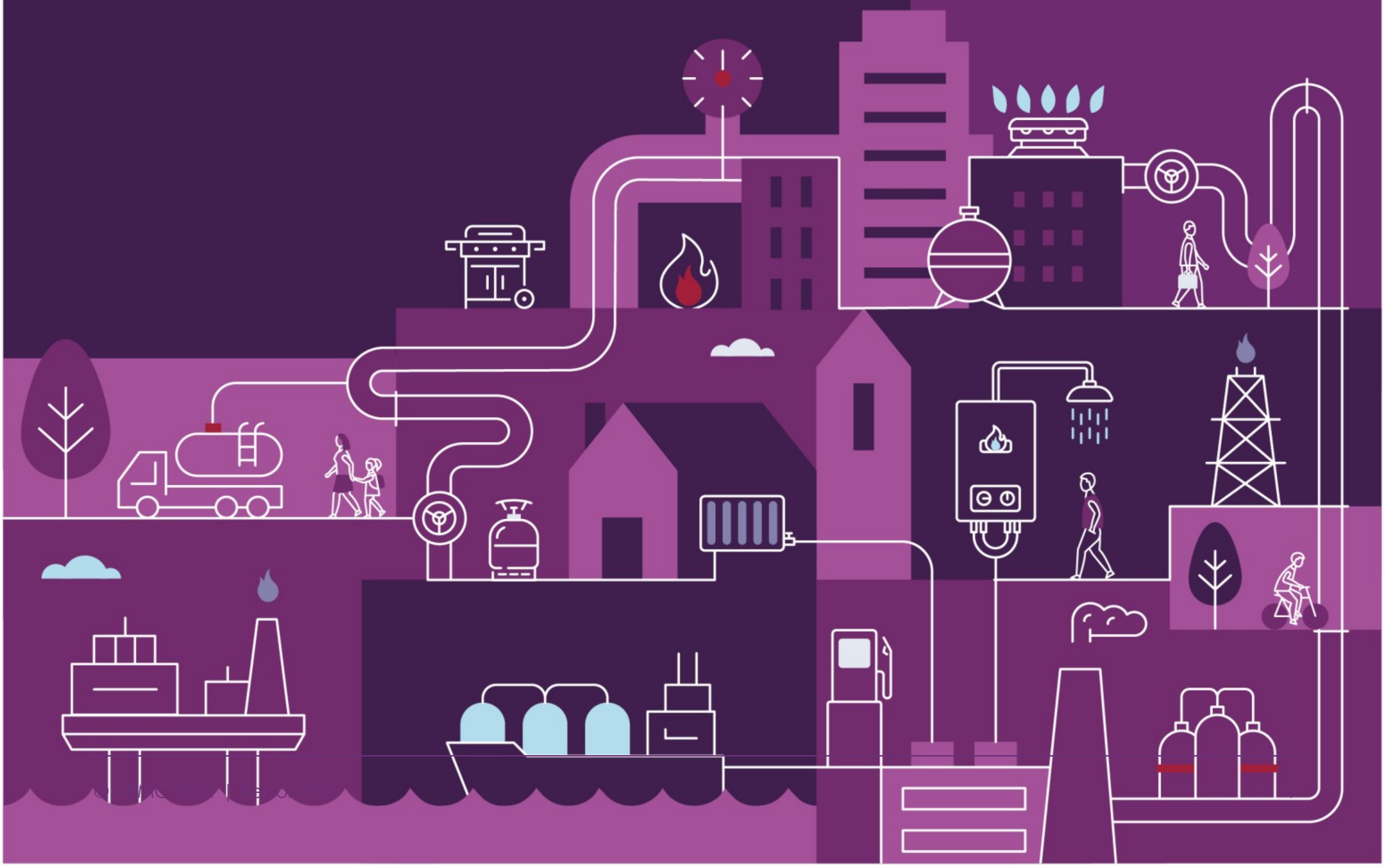
Quarterly Energy Dynamics Q2 2024

July 2024



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 Q2 2024 (1 April to 30 June 2024). This quarterly report compares results for the quarter against other recent quarters, focusing on Q1 2024 and Q2 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.

Disclaimer

This document or the information in it may be subsequently updated or amended. This document does not constitute legal, market or business advice, and should not be relied on as a substitute for obtaining detailed advice about:

- past, current or future market conditions, prices and outcomes; and
- the National Electricity Law, the National Electricity Rules, the Wholesale Electricity Market Rules, the National Gas Law, the National Gas Rules, the Gas Services Information Regulations or any other applicable laws, procedures or policies.

While AEMO has made reasonable efforts to ensure the quality of the information in this document, it cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

Copyright

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. AEMO Group is proud to have launched its first Reconciliation Action Plan in May 2024 (scan QR code to read).

Executive summary

East coast electricity and gas highlights

Wholesale electricity prices rose with low wind and rainfall and periods of price volatility

- Wholesale spot prices averaged $133 per megawatt hour (MWh) across all National Electricity Market (NEM) regions this quarter, 23% higher than Q2 2023's $108/MWh. Regional reference prices ranged from $173/MWh in New South Wales to $101/MWh in Queensland.
- A period of administered pricing, capping spot prices in New South Wales at $600/MWh, commenced from 1955 hrs on 8 May and concluded at 0400 hrs on 15 May. This followed a run of extreme price volatility which breached the NEM's cumulative price threshold. Major generation outages in the region coincided with transmission line works reducing support from both northern and southern zones and led to the volatility episodes.
- Low wind speeds and reduced rainfall in the southern NEM increased reliance on gas-fired generation and contributed to year-on-year increases in wholesale electricity prices in South Australia (up 9% to $135/MWh), Tasmania (up 104% to $131MWh) and Victoria (up 43% to $127/MWh).
- In contrast with the southern regions, Queensland saw a 20% reduction in wholesale energy prices from last year, with 14% of dispatch intervals recording zero or negative price intervals, a new high for a Q2.

Low wind and hydro output drove increased thermal generation and a southward shift in inter-regional transfers

- Wind output reduced to a quarterly average of 2,657 megawatts (MW), a fall of 657 MW (-20%) from last year, with wind available capacity factors down to their lowest levels since Q2 2017. This large reduction in average output was despite new and commissioning wind farms adding 167 MW to availability and half-hourly output reaching the highest level recorded to date at 8,375 MW on 30 May.
- Hydro-generation averaged 1,607 MW over the quarter, a reduction of 18% from last year and the lowest output for a Q2 since 2017, with large decreases in Tasmania (down 21% to 887 MW) and New South Wales (down 39% to 258 MW).
- With these reductions in wind and hydro output, and average operational demand slightly higher at 21,913 MW, up 0.9% from last year, all other generation sources increased output and inter-regional transfers shifted southwards to meet demand.
- Gas-fired generation rose to average 1,702 MW, up 16% from last year, with Tasmanian gas-fired generation averaging 85 MW, its highest level since Q2 2019. Black coal-fired generation averaged 10,857 MW, 7.3% above Q2 2023, with the return of capacity at Callide C3 increasing fleet availability.
- Batteries' role in supporting morning and evening demand peaks became more prominent, with average generation in those periods more than doubling since last year, reflecting the significant annual increase in

NEM battery capacity. Batteries saw the largest increases in price setting frequency out of all generation types, averaging 23% in some evening dispatch periods this Q2, against a peak of only 7% for Q2 2023.

- Inter-regional energy transfers shifted net southward, with average Victorian exports to New South Wales down from 455 MW in Q2 2023 to 68 MW this Q2, higher flows from Queensland into New South Wales, and average flows on Basslink switching from 59 MW northward a year ago to 144 MW southward this Q2.

East coast gas supply dynamics changing, higher domestic prices in June, increased gas-fired generation demand

- East coast wholesale gas prices averaged $13.66 per gigajoule (GJ) for the quarter, lower than Q2 2023's $14.21/GJ but higher than Q1 2024 which averaged $11.60/GJ.
- Gas demand increased slightly by 1% from Q2 2023, mostly driven by higher demand for gas-fired generation (+5 petajoules (PJ)), while demand for Queensland liquefied natural gas (LNG) exports also increased (+2 PJ) to its highest Q2 demand on record. AEMO markets demand decreased (-3 PJ), despite colder weather than Q2 2023, particularly in Victoria and South Australia.
- Changes in domestic gas supply dynamics evident since Q2 2023 continued, with gas production from Longford continuing to decline, replaced by supply to the southern states from Queensland rising to a new Q2 record and greater reliance on Iona Underground Gas Storage (UGS) to meet southern market demand. Production at Longford fell by 11 PJ from Q2 2023, reaching its lowest Q2 level since the commencement of data publication in 2009.
- AEMO issued an East Coast Gas System threat or risk notice on 19 June due to the potential for gas supply shortfalls caused by the depletion of southern storage inventories, particularly Iona UGS. The threat is ongoing until no later than 30 September 2024 and the situation continues to be monitored by AEMO.

Western Australia electricity and gas highlights

Increase in distributed photovoltaic (PV) generation more than offset underlying demand growth to reduce reliance on grid-scale generation

- An increase in underlying demand (+24 MW) compared to Q2 2023, with relatively warmer weather, was more than offset by an increase in distributed PV generation (+49 MW), resulting in a reduction in operational demand (-28 MW).
- The increase in distributed PV generation and an uplift in wind generation (+75 MW) resulted in an overall renewable penetration of 30.7%, a new Q2 record.

Energy prices remained flat despite the drop in operational demand from Q1 2024

- Operational demand reduced from the high recorded in Q1 2024, however energy prices remained relatively flat averaging $79.79/MWh (+$0.30/MWh) due to a reduction in quantities offered into the Real-Time Market by coal- and gas-fired generation as a result of planned and unplanned outages.

- In comparison to Q2 2023, there was a large reduction in energy prices (-$23.20/MWh), due to increased facility availability. Low facility availability in 2023, due to outages, resulted in a record quarterly average energy price.

Total real-time market costs increased driven by increases in frequency co-optimised essential system services (FCESS) uplift costs

- An increase in FCESS uplift payments (+$22.0 million) drove a $22.9 million increase to essential system services (ESS) and uplift costs compared to Q1 2024.
- This resulted in total real-time market costs (which includes energy, ESS and uplift) of an average of $116.72/MWh, an increase on Q2 2023 (+$11.01/MWh) and on Q1 2024 (+$16.52/MWh).

Domestic gas consumption increase was more than offset by production increases

- Domestic gas production increased to 107.3 PJ (+7.8%) compared to Q2 2023, largely driven by Karratha Gas Plant increasing production by 5.9 PJ (+52.8%), more than offsetting 1.8% increase in gas consumption.

Contents

1 NEM market dynamics

1.1 Electricity demand

1.1.1 Weather

Q2 2024 commenced with warmer than average temperatures during April in the northern regions, followed by a cold start to winter with mean minimum temperatures very much below average (in the lowest 10% of all Junes since 1910) in most of Victoria and parts of Queensland, New South Wales and Tasmania[1]. On a quarterly basis, however, the monthly temperature variations balanced out, resulting in slightly below average temperatures in South Australia and parts of Victoria, and slightly above average temperatures in parts of Queensland and New South Wales (Figure 1). Rainfall was also very much below average (in the lowest 10% of all Junes since 1900) in parts of Tasmania, Victoria and New South Wales. During Q2 2024, weather was dominated by a series of persistent high-pressure systems sitting over southern Australia causing extended periods of low surface winds over south-eastern areas (Figure 2).

Figure 1 Warmer than average temperatures in northern NEM regions but colder in south

Q2 2024 mean temperature deciles for Australia

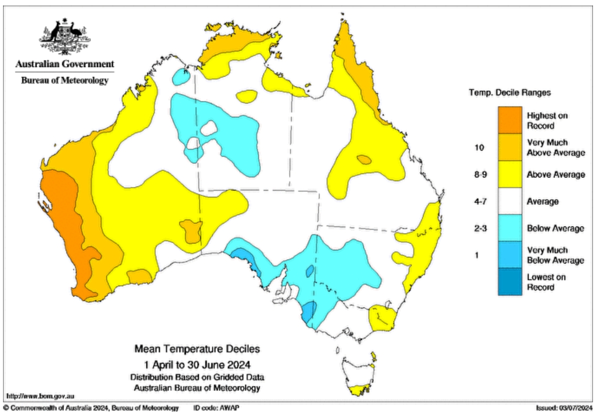
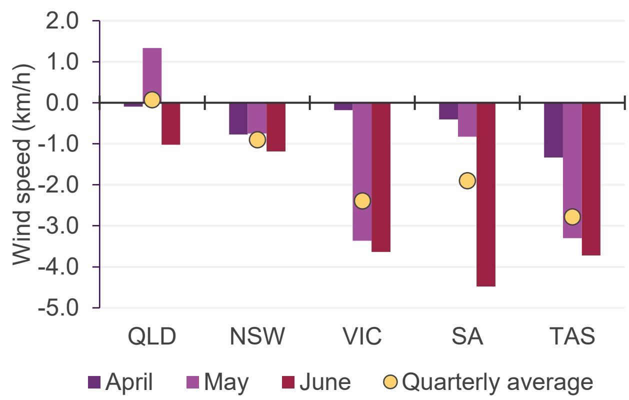


Figure 2 Significant drops in wind speed in all regions except Queensland

Change in average wind speed by region[2] – Q2 2024 vs Q2 2023



The observed reductions in wind speed during the quarter were even more significant than those in Q2 2017[3] in some instances. Compared to Q2 2023 **Victoria**, **South Australia**, and **Tasmania** experienced the largest reductions in quarterly average wind speed by 18%, 13%, and 14% respectively (mostly evident during May and June). **New South Wales** saw a quarterly average reduction of 8%. **Queensland**, however, saw increased wind speeds in May, almost offset by reductions observed in June resulting in little change in the quarterly average (+1%). These dynamics led to lower average wind generation in all regions, especially in South Australia and Victoria, with larger reductions given their significant installed wind capacity (see Section 1.3.4).

---

[1] http://www.bom.gov.au/climate/current/month/aus/summary.shtml

[2] Wind speeds are calculated as the average of wind speed observations in all stations (those capable of measuring wind speed) across each region.

[3] Q2 2017 saw a significant wind drought with wind speeds being lower than historical averages resulting in cooler than average nights in southern regions.

In Q2 2024, **Brisbane** experienced warmer conditions during April and colder in June with minimum temperatures averaging 1.3 °C higher than last year across the quarter (Figure 3). During the quarter, **Sydney** saw a shift with below-average rainfall and warmer average quarterly minimum temperatures relative to Q2 2023. Temperatures were slightly above average especially in May where Heating Degree Days (HDDs)[4] reduced significantly (Figure 4).

Average quarterly minimum temperatures reduced for **Melbourne** (relative to Q2 2023), and higher HDDs were observed during April and June reflecting colder than usual temperatures. **Adelaide** also saw temperature patterns similar to Melbourne as it faced colder and drier conditions with temperatures consistently below average during April and June. **Hobart** exhibited only small changes in temperatures, however rainfall levels were well below long-term average (thus significantly lower than Q2 2023 levels), especially during May and June, resulting in lower water storage levels as discussed in Section 1.3.3.

Figure 3 Minimums colder than 10-year average in southern regions

Average quarterly minimum temperature variance by capital city

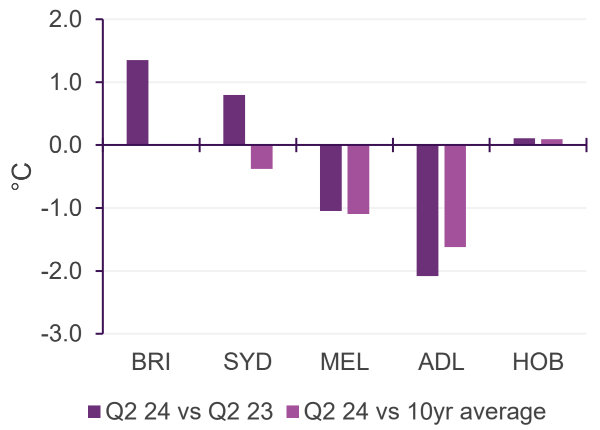
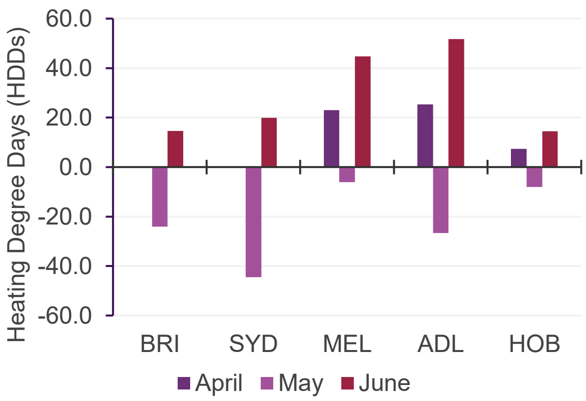


Figure 4 Higher April and June HDDs in southern regions

Change in monthly Heating Degree Days (HDDs) by capital city – Q2 2024 vs Q2 2023



1.1.2 Demand outcomes

Quarterly average underlying demand increased 1.5% year-on-year, rising by 359 MW from 23,605 MW in Q2 2023 to a new Q2 record high of 23,964 MW (Figure 5). Concurrently, distributed PV output achieved its highest Q2 quarterly average on record, reaching 2,050 MW. This was an increase of 163 MW on Q2 2023's 1,888 MW. The increase in underlying demand being partly offset by the rise in distributed PV output resulted in NEM operational demand increasing by 0.9% to 21,913 MW, 196 MW up on the average of 21,717 MW observed in Q2 2023.

The increase in operational demand was particularly evident outside solar peak hours (Figure 6), highlighting the continued influence of distributed PV generation on mid-day demand within the NEM.

[4] A "heating degree day" (HDD), which is based on the average daily temperature, is a measurement used as an indicator of outside temperature levels below what is considered a comfortable (base) temperature (higher HDD indicates that the weather is colder). HDD value is calculated as max (0, base temperature – average temperature).

Figure 5 Underlying demand reaches new Q2 high

NEM average underlying and operational demand – Q2s

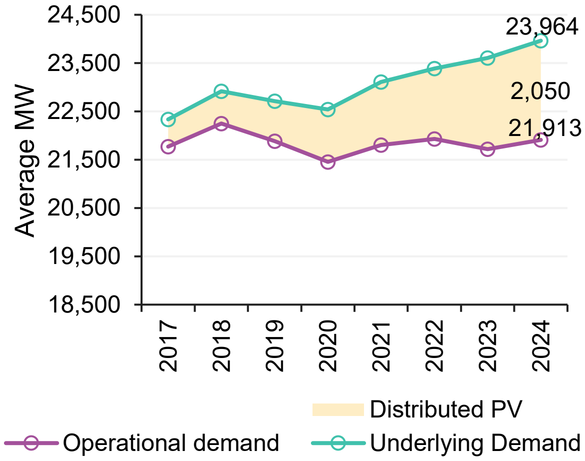
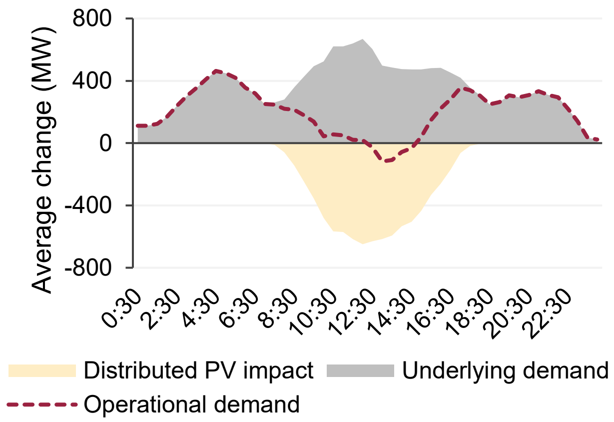


Figure 6 Operational demand increased at all times of the day except during solar peak

Changes in NEM average operational demand by time of day – Q2 2024 vs Q2 2023

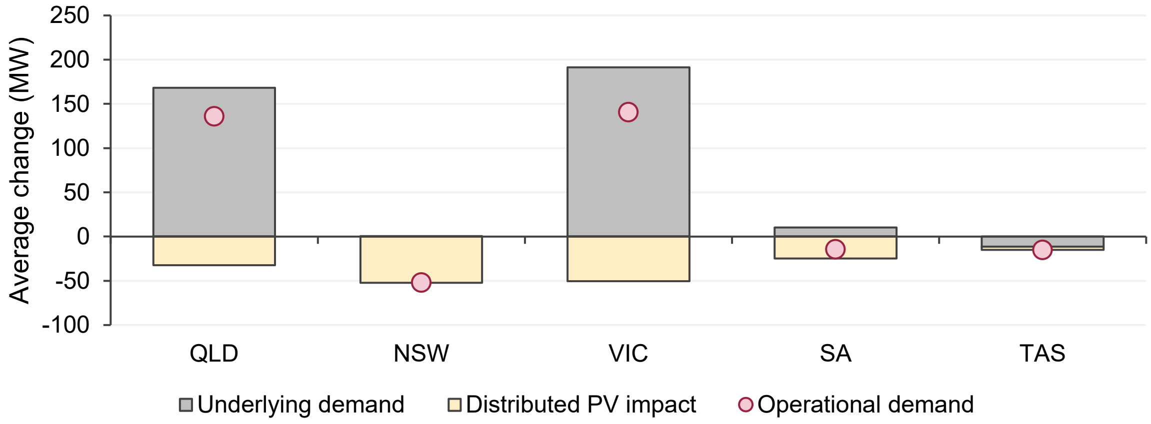


Victoria and Queensland recorded growth in operational demand while other regions saw small declines (Figure 7). In particular:

- **Queensland**'s operational demand saw a year-on-year increase of 136 MW (+2%) from 5,982 MW in Q2 2023 to 6,118 MW this quarter. This increase was driven by the increased cooling demand in April (warmer temperatures) as well as colder temperatures during June which resulted in growth in heating demand, year-on-year. Underlying demand in Queensland increased at all times of the day with a significant increase during mid-day hours, offsetting distributed PV output growth and resulting in operational demand also rising across all times of the day, relative to Q2 2023.
- **New South Wales** did not see a notable change in quarterly underlying demand, with month-to-month variations in temperature and heating demand offsetting over the quarter. This, coupled with increased distributed PV impact, resulted in average operational demand falling 52 MW (-1%) from 7,904 MW in Q2 2023 to 7,852 MW this quarter.
- With colder temperatures in **Victoria** (especially during June), underlying demand increased by 191 MW (+3.5%) year-on-year, which was only partly offset by higher distributed PV output (50 MW), yielding the largest increase in operational demand for any region during Q2 2024 at 141 MW. This was a 3% increase from 5,178 MW in Q2 2023 to 5,319 MW this quarter.
- In **South Australia**, quarterly average underlying demand increased by 10 MW, while **Tasmania** saw a reduction of 11 MW. These changes, coupled with slight increases in distributed PV impact, contributed to operational demand reductions of 14 MW (-1%) in South Australia and 15 MW (-1%) in Tasmania compared to Q2 2023.

Figure 7 Queensland and Victoria accounted for the increase in NEM operational demand

Changes in average demand components by region – Q2 2024 vs Q2 2023



Maximum and minimum demands

In Q2 2024, maximum NEM operational demand of 32,322 MW occurred during the half-hour ending 18:30 on 24 June 2024. This was a 2 MW increase from Q2 2023's maximum of 32,320 MW. Reflecting the same regional pattern as average demand growth, Queensland and Victoria recorded their all-time highest Q2 maximums at 8,655 MW and 8,328 MW respectively, representing increases of 576 MW (+7%) and 310 MW (+4%), relative to Q2 2023 levels (Figure 8). These all-time highest Q2 maximums, however, are still slightly below the previously set winter records of 8,716 MW in Queensland (set on 4 July 2022) and 8,351 MW in Victoria (set on 17 July 2007)[5].

NEM minimum operational demand in this quarter was 13,496 MW over the half-hour ending 12:30 on 14 April 2024, 118 MW (+1%) higher than Q2 2023's minimum demand of 13,378 MW. As shown in Figure 9, all mainland regions saw higher minimum operational demand this Q2 than last.

Figure 8 Marginal year-on-year changes in maximum operational demand

Maximum operational demand for mainland regions – Q2s

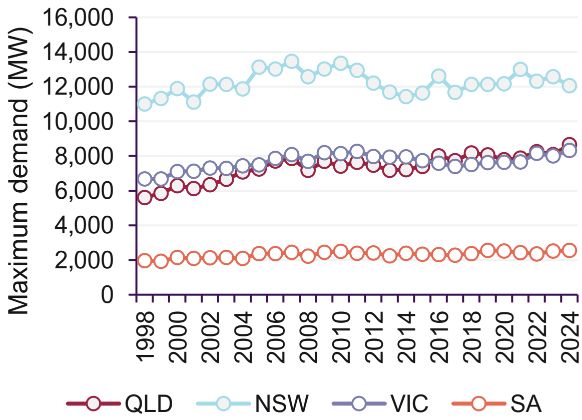
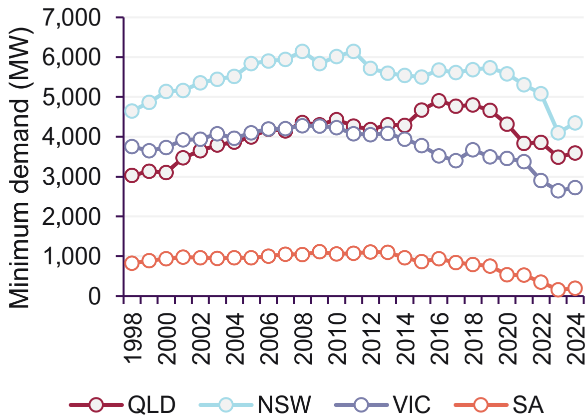


Figure 9 All mainland regions saw increased minimum operational demand

Minimum operational demand for mainland regions – Q2s



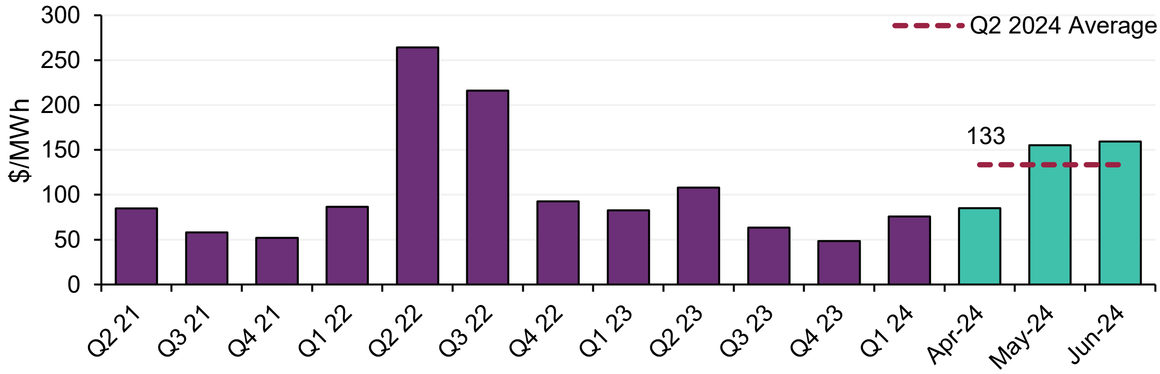
[5] Note new winter maximum demand records were set in Q3 2024: 8,612 MW in Victoria on 15 July and 8,728 MW in Queensland on 17 July 2024.

1.2 Wholesale electricity prices

In Q2 2024, wholesale spot prices across the NEM averaged $133/MWh, a $25/MWh (+23%) increase from Q2 2023 and a $58/MWh (+76%) increase from Q1 2024 (Figure 10). The year-on-year increase in average quarterly price was mainly driven by lower wind and hydro generation, and transmission outages and limitations during Q2 2024. The energy component[6] of wholesale prices saw an uplift of $24/MWh compared to the same period last year, while the average NEM cap return component increased by only $2/MWh to $13/MWh. Monthly average prices started the quarter at $85/MWh in April but rose strongly in May and June reaching $155/MWh and $159/MWh respectively.

Figure 10 Year-on-year increase (23%) in NEM average wholesale spot prices

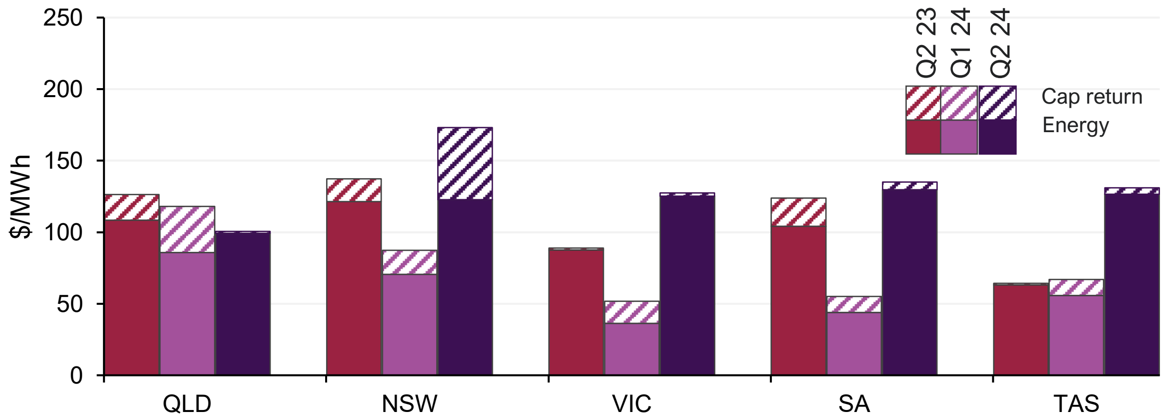
NEM average wholesale electricity prices – quarterly since Q2 2021



Regional quarterly average spot prices were higher everywhere except Queensland, relative to both Q2 2023 and Q1 2024, with notable rises in the energy price component in the three southern regions (Figure 11).

Figure 11 All regions, except Queensland, saw increase in average spot prices

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



[6] "Energy price" calculation in the analysis of average spot electricity prices truncates the impact of volatility (that is, the contribution to the quarterly average of any excess component of spot prices above $300/MWh, also known as "cap return"). Since commencement of Five-Minute Settlement (5MS) on 1 October 2021, energy prices and cap returns are calculated on a five-minute basis.

By region for Q2 2024:

- **Queensland** saw an average of $101/MWh for wholesale spot prices, a $26/MWh (-20%) reduction year-on-year. Both energy (-$9/MWh) and cap return (-$16/MWh) components fell. The region saw 527 intervals with prices higher than $300/MWh relative to 900 intervals during the same period last year. In comparison with Q1 2024, energy prices increased by $13/MWh from $86/MWh, while the cap return component reduced significantly by $31/MWh. This reduction in cap return reflects the high Queensland summer demand during Q1 2024 which was a significant price driver for that quarter.
- Quarterly average price in **New South Wales** increased by $36/MWh (+26%) from $137/MWh in Q2 2023 to $173/MWh this quarter. The majority of this year-on-year change was due to a higher cap return, which increased by $35/MWh from $16/MWh to $50/MWh. Notably, the region saw 862 intervals with prices higher than $300/MWh, 338 more than Q2 2023 levels. Market events during May led to a series of extreme spot prices, which contributed the bulk of the higher cap return for the region and triggered a period of Administered Pricing for New South Wales only. More detailed analysis of this event and its drivers is in Section 1.2.2.
- **Victoria**'s quarterly average price reached $127/MWh, an increase of $39/MWh (+43%) relative to $89/MWh last Q2. Similar to Q2 2023, the cap return component of average spot price was negligible and almost the entire increase in quarterly average was driven by price dynamics below $300/MWh with a $38/MWh uplift in the energy component. The main drivers of this increase were stronger regional demand and the higher gas-fired generation required to compensate for the quarter's low wind output and meet increased exports of energy to Tasmania where continuing dry conditions reduced hydro production.
- Similar to Victoria, **South Australia** was affected by lower wind generation levels pushing gas generation higher. The region's quarterly average price reached $135/MWh, up by $11/MWh from a year ago but by $80/MWh on Q1 2024. Relative to Q2 2023 a lower cap return component (-$14/MWh) was more than offset by higher energy prices (+$26/MWh). The region saw a significant reduction in the number of intervals with prices higher than $300/MWh from 2,129 intervals in Q2 2023 to 1,320 intervals this quarter.
- Challenged by reduced rainfall necessitating lower hydro production, as well as lower wind speeds, **Tasmania** experienced much higher energy prices relative to Q2 2023 and Q1 2024. Quarterly average prices reached $131/MWh, up by $67/MWh year-on-year, the highest increase for any region. The energy component of average spot price was more than doubled year-on-year from $63/MWh to $127/MWh, while the cap return saw a small increase of $3/MWh, reaching $4/MWh this quarter.

This quarter also saw a notable change in price relativities between the NEM's northern regions (Queensland and New South Wales) and the southern regions of Victoria and South Australia (Figure 12). In recent years prices in Queensland and New South Wales have generally been well above those in the southern regions, particularly during daylight hours, driven by higher renewable penetration in Victoria and South Australia and transmission limitations between Victoria and New South Wales.

This relativity reversed in Q2 2024 with Victoria and South Australia experiencing higher morning and mid-day prices than northern regions. This shift was driven by lower wind speeds in the southern regions and reduced Tasmanian hydro generation. Higher reliance in the southern regions on gas-fired generation and energy imports from northern NEM regions led to increased energy prices.

Figure 12 Southern region prices shift upward

Average regional energy price by time of day – Q2 2024

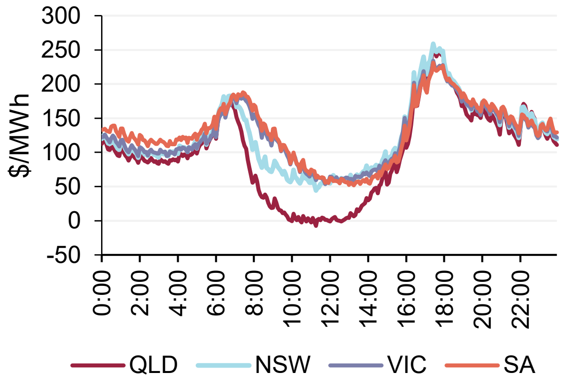
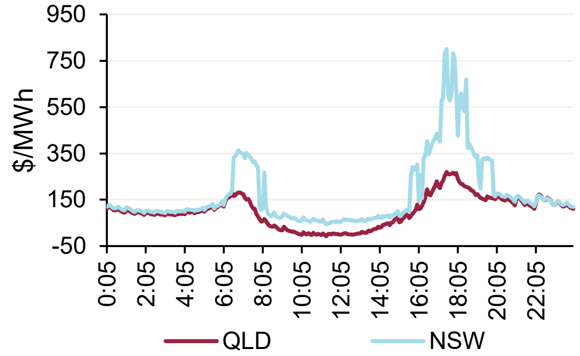


Figure 13 Significant price gaps between Queensland and New South Wales

Average regional spot price by time of day – Q2 2024



The time-of-day full spot price profiles for Queensland and New South Wales, shown in Figure 13, exhibit significant separation, particularly during the morning and evening peak hours. This price separation can be broken into two components: lower daytime energy prices in Queensland, and the impact of isolated volatility episodes in New South Wales. In particular:

- Queensland's black coal-fired generation fleet offered higher volumes in all price bands during the quarter (Figure 14), assisted by the return of capacity at Callide C3. However, during daytime hours when operational demand is relatively low and grid-scale solar output is high, the Queensland – New South Wales Interconnector (QNI) frequently reaches its southward flow limits (see Section 1.4) with limited ability to transfer additional low-cost energy out of Queensland. This results in higher negative price incidence (see Section 1.2.3) and a drop in Queensland energy prices, which does not flow correspondingly to prices in New South Wales.
- Transmission outages in both southern and northern New South Wales, together with coal-fired generation outages in the region's central zone, led to a series of extreme price volatility events in the region, occurring in both morning and evening peak hours as generation in the south of the state and energy imports from both adjoining regions were restricted. These events, which are discussed further in Section 1.2.2, lifted New South Wales' average prices well above other regions at the relevant times of day (Figure 15).

Figure 14 More volume offered by Queensland black coal-fired generators at all price levels

Queensland black coal bid supply curve – Q2 2024 vs Q2 2023

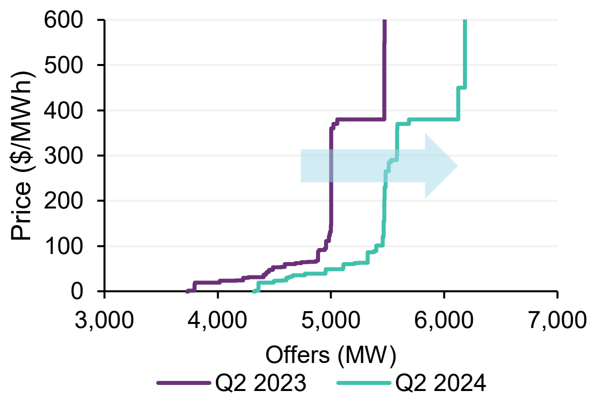
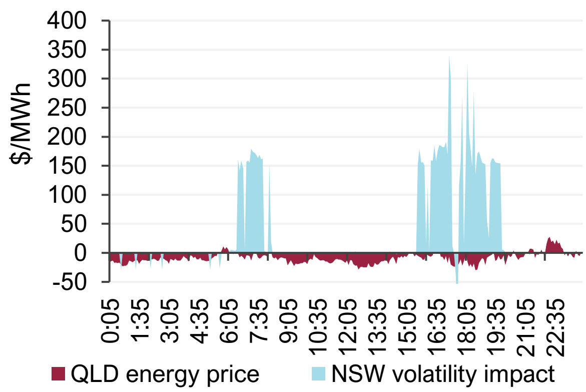


Figure 15 Queensland's energy price reduced while New South Wales saw large volatility uplift

Change in price by time of day – Q2 2024 vs Q2 2023



1.2.1 Wholesale electricity price drivers

Key factors influencing the movement of prices this quarter are summarised in Table 1, with further analysis and discussion referred to relevant sections of this report.

Table 1 Wholesale electricity price drivers in Q2 2024

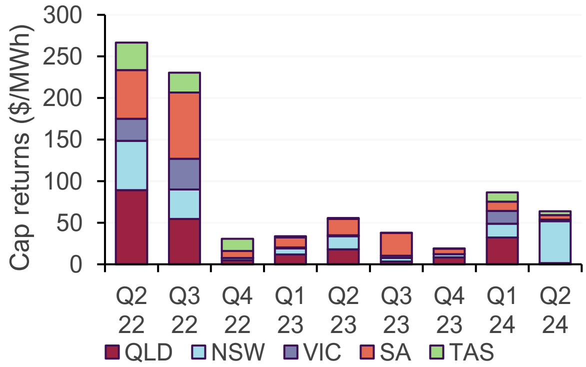
Wind and rainfall drought	This quarter saw very low wind speeds throughout and lower-than-average rainfall across the southern and eastern regions leading to considerable drops in wind availability (Section 1.3.4) and hydro generation. Reduced rainfall levels led to higher offer prices from hydro, with around 970 MW of supply offers shifted to prices equal or above $300/MWh to conserve water storage levels (Section 1.3.3, Figure 43). With both wind and hydro output falling significantly at all times of the day there was more reliance on gas generation (Section 1.3, Figure 30) and imports from the northern regions (Section 1.4) to meet operational demand, causing increases in energy prices in the southern regions.
Transmission outages	A scheduled line outage reduced transmission capacity between Yass and central New South Wales for most of the quarter (77 days). This outage affected the ability of a significant proportion of regional generation capacity (located in southern New South Wales) to fully contribute to meeting operational demand, and limited imports through the Victoria – New South Wales Interconnector (VNI). At times of high demand and lower supply availability, this led to more dispatch of higher priced offers in the region (from generators not affected by the line outages), contributing to higher prices in New South Wales. Another transmission outage contributing to higher prices in New South Wales was the planned outage of Tamworth – Armidale (86) 330 kilovolts (kV) line. While this was in place for only 13 days, coupled with the line outage in southern New South Wales and generator outages, it contributed to significant price volatility in New South Wales (Section 1.2.2).
Price volatility events	The transmission outages in northern and southern New South Wales, coupled with generator outages, led to price volatility events in the region over 7 and 8 May 2024, which resulted in an Administered Price Period over 8-14 May (discussed in Section 1.2.2). These two days of price volatility contributed $8/MWh (16%) and $37/MWh (72%) to the quarterly average cap return component of the regional average price.
Price separation	Reversing gaps observed in recent years, this quarter saw Victoria and South Australia experience higher energy prices than the northern regions, particularly during the morning peak. As discussed in Section 1.2.1 above, this price separation was driven by lower wind and hydro generation in the south being replaced by higher cost sources and interconnector imports. Meanwhile middle of day prices in Queensland fell, due to more available lower cost generation and QNI flows frequently reaching southward limits.
Black coal offers and availability	The government policies that were introduced in December 2022, capping domestic thermal coal prices, continued to be in place throughout Q2 2024. Black coal availability increased with reduced outages observed in the quarter in both Queensland and New South Wales (Section 1.3.1, Figure 32), leading to increased offer volumes at all price bands by black-coal fired generators. Volume increases were mainly from Queensland generators, with approximately 590 MW of additional offers at prices below $0/MWh, particularly during the day, and a similar increase in volumes offered at under $300/MWh (Figure 14 above), contributing to lower prices in Queensland.

1.2.2 Wholesale electricity price volatility

In Q2 2024, cap returns across the NEM – the contribution of spot prices in excess of $300/MWh to the quarterly average – when aggregated across all five regions increased by $8/MWh from $56/MWh in Q2 2023, reaching $64/MWh (Figure 16). New South Wales accounted for the majority of this as discussed in the preceding sections. Queensland saw only $1/MWh of cap return this quarter, a reduction of $16/MWh from Q2 2023. The quarter also saw a drop in South Australia's cap return from $20/MWh to $5/MWh. Victoria and Tasmania both saw higher cap returns of $2/MWh and $4/MWh respectively, increases of $1/MWh and $3/MWh relative to Q2 2023.

Figure 16 New South Wales accounted for 79% of NEM cap returns

Cap returns by region – quarterly



Administered Price Period in New South Wales

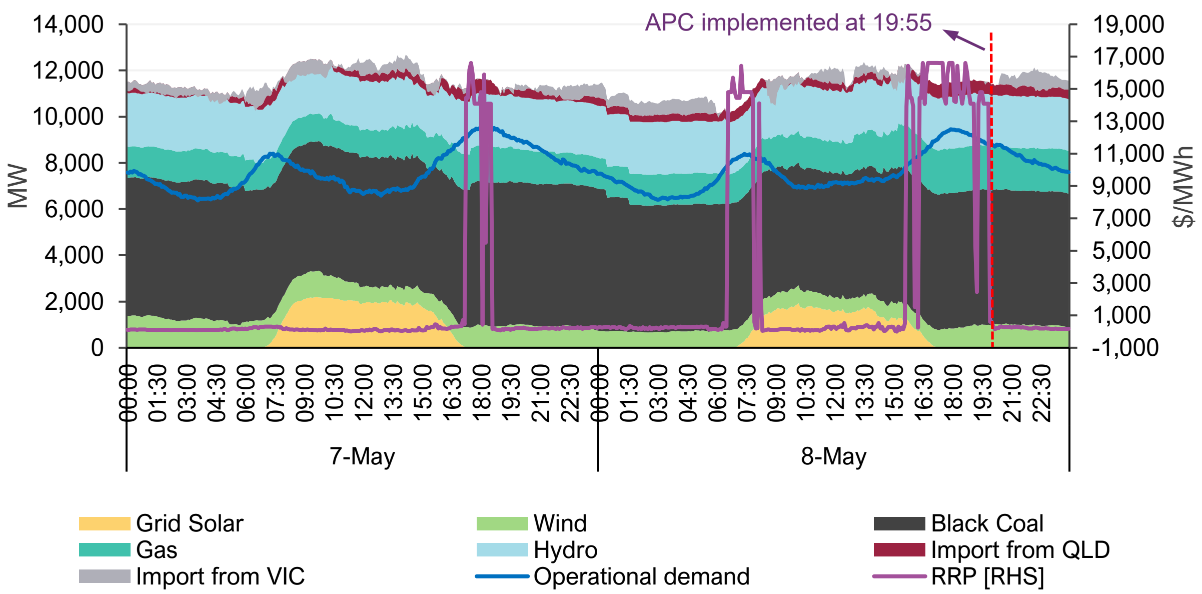
On 8 May 2024, New South Wales experienced a series of high prices leading to the cumulative price[7] in the region breaching the cumulative price threshold[8] (CPT) of $1,490,200 at 1955 hrs. This automatically triggered an administered price period[9] in the region during which the Administered Price Cap (APC) of $600/MWh was applied to spot prices for energy and market ancillary services. The cumulative price in New South Wales fell below the CPT on 14 May 2024 at 1745 hrs and the administered price period ended at 0400 hrs on 15 May.

Although administered price capping commenced on 8 May, price spikes in New South Wales had started a day earlier (Figure 17). This was driven by outages at major black coal-fired generation units, while a planned transmission outage between Yass and central New South Wales impacted generators in southern New South Wales and imports from Victoria, while an overlapping planned outage on part of QNI affected imports from Queensland. Price spikes on 7 May contributed $8/MWh to the quarterly cap return in New South Wales (16% of the total quarterly cap return).

While Figure 17 shows ample available generation capacity relative to demand, a significant proportion of this generation was constrained by the transmission outage in southern New South Wales, and hence unable to fully contribute to meeting operational demand in the region.

Figure 17 From price spikes on 7 and 8 May to administered price period in NSW

Generation availability per fuel type, actual operational demand[10], actual imports, and RRP in NSW during 7 and 8 May



[7] Cumulative price is calculated as the rolling sum of the uncapped regional reference prices (spot prices) in the energy market for the previous 2,016 trading intervals (equivalent to seven days).

[8] The cumulative price threshold was $1,490,200 during 2023-24 financial year and is now updated to $1,573,700 for the 2024-25 financial year.

[9] The administered price provisions of the National Electricity Rules form an important component of the market safety net which operates to protect and sustain electricity trading in the NEM during periods of sustained high prices. If market prices in a region rise to levels that are likely to cause substantial financial stress, then those prices are capped until they return to lower levels.

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

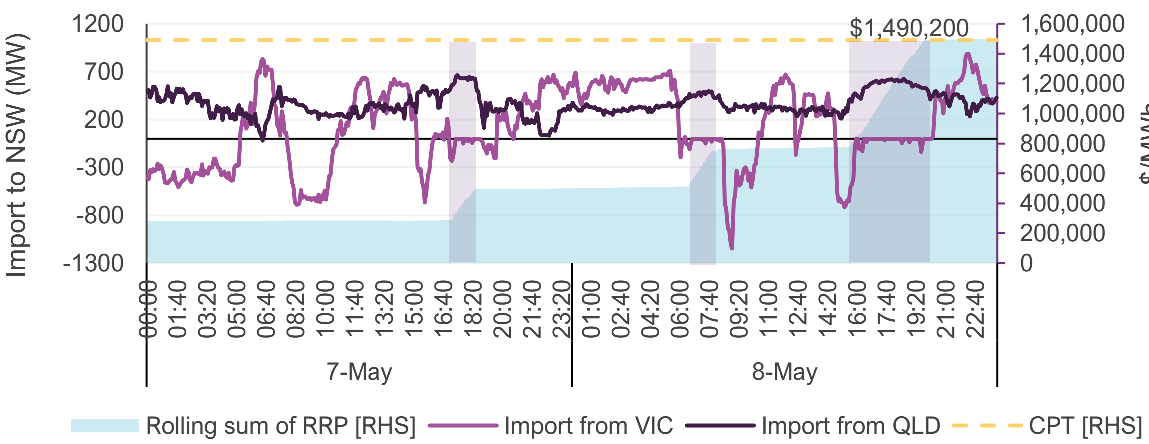
New South Wales began the day of 8 May 2024 with lower generation availability, relative to the day before, due to reductions in black coal-fired generation availability occurring in the early hours, along with slightly lower wind and solar availability.

The first volatility event on 8 May occurred before sunrise with operational demand reaching its morning peak, and the second volatility event occurred during evening peak. With the ongoing transmission outage in southern New South Wales capping transfers from generators in that area to the rest of the state, additional dispatch of these generators resulted in energy flows from New South Wales to Victoria as shown in Figure 18.

The balance of morning and evening peak operational demand had to be met by high-priced volumes offered by generators that were not affected by the transmission limit, or through import from Queensland, the cost of which was strongly affected by the transmission constraint on QNI. Price spikes on 8 May contributed $36.5/MWh to the New South Wales quarterly cap return (72% of the quarterly cap return).

Figure 18 Transmission outages caused limits on imports to New South Wales from neighbouring regions

Import from Victoria and Queensland (left), rolling sum of RRP and cumulative price threshold (right)



1.2.3 Negative wholesale electricity prices

In Q2 2024, 7% of dispatch intervals across the NEM experienced negative or zero prices, a 2 percentage point (pp) reduction compared to the 9% recorded in Q2 2023. The occurrence of negative prices significantly decreased in the southern regions, dropping in Victoria by 6 pp (from 13% to 7%), South Australia by 7 pp (from 17% to 10%), and Tasmania by 4 pp (from 5% to 1%), year-on-year (Figure 19).

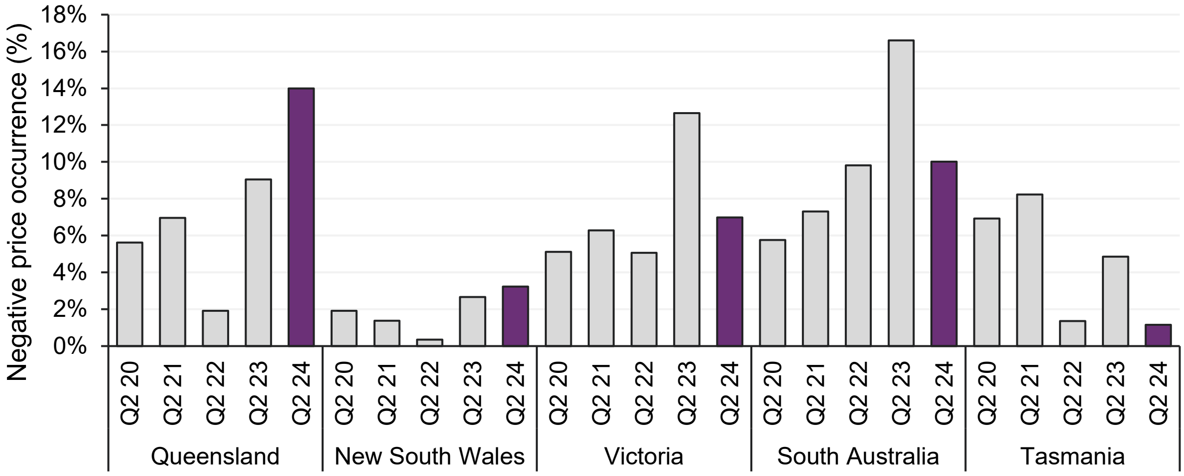
The reduction in negative price occurrences was particularly noticeable in June as cold conditions increased operational demand while wind output remained below average. Victoria recorded just 3% of dispatch intervals with negative prices in June 2024, compared to 19% in June 2023, and South Australia recorded 7% in June 2024 compared to 22% in June 2023.

New South Wales saw a slight year-on-year increase of 1 pp in negative price occurrence, while Queensland experienced a significant rise of 5 pp, from 9% in Q2 2023 to 14% in Q2 2024. This was the first quarter since Q3 2020 where Queensland has had the highest regional occurrence of negative prices.

Consistent with the overall reduction in negative price occurrence, the NEM-wide average of negative prices reduced in magnitude from Q2 2023's -$34.9/MWh to -$30.4/MWh over this quarter.

Figure 19 Negative price occurrence dropped in southern regions but significantly increased in Queensland

Negative price occurrence in NEM regions – Q2s



As Figure 20 shows, negative prices occurred predominantly during daylight hours, with Queensland experiencing notably higher occurrences than other NEM regions. This trend mirrors the increased price separation observed between Queensland and southern regions seen in Figure 12 and the incidence of QNI reaching southward transfer limits discussed later in Section 1.4.

Q2 2024 is the first quarter where, in addition to higher negative price occurrence, Queensland led the regions for negative price impact[11], with growth in this measure from $2.3/MWh in Q2 2023 to $4.0/MWh this quarter (Figure 21).

Figure 20 Queensland leads negative price occurrence

Negative price occurrence by time of day – Q2 2024

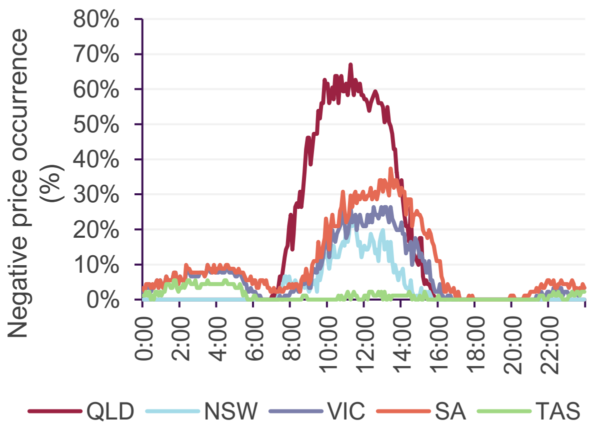


Figure 21 Strongest negative price impact in Queensland

Quarterly negative price impact – Q2 2024 vs Q2 2023

[11] ‘Negative price impact’ quantifies the effect of negative prices in reducing overall quarterly average spot prices.

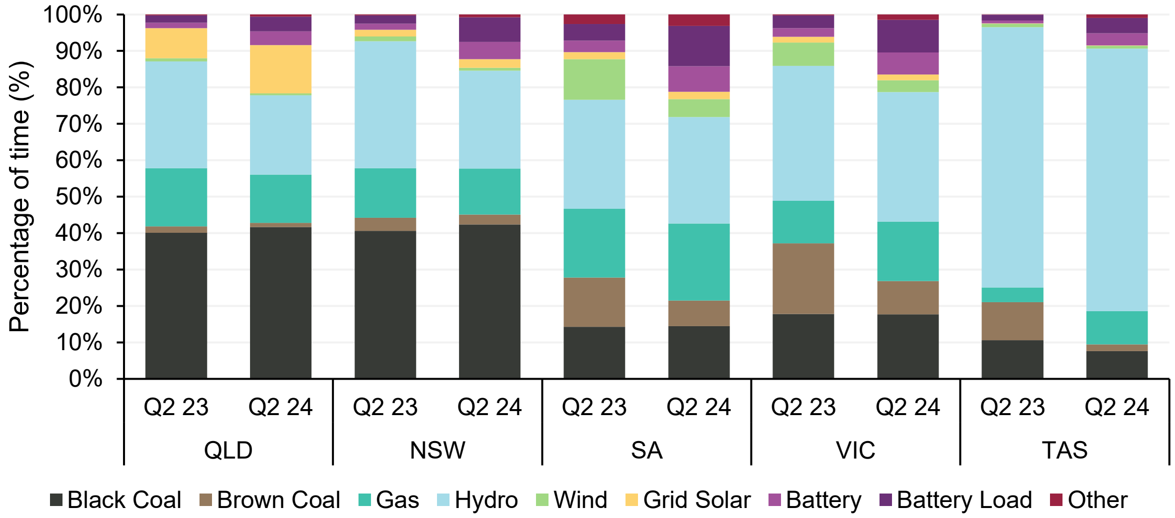
1.2.4 Price-setting dynamics

In Q2 2024, black coal set prices in 25% of intervals across the NEM, a similar level to Q2 2023, and continued to set about 40% of prices in New South Wales and Queensland (Figure 22). In the southern regions, brown coal and wind both recorded significant decreases, with brown coal price-setting frequency in Victoria down 10 pp and wind down 6 pp in South Australia. Gas-fired generation set prices slightly less often in the northern regions, down 1-3 pp, but more frequently in the south – up by 2 pp in South Australia and 5 pp in both Victoria and Tasmania. Hydro set price in fewer intervals, particularly in northern regions, down by 7 and 8 pp in Queensland and New South Wales, respectively.

Across the NEM, batteries saw the largest increases in price setting frequency. Intervals where prices were set by battery generation rose to 5% of the quarter, up from 2% in Q2 2023, and by batteries charging at 7% of the quarter, up from 3% a year ago. These changes reflect the significant annual increase in battery capacity across the NEM. Grid-scale solar set price significantly more often in Queensland this Q2, up from 8% of intervals a year ago to 13%, as higher levels of coal-fired minimum generation and limits on southward exports left solar as the marginal price-setter more often in that region.

Figure 22 Gas and batteries set prices more frequently in the NEM, wind and brown coal down

Price-setting frequency[12] by fuel type – Q2 2024 vs Q2 2023

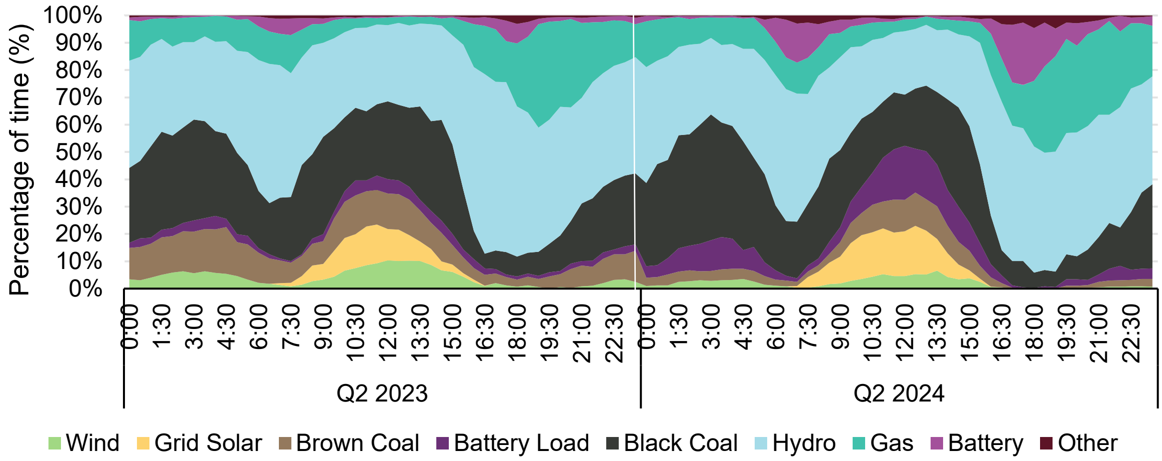


The increase in batteries' NEM-wide price setting frequency is most obvious in evening and morning peaks for battery generation, and conversely in the early morning and peak solar hours for battery loads (Figure 23). This reflects the profile of NEM prices, as batteries seek arbitrage by purchasing at lower prices and dispatching into the market when prices are high. For some evening dispatch intervals, the average frequency of price-setting by batteries this Q2 reached 23%, against a peak of only 7% for Q2 2023. During solar peak intervals (between half-hours ending 1000 – 1330), battery loads set prices in 16% of intervals NEM-wide.

[12] Price-setting data excludes the over-constrained dispatch and the Value of Lost Load (VoLL) override pricing period between 1320 hrs and 1515 hrs on 13 February.

Figure 23 Significant increase in price-setting frequency by batteries at all times of the day

NEM price-setting frequency by fuel type and time of day – Q2 2023 and Q2 2024

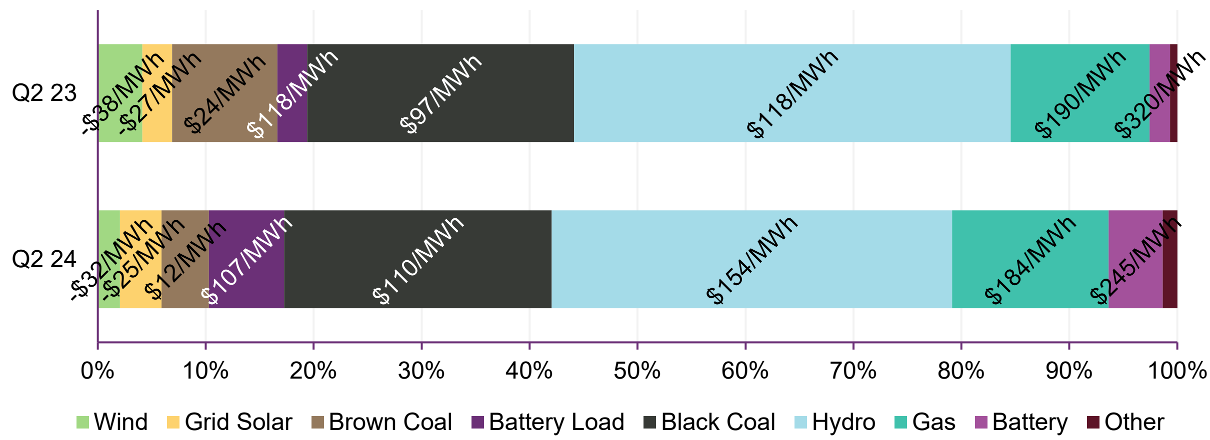


There were mixed changes from Q2 2023 to this Q2 in the average prices set by each energy source when marginal (Figure 24). There were significant increases from $118/MWh to $154/MWh for hydro, as generators sought to conserve water in storage (due to lower rainfall levels), and from $97/MWh to $110/MWh for black coal-fired generation. Notably, the latter increase was entirely attributable to price-setting dynamics in New South Wales on 7 and 8 May (see Section 1.2.2) – without these events the average price set by black coal-fired offers would have been lower this Q2 than last[13].

Conversely, average prices set by brown coal-fired units fell from $24/MWh to $12/MWh, as reduced wind and hydro output meant brown coal generation was less frequently marginal, particularly in higher-price morning and evening peak hours. Average prices set by batteries also fell, from $118/MWh to $107/MWh when charging, and from $320/MWh to $245/MWh when generating, consistent with this source's increased capacity and more frequent price-setting. There were only relatively small changes in prices set by other fuel types.

Figure 24 Average prices set by black coal and hydro increased but dropped for battery and brown coal

NEM price-setting frequency and average price when price-setter by fuel type – Q2 2024 vs Q2 2023



13 Excluding days 7 and 8 May, average price set by black coal when marginal was $89/MWh, a reduction of $8/MWh.

1.2.5 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.

In this quarter, ASX base contract prices for the 2024-25 financial year (FY25) averaged $101/MWh across all mainland NEM regions. This marks a 20% rise from the previous quarter's average of $84/MWh and a 4% drop from Q2 2023's average of $106/MWh. All regions experienced price increases from Q1 2024, with Victoria and New South Wales recording significant increases of 24% and 22%, averaging $79/MWh and $121/MWh, respectively. South Australia and Queensland saw increases of 18% and 16%, averaging $102/MWh and $104/MWh, respectively. Compared to Q2 2023, FY25 prices decreased in all regions except Queensland, which saw a 4% increase (Figure 25).

Figure 25 FY25 futures increased sharply following the high volatility in May

ASX Energy – Daily FY 2024-25 base future by region

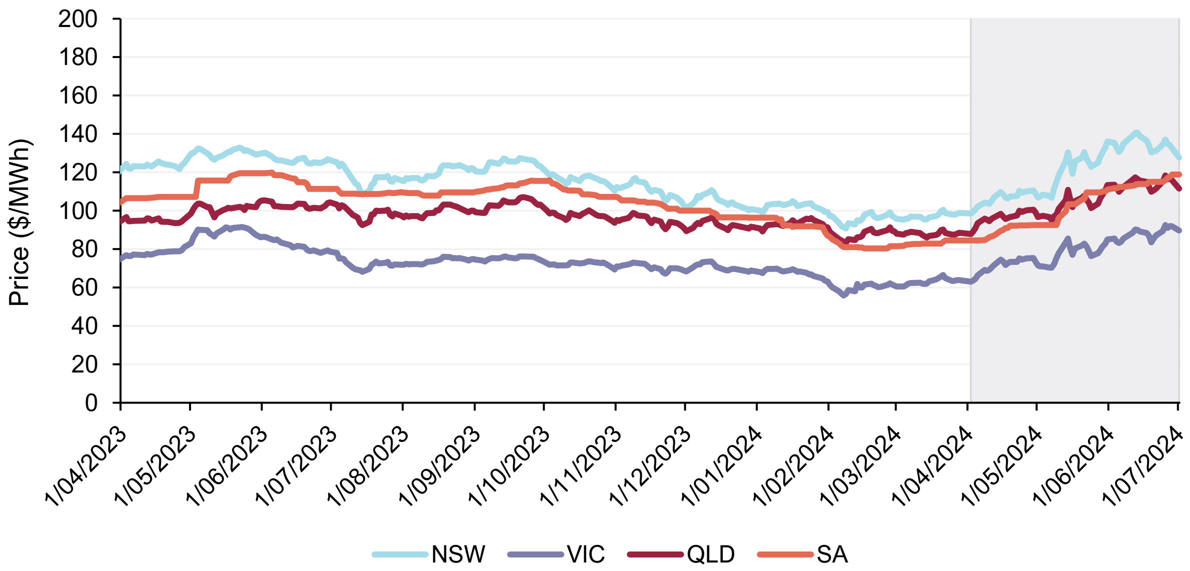


Figure 26 illustrates ASX daily prices for Q2 2024 base contracts in New South Wales. Final settlement prices for such current quarter contracts are set at quarter end to the time-weighted quarterly average spot price for the relevant region, but prior to this “delivery quarter” their traded prices reflect market expectations. During the delivery quarter, traded prices were influenced by both quarter-to-date spot price levels and expectations for the balance of quarter, ultimately converging to the final settlement price.

In 2023, ASX contract prices for Q2 2024 declined across all regions due to weaker-than-expected spot prices. This trend of contract prices closely following spot prices continued into 2024, before gradually increasing in April due to high energy spot prices. In New South Wales, the quarter-to-date average spot price jumped from $120/MWh on 7 May to $210/MWh following the high volatility event on 8 May, which triggered application of the APC in New South Wales. Consequently, the ASX New South Wales base futures price for Q2 2024 surged from $124/MWh on 7 May to $168/MWh on 8 May, and then to $181/MWh on 9 May. Daily futures prices continued to trend up, peaking on 14 May at $194/MWh, before falling back to $181/MWh on 15 May when administered price capping ended. The contract closed the quarter at $174/MWh, $80/MWh higher than its level at quarter start, while the spot prices over the quarter averaged $173/MWh.

Figure 27 illustrates the daily baseload $300 cap futures for Q2 2024 in New South Wales and the change in minimum cap return[14] in New South Wales during the quarter. On 8 May, the minimum cap return for Q2 in New South Wales increased to $47/MWh from $10/MWh the previous day. Consequently, the Q2 cap futures price rose by $40/MWh to $60/MWh. This upward movement was followed by a downward trend for the remainder of the quarter, attributed to lower-than-expected volatility, with the quarter closing at $51/MWh.

Figure 26 High spot price volatility drove New South Wales contract prices

ASX Energy – Daily Q2 2024 base futures price and daily average spot price in New South Wales

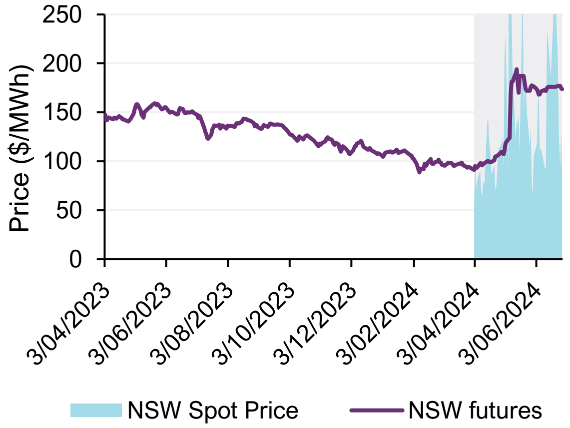
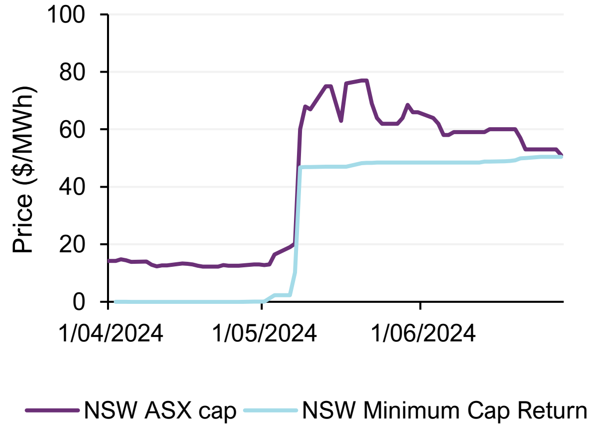


Figure 27 New South Wales caps jumped on the back of volatility event in May

ASX Energy – Daily Q2 2024 base cap price and the change in minimum cap return in New South Wales



At the end of Q2 2024, future financial year contracts closed significantly higher than at the end of Q1 2024 across all regions (Figure 28). Prices for FY25 concluded at $133/MWh in New South Wales, marking a $34/MWh (+34%) increase. Queensland saw a $27/MWh (+31%) rise, ending at $116/MWh for FY25. Victoria experienced the highest percentage increase, up by $28/MWh (+44%) to end at $92/MWh. South Australia ended at $119/MWh, up $34/MWh (+41%) from Q1 2024.

Despite these increases, all regions exhibited a longer-term downward trend in future contracts, with FY26 and FY27 prices notably lower than FY25 prices.

[14] The 'minimum cap return' at any point in a quarter represents the cumulative value of spot 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 spot price exceedances by the full number of intervals in the quarter.

Figure 28 Future financial year contracts ended the quarter significantly higher than the end of Q1 2024 levels but trending lower in out-years

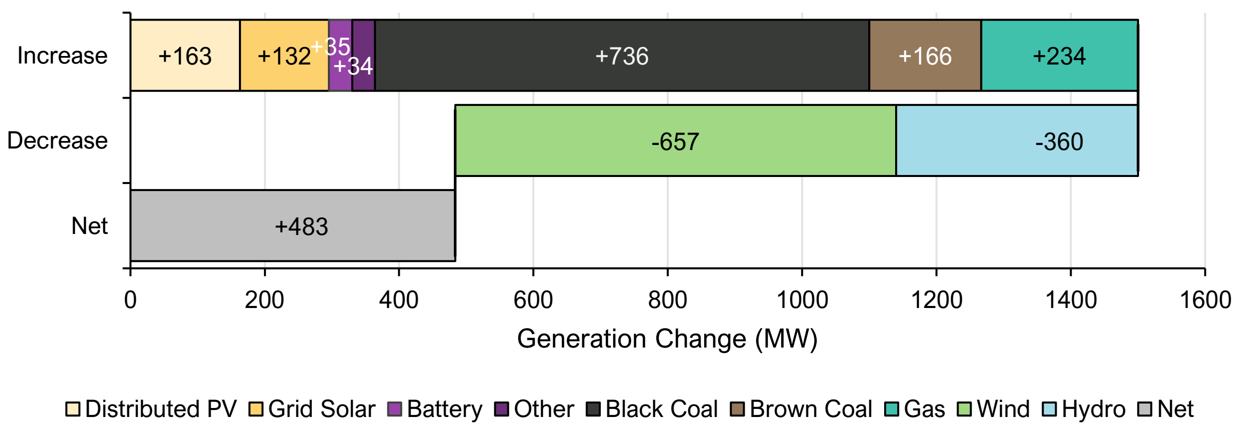
Financial year contract prices in mainland NEM regions – end of Q4 2023 and end of Q1 2024

1.3 Electricity generation

During Q2 2024, total NEM generation[15] increased by an average of 483 MW, up 2.0% from 23,881 MW in Q2 2023 to 24,364 MW, with significant reductions in wind and hydro generation offset by increases in generation from all other fuel types. The change in average NEM generation by fuel type relative to Q2 2023 is shown in Figure 29.

Figure 29 Significant reductions in wind and hydro generation

Change in NEM supply by fuel type – Q2 2024 vs Q2 2023

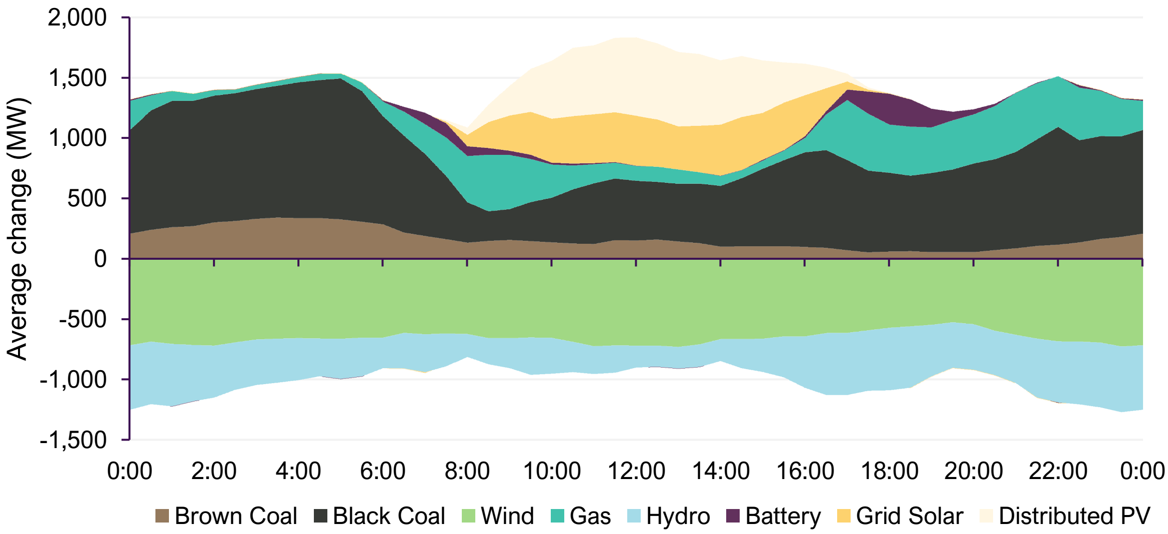


[15] Generation calculation is inclusive of AEMO's best estimates of generation from distributed PV. Generation also includes supply from certain non-scheduled generators and supply to large market scheduled loads (such as pumped hydro and batteries) which are excluded from the operational and underlying demand measures discussed in Section 1.1.2.

The time of day changes in generation by fuel type are shown in Figure 30, with the decrease in wind and hydro generation evident across all hours of the day. In response to these decreases, black coal-fired, brown coal-fired and gas-fired generation rose across all hours of the day. Battery generation increased to support the morning and evening peaks, reflecting the additional battery capacity installed since Q2 2023.

Figure 30 Large decreases in wind and hydro generation across all hours of the day

NEM generation changes by time of day – Q2 2024 vs Q2 2023



Comparing Q2 2024 with Q2 2023:

- Low wind conditions during the quarter drove a 657 MW, or 20%, drop in quarterly average wind generation, from 3,314 MW in Q2 2023 to 2,657 MW this quarter, the lowest quarterly average wind output since Q4 2021. This coincided with low rainfall in hydro catchments, leading to a 360 MW, or 18%, decrease in hydro generation across the quarter, to 1,607 MW.
- Black coal-fired generation increased to 10,857 MW, up 736 MW (+7%) from Q2 2023, and brown coal-fired generation averaged 3,947 MW, 166 MW (+4%) higher than Q2 2023. The increase in output occurred across all hours of the day but was most evident in the overnight and morning hours, before solar output commenced.
- Gas-fired generation averaged 1,702 MW, 234 MW (+16%) higher than during Q2 2023, increasing across all hours of the day with peaks in the morning and throughout the evening.
- Battery generation also contributed to meeting the morning and evening operational demand peaks, with average generation during the morning peak (between 700 hrs and 1000 hrs) doubling from Q2 2023's 67 MW to 138 MW. Generation during the evening peak (between 1800 hrs and 2100 hrs) more than doubled to reach an average of 227 MW, up 128 MW (+130%) from last year. Across all hours of the day battery generation averaged 74 MW this quarter, a 35 MW (+89%) uplift from last year.
- Distributed PV and grid-scale solar output increased, predominantly due to additional capacity. Grid-scale solar generation averaged 1,417 MW, an increase of 132 MW (+10%) from Q2 2023.

Table 2 summarises the changes in NEM generation share by fuel type. The large reduction in wind and hydro generation led to a decrease in the overall contribution of renewables, from 35.6% in Q2 2023 to 32.2% in Q2 2024.

Table 2 NEM supply mix contribution by fuel type

Quarter	Black coal	Brown coal	Gas	Liquid fuel	Distributed PV	Wind	Grid solar	Hydro	Battery	Biomass
Q2 2023	42.4%	15.8%	6.2%	0.0%	7.9%	13.9%	5.4%	8.2%	0.2%	0.0%
Q2 2024	44.6%	16.2%	7.0%	0.1%	8.4%	10.9%	5.8%	6.6%	0.3%	0.1%
Change	2.2%	0.4%	0.8%	0.1%	0.5%	-3.0%	0.4%	-1.6%	0.1%	0.1%

1.3.1 Coal-fired generation

Black coal-fired fleet

Average black coal-fired generation in Q2 2024 was 10,857 MW, a 736 MW (+7.3%) increase from Q2 2023, with reduced outages leading to quarterly average availability of 13,415 MW, an uplift of 786 MW (+6.2%) from Q2 2023 (Figure 31). Both New South Wales and Queensland black coal-fired generators contributed to the uplift in output, at 338 MW (+6%) and 398 MW (+8%) respectively, despite a small reduction in availability in New South Wales (-52 MW) due to an increase in partial outages limiting the maximum output of some units.

As shown in Figure 32, the reduction in full unit outages was most evident in Queensland (-1,052 MW), assisted by the return of Callide C3 unit, contributing to an overall 838 MW (+15%) increase in availability across Queensland black coal-fired generators.

Figure 31 Black coal-fired generation increased in Queensland and New South Wales

Quarterly average black coal-fired generation and availability by region (including decommissioned units) – Q2s

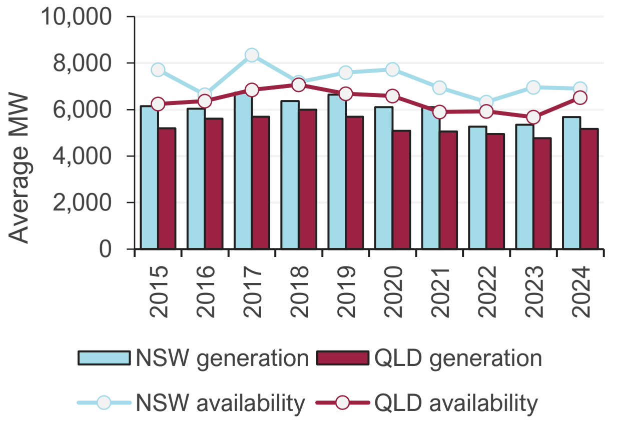


Figure 32 Significant decrease in Queensland coal-fired capacity on outage

Average black coal-fired capacity on full outage – Q2 2024 vs Q2 2023

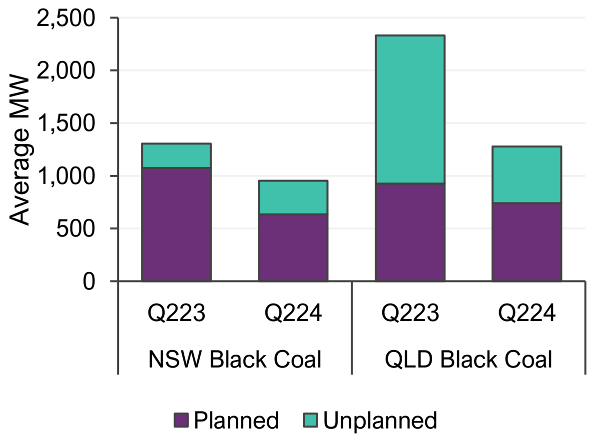


Figure 33 shows availability, generation and utilisation rates for the New South Wales black coal-fired power stations.

With increases in NEM operational demand, and decreases in wind and hydro generation, all existing black coal-fired power stations in New South Wales showed higher utilisation across the quarter, most notably Mt Piper with a 13 pp increase. Bayswater had the largest increase in output, at 259 MW (15%), followed by Mt Piper at 246 MW (34%) and Vales Point at 168 MW (25%).

Higher outages (+347 MW) led to a decrease in availability (-329 MW) and output (-85 MW) at Eraring, the only operating black-coal power station in New South Wales to record a year-on-year reduction in output.

Figure 33 Increased output from operating black coal-fired generators in New South Wales except Eraring

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q2 2024 vs Q2 2023

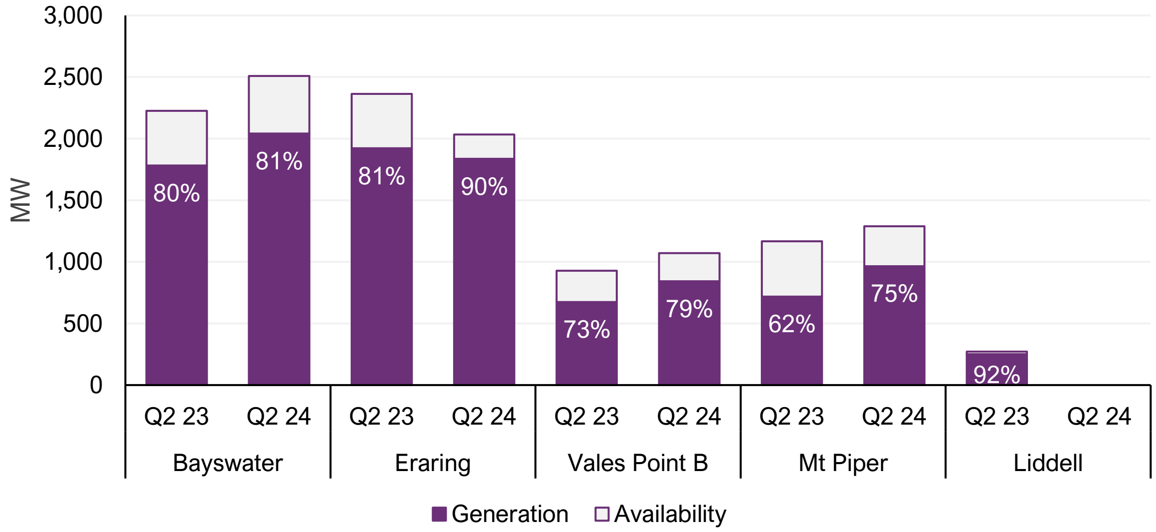
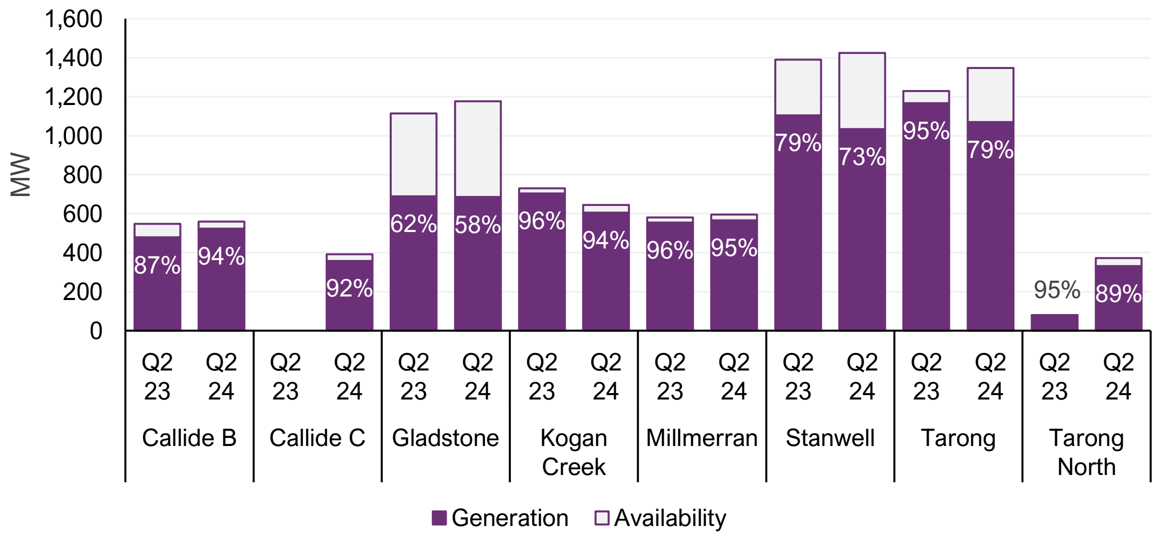


Figure 34 shows availability, generation and utilisation rates for the Queensland black coal-fired power stations.

Figure 34 Increased output at Callide C and Tarong North with reduced capacity on outage

Average quarterly availability and generation for Queensland black coal-fired power stations – Q2 2024 vs Q2 2023



Callide C3 unit returned to service this quarter with an average availability of 391 MW, and average output of 358 MW, after an extended forced outage which commenced in October 2022. CS Energy has advised the market of a revised return service date for unit C4 of 31 August 2024[16].

After an extended outage in Q2 2023, Tarong North availablity and output increased this Q2 to 372 MW (+292 MW) and 331 MW (+254 MW) respectively. These two power stations (Callide C3 and Tarong North)

[16] See https://www.csenergy.com.au/news/update-on-callide-unit-c4-return-to-service/july12#:~:text=The%20Callide%20C%20Power%20Station,(previously%2022%20July%202024).

contributed the most to the year-on-year overall increase in Queensland black coal-fired power generation, with smaller increases of output at Callide B (+45 MW) and Milmerran (+11 MW).

Utilisation and output levels reduced at the other stations, most noticably at Tarong with a 15 pp reduction in utilisation and a 96 MW (-8%) decrease in output. Kogan Creek output decreased by 99 MW (-14%), alongside a 84 MW (-12%) decrease in availability. Stanwell and Gladstone recorded decreases in output of 6% and 1% respectively, despite increases in availability of 2% and 6% respectively.

Higher operational demand in Queensland across all hours of the day, and additional availability, drove increased black coal-fired generation across all hours compared to Q2 2023. Intra-day swing for the Queensland fleet increased from 1,740 MW in Q2 2023 to 1,953 MW this Q2, driven by higher evening output levels (Figure 35). Intra-day swing for black coal-fired generation in New South Wales decreased slightly from 2,902 MW in Q2 2023, to 2,871 MW in Q2 2024 (Figure 36).

In both regions, the ‘duck curve’ for coal generation reversed its previous year-on-year trend of a deeper belly, influenced by the reduction in wind and hydro output generation across all hours of the day, and the relatively small uplift in grid-scale solar generation in the middle of the day (see Figure 30 above).

Figure 35 Queensland black coal-fired generation higher across the day

Queensland black coal-fired output by time of day – Q2s

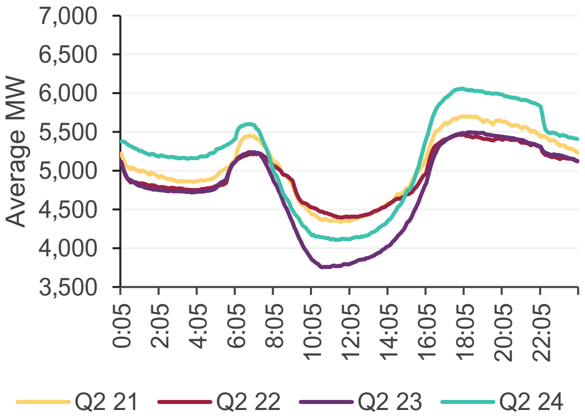
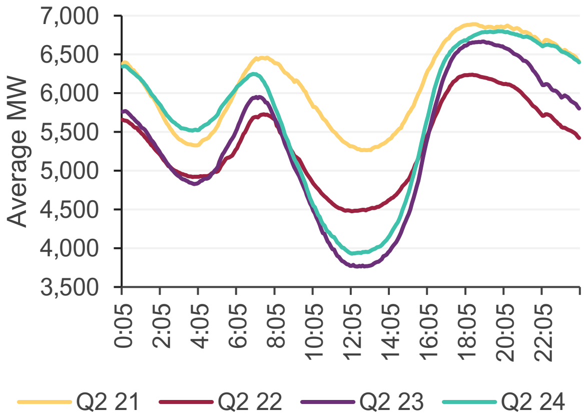


Figure 36 New South Wales black coal-fired generation higher across the day

New South Wales black coal-fired output by time of day – Q2s



Brown coal-fired fleet

Average brown coal-fired generation was 3,947 MW in Q2 2024, an increase of 166 MW (+4.4%) driven by low wind and hydro generation, and increased operational demand in Victoria over the quarter (Figure 37). There was a marginal increase in availability over the same time period, with availability averaging 4,101 MW over the quarter, up 13 MW (+0.3%) from the year prior.

Increases in brown coal-fired output were evident across all hours of the day, intra-day swing reduced from 629 MW in Q2 2023 to 547 MW in Q2 2024 (Figure 38) and the reduction in the depth of the ‘duck curve’ mirrored that seen in the northern regions’ black coal curves.

Figure 37 Brown coal-fired generation increased

Quarterly average generation and availability (including decommissioned units) – Q2s

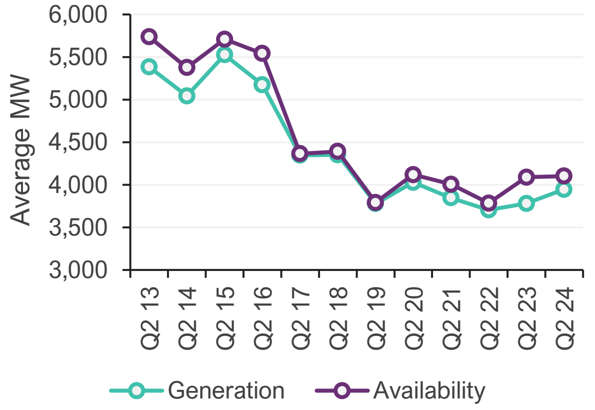
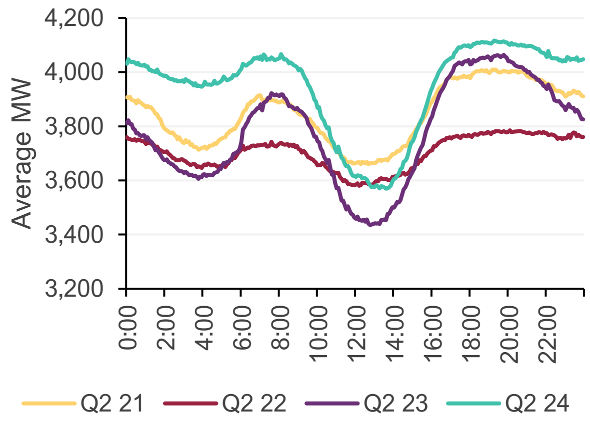


Figure 38 Brown coal-fired generation lifts across the day

Brown coal-fired output by time of day – Q2s



Less capacity on outage (-344 MW) at Loy Yang A compared to Q2 2023 offset reductions in availability at Loy Yang B (-124 MW) and Yallourn (-201 MW) due to outages this quarter (Table 3). All brown coal-fired power stations experienced increases in utilisation and reductions in intraday swing.

Table 3 Brown coal availability, output, utilisation, outage, and intraday swing by generator – Q2 2024 vs Q2 2023

Generator	Availability (MW)		Output (MW)		Utilisation		Outage (MW)		Intraday swing (MW)	
	Q2 23	Q2 24	Q2 23	Q2 24	Q2 23	Q2 24	Q2 23	Q2 24	Q2 23	Q2 24
Loy Yang A	1,769	2,107	1,606	2,001	91%	95%	423	79	361	354
Loy Yang B	1,145	1,021	1,048	994	92%	97%	11	133	181	109
Yallourn W	1,174	973	1,126	952	96%	98%	243	499	93	91

1.3.2 Gas-fired generation

During the quarter, average NEM gas-fired generation output increased to 1,702 MW, a 234 MW (+16%) rise from Q2 2023 (Figure 39). Low rainfall conditions in Tasmania contributed to the highest quarterly gas-fired generation in that region since Q2 2019, averaging 85 MW over Q2 2024.

The most significant uplift in gas-fired generation occurred in Victoria, with a quarterly average of 286 MW, more than doubling from 113 MW in the previous Q2. June's 474 MW was the highest monthly average recorded since August 2019. Gas-fired generation in South Australia averaged 582 MW, an increase of 106 MW (22%) from Q2 2023, with June's average of 735 MW the highest monthly output since July 2022.

In New South Wales, gas generation averaged 262 MW, up 18 MW (7%) from Q2 2023. The newly commissioned Tallawarra B unit contributed 14 MW to that average. Queensland was the only region to experience a decrease (-139 MW) in gas generation from last year, with a quarterly average of 487 MW.

These regional changes were consistent with electricity spot price movements, with prices higher in all regions apart from Queensland (see Section 1.2) driven by reduced supply from wind (see Section 1.3.4) and hydro generation (see Section 1.3.3). These factors resulted in operators of gas-fired generation committing more of their plant for dispatch. Across the NEM, the average volume of gas-fired generation offered at prices less than $300/MWh increased by around 200 MW (Figure 40).

Figure 39 Gas-fired generation ramped up over the quarter

Average gas-fired generation by region – Q2s

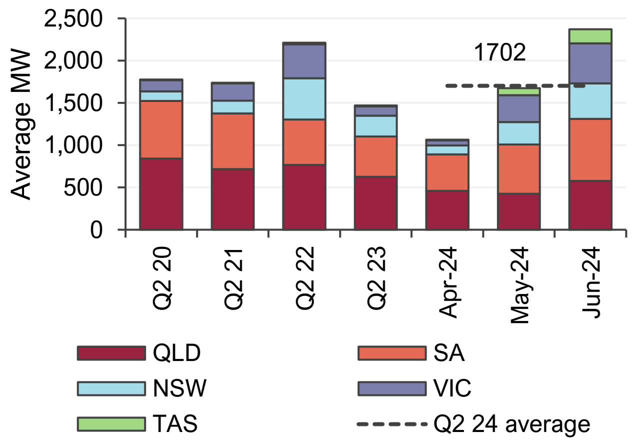
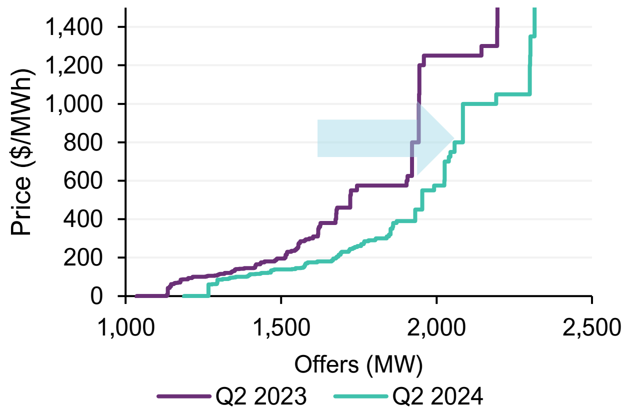


Figure 40 Gas offer volumes increased

Gas-fired generation bid supply curve – Q2 2024 vs Q2 2023

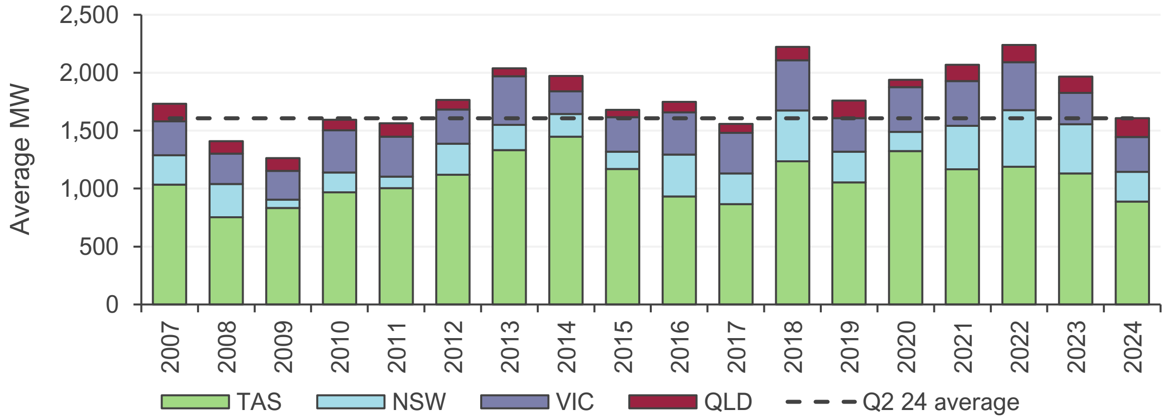


1.3.3 Hydro

In Q2 2024, quarterly hydro generation[17] fell 360 MW (-18%) to 1,607 MW, down from 1,967 MW in Q2 2023 and the lowest Q2 average since 2017 (Figure 41).

Figure 41 Hydro generation dropped in New South Wales and Tasmania

Average hydro output by region – Q2s



Tasmania saw the largest decrease in hydro generation out of all the NEM regions, with a 243 MW (-21%) reduction from 1,130 MW in Q2 2023 to 887 MW this quarter. Energy in storage across Tasmania's hydro systems were at 31.5% of full energy storage capacity at the end of Q2 2024, compared to 40.5% at the end of Q2 2023.[18] (Figure 42).

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

[18] See https://www.hydro.com.au/water.

New South Wales hydro generation also fell, by 168 MW (-39%) to reach 258 MW. Gross storage levels at Snowy Hydro's three main storages were signficantly down on 2023 levels, with Lake Eucumbene 49% full at the end of the quarter, compared to 62% at the end of Q2 2023[19]. These dam levels contributed to hydro generator operaters reducing lower-priced volumes offered to the market, with around 700 MW less volume offered at prices below $300/MWh (Figure 43).

In contrast, Queensland hydro generation increased by 19 MW (+14%) to average 161 MW over the quarter. Year-on-year increases at Wivenhoe (+33 MW) and Kareeya (+31 MW) were partially offset by a reduction at Barron Gorge (-45 MW) which commenced generating again late in the quarter (unit 1 on 12 June and unit 2 on 21 June) after sustaining damage in a flooding event in December 2023.

Victoria hydro generation also increased in Q2 2024, up 31 MW (+12%) from the previous year to average 301 MW over the quarter, with the increase in output most evident in the the overnight and morning hours, before solar output commenced.

Figure 42 Tasmania hydro storage levels finish quarter at 31.5%

Month end Tasmania energy storage levels in percentage compared to prudent storage level (PSL) and high reliability level (HRL) [20]

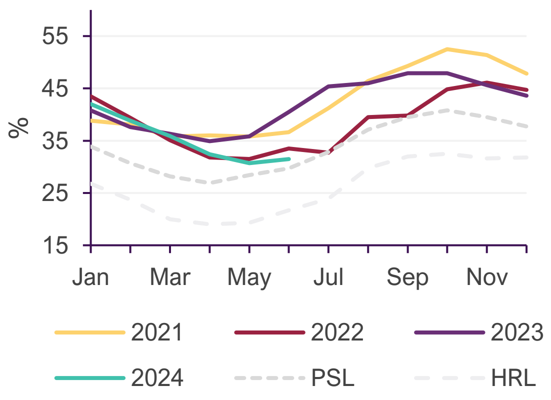
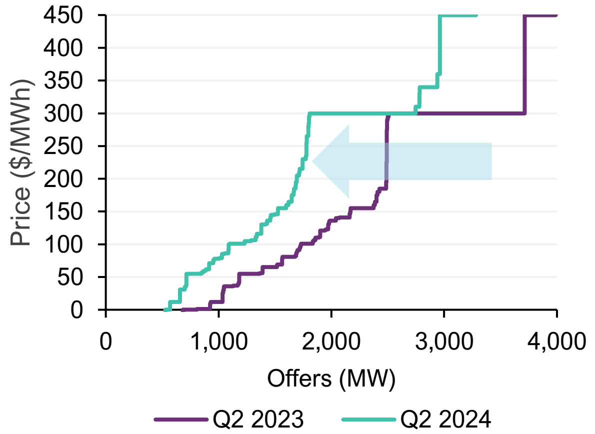


Figure 43 Hydro generation offer volumes declined

Hydro generation bid supply curve – Q2 2024 vs Q2 2023



1.3.4 Wind and grid-scale solar

Grid-scale variable renewable energy (VRE) output averaged 4,074 MW over Q2 2024, a 524 MW (-11%) reduction from Q2 2023's 4,599 MW (Figure 44).

Grid-scale solar output increased 132 MW (+10%) from 1,285 MW in Q2 2023 to 1,417 MW this quarter, mainly due to additional output from new and commissioning facilities in New South Wales.

---

[19] See https://www.snowyhydro.com.au/generation/live-data/lake-levels/.

[20] Tasmanian water storages are monitored by the Tasmanian Economic Regulator (TER) under Tasmania's Energy Security Risk Response Framework, and at this time has increased the frequency of its monitoring due to lower than average seasonal rainfall outlooks. When the storage level remains above the prudent storage level (PSL) Hydro Tasmania is free to operate in a fully commercial manner. See Tasmanian Energy Security Monthly Dashboard | Office of the Tasmanian Economic Regulator

Calm weather conditions drove wind output down to a quarterly average of 2,657 MW, a fall of 657 MW (-20%) from 3,314 MW in Q2 2023 (Figure 45). The decline in wind output was largest in Victoria with a 428 MW (-31%) fall in output to average 940 MW for the quarter.

Figure 44 Significant fall in wind generation

Average quarterly VRE generation by fuel type – Q2s

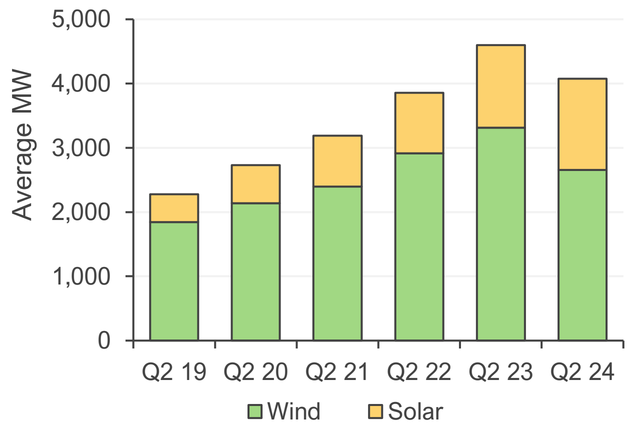
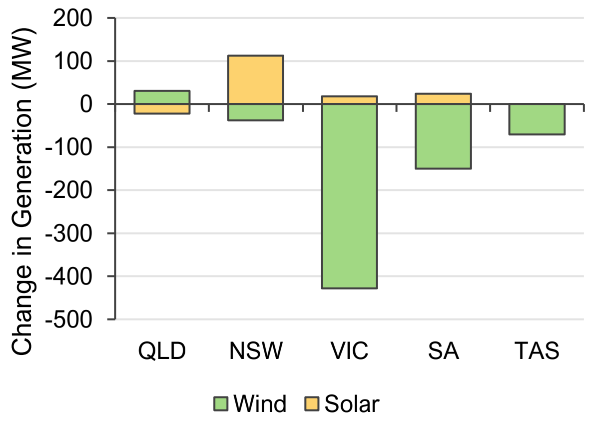


Figure 45 Wind generation dropped in southern regions

Average change in VRE output by region – Q2 2024 vs Q2 2023



Grid-scale solar

Increased VRE generation 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 151 MW increase in average quarterly solar availability from Q2 2023 (Figure 46).

Figure 46 Growth in output at new and commissioning grid-scale solar farms

Changes in grid-scale solar generation – Q2 2024 vs Q2 2023

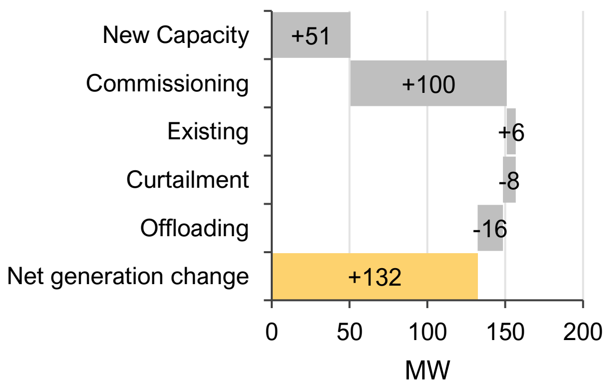
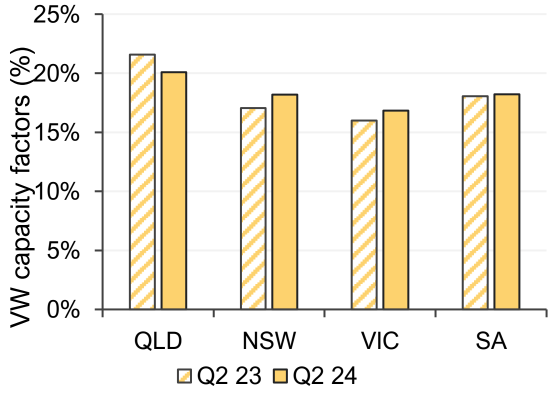


Figure 47 Grid-scale solar availability rose in all regions except Queensland

Volume-weighted grid-scale solar available capacity factors[21] – Q2s



The majority of this increase was in New South Wales, with increases from Avonlie (+34 MW), New England (+28 MW), and Wyalong (+12 MW). Wandoan (+25 MW) and Edenvale (+13 MW) in Queensland, Glenrowan (+ 20 MW) in Victoria and Tailem Bend 2 (+15 MW) in South Australia also contributed to growth in this category. Network curtailment increased slightly, causing a 8 MW decrease in generation compared to Q2 2023. Economic

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

offloading was highest in Queensland, averaging 57 MW this quarter, a 25 MW increase on Q2 2023. This was partially offset by decreases in the other regions yielding a net increase in economic offloading of 16 MW.

Established[22] grid-scale solar facilities showed increases in quarterly volume-weighted available capacity factor[23] in all regions except Queensland, yielding a small net increase in available output (+6 MW) from existing solar farms (Figure 47). Despite the 1.5 pp decrease from Q2 2023, the Queensland fleet still had the NEM's highest available capacity factor at 20.1% this quarter. New South Wales had the largest increase from Q2 2023, with a 1.1 pp rise to average 18.2% over Q2 2024.

Wind

New and commissioning wind farms added 167 MW to the quarter's available wind output, with Rye Park (+94 MW) and Flyers Creek (+16 MW) in New South Wales, and Dulacca (+36 MW) and Kaban (+19 MW) in Queensland accounting for the majority of this growth (Figure 48). Curtailment and economic offloading decreased over the quarter, with curtailment reducing by 28 MW and economic offloading more than halving, reducing by 50 MW to average 28 MW this quarter.

However, these sources of growth were more than offset by a 901 MW reduction in available output from existing generators, causing an overall 657 MW reduction in average quarterly output from Q2 2023 levels.

Established wind capacity across the NEM saw significant reductions in quarterly volume-weighted available capacity factors, with a 9.3 pp reduction in the NEM-wide capacity factor from 34.5% in Q2 2023 to 25.2% this quarter (Figure 49).

Figure 48 Significant reduction in output at existing wind farms

Changes in wind generation – Q2 2024 vs Q2 2023

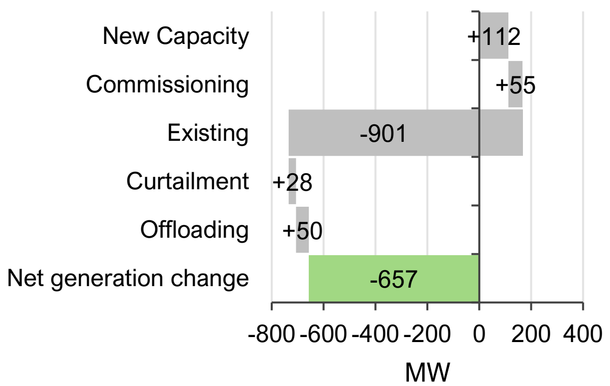


Figure 49 Reduction in wind availability most pronounced in southern regions

Volume-weighted wind available capacity factors – Q2s

Tasmania had the largest reduction in quarterly volume-weighted available capacity factor, with a 13.0 pp fall from Q2 2023's 42.5% to 29.5% over Q2 2024. Victoria experienced the lowest quarterly volume-weighted available

[22] Existing (or established) capacity in this section refers to the wind and grid-scale solar facilities that were fully commissioned prior to the start of Q2 2024. These facilities may also appear in the "New Capacity" or "Commissioning" categories in Figure 46 and Figure 48 if they were connected or exhibited ramping activity between Q2 2023 and Q2 2024 respectively.

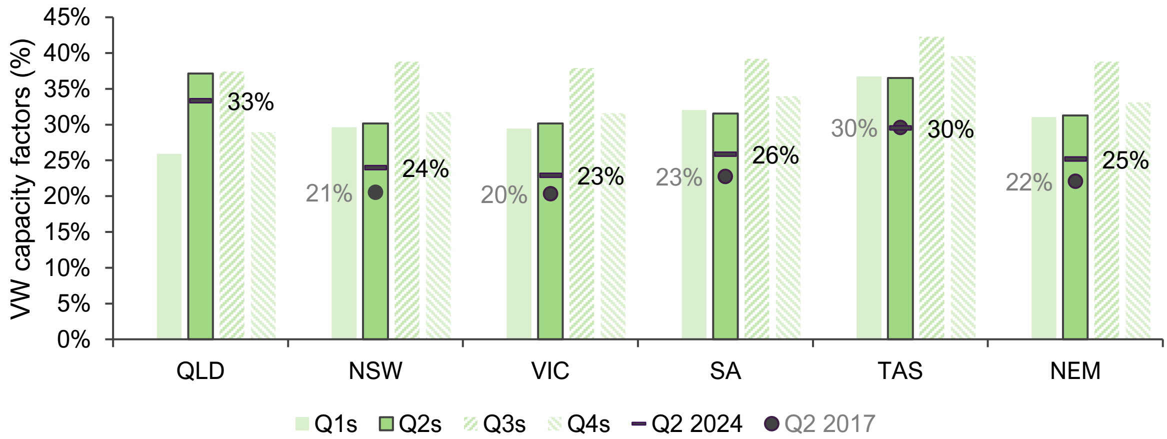
[23] Available capacity factors are calculated using average available energy divided by maximum installed capacity. The use of availability instead of generation output removes the impact of any economic offloading or curtailment and better captures in-service plant capacity and underlying wind or solar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

capacity factor at just 22.9% over this quarter, representing an 11.4 pp reduction from Q2 2023. Established wind capacity in Queensland was the least impacted by the low wind conditons, experiencing a 3.8 pp reduction in quarterly volume-weighted available capacity factor to average 33.3% in Q2 2024.

Figure 50 shows longer-term quarterly average volume-weighted wind available capacity factors for each quarter of the year, for each region and for the NEM overall. For all regions except Queensland the averages are over the period from 2011 to 2024, and the Queensland averages are from 2019 to 2024.

Figure 50 Wind resource in Q2 2024 below long-term average for Q2s, but higher than Q2 2017 wind drought

Average quarterly volume weighted wind available capacity factors – average over 2011-2024, Q2 2024 and Q2 2017



For all regions apart from Queensland, Q1s and Q2s exhibit the lowest wind availability on average, and the five quarters with the lowest NEM-wide wind availability have all occurred in Q1 or Q2: lowest to highest being Q2 2017, Q2 2024, Q1 2016, Q2 2013 and Q1 2024. The top five quarters with the highest NEM-wide wind availability have all occurred in Q3, with Q3s also having the highest long-term average availability.

Queensland wind availability has a different quarterly dynamic, with Q1s and Q4s exhibiting the lowest wind availability on average, and Q2s and Q3s the highest. This Q2 2024 still experienced lower than average wind availability in Queensland, 4 pp lower than the 2019 to 2024 average.

On a NEM-wide basis, Q2 2024 wind availability was particularly low at 25%, 6 pp lower than the Q2 average over 2011 to 2024, but remained 3 pp higher than the lowest wind quarter of Q2 2017.

To give an indication of the impact of the low wind availability experienced this quarter, Figure 51 shows average monthly output in MW over Q2 2024 compared to the two prior Q2s.

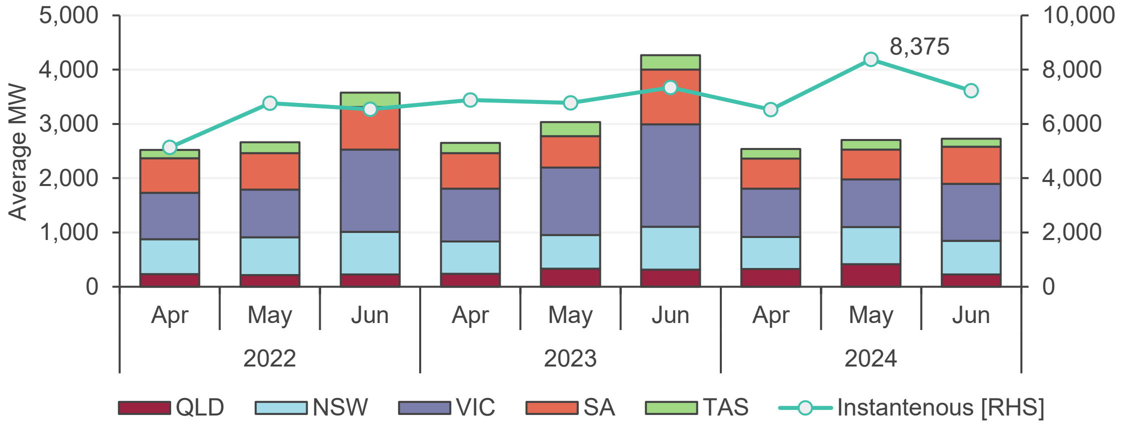
In this time, the maximum capacity of installed wind generation across the NEM has grown – from 9,873 MW in Q2 2022 to 10,303 MW in Q3 2023 to 11,369 MW in Q4 2024 – yet average output fell from 2,916 MW in Q2 2022, and 3,314 MW in Q2 2023 to 2,657 MW this quarter.

The low output over June 2024 was particularly notable, at 2,729 MW, this was 1,538 MW (-36%) lower than the June 2023 average of 4,267 MW, consistent with the low wind speeds noted in Section 1.1.1.

Despite the low average wind conditions, Q2 2024 recorded a half-hourly wind output maximum for the NEM on 30 May. At 8,375 MW, this was 335 MW (+4%) higher than the previous record in Q3 2023.

Figure 51 Average wind generation remained low in all months of Q2 2024, despite reaching a record instantaneous output in May 2024

Average monthly wind generation by region and maximum half-hourly instantaneous NEM-wide monthly wind generation

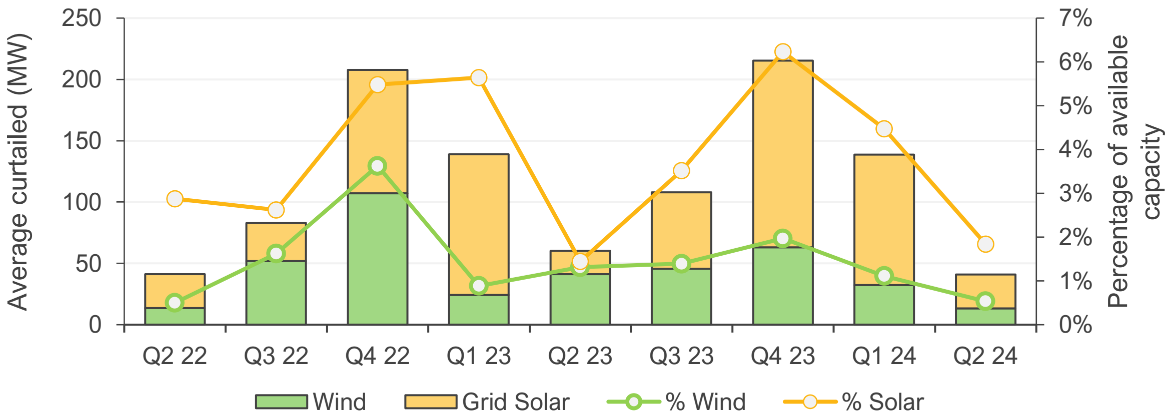


Curtailment

In line with the reduction in wind output, average wind curtailment reduced from 41 MW in Q2 2023 to 13 MW this quarter, representing just 0.5% of quarterly average availability (Figure 52). Grid scale-solar average curtailment increased from 19 MW in Q2 2023 to 28 MW this quarter, representing 1.8% of quarterly average availability.

Figure 52 Curtailment reduced in wind but increased for solar year-on-year

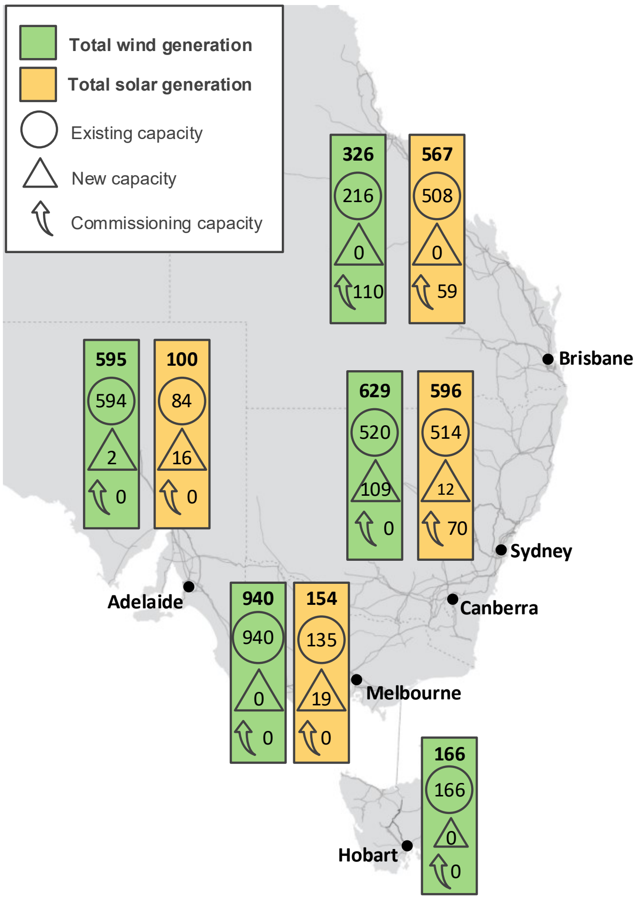
Average MW curtailment and percentage of availability by fuel type



The map in Figure 53 shows a summary representation of VRE output during Q2 2024. Numbers presented in this map are in megawatts and are calculated on a quarterly average basis.

Figure 53 Regional VRE generation summary during Q2 2024

Quarterly average generation (MW) by fuel type and region



1.3.5 Renewables penetration

Instantaneous renewable penetration and peak renewable output

This quarter, the maximum instantaneous share of renewable energy generation in the NEM reached a new Q2 high of 67.1%, a 0.7 pp increase on Q2 2023 (Figure 54). This maximum was achieved during the half-hour ending at 1100 hrs on Tuesday 23 April 2024, with distributed PV being the largest contributor at 34% of total supply. At the same time, VRE including wind and grid-solar reached 8,288 MW, comprising 31% of the total supply.

The year-on-year increase in instantaneous renewable penetration was mainly driven by grid-scale solar and distributed PV, which increased from 12% and 30% in Q2 2023 to 16% and 34% respectively this quarter, while wind's contribution fell by 7 pp. This quarter's maximum penetration was 5.0 pp below the record level of 72.1% set in Q4 2023, due to the seasonal increase in underlying demand between Q4 2023 and Q2 2024. In contrast, renewable potential[24] saw a decrease from 85.6% in Q2 2023 to 78.4% this quarter, 21.3 pp lower than its highest level of 99.7% recorded in Q4 2023.

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

Figure 54 Instantaneous renewable penetration increased year-on-year despite a lower wind contribution

Percentage of NEM supply from renewable energy sources at time of peak instantaneous renewable energy output

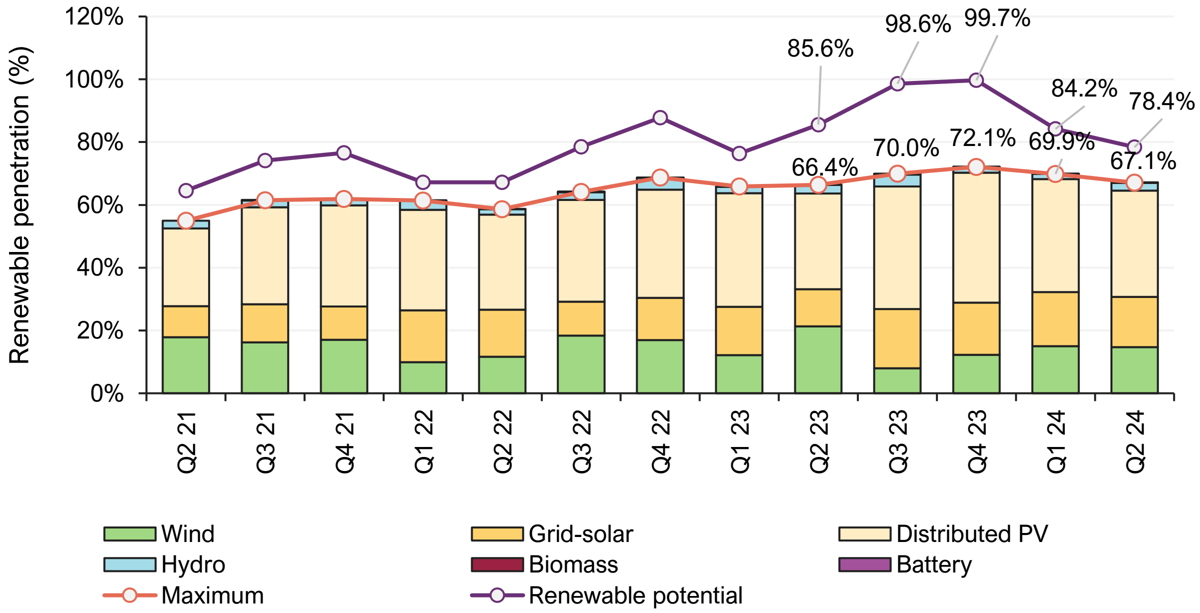


Figure 55 illustrates the range of minimum and maximum instantaneous renewable penetration in meeting NEM demand for the quarter. Over time, this range has steadily increased, reaching a 59.1% swing in Q2 2024. This change is due to both a higher maximum penetration of 67.1% and a lower minimum penetration of 8.0%, compared to previous Q2s. Minimum renewable penetration, influenced by reduced wind contributions, occurred during the half-hour ending at 0430 hrs on Wednesday 5 June 2024.

Figure 55 Instantaneous renewable penetration range widens

Percentage range of NEM supply from renewable energy sources – Q2s

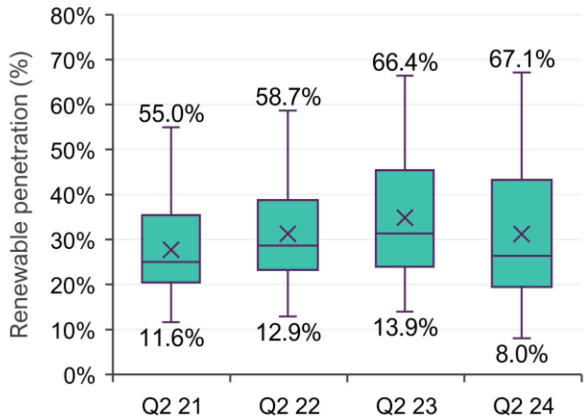


Figure 56 Record high for peak wind output

Maximum quarterly instantaneous generation by fuel type

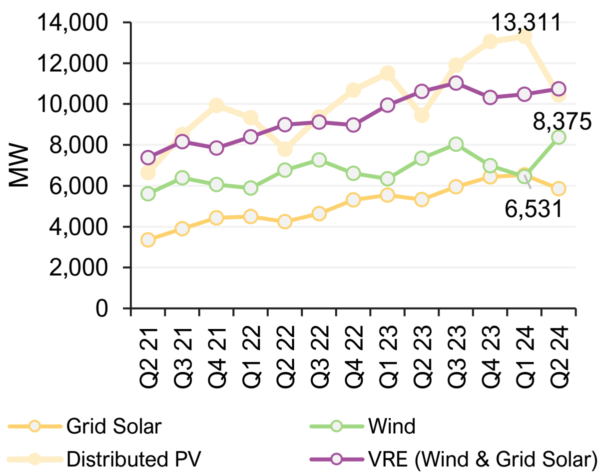


Figure 56 shows the instantaneous maximum outputs achieved by grid-scale solar, wind, and distributed PV for all quarters since Q2 2021. Despite a notably low wind generation during this quarter, some instances of very high wind speeds resulted in a new instantaneous record of 8,375 MW during the half-hour ending at 2130 hrs on Thursday 30 May 2024. This represents a 14% year-on-year increase and a 4% rise from the previous record of

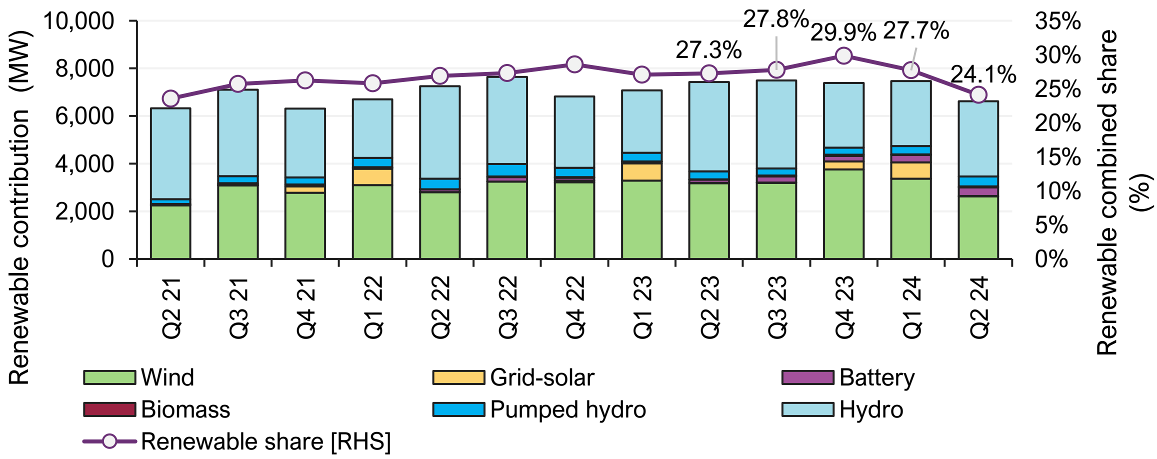
8,040 MW set in Q3 2023. Compared to the same period last year, grid-scale solar and distributed PV instantaneous maximum outputs increased by 10% and 11%, respectively. Due to the seasonality of solar generation these outputs were 10% and 21% lower than the records set in Q1 2024.

Renewable contribution to maximum demand

Figure 57 illustrates the contribution of large-scale renewable generation in meeting the daily maximum NEM operational demand, averaged across all days in each quarter. In Q2 2024, the average renewable contribution to supplying daily maximum operational demand dropped to 24.1%, due to lower wind and hydro sources at 9.6% and 11.5%, respectively. Since the daily maximum demand typically occurs during the evening peak period, when solar contribution is minimal, the decrease in wind and hydro resulted in a 3.2 pp reduction in renewable contribution compared to the same period the previous year. Conversely, battery contributions to meeting daily maximum operational demand increased to 1.3% this quarter, up from 0.5% in Q2 2023.

Figure 57 Low wind saw fall in renewable contribution to meet daily maximum demand, battery share grew

Average renewable contributions (MW) and combined share (%) at time of daily maximum operational demand – Quarterly



1.3.6 NEM emissions

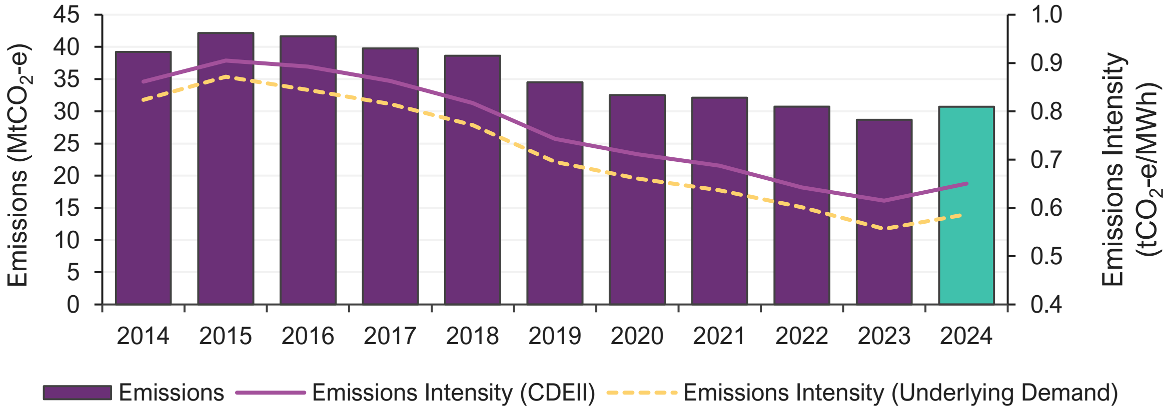
During Q2 2024, NEM total emissions increased by 2.0 million tonnes of carbon dioxide equivalent (MtCO2-e) on Q2 2023 levels, reaching 30.7 MtCO2-e (Figure 58). The Carbon Dioxide Equivalent Intensity Index (CDEII) emissions intensity combines sent out metering data with publicly-available generator emission and efficiency data to provide a NEM-wide CDEII[25]. This emissions intensity excludes generation from distributed PV, taking into consideration only sent out generation from market generating units. During this quarter, CDEII Emissions intensity rose to 0.65, from 0.61 in Q2 2023 due to the low wind and hydro generation over the quarter increasing the volume share of coal and gas-fired generation.

Using underlying demand to calculate an emissions intensity gives an indication of the impact of distributed PV on NEM-wide emissions intensity, which at 0.59 for Q2 2024 is 0.06 lower than the CDEII intensity metric.

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

Figure 58 Emissions and emissions intensity increased compared to Q2 2023

Quarterly NEM emissions and intensity – Q2s



1.3.7 Storage

Batteries

Total estimated net revenue for NEM grid-scale batteries this quarter was $41.2 million, an increase of $13.6 million from the $27.7 net revenue earned in Q2 2023 (Figure 59). Energy arbitrage[26] rose $12.5 million (+97%) to $25.4 million, due to a $22.6 million (+117%) uplift in energy revenue (including revenue from charging at negative prices), more than offsetting the $10.0 million (+155%) increase in energy costs.

Frequency control ancillary services (FCAS) revenue remained relatively steady compared to Q2 2023, with just a $1.1 million (7%) increase, leading to a year-on-year decrease in the proportion of overall revenue deriving from the FCAS markets, at 39% in this quarter, down from 54% in the previous year (Figure 60).

Figure 59 Increase in battery revenue from higher energy arbitrage

Quarterly revenue from NEM battery systems by revenue stream

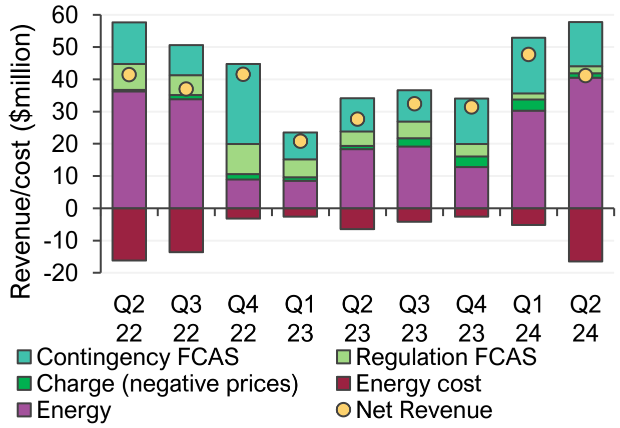
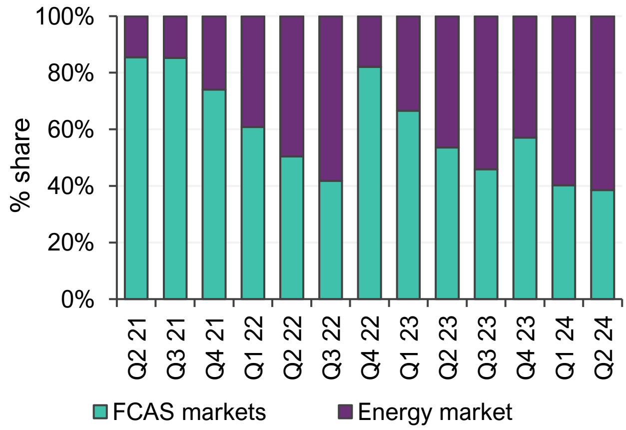


Figure 60 Decrease in proportion of battery revenue from FCAS markets

Percentage share of battery revenue – energy vs FCAS markets



[26] Energy arbitrage revenue for batteries includes three components: 1) revenue from discharging (selling energy), 2) revenue from recharging during negative priced intervals, and 3) cost of recharging at non-negative prices (buying energy).

The main driver for the increased net revenue was growth in battery capacity and availability, with NEM-wide average quarterly battery generation availability almost doubling from 496 MW in Q2 2023 to 985 MW in Q2 2024 (Figure 61).

The majority of net revenue was captured by batteries in New South Wales at $13.4 million, comprising $11.0 million from energy and $2.4 million from FCAS markets, representing a $10.3 million (+341%) increase from Q2 2023's $3.0 million net revenue. This region also had the highest growth rate in quarterly average availability, growing from 54 MW in Q2 2023 to 162 MW in Q2 2024, with Riverina Energy Storage System (ESS) 1, Riverina ESS 2 and Darlington Point ESS entering full operation in Q3 2023.

Queensland batteries had the next highest increase in net revenue, from $4.7 million in Q2 2023 to $10.3 million in this quarter, with most of this revenue arising from contingency FCAS revenue at $6.7 million for the quarter (see Section 1.5).

Figure 62 shows the time of day net revenue profile for NEM batteries for the energy market only. The increase in revenue in the morning and evening peaks this quarter compared to Q2 2023 is evident, driven by the additional battery availability and higher spot prices. Higher energy costs associated with charging offset the increased revenue earned when charging at negative prices (+$0.5 million) to yield a decrease in net revenue outside peak periods.

Figure 61 Increase in battery generation availability

Average quarterly battery generation availability

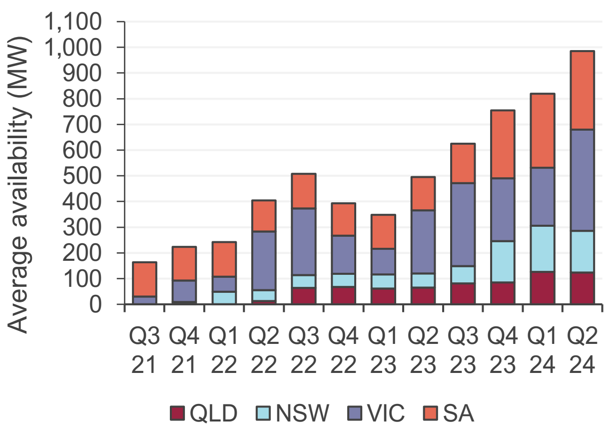
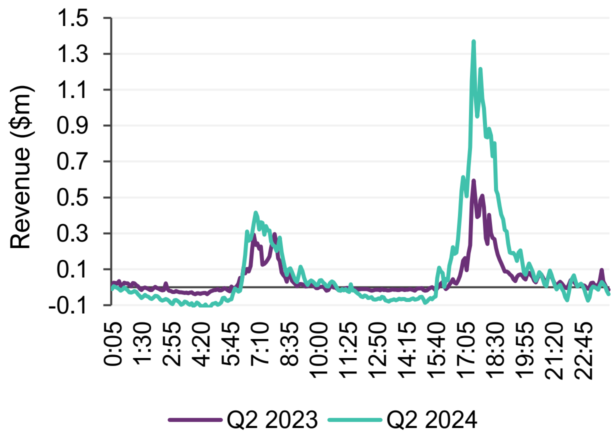


Figure 62 Net battery revenue in energy market rose year-on-year

Battery net revenue by time of day – Q2 2024 vs Q2 2023



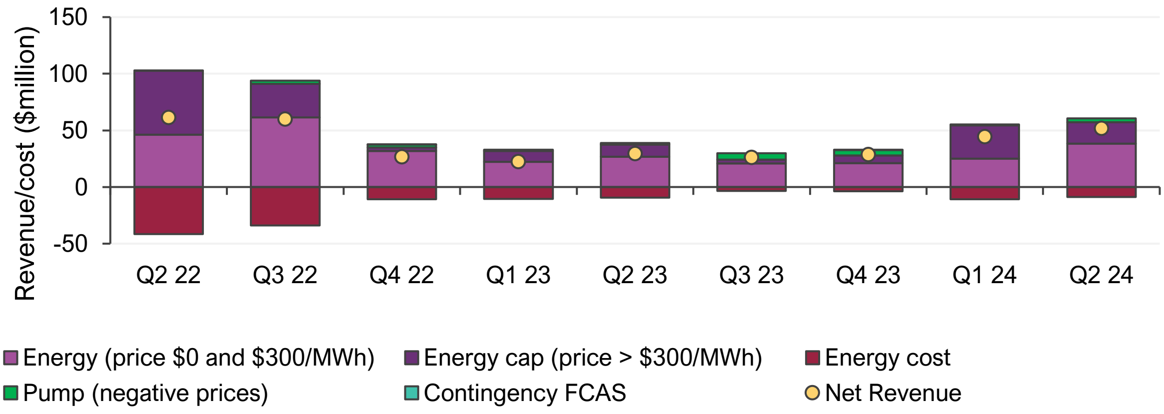
Pumped hydro

Pumped hydro revenue was $51.9 million this quarter, an uplift of $22.4 million (+76%) from Q2 2023 (Figure 63). Increased spot prices drove this increase, particularly spot volatility in New South Wales, with Shoalhaven's revenue from prices above $300/MWh up $14.9 million (+468%) to $18.1 million this quarter. Overall Shoalhaven's estimated net revenue was $24.4 million, a $17.1 million (235%) increase from Q2 2023.

With lower spot volatility in Queensland this quarter, Wivenhoe's revenue from prices above $300/MWh decreased by $6.8 million (-89%), to $0.8 million. However revenue from prices under $300/MWh increased, lifting Wivenhoe's estimated net revenue to $27.5 million, $5.2 million (+23%) more than in Q2 2023.

Figure 63 Pumped hydro revenue increased year-on-year

Quarterly revenue from NEM pumped hydro by revenue stream



1.3.8 Demand side flexibility

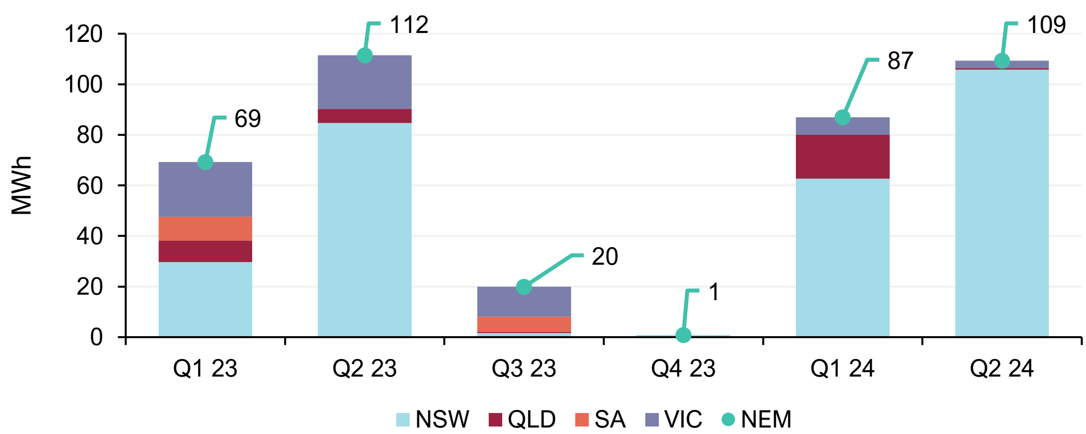
Consumer energy resources (CER) continued to be installed at high rates, with instantaneous distributed PV generation setting a new Q2 high this quarter. In line with this, AEMO continues to facilitate and prioritise initiatives to maximise the value of available assets and infrastructure such as demand side flexibility to smooth a transition from a one-way energy supply chain to a decentralised, two-way energy system. This includes initiatives that enable CER and demand response to provide energy and contingency services.

The wholesale demand response (WDR) mechanism started on 24 October 2021 to allow demand side participation in the wholesale electricity market. Demand Response Service Providers (DRSPs) classify and aggregate the demand response capability of large market loads for dispatch through the NEM's standard bidding and scheduling processes, and receive payment for the dispatched response, against a baseline estimate, at the electricity spot price.

During Q2 2024, WDR saw a total of 109 MWh of energy dispatched over the quarter, a 2% reduction from the 112 MWh in Q2 2023 (Figure 64). The majority of WDR dispatch was from units in New South Wales, with 106 MWh dispatched over the quarter, a 21 MWh (+25%) increase from Q2 2023.

Figure 64 Increased wholesale demand response dispatched in New South Wales

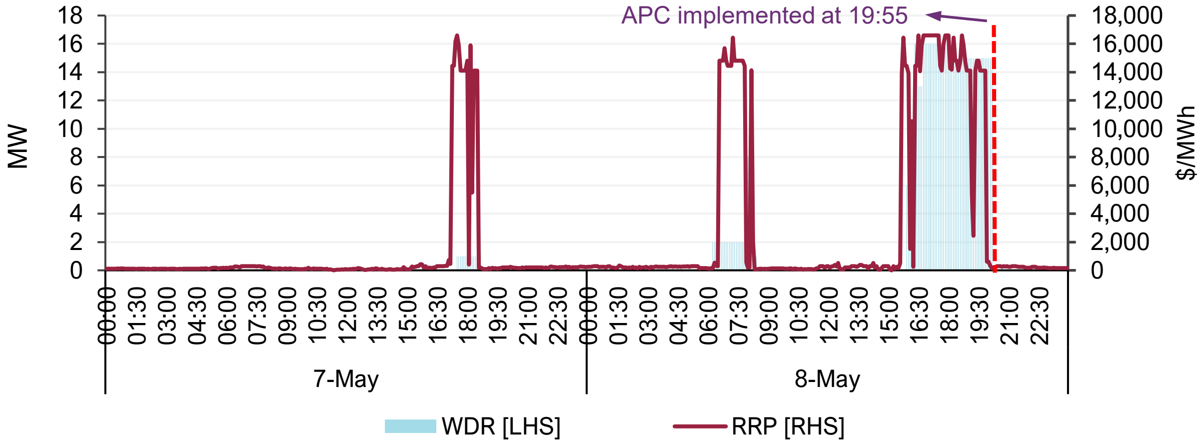
Total quarterly WDR energy dispatch



In the lead up the administered price period in New South Wales discussed in Section 1.2.2, 69 MWh of WDR was dispatched in total on 7 and 8 May 2024 (Figure 65). On 7 May, one unit in New South Wales was dispatched at a maximum output level of 1 MW for 14 intervals, with the New South Wales regional reference price averaging $10,823/MWh over those intervals. On 8 May, up to 4 units were dispatched at different times over 79 dispatch intervals with a maximum combined output level of 16 MW, with the New South Wales regional reference price averaging $11,659/MWh over those intervals.

Figure 65 WDR dispatch in lead up to the administered price period in New South Wales

New South Wales RRP and WDR dispatch during 7 and 8 May



WDR units were also dispatched in New South Wales on 3 May, 20 May and 13 June 2024. Outside New South Wales, low price volatiity meant that WDR dispatch was infrequent, with one unit in Queensland dispatched for 8 intervals on 20 May 2024, and one unit in Victoria dispatched for 8 intervals on 13 June 2024.

1.3.9 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[27] 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 Q2 2024, AEMO's snapshot of connection activities in progress shows that:

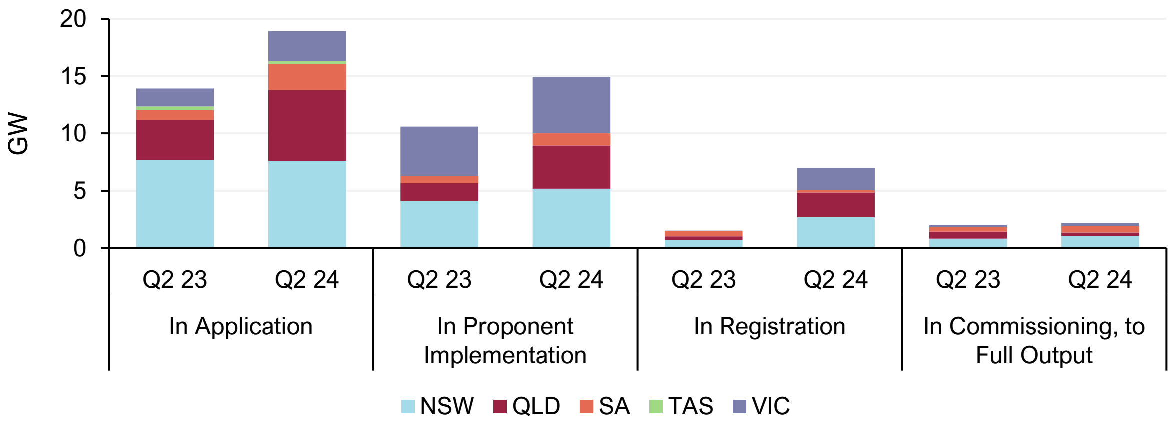
- There was 43 GW of new capacity progressing through the end-to-end connection process from application to commissioning, a 50% increase compared to at the end of Q2 2023 (Figure 66). Around 40% of this capacity is in New South Wales, 29% in Queensland, 23% in Victoria and 10% in South Australia.
- The majority (79%) of projects are in the early stages of development, in either application or proponent implementation stages. Connection projects in these early stages are 46% solar, 32% battery, 14% wind and 8% hydro.

[27] 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.

- The total capacity of in-progress applications was 18.9 GW, compared with 13.9 GW at the same time last year. Of the current capacity in application stage, 40% are New South Wales projects, 33% Queensland, 14% Victoria, 12% South Australia and 2% Tasmania.
- An additional 15.0 GW of new capacity projects are finalising contracts and under construction (proponent implementation), with 35% of this capacity in New South Wales, 33% in Victoria, 25% in Queensland and 7% in South Australia. This compares to 10.6 GW at the end of Q2 2023.
- There were 27 projects totalling 7.0 GW progressing through registration, compared with 1.5 GW at the end of Q2 2023. Around 40% of this capacity is in New South Wales, 30% in Queensland and 28% in Victoria.
- There was 2.2 GW of new capacity in commissioning to full output, compared to 2.0 GW at the end of Q2 2023. This commissioning measure considers all plant in commissioning up to the plant reaching its full output.

Figure 66 Increased capacity in all stages of the connection pipeline

Connections snapshot as at end Q2 for 2023 and 2024



During Q2 2024:

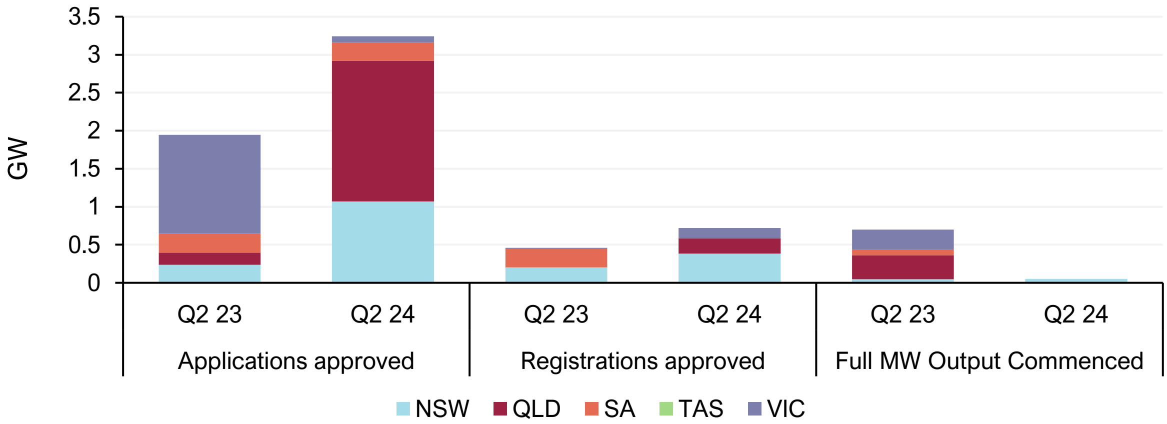
- 3.2 GW of applications were approved across 13 projects (Figure 67), compared with 1.9 GW in Q2 2023. Out of the applications approved, 57% (1.9 GW) were for six Queensland projects, and 33% (1.1 GW) were for five New South Wales projects.
- 0.7 GW of plant was registered and connected to the NEM, in comparison to 0.5 GW registered and connected during Q2 2023.
- 0.05 GW progressed through commissioning to reach full output, compared with 0.7 GW in Q2 2023.

The Connections Scorecard is published monthly and contains further information[28].

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

Figure 67 Increase in connection application approvals

Comparison of applications approved, registrations, and commissioning in Q2 for 2023 and 2024

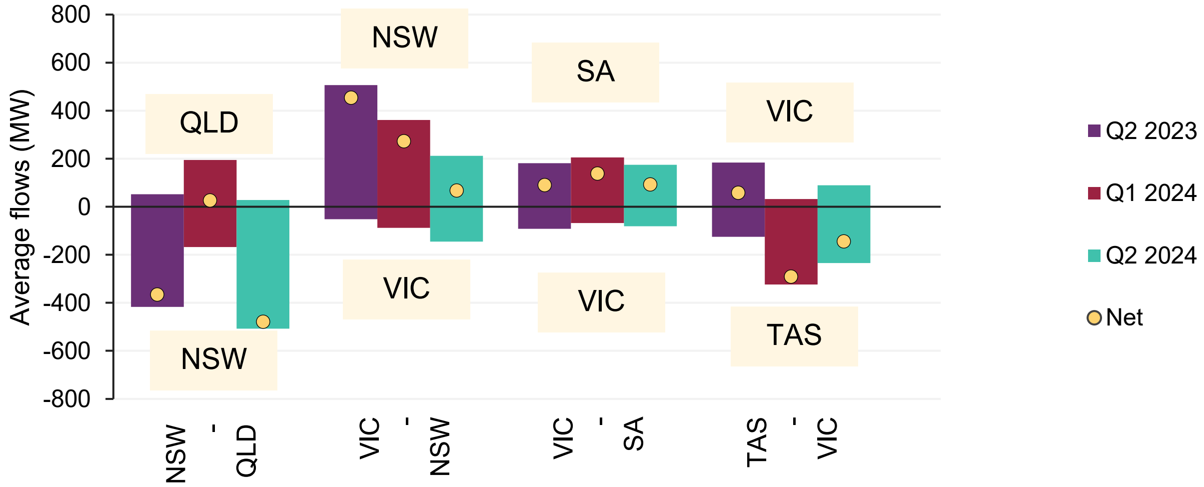


1.4 Inter-regional transfers

Total gross inter-regional energy transfers during Q2 2024 were 3,212 gigawatt hours (GWh), a 304 GWh (-9%) decrease from 3,517 GWh in Q2 2023. There was a marked southward shift in the direction of energy transfers relative to Q2 2023, with average net flows from Victoria to New South Wales falling from 455 MW to 68 MW, average flows between Victoria and Tasmania swinging from 59 MW northward in Q2 2023 to 144 MW southward this Q2, and average net flows from Queensland to New South Wales increasing from 364 MW to 478 MW (Figure 68). These changes were all consistent with this quarter's strong spot price increases in southern NEM regions relative to the smaller price movements in Queensland and New South Wales (Section 1.2).

Figure 68 Southward shifts in inter-regional energy transfers

Quarterly inter-regional transfers



Illustrating these southward shifts, Figure 69 shows average flows on the Victoria – New South Wales Interconnector (VNI) by time of day, with average flows turning southward during the morning peak period. Between 730 hrs and 1200 hrs, average energy prices (capped at $300/MWh) were $103/MWh in Victoria and $76/MWh in New South Wales this Q2, with the corresponding averages for Q2 2023 being $64/MWh and

$77/MWh. As a consequence of these shifts, VNI flows reached binding import limits (New South Wales into Victoria) in 23% of all dispatch intervals this Q2 compared to just 7% in Q2 2023 (Figure 70). This was the highest incidence of VNI import limits binding for any quarter since Q3 2019.

Figure 69 Average VNI flows shift southward

Average VNI flow by time of day

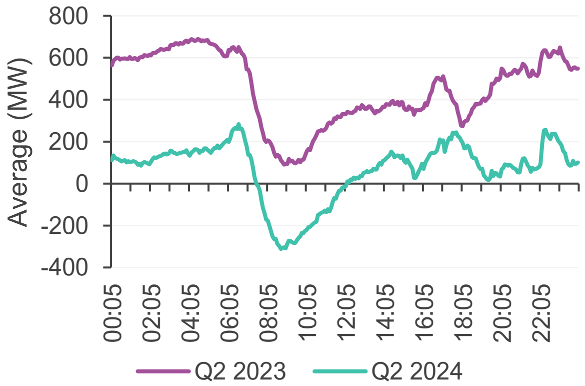
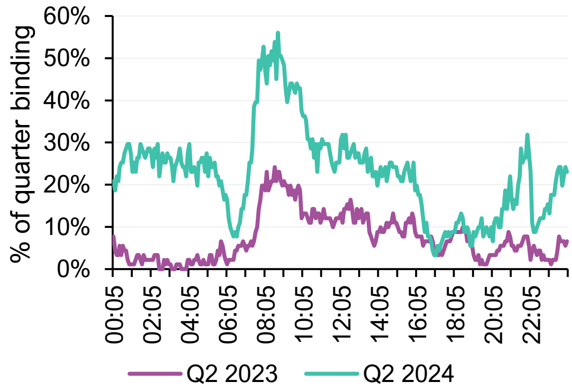


Figure 70 VNI southward limits bind more frequently

Proportion of intervals with binding VNI import limit by time of day



The equivalent charts for QNI show that there was limited scope for higher southward flows during peak daytime hours (Figure 71), as the interconnector very frequently binds at its transfer limits when solar generation is plentiful in Queensland and prices are correspondingly low (Figure 72). The increase in net southward energy transfers this Q2 was entirely associated with higher average transfers to New South Wales outside the period 0800 hrs to 1600 hrs, with southward flows at their limit within this time window for 52% of intervals this Q2 and 44% in Q2 2023.

Figure 71 Queensland to New South Wales flows increase outside daylight hours

Average QNI flow by time of day

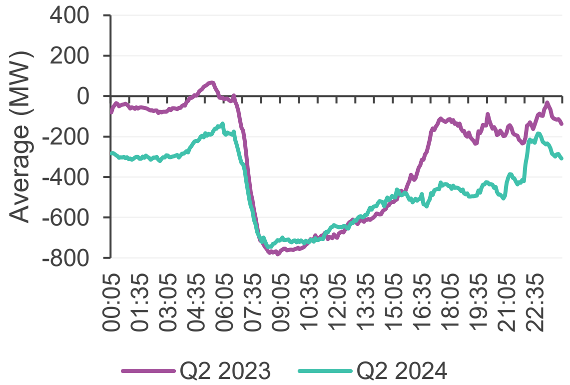
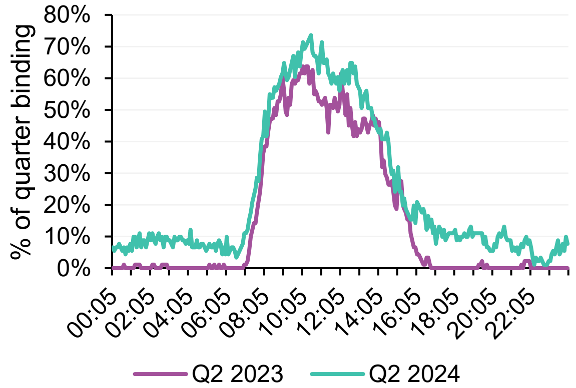


Figure 72 QNI daytime flows frequently hit southward limits

Proportion of intervals with binding QNI import limit by time of day

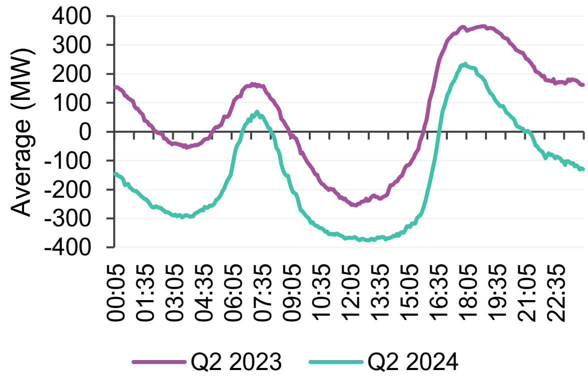


Flows between Victoria and Tasmania across the Basslink interconnector also shifted strongly southward in Q2 (Figure 73). Dry conditions led to reduced Tasmanian hydro output to preserve water storage levels, and lower wind generation further increased reliance on energy imports from the mainland.

Tasmania imported an average of 144 MW across Basslink this Q2, compared to an average export of 59 MW in Q2 2023. This was the highest Q2 level for Tasmanian energy imports since 2009. Basslink carried energy into Tasmania in 69% of dispatch intervals this Q2, up from 40% in Q2 2023.

Figure 73 Basslink flows shifted strongly southward

Average Basslink flow by time of day



1.4.1 Inter-regional settlement residue

Positive inter-regional settlement residue (IRSR) totalled $143 million in Q2 2024, the highest total for the last seven quarters (Figure 74). Residues on flows into New South Wales accounted for $119 million or 83% of the total, with $103 million of this being accumulated on flows from Queensland due to that region's lower prices than those in New South Wales. Over half of this $103 million arose during isolated price volatility episodes in New South Wales on 7 to 8 May 2024 as QNI transferred energy southward from the relatively low-priced Queensland region (Section 1.2.2). In contrast, transmission limitations in southern New South Wales meant that VNI was unable to transfer any significant energy into New South Wales during these events.

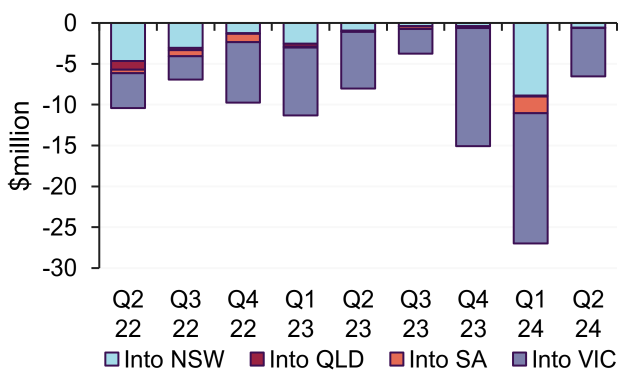
Negative IRSR reduced from its high levels in the last two quarters, totalling -$7 million in Q2 2024, similar to Q2 2023's -$8 million (Figure 75). As in all recent quarters, counter price flows into Victoria from New South Wales across VNI accounted for the bulk of the total, at -$6 million this Q2. With a scheduled line outage reducing transmission capacity between Yass and central New South Wales for most of the quarter, nearly two thirds of the negative residues on VNI accumulated over the high price events of 7 to 8 May 2024. During these events, large counter price energy flows out of New South Wales into Victoria occurred as southern New South Wales generators bid at the market floor price to maximise dispatched output, not all of which could be transferred northwards due to the line outage.

Figure 74 Large positive settlement residues into NSW

Quarterly positive IRSR values

Figure 75 Negative settlement residues reduce

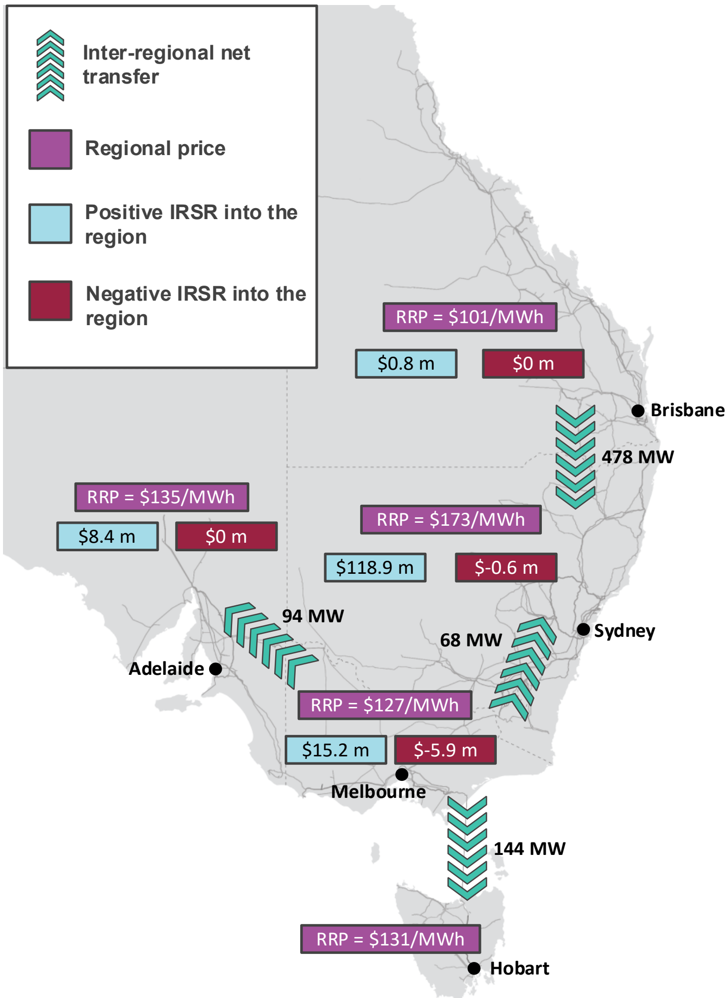
Quarterly negative IRSR values



The map in Figure 76 shows a summary representation of inter-regional exchanges during Q2 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 76 Inter-regional transfers, regional reference price, and settlement residues in Q2 2024

Quarterly average net inter-regional transfer (MW), quarterly average regional reference price ($/MWh), and quarterly total IRSRs per region ($ million)



1.5 Frequency control ancillary services

Total FCAS costs for the quarter were $45 million, representing a $6 million increase compared to Q2 2023 and a $16 million increase from Q1 2024 (Figure 77). All regions experienced a reduction in FCAS costs relative to Q2 2023, except for Queensland, which saw a significant increase of $19 million, bringing its total cost to $30 million for this quarter. Most of this increase was attributable to Queensland's contingency lower 6-second (L6SE) costs, which surged from just $0.3 million in Q2 2023 to $23 million this quarter, with $21 million incurred on 7 and 8 May.

L6SE contributed $24 million, or 54%, to total NEM FCAS costs this Q2 (Figure 78), up $23 million year-on-year.

Figure 77 FCAS costs reduced across all regions except Queensland

Quarterly FCAS costs by region

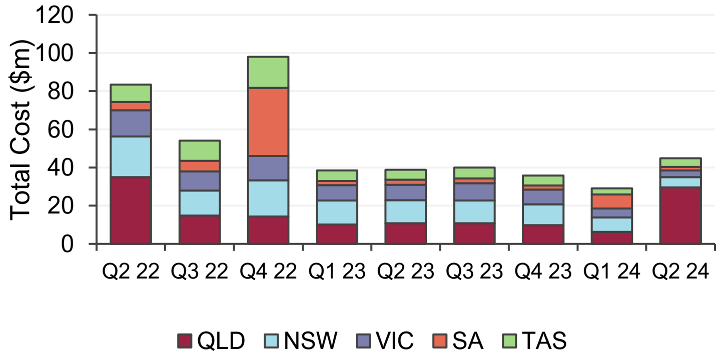
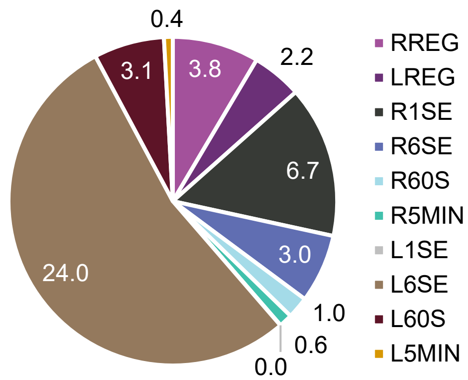


Figure 78 L6SE contributed more than half of the total FCAS costs

NEM quarterly FCAS cost by market – Q2 2024 ($m)

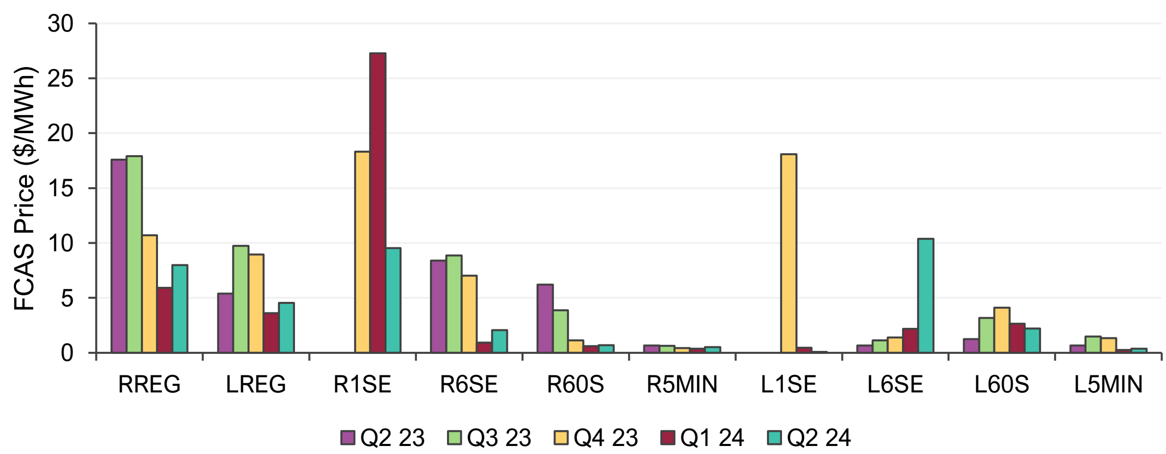


In this quarter, the NEM-wide average quarterly price for L6SE increased significantly to an average of $10.4/MWh from $0.7/MWh in Q2 2023 (Figure 79). This increase was more pronounced in Queensland, driven primarily by network constraints that raised the local L6SE requirement. Specifically, on 7 and 8 May, this led to significant spikes in daily average L6SE prices in Queensland, reaching $718/MWh and $3,180/MWh respectively on those days.

In addition to the NEM-wide average L6SE price, contingency raise 1-second (R1SE) remained notably higher than prices for other FCAS contingency services. Since the introduction of very fast FCAS markets in Q4 2023, the NEM-wide average quarterly prices for R1SE and contingency lower 1-second (L1SE) have continued to decline, averaging $9.5/MWh and $0.1/MWh respectively in Q2 2024.

Figure 79 Significant increase in L6SE average NEM price while R1SE and L1SE decreased

NEM average FCAS prices by service – quarterly since Q2 2023



In this quarter, batteries remained the predominant technology for providing FCAS, capturing a 52% market share (Figure 80). This was an increase from their 40% share in Q2 2023 but slightly lower than the 57% observed in Q1 2024. The average enablement of batteries rose by 541 MW compared to Q2 2023 (Figure 81). This increase was driven in part by the commencement of new 1-second markets, with batteries accounting for 68% of combined enablement for R1SE and L1SE services. Further year-on-year enablement growth across all regions came from new installations, including Hazelwood (+212 MW), Riverina (+280 MW), and Torrens Island (+209 MW).

In addition to batteries, increased average enablement levels since Q2 2023 were also seen for solar, demand response (DR), and virtual power plants (VPP), with gains of 11 MW, 67 MW, and 116 MW respectively. Most of the growth in DR was attributed to the R1SE service with a 52 MW increase in enablement, while VPP enablement saw a 46 MW increase across both the R1SE and L1SE services.

Figure 80 Batteries further grew FCAS market share

FCAS volume market share by technology – Q2 2024

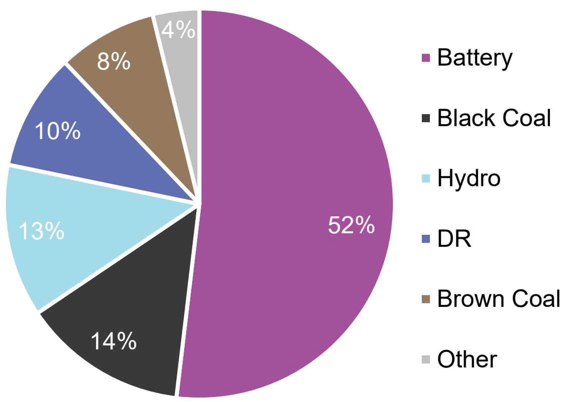
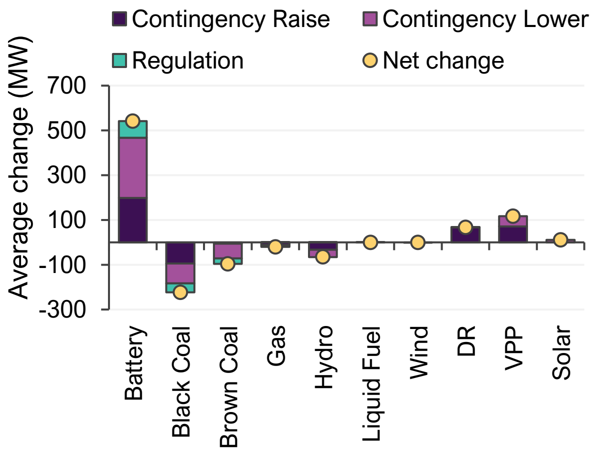


Figure 81 Increased enablement for batteries

Change in FCAS enablement by technology – Q2 2024 vs Q2 2023



Very fast frequency response market

The very fast FCAS markets commenced operation on 9 October 2023 at 1:00 pm (market time) and continued transitioning to full uncapped market operation during this quarter. On 15 April 2024, the caps on the R1SE and L1SE requirements were increased from 250 MW to 325 MW and from 125 MW to 200 MW, respectively. These caps were further raised to 350 MW and 225 MW on 11 June 2024. The R1SE and L1SE services combined contributed $6.7 million, accounting for 15% of the total FCAS costs in Q2 2024.

The R1SE enablement averaged 277 MW over the quarter, while availability averaged 654 MW (Figure 82). For the L1SE service, enablement averaged 27 MW, with availability averaging 513 MW (Figure 83). Several providers increased their offered availability to both the R1SE and L1SE markets compared to Q1 2024. Notable increases include Victorian Big Battery (+112 MW for R1SE and +95 MW for L1SE), Hazelwood Battery Energy Storage System (BESS, +41 MW for R1SE and +40 MW for L1SE), and Riverina (+33 MW for R1SE and +30 MW for L1SE).

Monthly NEM-wide prices for R1SE began the quarter averaging $8.8/MWh in April, rose to $12.1/MWh in May, and then decreased to an average of $7.5/MWh in June. Throughout the quarter, monthly NEM-wide average prices for L1SE remained below $1/MWh, with the underlying requirement for L1SE staying well under the cap.

Figure 82 R1SE enabled closer to the cap

Average R1SE cap, enablement, actual availability, and price

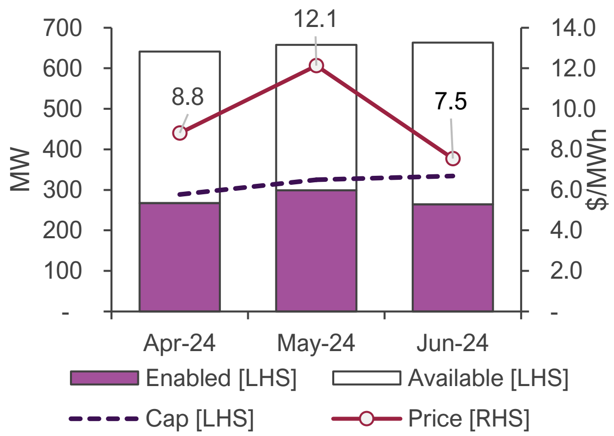
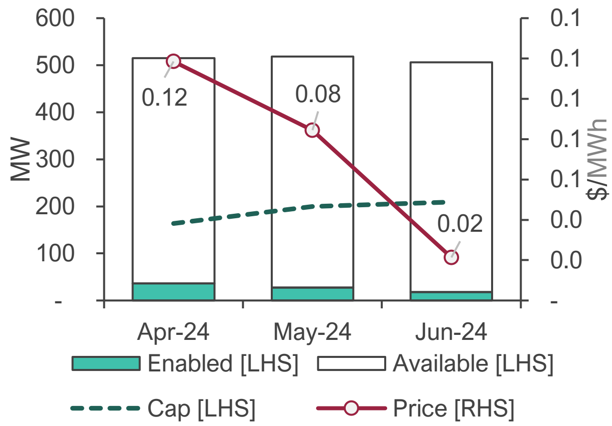


Figure 83 L1SE price remained low throughout the quarter

Average L1SE cap, enablement, actual availability, and price

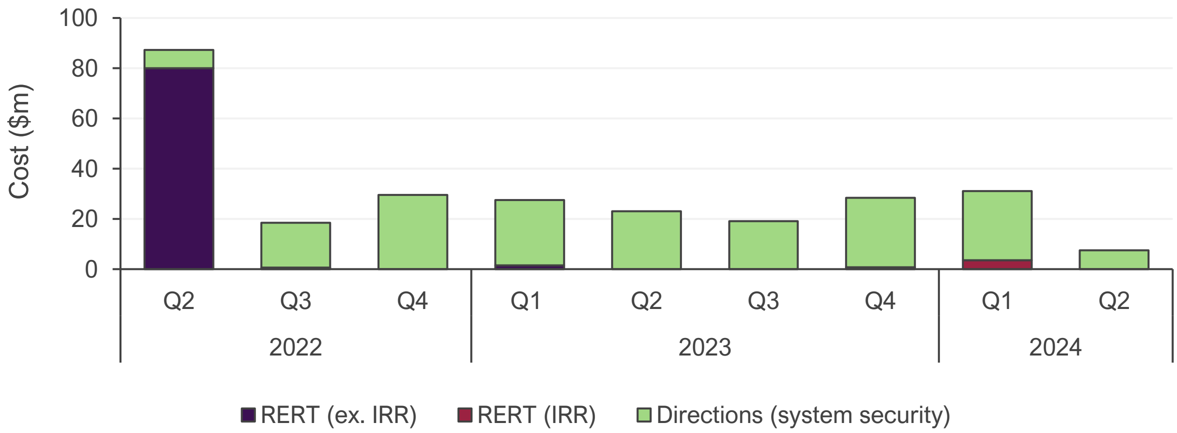


1.6 Power system management

In Q2 2024, estimated power system management costs were $7.5 million, all attributable to system security directions (Figure 84). This represented a reduction of $15.6 million (-68%) from the Q2 2023 costs of $23.1 million, which were also all due to system security directions. In contrast to Q2 2022, no Reliability and Emergence Reserve Trader (RERT) costs were incurred in Q2 2023 or Q2 2024.

Figure 84 System security costs down in Q2 2024

Estimated quarterly system security costs by category



1.6.1 South Australian system security directions

In Q2 2024, South Australian gas-fired generators increased their output in response to the relatively low VRE output and higher spot prices. This led to a decrease in directions required to maintain minimum synchronous generation levels to ensure system security, with directions in place for 21% of dispatch intervals over Q2 2024, compared to 36% in Q2 2023 (Figure 85).

The directed proportion of gas-fired generation in South Australia consequently decreased, with the directed proportion of total quarterly output halving from 6% in Q2 2023 to 3% in this quarter, and the average directed volume almost halving from 29 MW in Q2 2023 to 15 MW in this quarter (Figure 86). These reductions in the frequency and volume of directions, along with the decrease in compensation prices paid to directed participants from $337/MWh[29] in Q2 2023 to $179/MWh in Q2 2024, led to the reduction in overall costs shown in Figure 85.

Figure 85 Decline in South Australian direction hours and costs

South Australia system security directions – time and estimated costs

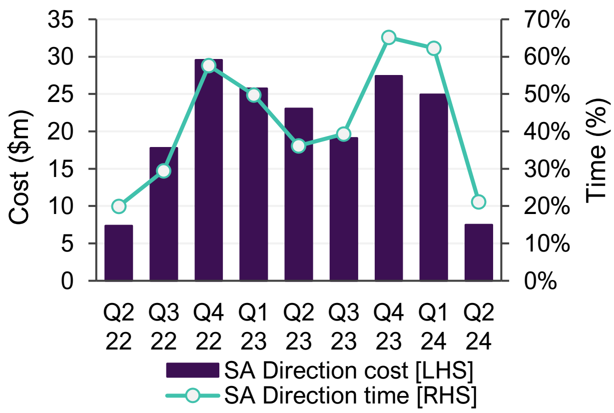
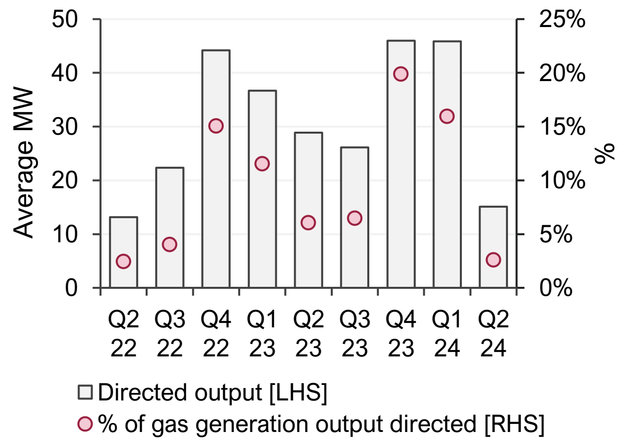


Figure 86 Reduction in share of directed South Australian gas volumes

South Australian gas-fired generation directed – volume and share



29 Directed generators receive a compensation price calculated as the 90th percentile of spot prices over a trailing 12-month window.

2 Gas market dynamics

2.1 Wholesale gas prices

Quarterly average wholesale gas prices increased compared to Q1 2024 but were 4% lower than Q2 2023. The average price across all AEMO markets was $13.66/GJ compared to $14.21/GJ in Q2 2023 (Table 4).

Table 4 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q2 2024	Q1 2024	Q2 2023	Change from Q2 2023
Declared Wholesale Gas Market (DWGM)	13.60	11.19	13.89	-2%
Adelaide	13.86	11.65	15.18	-9%
Brisbane	13.66	11.80	14.39	-5%
Sydney	13.94	11.71	14.76	-6%
Gas Supply Hub (GSH)	13.21	11.62	13.06	+1%

Key factors influencing the movement of prices throughout Q2 2024 are summarised in Table 5, with further analysis and discussion referred to relevant sections elsewhere in this report.

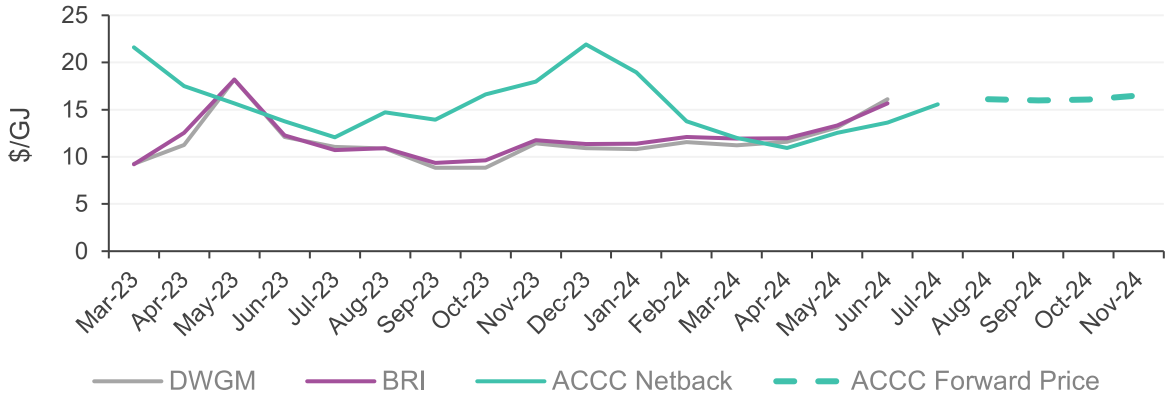
Table 5 Wholesale gas price levels: Q2 2024 drivers

Lower offer prices into DWGM and Short Term Trading Market (STTM) in April and May, but higher prices in June	Q2 2024 saw average prices in May 27% lower than Q2 2023, due to an increase in the proportion of volumes offered into the domestic spot markets at prices below $12/GJ which led to a reduction in the average price for the whole quarter (Figure 87). June 2024 offers were influenced by increased gas-fired generation demand, colder weather, unplanned Longford capacity reduction, record gas flows south from Queensland, and rapid emptying of Iona UGS storage inventory to supply southern markets. This led to higher prices for June compared to 2023, which experienced lower gas-fired generation demand and milder temperatures.
Higher gas-fired generation demand in June	Demand from gas-fired generation increased in May and saw further increases in June due to colder weather, higher NEM demand and reduced wind generation. This higher demand put upward pressure on spot prices across all AEMO markets. Gas-fired generation demand is discussed in more detail in section 2.2.1.
Increase in Queensland and Iona UGS supply in June	While Longford's declining production has been forecasted for some time, it produced even less than originally anticipated in June due to unplanned offshore maintenance issues. This led to increased reliance on Iona storage and Queensland producers to supply the southern markets, with record southerly flows on the South West Queensland Pipeline (SWQP), which also hit capacity at times during June. This comes after the SWQP capacity has increased by 25% over the last 2 years. This tighter supply/demand balance put upward pressure on domestic prices. More details on the supply situation are covered in section 2.3.

International prices increased during the quarter, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, with corresponding forward prices ranging from $16/GJ to $18/GJ over the next 6 months (Figure 87). Drivers for international prices are discussed in Section 2.1.1

Figure 87 Domestic prices increased during Q2 2024 staying marginally higher than international gas prices

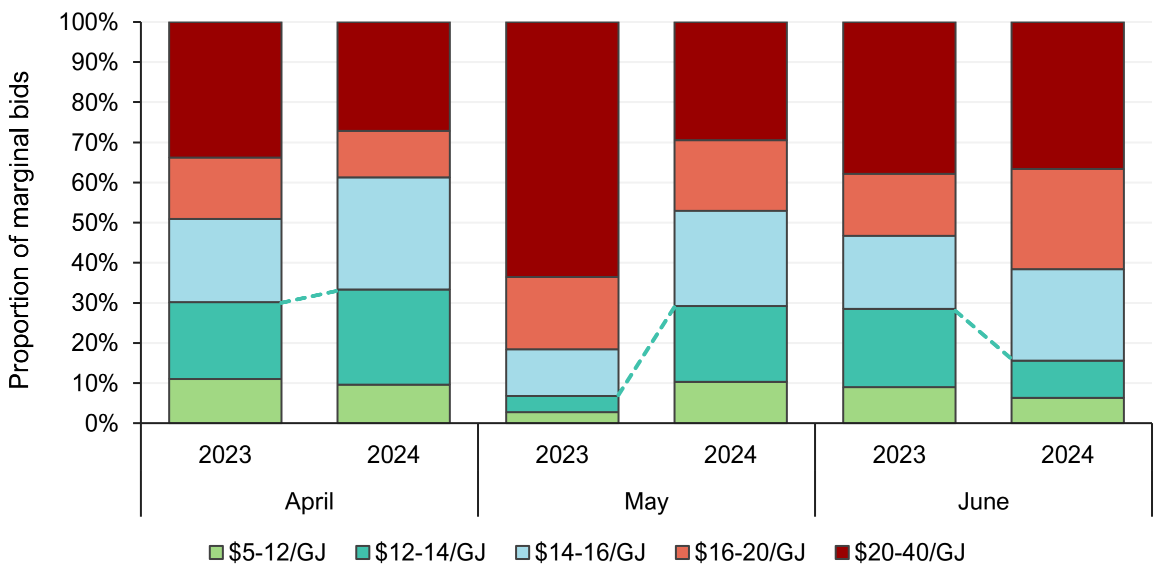
ACCC netback and forward prices[30], DWGM and Short Term Trading Market (STTM) Brisbane average gas prices by month



In contrast to Q2 2023, where average prices peaked in May before easing in June, prices increased considerably in June 2024, peaking at $28/GJ in DWGM and $27.95/GJ in Sydney on 20 June. The biggest contributing factor to this increase was gas-fired generation, which had been elevated in May 2023 before easing in June, when AEMO markets experienced above average temperatures and coal-fired generation availability improved. By contrast, in Q2 2024 gas-fired generation began increasing from mid-May then increased again in June (see section 2.2.1), leading to a very high drawn down of Iona storage inventory and record levels of supply from Queensland to southern markets. This shift in supply-demand balance in June is reflected in market participants increasing bid volumes priced between $14/GJ and $20/GJ (Figure 88).

Figure 88 More DWGM bids at lower prices in May 2024, but relativities reverse in June

DWGM – proportion of marginal bids[31] by price band – Q2 2024 vs Q2 2023 by month



---

30 ACCC 2023, LNG netback price series, https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

31 Bids between $5/GJ and $40/GJ.

2.1.1 International energy prices

Newcastle export coal prices averaged $207/tonne in the quarter, up from $193/tonne in Q1 2023 but down from $240/tonne in Q2 2023 (Figure 89). Prices increased in May 2024, reaching $225/ due to tight supply demand conditions with high demand in China and reduced production from Russian coal producers[32], before finishing the quarter at $198/tonne.

Figure 89 Traded thermal coal prices

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

Source: Bloomberg ICE data

Asian spot LNG prices rose consistently during the quarter due to supply constraints and increased demand for power generation (Figure 90). Both Gorgon[33] and Wheatstone[34] experienced temporary outages in LNG production in May and June, reducing supply to the market. Indian LNG buyers were particularly active as demand surged[35] amidst a severe heatwave necessitating increased gas-powered electricity generation to support their national grid. Temperatures soared in Delhi to a peak of 52.3°C, with 37 other cities in India recording temperatures above 45°C[36]. Despite these factors influencing prices, Chinese buyers continued robust LNG imports on the spot market[37]. European LNG storage is in a very healthy position ending the quarter at 77.4% of max capacity[38].

This quarter, Brent Crude prices averaged A$129/barrel, marking an A$5/barrel increase from last quarter (Figure 91). Despite this modest uptick, the International Energy Agency (IEA) has a bearish sentiment towards global oil

---

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

[33] Argus, 2024: https://www.argusmedia.com/en/news-and-insights/latest-market-news/2565654-australia-s-gorgon-lng-train-to-be-out-for-five-weeks.

[34] S&P Global, 2024: https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/lng/062024-australian-wheatstone-lngs-two-trains-to-reach-full-output-by-june-21-sources.

[35] Reuters, 2024: https://www.reuters.com/markets/commodities/extreme-asian-heat-spurs-lng-demand-ahead-summer-months-2024-05-31/.

[36] BBC, 2024: https://www.bbc.com/news/articles/c166xxd4y36o.

[37] Reuters, 2024: https://www.reuters.com/markets/commodities/china-imports-more-lng-not-enough-drive-spot-prices-russell-2023-07-06/.

[38] Energy Dashboard Switzerland, 2024: https://www.energiedashboard.admin.ch/gas/eu-gasspeicher.

consumption, influenced by subdued global economies and growing adoption of cleaner energy alternatives. In response, OPEC+ has outlined plans to gradually reduce voluntary supply additions, starting from Q4 2024 through to Q3 2025[39].

Figure 90 Asian spot LNG prices increased throughout the quarter on the back of some supply constraints and high demand for power generation

Asian LNG price in A$/GJ daily

Source: Bloomberg ICE data

Figure 91 Brent Crude prices averaged AU$129/barrel

Brent Crude oil in A$/Barrel daily

Source: Bloomberg ICE data

[39] IEA, 2024: https://www.iea.org/reports/oil-market-report-june-2024.

2.2 Gas demand

While total east coast gas demand was only slightly higher compared to Q2 2023 (Figure 92 and Table 6), there were decreases in AEMO markets (-3 PJ), offset by increases in gas-fired generation (+5 PJ) and a small increase in demand for Queensland LNG production (+2 PJ). While all AEMO markets experienced demand decreases, Victoria's Declared Wholesale Gas Market (DWGM) recorded a decrease of 2 PJ despite lower temperatures, particularly in June, which was Melbourne's coldest since 2007 but still yielded lower residential and commercial and industrial demand than June 2023. The decrease is being driven by lower commercial and industrial demand, as well as softer residential demand, a pattern also observed in Q1 2024. Adelaide hub demand also decreased by 5 TJ, despite this quarter being significantly colder than Q2 2023.

Figure 92 Gas generation and LNG export increases offset AEMO market demand decrease

Components of east coast gas demand change – Q2 2024 to Q2 2023

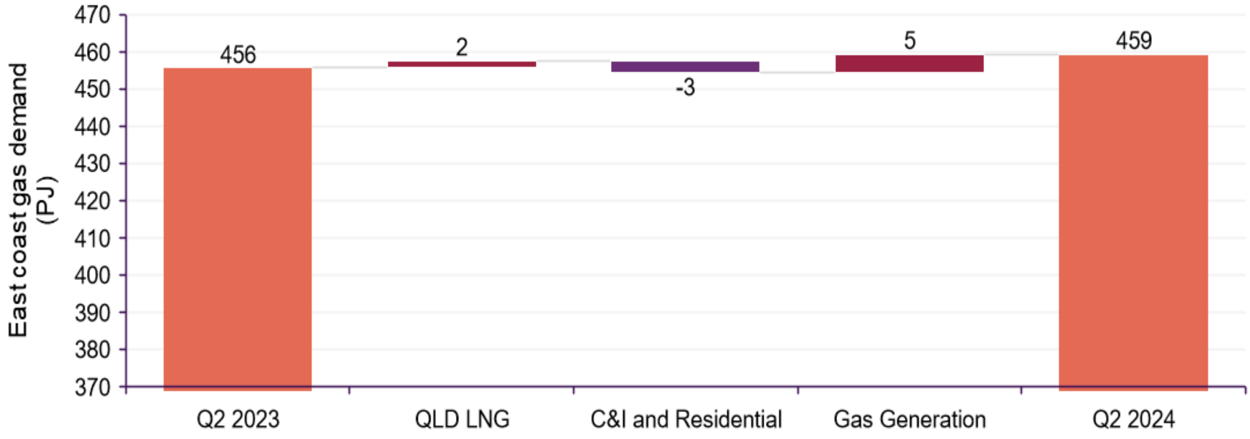


Table 6 Gas demand – quarterly comparison

Demand (PJ)	Q2 2024	Q1 2024	Q2 2023	Change from Q2 2023
AEMO markets *	84.3	46.2	87.5	-3 (-4%)
Gas-fired generation **	34.0	20.0	28.9	+5 (18%)
Queensland LNG	341.0	369.32	339.2	+2 (1%)
Total	459.4	435.5	455.7	+4 (1%)

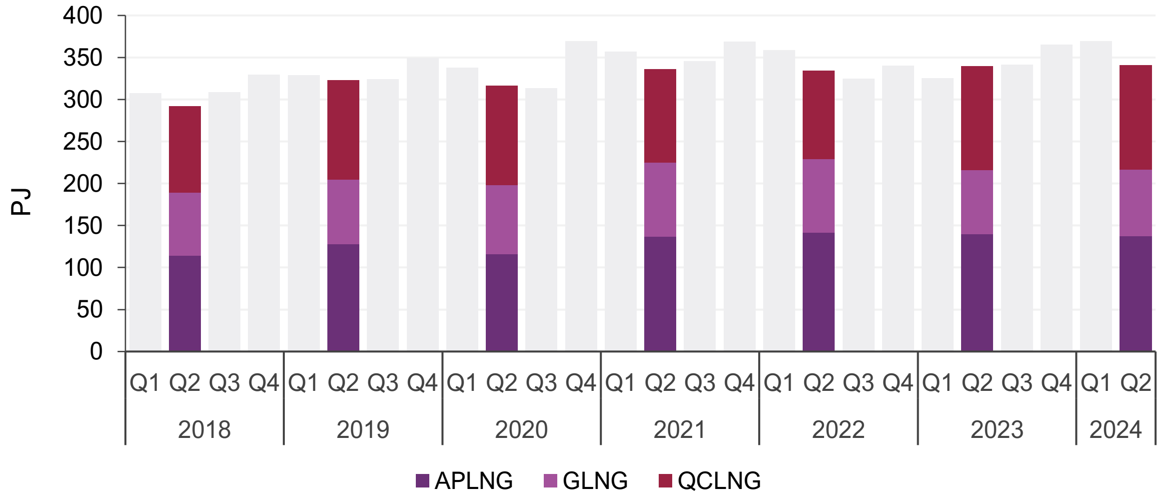
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand increased compared to Q2 2023 when production was impacted by train outages, which had resulted in Q2 2023 being GLNG's lowest export quarter since 2019. Australia Pacific LNG (APLNG) announced on 17 April that it had shipped its 1,000th cargo since beginning commercial operations in January 2016[40]. By participant, GLNG demand increased by 3.8 PJ while Queensland Curtis LNG (QCLNG) increased by 0.8 PJ and APLNG decreased by 2.7 PJ (Figure 93). There were 87 cargoes exported during the quarter, up from 86 cargoes in Q3 2022.

[40] See https://aplng.com.au/australia-pacific-lng-marks-1000th-cargo-milestone/.

Figure 93 Highest Q2 on record for Queensland LNG production

Total quarterly pipeline flows to Curtis Island



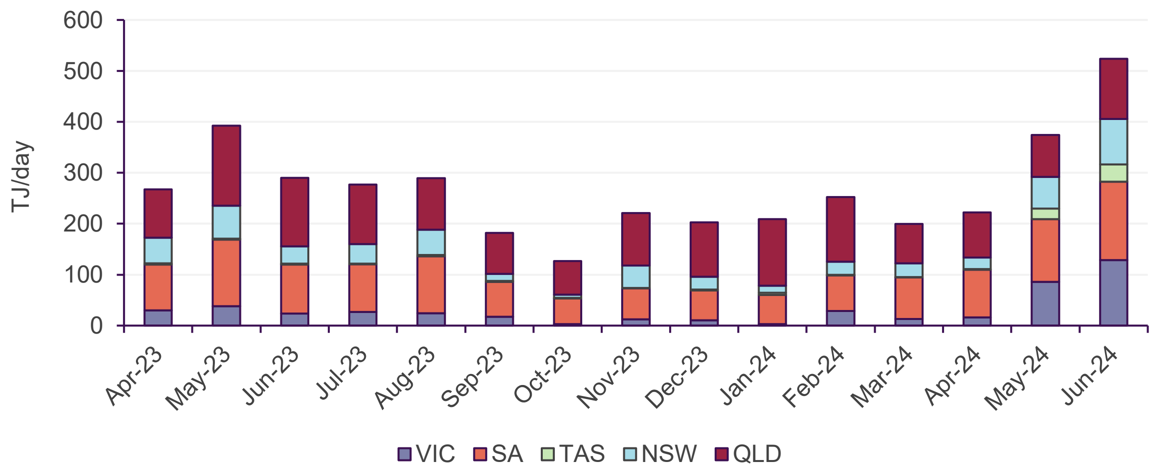
2.2.1 Gas-fired generation

Demand from gas-fired generation increased significantly during the quarter (Figure 94). Demand increases were observed in all states except Queensland where demand fell 25% from Q2 2023. Victoria's demand increased by 151%, South Australia's by 17%, New South Wales' by 16%, and Tasmania's by 781%. The large increase in June was one significant factor underlying that month's higher gas market prices. Drivers of this higher generation demand are discussed in Section 1.3.2.

Victoria set a new winter record for daily gas-fired generation demand on 13 June of 356 TJ, the highest daily demand for any time of the year since 25 January 2019 (when demand was 447 TJ, in a period when Victoria was experiencing its hottest weather in five years). Victoria's highest gas-fired generation demand days have historically occurred in summer. Total east coast gas-fired generation demand on 13 June was 911 TJ, which was also a new winter record.

Figure 94 Significant increase in gas-fired generation in June contributing to increased market prices

Average daily gas-fired generation demand by state



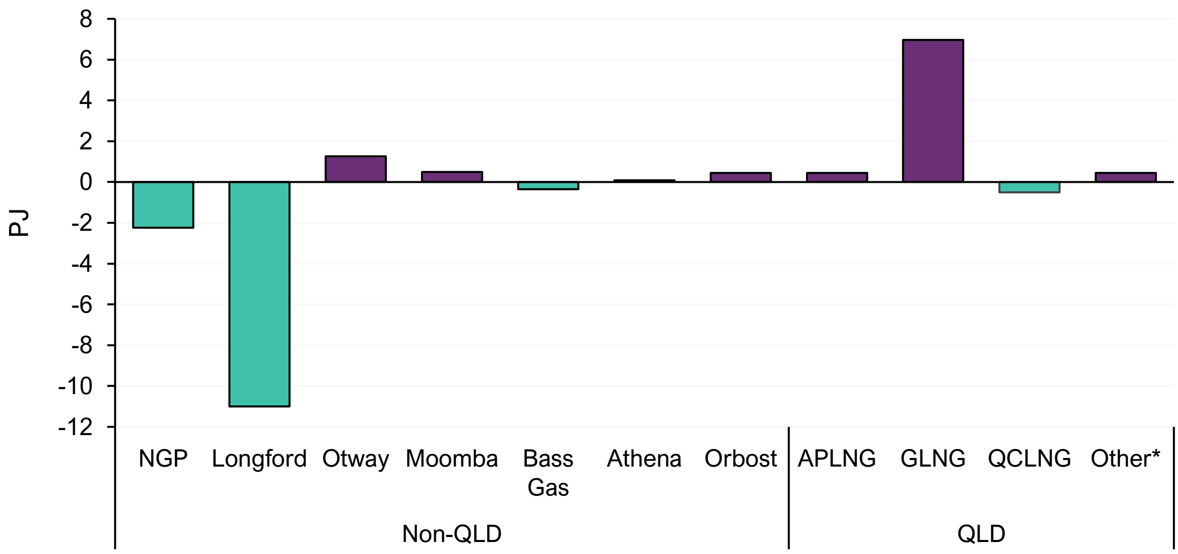
2.3 Gas supply

2.3.1 Gas production

East coast gas production decreased by 1.5 PJ compared to Q2 2023 (-0.3%, Figure 95).

Figure 95 Production continues to fall at Longford while Queensland output increases

Change in east coast gas supply – Q2 2024 vs Q2 2023



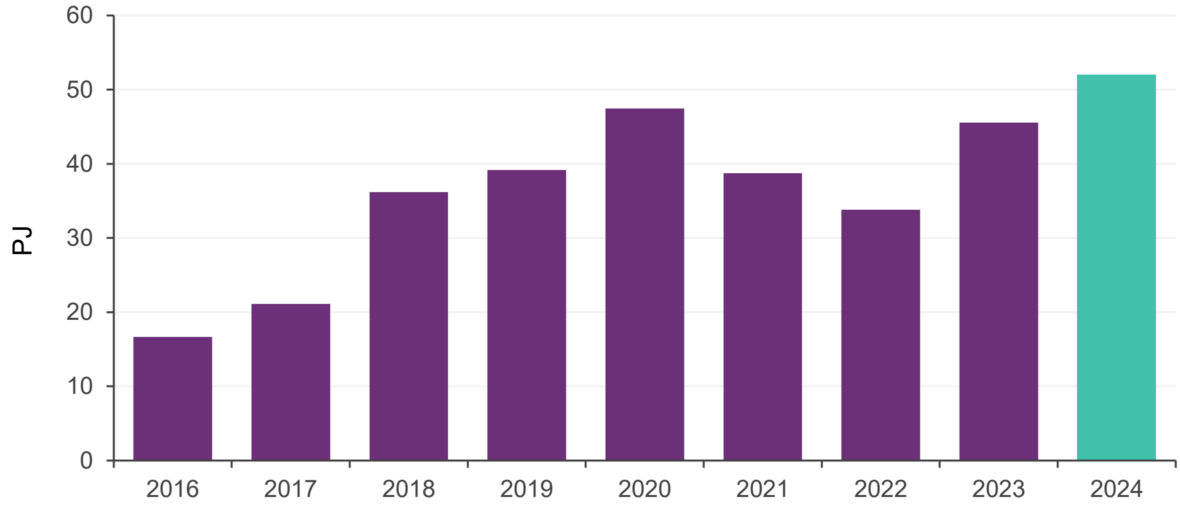
Key changes included:

- Decreased Victorian production (-9.6 PJ), mainly driven by lower production at Longford (-11.0 PJ). Otway production increased by 1.3 PJ due to production from the Enterprise gas field commencing in June[41].
- Increased Queensland production (+7.5 PJ), with assets operated by GLNG increasing by 7.1 PJ, APLNG operated assets by 0.5 PJ, while QCLNG operated assets decreased by 0.5 PJ. Gas demand for Queensland LNG exports increased by 1.8 PJ, meaning that an additional 5.7 PJ of supply associated with Queensland LNG projects went into the domestic market compared to Q2 2023. This led to the highest Q2 Queensland net domestic supply since all three LNG export projects were commissioned in January 2016 (Figure 96).
- Decreased Northern Gas Pipeline (NGP) supply (-2.2 PJ), with continuing upstream supply issues in the Northern Territory that began in February 2024. This meant there was no supply from the Northern Territory to Queensland for the entire quarter.

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

Figure 96 Highest Q2 Queensland net domestic supply since LNG export projects completed

Queensland net domestic supply – Q2s

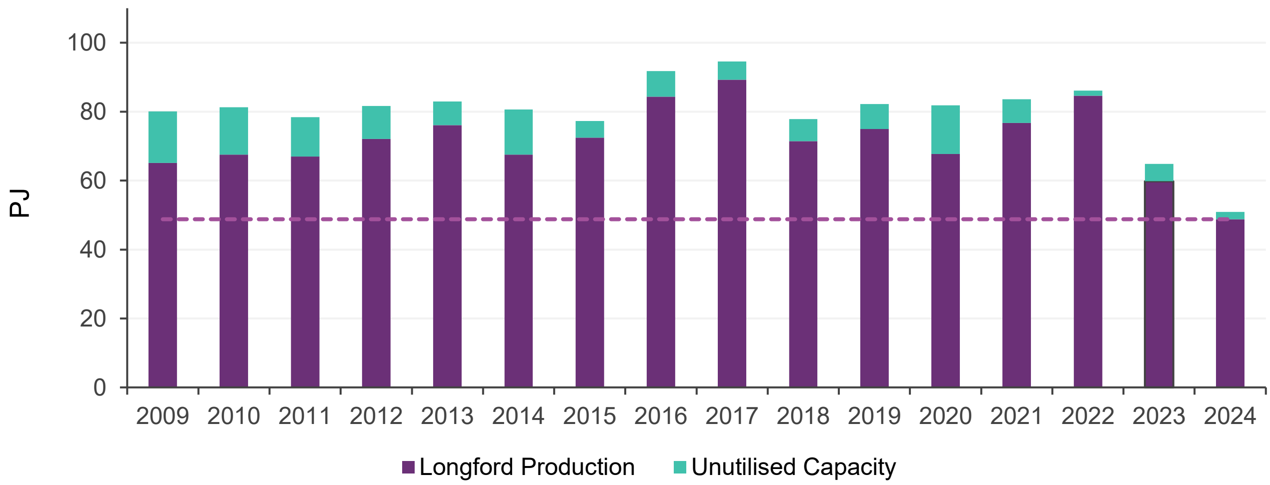


2.3.2 Longford production and capacity

This quarter saw the continued decline in Longford production that was observed through 2023 and Q1 2024. Longford's production of 49 PJ was the lowest for any Q2 since data collection commenced on the Gas Bulletin Board (GBB) in 2009 (Figure 97), and available production capacity of 51 PJ was also the lowest recorded since this time. AEMO's 2024 *Victorian Gas Planning Report Update* and 2024 *Gas Statement of Opportunities*[42] have recent updates on declining gas reserves in Bass Strait processed through Longford and future production forecasts.

Figure 97 Lowest Longford Q2 production and lowest available capacity since data reporting began

Longford Q2 production and unutilised capacity

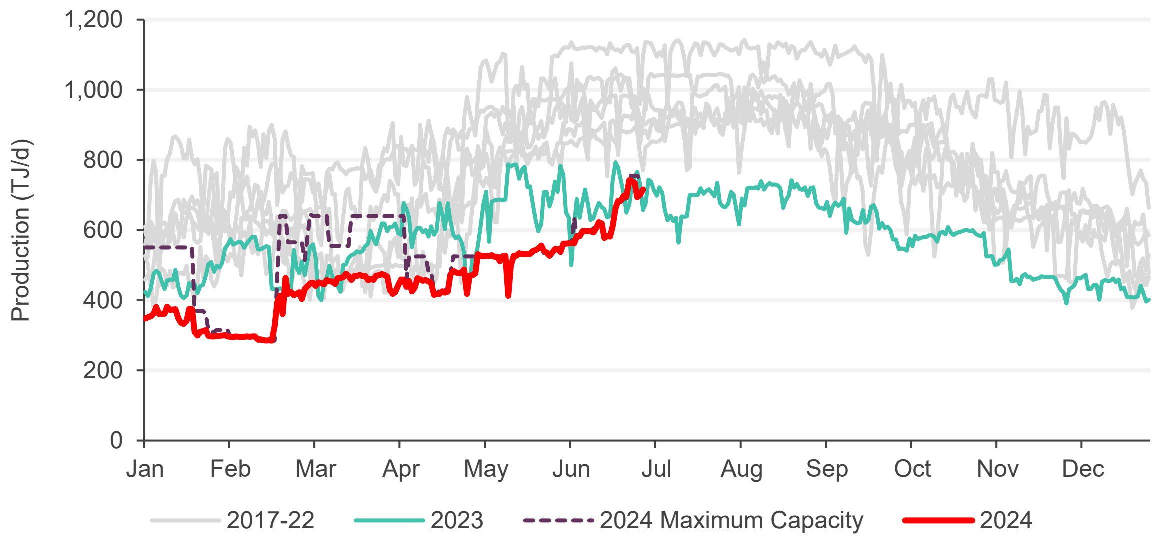


[42] See https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report and https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.

Daily production for most of the quarter was at or near capacity, which was lower this quarter than in 2023 due to extended maintenance (Figure 98). Longford's capacity was scheduled to increase to 775 TJ/d by the end of May, however unplanned offshore issues delayed this increase, with Longford's production averaging 630 TJ/d in June. Capacity and production gradually increased through June and peaked at 742 TJ on 25 June.

Figure 98 Daily Longford production continues to decline

Daily Longford production 2017-2024, maximum capacity profile 2024

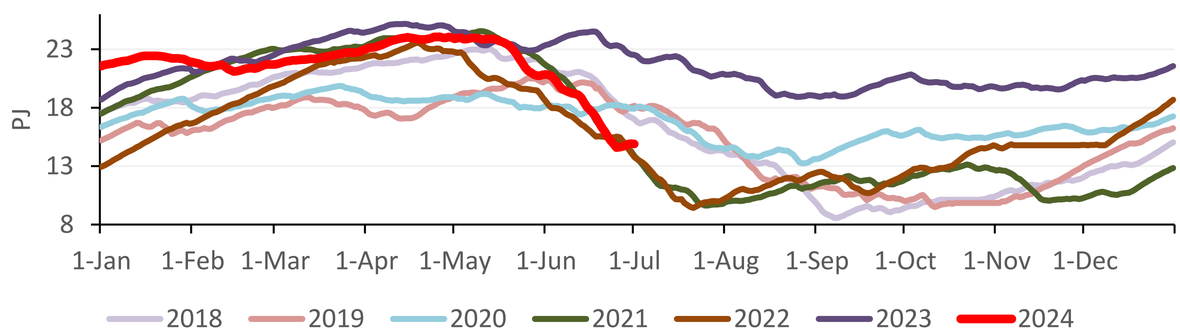


2.3.3 Gas storage

The Iona UGS facility finished the quarter with a gas balance of 14.8 PJ, 7.7 PJ lower than at the end of Q2 2023 (Figure 99) but marginally higher than at the end of Q2 2022 (14.1 PJ) and Q2 2021 (14.3 PJ). Iona was heavily utilised from mid-May, with growing gas-fired generation demand, delays in completing planned outage works at Longford and the onset of winter weather in southern states the main contributing factors. Iona supplied 2.7 PJ from storage between 17 June and 23 June, a weekly record driven by high gas-fired generation due to strong NEM electricity demand and low wind generation, combined with constrained supply from Longford. This occurred despite coinciding with record southerly flows on the South West Queensland Pipeline (SWQP, see Section 2.4).

Figure 99 Iona storage empties at high rates in June

Iona storage levels



2.3.4 East Coast Gas System Risk or Threat Notice

On 1 June 2023 AEMO's functions were extended in response to the projected supply shortfalls in the east coast gas market from winter 2023[43].

On 19 June 2024 AEMO issued an East Coast Gas System Risk or Threat Notice[44] due to the potential for gas supply shortfalls caused by the high rate of depletion of southern storage inventories, particularly Iona UGS. This reflected recent high gas-fired generation demand combined with lower than forecast Longford Gas Plant production (see Section 2.4.1).

Further rapid storage inventory depletion may occur if unexpected events impact either gas demand or supply. Low or depleted storage inventory would result in reduced gas supply capacity in the southern jurisdictions, and reduced storage facility delivery capacity may pose a risk to gas supply adequacy in southern jurisdictions on peak demand days through to 30 September 2024, the end of the peak winter demand period.

AEMO requested the following response from industry to mitigate the threat:

- Producers (including Queensland Producers), Transmission Pipeline Operators, Storage Providers, Shippers and Market Participants in the gas supply chain delivering gas to end users in the southern jurisdictions, to take reasonable measures to maximise production and supply from Queensland to the southern jurisdictions to reduce the rate of storage inventory depletion.
- Relevant entities (as defined in the National Gas Law (NGL)) to consider their demand requirements (including gas-powered generation) and source of supply to meet that demand, for the remainder of the winter period, and within the following locations:
  - off takers located within the southern jurisdictions; and
  - off takers located on the South West Queensland Gas Pipeline and the Carpentaria Gas Pipeline.

The likely duration of the identified risk was from 19 June and expected to continue until no later than 30 September 2024.

2.4 Pipeline flows

Compared to Q2 2023, there was a 7.9 PJ increase in net transfers south to Moomba from the South West Queensland Pipeline (SWQP, Figure 100). This represents the highest southerly SWQP transfer for any Q2 and the second highest southerly flow after Q3 2019. Increased flows coincided with an increase in Queensland net domestic supply, combined with reduced Longford production and higher gas-fired generation demand in southern states.

Northern Gas Pipeline (NGP) flows from the Northern Territory caused by upstream supply issues in February 2024 also remained at zero throughout Q2, creating additional requirements to supply the Mt Isa region from Queensland.

---

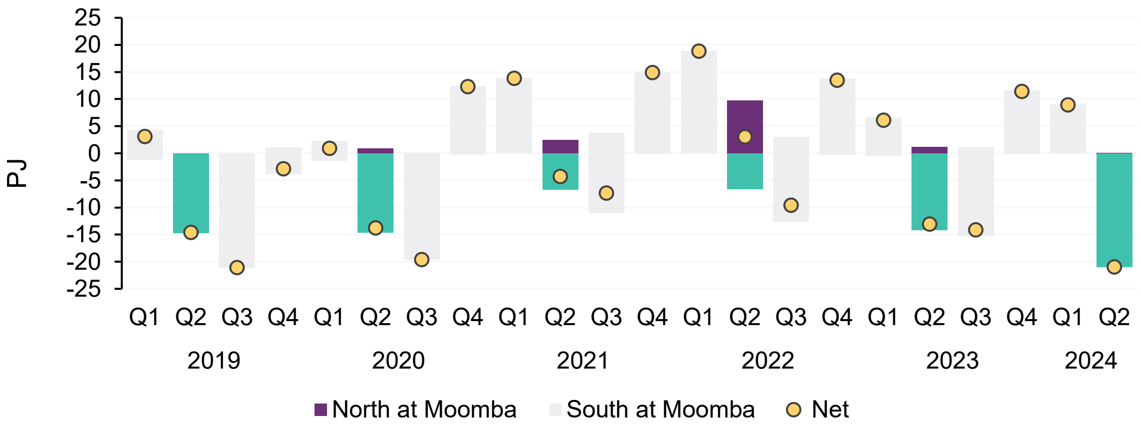
43 See https://aemo.com.au/en/energy-systems/gas/east-coast-gas-system/about-the-ecgs.

44 See https://www.nemweb.com.au/Reports/CURRENT/ECGS/ECGS_Notices/Attachments/20240619180058%20-%20EAST%20COAST%20GAS%20SYSTEM%20RISK%20OR%20THREAT%20NOTICE%2019%20JUNE%202024.PDF.

In addition to record SWQP southerly quarterly flows, a daily SWQP southerly flow record was also observed, with a 559 TJ flow recorded from Wallumbilla into the SWQP on 4 June 2024, against an increased nameplate rating[45] of 512 TJ. SWQP daily flows exceeded the previous record of 480 TJ on 14 occasions across May and June. The previous record was set in July 2021. The capacity of the SWQP has been expanded by approximately 25%, from 404 TJ/d in 2022, over the past two years[46].

Figure 100 Record SWQP Q2 southerly flows

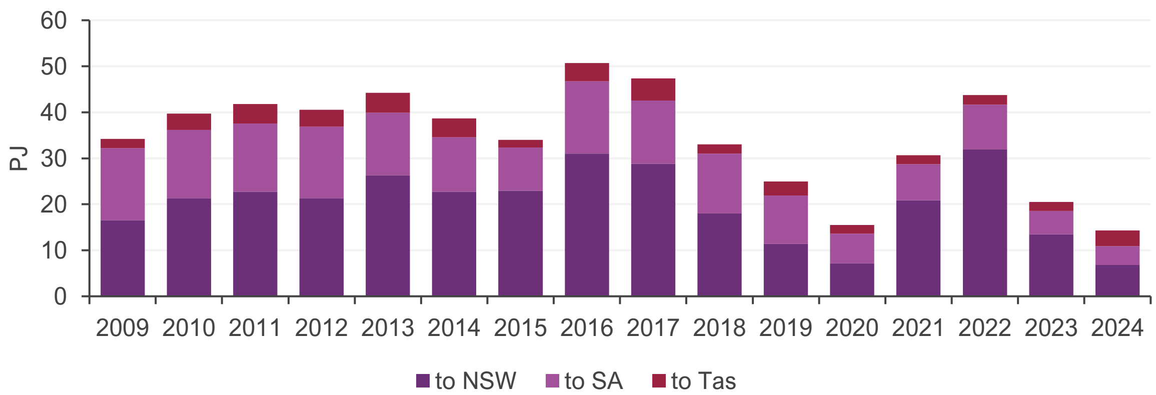
Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states fell 6.2 PJ from Q2 2023 levels due to reduced production at Longford alongside record SWQP flows from Queensland. This represents the lowest export flow from Victoria for any Q2 since data reporting began (Figure 101). Net flows from Victoria to New South Wales decreased by 6.6 PJ, comprising a 3.8 PJ increase in net import flows into Victoria via Culcairn and a 2.8 PJ decrease in exports via the Eastern Gas Pipeline (EGP). Flows from Victoria to South Australia decreased by 1.0 PJ, while flows from Victoria to Tasmania increased by 1.5 PJ due to higher gas-fired generation requirements in Tasmania.

Figure 101 Lowest Victorian Q2 exports since data reporting began

Victorian net gas transfers to other regions – Q2s



45 Nameplate rating is defined in the National Gas Rules 141(2) as the maximum daily capacity of the facility under normal operating conditions.

46 See https://www.apa.com.au/about-apa/our-projects/east-coast-grid-expansion/

2.4.1 Queensland Gas Pipeline Supply Interruption

The Queensland Gas Pipeline (QGP) supply interruption that occurred on 5 March 2024 continued to result in reduced capacity throughout Q2, with daily pipeline flows averaging 110 TJ/d, compared to 129 TJ/d before the pipeline rupture (Figure 102). AEMO published a preliminary report into the QGP event on 7 May 2024[47].

Figure 102 QGP flows continue to be affected after pipeline rupture on 5 March

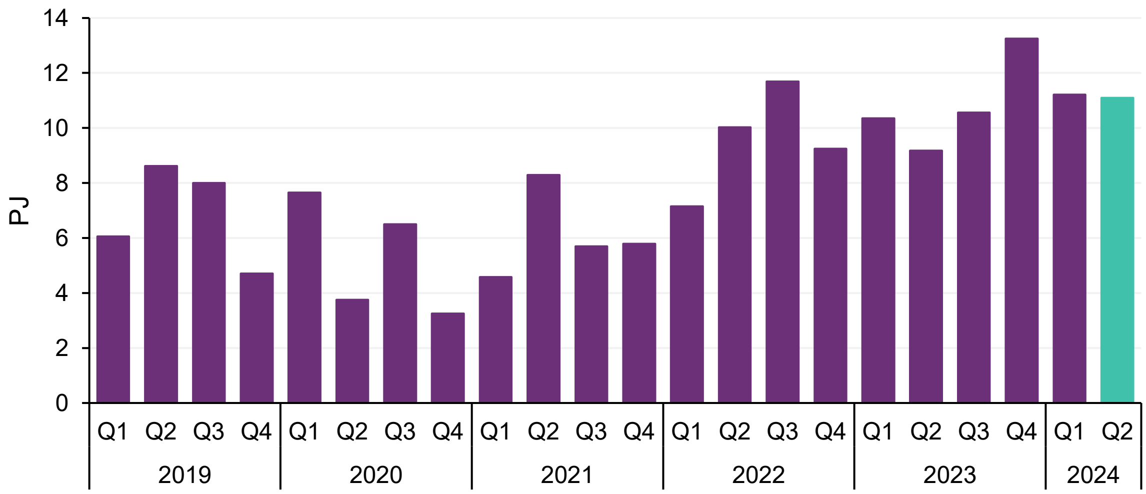
QGP – daily pipeline flows Q1 and Q2 2024

2.5 Gas Supply Hub (GSH)

In Q2 2024, traded volumes on the GSH increased by 1.9 PJ in comparison to Q2 2023, setting a new Q2 record (Figure 103). The traded volume this quarter was 11.1 PJ and represented the fourth highest volume on record.

Figure 103 Highest Q2 GSH traded volume since market start

Gas Supply Hub – quarterly traded volume



47 See https://aemo.com.au/energy-systems/gas/east-coast-gas-system/ecgs-reports-and-notices.

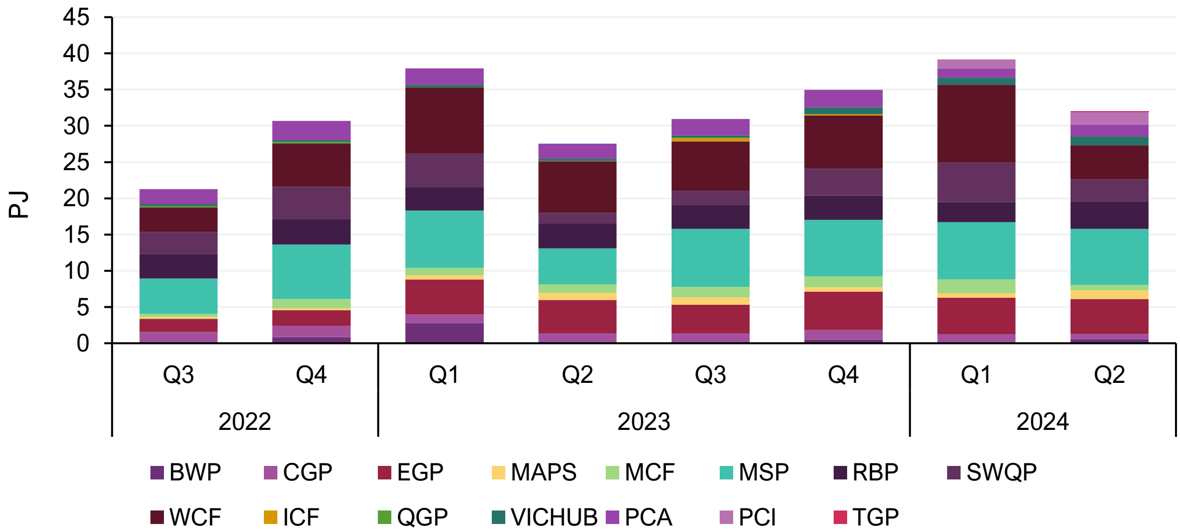
2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes traded in Q2 2024 set a Q2 record of 32.0 PJ, 4.5 PJ higher than the previous Q2 record set in 2023 (Figure 104). Compared to Q2 2023, the largest increase occurred on the Moomba to Sydney Pipeline (MSP, +2.8 PJ) and the SWQP (+1.5 PJ), reflecting the large increase in gas flows from Queensland to southern markets. The first DAA capacity won on the Tasmanian Gas Pipeline (TGP) occurred in April 2024, with 77 TJ traded in the quarter.

Average auction clearing prices were the highest on the Carpentaria Gas Pipeline (CGP, $0.32/GJ), followed by SWQP ($0.22/GJ) and Roma Brisbane Pipeline (RBP, $0.06/GJ). Other pipelines and compression facilities were at or close to $0/GJ.

Figure 104 Highest Q2 Day Ahead Auction utilisation since market start

Day Ahead Auction volumes by quarter



2.7 Gas – Western Australia

2.7.1 Gas consumption

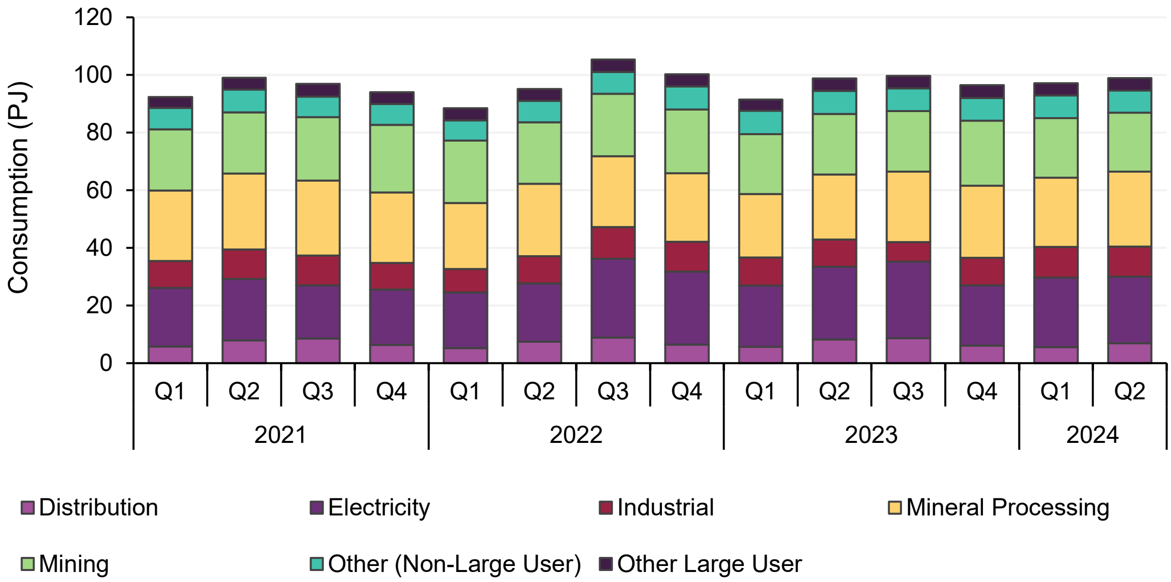
A total of 98.9 PJ was consumed from registered pipelines in the Western Australian domestic gas market in Q2 2024 (Figure 105). This was an increase of 1.7 PJ (+1.8%) compared to the previous quarter, and a slight increase (+0.1 PJ) from Q2 2023.

The largest differences compared to Q2 2023 were observed in distribution network gas consumption, down by 1.3 PJ (-16.3%) and in electricity consumption, down by 2.1 PJ (-8.3%) which can be partly explained by the milder weather this start of the winter compared to June last year. These decreases were offset by an increase of 3.4 PJ (+15.3%) by the mineral processing sector.

There are also changes in consumption by geographic zone compared to Q2 last year; Perth Metro reduced consumption by 4.7 PJ (-14.8%) whereas the South-West increased its consumption by 2.5 PJ (+9.2 %).

Figure 105 Western Australian domestic gas in Q2 2024 increased from last quarter, and remained similar to Q2 2023

WA quarterly gas consumption by sector – Q1 2021 to Q2 2024

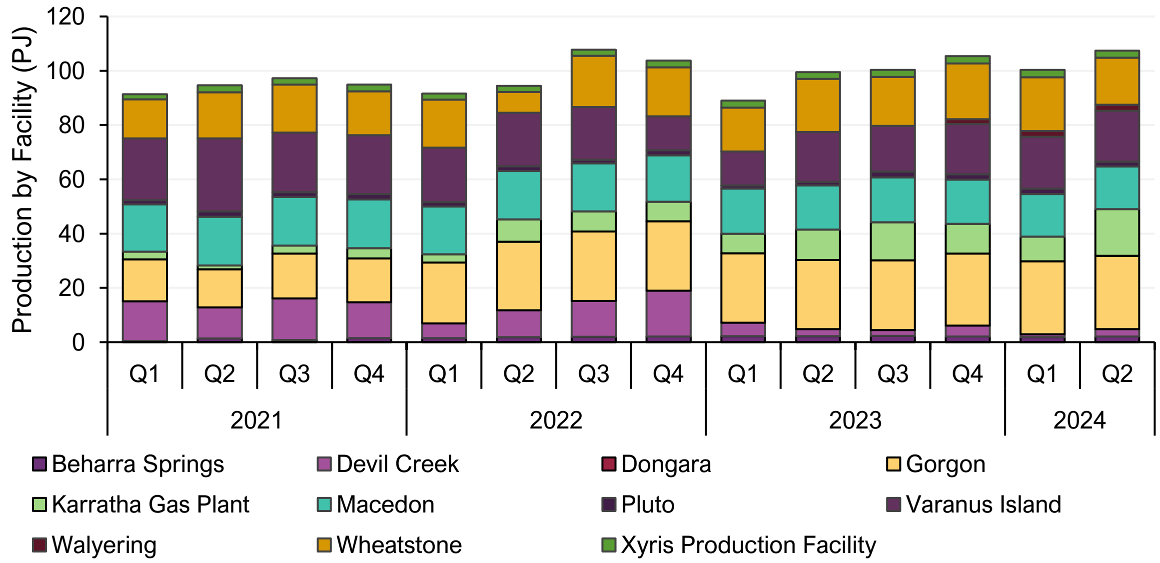


2.7.2 Gas production

Gas production in Western Australia was 107.3 PJ, an increase of 7.1 PJ (+7.1%) compared to Q1 2024 and an increase of 7.8 PJ (+7.8%) compared to the same quarter last year (Figure 106).

Figure 106 Western Australian domestic gas production in Q2 2024 increased compared to both Q2 2023 and Q1 2024

WA quarterly gas production by facility – Q1 2021 to Q2 2024



Production from the Karratha Gas Plant was the main driver of this increase, with production increasing by 5.9 PJ (+52.8%) from Q2 last year and by 8.0 PJ (+87.2%) compared to Q1 2024. The production from Karratha Gas

Plant this quarter was its highest since 2021, with June production levels particularly high. This can be partially attributed to increased production to offset the 10-day production outage at Wheatstone. Wheatstone reduced its output this quarter by 2.4 PJ (-12.0%) from Q2 2023 and by 2.5 PJ (-12.7%) compared to last quarter.

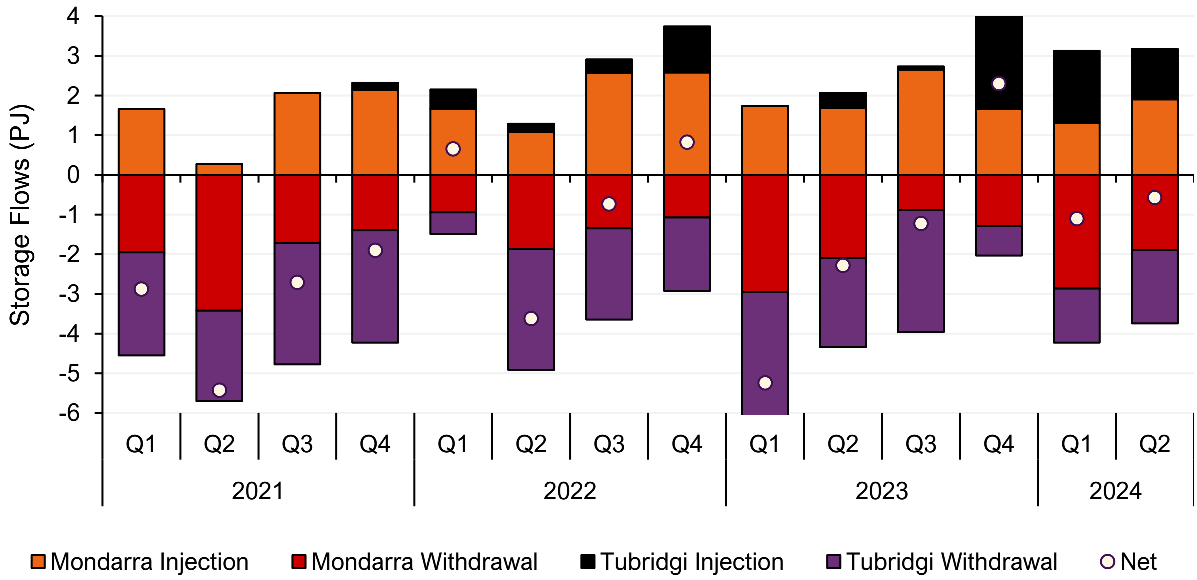
Devil Creek's production levels went up by 1.7 PJ (+171.7%) compared to the previous quarter. This Facility had almost no production in February and March of this year due to a well and processing constraint, but since mid-April has been progressivly increasing its production.

2.7.3 Storage facility behaviour

Over the last four Q2s there has been net withdrawal of gas from storage; this quarter's withdrawal has been the lowest, with a net withdrawal of 0.6 PJ from storage facilities (Figure 107). This is a decrease of 1.7 PJ from Q2 2023 when net withdrawals accounted for 2.3 PJ and a 0.5 PJ decrease from last quarter, primarily driven by milder weather and reduced tightness in the electricity market.

Figure 107 The trend of net withdrawal from storage in Q2 continues in 2024

WA gas storage facility injections and withdrawals – Q1 2021 to Q2 2024



3 WEM market dynamics

3.1 Weather observations and electricity demand

Q2 2024 saw a slight reduction in average operational demand for the quarter to 2,000 MW (28 MW less than Q2 2023) where increases in underlying demand were more than offset by increases in estimated distributed PV generation[48] (Figure 108). Demand levels reflected the higher average temperature of 18.6°C, 3.3°C greater than Q2 2022 (Figure 109), with higher demand early in the quarter driven by some especially elevated temperatures during April carrying over from the record-breaking Q1.

Figure 108 Net reduction in operational demand as increased underlying demand was offset by distributed PV

Change in average WEM demand components by time of day – Q2 2023 vs Q2 2024

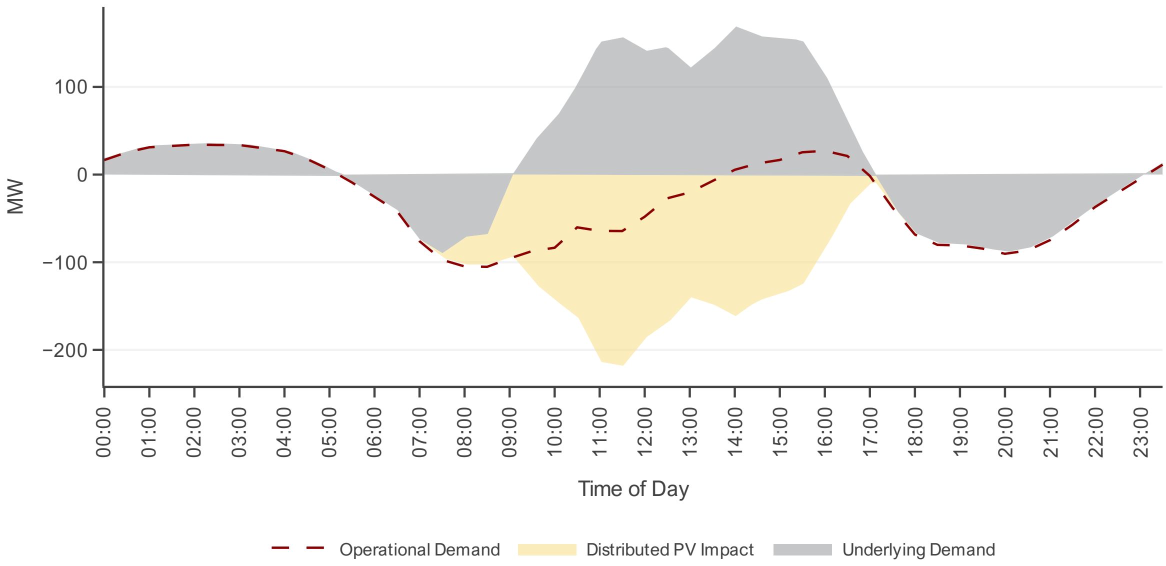
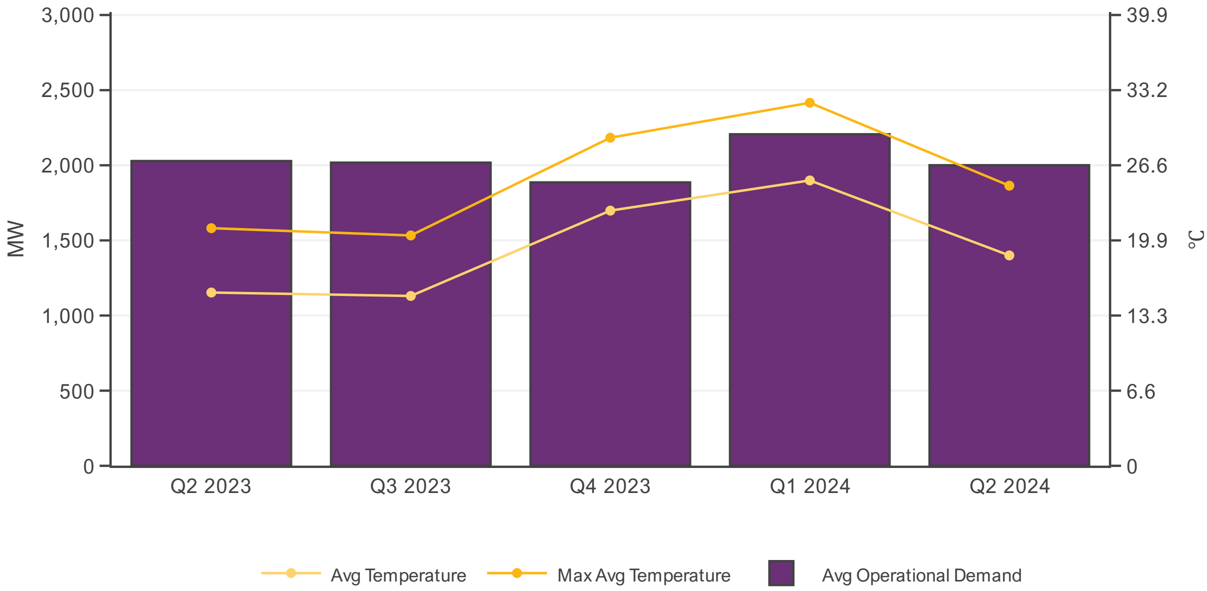


Figure 109 also shows that in comparison to Q1 2024, there was a reduction in average operational demand (-206 MW) consistent with a significant drop in temperature, down from 25.2°C on average.

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

Figure 109 Lower temperatures compared to Q1 2024 result in lower average operational demand

Average temperature and average maximum daily temperature, with average operational demand – Q2 2023 to Q2 2024

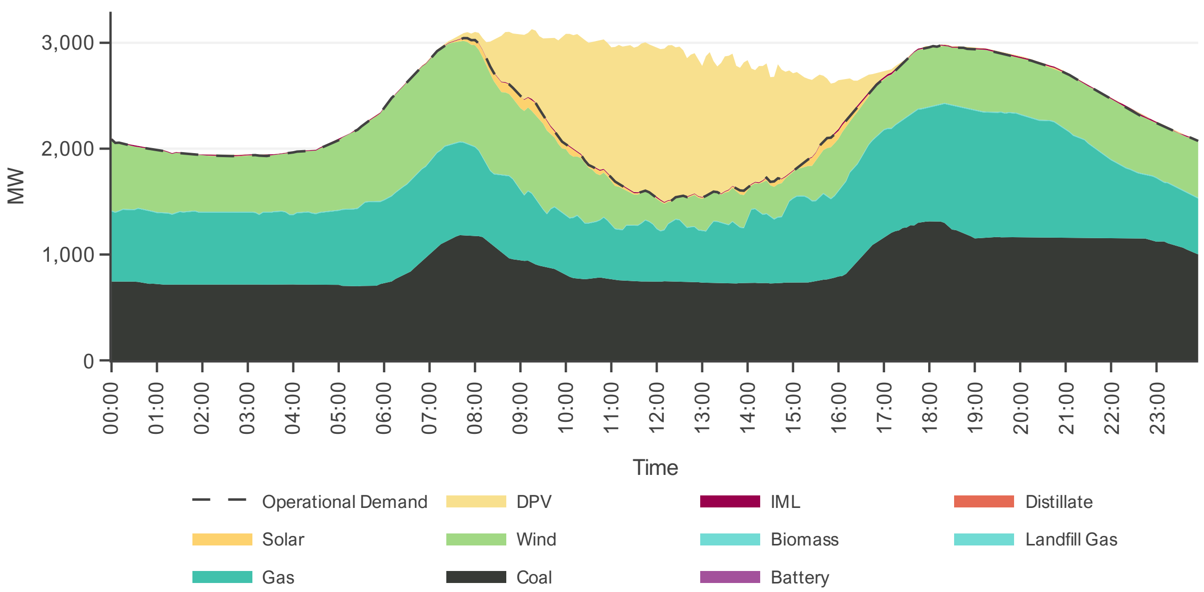


3.1.1 Morning average operational demand peak exceeding evening peak

On 20 and 21 June 2024, the WEM experienced daily average operational demand peaks during the morning peak, rather than the typical evening peak period. On 21 June 2024, Figure 110 shows the daily peak occured during the 09:15 interval with average operational demand peaking at 3,128 MW, higher than the evening peak of 2,986 MW in the 18:15 interval. While there were 13 prior instances of this occurring prior to this quarter since 2014, five have occurred in the last 12 months. In addition, it is the first time two days have occurred in succession, presenting a new operational consideration for AEMO.

Figure 110 Morning peaks exceeded evening peak on 21 June 2024

21 June 2024, 5-minute average generation by fuel type and operational demand (MW)



3.2 Electricity generation

3.2.1 Change in fuel mix

Total average underlying demand increased by 24 MW; increases in average wind generation and distributed PV generation covered this increase and displaced gas generation compared to Q2 2023 (Figure 111 and Table 7).

Figure 111 Increased generation from distributed PV and wind displaced gas generation

Change in quarterly average generation – Q2 2023 vs Q2 2024

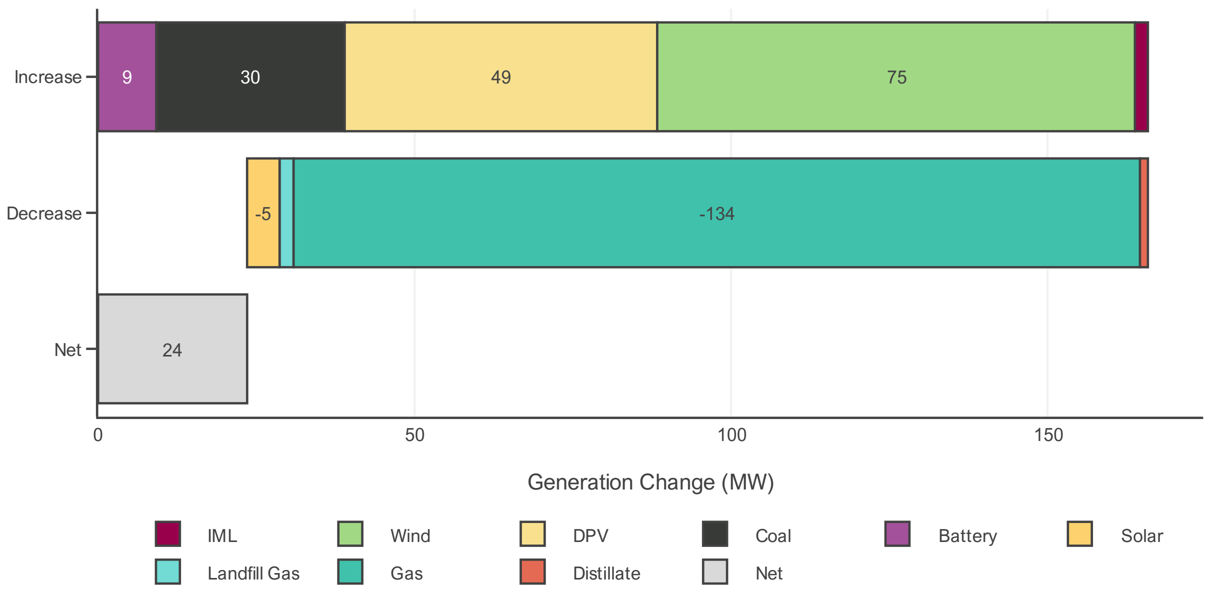


Table 7 WEM supply mix contribution by fuel type

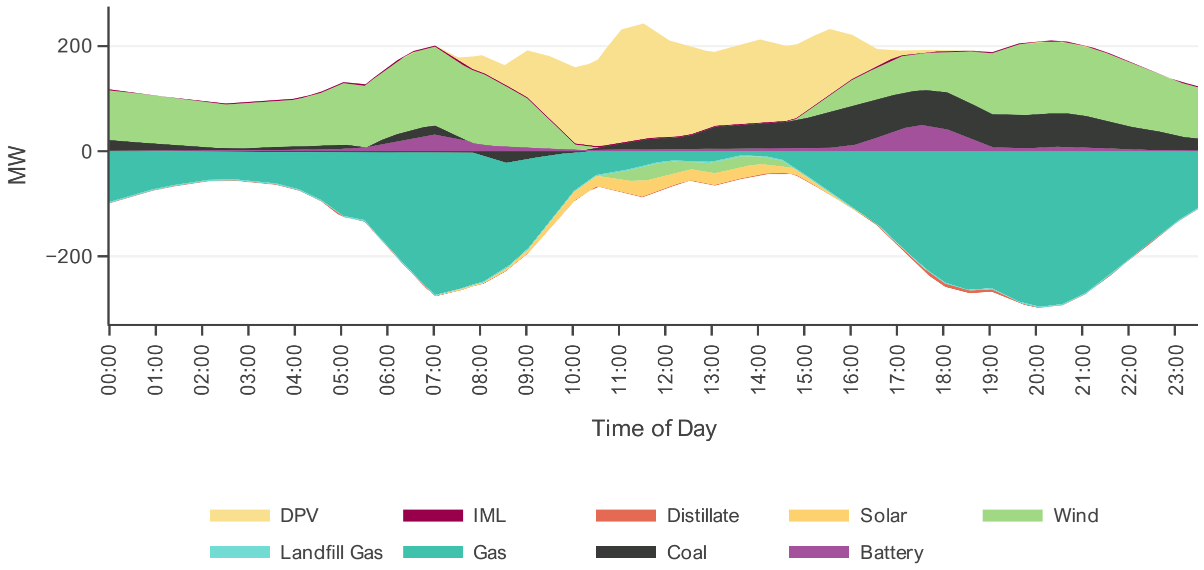
Quarter	Coal	Gas	Distillate	Grid Solar	Wind	Landfill Gas	Battery	Distributed PV
Q2 2023	31.7%	42.8%	0.1%	1.4%	13.7%	0.5%	0%	9.9%
Q2 2024	32.6%	36.5%	0.1%	1.1%	16.9%	0.4%	0.4%	11.9%
Change	0.9%	-6.3%	-	-0.3%	3.2%	-0.1%	0.4%	2.1%

Changes in generation by fuel type and time of day, compared to Q2 2023 (Figure 112), were:

- Wind increased by 75 MW, which can be partially attributed to Flat Rocks Wind Farm commencing participation in the WEM.
- Estimated distributed PV saw an increase of 49 MW. This can be linked to clear, sunny conditions extending through May, and increase in installed capacity.
- Coal slightly rebounded from the record Q2 low that was experienced in 2023, due to significant outages during that quarter, to increase by 30 MW.
- After a Q2 record high was experienced for gas generation in 2023, the increases in wind, distributed PV and coal resulted in a decrease of 134 MW for gas in Q2 2024. This was experienced at all times of the day (Figure 112).

Figure 112 Gas generation being displaced at all times of the day by distributed PV, wind and coal

Average WEM change in fuel mix by time of day – Q2 2023 vs Q2 2024

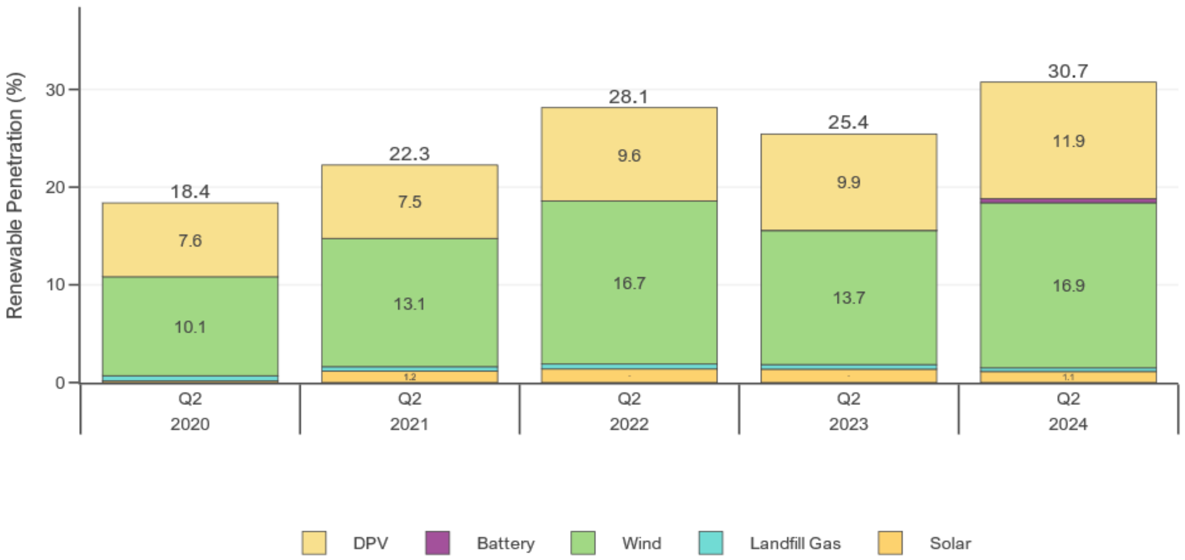


3.2.2 Renewable penetration

Q2 2024 set a new renewable penetration record for Q2, with renewables accounting for 30.7% of the overall fuel mix, up from 25.4% in Q2 2023 and above the previous Q2 record of 28.1% set in 2022 (Figure 113).

Figure 113 Average renewable penetration reached 30.7%, a new Q2 record

Renewable penetration components – Q2s



The key drivers of the new quarterly penetration high were:

- Wind increased to 16.9% (+3.2 pp) of generation compared to Q2 2023. This represents a Q2 record for wind.
- Uplift of distributed PV which saw an increase to 11.9% penetration (+2.0 pp on Q2 2023), also a Q2 record.

- The introduction of the Kwinana Battery Energy Storage System (KBESS), resulting in a battery contribution of 0.4% to total renewable penetration.

The highest instantaneous renewable penetration in Q2 2024 was 72.9%, which was recorded during the 12:00 interval on Saturday 10 April 2024. This was slightly higher than Q2 2023, when a instantaneous renewable penetration of 72.5% was recorded on Friday 14 April 2023.

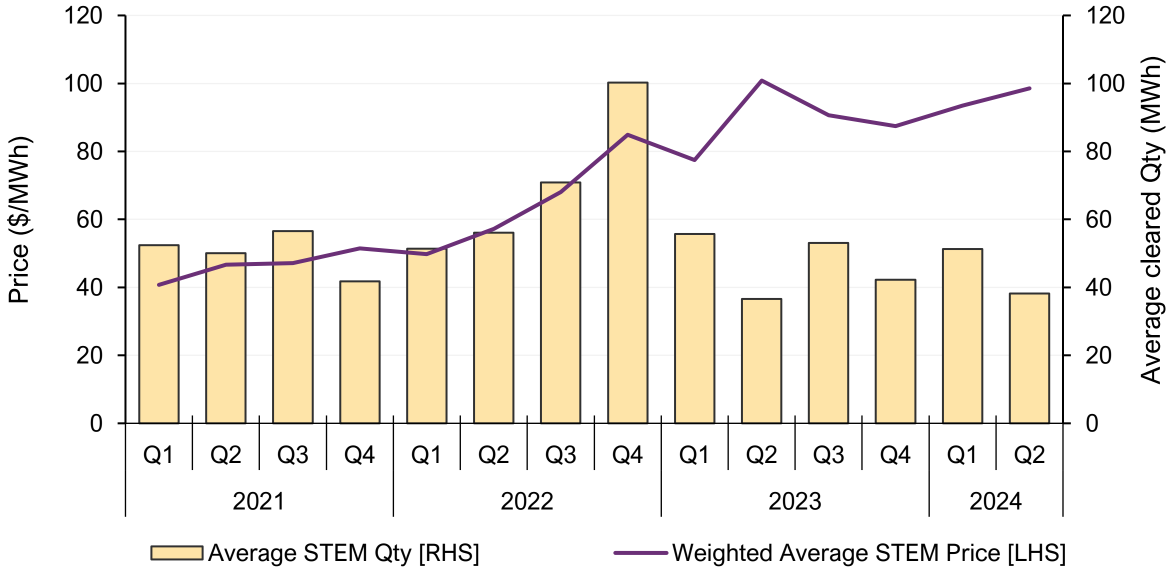
3.3 Short Term Energy Market

The weighted average Short-Term Electricity Market (STEM) price for Q2 2024 was $98.54/MWh, an increase of $5.11/MWh from the previous quarter but a decrease of $2.29/MWh compared to Q2 last year (Figure 114). Overall the STEM price has been gradually trending upwards since 2021, despite STEM volumes having returned to more normalised levels from Q1 2023 onwards.

The quarterly average quantity of energy cleared in the STEM per interval was 38 MWh, a reduction of 13 MWh from Q1 2024 (-34%). When compared to the same quarter last year, quantities cleared increased by 2 MWh (+4%).

Figure 114 The weighted average STEM price increased, while the quantities cleared in STEM decreased from Q1 2024

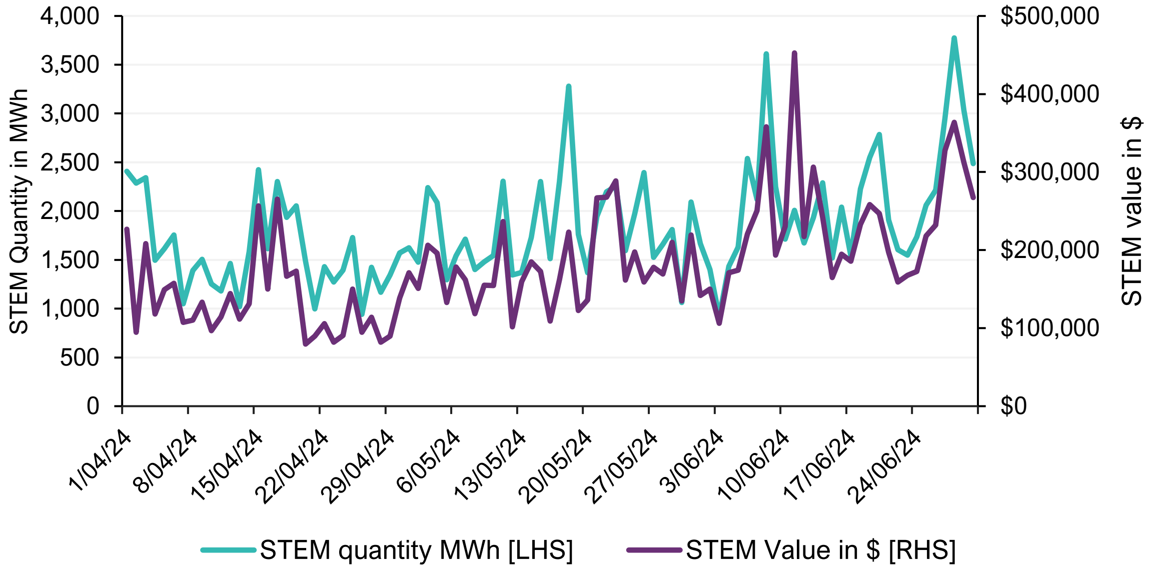
WEM weighted average STEM Price and quantity cleared in STEM – Q1 2021 to Q2 2024



The daily traded value in STEM ranged from $80,000 to $452,000 in Q2 2024, whereas the daily quantities traded in MWh varied between 914 MWh and 3,775 MWh (Figure 115). In Q2 2023, STEM value ranged between $55,000 and $515,000, whereas STEM quantities traded varied between 762 MWh and 3,324 MWh.

Figure 115 Daily quantities traded in STEM reached a maximum of 3,775 MWh and value traded of $452k

Daily quantities (MWh) and value ($) traded in STEM – Q2 2024



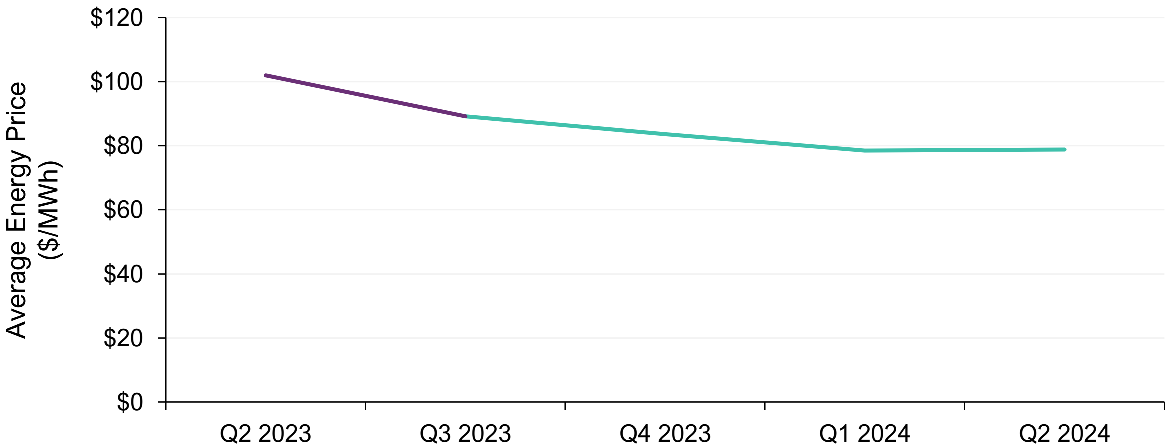
3.4 WEM Real-Time Market prices

3.4.1 Real-Time Market price dynamics

The average energy price[49] in Q2 2024 was $79.79/MWh. This was a decrease of $23.20/MWh from Q2 2023 where there was lower than average Facility availability combining with elevated operational demand that resulted in higher energy prices for that quarter[50] (Figure 116). It was marginally (+$0.30/MWh) higher than Q1 2024 despite a reduction in operational demand (see Section 3.1)

Figure 116 Energy prices remained relatively unchanged from Q1 2024

Quarterly Average Energy Prices – Q2 2023 to Q2 2024



[49] Energy Prices refer to Final Reference Trading Prices from the commencement of the new market (Q4 2023) onwards and Balancing Prices in prior quarters.

[50] See Quarterly Energy Dynamics – Q2 2023 at https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

The relatively similar average energy price between Q1 and Q2 2024, despite Q2 having 206 MW lower average operational demand, can be attributed to:

- An overall reduction in the quantities offered by coal Facilities of 269 MW, notably at the floor price (Figure 117).
- A reduction in the quantities offered by gas Facilities of 325 MW (Figure 118).
- A reduction in average wind and grid solar generation of a combined 114 MW.

This is due to an increase in planned outages scheduled after the Hot Season.

Figure 117 Decrease in average quantities offered from coal generators

Average total coal generation supply curve – Q1 2024 vs Q2 2024

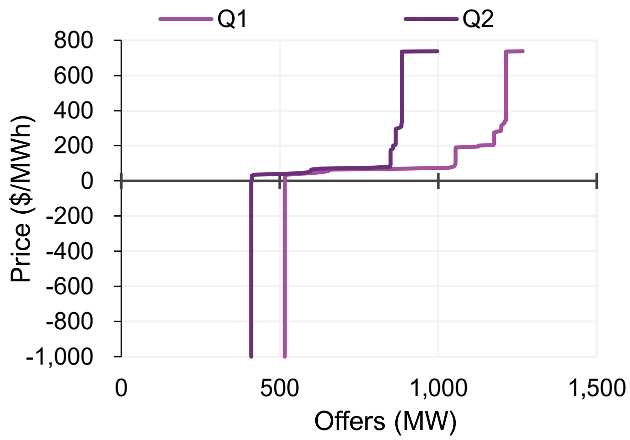
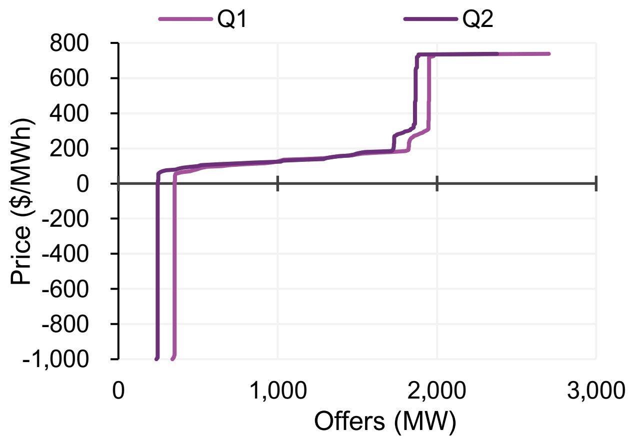


Figure 118 Decrease in average quantities offered from gas generators

Average total gas generation supply curve – Q1 2024 vs Q2 2024

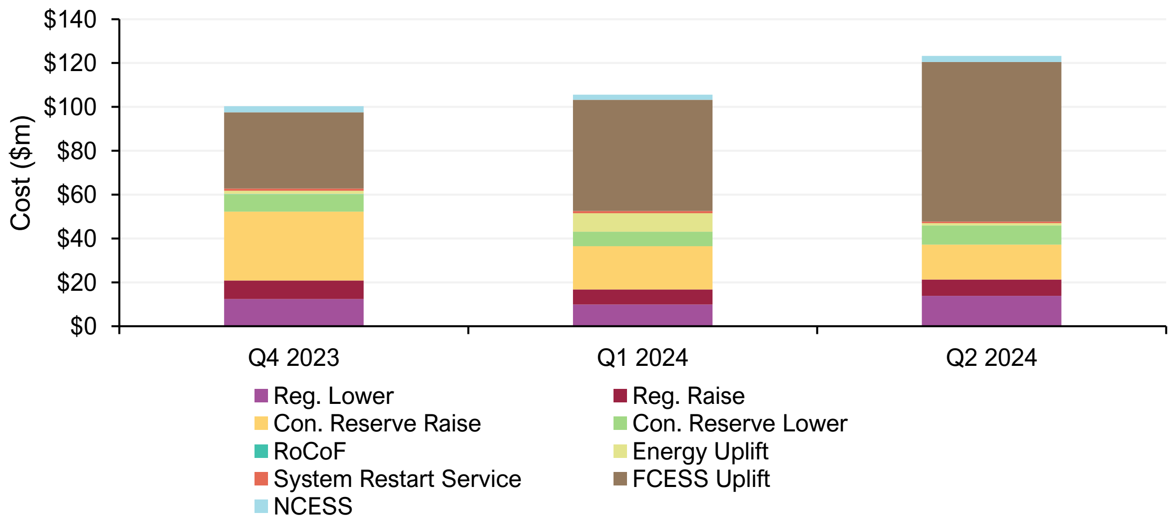


3.4.2 Essential System Services (ESS) costs

The total cost of ESS and Uplift in Q2 2024 increased by $22.9 million compared to Q1 2024 (Figure 119).

Figure 119 Total Essential System Services costs increased $22.9M compared to Q1 2024

Total Costs ESS and Uplift Q4 2023 to Q2 2024



This was primarily driven by increases in FCESS uplift payments and to a lesser extent increases in regulation raise and contingency reserve lower payments. Decreases in energy uplift and contingency reserve raise payments slightly offset the total increase.

- Contingency reserve raise and contingency reserve lower together accounted for $24.8 million of total ESS and uplift costs over the quarter, down from $26.3 million in Q1 2024. This was driven by a $3.8 million decrease in contingency reserve raise costs, offset by a $2.2 million increase for contingency reserve lower costs.
- The cost of regulation raise and lower rose from $16.7 million in Q1 2024 to $21.3 million, increasing by 9% and 40% respectively. This was driven by increases in average prices of $0.36/MW/hr and $0.99/MW/hr respectively compared to last quarter.
- There were no enablement costs from rate of change of frequency (RoCoF) control service this quarter.
- Energy uplift payments totalled $1.0 million this quarter, 88% lower than the cost in Q1 2024. The decrease of these payments was primarily driven by lower operational demand due to the ending of the hot season and subsequent decreases in temperature and absence of heatwave conditions.
- FCESS uplift costs totalled $72.7 million, accounting for over half of total ESS and uplift costs this quarter and an increase of $22.0 million (44%) compared to Q1 2024. See Section 3.4.4 for further details.

3.4.3 Impact of May 2024 rule change

In response to high FCESS costs, the Wholesale Electricity Market Amendment (Price Ceiling) Rules 2024 updated the FCESS Clearing Price Ceiling to be $500/MWh from 8:00 AM on 22 May 2024 to 8:00 AM on 20 November 2024[51]. This change does not impact FCESS uplift cost outcomes.

As the rule change was implemented partway through the quarter, to evaluate the impact of the rule change on FCESS enablement costs (that is, the cost of the five FCESS market services excluding FCESS uplift) is compared in two equal periods before and after the rule change.

The FCESS enablement cost in the five weeks immediately after the rule change was $13.3 million, compared to $25.2 million in the five weeks immediately preceding it, a 47% decrease.

While this is a coarse comparison, which does not account for other variables such as different supply and demand conditions or different enablement quantities, it does indicate that the rule change has had a material downwards impact on cost outcomes.

3.4.4 FCESS uplift share costs

When a Facility receives FCESS Uplift payments in a Dispatch Interval, those costs are assigned equally through all FCESS Market Services the Facility was enabled for in that Dispatch Interval, and recovered via normal cost distribution processes for that Market Service[52].

[51] See https://www.wa.gov.au/government/document-collections/wholesale-electricity-market-amendment-price-ceiling-rules-2024.

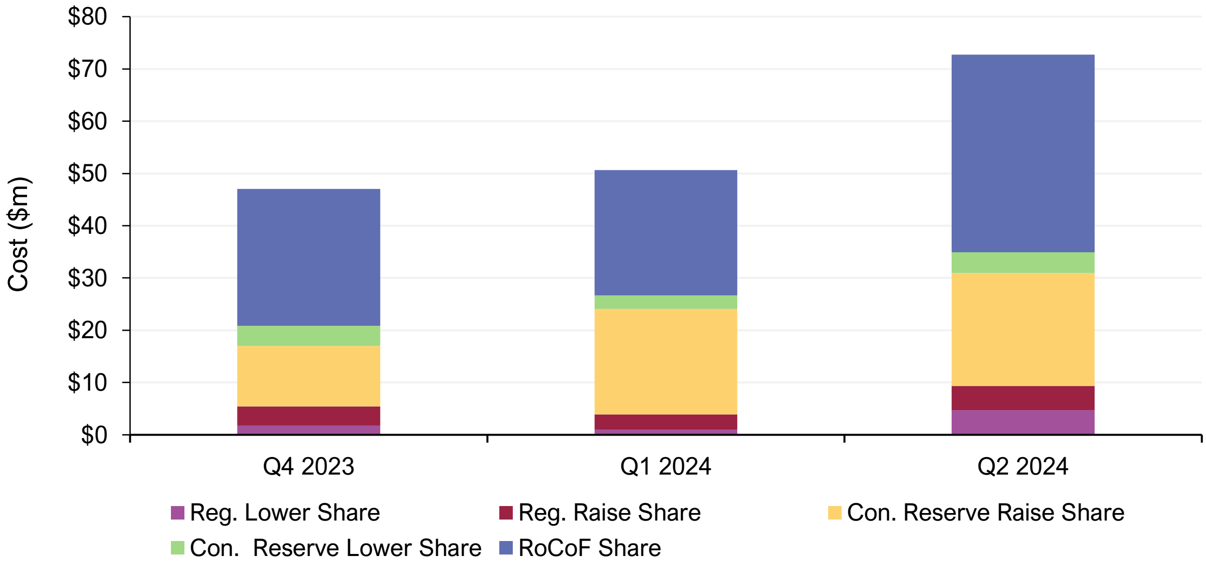
[52] Note that on a high level, regulation raise and lower costs are paid by consumers, semi-scheduled facilities and non-scheduled facilities; contingency reserve lower costs are paid by consumers; contingency reserve raise costs are paid by generating facilities; and RoCoF control service costs are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

The total cost of FCESS uplift in Q2 2024 was $72.7 million; Figure 120 provides a breakdown of the total FCESS uplift costs assigned to each of the five FCESS market services:

- The majority (52%) of this cost was recovered through RoCoF control service charges, a similar percentage to previous quarters. This occurs because it is rare for a facility to be enabled for a regulation or contingency reserve market service without also being enabled for RoCoF market service: as a result, whenever a facility receives FCESS uplift payments for a regulation or contingency reserve market service, part of that cost is recovered from RoCoF market service.
  - Of the total FCESS uplift cost recovered through RoCoF control service charges, 30% was related to facilities which were enabled for only RoCoF control service and no other FCESS market services in the relevant dispatch interval.
- 30% was recovered from contingency reserve raise, while contingency reserve lower, regulation raise, and regulation lower accounted for 5%-6% each. Relatively higher FCESS uplift costs for contingency reserve raise can be attributed to higher market service requirement quantities.

Figure 120 FCESS uplift costs increased by $22.0 million compared to Q1 2024

Total costs of FCESS uplift Q4 2023 to Q2 2024



3.4.5 Real-Time Market costs

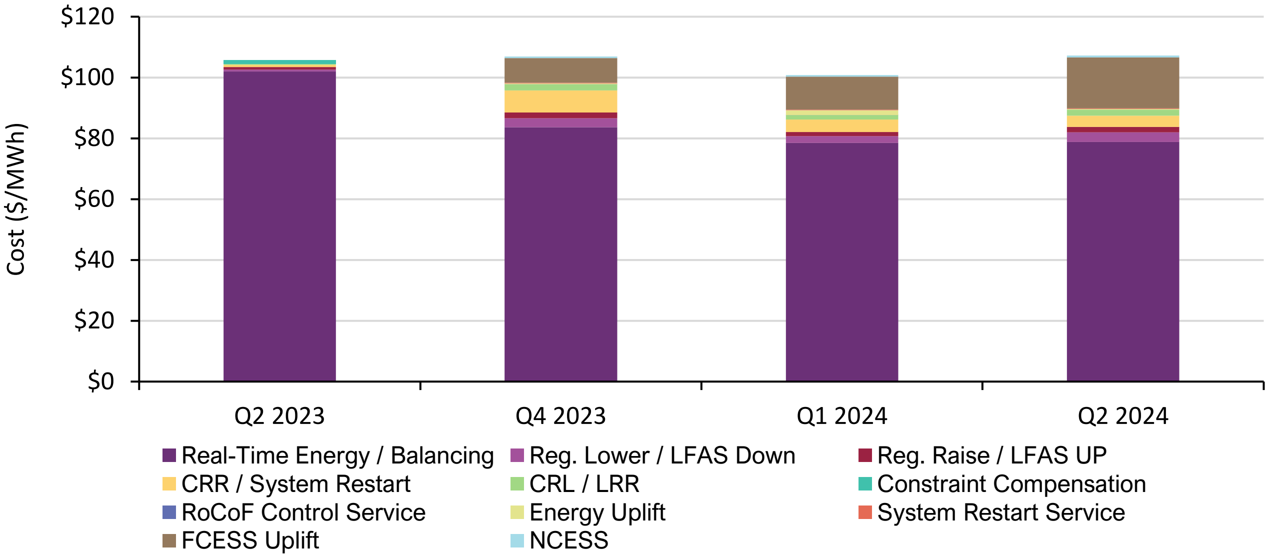
Figure 121 presents energy and ESS costs (including uplift costs) as a price-per-MWh normalised by total energy consumed, enabling some comparison of costs between new and previous markets and periods with different demand.

The total cost of the Real-Time Market (energy and ESS) rose from $105.71/MWh in Q2 2023, to $116.72/MWh in Q2 2024, an increase of 10%. Although the average cost of energy (including constrained compensation and energy uplift) decreased by $23.98/MWh, the ESS compared to ancillary services (AS) increased by $34.19/MWh, resulting in a net increase.

Compared to Q1 2024, total costs increased by $16.52/MWh. In particular, the average costs of FCESS uplift and regulation lower increased by $11.97/MWh and $2.21/MWh respectively. Note that these costs do not include Reserve Capacity or Supplementary Reserve Capacity (SRC).

Figure 121 Real-Time Market costs increased $16.52/MWh compared to Q1 2024

Normalised energy and AS/ESS costs per MWh consumed in the WEM



4 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 8 provides a brief description on the implementation of reforms delivered across the WEM, NEM and east coast gas markets over the last quarter.

Table 8 Reforms delivered Q2 2024

Reform initiative	Description	Reform delivered
Certification of 2024 Reserve Capacity Cycle (RCM Review)	Enhancements have been implemented to the Reserve Capacity Mechanism (RCM) Operations functionality that was delivered during WEM Reform. Changes to the Indicative Facility Classification (IFC) and Certified Reserve Capacity (CRC) processes have been expanded to implement changes addressed in the RCM Review. These changes have been delivered to enable AEMO and Market Participants in the CRC process for the 2024 Reserve Capacity Cycle. Reference: https://www.wa.gov.au/system/files/2023-12/wholesale_electricity_market_amendment_reserve_capacity_reform_rules_2023.pdf	April 2024
Short Term Projected Assessment of System Adequacy (ST PASA) (WEM Reform)	AEMO has introduced a new modelling approach to conduct ST PASA that cater for the volatility of intermittent renewable energy and work with network congestion in a security constrained economic dispatch market. The approach considers multiple demand forecast scenarios reflecting many different possible futures and produces more granular and detailed information, updated daily reflecting potential risks and uncertainty over a 7-day horizon. It also identifies low reserve conditions to prompt notifications / interventions to elicit response from market participants.	June 2024
Integrating Energy Storage Systems (IESS)	AEMO and industry have together implemented the final two releases under the IESS project. These two releases provide for significant changes to the calculation method to be used for non-energy cost recovery, as well as the introduction of the integrated resource provider (IRP) participant type and bidirectional unit (BDU) bidding and dispatch. Reference: https://aemo.com.au/en/initiatives/major-programs/integrating-energy-storagesystems-project	June 2024
Improving Security Frameworks for the Energy Transition	The Improving Security Frameworks for the Energy Transition rule builds on existing tools and frameworks within the power system to enhance system security procurement frameworks, providing increased transparency on system security needs and understanding of how AEMO plans to manage system security as we transition to a secure net zero emissions power system. The rule sets forth multiple implementation milestones, scheduled between 30 June 2024 and 2 December 2025. On 28 June 2024, AEMO published its provisional Security Enablement Procedure setting out the minimum and recommended requirements for contracting system security services. A complete Security Enablement Procedure is to be published August 2025 inclusive of methodology for enablement of these services. Full enablement obligations on AEMO will commence December 2025. Reference: https://aemo.com.au/initiatives/major-programs/improving-security-frameworks-for-the-energy-transition	June 2024
Victorian Declared Wholesale Gas Market (DWGM) integration of renewable gas	AEMO has implemented the Australian Energy Market Commission's (AEMC's) Other Gases rule changes which integrated renewable gases into the Victorian DWGM and Victorian Gas Retail Market. These reforms became effective on 1 May 2024. This package of reforms also included the extension of the DWGM from covering the Victorian Declared Transmission System to also include the Victorian Declared Distribution System to allow the distribution connected facilities to be part of the market.	May 2024

Reform initiative	Description	Reform delivered
	Reference: https://www.aemo.com.au/consultations/current-and-closed-consultations/amendments-to-victorian-declared-wholesale-gas-market-and-retail-market-1-may-2024-release	

In addition to this reform, work continues to progress on the next wave of initiatives set for release later in 2024. Table 9 below provides a brief description of those initiatives to be delivered in Q3 and Q4 2024.

Table 9 Upcoming reforms Q3 – Q4 2024

Reform initiative	Description	Reform to be delivered
DER Dashboard Uplift (DER Roadmap)	As part of the WA DER Program, AEMO is uplifting the visuals and data displayed reflecting changes made to the WA DER Register to produce a specific WEM DER Register dashboard ensuring compliance with AEMO's reporting obligations outlined in AEMO's WEM DER Register Information Procedure.	July 2024
Capacity Assignment of 2024 Reserve Capacity Cycle (RCM Review)	This project will implement enhancements and automation of processes within the RCM Operations functionality that was delivered in the previous phases of the RCM Reform project. This release will conclude delivery of the deferred scope from WEM reform: • Consolidate Network Access Quantity (NAQ) applications; • Implement amended Appendix 3 rules (relating to NAQ) into RCM; • Publish NAQ inputs and outputs to the public data website; • Implement Facility Sub-Metering into RCM; and • Introduce Facility Sub-Metering and components into Reserve Capacity Testing.	August 2024
Retail Market Improvements (Net System Load Profile, Metering Substitutions)	As part of the ongoing suite of Retail Market Improvement initiatives, work continues to progress on several changes including: September 2024 – introduction of a preferred longer-term Net System Load Profile (NSLP) Methodology providing for a more indicative NSLP shape supporting critical market settlements eliminating energy volume spikes in profile reads, and November 2024 – implementation of various Substitution Type and Reason code changes associated with small market interval metering providing 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. Reference: https://aemo.com.au/consultations/current-and-closed-consultations/july-2023-retail-electricity-market-procedures-consultation	September & November 2024
Improving Security Frameworks for the Energy Transition	In accordance with the Improving Security Frameworks for the Energy Transition, AEMO and participants continue to work towards the following key milestones: • July 2024: Changes to directions reporting framework providing for improved transparency on directions to commence. • December 2024: – Commencement of the new inertia framework 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 transition plan report for system security. – Revisions to Transmission Network Service Provider (TNSP) cost recovery for non-network system security costs to commence. Reference: https://aemo.com.au/initiatives/major-programs/improving-security-frameworks-for-the-energy-transition	July and December 2024

Reform initiative	Description	Reform to be delivered
Frequency Performance Payments (FPP) – Non-financial operation	In accordance with the Primary Frequency Response Incentive Arrangement rule change*, work continues to progress with the establishment of a new FPP system and associated procedures and guidelines (including Frequency Contribution Factor Procedures) that 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. Implementation of new FPP system includes 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 ahead of go-live in June 2025. Reference: https://aemo.com.au/initiatives/major-programs/frequency-performance-payments-project	December 2024

* See https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements#:~:text=Rule%20Change%3A%20Completed&text=Confirmation%20that%20the%20mandatory%20primary,changes%20in%20power%20system%20frequency.

List of tables and figures

Tables

Figures

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