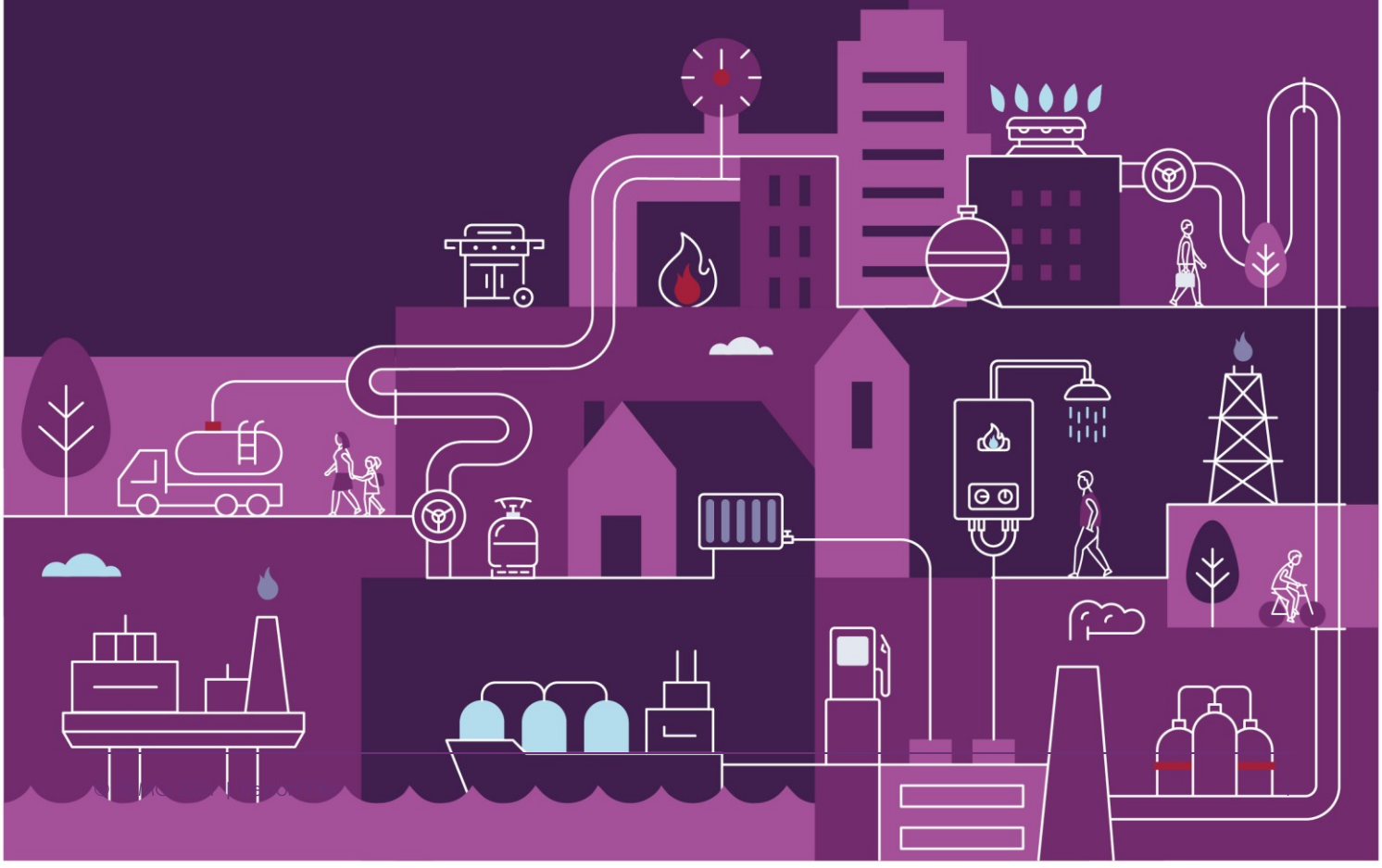
AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

# Quarterly Energy Dynamics Q3 2026

October 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.**

AEMO Group is proud to have launched its Innovate Reconciliation Action Plan in June 2026. Pictured left and featuring on the cover of the Innovate RAP is Wiradjuri artist Lani Balzan's 'Journey of unity: AEMO's Reconciliation Path', a visual representation of 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 Q3 2026 (1 July to 30 September 2026). This quarterly report compares results for the quarter against other recent quarters, focusing on Q3 2025 and Q2 2026. Geographically, the report covers:

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

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- the National Electricity Law, the National Electricity Rules, the Wholesale Electricity Market Rules, the National Gas Law, the National Gas Rules, the Gas Services Information Regulations or any other applicable laws, procedures or policies.

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## Version control

| Version | Release date | Changes |
|---|---|---|
| 1 | 23/10/2026 | First release |
| 2 | 6/11/2026 | Corrections to Section 4.1 (WEM Electricity Demand) and Section 4.2(WEM Electricity Generation) |

# Executive summary

## East coast electricity and gas highlights

### National Electricity Market (NEM) underlying demand grew while distributed energy resources (DER) continued to reshape its profile

- NEM-wide underlying demand reached a new Q3 high of 25,471 megawatts (MW) in Q3 2026, up 1.3% from the previous Q3 record set in 2025, despite warmer winter conditions. Victoria accounted for almost all the growth, reflecting ongoing electrification, higher industrial demand and increasing data centre loads. Victoria also recorded a new all-time winter maximum demand during the quarter, at 8,955 MW, up 137 MW from the previous winter record set in June 2025.
- Distributed photovoltaic (PV) output increased by 372 MW (+13%) to a record Q3 average of 3,203 MW. With growth in distributed PV output slightly exceeding the underlying demand increase, operational demand fell 55 MW (-0.2%) year-on-year to average 22,268 MW.
- Higher distributed PV output and mild spring conditions led to new minimum operational demand records. NEM-wide minimum operational demand fell to a new all-time low of 9,422 MW on Sunday 20 September. On the same day, Queensland recorded a new all-time minimum of 2,741 MW, while South Australia recorded a new Q3 minimum of -38 MW on Saturday 19 September.
- Uptake of home batteries continued to reshape demand profiles. Sample data analysis suggests households equipped with rooftop solar and batteries drew around three quarters less power from the grid during the evening peak (1600 hrs to 2100 hrs) than households with rooftop solar alone. Along with milder conditions and increasing daytime load shifting, this contributed to lower evening peak operational demand across the NEM.

### Renewables generated a record Q3 output share despite weaker wind conditions

- Renewable generation supplied a record Q3 share of 44.3% of NEM generation, up from 41.8% in Q3 2025. Grid-scale solar generation increased by 512 MW (+30%) to a new Q3 high of 2,211 MW, while hydro generation increased by 209 MW (+15%) to 1,572 MW, more than offsetting a 280 MW (-6.0%) decline in wind generation.
- Renewable contribution at half-hourly level also reached a new record, supplying 80.4% of total NEM generation on Saturday 19 September, up from the previous record of 78.6% set in Q4 2025.
- Thermal generation continued to decline, with gas-fired generation decreasing by 453 MW (-34%) to its lowest Q3 average since 2000 and black coal-fired generation falling by 291 MW (-2.9%). These reductions were partially offset by an increase in brown coal-fired generation of 313 MW (+8.9%), with both NEM total emissions (28.0 million tonnes of carbon dioxide equivalent [$MtCO_2$-e]) and emissions intensity (0.57 tonnes of carbon dioxide equivalent [$tCO_2$-e]/megawatt hour [MWh]) remaining broadly unchanged year-on-year (-0.2% and +0.1% respectively).

## Grid-scale batteries increased energy shifting and reduced renewable offloading

- Energy shifted by grid-scale batteries more than tripled year-on-year, with batteries charging 13.4 gigawatt hours (GWh) of energy per day on average during daylight hours (1000 hrs to 1600 hrs) before discharging 10.9 GWh during the evening peak (1600 hrs to 2100 hrs) in Q3 2026. This compared to 3.7 GWh charged and 3.2 GWh discharged per day on average during the respective periods in Q3 2025.
- During the evening peak, grid-scale batteries supplied 8.0% of total generation, exceeding the contribution from gas-fired generation (5.1%) for the first time in any quarter.
- Increased battery charging supported higher utilisation of grid-scale solar generation, with grid-scale solar economic offloading in response to low wholesale prices more than halving to 149 MW (-54%), reducing offloading from 15.7% to 5.9% of solar availability.

## Wholesale electricity prices fell as evening peak demand reduced and battery participation increased

- NEM-wide wholesale spot prices averaged $63/MWh, down $23/MWh (-27%) from Q3 2025 and $11/MWh (-15%) from Q2 2026. This was the lowest Q3 average since 2021, reflecting lower evening peak operational demand, increased grid-scale battery participation and less price volatility across the NEM.
- Grid-scale batteries increasingly influenced wholesale price outcomes, with battery charging or discharging setting prices in almost half (48%) of dispatch intervals, up from 18% in Q3 2025. Increased charging and discharge activity contributed to a flatter intraday price profile and significantly lower evening peak prices.
- Wholesale spot prices were lower across all NEM regions and ranged from $56/MWh in Victoria (-27%) to $74/MWh in New South Wales (-17%). Queensland averaged $61/MWh (-15%), South Australia $69/MWh (-34%) and Tasmania $56/MWh (-38%).

## East coast gas prices at lowest Q3 level since 2023 despite record Q3 Queensland liquefied natural gas (LNG) exports

- East coast wholesale gas prices averaged $10.77 per gigajoule (GJ) for the quarter, higher than Q2 2026 which averaged $9.08/GJ, but lower than Q3 2025 which averaged $12.62/GJ. This was the lowest average for a Q3 since 2023, which averaged $10.41/GJ. International LNG spot prices continued to be materially higher than prices observed in the east coast gas market, amid ongoing heightened supply risks linked to the conflict in the Middle East that began in March 2026.
- Gas demand decreased by only 0.1% in aggregate from Q3 2025, despite the lowest gas-fired generation demand in Q3 since 2003 (-9 petajoules [PJ]), and lower AEMO markets demand (-8 PJ). This was due to Queensland LNG exports increasing to their highest Q3 on record (+16 PJ). Continuing the trend observed throughout 2025 and Q1 and Q2 2026, Victoria experienced the largest demand decrease, with ongoing reduction in industrial, commercial and residential usage, exacerbated by above average temperatures, which decreased requirements for heating.
- Despite lower overall demand across AEMO markets and gas-fired generation, a large decrease in Queensland's domestic supply (-24 PJ) resulted in a large increase in Victorian gas exports (+10.8 PJ), primarily flowing into New South Wales. This sharp decline in Queensland supply resulted in gas flowing north on average from Moomba into

Queensland for the first Q3 since 2016. Victoria met most of this export demand via the Iona Underground Gas Storage (UGS) facility, drawing its inventory down to 13.1 PJ at the end of September, still higher than the 11.8 PJ balance recorded at the same time last year, despite total Victorian gas production being lower (-1.2 PJ).

## Western Australia electricity and gas highlights

### Wholesale Electricity Market (WEM) demand decreased while lower wind and coal-fired generation increased reliance on gas-fired generation

- Average unscheduled operational demand was 1,997 MW, a decrease of 132 MW (-6.2%) compared with Q3 2025. This reflected a 105 MW (-4.7%) reduction in underlying demand to 2,514 MW and a 27 MW (+7.0%) increase in distributed PV generation, with milder weather conditions significantly reducing heating demand.
- Wind generation decreased by 60 MW (-14%), reflecting weaker wind conditions and reduced wind farm availability, while coal-fired generation fell by 173 MW (-22%) as facility outages reduced coal unit availability. Reduced coal availability and lower wind generation increased reliance on gas-fired generation, which rose by 110 MW (+12%).
- Total WEM emissions were 2.33 $MtCO_2$-e, down 8.0% from Q3 2025, reflecting lower electricity demand and lower emissions intensity. Emissions intensity was 0.48 $tCO_2$-e/MWh, down 6.5%, with coal-fired generation accounting for a smaller share of the generation mix.

### Grid-scale batteries increased energy shifting and reduced Frequency Control Essential System Service (FCESS) costs

- Average battery charging increased by 92 MW (+100%) and average battery discharging increased by 79 MW (+98%) compared with Q3 2025, reflecting increased energy shifting between midday and overnight periods to morning and evening peak demand periods.
- Batteries accounted for 93% of enabled FCESS volume across contingency and regulation services, continuing to dominate FCESS provision in the WEM. Total FCESS costs decreased by $14.0 million (-98%) to $0.3 million, with reductions recorded across all FCESS markets.

### Average WEM energy prices increased despite a flatter daily profile

- The average real-time energy price was $120.72/MWh, up 19% from Q3 2025 and the highest quarterly average recorded in the WEM. Lower coal and wind generation availability contributed to higher prices throughout much of the day, while increased battery charging and discharge activity contributed to a flatter daily price profile, reducing price differences between daytime, overnight and peak demand periods.
- Overall normalised WEM costs were $179.63/MWh, up 21% from Q3 2025, driven primarily by higher energy costs (+$18.9/MWh). Increased Reserve Capacity costs (+$13.2/MWh) and Non-Co-Optimised Essential System Service (NCESS) costs (+$2.7/MWh) also contributed, while lower FCESS costs (-$2.4/MWh) and uplift costs (-$0.8/MWh) partially offset these increases.

## Western Australia's domestic gas consumption and production decreased

- Western Australia's domestic gas consumption was 104 PJ, a decrease of 8.9 PJ (-7.8%) compared with Q3 2025. Production was 102.9 PJ, which represented a 6.1 PJ (-5.6%) decrease. Net storage withdrawals of 2.0 PJ were recorded, compared with 5.2 PJ in Q3 2025.

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# 1 Weather

In Q3 2026, Australia experienced persistently warmer-than-average conditions, with above-average temperatures across most of the country throughout July, August and September (**Figure 1**). Warm conditions intensified as the quarter progressed, with the national average temperature ranking as the fifth-highest on record for August and the second-highest for September. In September, average maximum temperatures were the third-highest on record, while average minimum temperatures were the highest on record for the month.

Consistent with the warmer conditions, heating degree day (HDD) totals across Australia's major capital cities were lower than both Q3 2025 and the 10-year average (**Figure 2**). The largest year-on-year percentage reduction occurred in Brisbane, with more modest reductions across other NEM regions, indicating lower heating requirements than in Q3 2025.

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

Q3 2026 mean temperature deciles for Australia

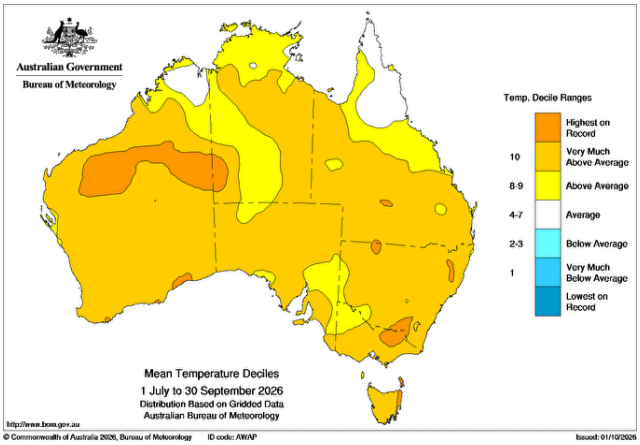
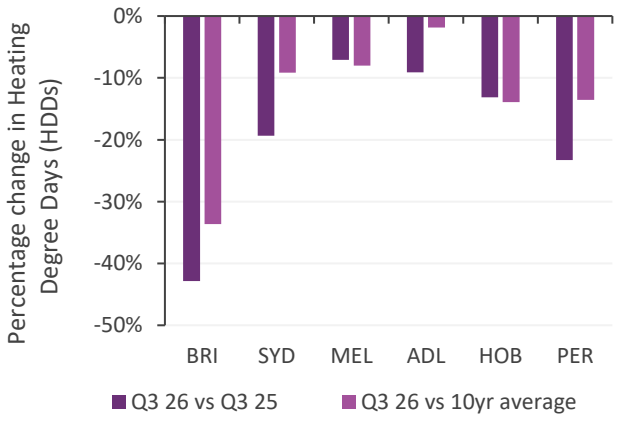



**Figure 2 Lower heating requirements across all capital cities**

Percentage change in quarterly HDDs by capital city – Q3 2026 vs Q3 2025




Source: Bureau of Meteorology (BOM)

Rainfall was below average across all states and territories in July, except the Northern Territory. This shifted in August, when low-pressure troughs and a cold front brought widespread rainfall, showers and thunderstorms to parts of Western Australia and much of south-eastern Australia. Drier weather returned in September, with below-average rainfall across all states and territories except Western Australia, which recorded its second-wettest September on record. These mixed conditions contributed to relatively smaller changes in solar exposure across capital cities this quarter.

Average wind speeds declined across most regions, with South Australia recording the largest year-on-year decrease of 17%, followed by Victoria (-9.1%), New South Wales (-7.7%) and Western Australia (-6.8%). In contrast, average wind speeds increased by 11% in Queensland and 2% in Tasmania. Lower wind speeds led to reduced quarterly generation from established wind farms across the NEM, with Queensland the only region to record an increase. The quarter also saw several periods of widespread wind lulls associated with high-pressure systems, particularly during July and August (see Section 2.3.4).

# 2 NEM market dynamics

## 2.1 Electricity demand

Average NEM-wide underlying demand reached a new Q3 high of 25,471 MW in Q3 2026, up 317 MW (+1.3%) from the previous Q3 record set in 2025 (**Figure 3**). Victoria accounted for almost all of this growth, driven by ongoing electrification, higher industrial demand and increasing data centre loads, which more than offset reduced heating requirements due to warmer weather.

NEM-wide distributed PV generation also reached a record Q3 average of 3,203 MW, up 372 MW (+13%) year-on-year, reflecting continued growth in installed capacity despite lower solar exposure in some regions. With growth in distributed PV output exceeding the increase in underlying demand (**Figure 4**), operational demand decreased by 55 MW (-0.2%) year-on-year to average 22,268 MW.

NEM-wide operational demand increased notably during daytime hours as growing home battery charging activity, higher consumption associated with load-shifting incentives (see **Figure 6**), together with growing industrial and data centre loads, outpaced the growth in distributed PV output. As a result, operational demand shifted away from the evening peak, as home batteries supplied a greater share of household consumption after sunset, while warmer weather reduced heating requirements. This trend was evident across most regions, highlighting the growing influence of home batteries and other load-shifting programs on the demand profile.

**Figure 3 Underlying demand increased despite warmer conditions**

NEM average underlying and operational demand – Q3s

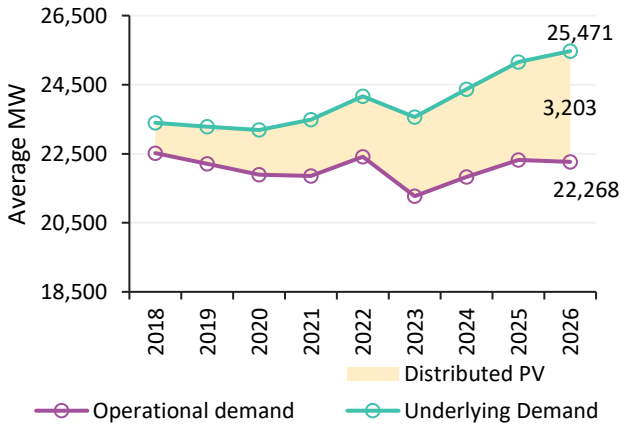
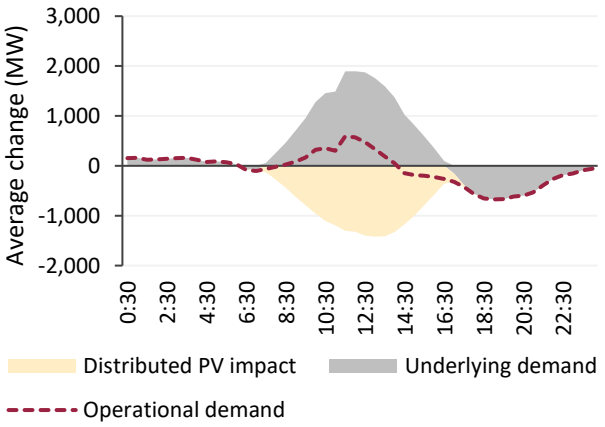



**Figure 4 Higher daytime operational demand as demand shifts away from the evening peak**

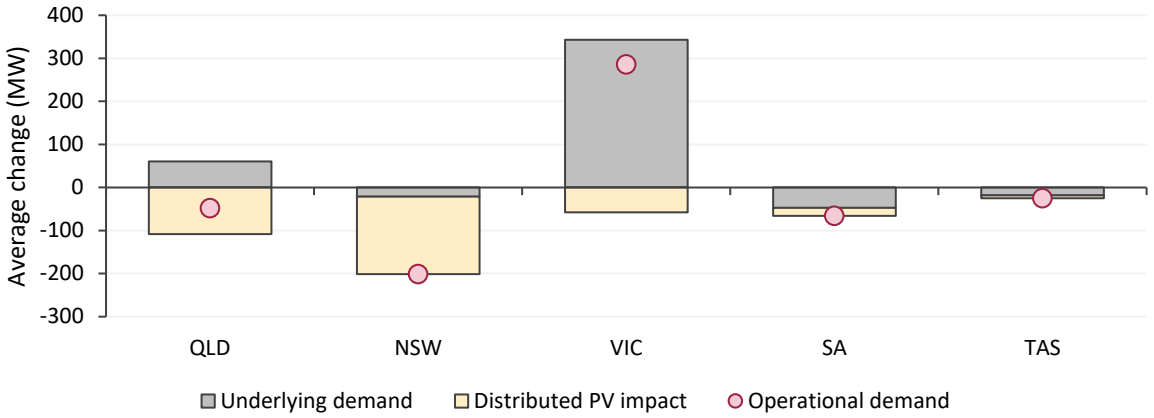
Average changes in NEM demands and distributed PV output by time of day – Q3 2026 vs Q3 2025




Victoria was the only region to record an overall increase in operational demand (**Figure 5**), with the growth in underlying demand only partially offset by higher distributed PV output. Distributed PV output reached new Q3 highs across all regions, driven by continued growth in rooftop solar installations despite lower solar exposure in most regions.

**Figure 5 Operational demand decreased in all regions except Victoria**

Changes in average demand components by region – Q3 2026 vs Q3 2025



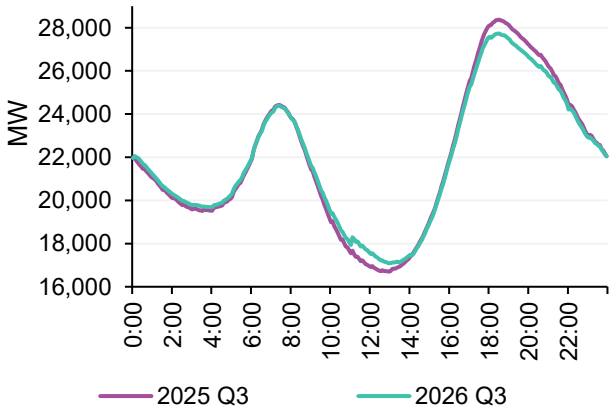

Comparing quarterly average outcomes in Q3 2026 with Q3 2025:

- In **Queensland**, underlying demand increased by 60 MW (+0.9%) from Q3 2025 to average 6,973 MW, as lower heating requirements partially offset growth in industrial load. Distributed PV output averaged 1,135 MW, up 108 MW (+11%) year-on-year, driven by continued growth in installed PV capacity. This increase in distributed PV output offset the increase in underlying demand, reducing the operational demand to an average of 5,838 MW, down 48 MW (-0.8%) year-on-year.
- In **New South Wales**, underlying demand averaged 9,043 MW, down 21 MW (-0.2%) from Q3 2025. The decline was driven by warmer conditions and associated lower heating demand, partially offset by continued growth in data centre demand, which averaged 484 MW (+40% year-on-year). Distributed PV output averaged 1,115 MW, up 180 MW (+19%) from Q3 2025. Together, lower underlying demand and increased distributed PV output reduced operational demand by 202 MW (-2.5%) to an average of 7,927 MW.
- **Victoria**'s underlying demand increased by 343 MW (+5.5%) year-on-year to average 6,547 MW, driven by ongoing electrification, higher industrial load and strong growth in data centre demand. Data centre demand increased from 136 MW in Q3 2025 to 225 MW this quarter. While warmer-than-average temperatures reduced heating requirements, ongoing electrification shifted some heating demand from gas to electricity (see **Figure 87** in Section 3.2.2), supporting underlying electricity demand. Distributed PV output increased by 57 MW (+11%) to average 594 MW. While this growth offset some of the increase in underlying demand, operational demand still rose by 286 MW (+5.0%) to average 5,953 MW.
- In **South Australia**, underlying demand decreased by 47 MW (-2.7%) year-on-year to average 1,717 MW, largely reflecting warmer conditions and associated lower heating requirements across the quarter. Distributed PV output increased by 18 MW (+6.1%) to average 315 MW. Together, lower underlying demand and higher distributed PV output reduced operational demand by 66 MW (-4.5%) to an average of 1,401 MW, with the decline particularly evident outside daylight hours.
- In **Tasmania**, underlying demand decreased by 18 MW (-1.5%) year-on-year to average 1,192 MW, largely due to lower industrial demand. Distributed PV output averaged 43 MW, up 7 MW (+21%). As a result, operational demand declined by 25 MW (-2.2%) to average 1,149 MW.

The increase in daytime demand was also likely influenced by higher midday electricity consumption associated with load-shifting schemes offering cheaper or free electricity. These included the Solar Sharer Offer (SSO)[1], which introduced a three-hour free electricity period for eligible households in Default Market Offer (DMO) areas, and Victorian Default Offer (VDO)[2], which includes a solar soaker tariff as the base offer[3]. Alongside increased home battery charging, these incentive schemes likely contributed to higher midday grid consumption, particularly from 1100 hrs onwards, further shifting electricity consumption away from peak periods into the middle of the day. In Q3 2026, average five-minute total demand[4] across the NEM increased by 360 MW between 1100 hrs and 1105 hrs, with the largest increases recorded in Victoria (+151 MW), followed by New South Wales (+114 MW) and Queensland (+111 MW) (**Figure 6**).

**Figure 6 Higher mid-day demand during cheap or free electricity hours**

Average total demand by time of day – Q3 2026 vs Q3 2025




### 2.1.1 Maximum and minimum demands

In Q3 2026, NEM-wide **maximum operational demand** reached 31,537 MW for the half-hour ending 1830 hrs on Tuesday 7 July, 1,727 MW (-5.2%) lower than the Q3 2025 maximum. Warmer conditions across the quarter contributed to lower maximum operational demand than Q3 2025 in all mainland regions except Victoria (**Figure 7**). Victoria recorded a new Q3 maximum operational demand of 8,955 MW also for the half-hour ending 1830 hrs on Tuesday 7 July 2026, 332 MW (+3.9%) above the previous Q3 high set in 2025. This was also a new all-time maximum winter operational demand for Victoria, 137 MW (+1.6%) higher than the previous winter record set in June 2025.

Despite higher operational demand during daytime hours across most regions over the quarter, warmer spring weather and higher distributed PV output on some days contributed to multiple new minimum operational demand records across the NEM (**Figure 8**). NEM-wide **minimum operational demand** fell to a new all-time low of 9,422 MW for the half-hour ending 1230 hrs on Sunday 20 September, 244 MW (-2.5%) below the previous record set in October 2025 and 753 MW (-7.4%) below the Q3 2025 minimum. On the same day, Queensland also recorded a new all-time minimum of 2,741 MW for the half-hour ending 1100 hrs. South Australia recorded a new Q3 minimum of -38 MW for the half-hour ending 1330 hrs on Saturday 19 September.

[1] See https://www.aer.gov.au/system/files/2026-05/AER%20-%20Solar%20Sharer%20Offer%20fact%20sheet%20-%20DMO%208%20final%20determination.pdf.

[2] See https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/victorian-default-offer.

[3] From 1 October 2026, the Victorian Government mandated a new standing offer, the Victorian Midday Power Saver (MPS), providing households with a period of free electricity during the middle of the day. See https://www.esc.vic.gov.au/electricity-and-gas/electricity-and-gas-prices-tariffs-and-benchmarks/victorian-midday-power-saver.

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

**Figure 7 Maximum operational demand lower in mainland regions except Victoria**

Maximum operational demand for mainland regions – Q3s

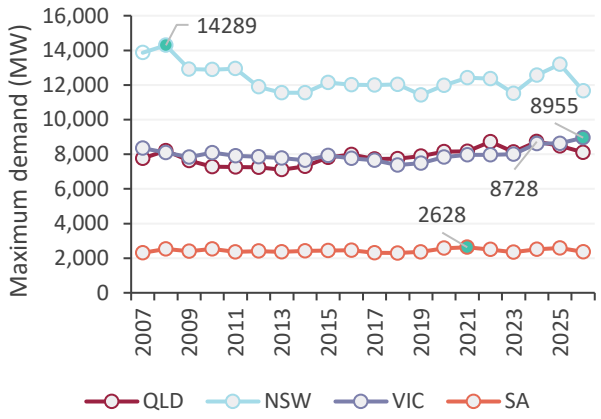
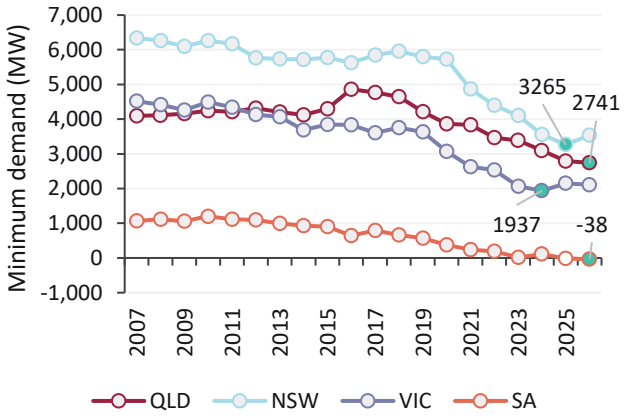



**Figure 8 Queensland recorded new all-time minimum operational demand, while South Australia set new Q3 low**

Minimum operational demand for mainland regions – Q3s




## 2.1.2 Consumer energy resources (CER)

Cumulative CER solar capacity[5] continued to expand across the NEM year-on-year, rising from 24 gigawatts (GW) at the end of Q3 2025 to 27 GW (+12%) at the end of Q3 2026 (**Figure 9**).

This was supported by growth in CER solar installations that increased from 3.7 million at the end of Q3 2025 to 3.9 million (+7.9%) by quarter end. CER solar capacity expanded consistently across all regions, with New South Wales reaching 9.3 GW, followed by Queensland at 8.3 GW. Victoria and South Australia distributed PV capacity reached 6.1 GW and 3.1 GW respectively. Growth in Tasmania remained comparatively smaller and reached 0.4 GW.

The Australian Government's Cheaper Home Batteries Program[6] continued to support growth in household battery adoption, with cumulative CER battery capacity under the program reaching 13,917 MWh and installations growing from 420,266 from 1 July 2026 to 483,835 at the end of September 2026[7] (**Figure 10**). Relative to the end of Q2 2026, cumulative CER battery capacity across the NEM increased by 1,652 MWh (+13%), with more than 10% growth in every region by the end of Q3 2026. Under the program, New South Wales recorded 5,885 MWh of installed capacity, followed by Victoria at 3,185 MWh and Queensland at 3,166 MWh. South Australia and Tasmania reached 1,568 MWh and 114 MWh, respectively.

[5] Data from Clean Energy Regulator: https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data. Data current as of 30 September 2026, noting that a 12-month creation period for registration persons to create small-scale technology certificates applies, so figures for the previous 12-month period 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, until 30 September 2026. Postcode data only includes installations that have had their application for small-scale technology certificates approved. It does not include installations with pending applications.

**Figure 9 CER solar capacity increased with growth in installations**

Cumulative CER solar capacity and installations by region – end of Q3

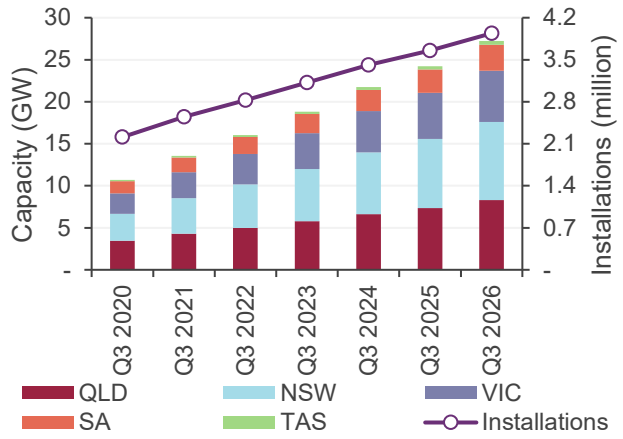
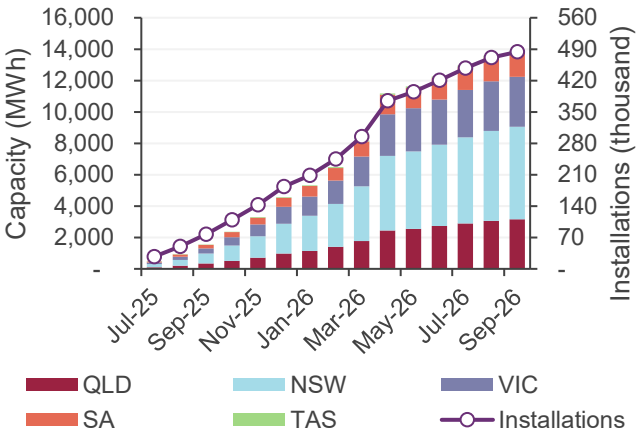



**Figure 10 Continued growth in CER battery capacity and installations across the NEM**

Cumulative CER battery capacity and installations by region

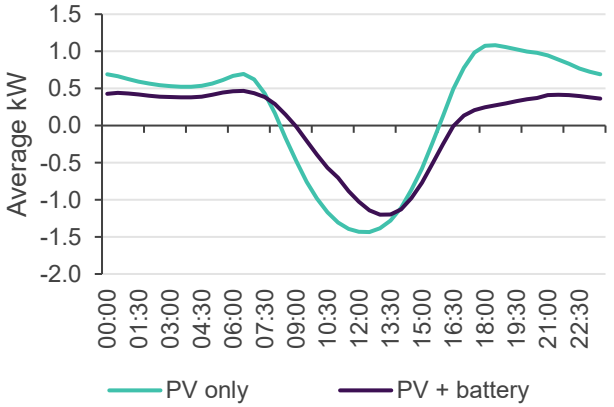



Source: Clean Energy Regulator

Emerging patterns in household PV and battery behaviour are reflected in intraday demand profiles, derived from demand data sourced from National Metering Identifier (NMI)[8] sample datasets of households with rooftop PV only and those with both PV and battery systems. **Figure 11** shows net profiles for PV-only households and those with both PV and battery systems across the NEM in Q3 2026 and Q3 2025.

**Figure 11 Households with PV and battery shift to net exports later and reduce net imports during peaks**

Average household PV and battery net kW in Q3 2026 – NEM




Positive net demand (kilowatts [kW]) represents imports from the grid, while negative net demand (kW) represents exports to the grid. On average, households with PV and battery systems shifted to net exports later in the morning than PV-only households and exported less energy, as batteries charged before any surplus PV was exported to the grid.

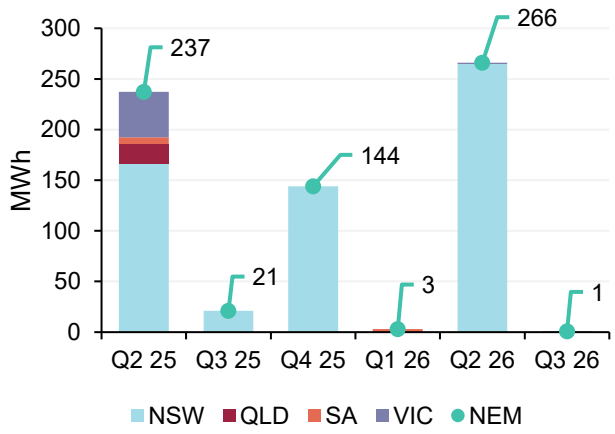
During the evening peak (1600 hrs to 2100 hrs), battery-equipped households remained net exporters for longer and recorded lower net imports than PV-only households. Across the NEM, average evening peak net import for households with PV and battery were 0.7 kW lower per household, equivalent to a 74% reduction relative to PV-only households.

[8] Households included in the NMI sample dataset were restricted are houses/detached dwellings with PV capacity in AEMO's DER Register. The resulting sample comprised approximately 2.4 million NMIs across the NEM, including 1.9 million PV only households and 0.5 million PV and battery households. PV only households are those with total PV capacity greater than zero and battery capacity equal to zero or null in the DER register. PV and battery households are those with battery systems installed before 1 July 2026, with total PV capacity and battery capacity greater than zero in the DER register.

### 2.1.3 Wholesale demand response (WDR)

**Figure 12 Decrease in WDR dispatch**

Total quarterly WDR energy dispatch




WDR dispatch decreased to 1 MWh in Q3 2026, down 20 MWh compared to Q3 2025 and a sharp decrease from 266 MWh in Q2 2026 (**Figure 12**). WDR activity was concentrated in Victoria, which accounted for 1 MWh across 11 dispatch intervals on 8 July 2026 during the price volatility event in the region (see Section 2.2.2), at an average dispatch price of $718/MWh.

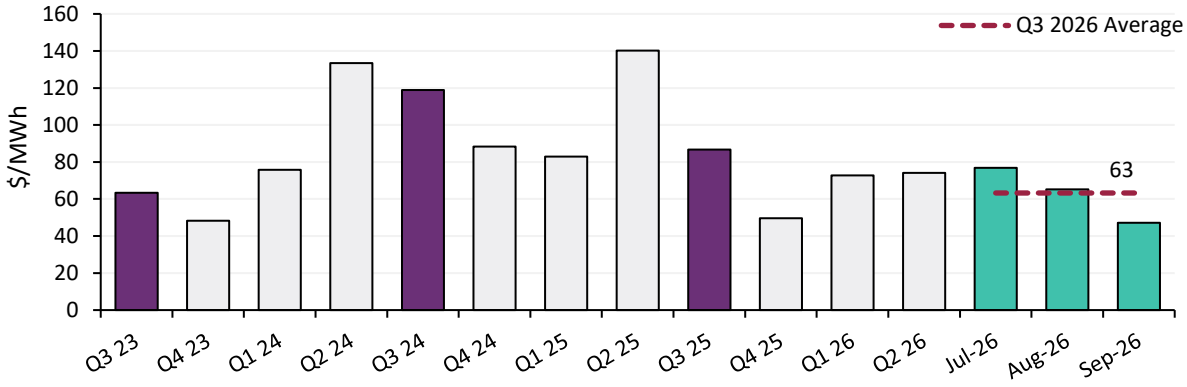
At the end of Q3 2026, registered WDR capacity in the NEM was 346 MW, providing scheduled demand response during periods of higher wholesale prices. Lower volatility this quarter contributed to reduced WDR dispatch, with WDR representing only part of the broader price-responsive demand in the NEM, as highlighted in AEMO's first annual *Unscheduled Price Responsive Resources* report[9], released in September 2026.

## 2.2 Wholesale electricity prices

In Q3 2026, NEM-wide wholesale spot prices averaged $63/MWh[10], down $23/MWh (-27%) from Q3 2025 and $11/MWh (-15%) from Q2 2026 (**Figure 13**). This was the lowest Q3 average since 2021, with year-on-year declines recorded across all regions. Prices declined progressively through the quarter, averaging $77/MWh in July, $65/MWh in August and $47/MWh in September.

**Figure 13 Average NEM spot prices fell 27% year-on-year**

NEM average wholesale electricity spot prices – quarterly since Q3 2023




[9] See https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/unscheduled-price-responsive-resources/uprr_annual_report_fy26_final.pdf?rev=c0e3d900533549d093b143800595f2fd&sc_lang=en.

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

The cap return[11] component of the NEM-wide average price fell to just $2/MWh in Q3 2026, down 70% from $6/MWh in Q3 2025 (**Figure 14**). South Australia accounted for most of this decline, with cap returns falling from $24/MWh in Q3 2025 to $4/MWh this quarter. Cap returns were near zero in Queensland and New South Wales, while Tasmania and Victoria recorded slight year-on-year increases, driven by high-priced events on 8 July (see Section 2.2.2). The energy component averaged $62/MWh, down $19/MWh (-24%) from Q3 2025, with lower energy prices recorded across all NEM regions.

**Figure 14 Year-on-year declines in both energy and cap return prices across all regions**

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




By region:

- **Queensland's** wholesale spot price averaged $61/MWh in Q3 2026, down $11/MWh (-15%) year-on-year. Increased grid-scale battery discharge and lower operational demand during peak periods contributed to a near-zero cap return component and the energy component accounted for virtually all the reduction. Daytime prices were slightly higher due to increased operational demand and grid-scale battery charging, but this was more than offset by lower prices at other times.
- **New South Wales** recorded the highest average wholesale spot price in the NEM this quarter at $74/MWh, despite declining by $16/MWh (-17%) year-on-year. The cap return component fell to near zero from $2/MWh in Q3 2025, while lower operational demand and higher grid-scale battery discharge during peak periods yielded a $14/MWh (-16%) reduction in the energy component, despite an increase in daytime price levels.
- **Victoria's** wholesale spot price declined by $21/MWh (-27%) year-on-year to average $56/MWh this quarter, the lowest regional average in the NEM this quarter. The cap return component increased slightly from Q3 2025, driven by the high-price event on 8 July, but remained low at $2/MWh. The energy component averaged $54/MWh, down $22/MWh (-28%), as higher solar, hydro and grid-scale battery output more than offset the impact of higher operational demand across most hours. Brown coal generators also offered higher volumes across most price bands this quarter, with offers below $15/MWh increasing by approximately 550 MW compared with Q3 2025. Combined with higher availability, this lifted average brown coal-fired generation and reduced the average price set by brown coal when marginal (see Section 2.2.4).

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

- **South Australia's** wholesale spot price averaged $69/MWh this quarter, down $35/MWh (-34%) from Q3 2025. The region's cap return component fell by $21/MWh (-84%) to average $4/MWh. The energy component declined by $14/MWh (-18%) to average $65/MWh. Prices declined during both peak and overnight hours, driven by a notable reduction in operational demand.
- **Tasmania** recorded the largest year-on-year decline in wholesale spot prices, falling by $35/MWh (-38%) to average $56/MWh. The cap return component increased slightly to $3/MWh from $1/MWh a year earlier, driven by the high-price event on 8 July, while the energy component declined by $37/MWh (-41%) to average $54/MWh. Prices declined across all hours, driven by lower operational demand, higher hydro generation during overnight hours, and increased Basslink flows following its transition to a regulated service and the removal of high-priced transfer offers. The increased flows also brought Tasmanian prices into closer alignment with Victoria.

In Q3 2026, NEM-wide average spot prices in the evening peak were well below those observed in Q3 2025, while morning peak and overnight prices also declined (**Figure 15**). This reflected lower operational demand and increased grid-scale battery discharge. The high-price event on 8 July resulted in a sharp increase in average prices between 1930 and 1940 hrs, while prices across the remainder of the evening peak were substantially lower year-on-year. During overnight hours, prices declined, particularly in South Australia and Tasmania, where operational demand was lower year-on-year. In Tasmania, hydro generation increased notably outside daytime, further putting downward pressure on prices.

In contrast, NEM daytime prices were slightly higher, as higher daytime operational demand (see **Figure 4** in Section 2.1) and increased grid-scale battery charging activity (See **Figure 53** in Section 2.4.1) offset downward price pressures from higher grid-scale solar output.

**Figure 15 Significant reduction in spot prices during the evening peak, while morning peak and overnight prices also declined**

NEM average spot price by time of day – Q3 2026 vs Q3 2025

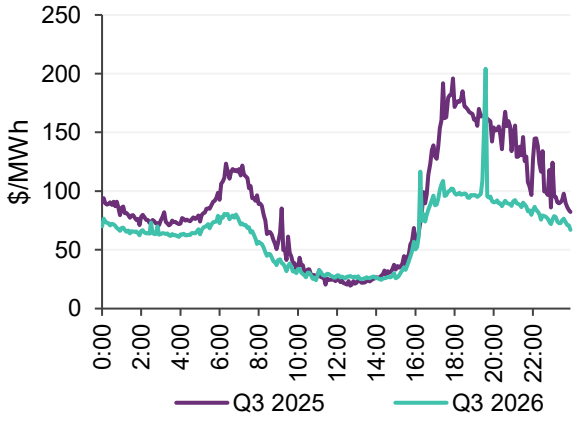
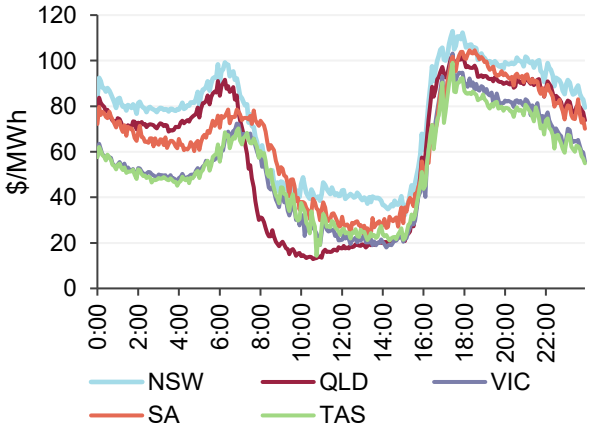



**Figure 16 Regional energy price separation was limited, with Tasmanian prices closely aligned with the mainland**

Average regional energy price by time of day – Q3 2026




Similar to Q2 2026, energy price separation across mainland NEM regions was relatively limited, with some divergence between Queensland and New South Wales during daylight hours and between Victoria and the other mainland regions overnight (**Figure 16**). With Basslink transitioning from a market network service provider (MNSP) to a regulated transmission network service provider (TNSP), the market-based transfer offering framework was removed, resulting in higher flows between Victoria and Tasmania (see **Figure 66** in Section 2.6). Consequently, there was no notable price separation between Tasmania and the mainland, with Tasmanian prices largely aligned with Victoria throughout the day.

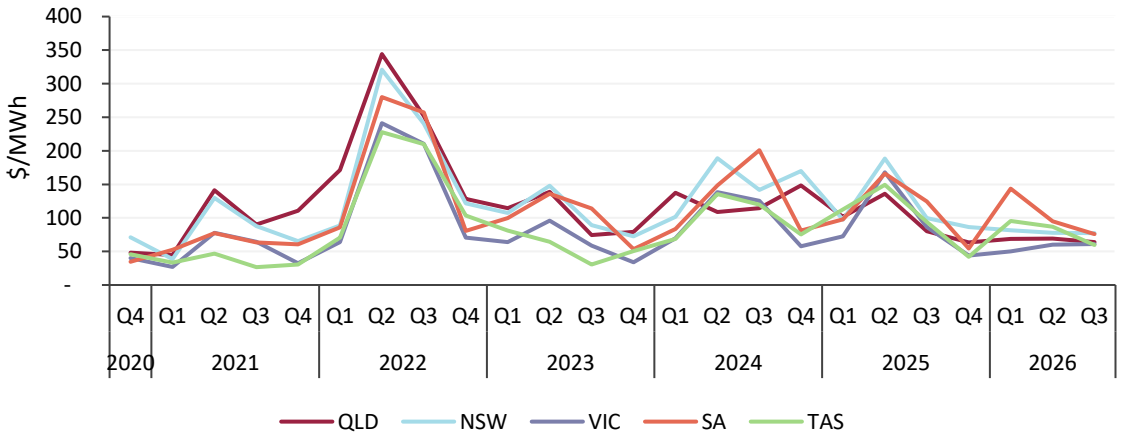
## Volume-weighted average price (VWAP)

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

This quarter, regional VWAPs ranged from $60/MWh in Tasmania to $77/MWh in New South Wales, with Victoria, Queensland and South Australia averaging $61/MWh, $64/MWh and $76/MWh, respectively (**Figure 17**). Compared to Q3 2025, VWAP declined across all regions, with the largest reductions in South Australia (-$48/MWh, -39%) and Tasmania (-$34/MWh, -37%).

**Figure 17 Volume-weighted average prices below Q3 2025 in all regions**

Volume-weighted average prices by region – quarterly since Q4 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 Q3 2026**

| | |
|---|---|
| **Operational demand shifts away from peak hours** | The profile of operational demand continued to change in Q3 2026, with demand growing during the day and reducing over the evening peak. Increased home battery charging, higher consumption due to load-shifting programs (see **Figure 6** in Section 2.1), and growth in industrial and data centre loads lifted daytime operational demand across mainland regions, despite continued growth in distributed PV output (see Section 2.1). In contrast, home battery discharging reduced grid demand during the evening peak, while warmer conditions also reduced heating requirements.<br>These changes were reflected in intraday spot prices. Evening peak prices declined substantially across most regions, reflecting lower demand during these hours. Daytime prices increased slightly year-on-year across all mainland regions, consistent with higher operational demand, while for Tasmania lower operational demand and much closer price alignment with the mainland saw daytime prices fall. |

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

**Growing grid-scale battery participation reshaped price-setting outcomes**

Total installed grid-scale battery capacity[13] in the NEM exceeded 10 GW/23 GWh by the end of Q3 2026, with 4,375 MW/12,628 MWh entering commissioning between Q3 2025 and Q3 2026. Reflecting this rapid expansion, energy shifted by grid-scale batteries more than tripled year-on-year, with batteries charging 13.4 GWh of energy per day on average during daylight hours (1000 hrs to 1600 hrs) before discharging 10.9 GWh during the evening peak (1600 hrs to 2100 hrs) in Q3 2026 (see Section 2.4.1).

This growth in grid-scale battery participation had an increasing influence on price-setting outcomes. Battery charging and discharging combined set spot prices in 48% of dispatch intervals, making batteries the NEM's most frequent price-setting technology and reducing the frequency with which other fuel types set prices (see Section 2.2.4). During the evening peak, increased battery discharge, alongside lower operational demand, contributed to lower peak prices and reduced price volatility across most regions, with NEM-wide aggregated cap returns falling to $8/MWh from $28/MWh in Q3 2025 (see Section 2.2.2). During daytime hours, increased battery charging absorbed more grid-scale solar output and reduced the frequency with which variable renewable energy (VRE) remained marginal and set prices, contributing to fewer negative price intervals (see Section 2.2.3).

### 2.2.2 Wholesale electricity price volatility

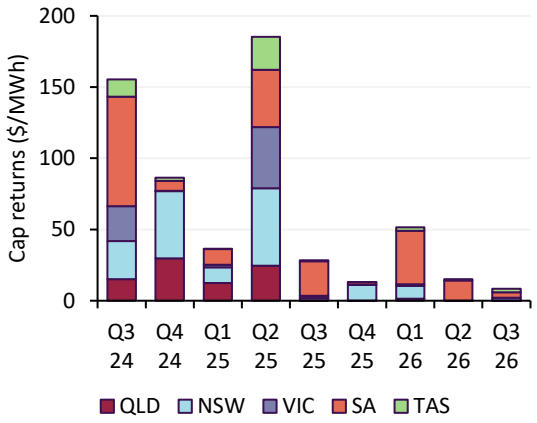
In Q3 2026, aggregated regional cap returns, representing spot price outcomes above $300/MWh, fell to $8/MWh, down from $28/MWh in Q3 2025 (**Figure 18**).

The decline was largely driven by South Australia, where cap returns fell from $24/MWh to $4/MWh, with the Q3 2025 result elevated by a high-price event in July 2025. Tasmania and Victoria recorded cap returns of $3/MWh and $2/MWh respectively, while cap returns in Queensland and New South Wales were negligible, averaging close to zero over the quarter.

The high-price event on 8 July accounted for most of the cap returns this quarter, contributing $1.9/MWh in Victoria and $1.6/MWh each in South Australia and Tasmania.

**Figure 18 Cap returns fell across the NEM with a notable drop in South Australia**

Cap returns by region – quarterly




## Price volatility across Victoria, South Australia and Tasmania on 8 July

On 8 July, brown coal generation in Victoria declined by more than 1,000 MW due to reduced output from Loy Yang A and B power stations as a result of unplanned restrictions on coal supply. Wind generation also remained low across the southern states during the evening peak, averaging just 82 MW in Victoria (1.4% of maximum capacity), 144 MW in South Australia (5.3%) and 26 MW in Tasmania (4.6%) between 1600 hrs and 2100 hrs. As solar generation declined, gas and battery discharge increased to meet demand. However, battery discharge subsequently declined as state of charge (SOC) levels fell, while persistently low wind generation and reduced brown coal output coincided with elevated evening demand, tightening the supply-demand balance across the southern states. Supply conditions were further constrained by transmission limitations on the Victoria – New South Wales Interconnector, where a voltage constraint restricted imports into Victoria to below 500 MW. Consequently, wholesale prices increased sharply between 1900 hrs and 2000 hrs, with prices exceeding $1,000/MWh in eight dispatch intervals in Victoria, five in South Australia and eight in Tasmania. At the 1940 hrs dispatch interval, prices exceeded $16,000/MWh across all three regions. Before the coal supply limitation was resolved towards the

[13] This represents the maximum capacity of registered grid-scale battery projects that are either in service or commissioning and have commenced operating.

end of the day, declining demand and increasing wind output in Victoria and South Australia helped ease supply conditions, with prices gradually returning to normal levels after 2100 hrs.

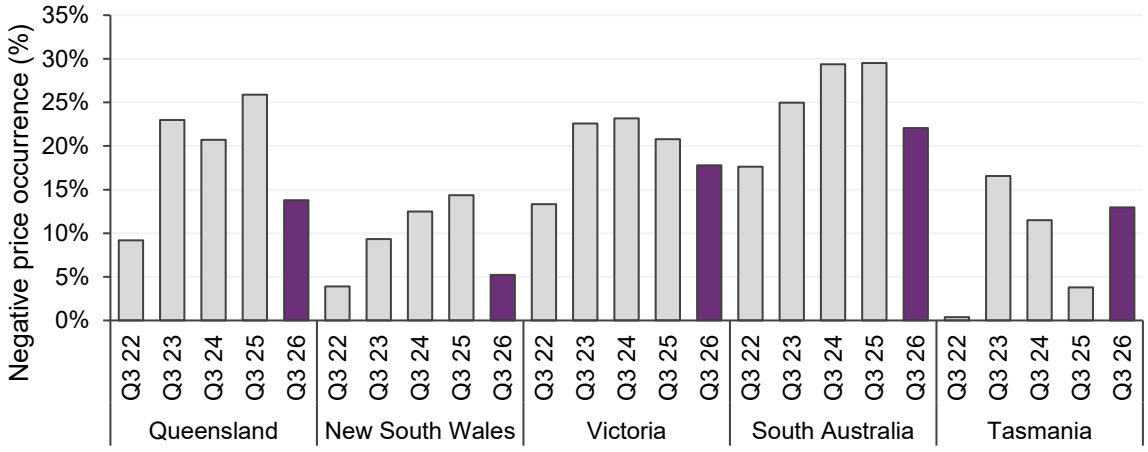
### 2.2.3 Negative wholesale electricity prices

In Q3 2026, negative or zero prices occurred in 14.4% of dispatch intervals across the NEM, down 4.5 percentage points (pp) from Q3 2025 (**Figure 19**). All mainland regions recorded lower negative price occurrence year-on-year, while Tasmania was the exception, increasing by 9.2 pp to 13% of intervals.

Queensland recorded the largest reduction, falling 12.1 pp to 13.8% of intervals, followed by New South Wales, where negative price occurrence declined 9.1 pp to 5.2%. South Australia and Victoria also recorded declines, with negative prices occurring in 22% (-7.5 pp) and 17.8% (-3.0 pp) of intervals, respectively.

**Figure 19 Negative price occurrence decreased in all mainland regions, increased in Tasmania**

Negative price occurrence in NEM regions – Q3s




In Q3 2026, all mainland NEM regions experienced lower daytime negative price occurrence (**Figure 20**), consistent with higher middle-of-day operational demand (see **Figure 4** in Section 2.1) and increased grid-scale battery charging (see **Figure 53** in Section 2.4.1), which absorbed more variable renewable energy (VRE) output and reduced the frequency with which VRE remained marginal and set prices. While VRE typically set prices at negative levels, battery charge was more likely to set prices at positive levels, contributing to the lower occurrence of negative prices. During the daytime period (1000 hrs to 1600 hrs), the largest reductions occurred in the northern regions, with negative prices falling to 43% of dispatch intervals in Queensland (-30 pp) and 17% in New South Wales (-26 pp) compared with Q3 2025. South Australia and Victoria also recorded declines, to 43% (-16 pp) and 34% (-9 pp) of intervals, respectively. Tasmania was the only NEM region to record an increase in daytime negative price occurrence, rising from 8% of intervals in Q3 2025 to 27% this quarter, consistent with lower daytime operational demand and higher flows from Victoria in the absence of significant MNSP offer costs. Tasmania also experienced an increase in overnight (2100 hrs to 0600 hrs) negative prices, from 3% to 10% of intervals, driven by lower operational demand and higher hydro generation. In Victoria, overnight negative price occurrence remained largely unchanged at 16% of dispatch intervals, while South Australia recorded a 5.0 pp decline to 15% compared to Q3 2025.

The distribution of negative prices also shifted markedly towards lower magnitudes in Q3 2026 and average spot price during negative price intervals increased from -$16/MWh in Q3 2025 to -$10/MWh this quarter. Prices between -$10/MWh and $0/MWh accounted for 85% of all negative price intervals, up from 32% in Q3 2025 (**Figure 21**). This shift was

consistent with lower large-scale generation certificate (LGC) prices, which averaged $7/certificate this quarter, down from $13/certificate in Q3 2025.

Reflecting both the lower frequency and reduced magnitude of negative prices, the negative price impact[14] declined across all mainland NEM regions year-on-year. Queensland recorded the largest reduction, falling by $4.3/MWh to $0.7/MWh. In contrast, Tasmania's higher frequency of negative prices increased its negative price impact by $0.9/MWh to $1.1/MWh. Across the NEM, the negative price impact fell from $3.0/MWh in Q3 2025 to $1.4/MWh this quarter.

**Figure 20 NEM-wide negative price occurrence declined during daytime**

Negative price occurrence by time of day – Q3 2026

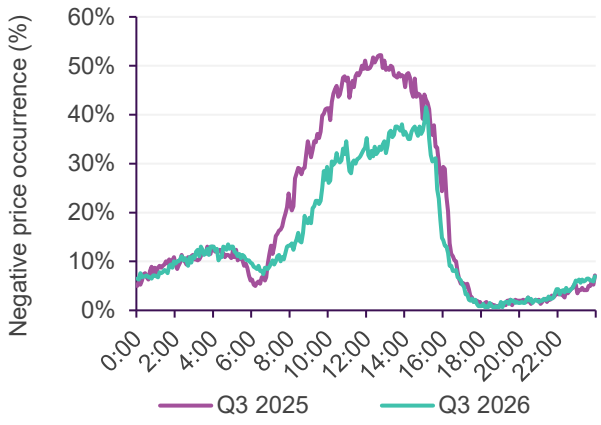
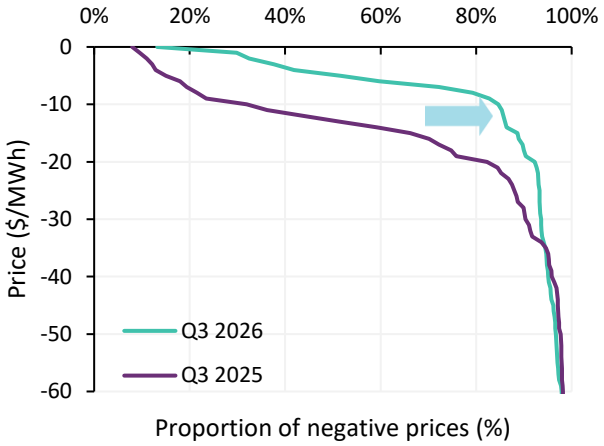



**Figure 21 Impact of negative prices decreased in Q3 2026**

Cumulative distribution of negative prices – Q3 2026 vs Q3 2025




### 2.2.4 Price-setting dynamics

This quarter, batteries remained the most frequent price-setting technology across the NEM, with battery charge and discharge combined setting prices in 48% of dispatch intervals, up from 18% in Q3 2025. Battery discharge and charge each set prices in 24% of intervals, increasing by 14 pp and 15 pp year-on-year, respectively. In contrast, all other fuel types set prices less frequently than in Q3 2025. Hydro recorded the largest decline, falling 15 pp to 13% of intervals, largely reflecting a substantial reduction in price setting by Tasmanian hydro generators, due to increased price setting by mainland generation associated with higher Basslink flows from Victoria.

The shift towards battery price setting was evident across all mainland regions, particularly Queensland and New South Wales (**Figure 22**). In Queensland, battery discharge and charge set prices in 26% and 28% of intervals, respectively, while in New South Wales they accounted for 27% and 29%. Battery price setting increased also in Victoria and South Australia, where discharge and charge combined set prices in 46% and 44% of intervals, respectively.

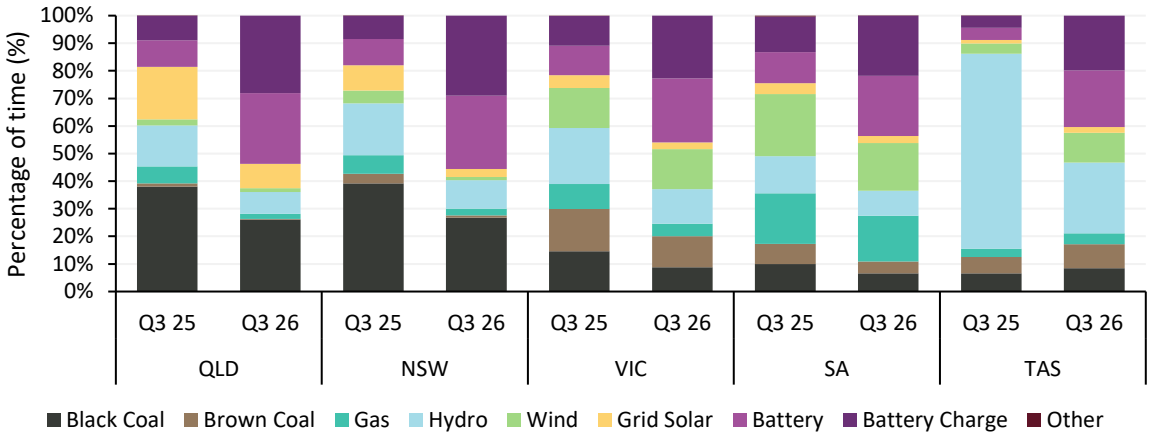
This shift coincided with less frequent price setting by hydro and thermal generation. Hydro price-setting frequency declined to 8% in Queensland, 10% in New South Wales, 13% in Victoria and 9% in South Australia. The largest change occurred in Tasmania, where hydro price setting fell from 71% of intervals in Q3 2025 to 26% this quarter, reflecting increased price setting by mainland generation following Basslink's shift to regulated status and the elimination of MNSP transfer prices from the cost of energy imports.

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

Grid solar and wind also set prices less frequently across all mainland regions. Higher daytime operational demand and increased battery charging absorbed more VRE output, reducing the frequency with which VRE remained marginal and set prices. This was also consistent with the lower occurrence of negative prices across mainland regions (see Section 2.2.3). Tasmania moved in the opposite direction, with lower operational demand and increased Basslink flows from Victoria in absence of MNSP offer costs, contributing to increased price setting by wind and grid solar.

**Figure 22 Batteries further increased price-setting across all NEM regions**

Price-setting frequency by region and fuel type – Q3 2026 vs Q3 2025



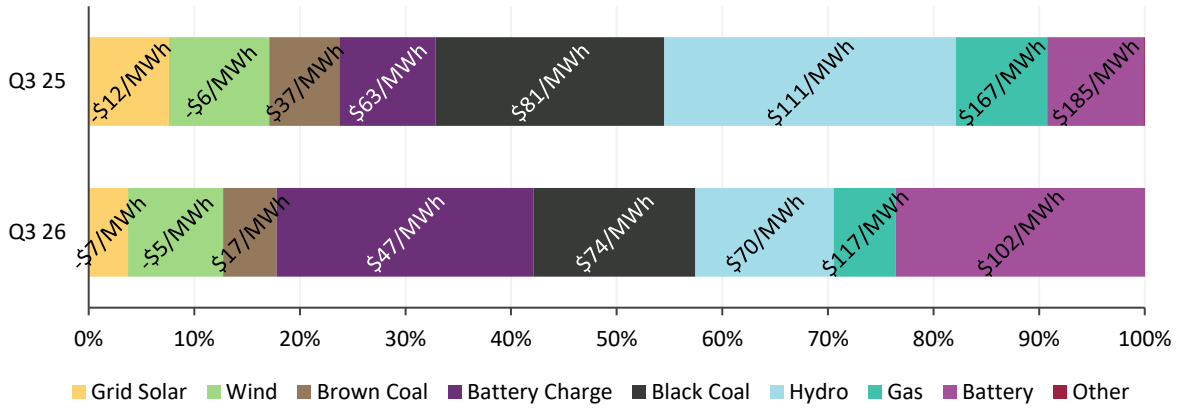

Average prices set while marginal increased for wind and grid-scale solar but declined for all other technology types (**Figure 23**). Wind and grid-scale solar recorded year-on-year increases of $1/MWh and $5/MWh, respectively, to average -$5/MWh and -$7/MWh. In contrast to the NEM-wide trend, Tasmanian prices set by wind and solar declined significantly, falling by $71/MWh and $77/MWh, respectively. This followed Basslink's transition to a regulated interconnector, with Tasmanian prices set by mainland generation no longer incorporating higher-priced Basslink transfer offers (see Section 2.6)

Battery discharge recorded the largest decline in average prices set while marginal, falling from $185/MWh in Q3 2025 to $102/MWh this quarter. This reflected lower NEM price volatility and batteries increasingly setting prices across a broader range of market conditions, rather than predominantly during high-price periods.

Average prices set by gas declined by $50/MWh to $117/MWh, with reductions across all mainland regions. Hydro also recorded lower average prices, falling from $111/MWh to $70/MWh, with declines across all regions. Black coal and brown coal similarly set prices at lower average levels than in Q3 2025.

**Figure 23 Increased battery price setting reshaped market outcomes in Q3 2026**

NEM price-setting frequency and average spot price when price-setter by fuel-type – Q3 2026 vs Q3 2025

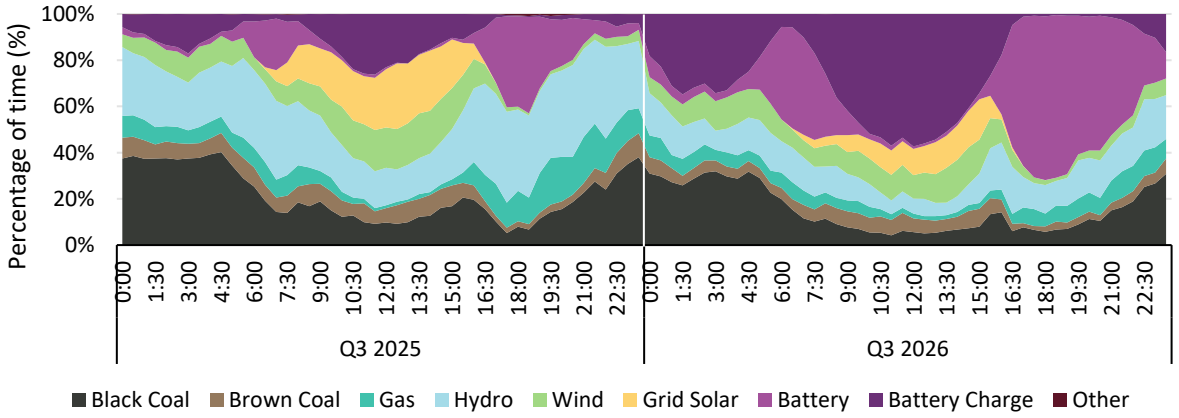



## Price-setting by time of day

Throughout the quarter, batteries played a substantially larger role in price setting across all hours of the day, displacing other fuel types (**Figure 24**).

**Figure 24 Battery charge and discharge drove time of day price-setting shifts in Q3 2026**

NEM price-setting frequency by fuel type and time of day – Q3 2026 and Q3 2025




Battery discharge continued to be the dominant price setter during the evening peak, with its price-setting frequency increasing by 34 pp year-on-year to 60% of dispatch intervals in Q3 2026. During daylight hours (1000 hrs to 1600 hrs), battery charging increasingly set the marginal price, accounting for 49% of intervals, up 30 pp from Q3 2025. In contrast, most other technologies set prices less frequently. Grid solar set prices less frequently during daylight hours declining by 10 pp to 12% of intervals. During the same hours, wind price setting also declined by 5 pp to 13%, consistent with the lower occurrence of negative prices over these periods. Hydro price setting declined across most trading hours, with the largest reduction occurring during the evening peak (1600 hrs to 100 hrs), falling 22 pp year-on-year to 15% of intervals.

### 2.2.5 Volume-weighted average prices by fuel type

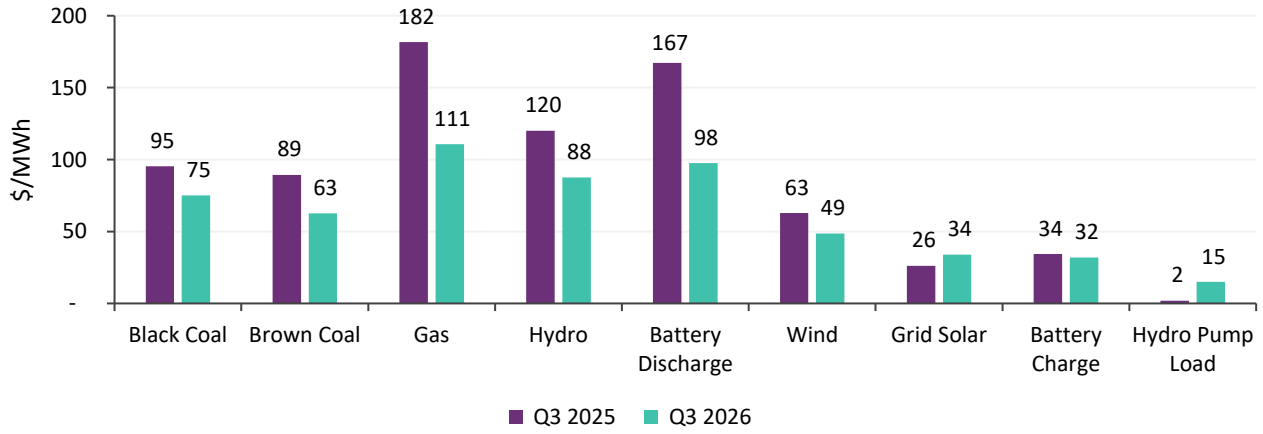
**Figure 25** shows the average spot prices earned[15] or incurred by different fuel types across the NEM, derived as volume-weighted averages based on their generation or load volumes in each dispatch interval.

In Q3 2026, VWAPs declined across all fuel types compared with Q3 2025, except for grid-scale solar and hydro pump load. Grid-scale solar earned an average VWAP of $34/MWh, up from $26/MWh in Q3 2025, supported by higher daytime prices across all mainland regions. Hydro pump loads also incurred a higher VWAP of $15/MWh compared to $2/MWh in Q3 2025. Despite higher daylight prices in all mainland regions, grid-scale battery charge incurred slightly lower VWAP of $32/MWh compared to $34/MWh in the same period previous year.

Lower evening peak prices particularly reduced returns for flexible generation. Gas and grid-scale battery discharge VWAPs fell by $71/MWh and $70/MWh to $111/MWh and $98/MWh, respectively. Hydro declined by $32/MWh to $88/MWh, while black coal and brown coal earned $75/MWh (-$20/MWh) and $63/MWh (-$27/MWh), respectively. Wind VWAPs also declined, falling by $14/MWh to $49/MWh. Overall, these declines reflected lower average price outcomes across the NEM, particularly during higher-priced evening periods.

**Figure 25 Most fuel types earned lower average spot prices**

Volume weighted average prices by fuel type – Q3 2026 vs Q3 2025




### 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.

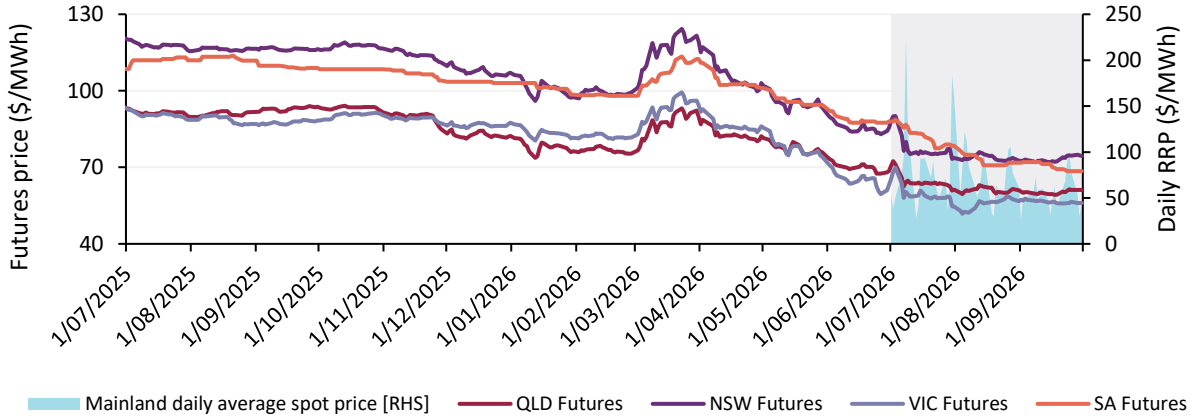
**Figure 26** shows Australian Securities Exchange (ASX) daily prices for Q3 2026 base contracts across mainland regions. Final settlement prices for such current quarter contracts are set at quarter end to the time-weighted quarterly average wholesale price for the relevant region, but prior to this "delivery quarter" their traded prices reflect market expectations. During the delivery quarter, traded prices were influenced by both quarter-to-date wholesale price levels and expectations for the balance of quarter, ultimately converging to the final settlement price.

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

ASX contract prices for Q3 2026 declined through the quarter in all regions, extending the decline from Q2 2026. Queensland and New South Wales base futures fell from $71/MWh and $89/MWh at the start of the quarter to $61/MWh and $75/MWh respectively by quarter end, while Victorian and South Australian contracts declined from $66/MWh and $88/MWh to $56/MWh and $69/MWh respectively. The decline reflected lower wholesale spot prices and lower volatility that softened market expectations.

**Figure 26 Q3 2026 base futures declined through the quarter across all regions**

ASX Energy – Regional daily Q3 2026 base future prices and daily average spot price for mainland regions




ASX base contract prices for the 2026-27 financial year (FY27) averaged $71/MWh across the mainland regions in Q3 2026, down $10/MWh (-13%) compared to Q2 2026 and $25/MWh (-26%) from Q3 2025 (**Figure 27**). Futures prices initially continued a steady decline from their March/April highs before reversing midway through Q3, coincident with raised geopolitical tensions in the Middle East and rising global energy prices (see Section 3.1.1). Compared with the end of Q2 2026, New South Wales recorded the largest increase over the quarter, closing at $92/MWh (+10%). Queensland and Victoria also ended Q3 higher, at $79/MWh (+9%) and $64/MWh (+7%) respectively, while South Australia declined to $73/MWh (-8%). Longer-dated futures also increased across most mainland regions at the end of this quarter compared with the end of Q2 2026 (**Figure 28**).

**Figure 27 FY27 futures increased towards the end of Q3 2026**

ASX Energy – Daily FY27 base futures by region

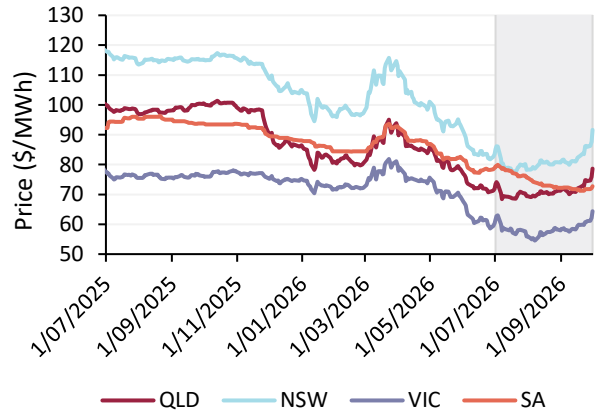
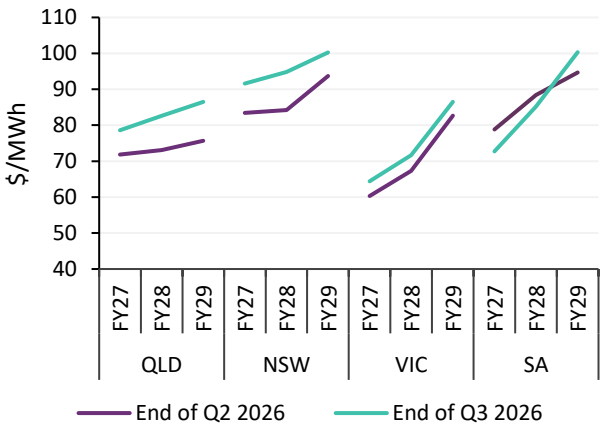



**Figure 28 Future financial year contracts higher across most regions at the end of Q3 2026**

ASX Energy – Financial year futures contract prices in mainland NEM regions – end of Q2 2026 and end of Q3 2026



## 2.3 Electricity generation

This section focuses on changes in electricity generation by fuel type, with batteries and pumped hydro considered separately in Section 2.4 as storage rather than primary generation. In Q3 2026, total electricity generation[16] across the NEM averaged 25,861 MW, increasing by 396 MW from Q3 2025 (**Figure 29**). Renewable energy sources[17] comprised 44.3% of total generation, a new Q3 high, and an increase from 41.8% in Q3 2025.

**Figure 29 Shift in supply mix driven by higher renewable output**

Change in NEM supply by fuel type – Q3 2026 vs Q3 2025

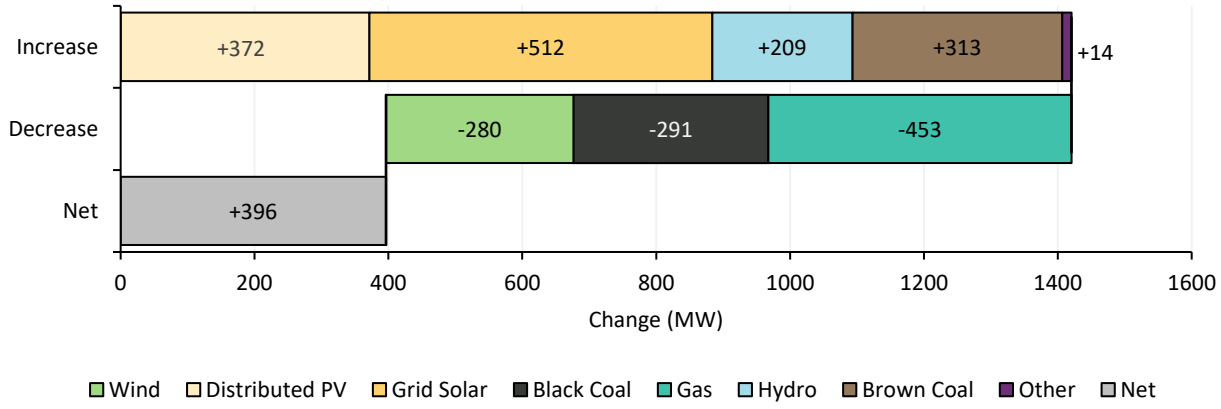



**Table 2 NEM supply mix contribution by fuel type**

| Quarter | Black coal | Brown coal | Gas | Liquid fuel | Distributed PV | Wind | Grid solar | Hydro | Biomass |
|---|---|---|---|---|---|---|---|---|---|
| Q3 25 | 39.2% | 13.8% | 5.2% | 0.01% | 11.1% | 18.4% | 6.7% | 5.4% | 0.3% |
| Q3 26 | 37.4% | 14.8% | 3.4% | 0.00% | 12.4% | 17.0% | 8.5% | 6.1% | 0.3% |
| Change | -1.7 pp | 1.0 pp | -1.8 pp | -0.01 pp | 1.3 pp | -1.4 pp | 1.9 pp | 0.7 pp | 0.1 pp |

Comparing Q3 2026 with Q3 2025:

- VRE generation, comprising wind and grid-scale solar, reached a Q3 high of 6,606 MW, an increase of 232 MW (+3.6%), with growth driven primarily by higher grid-scale solar generation. Grid-scale solar output increased by 512 MW (+30%), to a Q3 high of 2,211 MW, with growth largely driven by new connections and projects progressing through commissioning. As a result, grid-scale solar's share of total generation increased by 1.9 pp to 8.5%. In contrast, wind generation declined 280 MW (-6.0%), to 4,395 MW, reducing its share of total generation by 1.4 pp to 17%, reflecting lower wind speeds across most NEM regions during the quarter (see Section 1).
- Distributed PV output reached a Q3 high of 3,203 MW, up 372 MW (+13%) from Q3 2025, increasing its share to 12.4% (+1.3 pp).

[16] 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.

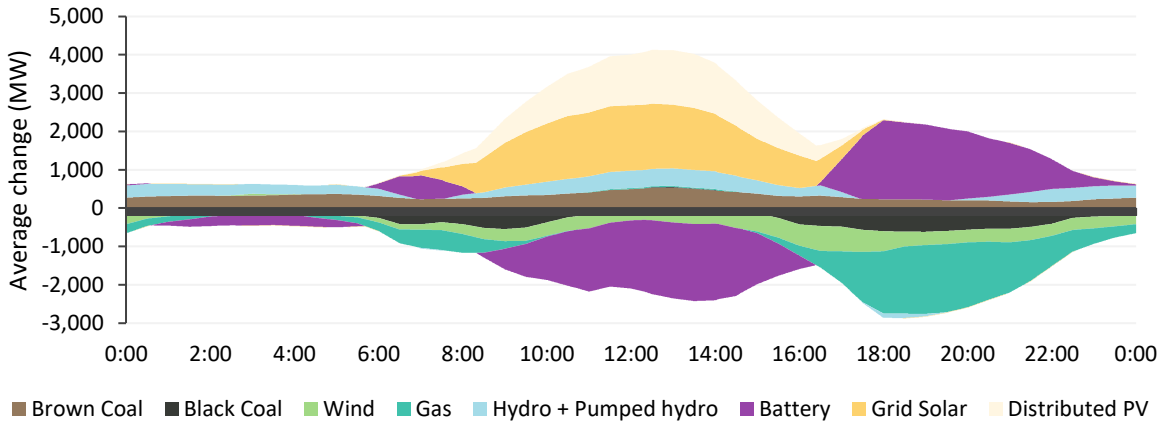
[17] Renewable energy share measures the renewable proportion of total generation but excludes grid-scale battery discharge and pumped hydro production from both renewable and total generation quantities. Pumped hydro production for Tumut 3 was estimated by multiplying its pumping load by round-trip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

- Hydro generation (excluding pumped hydro) averaged 1,572 MW this quarter, up 209 MW (+15%) from Q3 2025, increasing its share of total generation by 0.7 pp to 6.1%. This was predominantly driven by higher generation in New South Wales and Victoria, where output increased by 98 MW and 99 MW respectively.
- Biomass generation reached an all-time high of 83 MW, up 15 MW (+23%) from Q3 2025, increasing its share of total generation by 0.1 pp to 0.3%.
- Coal-fired generation increased by 22 MW year-on-year to average 13,515 MW in Q3 2026. Black coal generation fell by 291 MW (-2.9%), while brown coal generation increased by 313 MW (+8.9%). As a result, black coal and brown coal recorded generation shares of 37.4% (-1.7 pp) and 14.8% (+1.0 pp), respectively.
- Gas fired generation averaged 881 MW, the lowest Q3 average recorded since 2000, with its share of total generation falling to 3.4% (-1.8 pp). More than half of the NEM-wide reduction occurred in Queensland, where output fell by 246 MW (-55%) to average 203 MW.

**Figure 30** shows how the time-of-day generation profile for the NEM changed from Q3 2025 to Q3 2026. Storage technology changes are presented on a net basis to show how shifts in generation patterns across the day were underpinned by increased storage participation.

### Figure 30 Renewables and storage continue to supply energy throughout the day

Change in NEM generation and storage by time of day – Q3 2026 vs Q3 2025




Note: Storage technology changes are presented on a net basis where increases in supply (battery discharging and pumped hydro generation) are positive and increases in load (battery charging and hydro pumping) are negative. The chart series show the net change for each technology type, with pumped hydro incorporated within the hydro total.

Grid-scale solar recorded a significant increase in generation, with output across the daytime period (1000 hrs to 1600 hrs) averaging 5,878 MW, up 1,452 MW (+33%) compared with Q3 2025. This increase was primarily driven by growth in new and commissioning capacity. Increased grid-scale battery charging during daylight hours also supported higher grid-scale solar generation, reducing economic offloading in response to low wholesale prices (see Section 2.3.4). Average daily energy charged by grid-scale batteries during daytime hours more than tripled year-on-year, increasing from 3.7 GWh in Q3 2025 to 13.4 GWh in Q3 2026.

Energy stored during the daytime period was subsequently discharged during the evening peak period (1600 hrs to 2100 hrs), with average daily battery discharge reaching 10.9 GWh, up from 3.2 GWh in Q3 2025. As a result, grid-scale batteries supplied 8.0% of total evening peak supply, exceeding the contribution from gas-fired generation (5.1%) for the first time in any quarter. Gas-fired generation averaged 1,385 MW during the evening peak, down 50% year-on-year.

Wind generation declined across most hours of the day, consistent with the lower average wind speeds observed across most NEM regions and several wind lulls experienced during the quarter. Brown coal generation increased across all hours of the day, reflecting higher availability across Victoria's brown coal fleet and stronger Victorian demand.

### 2.3.1 Coal-fired generation

#### Black coal-fired fleet

Average black coal-fired generation fell to a new Q3 low, averaging 9,683 MW, down by 291 MW (-2.9%) compared to Q3 2025 (**Figure 31**). The reduction was driven by lower availability, which fell by 429 MW (-3.3%) compared to Q3 2025.

Availability is jointly driven by periods of capacity derating (partial outages), and capacity being fully offline. As **Figure 32** shows, fully offline capacity is classified into planned and unplanned maintenance/repair outages, or units being offline for market and operational reasons, referred to as economic withdrawals[18]. In New South Wales, fully offline capacity increased by 17 MW (+1.3%) year-on-year, with higher planned outage levels offset by lower unplanned outages. In Queensland, fully offline capacity increased by 427 MW (+34%), driven by higher planned outages and increased economic withdrawals.

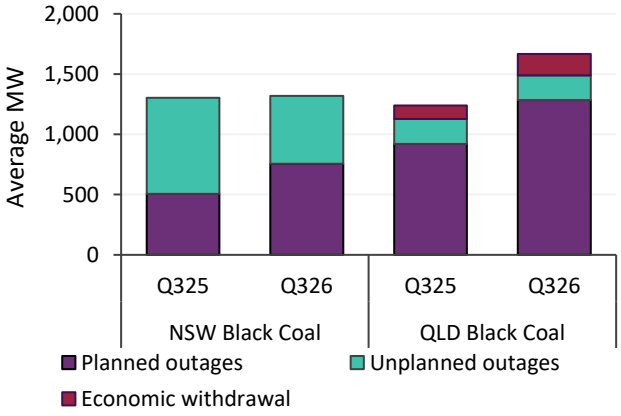
**Figure 31 NEM black coal-fired generation reached new Q3 low**

Quarterly average black coal-fired generation and availability by region – Q3s




**Figure 32 Black coal-fired capacity on outage increased year-on-year**

Average coal-fired capacity fully offline – Q3 2026 vs Q3 2025

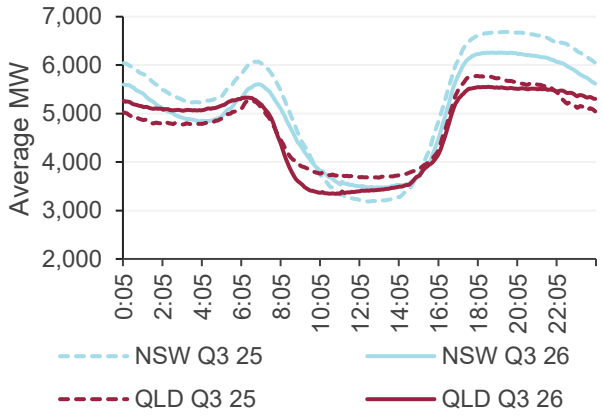



In New South Wales, black coal-fired generation averaged 4,997 MW in Q3 2026, down 252 MW (-4.8%) year-on-year, with a 196 MW (-2.9%) reduction in available capacity driven by significant capacity deratings during the quarter, particularly at Eraring. The decline was most pronounced during the evening peak (1600 hrs to 2100 hrs), when output was 393 MW lower than Q3 2025, and the morning peak (0600 hrs to 1000 hrs), down 299 MW year-on-year. Intra-day swing decreased by 713 MW to average 2,788 MW as output increased in the middle of the day (**Figure 33**).

[18] Economic withdrawals refer to periods where coal units are offline (generation below 5 MW) but are not undergoing planned or unplanned repair or maintenance work. This includes units classified under the Medium Term Projected Assessment of System Adequacy (MT PASA) as "Inactive Reserve", as well as intervals where a unit's market bid availability is zero, but non-zero PASA availability and a recall period of less than 24 hours indicates that it could come online if required.

**Figure 33 Lower black coal generation during morning and evening peak periods**

Black coal-fired output by time of day – Q3s




In Queensland, output decreased by 39 MW (-0.8%) to average 4,686 MW this quarter with availability down by 233 MW (-3.8%). Output was lower during both the evening peak (1600 hrs to 2100 hrs), down 167 MW year-on-year, and the morning peak (0600 hrs to 1000 hrs), down 149 MW compared to Q3 2025. Intra-day variability increased by 108 MW to average 2,209 MW this quarter.

The minimum generation as a share of average available capacity was 53% in New South Wales and 57% in Queensland, with greater flexibility among Queensland generators year-on-year reducing the difference relative to New South Wales.

**Figure 34** shows availability, generation and utilisation rates for New South Wales black coal-fired power stations. Most stations recorded lower utilisation rates and reduced availability year-on-year. Vales Point B was the only station with increased output, up by 141 MW (+19%) to average 865 MW, supported by a 330 MW reduction in capacity on outage leading to a 295 MW (+32%) increase in availability and. Mt Piper recorded the largest decrease in output, down by 191 MW (-22%) to average 692 MW. This was driven by lower availability (-75 MW), with full unit outages up by 107 MW compared to Q3 2025. Eraring output decreased by 110 MW (-6.3%), its availability falling by 223 MW due to increased capacity on full outage (+94 MW year-on-year) and higher partial outages.

**Figure 34 Decreased availability across all New South Wales black coal-fired stations except Vales Point B**

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q3 2026 vs Q3 2025

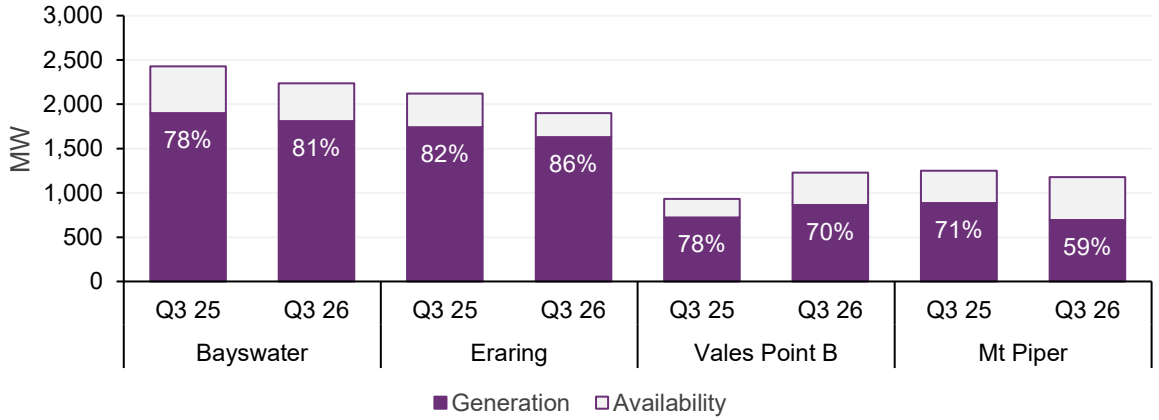
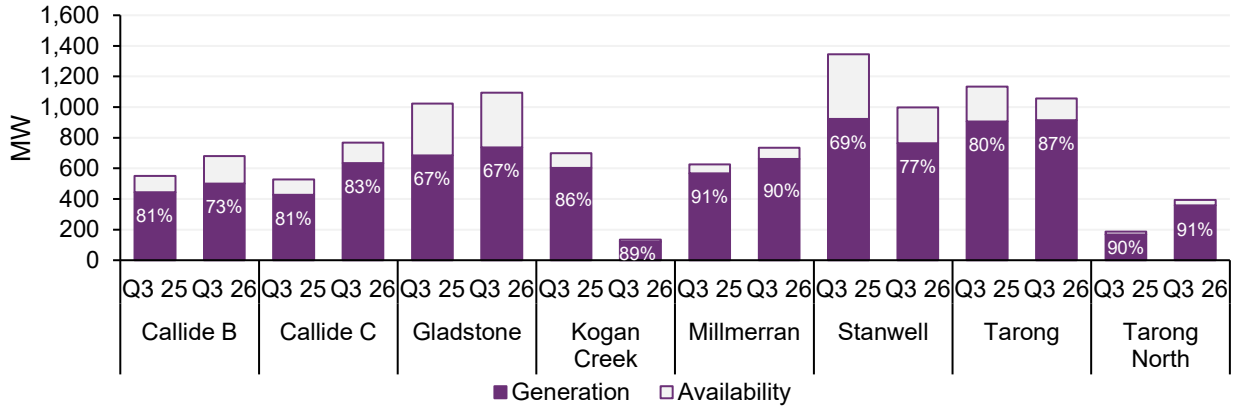



**Figure 35** shows availability, generation and utilisation rates for Queensland black coal-fired power stations. Kogan Creek and Stanwell were the only stations with decreased output compared to Q3 2025. Output at Kogan Creek fell by 484 MW (-80%) and at Stanwell by 159 MW (-17%), driven by reductions in availability with increased capacity on outages. These decreases offset increases in output at other stations in Queensland. Callide C output increased by 207 MW (+49%) and Tarong North by 190 MW (113%), with availability up by 239 MW (45%) and 206 MW (+111%) respectively due to reduced capacity on outage at these stations. Most Queensland black-coal fired stations also recorded higher utilisation rates, except Callide B and Millmerran.

**Figure 35 Queensland black coal-fired output decreased year-on-year driven by Kogan Creek and Stanwell**

Average quarterly availability and generation for Queensland black coal-fired power stations – Q3 2026 vs Q3 2025




## Brown coal-fired fleet

In Q3 2026, brown coal-fired generation averaged 3,832 MW, its highest Q3 level since Q3 2020, up 313 MW (+8.9%) year-on-year. This increase reflected a 278 MW (+6.9%) lift in availability, with a 370 MW (-45%) reduction in capacity on full outage across the quarter (**Figure 36**), alongside increased Victorian demand (see **Figure 5** in Section 2.1). All brown coal-fired generators recorded higher output year-on-year, with Yallourn W contributing the most. Higher availability and lower fully offline capacity at Yallourn W resulted in output increasing by 212 MW (+23%) year-on-year (**Table 3**). Yallourn's intraday swing also reduced from 187 MW to 73 MW, reflecting a flatter operating profile across the day. Brown coal-fired generation was higher across all hours of the day (**Figure 37**).

**Figure 36 Brown coal-fired availability and generation increased**

Quarterly average brown coal-fired generation and availability in Victoria (including decommissioned units) – Q3s




**Figure 37 Higher brown coal-fired generation across all hours**

Brown coal-fired output by time of day – Q3s

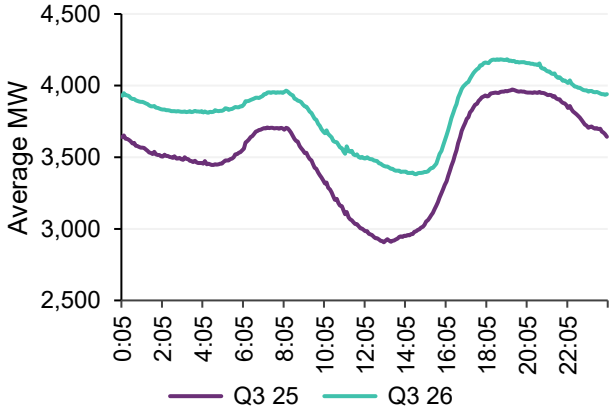



**Table 3 Brown coal availability, output, utilisation, offline capacity, and intraday swing – Q3 2026 vs Q3 2025**

| Generator | Availability (MW) | | Output (MW) | | Utilisation | | Fully offline capacity (MW) | | Intraday swing (MW) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Q3 25 | Q3 26 | Q3 25 | Q3 26 | Q3 25 | Q3 26 | Q3 25 | Q3 26 | Q3 25 | Q3 26 |
| Loy Yang A | 1,934 | 1,955 | 1,655 | 1,694 | 86% | 87% | 241 | 222 | 585 | 478 |
| Loy Yang B | 1,078 | 1,128 | 941 | 1,004 | 87% | 89% | 76 | 21 | 300 | 258 |
| Yallourn W | 1,006 | 1,212 | 922 | 1,134 | 92% | 94% | 505 | 209 | 187 | 73 |

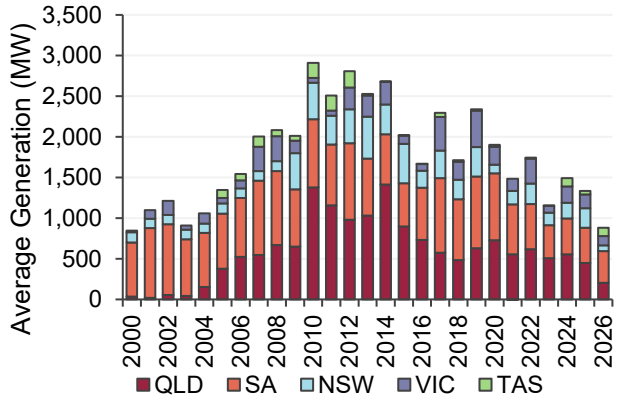
### 2.3.2 Gas-fired generation

In Q3 2026, NEM gas-fired generation averaged 881 MW, 453 MW (-34%) lower than Q3 2025 and the lowest Q3 average recorded since 2000 (**Figure 38**). Monthly NEM average gas-fired output declined steadily through the quarter, from 1,145 MW in July and 858 MW in August to 632 MW in September. Daily average output across the NEM peaked at 2,593 MW on 30 July during a wind lull event across South Australia and Victoria (see **Figure 47** in Section 2.3.4).

Gas-fired generation declined across all mainland regions. Queensland accounted for more than half of the NEM-wide reduction, with average output falling by 246 MW (-55%) year-on-year to 203 MW. Lower generation at Darling Downs (-146 MW) contributed most to the decline. New South Wales also recorded a substantial reduction and the lowest Q3 level on record, with output declining by 168 MW (-70%) to 71 MW. The largest reductions were recorded at Tallawarra A (-76 MW) and Uranquinty (-51 MW). In both regions, lower gas-fired generation was most evident during the evening peak period (1600 hrs to 2100 hrs), when average output declined by 688 MW in Queensland and 501 MW in New South Wales compared to Q3 2025.

**Figure 38 Lowest Q3 gas-fired output across the NEM since 2000**

Average gas-fired generation by region – Q3s




In Victoria, gas-fired generation averaged 114 MW, down by 57 MW (-33%) from Q3 2025. Similar to the northern regions, the reduction was most pronounced during the evening peak period, when average output was 205 MW lower than in Q3 2025.

Gas-fired generation averaged 392 MW in South Australia, a decrease of 40 MW (-9%) year-on-year and the lowest Q3 level on record, with the largest reduction at Pelican Point (-20 MW).

In contrast, gas-fired generation increased in Tasmania to average 101 MW, up by 59 MW (+141%) compared to Q3 2025.

### 2.3.3 Hydro

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

Hydro generation[19] across the NEM averaged 1,572 MW in Q3 2026 (**Figure 39**), a 209 MW (+15%) increase compared to Q3 2025, which recorded the lowest Q3 level since 2008.

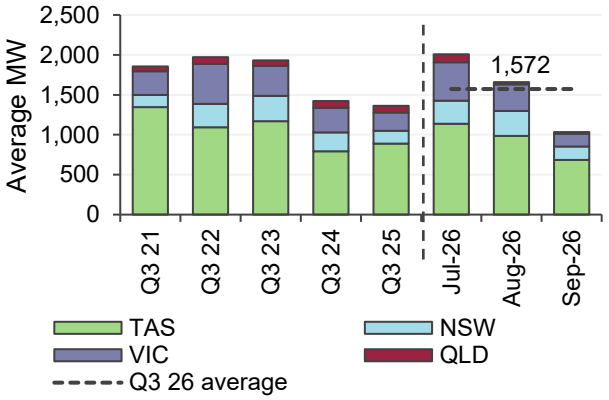
[19] Hydro generation excludes output from hydro pumped storage and does not net off electricity consumed by pumping at these facilities. When excluding pumped hydro generation, the pumped hydro production for Tumut 3 was estimated by multiplying its pumping load by round-trip efficiency (78%), while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

New South Wales recorded a substantial increase, with hydro output increasing by 98 MW (+62%) to 258 MW. This largely reflected higher output at Upper Tumut, up 64 MW (+67%) following the lower generation recorded in Q3 2025. Victoria's hydro generation increased by 99 MW (+44%) to average 327 MW, driven by higher output from Murray, up 107 MW (+77%) compared to Q3 2025.

Tasmanian hydro generation also increased by 47 MW (+5.3%) to average 938 MW, supported by improving storage conditions, with Tasmanian storage levels reaching 50.4% at the end of September, 1.9 pp higher than the same time last year. In contrast, Queensland hydro generation declined by 36 MW (-42%) year-on-year to average 49 MW.

**Figure 39 Hydro generation increased year-on-year**

Average hydro generation by region – Q3s




## 2.3.4 Wind and grid-scale solar

Average VRE generation in the NEM reached a new Q3 high of 6,606 MW, an increase of 232 MW (+3.6%) year-on-year. Solar generation led this growth, accounting for 512 MW (+30%), while wind generation decreased by 280 MW (-6.0%) from Q3 2025 (**Figure 40**).

This quarter, Queensland's wind generation reached a Q3 high, averaging 749 MW, up 200 MW (+36%) year-on-year. This was driven by stronger wind conditions and commissioning growth, most notably from MacIntyre where average generation increased by 86 MW (+85%) compared to Q3 2025 (**Figure 41**). In contrast, average wind output declined across the other states, falling to 878 MW in New South Wales (-141 MW), 825 MW in South Australia (-124 MW), 1,700 MW in Victoria (-196 MW) and 244 MW in Tasmania (-19 MW).

**Figure 40 Growth in VRE output**

Average quarterly VRE generation by fuel type – Q3s

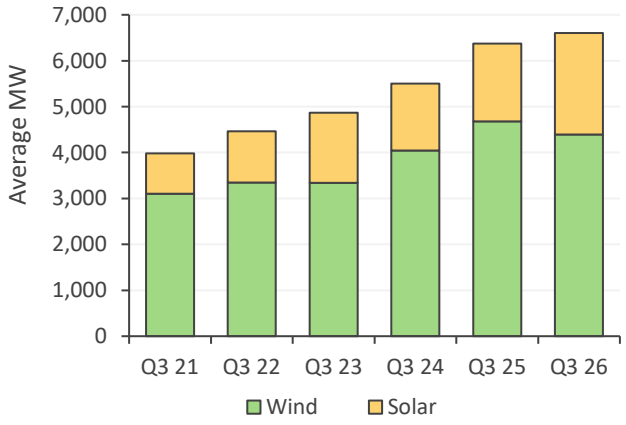
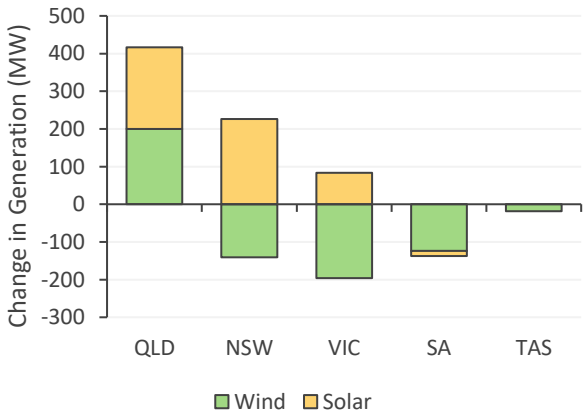



**Figure 41 Increase in solar generation and decrease in wind generation across the NEM**

Average MW change in output Q3 2026 vs Q3 2025



This quarter, Queensland, New South Wales and Victoria recorded new Q3 highs for grid-scale solar generation. New South Wales led growth, averaging 977 MW, up 226 MW (+30%), while Queensland averaged 861 MW, an increase of 217 MW (+34%) year-on-year. In Victoria generation averaged 295 MW (+83 MW, +39%), while South Australia was the only region to decline, falling to 78 MW (-14 MW, -15%).

## Grid-scale solar

In Q3 2026, grid-scale solar generation across the NEM reached a new Q3 high of 2,211 MW (+512 MW, +30%). **Figure 42** shows the overall quarterly change in grid-scale solar generation, together with the changes in availability at new connections and projects progressing through the commissioning process, and the impacts of offloading and curtailment on overall output.

New and commissioning projects were the highest contributors to this growth, contributing an average of 250 MW and 156 MW respectively to availability. Availability growth was led by Culcairn (+76 MW) in New South Wales, Broadsound (+57 MW) in Queensland and Goorambat East (+55 MW) in Victoria.

Increased grid-scale output was also supported by a 177 MW reduction in economic offloading, as higher battery charging and increased daytime operational demand reduced the need for grid-scale solar facilities to offload energy. However, this was partially offset by a 105 MW increase in curtailment, largely related to network limitations in southern New South Wales and northern Queensland.

The NEM-wide volume-weighted capacity factor[20] for grid-scale solar increased to 21.8%, a 0.7 pp increase compared with the previous Q3 (**Figure 43**). New South Wales recorded the largest increase, rising to 21% (+3.2 pp), while Victoria remained relatively unchanged at 20% (+0.2 pp). In contrast, Queensland and South Australia recorded declines in capacity factor, falling to 24% (-1.0 pp) and 17% (-3.6 pp), respectively reflecting lower solar exposure. In South Australia, the decline was further impacted by outages at several solar facilities, reducing available capacity during the quarter.

**Figure 42 Growth in grid-scale solar availability and generation**

Changes in grid-scale solar availability and generation – Q3 2026 vs Q3 2025

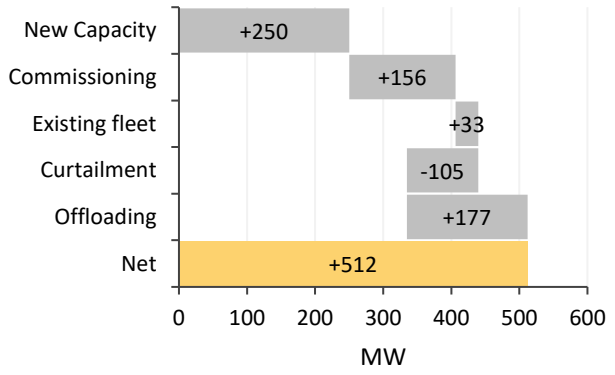
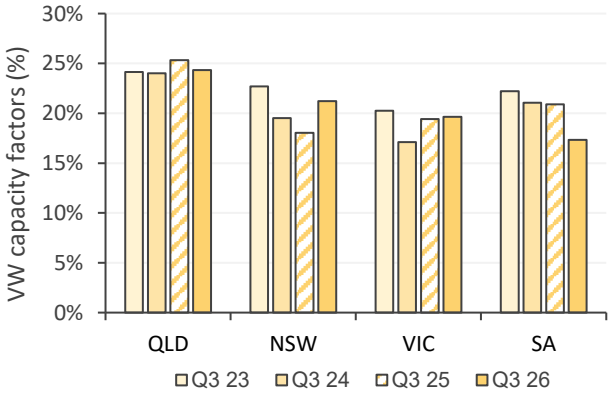



**Figure 43 Declines in grid-scale solar availability in Queensland and South Australia**

Volume-weighted grid-scale solar available capacity factors[21] – Q3s




[20] Available capacity factors are calculated using average available energy divided by maximum 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.

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

## Wind

NEM-wide wind generation averaged 4,395 MW this Q3, down 280 MW (-6.0%) year-on-year (**Figure 44**). This reduction occurred despite a 352 MW increase in availability at new and commissioning projects, with the largest contributions coming from Golden Plains West (+155 MW) in Victoria and MacIntyre (+86 MW) in Queensland. Weaker wind conditions across much of the NEM (see Section 1) reduced output from both existing and newly commissioned capacity, outweighing the increase in available capacity.

Consistent with these weaker wind conditions, the NEM-wide quarterly volume-weighted capacity factor declined to 34% (-5.3 pp) in Q3 2026 and was lower in all regions except Queensland (**Figure 45**), where it increased by 1.3 pp year-on-year to 36%, supported by higher wind speeds (see Section 1).

Victoria recorded the largest decline in wind capacity factor, falling 6.9 pp to 34%. This was followed by New South Wales, down 5.4 pp to 32%, and South Australia down 5.2 pp to 33%. Despite experiencing a 3.6 pp decline, Tasmania had the highest average wind capacity factor at 44%.

Changes in network curtailment and economic offloading had a relatively minor impact on overall wind output, with curtailment increasing by 34 MW year-on-year and economic offloading decreasing by 44 MW.

**Figure 44 Lower output from established wind farms**

Changes in wind availability and generation – Q3 2026 vs Q3 2025

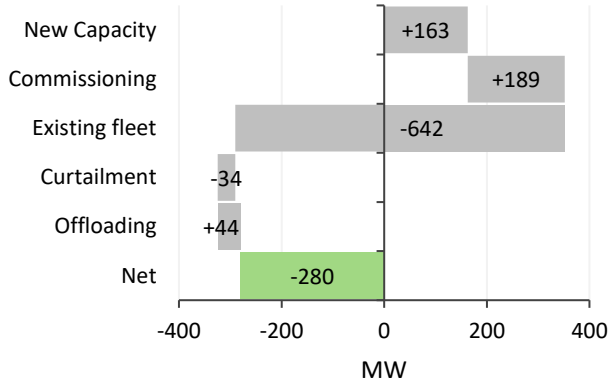



**Figure 45 Wind availability down across most regions**

Volume-weighted wind available capacity factors – Q3s

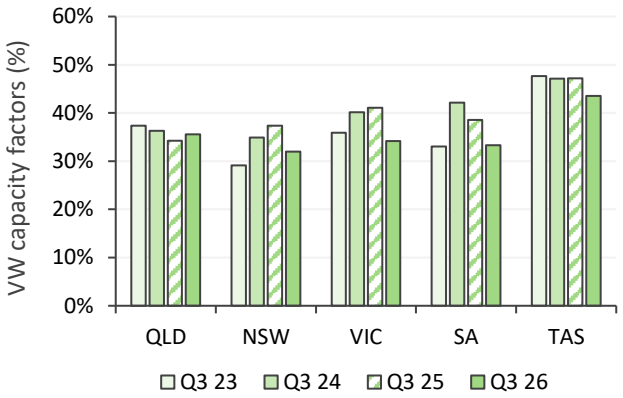



**Figure 46** shows the number of Q3 wind lull events across NEM regions. In Q3 2026, there were 46 events during which the daily average wind capacity factor[22] for a NEM region fell below 10%.

[22] Available capacity factors are calculated using the available energy divided by the maximum capacity. The use of availability instead of generation output removes the impact of economic offloading or curtailment to better capture in-service plant capacity and underlying wind resource levels. Wind farms are included in the capacity factor calculation from the first day of the quarter after they reach full output.

Victoria recorded the highest number of wind lull days, with 17 days below the 10% threshold, occurring in events ranging from single day to three-day lulls. The longest wind lull of the quarter occurred in Tasmania, where available wind capacity factor remained below 10% for four consecutive days (6-9 July 2026). This overlapped with a three-day lull in Victoria over 7-9 July 2026, with the NEM-wide available available wind capacity factor averaging 20% across the four-day period. New South Wales recorded fewer wind lull days than in Q3 2025, while Queensland was the only region to not record any wind lull days below the 10% threshold this quarter.

**Figure 46 Increase in multi-day wind lulls in Q3 2026**

Count of wind lulls (<10% availability) by region – Q3s

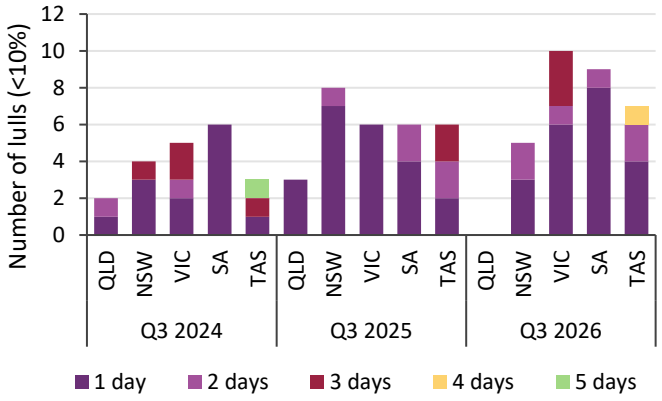
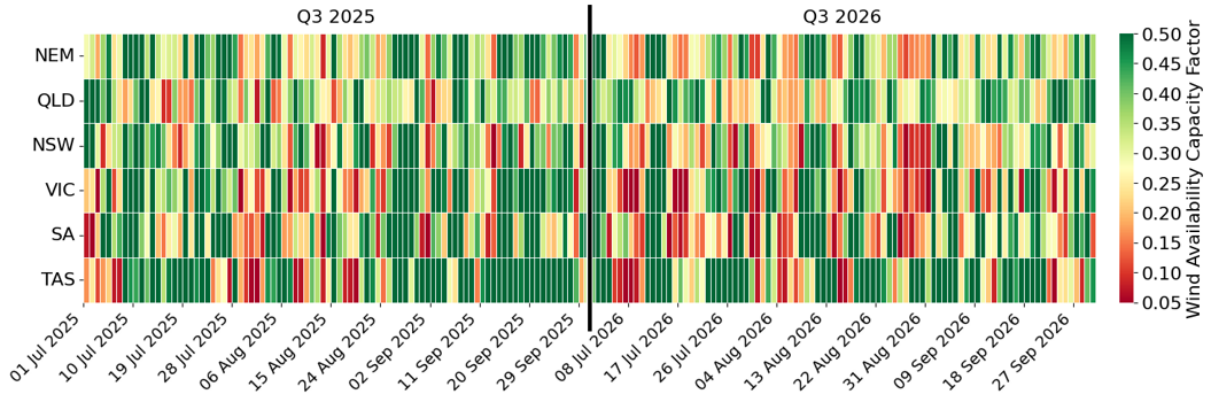



**Figure 47** further illustrates daily wind availability capacity factors for Q3 2025 and Q3 2026.

**Figure 47 Increased lows in wind availability across Q3 2026**

Daily wind availability capacity factor – Q3 25 and Q3 26




The 46 wind lull events in Q3 2026 represented a year-on-year increase of eight events. Most of this increase occurred in July, which experienced 11 more events than July 2025, driven by a four-day wind lull in Tasmania and two three-day wind lulls in Victoria.

Between 26 and 31 August 2026, Victoria, New South Wales and South Australia experienced a series of wind lull events, with periods of low wind availability occurring across the three regions at different times. Collectively, these events contributed to a prolonged period of low wind availability across the NEM. However, as the wind lulls did not occur simultaneously across all regions, the NEM-wide available wind capacity factor averaged 15% over the six-day period.

The lowest NEM-wide daily average wind available capacity factor recorded in Q3 2026 was 11% on 31 July 2026, coinciding with two-day wind lulls in South Australia and Victoria and a one-day wind lull in Tasmania.

## Economic offloading

Total economic offloading[23] for wind and grid-scale solar averaged 416 MW this quarter, a year-on-year decline of 221 MW (-35%, **Figure 48**). Economic offloading was highest in Victoria at 189 MW, largely driven by wind (168 MW). Economic offloading averaged 94 MW in Queensland and 103 MW in South Australia, driven primarily by grid-scale solar and wind respectively. Meanwhile, in New South Wales, offloading declined to 28 MW, down 45 MW (-62%) year-on-year.

Grid-scale solar economic offloading decreased by 177 MW (-54%) year-on-year, to average 149 MW, with offloading as a percentage of average solar availability also decreasing to 5.9% (-9.8 pp). This reduction reflected higher grid-scale battery charging and increased daytime operational demand, which reduced the need for grid-scale solar facilities to economically offload generation. This reduction was most prominent in Queensland, where average offloading declined by 139 MW (-63%) to average 81 MW, followed by New South Wales (-37 MW, -61%) and South Australia (-7.5 MW, -24%). This was partially offset by increases in Victoria (+7.0 MW, +52%) (**Figure 49**).

Wind economic offloading also declined this quarter, averaging 266 MW, with offloading as a share of average wind availability staying unchanged year-on-year at 5.9%. South Australia experienced the largest decline (-35 MW, -31%), followed by New South Wales (-8.1 MW, -66%) and Queensland (-8.6 MW, -39%). Wind economic offloading increased slightly in Victoria (+6.9 MW, +4.3%).

**Figure 48 Economic offloading declined for both fuel types**

Average MW offloading and as percentage of availability by fuel type

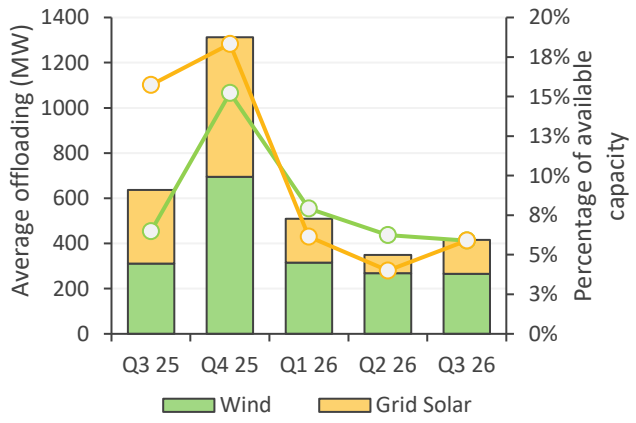
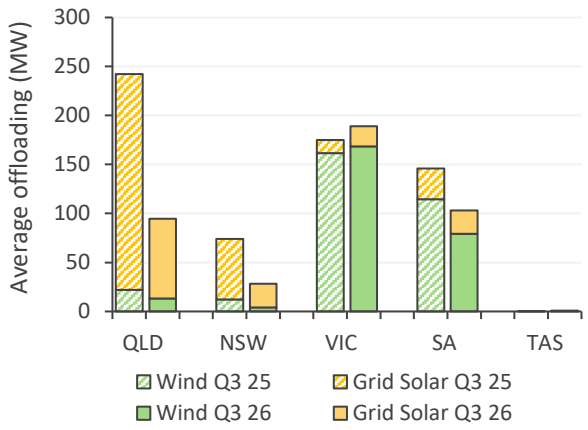



**Figure 49 Queensland experienced the largest reduction in offloading**

Average MW offloading by region – Q3s




## Network curtailment

Total network curtailment[24] of wind and solar generation reached a new Q3 high, averaging 281 MW, up 139 MW year-on-year (**Figure 50**).

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

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

Grid-scale solar accounted for most of this increase, with curtailment rising by 105 MW, to average 169 MW this quarter. As a percentage of solar availability, curtailment increased by 3.6 pp year-on-year to 6.7%. Increases were greatest in New South Wales, with curtailment at 104 MW (+64 MW), primarily at facilities in the south of the state, followed by Queensland at 48 MW (+41 MW) concentrated at facilities in the north of the state (**Figure 51**). In Victoria and South Australia, grid-scale solar curtailment remained largely unchanged year-on-year, averaging 15 MW and 1.0 MW respectively.

Average curtailment of wind generation increased by 34 MW year-on-year to 113 MW, with curtailment as a percentage of average wind availability rising 0.9 pp from the previous year to 2.5%. Victoria recorded the largest increase in wind curtailment, rising from 51 MW to 76 MW this quarter, followed by Queensland, where curtailment increased from 3 MW to 27 MW. These rises were partially offset by lower curtailment in South Australia and Tasmania which decreased by 13 MW and -1.6 MW, respectively. In New South Wales, wind curtailment remained unchanged.

**Figure 50 Curtailment increases for solar and wind farms**

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

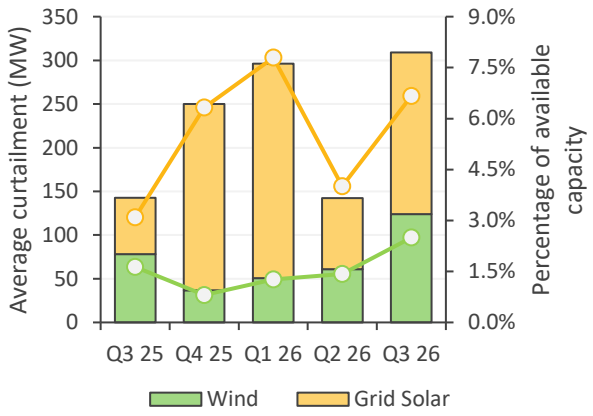
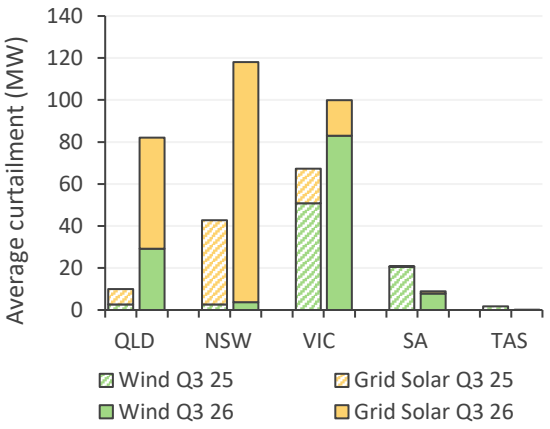



**Figure 51 Curtailment higher in New South Wales for solar and higher in Victoria for wind**

Average MW network curtailment by region – Q3s




## 2.3.5 NEM emissions

In Q3 2026, NEM total emissions remained broadly unchanged at 28.0 MtCO2-e (-0.2%), compared to 28.1 MtCO2-e in Q3 2025 (**Figure 52**).

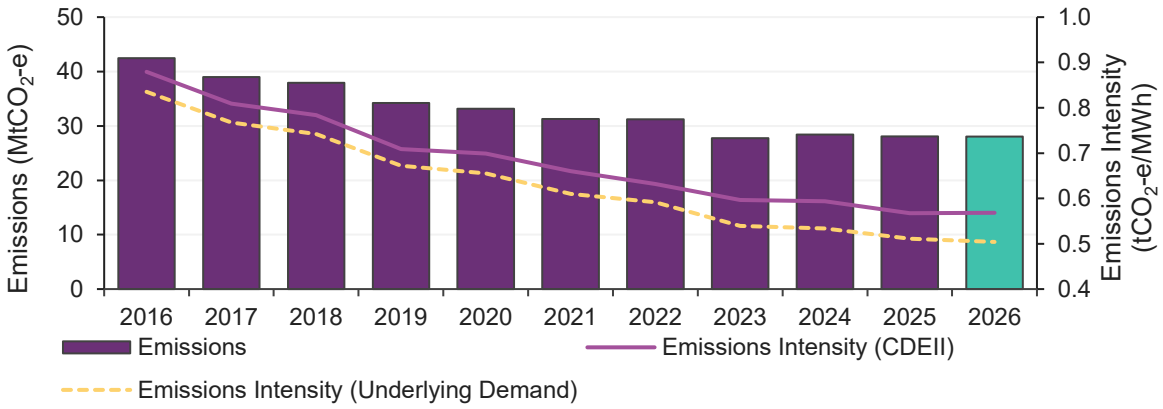
The Carbon Dioxide Equivalent Intensity Index (CDEII) emissions intensity is measured by combining sent out metering data with publicly available generator emission and efficiency data to provide a NEM-wide CDEII[25]. This emissions intensity excludes generation from distributed PV, considering only sent out generation from market generating units. This quarter, CDEII emissions intensity averaged 0.57 tCO2-e per MWh, broadly in line with Q3 2025 and up by 0.1% year-on-year, reflecting increased brown-coal fired generation despite higher grid-scale solar generation and lower output from black coal-fired and gas-fired generators. Continued growth in distributed PV output further reduced emissions intensity

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

associated with underlying demand[26], which declined by 0.01 tCO2-e/MWh year-on-year to 0.50 tCO2-e/ MWh, marking a new Q3 low.

**Figure 52 NEM total emissions remained broadly unchanged compared to Q3 2025**

Quarterly NEM emissions and intensity – Q3s




## 2.4 Storage and renewable contribution

### 2.4.1 Batteries

Between the end of Q3 2025 and Q3 2026, the installation of battery energy storage systems (BESS) saw a significant increase in grid-scale battery capacity in the NEM, with a combined capacity of 4,375 MW/12,628 MWh beginning commissioning. Of this total, 860 MW/2,970 MWh came online in Q3 2026 (**Table 4**). Total installed battery capacity in the NEM, including both fully commissioned facilities and projects still in their commissioning phase, exceeded 10 GW/23 GWh by the end of the quarter.

**Table 4 New battery systems that commenced commissioning in the NEM in Q3 2026**

| Battery | Region | Maximum Capacity (MW/MWh) |
|---|---|---|
| Summerfield BESS1 | South Australia | 120/480 |
| Williamsdale BESS | New South Wales | 250/500 |
| Eraring BESS2 | New South Wales | 240/1,390 |
| Pine Lodge BESS | Victoria | 250/600 |

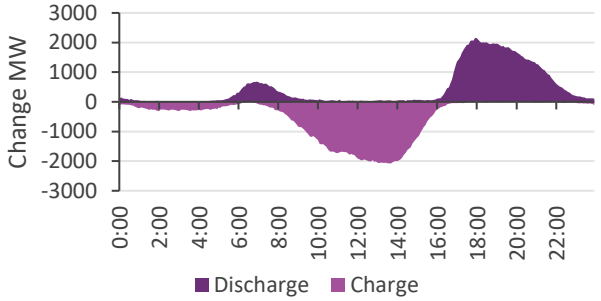
Average battery discharge increased to average 680 MW, over triple the 215 MW recorded in Q3 2025, reaching a new quarterly high. Average charging also more than tripled year-on-year to reach 805 MW GWh, concentrated in the daytime hours. Grid-scale batteries continued to shift energy from the middle of the day to the evening peak, with batteries charging 13.4 GWh of energy per day on average during daylight hours (1000 hrs to 1600 hrs) before discharging 10.9 GWh during the evening peak (1600 hrs to 2100 hrs) in Q3 2026 (**Figure 53**). This compared to 3.7 GWh charged and 3.2 GWh discharged per day on average during the respective periods in Q3 2025.

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

Both peak battery charging and discharging reached new records this quarter. On Saturday, 19 September 2026, during the half-hour ending at 1230 hrs, peak battery charging reached 4,414 MW, surpassing the previous record set in Q2 2026 by 762 MW. Peak battery discharge set a record of 4,616 MW on Sunday, 23 August 2026 during the half-hour ending at 1830 hrs, which was 856 MW higher than the previous record set in Q2 2026. In both cases, New South Wales and Queensland contributed the largest share of battery activity.

**Figure 53 Increased daytime charging and stronger evening discharge**

Change in average battery discharge/ charge by time of day – Q3 2026 vs Q3 2025




## Battery revenue

In Q3 2026, estimated revenue[27] for grid-scale batteries in the NEM averaged $90.9 million, a decline of $21.0 million from Q3 2025 (**Figure 54**). The decline was primarily driven by lower contingency frequency control ancillary services (FCAS) revenue, compared with the unusually high levels recorded in Q3 2025, when planned outages impacting the Heywood interconnector increased the need for local FCAS enablement.

FCAS revenue declined by $51.6 million (-96%) to average $2.1 million this quarter, with contingency FCAS services in South Australia accounting for nearly the entire decrease. As a result, FCAS accounted for only 2.3% of total battery revenue, down 45.7 pp from Q3 2025 (**Figure 55**).

**Figure 54 Decrease in FCAS and increase in battery arbitrage revenue**

Quarterly net revenue from NEM battery systems by revenue stream

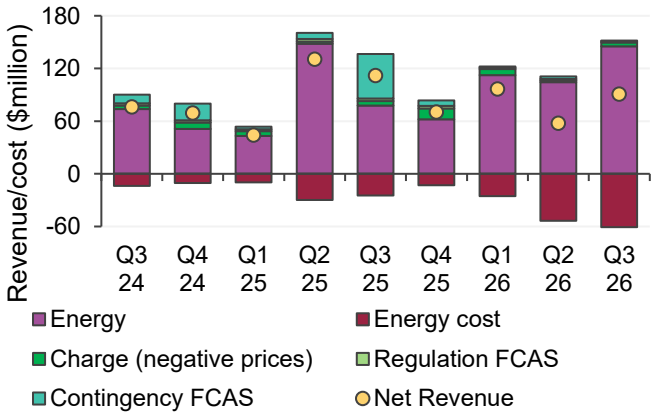
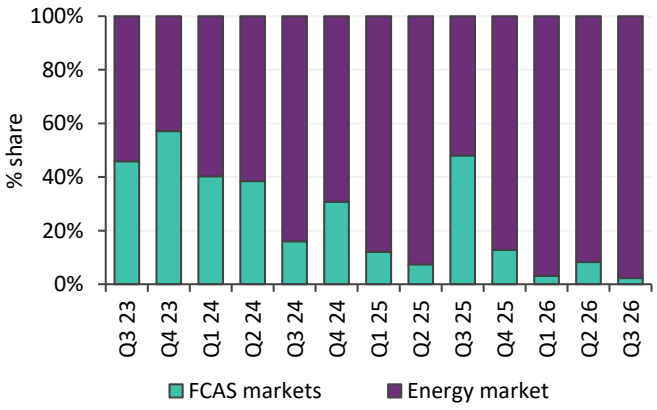



**Figure 55 Battery revenue share from FCAS markets decreased**

Percentage share of battery net revenue – energy vs FCAS markets




Despite the overall reduction in battery revenue, arbitrage earnings increased, primarily driven by higher energy discharge revenue in Queensland and New South Wales. While the magnitude of charging costs also increased, rising from

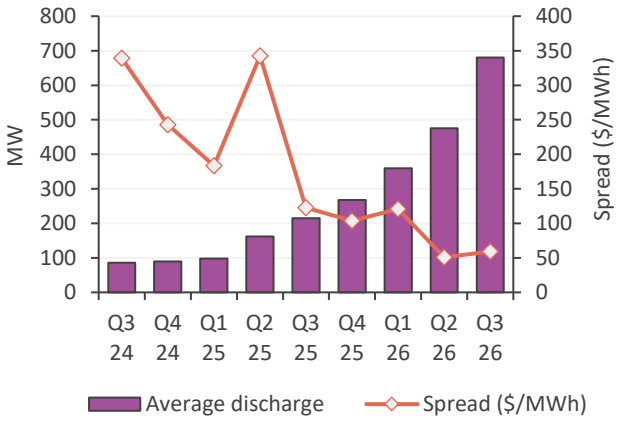
[27] Battery revenue comprises revenue from energy arbitrage – calculated as revenue from energy discharged (including charging at negative prices) net of charging costs – and revenue earned from frequency control ancillary services (FCAS). This measure excludes FCAS costs incurred by batteries and Frequency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

$24.5 million to $60.8 million (+148%), the increase in discharge revenue offset these costs, resulting in a net energy arbitrage revenue of $88.8 million this quarter. Energy arbitrage revenue increased by $15.4 million, $20.4 million and $0.9 million in Queensland, New South Wales and Victoria respectively but fell by $6.1 million in South Australia this quarter.

NEM-wide battery price spreads[28] fell from $123/MWh in Q3 2025 to $59/MWh in Q3 2026 (**Figure 56**), reflecting lower price volatility and the narrowing of the gap between charging and discharging prices (see **Figure 25** in Section 2.2.5).

**Figure 56 NEM-wide battery price spread**

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




All NEM regions experienced a decline in average price spreads year-on-year. The largest decrease in magnitude was in South Australia, where spreads fell by $82/MWh (-56%) to $65/MWh. Queensland and Victoria also experienced substantial year-on-year declines, down to $68/MWh and $58/MWh respectively. New South Wales recorded the lowest average price spread at $51/MWh, down $33/MWh from Q3 2025.

## 2.4.2 Pumped hydro

This section discusses pumped hydro generation, covering the Shoalhaven and Tumut 3 stations in New South Wales and Wivenhoe in Queensland. Revenue calculations include Shoalhaven and Wivenhoe only, with Tumut 3 excluded. Pumped hydro generation[29] averaged 85 MW this quarter, a year-on-year decline of 98 MW (-54%). This was driven by decreases at all three pumped hydro facilities in the NEM, with the largest absolute decline at Wivenhoe (-47 MW, -49%). Tumut 3 and Shoalhaven fell by 37 MW (-56%) and 14 MW (-66%), respectively.

### Pumped hydro revenue[30]

Estimated net pumped hydro revenue decreased to $9.0 million this quarter, a $27.5 million decline (-75%) year-on-year (**Figure 57**), driven by lower wholesale spot prices and reduced volatility. In Queensland, Wivenhoe's revenue fell by $22.4 million (-73%) to $8.2 million, while in New South Wales, Shoalhaven's revenue decreased by $5.1 million (-86%) to $0.8 million.

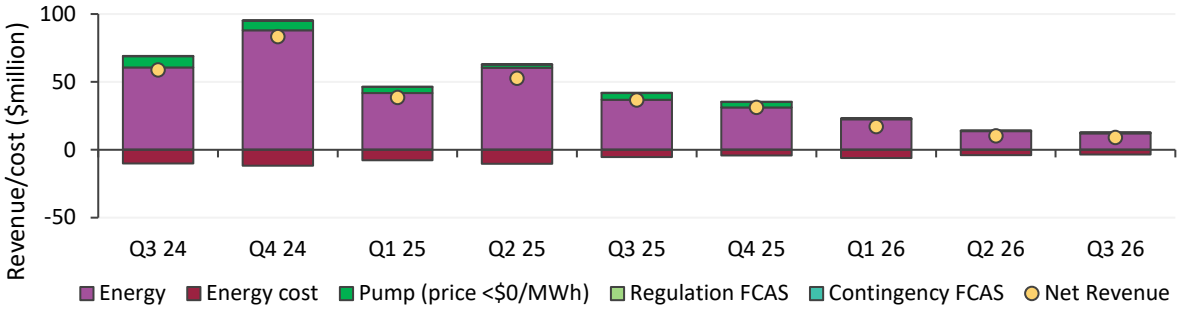
[28] Battery price spreads measure the difference between the prices at which batteries charge and discharge, providing an indication of arbitrage opportunities available for battery storage systems

[29] 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.

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

**Figure 57 Pumped hydro revenue decreased year-on-year**

Quarterly revenue from NEM pumped hydro by revenue stream



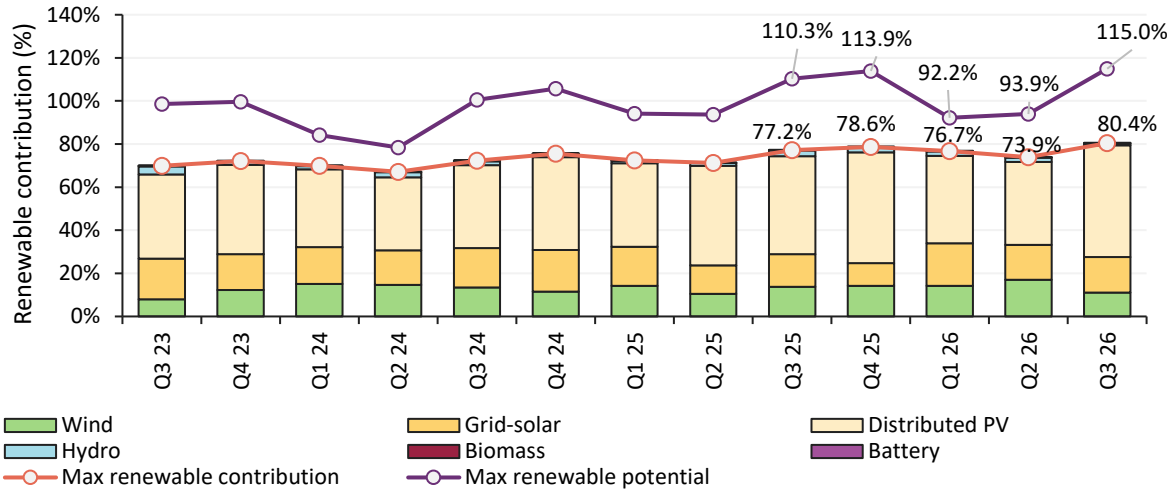

## 2.4.3 Peak renewable and storage contribution

This section examines renewable and storage contribution to demand at a 30-minute level, reflecting the combined role of renewable generation and battery discharge in meeting demand at any point in time. Peak renewable and storage contribution[31] reached an all-time high of 80.4% during the half-hour ending at 1230 hrs on Saturday, 19 September 2026. This was 3.2 pp higher the same period last year and exceeded the previous record, set in October 2025, by 1.8 pp (**Figure 58**). At the time of the peak, distributed PV provided 51.8% of total generation, with grid-scale solar and wind contributing 16.4% and 11.2%, respectively.

The next day, on Sunday, 20 September 2026 at the half-hour ending in 1300 hrs, maximum renewable and storage potential contribution also set a record at 115%, 1.0 pp higher than the previous record set in Q4 2025.

**Figure 58 Peak renewable and storage contribution sets a new record**

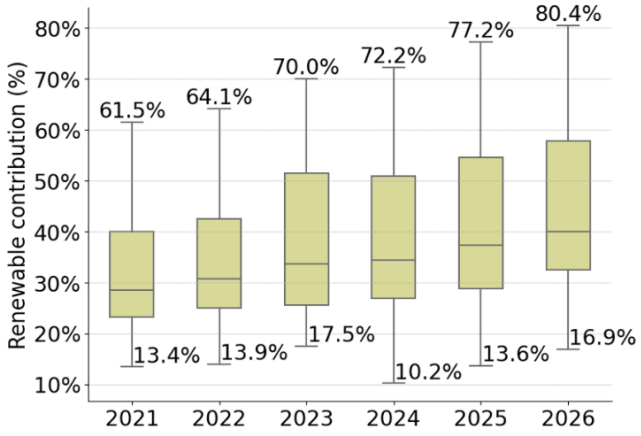
Percentage of NEM supply from renewable energy sources and storage at time of peak renewable and storage contribution




[31] Peak renewable and storage contribution is calculated as a 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 and storage includes grid-scale wind and solar, hydro generation (including pumped hydro), biomass, battery discharge and distributed PV. Total generation = large-scale generation + estimated distributed PV output.

**Figure 59 Renewable and storage contribution at all time high**

Range of NEM supply share from renewable sources and storage – Q3s




Renewable and storage contribution by half-hour varies widely with supply and demand conditions, ranging from a low of 16.9% to a high of 80.4% this quarter, a spread of 63.5 pp (**Figure 59**). The minimum occurred on Friday, 7 August 2026 during the half-hour ending at 0400 hrs and was 3.3 pp higher than the lowest level recorded in the same quarter last year.

By region, Queensland recorded a new high for renewable and storage contribution this quarter. On Monday, 21 September 2026 during the half-hour ending at 1100 hrs, Queensland recorded a record high contribution of 75.2%, 2.9 pp higher than the previous record of 72.2% set in Q2 2026. The Q2 2026 record was surpassed five times during the quarter before the new high was ultimately reached.

## Maximum renewable output

**Figure 60** highlights the highest quarterly peak half-hourly generation for grid-scale solar, wind and distributed PV since Q3 2023.

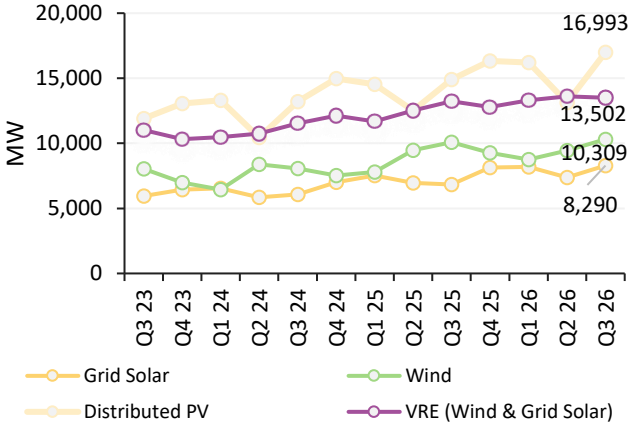
Grid-scale solar output reached 8,290 MW in the interval ending 1500 hrs on the Thursday 27 August 2026, 112 MW (+1.4%) above the previous peak set in Q1 2026.

Wind generation reached 10,309 MW in the interval ending 2130 hrs on Wednesday 1 July 2026, which was 229 MW (+2.3%) higher than the record set in Q3 2025.

Distributed PV output also set a new high, reaching 16,993 MW on Sunday 20 September 2026 at the interval ending in 1200 hrs, 674 MW (+4.1%) higher than the previous record set in Q4 2025.

**Figure 60 Record highs for grid-scale solar, wind and distributed PV**

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



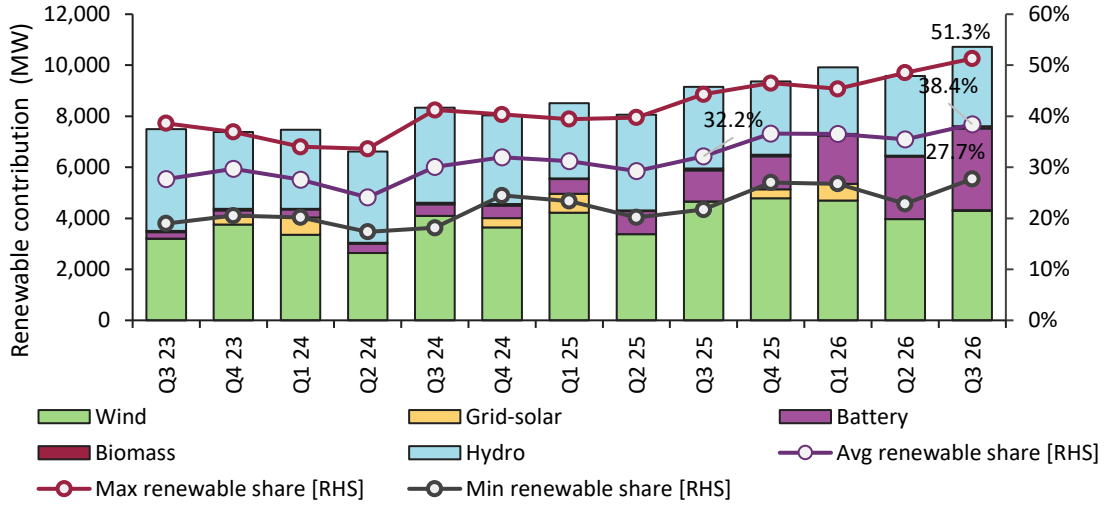

## Renewable and storage contribution to maximum demand

**Figure 61** shows the average share of large-scale renewable generation and storage in meeting daily maximum NEM operational demand, aggregated across all days in each quarter since Q3 2023[32].

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

**Figure 61 Renewable and storage contribution increased at time of daily maximum demand**

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




The average renewable and storage contribution at the time of daily maximum demand reached 38.4% in Q3 2026, increasing by 6.2 pp compared with Q3 2025. Wind remained the largest contributor, meeting an average of 15.3% of maximum daily demand, despite its share declining by 0.9 pp year on year. Meanwhile, the role of battery discharge during high demand periods continued to grow, with its share rising by 7.2 pp from Q3 2025 to meet an average 11.4% of maximum daily demand. Over the quarter, daily maximum demand contributions from renewables and storage ranged from 27.7% to 51.3%, reflecting variability in renewable resource availability, dispatch volumes, and demand.

## 2.5 New grid connections

### Data centre loads with connection applications submitted to AEMO

Rapid growth in data centre proposals is changing the connections landscape, presenting opportunities for greater coordination between customers, network service providers (NSPs) and AEMO. Prospective developments are significantly larger than recent load connections, are often geographically concentrated, and rely heavily on power-electronic interfaces. These developments require new approaches to modelling, operational visibility, assessment and registration arrangements, while ensuring that reliability and security outcomes are maintained.

Distribution-connected data centres are emerging as a significant area of focus, increasing the importance of appropriate visibility, consistent assessment and the application of appropriate technical requirements. As data centre activity continues to increase across distribution networks, AEMO has been working with distribution network service providers (DNSPs) on connection processes, technical assessment requirements, registration considerations and appropriate treatment of large inverter-based loads. While data centre activity is increasing across both transmission and distribution networks, the data below focuses on transmission-connected developments.

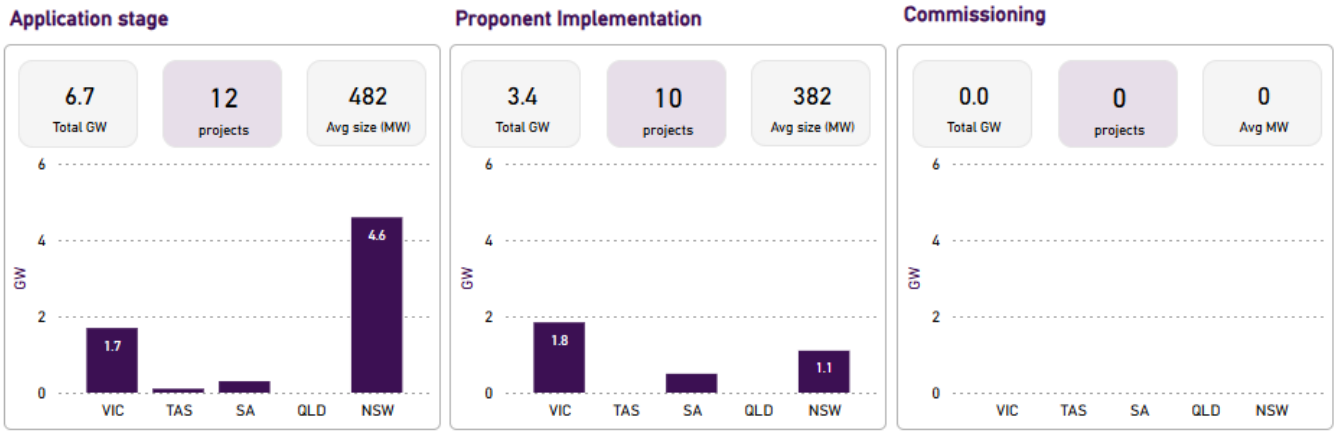
In Q3 2026, there are 22 data centres totalling 10.1 GW of maximum capacity load working through a transmission network connection (**Figure 62**). Of these:

- 56% of the capacity is in NSW, 35% in Victoria, 8% in South Australia and 1% in Tasmania,

- 12 projects (6.7 GW) are currently in the application stage, and
- 10 projects (3.4 GW) are in proponent implementation stage.

**Figure 62 Data centre load connection projects submitted to AEMO**

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




## Generation and storage connections

Connecting new generation and storage projects to the NEM involves coordinated work between project proponents, NSPs and AEMO. Before a formal connection application is submitted to AEMO, proponents work with the relevant NSP through the enquiry and optional pre-application phases to assess connection requirements. AEMO monitors progress across the key stages[33] of the connection process, including application, proponent implementation, registration, commissioning and model validation.

The capacity of generation and storage projects progressing through the connections pipeline continued to increase, reaching 80.9 GW in September, up 43% compared with the same time last year. The dominant technology is standalone battery (55%). Most of the pipeline capacity (88%) remains in the early stages of the pipeline, comprising projects in the application and proponent implementation stages.

This growth is being driven by the continued influx of new connection applications, with new capacity entering the pipeline faster than projects are progressing through commissioning. Despite the July-September quarter historically recording lower application volumes, interest this last quarter has been very strong, with AEMO receiving 25 connection applications totalling 7.5 GW. Standalone battery projects accounted for 5.8 GW, representing 76% of the capacity added to the pipeline during the quarter.

The proponent implementation stage has increased by 42% to 32.3 GW, reflecting the relatively low volume of projects progressing into registration stage. Between January and September 2026, the number of registration (R1 package) submissions remained below the levels recorded in the corresponding quarters of the previous two years, contributing to the accumulation of projects in the proponent implementation stage.

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

Projects that have remained in proponent implementation for more than 18 months are typically undergoing significant design changes (such as the addition of battery storage), experiencing uncertainty regarding financial viability, or progressing through project ownership transfers. To address these challenges, AEMO, the Clean Energy Council, and industry are progressing the Connections Reform Initiative (CRI) Phase 2 and other reform initiatives, which are focused on improving consistency, reducing cumulative effort and rework, streamlining registration processes, enhancing technical frameworks and improving the transparency and predictability of connection outcomes.

A significant proportion of projects in proponent implementation stage have yet to advance key commercial arrangements. The 25% of project capacity in proponent implementation received application approvals more than 12 months ago and have not yet executed network agreements, indicating extended timeframes of uncertainty after application approval. While this figure represents all technologies, solar and solar hybrid is disproportionately represented. A small number of projects were confirmed as no longer progressing, with five projects (1.1 GW) cancelled during the quarter from proponent implementation stage due to financial viability and land contracting challenges. These comprised four solar projects and one wind project.

Application approvals, predominantly battery and some solar, were strong across all regions, with 4.5 GW approved.

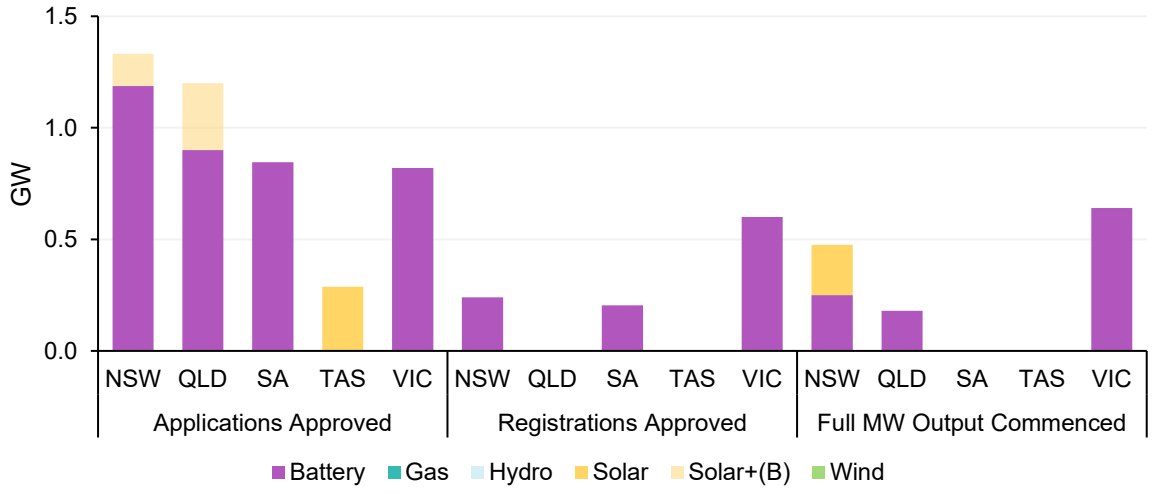
During Q3 2026:

- 4.5 GW of applications were approved across 23 projects (**Figure 63**).
- 1.0 GW of plant across 4 projects were registered and connected to the NEM.
- 1.3 GW of plant across seven projects progressed through commissioning to reach full output

Charts are based on current data, so some variances may exist compared to previously reported capacity in progress.

**Figure 63 Strong quarter for battery project milestones**

Application approved, registrations and plant commissioned to full output during Q3 2026




At the end of Q3 2026, AEMO's snapshot of connection activities in progress (**Figure 64**) shows that:

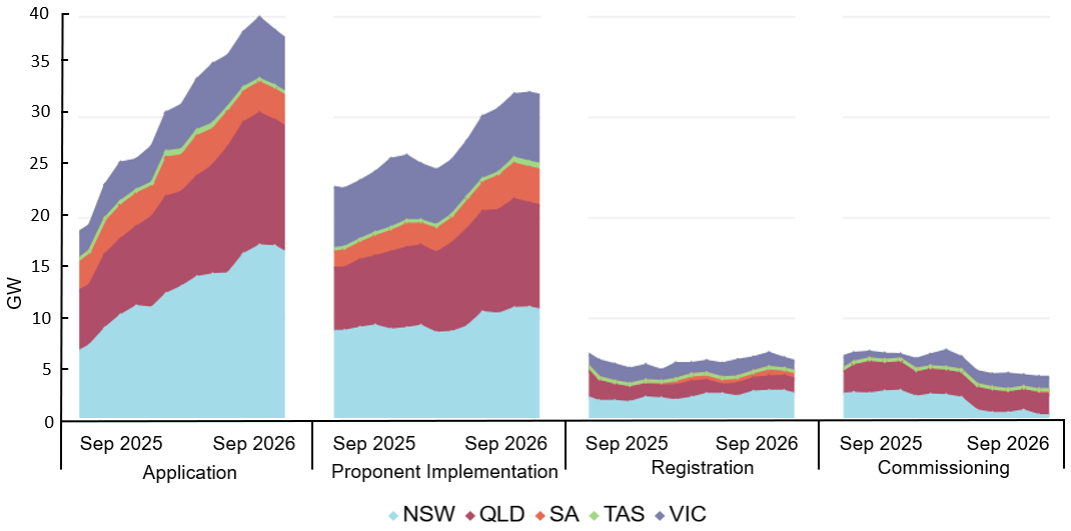
- 80.9 GW of new capacity is progressing through the end-to-end connection process from application to commissioning, made up of batteries (55%), solar hybrid (19%) and solar (5%), wind (15%), hydro (5%), and gas (1%).

- Battery remains the leading technology in the pipeline and is progressing through project stages faster than any other technology. Of the 44.7 GW of battery capacity in the pipeline, 38.5 GW is grid-forming, 6.0 GW is grid-following, and 0.2 GW is compressed air storage.
- Battery projects are increasingly providing longer-term storage – 38% of battery projects in the pipeline in September 2026 are 3-10 hour batteries.
- The GW capacity of applications in the pipeline has doubled since September 2025, from 19.2 GW to 38.5 GW, with the number of projects increasing by about 41%, indicating a shift towards larger projects on average.
- During the quarter, 25 applications were received, totalling 7.5 GW of capacity. More than half of this new application capacity is for New South Wales (3.9 GW); 76% are battery projects (19 projects, 5.8 GW).
- The capacity of projects in proponent implementation (32.3 GW) is 42% higher than in September 2025, due to application approvals outpacing R1 submissions.
- Capacity in commissioning is 37% lower than this time last year, primarily due to record capacity achieving full output in Q2.

Please refer to the Connections Scorecard[34] for further information.

**Figure 64 Increased capacity progressing through application stage driven by recent Queensland applications**

12-month trend of connection capacity in progress




## 2.6 Inter-regional transfers

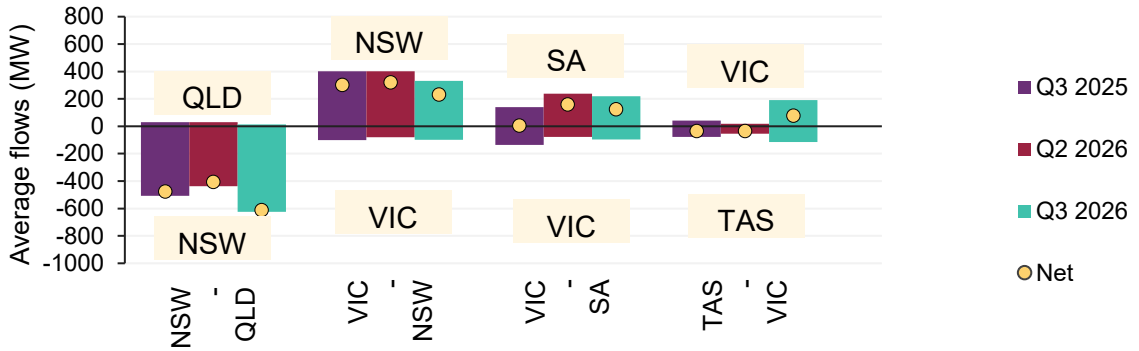
Total inter-regional transfers were 3,724 GWh in Q3 2026, up by 17% from 3,176 GWh in Q3 2025 and equivalent to 7.6% of operational demand for the quarter (**Figure 65**). The increase was primarily driven by higher transfers across Basslink (discussed further below), which rose from 112 MW in Q3 2025 to 305 MW this quarter, resulting in net transfers shifting by 120 MW towards Victoria. Other significant year-on-year changes were between Queensland and New South Wales,

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

where net flows increased from an average of 476 MW to 612 MW southward (+136 MW), and between Victoria and South Australia, where net transfers increased from 4MW to 123 MW into South Australia (+120 MW).

**Figure 65 Inter-regional transfers increased in Q3 2026**

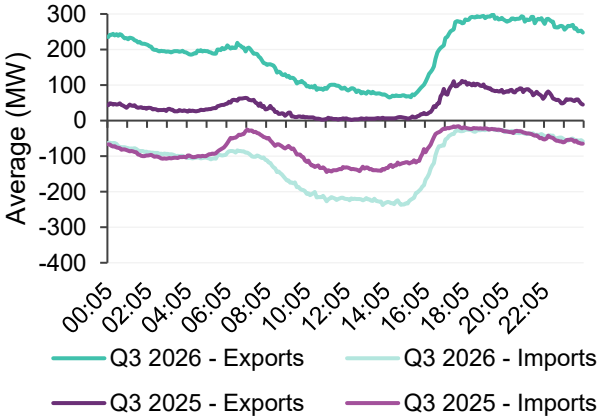
Quarterly inter-regional transfers




On 1 July 2026, Basslink transitioned from an MNSP to a regulated TNSP[35]. This followed the Australian Energy Regulator's (AER)'s Final determination on 27 February 2026[36] which removed the market-based transfer offering framework that contributed to reduced Basslink utilisation in Q3 2025.

**Figure 66 Increased Basslink flows into Victoria and Tasmania in Q3 2026**

Average Basslink imports and exports by time of day – Q3 2026 vs Q3 2025




In Q3 2026, average flows into Victoria increased by 149 MW year-on-year to 190 MW, with higher flows observed across all hours of the day (**Figure 66**). Conversely, when operating southward, Basslink flows into Tasmania increased during daytime hours (1000 hrs to 1600 hrs), rising by 91 MW to average 220 MW.

As discussed in the Q1 2025 *Quarterly Energy Dynamics* (QED), transfer capability provided by the first stage of Project EnergyConnect (PEC) was represented as an increment to the existing Heywood interconnector and is therefore reflected in increased Victoria-South Australia transfer flows. PEC was registered as the NSW1-SA1 interconnector in AEMO's market systems on 1 October 2026[37].

### 2.6.1 Inter-regional settlement residue (IRSR)

Positive IRSR totalled $67 million in Q3 2026, down 29% from $94 million in Q3 2025 (**Figure 67**). Positive IRSR into all regions decreased, with the largest year-on-year reduction into New South Wales, down from $67 million to $47 million.

[35] See https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/basslink-determination-participant-support-arrangements.

[36] See https://www.aer.gov.au/industry/registers/determinations/basslink-determination-2026-30/final-decision-revenue-determination.

[37] See https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2024/interconnector-capabilities.pdf?rev=c9c18469cd474b43993674586a6e45f2&sc_lang=en.

Negative IRSR totalled -$6.7 million this quarter, an increase of $2.5 million (+60%) compared to -$4.2 million in Q3 2025 (**Figure 68**). Negative IRSR increased into Victoria (up from -$1.2 million to -$3.7 million) and into South Australia (up from -$1.4 million to -$2.2 million), only partially offset by a decrease into New South Wales (down from -$1.6 million to -0.9 million).

**Figure 67 Positive IRSR decreased year-on-year**

Quarterly positive IRSR by region




**Figure 68 Increase in negative IRSR into Victoria and South Australia**

Quarterly negative IRSR by region




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

In Q3 2026, total FCAS costs fell to $5.1 million, representing 0.1% of cost of consumed energy[38] over this quarter. Compared to Q3 2025, total FCAS costs decreased by $68 million (-93%), with reduced costs across all regions (**Figure 69**). FCAS costs were elevated in Q3 2025 due to planned transmission outages in South Australia that increased local FCAS requirements and higher contingency FCAS costs in Tasmania associated with Basslink operational constraints. The reduction in FCAS costs was spread across all regulation and contingency services. Raise regulation (RREG) and lower regulation (LREG) comprised the largest proportion of total FCAS costs for the quarter at $1.9 million and $1.0 million respectively (**Figure 70**).

[38] 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 69 FCAS costs decreased across all regions**

Quarterly FCAS costs by region

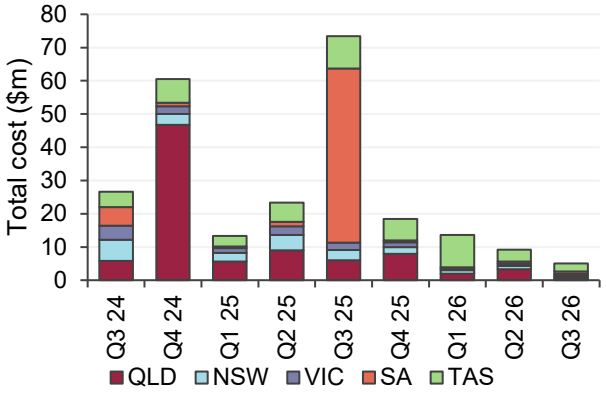
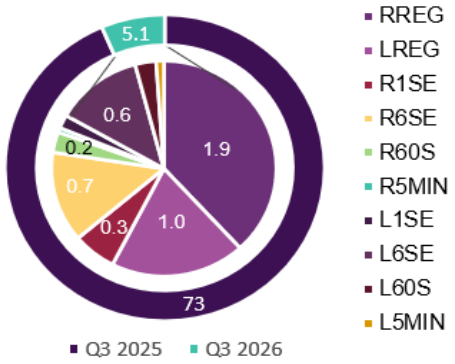



**Figure 70 RREG and LREG accounted for the highest shares of total FCAS costs**

NEM quarterly FCAS costs per service – Q3 2026 ($m)




Batteries grew their role as the dominant providers of FCAS, increasing from 56% in Q3 2025 to 75% this quarter (**Figure 71**). Average battery enablement rose by 559 MW compared to Q3 2025, with highest enablement growth at Bungama (+487 MW), Melbourne Renewable Energy Hub (+335 MW), Tarong (+263 MW), Latrobe Valley (+251 MW) and Smithfield (+161 MW). Enablement declined across most fuel types, with largest reductions recorded for demand response (DR) down 338 MW, followed by hydro, down 215 MW (**Figure 72**).

**Figure 71 Batteries FCAS market share rose to 75%**

FCAS volume market share by technology – Q3 2026

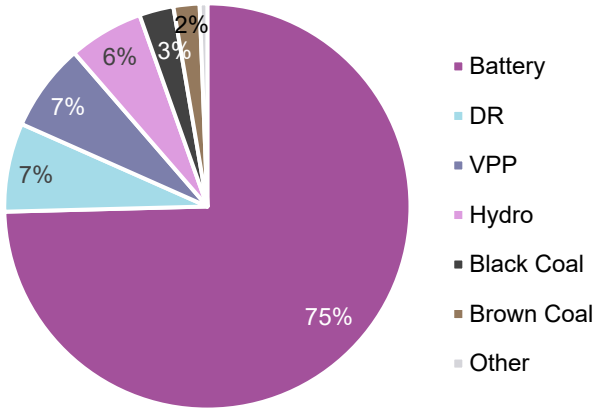
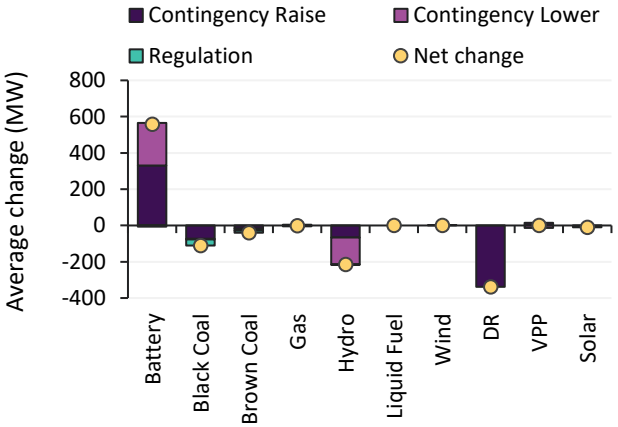



**Figure 72 Battery enablement increased across contingency FCAS services**

Change in FCAS enablement by technology – Q3 2026 vs Q3 2025




## Regulation FCAS and FPP

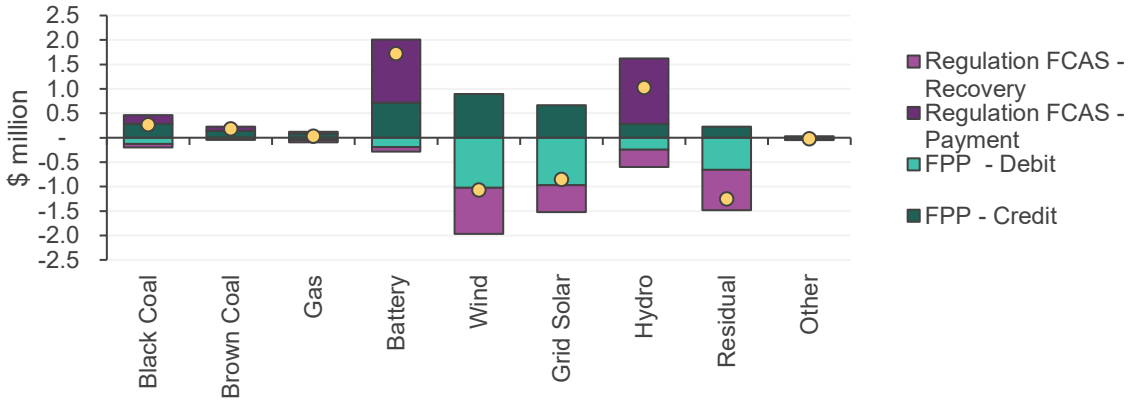
In Q3 2026, costs for regulation FCAS were $2.9 million, down $3.2 million from Q3 2025, and a total of $3.3 million in FPP incentive payments were distributed, down $4.3 million from Q3 2025 with lower FCAS prices and FPP volumes this quarter. **Figure 73** shows the FPP credits and debits, and regulation FCAS payments and costs recovery by fuel type in Q3 2026.

For batteries, hydro, black and brown coal-fired and gas-fired units, combined FPP credits and regulation FCAS payments offset the combined FPP debits and regulation FCAS recovery costs, with batteries receiving the large share of overall net settlements at $1.7 million. The residual category, which includes sites without appropriate metering to calculate individual

contribution factors, such as small consumers and distributed resources – recorded the largest share of net charges at -$1.3 million. Wind units incurred the next largest share of charges, with -$1.1 million in total net FPP and regulation FCAS settlements, followed by grid scale solar units at -$0.9 million.

**Figure 73 Batteries received highest share of FPP and FCAS net settlements**

Sum of FPP and regulation FCAS recovery and payments by fuel type – Q3 2026

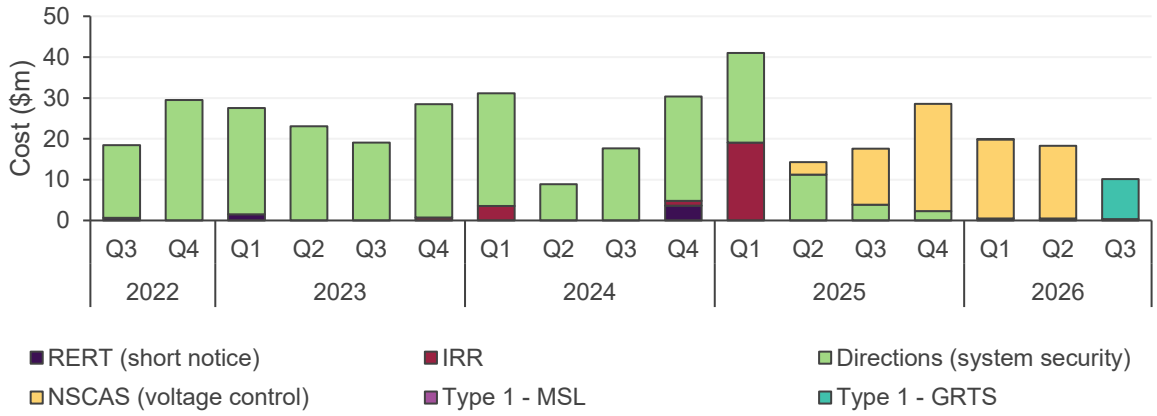



## 2.8 Power system management

In Q3 2026, power system management costs[39] were estimated at $10.1 million, representing 0.3% of the total cost of consumed energy for the quarter, and decreased by $7.3 million compared to Q3 2025 (**Figure 74**). The cost for system security energy directions decreased from $3.9 million in Q3 2025 to $0.3 million this quarter, with the commencement of grid reference transitional service (GRTS) contracts in South Australia (discussed in more detail below), which replaced network support and control ancillary services (NSCAS) arrangements for maintaining system security. The estimated costs for the enablement of these contracts across the quarter was $9.8 million.

**Figure 74 Estimated power system management costs decreased year-on-year**

Estimated quarterly system security costs by category




[39] 'Power system management costs' are costs associated with services procured by AEMO and include Reliability and Reserve Trader (RERT), estimated compensation for system security directions for energy services, costs associated with NCSAS for voltage control, and costs associated with Type 1 transition contracts. System restart ancillary services costs are not included. 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.

### 2.8.1 South Australian system security management

In November 2025, AEMO published a Statement of Need for South Australian Type 1 GRTS[40] to maintain power system security during minimum synchronous generator conditions following the expiry of existing NSCAS contracts. AEMO subsequently conducted an open competitive tender process between December 2025 and June 2026, with an Invitation to Tender issued in January 2026[41]. The first Type 1 GRTS contract became active from 1 July 2026 following the expiry of the previous NSCAS contracts, with a second GRTS contract activated on 29 September 2026.

In Q3 2026, gas-fired generation was dispatched under GRTS contracts, or directed where required, in 42% of dispatch intervals, compared with 46% in Q3 2025. This includes 13% of intervals with directions in place (**Figure 75**). Over the same period, the share of dispatch intervals requiring two or more units simultaneously under contract or direction declined from 31% to 12%, reflecting the South Australian operating condition changes introduced in Q3 2025[42]

The volume of gas-fired generation required for system security through contracts or directions totalled 24 MW in Q3 2026, compared with 32 MW in Q3 2025 (**Figure 76**). Dispatch for system security represented an 8% share of total gas-fired generation, up from 7% during the same period in 2025.

**Figure 75 Decrease in two-unit requirement for system security**

Percentage of time units simultaneously directed or contracted

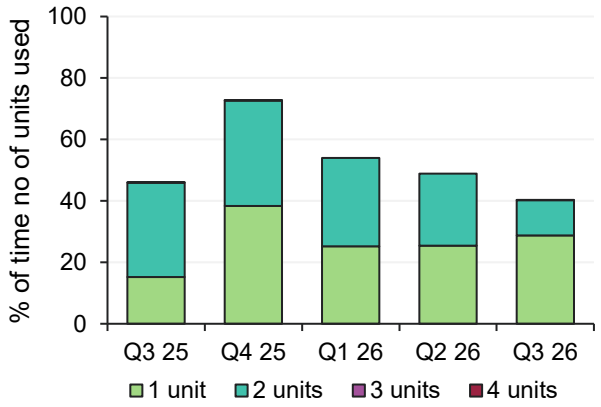
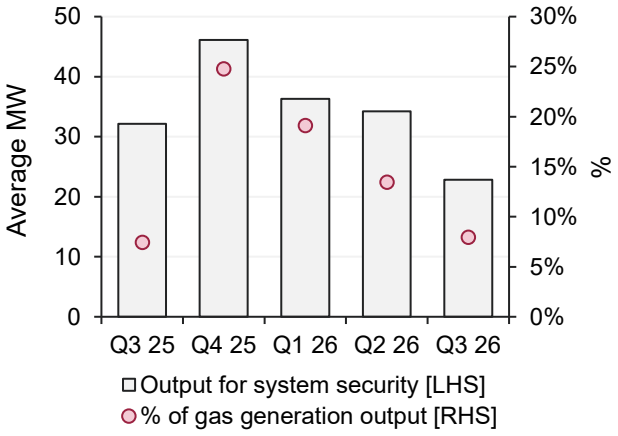



**Figure 76 Reduction in South Australian gas generation used for system security**

South Australian gas-fired generation directed or contracted– volume and share




[40] See Statement of Need – Grid Reference Transitional Services – Type 1, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/transition-planning/sa-transitional-services-for-grid-reference-son.pdf?rev=ced5c202e755488998b8a6b07df63adc&sc_lang=en.

[41] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/transition-planning/transitional-services---type-1-services/south-australian-grid-reference-transitional-service.

[42] 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.

# 3 East coast gas market dynamics

## 3.1 Wholesale gas prices

Quarterly wholesale gas prices increased from Q2 2026 but were 15% lower than Q3 2025. The average price across all AEMO markets was $10.77/GJ compared to $12.62/GJ in Q3 2025 (**Table 5**). This was the lowest average Q3 price since Q3 2023.

**Table 5 Average east coast gas prices – quarterly comparison**

| Price ($/GJ) | Q3 2026 | Q2 2026 | Q3 2025 | Change from Q3 2025 |
|---|---|---|---|---|
| Victoria Declared Wholesale Gas Market (DWGM) | 9.86 | 8.39 | 12.11 | -19% |
| Adelaide | 10.89 | 9.27 | 12.76 | -15% |
| Brisbane | 11.23 | 9.32 | 12.79 | -12% |
| Sydney | 10.92 | 9.21 | 12.75 | -14% |
| Gas Supply Hub (GSH) | 10.96 | 9.18 | 12.71 | -14% |

Key factors influencing the movement of prices throughout Q3 2026 are summarised in **Table 6**, with further analysis and discussion in relevant sections elsewhere in this report.

**Table 6 Wholesale gas price levels: Q3 2026 drivers**

| | |
|---|---|
| Lower offer prices into the DWGM and Short Term Trading Markets (STTM) across Q3 | Q2 2026 saw average prices in May 15% lower and June 40% lower than Q2 2025, due to an increase in the proportion of volumes offered into the domestic market at prices below $12/GJ, which led to a reduction in the average price for the whole quarter (**Figure 78** below). June 2026 offers, in particular, were influenced by lower demand in AEMO markets and for gas-fired generation compared to June 2025. |
| Lowest Q3 gas-fired generation demand since 2003 | As in Q4 2025, Q1 2026 and Q2 2026, demand from gas-fired generation dropped to near record low levels due to increased wind output and battery discharge in the NEM. This continues to put downward pressure on spot prices across all AEMO markets. |
| Continued mild weather across Q3 leading to decreased heating load requirements, particularly in Victoria | The above average temperatures experienced in Victoria in June continued throughout Q3, contributing to record low Q3 system demand in Victoria since 1983, on top of the impact of electrification on gas demand. |

International LNG spot prices increased further from Q2 2026 and were at their highest level since February 2023, reflected in an increase in the Australian Competition and Consumer Commission (ACCC) netback price to an average of $22.87/GJ, increasing to $25.70/GJ in September and $30.20/GJ in October, materially higher than the average AEMO market price of $10.77/GJ.

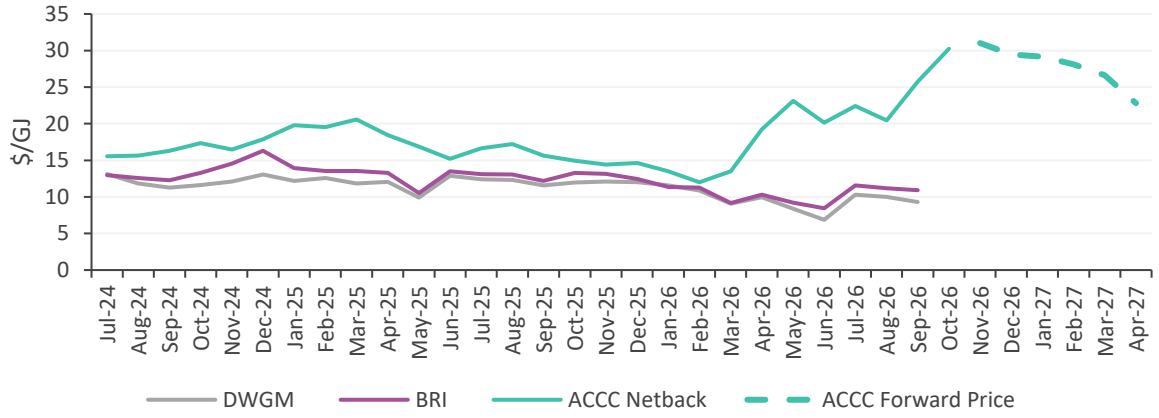
International prices began increasing in March amid heightened global supply risks linked to the conflict in the Middle East and have not returned to previous levels. This rapid increase in global energy prices is reflected in the increase in the ACCC netback price, with corresponding forward prices ranging from $26.60/GJ to $31.02/GJ over the next six months (**Figure 77**). Drivers for international prices are discussed in Section 3.1.1 .

As in Q2 2026, AEMO market domestic prices did not follow international markets higher and recorded their lowest Q3 averages since 2023. This reflects continued sufficient supply to the domestic market, with low demand particularly from

gas-fired generation, as well as residential and commercial and industrial users, caused by the continuing impact of electrification as well as above average temperatures that resulted in decreased gas heating requirements, particularly in Victoria. This led to market participants increasing bid volumes below $12/GJ across all months (**Figure 78**).

**Figure 77 Domestic prices continue to diverge from international prices**

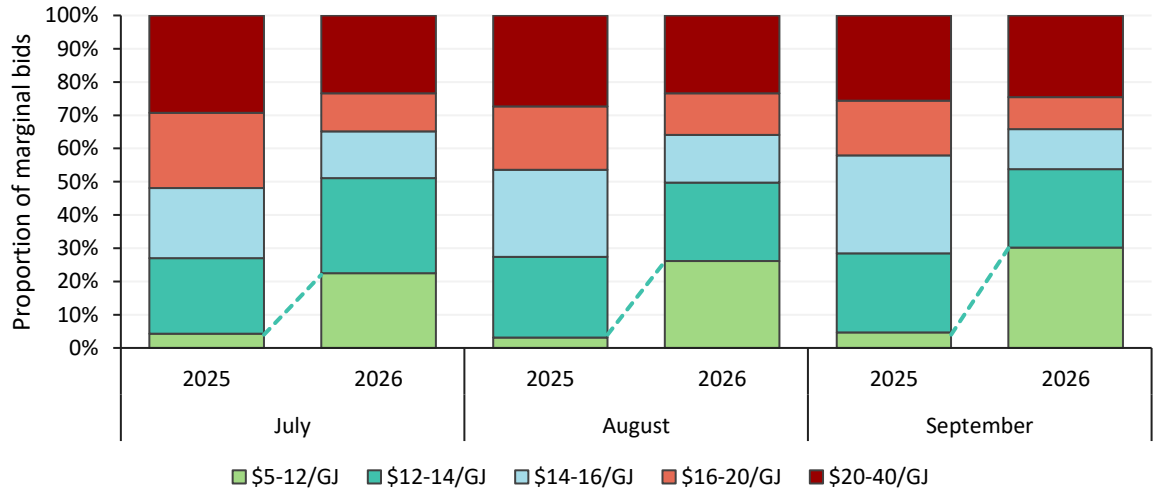
ACCC netback and forward prices, DWGM and STTM Brisbane average gas prices by month




Note: ACCC, LNG netback price series published on 1 October 2026: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

**Figure 78 Increased proportion of DWGM bids across all months at lower prices compared to 2026**

DWGM – proportion of marginal bids by price band – Q3 2026 vs Q3 2025 by month




### 3.1.1 International energy prices

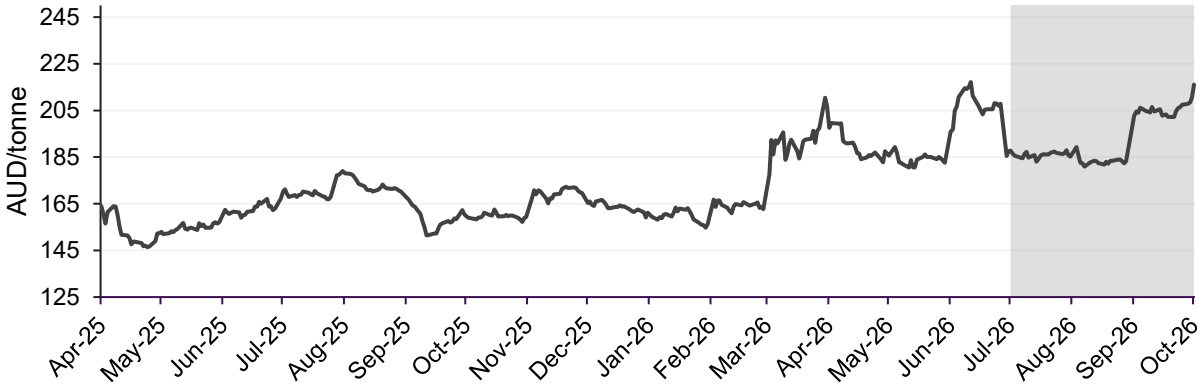
Newcastle export coal prices averaged $192/tonne in Q3 2026, up from $167/tonne in Q3 2025 (**Figure 79**).

Prices remained elevated as LNG supply disruptions associated with restrictions on shipping through the Strait of Hormuz supported gas-to-coal switching in major Asian import markets. Heatwaves across parts of the Northern Hemisphere also

increased electricity demand, contributing to higher coal consumption in major import markets including Japan, South Korea and Taiwan. Prices rose above $200/tonne late in the quarter as LNG supply disruptions persisted[43].

**Figure 79 Traded thermal coal prices remained elevated across the quarter, lifting further in September**

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




Source: Bloomberg ICE data.

Asian spot LNG prices continued its upward trend from last quarter, as the average price for Q3 2026 rose to A$29.70/GJ, up A$6.20/GJ, ending the quarter at A$34.90/GJ. The major factor behind the upward movement in prices is the ongoing geopolitical tensions, particularly in the Middle East leading to concerns regarding energy security and inability to transit through the Strait of Hormuz constraining tanker movements in the region. In Europe, below-average gas storage levels also contributed to upward price pressure, increasing competition for LNG cargoes ahead of the northern hemisphere winter.

Despite relatively reduced LNG import demand across key Northeast Asian markets where the Institute of Energy Economics, Japan (IEEJ) noted that demand was down 14% year-on-year in August[44], market participants continued to place a premium on supply security. Governments and buyers across Asia and Europe progressed a range of initiatives aimed at strengthening supply resilience, including additional LNG infrastructure, procurement arrangements and storage initiatives. This created competition between South Asian and European LNG importers which continued to push up Asian LNG prices (**Figure 80**) throughout the quarter.

Brent crude oil prices averaged A$129/barrel across Q3 2026 (**Figure 81**). Crude oil prices began the quarter slightly lower as a ceasefire was agreed between the nations and renewed peace negotiations in the Middle East were looking promising, however prices increased throughout the quarter as the conflict continued and no firm deal could be agreed, which continued to impact oil supply and shipping routes in the region[45].

By the end of the quarter there were no significant peace negotiations agreed to between the nations, and ongoing attacks affecting energy infrastructure and shipping had further delayed expectations of supply normalisation. Increased shipping

[43] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly September 2026, AT https://www.industry.gov.au/publications/resources-and-energy-quarterly-september-2026.

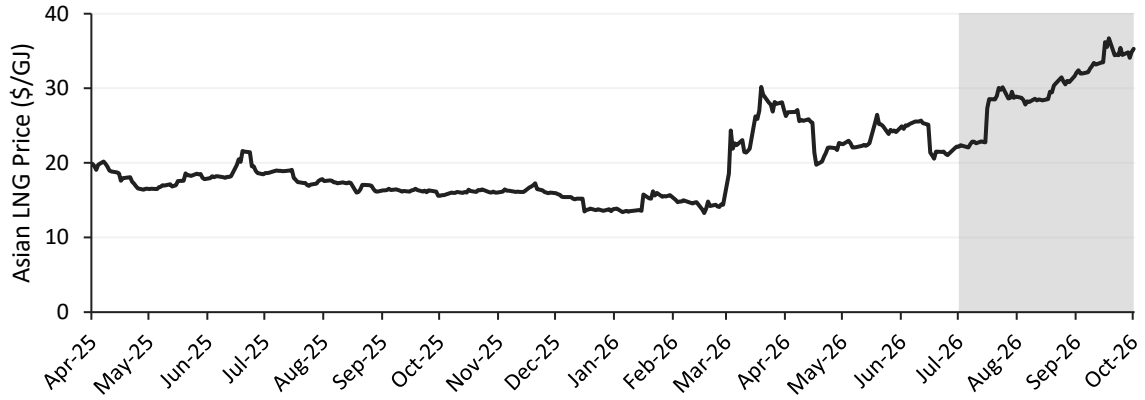
[44] Institute of Energy Economics, Japan, LNG Review September 2026, AT https://eneken.ieej.or.jp/data/13562.pdf.

[45] International Energy Agency (IEA), Oil Market Report, July 2026: https://www.iea.org/reports/oil-market-report-july-2026

costs and depleting inventories (including from each nation's strategic petroleum reserves) contributed to a further tightening of market conditions, leading to higher crude oil prices[46].

**Figure 80 Asian LNG spot prices continued to rise over the quarter as Asian and European LNG importers compete for cargoes**

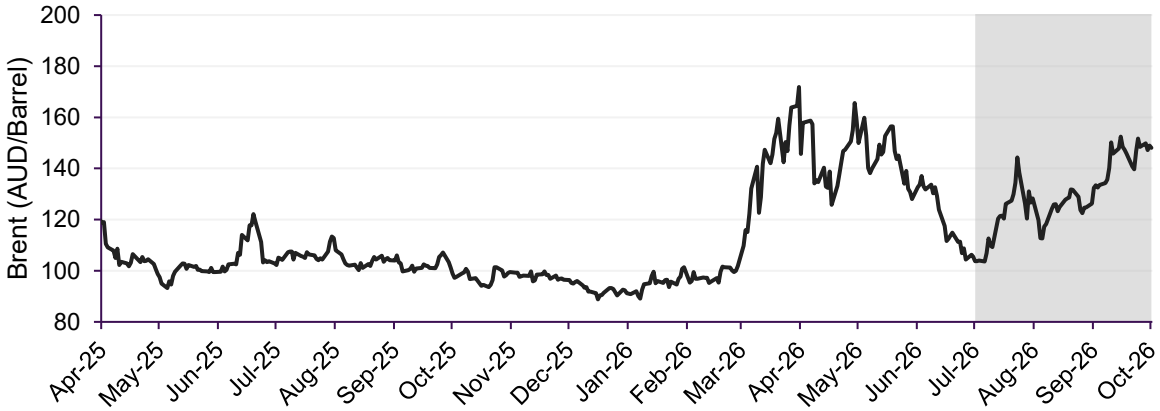
Asian LNG price in A$/GJ daily




Source: Bloomberg ICE data.

**Figure 81 Brent Crude prices averaged A$129/barrel ending the quarter at A$149/barrel**

Brent Crude Oil in A$/Barrel daily




Source: Bloomberg ICE data.

## 3.2 Gas demand

While total east coast gas demand only slightly decreased by a marginal 0.1% (**Figure 82** and **Table 7**), there were large decreases in gas-fired generation (-9 PJ) and AEMO markets demand (-8 PJ), offset by a large increase in Queensland LNG demand (+16 PJ). Most of the demand decrease in AEMO markets occurred in Victoria's Declared Wholesale Gas Market (DWGM, -7 PJ) due to a combination of structural declines in industrial, commercial and residential demand, and warmer

[46] International Energy Agency (IEA), Oil Market Report, September 2026: https://www.iea.org/reports/oil-market-report-september-2026

temperatures. This decline extends the trend in Victorian demand discussed in QED reports throughout 2025 and 2026 and is discussed further in Section 3.2.2. Queensland LNG production saw a large increase of 16 PJ.

**Figure 82 Large reduction in market demand offset by large increase in Queensland LNG demand**

Components of east coast gas demand change – Q3 2026 to Q3 2025

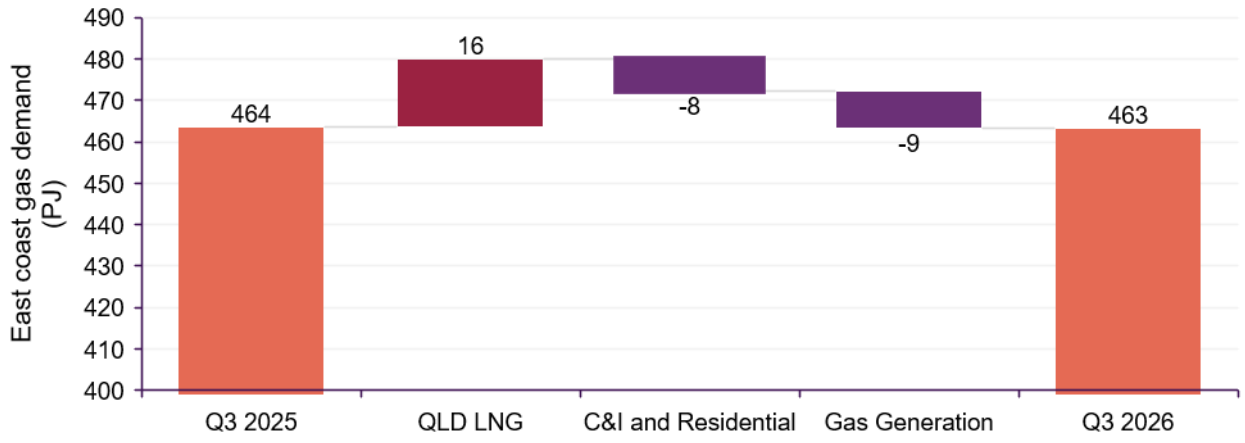



**Table 7 Gas demand – quarterly comparison**

| Demand (PJ) | Q3 2026 | Q2 2026 | Q3 2025 | Change from Q3 2025 |
|---|---|---|---|---|
| AEMO markets * | 84.1 | 69.5 | 92.0 | -8 (-9%) |
| Gas-fired generation ** | 17.2 | 20.4 | 26.1 | -9 (-34%) |
| Queensland LNG | 361.9 | 342.3 | 345.5 | 16 (+5%) |
| Total | 463.1 | 432.2 | 463.6 | -0.5 (-0.1%) |

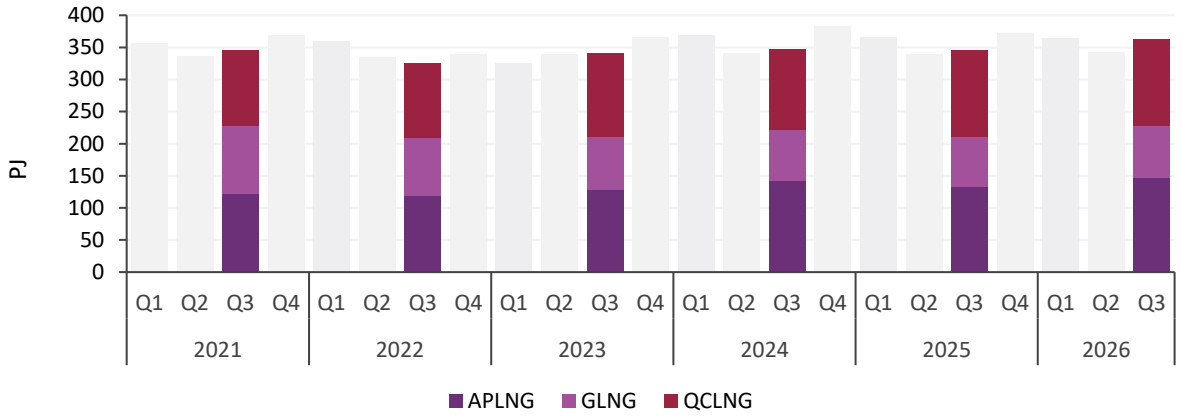
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand not only increased compared to Q3 2025 but set a new Q3 record. Much of the increase occurred at Australia Pacific LNG (APLNG), while Gladstone LNG (GLNG) saw a small increase, and Queensland Curtis LNG (QCLNG) demand was only marginally lower. The combined total demand of 361.9 PJ is a record for LNG export demand for Q3, surpassing the previous record of 346.1 PJ set in Q3 2024 **(Figure 83**). While higher export volumes typically occur during Q1 and Q4, the Q3 2026 volume was only marginally lower than the 364.6 PJ observed in Q1 2026.

By participant, in comparison to Q3 2025, APLNG demand increased by 15.6 PJ, while GLNG increased by 0.9 PJ and QCLNG decreased by 0.1 PJ. LNG spot cargo contracting increased during the first half of 2026 compared with the same period in 2025. Total spot volumes rose from 40.6 PJ to 47.8 PJ in the first half of 2026. At the same time, spot LNG prices were materially higher, as discussed in Section 3.1.1.

**Figure 83 Queensland LNG export demand increases to new Q3 high mostly due to APLNG**

Total quarterly pipeline flows to Curtis Island




## 3.2.1 Gas-fired generation

Gas-fired generation decreased by 34% compared to Q3 2025. The largest declines were in Queensland (-4.7 PJ) and New South Wales (-3.3 PJ). Similarly to Q1 and Q2 2026, lower demand for gas-fired generation reflected higher wind output and battery discharge in the NEM, and July was the highest month for gas-fired generation (**Figure 84**). The significant decreases across all months led to the lowest Q3 gas demand for gas-fired generation since Q3 2003 (**Figure 85**), noting that it was the lowest MWh demand since 2000.

**Figure 84 Large decrease in gas-fired generation demand across all mainland regions**

Average daily gas-fired generation by state

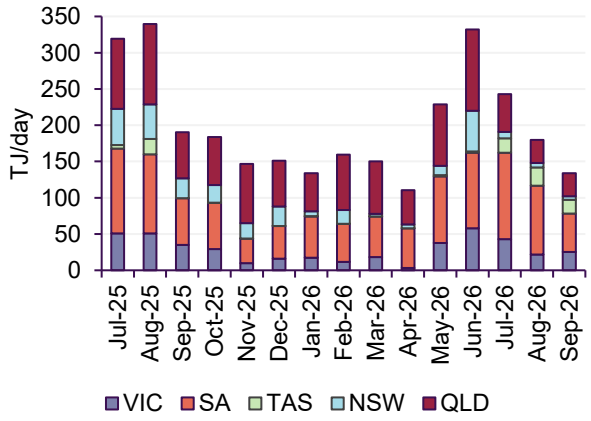
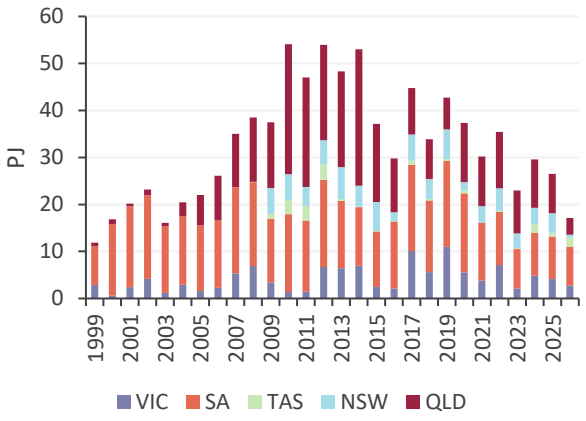



**Figure 85 Lowest Q3 demand for gas-fired generation since 2003**

Q3 gas-fired generation by state



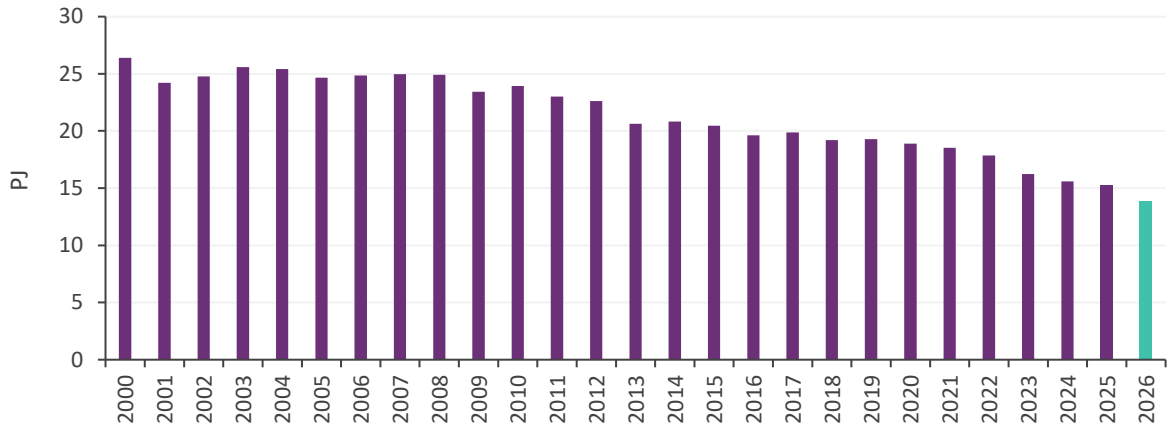

## 3.2.2 Victorian Declared Wholesale Gas Market (DWGM) demand

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

Q3 2026 saw ongoing Tariff D demand decreases, with demand dropping from 15.3 PJ in Q3 2025 to 13.9 PJ in Q3 2026, a 9% decrease (**Figure 86**).

**Figure 86 DWGM Tariff D demand continues to decline**

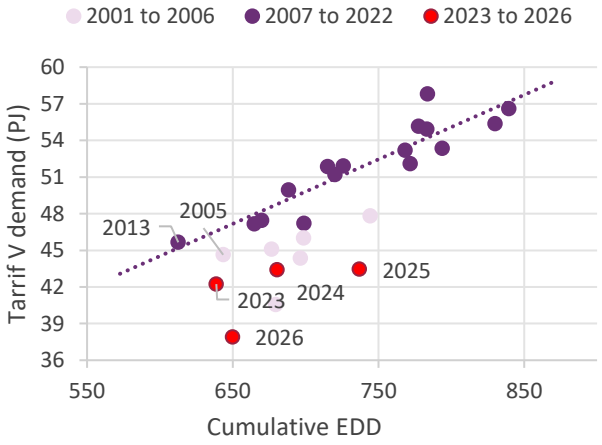
Q3 DWGM Tariff D Demand




Tariff V demand fell to the lowest level since at least 2000. As much of Tariff V demand is typically used for heating, it can vary from year to year depending on weather conditions. To capture the impact of weather on demand, AEMO uses a measure known as the Effective Degree Day (EDD), which considers the temperature profile, average wind speed, sunshine hours, and the season for the gas day. The higher the EDD, the higher the likely gas use.

**Figure 87 Tariff V demand has significantly decreased since 2023 and is not solely weather-driven**

Q3 Tariff V demand versus cumulative EDD 2001-2026




As also observed in Q2 2026, Tariff V demand was materially lower than in previous comparable warm Q3 periods, indicating that the decline in gas demand continues to not be solely weather-driven (**Figure 87**). While Q3 2026 recorded the lowest cumulative EDD total since 2023, Tariff V demand was 4.3 PJ lower than in Q3 2023, despite that quarter being warmer. As noted in the 2026 *Victorian Gas Planning Report Update*[47], AEMO considers this to be due to a combination of electrification of some gas use and cost of living pressures, as well as reduced small commercial customer demand. Government policies are also likely to be having an impact on reducing Tariff V gas consumption, with reductions in 2024 and 2025 correlating with increased registrations of Victorian Energy Efficiency Certificates (VEECs) for space heating, water heating and weather sealing applications.

[47] See https://www.aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report.

## 3.3 Gas supply

### 3.3.1 Gas production

East coast gas production decreased by 9.1 PJ (-1.8%) compared to Q3 2025 (**Figure 88**). Key changes included:

- Queensland production decreased by 8.1 PJ, with assets operated by APLNG decreasing by 8 PJ, while GLNG decreased by 2.5 PJ, and QCLNG operated assets increased by 2.4 PJ. Gas demand for Queensland LNG exports increased by 16.3 PJ, resulting in an overall 24.4 PJ decrease in supply associated with Queensland LNG projects entering the domestic market compared to Q3 2025, making it the lowest Q3 level since Q3 2016 (**Figure 89**).
- Victoria production decreased by 1.2 PJ, mainly driven by a decrease at Otway (-3.4 PJ), while Longford increased by 2 PJ.

**Figure 88 Production fell mainly due to lower Queensland output**

Change in east coast supply – Q3 2026 vs Q3 2025

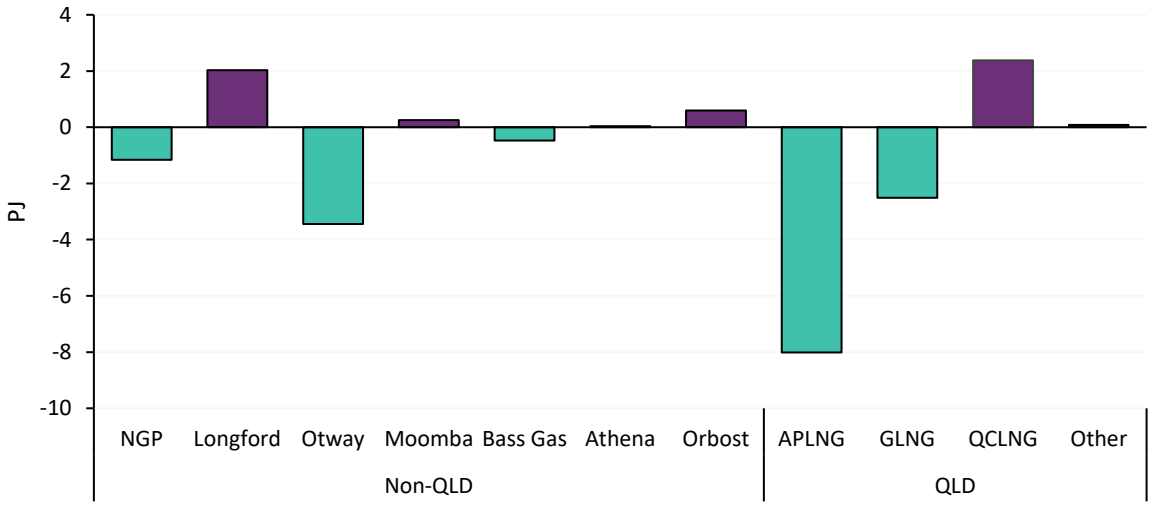
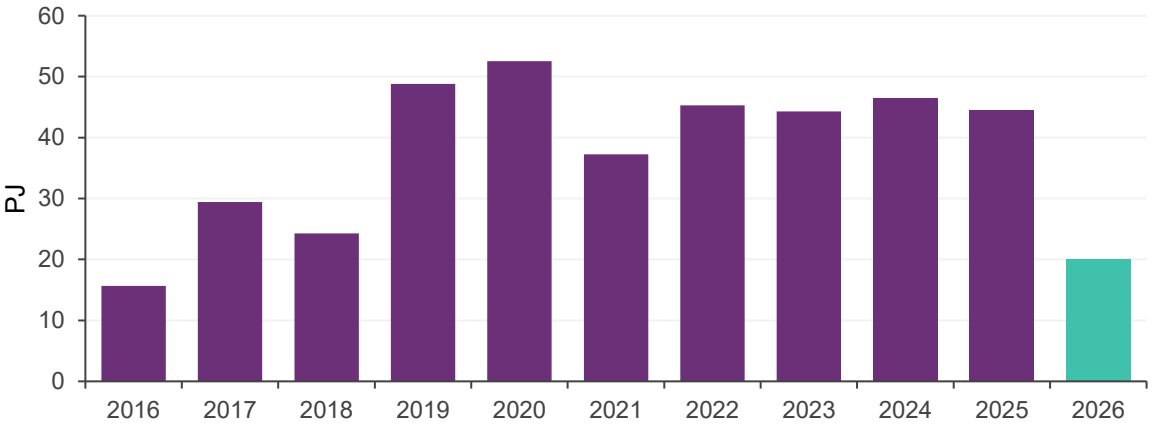



**Figure 89 Queensland Q3 2026 net domestic supply decreased to lowest level since 2016**

Queensland net domestic supply during Q3



### 3.3.2 Northern Territory supply

Northern Territory demand was supported by flows from Queensland of up to 43terajoules per day (TJ/d) from 19 July to 19 August, with only limited emergency gas supply from the Ichthys LNG facility of less than 5 TJ/d. The Yelcherr Gas Plant remained offline, following the outage at the offshore Blacktip gas field platform caused by Tropical Cyclone Fina in November 2025.

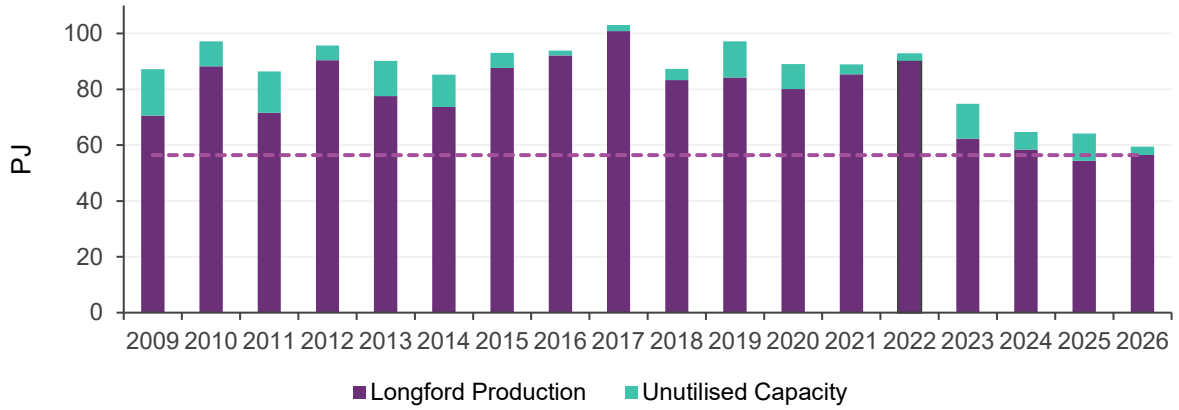
First gas was produced from Tamboran's Shenandoah South Pilot Project in the Beetaloo Sub-basin on 3 September. After ramping up during the month, production peaked at its capacity of 40 TJ/d on 29 and 30 September. It is expected to continue to produce at up to 40 TJ/d and be transported via the Sturt Plateau Pipeline into the Amadeus Gas Pipeline[48].

### 3.3.3 Longford production and capacity

Longford's gas production during Q3 2026 was slightly higher than for the same period in 2025, reaching 56.4 PJ compared to 54.4 PJ. Available production capacity of 59.4 PJ was lower than Q3 2025, which was 64.2 PJ (**Figure 90**).

**Figure 90 Longford Q3 production slightly higher**

Longford Q3 production and unutilised capacity



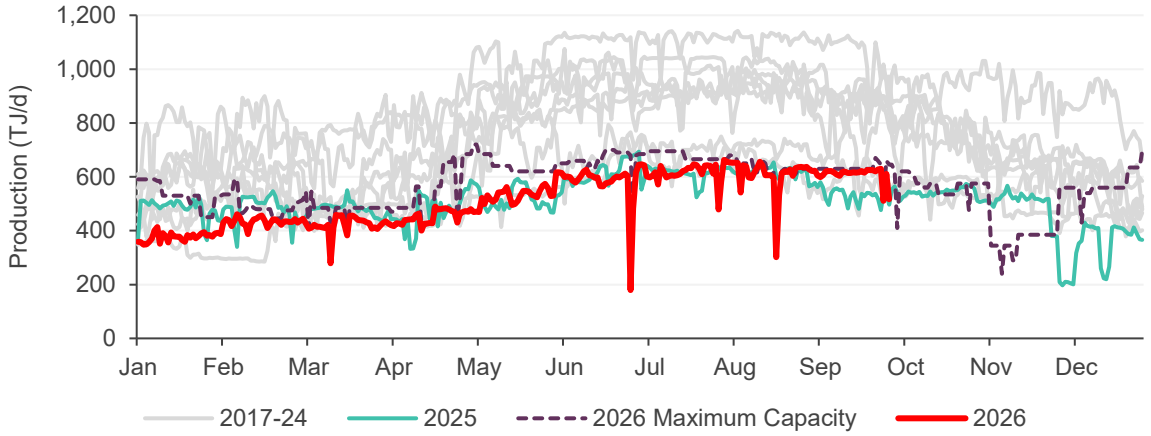

Daily production through much of Q3 was close to capacity for much of the quarter, with Longford operating at a capacity factor of 95%, its highest level since 2022.

On 20 August, planned offshore maintenance associated with the demobilisation of the drilling rig for the Turrum Phase 3 development project led to Longford production reducing to 302 terajoules (TJ). While there was a low risk of a full plant shutdown associated with the activity, this did not occur and was completed safely and on time (**Figure 91**). There was negligible impact to market prices.

[48] See https://www.abc.net.au/news/2026-09-01/fracked-gas-beetaloo-basin-flow-nt-power-grid/107097300.

**Figure 91 Longford planned outage on 20 August dropped production to 300 TJ**

Daily Longford production 2017-2026, maximum capacity profile 2026



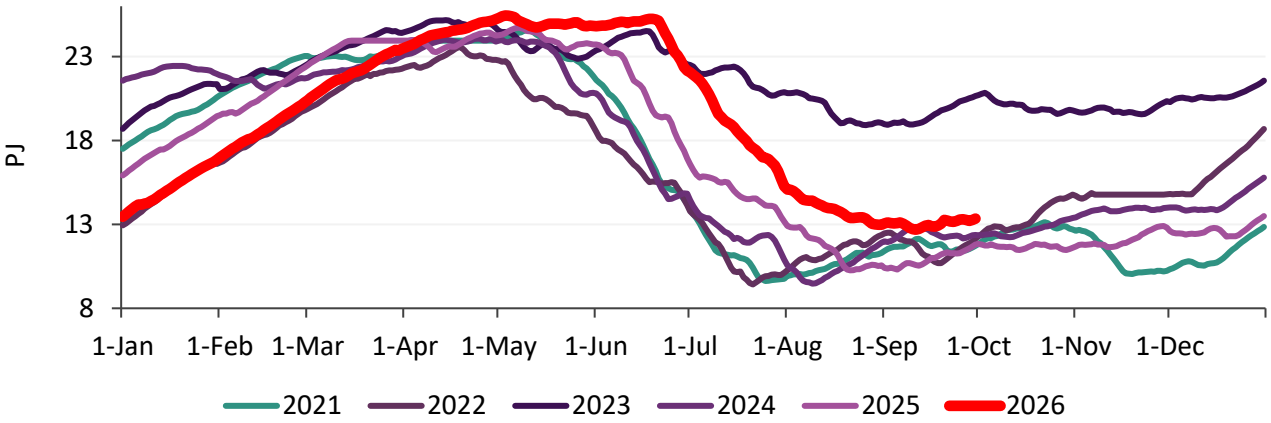

### 3.3.4 Gas storage

The Iona UGS facility finished the quarter with a gas inventory of 13.1 PJ, 1.3 PJ higher than at the end of Q3 2025 (**Figure 92**).

Iona UGS began July still close to full storage capacity at 22.1 PJ, reflecting mild weather, low gas-fired generation demand, and seasonal supply from Queensland to the southern region. During July and August, Iona became a greater source of supply for the southern regions, particularly with a large increase in supply to New South Wales via the Victoria Northern Interconnect (VNI). This resulted in Iona inventory decreasing and supply reducing from Queensland to southern region.

**Figure 92 Iona storage was utilised throughout July and August despite continued low market demand**

Iona storage levels

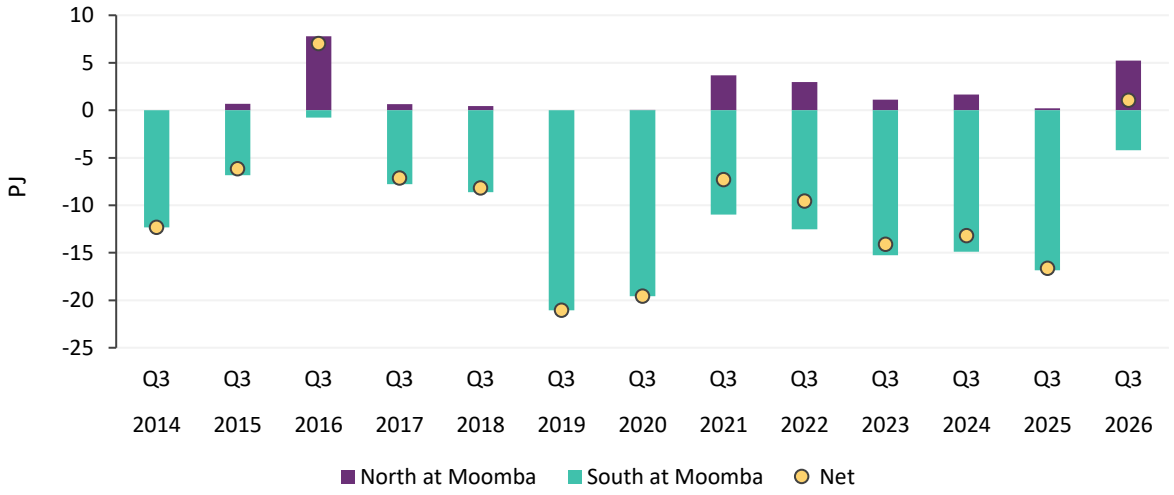



## 3.4 Pipeline flows

Q3 2026 saw a net transfer north from Moomba into the South West Queensland Pipeline (SWQP), the first time this has occurred in a Q3 since 2016 (**Figure 93)** and only the second time this has occurred since the pipeline became bi-directional in 2014. This represents a 17.7 PJ turnaround from Q3 2025. This net transfer north coincides with record Q3 Queensland LNG export demand, as well as lower demand in AEMO's markets and for gas-fired generation.

**Figure 93 Q3 net transfers north at Moomba for the first time since 2016**

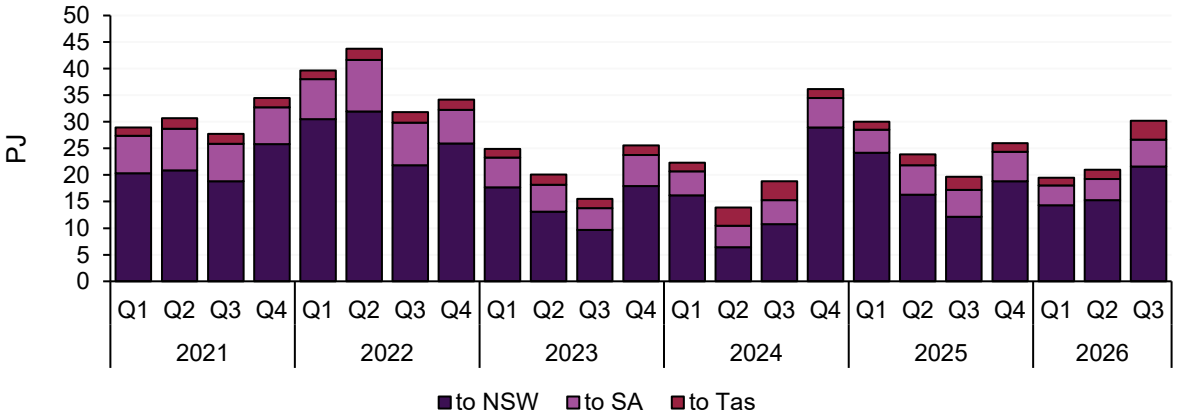
Flows on the South West Queensland Pipeline at Moomba




The net transfer north at Moomba was driven by higher Victorian net gas transfers to neighbouring states, which increased by 10.8 PJ due to lower demand. This represented the highest Victorian Q3 exports since 2022. State by state, Victoria exported 9.5 PJ more to New South Wales and 1.2 PJ more to Tasmania, while flows to South Australia were marginally lower (0.1 PJ less) (**Figure 94)**.

**Figure 94 Highest Victorian Q3 exports since 2022 mainly driven by a large increase to New South Wales**

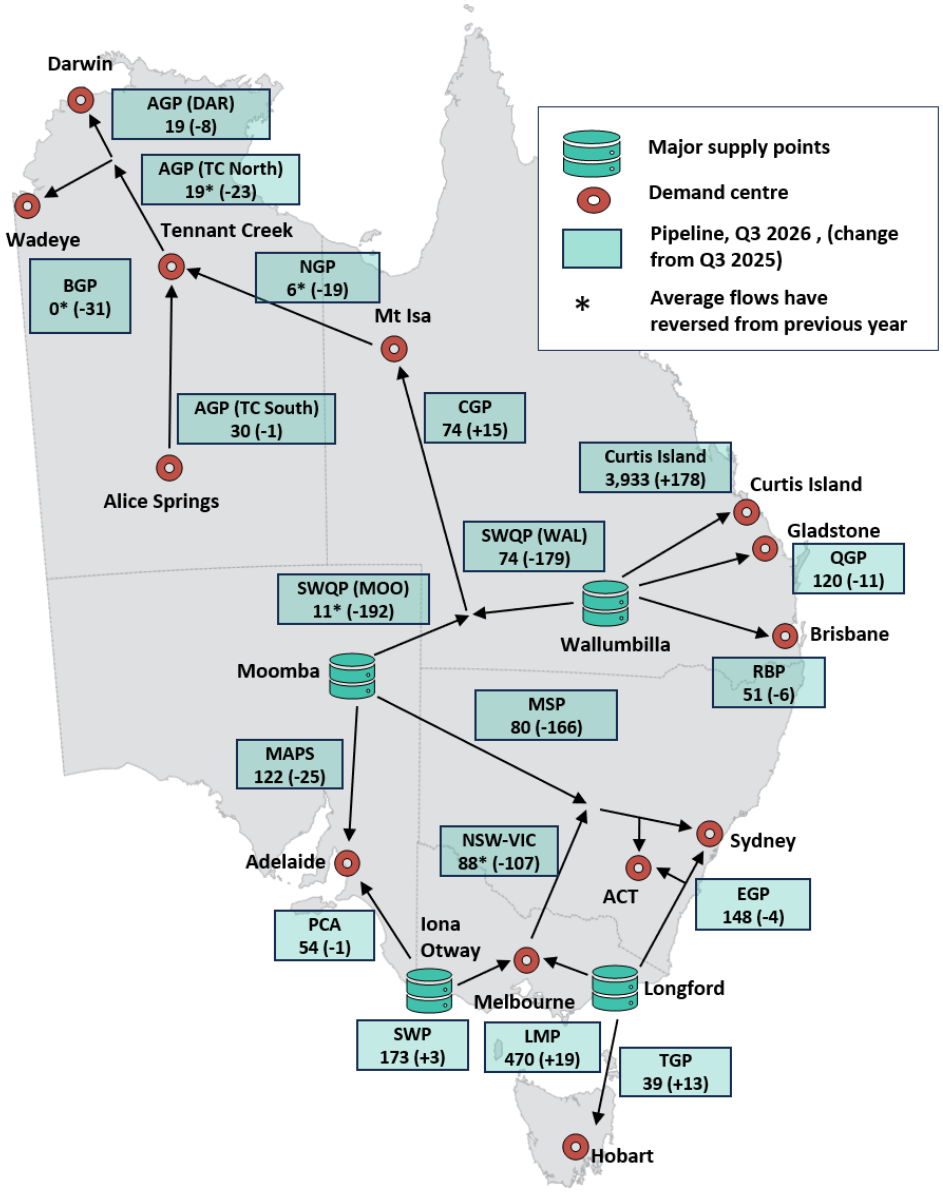
Victorian net gas transfers to other regions during Q3




Increased flows to Curtis Island resulted in a reduction in flows from Wallumbilla towards Moomba. Together with elevated demand at Mount Isa and the Northern Gas Pipeline (NGP) reversing direction (supplying up to 43 TJ/d for one month into the Northern Territory), SWQP had an overall net-flow north from Moomba into Queensland during Q3. This marks the first Q3 with a net-flow north from Moomba into Queensland since 2016. At the same time, the substantial increase in supply from Victoria to New South Wales was facilitated solely by higher volumes on the VNI, representing its first Q3 average net-flow north since 2022 (**Figure 95**).

**Figure 95 Significantly reduced flows from Wallumbilla south as Curtis Island flows increase**

Average daily pipeline flows TJ/day Q3 2026 vs Q3 2025

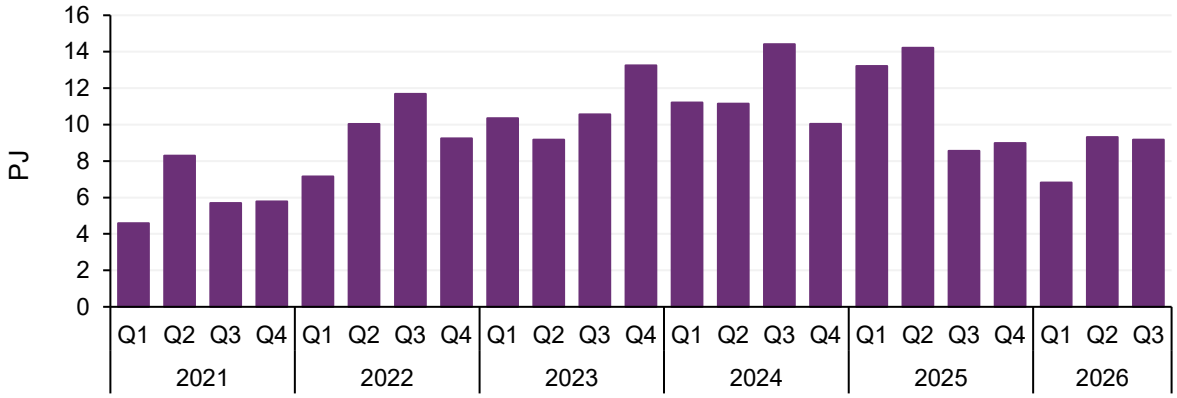



## 3.5 Gas Supply Hub (GSH)

In Q3 2026, traded volumes on the GSH increased by just 0.6 PJ compared to Q3 2025 (**Figure 96**). The traded volume this quarter was 9.2 PJ. Increased trading activity was observed during a few days in September, which coincided with lower reported LNG producer flows to the liquefaction facilities at Curtis Island. During the quarter, forward trading extended into CY 2027, with four trades executed at a volume-weighted average price of $10.38/GJ. These trades were primarily for January 2027 delivery, including one transaction covering the entire Q1 2027.

**Figure 96 GSH traded volume consistent with Q3 2025 and Q2 2026**

Gas Supply Hub – quarterly traded volume




## 3.6 Pipeline capacity trading and Day Ahead Auction

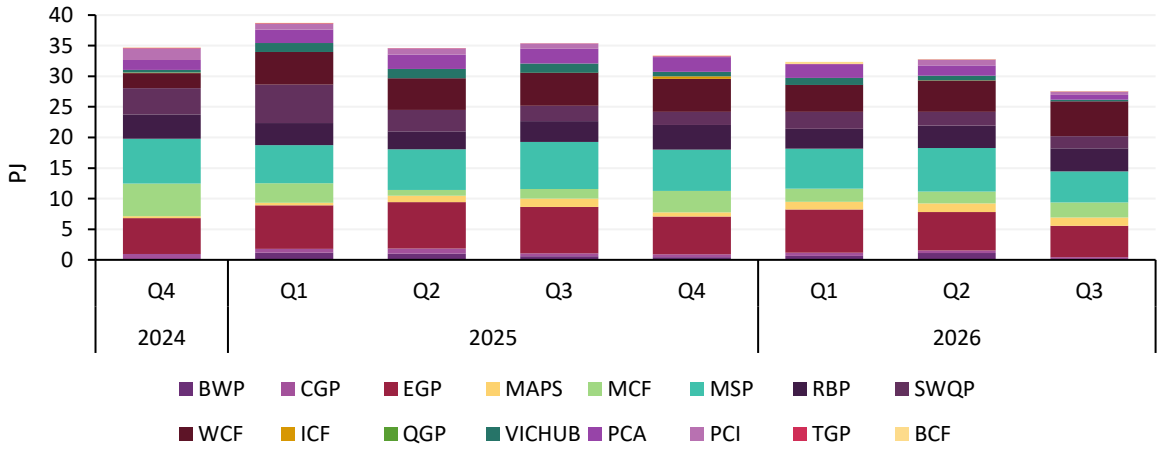
Day Ahead Auction (DAA) volumes decreased by 7.9 PJ in comparison to Q3 2025 (**Figure 97**) and were the lowest Q3 level since 2022. Compared to Q3 2025, there were notable decreases on the Moomba to Sydney Pipeline (MSP, -2.6 PJ), Eastern Gas Pipeline (EGP, -2.5 PJ), Port Campbell to Adelaide Pipeline (PCA, -1.6 PJ) and VicHub (-1.3 PJ). These decreases reflect lower AEMO markets and gas-fired generation demand.

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

- EGP North at $0.57/GJ and EGP South at $0.69/GJ,
- SWQP East at $0.27/GJ and SWQP West at $0.31/GJ,
- RBP East at $0.04/GJ and RBP West at $0.03/GJ,
- Moomba to Adelaide Pipeline (MAPS) South at $0.08/GJ, and
- MSP North at $0.07/GJ and MSP South at $0.05/GJ.

**Figure 97 Day Ahead Auction volumes decreased to lowest Q3 level since 2022**

Day Ahead Auction volumes by quarter



# 4 WEM market dynamics

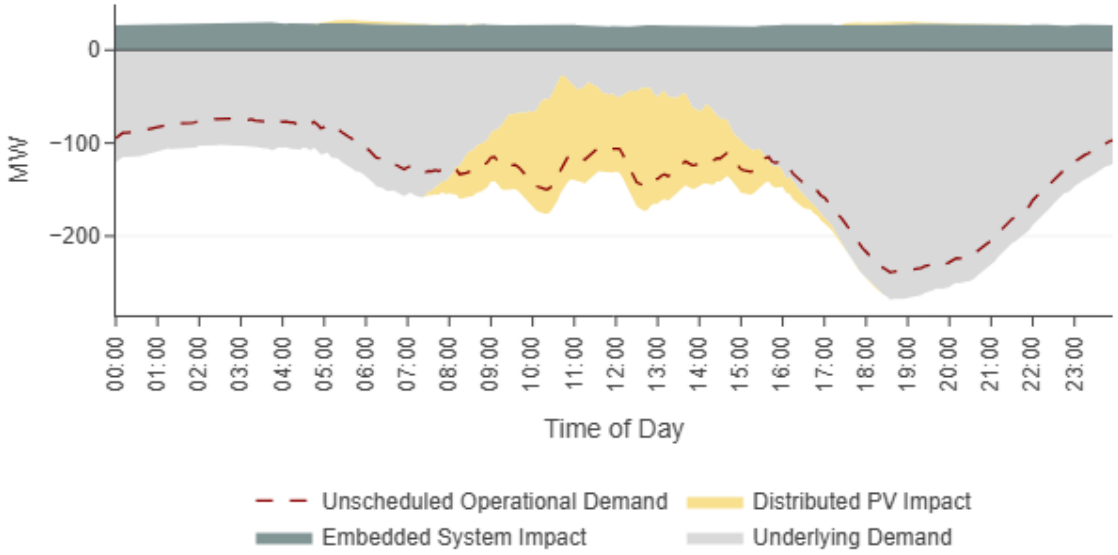
## 4.1 Electricity demand

Average unscheduled operational demand[49] was 1,997 MW in Q3 2026, a decrease of 132 MW (-6.2%) compared to Q3 2025 (**Figure 98**). This reduction was primarily driven by a 105 MW (-4.7%) decrease in average underlying demand[50]. Increased distributed PV[51] generation further reduced unscheduled operational demand by 27 MW (+7.0%). While a decrease in average embedded system[52] impact of 27 MW (-79.5%) contributed to an increase in unscheduled operational demand, this was more than offset by the reductions in underlying demand and the increase in distributed PV generation.

The reduction in underlying demand is consistent with milder weather conditions during Q3 2026. HDDs decreased by 23% compared to Q3 2025 (see **Figure 2** in Section 1), indicating substantially lower weather-driven heating demand.

**Figure 98 Decreased unscheduled operational demand at all times of day**

Change in WEM average unscheduled operational demand components by time of day – Q3 2025 vs Q3 2026




### 4.1.1 Consumer energy resources

CER solar capacity across the WEM continued to expand year-on-year, increasing from 3.0 GW at the end of Q3 2025 to 3.3 GW (+13%) at the end of Q3 2026. The number of WEM CER solar installations increased from 0.5 million to approximately 0.6 million (+7.2%) over the same period (**Figure 99**).

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

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

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

[52] 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.

Household battery uptake has grown significantly since July 2025 following the introduction of the Australian Government's Cheaper Home Batteries Program and the Western Australian Residential Battery Scheme (WARBS)[53]. On 1 May 2026, significant changes[54] took effect for all new and upgraded solar and battery systems in the South West Interconnected System (SWIS) (including an increased inverter size limit of 30 kilovolt amperes [kVa]), supporting the continued uptake of these renewable technologies. Clean Energy Regulator data[55] shows that WEM household storage capacity increased by 215 MWh (+20%) over Q3 2026, reaching 1,314 MWh, with the number of installations increasing by 10,334 (+20%) to more than 60,000 systems (**Figure 100**).

**Figure 99 Steady growth in rooftop solar capacity and installations in the WEM**

Cumulative CER solar capacity and installations – end of Q3

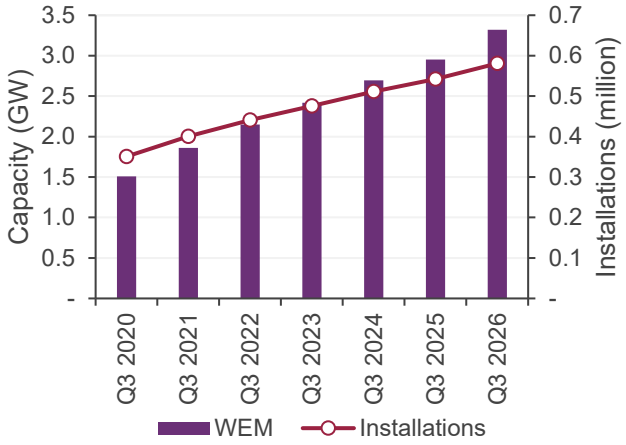
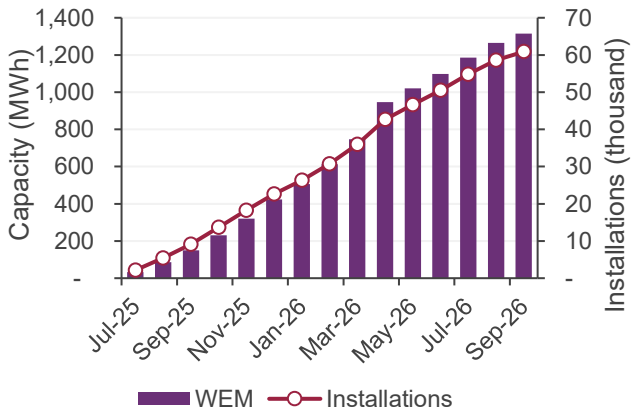



**Figure 100 Strong growth in CER battery installations increased total storage capacity**

Cumulative CER battery capacity and installation




Source: Clean Energy Regulator

## 4.2 Electricity generation

Coal-fired generation's share of the fuel mix declined, falling by 5.6 pp compared to Q3 2025, while gas-fired generation's share increased by 6.1 pp (**Table 8**). Wind generation's share of the fuel mix also decreased by 1.7 pp, reflecting weaker wind conditions and reduced wind generation output. Distributed PV continued to increase its contribution, consistent with continued growth in CER solar installations (see Section 4.1.1), with its share of the fuel mix rising by 1.8 pp.

**Table 8** shows all Q3 2026 contributions, with average generation shown in **Figure 101**.

Comparing Q3 2026 with Q3 2025:

- Average coal-fired generation decreased by 173 MW (-22%). This was driven by facility outages that lead to less coal unit availability.

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

[54] The new changes include increase in inverter size limit to 30 kVA (aggregate) for standard connections, requirement to enable remote disconnection and connection by the customers' electricity retailer or otherwise be export limited to 1.5 kW, and compliance requirement of all inverters with AS/NZS 4777.2:2020. See https://www.wa.gov.au/organisation/energy-policy-wa/new-requirements-small-scale-solar-and-battery-systems.

[55] Data from Clean Energy Regulator, at https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data. Data current as of 30 September 2026, noting that a 12-month creation period for registration persons to create small-scale technology certificates applies, so figures for the previous 12-month period will continue to rise.

- Average wind generation reduced by 60 MW (-14%), reflecting both weaker wind conditions and reduced wind farm availability due to forced outages.
- Average gas-fired generation increased by 110 MW (+12%).
- Average biomass generation increased 6.6 MW (+21%). This can be attributed to the commissioning of facility PHOENIX_KWINANA_WTE_G1, with a capacity of 43 MW, which commenced Commercial Operation in Q3 2025.
- Average embedded system impact decreased by 27 MW (-79%) due to the permanent retirement of ALCOA_KW_IL.

**Table 8 WEM supply mix contribution by fuel type**

| Quarter | Coal | Gas | Distillate | Grid solar | Wind | Biomass | Hybrid | Hydro | Distributed PV | Embedded systems |
|---|---|---|---|---|---|---|---|---|---|---|
| 2025 Q3 | 30.6% | 33.7% | <0.1% | 1.3% | 16.0% | 1.2% | 0.7% | <0.1% | 15.2% | 1.3% |
| 2026 Q3 | 25.0% | 39.8% | <0.1% | 1.3% | 14.3% | 1.6% | 0.7% | <0.1% | 17.0% | 0.3% |
| Change | -5.6 pp | 6.1 pp | 0.0 pp | 0.0 pp | -1.7 pp | 0.4 pp | 0.0 pp | 0.0 pp | 1.8 pp | -1.0 pp |

**Figure 101 Lower underlying demand reduced net generation, with lower coal-fired generation partly offset by increased gas-fired generation and distributed PV output**

Change in quarterly average generation – Q3 2025 vs Q3 2026

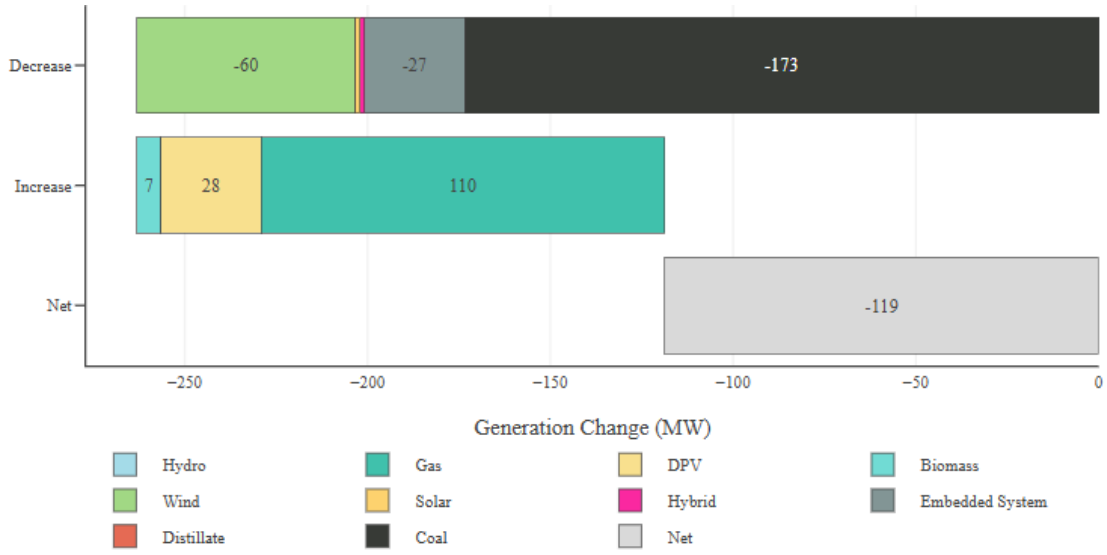
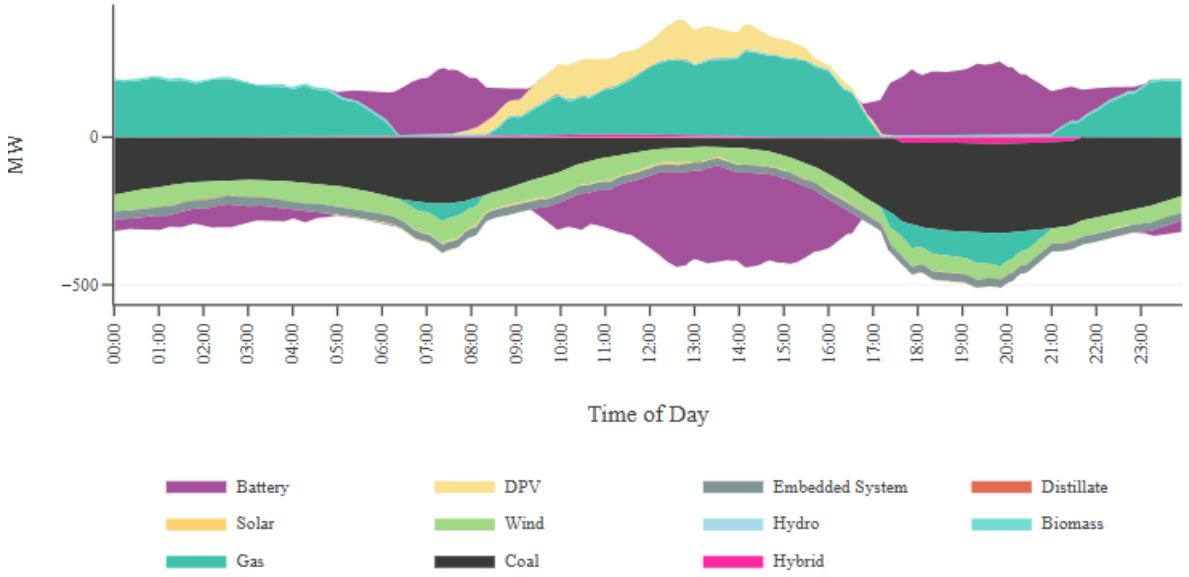



**Figure 102** shows how the WEM's generation profile changed by time of day. Battery charging and discharging are included on net basis to show the storage-driven shifts that underpinned changes in generation across the day.

**Figure 102 Increased battery discharge reduced coal-fired generation requirements and helped offset lower wind generation during morning and evening peak periods**

Change in average WEM generation and storage by time of day – Q3 2025 vs Q3 2026




### 4.2.1 Carbon emissions

Total WEM emissions decreased by 0.21 MtCO2-e (-8.0%) from 2.54 MtCO2-e in Q3 2025 to 2.33 MtCO2-e in Q3 2026 (**Figure 103**). Despite lower wind generation, emissions declined as both unscheduled operational demand and emissions intensity decreased. Emissions intensity fell by 0.03 tCO2-e/MWh (-6.5%) to 0.48 tCO2-e/MWh, reflecting reduced reliance on coal-fired generation, with increased battery discharge helping offset lower wind generation during morning and evening peak period. Although wind generation was lower in Q3 2026, the reduction in coal-fired generation was substantially larger, with increased gas-fired generation, distributed PV output and battery discharge helping offset lower wind output and displace coal-fired generation throughout the day.

**Figure 103 Emissions declined Q3 on Q3 despite decreased average wind generation**

Quarterly WEM emissions and emission intensity – Q3 2021 to Q3 2026



## 4.3 Electric Storage Resources (ESR)

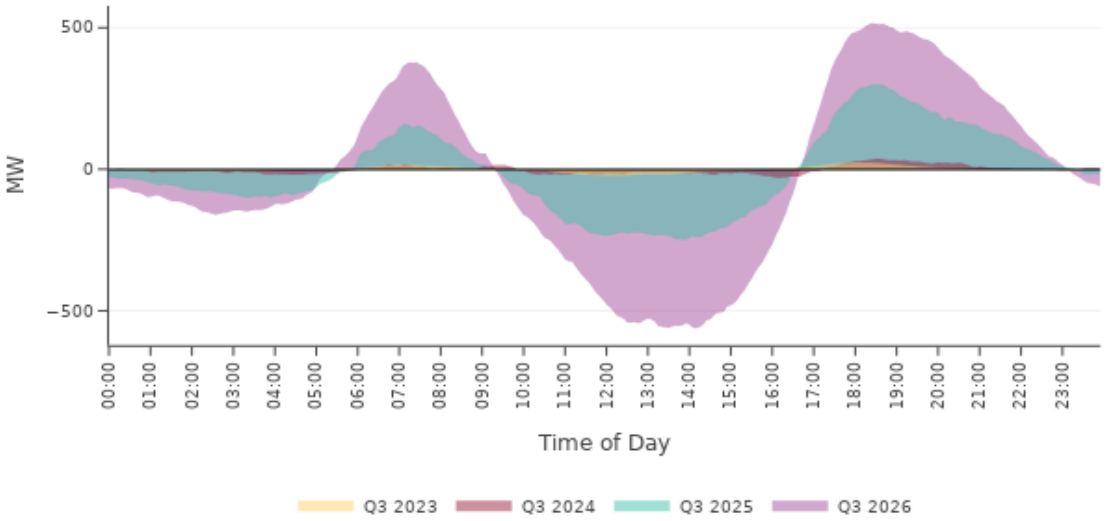
In Q3 2026, average battery charging doubled year-on-year, increasing by 92 MW (+100%), while average battery discharging increased by 79 MW (+98%) relative to Q3 2025, reflecting the expansion of grid-scale battery capacity in the WEM (see **Table 9** below).

Batteries continued to charge predominantly during midday and overnight periods and discharge during the morning and evening peaks (**Figure 104**). Relative to Q3 2025, grid-scale batteries doubled the energy shifted, with average daily energy charged during the midday hours (1000 hrs to 1300 hrs) increasing by 0.8 GWh (+121%), while average daily energy discharged during the evening peak (1700 hrs to 2000 hrs) increased by 0.7 GWh (+94%), highlighting the growing role of grid-scale batteries in shifting energy from periods of high solar output to periods of higher demand.

Q3 2026 saw three new battery charging records, of 1,100 MW, 1,086 MW, and 1,135 MW, occurring in the 24 July 1235 hrs, 20 September 1445 hrs, and 27 September 1445 hrs intervals, respectively.

**Figure 104 Battery charging and discharging reached new highs in Q3 2026**

Average battery energy injection/withdrawal, time of day – Q3s



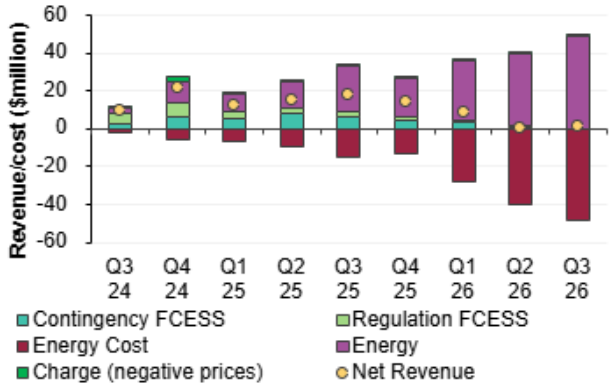

### 4.3.1 ESR revenue

In Q3 2026, estimated net Real-Time Market revenue[56] for WEM grid-scale batteries, in aggregate, was $1.0 million, down from $17.9 million in Q3 2025 (**Figure 105**). Both energy arbitrage and FCESS revenues declined year-on-year, with energy arbitrage revenue falling from $9.0 million to $0.8 million and FCESS revenue decreasing from $8.8 million to $0.2 million. Despite the decline in absolute revenues, the share of battery net revenue derived from energy markets increased to approximately 79% in Q3 2026, up from 51% in Q3 2025 (**Figure 106**). The reduction in FCESS revenue coincided with growing battery capacity and increased competition in FCESS markets, including the commissioning of ALINTA_WGP_ESR1 and the accreditation of COLLIE_ESR4 and COLLIE_ESR5 in Contingency markets since Q3 2025 (**Table 9**).

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

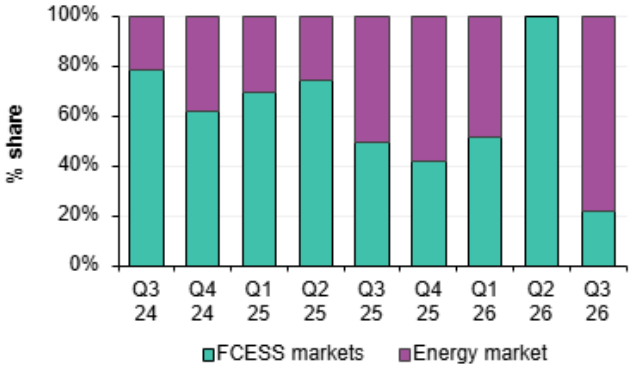
### Figure 105 FCESS revenue declined despite growing battery participation

Quarterly net revenue from WEM battery systems by revenue stream




### Figure 106 Battery revenue mix shifted from FCESS towards energy markets

Percentage share of battery net revenue – energy vs FCESS markets




### Table 9 Four new battery systems were commissioned and FCESS-accredited since end of Q3 2025

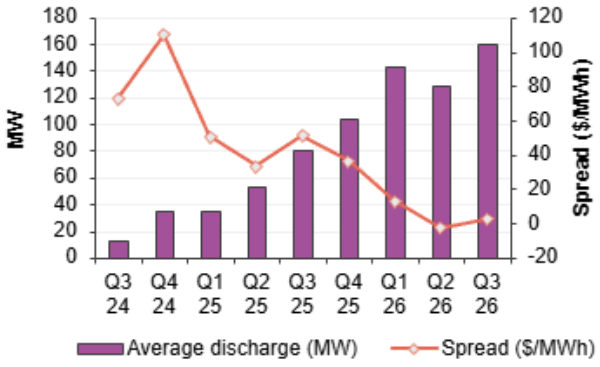
| Electric Storage Resource | Capacity | Commercial operation | FCESS accreditation |
|---|---|---|---|
| COLLIE_BESS2 | 300 MW/1,200 MWh | Q3 2025 | Q4 2025 |
| COLLIE_ESR4 | 250 MW/1,000 MWh | Q4 2025 | Q2 2026* |
| COLLIE_ESR5 | 250 MW/1,000 MWh | Q4 2025 | Q2 2026* |
| ALINTA_WGP_ESR1 | 100 MW/200 MWh | Q3 2026 | Not yet accredited |

* COLLIE_ESR4 and COLLIE_ESR4 became accredited in the contingency markets in Q2 2026. As of the date of publication, they are not accredited in the regulation markets.

As shown in **Table 9**, several battery systems were commissioned and FCESS-accredited between the end of Q3 2025 and Q3 2026. Over this period, total WEM battery capacity grew by 900 MW to 1,375 MW (5,320 MWh), an increase of 189%. This growth included the commissioning of ALINTA_WGP_ESR1, which added a further 100 MW of battery capacity in Q3 2026.

### Figure 107 Battery discharge increased as energy price spreads narrowed

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




Battery price spreads continued to decline year-on-year as increasing battery participation flattened the WEM energy price profile and reduced arbitrage opportunities. Average battery discharge increased to 160 MW in Q3 2026, up from 81 MW in Q3 2025, while the average price spread fell from $51/MWh to $2/MWh (**Figure 107**). The increase in charging demand during lower-priced periods, combined with increased battery discharge during morning and evening peaks, continued to reduce price differentials available to battery operators.

## 4.4 Frequency co-optimised essential system services (FCESS)

Batteries continued to dominate the FCESS markets in Q3 2026, accounting for 93% of enabled volume across the contingency and regulation services, excluding the Rate of Change of Frequency (RoCoF) Control Service, up 16 pp from Q3 2025. The largest year-on-year increase in market share occurred in the Contingency Lower service, where batteries increased their share by 26 pp to 98% of enabled volume (**Figure 108**). This was significantly greater than the next largest increase, Regulation Lower, where battery market share increased by 15 pp to 96%. Batteries also accounted for 98% of Regulation Raise and 88% of Contingency Raise enabled volume, reflecting the continued expansion and accreditation of grid-scale battery capacity since Q3 2025.

Compared to Q3 2025, Contingency Raise enablement increased and Contingency Lower enablement decreased, while Regulation Raise and Regulation Lower requirements remained broadly unchanged (**Figure 109**). The increase in Contingency Raise enablement was partly driven by the increase in allowable contingency size following the increase in the RoCoF Safe Limit introduced in February 2026. In contrast, the reduction in Contingency Lower enablement coincided with a decrease to the average Largest Credible Load Contingency (LCLC) decreasing from 209 MW to 199 MW (-4.8%).

**Figure 108 Batteries dominated FCESS provision across all services**

FCESS volume market share by market and fuel type, excluding RoCoF control service – Q3 2026

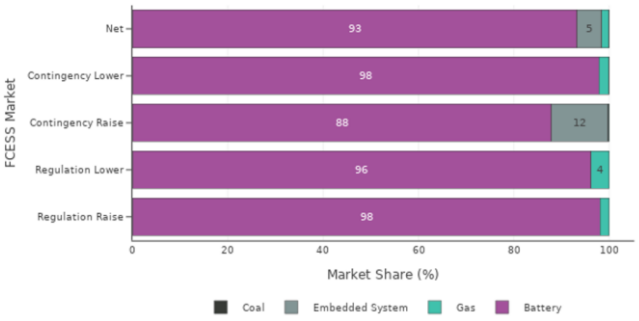
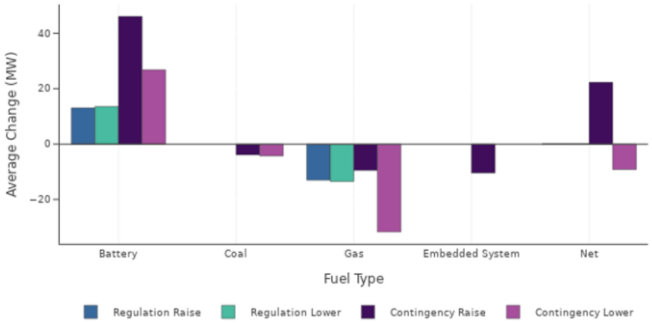



**Figure 109 Contingency Raise enablement increased while Contingency Lower enablement declined**

Change in FCESS (regulation and contingency markets) enablement by fuel type – Q3 2025 vs Q3 2026




## 4.5 WEM price outcomes

### 4.5.1 Real-Time Market price dynamics

The average real-time energy price in Q3 2026 was $120.72/MWh, an increase of $19.11/MWh (+19%) from Q3 2025 and the highest quarterly average shown for the WEM. The Q3 2026 daily price profile was notably flatter than Q3 2025 (**Figure 110**), with average final reference trading prices ranging from $100.63/MWh to $150.82/MWh in Q3 2026, compared with $53.83/MWh to $160.01/MWh in Q3 2025. Energy uplift costs decreased from $2.3 million in Q3 2025 to $0.2 million in Q3 2026, a reduction of $2.1 million (-92%).

In addition to flattening, the real-time energy price profile increased throughout the day except during the morning peak 0630 hrs to 730 hrs and the evening peak 1700 hrs and 1730 hrs. The flatter profile was most notable during the middle of the day and overnight, with smaller increases over the morning and evening peak. The quarterly energy price dynamics can be attributed to:

- increased battery charging during the middle of the day and overnight, which resulted in higher operational demand (**Figure 111**), and
- reduced coal- and wind-powered generation availability, which led to a reduction in available lower-cost generation throughout the day.

**Figure 110 Flatter average energy prices in the WEM in Q3 2026 compared to last year**

Average Real-Time Energy prices by Trading Interval

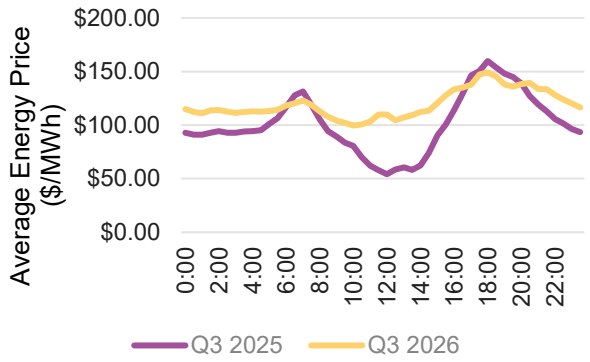
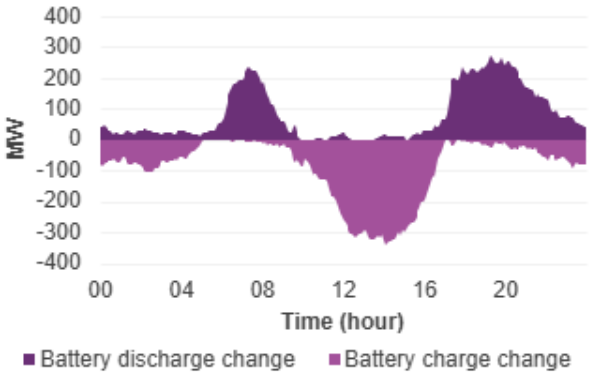



**Figure 111 Increased battery charging and discharging drove a flatter price profile**

Average change in battery charge and discharge – Q3 2025 vs Q3 2026

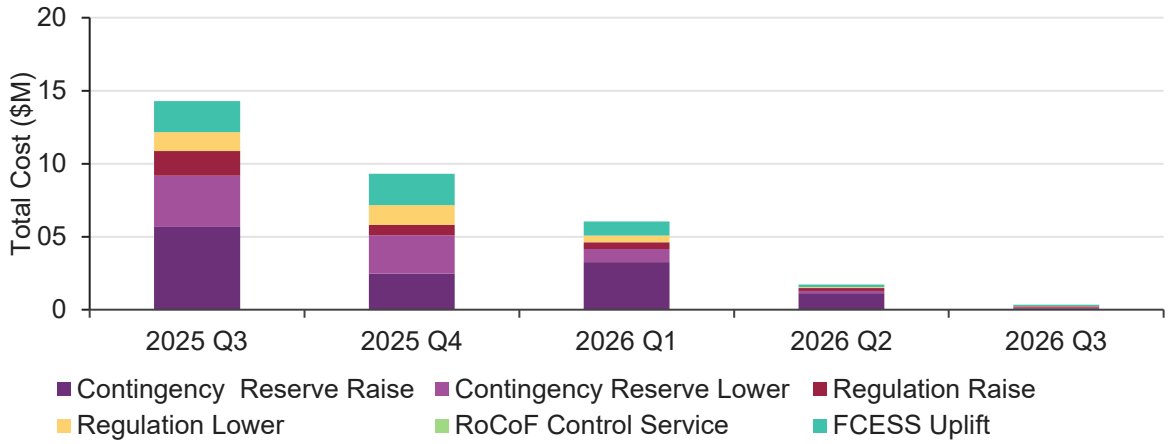



### 4.5.2 Frequency co-optimised essential system services (FCESS) costs

Total FCESS costs including FCESS uplifts decreased from $14.3 million in Q3 2025 to $0.3 million in Q3 2026, a reduction of $14.0 million (-98%) (**Figure 112**).

**Figure 112 Falling FCESS costs in the WEM**

Total ESS and Uplift cost per quarter since Q3 2025




Key observations include:

- FCESS enablement costs decreased from $12.2 million in Q3 2025 to $0.2 million in Q3 2026, a reduction of $11.9 million (-98%). Costs decreased across all FCESS enablement markets[57].

[57] Amounts are displayed to the nearest $0.1 million. Reductions and percentages are calculated using unrounded values, so displayed amounts may not sum exactly.

- Contingency Reserve Raise costs decreased from $5.7 million in Q3 2025 to $0.11 million in Q3 2026, a reduction of $5.6 million (-98%). It remained the largest contributor, accounting for 45% of Q3 2026 FCESS enablement costs.
- Contingency Reserve Lower costs decreased from $3.5 million in Q3 2025 to $0.04 million in Q3 2026, a reduction of $3.5 million (-99%).
- Regulation Raise costs decreased from $1.7 million in Q3 2025 to $0.07 million in Q3 2026, a reduction of $1.6 million (-96%).
- Regulation Lower costs decreased from $1.3 million in Q3 2025 to $0.02 million in Q3 2026, a reduction of $1.3 million (-98%).

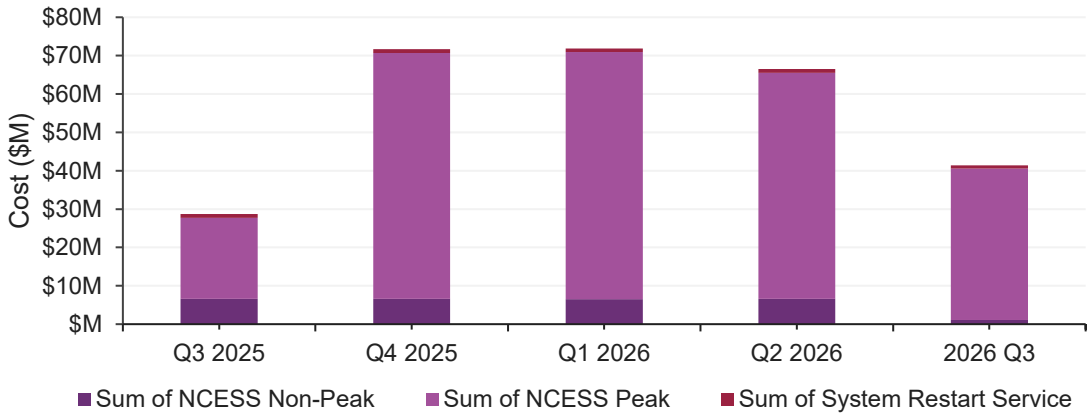
- FCESS uplift costs decreased from $2.1 million in Q3 2025 to $0.1 million in Q3 2026, a reduction of $2.1 million (-96%).

### 4.5.3 Contracted essential system services

Contracted ESS, shown in **Figure 113,** includes NCESS and system restart services (SRS). 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.

**Figure 113 NCESS costs increased from Q3 2025**

Cost ($M) by Contract type per quarter




Key observations include:

- NCESS costs increased from $27.7 million in Q3 2025 to $40.5 million in Q3 2026, an increase of $12.8 million (+46%). This was primarily due to Peak NCESS costs, partially offset by lower Non-Peak NCESS costs. the increase is largely attributable to a greater number of NCESS contracts being active in Q3 2026, with both the 2024-26 and 2025-27 contract periods contributing to costs. In contrast, Q3 2025 included only the 2024-26 NCESS contracts.
  - Peak NCESS costs increased from $21.1 million in Q3 2025 to $39.4 million in Q3 2026, an increase of $18.3 million (+86%). Peak NCESS costs accounted for 97% of total NCESS costs in Q3 2026.
  - Non-Peak NCESS costs decreased from $6.6 million in Q3 2025 to $1.1 million in Q3 2026, a decrease of $5.5 million (-83%).

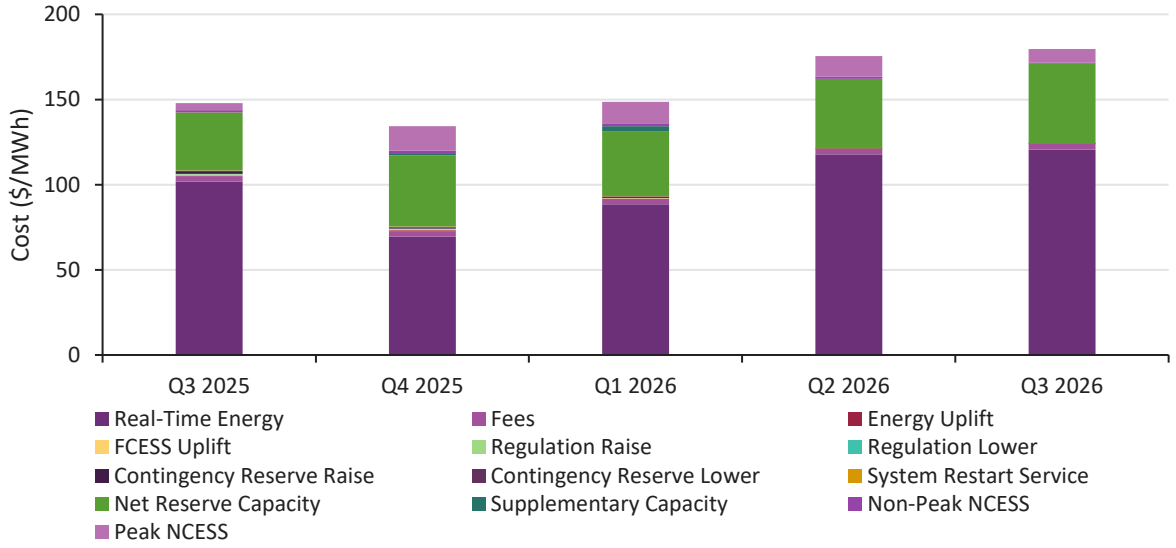
- SRS costs decreased from $1.0 million in Q3 2025 to $0.9 million in Q3 2026, a reduction of $0.2 million (-16%)[58].
- Compared with Q2 2026, NCESS costs decreased from $65.5 million to $40.5 million, a decrease of $25.0 million (-38%). This decrease was primarily driven by reduced availability payments following the early allocation of Capacity Credits to two Facilities from 1 June 2026
  - Compared with Q2 2026, Peak NCESS costs decreased by $19.5 million (-33%), from $58.9 million to $39.4 million. Peak NCESS costs accounted for 90% of total NCESS costs in Q2 2026.
  - Compared with Q2 2026, Non-Peak NCESS costs decreased by $5.5 million (-83%), from $6.6 million to $1.1 million.

### 4.5.4 Total Wholesale Electricity Market costs

**Figure 114** represents WEM costs as a price per MWh normalised by total energy consumed, enabling better comparison of costs between periods with different demand. The sum of all normalised costs in the WEM was $179.63/MWh in Q3 2026, an increase of $31.75/MWh (+21%) from Q3 2025. The increase was driven by higher real-time energy and capacity costs, partly offset by reductions across most ESS costs.

**Figure 114 Higher real-time energy prices drove higher costs for the quarter**

$/MWh costs in the WEM by market segment for recent quarters




Comparing Q3 2026 with Q3 2025:

- Normalised real-time energy prices were $120.70/MWh, an increase of $18.94/MWh (+19%) from Q3 2025
- Normalised energy uplift costs decreased by $0.42/MWh (-91%) to $0.04/MWh and normalised FCESS uplift costs decreased by $0.41/MWh (-96%) to $0.02/MWh.
- Regulation Raise costs decreased by $0.32/MWh (-96%) to $0.02/MWh and Regulation Lower costs decreased by $0.25/MWh (-98%) to less than $0.01/MWh, while Contingency Reserve Raise costs decreased by $1.10/MWh (-98%) to $0.02/MWh and Contingency Reserve Lower costs decreased by $0.68/MWh (-99%) to $0.01/MWh.

[58] For Trading Days where the Interval Meter Deadline has not yet passed, the data assumes no activations and full contract availability. NCESS data and SRS may change up to the statement and invoicing date for the relevant Trading Week.

- Total normalised NCESS costs increased by $2.70/MWh (+49%) to $8.19/MWh. Peak NCESS increased by $3.78/MWh (+90%) to $7.97/MWh, while Non-Peak NCESS decreased by $1.08/MWh (-83%) to $0.23/MWh.
- Normalised capacity costs, net of refunds, increased by $13.20/MWh (+39%) to $47.17/MWh, and normalised System Restart Service costs decreased by $0.04/MWh (-21%) to $0.16/MWh.

### 4.5.5 Short Term Energy Market (STEM) and Bilateral Trades

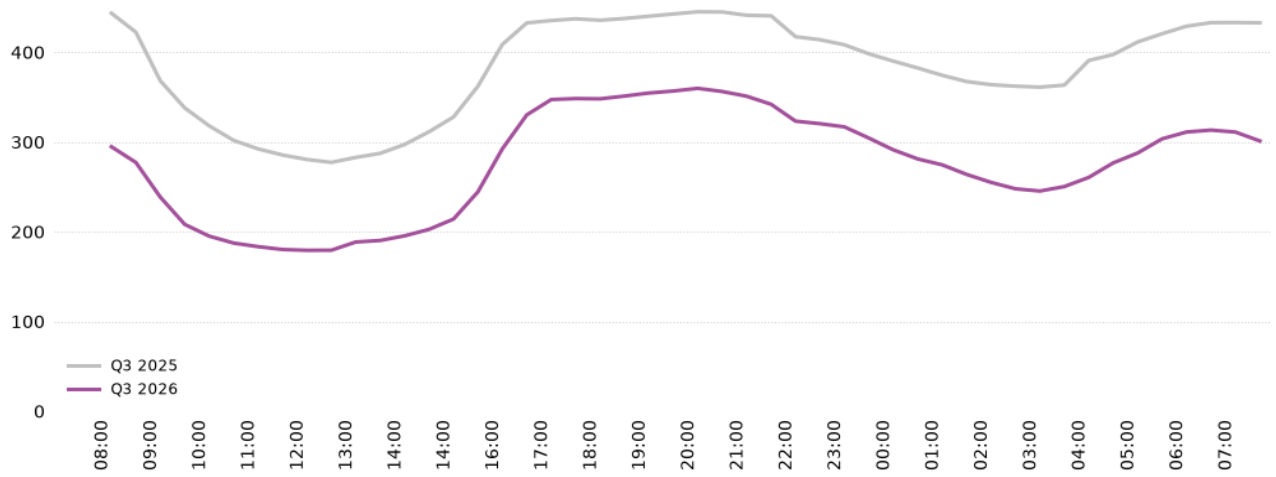
The day ahead STEM auction operates as a risk management tool for market participants to provide them an opportunity to trade around their contractual positions and manage variations before physical dispatch in the Real-Time market.

#### Bilateral Declared Quantity

**Figure 115** shows bilateral energy traded between participants by trading interval for Q3 2026 and Q3 2025, excluding trades between the same participant. Bilateral traded volumes in Q3 2026 were lower across most trading intervals compared to Q3 2025. The general trend shows that these reductions are concentrated during the early morning, with the largest year-on-year contraction observed for the 8:00 AM trading interval.

**Figure 115 Bilateral trades between market participants decreased between Q3 2025 and Q3 2026**

Average Bilateral Trades Between Participants (MWh) – Q3 2025 vs Q3 2026




#### STEM traded quantities

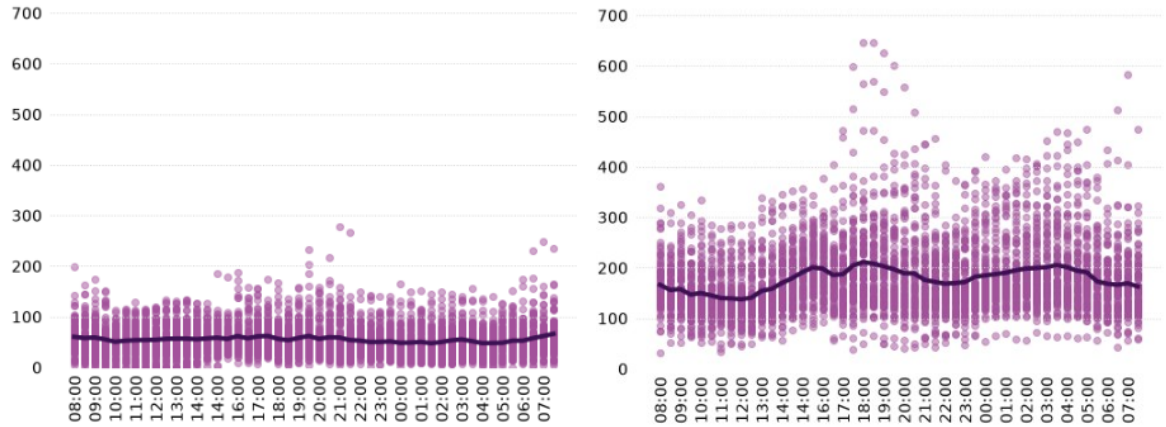
**Figure 116** shows the distribution of STEM quantities traded by trading interval for Q3 2025 and Q3 2026.

The energy traded between participants in STEM totalled 785 GWh, representing a 224% increase from the Q3 2025 traded volume of 243 GWh, with average traded quantities exceeding 138 MWh across all intervals, as shown with a dark purple line in **Figure 116**. Overlapping this behaviour to that shown in **Figure 115** means the reduction of bilateral trades resulted in the need to increase STEM activity to cover the shortfall.

In Q3 2025 traded volumes were lower and more tightly clustered. This changes significantly over the Q3 2026 period, with much higher total traded quantities and dispersion. The evening period shows significant outliers, as well in the early morning leading to the morning peak.

**Figure 116 STEM gross traded quantities were materially higher across all trading intervals in Q3 2026**

Distribution of STEM Gross Trade Quantities by Trading Interval (MWh) – Q3 2025 (LHS) and Q3 2026 (RHS)

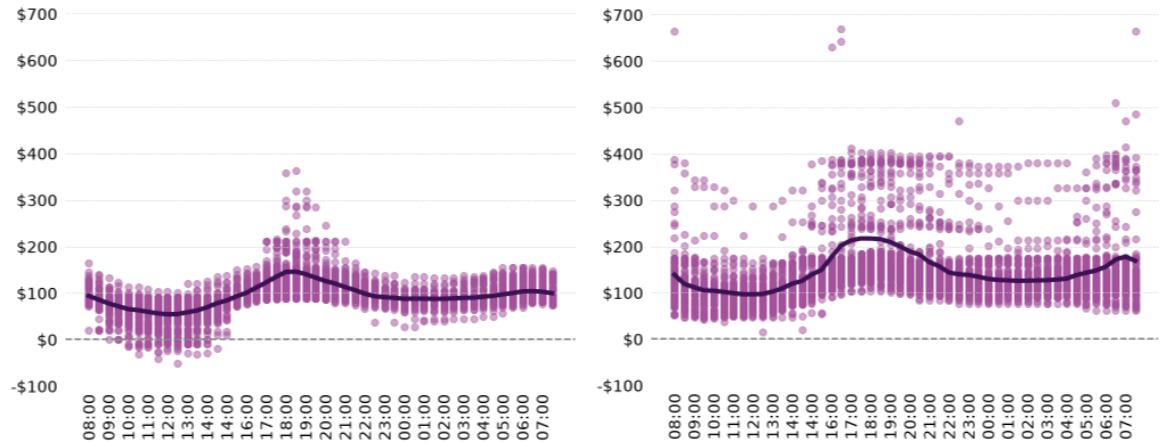



## STEM clearing price

The quarterly average STEM clearing price was $145/MWh in Q3 2026, which was an increase of $52/MWh (+51%) from $93/MWh in Q3 2025. **Figure 117** shows the distribution of STEM clearing prices by trading interval for Q3 2025 and Q3 2026, together with the average STEM price profile.

**Figure 117 The range and variability of observed STEM prices increased during the morning and evening peaks in Q3 2026**

Distribution of STEM Clearing Prices by Trading Interval ($/MWh) – Q3 2025 (LHS) and Q3 2026 (RHS)




STEM prices in Q3 2026 were significantly higher and more variable than those observed in Q3 2025 across all trading intervals. Significant price dispersion was present throughout the entire day, with clustering present around the evening peak and the early morning leading into the morning peak.

**Figure 118** shows the average price difference across each Trading Interval. The relationship between the STEM clearing price and the Reference Trading Price is net in favour of the STEM price for most trading intervals. Average STEM prices are below the reference trading price only in the middle of the day, while in the evening peak Q3 2026 prices are significantly higher than the reference trading price. Overnight Q3 2026 STEM prices are also higher than the reference trading price,

which is also contrasting to the Q3 2025 trend. This general behaviour marks a clear departure from Q3 2025 observed performance, where STEM prices were on average below the reference trading price.

**Figure 118 STEM was on average priced higher than the energy price across most hours of the day**

Average Daily Variance Between STEM Clearing Price and Energy Reference Trading Price ($/MWh) – Q3 2025 vs Q3 2026

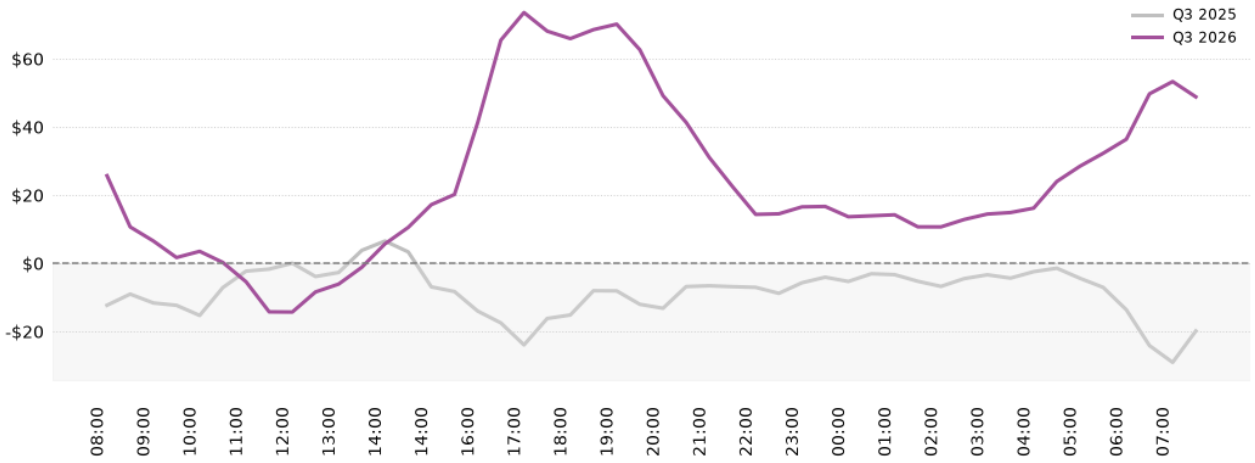
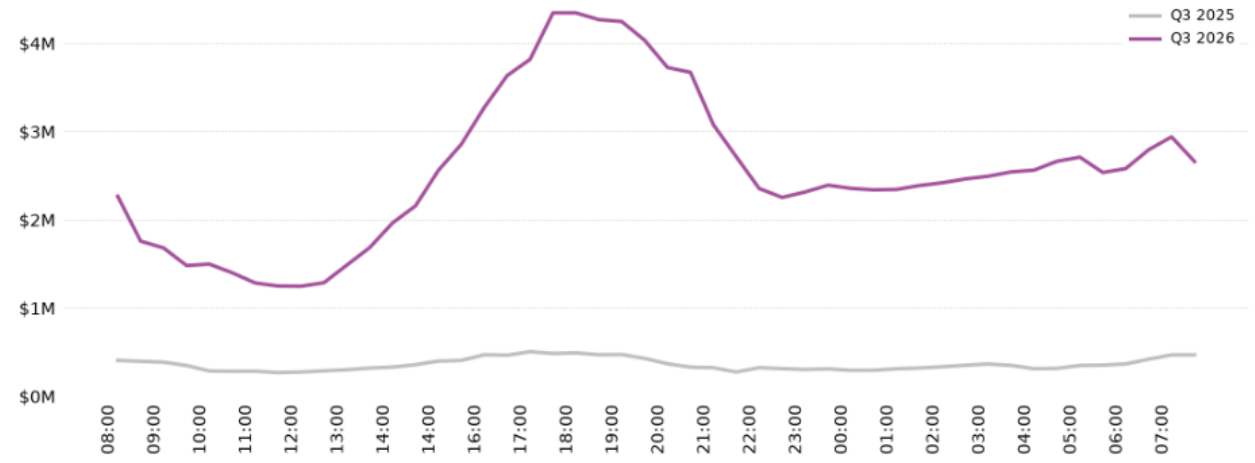



**Figure 119** shows the total transaction value of energy traded in the STEM by trading interval for Q3 2026 and Q3 2025, calculated as the product of STEM clearing price and net STEM energy sales. Based on price increase evidence presented in **Figure 117** and quantity increases presented in **Figure 116**, the total STEM transaction values for Q3 2026 are significantly above the values observed during Q3 2025. The evening peak effect is clearly visible in Q3 2026 as well as increased transaction values overnight and in the morning peak. The behaviour is contrasting to the flatter Q3 2025 profile, with less active STEM trading.

**Figure 119 Transaction value of the net STEM traded quantities increased**

Total STEM Transaction Value – Q3 2025 vs Q3 2026



# 5 Western Australia gas market dynamics

## 5.1 Gas consumption

A total of 104 PJ of gas was consumed across registered pipelines in the Western Australia domestic gas market in Q3 2026, representing a decrease of 8.9 PJ (-7.8%) from the 112.9 PJ consumed in Q3 2025, as shown in **Figure 120**. The decline in gas consumption was primarily driven by lower demand from Other (Non-Large User) category. Consumption in this category fell by 22.8 PJ to 8.6 PJ. Gas consumption in the Industrial, Mineral Processing, and Mining sectors also declined compared with the corresponding quarter in 2025.

As shown in **Figure 121**, gas consumption declined in both the Dampier and Metro zones during Q3 2026. Consumption in the Dampier zone fell from 30.2 PJ to 22.6 PJ, primarily due to lower gas demand from the Mining sector. In the Metro zone, consumption decreased from 27.3 PJ to 23.0 PJ, largely driven by reduced demand from the Electricity sector. Consumption in all other zones remained relatively stable compared with Q3 2025, with only minor fluctuations recorded.

**Figure 120 Gas consumption by sector in Western Australia decreased compared to Q3 2025**

Quarterly gas consumption by sector (PJ) – Q3 2025 and Q3 2026

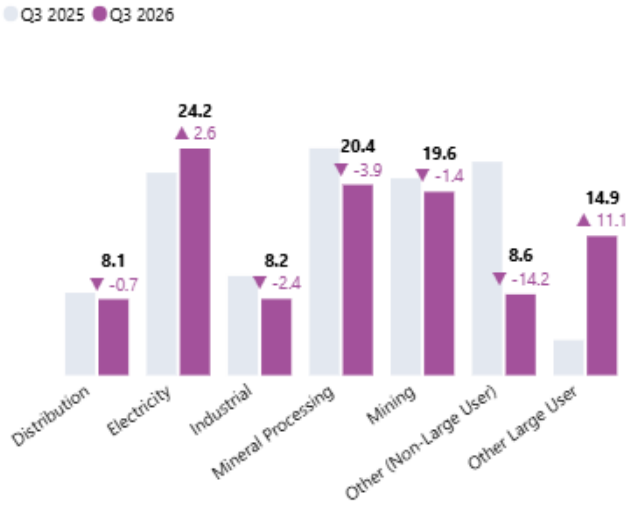
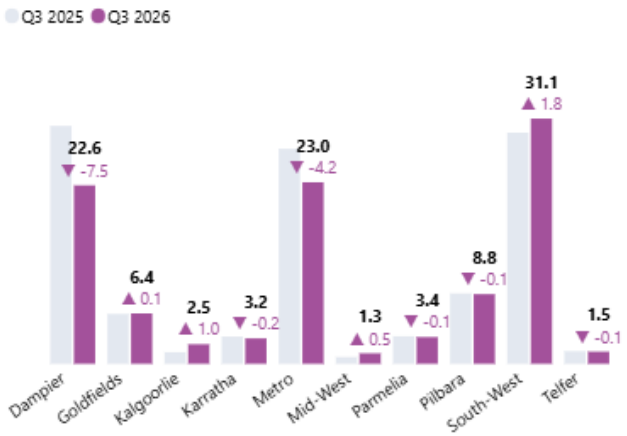



**Figure 121 Gas consumption by zone in Western Australia decreased compared to Q3 2025**

Quarterly gas consumption by zone (PJ) – Q3 2025 and Q3 2026



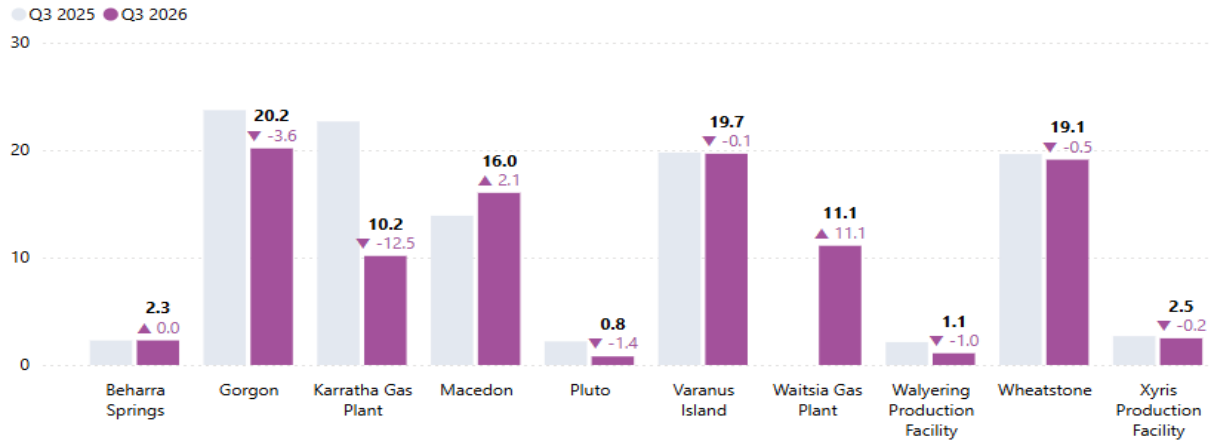

## 5.2 Gas supply and balance

### 5.2.1 Gas production

Total gas production decreased to 102.9 PJ in Q3 2026, representing a decline of 6.1 PJ (-5.6%) compared to 109 PJ in Q3 2025, as shown in **Figure 122**. The overall reduction was primarily driven by lower production across most gas production facilities. Compared with Q3 2025, production from the Karratha Gas Plant decreased by 12.5 PJ, while Gorgon recorded a decline of 3.6 PJ. Partially offsetting these declines, the Waitsia Gas Plant produced 11.1 PJ in Q3 2026, whereas it had not yet commenced production in Q3 2025.

**Figure 122 Gas production in Western Australia decreased by 6.1 PJ compared to Q3 2025.**

Quarterly gas production by facility (PJ) Q3 2025 and Q3 2026




## 5.2.2 Storage facility

Net withdrawals from storage facilities were recorded in Q3 2026, totalling 2 PJ, compared with net withdrawals of 5.2 PJ in Q3 2025, as shown in **Figure 123**. Mondarra recorded net injections of 1.9 PJ in Q3 2026, compared with 0.9 PJ of withdrawals in Q3 2025, while Tubridgi recorded net withdrawals of 4 PJ during the quarter, down from 4.3 PJ in the corresponding quarter of the previous year. In Q3 2026, cumulative gas storage levels were lower than in Q2 2025, as seen in **Figure 124**.

**Figure 123 Net withdrawals from storage in Q3 2026**

Gas storage facility injections and withdrawals (PJ) – Q3 2025 and Q3 2026

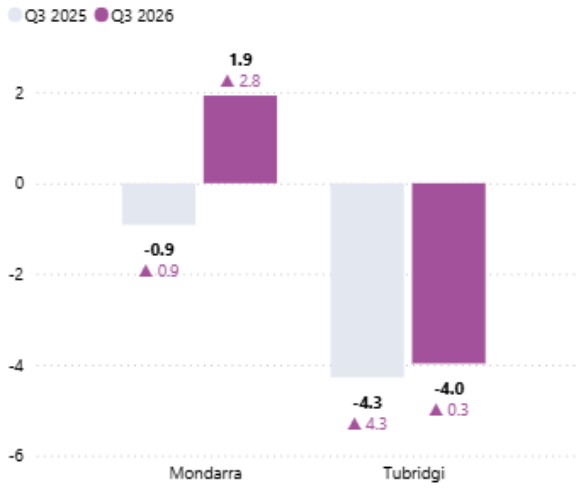
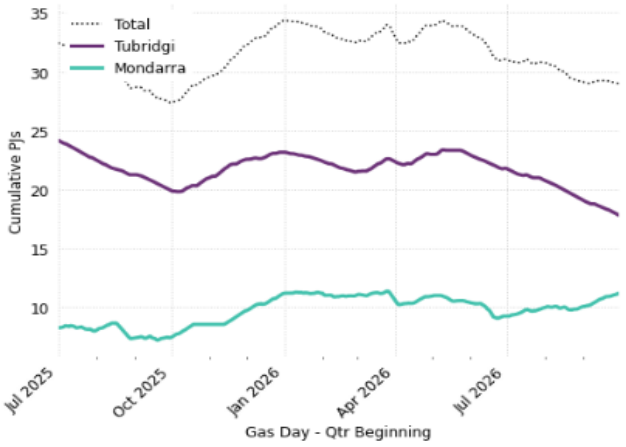



**Figure 124 Cumulative storage levels in Q3 2026**

Gas storage levels by facility over time




## 5.2.3 Linepack Capacity Adequacy (LCA)

For Gas Bulletin Board (GBB) pipelines, LCA is an indication of the actual or expected capability of a pipeline to meet relevant delivery nominations based on the pipeline's linepack and capacity. A Green flag indicates normal operating conditions, an Amber flag indicates likely curtailment of interruptible gas flows, and a Red flag indicates likely curtailment of firm gas flows.

For storage facilities, LCA is an indication of the estimated number of days for which natural gas supply can be maintained at maximum operational outlet capacity, allowing for forecast refilling. A Green flag indicates more than seven days of supply remaining, an Amber flag indicates between three and seven days of supply remaining, and a Red flag indicates less than three days of supply remaining.

No LCA events were reported across gas infrastructure during the Q3 2026.

# 6 Reforms delivered

AEMO, with government and industry, continues to deliver energy market reforms across the WEM, NEM and east coast gas markets. These reforms provide for changes to key elements of Australia's electricity and gas market design to facilitate a transition towards a modern energy system, capable of meeting the evolving wants and needs of consumers, as well as enabling the continued provision of the full range of services necessary to deliver a secure, reliable and lower emissions system at least cost. **Table 10** provides a brief description of the reforms implemented over the last quarter.

**Table 10 Reforms delivered Q3 2026**

| Reform initiative | Market | Description | Reform delivered |
|---|---|---|---|
| **Shortening the settlement cycle** | NEM | On 12 December 2024, the AEMC published its final determination on the "Shortening the settlement cycle" rule change. The final rule shortens the NEM settlement cycle to nine (9) business days following the end of a billing period and introduces a new revision 20 business days following the end of the billing period. The final rule has three major implementation components:<br>• establishing metering and settlement processes that support a new, shorter settlement cycle,<br>• adapting the credit limit procedures (CLP) and supporting process to reflect the shorter settlement cycle, and<br>• transitioning metering, settlement and prudential processes from the current settlement cycle to the shorter settlement cycle.<br>The reform commenced on 9 August 2026, beginning the transition to the shortened settlement arrangements. The transition period is scheduled to conclude on 17 October 2026.<br>More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/shortening-the-settlement-cycle. | August 2026 |
| **Metering Services Review – Package 2** | NEM | The Accelerating Smart Meter Deployment (ASMD) rule seeks to achieve universal smart meter deployment in the NEM by 2030. To facilitate the accelerated deployment, the AEMC final determination introduces new obligations for industry coordination between DNSPs, Financially Responsible Market Participants (FRMPs), and Metering Coordinators (MCs) for sites with shared points of isolation. This includes a requirement for MCs to provide DNSPs with a basic power quality data (PQD) service and for AEMO to determine the specifications, formats, and delivery mechanism for this service.<br>The second and final release commenced on 31 August 2026, enabling the exchange of Basic Power Quality Data (BPQD) through AEMO's Industry Data Exchange platform.<br>More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/metering-services-review---accelerating-smart-meter-deployment. | August 2026 |
| **Project EnergyConnect (PEC) – Market Integration – Release 1** | NEM | When implemented, PEC (Stage 2) will provide approximately 800 MW of transmission capacity between New South Wales and South Australia. This will create a parallel transmission configuration between three adjacent regions which presents new challenges for the NEM, especially for the way negative inter-regional settlement residue is managed.<br>AEMO undertook stakeholder consultation on PEC Market Integration (PEC-MI), with the final recommendations published on 9 February 2024. On 25 September 2025, the AEMC made a final determination and more preferable final rule that will net off IRSR in transmission loops.<br>The final rule commenced on 2 October 2025, noting that the new IRSR arrangements for transmission loops will not take effect until a transmission loop is in operation in the NEM dispatch engine and changes to AEMO's settlement systems have been implemented. The final rule requires project go-live to occur no earlier than 1 October 2026 and no later than 2 November 2026.<br>Integration of PEC Stage 2 into AEMO's systems is designed in two phases: | August |

| Reform initiative | Market | Description | Reform delivered |
|---|---|---|---|
| | | • Release 1 August 2026: Integrate a transmission loop into AEMO dispatch systems (price scaling and negative residue management), and<br>• Release 2 November 2026: Integrate PEC into AEMO settlement systems (IRSR, Settlement Residue Auction [SRA]).<br>Release 1 was delivered progressively during the quarter commencing from 13 August, with the transmission loop arrangements becoming operational from 1 October 2026.<br>More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/project-energyconnect-market-integration-project. | |
| **Demand Side Programme (DSP) Participation – Workstream 2** | WEM | In September 2023, the Western Australian Minister for Energy made several Electricity System and Market Rules (ESM Rules) 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 DSP within the Reserve Capacity Mechanism but increased the obligations for participation.<br>Commencing from 1 October 2026, The Western Australian Minister for Energy has effected changes to the Reserve Capacity Mechanism Review. The key change effects DSP Facilities which will be subject to more stringent refunds for failure to provide the obligated capacity when dispatched to subject to a reserve capacity test.<br>Workstream 1 was delivered in May 2026. Workstream 2 of this reform focuses on the dispatch, reserve capacity testing, and settlement obligations of DSP Facilities. AEMO will implement changes to enable:<br>• DSP aggregators to identify in their DSP Profile Submissions where the facility will provide injection or withdrawal,<br>• simplification of AEMO's dispatch process for DSPs to effectively dispatch large numbers of DSP Facilities within the obligations of the ESM Rules,<br>• both summer and winter testing of DSP facilities where they have not already proven their ability to provide their Capacity Credits,<br>• a new dynamic baseline methodology (Relevant Demand) to measure the performance of the DSP following a dispatch or reserve capacity test, and<br>• revised settlement calculations for failure to deliver the expected capacity in line with the Reserve Capacity obligations.<br>More information: https://www.aemo.com.au/-/media/files/initiatives/wem-reform-program/implementation-assessment/2025/dsp-participation---final-ia.pdf. | September 2026 |

In addition to these reforms, work continues to progress on the next wave of initiatives set for release in 2026. **Table 11** below provides a brief description of initiatives to be delivered in Q4 2026 and Q1 2027.

### Table 11 Upcoming implementation of reforms Q4 2026 – Q1 2027

| Reform initiative | Market | Description | Reform to be delivered |
|---|---|---|---|
| **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 was initially implemented across multiple milestones, scheduled between 30 June 2024 and 2 December 2025, providing for:<br>• alignment of existing inertia and system strength frameworks,<br>• removal of the exclusion to procuring inertia network services and system strength in the NSCAS framework,<br>• creation of a new transitional non-market ancillary services (NMAS) framework for AEMO to procure security services necessary for the energy transition,<br>• a requirement for AEMO to enable (or 'schedule') security services across the whole NEM for a variety of service types, and | Q4 2026 |

| Reform initiative | Market | Description | Reform to be delivered |
|---|---|---|---|
| | | • changing the directions reporting framework.<br>A subsequent release (release 1.1b) scheduled for November 2026 will deliver automated enablement functionality and market portal enhancements.<br>The industry go-live plan for release 1.1b was published on 11 September 2026.<br>More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/improving-security-frameworks-for-the-energy-transition. | |
| **Project EnergyConnect (PEC) – Market Integration – Release 2** | NEM | As outlined in **Table 10** above, AEMO is implementing PEC Market Integration across two releases:<br>• Release 1 commenced from 13 August and completed on 1 October, and<br>• Release 2 to integrate PEC into AEMO settlement systems (IRSR, Settlement Residue Auction [SRA]) is scheduled for November 2026.<br>More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/project-energyconnect-market-integration-project. | Q4 2026 |
| **Flexible Trading Arrangements (FTA) – Release 2** | 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.<br>The rule is optional, and allows:<br>• large customers to engage multiple energy service providers at their premise,<br>• 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<br>• minor energy metering flows to be metered to enable the delivery of innovative and essential products and services at lower cost.<br>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.<br>AEMO is implementing FTA across two releases:<br>• Release 1 giving effect to Type 9 metering arrangements went live on 31 May 2026.<br>• Release 2 in November 2026 will give effect to the remainder of the rule requirements.<br>The final industry go-live plan for release 2 was published on 18 September 2026.<br>More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/flexible-trading-arrangements. | Q4 2026 |
| **Cash Security** | NEM | On 26 June 2025, the AEMC published the final determination and rule 'Allowing AEMO to accept cash as credit support', to amend the credit support arrangements to increase flexibility for participants that provide credit support in the NEM.<br>The rule expands the range of eligible credit support instruments by enabling AEMO to accept cash deposits as an approved form of prudential collateral up to a limit of $20 million per market participant. Participants are now able to meet part or all of their credit support obligations through cash security held by AEMO, alongside existing instruments such as bank guarantees. This provides participants with greater flexibility in managing prudential requirements while maintaining the integrity of AEMO's risk management framework.<br>The draft industry go-live plan was published on 15 September 2026 and AEMO is implementing the Cash Security solution as a single release aligned to the rule commencement date of 1 November 2026.<br>More information: https://www.aemo.com.au/initiatives/major-programs/nem-reform-program/nem-reform-program-initiatives/cash-as-credit-support. | Q4 2026 |

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# Abbreviations

| Abbreviation | Expanded term |
|---|---|
| ASEFS | Australian Solar Energy Forecasting System |
| CRC | Certified Reserve Capacity |
| DBNGP | Dampier to Bunbury Natural Gas Pipeline |
| DTS | Declared Transmission System |
| DUID | Dispatchable Unit Identifier |
| ECGS | east coast gas system |
| ELCC | Effective Load Carrying Capability |
| MFP | Market Floor Price |
| 5MS | Five-Minute Settlement |
| ACCC | Australian Competition and Consumer Commission |
| ACE | Adjusted Consumed Energy |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| APLNG | Australia Pacific LNG |
| ASMD | Accelerating Smart Meter Deployment |
| ASX | Australian Securities Exchange |
| BESS | battery energy storage system |
| BOM | Bureau of Meteorology |
| BPQD | basic power quality data |
| CDEII | Carbon Dioxide Equivalent Intensity Index |
| CER | consumer energy resources |
| CGP | Carpentaria Gas Pipeline |
| CLP | credit limit procedures |
| DAA | Day Ahead Auction |
| DER | distributed energy resources |
| DNSP | distribution network service provider |
| DR | demand response |
| DSP | Demand Side Programme |
| DWGM | Declared Wholesale Gas Market |
| EDD | effective degree day |
| EGP | Eastern Gas Pipeline |
| ESM Rules | Electricity System and Market Rules (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 |

| Abbreviation | Expanded term |
|---|---|
| FRMP | Financially Responsible Market Participant |
| FTA | flexible trading arrangements |
| GBB | Gas Bulletin Board |
| GJ | gigajoule/s |
| GJ/h | gigajoules per hour |
| GLNG | Gladstone LNG |
| GSH | Gas Supply Hub |
| GW | gigawatt/s |
| GWh | gigawatt hour/s |
| HDD | heating degree day |
| IEA | International Energy Agency |
| IRSR | inter-regional settlement residue |
| kV | kilovolt/s |
| kVa | kilovolt ampere/s |
| kW | kilowatt/s |
| LCA | Linepack Capacity Adequacy |
| LGC | large-scale generation certificate |
| LNG | liquefied natural gas |
| LOR | Lack of Reserve |
| LREG | lower regulation (FCAS) |
| MAPS | Moomba to Adelaide Pipeline |
| MC | Metering Coordinator |
| MNSP | market network service provider |
| MoU | Memorandum of Understanding |
| MSP | Moomba Sydney Pipeline |
| MT PASA | Medium Term Projected Assessment of System Adequacy |
| $MtCO_2$-e | million tonnes of carbon dioxide equivalents |
| MW | megawatt/s |
| MWh | megawatt hour/s |
| NCESS | non-co-optimised essential system service |
| NEM | National Electricity Market |
| NGP | Northern Gas Pipeline |
| NMI | National Metering Identifier |
| NSCAS | network support and control and ancillary services |
| NSP | network service provider |
| PEC | Project EnergyConnect |
| PEC-MI | Project EnergyConnect – Market Integration |
| PJ | petajoule/s |
| pp | percentage points |
| PQD | power quality data |

| Abbreviation | Expanded term |
|---|---|
| PV | photovoltaic |
| QCLNG | Queensland Curtis LNG |
| QED | *Quarterly Energy Dynamics* |
| QNI | Queensland – New South Wales Interconnector |
| RBP | Roma to Brisbane Pipeline |
| RERT | Reliability and Emergency Reserve Trader |
| RHS | right hand side |
| RoCoF | Rate of Change of Frequency |
| RREG | raise regulation (FCAS) |
| RRP | regional reference price |
| SOC | state of charge |
| SRA | Settlement Residue Auction |
| STEM | Short-Term Energy Market |
| STTM | Short Term Trading Market |
| SWIS | South West Interconnected System |
| SWQP | South West Queensland Pipeline |
| tCO2-e | tonnes of carbon dioxide equivalent |
| TJ | terajoule/s |
| TNSP | transmission network service provider |
| TWAP | time-weighted average price |
| UGS | Underground Storage Facility |
| VEEC | Victorian Energy Efficiency Certificate |
| VNI | Victorian Northern Interconnect |
| VPP | virtual power plant |
| VRE | variable renewable energy |
| VWAP | volume-weighted average price |
| WARBS | Western Australian Residential Battery Scheme |
| WDR | wholesale demand response |
| WEM | Wholesale Electricity Market |