Quarterly Energy Dynamics Q1 2023

April 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 Q1 2023 (1 January to 31 March 2023). This quarterly report compares results for the quarter against other recent quarters, focusing on Q4 2022 and Q1 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	28/4/2023	

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Executive summary

East coast electricity and gas highlights

Wholesale electricity prices return to historic levels, but price separation between NEM regions remains

- Wholesale spot prices across the National Electricity Market (NEM) averaged $83/megawatt hour (MWh) in Q1 2023, with the average quarterly price varying from $56/MWh in Victoria to $104/MWh in Queensland. Mainland region price differences exhibited the same divide seen in recent quarters, with the northern regions of Queensland and New South Wales having higher average prices than the southern regions of South Australia and Victoria.
- Following the announcement of caps on thermal coal prices, black coal generators in both New South Wales and Queensland have increased offer volumes in lower price bands, decreasing the average price set by black coal generators when they are the marginal price-setter.
- Despite finishing the quarter higher than they started, electricity futures contract prices for the upcoming financial year averaged $107/MWh for all mainland NEM regions across the quarter, significantly lower than recent quarters, following the announcement on coal and gas price caps in December 2022.

Operational demand falls with distributed PV output at Q1 record

- Operational demand across the NEM declined to its lowest Q1 average since Tasmania joined the NEM in May 2005. Growth in distributed photovoltaics (PV) has continued, reaching a new Q1 output record, driving down operational demand, and reflecting resumption of high distributed PV installation growth rates after a slowdown in 2022. Operational demand in the evening lifted slightly, particularly in Queensland and New South Wales which experienced warm February and March conditions and periods of extreme temperatures.
- Several demand records were set this quarter, with Queensland reaching an all-time maximum operational demand record of 10,070 MW at 1730 hrs on 17 March. Conversely, high distributed PV peak output saw the NEM reach its lowest minimum Q1 operational demand since Tasmania joined the NEM at 14,375 megawatts (MW), while Victoria, New South Wales and South Australia all reached their lowest operational demands for any Q1.

Renewable generation increases output, with decreasing coal-fired generation

- Generation from grid-scale solar and wind increased this quarter by an average 330 MW and 134 MW respectively, yielding a record quarterly average of 4,654 MW (11% higher than the same time last year). Increases in grid-scale solar and wind output were predominantly from new and recently commissioned units.
- Gas-fired generation decreased compared to last Q1, reaching its lowest Q1 level since 2005 at 1,113 MW. Brown coal-fired generation in Victoria declined by 293 MW compared to Q1 2022 with decreased availability and lower utilisation. Black coal-fired generation output in New South Wales and Queensland declined 137 MW despite better availability in New South Wales where outages reduced by 353 MW from Q1 2022.

- Instantaneous penetration of renewable energy peaked at 65.8% this quarter, a Q1 record and 4.4 percentage points higher than the previous record for any Q1. Distributed PV accounted for 36% of supply during this interval.

Other NEM highlights

- Similar to previous quarters, constraints affecting the Victoria – New South Wales Interconnector (VNI) continued to bind frequently during the middle part of the day, limiting flows northward and further increasing the gap from higher prices in the northern NEM regions to lower levels in Victoria and South Australia.
- On 17 March, AEMO declared the spot market suspended in New South Wales in response to a SCADA failure[1] between 2015 hrs and 2110 hrs. AEMO concluded that the power system remained in a secure operating state throughout the market suspension, and no generation or load was lost due to the incident.
- AEMO activated the Reliability and Emergency Reserve Trader (RERT) reserves in Queensland on 3 February due to forecast Lack of Reserve (LOR) 2 conditions. Estimated payments for the RERT event totalled $1.5 million.

East Coast gas prices soften in March, demand and production down

- East Coast wholesale gas prices have declined from Q3 2022, and eased further in March to an average quarterly price across all markets of $11.86 per gigajoule (GJ), still above the $9.93/GJ average for the same time last year, and a record average Q1 price.
- Gas demand decreased by 9% this quarter compared to Q1 2022, driven by a large decrease in Queensland liquefied natural gas (LNG) export demand (-33.5 petajoules [PJ]), yielding the lowest Q1 flows to Curtis Island since 2018. Queensland Curtis LNG (QCLNG) started the quarter with an unplanned train outage which commenced on 27 December 2022, with another across February and March. Queensland gas production decreased by a smaller amount (-24.8 PJ), leading to additional supply for the domestic market. Gas-fired generation and domestic market demand was also lower, contributing to the lowest Q1 east coast gas demand since Q1 2016.
- Inventory at the Iona underground gas storage (UGS) facility ended the quarter with the highest end to Q1 balance since reporting began in 2017 and inventory close to its capacity limit.
- Gas Supply Hub (GSH) trading volumes were up compared to Q1 2022, and the total volume traded was a record for Q1. The Day Ahead Auction also set a new quarterly record of 37.9 PJ, surpassing the previous record set in the previous quarter of 30.7 PJ.

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

Western Australia electricity and gas highlights

Record high Q1 weighted Balancing Price and STEM price, STEM traded quantities returning to historically normal level

- The weighted average Balancing Price in the WEM for Q1 2023 was $81/MWh, a Q1-record high and a 33% increase from Q1 2022. Contributors to the price increase include a reduction in facility availability and changes to the fuel mix.
- The weighted average Short-Term Electricity Market (STEM) price for Q1 2023 was $77/MWh, a 56% increase compared to Q1 2022 and a Q1-record high.
- The quarterly average quantity of energy cleared in the STEM has returned to historically normal levels, partly driven by a decreased Balancing Price volatility since Q4 2022.

Q1 operational demand continues to fall as distributed PV output increases and milder temperatures are observed

- In Q1 2023, the WEM's average operational demand was 2,060 MW, a 8% decrease from Q1 2022. Mild temperatures and a 15.8% increase in average distributed PV generation were the main drivers.
- The Q1 2023 maximum operational demand (3,676 MW) was recorded on Thursday, 2 March 2023 across the 1600hrs interval, due to high temperatures and sudden cloud coverage reducing distributed PV output.

Q1 record low generation from coal-fired facilities, offset by an increase in generation from gas-fired facilities

- Average coal-fired generation obtained a record Q1-low of 799 MW, a 23% decrease on the same quarter last year. This was mainly driven by the coal preservation measures during January 2023 which reduced coal-fired generation availability.
- To offset the coal generation decrease, gas-fired generation increased by an average of 102 MW (+16%).

AEMO WA activated Supplementary Reserve Capacity for the first time

- On 30 January 2023, due to forecast LOR 2 conditions, AEMO activated Supplementary Reserve Capacity (SRC) for the first time. There was 67 MW of SRC activated over the evening peak (1700 hrs – 2100 hrs), of which 35 MW was received in additional generation or load reduction.
- The forecast LOR 2 conditions were a result of a high forecast instantaneous system demand (driven by high temperatures), low forecast wind generation and an unexpected trip of a large coal-fired generator.
- The combined response of SRC and Demand Side Programmes (DSP) over the period, a lower than forecast system load and slightly higher wind generation, resulted in the SWIS avoiding entering an LOR 2 by ~108 MW.

Gas consumption for electricity generation increase, and a gas supply disruption event occurred

- A total of 92 PJ was consumed in the WA domestic gas market in Q1 2023, a 4% increase from Q1 2022. Consumption from electricity generation increased by 10%, in line with the changes in fuel mix.
- Q1 2023 saw total WA domestic gas production of 89 PJ, a marginal reduction of 2.9% from Q1 2022.
- A significant gas supply disruption event occurred during the period 6 to 13 January 2023 requiring AEMO to activate the Emergency Management Facility (EMF) to support the industry response to maintain linepack above critical levels. The event was triggered by an unplanned outage at the Wheatstone Facility causing approximately 215 terajoules (TJ)/day gas volume to be removed from the WA gas market (approximately 20% of total production). The response from the industry resulted in the linepack returning back to a healthy status on Sunday, 8 January.

A note on future Quarterly Energy Dynamics reports

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. Future versions of this report will be updated to include:

- Connections – given the important role of new grid connections as part of the broader energy transition, future QED reports will present information on the connection process including the rate of connections and any new connections processed over the quarter.
- Reform delivery – any regulatory changes and reforms that have been introduced over the relevant quarter will be noted, including a high-level description of those changes.

Contents

1 NEM market dynamics

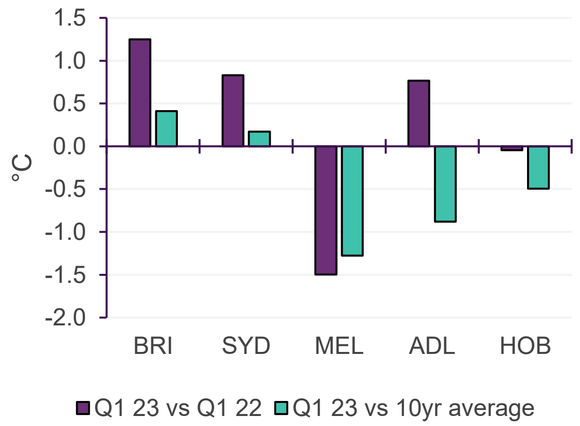
1.1 Electricity demand

1.1.1 Weather

La Niña conditions continued to ease over the quarter, with lower rainfall outside the tropics for much of eastern New South Wales and south-eastern Queensland. The quarter began with subdued maximum temperatures, with the mean January maximum temperature in Queensland the lowest since 2010. Temperatures increased as the quarter progressed, with Sydney experiencing its first day above 35°C since 2021 and both Brisbane and Sydney experiencing warmer than average February and March conditions (Figure 2). Brisbane's mean daily maximum and minimum temperatures were 1.7°C and 1.3°C above their long term averages for March, with temperatures above 35°C on a number of days. Although Melbourne's average maximum temperature was 1.5°C cooler than last quarter, there was a short lived heat wave from 15-17 February, with temperatures exceeding 40°C for the first time since January 2020. Adelaide had a prolonged heat wave in February with temperatures peaking over 40°C, coinciding with the highest South Australian demand since 2020.

Figure 1 Warmer weather in Brisbane and Sydney

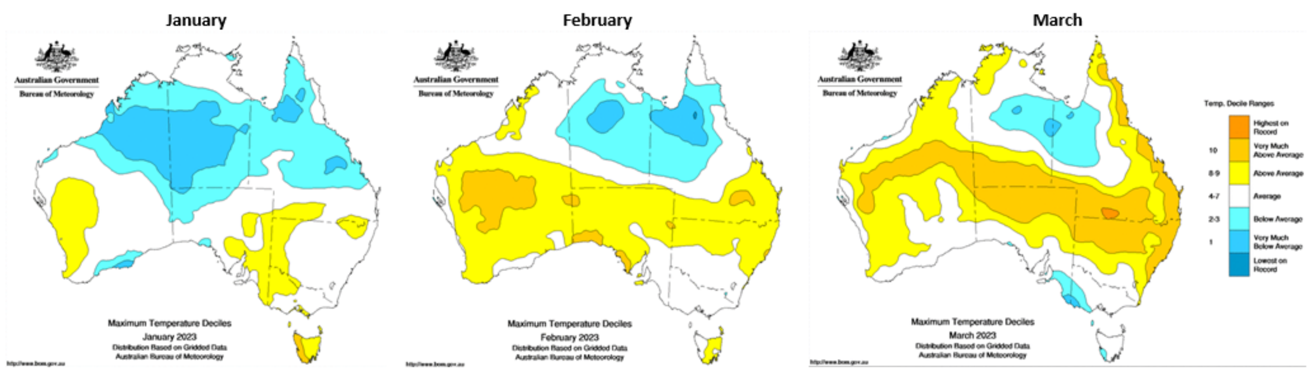
Average maximum temperature variance by capital city



Source: Bureau of Meteorology (BoM)

Figure 2 Maximum temperatures increase across the quarter

Maximum temperature deciles across Australia – January, February and March 2023



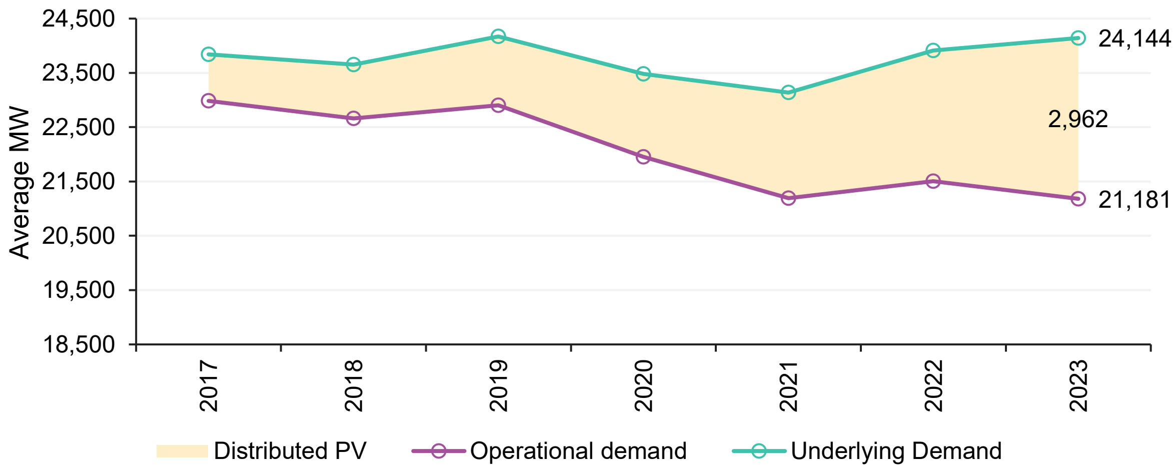
Source: Bureau of Meteorology (BoM)

1.1.2 Demand outcomes

Average quarterly NEM operational demand was 21,181 MW, 1.5% (324 MW) lower than in Q1 2022, and the lowest Q1 NEM average operational demand since Tasmania joined the NEM in May 2005. This fall was driven largely by a record year-on-year increase in distributed PV average output[2] (+556 MW from Q1 2022) to its highest average quarterly output of 2,962 MW (Figure 3). Underlying demand[3] across the NEM increased by 1.0% or 232 MW to average 24,144 MW, its highest Q1 level since 2019.

Figure 3 Distributed PV growth decreases operational demand but underlying demand increases slightly

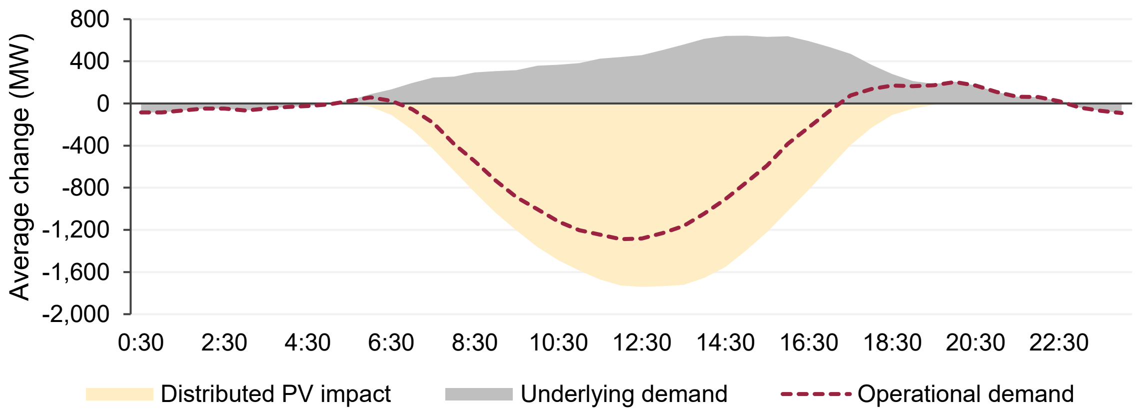
NEM average operational and underlying demand - Q1s



As distributed PV output has continued to increase, it has decreased the operational demand in middle of the day (Figure 4). Underlying demand increased in the daytime and evening peak, particularly in New South Wales and Queensland where both regions experienced warmer temperatures in Q1 2023.

Figure 4 Lower daytime operational demand driven by growth in distributed PV output

Changes in average NEM demand components by time of day – Q1 2023 vs Q1 2022



The strong year-on-year growth of distributed PV output (+23%) for Q1 reflects a return to trend after a slowdown experienced during 2022 (Figure 5), in line with the Clean Energy Regulator's observation[4] that small-scale PV installation rates experienced a strong rebound in Q4 2022.

[2] Increased distributed PV output reduces operational demand because its production lowers supply required from the grid. Distributed PV production is based on AEMO estimates using the Australian Solar Energy Forecasting System (ASEFS2).

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

[4] Clean Energy Regular 2022, Quarterly Carbon Market Report December Quarter 2022: https://www.cleanenergyregulator.gov.au/Infohub/Markets/quarterly-carbon-market-reports/quarterly-carbon-market-report-%E2%80%93-december-quarter-2022.

Figure 5 Growth in distributed PV output returns to trend after slowing in 2022

Year on year percentage change in PV output for like quarters– from Q1 2020

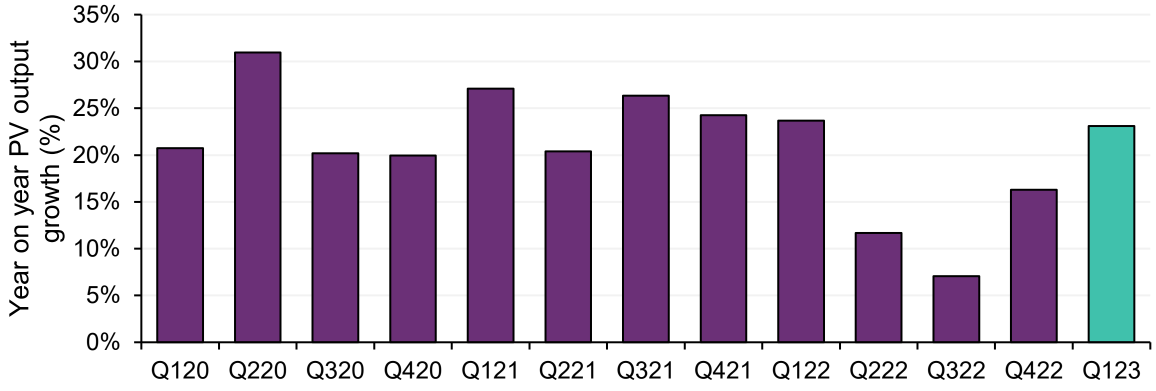
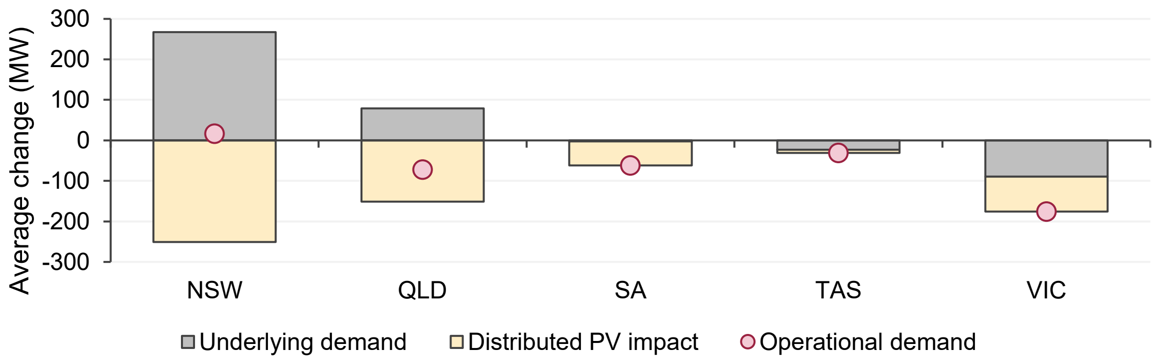


Figure 6 shows the regional breakdown of demand changes. Drivers varied by region:

- In **New South Wales**, underlying demand increased significantly (3.2%) from Q1 2022, and reached its highest level since 2019. Underlying demand growth was particularly pronounced in February and March as those months experienced higher maximum temperatures. This was offset by strong growth in distributed PV output (+36%) leaving operational demand flat.
- **Queensland** also experienced higher underlying demand, which reached a record Q1 level of 7,420 MW, with similar drivers to New South Wales. However this growth was more than offset by increased distributed PV output (+20%) resulting in lower operational demand.
- Other regions (**South Australia**, **Tasmania** and **Victoria**) also saw decreases in average operational demand, driven by increases in distributed PV output combining with underlying demand falls of different magnitudes.

Figure 6 New South Wales underlying demand growth balanced by higher distributed PV output

Changes in average demand components by region – Q1 2023 vs Q1 2022



Maximum demand

Queensland reached an all-time maximum operational demand record of 10,070 MW for the half-hour ending 1730 hrs on Friday 17 March, a small increase on the previous record of 10,058 MW in Q1 2022. Both 16 and 17 March had extreme temperatures, with the Brisbane metropolitan area experiencing maximums above 35°C.

Q1 maximum demands in other NEM regions were all up from the previous two years, but remained well below their all-time highs.

Minimum demand

Driven by increasing levels of distributed PV output, the NEM experienced its lowest Q1 minimum operational demand since Tasmania joined the NEM in May 2005, at 14,375 MW in the half-hour ending 1230 hrs on Saturday 21 January (Figure 7).

Record Q1 minimum demands were also set in the following regions (Figure 8);

- **Victoria** recorded 2,623 MW at the half-hour ending 1300 hrs on the Labour day public holiday, Monday 13 March, some 169 MW below the previous Q1 minimum.
- **New South Wales** reached 4,545 MW (down 97 MW) at 1300 hrs Sunday 8 January.
- **South Australia** reached 117 MW (down 92 MW) at 1330 hrs Sunday 5 February.

Figure 7 Lowest Q1 NEM minimum demand since Tasmania joined NEM in May 2005

NEM Q1 minimum operational demand

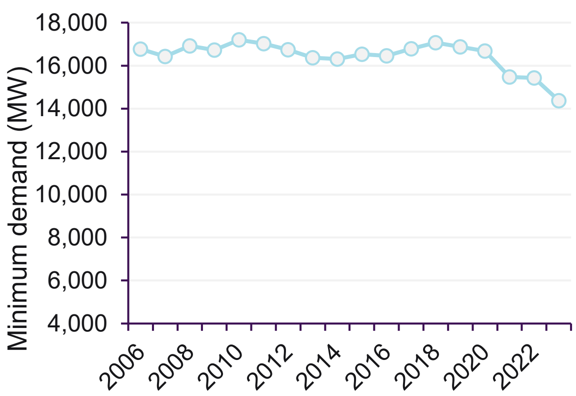
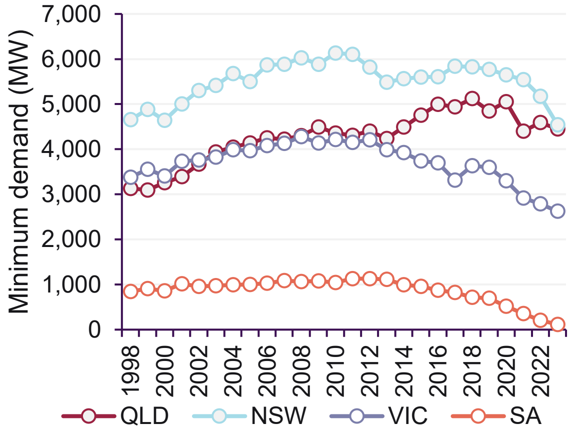


Figure 8 Record Q1 minimum demand in New South Wales, Victoria and South Australia

Q1 minimum operational demands for mainland regions

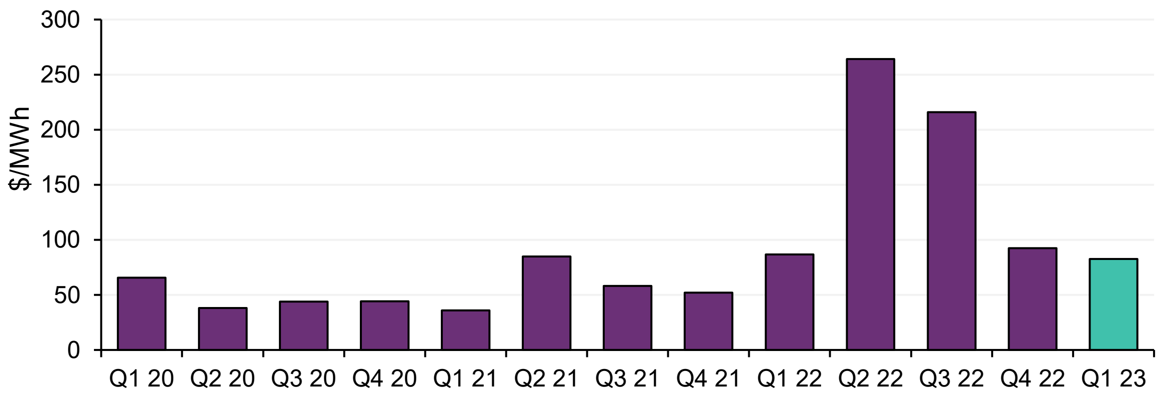


1.2 Wholesale electricity prices

Wholesale spot prices averaged $83/MWh across the five NEM regions in Q1, a decrease of $4/MWh from Q1 2022 (Figure 9). Spot prices have thus returned to levels seen just before the highs observed in Q2 and Q3 2022.

Figure 9 Average NEM spot prices continue to decline

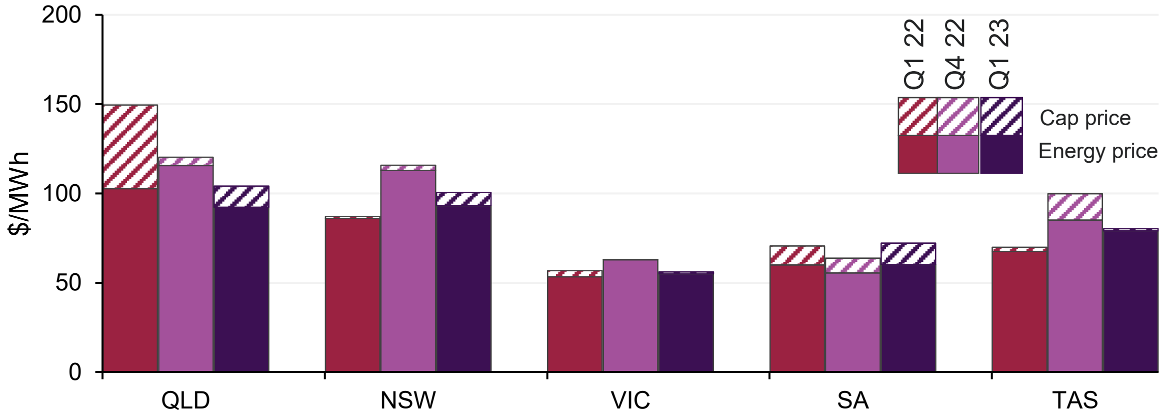
NEM average wholesale electricity price – quarterly since Q1 2020



Regional average prices this quarter ranged from $56/MWh in Victoria to $104/MWh in Queensland (Figure 10). Continuing a trend observed in recent quarters, there is a divide between higher average spot prices in the northern regions of Queensland and New South Wales, and lower prices in southern regions of Victoria and South Australia, with drivers causing this discussed in Section 1.4.

Figure 10 Lower volatility sees Q1 average spot price fall in Queensland, largely stable elsewhere

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



By region:

- **Queensland**'s average quarterly price was $104/MWh, a decrease of $45/MWh from last Q1. This quarter saw much lower spot price volatility than Q1 2022. In Q1 2022, Queensland experienced heat wave conditions and high demand coinciding with reduced thermal generation availability and constraints limiting imports from New South Wales into Queensland, causing spot prices to exceed $9,000/MWh for almost three hours each day. Although Queensland experienced several days of extreme temperature this Q1, and reached a record maximum demand on 17 March, system reserves were in general slightly higher. Spot price volatility in Q1 2023 occurred over much shorter periods than in Q1 2022.
- **New South Wales** had an average price of $101/MWh, increasing $13/MWh from Q1 2022. Unlike Q1 2022 where high price volatility in Queensland did not flow into New South Wales, this quarter saw the two states experience more periods of joint price volatility, lifting the New South Wales average (see Section 1.2.2).
- **Victorian** and **South Australian** prices averaged $56/MWh and $72/MWh respectively, marginally different from the same time last year ($57/MWh and $71/MWh). South Australia's higher average price compared with Victoria reflected isolated episodes of price volatility which did not occur in Victoria. Both southern mainland regions exhibited consistently low and negative prices in the middle of the day (Figure 11), also driving down NEM average daytime prices relative to Q1 2022 (Figure 12). The average price between 1000 and 1400 hrs in Victoria was -$12/MWh for this Q1, compared to $22/MWh in Q1 2022.
- **Tasmania** averaged $80/MWh, up $10/MWh from Q1 2022. A combination of higher priced offers and less generation from Hydro Tasmania (see Section 1.3.3) and more frequent interconnector binding (see Section 1.4) yielded spot prices above those in the southern mainland regions.

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

Figure 11 North-south price gap widens

Average energy prices by region – Q1 2023

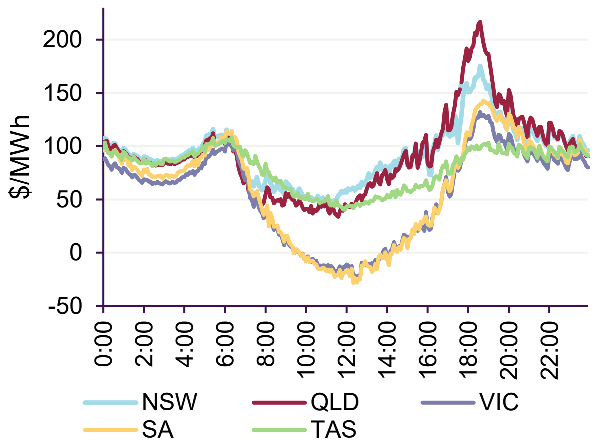
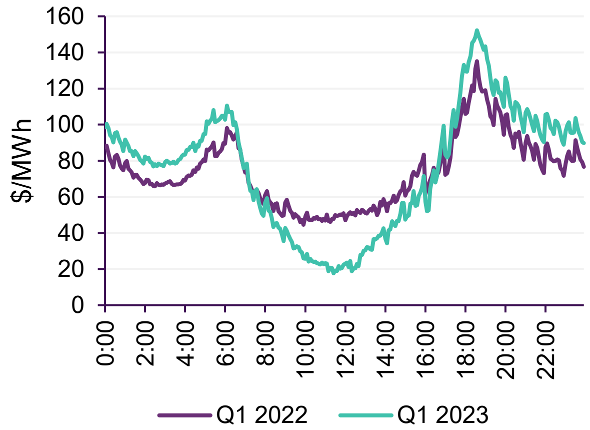


Figure 12 Lower daytime prices

Average NEM energy prices by time of day – Q1 2023 vs Q1 2022



Market suspension

On 17 March 2023, AEMO declared the spot market suspended in New South Wales in response to a SCADA failure[6]. AEMO concluded that the power system remained in a secure operating state throughout the market suspension, and no generation or load was lost due to the incident. During the period when the New South Wales market was suspended between 2015 hrs and 2110 hrs, market suspension schedule pricing[7] was used to set the New South Wales spot price and FCAS prices. Spot prices in neighbouring regions (Victoria and Queensland) exporting electricity into New South Wales while the market was suspended were scaled down in accordance with National Electricity Rules (NER) 3.14.5(f).

1.2.1 Wholesale electricity price drivers

Key factors influencing NEM electricity spot prices throughout Q1 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: Q1 2023 drivers

Decreased operational demand	Compared to Q1 2022, average operational demand was 324 MW lower (Section 1.1.2). Most of the decrease was observed during daylight hours (Figure 4Figure 4) driven by a substantial increase in distributed PV. The reduced day time operational demand has meant that lower price offers more frequently set the price, particularly in South Australia and Victoria which experienced negative prices 27% and 24% of the time respectively (see Section 1.2.3). Conversely, underlying demand in New South Wales and Queensland rose compared to Q1 2022 as those regions experienced warmer weather (Section 1.1.1). Some of this increase happened after daylight hours, pushing up operational demand and spot prices over the evening (Figure 12).
Offers from marginal generators	A significant shift in spot market offers from black coal-fired generators occurred this quarter that correlated with both the New South Wales and Queensland government-imposed caps on domestic thermal coal prices. Relative to Q4 2022 and preceding quarters, black coal generators offered more volume in marginal price bands below $300/MWh which sharply reduced the average offer price of key marginal stations (Figure 13), returning the overall offer curve for these generators to levels similar to a year ago (Figure 14). In Tasmania, hydro generators decreased the volumes offered at or below $100/MWh by around 200MW (Figure 35). As more generation was imported from the mainland, the Basslink interconnector bound at its import limits more often, and Tasmanian generators subsequently set the Tasmanian price more often (Section 1.2.4).

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

[7] In accordance with AEMO's published Estimated Price Methodology, the market suspension pricing schedule was based on a four-week rolling average of historic regional prices, separated into business and non-business days, with half-hourly resolution.

Price separation	Similar to previous quarters, there was marked price separation between the northern regions of Queensland and New South Wales and the southern regions of South Australia and Victoria. Constraints affecting VNI restricted daytime flows northward, severely limiting the amount of low-priced generation in southern regions flowing to New South Wales and Queensland. Likewise, flows south from Victoria to Tasmania were at the import limit (into Tasmania) more frequently, separating the Tasmanian price from the mainland (Section 1.4).
Price volatility	Although not a major driver of high prices, and far less than the contribution to Q1 2022 prices, spot prices above $300/MWh lifted the price in Queensland, New South Wales and South Australia as those regions experienced episodes of tight supply-demand balance (see Section 1.2.2).

Figure 13 Black coal generators' marginal offer pricing declines sharply from preceding quarters

Monthly volume-weighted marginal offers[8] – Eraring, Gladstone, Vales Point, Bayswater, Tarong and Stanwell power stations

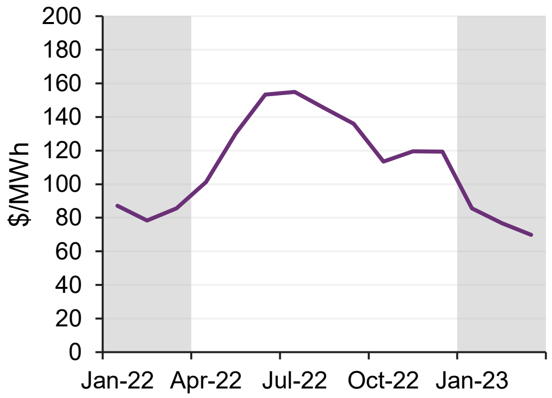
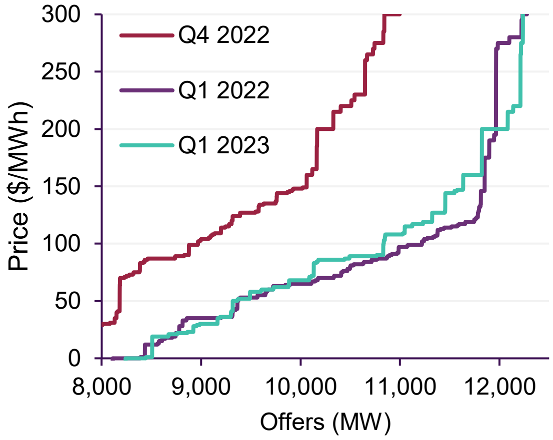


Figure 14 Black coal offer curves now similar to Q1 2022 levels

Black coal generation bid supply curve – Q4 22, Q1 22 and Q1 23



1.2.2 Wholesale electricity price volatility

South Australia, Queensland and New South Wales experienced periods of volatility, generally driven by extreme temperature-related peak demand.

Table 2 Significant volatility events in Q1 2023

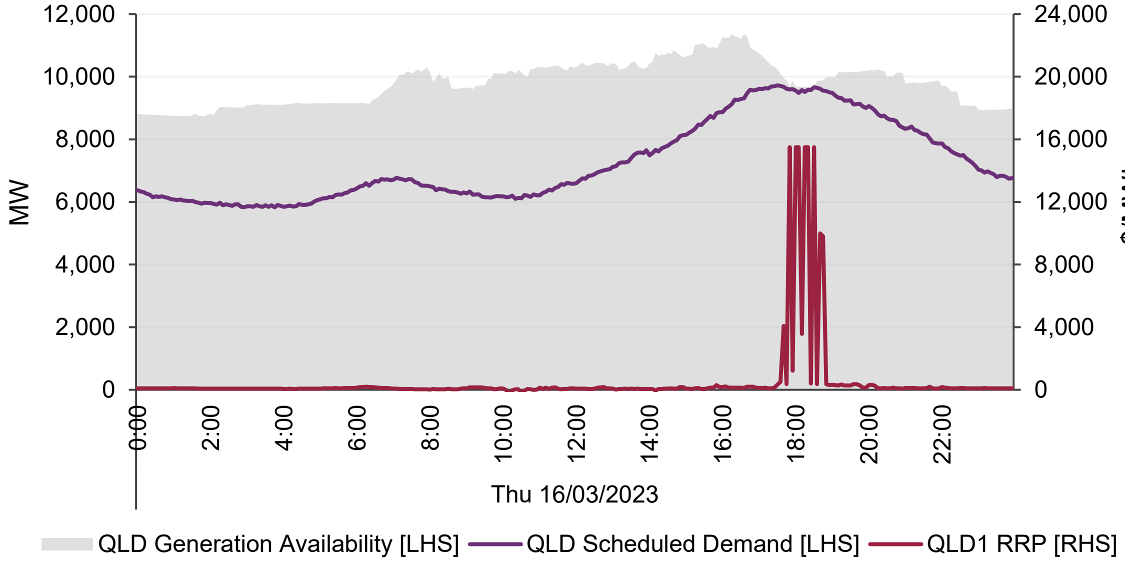
Region	Date	Contribution to quarterly cap price ($/MWh)	Drivers
SA	16 Feb	$5.16	With Adelaide experiencing extreme temperatures over 39°C on this day, operational demand in South Australia stayed above 2,700 MW for over one hour. During the evening high peak demand, South Australia had less than 100 MW of wind, while a binding constraint continued to limit interconnector flows below 600MW. There were 62 intervals over $300/MWh and 15 over $4,000/MWh across the day.
QLD	16 Mar	$4.59	Queensland recorded extremely high demand (>9,000 MW) with temperatures exceeding 35°C in many parts of Brisbane and Queensland. AEMO declared actual LOR 2 conditions as the availability of local generation fell close to the level of demand, and spot prices exceeded $300/MWh over 23 intervals between 1735 hrs and 2010 hrs, reaching the market price cap of $15,500/MWh in six intervals (Figure 15).
NSW	16 Mar	$4.13	New South Wales also experienced high demand (>12,000 MW), with above 35°C temperatures in parts of Sydney. AEMO declared LOR 2 conditions in NSW with reduced generation availability, and contracted 140 MW of RERT capacity, although this was not activated[9]. With Queensland simultaneously experiencing high demand and prices, NSW spot prices exceeded $300/MWh in 26 intervals between 1645 and 1945.

[8] Market offers between $10/MWh and $300/MWh

[9] https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert/rert-reporting

Figure 15 High Queensland prices on an extreme demand day

Queensland scheduled demand[10], generation availability and spot price – 16 March 2023

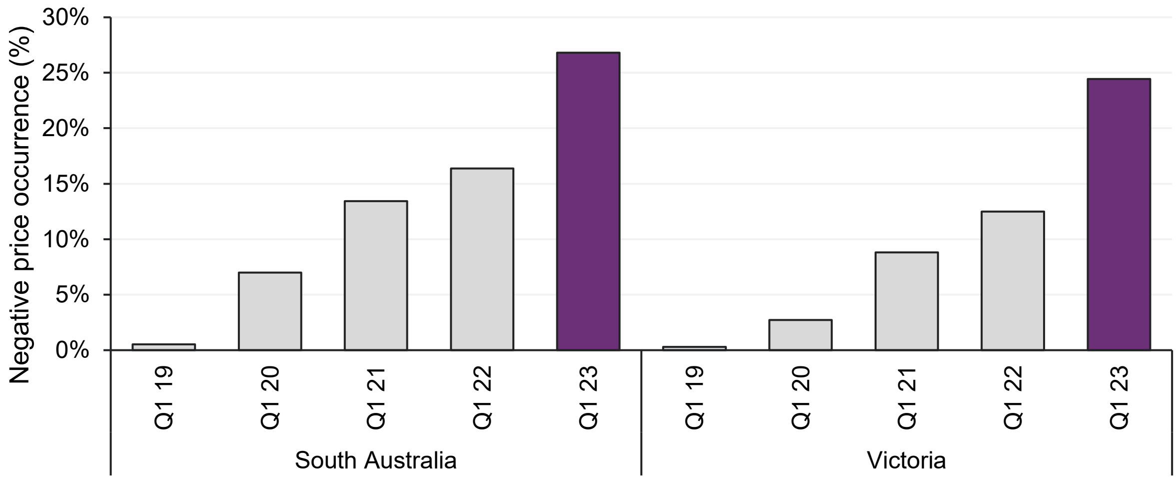


1.2.3 Negative wholesale electricity prices

The quarter saw a Q1 record level of 12% of dispatch intervals having negative or zero prices[11]. All mainland NEM regions had record Q1 negative price occurrences, with 27% and 24% of South Australian and Victorian spot prices at or below $0/MWh, respectively 10 and 12 percentage points (pp) higher than in last Q1 (Figure 16).

Figure 16 Negative price occurrence in South Australia and Victoria increases

South Australia and Victorian negative price occurrence – Q1's



The majority of negative prices occur during the daytime hours when operational demand is lower (in part caused by higher distributed PV output), and large scale VRE generation (Section 1.3.4) is higher. Between 0900 hrs and

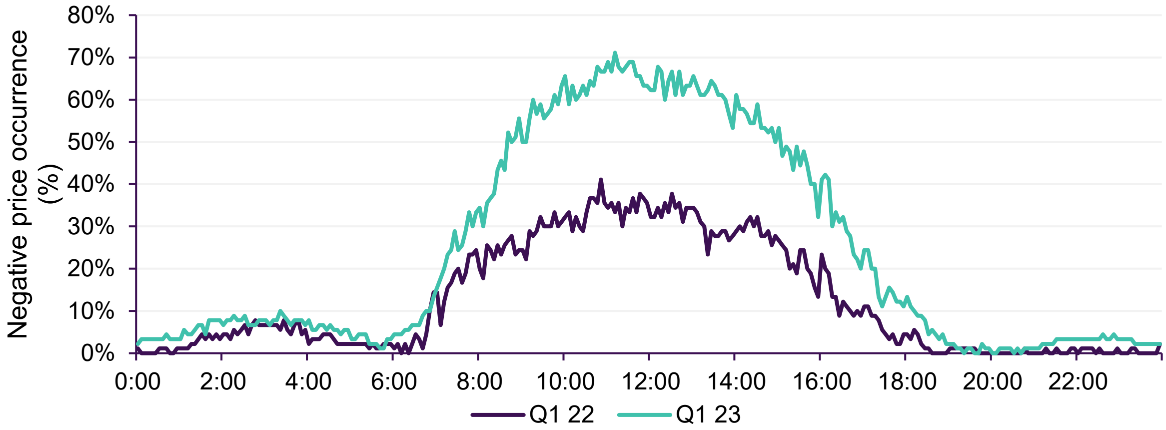
[10] 'Scheduled demand' is demand met through the market clearing process by large-scale scheduled and semi-scheduled generation and loads. It is supply required to meet the difference between underlying demand and supply from distributed PV and non-scheduled sources. This differs to operational demand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

[11] Hereafter referred to as negative prices.

1700 hrs, negative prices occurred 60% and 55% of the time in South Australia and Victoria, increases of 23 pp and 27 pp respectively (Figure 17).

Figure 17 Large daytime increase in Victorian negative price occurrence

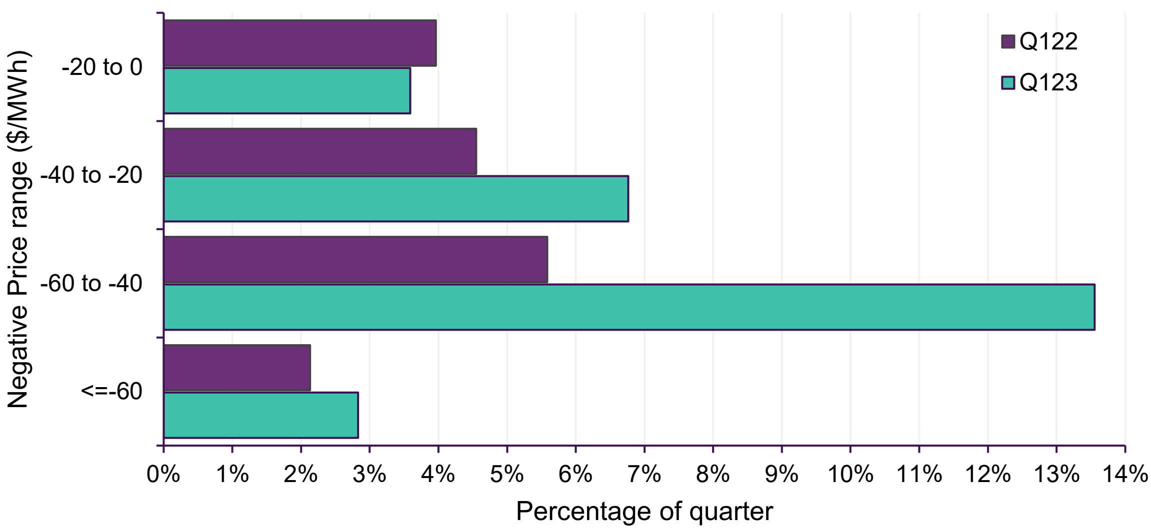
Occurrence of Victorian negative or zero prices by time of day – Q1 2023 and Q1 2022



Negative price impact[12] was \$12.2/MWh in South Australia and \$10.6/MWh in Victoria, increases of \$5.7/MWh and \$6.9/MWh respectively. In addition to the increased frequency of negative prices, price levels when negative were lower (larger in magnitude), with most of the negative prices being in the -\$60 to -\$40/MWh range (Figure 18). The spot value of a large-scale renewable certificate generated by renewable generation began the quarter at \$57 per certificate[13]. Although it declined in March, the average Q1 2023 LGC spot price was around \$48 per certificate, \$4 per certificate higher than Q1 2022[14].

Figure 18 South Australian negative prices increase in occurrence and decrease in value

South Australian negative price occurrence by price range – Q1 22 vs Q1 23



[12] 'Negative price impact' quantifies the effect of negative prices in reducing the overall quarterly average spot price

[13] Some wind and grid-scale solar generators will offer supply at negative prices as they realise one renewable energy certificate per MWh generated, which can be sold to retailers as they are obligated to purchase under the *Renewable Energy (Electricity) Act 2000* for a proportion of their customer load.

[14] https://lgc.mercari.com.au/

1.2.4 Price-setting dynamics

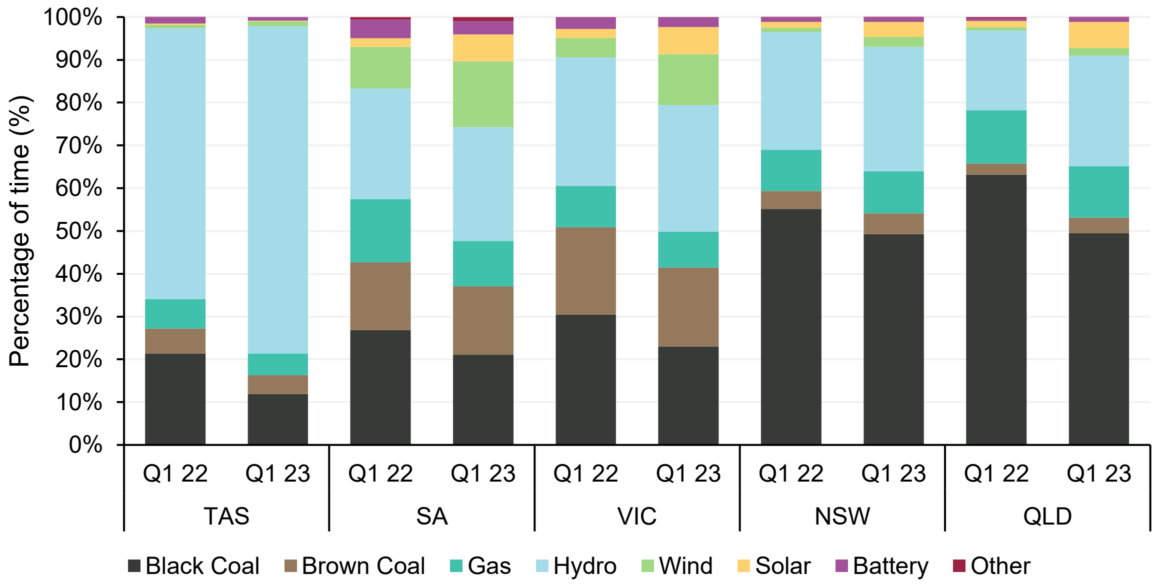
Price-setting data for Q1 shows a decrease in the proportion of dispatch intervals where the price was set by generation from thermal fuel sources; black coal-fired generation down by 8 pp and gas-fired generation by 2 pp. These changes were offset by increases in price-setting frequency by hydro (+2 pp), wind (+3 pp) and grid-scale solar (+3 pp).

By region;

- **Tasmania** saw a large increase in the proportion of time that hydro set the spot price, from 63% of intervals in Q1 2022 to 77% this quarter, offset largely by decreases in coal and gas (Figure 19).
- **South Australia** and **Victoria** have seen increases in price-setting frequency by wind generation, increasing 5 and 7 pp respectively to 15% and 12%. Price-setting by solar generation grew from 2% to 6% of intervals in both states, offset by decreases in coal and gas price-setting frequency.
- **New South Wales** and **Queensland** saw similar increases in percentages of time that prices were set by solar (+ 2pp and +5 pp), hydro (+2 pp and +7 pp) and wind (+1 pp in both regions), offset by less frequent coal and gas price-setting.

Figure 19 VRE generation set prices more frequently while price-setting by coal-fired generation declined

Price-setting frequency by fuel type[15] Q1 2023 vs Q1 2022



Additional renewable generation this quarter (Section 1.3.4) and relatively low Victorian spot prices saw increased energy flows southward to Tasmania, causing Basslink to bind at its import limit more often (Section 1.4). This saw Tasmania's price set more often by local generation (65% in Q1 2023 compared to 51% in Q1 2022).

On the mainland, the average spot price set by black coal generation when marginal was $88/MWh, a reduction on Q1 2022 of $4/MWh (Figure 20). For gas-fired generation the average fell by $41/MWh[16] to $138/MWh while

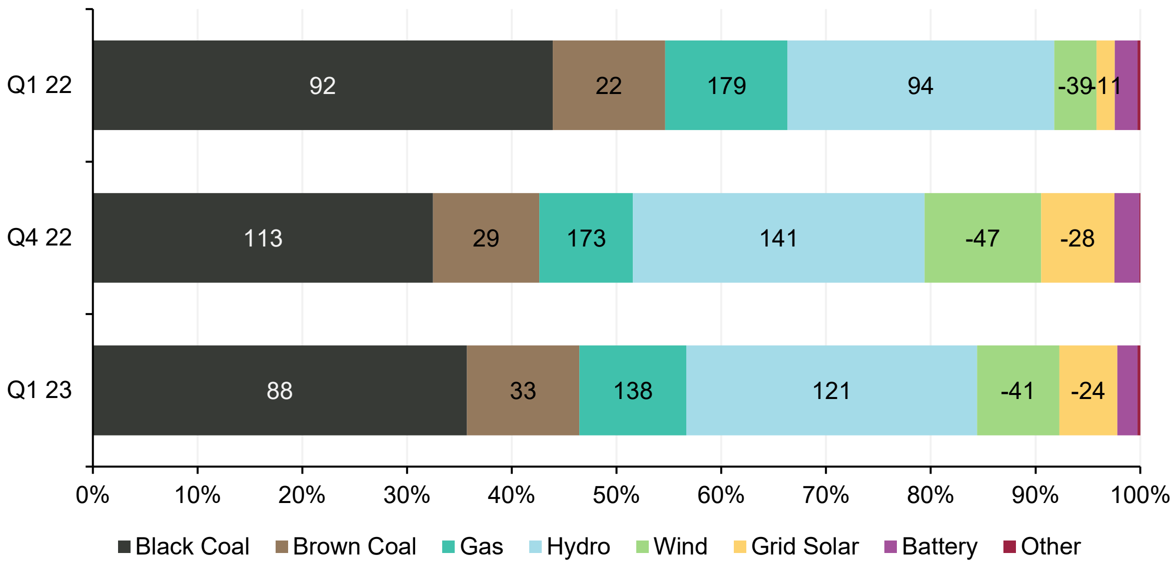
[15] The NEM's interconnected structure allows prices in one region to be set by market offers in a different region provided interconnector flows are not constrained; for example, offers from black coal generators in New South Wales or Queensland may at times set price in southern NEM regions as well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

[16] Note that the average price set by different fuel types differs from values in previous QEDs due to a change in methodology. The revised methodology identifies a single station as the marginal fuel type in each region and dispatch interval.

for hydro the average increased by $27/MWh to $121/MWh as its price-setting role shifted out of lower-priced daytime periods into the higher-priced shoulder and overnight periods. The average mainland price set by grid-scale solar generation fell from -$11/MWh to -$24/MWh which, combined with its increased price-setting frequency, contributed to the fall in NEM daytime prices.

Figure 20 Average prices set by black coal, gas and renewables fall from Q1 2022, up for hydro

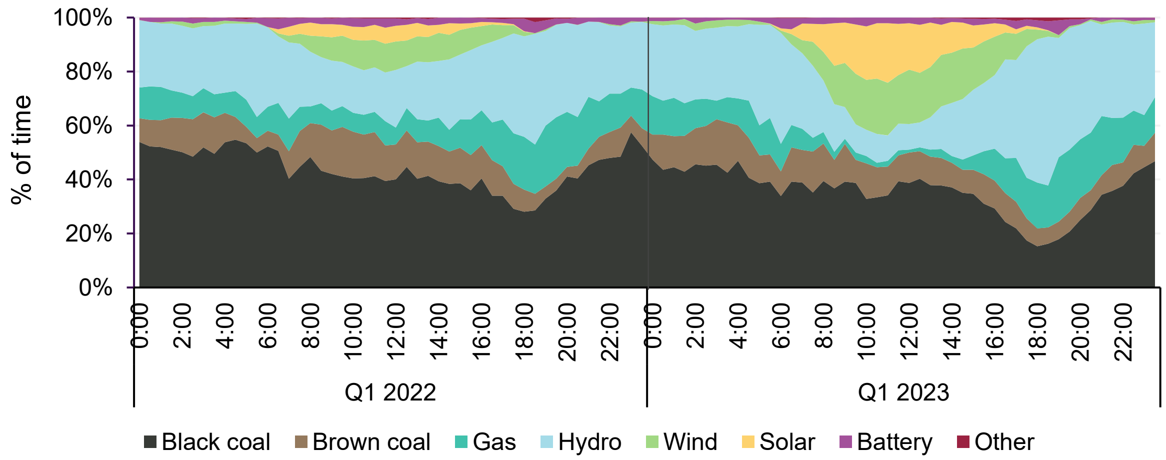
Mainland NEM price-setting frequency and average price set by fuel type - Q1 2023 vs Q1 2022



By time of day, solar and wind have increased their frequency of setting the mainland price during daylight hours, with an offsetting effect on thermal and particularly hydro generation (Figure 21). However over the evening peak the price-setting role of hydro generation has increased significantly to make it the most frequent price-setter by fuel type. This reflects the flexibility of hydro generation and the greater value of water at the higher spot prices prevailing during evening peaks than at low and often negative daytime prices.

Figure 21 Price-setting frequency of hydro displaced in the middle of the day by grid-scale solar and wind

Mainland NEM price-setting frequency by fuel type and time of day - Q1 2023 vs Q1 2022



1.2.5 Electricity futures markets

Forward prices for the next financial year period of 2023-2024[17] (referred to as FY24) across the four mainland NEM regions averaged $107/MWh, a $55/MWh decrease from the prior quarter's average FY24 price. Over this quarter daily closing FY24 prices varied, with the greatest increase seen in the last few days of March (Figure 22). In the prior quarter, FY24 base futures contracts peaked at $230/MWh for New South Wales before falling dramatically in December on Federal government announcements of intervention in the wholesale domestic gas and thermal coal markets, to close Q4 2022 at an average of $102/MWh across the regions.

New South Wales saw the largest rise this quarter of 31% to $145/MWh, with similar increases in Queensland (+26%) to $126/MWh and Victoria (+25%) to $96/MWh. Throughout the quarter South Australian prices remained steady with little contract volume traded, closing at $113/MWh (-5%). Later financial year contracts in all mainland regions other than South Australia closed the quarter trading at lower prices than FY24 contracts, indicating falling price expectations (Figure 23).

The AER released a draft determination of the Default Market Offer (DMO) for 2023-24[18], which each year estimates the costs retailers face for the cost of supplying electricity to residential and small business customers in South-East Queensland, New South Wales and South Australia. The calculation of wholesale costs includes a methodology that assumes that retailers hedge exposure to electricity spot prices by progressively buying forward contracts in advance of the pricing period. The AER factors in retailers incrementally buying contracts in the three years prior to the start of the pricing period, which has resulted in a large increase in assumed wholesale costs relative to last year, despite the forward curve for FY24 dropping since October 2022. The AER will publish a final determination in May, with changes applied by 1 July 2023.

Figure 22 FY24 Futures rose over Q1 2023 after dropping sharply in Q4 2022

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

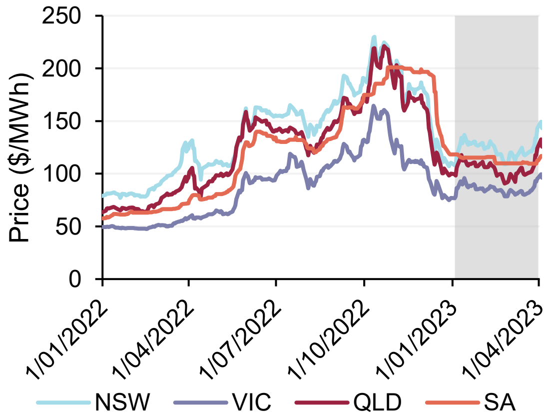
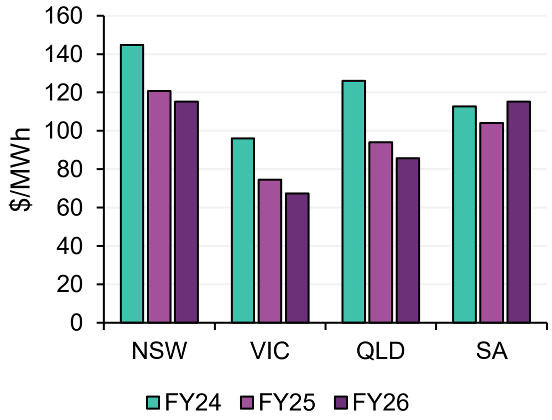


Figure 23 Future fin year contracts lower in most regions

Fin year contract prices by region as at 31 March 2023



[17] To align to both the AERs Default Market Offer and the Victorian Essential Services Commissions Victorian Default Offer pricing period, we have chosen to show financial year forward contracts rather than calendar year periods.

[18] https://www.aer.gov.au/retail-markets/guidelines-reviews/default-market-offer-prices-2023%E2%80%9324/draft-decision

1.3 Electricity generation

In Q1 2023, generation in the NEM[19] increased 1% (+265 MW) from Q1 2022, reflecting higher Q1 underlying demand. Continued shifts to increasing output from variable renewable energy (VRE) and distributed PV sources was accompanied by declines in thermal generation.

While coal-fired generation remained the largest contributor in Q1 2023, at 58% of total NEM generation, renewable energy generation's share of output increased 4 pp from Q1 2022, contributing 37% of the NEM total (Table 3).

Figure 24 shows the change in average NEM generation (MW) by fuel type relative to Q1 2022.

- Grid-scale wind and solar, and distributed PV each increased from the previous year, with an aggregate 1,019 MW increase across these fuel types. Average distributed PV output reached a record quarterly high of 2,962 MW, up 23 % from Q1 2022 (Section 1.1.2).
- Coal and gas-fired generation dropped 710 MW. Gas saw the largest percentage drop, down 20 % (-280 MW) from Q1 2022 to average 1,113 MW. Black coal-fired generation output dropped only 1.3% (-137 MW) from Q1 2022 to 10,495 MW. Brown coal saw much steeper output declines, dropping 7.4 % (-293 MW) year-on-year, down to 3,653 MW.

Figure 24 Higher renewable energy production offsets lower thermal generation and higher underlying demand

Change in supply by fuel source – Q1 2023 versus Q1 2022

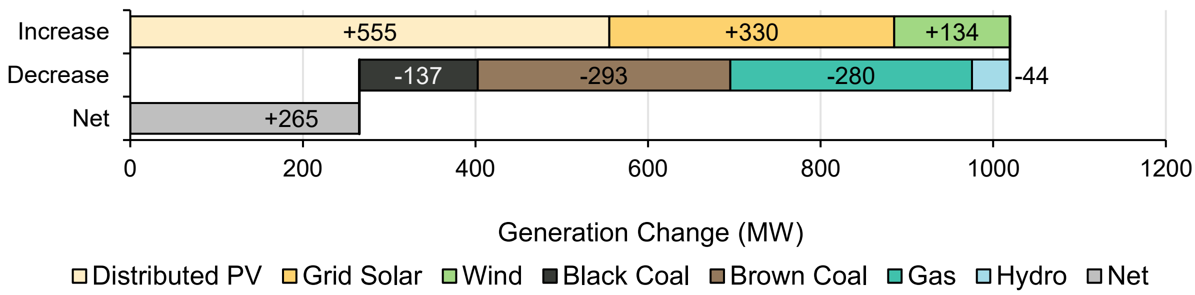


Table 3 NEM supply mix contribution by fuel type

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar	Distributed PV	Other
Q1 22	44.1%	16.4%	5.8%	6.3%	11.1%	6.2%	10.0%	0.1%
Q1 23	43.0%	15.0%	4.6%	6.1%	11.6%	7.5%	12.1%	0.1%
Change	-1.1%	-1.4%	-1.2%	-0.3%	0.4%	1.3%	2.2%	-

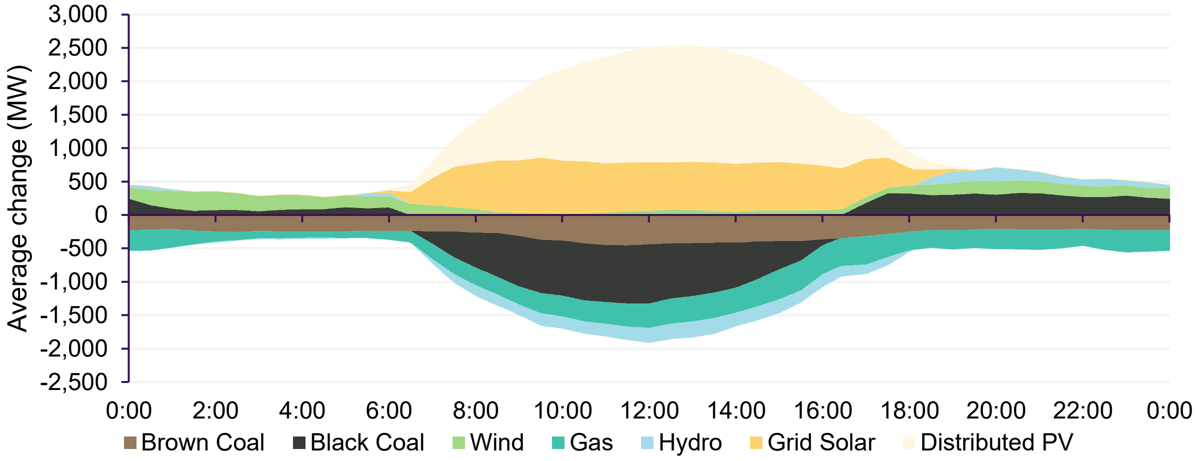
Figure 25 shows average change in supply by fuel type by time of day, with continued trends of increased solar output and declining thermal generation through the middle of the day.

- Despite overall increases, wind generation and grid-solar output plateaus through the middle of the day – reflecting increased economic offloading and curtailment of grid-scale VRE over this period.
- In contrast with recent Q1 outcomes, black coal generation increased over morning and especially evening periods, driven by higher availability and increases in evening and overnight prices.

[19] 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 daytime drops in thermal and hydro generation as solar output increases

NEM generation changes by time of day – Q1 2023 vs Q1 2022



1.3.1 Coal-fired generation

Q1 2023 saw a 3% reduction in coal-fired generation (-430 MW) from the previous year, to its lowest Q1 output on record. This decline was despite a 129 MW uptick in availability, as falling operational demand and lower-cost VRE continue to squeeze out other generation types.

Black coal-fired fleet

Black coal-fired output reduced 137 MW in Q1 2023 compared to Q1 2022 despite a 273 MW uptick in availability. Availability increased by 382 MW in New South Wales (despite the retirement of Liddell's unit 3 in April 2022), offsetting a 110 MW drop in Queensland.

The overall increase in availability was driven by declines in fleet capacity on outage (-353 MW). New South Wales saw a reduction of 661 MW on outages (down to an average of 1,211 MW on outage), offset by a 308 MW increase in Queensland outages (up to 1,586 MW).

Figure 26 Higher black coal-fired availability in NSW

Quarterly average black coal-fired availability by region – Q1s

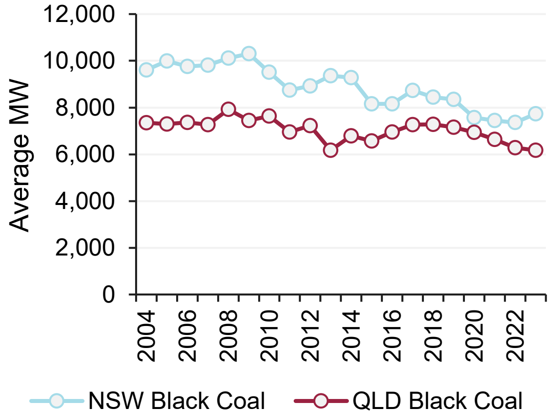
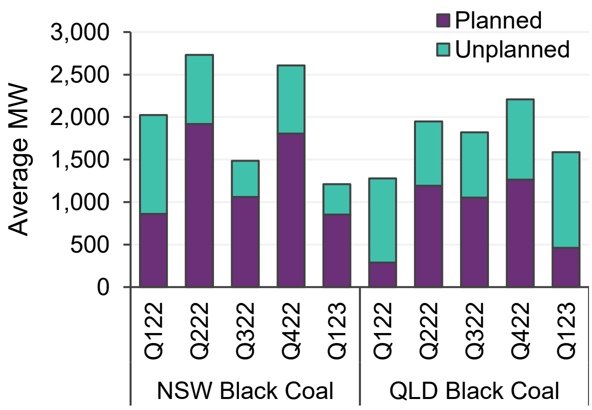


Figure 27 NSW black coal-fired outages decrease

Average black coal-fired capacity on outages – Q1 22 vs Q1 23



Generation in Queensland increased by 114 MW, while New South Wales output saw a 252 MW decline, driven in part by higher southward interconnector flows on the Queensland – New South Wales Interconnector (QNI) (see Section 1.4). Uplifts in output compared to Q1 2022 across Queensland stations and their causes include:

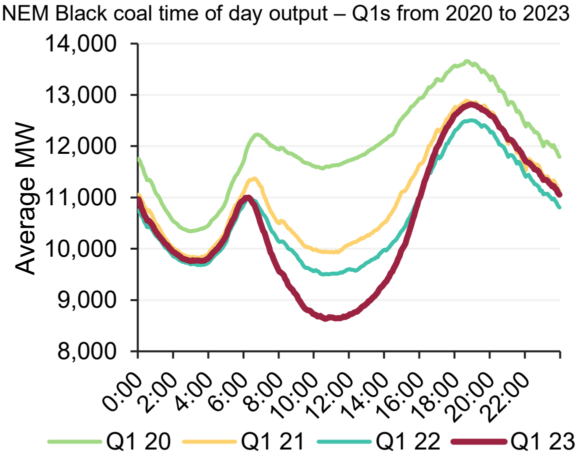
- Tarong increased by 328 MW, reflecting its utilisation rising to 92% (up from 79% in Q1 2022).
- Kogan Creek output increased by 197 MW from Q1 2022, when the generator was offline for much of February following an unplanned outage.
- Callide C output reduced from 345 MW to zero reflecting the full outages of units C3 (since October 2022) and C4 (since May 2021). On 8 March 2023, CS Energy advised the market that unit C3's return to service will be pushed back from June 2023 to September 2023. The expected return to service of unit C4 was also pushed back from May 2023 to 31 October 2023[20].

Conversely, New South Wales black coal-fired output declined despite a 382 MW increase in availability. Changes in New South Wales output compared to Q1 2022 and their causes include:

- Q1 2023 saw a large year-on-year decline in quarterly average output at Bayswater (-435 MW), and a smaller fall at Mount Piper (-47 MW) following declining utilisation. Utilisation fell 27 pp at Bayswater (from 91% to 65%) and by 8 pp at Mount Piper (from 57% to 49%).
- Liddell's output also saw a year on year decline of 97 MW following the retirement of unit 3 in April 2022.

Through Q1 2023, the flex in the daily output profile for the black coal-fired generation fleet – between average intraday minimum and maximum levels – grew by 1,172 MW from Q1 2022. Figure 28 shows increasing generation flex year on year with higher penetration of low-cost VRE through the middle of the day. In Q1 2023, the range from middle of the day troughs to evening peaks was also widened by evening demand growth driving higher peak generation.

Figure 28 Middle of day black-coal generation continues to decline



Bayswater and Eraring contributed approximately half of this growth in coal output flex, with the average intraday difference between minimum and maximum growing approximately 336 MW at Bayswater and 319 MW at Eraring (representing around 20% of quarterly average generation at each station).

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

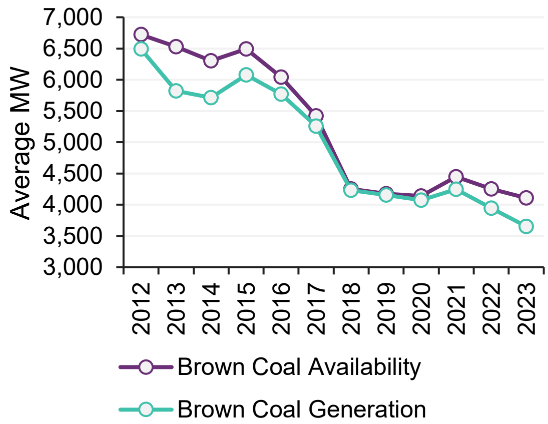
Brown coal-fired fleet

In Q1 2023, Victorian brown coal generation output declined by 293 MW from its average in Q1 2022 against availability dropping an average of 143 MW (Figure 29). These declines in output were seen at Loy Yang A (-248 MW) and Loy Yang B (-51 MW), while Yallourn saw increasing output (+7 MW). Loy Yang B had an additional 180 MW of outages following a planned outage throughout March.

Similarly to black coal units in New South Wales and Queensland, with declines in daytime demand and lower Victorian prices in Q1 2023, brown coal units show increased flexing of their daily output profile - with units reducing output through the middle of the day. The difference between average intraday minimum and maximum generation increased by 219 MW from Q1 2022 (Figure 30).

Figure 29 Brown coal generation declines with decreasing availability and utilisation

Quarterly average brown coal availability and output – Q1s



This decline through the middle of the day relative to availability drove a 4% reduction in utilisation in brown coal units (Figure 31) and was predominantly seen at Loy Yang A and B units:

- **Loy Yang A**'s difference between intraday maximum and minimum generation compared to Q1 2022 increased 115 MW, reaching record low quarterly utilisation rates of 86%, declining 6 pp from Q1 2022.
- **Loy Yang B** difference between intraday maximum and minimum generation increased by 76 MW compared to Q1 2022, with utilisation declining 3 pp to 87%.
- The declining mid-day generation and drops in utilisation were more subdued across **Yallourn**. Utilisation at Yallourn units remains high at 96% (-2 pp from Q1 2022), while the difference between intraday maximum and minimum generation saw a slight increase of 20 MW from Q1 2022.

Figure 30 Middle of the day output at Brown Coal units continues to decline

NEM brown coal time of day output – Q1s from 2020 to 2023

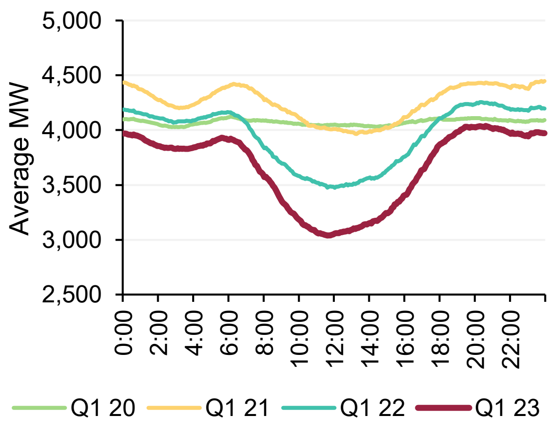
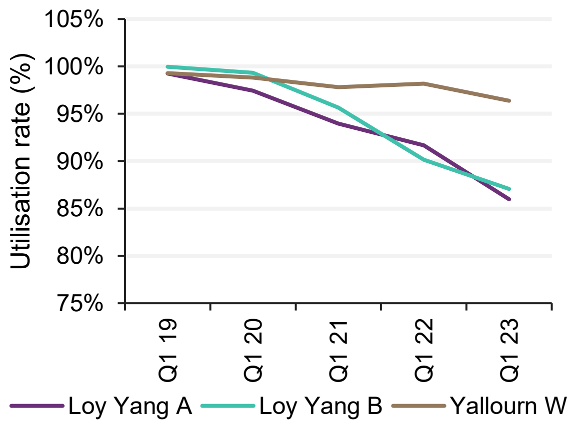


Figure 31 Utilisation at brown coal stations declines, steepest drops at Loy Yang A and B

Average quarterly utilisation (%) – Q1s



1.3.2 Gas-fired generation

Quarterly gas-fired generation reached its lowest Q1 level since 2005, dropping 280 MW from Q1 2022 to average 1,113 MW (Figure 32). In Q1 2023, there was a steep year-on-year decline in output from mid-merit gas plants (-220 MW), while peaking gas plant output declined slightly (-59 MW) from Q1 2022 (Figure 33).

Drivers for lower gas-fired generation include price increases relative to Q1 2022 in the wholesale domestic gas markets along the east coast (see Section 2.1), lower wholesale electricity spot prices (Section 1.2), and increased availability of black-coal units.

Figure 32 Gas-fired generation falls to its lowest Q1 level since 2005

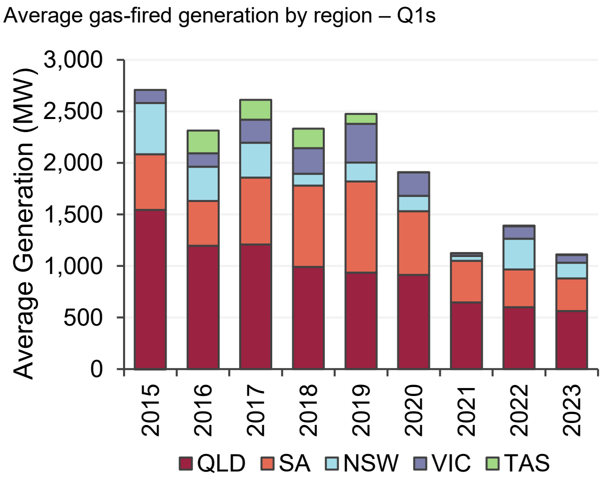
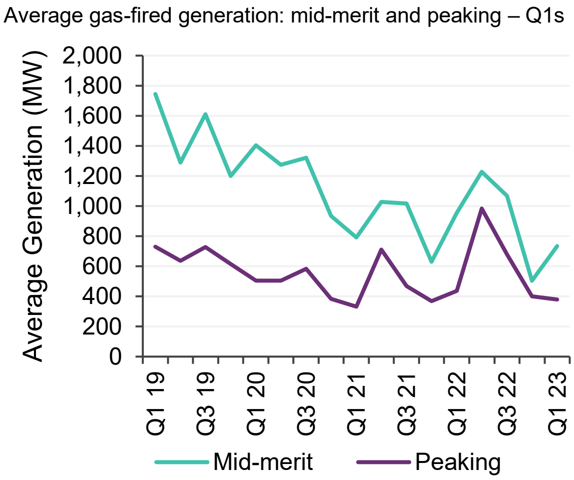


Figure 33 Declining gas generation reflects downtrend at mid-merit plants



In Q1 2023, gas-fired output in New South Wales declined 149 MW (50%) from Q1 2022, 148 MW of this reduction occurring at Tallawarra, where EnergyAustralia increased output last year to manage portfolio outages at other stations

In Victoria, gas-fired generation dropped 47 MW (38%), most of this at mid-merit units Mortlake (-23 MW) and Newport (-19 MW). In Queensland output declined by 39 MW, with large reductions at Darling Downs (-120 MW) offset by an increase of 140 MW from Swanbank E which was out of service for the entirety of Q1 2022.

In South Australia, output from gas-fired generation declined by 39 MW.

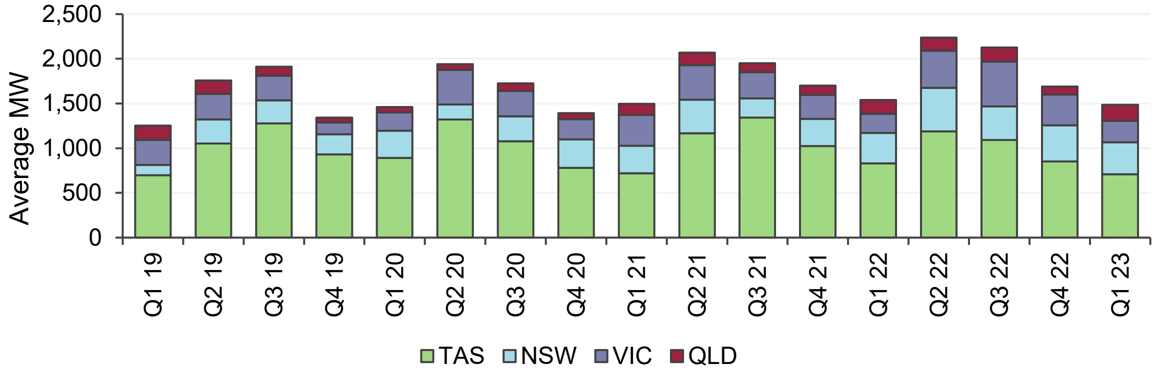
1.3.3 Hydro

Between Q1 2022 and Q1 2023, quarterly average hydro generation[21] declined 52 MW across the NEM to 1,486 MW (Figure 34). Generation from the Tasmanian hydro fleet declined 124 MW year on year, reaching its lowest quarterly average since Q1 2019. This was partially offset by uplifts in mainland hydro output across New South Wales (+19 MW), Queensland (+28 MW) and Victoria (+26 MW).

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

Figure 34 Declining hydro generation in Q1 2023 with lowest Tasmanian hydro output since Q1 2019

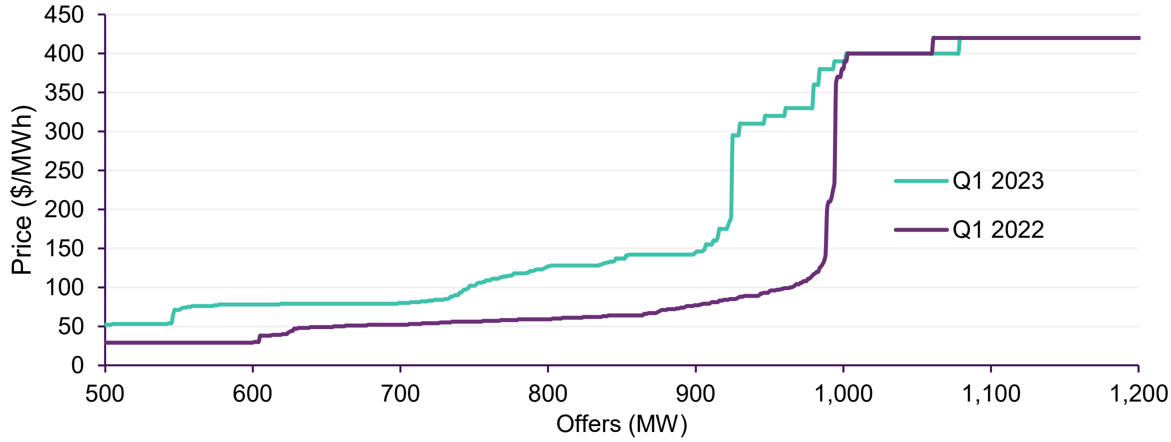
Average hydro output by region - quarterly



Falls in Tasmanian hydro output were driven by an 81 MW increase in flows southward on Basslink (Section 1.4) as Tasmanian hydro units shifted volume to higher price bands than in Q1 2022 (Figure 35), such that local generation was offset by import of lower-cost energy from the mainland. Upticks in Tasmanian wind output (+15 MW) and lower regional operational demand (-31 MW) also contributed to declining hydro output.

Figure 35 Tasmanian hydro generators shift offers to higher price bands

Tasmanian hydro generation bid supply curve – Q1 23 vs Q1 22



Mainland regions each saw slight upticks in hydro output, driven by higher evening peak demand and prices in New South Wales and Queensland. Through Q1 2023, hydro generation in the northern NEM regions set spot prices more frequently (Section 1.2.4), particularly in the evening.

Eucumbene storage levels were up on recent years to a 67.5% average, sitting 20 percentage points above Q1 2022 levels and 37 pp above Q1 2021 (Figure 36) . Tasmanian Hydro dam levels averaged 1 pp lower than Q1 2022 (Figure 37), with the two largest systems of Lake Gordon/Pedder and Great Lake finishing the quarter at 26% at 34% capacity respectively.

Figure 36 Eucumbene storage significantly higher than recent Q1s

Lake Eucumbene dam levels – 2019 to 2023

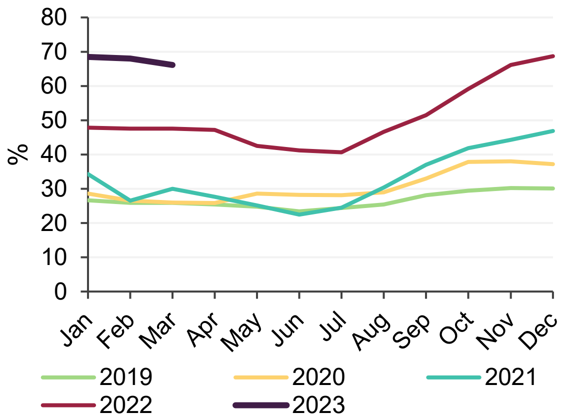
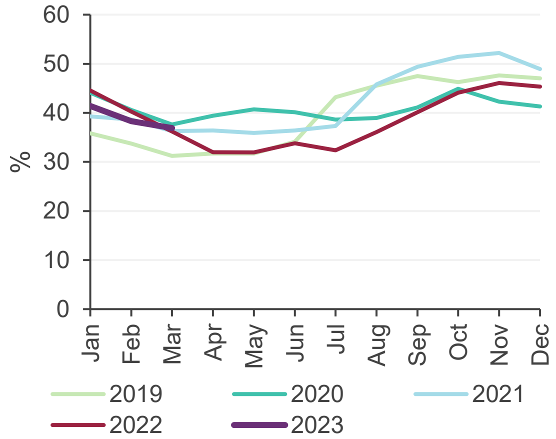


Figure 37 Tasmanian Hydro dam levels declined slightly from Q1 2022

Hydro Tas dam levels – 2019 to 2023



1.3.4 Wind and grid-scale solar

Average quarterly generation from grid-scale solar and wind assets in Q1 2023 reached a new record high of 4,654 MW, a 3% increase on the previous record (+121 MW from Q4 2022), and 11% (+464 MW) higher than the average in Q1 2022 (Figure 38). Total output rose from Q1 2022 in each NEM region (Figure 39).

Figure 38 Continued increases in VRE, with particularly high uplifts in grid solar

Average quarterly VRE generation by energy source

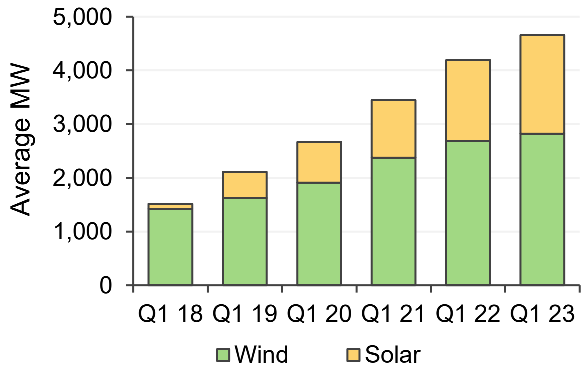
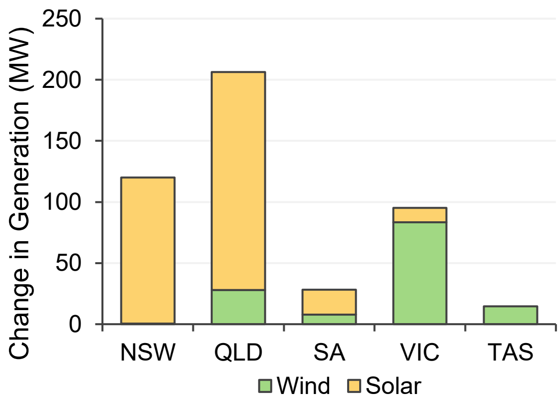


Figure 39 Change in output by region and fuel type

Generation change by region and fuel type from Q1 22 to Q1 23



The increases in VRE output are categorised by:

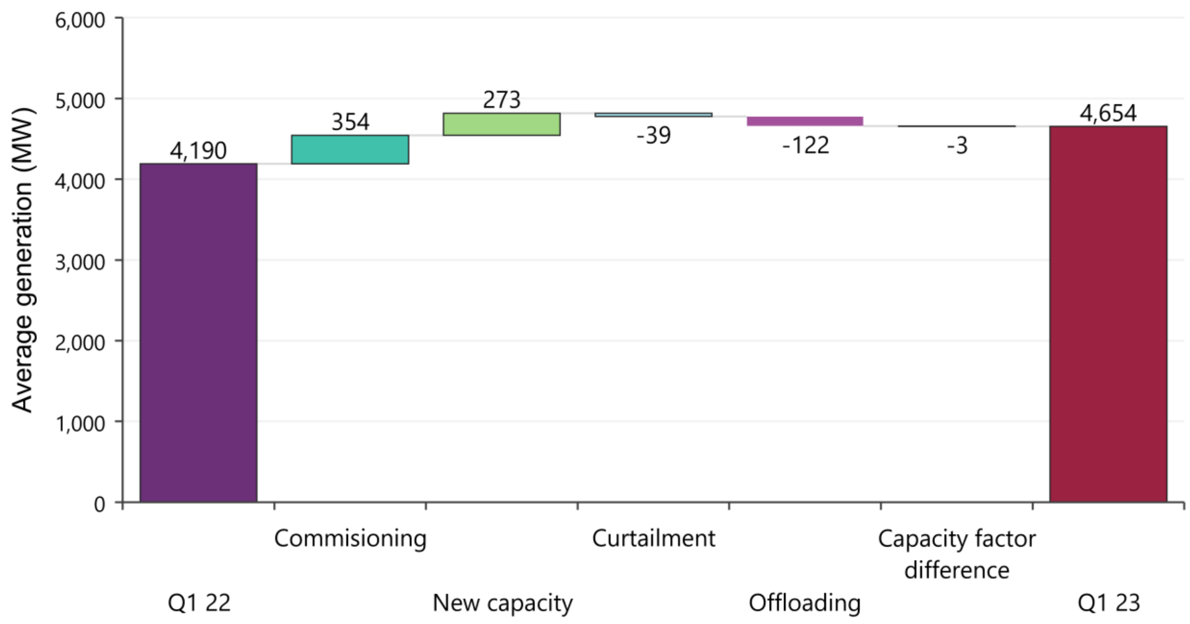
- Grid-scale solar contributed 71% of this increase, rising 22% from Q1 2022. Uplifts in solar were particularly high in Queensland (+178 MW) and New South Wales (+120 MW). This was driven by increasing capacity from new and commissioned solar farms, as well as an uptick in solar irradiation in the northern regions.
- Growth in Victorian wind output contributed 83 MW to increased average VRE generation, driven by additional output from Murra Warra wind farm following completion of its commissioning.

Increased VRE generation in the NEM was predominantly attributable to new and recently commissioned units (Figure 40). New installs and recently commissioned units contributed 628 MW to growth in available renewable energy, around half of this (338 MW) from grid-solar in Queensland and New South Wales. In the southern regions, increases in wind capacity in Victoria (including Murra Warra Wind Farm Stage 2, +63.6 MW output) and South Australia (including Port Augusta Renewable Energy Park Wind Farm, +85.2 MW output) contributed to growth in available output.

This growth in energy available from new and commissioning capacity was partially offset by a 39 MW increase in curtailment by network constraints, as well as 122 MW of additional economic offloading by VRE generators in response to low spot prices.

Figure 40 VRE generation rise driven by commissioning of recently installed capacity and new connections

Change in NEM average VRE generation by driver – Q1 2023 versus Q1 2022



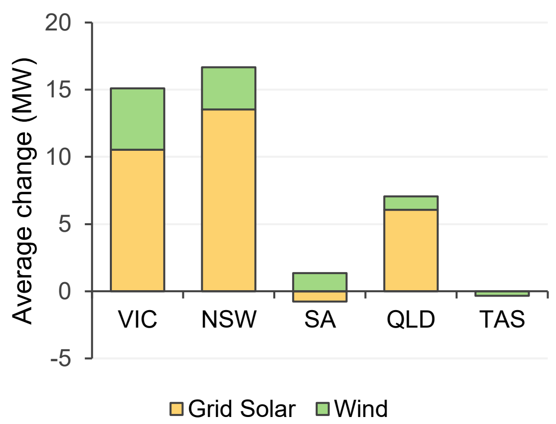
Curtailment and utilisation

In Q1 2023, curtailment of VRE output by network security and system strength constraints increased by 39 MW (+39%) from Q1 2022 to a 139 MW quarterly average. Figure 41 shows that the uplift in curtailment occurred mostly in Victoria and New South Wales, growing by 15 MW (+58%) and 17 MW (+28%) respectively.

Curtailment of grid-solar increased by 30 MW from Q1 2022 to a 115 MW quarterly average in Q1 2023. This was considerably higher than for wind curtailment, which increased 10 MW to a 24 MW quarterly average, reflecting the predominance of grid-solar capacity in network areas most subject to transmission capacity limitations and constraints.

Figure 41 Solar curtailment rose across NSW and Vic

Average MW Change in Curtailment Q1 2022 to Q1 2023



While the solar curtailment increase was highest in New South Wales, increased curtailment in Victoria represented a higher proportion of total solar availability – in New

South Wales, grid solar curtailment as a percentage of availability increased 0.4 pp through Q1 2023 to 7.8%, while the Victorian grid solar curtailment to availability ratio increased by 2.4 pp to 10%.

Output from solar generators is highly correlated given the relatively consistent solar profile across the east coast. As such, peak solar outputs are typically concentrated over the same period. In weaker sections of the network (in renewable energy zones [REZs] such as Murray River, South West New South Wales and Central-West Orana), transmission capacity can be insufficient to carry the full output of connected VRE generation. As a result, network constraints are required to control maximum power flows through critical transmission elements.

Increased output due to high solar irradiance and generation capacity growth in these regions can therefore result in higher curtailment; Figure 42 and Figure 43 show that curtailment continues to be concentrated in particular zones, with Murray River Region contributing 30 MW of the 41 MW curtailed in Victoria, while the South Western New South Wales and Central-West Orana zones accounted for approximately 53 MW of the 76 MW curtailed in New South Wales.

Figure 42 Curtailment in Victoria predominantly in the Murray River REZ

Quarterly average curtailment by candidate REZ - Victoria

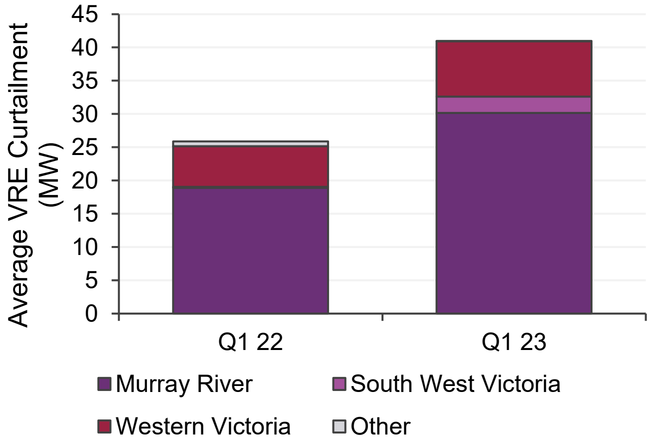
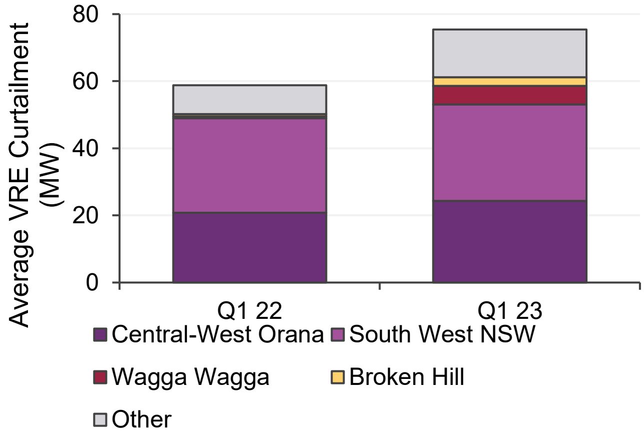


Figure 43 NSW curtailment predominantly in South-West NSW and Central-West Orana REZs

Quarterly average curtailment by candidate REZ – NSW[22]

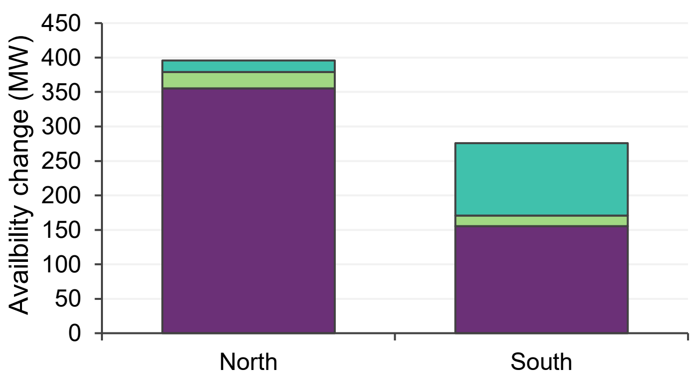


In northern mainland regions (New South Wales and Queensland), increases in available energy from semi-scheduled wind and solar generation led to broadly similar increases in generation dispatch[23]. Increased generation in these northern regions was 90% of the increase in availability from Q1 2022 to Q1 2023. Part of the difference represented economic offloading at times of low spot price rather than network curtailment.

In the southern mainland regions, the gap between higher VRE availability and dispatched output was much wider (Figure 44). The increase in VRE

Figure 44 Gap between growth of available vs dispatched VRE much higher in southern mainland regions

Change in available and dispatched generation by time of day - northern vs southern mainland regions – Q1 2022 to Q1 2023



[22] "Other" REZ refers to Cooma-Monaro, New England and North West New South Wales, each with low curtailment

[23] Available semi-scheduled VRE generation is offered and dispatched via the spot market, while non-scheduled generation is self-dispatched and does not provide availability data. In this analysis, availability and dispatch totals and growth exclude non-scheduled generation and differ slightly from corresponding measures for total VRE output.

dispatch in these regions represented only 56% of the increase in available energy. Unlike the northern regions, most of the gap between available and dispatched energy represents economic offloading. The much larger gap size in the southern mainland regions reflects limits on energy transfers northwards (Section 1.4) leading to much more frequent negative spot prices (Section 1.2.3).

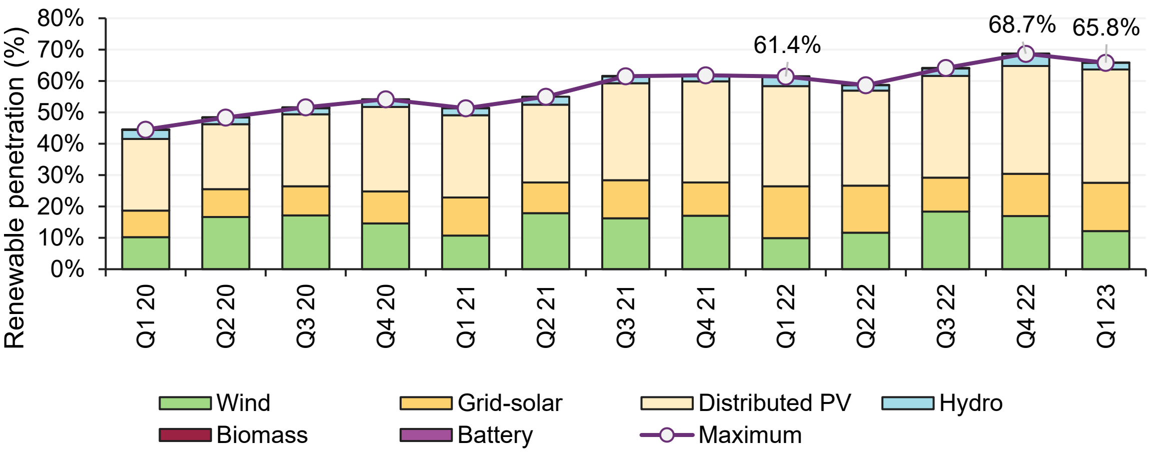
Utilisation rates measure the total output dispatched over the quarter and across each region as a percentage of availability. From Q1 2022 to Q1 2023, there was a considerable drop in utilisation for Victorian grid solar units (-9 pp to 79%) and for South Australian grid solar units (-6 pp to 87%). In contrast, the northern states saw 1 pp declines, to 92% in New South Wales and 95% in Queensland. Similar trends were seen for wind units. In the southern states, Victorian wind utilisation declined 5 pp to 91%, while South Australian wind utilisation declined 2 pp points to 94% from Q1 2022 to Q1 2022. Wind utilisation in northern regions saw very slight declines, declining -0.7 pp to 98.8% in New South Wales, and down 0.4 pp in Queensland, to 99%.

Instantaneous renewable penetration

The maximum instantaneous share of renewable energy generation[24] in the NEM reached a Q1 record of 65.8%. The record was reached in the half-hour ending 1200 hrs 5 March 2023, and was 4.4 pp higher than the previous Q1 record of 61.4% in 2022. Distributed PV accounted for over 36% of supply in this interval. Distributed PV and grid-solar were each up 2 pp from the contributions during the record maximum achieved in Q4 2022. Wind contribution declined 5 pp from the Q4 2022 record, down to 12%, and hydro was down 2 pp, to a 2% contribution (Figure 45).

Figure 45 Instantaneous renewable penetration rose from Q1 2022, though lower than Q4 2022

NEM % supply by renewable energy sources at time of peak instantaneous renewable energy output



[24] 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.

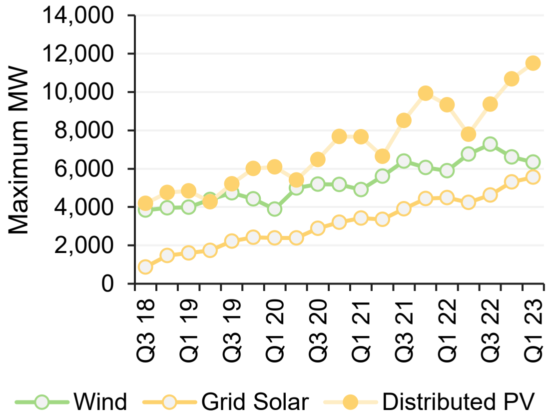
Distributed PV and VRE peak instantaneous outputs

Figure 46 shows the instantaneous maximum outputs reached by grid solar, wind and estimated distributed PV output.

- Distributed PV instantaneous output reached a record high of 11,504 MW on 11 February 2023, 818 MW higher than the previous record reached in Q4 2022.
- Grid-solar output also reached a record high of 5,551 MW on 13 February 2023, 240 MW above the previous record set in Q4 2022.
- Wind reached a Q1 maximum instantaneous output record at 6,341 MW on 2 February. This was 270 MW below its highest level in Q4 2022 and 930 MW below the all-time record set in Q3 2022, but was up 8% from Q1 2022's maximum level.

Figure 46 Record high instantaneous output for grid and distributed PV

Maximum quarterly instantaneous generation by fuel type



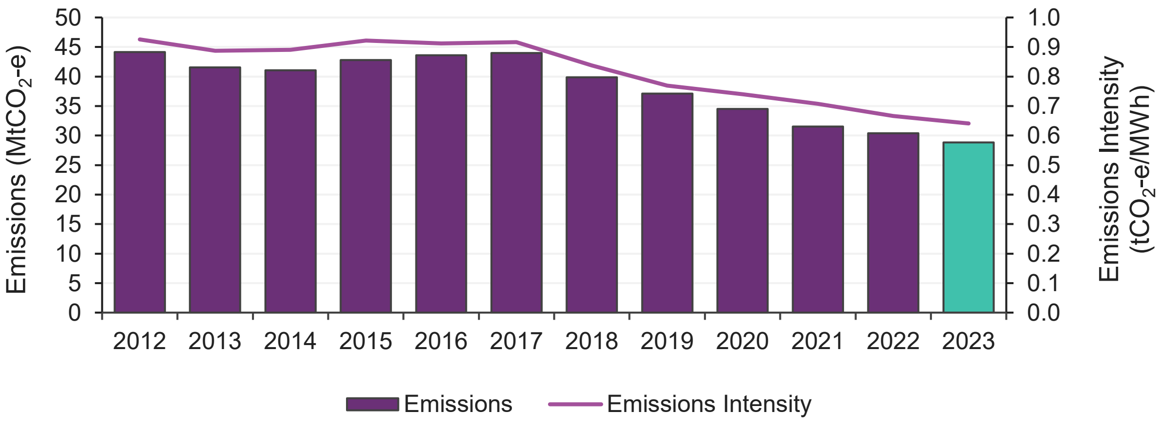
1.3.5 NEM emissions

NEM total emissions and emissions intensity both declined in Q1 2023 to their lowest Q1 levels on record (Figure 47). Emissions intensity excludes generation from distributed PV, taking into consideration sent out generation only from market generating units[25]. Q1 2023 total emissions, at 28.83 MtCO_2-e declined 5.1% from Q1 2022 (30.39 MtCO_2-e), while emissions intensity dropped 4% from Q1 2022 to 0.64 tCO_2-e/MWh.

The steeper decline in total emissions shows that emissions and emission intensity reduction is a result of both falling operational demand, and a reduction in the output share of thermal generating units.

Figure 47 Lowest Q1 emissions on record

Quarterly NEM emissions and Intensity (Q1s)



[25] 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.

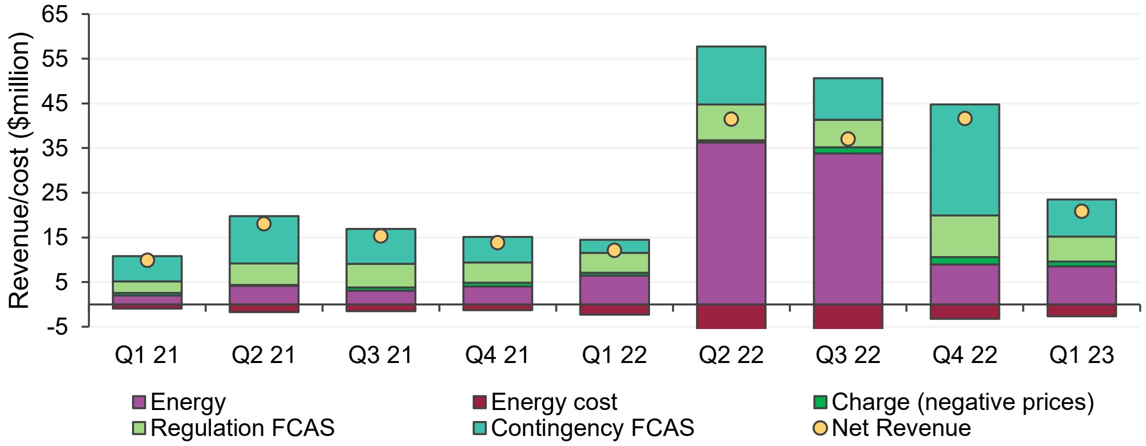
1.3.6 Storage

Batteries

Through Q1 2023 the estimated net revenue from batteries was $21 million, a 72% increase from Q1 2022 (+$9 million). Figure 48 shows that upticks were observed in both the energy and FCAS markets. The generally lower prices and volatility in energy and FCAS markets compared with Q2 – Q4 2022 saw battery revenues reduce from recent quarters.

Figure 48 Battery revenue up on Q1 2022 but well down on balance of 2022

Quarterly battery revenue estimates – Q1 21 to Q1 23



Energy revenue

Revenue from energy (generation) and charge (during negative prices) increased $2.5 million, offset by a $0.31 million increase in energy costs (charge during positive price). Increase in net energy revenue was largely driven by increased participation in Queensland, higher price volatility in New South Wales, and increased opportunities for negative-price charging across the NEM.

Completed commissioning of the 100 MW/150 MWh Wandoan Battery Energy Storage System (BESS) in Queensland (with full operation from Q3 2022) enabled the battery to capture high price volatility in Queensland through Q1 2023. This lead to a $2.3 million increase in revenue from energy dispatch and from charge during negative prices, offset slightly by a $0.42 increase in energy costs.

FCAS revenue

Battery FCAS revenue in Q1 2023 increased $6.5 million from Q1 2022, with 17% from regulation and 83% from contingency markets. This uplift in FCAS revenue was predominantly a result of the 286 MW increase in provision of contingency FCAS products by batteries, and a substantial lift in lower contingency and lower regulation FCAS prices in New South Wales, Victoria and South Australia (Section 1.5).

By region:

- Q1 2023 was the first Q1 with FCAS participation from batteries registered in **Queensland**. Total contingency FCAS revenue rose $1.1 million in Queensland from Q1 2022 to Q1 2023, while regulation FCAS rose $0.2 million year on year. Provision of raise contingency products increased 88 MW, while provision of lower contingency increased 79 MW resulting in increased revenue. Regulation FCAS provision rose slightly (+4.5 MW).

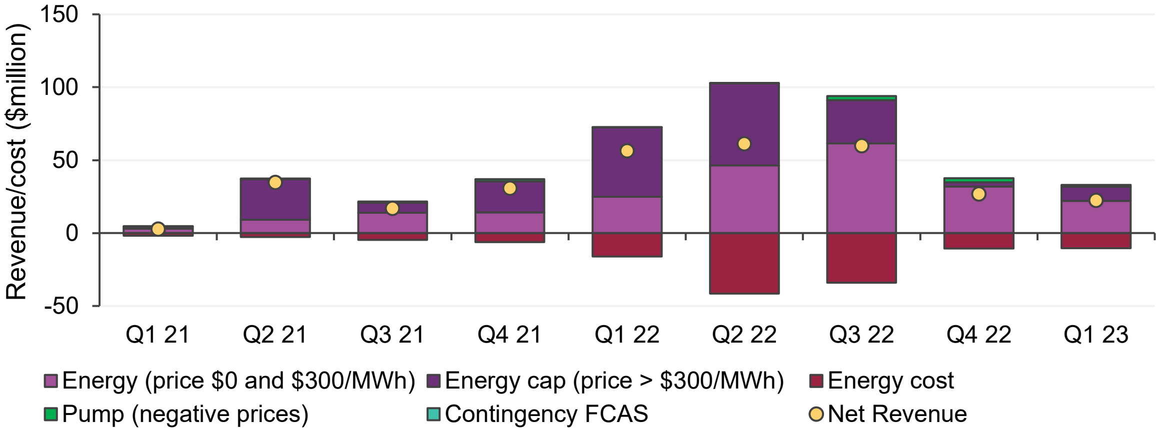
- Through Q1 2023, **South Australian** units shifted significantly more capacity into lower contingency FCAS markets while average prices for these products rose in the region. Average quarterly participation from South Australian batteries in lower contingency markets rose 53 MW from Q1 2022, while average prices increased to $4.50/MWh in Q1 2023 from $1.3/MWh in Q1 2022.
- **Victoria** saw an increase of 41 MW in service provision by batteries in FCAS regulation and contingency markets from Q1 2022 to Q1 2023 following the completed commissioning of Bulgana Battery (+28 MW average FCAS participation) and increased participation at Ballarat BESS (+24 MW average FCAS participation).
- **New South Wales** saw a 39 MW year-on-year lift in contingency market provision following completed commissioning of Wallgrove and Queanbeyan Batteries, supporting upticks in participation. Regulation FCAS saw slight decline (-7.6 MW) from Q1 2022 to Q1 2023.

Pumped hydro

Estimated net revenues for NEM pumped hydro storage facilities were $23 million in Q1 2023, down $34 million from Q1 2022 (Figure 49). Driving the fall was much lower Queensland spot price volatility this Q1 (Section 1.2.2), which saw Wivenhoe Pumped Hydro's revenue from prices above $300/MWh fall from $47 million a year ago to $8 million in Q1 2023. Partially offsetting this drop were $7 million in lower costs for pumping (including pumping at negative prices) and an increase of $2 million in volatility-related revenue for the Shoalhaven scheme due to higher spot price volatility in New South Wales. Energy generation from pumped hydro facilities was down by 11% on Q1 2022, and energy arbitrage value – net earnings divided by energy produced – fell from $336/MWh a year ago to $150/MWh this Q1.

Figure 49 Pumped hydro net revenue falls from Q1 2022 on lower spot price volatility

Quarterly pumped hydro revenue estimates – Q1 21 to Q1 23



1.3.7 Wholesale demand response

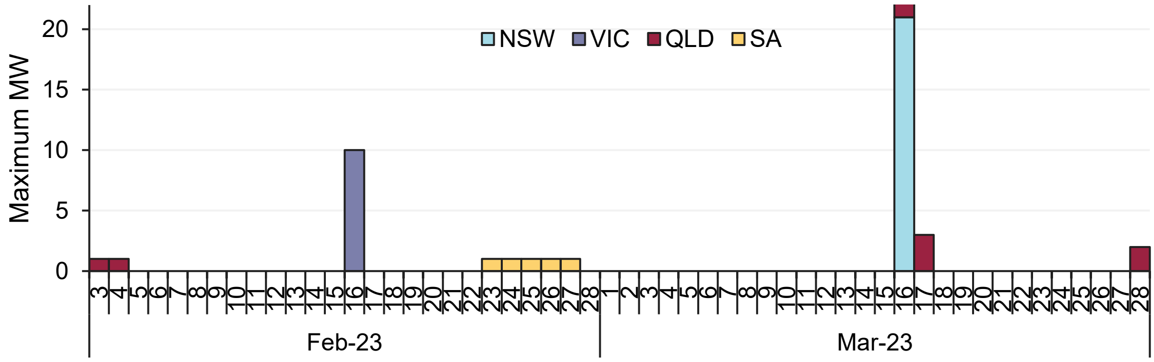
The Wholesale Demand Response (WDR) mechanism saw multiple days of dispatched WDR capacity across the quarter, with WDR participants active in all four NEM regions (Figure 50). There were two days of significant WDR dispatch corresponding with high energy prices – 16 February in Victoria and 16 March in Queensland and New South Wales.

In Victoria on 16 February, three WDR units dispatched between 1630 hrs and 1900 hrs to a maximum of 10 MW (from registered capacity of 27 MW). Over this period prices averaged $1,122/MWh with all intervals exceeding $300/MWh.

On 16 March, a time when demand in Queensland was greater than 9,000 MW and temperatures were above 35°C, prices reached the market price cap of $15,500/MWh for six intervals, with the New South Wales region exporting to Queensland and also near market price cap prices (Section 1.2.2). In Queensland, a maximum of 2 MW of WDR was dispatched (from registered capacity of 6 MW) and in New South Wales a maximum of 21 MW dispatched across five units (from registered capacity of 31 MW).

Figure 50 Active participation from WDR units in all mainland regions

Maximum daily WDR dispatch – 3 February to 28 March 2023

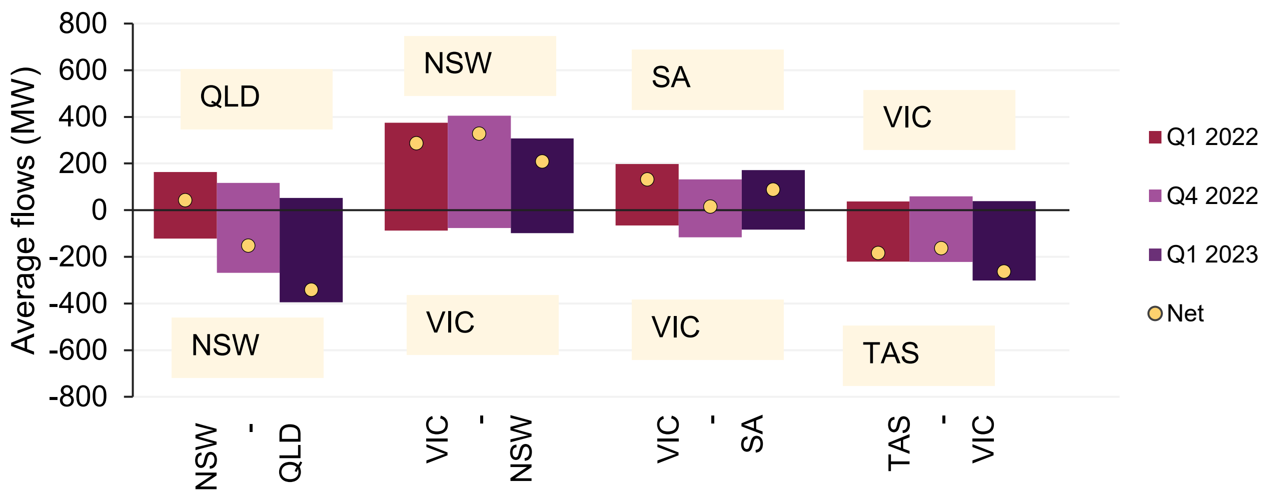


1.4 Inter-regional transfers

Total inter-regional energy transfers during Q1 2023 were 3,128 gigawatt hours (GWh), a 387 GWh increase from 2,742 GWh in Q1 2022. The largest component of this change was over QNI, which saw transfers increase by 349 GWh. Compared to Q1 2022, flow across all regional boundaries also tended more southward (Figure 51).

Figure 51 Interconnector flow has tended southwards since Q4 2021

Quarterly inter-regional transfers



Key outcomes by regional interconnection included:

- **Queensland to New South Wales** – average southward flows into New South Wales from Queensland more than tripled, increasing by 273 MW compared to Q1 2022. At the same time, northward flows from New South to Queensland were down 111 MW, resulting in a net shift southwards. In Q1 2022, the Queensland energy price[26] was $17/MWh higher than New South Wales. The net shift southwards is consistent with New South Wales and Queensland seeing similar energy prices this quarter. Other factors consistent with the net flow southward include higher New South Wales operational demand (+16 MW) and falling Queensland operational demand (-72 MW) as well as increased binding on VNI, reducing the amount of Victorian imports available to New South Wales. The return of Kogan Creek power station increased the binding frequency of a constraint related to QNI, further reducing the New South Wales to Queensland flow. Following the review of minor QNI testing, the New South Wales to Queensland upper notional transfer limit was increased to 750 MW applying from 2 March 2023.
- **Victoria to New South Wales** – through Q1 2023 there was an average decrease in the export limit for flows from Victoria to New South Wales between 0900 and 1700 hours of 138MW. Although the overall frequency of VNI binding when flowing toward New South Wales (exporting) decreased from 48% of the time to 42%, binding frequency was similar during day-time hours (Figure 52). However the maximum northward flow over the interconnector when export binding in the middle of the day decreased significantly (Figure 53). During the earlier part of the day (between 800 hrs and 1300 hrs), export constraints forced average flows southward when binding, despite higher prices in New South Wales, leading to an increase in the counter price flows across the interconnector (Section 1.4.1). These continuing increases in the severity of daytime export limits reduced the flow of lower-priced electricity generation from the south to support demand in the northern regions of New South Wales and Queensland.

Figure 52 VNI binding less frequently overnight

% of time VNI export bound by time of day – Q1 2023 vs Q1 2022

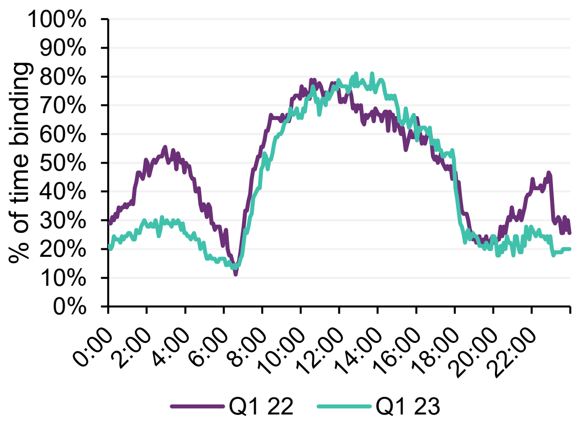
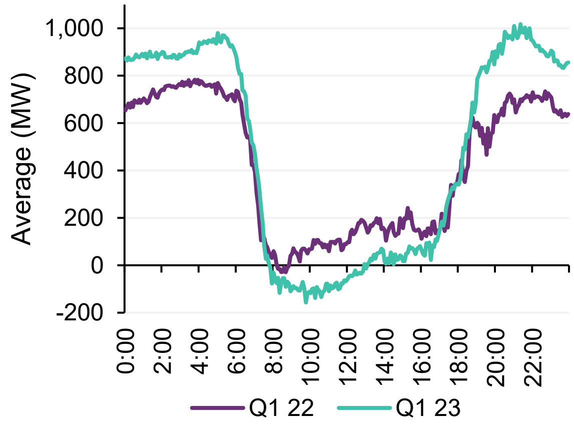


Figure 53 VNI daytime export limit falls further

Average VNI export limit when binding – Q1 2023 vs Q1 2022



- **Victoria to Tasmania –** flows southward over Basslink increased this quarter by 81 MW on average. Lower prices in Victoria meant that southward flows occurred more frequently: the proportion of time that these flows reached binding interconnector limits increased from 46% to 57%, with a large increase during daytime hours (Figure 54). Southward flows when at these import limits also increased in magnitude (Figure 55). As discussed in Section 1.2.4, generators located in Tasmania set the Tasmanian price 65% of time as opposed

[26] 'Energy price' being the average of spot electricity prices capped at $300/MWh to truncate the impact of volatility

to 51% of the time in Q1 2022, despite the decrease of Hydro Tas generation (Section 1.3.3), reflecting the increased extent of interconnector binding.

Figure 54 Basslink binding more often during daytime

% of time Basslink import bound by time of day

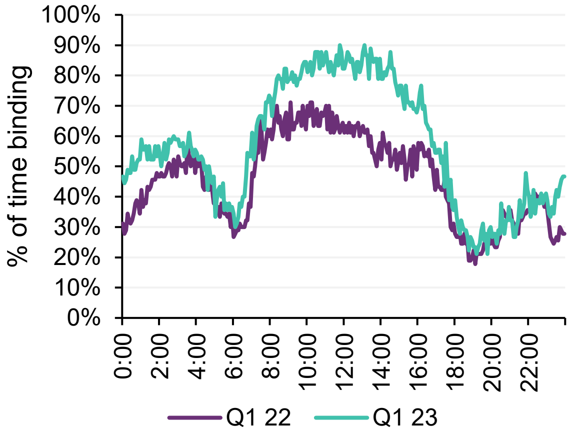
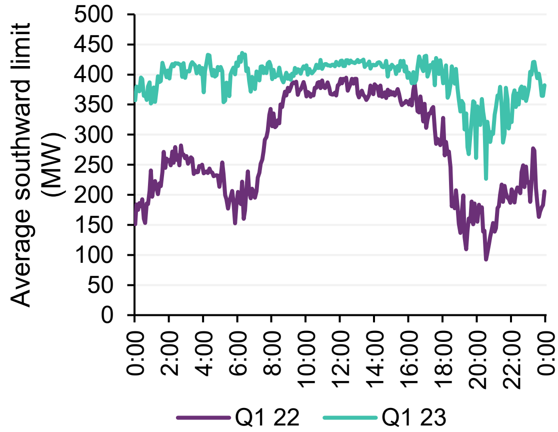


Figure 55 Basslink southward flow limits increase

Average Basslink import limit (southward flow) when binding



1.4.1 Inter-regional settlement residue

Positive inter-regional settlement residue (IRSR) across the NEM's regulated interconnectors totalled $81 million in Q1, an increase of $11 million on Q1 2022 but down from the higher levels of Q2 to Q4 2022 (Figure 56). Positive IRSR on flows into New South Wales at $46 million accounted for the majority (57%) of this total, increasing by $17 million on a year ago with most of this increase attributable to higher southward flows on QNI (Section 1.4). The other significant increase on Q1 2022 was on flows from Victoria to South Australia where positive IRSR grew from $13 million to $22 million due to episodes of South Australian spot price volatility (Section 1.2.2). Conversely, positive IRSR on flows into Queensland fell from $24 million in Q1 2022 to $7 million this Q1 with much lower volatility in Queensland spot prices (Section 1.2.2) and lower imports from New South Wales.

Figure 56 Increase in year on year Q1 positive IRSR, down on other quarters of 2022

Quarterly positive IRSR

Negative residue management

Negative IRSR grew slightly from -$9.8 million a year ago to -$11.3 million in Q1 2023 (Figure 57). After the cessation of the large negative residues which were incurred in 2021 on flows from Queensland into New South Wales, the result of outage works on QNI over that year, the recent trend most evident in negative IRSR has been the size and growth of negative Victorian residues. These reached -$8 million in Q1 2023, up from -$6 million in Q1 2022. This reflects the impact of constraints which have progressively reduced transfer limits between Victoria and New South Wales in daytime hours, and forced VNI flows southwards in a growing proportion of those hours (Figure 58), despite Victorian spot prices typically being much lower than those in New South Wales.

Figure 57 Negative IRSR dominated by flows into Victoria

Quarterly negative IRSR

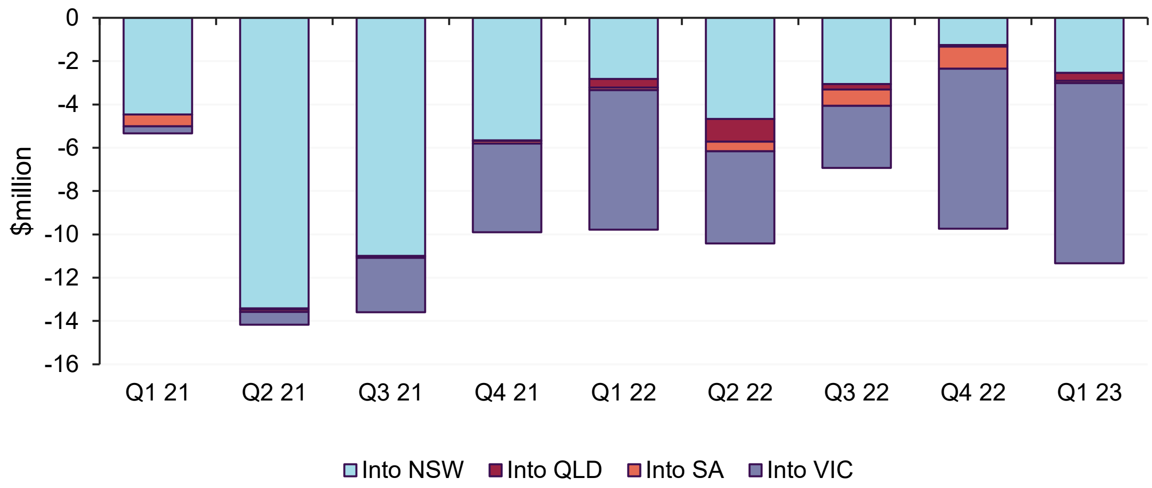
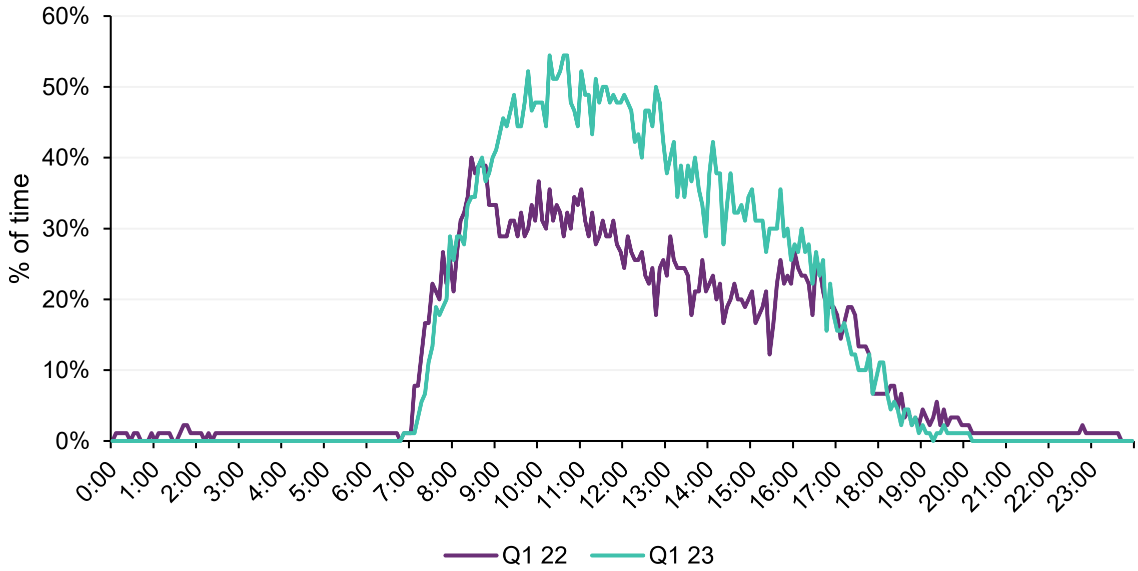


Figure 58 Increased frequency of forced counter-price flows from New South Wales to Victoria

Frequency of forced counter-price flows on VNI



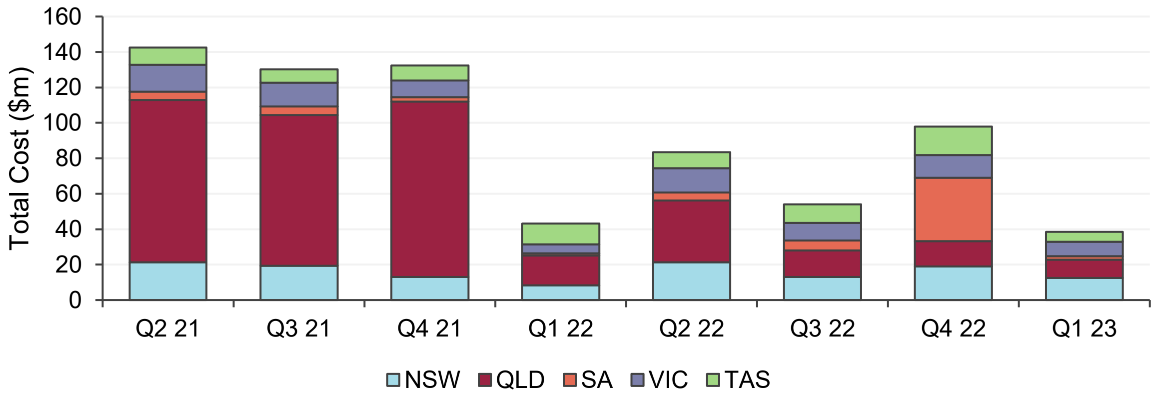
1.5 Frequency control ancillary services (FCAS)

FCAS costs for Q1 2023 totalled $38 million, down by $5 million from Q1 2022 and $60 million on Q4 2022 when costs were elevated by separate transmission events affecting South Australia and Tasmania. Relative to Q1 2022:

- Costs fell $7 million in Queensland, where a QNI-related outage in March 2022 caused high contingency lower FCAS prices last Q1, and by $6 million in Tasmania where prices for raise FCAS services (both regulation and contingency) were significantly lower this quarter than in Q1 2022.
- Partially offsetting these falls were higher overall costs in New South Wales (up $4 million), Victoria ($3 million) and South Australia ($1 million) mostly driven by higher prices for contingency lower services in these regions, increasing from a quarterly average of $1.2/MWh a year ago to $4.5/MWh this Q1.

Figure 59 Decreasing Q1 FCAS costs

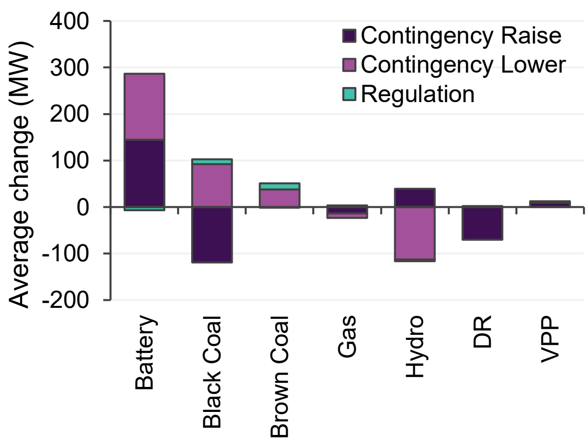
Quarterly FCAS costs by region



Growth in commissioned grid-scale battery capacity over the past 12 months (Section 1.3.6) meant that FCAS provision by batteries increased strongly on Q1 2022 levels (Figure 60), and that their total share of FCAS markets, by volume, continues to substantially exceed provision by other technologies (Figure 61).

Figure 60 Battery FCAS provision up year-on-year

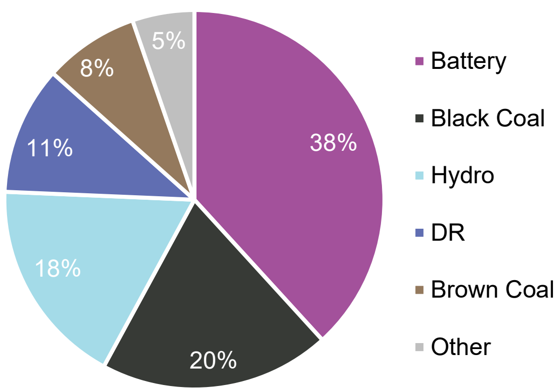
Change in FCAS supply by technology – Q1 2023 vs Q1 2022



Note: “DR” = Demand Response; “VPP” = Virtual Power Plant

Figure 61 Batteries lead FCAS market shares

FCAS volume market share by technology – Q1 2023

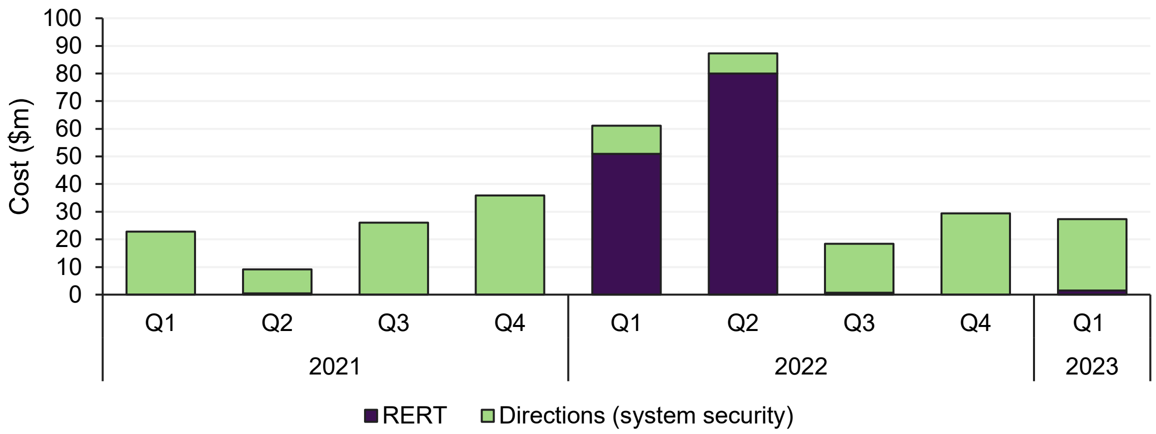


1.6 Power system management

Power system management costs reported in this QED[27] totalled $27.3 million in Q1 2023, attributable to system security directions in the South Australian ($25.5 million) and Queensland region ($0.3 million) and RERT ($1.5 million) (Figure 62). Aggregate costs declined $33.8 million from Q1 2022 when costs were driven up by high RERT expenses in Queensland.

Figure 62 System security direction costs up but RERT costs down in Q1 2023

Estimated quarterly system costs by category



- AEMO activated RERT in Queensland on 3 February 2023 due to forecast LOR 2 conditions. Through this event, 115 MW of capacity was contracted from multiple participants. There was 95 MW pre-activated, while 31 MWh of reserve was activated between 1705 hrs and 1930 hrs (varying between 10 MW and 21 MW over the duration). Estimated payments for the RERT event totalled $1.5 million[28], $917,000 due to pre-activation of reserve and $558,000 for activated energy.
- The estimated cost of system security directions to South Australian synchronous generators increased to $25.5 million in Q1, up $15.4 million from Q1 2022, but down $3.9 million on Q4 2022.

1.6.1 South Australian system security directions

Low daytime spot prices and strong VRE output meant that South Australian gas-fired synchronous generators regularly sought to decommit from the system in Q1. To maintain system security, AEMO was required to direct synchronous generating units to remain online slightly more frequently in Q1 2023 (covering 50% of dispatch intervals in the quarter), than in Q1 2022 (46% of intervals). Direction costs increased much more sharply, from $10.1 million a year ago to $25.5 million this Q1, driven by the very large increase in the compensation price paid to directed participants, from $112/MWh in Q1 2022 to $349/MWh in Q1 2023. The rise in this compensation price flows directly from the extremely high spot prices prevailing in Q2 and Q3 2022[29].

[27] QED reporting excludes reliability direction costs and compensation payments for operating under administered pricing or market suspension, as finalisation of these amounts can occur many months after the close of the relevant quarter.

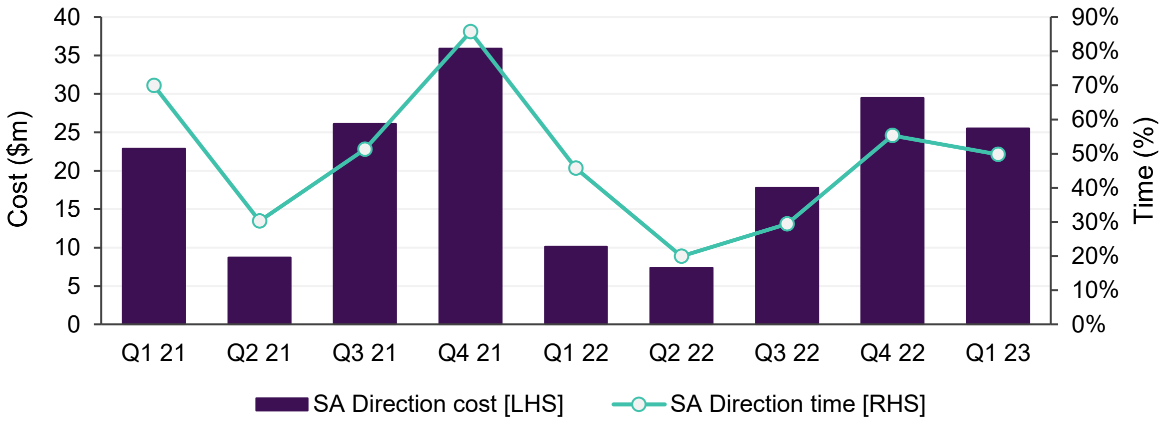
[28] AEMO 2023, RERT Activation Estimates 3 Feb 2023: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2023/rert-activation-estimates-report-for-3-feb-2023-final.pdf?la=en.

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

Time on direction and compensation costs were both slightly lower in Q1 than in Q4 2022 preceding, with similar factors driving results in both quarters.

Figure 63 South Australia system security direction time up slightly on Q1 2022 but costs rise sharply

Time and cost of energy only system security directions – South Australia Q1 2021 to Q1 2023



Corresponding with the changes in time on direction this quarter, the average volume of gas-fired generation directed and the share of total South Australian gas-fired output that this volume contributed were both slightly up on Q1 2022, but lower than in Q4 2022 (Figure 64). At 37 MW and 12% respectively, both measures remain very substantially below their levels in Q4 2021, the last quarter before full operation of the state's four synchronous condensers, when an average 127 MW of volume was directed representing 38% of gas-fired output. Statistics for the number of units directed simultaneously over the quarter were similar to those for Q1 and Q4 2022, with a small increase in directions for two units to remain online in Q1 2023 (Figure 65).

Figure 64 Slight increases in SA gas volumes directed

South Australian gas-fired generation directed – volume and share

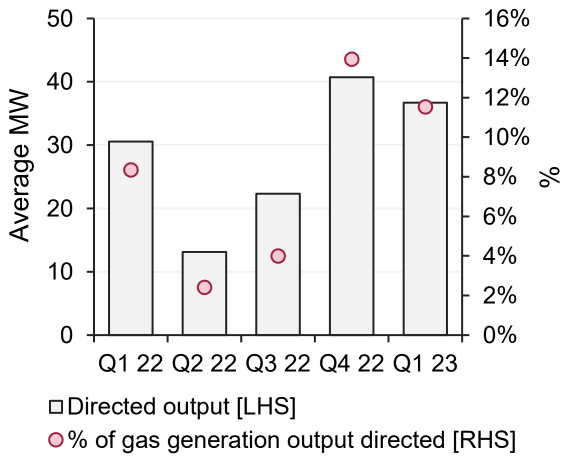
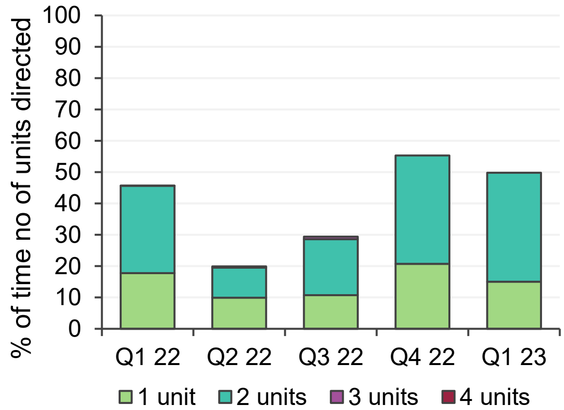


Figure 65 Minor increase in two-unit directions

Number of units simultaneously directed – proportion of quarter



2 Gas market dynamics

2.1 Wholesale gas prices

Quarterly average prices continued the downward trend observed in Q4 2022, with prices in January and February comparable to December, before declining further in March. The average price across all AEMO markets in March was $9.43/GJ, the lowest since January 2022 which was $8.81/GJ. The quarterly average price across all AEMO markets was $11.86/GJ, compared to $9.93/GJ in Q1 2022 (Table 4). Despite the recent declines this is the highest Q1 price on record.

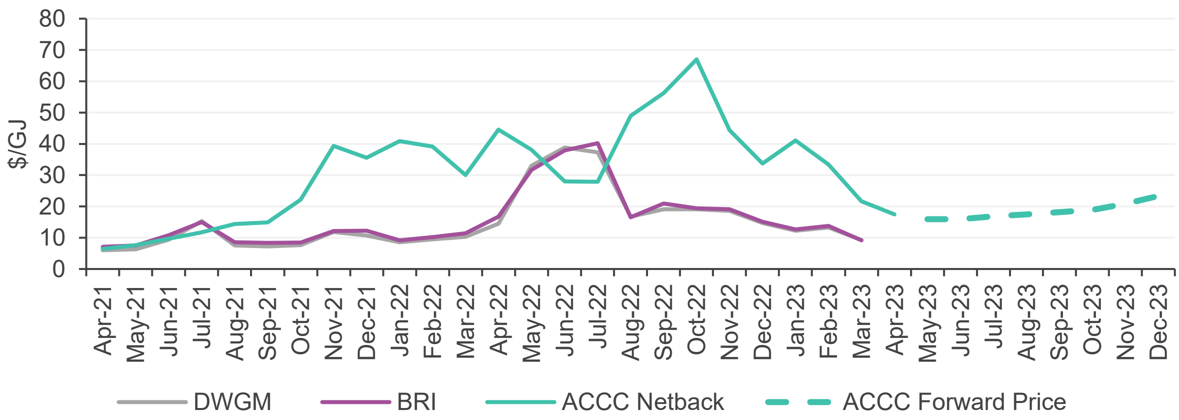
Table 4 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q1 2023	Q4 2022	Q1 2022	Change from Q1 2022
DWGM	11.59	17.43	9.47	22%
Adelaide	12.66	18.61	10.18	24%
Brisbane	11.87	17.86	10.21	16%
Sydney	12.11	17.71	9.81	23%
GSH	11.86	17.33	9.97	11%

International prices continued to fall, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, with corresponding forward prices ranging from around $16/GJ to $24/GJ over the next 12 months (Figure 66). Drivers for international prices are discussed in Section 2.1.1.

Figure 66 Domestic prices continue to ease before falling further in March

ACCC netback and forward prices[30], DWGM and STTM Brisbane average gas prices by month

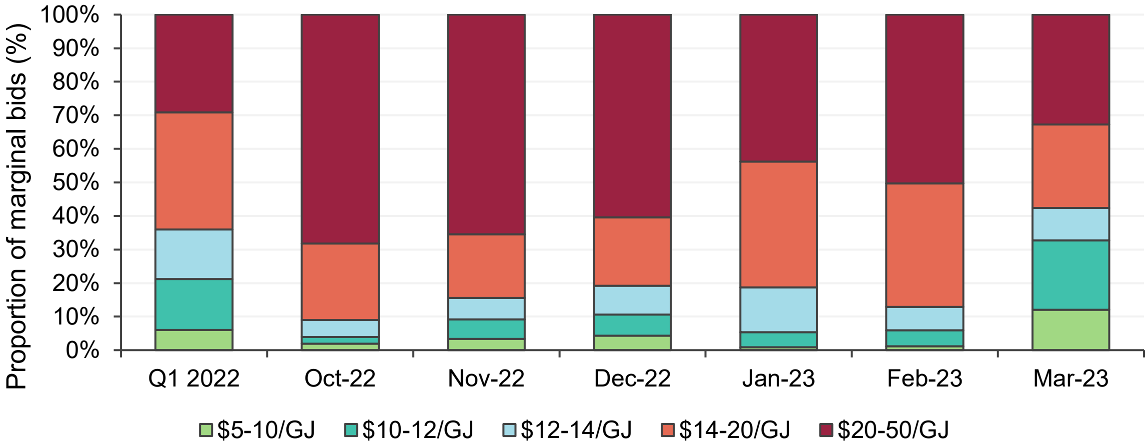


Domestic prices remained below international prices. Contributing factors were reduced demand across commercial, industrial and residential segments, a large reduction in gas supply to Queensland from southern markets, coinciding with continued train outages at QCLNG, lower gas-fired generation demand, and high Iona storage inventory. This prompted market participants to increase bid volumes below $12/GJ, most notably in March (Figure 67).

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

Figure 67 DWGM bids reflecting lower prices coinciding with lower demand

DWGM – proportion of marginal bids[31] by price band



2.1.1 International energy prices

Thermal export coal prices started the quarter at $584/tonne and saw a sharp drop towards the end of January falling to $357/tonne, finishing the quarter at $265/tonne (Figure 68). Throughout 2022 following the invasion of Ukraine European coal use increased and imports were stockpiled ahead of winter. However due to a milder than expected northern hemisphere winter, European coal inventory remains high, coinciding with a decline in thermal coal prices.

China begun withdrawing its informal import restrictions on Australia coal in early January, although given China's thermal coal imports are on a declining path, Australian exports to China are not expected to return to pre-2019 levels[32].

Figure 68 Traded thermal coal prices drop significantly during quarter

Newcastle export thermal coal AUD/tonne daily

Source: Bloomberg ICE data

Asian LNG prices continue to decline, with an average quarterly price of $AU25/GJ, $20/GJ lower than the prior quarter and $15/GJ lower than the same period last year (Figure 69). Similarly to thermal coal, European gas inventories reached a record high following a warmer than expected winter, bolstered by LNG imports from the

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

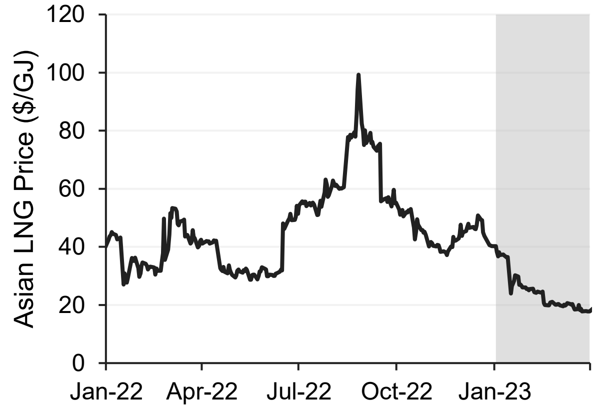
[32] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly March 2023: https://www.industry.gov.au/publications/resources-and-energy-quarterly-march-2023.

US. This is despite an expectation that global gas markets will remain tight and volatile until the end of 2024 as European buyers seek alternative supplies of LNG from Russian pipeline gas.

Brent Crude oil prices averaged AU$120/barrel this quarter, down from $15/barrel in Q4 2022 (Figure 70). Contributing to this price drop was a US$60/barrel cap imposed on Russian crude oil by the European Union and G7 countries (including Australia) introduced from 5 December 2022[33].

Figure 69 Asian LNG prices soften

Asian LNG price in A$/GJ daily



Source: Bloomberg ICE data

Figure 70 Brent Crude oil prices see decline

Brent Crude oil in A$/Barrel daily

Source: Bloomberg ICE data

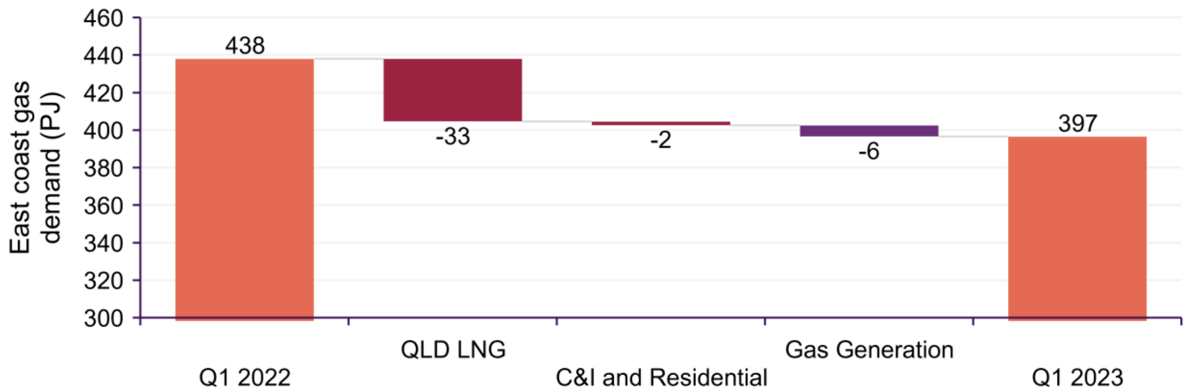
2.2 Gas demand

Total east coast gas demand decreased by 9% compared to Q1 2022 (Figure 71,Table 3).

There were decreases in AEMO markets demand (-3 PJ), gas-fired generation (-6 PJ), and a large decrease in gas usage for Queensland LNG production (-33.5 PJ). This was the lowest Q1 demand since 2016 when Australia Pacific LNG (APLNG) and Gladstone LNG (GLNG) were still in commissioning phase, and is the lowest since all three Queensland LNG export facilities have been fully operational.

Figure 71 Large Queensland LNG export decrease biggest contributor to lower east coast gas demand

Components of east coast gas demand change – Q1 2022 to Q1 2023



[33] European Commission, Questions and Answers 2022, G7 agrees oil price cap to reduce Russia's revenues, while keeping global energy markets stable: https://ec.europa.eu/commission/presscorner/detail/en/QANDA_22_7469

Table 3 Gas demand – quarterly comparison

Demand (PJ)	Q1 2023	Q4 2022	Q1 2022	Change from Q1 2022
AEMO Markets *	50.7	68.7	52.6	-2 (-4%)
Gas-fired generation **	20.7	17.8	26.8	-6 (-23%)
QLD LNG	325.2	339.9	358.7	-33 (-9%)
TOTAL	396.6	426.4	438.0	-41 (-9%)

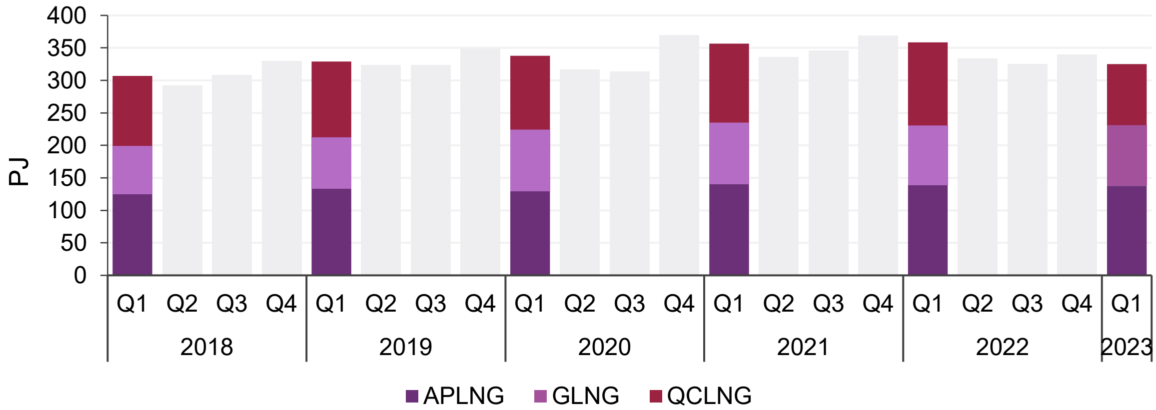
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand fell to its lowest Q1 level since 2018, caused by a significant decrease at QCLNG. As occurred in Q4 2022, QCLNG experienced train outages during the quarter, exporting under 100 PJ for the second quarter in a row and making Q1 2023 QCLNG's lowest export quarter since Q4 2017.

By participant, QCLNG demand decreased by 33.6 PJ, APLNG decreased by 1.2 PJ, while GLNG increased by 1.3 PJ (Figure 72). 84 cargoes were exported during the quarter, down from 92 cargoes in Q1 2022.

Figure 72 QCLNG flows to Curtis Island lowest for Q1 since 2018, driving reduced exports

Total quarterly pipeline flows to Curtis Island



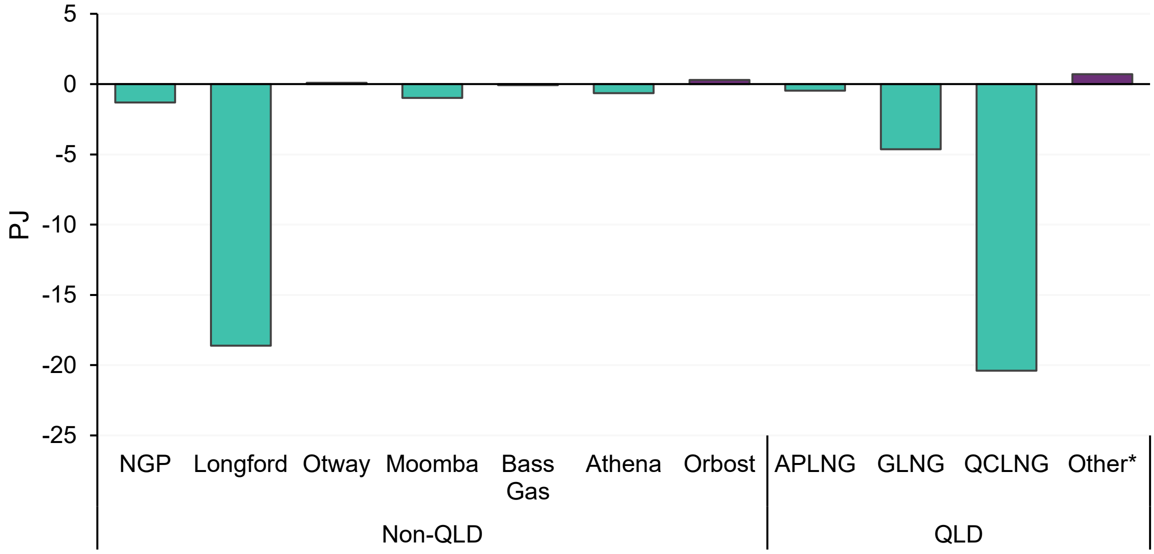
2.3 Gas supply

2.3.1 Gas production

East coast gas production decreased by 46.1 PJ compared to Q1 2022 (-10%, Figure 73).

Figure 73 Large production falls in Queensland and at Longford

Change in east coast gas supply – Q1 2023 vs Q1 2022



Key changes included:

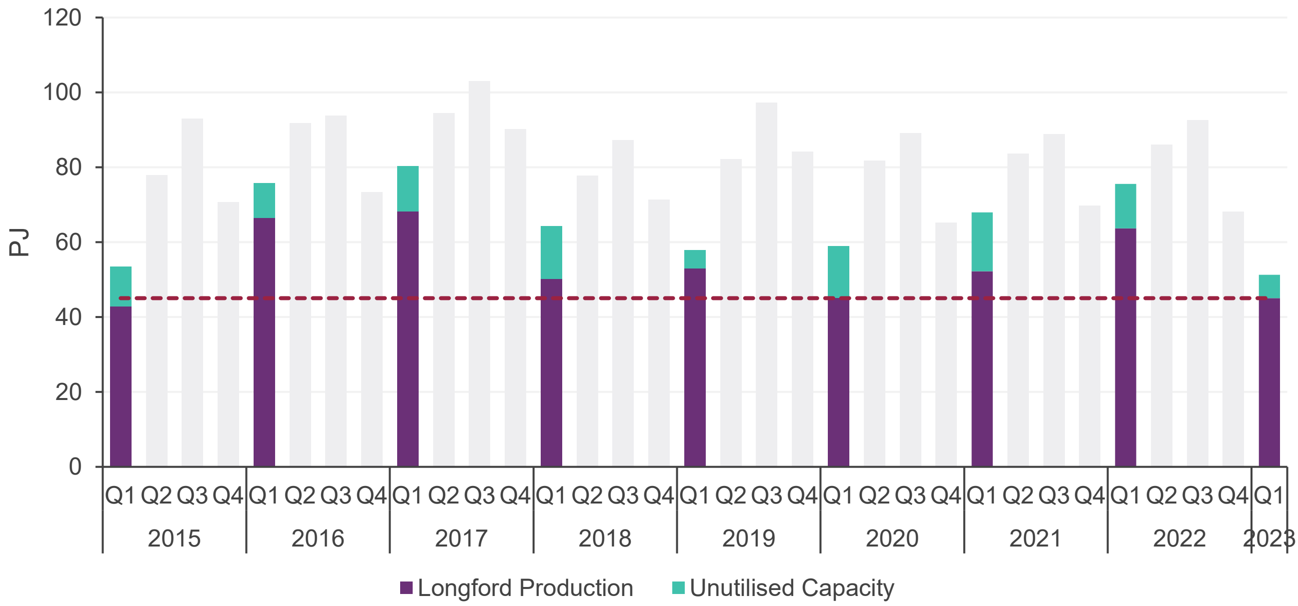
- Decreased Queensland production (-24.8 PJ), with QCLNG decreasing by 20.4 PJ, GLNG by 4.6 PJ, and APLNG by 0.5 PJ. While this was a significant production decrease, gas demand for Queensland LNG exports fell by 33.5 PJ, meaning that an additional 8.7 PJ of supply associated with Queensland LNG projects went into the domestic market compared to Q1 2022 (Figure 74).
- Decreased Victorian production (-19 PJ), mainly driven by lower production at Longford (-18.6 PJ). Longford's production of 45 PJ was its lowest for any quarter since Q1 2015. Longford's utilisation remains high however at 88%, compared to 84% in Q1 2022 (Figure 75).
- Decreased Moomba production (-1.0 PJ), continuing the trend of lower Moomba production year on year. Production was also affected by a pipeline outage in January and February.
- Decreased supply from the Northern Territory (-1.3 PJ) via the Northern Gas Pipeline (NGP). This coincided with lower production at the Yelcherr gas plant (-3.1 PJ).

Figure 74 Queensland domestic supply increased to highest Q1 level since 2020

Queensland domestic supply compared to Victorian gas exports by quarter

Figure 75 Lowest Longford production since Q1 2015

Longford production and unutilised available capacity by quarter



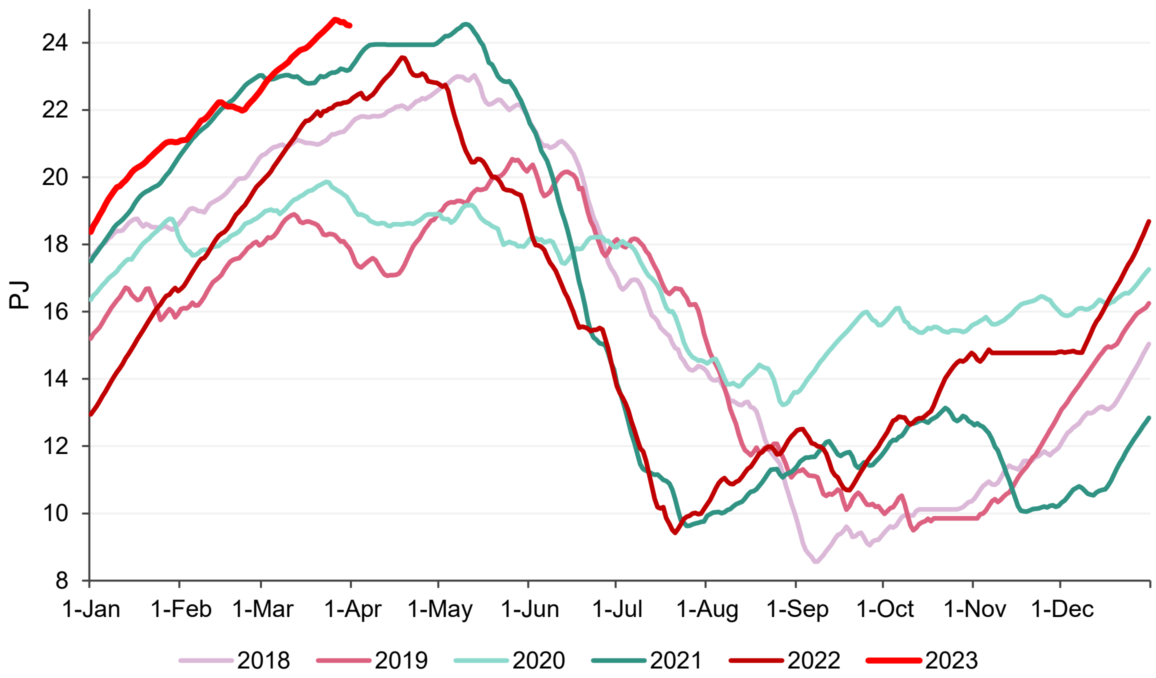
2.3.2 Gas storage

While Iona's official capacity is rated at 24 PJ, the Iona UGS facility finished the quarter with an inventory of 24.5 PJ, 2.2 PJ higher than at the end of Q1 2022 (Figure 76) and the highest end to a Q1 since reporting began in 2017. This suggests Iona's official capacity rating is conservative, with scope to go slightly higher.

Similarly to Q4 2022, factors contributing to the sharp increase in storage inventory included lower demand, including from gas-fired generation, and a reduction in supply to Queensland from southern markets, coinciding with QCLNG's reduced LNG exports due to train outages.

Figure 76 Iona storage at its highest end to Q1 since storage levels began reporting

Iona storage levels

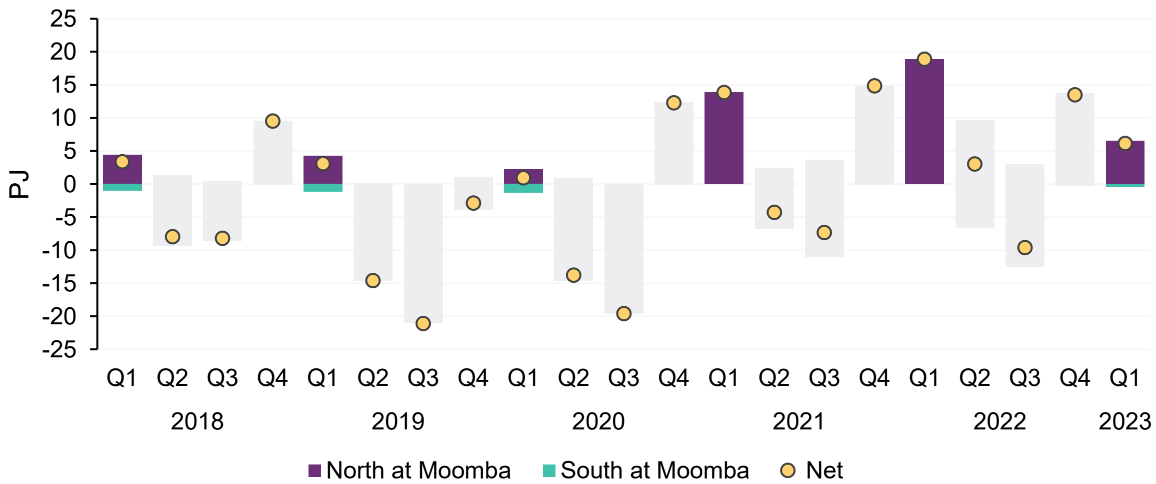


2.4 Pipeline flows

Compared to Q1 2022, there was a 12.7 PJ decrease in net transfers into Queensland on South West Queensland Pipeline (SWQP, Figure 77). Decreased flows coincided with a decrease in Queensland LNG export demand and an increase in net domestic supply associated with the Queensland LNG projects.

Figure 77 Net northwards flows into SWQP decrease in Q1 2023

Flows on the South West Queensland Pipeline at Moomba

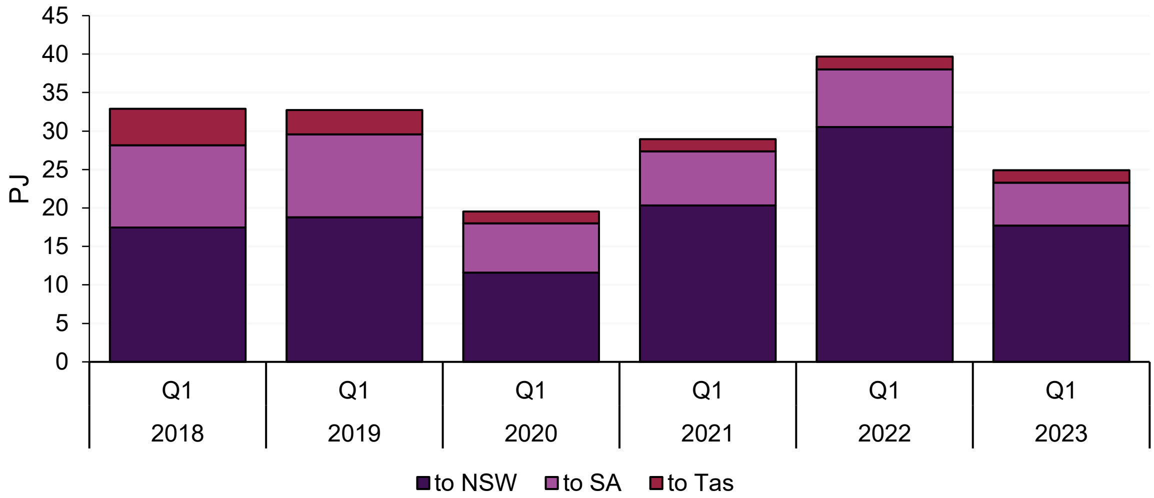


Victorian net gas transfers to other states decreased by 14.7 PJ from Q1 2022 levels, due to lower southern market demand, a decrease in Victorian production and increased net domestic production in Queensland

(Figure 78). This represented the lowest net transfer out of Victoria for any quarter since Q3 2020, and the lowest Q1 since Q1 2020, when Longford underwent heavy maintenance. There were decreased flows from Victoria to New South Wales comprising 3.4 PJ via Culcairn, compared to 7.5 PJ in Q1 2022, and 14.5 PJ via the Eastern Gas Pipeline (EGP), down from 23.1 PJ in Q1 2022. Flows from Victoria to South Australia decreased by 1.9 PJ, mostly due to lower gas-fired generation.

Figure 78 Victorian Q1 transfers decreased coinciding with decrease in Victorian production

Victorian net gas transfers to other regions – Q1s

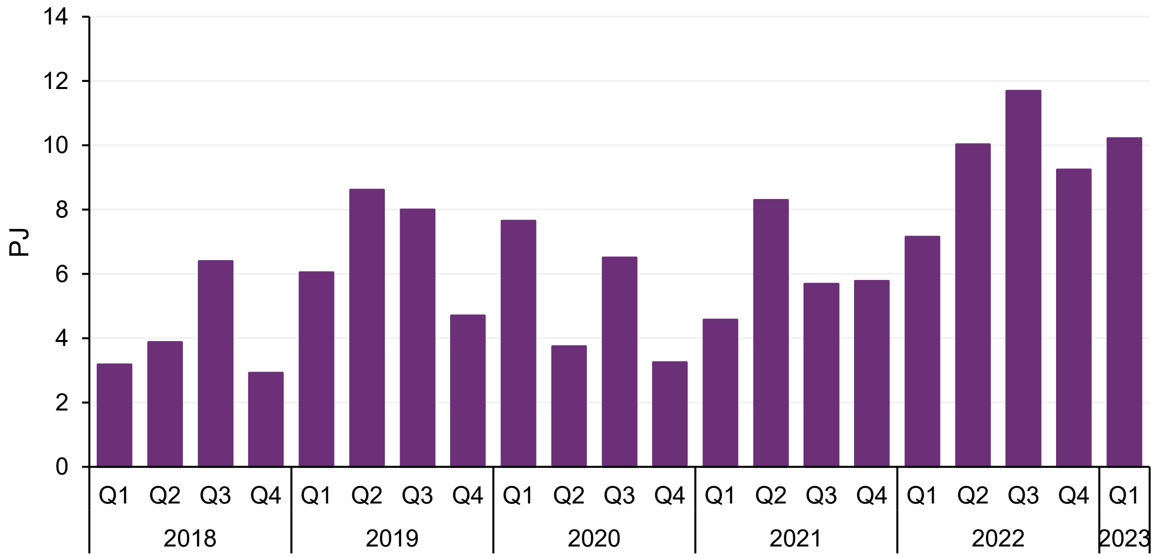


2.5 Gas Supply Hub (GSH)

In Q1 2023 there were increased trading volumes on the GSH compared to Q1 2022 (Figure 79), with traded volume up 3.1 PJ. The traded volume of 10.2 PJ is the highest on record for any Q1, surpassing the previous highest of 7.7 PJ in Q1 2020.

Figure 79 Highest Gas Supply Hub Q1 volumes on record

Gas Supply Hub – quarterly traded volume



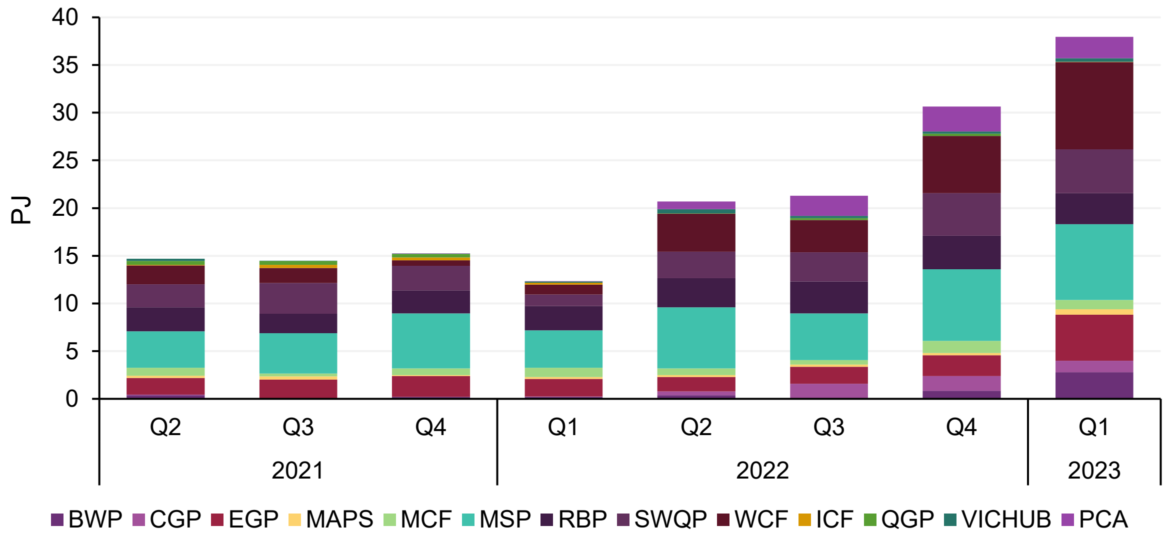
2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes continue to set new quarterly records, 7.3 PJ higher than the previous level set in Q4 2022, and 25.6 PJ higher than Q1 2022 (Figure 80). Compared to Q4 2022, the largest increases occurred on the Wallumbilla Compressor (+8.1 PJ), the SWQP (+3.4 PJ), the Moomba to Sydney Pipeline (MSP, +4.0 PJ), the EGP (+3.0 PJ) and the Berwyndale to Wallumbilla Pipeline (BWP, +2.6 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 $0.18/GJ, the MSP Culcairn to Sydney path which averaged $0.10/GJ, and the EGP North which averaged $0.05/GJ.

Figure 80 Highest quarterly Day Ahead Auction utilisation since market start

Day Ahead Auction volumes by quarter



2.7 Gas – Western Australia

2.7.1 Gas consumption

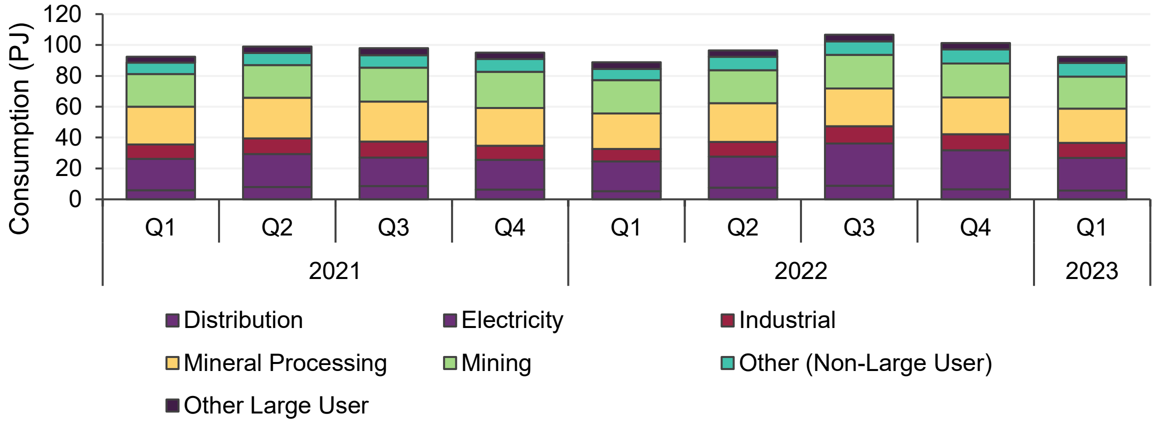
A total of 92 PJ was consumed in the Western Australian domestic gas market in Q1 2023. This is an increase of 3.6 PJ (+4%) from Q1 2022 and a decrease of 9 PJ (-8.9%) from Q4 2022 (Figure 81).

Key drivers of change compared to Q1 2022 included:

- an increase in gas consumption for electricity generation by 1.9 PJ (+10%). This can be attributed to lower coal-fired generation availability in Q1 2023 compared to Q1 2022 (see Section 3.2.1).
- The increase in consumption for electricity generation was offset by a decrease in consumption by the mineral processing sector by 0.9 PJ (-3.9%). This was largely due to the three Alcoa refineries collectively decreasing their consumption by 1.6 PJ. Consumption by the mining sector also decreased by 0.8 PJ (-3.6%). This was led by the Telfer Gold Mine Power Station, with a 0.2 PJ reduction.

Figure 81 Western Australia domestic gas consumption for Q1 2023 was an increase of 4% on Q1 2022

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



2.7.2 Gas production

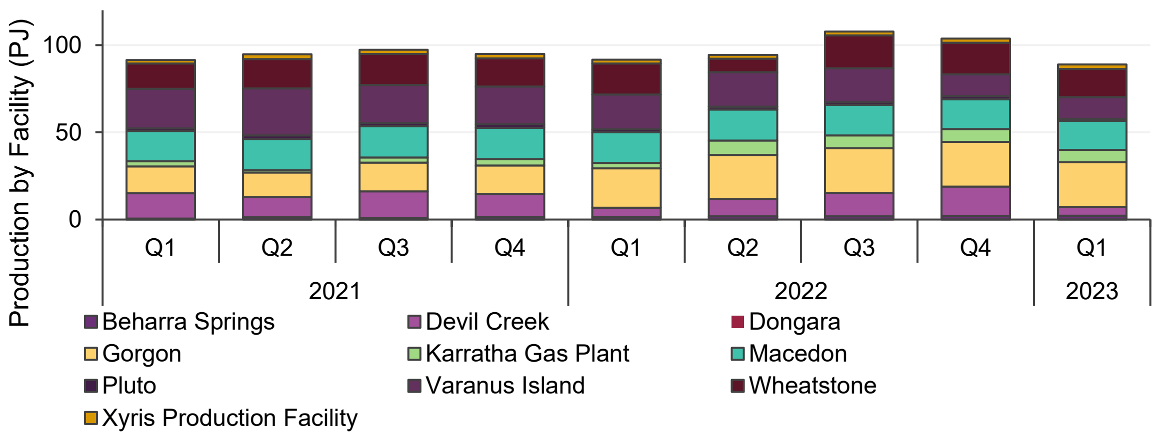
Q1 2023 saw total Western Australian domestic gas production of 89 PJ, a reduction of 2.7 PJ (-2.9%) from Q1 2022 (Figure 82). In both quarters Devil Creek experienced outages, with an overall quarterly production of 5 PJ, well below normal operating levels which average around 14 PJ. Future production from Devil Creek is expected to remain limited or cease due to depletion of reserves in the Reindeer gas field[34].

Varanus Island also saw a large reduction compared to Q1 2022, down 7.6 PJ (-38%) due to technical issues experienced since November 2022; however production data from midway through Q1 2023 indicates the facility has since returned to full production. These reductions were partially mitigated by increases from Gorgon facility, up 3.1 PJ (+14%), and Karratha Gas Plant, up 4.2 PJ (+141%).

When compared with Q4 2022, gas production decreased by 15 PJ (-14%) primarily driven by the 12 PJ (-70%) reduction from Devil Creek.

Figure 82 Western Australia domestic gas production down 3% on Q1 2022 and falls 14% from Q4 2022

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



[34] See the 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.

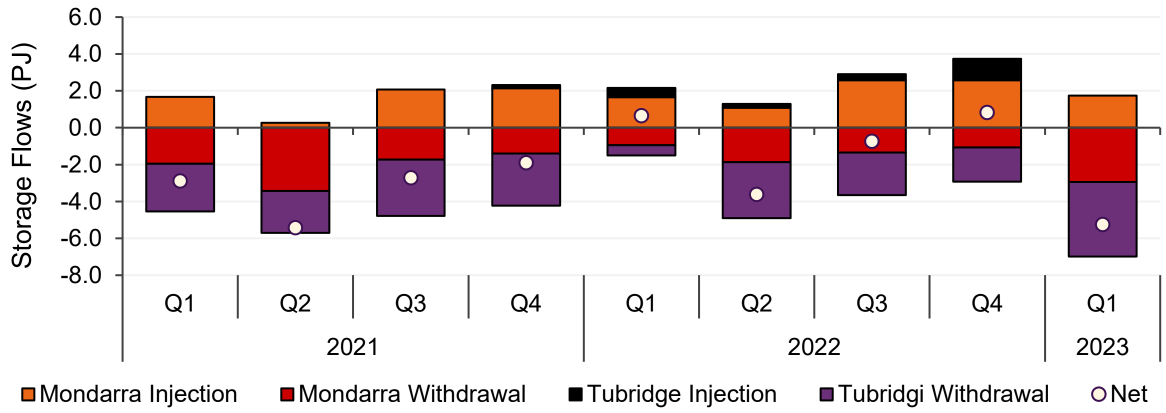
2.7.3 Storage Facility behaviour

Storage facility flows for Q1 2023 reflected the reduction in production for the quarter. There was a net outflow of gas from storage of 5.2 PJ (Figure 83). This contrasts with Q1 2022 which saw a net inflow into storage of 0.7 PJ.

From a facility perspective, net outflows from Mondarra were 1.2 PJ. For Tubridgi, there was zero injection for the quarter resulting in a 4 PJ net outflow.

Figure 83 Q1 2021 saw net outflows from storage of 5.2 PJ

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



2.7.4 Gas supply disruption event

A significant gas supply disruption event occurred during the period of 6 to 13 January 2023 requiring AEMO to activate the Emergency Management Facility (EMF)[35] to support an industry response to maintain linepack above critical levels[36].

The event was triggered by an unplanned outage at the Wheatstone Facility on Thursday, 5 January (Figure 84) which caused supply of approximately 215 TJ/day to be removed from the WA gas market (approximately 20% of total production). This occurred while other production facilities, Varanus Island and Devil Creek, were also constrained due to technical issues, reducing available production capacity by 445 TJ/day. Given the production shortfall, linepack on the Dampier to Bunbury Natural Gas Pipeline (DBNGP) approached critical levels.

Australian Gas Infrastructure Group (AGIG) notified AEMO of the Red Linepack Capacity Adequacy (LCA) status of the DBNGP at 2130 hrs on 5 January 2023, and the EMF was activated the following day to support a coordinated response from the WA gas industry, led by the Coordinator of Energy[37].

Industry response

Voluntary response from WA gas market participants mitigated further deterioration of the DBNGP linepack on Friday, 6 January and resulted in improvement over the weekend. The response included increased production output and decreased consumption, such as:

[35] This is an online information service which is part of the GBB, activated by AEMO at the direction of the Coordinator of Energy in the event of an emergency or gas supply disruption and accessible only by certain parties. The EMF places additional obligations to provide alternative fuel information or ad hoc information such as gas in storage, as well as regular submissions are required earlier.

[36] "Linepack" is the total volume of gas physically stored in a pipeline and must remain within a tolerance determined by the pipeline operator. Linepack levels are managed by monitoring and controlling supply and withdrawals.

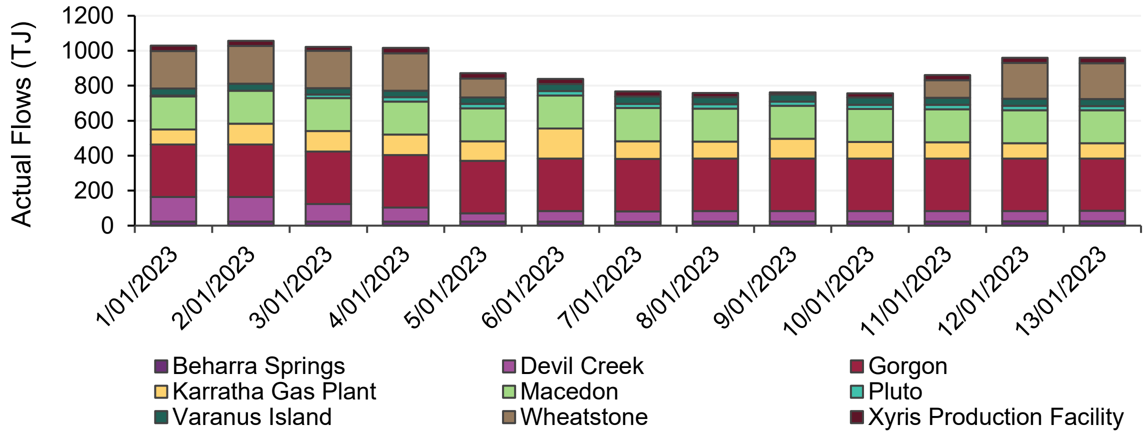
[37] The Coordinator of Energy is a role established under regulations, the role is performed by the Deputy Director General of Energy Policy WA - https://www.wa.gov.au/organisation/energy-policy-wa.

- The Karratha Gas Plant increased production above nominations on Friday 6 January to support the pipeline, but could not maintain further support (see Figure 84).
- Yarra Pilbara Liquid Ammonia Plant decreased consumption on Friday, 6 January by shutting down operations.
- Alcoa Kwinana, Alcoa Pinjarra and Worsley Alumina all briefly stepped down their gas usage and utilised diesel for the interim.

The industry response avoided further deterioration of the linepack level on Saturday, 7 January and assisted its return to healthy status on Sunday, 8 January. The DBNGP moved to Amber LCA status once linepack had recovered and remained Amber until the Wheatstone Facility returned to service on 11 January.

Figure 84 The outage at Wheatstone facility caused a 20% drop in production for the WA gas market

Production facilities daily output 1 January 2023 – 13 January 2023

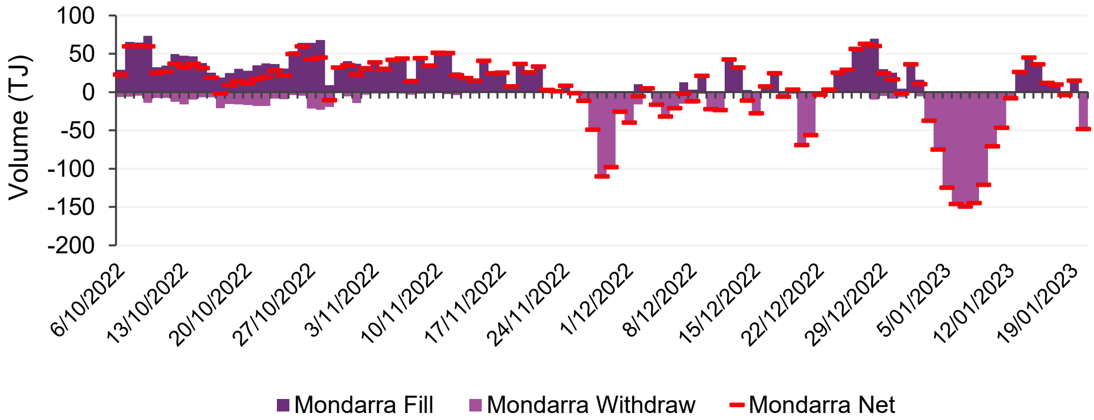


Impact on the Mondarra Storage Facility

Withdrawals from Mondarra Storage Facility began to ramp up on the day of the Wheatstone outage and remained close to a maximum withdrawal rate (150 TJ/day) between 6 January 2023 and 8 January 2023 (Figure 85). On 13 January 2023, the day after the EMF was deactivated, injections into Mondarra recommenced. Figure 85 also displays the impact of the Varanus Island outage which commenced in November 2022 resulting in high withdrawal rates.

Figure 85 Withdrawals from Mondarra increased over the disruption event

Storage flows at Mondarra Facility – 6/10/2022 to 19/01/2023



3 WEM Market Dynamics

3.1 Electricity demand

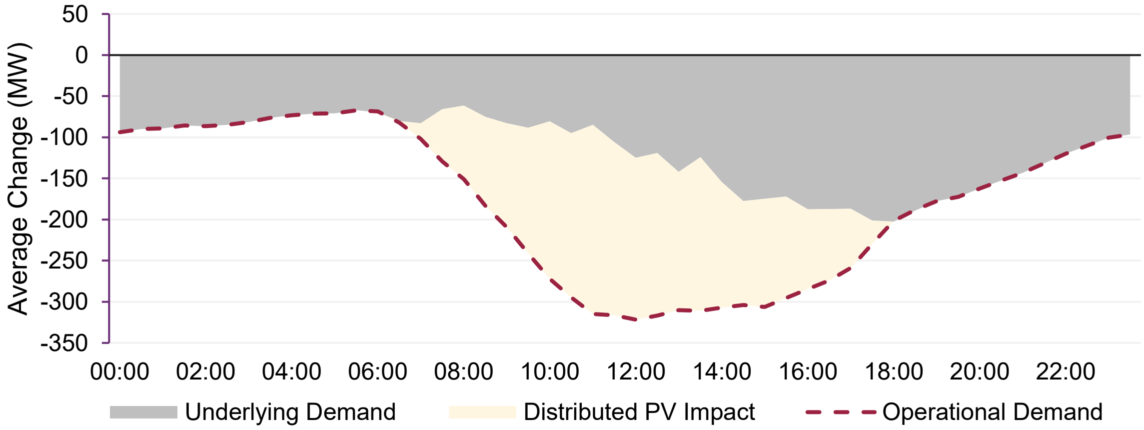
The WEM's average operational demand[38] was 2,060 MW in this quarter, down 179 MW (-8.0%) compared to Q1 2022.

Lower operational demand was observed in every interval, with a more pronounced reduction in the middle of the day, driven by a 15.8% increase in average distributed PV[39] generation (Figure 86).

This quarter's average underlying demand[40] was 2,512 MW, down 118 MW (-4.5%) on Q1 2022. This decrease can be attributed largely to milder temperatures leading to reduced cooling-related demand; both the average temperature and the average maximum temperature were lower than in Q1 2022 (1.3°C and 1.4°C cooler respectively).

Figure 86 Operational demand decreases driven by increased distributed PV output and milder weather

Change in average WEM demand components by time of day – Q1 2022 vs Q1 2023



3.1.1 Maximum operational demand

Maximum operational demand this quarter was 3,676 MW, recorded in the 1600hrs interval on Thursday 2 March 2023 (Figure 87). This was caused by a combination of high temperatures and unusual cloud coverage:

- 2 March was among the hottest days of the quarter with a 36.9°C daily maximum temperature leading to high underlying demand.

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

[39] 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 photovoltaic 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.

[40] 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.

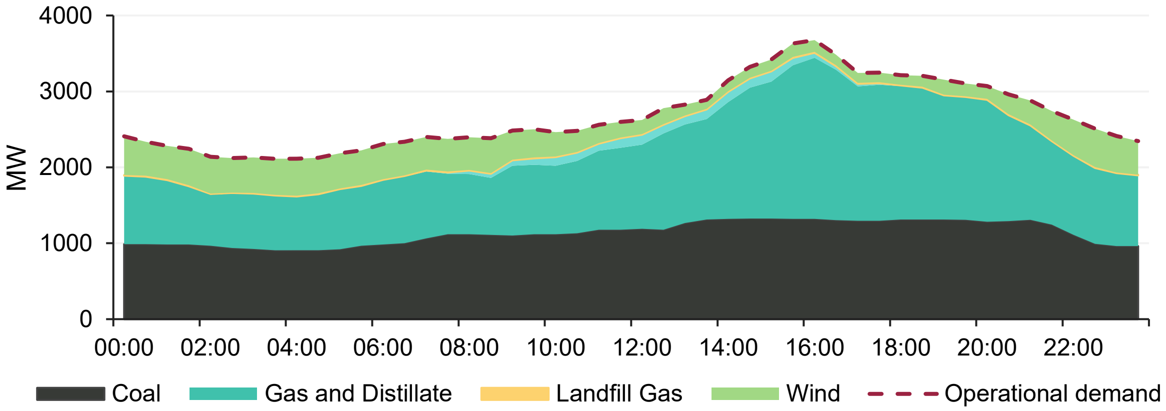
- Whilst the daily maximum operational demand is usually set later in the day when the sun sets, reducing distributed PV output to zero, on this day high cloud coverage during the afternoon caused a low level of distributed PV output and a peak in operational demand at around 1600hrs.

This example puts the increased sensitivity to weather conditions of a modernising energy grid into sharp focus, emphasising one of the central challenges of the energy transition. In this case, two uncontrollable external variables, in conjunction, caused a sudden and unforeseen spike in operational demand that put pressure on the SWIS.

However, Q1 2023 maximum operational demand was 303 MW lower (-7.6%) than the value recorded in Q1 2022 (3,980 MW), in line with the cooler temperatures seen during this quarter (see Section 3.1)

Figure 87 Fuel mix and operational demand on 2 March 2023

Fuel mix and operational demand by trading interval on day of maximum operational demand



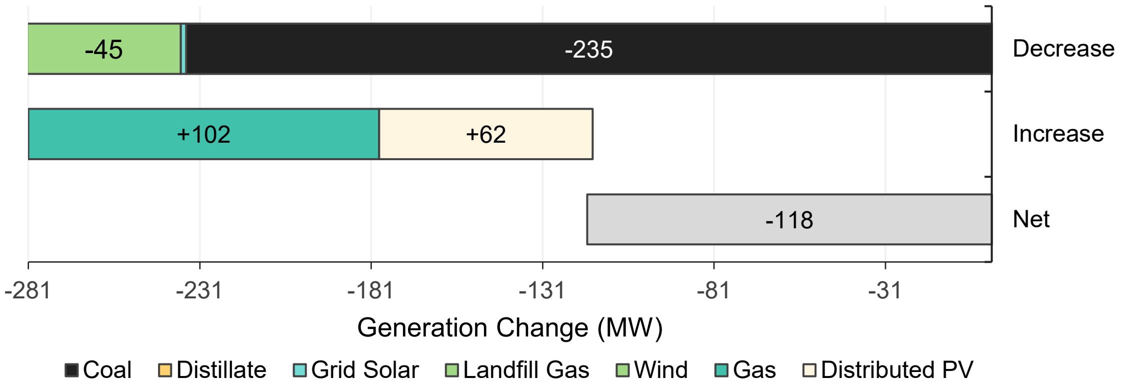
3.2 Electricity generation

3.2.1 Change in fuel mix

The total average output in the WEM during Q1 2023 was 118 MW lower than Q1 2022, in line with the overall decrease in underlying demand (see Section 3.1). Relative to Q1 2022 there was a large decrease in coal-fired generation, which was largely balanced by an increase in gas-fired generation and estimated distributed PV generation (Figure 88).

Figure 88 Decrease in coal-fired generation offset by increase in gas-fired and distributed PV output

Change in quarterly average generation output – Q1 2023 vs Q1 2022



Changes in generation by fuel type and time of day, compared to Q1 2022 (Figure 89, Table 4) were:

- Average coal-fired generation reached a record Q1 low of 799 MW, a decrease of 235 MW (-23%) on the same quarter last year. Due to the operation of the coal preservation[41] program during January 2023, coal-fired generation availability has been lower compared to Q1 2022, leading to decreased coal-fired generation in every interval. Conversely, average coal-fired generation was up 361 MW (+83%) on Q4 2022 due to the end of the coal preservation period - which operated throughout Q4 2022 – bringing coal availability up.
- Wind generation decreased by an average of 45 MW (-9%) and fell in every interval with a small bias towards the late morning. This can be attributed to a combination of lower average wind availability and constraints applied to the Synergy Balancing Portfolio in periods of low load to maintain power system security and reliability, which may displace generation from facilities not accredited to provide Ancillary Services.
- Grid-scale solar generation remained stable, with a small decrease of 2 MW (-3%) on average.
- Estimated distributed PV continues its growth trend, increasing by 62 MW (+16%) on average. This quarter recorded the second-highest average distributed PV generation of any quarter, at 452 MW.
- Gas-fired generation increased by an average of 102 MW (+16%). This increase occurred at almost all times of day and was a consequence of lower coal-fired generation availability.

[41] Refer to section 3.2.2 of the QED Q4 2022 (Low coal facility availability and summer readiness).

Figure 89 WEM coal-fired output reduced in all intervals, offset by increased gas-fired generation

Average WEM change in fuel mix by time of day – Q1 2023 vs Q1 2022

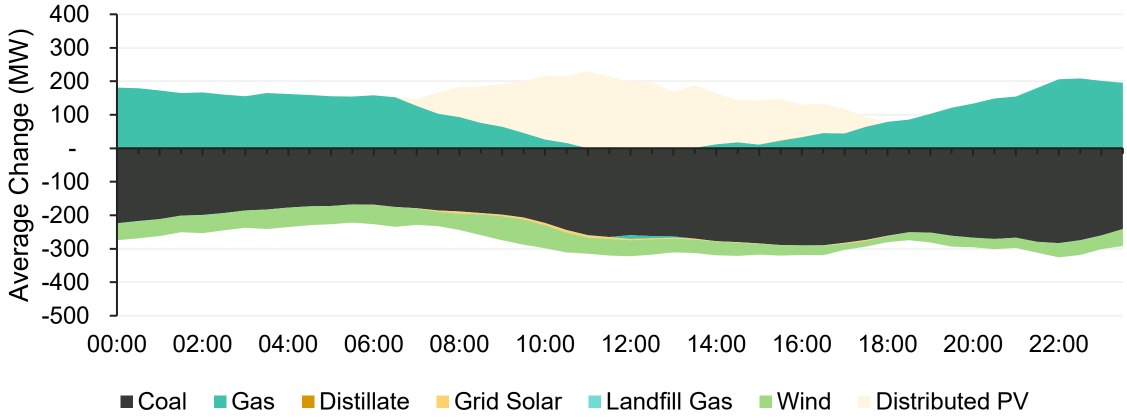


Table 4 WEM fuel mix Q1 2023 and Q1 2022

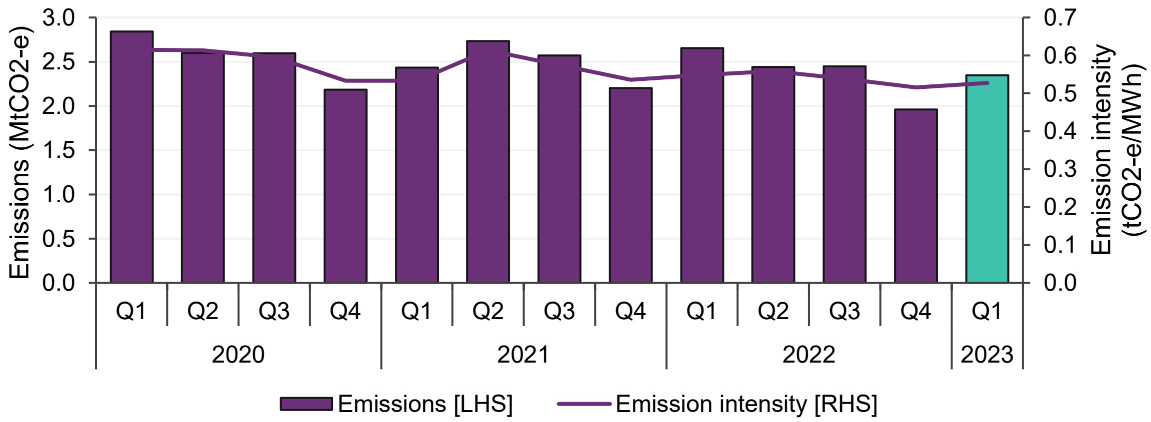
Quarter	Coal	Gas	Distillate	Grid Solar	Landfill Gas	Wind	Distributed PV
2022 Q1	39.3%	24.4%	0.0%	2.1%	0.4%	18.9%	14.9%
2023 Q1	31.8%	29.6%	0.0%	2.2%	0.4%	18.0%	18.0%
Change	-7.5%	+5.2%	-	+0.1%	-	-0.9%	+3.1

3.2.2 Carbon emissions

WEM emissions are trending downwards from 2.65 MtCO2-e[42] in Q1 2022 to 2.35 in Q1 2023. This represents a 12% decrease compared to the same quarter last year (Figure 90). The WEM emission intensity[43] also decreased, from 0.55 tCO2-e/MWh in Q1 2022 to 0.53 tCO2-e/MWh in Q1 2023, representing a 4% reduction. The decrease in emissions from Q1 2022 to Q1 2023 can be attributed to the increase in gas-fired generation in the fuel mix (see Section 3.2.1) and reduction in operational demand (see Section 3.1).

Figure 90 Emissions in the WEM reduced by 12% compared to Q1 2022

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



[42] Million tonnes carbon dioxide equivalent

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

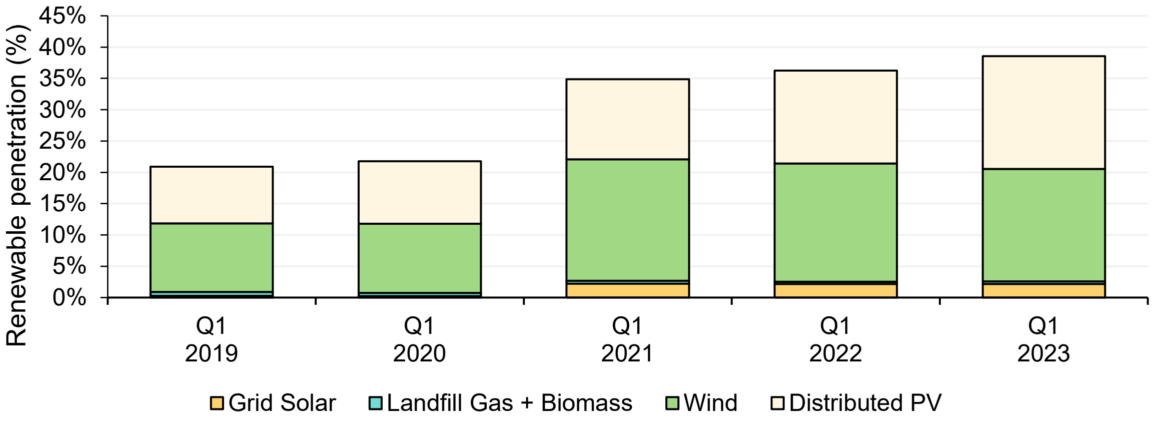
3.2.3 Renewable penetration

The quarterly average renewable penetration in Q1 2023 was 38.6%, a 2.3 percentage point increase relative to Q1 2022 (Figure 91). The increase was mainly driven by higher generation from distributed PV, in line with increased PV capacity. Approximately 290 MW of additional distributed PV capacity was installed between the end of Q1 2022 and end of Q1 2023.

The highest instantaneous renewable penetration in Q1 2023 was 79.9% and was recorded on Tuesday 17 January 2023 at 1230hrs. At that time, generation from distributed PV accounted for 60.5% of underlying demand.

Figure 91 Average renewable penetration grew 2.3 percentage points in Q1 2023

Renewable penetration components – Q1s



3.3 WEM Prices

The weighted average Balancing Price[44] in the WEM for Q1 2023 was $82/MWh, a Q1-record high and the second highest value for any quarter (Figure 92). This was a $20/MWh (+33%) increase from Q1 2022. Contributors to the price increase include:

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

The weighted average Short-Term Electricity Market (STEM) price[45] for Q1 2023 was $77/MWh, a $28/MWh (+56%) increase compared to Q1 2022 and a Q1 record high. This can be linked to the record high Balancing Prices and consequent changes in participant bidding behaviour in the STEM.

The quarterly average quantity of energy cleared in the STEM has returned to historically normal levels (Figure 92), reducing significantly from last quarter's record high. Market Participant behaviour indicates that the STEM is

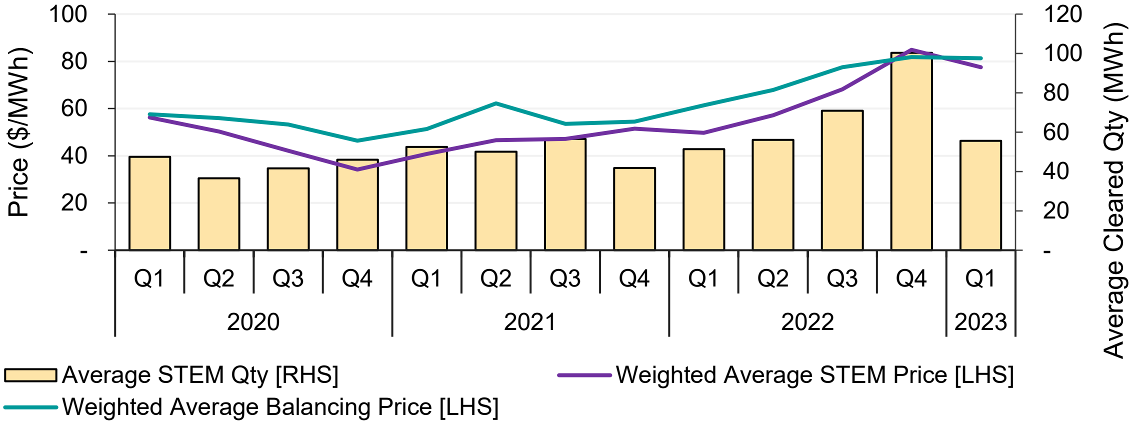
[44] The weighted average Balancing Price is a measure of the average Balancing Price that puts greater weighting on intervals where greater quantity is generated. This is to reflect the average Balancing Price more accurately against quantity of electricity generated, rather than against intervals.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

[45] 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

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 Q4 2022.

Figure 92 The weighted average Balancing Price remains high while average STEM quantity returns to historically normal levels

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



3.3.1 Balancing merit order dynamics

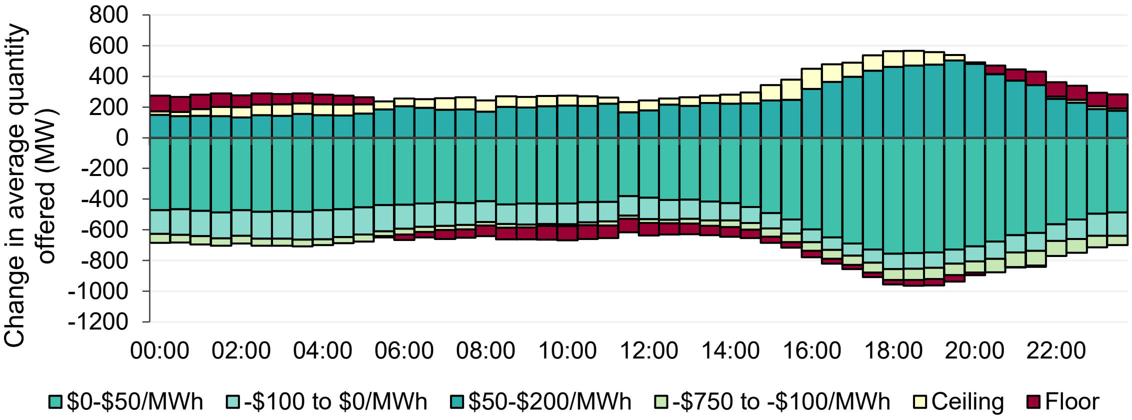
Participants in the Balancing Market in Q1 2023 traded lower quantities than in Q1 2022, on average, in every interval. The primary driver of this change was reduced facility availability over the quarter - in particular, a reduction in coal-fired generation availability (see Section 3.2.1).

Average quantities offered at the lower price bands decreased compared to Q1 2023, with the predominating decrease observed at the $0 to $50/MWh (-512 MW or -94%) and -$100 to $0/MWh price bands (-132 MW or -22%). Conversely, more participation was observed in the highest price bands: quantities traded in the $50 to $200/MWh price band increased by 245 MW (+20%) on average and quantities traded at the Ceiling increased 59 MW (+4%) (Figure 93).

These changes in Balancing Merit Order dynamics were one of the main drivers of the increase in the quarterly average Balancing Price (see Section 3.3).

Figure 93 A significant decrease in the $0 to $50/MWh price band partially counteracted by an increase in the $50 to $200/MWh price band

Change in average Balancing Merit Order structure by time of day – Q1 2023 vs Q1 2022



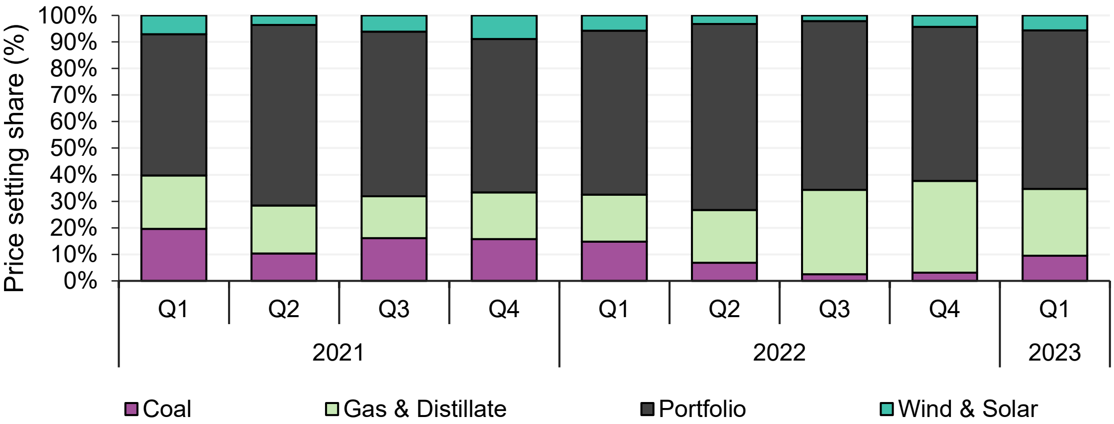
3.3.2 Price-setting dynamics

The key changes in price-setting dynamics in Q1 2023 relative to Q1 2022 were (Figure 94):

- The Balancing Portfolio[46] set the Balancing Price 60% of the time, down from 62% in Q1 2022.
- Independent coal-fired generation facilities set the price less frequently (9% of the time, down from 15% in Q1 2022), with independent gas-fired generation setting the price 25% of the time (up from 18%). This change is consistent with the change in fuel mix (see Section 3.2.1)
- Wind and grid solar facilities set the price 6% of the time, unchanged from Q1 2022.

Figure 94 Low coal availability contributed to decreased price-setting role in the Balancing Portfolio

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



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

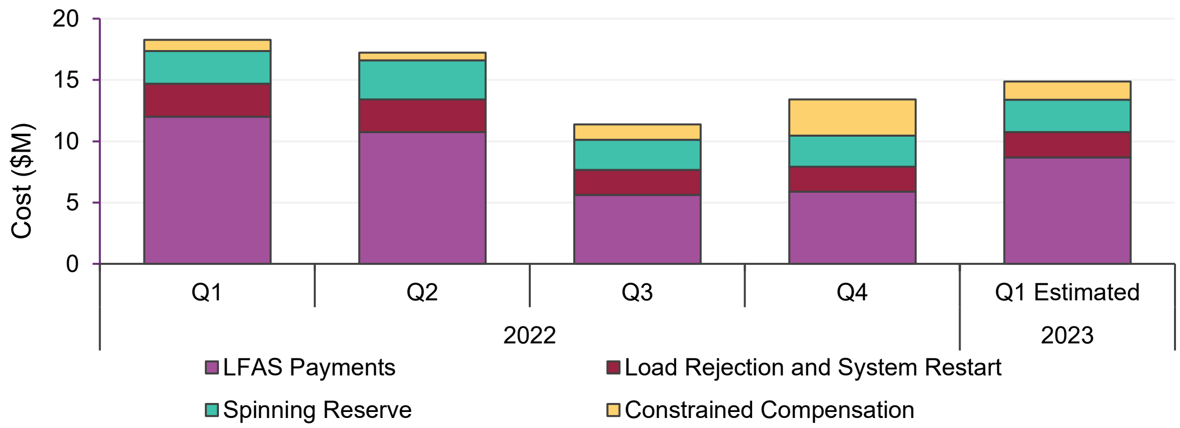
3.4 Power system management

The total cost of power system management in Q1 2023, including Ancillary Services and constrained compensation, was $14.9 million, a decrease of $3.4million (-19%) compared to Q1 2022 (Figure 95). The decrease in costs was attributable to a reduction in Load Following Ancillary Services (LFAS) costs, however this was partly offset by an increase in constrained compensation costs.

- LFAS costs for Q1 2023 were $8.7 million and accounted for 58% of all Ancillary Services costs during the quarter. LFAS costs decreased by $3.3 million (-28%) compared to Q1 2022 due to lower average prices in both LFAS Upwards and LFAS Downwards markets (see Section 3.4.1).
- Estimated spinning reserve costs for Q1 2023 were $2.6 million, unchanged compared to Q1 2022.
- Estimated load rejection and system restart costs decreased by $0.6 million (-23%) compared to Q1 2022, in line with a decrease to the COST_LR parameter set annually by the Economic Regulation Authority (ERA) for the financial year.
- Estimated constrained compensation increased by $0.5 million (+59%) compared to Q1 2022. This is partly due to an increase in the level of constraints required to ensure adequate Ancillary Services to maintain power system security during periods of high and low demand.

Figure 95 Total estimated cost of managing the power system decreased by 19%

Services costs and constrained compensation by quarter – Q1 2022 to Q1 2023



3.4.1 LFAS market

In Q1 2023, the average prices of LFAS Up and LFAS Down were $10/MW and $11/MW respectively, representing 26% and 42% decreases respectively on Q1 2022 (Figure 96). This occurred despite an increase since 6 July 2022 in the quantity of LFAS required between the 0530 hrs and 2000 hrs intervals, increasing from 100 MW to 110 MW. Furthermore, increased use of gas in the Balancing fuel mix has enabled LFAS-capable gas facilities to offer lower prices in the LFAS market.

Trading behaviour in the LFAS market showed a significant increase in quantity offered at less than $10/MW, with 61% of total offers in the $0-10/MW price bracket in Q1 2023 compared to 44% for Q1 2022. As a consequence, less quantity was offered at higher price bands, with 3% of total offers in the >$50/MW price bracket in Q1 2023 compared to 7% for Q1 2022 (Figure 97).

Figure 96 Fall in average LFAS prices reduced total LFAS costs

LFAS prices and costs Q1 2019 to Q1 2023

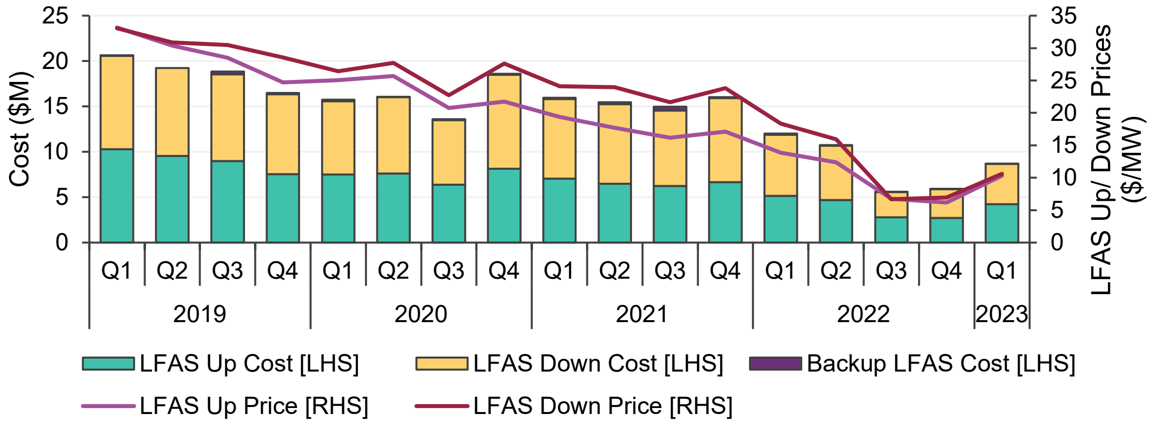
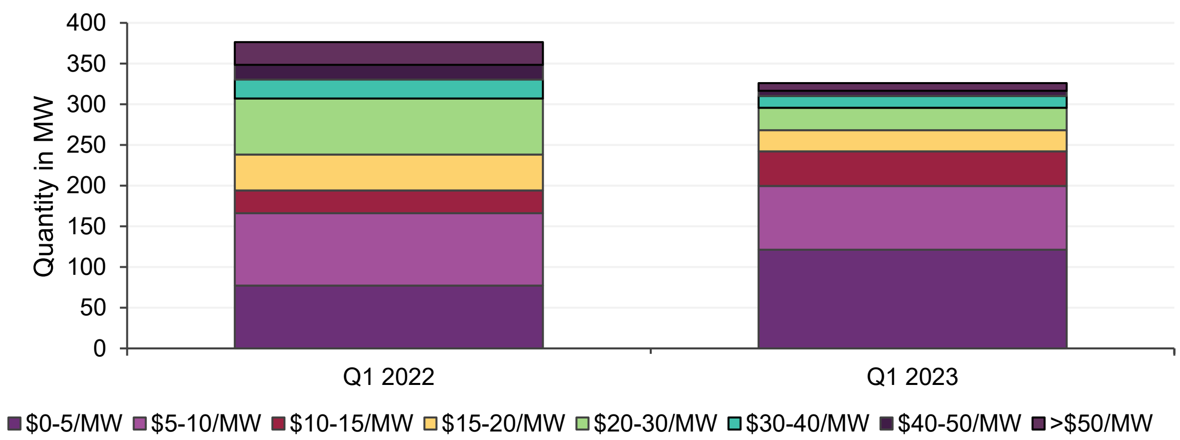


Figure 97 The LFAS average quantity offered at lower price bands ($0 – 10/MW) increased by 20% in Q1 2023

LFAS average offered quantities by price band



3.4.2 North Country blackout

Over the period of 14 to 17 March 2023, there were a number of interruptions of supply to the North Country region of the SWIS. A few individual occurrences contributed to the interruptions. This is currently being investigated by Western Power and AEMO.

3.5 Supplementary Reserve Capacity

In 2022, AEMO identified a potential generation capacity shortfall for the 2022-2023 Hot Season[47] and triggered the Supplementary Reserve Capacity (SRC) mechanism[48], with the aim of procuring up to 174 MW of SRC. The causes of this shortfall include the early retirement of the Kwinana Cogeneration Plant, an extended Forced

[47] Defined in the WEM Rules as 1 December 2022 to 31 March 2023.

[48] In accordance with clause 4.24.1 of the WEM Rules.

Outage of Pinjar unit 10 until 30 April 2023, increase in AEMO's peak demand forecasts, ongoing fuel supply limitations and project delays related to the 2022-23 Capacity Year[49].

Through the tender process AEMO procured up to 102 MW of SRC from a variety of providers, both existing WEM Market Participants and organisations not currently participating in the WEM, and a variety of technology types including generation and demand response.

3.5.1 SRC Activation Events

On 30 January 2023, due to forecast LOR 2 (Lack of Reserve 2) conditions[50], AEMO activated SRC for the first time. 67.4 MW of SRC was activated over the evening peak (1700hrs – 2100hrs), with 35.4 MW in additional generation or load reduction being received[51]. Due to similar drivers LOR 2 conditions were also forecast on 20 February which resulted in AEMO activating 60.8 MW of SRC over the evening peak period.

Lack of Reserve (LOR) 2 Conditions 30 January 2023

The forecast LOR 2 conditions were a result of a high forecast instantaneous system load[52] of 3,837 MW which was driven by high temperatures[53], low forecast intermittent non-scheduled generation[54] of 28 MW and an unexpected trip of a large coal fired generator.

To ensure sufficient reserves would be available during the evening peak, AEMO was required to take several action, including dispatching Demand Side Programmes (DSP) and activating SRC contracts. 67.4 MW of SRC was activated from 4 providers: 43.4 MW of generation response and 24 MW of demand response.

SRC Response 30 January 2023

During the evening peak period there was 4,225 MW of generation available, including 49 MW output from wind generation. Instantaneous system load reached a maximum of 3,823 MW at 1843hrs. At this time the total of SRAS and LFAS requirement was 349 MW[55], this means there was only about 53 MW of spare generation capacity available at the time of peak demand.

AEMO observed a total of 55.4 MW of SRC and DSP response over the period. This means that with the response from these providers the SWIS avoided entering an LOR 2 by about 108 MW.

[49] https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/supplementary-reserve-capacity

[50] The LOR framework is not formally defined in the WEM Rules, AEMO have adopted this terminology to communicate forecast shortfalls in reserves to WEM participants. Communications are issued through Dispatch Advisory. https://aemo.com.au/-/media/files/learn/fact-sheets/lack-of-reserve-dispatch-advisories.pdf?la=en

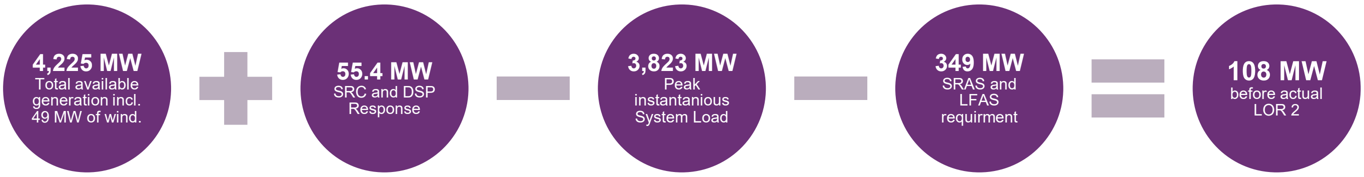
[51] SRC providers not meeting their activation quantities may be deemed unavailable and forgo availability payments until steps are taken to rectify their failure to respond to the required threshold.

[52] Instantaneous system load is the sum of gross generator outputs (including that which covers auxiliary loads at the generation sites). This is measured by non-loss adjusted SCADA at a 4 second sample rate.

[53] A maximum of 38.4 degrees on 29 January was followed by a maximum of 38.1 degrees on 30 January.

[54] This includes generation from wind and grid-solar facilities.

[55] The SRAS requirement is calculated at 70% of the largest generation contingency at the time, LFAS requirement is 110 MW over the evening peak.



Cost of SRC Activation

Participants who provide SRC receive two types of payments:

- an activation payment, which is $/MWh payment for responding to an activation notice from AEMO;
- an availability payment, which is accrued daily for making the service available during the term of the contract and is net of any refunds incurred for failing to do so.

Total SRC activation costs were $255k for 30 January 2023 and $205k for 20 February 2023. The net availability cost over the 2022-23 Hot Season was $3.4 million. The cost of SRC is offset by $1.3M in Reserve Capacity Security retained by AEMO and returned to Market Customers in October 2022, with remaining costs recovered from Market Customers through the Individual Reserve Capacity Requirement

List of tables and figures

Tables

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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
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
PV	Photovoltaic

Abbreviation	Expanded term
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