Quarterly Energy Dynamics Q3 2022

October 2022

Important notice

Purpose

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

Disclaimer

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Version control

Version	Release date	Changes
1	27/10/2022	

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Executive summary

East coast electricity and gas highlights

International and local drivers keep both gas and electricity prices at elevated levels

- Wholesale spot prices averaged $216 per megawatt-hour (MWh)[1] across all National Electricity Market (NEM) regions this quarter – the second highest priced quarter on record after Q2 2022 ($264/MWh), and over three times higher than Q3 2021's average price of $58/MWh.
- East coast gas prices recorded a similar high, averaging $26 per gigajoule (GJ) over the quarter, a 142% increase from last year's Q3 average of $10.74/GJ and only slightly below Q2 2022's $28.40/GJ. East coast gas prices continued to exceed the Australian Competition and Consumer Commission (ACCC) international netback price series in July, coinciding with high demand and an increase in gas-fired generation, before easing in August. An administered price cap (APC) in Victoria, which commenced on 30 May and capped the Declared Wholesale Gas Market (DWGM) price at $40/GJ, ended on 1 August.
- International energy commodity prices remain at record high levels, influenced by the ongoing war in Ukraine and associated falls in energy exports (coal, gas and oil) from Russia due to imposed sanctions and gas pipeline supply issues. As Northern Hemisphere countries look to build energy stockpiles before winter, they have been forced to seek energy security elsewhere, pushing up prices for liquefied natural gas (LNG) and thermal coal. Adding to this, historically wet weather across eastern Australia has also caused flooding and impacted the rail-bound supply of export-grade black coal.
- As in Q2 2022, these factors have had major impacts on generation offer prices in the NEM. Compared with the corresponding quarter of 2021, Q3 2022 saw a reduction of over 2,000 megawatts (MW) in black coal offers priced below $100/MWh, while hydro and gas-fired generation offers also saw shifts to higher price bands.
- Not normally a high priced or volatile quarter, this Q3 saw 24% of all spot prices exceeding $300/MWh. A great proportion of these prices were in the $300-500/MWh price band, and occurred most often in July, signifying a generally higher cost of energy rather than short-term scarcity-driven extreme prices. High mid-year spot prices have been reflected in the forward electricity contract market, with Australian Securities Exchange (ASX) electricity futures for Calendar Year (Cal) 2023 rising from an average of $168/MWh across mainland NEM regions at the end of Q2 2022 to $202/MWh at the end of this quarter.

Demand increases were met by renewable and gas-fired generation as coal-fired generation declined

- Average operational demand increased by 559 MW (2.6%) this quarter compared to Q3 2021, predominantly later in the quarter in New South Wales and Victoria. Drivers included the absence of COVID-19 restrictions

[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. 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.

which covered almost the entire Q3 period in both Victoria and New South Wales in 2021, and a slowdown in output growth from distributed photovoltaics (PV). This was the first Q3 since 2016 that did not see a decrease in average NEM operational demand across the middle part of the day.

- Renewable generation from wind, hydro, grid-scale solar and distributed PV largely met the increase in demand, with a combined 776 MW increase compared to the same quarter last year. Despite fewer outages, black coal-fired generation decreased primarily due to supply offers being moved to higher price bands, while brown coal-fired generation also decreased. Gas-fired generation increased by 259 MW on average, mostly in July and particularly during the morning and evening peaks, despite record high spot gas prices.
- Variable renewable energy (VRE) output set several records during the quarter, despite lower available capacity factors for both wind and grid-scale solar. The instantaneous penetration of renewable energy for the NEM as a proportion of total generation reached 64.1% on 18 September 2022, with the previous record of 61.9% (set on 15 November 2021) being surpassed on four separate days during the quarter.
- Revenues from battery and pumped hydro storage increased strongly from Q3 2021, corresponding with sustained high spot prices, higher arbitrage values and increased dispatch. The Victorian Big Battery (VBB) – able to participate up to its full capacity this quarter, outside the System Integrity Protection Scheme (SIPS) contract period – saw a significant increase in activity. Wivenhoe pumped hydro doubled its dispatch this Q3 compared to last year and recorded its highest generation and pumping for any quarter.

AEMO issues additional threat to system security notices in Victoria, Gas Supply Guarantee triggered again, and curtailment directions issued to two gas-fired generators

- AEMO issued notices of a threat to system security in the DWGM on 11 and 18 July 2022 due to low Iona underground gas storage inventory and the risk of supply shortfalls. The Gas Supply Guarantee (GSG) was triggered for the second time on 19 July 2022 due to an identified shortfall in gas supply for gas-fired generators. Subsequently, on 20 July, AEMO issued a notice stating an intervention had occurred in the DWGM and two gas-fired generators had been curtailed. The threat to system security was lifted on 30 September 2022.
- Queensland gas production was down 13.9 petajoules (PJ), but with a larger decline in LNG export demand this yielded an additional 6.8 PJ of supply to the domestic market. Approximately half of this supply was directed to Mt Isa after production issues in the Northern Territory resulted in reduced supply into Queensland, with the other half going to southern markets.
- Gas production in Victoria grew strongly (+11.6 PJ, +12%), with Longford achieving its highest quarterly production since Q3 2017. Combined with continuing production decreases at Moomba, and higher demand in South Australia, New South Wales and Tasmania, this saw Victorian gas supply to other states reach its highest Q3 level since 2018.

Inter-regional transfers, FCAS and power system management

- NEM inter-regional energy transfers fell in aggregate by 6% from Q3 2021 to Q3 2022. Underlying this decrease was a 56% reduction in aggregate flows across the Basslink interconnector, which sharply increased its market-offered prices for energy transfer in Q3 2022.

- Frequency control ancillary services (FCAS) costs at $54 million were $76 million (58%) lower than in Q3 2021. Most of this decrease was in Queensland, where upgrade-related outages on the Queensland – New South Wales Interconnector (QNI) had significantly elevated FCAS costs in 2021.
- System security costs in South Australia during Q3 2022 were $17 million. While costs rebounded from Q2 2022 levels ($7.5 million), this was still substantially lower than Q3 2021 ($26 million), primarily due to lower volumes directed.

Western Australia electricity and gas highlights

Weighted average Balancing and STEM price rise

- The weighted average Balancing Price during Q3 2022 increased by 44% to $77/MWh compared to Q3 2021 ($54/MWh), driven by a combination of increased demand, decreased coal availability and the change in fuel mix including an increase in gas-fired generation.
- The Short-Term Energy Market (STEM) price in Q3 2022 was 68/MWh, 44% higher than Q3 2021 ($47/MWh), driven by increased quantities of energy cleared in the STEM.

Coal generation decreases, gas generation increases

- Coal-fired generation decreased by 338 MW (-36%) on average compared to Q3 2021, with decreased average generation at all times of the day, mainly driven by a reduction in availability.
- To offset the coal decrease, gas-fired generation increased by an average of 397 MW (+61%), with gas supplying 45% of underlying demand on average, making it the primary fuel source throughout the quarter.

Minimum operational demand and maximum distributed PV output record

- An all-time minimum operational demand record of 742 MW occurred on Sunday 11 September 2022 at 1200 hrs, 2.5% lower than the previous record (761 MW) set on 14 November 2021.
- There was also an all-time record maximum distributed PV generation output of 1,777 MW on Friday 30 September 2022 at 1200 hrs.

Request for supplementary Reserve Capacity for the 2022-23 Capacity Year

- On 23 September, AEMO issued a request for up to 174 MW of supplementary Reserve Capacity for the period 1 December 2022 to 31 March 2023.

Contents

1 NEM market dynamics

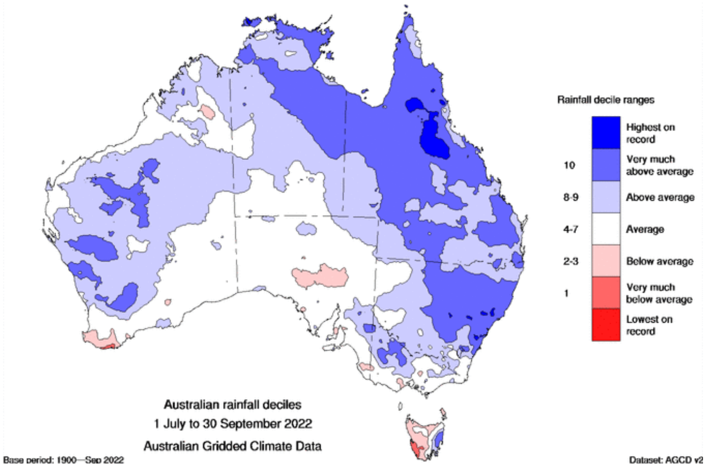
1.1 Electricity demand

1.1.1 Weather

This quarter was characterised by very wet weather (Figure 1). A La Niña event was declared by the Bureau of Meteorology (BoM) on 13 September[2] after a negative Indian Ocean Dipole (IOD) event was declared underway on 2 August[3]. La Niña events increase the likelihood of above average winter-spring rainfall across much of northern and eastern Australia, while a negative IOD event increases the likelihood of rainfall across southern and eastern Australia.

Figure 1 Heavy rainfall across east coast in Q3 2022

Q3 2022 rainfall deciles for Australia



The quarter began with very wet conditions across northern central Queensland down to the east coast of New South Wales, with many sites recording their wettest July on record. Wet weather continued across the quarter with September rainfall across Australia being the fifth highest on record. Contrasting with other parts of the NEM, Tasmania recorded around half its normal average rainfall in July, while September was its driest since 2018.

Temperatures at the beginning of the quarter were below average in many parts of Victoria and Tasmania (with some sites recording their lowest July mean daily maximum temperature). As the quarter progressed, above average minimum temperatures were experienced across south-east Australia.

1.1.2 Demand outcomes

NEM quarterly average operational demand was 22,414 MW, an increase of 2.6% (or 559 MW) relative to Q3 2021 (Figure 2) and the first year-on-year increase in Q3 operational demand since 2015 (Figure 3). This was underpinned by:

- The largest increase in underlying demand[4] in recent years (675 MW); and
- Only modest growth in distributed PV output[5] (115 MW or +7%), which offsets underlying demand growth, due to wet and cloudy conditions over the quarter and decelerating growth in PV installations.

[2] Bureau of Meteorology 2022, La Niña event declared - above average rainfall likely for eastern Australia: https://media.bom.gov.au/releases/1069/la-nina-event-declared-above-average-rainfall-likely-for-eastern-australia/.

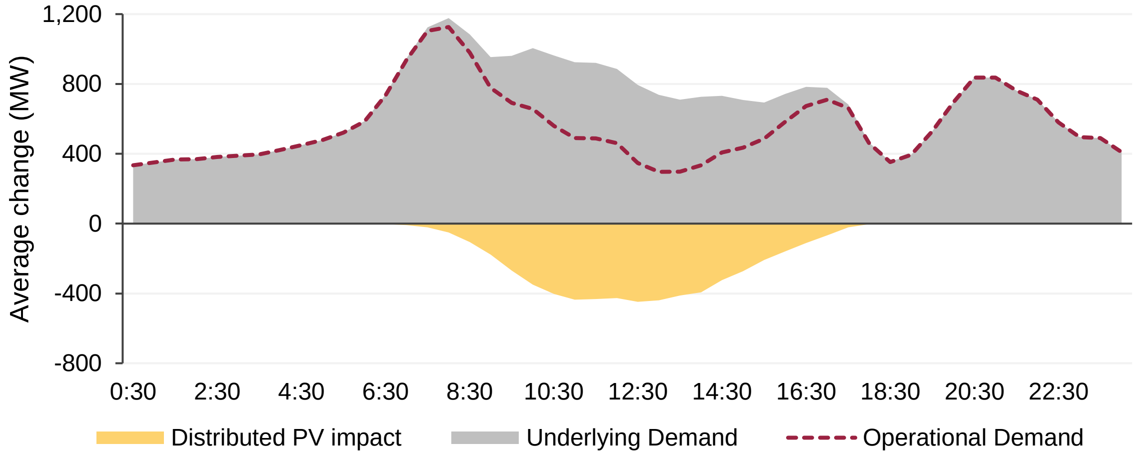
[3] Bureau of Meteorology 2022, Wet outlook continues with a negative Indian Ocean Dipole event underway: https://media.bom.gov.au/releases/1050/wet-outlook-continues-with-a-negative-indian-ocean-dipole-event-underway/.

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

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

Figure 2 Operational demand increase driven by growth in underlying demand

Changes in average NEM demand components by time of day – Q3 2022 vs Q3 2021



While average Q3 operational demand rose across most NEM regions, growth was most pronounced in New South Wales and Victoria, which saw average increases of 353 MW (+4.4%) and 155 MW (+3%) respectively, with the largest growth in demand during the morning peak across both regions. These changes were driven by rebounding demand following the impact of COVID-19 restrictions in New South Wales and Victoria during much of Q3 last year. South Australia also saw an average increase in operational demand of 4%. In Victoria and South Australia, colder weather led to increased heating requirements relative to Q3 2021, contributing to increased electricity demand. Most of the Q3 growth in demand occurred in August and September (Figure 4).

Figure 3 First year-on-year increase in NEM Q3 operational demand since 2015

NEM average operational demand (Q3s)

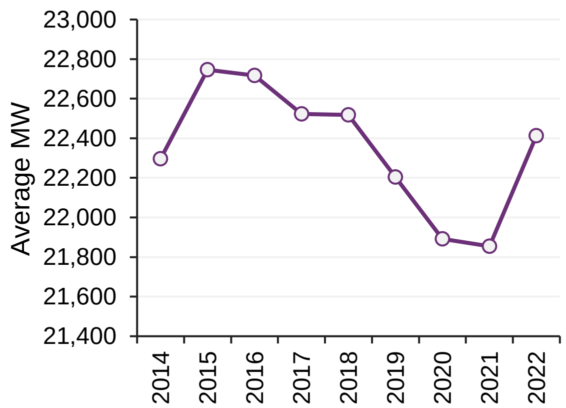
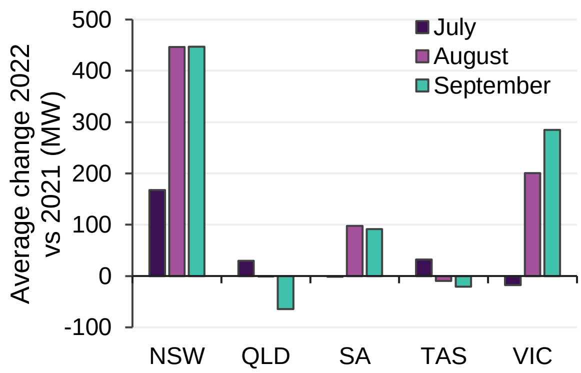


Figure 4 High operational demand growth over August and September for Victoria and New South Wales

Average monthly operational demand change by region – Q3 2022 vs Q3 2021

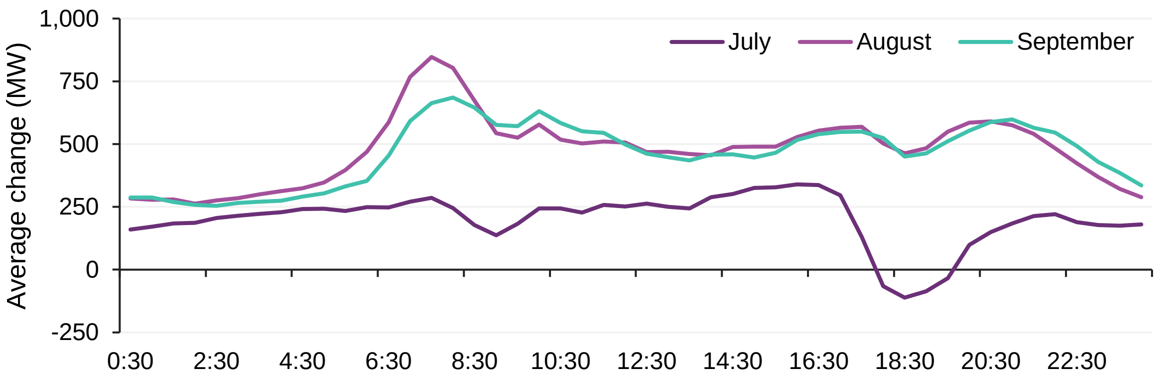


Q3 underlying demand was also up 3-4% relative to pre-COVID-19 levels of 2018 and 2019. In addition to demand rebounding following COVID-19 restrictions in New South Wales and Victoria, conditions were cooler than in 2018 and 2019, with Q3 2022 maximum temperatures below the 10-year average across all capital cities.

All mainland regions reached their highest Q3 average underlying demand levels in recent years. As Figure 5 shows, much of New South Wales' underlying demand increase (+380 MW) was driven by high growth in August and September, while July saw a decline in average evening peak demand relative to Q3 2021, reflecting industrial market customer response to elevated prices. Victoria saw a similar trend, with average July underlying demand growing only slightly relative to 2021 (+0.8%) before growing strongly in August (+4%) and September (+5.9%).

Figure 5 Growth in underlying demand strongest over August and September in New South Wales

Average change in New South Wales monthly underlying demand by time of day – Q3 2022 vs Q3 2021



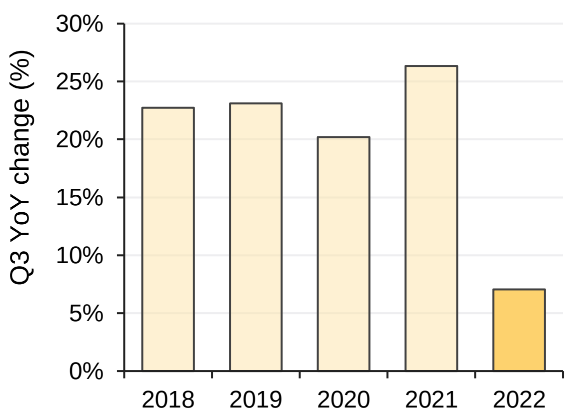
Growth in average distributed PV output was low relative to previous years, although varying materially within the quarter and between regions. Average distributed PV output across the NEM grew by just 7% between Q3 2021 and Q3 2022, falling from year-on-year (YoY) Q3 growth rates of over 20% since 2018 (Figure 6).

Key drivers included:

- Higher rainfall and cloudy conditions across the mainland NEM influenced by the La Niña climate pattern. This was also reflected in declines in average solar irradiation across key weather stations in the NEM relative to the three-year Q3 average[6].
- Decelerating growth in distributed PV installations over recent quarters. The number of systems installed in the first half of 2022 was 30% lower than the same period in 2021, driven by supply side factors (such as weather-related delays and labour supply issues) as well as demand side factors (such as cost of living increases)[7].

Figure 6 Declining growth in distributed PV output

Q3 year-on-year change in average estimated distributed PV output



Maximum demand

Queensland reached a new Q3 maximum quarterly operational demand record of 8,716 MW at 1800 hours on Monday 4 July 2022. This was 504 MW higher than the previous long-standing Q3 maximum demand record of 8,212 MW set in July 2008 and was also a new winter record, exceeding the previous winter record of 8,255 MW (set on 9 June 2022) by almost 461 MW. The following day, Tuesday 5 July, also exceeded the previous winter

[6] BoM 2022, Daily solar exposure data – selected sites: http://www.bom.gov.au/climate/data/.

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

record for multiple intervals, reaching a maximum of 8,625 MW. This high demand was driven by extremely cold temperatures, including the coldest winter day on record for many Queensland locations, coupled with very low distributed PV output due to cloudy and rainy conditions, and coincided with extended spot price volatility (discussed in Section 1.2.2, Figure 17).

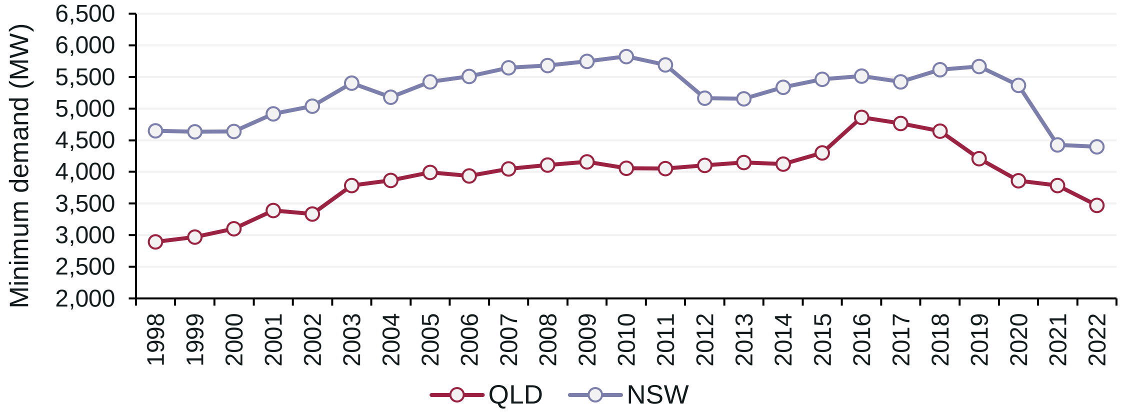
Minimum demand

The onset of spring saw new minimum operational demand records set in September, driven by mild and sunny conditions coinciding with low weekend demands (Figure 7). These records included:

- A new NEM-wide low of 12,583 MW at 1230 hours on Sunday 25 September. This was 353 MW (3%) lower than the previous record set in Q4 2021. During this interval, distributed PV output was 9,255 MW, accounting for 42% of NEM underlying demand.
- In the half-hour that followed (1300 hours on Sunday 25 September), New South Wales also hit an all-time minimum demand record of 4,398 MW, which was 27 MW lower than the previous record set in Q4 2021, with distributed PV output also accounting for 42% of underlying demand in the interval.
- Queensland also saw its lowest minimum demand since 2002, reaching 3,469 MW at 1300 hours on Sunday 11 September. During this interval, distributed PV provided 2,909 MW of output, meeting 46% of Queensland's underlying demand.

Figure 7 New minimum demand record for New South Wales, Queensland's lowest minimum demand since 2002

Queensland and New South Wales annual minimum operational demands



Victoria and South Australia also reached new Q3 quarterly minimum demand records:

- South Australia's new Q3 quarterly minimum demand record of 195 MW occurred at 1400 hours on 24 September 2022, with distributed PV accounting for 87% of underlying demand. This was 41 MW lower than South Australia's previous Q3 minimum demand record but still 91 MW above the region's all-time minimum demand record of 104 MW set in November 2021[8].
- On Sunday 25 September 2022, the same day that the NEM and New South Wales set new all-time minimum demand records, Victoria hit a new Q3 minimum demand record of 2,531 MW at 1230 hours, with distributed PV accounting for 47% of underlying demand[9].

[8] This record has been surpassed in Q4 2022. On 16 October 2022, South Australia set a new all-time minimum demand record of 100 MW.

[9] Just after the end of the quarter, Victoria set a new all-time minimum operational demand record, reaching 2,285 MW on Sunday 2 October 2022 at 1300 hours (previous all-time record was 2,333 MW in November 2021).

Intra-day demand swing

Daytime intra-day demand swing which refers to the difference between daily maximum and minimum demands are rising across the NEM as minimum operational demands increasingly occur during the middle of the day[10]. Efficient management of intra-day demand swings is becoming increasingly important as renewable penetration increases. Queensland, Victoria and South Australia all set new Q3 records this quarter:

- On the same day as its new Q3 minimum demand record (24 September 2022), South Australia reached a new Q3 daytime intra-day demand swing record of 1,496 MW[11], 119 MW higher than the previous Q3 record set in 2021.
- Queensland recorded its highest daytime Q3 intra-day demand swing of 3,696 MW on 16 August 2022, only 45 MW lower than its all-time record of 3,741 MW set in Q2 2022.
- Victoria's new Q3 record of 3,332 MW recorded on 21 August 2022 was 108 MW higher than its previous Q3 intra-day daytime demand swing record set in Q3 2021.

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

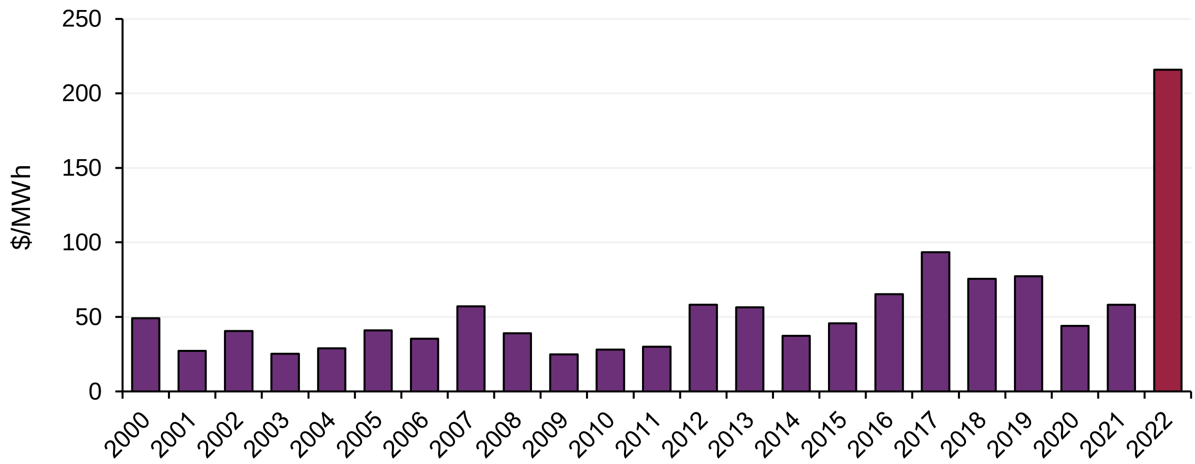
[11] Excluding 2016 black system.

1.2 Wholesale electricity prices

Wholesale spot prices averaged a Q3 record high of $216/MWh across all NEM regions, $158/MWh (271%) higher than Q3 2021 (Figure 8), but down $48/MWh from the highest recorded quarterly price of $264/MWh in Q2 2022.

Figure 8 NEM average spot prices reach highest Q3 level

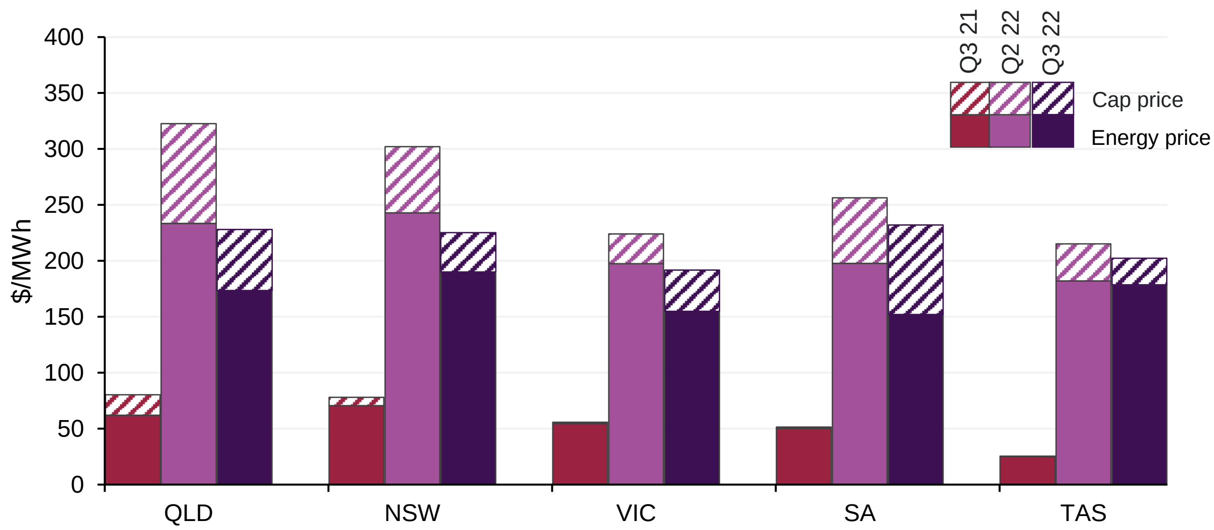
NEM average quarterly wholesale electricity spot price – Q3's since market start



Each NEM region set a Q3 record, with average prices ranging from $192/MWh in Victoria to $232/MWh in South Australia (Figure 9). No NEM region has previously recorded a Q3 average price of over $100/MWh, except for South Australia in Q3 2016 ($119/MWh).

Figure 9 High energy prices across all NEM regions in Q3 2022

Average wholesale electricity spot price by region – energy[12] and cap price

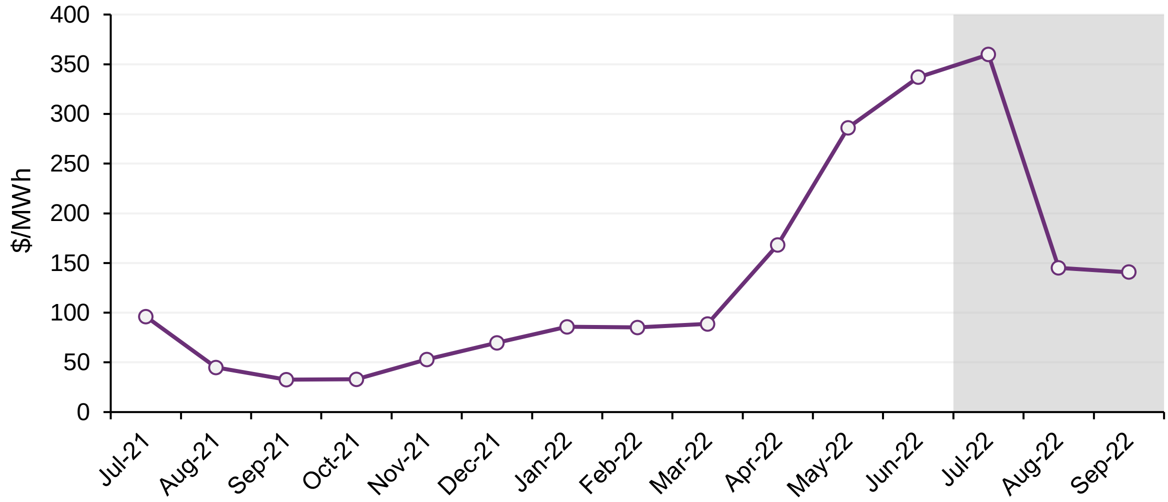


[12] 'Energy price' calculation in analysis of spot electricity price averages truncates the impact of price volatility (that is, price above $300/MWh, also known as "cap return"). Since commencement of Five Minute Settlement (5MS) on 1 October 2021, energy and cap prices are calculated on a 5-minute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

Very high spot prices occurred at the beginning of the quarter, continuing from the record highs in Q2 2022. The July NEM monthly average of $360/MWh was $23/MWh higher than the June 2022 average of $337/MWh (Figure 10), which was the previous all-time monthly record. Victoria, South Australia and Tasmania recorded their highest ever monthly price in July, and New South Wales and Queensland their second highest, behind June 2022. Prices fell in August to a NEM average of $145/MWh, although still at an elevated level, being the highest recorded August average prices in each NEM region.

Figure 10 NEM monthly average prices peak in July

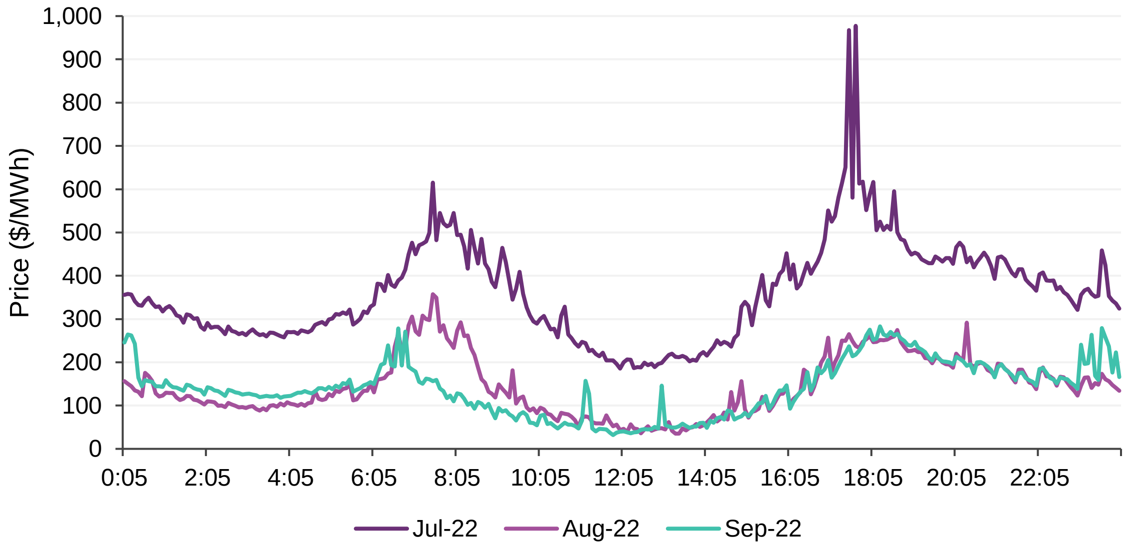
NEM average monthly wholesale electricity spot price – last 15 months



Although most of the quarter's price volatility occurred in July (Section 1.2.2), underlying energy prices were very high across Q3, at their second highest level in all regions for any quarter except Q2 2022. The profile of spot prices by time of day was consistently higher relative to Q3 2021. Similarly to Q3 2021, there was a substantial drop in these averages from July to August and September (Figure 11).

Figure 11 Average NEM prices drop over quarter

NEM average monthly wholesale electricity spot price by time of day – Q3 2022



1.2.1 Wholesale electricity price drivers

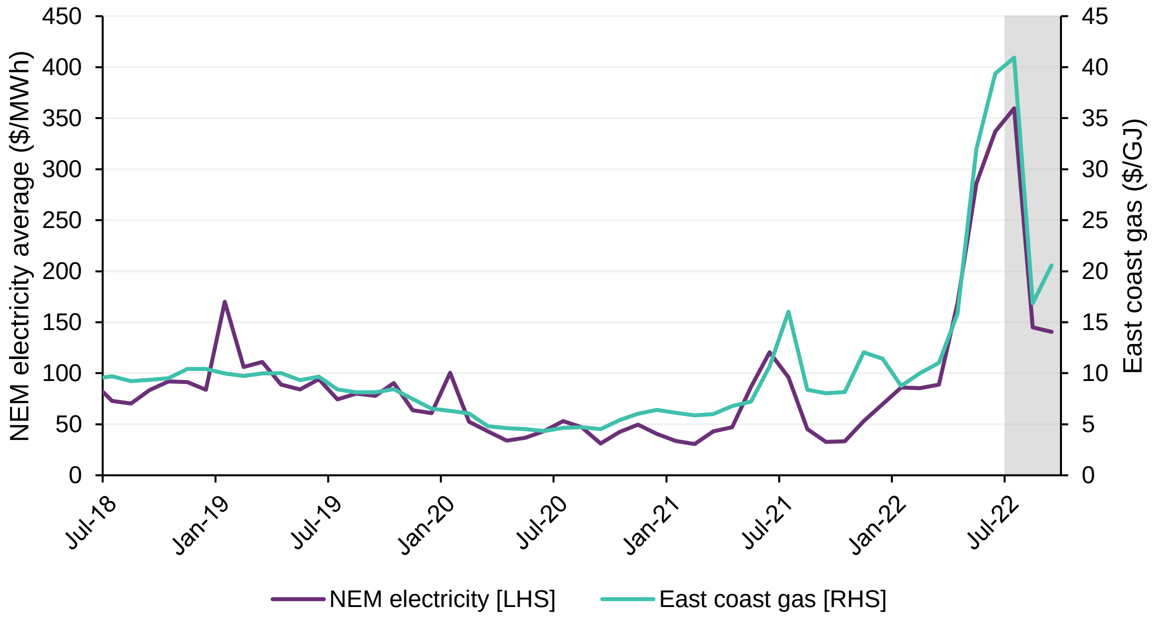
The high electricity spot prices seen throughout Q3 2022 were influenced by a number of factors continuing trends evident in Q2 2022. These drivers are discussed in Table 1.

Table 1 Wholesale electricity price levels: Q3 2022 drivers

Thermal generation	The ongoing war in Ukraine and higher demand ahead of the Northern Hemisphere winter has increased the market price for domestic gas and export-grade thermal coal (Section 2.1.1). Steep increases in traded price for thermal coal export combined with wet conditions across the east coast impacting local black coal supply saw many black coal generators repricing offer volumes to higher price bands. Compared to Q3 2021, volumes offered by NEM black coal below $100/MWh reduced by over 2,000 MW on average (Section 1.3.1). Increased reliance on gas generation at the start of the quarter (Section 1.3.2) at a time when east coast gas prices were at significantly elevated levels (Figure 12) meant the average NEM price when it was set by gas-generators was $330/MWh (Section 1.2.4).
Hydro price-setting	Hydro generators set the price more often and at higher prices than in Q3 2021 (Section 1.2.4). As other generators' offers and spot prices increase, managing the dispatch of limited water supply means that hydro units will also bid into higher price bands.
Increased operational demand	Compared to Q3 2021, underlying demand rose, predominantly in New South Wales and Victoria as those regions had COVID restrictions in place for much of the Q3 2021 quarter (Section 1.1.2). While distributed PV output was higher compared to Q3 2021, the rate of growth (+7%) was significantly less than previous years due to slower uptake of installed capacity as well as wet and cloudy conditions during the quarter. These factors combined to yield the first YoY growth in Q3 operational demand since 2015, an increase of 559 MW on average on Q3 2021. Brief periods of cold weather and low solar output saw Queensland's' maximum operational demand reach new records (Section 1.1.2).
Price volatility	Q3 is not typically a period associated with prices above $300/MWh, however a significant proportion of dispatch prices in the quarter exceeded this threshold (Section 1.2.2). In addition to the generally high level of spot prices seen in July, there were several episodes of extreme price events (>$1,000/MWh) that occurred in Queensland early July, driven by unusually cold and cloudy days and limited supply. Later in August and September, periods of extreme prices in South Australia lifted the average quarterly price in that region.

Figure 12 NEM electricity and east coast gas prices continue to follow each other

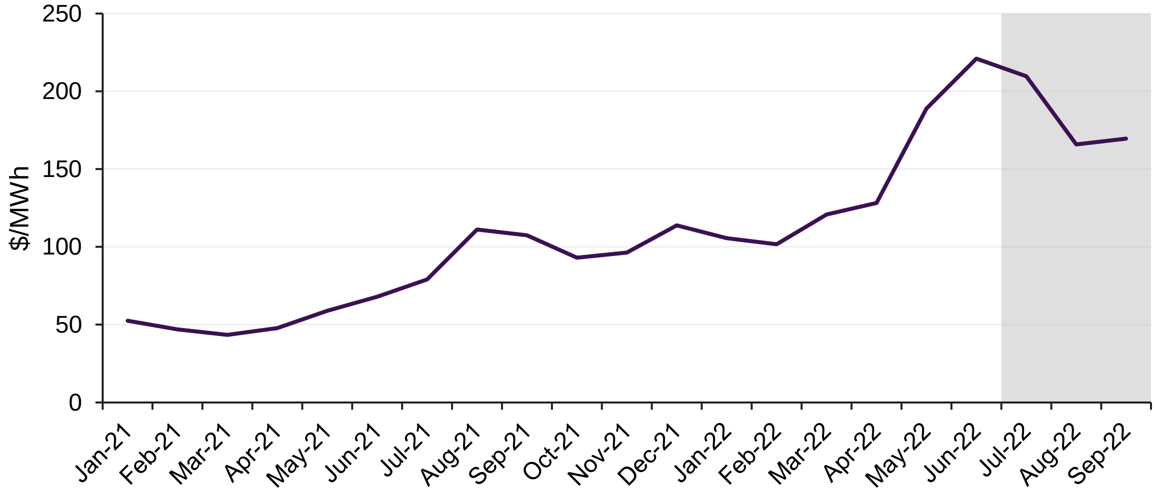
NEM wholesale spot electricity prices and east coast wholesale gas prices – monthly average price



As traded prices for export-grade black coal increased (Section 2.1.1), the volume-weighted marginal offer prices of key black coal generators in New South Wales and Queensland also continued an upward trend, peaking in June and staying at an elevated level in July before declining in August (Figure 13).

Figure 13 Black coal generators increasing marginal offers

Monthly volume-weighted marginal offer prices – Eraring, Mt Piper, Vales Point, Gladstone – last 15 months[13]



The impact of offer repricing by black coal generators in New South Wales is illustrated in Figure 14, which highlights the substantially lower average supply volumes offered by these generators at prices below $100/MWh, particularly for the month of July 2022 where volumes offered below this threshold decreased by nearly 2,600 MW relative to July 2021. This contributed to the especially elevated NEM spot prices recorded in the month. Section 1.3.1 covers this behaviour in more detail.

Figure 14 New South Wales black coal-fired generators offer less volume at sub-$100/MWh prices

Average monthly offers by price range for New South Wales black coal-fired generators – Q3 2021 vs Q3 2022 by month

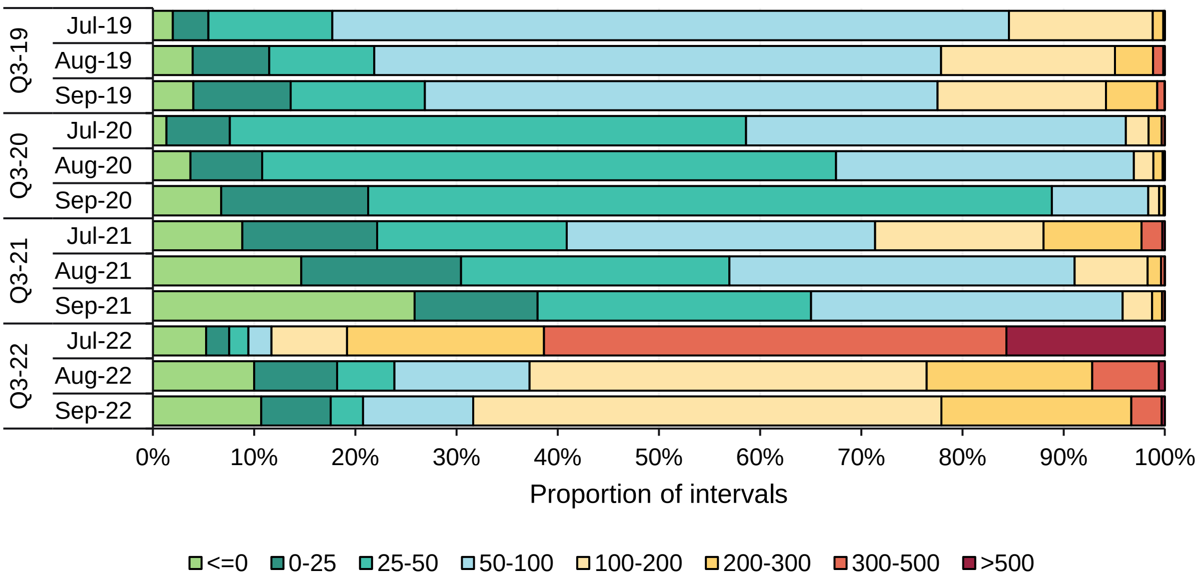
[13] Market offers between $10/MWh and $300/MWh

1.2.2 Wholesale electricity price volatility

Historically, Q3 is not a volatile period with no prior Q3 having recorded more than 1% of dispatch prices above $300/MWh[14]. This Q3 however saw 24% of dispatch intervals with a price over $300/MWh. In July, prices in 61% of dispatch intervals exceeded $300/MWh, the highest monthly proportion since NEM start (Figure 15). A significant portion of these intervals fell in the $300-$500/MWh range. This reflects a broad shift in spot prices moving up past the historical cap threshold of $300/MWh.

Figure 15 Frequent high spot prices throughout Q3

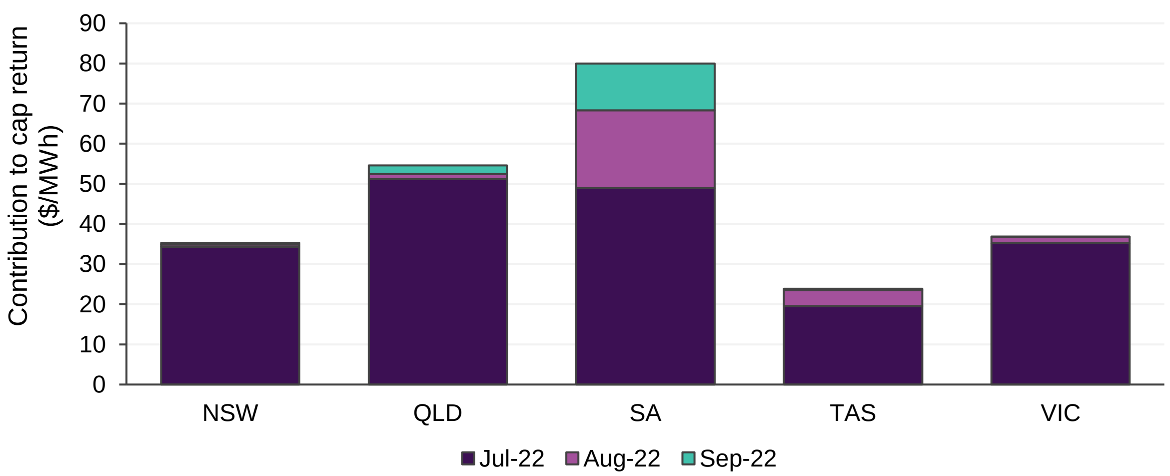
NEM quarterly wholesale electricity dispatch price frequency by price range



The combined cap return from all NEM regions was $231/MWh, compared to Q3 2021's $29/MWh and ranging from Tasmania's $24/MWh to South Australia's $80/MWh. Most of the cap return occurred in July (Figure 16), largely derived from prices in the $300/MWh to $1,000/MWh range.

Figure 16 High price volatility confined to July, with the exception of South Australia

Contribution to quarterly cap return by region and month – Q3 2022

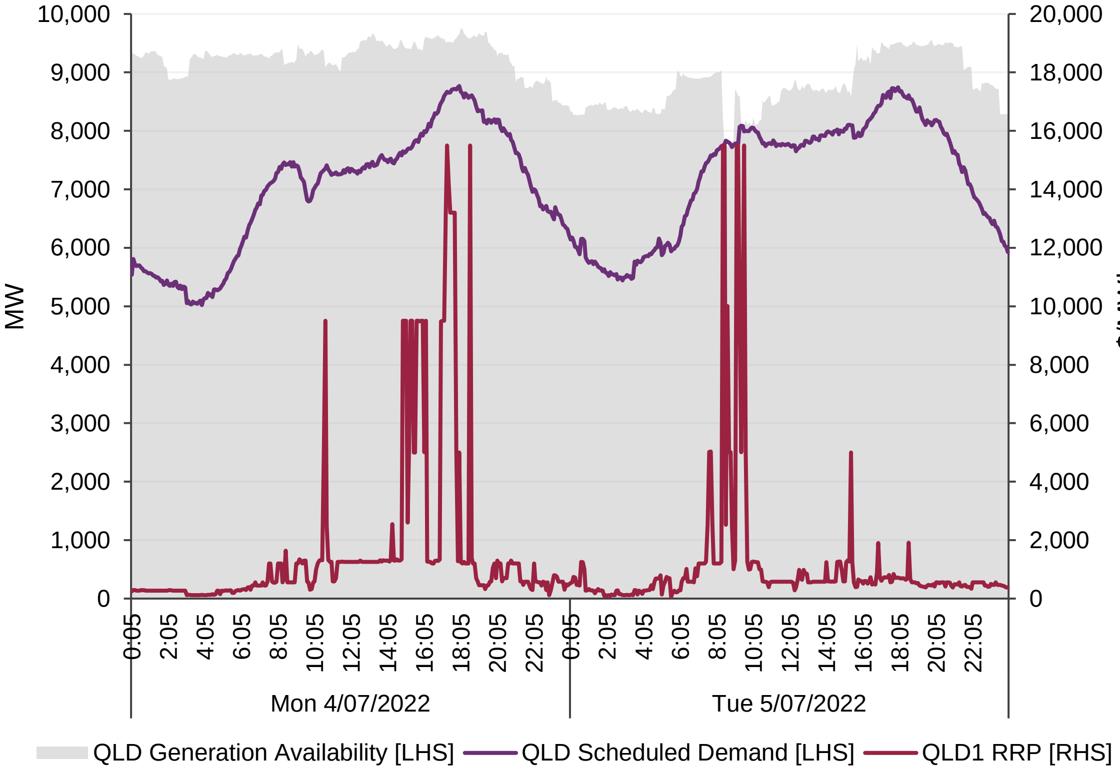


[14] Price volatility is generally measured as the contribution of spot prices above $300/MWh to the average price level for a period.

Queensland experienced particularly volatile days on 4 and 5 July (Figure 17). Low solar irradiance on both of these days due to heavy cloud cover over the region greatly reduced distributed PV output, and combined with an unusually cold period saw demand increase sharply as Queensland reached a new record Q3 operational maximum demand on 4 July (Section 1.1.2). This combined with limited supply in Queensland and constraints on inter-regional imports drove prices to high levels. Cold conditions continued on the next day, and a sudden drop in availability of over 1,300 MW between 0820 and 0830 hrs caused prices to spike. Later on this day, Reliability and Emergency Reserve Trader (RERT) contracts were activated due to a forecast Lack of Reserve (LOR) 2 condition (Section 1.6). Although market prices subsided on 6 July due to market response, lower demand and higher renewable output, the cumulative price[15] peaked at $1,331,162 at 0235 hrs on 7 July coming close to breaching the cumulative price threshold of $1,398,100, which in turn would have triggered administered price caps in the region.

Figure 17 High Queensland prices in early July

Queensland scheduled demand[16], generation availability and spot price – 4 to 5 July 2022



Outside of July, South Australia had several particularly volatile days. On the morning of 26 August, the Heywood interconnector had an imposed 50 MW limit, forcing additional power flow on Murraylink which itself was limited by a prior outage. Combined with low and reducing wind output, the resulting price volatility drove the average spot price for the day to $1,470/MWh, and contributed $13.03/MWh to the Q3 2022 cap return for South Australia. On three September days there were further brief periods of prices above $10,000/MWh in South Australia also attributable to constraints on interconnectors and low wind.

[15] Cumulative price is the sum of regional reference prices across a rolling seven-day period (the 2,016 most recent dispatch intervals).

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

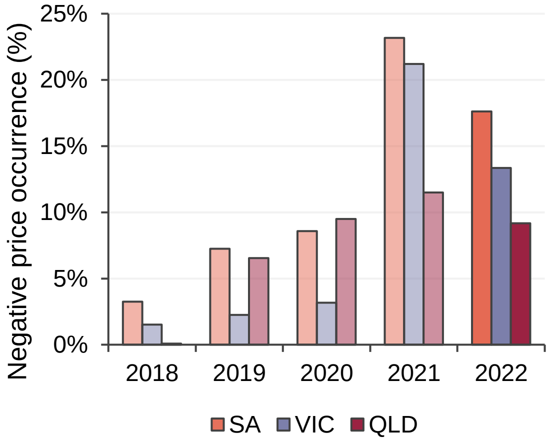
1.2.3 Negative wholesale electricity prices

Negative and zero price occurrence (hereafter referred to as "negative prices") across Q3 2022 was lower than in Q3 2021, with 9% of all dispatch intervals having prices of $0/MWh or lower, compared to Q3 2021's 17%. The impact of negative prices lowered the quarterly average NEM price by $3.6/MWh in Q3 2022 compared to $5.4/MWh in Q3 2021.

This is in contrast to recent Q3s where the occurrence of negative prices has been increasing (Figure 18). Compared to last Q3, this quarter saw an increase in operational demand in the middle of the day (Section 1.3.4) and a reduction in the growth of distributed PV (Section 1.1.2).

Figure 18 Negative price occurrences reduce in Q3

Frequency of zero or negative prices – Q3s selected regions

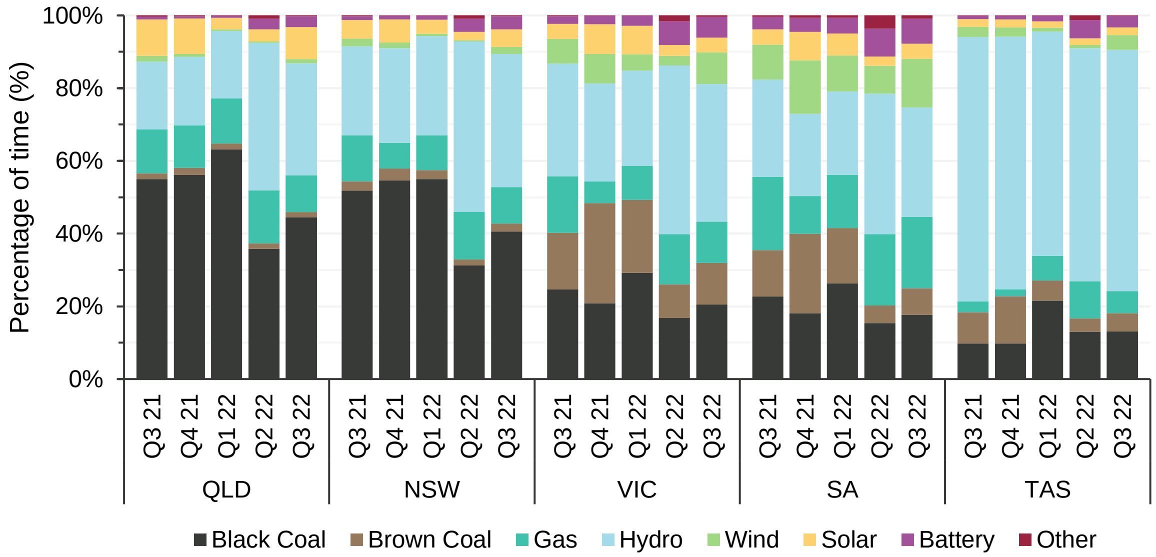


1.2.4 Price-setting dynamics

Prices set by different fuel types saw a change in distribution in Q3. Offers from hydro generators, both mainland and Tasmanian, set price across the NEM most often at a combined 40% of the time, an increase from Q3 2021 at 35%. Black and brown coal-fired generators set the price 33% of the time, down from Q3 2021's 41%. Price-setting frequency for gas-fired generation was slightly lower than last Q3 at around 11% of the time. Wind and solar set the price at 11% of the time, a marginal increase from last Q3. Notable this quarter was the proportion of time batteries set the price, at 6% of prices in Victoria and 7% of prices in South Australia. This is up from 2% and 3% respectively in Q3 2021, and the second highest proportion after Q2 2022 (Figure 19).

Figure 19 Hydro generation sets price most frequently in Q3, while coal's price setting role reduced

Price-setting frequency by fuel type[17]



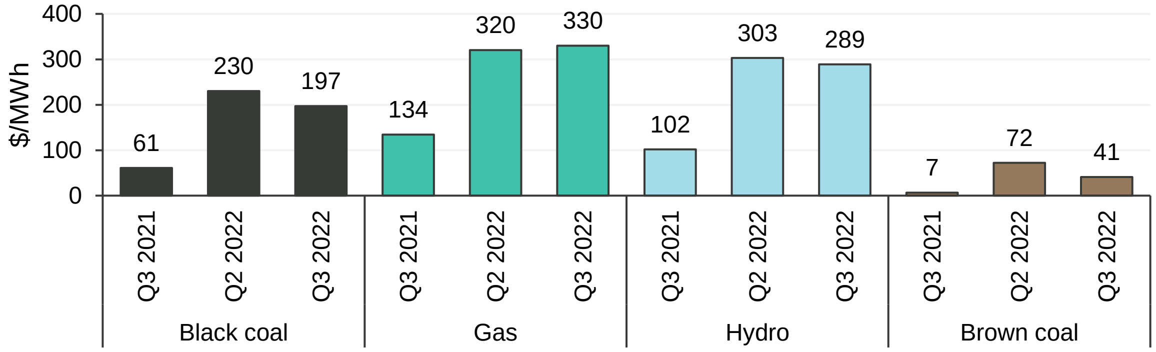
[17] The NEM's interconnected structure allows prices in one region to be set by market offers in a different region provided that interconnector flows are not constrained, meaning for example that offers from black coal generators in New South Wales or Queensland may at times set price in southern NEM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

The reduced frequency of coal-fired generation setting the price in Q3 2022 is a reflection of offered volume being moved to higher price bands and being dispatched less often (Section 1.3.1). This has lifted the incidence of gas-fired and hydro generation as marginal fuel sources, at average prices higher than would previously have been set by coal-fired generation.

The average mainland NEM price that hydro generators set while being the marginal generator was $289/MWh, significantly up from last year's Q3 average of $102/MWh. Gas-fired generators' average price set while marginal was $330/MWh, an increase of $196/MWh from Q3 2021 and even higher than the Q2 2022 level of $320/MWh (Figure 20).

Figure 20 Average marginal prices set by thermal and hydro generators reflect higher input costs

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



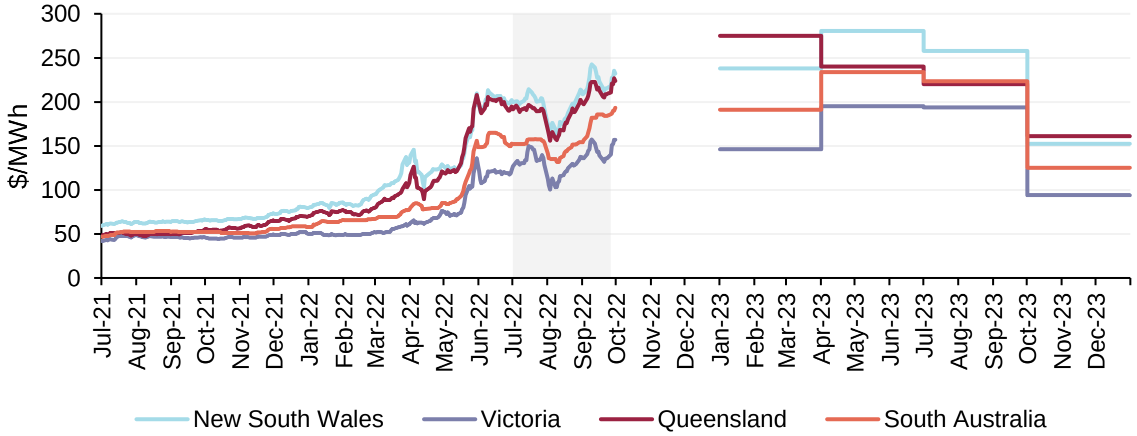
1.2.5 Electricity futures markets

ASX Calendar 2023 (Cal 23) base future prices continued to increase across the quarter in the four NEM mainland regions. Cal 23 New South Wales futures finished the quarter at $232/MWh, with Queensland at $224/MWh, South Australia at $193/MWh and Victoria at $157/MWh (Figure 21).

Throughout most of Q3 2022, baseload futures for Q2 and Q3 2023 were trading at higher prices than Q1 2023 baseload futures in all mainland regions other than Queensland (Figure 21). This indicates a market view that winter 2023 energy costs will be higher than the summer period. This reflects the scheduled closure of the remaining Liddell units in early Q2 2023, spot price outcomes in 2022 to date as well as concerns around ongoing high international energy commodity costs (Section 2.1.1).

Figure 21 Cal 23 Futures remain at elevated level, Q2 base quarters exceed Q1 in most regions

ASX Energy – daily Cal 2023 base futures by region; quarterly forward baseload contract prices as at 30 September 2022 shown at right



1.3 Electricity generation

The NEM generation mix in Q3 2022 was shaped by the combination of increased renewable output, a change in demand profile and pricing of dispatchable generation. Figure 22 and Table 2 illustrate the change in NEM generation mix in Q3 2022 compared to Q3 2021, while Figure 23 shows the change by time of day.

- NEM maximum instantaneous renewable share of total generation reached new highs during the quarter (64.1%), with the previous record of 61.9% set in Q4 2021 being surpassed on four separate days during Q3.
- Despite high gas prices, gas-fired generation was up by 259 MW, driven by a combination of high spot price, reduce coal-fired generation, increased operational demand and portfolio dynamics.
- Increased hydro generation particularly across mainland NEM was a reflection of reduced coal generation and increased rainfall. This was however partially offset by reduced output from Tasmanian generators due to dry conditions.
- Black coal generation declined by 144 MW to its lowest Q3 level since NEM start while high levels of unplanned outages across the brown coal fleet reduced quarterly output by 136 MW.

Figure 22 Increased output across all fuel types except coal

Change in supply – Q3 2022 versus Q3 2021

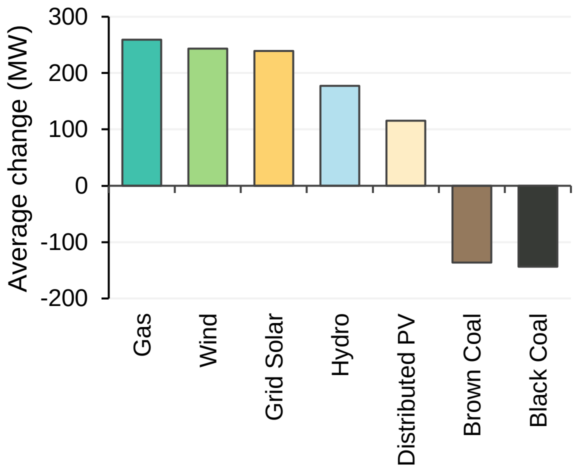
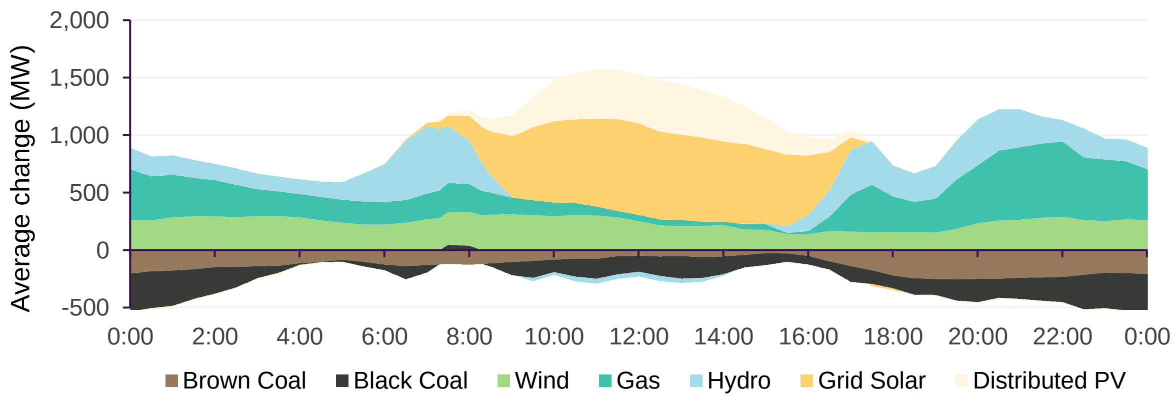


Table 2 NEM supply mix by fuel type[18]

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar	Distributed PV	Other
Q3 2021	46.1%	15.6%	6.2%	8.2%	13.0%	3.7%	6.9%	0.3%
Q3 2022	44.0%	14.6%	7.1%	8.7%	13.6%	4.5%	7.1%	0.3%
Change	-2.0%	-1.0%	0.9%	0.5%	0.6%	0.9%	0.2%	0.0%

Figure 23 Higher output across the day for all fuel types except coal

Change in supply – Q3 2022 versus Q3 2021 by time of day



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

1.3.1 Coal-fired generation

Black coal-fired fleet

Average black coal-fired generation during Q3 2022 was 10,825 MW, representing the lowest Q3 level since NEM start (Figure 24). Decreasing generation from both the New South Wales (-85 MW) and Queensland fleets (-59 MW) despite fewer outages and higher operational demand in New South Wales, was primarily due to a shift in supply offers to higher price bands. With international coal prices continuing to trade at record levels (Section 2.1.1), and a reduction in capacity resulting from the closure of Liddell Unit 3 earlier in Q2 2022, the volume of black coal offers priced under $100/MWh this quarter reduced by 2,065 MW compared to Q3 2021 (Figure 25).

Figure 24 Record low Q3 black coal generation

Average NEM black coal-fired generation by region – Q3s

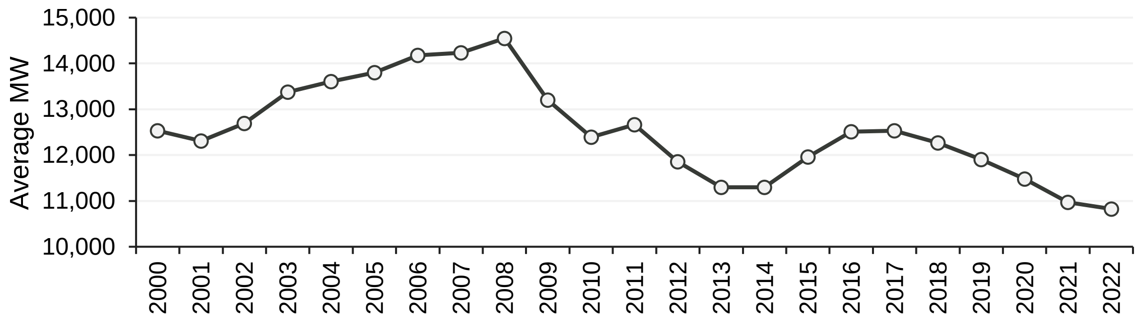
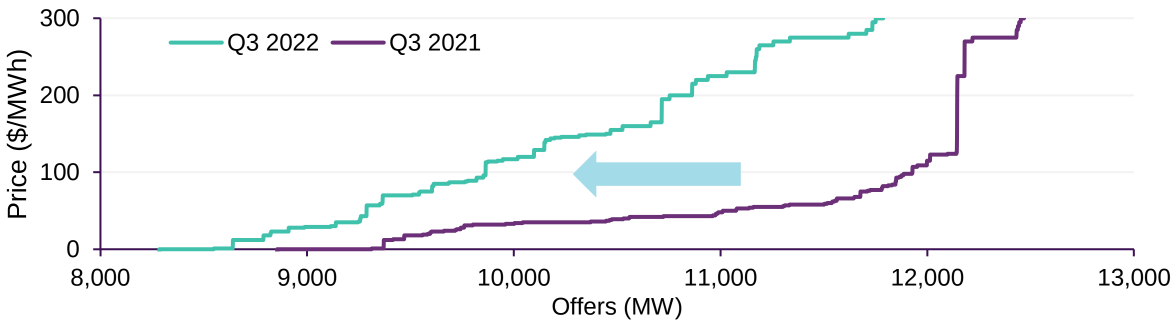


Figure 25 Large shift in black coal offers to higher price bands

NEM black coal-fired generation bid supply curve – Q3 2022 vs Q3 2021



Average New South Wales black coal-fired output declined by 85 MW to its lowest Q3 level since NEM start. Lower output was largely attributable to July as output during the month reduced by 481 MW compared to July last year. Key changes by power station compared to Q3 2021 included:

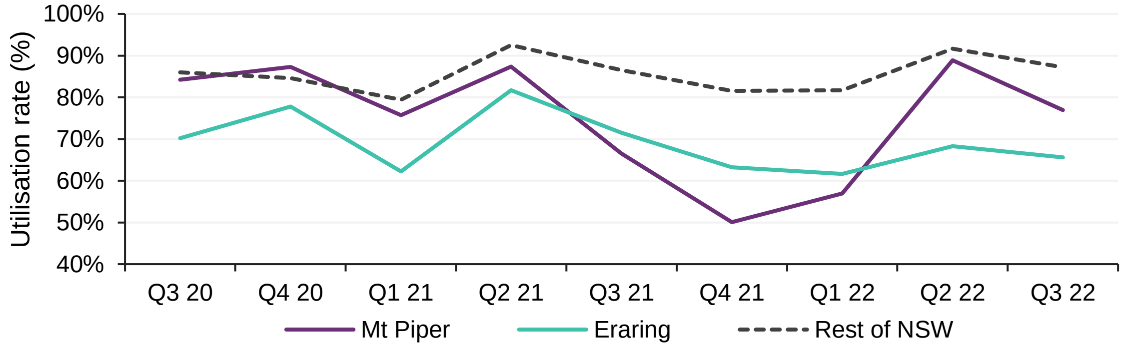
- At Liddell Power Station, reduced capacity due to the closure of Unit 3 in April 2022, coupled with increased outages (majority unplanned) of remaining units, reduced output at the power station by 343 MW on average.
- Average output at Eraring Power Station declined by 105 MW to its lowest Q3 level since 2013. Lower output was driven predominantly by units shifting offers to higher price bands, offsetting a slight improvement in average availability (+35 MW) due to reduced outages. Contrasting with other black coal generators in the region, utilisation of offered capacity at Eraring declined from 71% in Q3 2021 to 66% this quarter (Figure 26), with capacity offered at under $100/MWh declining by 850 MW on average.

- While Eraring's coal supplies have progressively improved since securing new fuel contracts, operation still remains exposed to the risk of under-delivery due to rail transport and mine performance[19].

- At Mt Piper Power Station, higher Q3 availability due to lower outages, and increased utilisation (77% in Q3 2022 compared to 67% in Q3 2021), resulted in average output rising by 255 MW (Figure 26).

Figure 26 Eraring utilisation rate lower than in Q3 2021, contrasting with other New South Wales coal generators

Black coal-fired generation quarterly utilisation rate – Eraring, Mt Piper and rest of New South Wales fleet



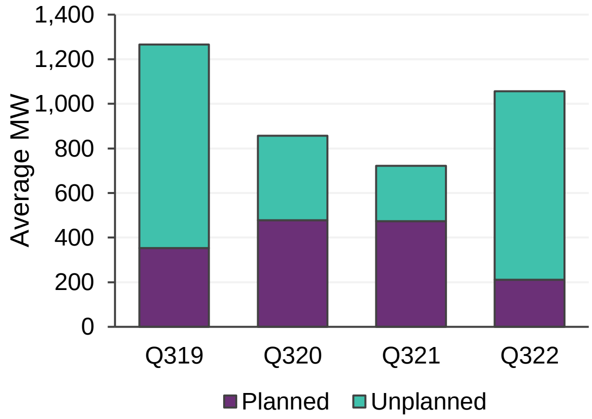
Despite fewer outages compared to Q3 2021, average Queensland black coal output decreased slightly by 59 MW, primarily driven by the shift in black coal bids to higher price bands with offer volume priced under $100/MWh this quarter decreasing by 469 MW on average.

Brown coal-fired fleet

Compared to Q3 2021, average brown-coal fired generation fell by 136 MW, with reductions across all three power stations – Loy Yang A (-60 MW), Yallourn (-41 MW) and Loy Yang B (-36 MW).

Figure 27 High brown coal unplanned outages

Brown coal outage classifications – Q3s



Lower brown coal availability driven by increased outages (largely unplanned, Figure 27) was a key contributor to the reductions, as utilisation rates increased slightly from 94% in Q3 last year to 96% primarily due to reduced occurrence of negative prices this quarter (Section 1.2.3). Of note was Loy Yang A Unit 2 which remained out of service for the entire quarter as its return to service schedule was extended to the second half of October due to a defect in a replacement part that was identified during testing[20]. On 29 September, AGL also announced that closure dates for Loy Yang A Power Station will be brought forward to FY 2035, 10 years earlier than previously announced[21].

[19] Origin 2022, Origin Energy 2022 Full Year Results: https://www.originenergy.com.au/wp-content/uploads/FY22_Investor-Presentation_FINAL.pdf.

[20] AGL 2022, Loy Yang A Unit 2 Generator Fault – Update on expected return to service: https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/media-centre/2022/220912-loy-yang-a-unit-2-generator-fault-update-on-expected-return-to-service.pdf

[21] AGL 2022, ASX & Media Release 29 September 2022: https://www.agl.com.au/content/dam/digital/agl/documents/about-agl/media-centre/2022/220929-review-of-strategic-direction-outcomes-and-fy23-guidance.pdf

1.3.2 Gas-fired generation

During Q3 2022, NEM gas-fired generation[22] averaged 1,744 MW, up 259 MW compared to Q3 2021. The increase in output on Q3 2021 levels despite higher gas prices was influenced by shifts in black coal-fired bidding, higher spot electricity prices, portfolio dynamics and increased operational demand. While average generation was higher than Q3 last year, it was down 467 MW from Q2 2022, as output progressively declined during the quarter from its July high (Figure 28).

Figure 28 Highest Q3 gas-fired generation since 2020, however down compared to Q2 2022

Average NEM gas-fired generation by region – quarterly and monthly for Q3 2022

- Victorian gas generation increased by 159 MW on average to its highest Q3 level since 2019, driven by a combination of higher spot prices, lower brown coal generation and portfolio dynamics. Increased output occurred despite higher gas prices and a direction by AEMO to two gas-fired generation facilities in the region to cease purchasing gas from the DWGM to run gas generation without a corresponding supply (Section 2.3.3). In response, some gas-fired generators were using secondary liquid fuels for part of their output during this period.
  - By generator, Origin's Mortlake and EnergyAustralia's Newport (combined increase of 102 MW) accounted for the majority of increased output in the region, with the latter predominantly covering for outages at Yallourn. Output at Snowy's Laverton and Valley Power also increased by 29 MW and 10 MW respectively, with elevated output during the first half of July accounting for most of the quarter on quarter increase.
- Increased New South Wales output (+86 MW, mostly from Tallawarra and Colongra) was driven by the combination of sustained high spot prices in the region, lower black coal-fired output and portfolio dynamics.
- In Queensland, increased output (+63 MW) was mostly from Braemar (+49 MW) which more than offset reduced output from Swanbank E (-27 MW). Swanbank E had been on an extended unplanned outage since December 2021, only returning to service in September.
- Contrasting with other regions, South Australian gas generation declined by 60 MW on average partly due to fewer system security directions to gas-fired generators in the region compared to Q3 2021 (Section 1.6.1).

[22] This includes any generation from liquid fuels where generators whose primary fuel source is gas were running on secondary liquid fuel sources such as diesel or fuel oil, due to limited availability or high prices of gas.

1.3.3 Hydro

Hydro generation rose by 177 MW (9%) on average compared to Q3 2021, reaching its highest Q3 level since 2018 (Figure 29). Higher hydro output this quarter was due to substantial increases in the mainland NEM regions as output in Tasmania declined significantly.

Figure 29 Increased hydro generation driven by mainland NEM regions

Average NEM hydro generation by region - quarterly

- Hydro output in mainland NEM regions increased by 428 MW on average, with increases across Victoria (+205 MW), New South Wales (+164 MW) and Queensland (+59 MW). In particular, output from Snowy Hydro generators was up by an average of 210 MW to the highest Q3 level since 2016, supported by higher storage levels associated with above average La Niña-driven rainfall (Figure 30). As an example, storage levels at Lake Eucumbene[23] progressively increased during the quarter, finishing at 51% compared to 37% in Q3 2021.
- Contrasting the mainland NEM, dry conditions in Tasmania[24] led to hydro generation in the region reducing by 251 MW as generators bid to conserve water, shifting on average over 700 MW of offers to prices above $100/MWh. Hydro Tasmania's storage levels remained comparatively low over the quarter, finishing at 40% compared to 49% in Q3 2021 (Figure 31), the lowest Q3 closing level since 2016.

Figure 30 Highest Q3 output for Snowy since 2016

Snowy hydro generation and pumping – Q3s

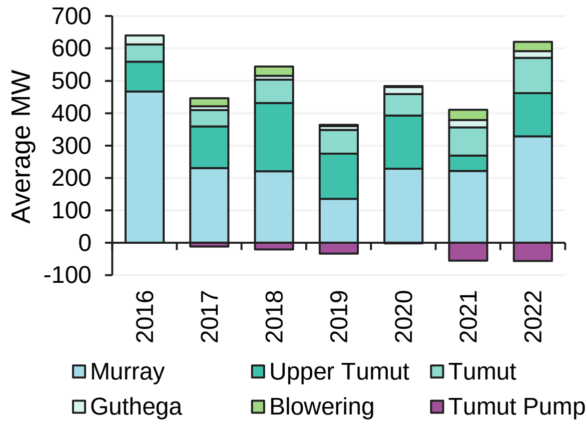
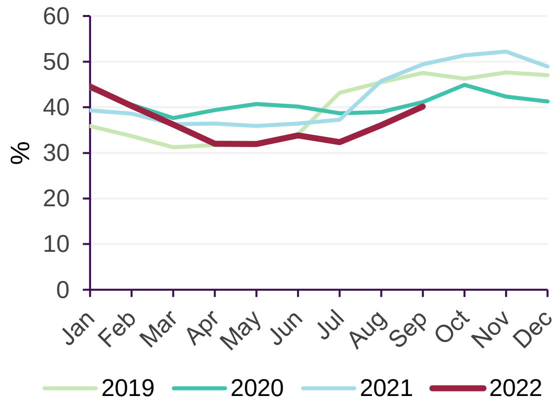


Figure 31 Hydro Tasmania dam levels remain low

Hydro Tasmania dam levels[25]



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

[24] Tasmania recorded its fifth-driest July on record: http://www.bom.gov.au/climate/current/month/tas/archive/202207.summary.shtml

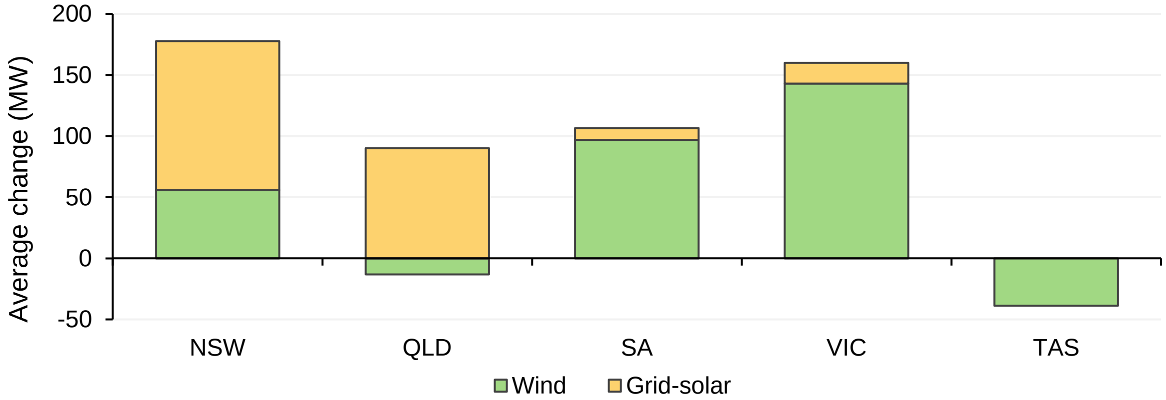
[25] Hydro Tasmania – Energy storage historical data: https://www.hydro.com.au/water

1.3.4 Wind and grid-scale solar

In Q3 2022, average NEM VRE generation reached a record quarterly high of 4,465 MW, surpassing the previous record set in Q1 2022 by 275 MW. Compared to Q3 2021, average VRE generation increased by 483 MW, with almost equal contributions from wind and grid-scale solar of 244 MW and 239 MW (Figure 32).

Figure 32 Increased VRE output across mainland NEM

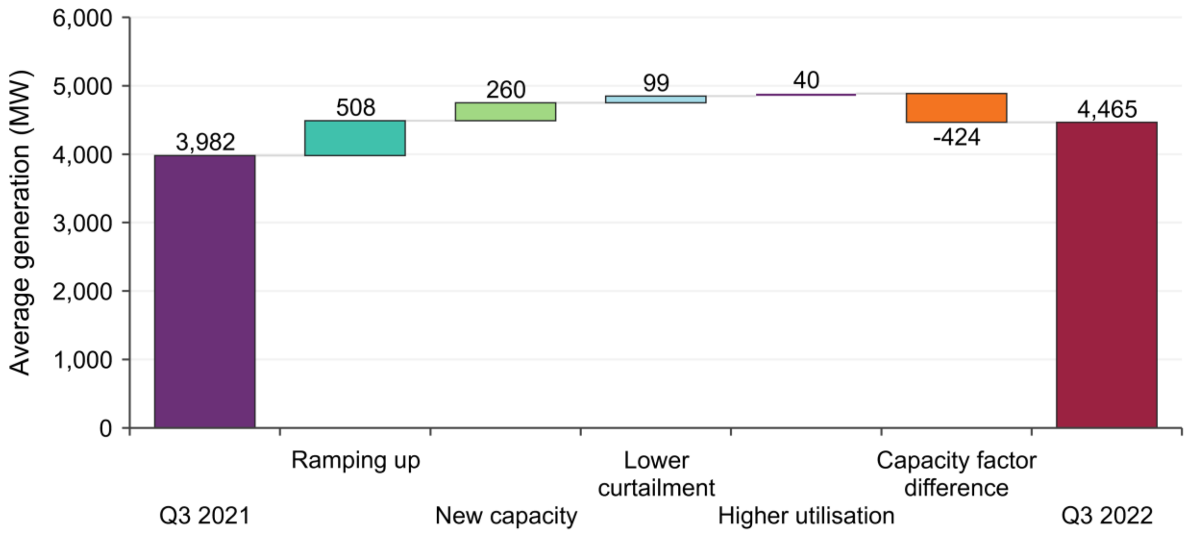
Average change in VRE generation – Q3 2022 versus Q3 2021



Ramping up of capacity that was still commissioning[26] and new capacity additions that have entered the NEM over the past year, compounded with lower curtailment and increased utilisation[27], were key drivers of the record. However, the growth in output resulting from the combination of these factors was partly offset by falls in available capacity factors due to lower wind speeds and solar irradiation during the quarter (Figure 33).

Figure 33 Ramping up of capacity and new capacity additions largest contributor to VRE output increase

Change in NEM VRE generation by drivers – Q3 2022 versus Q3 2021



[26] Includes projects which started generating in quarter(s) earlier than the comparison period (Q3 2021) but had not reached full capacity.

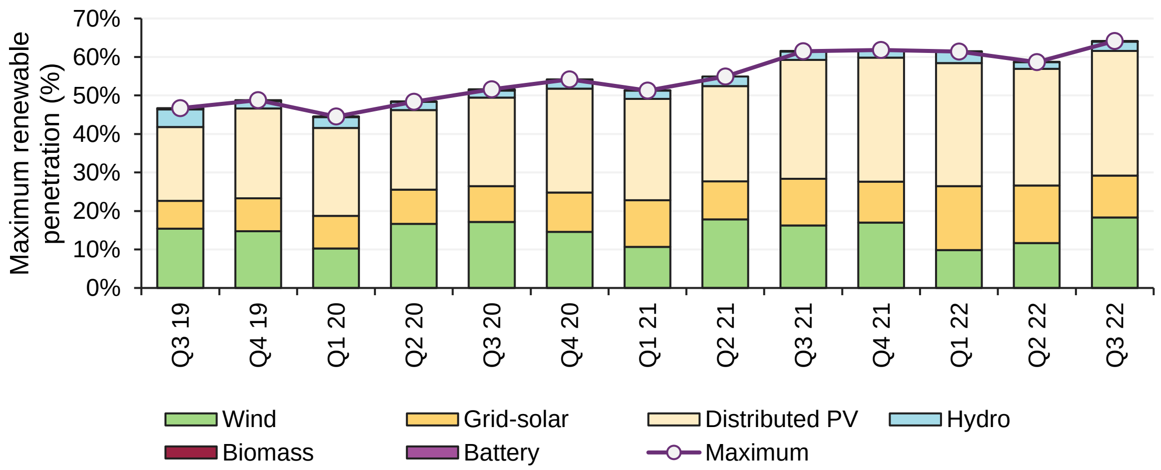
[27] VRE utilisation captures generators' economic offloading or market response to price signals such as negative spot prices or high FCAS prices. Here, a generator's utilisation rate refers to output divided by availability adjusted for the impact of constraints.

With record high quarterly VRE output, several other renewable records were set during the quarter:

- Highest NEM instantaneous renewable share of total generation[28] – on 18 September 2022, renewable penetration reached a record high of 64.1% of total NEM generation in the trading interval ending 1130 hrs (Figure 34). Notably, the record previously set on 15 November 2021 (61.9%[29]) had been successively broken on four separate days during Q3 2022.
  - During this interval, estimated distributed PV output accounted for 32% of total generation, followed by VRE at 29%.
- Highest wind output – NEM wind output reached 7,271 MW at 2100 hrs on 4 August 2022, 8% higher than the previous record set in Q2 2022.
- Highest grid-solar output – NEM large scale solar output reached 4,628 MW at 1000 hrs on 4 September 2022, 3% higher than the previous record set in Q1 2022.
- Highest VRE output – NEM VRE output (wind and grid-scale solar) reached 9,112 MW at 0930 hrs on 22 August 2022, surpassing the previous record set in Q2 2022 by 1%.

Figure 34 NEM instantaneous renewable penetration reached new highs of 64.1%

NEM maximum instantaneous renewable penetration quarterly records



Average wind generation reached a quarterly high of 3,348 MW on average, surpassing the previous record set in Q3 2021 by 8%, driven by increases across all NEM regions apart from Tasmania and Queensland. This record was a function of capacity continuing to ramp up while commissioning and new capacity additions entering the system in the last year. Growth was, however, partly impacted by lower wind speeds during the quarter as available wind capacity factor (36%) was lower than Q3 2021 (41%) as well as the 4-year Q3 average (40%, Figure 35).

By region:

- In Victoria, a majority of the output increase (+143 MW) was driven by ramping up of recently installed capacity (Stockyard Hill, Moorabool and Bulgana wind farms) and new capacity additions (Murra Warra Wind

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

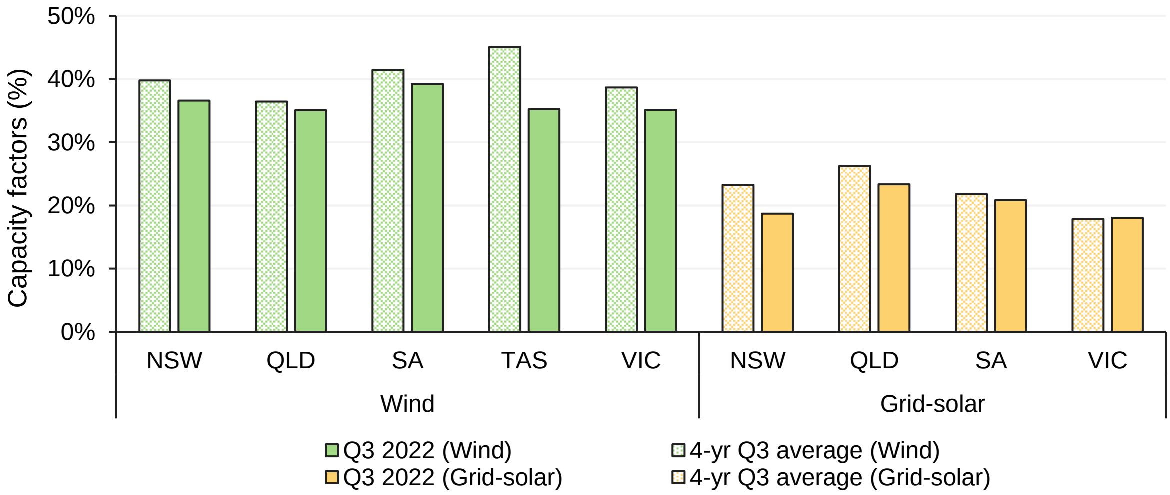
[29] Revised from 61.8% due to a refinement in methodology.

Farm Stage 2), offsetting a reduction in weighted average available wind capacity factors which fell from 41% in Q3 2021 to 35% this quarter. Of note was a marked decline in available capacity factor at Macarthur Wind Farm, averaging only 15% this quarter compared to 34% in Q3 2021 and yielding a quarterly output reduction of 76 MW.

- Despite lower wind speeds in South Australia, higher output (+97 MW) arose mainly from new capacity additions over the last year (Lincoln Gap and Port Augusta Renewable Energy Park wind farms) as well as lower curtailment.
- In New South Wales, higher wind output in Q3 (+56 MW) was a function of continued ramp up of Bango and Gullen Range (Stage 2) wind farms.
- Average output declined in Tasmania by 39 MW this quarter, driven by lower available capacity factors at Musselroe, Cattle Hill and Granville Harbour wind farms. Average available capacity factor in the region fell from 43% in Q3 2021 to 35% this quarter, and was also well below the 4-year Q3 average of 45% (Figure 35).

Figure 35 Substantially lower wind and grid-solar available capacity factors in Q3 2022

Volume-weighted wind and grid-solar capacity factors[30] – Q3 2022 versus 4-year average



Grid-scale solar output increased by 239 MW on average, with New South Wales and Queensland accounting for majority of the increase. While cloudy wet conditions impacted output during the quarter, it was still higher than in Q3 last year largely due to new capacity additions and recently installed capacity continuing to ramp up.

- Despite much lower solar irradiation in New South Wales due to cloudy and wet conditions (discussed earlier in Section 1.1.2), increased average grid-solar output this quarter (+122 MW) was largely driven by a combination of ramping up of capacity, new capacity additions and slightly lower curtailment.
- Similarly in Queensland, capacity additions coupled with ramping up of recently installed capacity and higher output from Sun Metals Solar Farm which was out of service in Q3 last year were key drivers of higher output (+90 MW on average) despite lower solar irradiation.

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

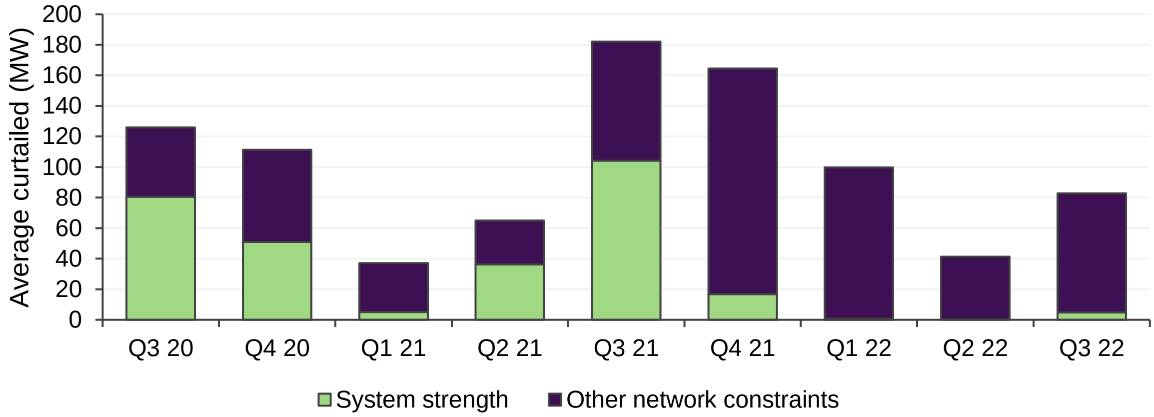
VRE curtailment

Overall constraint-driven curtailment of wind and grid-scale solar output fell from 182 MW in Q3 2021 to 83 MW in Q3 2022 (Figure 36), with the fall entirely attributable to lower impacts from system strength constraints in all mainland regions, particularly South Australia where curtailment due to these constraints fell from 62 MW in Q3 2021 to zero, reflecting operation of the region's four synchronous condensers.

Curtailment from other constraint types associated with network thermal and stability limits was steady versus last year at 78 MW, and seasonally higher than in Q2 2022 (+37 MW), reflecting higher available levels of VRE generation in Q3.

Figure 36 VRE system strength curtailment remains minimal since Q3 2021

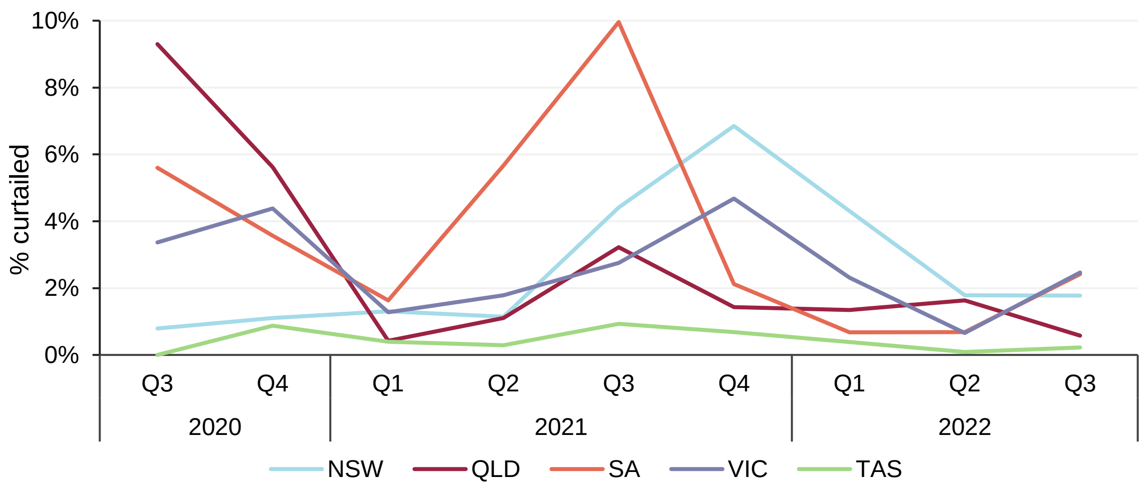
Average NEM VRE curtailed by constraint type



As a proportion of available VRE generation, curtailment across the NEM was down from nearly 5% in Q3 2021 to just under 2% in Q3 2022. At a regional level (Figure 37), South Australia had the largest year-on-year reduction from 10% to 2.4%, with other regions all seeing smaller falls. Relative to Q2 2022, higher regional curtailment percentages in South Australia and Victoria predominantly reflected increased wind farm curtailment, as available output from wind farms in these regions increased by 25% between Q2 and Q3 2022.

Figure 37 VRE curtailment down vs Q3 2021, Victoria and South Australia up on Q2 levels

% VRE curtailed by NEM region

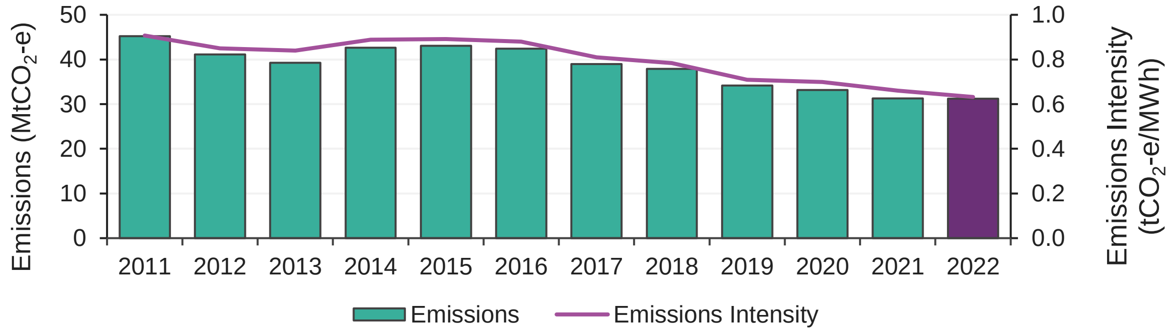


1.3.5 NEM emissions

NEM emissions for the quarter declined slightly to 31.2 million tonnes carbon dioxide equivalent ($MtCO_2$-e), representing the lowest Q3 quarterly emissions recorded (Figure 38). Relative to Q3 2021, the decline in absolute emissions was only marginal (-0.2%) due to higher quarterly operational demand. However, in emissions intensity terms which take into account of total sent out generation[31], the rate of decline was much greater at 4%, driven by lower coal generation combined with continuing growth in VRE output (Section 1.3).

Figure 38 Record low Q3 quarterly emissions

Quarterly NEM emissions and emissions intensity (Q3s)



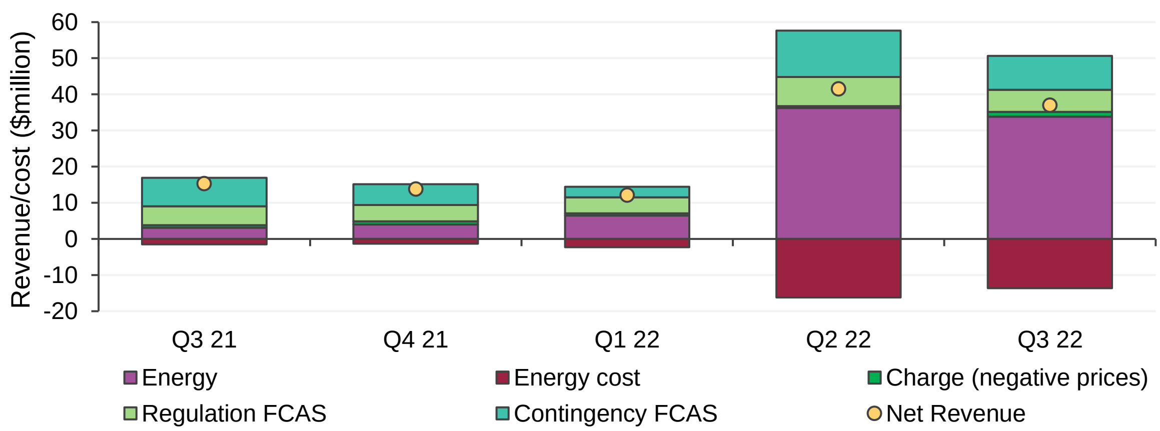
1.3.6 Storage

Batteries

Total estimated net battery market revenue in Q3 2022 remained high at $37 million, only marginally below Q2 2022 levels of $41 million (Figure 39). Compared to Q3 2021, net revenue was almost two and half times higher than Q3 levels a year ago, with majority of the increase from energy arbitrage (+$19 million), while FCAS markets contributed around $3 million. As in the preceding quarter, the energy market was the primary source of battery revenue, accounting for 69% of total gross revenue this quarter, slightly higher than in Q2 2022 (64%).

Figure 39 Battery net revenue remains high

Estimated battery revenue sources – quarterly



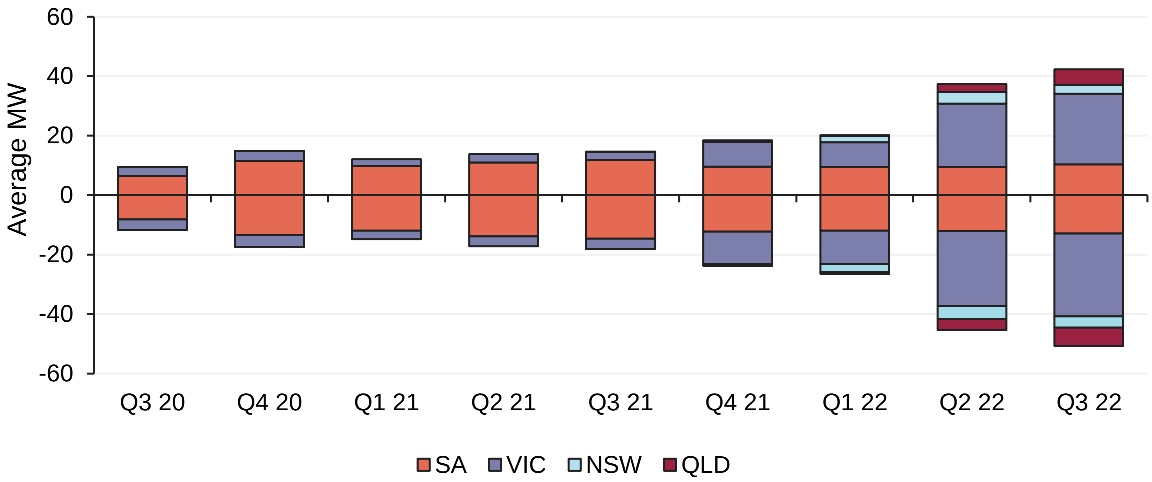
[31] Sent out generation derived from metering data is combined with publicly available generator Emission Factors to provide a NEM-wide Carbon Dioxide Equivalent Intensity Index calculated on a daily basis.

By region, compared to Q3 2021:

- In Victoria, a marked increase in net revenue (+$12.2 million) was predominantly from the energy market (+$9.4 million), a product of greater energy arbitrage value and battery dispatch (Figure 40). Of note was the increased activity from VBB which, as in Q2 2022, was able to participate in all markets up to its full capacity outside of the SIPS contract period[32].
- Increased net revenue in both Queensland (+$4 million) and New South Wales (+$2.6 million) was a function of increased energy dispatch and FCAS enablement at Wandoan and Wallgrove battery energy storage systems (BESS).
- Net revenue from South Australian batteries increased by $2.9 million, as higher energy market revenue (+$6.2 million) was partly offset by a decline in FCAS revenue (-$3.3 million). Higher energy market net revenue arose from a large increase in volume-weighted average energy arbitrage value (from $72/MWh to $357/MWh) which offset lower energy dispatch (-12%, Figure 40). Lower FCAS revenue was due to a decline in volumes enabled in both Contingency and Regulation markets, as recently commissioned batteries in other regions competed for FCAS market share.

Figure 40 Increased dispatch from batteries in Victoria, Queensland and New South Wales

Average quarterly battery generation (+ve) and charging (-ve) by region



Pumped hydro

Similar to battery storage, estimated pumped hydro spot market net revenue in Q3 2022 remained high at $60 million in Q3 2022, just marginally below the record level of Q2 2022 (Figure 41). Compared to Q3 2021, the net revenue increase of $43 million was driven by both Wivenhoe (+$28.6 million) and Shoalhaven pumped hydro (+$14.4 million), with revenue derived in July accounting for majority of the increase.

Sustained high spot prices particularly in July resulting in higher energy arbitrage values for both Wivenhoe and Shoalhaven, coupled with increases in dispatch to drive the increase. For Wivenhoe, dispatch this quarter doubled the levels of Q3 last year, reaching its highest generation and pumping for any quarter since NEM start (Figure 42).

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

Figure 41 Pumped hydro revenue remained high

Estimated pumped hydro sources - quarterly

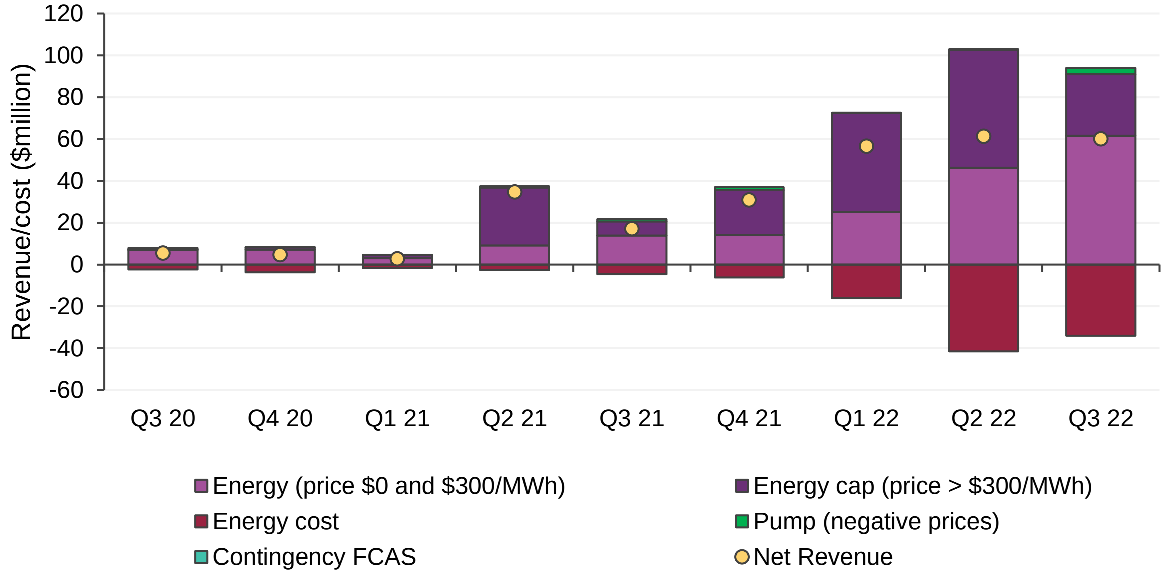
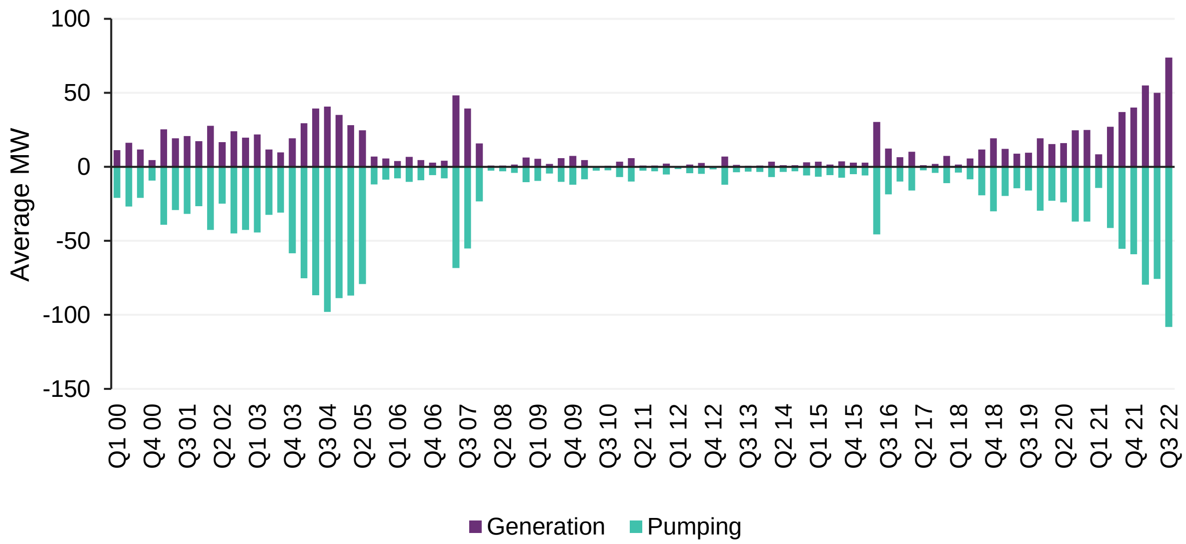


Figure 42 Record generation and pumping at Wivenhoe Pumped Hydro

Wivenhoe average generation and pumping – quarterly



1.3.7 Wholesale demand response

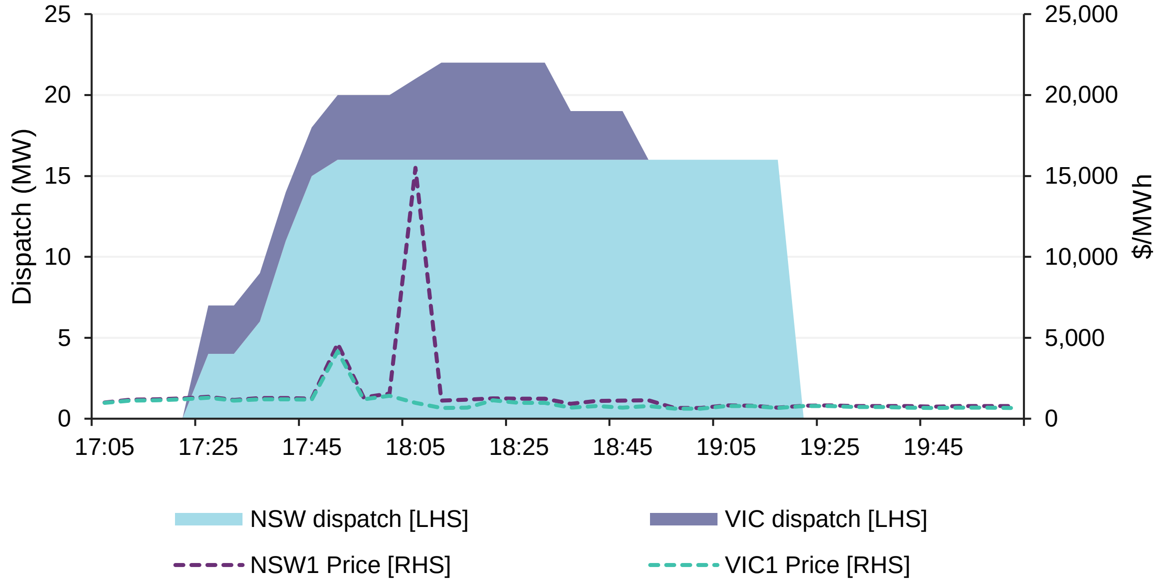
During the quarter, Wholesale Demand Response (WDR)[33] units in New South Wales and Victoria continued to participate in the mechanism. Figure 43 demonstrates an example of active participation from WDR units on 12 July when spot prices in the regions were high. On this day, spot prices in both New South Wales and Victoria were already elevated due to a particularly steep bidding curve. Demand-supply balance was further tightened during the evening when constraints on QNI limited imports from Queensland into New South Wales between trading interval ending 1735 hrs and 1820 hrs, which resulted in significant price volatility and New South Wales

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

reaching the market price cap of $15,500/MWh at 1805 hrs. Over this period of elevated spot prices, up to 22 MW[34] of WDR from New South Wales and Victoria was dispatched.

Figure 43 Active participation from New South Wales and Victoria WDR during price volatility

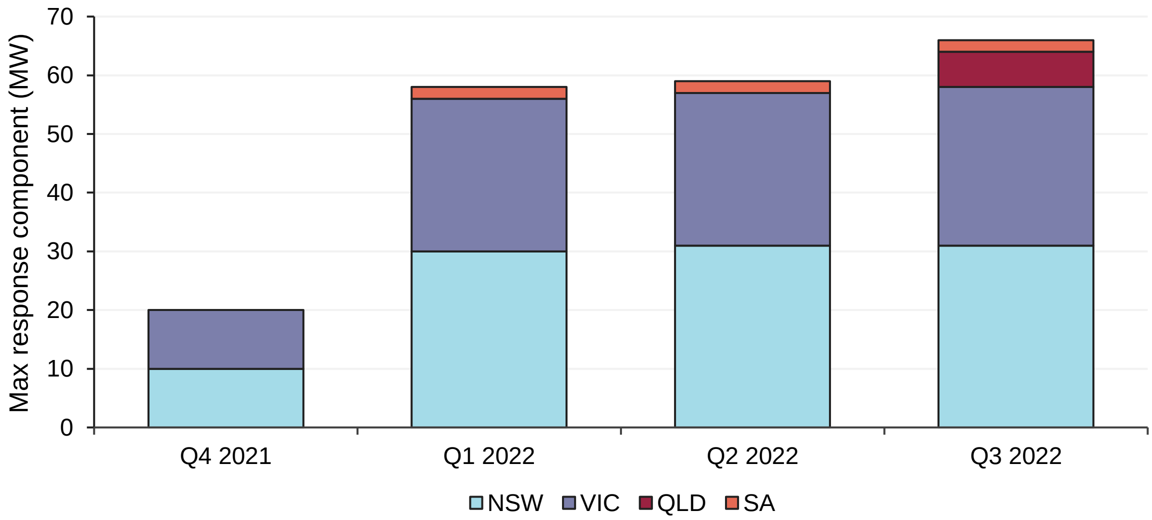
New South Wales and Victoria WDR dispatch and spot prices – 12 July 2022



AEMO continued to register new WDR units in Q3 – a combined 6 MW of capacity from two units in Queensland and an additional 1 MW in Victoria. These new registrations bring total WDR maximum response capacity across the NEM to 66 MW, up from 59 MW in Q2 2022, all of which is operated by Enel X (Figure 44).

Figure 44 New WDR capacity registered in Queensland

Total WDR capacity registered by quarter and region



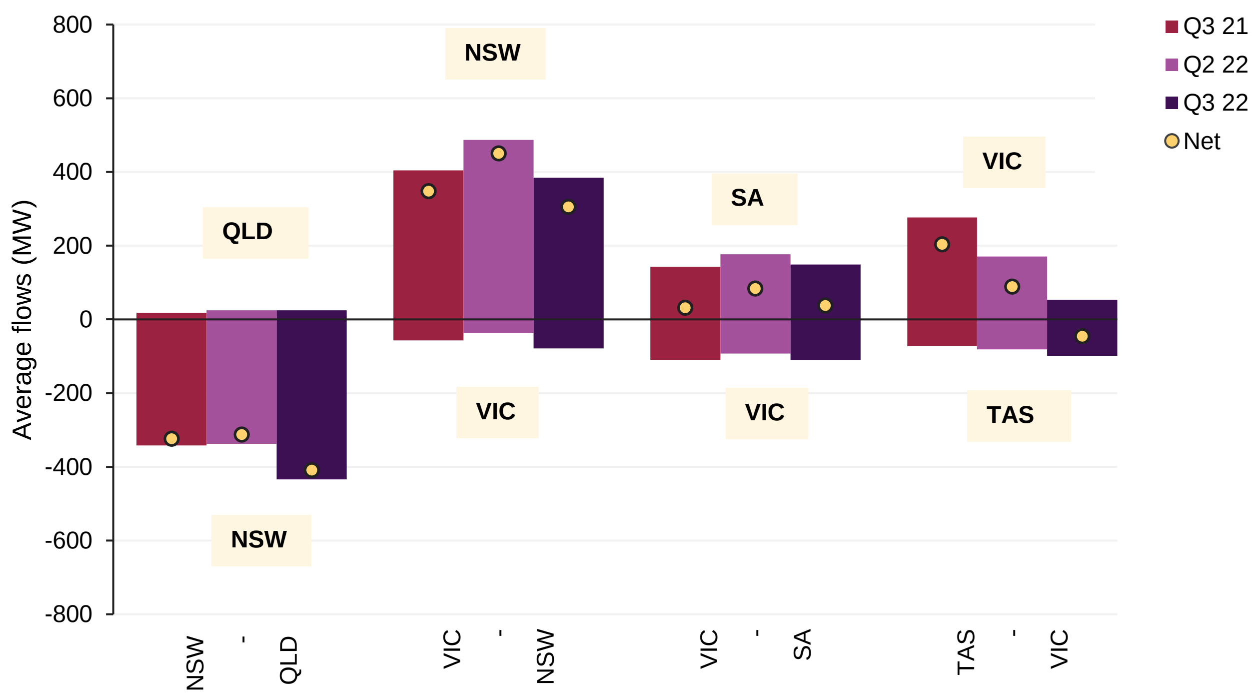
[34] Dispatch target a WDR unit receives from AEMO. Under the rules governing WDR, the quantity of response provided will be assessed by comparing metered consumption (or export) against a baseline, which reflects a counter-factual level of demand of the WDR unit. The actual quantity of demand response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

1.4 Inter-regional transfers

Total inter-regional energy transfers were 2,946 gigawatt hours (GWh) in Q3 2022, down 6% from 3,144 GWh in Q3 2021. Compared to Q3 2021, net flows switched from northward to southward, mainly due to Victoria exporting to Tasmania in Q3 2022 as well as increased flows from Queensland to New South Wales (Figure 45).

Figure 45 Swing in flows from a net northward direction to southward

Quarterly inter-regional transfers



Key outcomes by regional interconnection included:

- Queensland to New South Wales – increased flows this quarter (largely attributable to fewer transmission restrictions as outages for QNI upgrade works were completed in June 2022[35]), coupled with higher operational demand in New South Wales (+353 MW) resulted in an increase in net transfers south (+85 MW) compared to Q3 2021.
- Tasmania to Victoria (Basslink) – a decline in hydro generation in Tasmania (-251 MW) as a result of dry conditions (Section 1.3.3) combined with a shift in Basslink bidding behaviour (see below) led to a southward swing in net flows and aggregate transfers falling 56% from 772 GWh in Q3 2021 to 336 GWh this Q3.
- Victoria to New South Wales and South Australia – increased Victorian demand and reduced brown coal generation as well as net exports to Tasmania this quarter combined to reduce net Victorian transfers to New South Wales by 42 MW. Net flows to South Australia rose slightly from 32 MW to 38 MW average.

[35] When fully commissioned, the QNI upgrade will allow an extra 460 MW of power to be transferred into Queensland and 190 MW more into New South Wales. For more information, refer to https://www.transgrid.com.au/projects-innovation/queensland-nsw-interconnector.

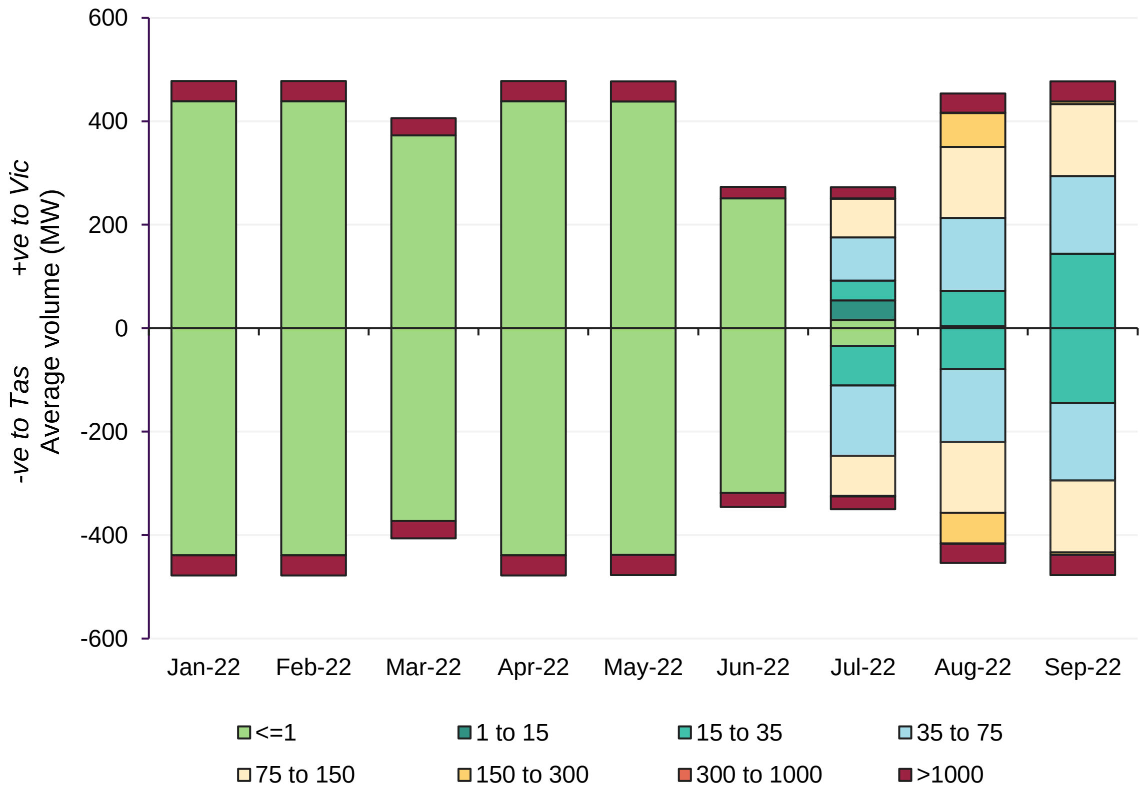
Basslink bidding changes

Unlike other NEM interconnectors, Basslink operates as a "non-regulated Market Network Service Provider" (MNSP) and offers its capacity into the NEM via "MNSP offers" to transfer power between Tasmania and Victoria, analogous to market supply and demand offers made by scheduled generators and loads. Essentially, the prices offered by Basslink for a particular flow level and direction represent the minimum price difference between importing and exporting regions at which the interconnector will transfer that inter-regional flow. Higher MNSP offer prices mean that larger inter-regional spot price differentials are required before a given level of flow on the link will be scheduled. Basslink is also able to specify a maximum flow capacity available to the market ("market availability") through its MNSP offers, analogous to generators' and loads' maximum available capacity offers.

Historically Basslink has offered most of its physically available capacity in each direction at very low transfer prices, typically $1/MWh or lower. However from late in Q2 2022 there were notable changes in Basslink's MNSP offered availability and prices, with periods of zero or only partial capacity offered to the market in one or both directions, and transfer prices in the range of $15/MWh to $300/MWh for increasing levels of flow. Figure 46 illustrates this change in Basslink offer behaviour, showing the monthly market availability and pricing of Basslink transfer capacity over 2022.

Figure 46 Basslink transfer capacity pricing increases substantially in Q3

Basslink MNSP offers: monthly average transfer capacity (MW) offered by price range ($/MWh)



The impact of these changes in Q3 was to:

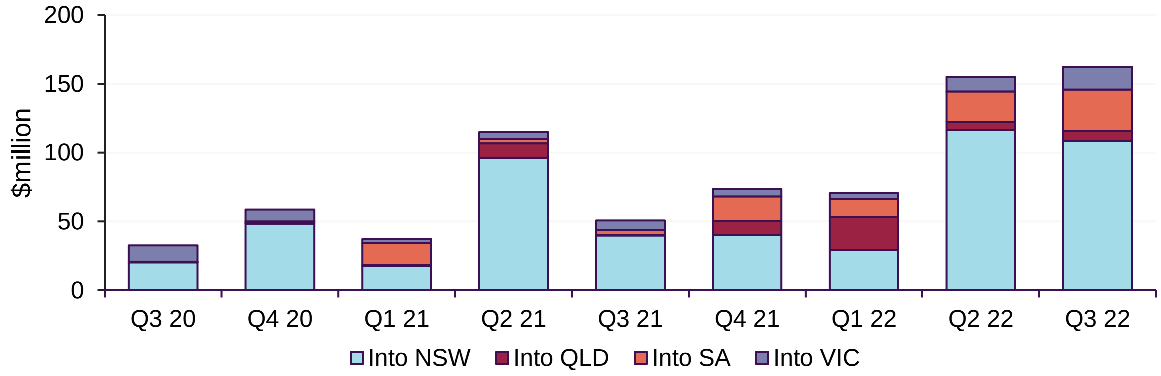
- Reduce the level of flows in either direction relative to those that would have prevailed under previous offering behaviour, reflected in Q3's 56% fall in aggregate Basslink transfer volumes.
- Increase the absolute magnitude of price differences between Tasmania and Victoria.

1.4.1 Inter-regional settlement residue

Positive inter-regional settlement residues (IRSR) totalled $162 million, up $112 million on Q3 2021 and $7 million on Q2 2022 (Figure 47). This was the highest quarterly aggregate recorded since the current regional structure of the NEM was established in July 2008. Drivers were similar to those in the preceding quarter, principally high absolute price differences between some regions, and episodes of region-specific price volatility. Transfers into New South Wales at $108 million were again the largest contributor to the total, but unlike Q2 where IRSR on flows on the Victoria – New South Wales interconnector (VNI) dominated, in Q3 positive IRSR on transfers from Queensland into New South Wales made a roughly equal contribution along with IRSR on VNI northward flows.

Figure 47 Positive IRSR reaches new quarterly record

Quarterly positive IRSR value[36]

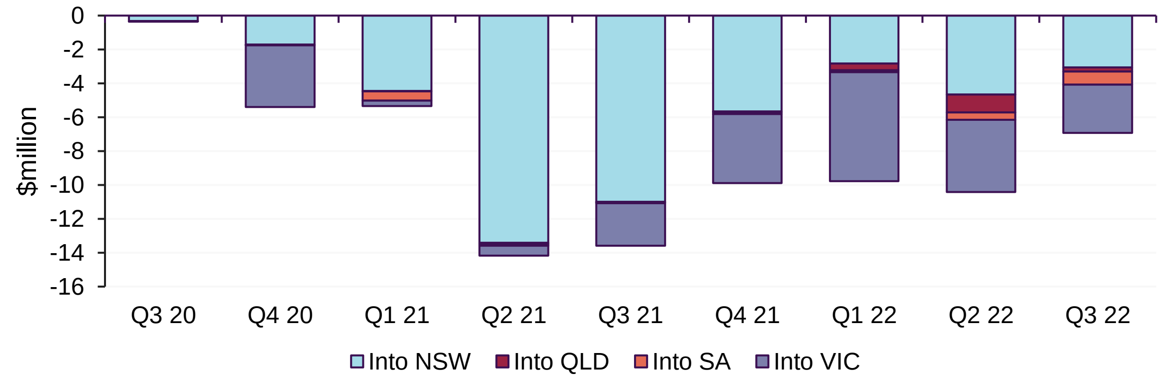


Negative residue management

Negative IRSR totalled $7 million for Q3 2022, down by $3 million on Q2 and by $7 million on Q3 2021 (Figure 48), continuing its generally reducing trend over the past five quarters. Nevertheless, this was still the second largest negative IRSR total for any Q3 since at least 2005. As in recent quarters, the largest contributions to negative IRSR arose on transfers into New South Wales at $4 million (predominantly on counter-price flows from Queensland) and into Victoria at $3 million (split roughly equally between negative residues on flows from New South Wales and South Australia).

Figure 48 Reducing trend in negative IRSR continues

Quarterly negative inter-regional settlement residue[37]



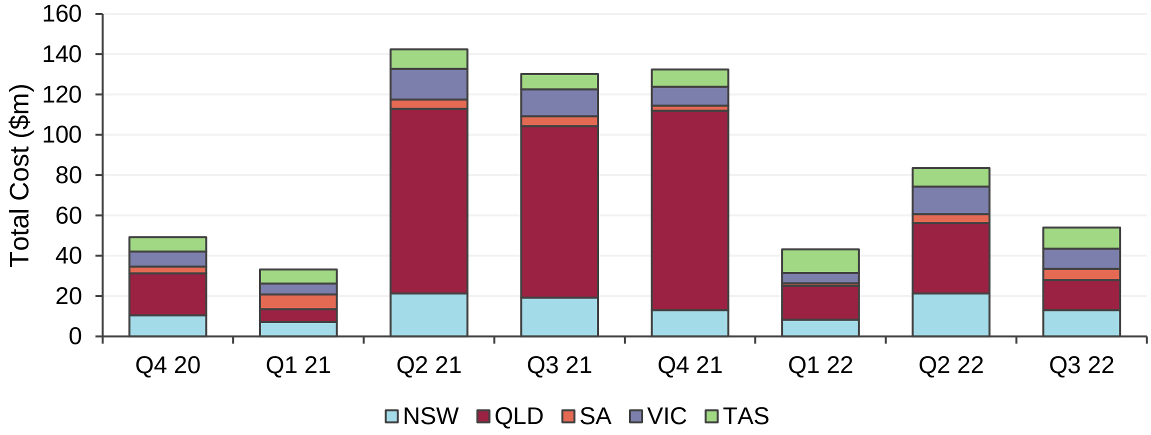
[36] Quarterly positive and negative IRSR values have been revised due to an update in methodology.

1.5 Frequency control ancillary services (FCAS)

At $54 million, total FCAS costs in Q3 2022 were 58% lower than in Q3 2021 ($130 million) and 35% lower than the prior quarter's $84 million (Figure 49). Driving these reductions were lower costs in Queensland, which were down by $20 million (57%) from Q2 and by $70 million (82%) on the very high levels of one year ago. This reflects conclusion of the program of upgrade-related outages on QNI which greatly elevated Queensland contingency FCAS costs in 2021 and to a lesser extent in the first half of 2022.

Figure 49 Reducing costs in Queensland drive falling trend in NEM FCAS expenses

Quarterly FCAS cost by region[37]



Continued commissioning of utility-scale battery capacity[38] saw strong increases in FCAS provision by this technology relative to Q3 2021 (Figure 50), with its aggregate market share by volume reaching twice that of any other source (Figure 51). Higher levels of hydro dispatch in Q3 2022 (Section 1.3.3) allowed this source to also increase its FCAS market participation, while levels for other technologies declined.

Figure 50 Battery provision of FCAS leaps on Q3 2021

Change in FCAS supply by technology – Q3 2022 vs Q3 2021

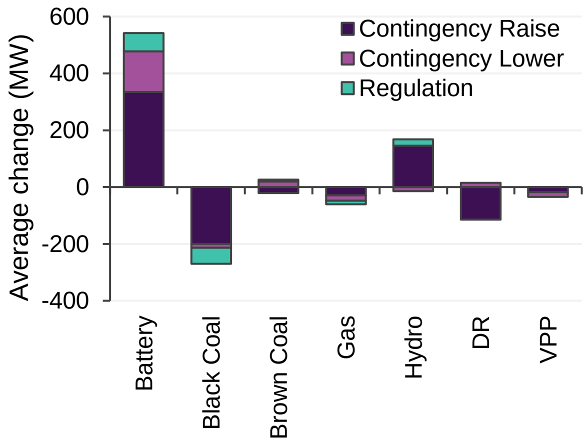
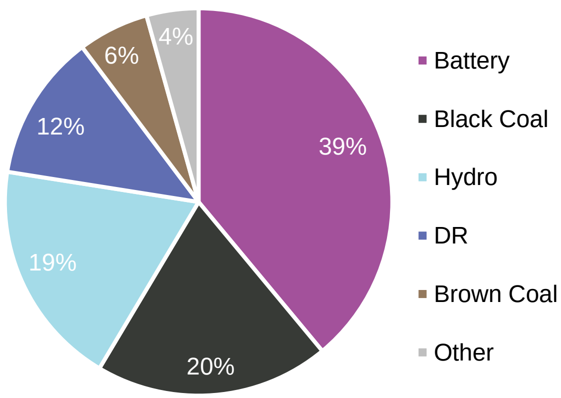


Figure 51 Battery FCAS market share reaches 39%

FCAS volume market share by technology – Q3 2022



DR: Demand response

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

[38] Victoria Big Battery (Victoria), Wallgrove BESS (New South Wales) and Wandoan BESS (Queensland).

NEMDE constraint calculation error – 10 August 2022

On 10 August, a software error related to an upgrade of the NEM Dispatch Engine (NEMDE) market clearing engine resulted in scheduling of excessive quantities of certain FCAS services, and calculated dispatch prices for those services reaching the market price cap, as the FCAS quantities that NEMDE was seeking to dispatch greatly exceeded volumes available to the market. There were consequential impacts on energy market dispatch volumes and prices, and further effects from participant rebids made in response to the extreme FCAS prices. This situation prevailed for approximately one hour before the software upgrade was rolled back. AEMO determined to revise all energy and FCAS prices using the reinstated version of NEMDE, and declared a scheduling error under the National Electricity Rules. AEMO has prepared a detailed report on this event published in October 2022[39].

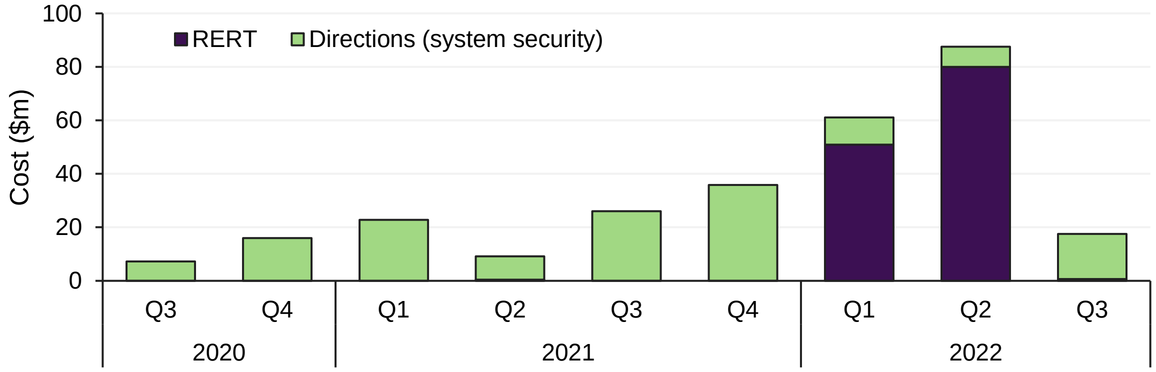
1.6 Power system management

Power system management costs declined to $17 million, down significantly from Q2 2022 levels and $26 million lower than Q3 2021 (Figure 52):

- AEMO activated RERT in Queensland on 5 July 2022 due to a forecast LOR2 condition (Section 1.2.2). During this event, an estimated 10 MWh of reserve was activated between trading interval ending 1705 hrs and 1800 hrs for a total estimated cost of $0.66 million[40].
  - Earlier on the same day, AEMO also issued directions to market participants in Queensland requesting 649 MW of additional capacity to maintain system reliability and security.
- Record Q3 electricity spot prices meant that there was a reduced requirement for AEMO to direct synchronous units to maintain system strength in South Australia, with the estimated cost of system security directions declining from $26 million in Q3 2021 to $17 million this quarter (Section 1.6.1).

Figure 52 System costs falls from record levels in Q2 2022

Estimated quarterly system costs by category



Note: system costs are preliminary estimates and subject to revision. Total costs excludes reliability direction and suspension pricing compensation costs. For provisional costs relating to the June 2022 NEM events (Q2 2022), please refer to an update published by AEMO on 15 August 2022: https://www.aemo.com.au/-/media/files/electricity/nem/data/mms/2022/compensation-update-15august22.pdf?la=en. Note that costs are provisional; additional compensation claims that require Independent Expert may take up to 30 weeks to finalise.

[39] AEMO 2022, Scheduling Error Report: https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/market_event_reports/2022/nem-dispatch-engine-constraint-calculation-error-10-august-2022.pdf?la=en.

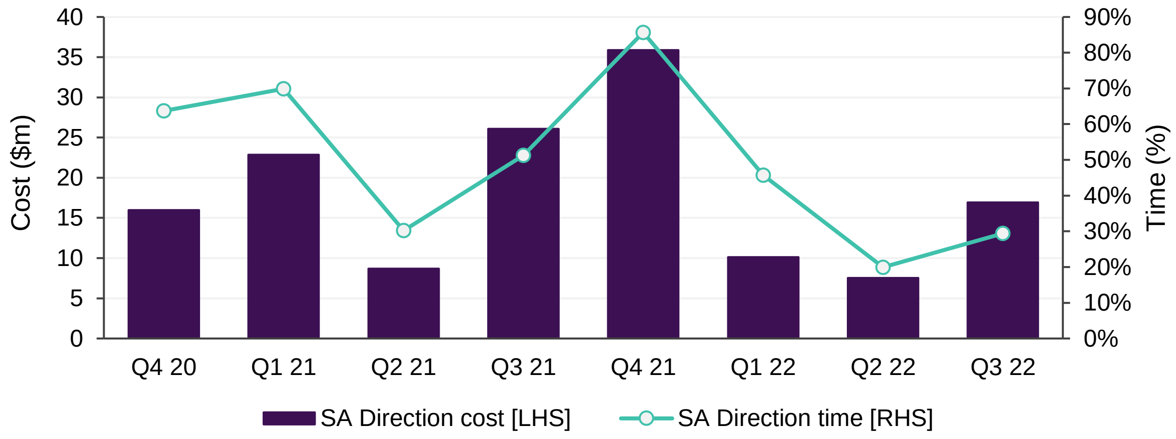
[40] AEMO 2022, Estimated payments and volumes for RERT activation on 5 July 2022: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2022/rert-activation-estimates-report-for-5-july-2022.pdf?la=en.

1.6.1 South Australian system security directions

AEMO continued to issue directions to generators in South Australia to maintain system security during Q3 2022. While system security directions costs during Q3 2022 ($17 million) rebounded relative to Q2 2022 ($7.5 million), these were still substantially lower than Q3 2021 ($26 million, Figure 53).

Figure 53 South Australian directions costs rebound from Q222 but substantially lower than Q321

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



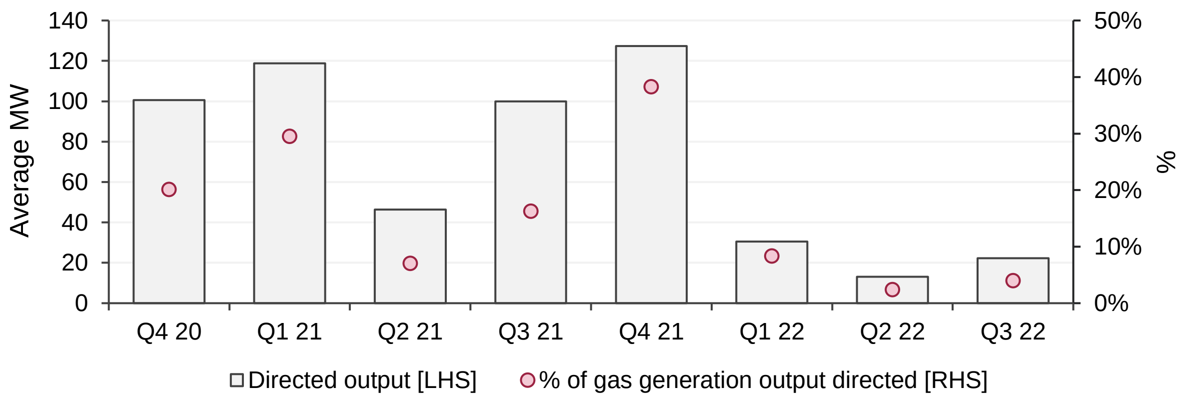
Note: direction costs are preliminary costs which are subject to revision

Compared to Q3 2021, the lower cost of directions – despite much higher 90th percentile compensation prices – was a reflection of much lower volumes directed, which reduced from an average of 100 MW to 22 MW in Q3 2022 (Figure 54). Similarly, the lower direction volumes meant that the proportion of South Australian gas generation output being directed reduced from 16% in Q3 2021 to just 4% this quarter.

Despite Adelaide's spot gas prices increasing to $27/GJ on average, higher electricity spot prices compared to Q3 2021 were a key driver of lower volumes being directed this quarter. With South Australian spot prices exceeding $200/MWh 41% of the time compared to just 6% in Q3 2022, it was more economic for gas-fired generators to remain online. This, coupled with full operation of the region's recently commissioned synchronous condensers, reduced requirements for AEMO to direct generators on to maintain system security.

Figure 54 Gas generation directed output lower than Q3 2021

South Australian gas-fired generation directed



2 Gas market dynamics

2.1 Wholesale gas prices

While July prices increased further from record levels in June 2022, prices eased in August and September, resulting in lower quarterly average prices than Q2 2022. These were nevertheless the highest Q3 prices on record. Prices peaked in mid-July across all markets coinciding with cold weather and high gas-fired generation demand. The highest price recorded was $59.49/GJ in Sydney on 18 July, while Adelaide recorded $59.23/GJ also on 18 July, and Brisbane $50/GJ on 17 July. The DWGM remained capped at $40/GJ due to CPT exceedance. The price cap was in place from 31 May and ended on 1 August. The CPT event is discussed in detail in the QED Q2 2022 report.

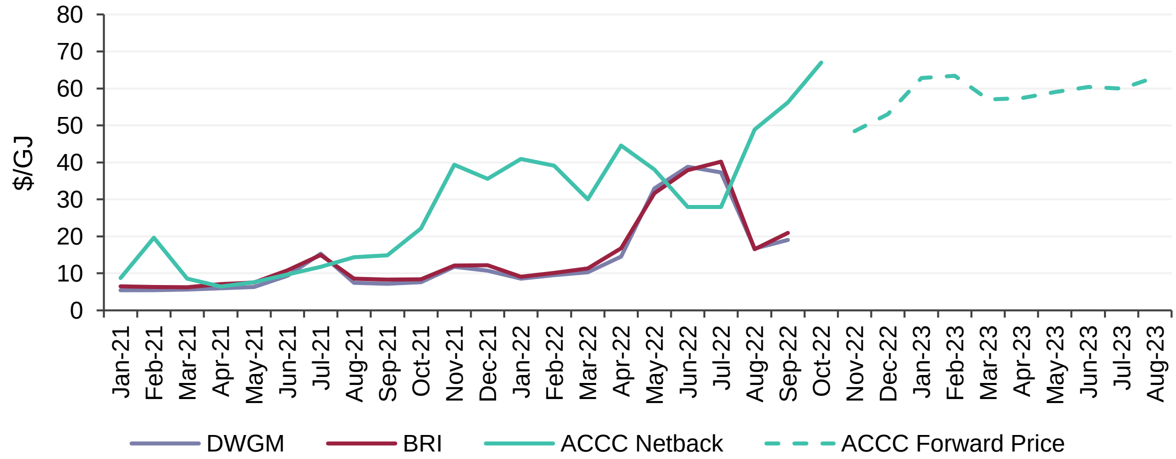
Table 3 Average east coast gas prices – quarterly comparison

Price ($/GJ)	Q3 2022	Q2 2022	Q3 2021	Change from Q3 2021
DWGM	24.41	28.81	10.05	143%
Adelaide	27.29	29.88	11.51	137%
Brisbane	25.95	28.81	10.65	144%
Sydney	27.06	28.87	11.16	143%
GSH	25.30	25.62	10.33	145%

After June's average domestic market prices had risen above international benchmark prices, as represented by the ACCC netback price series, the gap expanded in July (Figure 55). As in June, record prices coincided with increased heating demand, high gas-fired generation, and participants carefully managing their Iona storage inventory levels, which continued to decrease steeply during the month.

Figure 55 Domestic prices reach record levels in July before easing in August

ACCC netback and forward prices[41], DWGM and STTM Brisbane average gas prices by month

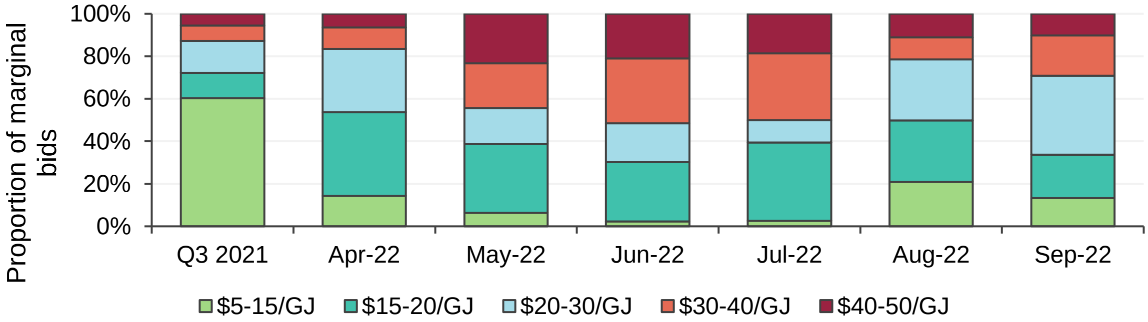


[41] ACCC 2022, LNG netback price series: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

While the netback price jumped in August, domestic market prices eased, with a large gap emerging between domestic and international prices. This reflected a combination of reduced heating demand due to milder weather, lower gas-fired generation demand, and an increase in gas supply from Queensland to southern markets, coinciding with the planned Australia Pacific LNG (APLNG) processing train outage from late July. The easing of the tight domestic supply and demand situation from late July prompted market participants to increase bid volumes offered at or below $30/GJ (Figure 56).

Figure 56 DWGM bids driving record July prices

DWGM – proportion of marginal bids[42] by price band



2.1.1 International energy prices

Thermal export coal prices continued rising to new record levels, averaging A$612/tonne across the quarter, A$98/tonne higher than Q2 2022 (A$514/tonne, Figure 57). Record prices were influenced by the ongoing war in Ukraine which has caused global energy supply concerns as many European nations imposed sanctions against Russia's gas and coal exports. In response, some European Union member states and the United Kingdom are preparing to increase output from coal-fired power stations[43]. Additionally, the continuation of wet La Niña conditions and flooding across eastern Australia have also impacted the supply of thermal coal to the Port of Newcastle[44].

Figure 57 Thermal coal remains at elevated levels

Newcastle export thermal coal A$/Tonne daily

Source: Bloomberg ICE data

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

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

[44] Reuters 2022, Key Australian coal rail line shut due to torrential rain: https://www.reuters.com/business/autos-transportation/key-australian-coal-rail-line-shut-due-torrential-rain-2022-07-06/.

Asian LNG prices continued to trend up, from an average of A$36/GJ in Q2 2022 to A$65/GJ in Q3 2022. Maintenance and supply disruptions at the Nord Stream 1 gas pipeline[45] and ongoing refilling of gas storages ahead of Northern Hemisphere winter were key drivers of elevated prices (Figure 58).

Figure 58 Asian LNG prices hit record high

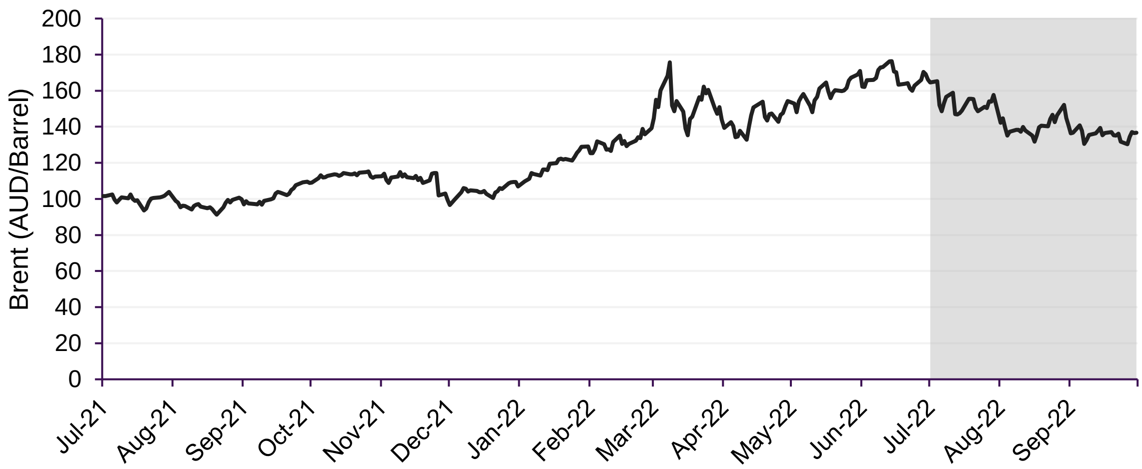
Asian LNG price in A$/GJ daily

Source: Bloomberg ICE data

Brent Crude oil prices fell across the quarter to an average of A$143/barrel, down from the previous quarter's average of A$157/barrel (Figure 59). The decline reflected market fears of a recession as central banks around the world increased interest rates.

Figure 59 Brent Crude oil prices plateau

Brent Crude oil in A$/Barrel daily



Source: Bloomberg ICE data.

[45] Bloomberg 2022, Europe's energy crisis deepens after Russia keeps pipeline shut: https://www.bloomberg.com/news/articles/2022-09-02/gazprom-says-nord-stream-to-remain-shut-after-technical-issue?sref=kkhkDP70.

2.2 Gas demand

Total east coast gas demand decreased compared to Q3 2021 (-2.6%, Figure 60, Table 4). While there was an increase in gas-fired generation (+5 PJ) and AEMO markets demand (+3 PJ), this was offset by a large decrease for Queensland LNG production (-21 PJ).

Figure 60 Queensland LNG export decrease offsets higher gas-fired generation and market demand

Change in east coast gas demand – Q3 2022 vs Q3 2021

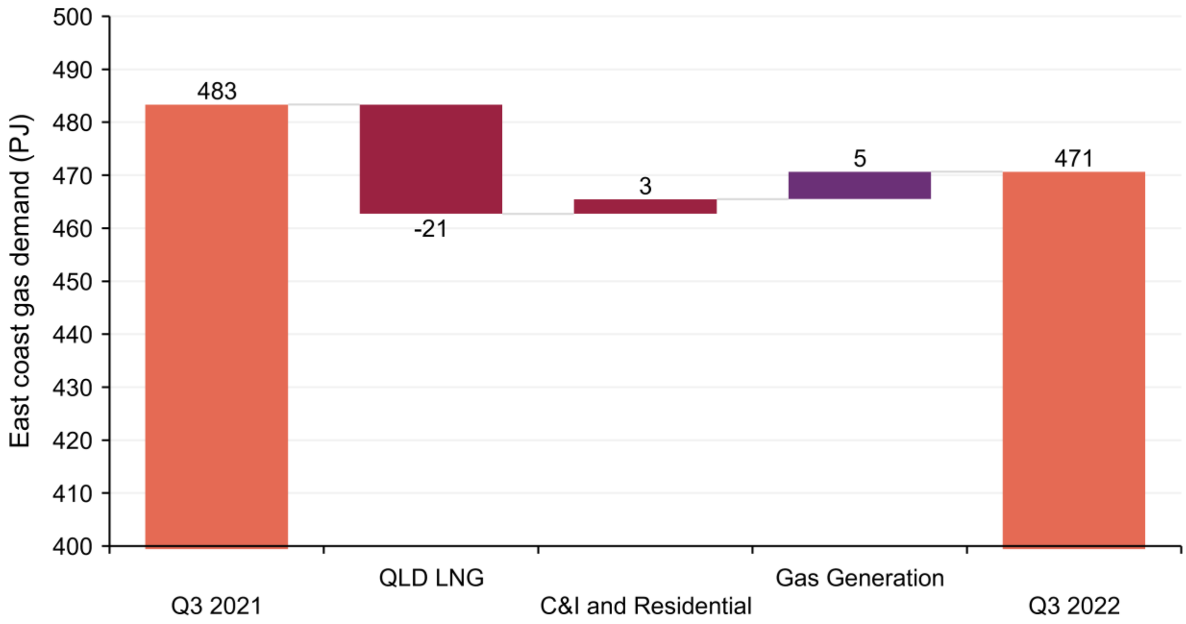


Table 4 Gas demand – quarterly comparison

Demand (PJ)	Q3 2022	Q2 2022	Q3 2021	Change from Q3 2021
AEMO Markets *	110.3	91.7	107.5	+3 (+3%)
Gas-fired generation **	35.4	45.1	30.2	+5 (+17%)
QLD LNG	325.0	334.0	345.6	-21 (-6%)
TOTAL	470.7	470.9	483.3	-13 (-3%)

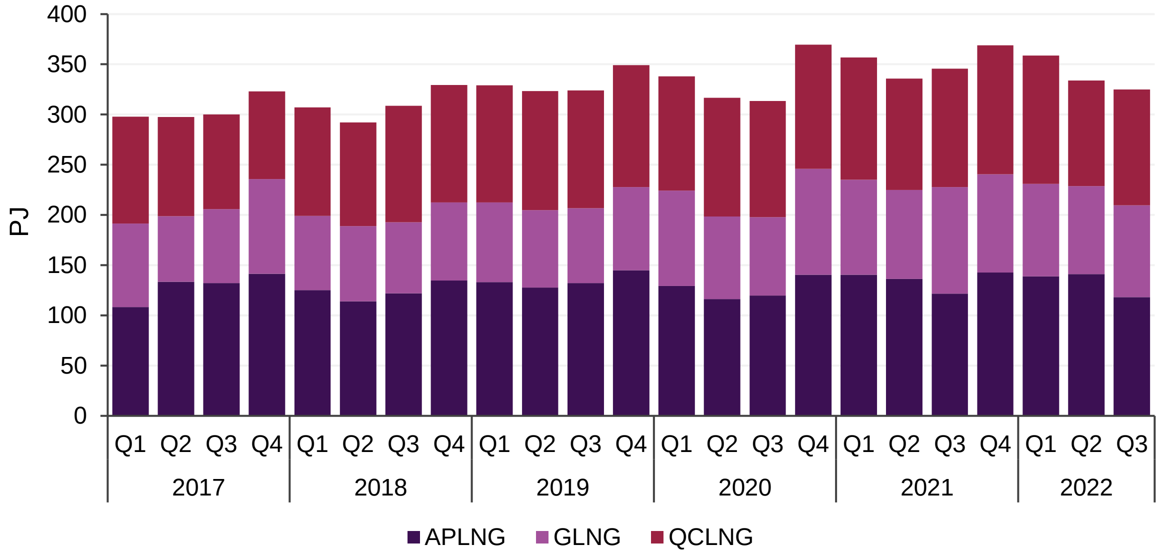
* AEMO Markets demand is the sum of customer demand across STTM hubs and the DWGM and excludes gas-fired generation in these markets.
** Includes demand for gas-fired generation usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

Queensland LNG export demand fell to its lowest quarterly level since Q3 2020, but still represented the second highest Q3 demand on record, after Q3 2021. While demand from all three Queensland LNG exporters decreased, the largest fall by a significant margin was from Gladstone Liquefied Natural Gas (GLNG).

By participant, GLNG demand decreased by 14.5 PJ, APLNG by 3.6 PJ, and Queensland Curtis LNG (QCLNG) by 2.6 PJ (Figure 61). Similarly to August 2021, APLNG had planned maintenance for most of August 2022. There was no planned maintenance for GLNG or QCLNG. 85 LNG cargoes were exported during the quarter, down from 87 in Q3 2021.

Figure 61 Flows to Curtis Island for LNG export lowest since Q3 2020 but still second highest Q3 on record

Total quarterly pipeline flows to Curtis Island



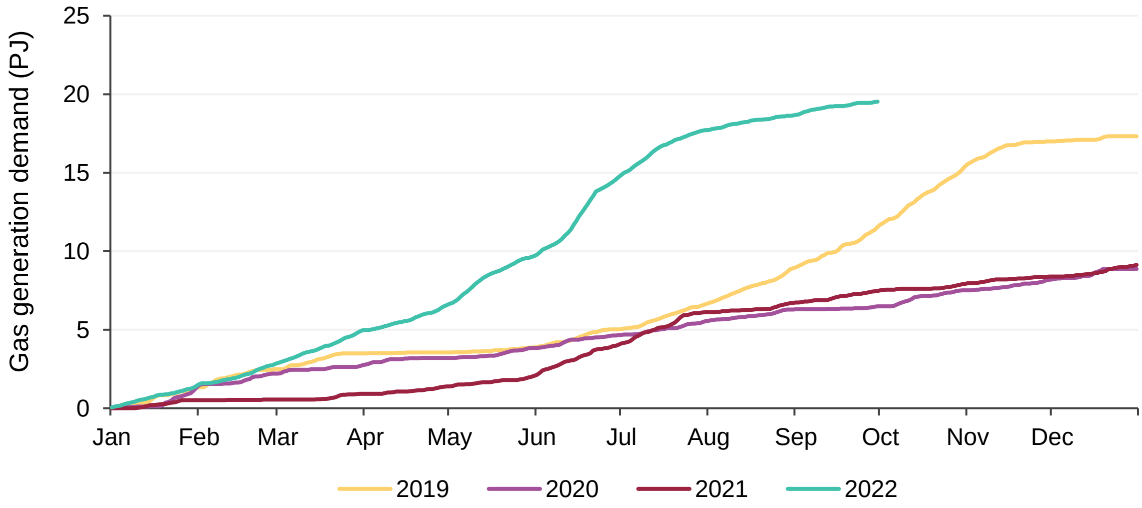
2.2.1 Gas-fired generation

Demand from gas-fired generators remained elevated for the quarter, particularly during July. Similarly to Q2 2022, Victoria and New South Wales saw the largest increases, with Victorian demand increasing by 85% in Q3 2022 compared to Q3 2021 and New South Wales demand up by 41%. Queensland demand increased by 13%, while South Australian demand fell 8%.

Cumulative gas-fired generation demand for 2022 remains significantly higher than in recent years in New South Wales and Victoria. New South Wales gas-fired generation 2022 year to date demand is 19.6 PJ compared to 7.5 PJ at the same point in 2021 (Figure 62), while Victoria's year to date total is 19.4 PJ compared to 9.8 PJ in 2021. Drivers for higher demand are discussed in Section 1.3.2.

Figure 62 New South Wales gas generation demand to end of Q3 more than treble recent levels

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



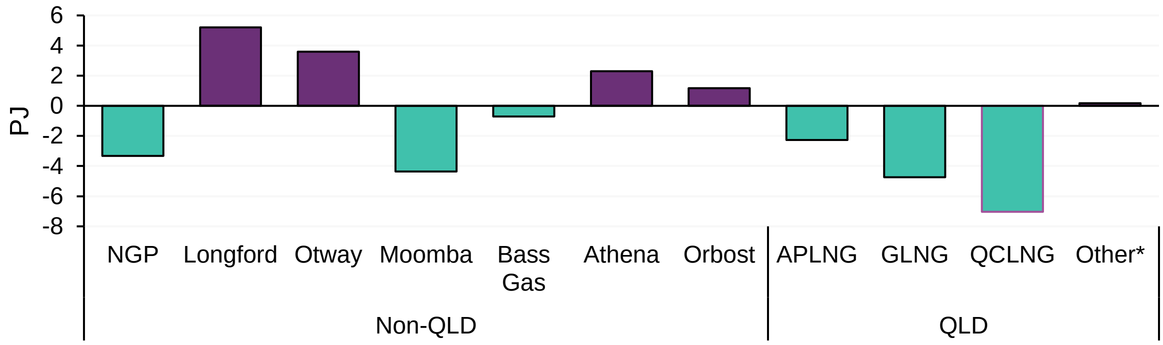
2.3 Gas supply

2.3.1 Gas production

East coast gas production decreased by 6.7 PJ compared to Q3 2021 (-1.3%, Figure 63)

Figure 63 Queensland production falls

Change in east coast gas supply – Q3 2022 vs Q3 2021



Key changes included:

- Decreased Queensland production (-13.9 PJ), with QCLNG decreasing by 7.0 PJ, GLNG by 4.7 PJ, and APLNG by 2.3 PJ. While this represented a significant production decrease, with Queensland LNG exports decreasing by 21 PJ, a net additional 6.8 PJ of supply associated with Queensland LNG projects went into the domestic market compared to Q3 2021 (Figure 64).
- Higher Victorian production (+11.6 PJ), mainly driven by higher production at Longford (+5.2 PJ) and Otway (+3.6 PJ). Longford's production was its highest since Q3 2017 (Figure 65).
- Decreased Moomba production (-4.4 PJ), continuing the trend of lower Moomba production year on year.
- Decreased supply from the Northern Territory (-3.3 PJ) via the Northern Gas Pipeline (NGP). Production issues experienced at the Yelcherr gas plant in May led to reduced NGP flows continuing into Q3, with flows reducing to zero from 7 September for the remainder of the quarter.

Figure 64 Queensland domestic supply increases to its highest level since Q3 2020

Queensland domestic supply compared to Victorian gas exports by quarter

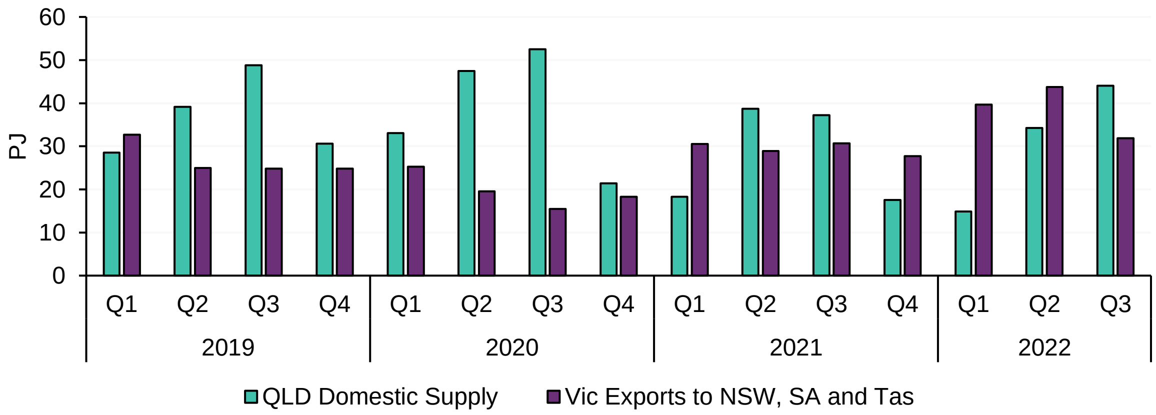
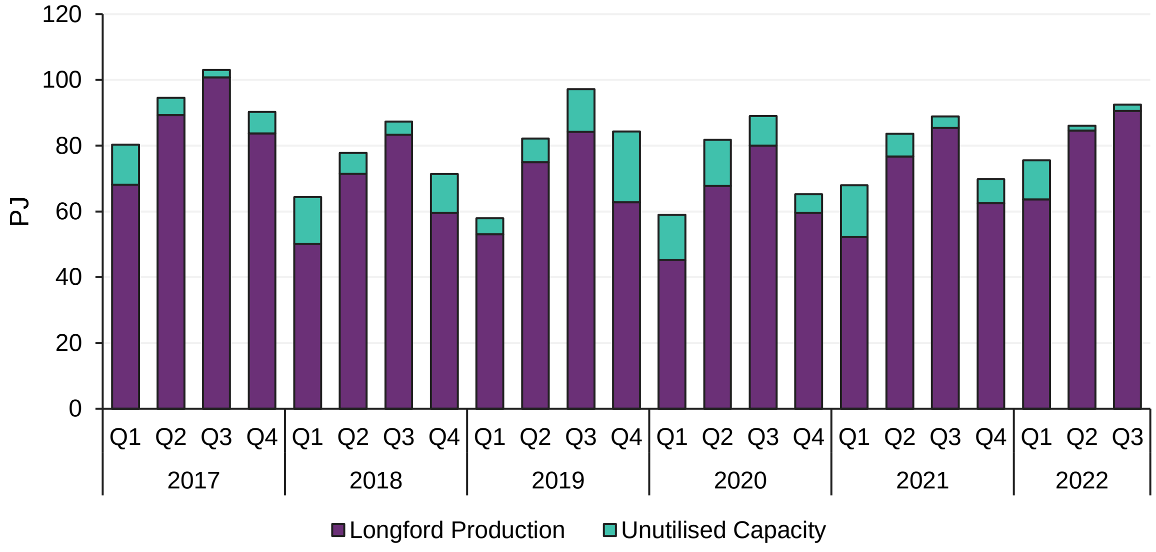


Figure 65 Highest Q3 Longford production since 2017

Longford production and unutilised capacity by quarter

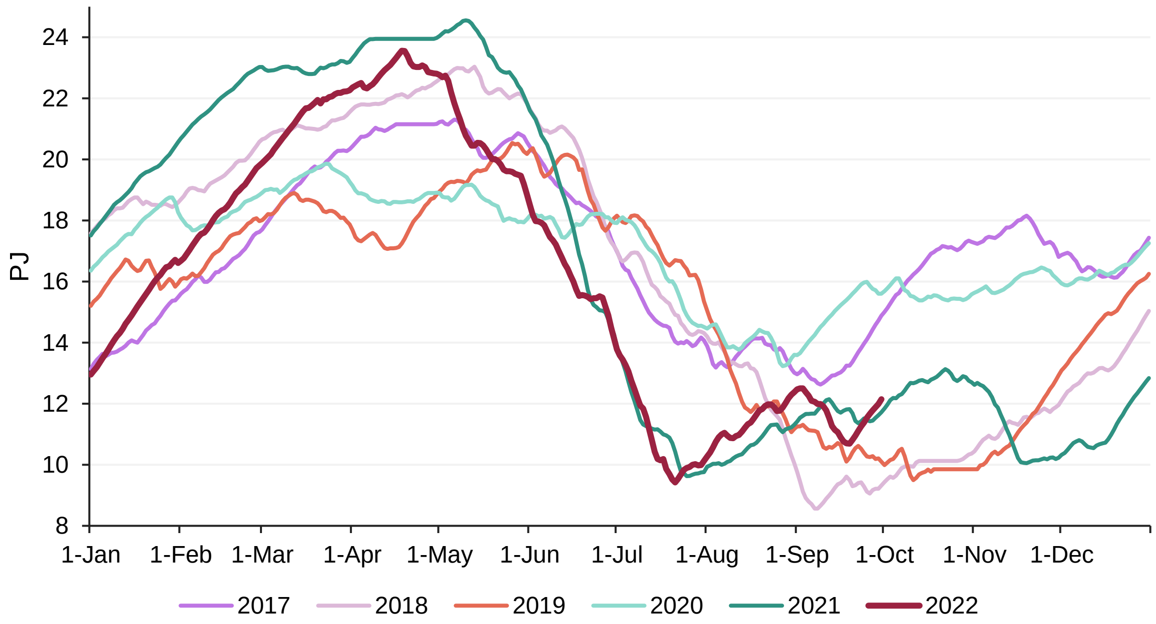


2.3.2 Gas storage

Iona Underground Gas Storage (UGS) facility finished the quarter with a gas balance of 12.2 PJ, 0.4 PJ higher than at the end of Q3 2021 (Figure 66). Storage inventory followed a similar trajectory in July to that of 2021, but recovered more quickly in August due to lower demand, increased supply from Queensland to southern markets, and improved coal-fired generation output. Increases in supply from Longford and Otway gas plants were also contributing factors.

Figure 66 After a rapid decrease in early-mid July, Iona storage levels track at similar rates to 2021

Iona storage levels



2.3.3 DWGM Threat to System Security

On 11 July 2022, AEMO issued a Notice of a Threat to System Security in the DWGM, due to low Iona UGS inventory and the risk of supply shortfalls due to Iona inventory depletion in winter. The notice advised that at the rate Iona inventory was declining storage levels would reduce to 6 PJ by 31 July - a threshold where Iona supply delivery capability may begin to reduce, with delivery capability reducing further if Iona inventory were to fall materially below that threshold. In this notice AEMO requested Market Participants (MPs) to cease purchasing gas from the DWGM to ship to other jurisdictions. A MP could however continue to withdraw gas when that MP was simultaneously supplying sufficient gas into the DWGM elsewhere to meet its own customer and gas generation demand, as well as a matching quantity of gas to that being withdrawn from the DWGM.

A further notice was published on 18 July, advising that with Iona depleting at over 200 terajoules (TJ) per day on average since the last notice, Iona storage would reach the 6 PJ threshold by 6 August. To mitigate the risk of supply shortfalls, in this notice AEMO requested Victorian gas generators connected to the DWGM not to generate using gas without supplying a corresponding quantity of gas into the system. AEMO noted that if the generator was unable to source gas supply, the Gas Supply Guarantee (GSG) process might be triggered.

On 19 July 2022, AEMO did trigger the GSG after identifying a gas supply shortfall for power generation in Victoria, New South Wales, South Australia and Tasmania for gas days 19 July 2022 to 30 September 2022. The event was triggered due to information provided by gas-fired generators. This was the second time the GSG had been triggered, after the first event on 1 June 2022 (discussed in the Q2 2022 QED report).

Subsequently, on 20 July, AEMO issued a DWGM system-wide notice, advising AEMO had intervened in the DWGM and directed the curtailment of two gas-fired generators in the DWGM in line with previous communications issued for Iona storage depletion threat due to the system security event.

An update to the threat notice was published on 2 August, advising that Iona storage levels had remained flat and as such MPs were no longer requested to support controllable withdrawals to refill Iona with corresponding supply. The notice still requested MPs to cease purchasing gas from the DWGM via controllable withdrawals, unless putting that gas into Iona storage, and not to use gas for gas-fired generation without a corresponding gas supply.

A further update was published on 10 August, advising that the Iona inventory depletion risk still existed. In this notice AEMO allowed limited net withdrawals from the DWGM by Victorian gas-fired generators, including the generators that had been curtailed on 20 July.

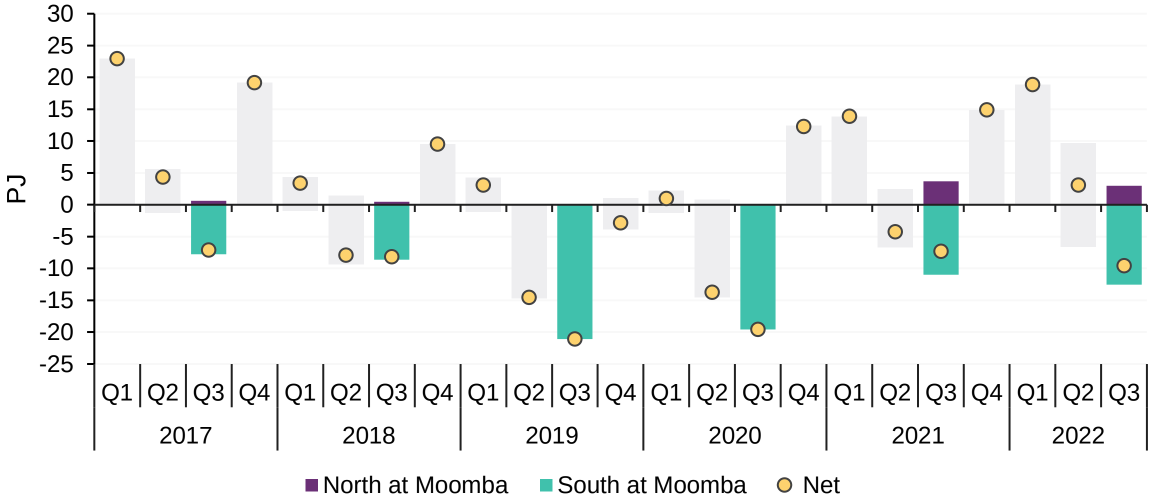
The threat notice period and the GSG ended on 30 September.

2.4 Pipeline flows

Compared to Q3 2021, there was a 2.3 PJ increase in net transfers into Moomba on the South West Queensland Pipeline (SWQP, Figure 67). Increased flows into Moomba occurred from August, coinciding with APLNG's planned maintenance outage of an LNG liquefaction train at Gladstone.

Figure 67 Net Q3 flows south on SWQP increase

Flows on the South West Queensland Pipeline at Moomba

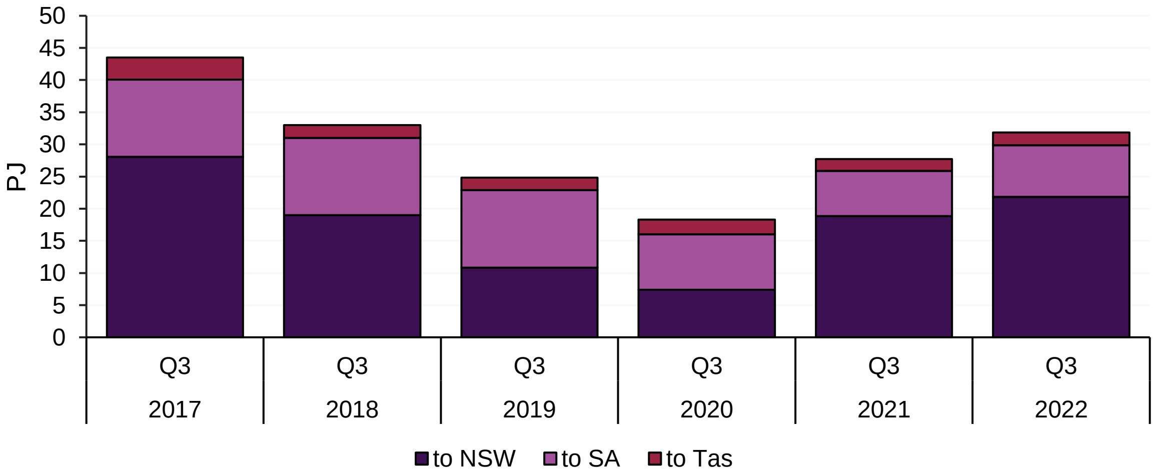


Victorian net gas transfers to other states increased by 4.1 PJ from Q3 2021 levels, due to increased Victorian supply and lower Moomba production. This represents the highest net transfer out of Victoria for a Q3 since 2018 (Figure 68).

There were increased flows from Victoria to New South Wales comprising 1.6 PJ via Culcairn, compared to 1 PJ in Q3 2021, and 20.2 PJ via the Eastern Gas Pipeline (EGP), up from 17.8 PJ in Q3 2021. Flows from Victoria to South Australia also increased by 1 PJ while there was a 0.2 PJ increase in the flow to Tasmania.

Figure 68 Highest Victorian Q3 gas exports since 2018

Victorian net gas transfers to other regions

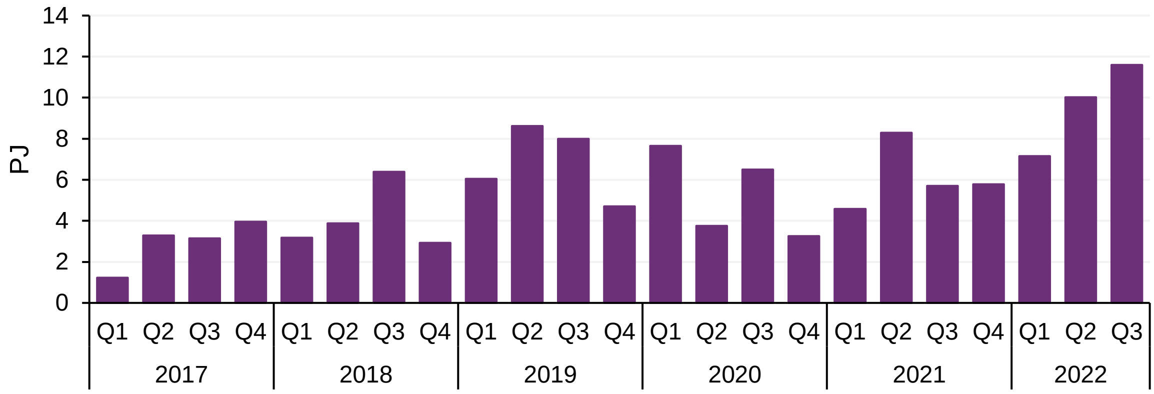


2.5 Gas Supply Hub (GSH)

In Q3 2022 there were increased trading volumes on the GSH compared to Q3 2021 (Figure 69), with traded volume up 5.9 PJ, more than doubling Q3 2021 volumes. This represents a record for any quarter, surpassing the previous record set in Q2 2022. Drivers continue to be a significant increase in volume for future periods beyond Q3 2022.

Figure 69 Highest Gas Supply Hub trading volumes on record

Gas Supply Hub – quarterly traded volume



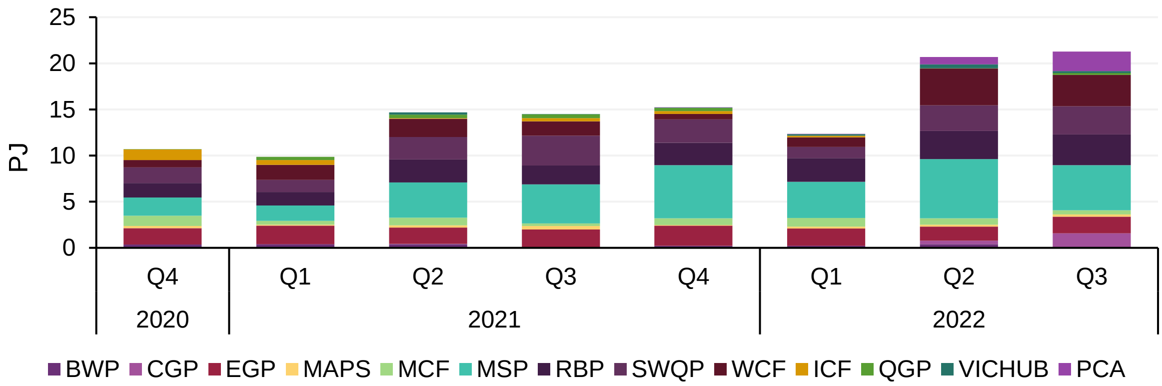
2.6 Pipeline capacity trading and day ahead auction

Day Ahead Auction (DAA) volumes set a new quarterly record, 0.6 PJ higher than the previous level set in Q2 2022, and 6.8 PJ higher than Q3 2021 (Figure 70). Compared to Q3 2021, the largest increases occurred on the Carpentaria Gas Pipeline (CGP, +1.6 PJ), the Wallumbilla Compressor (+1.8 PJ) and the Roma to Brisbane Pipeline (RBP, +1.3 PJ).

Average auction clearing prices remained at or close to $0/GJ on most pipelines. The exceptions to this were the EGP which averaged $0.22/GJ, the Moomba to Sydney Pipeline (MSP) which averaged $0.14/GJ, SWQP which averaged $0.04/GJ, and RBP which averaged $0.02/GJ.

Figure 70 Highest quarterly Day Ahead Auction utilisation since market start

Day Ahead Auction results by quarter

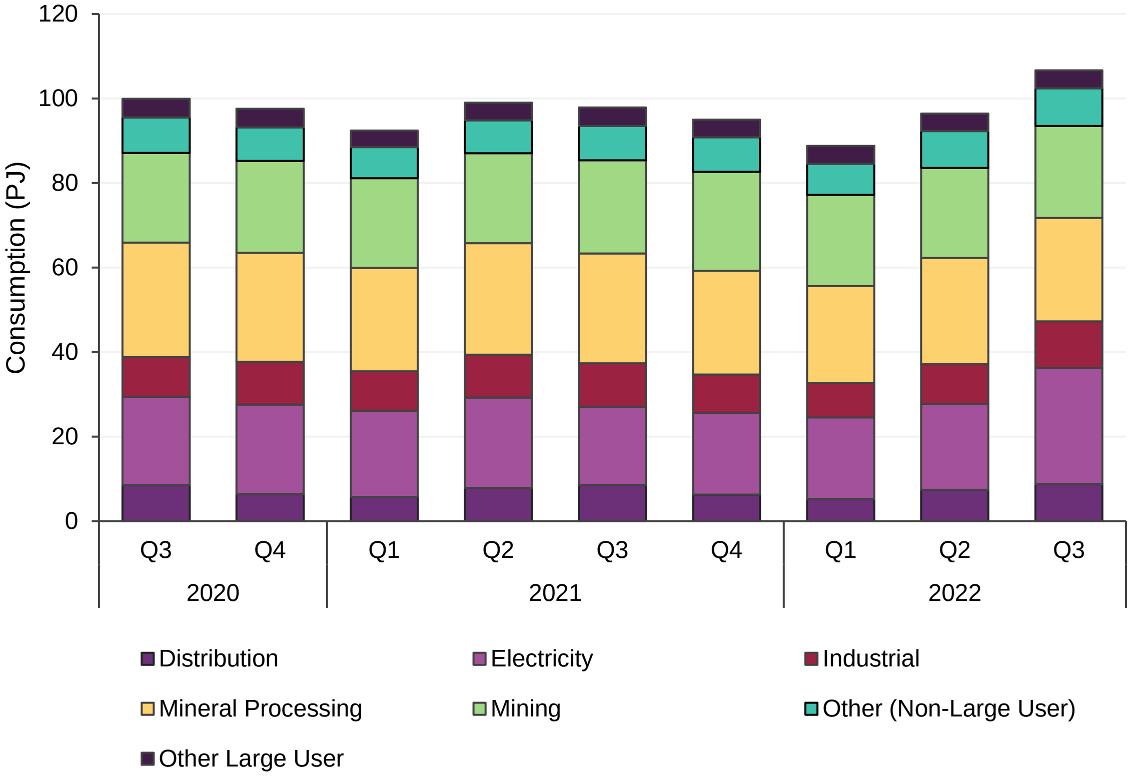


2.7 Gas – Western Australia

A total of 107 PJ was consumed in the Western Australian domestic gas market in Q3 2022, an increase of 9 PJ (+9%) from Q3 2021 and up 10 PJ (+10%) on Q2 2022 (Figure 71).

Figure 71 Western Australia domestic gas consumption increases 9% from Q3 2021

WA quarterly gas consumption by sector from Q3 2020 to Q3 2022



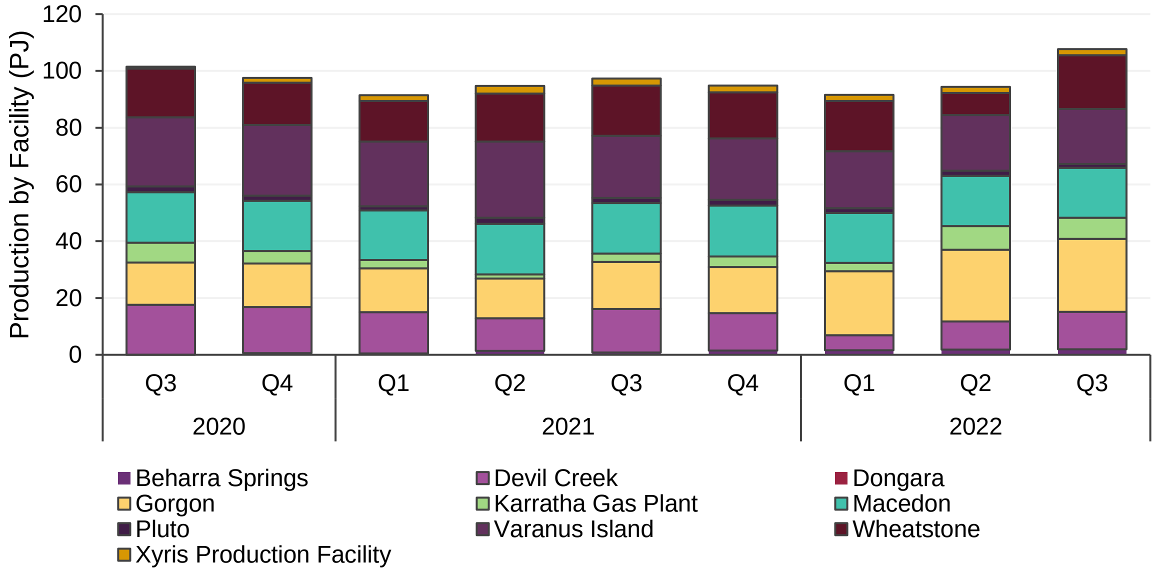
Domestic gas consumption in Western Australia increased in most user categories compared to the same quarter last year, with the largest increase being for electricity generation:

- Gas consumed for electricity generation increased by 9 PJ (+49%) from Q3 2021. This increase can be largely attributed to the decrease in coal-fired generation availability during Q3 2022 (see Section 3.3.1). The facilities with the largest increase in gas consumption compared to Q3 2021 were Cockburn Power Station, with an increase of 3 PJ (+543%), and Kemerton Power Station, up 2 PJ (+457%).
- Mineral processing consumption was 1.5 PJ (-6%) lower than in Q3 2021. The largest decrease was from Alcoa Pinjarra which reduced consumption by 0.8 PJ (-10%).

Total Western Australian gas supply this quarter was 108 PJ, an increase of 10 PJ (+11%) from Q3 2021 and 13 PJ (+14%) from Q2 2022, which can be partially attributed to the increase in gas demand during Q3 2022. The increase in gas production from last quarter was primarily driven by an increase in production from Wheatstone returning from maintenance, with production increasing by 11 PJ since last quarter (Figure 72). The increase from Q3 last year was largely due to Karratha Gas Plant increasing gas production by 4.49 PJ.

Figure 72 Western Australia domestic gas production increases from Q3 2021

WA quarterly gas production by zones – Q3 2020 to Q3 2022



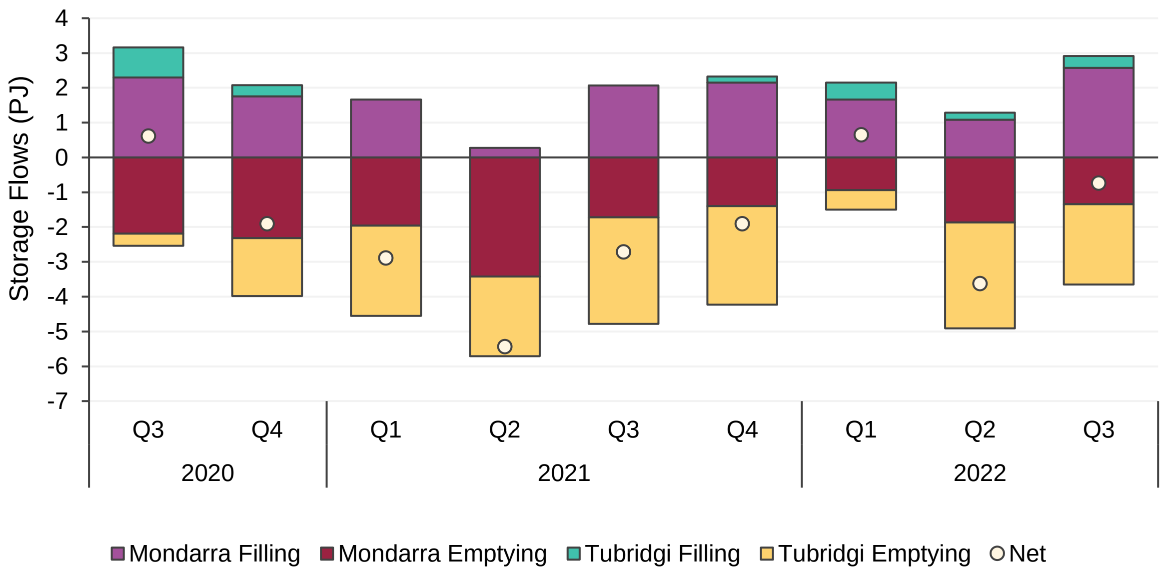
2.7.1 Storage Facility behaviour

There was a net injection[46] of gas from storage facilities into pipelines in Q3 2022 to meet gas demand. However, injection flows were 3 PJ lower compared to Q2 2022 (Figure 73). This change in injection flows was driven by Tubridgi emptying 0.8 PJ (-24%) less and Mondarra emptying 0.5 PJ (-28%) less than in Q2 2022.

Storage flows increased due to Mondarra filling 1.5 PJ and Tubridgi filling 0.1 PJ more than in Q2 2022.

Figure 73 Net injection of gas in Q3 2022

WA gas storage facility injections and withdrawals – Q3 2020 to Q3 2022



[46] A net injection occurs when gas flows from storage facilities into pipelines, resulting from emptying a gas storage facility.

3 WEM market dynamics

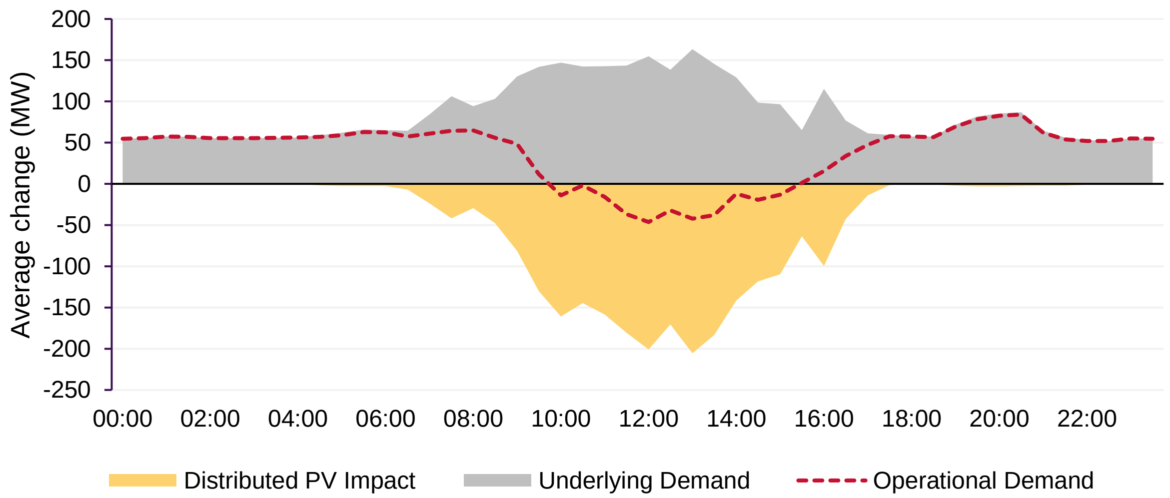
3.1 Electricity demand

Average underlying demand[47] in Q3 2022 was higher than the same quarter last year, increasing by 86 MW (+4%). While operational demand[48] increased by 36 MW (+2%) on average during the quarter, it was lower during the middle of the day compared to Q3 2021 due to increased estimated distributed PV generation (49 MW or +20%, Figure 74).

The increase in both average underlying and operational demand can be attributed to average temperatures dropping 0.5°C from Q3 2021, with colder temperatures resulting in increased heating requirements. The average maximum temperature was 0.2°C less and average minimum temperature 0.9°C less than Q3 2021.

Figure 74 Underlying demand increases, but higher distributed PV reduces midday operational demand

Change in average WEM underlying and operational demand by time of the day compared to Q3 2021



3.1.1 Minimum demand

Minimum operational demand in the Wholesale Electricity Market (WEM) continued to decrease, with an all-time record of 742 MW[49] set on Sunday 11 September 2022 at 1200 hrs (Figure 75). This was 2.5% lower than the previous record (761 MW) set on 14 November 2021 at 1130 hrs.

Estimated distributed PV generation continued to rise, with an all-time record of 1,777 MW on 30 September 2022 at 1200 hrs. This was 11% higher than the previous Q3 maximum distributed PV generation record of 1,594 MW on 22 September 2021 at 1200 hrs (Figure 75). Increasing distributed PV output is the primary factor influencing falling operational demand.

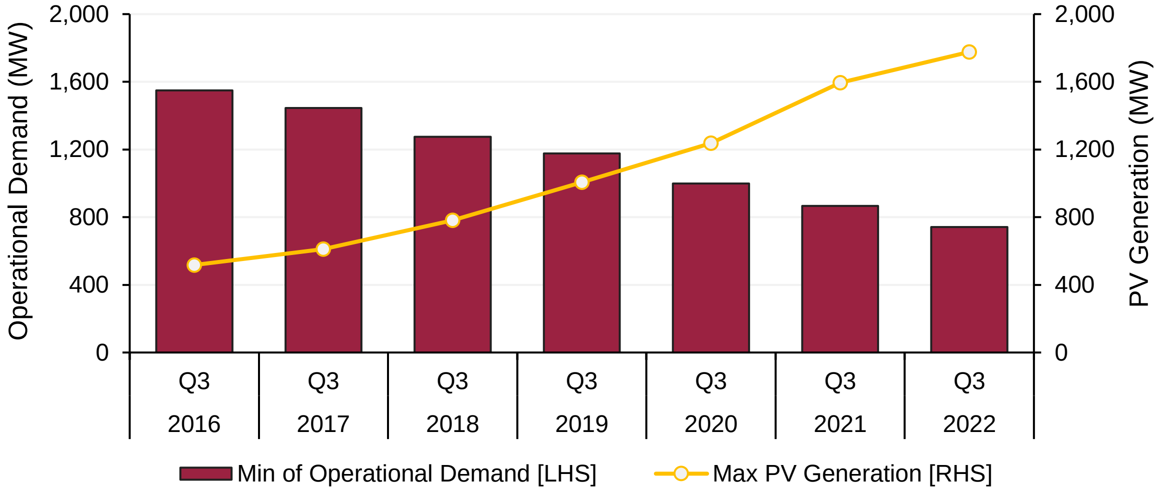
[47] Underlying demand is operational demand that has been adjusted to remove the impact of distributed PV output.

[48] Operational demand is total wholesale generation from registered facilities in the SWIS and is based on non-loss adjusted sent out SCADA data, averaged over 30-minute interval.

[49] The minimum operational demand continued to decline during Q4 2022, recording a new record minimum of 626 MW on Sunday 16 October 2022. Further insights will be presented in the Q4 2022 QED report.

Figure 75 Q3 minimum operational demand continued to decline

Q3 minimum operational demand and maximum PV generation trend

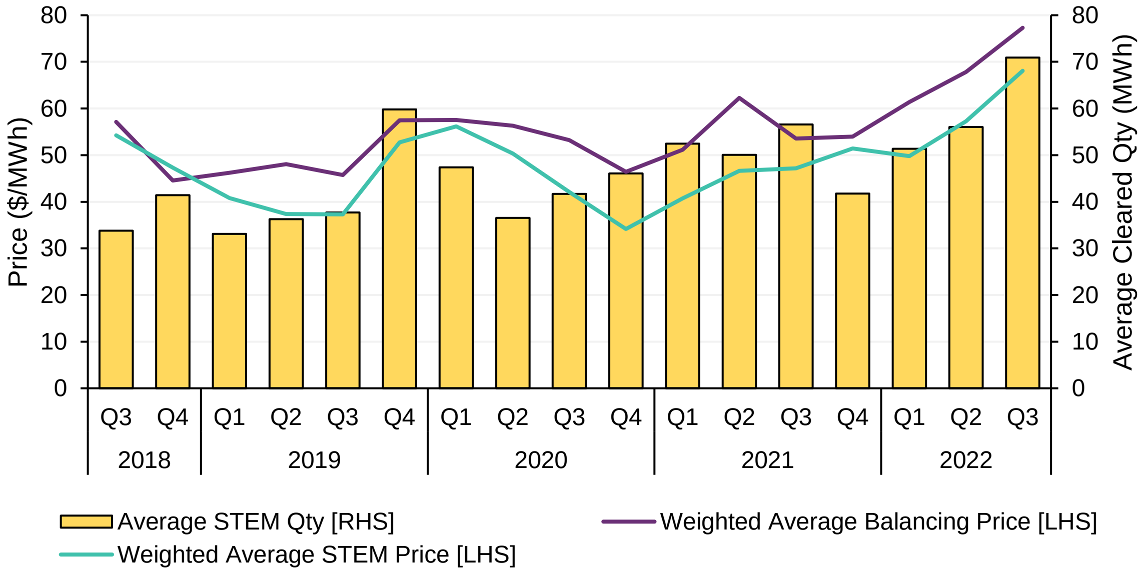


3.2 WEM prices

The weighted average Balancing Price[50] in the WEM for Q3 2022 was $77/MWh, a $9/MWh (+14%) increase from Q2 2022 and a $24/MWh (+44%) increase compared to Q3 2021 (Figure 76). Contributors to the price increase were the increase in demand, decreased coal-fired generation availability, and the change in fuel mix including the increase in gas-fired generation, offsetting the impact of low-cost generation output, such as wind and solar.

Figure 76 Weighted average Balancing Price continues to increase

WEM weighted average Balancing Prices, STEM Prices and quantity cleared in STEM – Q3 2018 to Q3 2022



[50] 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.

The weighted average Short-Term Electricity Market (STEM) Price[51] for Q3 2022 was $68/MWh, a $21/MWh (+44%) increase compared to Q3 2021, driven by increased participation in STEM; the quantity of energy cleared in STEM increased compared to the same quarter last year (+25%) and last quarter (+26%), which can be linked to high Q3 2022 Balancing Prices and subsequent market participant bidding behaviour in STEM.

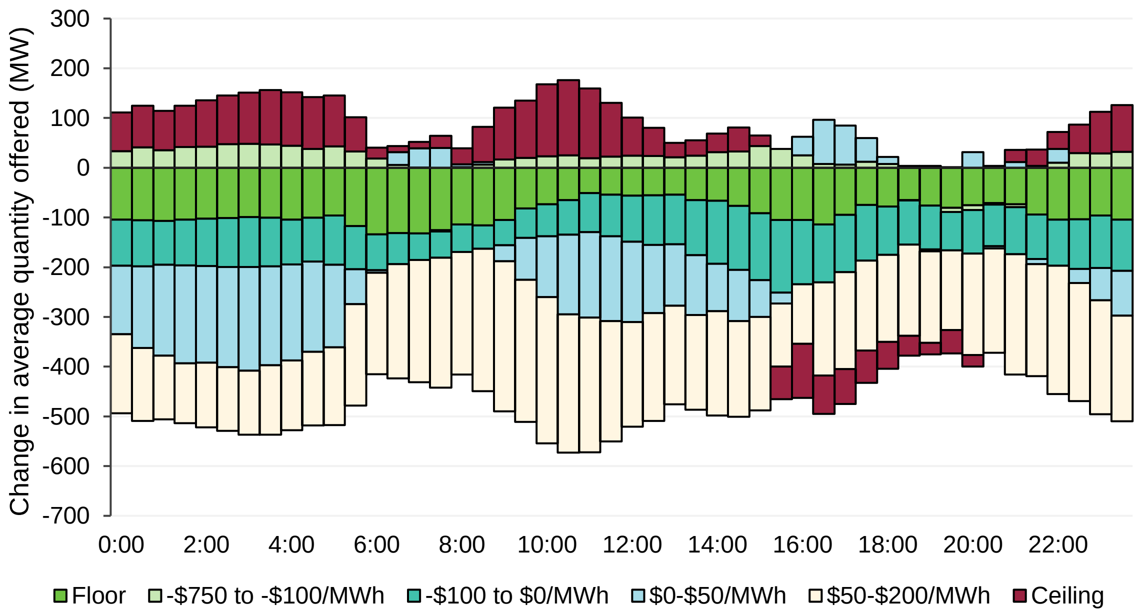
3.2.1 Balancing merit order dynamics

Participant behaviour in the Balancing Market in Q3 2022 showed a decrease in the average quantities offered at lower price bands (floor price and -$100 to $0/MWh), as well as an overall reduction in the average quantities offered in the market. This behaviour can be attributed to the change in generation mix and availability during the quarter (see Section 3.3, Figure 77). Changes in Balancing Market participation compared to Q3 2021 include:

- There was on average 92 MW (-9%) less offered at the floor price band (<-$750/MWh), with a decrease in quantities offered across the day.
- On average, there was a 21 MW (+27%) increase in quantities offered in the -$750 to -$100/MWh price band.
- Average quantities offered in the -$100 to $0/MWh price band declined by 91 MW (-18%) across the day while offers in the $0 to $50/MWh price band also decreased by an average of 71 MW (-13%).
- Participant offers in the $50 to $200/MWh price band decreased by an average 200 MW (-18%), decreasing across all intervals of the day.
- While there was an overall increase in offers in the ceiling price band above $200/MWh (+44 MW on average or 3%), there was a decline in offers between 1530 hrs and 2000 hrs.

Figure 77 Reduction in quantities offered in the Balancing Market

Change in average forecast Balancing merit order structure by time of day – Q3 2021 versus Q3 2022



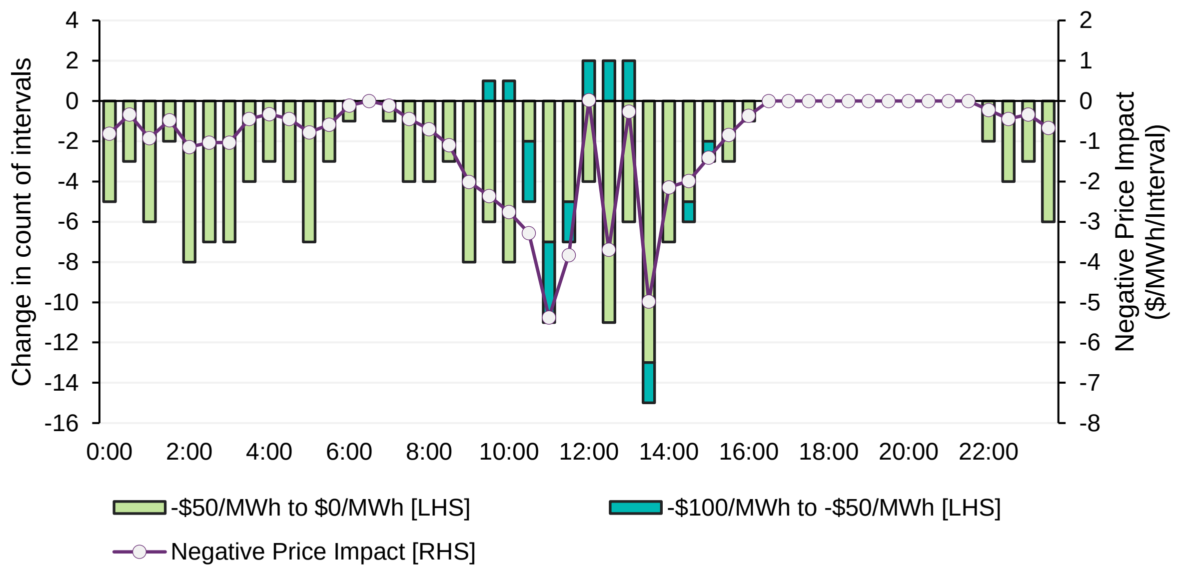
[51] The weighted average STEM Price is a measure of the average STEM Price that puts greater weighting on intervals where greater quantity is cleared. This is to reflect the average STEM Price more accurately against quantity of electricity cleared, rather than against intervals. Weighted average STEM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

3.2.2 Negative prices

The total number of negatively priced and $0/MWh intervals in Q3 2022 (3% of all intervals) reduced from Q3 2021 (7% of all intervals), with the quarter recording no intervals with a Balancing Price lower than -$100/MWh. The reduced frequency of negatively priced and $0/MWh intervals was predominantly observed during the morning and middle of the day. The decrease in negatively priced and $0/MWh intervals can be partially attributed to increased operational demand (Figure 78).

Figure 78 Less negatively priced intervals and lower negative price impact

Change in count of intervals with zero or negative Balancing Price from Q3 2021 to Q3 2022



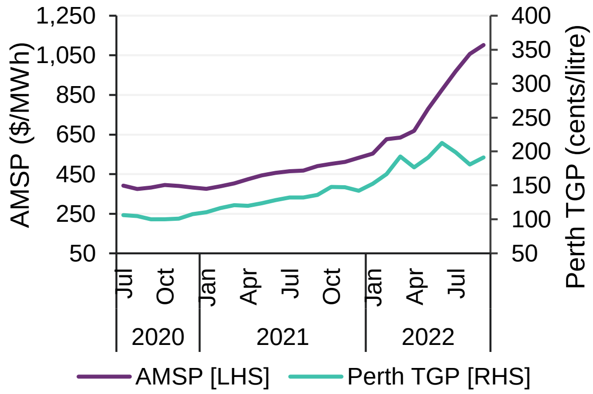
3.2.3 New Alternative Maximum STEM Price

During Q3 2022, the Alternative Maximum STEM Price (AMSP)[52] continued to trend upwards, reaching a record high of $1,102/MWh[53] in September 2022, a 124% increase since September 2021 (+$491MWh).

A key driver of the increasing AMSP is the growing Perth Diesel Terminal Gate Price (TGP, Figure 79). The Perth TGP price has risen by 40% since September 2021, growing from an average monthly price of 136 cents per litre (CPL) in September 2021 to 191 CPL in September 2022.

Figure 79 AMSP hits record high

AMSP and Perth Diesel TGP by month



[52] The Alternative Maximum STEM Price applies to generators that use distillate as a fuel source.

[53] September 2022 Alternative Maximum STEM Price: https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/price-limits.

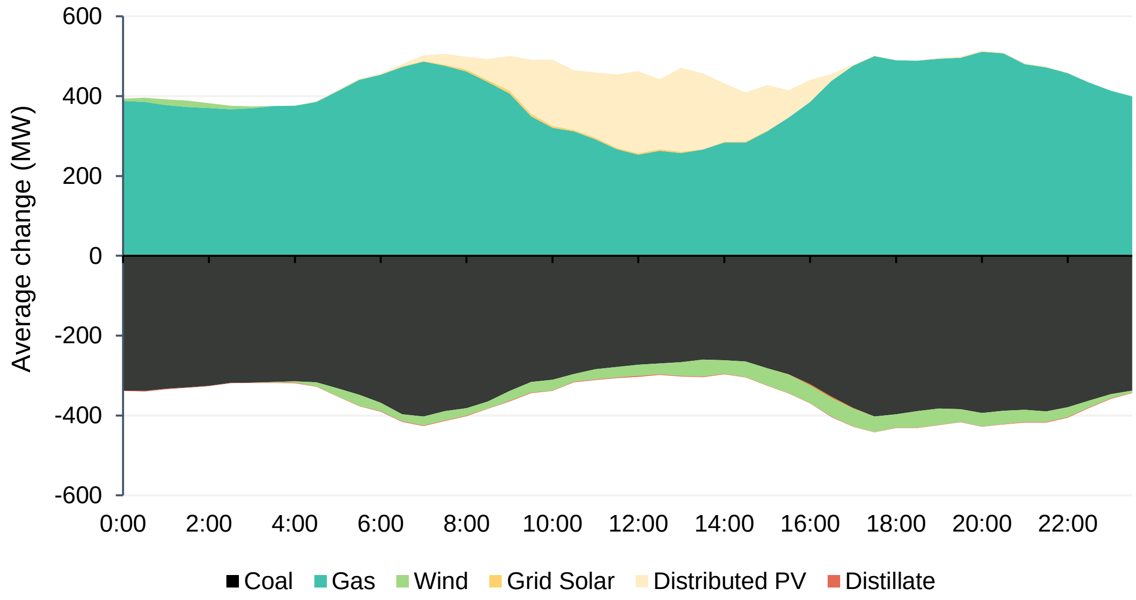
3.3 Electricity generation

3.3.1 Change in fuel mix

Q3 2022 saw an increase in gas-fired generation and a decrease in coal-fired generation at all times of the day, compared to Q3 2021 (Figure 80).

Figure 80 Gas generation increases while coal declines

Average change in WEM generation – Q3 2022 versus Q3 2021



In summary:

- Coal-fired generation reduced by an average 338 MW (-36%), decreasing across every interval. Decline in generation can be linked to coal availability reducing from 89% in Q3 2021 to 74% in Q3 2022, with coal outages increasing by 137%.
  - Driven by the reduction of coal generation availability at the end of Q3 2022, AEMO revised its operational processes where intervention is required to maintain power system security and reliability in order to deliver more efficient, equitable and transparent outcomes for market participants. Instead of constraining Independent Power Producers (IPPs), AEMO will instead constrain the Synergy Portfolio to a maximum or minimum level of output based on actual and forecast conditions on the power system. This intervention is required to ensure the appropriate levels of Ancillary Services are maintained on the power system. AEMO has applied this methodology as it allows the real-time dispatch engine (RTDE) to redispatch non-Synergy facilities in accordance with the Balancing Merit Order (BMO), providing the most transparent dispatch outcome to the market.
- Wind generation decreased by an average of 22 MW (-6%) in Q3 2022, predominantly due to a reduction in output from Alinta Wind Farm, which generated an average of 19 MW (-59%) less than Q3 2021. This reduction was due to the wind farm gradually returning to service in Q3, following a major failure in its infrastructure in June.

- Grid-scale solar generation was similar compared to Q3 2021, only increasing marginally by 1 MW on average. The increase can be attributed to the increase in output from Merredin Solar Farm, which generated an average of 1.4 MW (+6%) more than Q3 2021.
- Estimated distributed PV continued to grow, increasing by 49 MW (+20%) on average compared to Q3 2021. This can be attributed to an increase in additional PV capacity installed in the South West Interconnected System (SWIS) since Q3 2021.
- Gas generation increased by an average of 397 MW (+61%), with the largest increase occurring during the morning and evening peak.

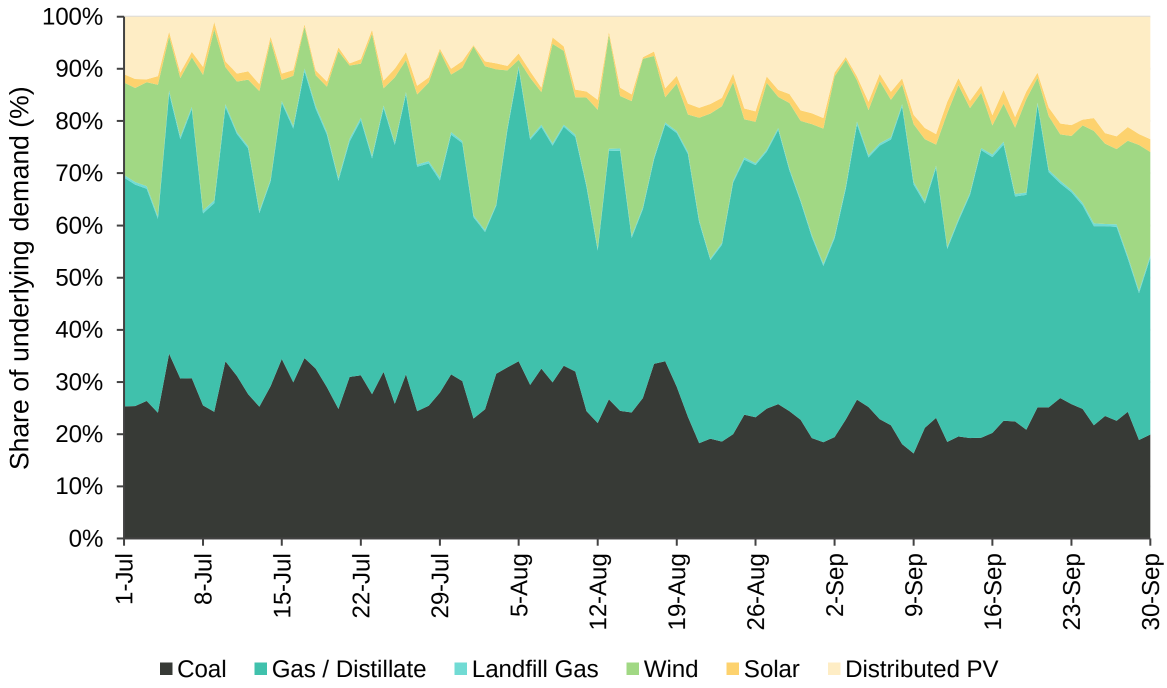
3.3.2 Decrease in coal generation

Q3 2022 saw a decrease in coal-fired generation at all times of the day compared to Q3 2021, with decreases in output occurring consistently throughout Q3 2022. A main driver was the decrease in coal availability from 89% in Q3 2021 to 74% in Q3 2022. During Q3 2022, coal generation on average met 26% of underlying demand.

The decrease in coal-fired generation resulted in an increase in the share of gas-fired generation, with gas and distillate supplying on average 45% of underlying demand, making gas the primary fuel throughout Q3 2022 (Figure 81).

Figure 81 Gas was the primary fuel throughout Q3 2022

Daily fuel mix as a share of underlying demand

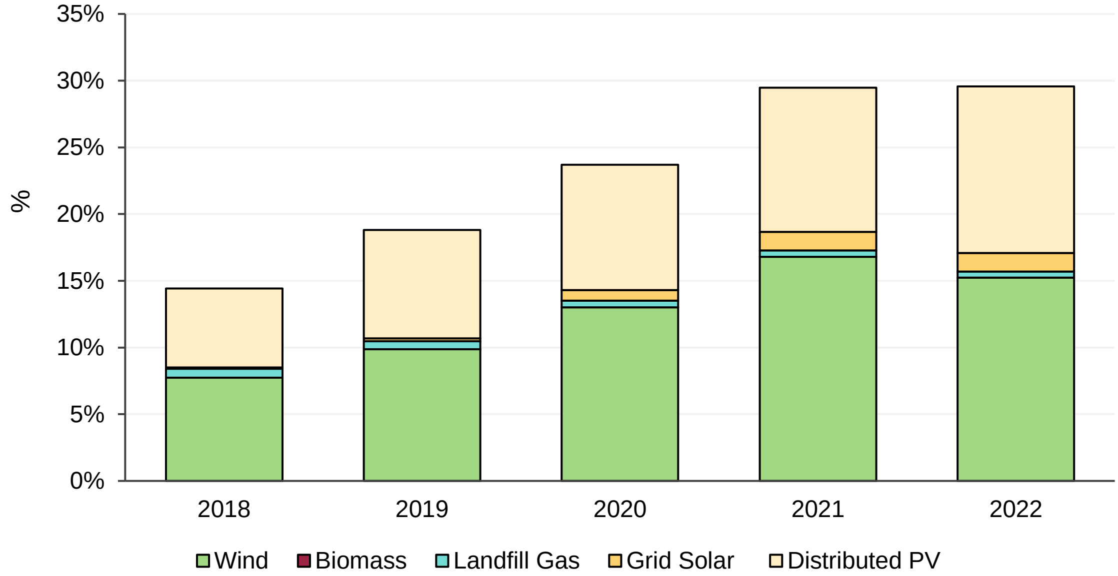


3.3.3 New Q3 renewable generation record

On 10 September 2022, during the 1130 hrs interval, renewable generation (including estimated distributed PV) supplied 74% of underlying demand, slightly below the all-time record of 79% on 7 September 2021. In Q3 2022, renewable generation (including distributed PV) supplied an average of 30% of underlying demand, a 0.1% increase compared to Q3 2021 (Figure 82).

Figure 82 Renewable energy meets a Q3 record share of underlying demand

Average Q3 renewable generation trend



3.3.4 Supplementary Reserve Capacity for the 2022-23 Capacity Year

AEMO has identified a potential shortfall of up to 174 MW of Reserve Capacity for the period 1 December 2022 to 31 March 2023, due to a combination of forecast increases in demand, extended generation outages, fuel supply constraints and project delays since the WEM Electricity Statement of Opportunities publication in June 2022[54].

On 23 September, AEMO released an invitation to tender for supplementary Reserve Capacity to procure additional capacity. Supplementary Reserve Capacity is a component of the WEM Reserve Capacity Mechanism, which ensures reliability of supply in the SWIS. Capacity is generally certified around two years prior to the relevant Capacity Year. The supplementary capacity mechanism addresses changed circumstances where these have arisen in the period since capacity was certified.

[54] AEMO 2022, WEM Electricity Statement of Opportunities: https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/wem-forecasting-and-planning/wem-electricity-statement-of-opportunities-wem-esoo

List of tables and figures

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Abbreviations

Abbreviation	Expanded term
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMSP	Alternative Maximum STEM Price
APLNG	Australia Pacific LNG
ASEFS2	Australian Solar Energy Forecasting System
ASX	Australian Securities Exchange
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
GSG	Gas Supply Guarantee
GSH	Gas Supply Hub
IOD	Indian Ocean Dipole
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

Abbreviation	Expanded term
PJ	Petajoule
PV	Photovoltaic
QED	Quarterly Energy Dynamics
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
RTDE	Real-time dispatch engine
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
TGP	Terminal Gate Price
TJ	Terajoule
UGS	Underground Storage Facility
VBB	Victoria Big Battery
VRE	Variable renewable energy
VNI	Victoria – New South Wales Interconnector
YoY	Year on year
WEM	Wholesale Electricity Market
WDR	Wholesale demand response