

Figure 2 Lower maximum temperatures in southern cities across the quarter

Average monthly maximum temperature variance by capital city – Q4 2025 vs Q4 2024

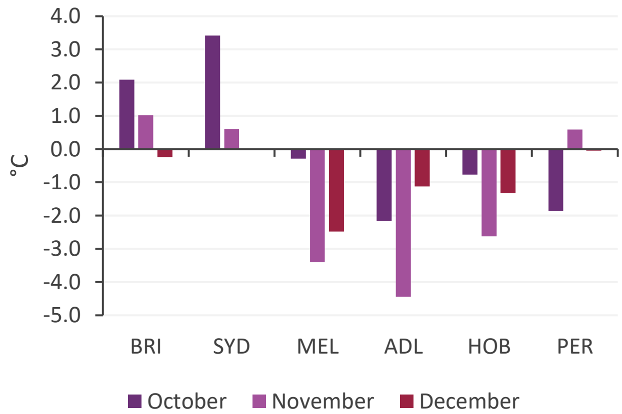


Figure 2 shows that southern capital cities experienced lower average monthly maximum temperatures this Q4 compared to the very warm conditions prevailing in Q4 2024, with Melbourne, Adelaide and Hobart recording lower average maximums year-on-year across all three months. The cooler temperatures were most evident in November, when maximum temperatures in Melbourne and Adelaide were 3.4°C and 4.4°C lower than last year. Sydney and Brisbane recorded above average maximum temperatures year-on-year in October and November. Compared to Q4 2024, Perth was 1.9°C cooler in October, with later quarter conditions comparable to last year's.

2 NEM market dynamics

2.1 Electricity demand

In Q4 2025, NEM-wide underlying demand[3] reached a record Q4 average of 24,271 MW, up 530 MW (+2.2%) from Q4 2024 (Figure 3). This year-on-year uplift in underlying demand was driven by warmer than average conditions in the northern regions increasing cooling demand, while cooler conditions in the southern regions lifted heating demand, alongside continuing load growth due to electrification, data centres and population drivers.

NEM-wide distributed PV output increased by 353 MW (+8.7%) from Q4 2024, reaching a new all-time high of 4,407 MW and surpassing the previous record of 4,054 MW set in the previous year. The growth in distributed PV partially offset higher underlying demand during daytime hours, resulting in a slight increase in NEM-wide operational demand[4], which rose by 177 MW (+0.9%) to 19,864 MW this quarter (Figure 4).

Figure 3 Underlying demand grew to a new Q4 high

NEM average underlying and operational demand – Q4s

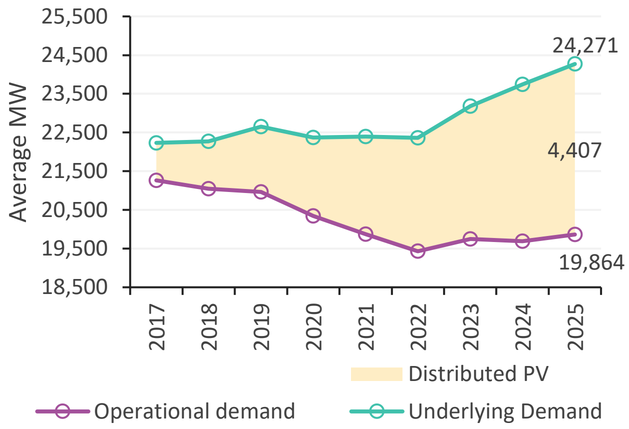
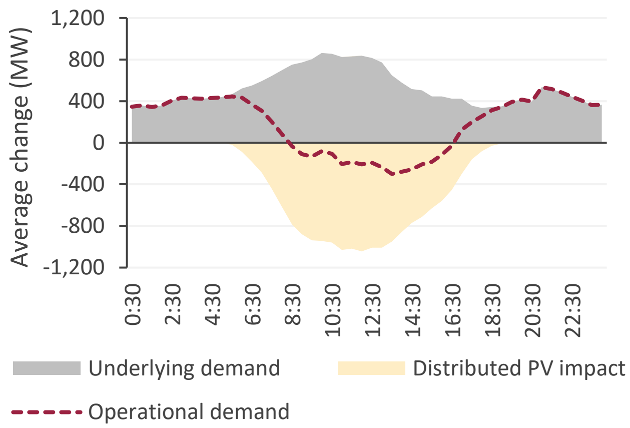


Figure 4 Higher underlying demand partially offset by distributed PV output growth

Average changes in NEM demands and distributed PV output by time of day – Q4 2025 vs Q4 2024



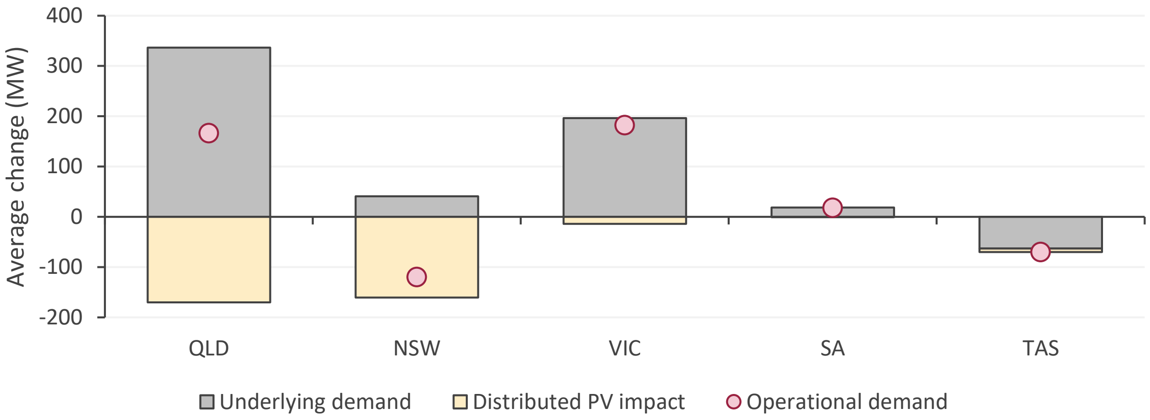
Operational demand increased in Queensland, Victoria and South Australia, but fell in New South Wales and Tasmania (Figure 5). Underlying demand increased in all mainland regions. Distributed PV output levels reached record highs in all regions, driven by continued growth in installed capacity. Increases in distributed PV output were strongest in Queensland and New South Wales, while output growth in South Australia and Victoria was modest this quarter due to decreased solar exposure year-on-year.

[3] Underlying demand is calculated by adding estimated production from distributed PV to operational demand, to yield an estimate of total electricity generated.

[4] 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.

Figure 5 NEM-wide underlying demand increase driven by Queensland and Victoria

Changes in average demand components by region – Q4 2025 vs Q4 2024



Comparing quarterly average outcomes in Q4 2025 with Q4 2024:

- **Queensland**'s underlying demand reached a new Q4 high of 7,685 MW this quarter, up 337 MW (+4.6%), with increases most evident during daytime hours. Distributed PV output also set a new high of 1,354 MW (+14%), partially offsetting underlying demand growth. As a result, operational demand rose to 6,331 MW, the highest Q4 level on record.
- **New South Wales** saw a slight rise in underlying demand, up by 41 MW (+0.5%) to average 8,388 MW this quarter. Higher temperatures and increased cooling requirements specifically during October contributed to higher daytime underlying demand. Distributed PV output surged to a record 1,513 MW (+12%), contributing to a new Q4 low in operational demand of 6,875 MW (-1.7%).
- In **Victoria**, underlying demand rose by 196 MW (+3.7%), averaging 5,485 MW this quarter, with increases across all times of day but most pronounced in morning hours due to heating requirements, partly offset by lower afternoon cooling loads. Distributed PV output increased slightly by 14 MW (+1.5%) to an average output of 956 MW, setting a record despite lower solar exposure year-on-year. Because of this limited distributed PV growth, operational demand increased by 182 MW (+4.2%) to average 4,530 MW.
- **South Australia**'s underlying demand reached a Q4 high of 1,624 MW this quarter, up 19 MW (+1.2%). Distributed PV also increased marginally to surpass previous year's record average, reaching 514 MW (+0.1%) this quarter. Lower year-on-year solar exposure limited distributed PV growth, particularly during October and November. Operational demand increased modestly by 18 MW (+1.6%) to average 1,111 MW this quarter, with underlying demand growth only marginally offset by distributed PV.
- **Tasmania** recorded the only decline in regional underlying demand this quarter, falling by 63 MW (-5.5%) to average 1,088 MW, the lowest Q4 average since Tasmania joined the NEM in 2005. As in previous quarters of 2025, this largely reflected lower industrial demand. Distributed PV output reached an all-time high, averaging 71 MW (+11%) and contributing to lower operational demand, which averaged 1,017 MW (-6.4%).

Consumer energy resources (CER)

CER continue to shape operational demand across the NEM. The ongoing uptake of household solar and increasing household battery penetration continued to influence operational demand across both daytime and evening intervals.

Cumulative CER solar capacity and installations have grown steadily across the NEM since 2020 (Figure 6). Total NEM-wide solar installations rose from 2.3 million in 2020 to 3.7 million by the end of 2025[5], an increase of nearly 61%. Over the same period, CER solar capacity more than doubled, rising from 12 gigawatts (GW) to 25 GW. Regionally, New South Wales recorded the largest growth, increasing from 3.5 GW to 8.4 GW, followed by Queensland (3.7 GW to 7.5 GW). Victoria grew from 2.6 GW to 5.6 GW, while South Australia increased from 1.5 GW to 2.8 GW.

Figure 6 Sustained growth in solar capacity and installations since 2020

Cumulative CER solar capacity and installations by region

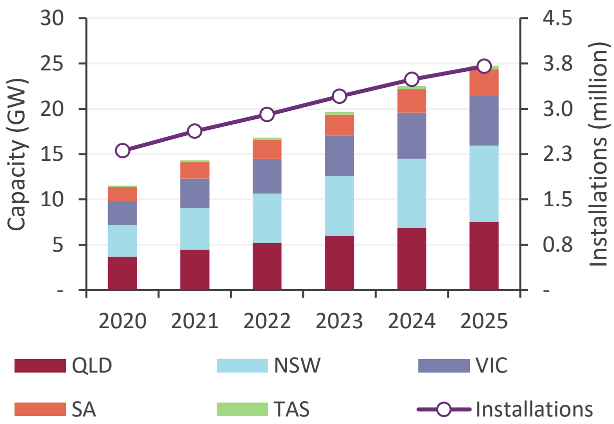
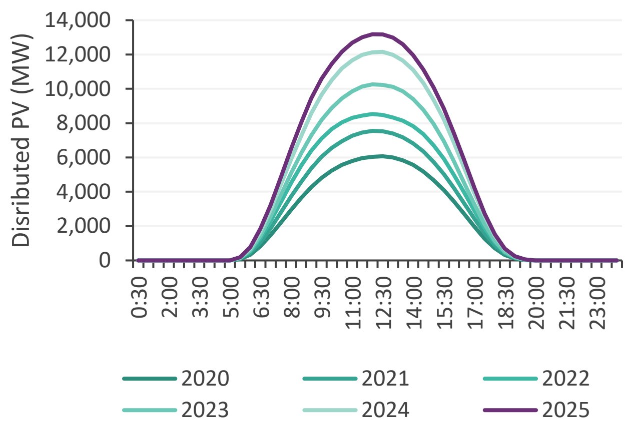


Figure 7 Distributed PV output continued to rise year-on-year

Average distributed PV output by time of day – Q4s



Source: Clean Energy Regulator

Consistent with the growth in installed capacity, distributed PV output continued to rise year-on-year across daytime hours (Figure 7). Average midday output (1000 hrs-1400 hrs) increased from 5,856 MW in Q4 2020 to 12,718 MW in Q4 2025, up 6,862 MW (+117%). This lifted distributed PV's share of underlying demand during these hours from 24% in Q4 2020 to 45% in Q4 2025. The peak contribution of distributed PV output also nearly doubled from a maximum of 32.2% in 2020 to 61.0% in 2025, recorded in the half-hour ending 1200 hrs on Saturday 4 October 2025.

Household battery capacity increased rapidly during the second half of 2025, with the introduction of the Australian Government's cheaper home battery program[6] (Figure 8). Under the program, cumulative household battery capacity reached 3,398 MWh at the end of December 2025, with installations surpassing 145,000[7]. Program-installed household batteries now provide a combined NEM-wide storage capacity three times higher than the largest fully commissioned grid-scale battery (Eraring, at 1,073 MWh), and in every mainland region the aggregate capacity is comparable to or larger

[5] Data from Clean Energy Regulator: https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data. Data current as of 31 December 2025, noting that a 12-month creation period for registered persons to create small-scale technology certificates applies so figures for 2025 will continue to rise.

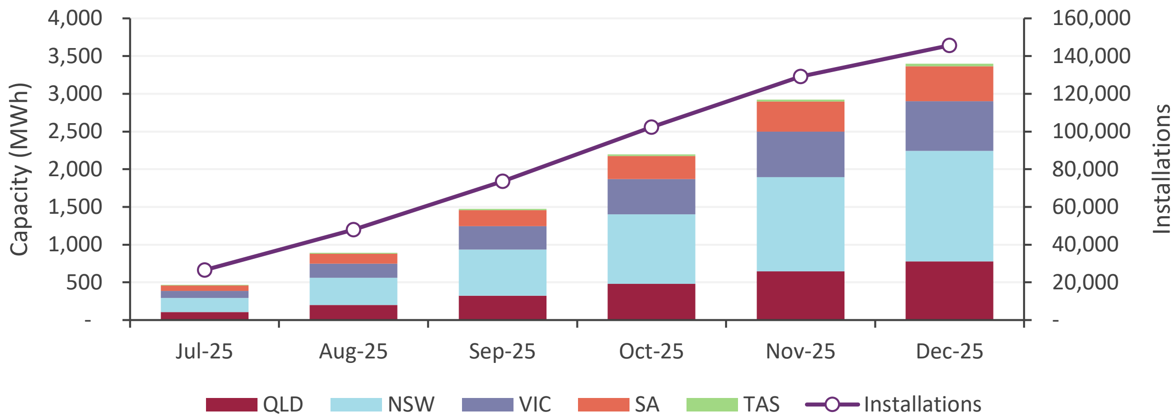
[6] See https://www.dcceew.gov.au/energy/programs/cheaper-home-batteries.

[7] 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 December 2025. Postcode data only includes installations that have had their application for small-scale technology certificates approved. It does not include installations with pending applications.

than each region's largest grid-scale battery. By the end of 2025, program-installed household battery capacity reached 1,468 MWh in New South Wales, followed by Queensland (776 MWh), Victoria (659 MWh), South Australia (463 MWh) and Tasmania (32 MWh).

Figure 8 Growth in CER battery capacity and installations across the NEM

Cumulative CER Battery capacity and installations by region



Source: Clean Energy Regulator

Maximum and minimum demands

In Q4 2025, NEM-wide **maximum operational demand** reached 32,321 MW during the half-hour ending 1830 hrs on Thursday, 18 December 2025. This was 1,395 MW (-4.1%) lower than the NEM Q4 maximum demand record of 33,716 MW set in the previous year.

Queensland recorded a new Q4 maximum operational demand of 10,373 MW in the half-hour ending 1800 hrs on 22 December 2025 (Figure 9), driven by hot conditions and elevated cooling demand during the evening peak. This was an increase of 559 MW (+5.7%) on the previous Q4 high set in Q4 2024. Maximum demand in New South Wales increased by 559 MW (+4.5%) from Q4 2024, reaching 13,022 MW this quarter. South Australia also recorded a higher maximum demand, up by 69 MW (+2.5%) year-on-year to 2,784 MW. In contrast, Victoria's maximum demand declined by 1,676 MW (-17%) to 8,175 MW, while Tasmania's maximum demand fell by 51 MW (-3.7%) to 1,336 MW.

NEM-wide **minimum operational demand** reached an all-time[8] low of 9,666 MW in the half-hour ending 1200 hrs on Saturday, 4 October 2025, 407 MW (-4.0%) lower than the previous record set in Q4 2024. Across mainland regions, minimum demand reached record low levels in Q4 2025 (Figure 10), with new Q4 lows set in New South Wales and Queensland, while Victoria, South Australia and Tasmania recorded all-time minimums.

Minimum operational demand in New South Wales reached 2,848 MW during the half-hour ending 1230 hrs on 29 December 2025, down 273 MW (-8.7%) compared to the previous Q4 low set in Q4 2024. Queensland minimum demand fell to 2,992 MW during the half-hour ending 1100 hrs on 5 October 2025, 99 MW (-3.2%) lower than the Q4 record also set last year. Victoria's minimum operational demand declined to 1,287 MW in the half-hour ending 1300 hrs on 27 December 2025, down 326 MW (-20%) from the previous Q4 low set in 2023, and 217 MW (-14%) below the prior all-time low set on

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

New Year's Day 2025. Minimum operational demand in South Australia reached -263 MW during the half-hour ending 1400 hrs on 25 December 2025, which was 58 MW lower than the previous Q4 and all-time record set in October 2024. Tasmania saw a decrease of 50 MW (-6.9%) compared to Q4 2024, to reach a record minimum operational demand of 678 MW on 2 November 2025.

Figure 9 Record Q4 maximum operational demand in Queensland

Maximum operational demand for mainland regions – Q4s

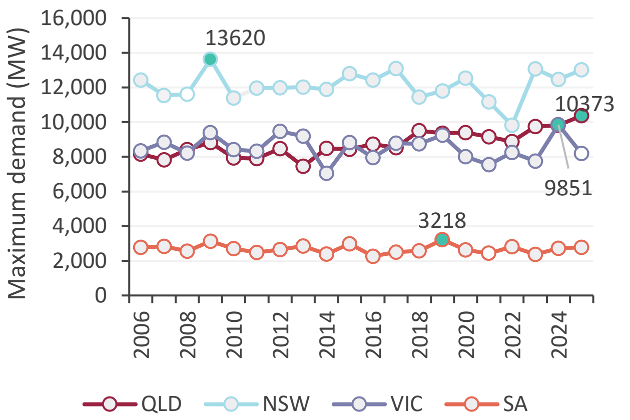
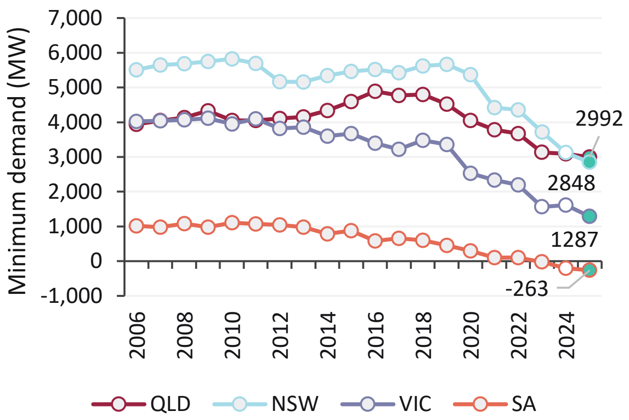


Figure 10 All mainland regions set new Q4 lows for minimum operational demand

Minimum operational demand for mainland regions – Q4s

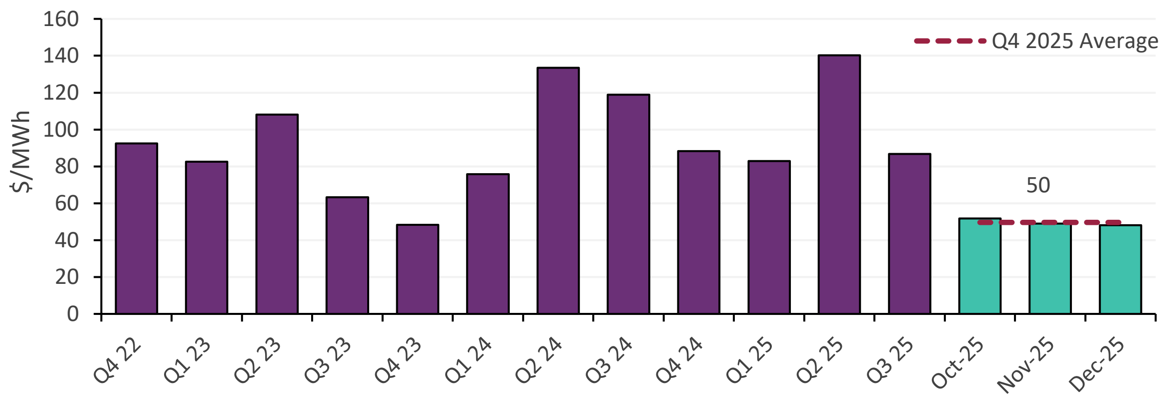


2.2 Wholesale electricity prices

This quarter, wholesale electricity prices across the NEM averaged $50/MWh[9], a $39/MWh (-44%) reduction from Q4 2024 and a $37/MWh (-43%) decline from Q3 2025 (Figure 11). Average monthly prices were $52/MWh in October, $49/MWh in November and $48/MWh in December.

Figure 11 NEM average wholesale prices fell significantly

NEM average wholesale electricity prices – quarterly since Q4 2022

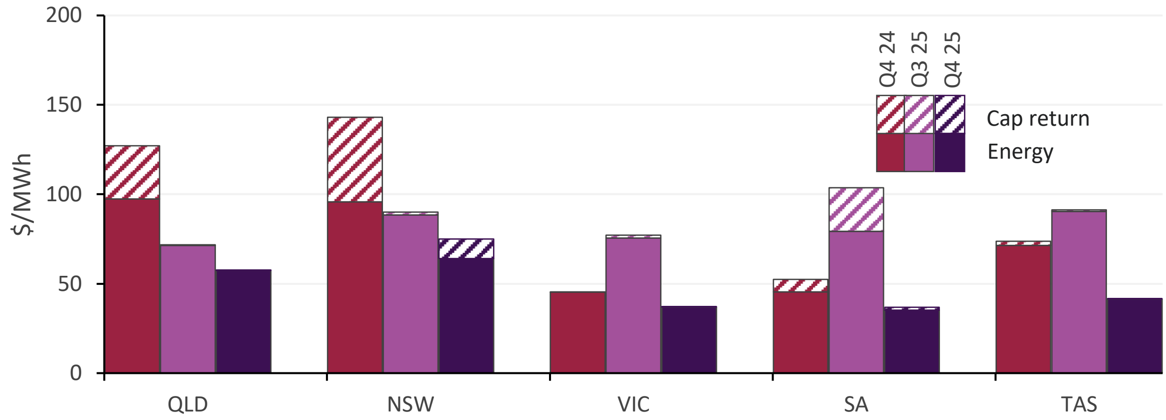


[9] Time-weighted average – simple average of regional wholesale electricity spot prices over each five-minute dispatch period over the quarter.

Lower volatility this quarter saw the cap return[10] component of the NEM average price fall to $3/MWh for the quarter, down 85% from $17/MWh in Q4 2024 (Figure 12). The energy component of average spot prices was $47/MWh this quarter, down $24/MWh (-34%) from Q4 2024.

Figure 12 Lower spot prices and price volatility across all regions

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



Average spot prices declined in all NEM regions, with reductions in both energy and cap return components:

- In **Queensland**, wholesale prices averaged $58/MWh, a decrease of $69/MWh (-55%) from Q4 2024. The energy component averaged $57/MWh, down $40/MWh (-41%) year-on-year. The cap return component fell by $30/MWh, averaging close to zero, with minimal price volatility in Queensland through the quarter.
- **New South Wales** recorded the highest regional average at $75/MWh, $68/MWh (-48%) lower than Q4 2024. It was also the only region to experience notable price volatility during the quarter as prices exceeded $300/MWh in 154 dispatch intervals, with cap returns averaging $11/MWh, down $36/MWh (-77%). The energy component averaged $64/MWh, down $32/MWh (-33%) year-on-year.
- **Victoria's** wholesale prices averaged $37/MWh, down $8/MWh (-18%) from the same quarter last year. The reduction was driven by lower energy prices, while cap returns remained close to zero, consistent with Q4 2024.
- **South Australia** recorded an average wholesale price of $37/MWh, a decrease of $16/MWh (-30%) from Q4 2024. The energy component decreased to $35/MWh, a $10/MWh (-23%) decline, while cap return component dropped to $2/MWh, down $5/MWh (-76%).
- **Tasmania** also experienced a year-on-year decrease in wholesale prices to an average of $41/MWh, $32/MWh (-41%) lower year-on-year. The energy component decreased by $30/MWh (-42%) to $41/MWh, while the cap return component declined to near zero from $2/MWh in Q4 2024.

In comparison to Q4 2024, NEM average price decreased across most hours of the day this quarter, with the largest reductions over the evening peak (Figure 13). During Q4 2025, price separation between northern regions (Queensland and New South Wales) and southern regions (Victoria and South Australia) persisted (Figure 14). During midday hours

[10] 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.

(1000 hrs-1600 hrs), New South Wales energy prices averaged $12/MWh, remaining $41/MWh above South Australia and $25/MWh above Victoria, while the price gap between New South Wales and Queensland narrowed to $5/MWh. Price separation was evident between Victoria and South Australia between 1300 hrs and 1600 hrs this quarter, with South Australian prices averaging -$33/MWh while prices in Victoria averaged -$10/MWh.

Price separation between Tasmania and the mainland regions widened across most times of the day this quarter, reflecting reduced energy transfers as higher-priced Basslink capacity offers limited inter-regional flows (see Section 2.4). This increased gap was most evident during midday hours, between 1000 hrs and 1600 hrs, with energy prices in Tasmania averaging $25/MWh, while Victorian prices averaged -$12/MWh.

Figure 13 NEM average prices lower at most times of day

NEM average spot price by time of day – Q4 2025 vs Q4 2024

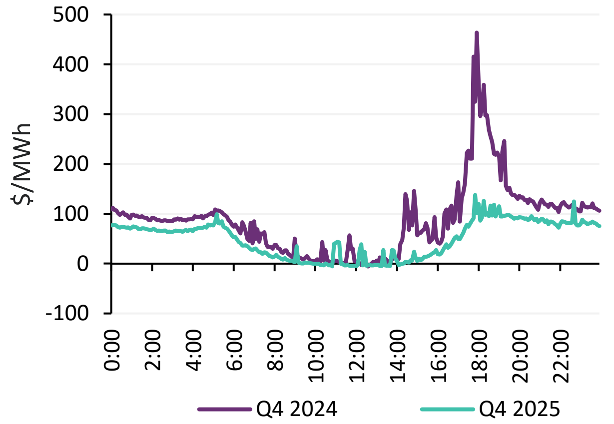
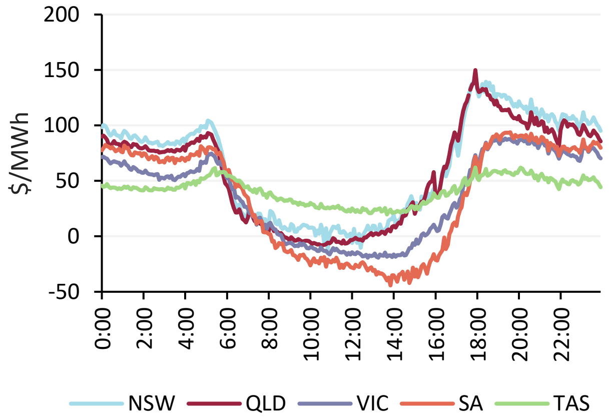


Figure 14 Price gap between northern and southern regions widened during the afternoon

Average regional energy price by time of day – Q4 2025



Volume-weighted average price (VWAP)

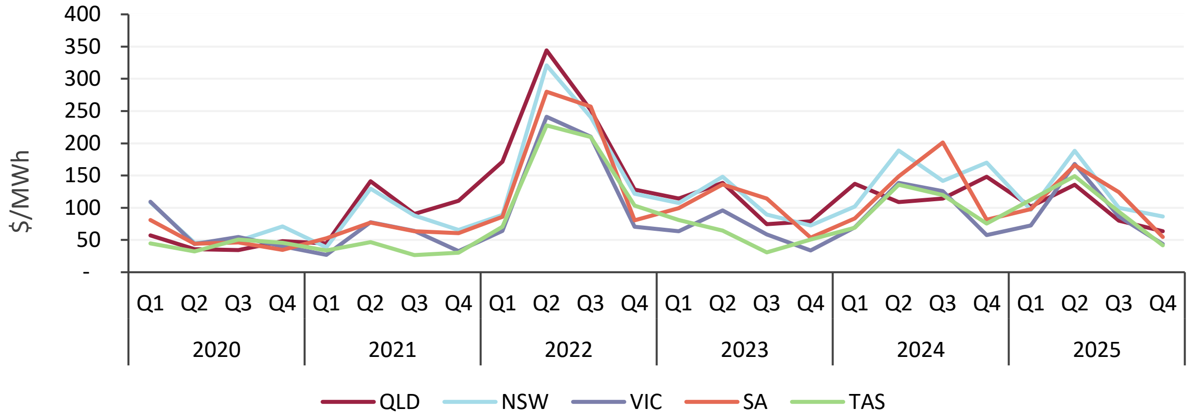
The VWAP[11] reflects the overall spot market value of energy supplied in each region, whereas the time-weighted average price (TWAP) (as discussed above) represents the simple average of prices across all intervals and does not account for variations in demand or generation. VWAP typically exceeds TWAP as prices are corelated with operational demand throughout the day, particularly during evening peaks when both demand and prices tend to be higher. Periods of elevated price volatility typically increase the spread between the two measures.

This quarter, with less volatility relative to Q4 2024, regional VWAP levels fell slightly more than TWAP values, resulting in a narrower spread across all regions. VWAP outcomes ranged from $42/MWh in Tasmania to $86/MWh in New South Wales, with Queensland, South Australia and Victoria averaging $64/MWh, $54/MWh, and $44/MWh respectively (Figure 15). These results represent year-on-year reductions of 24-57%, compared with 18-55% declines in TWAP over the same period.

[11] 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.

Figure 15 Volume-weighted average prices declined in all regions

Volume-weighted average prices by region – quarterly since Q1 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.

Table 1 Wholesale electricity price drivers in Q4 2025

Reduced price volatility	Wholesale electricity price volatility decreased, with the aggregate NEM-wide cap return decreasing from $86/MWh in Q4 2024 to $13/MWh this quarter. In Q4 2024, elevated price volatility was concentrated in New South Wales and Queensland, driven by high operational demands associated with a mid-November to early December heatwave. These conditions coincided with reduced coal generation availability, higher-priced coal bidding behaviour, increased reliance on gas-fired generation during peak periods, and periods of interconnector constraints that resulted in notable regional price separation. In Q4 2025, operational demand across the NEM increased only slightly by 177 MW (+0.9%) compared to Q4 2024. This was offset by higher wind generation across all hours, most evident during peak periods (see Figure 29 in Section 2.3). Increased wind and grid-scale solar output, supported by higher battery discharge, alongside increased coal availability, contributed to reduced wholesale price volatility this quarter. During the morning peak (0600 hrs-1000 hrs), wind generation rose by 706 MW (+26%) and grid-scale solar output was up by 686 MW (+16%), resulting in a year-on-year decrease in coal and gas-fired generation. During the evening peak (1600 hrs-2000 hrs), wind generation surged by 1,030 MW (+30%), while battery discharge increased by 486 MW (+175%), reducing the dispatch of gas and hydro generation. These outcomes led to a significant reduction in price volatility compared to Q4 2024. Price volatility was largely limited to New South Wales, driven by high demand days, with storm conditions that increased cloud cover and reduced distributed PV output, paired with transmission line outages (see Table 2 in Section 2.2.2).
Increased renewable output shaped price outcomes	In Q4 2025, average variable renewable generation (VRE) output reached a record 6,627 MW, up 253 MW or 4.0% from the previous high set in Q3 2025 and 23% above Q4 2024, driven by existing and new wind and solar capacity. Grid-scale solar set a new quarterly record at 2,535 MW, up 324 MW (+15%) year-on-year, while wind generation rose by 932 MW (+29%) from Q4 2024 to average 4,092 MW, its second-highest quarterly level on record (Section 2.3.4). The NEM share of renewable energy supply (including storage) reached an all-time high of 51.0% this quarter, surpassing 50.0% for the first time. Increased wind and solar generation reduced reliance on higher-cost coal and gas generation. The uplift in VRE and storage output lowered both average spot prices as well as incidence of high-priced intervals. Consequently, the energy component of wholesale prices fell from $71/MWh in Q4 2024 to $47/MWh in Q4 2025, with the decline observed across all regions (Section 2.2)

2.2.2 Wholesale electricity price volatility

In Q4 2025, aggregated cap returns across the NEM – representing contributions from spot prices exceeding $300/MWh – decreased by $74/MWh from Q4 2024 to $13/MWh (Figure 16). New South Wales' cap return component, which averaged $11/MWh, accounted for most of the total NEM cap return, driven by price volatility events during late November and December (Figure 17).

Figure 16 Cap return significantly lower across all regions

Cap returns by region – quarterly

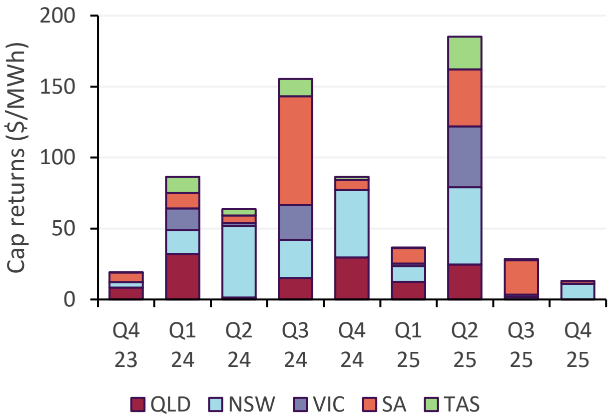


Figure 17 Significant volatility events limited to New South Wales this quarter

Cumulative cap return by region – Q4 2025

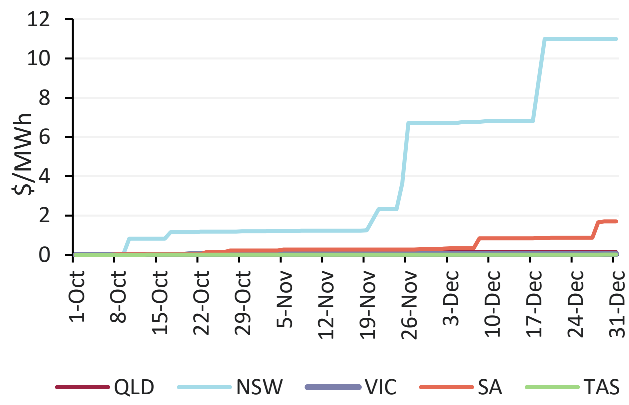


Table 2 summarises events of significant high-priced volatility during Q4 2025.

Table 2 Significant volatility events in Q4 2025

Date	Region	Contribution to quarterly regional cap return ($/MWh)	Drivers
26 November 2025	New South Wales	3.1	On this day, prices in New South Wales hit the market price cap (MPC) of $20,300/MWh at 1100 hrs and remained around the MPC for four consecutive dispatch intervals. The onset of storm conditions with increasing cloud cover led to a rapid deep decline in distributed PV output (Figure 18), tightening supply during the late morning period. In addition, the outage of the Avon to Marulan transmission line resulted in network constraints that limited generation within New South Wales and imports from Victoria, contributing to a tighter local supply demand balance.
18 December 2025	New South Wales	2.2	On this day, New South Wales saw operational demand during the evening exceed 12,000 MW while reductions in distributed PV and solar output during the evening transition period tightened demand supply conditions. As a result, between 1805 hrs and 1905 hrs, New South Wales experienced two intervals at nearly $14,000/MWh and three intervals surpassing $9,000/MWh.
19 December 2025	New South Wales	2.0	On this day, operational demand in New South Wales reached above 12,000 MW during the afternoon as cooling demand increased under a heatwave that pushed temperatures to a high of 42°C in parts of Sydney, while distributed PV output declined during the afternoon (Figure 19). Under these conditions, prices rose sharply, reaching $14,001/MWh during the 1230 hrs, 1350 hrs and 1355 hrs dispatch intervals.
25 November 2025	New South Wales	1.3	On this day, New South Wales experienced some weather-driven price volatility over two dispatch intervals, comparable to 26 November. During the 1215 hrs dispatch interval, prices increased to $14,975/MWh, coinciding with a slight uplift in demand (+329 MW) with a rapid reduction in distributed PV output due to increased cloud cover. In the subsequent 1220 hrs dispatch interval, prices reached the MPC of $20,300/MWh as supply conditions tightened further. This was influenced by the outage of the Lower Tumut to Canberra line, which restricted generation within New South Wales and limited imports from the south of the state.

Figure 18 Rapid distributed PV output decline under cloud cover on 26 November

New South Wales operational demand and distributed PV (dPV) output – 26 November and November average

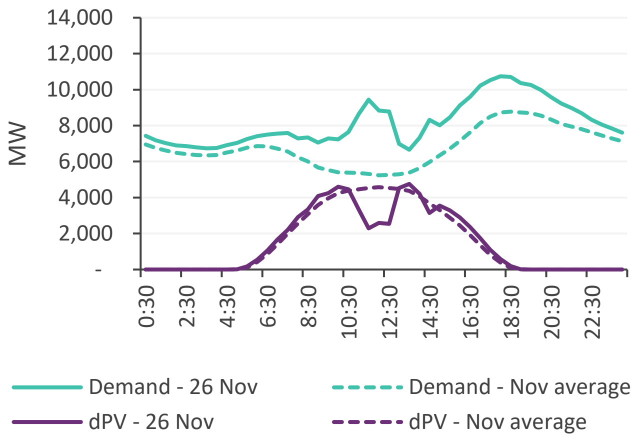
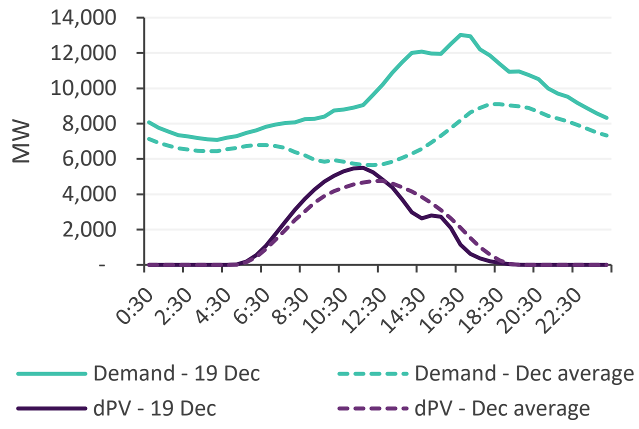


Figure 19 Heatwave lifted operational demand amid lower distributed PV output during the afternoon on 19 December

New South Wales operational demand and distributed PV output – 19 December and December average

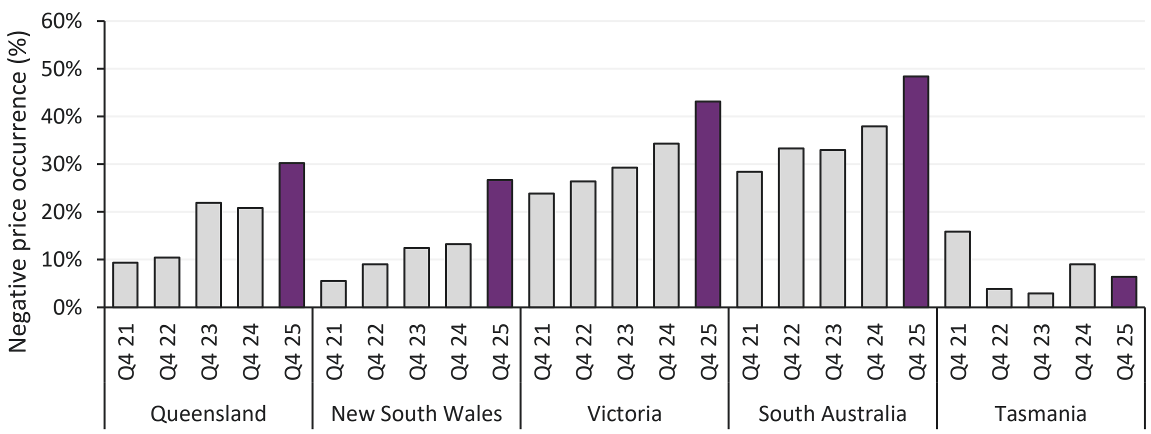


2.2.3 Negative wholesale electricity prices

In Q4 2025, NEM-wide negative price frequency reached a record high for any quarter, at 31.0% of regional dispatch intervals, up 7.9 percentage points (pp) from the previous high of 23.1% recorded in Q4 2024. All mainland NEM regions experienced record negative price occurrence, while in Tasmania the frequency dropped from 9.0% in Q4 2024 to 6.4% (Figure 20). South Australia recorded the highest occurrence of negative prices at 48.4% of all intervals in the quarter, followed by Victoria at 43.1%. Queensland's and New South Wales' negative price occurrence reached 30.2% and 26.7% respectively.

Figure 20 Record high negative price occurrence in all mainland regions

Negative price occurrence in NEM regions – Q4s



Negative price occurrence is higher in daytime hours when operational demand is low due to high distributed PV output, large-scale VRE generation output is strong, and coal-fired units maintain minimum stable output levels. During the daytime hours (0900 hrs-1700 hrs) in New South Wales and Queensland, negative prices occurred 60% and 66% of intervals respectively (Figure 21). Across the same time period, spot prices in South Australia and Victoria were zero or negative for

88% and 78% of intervals respectively. South Australia and Victoria also recorded year-on-year increases during overnight hours (2200 hrs-0600 hrs), recording negative or zero prices in 20% (+11 pp) of these intervals in South Australia and 19% (+11 pp) in Victoria.

Figure 21 Negative price occurrence led by South Australia and Victoria

Negative price occurrence by time of day – Q4 2025

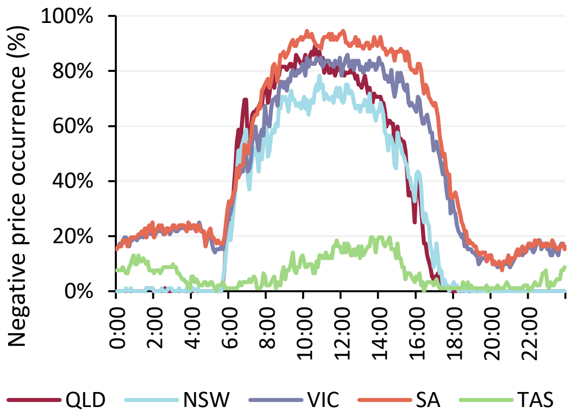
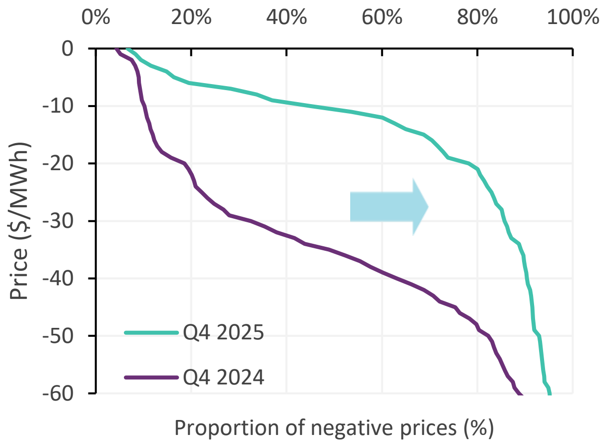


Figure 22 Magnitude of negative prices declined in Q4 2025

Cumulative distribution of negative prices – Q4 2025 vs Q4 2024



The proportion of negative prices in the -$30/MWh to $0/MWh range increased to 86% this quarter, up from 33% in Q4 2024 (Figure 22). This shift coincided with substantially lower prices for large-scale generation certificates (LGCs), which averaged $9/certificate in Q4 2025 compared with $34/certificate over the same quarter last year. As a result, the average spot price during negative price intervals rose from -$41.3/MWh in Q4 2024 to -$19.4/MWh this quarter. Because of this increase, NEM-wide negative price impact[12] – reflecting the combined effect of negative price levels and frequencies on quarterly average price – declined to $6.0/MWh this quarter, down by $3.5/MWh compared to Q4 2024, despite the higher frequency of negative price intervals.

2.2.4 Price-setting dynamics

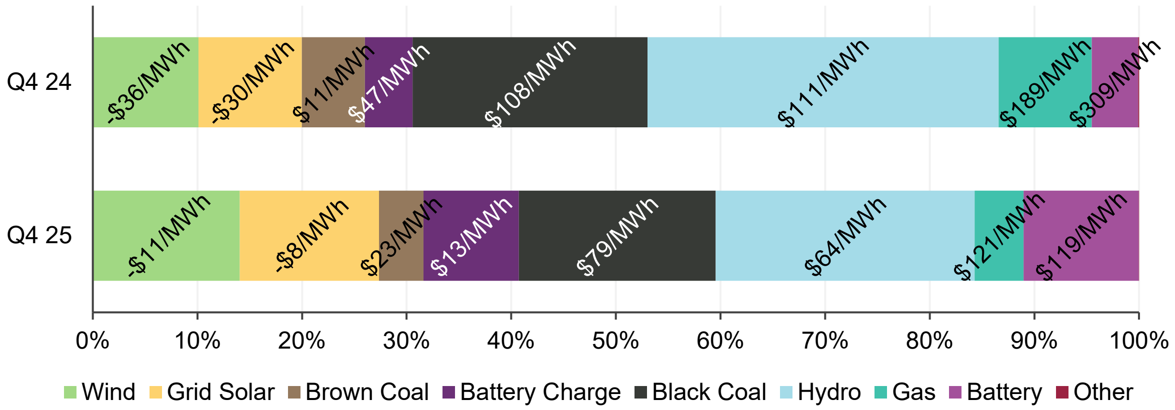
This quarter, wind, grid-scale solar, battery discharge and battery charge technologies set NEM prices more frequently compared to Q4 2024, while other energy sources recorded a decline (Figure 23). Hydro experienced a notable reduction in price-setting frequency, down 9 pp year-on-year, but remained the most frequent price-setting technology at 25%. Wind and grid-scale solar accounted for 14% and 13% of price-setting intervals respectively, while battery discharge and charge contributed 11% and 9%.

Compared to Q4 2024, average prices set when marginal declined for most sources, except wind, grid-scale solar, and brown coal, which averaged -$11/MWh (+26/MWh), -$8/MWh (+$23/MWh) and $23/MWh (+$11/MWh) respectively. Battery discharge recorded the largest decrease, down from $309/MWh in Q4 2024 to $119/MWh this quarter. The average price set by gas also fell by $67/MWh to $121/MWh in Q4 2025, while hydro decreased by $47/MWh from Q4 2024 to $64/MWh this quarter. The decline in average prices set by most sources reflected reduced spot prices and less high-price volatility this quarter.

[12] 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.

Figure 23 Wind, grid-scale solar and brown coal set higher prices when marginal

NEM price-setting frequency and average spot price when price-setter by fuel type – Q4 2025 vs Q4 2024

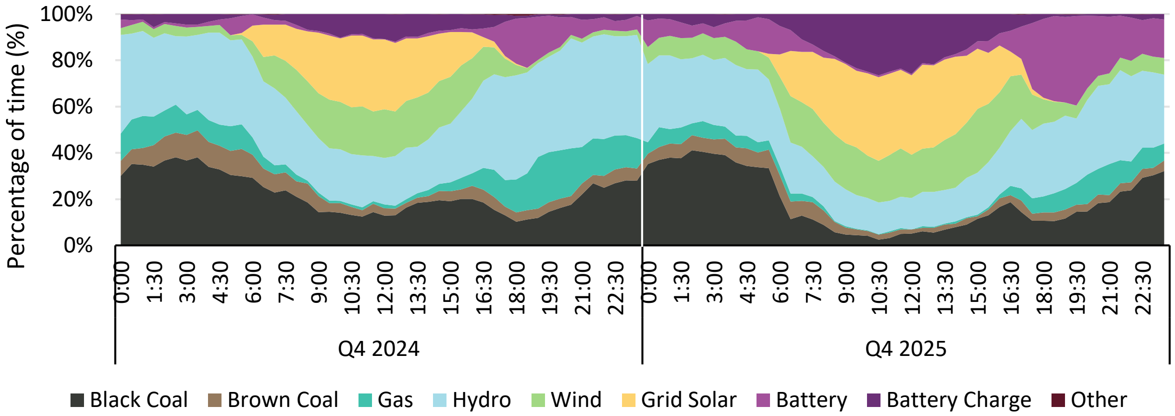


Price-setting by time of day

Figure 24 illustrates price-setting frequency by source on a time-of-day basis. During the evening peak between 1600 hrs and 2000 hrs, battery discharge was marginal in 25% of pricing intervals, displacing gas and hydro, which saw frequencies decline by 8 pp and 13 pp respectively. Battery charging set prices more frequently during the daytime between 1000 hrs and 1600 hrs, up 11 pp to 20%, reflecting increased charging activity during these periods. In contrast, black coal price-setting frequency during the daytime hours reduced from 16% in Q4 2024 to 7% this quarter.

Figure 24 Price setting during the evening peak shifted from hydro and gas to battery discharge

NEM price-setting frequency by fuel type and time of day – Q4 2025 vs Q4 2024



2.2.5 Volume-weighted average prices by fuel type

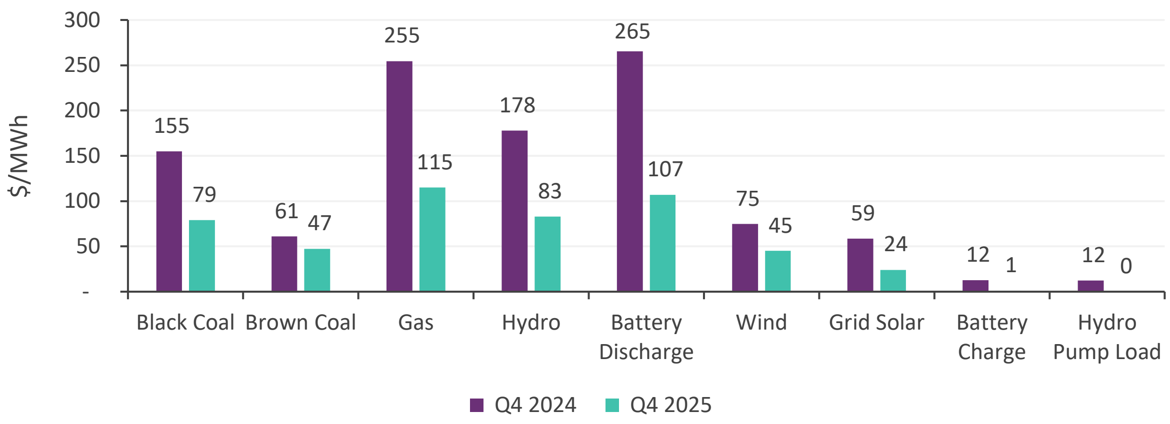
Figure 25 shows the average spot prices earned[13] or incurred by various fuel types across the NEM, calculated as a volume-weighted average using generation or load volumes in each dispatch interval. This quarter, all sources experienced reductions in VWAP compared to Q4 2024, with lower spot prices across the NEM. Reflecting Q4's reduced spot price

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

volatility, the largest VWAP reductions were recorded for gas and battery discharge, which fell by $140/MWh and $158/MWh to $115/MWh and $107/MWh respectively. VWAP for hydro decreased by $95/MWh year-on-year to $83/MWh. VWAPs for coal-fired generation also decreased, with black coal down by $76/MWh to $79/MWh and brown coal down by $14/MWh to $47/MWh. Among generation technologies, grid-scale solar and wind recorded the lowest VWAP levels at $24/MWh and $45/MWh respectively.

Figure 25 All fuel types experienced lower average spot prices year-on-year

Volume weighted average prices by fuel type – Q4 2025 vs Q4 2024

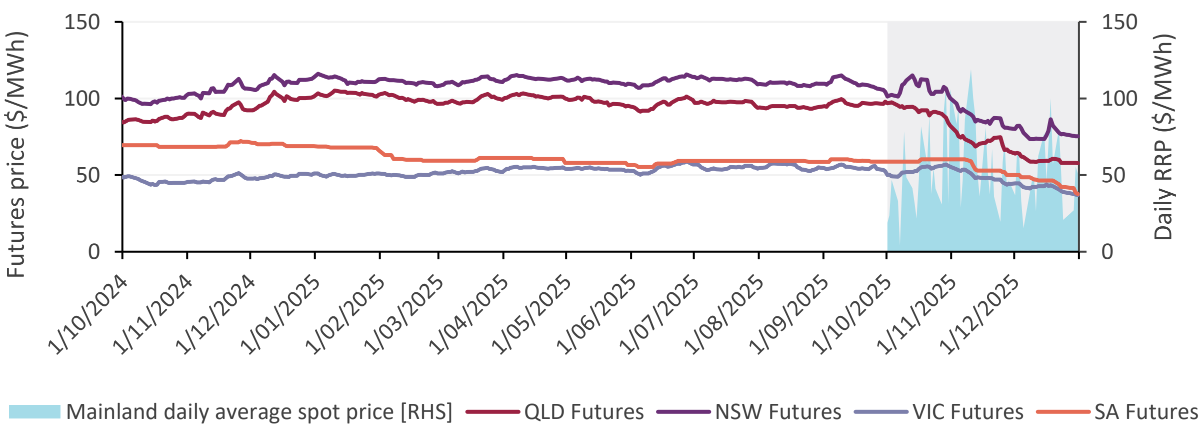


2.2.6 Electricity futures markets

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 26 illustrates Australian Securities Exchange (ASX) daily prices for Q4 2025 base contracts across mainland regions.

Figure 26 Q4 2025 base futures declined through the quarter

ASX Energy – Regional daily Q4 2025 base futures prices and daily average spot price for mainland regions

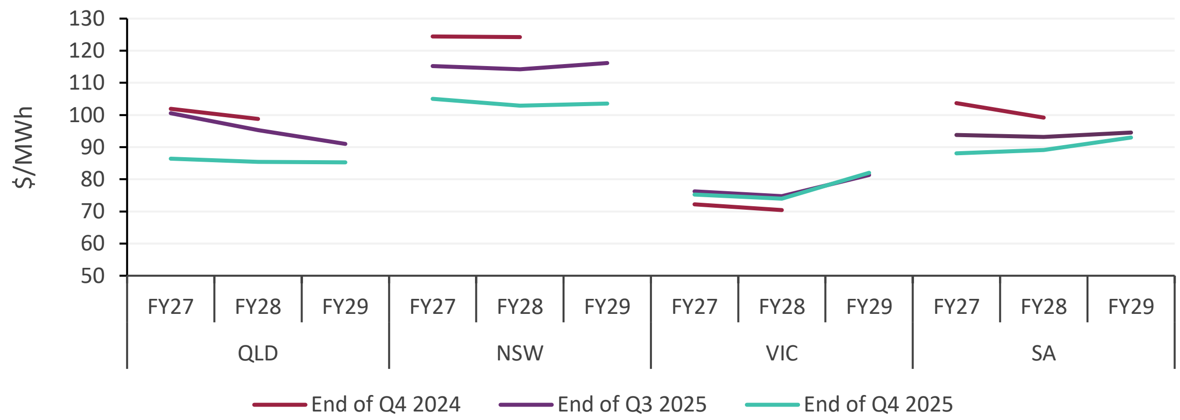


Final settlement prices for such current quarter contracts are set at quarter end to the time-weighted quarterly average wholesale price for the relevant region, but prior to this “delivery quarter” their traded prices reflect market expectations. During the delivery quarter, traded prices were influenced by both quarter to date wholesale price levels and expectations for the balance of quarter, ultimately converging to the final settlement price. Across mainland regions, ASX contract prices in Q4 2025 declined steadily through the quarter, reflecting lower wholesale spot prices. While contract prices trended lower overall, there were periods of elevated volatility in New South Wales, consistent with intermittent spot price variability during the quarter. In contrast, ASX contract prices in other regions were comparatively more stable and trended lower through the quarter.

ASX base contract prices for FY27 declined over Q4 2025 across the regions (Figure 27). The average across mainland regions fell from $101/MWh at the end of Q4 2024 and $96/MWh at the end of Q3 2025 to $89/MWh at the end of Q4 2025. On a year-on-year basis, declines were most pronounced in New South Wales, Queensland and South Australia, while Victoria recorded smaller upward movements. FY27 future prices in New South Wales fell from $124/MWh at the end of Q4 2024 to $105/MWh at the end of Q4 2025. Over the same period, FY27 future prices in Queensland declined from $102/MWh to $86/MWh, and in South Australia from $104/MWh to $88/MWh. Compared to Q3 2025, future prices for FY27 also saw declines across all regions. By the end of this quarter, forward futures for Queensland and New South Wales were relatively stable into FY28 and FY29, while prices trended upward in Victoria and South Australia.

Figure 27 Future financial year prices were lower at the end of Q4 2025

ASX Energy – Financial year futures contract prices in mainland NEM regions – end of Q4 2024, end of Q3 2025 and end of Q4 2025



Trading activity in the ASX morning and evening peak electricity futures products remained limited in Q4 2025, with low liquidity observed following their launch in Q3 2025.

2.3 Electricity generation

Total NEM generation[14] averaged 25,064 MW in Q4 2025, up by 756 MW (+3.1%) from Q4 2024. This growth largely reflected higher underlying demand (+530 MW) and increased supply for grid-scale battery charging (+216 MW).

Changes in average NEM generation by fuel type relative to Q4 2024 are shown in Figure 28, with corresponding shifts in supply-mix contributions summarised in Table 3. This quarter, the renewable energy share (including storage) reached an all-time high of 51.0%, exceeding 50% for the first time. This represented an increase of 5.0 pp from 46.0% in Q4 2024. The

[14] 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.

rise was primarily driven by higher wind, grid-scale solar and distributed PV output, partially offset by lower hydro generation. Storage-adjusted[15] renewable energy share, which captures the primary renewable generation by excluding battery discharge and pumped hydro generation, also reached a record high of 50.1% this quarter.

Figure 28 Net supply rose with higher renewable output

Change in NEM supply by fuel type – Q4 2025 vs Q4 2024

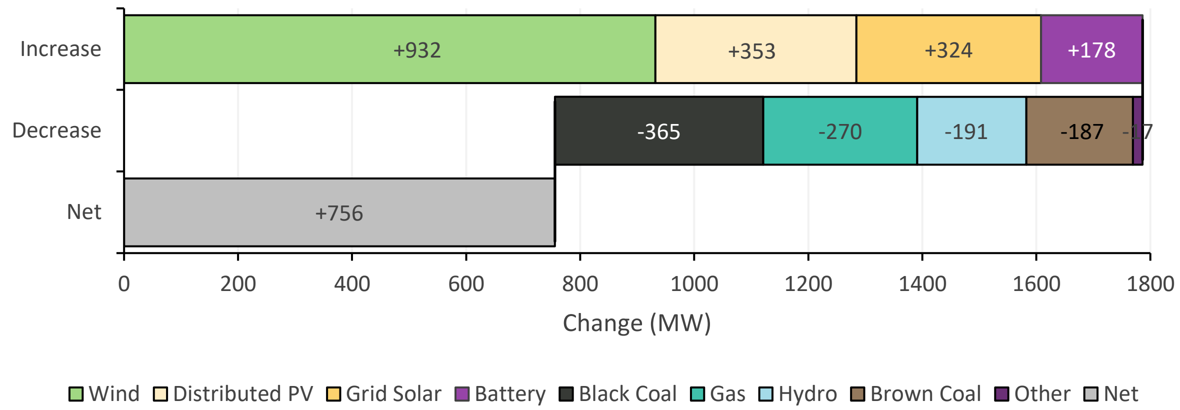


Table 3 NEM supply mix contribution by fuel type

Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Biomass	Battery
Q4 24	37.4%	12.4%	4.2%	0.0%	16.7%	13.0%	9.1%	6.6%	0.3%	0.4%
Q4 25	34.8%	11.2%	3.0%	0.0%	17.6%	16.3%	10.1%	5.7%	0.2%	1.1%
Change	-2.6%	-1.1%	-1.2%	0.0%	0.9%	3.3%	1.0%	-1.0%	0.0%	0.7%

Comparing Q4 2025 with Q4 2024:

- VRE generation, comprising wind and grid-scale solar, reached a new record average of 6,627 MW, exceeding the previous high set in Q3 2025 by 253 MW (+4.0%). Grid-scale solar generation also set a new quarterly record, rising by 149 MW (+6.3%) from the previous record in Q1 2025 to average 2,535 MW. This increase reflected continued growth in new and commissioning solar capacity, although it was partially offset by higher levels of economic offloading and network curtailment. Wind generation rose by 932 MW (+29%) from Q4 2024 to average 4,092 MW, its second-highest quarterly outcome on record, while distributed PV generation increased to an all-time high of 4,407 MW (+8.7%).
- Battery discharge recorded the strongest percentage growth of any fuel type as new battery systems entered the NEM. Average battery discharge increased by 198% year-on-year to 268 MW, marking a new quarterly high.
- Coal-fired generation across the NEM declined to an all-time low quarterly average of 11,544 MW, 553 MW (-4.6%) below the previous low of 12,096 MW recorded in Q4 2024. Both black and brown coal generation reached record lows, averaging 8,729 MW and 2,815 MW, respectively, down 365 MW (-4.0%) and 187 MW (-6.2%) from their prior lows in Q4 2024. The share of black coal-fired generation fell to a record low of 34.8% (-2.6 pp), while brown coal's

[15] Storage-adjusted 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.

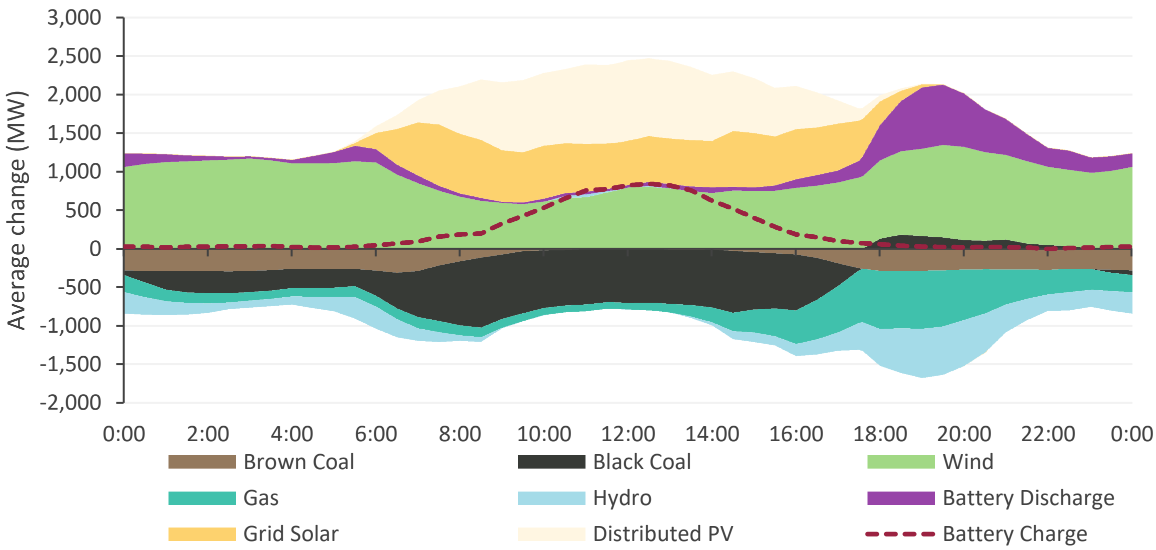
share declined to 11.2% (-1.1 pp), reflecting the increasing contribution of renewable generation in meeting higher overall demand.

- Gas-fired generation also declined, falling by 270 MW (-27%) to average 741 MW, its lowest quarterly average since Q4 2000. Consequently, the fossil fuel share of total generation decreased from 54.0% in Q4 2024 to 49.0% in Q4 2025.

Figure 29 shows changes in the NEM supply mix between Q4 2024 and Q4 2025 by time of day. Wind output increased across all hours, with a more pronounced uplift outside daylight hours. During the evening peak (1600 hrs-2000 hrs), battery discharge surged by 486 MW (+175%) year-on-year, while wind generation increased by 1,030 MW (+30%). This additional supply lowered gas and hydro generation during the evening peak, with output declining by 679 MW (-30%) and 432 MW (-19%) respectively.

Figure 29 Renewables and battery discharge displaced other sources while supporting demand across the day

NEM change in fuel mix by time of day – Q4 2025 vs Q4 2024



With increased battery capacity, charging activity also grew significantly, rising by 620 MW (+241%) during the daytime (1000 hrs-1600 hrs). Grid-scale solar output increased by 629 MW (+13%) during daytime hours, driven by higher levels of new and commissioning capacity. Wind generation also increased by 745 MW (+34%) during the same period, contributing to a decline in black coal and gas-fired generation of 752 MW (-10%) and 186 MW (-31%) respectively. Black coal output also fell sharply during the morning peak (0600 hrs-1000 hrs), declining by 739 MW (-9.7%), reflecting lower spot prices across the NEM.

2.3.1 Coal-fired generation

Black coal-fired fleet

Black coal-fired generation reduced to a new all-time low of 8,729 MW this quarter, down 365 MW (-4.0%) from its previous record low of 9,094 MW in Q4 2024. The decline reflected a 517 MW (-11%) reduction in New South Wales output, partially offset by a 152 MW (+3.3%) increase in Queensland output (Figure 30).

Black coal-fired generation in New South Wales fell to an all-time low of 4,026 MW this quarter, driven by lower availability and reduced utilisation. Available capacity declined by 224 MW (-3.8%) to a record low of 5,659 MW, while utilisation fell

7 pp to 71%, reflecting higher renewable output during the quarter. The reduction in availability was largely driven by higher unplanned full-unit outages, with average capacity fully offline increasing by 247 MW (+11.9%) (Figure 31).

Figure 30 NEM black coal-fired output reduced to an all-time low despite increased availability

Quarterly average black coal-fired generation and availability by region – Q4s

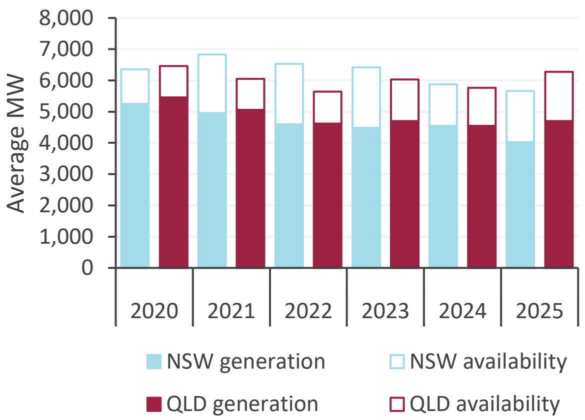


Figure 31 Unplanned outages lifted offline capacity in New South Wales, while Queensland offline capacity declined

Average coal-fired capacity fully offline – Q4 2025 vs Q4 2024

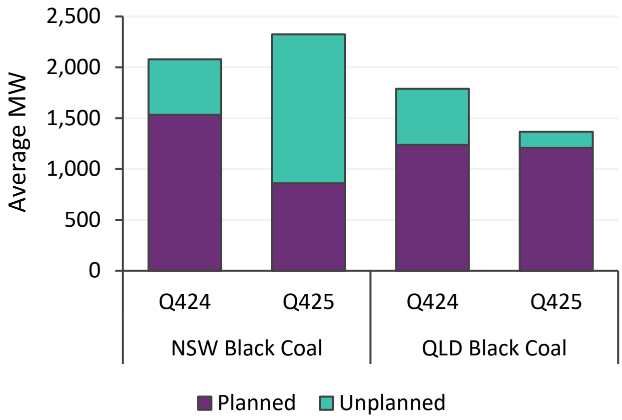
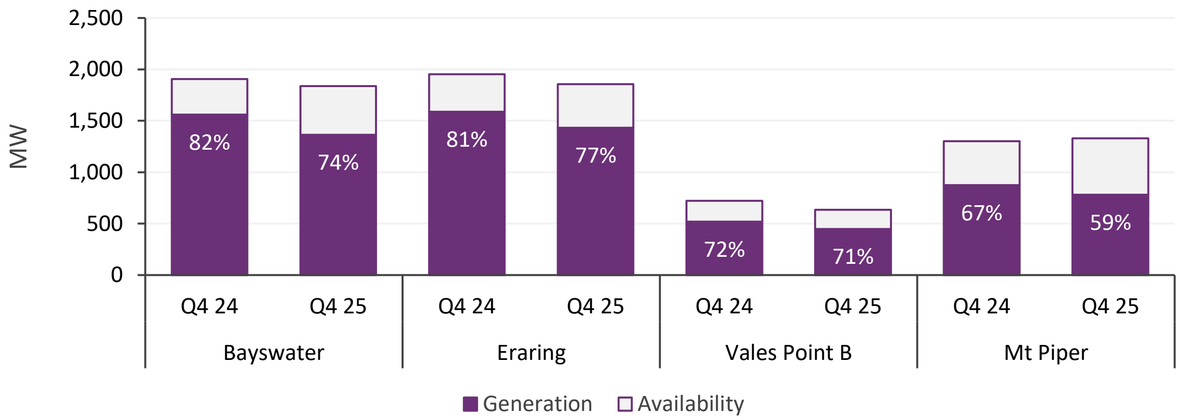


Figure 32 shows availability, generation and utilisation rates for the New South Wales black coal-fired power stations.

Figure 32 Lower utilisation across New South Wales black coal-fired fleet

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q4 2025 vs Q4 2024



Bayswater output decreased by 198 MW (-13%) to average 1,363 MW, its lowest quarterly output since Q4 2010. Availability declined by 66 MW (-3.5%), and utilisation reduced from 82% to 74%. Eraring output reduced by 154 MW (-9.7%) to 1,434 MW, with availability down 97 MW (-5.0%), due to a 95 MW increase in average capacity on full outage. The utilisation rate decreased by 4 pp to 77%. Vales Point B output averaged 449 MW, its lowest level since Q3 2014, with a year-on-year decline of 71 MW (-14%). Availability declined by 87 MW (-12%) and the utilisation rate slightly decreased by 1 pp to average 71%, and capacity on full outage increased by 160 MW. Mount Piper was the only station with increased availability, up 27 MW (+2.1%) from Q4 2024. However, with a significantly lower utilisation rate of 59% compared to 67% in Q4 2024, generation was down by 95 MW (-11%) averaging 780 MW.

In contrast, both black coal-fired generation and availability in Queensland increased from the same period last year, with output averaging 4,703 MW for the quarter. Availability increased by 504 MW (+8.7%) to average 6,274 MW, driven by a 548 MW (-31%) reduction in capacity on full outage.

Figure 33 shows the availability, generation and utilisation rates for the Queensland black coal fleet. This quarter, Callide B and Kogan Creek recorded the largest increases in average output, up 258 MW and 142 MW respectively, due to reduced full outages that lifted availability by 323 MW at Callide B and 166 MW at Kogan Creek. Callide B's utilisation rate declined by 5 pp, while Kogan Creek remained stable at 86%. Millmerran and Tarong output also rose by 80 MW and 46 MW, supported by availability increases of 178 MW and 85 MW. Callide C saw the largest drop in output, down 163 MW from Q4 2024, driven by higher capacity on full outage reducing availability by 144 MW. Stanwell and Tarong North output also fell by 118 MW and 28 MW respectively, with availability decreasing by 85 MW and 26 MW. Despite a slight 8 MW increase in availability, Gladstone's output declined by 65 MW, with utilisation rate decreasing by 7 pp to 63%.

Figure 33 Queensland black coal-fired output rose

Average quarterly availability and generation for Queensland black coal-fired power stations – Q4 2025 vs Q4 2024

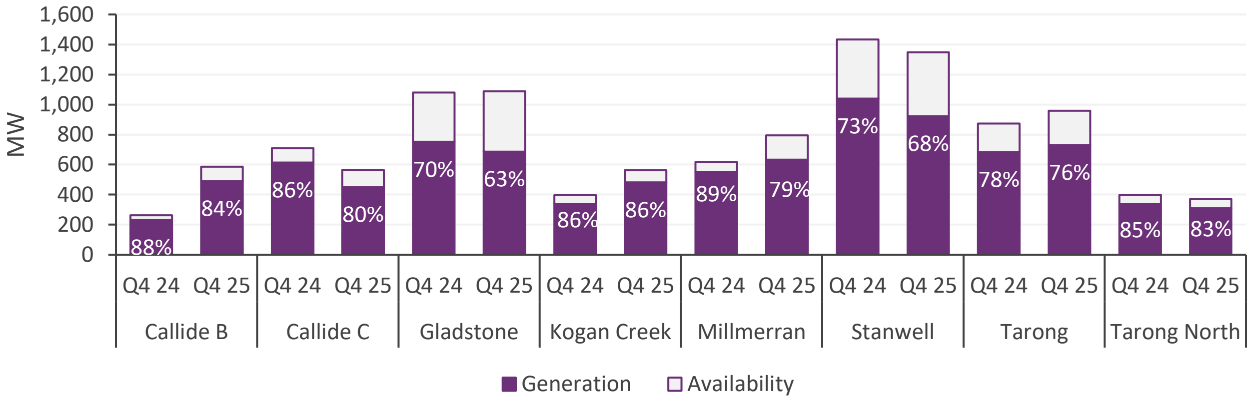
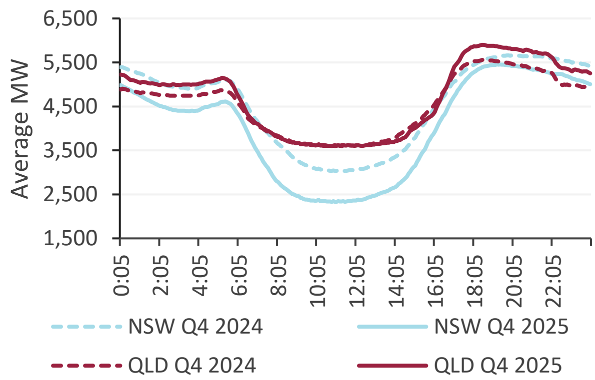


Figure 34 New South Wales black coal-fired generators increased swing year-on-year

Black coal-fired output by time of day – Q4s



In this quarter, the decline in New South Wales generation was observed across all hours of the day, with a more pronounced reduction during the morning peak between 0600 and 1000 hrs (Figure 34). During this period, output fell by 757 MW to an average of 2,970 MW. As a result, intraday variation in New South Wales increased by 495 MW to 3,125 MW in Q4 2025. Most black coal-fired generator units in New South Wales exhibited increased intra-day swings this quarter, driven by reduced daytime generation.

Notably, Bayswater Unit 2 fully went offline during daytime on three occasions this quarter, on Saturday 4 October, Sunday 5 October, and Saturday 11 October 2025.

On each occasion, the unit went offline in the mid-morning (around 0800 hrs) and returned to service in the mid-afternoon (around 1500 hrs) during periods of lower operational demand and higher solar availability. This pattern indicated more routine two-shifting[16] behaviour, contributing to the observed increase in intra-day variability. Additionally, several coal units have reduced minimum loads to enable lower generation during the times of low demand.

In Queensland, intraday swing increased by 340 MW to 2,302 MW, reflecting higher generation during the evening peak, with output rising by 240 MW between 1600 and 2000 hrs. Average minimum generation as a share of average available capacity was 41% in New South Wales, indicating greater flexibility compared with Queensland, where the ratio was 57%.

Brown coal-fired fleet

In Q4 2025, Victorian brown coal-fired generation dropped to an all-time low of 2,815 MW, down 187 MW (-6.2%) from the previous low recorded in Q4 2024 (Figure 35). This was partly driven by lower availability, which decreased to an all-time low of 3,496 MW due to higher outage levels. Average capacity on outage rose to 1,319 MW, up 171 MW (+14.9%) from Q4 2024.

The decline in output was led by Loy Yang B (-163 MW) and Loy Yang A (-24 MW), while Yallourn output remained largely unchanged at 843 MW. Loy Yang A recorded its all-time lowest quarterly output at 1,207 MW and Loy Yang B reached its lowest output since Q3 2010. Loy Yang B experienced increased outage levels resulting in lower availability (-160 MW) while reduced outage levels at Loy Yang A lifted availability (+76 MW). Both Loy Yang B and A stations saw reduced utilisation (-3.5 pp and -5.4 pp respectively).

Figure 35 Brown coal-fired availability and generation decreased

Quarterly average brown coal-fired generation and availability in Victoria (including decommissioned units) – Q4s

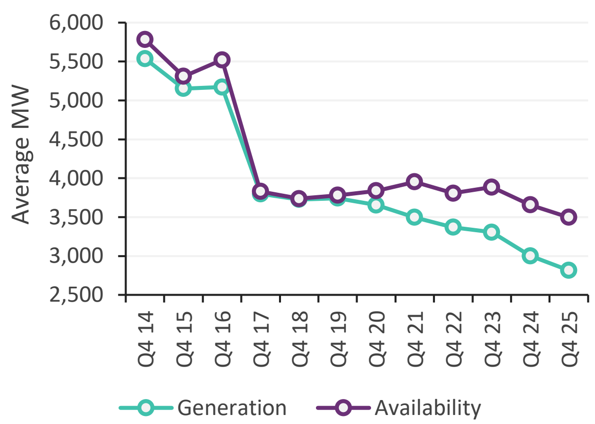
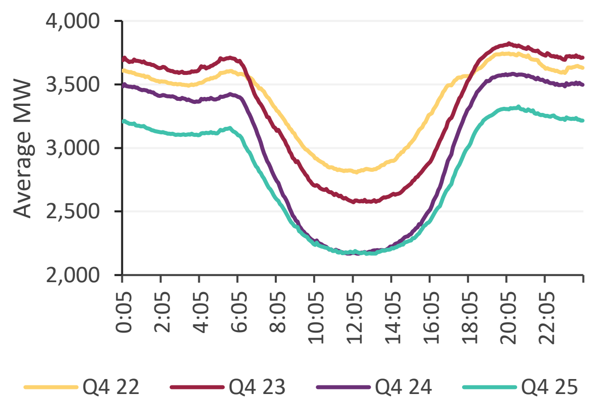


Figure 36 Brown coal-fired output lower except at times of minimum generation

Brown coal-fired output by time of day – Q4s



Brown coal-fired generation remained largely unchanged during midday hours but was notably lower outside these hours, leading to a 255 MW reduction in intraday flexibility, declining from 1,415 MW in Q4 2024 to 1,160 MW in Q4 2025 (Figure 36). While Loy Yang A has increased its swing capability over time (Table 4), Loy Yang B and Yallourn W exhibited lower day-to-day variation in output compared with the previous year. In Victoria, average minimum generation equated to 62% of average available capacity this quarter.

[16] "Two-shifting" is an operating regime where steam-cycle power stations shut down both boiler and turbine then restart for demand peaks within the same day.

Table 4 Brown coal availability, output, utilisation, outage, and intraday swing – Q4 2025 vs Q4 2024

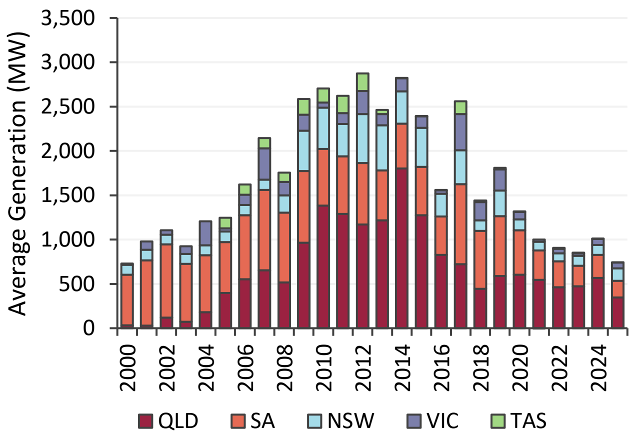
Generator	Availability (MW)		Output (MW)		Utilisation		Outage (MW)		Intraday swing (MW)	
	Q4 24	Q4 25	Q4 24	Q4 25	Q4 24	Q4 25	Q4 24	Q4 25	Q4 24	Q4 25
Loy Yang A	1,517	1,593	1,232	1,207	81%	76%	663	592	571	665
Loy Yang B	1,155	995	928	764	80%	77%	0	161	501	398
Yallourn W	987	908	843	843	85%	93%	485	566	350	104

2.3.2 Gas-fired generation

In Q4 2025, gas-fired generation across the NEM averaged 741 MW, down 270 MW (-27%) from Q4 2024, marking its lowest quarterly average since Q4 2000 (Figure 37). Compared to Q4 2024, all NEM regions saw lower gas-fired generation except New South Wales, where output increased year-on-year by 26 MW (+23%) to average 141 MW this quarter. The increase was largely driven by higher generation at Tallawarra A (+28 MW) and Uranquinty Power Station (+17 MW). Hunter Power Station continued its commissioning activities through the quarter, with the second unit starting commissioning in December, and an average output of 7 MW across both units.

Figure 37 NEM-wide gas-fired generation dropped

Average gas-fired generation by region – Q4s



Queensland saw the largest year-on-year decline, with output falling by 217 MW to average 349 MW, its lowest quarterly average since Q1 2005. The reduction was evident across all hours of the day, reflecting lower spot prices this quarter. While most generators recorded year-on-year declines, the largest decrease occurred at Darling Downs Power Station, where output averaged 128 MW, down 87 MW (-40%) from Q4 2024. Braemar 1 and Braemar 2 also reduced output by 37 MW and 19 MW, respectively.

In South Australia, gas-fired generation averaged 186 MW, down 74 MW (-29%) from Q4 2024, marking the lowest quarterly average on record.

Victorian output was slightly lower (-2 MW) than during Q4 2024, averaging 66 MW this quarter. Most stations recorded slightly lower generation, with Mortlake Power Station the exception, increasing output by 8 MW (+20%) to average 50 MW.

2.3.3 Hydro

In Q4 2025, hydro generation[17] across the NEM decreased by 191 MW (-12%) year-on-year to an average of 1,421 MW, the lowest Q4 level since 2020 (Figure 38). Victoria recorded the largest decline in average hydro generation this quarter, with output falling by 109 MW (-36%) to 194 MW. This reduction was primarily driven by significantly lower generation at Dartmouth (-53 MW, -81%) and reduced output from Murray (-48 MW, -28%).

[17] Hydro generation includes output from hydro pumped storage and does not net off electricity consumed by pumping at these facilities.

New South Wales also experienced a substantial decline, with average hydro generation decreasing by 106 MW (-29%) to 264 MW. This was led by a 79 MW (-51%) reduction at Upper Tumut, alongside lower output across other regional generators. Reflecting these conditions, Snowy Hydro's Lake Eucumbene storage levels stood at 44% at the end of Q4 2025, down from 48% at the same time last year.

Queensland's hydro output remained relatively stable, averaging 167 MW, down 5 MW (-3.0%) from Q4 2024. Higher generation at Barron Gorge (+16 MW) and Wivenhoe (+3 MW) was largely offset by lower output at Kareeya (-25 MW).

Figure 38 Hydro generation reached lowest Q4 level since 2020

Average hydro-generation by region – Q4s

In contrast, Tasmania recorded a modest increase in hydro generation, averaging 796 MW, up 29 MW (+3.8%) from Q4 2024. Tasmanian hydro dam storage levels rose during the first half of the quarter, reaching 52.8% by the end of December, 6 pp higher than at the same time last year.

2.3.4 Wind and grid-scale solar

Average VRE generation in the NEM reached a new quarterly record of 6,627 MW, surpassing the previous high of 6,374 MW in Q3 2025 by 253 MW (+4.0%). Compared with Q4 2024, average VRE output increased by 1,256 MW (+23%), driven by a 932 MW (+29%) uplift in wind generation and a 324 MW (+15%) increase in grid-scale solar (Figure 39).

Figure 39 Wind drove strong VRE output growth

Average quarterly VRE generation by fuel type – Q4s

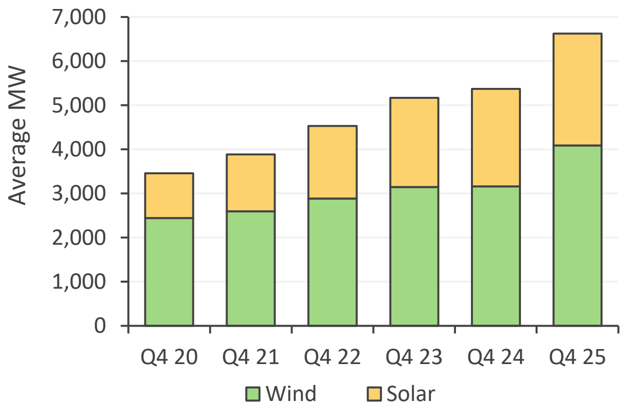
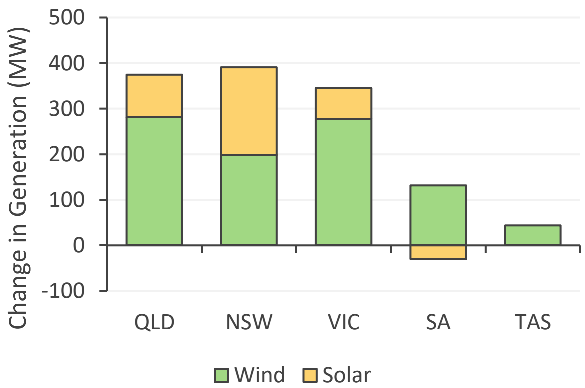


Figure 40 Queensland, New South Wales and Victoria led renewable increases

Average MW change in output Q4 2025 vs Q4 2024



Wind generation growth was led by Queensland (+281 MW, +85%) and Victoria (+278 MW, +24%), with further increases in New South Wales (+198 MW, +27%), South Australia (+131 MW, +19%) and Tasmania (+44 MW, +19%) (Figure 40). Queensland and Tasmania both recorded their highest-ever quarterly average wind output, at 611 MW and 272 MW respectively. Grid-scale solar growth was strongest in New South Wales (+192 MW, +18%), followed by Queensland (+93 MW, +12%) and Victoria (+68 MW, +27%), while South Australia recorded a decline of 30 MW (-28%).

Grid-scale solar

Grid-scale solar output across the NEM reached an all-time quarterly high of 2,535 MW this Q4, surpassing the previous record of 2,386 MW set in Q1 2025 by 149 MW (+6.3%). Output was also 324 MW higher (+15%) than the 2,212 MW average in Q4 2024.

Higher grid-scale solar availability across the NEM was driven by 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 628 MW from Q4 2024 (Figure 41). Most of this increase occurred in New South Wales, led by Stubbo (+142 MW), Wollar (+91 MW), Culcairn (+81 MW) and Walla Walla (+68 MW), while Aldoga Solar Farm in Queensland added 129 MW.

NEM-wide quarterly volume-weighted available capacity factors[18] for established[19] grid-scale solar facilities remained broadly consistent with last year, averaging 32% this quarter. Victoria recorded the highest average capacity factor at 34% (+1.4 pp), followed by New South Wales at 33% (+0.3 pp) (Figure 42). South Australia and Queensland also saw modest increases, averaging 32% (+0.2 pp) and 31% (+0.8 pp), respectively.

Network curtailment and economic offloading increased year-on-year, reducing potential growth in grid-scale solar output by 312 MW.

Figure 41 New and commissioning capacity led the year-on-year grid-scale solar growth

Changes in grid-scale solar generation – Q4 2025 vs Q4 2024

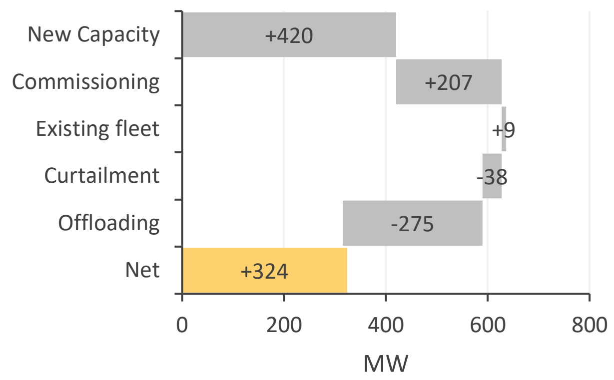
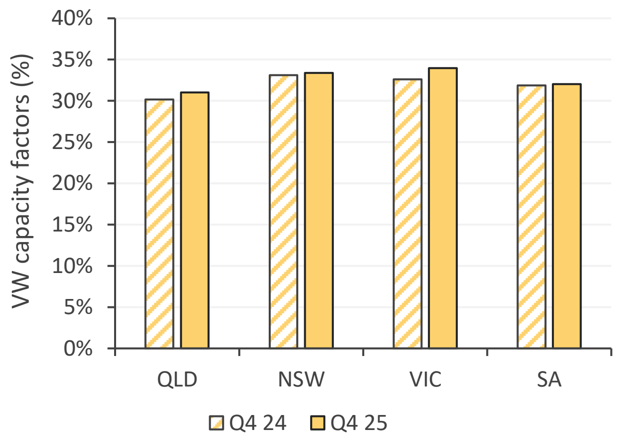


Figure 42 Increased grid-scale solar availability in all NEM regions

Volume-weighted grid-scale solar available capacity factors[20] – Q4s



Wind

In Q4 2025, NEM-wide wind output averaged 4,092 MW, reaching its second-highest quarterly level on record after the peak of 4,676 MW in Q3 2025. Output was 932 MW higher (+29%) than the 3,160 MW recorded in Q4 2024.

[18] 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.

[19] Existing (or established) capacity in this section refers to the wind and grid-scale solar facilities that were fully commissioned prior to the start of Q4 2025. These facilities may also appear in the "New Capacity" or "Commissioning" categories in Figure 41 and Figure 43 if they were connected or exhibited ramping activity between Q4 2024 and Q4 2025 respectively.

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

New and commissioning wind farms increased average quarterly availability by 748 MW compared with Q4 2024 (Figure 43). Queensland and Victoria led this growth, with major contributions from Clarke Creek (+170 MW) and MacIntyre (+137 MW) in Queensland, Golden Plains (+282 MW) and Ryan Corner (+29 MW) in Victoria, and Goyder South (+97 MW) in South Australia.

Quarterly volume-weighted available capacity factors for established wind farms increased substantially, with the NEM-wide average rising to 37% in Q4 2025 from 31% in Q4 2024. Tasmania recorded the highest average capacity factor at 49%, up 7.7 pp year on year (Figure 44). New South Wales saw the largest increase, rising by 7.8 pp to 36%. Victoria's average increased by 6.1 pp to 36%, while South Australia rose by 5.2 pp to 37%. In contrast, Queensland's available capacity factor declined by 2.8 pp to 31%, partially offsetting gains elsewhere.

While there was no change in network curtailment of wind, economic offloading increased year-on-year, partially offsetting higher availability and reducing potential wind output growth by 378 MW.

Figure 43 Increased output from new, commissioning and existing wind farms

Changes in wind generation – Q4 2025 vs Q4 2024

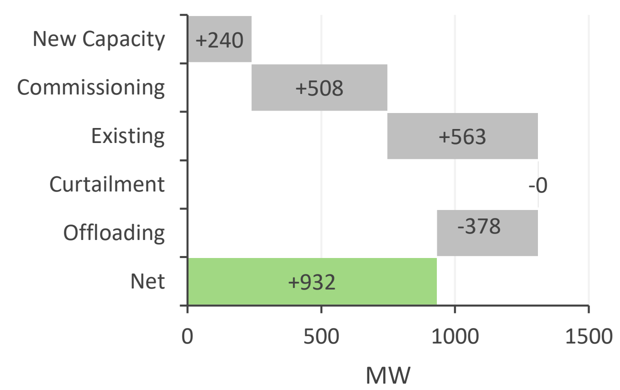


Figure 44 Wind availability up in all NEM regions except Queensland

Volume-weighted wind available capacity factors – Q4s

Economic offloading

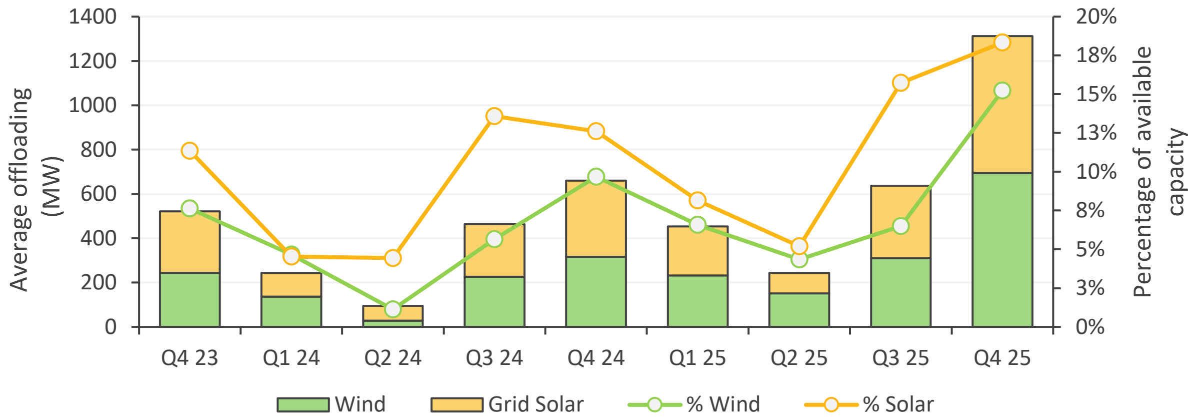
During Q4 2025, total economic offloading of wind and grid-scale solar generation averaged 1,312 MW, the highest quarterly average on record (Figure 45). This exceeded the previous peak set in Q4 2024 by 653 MW (+99%).

Grid-scale solar economic offloading rose sharply, increasing from 343 MW to an all-time high of 618 MW (+275 MW, +80%). As a share of average grid-scale solar availability, offloading increased from 13% to 18%. The largest increases occurred in New South Wales (+132 MW) and Queensland (+72 MW), with further rises in Victoria (+36 MW) and South Australia (+34 MW). Although South Australia's increase was the smallest across the NEM, economic offloading of its grid-scale solar facilities as a proportion of available output reached 59%, reflecting the region's very low daytime spot prices (see Figure 13 in Section 2.2) and limitations on energy transfers to Victoria (see Section 2.4).

Wind economic offloading increased from 316 MW in Q4 2024 to an all-time high of 695 MW (+378 MW, +120%), rising from 10% to 15% of average wind availability. Wind offloading was most pronounced in Victoria, where it increased by 269 MW and exceeded 25% of available wind output in the region. Constraint-driven limitations on transfers northward to New South Wales, and lower flows on Basslink due to its changed bidding behaviour since July 2025 (see Section 2.4) contributed to lower Victorian spot prices and higher economic offloading during periods of lower operational demand and high VRE availability.

Figure 45 Increased economic offloading for wind and grid-scale solar generation

Average MW offloading and as percentage of availability by fuel type



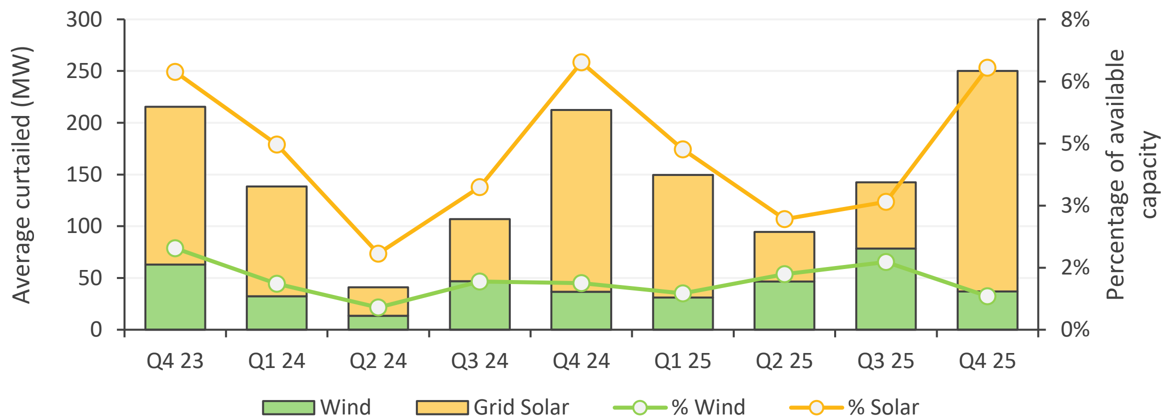
Network curtailment

Average curtailment of grid-scale solar generation by network constraints increased from 176 MW in Q4 2024 to an all-time high of 213 MW in Q4 2025, an increase of 38 MW (+21%) (Figure 46). This increase was driven by outcomes in New South Wales, where curtailment rose by 50 MW.

Despite higher absolute curtailment, curtailment as a share of average grid-scale solar availability edged down slightly to 6.3% from 6.5% in Q4 2024, reflecting the continued growth in new and commissioning VRE capacity. Wind curtailment remained broadly unchanged at 37 MW this quarter. As a proportion of average wind availability, curtailment declined marginally by 0.3 pp to 0.8%.

Figure 46 Grid-scale solar curtailment increased while curtailment at wind farms remained relatively stable

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



2.3.5 Renewables contribution

Peak renewable contribution

Peak renewable contribution[21] in the NEM reached a new record of 78.6% during the half-hour ending 1130 hrs on Saturday 11 October 2025, exceeding the previous record of 77.2% set on 22 September 2025 (Figure 47). That earlier record was surpassed in three consecutive 30-minute intervals before the new high was established. The latest outcome also represents a 3.1 pp increase on Q4 2024's peak of 75.6%. At the time of the record, distributed PV accounted for 51.3% of total generation, while wind and grid-scale solar contributed 14.2% and 10.6%, respectively.

Maximum renewable potential this quarter also set a new record, reaching 113.9% in the half-hour ending 1330 hrs on 5 October, surpassing the previous high of 110.3% recorded in Q3 2025 by 3.7 pp. Over October 2025, renewable potential exceeded 100% in 55 half-hour intervals, compared with 13 intervals in October 2024.

Figure 47 Peak and potential renewable contribution reached record highs

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

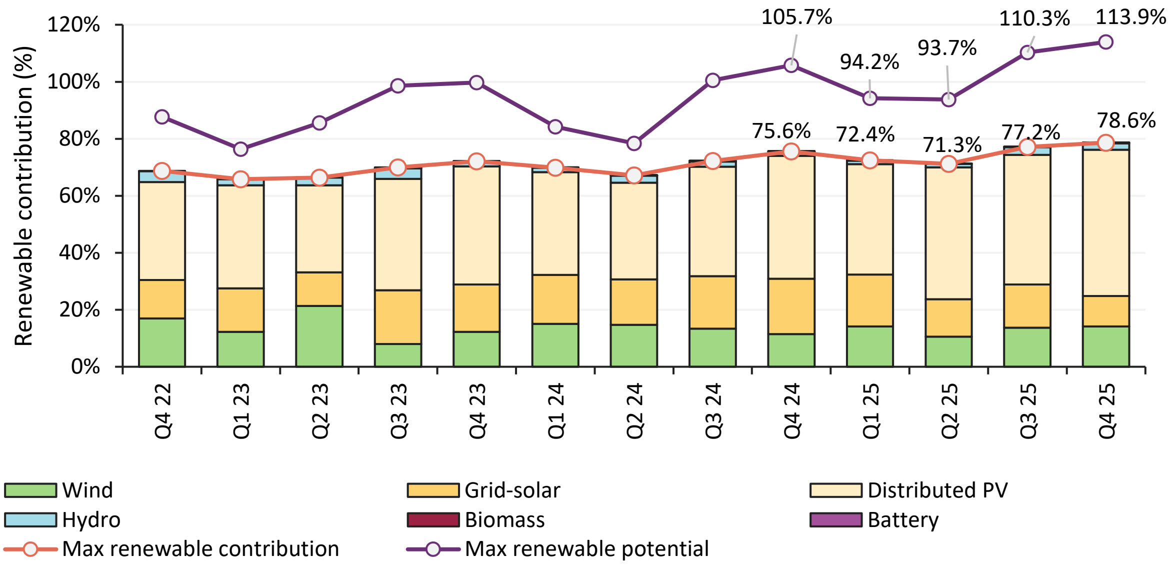


Figure 48 illustrates the quarterly range in renewable generation contribution, which recorded a 60.6 pp swing, from a high of 78.6% to a quarterly minimum of 18.0%. The minimum occurred in the half-hour ending 0200 hrs on 28 November 2025 and was 1.9 pp higher than the Q4 2024 minimum of 16.1%.

Both New South Wales and Victoria set new records for renewable generation contribution this quarter. New South Wales reached 86.0% during the half-hour ending 1100 hrs on 11 October 2025, 2.8 pp above the previous record set on 30 September 2025. Victoria achieved a peak contribution of 82.5% in the half-hour ending 1400 hrs on 16 October 2025, exceeding the previous record from 2 December 2024 by 4.5 pp (Figure 49).

[21] 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, biomass, battery discharge and distributed PV. Total generation = large-scale generation + estimated PV output.

Figure 48 Higher maximum and minimum renewable contribution

Range of NEM supply share from renewable energy sources – Q4s

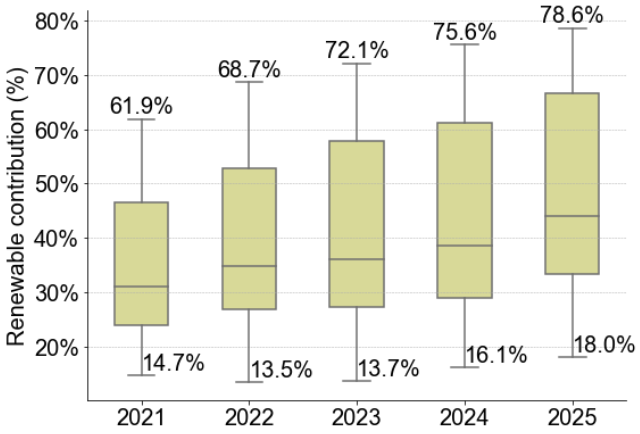
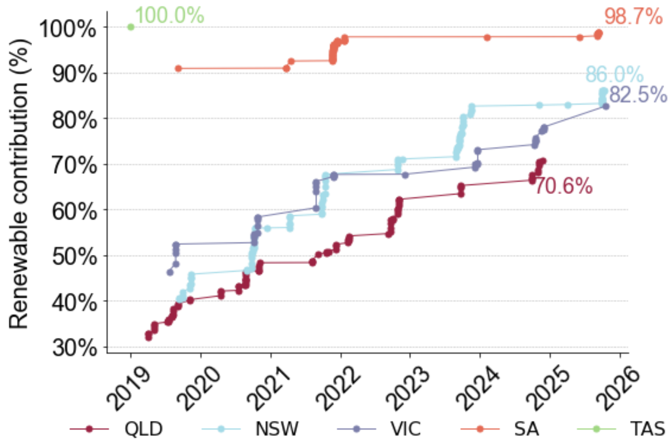


Figure 49 Record high renewable contributions in New South Wales and Victoria

Change in peak renewable contribution record by region



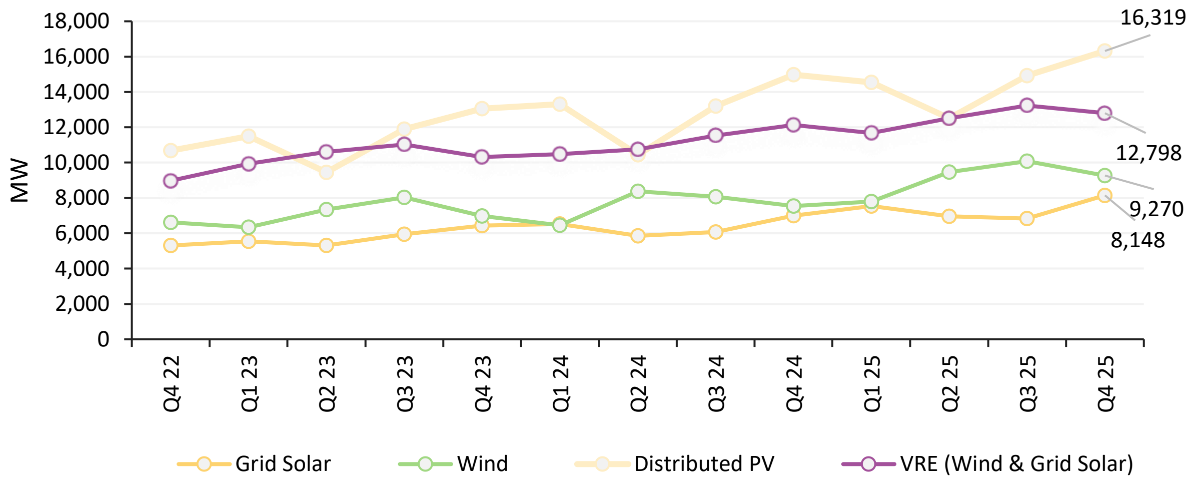
Maximum renewable output

Figure 50 highlights the highest quarterly peak half-hourly generation for grid-scale solar, wind, and distributed PV since Q4 2022. In Q4 2025, grid-scale solar reached a new record half-hourly output of 8,148 MW in the interval ending 1000 hrs on Monday, 24 November 2025, exceeding the previous peak of 7,536 MW set in Q1 2025 by 8.1%.

Distributed PV also set a new record, reaching 16,319 MW in the half-hour ending 1230 hrs on Wednesday, 3 December 2025, an 8.9% increase on the previous record of 14,980 MW recorded in Q4 2024.

Figure 50 Record high for grid-scale solar and distributed PV generation

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

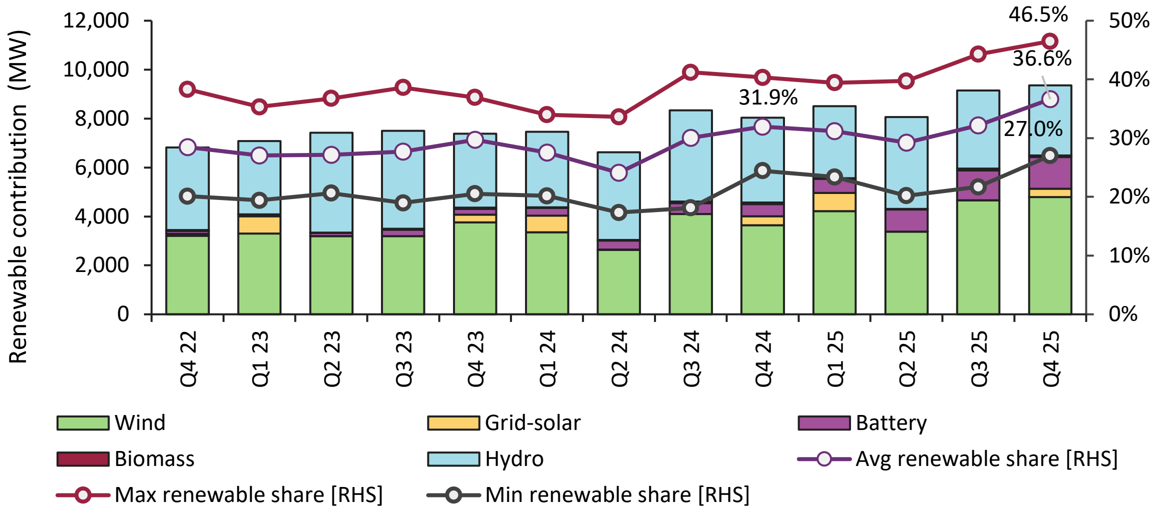


Renewable contribution to maximum demand

Figure 51 illustrates 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 Q4 2022[22].

Figure 51 Renewable 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 Q4 2025, the average renewable contribution to daily maximum demand increased to 36.6%, up from 31.9% in Q4 2024. This uplift was primarily driven by higher wind output, which supplied 18.7% on average (+4.3 pp), and increased battery discharge, contributing 5.1% (+3.2 pp). During the quarter, the renewable contribution to daily maximum demand ranged from a low of 27.0% to a high of 46.5%.

2.3.6 NEM emissions

In Q4 2025, total emissions across the NEM fell to an all-time quarterly low of 23.4 MtCO_2-e, a decline of 1.5 MtCO_2-e (-6.2%) compared to Q4 2024 (Figure 52). 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[23]. This emissions intensity excludes generation from distributed PV, considering only sent out generation from market generating units.

In Q4 2025, average CDEII emissions intensity fell to 0.53 tCO_2-e/MWh, the lowest level on record. This represents a year-on-year reduction of 0.04 tCO_2-e/MWh (-7.0%), driven by a lower combined share of coal- and gas-fired generation. Emissions intensity associated with underlying demand[24] also declined by 0.04 tCO_2-e/MWh year-on-year to 0.44 tCO_2-e/MWh, marking a record low for any quarter.

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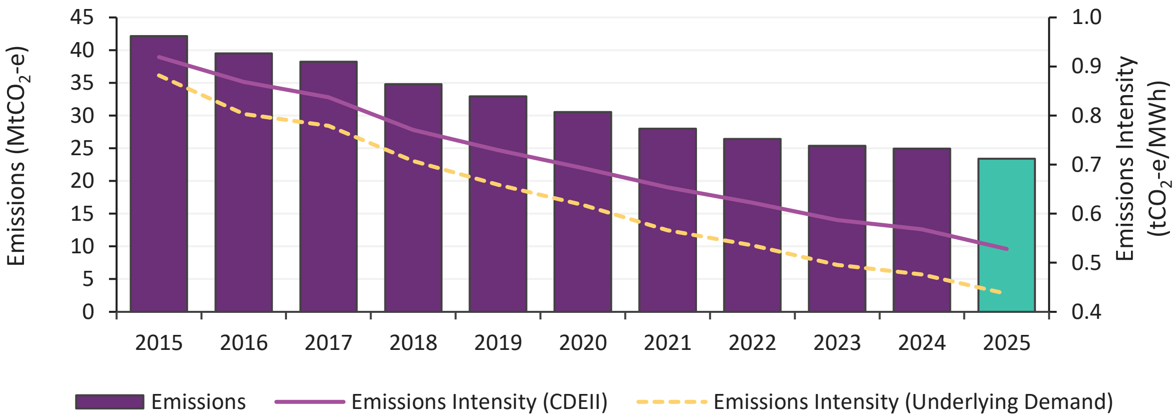
[22] For every day in the quarter, the half-hour of maximum NEM operational demand is found along with large-scale renewable sources' contribution to meeting that demand. These quantities are then averaged over all days in the quarter to compute renewables 'average contribution to supplying maximum demand.

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

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

Figure 52 Emissions and emissions intensity decreased to an all-time low

Quarterly NEM emissions and intensity – Q4s



2.3.7 Storage

Batteries

In Q4 2025, estimated net revenue for NEM grid-scale batteries remained broadly unchanged at $70.4 million, up $1.0 million (+1.4%) from Q4 2024 (Figure 53). Energy arbitrage revenue increased by $13.3 million (+28%) to $61.4 million, compared with $48.1 million in the same period previous year. This increase was largely offset by a decline in frequency control and ancillary services (FCAS) revenue, which fell to $9.0 million in Q4 2025, a reduction of $12.3 million (-58%). As a result, FCAS revenue accounted for only 13% of total battery revenue this quarter, down from 31% in Q4 2024, while the energy market share increased to 87%, up from 69% a year earlier (Figure 54).

Figure 53 Increase in battery arbitrage revenue offset by lower FCAS revenue

Quarterly net revenue from NEM battery systems by revenue stream

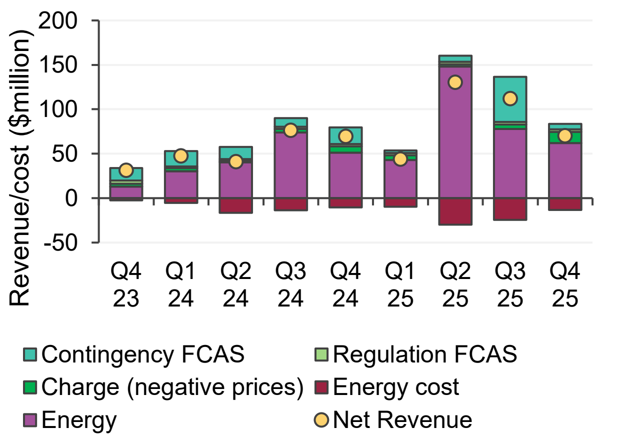
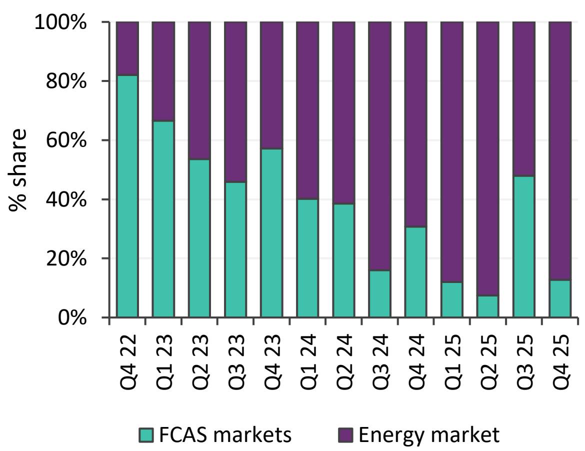


Figure 54 Battery revenue from FCAS markets decreased

Percentage share of battery net revenue – energy vs FCAS markets



All regions saw notable declines in contingency FCAS revenues, contributing to the overall reduction in FCAS earnings. This analysis does not incorporate net Frequency Performance Payment (FPP) outcomes for batteries. During the quarter, FPP credits more than offset FPP debits, resulting in a net credit of $3.8 million for batteries (see Section 2.5).

The increase in energy arbitrage revenue reflected higher energy revenues (including revenue earned from charging at negative prices), which rose by $16.1 million (+28%) to $74.5 million. This was partially offset by higher energy (charging) costs, which increased by $2.8 million (+27%) to $13.1 million.

The uplift in energy revenue was underpinned by a substantial increase in battery capacity that commenced commissioning since the end of Q4 2024. Between the end of Q4 2024 and the end of Q4 2025, multiple major battery energy storage systems (BESS) with a combined capacity of 3,796 MW/8,602 MWh commenced initial commissioning in the NEM. Of this total, 1,060 MW/2,520 MWh of new capacity came online in Q4 2025 (Table 5). These assets are now either fully commissioned or continuing through their commissioning processes, lifting the total installed capacity (both commissioning and commissioned) to nearly 7,000 MW at the end of quarter.

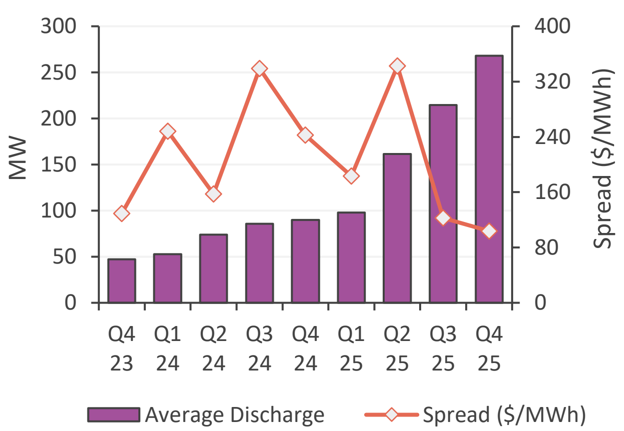
Table 5 New battery systems commenced commissioning in the NEM in Q4 2025

Battery	Region	Capacity
Liddell	New South Wales	500 MW/1,000 MWh
Limondale	New South Wales	50 MW/400 MWh
Supernode	Queensland	260 MW/620 MWh
Swanbank	Queensland	250 MW/500 MWh

Reflecting this capacity growth, NEM-wide average quarterly battery discharge availability increased by 1,918 MW (+176%), rising from 1,087 MW in Q4 2024 to 3,005 MW in Q4 2025. Average battery discharge across the NEM also increased sharply to 268 MW, around three times higher than the 90 MW recorded in the same period a year earlier, reaching a new quarterly high. However, lower spot price volatility in Q4 2025 reduced the value of arbitrage opportunities. As a result, the NEM-wide price spread earned by batteries declined by 57%, from $243/MWh in Q4 2024 to $104/MWh (Figure 55).

Figure 55 Decrease in NEM-wide battery price spread with lower price volatility

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



This narrowing of price spreads explains the relatively modest increase in total battery earnings from energy arbitrage, despite the very strong growth in battery capacity and output.

Growth in energy arbitrage revenue was concentrated in Victoria and South Australia, where revenues increased by $13.5 million and $7.5 million, respectively. In contrast, arbitrage revenue declined in Queensland and New South Wales by $3.6 million and $4.1 million. Although battery discharge volumes increased across all regions compared with Q4 2024, materially narrower price spreads in the northern regions constrained arbitrage earnings.

In Queensland and New South Wales, average price spreads fell sharply by 74% and 77% to $99/MWh and $85/MWh respectively. By comparison, price spreads in Victoria and South Australia declined more modestly – by 4% and 15% – averaging $108/MWh and $122/MWh. The lower price spreads relative to Q4 2024 were driven by a reduction in average prices, particularly during the evening peak (see Section 2.2).

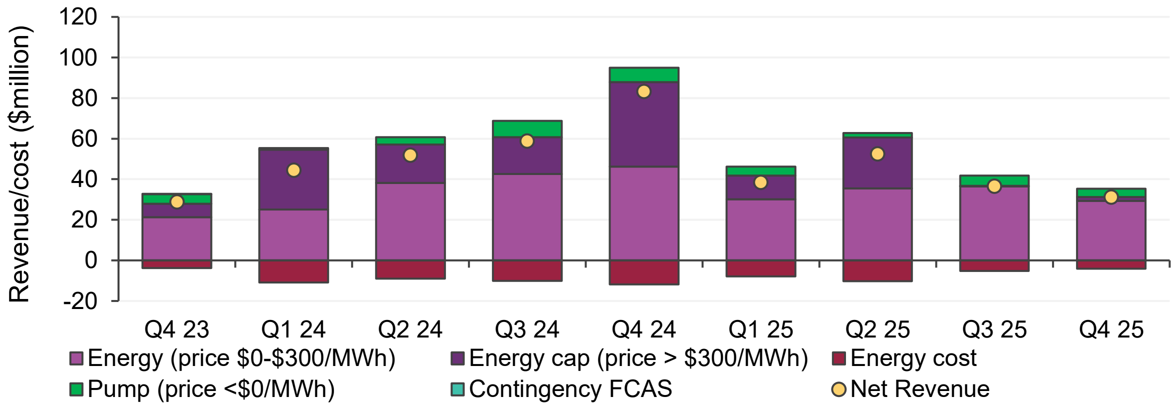
Batteries set a new peak discharge record this quarter, reaching 2,885 MW on 29 December 2025 during the half-hour ending 1930 hrs. This was 894 MW (+45%) above the previous record of 1,991 MW set earlier this year in Q3 2025. Battery charging also reached a new high of 2,834 MW (+88%) in the half hour ending 1000 hrs on 18 December 2025.

Pumped hydro

Estimated net pumped hydro revenue fell to $31.2 million this quarter, down $52.1 million (-63%) from Q4 2024 (Figure 56). In Queensland, lower spot prices reduced Wivenhoe's revenue by $41.0 million to $25.5 million. In New South Wales, Shoalhaven's revenue declined by $11.1 million (-66%) to $5.7 million, as price volatility eased compared with last year. This softening was also reflected in revenue from prices exceeding $300/MWh, which fell sharply year on year, declining to nearly zero for Wivenhoe and by 84% for Shoalhaven.

Figure 56 Pumped hydro revenue decreased year-on-year

Quarterly revenue from NEM pumped hydro by revenue stream

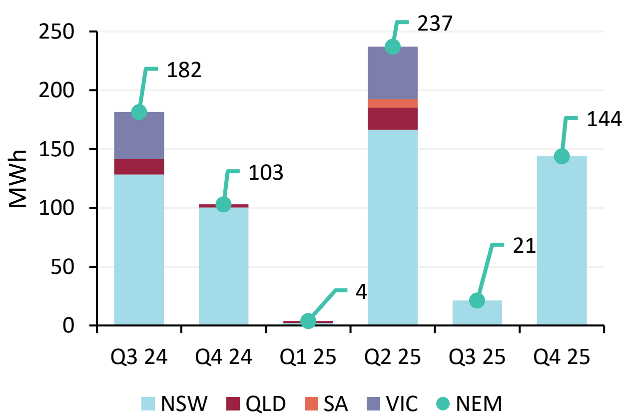


2.3.8 Demand side flexibility

This section discusses wholesale demand response (WDR), whereas Section 2.1 covered CER including rooftop solar and household battery installations.

Figure 57 Increase in WDR dispatch

Total quarterly WDR energy dispatch



WDR totalled 144 MWh this quarter, up 41 MWh (+40%) from Q4 2024, with all dispatch occurring in New South Wales (Figure 57). WDR was dispatched across 864 intervals, a substantial increase from 107 intervals in Q4 2024 and from just seven intervals in Q3 2025.

The majority of WDR dispatch occurred between 1 and 6 October, with one unit dispatched each day at 2 MW across 860 intervals (143 MWh), driven by a $2/MWh participant bid for those days that cleared at an average regional reference price of $70/MWh. Another dispatch occurred on 18 December, when one unit was dispatched at 2 MW over four intervals, with an average regional reference price of $168/MWh.

Demand flexibility also continued to play an increasingly competitive role in FCAS markets, with demand response (DR) supplying 21% of combined contingency raise services in Q4 2025, up from 17% in Q4 2024.

2.3.9 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 completes a pre-feasibility and enquiry phase where the connecting NSP is engaged in the process. The key stages[25] 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 year there has been an increase in standalone battery projects. Battery connections during this latest quarter made up half of applications approved and registrations (Figure 58). Batteries comprise 46% of the capacity of projects in the connections pipeline, with 74% of batteries being grid forming.

Generation project capacity in the pipeline has grown 9% in the past year to 34.2 GW. Growth came from wind (17% increase), hydro (10% increase) and solar (8% increase).

Investment in gas projects remains low, with only 0.9 GW of gas projects currently in the end-to-end connections process.

During Q4 2025:

- 3.8 GW of applications were approved across 18 projects.
- 1.9 GW of plant across 11 projects were registered and connected to the NEM.
- 1.8 GW of plant across nine projects progressed through commissioning to reach full output: Munna Creek Solar Farm (120 MW), Culcairn Solar Farm (350 MW) and seven battery projects: Melbourne Renewable Energy Hub A1, A2 and A3 (600 MW/1.6 gigawatt hours [GWh]), Tarong BESS (300 MW/600 MWh), Brendale BESS (205 MW/410 MWh), Templers BESS (111 MW/270 MWh), Smithfield BESS (65 MW/130 MWh)

Please see the Connections Scorecard[26] for further information.

At the end of Q4 2025, AEMO's snapshot of connection activities in progress shows that:

- 63.5 GW of new capacity was progressing through the end-to-end connection process from application to commissioning, 30% more than at the same time last year when 49.6 GW was in-progress. An influx of new applications during the last quarter has contributed to this connection pipeline growth with the majority (61%) of these new applications coming from the New South Wales region (Figure 59).
- Battery project capacity in the end-to-end connection process increased by 64% over the year, from 17.9 GW to 29.3 GW, comprising 21.5 GW grid-forming, 7.4 GW grid-following, and 0.2 GW compressed air storage.

[25] Application stage establishes technical performance and grid integration requirements. In proponent implementation stage, contracts are finalised and the plant is constructed. 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.

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

- Wind project capacity increased 1.5 GW (from 8.7 GW to 10.2 GW). Projects with solar generation (20.1 GW) increased 8% since last year, with hybrid solar plus battery projects making up more than 60% of this capacity. Gas (0.9 GW) decreased, and hydro (3.0 GW) remained stable.
- The total capacity of in-progress applications increased 37% from 19.0 GW to 26.1 GW.
- 26.1 GW of generation and storage projects were finalising contracts and/or under construction (proponent implementation), compared with 19.9 GW at the same time last year (31% increase).
- There was 6.6 GW of new capacity in commissioning, compared to 5.2 GW at the same period last year (27% increase).

Figure 58 Strong quarter for application approvals and steady progress for registrations and commissioning

Application approved, registrations and plant commissioned to full output during Q4 2025

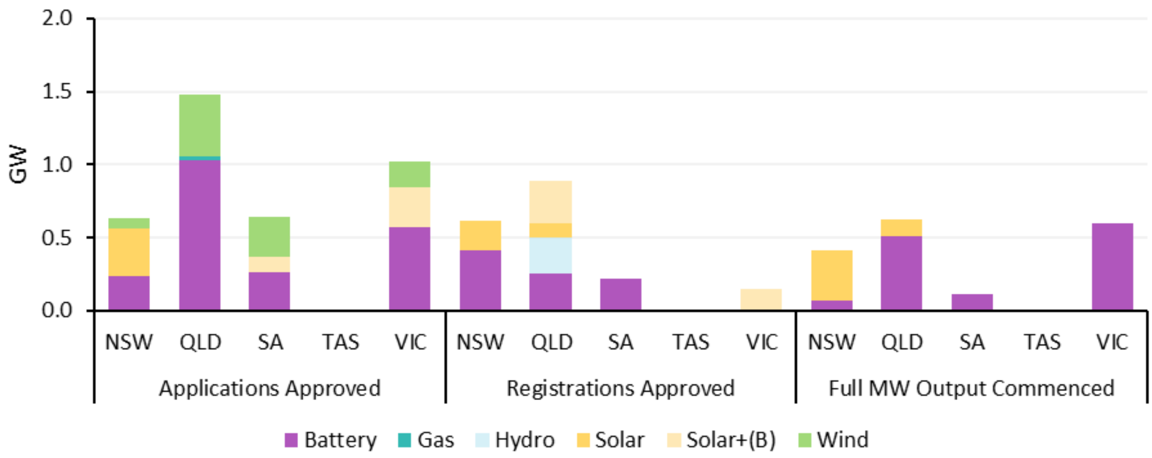
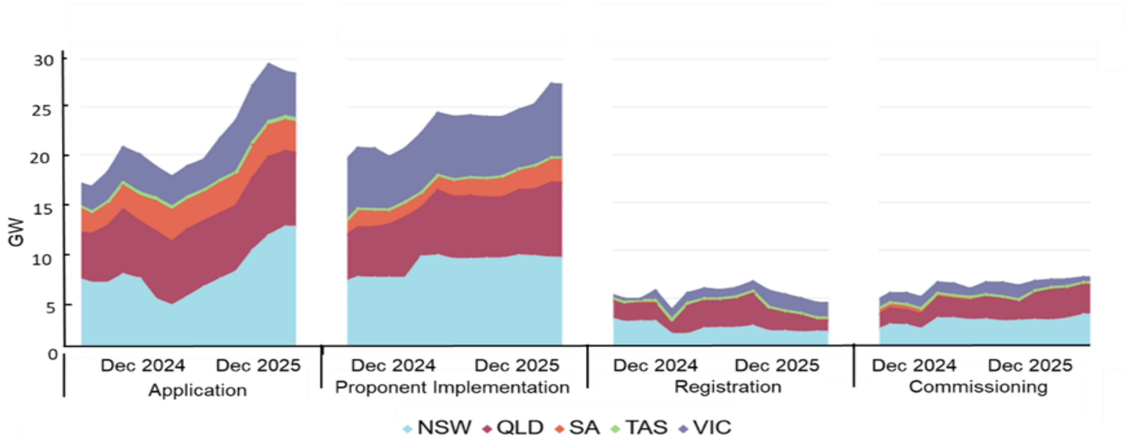


Figure 59 Increased capacity progressing through application, proponent implementation and commissioning stages of the connection pipeline over the year

12-month trend[27] of connection capacity in progress



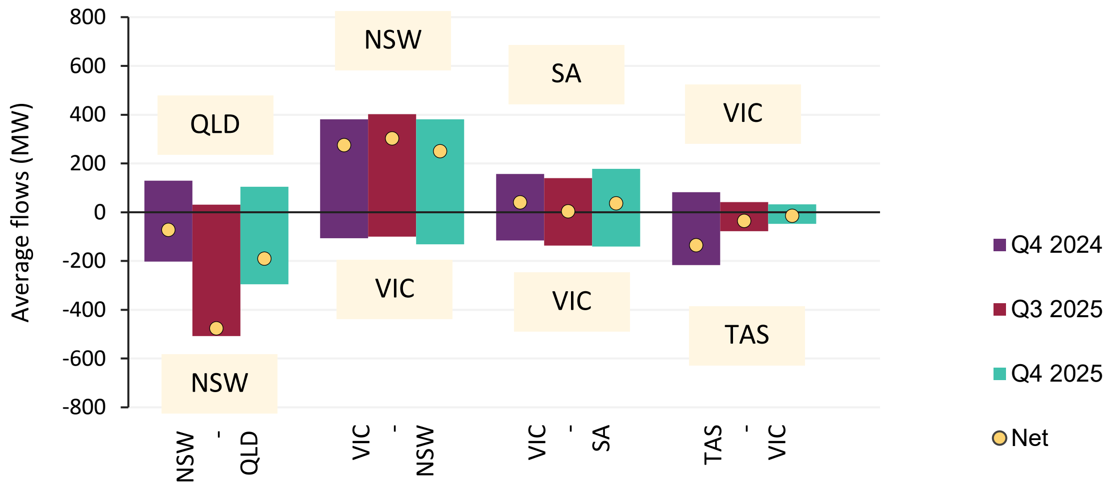
[27] Charts are based on current data, and therefore some variances may exist compared to previously reported capacity in-progress.

2.4 Inter-regional transfers

Total inter-regional transfers were 2,895 GWh in Q4 2025, equivalent to 6.6% of operational demand, and 180 GWh (-5.8%) lower than in Q4 2024. This decrease was driven by reduced transfers between Victoria and Tasmania on Basslink, with net flows dropping from 135 MW southwards in Q4 2024 to just 14 MW southwards this quarter (Figure 60).

Figure 60 Decreased transfers between Victoria and Tasmania

Quarterly inter-regional transfers



Southward flows from Queensland to New South Wales rose from an average of 202 MW in Q4 2024 to 296 MW this quarter, mainly due to increased overnight transfers.

The transfer capacity provided by the first stage of Project EnergyConnect (PEC-1) between South Australia and New South Wales is represented as an increase in the capacity of the existing Heywood interconnector, so transfer on PEC-1 is included in the net flows between Victoria and South Australia shown in Figure 60. Overall net transfers remained fairly consistent year-on-year, with increases in both net westward (156 MW to 177 MW) and net eastward (116 MW to 141 MW) directions. However, net eastward transfers were limited by constraints in New South Wales and Victoria that drive westward energy flows on PEC-1 and the Murraylink interconnector at times of high solar and wind generation in south-western New South Wales and north-western Victoria, even when South Australian prices are lower than Victoria's. As a result, during daytime hours (0900 hrs-1700 hrs), transfers out of South Australia on Heywood (and PEC-1) were constrained for 50% of dispatch intervals at an average import level of 223 MW, compared to 31% of intervals at 419 MW in Q4 2024.

Basslink

As discussed in the Q3 2025 QED, Basslink offers its capacity to transfer power between Tasmania and Victoria through market offers, where higher priced offers require larger inter-regional spot price differentials for flow to be scheduled. From 1 July 2025 Basslink shifted from offering most capacity at low prices (usually $1/MWh or less in Q4 2024) to higher-priced volumes, resulting in reduced transfers.

In Q4 2025, 93% of Basslink’s transfer capacity to Tasmania, and 48% to Victoria, was offered at prices between $35/MWh and $75/MWh, with most of the remaining capacity to Victoria offered between $75/MWh and $150/MWh (Figure 62).

Compared to Q4 2024, transfers from Victoria to Tasmania dropped by 78%, while transfers from Tasmania to Victoria fell by 61%. Basslink spent 48% of dispatch intervals at 0 MW flow compared to 7% previously (Figure 61).

Figure 61 Significantly reduced southward flows on Basslink

Average Basslink flow by time of day

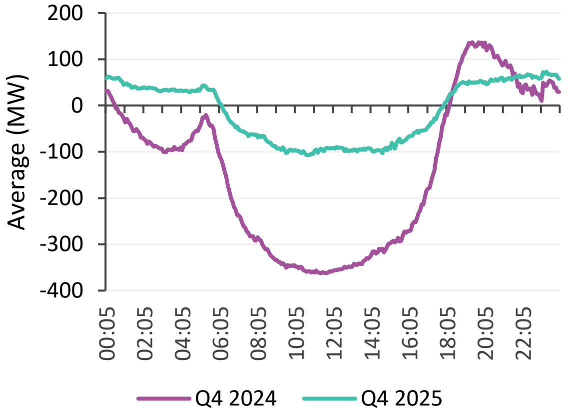
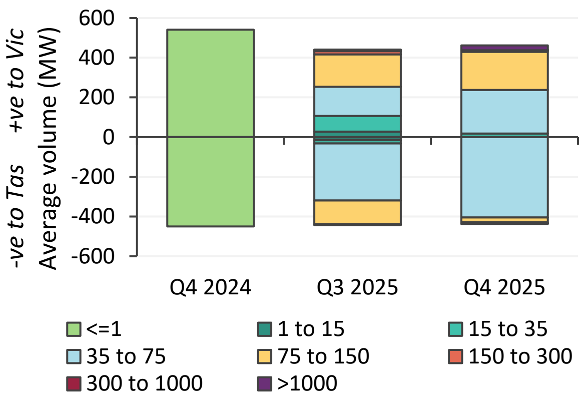


Figure 62 Majority of Basslink transfer capacity offered at prices between $35 to $75/MWh

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



2.4.1 Inter-regional settlement residue (IRSR)

Total positive IRSR decreased from $122 million in Q4 2024 to $91 million in Q4 2025 (Figure 63). The largest reductions were into New South Wales, with residues into the region from Queensland totalling $35 million (down from $51 million in Q4 2024) and residues from Victoria at $33 million (down from $46 million in Q4 2024). These reductions were in line with less high-priced volatility this quarter. Just over half of the quarter's positive IRSR into New South Wales from Queensland accrued on 25-26 November and 18-19 December, when high-priced volatility in New South Wales coincided with imports from lower-priced Queensland (see Table 2 in Section 2.2.2). In contrast, positive residues into New South Wales from Victoria accumulated steadily with persistent moderate price differences between Victoria and New South Wales.

Figure 63 Lowest positive IRSR in recent quarters

Quarterly positive IRSR by region

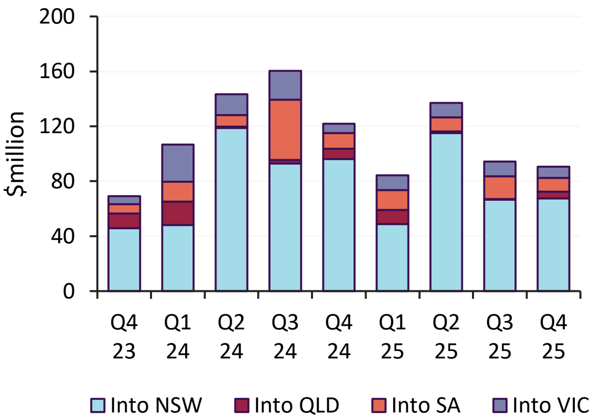
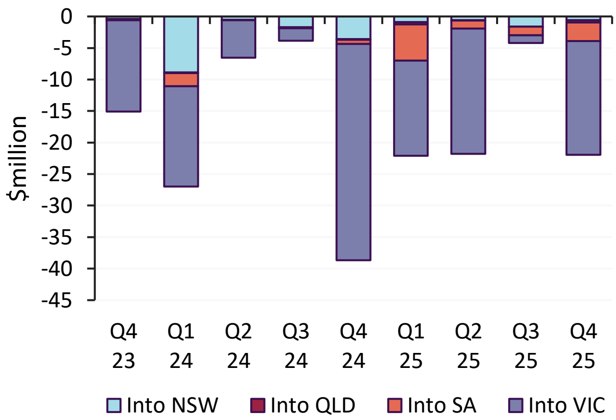


Figure 64 Negative IRSR reduced year-on-year

Quarterly negative IRSR by region



Negative IRSR reduced from the quarterly high of -$39 million in Q4 2024, to -$22 million in Q4 2025 (Figure 64). The largest share of this negative residue was into Victoria from New South Wales, at -$18 million (reduced from -$34 million in Q4

2024), followed by residues into South Australia at -$3 million (up from -$0.7 million in Q4 2024). Around 40% (-$8 million) of the negative residue into Victoria arose on the high-priced volatility days of 25-26 November and 18-19 December, when transmission constraints combined with high generation in southern New South Wales to force energy transfers southwards against large inter-regional price differences.

2.5 Frequency control ancillary services and frequency performance payments

Total FCAS costs were $18 million in Q4 2025, equivalent to approximately 0.7% of the cost for consumed energy[28] over the quarter. This was $42 million (-70%) lower than total FCAS costs in Q4 2024, with reductions recorded across all regions (Figure 65). The total costs for regulation and raise contingency FCAS services decreased year-on-year, with the costs for the lower contingency services increasing year-on-year. The contingency lower 6-second (L6SE) service recorded the largest year-on-year increase, up by 30% to $5.6 million, and also contributed the largest proportion to the quarter's total FCAS costs (Figure 66). The majority of the L6SE cost arose in Queensland during planned outages impacting the Queensland – New South Wales Interconnector (QNI) in October and early November. These outages (Armidale – Dumaresq 330 kilovolt [kV] line) increased the region's risk of separating from the NEM requiring local enablement of FCAS.

Figure 65 FCAS costs in all regions reduced year-on-year

Quarterly FCAS costs by region

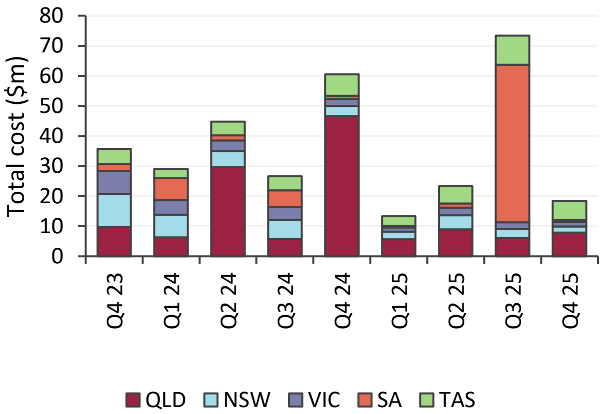
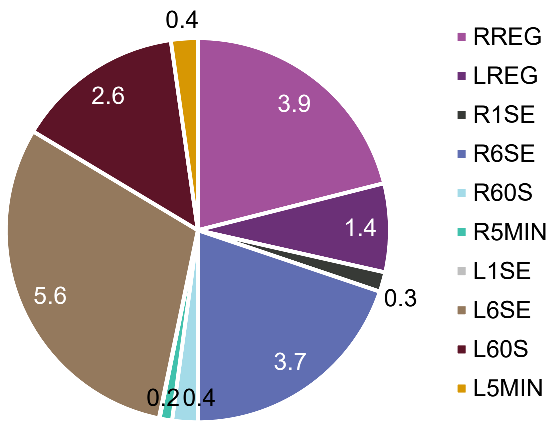


Figure 66 L6SE, R6SE and RREG the highest shares of FCAS costs

NEM quarterly FCAS costs per service – Q4 2025 ($m)



Battery enablement continued to be the dominant source technology providing FCAS, with volume share rising to 64% this quarter (Figure 67). Average enablement of batteries rose by 537 MW from Q4 2024, with enablement at new entrants Latrobe Valley BESS and Melbourne Renewable Energy Hub in Victoria averaging 330 MW and 235 MW respectively. In contrast, there was a decline in virtual power plants (VPP) and black coal FCAS enablement (Figure 68).

The 192 MW decrease in VPP enablement was primarily driven by Energy Local's VPP availability for FCAS dropping to 0 MW this quarter, from an average of 225 MW in Q4 2024.

[28] 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.

Figure 67 Battery FCAS market share rose to over 60%

FCAS volume market share by technology – Q4 2025

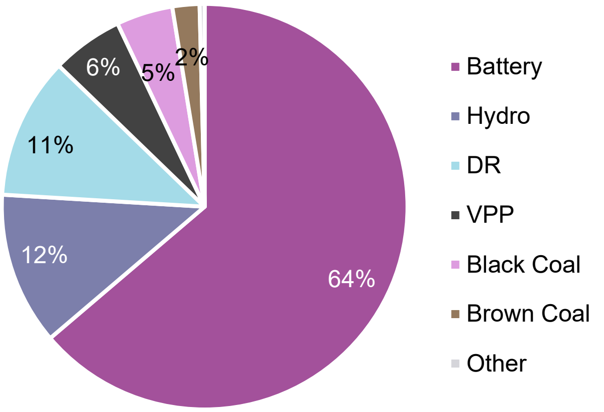
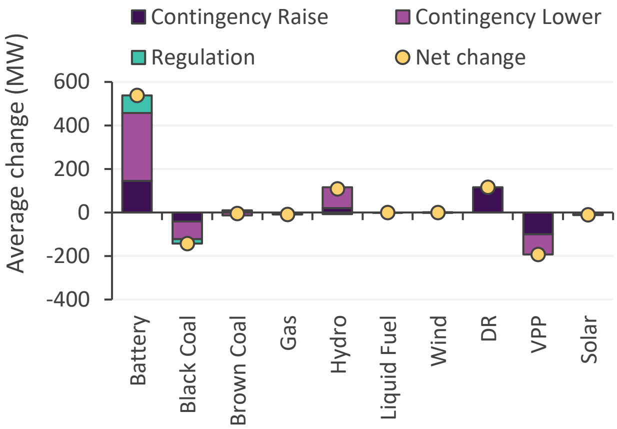


Figure 68 Decreased VPP FCAS enablement

Change in FCAS enablement by technology – Q4 2025 vs Q4 2024

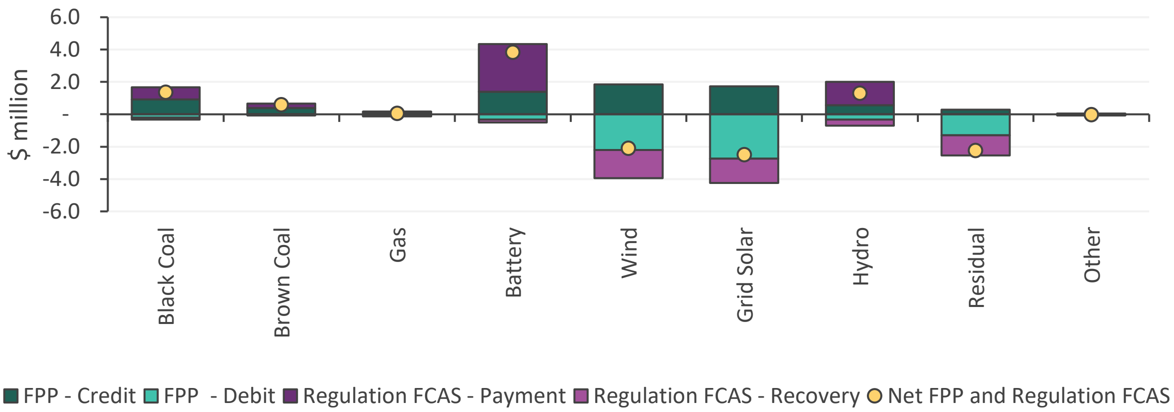


Regulation FCAS and FPP

In Q4 2025, costs for regulation FCAS were $5.3 million, $0.9 million (-29%) lower than in Q4 2024, and a total of $7.3 million in FPP incentive payments were distributed. Figure 69 shows the FPP credits and debits, and regulation FCAS payments and cost recovery by fuel type in Q4 2025.

Figure 69 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 – Q4 2025



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 $3.8 million. Grid-scale solar units incurred the largest share of charges, with -$2.5 million in total net FPP and regulation FCAS settlements. The residual category, which includes sites without appropriate metering to calculate individual contribution factors, such as small consumers and distributed resources, followed at -$2.3 million, then wind units at -$2.1 million.

2.6 Power system management

In Q4 2025, directions to registered participants were required for minimum system load (MSL) management and voltage control services in South Australia, system strength services in both Victoria and New South Wales, and reserve services in New South Wales. Additionally network support and control ancillary services (NSCAS) agreements were activated for voltage control in South Australia.

Table 6 summarises this quarter's directions for MSL management, reserve and system strength services. Directions and NSCAS activation for voltage control in South Australia are discussed in Section 2.6.1, and further information on system strength and MSL management is provided in Sections 2.6.2 and 2.6.3 respectively.

Table 6 Summary of directions for system strength, reserve and MSL management – Q4 2025

Region	Services	Dates	Description
New South Wales	System strength	5, 28, 29, 30 and 31 October	Hydro units to synchronise and operate as a synchronous condenser
New South Wales	Reserve	18 and 19 December	Batteries to maintain specified energy storage level and follow dispatch targets
Victoria	System strength	15 and 16 October	Hydro units to synchronise and operate as a synchronous condenser (15 October) Gas units to synchronise and follow dispatch targets (15 and 16 October)
South Australia	MSL management	11, 12 and 15 November 7, 25 and 26 December	Batteries to remain synchronised and follow dispatch targets and/or follow directions to manually charge/discharge

Estimated power system management costs[29] were $27.8 million in Q4 2025 (Figure 70), representing approximately 1.0% of the total cost of consumed energy for the quarter, and in line with Q4 2024's costs. No costs were associated with short notice reserve or interim reliability reserve (IRR)[30] under the Reliability and Emergency Reserve Trader (RERT) mechanism this quarter[31]. AEMO entered into six short notice reserve contracts on 18 December in response to a forecast Lack of Reserve 2 (LOR 2) condition in New South Wales, however none of these contracted reserves were activated or preactivated.

Combined costs for system security energy directions[32] and costs associated with NSCAS agreements for voltage control in South Australia were estimated at $27.6 million this quarter. Costs for directions for system strength services in Victoria on the 15 and 16 October were estimated at $0.1 million, noting that costs for the directions to hydro units to synchronise and operate as synchronous condensers on 15 October in Victoria are not yet available and are not included in the overall cost estimates.

[29] 'Power system management costs' are those associated with Reliability and Reserve Trader (RERT) and estimated compensation for system security directions for energy services and costs associated with NCSAS for voltage control. 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.

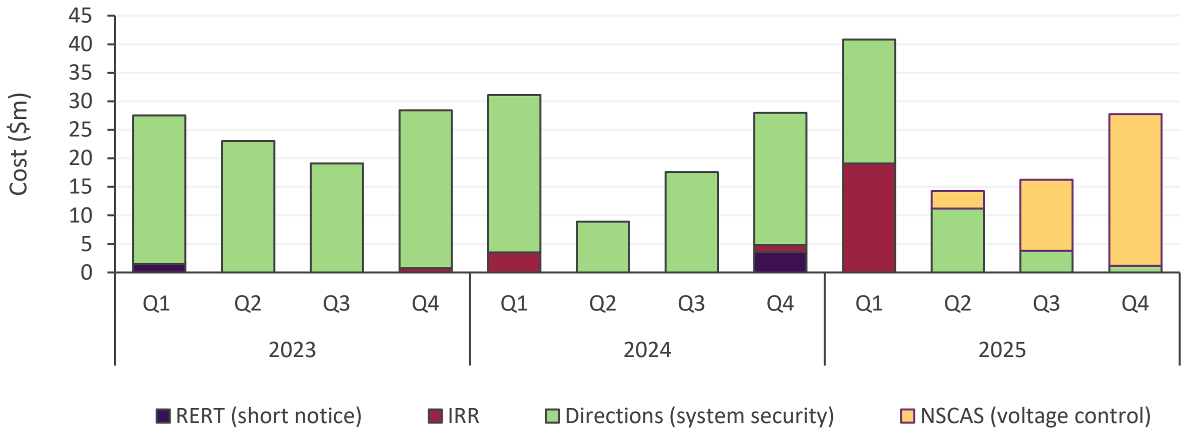
[30] IRR was enabled under National Electricity Rules clause 11.128 which expired on 31 March 2025 after which new IRR contracting is no longer permitted. The QED continues to report IRR costs for periods in which IRR contracts were active prior to the enquiry of the mechanism.

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

[32] 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.

Figure 70 System security costs in Q4 2025 remained steady year-on-year

Estimated quarterly system security costs by category



2.6.1 South Australian voltage control

With contracted NSCAS voltage control services in South Australia becoming operational during Q2 and Q3 2025, these services are now dispatched ahead of issuing directions. This has led to a substantial reduction in the use of directions for voltage control in South Australia, with the proportion of time directions were in place dropping from 65% of dispatch intervals in Q4 2024 to 3% in Q4 2025.

However in this quarter, South Australia saw a significant reduction in gas-fired generation (see Section 2.3.2) as generators more frequently opted to decommit their units from the system in response to lower electricity spot prices compared to Q4 2024 and higher VRE output. As a result, NSCAS voltage control services were activated more frequently to maintain system strength, with directions issued only when contracted services were insufficient. The proportion of total output that was dispatched under NSCAS contracts (or through direction when required) increased from 18% in Q4 2024 to 25% this quarter (Figure 71). The overall volume of gas-fired generation required to be on-line for voltage control, either under contract or via direction, was slightly lower compared to with Q4 2024, averaging 46 MW compared to 47 MW in Q4 2024.

With the reduction in gas-fired generation in response to market signals, the overall percentage of time in which gas-fired generation was dispatched under contract (or directed when necessary) for voltage control increased from 65% of dispatch intervals in Q4 2024 to 73% this quarter (Figure 72). However, the proportion of time that two or more units were required simultaneously under contract or direction decreased from 49% to 34% of dispatch intervals. This followed AEMO and ElectraNet reducing the minimum synchronous generator requirement in South Australia from two units to one under certain operating conditions on 2 September 2025[33]. One of the conditions for operation with one large synchronous generator in service is that operational demand in South Australia exceeds 600 MW. This condition was not met for almost 20% of the quarter, with distributed PV output reducing operational demand below 600 MW in 63% of the half-hourly intervals between 1000 hrs and 1600 hrs.

[33] 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 71 Increase in proportion of South Australian gas generation for voltage control

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

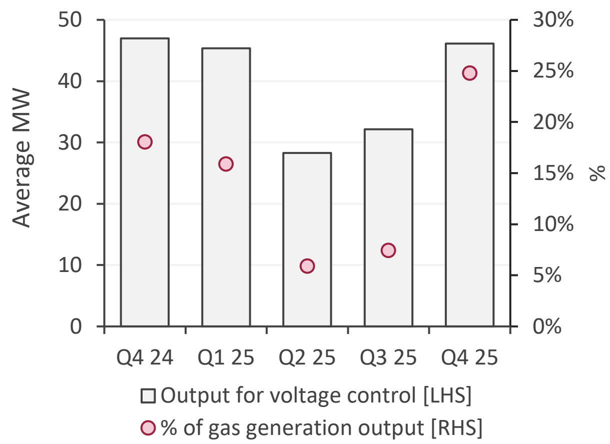
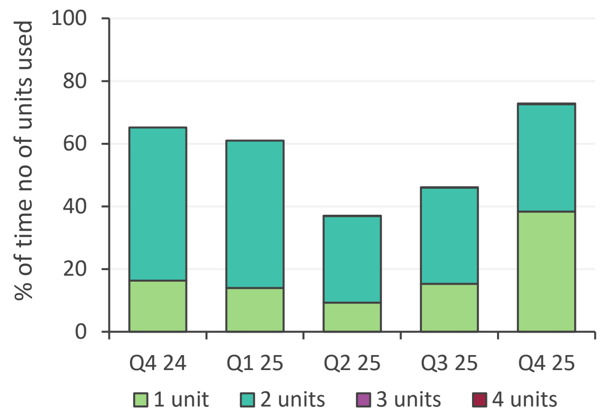


Figure 72 Decrease in two-unit requirement for voltage control

Percentage of time units simultaneously used for voltage control



2.6.2 System strength directions in New South Wales and Victoria

System security in New South Wales[34] and Victoria[35] is heavily reliant on large synchronous generators, with coal-fired units currently providing the majority of system strength support. When there are not sufficient synchronous generators online in response to market signals, AEMO may need to intervene to maintain secure operating conditions.

In Q4 2025, AEMO issued directions to participants in New South Wales and Victoria to provide system strength services on five and two days respectively (see Table 6 above). These services were required due to the number of synchronous units online falling below regional system strength requirements, typically due to an unplanned coal-fired generating unit outage. These system strength directions occurred before the System Security Management (SSM) tool went live on 2 December 2025. This tool was implemented under the Improving Security Frameworks (ISF) initiative (see Table 11 in Section 5) and enables AEMO to schedule system security services ahead of resorting to directions. Reporting on services scheduled through the SSM tool will be included in future QEDs.

In this quarter, with an increase in the capacity of coal-fired generators offline due to full unit unavailability in New South Wales and Victoria (see Section 2.3.1), the number of units online at any one time decreased overall, contributing to the increased need for directions. In New South Wales, the proportion of time that only seven units were online rose from 0.3% of the quarter in Q4 2024, to 5.0% this quarter, and the proportion of time that 11 or 12 units were online fell from 17% to 0% (Figure 73). In Victoria, the proportion of time with six or fewer units online increased from 5.3% of time in Q4 2024 to 15% in Q4 2025, including 0.4% with five units (up from 0.3%) and 0.1% with four units (up from 0%) (Figure 74).

[34] TransGrid, New South Wales Synchronous Generation. September 2025: https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2024/transfer-limit-advice---system-strength-nsw.pdf?rev=dcc5804b14624f089c59d5d47a7a4f9d&sc_lang=en.

[35] Transmission limits advices including Victorian system strength requirements under system normal and outage conditions are available at https://www.vicgrid.com.au/transmission-planning/planning-the-energy-grid#heading-5.

Figure 73 Proportion of time with seven New South Wales coal units online increased

Number of New South Wales black coal-fired units online

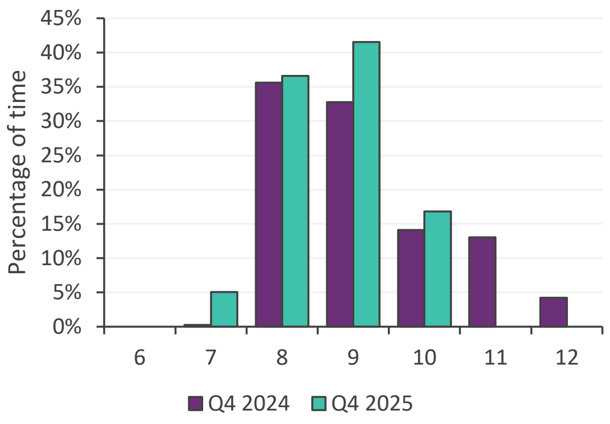
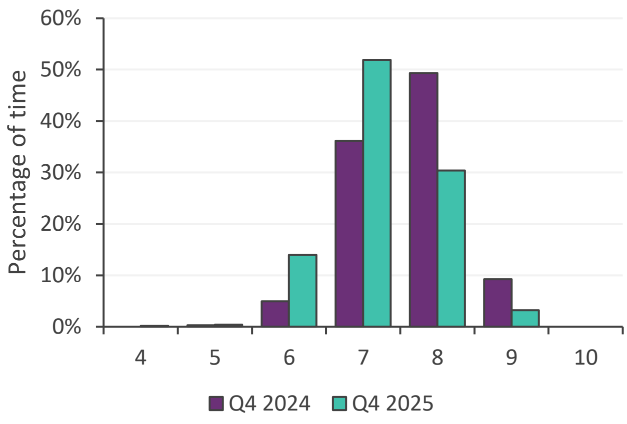


Figure 74 Proportion of time with six or fewer brown coal units online increased

Number of Victorian brown coal-fired units online



2.6.3 Minimum system load management in South Australia

When high output from distributed PV combines with low underlying demand, operational demand on the transmission system can be significantly reduced, creating minimum system load (MSL) conditions[36]. With record high distributed PV output this quarter, MSL conditions were declared in South Australia and Victoria on multiple occasions[37], including four instances of forecast MSL2[38] and four actual MSL2 conditions in South Australia and two forecast MSL2 in Victoria. Both forecast MSL2 in Victoria and two of the forecast MSL2 events in South Australia were cancelled prior to the day in question.

Under MSL2 conditions, grid-scale action such as reducing grid-scale generation, increasing electricity demand by large users or procuring[39] 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 Q4 2025, AEMO issued directions on six 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 11, 12 and 15 November and Blyth on 7, 25 and 26 December) 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.

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

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

[38] 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.

[39] 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 Gas market dynamics

3.1 Wholesale gas prices

Quarterly wholesale gas prices slightly increased from Q3 2025 but were 7% lower than Q4 2024. The average price across all AEMO markets was $12.68/GJ compared to $13.60/GJ in Q4 2024 (Table 7).

Table 7 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q4 2025	Q4 2024	Q3 2025	Change from Q4 2024
Victoria Declared Wholesale Gas Market (DWGM)	12.02	12.25	12.11	-2%
Adelaide	12.82	13.55	12.76	-5%
Brisbane	12.95	14.71	12.79	-12%
Sydney	12.82	13.66	12.75	-6%
Gas Supply Hub (GSH)	12.76	13.85	12.71	-8%

Key factors influencing the movement of prices throughout Q4 2025 are summarised in Table 8, with further analysis and discussion in relevant sections elsewhere in this report.

Table 8 Wholesale gas price levels: Q4 2025 drivers

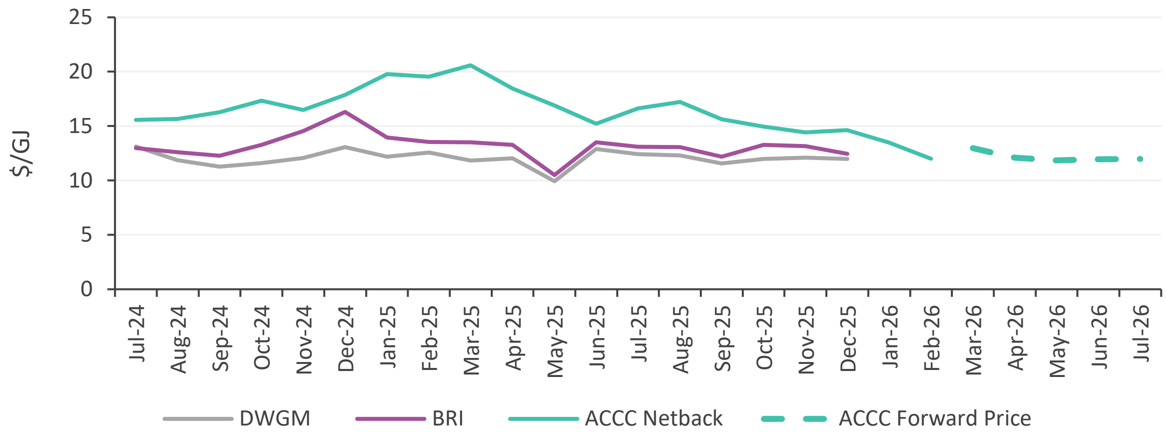
Decrease in gas flows to Queensland from southern markets due to a decrease in Queensland LNG demand combined with an increase in net domestic supply from LNG participants	Compared to Q4 2024, aggregate demand from the Queensland LNG export projects was 10.1 PJ lower, while supply into the domestic market associated with the LNG projects increased by 2.4 PJ. This led to less reliance on Victorian supply to meet demand, with significantly lower flows from southern markets to Queensland. As a result, much of this supply was offered into markets at prices lower than Q4 2024, especially in November and December. This particularly impacted the Brisbane Short Term Trading Market (STTM) price and narrowed the price gap between the southern states and Queensland.
Lower gas-fired generation demand, particularly in November and December	Demand from gas-fired generation dropped to record low levels in Q4 due to increased renewable supply and higher coal availability. This put downward pressure on spot prices across all AEMO markets, particularly in Brisbane which saw a large decrease in gas-fired generation demand combined with a simultaneous decrease in Queensland LNG demand.

International prices reversed the upward trend observed in Q3 2025. This decrease was reflected in downward movements in the Australian Competition and Consumer Commission (ACCC) netback price to December 2025, with corresponding forward prices ranging between $11.83/GJ and $13.61/GJ over the next six months (Figure 75). Driver for international prices are discussed in Section 3.1.1.

Prices in October 2025 were consistent with those recorded in October 2024, averaging $12.89/GJ for the month. Prices remained relatively steady for the rest of the quarter, in contrast to the increase during November and December 2024 when prices lifted due to record Queensland LNG production and higher gas-fired generation demand.

Figure 75 Domestic prices lower year-on-year mostly due to lower levels in December

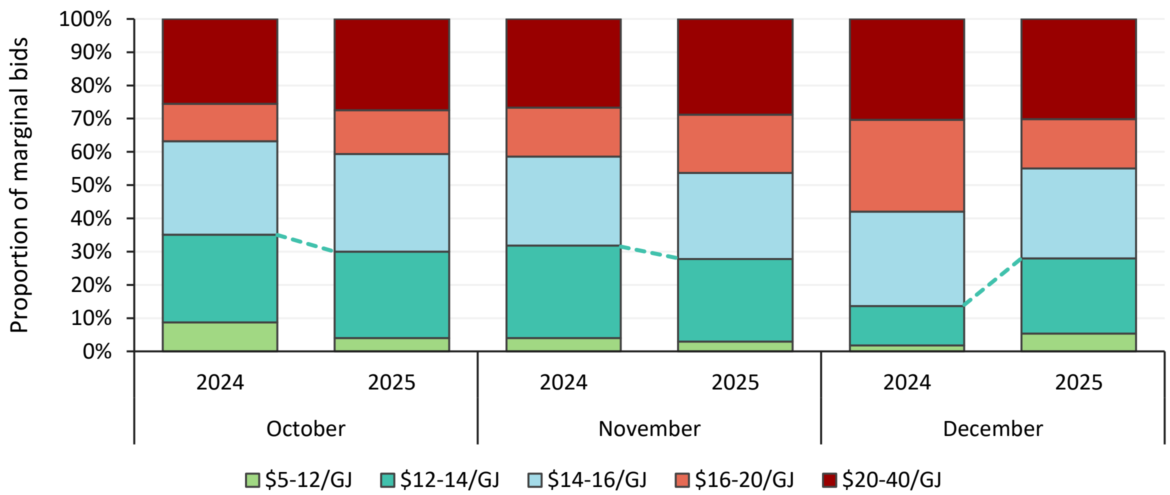
ACCC netback and forward prices[40], DWGM and STTM Brisbane average gas prices by month



Compared to Q4 2024, there was a significant increase in the proportion of Declared Wholesale Gas Market (DWGM) bid volumes below $14/GJ in December, while there were small decreases in October and November (Figure 76). This occurred despite large decreases in capacity at Longford for much of the first half of December for planned maintenance (see Section 3.3.3). Factors contributing to this include decreased gas-fired generation and decreased exports from Victoria, particularly to New South Wales which saw a large increase in southerly flows from Queensland.

Figure 76 Increased proportion of DWGM bids in December at lower prices compared to 2024

DWGM – proportion of marginal bids by price band – Q4 2025 vs Q4 2024 by month



3.1.1 International energy prices

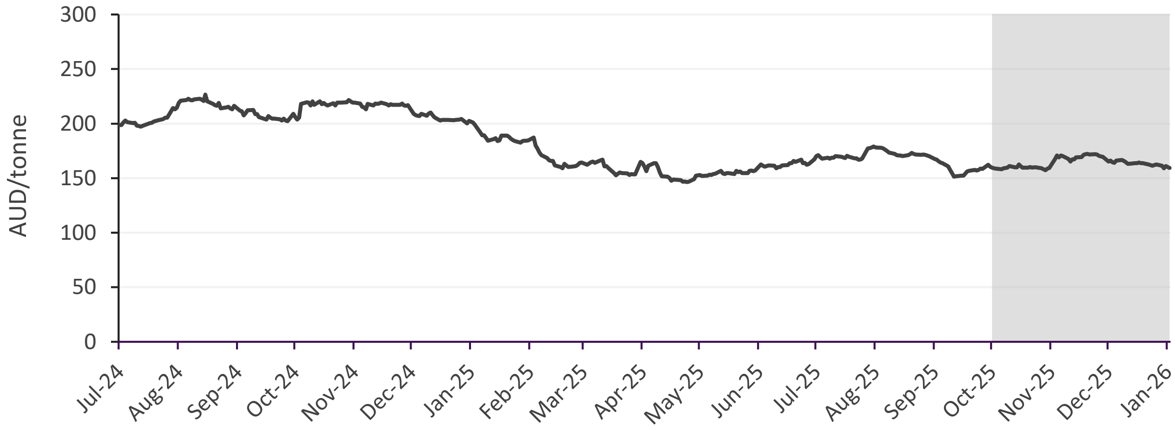
Newcastle export coal prices averaged $164/tonne this quarter, down from $213/tonne in Q4 2024 (Figure 77). Prices remained relatively unchanged from the previous quarter (Q3 2025) and remained within a $157 to $172/tonne band throughout the quarter. reflecting increased supply and overall weaker demand as key import countries continue to shift

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

away from thermal coal power generation[41]. After starting the quarter at $160/tonne, prices rose slightly in late November with a rise in demand with the onset of the Northern Hemisphere winter conditions, before finishing the quarter at $161/tonne.

Figure 77 Thermal coal prices remained relatively stable over the quarter

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



Source: Bloomberg ICE data.

Asian LNG prices (Figure 78) saw a brief uptick in November, peaking at A$19.20/GJ. The modest increase was driven primarily by rising charter costs amid a shortage of LNG vessels due to increased United States (US) LNG production tightening global shipping capacity[42]. US LNG production increased by just under 21% (year-on-year) compared to 2024[43]. However, the price spike was short-lived as there was abundant regional supply available putting downward pressure on market prices. By mid-December prices had fallen sharply, ending the quarter at A$15.40/GJ[44].

Figure 78 Asian LNG prices fell on the back of abundant supply in the region

Asian LNG price in A$/GJ daily

Source: Bloomberg ICE data.

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[41] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly December 2025: https://www.industry.gov.au/publications/resources-and-energy-quarterly-december-2025.

[42] LNG Shipping rates surge, December 2025: https://www.maritimenews.com/charter-rates/lng-charter-rates-surge-100k-day.

[43] US LNG Exports break records, January 2026: https://oilprice.com/Latest-Energy-News/World-News/US-LNG-Exports-Break-100-Million-Tons-in-Record-2025.html.

[44] Asia spot prices fall to 20-month low on weak demand, December 2025: https://www.hellenicshippingnews.com/asia-spot-prices-fall-to-20-month-low-on-weak-demand/.

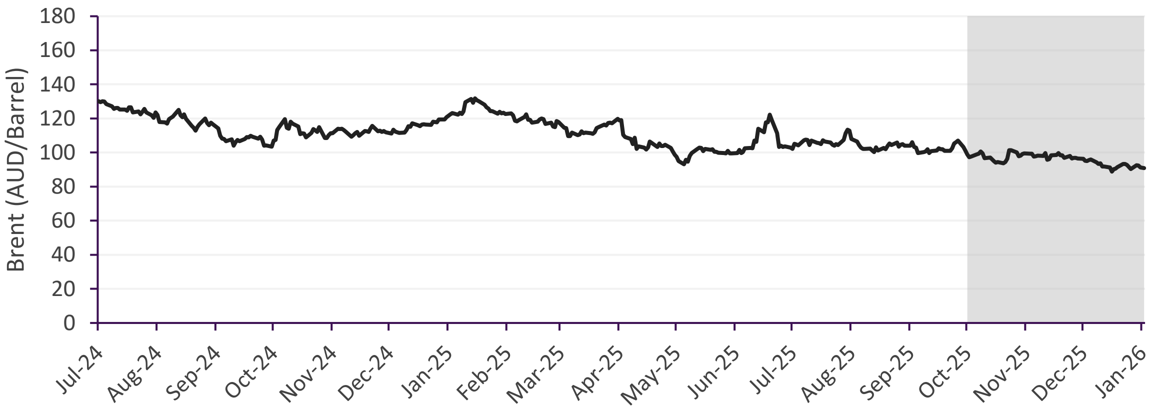
The regional oversupply was driven by a variety of factors – warmer-than-average temperatures across North Asia, a significant increase to China's domestic gas production and higher pipeline flows via the Power of Siberia 1 pipeline (from Russia into north China) – all of which reduced demand for spot LNG cargoes[45]. Another contributor to softer LNG prices has been the decline in Brent crude oil.

Brent crude prices softened through Q4 2025 as global supply continued to exceed demand (Figure 79). Supply growth outpaced consumption throughout 2025, with rising output from OPEC+ members and other major producers adding several million barrels per day to the market. Elevated inventories and higher volumes of "oil on water" also highlighted the absence of tightness in physical markets despite ongoing geopolitical risks[46].

At the same time, demand growth remained modest and below earlier projections, providing limited support to prices. International Energy Agency (IEA) data showed only moderate increases in global oil demand in 2025 – insufficient to absorb additional supply, particularly from the US and other non-OPEC producers. There has been slower-than-expected demand growth across major consuming regions and repeated downward revisions to demand forecasts added further downward pressure to the market[47].

Figure 79 Brent Crude softened throughout the quarter as global supply continued to exceed demand

Brent Crude Oil in A$/Barrel daily



Source: Bloomberg ICE data.

3.2 Gas demand

Total east coast gas demand decreased by 3% compared to Q4 2024 (Figure 80 and Table 9), due to a large decrease in Queensland LNG production (-10 PJ), and a decrease in gas-fired generation (-6 PJ). AEMO markets saw an increase in demand (+3 PJ), mainly driven by a lift of 2.9 PJ in Victoria's DWGM due to cooler temperatures increasing heating load. The main reasons for reduced gas-fired generation were higher wind output and battery discharge in the NEM, particularly during the evening peak (see Figure 29 in Section 2.3).

[45] China's Strategic Energy Independence Initiative, January 2026: https://discoveryalert.com.au/china-strategic-energy-independence-initiative-2026.

[46] IEA Oil Market Report, December 2025: https://www.iea.org/reports/oil-market-report-december-2025.

[47] S&P Global, IEA cuts oil demand growth estimates in 'ever more bloated market": https://www.spglobal.com/energy/en/news-research/latest-news/crude-oil/081325-iea-cuts-oil-demand-growth-estimates-in-ever-more-bloated-market.

Figure 80 Large decrease in Queensland LNG and gas-fired generation demand

Components of east coast gas demand change – Q4 2025 to Q4 2024

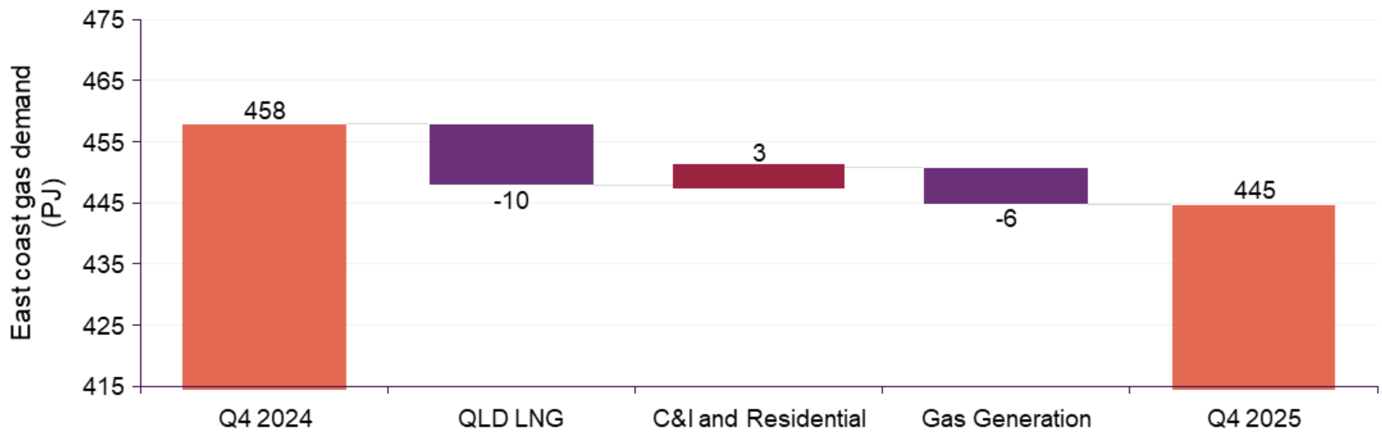


Table 9 Gas demand – quarterly comparison

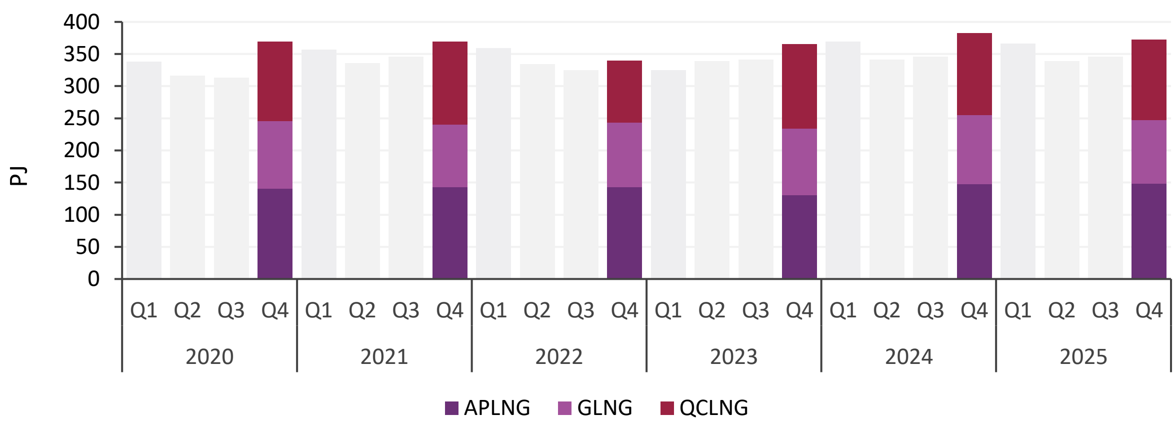
Demand (PJ)	Q4 2025	Q3 2025	Q4 2024	Change from Q4 2024
AEMO markets *	57.5	92.6	54.4	3 (+6%)
Gas-fired generation **	14.8	26.1	20.8	-6 (-29%)
Queensland LNG	372.5	345.5	382.6	-10 (-3%)
Total	444.8	464.3	457.9	-13 (-3%)

* 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 while significantly lower than Q4 2024, by 10 PJ, was still the second highest demand on record for any quarter with a combined total demand of 372.5 PJ, with APLNG setting its record demand for any quarter, surpassing the previous record achieved in Q4 2024 (Figure 81).

Figure 81 Queensland LNG production lower despite record APLNG production

Total quarterly pipeline flows to Curtis Island



By participant, in comparison to Q4 2024, APLNG demand increased by 1.3 PJ, while GLNG decreased by 9.1 PJ and QCLNG decreased by 2.3 PJ. There were 95 cargoes[48] exported during the quarter, down from 99 cargoes in Q4 2024.

3.2.1 Gas-fired generation

Gas-fired generation decreased 29% compared to Q4 2024 (Figure 82). The largest decreases occurred in Queensland (-4.3 PJ) and South Australia (-1.5 PJ), both significantly lower than November and December 2024. The lower demand for gas-fired generation was due to higher wind output and increased battery discharge, particularly during the evening peak.

The significant decrease in November and December gas-fired generation led to the lowest Q4 demand for gas-fired generation since Q4 2000 (Figure 83).

Figure 82 Daily gas-fired generation in November and December well below 2024 levels

Average daily gas-fired generation by state

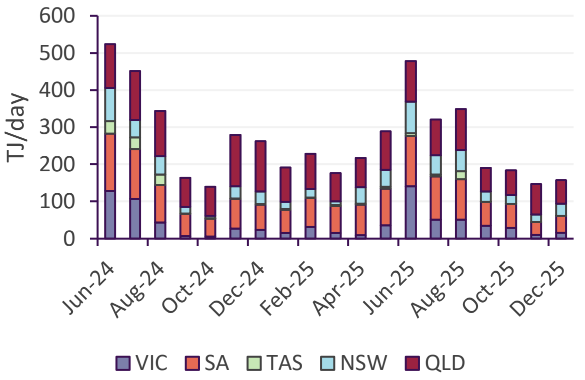
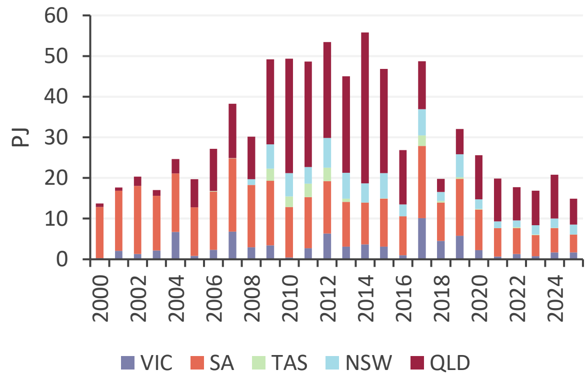


Figure 83 Lowest Q4 gas-fired generation since 2000

Q4 gas-fired generation by state



3.2.2 Victorian Declared Wholesale Gas Market (DWGM) demand

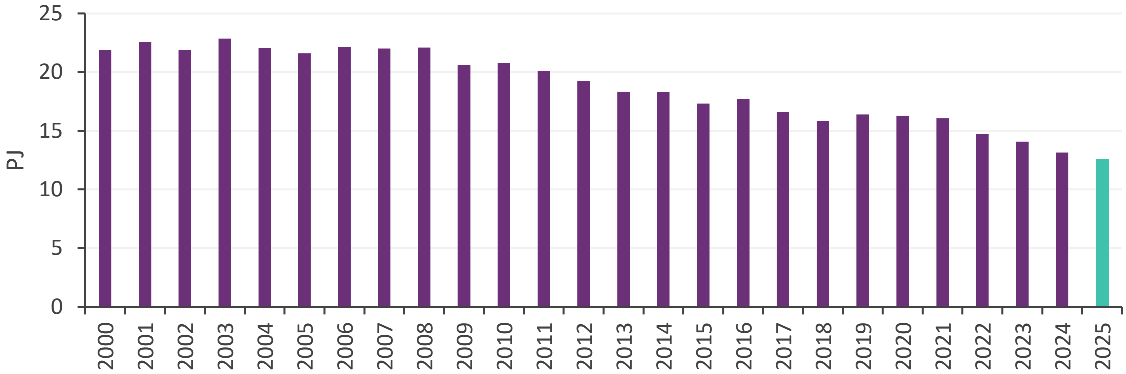
In the Victorian DWGM, Tariff D customers are defined as large commercial and industrial users that consume more than 10 TJ/year or more than 10 GJ/hour of gas. These customers typically have flat consumption profiles across a year, with their gas consumption often linked to economic conditions. They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

Continuing the trend observed in throughout 2025, Q4 2025 saw another decrease in Tariff D demand, with consumption decreasing from 13.1 PJ in Q4 2024 to 12.6 PJ in Q4 2025, a 4% decrease (Figure 84). This represents the lowest Q4 Tariff D demand since the DWGM began in 1999, and a 10.3 PJ or 45% decrease from the peak in 2003.

[48] The cargo of an LNG tanker is typically 3.5-4 PJ.

Figure 84 Victorian industrial and large commercial demand at lowest level since the DWGM began

Q4 DWGM Tariff D demand



3.3 Gas supply

East coast gas production decreased by 17.2 PJ (-3%) compared to Q4 2024 (Figure 85). Key changes included:

- Victorian production decreased by 9 PJ, driven by decreases in Longford production (-7.1 PJ) and Otway (-2.4 PJ), and a small decrease by Athena (-0.4 PJ). Other Victorian production facilities saw small increases, with Orbost increasing by 0.6 PJ, followed by Bass Gas (+0.2 PJ).
- Queensland production decreased by 7.7 PJ, with assets operated by QCLNG decreasing by 3.1 PJ, GLNG operated assets decreasing by 2.0 PJ, and APLNG operated assets decreasing by 1.9 PJ. Gas demand for Queensland LNG exports decreased by 10 PJ, resulting in 2.3 PJ more net supply associated with Queensland LNG projects entering the domestic market compared to Q4 2024 (Figure 86).
- Production fell by 0.6 PJ at Moomba, though improvements in average daily output occurred compared to Q3 2025, which had been impacted by widespread flooding in far northern South Australia in mid-April[49]. Average daily output increased to 243 TJ/day in Q4 2025 compared to 216 TJ/day in Q3 2025.

[49] Santos, 2025 Fourth quarter report, 22 January 2026: https://www.santos.com/news/2025-fourth-quarter-report/,

3.3.1 Gas production

Figure 85 Large decreases across all major production facilities

Change in east coast gas supply – Q4 2025 vs Q4 2024

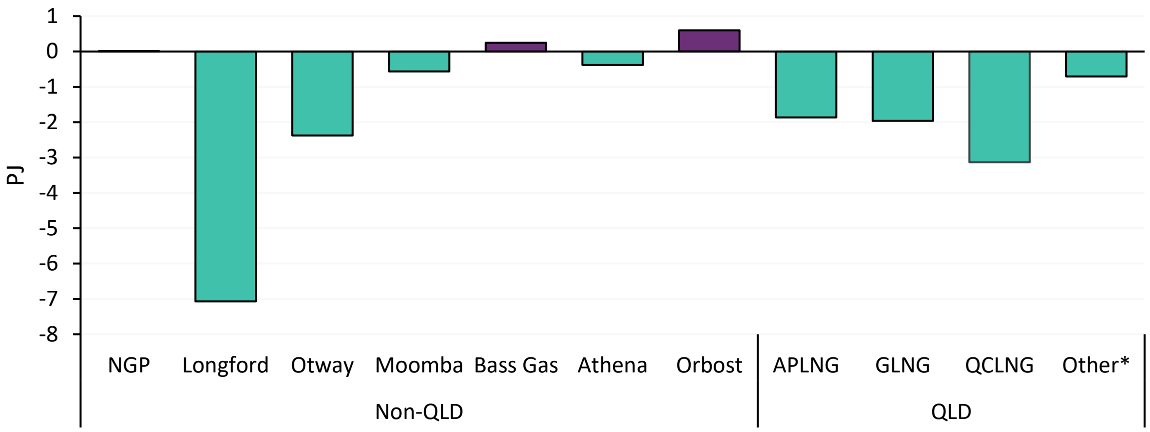
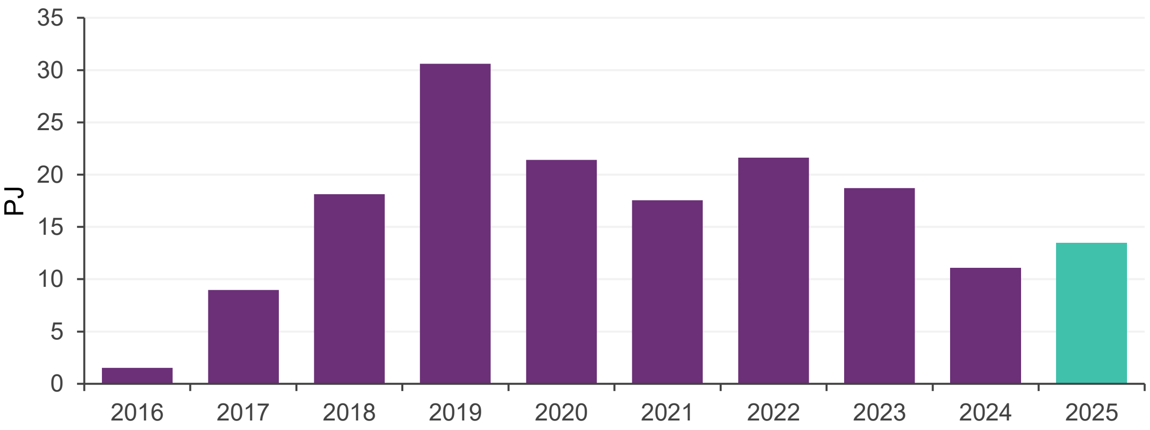


Figure 86 Queensland net domestic supply higher than 2024

Queensland net domestic supply during Q4



3.3.2 Northern Territory supply

In November, Tropical Cyclone Fina caused the shutdown of the Northern Territory's main gas supply, the Blacktip gas field. Production at the Yelcherr Gas Plant was halted while damage was assessed. Supply was covered by the Ichthys LNG plant except during planned maintenance in late December, when Queensland inflows via the Northern Gas Pipeline supported Northern Territory gas needs. At the end of Q4, the Yelcherr Gas Plant remained offline.

While Santos' Barossa gas project[50] began flowing in late September, providing a new source of supply to the Darwin LNG facility, they were unable to ship any cargoes from Barossa gas during the quarter[51].

[50] See https://www.santos.com/barossa/.

[51] See https://www.afr.com/companies/energy/santos-misses-end-of-year-deadline-for-first-barossa-lng-cargo-20251229-p5nqi5.

3.3.3 Longford production and capacity

Longford's gas production in Q4 2025 was 7 PJ lower compared to the same period in 2024, reaching 42.6 PJ compared to 49.6 PJ in Q4 2024, Longford's lowest Q4 production since 2014, when production was impacted by surplus gas being supplied into the domestic market resulting from commissioning associated with the Queensland LNG export projects. Available production capacity also decreased, with Q4 2025 capacity at 50.7 PJ, compared to 56.6 PJ in Q4 2024, predominately due to planned maintenance in December (Figure 87). This represents the lowest capacity for Q4 since data began being reported on the Gas Bulletin Board in 2008.

Despite the capacity reduction, daily production through much of Q4 remained below available capacity, with Longford operating at a capacity factor of 84%, its lowest capacity factor since 2019. This decrease in capacity factor occurred despite Longford daily capacity decreasing to around 200 TJ/day for 10 days in December due to planned offshore maintenance (Figure 88). Consistent with trends observed throughout 2025, this reduction in capacity factor remains largely due to a proportion of Longford supply offers from the Longford producers, Esso and Woodside, continuing to exceed daily price outcomes in the DWGM and Sydney Short Term Trading Market (STTM).

During the planned maintenance period, Longford's production of 197 TJ on 2 December is the lowest daily recorded output recorded by the plant since at least the Gas Bulletin Board began reporting data in 2008.

Figure 87 Longford production at lowest Q4 levels since 2014 and capacity at lowest level since at least 2008

Longford Q4 production and unutilised capacity

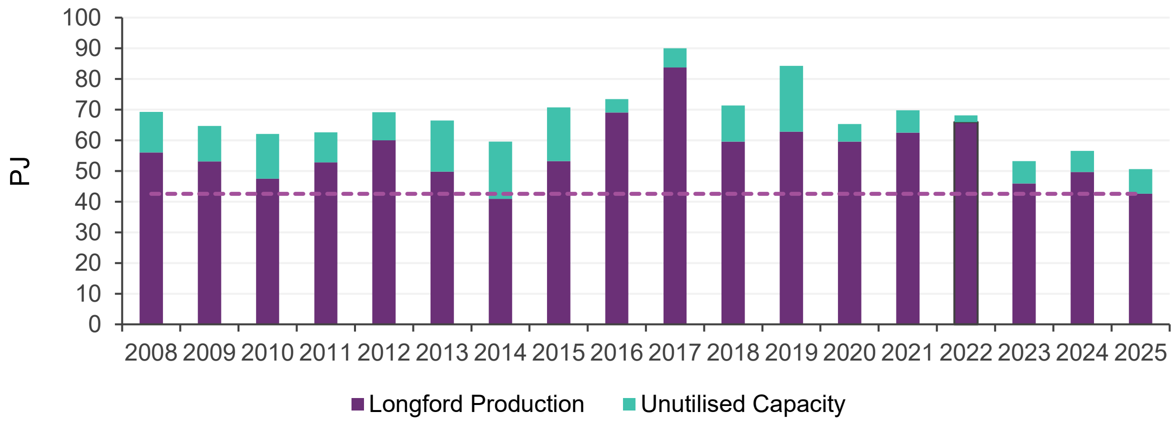
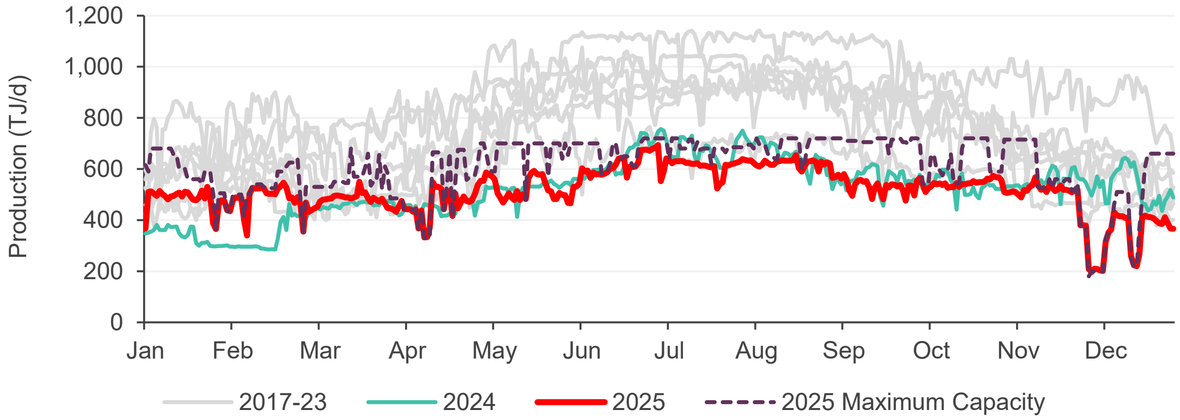


Figure 88 Daily Longford production lower than 2024 levels

Daily Longford production 2017-2025, maximum capacity profile 2025



3.3.4 Gas storage

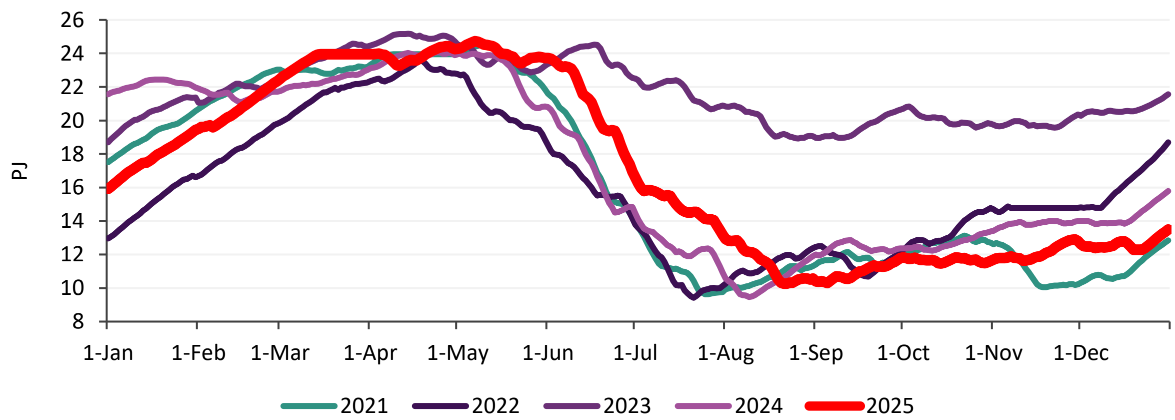
The Iona underground gas storage (UGS) facility finished the quarter with an inventory of 13.5 PJ, 2.3 PJ lower than at the end of Q4 2024 (Figure 89), and the lowest end to a Q4 since 2021.

Storage levels fell slightly in October, bottoming at 11.48 PJ on 29 October as Iona was utilised to meet increased Victorian demand resulting from cooler weather, before slightly increasing in November. Filling stalled again in December due to planned outages at Longford and Otway gas plants.

Storage levels were able to substantially increase in the last week of December, aided by lower demand traditionally associated with the holiday period and the end of the Longford maintenance.

Figure 89 Iona storage at its lowest end to Q4 since 2021

Iona storage levels

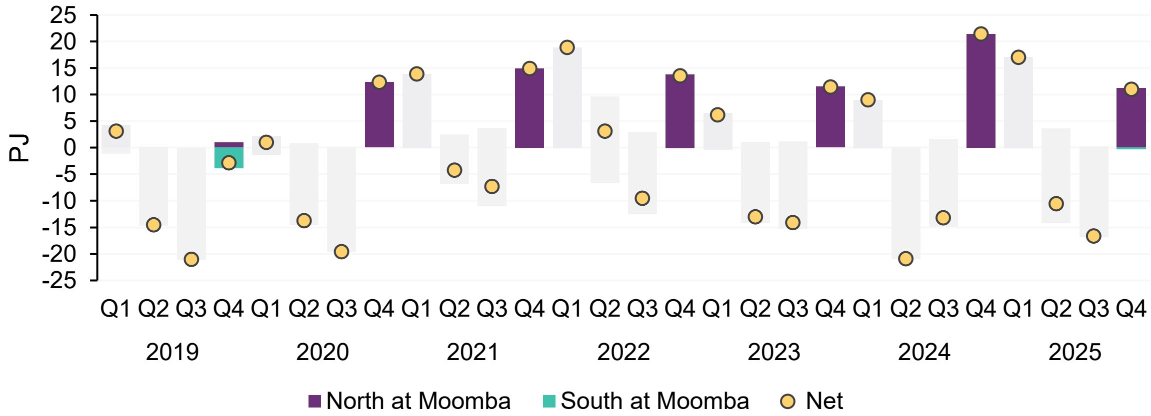


3.4 Pipeline flows

Compared to Q4 2024, there was a 10.4 PJ decrease in net transfers north from Moomba on the South West Queensland Pipeline (SWQP, Figure 90) which represents the lowest flow north from Moomba for a Q4 since 2019, though it was only slightly lower than Q4 2023, with Q4 2024 northerly flows at Moomba substantially higher than any other recent Q4. This decrease reflects the reduction in Queensland LNG export demand, with much of Moomba's production and GLNG's demand decrease redirected to Queensland to New South Wales and South Australia instead.

Figure 90 Net Q4 flows north on SWQP decreased to lowest level since 2019

Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states decreased by 10.2 PJ from Q4 2024 levels, due to lower Victorian production, and increased southerly flows from Moomba on the Moomba to Sydney Pipeline (MSP). Only 2023 (0.5 PJ lower), 2019 (0.6 PJ lower) and 2014 (6.9 PJ lower) saw lower Q4 net transfers out of Victoria since data reporting on the Gas Bulletin Board began in July 2008 (Figure 91).

Figure 91 Fourth lowest Victorian Q4 exports since data reporting began

Victorian net gas transfers to other regions – Q4s

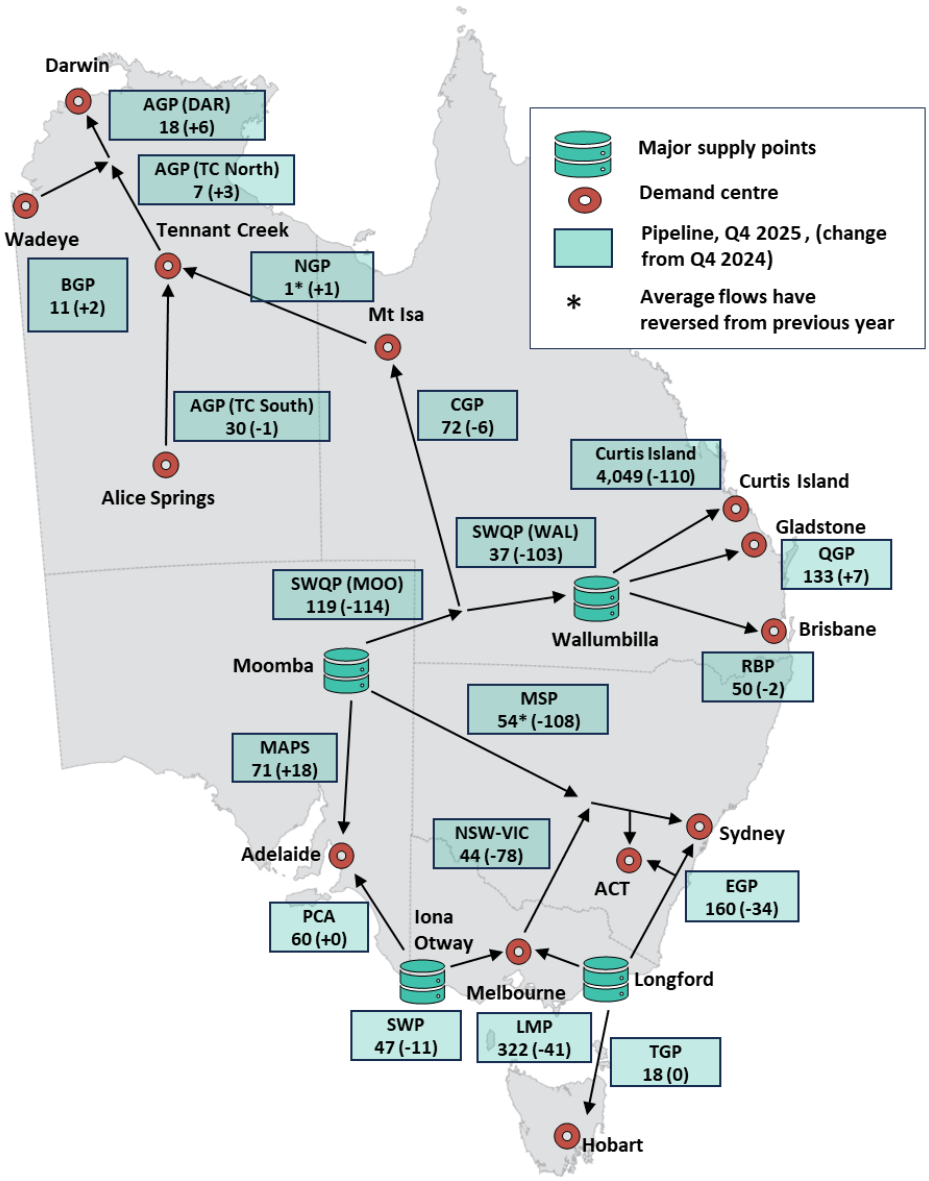
Average northerly flows in Q4 2024 were significantly lower on the New South Wales to Victoria Interconnect (Figure 92), reflecting a redirection of Moomba gas from Queensland to southern regions, and lower Longford and Otway production.

In Queensland, Mt Isa demand continued 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 lower mostly due to decreased production at GLNG.

There was a small flow on the Northern Gas Pipeline (NGP) from Queensland to Northern Territory in mid-December while the Ichthys LNG plant was offline for maintenance.

Figure 92 Significant increase in redirection of Moomba production from Queensland to southern regions

Average daily pipeline flows Q4 2025 vs Q4 2024

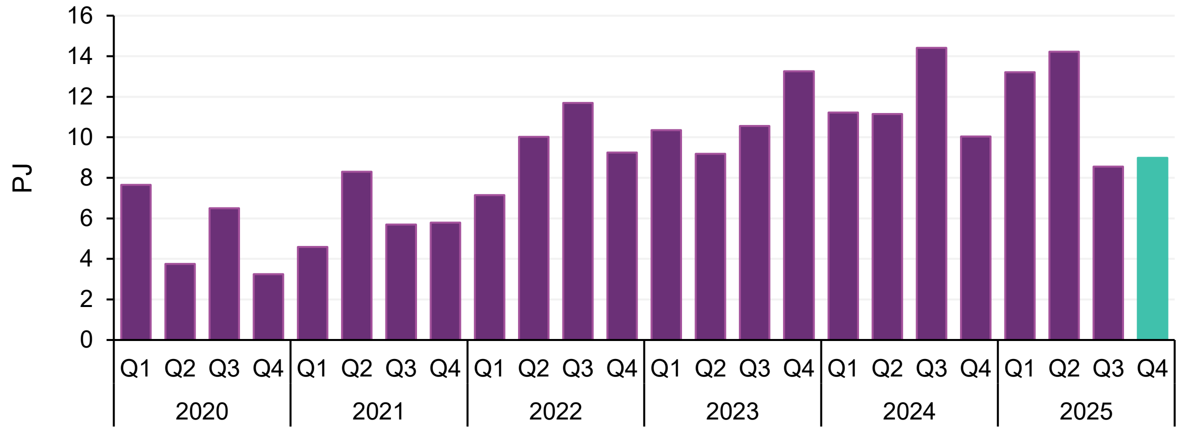


3.5 Gas Supply Hub (GSH)

In Q4 2025, traded volumes on the GSH decreased by 1.1 PJ compared to Q4 2024 (Figure 93). The traded volume this quarter was 9.0 PJ which was the lowest Q4 GSH traded volume since 2021. November was the highest monthly traded volume for the quarter at 3.5 PJ, mostly traded between a combination of delivery for the same month (1.5 PJ) and for delivery in Q1 2026 (1.1 PJ).

Figure 93 Lowest Q4 GSH traded volume since 2021

Gas Supply Hub – quarterly traded volume

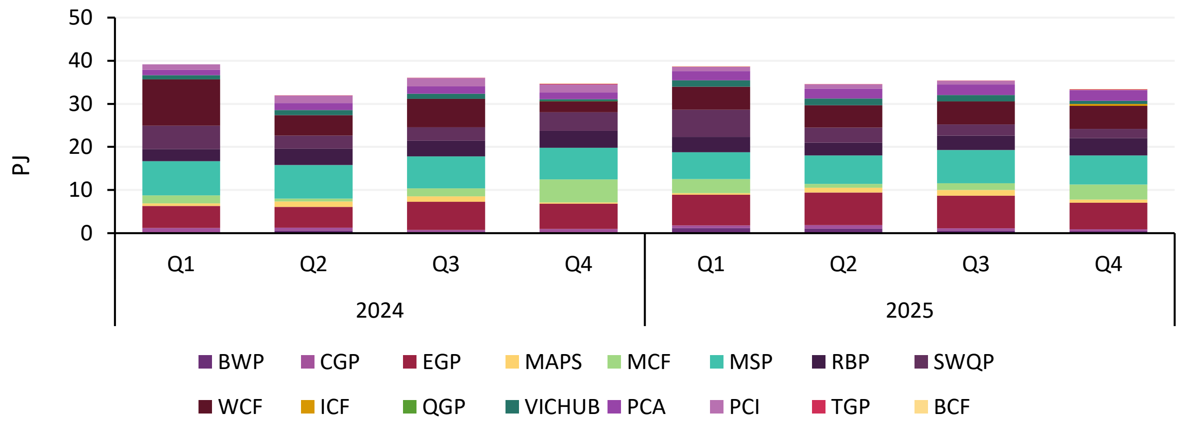


3.6 Pipeline capacity trading and Day Ahead Auction

Day Ahead Auction (DAA) volumes decreased by 1.3 PJ in comparison to Q4 2024 (Figure 94). Compared to Q4 2024, there were notable decreases in auction volumes on the SWQP (-2.1 PJ), Port Campbell to Iona Pipeline (PCI, -1.8 PJ) and Moomba Compressor (MCF, -1.8 PJ) and notable increases in auction volumes on the Wallumbilla Compressor (WCF, 2.9 PJ) and Port Campbell to Adelaide (PCA, 0.8 PJ).

Figure 94 Slight decrease in Day Ahead Auction volumes compared to Q4 2024

Day Ahead Auction volumes by quarter



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

- the Carpentaria Gas Pipeline (CGP) which averaged $0.37/GJ,
- the Eastern Gas Pipeline (EGP) which averaged $0.20/GJ, and
- the SWQP which averaged $0.18/GJ.

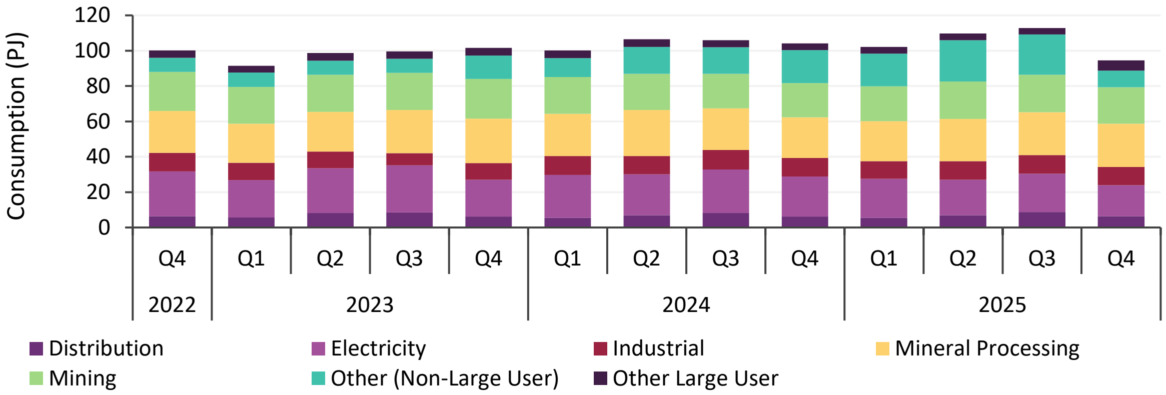
3.7 Gas – Western Australia

3.7.1 Gas consumption

A total of 94.5 PJ was consumed from registered pipelines in the Western Australian domestic gas market in Q4 2025 (Figure 95). This was a decrease of 9.7 PJ (-9.3%) compared to Q4 last year and a decrease of 18.4 PJ (-16.3%) from Q3 2025. The largest difference compared to Q3 2025 was observed in the Other (Non-Large User) category, which decreased by 13.5 PJ (-59.3%). Average gas-fired generation decreased by 126 MW (-16.4%) from the previous quarter, contributing to the reduction in reduced gas consumption (see Section 4.2). There were also changes in consumption when reviewing geographic zones with Q3 2025; the largest decrease was 11.35 PJ (-38.2%) in the Dampier Zone.

Figure 95 Gas consumption in Western Australia decreased compared to Q3 2025

Western Australian quarterly gas consumption by sector – Q4 2022 to Q4 2025

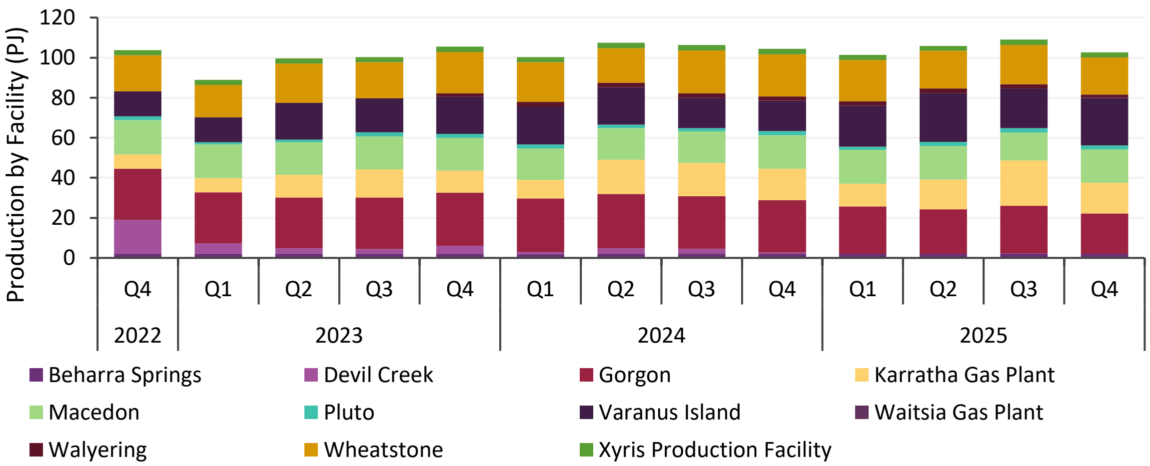


3.7.2 Gas production

Gas production in Western Australia was 102 PJ, a decrease of 1.8 PJ (-1.7%) compared to Q4 2024, and a decrease of 6.4 PJ (-5.9%) compared to last quarter (Figure 96). This can be attributed to reduction in both gas consumption from gas-fired generation (see Section 3.7.1) and the Other (Non-Large User) category.

Figure 96 Q4 2025 saw a decrease in gas production of 6.4 PJ from Q3 2025

Western Australia quarterly gas production by facility – Q4 2022 to Q4 2025

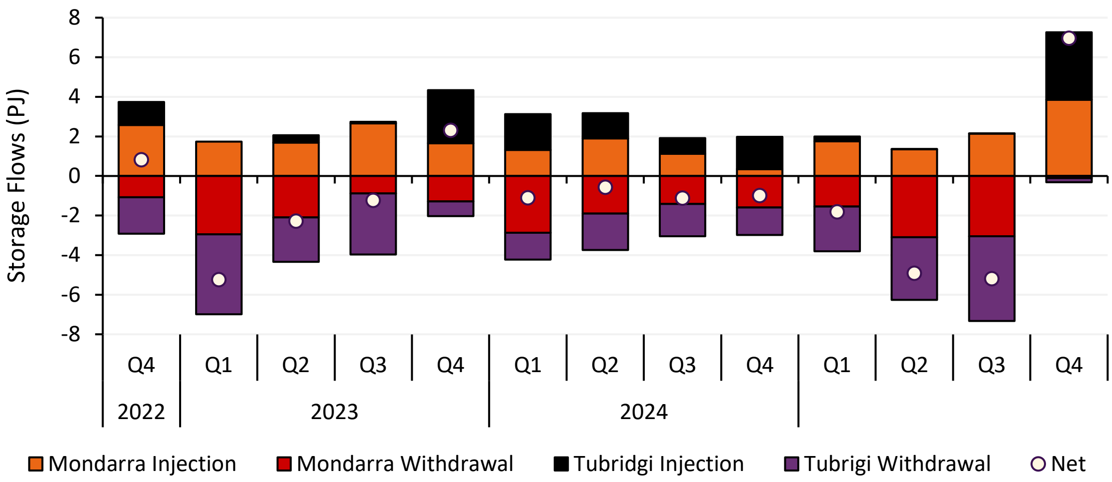


3.7.3 Storage facility behaviour

Net injection into storage facilities in Q4 2025 was 6.9 PJ (Figure 97), compared with a net withdrawal of 1 PJ in Q4 2024 and 5.2 PJ in Q3 2025.

Figure 97 Net injections from storage for Q4 2025

Western Australian gas storage facility injections and withdrawals – Q4 2022 to Q4 2025



3.7.4 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.

During Q4 2025, there was a red LCA flag for Mondarra storage facility and Parmelia Gas Pipeline on 13 October 2025 due to an issue with Mondarra storage Facility delivery stream. Additionally, Mondarra storage facility flagged an Amber LCA on 22 October to 13 November due to planned maintenance.

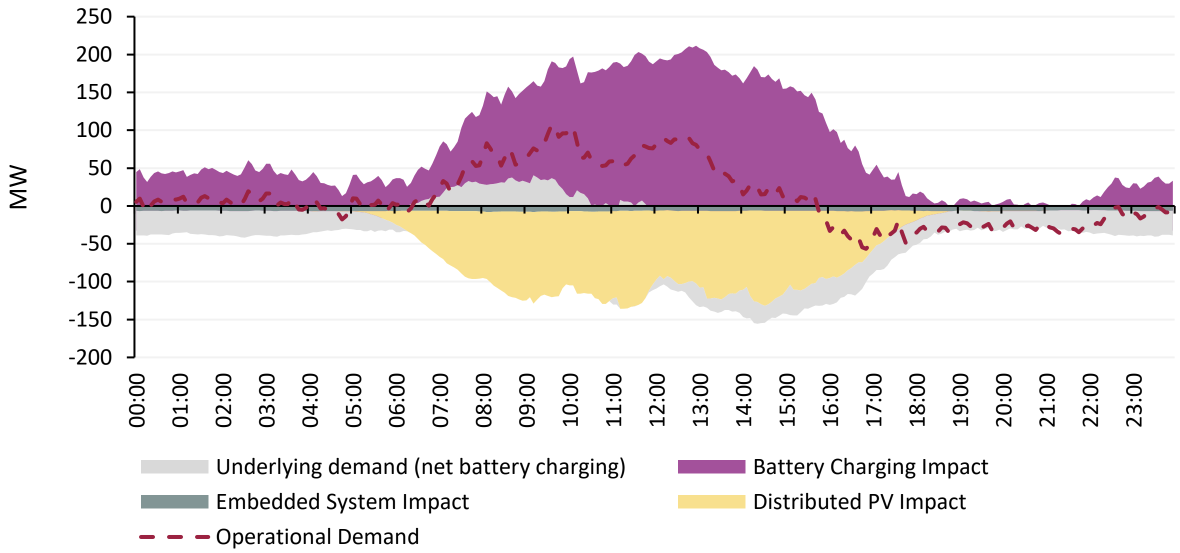
4 WEM market dynamics

4.1 Electricity demand

Average operational demand[52] was 1,882 MW in Q4 2025, an increase of 12 MW (+0.7%) compared to Q4 2024 (Figure 98). The demand increase was driven by higher average battery charging, up 81 MW (+199%), partially offset by increases of 46 MW (+7.8%) in distributed PV[53] generation and 6.5 MW (+42.8%) in average embedded system[54] generation. Average underlying demand independent of battery charging fell 17 MW (-0.7%).

Figure 98 Operational demand was relatively steady with increased distributed PV balancing higher battery charging during the middle of the day

Change in WEM average operational demand components by time of day – Q4 2024 vs Q4 2025



The increase in average battery charging can be attributed to an increase in battery capacity (see Section 4.2), while the reduction in other underlying demand can be attributed to cooler average temperatures – the average daily maximum and minimum temperatures were 0.4°C and 0.6°C degrees lower than Q4 2024, respectively.

[52] 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).

[53] Distributed PV is an estimation based on solar irradiance data and installed distributed PV capacity data available to AEMO. Note: AEMO has revised the Q4 2024 estimated distributed PV data since the publication of the QED Q4 2024.

[54] 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.

4.2 Electricity generation

The average share of coal and gas-fired generation in the fuel mix decreased by -1.9 pp and -5.8 pp, respectively, and was largely offset by increased average battery discharge (+2.7 pp) and renewable generation (+4.7 pp). Table 10 shows all Q4 2025 contributions, with average generation show in Figure 99. The following key changes were observed since Q4 2024:

- Coal-fired generation decreased by 33 MW (-5.8%), driven by battery discharge replacing coal-fired generation during the evening peak as well as a slight reduction in coal availability as Muja C Unit 6 was decommissioned in Q2 2025.
- Average gas-fired generation decreased by 126 MW (-16.4%), contributing to the reduction in reduced gas consumption (see Section 3.7.1). This can be attributed partly to gas-fired generation being replaced by renewable generation at all times of day, particularly by battery discharge during the evening peak (Figure 100), and partly to the decommitment of synchronous facilities due to changes to the FCESS Uplift payment framework.
- Average battery discharge increased by 70 MW (+200%). The WEM also experienced battery discharge surpassing 1 GW of injection for the first time on 15 December 2025 in the 18:35 interval. This record was exceeded on 23 December 2025 in the 18:30 interval, which saw 1,050 MW of battery discharge. The increased discharge is attributable to new battery capacity since the commencement of Q4 2024, composed of:
  - COLLIE_ESR1, with a capacity of 200 MW/800 MWh, which was commissioned during Q4 2024,
  - KWINANA_ESR2, with a capacity of 225 MW/900 MWh, which was commissioned during Q1 2025,
  - COLLIE_BESS2, with a capacity of 300 MW/1200 MWh, which was commissioned during Q2 2025,
  - COLLIE_ESR4, with a capacity of 250 MW/1000MWh, which was commissioned during Q4 2025, and
  - COLLIE_ESR5, with a capacity of 250 MW/1000MWh, which was commissioned during Q4 2025.
- Average biomass generation increased 30 MW (+343%). This can be attributed to the commissioning of facility PHOENIX_KWINANA_WTE_G1, with a capacity of 46.1 MW, registered in Q1 2025.
- The hybrid fuel type increased its average generation by 27 MW (+603%). This can be attributed to the commissioning of the Cunderdin Hybrid Facility (a 100 MW solar/battery hybrid) which completed commissioning during Q1 2025.

Table 10 WEM supply contributions by fuel type

Quarter	Coal	Gas	Distillate	Grid solar	Wind	Biomass	Battery	Hybrid	Hydro	Distributed PV	Embedded systems
Q4 2024	23.3%	31.1%	0.1%	1.8%	17.5%	0.4%	1.4%	0.2%	<0.1%	23.8%	0.6%
Q4 2025	21.4%	25.3%	<0.1%	2.3%	18.2%	1.5%	4.2%	1.3%	<0.1%	24.9%	0.9%
Change	-1.9%	-5.8%	<0.1%	0.5%	0.7%	1.1%	2.8%	1.1%	-	1.1%	0.3%

Figure 99 Gas and coal-fired generation replaced by renewable generation and battery discharge

Change in quarterly average generation – Q4 2024 vs Q4 2025

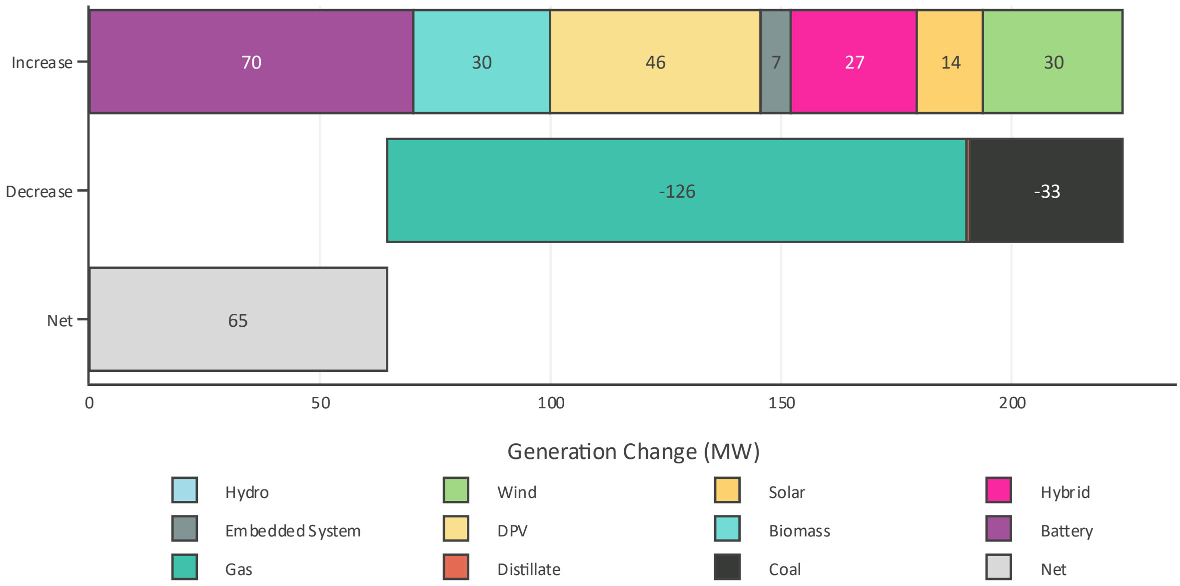
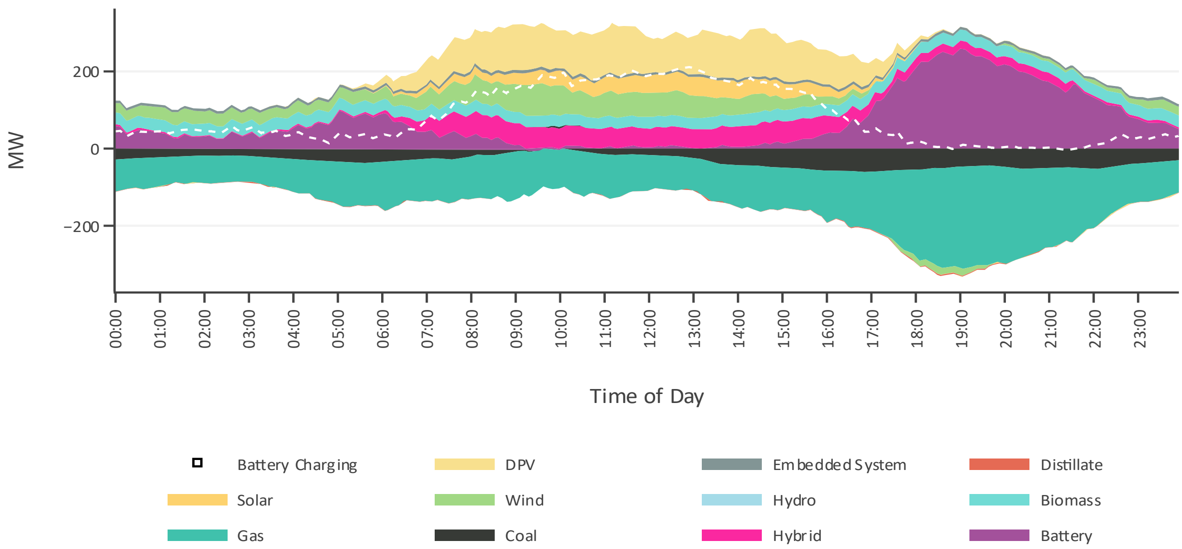


Figure 100 Gas and coal-fired generation replaced by batteries at the evening peak, batteries increased charging during the day

Average WEM change in fuel mix by time of day – Q4 2024 vs Q4 2025



4.2.1 Consumer energy resources (CER)

Total WEM solar installations increased from 0.4 million at the end of 2020 to 0.6 million at the end of 2025[55]. In the same period, CER solar capacity increased from 1.6 GW to 3.0 GW (Figure 101). Consistent with this growth trend, in Q4 2025 distributed PV generation increased by 46 MW (+7.8%) when compared to Q4 2024, as noted in Section 4.1. Cumulative WEM household storage reached 350 MWh by the end of 2025, with installations approaching 20,000 (Figure 102).

[55] Data from Clean Energy Regulator: https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data. Data current as of 31 December 2025, noting that a 12-month creation period for registered persons to create small-scale technology certificates applies so figures for 2025 will continue to rise.

Figure 101 Growth in the WEM's solar capacity and installations since 2020

Cumulative CER solar capacity and installations

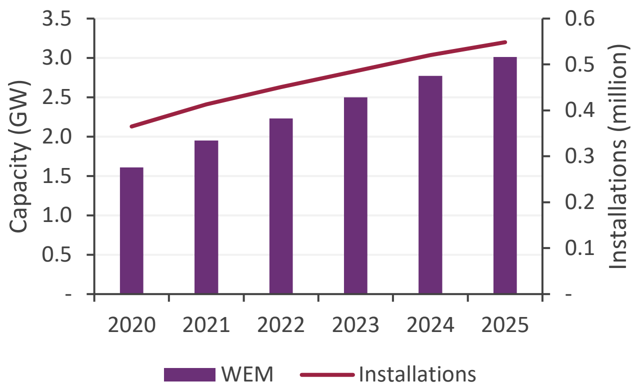
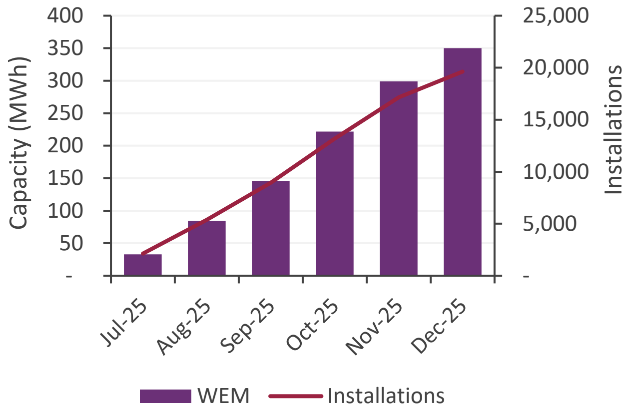


Figure 102 Growth in the WEM's CER battery capacity

Cumulative CER battery capacity and installation



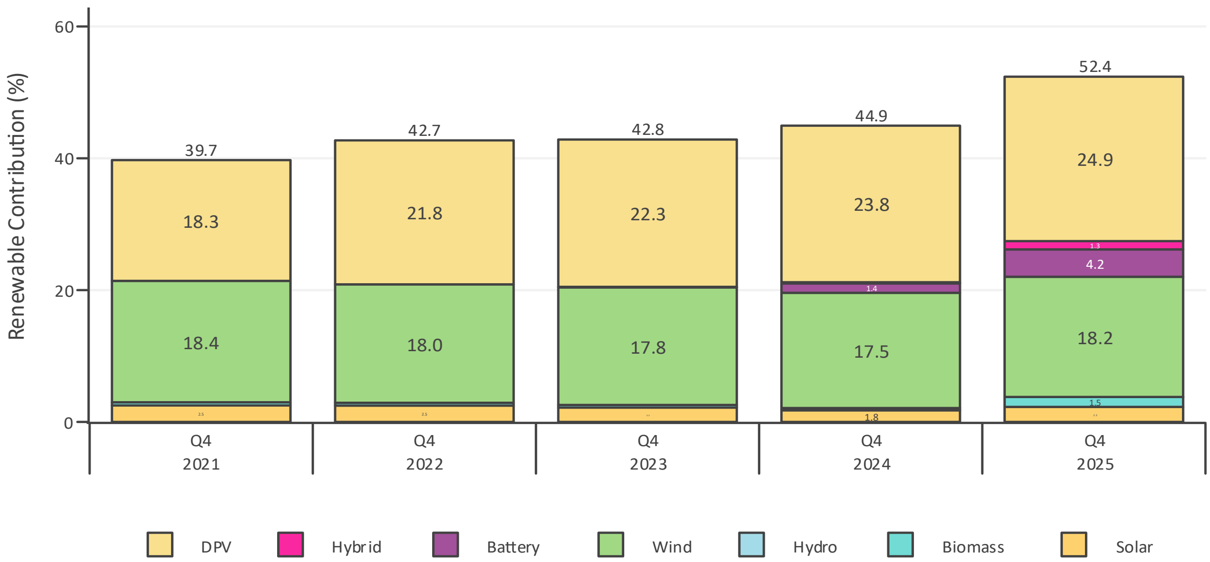
4.2.2 Renewable contribution

Renewable contributions in the WEM set several records in Q4 2025:

- A record average renewable contribution of 52.4% of overall generation marks the first time average renewable contributions have surpassed 50% of overall generation, and represents a 7.5 pp increase on Q4 2024 (Figure 103). This was driven by the commissioning of new Biomass and Hybrid facilities (see Section 4.2) and an increased share of battery discharge, up 2.8 pp to 4.2%. Battery-adjusted renewable contribution[56] was 50.3%.
- The WEM experienced a new peak renewable contribution record of 91.1% on Saturday 20 December 2025 during the 11:35 interval (see Section 4.2.3).

Figure 103 Average quarterly renewable share exceeded 50% for the first time

Renewable contribution components – Q4s



[56] 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.

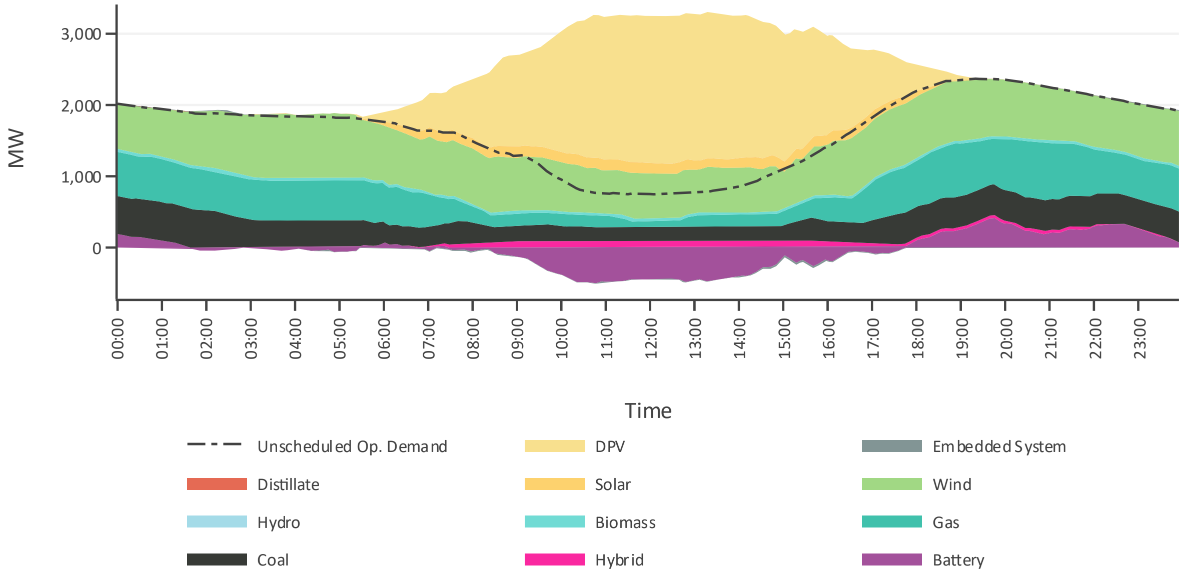
4.2.3 Peak Renewable Contribution Record on Saturday 20 December 2025

On Saturday 20 December 2025, the WEM experienced a record peak renewable contribution of 91.1% during the 11:35 interval (Figure 104). Prior to Q4 2025, the record was 85.1% set during Q4 2024. This was driven by an ideal combination of factors:

- clear, sunny conditions and mild temperatures facilitated a high distributed PV contribution (62.6%),
- a high wind contribution (19.8%) facilitated by battery charging, which supplied 466 MW of demand and thereby relieved wind curtailment, and
- unusually low coal-fired generation commitment (6.3%) due to forced outages.

Figure 104 New renewable contribution record observed on Saturday 20 December 2025

20 December 2025, five-minute average generation by fuel type and unscheduled operational demand (MW)

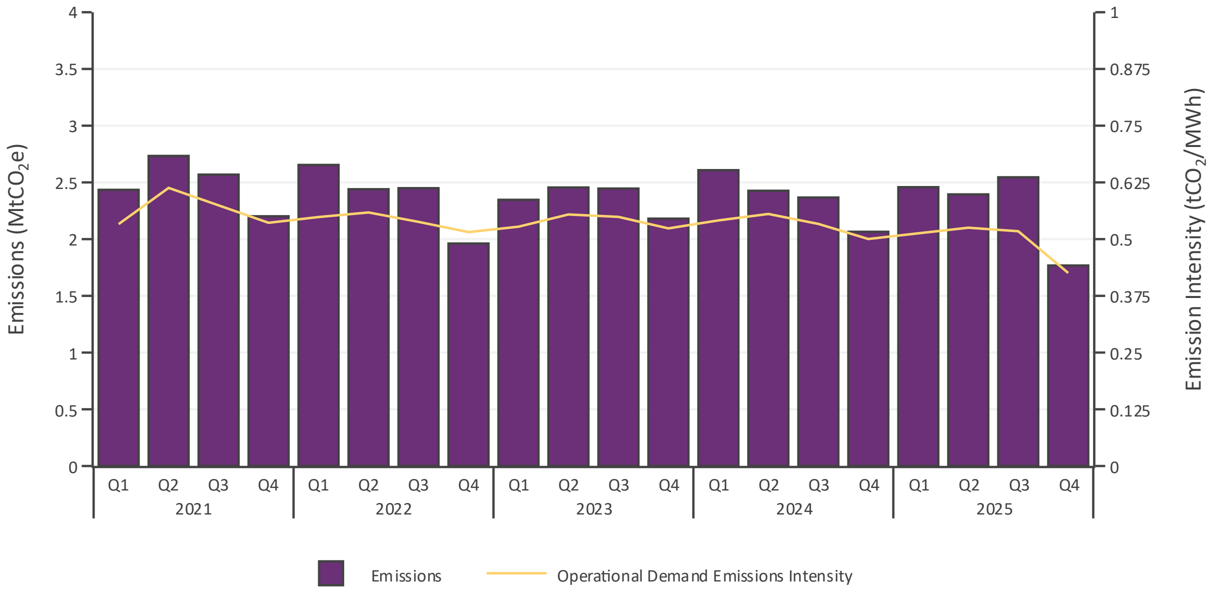


4.3 Carbon emissions

Total WEM emissions decreased from 2.06 MtCO2-e in Q4 2024 to 1.77 MtCO2-e (-14.4%) in Q4 2025 (Figure 105). This can be attributed to a reduction in emission intensity of 0.43 tCO2-e/MWh (-15%). The reduction in emission intensity can be attributed to the greater share of the fuel mix taken by renewable generation (see Section 4.2) in place of gas and coal.

Figure 105 Emissions decreased as share of renewable generation rose

Quarterly WEM emissions and emission intensity – Q1 2021 to Q4 2025



4.4 Frequency co-optimised essential system services (FCESS)

Q4 2025 saw batteries increase their market share of the contingency and regulation markets, reaching 84% of total volume (Figure 106), an increase of 48 pp on Q4 2024 (Figure 107) and 7 pp on Q3 2025. This can be attributed to two additional batteries becoming accredited in FCESS markets since the end of Q4 2024 (COLLIE_ESR1 and KWINANA_ESR2).

Average contingency lower requirements increased by 61.3 MW (+113%). This can be attributed to the increase in battery sizes (see Section 4.2) as well as regulatory changes which facilitated larger credible load contingencies. In the Rate of Change of Frequency (RoCoF) Control Service market, gas covered 65% of the market, with coal the remaining 35%.

Figure 106 Batteries took 84% of the contingency and regulation market volume in Q4 2025

FCESS volume market share by market and fuel type, excluding RoCoF control service – Q4 2025

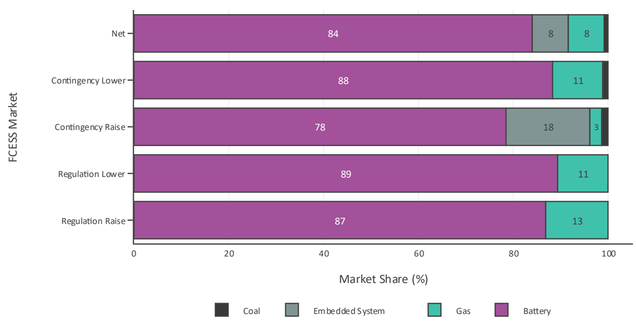
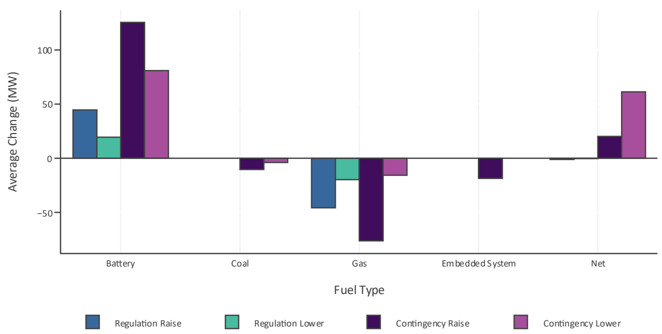


Figure 107 Batteries increased market share and contributed to higher contingency lower requirements

Change in FCESS (regulation and contingency markets) enablement by fuel type – Q4 2024 vs Q4 2025



4.5 WEM price outcomes

4.5.1 Real-Time Market price dynamics

The average energy price in Q4 2025 was $69.55/MWh, a decrease of $10.37/MWh (-13%) from Q4 2024 and a decrease of $32.21/MWh (-32%) from Q3 2025 (Figure 108). This represents the lowest quarterly average energy price since the commencement of the new WEM market on 1 October 2023. In addition to the lower quarterly average energy price, the WEM continued to observe a flattening of the daily price profile (Figure 109). 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,
- adjustments to the FCESS Uplift payment framework, resulting in fewer committed synchronous facilities during the middle of the day, driving lower FCESS Uplift costs, but also putting upward pressure on energy clearing prices,
- increased battery charging during the middle of the day, increasing operational demand and therefore also daytime prices (Figure 110), and
- increased battery discharge during the evening peak, reducing prices as more expensive facilities are displaced.

Figure 108 Average energy price decreased in Q4 2025 compared to prior quarters

Quarterly average energy prices – Q3 2024 to Q4 2025

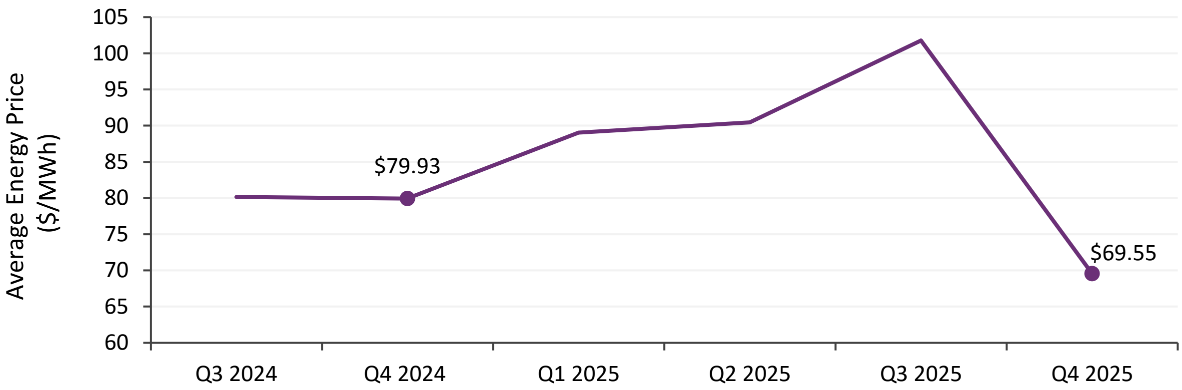


Figure 109 Flattening of the daily price profile

Average energy price by time of day – Q4 2024 vs Q4 2025

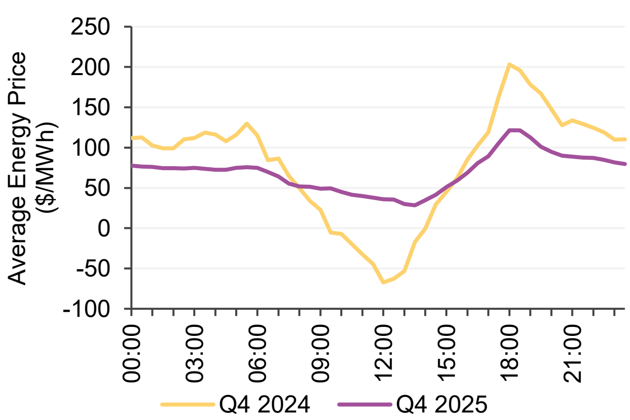
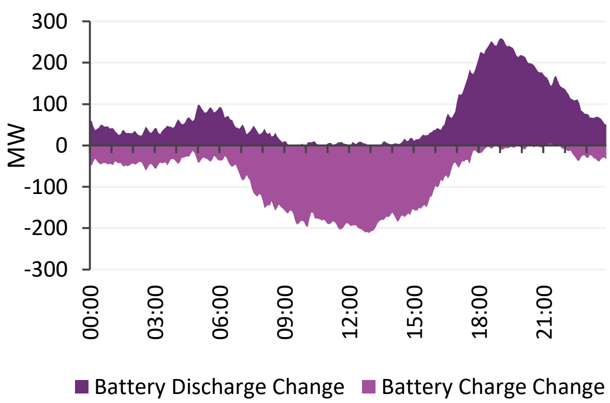


Figure 110 Batteries are a driver of flatter price profile

Average change in battery charge and discharge – Q4 2024 vs Q4 2025



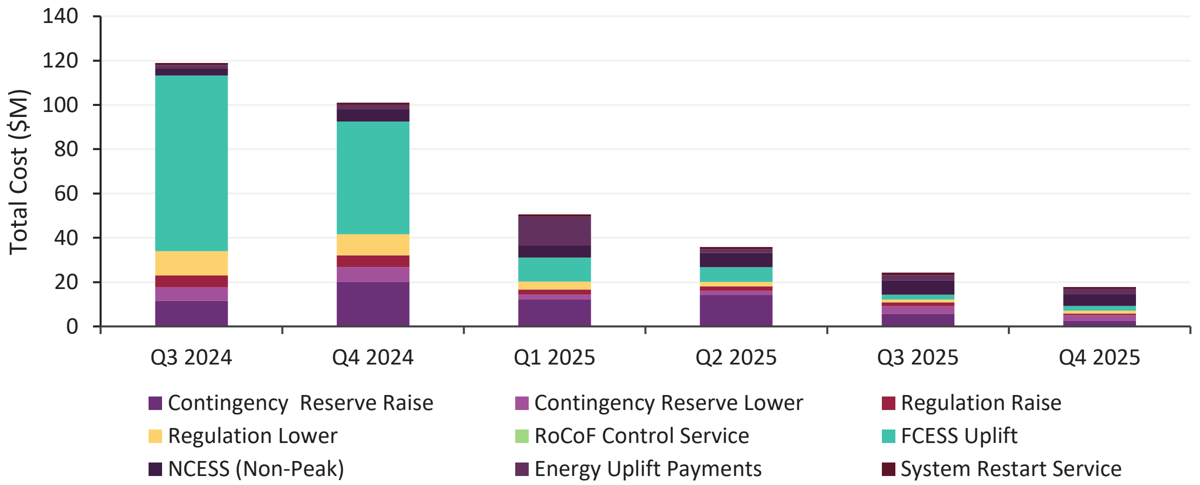
4.5.2 Essential system services (ESS) costs

Total ESS including Uplift costs fell to $17.7 million in Q4 2025, down $83.3 million (-82%) from Q4 2024, primarily driven by changes implemented as part of the FCESS Cost Review in November 2024 (Figure 111). Key observations include:

- FCESS Uplift costs were $2.1 million in Q4 2025, a significant reduction of $48.8 million (-96%) from $50.9 million in Q4 2024, driven primarily by the FCESS Cost Review. Figure 112 shows how FCESS Uplift Costs were assigned to the five FCESS Market Services[57].
- FCESS enablement costs decreased to $7.2 million in Q4 2025, a reduction of $34.5 million (-83%) compared to Q4 2024. This was largely driven by the accreditation of three new batteries in FCESS markets since Q3 2024, including KWINANA_ESR2 in Q2 2025.
  - The largest decrease occurred in the contingency reserve raise market, decreasing to $2.5 million (-88%) from $20.2 million in Q4 2024.
  - The regulation lower market also saw a significant decrease of $8.2 million (-86%).
  - The contingency reserve lower market became the largest contributor to total FCESS enablement costs, accounting for $2.6 million (37%) for Q4 2025. This was still a decrease compared to both Q4 2024 (-60%) and Q3 2025 (-25%), despite a 113% increase in the average contingency lower requirement from Q4 2024 (see Section 4.4).
- Provisional Non-Peak NCESS costs were $5.3 million in Q4 2025, remaining similar to Q4 2024 (-5%). Note that NCESS costs data in this report are only available up to 13 December 2025 due to timing discrepancies in payment reconciliation at the time of reporting.
- Energy Uplift costs totalled $2.3 million in Q4 2025, an increase of $0.4 million (+23%) compared to Q4 2024.

Figure 111 Total ESS and Uplift cost decrease driven by FCESS Cost Review and battery participation

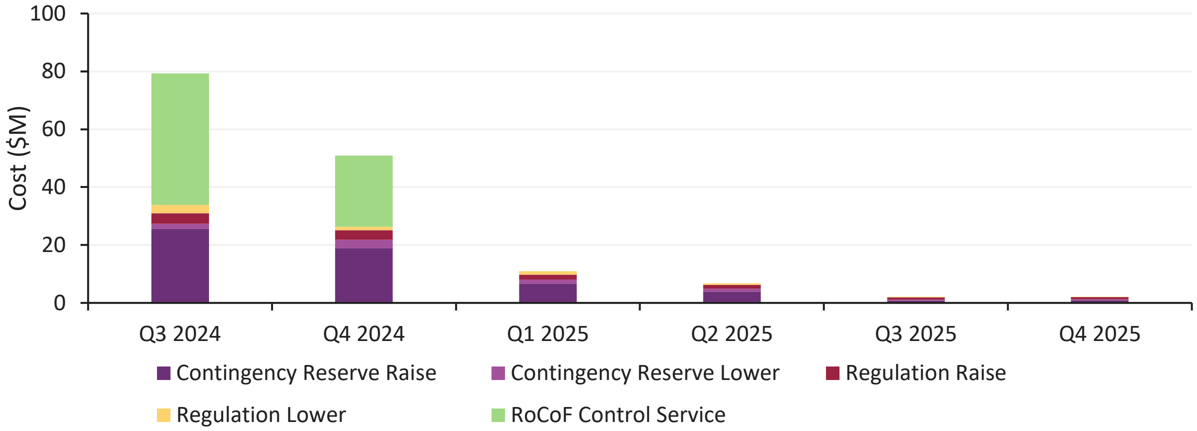
Total ESS and Uplift cost per quarter- Q3 2024 to Q4 2025



[57] Note that since November 2024, no FCESS Uplift costs are assigned to the RoCoF Control Service Market Service.

Figure 112 Total FCESS Uplift Share Costs decreased by $48.8 million (-96%) in Q4 2025 compared to Q4 2024

Distribution of FCESS Uplift costs across market services per quarter – Q3 2024 to Q4 2025



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

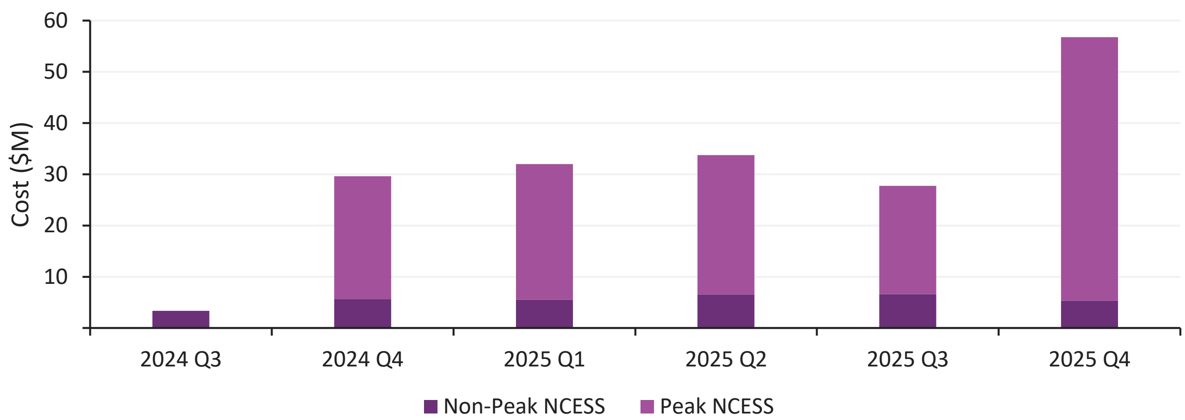
Since 7 October 2024, NCESS costs are divided into two categories, with different cost-recovery mechanisms, based on the nature of the NCESS service. AEMO refers to these as “Peak NCESS” and “Non-Peak NCESS” costs, and groups these with Capacity and ESS costs for reporting purposes.

Note that NCESS cost data in this report is only available up to 13 December 2025 due to timing discrepancies in payment reconciliation at the time of reporting.

In Q4 2025, total NCESS costs reached $56.8 million, a $27.2 million (+92%) increase compared to Q4 2024 (Figure 113). 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 $27.5 million (+115%) compared to Q4 2024, contributing $51.4 million to total NCESS costs. Non-Peak NCESS costs were $5.3 million in Q4 2025.

Figure 113 NCESS costs increased as 11 new Peak NCESS contracts commenced since Q4 2024

NCESS cost by cost recovery mechanism (excluding NCESS costs after 13 December 2025) – Q3 2024 to Q4 2025



4.5.4 Total Wholesale Electricity Market costs

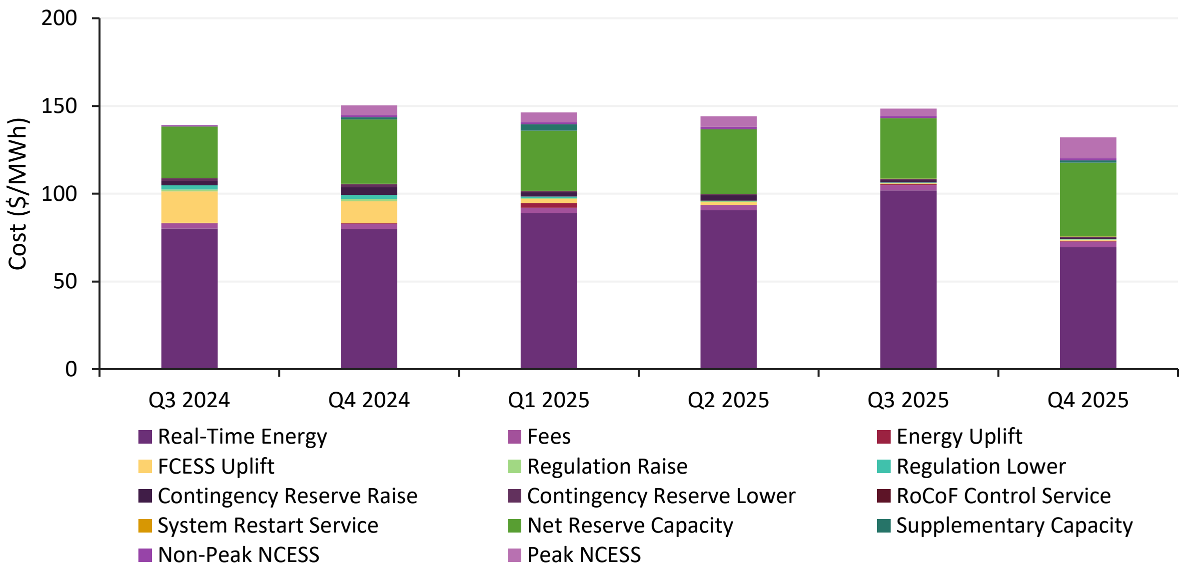
Figure 114 represents the WEM costs as a price per MWh, normalised by total energy consumed. This enables improved visualisation of cost comparison between periods of different demand.

In Q4 2025, the sum of all normalised costs in the WEM totalled $132.09/MWh, a decrease of $18.30/MWh (-12%) compared to Q4 2024. The largest changes are further outlined below and discussed in more detail in the referenced sections:

- FCESS Uplift costs decreased by 96% to $0.50/MWh in Q4 2025 compared to $12.40/MWh in Q4 2024. This was largely due to the changes to the FCESS Uplift payment framework in November 2024 (Section 4.5.2).
- Normalised energy prices reduced to $69.55/MWh in Q4 2025, a decrease of $10.37/MWh from Q4 2024 (Section 4.5.1).
- Normalised FCESS enablement costs also reduced in Q4 2025 to $1.62/MWh, an 83% reduction from Q4 2024 (Section 4.5.2).
- Normalised NCESS costs increased to $13.04/MWh in Q4 2025, a 92% increase from $6.79/MWh in Q4 2024. Peak NCESS cost contributed 91% of all NCESS costs in Q4 2025 (Section 4.5.3).
- Normalised reserve capacity cost, net of reserve capacity refunds, increased from $34.42/MWh to $42.22/MWh, primarily driven by a higher Reserve Capacity Price having been set for the 2025-26 Capacity Year[58].

Figure 114 Wholesale Energy Market costs decreased in Q4 2025 compared to prior quarters

Normalised Energy, ESS and Capacity costs per MWh consumed in the WEM – Q3 2024 to Q4 2025



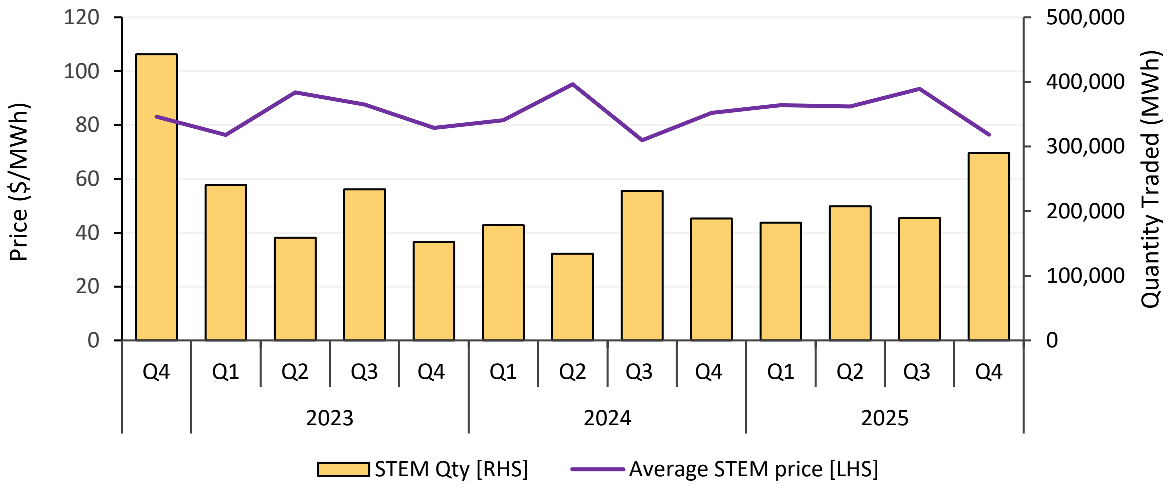
[58] The reserve capacity price for transitional facilities, which is applicable to the majority of facilities, increased from $150,754.81 to $155,418.93/MW/yr, while the reserve capacity price increased from $194,783.54/MW/yr to $251,420.00.

4.5.5 Short Term Energy Market (STEM)

The energy traded between participants on the STEM was 290 GWh, a 53% increase from Q3's traded volume of 189 GWh. The average STEM price for Q4 2025 was $76.45/MWh, a decrease of $16.97/MWh (-18%) from the previous quarter and a decrease of $8.06/MWh (-10%) compared to Q4 last year (Figure 115).

Figure 115 The quantity traded between participants in the STEM increased 53% and price decreased 18%

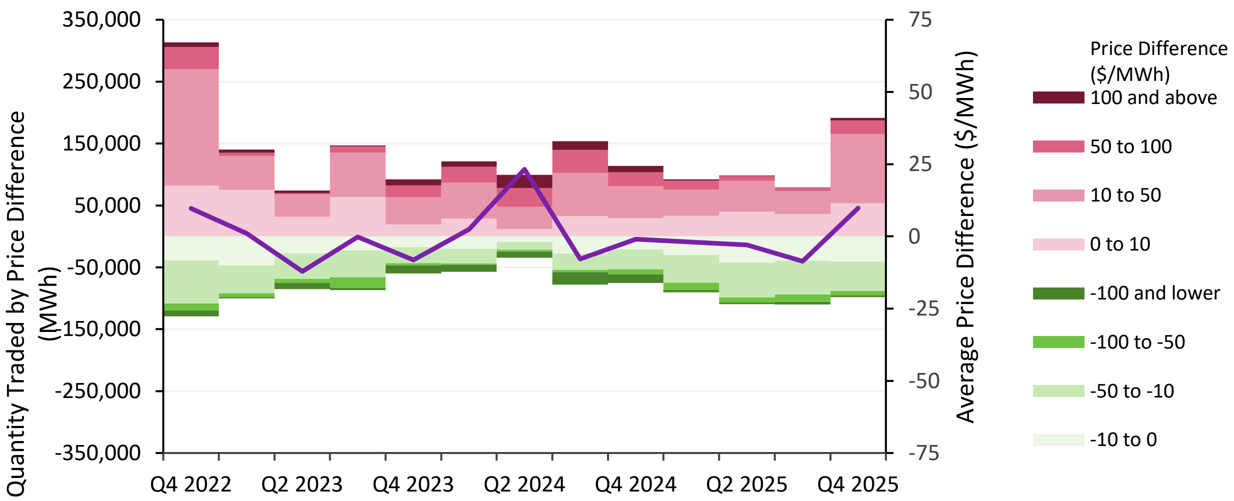
Quantity traded and average price in the STEM – Q4 2022 to Q4 2025



In Q4 2025, the average price difference between the Short Term and Reference Trading Price was $9.64/MWh, representing a higher average cost from purchasing in the STEM than the Real Time Market. Figure 116 shows the weighted average price difference and energy traded grouped by the price difference in each Trading Interval. Trades displayed as negative quantities are traded at a negative price difference with the STEM price lower than the Reference Trading Price (or Balancing Price prior to Q4 2023). In Q4 2025 2% of trades were at price differences greater than $100/MWh (higher or lower), down from 13% of trading in Q4 2024. 33% of trades were at price differences below $10/MWh, increased from 27% of trading in Q4 2024.

Figure 116 The STEM price was higher than the corresponding RT price on average in Q4 2025

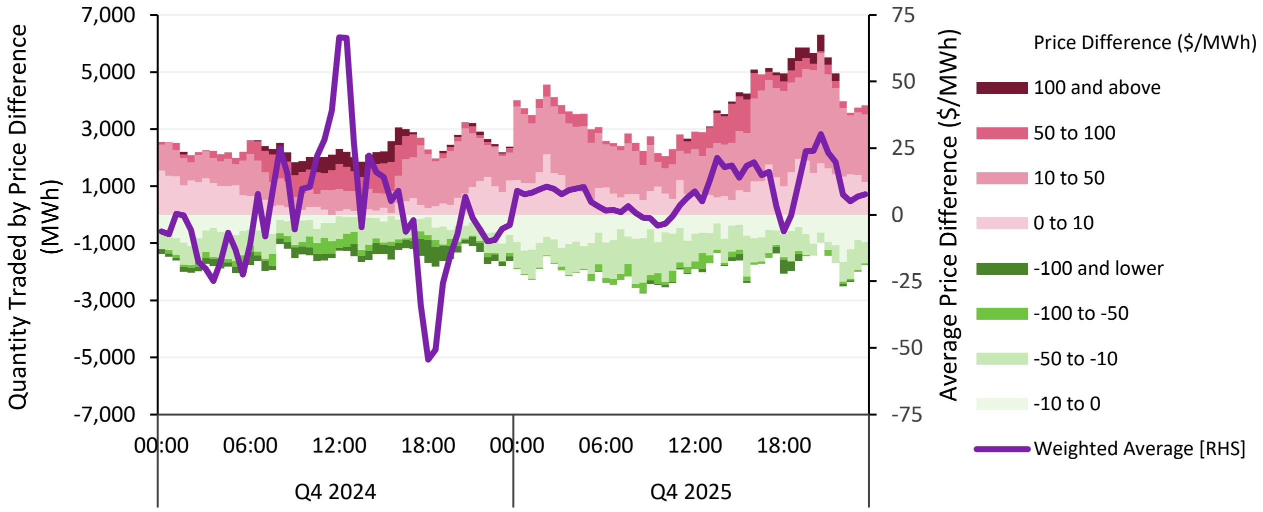
STEM trading and the difference between STEM Price and RT or Balancing Price for trades – Q4 2022 to Q4 2025



Trends in price differences by time of day show that the historical trend of lower average evening peak prices in STEM largely ceased in Q4 2025 (Figure 117).

Figure 117 The trend of STEM prices being lower than RT prices during the evening peak largely ceased in Q4 2025

STEM trading and the difference between STEM Price and RT Price for trades, by time of day – Q4 2024 and Q4 2025



5 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 Q4 2025

Reform initiative	Market	Description	Reform delivered
Metering Services Review – Package 1	NEM	The Accelerating Smart Meter Deployment (ASMD) rule change seeks to achieve universal smart meter deployment in the NEM by 2030. There are four key changes for 2025 as part of this Rule change: • Legacy Meter Replacement Plan: a plan developed by the distribution network service provider (DNSP) that provides for the replacement of all legacy (Type 5 & 6) meters at connection points on its distribution network. The program starts on 1 December 2025 to 30 November 2030. • Defect Management: Metering Coordinators are required to notify the retailer of a defect when attempting to exchange a meter as well a record the defect in Market Settlements and Transfer Solution (MSATS), including the nature of the defect. • One in All in: a new procedure for managing the replacement of meters with shared fusing. • Testing and inspection: AEMO has proposed a new Procedure for testing and inspection for all metering installations and changes to the malfunction and exemption process. A second release package (Package 2) enabling better access to power quality data (PQD) for DNSPs is to go live in July 2026. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/metering-services-review---accelerating-smart-meter-deployment.	December 2025
Improving Security Frameworks	NEM	The Improving Security Frameworks for the Energy Transition Rule builds on existing tools and frameworks within the power system to enhance system security procurement frameworks, providing increased transparency on system security needs and understanding of how AEMO plans to manage system security as we transition to a secure net zero emissions power system. The rule sets forth multiple milestones, scheduled between 30 June 2024 and 2 December 2025 and provides for: • alignment of existing inertia and system strength frameworks, • removal of the exclusion to procuring inertia network services and system strength in the NSCAS framework, • creation of a new transitional non-market ancillary services (NMAS) framework for AEMO to procure security services necessary for the energy transition, • a requirement for AEMO to enable (or 'schedule') security services across the whole NEM for a variety of service types, and • changing the directions reporting framework. AEMO is implementing ISF system security enablement functions across two releases. • The first release delivers enablement functions focusing on external-facing components and reporting from 2 December 2025. • A subsequent release in mid-2026 (August) will deliver automated enablement functionality and other non-core components of the solution. More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/improving-security-frameworks-for-the-energy-transition.	December 2025

Reform initiative	Market	Description	Reform delivered
Contingency Reserve Lower Procurement and Recovery	WEM	The Western Australian Government has introduced changes, commencing 30 October 2025 in the Electricity System and Market Rules (ESM Rules), to modernise how AEMO manages system security and cost allocation in a changing energy landscape. With more batteries entering the market, this will ensure that system security is maintained and costs are fairly distributed to those driving system needs. AEMO has delivered changes to its dispatch systems to enable the co-optimised procurement of the Largest Credible Load Contingency within the dispatch algorithm. A complementary change to the settlement recovery methodology will introduce a modified runway method to allocate costs based on the causer pays principle. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/p3109-first-final.pdf.	Oct 2025

In addition to these reforms, work continues to progress on the next wave of initiatives set for release in 2026. Table 12 provides a brief description of initiatives to be delivered in Q1 and Q2 2026.

Table 12 Upcoming implementation of reforms Q1 2026 – Q2 2026

Reform initiative	Market	Description	Reform to be delivered
East coast gas system (ECGS) notice of closure rule change	Gas	On 11 September 2025, the Australian Energy Market Commission (AEMC) completed its consultation on the ECGS notice of closure rule change request. AEMO is amending the Gas Statement of Opportunities (GSOO) Procedures in response to the Rule change. 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. This reform strengthens transparency and supports more effective planning across the ECGS. More information: https://www.aemc.gov.au/rule-changes/ecgs-notice-closure-gas-infrastructure. The amended Procedures are expected to be effective from 13 February 2026. AEMO Procedure change: https://www.aemo.com.au/consultations/current-and-closed-consultations/implementation-of-the-ecgs-notice-of-gas-infrastructure-closure.	Q1 2026
Update to Wholesale Market Gas Quality Monitoring Procedures	Gas	On 13 June 2025, Standards Australia published AS4564:2025 General-purpose natural gas and natural gas equivalents. This amendment to AS4564 was implemented to facilitate the incorporation of renewable gas including hydrogen and biomethane. This consultation is to implement amendments to the Wholesale Gas Quality Monitoring Procedures for consistency with AS4564:2025. The amended Procedures are expected to be effective from 10 March 2026. AEMO Procedure change: https://www.aemo.com.au/consultations/current-and-closed-consultations/update-to-wholesale-market-gas-quality-monitoring-procedures.	Q1 2026
Extension of the DWGM Dandenong LNG interim arrangements	Gas	On 30 October 2025, the AEMC completed its consultation on the extension of the DWGM Dandenong LNG (DLNG) interim arrangements rule change request. AEMO is amending the Wholesale Market Maintenance Planning Procedures and Wholesale Market Operations Procedures in response to the Rule change. This Rule change: • extended the DLNG interim arrangements until 31 December 2029, • requires the declared LNG supplier for the liquefaction facility supplying the DLNG facility to comply with Rule 324 (Participant disclosure obligations) and 326 (Maintenance planning) requirements, and • requires the declared LNG supplier to apply to AEMO to register as the BB reporting entity for its liquefaction facility and allows that liquefaction facility supplying the DLNG facility to be registered on the Gas Bulletin Board as either a BB Storage Facility or a BB Liquefaction Facility. The transitional rules require the amended Procedures to be effective from 1 April 2026. AEMO Procedure change: https://www.aemo.com.au/consultations/current-and-closed-consultations/implementation-of-extension-of-the-dwgm-dandenong-lng-interim-arrangements.	Q2 2026

Reform initiative	Market	Description	Reform to be delivered
Flexible Trading Arrangements (FTA)	NEM	On 15 August 2024, the 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
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 will commence 26 February 2025. These changes encompass modification 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; and • 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 will implement changes to its settlement system and supporting applications of the dispatch engine to effect the requirements of the ESM Rules. Once the revised methodology is implemented, 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.	Q1 2026
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

Reform initiative	Market	Description	Reform to be delivered
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. More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/dsp-participation-draft-ia.pdf.	Q2 2026
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

List of tables and figures

Tables

Figures

Abbreviations

Abbreviation	Expanded term
5MS	Five-Minute Settlement
ACCC	Australian Competition and Consumer Commission
ACE	Adjusted Consumed Energy
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
ASMD	Accelerating Smart Meter Deployment
ASX	Australian Securities Exchange
BESS	battery energy storage system
BOM	Bureau of Meteorology
CDEII	Carbon Dioxide Equivalent Intensity Index
CER	consumer energy resources
CGP	Carpentaria Gas Pipeline
CRR	Contingency Reserve Raise
DAA	Day Ahead Auction
DER	distributed energy resources
DLNG	Dandenong LNG
DNSP	distribution network service provider
DPV	distributed photovoltaic
DR	demand response
DSP	Demand Side Programme
DWGM	Declared Wholesale Gas Market
ECGS	east coast gas system
EGP	Eastern Gas Pipeline
ELCC	Effective Load Carrying Capability
ESM	Electricity System and Market (previously WEM Rules)
ESR	electric storage resource
ESS	essential system services
FCAS	frequency control ancillary services
FCESS	frequency co-optimised essential system services
FPP	Frequency Performance Payment
FTA	Flexible Trading Arrangements
GJ	gigajoule/s
GJ/h	gigajoules per hour
GLNG	Gladstone LNG
GSH	Gas Supply Hub
GSOO	Gas Statement of Opportunities
GW	gigawatt/s
GWh	gigawatt hour/s

Abbreviation	Expanded term
IEA	International Energy Agency
IRR	interim reliability reserve
IRSR	inter-regional settlement residue
ISF	Improving Security Frameworks
kV	kilovolt/s
L6SE	lower 6-second (FCAS)
LCA	Linepack Capacity Adequacy
LGC	large-scale generation certificate
LNG	liquefied natural gas
LOR	lack of reserve
MCF	Moomba Compressor Facility
MPC	Market price cap
MSATS	Market Settlements and Transfer Solution
MSL	minimum system load
MSP	Moomba Sydney Pipeline
$MtCO_2$-e	million tonnes of carbon dioxide equivalents
MW	megawatt/s
MWh	megawatt hour/s
NCESS	non-co-optimised essential system service
NEM	National Electricity Market
NGP	Northern Gas Pipeline
NMAS	non-market ancillary service
NSCAS	network support and control and ancillary services
NSP	network service provider
PCA	Port Campbell to Adelaide Pipeline
PCI	Port Campbell to Iona Pipeline
PEC	Project EnergyConnect
PJ	petajoule/s
pp	percentage points
PQD	power quality data
PV	photovoltaic
QCLNG	Queensland Curtis LNG
QED	Quarterly Energy Dynamics
QNI	Queensland – New South Wales Interconnector
RCF	RoCoF Control Service
RERT	Reliability and Emergency Reserve Trader
RLM	Relevant Level Method
RoCoF	Rate of Change of Frequency
RRP	regional reference price
SSM	system security management

Abbreviation	Expanded term
ST PASA	Short Term Projected Assessment of System Adequacy
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
TWAP	time-weighted average price
UGS	Underground Storage Facility
US	United States
VPP	virtual power plant
VRE	variable renewable energy
VWAP	volume-weighted average price
WCF	Wallumbilla Compression Facility
WDR	wholesale demand response
WEM	Wholesale Electricity Market