Quarterly Energy Dynamics Q3 2023

October 2023

Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q3 2023 (1 July to 30 September 2023). This quarterly report compares results for the quarter against other recent quarters, focusing on Q2 2023 and Q3 2022. Geographically, the report covers:

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

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Version control

Version	Release date	Changes
1	23/10/2023	

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Executive summary

East coast electricity and gas highlights

Warmer weather and increased distributed photovoltaic output reduced operational demand

- Above average temperatures across Australia decreased underlying demand in most National Electricity Market (NEM) regions in Q3 2023. Distributed photovoltaic (PV) output grew to average 2,287 megawatts (MW), up 31% on Q3 2022 and a new high for any Q3. Both factors drove average NEM operational demand to a new Q3 low of 21,270 MW.
- Numerous minimum demand records were set this quarter. The NEM as a whole reached an all-time minimum demand of 11,393 MW on Sunday 17 September, 499 MW below the previous record in Q4 2022. New South Wales, Victoria and South Australia all saw record minimum operational demands this quarter, and Queensland recorded its lowest operational demand since 2002. South Australia's minimum operational demand was 21 MW in the half-hour ending 1330 hrs on 16 September, when distributed PV output represented 98.5% of underlying demand.

Reduced wholesale prices despite reduction in black coal-fired capacity

- Wholesale spot electricity prices across the NEM averaged $63 per megawatt-hour (MWh) in Q3 2023, a 71% decline from the same time last year, and a 41% drop from Q2 2023. Average quarterly spot prices ranged from $29/MWh in Tasmania to $92/MWh in South Australia.
- Despite the retirement of the remaining Liddell units in April 2023, there were significant increases in the volume offered by black coal generators in lower price bands compared to Q3 2022.
- Higher output from variable renewable energy (VRE) generators and lower operational demand, particularly in the middle of day, increased the occurrence of negative prices in the NEM to its highest ever level, 19% of all dispatch intervals. All regions in the NEM saw an increase in negative price occurrences. Queensland had a notable increase in daytime negative prices, with grid-scale solar generators setting the price more often than all other forms of generation in peak daytime hours.

Gas and black coal-fired output declined, increases in grid-scale solar and distributed PV

- Black coal-fired generation output fell to its lowest Q3 average since NEM start at 9,718 MW, a 10% decline from the same quarter last year. Several black coal-fired generators saw markedly lower utilisation rates as they reduced daytime output and ramped up for evening peaks.
- Gas-fired generation recorded its lowest Q3 output since 2004, down 34% on Q3 2022 (which saw high gas generation with elevated electricity and gas spot prices and extended coal-fired unit outages).
- Grid-scale solar output increased this quarter by 412 MW from Q3 2022, driven predominantly by new and recently commissioned units in Queensland and New South Wales.

New actual and potential instantaneous renewable penetration records

- A new instantaneous renewable penetration record was set in the half-hour period ending 1230 hrs on Thursday 21 September, when 70.0% of total NEM generation came from renewable sources. This was a 1.3 percentage point increase from the previous record set in Q4 2022.
- NEM renewable potential also reached a new high point this quarter, at 98.6% for the half-hour ending 1230 hrs on Saturday 16 September. Renewables supplied 15,410 MW (64.9%) of total NEM generation in this interval. Grid-scale solar and wind VRE generators offered an additional 7,980 MW to the market at this time, but at band prices above the prevailing spot price and therefore not dispatched. Total VRE availability and actual output from other renewable sources potentially represented 98.6% of the NEM supply requirement in this half-hour. The previous high point for this measure was 87.8% in November 2022.

NEM connections

- At the end of Q3 2023, 33 gigawatts (GW) of new capacity was progressing through the connection process from application to commissioning, with one-third of this capacity in new applications submitted during the last six months.

East coast gas prices under half Q3 2022 levels, demand and production trended downwards

- East coast wholesale gas prices declined from record levels a year ago to average $10.41 per gigajoule (GJ) for the quarter, significantly lower than Q3 2022's $25.94/GJ, and slightly lower than $10.74/GJ in Q3 2021.
- Gas demand decreased by 3% this quarter compared to Q3 2022, driven by lower usage for gas-fired generation (-12 petajoules (PJ)), and reduced AEMO markets demand (-19 PJ).
- Domestic gas supply shifts observed in Q2 2023 continued, again driven by declining production from gas fields connected to the Longford Gas Plant in Victoria. Aggregate Longford production fell by nearly 28 PJ compared to Q3 2022, and maximum daily production levels also decreased. This supply decrease was offset by the reduction in domestic demand, with Queensland supply only marginally lower (-1.0 PJ).
- As in Q1 and Q2 2023, inventory held in the Iona underground gas storage (UGS) facility ended Q3 at its highest quarter-end balance since reporting began in 2017.

Western Australia electricity and gas highlights

Balancing and Load Following Ancillary Service markets concluded

- Q3 2023 concluded the operation of the Balancing and Load Following Ancillary Services (LFAS) markets in Western Australia's Wholesale Electricity Market (WEM). The “New WEM Commencement Day" – on 1 October 2023 – marked the transition to the Real Time Market and Frequency Co-optimised Essential System Service markets in the WEM.

Operational demand decreased by 2.1% with another minimum demand record set

- In Q3 2023, the WEM's average operational demand was 2,017 MW, a decrease of 2.1% compared to Q3 2022. This decrease is linked to the decrease in average underlying demand, further reduced by an 11% increase in average estimated distributed PV generation.

- An all-time minimum demand record of 595 MW was set on 25 September 2023 during the 1230 interval. This superseded the previous record of 626 MW on 16 October 2022. An all-time maximum distributed PV output share of 76.3% was also recorded on this day at 1200 hrs.

Decreased gas-fired and wind generation offset by an increase in coal, distributed PV and battery generation

- Despite the retirement of MUJA_G5 in Q4 2022, average coal-fired generation reached 664 MW this quarter, an increase of 55 MW from the same quarter last year. At the same time, gas-fired generation decreased by an average of 62 MW. The reduction of gas was most notable between 1000 hrs and 1600 hrs, when distributed PV output is at its highest.
- Wind generation decreased by an average of 44 MW from Q3 2022, falling consistently in every interval. For the first time battery generation is included in the fuel mix this quarter, with the KWINANA_ESR1 (KBESS) commissioning. This is the first large battery operating in the South West Interconnected System (SWIS), with 100 MW rated active power and energy storage of 200 MWh.

High weighted average Balancing Price and STEM price

- This quarter's weighted average Balancing Price was $99/MWh, the highest average for Q3 and a 27% increase from Q3 2022, but lower than the Q2 record. The weighted average Short-Term Electricity Market (STEM) price for Q2 2023 was $91/MWh, a 33% increase compared to Q3 2022.

Gas production and consumption reduced, the trend of withdrawal from storage continued

- WA domestic gas production was 99 PJ, a decrease of 8.6 PJ (-8%) from Q3 2022. Consumption also decreased compared to Q3 2022 and was 99.9 PJ, a decrease of 6.7 PJ (-6.3%). There was a net withdrawal from storage of 1.2 PJ, which was a 0.5 PJ increase in withdrawals compared to Q3 2022.

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1 NEM market dynamics

1.1 Electricity demand

1.1.1 Weather

Warmer than average weather characterised this quarter, with almost all parts of Australia having above average mean temperatures (Figure 1). Tasmania experienced its warmest July on record, and New South Wales, Victoria and South Australia each had one of their top 10 warmest Julys. The July mean daily maximum temperature in the Greater Sydney area was the highest since records commenced in 1900. Warmer than average weather continued in August, with the mean maximum temperature across Queensland 2.83º C above the 1961-1990 average, yielding the state's warmest August since 2009.

The Bureau of Meteorology (BoM) declared an El Niño event on 19 September[1] after being in an alert state since 6 June[2]. El Niño events typically lead to lower rainfall for eastern Australia and warmer days for the southern part of Australia.

Figure 1 Warmer than average temperatures across Australia

Q3 2023 mean temperature deciles for Australia

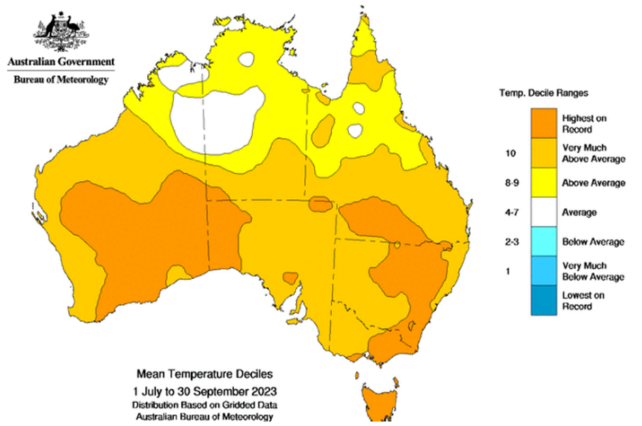
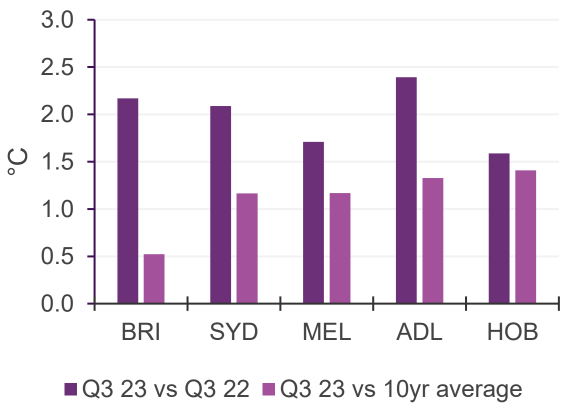


Figure 2 Temperatures warmer than 10-year average across the east coast

Average maximum temperature variance by capital city



1.1.2 Demand outcomes

Average quarterly NEM operational demand was 21,270 MW, 5.1% (1,143 MW) lower than in Q3 2022 and the lowest Q3 average since Tasmania joined the NEM in 2005. The year-on-year fall in quarterly operational demand was the largest such decrease for any quarter over the same period.

Drivers of the decrease were warmer than average weather (Section 1.1.1), which reduced underlying demand by 608 MW to 23,557 MW, and increased distributed PV generation (Figure 3). This quarter had the highest average distributed PV output for any Q3 at 2,287 MW, up 535 MW from Q3 2022 (Figure 4).

[1] Bureau of Meteorology 2023, El Niño under way in the tropical Pacific: https://media.bom.gov.au/releases/1183/the-bureau-declares-el-nino-and-positive-indian-ocean-dipole-events/.

[2] Bureau of Meteorology 2023, The Bureau of Meteorology issues an El Niño ALERT: https://media.bom.gov.au/releases/1170/the-bureau-of-meteorology-issues-an-el-nino-alert/.

Figure 3 Lower underlying demand and distributed PV growth reduced operational demand

NEM average underlying and operational demand – Q3s

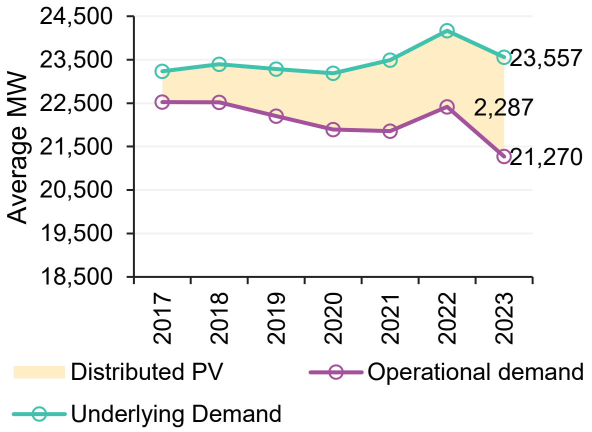
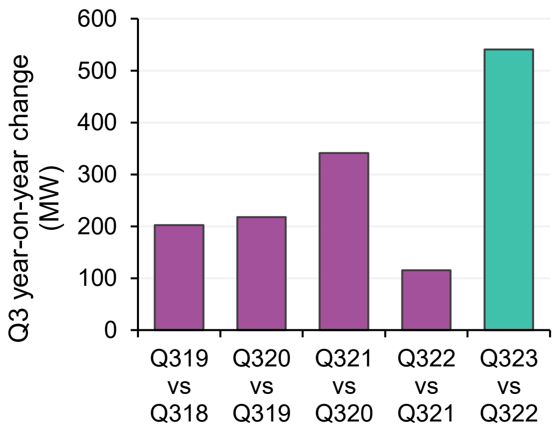


Figure 4 Highest year-on-year growth in Q3 distributed PV output

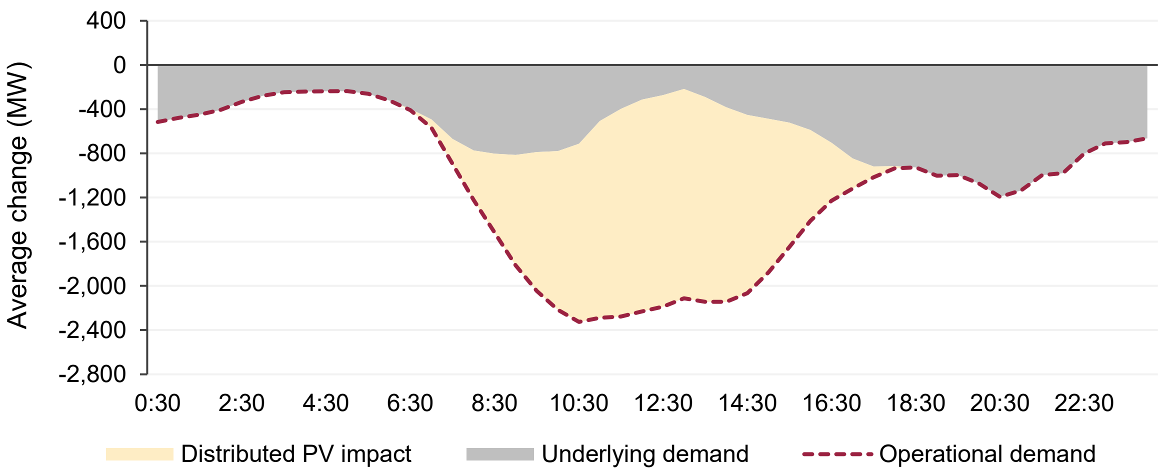
Year-on-year changes in Q3 distributed PV average output



Compared to Q3 2022, the warmer than average temperatures decreased underlying demand throughout the day while the growing output of distributed PV generation led to a large fall in average operational demand during daylight hours (Figure 5).

Figure 5 Underlying and operational demands down in all hours

Changes in operational demand components – Q3 2023 vs Q3 2022

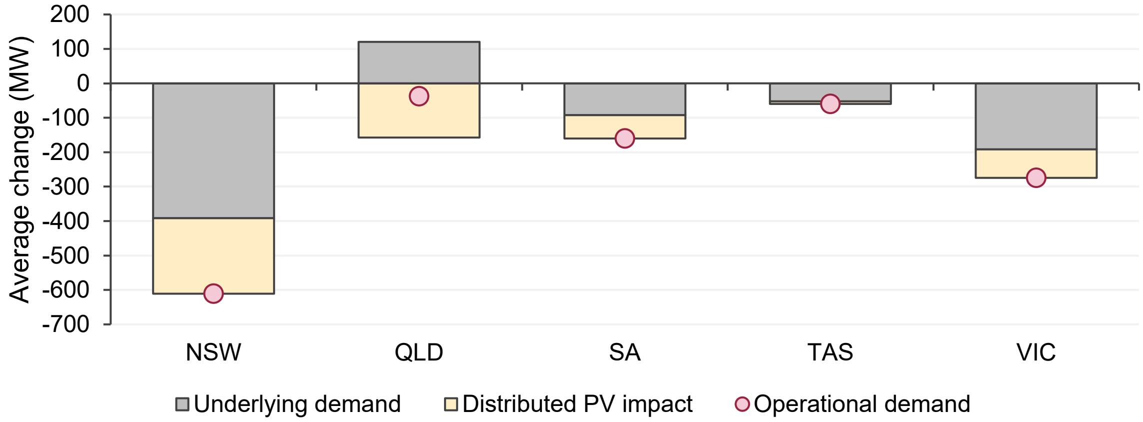


Three regions recorded their lowest average Q3 operational demands: **New South Wales** (7,721 MW), **Victoria** (5,176 MW), and **South Australia** (1,351 MW). All regions recorded their highest Q3 average distributed PV generation since estimates commenced in 2016.

Both underlying and operational demand fell in all NEM regions outside **Queensland** (Figure 6). That region's underlying demand growth of 1.9% (120 MW) was offset by 25% (158 MW) growth in distributed PV output, resulting in a relatively small decline of 0.6% (38 MW) in Queensland's operational demand relative to Q3 2022.

Figure 6 Operational demand down in all regions, Queensland recorded a small underlying demand increase

Changes in average demand components by region – Q3 2023 vs Q3 2022

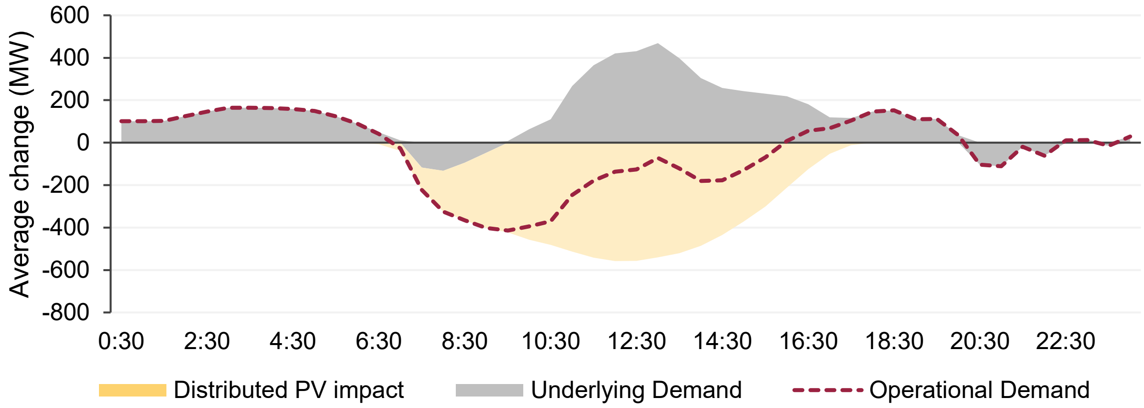


Shifting controlled load to day-time hours – Energy Queensland's 'Solar soak' program

Increased industrial load this quarter compared to Q3 2022, and warmer temperatures, may have increased Queensland's overall underlying demand, but there was also a noticeable change in its time of day profile, with a decrease of around 100 MW between 0730 hrs and 0900 hrs and large increases during the middle of the day (Figure 7). Some of this change may be attributable to a demand management program which Queensland distribution networks have recently enabled[3]. This shifts the operation time of remotely controllable appliances, such as hot water systems on controlled load tariffs, from earlier in the day to the middle of the day when distributed PV output is typically highest, and helps to address minimum operational demand issues.

Figure 7 Significant change in Queensland's underlying demand time of day profile

Changes in Queensland average demand components by time of day – Q3 2023 vs Q3 2022



Maximum demand

Overall NEM maximum demand declined by 3% (975 MW) relative to Q3 2022, to 30,758 MW. No NEM regions reached quarterly maximum demand records in Q3 2023. Maximum demands for **New South Wales** and **Queensland** both declined by 7% from Q3 2022, whereas **South Australia**'s and **Tasmania**'s maximums fell by 6% and 3% respectively. Maximum demand in **Victoria** remained unchanged relative to Q3 2022.

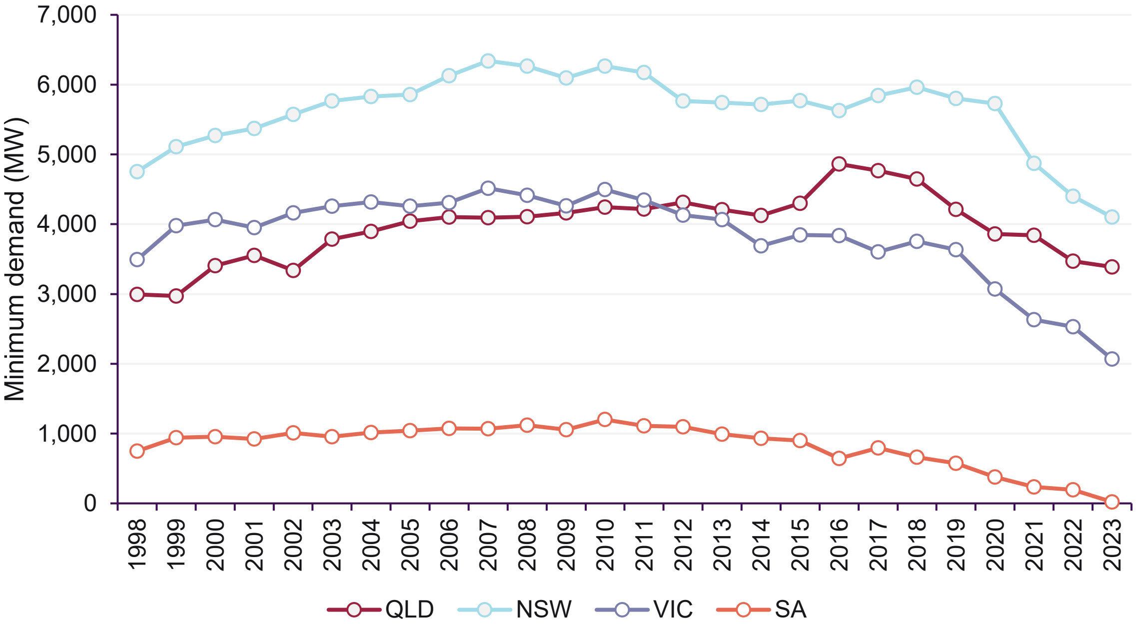
[3] Energy Queensland Annual Report 2022-23: https://www.energyq.com.au/__data/assets/pdf_file/0011/1118828/Energy-Queensland-Ltd-Annual-Report-2022-23.pdf.pdf.

Minimum demand

The final weeks of Q3 2023 yielded several minimum half-hourly operational demand records for the NEM and individual regions (Figure 8). The NEM saw its all-time[4] lowest minimum demand of 11,393 MW at 1230 hrs on Sunday 17 September 2023, 499 MW below the prior all-time low of 11,892 MW on Sunday 6 November 2022.

Figure 8 New South Wales, Victoria and South Australia reached record minimum demands this quarter

Q3 minimum operational demands for mainland regions



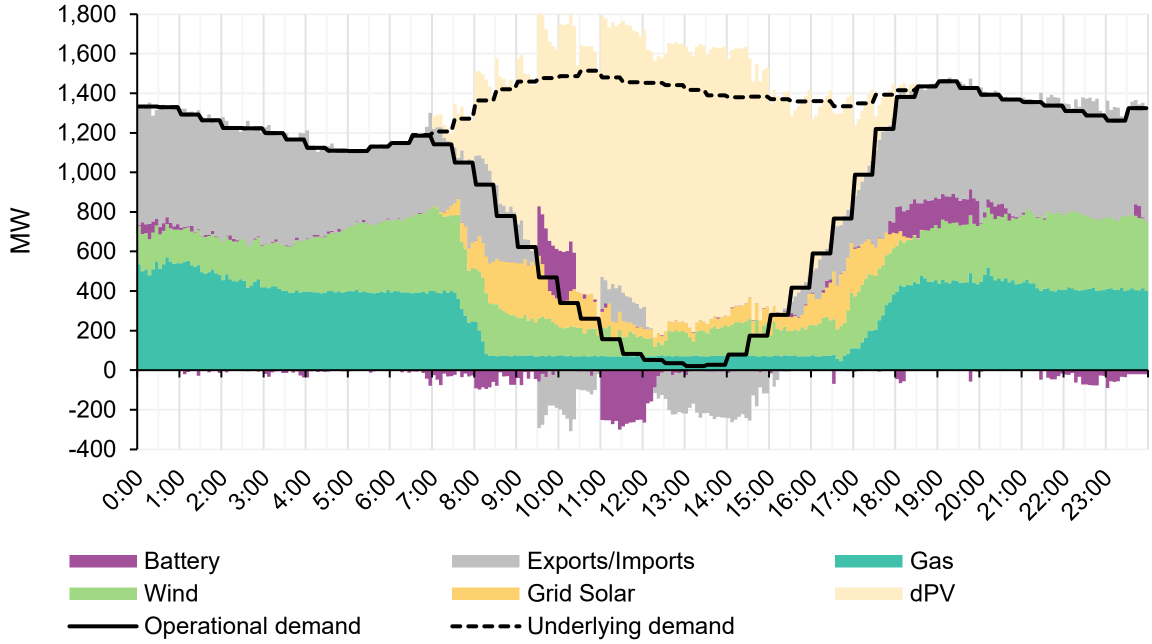
South Australia, **Queensland**, and **Victoria** also registered all-time minimum demand records this quarter, driven by lower underlying demand and higher distributed PV output:

- **New South Wales'** all-time minimum demand record of 4,101 MW, previously reached at 1300 hours on Sunday 9 April 2023 (Easter Sunday), was equalled on Sunday 24 September 2023. At the time, distributed PV accounted for 46% of the region's underlying electricity demand.
- A new minimum demand record of 2,068 MW was set in **Victoria** at the same time (1330 hours on Sunday 24 September 2023). This was 463 MW lower than the previous Q3 record of 2,531 MW set in 2022, and 127 MW below the former all-time lowest minimum demand of 2,195 MW recorded at 1300 hrs on Sunday 18 December 2022.
- **South Australia's** operational demand reached a new record low of 21 MW in the half-hour ending 1330 hrs on Saturday 16 September 2023, with distributed PV accounting for 98.5% (1,396 MW) of the region's underlying electricity demand (1,417 MW). At this time there was also approximately 223 MW of output from grid-scale South Australian generators, with net excess supply being exported to Victoria (Figure 9). This demand minimum was 79 MW less than the previous all-time low of 100 MW recorded on Sunday 16 October 2022.
- **Queensland** experienced its lowest operational demand since 2002, of 3,387 MW at 1100 hrs on Sunday 17 September 2023.

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

Figure 9 South Australia hit an all-time minimum operational demand of 21 MW

South Australia demand (line) and generation by fuel type – 16 September 2023

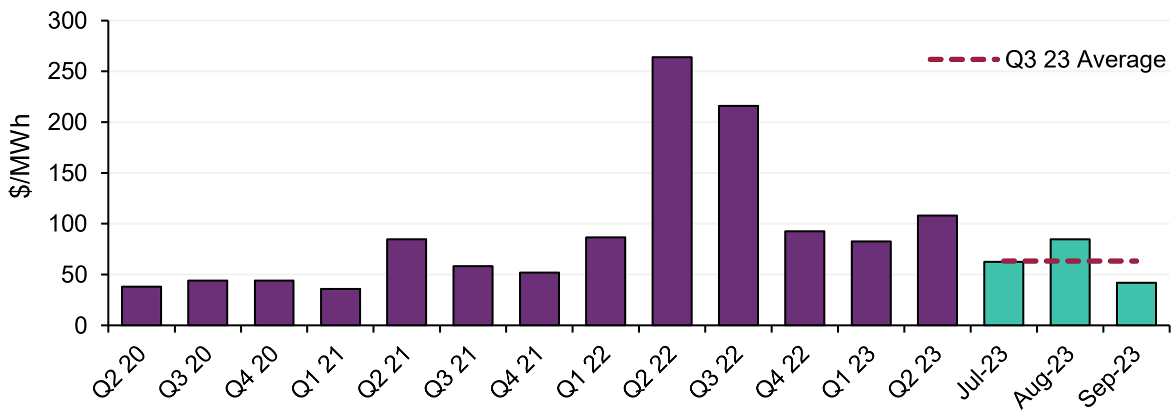


1.2 Wholesale electricity prices

During Q3 2023, NEM-wide wholesale electricity prices averaged $63/MWh, representing a 71% drop in average quarterly prices from $216/MWh in Q3 2022, and a 41% fall from Q2 2023 when prices averaged $108/MWh (Figure 10). While this Q3's average price outcome is a significant reduction from a year ago, it is at a slightly higher level than average prices in Q3 2020 ($44/MWh) and Q3 2021 ($58/MWh), and close to the average of Q3 prices over the 10 years preceding 2022.

Figure 10 Average NEM spot prices down 71% on Q3 2022, but slightly up on two prior Q3s

NEM average wholesale electricity prices – quarterly since Q2 2020



Monthly average prices increased from $63/MWh in July to $85/MWh in August, while September saw the average price dropping to $42/MWh. The August rise in prices was driven largely by significant volatility in South Australia due to a number of planned outages limiting flows on the Heywood interconnector. When these limitations coincided with low wind conditions outside daylight hours, increased gas-fired generation was required, leading to episodes of price volatility (Section 1.2.2). Seasonally lower operational demand and increases in grid-scale renewable output, leading to frequent occurrence of negative prices (Section 1.2.3), then led to the much lower average level of NEM prices in September.

By region, **South Australia** recorded the highest average quarterly price at $92/MWh. This was followed by **New South Wales** and **Queensland** averaging $81/MWh and $65/MWh respectively, while **Victoria** and **Tasmania** recorded lower averages of $49/MWh and $29/MWh respectively (Figure 11).

Quarterly average prices were significantly lower for all regions than in Q3 2022. **Tasmania** saw the biggest reduction, dropping 86% from $202/MWh in Q3 2022 to $29/MWh. Reductions in other regions ranged from 74% in **Victoria** to 60% in **South Australia**. The cap return component of the quarterly average price reduced in all regions from Q3 2022 levels, with **South Australia** the only region to record a substantial cap return in Q3 2023 (see Table 2 in Section 1.2.2 for significant volatility events during the quarter).

Figure 11 All regions saw price declines on Q3 2022 – with minimal cap returns outside South Australia

Average wholesale electricity spot price by region – energy[5] and cap return[6] components for selected quarters

With lower operational demand and increases in distributed PV output (Section 1.1), Q3 2023 saw time of day price averages return towards Q3 2021 levels, but with lower daytime prices including negative averages during the solar peak, and slightly higher overnight prices (Figure 12).

By region in Q3 2023:

- **Queensland** saw a one-year drop of 71% in average quarterly price from $228/MWh in Q3 2022 to $65/MWh, also below Q3 2021's average of $80/MWh. Cap returns were low, with only 274 dispatch intervals recording prices higher than $300/MWh, compared with 5,746 intervals in Q3 2022. Overall drivers of lower Queensland prices included a significant increase in wind and grid-scale solar output (Section 1.3.4).
- **New South Wales** recorded a quarterly average of $81/MWh, a 64% reduction from $225/MWh in Q3 2022, and 41% lower than Q2 2023 when prices averaged $137/MWh. Liddell's closure in Q2 2023 and increasing grid-scale renewable output in Queensland led to wider daytime price separation between the two regions (Figure 13), and higher interconnector flows from Queensland to New South Wales (Section 1.4).

[5] "Energy price" calculation in the analysis of average spot electricity prices truncates the impact of volatility (that is, 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.

[6] Cap return component of quarterly average price is measured as the contribution of spot prices in excess of $300/MWh to the quarterly average.

- **Victoria** saw a quarterly average price reduction of 74%, from $192/MWh a year ago to $49/MWh. This was 45% lower than Q2 2023's average of $89/MWh. As in Queensland and New South Wales, cap returns were marginal in Victoria with prices exceeding $300/MWh in only 167 intervals, compared to 6,655 intervals in Q3 2022.
- **South Australia** had the highest volatility and range in spot prices of any region. Its quarterly average of $92/MWh included a cap return contribution of 30% ($27/MWh) from 1,083 intervals exceeding $300/MWh, with some dispatch prices just below the market cap of $16,600/MWh recorded. Comparison with Q3 2023 nevertheless shows significant reductions in both energy and cap return components of 57% and 66% respectively.
- **Tasmania** recorded the lowest quarterly average price across the NEM, down 86% from $202/MWh in Q3 2022 to $29/MWh in Q3 2023. The low average price in Tasmania was the main driver of higher average exports to Victoria, increasing by 180 MW from Q3 2022 levels.

Figure 12 Prices returned to Q3 2021 levels with more daytime negatives and higher overnight prices

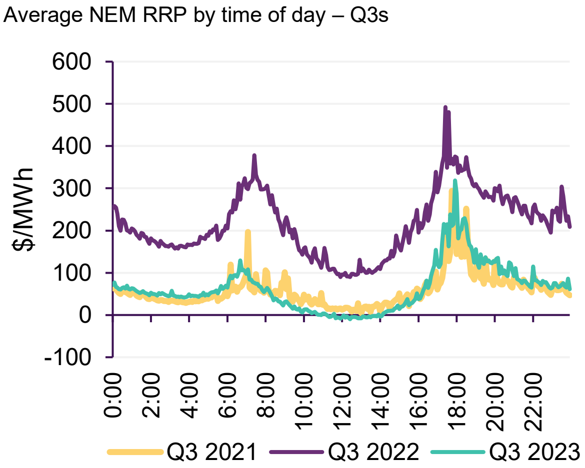
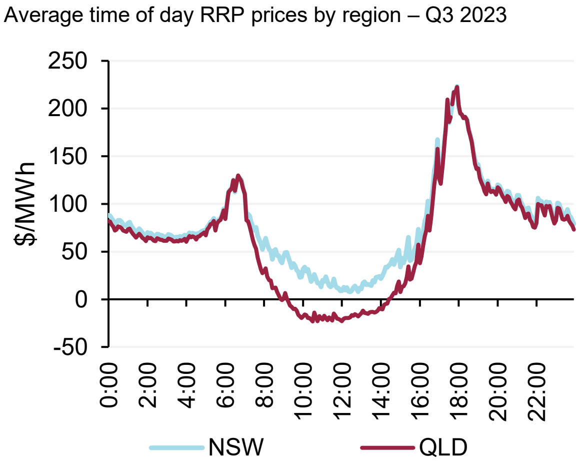


Figure 13 New South Wales prices higher than Queensland, with wider daytime separation



1.2.1 Wholesale electricity price drivers

The following table summarises the main drivers of price changes in the NEM during this quarter, with a combination of factors behind the large year-on-year fall.

Table 1 Wholesale electricity price levels: Q3 2023 drivers

Black coal lower offer curve	Relative to Q3 2022 there were significant increases in the volume and proportion of output offered at lower price ranges by black coal-fired generators in the northern NEM regions (Figure 14). This reflected the introduction of policies capping domestic thermal coal prices over the last year and improvements in the fuel supply position of key generators. Moreover, increasing renewable output in northern regions along with lower operational demand resulted in reduced reliance on and dispatch of thermal generation. In particular, available black coal capacity in Queensland and New South Wales ran at a lower utilisation rate, averaging 75% this quarter compared to 80% in the same period last year (see Section 1.3.1).
Lower underlying and operational demands	The combination of mild weather which reduced underlying demand and strongly increasing distributed PV output led to the largest year-on-year fall in NEM operational demand recorded for any quarter, at -1,143 MW or -5.1%.
New and commissioning VRE capacity in the NEM	During Q3 2023, new and commissioning capacity provided a 425 MW increase in grid-scale solar availability compared to Q3 2022. New and commissioning wind farm capacity contributed a 211 MW increase to available energy.

Price volatility events	Significant price volatility was only evident in South Australia during August when Heywood interconnector capacity was limited over several periods due to line outage works. During these outage periods, some instances of low wind generation resulted in price volatility. A significant portion of the quarterly total cap return for South Australia occurred in intervals where the limit on flows from Victoria via Heywood was binding at 50 MW or lower, compared to a normal capacity of up to 600 MW. Occasional low wind conditions in Victoria in August resulted in isolated price spikes in all mainland regions. See Table 2 (in Section 1.2.2) for more information on price volatility events.
Record negative price occurrence	Lower demand with increased VRE output in the NEM led to a significant increase in negative price occurrence, often being set by VRE generators offering energy at negative levels to reflect the value of Large Generation Certificates. Queensland saw the greatest increase in negative price occurrence relative to Q3 2022.
Lower hydro offer curve	Tasmania had the lowest quarterly price of all NEM regions at $29/MWh. Slightly lower demand, windy conditions (resulting in an increase of 65 MW in average wind generation), increased hydro availability and a significant reduction in hydro offer pricing relative to Q3 2022 (Figure 15) all combined to drive the region's low prices.

Figure 14 More black coal volume offered at lower prices in northern regions

Black coal offer volumes by price range – Q3 2022 - 2023

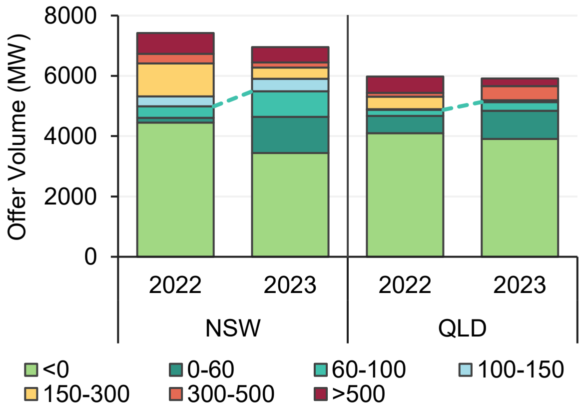
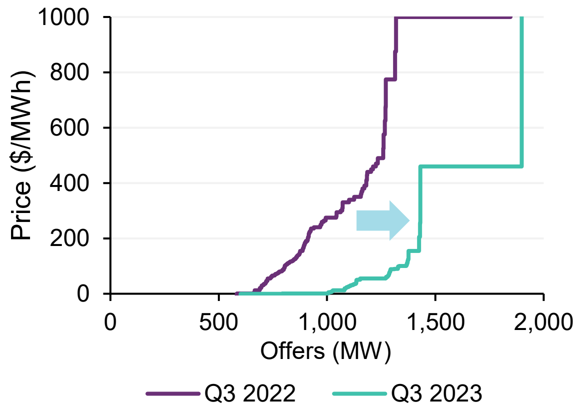


Figure 15 Hydro offer prices in Tasmania significantly reduced from Q3 2022 levels

Hydro bid supply curve (Tasmania) – Q3 2022 - 2023

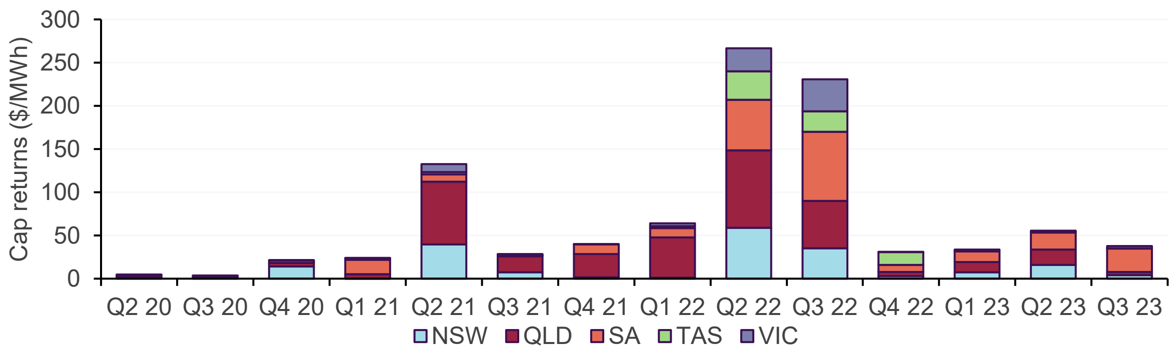


1.2.2 Wholesale electricity price volatility

NEM spot price volatility, measured via cap return (the contribution of spot prices in excess of $300/MWh to the quarterly average), aggregated across the five NEM regions, fell from $231/MWh in Q3 2022 to $38/MWh during Q3 2023 (Figure 16). More than 24% of dispatch intervals in Q3 2022 recorded prices higher than $300/MWh compared to just over 1% for Q3 2023. Q3 2023 cap returns were also below Q2 2023's $56/MWh.

Figure 16 Sharp drop in cap returns in all regions from Q3 2022, South Australia up on Q2 2023

Cap returns by region - quarterly



Q3 2023 was an eventful quarter for **South Australia**, with prices spiking during morning and evening peak mostly during the first half of August. This was the first Q3 since 2018 where South Australia accounted for the majority of total cap return value (72%) across the NEM. This price volatility largely coincided with transmission outage works limiting flows on the Heywood interconnector for periods of several days (between 1-6 August and 11-15 August), and coincident low wind conditions were experienced, tightening supply to the region.

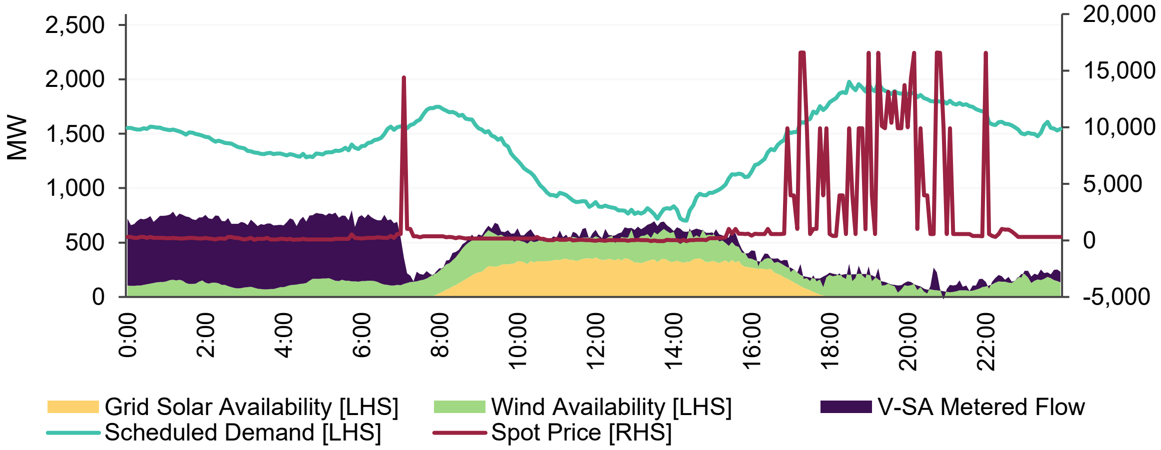
Table 2 summarises events of significant spot price volatility during Q3 2023.

Table 2 Significant volatility events in Q3 2023

Date	Region	Contribution to quarterly cap return ($/MWh)	Drivers
11 August	South Australia	15.26	The major volatility event during the quarter occurred on 11 August in South Australia when the region faced limits on the Heywood interconnector and low wind conditions (Figure 17). Imports via Heywood were limited from 0700 hrs before solar generation ramped up. Major price volatility accompanied the evening peak with falling solar, low wind, and imports constrained. This volatility event accounted for 40% of the total NEM quarterly cap return.
15 August	New South Wales	1.49	On 15 August, low wind conditions in all regions mostly affected South Australian and Victorian wind generation during evening peak, which fell to minimums of 28 MW and 9 MW respectively. Volatile evening prices were seen briefly in all mainland regions (Queensland being the least affected with only 0.35 $/MWh of contribution to quarterly cap return).
	Victoria	1.34	
	South Australia	1.35	

Figure 17 High South Australian prices due to Heywood interconnector limits and low wind

South Australia scheduled demand[7], Heywood flows, available wind and solar, and spot price during 11 August 2023



1.2.3 Negative wholesale electricity prices

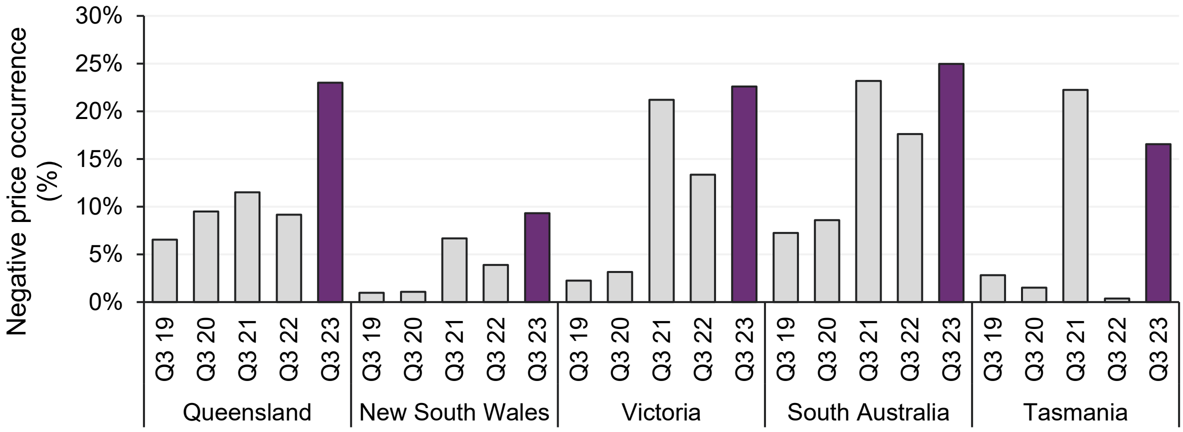
Negative price occurrence across the NEM reached its highest ever level, with 19% of intervals recording negative or zero prices (referred to jointly as "negative price occurrence") during Q3 2023, more than double corresponding levels for Q3 2022 (8.9%), and Q2 2023 (9.2%). All NEM regions saw increased negative price occurrence (Figure 18), with common drivers being large reductions in daytime operational demand and increased grid-scale VRE availability. **South Australia** experienced the highest regional level this quarter at 25% of intervals, driven by extremely low daytime operational demands (160 MW reduction in quarterly average operational demand relative to previous Q3) reflecting increased installed capacity of distributed PV in the state. **Victoria** and **Queensland** both reached 23% negative price occurrence in Q3 2023, followed by **Tasmania** and

[7] 'Scheduled demand' is demand met through the market clearing process by large-scale scheduled and semi-scheduled generation and loads. It is supply required to meet the difference between underlying demand and supply from distributed PV and non-scheduled sources. This differs to operational demand as reported in Section 1.1.2, which excludes demand of dispatchable loads and includes supply from intermittent non-scheduled generation.

New South Wales which saw negative prices in 17% and 9% of intervals respectively. **Tasmania** had the biggest jump in negative price occurrence relative to Q3 2022, mainly due to lower hydro bids as well as higher coal availability in neighbouring Victoria leading to more frequent negative price occurrence in that region.

Figure 18 High Q3 negative price occurrence in all NEM regions

Negative price occurrence in NEM regions – Q3s



Negative price occurrence remained strongly concentrated in daylight hours, reflecting low daytime operational demand due to growing distributed PV output as well as higher grid-scale solar supply.

Queensland had the most notable increases in negative price occurrence from its previous Q3 highs, with a 151% increase from Q3 2022 and a 100% increase from Q3 2021 levels. Figure 19 shows the concentration of this growth in daytime hours, with 77% of intervals between 1000 hrs and 1400 hrs recording negative prices in Q3 2023. Queensland's more frequent negative price intervals than those in **New South Wales** (Figure 20) resulted in a price separation between the two regions, a phenomenon also seen in the last quarter.

Figure 19 New record in Queensland negative price occurrence

Occurrence of negative price by time of day – Q3s 2021-2023

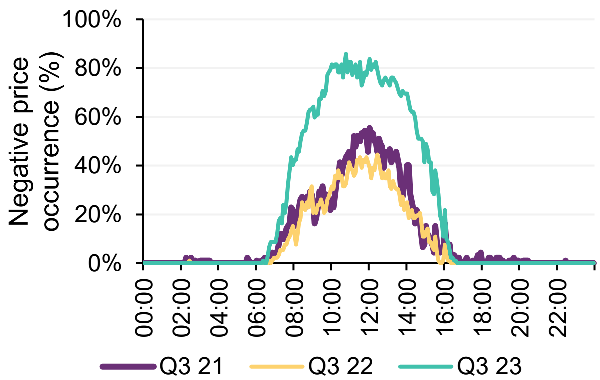
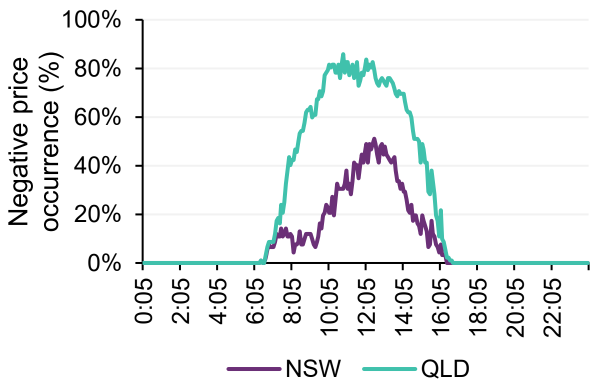


Figure 20 Increased daytime price separation between northern regions

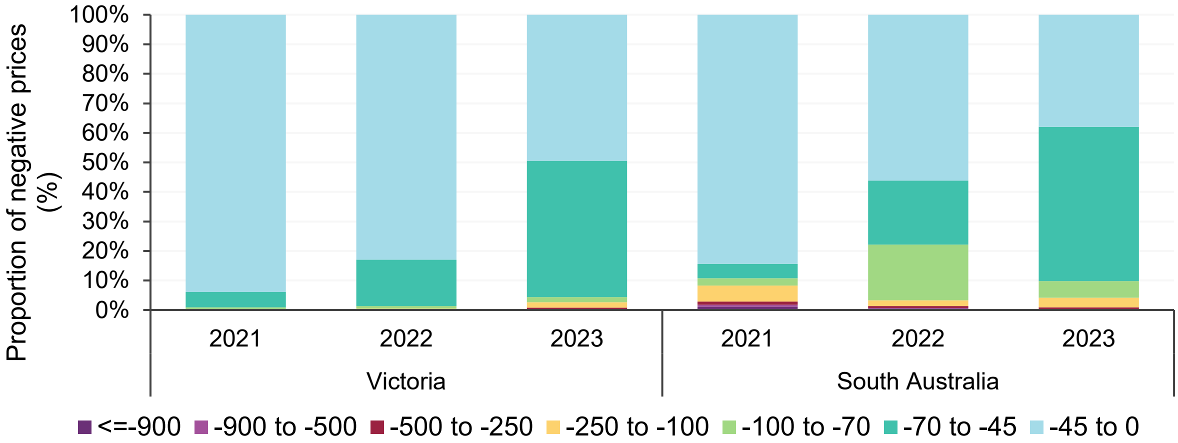
Occurrence of negative prices by time of day – Q3 2023



A breakdown of negative price levels for Q3s since 2021 (Figure 21) shows that when negative prices occur they are tending to fall into lower price ranges. **Victoria** and **South Australia** have seen significant increases in the proportion of negative prices below -$45/MWh, relative to previous Q3s. Across Q3 2023 the proportion of negative Victorian prices in the -$70/MWh to -$45/MWh range was nearly five times larger than Q3 2022 level.

Figure 21 Q3 negatives shifting to more impactful ranges since 2021

Proportion of negative price intervals by price range for Victoria and South Australia – Q3s 2021-2023

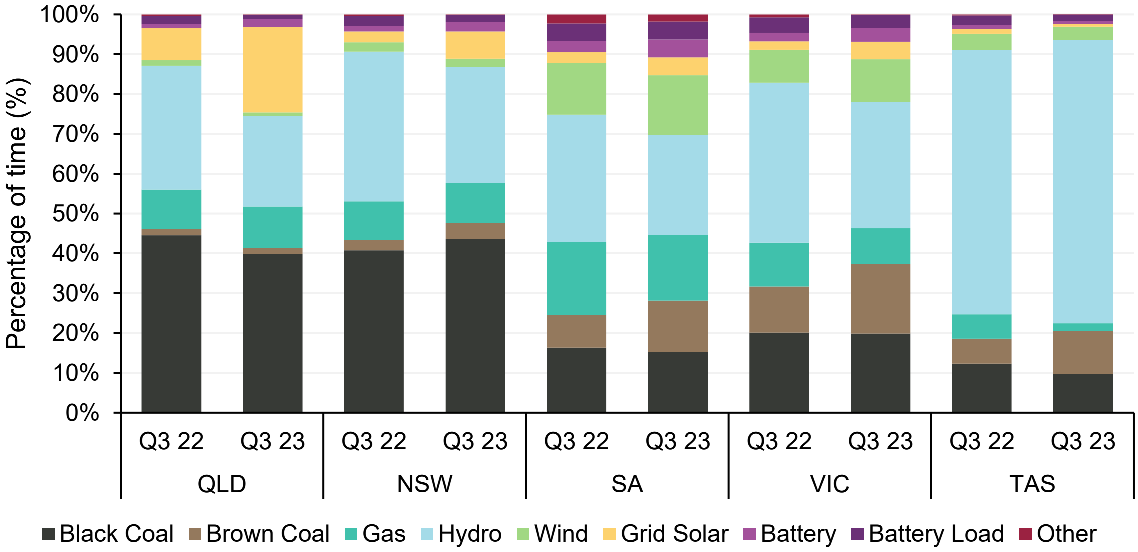


1.2.4 Price-setting dynamics

This Q3 saw a significant increase in grid-scale renewable generators setting the spot price in mainland NEM regions (Figure 22). Hydro still set price most often across the NEM, but its price-setting frequency reduced by 5 percentage points (pp) to 36%. Black coal-fired and gas-fired generation each saw 1 pp decreases, to 26% and 10% respectively. These decreases were offset by increases from grid-scale solar (+4pp) to 8%, brown coal-fired generation (+3pp) to 9% and wind (+1pp) to 6%.

Figure 22 Renewables and brown coal set prices more frequently across the NEM

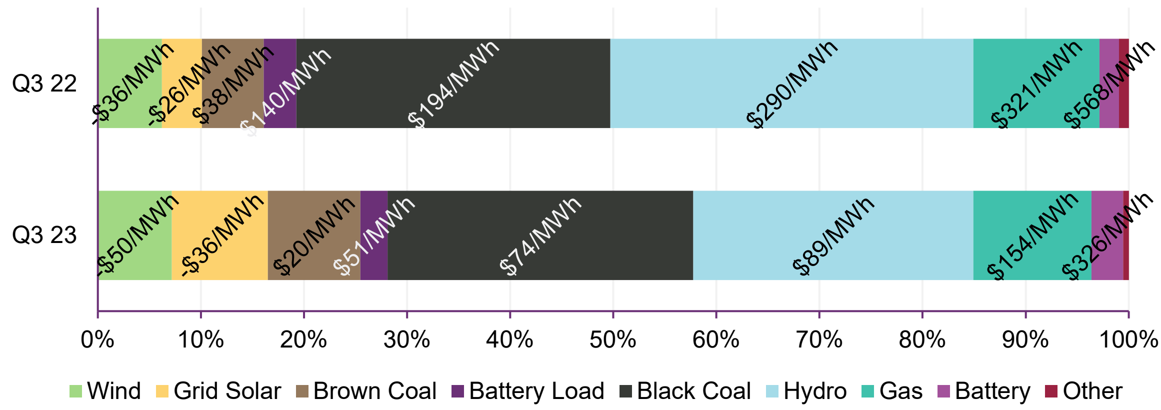
Price-setting frequency by fuel type – Q3 2022 vs Q3 2023



In mainland NEM regions the average prices set by different fuel types all decreased (Figure 23). In Q3 2023, gas, black coal and hydro fuel types set mainland NEM prices 68% of the time compared to 78% in Q3 2022. In both years the contribution of these fuel types to the average price was about the same (approximately 90% of the time-weighted price), but their weighted average price set decreased by $137/MWh, reflecting the higher volumes of black coal generation being offered at lower prices (Section 1.2.1) and reduced operational demand (Section 1.1.2).

Figure 23 Large decreases in averages prices set by all fuel types

Mainland NEM price-setting frequency and average price when price-setter by fuel type – Q3 2022 vs Q3 2023

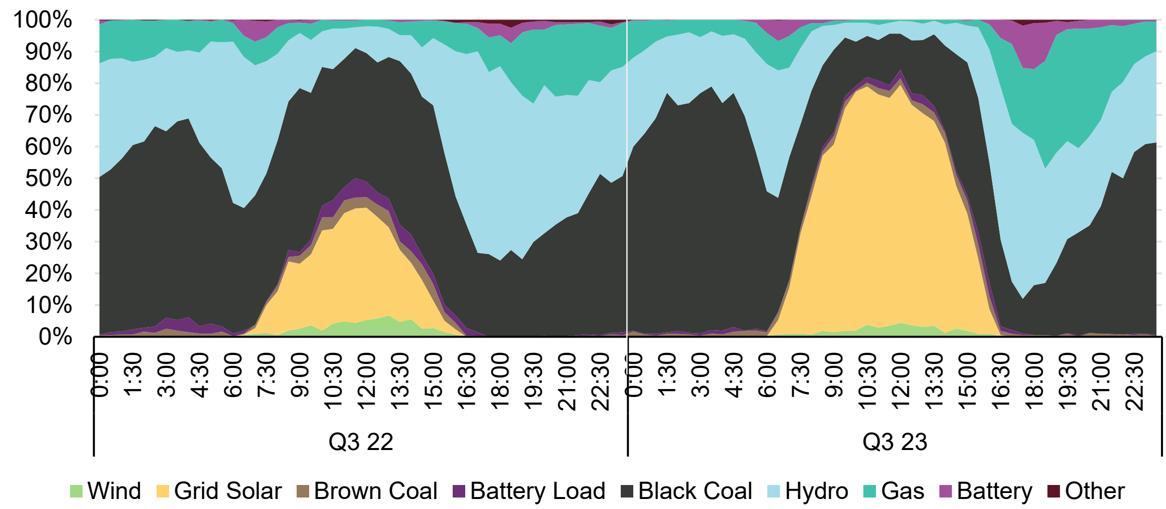


In the southern regions of **Victoria** and **South Australia**, brown coal-fired generators increased the proportion of time they set the price, by 5pp and 6pp respectively. This largely offset decreases in hydro and gas-fired generation price-setting frequency compared to Q3 2022.

In the northern regions of **Queensland** and **New South Wales**, black coal-fired generators were still the most common price-setter by fuel type, although black coal-fired generators' price-setting frequency fell 5 pp in Queensland, offset by a large increase in grid-scale solar (+13pp). Grid-scale solar set the Q3 2023 spot price in Queensland 21% of the time in Q3 2023, but in New South Wales only 7%. Between 1000 hrs and 1400 hrs, grid-scale solar set the Queensland spot price 72% of the time in Q3 2023 compared to 31% in Q3 2022 (Figure 24). In New South Wales, grid-scale solar offers set only 27% of prices in this time period in Q3 2023, reflecting increased daytime binding on the Queensland – New South Wales Interconnector (QNI) (Section 1.4).

Figure 24 Grid-scale solar daytime price-setting frequency increased strongly in Queensland

Queensland price-setting frequency by fuel type and time of day – Q3 2022 and Q3 2023



1.2.5 Electricity futures markets

The price of current financial year (referred to as FY24) ASX base future contracts across all mainland NEM regions averaged $96/MWh at the end of Q3 2023, $24/MWh lower than at the end of Q2 2023 (Figure 25).

Queensland saw the largest change in FY24 prices, decreasing 26% to $100/MWh, followed by **Victoria** (-24%) to $68/MWh and **New South Wales**, down 23% to $108MWh. **South Australian** prices also decreased, although with less daily volatility.

Most of the decrease of FY24 contract prices occurred in July, then remained relatively stable with a slight downward trend. By comparison, forward financial year contracts remained at around the same level (Figure 26).

Figure 25 FY24 futures trended downward at the start of the quarter

ASX Energy – daily FY 2023-24 base futures by region

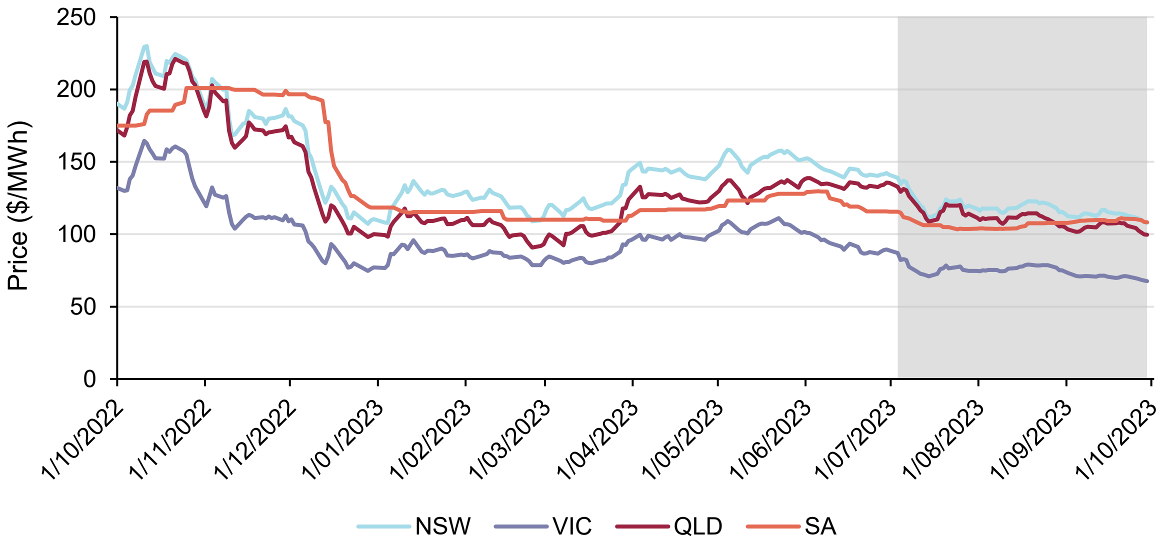


Figure 26 Decrease in FY24 contract prices in Queensland, New South Wales and Victoria

Financial year contract prices in mainland NEM regions – end of Q2 2023 vs end of Q3 2023

1.3 Electricity generation

Total generation across the NEM[8] averaged 23,899 MW in Q3 2023, 678 MW (-2.8%) lower than Q3 last year. The average output of grid-scale solar and distributed PV generation rose significantly, offset by larger decreases in black coal and gas-fired generation which also reflected lower underlying demands (Figure 27).

- The combined output of grid-scale solar and distributed PV averaged 3,816 MW this quarter, up by 947 MW (33%) from Q3 last year. Increased grid-scale solar generation was driven by the uplift in output from new and commissioning grid-scale solar facilities in Queensland and New South Wales. Compared to Q3 2022, wind output was largely unchanged (-9 MW) with increased output from newly connected units in Queensland and Victoria offset by lower availability from established wind farms in New South Wales and South Australia, particularly in August (Section 1.3.4).
- Black coal-fired generation across the NEM dropped by 1,107 MW from Q3 2022. Average availability from this source decreased by 514 MW, primarily driven by closure of Liddell Power Station, partially offset by higher availability at remaining New South Wales coal units. Despite their higher availability, combined output from these remaining units decreased by 166 MW due to a lower utilisation rate in this quarter. The reduction in output was most evident in the middle of the day, in response to higher distributed PV and grid-scale solar output (Section 1.3.1) and lower spot prices (Section 1.2).

Figure 27 Large declines in black coal and gas-fired generation

Change in NEM supply by fuel source – Q3 2023 vs Q3 2022

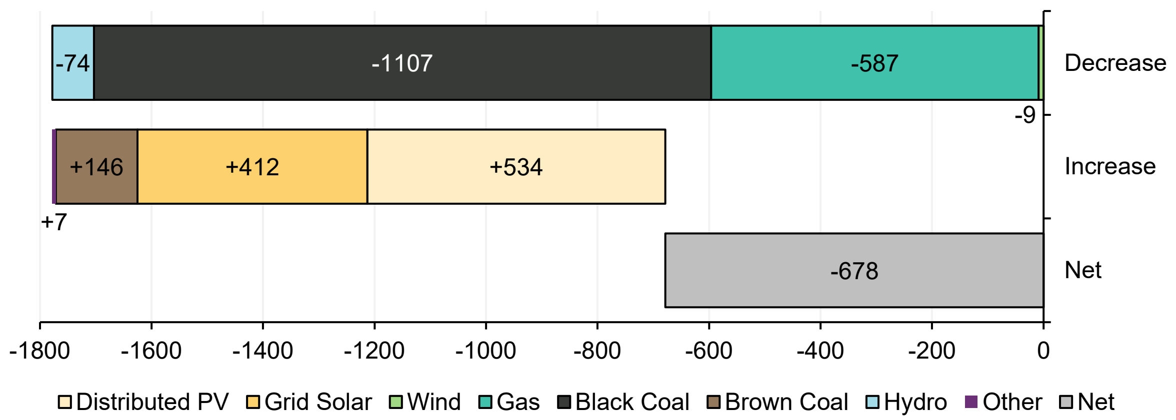


Table 3 shows the NEM supply mix by fuel type. Black coal saw a reduction of 3.4 pp in its share, primarily due to the loss of Liddel's generation. Gas-fired generation's share fell to 4.8% this quarter from 7.1% in Q3 last year, which saw elevated gas-fired output on the back of coal-fired generation outages. Wind, grid-scale solar and distributed PV saw a combined increase of 4.6 pp from Q3 last year.

Table 3 NEM supply mix contribution by fuel type

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar	Distributed PV	Other
Q3 22	44.0%	14.6%	7.1%	8.7%	13.6%	4.5%	7.1%	0.3%
Q3 23	40.7%	15.6%	4.8%	8.6%	14.0%	6.4%	9.6%	0.4%
Change	-3.4%	1.0%	-2.3%	-0.1%	0.3%	1.9%	2.4%	0.0%

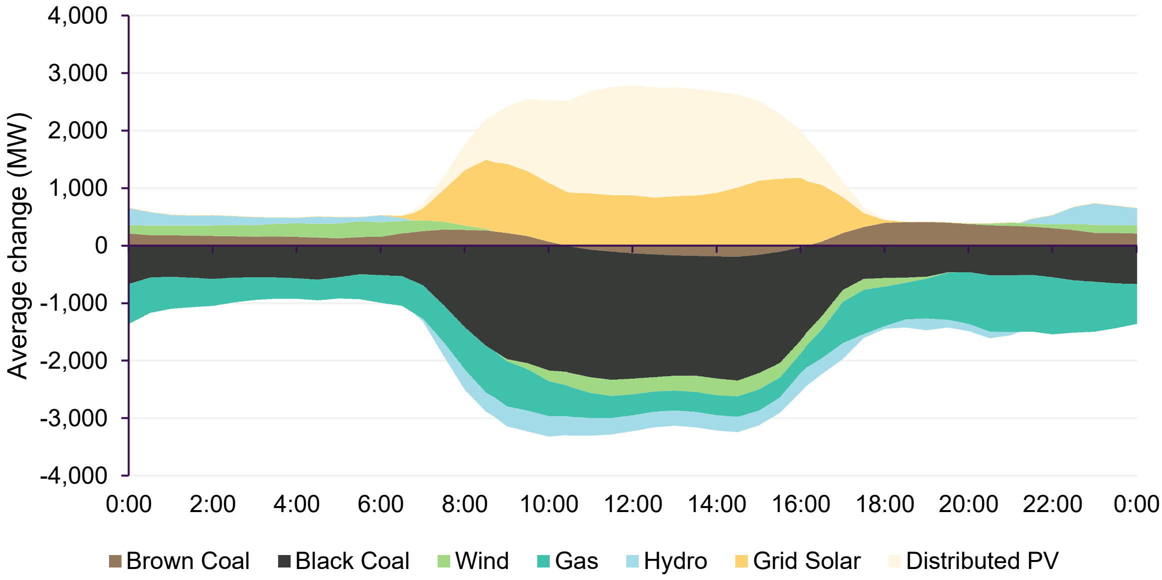
[8] Generation calculation includes AEMO's best estimates of generation from distributed PV, and supply from certain non-scheduled generators and supply to large market scheduled loads (such as pumped hydro and batteries) which are excluded from operational and underlying demand measures discussed in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

Figure 28 shows changes in generation by fuel type between Q3 2022 and Q3 2023 by time of day:

- The uplift in distributed PV and grid-scale solar output in the middle of the day offset reduced output from black coal-fired generation, which saw this quarter's largest decrease for a single fuel source.
- Brown coal-fired generation increased in most hours except when solar output was highest.
- Gas-fired generation decreased in all periods with its most pronounced reduction overnight.
- Hydro output decreased during daytime hours but increased overnight as hydro generators aimed to maximise the value of released water.
- Lower wind output during daytime and early evening hours arose from a combination of reduced available energy during these periods, driven by lower wind speeds in New South Wales and South Australia, and increases in price-based offloading during peak daylight hours.

Figure 28 Large daytime drops in gas and black coal generation as VRE output increased

NEM generation changes by time of day – Q3 2023 vs Q3 2022



1.3.1 Coal-fired generation

Black coal-fired generation

In this quarter, black coal-fired generation averaged 9,718 MW, its lowest Q3 output recorded since NEM start (Figure 29). Output decreased by 1,107 MW (-10%) from the same period last year as a result of reduced available generation and lower utilisation rates. Black coal availability reduced by 514 MW (-4%) to its lowest Q3 average of 12,885 MW, while its utilisation rate[9] dropped from 80% in Q3 2022 to 75% this quarter.

The reduction in black coal availability was predominantly in **New South Wales** (-466 MW), driven by the closure of Liddell units in late April 2023 which reduced available Q3 generation by 784 MW year-on-year. **Queensland** saw a minor reduction (-48 MW) from Q3 2022 (Figure 30). The closure of Liddell was partially offset by increased availability of the remaining New South Wales black coal fleet, with a 318 MW availability uplift driven by fewer

[9] Utilisation rate is calculated as average generation output divided by average available energy.

planned and unplanned outages (Figure 31). As a result, the available capacity factor[10] of black coal units increased by 3 pp to 73% in Q3 2023.

Figure 29 Black coal-fired generation reduced to its lowest Q3 level

Quarterly average black coal-fired generation by region (including decommissioned units) – Q3s

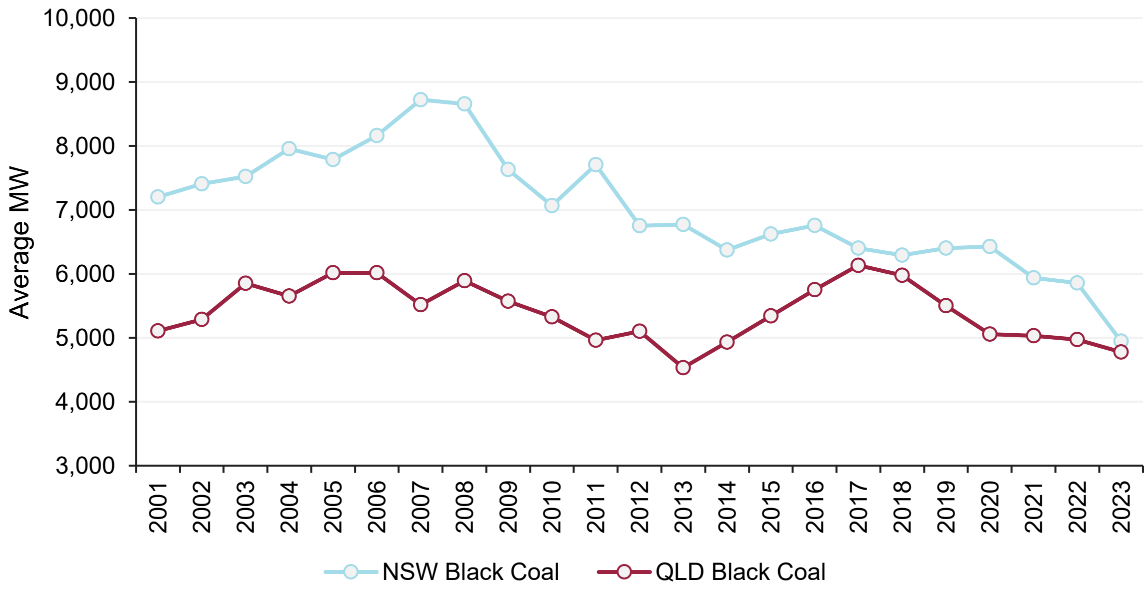


Figure 30 Lowest Q3 black coal-fired available generation on record

Quarterly average black coal-fired availability– Q3s

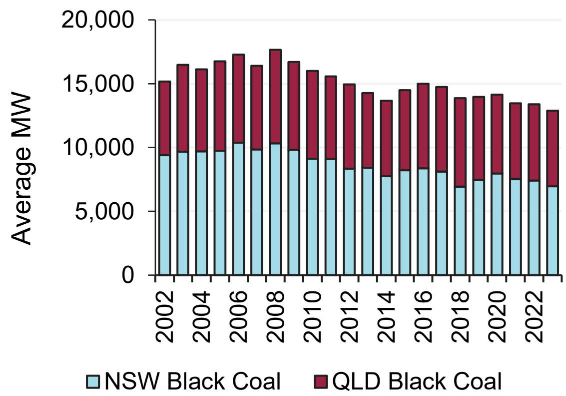
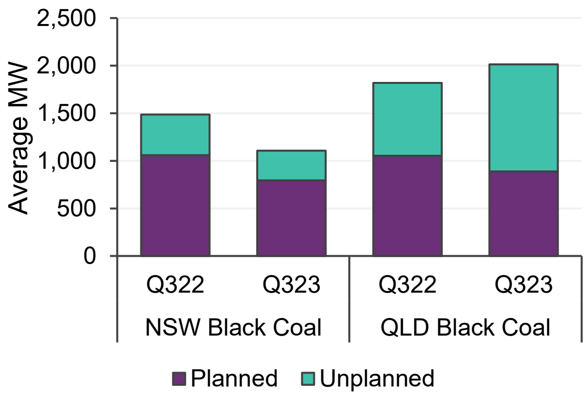


Figure 31 Coal-fired capacity on outage declined in New South Wales

Average coal-fired capacity on outages – Q3 22 vs Q3 23



The largest decrease in black coal-fired generation output was in **New South Wales**, with a reduction of 909 MW (-16%) from Q3 2022. Liddell's closure accounted for most of this drop (-743 MW), while output from the state's remaining coal-fired generators fell by 166 MW. Key changes by power station, as shown in Figure 32, were:

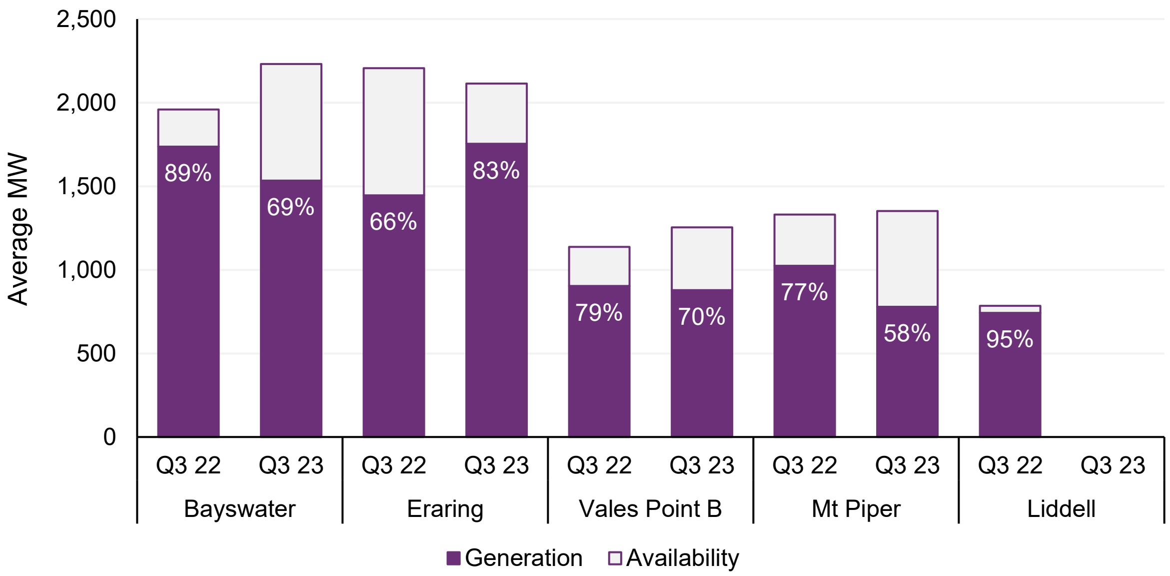
- Bayswater output fell by 204 MW despite a 272 MW increase in availability. The station's utilisation rate dropped by 20 pp with middle-of-day generation decreasing but evening generation higher.

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

- Despite a 91 MW reduction in availability, and unlike its peers, Eraring recorded a strong uplift in output of 307 MW with its utilisation rate increasing to 83% this quarter from 66% in Q3 2022. The increase was most evident during morning and evening peak periods as well as overnight hours, while middle of day generation remained unchanged.
- Mount Piper average generation fell 244 MW despite a 21 MW availability uplift.
- Vales Point average output decreased by 24 MW while availability increased by 117 MW.

Figure 32 Bayswater, Vales Point B and Mt Piper increased availability, offsetting Liddell closure

Average quarterly availability, generation and utilisation for New South Wales black coal-fired power stations – Q3 2023 vs Q3 2022



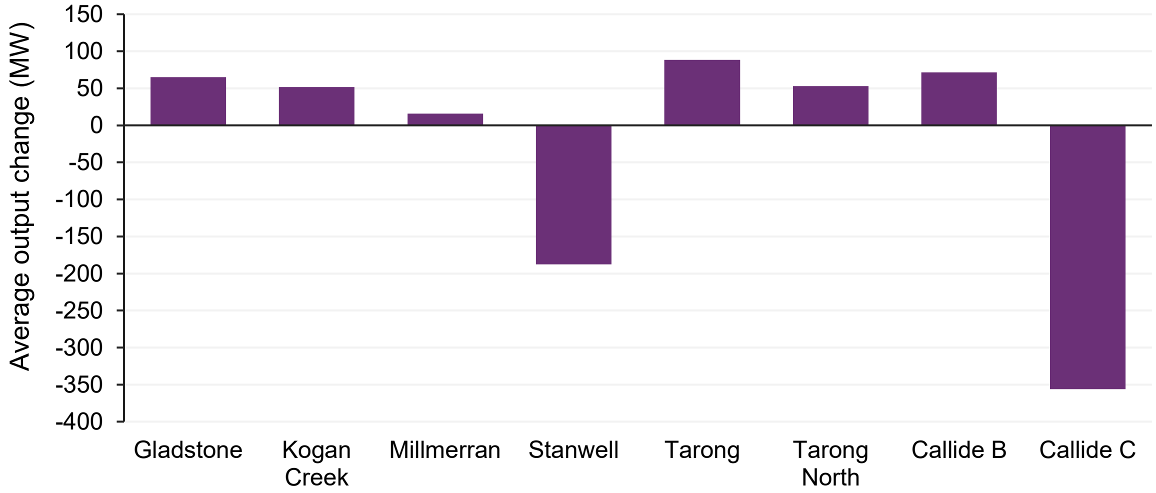
Black coal-fired output in **Queensland** reduced by 198 MW this quarter compared to Q3 2022, driven by reduced output from Stanwell and Callide C units. Key changes by power station, as shown in Figure 33, were:

- Stanwell output decreased by 187 MW despite an availability increase of 33 MW this quarter. Stanwell's utilisation rate dropped to 69% from last year's 89%. The reduction in Stanwell's output was evident throughout the day with a relatively smaller fall during evening peak period.
- A drop of 356 MW at Callide C following unit C3's long term forced outage which began in October 2022. On 30 May, CS Energy advised the market of revised return-to-service dates for both units at Callide C Power Station. C3 unit's full return has been delayed until February 2024, with 50% capacity to return in January 2024. The rebuilt C4 unit's full return has been revised to July 2024, with 50% capacity expected by May 2024[11].
- Tarong increased output by 89 MW despite a 55 MW reduction in availability, lifting its utilisation rate from 77% in Q3 last year to 88% this quarter.
- Remaining Queensland black coal units including Gladstone, Kogan Creek, Millmerran, Tarong North and Callide B units saw increased availability as well as higher generation.

[11] See https://www.csenergy.com.au/news/updated-return-to-service-dates-for-callide-c-generating-units/may2023.

Figure 33 Stanwell and Callide output decreases

Average Queensland black coal-fired output change by generator – Q3 2023 vs Q3 2022

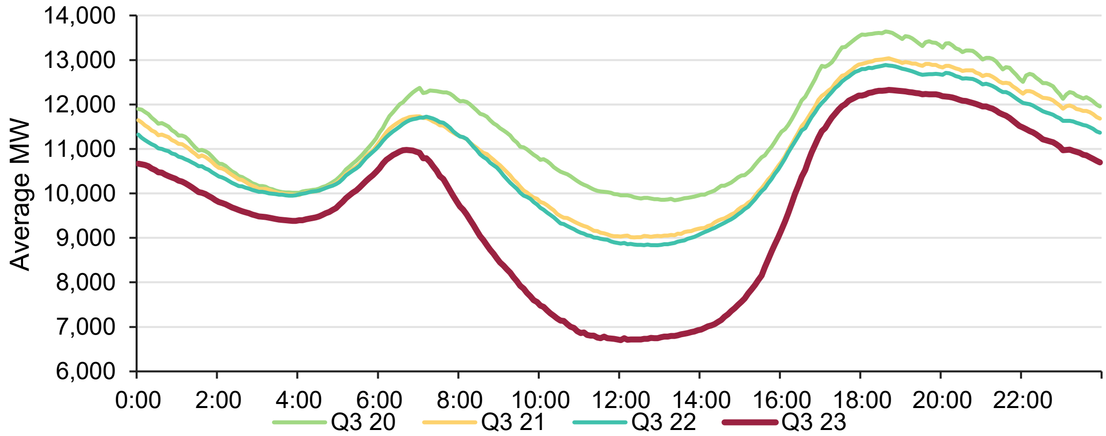


Continuing trends from recent quarters, black coal-fired output fell in the middle of the day in Q3 2023 as renewable output displaced thermal generation (Figure 34). While lower output was evident throughout the day, black coal-fired generators were dispatching significantly less in the middle of the day when operational demand was low, grid-scale solar generation was high, and spot prices were at low or negative levels.

The difference between minimum and maximum values of average output over the day increased by 1,573 MW to 5,624 MW, indicating capability to operate flexibly according to market signals. In **New South Wales**, Bayswater and Vales Point B showed increased flexibility, with the variation between minimum and maximum averages increasing by 669 MW and 184 MW respectively. In **Queensland**, Gladstone, Kogan Creek, Millmerran, and Stanwell also exhibited significant increases in this measure.

Figure 34 Daytime black coal-fired generation continued to decline

NEM black coal-fired output by time of day – Q3s from 2020 to 2023



Brown coal-fired generation

In Q3 2023, brown coal-fired generation averaged 3,730 MW, 146 MW (4%) higher than the same period last year. Brown coal availability increased by 477 MW (13%) to 4,299 MW in Q3 2023, its highest Q3 level for seven years (Figure 35), yielding a utilisation rate of 89% compared to 96% in Q3 2022. In this quarter, there were fewer unplanned coal-fired outages in **Victoria** compared to Q3 last year, with Loy Yang A accounting for most of the reduction (-539 MW) in total outages.

This quarter saw availability increase at both Loy Yang A and Loy Yang B. Loy Yang A's availability increased by 516 MW while generation increased by 261 MW, bringing down its utilisation from 95% to 85%. At Loy Yang B, availability increased by 3 MW while output decreased by 27 MW. Yallourn saw a 42 MW availability drop while its output decreased by 88 MW, resulting in utilisation of 94% compared to 98% last year.

Brown coal units also exhibited a more flexible profile over the day, with the difference between daily minimum and maximum average output increasing by 567 MW from Q3 2022 (Figure 36).

Figure 35 Brown coal-fired availability and output increased

NEM brown coal-fired generation and availability – Q3s

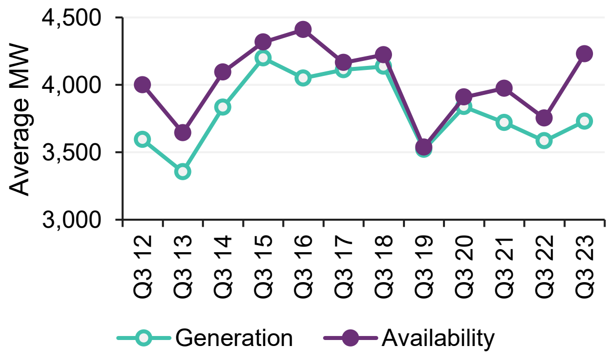
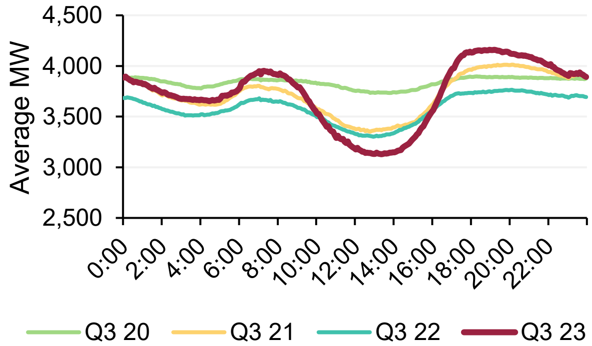


Figure 36 Increasing swing at brown coal-fired generators

Brown coal-fired output by time of day – Q3s from 2020 to 2023

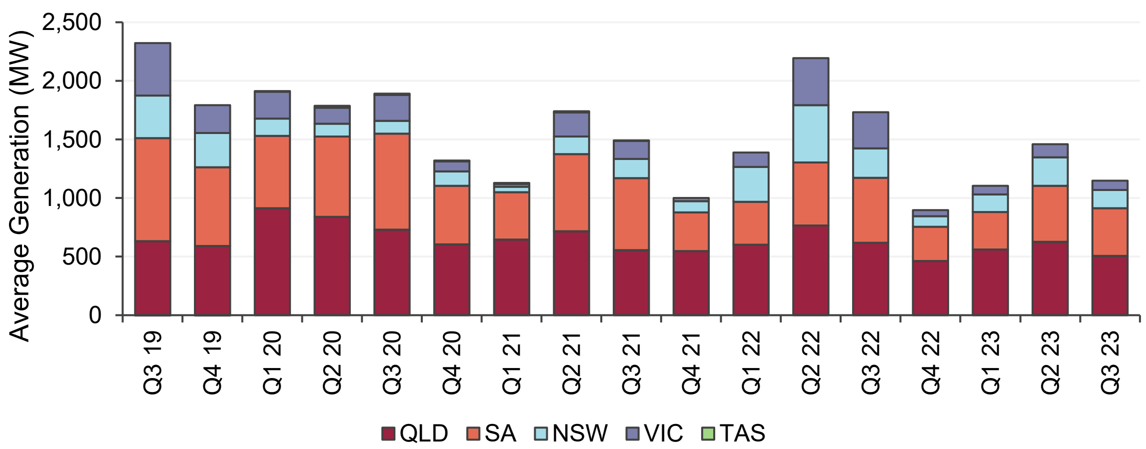


1.3.2 Gas-fired generation

In Q3 2023, gas-fired generation across the NEM averaged 1,156 MW, the lowest Q3 output since 2004 and a decrease of 587 MW (-34%) on Q3 2022 (Figure 37). Although average generation decreased throughout the quarter, its fall was most pronounced in July, with a decline of 1,195 MW compared to July 2022. Q3 2022 witnessed relatively high gas-fired generation, particularly in July, driven by high electricity spot prices and extended coal plant outages.

Figure 37 Gas-fired generation in Q3 2023 reached its lowest Q3 level since 2004

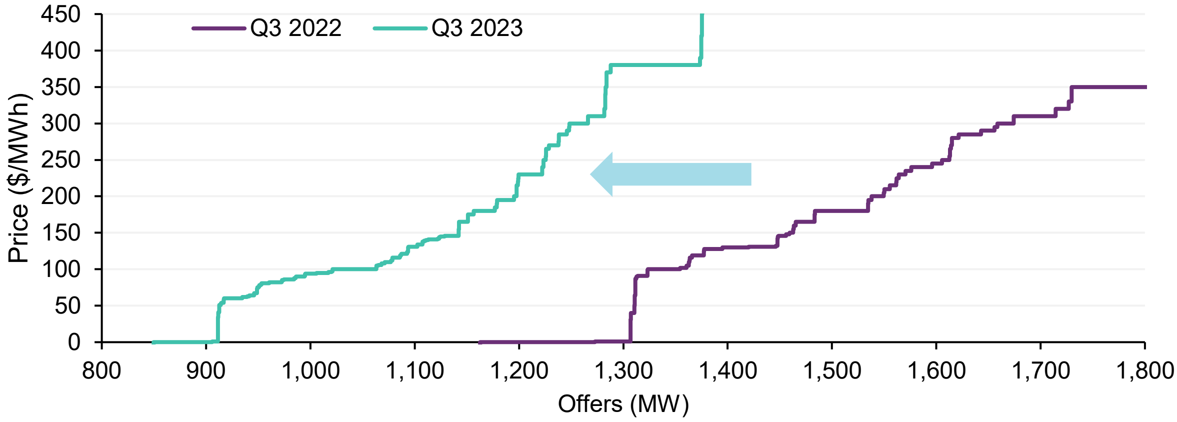
Quarterly average gas-fired generation by region



In Q3 2023, electricity spot prices fell significantly across the NEM (Section 1.2) with substantial additional supply from renewable sources (Section 1.3.4), and lower demand (Section 1.1) which eased the supply-demand balance. These factors collectively led to gas-fired generators committing less capacity for dispatch. As Figure 38 shows, the average volume of gas-fired generation offered to the market decreased by 300-400 MW in offer price bands between $0 and $300/MWh. This, combined with increased coal and hydro volumes offered in these price bands (Section 1.2.1), and record high grid-scale VRE output, resulted in lower dispatch of gas-fired generation this quarter.

Figure 38 Gas-fired generation offer volumes declined

Gas-fired generation bid supply curves – Q3 22 and Q3 23



By region, changes in average quarterly gas-fired generation compared to Q3 2022 were:

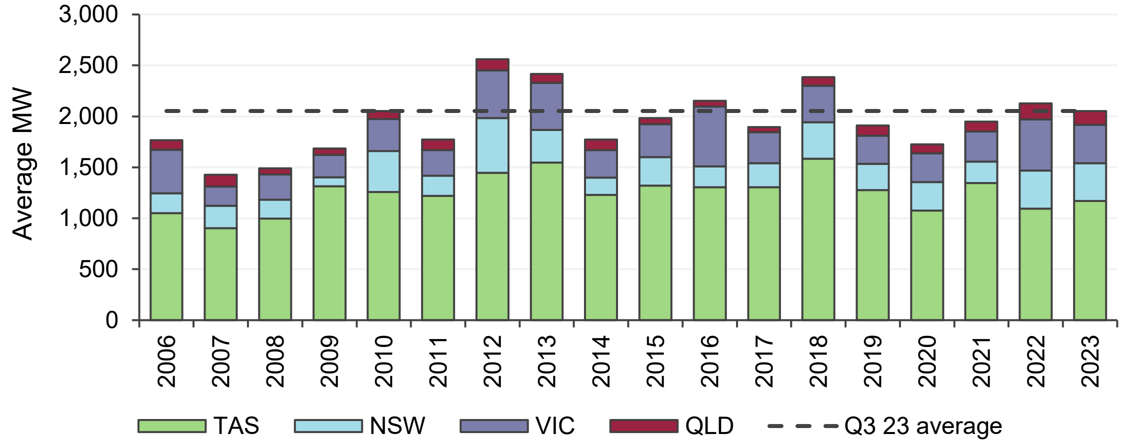
- In **Victoria**, gas-fired generation fell by 228 MW (-74%) to average just 82 MW, the lowest Q3 output since 2011. While most Victorian gas-fired generators saw decreased output, the reduction was largest at Mortlake and Newport power stations, where outputs fell by 83 MW and 81 MW respectively. Laverton and Somerton power stations also reduced output, by 29 MW and 18 MW respectively.
- **South Australian** gas-fired generation decreased by 150 MW (-27%) to average 405 MW in this quarter. This decrease was primarily driven by Torrens Island and Osborne power stations generating respectively 83 MW and 61 MW less on average than in the same period last year. Conversely, Pelican Point (+28 MW) and Mintaro (+15 MW) power stations saw increased generation compared to Q3 2022.
- Gas-fired generation in **Queensland** averaged 507 MW this quarter, 110 MW (-18%) lower than Q3 2022. Origin's Darling Downs Power Station lowered its output by 72 MW but remained the largest producer in this quarter with an average output of 177 MW. Swanbank E, which was mostly offline in Q3 last year due to an extended outage, lifted its average output by 77 MW this quarter.
- Gas-fired generation in **New South Wales** averaged 156 MW, 96 MW (-38%) below Q3 2022. Energy Australia's Tallawarra lowered its output by 69 MW, and average output from Snowy Hydro's Colongra power station dropped from 65 MW in Q3 2022 to just 2 MW in Q3 2023. Conversely, output at Origin's Uranquinty Power Station increased from 17 MW a year ago to average 51 MW in Q3 2023.

1.3.3 Hydro

In this quarter, hydro generation across the NEM averaged 2,053 MW, 74 MW (-4%) lower than Q3 2022 (Figure 39). This decline was evident in all mainland regions, particularly in Victoria, and was partially offset by increased output from Tasmanian hydro generators.

Figure 39 Hydro generation dropped in mainland regions, but increased in Tasmania

Average hydro output by region – Q3s



Lower spot prices, particularly the substantial reduction in intervals where prices exceeded $300/MWh[12], largely explain the lower hydro generation volumes in mainland regions. Reductions in mainland hydro generation occurred across most times of day outside overnight periods (Figure 40).

In contrast, **Tasmania** saw an uplift in hydro output, driven by increased supply volumes offered below $300/MWh this quarter (Figure 15, Section 1.2.1). As in mainland regions, Tasmanian generation decreased during daytime hours but significantly increased during the overnight period as hydro generators aimed to maximise the value of released water while maintaining upstream storage volumes. As Figure 41 shows, Tasmanian hydro dam levels were at 48% of capacity by the end of September, 8 pp higher than at the same time last year.

Figure 40 NEM mainland hydro generation declined outside overnight periods

NEM mainland hydro generation by time of day – Q3 2023 vs Q3 2022

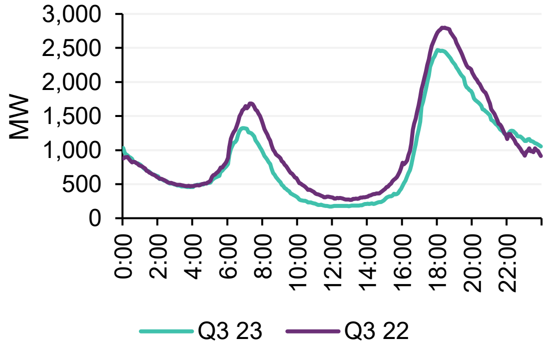
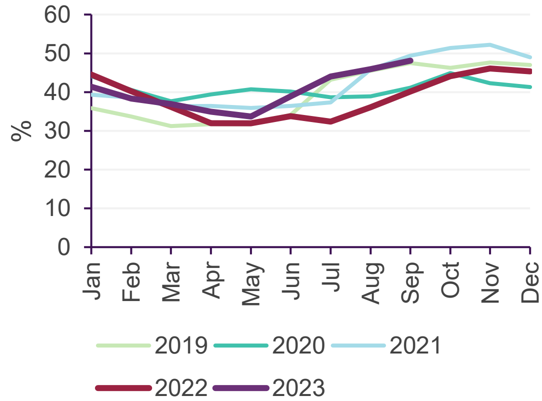


Figure 41 Higher Tasmanian hydro dam levels

Hydro Tasmania dam levels 2019 to 2023



Changes in average quarterly hydro generation by region compared to Q3 2022 were:

- In **Tasmania**, hydro generation averaged 1,168 MW this quarter, 75 MW (+7%) higher than same time last year. Most of this increase was from John Butters (+65 MW) and Reece (+47 MW) power stations.

[12] Cap contracts require the seller to make “difference payments” to the cap contract buyer when spot prices exceed a fixed contract “strike price”, which is typically set at $300/MWh. Cap sellers who own generation therefore have a strong incentive to operate that generation if spot prices exceed this level.

- **Victoria** saw the largest decrease in hydro generation, with a 123 MW drop from Q3 2022 to 377 MW this quarter. The majority of this was from Murray (-73 MW), and McKay Power Station (-29 MW), which came online in August this year after being on a planned outage from March 2023.
- Hydro generation in **Queensland** and **New South Wales** decreased by 23 MW (-14%) and 4 MW (-1%) respectively to average 135 MW and 372 MW. In Queensland, all generators decreased their output, while in New South Wales, increased output from Upper Tumut (+32 MW) and Blowering (+15 MW) was offset by generation decreases at Shoalhaven (-28 MW) and Tumut 3 (-13 MW).

1.3.4 Wind and grid-scale solar

This quarter saw average output from grid-scale VRE reach a record high for any quarter at 4,868 MW, up by 404 MW (+9%) from Q3 last year (Figure 42). Grid-scale solar output increased by 412 MW (+37%), accounting for the entire net uplift in VRE, and reached a record Q3 average output of 1,529 MW. Wind output fell 9 MW (-0.3%) on Q3 2022 but still recorded its second highest quarterly level at 3,340 MW.

Queensland and **New South Wales** led the grid-scale solar growth, with outputs increasing by 183 MW (+42%) and 221 MW (+48%) respectively (Figure 43). **South Australia** also saw grid-scale solar output increase, by 16 MW (+23%), while **Victoria** saw an 8 MW (-6%) reduction.

Wind output increased in **Queensland** (128 MW, +56%), **Victoria** (83 MW, +6%) and **Tasmania** (65 MW, +33%). This was offset by **New South Wales** and **South Australia** where wind output decreased by 141 MW (-18%) and 144 MW (-17%) respectively.

Figure 42 Steady increase in grid-scale solar output

Average quarterly VRE generation by energy source – Q3s

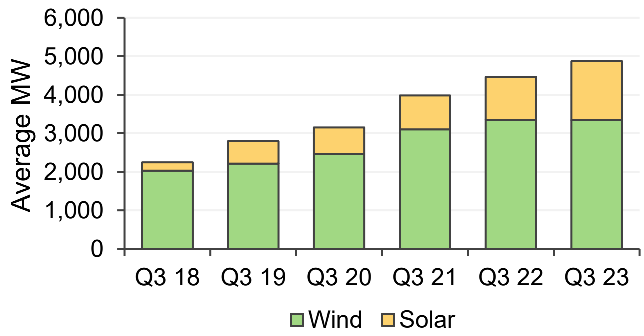
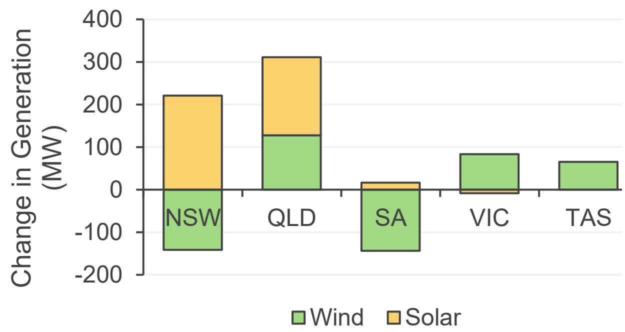


Figure 43 New South Wales and Queensland grid-scale solar drove VRE output growth

Average MW change in VRE output Q3 2022 to Q3 2023



In this quarter, increased VRE output was primarily driven by new and commissioning facilities accounting for a 636 MW uplift in available energy. The available output of existing grid-solar units also rose by 161 MW, driven by increased solar irradiance (Figure 44). This was partially offset by lower wind resource availability at existing facilities (-155 MW, Figure 45) and increased economic offloading by some wind and solar generators (-214 MW) in response to a higher incidence of negative spot prices (Section 1.2.3). Network-driven curtailment increased by 25 MW.

Figure 44 New solar farms largest contributors to grid-scale solar growth

Increase in grid-scale solar generation – Q3 2022 vs Q3 2023

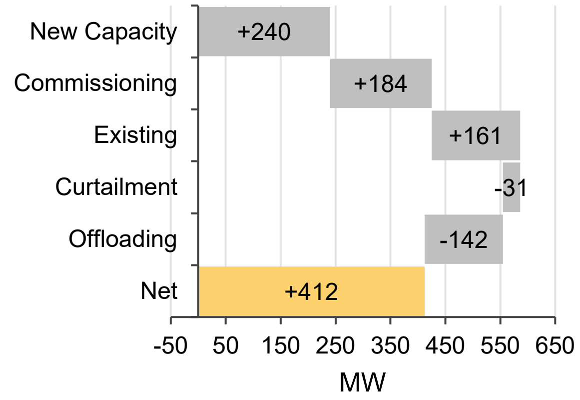
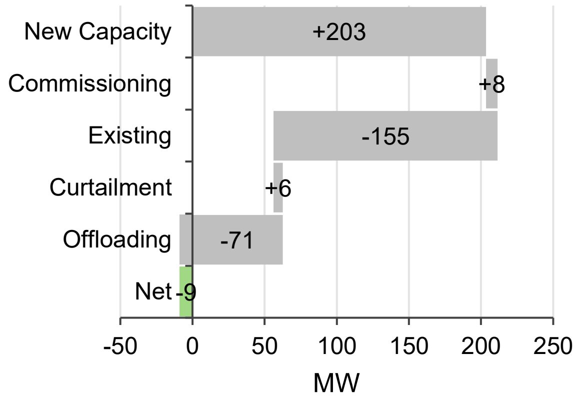


Figure 45 Reduced availability at established wind farms offset growth from new capacity

Increase in wind generation – Q3 2022 vs Q3 2023

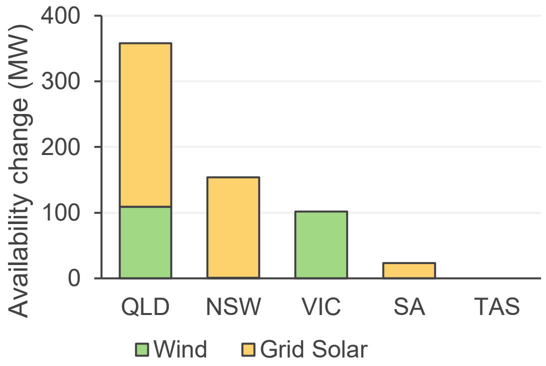


New and commissioning capacity

Of the 636 MW availability uplift from new and commissioning VRE units this quarter relative to Q3 2022, grid-scale solar added 425 MW (Figure 46).

Figure 46 Queensland led uplift in available VRE output

New and commissioning units availability change by region – Q3 2023



Queensland saw an increase of 67 MW from newly connected grid-scale solar facilities and 182 MW from those continuing their commissioning. Availability increases from newly added capacity included Edenvale (+38 MW), Moura (+16 MW) and Wandoan (+12 MW) solar farms, with significant increases from solar farms continuing commissioning at Bluegrass (+41 MW), Columboola (+37 MW), Western Downs Green Power Hub (+77 MW) and Woolooga (+27 MW).

In **New South Wales**, an increase of 153 MW came from new farms New England 1 and 2 (+91 MW), Avonlie (+33 MW), West Wyalong (+23 MW) and Wyalong (+6 MW).

Availability from new and commissioning wind farms across the NEM grew 211 MW, with a significant increase in **Queensland** due to newly connected Kaban Green Power Hub (+62 MW) and Dulacca Wind Farm (+47 MW). In **Victoria**, 93 MW was added from Berrybank 2 (+45 MW) and Mortlake South Wind Farm (+48 MW).

Existing capacity

In Q3 2023, available output from existing grid-scale solar units across the NEM increased by 161 MW, but availability from existing wind units decreased by 155 MW. Higher solar irradiance this quarter increased available grid-scale solar energy across the NEM, particularly in **New South Wales** (+105 MW) and **Queensland** (+31 MW) (Figure 47).

Drops in wind availability were prominent in **New South Wales** (-140 MW) and **South Australia** (-123 MW) (Figure 48), with available capacity factor for Crudine Ridge and Gullen Range 2 wind farms in New South Wales decreasing by 11 pp and 14 pp respectively. In South Australia, available capacity factors for Lincoln Gap 1 and Willogoleche each decreased from 47% to 32%, Snowtown decreased from 44% to 35%, and Lincoln Gap 2 decreased from 47% to 36%.

Figure 47 Increased solar irradiance across the NEM

Volume-weighted grid-scale solar available capacity factors for established solar farms – Q3 23 vs Q3 22

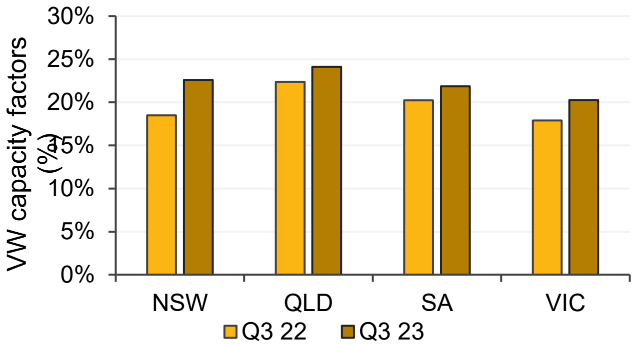
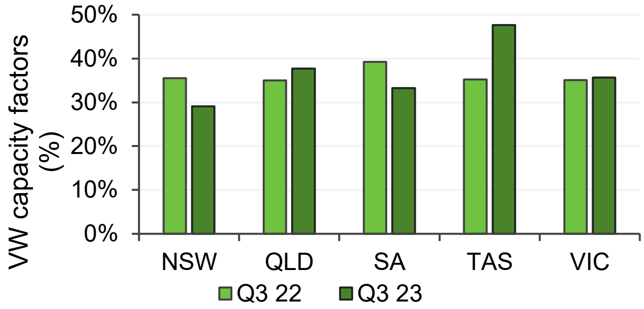


Figure 48 Lower availability for wind farms in New South Wales and South Australia

Volume-weighted wind available capacity factors for established wind farms – Q3 23 vs Q3 22

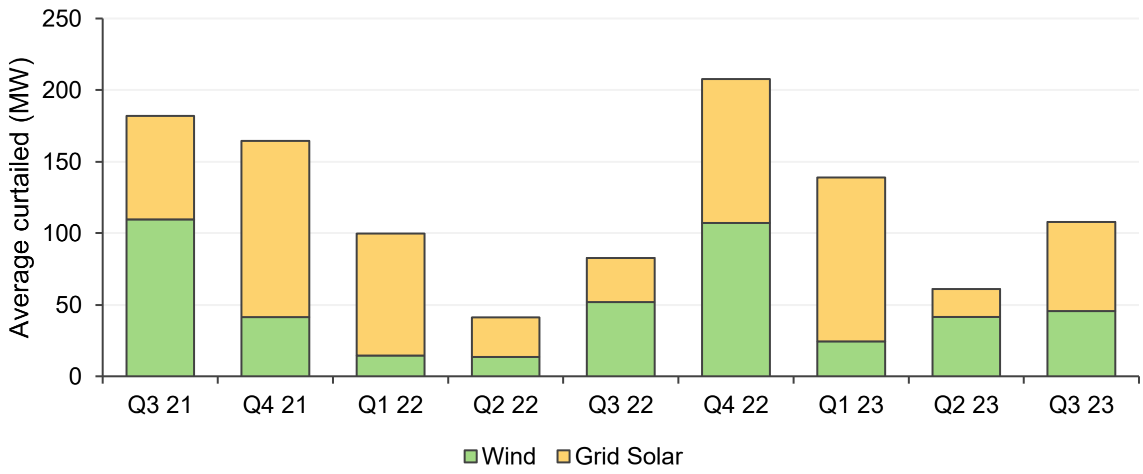


Curtailment

In this quarter, forced curtailment due to network constraints (including system strength) in the NEM increased by 25 MW to average 108 MW (Figure 49), 2.1% of available semi-scheduled VRE output. Consistent with changes in available energy output, curtailment of grid-scale solar units increased by 31 MW while curtailment of wind was 6 MW lower than the same period last year. The rise in grid-scale solar curtailment was more evident in **Victoria** and **New South Wales**, which saw increases of 14 MW and 15 MW respectively.

Figure 49 Curtailments at solar farms up while wind curtailment down year-on-year

Average MW curtailment by fuel type



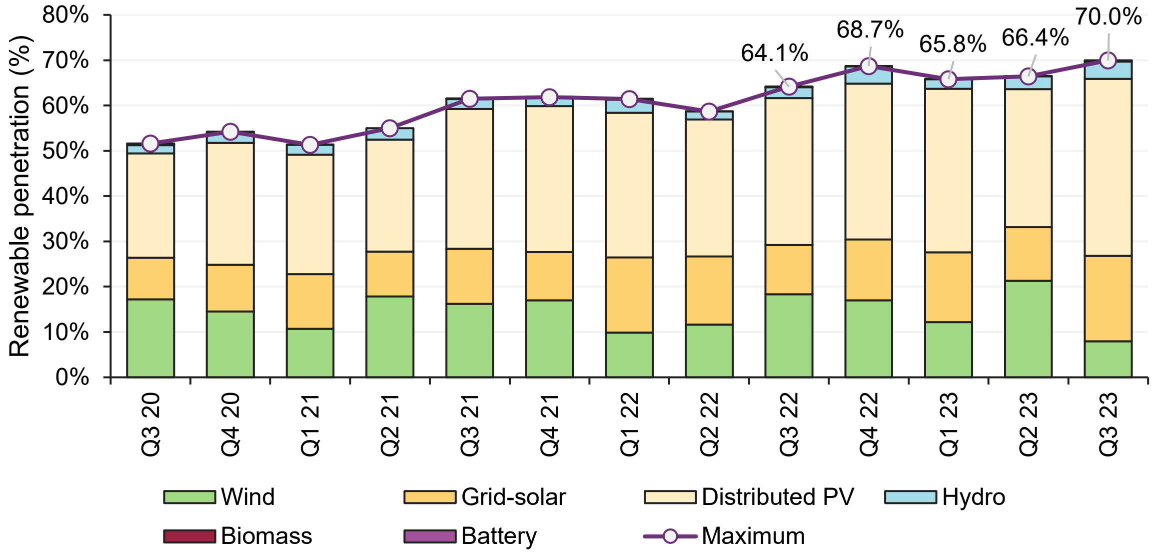
Much of **Victoria**'s increased curtailment (both grid-scale solar and wind) arose in the Murray River Renewable Energy Zone (REZ), which saw an additional 14 MW of curtailment compared to Q3 2022. Conversely, Western Victoria REZ saw a 9 MW reduction in curtailment. In **New South Wales**, the increase in network curtailment was driven by New England (+5 MW) and Central-West Orana (+4 MW) REZs.

Instantaneous renewable penetration

This quarter saw maximum instantaneous renewable penetration[13] in the NEM reach a record high of 70.0% for the half-hour ending 1230 hrs on Thursday 21 September. This was an increase of 1.3 pp from the previous record (68.7%) set in Q4 2022 and an increase of 5.8 pp from Q3 last year (Figure 50). At this time, total NEM generation averaged 26,854 MW, with VRE (grid-scale solar and wind) contributing 26.8%, and distributed PV 39.0%.

Figure 50 Instantaneous renewable penetration rose to an all-time high

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



Distributed PV and VRE peak instantaneous outputs

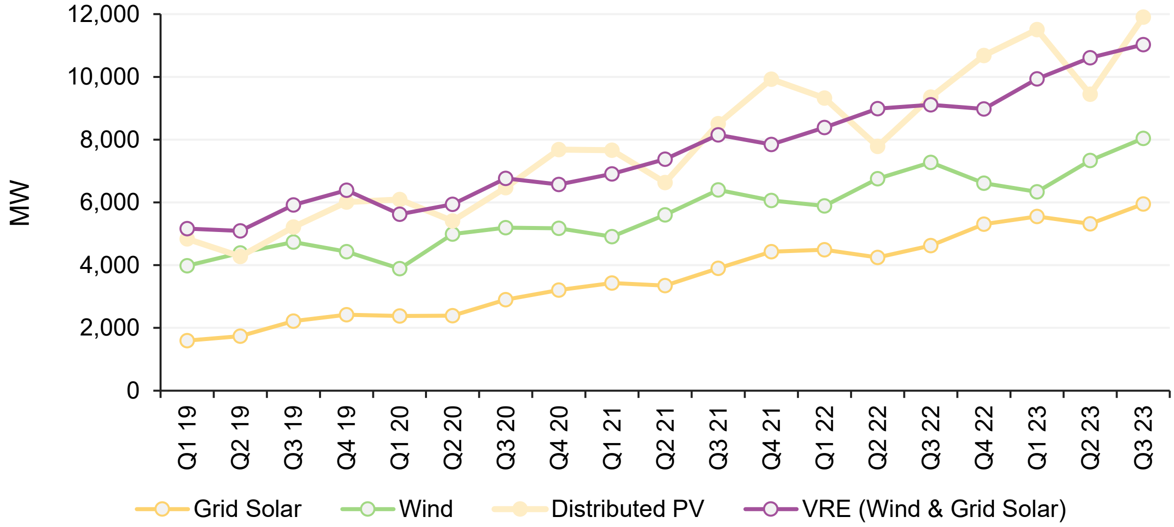
Figure 51 shows the instantaneous maximum outputs achieved by grid-scale solar, wind and distributed PV output:

- Distributed PV reached a record high of 11,900 MW on 30 September 2023, 397 MW (+3%) higher than the previous record set in Q1 2023. At this time distributed PV accounted for 48% of total supply.
- Grid-scale solar reached a record high of 5,949 MW on 22 September 2023, 398 MW (+7%) higher than the previous record set in Q1 2023.
- Wind reached a record maximum instantaneous output of 8,040 MW on 7 July 2023, an increase of 698 MW (+10%) from Q2 2023.
- Combined VRE output (wind and grid-scale solar) also recorded its highest output in this quarter, reaching 11,029 MW on 8 July 2023, 417 MW (+4%) higher than the previous record set in Q2 2023. At this time, VRE accounted for 42% of total generation.

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

Figure 51 Record high instantaneous wind, solar and combined VRE output in Q3 2023

Maximum quarterly instantaneous generation (half-hourly basis) by fuel type

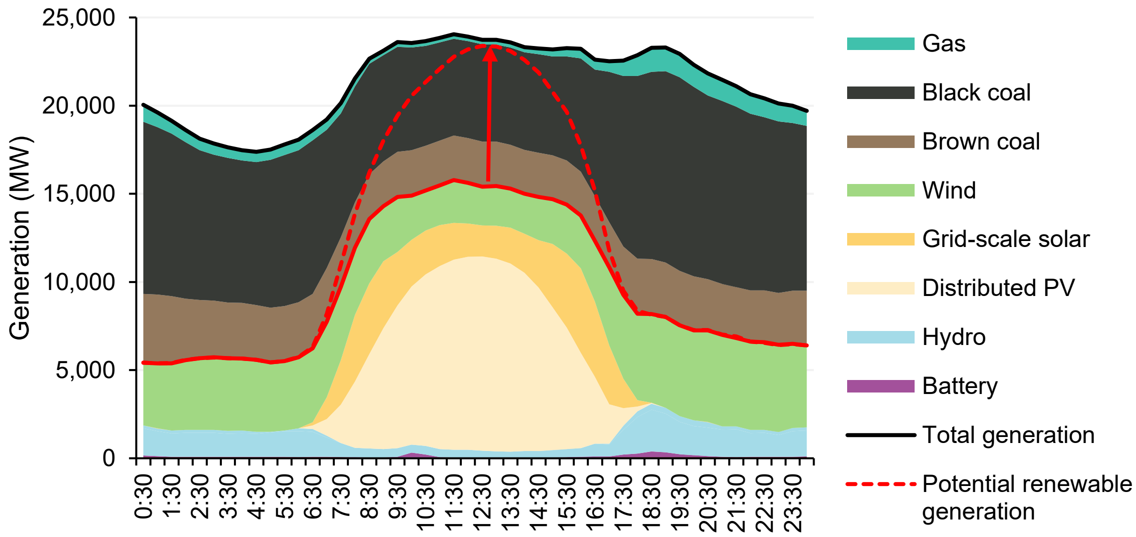


Renewable potential

On Saturday 16 September 2023, for the half-hour ending 1230 hrs, supply comprised 23,728 MW of total generation from all fuel types (including distributed PV) across the NEM. At this time, 15,410 MW (64.9%) was generated from renewable sources, with grid-scale solar and wind contributing 3,968 MW and distributed PV 11,020 MW (Figure 52).

Figure 52 Record high renewable potential on Saturday 16 September 2023

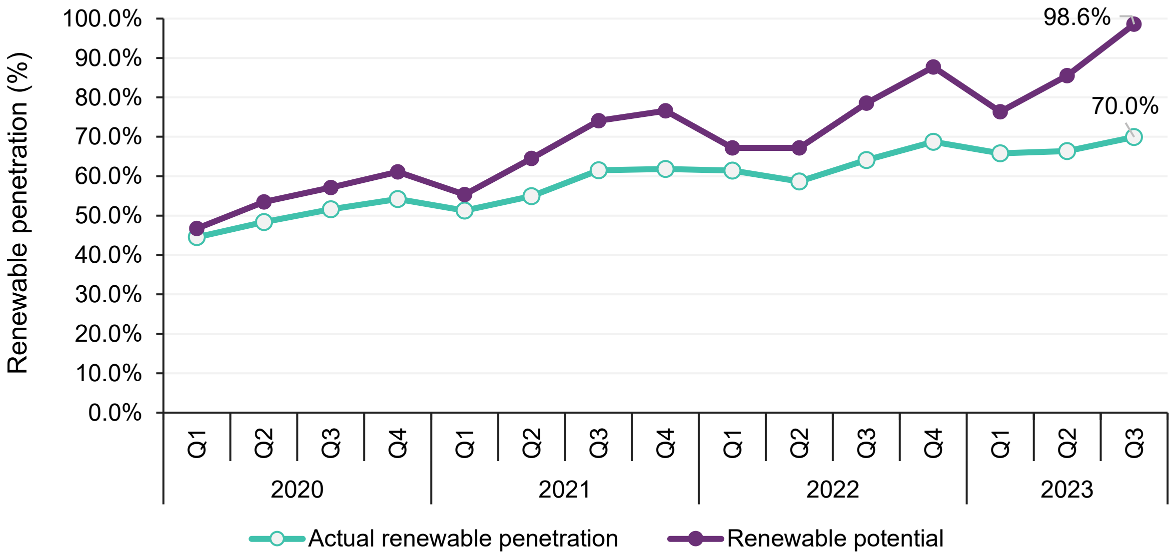
Output by fuel type and potential renewable output – 16 September 2023



In this half-hour there was an additional 7,980 MW of available energy from wind and grid-scale solar sources offered in price bands above the prevailing spot price and therefore not dispatched. At maximum available output from these and including the actual dispatched output from other renewable sources, renewable potential represented 98.6% of the total NEM supply required in this interval (Figure 53). Prior to this quarter, the maximum renewable potential as a proportion of total generation was 87.8% in November 2022.

Figure 53 Record high actual and potential renewable penetration

Quarterly maximum instantaneous actual renewable penetration and renewable potential



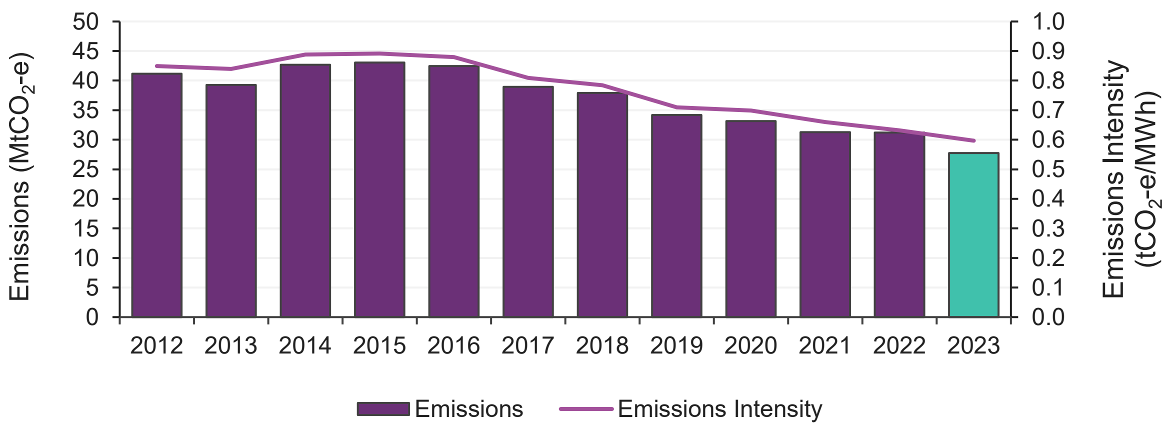
Achieving very high actual instantaneous penetration of renewables, at times up to 100%, is dependent on both market responses to energy and essential system services needs, as well as engineering and operational readiness enablers for secure and reliable power system operation at times without fossil fuels. AEMO's Engineering Roadmap[14] is a body of work that aims to remove barriers to running a secure and reliable power system at times of very high renewable penetration.

1.3.5 NEM emissions

This quarter saw NEM total emissions and emissions intensity drop to the lowest Q3 levels on record (Figure 54).

Figure 54 Lowest Q3 emissions and emissions intensity on record

Quarterly NEM emissions and Intensity (Q3s)



Total emissions in Q3 2023 averaged 27.7 million tonnes carbon dioxide equivalent (MtCO2-e), 3.5 MtCO2-e (-11%) lower than Q3 2022. Emissions intensity averaged 0.60 tonnes carbon dioxide equivalent (tCO2-e)/MWh,

[14] AEMO, *Engineering Roadmap to 100% Renewables*, https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

a decrease of 0.04 tCO2-e/MWh (-5.6%) from same period last year. These reductions were driven by lower operational demand and declining gas and coal-fired generation being offset by increased VRE generation. Emissions intensity calculations exclude generation from distributed PV, taking into consideration only sent out generation from market generating units[15].

1.3.6 Storage

Batteries

In Q3 2023, estimated battery net revenue totalled $32.5 million, $4.5 million (-12%) lower than Q3 last year, with most of the decrease being lower energy arbitrage earnings (-$4.0 million) while revenue from frequency control ancillary services (FCAS) markets fell by $0.5 million (Figure 55). The quarter saw reductions in volatile energy spot prices and FCAS prices compared to Q3 2022. The energy market remained the larger source of battery revenue this Q3, accounting for 59% of total gross revenue, a lower proportion than last year's 69% (Figure 56).

By region, compared to Q2 2022:

- Net revenue for batteries in **South Australia** was $10.9 million this quarter, $4.4 million lower than Q3 last year, with falls from both energy arbitrage (-$2.3 million) and FCAS markets (-$2.0 million). Hornsdale Power Reserve accounted for most of this decrease with a drop of $3.4 million.
- Net revenue for **Victorian** batteries totalled $13.8 million, the highest among all states but down $1.3 million on Q3 2022. The state's largest battery, the Victorian Big Battery (VBB), accounted for most of this decrease.
- Conversely, **Queensland** and **New South Wales** batteries saw net revenue increase by $0.4 million and $0.8 million respectively. Queensland saw a drop of $0.6 million in revenue from energy arbitrage, which was offset by a $1.0 million increase in FCAS revenue. In New South Wales, energy arbitrage increased by $0.8 million while FCAS revenue remained largely unchanged.

Figure 55 Battery net revenue down from Q3 2022 on lower energy arbitrage

Quarterly revenue from NEM battery systems by revenue stream

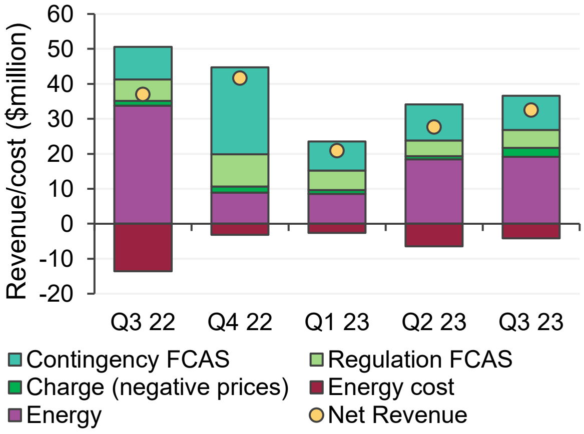
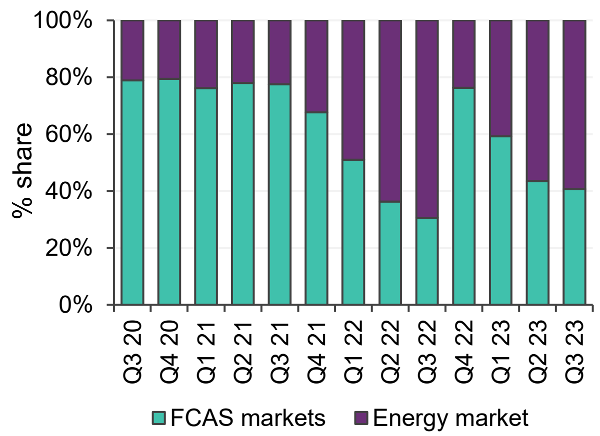


Figure 56 Energy market remained the larger source of battery revenue

Percentage share of battery revenue – energy vs FCAS markets



[15] Sent out generation derived from metering data is combined with publicly available generator emission factors to provide a NEM-wide Carbon Dioxide Equivalent Intensity Index calculated on a daily basis.

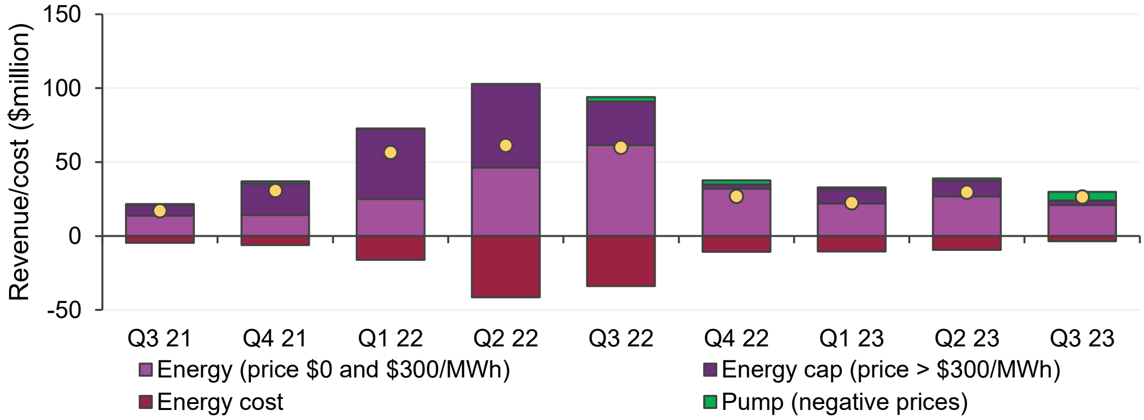
Pumped hydro

Pumped hydro estimated revenue was $26.3 million this quarter, a reduction of $33.7 million from Q3 2022 (Figure 57). Lower spot prices in **Queensland**, coupled with lower price volatility, saw Wivenhoe's estimated revenue drop by $19.7 million compared to Q3 last year. In **New South Wales**, Shoalhaven's estimated revenue dropped by $14.0 million due to lower spot prices and arbitrage values.

While lower spot prices reduced generation revenue, this also lowered total pumping energy costs by $30.4 million, with pumping during negative price periods adding $2.8 million to revenues.

Figure 57 Pumped hydro revenue dropped from Q3 2022 with reduced energy and cap returns.

Quarterly revenue from NEM pumped hydro by revenue stream

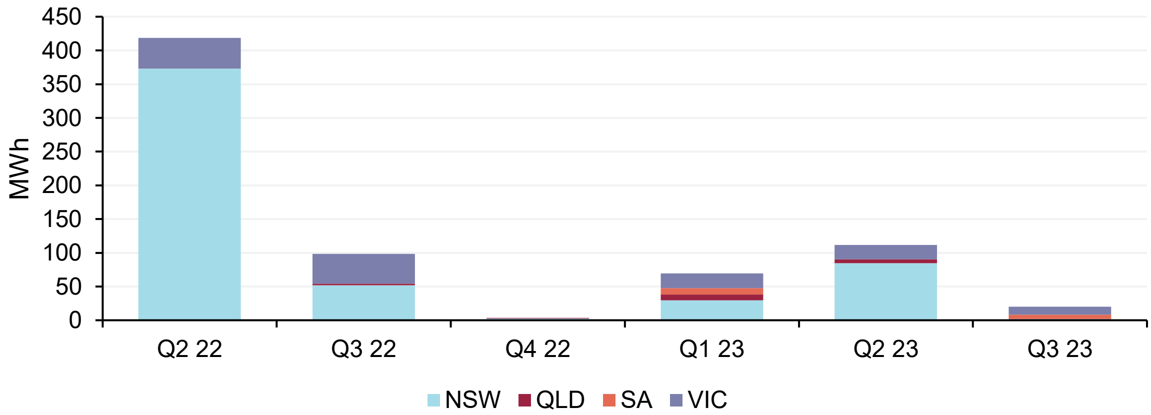


1.3.7 Wholesale demand response

Wholesale Demand Response (WDR) saw a total of 20 MWh of energy dispatched over the quarter, a drop of 79 MWh from Q3 2022 (Figure 58).

Figure 58 Reduction in Wholesale Demand Response dispatch this Q3 compared to Q3 2022

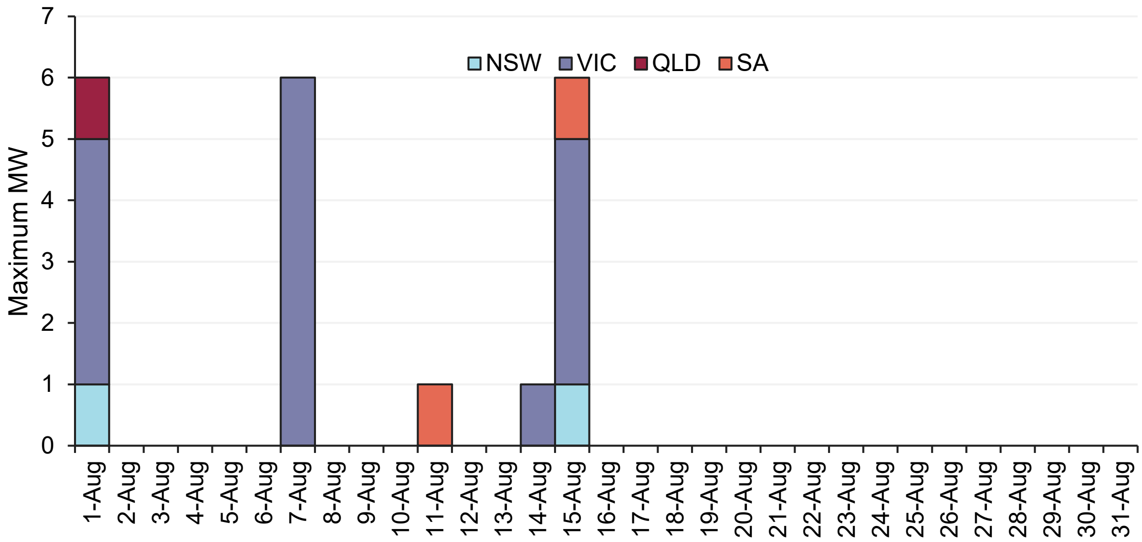
Total quarterly WDR energy dispatch



WDR capacity was dispatched on multiple days in August (Figure 59). In **Victoria**, high price events on 1, 7, 14 and 15 August prompted a total of 12 MWh of WDR being dispatched, with three days peaking at or above 4MW. **South Australia** also saw two days of WDR being dispatched, with 11 August accounting for 5.2 MWh (26% of total WDR dispatched).

Figure 59 Active participation from Wholesale Demand Response units across August

Maximum daily WDR dispatch – August 2023



1.3.8 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[16] monitored by AEMO to track the progress of projects going through the connections process include application, pre-registration, registration, commissioning, and model validation.

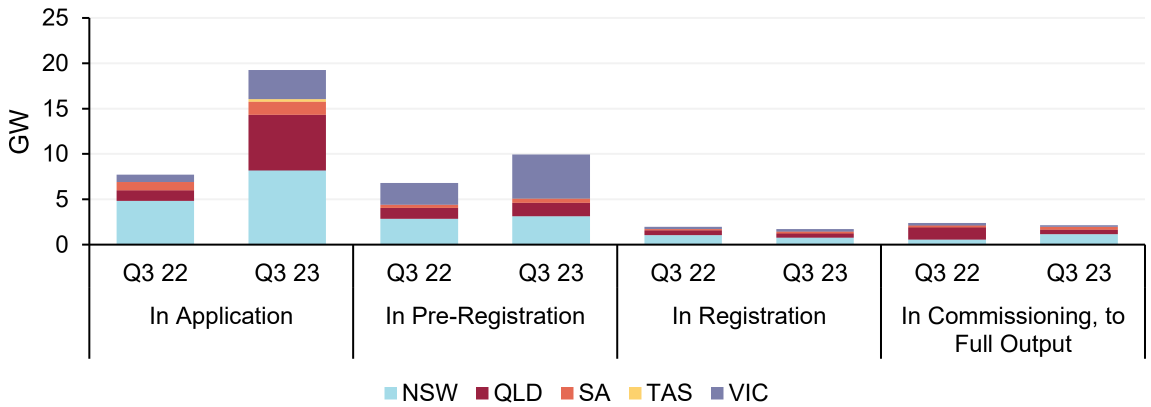
At the end of Q3 2023, AEMO's snapshot of connection activities in progress shows that:

- There was 33 GW of new capacity progressing through the end-to-end connection process from application to commissioning, compared to 19 GW at the end of Q3 2022, with around 40% of this capacity in **New South Wales** (Figure 60).
- The total capacity of in-progress applications was 19.2 GW, compared to 7.7 GW at the same time last year. There has been a marked influx of applications during the past two quarters, with applications totalling 5.6 GW received in Q3 and 5.1 GW in Q2. Most of these are in the early phase of application assessment, with 43% in **New South Wales** and 32% in **Queensland**.
- There was 10 GW of new capacity finalising contracts and under construction (pre-registration), with more than 50% of this total in **Victoria**. This compares to 6.8 GW total at the end of Q3 2022.
- There was 1.7 GW of new capacity progressing through registration, compared to 2.0 GW at the end of Q3 2022. More than 40% of this capacity was in **New South Wales**.
- There was 2.1 GW of new capacity in commissioning to full output, compared to 2.4 GW at the end of Q3 2022. More than 50% of this capacity was in **New South Wales**. This commissioning measure considers all plant in commissioning up to the plant reaching its full output. Note that in previous quarters this measure included all commissioning activities, beyond reaching full output.

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

Figure 60 Increase in applications and projects under construction (pre-registration)

Connections snapshot as at end Q3 for 2022 and 2023



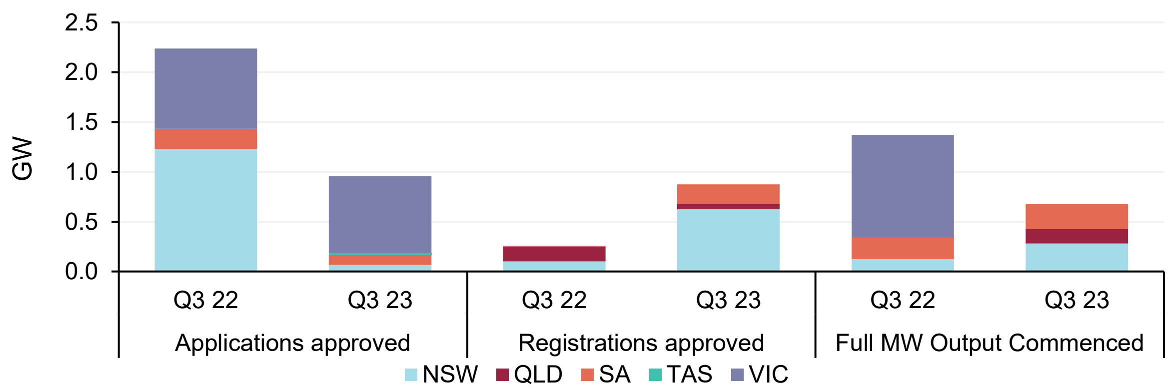
During Q3 2023, approvals achieved included:

- 1 GW of applications across 10 projects (Figure 61). In Q3 2022, 2.2 GW of applications were approved across seven projects, including three large wind farm projects with a cumulative capacity of 1.3 GW. Projects approved in Q3 2023 were smaller in capacity. **Victorian** projects contributed to 80% of the capacity approved this quarter, and storage projects accounted for 0.6 GW of the 1 GW capacity approved.
- 0.9 GW across five projects **registered and connected to the NEM** in Q3 2023, ready to start commissioning. This includes 0.4 GW from Rye Park Wind Farm in **New South Wales**, registered in August 2023.
- 0.7 GW of plant across six projects progressed through **commissioning to reach full output**. 50% of this capacity comprised energy storage plant in **South Australia** and **New South Wales**. In Q3 2022, 1.4 GW across seven projects reached full output. This included two large projects in Victoria – Stockyard Hill Wind Farm (0.5 GW) and Moorabool Wind Farm (0.3 GW) – reaching full output.

The connections scorecard[17] is published monthly and contains further information.

Figure 61 Increase in registrations and decrease in application approvals

Comparison of applications approved, registrations and commissioning in Q3 for 2022 and 2023



[17] AEMO, Connections Scorecard, https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connections-scorecard.

1.4 Inter-regional transfers

Total inter-regional energy transfers were 3,952 gigawatt-hours (GWh), a 34% increase from Q3 2022.

Compared to Q3 last year, net transfers into **New South Wales** from **Queensland** and **Victoria** increased by 20% and 69% respectively. Only Basslink reversed net transfer direction this quarter compared to Q3 2022, with net transfers switching strongly northward to **Victoria** (Figure 62).

Figure 62 Flow into New South Wales increased

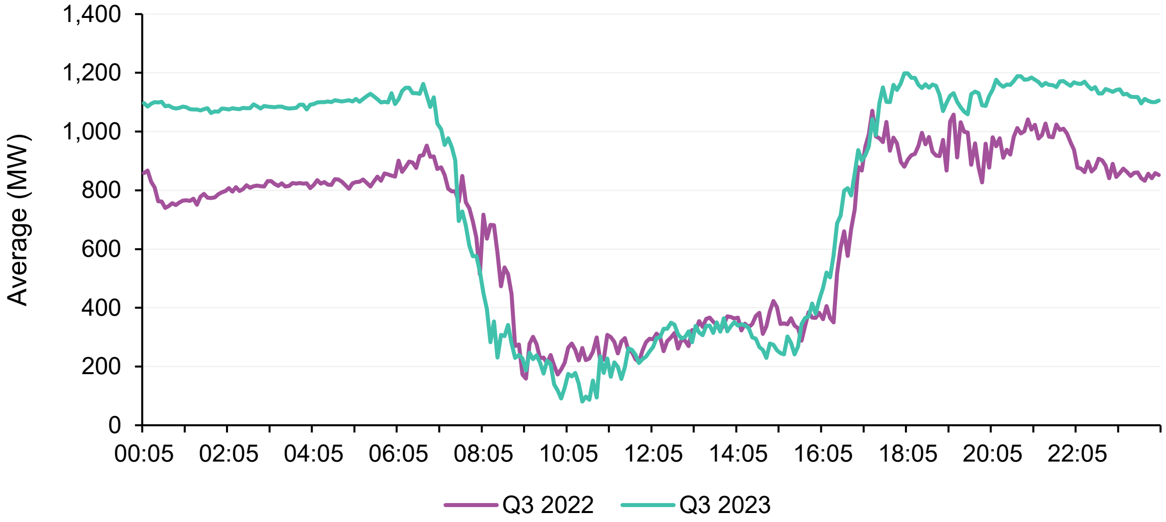
Quarterly inter-regional transfers

Key outcomes by regional interconnector included:

- **QNI** – flows southward increased by 73 MW compared to Q3 2022. The net southward flow increased at almost all times of the day, but the increase was greater outside daytime hours, with QNI reaching binding southward flow limits more frequently during daytime hours. Overall, QNI was at its import limit in 21% of dispatch intervals in Q3 2023, compared to 16% in Q3 2022. The increased flows southward are consistent with prices being generally higher in New South Wales than Queensland.
- **Victoria – New South Wales Interconnector (VNI)** – net flow northward from Victoria to New South Wales increased by 211 MW to 517 MW. VNI flowed at its export limits for 41% of the quarter, an increase from 30% last Q3, and achieved significantly higher transfer limits outside daytime hours (Figure 63). This increase reflected fewer transmission outages, which were a factor affecting overnight export limits in Q3 2022.
- **Basslink** – net flows were northward this Q3 compared to southward for the same time last year. This is consistent with an increase in the price differential between Victoria and Tasmania.

Figure 63 VNI export limit increased outside daylight hours

Average VNI export limit (Victoria to New South Wales) when binding, by time of day



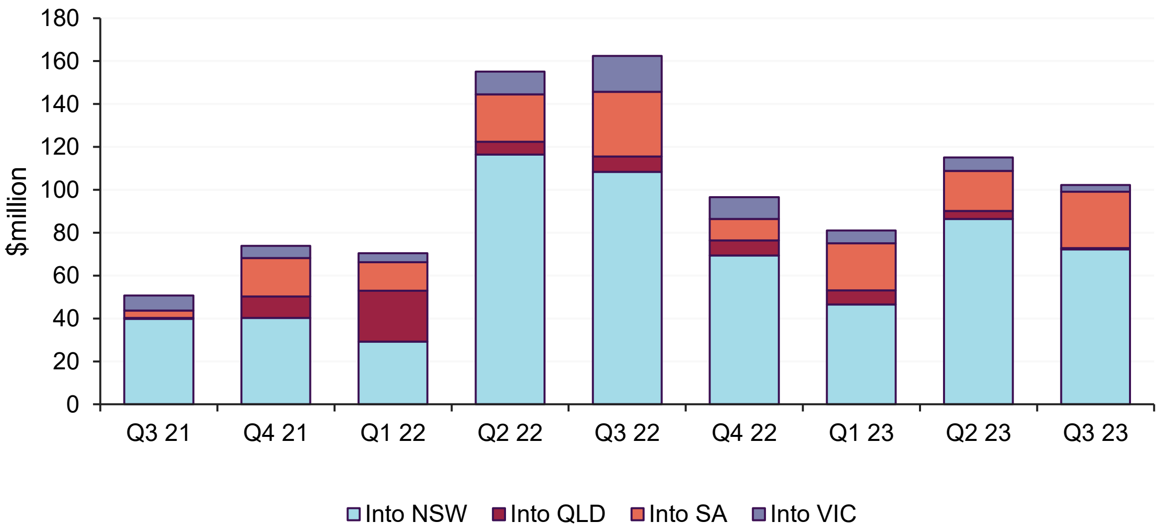
1.4.1 Inter-regional settlement residue

Positive inter-regional settlement residue (IRSR) totalled $109 million, compared to $162 million in Q3 2022 (Figure 64).

Q3 2022 had record levels of positive IRSR due to periods of region-specific price volatility. In contrast, this Q3 had reduced volatility (see Figure 16 in Section 1.2.2). The largest reduction in positive IRSR was for flows into **New South Wales**, with residues from **Queensland** decreasing $20 million to $28 million and from **Victoria** decreasing $11 million to $49 million. Despite episodes of high price separation between **South Australia** and **Victoria**, positive IRSR from flows into South Australia this Q3 was $2 million lower than in Q3 2022, because much of this price separation occurred at times of limited flow to South Australia.

Figure 64 Drop in Q3 positive IRSR

Quarterly positive IRSR values



Negative residue management

Negative IRSR totalled $3.8 million, the lowest since Q3 2020 (Figure 65). Negative IRSR into **New South Wales** dropped by $3 million, mainly due to a reduction in counter-price flows from **Queensland** to **New South Wales**.

Figure 65 Lowest negative IRSR in recent quarters

Quarterly negative IRSR values

1.5 Frequency control ancillary services

During Q3 2023, FCAS costs totalled $39.9 million, very close to previous quarters in 2023 and a 26% reduction in quarterly FCAS costs relative to Q3 2022 (Figure 66). Each region's share of FCAS costs was similar to previous 2023 quarters, with **New South Wales** highest at $11.9 million and **Queensland** at $10.8 million. This was followed by **Victoria** and **Tasmania** maintaining their FCAS cost at $9 million and $5.6 million respectively, while **South Australia** recorded the lowest total of $2.6 million.

Among FCAS services, payments for six-second contingency raise (R6SE) comprised the largest share of FCAS costs at $13.8 million (35%) of total costs in Q3 2023 (Figure 67), an 18% reduction relative to Q3 2022 levels. Regulation payments accounted for $14 million (35%) of FCAS costs in the quarter.

Figure 66 FCAS costs similar to previous two quarters, but reduced from Q3 2022

Quarterly FCAS costs by region

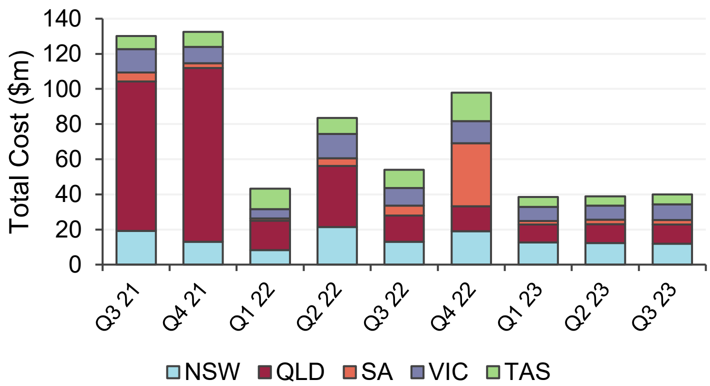
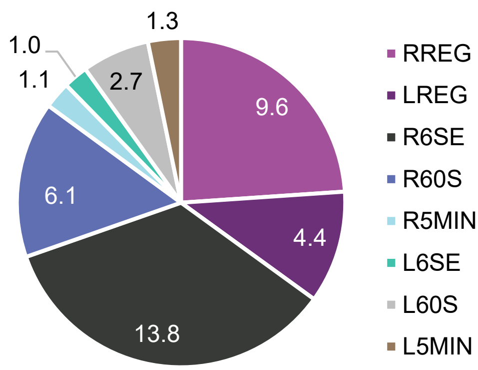


Figure 67 R6SE and RREG the highest shares of FCAS costs

NEM quarterly FCAS cost by market – Q3 2023 ($m)



Q3 2023 saw FCAS market shares by technology remain similar to Q3 2022. Batteries remained the dominant technology, providing FCAS with 40% volume share (Figure 68).

Figure 69 shows that most technology types saw reductions in enablement (except demand response (DR) FCAS, virtual power plants (VPP), and solar) with hydro and brown coal having the largest drops in quarterly average enablement, by 98 MW (mainly contingency raise) and 59 MW (mainly contingency lower) respectively. In aggregate, there were slightly reduced volumes of contingency services enabled across the NEM in Q3 2023, with less contingency raise required in Tasmania as Basslink flowed predominantly northward, and smaller volumes of contingency lower services required on the mainland.

Figure 68 Batteries again led FCAS market share

FCAS volume market share by technology – Q3 2023

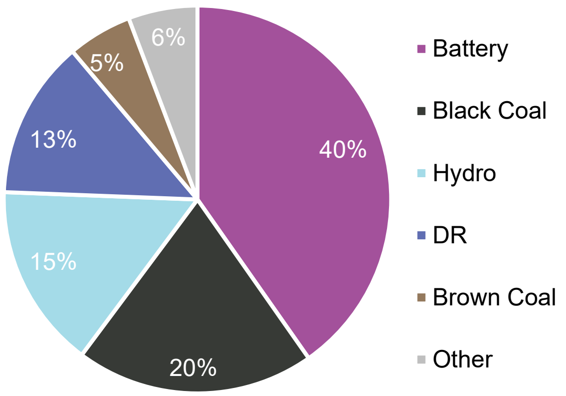
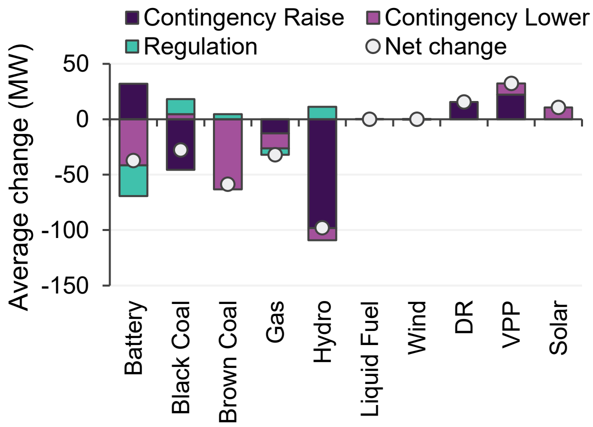


Figure 69 Reduced enablement for most technologies

Change in FCAS enablement by technology – Q3 2023 vs Q3 2022

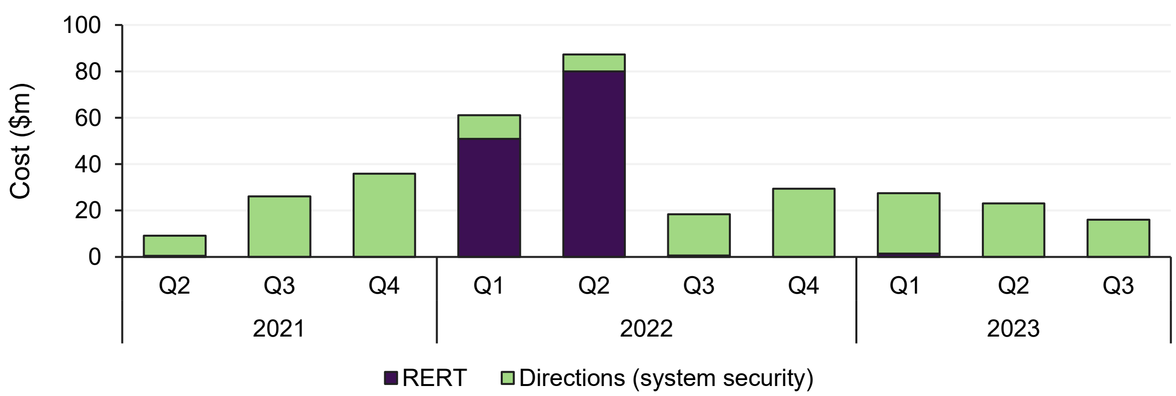


1.6 Power system management

Power system management costs declined to $16.1 million, down from Q2 2023 and Q3 2022 costs of $23.1 million and $17.8 million respectively (Figure 70). Lower spot prices, and higher distributed PV causing lower levels of operational demand, increased the requirement for AEMO to direct synchronous units to maintain system strength in **South Australia**. Despite increases since Q3 2022 in the number of directions issued and the volume of directed generation, the estimated cost of system security directions fell, due to lower average compensation prices paid to directed generators. Reliability and Emergency Reserve Trader (RERT) was again not required in Q3 2023.

Figure 70 Slight decline in system security costs this Q3

Estimated quarterly system costs by category

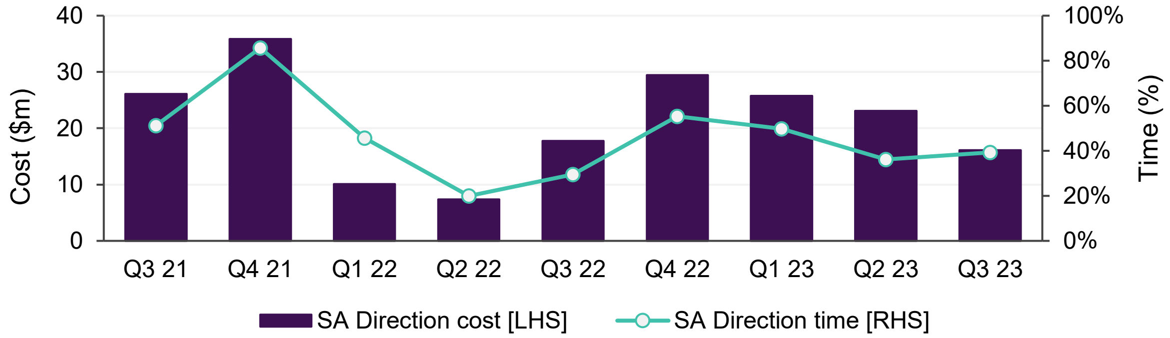


1.6.1 South Australian system security directions

Directions were in place for 39% of dispatch intervals in Q3 2023, higher than Q3 2022's 29% and Q2 2023's 36%. However, direction costs fell from $17.8 million in Q3 last year and $23.1 million in Q2 this year to $16.1 million this quarter (Figure 71). This decline, despite a higher volume of directed generation, flows from a lower average quarterly direction compensation price[18], down from $336/MWh in Q3 2022 to $236/MWh in Q3 2023.

Figure 71 Decline in South Australian system security direction cost despite increased direction time in Q3 2023

Time and cost of energy only system security directions – South Australia Q3 2021 to Q3 2023



With lower electricity spot prices this Q3 compared to Q3 2022 ($92/MWh and $232/MWh respectively), and higher VRE output compared to Q3 2022, gas-fired generators more frequently opted to decommit their units from the system. These factors led to an increase in directions required to maintain minimum synchronous generation levels to ensure system security. In September alone, directions were in place for 53.5% of dispatch intervals, owing to relatively low spot prices and operational demand due to higher distributed PV generation.

Gas-fired generation in **South Australia** consequently saw a 4 MW increase in average directed volume, from 22 MW in Q3 2022 to 26 MW in Q3 2023, and the directed proportion of its total quarterly output rose from 4% in Q3 2022 to 6% this quarter (Figure 72), as overall gas-fired output fell. There was a notable increase in the percentage of time that two units were directed simultaneously, rising from 18% last Q3 to 29% in Q3 this year (Figure 73). This change aligned with the overall increase in the volume of directions.

Figure 72 Slight increase in South Australian gas volumes directed

South Australian gas-fired generation directed – volume and share

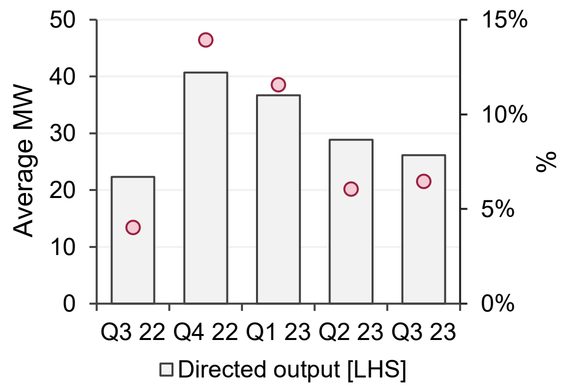
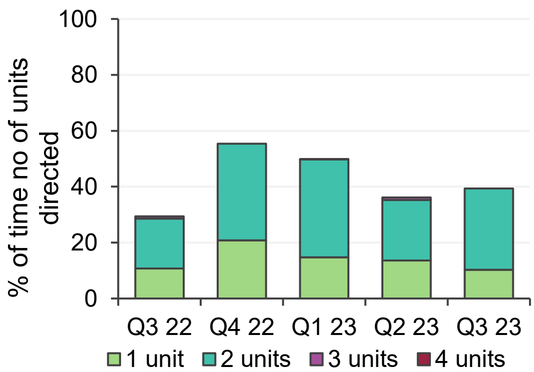


Figure 73 Significant increase in two-unit directions

Number of units simultaneously directed – proportion of quarter



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

2 Gas market dynamics

2.1 Wholesale gas prices

Quarterly average prices were 60% lower than the same quarter last year, continuing the trend seen in Q2. Warmer than average weather, as outlined in Section 1.1.1, led to some of the lowest domestic Q3 gas demands observed on the east coast.

The average price across all AEMO markets was $10.41/GJ compared to $25.94/GJ in Q3 2022 (Table 4). The Declared Wholesale Gas Market (DWGM) beginning-of-day price reached a two-and-a-half year low on 28 September, opening at $4.80/GJ.

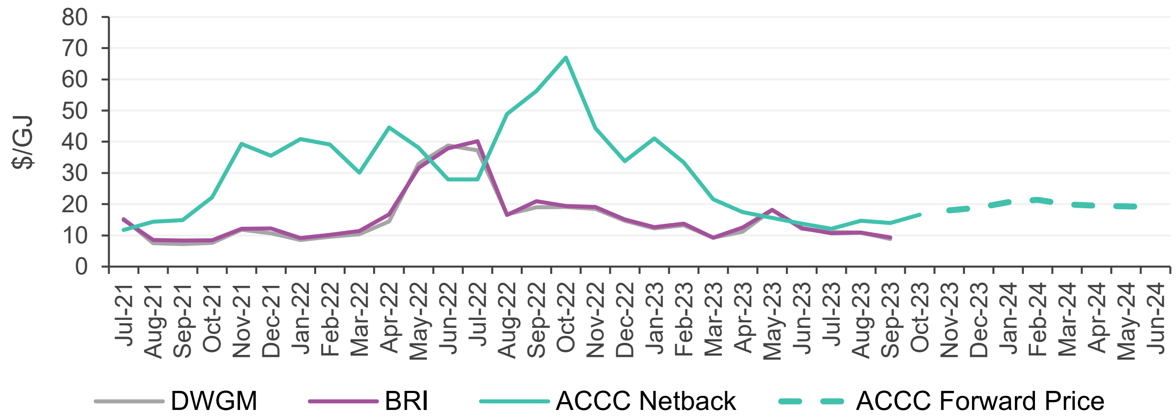
Table 4 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q3 2023	Q2 2023	Q3 2022	Change from Q3 2022
DWGM	10.26	13.84	24.35	-58%
Adelaide	10.78	15.13	27.23	-60%
Brisbane	10.33	14.34	25.89	-60%
Sydney	10.34	14.70	26.98	-62%
Gas Supply Hub (GSH)	10.33	13.03	25.26	-59%

International prices began to rise during the quarter, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, with corresponding forward prices heading toward $20/GJ in Q1 2024. The divergence of domestic prices from the ACCC netback price (Figure 74) is likely a result of lower demand conditions in the east coast gas markets.

Figure 74 Slight divergence between domestic prices and the ACCC netback price for Q3

ACCC netback and forward prices[19], DWGM and Short Term Trading Market (STTM) Brisbane average gas prices by month



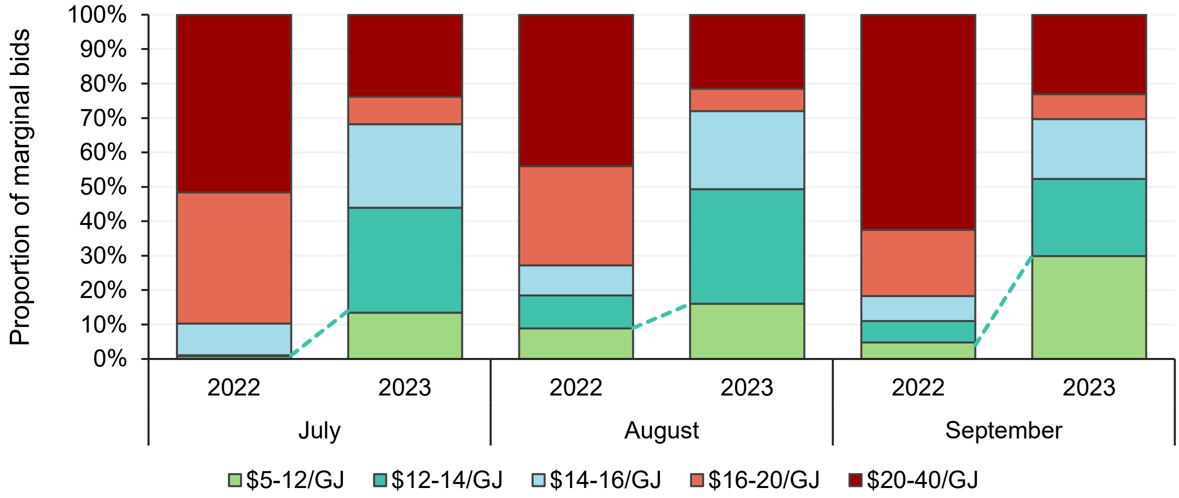
Market outcomes were strongly influenced by lower demand due to warm weather and low gas-fired generation (see Section 1.3.2). Increased southern flows from Moomba (see Section 2.4) helped offset the reduction in supply from Longford (see Section 2.3.2). These changing events and market conditions had impacts on

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

participants' bidding behaviours. This is represented by Figure 75, showing that there was a significant increase in bid volumes below $16/GJ throughout Q3, with the largest change in the $5-$12/GJ price range in September.

Figure 75 Larger proportion of DWGM bids at lower prices for Q3 2023

DWGM – proportion of marginal bids[20] by price band – Q3 2022 vs Q3 2023 by month

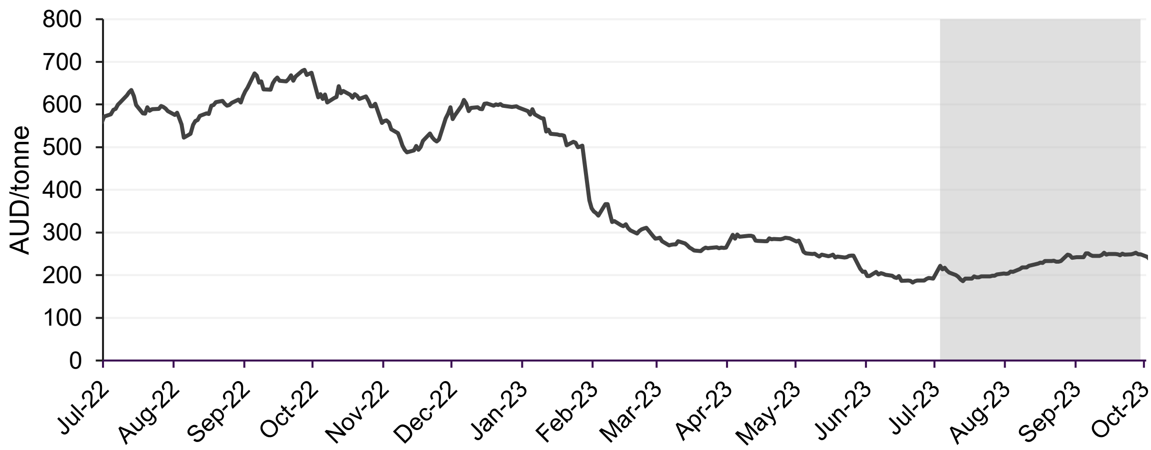


2.1.1 International energy prices

Newcastle export coal prices averaged $225/tonne this quarter, $387/tonne lower than the record high prices in Q3 2022 (Figure 76).

Figure 76 Thermal coal rises slightly over quarter but well below Q3 2022 records

Newcastle export thermal coal A$/Tonne daily



Source: Bloomberg ICE data

The Q3 2022 high prices were due to local weather-related issues affecting supply, and high international energy commodity prices following sanctions against Russia and increased European coal-fired generation use. Prices for Newcastle export thermal coal stabilised earlier this year as congestion in Australian ports largely cleared and

[20] Bids between $5/GJ and $40/GJ.

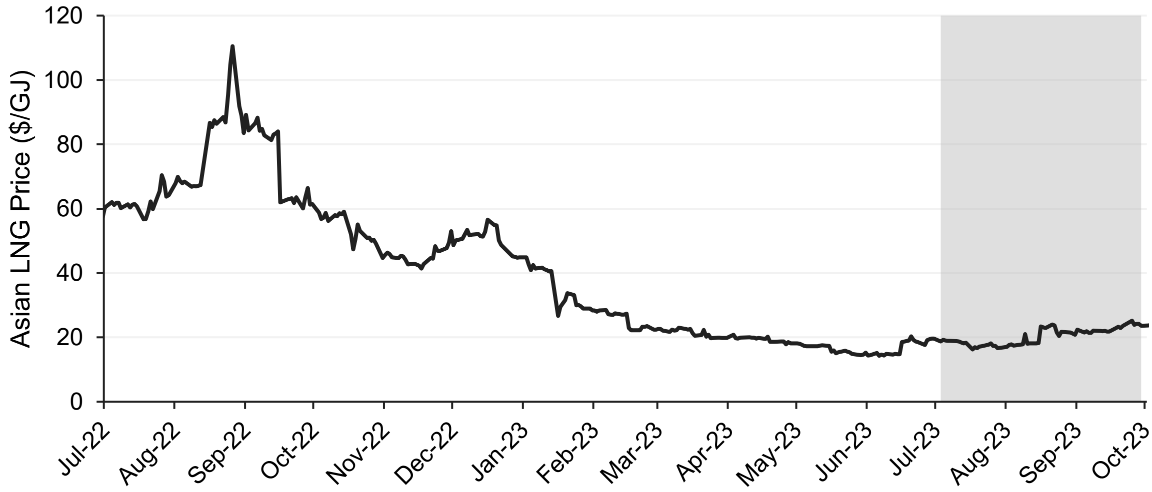
supply improved following the end of the La Niña weather cycle[21]. Although higher-than-average temperatures over the northern hemisphere summer increased demand, many European nations built up large stockpiles of coal and have invested in new gas and renewable energy sources since the Russian invasion of Ukraine.

Asian spot liquified natural gas (LNG) prices trended upward during Q3 (Figure 77). Some of the price spikes during the quarter correlated with news of planned industrial action at both Chevron and Woodside's operations at the North West Shelf, Gorgon and Wheatstone LNG projects in Western Australia. These projects have a combined capacity of 40.8 million tonnes per annum of LNG, which accounted for approximately 10.5% of global LNG exports in 2022[22].

Prices continued in an upward trajectory over the quarter as there was some activity on the spot market from Asia[23,24] and the subcontinent[25]. Japanese LNG inventory stockpiles were at their lowest levels since the end of January 2021[26] due to increased LNG demand for power generation. Last year close to 30% of Japan's electricity grid was powered by LNG[27]. As temperatures begin to cool and market demand lowers, it is expected that inventory levels will rise with supply under long-term oil linked LNG cargoes[24].

Figure 77 LNG prices drift upwards with potential strike action in W.A. and spot trading activity

Asian LNG price in A$/GJ daily



Source: Bloomberg ICE data

Brent Crude oil price averaged A$131/barrel this quarter; this was up A$15/barrel from Q2 2023 (Figure 78). Voluntary supply curtailment continued by OPEC producers, noting that Saudi Arabia cut production for the months of August and September[28]. Exports from Russia slowed down during the quarter, tightening an already

[21] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly September 2023: https://www.industry.gov.au/publications/resources-and-energy-quarterly-september-2023.

[22] Columbia School of International and Public Affairs 2023, Q&A | Potential Supply Disruptions from Industrial Action at Australia's LNG Plants: https://www.energypolicy.columbia.edu/qa-potential-supply-disruptions-from-industrial-action-at-australias-lng-plants/.

[23] Reuters 2023, "Sinopec buys over 30 LNG cargoes for winter demand, trading, sources say": https://www.reuters.com/business/energy/sinopec-buys-over-30-lng-cargoes-winter-demand-trading-sources-2023-09-20/.

[24] S&P Global 2023, "Japan's LNG stocks to rise in Oct on spot purchases, weaker demand": https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/lng/092923-japans-lng-stocks-to-rise-in-oct-on-spot-purchases-weaker-demand.

[25] Reuters 2023, "India seeks more natural gas amid emergency measures to end blackouts": https://www.reuters.com/business/energy/india-seeks-additional-natural-gas-volumes-boost-power-generation-2023-09-06/.

[26] Reuters 2023, "Japan's industry ministry sees LNG stocks recovering towards winter": https://www.reuters.com/markets/commodities/japans-industry-ministry-sees-lng-stocks-recovering-towards-winter-2023-09-27/.

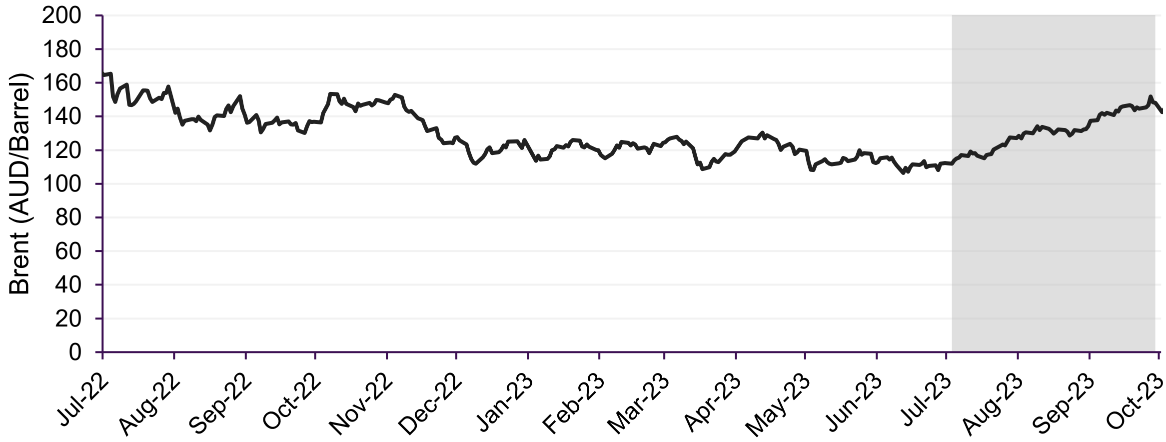
[27] Institute for Sustainable Energy Policies 2023, 2022 Share of Electricity from Renewable Energy Sources in Japan (Preliminary): https://www.isep.or.jp/en/1436/.

[28] International Energy Agency 2023, Oil Market Report - September 2023: https://www.iea.org/reports/oil-market-report-september-2023.

finely balanced market, and the country temporarily banned exports of gasoline and diesel at the end of September[29], however this may be alleviated in the coming weeks.

Figure 78 Brent Crude oil prices rally

Brent Crude oil in A$/Barrel daily



Source: Bloomberg ICE data

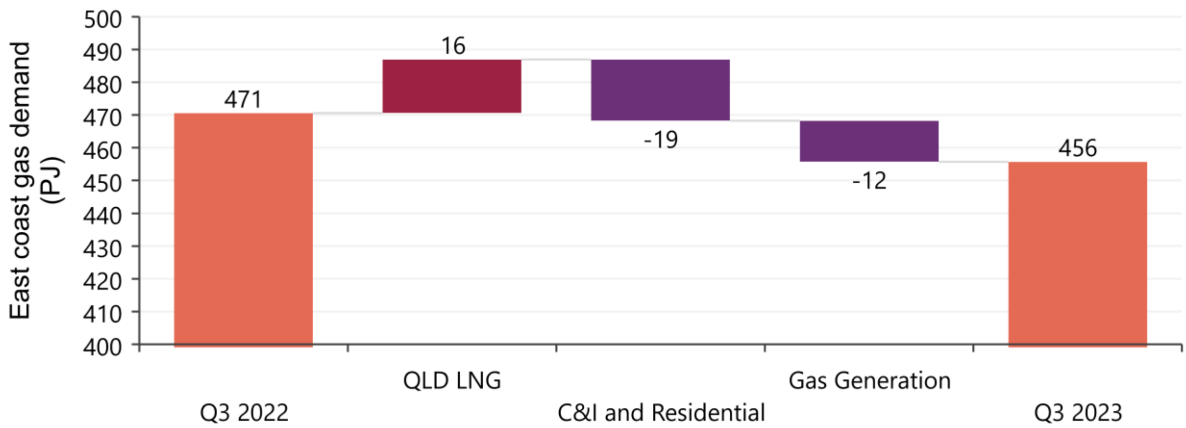
2.2 Gas demand

Total east coast gas demand decreased by 3% compared to Q3 2022 (Figure 79 and Table 5).

There were large falls in demand from AEMO markets (-19 PJ) and for gas-fired generation (-12 PJ), but an increase in demand for **Queensland** LNG production (+16 PJ). **Victoria**'s Declared Wholesale Gas Market (DWGM) experienced lower demand (-13 PJ) due to warmer than normal temperatures combined with lower commercial and industrial demand, while the **Brisbane** Short Term Trading Market (STTM) recorded a decrease (3 PJ) primarily due to the shutdown of Incitec Pivot's Gibson Island facility in January 2023. Prior to its shutdown, this facility was Brisbane's largest gas user, typically consuming 2-3 PJ per quarter.

Figure 79 Warm weather and lower gas-fired generation reduced domestic gas consumption

Components of east coast gas demand change – Q3 2022 to Q3 2023



[29] Reuters 2023, Russia temporarily bans fuel exports to most countries in response to shortages: https://www.reuters.com/markets/commodities/russia-imposes-temporary-restrictions-fuel-exports-2023-09-21/.

Table 5 Gas demand – quarterly comparison

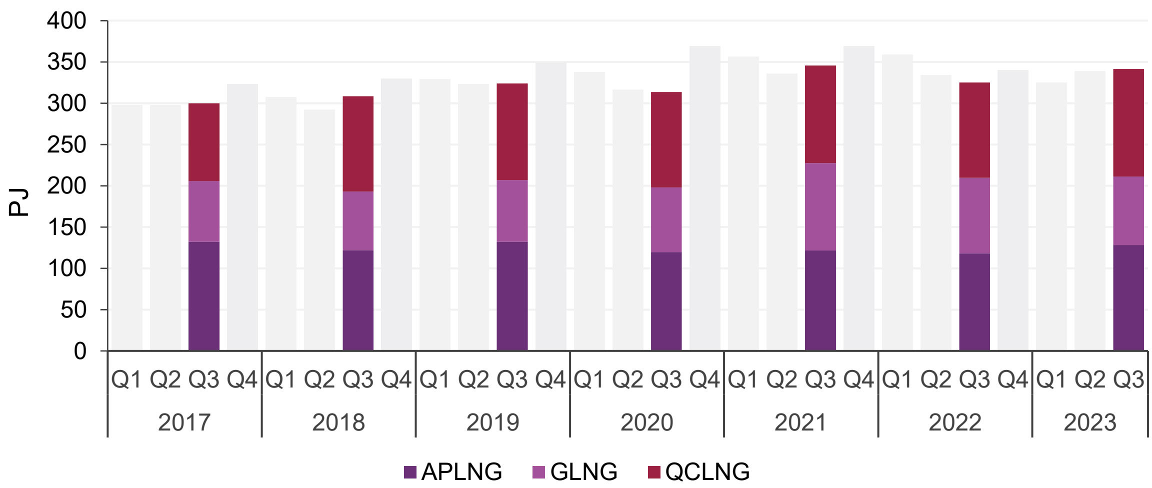
Demand (PJ)	Q3 2023	Q2 2023	Q3 2022	Change from Q3 2022
AEMO markets *	91.4	87.6	110.2	-19 (-17%)
Gas-fired generation **	23.0	28.9	35.5	-12 (-35%)
Queensland LNG	341.3	339.2	325.0	16 (5%)
Total	455.8	455.7	470.6	-15 (-3%)

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

Queensland LNG export demand continued to trend upward, with APLNG and QCLNG ramping up production (Figure 80), despite APLNG undertaking planned maintenance at one of its processing trains during the quarter. A reduction in volume being delivered from the Darling Downs Pipeline to the APLNG Pipeline was also observed from 11 July 2023[30]. QCLNG had planned and unplanned outages during the quarter, while GLNG completed a planned full single train outage early in the quarter. By participant, in comparison to Q3 2022, QCLNG demand increased by 14.9 PJ, APLNG increased by 10.3 PJ, and GLNG decreased by 8.8 PJ. There were 86 LNG cargoes exported during the quarter, up from 85 in Q3 2022.

Figure 80 APLNG and QCLNG increase production despite planned and unplanned outages

Total quarterly pipeline flows to Curtis Island



2.3 Gas supply

2.3.1 Gas production

East coast gas production decreased by 15.7 PJ (-3%) compared to Q3 2022 (Figure 81). Key changes included:

- Decreased **Victorian** production (-34.7 PJ), mainly driven by lower production at Longford (-28.2 PJ).
- Increased **Queensland** production (+15.3 PJ), with assets operated by APLNG increasing by 9.4 PJ and QCLNG operated assets by 5.6 PJ, while GLNG operated assets decreased by 1.2 PJ. Gas demand for Queensland LNG exports increased by 16.4 PJ, meaning supply associated with Queensland LNG projects into the domestic market was 1 PJ lower compared to Q3 2022 (Figure 82).

[30] AEMO 2023, Gas Bulletin Board: https://aemo.com.au/energy-systems/gas/gas-bulletin-board-gbb/data-gbb/gas-flows.

- Increased Moomba production (+3.9 PJ), bucking the trend of lower Moomba production year-on-year and continuing the higher production observed in Q2 2023 compared to Q2 2022. Increased production has coincided with an increase in the number of wells drilled in the Cooper Basin throughout 2023.

Figure 81 Production continued to fall at Longford

Change in east coast gas supply – Q3 2023 vs Q3 2022

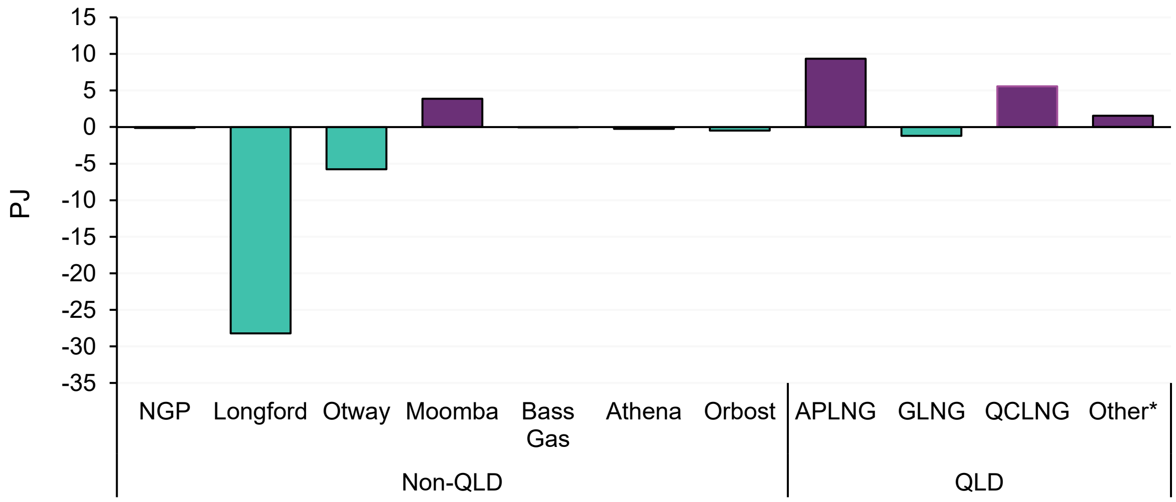
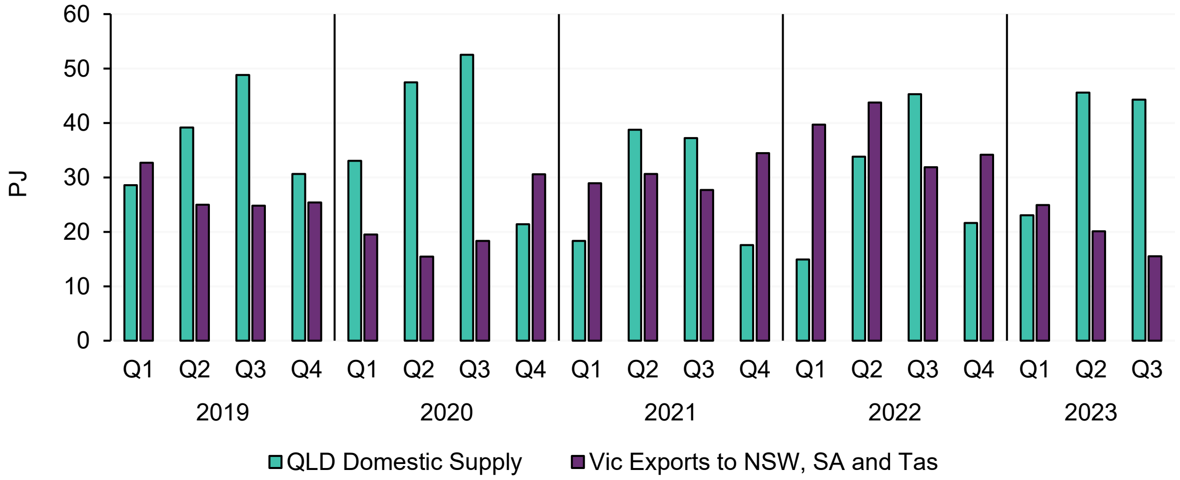


Figure 82 Queensland domestic supply continued to replace Victorian exports

Queensland domestic supply compared to Victorian gas exports by quarter



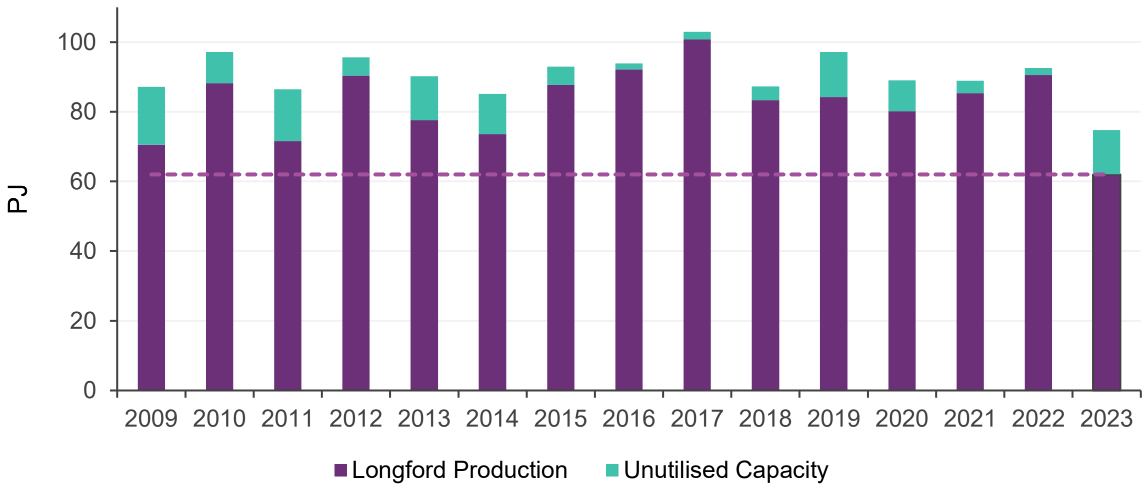
2.3.2 Longford production and capacity

Q3 continued the trend of declining Longford production and capacity observed in Q1 and Q2 2023. Longford's production of 62 PJ and capacity of 75 PJ was its lowest Q3 for both since data began being reported on the Gas Bulletin Board (GBB) in 2009 (Figure 83). Production was 8 PJ lower than the previous low in Q3 2009, and 28 PJ lower than 2022. As noted in the Q2 2023 QED, the capacity decrease mostly reflects declining gas reserves in the Bass Strait fields connected to Longford, and was forecast and reported in AEMO's *Victorian Gas Planning Report* and *Gas Statement of Opportunities*[31].

[31] 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.

Figure 83 Lowest Longford Q3 production and capacity since data reporting began

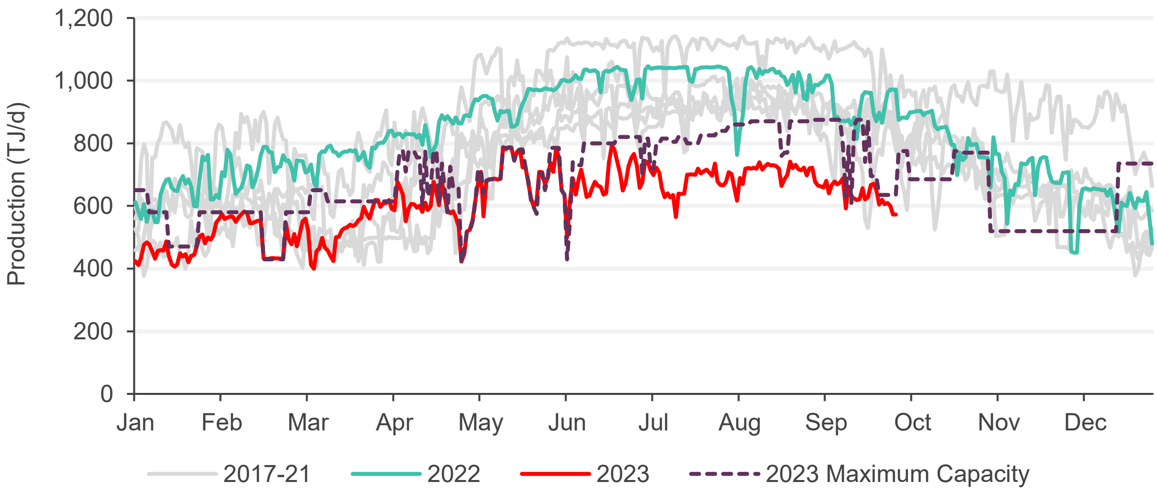
Longford Q3 production versus unutilised capacity



Notwithstanding Longford's overall capacity decrease, daily production through Q3 was well below available capacity (Figure 84), with Longford's capacity factor dropping to 83%, its lowest since 2009. While some of this gap was driven by reduced demand, the increase in unutilised capacity was also driven by an increase in Longford supply offers to above the daily DWGM and Sydney STTM price outcomes.

Figure 84 Daily Longford production declining but still well below maximum capacity

Daily Longford production 2017-2023, maximum capacity profile 2023



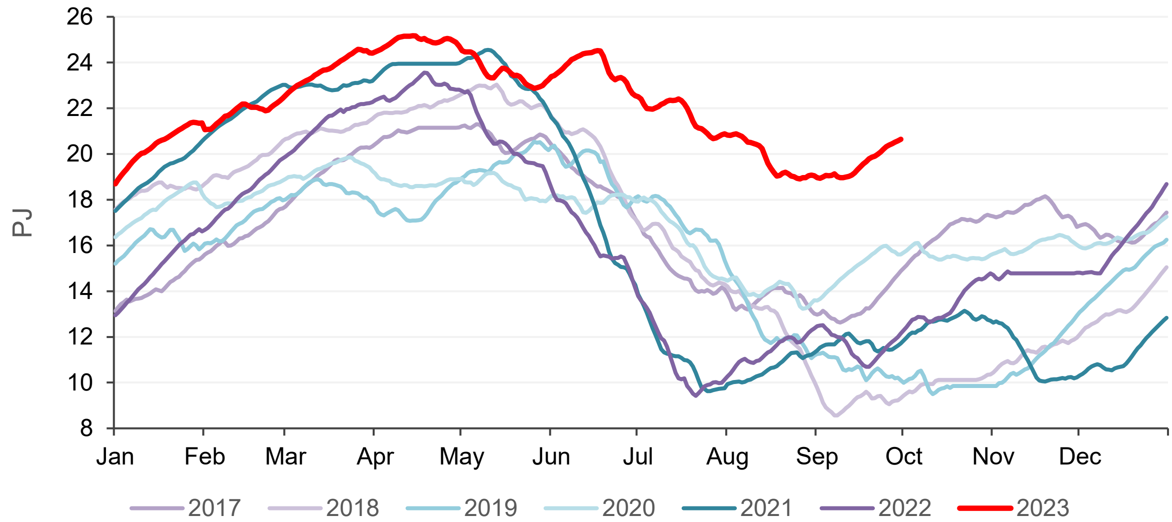
2.3.3 Gas storage

The Iona underground gas storage (UGS) facility finished the quarter with an inventory of 20.6 PJ, 8.6 PJ higher than at the end of Q3 2022 (Figure 85), and the highest end to a Q3 since reporting began in 2017.

As in Q1 and Q2 2023, factors that contributed to the higher storage inventory included lower gas-fired generation demand, milder temperatures, and an increase in supply from Queensland to the southern markets.

Figure 85 Iona storage at its highest end to Q3 since storage levels began reporting

Iona storage levels

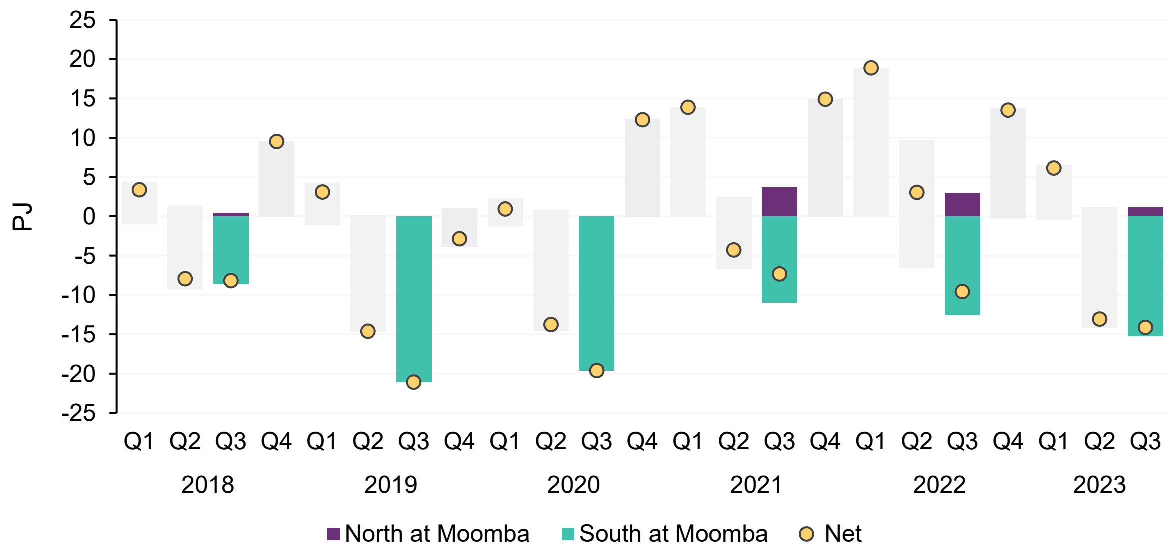


2.4 Pipeline flows

Compared to Q3 2022, there was a 4.6 PJ increase in net transfers south to Moomba on the South West Queensland Pipeline (SWQP, Figure 86) which represents the highest flow south to Moomba for a Q3 since 2020. Increased flows south to Moomba occurred predominantly in June and August, coinciding with increased Moomba production to meet higher demand from the southern markets.

Figure 86 Net Q3 flows south on SWQP increased

Flows on the South West Queensland Pipeline at Moomba

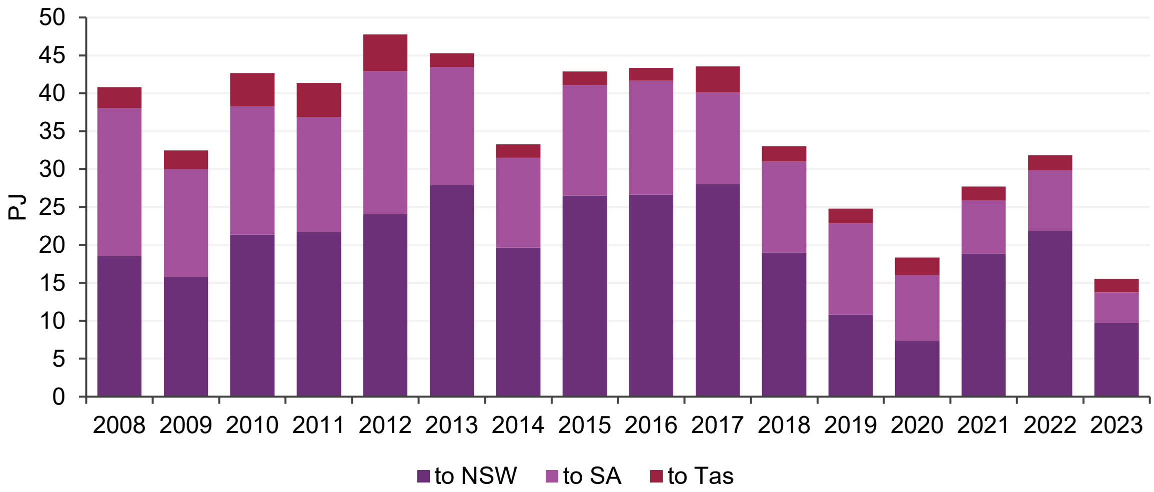


Victorian net gas transfers to other states decreased by 16.3 PJ from Q3 2022 levels, due to lower Longford production, increased Moomba production, and increased gas flows from Queensland. This represents the lowest Q3 net transfer out of Victoria since data reporting on the GBB began in July 2008 (Figure 87).

Net flows from **Victoria** to **New South Wales** decreased 12.1 PJ in comparison to Q3 2022 levels; there was a 5.9 PJ decrease in net flows via Culcairn and a 6.2 PJ decrease in flows via the Eastern Gas Pipeline (EGP). Instead, **Sydney** STTM demand was met by increased flows from **Queensland**. Flows from **Victoria** to **South Australia** decreased by 4 PJ from Q3 2022 levels, while there was a 0.2 PJ decrease in flows to **Tasmania**.

Figure 87 Lowest Victorian Q3 gas exports since data reporting began

Victorian net gas transfers to other regions – Q3s

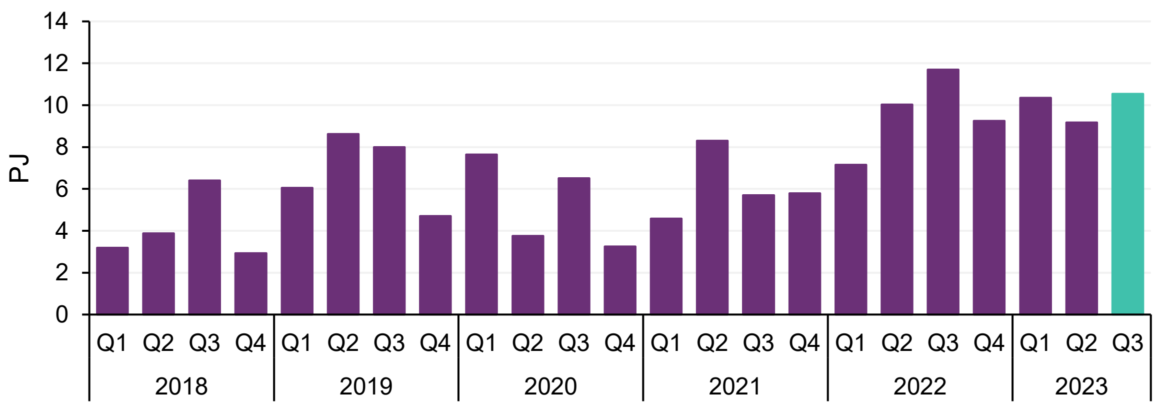


2.5 Gas Supply Hub (GSH)

In Q3 2023, traded volumes on the GSH decreased by 1.2 PJ in comparison to the record set in Q3 2022 (Figure 88). The traded volume this quarter was 10.5 PJ and represented the second highest volume on record.

Figure 88 Second highest GSH traded volumes on record

Gas Supply Hub – quarterly traded volume

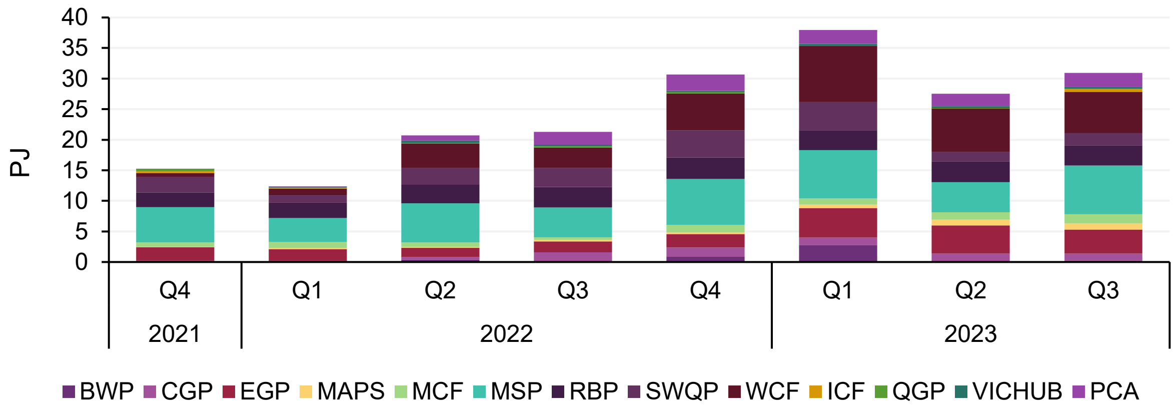


2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes set a new Q3 record of 30.9 PJ, 9.7 PJ higher than the previous Q3 record of 21.3 PJ set in 2022 (Figure 89). Compared to Q3 2022, the largest increases occurred on the Wallumbilla Compressor (WCP, +3.4 PJ), largely utilised to support transportation on the SWQP to send gas to the southern markets. A large increase in auction volume also occurred to send gas south on the Moomba to Sydney Pipeline (MSP, +3.1 PJ). Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were the EGP and the SWQP, which averaged $0.02/GJ, and the MSP and Roma to Brisbane Pipeline (RBP), which averaged $0.01/GJ.

Figure 89 Highest Q3 Day Ahead Auction utilisation since market start

Day Ahead Auction volumes by quarter



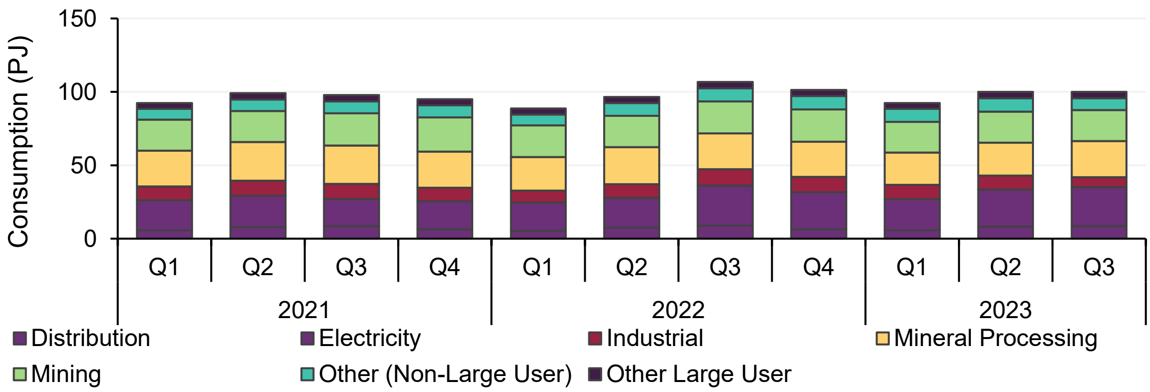
2.7 Gas – Western Australia

2.7.1 Gas consumption

A total of 99.9 PJ was consumed via pipeline in the Western Australian domestic gas market in Q3 2023. This was a decrease compared to Q3 2022 consumption of 106.7 PJ (-6.3%) and equal to Q2 2023 consumption of 99.9 PJ (Figure 90).

Figure 90 Western Australian domestic gas consumption reduced from Q3 2022 and remained equal to Q2 2023

WA quarterly gas consumption by sector – Q1 2021 to Q3 2023



Key drivers of consumption compared to Q3 2022 included decreases in gas consumption for industrial processes of 4.3 PJ (-39%), electricity generation of 0.8 PJ (-3%) and mining of 0.7 PJ (-3%).

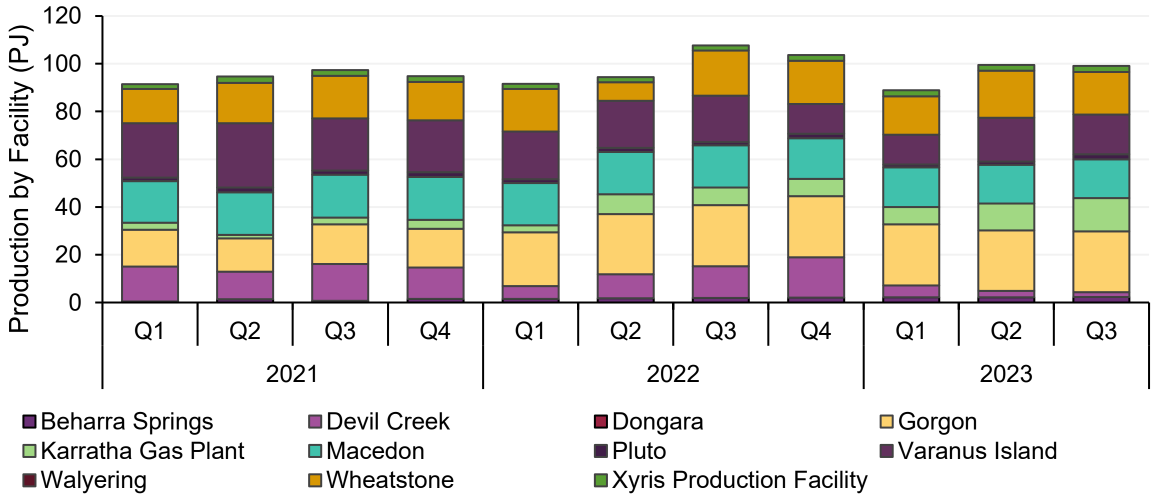
2.7.2 Gas production

Q3 2023 saw total Western Australian domestic gas production of 99 PJ, a decrease of 8.6 PJ (-8%) from Q3 2022 and a decrease of 0.5 PJ (-0.5%) from Q2 2023 (Figure 91). Key drivers of this production figure included:

- Wheatstone was down 1 PJ (-6%) compared to Q3 2022 and down 1.8 PJ (-9%) on Q2 2023, largely due to several days of zero production during early September.
- Karratha was up 6.5 PJ (+88%) compared to Q3 2022 and up 2.7 PJ (+24%) on Q2 2023 as the facility continued to increase production.
- The lower production volumes persisted at the Devil Creek facility in Q3 2023.
- Production commencement from Strike Energy's Walyering Production Facility, a 33 TJ/day capacity onshore facility connected to the Parmelia Pipeline in the south-west of Western Australia.

Figure 91 Western Australian domestic gas production remained consistent with Q2 2023

WA quarterly gas production by facility – Q1 2021 to Q3 2023

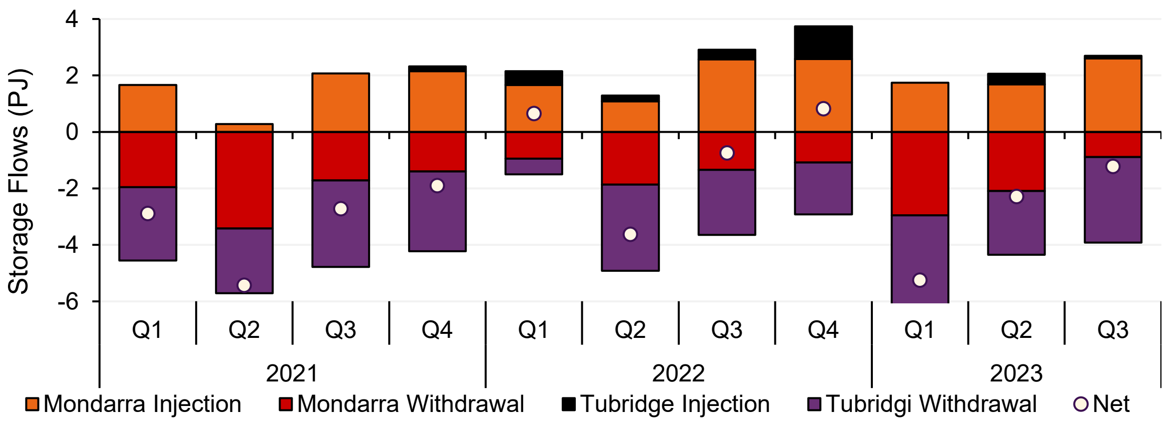


2.7.3 Storage facility behaviour

There was a continuation of the withdrawal of gas from storage in Q3 2023. Net withdrawal from storage was 1.2 PJ, which is a 0.5 PJ (66%) increase in withdrawals compared to Q3 2022 and a 1.1 PJ reduction in withdrawals from Q2 2023 (Figure 92).

Figure 92 Storage flows in Q3 continued the trend of net withdrawals

WA gas storage facility injections and withdrawals – Q1 2021 to Q3 2023



3 WEM market dynamics

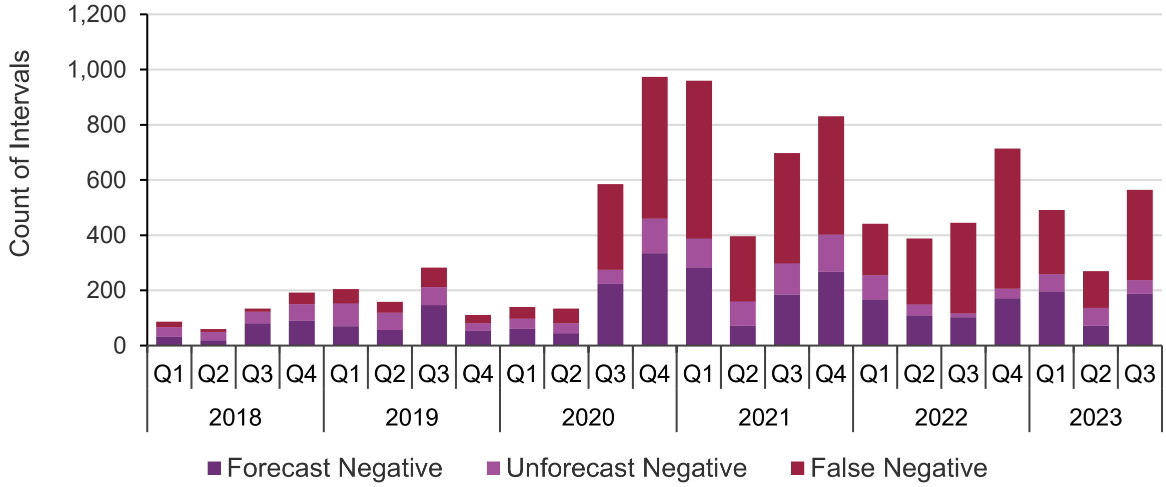
3.1 Balancing and Load Following Ancillary Service markets conclude

Q3 2023 concluded the operation of the Balancing and LFAS markets, more than a decade after these markets started in Q3 2012. The "New WEM Commencement Day" – 0800 hrs on 1 October 2023 – marked the transition to the Real-Time Market and Frequency Co-optimised Essential System Service markets[32]. Changes in the New WEM are designed to improve the effectiveness of the markets and address challenges in the previous markets.

Since Q3 2020, ex-post pricing has resulted in more changes in direction between forecast and final pricing, particularly negative prices being forecast but not realised in final pricing. Q3 2023 continued this trend, as more negative price intervals were forecast but not realised, and 13% of all intervals had negative prices in the forecast and/or final prices (Figure 93). This trend is not expected to continue in the New WEM, as prices are set ex-ante.

Figure 93 Since 2020, ex-post pricing resulted in negative prices forecast and not realised in final pricing

Count of intervals with negative Balancing Prices in the forecast only (false negative), final prices only (unforecast negative), or both (forecast negative) – Q1 2018 to Q3 2023



3.2 Weather observations and electricity demand

The weather in Q3 was characterised by 'average' to 'record warm' temperatures. Where July was on par with previous years, August had relatively warm daytime temperatures that were 1 to 2°C higher than usual. September turned out to be the warmest on record in Western Australia and many other states across Australia. Daytime temperatures were amongst the highest 10% of historical observations (compared with all Septembers since 1910), with state-wide mean maximum temperatures 3.77°C above the 1961-1990 average[33].

[32] Future QEDs will describe insights and outcomes related to these new markets. Many existing concepts in the Balancing Market will be different but comparable to the Real Time Market, such as Final Balancing Prices being comparable to Market Clearing Prices. Some concepts will not be comparable; for example, the current ex-post pricing mechanism to set balancing prices will cease and transition to ex-ante pricing to set Market Clearing Prices through the Dispatch Algorithm.

[33] Bureau of Meteorology 2023, Australia in September 2023: http://www.bom.gov.au/clim_data/IDCKGC1AR0/202309.summary.shtml.

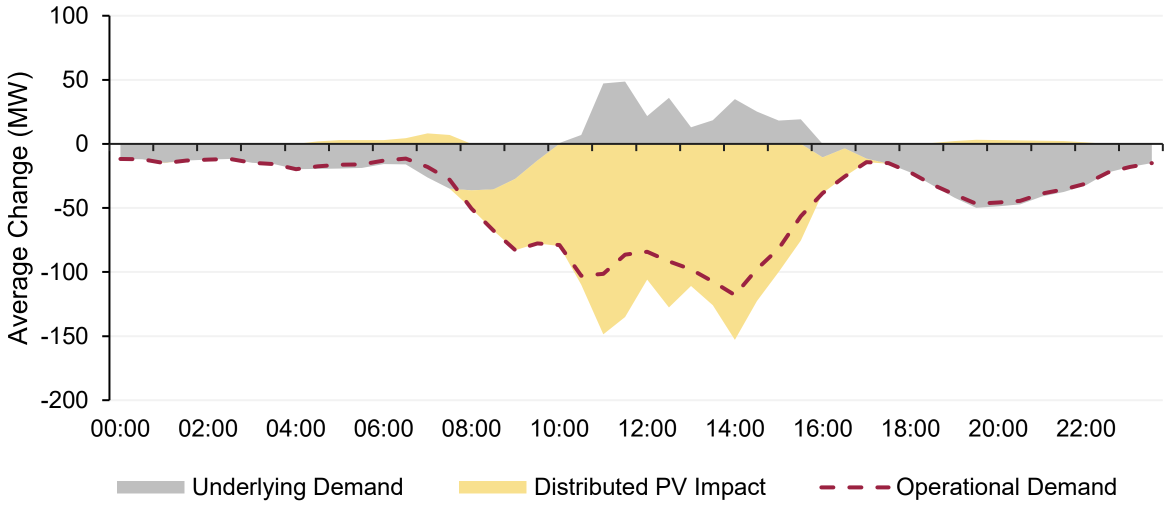
This resulted in an average number of Heating Degree Days (HDD)[34] in July, a slightly lower number of HDD in August, and only half the number of HDD in September compared to the previous two years.

Despite these 'higher than normal' temperatures, the WEM quarterly average underlying demand[35] was 2,345 MW, a decrease of only 11 MW (-0.5%) compared to Q3 2022, a relatively insignificant change. What can be observed, however, is that while average underlying demand decreased slightly, it showed small increases from 1000 hrs to 1600 hrs and slight decreases during the evening peak (Figure 94). Overall, the graph depicts the widening gap between underlying and operational demand due to growing distributed PV generation.

WEM quarterly average operational demand[36] was 2,017 MW, a decrease of 44 MW (-2.1%) compared to Q3 2022. This decrease is linked to the decrease in average underlying demand and further reduced by a 33 MW (11%) increase in average estimated distributed PV generation[37].

Figure 94 Operational demand decrease mainly driven by increased distributed PV generation

Change in average WEM demand components by time of day – Q3 2022 vs Q3 2023



The WEM set an all-time minimum demand record on 25 September 2023 (Figure 95). During the 1230 hrs interval, operational demand was down to 595 MW. This superseded the previous record of 626 MW at the 1230 hrs interval on 16 October 2022.

The maximum operational demand this quarter, observed at the 1800 hrs interval on 26 July 2023, was 3,407 MW. That day, maximum temperatures did not reach above 16°C, almost 25 mm of rain fell, and greater Perth experienced only 1.2 hours of sun. This 3,407 MW maximum was 200 MW below the maximum operational demand observed in Q3 2022.

[34] Heating and cooling degree days are based on the average daily temperature. The average daily temperature is calculated as follows: [maximum daily temperature + minimum daily temperature] / 2. If the average daily temperature falls below comfort levels, heating is required; and if it is above comfort levels, cooling is required. Comfort level values used for heating are between 12 and 18°C.

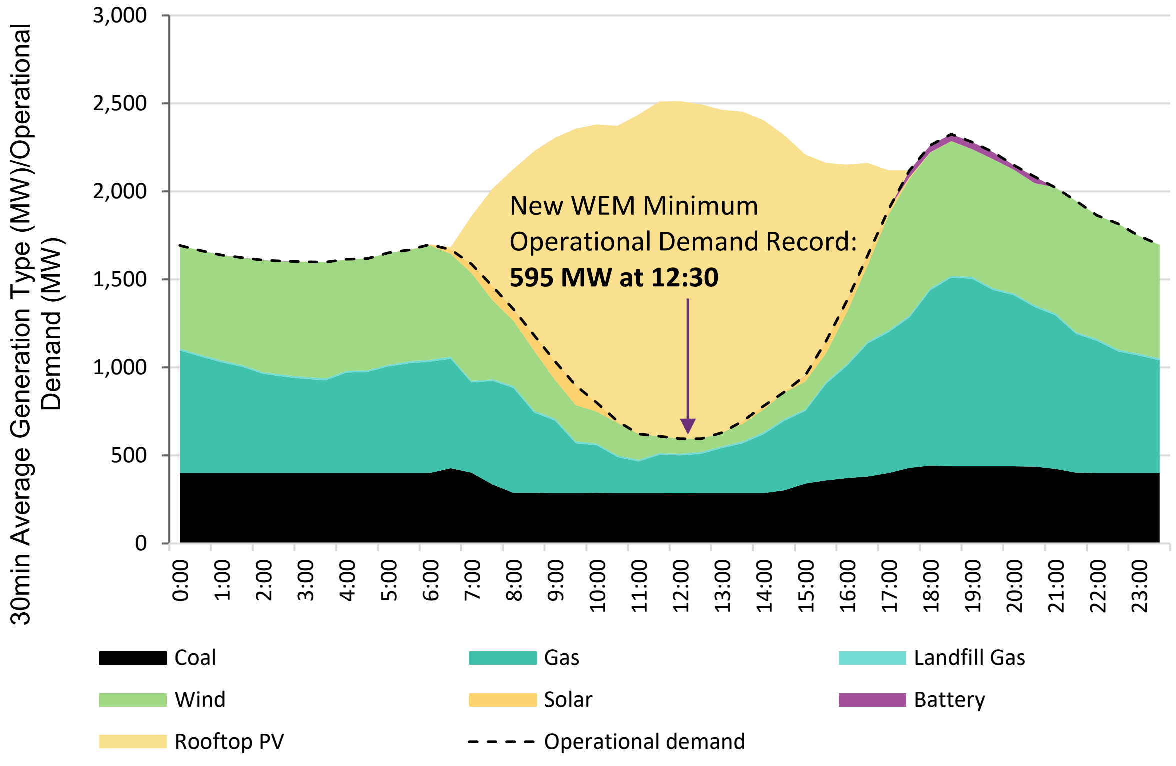
[35] Underlying demand is an estimated measurement of the total load on the SWIS, including behind-the-meter demand. Underlying demand is measured as operational demand adjusted to remove the impact of distributed PV output.

[36] Operational demand is the average measured total of all wholesale generation from registered facilities in the SWIS and is based on non-loss adjusted sent out SCADA data: http://data.wa.aemo.com.au/#operational-demand.

[37] Estimated distributed PV generation is the average estimated total of distributed PV generation in the SWIS. The estimate includes the generation used to supply behind-the-meter loads. It is based on PV sensor data across the SWIS and extrapolated based on the total installed capacity of distributed PV in the SWIS: http://data.wa.aemo.com.au/#distributed-pv.

Figure 95 All-time WEM minimum operational demand recorded: 595 MW on 25 September 2023

WEM operational demand components by time of day – 25 September 2023



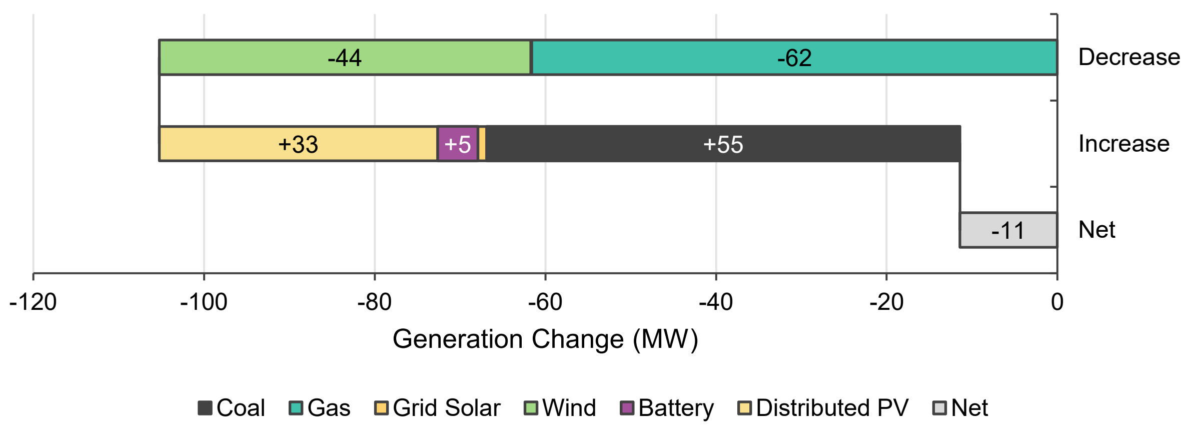
3.3 Electricity generation

3.3.1 Change in fuel mix

The total average generation output in the WEM over Q3 2023 was 11 MW lower than Q3 2022, driven by the overall decrease in underlying demand (see Section 3.2). The decrease was met by decreased gas-fired and wind generation, offset by an increase in coal, distributed PV and battery generation (Figure 96).

Figure 96 Coal-fired, distributed PV and battery generation offset a decrease in gas-fired and wind generation

Change in quarterly average generation – Q3 2022 vs Q3 2023



Changes in generation by fuel type and time of day, compared to Q3 2022 (Figure 97 and Table 6) were:

- Despite the retirement of MUJA_G5 in Q4 2022, average coal-fired generation reached 664 MW, an increase of 55 MW (+9%) on Q3 2022, increasing across every interval. Coal availability on average was 75% during Q3 2023, compared to 74% in Q3 2022. August saw high levels of coal availability, of 88%.
- Estimated distributed PV continued its growth trend, increasing by 33 MW (+11%) on average.
- Gas-fired generation decreased by an average of 62 MW (-6%). This was observed across all intervals except during the morning peak. The reduction of gas was most notable between 1000 hrs and 1600 hrs, when distributed PV output is at its highest.
- Wind generation decreased by an average of 44 MW (-12%), falling in every interval of the day, most notably overnight.
- Distillate levels normalised, as the tight market conditions that were observed in Q2 2023 did not continue in Q3. As such, distillate levels were on par with Q3 2022, with a slight reduction of 0.03 MW.
- Battery is included in the fuel mix due to the KBESS commissioning. This is the first large battery operating in the SWIS, with 100 MW rated active power and energy storage of 200 MWh. Injection via battery accounted for an average increase of 5 MW in Q3 2023 from low initial levels in Q2 2023.

Figure 97 Coal-fired generation increase in all intervals offset by decreased gas-fired and wind generation

Average WEM change in fuel mix by time of day – Q3 2022 vs Q3 2023

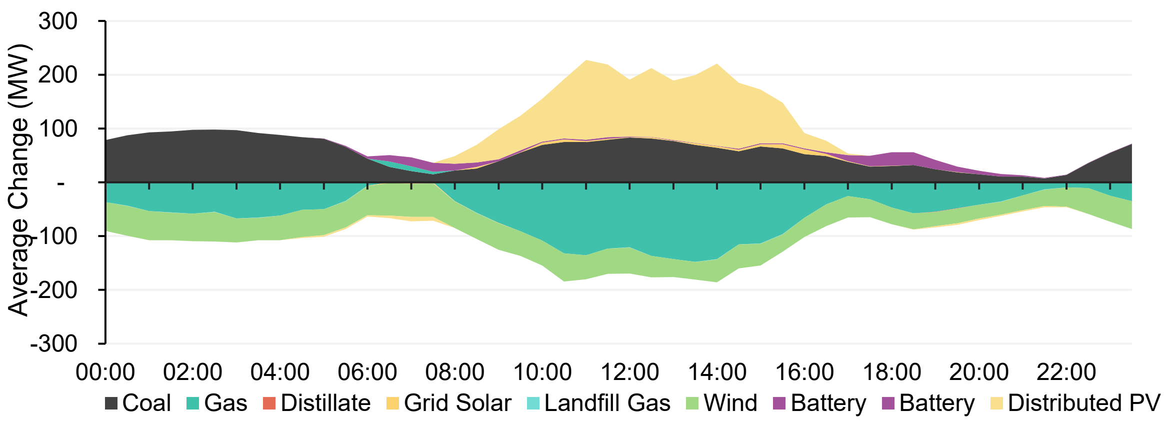


Table 6 WEM fuel mix Q3 2022 and Q3 2023

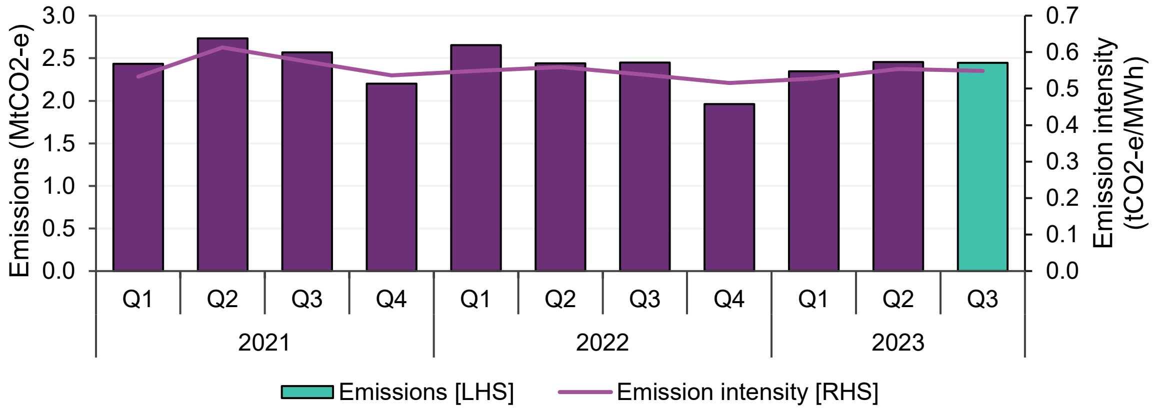
Quarter	Coal	Gas	Distillate	Grid solar	Landfill gas	Wind	Battery	Distributed PV
Q3 2022	25.8%	44.6%	0%	1.4%	0.4%	15.2%	N/A	12:5%
Q3 2023	28.3%	42.2%	0%	1.5%	0.4%	13:5%	0.2%	13.9%
Change (pp)	2.5%	-2.4%	0%	0.1%	0%	-1.8%	0.2%	1.5%

3.3.2 Carbon emissions

WEM emissions remained the same in Q3 2023 as in Q3 2022, at 2.45 MtCO2-e. Over the same period, WEM emission intensity increased from 0.54 tCO2-e/MWh to 0.55 tCO2-e/MWh in Q3 2023, representing an increase of 2% (Figure 98). This increase in emission intensity in Q3 2023 is largely due to an increase in coal as a share of the fuel mix, which has a higher emission intensity.

Figure 98 Emissions in the WEM remained at 2.45 MtC02-e in Q3 2023

Quarterly WEM emissions and emission intensity – Q1 2021 to Q3 2023

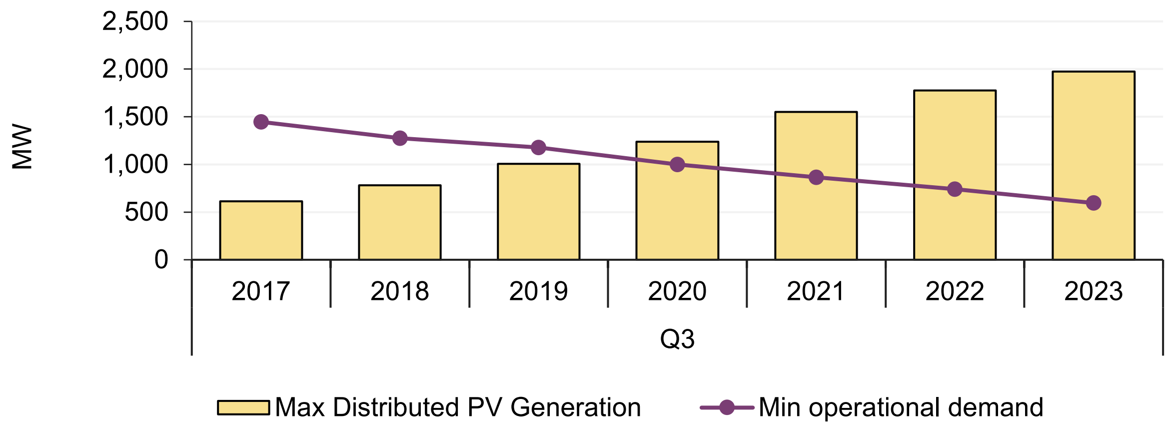


3.3.3 All-time record for maximum distributed PV output

The highest instantaneous renewable penetration in Q3 2023 was 81.9%, which was recorded at 1200 hrs on Sunday 24 September 2023; this is a new Q3 record. The maximum distributed PV output share was 76.3% on Monday 25 September 2023 at 1200 hrs. This was not only a Q3 record, but an all-time record for maximum distributed PV output. The impact of continuously increasing estimated distributed PV capacity on operational demand levels is clearly shown in Figure 99.

Figure 99 Operational demand in the SWIS fell below 600MW as distributed PV continued to grow

Minimum operational demand levels and maximum distributed PV generation – Q3s 2017 to 2023

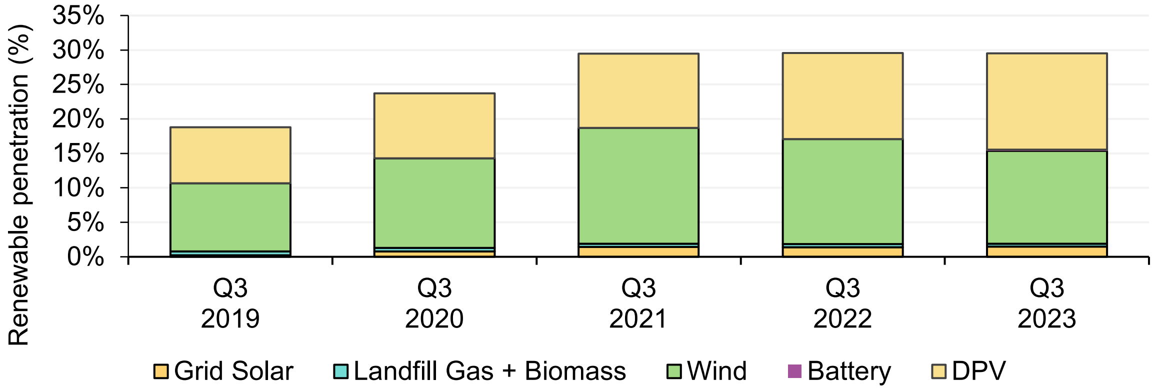


The quarterly average renewable penetration remained almost the same at 29.5% in Q3 2023, only slightly down from 29.6% in Q3 2022 (Figure 100). In the latest quarter, wind penetration reduced by 1.8 pp, while distributed PV average penetration grew by 1.5 pp, as a result of approximately 326 MW of additional capacity being installed between the end of Q3 2022 and end of Q3 2023.

The commissioning of KBESS meant that for the first time in Western Australia, battery storage is included in the renewable penetration figures of the SWIS. The average renewable penetration of battery was 0.2 pp.

Figure 100 Average renewable penetration remained at 29.5% in Q3 2023

Renewable penetration components – Q3s



3.4 WEM prices

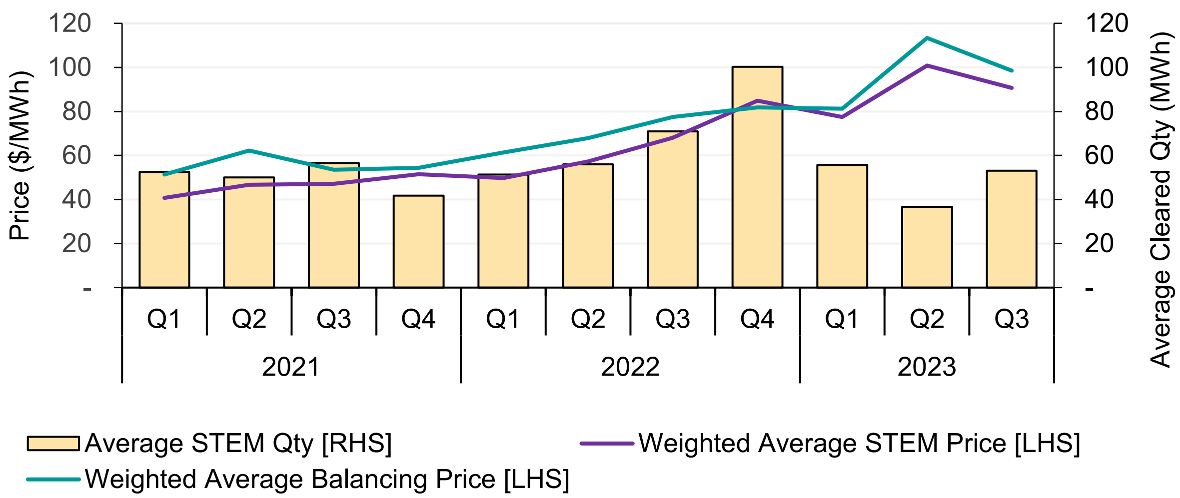
This quarter's weighted average Balancing Price[38] was $99/MWh, the highest average for a Q3, but reduced from the Q2 2023 record high prices (Figure 101). This was a $21/MWh (+27%) increase from Q3 2022. Contributors to the price change relative to Q3 2022 included a reduction in the quantity of energy made available in the Balancing Market in all intervals and consequent increases in the prices for quantities offered (Section 3.4.1).

The weighted average Short-Term Electricity Market (STEM) price[39] for Q3 2023 was $91/MWh, a $23/MWh (+33%) increase compared to Q3 2022.

The quarterly average quantity of energy cleared in the STEM increased from Q2 2023 to 53 MWh, down 25% from Q3 2022. This value resides within the historically normal range.

Figure 101 The weighted average balancing price and STEM price reached a record high for Q3, but reduced from the record set in Q2

WEM weighted average Balancing Price, STEM Price and quantity cleared in STEM – Q1 2021 to Q3 2023



[38] The weighted average Balancing Price is a measure of the average Balancing Price that puts greater weighting on intervals where greater quantity is generated. This is to reflect the average Balancing Price more accurately against quantity of electricity generated, rather than against intervals. Weighted average Balancing Price is sum(Balancing Price * EOI Demand)/sum(EOI Demand) across the quarter

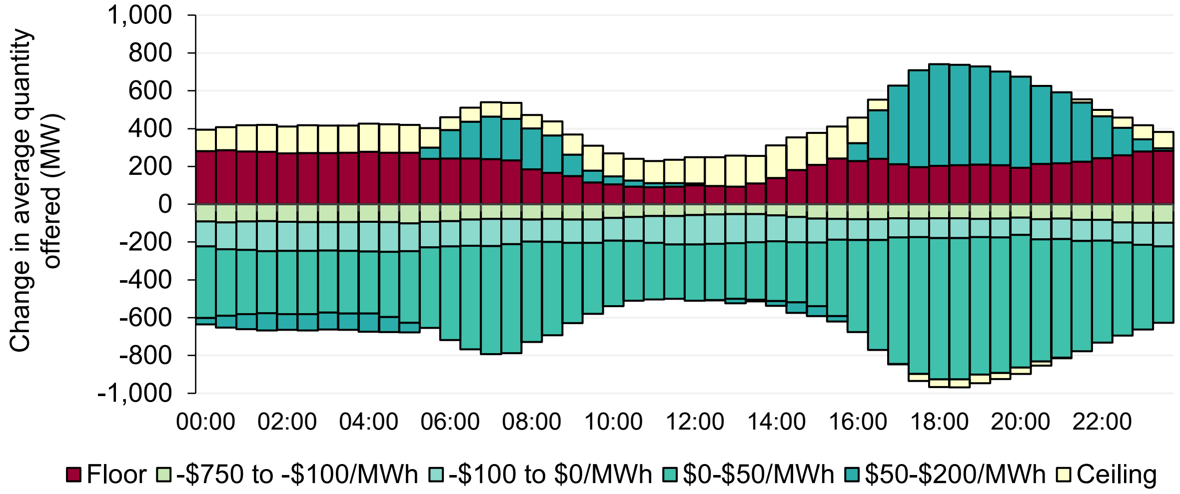
[39] The weighted average STEM Price is a measure of the average STEM Price that puts greater weighting on intervals where greater quantity is cleared. This is to reflect the average STEM Price more accurately against quantity of electricity cleared, rather than against intervals. Weighted average STEM Price is sum(STEM Price * Qty Cleared)/sum(Qty Cleared) across the quarter.

3.4.1 Balancing merit order dynamics

Lower quantities were offered for trade in the Balancing Market in Q3 2023 compared to Q3 2022, on average, in every interval. This was primarily the result of decreases in the quantity of bids made in the $0 to $50/MWh price band (-456 MW or -94%). Conversely, there was a 208 MW (+22%) increase in the quantity of bids at the price floor and an increase in the $50 to $200/MWh price band of 123 MW (13%) which was primarily targeted to the morning and evening peaks (Figure 102). These changes in Balancing Merit Order dynamics, in particular the reduction in the $0-$50/MWh price band, were the main drivers of the increase in the quarterly average Balancing Price.

Figure 102 Net reduction in quantities offered in the Balancing Market

Change in average Balancing Merit Order structure by time of day – Q3 2022 versus Q3 2023



3.4.2 Price-setting dynamics

The price-setting dynamics in Q3 2023 were consistent with Q3 2022 and observations over the previous year of reduced price-setting by independent coal fired generation and an increased share from independent gas-fired generation (Figure 103):

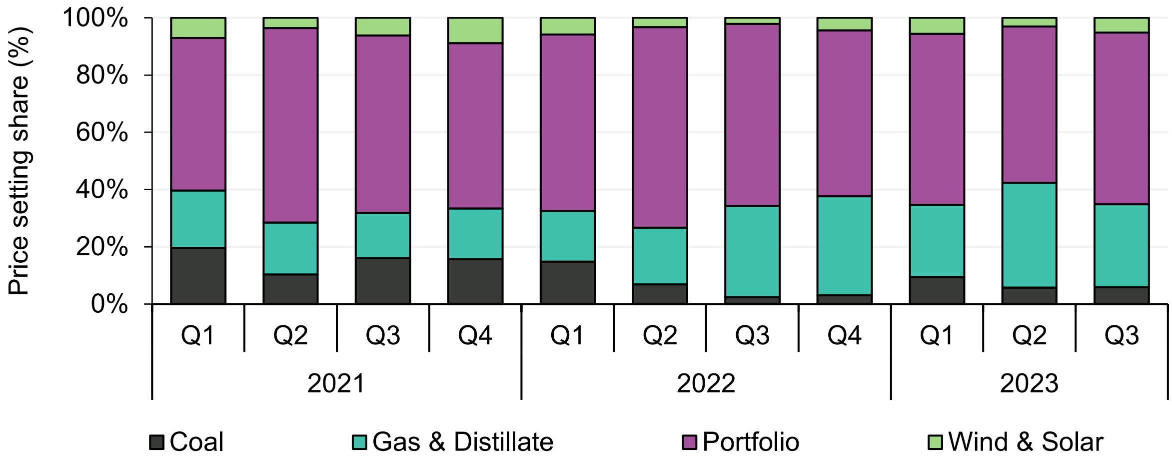
- The Synergy Balancing Portfolio[40] set the balancing price 60% of the time, down from 64% in Q3 2022.
- Independent coal-fired generation facilities set the price 6% of the time, an increase from 2% in Q3 2022.
- Independent gas-fired generation set the price 29% of the time, down from 32% in Q3 2022, with a continued elevated share compared to periods prior to Q3 2022.
- Wind and grid-scale solar facilities set the price 5% of the time, an increase from 2% in Q3 2022.

The slight decrease in gas-fired generation price-setting reduced pressure on the record high balancing prices from Q2 2023 but continued to drive increases from the historical average.

[40] The Balancing Portfolio is defined in the WEM Rules as all Synergy Registered Facilities, excluding Stand Alone Facilities, Demand Side Programmes and Interruptible Loads.

Figure 103 The increased share of price-setting by independent gas-fired generation continued for the fifth consecutive quarter

Price setting by the balancing Portfolio and fuel-type of non-Balancing Portfolio Facilities – Q1 2021 to Q3 2023



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 7 provides a brief description on the implementation of reforms delivered across the NEM over the last quarter.

Table 7 Reforms delivered Q3 2023

Reform initiative	Description	Reform delivered
Integrating Energy Storage System (Aggregated Dispatch Conformance)	Participants with aggregate systems can now register to dispatch the energy from their units collectively, rather than individually. Aggregated Dispatch Conformance (ADC) allows the units in an aggregate system to conform in aggregate with their dispatch instructions, subject to an AEMO requirement for individual conformance or Resource Level Compliance (RLC). This change gives participants flexibility to control energy flows in a cost and energy efficient way. Reference: https://aemo.com.au/en/initiatives/major-programs/integrating-energy-storage-systems-project.	August 2023
Fast Frequency Response **(Registration only)**	AEMO has opened registration for participants who wish to register their eligible facilities for participation in two new Very Fast Frequency Control Ancillary Services (FCAS) markets to operate alongside the existing contingency FCAS markets. The two new markets are scheduled to commence 09 October 2023. Reference: https://www.aemo.com.au/initiatives/major-programs/fast-frequency-response.	August 2023

The quarter also saw preparation for key reforms to go live in October 2023, including the new WA market to commence on 1 October 2023, and the NEM very fast frequency response services on 9 October 2023.

List of tables and figures

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Abbreviations

Abbreviation	Expanded term
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
ASX	Australian Securities Exchange
BESS	Battery energy storage system
CGP	Carpentaria Gas Pipeline
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EOI	End of interval
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
FCESS	Frequency Co-Optimised Essential System Services
GJ	Gigajoule
GWh	Gigawatt hours
GLNG	Gladstone LNG
GSH	Gas Supply Hub
IRSR	Inter-regional settlement residue
LNG	Liquefied natural gas
MSP	Moomba to Sydney Pipeline
$MtCO_2$-e	Million tonnes of carbon dioxide equivalents
MW	Megawatts
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NGP	Northern Gas Pipeline
pp	Percentage points
PJ	Petajoule
PV	Photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
RTM	Real Time Market
SIPS	System Integrity Protection Scheme
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline

Abbreviation	Expanded term
TJ	Terajoule
UGS	Underground Storage Facility
VBB	Victoria Big Battery
VRE	Variable renewable energy
VNI	Victoria – New South Wales Interconnector
WEM	Wholesale Electricity Market
WDR	Wholesale demand response