Quarterly Energy Dynamics Q4 2022

January 2023

Important notice

Purpose

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q4 2022 (1 October to 31 December 2022). This quarterly report compares results for the quarter against other recent quarters, focusing on Q3 2022 and Q4 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	25/1/2023	

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Executive summary

East coast electricity and gas highlights

High recent wholesale prices ease, but north-south price separation widens

- Wholesale spot prices averaged $93 per megawatt-hour (MWh)[1] across all National Electricity Market (NEM) regions, with Queensland, New South Wales and Tasmania at Q4 record highs. However, prices have eased from extreme levels seen early in the year.
- As in Q4 2021, there was a large gap between prices in the northern regions of Queensland and New South Wales and those in the southern mainland. This differential increased due to higher-priced offers from black coal-fired generation setting prices in the north, contrasting with low middle of the day prices in the south.
- Forward electricity contract prices started the quarter high and increased throughout the start of October before easing in mid-October and November and dropping significantly in December after the Federal Government's announcement of intervention in the wholesale domestic gas and thermal coal markets via temporary price caps.

South Australia synchronously separates from the rest of the NEM

- Most of South Australia synchronously separated from the rest of the NEM on 12 November following a transmission tower failure, islanding the region for a week until repairs were made. Without support from imports, there were periods of extreme volatility in both the energy and frequency control ancillary services (FCAS) markets, triggering an administered pricing period (APP) and capping of South Australian FCAS prices at $300/MWh.
- To manage the power system within secure limits, AEMO directed some synchronous generators online for FCAS provision, and South Australia Power Networks applied a range of mechanisms to curtail distributed PV for approximately four to 10 hours on each day from 13 and 17 November and on 19 November 2022.
- During the South Australia islanding event, that region's instantaneous renewable penetration peaked at 91.5% on 19 November 2022.

Lower temperatures and higher distributed PV reduce underlying and operational demand

- Milder temperatures and higher rainfall across most of the country compared to Q4 2021, combined with higher distributed photovoltaic (PV) output, drove a 2% reduction in operational demand to 19,431 megawatts (MW) this quarter, the lowest Q4 average on record. Northern regions saw the largest declines, with an underlying demand drop of 269 MW (-4%) in Queensland coinciding with below-average temperatures across much of the state, and lower New South Wales operational demand (-2%) driven by a 28% increase in distributed PV.

[1] Wholesale electricity prices refer to the value of energy traded between participants in the NEM, and affect only one component of the retail energy bills that consumers pay. In addition to wholesale energy purchases, costs that retailers incur to supply electricity to consumers include transmission and distribution network charges, environmental costs and retail operating expenses. AEMO 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.

- New minimum operational demand records were set in Q4, with the NEM reaching a new low of 11,892 MW at 1100 hrs on Sunday 6 November. South Australia, Victoria and New South Wales all recorded new minimums for any quarter since NEM start, and Queensland its lowest Q4 operational demand since 2002.

Coal-fired generation falls, offset by large increases in renewable output

- This quarter saw the lowest output from black and brown coal-fired generation since NEM start, driven by outages (particularly in Queensland) and offered volumes being moved to higher price bands. During the middle of the day, black coal-fired generation levels continued to decline in response to lower operational demand and increased output from grid-scale variable renewable energy (VRE).
- Output from wind and grid-scale solar grew strongly as new facilities were connected and commissioned. Although the NEM's wind fleet recorded its lowest recent quarterly utilisation rate, Q4 2022 was the highest wind generation for any Q4 on record. Queensland and New South Wales saw large increases in grid-scale solar, setting daytime prices more frequently than in the same quarter last year.
- The instantaneous penetration of renewable energy for the NEM as a proportion of total generation reached 68.7% on 28 October 2022, exceeding the previous record of 64.1% (set on 22 September 2022).

Other NEM highlights

- Total FCAS costs for the quarter reached $98 million, $35 million lower than Q4 2021, with revenues for batteries increasing strongly as they continued to provide the largest share of FCAS in the NEM and, in South Australia, benefited from very high FCAS prices during the state's islanding event.
- Since mid Q4 2021, the full operation of synchronous condensers has reduced the average volume and proportion of time for South Australian generation operating under direction by AEMO for system security reasons. Direction costs were around $6 million lower, despite the compensation price paid to directed generators increasing from an average of $96/MWh in Q4 2021 to $349/MWh this quarter, driven by the sustained high spot prices over Q2 and Q3 2022.

East Coast gas prices decline, demand and production down

- East Coast wholesale gas prices have declined from the record highs seen in June and July, and eased further in December to an average quarterly price across all markets of $17.79 per gigajoule (GJ), but remained well above $10.60/GJ for the same time last year.
- Gas demand decreased by 7% this quarter compared to Q4 2021, driven by a large decrease in Queensland liquefied natural gas (LNG) export demand (-29.1 petajoules [PJ]), yielding the lowest Q4 flows to Curtis Island since 2018, with Queensland Curtis LNG (QCLNG) experiencing two unplanned train outages. Queensland gas production decreased by a smaller amount (-25.1 PJ), leading to additional supply for the domestic market.
- Inventory at the Iona underground gas storage (UGS) facility ended the quarter with the highest calendar year-end balance since reporting began in 2017, despite a planned outage lasting from 6 November to 30 November.
- Gas Supply Hub trading volumes were up compared to Q4 2021, and the total volume traded for the calendar year was the highest on record. The Day Ahead Auction set new quarterly record for the pipeline capacity volume doubling that of Q4 2021 to 31 PJ.

Western Australia electricity and gas highlights

Highest quarterly weighted average Balancing Price and STEM price

- The weighted average Balancing Price for Q4 2022 was $81.80/MWh, the highest quarterly average of all time and a 50% increase from Q4 2021. Drivers were a combination of reduced facility availability, change in fuel mix with an increase of gas-fired generation and a reduction in prevalence of negative Balancing Prices.
- Q4 2022 set a new record for the maximum Balancing Price, which cleared at $1,018/MWh in four trading intervals from 1730 hrs to 1930 hrs on Tuesday, 29 November 2022.
- The weighted average Short-Term Electricity Market (STEM) Price was $84.87/MWh, a 65% increase compared to Q4 2021, driven by an increase in the average quantities bid into STEM, compared to Q4 2021.

Record minimum operational demand and maximum distributed PV output

- The Wholesale Electricity Market (WEM) quarterly average operational demand was 1,723 MW, representing a 7.4% decline relative to Q4 2021 and the lowest quarterly average since Q3 2006. Mild temperatures and an increase in distributed PV generation were the main drivers. An all-time minimum operational demand record of 626 MW occurred on Sunday, 16 October 2022.
- As these low operational demand conditions were forecasted ahead of time, AEMO implemented a Minimum Demand Threshold (MDT) to manage low loads operationally.
- There was also an all-time record maximum distributed PV generation output of 1,865 MW on Tuesday, 1 November 2022.

All-time lowest quarterly average coal-fired generation, offset by gas-fired generation increase

- Quarterly average coal-fired generation in Q4 2022 reached an all-time low of 438 MW, 42% lower than in Q4 2021. This was mainly driven by a reduction in facility availability due to coal preservation and ensuring adequate stockpiles for summer, which has been a key focus of the industry over Q4 2022.
- To offset the coal decrease, gas-fired generation increased by an average of 213 MW (+35%), with gas supplying 37.4% of underlying demand on average, making it the primary fuel type throughout the quarter.

Record renewable penetration

- Renewable penetration in Q4 2022 reached an all-time record quarterly share of 42.7% (a 3 percentage point increase from Q4 2021). Several all-time instantaneous renewable penetration records were set during the quarter, the most recent being 84.3% on Monday, 12 December 2022.

Gas consumption and production increase from Q4 2021

- Gas consumption in the WA domestic gas market increased by 7% from Q4 2021, with a 31% increase in gas consumed for electricity generation, in line with the changes in the WEM fuel mix observed during the quarter.
- Gas production increased by 9% from Q4 2021, despite the sudden reduction of production from the Varanus Island facility caused by a pipeline leak in mid-December.

Market events and AEMO reporting

On 12 November 2022, two South East – Tailem Bend 275 kV transmission lines tripped on failure of a tower structure in a storm, causing the synchronous separation of a major part of the South Australian power system from the rest of the NEM. AEMO has published a preliminary event report outlining the event and AEMO's operational response[2].

This Quarterly Energy Dynamics (QED) report provides an overview of wholesale electricity and gas market outcomes and drivers across the entire quarter. This report makes reference to the distributed PV curtailment during the SA islanding event in section 1.1.2, increased spot price volatility in section 1.2.1, the maximum instantaneous renewable penetration reached in the islanding region in section 1.3.4 and describes the impact on FCAS prices in section 1.5.

A separate transmission tower failure caused by a landslide occurred in Tasmania on 14 October which is detailed in a preliminary event report[3].

Readers should refer to the published and forthcoming reports for further details of the specific responses made by AEMO and the circumstances underlying them.

[2] https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/preliminary-report--trip-of-south-east-tailem-bend.pdf?la=en.

[3] https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/preliminary-report-trip-of-liapootah-palmerston-lines.pdf?la=en.

Contents

1 NEM market dynamics

1.1 Electricity demand

1.1.1 Weather

Rainfall was generally above average across the country over the quarter as the La Niña weather pattern persisted into summer[4]. The quarter began with the second-highest rainfall on record for Australia as a whole in October, with significant flooding impacting large areas of eastern Australia. Flooding continued at many sites into the middle of the quarter, with the tenth highest national November rainfall on record. A notable exception was south-east Queensland and the northern half of the New South Wales coast, where November saw rainfall ease to average or below average levels. The end of the quarter brought significant geographic differences in rainfall across the NEM regions, with below average rainfall across eastern New South Wales, south-east Queensland and much of Tasmania, while above average rainfall continued in northern Queensland.

Mean temperatures were cooler than average across much of the country over the quarter, particularly in New South Wales and south-east Queensland (Figure 1). The northern tropics were an exception, where mean temperatures were above or very much above average in October and November before easing to below average temperatures in December. As Figure 2 shows, average maximum temperatures were cooler relative to last Q4 (particularly in Brisbane) and cooler than the 10-year average across all NEM capital cities.

Figure 1 Cooler than average across the south east, warmer than average in northern tropics

Q4 2022 mean temperature deciles for Australia

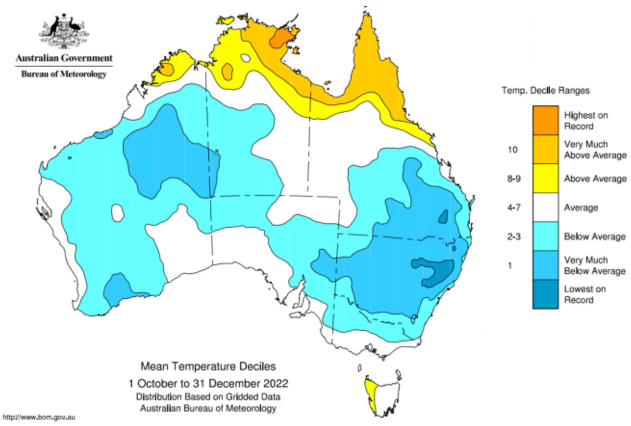
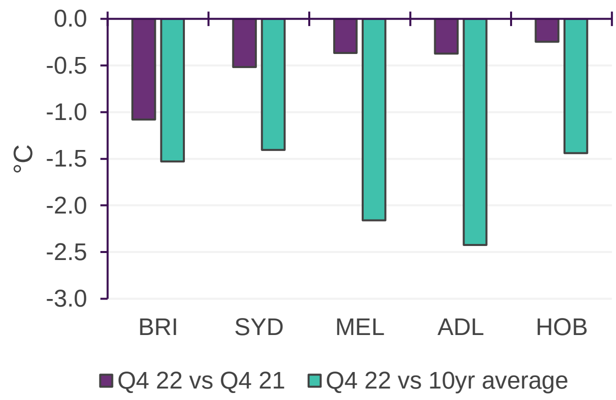


Figure 2 Temperatures cooler than 10-year average across the east coast

Average maximum temperature variance by capital city



1.1.2 Demand outcomes

NEM quarterly average operational demand was 19,431 MW, representing a 2% decline relative to Q4 2021 (see Figure 3) and the lowest Q4 average recorded (Figure 4). This was underpinned by an average increase of 16%

[4] See http://www.bom.gov.au/climate/enso/.

(410 MW) in distributed PV output reducing daytime operational demand[5], with average underlying demand[6] declining slightly (-0.2%, 35 MW).

Figure 3 Distributed PV output reduced daytime operational demand

Changes in average NEM demand components by time of day – Q4 2022 vs Q4 2021

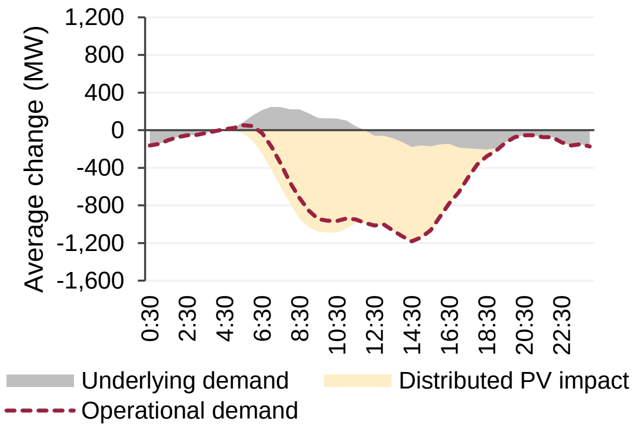
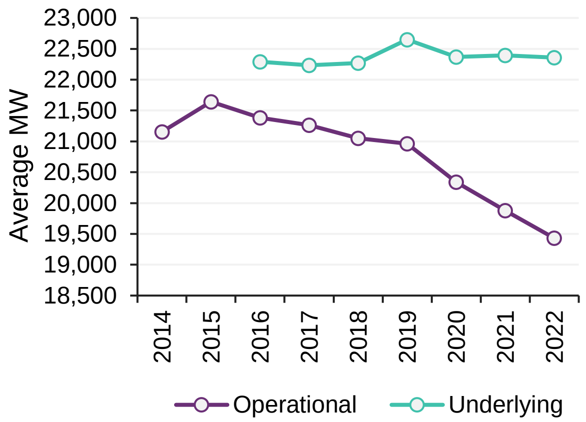


Figure 4 Declining average operational demand in the NEM

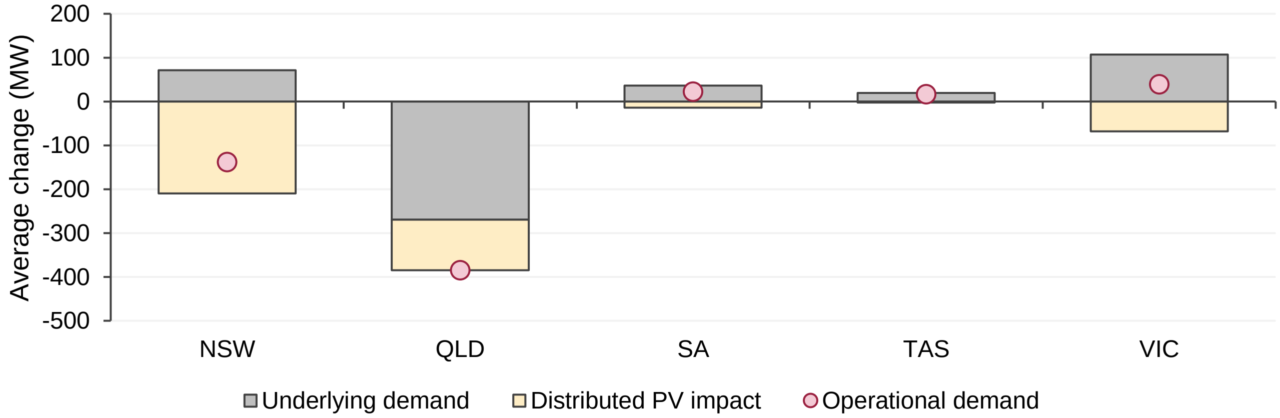
NEM average operational and underlying demand (Q4s)[7]



As Figure 5 illustrates, the reduction in average operational demand was driven by Queensland and New South Wales, where operational demand declined by 385 MW (-6%) and 138 MW (-2%) respectively, while other NEM regions each saw increases of around 1% to 2%.

Figure 5 Operational demand declined, driven by growth in distributed PV output and declining underlying demand in Queensland

Change in demand components – Q4 2022 vs Q4 2021



In Queensland, in addition to growth in distributed PV output (+15%), there was a substantial decline in underlying demand of 269 MW (-4%) relative to last Q4. This is likely due to a combination of factors including reduced industrial demand and lower cooling requirements relative to last Q4. December in particular saw a large decline

[5] Increased distributed PV generation results in reduced operational demand because its production lowers supply required from the grid.

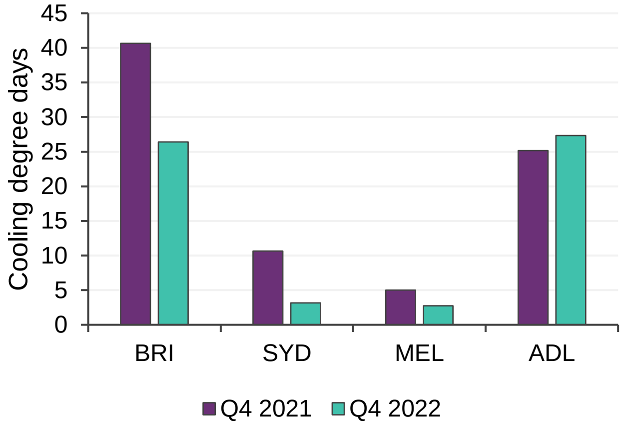
[6] Underlying demand is calculated by adding estimated production from distributed PV to operational demand, to yield an estimate of total electricity generated.

[7] Underlying demand is not available prior to 2016 because distributed PV production is based on AEMO estimates using the Australian Solar Energy Forecasting System (ASEFS2), which commenced 30 March 2016.

in underlying demand (-7%, 466 MW), coinciding with below-average temperatures across much of the state leading to a sharp decline in cooling degree days[8] in Brisbane relative to last year (Figure 6).

Figure 6 Decreased cooling requirements in Brisbane, Sydney and Melbourne

Cooling degree days – Q4 2022 vs Q4 2021



In New South Wales, where operational demand declined to its lowest recorded Q4 average, there was a large increase in distributed PV output (+28%) relative to last Q4, with most of the increase occurring in November (+67%, 434 MW) and December (+28%, 231 MW). This was in part driven by low irradiation due to cloudy and wet weather conditions last Q4, in addition to continued uptake of distributed PV.

South Australia (+4%), Victoria (+12%) and Tasmania (+7%) also experienced growth in distributed PV output relative to last quarter. Following two quarters of substantial declines in rooftop PV installation rates during the first half of 2022 (27% lower installed capacity compared with first half of 2021), the Clean Energy Regulator has reported a recent pick-up in installations, with an estimated 729 MW of small-scale PV capacity installed in Q3 2022[9]. These trends may be due in part to wholesale electricity price rises being passed through to consumers as well as shifts in discretionary spending from broader economic drivers.

In South Australia, an operating incident on 12 November 2022 resulted in the separation of a major part of the South Australian power system from the rest of the NEM (see Section 1.5 and AEMO's preliminary report[10] for more detailed information). To manage the power system within secure limits, SA Power Networks applied a range of mechanisms to curtail distributed PV on each day from 13 and 17 November and on 19 November 2022 for approximately four to 10 hours, up to a maximum curtailment of approximately 410 MW on Thursday 17 November 2022. This mechanism was applied as a 'last resort', implemented only when other options to maintain power system security were not available or had been exhausted.

Minimum and maximum demands

At the half hour ending 1100 hrs on Sunday 6 November 2022, the NEM reached a new minimum operational demand record of 11,892 MW with 45% of underlying demand met by distributed PV. This was 6% lower than the previous record set on 25 September 2022. This quarter also saw several new regional minimum demand records across the NEM driven by mild conditions and low weekend demand (Section 1.1.2). These included:

- At 1300 hrs on Sunday 16 Oct 2022, **South Australia** reached a new minimum operational demand record of 100 MW with 93% of South Australia's underlying demand met by distributed PV. This was down 4 MW from the previous record set on 21 November 2021.

[8] A "cooling degree day" (CDD) is a measurement used as an indicator of outside temperature levels above what is considered a comfortable temperature. CDD value is calculated as max (0, average [maximum temperature, minimum temperature] – 24).

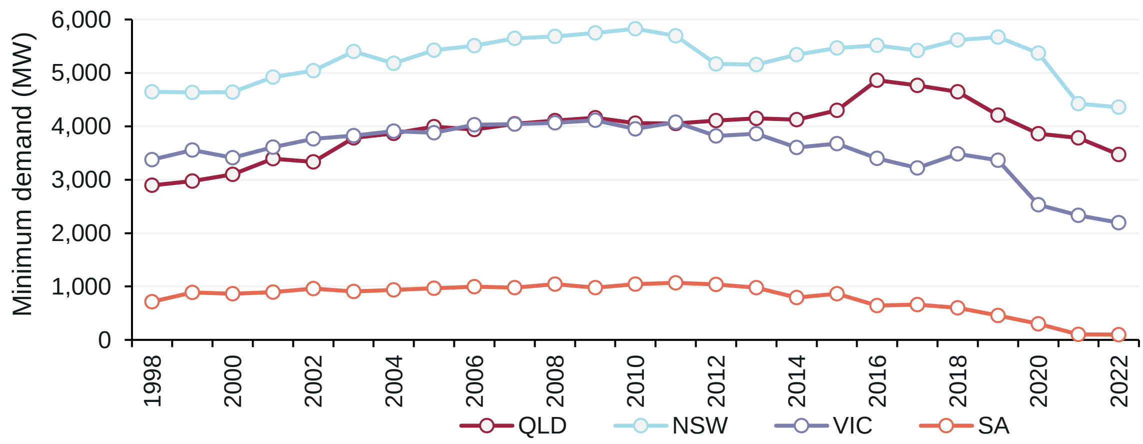
[9] Clean Energy Regulator 2022, Small-scale technology certificates, at https://www.cleanenergyregulator.gov.au/Infohub/Markets/Pages/qcmr/september-quarter-2022/Small-scale-technology-certificates-(STCs).aspx.

[10] At https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/preliminary-report--trip-of-south-east-tailem-bend.pdf?la=en.

- **Victoria** broke its minimum demand record on two separate days this quarter. At 1300 hrs Sunday 2 October 2022, Victoria recorded a minimum demand level of 2,285 MW, down from previous record of 2,333 MW set in November 2021. At the time, distributed PV met half of Victoria's underlying demand. This was superseded towards the end of the quarter by a new record of 2,195 MW set at 1300 hrs on Sunday 18 December 2022, 3.9% lower than the minimum reached earlier in the quarter, with distributed PV contributing 55% of underlying demand.
- **New South Wales** reached a new all-time record of 4,356 MW at 1300 hrs on Saturday 29 October 2022, down 42 MW from the previous all-time record of 4,398 MW set on 25 September 2022. The same record was reached again the next day.
- Finally, **Queensland** experienced its lowest Q4 operational demand since 2002, reaching 3,676 MW on Sunday 6 November 2022.

Figure 7 Declining minimum operational demand across the NEM

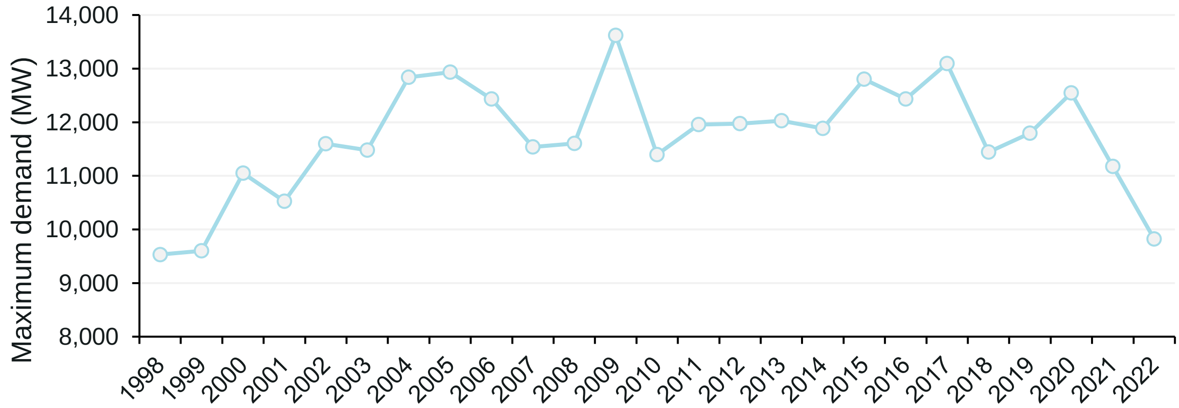
Annual minimum operational demand for New South Wales, Victoria, South Australia and Queensland



Cooler than average Q4 conditions and increased distributed PV output also led to reduced maximum operational demands in some regions. In New South Wales, Q4 maximum demand reached only 9,820 MW, representing a 1,356 MW (-12%) decline relative to last Q4 and its lowest recorded Q4 maximum demand since 1999 (Figure 8).

Figure 8 Lowest recorded New South Wales Q4 maximum demand since 1999

NSW maximum operational demands – Q4s



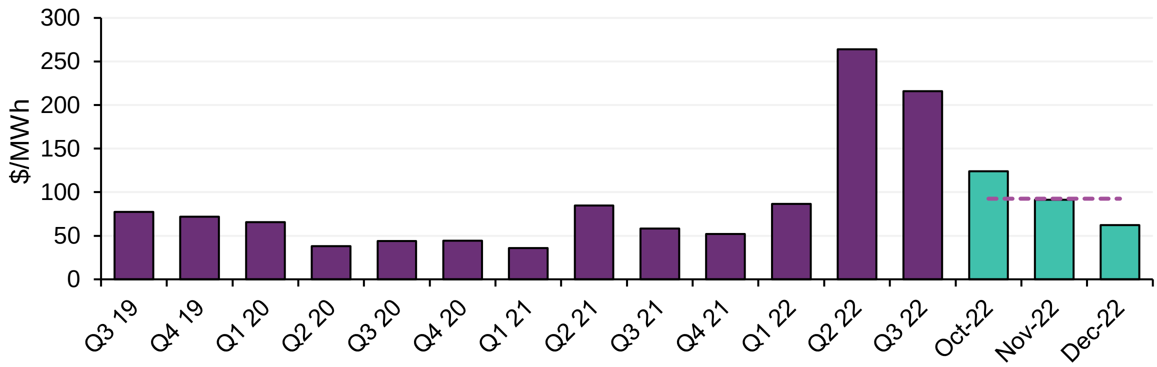
1.2 Wholesale electricity prices

Wholesale spot prices averaged $93/MWh across the five NEM regions during Q4 2022, a rapid decline on recent quarters and just 43% of Q3 2022's $216/MWh average spot price. Furthermore, prices dropped as the quarter progressed (Figure 9).

Despite the fall in spot prices, the NEM average spot price was a record for Q4, and 78% higher than Q4 2021's $52/MWh average.

Figure 9 Spot prices reached a record Q4 high at $93/MWh but well down on Q2 and Q3 2022

NEM average wholesale electricity spot prices – since Q3 2019



Regional average prices ranged from $120/MWh in Queensland to $63/MWh in Victoria (Figure 10). Prices in Queensland, New South Wales and Tasmania were all record highs for any Q4.

Figure 10 High energy prices across all NEM regions in Q4 2022

Average wholesale electricity spot price by region – energy[11] and cap return components, selected quarters

By region:

- **Tasmania** recorded a Q4 quarterly average spot price of $100/MWh, a 229% rise on Q4 2021 ($30/MWh). Low rainfall in the south-west and catchment areas for Hydro Tasmania's generators resulted in upward repricing of offer volumes, pushing up the 'underlying' energy price (Section 1.3.3). Periods of price volatility

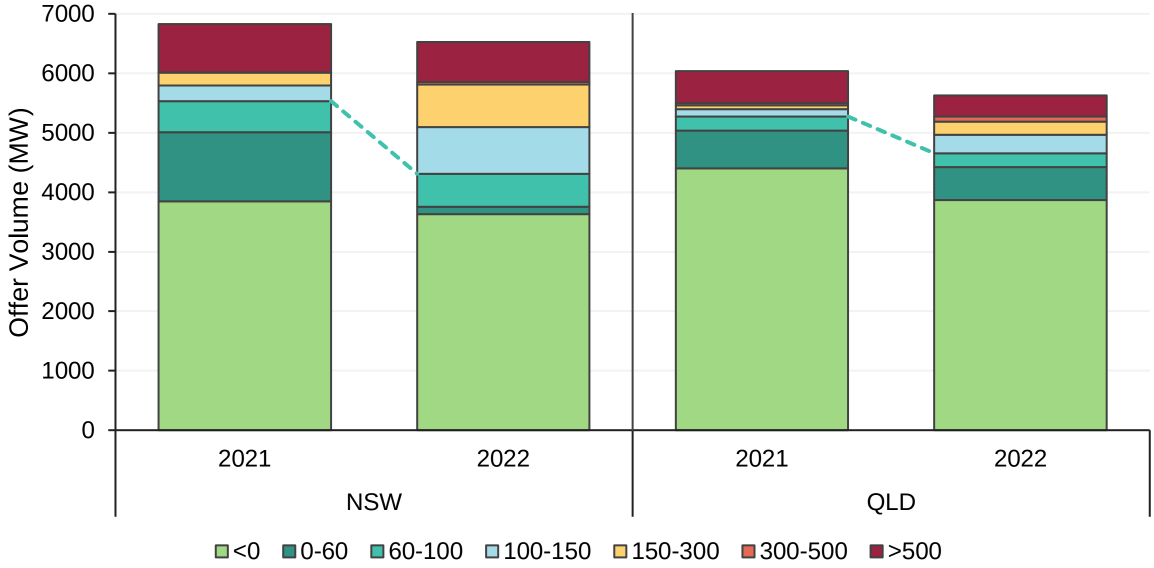
[11] 'Energy price' calculation in analysis of spot electricity price averages truncates the impact of price volatility (that is, price above $300/MWh, also known as "cap return"). Since commencement of Five Minute Settlement (5MS) on 1 October 2021, energy and cap prices are calculated on a 5-minute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

arose during October and November following major unplanned outages of key transmission lines, as well as forced flow into Victoria during the South Australia island event.

- **Queensland** and **New South Wales** prices reached $120/MWh (24% uplift on Q4 2021) and $116/MWh (83% uplift on Q4 2021) respectively. Rising thermal coal prices (Section 2.1.2), as well as increased outages (particularly in Queensland, Section 1.3.1), led to black coal generators shifting supply offers to higher price bands, with offer volume priced below $100/MWh reduced by around 1,200 MW in New South Wales and 600 MW in Queensland compared to Q4 2021 (Figure 11).

Figure 11 New South Wales and Queensland black coal-fired generators shifted bids to higher price bands

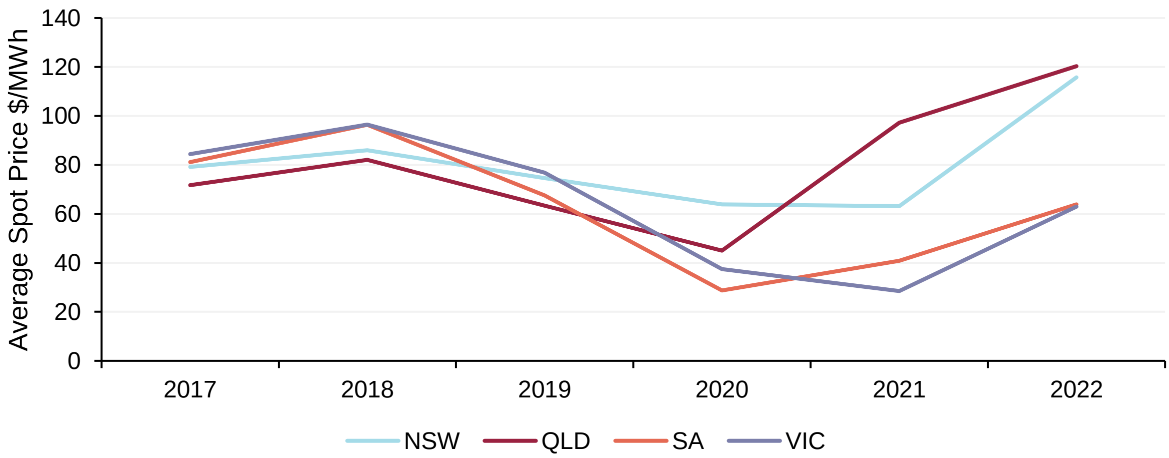
New South Wales and Queensland black coal unit supply offer prices - average Q4 2021 and Q4 2022



- With spot prices reaching Q4 record levels in Queensland and New South Wales, price separation between these northern regions and southern mainland states (Victoria and South Australia[12]) increased to the highest Q4 differential on record, ranging from $120/MWh in Queensland to $63/MWh in Victoria (Figure 12).

Figure 12 Price divide between northern and southern regions increased

Average spot electricity price by mainland NEM region - Q4's only

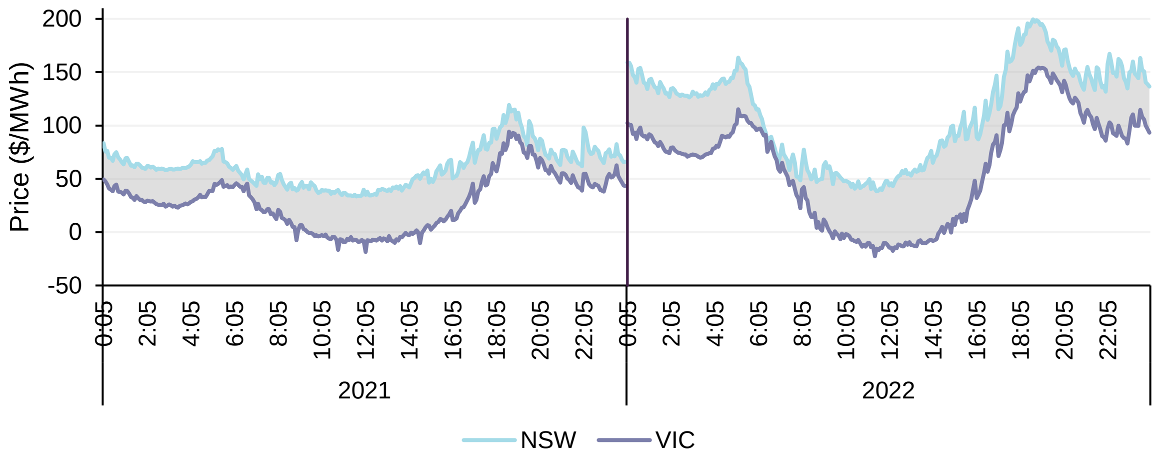


[12] Excluding Tasmania, which experienced different price drivers

To provide further detail on north-south price separation in the NEM, Figure 13 shows an intra-day view of New South Wales and Victoria energy prices. Evening and overnight spot prices increased markedly in both northern and southern regions, whereas day-time prices did not exhibit the same relative increase. This can be attributed to black coal-fired generation offers moving to higher price bands and higher thermal coal and gas input costs. During daylight hours, increased grid-scale solar and wind generation (Section 1.3.4) and lower operational demand kept prices low, with significant incidence of negative prices in the southern mainland regions (Section 1.2.2). The influence of the Victoria – New South Wales interconnector (VNI) in the trends shown in Figure 13 is discussed in Section 1.4.

Figure 13 Price separation between New South Wales and Victoria increased

New South Wales and Victoria average energy price by time of day – Q4 2021 and Q4 2022

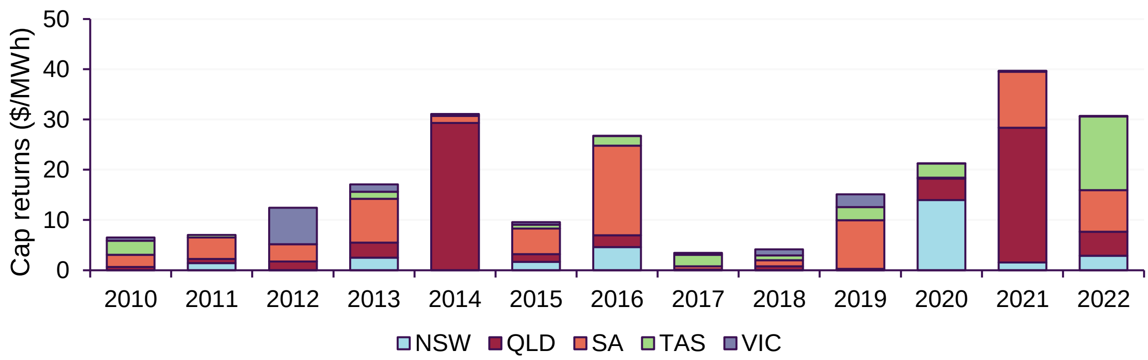


1.2.1 Wholesale electricity price volatility

NEM spot price volatility in Q4 2022 dropped slightly from Q4 2021 to $31/MWh in aggregate (Figure 14).

Figure 14 Price volatility lower than Q4 2021, with Tasmania being the major contributor to quarterly cap returns

Quarterly cap returns (excess of spot prices above $300/MWh) – Q4s, stacked by region



Volatility was low across the mainland NEM regions, with South Australia, Queensland and New South Wales recording cap returns of $8/MWh, $5/MWh and $3/MWh respectively and no material volatility in Victoria. Tasmania saw increased volatility, returning a Q4 record of $15/MWh. Volatility in Tasmania is typically low in Q4; high cap returns in Q4 2022 can be attributed to a number of volatility episodes that followed a major operating incident on the morning of 14 October 2022. This resulted in a 49-day full then partial outage of the major

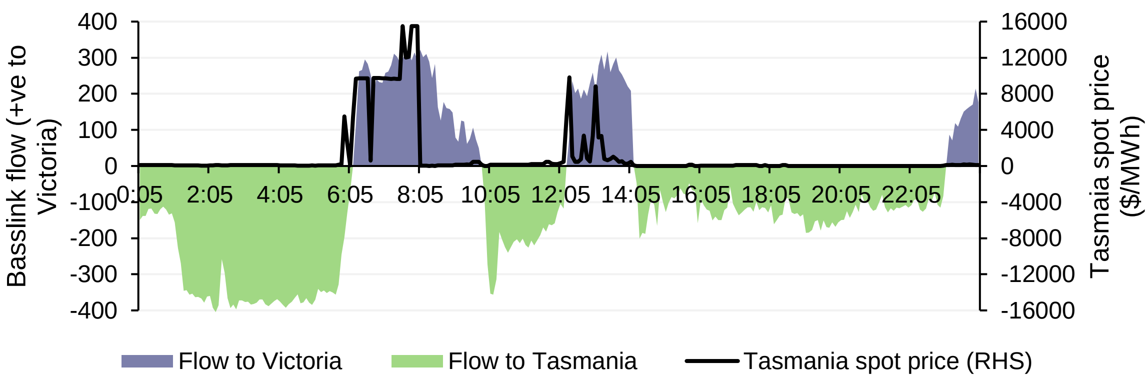
220 kilovolt (kV) transmission lines linking the north and south of Tasmania, after a landslide impacted the footings of a transmission line strain tower (for more details of the event, see AEMO's preliminary report[13]). Table 1 below summarises events of significant spot price volatility during Q4 2022.

Table 1 Significant volatility events in Q4 2022

Region	Date	Contribution to quarterly cap returns ($/MWh)	Drivers
TAS	14 Oct	$2.05	Upon the trip of the Liapootah – Palmerstone 220 kV lines, Tasmania spot prices spiked above $7520/MWh for 10 minutes, with an additional 2 hours 10 mins of spot prices settling above $300 through the day. The total cap return contribution over the day was $2.05/MWh. Numerous network trips occurred pushing prices to volatile highs between 0925 and 1600 hrs. These included the loss of: • Supply to Tasmania from the mainland via the Basslink interconnector. • Supply from 234 MW of Tasmanian generation. • 530 MW of load (495 MW of which was industrial load). • Loss of Waddamana to Lindisfarne 220 kV line that connected north to south of Tasmania.
	14 Nov	$10.55	While the 220 kV Liapootah – Palmerstone line remained offline, generation in the south of Tasmania was limited to avoid overloading lines. During some of this period, most of the South Australian region became synchronously separated from the rest of the NEM after a transmission failure near Tailem Bend. This limited flow into Victoria from South Australia, and on 17 November network constraints forced Tasmanian generation to flow north into Victoria. Forced flow into Victoria imposed additional constraints on Tasmanian generation. As Figure 15 shows; • At 05:55 hrs, when southern Tasmanian generators were limited in their capacity to supply electricity, prices jumped to >$5,000. • At 06:15 hrs, when northern Tasmanian generation was forced to flow into Victoria, prices spiked above $9,600/MWh for 90 minutes. • At 07:35 hrs, when Victorian hydro generation fell, additional generation was supplied to Victoria from Tasmania, and Tasmanian prices rose to $15,500/MWh. In total Tasmanian spot prices exceeded $300/MWh for 4 hours and 25 minutes.
SA	12 Nov to 19 Nov	$5.40	A tower failure on the Tailem Bend – South East 275 kV transmission lines connecting south-east South Australia with the rest of the state synchronously isolated most of the South Australian region from the rest of NEM. The outage spanned from 1639 hrs on 12 November to 1803 hrs on 19 November. Without support from imports, price volatility arose from occasional drops in low-cost generation availability or spikes in demand. Over the eight days from 12 November, price volatility contributed $5.40/MWh to the quarterly total $8.32/MWh cap return.

Figure 15 High prices in Tasmania on 14 November driven by forced Basslink exports

Basslink flows and Tasmania spot price – 14 November 2022



[13] At https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/preliminary-report-trip-of-liapootah-palmerston-lines.pdf?la=en.

1.2.2 Negative wholesale electricity prices

The impact of negative and zero prices[14] on average regional spot prices in the southern mainland regions (Figure 16) almost doubled from last year's Q4 values, reaching $23/MWh for South Australia (83% increase) and $11/MWh for Victoria (82% increase). Although the frequency of occurrence of negative prices increased only slightly in both regions, the larger impact was mostly attributable to negative spot prices being set by lower offer prices from wind and grid-scale solar units. Some wind and grid-scale solar generators will offer supply at negative prices as they realise one renewable energy certificate per MWh generated. The increase in negative price impact and more frequent occurrence of negative prices in ranges below -$45/MWh (Figure 17) coincides with an increase in spot prices for large-scale renewable energy certificates from an average of $42 per certificate during Q4 2021 to $65 per certificate this quarter[15].

In South Australia, these trends were amplified by the region's one week separation from the NEM during November (Section 1.5). This period and its aftermath, when export capacity from South Australia remained severely limited, covered 12% of Q4 by time but accounted for 23% of the negative prices recorded over the quarter. On average negative prices were also larger in magnitude during this period, and contributed about $7/MWh or one third of the quarter's total negative price impact.

Negative price occurrence and impact remained minimal in Queensland, New South Wales and Tasmania.

Figure 16 Sharp rise in the impact of negative prices in Victoria and South Australia

South Australia and Victoria negative price impact, quarterly

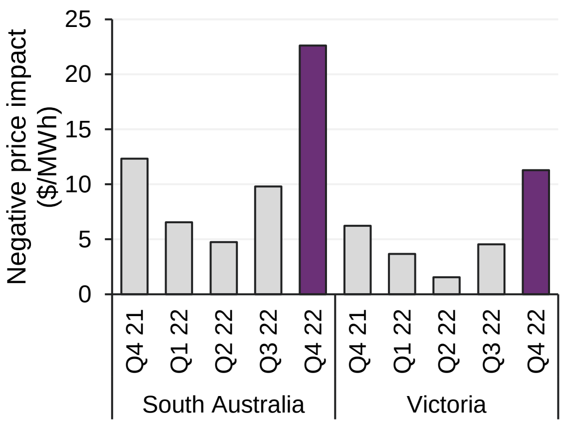
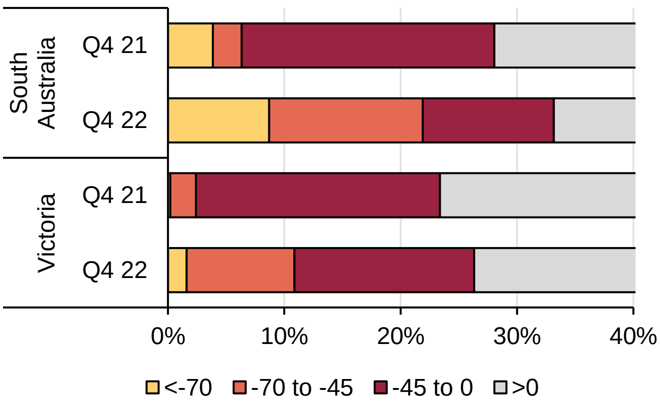


Figure 17 Negative prices set more frequently below -$45/MWh in South Australia and Victoria

Negative price occurrence by price range, Victoria and South Australia



1.2.3 Price-setting dynamics

Across the NEM, offers from black and brown coal-fired generation set spot prices less frequently in Q4 2022 at a combined 39% of the time compared to 45% in Q4 2021. Offers from hydro, wind and grid-scale solar made up the difference at 34% (+1%), 9% (+3%) and 8% (+1%) respectively. Price-setting frequency by gas-fired generation and batteries varied only negligibly.

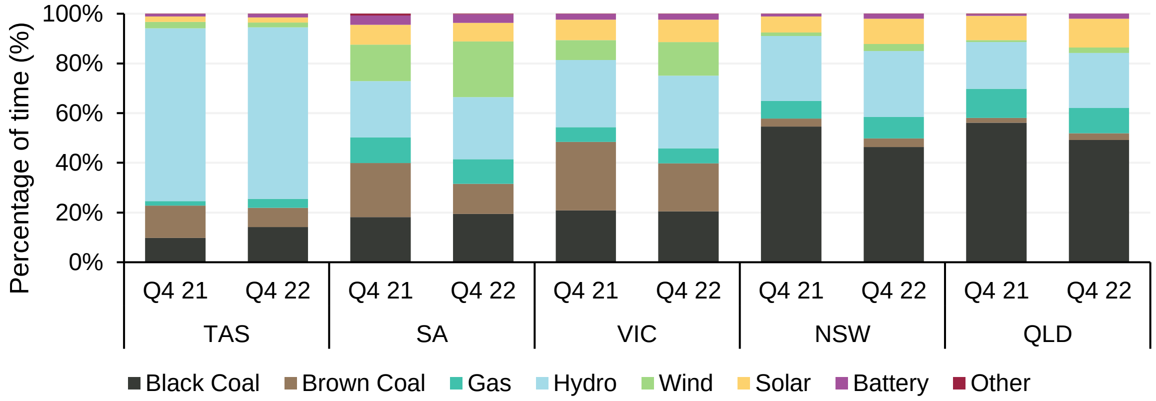
[14] Hereafter referred to as negative prices. 'Negative price impact' quantifies the effect of negative prices in reducing the overall quarterly average spot price.

[15] Source: https://lgc.mercari.com.au/.

By region, South Australia and Victoria saw increases in price-setting frequency by wind generation, up by 8 and 6 percentage points respectively, whereas in New South Wales and Queensland grid-solar generation increased its price-setting frequency by 4 and 2 percentage points respectively (Figure 18).

Figure 18 VRE generation increased price-setting frequency while coal-fired generation declined

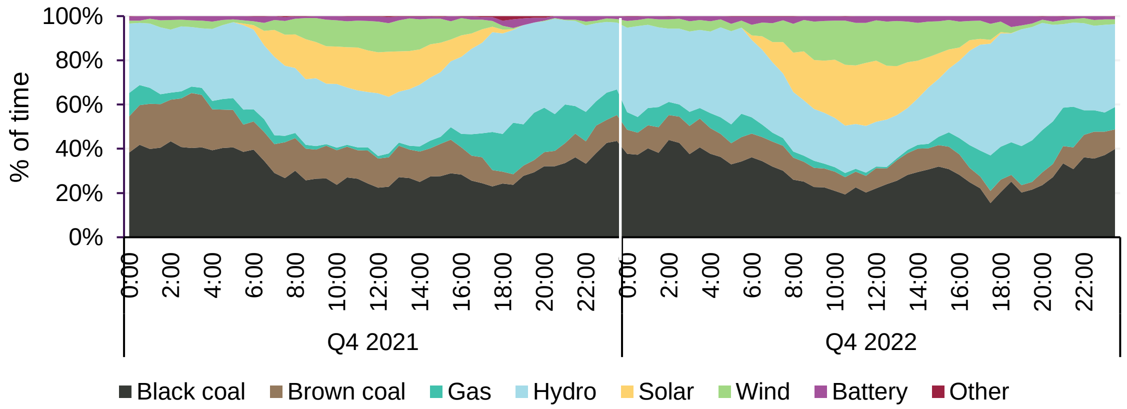
Price-setting frequency by fuel type[16] Q4 2022 vs Q4 2021



There was a notable increase in grid-scale solar setting the price in the middle of the day, with New South Wales and Queensland having 38% and 37% of prices for the half hour ending at 1230 hrs set by solar generation offers compared to 17% and 28% for the same half hour in Q4 2021. This contributed to prices across the NEM being set noticeably more often by solar or wind generation in the middle of the day, with corresponding reductions in price-setting by other fuels (Figure 19).

Figure 19 Grid-scale solar and wind generation saw marked increase in price-setting frequency

NEM price-setting frequency by fuel type and time of day



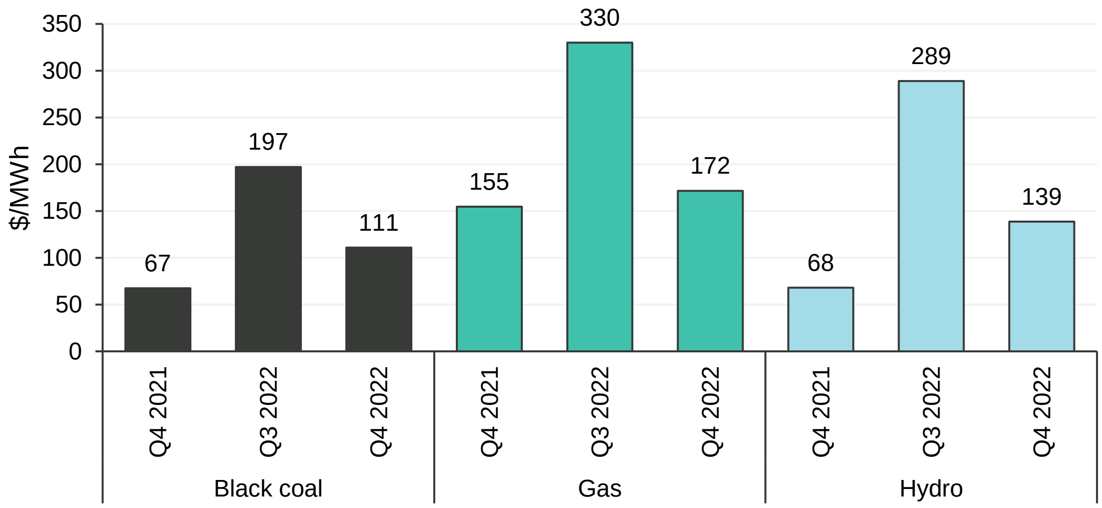
Average mainland NEM spot prices set by the key fuel types decreased substantially this quarter from Q3 2022, but were well above corresponding levels in Q4 2021 (Figure 20). Black coal-fired generators set mainland NEM spot prices at an average of $111/MWh, significantly up from $67/MWh in Q4 2021, driven by offers in higher price bands (Figure 11) and reduced availability (Section 1.3.1). Hydro generation set the mainland NEM price at an average $139/MWh in Q4 2022, a rise of $71/MWh, with mainland hydro generators dispatching more often in

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

the morning and evening peaks when prices were higher (Section 1.3.3). Gas-fired generation set mainland prices at an average of $172/MWh when marginal, an increase of $17/MWh on Q4 2021, driven by higher gas prices (Section 2.1).

Figure 20 Average price setting levels in Q4 2022 down from Q3 2022 for key fuels, but well above Q4 2021

Average mainland NEM spot price set by fuel type – selected quarters and fuels

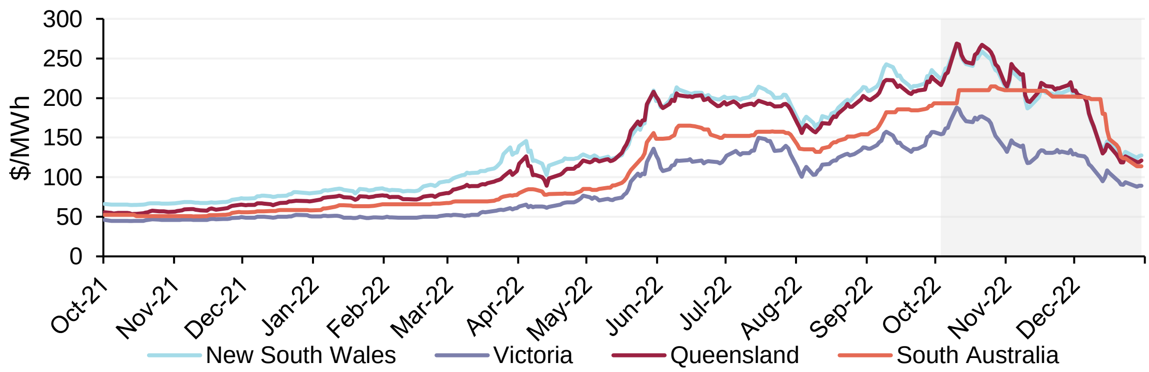


1.2.4 Electricity futures markets

ASX Calendar 2023 (Cal23) base future prices increased through the start of October, then trended downwards through mid-October to December, finishing Q4 at $127/MWh in New South Wales, $121/MWh in Queensland, $89/MWh in Victoria and $114/MWh in South Australia (Figure 21).

Figure 21 Cal23 Futures trended upwards through October, then declined rapidly from November

ASX Energy – daily Cal 2023 base futures by region



Sustained high commodity prices, upcoming coal unit outages and tight gas supply led to futures prices remaining elevated early in the quarter. Prices in each region stayed high through October, peaking at $269/MWh in Queensland and $267/MWh in New South Wales for Cal23 base contracts.

Cal23 prices then began to decline through November, with high inter-day price volatility reflecting anticipation of government intervention in the market aimed at reducing wholesale electricity prices. From 9 December 2022, the Federal Government announced a 12-month intervention into wholesale domestic gas and thermal coal markets (in the form of temporary price caps) and an ongoing mandatory code of conduct for the gas production sector

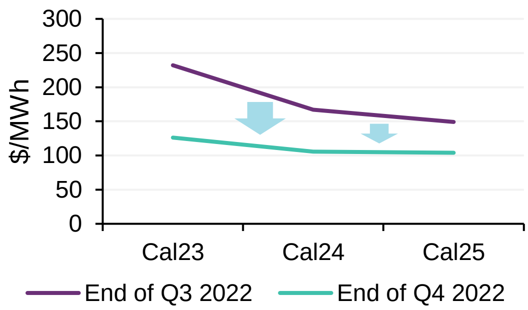
(See Section 2.1.1 for more detail). Prices for certain east coast wholesale gas contracts will be capped at $12/GJ for 12 months from late December 2022, and thereafter will be regulated by a reasonable pricing framework.

Following these announcements, ASX Cal23 electricity futures prices fell steeply for each of the mainland states through to the end of the Quarter, with prices dropping between 41% in South Australia and 46% in Queensland from the end of Q3 22.

The expectation and then announcement of government intervention through the quarter saw reductions in futures prices for later years similar to those for Cal23 across the mainland regions (Figure 22).

Figure 22 Cal23-25 futures prices fell across Q4 2022

ASX Energy – NSW Calendar strip prices at last day of quarter



1.3 Electricity generation

Total generation in the NEM across Q4 2022 increased slightly by 25 MW compared to Q4 2021. Figure 23 and Table 2 show the net changes, with large increases in renewable output representing a 4.5 percentage point lift in combined NEM supply share, offset by decreases in coal and gas-fired generation and a marginal reduction in hydro generation.

Figure 23 Increase in renewable output was offset by decline in coal and gas-fired generation

Change in supply – Q4 2022 versus Q4 2021

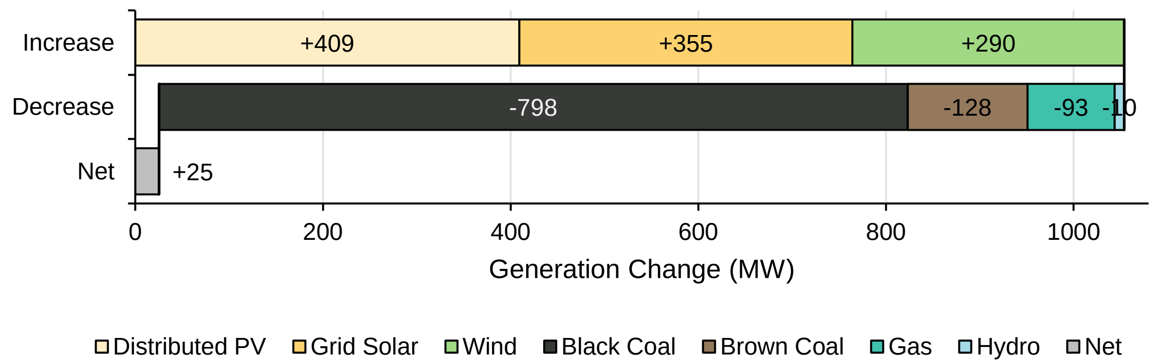


Table 2 NEM supply mix by fuel type[17]

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar	Distributed PV	Other
Q4 21	44.2%	15.4%	4.4%	7.5%	11.5%	5.7%	11.1%	0.2%
Q4 22	40.6%	14.8%	4.0%	7.4%	12.7%	7.2%	12.9%	0.3%
Change	-3.6%	-0.6%	-0.4%	-0.1%	1.3%	1.6%	1.8%	0.0%

In summary, changes in generation by fuel type compared to Q4 2021 were:

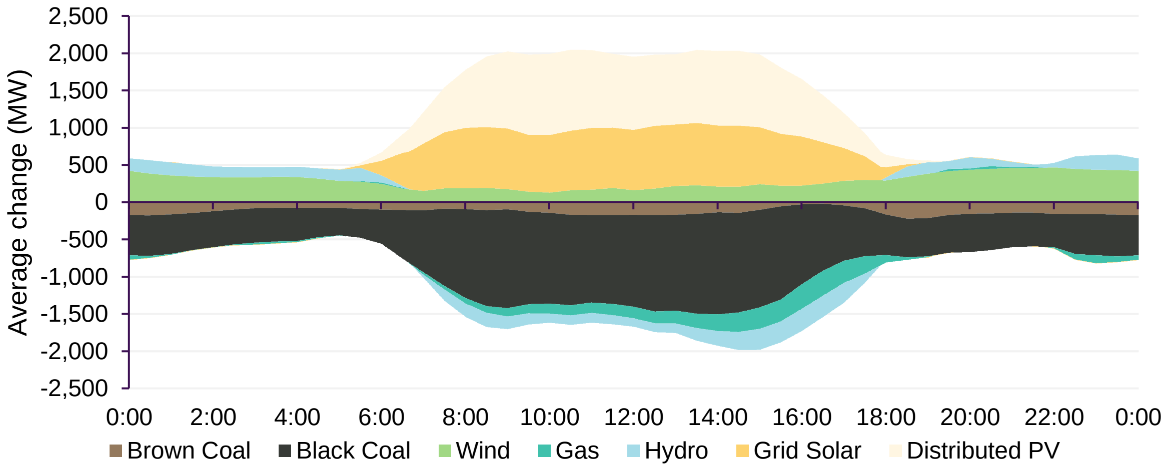
[17] Distributed PV has been included in the total supply mix (total generation = NEM generation + distributed PV generation).

- Additional generation from distributed PV (+409 MW) and grid-scale VRE generators (+645 MW) led the increase, offset by a reduction of 10 MW from hydro generation.
- Black coal-fired generation output fell by 798 MW to the lowest level in any quarter since NEM start, 8% lower than Q4 2021, the previous lowest quarter. This was driven by a combination of factors: retirement of Liddell's unit 3 in April 2022, a number of outages (particularly in Queensland), and displacement by increased distributed PV and VRE.
- Victoria's brown coal-fired generators decreased output, reducing by 128 MW, also to the lowest level since NEM start. This was largely driven by increased outages at Loy Yang A.
- Gas-fired generation decreased by 93 MW to the lowest quarterly output since Q1 2004, driven by low demand and high gas prices (Section 2.1).

By time of day, Figure 24 shows the large increase in distributed PV and grid-scale solar output in the middle of the day. Generation from black and brown coal-fired sources has decreased across the day, with the decline most prominent in the middle of the day.

Figure 24 Renewables growth displacing conventional sources in Q4 2022

NEM generation changes by time of day – Q4 2022 vs Q4 2021



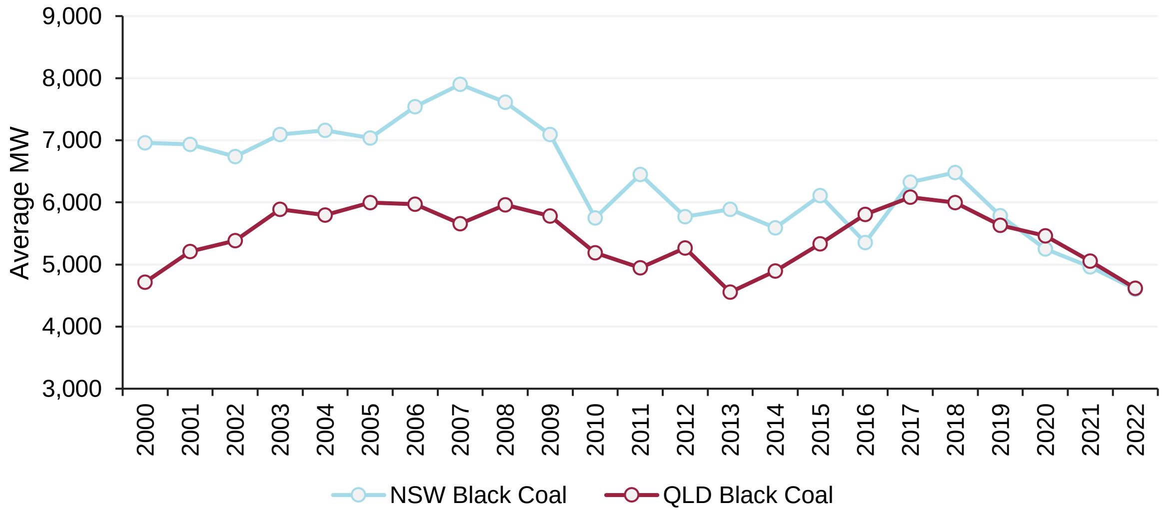
1.3.1 Coal-fired generation

Black coal-fired fleet

This quarter saw the lowest average output from black coal-fired generation for any quarter since NEM start, averaging 9,219 MW during Q4 2022. This is was 798 MW lower than in Q4 2021, which recorded the previous lowest black coal-fired output for any quarter. Both the Queensland and New South Wales fleets decreased output, by 439 MW and 359 MW respectively (Figure 25).

Figure 25 NEM black coal-fired generation recorded its lowest average output for any quarter since NEM start

Average NEM black coal-fired generation by region – Q4s



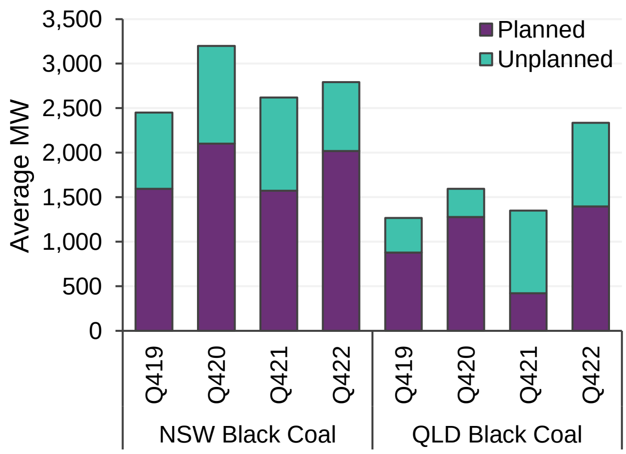
Reduced output coincided with lower availability (699 MW less than Q4 2021) due to increased outages, predominatly in Queensland (Figure 26), and with movement of supply offers to higher priced bands in both New South Wales and Queensland (Figure 11). Compared to Q4 2021, there was a reduction of around 1,800 MW in black coal offer volume priced below $100/MWh.

Decreases in output from Queensland coal-fired generators and their drivers were:

- 567 MW from Kogan Creek Power Station, which began a planned outage on 17 September for a major overhaul. On 12 October, CS Energy announced that the outage would extend by a month to 18 December 2022[18], and it eventually returned to service on 20 December 2022.
- 267 MW from Callide C, as the remaining unit C3 had an unplanned outage beginning 31 October. On 25 November, CS Energy advised the market that the unit was expected to return to service on 11 February 2023[19], which was revised to 8 May 2023 later in December, with announcement of a delayed return to service for the rebuilt Callide C4 unit[20] from April 2023 to May 2023.

Figure 26 Black coal-fired outages increased

Black coal outage classifications – New South Wales and Queensland Q4s



These were offset by an additional 221 MW output from Stanwell Power Station and 160 MW from Tarong, despite the latter having higher outage levels (246 MW) this Q4. Utilisation rates for both stations rose by 5 and 6 percentage points to 81% and 85% respectively this quarter compared to Q4 21.

[18] See https://www.csenergy.com.au/news/kogan-creek-power-station-overhaul-extended.

[19] See https://www.csenergy.com.au/news/updated-return-to-service-date-for-callideunitc3.

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

Most of the black coal-fired generation decrease in New South Wales comprised:

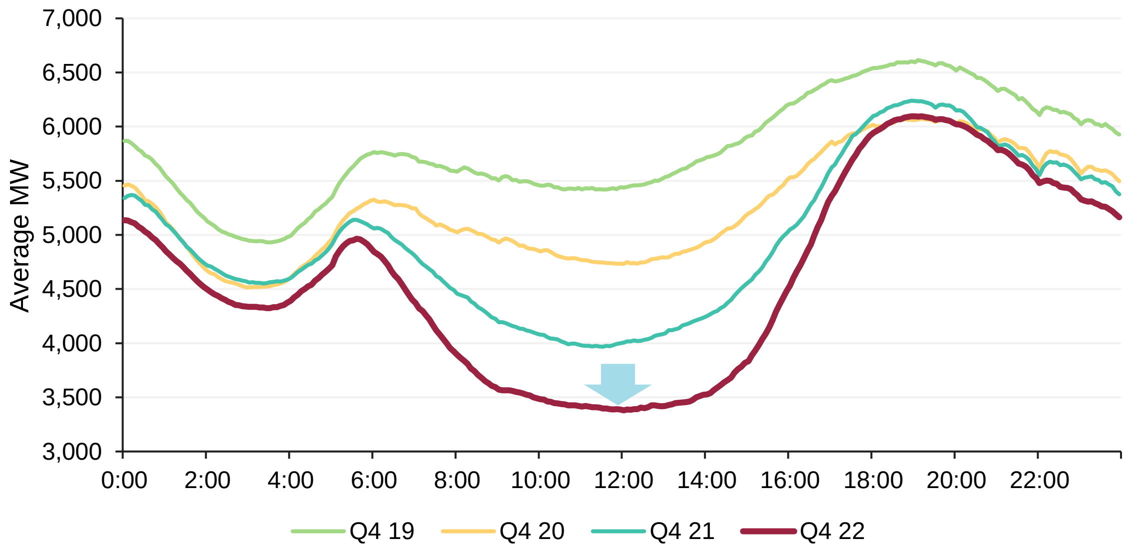
- 248 MW at Liddell Power Station. The permanent closure of Liddell Unit 3 in April 2022 reduced output by 258 MW, with the station's remaining units having a 10 MW increase.
- 236 MW at Bayswater, where outages reduced availability by 113 MW.

Offsetting this was an increase in average generation of 160 MW from Vales Point B, where outages were 169 MW lower than in Q4 2021.

The New South Wales fleet's average output declined by over 600 MW throughout the middle of the day between 0800 and 1700 hours (Figure 27), being displaced by grid-scale and distributed PV (Figure 24 above) and reduced by the retirement of Liddell unit 3. Bayswater, Liddell and Eraring experienced the greatest decrease during these times (280 MW, 238 MW and 162 MW respectively).

Figure 27 New South Wales black coal-fired generation daytime output reduced further in Q4 2022

Average NSW black coal-fired generation output by time of day – Q4s 2019 to 2022

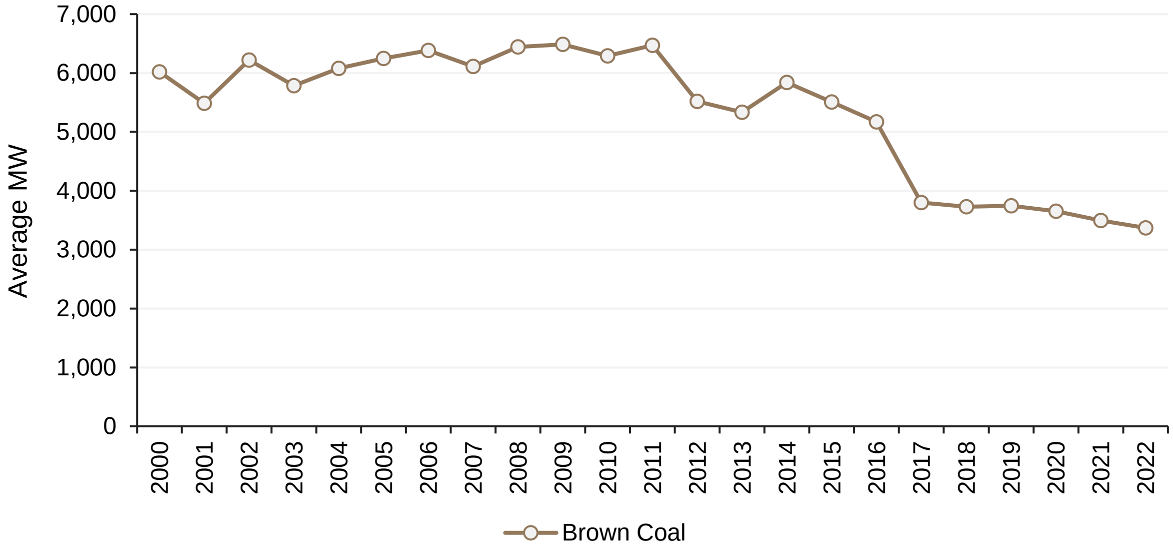


Brown coal-fired fleet

Average brown coal-fired generation decreased by 128 MW compared to Q4 2021, its lowest quarterly output since NEM start, at 3,370 MW (Figure 28). The decline in output was largely driven by increased outages and low utilisation (with Loy Yang B reaching a historical low utilisation rate of 84%). Increased outages at Loy Yang A (+225 MW, mostly unplanned) was the key driver for the decline in output (-179 MW), despite Unit 2 returning from a long-term outage that began in Q2 2022.

Figure 28 Brown coal-fired generation recorded its lowest quarterly output

Average brown coal-fired generation output – Q4s

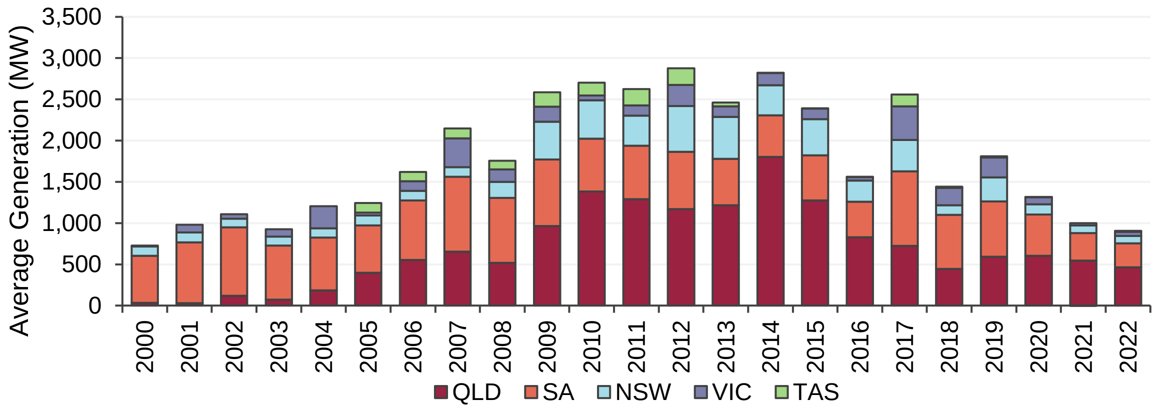


1.3.2 Gas-fired generation

During Q4 2022, NEM gas-fired generation averaged 905 MW, 9% lower than Q4 2021. This was the lowest quarterly output since Q1 2004, and the lowest Q4 since 2000 (Figure 29).

Figure 29 Gas-fired generation records lowest quarterly output since Q1 2004

Average NEM gas-fired generation by region – Q4s



By region, compared to Q4 2021, gas-fired generation:

- Was down 84 MW in **Queensland** – Darling Downs output reduced by 113 MW with lower availability. Offsetting this was a 50 MW increase from Swanbank E, which returned to service on 28 September 2022 after an extended outage.
- Decreased by 40 MW in **South Australia** – Osborne and Pelican Point stations reduced by 37 MW and 36 MW respectively, partially offset by increases at Quarantine (+21 MW) and Barker Inlet (+8 MW). This quarter saw reduced volumes directed by AEMO compared to Q4 2021 (Section 1.6.1).
- Saw minimal net changes in other NEM regions – increasing by 24 MW in **Victoria** and 12 MW in **Tasmania**, while falling by 5 MW in **New South Wales**.

1.3.3 Hydro

Hydro generation decreased marginally this quarter by 10 MW compared to Q4 2021 (Figure 30). As in Q3 2022, the small net change in hydro output arose from substantial increases in mainland NEM regions, particularly Victoria and New South Wales, offset by a matching decrease in Tasmanian hydro output.

Figure 30 Marginal growth in Q4 hydro generation; mainland up, Tasmania down

Average NEM hydro generation by region – Q4s

By region:

- **New South Wales** hydro generation increased by 100 MW, with all hydro units other than Blowering increasing compared to Q4 2021. Snowy hydro units recorded their highest Q4 output since 2016. Storage levels at Lake Eucumbene continued to increase with higher rainfall from La Niña conditions (Figure 31).
- **Victorian** hydro generators increased average output by 74 MW, with Eildon up by 59 MW from Q4 2021. Eildon generated 67 MW on average this quarter, 50% greater than its previous high for any quarter. The Kiewa hydroelectric stations (West Kiewa, McKay and Clover) all recorded increases with a total of 48 MW.
- Contrasting with the mainland NEM regions, **Tasmanian** hydro generation decreased by 172 MW. Despite much of Tasmania having record rainfall across October and November, there was less rainfall in the south-west and catchment areas of Hydro Tasmania's generators, with dam levels finishing the year at 45% of capacity compared to 49% for 2021. This resulted in the volume of offers priced below $100/MWh being reduced by approximately 500 MW compared to Q4 2021 (Figure 32).

Figure 31 Lake Eucumbene reached highest levels in recent years

Lake Eucumbene levels – from 2019[21]

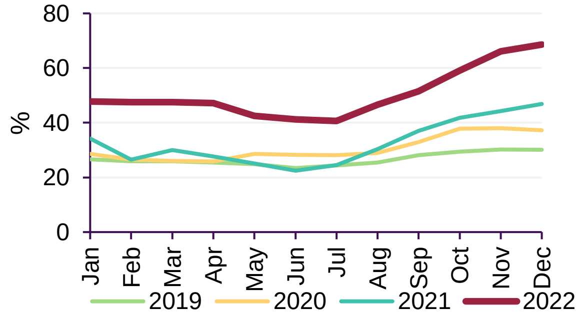
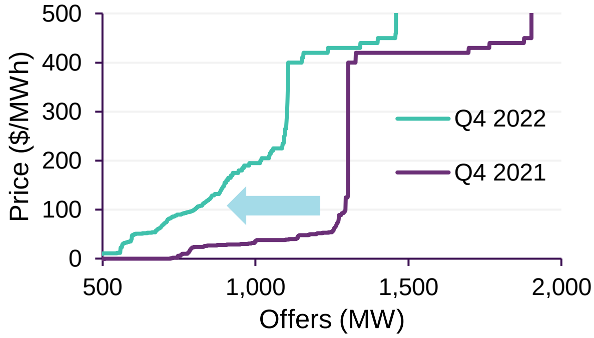


Figure 32 Shift in Tasmanian hydro offers to higher price bands

Tasmanian hydro generation bid supply curve – Q4 22 vs Q4 21



[21] Snowy Hydro Lake Eucumbene storage levels: https://www.snowyhydro.com.au/generation/live-data/lake-levels/.

1.3.4 Wind and grid-scale solar

In Q4, NEM grid-scale VRE generated 20% of total NEM generation across the quarter. This continued VRE's upwards trend upwards, increasing 645 MW from Q4 2021 to a record quarterly average of 4532 MW. Grid-scale solar reached an all-time average output record of 1644 MW led by increases in Queensland and New South Wales (Figure 34), while average wind output of 2888 MW was a record Q4 high (Figure 33).

This increase in VRE output was driven predominantly by the commissioning and connection of new VRE capacity across the NEM (Figure 35). Offsetting the increase were higher curtailment of VRE resources and lower utilisation (economic offloading).

Figure 33 Record quarter for grid-scale solar

Average VRE output – recent quarters

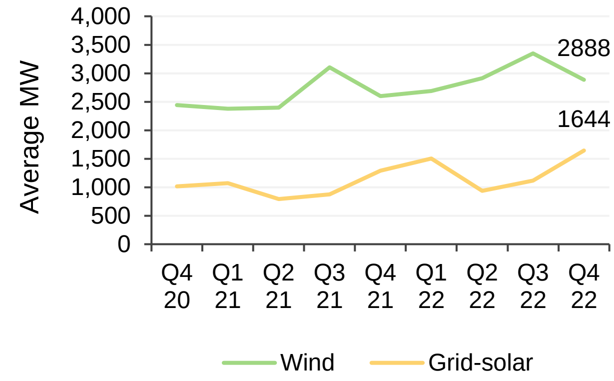


Figure 34 Increased VRE output across mainland NEM

Average change in VRE generation – Q4 2022 versus Q4 2021

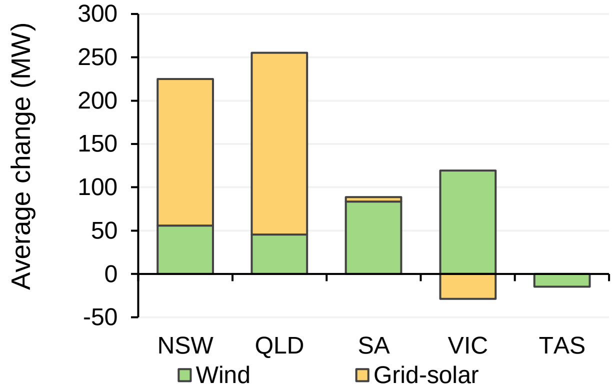
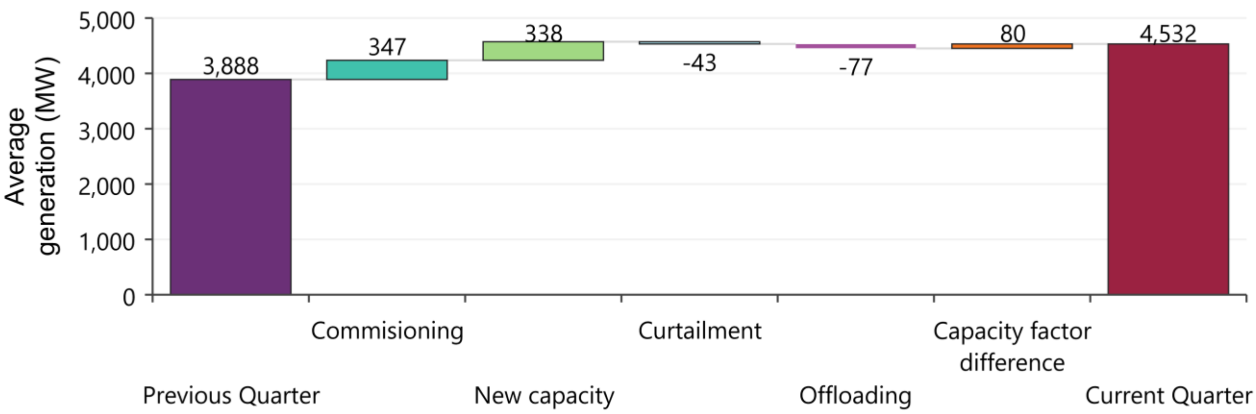


Figure 35 VRE generation rise driven by commissioning of recently installed capacity and new connections

Change in NEM average VRE generation by driver – Q4 2022 versus Q4 2021



New and commissioning capacity

- 208 MW of increased wind generation was from ramping up of wind farms commissioning over the Q4 2021 to Q4 2022 period, including Stockyard Hill Wind Farm (+46 MW) and Moorabool Wind Farm (+61 MW) in Victoria, South Australia's Lincoln Gap Wind Farm 2 (+31 MW), and +58 MW from the Bango and Gullen Range Wind Farms in New South Wales.
- 139 MW of increased grid-scale solar generation arose from ramping up of solar farms commissioning over the same period, mostly from New South Wales solar farms ramping up (+95 MW) and +37 MW from Queensland solar farms, particularly Gangarri Solar Farm.

- 200 MW of the VRE generation increase was from new grid-scale solar commencing production subsequent to Q4 2021. Of this, 159 MW was from recently connected Queensland solar, including Western Downs Green Power Hub, Blue Grass, Woolooga and Coolumboola solar farms. Moura, Port Augusta Renewable Energy Park and West Wyalong solar farms began generating this quarter.
- 138 MW of VRE generation was from new wind farms, with 68 MW from Murra Warra 2 in Victoria and 64 MW from Port Augusta Renewable Energy Park wind in South Australia. Kaban Green Power Hub, Mortlake and Berrylake 2 wind farms all began generating this quarter.

Curtailment and utilisation

VRE curtailment due to system strength and network constraints averaged 208 MW over Q4 2022, representing 4.3% of total VRE availability. With increasing capacity of intermittent renewables, curtailment was 43 MW (26%) higher than the 164 MW average recorded in Q4 2021 (Figure 36).

The majority of curtailment in the quarter arose from constraints due to transmission congestion. Around half this curtailment was 20 MW at Tasmanian wind farms, 20 times higher than the region's 1 MW curtailment in Q4 2021. Network curtailment in Tasmania in Q4 2022 resulted from unprecedented network vulnerability after the line outages in October discussed in Section 1.2.1. Outside Tasmania, mainland NEM wind farm curtailment increased 47 MW from Q4 2021.

The total utilisation rate (generated energy as a percentage of availability) for wind decreased to its lowest recent quarterly level (90%), down four percentage points from Q4 2021, as lower daytime prices in the southern regions also led to increased offloading of wind resources (Figure 37). Conversely, utilisation rates for grid-scale solar farms increased from Q4 2021 levels by five percentage points to 89%. Reduced curtailment (23 MW), predominantly in Victoria, and higher daytime prices leading to reduced economic offloading in the northern regions which host most of the NEM's grid-solar capacity were drivers of this year-on-year utilisation increase.

Figure 36 Increase in curtailment on Q4 2021

Average NEM VRE MW curtailed by constraint type

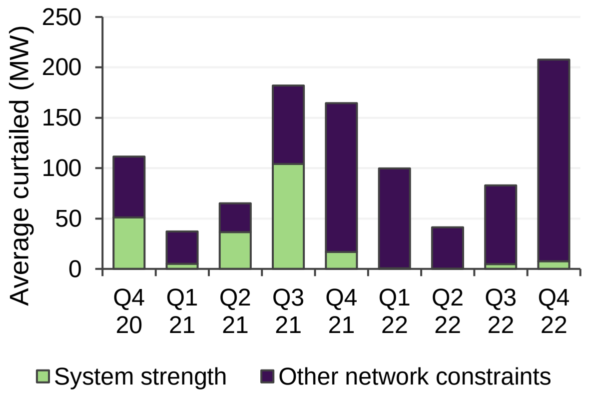
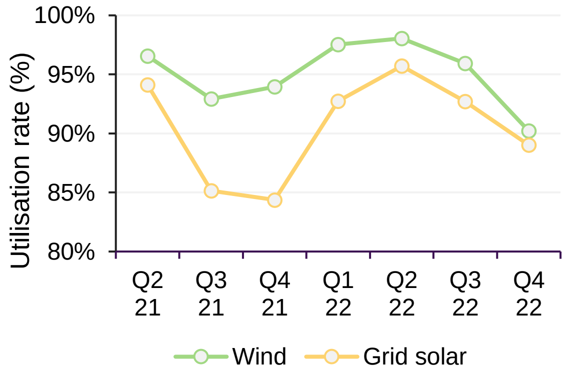


Figure 37 VRE utilisation fell from recent quarters

Quarterly utilisation rates by fuel type



Instantaneous renewable penetration

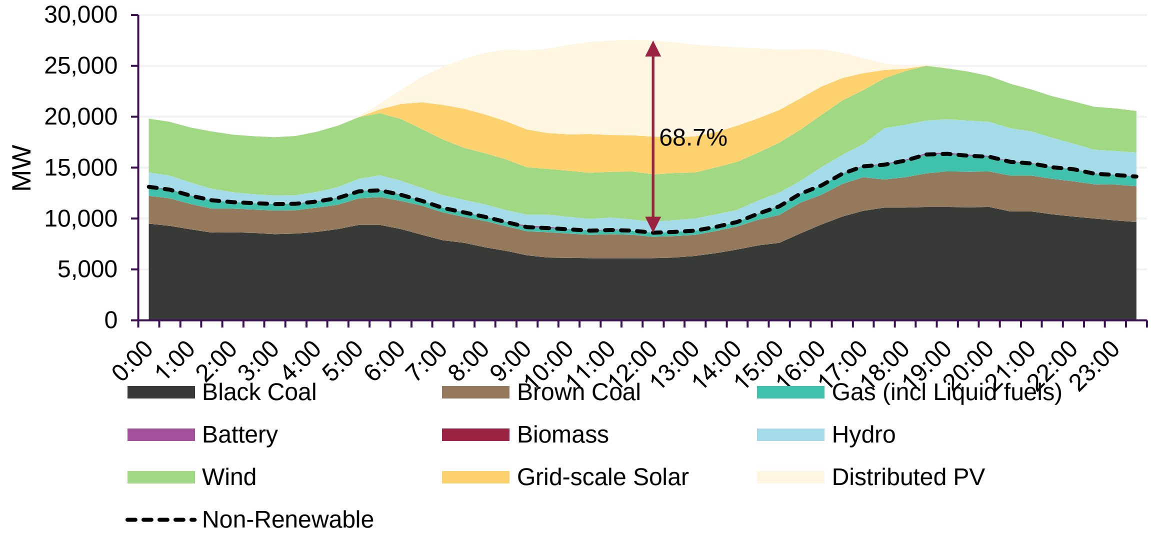
The maximum instantaneous share of renewable energy generation[22] in the NEM reached a new record high in Q4 2022 at 68.7%. The record was reached in the half-hour ending 1230 hrs on 28 October 2022, and was 4.6

[22] Instantaneous renewable penetration is calculated using the NEM renewable generation share of total generation The measure is calculated on a half-hourly basis, because this is the granularity of estimated output data for distributed PV. Renewable generation includes grid-scale

percentage points higher than the previous record of 64.1% set in Q3 2022. Distributed PV accounted for over 34% of supply in this interval, while VRE contributed 30% and hydro 4% (Figure 38).

Figure 38 New maximum instantaneous renewable penetration reached in Q4 2022

NEM supply by fuel type and time of day – 28 October 2022

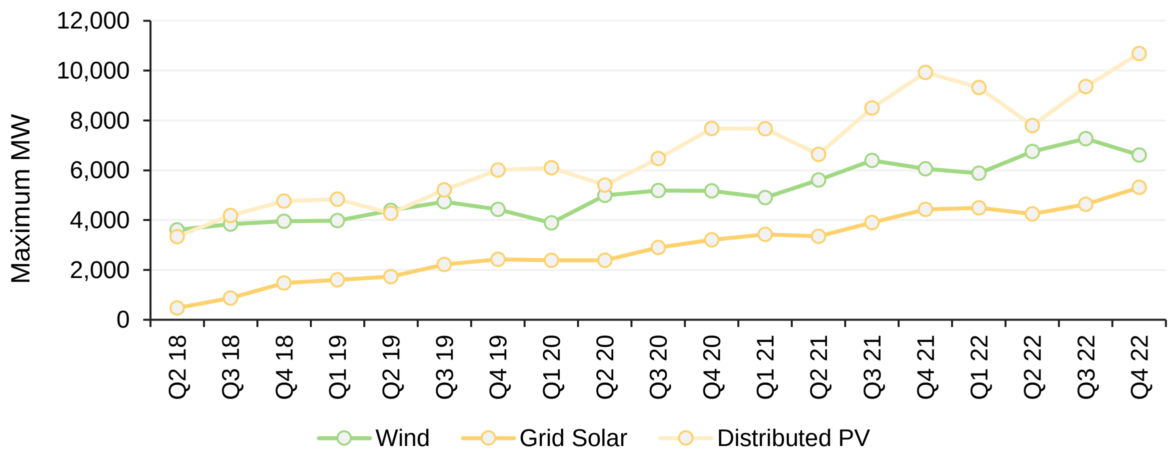


Distributed PV and VRE peak instantaneous outputs

- Distributed PV instantaneous output reached a record high of 10,685 MW on 27 December 2022, 8% higher than the previous record reached in Q4 2021 (Figure 39).
- Grid-solar output also reached a record high of 5,311 MW on 6 December 2022, 15% above the previous record set in Q3 2022.
- Wind reached a Q4 instantaneous high of 6,611 MW on 14 December 2022.

Figure 39 Solar peak output hit new records

Maximum instantaneous output of wind, grid-scale solar and distributed PV



wind and solar, hydro generation, biomass, battery generation and distributed PV, and excludes battery load and hydro pumping. Total generation = NEM generation + estimated distributed PV generation.

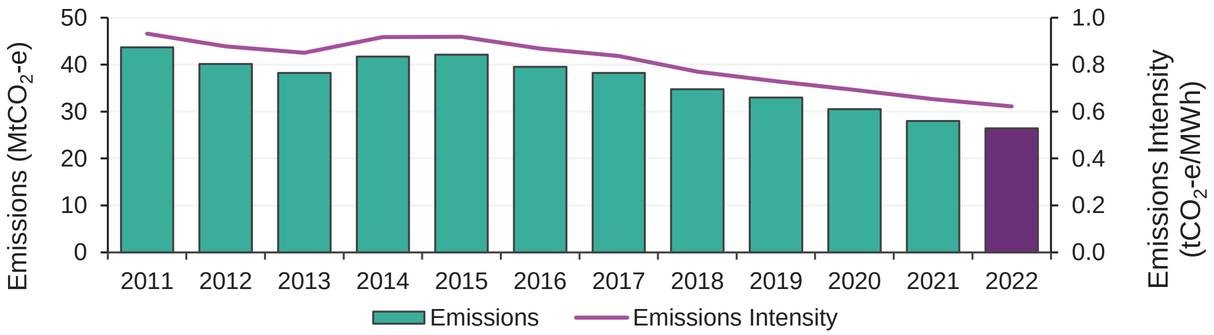
During the SA islanding event when the state was synchronously separated from the rest of the NEM, the instantaneous renewable penetration peaked at 91.5% on 19 November during the 0930 hrs trading interval, with distributed PV contributing 55%, generation from wind 33% and grid-scale solar 4%.

1.3.5 NEM emissions

Q4 2022 NEM emissions were the lowest on record for any quarter at 26.4 million tonnes carbon dioxide equivalent ($MtCO_2$-e). Likewise, emissions intensity, which takes into account total sent out generation[23], dropped to a record low of 0.62 tCO2-e/MWh (Figure 40), driven by falling coal generation and continuing growth in VRE output.

Figure 40 Record low quarterly emissions in Q4 2022

Quarterly NEM emissions and emissions intensity (Q4s)



1.3.6 Storage

Batteries

Total estimated net revenue for NEM batteries in Q4 2022 was $42 million, $28 million higher than Q4 2021. The majority ($34 million) was FCAS revenue, mostly due to South Australia's islanding event between 12 and 19 November when South Australian FCAS prices reached extreme levels before application of administered pricing.

Figure 41 Battery revenue dominated by FCAS markets

Estimated battery revenue sources - quarterly

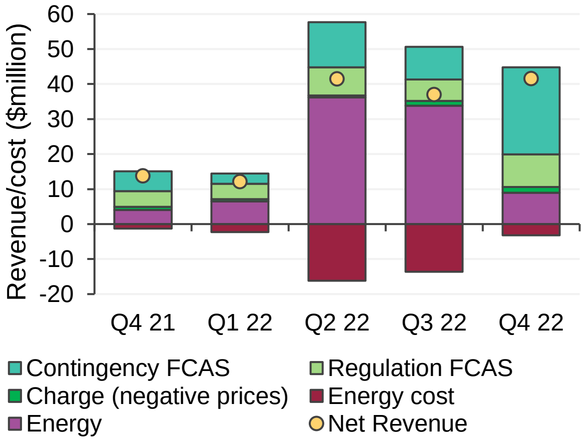
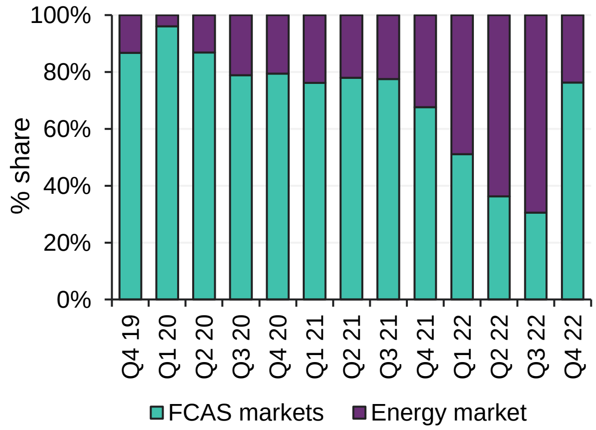


Figure 42 High FCAS revenues reverse trend in battery revenue split by market

Share of revenue by market type – quarterly



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

By region, compared to Q4 2021:

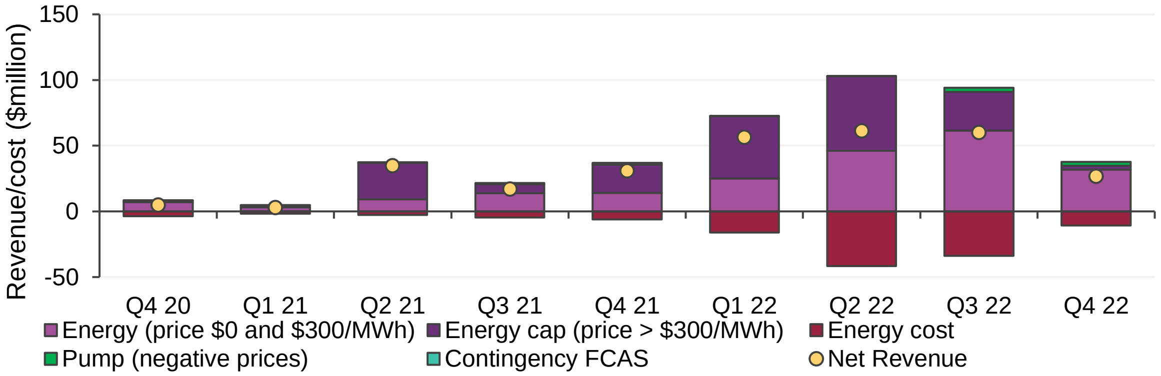
- In **South Australia**, of the net revenue increase of $15.5 million, $16.4 million arose from FCAS markets ($15.2 million from Contingency FCAS), offset by -$0.9 million of net energy costs. Hornsdale Power Reserve had a net revenue increase of $10.6 million driven by the high FCAS prices during the South Australian islanding event, despite a 66 MW reduction in its average FCAS enablement volume, and Dalrymple North battery energy storage system (BESS) $4.0 million, making up the majority of the South Australian increase.
- In Victoria, an increase of $6.0 million was split between energy ($2.4 million) and FCAS markets ($3.5 million). As in Q4 2021, from 1 November the Victorian Big Battery (VBB) entered its system integrity protection scheme (SIPS) contract period, reducing its participation in the energy and FCAS markets[24].
- Queensland's $3.8 million increase was driven by Wandoan BESS fully participating in the energy markets (+$1.9 million) and contingency FCAS markets (+$1.9 million).
- Increased revenue in New South Wales (+$2.5 million) arose from Wallgrove Grid Battery's participation in the FCAS markets (+$2.1 million) and energy markets (+$0.4 million).

Pumped hydro

Estimated pumped hydro spot market revenue in Q4 2022 was $26.8 million, a drop of $4.0 million from Q4 2021 (Figure 43). Wivenhoe spot revenue decreased by $8.7 million, with much lower arbitrage values in Queensland in Q4 2022 compared to Q4 2021, despite greater volume generated. This reflected much lower spot price volatility in Queensland over the quarter, with Wivenhoe revenues from spot prices above $300/MWh falling by $18.6 million from Q4 2021. Shoalhaven's estimated spot revenue increased $4.7 million, driven by both an increase in dispatch and higher arbitrage values.

Figure 43 Pumped hydro revenue declines on lower volatility

Estimated pumped hydro revenue sources – quarterly



1.3.7 Wholesale demand response

There was no significant participation from wholesale demand response (WDR) units in Q4 2022. On 5 October, 2 MW of WDR was dispatched in New South Wales and 1 MW in Queensland on 6 December. No additional units were registered, although a unit in South Australia reduced its maximum capacity by 1 MW, bringing the total capacity across the NEM to 65 MW, all of which are operated by Enel X.

[24] Under the SIPS contract, AEMO reserves up to 250 MW of VBB's 300 MW capacity between 1 November and 31 March of each year until 2032 to support a control scheme to increase capability of the Victoria – New South Wales Interconnector (VNI) and respond to unexpected network outages in Victoria.

1.4 Inter-regional transfers

Total inter-regional energy transfers were 3,083 gigawatt hours (GWh) in Q4 2022, up 5% from 2,925 GWh in Q4 2021. This trend was driven by Queensland – New South Wales Interconnector (QNI) flows, where a 340 GWh increase in energy transfer more than offset slight reductions in transfer across all other regional boundaries. Compared to Q4 2021, flow across all regional boundaries also tended more southward (Figure 44).

Figure 44 Interconnector flow has tended southwards since Q4 2021

Quarterly inter-regional transfers

Key outcomes by regional interconnection included:

- **Queensland to New South Wales** – the conclusion of upgrade-related outages on QNI[25] in June 2022, and a subsequent 100 MW increase in northern capacity to 700 MW on 6 December, facilitated a 67% increase in energy transfer in Q4 2022 compared to Q4 2021. Between 2021 and 2022, average Q4 operational demand in Queensland decreased by 385 MW, compared to a smaller decrease (138 MW) in New South Wales.
  - This contributed to average net flow tending more southward. Relative to Q3 2022, net flows to the south were reduced in Q4, driven by seasonal factors with average New South Wales operational demand 1,450 MW lower in Q4 than Q3.
- **Victoria to Tasmania** – all available capacity on Basslink was priced at $1/MWh throughout Q4. This represents a return to previous market bidding, following an approach in Q3 where capacity was distributed across higher price bands[26]. With these lower bid prices, 286 GWh more energy was transferred across Basslink in Q4 than Q3, despite Basslink being de-rated by 16 MW to 462 MW from 13 October. Comparing Q4 2022 to Q4 2021, Tasmanian hydro generation was lower by an average of 172 MW (Section 1.3.3), and Tasmanian prices were higher by an average of $69/MWh (Section 1.2). This contributed to net Basslink flow trending strongly towards Tasmania.

[25] For more information, see https://www.transgrid.com.au/projects-innovation/queensland-nsw-interconnector.

[26] Refer to Section 1.4 of AEMO's Q3 2022 QED for more information on Basslink bidding in Q3: https://aemo.com.au/energy-systems/major-publications/quarterly-energy-dynamics-qed.

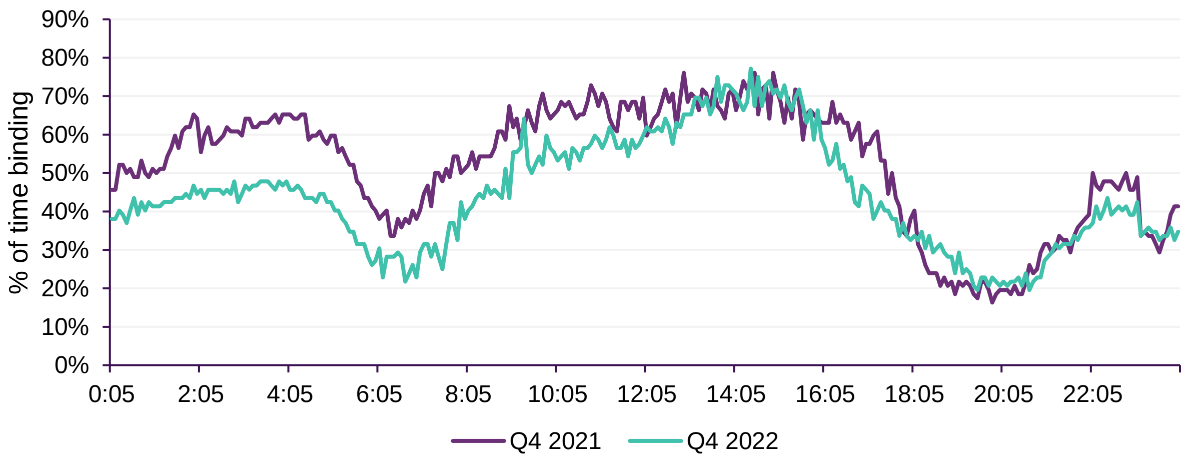
Victoria to New South Wales – despite a relative increase in northern region offer prices compared to southern regions, Q4 interconnector flows on VNI tended more southward in 2022 than 2021. Changes in regional demands and flows on other interconnectors were key drivers for this trend. Specifically, New South Wales operational demand decreased by 138 MW, while Victorian demand increased modestly (by 39 MW). Further, New South Wales was receiving greater interconnector support from Queensland, and at the same time there was a greater need for Victorian generation to support southward flow on Basslink to account for Tasmania's reduction in hydro generation (Section 1.3.3).

Southern to northern NEM flows and price differences

As outlined in Section 1.2, the gap between northern and southern mainland prices grew significantly this quarter. This would often be associated with more frequent binding of VNI while flowing towards New South Wales (exporting). However, Figure 45 shows that VNI was constrained at its export limit less often in Q4 2022 than in Q4 2021 (47% vs 55% of the time). The greater overall price gap reflects that in periods when VNI bound at its export limit, price separation between New South Wales and Victoria was substantially higher in Q4 2022, averaging $107/MWh compared to $60/MWh in Q4 2021. In these constrained periods, average regional spot prices in Q4 2022 were $104/MWh in New South Wales and only -$2/MWh in Victoria, reflecting different price setting dynamics in the north and south, with higher black coal offers often setting northern region prices while southern region prices were set more frequently by VRE or brown coal offers (Section 1.2.3). This more than offset the reduced frequency of export-binding periods.

Figure 45 VNI bound less frequently than last Q4

Proportion of time VNI is binding at its export limit by time of day



1.4.1 Inter-regional settlement residue

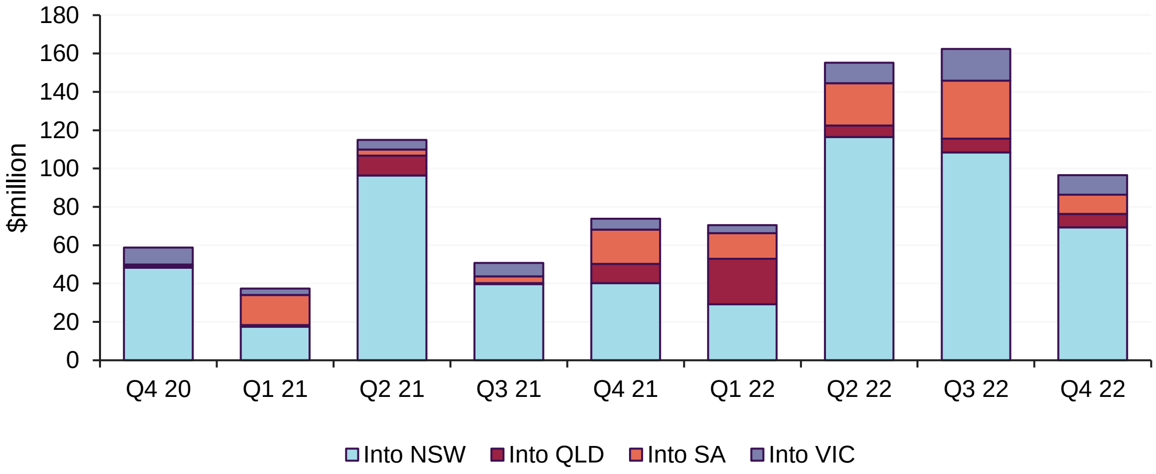
Between Q3 and Q4 2022, there was a 41% reduction in total positive inter-regional settlement residue (IRSR) in the NEM. Record levels of IRSR in Q3 in part reflected episodes of region-specific price volatility. In contrast, Q4 volatility was relatively subdued (Section 1.2), leading to reductions in IRSR.

However, Q4 2022 still saw positive IRSR totalling $97 million – the highest Q4 total since 2009 (Figure 46). The increase over Q4 2021 can be attributed to a $29 million increase in residues accruing into New South Wales, which arose from the greater price separation between New South Wales and Victoria discussed above. This increase saw New South Wales account for 72% of the NEM's total positive IRSR in Q4 2022. Only 17% of New

South Wales' positive residues arose on flows from Queensland. This was a slightly larger proportion than in Q4 2021 (10%) but a markedly smaller proportion than in Q3 2022, when IRSR on flows from Queensland accounted for 45% of the total. This is consistent with lower transfers from Queensland into New South Wales in Q4 than in Q3 2022 (Figure 44).

Figure 46 Highest Q4 positive IRSR since 2009, despite falls since Q3

Quarterly positive IRSR



Negative residue management

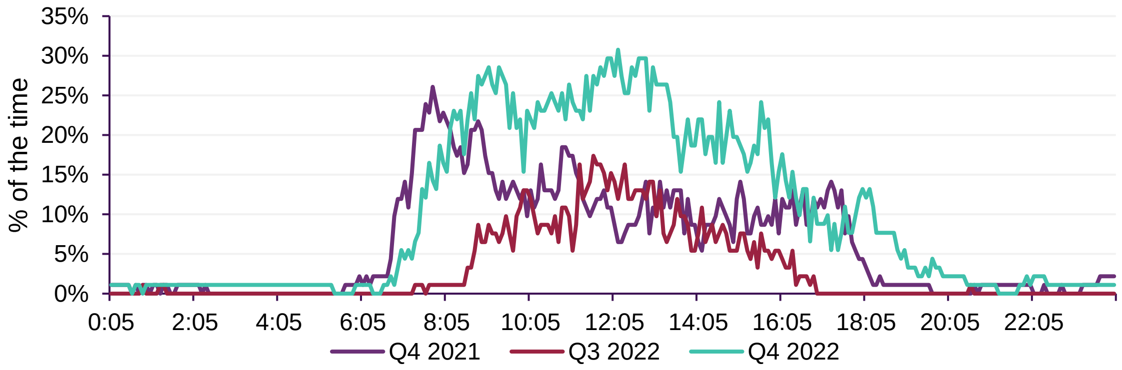
Negative IRSR accrues during periods of 'counter-price flow' between regions, where electricity is transferred from higher price to lower-price regions. Aggregate negative IRSR totalled $10 million in Q4 2022 – similar to Q4 2021 and an increase of $3 million on Q3 2022. Compared to either of these previous quarters, Q4 2022 saw flows into Victoria account for a much larger proportion (76%) of total negative residues (Figure 47). This reflected more frequent incidence of counter-price flows on VNI, particularly during daytime hours (Figure 48).

Figure 47 Negative IRSR dominated by flows into Victoria

Quarterly negative IRSR

Figure 48 High frequency of counter-price flows on VNI in Q4 2022

Frequency of counter-price flows on VNI



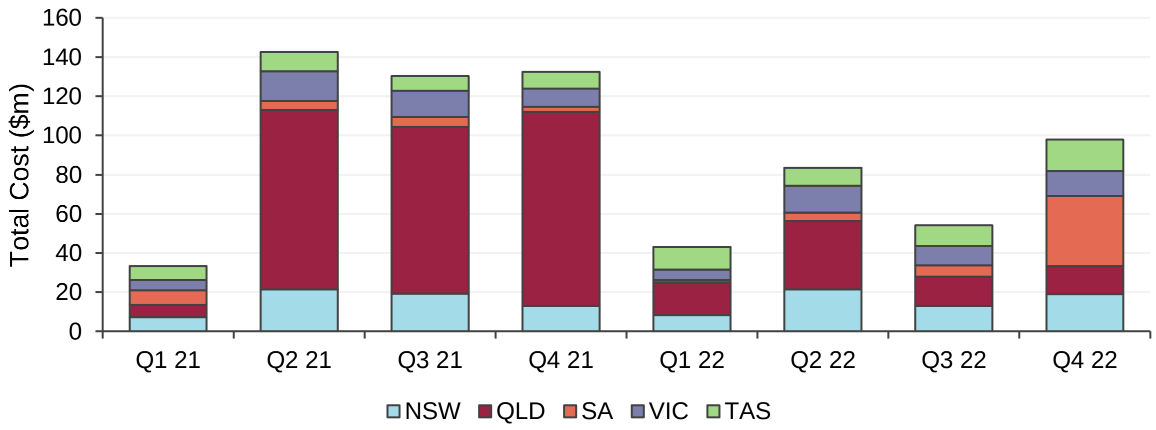
1.5 Frequency control ancillary services (FCAS)

Total FCAS costs for the quarter were $98 million, some $35 million lower than for Q4 2021 but well above Q3 2022's total of $54 million (Figure 49). Drivers for these changes were:

- Much lower costs in Queensland than in Q4 2021 ($14 million versus $99 million) when upgrade-related outages of QNI over the quarter required expensive local provision of FCAS.
- Elevated costs in South Australia this quarter ($36 million versus $3 million a year ago) were due to volatile FCAS prices caused by local provision requirements during the region's synchronous islanding from the rest of the NEM in November, discussed further below.

Figure 49 Increase in FCAS costs driven by SA islanding event

Quarterly FCAS costs by region



As reported in prior QEDs, year-on-year growth in grid-scale batteries' provision of FCAS (Figure 50) has resulted from construction and full commissioning of new batteries, with growth since Q4 2021 led by increased provision from Wandoan (+222 MW), Wallgrove (+105 MW) and VBB (+107 MW). Offsetting these increases was a reduction of 66 MW in aggregate enablement from Hornsdale Power Reserve. Batteries continue to comfortably lead the NEM in overall FCAS market share by volume (Figure 51).

Figure 50 Battery provision of FCAS grows strongly

Change in FCAS supply by technology – Q4 2022 vs Q4 2021

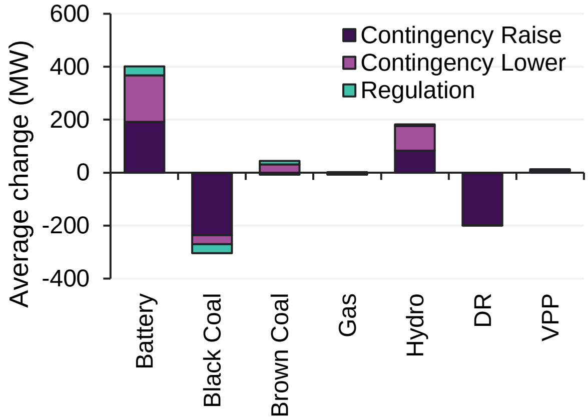
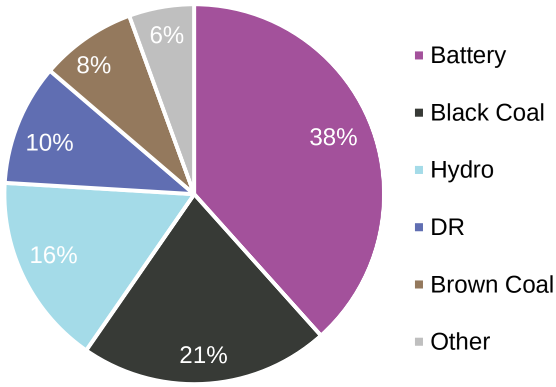


Figure 51 Batteries lead FCAS market shares

FCAS volume market share by technology – Q4 2022



South Australia islanding event

On 12 November 2022, two South East – Tailem Bend 275 kV transmission lines tripped on failure of a tower structure in a storm, causing the synchronous separation of a major part of the South Australian power system from the rest of the NEM. This area of the system remained electrically 'islanded' until one of the lines was returned to service on 19 November[27].

During this event, only sources within the islanded area could be used to meet South Australian FCAS requirements. As a result, all FCAS markets experienced significant price volatility. The highest prices were observed in the Lower Regulation market and, on 14 November 2022 at 1300 hrs, this market breached the cumulative price threshold (CPT) and an administered pricing period (APP) was automatically triggered[28]. This meant that a cap of $300/MWh was applied to all eight FCAS markets. Administered pricing ended on 26 November 2022 (at 0400 hrs), because this was the first trading day which commenced with seven-day cumulative prices (calculated as if the $300/MWh cap had not been applied) below the CPT for all services. Figure 52 shows the cumulative prices in the FCAS markets which triggered the start of the APP (Lower Regulation), and the last market to fall below the CPT (Raise Regulation).

Despite application of the administered price cap, aggregate SA FCAS costs were several times larger in Q4 2022 than in recent quarters (Figure 53), reaching their highest quarterly level since Q1 2020[29]. As described in Section 1.3.6, this contributed to substantial increases in revenues for batteries.

For gas generators, high FCAS prices created incentives to remain online despite low energy prices (Section 1.2.2). However, once these prices were capped this incentive was weakened, and as described in the preliminary event report, AEMO was required to direct some gas-fired units online to provide sufficient FCAS for maintenance of system security.

[27] For more detail, see AEMO's preliminary event report at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2022/preliminary-report--trip-of-south-east-tailem-bend.pdf?la=en.

[28] Refer to AEMO's 'Guide to Administered Pricing' for further detail: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/guide-to-administered-pricing.pdf?la=en.

[29] In Q1 2020, the South Australian system and a small section of western Victoria was separated from the rest of the NEM for 18 days, also leading to very high FCAS costs ($113 million across all SA FCAS markets).

Figure 52 High cumulative prices triggered administered pricing for South Australian FCAS

Seven-day cumulative South Australian FCAS Regulation prices after separation event

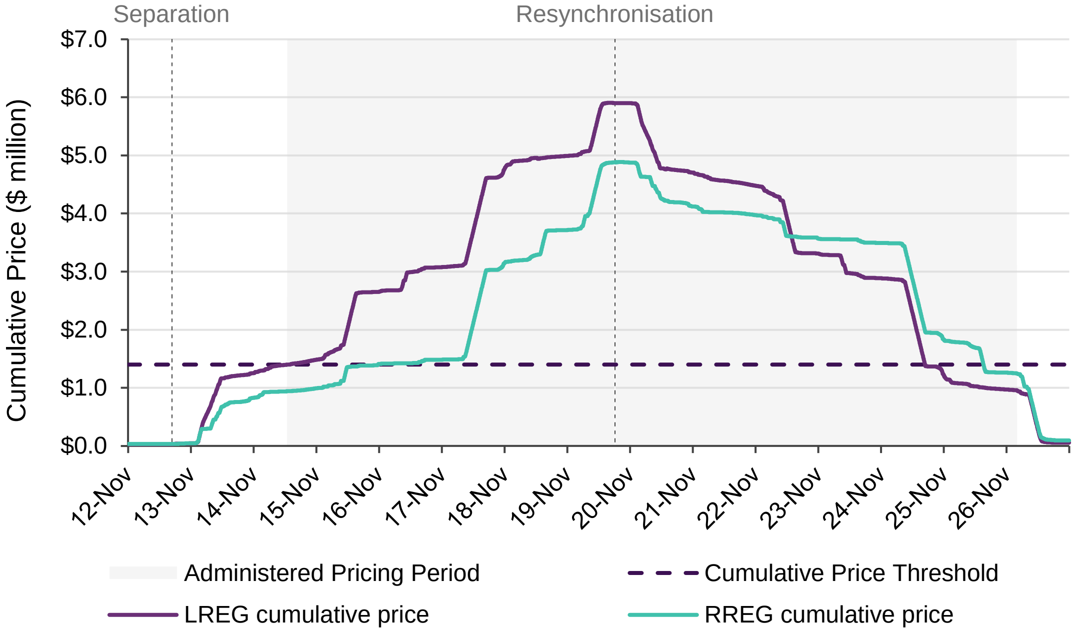
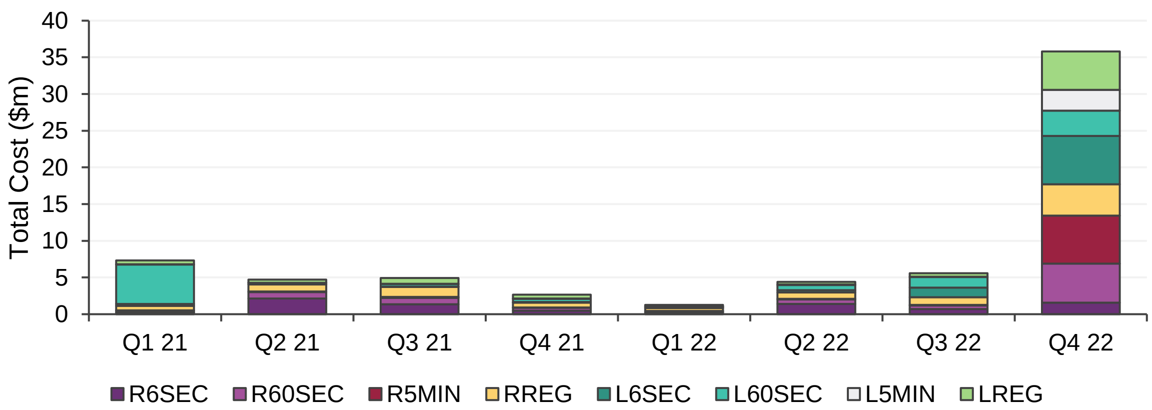


Figure 53 Large increase in SA FCAS costs driven by separation and price volatility

Quarterly FCAS costs – South Australia

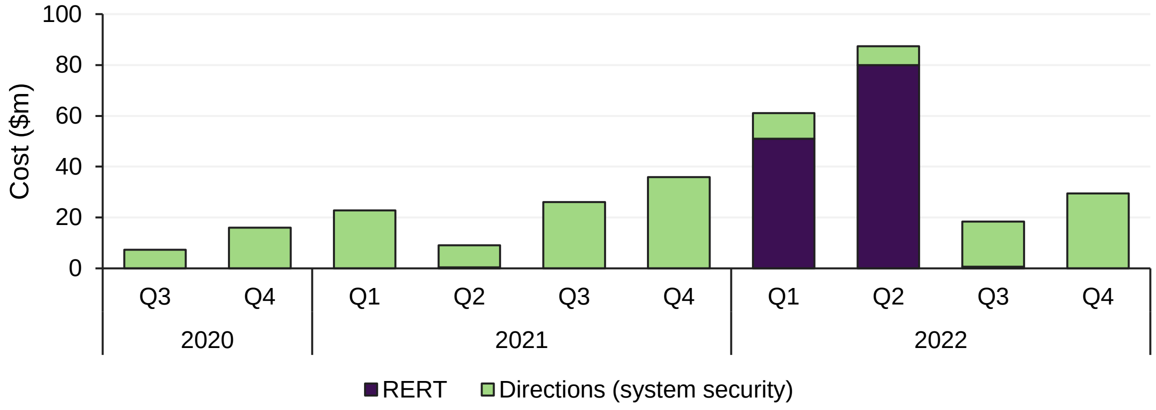


1.6 Power system management

Power system management costs for Q4 2022 reported here were all attributable to system security directions in South Australia. While higher than in Q3, these costs remained well below the levels in Q1 and Q2 2022, which were elevated by Reliability and Emergency Reserve Trader (RERT) activation expenses, and also below those of Q4 2021 (Figure 54).

Figure 54 System costs up on Q3 2022 but lower than preceding three quarters

Estimated quarterly system costs by category



Costs not tabulated in this QED include compensation payable to market participants arising from reliability directions and operation under administered pricing or market suspension in June 2022. Finalisation of these compensation amounts is continuing, with progressive updates available via AEMO's June 2022 market event web page[30], including the most recent update[31] published on 6 January 2023.

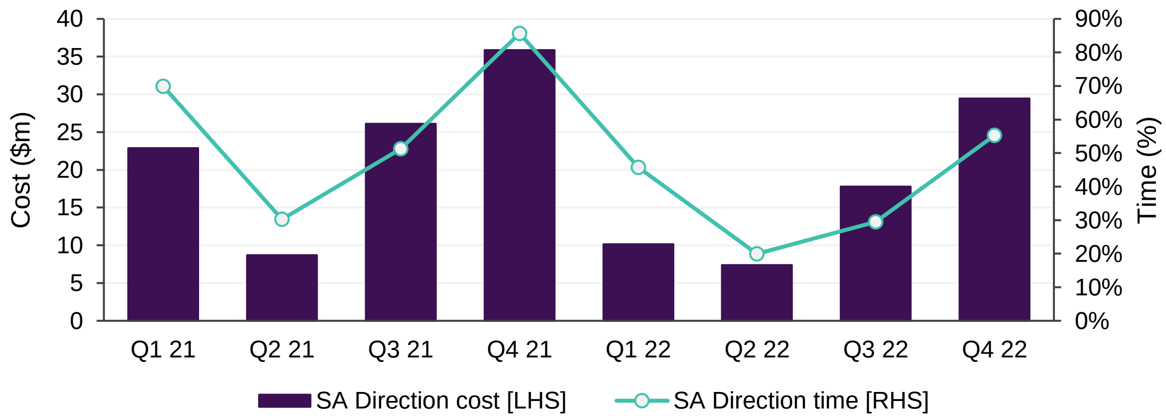
Also yet to be finalised are estimated compensation costs for directions to certain participants in South Australia to provide FCAS capability during the South Australian islanding event in November. These directions were required following application of administered price caps to the FCAS markets (Section 1.5).

1.6.1 South Australian system security directions

Lower spot prices in South Australia and higher levels of VRE generation meant that AEMO issued directions for one or more South Australian synchronous generating units to remain online to maintain system security more frequently in Q4 2022 than in preceeding quarters (Figure 55).

Figure 55 South Australian direction costs increased on Q3 2022 but remained lower than Q4 2021

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



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

[30] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports.

[31] See https://aemo.com.au/-/media/files/electricity/nem/data/mms/2022/june-2022-nem-events-compensation-jan-6.pdf?la=en.

The proportion of time in the quarter covered by these directions was however significantly lower at 55% than Q4 2021's 86%, while the estimated cost of directions was $6 million lower than a year ago. This reduction in costs occurred despite the compensation price paid to directed generators increasing from an average of $96/MWh in Q4 2021 to $349/MWh in Q4 2022, driven by the sustained high level of spot prices over Q2 and Q3 2022[32].

As reported in previous QEDs, full operation of South Australia's synchronous condensers since mid-Q4 2021 has reduced the average volume of directed generation in both absolute and relative terms (Figure 56), and the number of units required to be directed online (Figure 57). Recent quarterly trends in these metrics reflect the same general pattern as the frequency and cost of directions discussed above.

Figure 56 Syncons reduced Q4 directions

South Australian gas-fired generation directed – volume and share

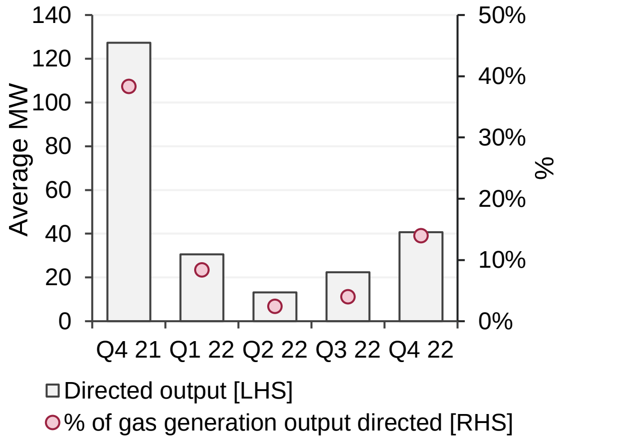
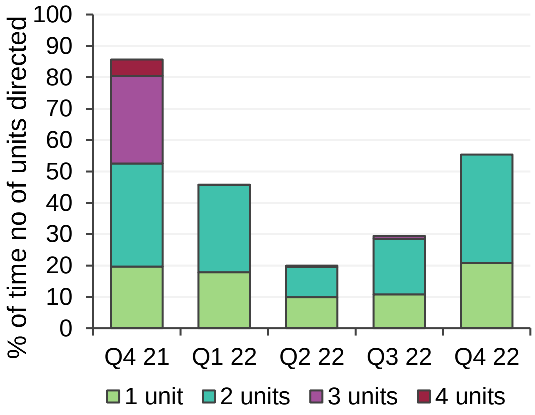


Figure 57 Number of units directed declines

% of time number of gas-fired generation units directed



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

2 Gas market dynamics

2.1 Wholesale gas prices

After the record prices observed in June and July 2022, prices in October and November remained comparable to levels seen in August and September, before easing further in December, particularly in the second half of the month. The quarterly average price across all AEMO markets was $17.79/GJ, compared to $10.60/GJ in Q4 2021. This is the highest Q4 price on record.

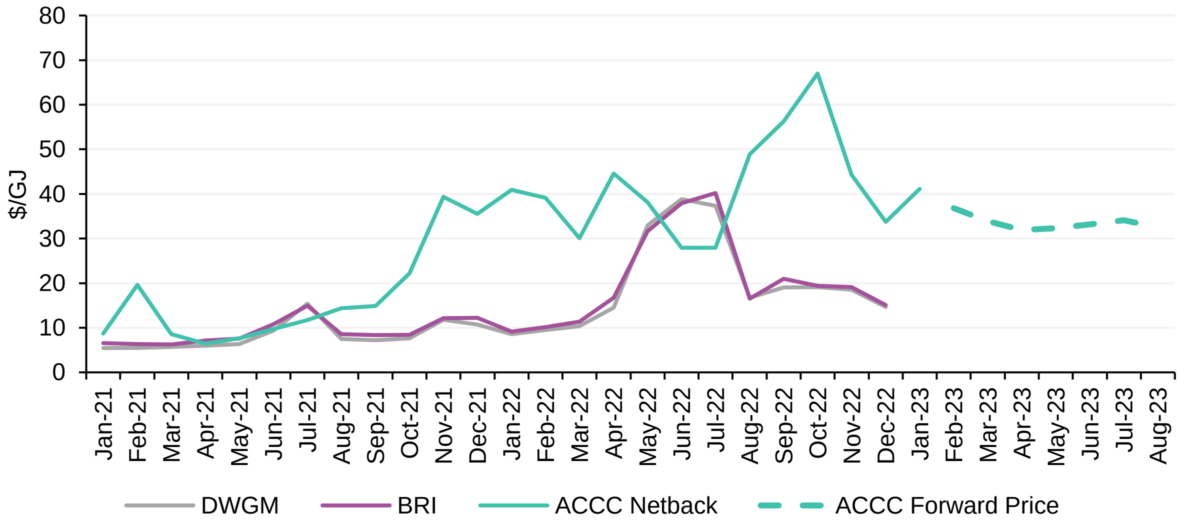
Table 3 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q4 2022	Q3 2022	Q4 2021	Change from Q4 2021
DWGM	17.42	24.41	10.02	74%
Adelaide	18.59	27.29	10.67	74%
Brisbane	17.85	25.95	10.91	64%
Sydney	17.71	27.06	10.52	68%
GSH	17.32	25.30	10.86	59%

International prices peaked in October, as represented by the Australian Competition and Consumer Commission (ACCC) netback price, before easing in November and December, but corresponding forward prices remain elevated (Figure 58). Drivers for elevated international prices are discussed in section 2.1.2.

Figure 58 Domestic prices remained steady before slightly easing in December

ACCC netback and forward prices[33], DWGM and STTM Brisbane average gas prices by month



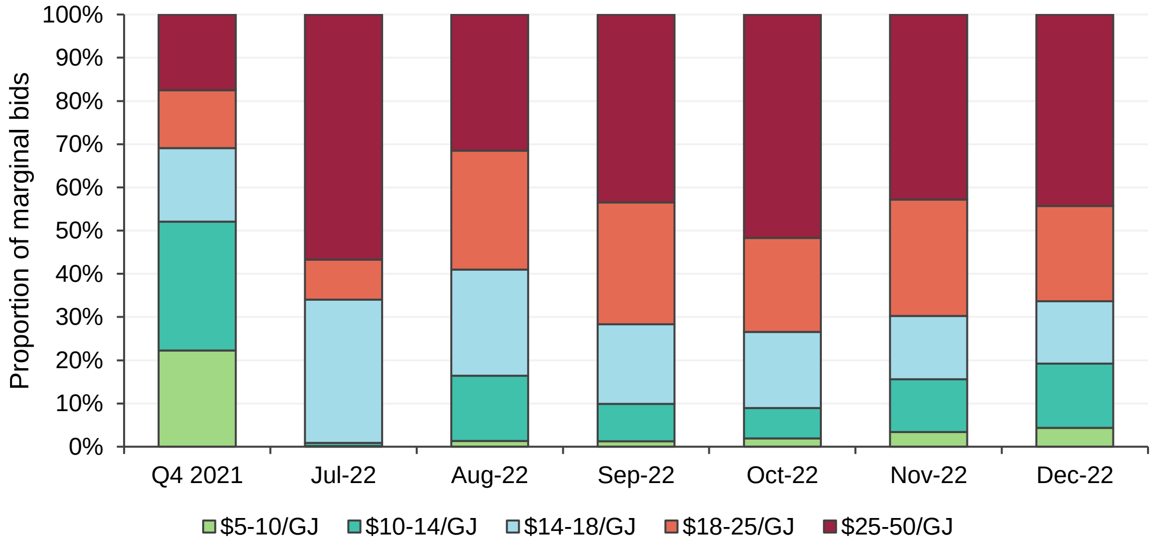
The large gap that emerged between domestic and international prices in August increased further in October. Contributing factors were reduced heating demand and lower gas-fired generation compared to June and July, as well as the reduction in gas supply to Queensland from southern markets, coinciding with two train outages at

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

QCLNG. This prompted market participants to increase bid volumes offered at prices below $14/GJ, particularly in December (Figure 59).

Figure 59 DWGM bids reflecting lower prices after record July prices

DWGM – proportion of marginal bids[34] by price band



2.1.1 East Coast Gas domestic price cap

On 9 December 2022, the Federal Government published a consultation paper, ‘Options to ensure the domestic wholesale gas market delivers for Australians’[35]. This paper proposed a temporary, emergency price cap, and a mandatory code of conduct. The mandatory code of conduct aims to provide a ‘reasonable pricing framework’, which will set out the guidelines for producers and buyers to negotiate wholesale domestic gas contracts at ‘reasonable prices’. The price cap and code of conduct apply to the east coast of Australia, including the Northern Territory, while Western Australia is excluded. The legislation for the price cap and mandatory code of conduct was assented into law on 16 December 2022[36], and the emergency price cap became effective from 23 December 2022 for 12 months[37], with the reasonable pricing framework to commence thereafter. Consultation for the details of the reasonable pricing framework is open until 7 February 2023.

In summary, while the price cap is set at $12/GJ, the cap does not apply to the Declared Wholesale Gas Market (DWGM) or Short Term Trading Markets (STTM). The Gas Supply Hub (GSH) is also excluded for offers made up to three days in advance of the delivery date, but the cap applies to all offers beyond that.

Full details of the price cap and code of conduct can be found at the links in the footnotes.

2.1.2 International energy prices

Thermal export coal prices averaged $578/tonne across the quarter, reducing $34/tonne from Q3 2022 (Figure 60). Although still at historical high levels, prices weakened significantly in November, but recovered in December. Northern hemisphere demand for thermal coal softened due to rising European coal inventories and

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

[35] At https://treasury.gov.au/consultation/c2022-343998.

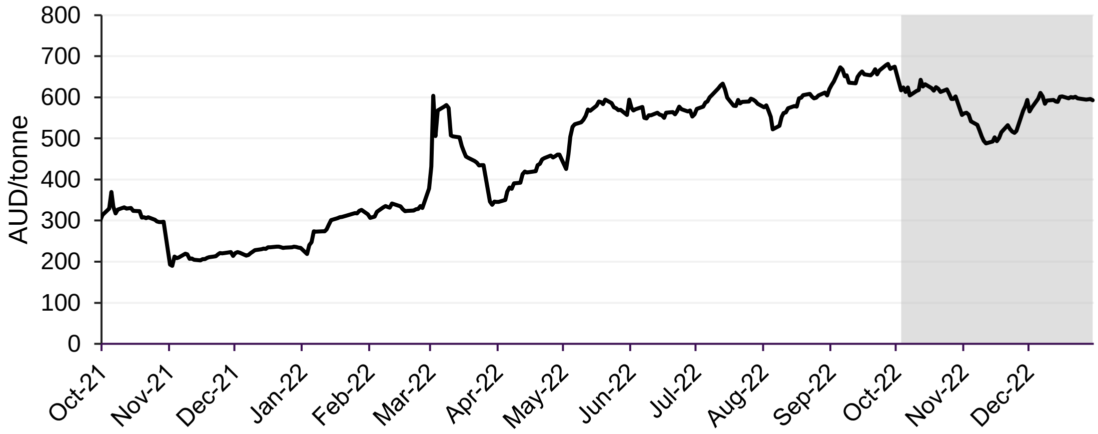
[36] See https://www.legislation.gov.au/Details/C2022B00150.

[37] See https://www.legislation.gov.au/Details/F2022L01743.

gas storage levels – European gas storage is more than double the level of nine months ago[38]. Domestically, supply disruptions have persisted after issues caused by weather conditions throughout 2022 in New South Wales and Queensland.

Figure 60 Traded thermal coal prices remained at elevated levels

Newcastle export thermal coal AUD/tonne daily



Source: Bloomberg ICE data

Asian LNG prices have fallen significantly this quarter to an average of $45/GJ, down from an average of $65/GJ in Q3 2022 and from the peak price of $99/GJ in late August (Figure 61). Brent Crude oil prices have also fallen to an average of A$135/barrel from Q3's A$143/barrel, despite the world's biggest crude importer, China, announcing its lifting of COVID restrictions[39] (Figure 62).

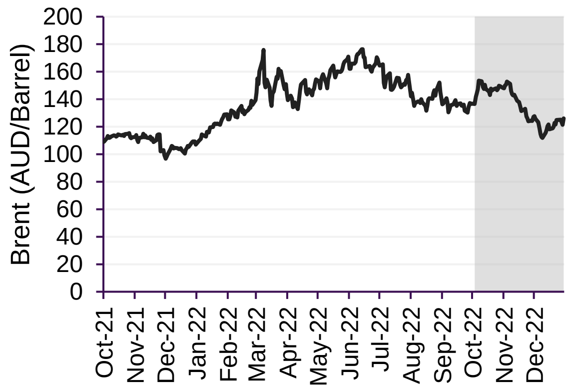
Figure 61 Asian LNG prices soften

Asian LNG price in A$/GJ daily

Source: Bloomberg ICE data

Figure 62 Brent Crude oil prices see decline

Brent Crude oil in A$/Barrel daily



Source: Bloomberg ICE data

[38] Department of Industry, Science and Resources, Commonwealth of Australia Resources and Energy Quarterly December 2022: https://www.industry.gov.au/publications/resources-and-energy-quarterly-december-2022.

[39] Reuters, Oil gives up the year's gains, closing at 2022 low; https://www.reuters.com/markets/commodities/oil-opens-mixed-economic-fears-pressure-prices-2022-12-07/.

2.2 Gas demand

Total east coast gas demand decreased by 7% compared to Q4 2021 (Figure 63, Table 4). While there was a small increase in AEMO markets demand (+1 PJ), there was a decrease in gas demand for gas-fired generation (-2 PJ), and a large decrease in gas usage for Queensland LNG production (-29 PJ).

Figure 63 Large Queensland LNG export decrease drove lower east coast gas demand

Change in east coast gas demand – Q4 2022 vs Q4 2021

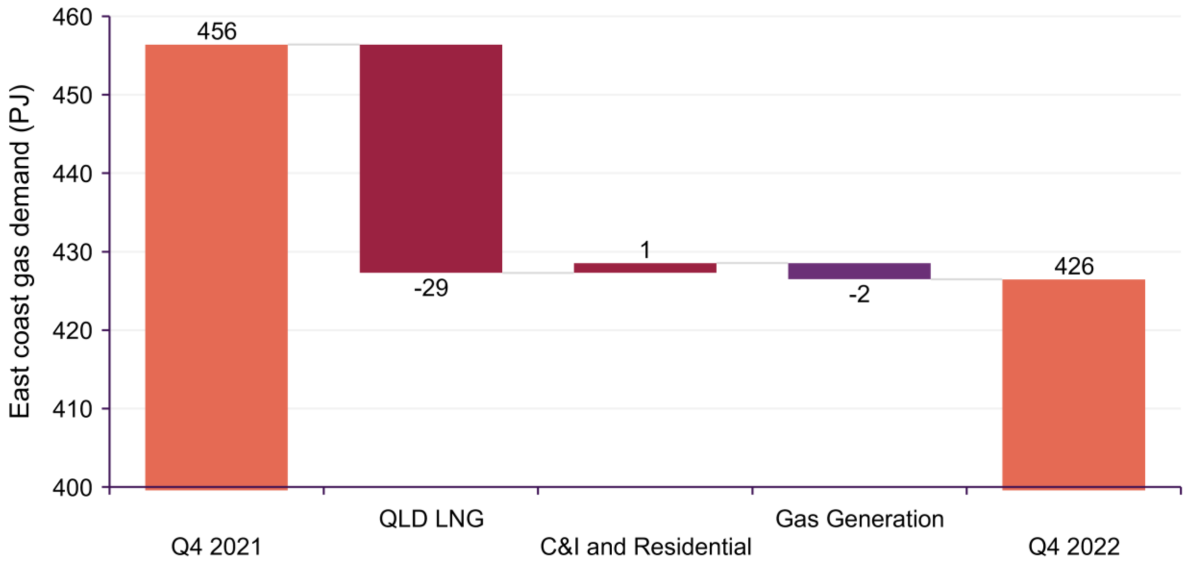


Table 4 Gas demand – quarterly comparison

Demand (PJ)	Q4 2022	Q3 2022	Q4 2021	Change from Q3 2021
AEMO markets *	68.1	110.3	67.5	+1 (+1%)
Gas-fired generation **	17.8	35.4	19.9	-2 (-11%)
QLD LNG	339.9	325.0	369.0	-29 (-8%)
TOTAL	425.8	470.7	456.4	-31 (-7%)

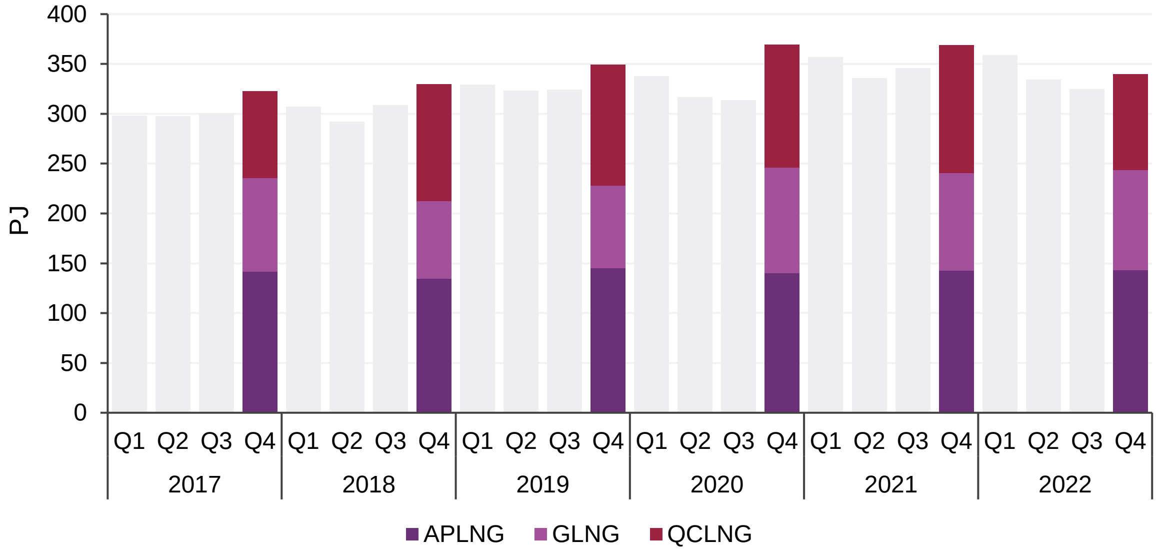
* AEMO markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand fell to its lowest Q4 level since 2018, caused by a significant decrease from QCLNG, which experienced multiple train outages during the quarter. It is the first time since Q4 2017 that QCLNG exported under 100 PJ in a quarter, and was the first time since the same quarter that Gladstone Liquefied Natural Gas (GLNG) exported more than QCLNG.

By participant, QCLNG demand decreased by 32.5 PJ, Australia Pacific LNG (APLNG) remained steady, while GLNG increased by 3.4 PJ (Figure 64). 88 cargoes were exported during the quarter, down from 93 cargoes in Q4 2021.

Figure 64 QCLNG flows to Curtis Island lowest for Q4 since 2018, driving reduced exports

Total quarterly pipeline flows to Curtis Island



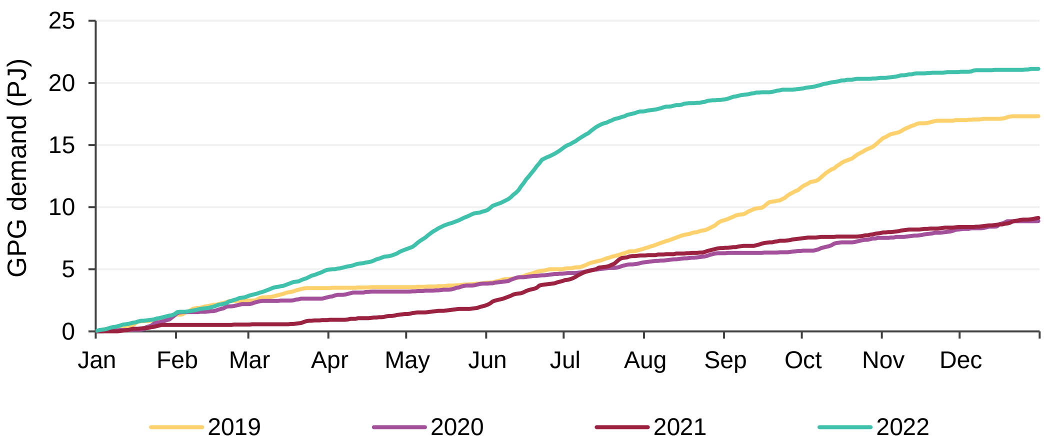
2.2.1 Gas-fired generation

Overall demand from gas-fired generators decreased during the quarter. Queensland demand decreased by 2.4 PJ, South Australia by 0.5 PJ, and New South Wales by 0.1 PJ. Victorian demand increased by 0.6 PJ compared to Q4 2021, and Tasmania also increased, by 0.2 PJ.

Cumulative gas-fired generation demand for 2022 ended higher than in recent years for New South Wales and Queensland. New South Wales gas-fired generation demand for the 2022 calendar year was 21.1 PJ compared to 9.1 PJ in 2021 (Figure 65), while Queensland's 2022 total was 40.6 PJ compared to 33.8 PJ in 2021. Events over Q2 2022, particularly the high level of coal-fired generation outages and early winter demands, were the major drivers of this increased annual gas generation demand.

Figure 65 New South Wales gas generation demand softened but still ended 2022 higher than recent years

Cumulative annual demand for gas-fired generation in New South Wales



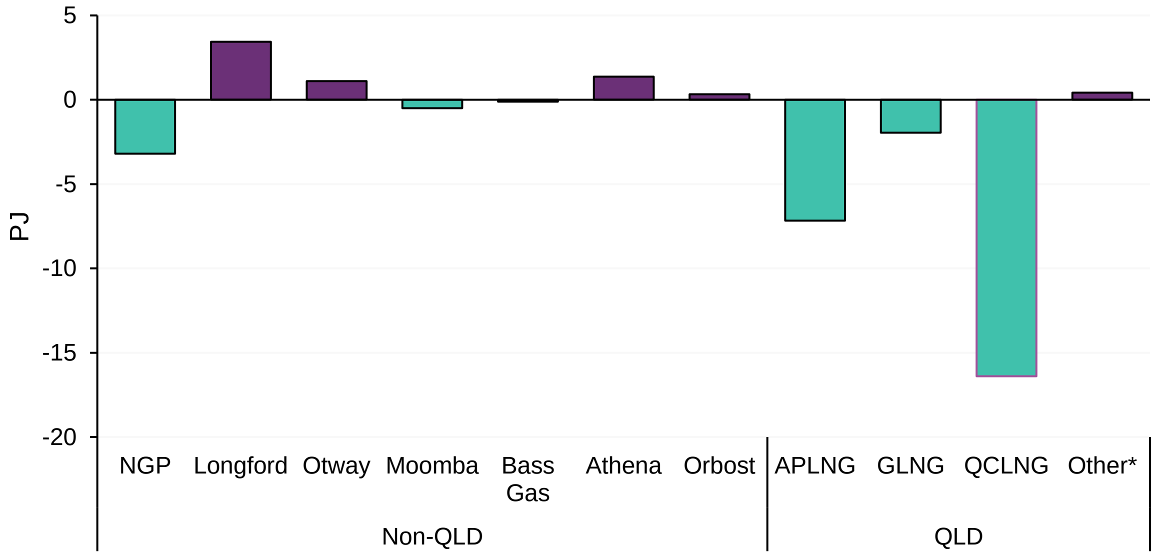
2.3 Gas supply

2.3.1 Gas production

East coast gas production decreased by 22.7 PJ compared to Q4 2021 (-4%, Figure 66).

Figure 66 Queensland production continued to fall

Change in east coast gas supply – Q4 2022 vs Q4 2021



Key changes included:

- Decreased Queensland production (-25.1 PJ), with QCLNG decreasing by 16.4 PJ, APLNG by 7.2 PJ, and GLNG by 2.0 PJ. While this represented a significant production decrease, gas supplied for Queensland LNG exports decreased by 29.1 PJ, meaning that an additional 4.0 PJ of supply associated with Queensland LNG projects went into the domestic market compared to Q4 2021 (Figure 67).
- Higher Victorian production (+6.1 PJ), mainly driven by higher production at Longford (+3.4 PJ), Athena (+1.4 PJ) and Otway (+1.1 PJ). Longford's production reached its highest Q4 level since 2017 (Figure 68).
- Decreased Moomba production (-0.5 PJ), continuing the trend of lower Moomba production year on year.
- Decreased supply from the Northern Territory (-3.2 PJ) via the Northern Gas Pipeline (NGP). Production issues experienced at the Yelcherr gas plant in May led to zero flows which began on 7 September, and continued until 12 December when small flows through the NGP resumed. NGP flows averaged 25 TJ/d for the remainder of December, compared to 40 TJ/d across all of Q4 2021.

Figure 67 Queensland domestic supply increased to highest Q4 level since 2019

Queensland domestic supply compared to Victorian gas exports by quarter

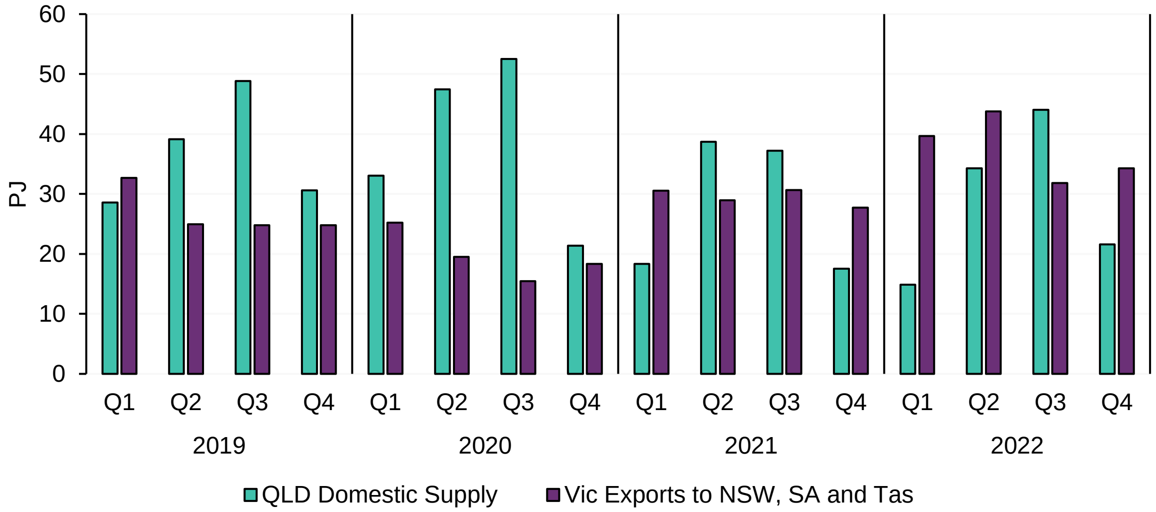
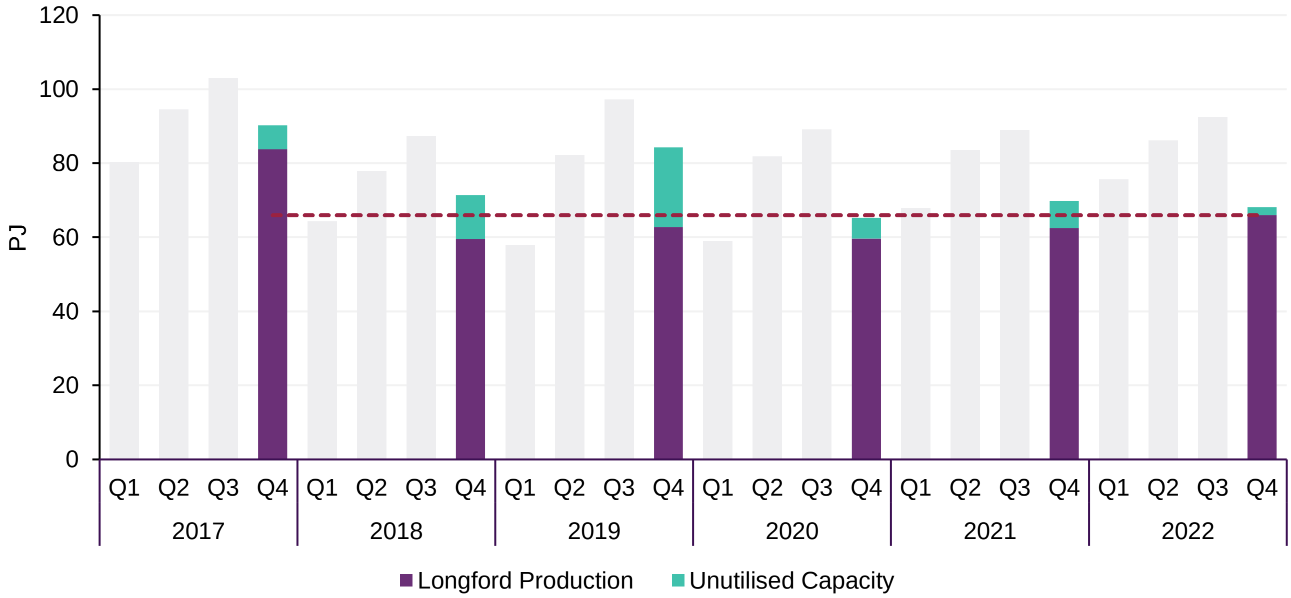


Figure 68 Highest Longford Q4 production since 2017

Longford production and unutilised capacity by quarter



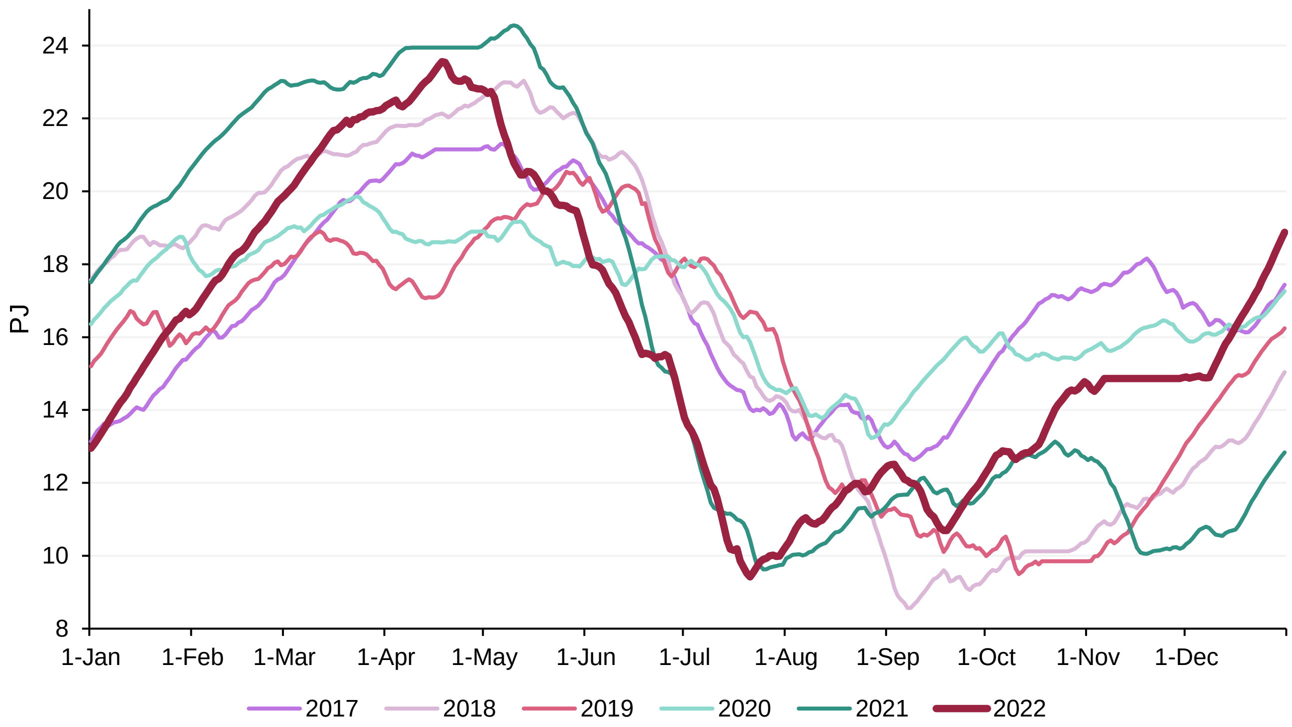
2.3.2 Gas storage

The Iona UGS facility finished the quarter with an inventory of 18.9 PJ, 6.0 PJ higher than at the end of Q4 2021 (Figure 69) and the highest end to a calendar year since reporting began in 2017. This occurred despite a planned outage at Iona from 6 November to 30 November.

Factors contributing to the sharp increase in storage inventory included lower demand, including lower gas-fired generation, and a reduction in supply to Queensland from southern markets, particularly in December, coinciding with QCLNG's reduced LNG exports due to a train outage. Increases in supply from Longford, Athena and Otway gas plants were also contributing factors.

Figure 69 Iona ended 2022 at its highest level since storage levels began reporting

Iona storage levels

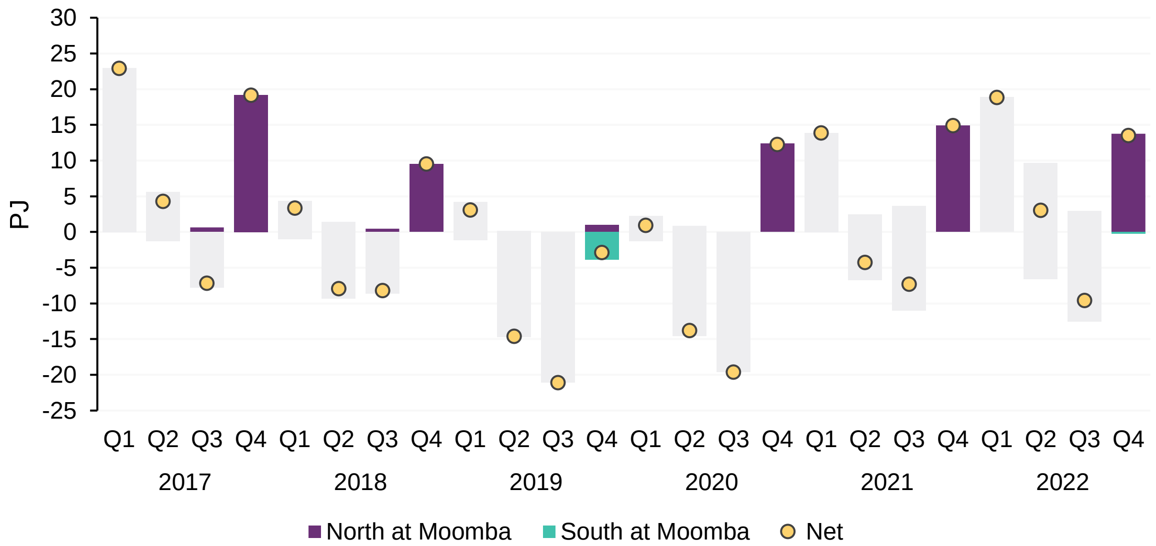


2.4 Pipeline flows

Compared to Q4 2021, there was a 1.4 PJ decrease in net transfers into Queensland on South West Queensland Pipeline (SWQP, Figure 70). Decreased flows coincided with a decrease in Queensland LNG export demand and an increase in net domestic supply associated with the QLD LNG projects.

Figure 70 Net northwards flows into SWQP decrease in Q4 2022

Flows on the South West Queensland Pipeline at Moomba



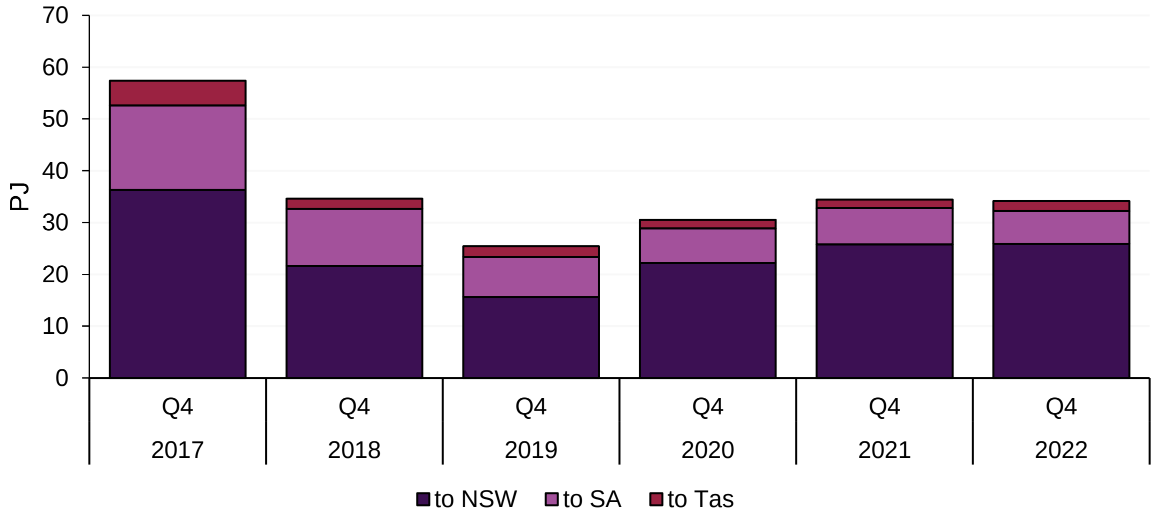
Victorian net gas transfers to other states decreased by 0.3 PJ from Q4 2021 levels, solely due to a decrease in flows to South Australia as a result of reduced gas-fired generation demand (Figure 71).

There was a small overall increase in flows from Victoria to New South Wales, comprising 20.5 PJ via the Eastern Gas Pipeline (EGP), up from 19.5 PJ in Q4 2021, but this was offset by a decrease in exports via Culcairn, at 5.5 PJ compared to 6.4 PJ in Q4 2021.

Flows from Victoria to Tasmania also increased by 0.2 PJ ,while there was a 0.7 PJ decrease in the flow to South Australia.

Figure 71 Victorian Q4 transfers decreased slightly due to reduction in flows to South Australia

Victorian net gas transfers to other regions – Q4s

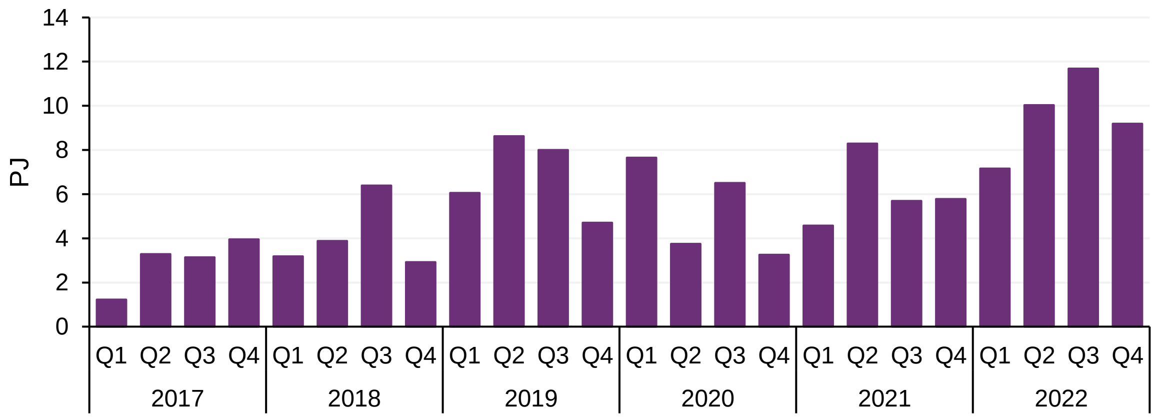


2.5 Gas Supply Hub (GSH)

In Q4 2022 there were increased trading volumes on the GSH compared to Q4 2021 (Figure 72), with traded volume up 3.4 PJ. Overall, 2022 was the highest volume year for the GSH on record, totalling 38.1 PJ, surpassing the 2021 volume of 24.4 PJ, and the previous record of 27.4 PJ set in 2019.

Figure 72 Highest Gas Supply Hub volumes in a calendar year on record

Gas Supply Hub – quarterly traded volume



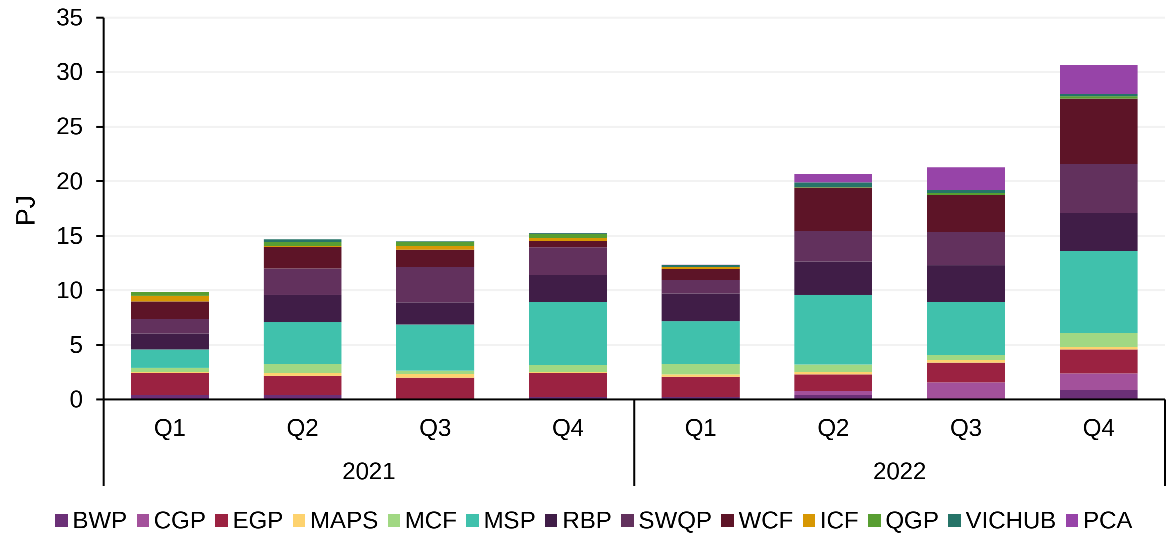
2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes set a new quarterly record, 9.4 PJ higher than the previous level set in Q3 2022, and 15.4 PJ higher than Q4 2021 (Figure 73). Compared to Q3 2021, the largest increases occurred on the Wallumbilla Compressor (+5.4 PJ), the SWQP (+1.9 PJ), the Moomba to Sydney Pipeline (MSP, +1.7 PJ), and the Carpentaria Gas Pipeline (CGP, +1.5 PJ). Auction volumes for 2022 totalled 85 PJ, easily surpassing the 2021 volume of 54.3 PJ.

Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were the EGP which averaged $0.06/GJ, and the MSP North path which averaged $0.05/GJ.

Figure 73 Highest quarterly Day Ahead Auction utilisation since market start

Day Ahead Auction volumes by quarter



2.7 Gas – Western Australia

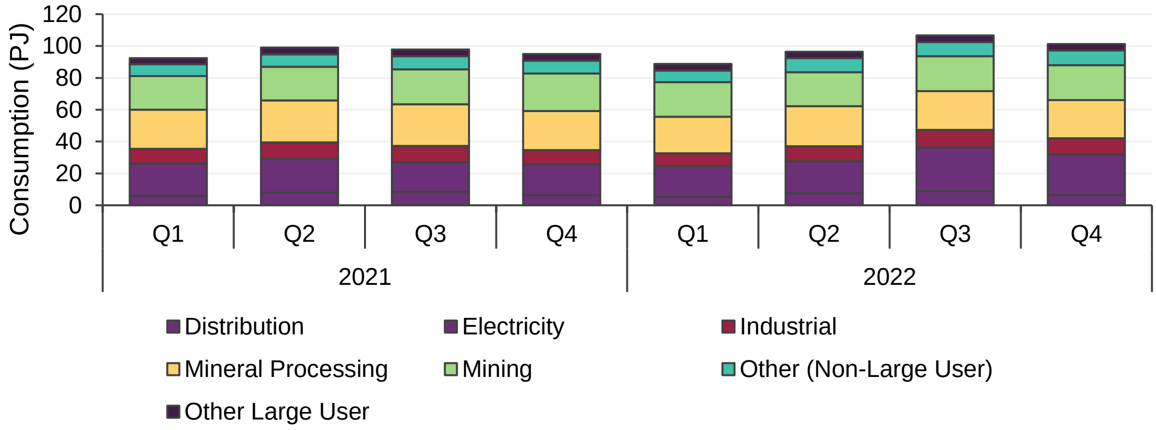
A total of 101 PJ was consumed in the Western Australian domestic gas market in Q4 2022, an increase of 6 PJ (+7%) from Q4 2021 and a decrease of 5 PJ (-5%) from the previous quarter this year (Figure 74).

Compared to Q4 2021:

- Consumption from the mining sector decreased by 1.3 PJ (-5%), driven by the 0.3 PJ (-51%) decrease at Parkeston Power Station and 0.3 PJ (-16%) decrease at Port Hedland Power Station. Mineral processing sector consumption decreased by 0.7 PJ (-3%), mainly driven by decreases in consumption from Kwinana Nickel Refinery (by 0.3 PJ, -30%) and Alcoa Kwinana (by 0.7 PJ, -11%).
- Gas consumption for electricity generation increased by 6.1 PJ (+31%), which can be largely attributed to lower coal-fired generation availability during the quarter resulting in higher gas-fired generation (see Section 3.2.1).

Figure 74 Western Australia domestic gas consumption increased 7% from Q4 2021

WA quarterly gas consumption by sector – Q1 2021 to Q4 2022

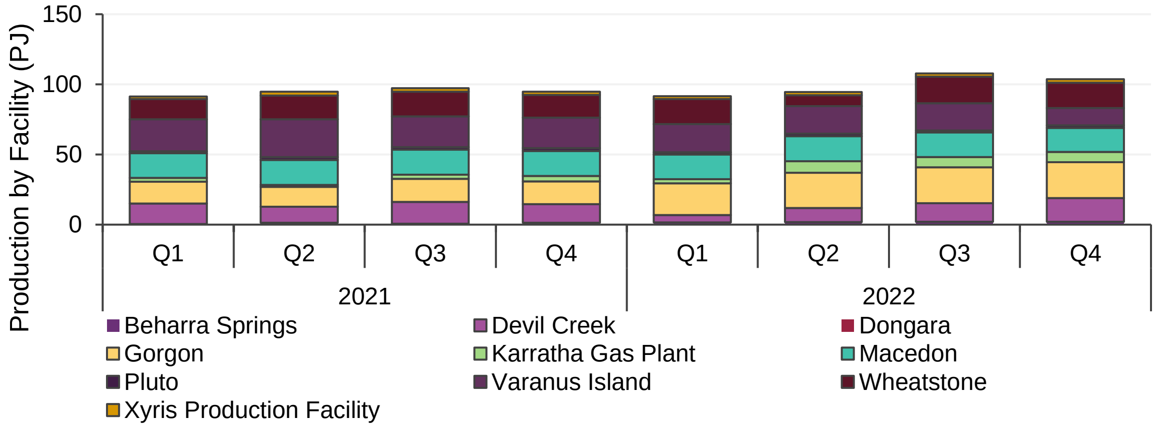


2.7.1 Gas production

In Q4 2022, total Western Australian gas production was 104 PJ, an increase of 9 PJ (+9%) from Q4 2021, but a decrease of 4 PJ (-4%) from Q3 2022 (Figure 75). This can be partially attributed to decreased production from Varanus Island as a result of a pipeline leak at the John Brookes platform in mid-December, which reduced production by 6.9 PJ (-36%) compared to Q3 2022. The reduction was offset by increases at other production facilities, in particular Devil Creek, which increased production by 3.6 PJ (+27%) compared to Q3 2022.

Figure 75 Western Australia domestic gas production increased by 9% from Q4 2021

WA quarterly gas production by facility – Q1 2021 to Q4 2022

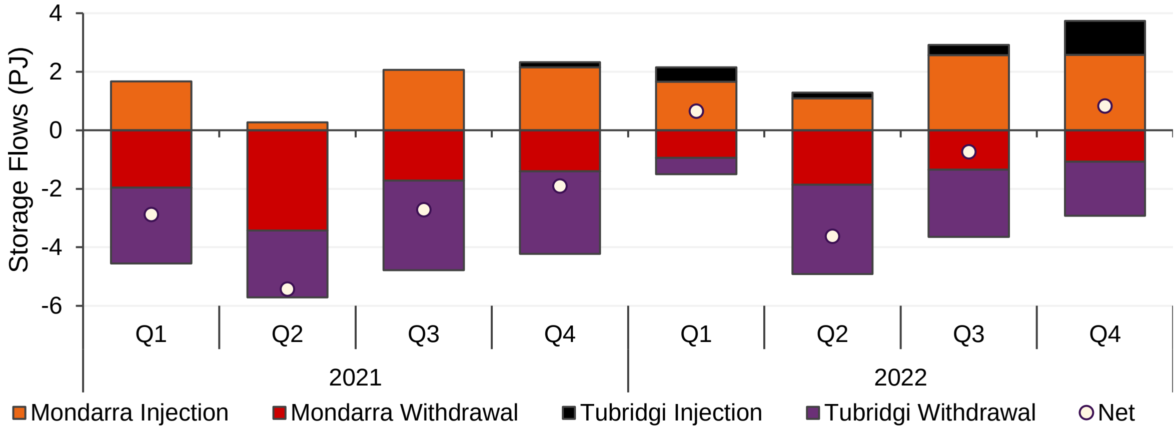


2.7.2 Storage facility behaviour

During Q4 2022 there was a net flow of gas into storage facilities of 0.8 PJ (Figure 76). The change in storage flows in Q4 2022 was driven by a net 1.5 PJ injection into Mondarra, and only a net 0.7 PJ withdrawal from Tubridgi (compared to a net 2.0 PJ withdrawal in Q3 2022).

Figure 76 Net storage of gas in Q4 2022

WA gas storage facility injections and withdrawals – Q1 2021 to Q4 2022



3 WEM market dynamics

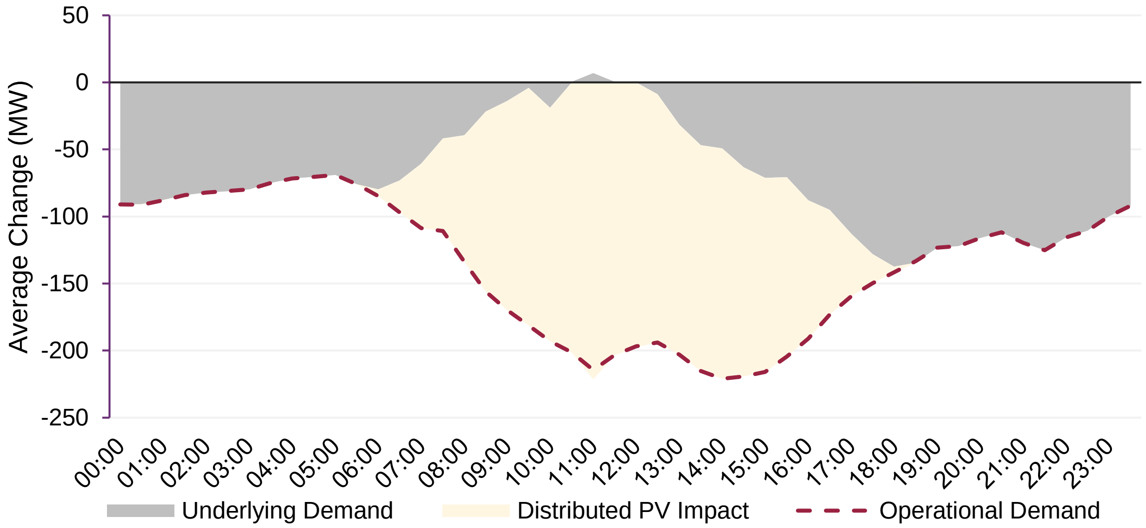
3.1 Electricity demand

WEM quarterly average operational demand[40] was 1,723 MW, representing a 7.4% decline relative to Q4 2021 and the lowest quarterly average since Q3 2006. As Figure 77 shows, the reduction was observed across every interval but was more pronounced in the middle of the day. This was mostly driven by a 15% increase in estimated distributed PV[41] average generation.

Quarterly average underlying demand[42] was 3% lower than Q4 2021, with a decrease observed in both morning and evening. This can be attributed to milder temperatures, especially in November and December, causing a decrease in cooling related demand. Compared to December Q4 2021, the average minimum and maximum temperatures in Perth in December 2022 were 1.3°C and 2°C lower respectively.

Figure 77 Operational demand decrease driven by increased distributed PV output and milder weather

Change in average WEM demand components by time of day – Q4 2022 vs Q4 2021



3.1.1 Minimum demand

The trend of decreasing minimum operational demand in the WEM continues year on year, with an all-time record of 626 MW set on Sunday, 16 October 2022 across the trading interval from 1230 hrs to 1300 hrs. During this interval, distributed PV output was estimated to be 1,746 MW, which represented 74% of the total underlying demand (Figure 78). This, combined with mild weather conditions, were the main drivers of the record minimum demand which followed a prior record minimum on the previous day of 683 MW.

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

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

[42] 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.

The minimum operational demand record on 16 October 2022 was 18% lower than the Q4 2021 minimum operational demand of 761 MW, which occurred on 14 November 2021.

Estimated distributed PV generation has continued to rise, with an all-time record of 1,865 MW on Tuesday, 1 November 2022 across the 1130 hrs -1200 hrs trading interval. This was 20% higher than the Q4 2021 maximum output of 1,557 MW on 30 October 2021. Increasing distributed PV generation output is the primary factor influencing falling operational demand (Figure 79).

Figure 78 Operational demand on 16 October 2022

Fuel mix by trading interval on the record minimum operational demand day

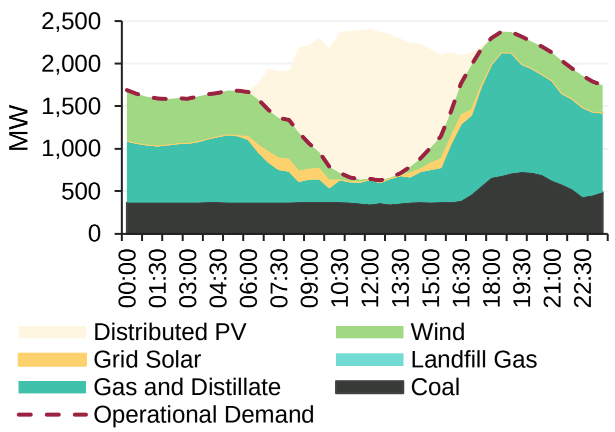
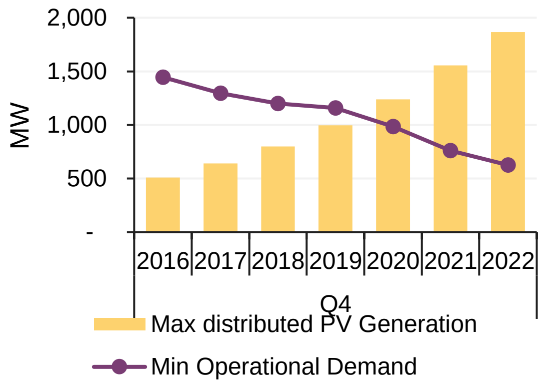


Figure 79 Distributed PV output driving decrease of minimum operational demand

Q4s minimum operational demand and maximum distributed PV output



3.1.2 Challenges over the shoulder season

During the shoulder seasons, high solar irradiance and cool temperatures lead to very high penetration of distributed PV generation. Increasing installed distributed PV capacity has led to lower operational demand troughs during the middle of the day. The high percentage of distributed PV generation in the South West Integrated System (SWIS) has also resulted in more frequent load volatility than in previous years, with cloud cover over the Perth Metropolitan Area causing large demand swings.

Low load management

The 2022 spring shoulder season was the first in which AEMO implemented a Minimum Demand Threshold (MDT)[43]. The MDT[44] defines the minimum load, on any given day, at which the system can securely operate while maintaining sufficient levels of Ancillary Services to withstand a credible contingency event.

[43] https://www.wa.gov.au/system/files/2022-08/EPWA-SWIS%20Low%20Demand%20Project%20Stage%201.pdf

[44] In formulating the MDT, AEMO considers the following factors: relevant generation dispatch, system load, system inertia, Spinning Reserve requirements, Load Rejection Reserve requirements, droop ramp-rate of Facilities, distributed PV generation, largest generation contingency, and forecast load contingency.

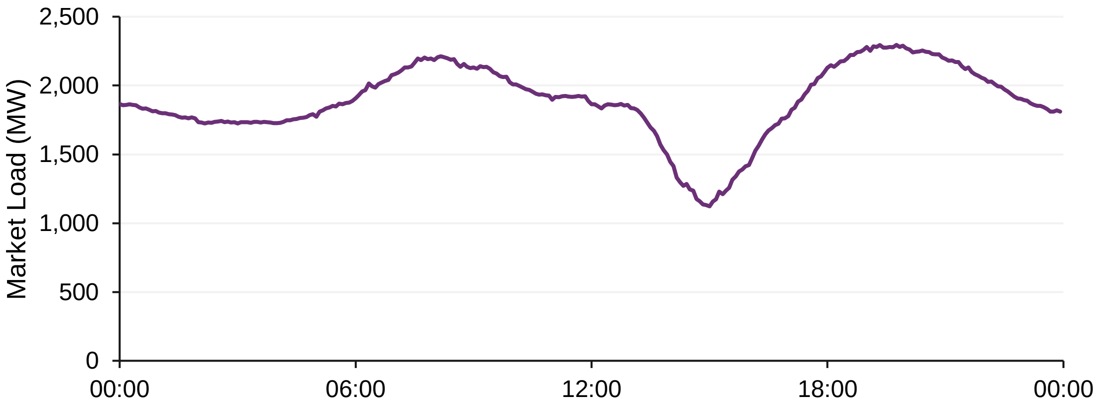
The MDT can vary between 550 MW and 660 MW (system load[45]) depending on the combination of online generation in the SWIS. Generation dispatch profiles were reconfigured during low load days during Q4 2022, however no additional intervention[46] was required, as the system load did not reach the MDT.

Rapid demand swings

During Q4 2022, there were 33 separate days where demand decreased by 20% or more in an hour. This is more than double the number of days that had a similar decrease in Q4 2021 (15 days). One example of these large demand swings is illustrated in Figure 80; on 13 December 2022, there was significant cloud cover over the Perth Metropolitan Area until around 1300 hrs, when increased distributed PV caused a sudden drop in demand. These rapid decreases in demand create challenging operational scenarios where multiple generators must suddenly decrease their output to maintain power system security.

Figure 80 Example of large load decrease due to cloud reduction

Market load on 13 December 2022



The behaviour of the clouds over the Perth Metropolitan Area can also result in smaller but quicker demand swings up and down. During Q4 2022, there were occasions where the instantaneous market load[47] increased by up to 370 MW over a thirty minute period and then immediately decreased by up to 350 MW in the following thirty minutes. These demand swings can happen multiple times during the day. An example of this is illustrated in Figure 81; on 18 November 2022, patchy clouds throughout the day over the Perth Metropolitan Area resulted in generation from distributed PV repeatedly increasing and decreasing impacting the demand profile.

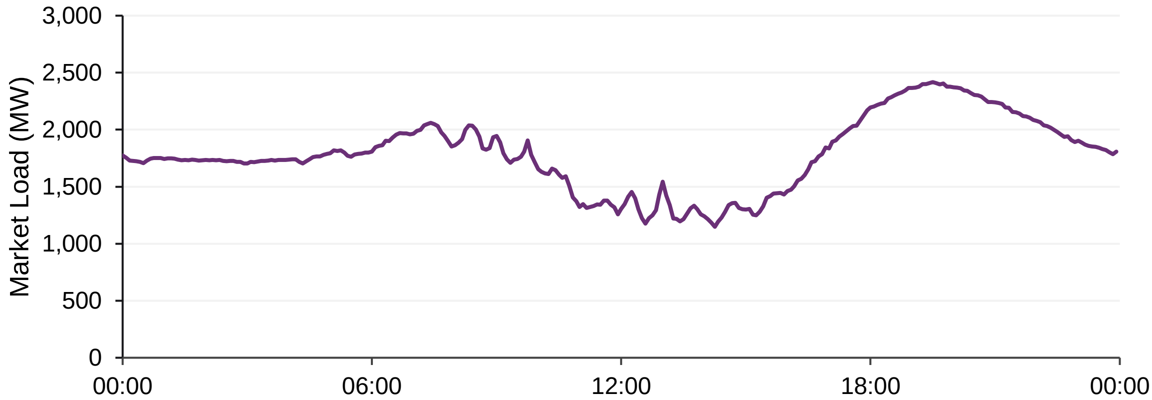
[45] System load is the sum of gross generator outputs (including that which covers auxiliary loads at the generation sites). This is measured by non-loss adjusted SCADA at a 4-second sample rate. Operational Demand is approximately 90-100 MW less than system load.

[46] Additional actions (such as Emergency Solar Management or Curtailment of DPV on the SWIS taken by Western Power under the direction of AEMO to maintain Operational Demand.

[47] The instantaneous market load is the total loss-adjusted generation from all generators registered in the WEM. This is similar to the 30-minute operational demand but taken instantaneously rather than averaged over 30 minutes.

Figure 81 Example of demand swings due to clouds

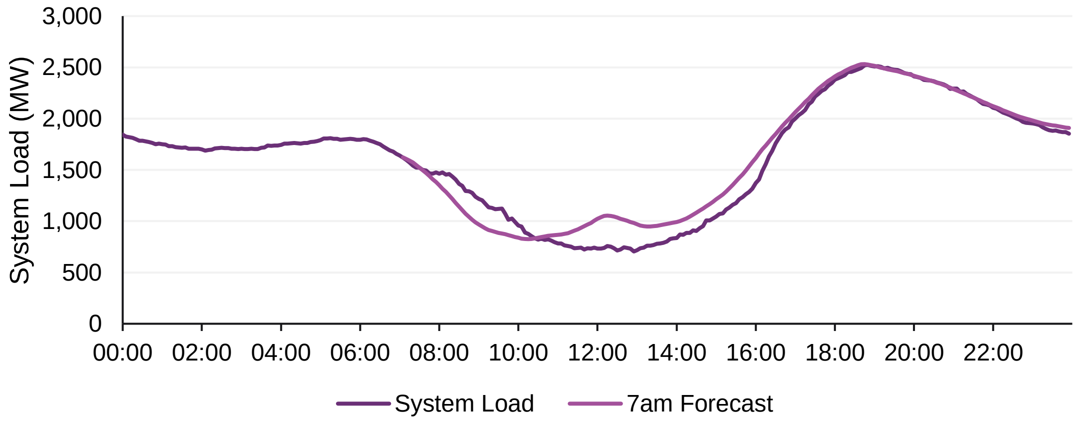
Market load on 18 November 2022



As distributed PV generation makes up a large proportion of the generation mix during the day, cloud cover has a major influence on demand. Forecasting cloud cover has therefore increased in importance. If cloud forecasts over the Perth Metropolitan Area are inaccurate, it can result in unexpected demand outcomes in the SWIS. An example of this is illustrated in Figure 82; on 16 October 2022, the morning forecast predicted light cloud cover over parts of the Perth Metropolitan area in the middle of the day, however the day was much clearer than forecast, so the generation from distributed PV was higher than expected. This resulted in actual demand being significantly lower than forecast. The actual minimum demand was 120 MW (-15%) lower than expected at the start of the day, creating additional challenges in operating the power system.

Figure 82 Example of inaccurate cloud forecast and its effects on demand

System load on 16 October 2022 with overlayed forecast



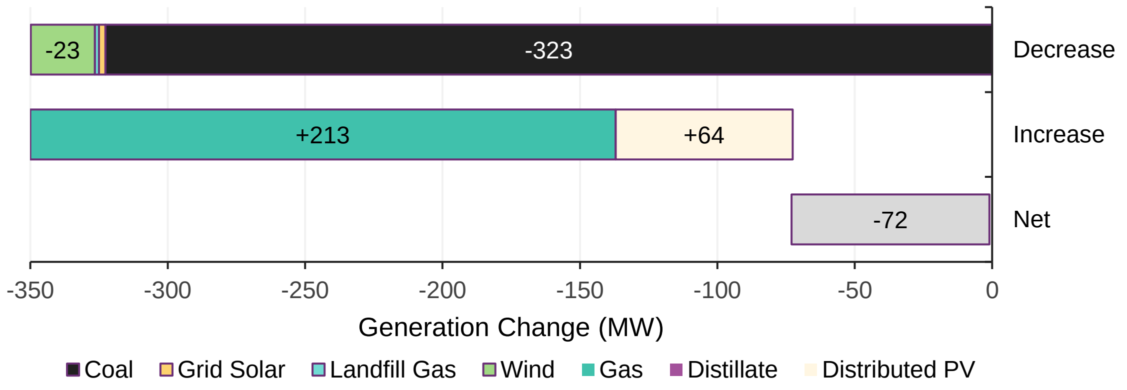
3.2 Electricity generation

3.2.1 Change in fuel mix

Total average output in the WEM over Q4 2022 decreased by 72 MW compared to Q4 2021, in line with the overall decrease in underlying demand (see Section 3.1). A large decrease in coal-fired generation was offset by increased gas-generation and estimated distributed PV generation (Figure 83).

Figure 83 Decrease in coal generation offset by increase in gas and estimated distributed PV output

Change in quarterly average generation output – Q4 2022 vs Q4 2021



Changes in generation by fuel type and time of day compared to Q4 2021 (Figure 84, Table 3) were:

- Quarterly average coal-fired generation in Q4 2022 reached an all-time low of 438 MW, reducing by an average 323 MW (-42%) from the same quarter last year. The decrease was observed across every interval and can be linked to reduced coal-fired generation availability.
- Wind generation decreased by an average of 23 MW (-6%), predominantly in the middle of the day. This can be linked to constraints applied to the Synergy Balancing Portfolio in periods of low load to maintain power system security and reliability, which may displace generation from facilities not accredited to provide Ancillary Services.
- Grid-scale solar generation remained stable, with a small decrease of 2 MW (-4%) on average.
- Estimated distributed PV continued to grow, increasing by 64 MW (+15%) on average, with an all-time highest quarterly average output of 482 MW. This increase can be attributed to additional PV capacity installed in the SWIS since Q4 2021.
- Gas generation increased by an average of 213 MW (+35%), and was higher at all times of the day. The largest increases compared to Q4 2021 were in the morning and during the evening peak, due to estimated distributed PV output increasing during the middle of the day. The overall increase in gas-fired generation was a consequence of lower coal-fired generation availability.

Figure 84 WEM coal-fired output reduced in all intervals, offset by increased gas-fired generation

Average WEM change in fuel mix by time of day – Q4 2022 vs Q4 2021

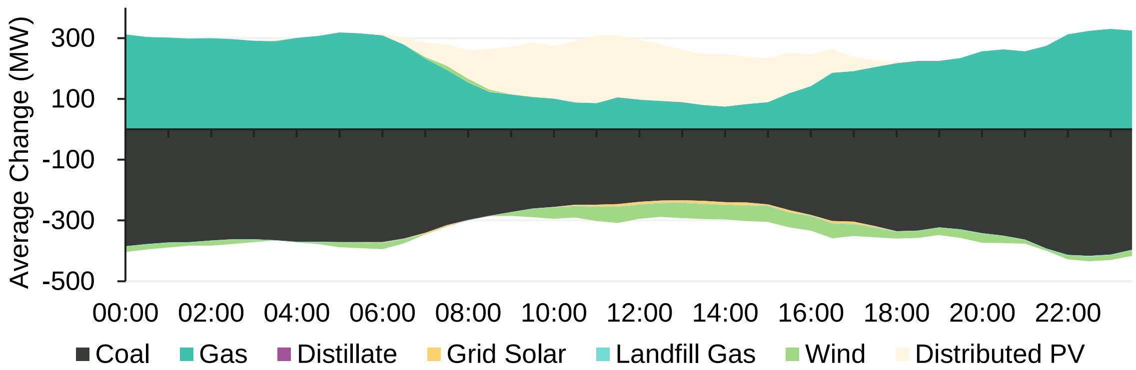


Table 3 WEM fuel mix Q4 2022 and Q4 2021

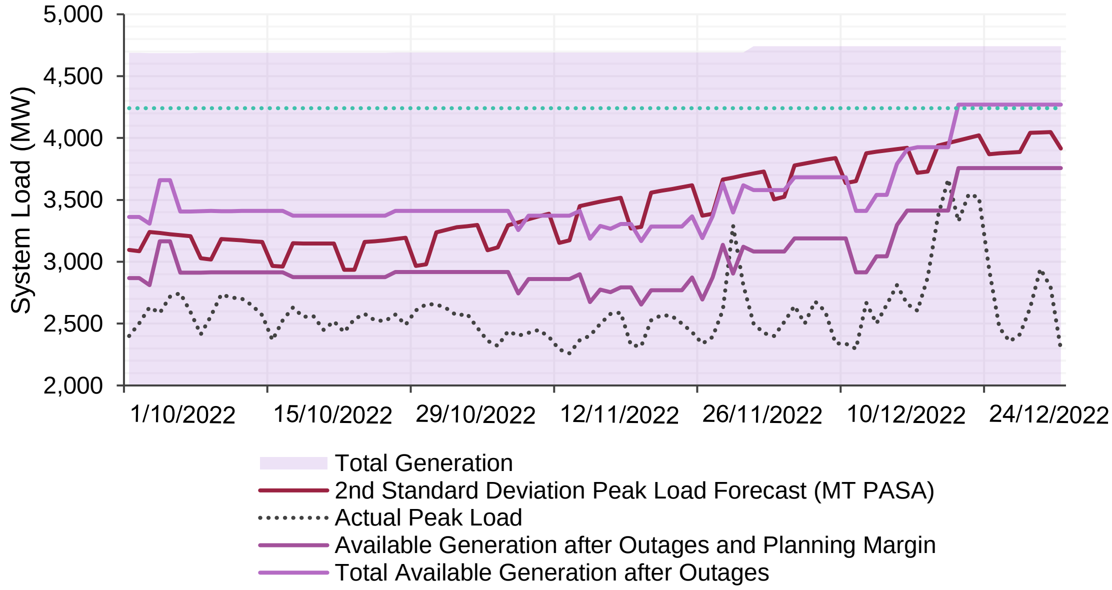
Quarter	Coal	Gas	Grid Solar	Wind	Distributed PV	Other
Q4 2021	33.4%	26.9%	2.5%	18.4%	18.3%	0.5%
Q4 2022	19.9%	37.4%	2.48%	18.0%	21.8%	0.42%
Change	-13.50%	+10.50%	-0.02%	-0.40%	+3.50%	-0.08%

3.2.2 Low coal facility availability and summer readiness

Due to several forced outages in the SWIS, the medium-term planning outlook for spring and summer indicated periods of significant shortfalls in reserves (Figure 85). Coal preservation and ensuring adequate stockpiles for summer has been a key focus of the industry.

Figure 85 Balancing supply and demand (comparison of forecast October 2022 and actual demand)

System load over Q4 2022



AEMO has enhanced its procedures to manage the tight conditions the power system is experiencing. This includes the development of new Lack Of Reserve (LOR) Guidelines and updated processes for managing periods of tight reserve margins (created in line with current LOR Guidelines in the NEM with some adjustments to suit the SWIS).

Due to the high volume of generation experiencing forced outages over December 2022, there has been little opportunity for AEMO to approve any additional planned outages. Outage approvals during the hot season are closer to proposed start time (within seven days, utilising the Short term Projected Assessment of System Adequacy [ST PASA] forecast) where demand forecasts are updated, and more accurate estimates of wind are considered.

In addition to procuring Supplementary Reserve Capacity (SRC), to prepare for peak demand periods AEMO has also been coordinating market generators and demand side response capacity to operate as required, recalling units from outages where possible, and working with Western Power to ensure other non-market sources of capacity are available to provide support if required.

Throughout the summer months, potential risks to power system security may still materialise at times when extreme conditions occur, and AEMO will continue to work closely with the Western Australian Government and industry to manage these risks to ensure a secure and reliable power supply.

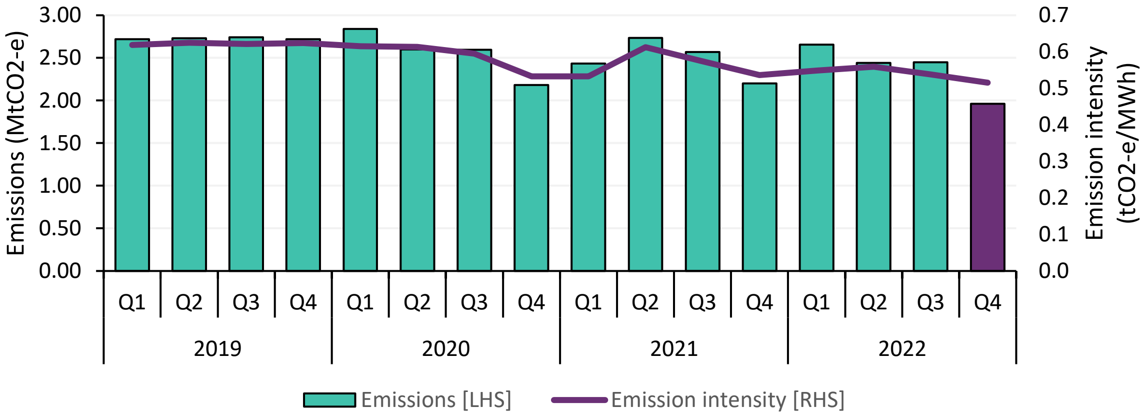
3.2.3 Carbon emissions

WEM emissions are trending downwards from 2.72 MtCO2-e[48] in Q4 2019 to 1.96 MtCO2-e in Q4 2022 (Figure 86). This represents a 28% reduction in emissions over four years and an 11% decrease from Q4 2021. The WEM emission intensity[49] index also decreased, from 0.62 tCO2-e/MWh in Q4 2021 to 0.52 tCO2-e/MWh in Q4 2022.

The decreasing trend of emissions and emission intensity can be largely attributed to the gradual increase of renewable penetration in the SWIS (see Section 3.3), with the sharp decrease in Q4 2022 also linked to the reduction in coal-fired generation availability and subsequent increase in gas-fired generation (see Section 3.2.1).

Figure 86 Emissions in the WEM decreased by 11% from Q4 2021

Quarterly WEM emissions and emission intensity – Q1 2019 to Q4 2022



3.3 Renewable penetration

Each year the share of renewable generation in the SWIS increases; renewable penetration[50] in Q4 2022 reached an all-time record quarterly share of 42.7%, up from 39.7% in Q4 2021 (Figure 87). This increase is driven by the continued increase of distributed PV, which contributed 21.8% of the total generation in Q4 2022 (+3.5 percentage points from Q4 2021).

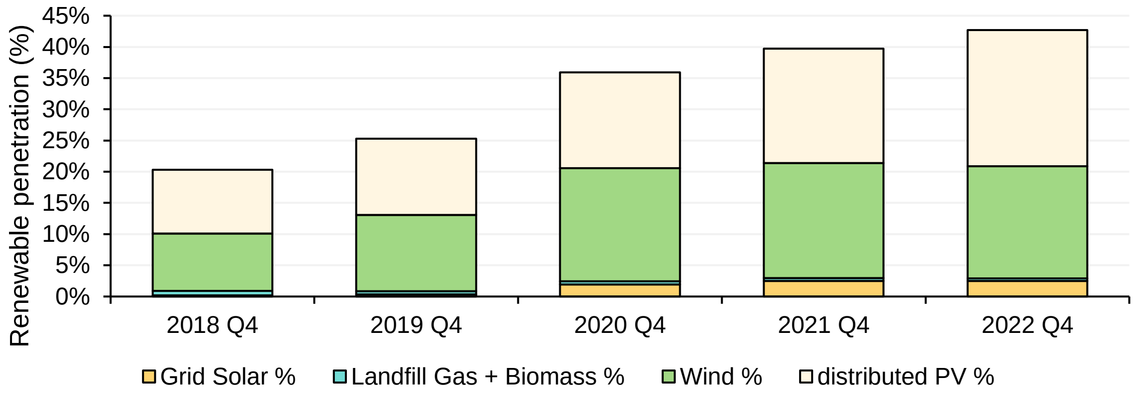
[48] Million tonnes carbon dioxide equivalent.

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

[50] Renewable penetration is calculated using the WEM renewable generation share of total generation (including distributed PV). Renewable generation includes grid-scale wind and solar, landfill gas, biomass and distributed PV. Total generation = WEM generation + estimated distributed PV generation.

Figure 87 Highest quarterly renewable penetration of all time in Q4 2022 (42.7%)

Renewable penetration components – Q4s



3.3.1 Instantaneous renewable penetration records

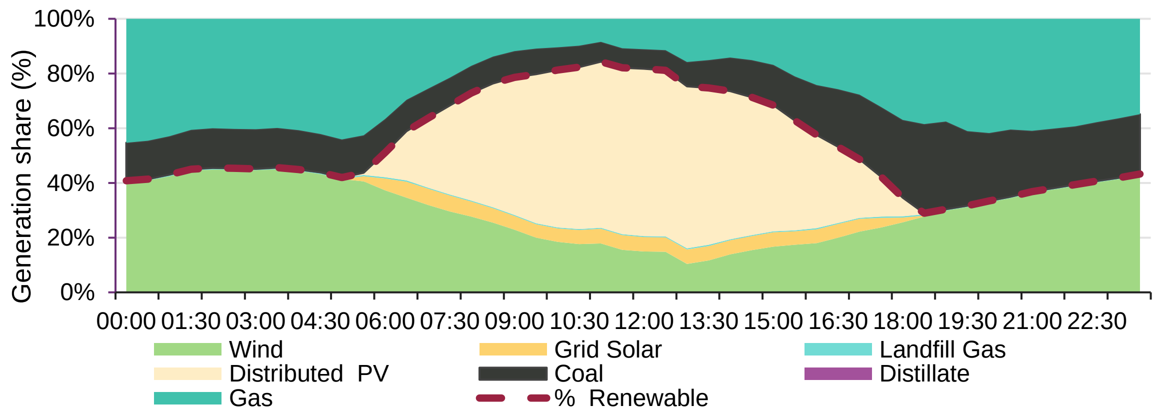
The high renewable penetration in Q4 2022 is reflected in the frequency of new all-time records being set for instantaneous renewable penetration[51] during the quarter. In November, all-time renewable penetration records were broken in three consecutive weekends (12, 20 and 26 November). The most recent renewable penetration record was set on Monday, 12 December 2022 over the 1100 hrs to 1130 hrs trading interval. During this interval renewables met 84.3% of underlying demand: 60.6% from estimated distributed PV, 17.9% from wind, 5.4% from grid solar (Figure 88). At that time operational demand was 1,090.6 MW.

This was a 3 percentage point jump from the previous record (81.3% on 26 November 2022). A number of factors played a role in setting this record, including high wind speeds, mild temperatures and sunny conditions, and lower coal generation during the trough than on a usual weekday.

On the same day renewable penetration was above 70% during 14 intervals from 0800 hrs to 1500 hrs, with an 78% average contribution across those intervals.

Figure 88 Renewable penetration reached a record 84.3% on 12 December 2022

Fuel mix on day of renewable penetration record



[51] Instantaneous renewable penetration is calculated on a half-hourly basis (trading interval basis).

3.4 WEM prices

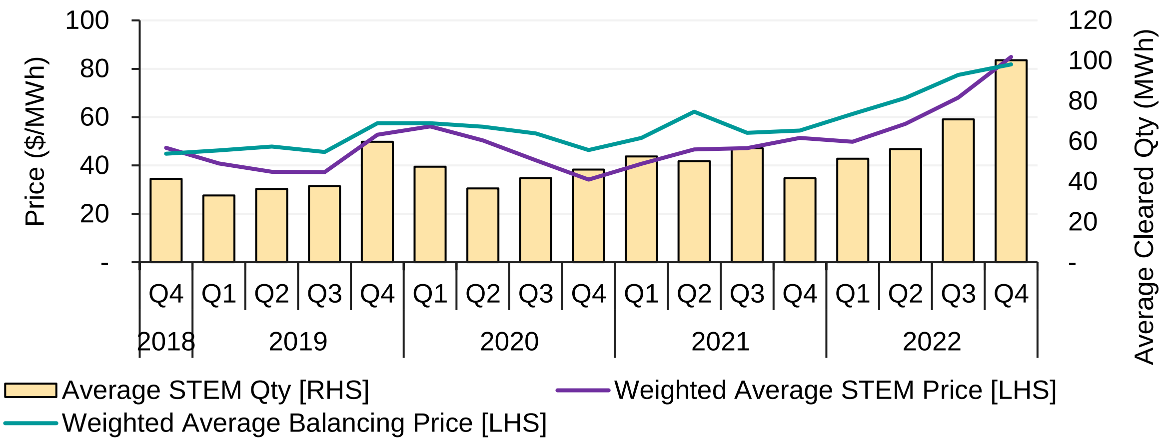
The weighted average Balancing Price[52] in the WEM for Q4 2022 was $81.80/MWh, the highest quarterly average of all time (Figure 89). This was a $4.33/MWh (+6%) increase from Q3 2022 and a $27.37/MWh (+50%) increase from Q4 2021. Contributors to the price increase include:

- Reduction in the quantity of energy made available in the Balancing Market at all times of the day due to a reduction in facility availability during the quarter (see Section 3.4.1) and subsequent changes to the facilities setting the Balancing Price compared to previous quarters (see Section 3.4.4).
- Changes in the fuel mix, in particular an increase in gas-fired generation (see Section 3.2.1).
- A reduction in the prevalence of negative Balancing Prices and new record high interval Balancing Prices (see Sections 3.4.2 and 3.4.3).

The weighted average Short-Term Electricity Market (STEM) price[53] for Q4 2022 was $84.87/MWh, a $33.43/MWh (+65%) increase compared to Q4 2021, driven by an increase in the average quantities bid into STEM, compared to Q4 2021. The quarterly average quantity of energy cleared in the STEM in Q4 2022 was the largest of all time (100.27 MWh), increasing by 140% and 41% compared to the same quarter last year and last quarter respectively. This can be linked to high Q4 2022 Balancing Prices and subsequent change in participant bidding behaviour in the STEM.

Figure 89 Weighted average Balancing Price continued to increase

WEM weighted average Balancing Price, STEM Price and quantity cleared in STEM – Q4 2018 to Q4 2022



3.4.1 Balancing merit order dynamics

Participant behaviour in the Balancing Market in Q4 2022 shows a decrease in the average quantities offered in the Balancing Market when compared to Q4 2021, with a decrease across all price bands (Figure 90).

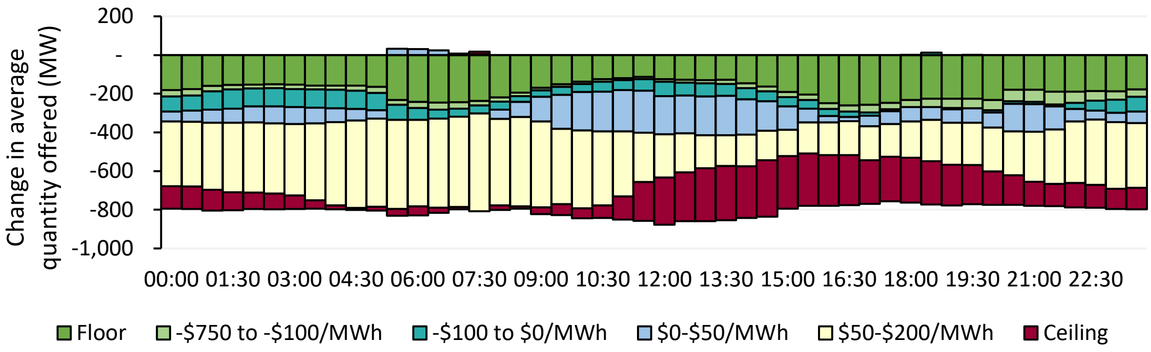
[52] The weighted average Balancing Price is a measure of the average Balancing Price that puts greater weighting on intervals where greater quantity is generated. This is to reflect the average Balancing Price more accurately against quantity of electricity generated, rather than against intervals.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

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

The primary driver of this change was reduced facility availability observed over the quarter, in particular reduction in coal-fired generation availability. The largest decreases in Balancing Market participation observed in Q4 2022 when compared to Q4 2021 were an average of 310 MW (-27%) less offered at the $50 to $200/MWh price band and 185 MW (-18%) less offered at the floor price band (<-750/MWh).

Figure 90 Reduction in quantities offered in the Balancing Market in all price bands

Change in average Balancing Merit Order structure by time of day – Q4 2022 versus Q4 2021



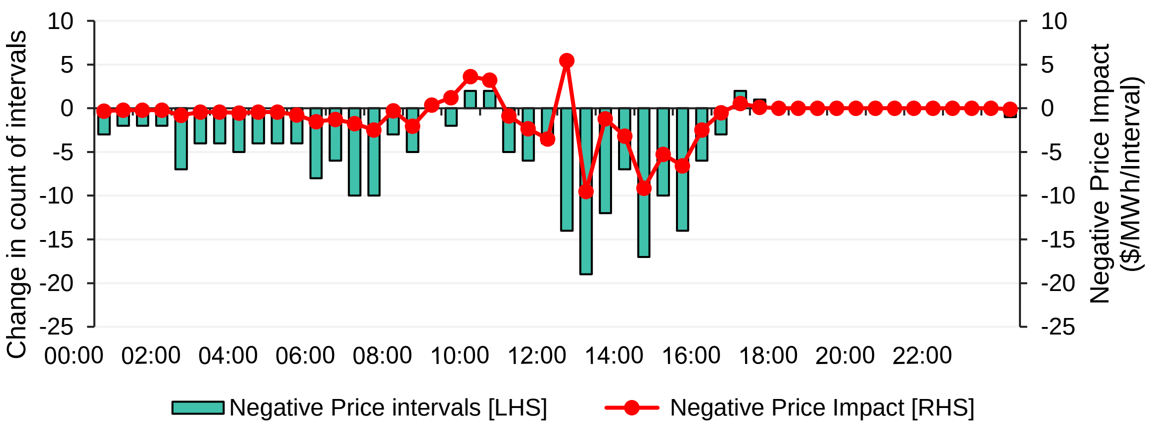
3.4.2 Negative prices

The total number of negatively priced and $0/MWh intervals in Q4 2022 (5% of all intervals) reduced from Q4 2021 (9% of all intervals) (Figure 91). A contributing factor to this change at all times of the day was a reduction in coal-fired generation availability during the quarter, which was replaced with typically higher cost gas-fired generation (see Section 3.2.1).

The reduced frequency of negatively priced and $0/MWh intervals was predominantly observed during the middle of the day. This can be partially attributed to the change in AEMO's approach to managing power system security and reliability during low load periods; to ensure sufficient Ancillary Services and reserves are available, AEMO constrains on the Synergy Balancing Portfolio to a minimum output during low demand periods. The low demand periods typically occur during the middle of the day when output from distributed PV is higher.

Figure 91 Fewer negatively priced intervals and lower negative price impact

Change in count of intervals with zero or negative Balancing Price - Q4 2022 versus Q4 2021



3.4.3 Maximum Balancing Price

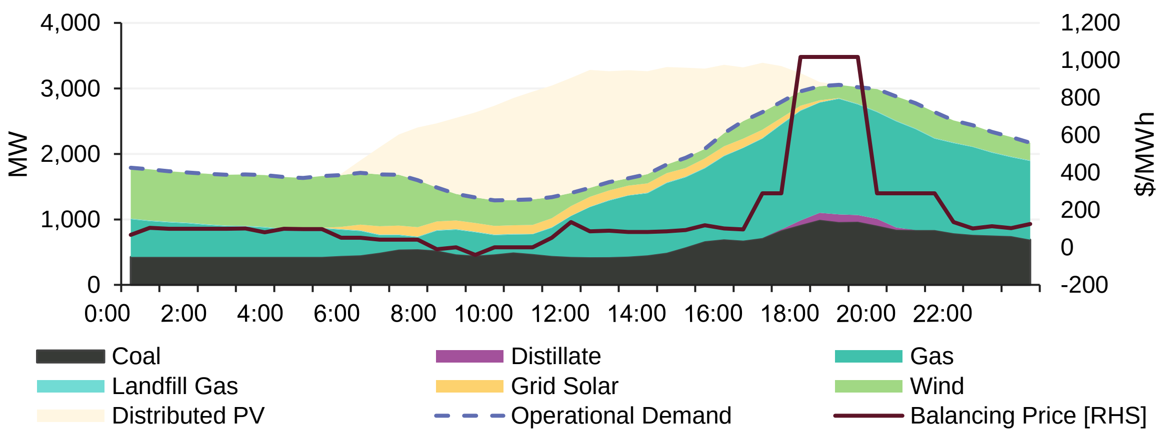
In Q4 2022, for the first time in WEM history, the Balancing Price cleared at the Alternative Maximum STEM Price[54] (AMSP). This occurred on Tuesday, 29 November 2022 with the Balancing Price clearing at $1,018/MWh in four trading intervals from 1730 hrs to 1930 hrs.

This occurrence was due to a combination of high temperatures and a large quantity of outages, resulting in tight conditions during the evening peak. During the evening peak, operational demand reached a maximum of 3,054 MW, and all facilities in the Balancing Merit Order were in merit and received dispatch instructions to generate, including diesel facilities (Figure 92).

The frequency of high Balancing prices also increased in Q4 2022, with 79 intervals clearing at the Maximum STEM Price[55] compared to 12 intervals in Q4 2021. This primarily occurred during the evening peak periods.

Figure 92 Record maximum Balancing Price on 29 November 2022

Fuel mix and Balancing Price by Trading Interval on day of record maximum Balancing Price



3.4.4 Price-setting dynamics

The key changes in price-setting dynamics in Q4 2022 were (Figure 93):

- The Balancing Portfolio[56] set the Balancing Price 58% of the time, the same level as Q4 2021 and a 6% decrease from Q3 2022.
- Compared to Q4 2021, coal-fired generation facilities set the price less frequently (-13%), with gas-fired generation setting the price more frequently (+17%). This is in line with the change in fuel mix (see Section 3.2.1)
- Wind and grid solar facilities set the price 5% less often than in Q4 2021.

The decrease in wind and solar price-setting, paired with the increase in gas generation price-setting, put upwards pressure on the Balancing Price.

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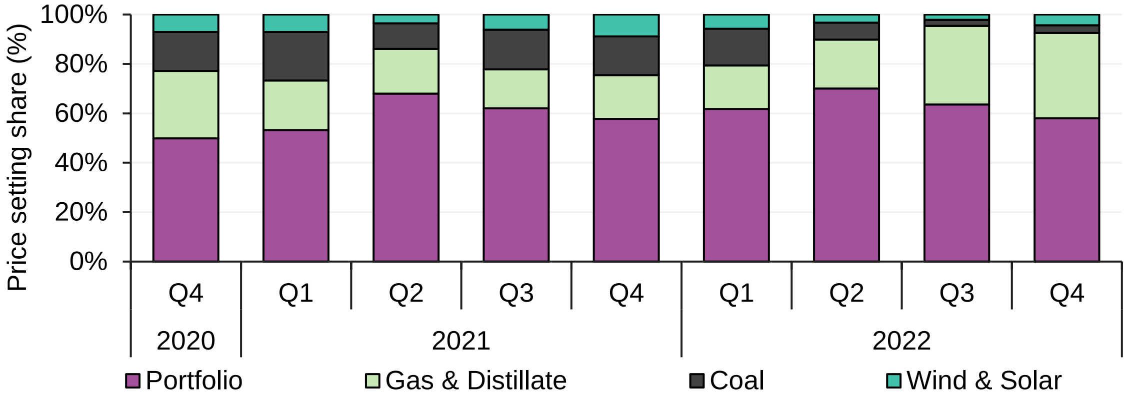
[54] The Alternative Maximum STEM price is an Energy Price Limit that applies to generators that use distillate as a fuel source: https://www.erawa.com.au/electricity/wholesale-electricity-market/price-setting/energy-price-limits.

[55] The Maximum STEM price is an Energy Price Limit that applies to generators that use non-liquid fuel. This was $267 in Q4 2021 and $290 in Q4 2022: https://www.erawa.com.au/electricity/wholesale-electricity-market/price-setting/energy-price-limits.

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

Figure 93 Low coal availability contributed to a decreased price-setting role in the Balancing Portfolio

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



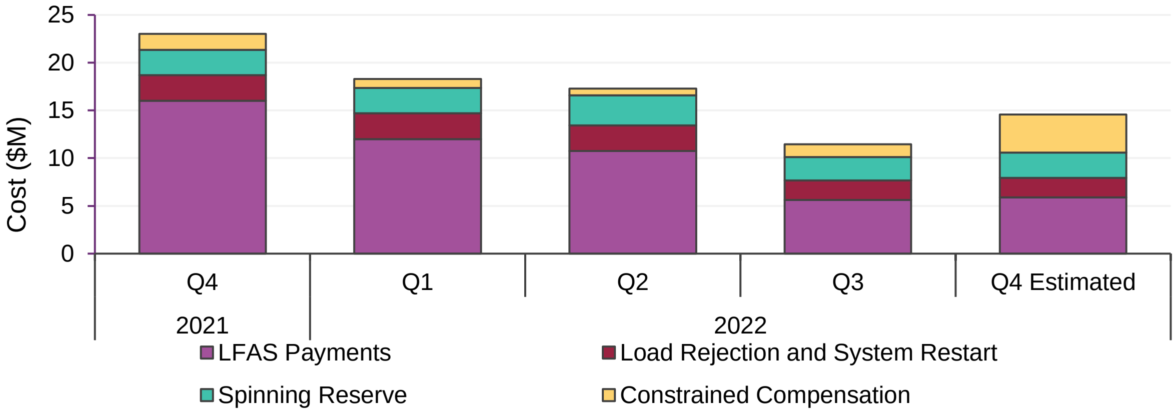
3.5 Power system management

In Q4 2022, the total cost of power system management, including Ancillary Services and constrained compensation, was $14.6 million, a decrease of $8.4 million (-37%) compared to Q4 2021 (Figure 94). The decrease in costs was largely attributed to a reduction in Load Following Ancillary Services (LFAS) costs, however this was partly offset by a significant increase in constrained compensation costs.

- LFAS costs for Q4 2022 were $5.9 million and accounted for 40% of all Ancillary Services costs for the quarter. LFAS costs decreased by $10.1 million (-63%) compared to Q4 2021 due to lower average prices in both LFAS Upwards and LFAS Downwards markets (see Section 3.5.1).
- The estimated spinning reserve cost change was negligible compared to Q4 of 2021, with an increase of $14,300 (<1%) compared to Q4 of 2021.
- Estimated load rejection and system restart costs decreased by $0.6 million (-23%) compared to Q4 2021, in line with the decrease to the COST_LR parameter, which is set annually by the Economic Regulation Authority (ERA) in line with financial years.
- Estimated constrained compensation increased by $2.3 million (+138%) compared to Q4 2021. This is in part due to an increase in the level of constraints required to ensure adequate Ancillary Services to maintain power system security during periods of high and low demand. During the period, a large volume of generator outages resulted in tight operating conditions, contributing to an increase in the frequency of constraints applied during the quarter.

Figure 94 Total estimated cost of operating the power system decreased by 37%

Ancillary Services costs and constrained compensation by quarter - Q4 2021 to Q4 2022

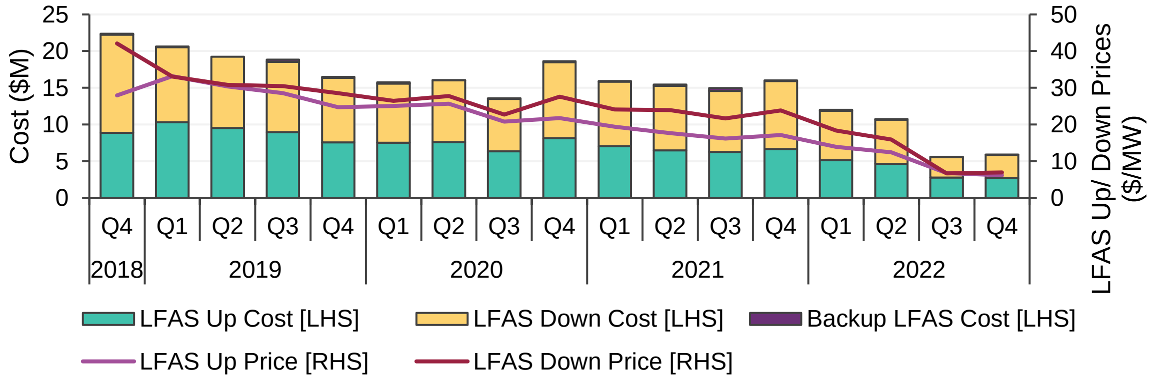


3.5.1 LFAS market

The average price of LFAS Up in Q4 2022 was $6.17/MW and it was $6.94/MW for LFAS Down, representing a decrease of $10.95/MW and $16.90/MW respectively compared to Q4 2021 (Figure 95). This occurred despite an increase in the required quantity of LFAS between the 530 hrs and 2000 hrs intervals from 6 July 2022, increasing from 100 MW to 110 MW. As a result, the total cost of LFAS decreased by $10.1 million (-63%) compared to Q4 2021, continuing the general trend of decreasing LFAS prices and costs over the last five years. This trend can be partially attributed to increased competition since the entry of three new Facilities to the LFAS market in 2019.

Figure 95 Fall in average LFAS Prices reduced total LFAS costs to five-year low

LFAS prices and costs Q4 2018 to Q4 2022



3.6 Reserve Capacity Mechanism

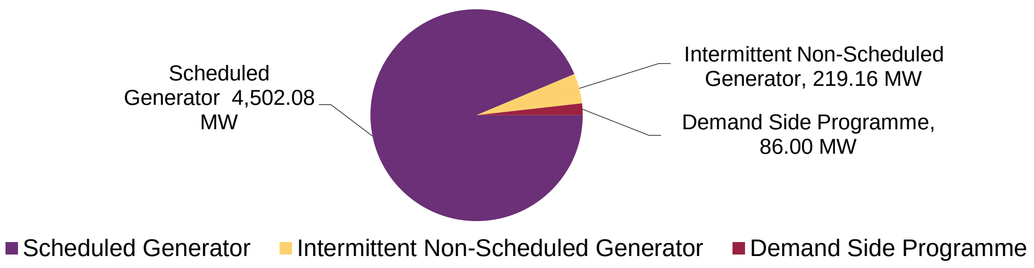
3.6.1 2022-23 Capacity Year commencement

The 2022-23 Capacity Year commenced on 1 October 2022 and will end on 1 October 2023. The 2022-23 Capacity Year is Year 3 of the 2020 Reserve Capacity Cycle (RCC). In the 2020 RCC, 4,807.237 Capacity

Credits were assigned to 67 Facilities. There were 4502.082 MW Capacity Credits assigned to Scheduled Generators (Figure 96)[57].

Figure 96 Capacity Credits assigned for the 2020 Reserve Capacity Cycle

Assigned Capacity Credits by facility type



The total number of Capacity Credits assigned for the 2020 RCC has reduced as a result of:

- The unexpected retirement of the Facility PPP_KCP_EG1 (cogeneration facility located at the now closed BP refinery) and resulting reduction in 80.4 MW of assigned Capacity Credits.
- The voluntary reduction in 10 MW of capacity by the ALCOA_WGP facility and resulting reduction in assigned Capacity Credits from 26 MW to 16 MW.

Following the reduction in Capacity Credits, 4,716.837 MW of Capacity Credits were assigned to Facilities when the 2022-23 Capacity Year commenced.

3.6.2 Supplementary Reserve Capacity for summer readiness

As part of preparation for the 2022-23 summer, AEMO assessed the capacity supply-demand position in light of recently updated demand forecasts and changes to the expected availability of generation facilities, including ongoing coal supply challenges (see Section3.2.2). This assessment identified a preliminary capacity shortfall of up to 174 MW for the period 1 December 2022 to 31 March 2023.

Clause 4.24.1 of the WEM Rules requires AEMO to seek to procure Supplementary Reserve Capacity (SRC) where it identifies a capacity shortfall in the coming six months[58]. In doing so, AEMO must, using the most recent published Long Term Projected Assessment of System Adequacy (LT PASA)[59]:

a) determine the expected start and end dates for the period of the shortfall;

b) determine the expected amount of the shortfall; and

c) seek to acquire supplementary capacity in accordance with relevant requirements in the WEM Rules.

The SRC Invitation to Tender closed on 21 October 2022. In response to the SRC tender process, AEMO has received more than 200 MW of potential reserve capacity proposals for the period of 1 December 2022 to 1 April 2023. AEMO is currently finalising the total reserve capacity and associated technical reviews, which includes a mixture of load curtailment and power generation solutions, and have started the process of executing contracts with proponents.

[57] See *Summary of Capacity Credits Assigned by Facility for the 2020 Reserve Capacity Cycle*, at https://aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/certification/2022/capacity-credits-assigned-for-the-2022-23-capacity-year.pdf?la=en.

[58] The SRC process has only operated once in the history of the WEM – in 2007-08. No SRC was activated at this time.

[59] The demand forecasts in the 2022 WEM ESOO.

List of tables and figures

Tables

Figures

Abbreviations

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

Abbreviation	Expanded term
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
SIPS	System Integrity Protection Scheme
STEM	Short-Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TJ	Terajoule
UGS	Underground Storage Facility
VBB	Victoria Big Battery
VRE	Variable renewable energy
VNI	Victoria – New South Wales Interconnector
WEM	Wholesale Electricity Market
WDR	Wholesale demand response