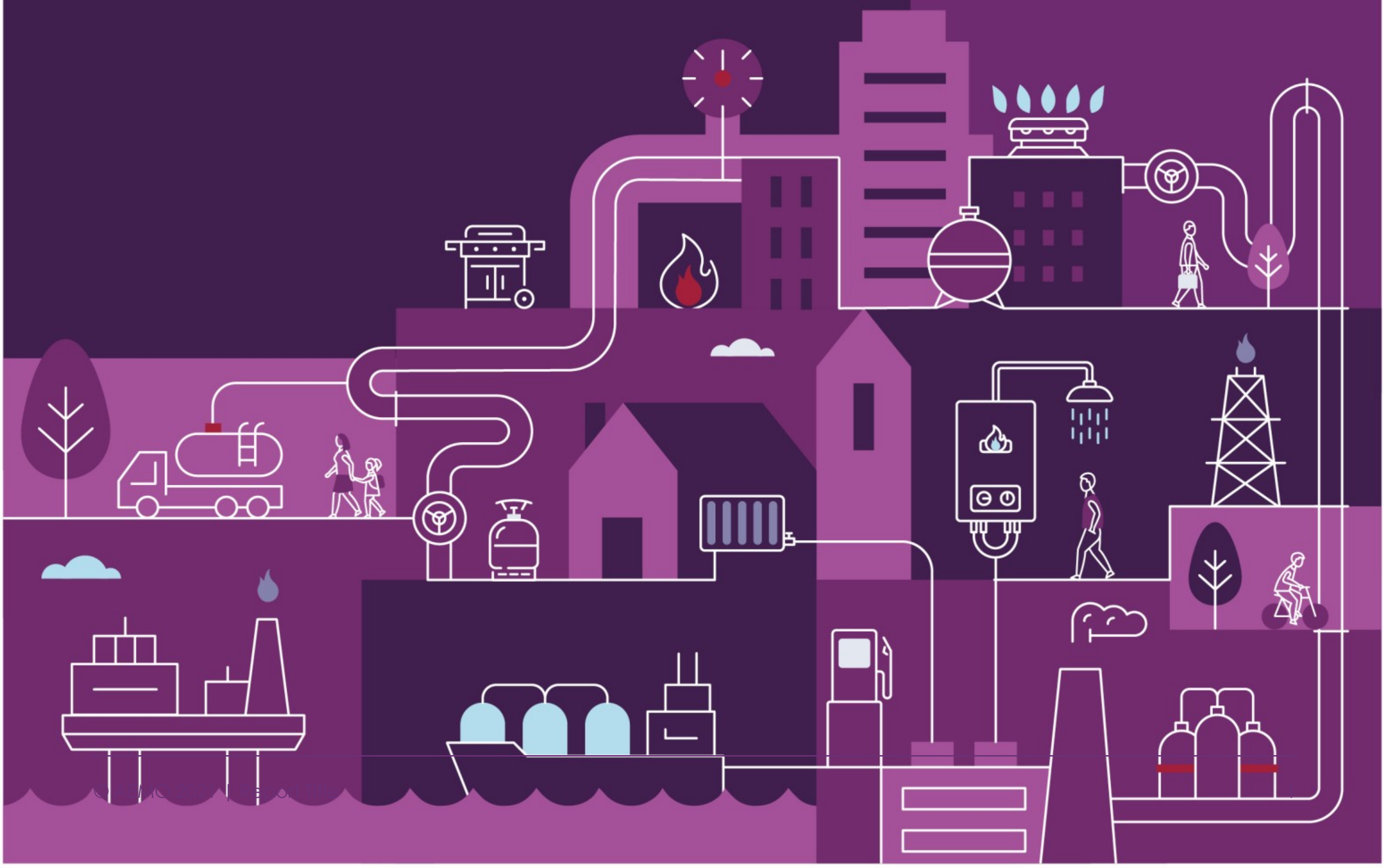
Quarterly Energy Dynamics Q4 2024

January 2025



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

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

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

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

Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q4 2024 (1 October to 31 December 2024). This quarterly report compares results for the quarter against other recent quarters, focusing on Q3 2024 and Q4 2023. 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.
- The gas markets operating in Queensland, New South Wales, Victoria and South Australia.

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Executive summary

East coast electricity and gas highlights

Record distributed PV output continued to shape the National Electricity Market (NEM) demand profile

- All mainland NEM regions experienced their highest Q4 underlying demand since at least 2016, yielding the highest NEM-wide underlying demand average for any Q4 at 23,737 megawatts (MW) in Q4 2024, up 2.4% from the same quarter last year.
- Distributed photovoltaic (PV) output was at an all-time quarterly high in all NEM regions, with a NEM-wide average output of 4,054 MW, 18% higher than the previous record of 3,433 MW set in Q4 2023. As a result, average operational demand was slightly lower across the NEM, at 19,683 MW, down 0.3% from Q4 2023.
- The NEM operational demand profile continued to widen at both its extremes, with growth in underlying demand driving new Q4 maximum demand records for the NEM (33,716 MW), and in Queensland (9,814 MW) and Victoria (9,851 MW). At the other end, distributed PV output drove new all-time minimum demand records for the NEM (10,073 MW), and in Queensland (3,091 MW), New South Wales (3,121 MW), South Australia (-205 MW) and Tasmania (728 MW).

Demand growth, transmission constraints and reduced coal availability contributed to higher NEM wholesale electricity prices

- NEM wholesale spot prices averaged[1] $88 per megawatt hour (MWh) over Q4 2024, up 83% from the corresponding quarter last year, with New South Wales ($143/MWh) and Queensland ($127/MWh) at Q4 record highs. NEM wholesale prices were, however, 26% lower than Q3 2024's average of $119/MWh.
- Average wholesale prices in South Australia ($52/MWh) and Victoria ($45/MWh) were at less than half the level of the northern regions with constraints on the Victoria – New South Wales Interconnector (VNI) frequently limiting the northwards transfer of lower-cost energy. With Basslink's capacity to transfer lower-cost energy from Victoria often fully utilised during daylight hours, wholesale spot prices in Tasmania averaged $74/MWh for the quarter.
- Black coal-fired generators recorded all-time low availability during Q4 2024, down 6.5%, and reduced volumes offered to the market at prices below $100/MWh. Brown coal-fired output fell to its lowest level for any quarter, down 304 MW (-9.2%) from Q4 2023. These factors contributed to higher overnight prices across the NEM and to several high-priced events in New South Wales and Queensland on high demand days.

[1] Calculated as the time-weighted average, which is the simple average of regional wholesale spot prices over each 5-minute dispatch period over the quarter. The Australian Energy Regulator (AER) reports volume-weighted average spot prices, which are weighted using native regional demands.

Changing supply mix and record negative price occurrence

- Growth in distributed PV output and reduced coal availability saw renewable sources reaching a record 46% share of the overall NEM supply mix, with the contribution of coal-fired generation dipping below 50% for the first time. This drove quarterly NEM total emissions and emissions intensity to new all-time record low levels of 24.9 million tonnes of carbon dioxide equivalent (MtCO2-e), down 1.7% from Q4 2023, and 0.57 tonnes of carbon dioxide equivalent (tCO2-e)/MWh, down 3.2% from Q4 2023, respectively.
- Renewable contribution also set a record on a half-hourly basis, reaching 75.6% of total NEM generation on Wednesday 6 November 2024, with distributed PV accounting for 43% of the generation mix, while grid-scale solar and wind contributed 19% and 11% respectively.
- With grid-scale solar output also at a new quarterly high average of 2,212 MW (up 9% year on year), a record high of 23% of intervals experienced negative or zero wholesale prices across the NEM. South Australia (at 38%), Victoria (at 34%) and New South Wales (at 13%) all reached their highest ever number of intervals with negative or zero prices in this quarter.

East coast Q4 2024 gas prices higher than Q4 2023, Queensland liquified natural gas (LNG) sets new demand record

- East coast wholesale gas prices averaged $13.60 per gigajoule (GJ) for the quarter, higher than Q4 2023's $10.83/GJ and Q3 2024 which averaged $12.50/GJ.
- Gas demand increased by 4% from Q4 2023, driven by record demand for Queensland LNG exports for any quarter (+17 petajoules (PJ)), and higher supply to gas-fired generation (+4 PJ). AEMO markets demand decreased (-3 PJ), impacted by significantly warmer than average temperatures across the quarter.
- While projects associated with Queensland LNG exports reduced supply into the domestic market, Victorian production increased, with the Otway Gas Plant continuing to see an increase in supply in Q4 (+6.1 PJ), and Longford Q4 gas production increasing for the first time since Q4 2022 (+3.7 PJ).
- The Queensland Gas Pipeline (QGP) supply interruption that began on 5 March 2024 ended on 10 December after Jemena advised AEMO that repair works were complete. AEMO revoked its East Coast Gas System Risk or Threat Notice for the QGP on the same day.

Western Australia electricity and gas highlights

Increase in battery capacity driving changes in the Wholesale Electricity Market (WEM)

- An additional 425 MW of battery capacity was either completed prior to Q4 2024 or undertaking commissioning tests during the quarter. As a result, average battery withdrawal (charging) increased to 116 MW during minimum demand periods (between 10:00 and 14:00) and average battery generation increased to 103 MW during peak demand periods (between 17:30 and 21:00) in Q4 2024, up 112 MW and 97 MW from Q4 2023 levels, respectively.
- Batteries also participated in the frequency co-optimised essential system services (FCESS) markets for the first time in a Q4, capturing 36% of the FCESS market share (from 0% in Q4 2023) by volume. This displaced

gas, which was down an average of 79.4 MW (-28.9%), and coal (contingency markets only), which reduced on average by 12.8 MW (-40.8%).

Growth in underlying demand offset by record distributed PV and new WEM demand records set at both ends of the spectrum

- The WEM's average underlying demand increased to a new Q4 high of 2,539 MW, 105 MW (+4.3%) higher than during Q4 2023. This was offset by a 110 MW (+20%) uplift in distributed PV, leading to a 16.7 MW (-0.9%) reduction in average operational demand.
- High temperatures on 11 December 2024 resulted in a new maximum underlying demand record for the WEM of 5,263 MW and a new Q4 operational demand record of 4,163 MW. Conversely, there were also records set for minimum operational demand (511 MW) and minimum unscheduled operational demand (474 MW) on 10 November 2024, when low weekend demand combined with mild temperatures and high distributed PV.

Increasing renewables and coal reductions changing WEM supply mix

- Coal facilities contributed 139 MW less (-19.5%) to average WEM generation during Q4 2024 due to reduced coal facility availability during Q4 2024 compared to Q4 2023. This was replaced by increases of distributed PV by 110 MW (+20.3%), gas by 97 MW (+14.4%) and batteries by 33 MW (from a base of 2.2 MW in Q4 2023).
- The replacement of emissions-intensive coal generation by renewables and gas generation resulted in a 5.3% reduction in WEM total emissions (Q4 2024 compared to Q4 2023) to 2.06 MtCO2-e. This was driven by lower operational demand, down on average 16.7 MW (-0.9%) and lower emissions intensity of 0.518 tCO2-e/MWh (-1.3%).
- Average renewable contribution set a new all-time quarterly high of 46.4%, a 3.6 percentage point (pp) increase on the previous record observed in Q4 2023. This was primarily driven by distributed PV contribution increasing 3.4 pp (to 25.8%) and battery contribution increasing 1.3 pp (to 1.4%).
- The WEM also experienced its highest peak renewable contribution of 85.1% during the 13:35 interval on 17 November 2024, with distributed PV accounting for 72.4% of the generation mix, and wind providing 11.3%. The previous peak of 84.3% was recorded during the 11:00 interval on 12 December 2022.

Energy clearing prices reduced, with changes in essential system services (ESS) costs

- The average energy price in the WEM in Q4 2024 was $79.93/MWh, a decrease of $3.70/MWh (-4%) from Q4 2023 and similar to Q3 2024's average energy price of $80.15/MWh.
- Rule changes midway through Q4 2024 resulted in a significant reduction in ESS costs compared to the previous quarter (Q3 2024). This consisted of a reduction of FCESS Uplift payments by $28.8 million (-36%), which was slightly offset by an increase in Energy Uplift payments (for facilities constrained on to provide Rate of Change of Frequency (RoCoF) control service) of $1.5 million.
- Non-co-optimised essential system services (NCESS) costs increased by $23.4 million from Q4 2023 due to the commencement of seven NCESS contracts in Q4 2024, providing up to 311 MW of peak demand service and 197 MW of minimum demand service.

Q4 2024 saw a reduction in both production and consumption for WA domestic gas

- Western Australia's domestic gas consumption reduced to 93.9 PJ in Q4 2024 (-2.6% compared to Q4 2023). Likewise, production reduced to 104.3 PJ (-1% compared to Q4 2023). Storage saw a net withdrawal of 1 PJ, reversing a net injection in Q4 2023 of 2.3 PJ.

Contents

1 Weather

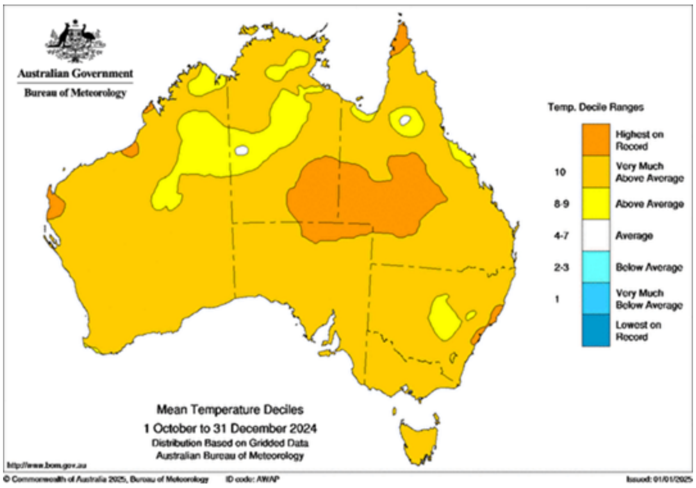
Q4 2024 saw above-average temperatures across most of Australia, as illustrated in Figure 1. The quarter was generally characterised by warmer conditions, with severe heatwaves impacting the Northern Territory, Western Australia, and Queensland in October, followed by south-eastern Australia in November.

Perth Metro recorded its second-ever October streak of four consecutive days with maximum temperatures of 32°C or higher[2], the other occurring in October 2015. In contrast, the last week of October witnessed a cold front sweeping across south-eastern Australia, bringing unusually low minimum temperatures to parts of south-eastern and central Australia.

A particularly intense heatwave developed in mid-November, causing daytime temperatures to soar up to 14°C above average[3] in some parts of South Australia, Victoria, and New South Wales. The warmer conditions continued into December, resulting in the area-averaged mean temperatures for all states and territories being among the top 10 warmest Decembers on record for each state or territory.

Figure 1 Warmer than long-term average throughout Australia

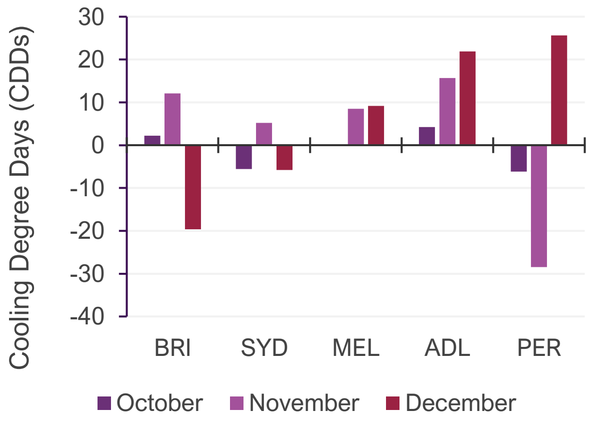
Q4 2024 mean temperature deciles for Australia



Source: Bureau of Meteorology (BOM)

Figure 2 Higher cooling requirements in southern regions

Cooling Degree Days (CDDs) variance by capital city – 2024 vs 2023



Compared to Q4 last year, cooling degree days (CDDs)[4] for Adelaide were 42 degree days higher (+290%), while Melbourne saw an increase of 18 degree days (+361%) (Figure 2). Brisbane and Sydney also experienced a notable rise in CDDs during November, although December saw a significant reduction in cooling requirements. In Perth, October and November experienced a year-on-year decline in CDDs, while December saw a notable increase.

[2] http://www.bom.gov.au/climate/current/month/wa/archive/202410.perth.shtml

[3] http://www.bom.gov.au/clim_data/IDCKGC1AR0/202411.summary.shtml

[4] A CDD, which is based on the average daily temperature, is a measurement used as an indicator of outside temperature levels above what is considered a comfortable (base) temperature (24°C). CDD value is calculated as max (0, average temperature – base temperature).

In Q4 2024, average maximum temperatures in southern major cities were notably higher than in the same period of 2023, with Adelaide and Melbourne experiencing increases of 2.9°C and 2.2°C respectively (Figure 3). These higher daytime temperatures contributed to greater cooling demand.

Minimum temperatures were higher in all major east coast cities, contributing to increased overnight cooling requirements. Compared to Q4 2023, average minimum temperatures rose by 0.8°C in Brisbane, 0.5°C in Sydney, 0.5°C in Melbourne, 1.9°C in Adelaide, and 0.4°C in Hobart (Figure 4). However, Perth witnessed a drop in both average maximum and minimum temperatures compared to Q4 2023, with the maximum temperature decreasing by 1.9°C and minimum by 1.0°C.

Figure 3 Higher maximum temperatures in Melbourne and Adelaide

Average quarterly maximum temperature variance by capital city

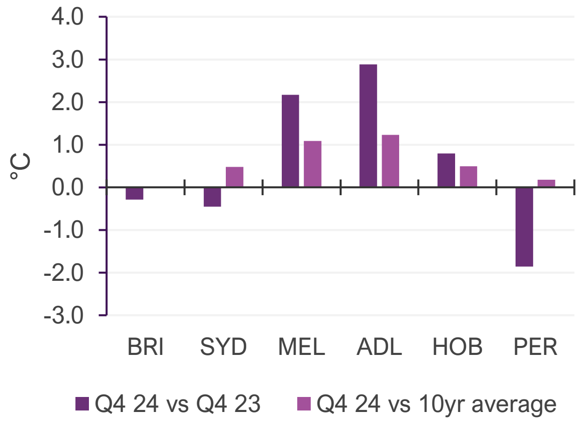
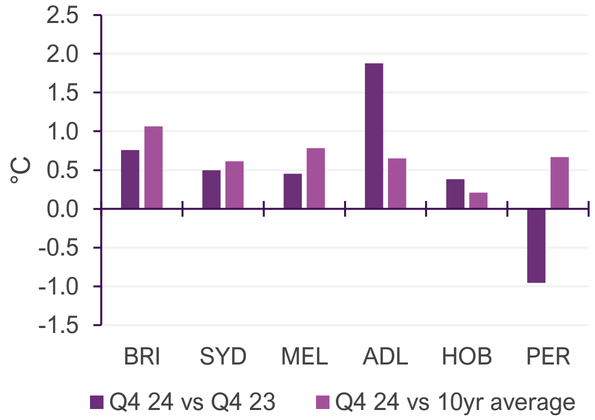


Figure 4 Higher minimum temperatures compared to long term averages in all major cities

Average quarterly minimum temperature variance by capital city



2 NEM market dynamics

2.1 Electricity demand

In this quarter, NEM-wide underlying demand[5] reached its highest Q4 average at 23,737 MW, 558 MW (+2.4%) higher than the same period last year. This growth in underlying demand contrasts with the downward trend seen in gas demand from residential, commercial and industrial consumers (as discussed in Section 3.2), with electrification a likely driver of this trend[6], along with warmer temperatures.

The growth in underlying demand was offset by distributed PV output averaging 4,054 MW, the highest recorded for any quarter, some 621 MW (+18%) above the previous record of 3,433 MW set in Q4 2023. As a result, compared to Q4 2023, average operational[7] demand across the NEM declined by 63 MW (-0.3%) to 19,683 MW, its second-lowest average for any quarter since Tasmania joined the market in 2005 (Figure 5).

Figure 5 Underlying demand growth to new Q4 high, offset by record distributed PV output

NEM average underlying and operational demand – Q4s

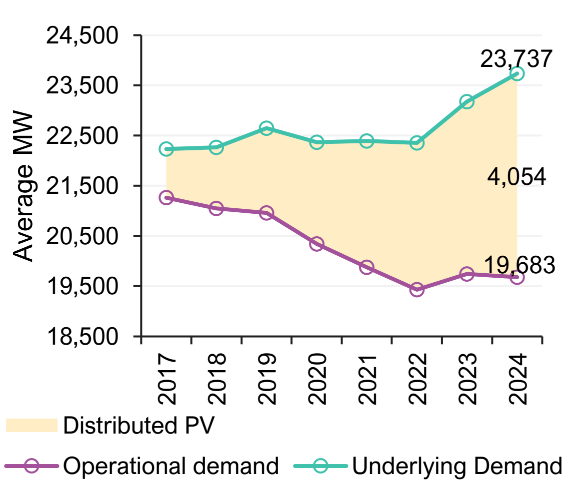
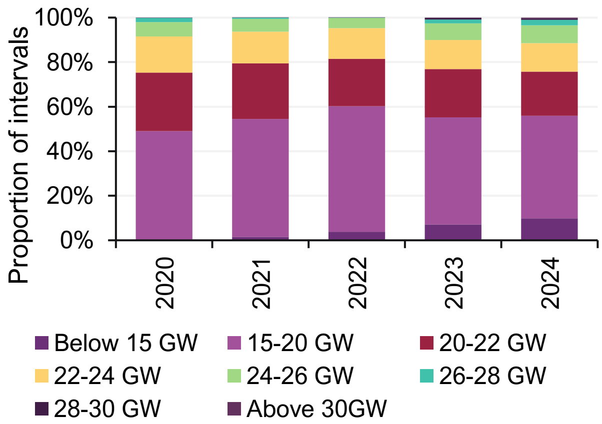


Figure 6 Growing proportion of intervals in both low and high operational demand ranges

NEM operational demand range - Q4s



The quarter began with low operational demand, recording the lowest October average since 2005. During October, several regions, as well as the whole NEM, experienced record low minimum demand levels. In November, warmer conditions pushed underlying demand up, but this was offset by higher distributed PV output, driven by growth in rooftop PV installations. This trend continued into December, resulting in a small year-on-year reduction in average operational demand for Q4 2024.

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

[6] For more information see: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting.

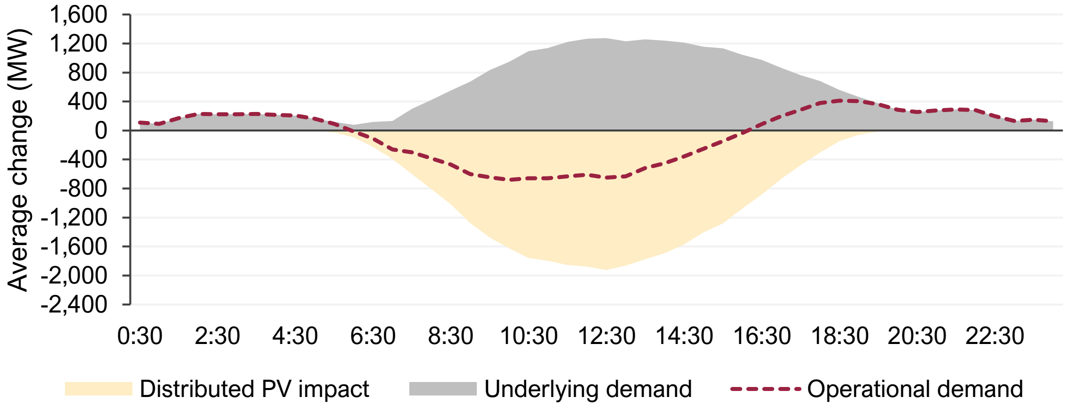
[7] Operational demand in a region is demand that is met by local scheduled generation, semi-scheduled generation, non-scheduled wind and solar generation of aggregate capacity >=30 MW, and by generation imports to the region, excluding the demand of local scheduled loads and including Wholesale Demand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

As illustrated in Figure 6, the NEM-wide operational demand trend shows an increase in the number of intervals below 15 gigawatts (GW), driven by higher distributed PV output. In this quarter, 9.9% of intervals saw NEM-wide operational demand fall below 15 GW, compared to 7.1% in Q4 2023. At the higher end, the proportion of intervals exceeding 26 GW also showed an upward trend, increasing from 0.2% in Q4 2022 to 2.6% in Q4 2023, and reaching 3.5% in Q4 2024, driven by growing underlying demand.

The increase in underlying demand was evident at most times of the day, with notable growth during mid-day periods reflecting warmer daytime temperatures, particularly in November and December (Figure 7). Overnight hours also saw an increase in underlying demand, particularly in November and December, contributed to by higher minimum temperatures (see Figure 4 in Section 1). However, the significant lift in distributed PV output resulted in lower average operational demand during morning and afternoon periods.

Figure 7 Underlying demand higher at all times but distributed PV lowered daytime operational demand

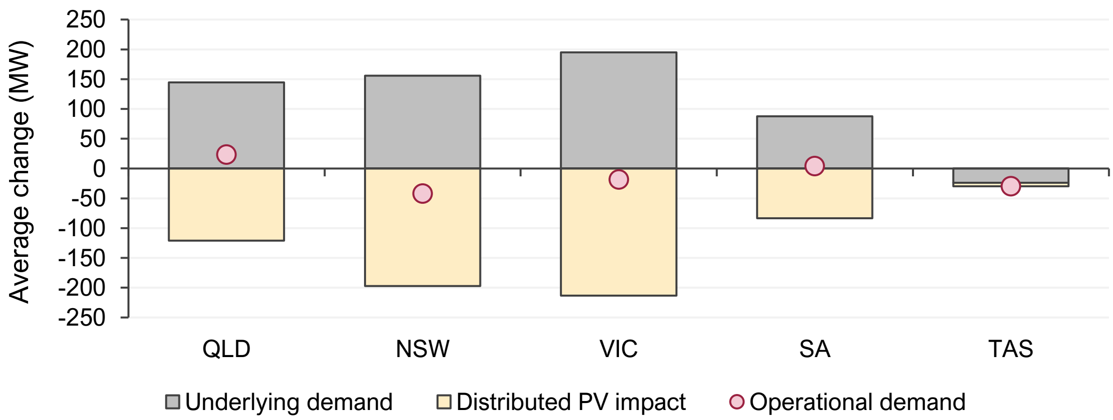
Changes in NEM average operational demand by time of day – Q4 2024 vs Q4 2023



In Q4 2024, all NEM regions except Tasmania experienced higher underlying demand compared to Q4 2023. However, the quarter also saw record-high average distributed PV output levels for any quarter in all regions, driven by growth in distributed PV installations and increased solar exposure in major cities, resulting in average operational demand being lower or flat except in Queensland (Figure 8).

Figure 8 Strong year-on-year increases in underlying demand in mainland regions

Changes in average demand components by region – Q4 2024 vs Q4 2023



Comparing Q4 2024 with Q4 2023:

- **Queensland's** underlying demand reached a new Q4 high of 7,344 MW this quarter, an increase of 144 MW (+2.0%) from Q4 2023. Higher temperatures contributed to an increase in underlying demand during daytime hours while distributed PV output reached an all-time high of 1,184 MW, resulting in a slight increase of 23 MW (+0.4%) in operational demand to 6,160 MW.
- **New South Wales** experienced an increase of 156 MW (+1.9%) in underlying demand to average 8,347 MW, its highest Q4 average since 2010. Like Queensland, daytime underlying demand increased significantly while higher minimum temperatures contributed to a slight increase in overnight demand. Distributed PV output saw a record high of 1,352 MW, which drove a drop in overall operational demand by 42 MW (-0.6%) to 6,995 MW.
- In **Victoria**, underlying demand reached its highest Q4 average since 2013 at 5,289 MW, 195 MW (+3.8%) higher than Q4 2023. This increase was evident at all times of the day, in line with higher CDDs. Distributed PV saw a record high average output of 942 MW, yielding a drop of 19 MW (-0.4%) in average operational demand to a record Q4 low of 4,347 MW.
- **South Australia** saw an 87 MW (+5.8%) increase in underlying demand to average 1,606 MW, its highest Q4 average since at least 2016[8]. While this increase was evident at most hours of the day, it was more notable during daytime, with elevated cooling requirements. Overnight periods also saw increased underlying demand compared to previous year, alongside higher minimum temperatures. South Australia's distributed PV reached an all-time high average of 513 MW this quarter, while operational demand averaged 1,093 MW, marginally higher than Q4 2023's 1,089 MW.
- **Tasmania** experienced the quarter's only decrease in regional underlying demand, down 24 MW (-2.4%) from Q4 2023 to an average of 1,151 MW. Unlike other NEM regions, Tasmania saw lower average underlying demand in all hours due to a notable demand drop during December. Tasmania also recorded its all-time highest average distributed PV output at 64 MW. These factors jointly reduced operational demand by 30 MW (-2.7%) to average 1,087 MW this quarter.

Maximum and minimum demands

As the range of NEM operational demand expanded at both ends of the scale, several NEM regions set new records for both minimum and maximum demand during this quarter (Table 1).

This quarter's maximum NEM-wide operational demand reached a new Q4 high of 33,716 MW during the half-hour ending 1800 hrs on Monday, 16 December 2024. This was an increase of 3,536 MW (+11.7%) from Q4 2023's maximum of 30,180 MW and a 159 MW (+0.5%) increase from the previous Q4 high set in 2009. Elevated cooling requirements driven by extremely hot days in December also resulted in both Queensland and Victoria reaching their highest ever Q4 maximum demands at 9,814 MW and 9,851 MW respectively (Figure 9).

October witnessed episodes of mild temperatures and sunny days with high distributed PV output leading to all NEM regions, except for Victoria, recording all-time[9] minimum demand records. NEM-wide operational demand reached a new record minimum of 10,073 MW during the half-hour ending at 1130 hrs on Saturday, 26 October

[8] The quarterly underlying demand records for NEM regions are computed based on AEMO's distributed PV data starting from May 2016.

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

2024, 936 MW (-8.5%) lower than the previous record set in Q4 2023. On the same day at 1300 hrs, New South Wales reached a new minimum demand record of 3,121 MW, 434 MW (-12.2%) lower than the previous low set in Q3 2024 (Figure 10).

Queensland set a new minimum demand record of 3,091 MW during the half-hour ending 1030 hrs on Saturday, 5 October 2024, which was 5 MW (-0.2%) lower than the previous record set in Q3 2024.

South Australia's minimum demand dropped to a new low of -205 MW during the half-hour ending 1300 hrs on 19 October 2024. This was partly driven by a significant loss of load in South Australia, including Olympic Dam, due to extreme weather damaging several transmission towers causing a network outage.

Tasmania also set a new minimum demand record of 728 MW during the half-hour ending 1330 hrs on Wednesday, 25 December 2024 which was 4 MW (-0.5%) lower than the previous record set in Q1 2013.

Figure 9 Record high Q4 maximum operational demand in Queensland and Victoria

Maximum operational demand for mainland regions – Q4s

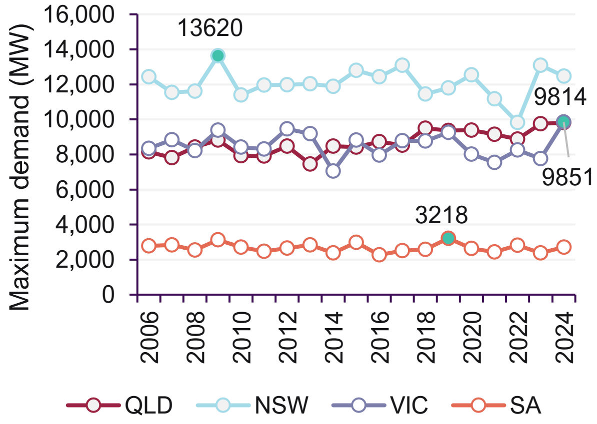


Figure 10 Record low minimum operational demand in all mainland regions, except Victoria

Minimum operational demand for mainland regions – Q4s

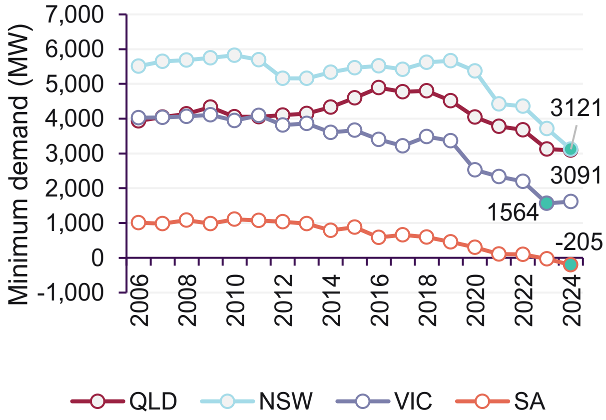


Table 1 Q4 2024 maximum and minimum operational demand records

Region	New Q4 maximum demand record	New all-time minimum demand record
NEM	33,716 MW (1800 hrs on Monday 16 December 2024) *Previous record: 33,557 MW on 19 November 2009*	10,073 MW (1130 hrs on Saturday 26 October 2024) *Previous record: 11,009 MW on 29 October 2023*
Queensland	9,814 MW (1800 hrs on Sunday 8 December 2024) *Previous record: 9,750 MW on 29 December 2023*	3,091 MW (1030 hrs on Saturday 5 October 2024) *Previous record: 3,096 MW on 18 August 2024*
New South Wales	-	3,121 MW (1300 hrs on Saturday 26 October 2024) *Previous record: 3,555 MW on 21 September 2024*
Victoria	9,851 MW (1700 hrs on Monday 16 December 2024) *Previous record: 9,462 MW on 29 November 2012*	-
South Australia	-	-205 MW (1300 hrs on Saturday 19 October 2024) *Previous record: -26 MW on 31 December 2023*
Tasmania	-	728 MW (1330 hrs on Wednesday 25 December 2024) *Previous record: 732 MW on 21 March 2013*

2.2 Wholesale electricity prices

In Q4 2024, wholesale electricity spot prices averaged $88/MWh[10] across the NEM, an increase of $40/MWh (+83%) compared to Q4 2023, but a decrease of $31/MWh (-26%) from Q3 2024 (Figure 11). The quarter began with relatively low spot prices, averaging $51/MWh in October. However, as demand increased, prices rose significantly, reaching $124/MWh in November before dropping to $92/MWh in December. The cap return[11] component of the NEM average price increased to an average of $17/MWh for the quarter, a sharp increase of $13/MWh (+352%) compared to Q4 2023. This was driven by several high-priced events in New South Wales and Queensland. The corresponding quarter in 2023 saw relatively little high-priced volatility across the NEM. The energy component of average spot prices was $71/MWh, up $27/MWh (+60%) from Q4 2023.

Figure 11 NEM average wholesale spot price increased year-on-year, but declined from the previous quarter

NEM average wholesale electricity spot prices – quarterly since Q4 2021

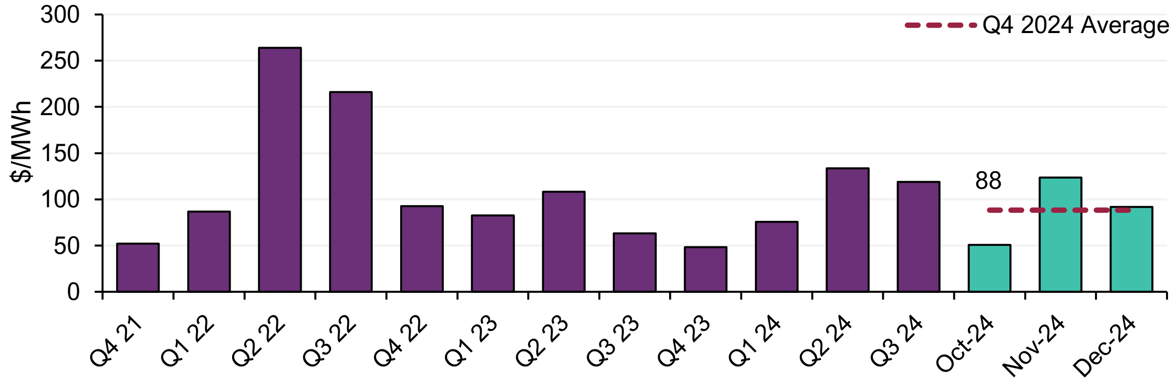
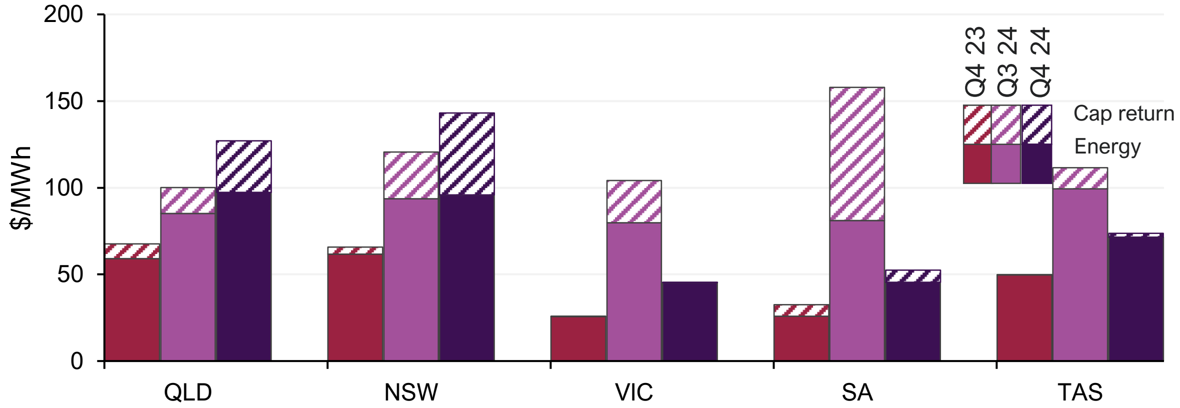


Figure 12 Higher year-on-year average spot prices, with elevated cap returns in northern regions

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



[10] Time weighted average – simple average of regional wholesale electricity spot prices over each 5-minute dispatch period over the quarter.

[11] The price analysis divides the average spot electricity 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.

All regions contributed to the year-on-year increase in quarterly average spot price with higher energy price components, while the cap return component jumped in Queensland and New South Wales (Figure 12). Compared to Q3 2024, prices in Victoria, South Australia and Tasmania decreased significantly, while those in the NEM's northern regions increased, principally due to increased high-priced volatility.

- **Queensland's** wholesale prices averaged $127/MWh in Q4 2024, a $59/MWh (+88%) increase on Q4 2023, setting a new Q4 high. The energy component averaged $97/MWh, up $38/MWh (+65%) from the same period last year. The cap return component reached a new Q4 high of $30/MWh, a $21/MWh (+252%) increase from Q4 2023. The energy price increases were more notable during overnight hours, partly driven by higher demand (see Figure 8 in Section 2.1) and higher-priced coal bids (see Figure 16 in Section 2.2.1), while high-priced volatility events during November drove a surge in evening peak prices and cap returns.
- **New South Wales** recorded the highest regional average price in the NEM this quarter, with a $77/MWh (+118%) increase to $143/MWh, a new Q4 high. The cap return component reached a new Q4 high of $47/MWh, with New South Wales' prices exceeding $300/MWh in 531 intervals during the quarter. The energy component averaged $96/MWh, up $34/MWh (+55%) from Q4 2023. Like Queensland, increases in the energy price component were more notable during overnight hours, with the high-priced volatility occurring over morning and evening peak periods.
- **Victoria's** wholesale prices averaged $45/MWh, a $20/MWh (+76%) increase on Q4 2023, although this was the lowest average for any NEM region this quarter. This change was solely due to a higher energy price component, as cap returns were close to zero in both this quarter and last Q4. Victoria saw increased prices primarily during overnight hours, partly driven by a significant uplift in underlying demand as well as lower brown coal-fired generation availability and output.
- In **South Australia**, spot prices averaged $52/MWh, up $20/MWh (+61%) from Q4 2023. As in Victoria, this increase was driven by the energy component, which averaged $45/MWh, an increase of $20/MWh (+75%) from last Q4. The cap return component remained largely unchanged at $7/MWh. Like other mainland regions, there was a notable uplift in overnight prices, with some high-priced volatility during morning peak and afternoon hours.
- **Tasmania** saw the lowest year-on-year percentage growth in prices this quarter with an increase of $24/MWh (+48%) to $74/MWh. The energy component increased by $22/MWh (44%) to $71/MWh, while the cap return component averaged $2/MWh. Higher overnight prices in Victoria reduced imports across Basslink and correspondingly raised overnight prices in Tasmania, offsetting any impact from lower operational demand. During daylight hours, despite frequent low and negative prices in Victoria, Basslink flows were generally constrained southwards and Tasmanian prices settled at significantly higher levels than those in Victoria.

During overnight hours in Q4 2024, higher average operational demand and lower output from brown coal-fired generators contributed to growth in prices in all regions. Several high-priced volatility events (discussed in Section 2.2.2) led to a surge in afternoon and evening peak prices, principally in the northern regions of Queensland and New South Wales. Mid-day prices between 1000 hrs and 1400 hrs remained largely unchanged with reduced operational demand (Figure 13).

Figure 13 NEM average price increased during overnight hours and evening peak period

NEM average spot price by time of day – Q4 2024 vs Q4 2023

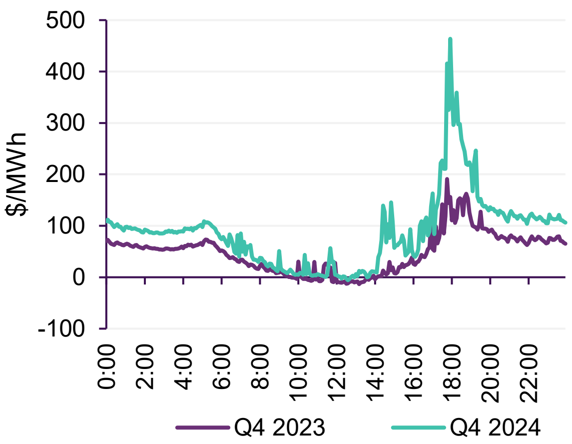
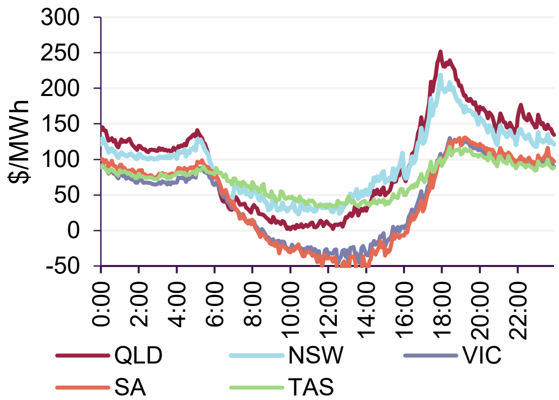


Figure 14 Significant price gaps between northern and southern regions

Average regional energy price by time of day – Q4 2024



There were several notable price separations between regions this quarter (Figure 14):

- As in many previous quarters, a marked price disparity between northern and southern mainland regions was evident throughout most hours of the day. During daytime hours, the average northward (export) limit on flows across VNI remained close to zero (discussed in Section 2.4), limiting flows into New South Wales and resulting in higher prices in New South Wales compared to Victoria. A smaller, but still significant price divide was observed during overnight hours as export limits on VNI continued to restrict the flow of lower cost energy from Victoria into New South Wales.
- Queensland and New South Wales experienced price separation during the mid-day period, primarily due to frequent binding of southward (import) limits on the Queensland – New South Wales Interconnector (QNI), discussed in Section 2.4. As a result, New South Wales' average spot prices were higher than those in Queensland during daytime periods this quarter. Across overnight hours, flows across QNI tended northwards from New South Wales into Queensland. However, as the QNI export limit bound during these periods, these northward flows were restricted, leading to overnight prices in Queensland exceeding those in New South Wales.
- Although Tasmania experienced lower operational demand this quarter compared to the same period last year, its average spot prices were notably higher. In overnight hours, Tasmanian prices increased in parallel with those on the mainland as southward (import) flows across Basslink reduced. During daytime hours, Tasmania's spot price remained significantly above Victoria's, as Basslink import capacity frequently constrained transfer of lower-cost energy from the mainland (discussed in Section 2.4).

2.2.1 Wholesale electricity price drivers

Table 2 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 2 Wholesale electricity price drivers in Q4 2024

Lower coal availability	This quarter, both black and brown coal availability decreased significantly compared to Q4 2023, driven by an increase in capacity on full outage (discussed in Section 2.3.1). Black coal availability hit an all-time low, with a year-on-year decline of 804 MW (-6.5%), while brown coal availability fell by 228 MW (-5.9%). This reduction in coal generation availability, particularly brown coal outages, contributed to the higher overnight prices. Additionally, the lower coal availability also contributed to several high-priced events in New South Wales and Queensland on peak demand days, driving up average prices in those regions.
Higher priced black coal bids	Black coal generators offered lower volumes across most price bands this quarter, with offers under $100/MWh falling by approximately 700 MW compared to Q4 2023 (Figure 16). As a result, the average price set by black coal when marginal rose to $108/MWh, up from $58/MWh in Q4 2023 (discussed in Section 2.2.4). This shift also led to higher gas-fired generation, which more frequently set prices during evening peak hours. This resulted in higher average prices set by gas when marginal at $189/MWh for the quarter. The frequency of prices across the NEM exceeding $100/MWh rose from 13% in Q4 2023 to 39% this quarter (Figure 15).
Higher overnight operational demand	All NEM mainland regions saw increases in average overnight operational demand this quarter, as higher minimum temperatures were recorded in all major cities compared to the previous year (discussed in Section 1). This lift in demand contributed to higher prices during overnight hours.
Transmission constraints	This quarter saw significant price separations due to interconnector constraints (Figure 14). Lower northward flow limits on VNI pushed northern prices higher, while binding southward limits on QNI kept daytime prices in New South Wales above Queensland's. Basslink import capacity limits kept Tasmania's prices above Victoria's during daytime hours (discussed in Section 2.4). Additionally, there were several intra-regional constraints and transmission outages such as the Marulan-Yass outage in early November that contributed to periods of high-priced volatility, particularly in New South Wales and Queensland.

Figure 15 Higher proportion of prices between $100/MWh and $200/MWh

NEM average spot price ranges – Q4 2024 vs Q4 2023

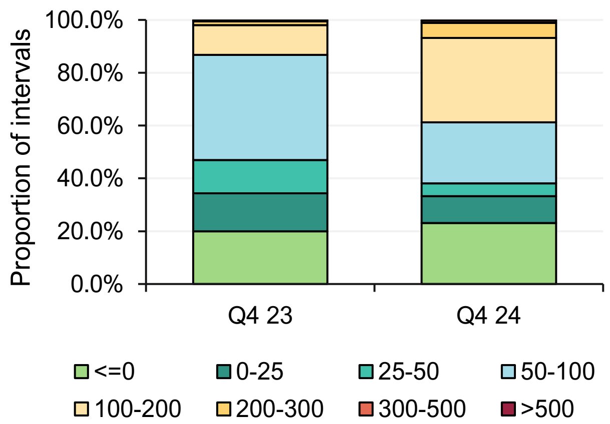
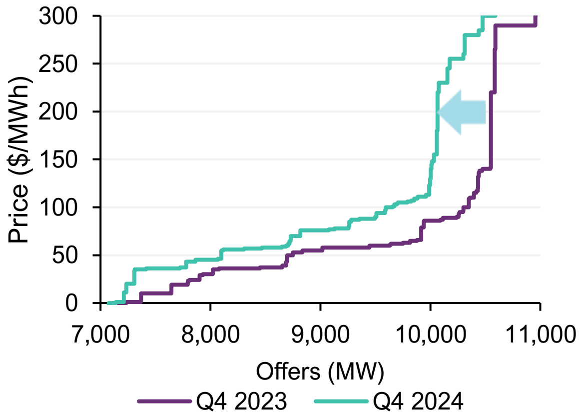


Figure 16 Less volume offered at all price bands by black coal generators

NEM black coal bid supply curve – Q4 2024 vs Q4 2023



2.2.2 Wholesale electricity price volatility

In Q4 2024, aggregate cap returns across the NEM – representing the contribution of any excess of spot price above $300/MWh – rose by $67/MWh, from $19/MWh in Q4 2023 to $86/MWh, the second highest Q4 level after $115/MWh recorded in Q4 2009 (Figure 17). Queensland and New South Wales accounted for most of the total NEM cap return, driven by several high-priced volatility events in November and December, particularly on 7 November and at the end of November and early December (Figure 18).

Figure 17 Significant cap returns in New South Wales and Queensland

Cap returns by region – quarterly

Figure 18 Significant volatility in New South Wales and Queensland in November

Cumulative cap return by region – Q4 2024

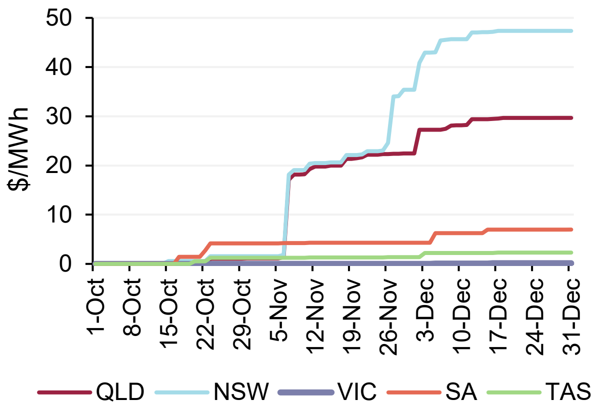


Table 3 summarises events of significant high-priced volatility during Q4 2024.

Table 3 Significant price volatility events in Q4 2024

Date	Region	Contribution to regional cap return ($/MWh)	Drivers
7 November	New South Wales	16.3	During the evening peak period, prices exceeded $14,000/MWh in New South Wales for 20 dispatch intervals (1 hour 40 minutes), and in Queensland for 19 intervals. Several black coal-fired units were offline, with around 2,700 MW of capacity unavailable in New South Wales and 2,100 MW in Queensland, contributing to high-priced volatility in both regions. Additionally, the outage of the Marulan-Yass transmission line in southern New South Wales capped generation output in that part of the state and prevented Victoria from supplying additional energy to New South Wales, further adding to the price volatility.
	Queensland	15.7	
27 November	New South Wales	9.4	On this day, New South Wales experienced peak operational demand exceeding 11,000 MW, more than 2,000 MW above peak November demands for the preceding three years, driven by a heatwave that pushed temperatures to a high of 39°C in some parts of Sydney. During this period, four coal units and one major gas unit were offline in New South Wales and transmission limitations capped the dispatch of some NSW generation and imports from both south and north of the state. Prices hit the market price cap (MPC) of $17,500/MWh at 1430 hrs and stayed at the MPC for 13 intervals until 1535 hrs, with a single intervening interval at $16,001/MWh.
2 December	New South Wales	5.5	On this day, New South Wales and Queensland saw peak operational demand surpassing 11,000 MW and 9,000 MW, respectively, with maximum temperatures exceeding 36°C in parts of Sydney and 33°C in parts of Brisbane. During the evening peak, a drop in solar output coincided with reduced wind availability, averaging around 340 MW in New South Wales and 220 MW in Queensland between 1730 and 1840 hrs. As a result, prices surged, with New South Wales experiencing nine intervals exceeding $10,000/MWh and Queensland seeing seven intervals surpassing $12,000/MWh.
	Queensland	4.8	

2.2.3 Negative wholesale electricity prices

Q4 2024 saw record high NEM-wide negative price frequency for any quarter, reaching 23.1%, a 3.2 pp increase from the previous high of 19.9% recorded in Q4 2023. All NEM regions experienced a higher occurrence of negative prices compared to Q4 2023, except Queensland, where the frequency dropped from 21.9% in Q4 2023 to 20.9% (Figure 19). New South Wales, Victoria, and South Australia each recorded all-time high regional negative price frequencies for any quarter, at 13.3%, 34.3% and 38.0% respectively.

The higher incidence of negative prices was especially pronounced in the southern regions, particularly Victoria and South Australia, where record-high distributed PV output lowered operational demand during daytime hours (Figure 20). Spot prices in South Australia were zero or negative for 84% of intervals between 1000 hrs and 1200 hrs this quarter, while the corresponding figure for Victoria was 79%.

Figure 19 Record high negative price occurrence in New South Wales, Victoria and South Australia

Negative price occurrence in NEM regions – Q4s

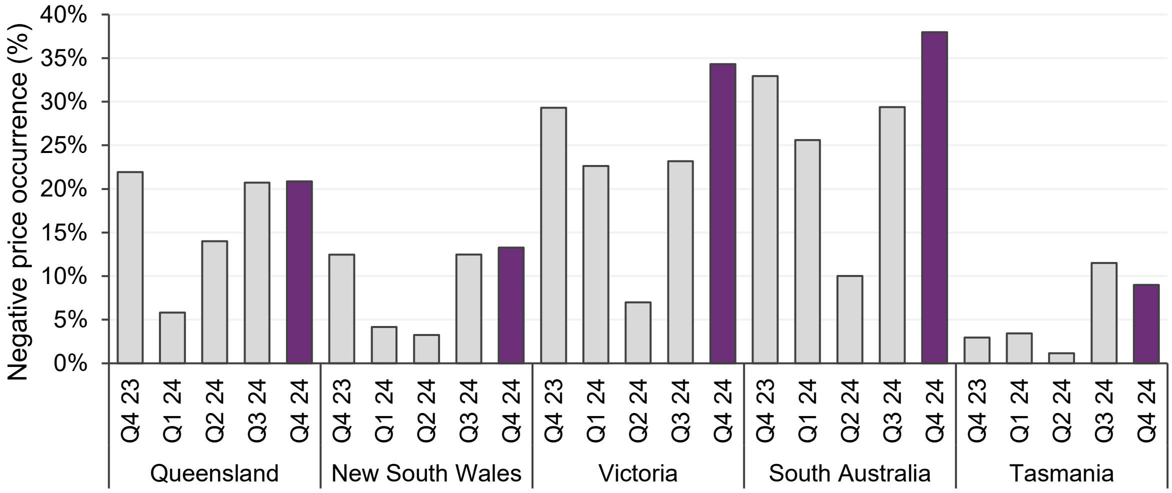


Figure 20 Victoria and South Australia led negative price occurrence

Negative price occurrence by time of day – Q4 2024

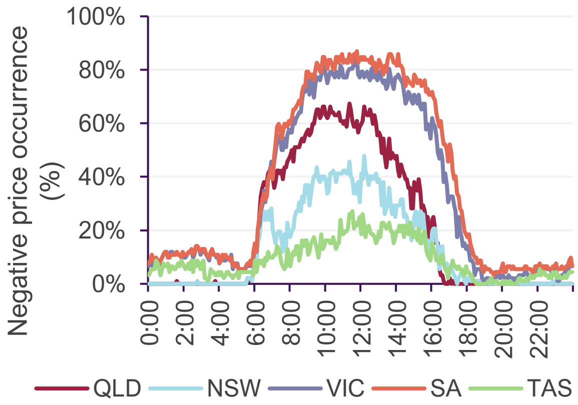
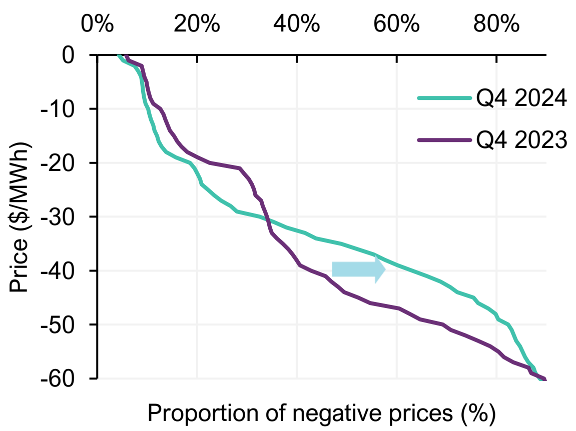


Figure 21 Increased proportion of negative prices between $0/MWh and -$40/MWh

Cumulative distribution of negative prices – Q4 2024 vs Q4 2023



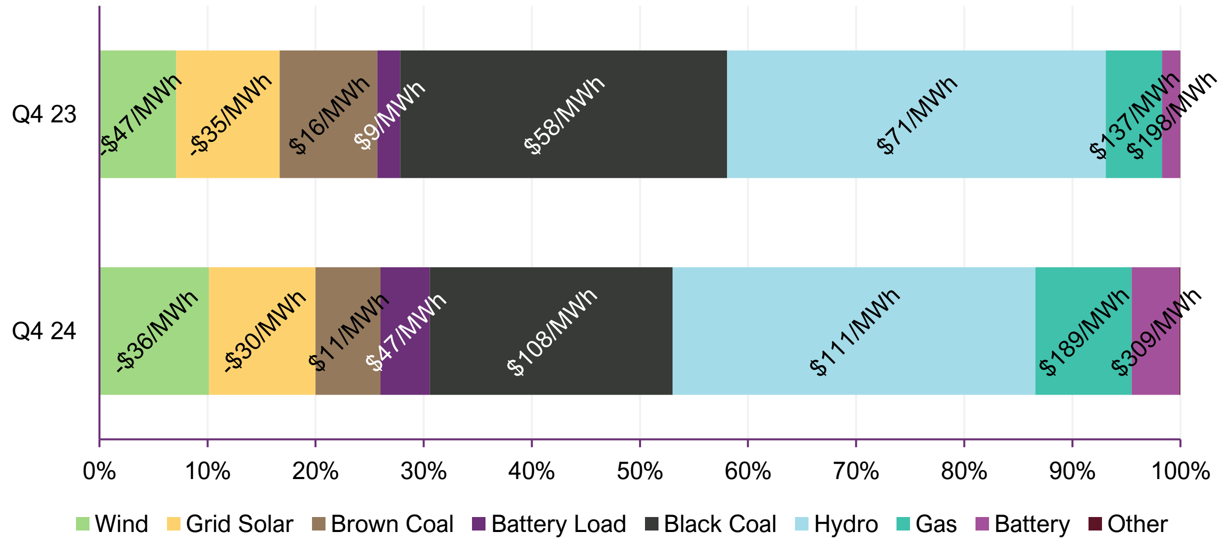
A higher proportion of negative prices across the NEM settled between -$40/MWh and $0/MWh (Figure 21), in line with lower large-scale generator certificate (LGC) prices this quarter, which averaged $34/certificate compared to $49/certificate in Q4 2023. As a result, the average spot price during negative price intervals rose from -$44.4/MWh in Q4 2023 to -$41.3/MWh in Q4 2024, partially offsetting the impact of higher negative price frequencies. The negative price impact, the combined effect of negative price levels and frequencies on quarterly average price[12], was larger this quarter in all NEM regions, with Victoria reaching a record high of $15.7/MWh.

2.2.4 Price-setting dynamics

Reflecting the strong overall increase in average spot prices this quarter, there were material upward movements in average prices set when marginal for most fuel types (Figure 22). Frequencies of price-setting fell for black coal, brown coal, and hydro sources compared to Q4 2023, with other fuel types recording increases.

Figure 22 Batteries, gas, hydro and black coal saw largest increases in average prices set when marginal

NEM price-setting frequency and average spot price when price-setter by fuel type – Q4 2024 vs Q4 2023



Black coal saw a notable drop in price-setting frequency, declining from 30% of dispatch intervals in Q4 2023 to 22% in Q4 2024. This reduction in price-setting frequency coincided with lower availability (see Figure 31 in Section 2.3.1) and reduced volumes offered at most price bands (see Figure 16 in Section 2.2.1). As a result, black coal set prices at an average of $108/MWh when marginal this quarter, up from $58/MWh during the same period previous year.

Similarly, brown coal saw a 3 pp reduction in price-setting frequency, averaging 6% this quarter and reflecting lower generation availability (see Figure 37 in Section 2.3.1). Unlike black coal, the average price set by brown coal when marginal decreased, from $16/MWh to $11/MWh.

Hydro, which remained the most frequent price-setter this quarter, saw a slight decrease of 1pp in its price-setting frequency, to 34% of dispatch intervals this quarter. The average price set by hydro increased by $39/MWh from Q4 2023, reaching $111/MWh this quarter.

[12] 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.

Gas set prices in 9% of intervals this quarter, an increase of 4 pp compared to Q4 2023, driven by a notable rise in the volumes offered at most price bands (see Figure 40 in Section 2.3.2). Increased gas generation, particularly in volatile evening peak periods, resulted in higher average prices set by gas at $189/MWh, $51/MWh above Q4 2023.

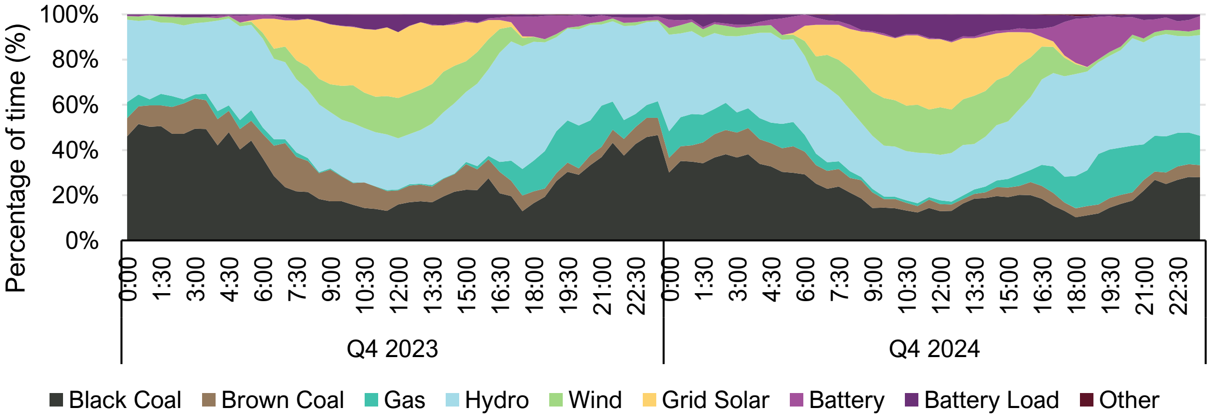
Wind and grid-scale solar sources each set prices in 10% of intervals, with average prices set when marginal increasing by $11/MWh and $5/MWh respectively to -$36/MWh and -$30/MWh. Battery generation set prices in 4% of intervals this quarter, an increase of 3 pp from Q4 2023. Batteries' involvement in price setting during peak high-priced volatility periods led to the largest year-on-year growth in average price set for any source, averaging $309/MWh, $110/MWh higher than in Q4 2023. Battery loads' demand-side bids[13] set prices in 5% of intervals this quarter, at an average price of $47/MWh.

Price-setting by time of day

On a time-of-day basis, the decline in black coal's price-setting frequency was observed across nearly all periods, with a more pronounced drop in overnight hours (Figure 23). Brown coal also saw a decrease in price-setting frequency throughout most hours, but the decline was more pronounced during daytime periods. Hydro experienced a reduction in price-setting frequency across daytime hours, particularly in the evening peak, but saw an increase in overnight hours.

Figure 23 Notable increase in price-setting frequency by batteries during peak hours while coal drops

NEM price-setting frequency by fuel type and time of day – Q4 2023 and Q4 2024



In this quarter, gas generators set prices more frequently during the overnight, morning, and evening peak periods, accounting for 14% of the intervals between 1800 and 0600, up from 9% during the same period last year. The increase on overnight price setting frequency was primarily driven by gas generators in South Australia.

Battery generation's price-setting frequency rose significantly during the evening peak period, averaging 13% between 1600 hrs and 2000 hrs, more than double the 6% recorded during the same hours in Q4 last year. Battery loads' increased price-setting frequency was primarily observed during mid-day periods, driven by higher charging during these hours.

[13] Scheduled market loads such as batteries and hydro pumps bid in the NEM spot market for volumes of energy at prices which specify the maximum level they will pay for that energy. When such a bid is marginal (incremental demand in a region would be met by reducing supply to the scheduled load) its bid price sets the regional reference price (RRP, or spot price).

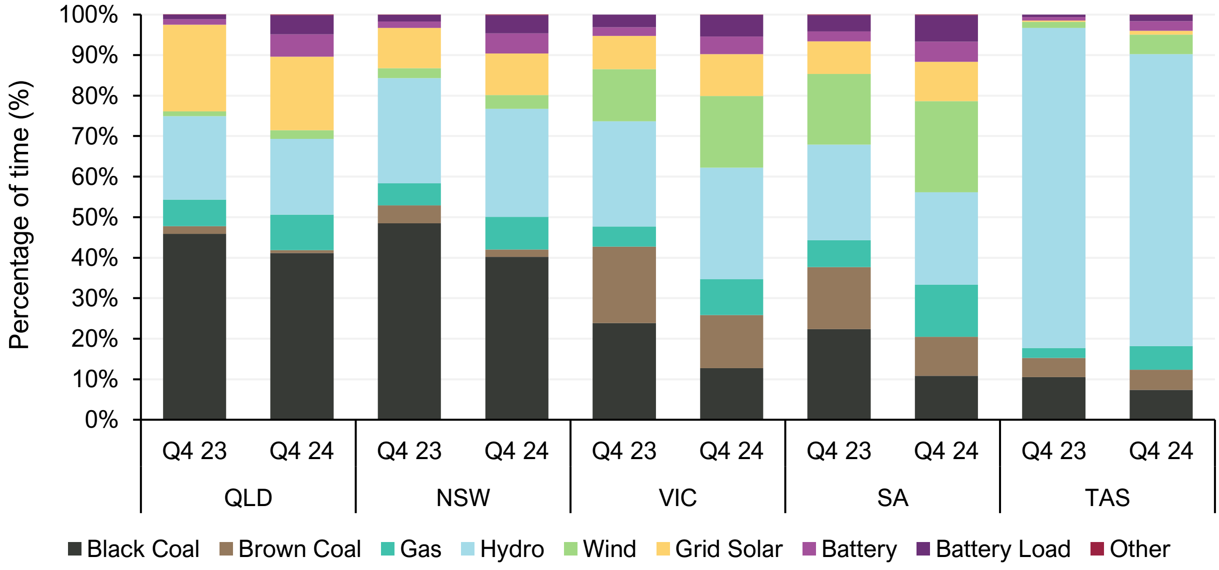
Regional price-setting trends

The drop in price-setting frequency for black coal was observed across all regions, with the most notable decreases of 11 pp in both Victoria and South Australia. Brown coal also saw a 6 pp decline in each of these regions, while hydro experienced a significant 7 pp drop in Tasmania (Figure 24). In contrast, the price-setting frequency of wind and grid solar saw greater increases in the southern regions, while grid solar set prices 3 pp less frequently in Queensland. Gas price-setting frequency rose across all regions, with the most significant increase of 6 pp in South Australia.

Batteries set prices more frequently in all NEM regions. In Queensland and New South Wales, battery generation and load price-setting frequencies increased by 4 pp and 3 pp respectively. Reflecting substantial peak period high-priced volatility in the northern regions, for New South Wales the average price set by battery generation rose by $264/MWh to $489/MWh, while in Queensland the increase was $223/MWh to $466/MWh. Notably, South Australia saw lower prices set by both batteries and gas compared to the same period last year, with average prices set falling by $66/MWh and $12/MWh respectively.

Figure 24 Gas, batteries and wind set prices more frequently in the NEM while other fuel types saw reductions

Regional price-setting frequency by fuel type – Q4 2024 vs Q4 2023



2.2.5 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 25 illustrates ASX daily prices for Q4 2024 base contracts across NEM 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.

In 2024, ASX contract prices for Q4 2024 increased through Q2 2024 with low wind and rainfall conditions putting upward pressure on wholesale spot prices. Contract prices stabilised in Q3 2024 before starting to rise in the northern regions reflecting high-priced volatility in early November in those regions. In Victoria Q4 2024 contract prices continued their Q3 2024 decline into Q4 2024, reflecting the growing price separation between southern and northern NEM regions, before stabilising from the middle of the quarter.

Figure 26 illustrates daily baseload $300 cap futures for Q4 2024 in New South Wales and the change in minimum cap return[14] in New South Wales during the quarter, showing the market's reactions to the high-priced volatility events on 7 and 27 November and 2 December 2024 (as discussed in Table 3 in Section 2.2.2).

Figure 25 Increase in northern region Q4 2024 base future prices driven by price volatility

ASX Energy – Regional daily Q4 2024 base future prices and daily average spot price for mainland regions

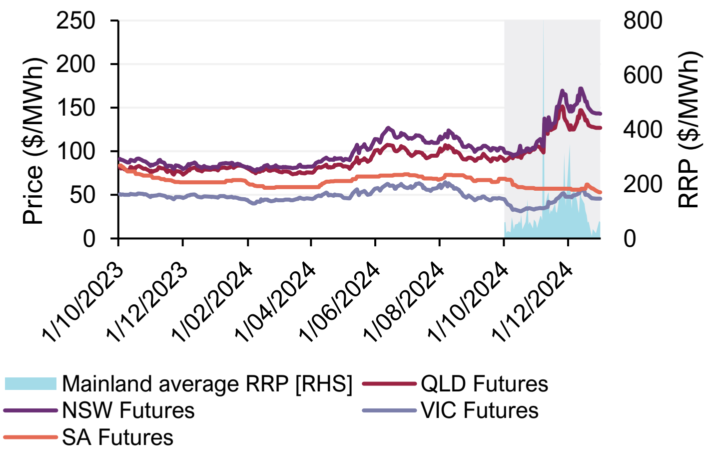
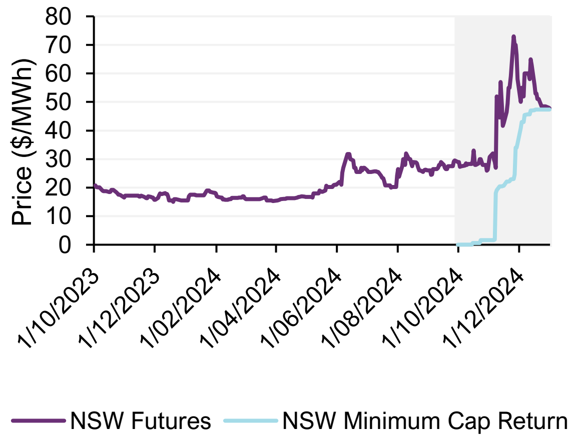


Figure 26 New South Wales cap prices responded to volatility events

ASX Energy – Daily Q4 2024 base cap price and the change in minimum cap return in New South Wales



Q4 2024 cap futures prices in New South Wales almost doubled from $27/MWh to $52/MWh on 8 November, following high-priced volatility lifting the minimum cap return for Q4 in New South Wales from $2/MWh to $18/MWh on 7 November. New South Wales Q4 cap futures prices then reached a high for the quarter of $73/MWh on 25 November alongside LOR3 (Lack of Reserve 3) forecasts for that region on the 27 November, before closing the quarter at $48/MWh.

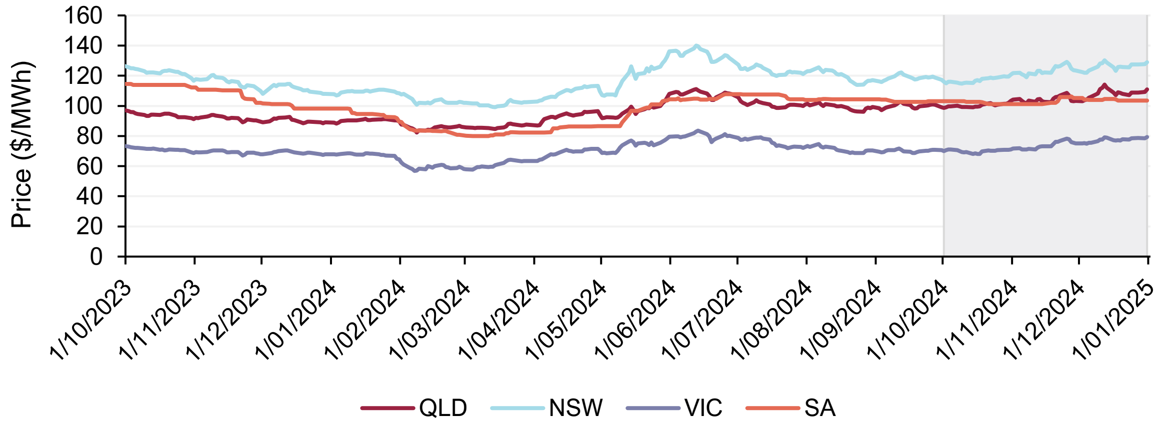
In this quarter, ASX base contract prices for the 2025-26 financial year (FY26) averaged $101/MWh across all mainland regions, slightly higher than the $99/MWh in the previous quarter and Q4 2024's $97/MWh (Figure 27).

Despite the lower average spot prices over Q4 2024, compared to the previous two quarters, mainland FY26 futures prices exhibited a slight upward trend over the quarter, increasing from $98/MWh at the start of the quarter to $106/MWh at the end. This reversed the slight downward trend experienced during the preceding quarter to leave FY26 prices at the same level as at the end of Q2 2024.

[14] The 'minimum cap return' at any point in the quarter represents the cumulative value of wholesale electricity prices in excess of $300/MWh up to that specific point, when averaged over the entire quarter. It is calculated by dividing the quarter to date sum of these wholesale electricity price exceedances by the full number of intervals in the quarter.

Figure 27 Slight upward trend in FY26 futures

ASX Energy – Daily FY 2025-26 base future by region

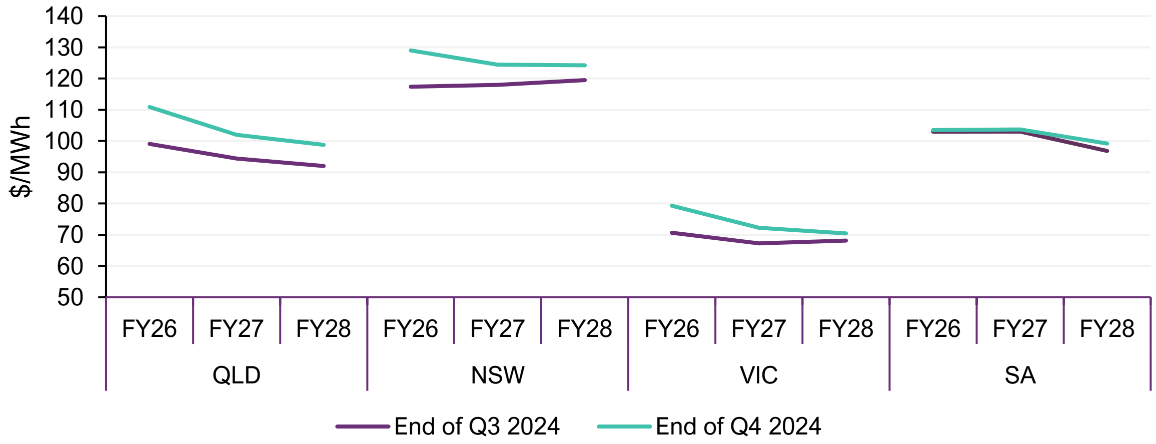


At the end of Q4 2024, future financial year contracts closed higher than at the end of Q3 2024 across all regions (Figure 28). New South Wales, Queensland and Victoria all experienced similar increases in FY26 prices, with New South Wales up $12/MWh (+10%) to end at $129/MWh, Queensland up $12/MWh (+12%) to end at $111/MWh, and Victoria up $9/MWh (+12%) to end at $79/MWh. FY26 prices in South Australia only increased slightly with a $0.5/MWh (+0.5%) rise to end the quarter at $103/MWh.

Despite these increases, futures contract prices exhibit a declining profile for forward years in all regions, with FY28 prices ranging lower than FY26 prices by between 4% (in New South Wales and South Australia) and 11% (in Queensland and Victoria).

Figure 28 Future financial year contracts ended the quarter higher than their end of Q3 2024 levels

Financial year contract prices in mainland NEM regions – end of Q3 2024 and end of Q4 2024



2.3 Electricity generation

Total generation across the NEM[15] averaged 24,308 MW in Q4 2024, 785 MW (+3.3%) higher than Q4 2023, driven by growth in underlying demand and increased supply requirements for battery charging (+55 MW) and hydro pumping (+97 MW).

Figure 29 shows changes in average NEM generation by fuel type and Table 4 shows the resultant changes in supply contribution. The share of overall NEM supply from black and brown coal-fired generation fell to less than 50% in Q4 2024, the lowest share since NEM start. Contributions from renewables reached a new quarterly high of 46.0%, up 2.8 pp from the previous high of 43.2% for Q4 2023.

Figure 29 Reduction in coal-fired generation offset by increased renewable and gas output

Change in NEM supply by fuel type – Q4 2024 vs Q4 2023

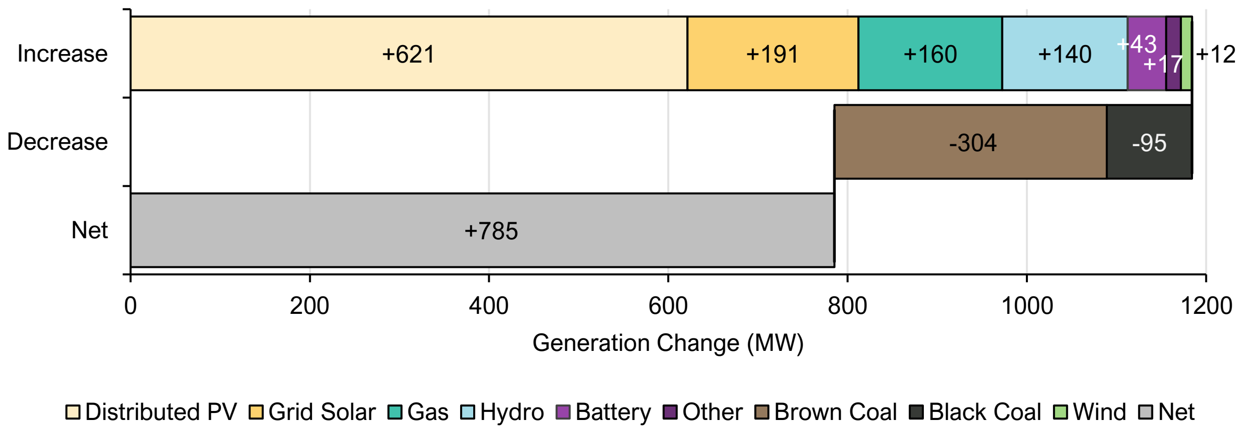


Table 4 NEM supply contribution by fuel type

Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Biomass	Battery
Q4 2023	39.1%	14.1%	3.6%	0.0%	14.6%	13.4%	8.6%	6.3%	0.2%	0.2%
Q4 2024	37.4%	12.4%	4.2%	0.0%	16.7%	13.0%	9.1%	6.6%	0.3%	0.4%
Change	-1.7%	-1.7%	0.5%	0.0%	2.1%	-0.4%	0.5%	0.4%	0.0%	0.2%

In summary, comparing Q4 2024 with Q3 2024:

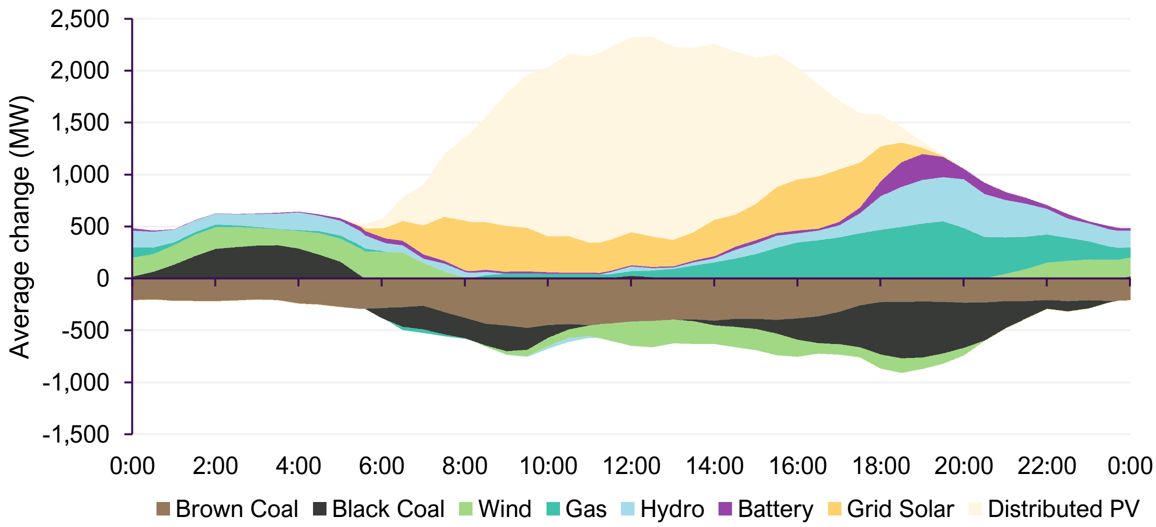
- Average output from both distributed PV and grid-scale solar reached new quarterly highs. Distributed PV output averaged 4,054 MW (+18%) driven by growth in installed capacity and increased solar irradiance. Grid-scale solar generation increased by 9.4% to average 2,212 MW with additional availablity from new and commissioning facilites moderated by greater economic offloading and network curtailment.

[15] 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.

- In contrast, average output from coal-fired facilities fell to new quarterly lows. Black coal-fired generation averaged 9,094 MW (-1.0%) and brown coal-fired generation averaged 3,002 MW (-9.2%) – with each source contributing 1.7 pp less to the overall supply mix this quarter.
- Gas-fired generation increased to average 1,011 MW (+19%), with this uplift most significant in the evening peak, recording an average output of 2,247 MW (+26%) between 1600 hrs and 2000 hrs (Figure 30).
- Hydro generation lifted across all hours of the day to average 1,612 MW MW (+10%), increasing to 2,701 MW (+13%) across the evening peak hours.
- Ongoing growth in installed battery capacity drove average battery generation to a new quarterly high of 90 MW (+91%), and contributed an average of 278 MW (+89%) to the evening peak.
- Wind generation averaged 3,160 MW (+0.4%), with growth in availability from new and commissioning facilities largely offset by reductions in output at existing facilities due to lower wind speeds, facility and network outages, and higher economic offloading.

Figure 30 Solar meeting daytime growth; gas, hydro and batteries lifting to cover evening peaks and lower coal

NEM generation changes by time of day – Q4 2024 vs Q4 2023



2.3.1 Coal-fired generation

Black coal-fired fleet

Black coal-fired generation recorded an all-time low quarterly average of 9,094 MW in Q4 2024, 95 MW (-1.0%) less than during the previous Q4 (Figure 31). Availability was also at an all-time low, averaging 11,652 MW in Q4 2024, down 804 MW (-6.5%) from Q4 2023. This significant reduction in availability was driven by an increase in capacity on full outage, averaging 3,866 MW over Q4 2024, 410 MW (+12%) higher than during Q4 2023 (Figure 32), as well as an increase in partial deratings at units remaining online.

Figure 31 NEM black coal-fired availability and generation reduced to all-time lows

Quarterly average black coal-fired generation and availability by region (including decommissioned units) – Q4s

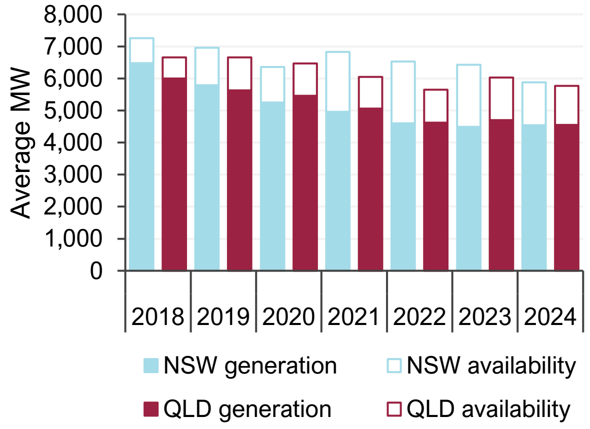
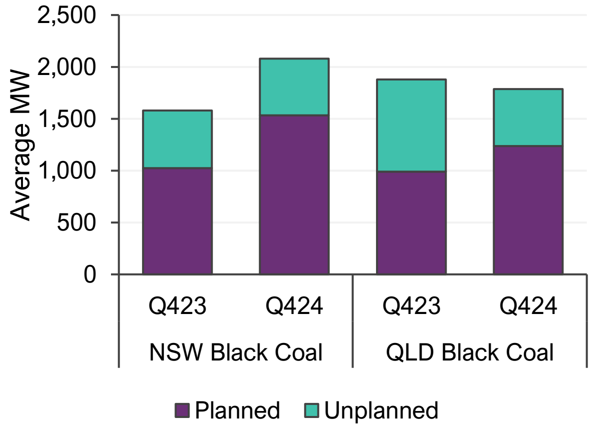


Figure 32 Increased black coal-fired capacity on full unit outage

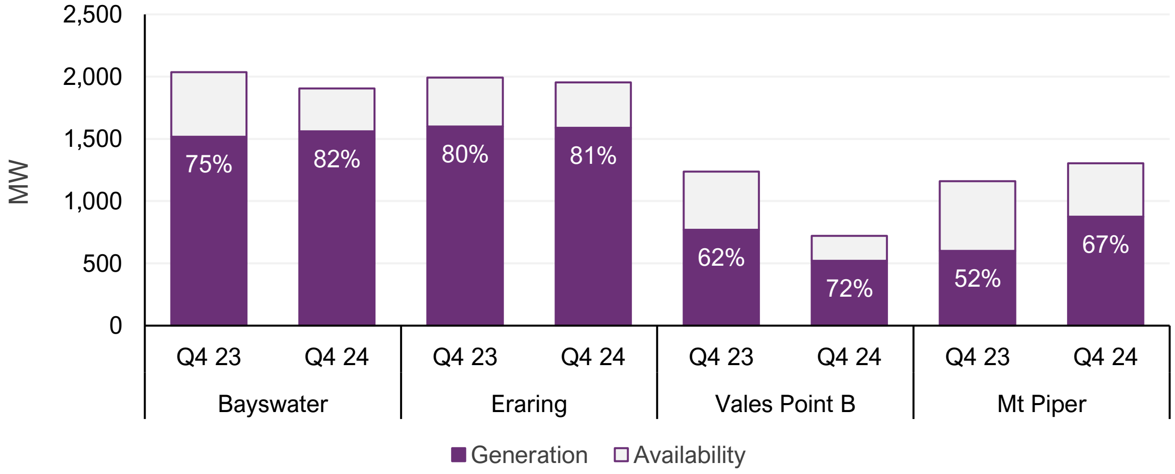
Average black-coal fired capacity on full outage – Q4 2024 vs Q4 2023



Average availability across New South Wales black coal-fired generators decreased by 542 MW (-8.4%), with a 499 MW (+32%) increase in average capacity on full unit outage over the quarter compared to Q4 2023. Despite this decrease in availability, average quarterly generation for the New South Wales fleet rose by 57 MW (+1.3%) from Q4 2023 levels, with Mt Piper, Vales Point B, and Bayswater power stations recording substantial increases in utilisation rates (Figure 33).

Figure 33 Higher utilisation rates at all New South Wales black coal-fired power stations

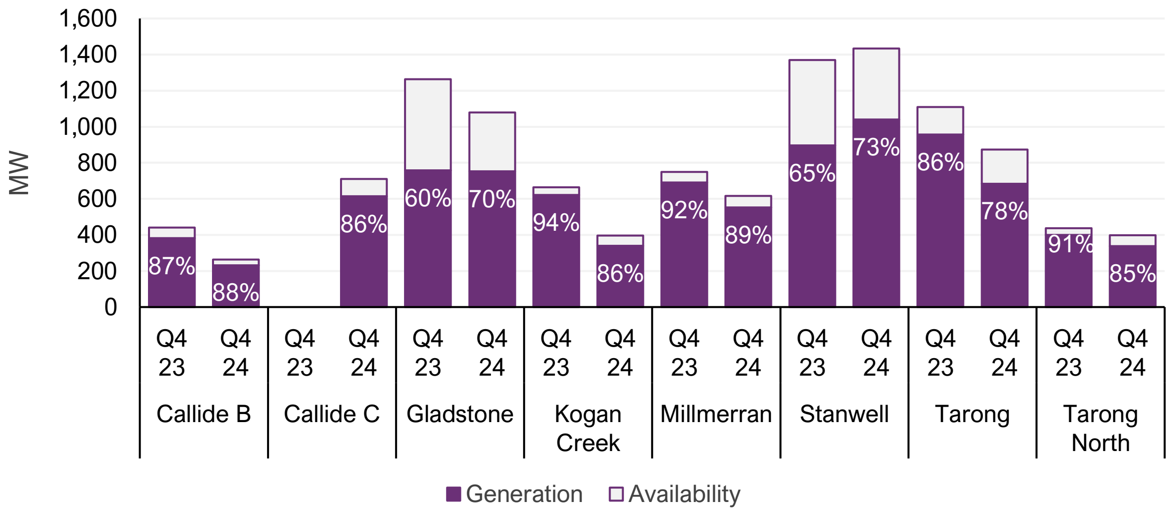
Average quarterly availability and generation for New South Wales black coal-fired power stations – Q4 2024 vs Q4 2023



Across the Queensland black coal-fired generators, the average capacity on full unit outage reduced by 90 MW (-4.8%) compared to Q4 2023. However, higher levels of partial outages saw average availability drop by 263 MW (-4.4%) and generation reduced by 152 MW (-3.2%, Figure 34). Partial outages, which reduce maximum availability at some units, included Callide C power station unit 4 which remained at around half of its rated capacity after its return from extended outage on 30 August 2024 until the first week of November. Millmerran's availability was also impacted by partial outages, including nine days in mid-November and six days in mid-December when both units were limited to less than half their rated capacity. Kogan Creek had notable reductions in both availability, down 267 MW (-40%), and generation, down 282 MW (-45%), when compared to Q4 2023, with full unit outages for three weeks in November and another two weeks in December.

Figure 34 Decreased availability at Queensland coal-fired power stations except Callide C and Stanwell

Average quarterly availability, generation and utilisation for Queensland black coal-fired power stations – Q4 2024 vs Q4 2023



Average black coal-fired generation in New South Wales was higher or unchanged across most hours of the day, but significantly lower over the evening peak when compared to the same intervals last Q4. Output was, on average, 285 MW less between the hours of 1600 hrs and 2000 hrs, reflecting the fleet's lower available capacity this quarter (Figure 35). All New South Wales black coal power stations, apart from Mt Piper, averaged lower output over the evening peak than in Q4 2023. The largest reduction was at Vales Point power station, with average station output across the evening peak down 368 MW year-on-year, with unit 6 offline for planned maintenance for all of October and November.

In contrast, average black coal-fired generation in Queensland was lower across all hours of the day in Q4 2024 when compared to Q4 2023 (Figure 36).

Figure 35 Significant decrease in New South Wales black coal generation during evening peak

New South Wales black coal-fired output by time of day – Q4s

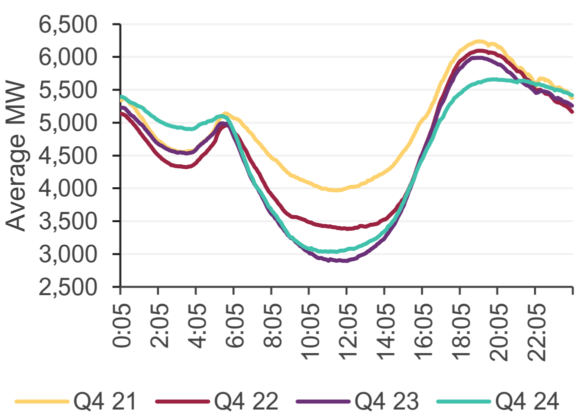
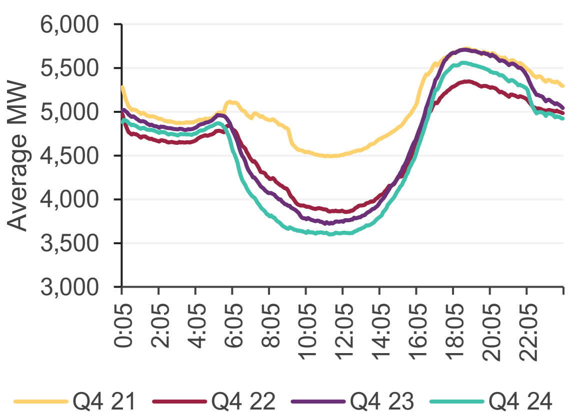


Figure 36 Decrease in Queensland black coal generation across all hours of the day

Queensland black coal-fired output by time of day – Q4s



Brown coal-fired fleet

In Q4 2024, average brown coal-fired generation declined to 3,002 MW, its lowest recorded level, and 304 MW (-9.2%) below Q4 2023 (Figure 37). This was partially driven by a 228 MW (-5.9%) decrease in availability with an additional average 256 MW (+29%) capacity on full unit outage over the quarter.

The reduction in brown coal-fired generation occurred across all hours of the day but was most pronounced during the middle of the day, leading to a 164 MW year-on-year increase in intraday swing to 1,415 MW in Q4 2024 (Figure 38). This reduction in middle of the day output was enabled by the lowering of minimum output levels at Loy Yang A and Loy Yang B units to around 250 MW and 220 MW respectively this quarter.

Figure 37 Brown coal-fired generation reduced to all-time low

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

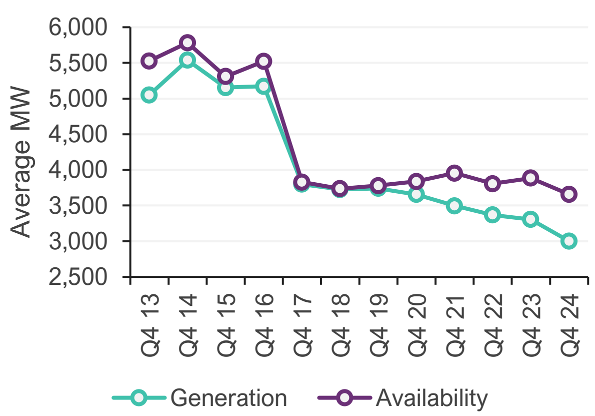
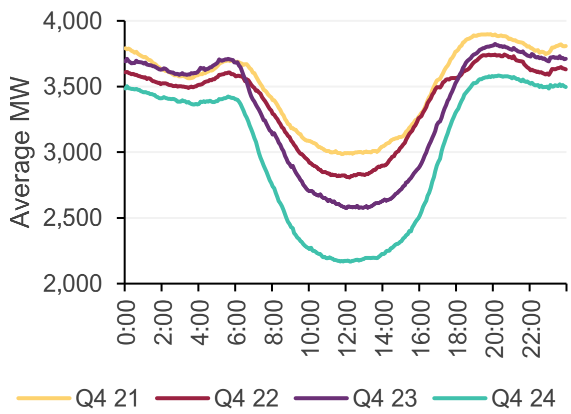


Figure 38 Large decrease in brown coal-fired generation across all hours of the day

Brown coal-fired output by time of day – Q4s



The year-on-year reductions in average brown coal-fired availability and generation over Q4 2024 were driven by Loy Yang A, with unit 4 offline for planned maintenance from the start of the quarter until the middle of December (Table 5) then returning at around half its normal capacity. Loy Yang B and Yallourn both recorded increases in availability and output, but declining utilisation as they increased their intra-day swing by reducing minimum output during low priced periods in the middle of the day.

Table 5 Brown coal availability, output, utilisation, outage, and intraday swing – Q4 2024 vs Q4 2023

Generator	Availability (MW)		Output (MW)		Utilisation		Outage (MW)		Intraday swing (MW)	
	Q4 23	Q4 24	Q4 23	Q4 24	Q4 23	Q4 24	Q4 23	Q4 24	Q4 23	Q4 24
Loy Yang A	1,872	1,517	1,557	1,232	83%	81%	312	663	659	571
Loy Yang B	1,116	1,155	927	928	83%	80%	35	0	421	501
Yallourn W	898	987	821	843	91%	85%	544	485	173	350

2.3.2 Gas-fired generation

NEM gas-fired generation averaged 1,011 MW in Q4 2024, up 160 MW (+19%) from the previous Q4 with increases in all regions apart from Tasmania, with percentage increases ranging from 2% in New South Wales to 135% in Victoria (Figure 39). Tasmania gas-fired generation was low over the quarter, averaging 3 MW in Q4 2024, compared to 6 MW in Q3 2024.

The largest increase in gas-fired generation occurred in Queensland, up by 93 MW (+20%) to a quarterly average of 566 MW. This uplift was particularly notable across the evening peak hours – with an additional 247 MW of output between 1600 hrs and 2000 hrs – driven by reductions in black coal-fired generation and increased exports to New South Wales in those hours.

With higher wholesale prices across the NEM this quarter, gas-fired generators sought increased dispatch by offering more volume at lower price points compared to Q4 2023 (Figure 40). On average they offered between 50 MW to 160 MW more volume at price bands up to $300/MWh, increasing to 160 MW to 330 MW at price bands between $300/MWh and $1,000/MWh.

Figure 39 Gas-fired generation higher in all mainland NEM regions

Average gas-fired generation by region – Q4s

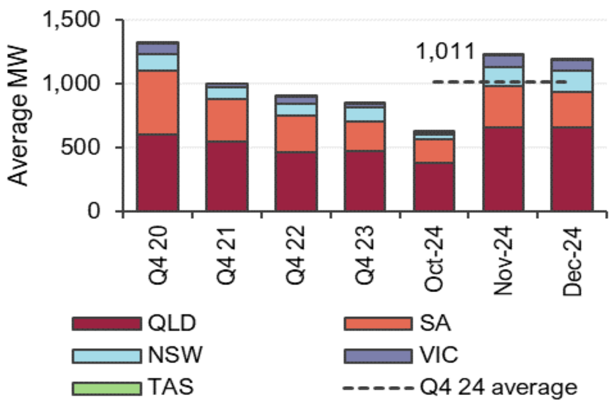
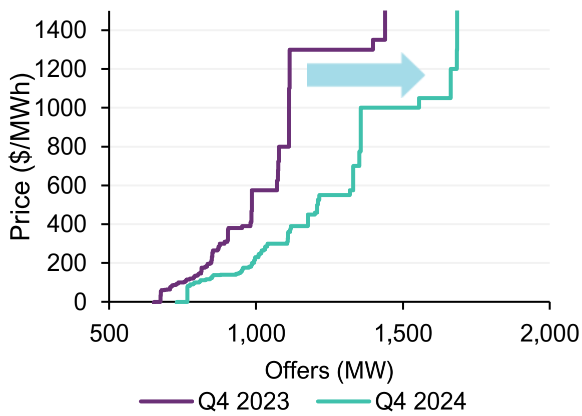


Figure 40 Gas offer volumes increased

Gas-fired generation bid supply curve – Q4 2024 vs Q4 2023



2.3.3 Hydro

In Q4 2024, NEM hydro generation[16] averaged 1,612 MW, up 140 MW (+10%) from Q4 2023 but slightly lower than in the two preceding Q4s (Figure 41). Output from Victorian hydro generation increased the most, up by 72 MW (+31%), due to higher output from Murray (+60 MW) and Dartmouth (+17 MW) hydro stations.

Figure 41 Hydro generation increased in all regions except New South Wales

Average hydro output by region – Q4s

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

2.3.4 Wind and grid-scale solar

Grid-scale variable renewable energy (VRE) average output increased to 5,371 MW in Q4 2024, up 203 MW (+3.9%) from Q4 2023 (Figure 42). Nearly all this increase arose from grid-scale solar generation, which grew 191 MW (+9.4%) to average 2,212 MW across the quarter. There was little growth in average wind generation, up by just 12 MW (+0.4%) to 3,160 MW.

New South Wales recorded the greatest uplift in VRE generation, with year-on-year generation increases for both wind (+6.3%) and grid-scale solar (+14%) (Figure 43).

Figure 42 Steady increase in grid-scale solar generation

Average quarterly VRE generation by fuel type – Q4s

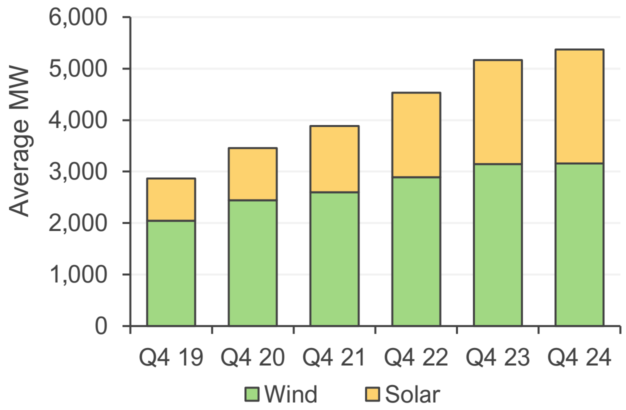
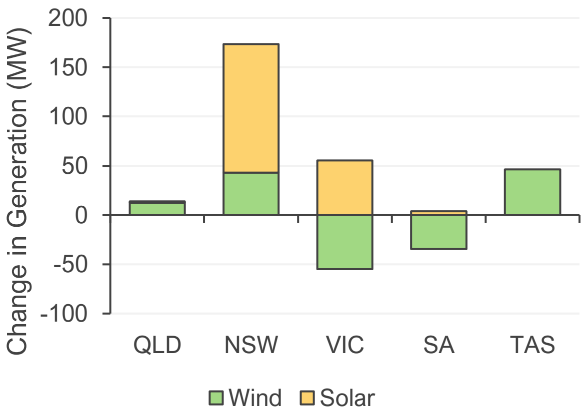


Figure 43 VRE increases led by New South Wales

Average change in VRE output by region – Q4 2024 vs Q4 2023



Grid-scale solar

Increased VRE availability in the NEM arises from both newly connected facilities and those progressing through their commissioning processes, which can extend over 12 months or longer. These growth sources contributed a 259 MW increase in average quarterly grid-scale solar availability from Q4 2023 (Figure 44).

The majority of this increase was in New South Wales, with increases in availability from Wellington North (+116 MW) and Walla Walla (+32 MW). Glenrowan (+37 MW) and Girgarre (+19 MW) in Victoria and Tailem Bend 2 (+23 MW) in South Australia also contributed to the growth in this category.

These gains were partially offset by increased network curtailment and economic offloading. Together, these two factors accounted for an 89 MW decrease in generation compared to Q4 2023. Economic offloading increased to an average of 343 MW, 66 MW (+24%) more than during Q4 2023. Economic offloading was highest in Queensland, averaging 133 MW across the quarter, up 6% from the previous Q4. The regions with the largest growth in economic offloading were New South Wales, up 84% to average 79 MW, and South Australia, up 54% to average 78 MW. Economic offloading decreased in Victoria, down 8% year on year to average 52 MW.

Established[17] grid-scale solar facilities showed small increases in quarterly volume-weighted available capacity factors across all NEM regions, with the NEM-wide capacity factor increasing by just 0.6 pp to 31.8% in Q4 2024

[17] Existing (or established) capacity in this section refers to the grid-scale solar and wind facilities that were fully commissioned prior to the start of Q4 2024. These facilities may also appear in the "New Capacity or "Commissioning" categories in Figure 44 and Figure 46 if they were connected or exhibited ramping capacity between Q4 2023 and Q4 2024 respectively.

(Figure 45). Across NEM regions, the New South Wales fleet recorded the highest available capacity factor at 33.1%, up 0.7 pp from Q4 2023, followed by the Victorian fleet at 32.6% with this region having the greatest year-on-year increase in availability at 1.3 pp.

Figure 44 Increased availability from new and commissioning solar farms

Changes in grid-scale solar generation – Q4 2024 vs Q4 2023

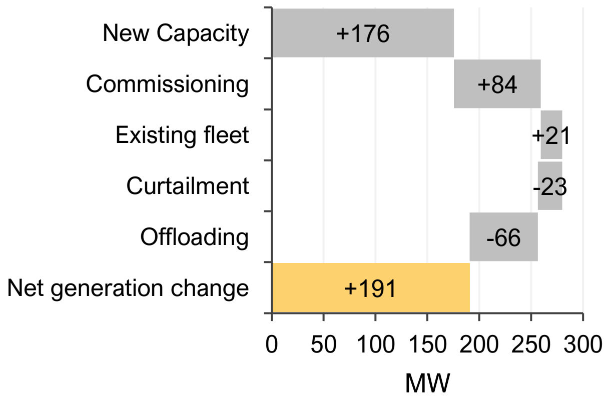
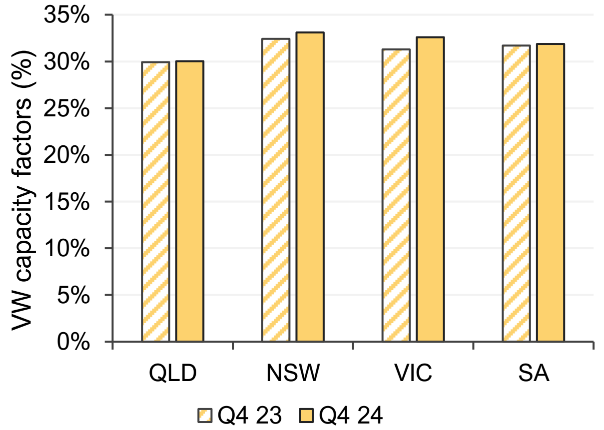


Figure 45 Solar availability slightly higher across all NEM regions

Volume-weighted grid-scale solar available capacity factors[18] – Q4s



Wind

New and commissioning wind farms added 322 MW to the quarter's available wind output, with Rye Park (+81 MW) and Flyers Creek (+43 MW) in New South Wales, Ryan Corner (+64 MW) and Hawkesdale (+34 MW) in Victoria, Goyder South (+58 MW) in South Australia the largest contributors (Figure 46).

Network curtailment decreased, allowing a further 26 MW potential increase in wind generation compared to Q4 2023. However, these drivers of potential generation growth were almost entirely offset by lower availability across the wind fleet (-263 MW) and higher economic offloading (-72 MW). Economic offloading of wind was highest in Victoria, which increased 10% from Q4 2023 levels to average 180 MW over Q4 2024, followed by South Australia with a 57% year-on-year increase to average 112 MW this quarter.

Established wind facilities showed decreases in quarterly volume-weighted available capacity factors across NEM regions apart from Tasmania and Queensland (Figure 47). Overall, the NEM-wide available capacity factor averaged 30.9% in Q4 2024. This 2.5 pp reduction from Q4 2023 was driven by lower average wind speeds and both network and facility outages reducing availability at times during the quarter. The Tasmanian fleet recorded the highest volume-weighted available capacity factor at 41.0%, up 8.6 pp year-on-year. Queensland was the only other NEM region to record an increase, up 1.6 pp to average 34.0%. Victoria saw the largest reduction (-4.1 pp), followed by South Australia (-3.2 pp) and New South Wales (-2.8 pp).

[18] Available capacity factors are calculated using average available energy divided by maximum installed capacity. The use of availability instead of generation output removes the impact of any economic offloading or curtailment and better captures in-service plant capacity and underlying solar or wind resource levels. Available capacity factors for each established facility are weighted by maximum installed capacity to derive a regional weighted average.

Figure 46 Growth from new and commissioning wind farms offset by lower fleet capacity factors and higher economic offloading

Changes in wind availability and generation – Q4 2024 vs Q4 2023

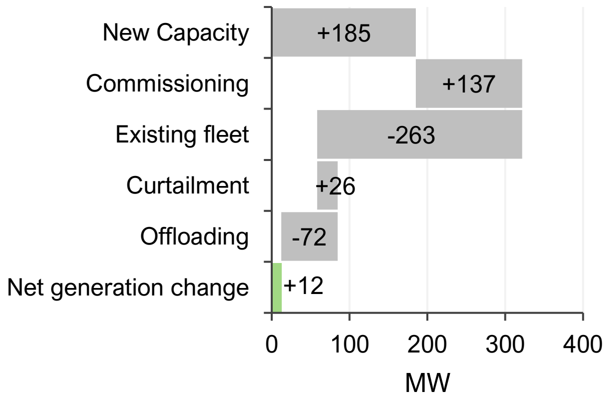
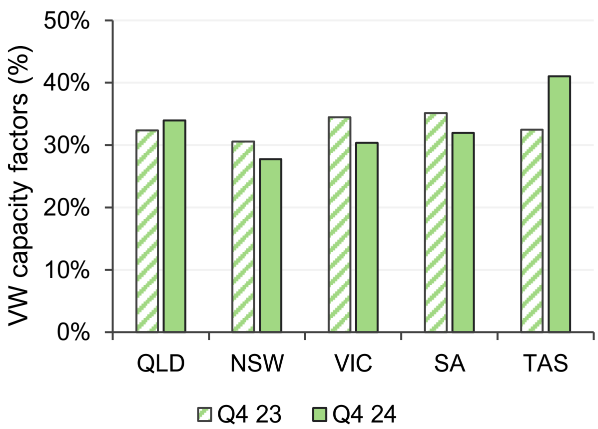


Figure 47 Wind availability up in Tasmania and Queensland, but reduced in other NEM regions

Volume-weighted wind available capacity factors – Q4s

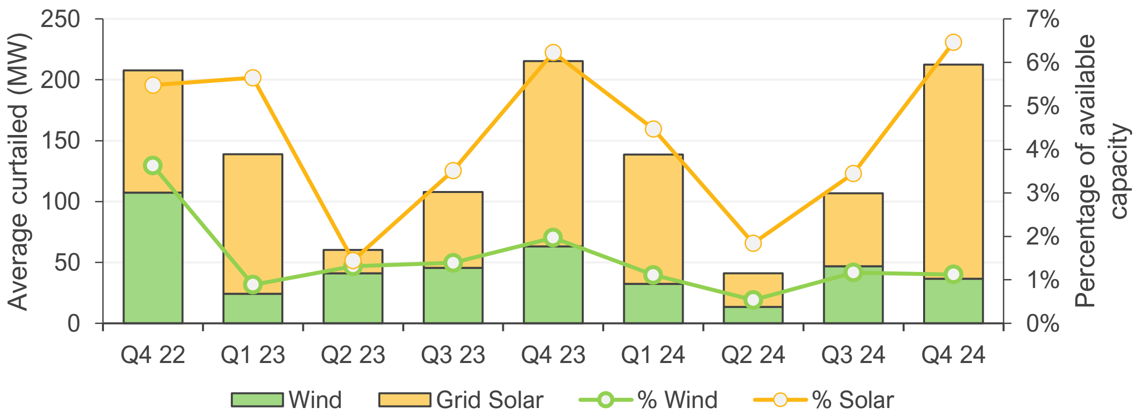


Curtailment

Compared to Q4 2023, average curtailment of grid-scale solar generation increased by 23 MW (+15%) to 176 MW, in line with availability growth, while average curtailment of wind generation decreased by 26 MW (42%) to average 37 MW this quarter (Figure 48).

Figure 48 Curtailment of wind generation decreased while curtailment of grid-scale solar generation increased year-on-year

Average MW curtailment and as percentage of availability by fuel type

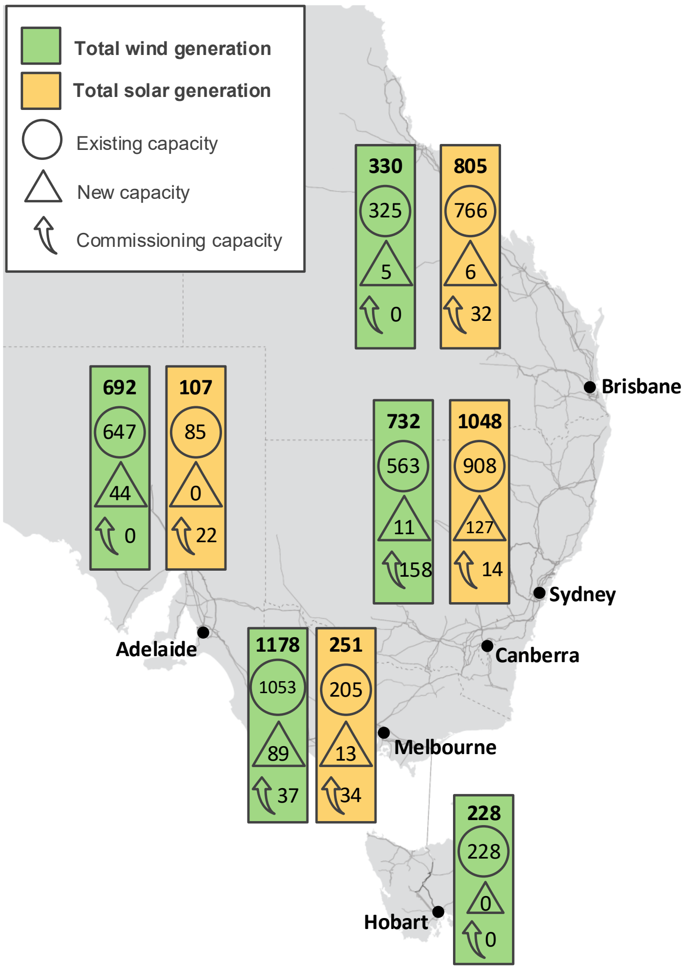


VRE generation summary

The map in Figure 49 shows a summary representation of VRE output during Q4 2024.

Figure 49 Regional VRE generation summary during Q4 2024

Quarterly average VRE generation (MW) by fuel type and region



2.3.5 Renewables contribution

Peak renewable contribution

A new record for peak renewable contribution[19] was set this quarter, with renewables supplying 75.6% of total generation during the half-hour interval ending at 1300 hrs on Wednesday, 6 November 2024. At the time of this record, distributed PV accounted for 43% of the generation mix, while grid-scale solar and wind contributed 19% and 11% respectively (Figure 50).

Renewable potential[20] also saw a notable increase of 5 pp from the previous quarter's record of 100.5%.

[19] Peak renewable contribution is calculated using the NEM renewable share of total generation. This measure is calculated on a half-hourly basis, because this is the granularity of estimated output data for distributed PV. Renewable generation includes grid-scale wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Total generation = NEM generation + estimated PV generation.

[20] Renewable potential in an operating interval refers to the total available energy from VRE sources, even if not necessarily dispatched, and actual output from dispatchable renewables, expressed as a percentage of the total NEM supply requirement.

Figure 50 Peak renewable contribution and potential reached all-time highs

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

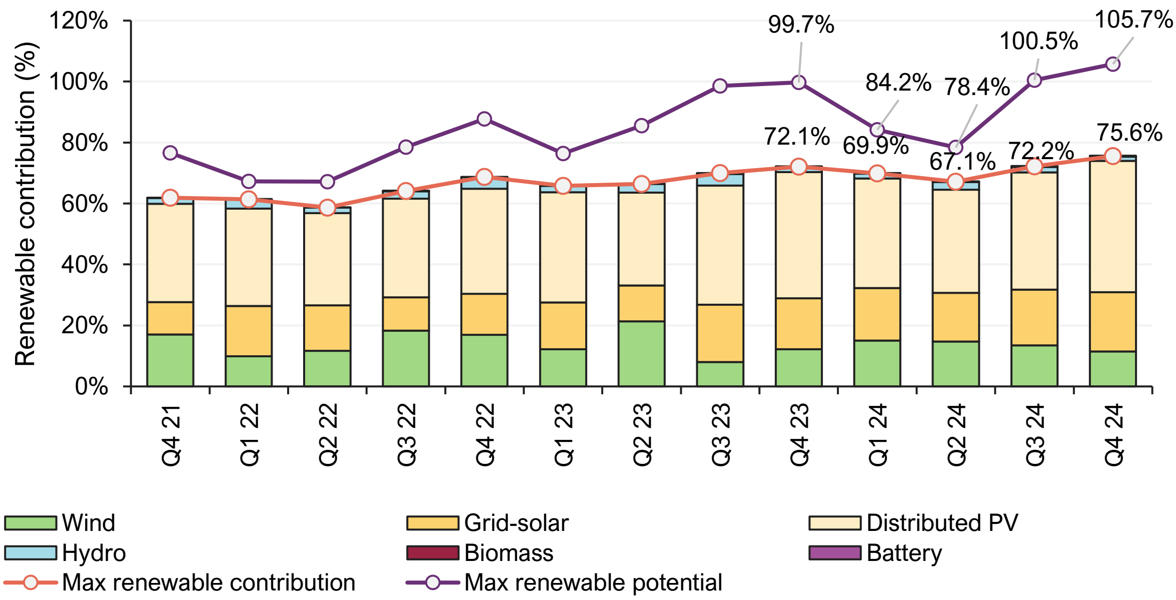


Figure 51 illustrates the expanding width between minimum and maximum renewable contributions, which varied over a 60% range in Q4 2024, with a high of 75.6% and a low of 16.1%. The quarter's minimum renewable contribution occurred during the half-hour ending at 0330 hrs on Tuesday, 31 December 2024, and was 2.4 pp higher than Q4 2023's 13.7%. During this quarter, Queensland, New South Wales and Victoria set new records for peak renewable contribution, reaching 70.6%, 82.8% and 78.0%, respectively (Figure 52).

Figure 51 Both minimum and maximum renewable contribution levels increased

Range of NEM supply share from renewable energy sources – Q4s

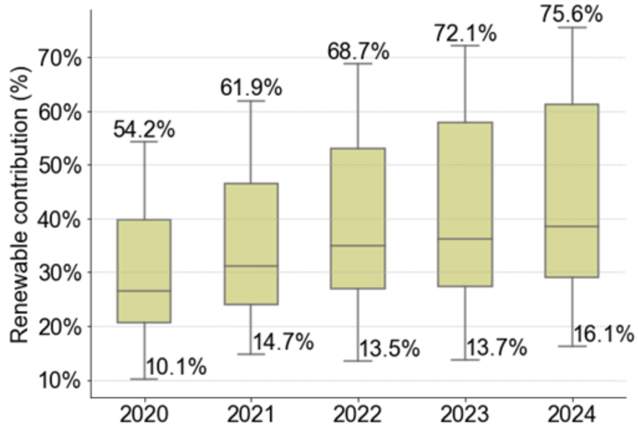
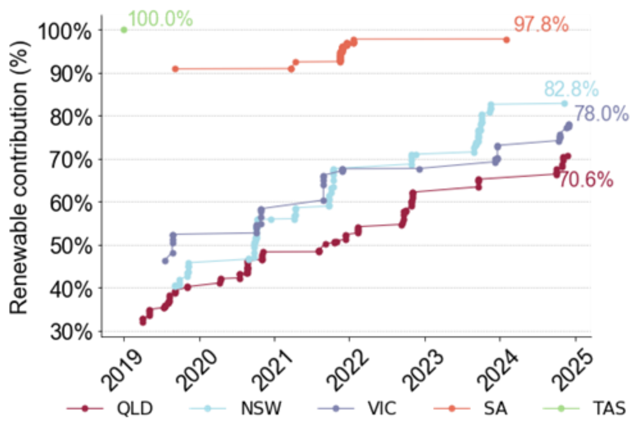


Figure 52 Record high renewable contribution in Queensland, New South Wales and Victoria

Change in peak renewable contribution record by region

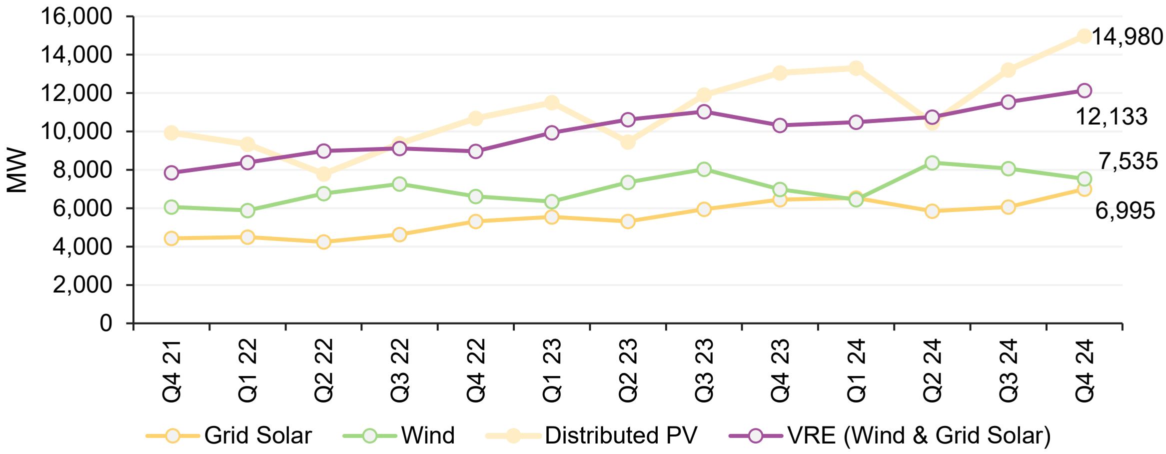


Maximum peak renewable output

Figure 53 highlights the highest quarterly instantaneous outputs for grid-scale solar, wind, and distributed PV since Q4 2021. This quarter set new all-time records for grid-scale solar at 6,995 MW and distributed PV at 14,980 MW. Peak wind output increased by 552 MW from 6,983 MW in Q4 2023 to 7,535 MW this quarter but remained below its record of 8,375 MW set in Q2 2024. Additionally, VRE output, which combines wind and grid-scale solar, increased from its previous record of 11,536 MW in Q3 2024 to a peak of 12,133 MW this quarter.

Figure 53 Record high for peak grid solar and distributed PV

Maximum quarterly peak generation by fuel type

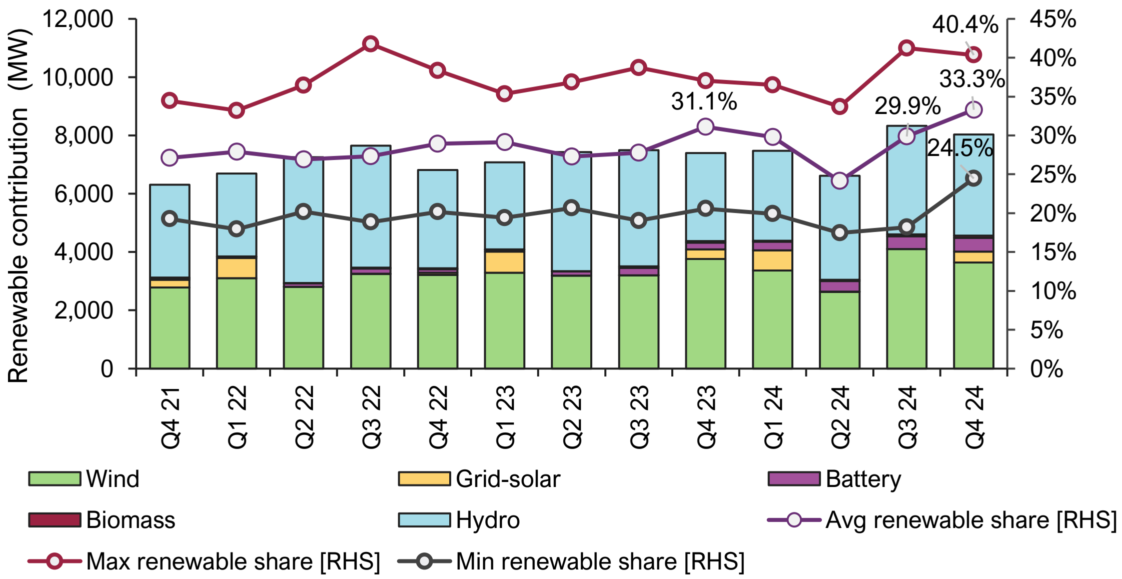


Renewable contribution to maximum demand

Figure 54 illustrates the average contribution of large-scale renewable generation in meeting daily maximum NEM operational demand, computed as an average across all days in each quarter[21]. In Q4 2024, this measure reached 33.3%, a new all-time high. This represents a notable uplift of 2.2 pp compared to the Q4 last year.

Figure 54 Increased renewable contribution to meeting daily maximum demand

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



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

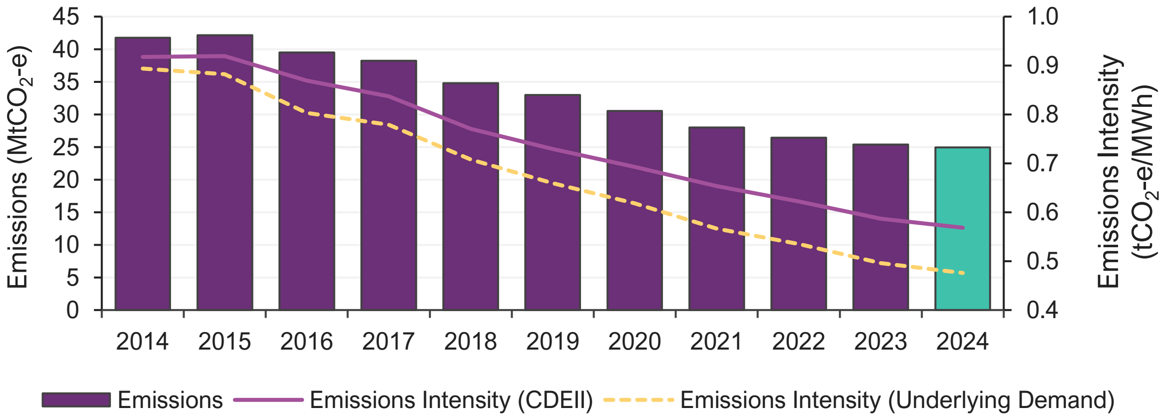
Since daily maximum operational demand typically occurs during the evening peak, solar generation had minimal impact during these times. In contrast, hydro's contribution increased significantly, rising from 12.2% in Q4 2023 to 13.8% this quarter. Batteries also saw an increase, contributing an average of 1.9%, up from 1.0% in Q4 2023. Compared to Q4 2023, both maximum and minimum renewable share during daily maximum operation demand periods increased by 3.3 pp and 3.9 pp respectively, reaching 40.4% and 24.5%.

2.3.6 NEM emissions

In Q4 2024, total emissions across the NEM were 24.9 MtCO2-e, a decrease of 0.4 MtCO2-e (-1.7%) from Q4 2023, reaching a new quarterly low (Figure 55). The Carbon Dioxide Equivalent Intensity Index (CDEII) emissions intensity is measured by combining sent out metering data with publicly available generator emissions and efficiency data, to provide a NEM-wide CDEII[22]. This emissions intensity excludes generation from distributed PV, taking into consideration only sent out generation from market generating units. This quarter, emissions intensity for this measure averaged 0.57 tCO2-e per MWh, down 3.2% from 0.59 tCO2-e per MWh in Q4 2023, also a new quarterly low. Emission intensity associated with underlying demand[23] also saw a reduction from 0.50 tCO2-e per MWh last Q4 to 0.48 tCO2-e per MWh this quarter. These declines reflect a reduced share of coal-fired generation in the overall energy mix and highlight the impact of increasing penetration of distributed PV in reducing emissions.

Figure 55 Year-on-year reduction in emissions and emissions intensity to all-time lows

Quarterly NEM emissions and intensity – Q4s



2.3.7 Storage

Batteries

This quarter, estimated net revenue (covering both energy and FCAS markets) for NEM grid-scale batteries reached $69.5 million, more than doubling the $31.5 million estimate for Q4 2023, as shown in Figure 56.

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

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

Energy market[24] net revenue for batteries increased $34.6 million (+257%) to a total of $48.1 million, representing 69% of total estimated net revenue. This growth from energy arbitrage was primarily due to a $38.4 million (+300%) increase in revenue from energy generation (discharging). Charging during negative price periods also yielded a $3.9 million revenue increase for batteries during the quarter, reaching $7.2 million. Energy cost (charging at prices above $0/MWh) increased $7.7 million (+298%) year-on-year.

Although the majority of estimated battery net revenue arose from energy market arbitrage (Figure 57), frequency control ancillary services (FCAS) revenue also contributed, growing by $3.4 million (+19%) to total $21.3 million for the quarter.

Figure 56 Growing battery net revenue from energy arbitrage

Quarterly net revenue from NEM battery systems by revenue stream

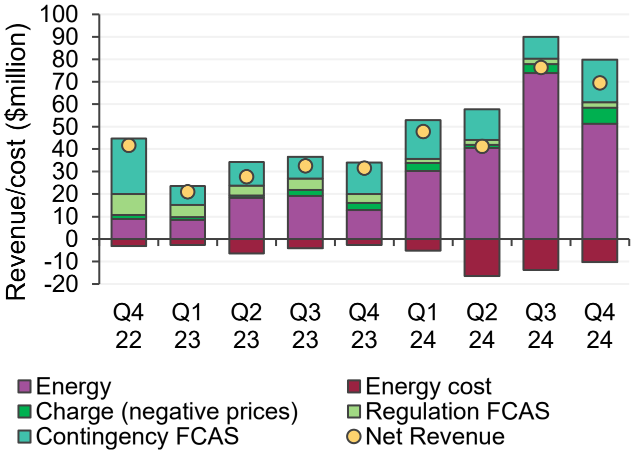
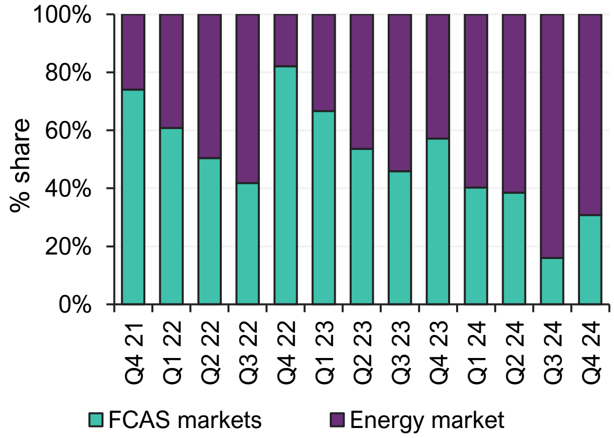


Figure 57 Proportion of battery net revenue from FCAS markets fell

Percentage share of battery net revenue – energy vs FCAS markets



The rise in energy arbitrage net revenue across the NEM was driven in part by year-on-year increases in battery capacity driving higher availability and output in the energy market. NEM-wide average battery availability grew by 44%, from 755 MW in Q4 2023 to 1,087 MW in Q4 2024 (Figure 58). Battery generation averaged 90 MW this quarter, a 43 MW (+91%) increase compared to Q4 2023.

The NEM-wide price spread[25] for batteries averaged $243/MWh, up from $129/MWh in Q4 2023 (Figure 59), reflecting increased high-priced volatility that saw battery operators capture more value during peak pricing events, particularly in the NEM's northern regions.

This quarter, capacity increases and high spot price volatilty in Queensland and New South Wales saw batteries record very large uplifts in energy arbitrage, up by $19.1 million (+604%) and $10.0 million (+370%) respectively. Energy arbitrage for Victorian and South Australian batteries grew $2.7 million (+64%) and $2.8 million (+84%) respectively.

[24] Also known as energy arbitrage revenue for batteries which includes three components: 1) revenue from discharging (selling energy), 2) revenue (or equivalently, negative costs) from recharging during negatively-priced intervals, and 3) cost of recharging at non-negative prices.

[25] The battery price spread represents the arbitrage revenue per MWh of generation, calculated as arbitrage revenue/generation.

Figure 58 Year-on-year increase in battery availability in all mainland regions

Average quarterly battery generation availability

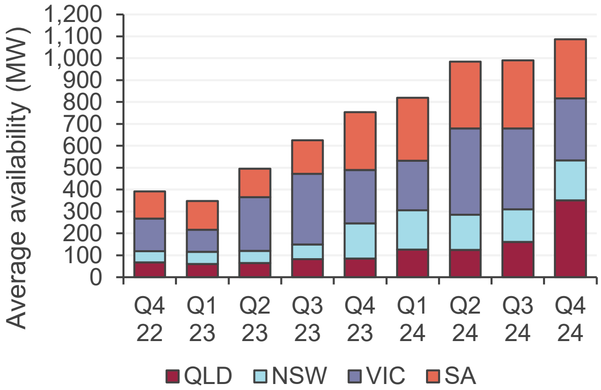
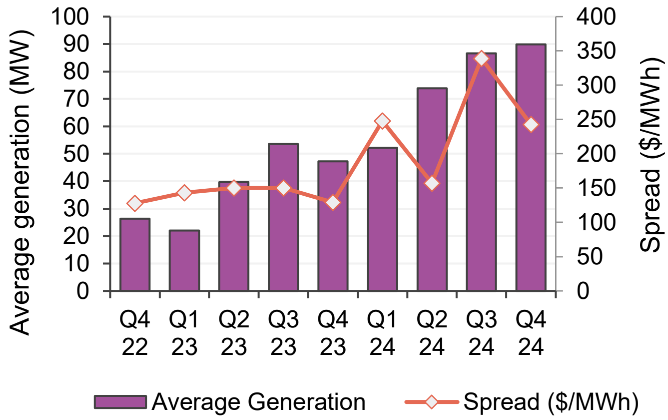


Figure 59 Increase in battery price spread

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



Pumped hydro

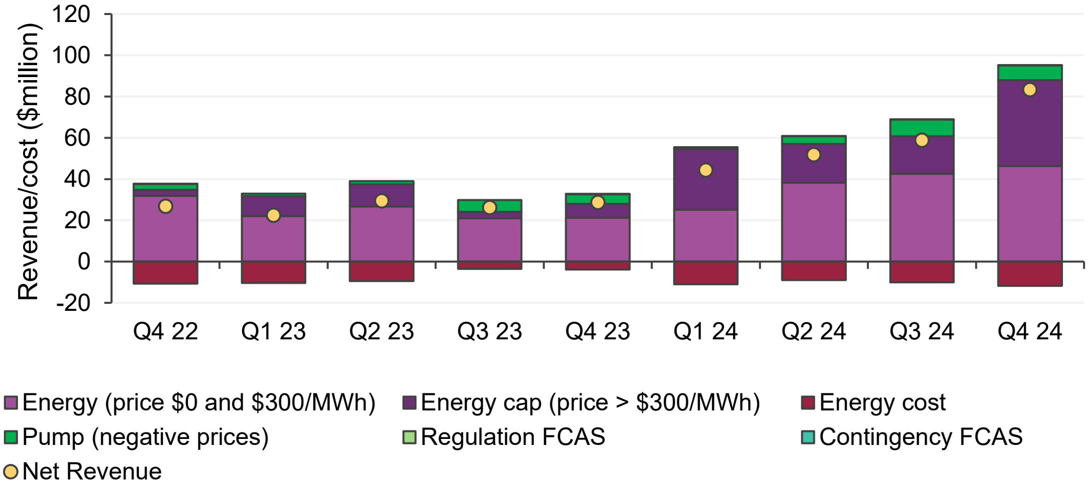
Pumped hydro estimated net revenue surged to $83.3 million this quarter, up $54.5 million (+189%) compared to Q4 2023 (Figure 60). This significant growth was driven by increased generation and high-priced volatility in Queensland and New South Wales. Revenue from prices exceeding $300/MWh saw a notable rise of $34.9 million (+521%), reaching $41.6 million, while revenue from prices below $300/MWh also increased by $25.0 million year-on-year to $46.3 million.

Wivenhoe's performance played a key role in this growth, with its net revenue increasing by $38.4 million. This was driven by a 24% year-on-year rise in generation, as its quarterly output averaged 99 MW – an all-time high, surpassing its previous record of 91 MW set in Q3 2024.

Shoalhaven also delivered strong results, with average output up from just 3 MW last year to 20 MW this Q4, contributing to a $16.1 million net revenue increase. This uplift was primarily attributed to a $10.5 million rise in revenue from prices above $300/MWh, complemented by an additional $6.9 million from prices below $300/MWh.

Figure 60 Pumped hydro net revenue increased year-on-year

Quarterly net revenue from NEM pumped hydro by revenue and cost stream

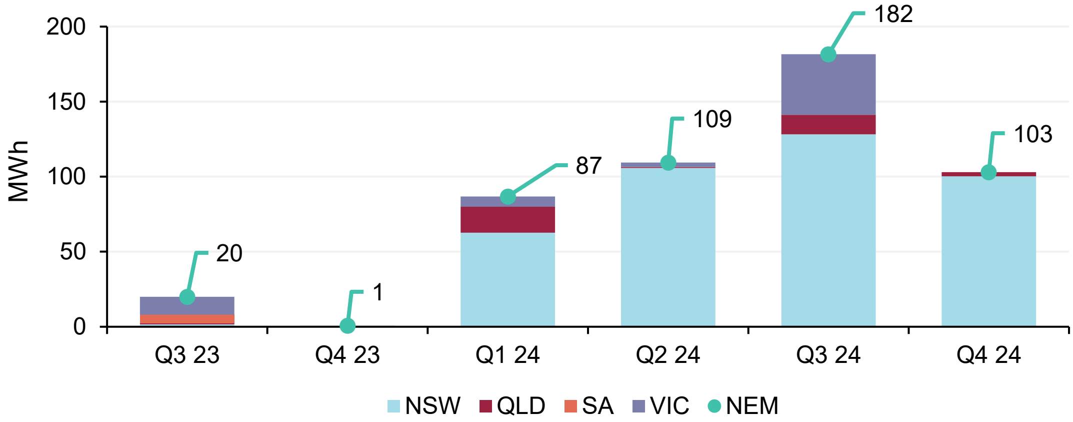


2.3.8 Demand side flexibility

In Q4 2024, wholesale demand response (WDR) dispatch totalled 103 MWh, compared to only 1 MWh in Q4 2023 (Figure 61).

Figure 61 Increase in wholesale demand response driven by New South Wales

Total quarterly WDR energy dispatch



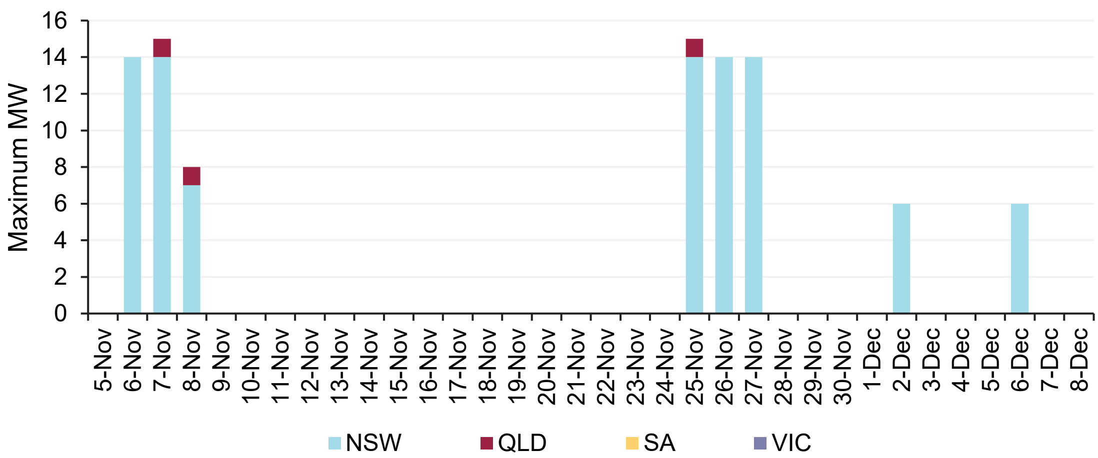
During the quarter, WDR was dispatched for 107 intervals at a peak output level of 14 MW in New South Wales and 33 intervals at a peak output level of 1 MW in Queensland (Figure 62).

The majority of WDR dispatch occurred during November, in response to high-priced volatility events discussed in Table 3 in Section 2.2.2. A total of 54 MWh was dispatched in New South Wales over 6 to 8 November, with New South Wales wholesale spot prices averaging $3,633/MWh across the 51 dispatch intervals. A further 38 MWh was dispatched over 25 to 27 November with New South Wales wholesale spot prices across the 39 dispatch intervals averaging $2,994/MWh.

High-priced volatility early in December again saw WDR dispatched in New South Wales on two days.

Figure 62 Active WDR participation dispatch in November and December mainly in New South Wales

Maximum daily WDR dispatch



2.3.9 New grid connections

New grid connections to the NEM follow a process which involves the applicant, network service provider (NSP) and AEMO. Prior to submission of a connection application with AEMO, the applicant completes a pre-feasibility and enquiry phase where the connecting NSP is engaged in the process. The key stages[26] monitored by AEMO to track the progress of projects going through the connections process include application, proponent implementation, registration, commissioning, and model validation.

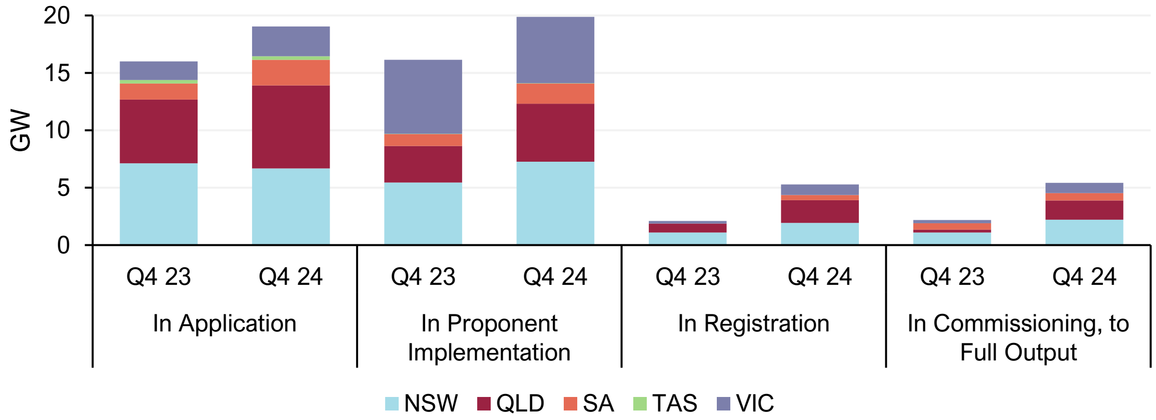
At the end of Q4 2024, AEMO's snapshot of connection activities in progress showed that:

- There was 49.6 GW of new capacity progressing through the end-to-end connection process from application to commissioning, which is a 36% increase in capacity compared to 36.4 GW at the end of Q4 2023 (Figure 63). Around 36% of this capacity was in New South Wales, 32% in Queensland, 21% in Victoria and 10% in South Australia.
- The capacity of battery projects in the end-to-end connection process was 18.1 GW at the end of Q4 2024, a 97% increase compared to 9.2 GW at the end of Q4 2023. There were 18.7 GW capacity of solar projects, a 22% increase compared to 15.3 GW at the end of Q4 2023.
- The majority (78%) of projects were in the early stages of development, in either Application or Proponent Implementation stages. Connection projects in these early stages were 40% solar, 37% battery, 15% wind, 6% hydro and 2% gas.
- The total capacity of in-progress applications was 19.0 GW, compared with 16.0 GW at the same time last year (+19%) – 38% of the current capacity in application stage were Queensland projects, 35% New South Wales, 14% Victoria, 12% South Australia, and 2% Tasmania.
- An additional 19.9 GW of new capacity projects were finalising contracts and under construction (proponent implementation), compared with 16.1 GW at the end of Q4 2023 (+23%) – 37% of this capacity was in New South Wales, 25% in Queensland, 29% in Victoria, and 9% in South Australia.
- There were 5.3 GW of projects progressing through registration, compared with 2.1 GW at the end of Q4 2023 (+150%). Around 37% of this 5.3 GW capacity was in New South Wales, 37% in Queensland, 17% in Victoria and 8% in South Australia.
- There was 5.4 GW of new capacity in commissioning to full output, compared to 2.2 GW at the end of Q4 2023 (+150%). This commissioning measure considers all plant in commissioning up to the plant reaching its full output.

[26] Application stage establishes technical performance and grid integration requirements. In proponent implementation stage, contracts are finalised and the plant is constructed. Registration stage reviews the constructed plant models for compliance with agreed performance standards. Once the plant is electrically connected to the grid, commissioning confirms alignment between modelled and tested performance.

Figure 63 Increased capacity in all stages of the connection pipeline

Connections snapshot as at end Q4 for 2023 and 2024



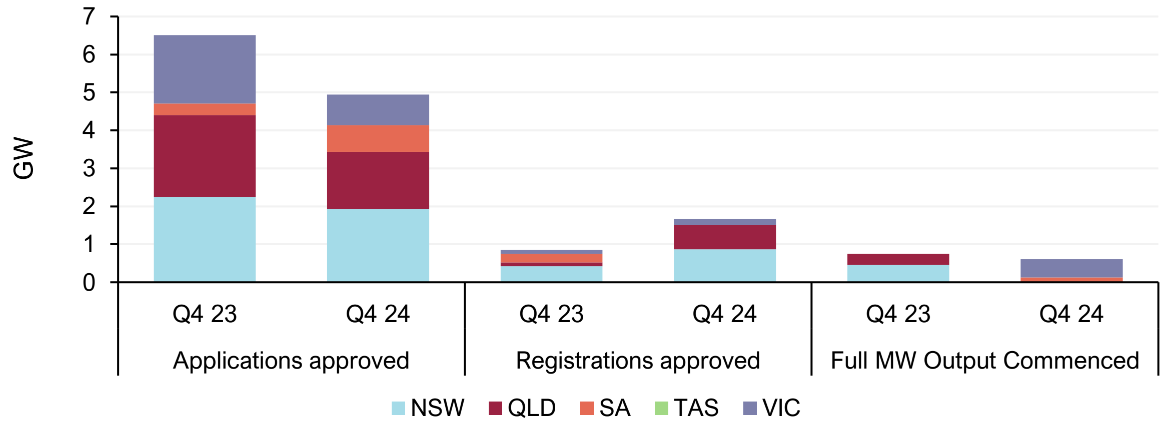
During Q4 2024:

- 4.9 GW of applications were approved across 20 projects (Figure 64) compared with 6.5 GW across 28 projects during Q4 2023. Comparing the half-year shows a total of 7.5 GW was approved for Q3 and Q4 in both 2023 and 2024.
- 1.7 GW of plant across 11 projects were registered and connected to the NEM, in comparison to 0.9 GW across seven projects during Q4 2023.
- 0.6 GW of plant across four projects progressed through commissioning to reach full output, compared with 0.8 GW across four projects in Q4 2023.

The Connections Scorecard[27] contains further information.

Figure 64 Decrease in application approvals and increase in registrations in Q4 2024 compared with Q4 2023

Comparison of applications approved, registrations and commissioning in Q4 for 2023 and 2024



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

2.4 Inter-regional transfers

Inter-regional energy transfers across the NEM totalled 3,074 gigawatt hours (GWh) in Q4 2024, a drop of 309 GWh (-9.1%) compared to Q4 2023. Flows from Queensland to New South Wales reduced significantly, with average flows dropping from 292 MW in Q4 2023 to 202 MW this quarter (Figure 65). This, along with a slight increase in flows to the north, resulted in net southward flows from Queensland to New South Wales declining from 183 MW to 73 MW. On VNI, net flows also decreased, driven by lower export limits into New South Wales. Net flows northward dropped from 339 MW in Q4 2023 to 275 MW this quarter.

On Basslink, stronger overnight demand in Victoria along with lower brown coal availability led to higher exports from Tasmania to Victoria year-on-year, with northward flows increasing from 38 MW to 82 MW. Correspondingly, imports from Victoria to Tasmania fell, reducing net southward flows from 252 MW in Q4 2023 to 135 MW this quarter. Average flows between Victoria and South Australia did not change materially with net flows averaging 41 MW into South Australia.

Figure 65 Net flows decreased year-on-year on all interconnectors, except between Victoria and South Australia

Quarterly inter-regional transfers

QNI saw a notable reduction in flows from Queensland to New South Wales at all times of the day except during evening peak (Figure 66). Daytime reductions in transfers from Queensland were due in part to significant transmission outages affecting QNI during October and early November which constrained southward flow limits.

In Q4 2024, late afternoon and evening flows on QNI shifted from northward to southward reflecting relative price differences between New South Wales and Queensland and transmission constraints. In Q4 2023, Queensland experienced multiple price spikes in the evening peak hours causing Queensland regional spot prices to average $52/MWh more than those in New South Wales between 1600 hrs to 2000 hrs. In contrast in Q4 2024, prices in Queensland and New South Wales were generally closer during the evening peak hours, with Queensland prices only $7/MWh higher than New South Wales. Moreover, even when Queensland prices exceeded those in New South Wales in Q4 2024, export (northward) flows were more often limited to low levels, and at times pushed southward, by the outage-related constraints on QNI discussed above (Figure 67).

Figure 66 Southward flows on QNI reduced during the day but extended into the evening peak

Average QNI flow by time of day

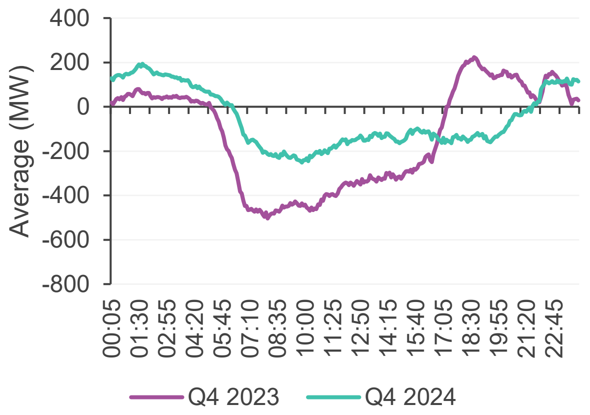


Figure 67 Lower export limits on QNI at almost all times of the day

Average QNI export limit (when binding) by time of day

Average net northward flows on VNI reduced across most times of day except in morning peak hours. This reduction in net northward flows was driven by lower export limits on VNI when binding, due to several outage-related constraints binding for significant periods across the quarter (Figure 68).

On Basslink, average net southwards flow reduced across all hours of the day, with flows shifting northward in some overnight hours (Figure 69). Flows during daylight hours (between 6:00 and 18:00 hours) were also reduced, with Basslink's import limit into Tasmania binding for 77% of dispatch intervals during these hours in Q4 2024, at an average import limit of -353 MW. This was a slight decrease in binding frequency from 79%, but at a more restrictive average import limit than the -394 MW recorded during the same daylight hours in Q4 2023.

Figure 68 Tighter limits were observed on VNI exports across almost all hours of the day

Average VNI export limit (when binding) by time of day

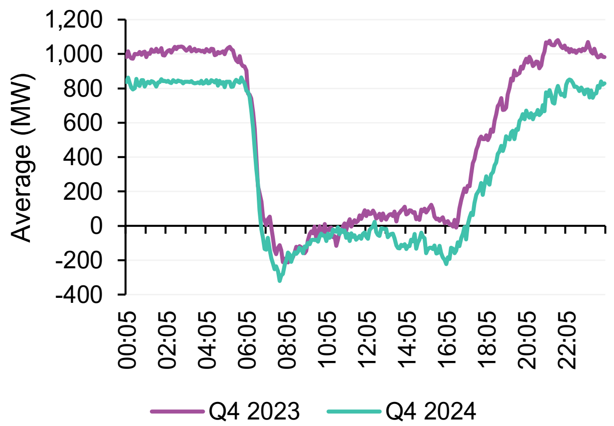
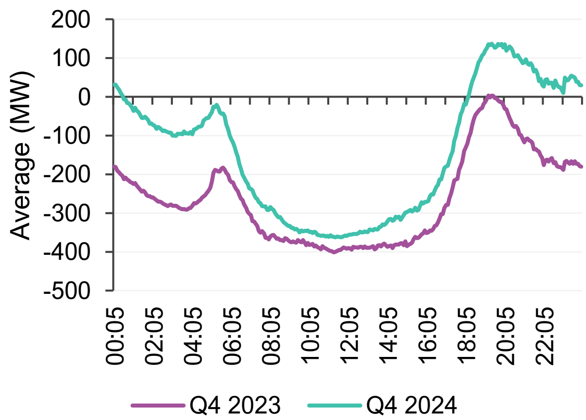


Figure 69 Average southward flows on Basslink reduced across all hours of the day

Average Basslink flow by time of day



2.4.1 Inter-regional settlement residue

In Q4 2024, positive inter-regional settlement residues (IRSR) totalled $121.9 million, a $52.8 million (+76%) increase from Q4 2023 but well down on Q3 2024's $160 million (Figure 70). The bulk of these residues, $96.2 million or 79% of the total, arose from flows into New South Wales. This comprised $50.7 million from

Queensland and $45.6 million from Victoria, driven by lower-priced energy from these regions flowing into New South Wales. A significant portion ($21.7 million) of this positive IRSR into New South Wales occurred on November 27, when high-priced volatility in the region coincided with imports from lower-priced Queensland and Victoria.

Figure 70 Increased positive settlement residues into New South Wales

Quarterly positive IRSR values

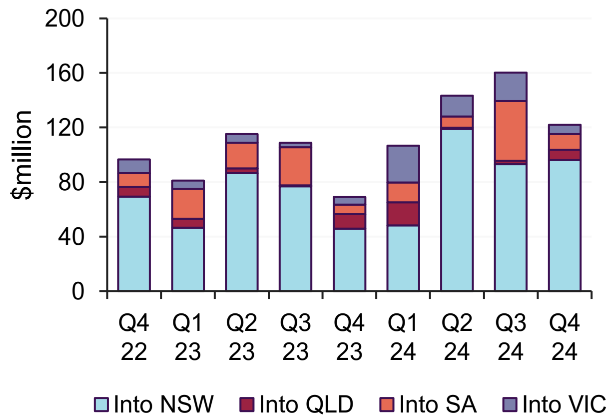
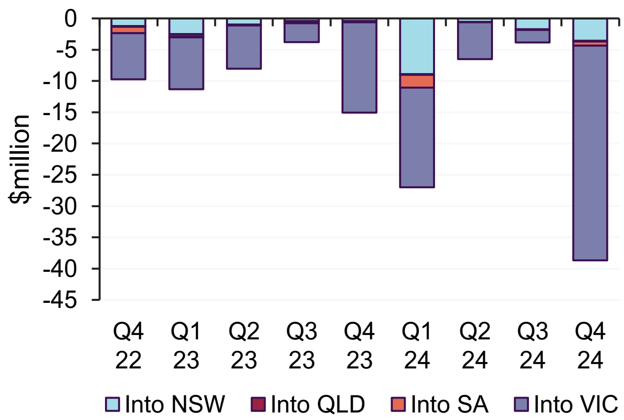


Figure 71 Negative settlement residues notably increased driven by residues into Victoria

Quarterly negative IRSR values

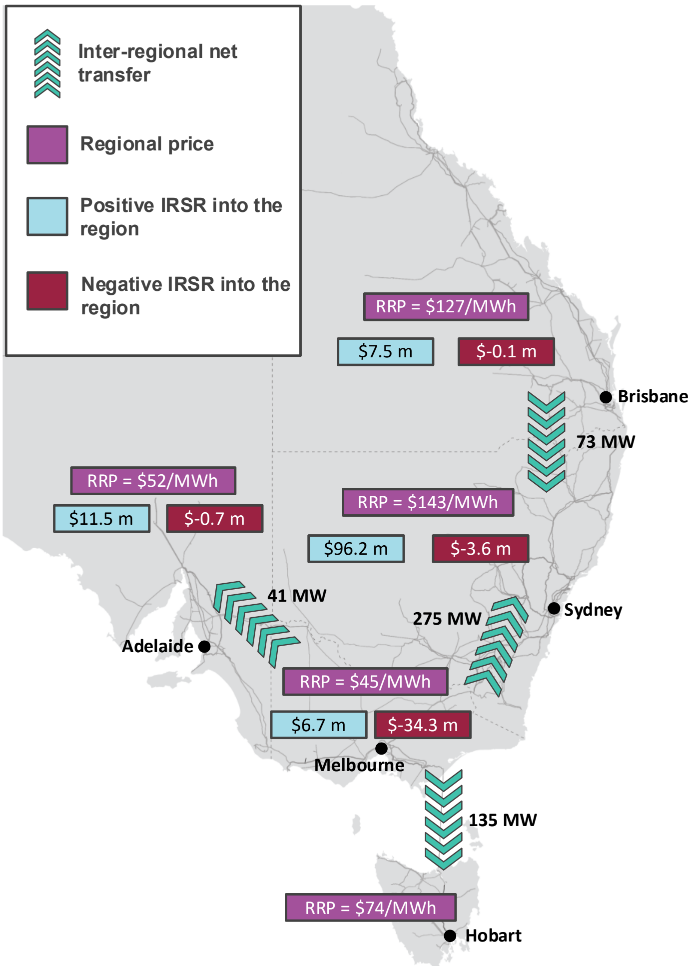


Negative IRSR for the quarter totalled -$38.7 million, a 157% increase on Q4 2023, and the largest such total for any quarter in the NEM (Figure 71). Counter-price flows from New South Wales into Victoria at -$33.9 million accounted for the majority (88%) of this negative IRSR. These arose during high price periods when transmission constraints and strong generation in southern New South Wales forced energy transfers southwards against large inter-regional price differences. Counter-price flows from Queensland into New South Wales contributed -$3.3 million.

The map in Figure 72 shows a summary representation of inter-regional exchanges during Q4 2024. Regional reference prices and the inter-regional net transfers are shown on a quarterly average basis. The positive and negative IRSR numbers refer to the total IRSR into the region from its neighbouring regions.

Figure 72 Inter-regional transfers, wholesale spot price, and settlement residues in Q4 2024

Quarterly average net inter-regional transfer, quarterly average wholesale spot price, and quarterly total IRSRs per region



2.5 Frequency control ancillary services

Total FCAS costs were $61 million in Q4 2024, equivalent to approximately 1.1% of the cost for consumed energy[28] over the quarter. This represents a $25 million year-on-year increase, driven by an uplift in Queensland's FCAS costs from $10 million last year to $47 million this Q4 (Figure 73). Costs in New South Wales and Victoria saw significant year-on-year falls, down by $7.7 million and $5.3 million respectively.

On 11 October, Queensland incurred FCAS costs of $22 million, the single day totalling 37% of the NEM's quarterly cost. Planned network outages affecting QNI (Tamworth No.1 330 kV bus outage) increased the region's risk of separating from the NEM requiring local enablement of frequency control ancillary services. This drove the local price for the contingency raise 6-second (R6SE) service to the market price cap. As a result, the R6SE service accounted for the largest share (62%) of total FCAS costs this quarter as well as the largest year-on-year increase, up by $27.1 million to $37.3 million (Figure 74). The second highest cost contribution was the R60S service, with a $5.9 million year-on-year increase to $7.6 million this quarter. In contrast, the contingency raise

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

1-second service (R1SE) recorded its lowest quarterly cost since being introduced in Q4 2023, falling from $6.2 million a year ago to $2.9 million this Q4.

Figure 73 Increased FCAS costs driven by Queensland

Quarterly FCAS costs by region

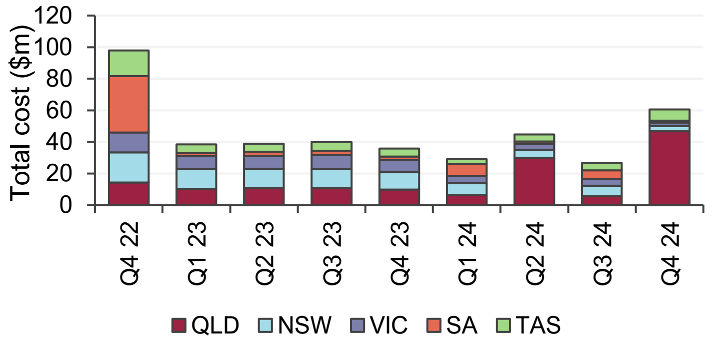
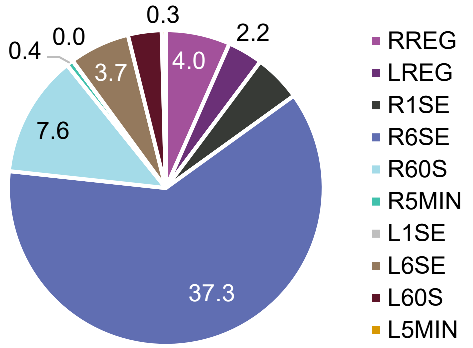


Figure 74 High share for raise 6-sec costs

NEM quarterly FCAS cost per service – Q4 2024 ($m)



Battery enablement continued to be the dominant source technology providing FCAS, with a 55% volume share this quarter (Figure 75). Average enablement of batteries rose by 262 MW from Q4 2023 (Figure 76). This was followed by virtual power plants (VPPs) and demand response with enablement increasing by 144 MW and 47 MW respectively year-on-year.

Although hydro saw a marginal increase in enablement in contingency lower services, this was more than offset by a notable reduction in enablement for contingency raise services, resulting in a net reduction of 124 MW in FCAS enablement for this fuel type.

Figure 75 Batteries dominated FCAS market share

FCAS volume market share by technology – Q4 2024

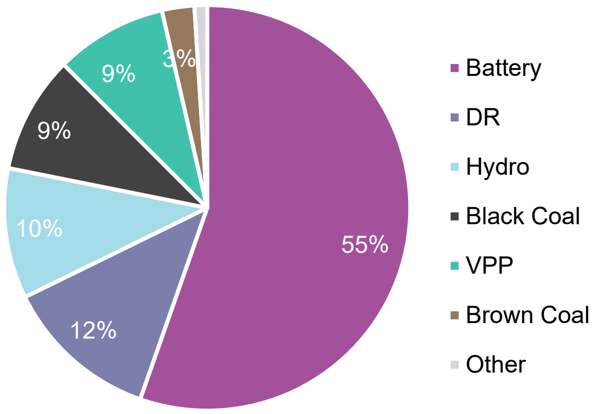
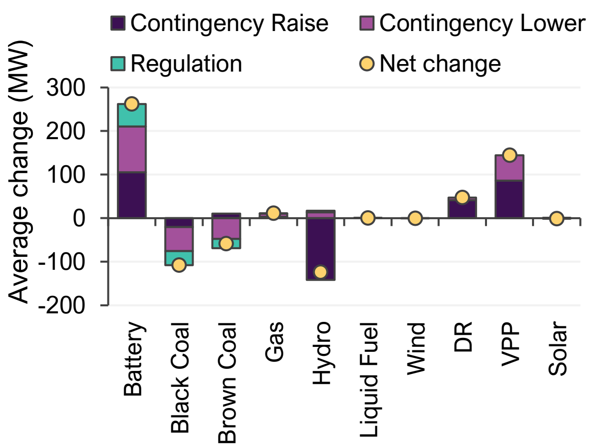


Figure 76 Higher enablement for batteries, demand response and VPP

Change in FCAS enablement by technology – Q4 2024 vs Q4 2023



2.6 Power system management

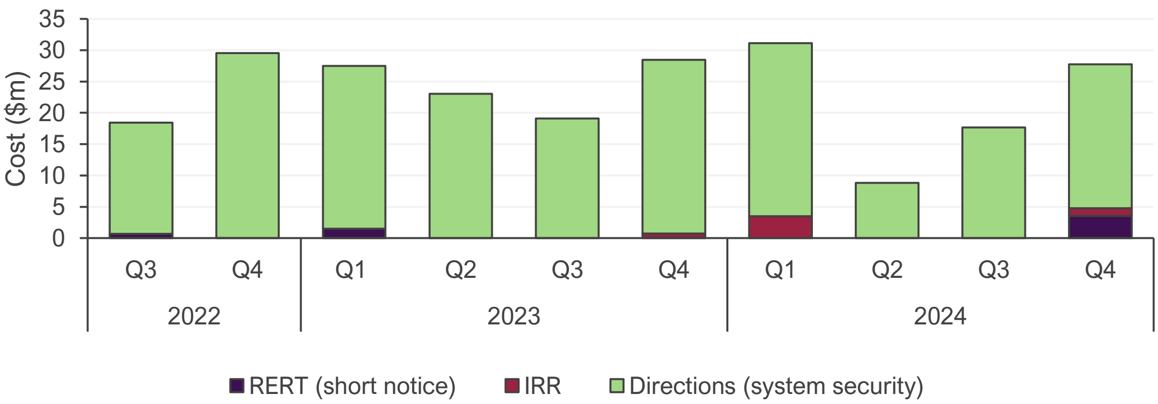
Estimated power system management costs[29] were $27.8 million over Q4 2024, equivalent to approximately 0.5% of the cost for consumed energy over the quarter. This represents a $10.1 million increase from Q3 2024, but a $0.7 million decrease from Q4 2023 (Figure 77).

Reliability and Emergency Reserve Trader (RERT) is a function conferred on AEMO to ensure reliability of supply by securing the availability of reserves using reserve contracts. AEMO entered into interim reliability reserve (IRR) agreements with four providers for the New South Wales region for the period from 1 December 2024 to 31 March 2025[30]. Payments from 1 December 2024 to the end of the quarter were $1.2 million. Additionally, AEMO activated separate short notice reserve contracts in New South Wales to maintain the power system in a reliable operating state on 27 November 2024. The estimated payments associated with these contracts were $3.6 million.

Also included in the power system management costs is $23 million for estimated compensation costs to generating systems related to directions for energy services to maintain system security in both South Australia and Victoria during the quarter.

Figure 77 System security direction costs down year-on-year while short notice RERT and IRR costs increased

Estimated quarterly system security costs by category



2.6.1 System security energy directions

System security energy directions were in place in South Australia for 65% of dispatch intervals in Q4 2024, higher than the 53% in Q3 2024, but the same frequency as during Q4 2023 (Figure 78). The average amount of South Australian gas-fired generation directed increased slightly from Q4 2023 levels, up 1 MW to average 47 MW this quarter.

The initial estimated cost associated with these Q4 2024 directions in South Australia is $22.7 million, which is currently lower than the finalised total of $27.4 million related to Q4 2023 directions compensation. However, whilst the average compensation prices paid to direction participants increased from $188/MWh in Q4 2023 to

[29] 'Power system management costs' are those associated with Reliability and Reserve Trader (RERT) and compensation for system security directions for energy services only and excludes compensation costs for reliability directions (including those to maintain a state of charge) and system security directions for other services (that is, operating as synchronous condenser).

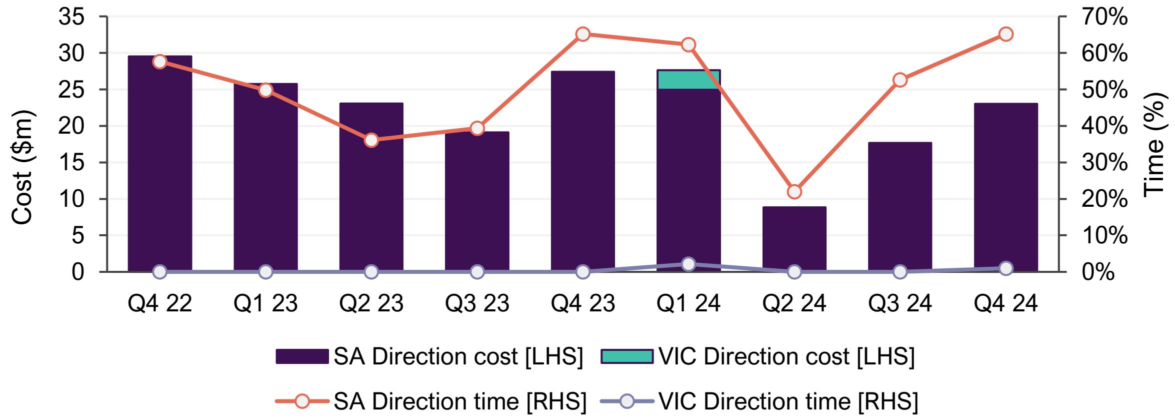
[30] AEMO, RERT Reporting, at https://aemo.com.au/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting.

$223/MWh in Q4 2024, any additional compensation claims for generators directed during Q4 2024 have not yet been finalised so the estimated costs are subject to change[31].

System strength energy directions were also in place in Victoria on 14 November when several coal unit outages coincided with a network outage, with an initial estimated cost of $0.3 million.

Figure 78 Direction frequency of South Australian generators remained constant year-on-year

Time and cost of energy only system security directions – South Australia and Victoria Q4 2022 to Q4 2024



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

3 Gas market dynamics

3.1 Wholesale gas prices

Quarterly average wholesale gas prices increased compared to Q4 2023 and were also 9% higher than Q3 2024. The average price across all AEMO markets was $13.60/GJ compared to $10.83/GJ in Q4 2023 (Table 6). This is the highest average Q4 price since Q4 2022.

Table 6 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q4 2024	Q3 2024	Q4 2023	Change from Q4 2023
Victoria Declared Wholesale Gas Market (DWGM)	12.25	12.08	10.39	18%
Adelaide	13.55	12.78	11.23	21%
Brisbane	14.71	12.63	10.91	35%
Sydney	13.66	12.57	10.81	26%
Gas Supply Hub (GSH)	13.85	12.48	10.73	29%

Key factors influencing the movement of prices throughout Q4 2024 are summarised in Table 7, with further analysis and discussion referred to relevant sections elsewhere in this report.

Table 7 Wholesale gas price levels: Q4 2024 drivers

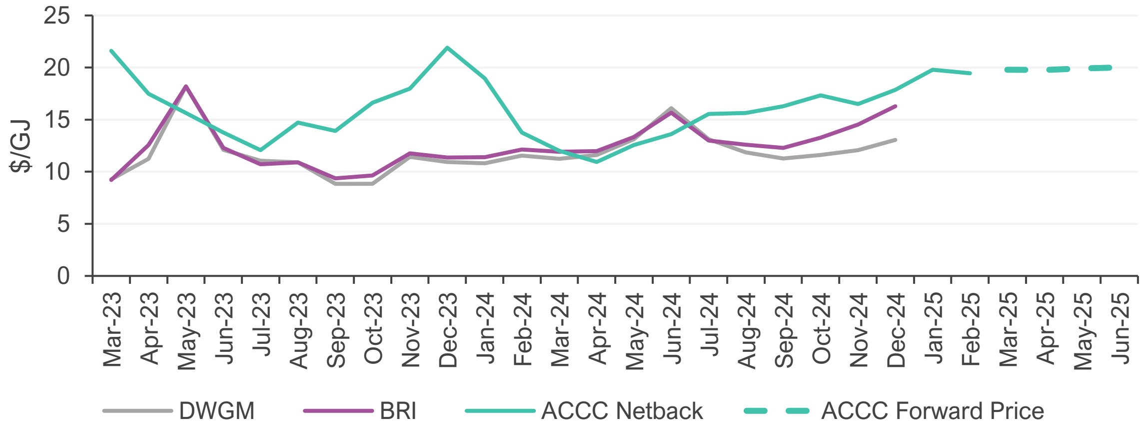
Increase in gas flows to Queensland from southern markets to support record Queensland LNG demand combined with a reduction in net domestic supply from LNG participants	Compared to Q4 2023, aggregate demand from the Queensland LNG export projects was 17 PJ higher, while supply into the domestic market associated with the LNG projects decreased by 6 PJ. This led to greater reliance on Victorian supply to meet demand, with significantly higher flows into Queensland from southern markets. As a result, much of this supply was offered into markets at prices higher than Q4 2023. This also led to Brisbane becoming the highest price market, creating a notable price gap between the southern states and Queensland.
Higher gas-fired generation demand in November and December	While demand from gas-fired generation remained subdued in October, demand notably increased in November and December due to higher NEM demand and reduced coal availability. This put upward pressure on spot prices across all AEMO markets, but particularly in Brisbane which became the highest priced market, where domestic demand was already competing with record Queensland LNG demand. Gas-fired generation demand is discussed in more detail in Section 2.3.2.

International prices continued the trend observed in Q3 2024 and increased during the quarter, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, with corresponding forward prices ranging between $20/GJ and $21/GJ over the next six months (Figure 79). Drivers for international prices are discussed in Section 3.1.1.

Prices in Q4 2024 steadily increased during the quarter, with all markets experiencing their highest Q4 average price since Q4 2022 when the average price was $17.79/GJ. A widening price gap between Brisbane and southern states emerged during the quarter, with the Brisbane price peaking at $21.09/GJ on 16 December, compared to the Victorian Declared Wholesale Gas Market (DWGM) price which peaked at $14.79/GJ on the same day. The regional price differences were driven by a combination of factors, including the need to transport gas from southern states to meet record Queensland LNG production, and higher gas-fired generation demand. Prices eased over the final two weeks of the quarter due to the usual seasonal reduction in domestic demand.

Figure 79 Domestic prices increased during Q4 and peaked in December

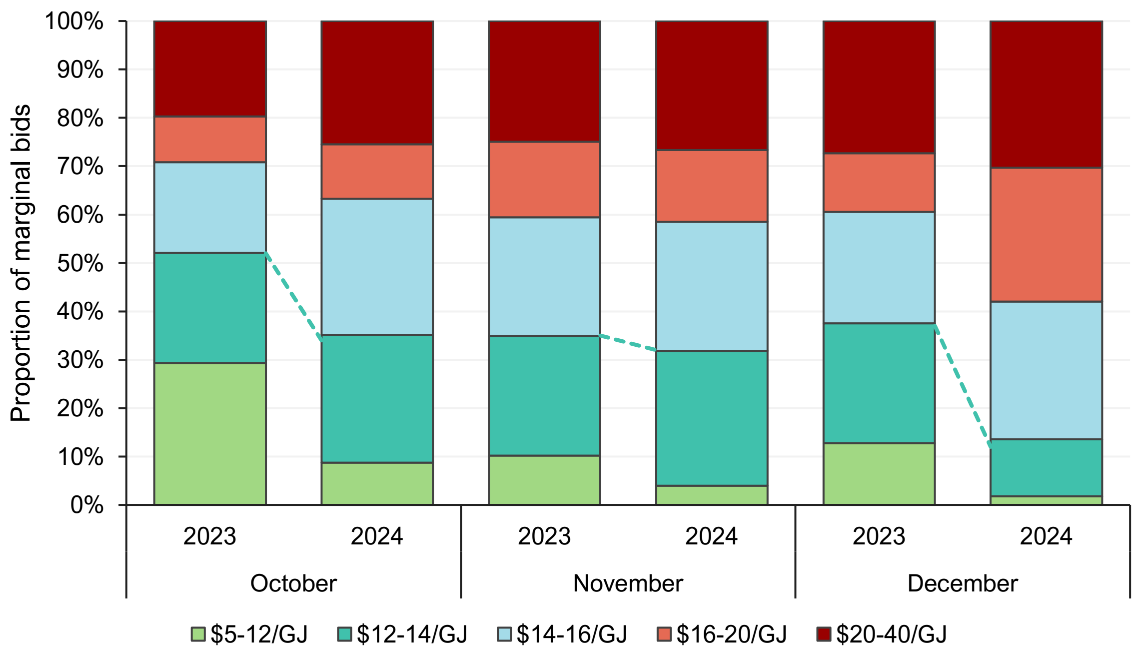
ACCC netback and forward prices[32], DWGM and Short Term Trading Market (STTM) Brisbane average gas prices by month



Compared to Q4 2023, there was a significant increase in the proportion of DWGM bid volumes above $14/GJ, particularly in December (Figure 80). Factors contributing to this include increased gas-fired generation and increased exports from Victoria, particularly to New South Wales which saw a large increase in northerly flows to Queensland.

Figure 80 Reduced DWGM bids at lower prices particularly in December 2024 compared to 2023

DWGM – proportion of marginal bids by price band – Q4 2024 vs Q4 2023 by month



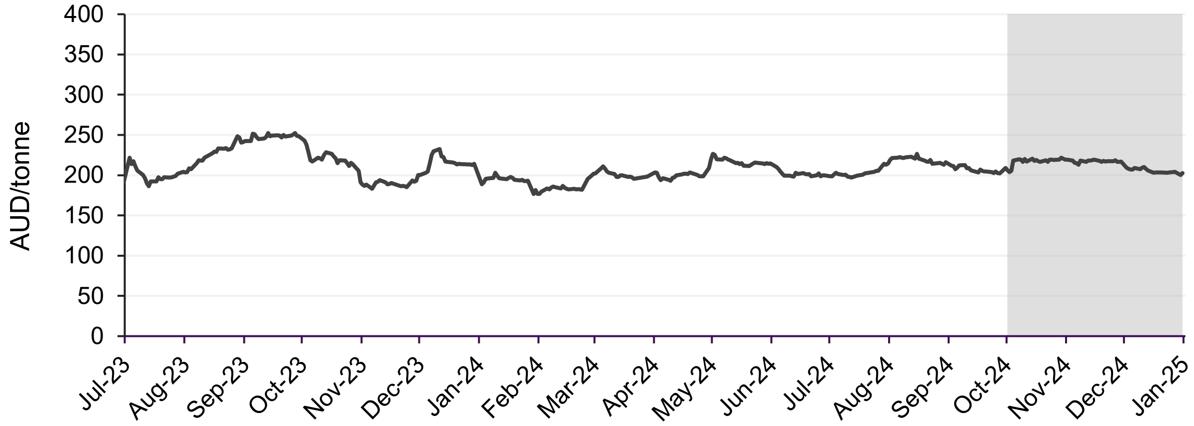
32 ACCC, LNG netback price series published on 16 January 2025, https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

3.1.1 International energy prices

Newcastle export coal prices averaged $213/tonne, up slightly from $209/tonne in Q3 2024, and $208/tonne in Q4 2023 (Figure 81). Prices rose in early October, held steady at that level driven by increased power demand (due to hot weather), restocking in anticipation of a cold winter in the northern hemisphere, reduced supply from Russia, and higher gas prices[33]. Prices declined again in December, ending the quarter at similar levels to those at the close of Q3 2024, hovering just above the $200/tonne mark.

Figure 81 Traded thermal coal prices closed at similar levels to the end of Q3 2024

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



Source: Bloomberg ICE data

Asian spot LNG prices rose during the quarter ending in 2024, reaching A$23.4/GJ (Figure 82). This increase was driven by cooler temperatures in North Asia in November and higher LNG consumption in the European Union, where increased heating demand led to greater depletion of LNG reserves[34]. The Dutch TTF reached 12-month highs, with reports indicating that at least five LNG cargoes were diverted from Asia to Europe due to ongoing tensions in Eastern Europe[35].

A brief dip in prices occurred in mid-December, attributed to strong LNG inventory levels in Asia. However, this decline was short-lived, as reports emerged that Russian gas supplies to Eastern Europe through Ukraine (via the “Transit Agreement”) were set to cease from 1 January 2025, a situation that ultimately came to pass[36]. Russian gas accounted for 10% of European Union gas imports in 2023, down from nearly 40% in 2021. The continued depletion of LNG reserves from European Union storage facilities further impacted the market.

LNG Production from the southern United States received a significant boost with the commencement of shipments from Plaquemines LNG, the eighth export terminal in the United States[37]. This milestone was reached in

[33] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly December 2024, at https://www.industry.gov.au/publications/resources-and-energy-quarterly-december-2024.

[34] Hellenics Shipping News, December 2024: https://www.hellenicshippingnews.com/asian-spot-lng-gains-as-colder-weather-drives-demand/.

[35] Reuters, November 2024: https://www.reuters.com/business/energy/lng-tankers-divert-europe-asia-after-russia-halts-supplies-austrias-omv-2024-11-18/.

[36] EU Energy Commission, December 2024: https://energy.ec.europa.eu/document/download/e8a46964-f29b-44f8-9410-689f9e34463b_en?filename=241211%20-%20End%20of%20UA%20transit%20-%20draft%20conclusions%20for%20publication%20-%20final_1.pdf.

[37] US Energy Information Administration, December 2024: https://www.eia.gov/todayinenergy/detail.php?id=64224.

mid-December and is expected to supplement European Union supply sources, where storage levels have been depleting at an accelerated rate.

Figure 82 Increase in Asian spot LNG driven by heating demand and diversion of LNG cargoes from Asia to the EU

Asian LNG price in A$/GJ daily

Source: Bloomberg ICE data

Brent crude oil prices averaged A$113/barrel, which was a A$4/barrel decrease from last quarter, and ended Q4 at A$121/barrel (Figure 83). The modest price increase was primarily due to the decline in the Australian dollar relative to the US dollar. At the start of Q4, the exchange rate was $0.69 USD per $1 AUD, but by the end of the quarter, it had fallen to $0.62 USD per $1 AUD[38].

The International Energy Agency (IEA) reported in October that spare production stands at historic highs. This puts global oil stocks at three-year highs, resulting in margin pressure across key refining hubs[39]. This message was echoed in their December 2024 report highlighting that ministers of the eight OPEC+ countries had agreed to further delay increase production to the market[40].

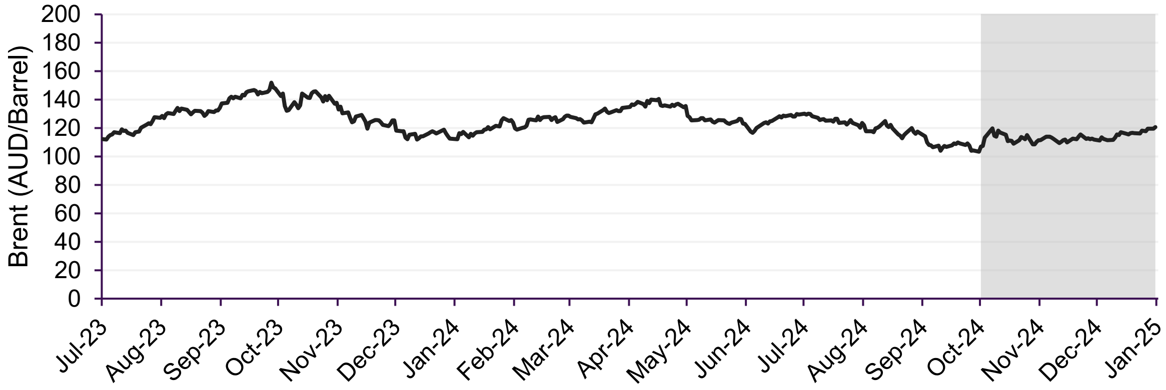
[38] ABC, January 2025: https://www.abc.net.au/news/2025-01-13/australian-dollar-falling-explainer-inflation-rates-trump/104810110.

[39] IEA Oil Market Report, October 2024: https://www.iea.org/reports/oil-market-report-october-2024.

[40] IEA Oil Market Report, December 2024: https://www.iea.org/reports/oil-market-report-december-2024.

Figure 83 Increase in Brent Crude oil price attributed to the fall in the Australian dollar against the USD

Brent Crude Oil in A$/Barrel daily



Source: Bloomberg ICE data

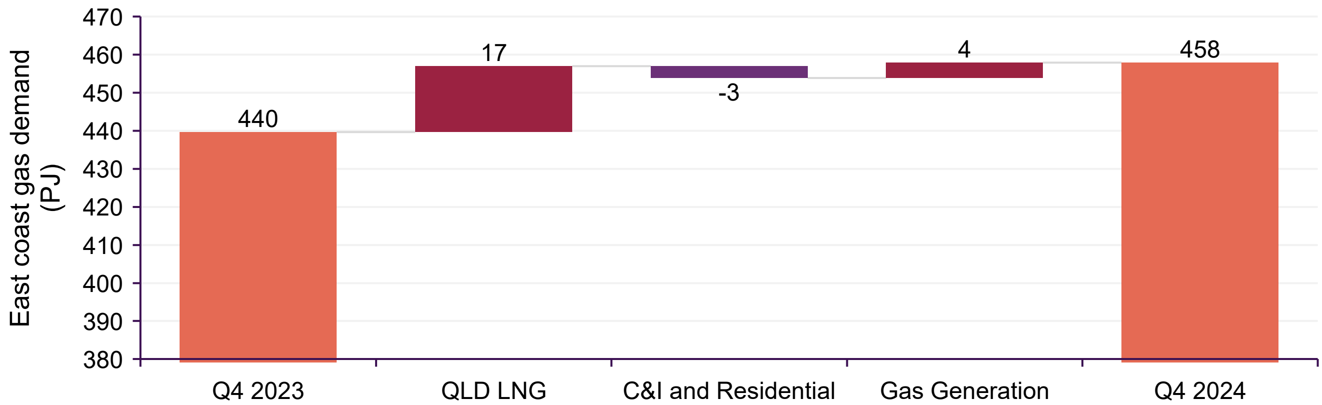
3.2 Gas demand

Total east coast gas demand increased by 4% compared to Q4 2023 (Figure 84 and Table 8), due to a large increase in Queensland LNG production (+17 PJ), and a smaller increase in gas-fired generation (+4 PJ). AEMO markets saw a fall in demand (-3 PJ), with the largest decrease of 4.3 PJ in Victoria's DWGM due to warmer temperatures combined with lower commercial and industrial demand.

A new record was set in Q4 2024 for Queensland LNG demand to Curtis Island. Flows to Gladstone have been over 4 PJ/day from the 26 October 2024. The main factor behind the increased flows to Curtis Island was time-swaps being returned back to LNG producers who seasonally shape their portfolio to supply gas to the southern states during winter. This can be seen from data on the AEMO Gas Bulletin Board, which shows that the average flow to Queensland LNG facilities in Q2 and Q3 over the past five years was 3.6 PJ/day, however in Q4 this increased significantly to 3.97 PJ/day[41].

Figure 84 Higher gas demand mainly due to large increase in LNG exports

Components of east coast gas demand change – Q4 2023 to Q4 2024



[41] AEMO Gas Bulletin Board, Actual Flow and storage (all data): https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-gbb/gas-flows.

Table 8 Gas demand – quarterly comparison

Demand (PJ)	Q4 2024	Q3 2024	Q4 2023	Change from Q4 2023
AEMO markets *	54.4	91.9	57.5	-3 (-5%)
Gas-fired generation **	20.8	29.6	16.8	+4 (+24%)
Queensland LNG	382.6	346.1	365.3	+17 (+5%)
Total	457.9	467.6	439.6	+18 (+4%)

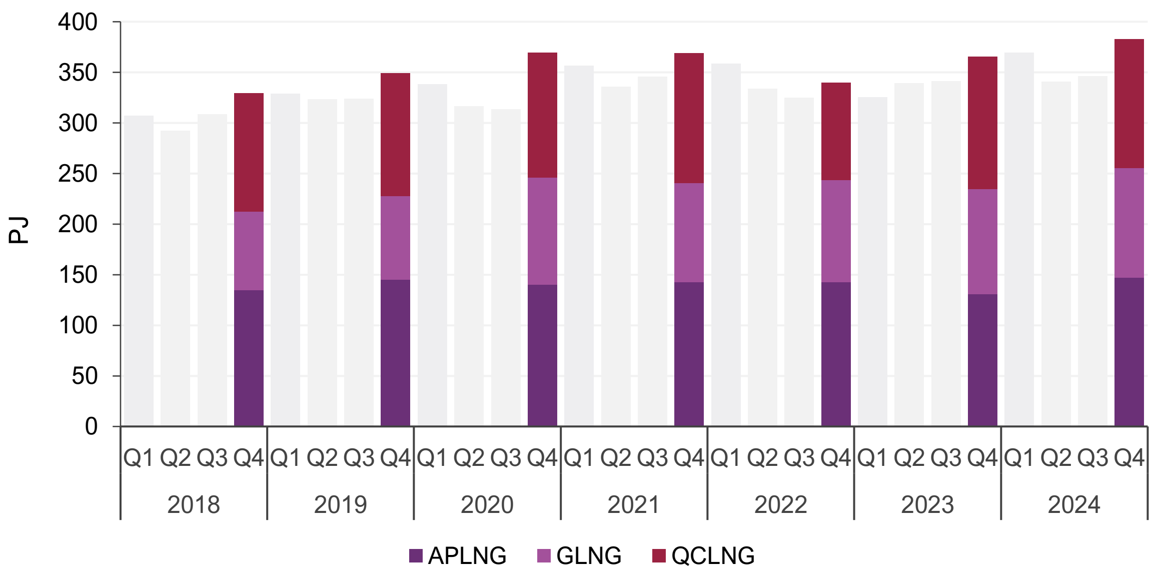
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand increased compared to Q4 2023 due to a large increase in APLNG demand and a smaller increase in GLNG demand, offset by a small decrease in QCLNG demand. The combined total demand of 382.6 PJ is an LNG export demand record for any quarter (Figure 85), with APLNG and GLNG also setting their own demand records for any quarter.

By participant, in comparison to Q4 2023, APLNG demand increased by 16.8 PJ and GLNG by 4 PJ, while QCLNG decreased by 3.5 PJ. There were 99 cargoes exported during the quarter, up from 87 cargoes in Q4 2023.

Figure 85 APLNG production increase drove record Queensland LNG production for any quarter

Total quarterly pipeline flows to Curtis Island

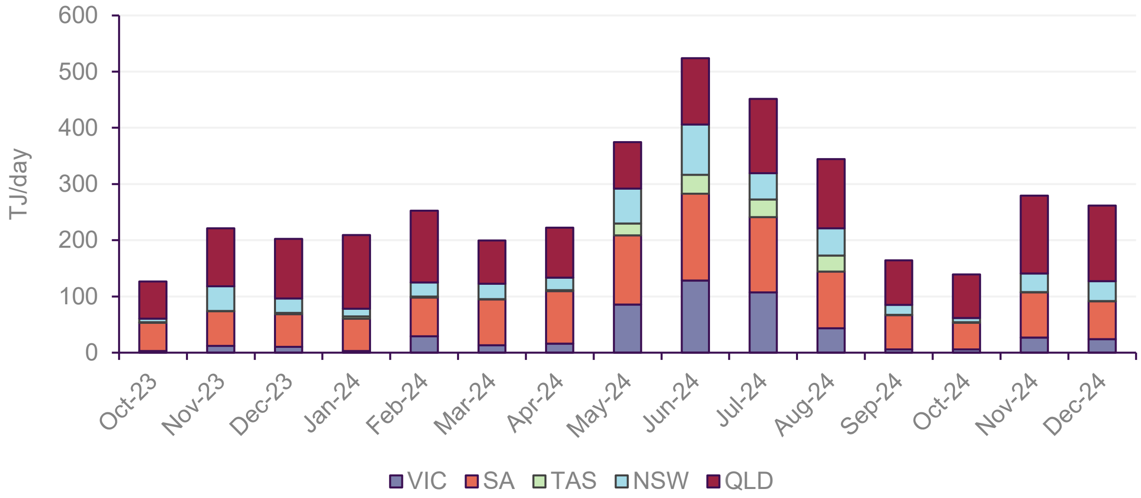


3.2.1 Gas-fired generation

Demand from gas-fired generation remained subdued in October but increased in November and December (Figure 86). Demand increases for the entire quarter were observed in all states except Tasmania. Victoria's demand increased by 121%, Queensland by 27%, South Australia by 15%, New South Wales by 1%, while Tasmania's decreased by 40%. Section 2.3.2 discusses drivers of this higher generation demand.

Figure 86 Increase in gas-fired generation in November and December contributed to increased market prices

Average daily gas-fired generation demand by state



3.3 Gas supply

3.3.1 Gas production

East coast gas production increased by 20.8 PJ (+4%) compared to Q4 2023 (Figure 87). Key changes included:

- Increased Victorian production (+11.6 PJ), mainly driven by higher production at the Otway Gas Plant (+6.1 PJ) and Longford (+3.7 PJ). As previously reported, the Otway increase is due to the Enterprise gas field commencing production in June[42].
- Increased Queensland production (+10.7 PJ), with assets operated by APLNG increasing by 7.1 PJ, GLNG operated assets by 0.9 PJ, and QCLNG operated assets by 0.8 PJ. Gas demand for Queensland LNG exports increased by 17.3 PJ, meaning supply associated with Queensland LNG projects into the domestic market was 6.7 PJ lower compared to Q4 2023. This represents the lowest domestic market supply for Q4 since 2017 (Figure 88).

[42] See https://beachenergy.com.au/enterprise-project/

Figure 87 Victorian supply increase due to higher Otway and Longford production

Change in east coast gas supply – Q4 2024 vs Q4 2023

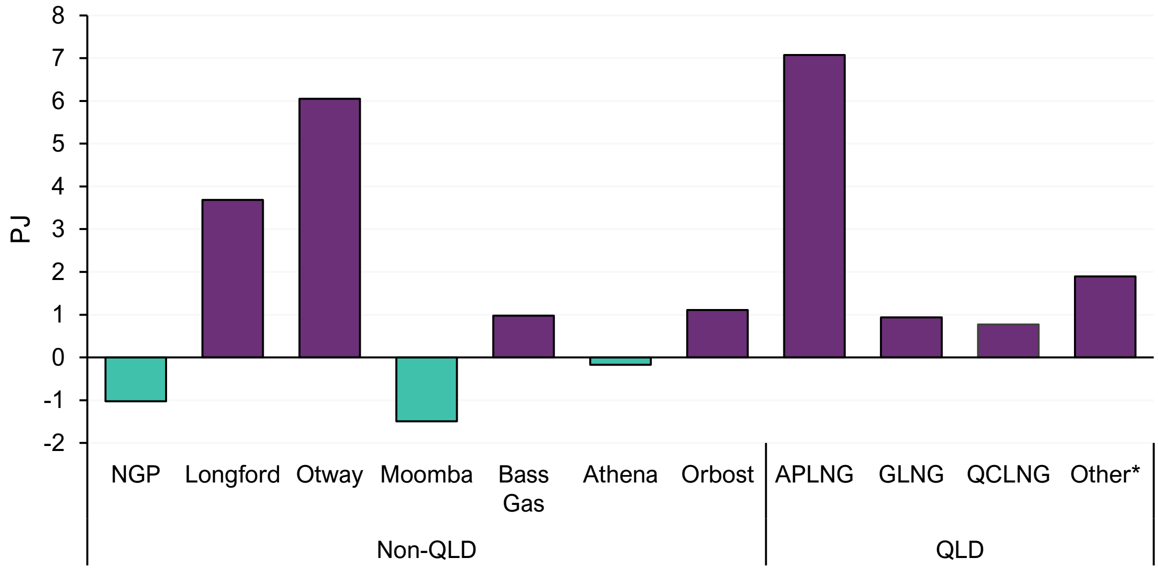
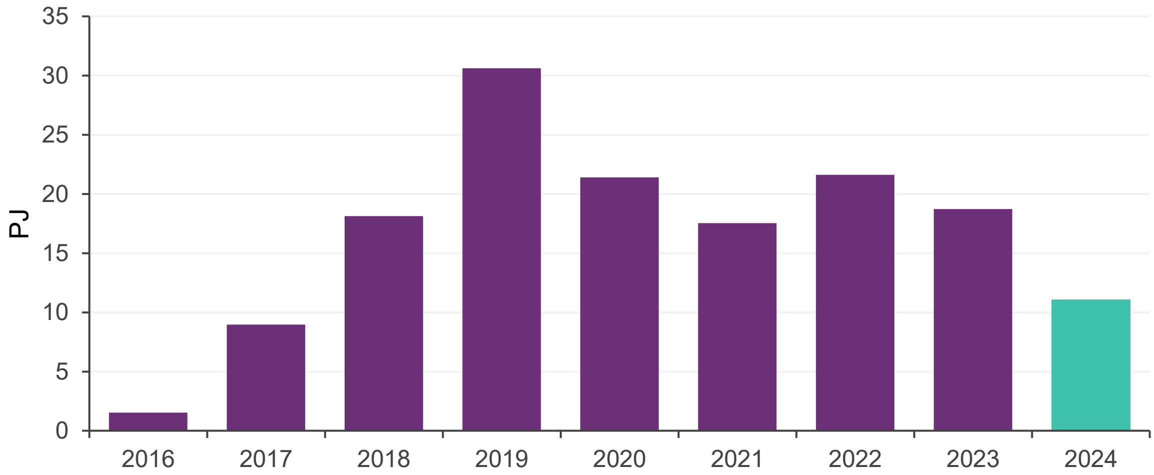


Figure 88 Queensland Q4 2024 net domestic supply decreases to lowest level since 2017

Queensland net domestic supply during Q4



3.3.2 Longford production and capacity

This quarter saw an increase in year-on-year Longford production for the first time since Q4 2022, reaching 50 PJ (Figure 89). Longford's available production capacity of 57 PJ was higher than Q4 2023, reflecting fewer maintenance outages.

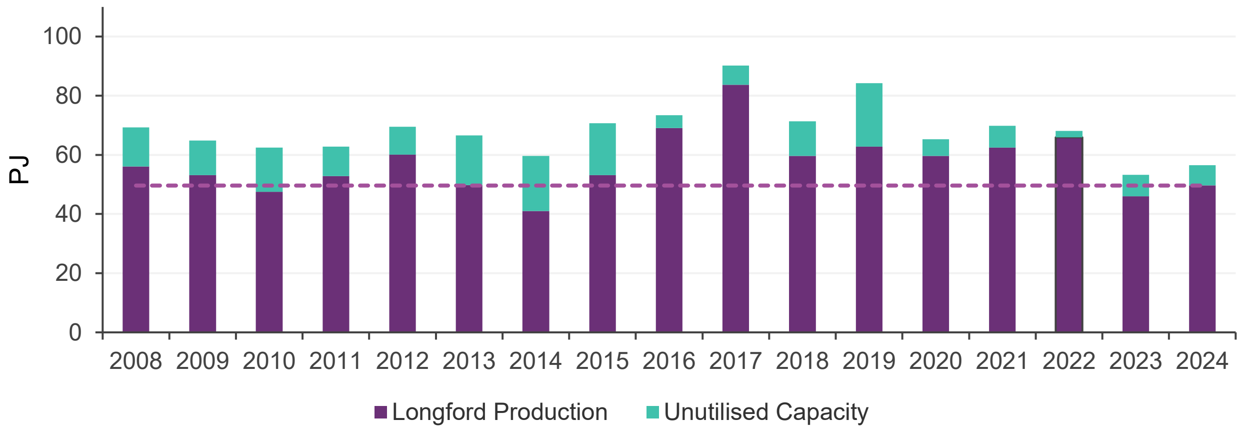
The Kipper Compression Project was commissioned during October [43], to maintain production from Esso and Woodside's Kipper gas field, which was experiencing pressure decreases as the field depletes.

[43] See https://corporate.exxonmobil.com/locations/australia/australia-newsroom/news-releases/2024/esso-australia-delivers-crucial-project-for-australian-natural-gas-supplies

As previously reported, Longford Gas Plant 1, operational since 1969, was retired in October. This leaves gas plants 2 and 3 in operation, limiting Longford's production to approximately 700 TJ/day going forward, meaning production levels seen during winter 2024 and in prior years are no longer achievable.

Figure 89 Longford Q4 production increases for first time since 2022

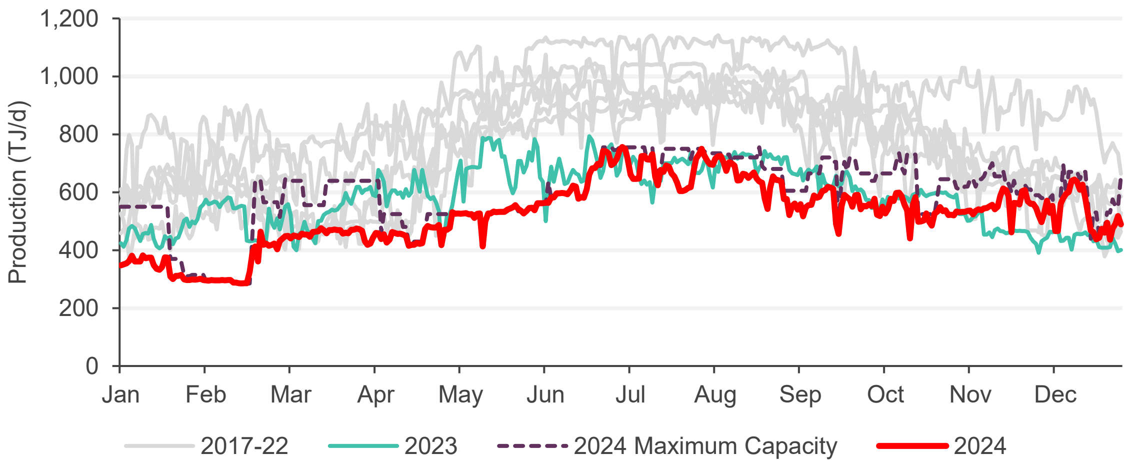
Longford Q4 production and unutilised capacity



Continuing from Q3 2024, daily production through much of Q4 was below available capacity, particularly in October (Figure 90), with Longford's capacity factor at 88%. This gap was mainly driven by a continuation of Longford supply offer prices being above the daily DWGM and Sydney STTM price outcomes. This narrowed in November to mid-December when market prices began to increase, reflecting higher gas-fired generation demand, resulting in Longford supply offers regularly setting the DWGM price.

Figure 90 Higher prices saw daily Longford production closer to capacity from November to mid-December

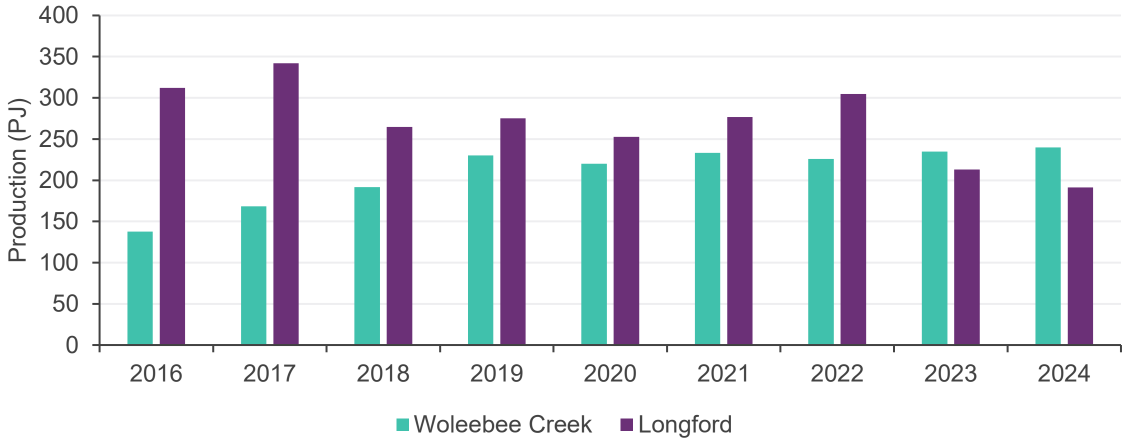
Daily Longford production 2017-2024, maximum capacity profile 2024



As reported in the Q4 2023 QED, in 2023 the QGC-operated Woleebee Creek production facility in Queensland overtook Longford as the largest gas production facility on the East Coast on an annual production basis (Figure 91). The gap widened in 2024, with Woleebee Creek achieving a new annual production record of 239 PJ, compared to Longford's 191 PJ, a year-on-year decrease of 22 PJ. The QGC-operated Ruby Jo Gas Plant was the next highest at 152 PJ, an increase of 23 PJ compared to 2023.

Figure 91 Woleebee Creek widened the gap on Longford as the largest production facility on the east coast

Annual Woleebee Creek vs Longford production



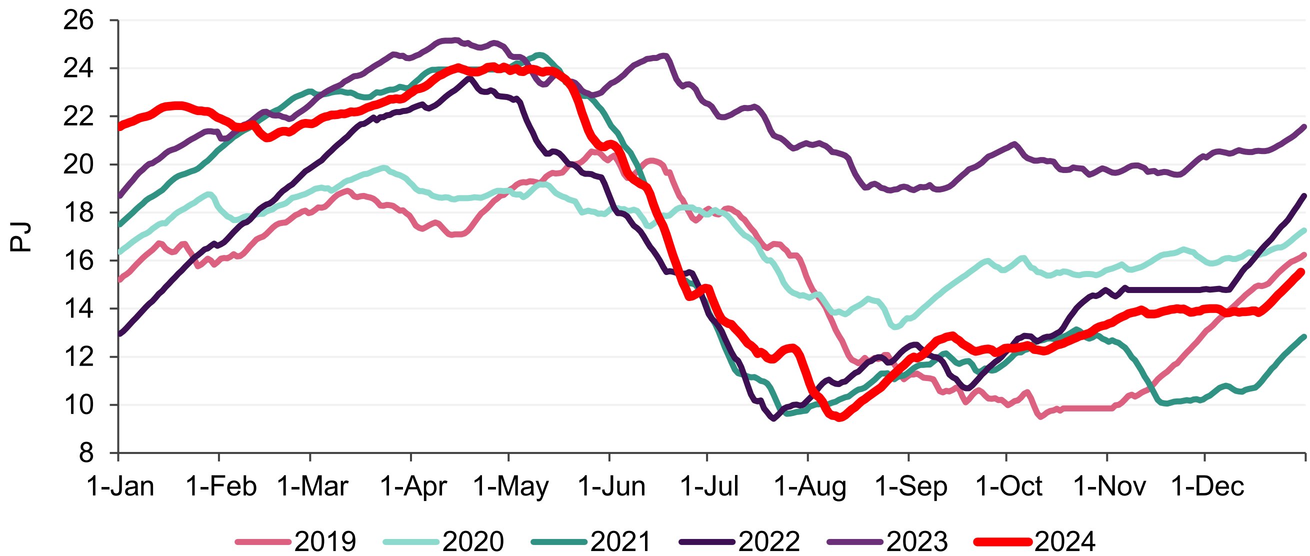
3.3.3 Gas storage

The Iona underground gas storage (UGS) facility finished the quarter with an inventory of 15.8 PJ, 5.7 PJ lower than at the end of Q4 2023 (Figure 92), and the lowest end to a Q4 since 2021.

Storage inventory filling saw modest increases from October to early November, before slowing through to mid-December, primarily due to higher prices resulting from an increase in Victorian gas exports as well as an increase in gas-powered generation. Storage levels saw a substantial increase in the last two weeks of December, aided by lower demand traditionally associated with the holiday period.

Figure 92 Iona storage at its lowest end to Q4 since 2021

Iona storage levels



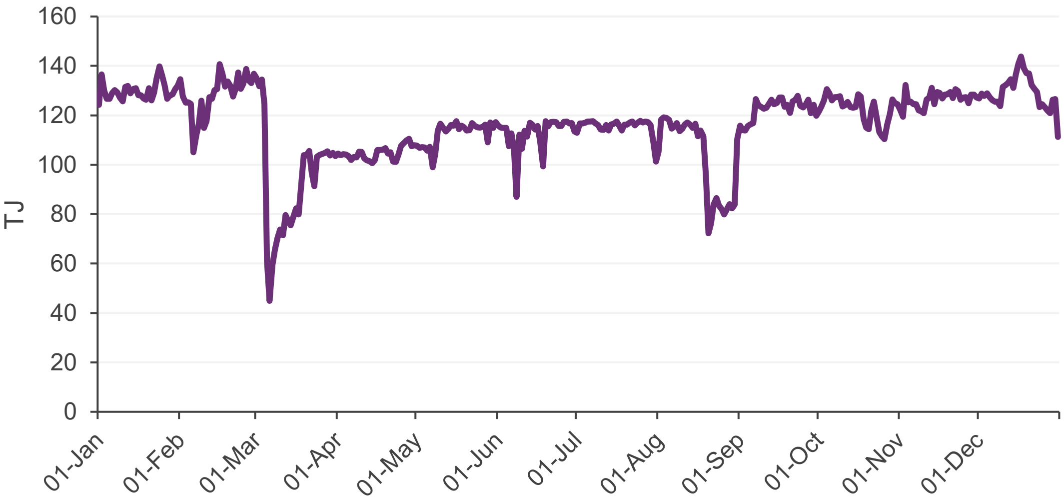
3.3.4 Queensland Gas Pipeline supply interruption

The Queensland Gas Pipeline (QGP) supply interruption that occurred on 5 March 2024 ended on 10 December after Jemena advised AEMO that it had completed repair works and a pipeline integrity review. With the QGP restored to its firm full contracted capacity, AEMO subsequently revoked the East Coast Gas System Risk or Threat Notice on the same day[44]. QGP daily flows peaked at 143 TJ on 17 December, their highest level since the pipeline rupture (Figure 93).

AEMO published a final post intervention report on the QGP event on 19 December[45].

Figure 93 QGP flows increase from 10 December after repair works successfully completed

QGP – daily pipeline flows



3.4 Pipeline flows

Compared to Q4 2023, there was a 10.0 PJ increase in net transfers north at Moomba on the South West Queensland Pipeline (SWQP, Figure 94) which represented the highest flow north from Moomba in the last five years. There were record flows north at Moomba in December, which was coincident with record LNG demand and increased production at Otway and Longford.

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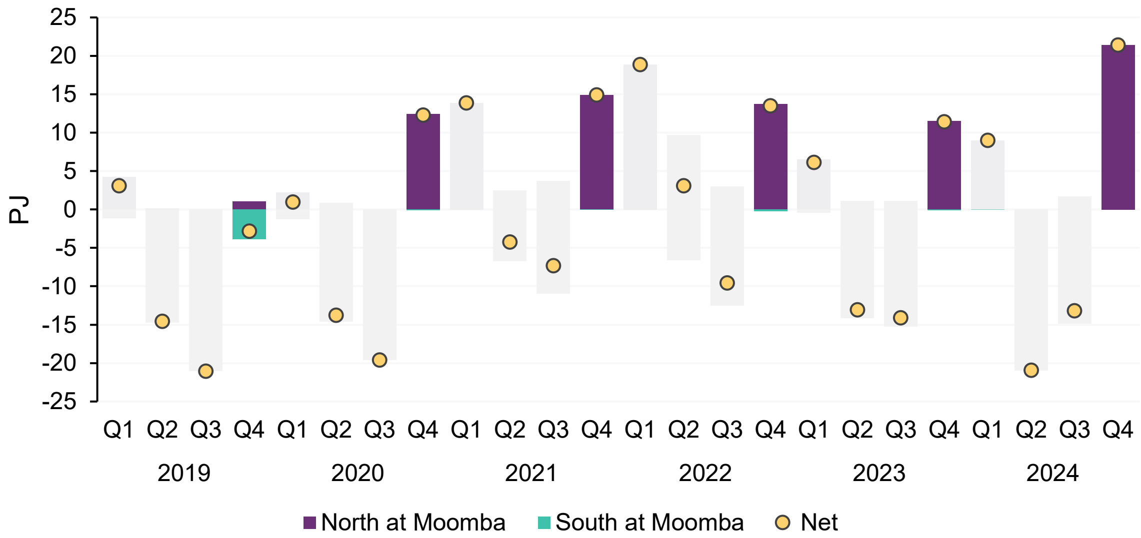
[44] https://www.nemweb.com.au/RePoRts/CURRENT/ECGS/ECGS_Notices/Attachments/

[45] https://aemo.com.au/energy-systems/gas/east-coast-gas-system/ecgs-reports-and-notices

Figure 94 Net Q4 flows north on SWQP increased to highest level in the last five years

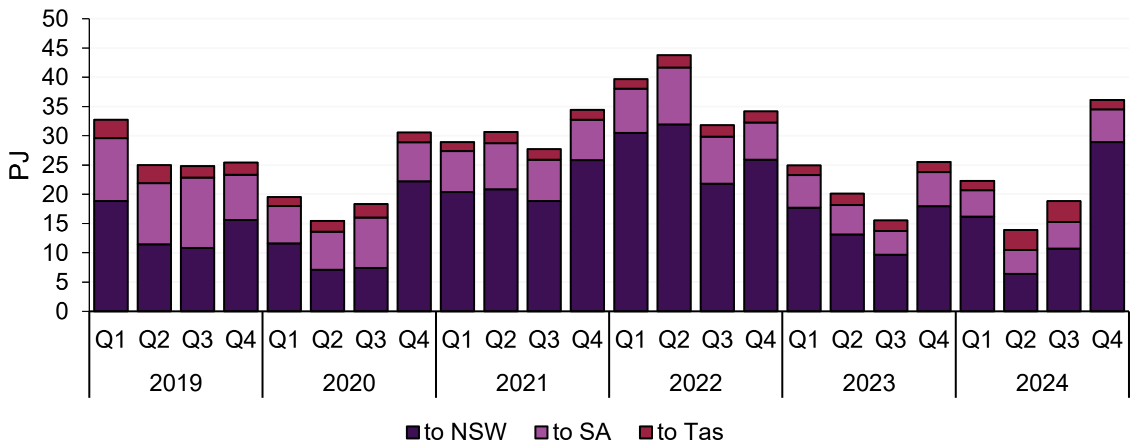
Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states increased by 10.6 PJ from Q4 2023 levels (Figure 95), solely due to an increase in flows to New South Wales. Victoria exported a net 11.2 PJ via Culcairn, compared to 3.2 PJ in Q4 2023. Exports to New South Wales via the Eastern Gas Pipeline (EGP) increased by 3.0 PJ.

Figure 95 Highest Victorian Q4 exports to New South Wales in the last five years

Victorian net gas transfers to other regions

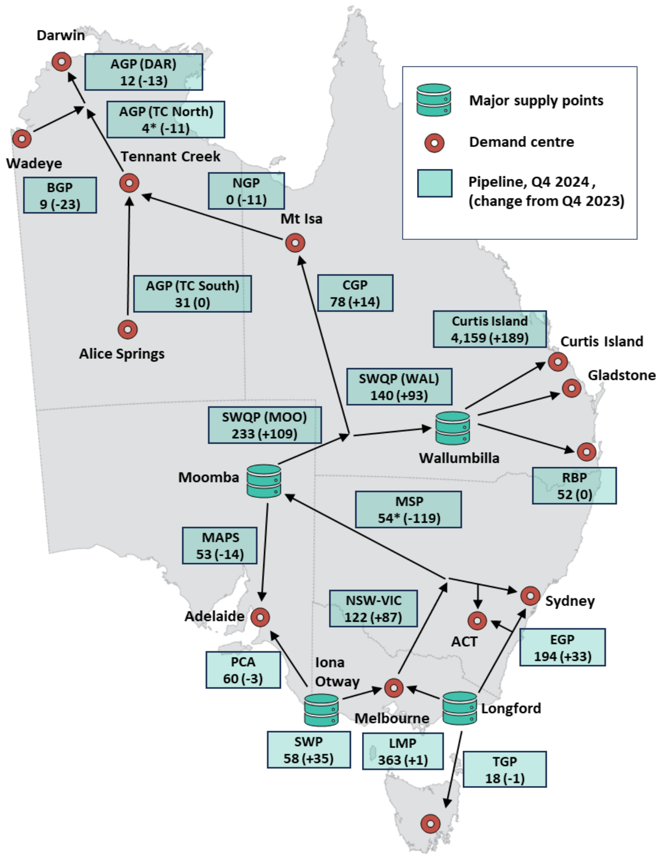


Average daily pipeline flows in Q4 2024 were significantly higher on the New South Wales – Victoria Interconnect (Figure 96), reflecting greater production at the Otway and Longford gas plants to supply New South Wales.

In Queensland, Mt Isa demand continued to be solely supplied from Queensland, reflecting the upstream supply issues experienced in the Northern Territory. Average daily Curtis Island flows in Q4 2024 were significantly higher mostly due to increased production at APLNG.

Figure 96 Increased average daily pipeline flows North

Average daily pipeline flows Q4 2024 vs Q4 2023

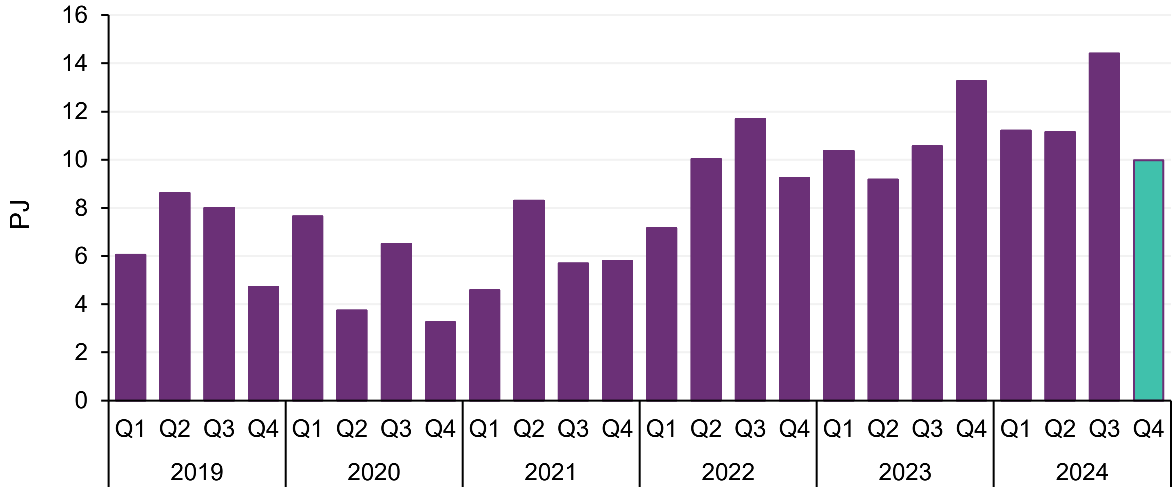


3.5 Gas Supply Hub (GSH)

In Q4 2024, traded volumes on the GSH decreased by 3.3 PJ in comparison to Q4 2023 (Figure 97). The traded volume this quarter was 10.0 PJ and represented the second highest Q4 GSH traded volume since market start. November was the highest monthly traded volume for the quarter at 4.6 PJ, traded predominantly for delivery in the same month (2.6 PJ) and for delivery in January 2025 (1.2 PJ).

Figure 97 Decrease in traded volumes on the GSH

Gas Supply Hub – quarterly traded volume

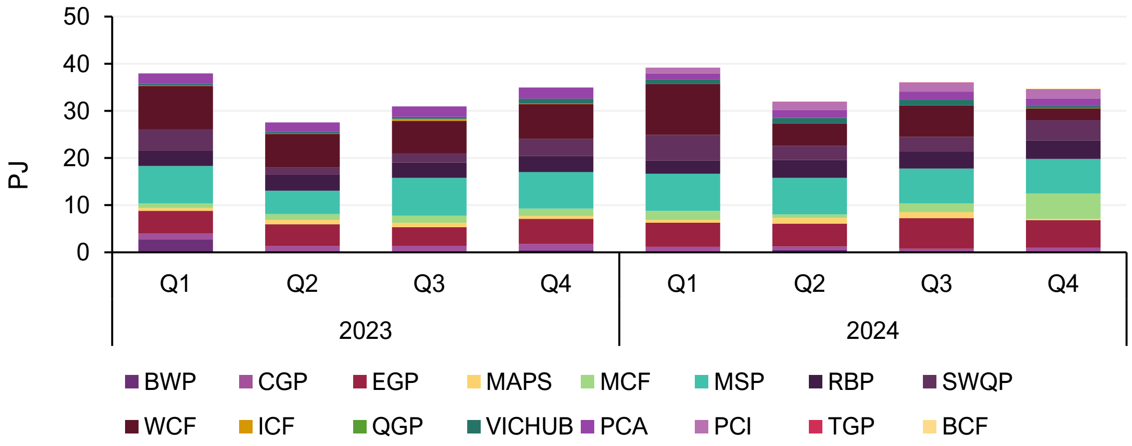


3.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes decreased by 0.3 PJ in comparison to the Q4 record of 35.0 PJ set last year (Figure 98). Compared to Q4 2023, there was a decrease in auction volumes on the Wallumbilla Compression Facility (WCF, -4.9 PJ) and increases in auction volumes on the Moomba Compression Facility (MCF, +3.8 PJ) and on the Port Campbell to Iona lateral pipeline (PCI, +1.9 PJ).

Figure 98 Slight decrease in DAA volumes traded

Day Ahead Auction volumes by quarter



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

- The Eastern Gas Pipeline (EGP) which averaged $0.45/GJ.
- The SWQP eastern flows which averaged $0.38/GJ.
- The Moomba to Sydney Pipeline (MSP) northern flows which averaged $0.11/GJ.
- The Carpentaria Gas Pipeline (CGP) which averaged $0.10/GJ.

- The Roma to Brisbane Pipeline (RBP) which averaged $0.06/GJ.

Compared to Q4 2023, where the average auction clearing price for the SWQP was $0.02/GJ and the EGP averaged $0.09/GJ, average prices for Q4 2024 increased significantly. Notably, the SWQP East path set a record daily price of $2.20/GJ in early December.

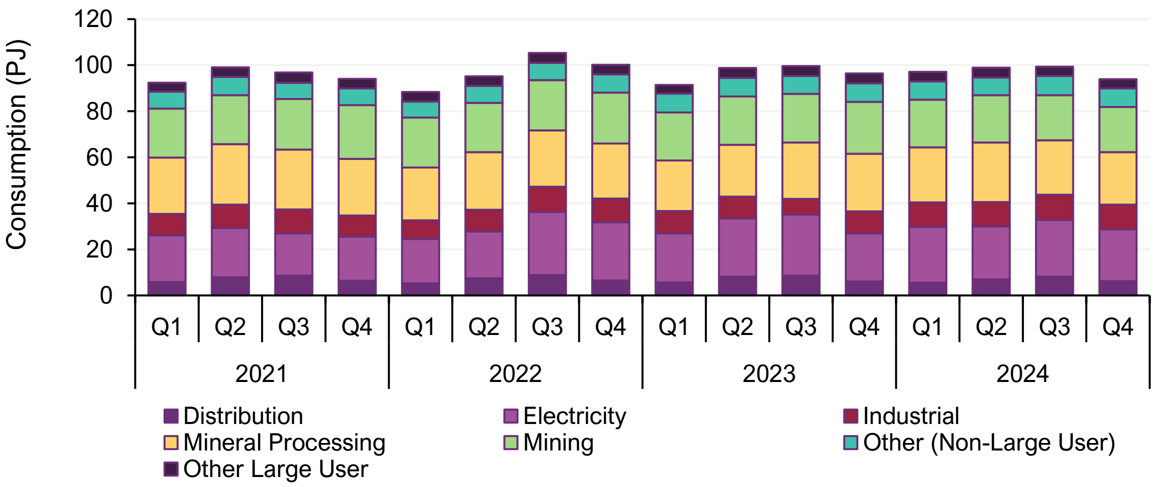
3.7 Gas – Western Australia

3.7.1 Gas consumption

A total of 93.9 PJ was consumed from registered pipelines in the Western Australian domestic gas market in Q4 2024 (Figure 99). This was a slight decrease (-2.6 PJ) to Q4 last year and a decrease (-5.5 PJ) from Q3 2024. The largest difference compared to Q3 2024 was observed in the electricity sector, down by 2 PJ (-8%). All other sectors saw slight reductions this quarter. There were also changes in consumption when reviewing geographic zones with Q3 2024; Perth Metro zone reduced its consumption by 3.8 PJ (-14%) compared to last quarter, whereas the Telfer zone increased its consumption by 0.8 PJ (+153%).

Figure 99 Gas consumption in Western Australia dropped slightly compared to Q4 2023

Western Australia quarterly gas consumption by sector – Q1 2021 to Q4 2024



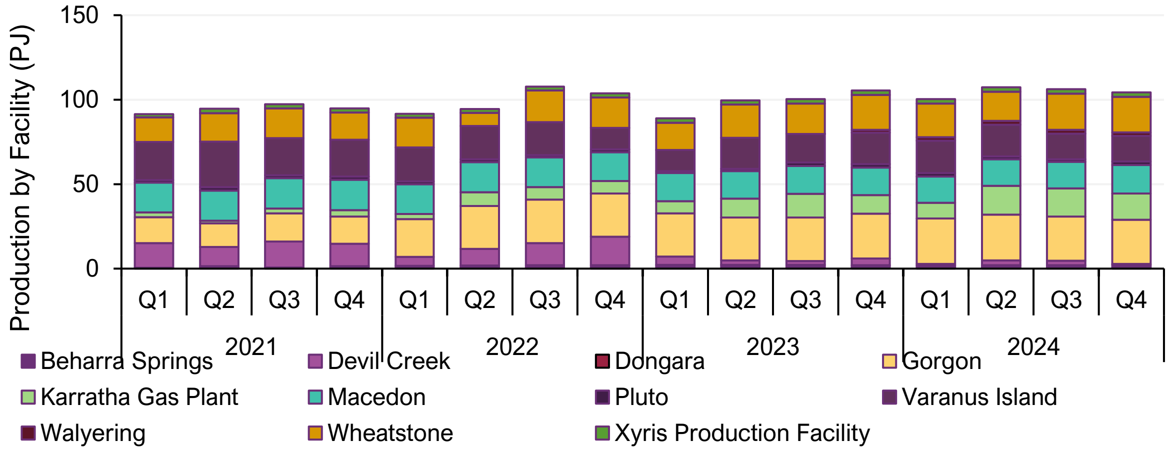
3.7.2 Gas production

Gas production in Western Australia was 104.3 PJ, a decrease of 1.1 PJ (-1%) compared to Q4 2023 and a reduction of 1.9 PJ (-2%) compared to last quarter (Figure 100)[46].

[46] Imbalance between production, consumption, and storage flows can be attributed to changes in linepack, pipeline usage, losses and other factors that are currently under investigation. See item #7 of August 2024 Gas Advisory Board (GAB) minutes, at https://www.wa.gov.au/system/files/2024-10/gab_2024_08_29_minutes.pdf.

Figure 100 Q4 2024 saw a decrease in gas production of 1.1 PJ from Q4 2023

Western Australia quarterly gas production by facility – Q1 2021 to Q4 2024



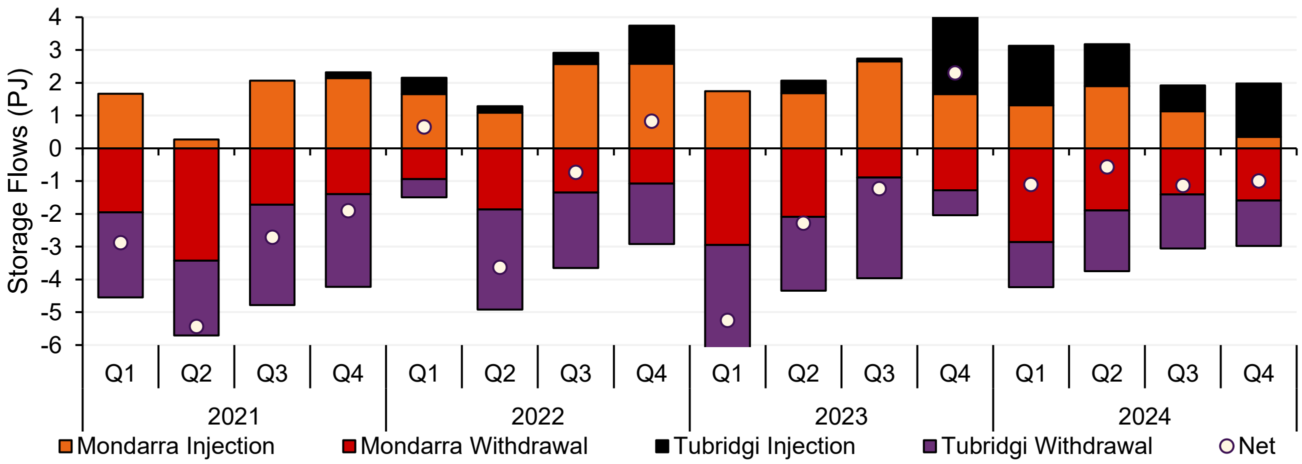
The decrease in production from Q4 2023 can be mainly attributed to: (1) lower output levels at Devil Creek, down by 3.3 PJ (-84%) due to a well constraint with the Reindeer gas field nearing end of production, and (2) Varanus Island, down by 3.3 PJ (-18%) with a processing constraint at the start of October resulting in no production for around 6 days. Lower production compared to the previous quarter can be attributed to decreases to Devil Creek, 1.9 PJ (-75%), and Karratha Gas Plant, 1 PJ (-6.1%).

3.7.3 Storage facility behaviour

In Q4 2024 there was net withdrawal from storage facilities of 1.0 PJ (Figure 101). This is the fourth consecutive quarter of net withdrawals. Withdrawal from storage in Q4 2024 increased by 0.9 PJ (46.3%) compared to the same quarter last year, when there was a net injection of 2.3 PJ. Compared to Q3 2024, withdrawals slightly reduced 0.1 PJ (-2%).

Figure 101 Net withdrawals from storage continue in Q4 2024

Western Australia gas storage facility injections and withdrawals – Q1 2021 to Q4 2024



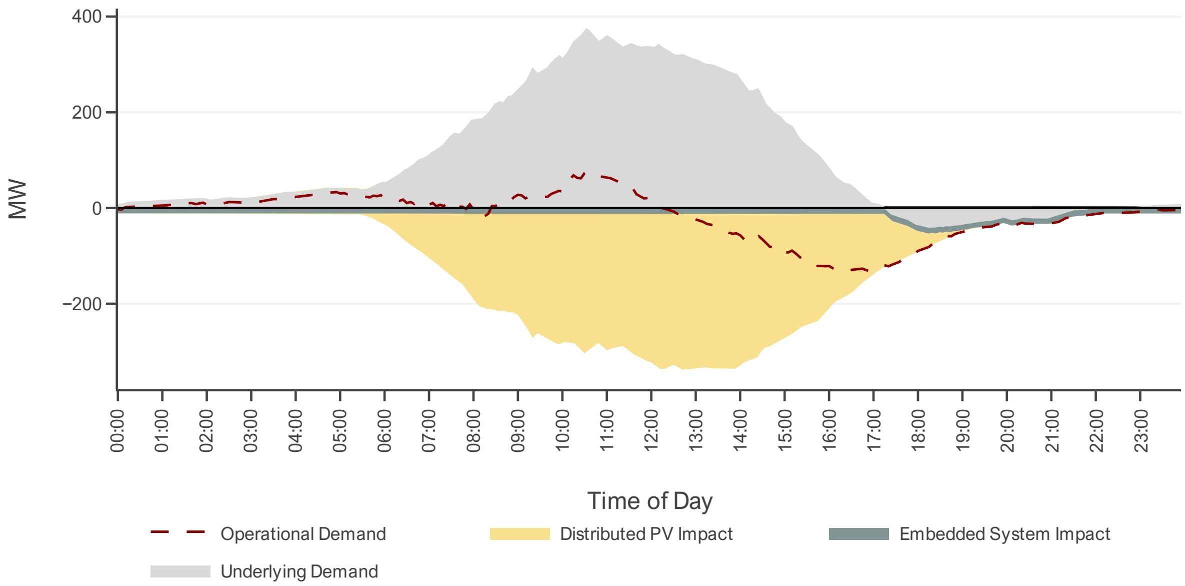
4 WEM market dynamics

4.1 Electricity demand

Operational demand[47] reduced by an average of 16.7 MW (-0.9%) in Q4 2024 compared to Q4 2023 (Figure 102). An average increase in underlying demand of 105 MW (+4.3%), to 2,539 MW (a Q4 record), was partially a result of an increase in average battery withdrawal (charging) of 38 MW (from a base of 2 MW in Q4 2023), primarily increasing during the day where it averaged 116 MW of withdrawal during 10:00 and 14:00 (+112 MW on Q4 2023) (Figure 103). This average underlying demand increase was offset by an increase in average estimated distributed PV generation[48] by 110 MW (+20.3%) and increases in average embedded system generation by 11 MW (+283%): both reduce operational demand.

Figure 102 Operational demand down slightly, with increases in distributed PV outweighing an increase in underlying demand

Change in WEM average operational demand components by time of day – Q4 2023 vs Q4 2024

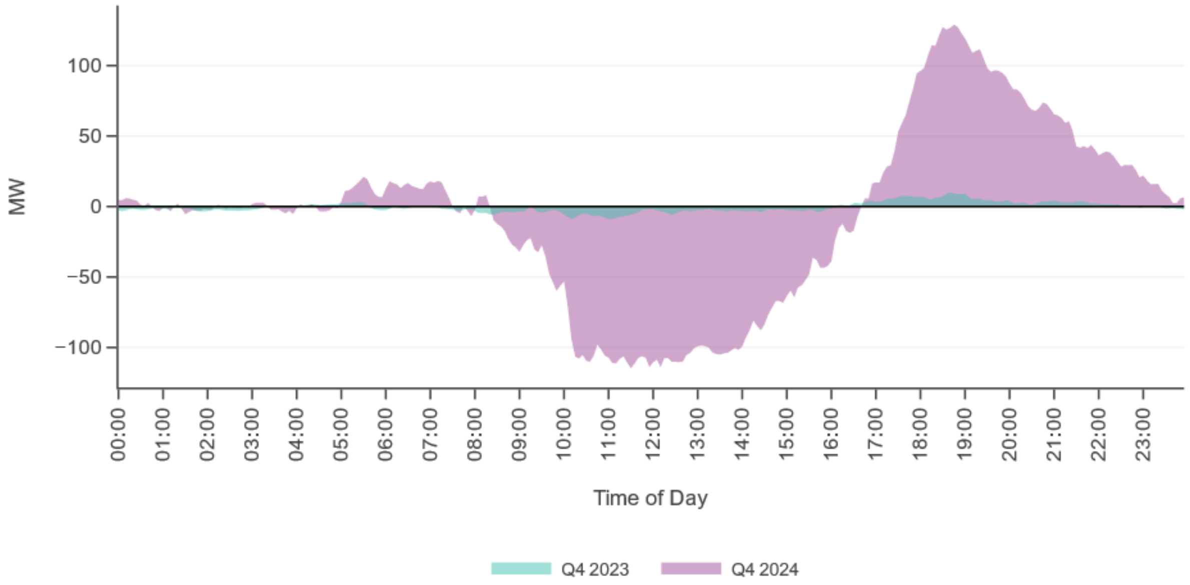


[47] Operational demand considers the total injection, in MW, from all scheduled facilities, semi-scheduled facilities and non-scheduled facilities that are injecting at the end of the dispatch interval.

[48] Estimated distributed PV is an extrapolation based on solar irradiance data and installed distributed PV capacity data available to AEMO.

Figure 103 Q4 2024 saw significant change in battery withdrawal and generation

Batteries average energy generation/withdrawal, time of day – Q4 2023 and Q4 2024



New records for both minimum operational demand and minimum unscheduled operational demand[49] were set during Q4 2024. This was primarily due to increases in distributed PV combined with weekend days of mild weather, driving low demand. Additionally, high temperatures on 11 December 2024 resulted in a maximum underlying demand record and Q4 maximum operational demand record (Table 9).

Table 9 Summary of WEM demand records set in Q4 2024

Demand measure	Demand record	Interval
Minimum operational demand	511 MW *Previous record: 595 MW*	13:40 10 November 2024 *Previous record: 12:30 25 September 2023*
Minimum unscheduled operational demand	474 MW *Previous record: 499 MW*	13:20 10 November 2024 *Previous record: 3 November 2024*
Maximum underlying demand	5,263 MW *Previous record: 4,990 MW*	14:25 11 December 2024 *Previous record: 19 February 2024*
Q4 maximum operational demand	4,163 MW *Previous record: 4,040 MW*	18:25 11 December 2024 *Previous record: 17:55 23 November 2023*

4.2 Electricity generation

The change in average WEM generation by fuel type relative to Q4 2023 is shown in Figure 104 and the resultant changes in supply mix contributions are shown in Table 10. Key changes included:

[49] Unscheduled operational demand represents the total injection required, in MW, from scheduled facilities, semi-scheduled facilities and non-scheduled facilities at the end of the interval, to serve demand that does not relate to: (a) withdrawals by non-scheduled facilities; or (b) withdrawals scheduled by the dispatch algorithm for scheduled facilities or semi-scheduled facilities.

- Reduction in average coal generation by 139 MW (-19.5%). This can be attributed to reduced availability of coal facilities during Q4 2024 compared to Q4 2023.
- As noted in Section 4.1, an increase in average estimated distributed PV generation by 110 MW (+20.3%).
- Increase in average gas generation by 97 MW (+14.4%), which replaced the reduction in coal generation at all times of the day except for some intervals during the evening peak (Figure 105).
- Increase in average battery injection of 33 MW (up 1400% from a base of 2.2 MW in Q4 2023), which was concentrated on the evening peak where it replaced coal generation: during 17:30 and 21:00 average battery injection was 103 MW, an increase of 97 MW on Q4 2023. This is attributable to an increase in battery generation capacity comprised of:
  - 200 MW/800 MWh commissioned since Q4 2023.
  - 225 MW/900 MWh undergoing commissioning during Q4 2024.
- Average increase in contribution of 5 MW from hybrid fuel type due to the first hybrid facility undergoing commissioning tests (50 MW capacity).

Figure 104 Lower coal generation replaced by distributed PV, gas and batteries

Change in quarterly average generation – Q4 2023 vs Q4 2024

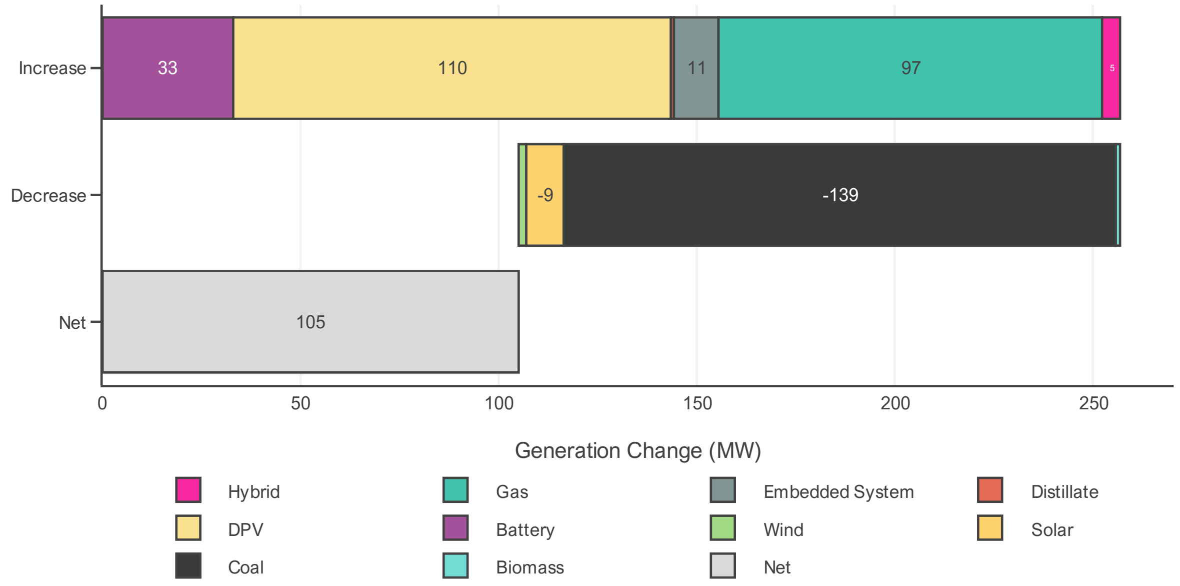


Figure 105 Lower coal generation replaced by distributed PV, gas and batteries

Average WEM change in fuel mix by time of day – Q4 2023 vs Q4 2024

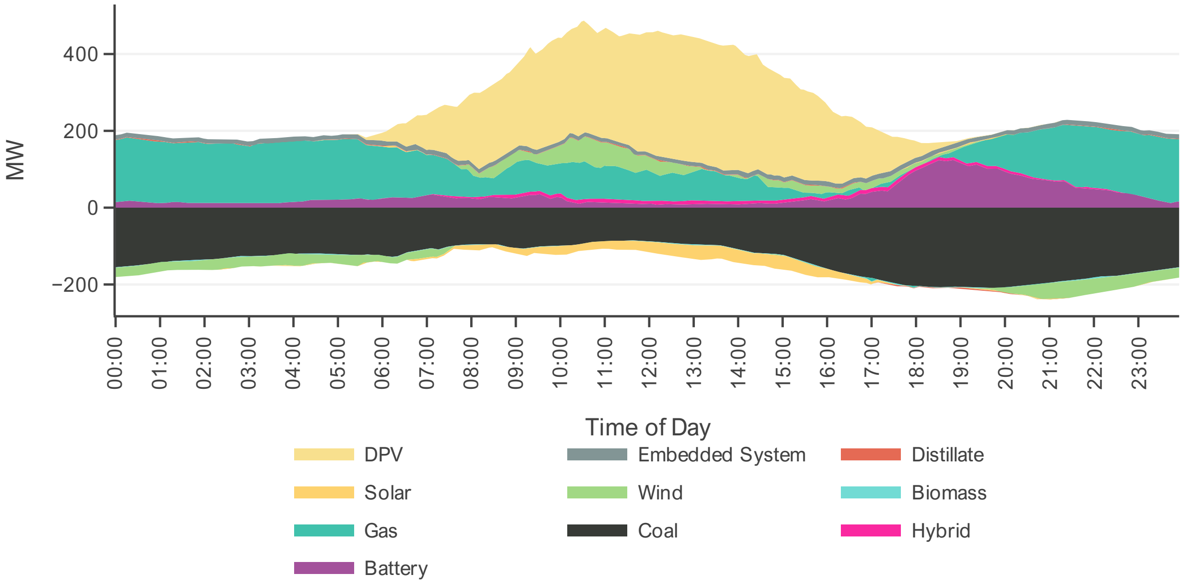


Table 10 WEM fuel mix Q4 2023 and Q4 2024

Quarter	Coal	Gas	Distillate	Grid Solar	Wind	Biomass	Battery	Hybrid	Distributed PV
Q4 2023	29.4%	27.6%	0.0%	2.2%	17.8%	0.4%	0.1%	0%	22.3%
Q4 2024	22.7%	30.2%	0.1%	1.7%	17.0%	0.3%	1.4%	0.2%	25.8%
Change	-6.7%	2.6%	0.1%	-0.5%	-0.8%	-0.1%	1.3%	0.2%	3.5%

4.2.1 Renewable contribution

Renewable contributions[50] in the WEM set numerous records during Q4 2024, including:

- A record quarterly high average of 46.4% of the overall generation, a 3.6 pp increase compared to the previous record observed in Q4 2023. This was driven by record contribution from distributed PV of 25.8% (up 3.5 pp on Q4 2023) and increase in battery share to 1.4% (up 1.3 pp on Q4 2023) (Figure 106).
- The WEM experienced its highest peak renewable contribution of 85.1%[51] during the 13:35 interval on 17 November 2024. This was primarily driven by high average distributed PV (72.4%) and wind (11.3%) generation (Figure 107), with the remainder coming from grid-scale solar and biomass. The previous peak of 84.3% was recorded during the 11:00 interval on 12 December 2022.
- Renewable contribution was at least 50% during 37.7% of intervals, an increase of 3.4 pp on Q4 2023, representing 10% more intervals over the quarter.

[50] Renewable contribution refers to percentage of underlying demand met by renewable fuel types.

Figure 106 Q4 2024 saw the highest quarterly average renewable contribution

Renewable contribution components – Q4s

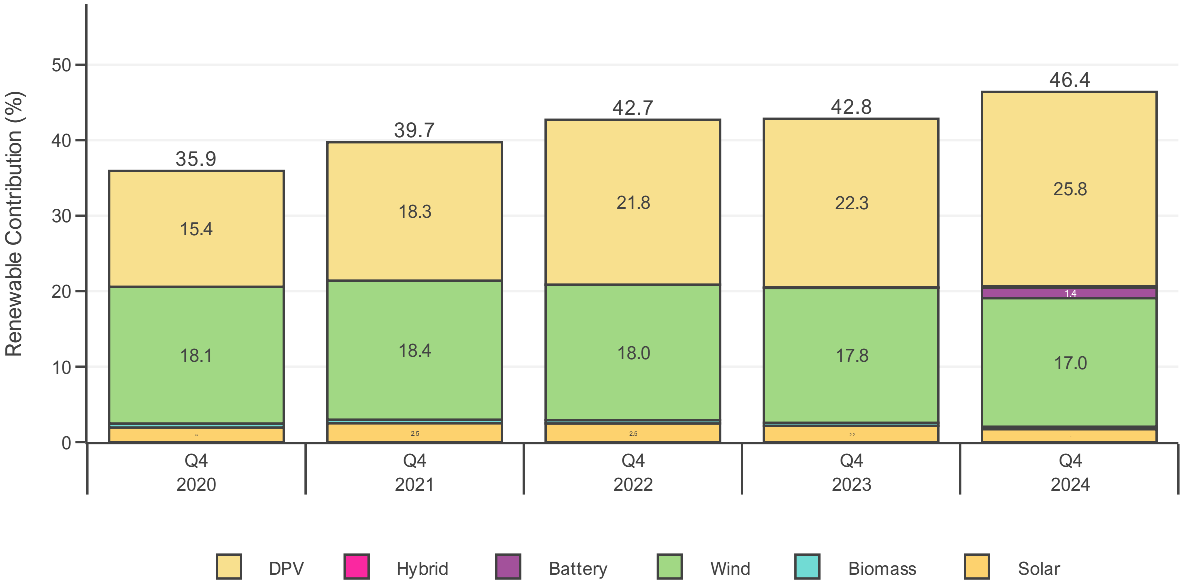
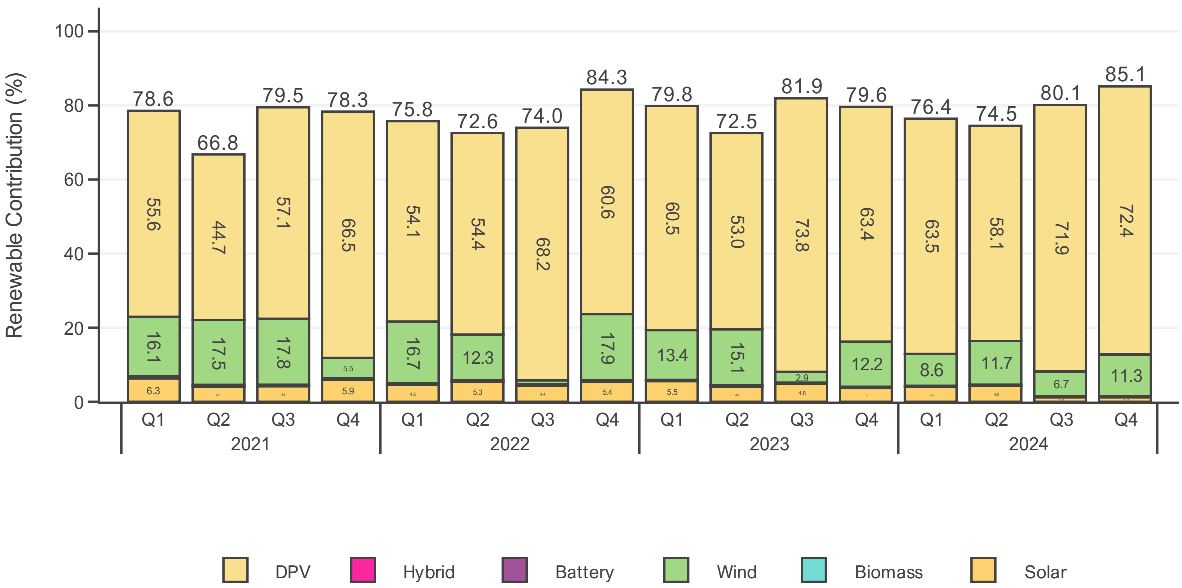


Figure 107 New WEM peak renewable contribution

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



4.2.2 Carbon emissions

Total WEM emissions[52] in Q4 2024 were 2.06 MtCO2-e, a decrease of 0.12 MtCO2-e (-5.3%) on Q4 2023 (Figure 108). This can be attributed to:

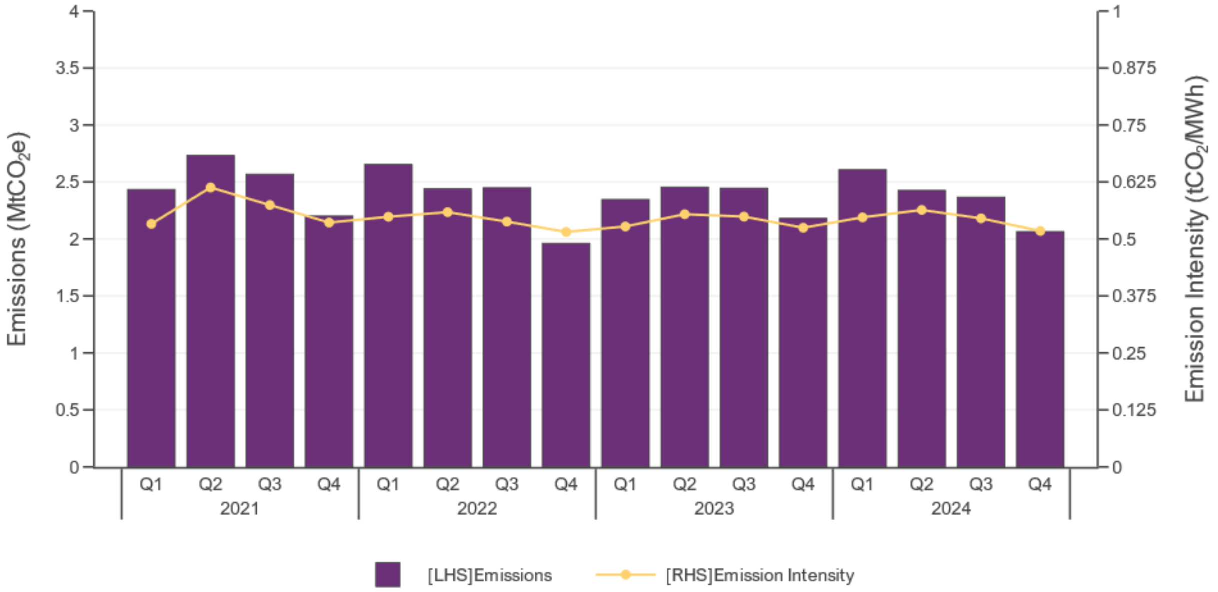
[52] Emissions intensity ratings are obtained from data published by the Clean Energy Regulator at https://cer.gov.au/node/4444 (Greenhouse and energy information by designated generation facility). Where the facility emissions intensity is not published by the Clean Energy Regulator, the average for the same fuel type of published facilities is used.

- A reduction in average emissions intensity from 0.525 tCO2-e/MWh to 0.518 tCO2-e/MWh (-1.3%). This is due to the reduction of coal in the fuel mix (see Section 4.2), which was replaced by lower intensity gas generation and no emissions renewables.
- A reduction in average operational demand (see Section 4.1).

Despite being lower than 2023, Q4 emissions were higher than recorded in Q4 2022, which experienced both lower operational demand and emissions intensity.

Figure 108 Reduction in emissions driven by lower coal contribution

Quarterly WEM emissions and emission intensity – Q1 2021 to Q4 2024



4.3 Frequency co-optimised essential system services (FCESS)

An increasing amount of FCESS market share was captured by batteries (Figure 109). Across the regulation and contingency markets, batteries captured on average an additional 62 MW (0 MW in Q4 2023) of FCESS, displacing gas which was down an average of 79.4 MW (-28.9%) and coal (contingency markets only) which reduced on average by 12.8 MW (-40.8%).

Overall, this resulted in market share of all FCESS markets by batteries of 36% in Q4 2024, the first Q4 where batteries contributed to FCESS (Figure 110). This is driven by the accreditation of two battery energy storage systems since Q4 2023 (KWINANA_ESR1 in Q2 2024 and COLLIE_ESR1 midway through Q4 2024).

Figure 109 Higher enablement for batteries in FCESS markets

Change in FCESS enablement by fuel type – Q4 2023 vs Q4 2024

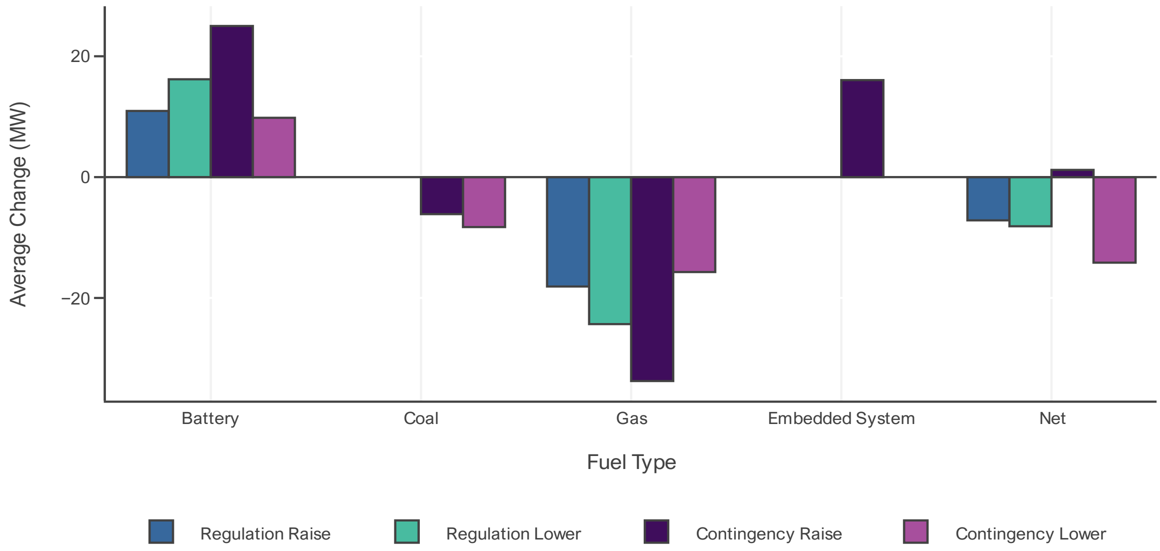
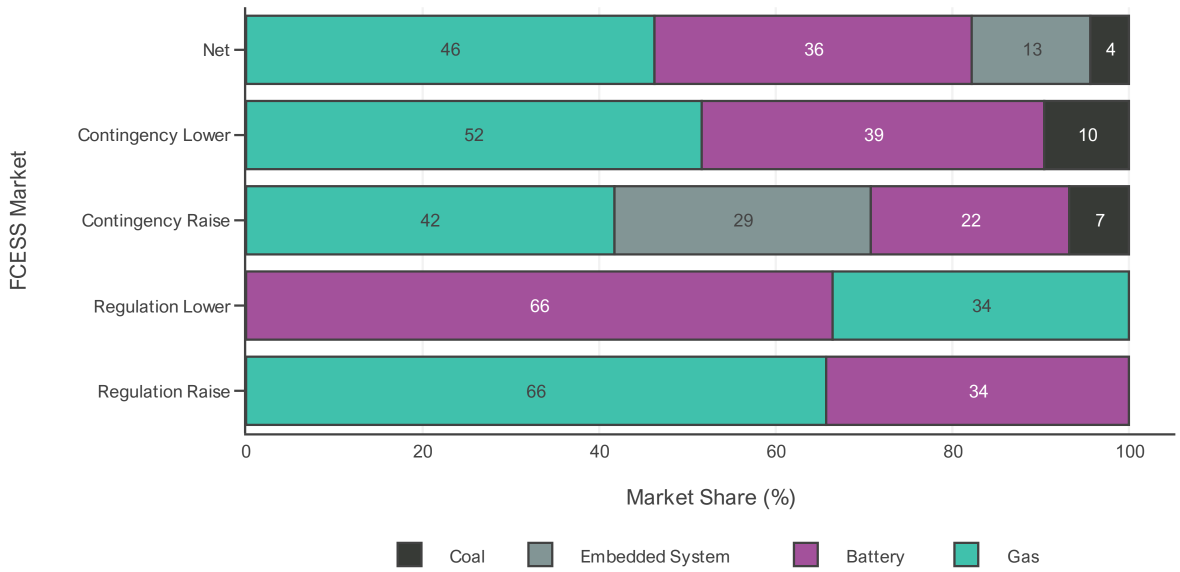


Figure 110 Batteries capture FCESS market share

FCESS volume market share by market and fuel type – Q4 2024



4.4 WEM price outcomes

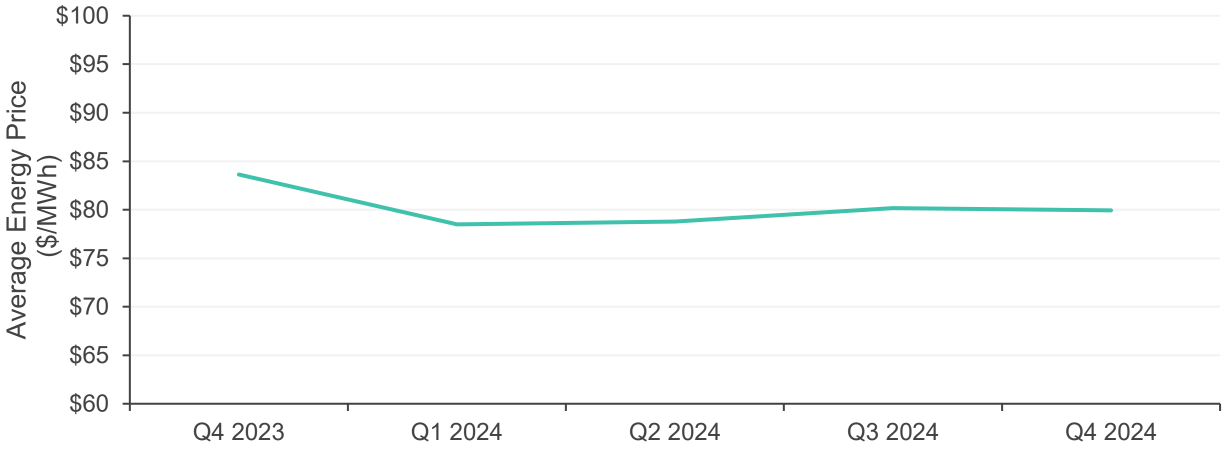
4.4.1 Real-Time Market price dynamics

The average energy price in Q4 2024 was $79.93/MWh, similar to Q3 2024 (average energy price of $80.15/MWh) but a decrease of $3.70/MWh (-4%) from Q4 2023, during which there was lower than average facility availability combined with elevated operational demand resulting in higher energy prices[53] (Figure 111).

[53] See Quarterly Energy Dynamics – Q4 2023, at https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

Figure 111 Average Energy prices remained relatively unchanged from Q3 2024

Quarterly Average Energy Prices – Q4 2023 to Q4 2024



4.4.2 Essential system services (ESS) costs

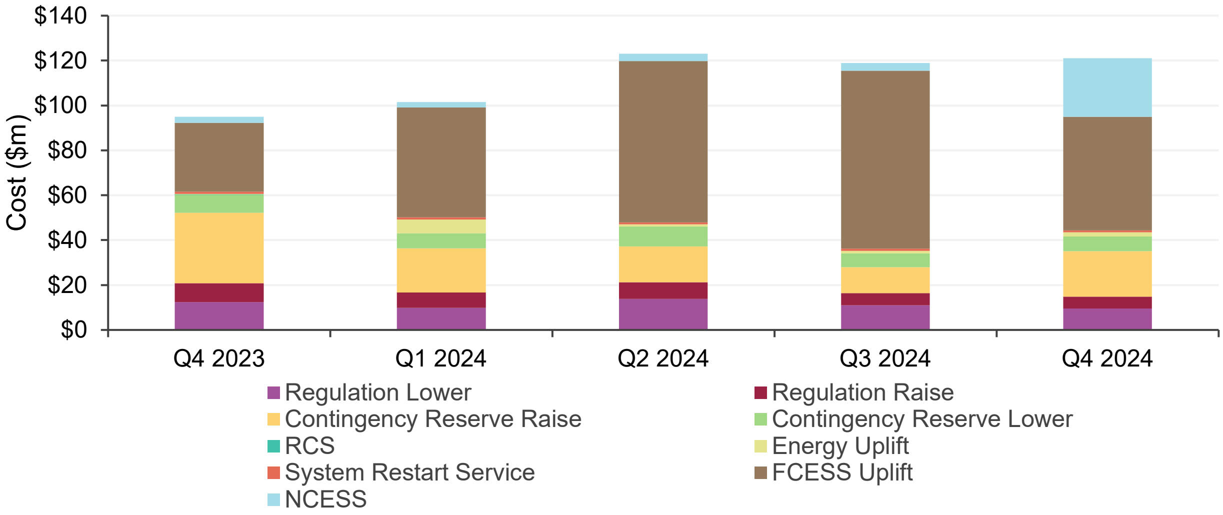
The total cost of ESS and Uplift in Q4 2024 increased by $26.1 million (+27.5%) compared to Q4 2023 (Figure 112). Compared to Q3 2024, this represents a marginal increase of $2.1 million (+1.8%). This increase in costs in Q4 2024 compared to Q4 2023 was driven by a number of significant counteractive factors:

- Non-co-optimised essential system services (NCESS) costs increased by $23.4 million on Q4 2023 to $26.1 million due to the commencement of seven NCESS Contracts in October 2024, providing up to 311 MW of peak demand service and 197 MW of minimum demand service.
- FCESS Uplift costs were $50.6 million, a $19.9 million increase from Q4 2023, this was partially due to higher energy prices in Q4 2023 driving lower Uplift costs. However, this was a decrease of $28.8 million on Q3 2024, driven by changes implemented as part of the FCESS Cost Review (see Section 4.4.5).
- The combined enablement cost of regulation and contingency services together was $41.6 million, a decrease of $18.6 million (-31%) compared to Q4 2023. There were several factors which contributed to this:
  - The FCESS clearing price ceiling for these services was reduced to $500/MW/hr between Trading Days 22 May 2024 and 19 November 2024 (inclusive), resulting in lower average clearing prices compared to Q4 2023.
  - There was downward pressure on clearing prices due to increased competition as a result of a significant increase in the accredited quantity of regulation and contingency available in the WEM, most notably a combined additional capacity of 300 MW of regulation raise and lower and 250 MW of contingency reserve raise and lower from the accreditation of KWINANA_ESR1 in Q2 2024 and COLLIE_ESR1 in Q4 2024 (representing an increase of 30%-35% in the available capacity in these FCESS markets).
- Energy Uplift payments totalled $1.9 million this quarter, an increase of $1.5 million from the cost in Q4 2023. This was largely driven by rule changes relating to the FCESS Cost Review which commenced on 20 November 2024, which introduced Energy Uplift payments for facilities constrained on by AEMO during a low reserve condition declaration or to provide RoCoF Control Service (RCS) only.

- There were no enablement costs from RCS this quarter, a small decrease (-$0.2 million) from Q4 2023 (RCS Costs in Q4 2023 were driven almost exclusively by a single dispatch interval in which the market service cleared at $300/megawatt seconds (MWs)/hr).

Figure 112 Total ESS costs increased $26.1 million compared to Q3 2024

Total Costs ESS and Uplift – Q4 2023 to Q4 2024



4.4.3 FCESS Uplift share costs

When a facility receives FCESS Uplift payments in a dispatch interval, those costs are assigned to, and recovered through, normal cost distribution processes for FCESS market services[54]. Note that since 20 November 2024, FCESS Uplift costs are no longer paid with respect to RCS nor recovered through RCS charges (see Section 4.4.5).

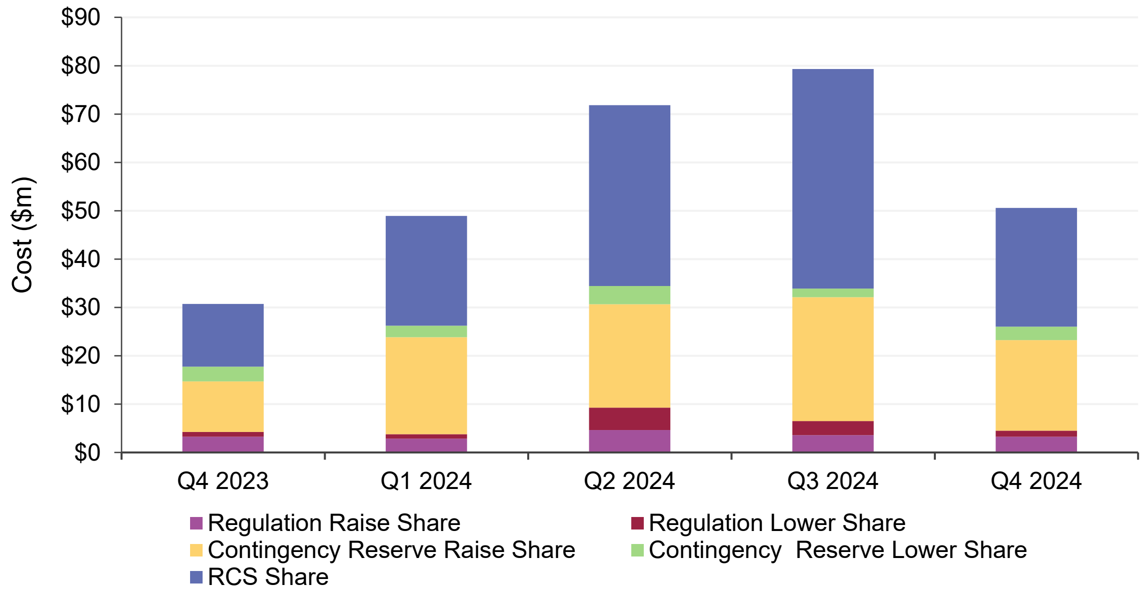
The total cost of FCESS Uplift in Q4 2024 was $50.6 million; Figure 113 provides a breakdown of the total FCESS Uplift costs assigned to each FCESS market service.

In this quarter, 49% of FCESS Uplift costs were recovered through RCS charges and 37% through contingency reserve raise charges, while contingency reserve lower, regulation raise, and regulation lower costs included 3%-6% each. This breakdown is broadly similar to previous quarters.

[54] Note that on a high level, regulation raise and lower costs are paid by consumers, semi-scheduled facilities and non-scheduled facilities; contingency reserve lower costs are paid by consumers; contingency reserve raise costs are paid by generating facilities; and RoCoF control service costs are paid by generating facilities, network operators, and consumers. Refer to the WEM Rules for full details including exceptions.

Figure 113 FCESS Uplift costs decreased by $28.8 million (-36%) compared to Q3 2024

Distribution of FCESS uplift costs to FCESS market services – Q4 2023 to Q4 2024

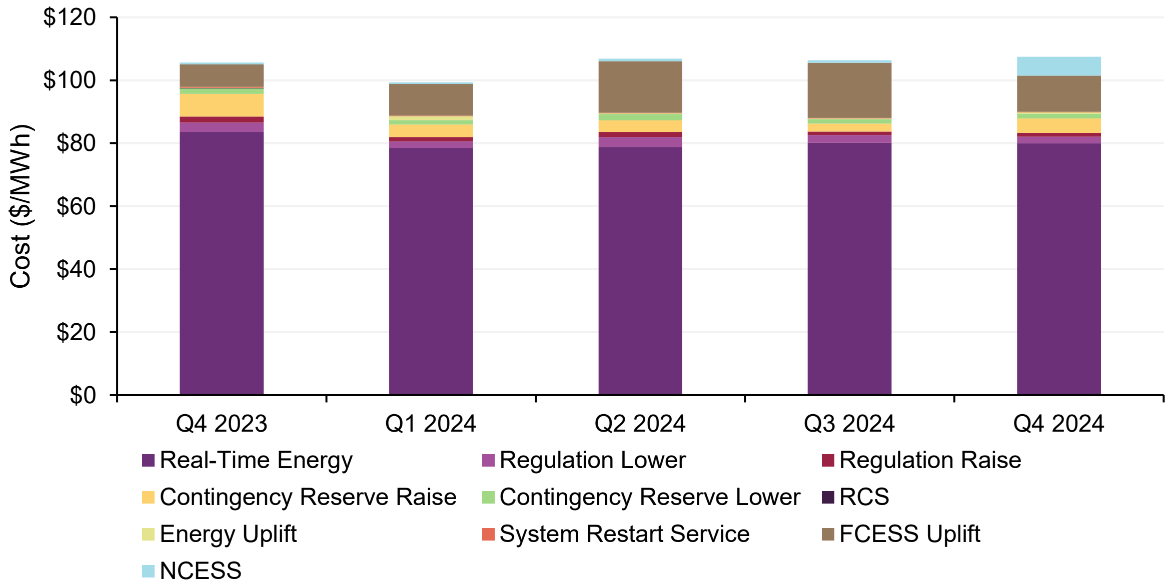


4.4.4 Real-Time Market costs

Figure 114 presents energy and ESS costs (including Uplift costs) as a price-per-MWh normalised by total energy consumed, enabling better comparison of costs between periods with different demand. Note that these costs do not include Reserve Capacity or Supplementary Capacity (SC).

Figure 114 Real-Time Market costs increase slightly compared to Q4 2023

Normalised energy and ESS costs per MWh consumed in the WEM – Q4 2023 to Q4 2024



The total cost of the Real-Time Market (Energy and ESS) was $107.42/MWh in Q4 2024, a small increase from $105.60/MWh in Q4 2023. This was mostly driven by increases in the normalised costs of NCESS (+$5.31/MWh) and FCESS Uplift (+4.38/MWh), which were largely offset by decreases in the average energy price (-$3.71/MWh) and normalised contingency reserve raise costs (-$2.67/MWh), with smaller changes in other segments.

4.4.5 Impact of FCESS Cost Review Rule Changes

The FCESS Cost Review resulted in a number of rule changes taking effect on 20 November 2024[55], including:

- FCESS Uplift payment calculations were modified to avoid over-compensating FCESS providers when their enablement losses are partially or completely covered by other Real-Time Market payments.
- Introduced more efficient tiebreak methods for FCESS and energy, intended to reduce the overall cost of FCESS Uplift payments.
- FCESS Uplift payments are no longer made for the provision of RCS.
- Energy Uplift payments are now provided for:
  - Facilities that are constrained on by AEMO to provide RCS only.
  - Facilities that are constrained on by AEMO during a period covered by a Low Reserve Condition Declaration.

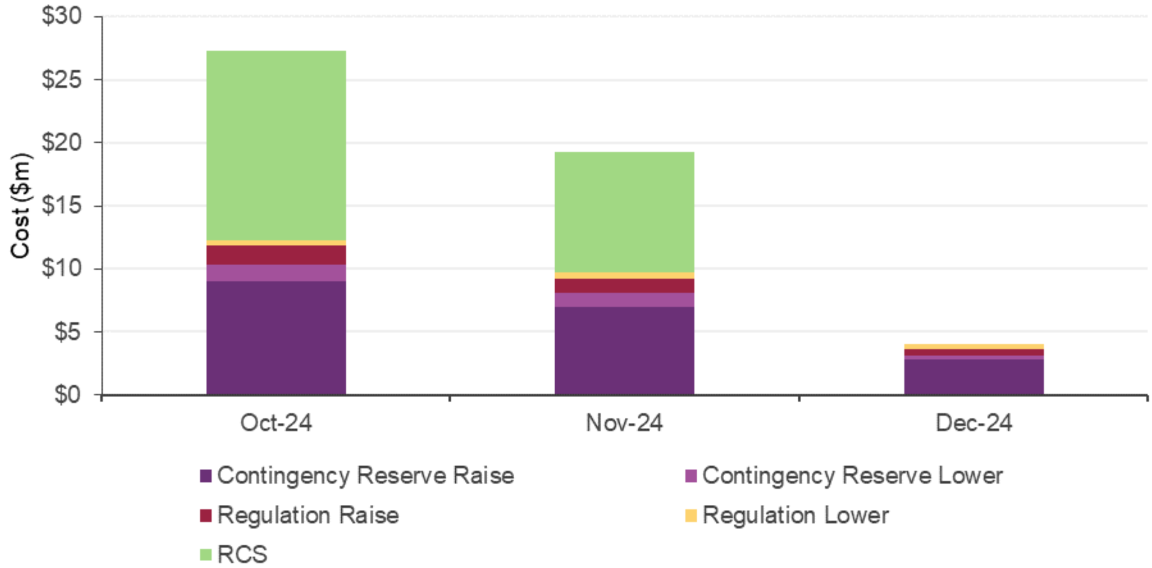
This has resulted in an overall decrease in Uplift (FCESS and Energy) costs of $28.1 million (-35%) between Q3 and Q4 2024, comprised of:

- A decrease of $28.8 million (-36%) in FCESS Uplift payments to $50.6 million. Given the change occurred midway through the quarter (20 November 2024), the impact is even more evident when comparing monthly FCESS Uplift payments within Q4 2024 – a reduction of $23.4 million (-85%) in December 2024 when compared to October 2024 (Figure 115). The majority of this reduction is attributable to costs recovered through RCS charges, which decreased from $15.0 million to zero as a result of the rule change.
- An increase of $0.7 million in Energy Uplift payments to $1.9 million. This is the second highest Energy Uplift cost in any quarter since the commencement of the new WEM on 1 October 2023 (Energy Uplift costs in Q1 2024 were $6.2 million, driven by record high demand). The majority of the Q4 2024 costs were driven by payments to facilities constrained on by AEMO to provide RCS or due to a Low Reserve Condition Declaration, as a result of the rule changes.

[55] For FCESS Cost Review details, see: https://www.wa.gov.au/government/publications/fcess-cost-review.

Figure 115 FCESS Cost Review rule changes drive lower FCESS Uplift costs

Distribution of FCESS uplift costs to FCESS market services – Oct 2024 to Dec 2024

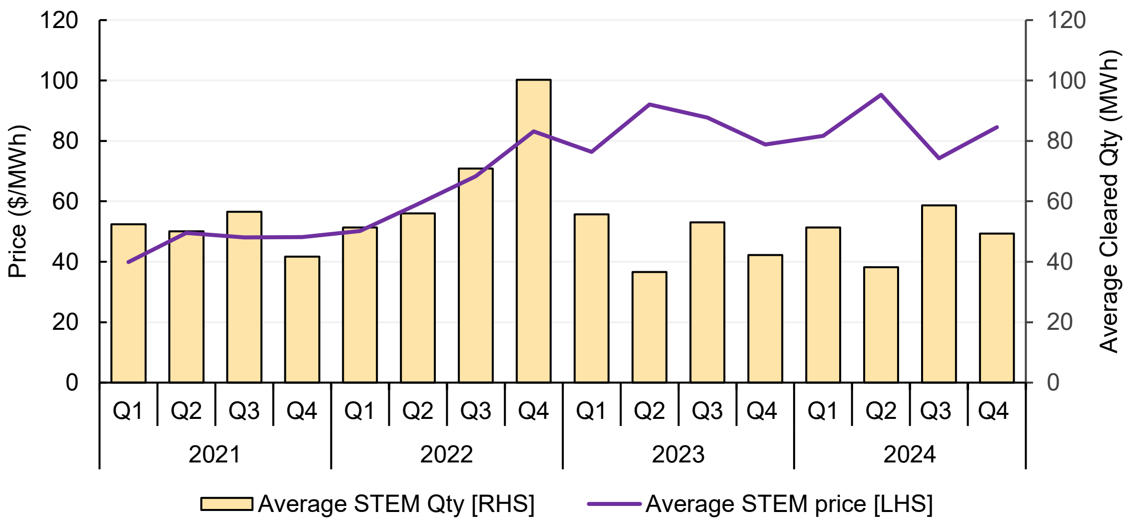


4.4.6 Short Term Energy Market

The average Short-Term Electricity Market (STEM) price[56] for Q4 2024 was $84.59/MWh, an increase of $10.33/MWh (+14%) from the previous quarter and an increase of $5.72/MWh (+7%) compared to Q4 last year (Figure 116). The quarterly average quantity of energy cleared in the STEM per interval was 49 MWh, a decrease of 9 MWh (-16%) from Q3 2024. When compared to the same quarter last year, quantities cleared increased by 7 MWh (+17%).

Figure 116 The average STEM price increased by 14% in Q4 2024

WEM average STEM Price and quantity cleared in STEM – Q1 2021 to Q4 2024

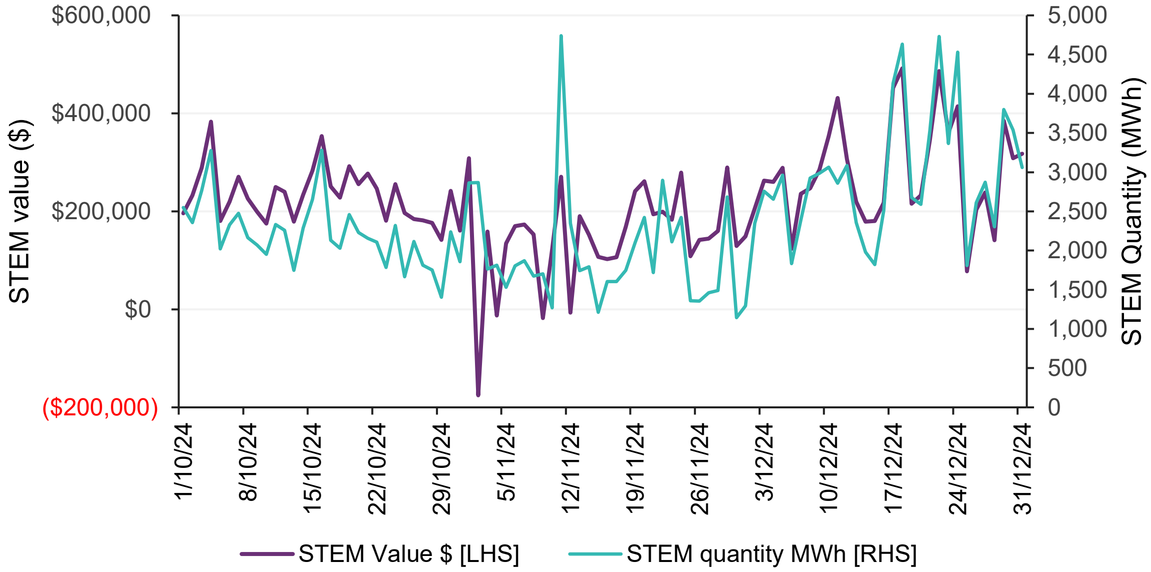


[56] AEMO has changed this reporting metric from 'weighted average STEM price' to 'average STEM price' for better alignment with other metrics in this report such as the average reference trading price.

The daily traded value in STEM ranged from -$175,433 to $491,927 in Q4 2024, whereas the daily quantities traded in MWh varied between 1,145 MWh and 4,741 MWh (Figure 117). The negative STEM daily value on 2 November was assisted by the STEM price being negative for 12 consecutive intervals during the middle of the day, including two intervals close to the floor price of -$1,000.

Figure 117 Negative daily STEM values as a result of negative prices in STEM

Daily quantities (MWh) and value ($) traded in STEM – Q4 2024



5 Reforms delivered

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

Table 11 Reforms delivered Q4 2024

Reform initiative	Market	Description	Reform delivered
FCESS Cost Review (Stage 1)	WEM	AEMO successfully implemented and operationalised the rule changes to the FCESS markets in the WEM from the 20 November. These changes are aimed at reducing the costs associated with the provisioning of FCESS relative to comparable historical Ancillary Service costs in the Balancing Market. The changes introduced: • A new FCESS Tie-Break methodology; • Changes to FCESS Uplift Payments; and • Additional Facility commitment obligations on Market Participants. The changes also removed the temporary FCESS Price ceiling. https://www.wa.gov.au/system/files/2024-10/wem_amending_rules_fcess_cost_review_ministerial_instrument.pdf	November 2024
Retail Market Improvements (Metering Substitutions)	NEM	As part of the ongoing suite of Retail Market Improvement initiatives, AEMO has implemented various Substitution Type and Reason Code changes associated with small market interval metering. These changes provide for greater insights, improved customer communication and support and more efficient processes including introduction of seven new substitution types; the obsoletion of substitution type 16; and the addition of 10 new Reason Codes. https://aemo.com.au/consultations/current-andclosedconsultations/july-2023-retail-electricity-market-procedures-consultation	November 2024
Outage Intention Plans	WEM	AEMO has implemented changes to the WEMS Outage Management Systems. The changes include: • New Outage Intention Plan (OIP) user interface to improve the visibility and coordination process for planned facility outages between AEMO, Market Participants and Western Power. The OIP is a requirement under the new WEM Rules (Section 3.19) which takes effect 1 March 2025; and • Incremental improvements to the Commissioning Test Plan (CTP) user interface, by submitting plans via the user interface. This improves AEMO's cyber security posture by enabling critical data being sent via secure technologies. https://aemo.com.au/consultations/current-and-closed-consultations/aepc_2024_17	December 2024
Improving Security Frameworks for the Energy Transition	NEM	In accordance with the Improving Security Frameworks for the Energy Transition rule change, the following milestones were reached in December 2024: • Commencement of the new inertia framework in the NEM with AEMO to publish updated inertia requirements, methodology and system security reports. • Publication of the Transitional Services Guideline providing AEMO with the ability to procure transitional services. • Publication of the first NEM transition plan for system security report. https://aemo.com.au/initiatives/major-programs/improvingsecurityframeworks-for-the-energy-transition	December 2024

Reform initiative	Market	Description	Reform delivered
Frequency Performance Payments (Non-financial Operation)	NEM	In accordance with the NEM Primary Frequency Response Incentive Arrangement rule change, non-financial operation of the new Frequency Performance Payment (FPP) system commenced in December 2024. The Frequency Performance Payments system and associated procedures and guidelines (including Frequency Contribution Factor Procedures) provide incentives for all facilities to operate in a way that helps maintain power system frequency within the normal operating band, at the lowest cost to consumers. Financial operation of the new system is scheduled to go-live in June 2025. https://aemo.com.au/initiatives/majorprograms/frequencyperformance-payments-project	December 2024

In addition to these reforms, work continues to progress on the next wave of initiatives set for release later in 2025. Table 12 below provides a brief description of those initiatives to be delivered in Q1 and Q2 2025.

Table 12 Upcoming implementation of reforms Q1 – Q2 2025

Reform initiative	Market	Description	Reform to be delivered
RCM Review (Flexible Capacity Certification)	WEM	AEMO is implementing the system and process changes to enable the certification of Flexible Capacity in the 2025 Reserve Capacity Cycle. Flexible Capacity is a new incentive for providers to invest in capacity that can start, stop and ramp quickly. Facilities that can meet the minimum requirements will be able to apply for Flexible Capacity in addition to their Peak Capacity Credits from the 2025 Reserve Capacity Cycle onwards. https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism	April 2025
WEM Investment Certainty (WIC) Review outcomes	WEM	Following gazettal of the relevant WEM Rules on 15 January 2025, AEMO is currently implementing the outcomes of two initiatives under the WIC Review. These include changes to the Reserve Capacity Price (RCP) Curve and the introduction of a 10-year RCP guarantee for new eligible generators: • Adjustments to the RCP provide more appropriate price signals to stimulate investment when needed and reduce costs during periods of over-supply. The RCP for flexible capacity is set relative to peak capacity to ensure that additional incentives are provided to bring flexible capacity to market. • The 10-year RCP guarantee will provide eligible new generators with the option of revenue certainty to assist in financing new projects.	June 2025
SCADA Lite	NEM	SCADA Lite (an AEMO foundational and strategic initiative under the NEM Reform Program) will enable NEM non-NSP participants to establish a bi-directional connection to exchange operational information (telemetry and control) with AEMO. Specifically, those requirements defined in both the Wholesale Demand Response Guidelines (Version 1.0, Effective Date: 24 June 2021) and Power System Data Communication Standard (Version 3.0, Effective Date: 3 April 2023). AEMO continues to progress with implementation in conjunction with its pilot test partner. https://aemo.com.au/initiatives/major-programs/nem-reformprogram/nem-reform-program-initiatives/scada-lite	June 2025
Frequency Performance Payments (Financial Operation)	NEM	In accordance with the NEM Primary Frequency Response Incentive Arrangement rule change, financial operation of the new Frequency Performance Payment (FPP) system is scheduled to go-live in June 2025. This follows an extended period of non-financial operation from December 2024 of the new FPP system to allow market participants to familiarise themselves with its operation. https://aemo.com.au/initiatives/majorprograms/frequencyperformance-payments-project	June 2025

List of tables and figures

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Abbreviations

Abbreviation	Expanded term
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
ASX	Australian Securities Exchange
BESS	Battery energy storage system
CGP	Carpentaria Gas Pipeline
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
FCESS	Frequency co-optimised essential system services
GJ	Gigajoule/s
GWh	Gigawatt hour/s
GLNG	Gladstone LNG
GSH	Gas Supply Hub
IRSR	Inter-regional settlement residue
L1SE	Contingency lower 1-second FCAS
L6SE	Contingency lower 6-second FCAS
LNG	Liquefied natural gas
MPC	Market price cap
MSP	Moomba to Sydney Pipeline
$MtCO_2$-e	Million tonnes of carbon dioxide equivalents
MW	Megawatt/s
MWh	Megawatt hour/s
NEM	National Electricity Market
NER	National Electricity Rules
NCESS	Non-co-optimised essential system service
NGP	Northern Gas Pipeline
pp	Percentage points
PJ	Petajoule/s
PV	Photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
R1SE	Contingency raise 1-second FCAS
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
RTM	Real Time Market

Abbreviation	Expanded term
SCED	Security Constrained Economic Dispatch
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWQP	South West Queensland Pipeline
TJ	Terajoule/s
UGS	Underground Storage Facility
VRE	Variable renewable energy
VNI	Victoria – New South Wales Interconnector
WEM	Wholesale Electricity Market
WDR	Wholesale demand response