# Quarterly Energy Dynamics Q2 2023

July 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 Q2 2023 (1 April to 30 June 2023). This quarterly report compares results for the quarter against other recent quarters, focusing on Q1 2023 and Q2 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 | 27/7/2023 | |

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# Executive summary

## East coast electricity and gas highlights

### Wholesale electricity prices well down from Q2 2022 records, but remained historically elevated

- Wholesale spot prices averaged[1] $108 per megawatt hour (MWh) across all regions in the National Electricity Market (NEM) in this quarter, 59% lower than Q2 2022's $264/MWh, but still the second highest Q2 average price on record. Within the quarter, prices increased to average $154/MWh in May before falling to half that level in June.
- Lower thermal coal prices and fewer fuel supply restrictions this quarter than in Q2 2022 impacted generator bidding behaviour. Black coal-fired generation availability increased this quarter, driven by lower planned and unplanned outages in New South Wales, despite the retirement of the remaining Liddell units in April. As a result, coal-fired generators offered more volume at lower price bands.
- Significantly less price volatility occurred this quarter, with only 3% of intervals across all regions recording prices in excess of $300/MWh compared to 26% in Q2 2022. Continuing the trend observed in recent quarters, negative spot prices increased in frequency this quarter, driven by lower operational demand and greater variable renewable energy (VRE) generation.

### Lower operational demand driven by increased distributed PV output

- Despite this quarter having the highest Q2 underlying demand since 2016, growth in distributed photovoltaic (PV) output decreased average NEM operational demand to 21,717 megawatts (MW), the second lowest Q2 average since Tasmania joined the NEM in 2005. Year-on-year distributed PV growth for Q2 was 1,888 MW (30%), and was the second-highest year-on-year growth rate seen for any quarter. In contrast, demand increased outside distributed PV generation hours, driven by colder weather, particularly in May.
- Multiple minimum demand records were set this quarter, New South Wales reaching an all-time record low of 4,101 MW at 1300 hrs on Easter Sunday (9 April 2023), with distributed PV accounting for 43% of that region's underlying demand across the half-hour. On 2 April, Victoria and South Australia both recorded new Q2 minimum demand lows of 2,640 MW and 157 MW respectively.

### Variable renewable energy (VRE) output increases as gas and hydro generation declines

- Continuing recent trends, output from wind and grid-scale solar increased by 398 MW and 347 MW respectively this quarter compared to Q2 2022, driven largely by newly connected or commissioning units. Queensland saw a 69% jump in output from grid-scale solar, and Victoria a 27% increase in wind production.
- Gas-fired generation output this quarter averaged 1,469 MW, the lowest Q2 output since 2006 and 742 MW (-34%) below Q2 2022. This reflected lower electricity spot prices and operational demand, fewer coal unit outages and higher VRE output. As a result, gas-fired generators offered 300-500 MW less volume into the

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

spot market at most price levels and were less frequently dispatched. Similar price dynamics reduced average hydro generation output by 272 MW (-12%).

- Despite Liddell's retirement in April, this quarter saw a net lift in average black coal-fired availability of 373 MW. However there was a 95 MW reduction in output to 10,121 MW, the lowest Q2 level since 2001. This reflected lower utilisation rates as both black- and brown-coal fired units reduced daytime output in response to lower daytime operational demand and displacement by lower-priced VRE offers.

### Other NEM highlights

- Following a Q1 where the Victoria – New South Wales Interconnector (VNI) bound frequently at very low (and at times negative) export limits, VNI flows returned to near average levels for Q2. Negative inter-regional settlement residue fell by $2 million, largely due to reductions in counter-price flows from Queensland to New South Wales which occurred during volatile price events in June 2022.
- Coinciding with reduced energy spot prices this quarter compared to last Q2, frequency control ancillary services (FCAS) costs reduced by 54% to $39 million, with Queensland FCAS costs falling from $35 million to $11 million.
- Power system management costs totalled $21.7 million this quarter, significantly below Q2 2022. However, system security direction costs increased by $14.3 million, corresponding to higher volumes of South Australian gas-fired generation directed and a higher average quarterly compensation price.

### East Coast gas prices half Q2 2022 levels, demand and Victorian production down

- East coast wholesale gas prices significantly declined from record levels a year ago to average $14.20 per gigajoule (GJ) for the quarter, still the second highest Q2 price on record after Q2 2022's $28.39/GJ.
- Gas demand decreased by 5% this quarter compared to Q2 2022, driven by lower usage for gas-fired generation (-16 petajoules (PJ)), and lower AEMO markets demand (-5 PJ).
- A fundamental shift in domestic gas supply is underway, driven by declining production from gas fields connected to the Longford Gas Plant in Victoria. Aggregate Longford production decreased by nearly 25 PJ compared to Q2 2022, and daily production levels also decreased. Longford supply was mostly replaced by a net increase in Queensland supply (+11 PJ).
- Similar to Q1 2023, inventory at the Iona underground gas storage (UGS) facility ended the quarter with the highest end to Q2 balance since reporting began in 2017.

## Western Australia electricity and gas highlights

### All-time record high weighted average Balancing Price and record high Q2 STEM price.

- The weighted average Balancing Price in the Wholesale Electricity Market (WEM) for Q2 2023 was $113/MWh, an all-time record high and a 67% increase from Q2 2022. Contributors to the price increase include a reduction in the quantity of energy made available and changes to the fuel mix.
- The weighted average Short-Term Electricity Market (STEM) price for Q2 2023 was $101/MWh, a 76% increase compared to Q2 2022 and a Q2-record high.

- The quarterly average quantity of energy cleared in the STEM returned to historically normal levels, partly driven by decreased Balancing Price volatility since Q2 2022.

### Operational demand increased by 1.4% as a result of lower temperatures being observed, despite distributed PV output increasing

- In Q2 2023, the WEM's average operational demand was 2,028 MW, a 29 MW increase from Q2 2022. This increase was primarily driven by low temperatures, and occurred despite a 5% increase in distributed PV generation.
- The Q2 2023 maximum operational demand (3,652 MW) was recorded across the 1800 hrs interval on Monday 26 June 2023, due to cold temperatures driving high underlying demand. This is the highest recorded maximum operational demand in June on record since 2007.
- Q2 2023 also observed a new Q2 record low operational demand (904 MW) as a result of periods of high distributed PV generation and correspondingly lower troughs of operational demand in the middle of the day.

### Low generation from coal-fired facilities continued, offset by an increase in generation from gas-fired facilities, setting a new Q2 record

- Average coal-fired generation reached a record Q2 low of 712 MW, a decrease of 118 MW (-14%) on the same quarter last year.
- To offset the coal generation decrease, gas-fired generation increased by an average of 206 MW (+27%), a new Q2 record high. This significant increase was a consequence of gas-fired generation both compensating for lower coal-fired and wind-based generation and capturing most of this quarter's increased average underlying demand.
- Q2 2023 experienced high quarterly distillate-fired generation as a result of unusually high demand coinciding with several planned and forced outages.

### Gas production increased and storage flows stabilised

- WA domestic gas production increased by 10.6 PJ from Q1 to almost 100 terajoules (TJ) in Q2 2023. This represents an increase of almost 12%.
- There was relative stabilisation of storage flows in Q2 2023, with net withdrawal from storage of 2.3 PJ, which is a 3 PJ (57%) reduction compared to Q1 2023.

## New additions to this report

The aim of the Quarterly Energy Dynamics (QED) report is to provide valuable and comprehensive insights into wholesale electricity and gas market outcomes and drivers across the entire quarter. This report includes two new sections:

- Connections – connecting new technologies to the grid quickly and efficiently is essential to the broader energy transition. AEMO has focused its connections efforts on engaging early and proactively with project developers, equipment manufacturers and network service providers (NSPs). Section 1.3.8 summarises the number of connection applications and capacity processed over the quarter, highlighting increases in the capacity of projects progressing through the connection application and subsequent construction phases this quarter, as well as a significant increase in the capacity of projects which had been fully commissioned by the end of the 2022-23 financial year.

- Reform delivery – regulatory changes and reforms that were introduced over the current quarter have been listed in Section 4 with references for further information. Reforms delivered since March this year include changes to:
  - support market integration of small storage, generation and stand-alone power systems,
  - improve the efficiency of retail processes, and
  - enact important transparency and security mechanisms for the east coast gas markets.

# Contents

# 1 NEM market dynamics

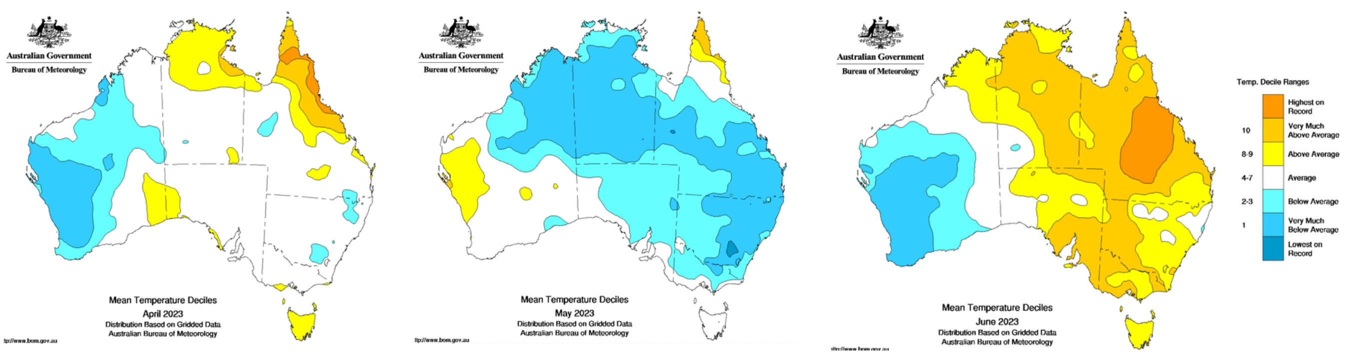
## 1.1 Electricity demand

### 1.1.1 Weather

The quarter began with the highest April rainfall since 2006 nationally, with above average rainfall across much of South Australia, far north and south west Queensland, and parts of New South Wales and Victoria. Nationally, April temperatures were the coolest since 2015, although temperatures were above average in northern Queensland and Tasmania (Figure 1).

**Figure 1 Cooler than average temperatures in middle of the quarter gave way to a warmer than average June**

Mean temperature deciles across Australia – April, May and June 2023

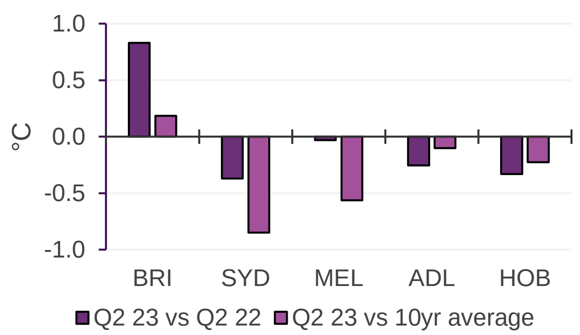



Source: Bureau of Meteorology

May was an exceptionally dry month, with the second-driest conditions recorded for Australia as a whole (73% below average for May). This was coupled with the lowest mean temperatures since 2011 (1.1°C below the 1961-1990 average for May).

**Figure 2 Temperatures in most capital cities below 10-year average**

Average maximum temperature variance by capital city




Early May brought cold fronts to south-eastern regions, leading to snow in alpine areas and some weather stations in south-eastern New South Wales and north-eastern Victoria experiencing their lowest daily recorded maximum May temperatures.

The end of the quarter brought warmer than average temperatures nationally (the national area-average mean temperature was 1.1°C above the 1961-1990 average for June). Queensland had the warmest June on record since observations began, with mean maximum temperatures 3.1°C above average. Although it was a wet end to the quarter for Australia as a whole, rainfall was below average for much of the east coast.

Over the quarter, maximum temperatures were below those of Q2 2022 and the 10-year average for most capital cities except Brisbane, which recorded an average maximum temperature nearly 0.8°C above Q2 2022 (Figure 2).

### 1.1.2 Demand outcomes

Overall average quarterly National Electricity Market (NEM) operational demand was 21,717 megawatts (MW), 1% (214 MW) lower than in Q2 2022 and the second lowest Q2 average since Tasmania joined the NEM in 2005.

As Figure 3 shows, changes in operational demand varied by time of day. The highest average Q2 underlying demand recorded since 2016[2] (23,605 MW; Figure 4) was offset by the highest Q2 average distributed photovoltaic (PV) output (1,888 MW) recorded. It was also the highest year-on-year growth in distributed PV average output recorded (431 MW higher than Q2 2022), and the second-highest recorded growth in percentage terms (Figure 5). In contrast, outside distributed PV generation hours, growth in underlying demand drove higher operational demand in the morning and evening relative to Q2 2022, especially in May.

**Figure 3 Distributed PV reduced daytime operational demand**

Change in operational demand – Q2 2023 versus Q2 2022

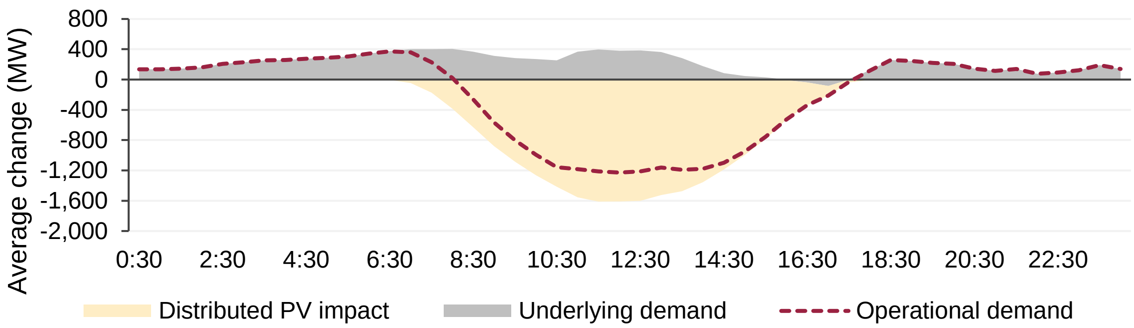



**Figure 4 Rising underlying demand offset by high distributed PV output**

NEM average operational and underlying demand – Q2s

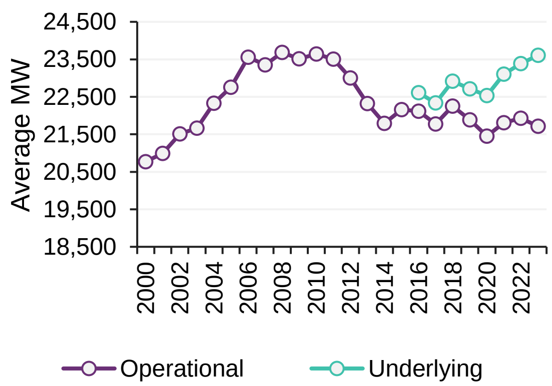
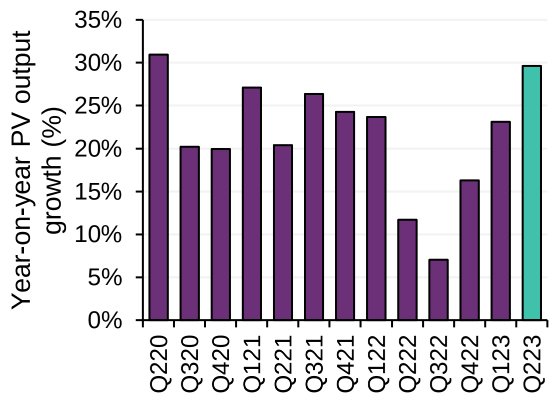



**Figure 5 Second highest year-on-year growth in distributed PV output**

Year-on-year percentage changes in PV output




As Figure 6 shows, observations varied by region over the quarter:

- In **Queensland**, a 2.9% (191 MW) increase in underlying demand was offset by a 38% (198 MW) increase in distributed PV output relative to Q2 2022, with distributed PV output growth especially pronounced in May due to high monthly solar exposure. Approximately half of the increase in underlying demand was due to higher

[2] Consistent quarterly estimates of distributed PV output and underlying demand are not available for Q2 prior to 2016. However, in years prior to 2011, installed distributed PV capacity was very small, meaning that operational and underlying demands were essentially identical.

industrial demand from Boyne Island smelter, which operated at reduced levels in Q2 2022. Increased heating requirements in May also likely contributed, with the number of heating degree days[3] considerably higher than last Q2 (Figure 7).

- A small increase in underlying demand (+0.6%) in **New South Wales** was more than offset by a 31% (148 MW) increase in distributed PV output relative to Q2 2022, resulting in an overall decline in operational demand of 1.2%. Within the quarter, cold weather in May contributed to a 4.7% (393 MW) increase in underlying demand for the month relative to May 2022. This was followed by a decline in June relative to June 2022 driven by warmer-than-average temperatures.
- **Victoria** was the only region where underlying demand fell (-0.5% or -28 MW), and coupled with a 24% increase in distributed PV output, this led to a 1.7% decline in operational demand relative to last Q2.

**Figure 6 Growth in distributed PV output more than offset underlying demand increases in New South Wales**

Changes in average demand components by region – Q2 2023 vs Q2 2022

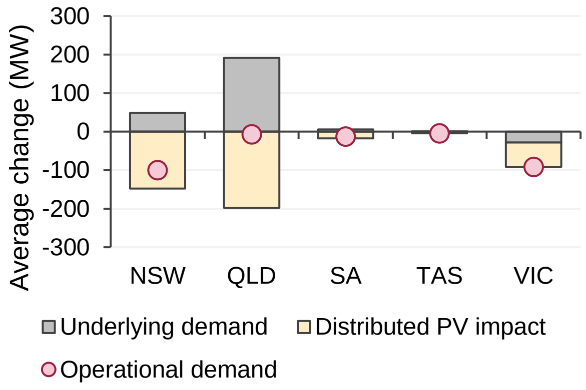
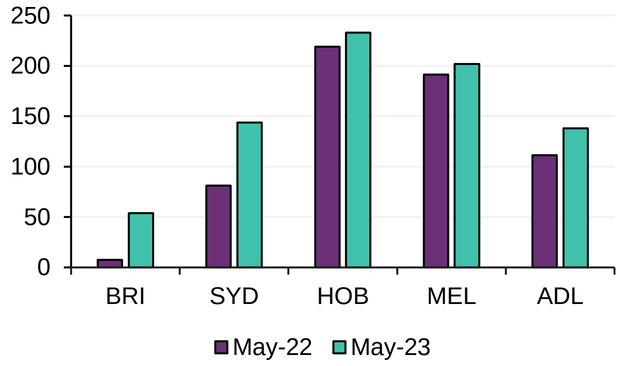



**Figure 7 Higher heating requirements in May drove underlying demand increases in Queensland and New South Wales**

Heating degree days – May 2023 vs May 2022




## Maximum demand

Overall NEM maximum demand declined slightly relative to Q2 2022 to 32,320 MW (-0.2%). No NEM regions reached new quarterly maximum demand records in Q2 2023. **Queensland**, **Tasmania** and **Victoria**'s maximum demand declined by approximately 2%, **New South Wales**' rose by 2% and **South Australi**a's rose by approximately 8% (180 MW) relative to last Q2.

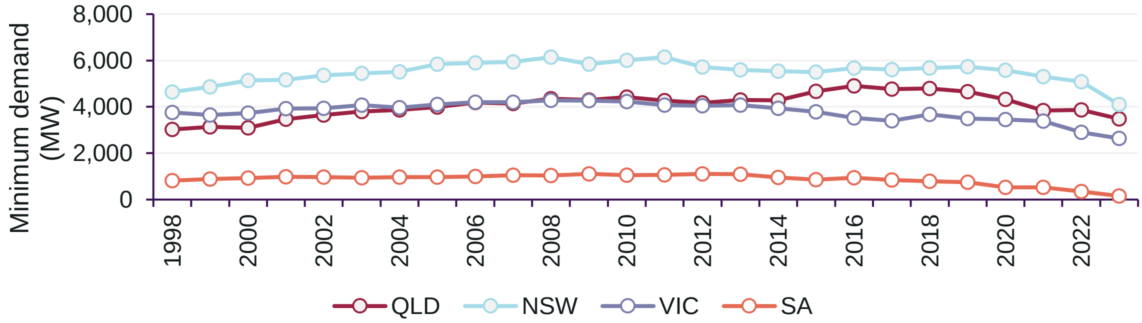
## Minimum demand

**New South Wales** reached an all-time minimum demand record of 4,101 MW in the half-hour ending 1300 hours on Sunday 9 April 2023 (Easter Sunday), driven by clear skies and mild temperatures (Figure 8). At the time, distributed PV accounted for 43% of the region's underlying electricity demand. This new record is 255 MW lower than the previous all-time minimum demand record reached in Q4 2022, and 979 MW lower than the Q2 2022 minimum.

[3] A "heating degree day" (HDD) is a measurement used as an indicator of outside temperature levels below what is considered a comfortable temperature. Here, the HDD value is the sum over the quarter of daily HDD values which are calculated as max (0, 18 – temperature).

**Figure 8 Minimum demand records for New South Wales (all time), South Australia and Victoria (Q2)**

Q2 minimum operational demands for mainland regions




The NEM as a whole reached its lowest Q2 minimum demand since Tasmania joined the NEM in 2005 (13,378 MW); this was 1,002 MW lower than last Q2.

South Australia and Victoria also reached Q2 minimum demand records this quarter, driven by increasing distributed PV output:

- **South Australia** reached 157 MW in the half hour ending 1330 hours on 2 April 2023, with distributed PV accounting for 89% of the region's underlying electricity demand. This was 189 MW lower than the previous Q2 2022 record of 346 MW.
- **Victoria's** new Q2 minimum demand record was 2,640 MW, set in the half-hour ending 1300 hours on 2 April 2023, with distributed PV accounting for 46% of the region's underlying electricity demand. This was 261 MW lower than the previous Q2 2022 minimum demand record of 2,901 MW.

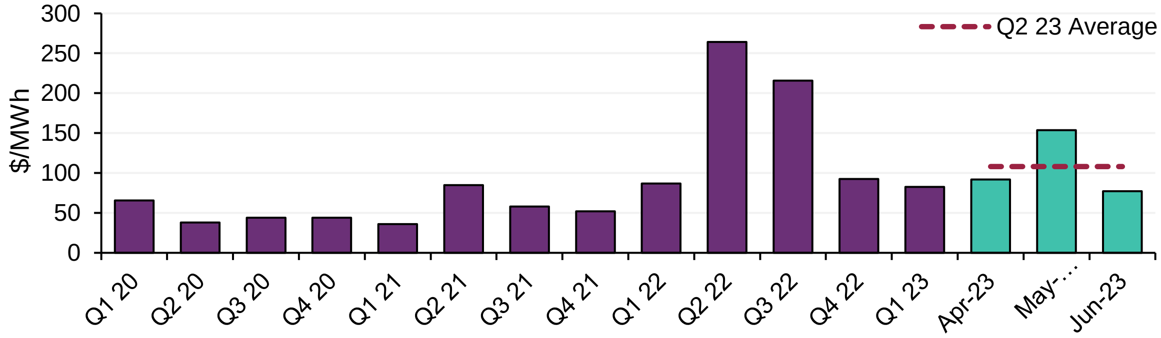
**Queensland's** minimum demand this quarter also declined by 375 MW relative to last Q2, reaching its lowest Q2 level since 2001 (3,487 MW) on 9 April 2023.

## 1.2 Wholesale electricity prices

Wholesale spot prices averaged $108/MWh across the five NEM regions in Q2 2023, 31% higher than the Q1 2023 average of $83/MWh, but down 59% from the highest recorded quarterly price of $264/MWh in Q2 2022 (Figure 9). After Q2 2022, this represents the second highest Q2 average quarterly price recorded for the NEM since Tasmania joined in 2005. Average monthly spot prices across the quarter continued a rising trend evident from the beginning of 2023 to reach $154/MWh in May, before falling sharply to just $77/MWh in June.

**Figure 9 Average NEM spot prices down 59% on Q2 2022, but remained the second-highest Q2 level recorded**

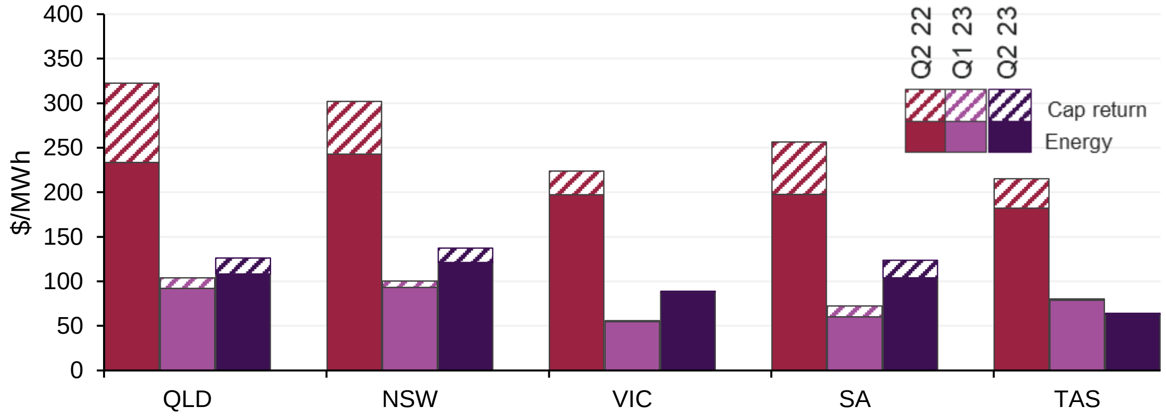
NEM average wholesale electricity prices – quarterly since Q1 2020



Quarterly average prices by region ranged from $64/MWh in Tasmania to $137/MWh in New South Wales, with Victoria, South Australia and Queensland averaging $89/MWh, $124/MWh and $126/MWh respectively (Figure 10). Each NEM region experienced price decreases exceeding 50% from Q2 2022 levels with reductions in both energy[4] and cap return[5] components. Compared to Q1 2023, spot prices were elevated in all regions except for Tasmania.

**Figure 10 All regions saw price declines exceeding 50% on Q2 2022 levels**

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




By region:

- **Queensland**'s average quarterly price was $126/MWh, an increase of $22/MWh from Q1 2023 but $196/MWh lower than Q2 2022. The cap return component of Queensland's average decreased by $71/MWh from Q2 2022 while the energy component dropped by $125/MWh. This quarter saw much lower spot price volatility than Q2 2022, with prices influenced by relatively lower thermal coal costs and marginal coal offers. The number of five-minute trading intervals where prices exceeded $300/MWh in Queensland dropped to 900 in Q2 2023 from 9,858 in Q2 last year. Q2 2023 also saw a lift in grid-scale solar output that led to an increase in daytime negative price occurrence in Queensland (Section 1.2.3).
- **New South Wales**' average quarterly price of $137/MWh was $37/MWh higher than Q1 this year but $165/MWh lower than Q2 2022. The drop in operational demand coupled with increased black coal availability caused New South Wales price volatility to fall relative to Q2 2022. However, New South Wales' average quarterly price remained above Queensland's, with a notable price separation between the two regions during daytime hours (Figure 11). During this quarter, the net southward flows from Queensland to New South Wales experienced an increase (+52 MW) due to relatively lower daytime prices in Queensland. Consequently, the Queensland – New South Wales Interconnector (QNI) reached its import limit more frequently than in the previous quarter (Section 1.4), leading to a more apparent price separation during daytime. This was the first time since Q4 2020 that the Queensland quarterly average price has fallen below that in New South Wales.
- **Victoria** had an average price of $89/MWh, increasing $33/MWh from Q1 2023, but down $135/MWh from Q2 2022. Victoria's cap return dropped to $1/MWh from $27/MWh in Q2 last year.

4 "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

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

- **South Australia** averaged $124/MWh, up by $52/MWh over Q1 2023, but down $133/MWh from Q2 2022. South Australia's higher quarterly average compared to Victoria was particularly evident in the cap return component, with South Australia's amounting to $20/MWh compared to Victoria's $1/MWh. This was driven by a number of price volatility events that led to price separation between the two regions on the back of outage-driven limitations on Heywood interconnector flows. In this quarter, South Australia had 2,129 trading intervals where prices exceeded $300/MWh, whereas Victoria had 420 intervals. In 842 of those 2,129 intervals, the Heywood interconnector's limit into South Australia was constrained to 50 MW or below. South Australia recorded the largest regional quarterly price increase over Q1 2023, closing the gap to higher average spot prices in the northern regions of Queensland and New South Wales. Previous quarters had seen average prices in South Australia, as well as in Victoria, significantly below those in northern regions
- **Tasmania** averaged $64/MWh, a decrease of $151/MWh from Q2 2022. While all mainland regions saw increases in spot price compared to Q1 2023, Tasmania's quarterly average decreased by $16/MWh. The lower prices were influenced by increased generation output and price-setting frequency by hydro, and relatively lower average prices set by hydro when marginal. This resulted in greater northward flows from Tasmania to Victoria on Basslink interconnector in this quarter.

Q2 2023 saw time of day average prices returning towards pre-2022 levels, but with higher overnight prices relative to Q2 2021 (Figure 12).

**Figure 11 Daytime price separation between New South Wales and Queensland**

Average energy prices by region – Q2 2023

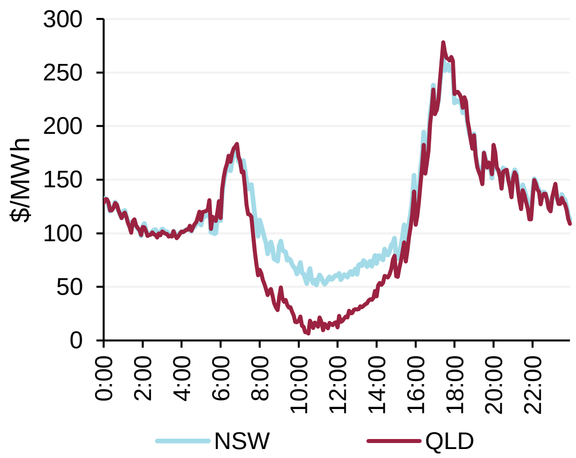
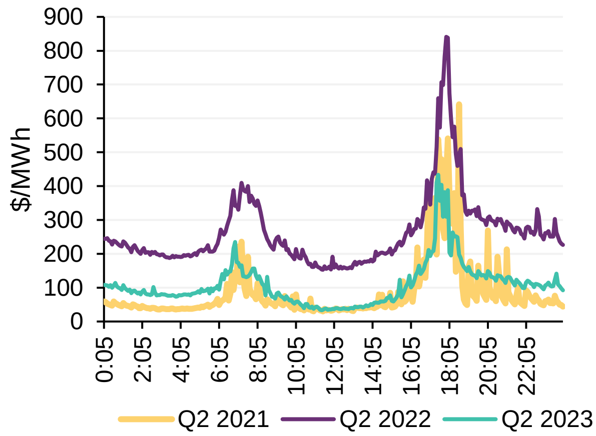



**Figure 12 Prices return to pre-Q2 2022 levels but remain significantly higher overnight**

Average NEM RRP by time of day – Q2s




## Market suspension

On 22 April 2023, AEMO declared the spot market suspended in Victoria in response to a loss of Supervisory Control and Data Acquisition (SCADA) across Victorian electricity transmission assets and AusNet's electricity and gas distribution networks in Victoria[6]. During the event Victorian spot prices and ancillary service prices were set using market suspension schedule pricing from trading interval (TI) ending 1620 hrs on 22 April 2023 until TI 0435 hrs on 23 April 2023, in accordance with National Electricity Rules (NER) 3.14.5(e). The use of dispatch prices resumed from TI 0440 hrs on 23 April 2023 and the suspension ended at 1700 hrs on 23 April 2023. Based

[6] See AEMO's preliminary report for more information on the New South Wales market suspension event: https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2023/preliminary-report-vic-market-suspension.pdf?la=en.

on its initial review, AEMO has not identified any power system security issues, including any disconnection of generation or load, associated with this incident.

### 1.2.1 Wholesale electricity price drivers

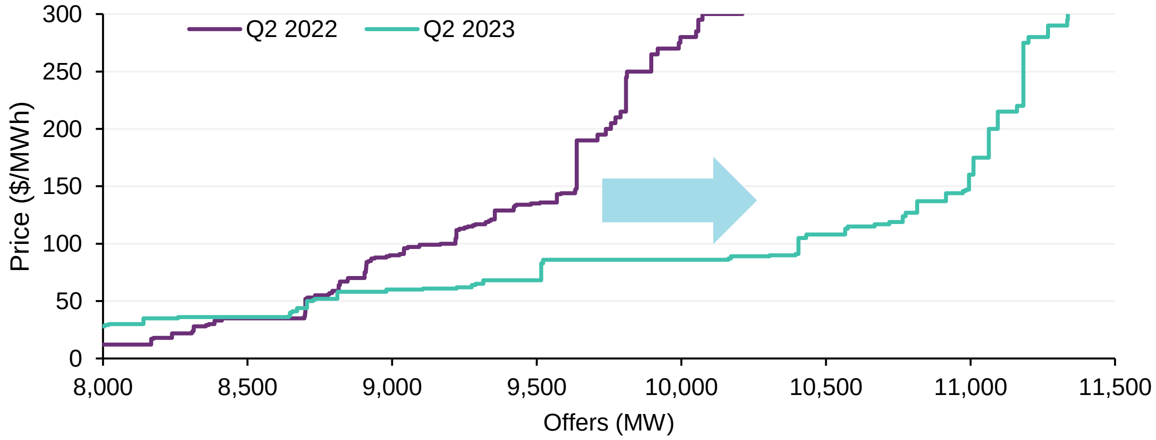
This quarter saw average spot prices decreasing on Q2 2022 but increasing from Q1 2023 in all NEM mainland regions. Key factors influencing the movement of prices throughout Q2 2023 are summarised in Table 1, with further analysis and discussion referred to relevant sections elsewhere in this report.

**Table 1 Wholesale electricity price levels: Q2 2023 drivers**

| | |
|---|---|
| **Offers from marginal generators** | Q2 2022 saw unprecedented NEM wholesale price outcomes, partly driven by elevated thermal coal prices and fuel supply restrictions that impacted thermal generators' bidding behaviours. Since then, thermal coal prices dropped from $514/tonne in Q2 2022 to $240/tonne in Q2 2023 (Section 2.1.1). This, together with policies capping domestic thermal coal prices, reduced the marginal costs of black coal-fired generators, with larger volumes of energy being offered to the spot market at prices levels from $50/MWh upwards, yielding lower average electricity prices in Q2 2023 (Figure 13). |
| **Coal availability** | Throughout this quarter, total black coal availability increased by 373 MW driven by relatively lower planned and unplanned outages in New South Wales leading to higher availability in that state despite the retirement of Liddell units in late April (Section 1.3.1). Q2 typically sees higher levels of seasonal planned maintenance on thermal generation units in preparation for winter and Q2 2022 saw multiple unplanned outages of coal-fired units clustered at different times over the quarter. |
| **Daytime operational demand** | Average quarterly NEM operational demand in Q2 2023 was 214 MW lower than in Q2 2022 (Section 1.1.2). This was driven by increased distributed PV output that more than offset higher underlying demand. Due to reduced daytime operational demand, lower-priced offers set the price more frequently, particularly in South Australia and Victoria which experienced negative prices 17% and 13% of the time respectively (Section 1.2.3).<br>The month of May saw lower than average temperatures across the east coast that led to increased heating requirements. The end of the quarter brought warmer than average temperatures, resulting in relatively lower operational demand in June (Section 1.1.2). |
| **VRE Generation** | In Q2 2023, variable renewable energy (VRE) output increased by 745 MW (Section 1.3.4). This, combined with lower operational demand increased the occurrence of daytime negative prices. Queensland's negative price occurrence between 0900 hrs and 1700 hrs rose to 25%, an increase of 19 pp due to a significant uptick in grid-scale solar output. Negative price impact grew in all NEM regions reaching $8/MWh in South Australia, $4/MWh in Victoria and $2/MWh in Queensland. An increase in market prices of large-scale renewable certificates in Q2 2023 also contributed to these larger negative price impacts, as average spot prices set by some renewable generators fell (Section 1.2.3). |

**Figure 13 Increased black coal offer volumes at most price levels**

Black coal generation bid supply curve – Q2 2022 and Q2 2023

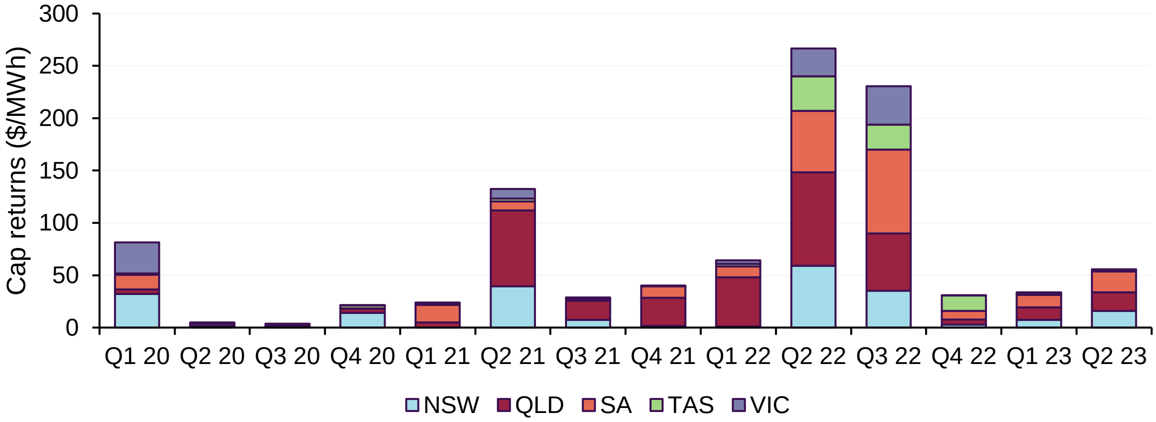



### 1.2.2 Wholesale electricity price volatility

NEM spot price volatility, which is measured via cap return (the contribution of spot prices in excess of $300/MWh to the quarterly average) aggregated across the five NEM regions, decreased to $56/MWh in Q2 2023 from the record high level of $267/MWh in Q2 2022 (Figure 14). During Q2 and Q3 last year, prices exceeded $300/MWh in an unprecedented proportion of dispatch intervals, with nearly half the NEM's aggregate cap return in Q2 2022 arising from prices between $300/MWh and $1,000/MWh. This Q2 saw far fewer high price occurrences, resulting in much lower cap returns across all NEM regions. Queensland and New South Wales saw the largest reductions relative to Q2 2022, with cap returns reducing by $71/MWh and $43/MWh respectively.

**Figure 14 Sharp drop in cap returns in all regions**

Cap returns by region - quarterly




Q2 2023 experienced 4,036 dispatch intervals (aggregated across five regions) exceeding $300/MWh, compared to 34,066 observed in Q2 2022, representing 3% and 26% respectively of all intervals in each quarter. However, in comparison to Q1 2023, all regions witnessed a greater number of intervals this quarter where prices exceeded $300/MWh (Figure 15). The increase in the number of high-price events compared to Q1 was largely driven by colder weather conditions, low wind levels and outage-driven transmission restrictions.

**Figure 15 Significantly lower incidence of spot price volatility than Q2 2022 across all regions**

Percentage of trading intervals exceeding $300/MWh by region

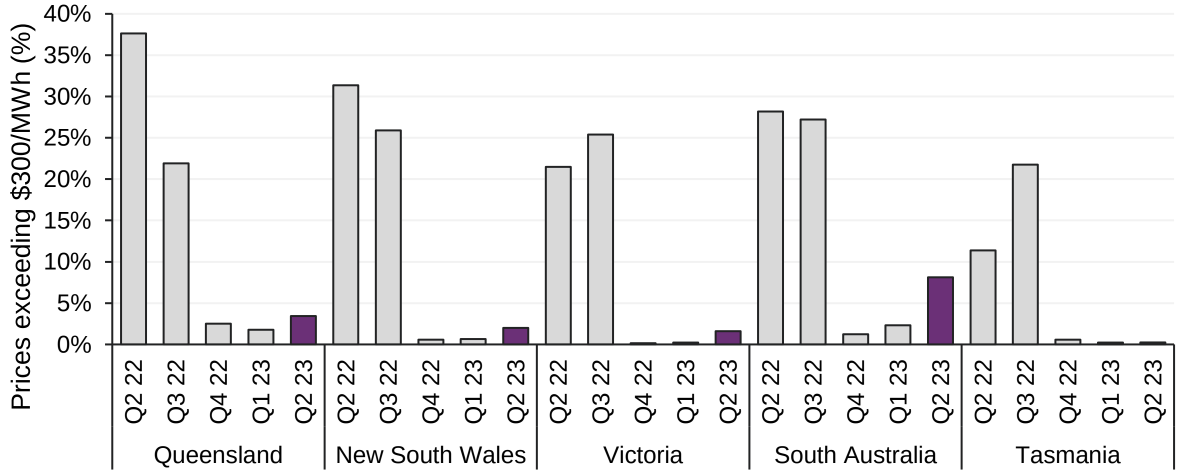


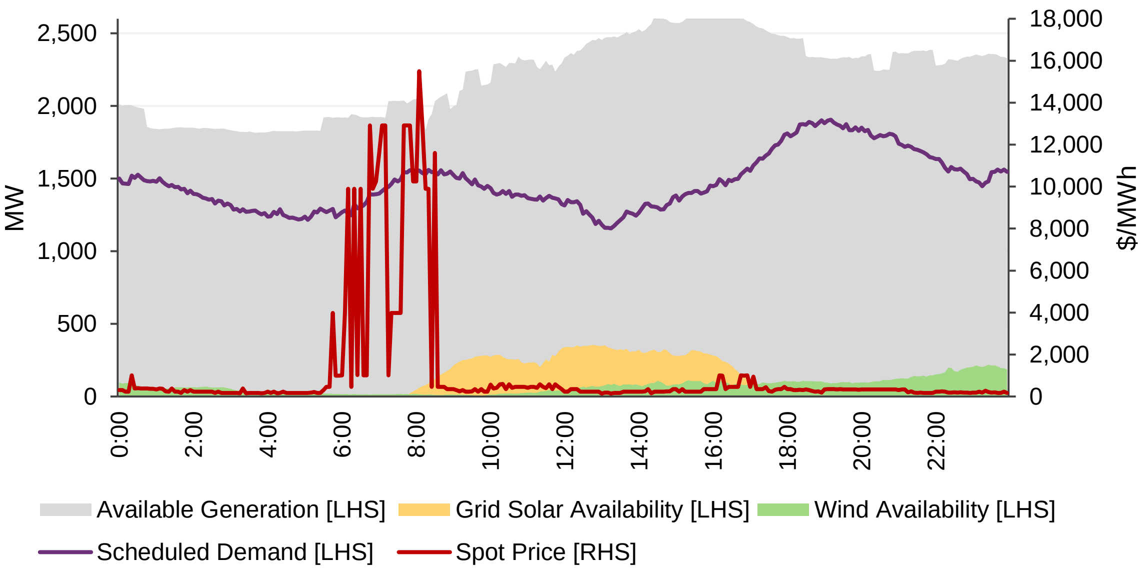

Table 2 summarises events of significant spot price volatility during Q2 2023.

**Table 2 Significant volatility events in Q1 2023**

| Date | Region | Contribution to quarterly cap return ($/MWh) | Drivers |
|---|---|---|---|
| 4 May | South Australia (SA) | 9.73 | South Australia experienced price spikes on this day between 0550 and 0835 hrs with 19 intervals above $9,000/MWh, The morning peak period saw South Australia demand sustaining around 1300-1500 MW with significant reduction of wind generation below 100 MW throughout the early morning (Figure 16). In addition, exports into South Australia from Victoria were constrained to 50MW due to interconnection maintenance works, causing the price to rise in South Australia. During this high-price period South Australia price averaged $7,386/MWh and hit the price cap of $15,500/MWh at 0810 hrs. |
| 24 May | New South Wales (NSW) | 4.20 | Prices spiked between 1730 and 1835 hrs with 8 intervals above $10,000/MWh in both New South Wales and Queensland. In the week leading up to this event, temperatures dropped across eastern Australia, elevating NEM demand during morning and evening peak periods. A network outage due to refurbishment of the Dapto-Kangaroo Valley transmission line limited supply from Victorian and southern New South Wales generators to northern regions. Actual Lack of Reserve (LOR) 1 was declared in New South Wales from 1700 to 2130 hrs during the event on the back of thermal generation outage. |
| | Queensland (QLD) | 3.64 | |
| 30 May | New South Wales (NSW) | 3.13 | On this day, New South Wales and Queensland experienced elevated prices between 1720 hrs and 1815 hrs driven by increased demand, lower VRE output, and continuation of the transmission outage limiting transfers from the south. During the high price period, New South Wales' demand consistently exceeded 10,500 MW with four intervals at the price cap of $15,500/MWh, while Queensland's demand reached above 8,000 MW, witnessing five intervals above $14,000/MWh. Actual LOR 1 was declared in New South Wales from 1730 hrs to 1945 hrs and in Queensland from 1730 hrs to 1815. |
| | Queensland (QLD) | 2.96 | |

**Figure 16 High South Australian prices on a low wind day**

South Australia scheduled demand[7], available generation and spot price – 4 May 2023




## 1.2.3 Negative wholesale electricity prices

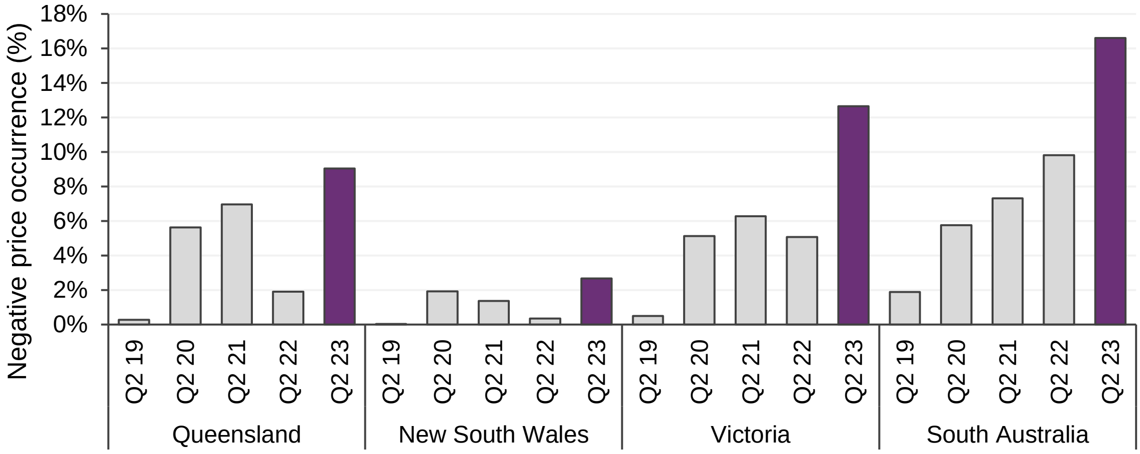
This quarter saw 9% of dispatch intervals recording negative or zero prices, a record high for Q2 and 5 percentage points (pp) higher than last Q2. All mainland NEM regions saw Q2 record high levels of negative price occurrence (Figure 17). South Australia and Victoria recorded 17% and 13% of quarterly spot prices at or below $0/MWh, respectively 7 pp and 8 pp more than last Q2. Relative to Q1 this year, negative price occurrence

[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.

was lower in all mainland NEM regions except for Queensland, which saw a 3 pp increase over Q1 2023 and 7 pp over Q2 2022 to reach 9% in Q2 2023.

**Figure 17 Record high Q2 negative price occurrence in all NEM mainland regions**

Negative price occurrence in NEM mainland regions – Q2s




Continuing a trend observed in recent quarters, negative price occurrence continued to be more frequent in daytime hours when operational demand is lower (driven by higher distributed PV output) and large-scale VRE generation is higher. Between 0900 hrs and 1700 hrs, negative prices occurred 29% and 20% of the time in South Australia and Victoria, increases of 8 pp and 12 pp respectively on Q2 2022 (Figure 18). Overnight negative price occurrence in South Australia also rose significantly, driven by periods of high wind output. Queensland's negative price occurrence between 0900 hrs and 1700 hrs rose to 25%, an increase of 19 pp due to significantly higher grid-scale and rooftop PV solar output (Figure 19). The relatively low occurrence of negative prices in New South Wales, only at 7% (between 0900 and 1700), reflected increased southward flows on QNI and more frequent binding of QNI at its import limit (Section 1.4). This led to price separation between the two regions during daytime (Section 1.2).

**Figure 18 Increases in negative price occurrence in South Australia**

Occurrence of South Australia negative or zero prices by time of day – Q2 2023 and Q2 2022

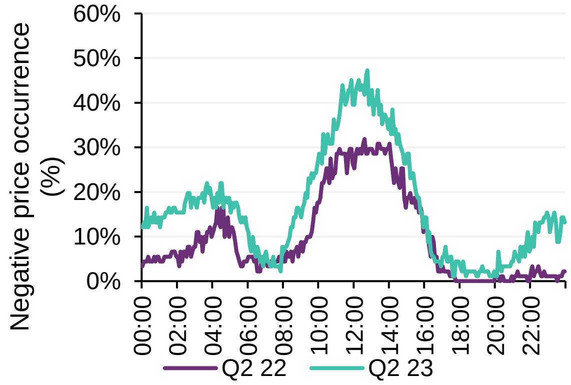
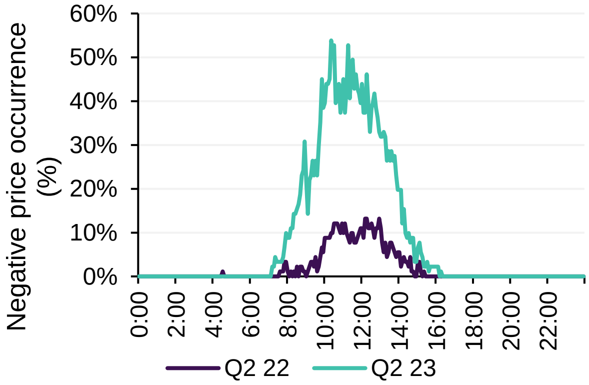



**Figure 19 Sharp increase in Queensland daytime negative price occurrence**

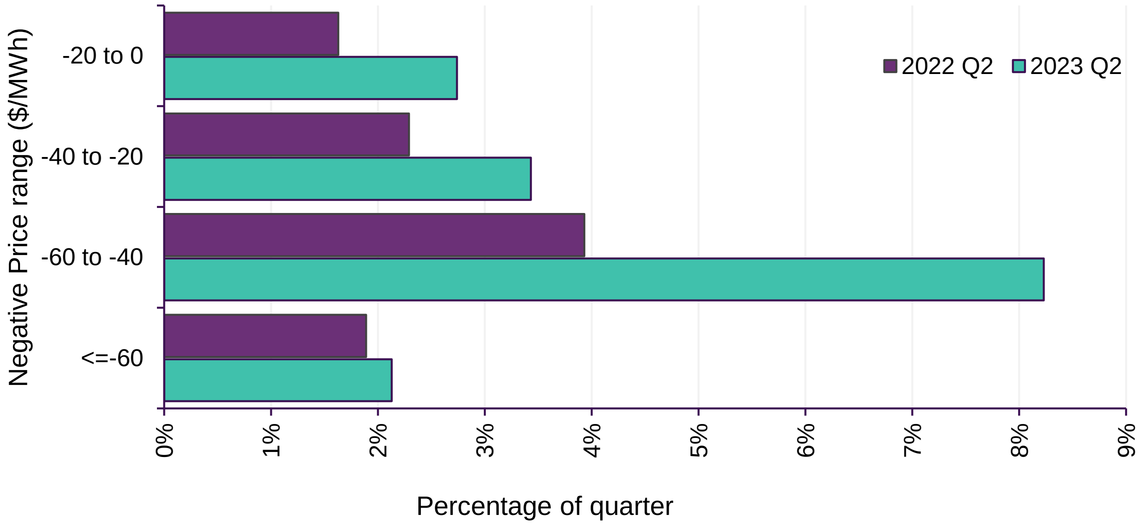
Occurrence of Queensland negative or zero price by time of day – Q2 2022 vs Q2 2023



Negative price impact[8] increased in all NEM regions from last Q2, reaching $8/MWh in South Australia (+$3/MWh) and $4/MWh in Victoria (+$3/MWh). The NEM average negative price impact reached a record high Q2 level of $3/MWh, which can be attributed jointly to increased negative price occurrence and lower negative prices set by wind and grid-scale solar units. More frequent occurrence of negative prices in the -$60/MWh to -$40/MWh range (Figure 20) coincided with an increase in spot prices of large-scale renewable certificates created by renewable generation, from an average of $49 per certificate during Q2 2022 to $53 per certificate this quarter.

**Figure 20 South Australian negative price occurrence increases, at larger negative values**

South Australian negative price occurence by price range – Q2 2022 vs Q2 2023




### 1.2.4 Price-setting dynamics

Q2 price-setting data showed a notable increase in the proportion of spot prices set by thermal coal generators, with brown and black coal-fired generation up by 5 pp and 3 pp respectively. The proportions of prices set by wind and grid-scale solar each increased by 2 pp, with solar setting price in 7.4% of intervals between 0900 hrs and 1700 hrs during Q2 2023 compared with 2.4% in Q2 2022. Conversely, price-setting frequency by gas-fired generators decreased by 1 pp while hydro price-setting fell by 9 pp, the largest drop by fuel type on Q2 last year.

By region (Figure 21):

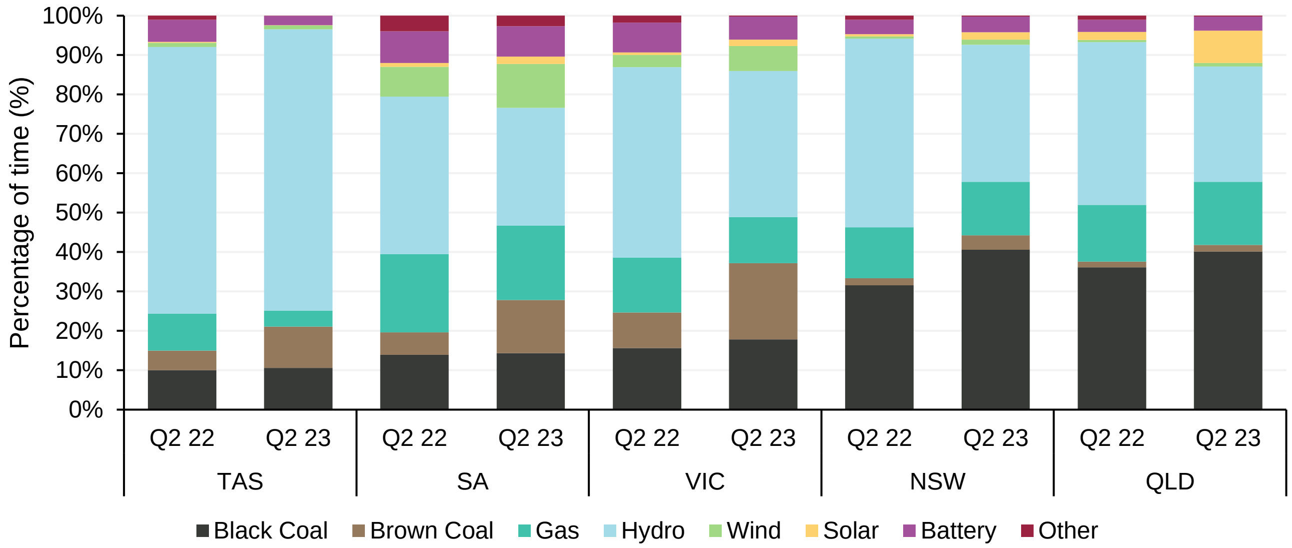
- **Queensland** saw an uptick in the proportion of time that solar set the spot price, from 2% in Q2 2022 to 8% this quarter. Thermal generation also saw an increase in price-setting frequency with black coal-fired and gas-fired generation rising 4 pp and 2 pp respectively to 40% and 16% this quarter. This was offset by a 12 pp reduction in hydro price-setting frequency.
- **New South Wales** also saw a notable increase in price-setting frequency by black coal generation (+9 pp) while gas, wind and solar each increased by 1 pp from Q2 2022. Hydro price-setting frequency dropped 13 pp from 48% in Q2 2022 to 35% in Q2 2023.
- **South Australia** and **Victoria** saw increases in price-setting frequency by brown coal-fired generation, increasing 8 pp and 10pp respectively to 13% and 19%. This was offset by the lower proportion of time that hydro set prices in both regions, reducing to 30% in South Australia and 37% in Victoria.

[8] Negative price impact measures the contribution of negative prices to lowering the average spot price – a negative price impact of $5/MWh means that with all negative prices replaced by values of $0/MWh, the average would have been $5/MWh higher than actually recorded.

- **Tasmania** saw a higher proportion of spot prices set by brown coal and hydro, increasing 5 pp and 4 pp respectively to 10% and 71% in this quarter. In contrast, price-setting frequency of gas and battery were down by 5 pp and 3 pp respectively to 4% and 2%.

**Figure 21 Coal-fired generation set prices more while price-setting by hydro declined**

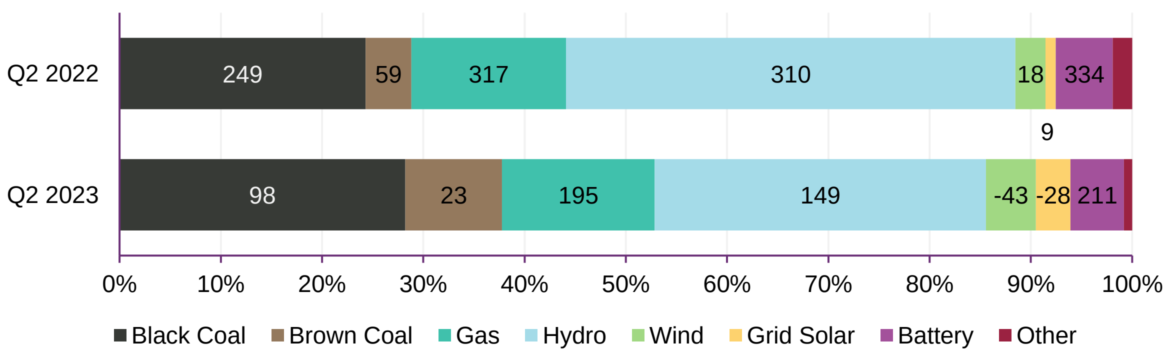
Price-setting frequency by fuel type[9] Q2 2023 vs Q2 2022




All mainland regions saw significant reductions in the average prices set by key fuel types in this quarter (Figure 22). Hydro saw the largest drop in average spot price set when marginal, decreasing by $161/MWh from Q2 2022 to average $149/MWh this quarter. The average spot price set by black coal-fired generation reduced by $150/MWh to $98/MWh, while for gas-fired generation the decrease was $122/MWh to $195/MWh. Average mainland spot prices set by wind and grid-scale solar also fell, decreasing by $61/MWh and $36/MWh to levels of -$43/MWh and -$28/MWh respectively.

**Figure 22 Significant reductions in the average prices set by key fuel types**

Mainland NEM price-setting frequency and average price set by fuel type – Q2 2023 vs Q2 2022



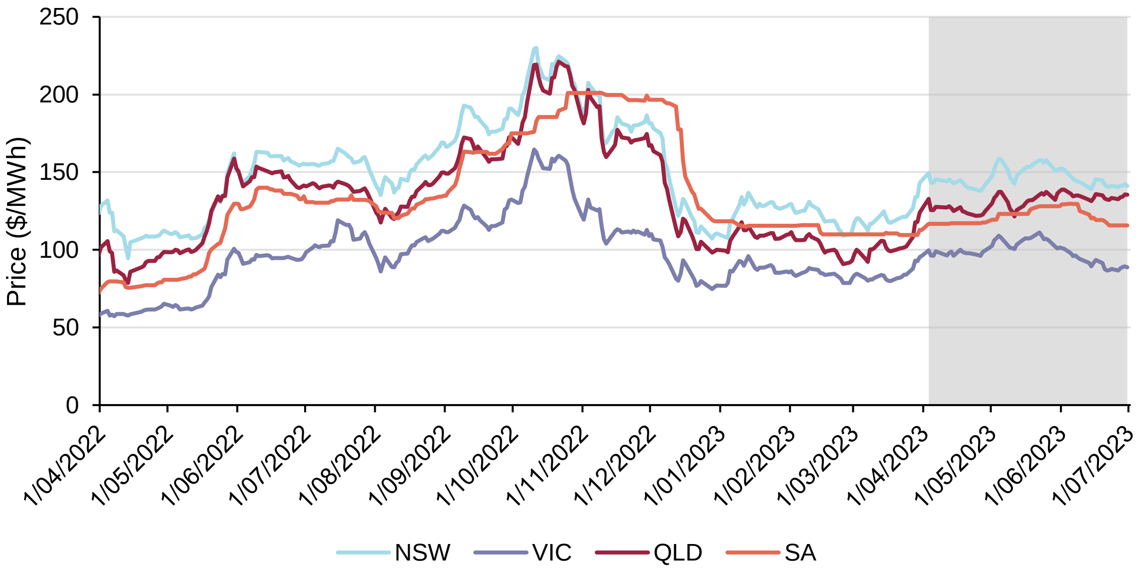

[9] The NEM's interconnected structure allows prices in one region to be set by market offers in a different region provided interconnector flows are not constrained; for example, offers from black coal generators in New South Wales or Queensland may at times set price in southern NEM regions as well as in those generators' home regions.

### 1.2.5 Electricity futures markets

ASX forward contract prices for the 2023-24 financial year (referred to as FY24) averaged $124/MWh across all mainland NEM regions, 17% higher than the previous quarter's average of $107/MWh. Queensland saw the largest rise in FY24 quarterly average, increasing 25% to reach $131/MWh, while prices for New South Wales, Victoria and South Australia averaged $147/MWh (+19%), $99/MWh (+15%) and $121/MWh (+8%) respectively. FY24 prices have generally exhibited a slow upward trend since decreasing in December last year on Federal Government announcements of intervention in the wholesale domestic gas and thermal coal markets. After closing Q1 2023 at an average of $120/MWh, FY24 prices across all mainland regions continued to rise in April and May before drifting down in June to end Q2 at similar closing levels to Q1 (Figure 23). Contract prices during the quarter exhibited a similar trajectory to spot prices, which rose in May influenced by cooler weather, higher demand and the retirement of Liddell. In late May, CS Energy announced delayed return-to-service dates for Callide C Power Station[10], which further contributed to the upward pressure on prices. Unit 3's return has been delayed until January 2024 while Unit 4 is not expected to resume operations until May 2024.

**Figure 23 FY24 futures closed at similar levels to Q1 2023**

ASX – Energy daily 2023-24 base futures by region



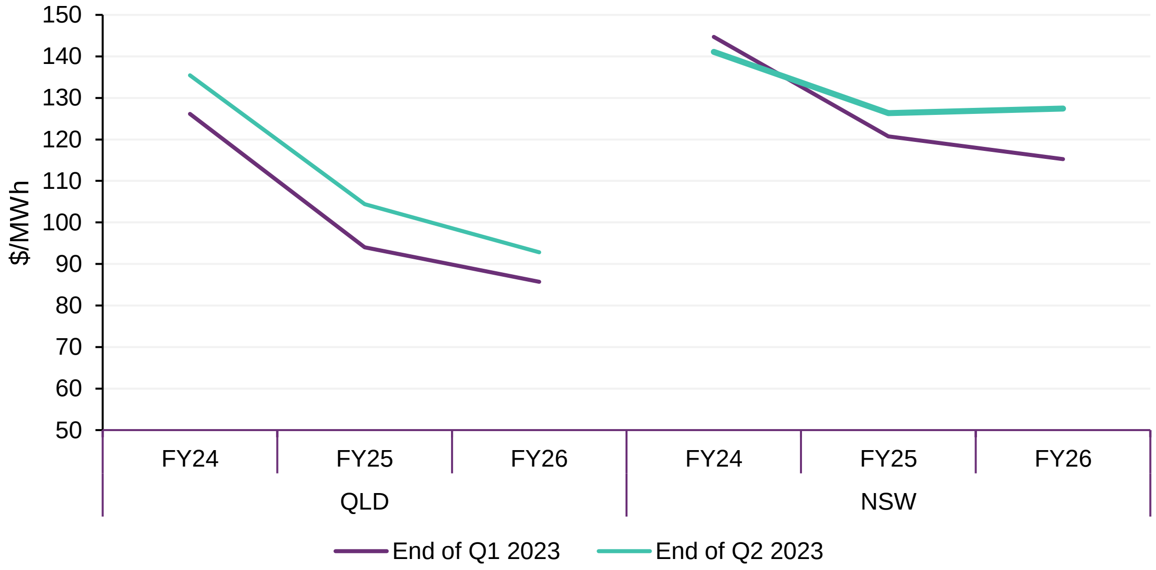

During this quarter, FY24 prices in all mainland regions exhibited a general trend of moving together. Queensland and South Australia FY24 prices closed slightly higher than Q1 end levels, reaching $135/MWh (+7%) and $116/MWh (+3%) respectively on June 30 2023. New South Wales and Victoria ended Q2 lower than Q1 closing levels, at $141/MWh (-2%) and $89/MWh (-8%).

FY25 and FY26 prices closed the quarter at higher levels in all mainland regions (Figure 24).

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

**Figure 24 Future financial year contracts higher in Queensland and New South Wales**

Financial year contract prices in Queensland and New South Wales – end Q1 2023 vs end Q2 2023




## 1.3 Electricity generation

Total generation across the NEM[11] this quarter increased by 143 MW (+0.6%) from Q2 2022. Similar to recent quarters, variable renewable generation continued to increase in average output, offsetting decreases in gas-fired and black coal-fired generation.

Figure 25 shows the changes in average NEM generation by fuel type relative to Q2 2022, and Table 3 shows the supply mix by fuel type.

Summarising these changes in generation by fuel type compared to Q2 2022:

- VRE output from grid-scale solar and wind and distributed PV increased compared to the previous year, with an aggregate 1,176 MW increase. High VRE was a product of both high solar irradiance in Queensland and Victoria through the quarter, and a continued increase in installed capacity of these technologies. Generation from brown coal-fired generation also saw a small increase this quarter of 76 MW, following increases in availability at each of the brown coal stations.
- Black coal-fired generation declined by 95 MW despite the numerous coal station outage and fuel supply issues seen in Q2 2022. In response to the high spot prices seen in Q2 2022, gas-fired generation and hydro generation output were at elevated levels. With a return to more subdued spot price levels and higher availability from low cost renewables, gas-fired generation dropped by 742 MW and hydro by 272 MW.

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

**Figure 25 Large declines in gas-fired generation driven by increases in renewable output**

Change in NEM supply by fuel source – Q2 2023 versus Q2 2022

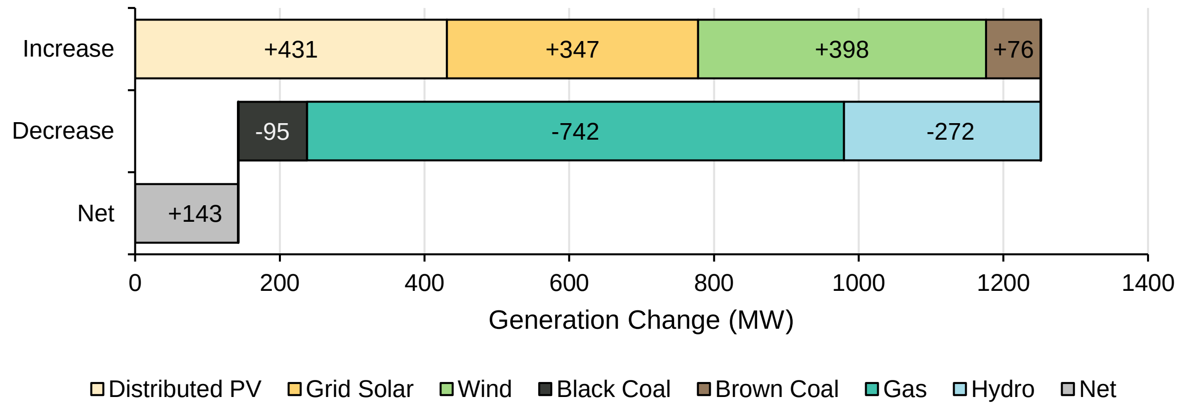


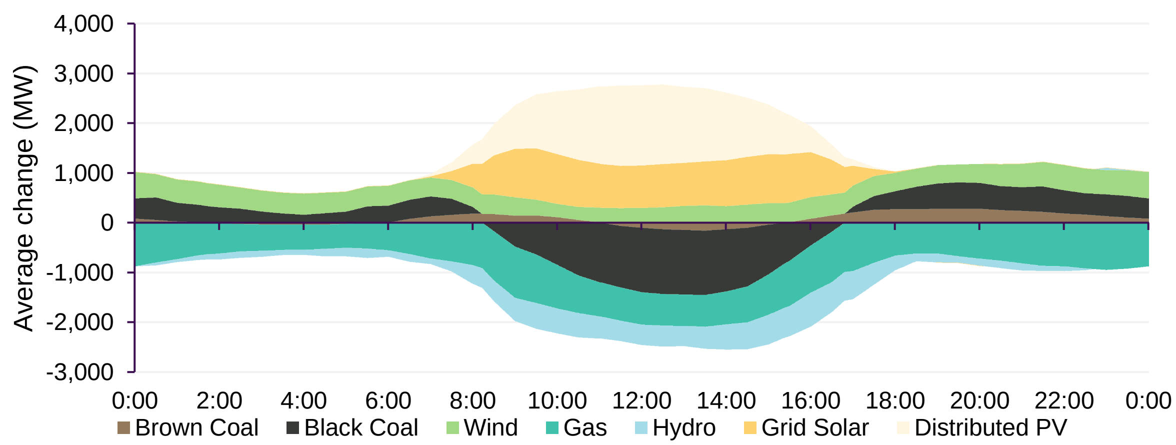

**Table 3 NEM supply mix contribution by fuel type**

| Quarter | Black coal | Brown coal | Gas | Hydro | Wind | Grid solar | Distributed PV | Other |
|---|---|---|---|---|---|---|---|---|
| Q2 22 | 43.0% | 15.6% | 9.3% | 9.4% | 12.3% | 3.9% | 6.1% | 0.3% |
| Q2 23 | 42.4% | 15.8% | 6.2% | 8.2% | 13.9% | 5.4% | 7.9% | 0.2% |
| Change | -0.6% | 0.2% | -3.2% | -1.2% | 1.6% | 1.4% | 1.8% | 0.0% |

Figure 26 shows the changes in generation from Q2 2022 to Q2 2023 by time of day. Distributed PV and grid-scale solar output increased in the middle of the day, offset against matching declines in black coal-fired generation and hydro output. Gas-fired generation decreased at all times throughout the day, and had the largest average quarterly decrease by single fuel source.

**Figure 26 Large daytime drops in gas, hydro and black coal generation as VRE output increased**

NEM generation changes by time of day – Q2 2023 vs Q2 2022




## 1.3.1 Coal-fired generation

### Black coal-fired fleet

Average black coal-fired generation this quarter was 10,121 MW, the lowest Q2 output since NEM start (Figure 27). Compared to Q2 2022 there was an output decrease of 95 MW (-0.9%), despite a 373 MW increase in availability (+3%). The lower utilisation rate this quarter follows a continuing decline in daytime output as higher-cost generation is displaced by increasing penetration of renewable energy.

Higher availability in New South Wales (+625 MW) – despite the full retirement of Liddell Power Station at the end of April – was partially offset by lower availability in Queensland (-252 MW). Fewer planned and unplanned outages in New South Wales (-1,323 MW) contrasted with higher capacity on unplanned outages in Queensland (+382 MW) (Figure 28).

**Figure 27 Lowest Q2 black coal-fired generation output on record**

Quarterly average black coal-fired generation– Q2s

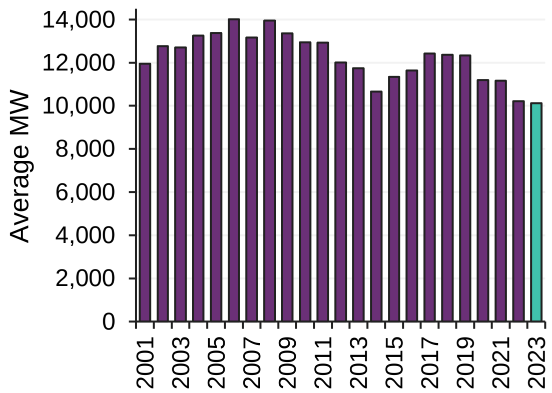
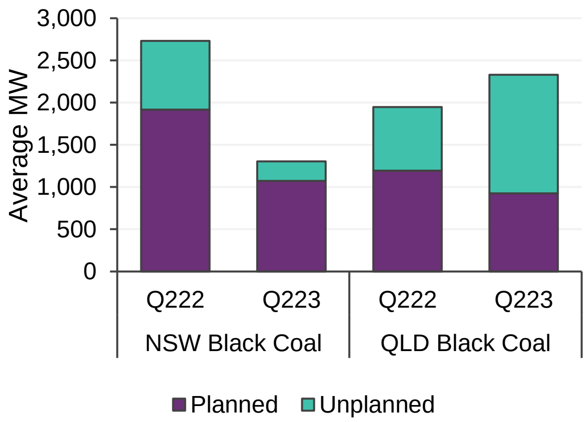



**Figure 28 Coal-fired capacity on outage declined, driven by New South Wales**

Average coal-fired capacity on outages – Q2 22 vs Q2 23

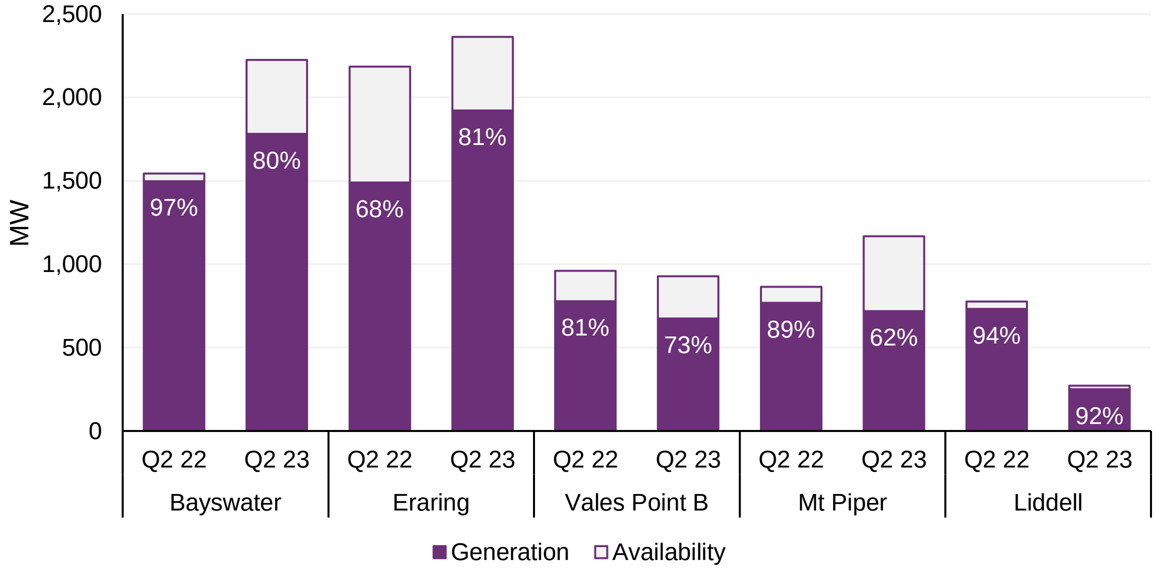



New South Wales saw a net output increase of 79 MW this quarter compared to Q2 2022. Key changes by power station, as summarised here and shown in Figure 29, were:

- Bayswater increased average output by 284 MW. Less capacity on outage (-656 MW) across the quarter increased availability by 681 MW. There was a 17 pp drop in Bayswater utilisation as its middle of day generation decreased but evening and overnight generation increased.
- Eraring produced an average generation increase of 430 MW. This was attributable to a 13 pp increase in utilisation from Q2 2022 (from 68% in Q2 22 to 81% in Q2 23), with most of the increase in generation occurring over the evening and into the early morning.
- Vales Point output declined 104 MW with an increase of 82 MW on outage and a drop in utilisation.
- Mount Piper average generation fell 49 MW despite a 303 MW increase in availability, representing a utilisation drop of 27 pp.
- Quarterly average generation from Liddell declined 482 MW following the decommissioning of the station's remaining three units on 24, 26 and 28 of April.

**Figure 29 Bayswater and Mt Piper increased lift in New Southy Wales black coal-fired station availability despite Liddell closure**

Average quarterly availability and generation for New South Wales black coal-fired power stations – Q2 2023 vs Q2 2022




Conversely, average black coal-fired generation output in Queensland saw a 174 MW decline. Declining output across Queensland stations and its causes included:

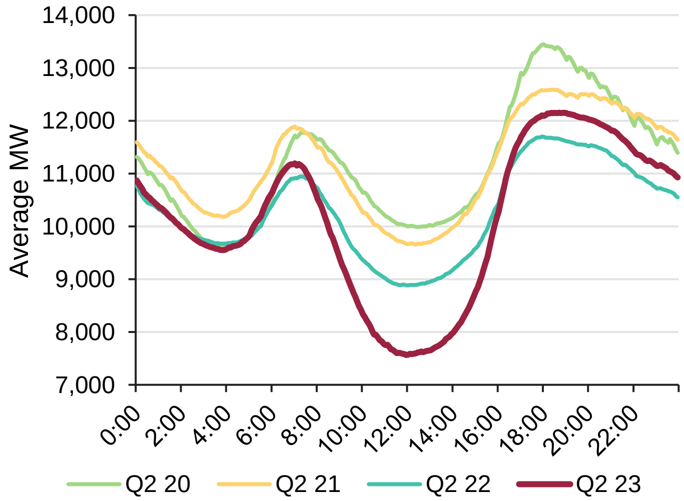
- A 319 MW decline at Tarong North, which experienced an extended outage from 1 April to mid-June, averaging 388 MW on outage over the quarter.
- A drop of 175 MW at Callide C following the Callide C3 outage which began in October 2022. On 30 May, CS Energy advised the market of a revised return to service date of both the C3 unit (50% capacity in January 2024 and the remainder in February 2024) and the C4 unit (50% capacity by May 2024 and the remainder July 2024)[12].
- Gladstone (+75 MW), Stanwell (+119 MW) and Callide B (+61 MW) each saw slight upticks in generation with reduced capacity on outages. Tarong units also saw an increase of 93 MW despite increased time on outage (+20 MW), resulting in higher utilisation.

Black coal-fired output continued to decline through the middle of the day in Q2 2023 as increasing renewable output displaced thermal generation (Figure 30).

Evening, overnight and morning peak generation was similar to that of Q2 2022, but with lower operational demand and increased

**Figure 30 Daytime black coal-fired generation continued to decline but lifted over Q2 2022 evening time**

NEM black coal-fired output by time of day – Q2s from 2020 to 2023




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

grid-scale solar generation in the middle of the day, black coal-fired generators were dispatching less during this time period.

The difference between average minimum and maximum output increased by 1,772 MW to 4,589 MW, showing generators' ability and need to operate flexibly on market signals. Bayswater contributed nearly half of the increase in intraday swing – its variation between daily average minimum and maximum generation increasing some 828 MW. Stanwell, Mount Piper and Gladstone also exhibited significant increases in this measure.

## Brown coal-fired fleet

Brown coal-fired generation in Q2 2023 increased 2.0% (+76 MW) from Q2 2022 following a 303 MW increase in availability (Figure 31). Increasing availability followed a reduction in capacity on outages, with a large drop in unplanned outages (-610 MW), partly offset by an increase in planned outages (+274 MW) (Figure 32).

While availability increased across each of Loy Yang A, Loy Yang B and Yallourn stations, only Yallourn saw an increase in generation, with outages for that station down 216 MW. The 151 MW increase in average generation at Yallourn was offset by declines in generation at Loy Yang A (-49 MW) and Loy Yang B (-26 MW) with their utilisation dropping 7 pp and 5 pp respectively.

**Figure 31 Brown coal-fired availability and output increase**

Quarterly average generation and availability – Q2s

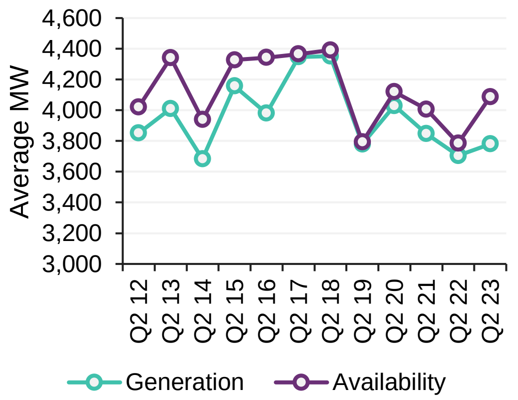
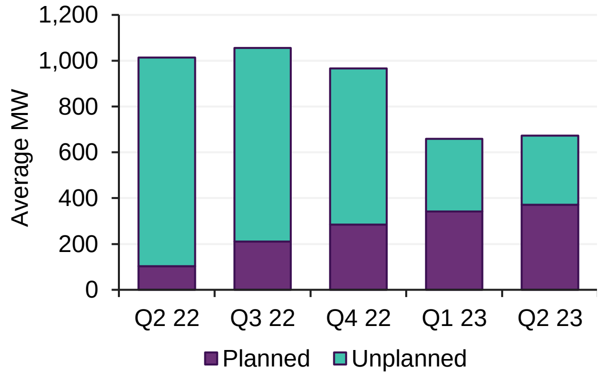



**Figure 32 Lower unplanned outages for brown coal**

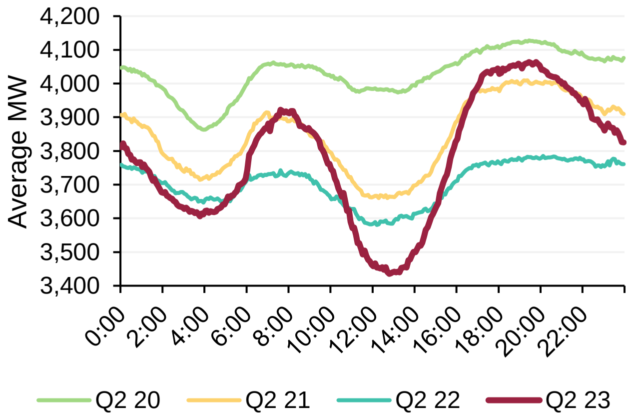
Average brown coal-fired capacity on outages – quarterly




Brown coal units also continued to operate with a more flexible profile over the day, with the difference between average daily minimum output and average daily maximum output increasing by 424 MW from Q2 2022 (Figure 33).

**Figure 33 Increasing swing at brown coal-fired generators**

Brown coal-fired output by time of day – Q2s from 2020 to 2023

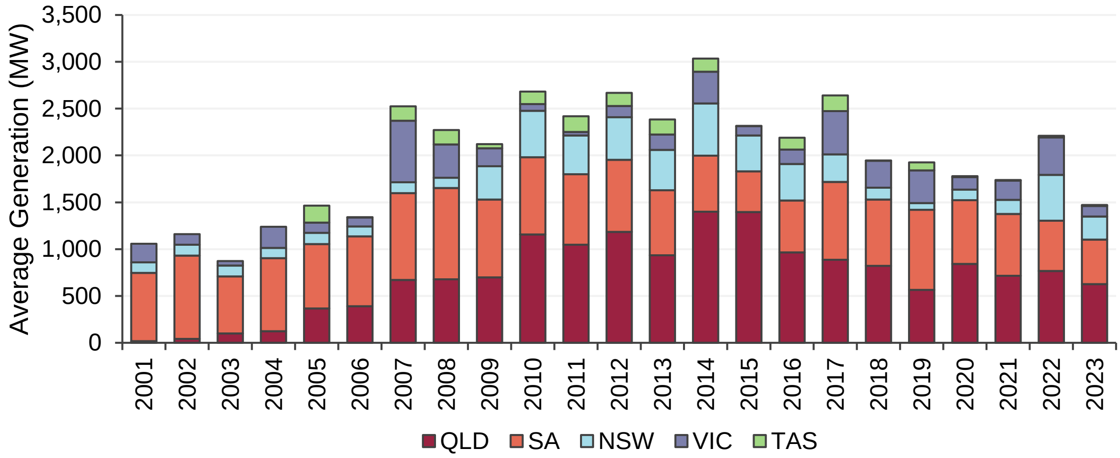


### 1.3.2 Gas-fired generation

During the quarter, NEM gas-fired generation averaged 1,469 MW – the lowest Q2 output since 2006. This was a decrease of 742 MW (-34%) compared to Q2 2022 which had seen the highest gas-fired generation output for Q2 since 2017 (Figure 34). High gas-fired generation in Q2 2022 reflected the sustained levels of extremely high spot electricity prices experienced over the quarter, multiple coal-fired generation outages, and limitations on substantially increasing overall energy output from other forms of generation such as hydro to respond to these very high prices and outages.

**Figure 34 Gas-fired generation fell to lowest Q2 level since 2006 with large drops in New South Wales and Victoria**

Average gas-fired generation by region – Q2s




This Q2, electricity spot prices were significantly lower (see Section 1.2), availability of coal-fired generation improved (Section 1.3.1), and significant additional supply from renewables eased the supply-demand balance (Section 1.3). These factors all resulted in operators of gas-fired generation committing less of their plant for dispatch. Across the quarter, the average volume of gas-fired generation offered to the market fell by around 300-500 MW at all offer price levels up to $350/MWh, and by more at higher price levels (Figure 35). In combination with the lower spot prices resulting from greater coal and hydro volumes being offered in these price ranges, as well as renewable supply growth, this yielded much lower dispatch of gas-fired generation (Figure 36). The month of June saw the lowest gas fired-generation since 2005 at 1,347 MW, a 1,440 MW reduction from June 2022.

**Figure 35 Gas offer volumes decreased**

Gas-fired generation bid supply curve – Q2 22 and Q2 23

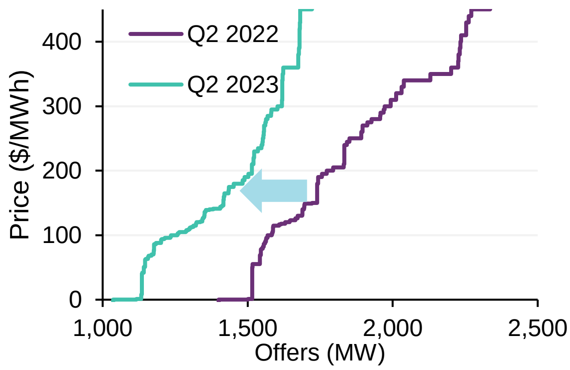
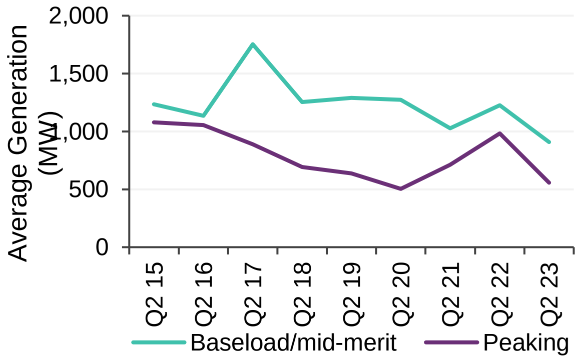



**Figure 36 Both mid-merit and peaking plant output declined**

Average gas-fired generation: mid-merit and peaking – Q2s



By region, changes in average quarterly gas-fired generation compared to Q2 2022 were:

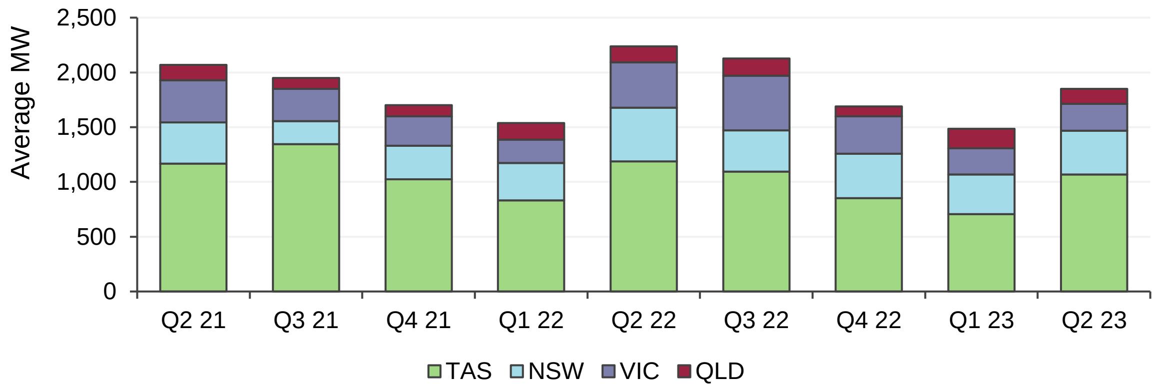
- 287 MW lower in Victoria to an average quarterly output of 113 MW, the lowest Q2 level since 2015. Output fell at each Victorian generator, with Newport down 118 MW, Laverton 62 MW, Mortlake 44 MW and Valley Power 34 MW.
- 246 MW lower in New South Wales. Every station reduced output, with Snowy Hydro's Colongra station reducing 99 MW and EnergyAustralia's Tallawarra station 98 MW.
- 138 MW less output from Queensland gas-fired stations. The biggest decreases were at Darling Downs (-132 MW), Braemar 1 (-55 MW) and Condamine (-53 MW), offset by an 126 MW increase at Swanbank E which was out of service for the entirety of Q2 2022.
- A 61 MW reduction in South Australia. AGL's Torrens Island and Barkers Inlet power stations saw a decrease of 120 MW along with Origin's Osborne (-40 MW). The decreases were offset by increases at Pelican Point (+79 MW) and Mintaro (+22 MW) – which did not operate in 2022.

### 1.3.3 Hydro

Quarterly average NEM hydro generation[13] declined 272 MW (-12%) from Q2 2022 to average 1,967 MW in Q2 2023 (Figure 37).

**Figure 37 Hydro generation declined year-on-year with low Vic output, but up on Q1 with lift in Tasmania**

Average hydro output by region - quarterly



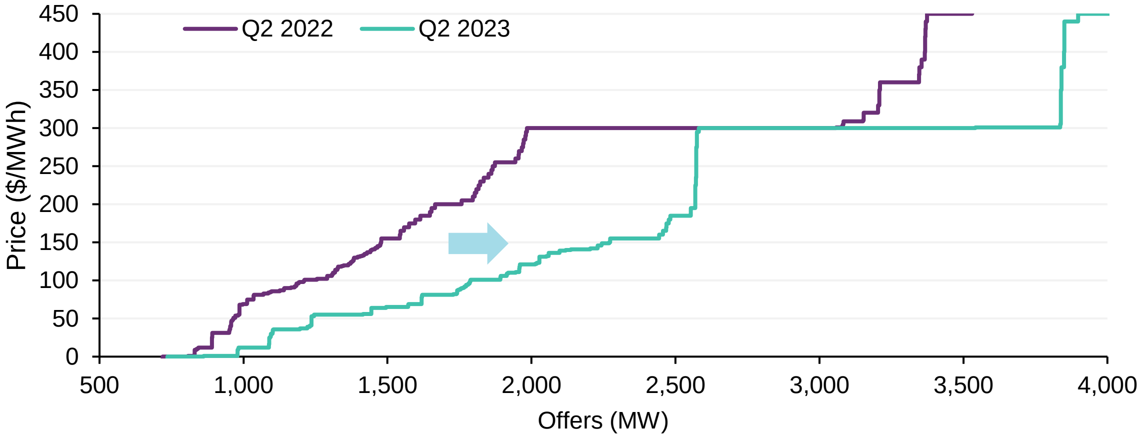

Lower spot prices, including much lower incidence of prices exceeding $300/MWh – a price point at which owners of hydro plant who have sold cap contracts[14] will typically offer significant volumes of supply – explain much of the fall in hydro generation volumes. Mitigating the extent of this fall were increases in hydro volumes offered to the market at lower price levels than in Q2 2022 (Figure 38). This reflects the need for hydro generation operators to maintain agreed water release levels and manage upstream storage volumes. Unlike gas-fired generation, which reduced output across all hours of the day, Figure 26 in Section 1.3 above shows that the decrease in hydro generation was concentrated in the lower-priced daytime hours, as generators sought to obtain the best value for their released water.

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

[14] These 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.

**Figure 38 Shift in hydro offers to lower price bands**

Hydro generation bid supply curve – Q2 23 vs Q2 22




Victoria saw the biggest decrease in hydro generation, with a 145 MW decrease from Q2 2022 to 270 MW, the lowest Q2 output since 2014. The majority of this was from Murray (-156 MW), which nearly halved its Q2 2022 output, and McKay Power Station (-23 MW), which has been on a planned outage since March 2023.

New South Wales average hydro generation declined 63 MW. Tumut 3 had the largest decrease with 43 MW, and Blowering output was 24 MW lower.

Tasmanian hydro output was down an average of 58 MW this quarter, with Gordon Power Station generating 206 MW less than last quarter, offset by increases in most other power stations. However Tasmanian hydro output was well up on Q1 2023 (+51%) with increasing local demand and higher energy exports across Basslink.

### 1.3.4 Wind and grid-scale solar

Q2 2023 saw output from grid-scale variable renewable energy (VRE) reach a record Q2 average of 4,599 MW, 19% up on last year (Figure 39). Just over half (53%) of the 745 MW uplift arose from wind, with the balance from grid solar for which year-on-year output growth was 37%. The largest growth in grid solar output was in Queensland (241 MW, +69%) and New South Wales (74MW, +18%) (Figure 40). Wind output increased by 14% (398 MW) from Q2 2022. Victorian wind saw a 27% (289 MW) lift in average output with a large increase in available capacity from new and recently connected facilities.

**Figure 39 Steady VRE growth continued**

Average quarterly VRE generation by energy source – Q2s

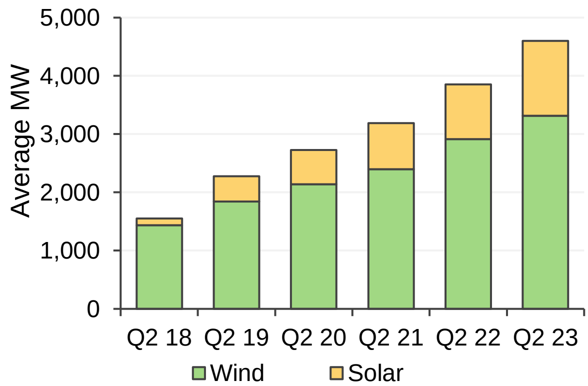
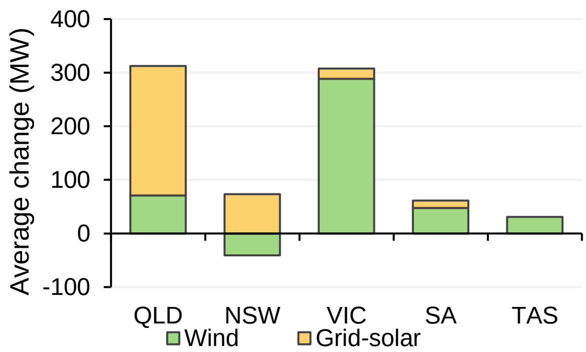



**Figure 40 VRE increased led by Queensland grid-scale solar and Victorian wind**

Average MW change in output Q2 2022 to Q2 2023



Increased VRE generation in the NEM arises from both newly connected facilities and those progressing through their commissioning processes, which can extend over 12 months or longer. These growth sources contributed a 669 MW increase in average quarterly availability from Q2 2022 (Figure 41 and Figure 42). Q2 2023 also saw higher available output from established facilities partly due to more favourable wind and solar conditions. Offsetting growth were slightly higher curtailment of VRE output and increased economic offloading by some wind and solar generators in response to a higher incidence of negative spot prices (Section 1.2.3).

**Figure 41 New solar farms largest contributor to growth**

Increase in grid-scale solar generation – Q2 22 vs Q2 23

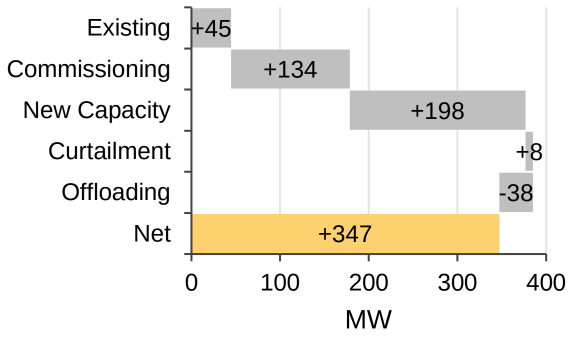
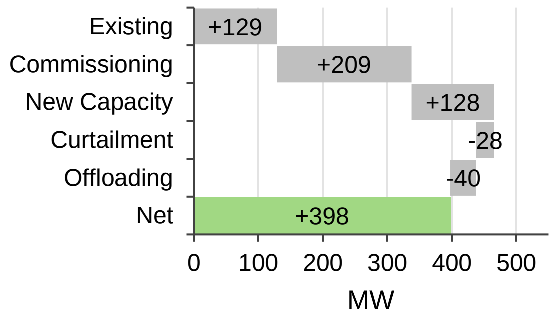



**Figure 42 Wind farm commissioning drives increase**

Increases in wind generation – Q2 22 vs Q2 23




## New and commissioning capacity

Compared to Q2 2022, a 337 MW increase in wind availability this quarter was from newly connected wind farms and those continuing their commissioning. Victorian wind farms contributed the majority of this at 210 MW, with significant increases from Moorabool (+77 MW) and Murra Warra 2 (+60 MW) as commissioning progressed, and 73 MW from newly-connected wind farms Mortlake South (+38 MW) and Berrybank 2 (+35 MW). Three new and commissioning wind farms in Queensland added 63 MW, while commissioning at Port Augusta Renewable Energy Park wind farm in South Australia added 47 MW.

Availability from new and commissioning grid-scale solar generators grew 332 MW. The majority of this was in Queensland, where growth of 227 MW came from 10 solar projects either recently connected or continuing to be commissioned. These included Western Downs Green Power Hub (+64 MW), Bluegrass Solar Farm (+41 MW), Columboola Solar Farm (+39 MW), Woolooga Solar Farm (+26 MW), Edenvale Solar Park (+22 MW) and Moura Solar Farm (+20 MW). Availability from new or commissioning grid-scale solar increased by 82 MW in New South Wales, and by 21 MW in South Australia, predominantly from the recently connected Port Augusta Renewable Energy Park solar farm.

## Existing capacity

Available output from established wind and grid-scale solar units increased by 129 MW and 45 MW respectively this Q2 compared to last. Wind farms in all regions other than New South Wales saw increases, indicating greater wind speeds and in some cases improved facility availability. Victorian wind farms saw the greatest increase, with available capacity factor[15] for Macarthur Wind Farm in the south-west of the state rising from 15% to 25% and Stockyard Hill from 34% to 39%. Tasmanian wind farms all saw increases in availability, increasing from 27% to 29% (Figure 43).

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

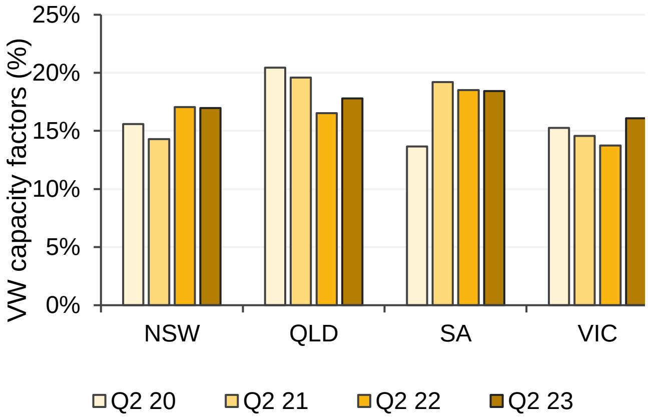
Higher solar irradiance this quarter increased regional average available capacity factors for grid-solar facilities in Queensland and Victoria (Figure 44). Across the quarter Queensland solar farms had a volume-weighted availability capacity factor of 18%, 1pp higher than Q2 2022, with Oakey 2 increasing to 21% from 13% in Q2 2022, and Clermont Solar Farm increasing to 23% from 17%. Victorian solar farms saw an increase in volume-weighted availability capacity factor to 16% from 14%, mainly driven by Kiamal Solar Farm seeing an increase to 15% from a low value of 9% in Q2 22 when technical issues were limiting its available capacity.

**Figure 43 Higher Q2 availability for established wind farms**

Volume-weighted wind available capacity factors[16] – Q2s


**Figure 44 Increased solar irradiance in Queensland and Victoria**

Volume-weighted grid-scale solar available capacity factors – Q2s

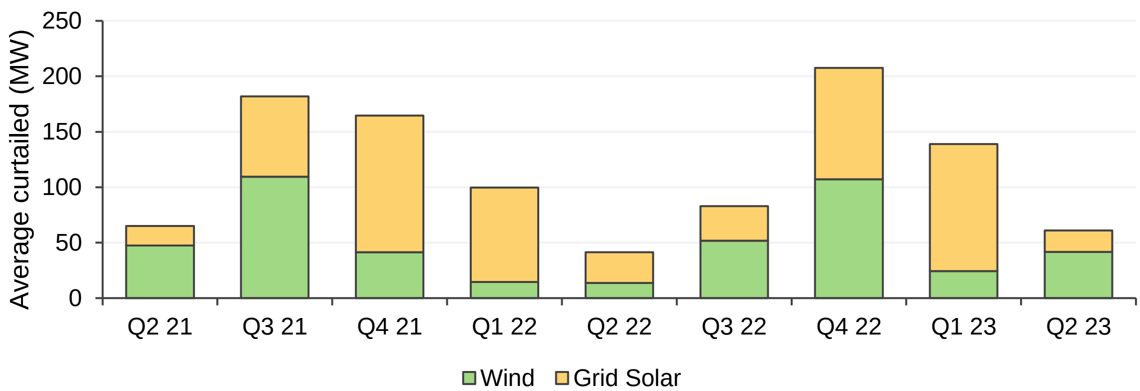



## Curtailment

Curtailment due to system strength and other network constraints increased by 20 MW from Q2 2022 to an average of 61 MW. Seasonally lower grid-solar output meant that Q2 curtailment was 78 MW lower than in Q1 2023 and 147 MW lower than in Q4 2022 (Figure 45). Relative to Q2 2022, higher curtailment occurred in Victoria and South Australia (+31 MW), offset by decreases in Queensland and New South Wales. Much of Victoria's increased curtailment arose in the Western Victorian Renewable Energy Zone (REZ) (+15 MW), which accounted for 78% of the state-wide increase. Curtailment of New South Wales and Queensland grid-scale solar generation fell 6 MW and 5 MW respectively from Q2 2022 despite strong year-on-year growth in available output.

**Figure 45 Curtailments at wind farms increased year-on-year while solar farm curtailments decreased**

Average MW curtailment by fuel type



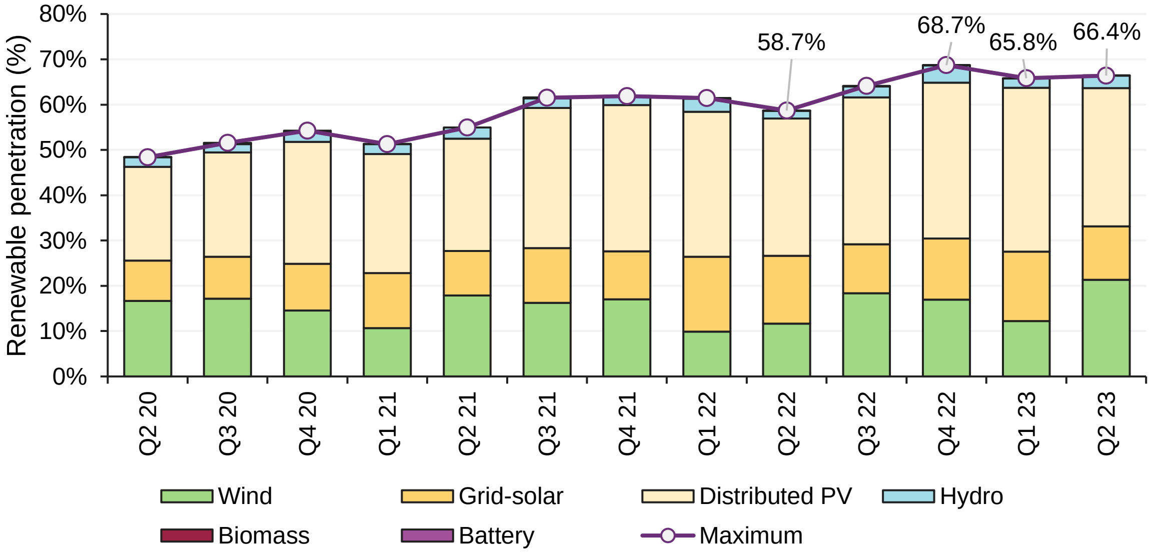

[16] Available capacity factors for each established facility are weighted by maximum capacity to derive a statewide weighted average.

## Instantaneous renewable penetration

The maximum instantaneous share of renewable energy generation[17] in the NEM this quarter reached 66.4% for the half-hour ending 1300 hrs on Wednesday 3 May, an increase of 7.7 pp from Q2 2022, and only 2.3 pp lower than the record set in Q4 2022 (Figure 46). At this time VRE (grid-scale solar and wind) accounted for 33.2% of total generation, and distributed PV for 30.5%.

**Figure 46 Instantaneous renewable penetration rose from Q2 2023, with an increasing contribution from wind**

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




## Distributed PV and VRE peak instantaneous outputs

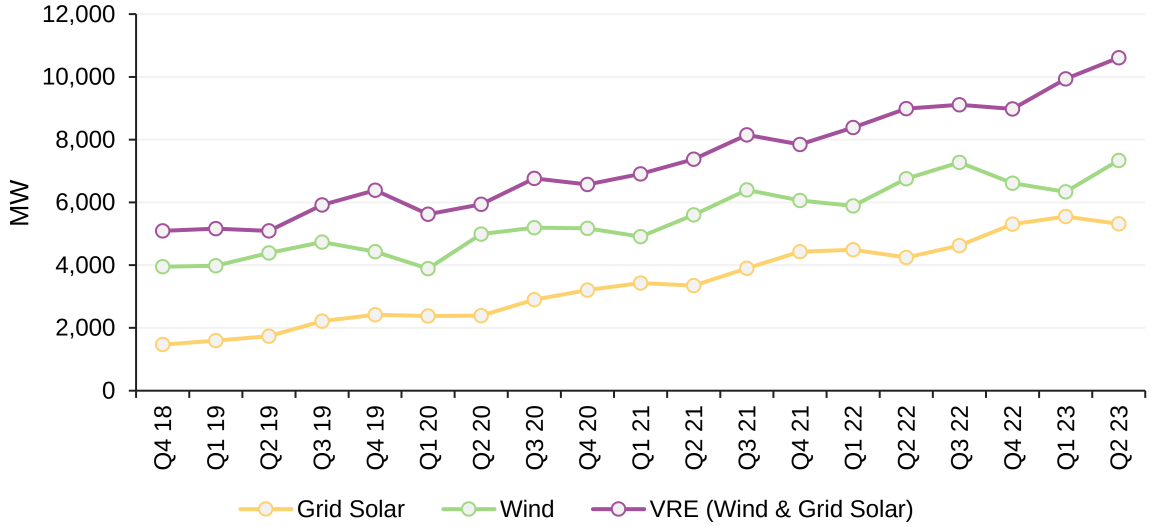
Wind generation hit a peak instantaneous output record this quarter, reaching 7,342 MW for the half-hour ending 2230 hrs on Sunday 25 June[18], a 70 MW increase on the previous record set in Q3 2022 (Figure 47). On the same day at 1000 hrs, combined VRE generation reached a peak quarterly average of 10,612 MW, 7% higher than the previous record set on 16 March 2023.

[17] 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.

[18] This record was subsequently broken on 7 July 2023 by a peak of 8,040 MW.

**Figure 47 Record high instantaneous wind and combined VRE output in Q2 2022**

Maximum quarterly instantaneous generation by fuel type

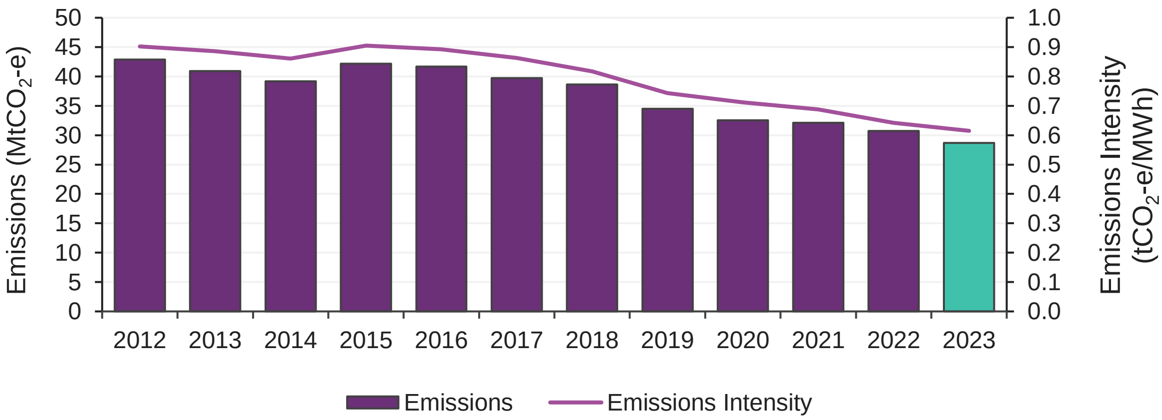



### 1.3.5 NEM emissions

NEM total emissions and emissions intensity declined this quarter to the lowest Q2 levels on record (Figure 48). Emissions intensity excludes generation from distributed PV, taking into consideration sent out generation only from market generating units[19]. Q2 2023 emissions were 2.0 million tonnes carbon dioxide equivalent (MtCO2-e ) (-6.6%) lower than Q2 2022 and emissions intensity was 0.61 tonnes carbon dioxide equivalent (tCO2-e)/MWh (-4.3% on Q2 2022). Reductions in emissions and intensity were due to lower operational demand and declining fossil-fuelled generation (including the retirement of Liddell Power Station) being offset by increased VRE generation.

**Figure 48 Lowest Q2 emissions and emissions intensity on record**

Quarterly NEM emissions and Intensity (Q2s)




[19] 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.

### 1.3.6 Storage

#### Batteries

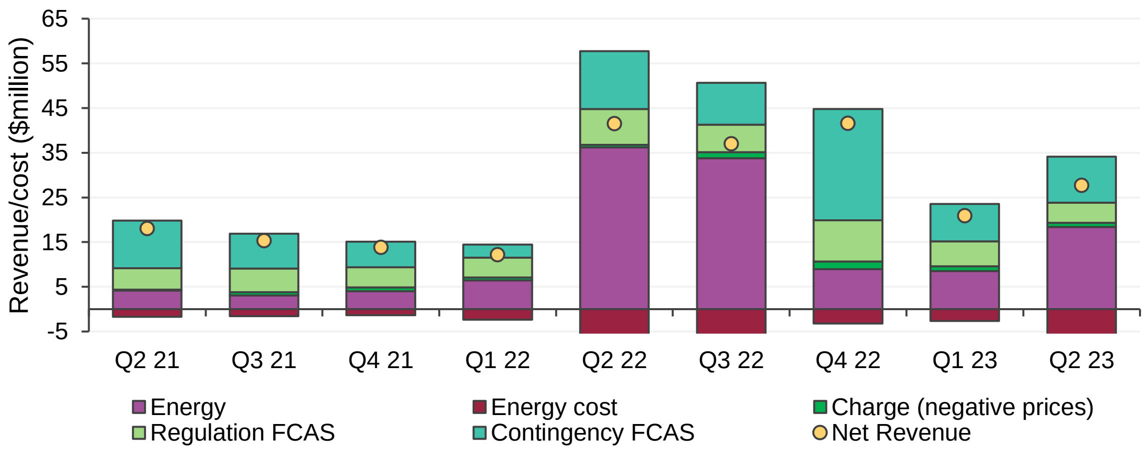
Total estimated net revenue for NEM grid-scale batteries this quarter was $28 million, a decrease of $14 million from Q2 2022 (Figure 49). Energy arbitrage earnings decreased $8 million as a result of less volatile prices this quarter, and frequency control ancillary services (FCAS) revenue decreased $6 million. The proportion of gross revenue from energy arbitrage was 57%.

By region, compared to Q2 2022:

- Net revenue for **Victorian** batteries decreased this quarter (-$6.7 million), with falls from both energy arbitrage (-$3.4 million) and FCAS markets (-$3.3 million). Key drivers for this were reductions in volatile energy spot prices and FCAS prices. The state's largest battery, the Victorian Big Battery (VBB), accounted for the majority of these decreases.
- **South Australian** batteries saw a net revenue decrease of $6.1 million. Revenue from energy arbitrage decreased by $2.3 million and from FCAS by $3.8 million. Most of these decreases were at Hornsdale Power Reserve.
- **New South Wales** saw a small decrease in battery net revenue (-$1.2 million), split between energy arbitrage (-$0.5 million) and FCAS revenue (-$0.7 million)
- **Queensland** batteries had a small increase in net revenue (+$0.2 million).

**Figure 49 Battery revenue dropped from Q2 2022 with reduced energy arbitrage, contingency FCAS remained at similar levels**

Quarterly revenue from NEM battery systems by revenue stream

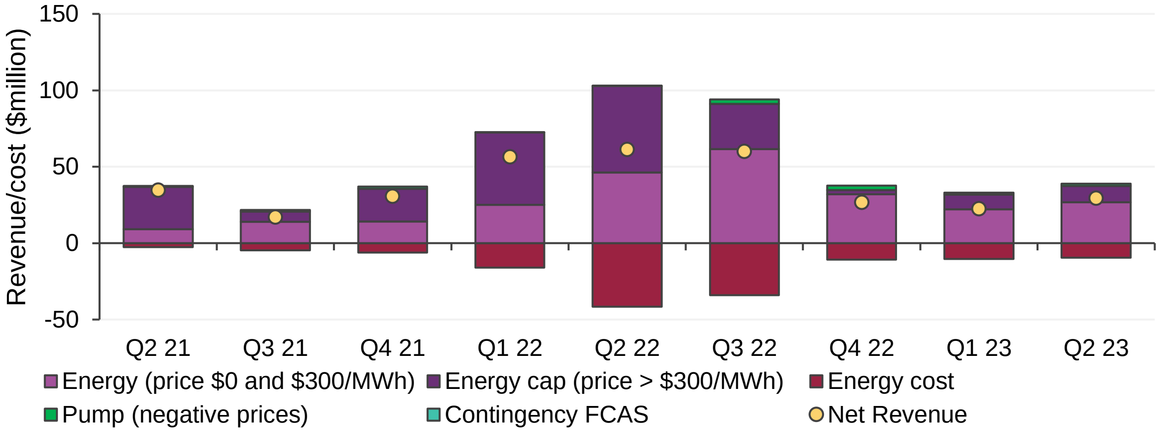



#### Pumped hydro

Pumped hydro spot market revenue was $29.6 million this quarter, a drop of $31.8 million from Q2 2022 (Figure 50). Lower Queensland spot prices drove this fall, particularly lower spot volatility, with Wivenhoe's revenue from prices above $300/MWh down $40 million. Increased negative prices, allowing storage facilities to be paid for pumping, offset the fall in revenue by $1.3 million. In New South Wales, Shoalhaven's estimated spot revenue decreased $4.7 million, driven by lower spot prices and arbitrage values.

**Figure 50 Pumped hydro revenue dropped from Q2 2022 with reduced energy and cap returns.**

Quarterly revenue from NEM pumped hydro by revenue stream

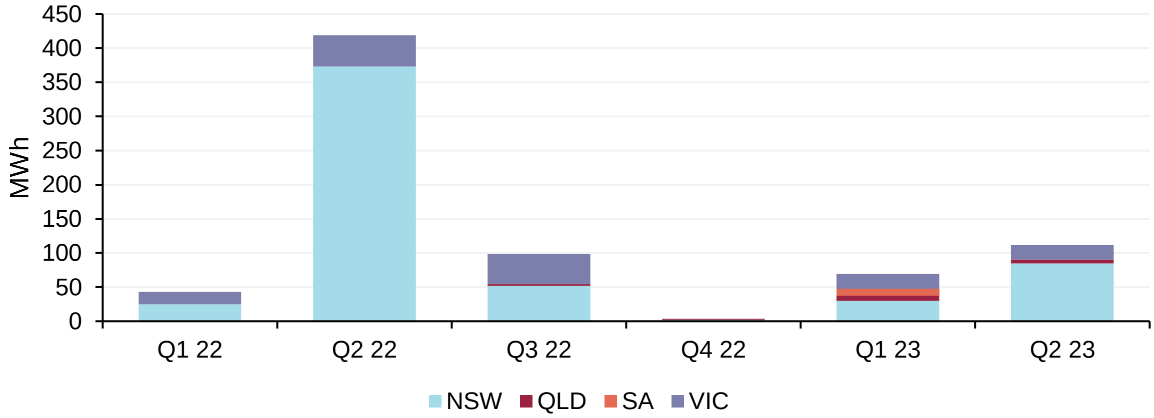



## 1.3.7 Wholesale demand response

Overall this quarter the Wholesale Demand Response (WDR) mechanism saw 307 MWh less energy dispatched compared to Q2 2022 (Figure 51). Less frequent high spot price volatility this quarter drove the reduction in dispatch.

**Figure 51 Reduction in Wholesale Demand Response dispatch this Q2 compared to 2022**

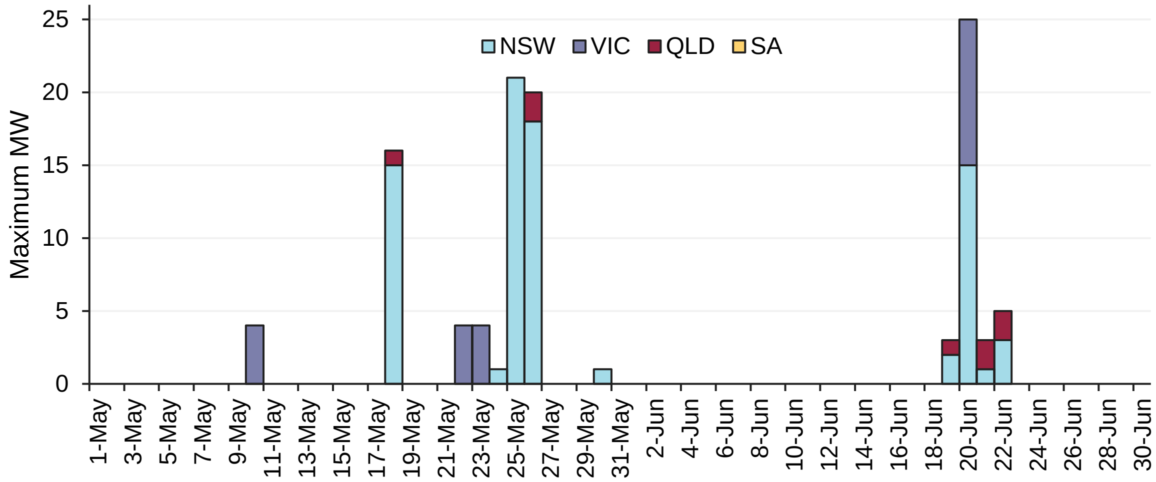
Total quarterly WDR energy dispatch




WDR capacity was dispatched on multiple days across the quarter, most often in New South Wales (Figure 52). High price events in New South Wales on 5 April, 18, 25 and 26 May and 20 June saw dispatch levels peak at or above 15 MW in each event. Victoria saw four days of WDR being dispatched, with 20 June accounting for 47% of the region's total WDR energy dispatched this quarter.

**Figure 52 Active participation from Wholesale Demand Response units across May and June**

Maximum daily WDR dispatch – May and June 2023




## 1.3.8 New grid connections

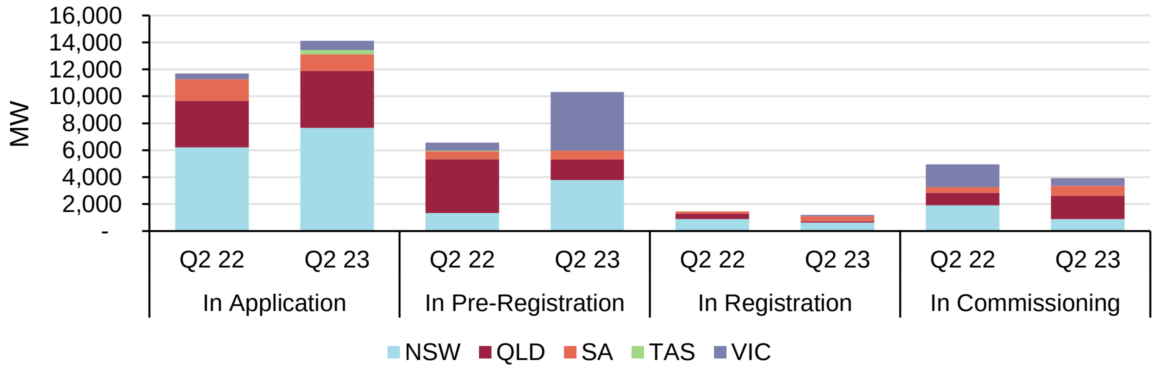
New grid connections to the NEM follow a process which involves the applicant, network service provider (NSP) and AEMO. Prior to submission of a connection application with AEMO, the applicant completes a pre-feasibility and enquiry phase where the connecting NSP is engaged in the process. The key stages 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 Q2 2023, 30 GW of new capacity were progressing through the connection process from application to commissioning compared to 25 GW at the end of Q2 2022 (Figure 53). In the current quarter, AEMO received an additional 16 new applications, totalling 3.9 GW, to commence the connection process.

At the end of Q2 2023 there were 10.3 GW of plant at various stages of construction (pre-registration), compared to 6.5 GW at the end of Q2 2022. The number of connections progressing through registration and commissioning remains relatively similar across both quarters, with 1.2 GW and 3.9 GW of plant progressing through registration and commissioning respectively in Q2 2023, compared with 1.5 GW and 5.0 GW in Q2 2022. Common issues currently reported to be impacting construction timelines include the need to refinance projects, long lead times for equipment, and the need to change original equipment manufacturers.

**Figure 53 Increases in number of applications received and projects under construction (pre-registration)**

Connections snapshot as at end Q2 for 2022 and 2023

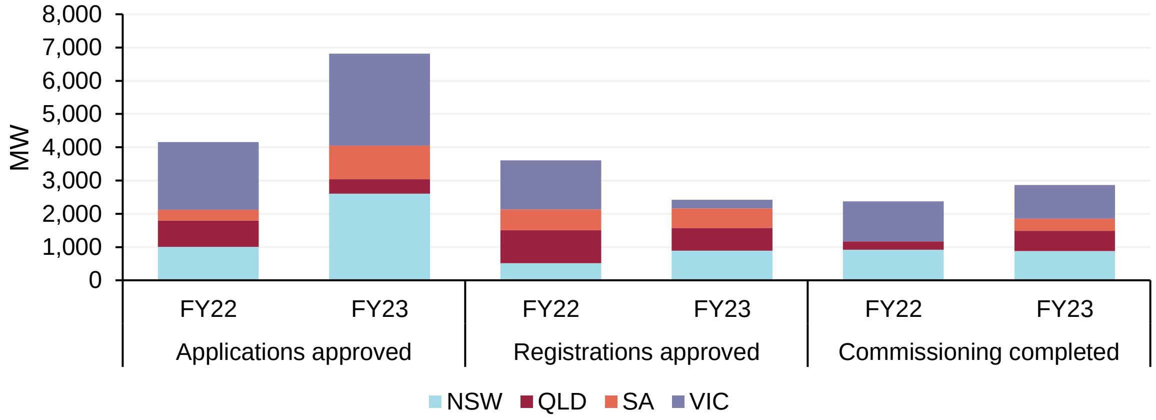


An increase from 4.2 GW to 6.8 GW (+63%) capacity of new connection applications were approved in 2022-23 (FY23) compared to 2021-22 (FY22) (Figure 54). By the end of FY23:

- 2.4 GW of plant had been approved over the year for market registration to commence commissioning. This is 32% lower than registrations approved over FY22 (3.6 GW).
- 2.9 GW of plant completed commissioning over the year and were approved for full operation. This is 21% higher than capacity approved for full operation by the end of FY22 (2.4 GW).

**Figure 54 Large increase in connection applications approved**

Comparison of applications approved, registrations and commissioning for FY22 and FY23

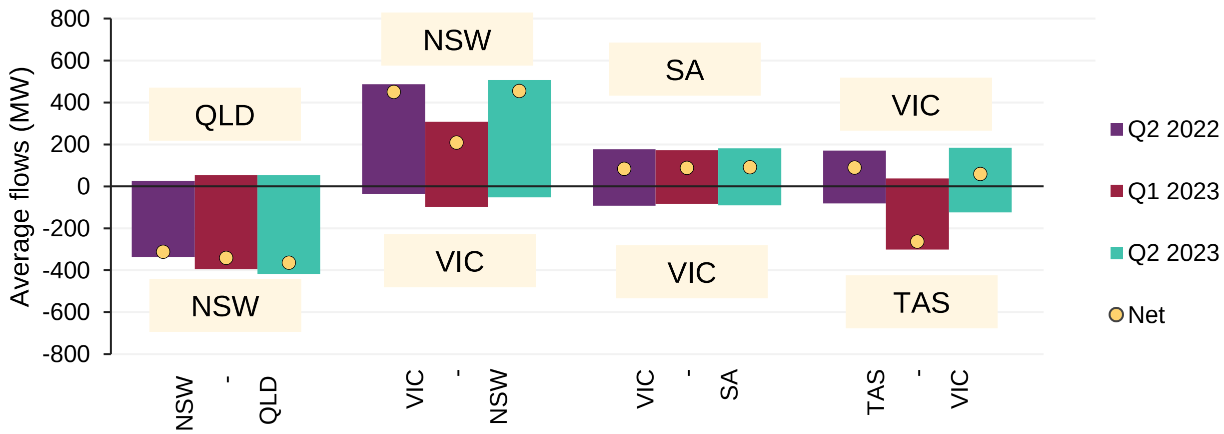



## 1.4 Inter-regional transfers

Total inter-regional energy transfers in Q2 2023 were 3,516 gigawatt hours (GWh), a 14% increase on Q2 2022. QNI (+234 GWh) and Basslink (+122 GWh) accounted for the majority of this increase. In general, net flows across regional boundaries in Q2 2023 were very similar to Q2 2022 (Figure 55). The exception was between Queensland and New South Wales, where net flows were an average of 52 MW more southward. This increase in southward flow saw QNI bind at its import limit 15% of the time over the quarter, up from 9% in Q2 2022. Flows on this interconnector bound predominantly between 6.00 am and 6.00 pm, explaining why price separation between New South Wales and Queensland was most evident during the daytime (Figure 11, Section 1.2).

**Figure 55 VNI and Basslink increased northward flows since Q1, returning to Q2 averages**

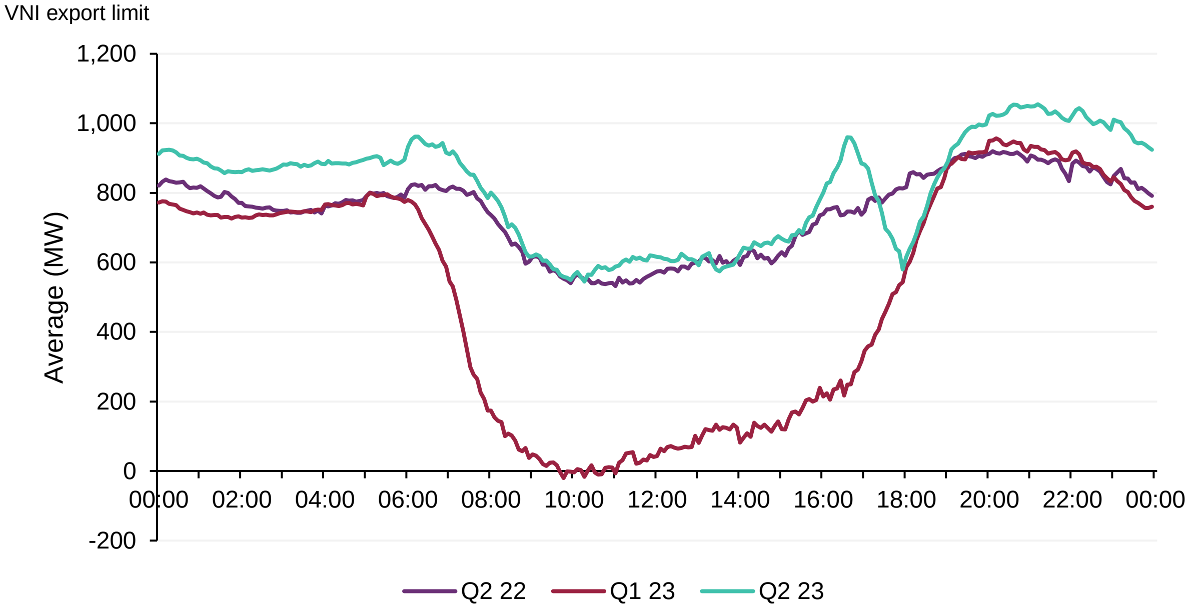
Quarterly inter-regional transfers



Comparing Q2 2023 with Q1 2023, the most significant changes in interconnector flows were across VNI and Basslink, with flows tending more northward in both cases:

- **Victoria to New South Wales** – although New South Wales prices were generally higher than Victoria's in both Q1 and Q2, Q2 saw greater northward flows on VNI. Northward flows were restricted by export limits in Q1 that were especially low during the middle of the day. In contrast, Q2 saw the export limit increase to similar levels as last Q2 (Figure 56).

**Figure 56 After an especially low Q1, VNI export limits returned to their seasonal trend**




- **Tasmania to Victoria** – Q1 Basslink flows averaged 263 MW towards Tasmania, whereas Q2 flows averaged 59 MW towards Victoria. This large northward swing across the first half of 2023 is aligned with regional price dynamics, as Tasmanian prices fell by $49/MWh relative to Victorian prices between Q1 and Q2 (Section 1.2). Greater northward flows were enabled in part by a 40 MW increase in Basslink's average export limit, while southward flows were somewhat restricted due to a 40 MW decrease in the import limit.

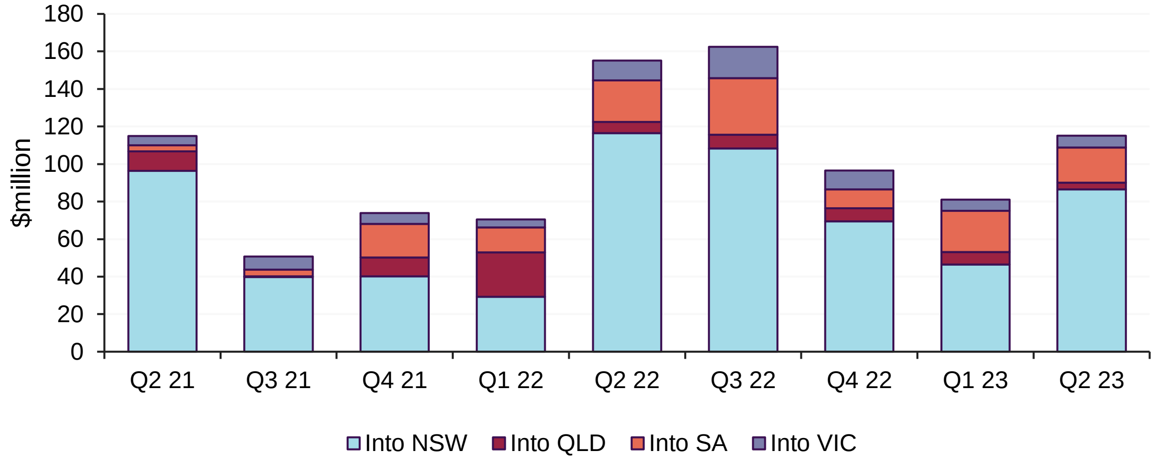
### 1.4.1 Inter-regional settlement residue

NEM-wide positive inter-regional settlement residue (IRSR) was $115 million in Q2 2023, a year-on-year fall of 26% (Figure 57). This result came despite the 14% increase in inter-regional transfers noted in Section 1.4, and all interconnectors (except Directlink) binding more frequently. This reflects that, at times when interconnectors did bind, the magnitude of price differences between regions was smaller in Q2 2023 than in Q2 2022. This is consistent with the significant price volatility observed in Q2 2022 driving large inter-regional price differences. The proportions of Q2 IRSR attributable to flow into various NEM regions was relatively stable year-on-year.

Compared to Q1 2023, positive IRSR was dominated (75% of NEM IRSR) by flows into New South Wales. This was driven by increased flow into NSW on both QNI and VNI, as covered in Section 1.4. While the New South Wales share increased, the proportional IRSR contribution due to flows into other regions declined.

**Figure 57 Settlement residues dominated by flows into New South Wales**

Quarterly positive IRSR

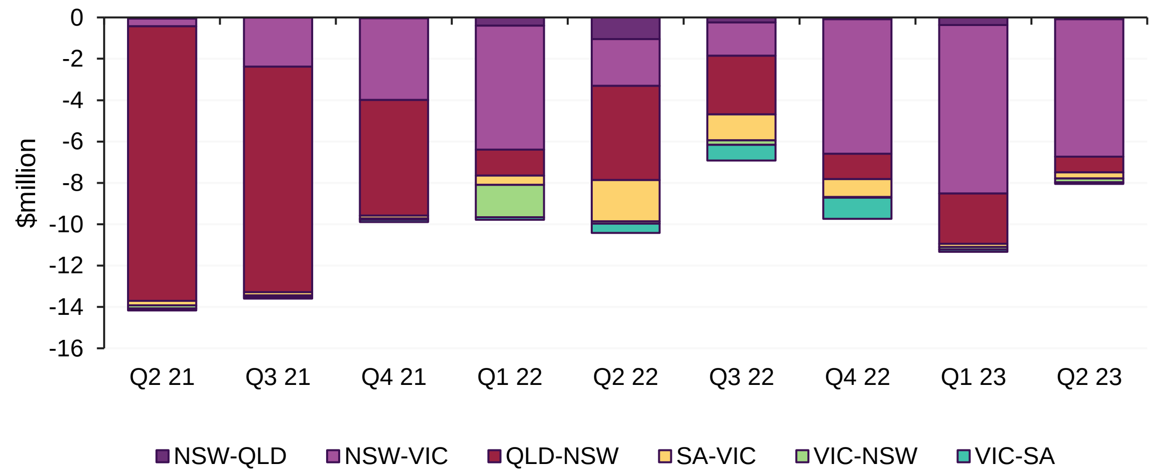



## Negative residue management

Total negative IRSR fell by $2 million (23%) compared to the previous Q2, due largely to reduced contributions ($4 million lower) from counter-price flows from Queensland to New South Wales which arose in association with price volatility events in June 2022. As per recent quarters, negative IRSR accruing across VNI on counter-price flows from New South Wales into Victoria accounted for the majority (83%) of negative IRSR in Q2 2023.

**Figure 58 Negative settlement residues dominated by counter-price flows on VNI**

Quarterly negative IRSR




As Figure 58 shows, negative IRSR on counter-price flows into Victoria across VNI fell between Q2 and Q1 2023 (-$1.5 million). However, it did not reduce to nearly the same extent as the frequency of counter-price flows decreased (Figure 59). This is because the average price difference between New South Wales and Victoria was much larger during periods of counter price flow into Victoria in Q2 ($264/MWh) than in Q1 ($97/MWh). An especially large proportion (44%) of negative IRSR due to southward flow on VNI for the quarter occurred on 25 May, due to the combination of price volatility in New South Wales, subdued prices in Victoria, and substantial counter-price flow volumes driven by a transmission outage which prevented the full output of generation in southern New South Wales from reaching Sydney, with the excess flowing south into Victoria (Figure 60).

**Figure 59 Substantial reduction in the frequency of counter-price flows**

Frequency of counter-price flows – Q2 vs Q1 2023

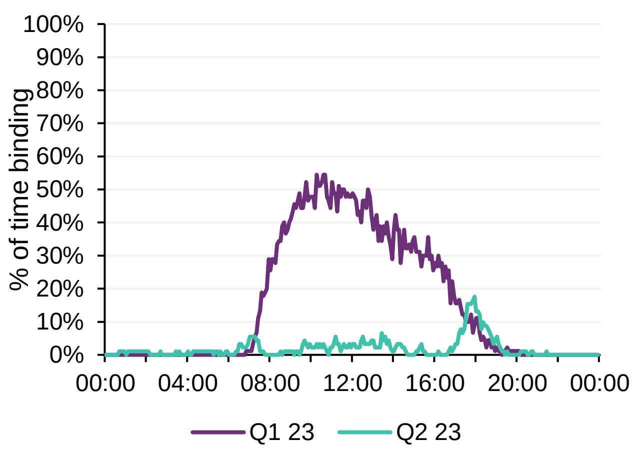
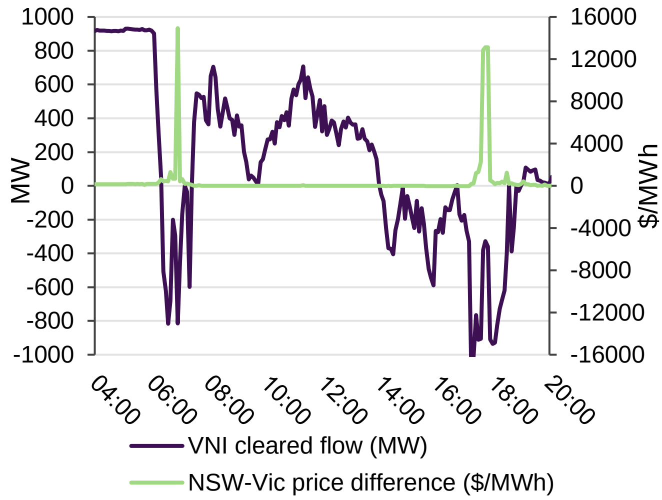



**Figure 60 Significant negative residues accumulate over morning and evening peaks on 25 May**

NSW-Vic price difference and VNI flow on 25 May 2023

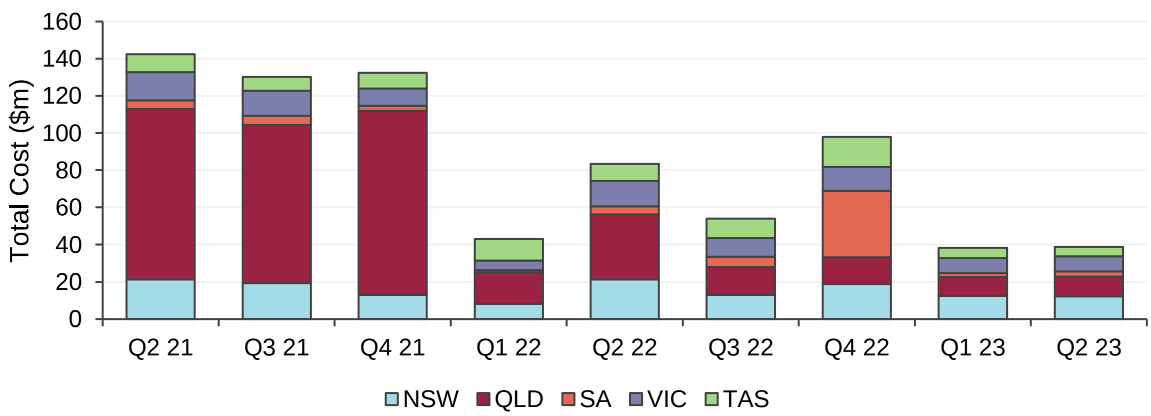



## 1.5 Frequency control ancillary services

As in Q1, FCAS costs were relatively subdued this quarter and had a similar breakdown across regions (Figure 61). Total NEM costs were $39 million, a 54% reduction on Q2 2022. In relative terms, this decrease was of a similar magnitude to the decrease in energy prices (59%) over the same period. The largest regional contribution to this change came from Queensland, whose FCAS costs fell from $35 million to $11 million. This was aligned with energy price dynamics, with Q2 2022 being an especially high-priced ($323/MWh average energy price) and volatile quarter in Queensland. Notably, Q2 2022 still saw lower Queensland FCAS costs than in 2021, where outage-related constraints on QNI and outages at key black coal-fired generators contributed to historic levels of volatility in Queensland FCAS markets.

**Figure 61 FCAS costs remained low**

Quarterly FCAS costs by region




The volume share of batteries in FCAS markets has continued its upward trend, rising from 35% of the NEM total in Q2 2022 to a record high of 40% this quarter (Figure 62). Total Q2 FCAS volumes have been relatively constant year-on-year, meaning the growth of batteries has displaced FCAS provision by synchronous generators

(Figure 63). Due to reduced consumption at some key industrial facilities, the demand response category also provided significantly lower contingency raise volumes (46 MW lower on average) than last Q2.

**Figure 62 Battery market share reached record highs**

FCAS volume market share by technology – Q2 2023

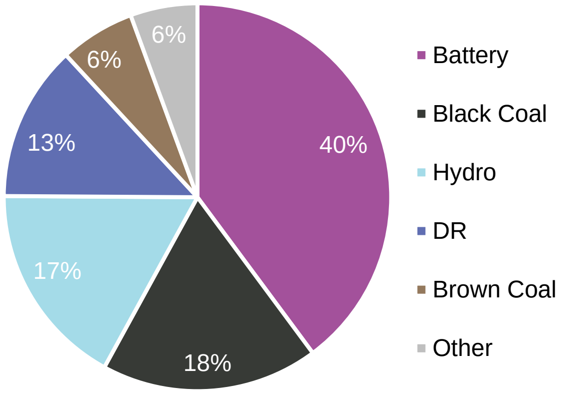
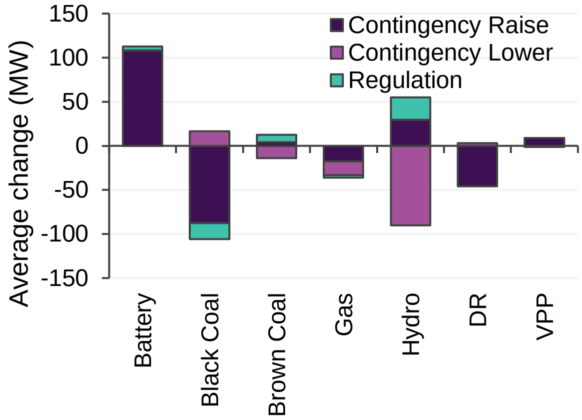



**Figure 63 Batteries displaced synchronous FCAS sources**

Change in FCAS supply by technology – Q2 2023 vs Q2 2022

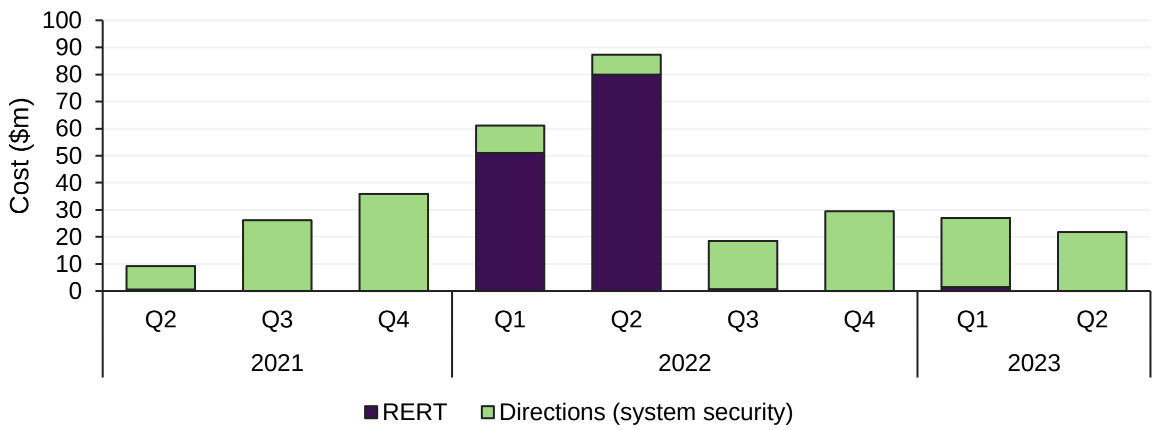



## 1.6 Power system management

In this quarter, power system management costs totalled $21.7 million, all attributable to system security directions in South Australia. Although aggregated costs were well down on Q2 2022, their system security component increased by $14.3 million (Figure 64). Elevated total costs in Q2 last year were primarily driven by significant expenses related to Reliability and Emergency Reserve Trader (RERT) activation.

**Figure 64 System security direction costs up but RERT costs down in Q2 2023**

Estimated quarterly system costs by category



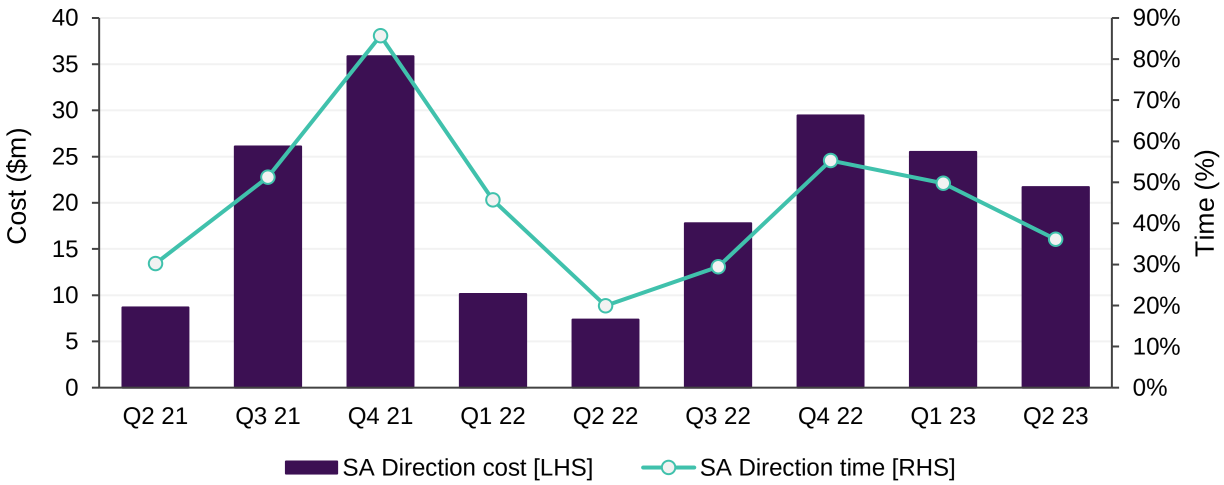

### 1.6.1 South Australian system security directions

This quarter witnessed an increase in both the cost of system security directions in South Australia and the proportion of time within the quarter that was covered by these directions. Directions were in place for 36% of dispatch intervals across Q2 2023, higher than Q2 2022's 20% but lower than Q1 2023's 50%. Direction costs also increased sharply from $7.4 million in Q2 last year to $21.7 million this year (Figure 65). The increase in direction costs reflected both higher volumes of directed generation and a significant increase in the average quarterly direction compensation price, from $192/MWh in Q2 2022 to $337/MWh in Q2 2023[20].

Due to relatively lower electricity spot prices and high VRE output, gas-fired generators more frequently opted to decommit their units from the system. This behaviour, observed in both gas offer curves and actual market dynamics, led to an increase in directions required to maintain minimum synchronous generation levels to ensure system security.

**Figure 65 Sharp rise in South Australia system security direction time and cost on Q2 2022**

Time and cost of energy only system security directions – South Australia Q2 2021 to Q2 2023




Gas-fired generation in South Australia consequently saw a 16 MW increase in directed volume, from 13 MW in Q2 2022 to 29 MW in Q2 2023, and the directed proportion of its total quarterly output rose from 2% in Q2 2022 to 6% this quarter (Figure 66), as overall gas-fired output fell. This quarter also witnessed a notable increase in the percentage of time when two units were directed simultaneously, rising from 10% last Q2 to 22% this year. This change aligned with the overall increase in the volume of directions (Figure 67).

**Figure 66 Slight increase in South Australian gas volumes directed**

South Australian gas-fired generation directed – volume and share

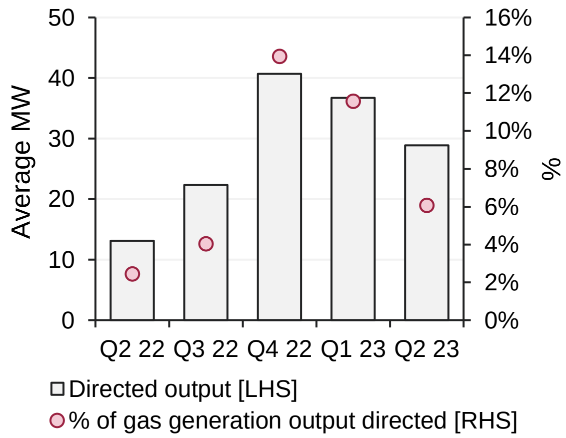
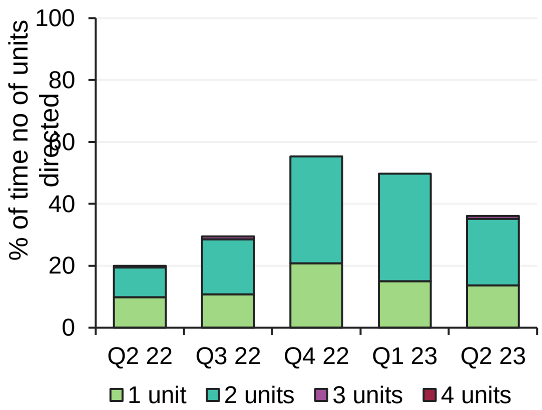



**Figure 67 Significant increase in two-unit directions**

Number of units simultaneously directed – proportion of quarter




[20] 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

While quarterly average prices increased compared to Q1 2023, all prices were approximately half of Q2 2022 levels, which remain the highest market prices on record. The average price across all AEMO markets in May increased to $18.16/ gigajoule (GJ), however in June it decreased to $12.34/GJ. The quarterly average price across all AEMO markets was $14.21/GJ, compared to $28.39/GJ in Q2 2022 (Table 4). While significantly lower, this is still the second highest Q2 price on record.

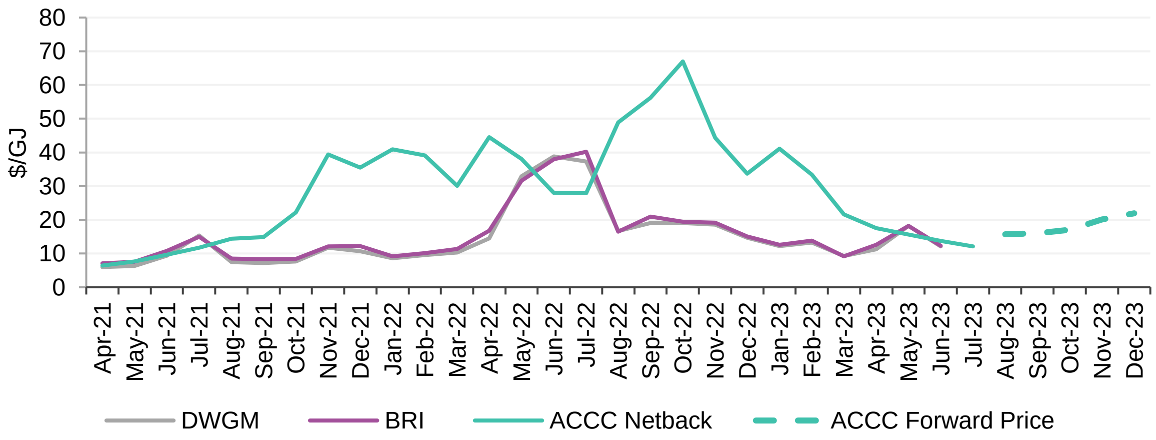
**Table 4 Average east coast gas prices – quarterly comparison**

| Price ($/GJ) | Q2 2023 | Q1 2023 | Q2 2022 | Change from Q2 2022 |
|---|---|---|---|---|
| Declared Wholesale Gas Market (DWGM) | 13.84 | 11.59 | 28.76 | -52% |
| Adelaide | 15.13 | 12.66 | 29.84 | -49% |
| Brisbane | 14.34 | 11.87 | 28.77 | -50% |
| Sydney | 14.70 | 12.11 | 28.85 | -49% |
| Gas Supply Hub (GSH) | 13.03 | 11.09 | 25.72 | -49% |

International prices continued to fall, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, with corresponding forward prices ranging from around $13/GJ to $22/GJ over the next 12 months (Figure 68). Drivers for international prices are discussed in Section 2.1.1.

**Figure 68 Domestic prices at half of Q2 2022 levels but still second highest Q2 on record**

ACCC netback and forward prices[21], DWGM and Short Term Trading Market (STTM) Brisbane average gas prices by month



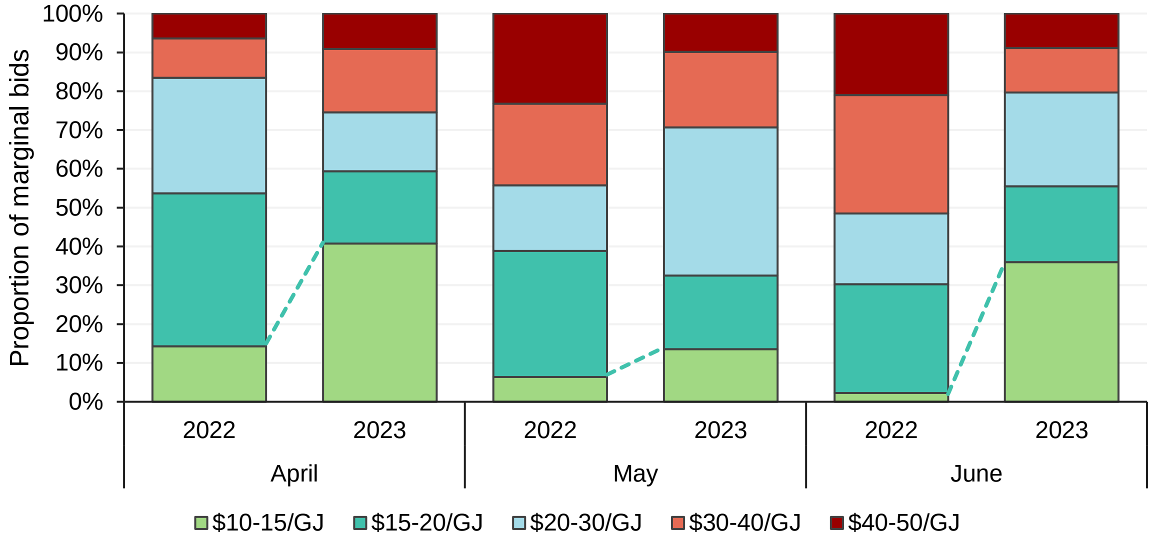

While domestic prices slightly exceeded international prices in May, they dropped slightly below in June, a stark contrast to 2022 where domestic prices were at record levels and significantly higher than the international price. Contributing factors were reduced demand from gas-fired generation (see Section 1.3.2), reduced demand in Brisbane and Victoria, and an increase in gas supply to the domestic market from Queensland producers. This

[21] ACCC 2022, LNG netback price series: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

shift in supply and demand balance in June is reflected in market participants increasing bid volumes below $15/GJ (Figure 69).

**Figure 69 Declared Wholesale Gas Market bids reflecting lower prices coinciding with lower demand**

DWGM – proportion of marginal bids[22] by price band - Q2 2022 vs Q2 2023 by month

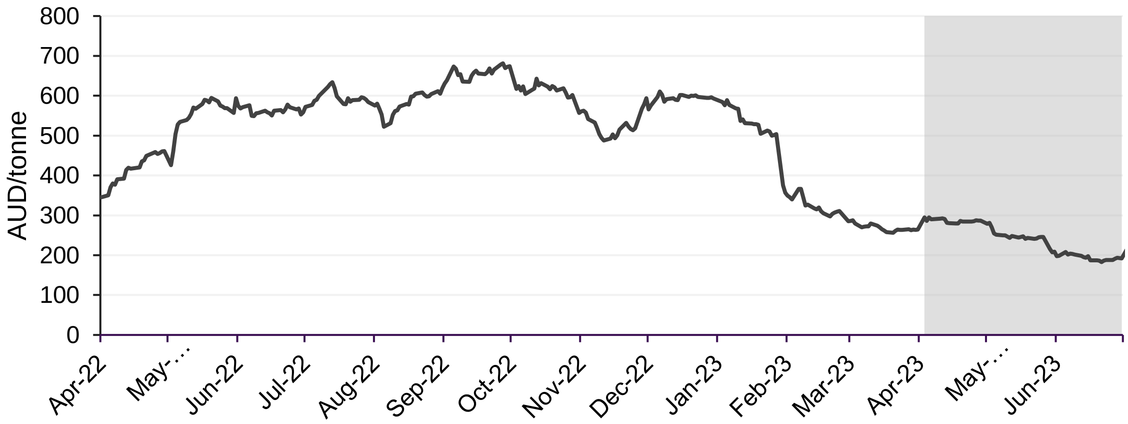



### 2.1.1 International energy prices

Thermal coal prices this quarter averaged A$240/tonne, down A$274/tonne from Q2 2022, which experienced very high prices due to supply issues and international energy commodity price volatility influenced by sanctions against Russia following the war in Ukraine and weather-related supply issues (Figure 70). European coal demand was overestimated during early 2023, creating expensive stockpiles of coal and driving some price correction[23]. Compared to Q1 2023, thermal coal prices declined by A$128/tonne, but remain above the recently imposed price cap of A$125/tonne that applies to coal offers from suppliers to certain domestic power stations.

**Figure 70 Thermal coal prices remain significantly lower from the highs of 2022**

Newcastle export thermal coal A$/Tonne daily




Source: Bloomberg ICE data

[22] Bids between $5/GJ and $50/GJ.

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

Asian spot liquefied natural gas (LNG) prices declined once again, with an average quarterly price of A$17.40/GJ, which was $8/GJ lower than Q1 2023. (Figure 71). This has been driven by North Asian and European gas inventories being at very healthy levels. European LNG inventory stocks reached 78% capacity by the end of the quarter[24], which coupled with weaker economic data coming out of China[25] along with muted demand led to an increased amounts of floating LNG inventories in Asia[26]. The global head of trading at Trident LNG commented that "the market is active, just not on a spot basis, the focus as of late has been around new long-term contract bookings”.[27]

Brent Crude oil price averaged A$116/barrel this quarter, down $4/barrel from Q1 2023 (Figure 72). Similar to spot LNG prices, this was due to weaker economic data from China and even supply curtailments from OPEC+ could not offset this slip in demand.

**Figure 71 Asian LNG prices soften further**

Asian LNG price in A$/GJ daily


Source: Bloomberg ICE data

**Figure 72 Brent Crude oil prices see continued decline**

Brent Crude oil in A$/Barrel daily


Source: Bloomberg ICE data

## 2.2 Gas demand

Total east coast gas demand decreased by 5% compared to Q2 2022 (Figure 73, Table 5).

There were decreases in AEMO markets demand (-5 petajoules (PJ)) and gas-fired generation (-16 PJ) and an increase Queensland LNG production (+5 PJ). Victoria’s Declared Wholesale Gas Market (DWGM) experienced lower demand (-3 PJ) due to slightly milder weather combined with lower commercial and industrial demand, while Brisbane recorded a decrease (-2.4 PJ) primarily due to the shutdown of Incitec Pivot’s Gibson Island facility in January. Prior to its shutdown, this facility was Brisbane’s largest gas user, typically consuming 2-3 PJ per quarter.

[24] See https://gasdashboard.entsog.eu/.

[25] See https://www.reuters.com/business/energy/growth-risks-restrain-oil-prices-this-year-2023-06-30/.

[26] See https://www.reuters.com/business/energy/high-lng-stocks-north-asia-weak-demand-leads-more-storage-sea-2023-04-21/.

[27] See https://au.news.yahoo.com/global-lng-asia-spot-prices-104139264.html.

**Figure 73 Large gas-fired generation decrease the biggest contributor to lower east coast demand**

Components of east coast gas demand change – Q2 2022 to Q2 2023

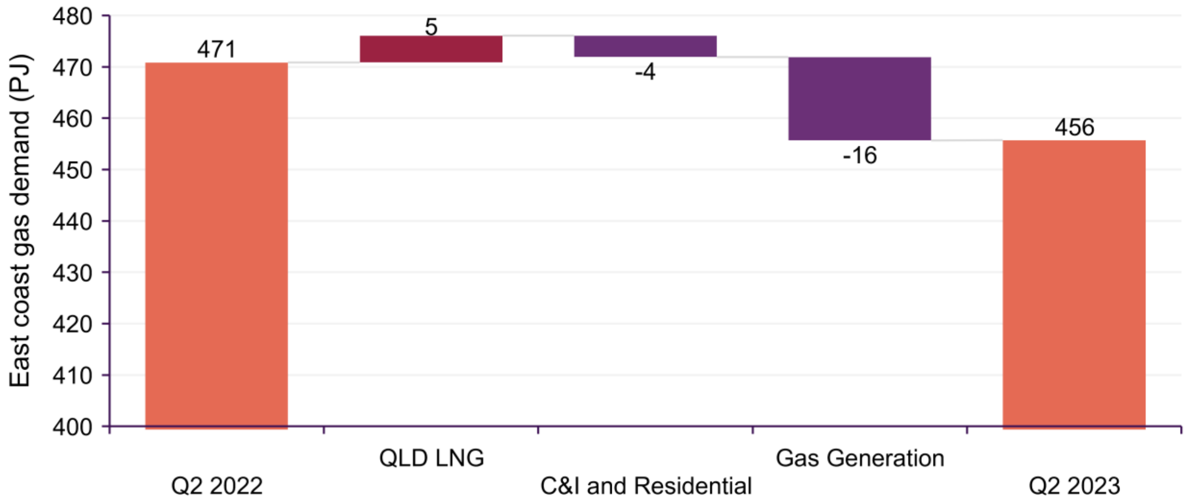



**Table 5 Gas demand – quarterly comparison**

| Demand (PJ) | Q2 2023 | Q1 2023 | Q2 2022 | Change from Q2 2022 |
|---|---|---|---|---|
| AEMO Markets * | 87.6 | 50.6 | 91.7 | -7 (-7%) |
| Gas-fired generation ** | 28.9 | 20.8 | 45.1 | -16 (-36%) |
| Queensland LNG | 339.2 | 325.2 | 334.0 | 5 (2%) |
| Total | 455.7 | 396.6 | 470.9 | -18 (-4%) |

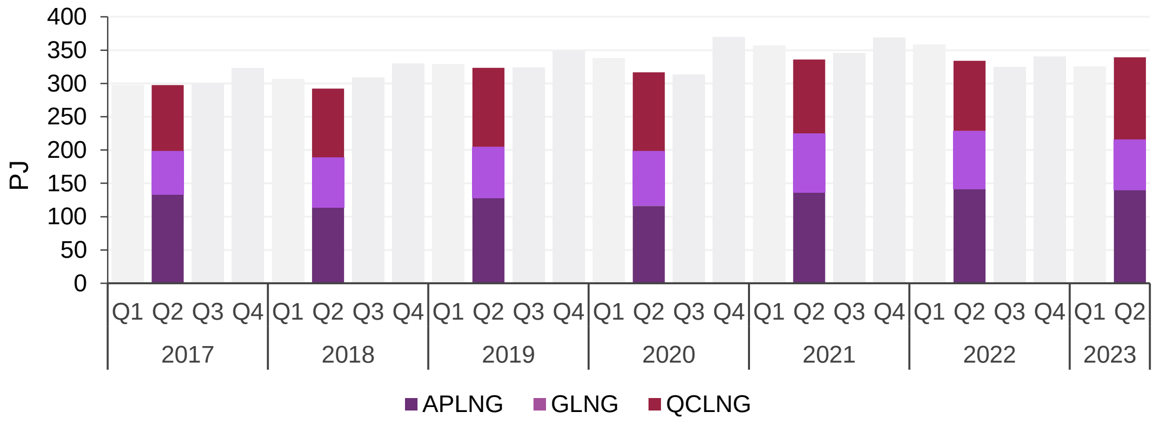
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand bounced back slightly, with QCLNG ramping up LNG production after train outages in Q1, however GLNG experienced train outages during Q2 which meant, that overall (year-on-year), there was an aggregate increase of only 2%. The GLNG train outage led to their lowest export quarter since Q3 2019, exporting 76 PJ.

By participant, QCLNG demand increased by 18.1 PJ while APLNG decreased by 1.4 PJ and GLNG decreased by 11.5 PJ (Figure 74). There were 86 cargoes exported during the quarter, down from 87 cargoes in Q2 2022.

**Figure 74 Increase in QCLNG flows to Curtis Island offset by GLNG flows which were their lowest since Q3 2019**

Total quarterly pipeline flows to Curtis Island



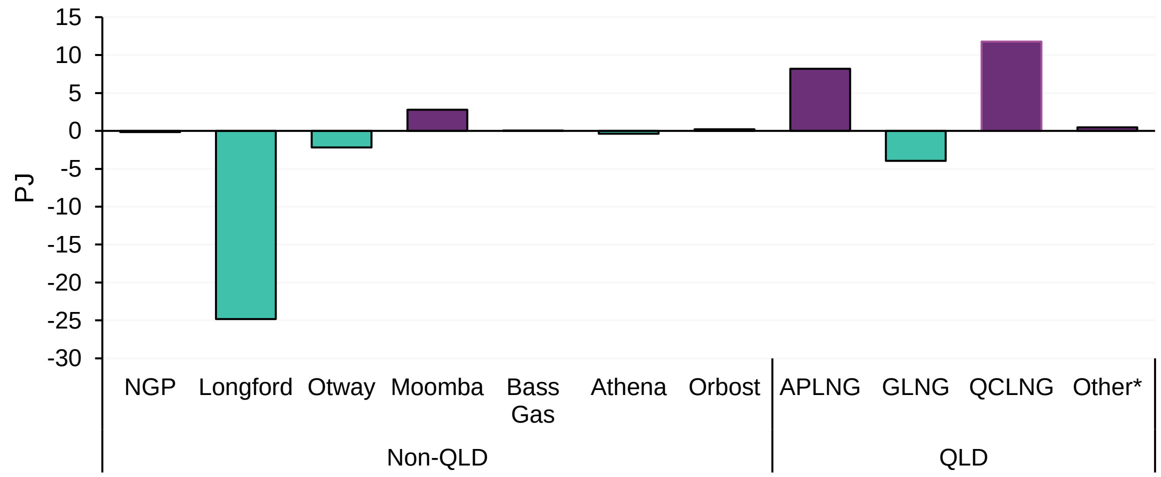

## 2.3 Gas supply

### 2.3.1 Gas production

East coast gas production decreased by 8.0 PJ compared to Q2 2022 (-2%, Figure 75).

**Figure 75 Large production fall at Longford**

Change in east coast gas supply – Q2 2023 vs Q2 2022

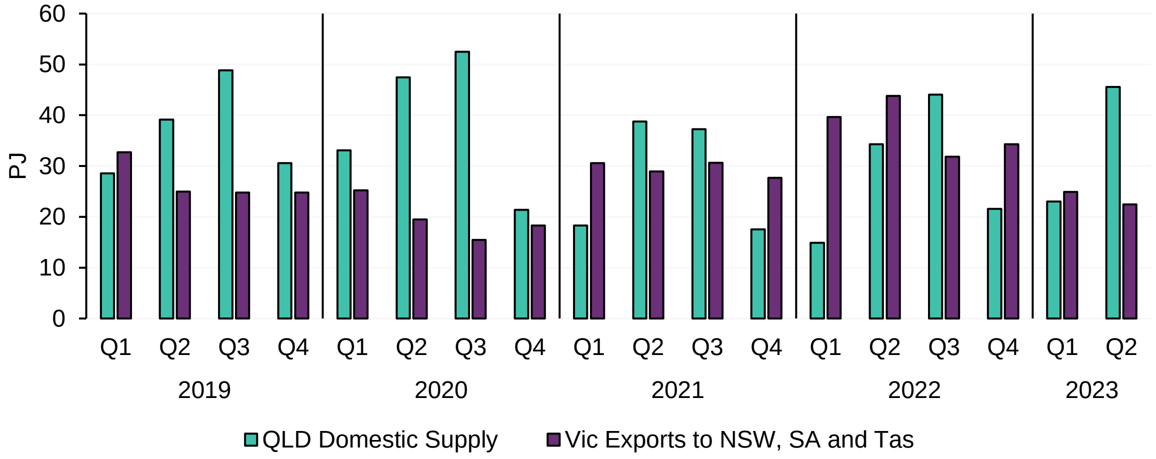



Key changes included:

- Decreased Victorian production (-23.7 PJ), mainly driven by lower production at Longford (-24.8 PJ).
- Increased Queensland production (+16.5 PJ), with assets operated by QCLNG increasing by 11.8 PJ, APLNG operated assets by 8.2 PJ, while GLNG operated assets decreased by 4.0 PJ. Gas demand for Queensland LNG exports increased by 5.2 PJ, meaning that an additional 11.3 PJ of supply associated with Queensland LNG projects went into the domestic market compared to Q2 2022 (Figure 76).
- Increased Moomba production (+2.8 PJ), bucking the trend of lower Moomba production year-on-year.

**Figure 76 Large increase in Queensland domestic supply replacing Victorian exports**

Queensland domestic supply compared to Victorian gas exports by quarter

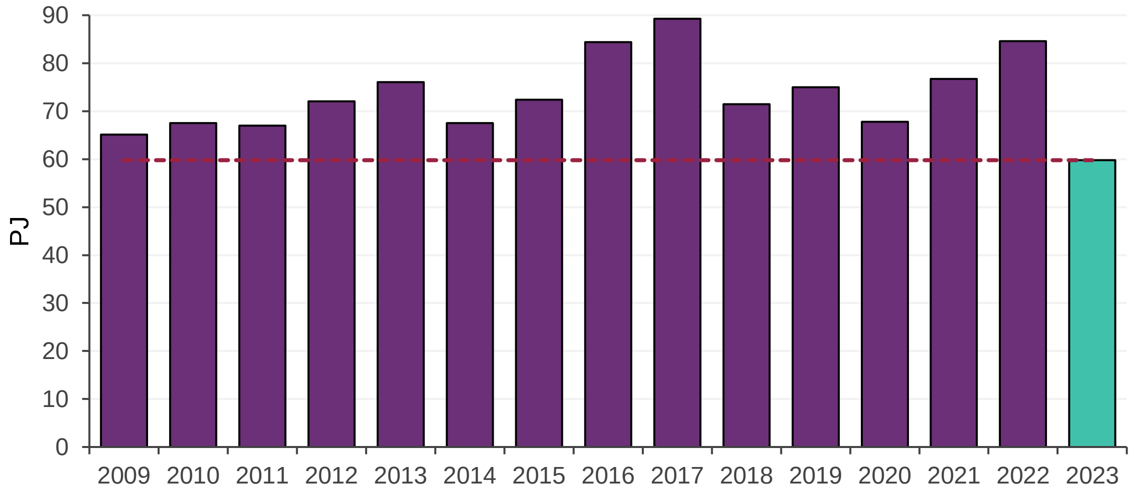



### 2.3.2 Longford production decline

Longford's production of 60 PJ was its lowest Q2 since data began being reported on the Gas Bulletin Board (GBB) in 2009 (Figure 77). Similarly, Longford's daily production is also lower in 2023 compared to previous years, noting that 2022 Longford production was the highest since 2017. While some of this decrease has been due to unplanned maintenance, the decrease mostly reflects the declining gas reserves in the Bass Strait fields connected to Longford. This decrease was forecast and reported in AEMO's *Victorian Gas Planning Report* and *Gas Statement of Opportunities*[28].

**Figure 77 Lowest Longford Q2 production since data reporting began**

Longford Q2 production



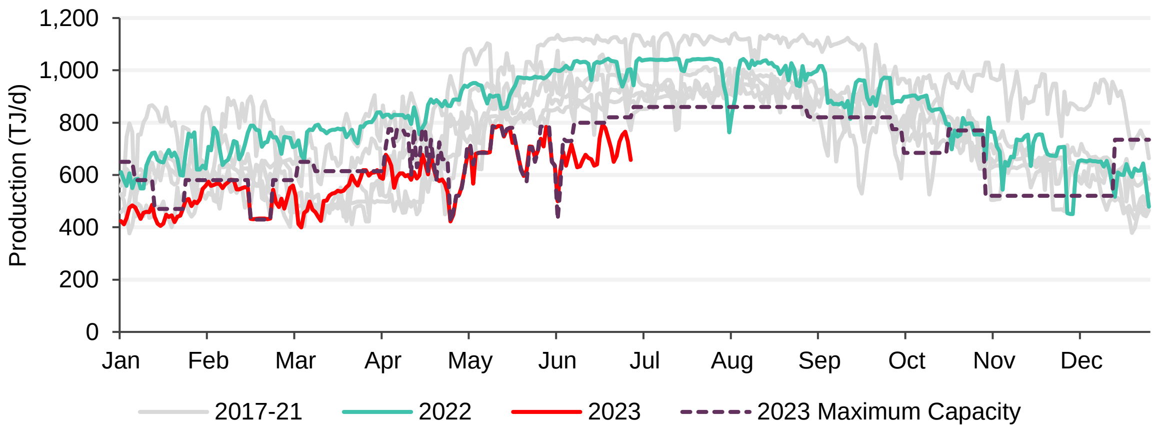

Despite declining Longford production due to declining gas reserves, daily Longford production was still below capacity for much of June (Figure 78). This was due to a combination of low demand driven by lower gas-fired

[28] 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.

generation and above average temperatures leading to reduced heating load, as well as high supply from Queensland to southern states.

**Figure 78 Daily Longford production declining**

Daily Longford production 2017-2023, maximum capacity profile 2023



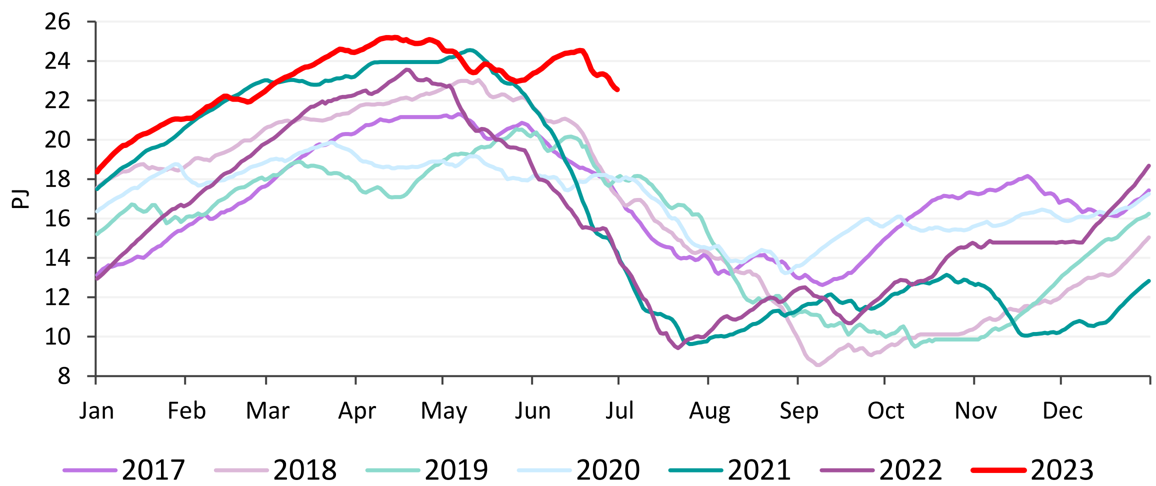

### 2.3.3 Gas storage

The Iona Underground Gas Storage (UGS) facility finished the quarter with an inventory of 22.6 PJ, 8.4 PJ higher than at the end of Q2 2022 (Figure 79), and the highest end to a Q2 since reporting began in 2017. Typically Iona inventory begins to deplete significantly throughout June, however Iona was still filling until 19 June, and as such storage only emptied by 0.8 PJ, leaving Iona still close to full at the end of the quarter.

As in Q1 2023, factors contributing to the high level of storage inventory included lower demand caused by a large decrease in gas-fired generation and market demand due to milder temperatures, and an increase in supply from Queensland to the domestic market.

**Figure 79 Iona storage at its highest end to Q2 since storage levels began reporting**

Iona storage levels



### 2.3.4 Dandenong LNG

Dandenong LNG is a critical piece of infrastructure in the Victorian Declared Transmission System (DTS) due to its proximity to Melbourne and its ability to quickly ramp up and inject gas into the DTS to restore pipeline pressures. It is not uncommon for AEMO to schedule gas to be injected into the DTS from the Dandenong LNG facility because of a threat to system security, although this typically only occurs on high demand days.

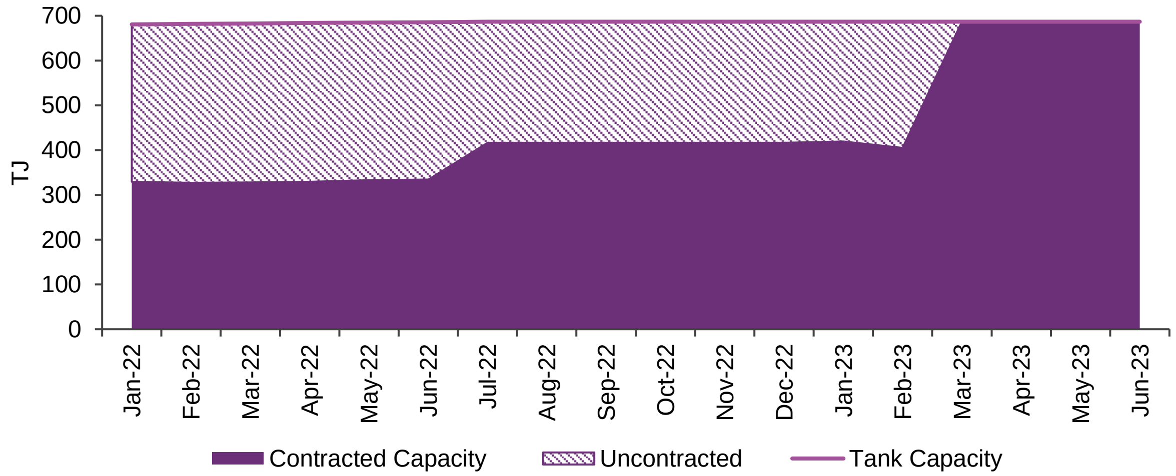
From 15 December 2022, the Australian Energy Market Commission (AEMC) made a rule to enable AEMO to better manage the risk of curtailment for gas users during the tight demand-supply conditions expected from 2023 to 2025[29]. This rule change requires AEMO to act as both buyer and supplier of last resort for the Dandenong LNG facility, requiring AEMO from 1 March 2023 to buy all the uncontracted capacity of the facility and purchase gas from the DWGM to fill the tank to capacity.

As a result of this rule, AEMO holds the volume of the Dandenong LNG tank that is not contracted by other parties. Contracted levels as a consequence of this rule, which include AEMO contracted volumes, are shown in Figure 80.

To date, no AEMO-held volume has been required to be scheduled in the market.

**Figure 80 Dandenong LNG contracted versus uncontracted capacity**

Dandenong LNG contracted levels




### 2.3.5 East Coast Gas System Reforms

In response to the projected supply shortfall in the south in 2023 and the heightened susceptibility of the gas markets to reliability and supply adequacy threats, Energy Officials developed and implemented a framework extending AEMO's powers and functions.

The *National Gas (South Australia) (East Coast Gas System) Amendment Bill 2023* and Part 27 of the National Gas Rules provide AEMO with east coast gas system reliability and supply adequacy powers and functions. Stage 1 East Coast Gas System (ECGS) reforms extend AEMO's powers and functions to provide it with tools to monitor, signal and manage supply shortfalls in the east coast gas market in winter 2023:

- Transparency – new and existing participant disclosure obligations to enable AEMO to assess the likelihood of risk or threat to the reliability or adequacy of gas supply in the ECGS.

[29] DWGM interim LNG storage measures: https://www.aemc.gov.au/rule-changes/dwgm-interim-lng-storage-measures.

- Signalling – establishing a register of contacts to communicate information about risks or threats, including the ability to hold conferences.
- Directions – AEMO can give directions to gas industry participants to resolve an identified risk or threat. This includes an interim compensation framework.
- Trading – AEMO can trade in natural gas to maintain or improve the reliability or adequacy of gas supply in the east coast gas system. AEMO must establish a $35 million trading fund.

This function replaced the Gas Supply Guarantee, which was a mechanism developed by the gas industry in March 2017 to make gas available to meet peak demand periods in the NEM.

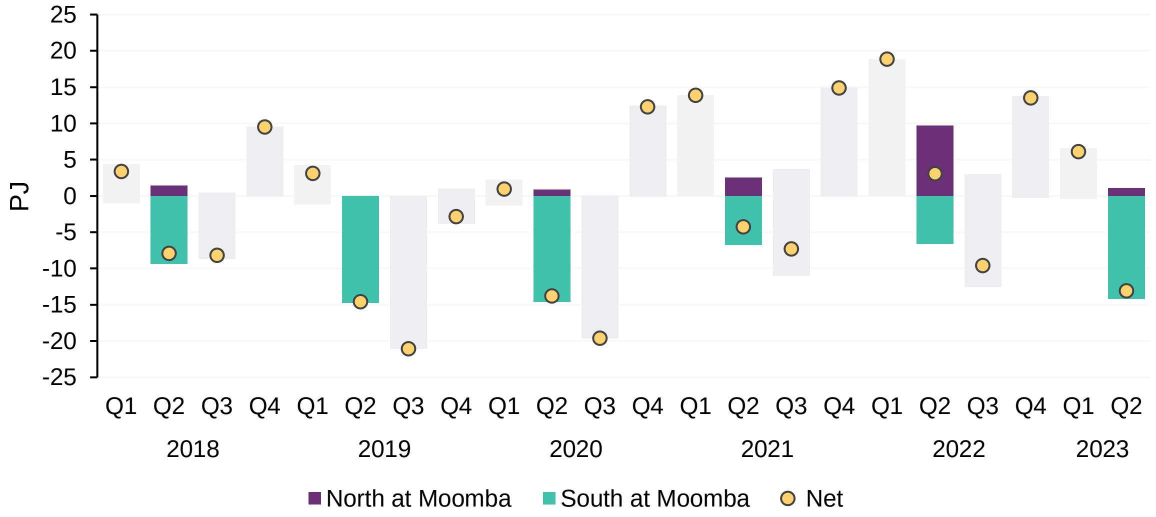
These rules were effective from 1 June 2023. These reform changes, as well as other various market reforms recently delivered are listed in Section 4.

## 2.4 Pipeline flows

Compared to Q2 2022, there was a 16.1 PJ turn around in net transfers, reverting from a net transfer into Queensland to a net transfer south at Moomba on the South West Queensland Pipeline (SWQP, Figure 81). This represents the highest flow south from Moomba for Q2 since Q2 2020. The large reversal in net transfers from Q2 2022 was driven by a reduction in LNG exports to Curtis Island in May, combined with an increase in production at production facilities associated with QCLNG and APLNG. While QLD LNG export demand increased in June compared to 2022, the higher production meant supply to the domestic market also increased, enabling higher flows to Moomba.

**Figure 81 Highest southward flows into Moomba from Queensland since Q2 2020**

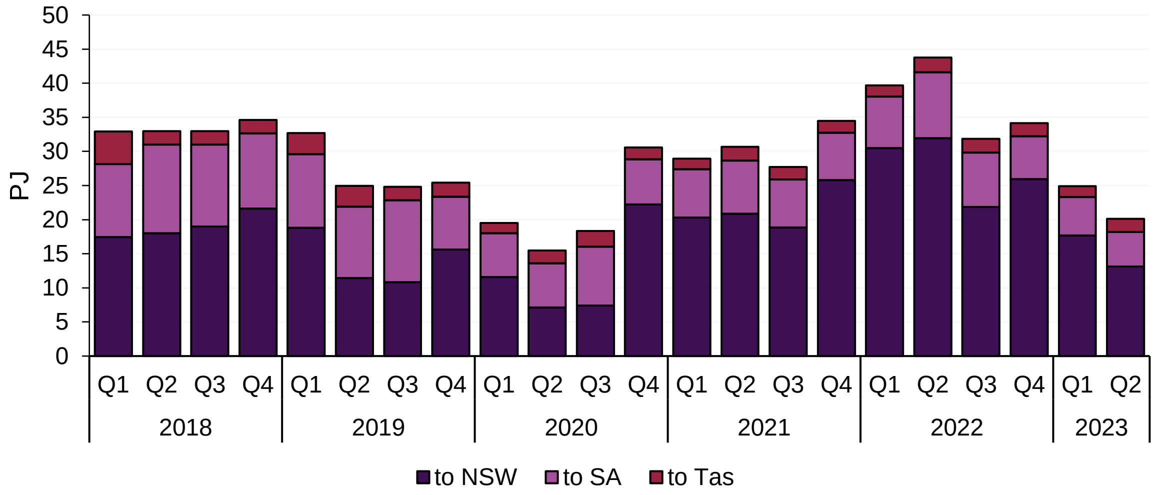
Flows on the South West Queensland Pipeline at Moomba




Victorian net gas transfers to other states decreased by 23.7 PJ from Q2 2022 levels, mainly due to decreased Longford production, higher Moomba production (Section 2.3.1), higher net domestic production in Queensland, and lower domestic demand. This represented the lowest net transfer out of Victoria for any quarter since Q3 2020 (Figure 82). There were decreased flows to all states, with Victoria to New South Wales reduced by 8 PJ on the Eastern Gas Pipeline (EGP), and a 10.8 PJ turnaround via Culcairn, with Victoria being a net importer at that location compared to an exporter in Q2 2022. Flows from Victoria to South Australia decreased by 4.6 PJ, while there was a 0.2 PJ decrease in the flow to Tasmania.

**Figure 82 Victorian Q2 transfers decreased coinciding with decrease in Victorian production**

Victorian net gas transfers to other regions

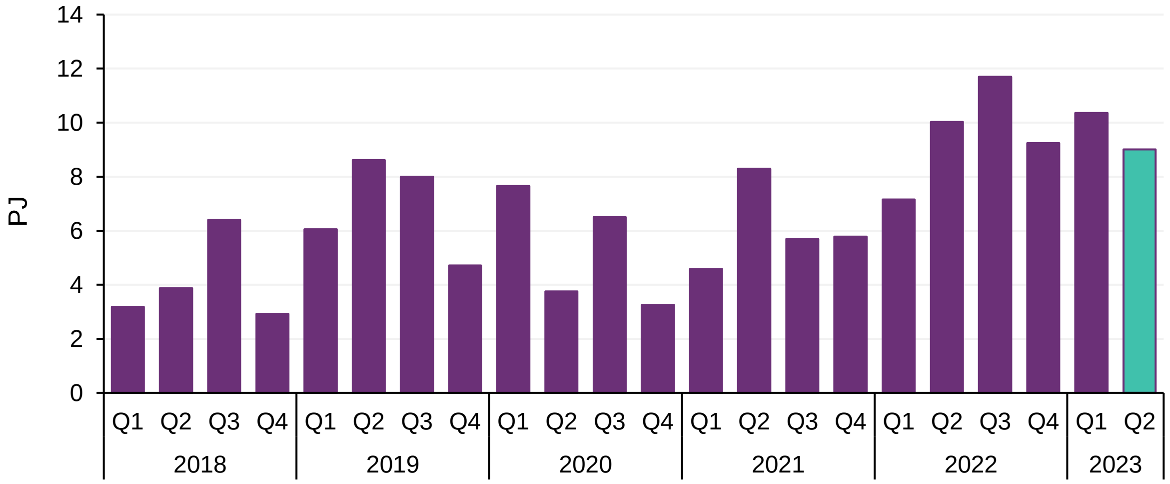



## 2.5 Gas Supply Hub (GSH)

In Q2 2023 there were decreased trading volumes on the GSH compared to Q2 2022 (Figure 83), with traded volume down 1 PJ. The traded volume of 9.0 PJ is, however, the second highest on record for any Q2.

**Figure 83 GSH traded volumes down, but second highest Q2 on record**

Gas Supply Hub – quarterly traded volume



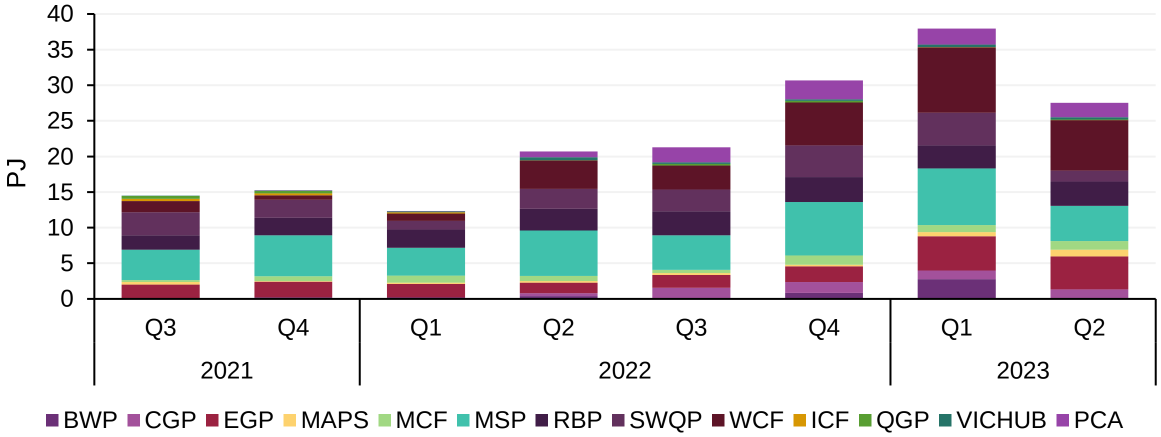
## 2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes decreased from the record levels seen in Q1 2023, however were still 6.8 PJ higher than Q2 2022 (Figure 84). Compared to Q2 2022, the largest increases occurred on the Wallumbilla Compressor (+3.1 PJ) and the EGP (+3.1 PJ)

Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were the Roma to Brisbane Pipeline West which averaged $0.02/GJ, the Moomba to Sydney Pipeline (MSP) which averaged $0.04/GJ, and the EGP North which averaged $0.08/GJ.

**Figure 84 DAA volumes lower than Q1 2023, but significantly higher than Q2 2022**

Day Ahead Auction volumes by quarter




## 2.7 Gas – Western Australia

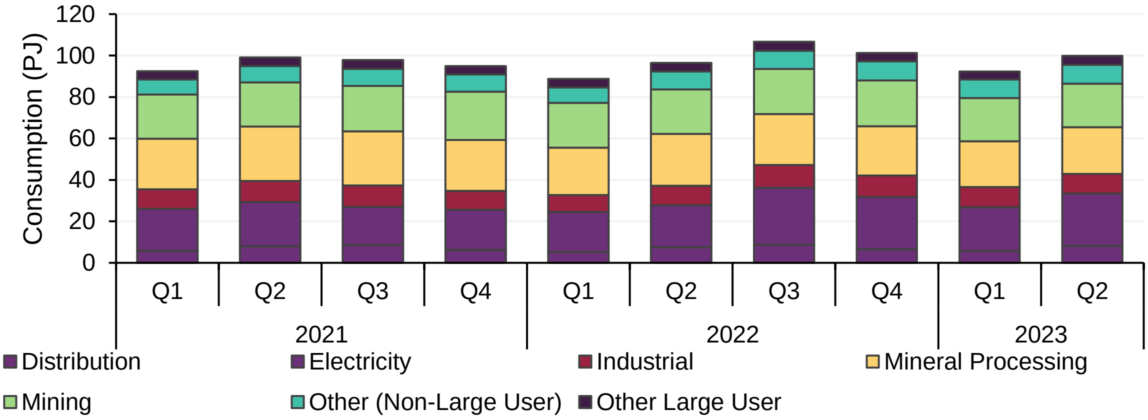
### 2.7.1 Gas consumption

A total of 100 PJ was consumed in the Western Australian domestic gas market in Q2 2023. This was an increase compared to both Q2 2022 consumption of 3.4 PJ (+3.6%) and Q1 2023 consumption of 7.6 PJ (+8.2%) (Figure 85). Key drivers of consumption compared to Q2 2022 included:

- Increase in gas consumption for electricity generation of 5 PJ (+26%). Gas-fired electricity generation increased both in proportion (fuel mix) and overall terms (see Section 3.2). There was also an increase in gas used in distribution networks of 0.7 PJ (+9.6%).
- Increased consumption for electricity generation and distribution was offset by a decrease in consumption by the mineral processing sector by 2.6 PJ (-10%). This was largely due to the three Alcoa refineries reducing consumption by 2.5 PJ.

**Figure 85 Western Australian domestic gas consumption remained similar to Q2 2022**

WA quarterly gas consumption by sector – Q1 2021 to Q2 2023



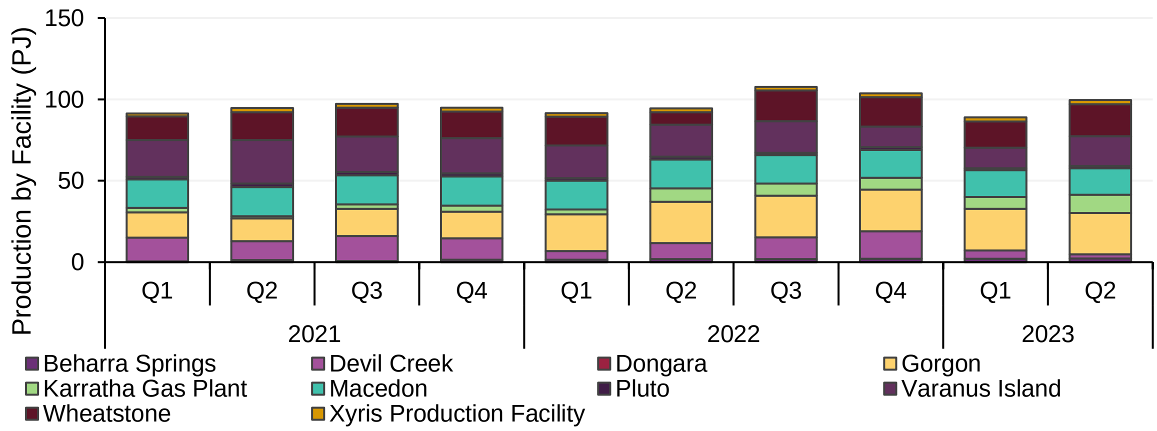

### 2.7.2 Gas production

Q2 2023 saw total Western Australian domestic gas production of 100 PJ, an increase of 5.1 PJ (+5.4%) from Q2 2022 and an increase of 11 PJ (+12%) from Q1 2023 (Figure 86). Key drivers of the quarter's production figure included:

- Wheatstone was up 12 PJ (+154%) compared to Q2 2022 and up 3.5 PJ (+22%) on Q1 2023 as the facility operated at full capacity across the quarter.
- Karratha Gas Plant's domestic gas production was at its highest output since Q2 2020 at 11 PJ, an increase of 2.9 PJ (+35%) on Q2 2022 and 4 PJ (+56%) on Q1 2023.
- The trending lower production volume persisted (and even further reduced) at the Devil Creek facility in Q2 2023 due to the depletion of the Reindeer gas field[30]. This was reflected in the reduction to 2.6 PJ for the quarter, a decrease of 9.9 PJ (-79%) on its average domestic production across 2021 and 2022.

**Figure 86 Western Australian domestic gas production increased by 5.4% from Q2 2022 and 11.9% from Q1 2023**

WA quarterly gas production by facility – Q1 2021 to Q2 2023



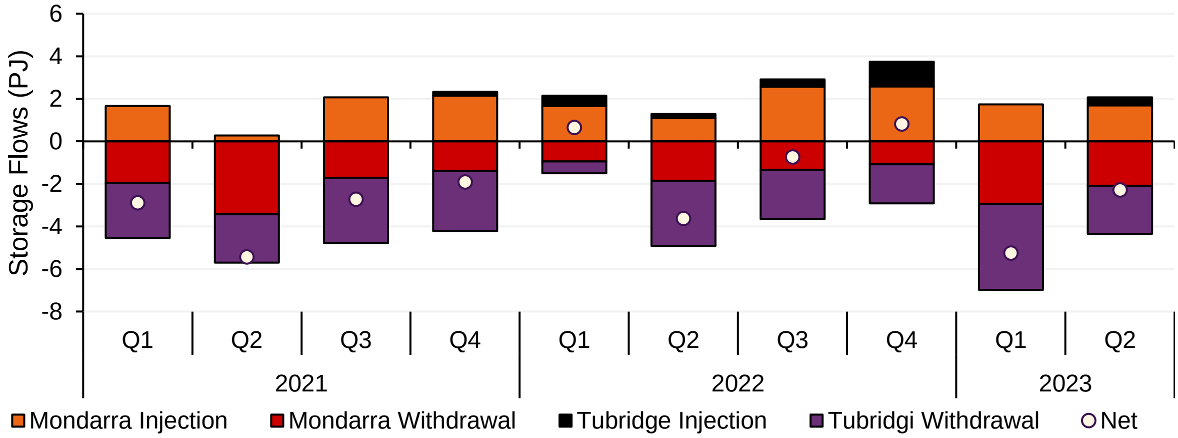

[30] See the WA 2022 *Gas Statement of Opportunities* for more detail: https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/wa_gsoo/2022/2022-wa-gas-statement-of-opportunities.pdf?la=en.

### 2.7.3 Storage Facility behaviour

There was relative stabilisation of storage flows in Q2 2023, with net withdrawal from storage of 2.3 PJ, which is a 3 PJ (57%) reduction compared to Q1 2023 (Figure 87). In Q1 2023, withdrawals were particularly high due to gas production outages early in the quarter resulting in increased utilisation of gas in storage[31].

**Figure 87 Storage flows in Q2 2023 stabilised with a 57% reduction in withdrawals compared to Q1 2023**

WA gas storage facility injections and withdrawals – Q1 2021 to Q2 2023




### 2.7.4 Northern Goldfields Interconnect Pipeline

In Q2 2023, the Northern Goldfields Interconnect Pipeline (NGIP) registered on the GBB (WA). This is the first new pipeline to be registered on the GBB (WA) since the Wheatstone Ashburton Pipeline in 2018. The pipeline connects the Dampier to Bunbury Natural Gas Pipeline at an intersection near Geraldton, and to the Goldfields Gas Pipeline south of Leinster. It has a nameplate capacity of 76 terajoules (TJ)/day and is intended to bring gas from production facilities in the Mid-West to the Northern Goldfields region.

[31] See the QED Q1 2023 for more detail: https://aemo.com.au/-/media/files/major-publications/qed/2023/qed-q1-2023-report.pdf?la=en.

# 3 WEM market dynamics

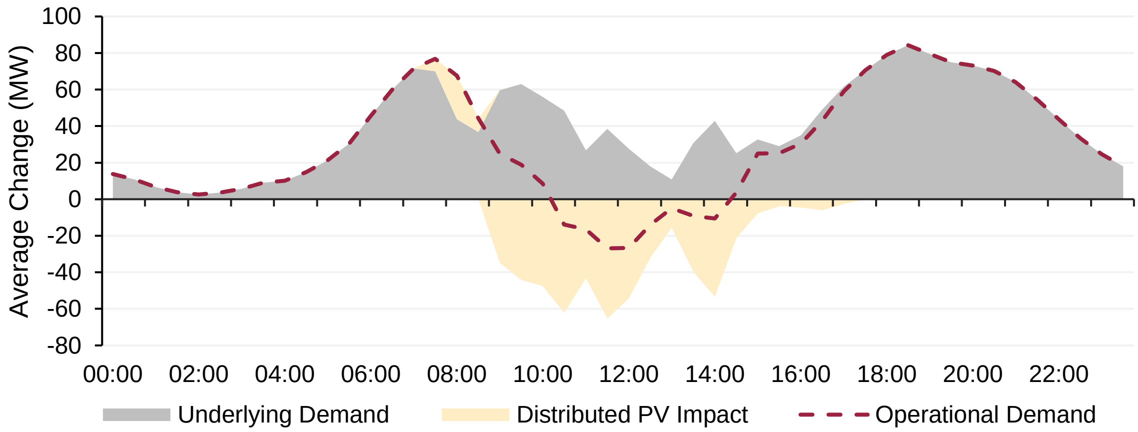
## 3.1 Electricity demand

WEM quarterly average underlying demand[32] was 2,250 MW, an increase of 39 MW (+1.8%) compared to Q2 2022 and a record Q2 high. Figure 88 illustrates that while average underlying demand increased in every interval, the increase in the quarterly average was predominantly driven by increases in the morning and evening peaks. The overall increase can be attributed to lower temperatures and associated increases in heating-related demand; compared to Q2 2022 the average temperature and average maximum temperature in the Perth metropolitan region were 1.5°C and 1.6°C cooler, respectively.

WEM quarterly average operational demand[33] was 2,028 MW, an increase of 29 MW (+1.4%) compared to Q2 2022. This increase was driven by the increase in average underlying demand but was offset by a 10 MW (+4.9%) increase in average estimated distributed PV generation[34].

**Figure 88 Operational demand increase driven by lower temperatures offset by increased distributed PV generation**

Change in average WEM demand components by time of day – Q2 2022 vs Q2 2023




### 3.1.1 Operational demand volatility

In Q2 2023, distributed PV installed capacity[35] in the South-West Interconnected System (SWIS) was 2,484 MW, an increase of 310 MW (+14%) compared to Q2 2022. Additionally, during the shoulder seasons, high solar irradiance and cool temperatures increase peak distributed PV generation. These circumstances can cause periods of high distributed PV penetration and correspondingly lower troughs of operational demand in the middle

[32] 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.

[33] 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.

[34] 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.

[35] Estimates are based on Clean Energy Regulator small-scale solar data installations and solar-irradiance sensors in the SWIS: https://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

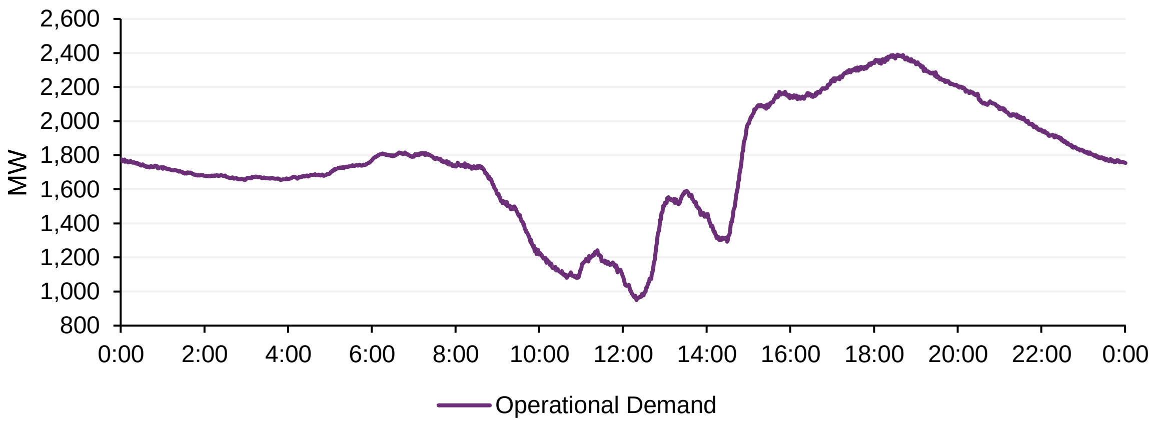
of the day. This, in combination with this quarter's high underlying demand, led Q2 2023 to achieve both the Q2 record high (3,652 MW in the 1800 hrs interval on 26 June 2023) and Q2 record low (904 MW in the 1200 hrs interval on 23 April 2023) operational demand.

In addition to this general increase in the variability of operational demand, the SWIS has experienced increasingly frequent acute operational demand volatility, with intermittent cloud coverage over the Perth Metropolitan Area causing large demand swings.

Figure 89 shows the profile of the most significant example of this during Q2 2023. On 10 April 2023, intermittent cloud coverage caused two significant ramps in operational demand. During the first ramp operational load increased by 157 MW (13%) in 5 minutes (1245 hrs to 1250 hrs). Approximately two hours later, during the second ramp, operational load increased by 690 MW (53%) in 30 minutes (1429 to 1459 hrs). These rapid changes in operational demand create challenging operational conditions where multiple generators must respond and rapidly modulate their output to maintain power system security.

**Figure 89 An example of intermittent cloud coverage causing operational demand volatility**

Operational demand on 10 April 2023




### 3.1.2 Solar eclipse – 20 April 2023

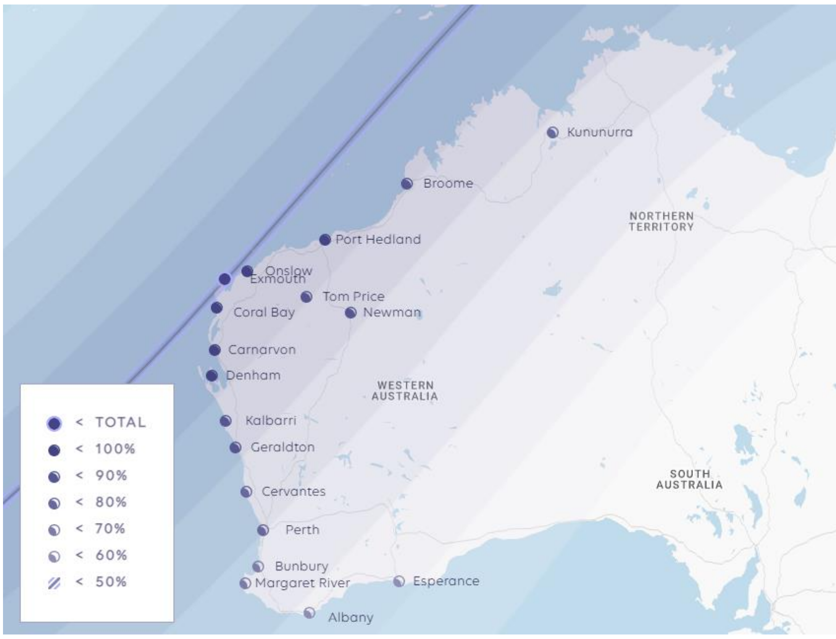
At approximately 1120 hrs on 20 April 2023, Exmouth experienced total darkness for 62 seconds as the moon's shadow crossed the Exmouth Peninsula in a total solar eclipse (see Figure 90). During this event the greater Perth area witnessed a range of 60-80% of this total solar eclipse, affecting the amount of distributed PV output in the SWIS. The moon's transit across the sun spanned almost three hours, starting at 1005 hrs (in Perth metro), peaking at around 1120 hrs and concluding at 1245 hrs.

This resulted in an upward swing of 684 MW followed by a downward swing of 974 MW of operational demand over the period (0).

Planning for the event required AEMO to source a reliable model of the expected impact to distributed PV from the eclipse traversing the state. This planning was crucial to prepare the real-time operations team and provide the market with an accurate indication of how load would behave during the event. On the day, actual demand tracked very close to the forecast, which resulted in the power system encountering no issues in managing the large swings in demand.

**Figure 90 Exmouth experienced a total solar eclipse for 62 seconds**

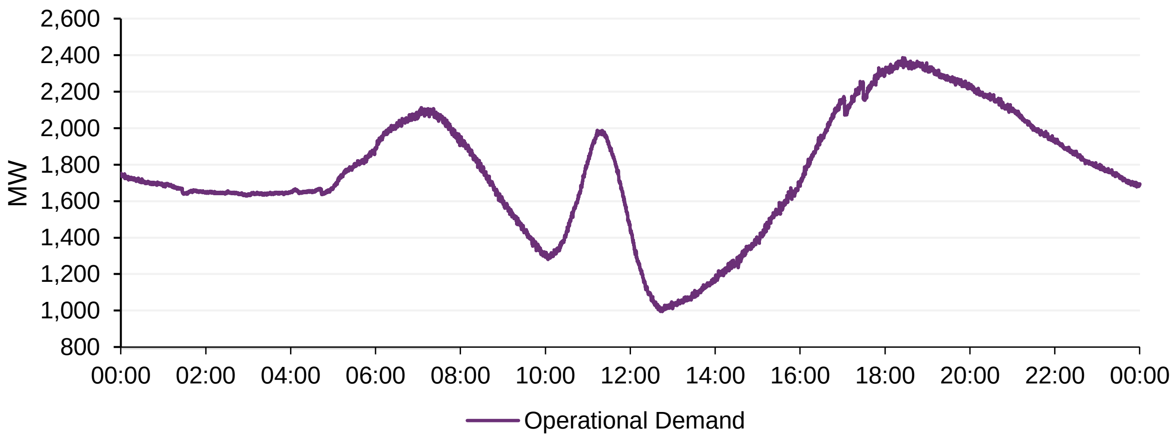
Western Australia solar eclipse path on 20 April 2023




Source: https://ningalooeclipse.com/.

**Figure 91 The SWIS experienced large upwards and downwards swings in operational demand during the eclipse**

Impact of the eclipse on SWIS demand



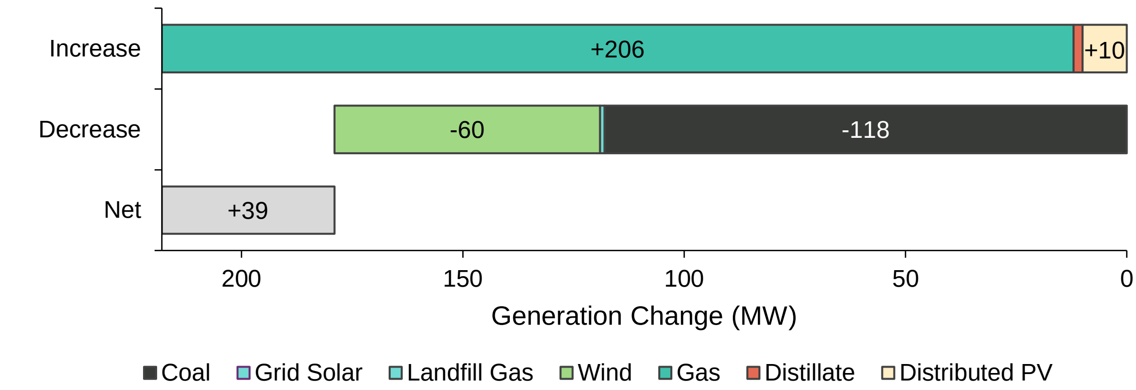

## 3.2 Electricity generation

### 3.2.1 Change in fuel mix

The total average generation output in the WEM over Q2 2023 was 39 MW higher than Q2 2022, driven by the overall increase in underlying demand (see Section 3.1). A moderate decrease in coal-fired and wind generation was compensated for by a large increase in gas-fired generation (Figure 92).

**Figure 92 Gas-fired generation compensates for a moderate decrease in coal-fired and wind generation**

Change in quarterly average generation – Q2 2022 vs Q2 2023




Changes in generation by fuel type and time of day, compared to Q2 2022 (Figure 93 and Table 6) were:

- Average coal-fired generation reached a record Q2 low of 712 MW, a decrease of 118 MW (-14%) on Q2 2022, largely due to outages of coal-fired generation facilities.
- Wind generation decreased by an average of 60 MW (-16%), falling in every interval but most notably during the morning and evening peak periods (Figure 93). This decrease can be attributed to sustained low wind availability.
- Estimated distributed PV continued its growth trend, increasing by 10 MW (+5%) on average.
- Gas-fired generation increased by an average of 206 MW (+27%). This significant increase was a consequence of gas-fired generation both compensating for lower coal-fired and wind-based generation and capturing most of this quarter's increased average underlying demand. In doing so, average gas-fired generation reached a Q2 record high.
- Q2 2023 saw high quarterly distillate-fired generation, with an average of 2.9 MW, up 122% from Q2 2022. Due to unexpectedly high demand coinciding with several planned and forced outages, distillate-fired generation was required on multiple occasions to maintain power system security and reliability, resulting in the highest output from distillate generation since Q1 2008 (4,219 MWh). While average output was small in absolute terms, distillate is disproportionately expensive in both the measures of $/MWh and emissions.

**Figure 93 Gas-fired generation increase in all intervals offset by decreased coal-fired and wind generation**

Average WEM change in fuel mix by time of day – Q2 2023 vs Q2 2022

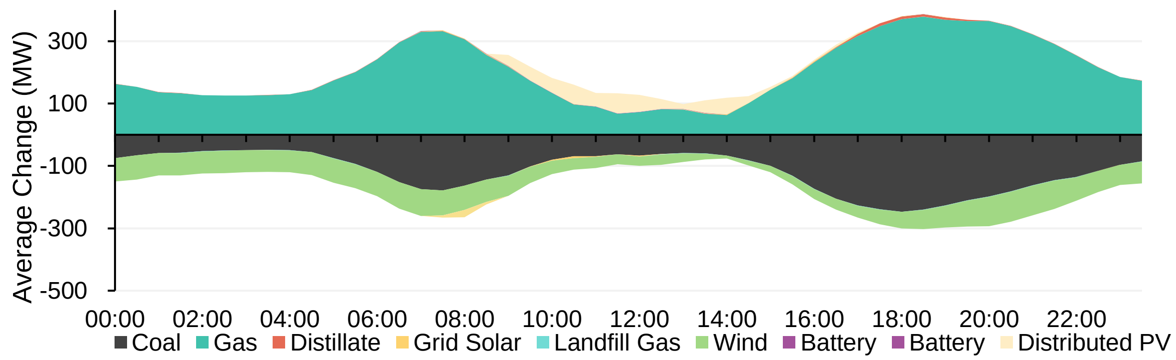


**Table 6 WEM fuel mix Q2 2022 and Q2 2023**

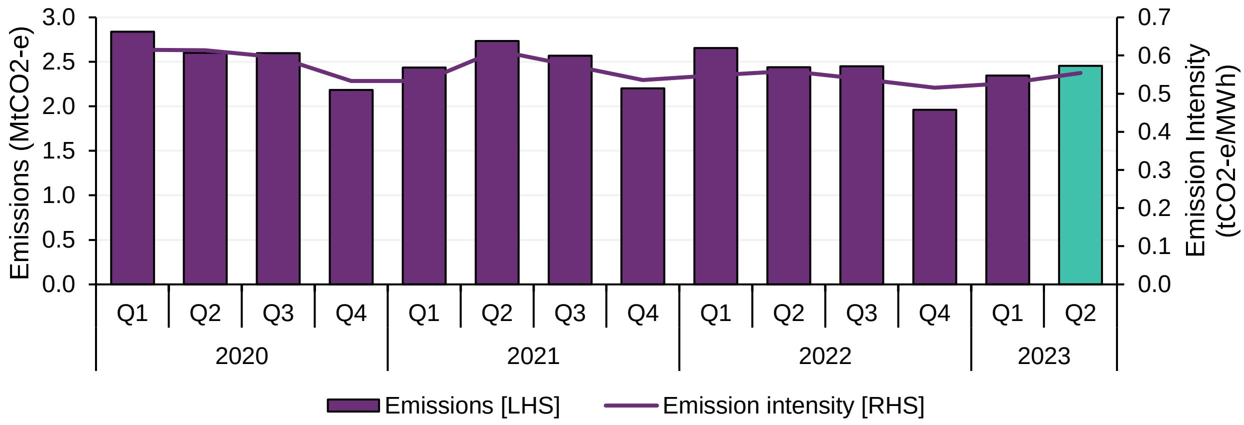
| Quarter | Coal | Gas | Distillate | Grid solar | Landfill gas | Wind | Distributed PV |
|---|---|---|---|---|---|---|---|
| Q2 2022 | 37.6% | 34.2% | 0.1% | 1.4% | 0.5% | 16.7% | 9.6% |
| Q2 2023 | 31.7% | 42.8% | 0.1% | 1.4% | 0.5% | 13.7% | 9.9% |
| Change (pp) | -5.9% | 8.6% | 0.1% | 0.0% | 0.0% | -3.0% | 0.3% |

### 3.2.2 Carbon emissions

WEM emissions increased from 2.44 MtCO2-e in Q2 2022 to 2.46 MtCO2-e in Q2 2023. This represents a 1.4% increase compared to the same quarter last year (Figure 94Figure 94). WEM emission intensity[36], however, decreased from 0.56 tCO2-e/MWh in Q2 2022 to 0.55 tCO2-e/MWh in Q2 2023, representing a small reduction of less than 1%. The reduction in emission intensity in Q2 2023 is due to a 14% decrease in coal usage, which has a high emission intensity. The increase in absolute emissions is primarily a result of the increase in operational demand of 1.4% compared to Q2 2022.

**Figure 94 Emissions in the WEM increased by 1.4% compared to Q2 2022**

Quarterly WEM emissions and emission intensity – Q1 2020 to Q2 2023




### 3.2.3 Renewable penetration

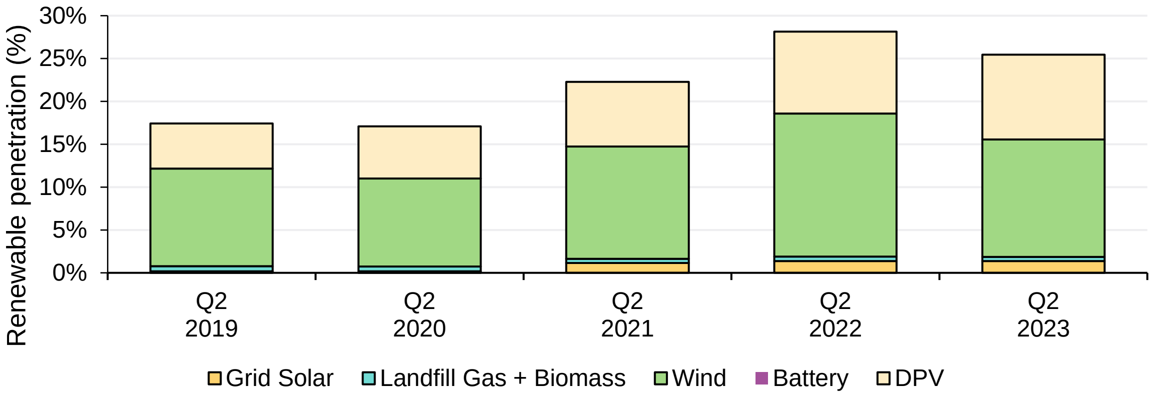
The quarterly average renewable penetration in Q2 2023 was 25.4%, down from 28.1% in the same quarter last year (Figure 95), almost solely driven by a decrease in wind output of close to 3 pp relative to Q2 2022. Distributed PV average penetration only marginally grew, despite approximately 310 MW of additional capacity being installed between the end of Q2 2022 and end of Q2 2023.

The highest instantaneous renewable penetration in Q2 2023 was 72.5%, which was recorded at 1230 hrs on Friday 14 April 2023. Maximum distributed PV output was almost 60% on Sunday 23 April 2023 at 1200 hrs.

[36] Emission intensity combines sent out facilities SCADA data with publicly available generators emission factors.

**Figure 95 Average renewable penetration reduced by 2.7 percentage points in Q2 2023**

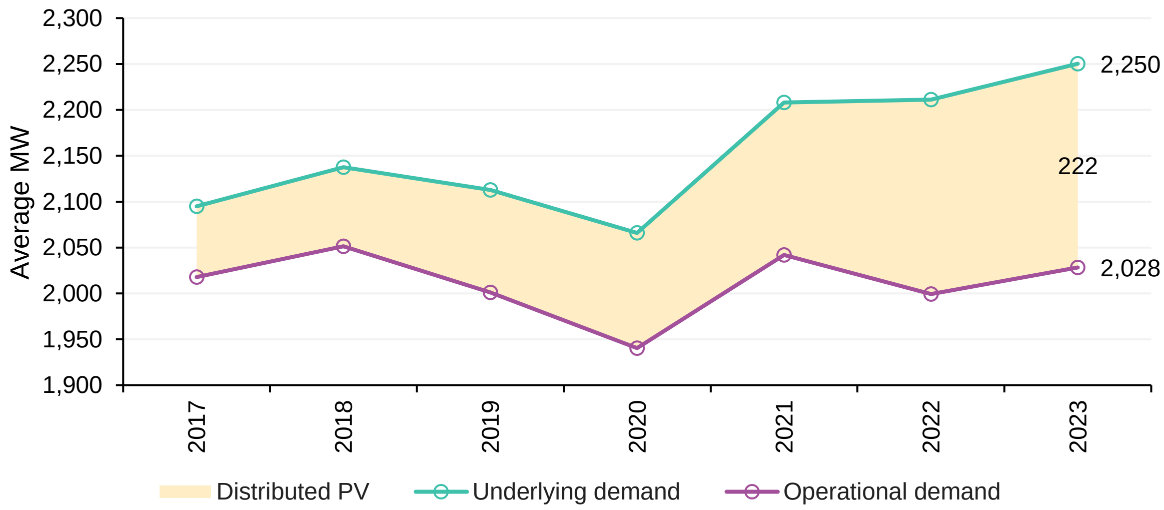
Renewable penetration components – Q2s




Despite the distributed PV average penetration only marginally increasing, Q2 2023 set a record average output of 222 MW distributed PV, up 5% from Q2 2022 (Figure 96).

**Figure 96 Q2 record average output of distributed PV in Q2 2023**

WEM average operational and underlying demand – Q2




## 3.2.4 Tight operating conditions – June 2023

Operating conditions in June 2023 were particularly tight, with AEMO forecasting Lack of Reserve (LOR) 1 conditions on 23 days and LOR 2 days on five days over the month[37]. This was due to forced outages of scheduled generators and low wind conditions which resulted in only 66% of total installed generation capacity being available[38] for dispatch, and higher than average demand for the period due to very cold conditions (see Section 3.1) This was more notable over 6-8 June 2023 (Figure 97).

To manage the power system over this period a number of real-time actions were required to be taken, resulting in no actual LOR 2 conditions over the month:

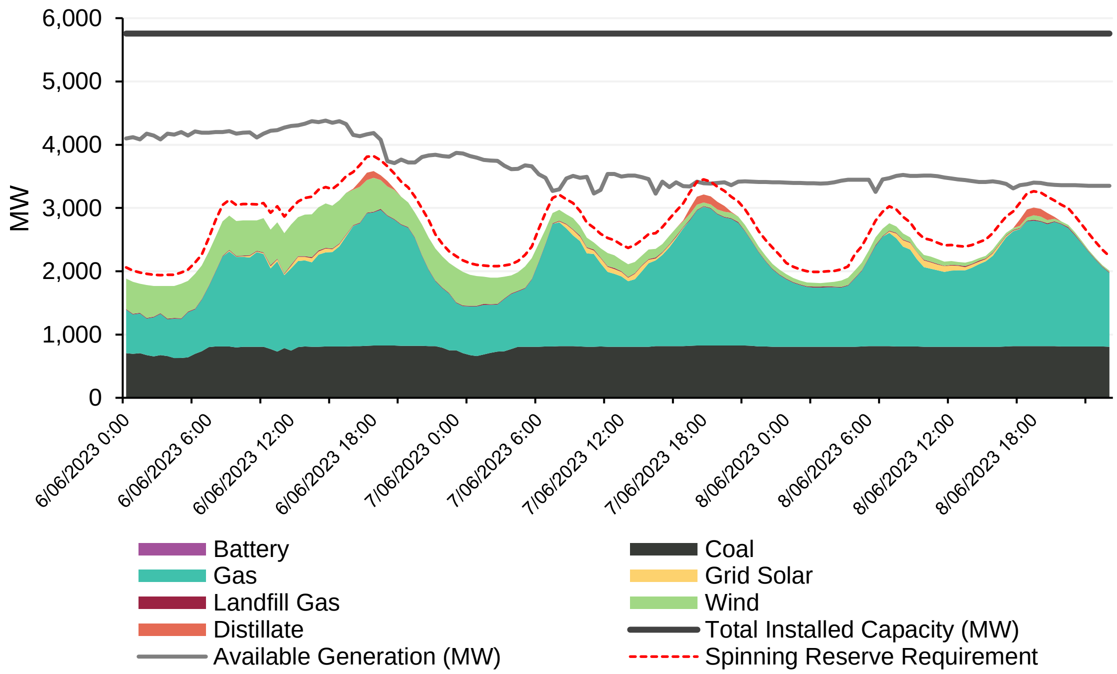
[37] See https://www.aemo.com.au/-/media/files/learn/fact-sheets/lack-of-reserve-dispatch-advisories.pdf?la=en.

[38] Available Generation (MW) = Total Scheduled Generation – Scheduled Generation Outages + Wind Generation + Grid-Scale Solar Generation – Network Constraints.

- Dispatch of all generation in the merit order, including diesel generation facilities on six occasions during evening peak periods.
- Dispatch of contracted Demand Side Programme (DSP) facilities on five occasions, which is the first time a DSP has been dispatched in June.
- Activation of voluntary load reduction from large consumers.

**Figure 97 Particularly tight operating conditions over 6-8 June 2023**

Fuel mix and availability over 6-8 June 2023




## 3.3 WEM prices

This quarter's weighted average Balancing Price[39] was $113/MWh, the highest quarterly average of all time (Figure 98). This was a $46/MWh (+67%) increase from Q2 2022. Contributors to the price change included:

- A reduction in the quantity of energy made available in the Balancing Market in all intervals (Section 3.3.1) and consequent changes to the facilities setting the Balancing Price compared to previous quarters (Section 3.3.2).
- Changes in the fuel mix, in particular an increase in gas-fired generation (Section 3.2.1).

The weighted average Short-Term Electricity Market (STEM) price[40] for Q2 2023 was $101/MWh, a $44/MWh (+76%) increase compared to Q2 2022 and a Q2 record high. This can be linked to the record high Balancing Prices and consequent changes in participant bidding behaviour in the STEM.

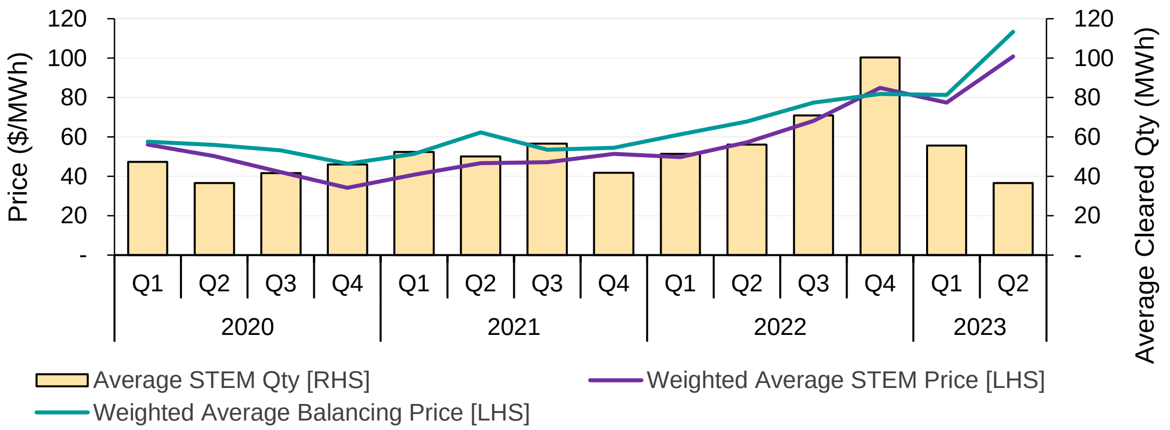
[39] The weighted average Balancing Price is a measure of the average Balancing Price that puts greater weighting on intervals where greater quantity is generated. This is to reflect the average Balancing Price more accurately against quantity of electricity generated, rather than against intervals.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

[40] 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.

The quarterly average quantity of energy cleared in the STEM reduced to 37 MWh, down 35% from Q2 2023. This value resides at the low end of the historically normal range. Market Participant behaviour indicates that the STEM is used as a hedging mechanism against Balancing Price volatility. The decrease in the quarterly average STEM quantity can therefore be attributed to the decrease in Balancing Price volatility since Q2 2022.

**Figure 98 The weighted average balancing price reached a record high while average STEM quantity continued to decrease**

WEM weighted average Balancing Price, STEM Price and quantity cleared in STEM – Q1 2020 to Q2 2023



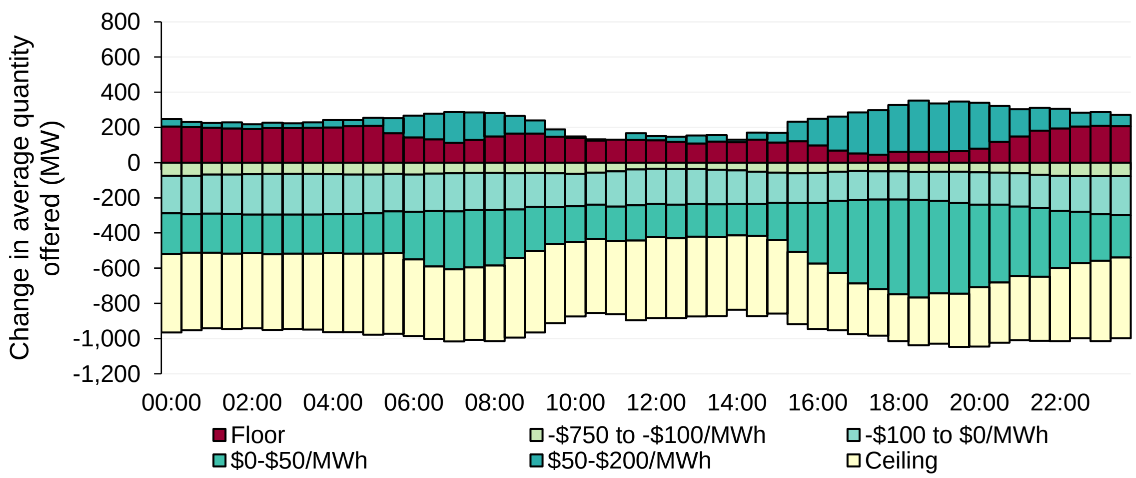

### 3.3.1 Balancing merit order dynamics

Lower quantities were offered for trade in the Balancing Market in Q2 2023 compared to Q2 2022, on average, in every interval. This was primarily the result of decreases in the quantity of bids made at the Ceiling (-407 MW or -23%) and in the $0 to $50/MWh price band (-293 MW or -78%). Conversely, there was a 101 MW (+10%) increase in the quantity of bids in the $50 to $200/MWh price band; as can be seen in Figure 99, the changes to activity in this price band were concentrated in the intervals of the morning and evening peaks.

These changes in Balancing Merit Order dynamics, and in particular the changes to the $50-$200/MWh price band, were one the main drivers of the increase in the quarterly average Balancing Price (Section 3.2.4).

**Figure 99 Net reduction in quantities offered in the Balancing Market**

Change in average Balancing Merit Order structure by time of day – Q2 2022 versus Q2 2023



### 3.3.2 Price-setting dynamics

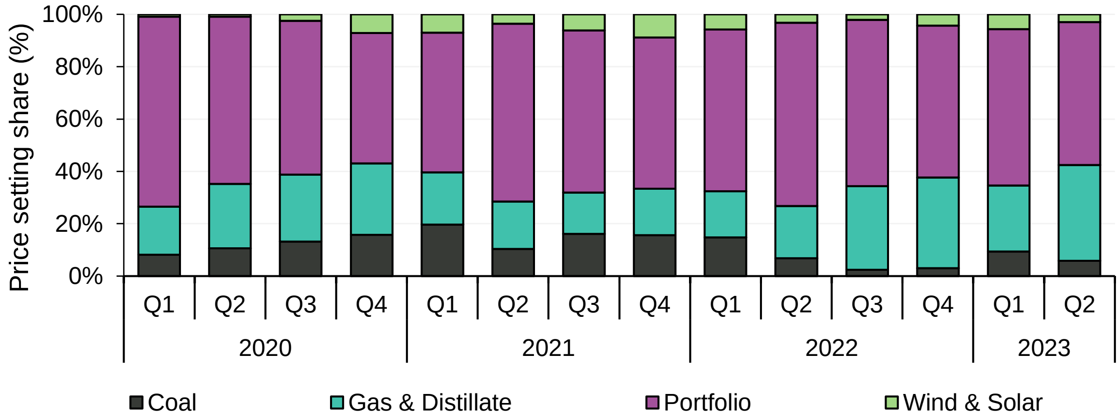
The key changes in price-setting dynamics in Q2 2023 were (Figure 100):

- The Synergy Balancing Portfolio[41] set the balancing price 55% of the time, down from 70% in Q2 2022.
- Independent coal-fired generation facilities set the price less frequently (6% of the time, down from 7% in Q2 2022), with independent gas-fired generation setting the price 37% of the time, up from 20% in Q2 2022. This change is consistent with the change in fuel mix (Section 3.2.1).
- Wind and grid solar facilities set the price 3% of the time, unchanged from Q2 2022.

The increase in gas-fired generation price-setting put upwards pressure on the balancing price.

**Figure 100 The Balancing Portfolio ceded a large minority of its price-setting predominance to gas-fired generation**

Price-setting by the Balancing Portfolio and fuel-type of non-Balancing Portfolio Facilities – Q1 2020 to Q2 2023




## 3.4 Power System Management

The total cost of power system management in Q2 2023, including ancillary services and constrained compensation, was $17.6 million, an increase of $0.36 million (+2.1%) compared to Q2 2022. The small increase in cost masks large changes in underlying cost contributors, with a large increase in constraint payments offset by a reduction in Load Following Ancillary Services (LFAS) of similar size (Figure 101).

- LFAS costs for Q2 2023 were $6.5 million and accounted for 37% of all ancillary services costs during the quarter. LFAS costs decreased by $4.2 million (-39%) compared to Q2 2022 (see Section 3.4.1).
- Estimated constrained compensation increased by $4.8 million (+773%) compared to Q2 2022 (see Section 3.4.2).
- Estimated spinning reserve costs for Q2 2023 were $3.5 million, a 12% increase compared to Q2 2022. This is due to an increase in the settlement parameters for Synergy spinning reserve compensation which are set annually by the Economic Regulation Authority (ERA)[42]. This is primarily due to an increase in the total

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

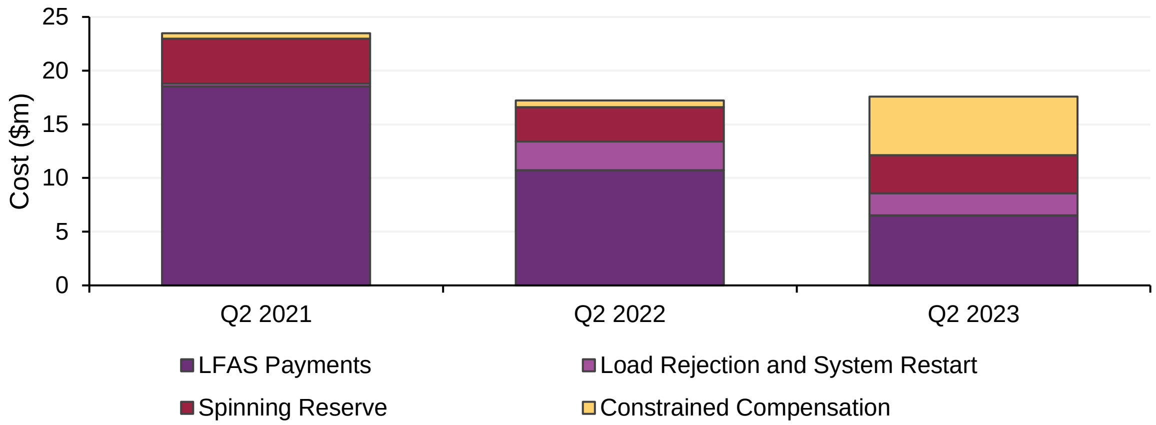
[42] ERA determination on spinning reserve compensation, section 3.1: https://www.erawa.com.au/cproot/22556/2/-MVCLR.202223---Approval-of-Margin-Values-Cost_LR-202223-Final-determination_Clean-version.PDF.

Spinning Reserve Ancillary Services requirement in FY23 in the ERA's Margin Values determination and the increase in the Balancing Price during this quarter.

- Estimated load rejection and system restart costs decreased by $0.6 million (-23%) compared to Q2 2022, in line with a decrease to the COST_LR parameter set annually by the ERA for the 2022-23 financial year.

**Figure 101 Sharp increase in constrained compensation offset by lower LFAS costs**

Cost of power system management in $millions, Q2s




### 3.4.1 LFAS market

In Q2 2023, the average price of LFAS Up was $9.1/MW, a decrease of 27% on Q2 2022, and the average price of LFAS Down was $6.5/MW, a decrease of 59% on Q2 2022 (Figure 102). This translated into an overall reduction in LFAS costs of $4.2 million. This can be linked to the increased gas-fired generation in fuel mix, enabling LFAS capable gas facilities to offer lower prices in the LFAS market.

Trading behaviour in the LFAS market showed 50% of bids came in the $0 - $5/MW range and only 14% in the over $20/MW range. This compares to 32% and 30% for the same ranges, respectively, in Q2 2022 (Figure 103) despite an overall reduction in quantity offered in the LFAS markets.

**Figure 102 Total LFAS cost was down $4.2m in Q2 2023 from Q2 2022**

LFAS prices and costs Q1 2020 to Q2 2023

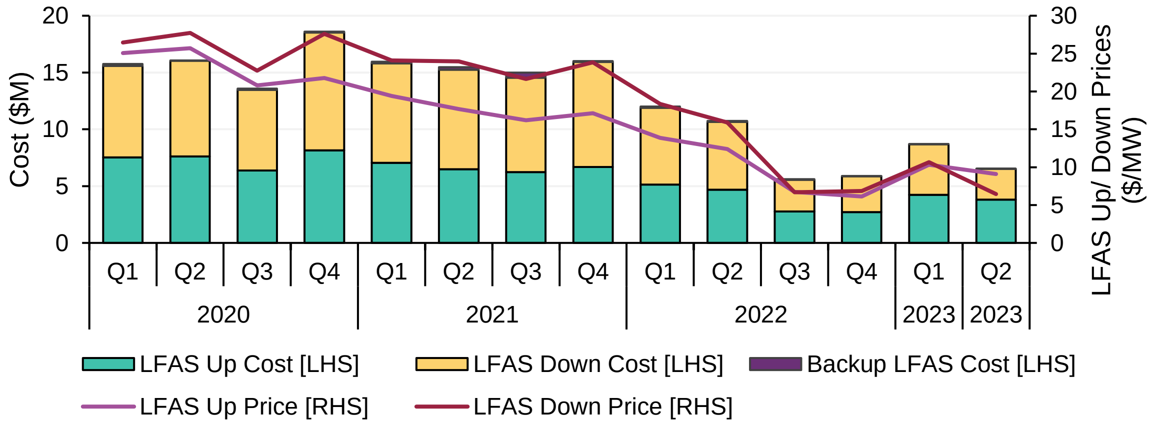
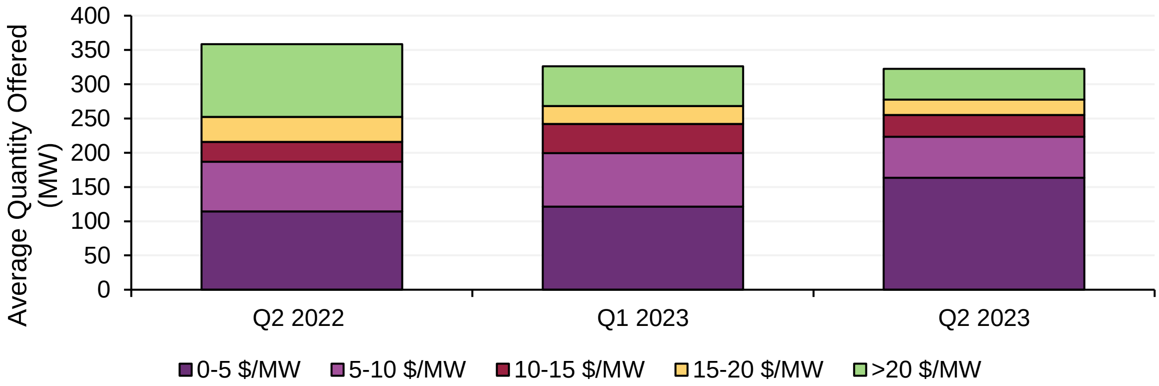


**Figure 103 50% of LFAS bids were in the $0-$5/MW band**

LFAS average offered quantities by price band




### 3.4.2 Constraint quantities

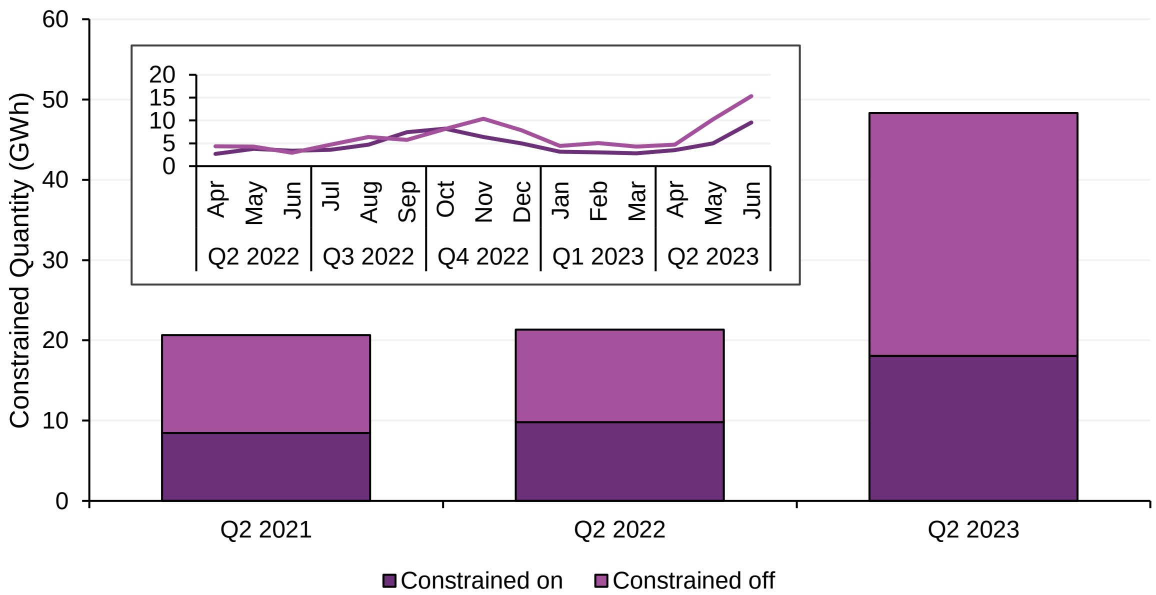
As noted in Section 3.1, in Q2 2023 the WEM experienced tight supply conditions that required periods of out-of-merit dispatch to maintain power system security and reliability. To maintain the required ancillary service on the power system, AEMO primarily constrains the Synergy portfolio to a maximum output, therefore dispatching higher priced facilities to provide the generation deficit.

Driving the $4.8 million increase (from Q2 2022) of estimated constrained compensation was an increase of 27 GWh in constrained on and off quantities (+134%). In particular, June saw a total 25 GWh of constrained quantities, an increase of 17 GWh (+296%) compared to June 2022, representing more than half of the quarterly constrained quantities (see Figure 104, inset).

This also resulted in the average constrained compensation prices also increasing from $29/MWh in Q2 2022 to $113/MWh in Q2 2023, further contributing to the increase in constrained compensation payments.

**Figure 104 Constrained on and off quantities in Q2 2023 jumped 134% from Q2 2022**

Constrained quantities dispatched in GWh – Q2 2021 to Q2 2023, inset: monthly constrained dispatch quantities in GWh



# 4 Reforms delivered

AEMO, with 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 the various electricity and gas market reforms delivered across the NEM, east coast gas system and facilitated markets over the last quarter.

**Table 7 Reforms delivered Q2 2023**

| Reform initiative | Description | Reform delivered |
|---|---|---|
| **Integrating Energy Storage System (First Release)** | Aggregators of small generating and storage units can now provide ancillary services (if they choose to do so).<br>Reference: https://aemo.com.au/en/initiatives/major-programs/integrating-energy-storage-systems-project | March 2023 |
| **Business to Business (B2B) v3.8** | Updates to AEMO's existing retail processes (for example, Business to Business (B2B) v3.8), to deliver efficiencies for electricity retailers when interacting with customers and each other. One change makes it possible for retailers and their metering service providers to better access and share information they need to communicate with consumers with shared fuses.<br>Reference: https://aemo.com.au/consultations/current-and-closed-consultations/b2b-procedures-v38 | May 2023 |
| **Stand-Alone Power Systems** | Established market processes and enabling systems allowing it to assist Stand-Alone Power Systems (SAPS) with all the NEM processes related to settling market transactions.<br>Reference: https://aemo.com.au/en/consultations/current-and-closed-consultations/standalone-power-systems | May 2023 |
| **Consumer Data Right** | Implementation of Tranche 2 of the Consumer Data Right (CDR) allowing integration with initial retailers (AGL, Energy Australia, and Origin Energy, and others who opt-in) for complex requests.<br>Reference: https://aemo.com.au/en/initiatives/major-programs/cdr-at-aemo | May 2023 |
| **Gas Transparency Measures** | Increasing the information available on the GBB and increasing the powers of the *Gas Statement of Opportunities* (GSOO). New information published on the GBB includes:<br>• Summarised off-market gas transactions (including LNG export transactions).<br>• Gas field reserves and resources.<br>• Gas facility developments.<br>Reference: https://aemo.com.au/en/consultations/current-and-closed-consultations/gas-transparency-measures | March 2023 |
| **DWGM interim LNG storage measures** | Aimed as an interim measure for AEMO to contract with the Dandenong LNG facility in response to concerns of system security in the DWGM.<br>Reference: https://aemo.com.au/en/consultations/current-and-closed-consultations/implementation-of-dwgm-interim-lng-storage-measure-rule-change | March 2023 |
| **East Coast Gas System (Stage 1)** | Expansion of AEMO's role to monitor, signal and respond to potential or actual threats to the reliability and adequacy of gas supply in the east coast gas system. Stage 1 focuses on those elements required to enable AEMO to monitor and communicate emerging threats to the reliability and/or adequacy of supply and to respond to any such threats by winter 2023<br>Reference: https://aemo.com.au/initiatives/major-programs/east-coast-gas-reforms | June 2023 |

# List of tables and figures

## Tables



## Figures

# Abbreviations

| Abbreviation | Expanded term |
|---|---|
| ACCC | Australian Competition and Consumer Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| AMSP | Alternative Maximum STEM Price |
| APLNG | Australia Pacific LNG |
| ASEFS2 | Australian Solar Energy Forecasting System |
| ASX | Australian Securities Exchange |
| BESS | Battery energy storage system |
| BMO | Balancing Merit Order |
| CGP | Carpentaria Gas Pipeline |
| COVID-19 | Coronavirus disease |
| CPL | Cents per litre |
| CPT | Cumulative price threshold |
| DAA | Day Ahead Auction |
| DWGM | Declared Wholesale Gas Market |
| EOI | End of interval |
| EGP | Eastern Gas Pipeline |
| FCAS | Frequency control ancillary services |
| GJ | Gigajoule |
| GWh | Gigawatt hours |
| GLNG | Gladstone LNG |
| GSH | Gas Supply Hub |
| IRSR | Inter-regional settlement residue |
| LNG | Liquefied natural gas |
| LOR | Lack of Reserve |
| IPP | Independent Power Producer |
| MNSP | Market Network Service Provider |
| MP | Market Participant |
| MPC | Market price cap |
| MSP | Moomba to Sydney Pipeline |
| $MtCO_2$-e | Million tonnes of carbon dioxide equivalents |
| MW | Megawatts |
| MWh | Megawatt hours |
| NEM | National Electricity Market |
| NEMDE | NEM Dispatch Engine |
| NER | National Electricity Rules |
| NGP | Northern Gas Pipeline |
| pp | Percentage points |
| PJ | Petajoule |

| Abbreviation | Expanded term |
|---|---|
| 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 |
| 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 |
| 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 |