Quarterly Energy Dynamics Q1 2022

April 2022

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 2022 (1 January to 31 March 2022). This quarterly report compares results for the quarter against other recent quarters, focusing on Q4 2021 and Q1 2021. 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	29 April 2022	

Executive summary

East coast electricity and gas highlights

Demand and prices rise strongly

- Despite ongoing La Niña conditions and unprecedented rainfall events in Q1 2022, average temperatures across much of Australia were well above Q1 2021, increasing average electricity demand in all National Electricity Market (NEM) regions. Together with reduced availability of thermal generators and higher prices for key generation fuels, influenced by volatile international energy commodity prices, this drove NEM wholesale spot prices to an average of $87 per megawatt-hour (MWh)[1], up 67% on Q4 2021 and 141% on Q1 2021.
- Queensland experienced significant episodes of high demand and price volatility, reaching a new all-time maximum operational demand record of 10,058 megawatts (MW) on 8 March. Earlier in the quarter, heatwave conditions and reduced generation availability on 1 February led AEMO to dispatch Reliability and Emergency Reserve Trader (RERT) reserves for four and a half hours to maintain system security, at an estimated cost of $51 million. Average spot prices for these two days were amongst the 10 highest daily levels recorded in Queensland since commencement of the NEM, and overall price volatility (spot prices above $300/MWh) contributed $47/MWh or 31% of the region's average Q1 price of $150/MWh.
- East coast gas prices averaged $9.93 per gigajoule (GJ) in Q1, slightly below Q4 2021 but up strongly on their average of $6.05/GJ in Q1 2021. International liquefied natural gas (LNG), oil and coal prices all traded at elevated levels with the high volatility in global energy markets evident since the latter part of 2021 continuing.
- Higher NEM spot prices and underlying market trends saw prices for ASX electricity futures rise strongly over the quarter, with Calendar Year (CY) 2023 base contracts up 46% to an average price of $94/MWh. Prices for the northern NEM regions rose most strongly with New South Wales CY 2023 base contracts at $131/MWh by quarter end, and Queensland $108/MWh. Victorian CY 2023 base futures closed at $61/MWh.
- The ongoing electricity price gap between northern and southern NEM states, evident in both average spot and futures prices, reflects multiple factors including:
  - Thermal generation outages and repricing of supply offers into higher price bands, particularly from black coal generators which set prices more frequently in the northern NEM states. Between Q1 2021 and Q1 2022, black coal generators repriced supply offers for an average volume of over 3,000 MW from prices less than $60/MWh to higher price levels.
  - Continuing constraints on northward energy transfers from the southern states via the Victoria – New South Wales interconnector (VNI). During daytime hours between 0800 hrs and 1800 hrs, average transfers fell to only 66 MW northward (from 470 MW in Q1 2021) despite an average energy price difference of $48/MWh.

Renewables and new technologies further increase market share

- Renewable sources continued to grow in Q1 with grid-solar, small-scale distributed photovoltaics (PV), and wind generation increasing their combined share of the NEM's energy supply mix to 27.3%, up by over

[1] Uses the time-weighted average which is the simple average of regional wholesale electricity spot prices in the quarter. The Australian Energy Regulator (AER) reports the volume-weighted average spot price which is weighted against native demand.

4 percentage points since Q1 2021. Including hydro, the total renewable share reached 33.7% of NEM large- and small-scale supply. Conversely, record low black coal generation for any Q1 and a decline in brown coal output saw the coal-fired generation share fall to 60.4%, a drop of over 5 percentage points from Q1 2021.

- Grid-scale batteries were the largest providers by fuel/technology type of Frequency Control Ancillary Services (FCAS) in Q1, reaching a combined share of 31% across the NEM's eight FCAS markets. Battery revenues from energy market participation also increased to their highest quarterly level since Q1 2019.
- On 31 January, as Victorian and South Australian afternoon spot prices spiked to high levels, Wholesale Demand Response (WDR) capacity was dispatched for the first time in the NEM, with two Victorian WDR units participating. Since implementation of this new mechanism in late October 2021, 58 MW of WDR capacity has registered across New South Wales, Victoria and South Australia, with 38 MW of this newly registering in Q1.

Other highlights

- FCAS costs retreated in Q1 to $43 million from the very high quarterly levels (exceeding $130 million) experienced over Q2 to Q4 2021, driven by lower FCAS prices in Queensland.
- In South Australia, the first quarter of full operation with four synchronous condensers saw the costs of system security directions to gas generators fall from $37 million in Q4 2021 to an estimated $7.5 million in Q1 2022.
- Separate disruptions to market communications systems involving loss of Supervisory Control and Data Acquisition (SCADA) datastreams required suspension of the spot market in South Australia for around two hours on 18 February, and in Tasmania for nearly seven hours on 1 March. No generation nor load was lost and AEMO concluded that the power system remained in a secure operating state throughout both incidents.
- East coast gas production increased 8 petajoules (PJ) on Q1 2021, a 2% increase, driven by a 16 PJ increase in Victoria and reductions in other regions. Victorian gas transfers to neighbouring states reached their highest level since Q4 2017.

Western Australia electricity and gas highlights

High temperatures drive demand and prices

- Warm conditions in the Perth metropolitan region resulted in a 5.9% increase in operational demand this quarter compared to Q1 2021, as higher underlying demand more than offset growth in distributed PV output, and no new minimum demand records were set this quarter. Extended high temperatures contributed to the Wholesale Electricity Market (WEM) recording its second highest all-time maximum operational demand of 3,980 MW on 19 January 2022, only 26 MW below the record set in February 2016.
- Higher operational demand contributed to the weighted average Balancing Price increasing to $61/MWh, a 14% increase from Q4 2021, and reduced the frequency of negative prices.

All fuel types increased output to meet the evening peak

- Increased generation from wind and solar this quarter assisted with meeting higher demand. This quarter also saw increased output from all fuel types in the evening, including coal and gas.
- This caused spare capacity (certified capacity credits of coal and gas less dispatched capacity) for both coal and gas to fall compared to last year, but remain sufficient to meet higher peak demand.

Contents

1 NEM market dynamics

1.1 Electricity demand

1.1.1 Weather

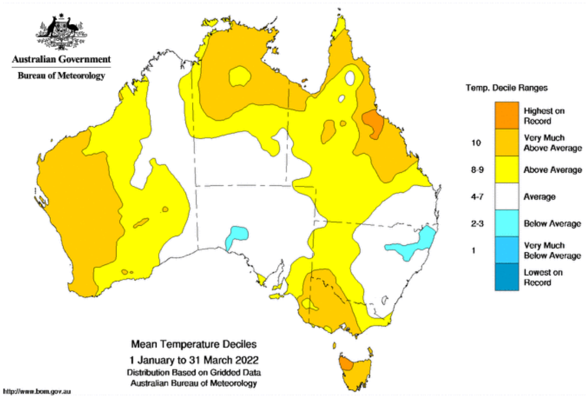
During the quarter, the weather was dominated by heavy rainfall and flooding in parts of Queensland and New South Wales, with many sites recording their highest daily rainfall on record, as the La Niña weather pattern continued[2].

Across the east coast, temperatures varied across the quarter, with warmer temperatures in January for the vast majority of Australia, with Victoria experiencing its warmest January nights on record[3].

Central and northern parts of Queensland experienced severe to extreme heatwaves in the first week of March, which was the state's fifth warmest on record[4]. However coastal New South Wales temperatures over Q1 were comparable to last year's mild quarter.

Figure 1 Hot weather in Queensland and Victoria

Q1 2022 mean temperature deciles for Australia



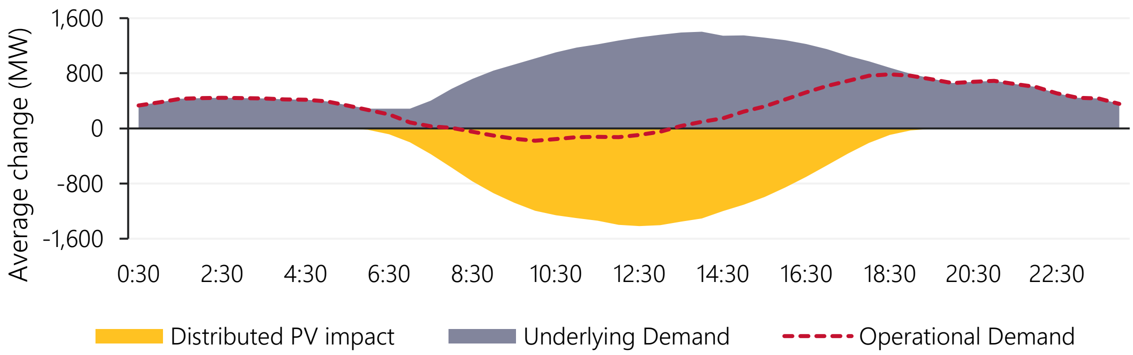
Source: Bureau of Meteorology (BoM)

1.1.2 Demand outcomes

NEM quarterly average operational demand increased to 21,506 MW, 314 MW (1.5%) higher than that of last year's very mild Q1, driven by 774 MW (3.3%) growth in underlying demand across all regions, offset by a 460 MW (24%) increase in average distributed PV output[5] (Figure 2).

Figure 2 Warmer weather drives up daytime underlying demand after a mild Q1 2021

Changes in average NEM demand components by time of day – Q1 2022 vs Q1 2021



[2] BoM 2022, La Niña retreat stalls as trade winds strengthen: http://www.bom.gov.au/climate/enso/

[3] BoM 2022, Victoria in January 2022: http://www.bom.gov.au/climate/current/month/vic/archive/202201.summary.shtml

[4] BoM 2022, Queensland in March 2022: http://www.bom.gov.au/climate/current/month/qld/summary.shtml

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

While underlying demand[6] increased across all states, changes by region within the quarter varied (Figure 3):

- Victoria led the increase in underlying demand by 253 MW (4.9%) to reach 5,442 MW, its highest Q1 average in recent years (Figure 4), mainly due to a much warmer and more humid January, accounting for 45% of the NEM increase during that month.
- Queensland at 7,341 MW also reached its highest Q1 average underlying demand in recent years, with a 198 MW (2.8%) increase over Q1 2021, driven by generally warmer weather in January and heatwave conditions in early March, which led to a new all-time maximum operational demand record, covered in the following section.
- New South Wales' underlying demand, averaging 8,279 MW for the quarter, was up 165 MW (2%) on Q1 2021. While smaller in absolute size, underlying demand increases in Tasmania of 80 MW and South Australia of 79 MW were higher in percentage terms at 7% and 5% respectively. In Tasmania's case strong increases in industrial load drove the increase.

Figure 3 NEM average demands increase across all regions

Change in demand components – Q122 vs Q121

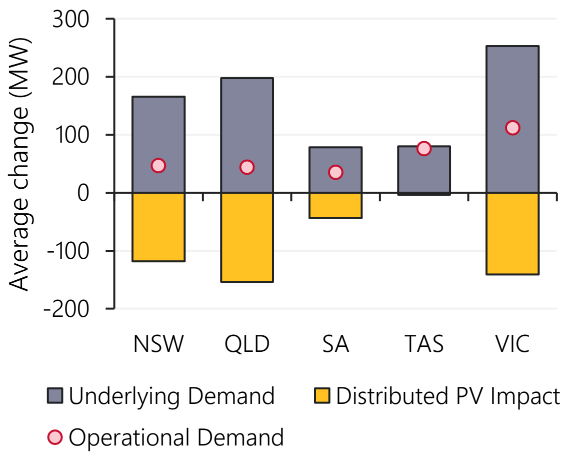
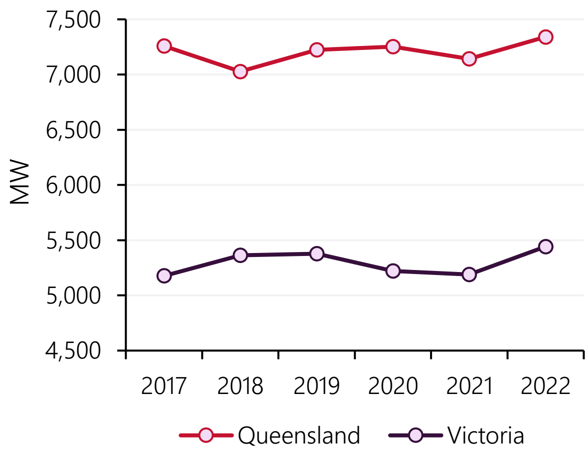


Figure 4 Highest Q1 underlying demand in recent years for Queensland and Victoria

Queensland and Victoria average underlying demand (Q1s)



Minimum and maximum demands

During Q1 2022, new Q1 minimum operational demand records were set in Victoria and South Australia, both on the same day – Saturday 19 February 2022:

- Victoria's new Q1 minimum demand of 2,792 MW occurred over the half hour ending 1300 hrs, 124 MW lower than the previous record set in Q1 2021 but 459 MW higher than the all-time record set in Q4 2021. A combination of sunny, mild conditions and low weekend underlying demand contributed to the record. During the interval, distributed PV provided 2,308 MW of output, meeting 45% of underlying demand.
- In South Australia, demand reached a minimum of 209 MW over the half hour ending 1330 hrs, 149 MW lower than the previous Q1 minimum set in 2021[7]. Drivers for the record were similar to those in Victoria, and 1,270 MW of distributed PV output during the interval accounted for 86% of underlying demand.

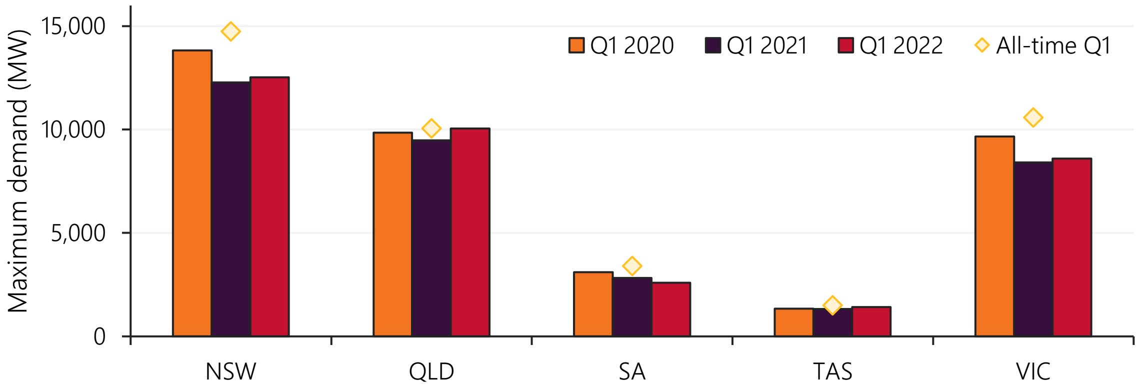
[6] Underlying demand is calculated by adding estimated production from distributed PV to operational demand, to yield an estimate of total electricity demand.

[7] South Australia's all-time minimum operational demand record of 104 MW was set in Q4 2021 on 21 November.

Q1 2022 maximum operational demand outcomes were mixed. Despite higher maximum demands in four NEM regions, this was relative to a mild Q1 2021, with 2022 maximums in most regions remaining well below all-time Q1 highs (Figure 5). Contrasting other regions this quarter was South Australia, recording a maximum demand 241 MW lower than in Q1 2021. At just 2,589 MW, this was the region's lowest Q1 maximum demand since 2004.

Figure 5 Q1 2022 maximum demands generally up from a mild Q1 2021

Maximum operational demands by region – selected Q1 quarters and all-time Q1 records



However Queensland's maximum operational demand of 10,058 MW in the half hour ending 1900 hrs on 8 March did set a new all-time record for the state, 14 MW higher than the previous high set in Q1 2019 and 585 MW above 2021's maximum (Figure 6). Very warm conditions across the state on this day (maximum temperatures between 33°C and 38°C) as well as continuous periods of elevated humidity were key drivers of the record, with notable regional demand increases particularly in Northern Queensland.

- On the same day, Queensland also recorded its highest daytime intra-day operational demand swing for a Q1, with a difference of 3,585 MW between daytime minimum operational demand of 6,473 MW at 1000 hrs and maximum operational demand of 10,058 MW (Figure 7).

Figure 6 New Queensland maximum demand record

Queensland maximum operational demand - annual

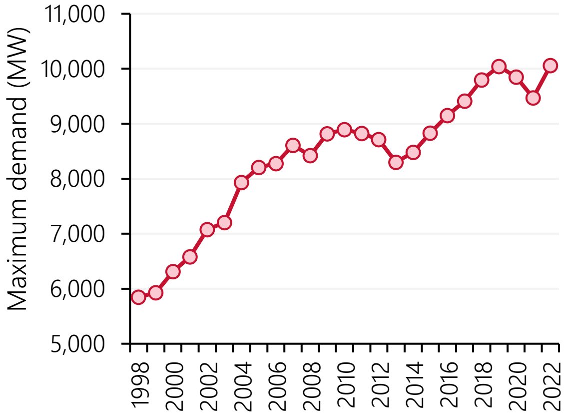
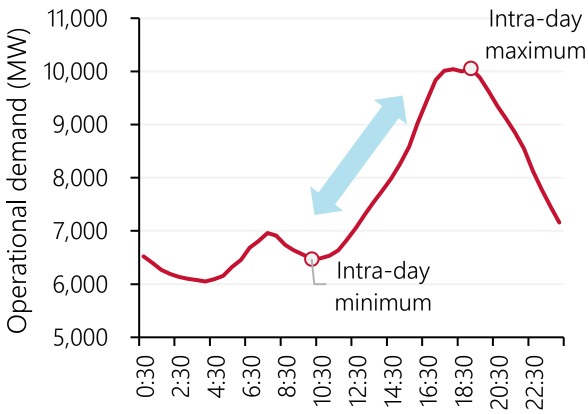


Figure 7 Operational demand intraday swing of 3,585 MW[8] between 1000 hrs and 1900 hrs

QLD operational demand by time of day – 8 March 2022

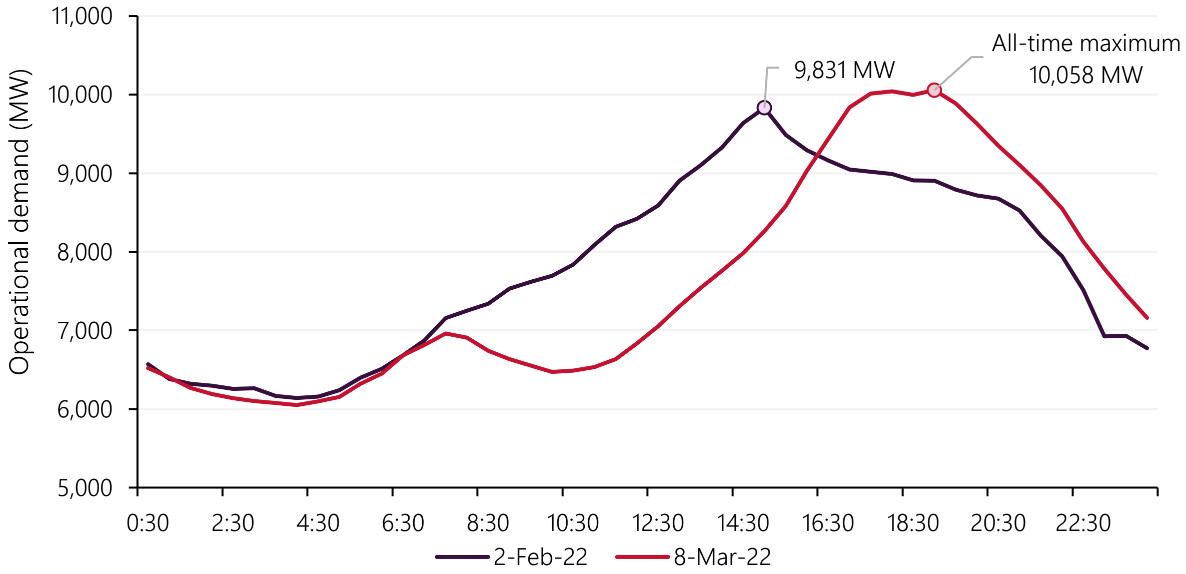


[8] Daytime intra-day operational demand swing is measured for each day as the difference between minimum and maximum operational demands recorded between 0600 hrs and 2000 hrs. Prior to high levels of distributed PV penetration, daily minimum demands typically fell outside this window, in the early overnight hours.

  - Dispatching generation and demand-side resources to meet large daily demand swings introduces operational challenges and places increased importance on short-term demand forecasting accuracy. The efficient management of intra-day swings in demand, driven by distributed PV, demand-side response, and ramps in renewable generation, become increasingly important as renewable penetration increases. Operational demand forecasting for demand ramps and associated uncertainty and variability driven by the weather systems and/or market responses are critical for short term commitment and utilisation of resources. Demand variability and uncertainty are two distinct operational challenges that require management, both via market structures and through deployment of enhanced forecasting techniques.
  - As the energy transition progresses, it is expected there will be a higher demand for flexible resources to be online and ready to be dispatched to match variability and uncertainty in supply and demand. Without a new operational reserve product, interventions may increase due to the lack of suitable flexibility that can physically respond to increasing variability. A dispatchable operating reserve product/market could be procured 30 minutes ahead of time and co-optimised with other energy market services. The product could enhance operational tools available to return the system to a secure operating state within 30 minutes.
- Another notable day in Queensland during the quarter was 2 February where very warm and humid conditions (the third consecutive day of a tropical heatwave), coupled with cloud cover impacting distributed PV output resulted in elevated operational demand during the day. While operational demand did not reach an all-time high, peaking at 9,831 MW at 1500 hrs before a storm and cool change, the operational demand profile for the day indicates clear potential for a significantly higher maximum demand to have eventuated had the cool change been delayed (Figure 8).

Figure 8 Elevated Queensland operational demand throughout the day on 2 Feb 2022

QLD operational demand by time of day – 2 February and 8 March 2022

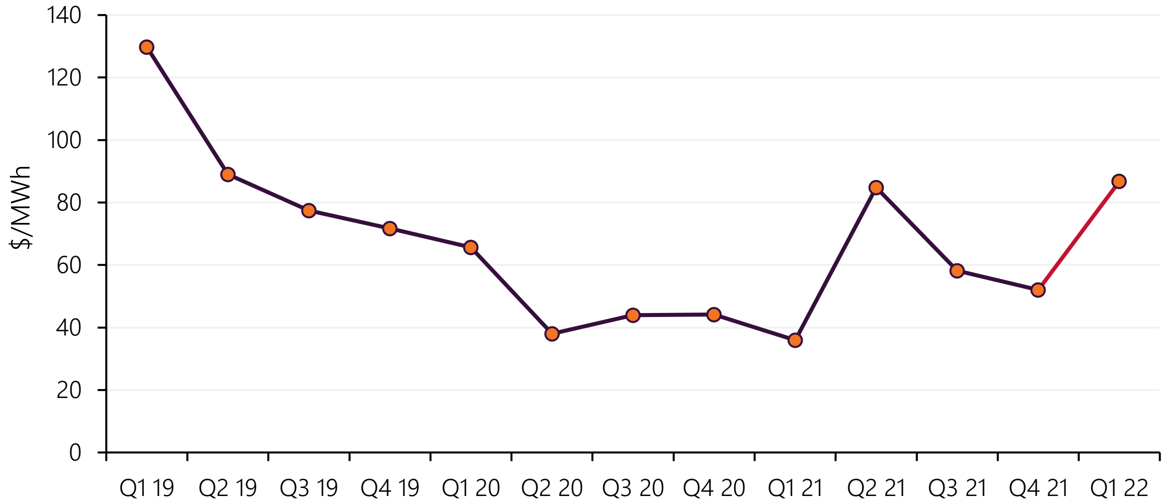


1.2 Wholesale electricity prices

NEM wholesale electricity spot prices rose sharply this quarter, averaging $87/MWh across the five NEM regions, up 67% on Q4 2021 and 141% on Q1 last year (Figure 9).

Figure 9 NEM prices rise sharply

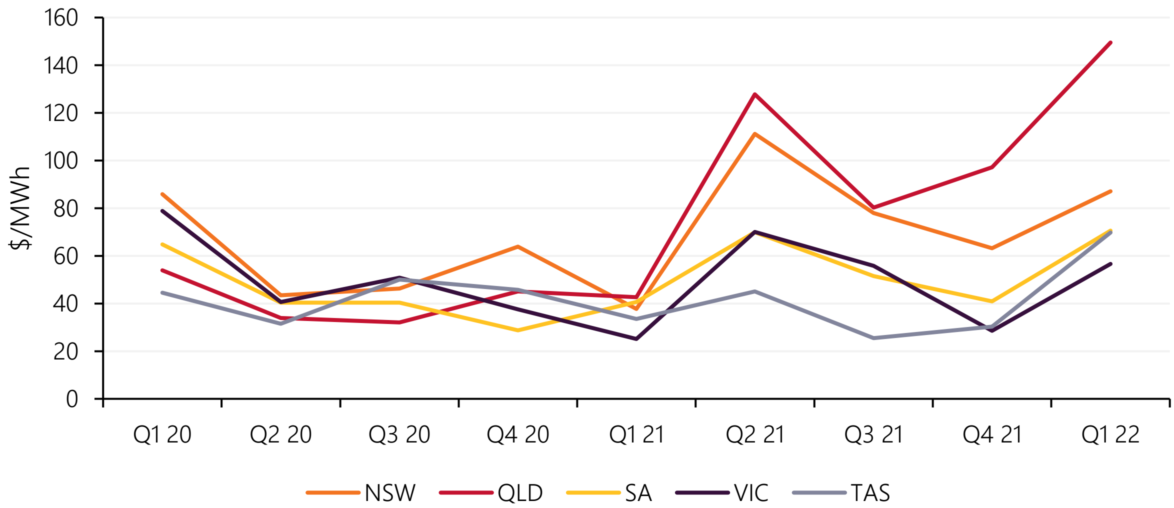
NEM average wholesale electricity spot price



Prices were consistently higher in all NEM regions. Queensland's quarterly average was three and a half times its level of one year ago, while prices in the other four regions were roughly double those of Q1 2021 (Figure 10).

Figure 10 Significant uplift in Queensland spot prices

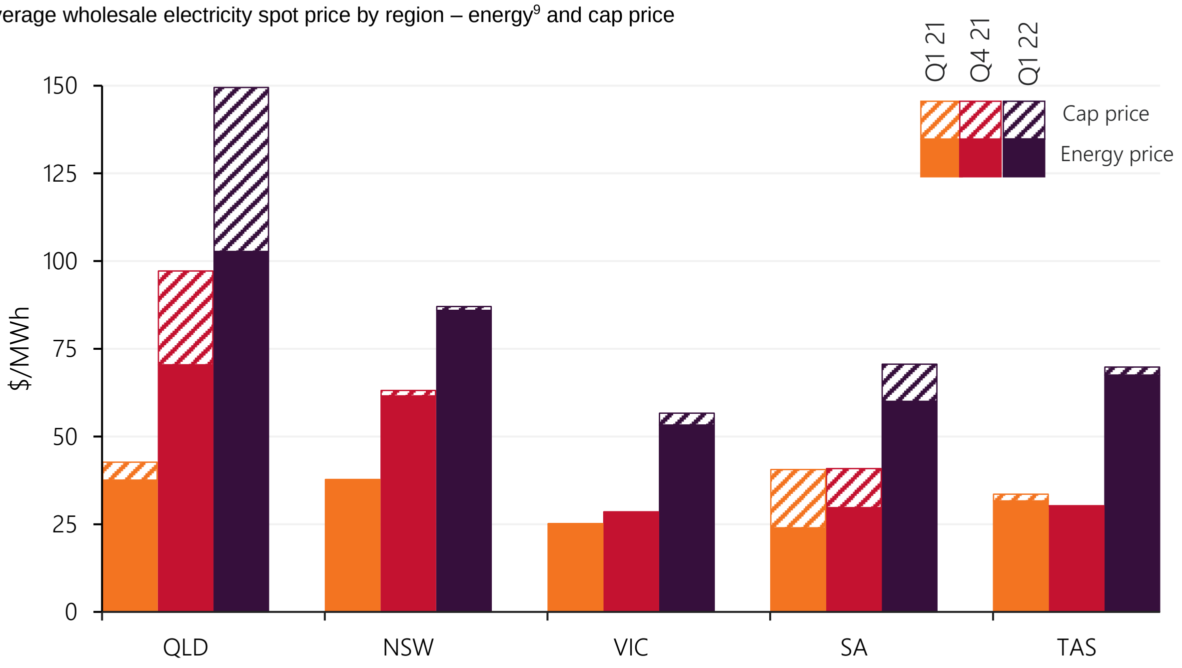
Average wholesale electricity spot price by NEM region



Episodes of price volatility contributed $47/MWh to Queensland's average price of $150/MWh, which is the second highest average price recorded for that region in any quarter since NEM start. In the other NEM regions volatility was a much less significant price driver, adding $11/MWh to South Australia's quarterly average price and $3/MWh or less elsewhere in the NEM (Figure 11).

Figure 11 Volatility accentuates Queensland price rise

Average wholesale electricity spot price by region – energy[9] and cap price



Since Q1 2021, average energy prices have risen across all times of day, with increases in morning and evening peak as well as overnight prices being particularly evident (Figure 12). Between NEM regions, a strong north-south divide in daytime average prices persisted over Q1: between 0800 hrs and 1800 hrs, New South Wales energy prices exceeded those in Victoria by an average $48/MWh or 146% (Figure 13).

Figure 12 Price increase largest during morning and evening peaks

Average NEM (energy) price by time of day[10]

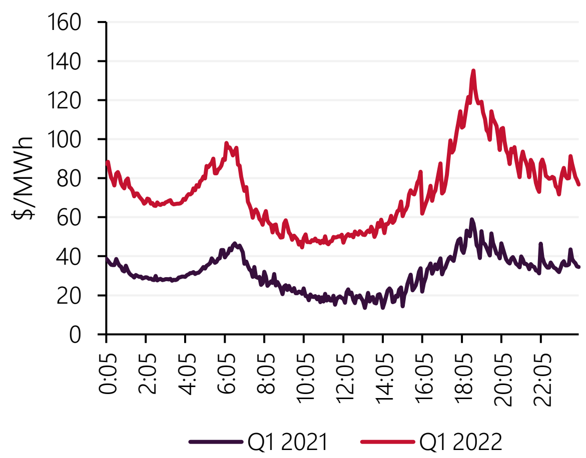
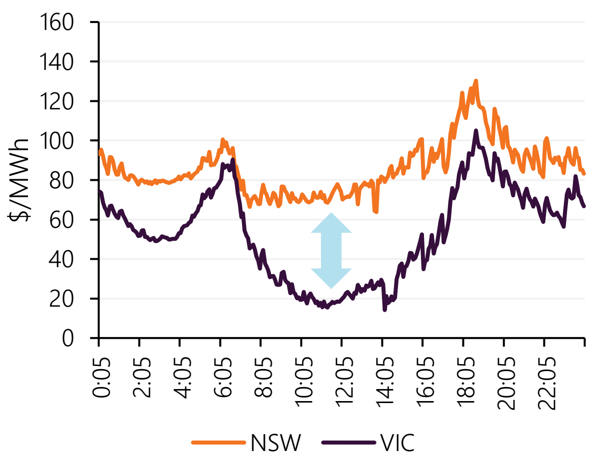


Figure 13 North-South divide most prominent during daytime hours

Average NSW and VIC (energy) price by time of day – Q1 2022



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

[10] Spot price capped at $300/MWh

1.2.1 Wholesale electricity price drivers

Key influences on NEM electricity spot prices for the quarter are summarised in Table 1 below, with further analysis and discussion provided in referenced sections of this report.

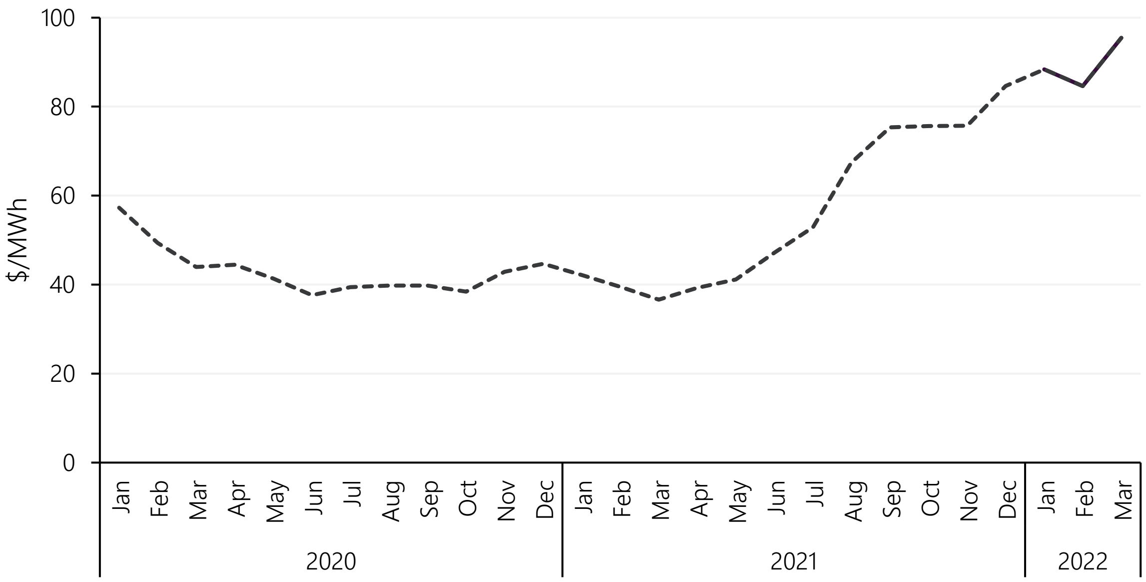
Table 1 Wholesale electricity price levels: Q1 2022 drivers

Thermal generation	Availability of thermal generators was significantly lower than in Q1 2021, with black coal generation availability down by an average of 456 MW (3%) on 2021 and at its lowest level for Q1 since at least 2002. Steeply increased domestic and international prices for traded fuels over the last 12 months have also influenced thermal generators' bidding. Black coal generators have repriced substantial offer volumes into higher price bands since Q1 2021, with volumes offered below $60/MWh reducing on average by over 3,000 MW (Section 1.3.1). East coast gas prices were up significantly from Q1 2021 (Section 2.2), reflected in gas-fired generators' offers and price-setting levels.
Higher operational demand	Relative to Q1 2021, average operational demand was up 314 MW across the NEM, driven by a strong increase of 774 MW (3.3%) in underlying demand due to a return to warmer conditions after a very mild Q1 2021 and increased economic activity. Operational demand growth across the evening peak was particularly evident, averaging 699 MW between 1700 hrs and 2200 hrs, contributing to higher prices in this period. Refer Section 1.1.2.
Price volatility	Price volatility, largely in Queensland, added $13/MWh to the NEM price average for Q1, compared to $5/MWh in Q1 2021 and $8/MWh in Q4. Section 1.2.2 discusses volatility events and drivers in more detail.
Price separation	Energy prices (backing out the contribution of volatility) were again substantially higher in Queensland and New South Wales than in the southern NEM regions. Transmission constraints on the VNI contributed significantly to holding back flows of lower-priced energy from south to north, particularly during daytime hours, and are discussed in Section 1.4.

The progressive repricing of offers from black coal generators is illustrated in Figure 14, showing the volume-weighted average of marginally-priced offer bands at selected generators in New South Wales and Queensland. As these generators frequently contribute to setting NEM spot prices, such movements in marginal offer prices can strongly influence average spot price outcomes.

Figure 14 Black coal generators progressively increasing marginal offer prices

Monthly volume-weighted marginal offers – Eraring, Gladstone, Mount Piper and Vales Point power stations[11]



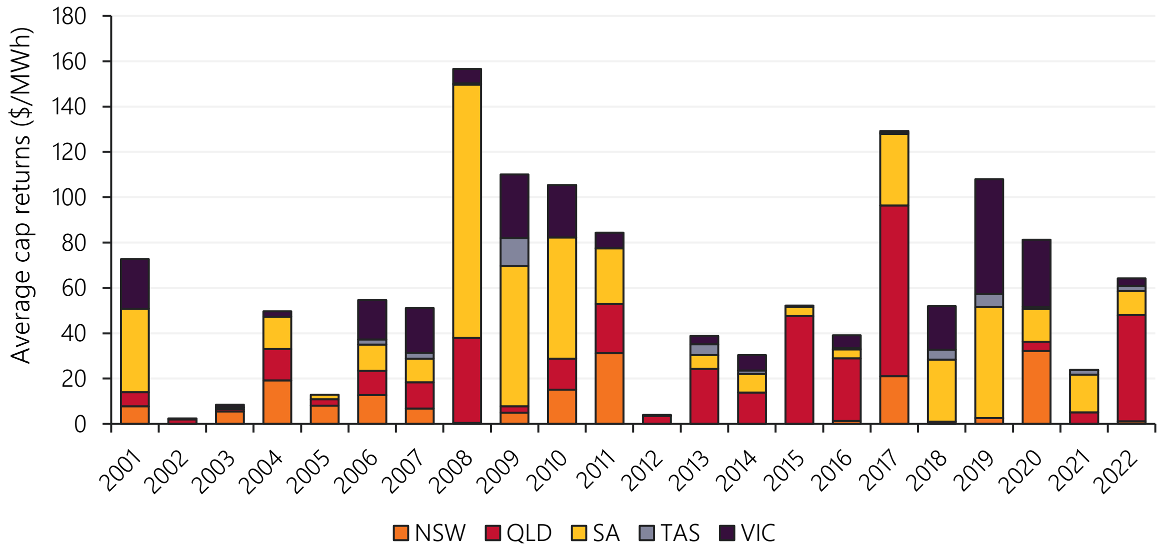
[11] Market offers between $10/MWh and $150/MWh

1.2.2 Wholesale electricity price volatility

Spot price volatility in Q1, as measured by aggregate cap returns across all NEM regions, was significantly higher than in Q1 2021, and fell in the mid-range of historical Q1 outcomes (Figure 15).

Figure 15 Queensland volatility drives Q1 2022 cap returns

NEM average quarterly cap returns by region (stacked) – Q1s



This was largely driven by high volatility in Queensland, where average daily spot prices on 1 February and 8 March were amongst the highest 10 values recorded for this metric since market start (Figure 16). These two days contributed over 60% of the region's quarterly cap return.

Figure 16 Two of Queensland's 10 all-time highest priced days occurred in Q1 2022

Queensland 10 highest daily average spot prices on record

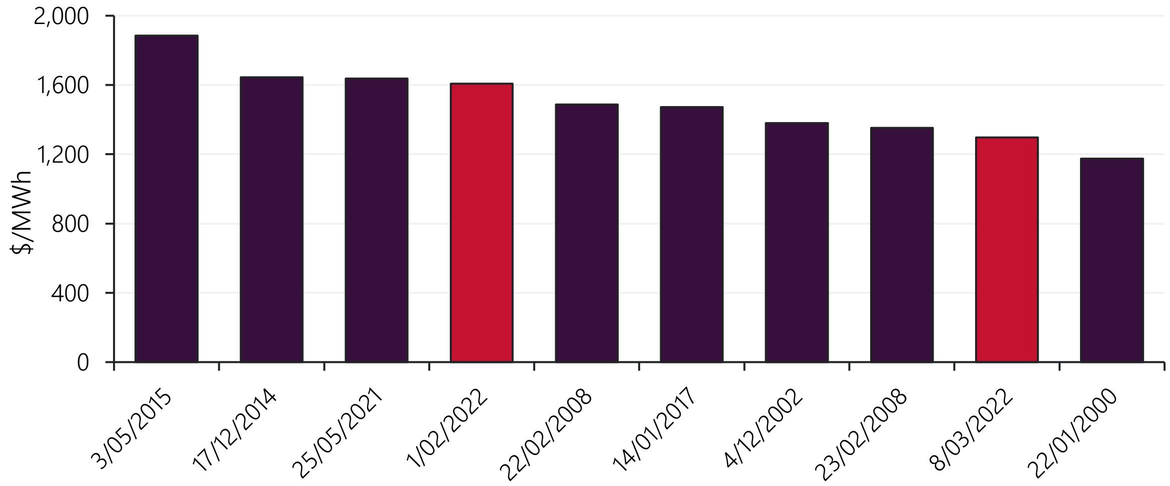


Table 2 below summarises days of significant regional spot price volatility and associated drivers during Q1. Under its wholesale market performance reporting obligations, the AER has published further analysis of market price outcomes for a number of these events.

Table 2 High priced days in Q1 2022

Region	Date	Average daily price ($/MWh)	# of interval prices >=$10k/MWh	Contribution to quarterly cap returns ($/MWh)	Drivers
QLD	31 Jan[12]	$859	15	$7.63	• High evening peak demand > 9,000 MW • Reduced thermal generation availability • Declining grid-solar output and low wind
	01 Feb[13]	$1,608	28	$15.93	• Heatwave conditions, high humidity • Evening peak demand > 9,000 MW • Further reductions in thermal generation availability • RERT of up to 331 MW was activated, additional voluntary load reductions • Intervention Pricing applied to set spot prices
	08 Mar[14]	$1,297	12	$12.60	• Queensland operational demand exceeding 10,000 MW – all-time record of 10,058 MW was set • Constraints limiting imports from New South Wales and dispatch of some Queensland generation • LOR2 condition declared – estimated minimum reserve of 211 MW
SA	10 Jan[15]	$464	7	$3.82	• Middle of day price volatility driven by low wind and variable cloud cover affecting grid-solar output and operational demand • Rapid changes in supply/demand balance • Security constraints limiting imports from Victoria
	31 Jan[16]	$465	6	$3.43	• (see 31 Jan drivers for Victoria)
VIC	31 Jan[17]	$459	6	$3.41	• High evening peak demands in Victoria and South Australia with temperatures exceeding 35 degrees • Security constraint limiting combined output from Murray power station and imports from New South Wales by 500-700 MW below typical capability • Gas and liquid fuel generation offers setting Victorian and South Australia prices

Figure 17 below shows key dispatch outcomes for Queensland on 1 February. Spot prices exceeded $10,000/MWh in 28 5-minute trading intervals. With demand forecast to exceed available local generation, and net import capability from New South Wales limited to around 200 MW by system security constraints, forecast low reserve conditions led to the dispatch of up to 331 MW of RERT reserves[18], indicated on the chart below. This triggered the application of Intervention Pricing, under which spot prices are determined as those which would have occurred in the absence of RERT dispatch. More information on RERT dispatch and Directions issued to certain Queensland generators is contained in Section 1.6 of this report, while detailed analysis of market

[12] AER 2022, Prices above $5,000/MWh – 31 January and 1 February 2022 (Qld): https://www.aer.gov.au/wholesale-markets/performance-reporting/prices-above-5000-mwh-31-january-and-1-february-2022-queensland

[13] See footnote 12.

[14] AER's forthcoming report Prices above $5,000/MWh – 8 March 2022 (Qld) will provide further analysis on this event: https://www.aer.gov.au/wholesale-markets/performance-reporting/prices-above-5000-mwh-8-march-2022-queensland

[15] AER 2022, Prices above $5,000/MWh – 10 January 2022 (SA): https://www.aer.gov.au/wholesale-markets/performance-reporting/prices-above-5000-mwh-10-january-2022-south-australia

[16] AER 2022, Prices above $5,000/MWh – 31 January 2022 (VIC & SA): https://www.aer.gov.au/wholesale-markets/performance-reporting/prices-above-5000-mwh-31-january-2022-victoria-and-south-australia

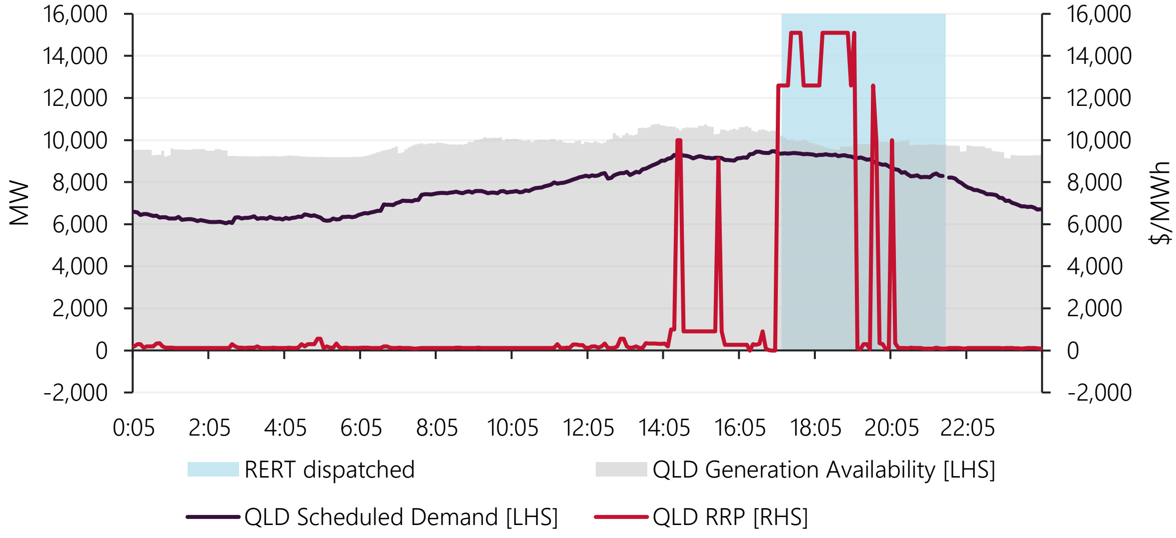
[17] See footnote 16.

[18] 'RERT reserves' are non-market generation or demand-side resources procured by AEMO under provisions of the NER (Rule 3.20) specifically to manage conditions where levels of reserve in the wholesale spot market are insufficient to maintain adequate reliability.

conditions and price outcomes on this day has been published by the AER[19], and AEMO will shortly be publishing a Quarterly RERT report providing full details of RERT activation and dispatch.

Figure 17 Queensland records its fourth highest daily average price on record, RERT dispatched

Queensland scheduled demand[20], generation availability, and spot price: 1 February 2022



Market suspension

During Q1 2022, two separate market suspension[21] events were declared in South Australia and Tasmania.

- On 18 February 2022, AEMO declared the spot market suspended in South Australia in response to a SCADA failure[22]. 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 South Australian market was suspended between 1420 hrs and 1610 hrs, market suspension schedule pricing[23] was used to set the South Australian spot price.
- AEMO suspended the spot market in Tasmania between 1235 hrs and 1915 hrs on 1 March 2022 due to the failure of SCADA systems resulting from a loss of Tasmanian SCADA visibility at AEMO due to both Bass Strait fibres being severed[24]. Based on initial analysis, AEMO believes that the power system remained in a secure operating state throughout the event, and that no generation or load was lost due to the incident. During this event, market suspension schedule pricing was used to set the Tasmanian spot price.

[19] See footnote 12.

[20] '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.

[21] Under clause 3.14.3 of the National Electricity Rules (NER), AEMO may declare the spot market to be suspended in a region when either the power system in the region has collapsed to a black system and/or AEMO has been directed by a participating jurisdiction to suspend the market following declaration by that jurisdiction of a state emergency and/or AEMO determines that it has become impossible to operate the spot market in accordance with the provisions of the NER.

[22] See AEMO's preliminary report for more information on the SA market suspension event: https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/preliminary-report-sa-market-suspension.pdf

[23] 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.

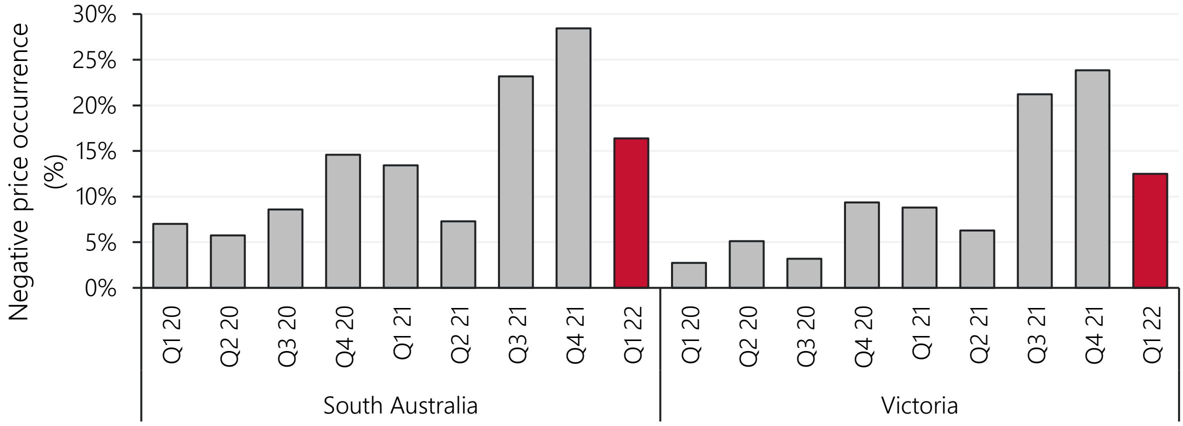
[24] See AEMO's preliminary report for more information on the TAS market suspension event: https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/preliminary-report-tas-market-suspension.pdf

1.2.3 Negative wholesale electricity prices

During Q1 2022, the occurrence of negative and zero spot prices[25] reached a new high for Q1 at 6.6% of all dispatch intervals across NEM regions, although seasonally down on the second half of 2021. Southern states continued to see higher incidences at 16.4% for South Australia and 12.5% for Victoria (Figure 18), compared to only around 1% across the northern states.

Figure 18 High negative spot price occurrence in South Australia and Victoria compared to northern regions

Frequency of negative or zero spot prices

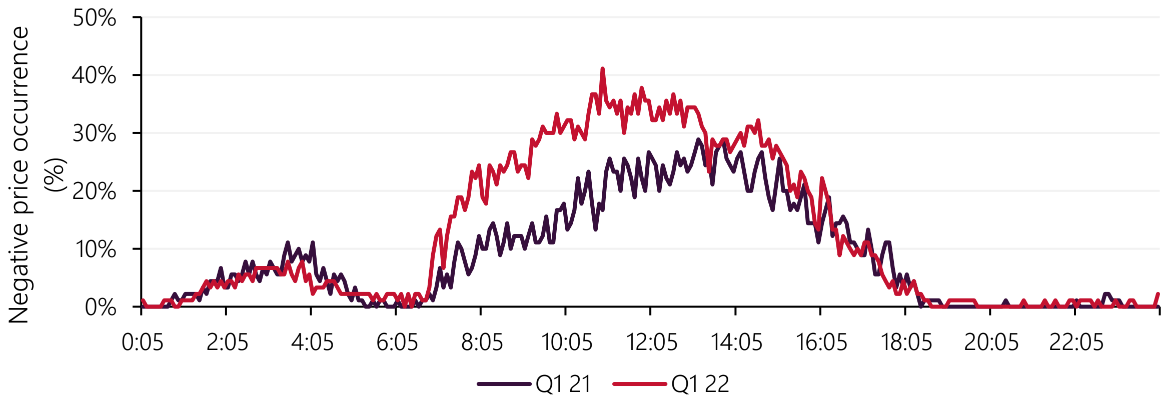


While negative price occurrence was higher in comparison to previous Q1 levels, its impact on the quarterly spot price average declined in South Australia, reducing from $10.8/MWh a year ago to $6.6/MWh this quarter, as the relative frequency of extreme negative prices (below minus $100/MWh) in that state decreased to just 1% of all negative prices this Q1 compared to 20% a year ago. In Victoria, the impact of negative prices on the quarterly average grew from $2.3/MWh in Q1 2021 to $3.7/MWh in Q1 2022.

One contributor to the increase in negative price occurrence relative to Q1 2021 was a higher frequency of daytime negative prices in South Australia and Victoria, with the most notable increase occurring in Victoria between 0700 hrs and 1300 hrs (Figure 19), as transfers of energy to New South Wales across VNI were constrained more frequently compared to a year ago (Section 1.4).

Figure 19 Increased negative price occurrence predominantly occurring between 0700 and 1300 hrs

Frequency of negative or zero spot prices by time of day – Victoria



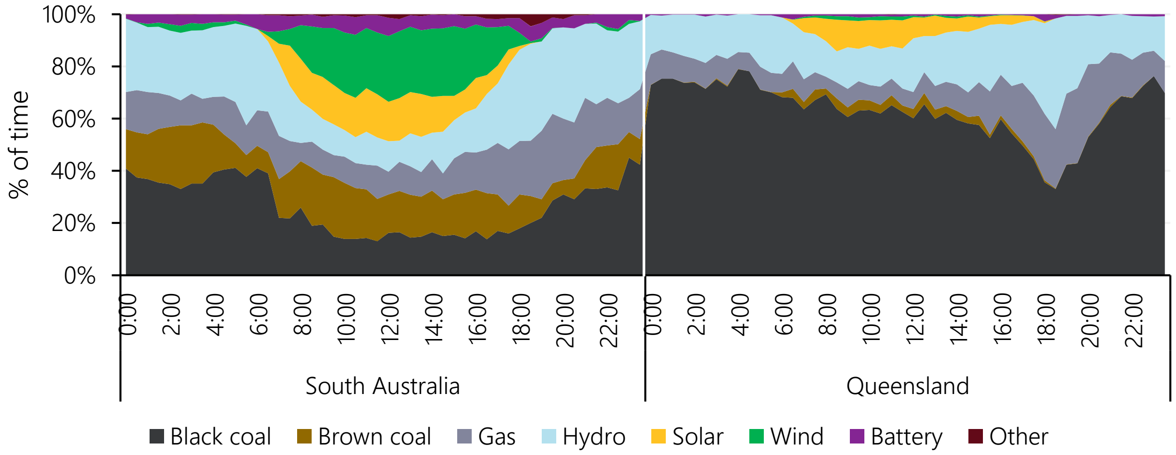
[25] Hereafter referred to as negative prices.

1.2.4 Price-setting dynamics

Figure 20 illustrates regional differences in the NEM's price-setting fuel mix in Q1 2022, an important driver of variations in regional spot price levels and profiles, comparing different fuel sources' price-setting frequency by time of day at opposite ends of the NEM. In South Australia, middle of day prices were frequently set by offers from renewable generation and batteries, with black coal offers setting price[26] in only 17% of dispatch intervals between 0700 hrs and 1900 hrs, and 26% across all hours. The relatively high frequency of South Australian price setting by hydro offers reflects the influence of Tasmanian generation bidding on southern NEM prices. In contrast, Queensland spot prices were set by offers from black coal generators in 63% of all dispatch intervals. The dip in black coal offers' price-setting frequency in Queensland around the evening peak reflects the role of peaking resources such as gas and local hydro generation over these hours.

Figure 20 Renewables frequently set South Australian daytime prices but coal dominates in Queensland

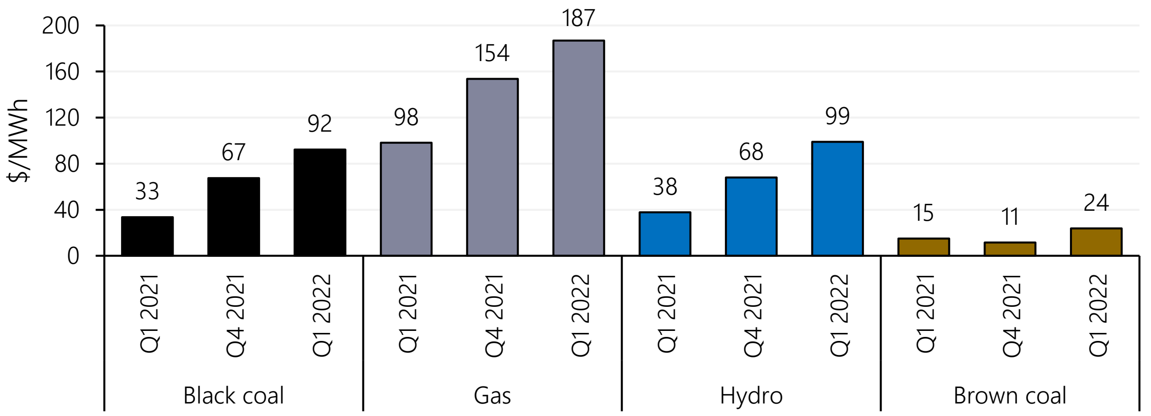
Price-setting frequency by fuel type by time of day – South Australia and Queensland – Q1 2022



Complementing price-setting frequency data, the average spot prices set by offers from key fuel types across recent quarters illustrate a major driver of higher spot prices in Q1 2022, with sharp increases in average prices set by black coal, gas and hydro offers across the NEM (Figure 21).

Figure 21 Strong increases in average NEM spot prices set by black coal, gas and hydro offers

Average NEM spot prices set by fuel type – selected quarters



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

1.2.5 Electricity futures markets

ASX Calendar Year 2023 (Cal23) base futures prices increased sharply from an average of $65/MWh by the end of last year to finish Q1 2022 at $94/MWh for the four mainland regions (Figure 22). Futures market participants' outlooks were influenced by spot price trends, announcements concerning New South Wales generation closure timing and delayed return of major units on outage including Callide C4 and Swanbank E in Queensland, and potentially higher fuel cost expectations (Section 2.2.1). Elevated forward year prices for New South Wales in particular continue out to Cal25 (Figure 23).

New South Wales base futures led the Cal23 price rally increasing by $51/MWh to finish the quarter as the highest regional price ($131/MWh), exceeding levels reached after the shutdown of Hazelwood in Victoria in 2017. Queensland Cal23 prices ($108/MWh) closed $23/MWh below New South Wales, reversing the Cal22 relativity between these regions.

Victoria Cal23 futures remained the lowest priced ($61/MWh) followed by South Australia ($78/MWh), with the average spread to the two northern states increasing by $30/MWh to $50/MWh.

Figure 22 New South Wales Cal23 rally

ASX Energy – daily 2023 base futures price by region

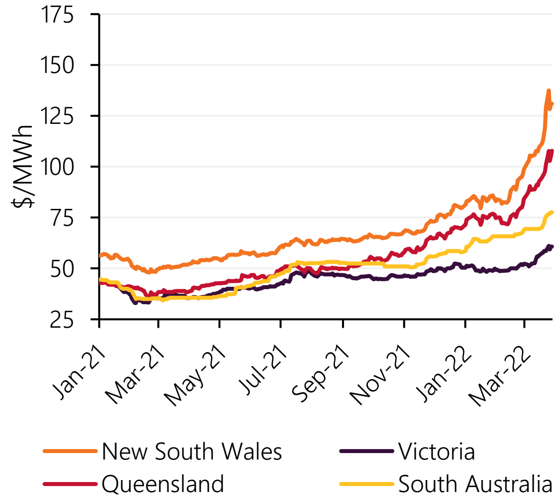
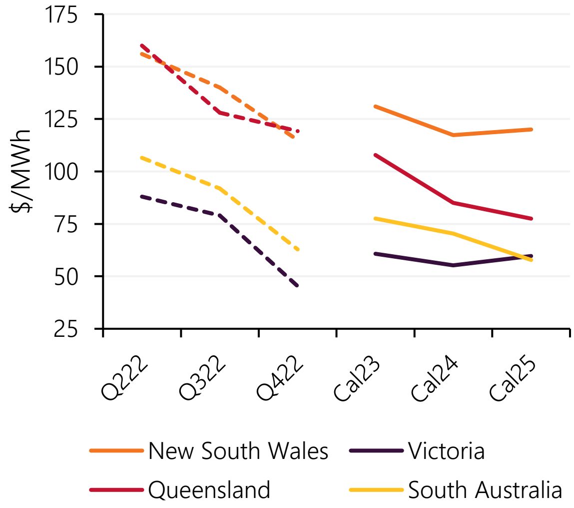


Figure 23 New South Wales forwards at high levels

ASX Energy – End Q1 2022 closing prices by region



1.3 Electricity generation

Figure 24 and Table 3 show the change in NEM generation mix in Q1 2022 compared to Q1 2021, while Figure 25 shows the change by time of day. Compared to Q1 2021:

- With increased output from grid-scale variable renewable energy (VRE) generators (+743 MW) and distributed PV (+460 MW), maximum instantaneous penetration of renewable generation peaked at 61.3%, marginally below Q4 2021's 61.8%, while the overall renewable supply share for the quarter was 33.7% (Table 3).
- Gas-powered generation increased by 271 MW on average, up from very low levels in Q1 2021, largely driven by New South Wales and Victoria.
- Low availability coupled with units repricing marginal offers upwards resulted in black coal-fired generation output falling 374 MW to its lowest Q1 average since NEM start. Output from brown coal also declined (-304 MW) predominantly due to increased outages this quarter.

Figure 24 VRE increased while coal output declined

Change in supply – Q1 2022 versus Q1 2021

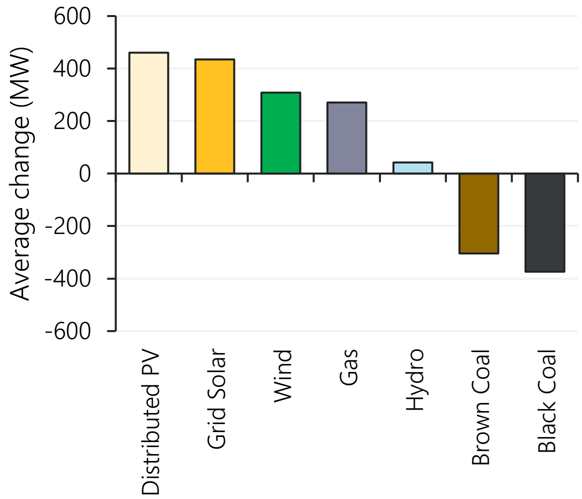
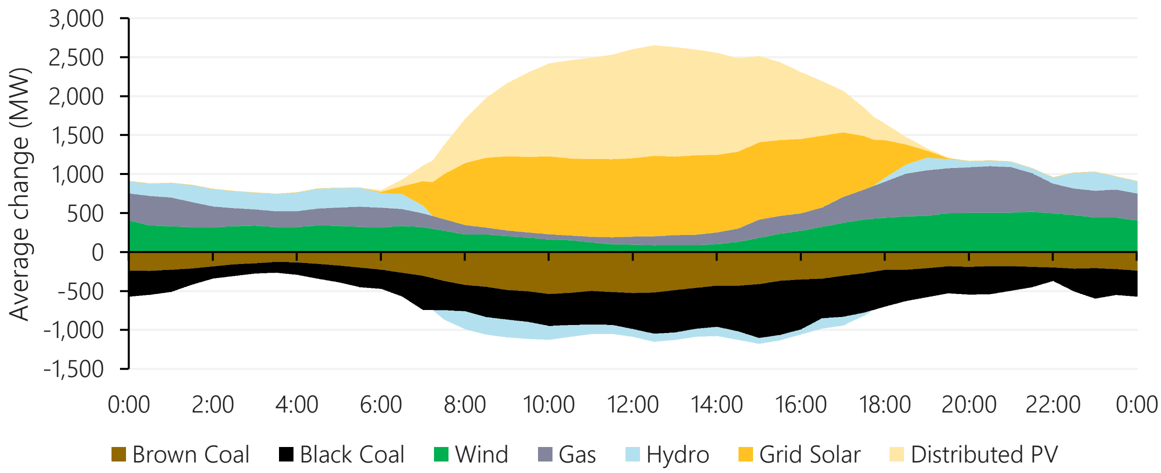


Table 3 NEM supply mix by fuel type[27]

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar	Distributed PV	Other
Q1 2021	47.2%	18.2%	4.8%	6.4%	10.2%	4.6%	8.3%	0.1%
Q1 2022	44.0%	16.3%	5.8%	6.4%	11.1%	6.2%	10.0%	0.1%
Change	-3.2%	-1.9%	0.9%	-0.1%	0.9%	1.6%	1.6%	0.0%

Figure 25 Renewable and gas generation up while black and brown coal output decline

Change in supply – Q1 2022 versus Q1 2021 by time of day



[27] Distributed PV (behind-the-meter) continues to play an increasingly important role in the Australian energy mix and the dynamics of the NEM markets. In this edition of the QED, distributed PV has been included in the total supply mix (total generation = NEM generation + distributed PV generation). This adjustment results in changes to previously reported quarterly fuel mix percentages.

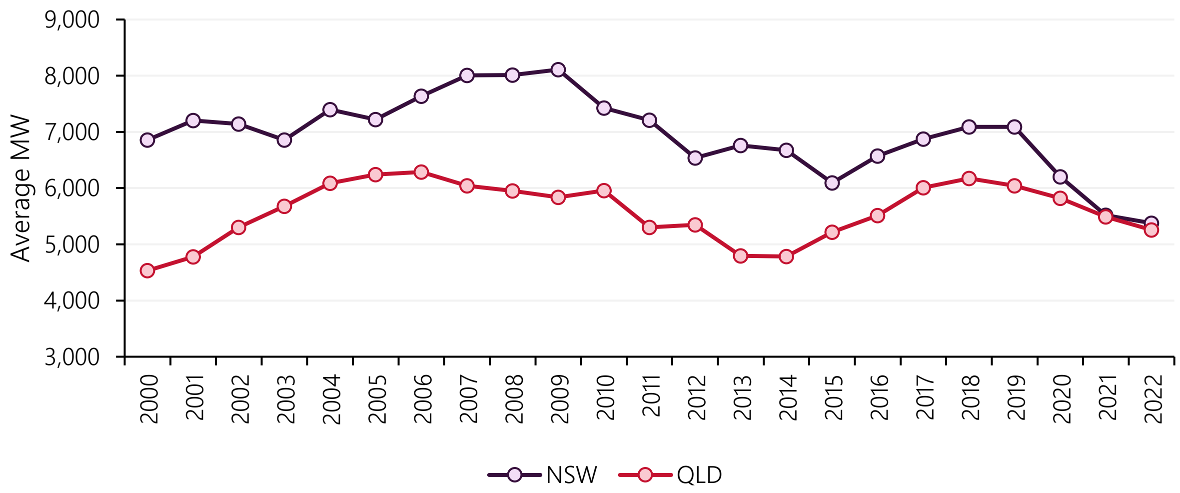
1.3.1 Coal-fired generation

Black coal-fired fleet

During Q1 2022, average black coal-fired generation declined to 10,632 MW, its lowest Q1 output since NEM start and 374 MW lower than Q1 2021. Record low Q1 output was largely driven by the Queensland fleet (-234 MW) followed by New South Wales (-140 MW, Figure 26).

Figure 26 Decline in black coal output from both Queensland and New South Wales fleet

Average NEM black coal-fired generation by region – Q1s



The output decline came despite higher operational demands, driven by a substantial shift in supply offers to higher price bands (Figure 27) and record low Q1 availability due to increased outages (mostly unplanned, Figure 28). Compared to Q1 2021, over 3,000 MW on average of black coal offers shifted from lower-price bands to above $60/MWh – the largest year on year quarterly change since NEM start. While higher offer prices this quarter coincided with the surge in international coal prices to record levels (Section 2.2.1), offers had already trended upwards in the months leading up to Q1 2022 (Section 1.2.1).

Figure 27 Significant shift in black coal offers to higher price bands

NEM black coal-fired generation bid supply curve – Q1 2022 versus Q1 2021

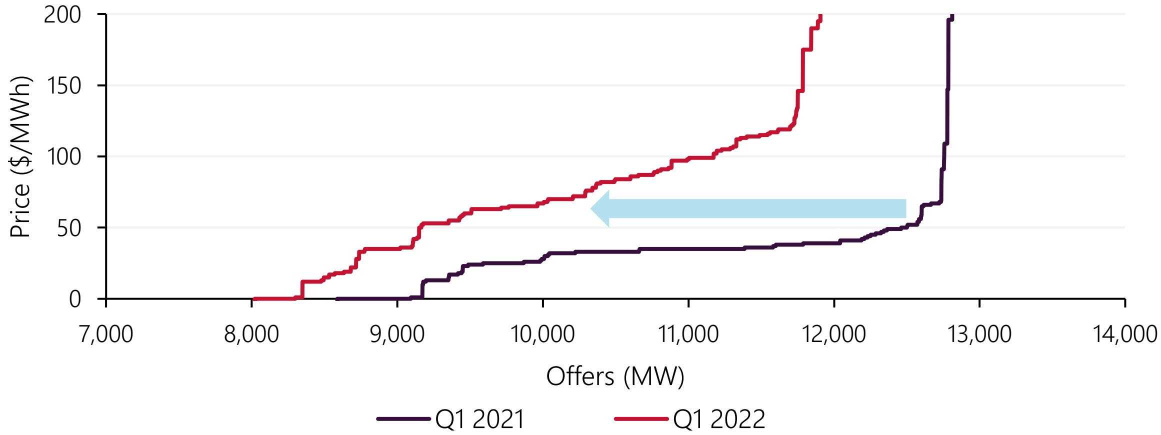
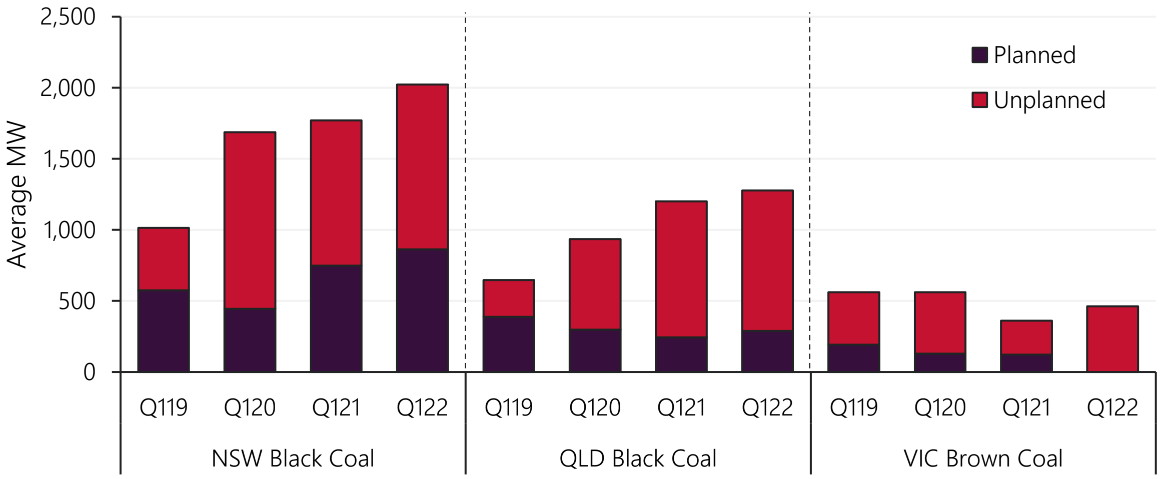


Figure 28 High levels of coal outages across the NEM

Coal outage classification – Q1s



Key changes by power station compared to Q1 2021 were:

- Lower availability at Mt Piper Power Station due to increased outages, coupled with units shifting offers from lower priced bands to bands above $60/MWh, reduced average output significantly by 360 MW to 583 MW this quarter. Most notably, Unit 2 was taken out of service on 28 February for a major planned maintenance program that is expected to span up to three months[28].
- Increased unplanned outages at both Callide C and Kogan Creek Power Stations reduced output by 355 MW and 207 MW respectively. Callide C Unit 4 has remained out of service since its major incident in Q2 2021[29] while Kogan Creek was out of service for around 26 days due to an unplanned outage during the quarter.
- Despite almost no outages at Tarong Power Station this quarter, average output declined by 165 MW as units continued to offer capacity at reduced levels. Average availability during Q1 2022 was 1,174 MW, 220 MW lower than Q1 2021.
- Almost no outages at Stanwell Power Station this quarter, coupled with increased utilisation increased average output by 328 MW to 1,045 MW this quarter, its highest Q1 level since 2008.
- Output at Bayswater Power Station increased by 237 MW driven by a combination of increased availability and utilisation. Of note was Unit 3 which went out of service on 4 March for a major maintenance and upgrade program to increase unit capacity from 660 MW to 685 MW.

Several announcements concerning early coal generation closures were made during the quarter – AGL announced on 10 February that closure dates for its Bayswater and Loy Yang A Power Stations will be brought forward to no later than 2033 (previously 2035) and 2045 (previously 2048), respectively[30]. A week later on 17 February, Origin submitted notice to AEMO of the potential early retirement of Eraring Power Station in August 2025[31].

[28] EnergyAustralia 2022, EnergyAustralia's Mt Piper maintenance program focused on COVID-19 safety: https://www.energyaustralia.com.au/about-us/media/news/energyaustralias-mt-piper-maintenance-program-focused-covid-19-safety

[29] Callide C Unit 4 is currently scheduled to return on 7 April 2023.

[30] AGL 2022, 1H22 Results Announcement: https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/media-centre/2022/220210-agl-energy-fy22-half-year-results-announcement.pdf

[31] Origin 2022, Origin proposes to accelerate exit from coal-fired generation: https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/

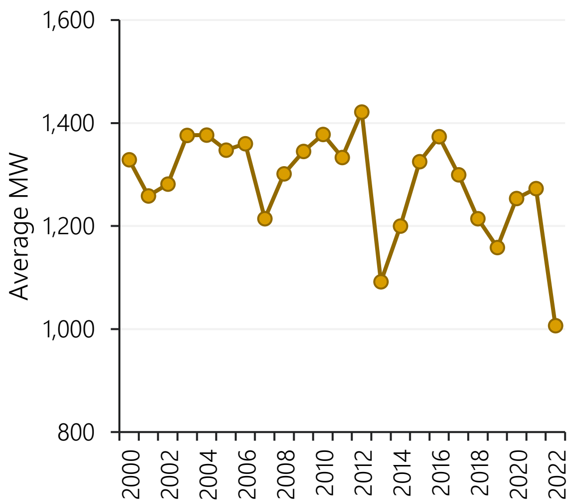
Brown coal-fired fleet

Compared to Q1 2021, average brown coal-fired generation declined by 304 MW, driven by reductions from Yallourn (-266 MW) and Loy Yang B (-63 MW), which more than offset a small increase from Loy Yang A (+25 MW).

Higher unplanned outages, coupled with increased low and negative daytime spot prices in Victoria were key drivers of lower brown coal output this quarter. Most notably, Yallourn's quarterly average output declined to 1,007 MW, its lowest Q1 level since NEM start (Figure 29), mostly driven by increased outages – on average, Yallourn units were on outage for 20.5 days this quarter compared to 12.5 days in Q1 2021. Towards the end of the quarter on 30 March 2022, a small fire at Units 3 and 4 station coal bunker area at Yallourn impacted the operations of the two units[32]; while the units were taken out of service, impact on Q1 output was not material.

Figure 29 Lowest Yallourn Q1 output since NEM start

Yallourn average quarterly output - Q1s

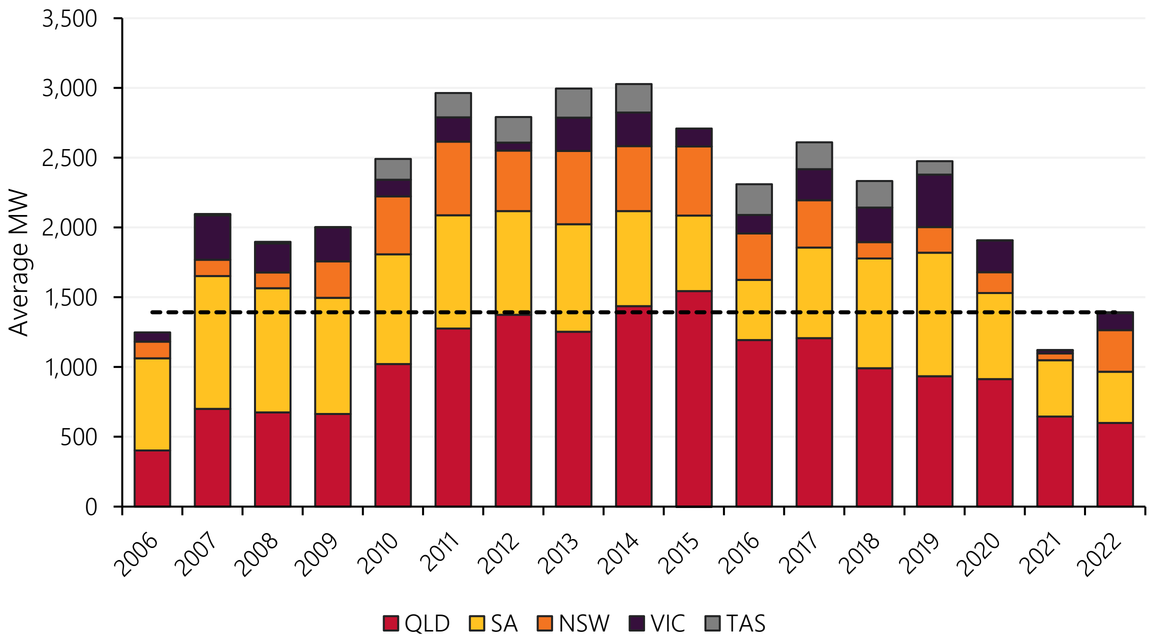


1.3.2 Gas-powered generation

During the quarter, NEM gas-fired generation output increased to 1,393 MW on average. While this was 271 MW higher than Q1 2021, it was still the third lowest Q1 level since 2006 (Figure 30).

Figure 30 Q1 2022 gas generation up from 2021 but third lowest Q1 since 2006

Average gas generation by state (Q1s)



[32] EnergyAustralia 2022, Statement on Yallourn fire: https://www.energyaustralia.com.au/about-us/media/news/statement-yallourn-fire

- New South Wales' output increased by 252 MW to the highest Q1 average since 2017, driven by a combination of portfolio dynamics and sustained high spot prices in region. Reduced output from EnergyAustralia's coal-fired Mt Piper Power Station led to increased running of Tallawarra this quarter (+238 MW), accounting for 95% of the region's increase. Similarly in Victoria, output increased by 96 MW on average, largely driven by EnergyAustralia's Newport (+55 MW) as it covered for outages at Yallourn.
- Queensland's output declined by 46 MW on average to its lowest Q1 average since 2006. Decline in output was driven by Swanbank E (-171 MW) which was out of service for the entire Q1 following an event that damaged the station's Automatic Voltage Regulator (AVR) in December 2021[33].
- In South Australia, average output decreased by 36 MW to its lowest quarterly level since NEM start, reflecting a full quarter with four synchronous condensers in operation, requiring fewer directions to gas-fired generators (Section 1.6.1). Snapper Point Power Station (150 MW) commenced generation late in the quarter[34].

1.3.3 Hydro

Hydro generation was comparable to recent Q1 levels at 1,538 MW on average. Tasmanian hydro output increased by 114 MW on Q1 2021, reflecting increased operational demand (+76 MW) and decreased local wind output (-43 MW), keeping net imports across Basslink at similar levels to last year, while mainland hydro generation decreased by 71 MW on average (Figure 31).

Changes in overall hydro generators' supply offers reflected the rise in NEM spot prices and bidding behaviour from other key generators. Close to 1,000 MW shifted from below $60/MWh to higher price bands (Figure 32), with Hydro Tasmania preferentially importing at lower prices from Victoria during the middle of the day.

Figure 31 Q1 hydro comparable to previous years

Average Q1 hydro generation by state

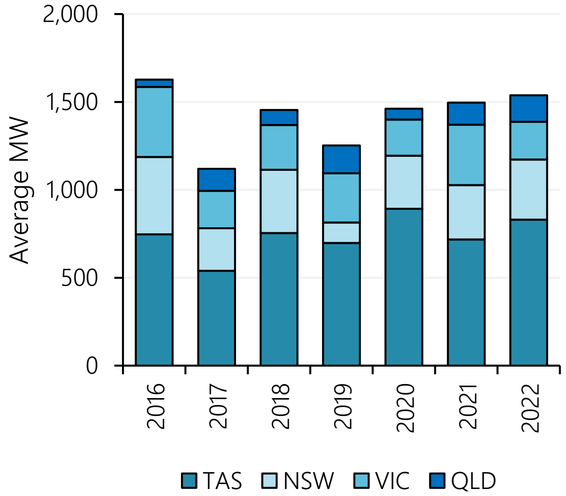
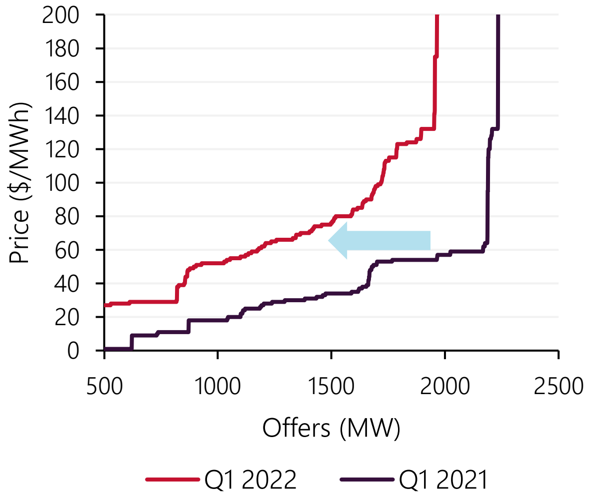


Figure 32 Shift in hydro offers to higher price bands

NEM hydro generation bid supply curve – Q1 2022 vs Q1 2021



[33] Swanbank E is currently scheduled to return in September 2022. For more information: https://cleancoqueensland.com.au/our-community/

[34] For more information: http://www.nexifenergy.com/project/snapper-point/

1.3.4 Wind and solar

During Q1 2022, average NEM VRE generation reached a record quarterly high of 4,190 MW, surpassing the previous record set in Q3 2021 by 208 MW. Compared to Q1 2021, average VRE generation increased by 743 MW, with grid-solar and wind contributing 435 MW and 308 MW, respectively (Figure 33).

Record output this quarter was mainly a product of recently installed capacity continuing to ramp up and new capacity additions that have entered the NEM over the past year, more than offsetting greater network-related curtailment (+63 MW, Section 1.6.2). While VRE utilisation[35] in Q1 2022 was comparable to the same period last year, it increased on Q3 and Q4 2021 (Figure 34), in line with higher spot prices and declining frequency of negative prices relative to recent quarters.

Figure 33 New South Wales and Victoria lead VRE output increase while Tasmania declines

Average change in VRE generation – Q1 2022 versus Q1 2021

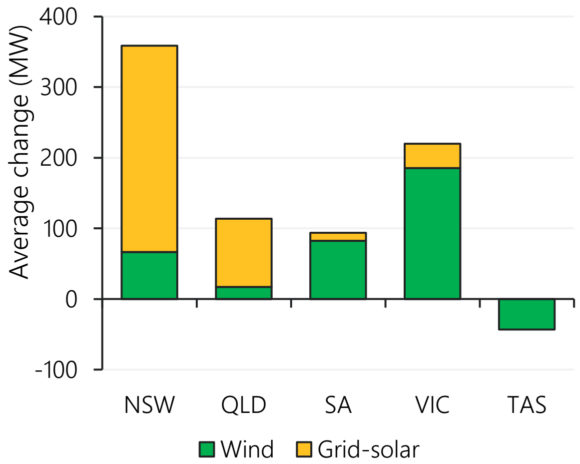
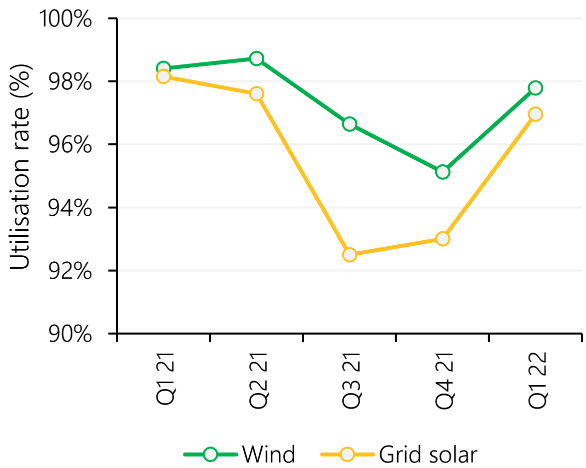


Figure 34 VRE utilisation increase on Q4 2021

NEM VRE volume-weighted utilisation rate



With continued increases in VRE output, several renewable generation records were set during the quarter:

- **Highest VRE output** – NEM VRE output (wind and grid-scale solar) reached 8,375 MW at 1000 hrs on 31 March 2022, 239 MW higher than the previous record set in Q3 2021.
- **Highest grid-solar output** – NEM grid-scale solar output reached 4,493 MW in the half-hour ending 1030 hrs on 14 February 2022, marginally higher than the previous record set in Q4 2021 (4,444 MW).

While NEM instantaneous renewable penetration[36] did not reach a new maximum this quarter (61.3% on 6 February 2022 in half hour ending 1200 hrs), it was only marginally lower than the record set in Q4 2021 on 15 November 2021 (61.8%). During this interval, distributed PV output accounted for 32.4% of total generation followed by VRE output (wind and grid-scale solar) at 26%.

[35] VRE utilisation rate captures generators' economic offloading or market response to price signals such as negative spot prices or high FCAS prices. Here, a generator's utilisation rate refers to output divided by availability adjusted for the impact of constraints. Utilisation rates of each generator are then weighted by maximum capacity to derive the volume weighted average by technology.

[36] Instantaneous renewable penetration is calculated as the NEM renewable generation share of total large- and small-scale 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 + distributed PV generation.

Average grid-scale solar generation continued to set new records, reaching a quarterly high of 1,504 MW, 214 MW above the previous record set in Q4 2021. Record levels of output occurred as ramping up of recently installed capacity, new capacity additions and increased solar irradiation in some regions more than offset increased grid-solar curtailment (+65 MW). By region, the increase was largely driven by New South Wales (+292 MW) followed by Queensland (+97 MW) and Victoria (+35 MW). This quarter saw first output from two new solar farms – Metz Solar Farm (115 MW) in New South Wales and Western Downs Green Power Hub in Queensland (400 MW).

- In New South Wales, continued ramp up of Limondale, Darlington Point, Wellington, Sunraysia and Suntop solar farms accounted for majority of the output increase despite higher grid-solar curtailment driven by network constraints.
- Increased grid-solar output in Queensland was predominantly driven by increased solar irradiation as available capacity factor[37] increased from 23% in Q1 2021 to 28% this quarter.

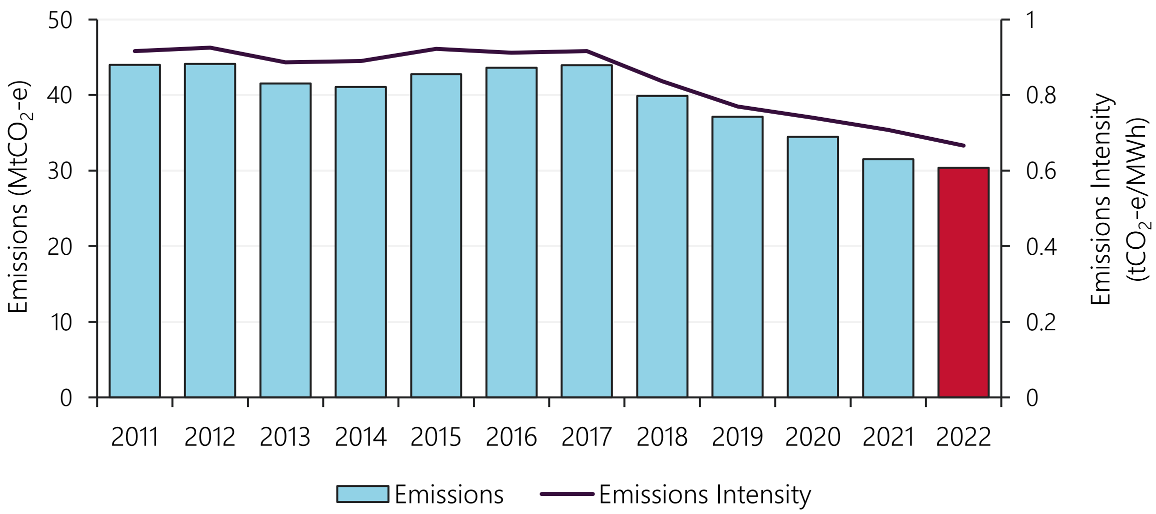
Average wind generation was 2,686 MW, 308 MW higher than Q1 2021, with increases occurring across all NEM regions apart from Tasmania. By region, Victoria had the largest increase in wind output (+185 MW) with continued ramp up of Stockyard Hill Wind Farm (+136 MW), accounting for 73% of the increase. Contrasting this was Tasmania where average quarterly wind output declined by 43 MW, largely due to lower wind speed as available capacity factor declined from 37% in Q1 2021 to 30% this quarter, its lowest Q1 level in recent years. During the quarter, one new wind farm commenced generation in Victoria – Murra Warra Wind Farm 2 (203 MW).

1.3.5 NEM emissions

During the quarter, NEM emissions declined to their lowest Q1 on record at 30.4 million tonnes carbon dioxide equivalent (MtCO_2-e), 4% lower than a year ago (Figure 35) despite increased operational demand, driven by lower coal generation combined with continuing growth in VRE output.

Figure 35 Record low Q1 quarterly emissions

Quarterly NEM emissions and emissions intensity (Q1s)



[37] Capacity factors of each project are weighted by maximum capacity to derive the weighted average by state. Project capacity factors are calculated using average availability divided by maximum installed capacity. The use of availability instead of generation removes the impact of any economic offloading or curtailment and better captures plant available capacity and underlying wind or solar resource levels.

1.3.6 Storage

Batteries

During Q1 2022, total estimated net battery market revenue was $12 million, $2 million higher than Q1 2021 ($10 million, Figure 36). Of note was an increasing proportion of total gross revenue from the energy market, up from 24% in Q1 2021 to 49% this quarter, reducing the FCAS market proportion (Figure 37). Higher net revenue compared to Q1 2021 was largely driven by increases from Victorian (+$2.5 million) and New South Wales batteries (+$1.5 million), partly offset by a decline in revenue from South Australian batteries (-$1.8 million). By region, compared to Q1 2021:

- Higher net battery revenue in Victoria was largely driven by the energy market (+$1.6 million), accounting for 64% of the increase. Higher net energy revenue arose from increasing volume-weighted average energy arbitrage value (from $18/MWh to $95/MWh) as well as increased dispatch (+254%), mostly from the Victorian Big Battery (VBB).
  - Following VBB's successful commissioning in Q4 2021, increased activity in both energy and FCAS markets increased net revenue for the battery by $2.2 million.
- In New South Wales, higher net revenue (+$1.5 million) was driven by Wallgrove Grid Battery as it continues to participate in both energy (+$0.2 million) and FCAS markets (+$1.3 million) following its commissioning in Q4 2021.
- Despite an increase in net energy revenue from South Australian batteries due to increased volume-weighted average energy arbitrage value (from $75/MWh to $141/MWh), overall net revenue declined by $1.8 million largely due to lower revenue received from Contingency FCAS markets.

Figure 36 Net revenue up on Q121 but down on Q421

Estimated battery revenue sources – quarterly

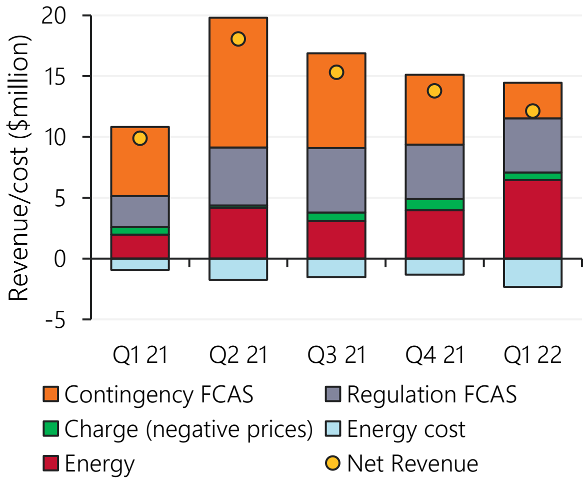
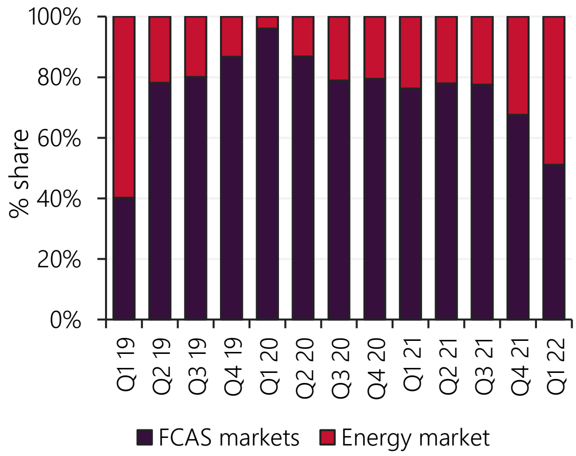


Figure 37 Energy markets' share highest since Q119

FCAS and energy market share of total gross revenue - quarterly



Pumped hydro

Pumped hydro spot market revenue in Q1 2022 reached a record quarterly high of $56.5 million, up substantially from $2.9 million in Q1 2021 (Figure 38). The marked increase in net revenue was overwhelmingly due to Wivenhoe Pumped Hydro, which accounted for 94% of net revenue.

Compared to Q1 2021, by power station:

- Record net revenue from Wivenhoe Pumped Hydro (+$51 million) was driven by high Queensland price volatility during the quarter, along with utilisation increasing (+551%) from very low levels in Q1 2021 (Figure 39).
  - During the quarter, Wivenhoe was highly responsive to price volatility in Queensland, with revenue received from generation at spot prices above $300/MWh accounting for 83% of total net revenue. Net revenue received on three separate days of extreme price volatility in Queensland during the quarter – 31 January, 1 February (Figure 40) and 8 March, accounted for 74% of Wivenhoe's Q1 total.
- In New South Wales, higher net revenue from Shoalhaven Pumped Hydro this quarter (+$2.6 million) was a function of increased utilisation (+54%) and increased average energy arbitrage value (up from $22/MWh in Q1 2021 to $66/MWh this quarter).

Figure 38 Record high pumped hydro net revenue in Q122

Estimated pumped hydro revenue sources - quarterly

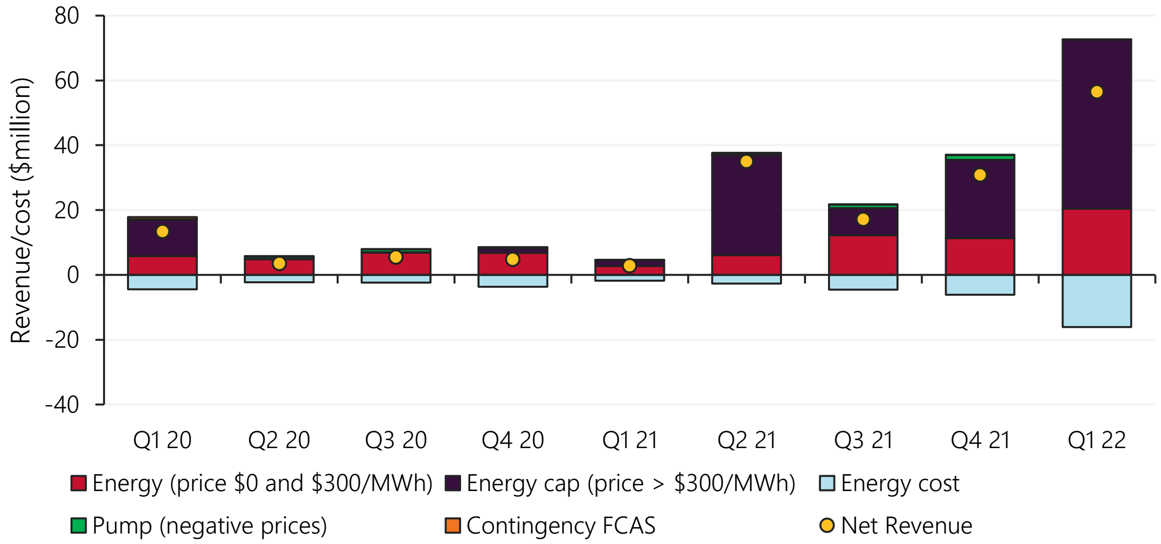


Figure 39 Increased utilisation compared to Q121

Wivenhoe quarterly generation and pumping – Q122 vs Q121

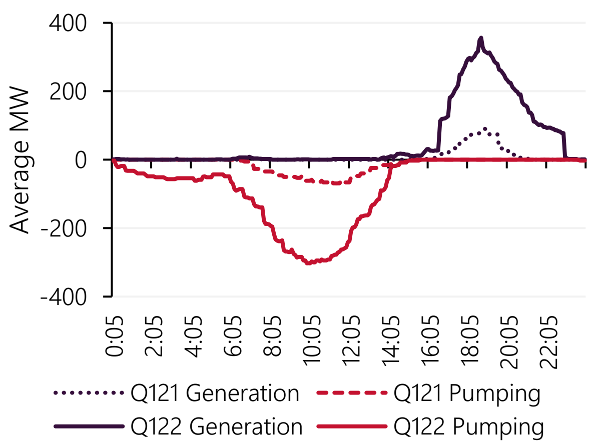
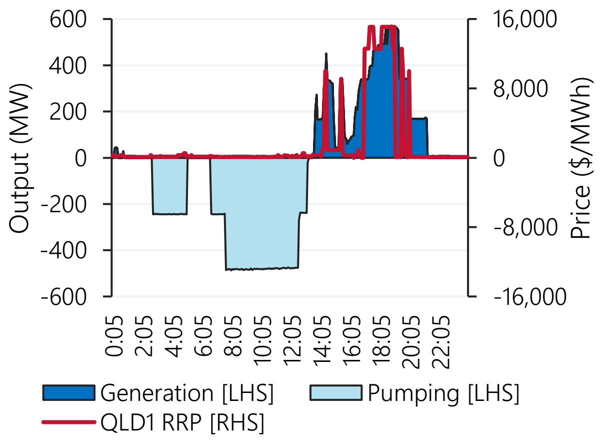


Figure 40 Wivenhoe captured price volatility

Wivenhoe operation on 1 February 2022



1.3.7 Wholesale demand response

Following the commencement of the Wholesale Demand Response (WDR) mechanism[38] in Q4 2021, the first NEM dispatch of WDR capacity occurred in Victoria during Q1. On 31 January 2022, high evening peak demand in Victoria due to very warm temperatures, coupled with constraints on interconnector imports from New South Wales and Murray hydro generation, led to price volatility with Victoria's spot price spiking above $10,000/MWh between 1730 hrs and 1800 hrs (Section 1.2.2). Over this period, up to 10 MW[39] from two Victorian WDR units was dispatched between 1705 hrs and 1910 hrs (Figure 41). Subsequently, on 17 February in New South Wales WDR capacity was dispatched up to 10 MW between 1645 hrs and 2035 hrs.

During the quarter, AEMO registered eight new WDR units – four in New South Wales (combined 20 MW), three in Victoria (combined 16 MW) and one in South Australia (2 MW) – all of which are operated by Enel X (Table 4[40]). These registrations bring total NEM WDR maximum response capacity to 58 MW, up from 20 MW in Q4 2021. Separately from WDR, AEMO also registered a new market scheduled load (St Leonards Data Centre, 20 MW) in Tasmania for both energy and Contingency Raise FCAS markets in Q1 2022.

Figure 41 First ever dispatch from NEM wholesale demand response units

Victorian WDR dispatch targets and spot price – 31 January 2022

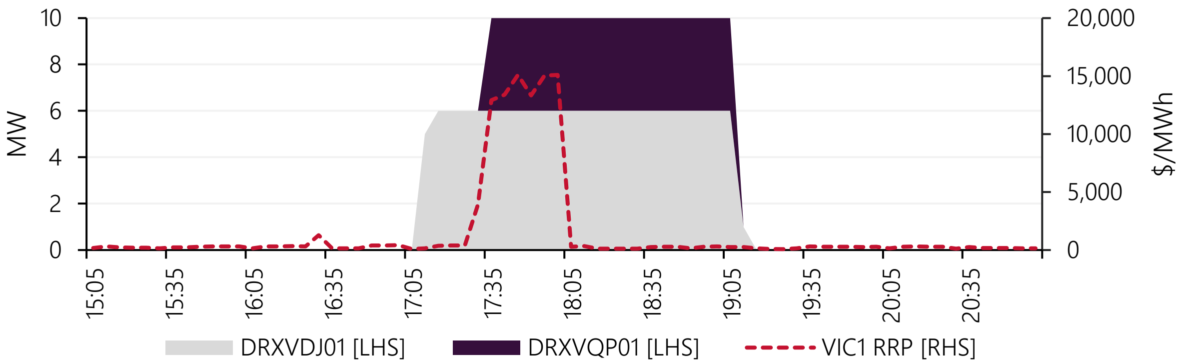


Table 4 Wholesale demand response units registered in Q1 2022

Facility Name	Region	WDRU DUID	Maximum response component (MRC) (MW)	Maximum ramp rate (MW/minute)
DR ENELX V17	VIC1	DRXVDP01	10	2
DR ENELX V12	VIC1	DRXVDX01	2	1
DR ENELX V24	VIC1	DRXVQX01	4	1
DR ENELX S2	SA1	DRXSQS01	2	1
DR ENELX N3	NSW1	DRXNDE01	2	1
DR ENELX N31	NSW1	DRXNDA02	6	2
DR ENELX N32	NSW1	DRXNDA03	6	2
DR ENELX N34	NSW1	DRXNDA04	6	2

[38] The WDR mechanism commenced operation on 24 October 2021. WDR enables demand-side (consumer) participation in the NEM spot market separately from retail energy procurement, with the mechanism typically expected to be utilised at times of high electricity prices and electricity supply scarcity.

[39] Dispatch target a WDR unit receives from AEMO. Under the rules governing WDR, the quantity of response provided will be assessed by comparing metered consumption (or export) against a baseline, which reflects a counter-factual level of demand of the WDR unit. The actual quantity of demand response assessed as being provided by WDR units is confidential.

[40] AEMO 2022, NEM Registration and Exemption List: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/NEM-Registration-and-Exemption-List.xls

1.4 Inter-regional transfers

Inter-regional energy flows in Q1 were characterised by a northward shift in flows between New South Wales and Queensland, but reduced net exports from Victoria to New South Wales on VNI (Figure 42). For the first Q1 since 2001, net flows between New South Wales and Queensland ran northward, as reduced generation availability, high operational demands, and elevated spot prices in Queensland lowered opportunities to export to New South Wales and significantly increased Queensland's imports (Figure 43). With this turnaround in flows and reduced northerly transfers on VNI, discussed further below, in Q1 New South Wales' net energy imports from neighbouring regions reached their lowest level for any quarter since the abolition of the Snowy region in July 2008. Flows between Victoria and neighbouring southern NEM regions were similar to Q1 2021; notably the Murraylink DC interconnector carried its highest ever level of quarterly net flow from Victoria into South Australia (86 MW), accounting for nearly half the net flow between these regions.

Figure 42 New South Wales exports to Queensland while imports from Victoria fall

Quarterly inter-regional transfers

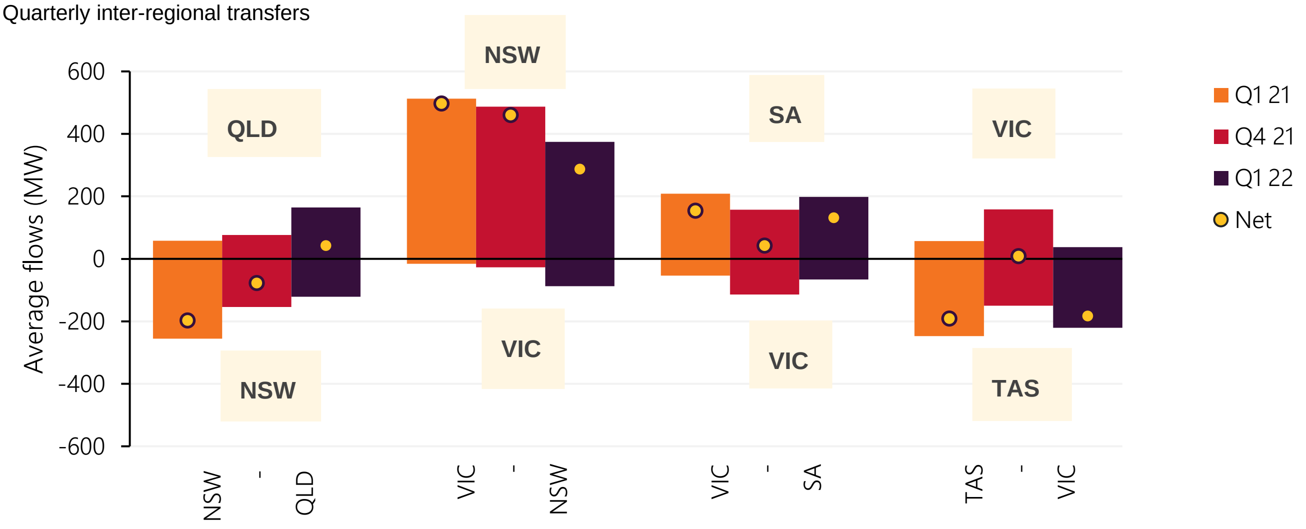
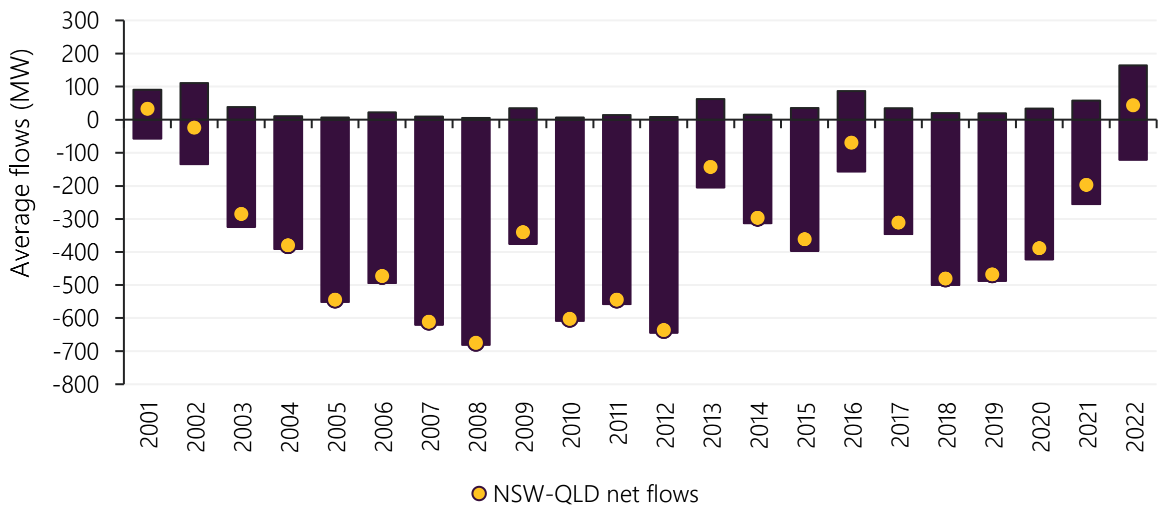


Figure 43 Net Q1 flows between New South Wales and Queensland turn northward for the first time since 2001

Average quarterly NSW-Qld (QNI and Directlink) flows – Q1s



Southern to northern NEM flows and price differences

Amplifying the trend noted in AEMO's Q4 2021 Quarterly Energy Dynamics (QED) report, exports from the southern NEM regions to the higher-priced northern regions via VNI were even more significantly restricted by transmission constraints in Q1, particularly during daytime hours (Figure 44). Between 0800 hrs and 1800 hrs, average VNI flows were only 66 MW into New South Wales, despite an average energy price difference of $48/MWh. Corresponding flows in Q1 2021 were 470 MW with an average price difference of only $19/MWh. Outside these hours, flows in Q1 2022 averaged 446 MW with a significantly lower price difference of $22/MWh.

The impact of key daytime transmission constraints is evident in reduced average export limits for VNI, profiled by time of day, in Q1 2022 relative to Q1 2021 (Figure 45). Average export limits fell by more than two thirds over morning hours (0800 hrs to 1200 hrs) and remained significantly lower until late evening.

Figure 44 VNI daytime exports collapse

VNI interconnector flows and energy price difference[41]

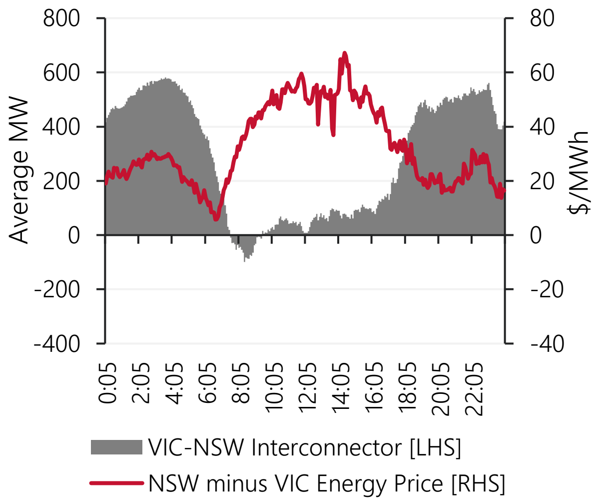
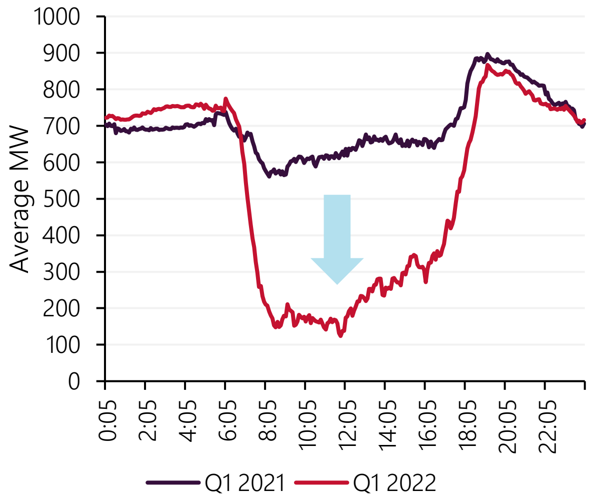


Figure 45 Constraints reduce VNI export limits

Average VNI export limit – Q1 2022 versus Q1 2021



Unsurprisingly, exports on VNI were more often constrained at these reduced limits in Q1 2022 compared with Q1 2021, for around 50-70% of all dispatch intervals across the hours of 0800 hrs to 1800 hrs, while constraints on imports to Victoria remained infrequent (Figure 46).

The key constraint affecting daytime exports on VNI – limiting export flows in over 25% of dispatch intervals in Q1, five times more frequently than any other constraint – addresses system security risks (voltage collapse after loss of a key Victorian transmission line) in the relatively weak south-western New South Wales transmission network, which carries a significant share of flows from a large number of newer grid-solar and wind generation facilities located in this zone or in adjoining north-western Victoria. This transmission path forms part of the Victoria – New South Wales interconnection and is impacted by the overall level of VNI transfers. To manage security risks when generation in these zones is high, VNI flows north may be limited or counter-price southward flows scheduled, which also contributed to an increase in negative inter-regional settlement residues on flows into Victoria in Q1 (Section 1.4.1). The high capacity of grid-solar generation now commissioned in this area and its effect on this security constraint are reflected in the time of day profile over which it limits VNI flows (Figure 47). Easing of other constraints previously limiting generation in the area also contributed to greater impacts on VNI in Q1 2022.

[41] Spot prices capped at $300/MWh.

Figure 46 VNI daytime export constraints growing

% of time VNI limits bound by time of day – Q122 vs Q121

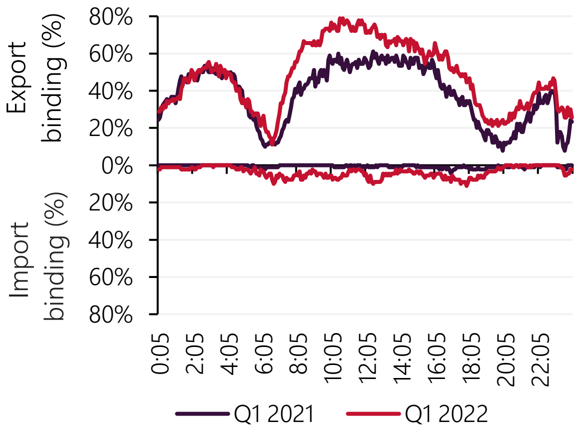
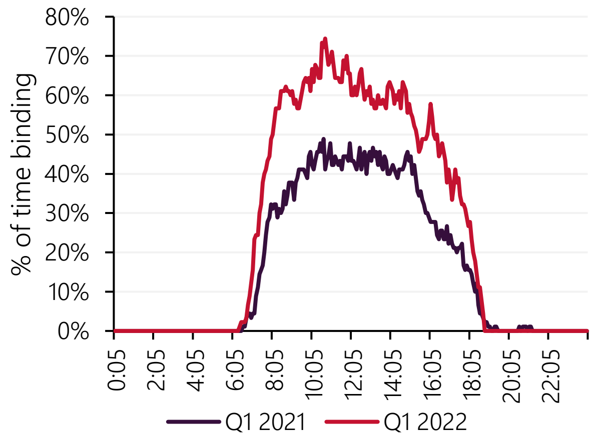


Figure 47 Key constraint reflects grid-solar profile

% of time N^^N_NIL_3 bound by time of day – Q122 vs Q121



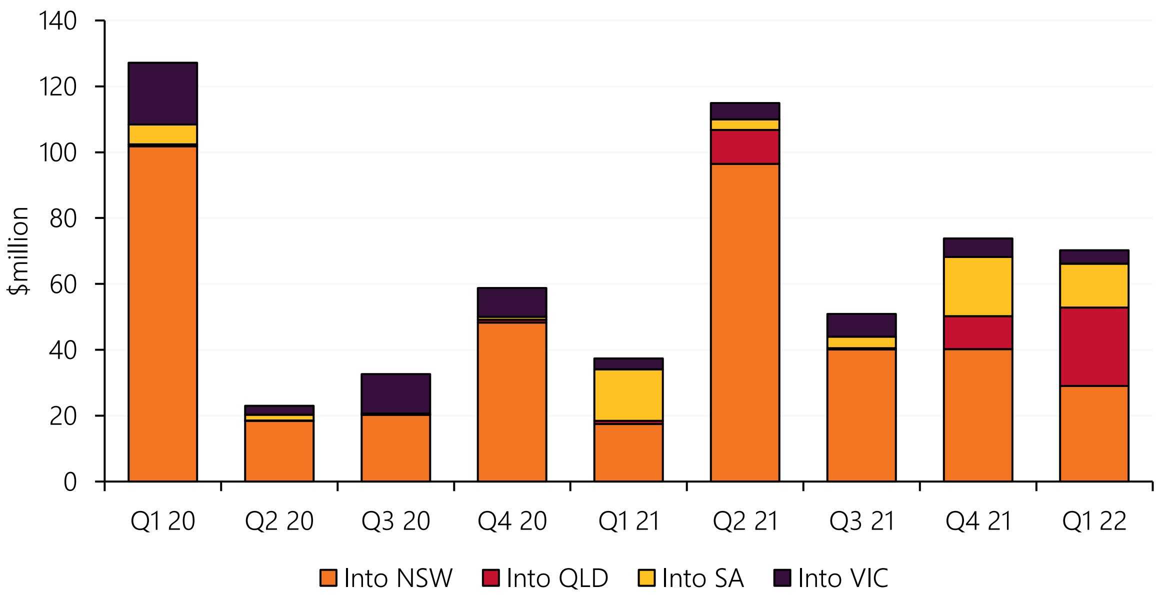
1.4.1 Inter-regional settlement residue

Total positive inter-regional settlement residue (IRSR) fell marginally to $70 million in Q1 from $74 million in Q4 2021 but was well above the Q1 2021 level of $37 million (Figure 48).

As in Q4 2021, persistent price differences between Victoria and New South Wales led to accumulation of IRSR on VNI flows into New South Wales, but the reduced export volumes on VNI due to transmission constraints led to lower positive IRSR (down from $36 million in Q4 to $27 million this quarter). Conversely, isolated volatility episodes in Queensland led to significant IRSR on flows from New South Wales (up to $24 million from $10 million in Q4 and just $1 million in Q1 2021). Positive IRSR on Victoria to South Australia transfers arose from a mixture of isolated volatility events and longer periods of moderate price separation, and at $13 million for Q1 was down by $5 million on Q4 and $2 million on Q1 2021.

Figure 48 Regional price differences and volatility contribute to IRSR returns

Quarterly positive IRSR value



Negative residue management

Negative IRSR accumulations totalled $10 million for Q1, very similar to Q4 and roughly double those of Q1 2021 (Figure 49). The largest contribution to negative residues ($6 million) was from counter-price flows from New South Wales into Victoria, arising when transmission constraints on VNI forced flows southwards despite spot prices in New South Wales exceeding those in Victoria. The high frequency of these events (Figure 50) was reflected in a record incidence of Negative Residue Management (NRM) constraints, invoked to limit the rate of accumulation in negative residues, which bound for this flow direction in Q1 (Figure 51). Unlike Q2 to Q4 2021 there were few outage-related transmission constraints affecting QNI, and negative IRSR on flows into New South Wales of $3 million arose from limited counter-price flows into New South Wales on VNI and the Queensland – New South Wales Interconnector (QNI) in roughly equal proportions.

Figure 49 Negative residues between NSW and Victoria reached new highs

Quarterly negative inter-regional settlement residue

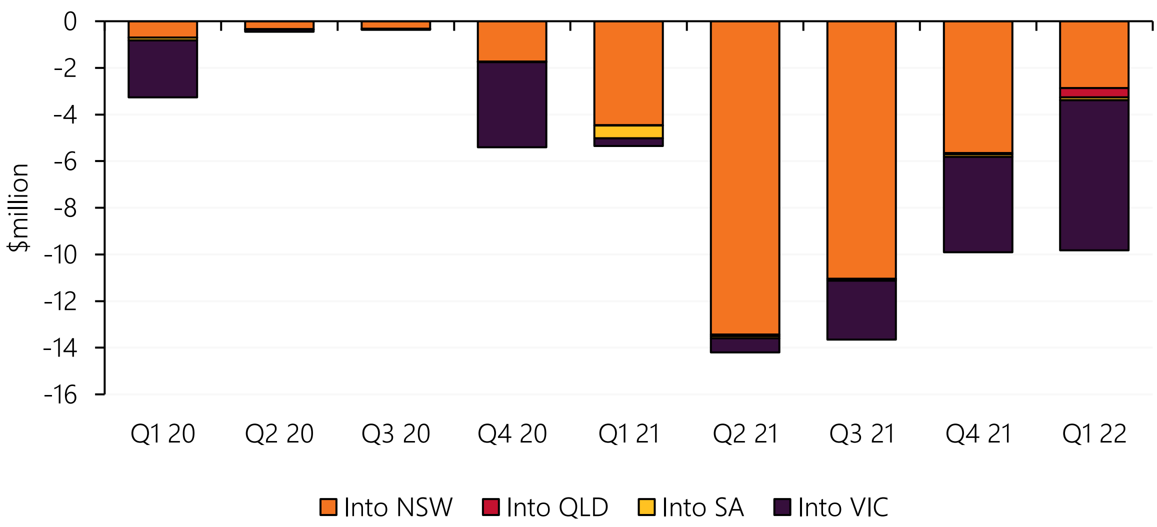


Figure 50 Increase in counter-price flows on the VNI

Counter-price flows south on the VIC-NSW interconnector[42]

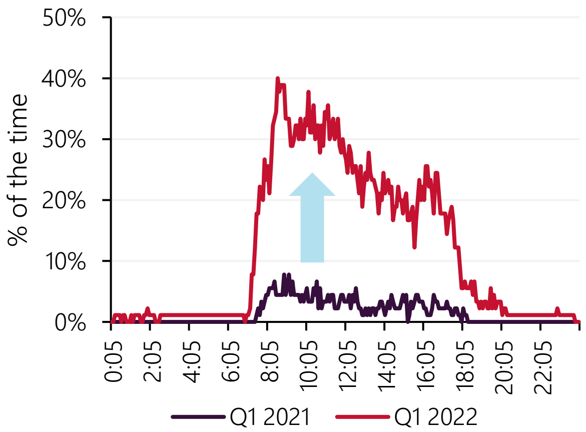
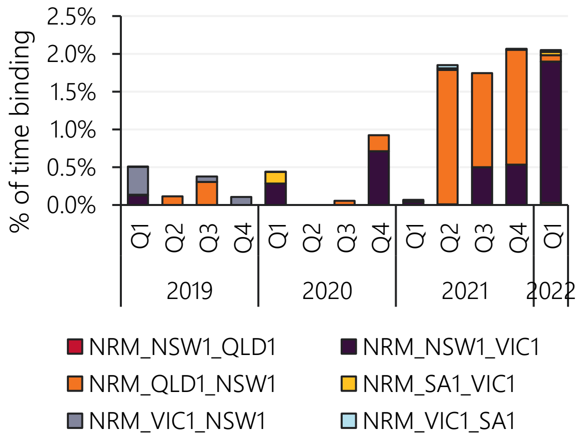


Figure 51 Record NSW to VIC NRM constraint binding

Proportion of time NRM constraint bound by quarter



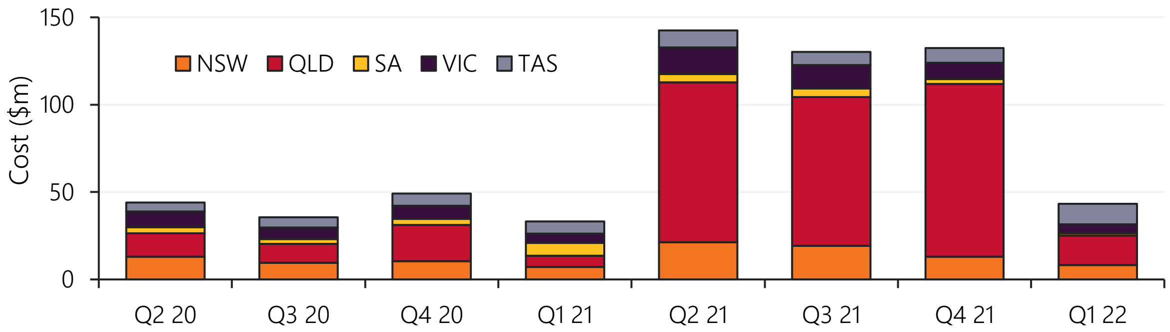
[42] Counter-price flows occur when electricity is exported from a high price region into a lower priced region in order to manage congestion or system security risks. This occurs when the market dispatch algorithm determines that the optimal outcome to manage these risks in one region is to force the flow of electricity into an adjoining region.

1.5 Frequency control ancillary services

FCAS costs fell to $43 million in Q1 2022, around one-third of their level in the preceding three quarters (Figure 52). Costs in Queensland at $17 million for the quarter were down $82 million on the record reached in Q4 2021 but $10 million higher than in Q1 2021, equalling the overall increase in quarterly NEM-wide FCAS costs relative to one year ago. Both the fall from Q2-Q4 levels and the increase on Q1 2021 relate to the impact of transmission upgrade works involving scheduled outages on QNI, which regularly led to very high prices and costs for Contingency FCAS products in Queensland across the prior three quarters, as documented in recent QED reports. There was only one relevant outage in Q1 2022, leading to elevated Contingency Lower costs over a two-day period in March, and none in Q1 2021. Tasmanian FCAS costs grew to $12 million this quarter, up $5 million on Q1 2021 due to significantly higher prices for most FCAS products, but this increase was offset by flat or lower costs in the remaining regions.

Figure 52 FCAS quarterly costs return to more typical levels

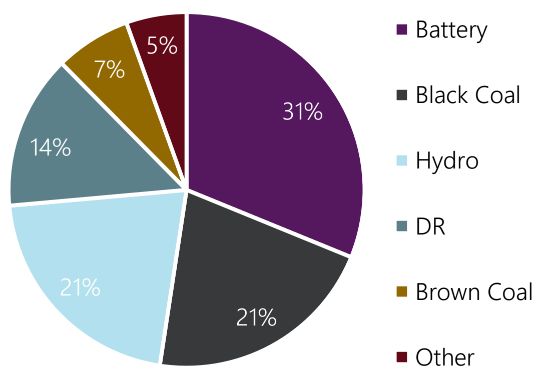
Quarterly FCAS cost by region[43]



Analysis of FCAS market shares (Figure 53) and year-on-year changes in enablement volumes for Q1 (Figure 54) show that grid-scale batteries now lead the overall provision of FCAS services while other relatively new sources including demand response and Virtual Power Plants (VPP) have also grown volumes at the expense of conventional generation providers.

Figure 53 Batteries top FCAS market shares

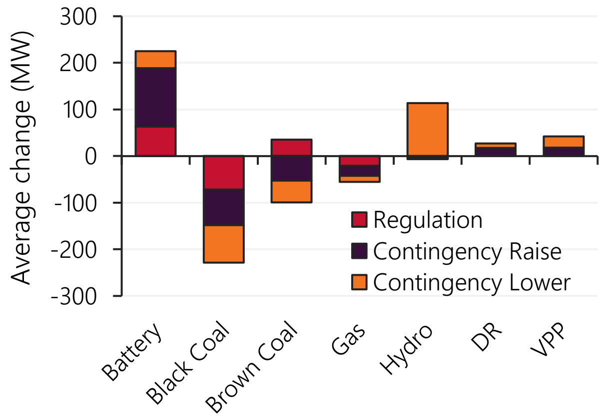
Share of FCAS volumes by fuel type – all services Q1 2022



DR: Demand response

Figure 54 Growing non-generator FCAS enablement

Changes in FCAS enablement by fuel type – Q1 2022 vs Q1 2021



[43] Based on AEMO Settlement data and represents preliminary data that will be subject to minor revisions.

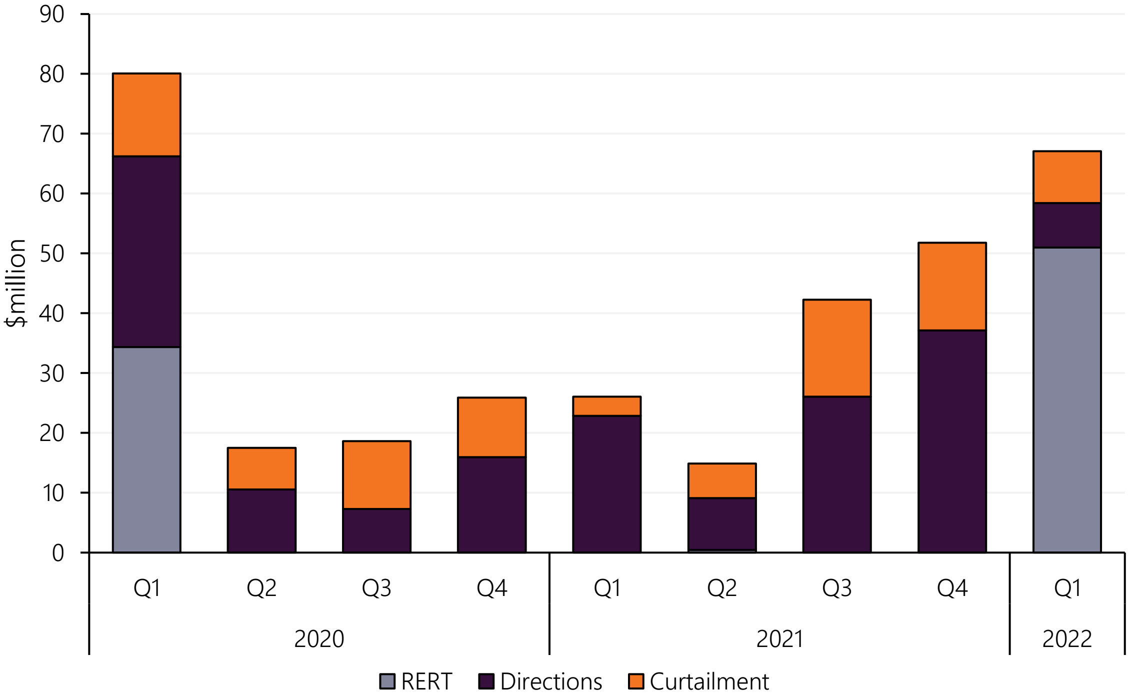
1.6 Power system management

Power system management costs increased to $67 million, up $41 million from Q1 2021 and $15 million on Q4 2021 levels (Figure 55). The dispatch of RERT resources in Queensland on 1 February 2022 (Section 1.2.2) led to substantial one-off activation and compensation costs which dominated other categories and accounted for the entire increase in system management costs over Q1 2021.

- AEMO activated **RERT** in Queensland on 1 February 2022 due to forecast and actual LOR2 conditions (Section 1.2.2). During the event between 1705 hrs and 2130 hrs, up to 331 MW of reserve was procured for RERT, with a total estimated cost of $51 million[44].
- The estimated cost of **system security directions** to South Australian synchronous generators fell to just $7.5 million in Q1, down from $37 million in Q4 2021 and $23 million one year ago. This is attributable to full operation of four synchronous condensers allowing reduced minimum levels of online gas generation for the whole quarter, and higher spot prices inducing gas generators to remain online for economic reasons.
- Notional costs of **VRE curtailment**[45] rose from $3 million in Q1 2021 to $9 million in Q1 2022 due to growing output and increases in volumes curtailed in New South Wales and Victoria by transmission network congestion and security constraints.

Figure 55 RERT expenses in Queensland dominate Q1 power system management costs

Quarterly system costs by category[46]



[44] AEMO 2022, RERT Activation Estimates 1 Feb 2022: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2022/rert-activation-estimates-report-for-1-feb-2022.pdf?la=en

[45] The notional cost of curtailed VRE output is calculated using a generic value of $40/MWh for output curtailed.

[46] In this edition of the QED, 'power system management costs' are those associated with RERT, directions compensation and VRE curtailment. Market FCAS costs which were previously included in this section are now reported separately in Section 1.5.

1.6.1 Directions

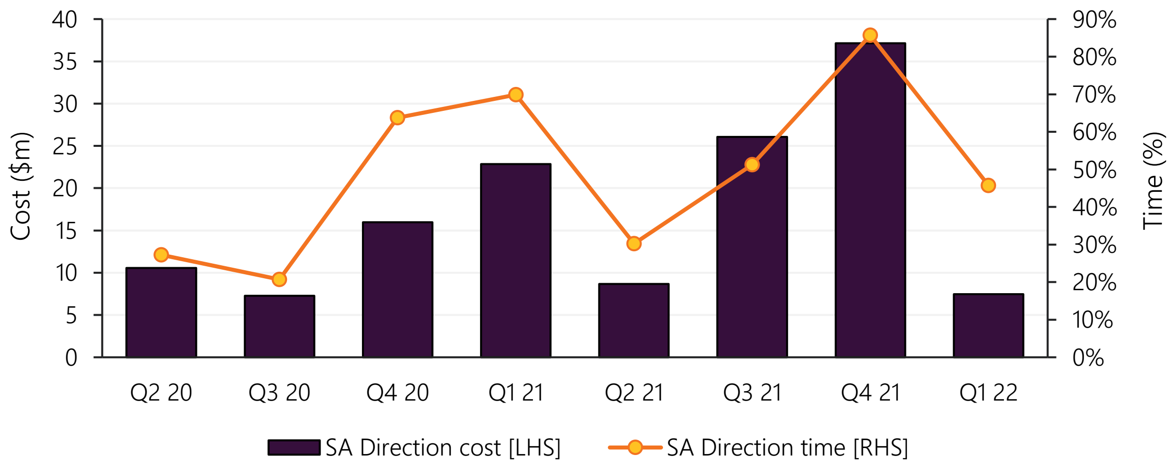
During Q1 2022, AEMO issued directions to generators in South Australia and Queensland to maintain system security. Directions were issued to several Queensland coal generators on 1 February 2022 to maintain the power system in a reliable operating state in response to consistent forecasts of low reserves, but no compensation was payable as intervention pricing did not apply for these directions[47].

Total NEM direction costs in Q1 2022, all related to South Australia, declined to $7.5 million, reversing the upward trend in recent quarters (Figure 56). Lower direction costs compared to record highs in Q4 2021 reflected lower volumes directed, falling from an average of 127 MW in Q4 2021 to 31 MW this quarter. Reduced volumes directed also led to a much smaller proportion of South Australian gas generation output this quarter being attributable to directions, down from 38% in Q4 2021 to just 8% this quarter (Figure 57).

A key driver of the marked reduction in directed volumes for South Australian gas-fired generation units this quarter was the move to full operation of four synchronous condensers in late November 2021, which allows AEMO to operate the South Australian region securely with a reduced number of synchronous generators online[48]. During Q1 2022, in most circumstances, only two larger gas generation units were needed online to maintain system security (Figure 58). This – coupled with higher South Australian spot prices (Section 1.2) inducing gas generators to stay online for economic reasons – resulted in reduced direction requirements in Q1 2022. Additionally, with the average 12-month 90th percentile spot price (used as the benchmark for compensating participants) increasing to $112/MWh this quarter, the number of claims for additional compensation[49] declined to 13, accounting for only 15% of total directions costs[50].

Figure 56 Decline in South Australian directions costs and time directed

Time and cost of system security directions (energy only) in South Australia



Note: direction costs are preliminary costs which are subject to revision

[47] For further information on this direction event, see: https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-event-direction-to-queensland-generators-1-february-2022.pdf?la=en

[48] On 25 November 2021, AEMO updated its system strength limit advice to reduce the minimum number of gas generation units required to ensure power system security from the equivalent of four large units to two under most operating conditions. For further information, please see: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/related-resources/operation-of-davenport-and-robertstown-synchronous-condensers

[49] Under NER clause 3.15.7B, a directed participant is entitled to claim additional compensation for the net loss of revenue and additional costs not covered by the standard compensation amounts calculated under the NER.

[50] Additional claims and additional claims that require independent expert may take up to 30 weeks to finalise.

Figure 57 Substantial reductions in volume directed

SA gas-fired generation directed

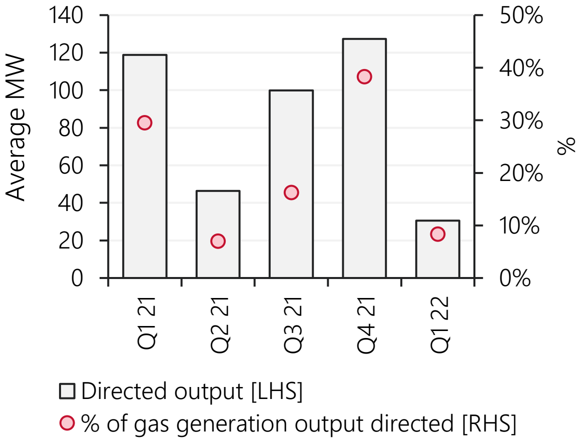
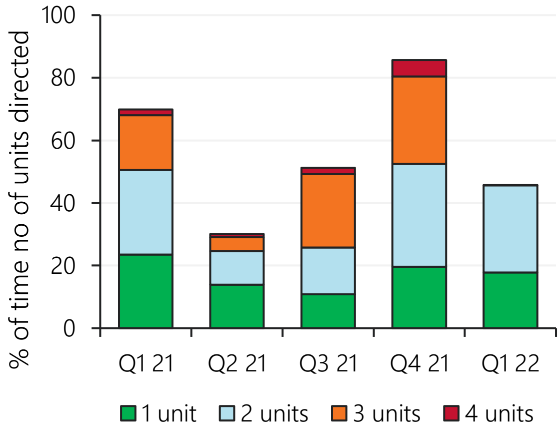


Figure 58 Number of units directed declines

% of time number of gas-fired generation units directed



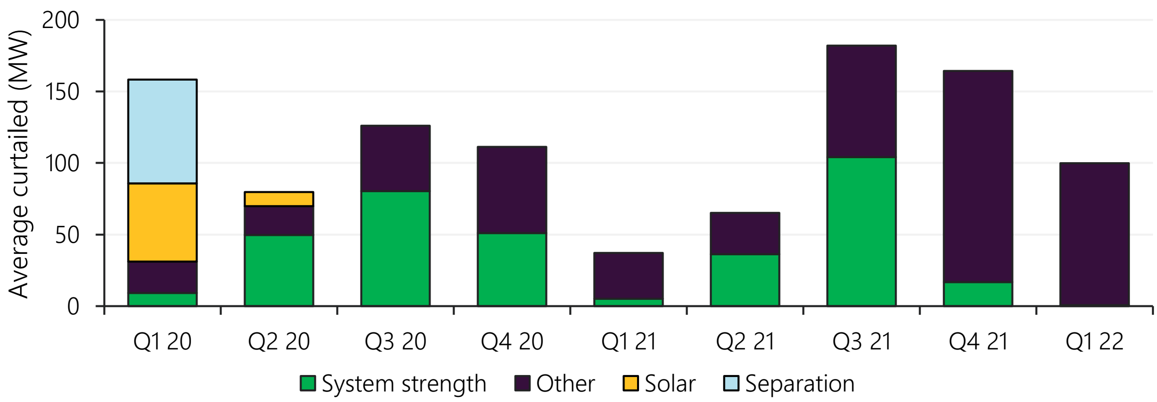
1.6.2 VRE curtailment

Analysis of VRE generation curtailment in this report is now confined to the impact of constraints imposed on dispatch of this generation for reasons such as maintenance of system strength, stability of inverter-based generators, or management of transmission congestion and general system security. With the growing price-responsiveness and active market participation of VRE generators, offloading of available output bid at prices equal to or above the spot price is no longer reported as "economic curtailment", as it represents the normal operation of the NEM dispatch process applying to all forms of scheduled generation and load. Any economic offloading is reflected in utilisation data for grid-solar and wind generation presented in Section 1.3.4.

Curtailment as defined above fell to an average of 100 MW in Q1 2022 from 164 MW in Q4 2021 but was up from 37 MW in Q1 2021. There was no material curtailment of VRE for maintenance of system strength in Q1, with full operation of South Australia's four synchronous condensers lifting previous system strength limits in that region, meaning that nearly all curtailment arose from more general transmission congestion and security constraints (Figure 59).

Figure 59 Transmission congestion and security constraints account for nearly all VRE curtailment in Q1

Average NEM VRE curtailed by curtailment type[51]

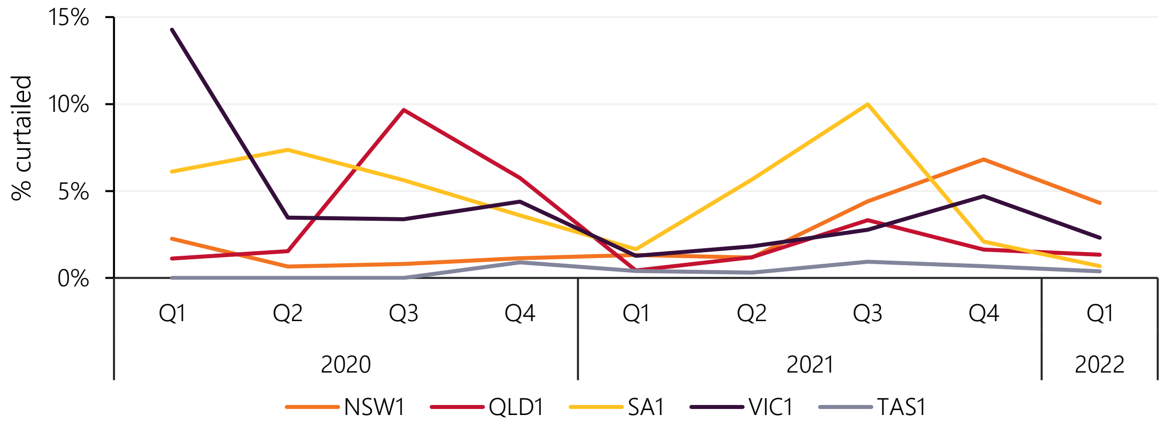


[51] Curtailment amount is based on combination of market data and AEMO estimates. For more information on the calculation, see https://wattclarity.com.au/articles/2020/06/not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation/?utm_source%20=rss&utm_medium=rss&utm_campaign=not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation. In this edition of the QED, curtailment excludes any offloading resulting from price-based economic dispatch.

As a proportion of available energy by region, curtailment was highest in New South Wales at 4.3% followed by Victoria at 2.3% (Figure 60).

Figure 60 Curtailment below 5% in all NEM regions, highest in NSW and Victoria

% VRE curtailed by NEM region

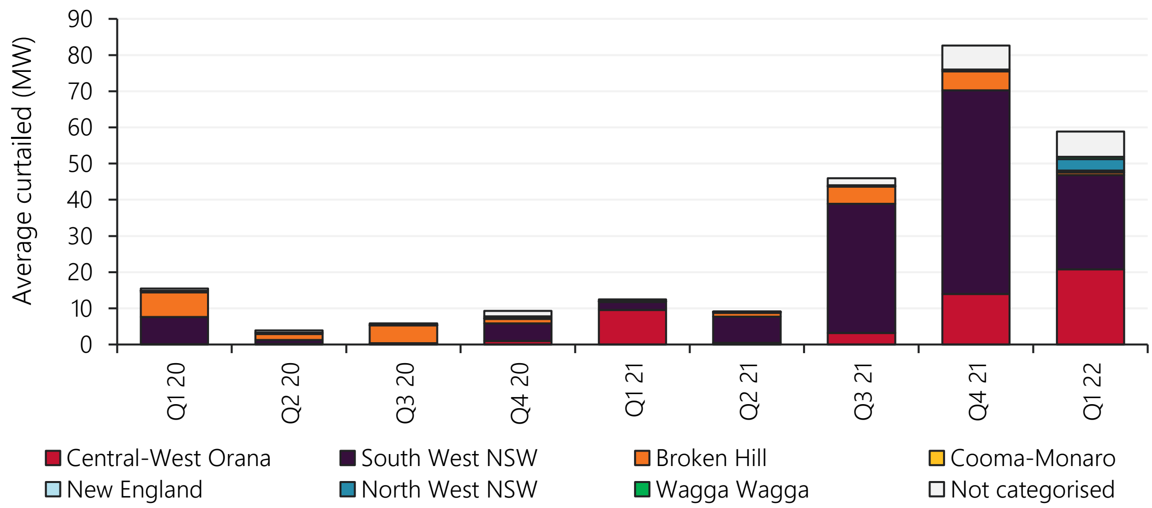


Focusing on the geographic distribution of curtailment within New South Wales reveals that the majority of curtailed output in Q1 and preceding quarters arose in two zones which have seen the largest increases in VRE production in that state over the past year: the south-western zone where curtailment as proportion of available output in Q1 2022 was 7% and the central-west Orana zone where the corresponding figure was 8% (Figure 61). Similar analysis for Victoria locates the bulk of curtailment in the Murray River zone, accounting for 11% of that zone's available output in Q1.

These results highlight the very location-specific nature of VRE curtailment, which reflects varying balances between growth in generation capacity and transmission capability in different areas of the network. The proposed development of "Renewable Energy Zones" (REZs) is one approach to managing these balances as further VRE growth proceeds.

Figure 61 Majority of VRE curtailment occurring in South West NSW and Central-West Orana regions

Average New South Wales VRE curtailed by candidate Renewable Energy Zone (REZ)[52]



52 REZ candidates shortlisted in the Draft Integrated System Plan 2022.

2 Gas market dynamics

2.1 Gas demand

Total east coast gas demand remained stable compared to Q1 2021 (+0.3%). While demand in AEMO markets decreased (-4.6 PJ), this was offset by an increase in gas-fired generation demand (+5.2 PJ), and a small demand increase for Queensland liquefied natural gas (LNG) demand (+1 PJ, Table 5).

Queensland LNG exports continue to be influenced by strong Asian LNG demand and high prices (Section 2.2.1) Volumes this quarter represent the highest Q1 export level recorded and continue the trend of significantly higher exports that began in Q4 2020.

By participant, Queensland Curtis LNG (QCLNG) recorded an increase of 5.5 PJ while Australia Pacific LNG (APLNG) and Gladstone Liquified Natural Gas (GLNG) decreased by 1.4 PJ and 3 PJ respectively (Figure 62). During the quarter, 92 LNG cargoes were exported, an increase from 90 in Q1 2021[53]. QCLNG increased from 30 to 33 cargoes, APLNG remained steady at 33, while GLNG decreased from 27 to 26.

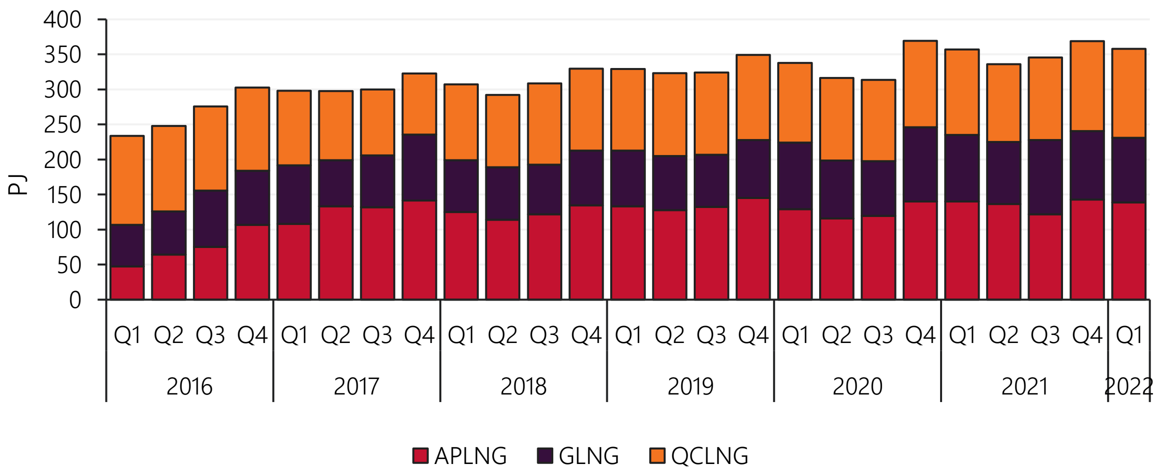
Table 5 Gas demand – quarterly comparison

Demand (PJ)	Q1 2022	Q4 2021	Q1 2021	Change from Q1 2021
AEMO Markets *	52.8	67.6	57.4	-4.6 (-8%)
Gas-fired generation **	26.8	19.9	21.6	+5.2 (24%)
QLD LNG	357.9	369.0	356.8	+1.0 (0.3%)
TOTAL	437.5	456.5	435.8	+1.4 (0.3%)

* AEMO Markets demand is the sum of customer demand in each of the Short Term Trading Markets (STTMs) and the Declared Wholesale Gas Market (DWGM) and excludes gas powered generation in these markets.
** Includes demand for gas generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Figure 62 Highest Q1 Queensland LNG exports on record

Total quarterly pipeline flows to Curtis Island



53 Queensland Government Maritime Safety Queensland: https://qships.tmr.qld.gov.au/webx/

2.2 Wholesale gas prices

Continuing from Q4 2021, quarterly average prices remained at or near record levels across all AEMO markets, averaging $9.93/GJ compared to $6.05/GJ in Q1 2021 (Table 6). Victoria's Declared Wholesale Gas Market (DWGM), Brisbane and Adelaide average prices set new Q1 records, while Gas Supply Hub (GSH) and Sydney saw their second highest Q1 levels on record since 2017.

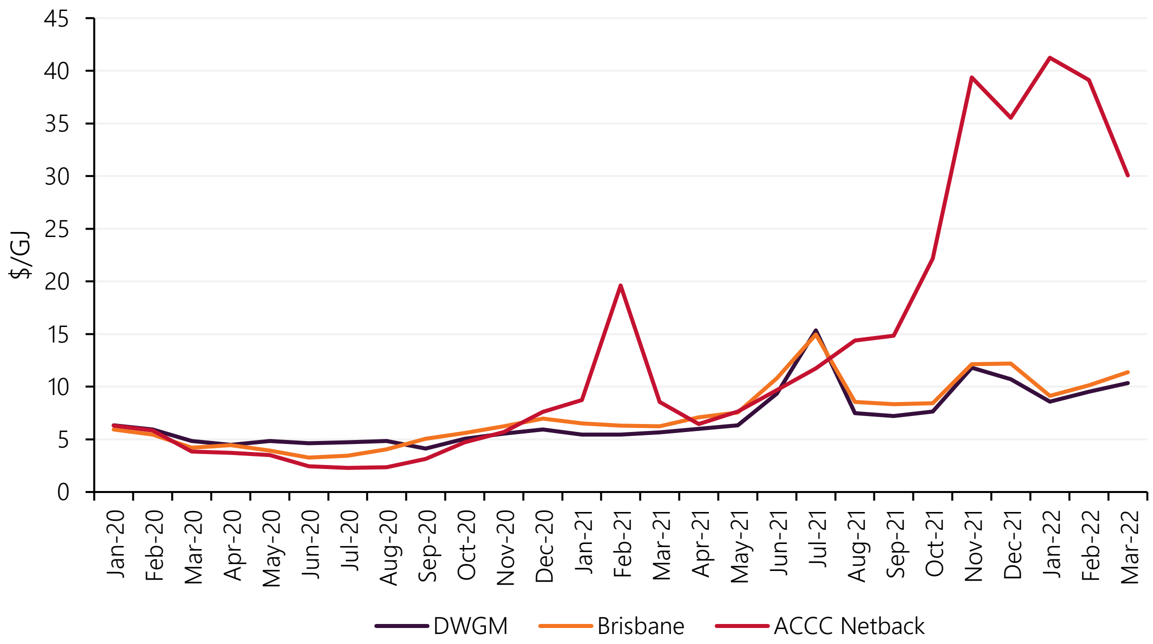
Table 6 Average gas prices – quarterly comparison

Price ($/GJ)	Q1 2022	Q4 2021	Q1 2021	Change from Q1 2021
DWGM	9.47	10.02	5.52	+72%
Adelaide	10.18	10.67	6.05	+68%
Brisbane	10.22	10.91	6.36	+61%
Sydney	9.81	10.52	6.05	+62%
GSH	9.97	10.86	6.12	+63%

While domestic market prices remain higher than Q1 2021, international prices as represented by the Australian Competition and Consumer Commission (ACCC) netback price continued at significantly higher levels, peaking at a record $41.24/GJ in January (Figure 63). Drivers for higher international prices are discussed in Section 2.2.1.

Figure 63 Domestic prices increase but remain well below international prices

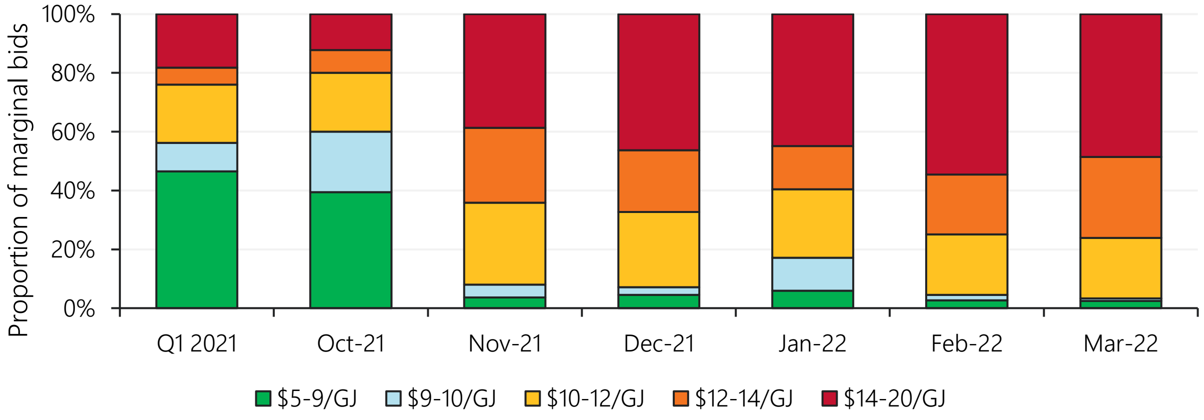
ACCC netback, DWGM and Brisbane average gas price per month



Prices in January eased compared to November and December, caused by increased supply from the Longford Gas Plant and lower market demand, and participants began moving bid volumes to lower price bands (Figure 64). However February and March saw this trend reverse, with bid volumes moved back to higher price bands, closer to November and December bidding behaviour.

Figure 64 DWGM bids driving price increases since November 2021

DWGM – proportion of marginal bids by price band

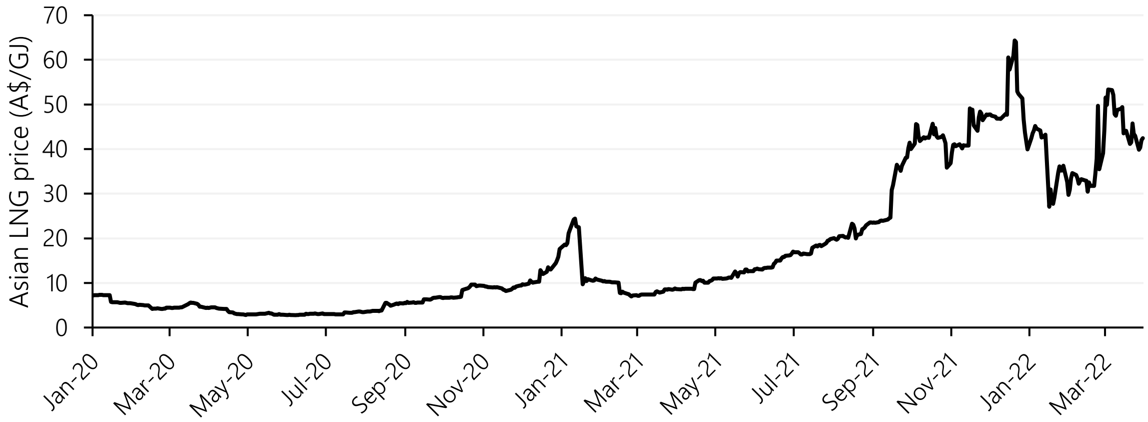


2.2.1 International energy prices

International energy prices remained volatile during the quarter, as the war in Ukraine and sanctions against Russia added uncertainty to markets already impacted by global supply constraints[54]. Asian LNG prices averaged A$40/GJ, A$6/GJ lower than the previous quarter, while volatility and a peak price of A$53/GJ in the quarter contributed to the continuation of high LNG exports (Figure 65).

Figure 65 Volatile Asian LNG prices

Asian LNG price in A$/GJ daily



Source: Bloomberg ICE data

Brent Crude oil averaged A$135/barrel during the quarter, A$26/barrel higher than the previous quarter after reaching a record level of A$176/barrel on 8 March (Figure 66). Thermal export coal prices averaged A$367/tonne, A$116/tonne higher than Q4 2021 after briefly reaching a new A$604/tonne record on 2 March, influenced by sanctions against Russia, a major global oil[55] and thermal coal[56] producer (Figure 67).

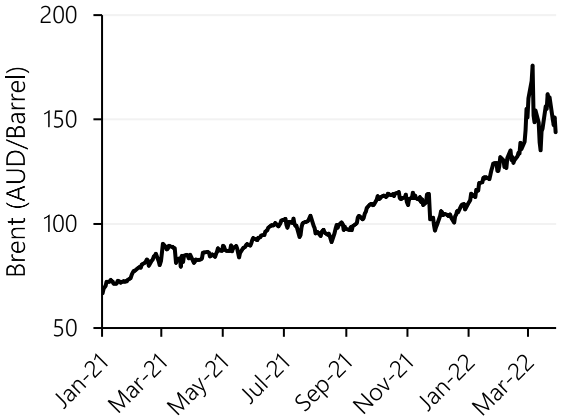
[54] Bloomberg 2022, Commodities soar as war builds anxiety over supply shortages: https://www.bloomberg.com/news/articles/2022-03-04/commodities-soar-as-russia-s-nuclear-plant-attack-raises-tension?sref=kkhkDP70

[55] OPEC 2022, Russian production comparable to Saudi Arabia: https://www.opec.org/opec_web/en/press_room/6830.htm

[56] Bloomberg 2022, Rush to replace Russian coal: https://www.bloomberg.com/news/articles/2022-03-02/coal-benchmark-jumps-46-as-ukraine-war-stokes-supply-fears?utm_source=google&utm_medium=bd&cmpId=google&sref=kkhkDP70

Figure 66 Brent Crude oil volatile prices

Brent Crude oil in A$/Barrel daily



Source: Bloomberg ICE data

Figure 67 Thermal coal soared to new record high

Newcastle export thermal coal A$/Tonne daily[57]

Source: Bloomberg ICE data

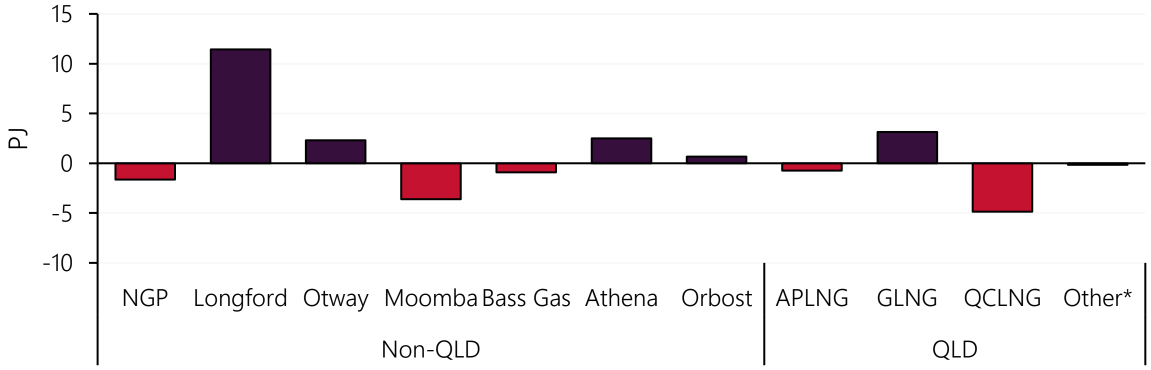
2.3 Gas supply

2.3.1 Gas production

East coast gas production increased by 8.2 PJ on Q1 2021 levels (+2%, Figure 68).

Figure 68 East coast gas production up 2%

Change in East Coast gas supply – Q1 2022 versus Q1 2021



Key changes included:

- Higher Victorian production (+16.0 PJ), mainly driven by higher Longford production (+11.4 PJ), Athena (+2.5 PJ) and Otway (+2.3 PJ).
- Decreased Moomba production (-3.6 PJ) despite increased South West Queensland Pipeline (SWQP) flows north to Queensland.
- Decreased Queensland production, particularly QCLNG (-4.9 PJ) and APLNG (-0.7 PJ) despite continued high Curtis Island flows. GLNG however increased production (+3.1 PJ).

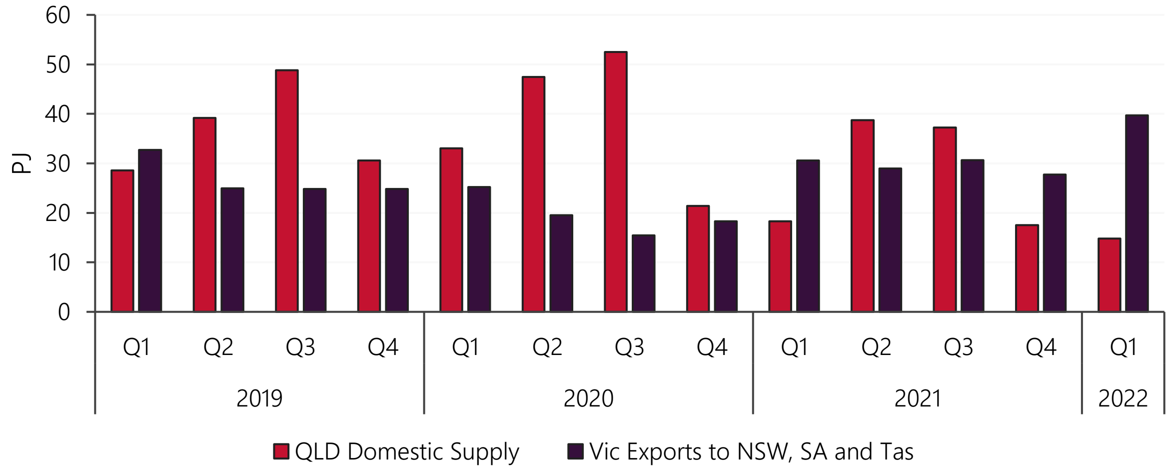
[57] In this edition of the QED, Newcastle export thermal coal prices are based on Bloomberg Intercontinental Exchange (ICE) futures as average weekly Free On Board (FOB) prices used in previous QEDs are no longer available.

2.3.2 Queensland net domestic production

Total net domestic supply into Queensland was 14.8 PJ in Q1 2022 compared to 18.4 PJ in Q1 2021 (Figure 69). Queensland gas production decreased by 2.6 PJ, while LNG exports increased by 1 PJ. With only a small decrease in Queensland domestic demand (-0.2 PJ), this required higher flows from the south via SWQP into Queensland to balance demand. With Victorian production higher, this resulted in a recent quarterly high for Victorian exports to other states (Section 2.4).

Figure 69 Victorian gas exports increase while Queensland domestic supply reduces

QLD domestic supply and Victorian gas exports by quarter

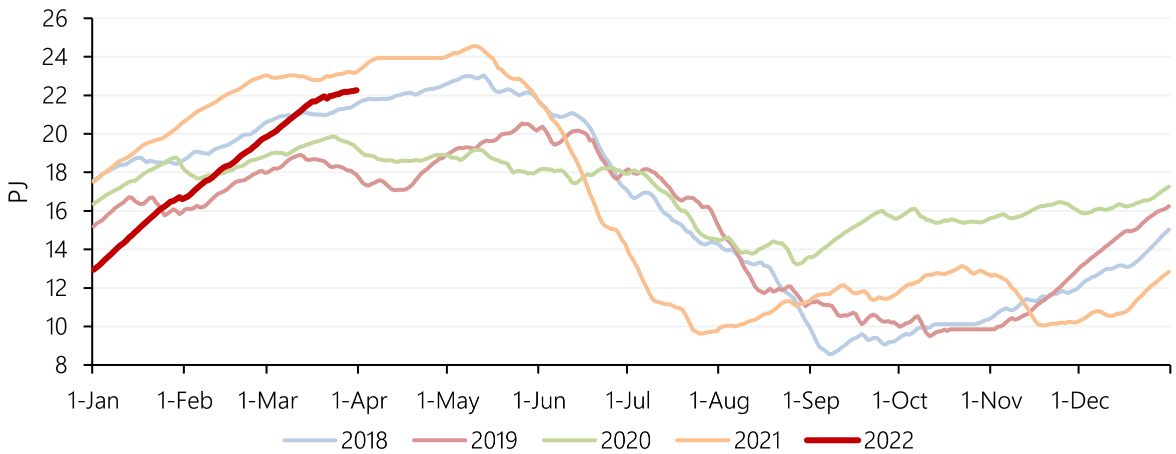


2.3.3 Gas storage

Iona Underground Storage Facility (UGS) finished the quarter with a gas balance of 22.3 PJ, only 0.9 PJ lower than at the end of Q1 2021 (Figure 70). This is despite storage levels starting the quarter at significantly lower levels (12.8 PJ) than the start of 2021 (17.5 PJ), with Iona filling on all but 2 days during the quarter. The rapid increase in gas balance was a function of increased Victorian production, notably Longford, Otway and Athena, combined with lower summer gas demand.

Figure 70 Iona refilling strongly throughout the quarter

Iona storage levels

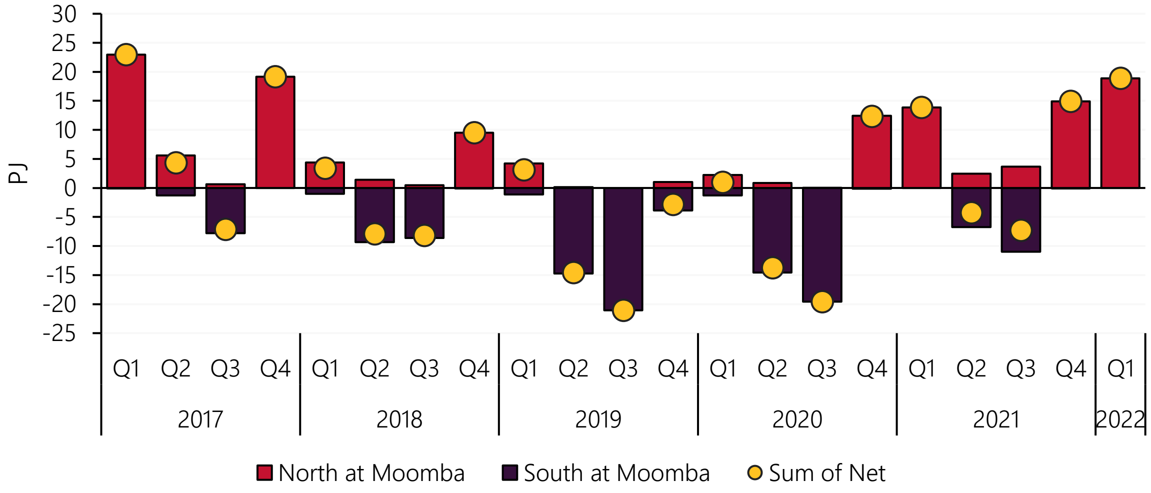


2.4 Pipeline flows

Compared to Q1 2021, there was a 5 PJ increase in net transfers into Queensland on SWQP (Figure 71). This represents the highest flow north from Moomba for any quarter since Q4 2017, driven by an increase in Queensland LNG export demand, and a decrease in Queensland production coupled with lower supply from the Northern Territory.

Figure 71 Highest gas flows north to Queensland since Q4 2017

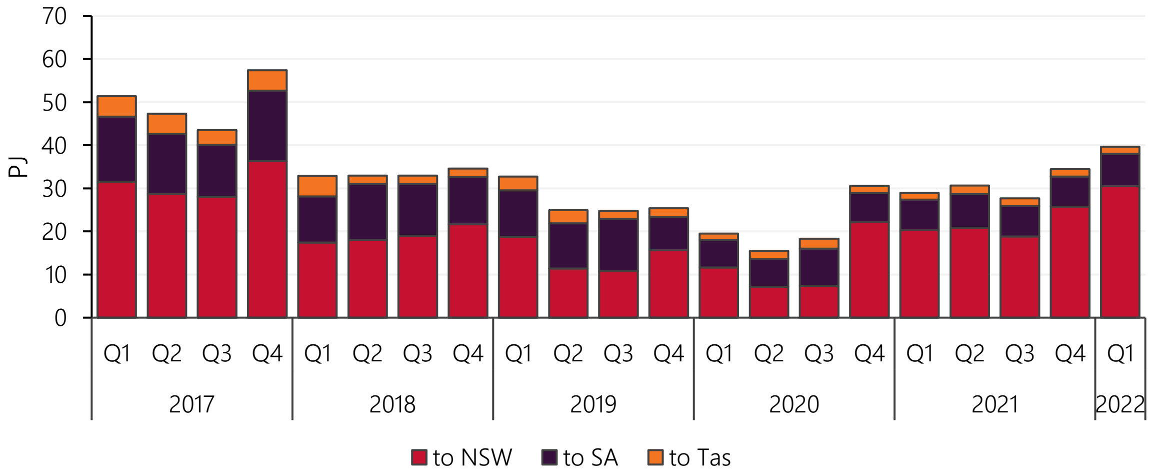
Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states increased by 10.7 PJ from Q1 2021 levels, due to increased Victorian supply, lower Moomba production (Section 2.3.1) and reduced net domestic production in Queensland (Section 2.3.2). This represented the highest net transfer out of Victoria for any quarter since Q4 2017 (Figure 72). There were increased flows from Victoria to New South Wales comprising 7.4 PJ via Culcairn, compared to 3.2 PJ in Q1 2021, and 23 PJ via the Eastern Gas Pipeline (EGP), up from 17.2 PJ in Q1 2021. Flows from Victoria to South Australia increased slightly by 0.5 PJ.

Figure 72 Victorian gas transfers highest for any quarter since Q4 2017

Victorian net gas transfers to other regions

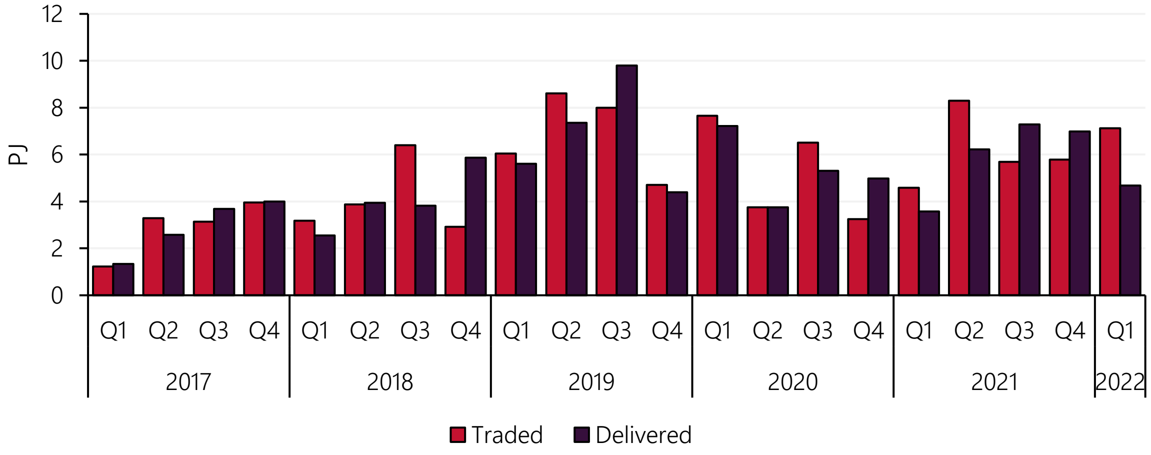


2.5 Gas Supply Hub (GSH)

In Q1 2022 there were increased trading and delivered volumes on the GSH compared to Q1 2021 (Figure 73), with traded volume up by 2.5 PJ and delivered volume by 1.1 PJ. Traded volume was 2.4 PJ higher than delivered volume, due to a large number of trades that are due to be delivered in Q2 and Q3 2022.

Figure 73 GSH volumes increase from Q1 2021

Gas Supply Hub – quarterly trades and deliveries



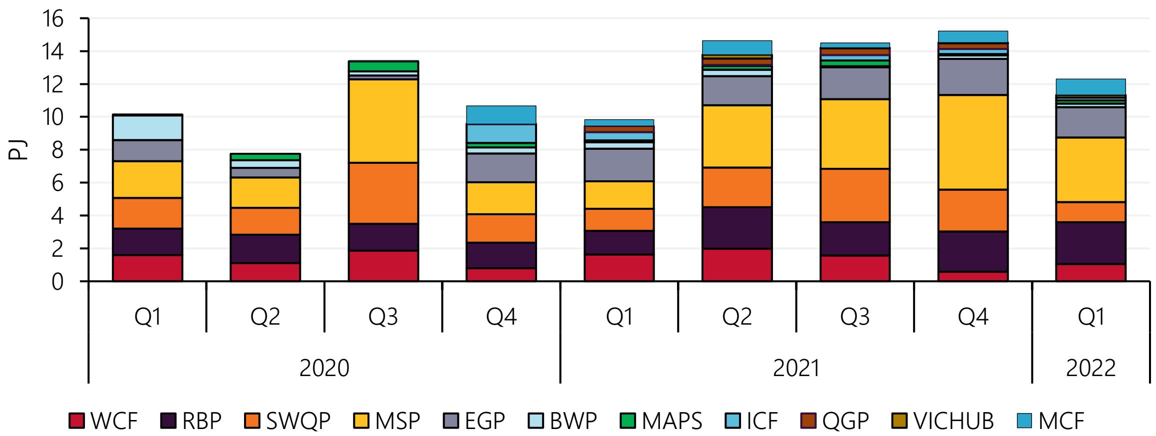
2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes set a record for any Q1, 2.2 PJ higher than the previous record set in Q1 2020, and 2.5 PJ higher than Q1 2021 (Figure 74). Compared to Q1 2021, the largest increases occurred on the Moomba Sydney Pipeline (MSP, +2.2 PJ) and the Roma to Brisbane Pipeline (RBP, +1.1 PJ).

Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were the EGP which averaged $0.26/GJ, SWQP which averaged $0.05/GJ, and RBP which averaged $0.04/GJ.

Figure 74 Day Ahead Auction utilisation sets a record for Q1

Day Ahead Auction results by quarter

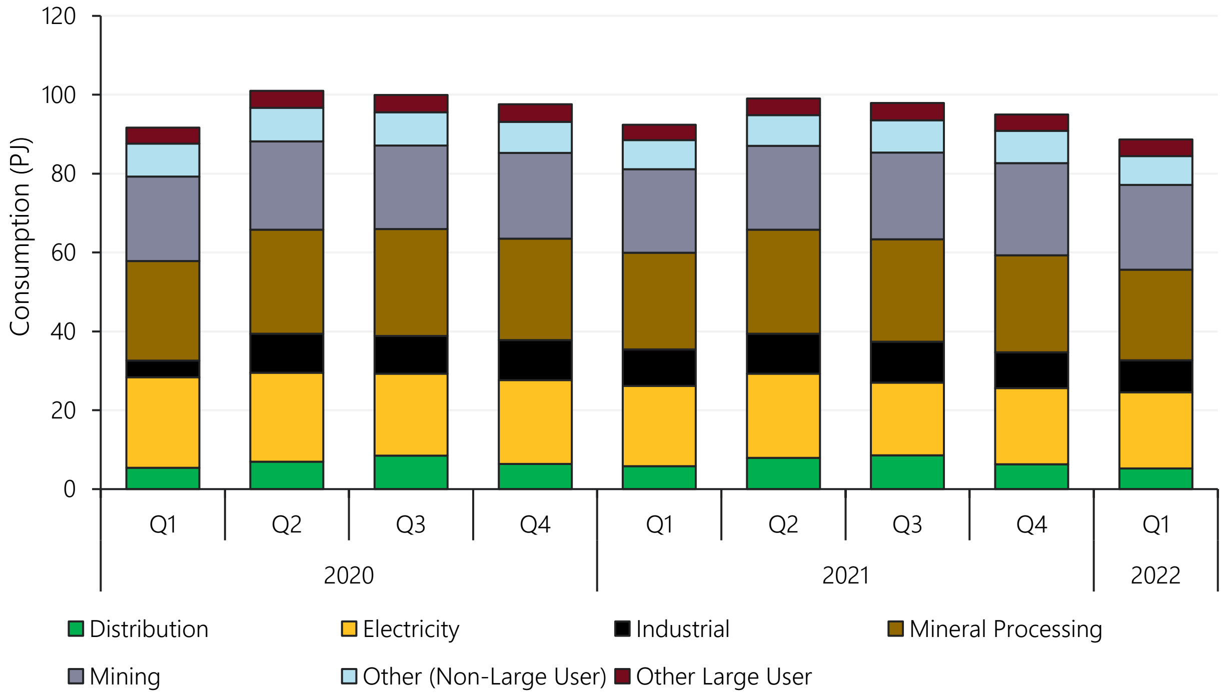


2.7 Gas – Western Australia

A total of 88.7 PJ was consumed in the Western Australian domestic gas market in Q1 2022, which was a 6.2 PJ (6.6%) decrease from Q4 2021 and a 3.6 PJ (3.9%) decrease from the same quarter last year (Figure 75).

Figure 75 Western Australia domestic gas consumption drops 3.9% from Q1 2021

WA quarterly gas consumption by industry – Q1 2020 to Q1 2022



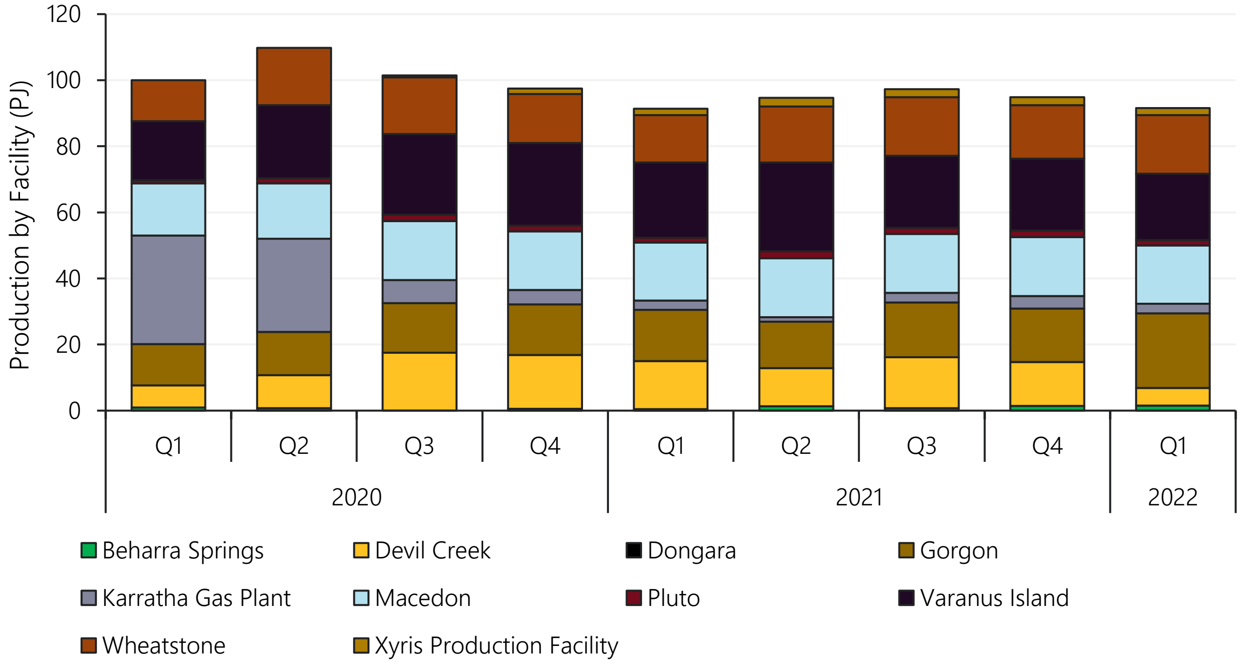
Domestic gas consumption in Western Australia decreased in almost all user categories compared to the same quarter last year, primarily from reductions in consumption for electricity generation, industrial use and mineral processing:

- Gas consumed for electricity generation reduced by 1.0 PJ (5.1%), which was in line with fuel mix trends observed in the WEM, as gas generation was displaced by increased availability of coal-fired generation in Q1 2022 (See Section 1.3).
- Gas consumption for industrial use also reduced in Q1 2022, with a 1.2 PJ (12.9%) decrease on the same quarter last year due to a reduction in operation from Yara Pilbara Liquid Ammonia Plant by 1.2 PJ (18%).
- Mineral processing consumption was 1.5 PJ (6.2%) lower than Q1 2021, largely due to a reduction in consumption from Alcoa Pinjarra by 1.0 PJ (13%).

Total Western Australian gas supply this quarter was 91.6 PJ, a 0.2 PJ (0.2%) increase from Q1 2021, but a 3.3 PJ (3.4%) decrease from Q4 2021 (Figure 76). The decrease from last quarter was primarily from Devil Creek which reduced production by 7.9 PJ (59.8%), outweighing increases from Gorgon by 6.3 PJ (38.8%) and Wheatstone by 1.5 PJ (9.4%).

Figure 76 Western Australia domestic gas production drops 3.4% from Q4 2021

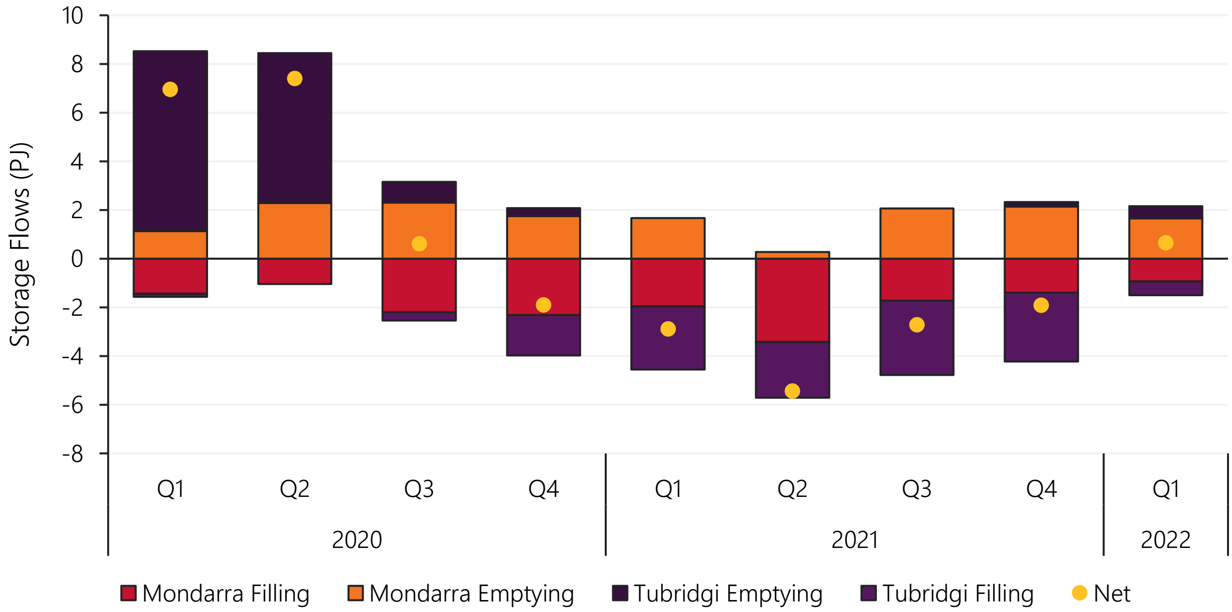
WA quarterly gas production by facility – Q1 2020 to Q1 2022



For the first time since Q3 2020, gas storage facilities had a net injection into the pipelines this quarter, with a net flow out of storage of 0.7 PJ. This was a net change of 2.6 PJ (34%) from Q4 2021, and was largely driven by Tubridgi emptying a net 2.5 PJ less than Q4 2021, while Mondarra's net flows remained similar to last quarter (Figure 77). The combination of reduced consumption and net storage emptying resulted in net pipeline inflows of 3.6 PJ this quarter, indicating an increase in overall linepack.

Figure 77 Net flows from gas storage facilities shift to net injection for the first time since Q3 2020

WA gas storage facility injections and withdrawals – Q1 2020 to Q1 2022



3 WEM market dynamics

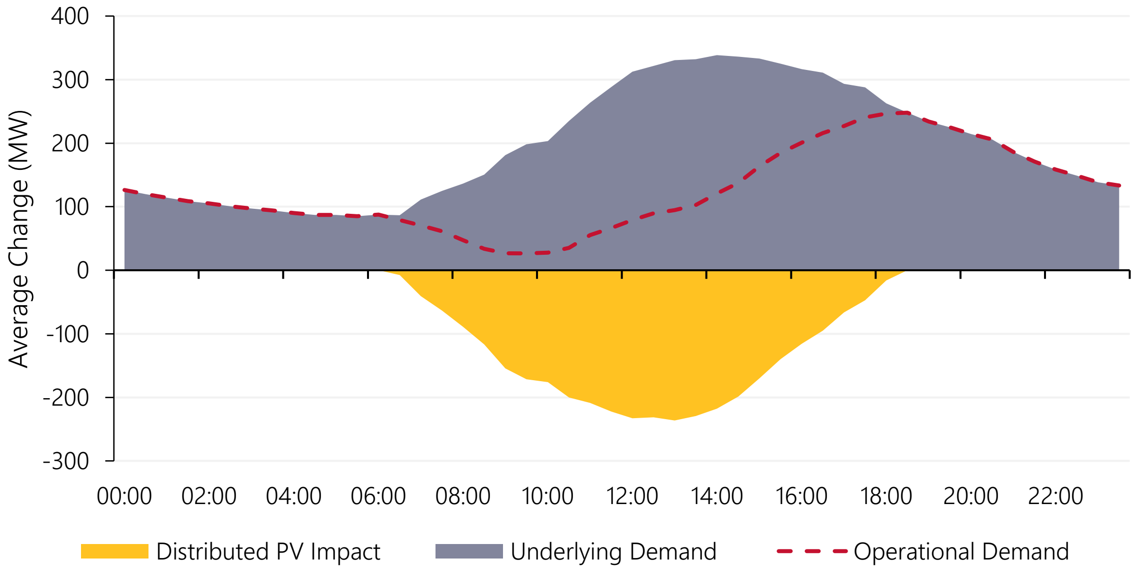
3.1 Electricity demand

Average underlying demand[58] was 197 MW (8.1%) higher than the previous year and was higher across all intervals. The increase in underlying demand outweighed average growth of 72 MW (23%) in distributed PV output and resulted in average operational demand[59] across all times of the day increasing by 125 MW (5.9%) compared to Q1 2021 (Figure 78).

The increase in both underlying and operational demand is attributed to average temperatures being up 1.1°C from Q1 2021, resulting in increased cooling load throughout the quarter. In particular, the average maximum temperature this quarter was 32.7°C, a 1.7°C increase from both last year and the 10-year Q1 average maximum. As a result, average operational demand was 2,239 MW this quarter, its highest Q1 level since 2016.

Figure 78 Higher underlying demand outweighs impact of distributed PV to increase daytime operational demand

Change in Q1 2022 WEM-average operational and underlying demand by time of day compared to Q1 2021



3.1.1 Second highest maximum demand on record

High temperatures contributed to this quarter recording the second highest all-time maximum operational demand interval in the WEM. At 1800 hrs on 19 January 2022, operational demand reached 3,980 MW, only 26 MW below the record of 4,006 MW set at 1730 hrs on 8 February 2016 (Figure 79). Distributed PV helped shift operational demand downwards on 19 January 2022, with maximum underlying demand reaching 4,496 MW at 1430 hrs, nearly 500 MW higher than the 2016 all-time record operational demand.

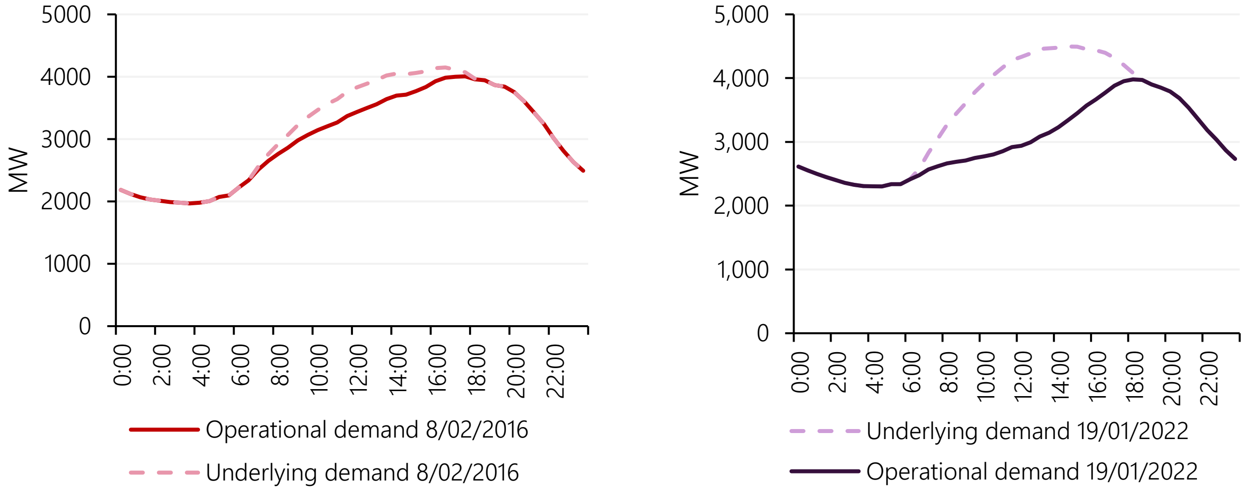
[58] Underlying demand is an estimated measurement of the total load on the SWIS, including behind-the-meter demand. Underlying demand is measured as Operational demand adjusted to remove the impact of distributed PV output.

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

The maximum operational demand interval occurred on the second day of a heatwave in which the Perth metropolitan region experienced six consecutive days over 40°C between 18 and 23 January 2022[60]. This was the second heatwave of the summer, following four consecutive days over 40°C in Q4 2021.

Figure 79 Demand curve on record maximum operational demand days has changed significantly since the 2016 record

Operational and underlying demand – maximum demand day Q1 2016 vs Q1 2022



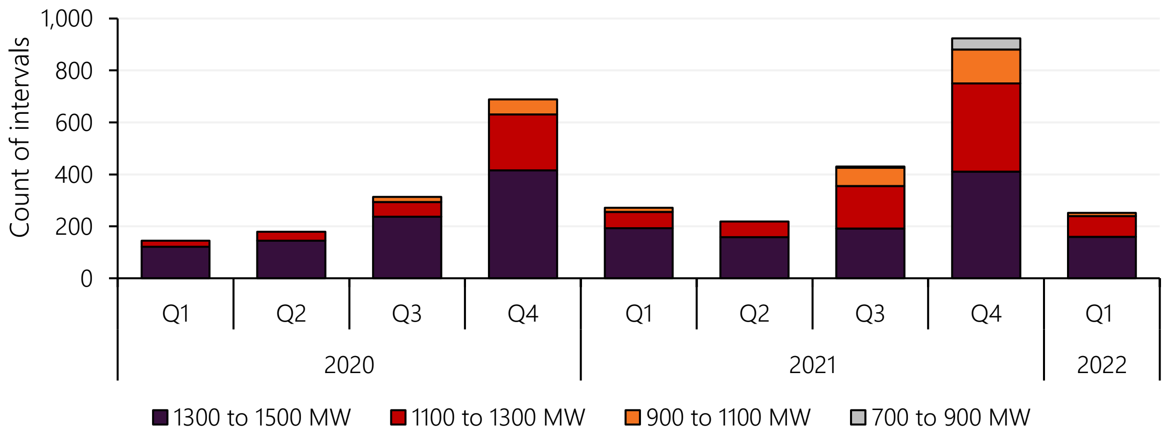
3.1.2 Decreased frequency of minimum demand events this quarter

Minimum operational demand reached 989 MW this quarter at 1130 hrs on 9 January 2022, an increase of 37 MW compared to the minimum demand interval in Q1 2021, and a 228 MW increase from the new all-time minimum demand record set in Q4 2021.

Higher than average temperatures this quarter also resulted in a decrease in the number of intervals in which operational demand fell below 1,500 MW compared to both last quarter (-73%) and Q1 2021 (-7%). Specifically, there were no intervals below 900 MW, and fewer intervals between 900 and 1,100 MW (Figure 80).

Figure 80 Low load events dropped in frequency in Q1 2022

Count of intervals where operational demand was below 1,500 MW – Q1 2020 to Q1 2022



[60] BoM 2022, Perth Metro daily maximum temperature: http://www.bom.gov.au/jsp/ncc/cdio/weatherData/av?p_nccObsCode=122&p_display_type=dailyDataFile&p_startYear=&p_c=&p_stn_num=9225

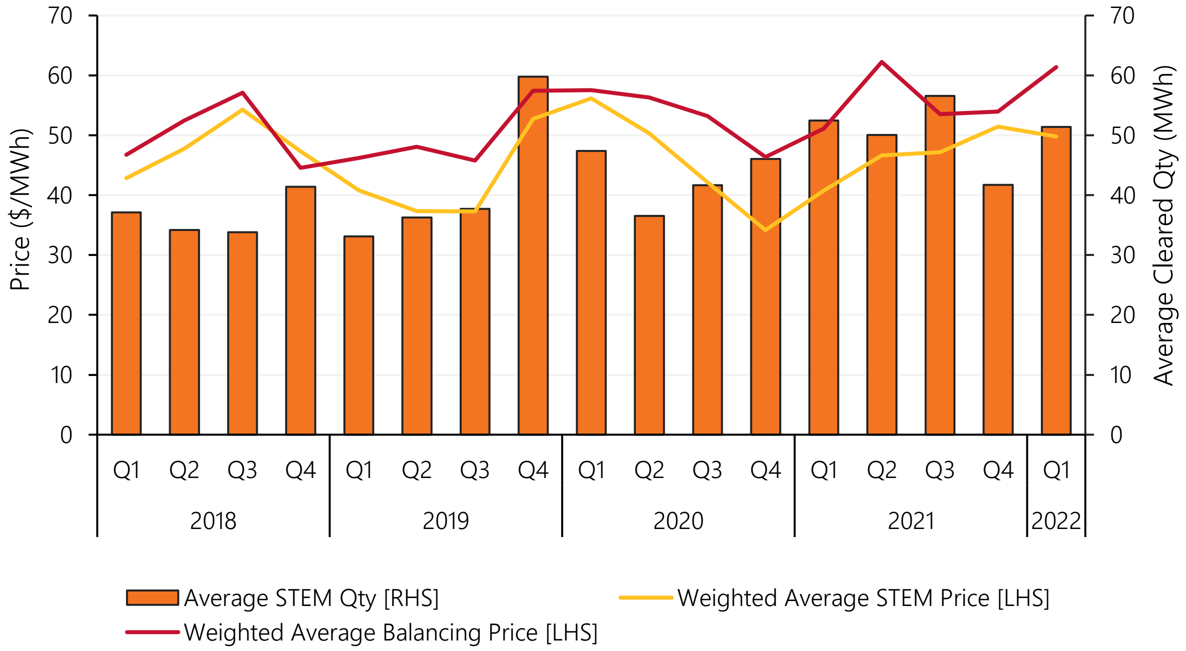
3.2 WEM prices

The weighted average Balancing Price[61] in the WEM for Q1 2022 was $61/MWh, an increase from Q4 2021 by $7.39/MWh, or 14% (Figure 81), and increased across all intervals. This was in part due to average End of Interval (EOI) demand increasing between quarters at all times of the day and the reduced impact of zero and negative priced intervals (see Section 3.2.2).

The weighted average Short-Term Electricity Market (STEM) Price[62] for Q1 2022 was $50/MWh, which was a $9/MWh (22%) increase from Q1 2021. The quantity of energy cleared in STEM was similar this quarter compared to Q1 2021 (-2%) and an increase from Q4 2021 (23%) following lower than average STEM quantities last quarter.

Figure 81 Weighted average Balancing Price increases

WEM weighted average Balancing Prices, STEM Prices and quantity cleared in STEM – Q1 2018 to Q1 2022



3.2.1 New Alternative Maximum STEM Price

The Alternative Maximum STEM Price (AMSP)[63] reached $635/MWh this quarter, a 13-year high, in response to recent rises in fuel prices (Figure 82). This is the highest the AMSP has been since Q4 2008 due to high international oil prices at the time. No AMSP events have occurred in recent years, and only five Maximum STEM Price events occurred this quarter, down from 12 in Q4 2021.

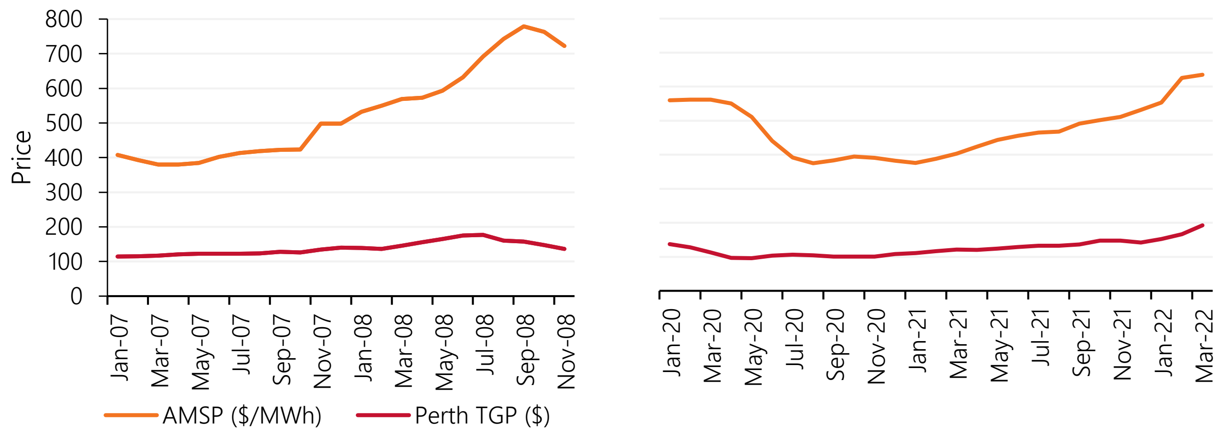
[61] The weighted average Balancing Price is a measure of the average Balancing Price that puts greater weighting on intervals where greater quantity is generated. This is to reflect the average Balancing Price more accurately against quantity of electricity generated, rather than against intervals.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

[62] 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.

[63] The AMSP is the maximum price which applies to generators that use distillate as a fuel source and is updated monthly based on terminal gate prices. The Maximum STEM Price is applied to all other generators.

Figure 82 Increasing fuel prices result in 13-year record AMSP

AMSP and Perth TGP[64] over time



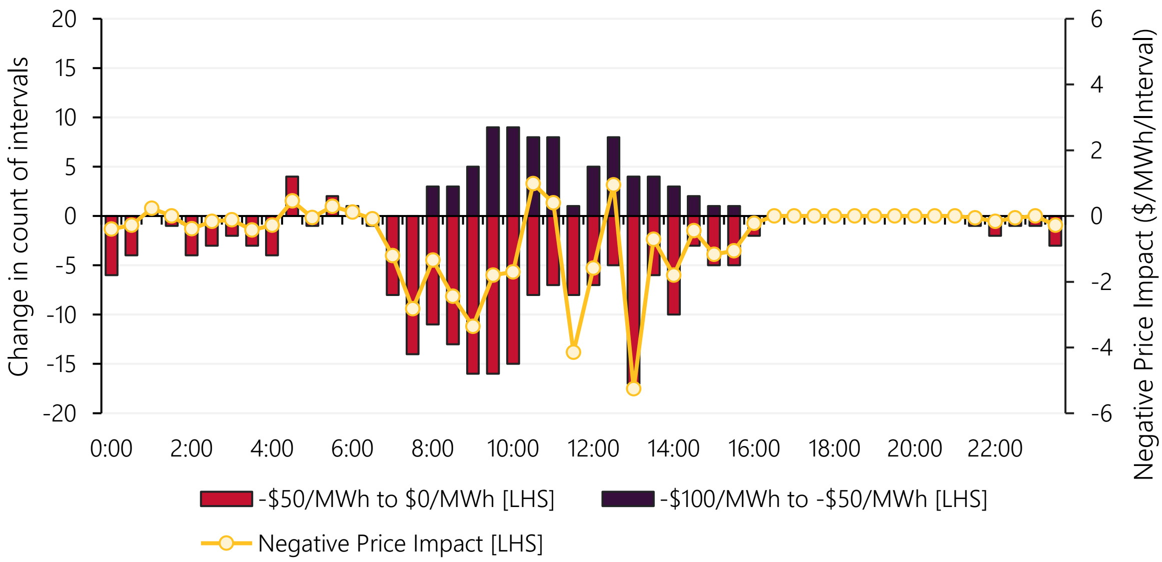
3.2.2 Negative prices

The number of negatively priced and $0/MWh intervals in Q1 2022 (6% of all intervals) was down from Q1 2021 (9% of all intervals) and the quarter recorded no intervals with a Balancing Price lower than -$100/MWh. The reduced frequency of negative and $0/MWh intervals was mostly observed in the morning and afternoon and can be attributed to higher temperatures increasing EOI demand at all times of the day (Figure 83).

This resulted in the negative price impact[65] in Q1 2022 decreasing by 30% compared to last year, from $2.06/MWh in Q1 2021 to $1.45/MWh this quarter.

Figure 83 Reduced impact of negative prices on average despite more intervals below -$50/MWh

Change in count of intervals with zero or negative Balancing Price from Q1 2021 to Q1 2022



[64] The average monthly Diesel Terminal Gate Price (TGP) for Perth.

[65] Impact of negative prices is a measure of both frequency and magnitude of negative prices. It is defined as the change from the average Balancing Price including negative intervals to the average that would result if the floor price was $0/MWh. It is calculated as the absolute sum of the Balancing Price in all negatively priced intervals, divided by the total number of intervals

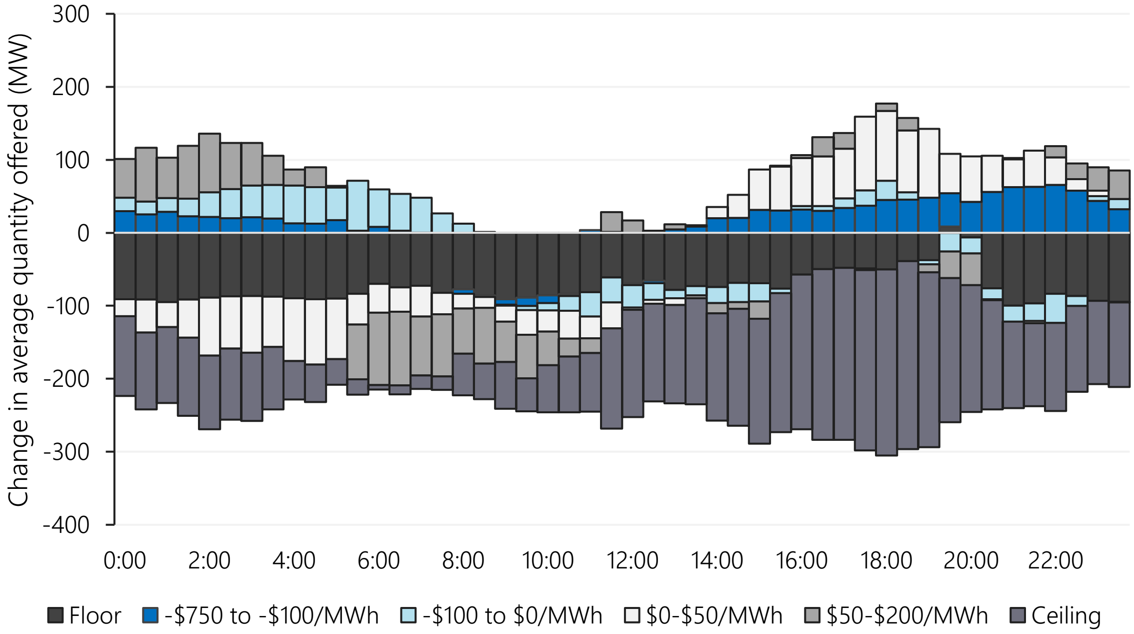
3.2.3 Balancing merit order dynamics

Participant behaviour in the Balancing Market shows a decrease in the average quantities offered at the floor (-$1,000/MWh to -$750/MWh) and ceiling (>$250/MWh) price bands across every interval, between Q1 2021 and Q1 2022 (Figure 84). Changes to quantities offered in other price bands were varied throughout the day. The key changes in Balancing Market participation were:

- Bids in the floor price band (-$1,000/MWh to -$750/MWh) decreased by 74 MW on average between Q1 2021 and Q1 2022. This represents a reduction in market generators' willingness to generate at the floor price.
- Small volume increases can be observed in the -$750 to -$100/MWh price band across most intervals (with the exception of intervals between 0730 hrs to 1030 hrs, and 1200 hrs to 1230 hrs intervals). The average volume change in this price band was +22 MW between Q1 2021 and Q1 2022.
- Changes to the -$100/MWh to $0/MWh price band were varied throughout the day; increasing marginally during morning hours (to 0830 hrs) and evening peak hours (1600 hrs to 1900 hrs), whilst decreasing at all other times. The average change in volume offered in this band was +6 MW between Q1 2021 and Q1 2022.
- Quantities offered in the $0/MWh to $50/MWh and $50/MWh to $200/MWh price bands varied throughout the day. Overall, the increases and decreases were comparable, resulting in an overall average change in volume of only -2 MW ($0/MWh to $50/MWh) and -3 MW ($50/MWh to $200/MWh), between Q1 2021 and Q1 2022.
- Bids in the ceiling price band (>$250/MWh) decreased by 119 MW on average between Q1 2021 and Q1 2022. This decrease is most notable during the afternoon and evening hours (between 1400 hrs and 2000 hrs), when demand typically transitions from midday trough to evening peak and generation must ramp up.

Figure 84 Balancing Market offer volumes moved out of floor and ceiling bands

Change in average forecast Balancing merit order structure by time of day - Q1 2021 to Q1 2022



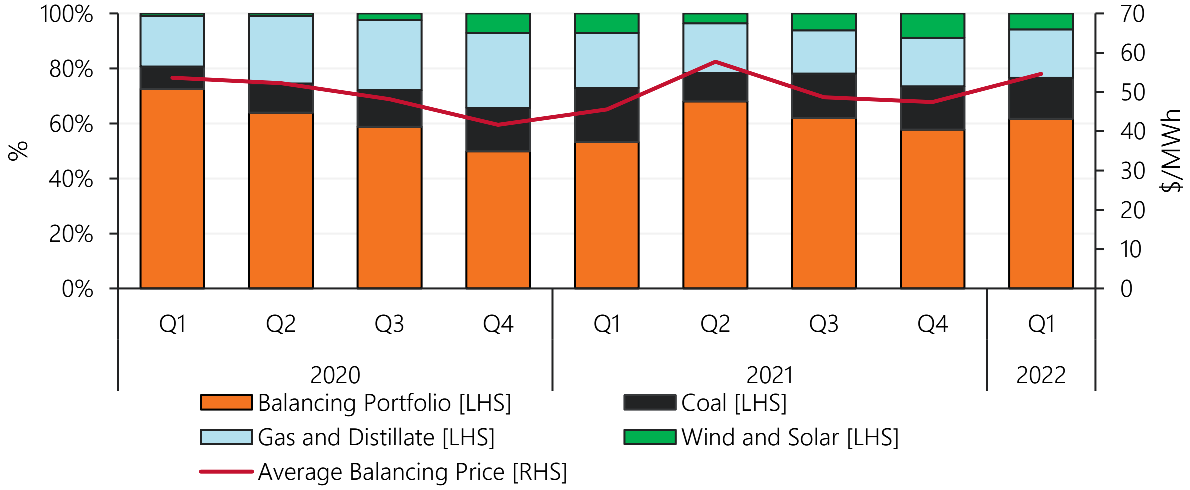
3.2.4 Price setting dynamics

In Q1 2022, the Balancing Portfolio[66] set the Balancing Price 62% of the time, an 8.5% increase from Q1 2021 (Figure 85). The increased price-setting role of the Balancing Portfolio was the result of higher-priced offers being dispatched due to increased EOI demand in Q1 2022 compared to last year. This put upwards pressure on the Balancing Price, increasing its time-weighted average from $51/MWh in Q1 2021 to $61/MWh in Q1 2022.

- Wind and solar facilities set the price less frequently at around 6% of the time, a 1% decrease compared to Q1 2021.
- The increase in the Balancing Portfolio price-setting role was largely offset by Independent Power Producer coal, gas and distillate facilities setting the price less frequently. Coal set the price 15% of the time, and gas and distillate generation set the price just under 18% of the time, down 5% and 2% respectively from last year.

Figure 85 Higher operational demand contributes to increased price-setting role of the Balancing Portfolio

Price-setting by the Balancing Portfolio and fuel-type of non-Balancing Portfolio Facilities



3.3 Electricity generation

3.3.1 Change in fuel mix

Q1 2022 saw a decrease in gas and distillate powered generation at all times of the day except the evening peak, with an increase in all other fuel types when compared to Q1 2021 (Figure 86). With continued increases in VRE output, renewable penetration during the quarter remained high: on 16 January 2022 during the 1230 hrs interval, renewable generation (including distributed PV) supplied 75.6% of underlying demand[67].

- Coal-fired generation increased by an average 81 MW (21%). This increase was primarily due to higher demand, along with an average 26 MW increase in coal availability compared to Q1 2021.
- Wind increased by an average of 22 MW (5%). The largest contribution to this change was from Yandin Wind Farm and Warradarge Wind Farm, which generated a respective additional average 11 MW and 8 MW compared to Q1 2021.

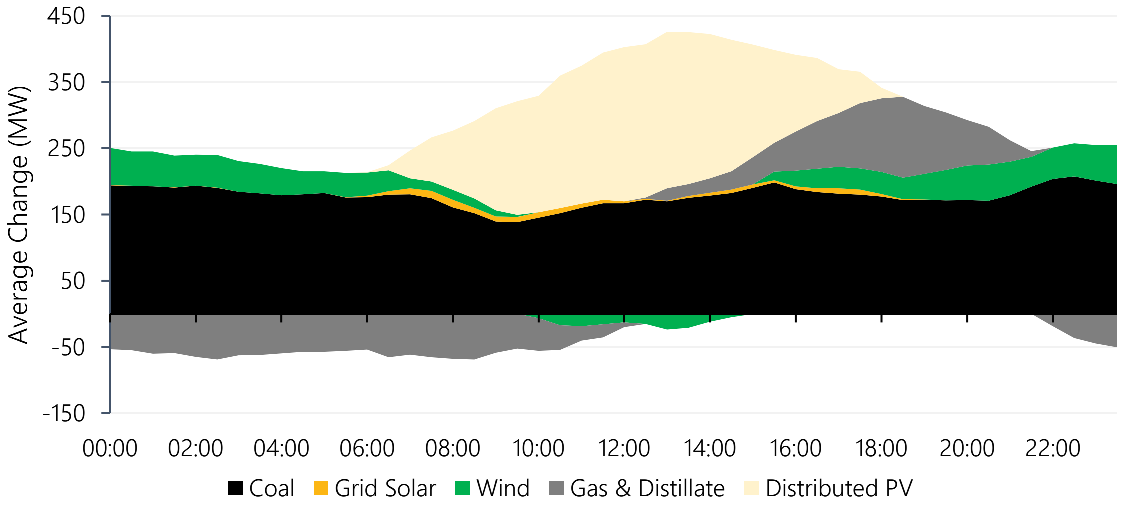
[66] The Balancing Portfolio has a total Sent Out Capacity of more than 2,700 MW.

[67] All-time record of 78.6% was set in Q3 2021 on 7 September 2021 during the 1200 hrs interval.

- Grid-scale solar increased by an average of 14 MW (6%). The increase was predominantly due to an increase in output from Merredin Solar Farm.
- Distributed PV continued to grow, increasing by 72 MW (23%) on average compared to Q1 2021. This increase was due to an estimated 352 MW of additional PV capacity installed in the South West Interconnected System (SWIS) since Q1 2021.
- Gas and distillate generation decreased by an average of 9 MW (1%) compared to Q1 2021, but increased for the intervals beginning from 1230 hrs to 2130 hrs due to more gas becoming in merit because of high demand. Smaller increases in demand overnight and in the morning meant that gas-fired generation was displaced by lower cost generation, such as wind.

Figure 86 Higher demand causes increase in all fuel types during the evening peak

Average change in WEM generation – Q1 2022 versus Q1 2021



3.3.2 Spare capacity analysis

Comparing spare capacity[68] and outages for coal and gas units between Q1 2021 and Q1 2022 shows that spare capacity was reduced in the most recent quarter (Figure 87). The key trends are as follows:

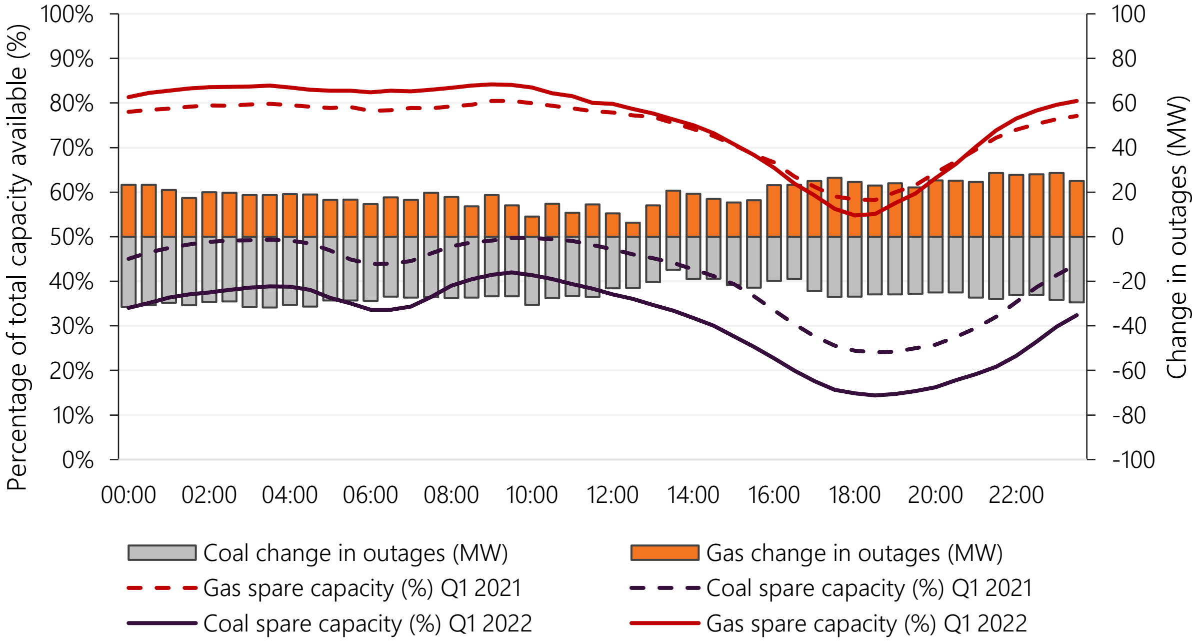
- Spare capacity for coal units reduced by 10% on average, across the day.
  - Coal units experienced less (-26 MW) outages on average compared to Q1 2021, suggesting that this reduction in spare capacity is driven primarily by increased coal generation being dispatched due to higher demands in Q1 2022 than Q1 2021 (See Section 3.1 and Section 3.3.1).
  - Coal spare capacity changes are steady across the day, consistent with a uniform increase in base load generation. This is to be expected from coal units, which typically serve in this role.
- Spare capacity for gas units increased by 2% on average across the day, however a slight reduction in gas spare capacity (2%) was observed between 1600 hrs to 2000 hrs when demands are typically higher.
  - Despite a slight increase in gas unit outages (+19 MW) on average, the timing of the reduced spare capacity in gas is indicative of a demand driven trend. Increases in gas generation strongly correlate with periods of increasing (ramping) and peaking demand (See Section 3.1 and Section 3.3.1).

[68] Spare capacity here refers to available capacity (based on certified capacity credits of coal and gas units) less dispatched capacity.

– This trend is expected from gas facilities, which typically service demand ramping and peaking requirements.

Figure 87 Higher utilisation due to increased demand reduces coal spare capacity

Changes in spare capacity margin and outages (for coal and gas) by time of day - Q1 2021 to Q1 2022



3.4 Power system management

Q1 2022 saw a reduction from Q4 2021 in total costs associated with essential system services, down by $4.7 million (20.1%) to $18.5 million[69].

- Estimated load following ancillary service (LFAS) costs for Q1 2022 were $12 million and accounted for 69% of all essential system services costs[70] for the quarter (Figure 88). LFAS costs decreased by $4.0 million (25%) from Q4 2021. Lower LFAS costs can be attributed to lower average prices in both LFAS Upwards and LFAS Downwards markets. The reduction in LFAS costs compared to Q1 2021 was similar, decreasing by $3.9 million (24.7%).
- Estimated spinning reserve costs increased by $0.1 million (5%) compared to last quarter, driven by higher average Balancing Prices during all periods (+$7.2/MWh) and only partially offset by the two fewer trading days in Q1 compared to Q4. Estimated spinning reserve costs decreased by $0.9 million (25%) compared to Q1 2021 due to a reduction in margin values during peak periods this financial year (12.6% in 2021-22 compared to 25.46% in 2020-21[71]).

[69] The Q1 2022 Ancillary Service costs are estimated values due to March 2022 NSTEM Settlement not occurring until May 2021. The estimated values are calculated as per the WEM Metering, Settlement & Prudential Calculations published here https://www.aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/procedures-policies-and-guides/guides/settlement-technical-guides on the AEMO website.

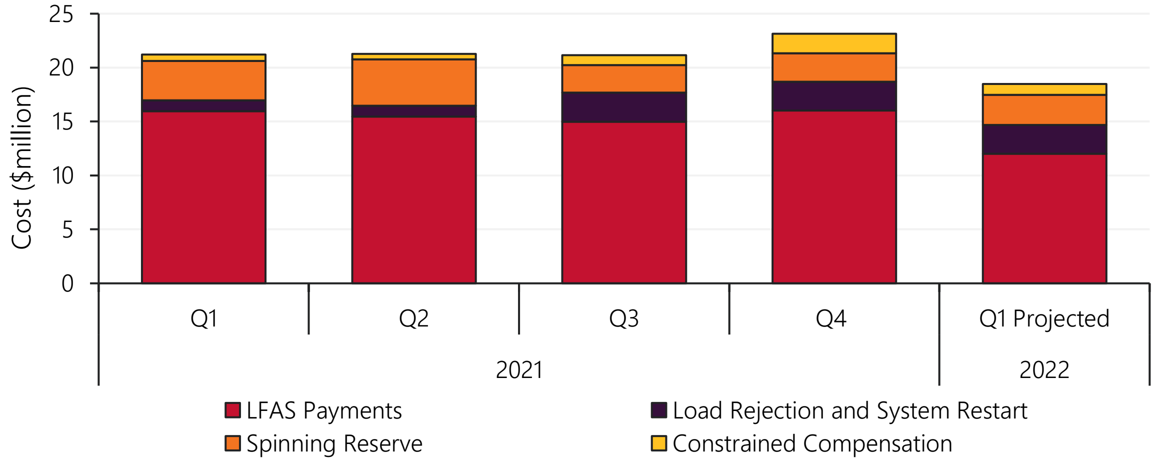
[70] Essential system services costs are considered as the total cost of all ancillary services and constrained payments.

[71] Spinning Reserve margin values and requirements are determined by the Economic Regulation Authority (ERA): Ancillary Service Parameters published for 2021/22 are available here on the ERA website: https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/spinning-reserve-margin-peak-and-off-peak-load-rejection-reserve-and-system-restart-cost_lr/margin-peak-and-margin-off-peak-parameters-and-load-rejection-cost_lr-for-202122

- Estimated load rejection and system restart costs remained the same in Q1 2022 as for Q4 2021, as the COST_LR[72] parameter is set annually in line with financial years[73]. The higher COST_LR value for 2021-22 is the driver of increased load rejection and system restart costs compared to Q1 2021 (+167%).
- The cost of constrained compensation fell by 43% following notably high values last quarter due to constrained off compensation during low load conditions. Similar low load conditions were not as frequently experienced this quarter, with minimum demand for Q1 2022 at 989 MW (see Section 3.1.2).

Figure 88 Total estimated cost of operating the power system decreases by 20.1% in Q1 2022

Ancillary services costs and constrained compensation by quarter – Q1 2021 to Q1 2022

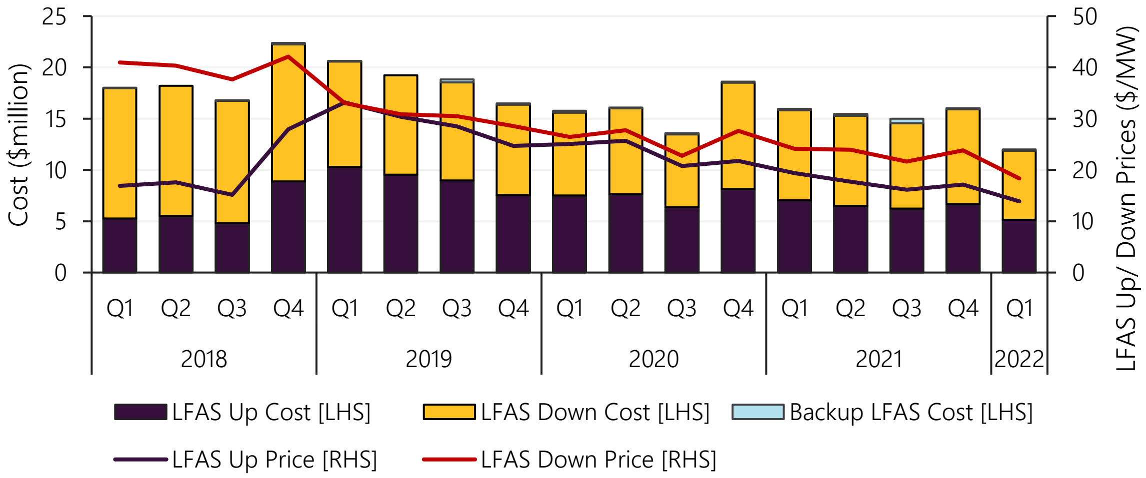


3.4.1 LFAS market

In Q1 2022, the cost of LFAS decreased by 25% from the previous quarter. This was driven by decreases in both LFAS Up Prices (-$3.24/MW) and LFAS Down Prices (-$5.50/MW), which fell to their lowest levels since 2018 (Figure 89). This continues the downwards trend in LFAS prices observed for most quarters since Q4 2020.

Figure 89 Fall in average LFAS Prices reduces total LFAS costs to four-year low

LFAS costs and prices – Q1 2018 to Q1 2022



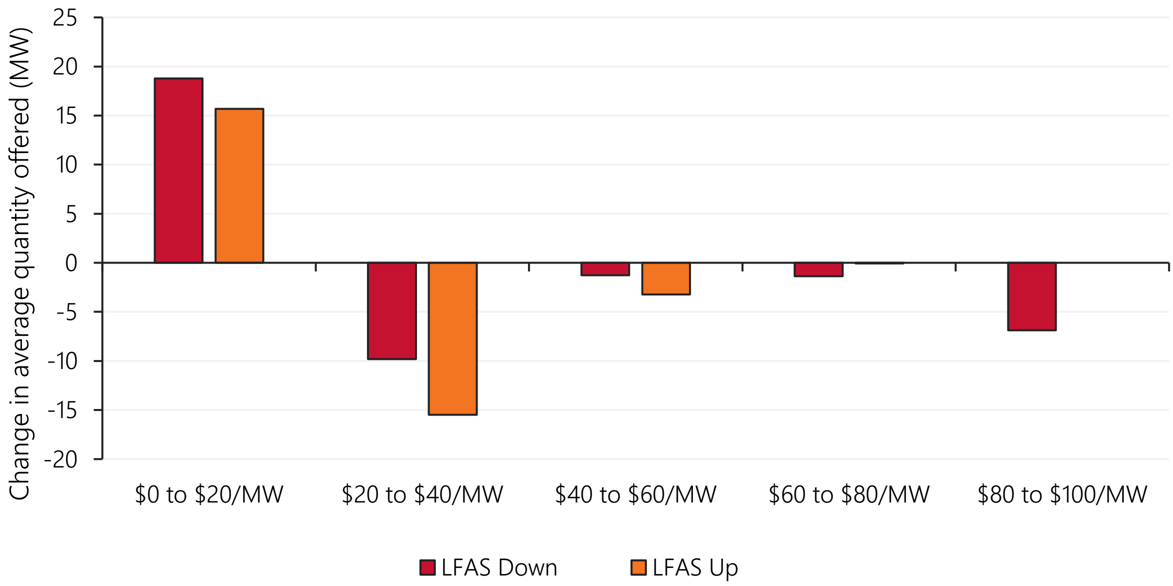
[72] COST_LR refers to the total cost of Load Rejection Reserve and System Restart, as determined by the ERA.

[73] Load Rejection and System Restart costs determined by the ERA are at: https://www.erawa.com.au/electricity/wholesale-electricity-market/ancillary-services-parameters/load-rejection-cost_lr/load-rejection-cost_lr-1-july-2019-to-30-june-2022.

The decrease in average LFAS prices compared to previous quarters was caused by an increase in the average quantity offered in both LFAS markets between $0/MW and $20/MW (Figure 90) The LFAS Down market saw a 19 MW increase in the quantity offered between $0/MW and $20/MW compared to Q4 2021, while an additional 16 MW was offered in this price range in the LFAS Up market. There were corresponding decreases in the average quantity offered between $20/MW and $40/MW, and between $80/MW and $100/MW. The change in bidding behaviour was primarily from Synergy who offered an average additional 19 MW below $20/MW in both LFAS markets this quarter compared to Q4 2021.

Figure 90 Average LFAS offers shifted to lower prices in Q1 2022

Change in average LFAS quantity offered in different price bands – Q4 2021 versus Q1 2022



The increased quantity offered by Synergy at lower prices meant that the other LFAS Market Participants (Alinta and Newgen) were more frequently setting the price in both LFAS markets, up from 4.3% of the time in Q4 2021 to 11.7% in Q1 2022. The increase in quantity offered below $20/MW meant that on average Synergy cleared a greater quantity in LFAS, increasing its LFAS market share from 31% in Q4 2021 to 38% this quarter.

3.4.2 Demand variability

A swift cloud formation over the Greater Perth Metropolitan area on Saturday 26 March 2022 meant that between 1038 hrs and 1216 hrs the WEM recorded an 800 MW increase in instantaneous demand[74], followed by a 720 MW decrease between 1230 hrs and 1326 hrs. Both changes were driven by swings in distributed PV output. This resulted in a 718 MW decrease in EOI demand between the trading intervals commencing 1200 hrs and 1300 hrs. As EOI demand is the measure used to set the Balancing Price, variability also has market impacts and resulted in the price settling at the Maximum STEM Price of $290/MWh for the 1100 hrs trading interval.

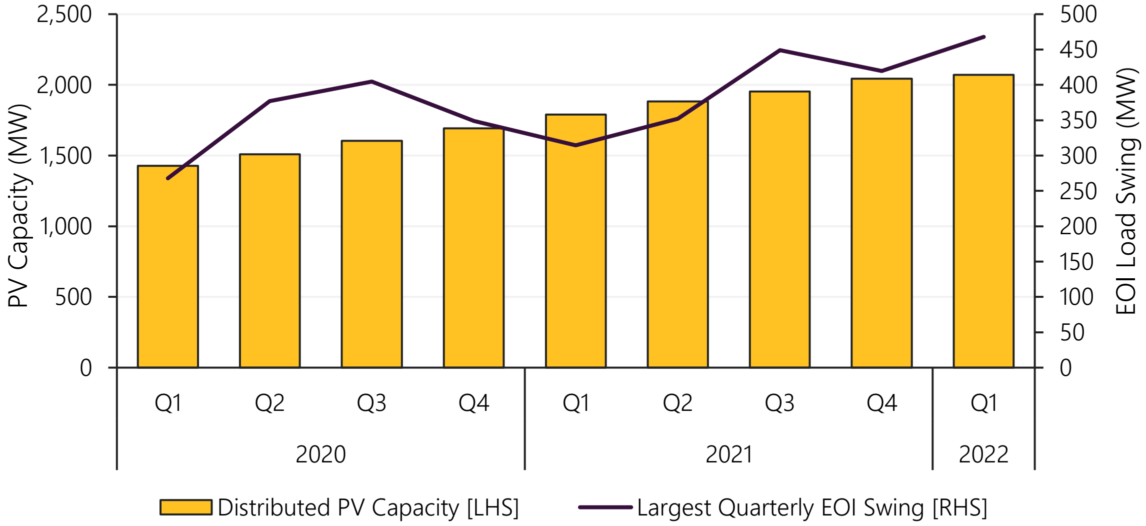
The record largest upwards change in EOI demand was also recorded in Q1 2022. On Friday 11 March 2022, EOI demand increased a record 468 MW between the trading intervals commencing 1130 hrs and 1200 hrs. This was caused by a loss of 212 MW in distributed PV generation combined with demand starting to ramp up to the afternoon peak of 3,457 MW by 1500 hrs.

[74] Operational demand measurement at a given point in time.

Demand variability is becoming more pronounced with the increasing distributed PV capacity (Figure 91).

Figure 91 Demand variability continues to increase as distributed PV capacity grows

Distributed PV capacity and largest swing in demand[75] – Q1 2020 to Q1 2022



[75] Demand swing is measured as the difference in EOI demand from one trading interval to the next trading interval.

List of tables and figures

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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
BoM	Bureau of Meteorology
CY	Calendar Year
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EOI	End of interval
EGP	Eastern Gas Pipeline
ERA	Economic Regulation Authority
FCAS	Frequency control ancillary services
FOB	Free On Board
GJ	Gigajoule
GW	Gigawatts
GLNG	Gladstone LNG
GSH	Gas Supply Hub
ICE	Intercontinental Exchange
IRSR	Inter-regional settlement residue
LFAS	Load Following Ancillary Services
LNG	Liquefied natural gas
MSP	Moomba to Sydney Pipeline
MtCO2-e	Million tonnes of carbon dioxide equivalents
MW	Megawatts
MWh	Megawatt hours
NEM	National Electricity Market
NER	National Electricity Rules
NGP	Northern Gas Pipeline
NRM	Negative residue management
NSG	Non-scheduled generation
OPEC	Organisation of Petroleum Exporting Countries
PJ	Petajoule
PV	Photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG

Abbreviation	Expanded term
QNI	Queensland to New South Wales Interconnector
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
REZ	Renewable Energy Zones
SCADA	Supervisory Control and Data Acquisition
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TGP	Terminal Gate Price
TJ	Terajoule
TWh	Terawatt hours
UGS	Underground Storage Facility
VBB	Victoria Big Battery
VRE	Variable renewable energy
VNI	Victoria to New South Wales Interconnector
VPP	Virtual Power Plants
WEM	Wholesale Electricity Market
WDR	Wholesale demand response