



Quarterly Energy Dynamics Q2 2021

Market Insights and WA Market Operations

Important notice

PURPOSE

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q2 2021 (1 April to 30 June 2021). This quarterly report compares results for the quarter against other recent quarters, focusing on Q1 2021 and Q2 2020.

Geographically, the report covers:

- The National Electricity Market – which includes Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.
- The Wholesale Electricity Market operating in Western Australia.
- The gas markets operating in Queensland, New South Wales, Victoria and South Australia.

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VERSION CONTROL

Version	Release date	Changes
1	23/07/2021	

Executive summary

East coast electricity and gas highlights

Wholesale electricity and gas prices rebound from recent lows

- Q2 2021 (1 April to 30 June 2021) saw a dramatic turnaround in electricity prices following an exceptionally low Q1. Mainland wholesale electricity prices rebounded strongly after a year in decline, averaging¹ \$95/megawatt hour (MWh) compared to \$37/MWh in Q1 2021.
 - Queensland recorded its highest Q2 average on record at \$128/MWh, while New South Wales also increased significantly to \$111/MWh, with significant price volatility in both regions. High spot prices (>\$300/MWh) contributed \$61/MWh to the Queensland average price and \$36/MWh to the New South Wales average price.
 - Coal-fired generator outages, combined with cooler weather, were key drivers. With a significant incident at Callide Power Station on 25 May and several other extended outages, National Electricity Market (NEM) black coal-fired generator availability fell to its lowest Q2 level on record.
- Gas prices increased in all east coast gas markets, averaging \$8.20/gigajoule (GJ) for the quarter, up from \$6.03/GJ in the first quarter and nearly double the average of \$4.37/GJ in Q2 2020. From late May, average market prices rose sharply, ending the quarter at \$12/GJ, influenced by rising international prices and high June gas-powered generation (GPG) demand.
- Higher gas prices also impacted electricity prices with gas' price-setting role increasing from 8% in Q1 2021 to 20% this quarter, with a large proportion of the increase occurring during the evening peak.
- ASX futures prices rallied strongly, influenced by high spot prices and the unexpected major outages at Callide and Yallourn power stations. Calendar year (Cal) 2022 swap contract prices increased across all states, from an average of \$40/MWh at the end of Q1 2021, to finish Q2 at \$53/MWh (+34%), with the largest increase occurring in Queensland.

Major thermal generator outages drive significant price volatility

- On 25 May 2021, following an incident at Callide Power Station, multiple generators and transmission lines in Queensland tripped, leading to under-frequency load shedding and extreme price volatility². The rapid reduction in Queensland coal-fired generation – more than 2,000 megawatts (MW) in five minutes – and the transmission line outages, led to Queensland's trading price spiking to the Market Price Cap (MPC) for an extended period, and Queensland's spot price averaging \$1,638/MWh for the day.
- Following the Callide incident and ongoing Callide (and other) coal-fired unit outages, the supply-demand balance was tight in Queensland and New South Wales for much of the quarter, contributing to significant price volatility.

¹ Uses the time-weighted average which is the average of spot prices in the quarter. The Australian Energy Regulator (AER) reports the volume-weighted average price which is weighted against demand in each 30minute trading interval.

² For more preliminary report on operational outcomes on this day, see: AEMO 2021, Preliminary Report: Trip of multiple generators and lines in Queensland and associated under-frequency load shedding on 25 May 2021. Available at: https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/preliminary-report--trip-of-multiple-generators-and-lines-in-queensland-and-associated-underfrequenc.pdf?la=en.

- Flood damage at the Yallourn mine severely affected Yallourn Power Station's operation in mid-June, with three units taken offline while repairs were undertaken. This contributed to Yallourn's quarterly average output falling to 900 MW, 146 MW lower than in Q2 2020.
- GPG was particularly high in June – almost twice as high as in May – with GPG providing backup capacity following the Callide and Yallourn incidents. Newport ramped up output to cover for Yallourn's outages, while Darling Downs increased significantly as it returned from a planned outage.

Other highlights

- NEM quarterly average underlying demand³ increased by 571 MW compared to a COVID-19 impacted Q2 2020, and 398 MW compared to Q2 2019, due to increased heating requirements in Sydney and Brisbane resulting from colder than average conditions.
- Transmission line outages associated with upgrade of the Queensland – New South Wales Interconnector (QNI) contributed to very high Frequency Control Ancillary Service (FCAS) costs (\$141 million), increased occurrence of negative spot prices in Queensland (5.6% of the time), and record high application of negative residue management (NRM) on the interconnector.
- High gas demand in May and June resulted in the rapid depletion of Iona Underground Gas Storage (UGS) facility. Storage levels fell from a record high of 24.5 petajoules (PJ) on 10 May to finish the quarter at 14.3 PJ, 3.6 PJ lower than at the end of Q2 2020 and the lowest level end of Q2 since storages began being reported. The Iona UGS facility also took an unplanned maintenance outage on 24 June.
- Increased gas demand and prices also contributed to increased utilisation of Longford Gas Plant, with output 8.8 PJ higher than in Q2 2020. However, Longford daily production finished the quarter at lower levels due to a partial outage from 28 June, which reduced its production from 980 TJ/d to 771 TJ/d.

Western Australia electricity and gas highlights

Cold weather contributes to increased operational demand

- Perth experienced its coldest June in 31 years, with heating requirement increasing by 71% compared to Q2 2020, contributing to an operational demand increase of 102 MW. A new Q2 operational demand record of 3,528 MW occurred on 22 June, the coldest day of the quarter.
- Higher operational demand contributed to the quarterly average Balancing Price increasing to \$58/MWh, its highest since Q3 2017, and increased frequency of high price events (>\$150/MWh).

Major cyclone event impacts wind generation

- On 11 April 2021, Cyclone Seroja made landfall on the Western Australian coast near Kalbarri, resulting in the outage of several transmission lines connecting the North Country region to the rest of the South West Interconnected System (SWIS). The region was islanded until 21 April and all transmission lines were restored by 25 May. A total of 767 MW of installed wind capacity was affected by the network outages.

Increasing withdrawals from gas facilities offset decreased production

- Total Western Australian gas production was down 15 PJ (13.7%) compared to the historic peak in Q2 2020, predominantly due to decreased production from Karratha Gas Plant. The reduced supply was met by a net withdrawal of 5.4 PJ from gas storage facilities, in contrast to net injection of 7.4 PJ in Q2 2020.

³ Underlying demand is operational demand that has been adjusted to remove the impact of distributed photovoltaics (PV) output.

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1. NEM market dynamics

1.1 Electricity demand

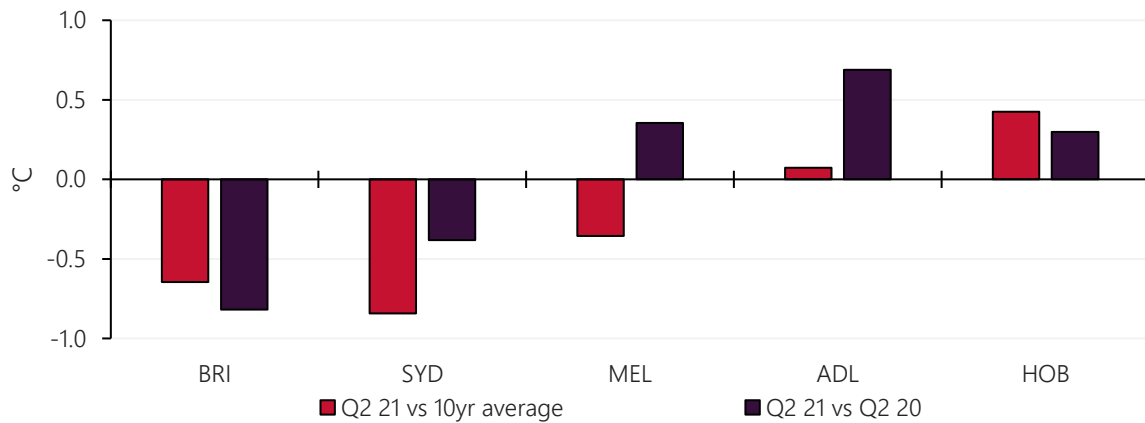
1.1.1 Weather

During the quarter, the weather was colder than average across the eastern seaboard. Notably, Brisbane and Sydney experienced much cooler than average conditions, with overnight minimum temperatures 0.6°C and 0.8°C below the 10-year average respectively (Figure 1), and below-average maximum temperatures.

Colder temperatures in Brisbane and Sydney led to higher heating degrees days (HDDs⁴), which reached their highest levels since 2011 and 2012 respectively (Figure 2), resulting in increased electricity demand (Section 1.1.2).

Figure 1 Cold Q2 weather in the Sydney and Brisbane

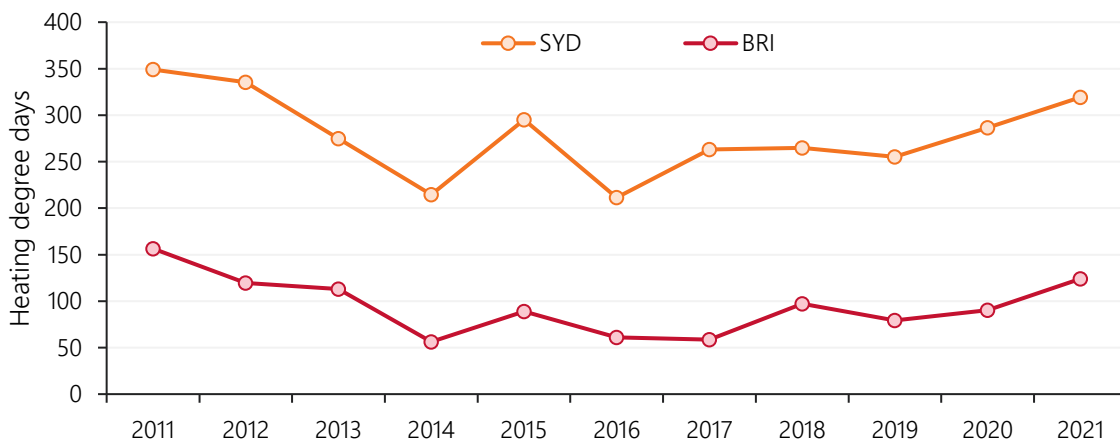
Average minimum temperature variance by capital cities



Source: Bureau of Meteorology

Figure 2 Increased heating requirements in Sydney and Brisbane

Heating degree days (Q2s) – 2011 to 2021



⁴ A "heating degree day" (HDD) is a measurement used as an indicator of outside temperature levels below what is considered a comfortable temperature. Here, the HDD value is the sum of daily HDD values over the quarter which are calculated as max(0, 18 – temperature).

1.1.2 Demand outcomes

NEM quarterly average operational demand increased by 350 megawatts (MW) compared to Q2 2020, reversing the downward trend since Q2 2018. Higher operational demand was driven by a 571 MW increase in underlying demand (+2.5%), which more than offset the impact of increased output from distributed photovoltaics (PV)⁵ (+221 MW). NEM-average underlying demand reached 23,109 MW, not only higher than the COVID-19 impacted Q2 2020, but its highest Q2 level since 2012⁶ (Figure 3), with increases in all NEM regions except for South Australia (Figure 4).

Figure 3 Highest NEM Q2 underlying demand since 2012

Average NEM underlying demand (Q2s) – 2012 to 2021

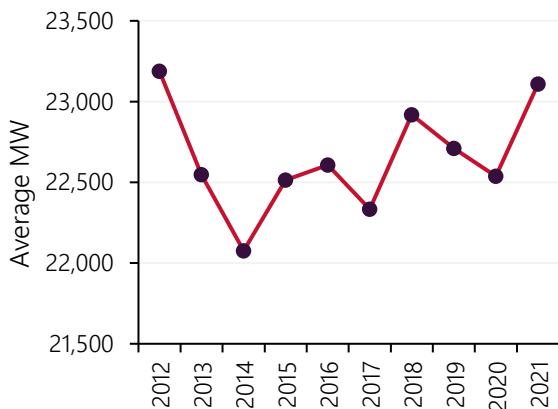
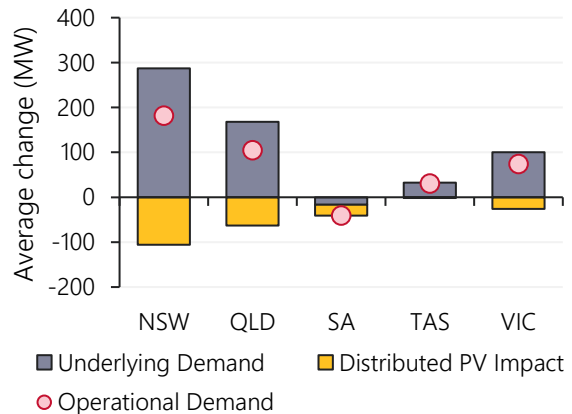


Figure 4 New South Wales and Queensland lead NEM 2.5% underlying demand increase

Change in average operational demand – Q2 2021 vs Q2 2020



The largest underlying demand increases occurred in New South Wales (+287 MW) and Queensland (+168 MW). Drivers included:

- **Cold Q2 conditions** – colder-than-average temperatures in Brisbane and Sydney resulted in elevated heating requirements contributing to increased underlying demand across the day (Figure 5).
- **Lack of prolonged COVID-19 restrictions** also contributed to increased underlying demand, predominantly during the morning peak.
 - With the exception of Victoria, there were almost no COVID-19 restrictions this quarter, and there was a notable increase in underlying demand between 0600 hrs and 0900 hrs (+1,005 MW) as working patterns returned to normal⁷.
- **Increased liquefied natural gas (LNG) production** (Section 2.3.1) contributed to increased underlying demand in Queensland, mainly from increased electricity consumption in the gas production process.

While quarterly operational demand was up on Q2 2020 levels, the uptake of distributed PV continued to contribute to declining daytime demand – on average, NEM average operational demand was down 298 MW between 1000 hrs and 1430 hrs. The largest changes in distributed PV output occurred in New South Wales (+105 MW) and Queensland (+63 MW).

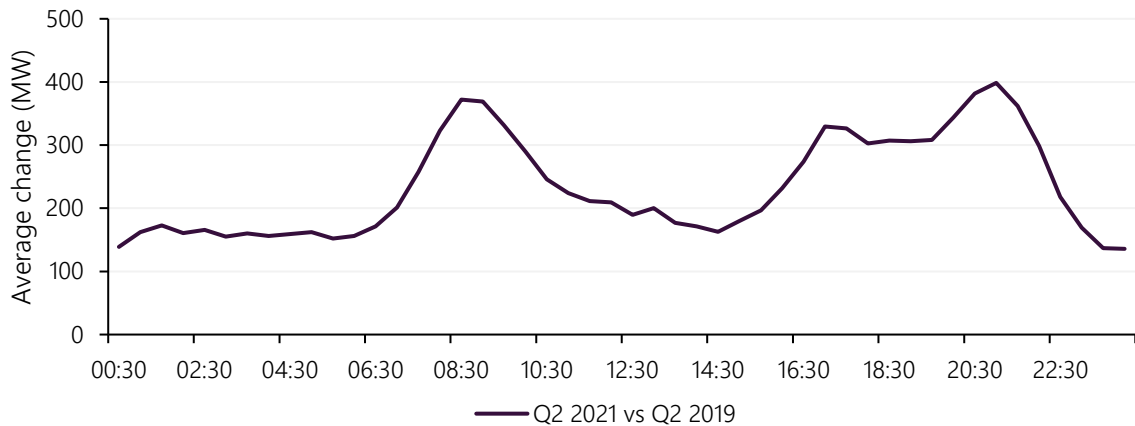
⁵ Increased distributed PV generation results in reduced operational demand because distributed PV is behind the meter and is based on AEMO estimates using ASEFS2.

⁶ Calculated using pre-2016 estimates for distributed PV output

⁷ See AEMO Quarterly Energy Dynamics Q2 2020 for more information: <https://aemo.com.au/-/media/files/major-publications/qed/2020/qed-q2-2020.pdf?la=en>

Figure 5 Increased underlying demand across the day due to increased heating load

Change in combined New South Wales and Queensland average underlying demand by time of day – Q2 2021 compared Q2 2019



Maximum and minimum demand

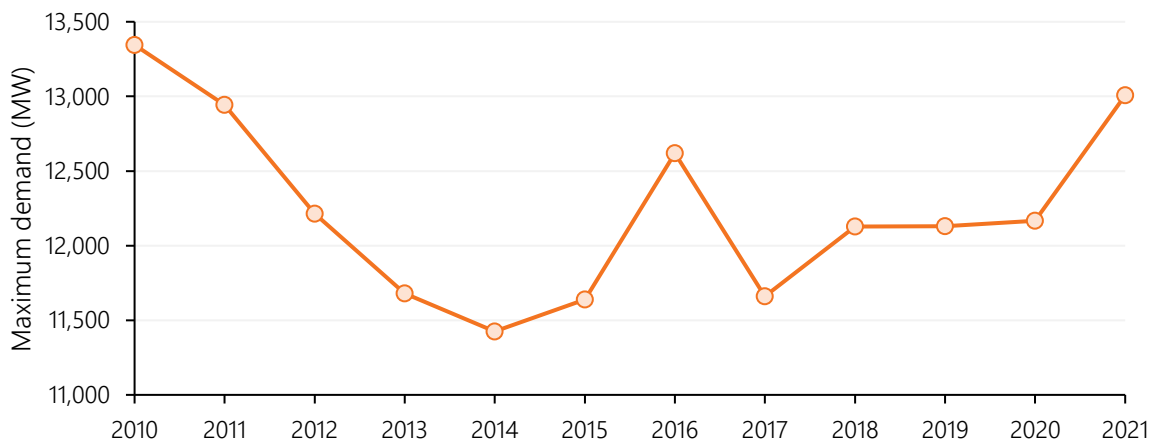
During Q2 2021, new Q2 operational demand minimums were set in Victoria and South Australia, however, these were only slightly lower than previous records.

- **Victoria’s** new Q2 minimum demand of 3,379 MW occurred at 1400 hrs on Easter Monday (5 April 2021), and was 22 MW lower than the previous Q2 minimum set in Q2 2017. A combination of sunny, mild conditions and low demand associated with the public holiday contributed to the record.
- **South Australia’s** new Q2 minimum demand of 523 MW occurred at 1330 hrs on its ANZAC day holiday, Monday 26 April 2021⁸, and was 10 MW lower than the previous record set in Q2 2020. Drivers were similar to the Victorian record, with distributed PV providing 833 MW of output (61% of underlying demand).

Extremely cold conditions in New South Wales led to it reaching its highest Q2 maximum operational demand since 2010 (Figure 6). On 10 June 2021, New South Wales’ operational demand reached 13,007 MW at 1800 hrs as Sydney recorded its coldest day in 37 years⁹, contributing to significant spot price volatility (Section 1.2.2).

Figure 6 Highest Q2 maximum demand in New South Wales since 2010

Q2 maximum operational demands – New South Wales



⁸In South Australia, Queensland and Northern Territory, ANZAC Day public holiday was observed on Monday 26 April 2021.

⁹ Weather Zone 2021, Sydney’s coldest day in decades: <https://www.weatherzone.com.au/news/sydneys-coldest-day-in-decades-/534322>

1.2 Wholesale electricity prices

This quarter, mainland wholesale electricity prices rebounded strongly after two years in decline, averaging \$95/megawatt hour (MWh) compared to \$37/MWh in Q1 2021 (+159%, Figure 7). This represents the highest quarterly average in almost two years, occurring in what is typically a lower-priced quarter.

Notably, Queensland recorded its highest Q2 average on record at \$128/MWh, while New South Wales also increased significantly to \$111/MWh, with significant price volatility in both regions (Figure 8). This price volatility was the main contributor to the large increase in price spread between the northern and southern regions – the northern regions traded at a 71% premium to Victoria and South Australia. By contrast, the underlying energy price¹⁰ was relatively consistent across mainland NEM regions. Tasmania’s quarterly average price remained comparatively low at \$45/MWh.

Section 1.2.1 discusses general electricity price drivers, and Section 1.2.2 unpacks the price volatility results in more detail.

Figure 7 Mainland wholesale electricity prices rebound in Q2 2021

Mainland average wholesale electricity price

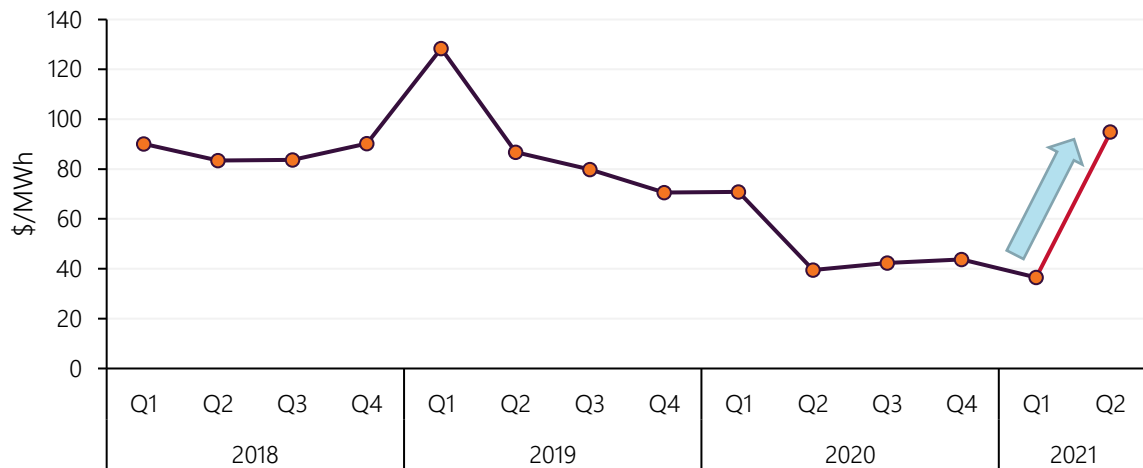
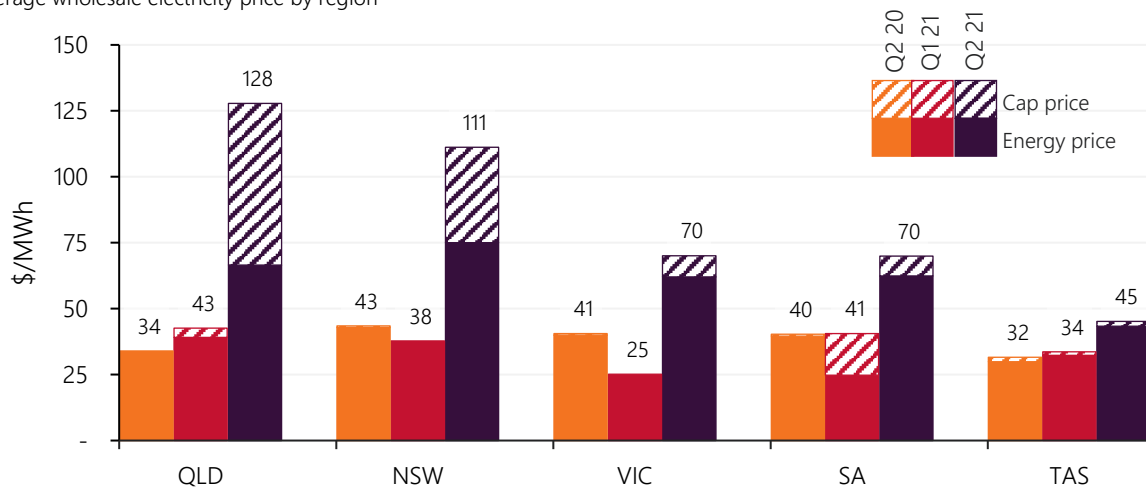


Figure 8 Record high Q2 spot electricity prices in Queensland and New South Wales

Average wholesale electricity price by region



¹⁰ 'Energy price' is used in electricity pricing to remove the impact of price volatility (that is, price above \$300/MWh).

1.2.1 Wholesale electricity price drivers

Table 1 outlines general drivers of increased electricity prices this quarter.

Table 1 Wholesale electricity price increase: Q2 2021 drivers

Price volatility	The largest increase in NEM prices this quarter occurred in the peak evening period, largely due to significant price volatility in Queensland and New South Wales (Section 1.2.2).
Thermal generator outages	<p>Compared to Q2 2020, thermal generator availability was down across all generation types and all NEM regions (Figure 9). These outages, coupled with rising fuel costs (as indicated by rising domestic gas prices and international commodity prices [Section 2.2.1]), led to a substantial shift in the NEM-wide thermal generation supply curve. Compared to Q2 2020, there was a 3,113 MW reduction in offers below \$100/MWh (Figure 10)¹¹. By fuel type:</p> <ul style="list-style-type: none"> • Black coal-fired generator availability reduced by 1,479 MW due to increased planned and unplanned outages (Section 1.3.1). • Outages at Braemar 1, Darling Downs and Swanbank E reduced gas-powered generation (GPG) availability by 773 MW. • Hydro availability reduced by 668 MW, with the largest availability reductions occurring at Shoalhaven (due to an extended outage), Murray, and Tumut 3. • Flood damage at the Yallourn coal mine resulted in brown coal-fired generator availability reducing by 113 MW.
Increased demand	Cold conditions in Sydney and Brisbane, as well as the lack of widespread COVID-19 related restrictions of Q2 2020, contributed to increased operational demand (Section 1.1.2).

Figure 9 Significant reduction in thermal unit availability in Queensland and New South Wales

Change in availability by NEM region – Q2 2021 versus Q2 2020

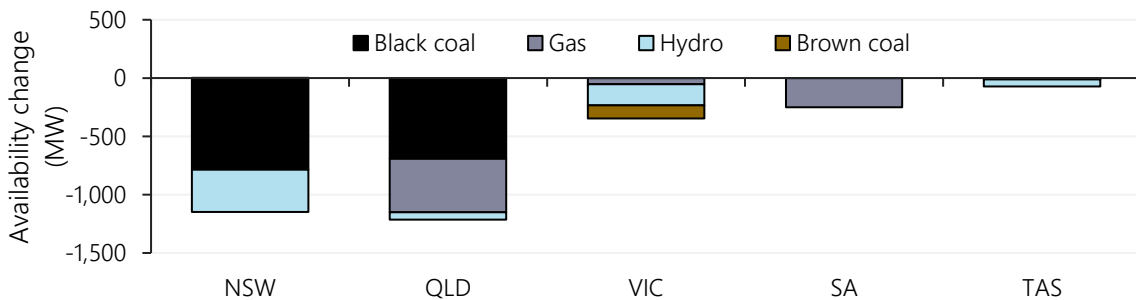
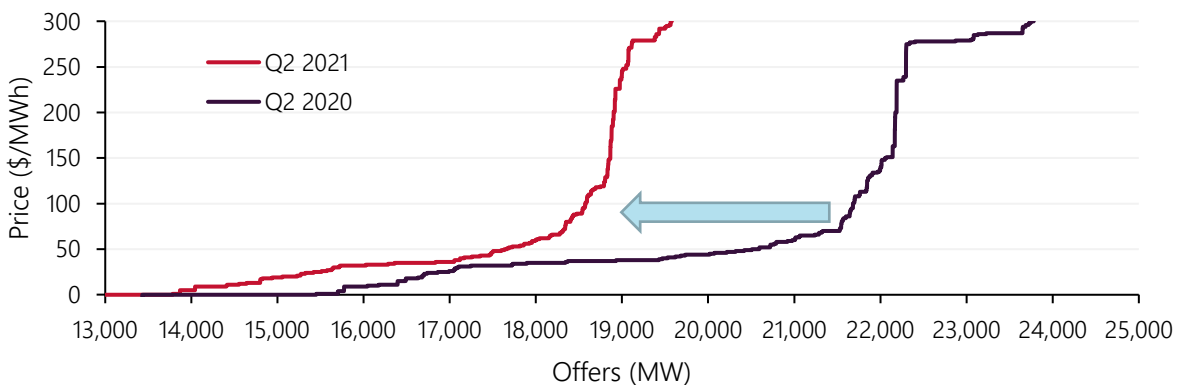


Figure 10 Outages and rising fuel costs result in higher cost supply

NEM thermal generation bid supply curve – Q2 2021 and Q2 2020



¹¹ The AER's Quarter 2 2021 Wholesale Market Quarterly Report will analyse weekly black coal and gas offers.

1.2.2 Wholesale electricity price volatility

Q2 2021 marked a return to extreme spot price volatility after an absence of more than a year. NEM-wide cap returns¹² increased to the third highest level since market start, with Queensland’s cap returns of \$61/MWh, and New South Wales’ cap returns of \$36/MWh the second highest quarters on record for both regions (Figure 11). Of note, there was a greater spread in Queensland’s trading price compared to Q2 2020, with a higher proportion of negatively priced intervals during the daytime, and a higher proportion of high-priced intervals during the peak evening period (Figure 12).

Victoria and South Australia recorded cap returns of around \$8/MWh, much lower than the northern regions, but higher than usual for a Q2 in these regions.

Figure 11 Extreme spot price volatility in Queensland and New South Wales

Quarterly average cap returns by region - stacked

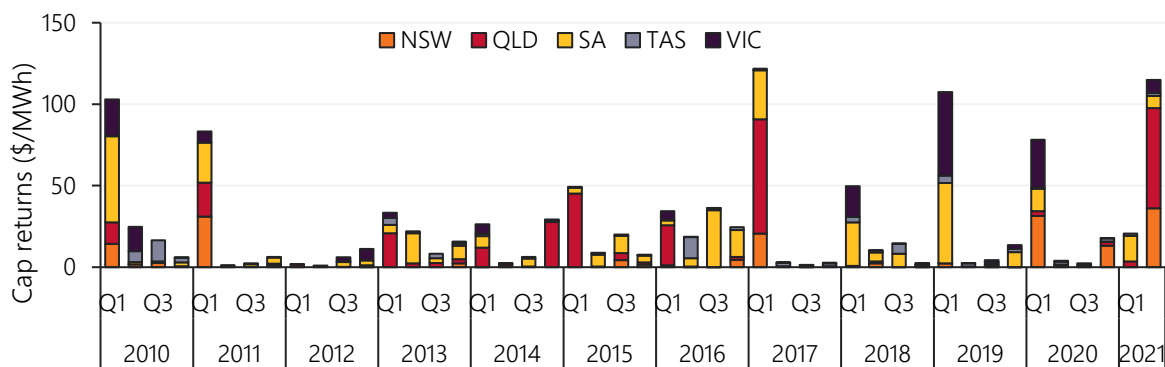
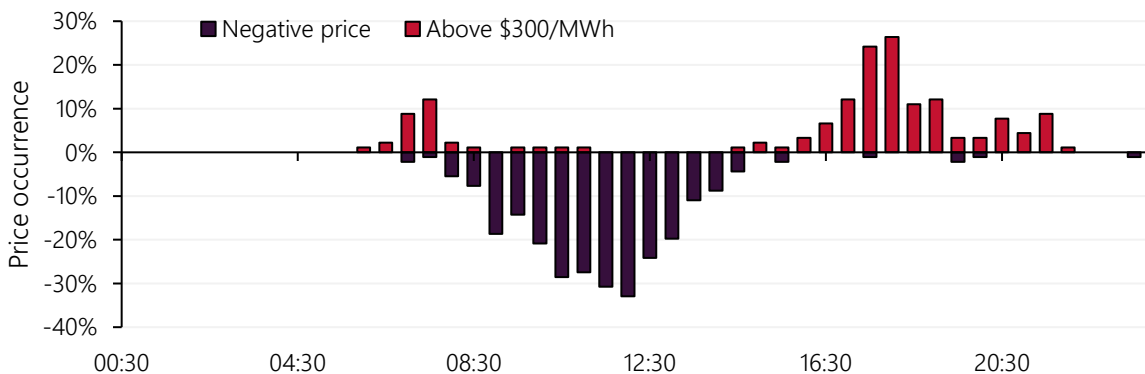


Figure 12 Large occurrence of high and low price volatility in Queensland

Queensland frequency of prices ≤\$0/MWh and >\$300/MWh by time of day – Q2 2021



Callide incident – 25 May 2021

On 25 May 2021, the trip of multiple generators and transmission lines in Queensland led to under-frequency load shedding and extreme price volatility¹³. On this day, Callide C4 ceased exporting active power at 1334 hrs, with CS Energy reporting a turbine hall fire. Subsequently, at 1344 hrs, Callide C3 tripped, and then at 1406 hrs trip of the following occurred¹⁴: Callide B2, three Stanwell Power Station units to house load, three

¹² A measure of volatility in electricity prices is the presence of high price events – prices above \$300/MWh. This is often represented as ‘quarterly cap returns’, which is the sum of the NEM pool price minus the \$300 cap price for every half hour in the contract quarter where the pool price exceeds \$300/MWh, divided by the number of half-hours in the quarter.

¹³ For more details, on operational outcomes on this day, see: AEMO 2021, Preliminary Report: Trip of multiple generators and lines in Queensland and associated under-frequency load shedding on 25 May 2021, at https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/preliminary-report--trip-of-multiple-generators-and-lines-in-queensland-and-associated-underfrequenc.pdf?la=en

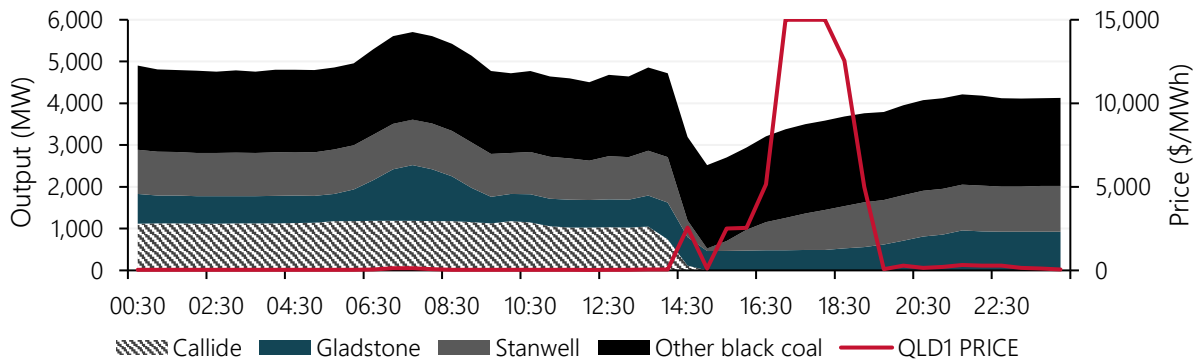
¹⁴ The exact sequence of events is subject to investigation.

Gladstone Power Station units, Yarwun Power Station, multiple transmission lines, and the Queensland – New South Wales Interconnector (QNI).

The rapid reduction in Queensland coal-fired generation – more than 2,000 MW in five minutes – and the transmission line outages, led to Queensland’s trading price spiking to the Market Price Cap (MPC, \$15,000/MWh) for 90 minutes (Figure 13). This resulted in a daily average price of \$1,638/MWh, Queensland’s third-highest day on record¹⁵.

Figure 13 Extreme Queensland price volatility following the Callide incident – 25 May 2021

Queensland coal-fired generation and trading price – 25 May 2021



In response to the coal-fired generator outages and price volatility, Queensland GPG, hydro, and diesel generators ramped up to high output, increasing by around 2,200 MW within three hours of the event. In addition, Stanwell Power Station – which had tripped to house load – ramped up output between 1450 hrs and 1830 hrs. During this period (1415 hrs to 1725 hrs), around 400 MW of Queensland solar and wind output was automatically constrained in response to the reduction in system strength.

The large reduction of generation availability also led to actual Lack of Reserve 1 (LOR1) and LOR2 conditions, and forecast LOR3 conditions in Queensland, as well as activation of 15 MW of Reliability and Emergency Reserve Trader (RERT) capacity in Queensland (Section 1.5). Actual LOR1 and forecast LOR2 conditions also occurred in New South Wales.

Further price volatility and steep bid stacks

Following the Callide incident and ongoing Callide (and other) coal-fired unit outages, the supply-demand balance was tight in Queensland and New South Wales for much of the quarter, contributing to significant price volatility on several days (Table 2). While much of this volatility occurred during and after the Callide incident, several other factors meant there was already increased risk of price volatility in Queensland and New South Wales. These included:

- **Coal-fired generator outages** removed an average of 2,110 MW of low-priced supply (<\$60/MWh) compared to Q2 2020 (Section 1.3.1).
- **Steep bid stack during evening peak** – this is covered in more detail later in this section.
- **Increased peak evening demand** – colder than average weather contributed to a combined 374 MW increase in New South Wales and Queensland peak evening¹⁶ demand compared to Q2 2020 (Section 1.1.2). On 10 June, very cold winter conditions led to New South Wales’ highest Q2 operational demand since 2010 and significant price volatility resulted.
- **Transmission line outages** – transmission line outages – including those required for the upgrade of the QNI – limited transfers into Queensland, contributing to price volatility.

¹⁵ The AER publishes \$5000/MWh reports which analyse the cause of these events in more details: <https://www.aer.gov.au/taxonomy/term/310>

¹⁶ 1600 hrs to 1900 hrs

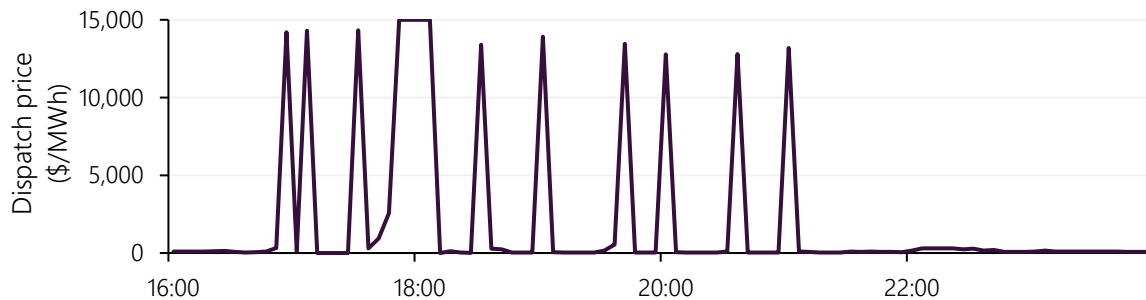
Table 2 Volatile days in the NEM – Q2 2021

Day	Affected region(s)	Daily average price (\$/MWh)	Trading intervals > \$2,000/MWh
18 May	NSW, VIC, & SA	442 (NSW); 440 (VIC); 411 (SA)	3 in all regions
25 May	QLD & NSW	1,638 (QLD); 369 (NSW).	9 in QLD; 3 in NSW.
3 June	QLD	793	4
10 June	NSW and QLD	774 (NSW); 762 (QLD)	11 in both regions
15 June	NSW and QLD	564 (NSW); 648 (QLD)	8 in both regions

Price volatility on these days was characterised by sharp and sudden price spikes, sometimes followed by zero or negative price spikes. Figure 14 shows an example of this in New South Wales on 10 June, when dispatch regularly bounced between below \$100/MWh and above \$10,000/MWh.

Figure 14 New South Wales dispatch price volatility – 10 June 2021

New South Wales dispatch price

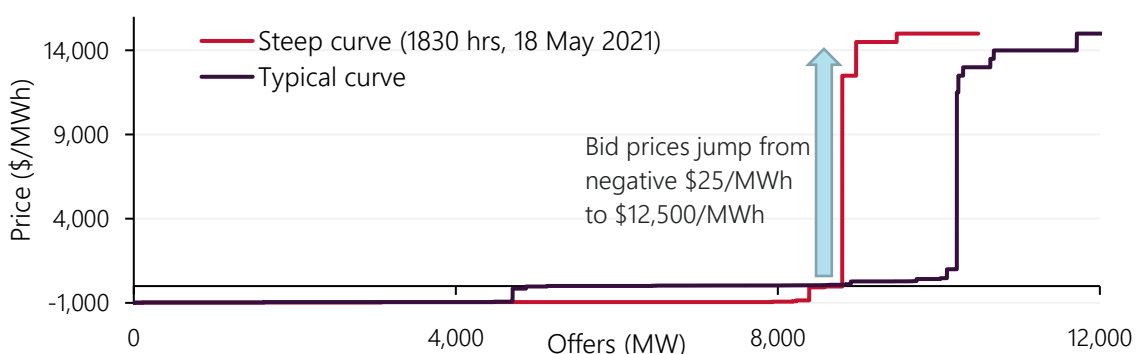


During Q2 2021, NEM dispatch prices soared from below \$100/MWh to above \$10,000 within one dispatch interval 66 times, more than the last four years combined. This type of price volatility also contributed to high occurrence of negative inter-regional settlement residue (IRSR), and frequent application of Negative Residue Management (NRM, Section 1.4.1). Drivers included:

- **Steep bid stack** – during peak evening periods in May and June, there were multiple occasions when the bid stack became highly polarised, with all generation bids either below \$0/MWh or above \$12,000/MWh. Figure 15 shows this occurring in New South Wales during the evening peak on 18 May, and contrasts this with a typical bid stack.
- **Generator re-bidding** – following Queensland dispatch prices spiking above \$10,000/MWh, some generators – including Braemar 2, Oakey, and Millmerran – frequently re-bid capacity from high-priced bands to low-priced bands to capture the higher prices during the trading interval.

Figure 15 Steep bid supply curve in New South Wales – 1830 hrs 18 May 2021

New South Wales bid supply curves



1.2.3 Negative wholesale electricity prices

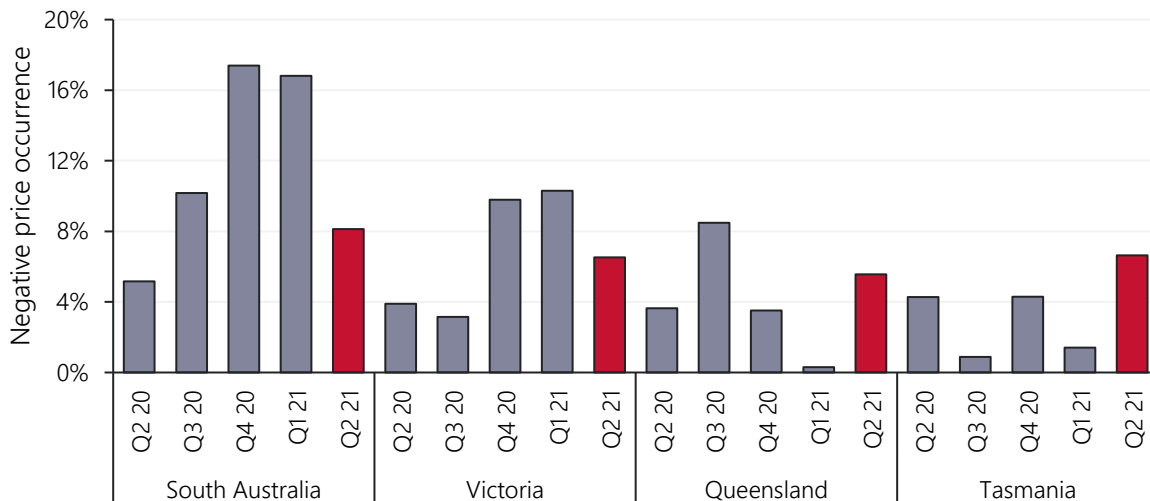
During Q2 2021, negative and zero spot prices¹⁷ occurred in 5.5% of all trading intervals, up from 4% in Q2 2020. Contrasting recent quarters, the occurrence of negative prices was no longer confined to South Australia and Victoria, with increased prevalence in Queensland and Tasmania (Figure 16).

In Queensland, spot prices were negative 5.6% of the time, its second highest quarter on record, while Tasmania reached a record quarterly high of 6.6%. In South Australia and Victoria, spot prices were negative more often than Q2 2020, but were down compared to the record levels of recent quarters.

While negative spot price occurrences were relatively high across the four states, the negative price impact was very limited. Negative prices only reduced Queensland and Tasmania prices by \$1.3/MWh and \$0.5/MWh respectively, due to very few intervals where prices were below minus \$100/MWh.

Figure 16 High prevalence of negative spot prices in four NEM regions

Quarterly negative price percentage occurrence



In Queensland, drivers of increased occurrence of negative prices included:

- Interconnector constraints** – outages on multiple transmission lines due to upgrade works on the QNI contributed to reduced interconnector limits (Section 1.4). The quarterly average import limit on QNI was 728 MW, 123 MW below the two-year average.
 - With low daytime operational demand and daytime grid-solar output, lower limits on the interconnector contributed to periods of oversupply in Queensland; spot prices were negative 84% of the time when the import limit was less than 500 MW.
- Reduced daytime demand** – increased distributed PV output reduced daytime operational demand¹⁸ by 100 MW compared to Q2 2020, with 84% of negative price intervals in Queensland occurring during this period.
- Increased local hydro output** resulted in an additional 71 MW of offers below \$0/MWh during daytime hours.

Negative spot prices in Tasmania mostly occurred during the peak evening hours, with 56% of negative price intervals occurred between 1730 hrs and 2330 hrs. During these hours, around 100 MW more Tasmanian generation was offered below \$0/MWh than in Q2 2020, influenced by high peak Victorian prices (which can incentivise increased Tasmanian transfers into Victoria via Basslink).

¹⁷ Hereafter referred to as negative spot prices.

¹⁸ 0930 hrs to 1430 hrs.

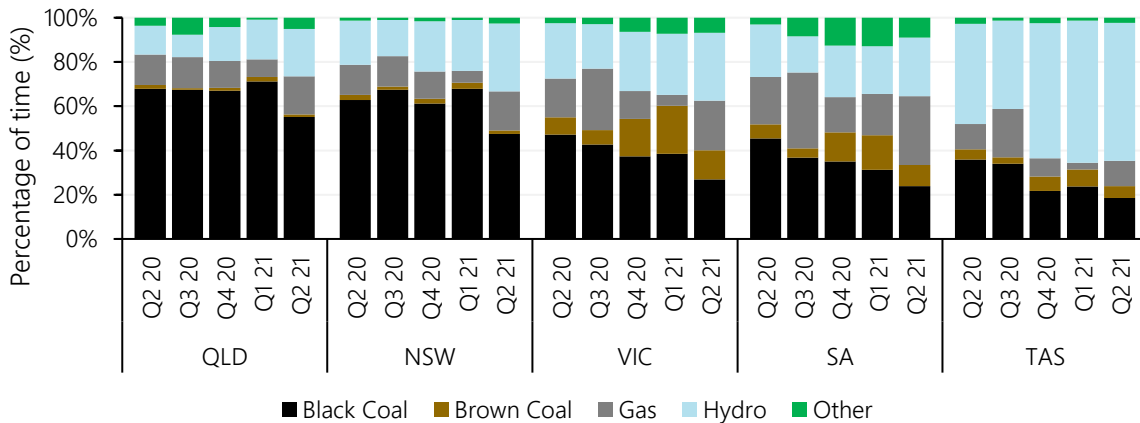
1.2.4 Price-setting dynamics

Price-setting outcomes reversed recent trends, with black coal-fired generation’s price-setting role somewhat diminished, as gas and hydro played greater roles (Figure 17). By fuel type:

- **Black coal** decreased its NEM average price-setting role to 34% of the time, significantly down from 46% in Q1 2021. Drivers included decreased black coal-fired generator availability, and spot prices more often occurring outside levels in which coal-fired generation was the marginal unit (typically \$0-\$40/MWh).
- **Gas and hydro’s** price-setting roles increased from a combined average of 39% in Q1 2021 to 54% this quarter, their highest quarterly levels since Q3 2019. A large proportion of the increase occurred during the evening peak, setting the price 73% of the time between 1730 hrs and 2130 hrs.
 - Gas’ price-setting role rebounded from the lows of Q1 2021 (8%) to 20% this quarter, largely due to the shift in the bid stack (Section 1.2.1), and GPGs bidding in higher price bands. Notably in Queensland, the average marginal price set by GPGs increased significantly to \$358/MWh (Figure 18).
 - Hydro set the price 34% of the time this quarter, up from 31% in Q1 2021, as output increased in New South Wales and Queensland. Similar to GPG, the average Queensland price set by hydro generators this quarter (\$151/MWh) more than tripled prices set in Q1 2021.

Figure 17 Diminished price-setting role for black coal

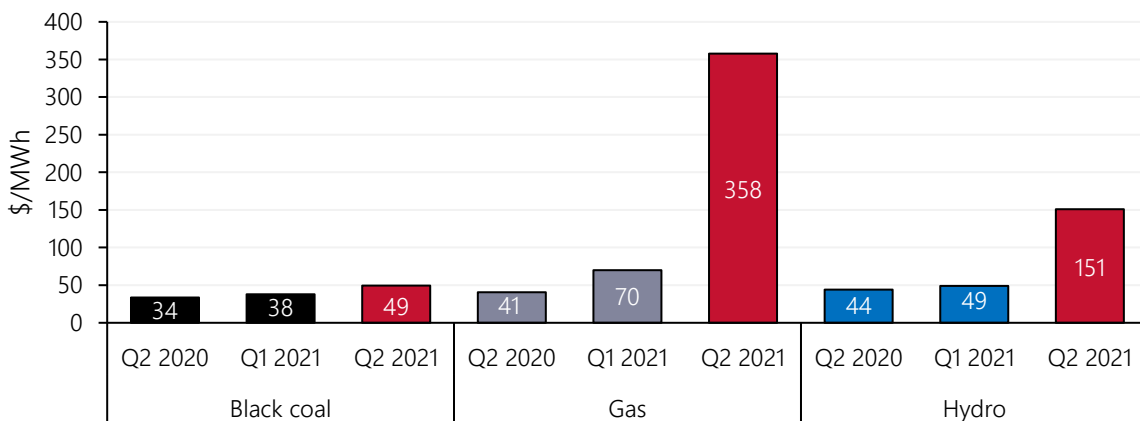
Price-setting by fuel type



Note: price setting can occur inter-regionally: for example, Victoria’s price can be set by generators in other NEM regions.

Figure 18 Gas and hydro set spot prices at high levels

Average marginal price set for Queensland for the key price setting fuel types



1.2.5 Electricity futures markets

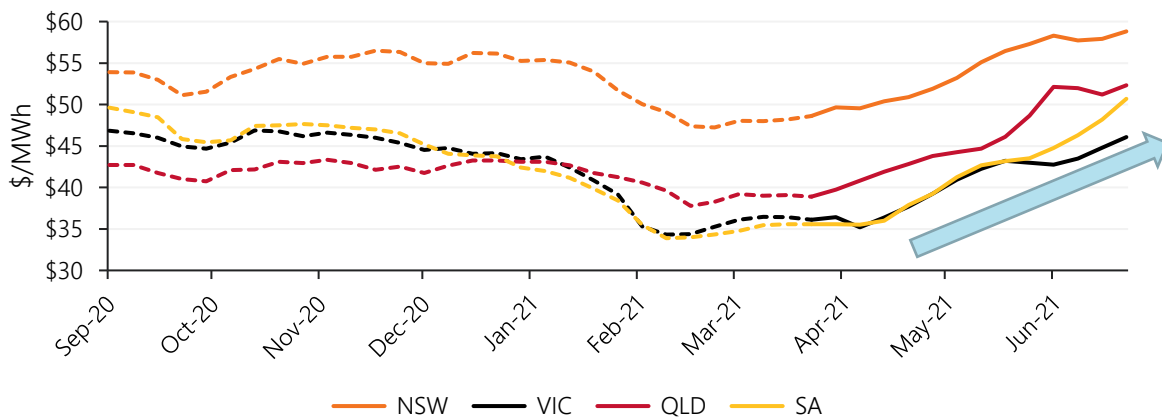
This quarter, ASX futures prices rallied strongly influenced by high spot prices and spot price volatility, and unexpected major outages – including the Callide incident and flood damage of Yallourn’s mine (Section 1.3.1).

Calendar year (Cal) 2022 swap contract prices increased across all states, from an average of \$40/MWh at the end of Q1 2021 to finish Q2 at \$53/MWh (+34%). The largest increase occurred in Queensland, following the Callide incident, finishing the quarter at \$54/MWh (+\$15/MWh). Cal22 prices also increased in the southern states, with South Australia increasing by \$15/MWh, while Victoria became the lowest-priced state on a futures basis at \$47/MWh.

Ongoing uncertainty about the short-term availability of units at Callide and Yallourn power stations led to sharp price increases in near-term futures prices. Queensland’s Q3 2021 swap price rose by \$35/MWh during the quarter (+98%), while Victoria’s Q3 2021 swaps increased by \$29/MWh (+79%).

Figure 19 ASX CAL22 swap price rallies 34 percent in Q2 2021

ASX Energy – Cal22 swap price by region – seven-day averages

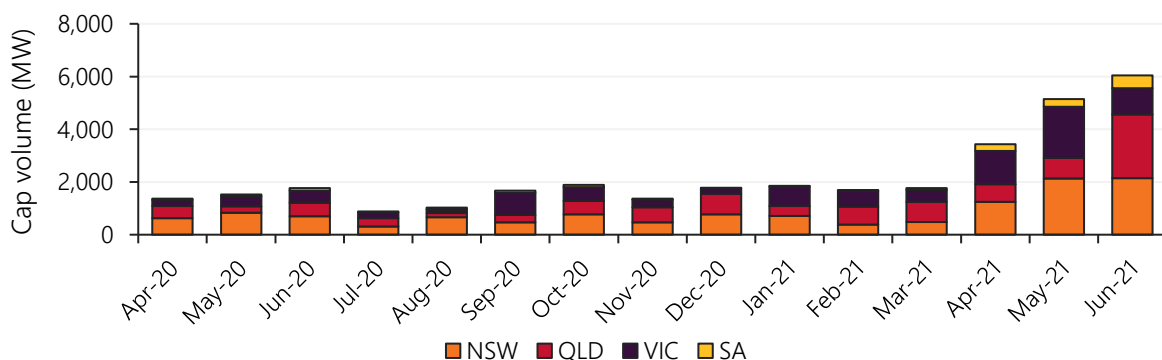


ASX cap prices also rose sharply, influenced by the high levels of spot price volatility this quarter. Queensland and New South Wales’ Q3 2021 cap prices increased by around \$9/MWh to finish the quarter at \$12/MWh, while Queensland’s Q1 2022 cap price increased to \$24/MWh (+\$11/MWh) narrowing the gap to New South Wales at \$26/MWh.

With the return of NEM price volatility and the listing of 5-minute cap products in late March 2021, there was a significant increase in ASX cap volumes, particular in May and June (Figure 20). June alone had higher volumes than all of Q2 2020, with the largest increases occurring in Queensland and New South Wales.

Figure 20 ASX cap volumes increase significantly in Q2

ASX Energy – monthly cap volumes



1.3 Electricity generation

Figure 21 and Table 3 show the change in NEM generation mix compared to Q2 2020, while Figure 22 shows the change by time of day. Key outcomes compared to Q2 2020 included:

- Despite a significant level of outages, **black coal-fired output** was comparable to Q2 2020. This was due to available generators running at high capacity factors, including units at Stanwell and Eraring.
- **Brown coal-fired generation** decreased by 182 MW as Yallourn declined to its lowest Q2 average since NEM start due to mine flood damage in June.
- **GPG** was similar to Q2 2020, with increased output during the high-priced peak evening period almost offsetting reductions during other times.
- **Grid-scale variable renewable energy** (VRE – wind and solar) increased by 457 MW on average compared to Q2 2020 due to new capacity, while **hydro generation** ramped up by 130 MW during the quarter despite dry conditions in some NEM regions.

Figure 21 Renewable generation increases as thermal generation declines

Change in supply – Q2 2021 versus Q2 2020

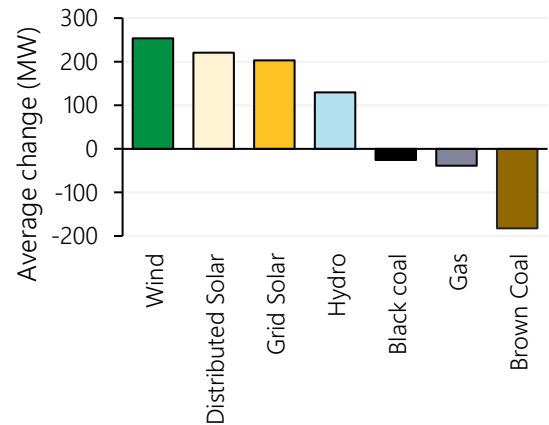
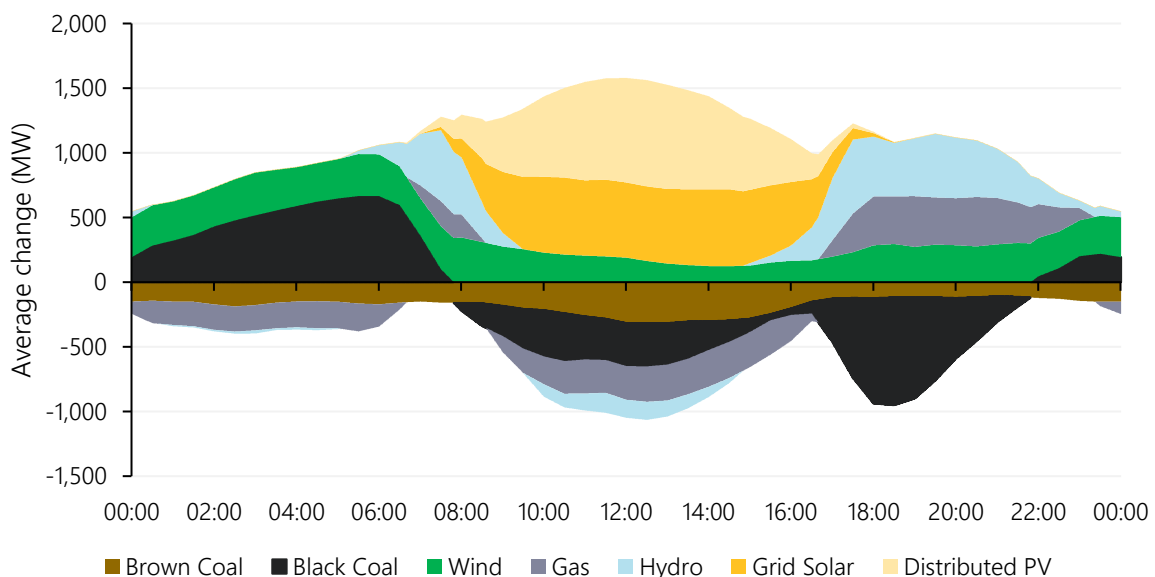


Table 3 NEM supply mix by fuel type

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar
Q2 2020	51.6%	18.6%	8.2%	9.0%	9.9%	2.7%
Q2 2021	50.7%	17.5%	7.9%	9.4%	10.9%	3.6%
Change	-0.9%	-1.1%	-0.3%	0.4%	1.0%	0.9%

Figure 22 Greater role for GPG and hydro generation during evening peak

Change in supply – Q2 2021 versus Q2 2020 by time of day



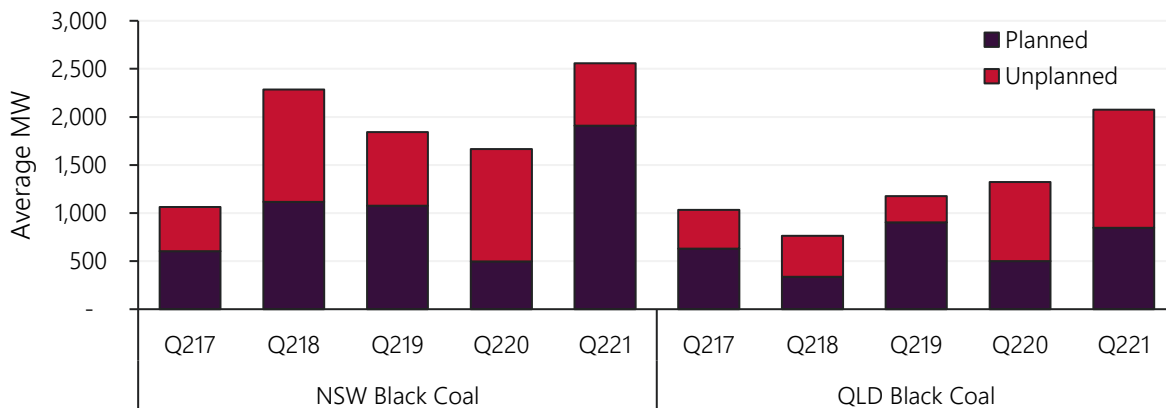
1.3.1 Coal-fired generation

Black coal-fired fleet

During Q2 2021, average black coal-fired generation declined to 11,164 MW, only slightly lower than Q2 2020 (-26 MW). This was despite a very high number of outages, which reduced black coal-fired unit availability by 1,479 MW, its lowest Q2 since NEM start¹⁹ (mostly planned in New South Wales and unplanned in Queensland, Figure 23).

Figure 23 High levels of planned outages in New South Wales and unplanned outages in Queensland

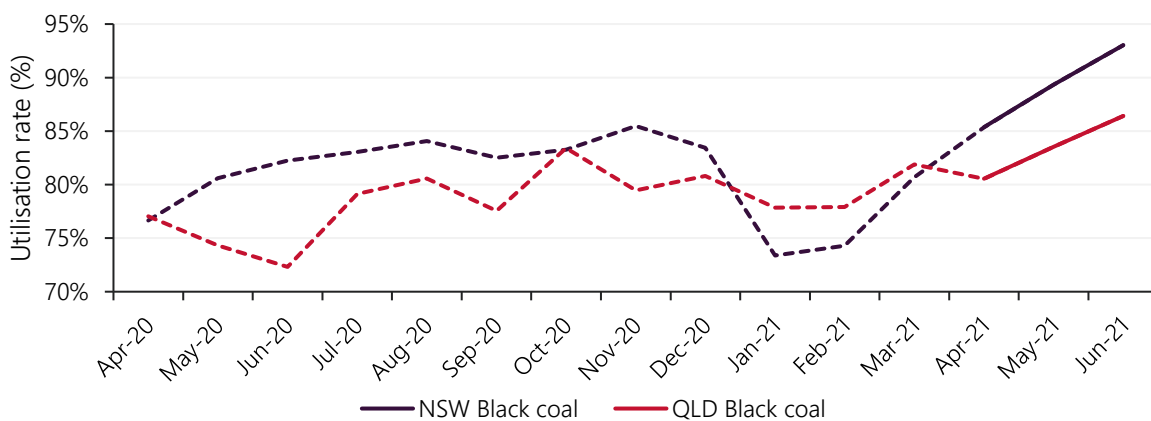
Average black coal-fired generation outage by classification (Q2s)



Reduced black coal-fired generator availability was almost offset by those black coal-fired generators which were online bidding in at lower prices to run at elevated levels, particularly after the major incident at Callide Power Station on 25 May. **Queensland** black coal-fired generator utilisation increased across the fleet to 84%, up from 74% in Q2 2020, while **New South Wales** generator utilisation increased to 88%, up from 80% in Q2 2020 (Figure 24).

Figure 24 Online black coal-fired units run hard during Q2 2021

Black coal utilisation rate²⁰ by region – April 2020 to June 2021



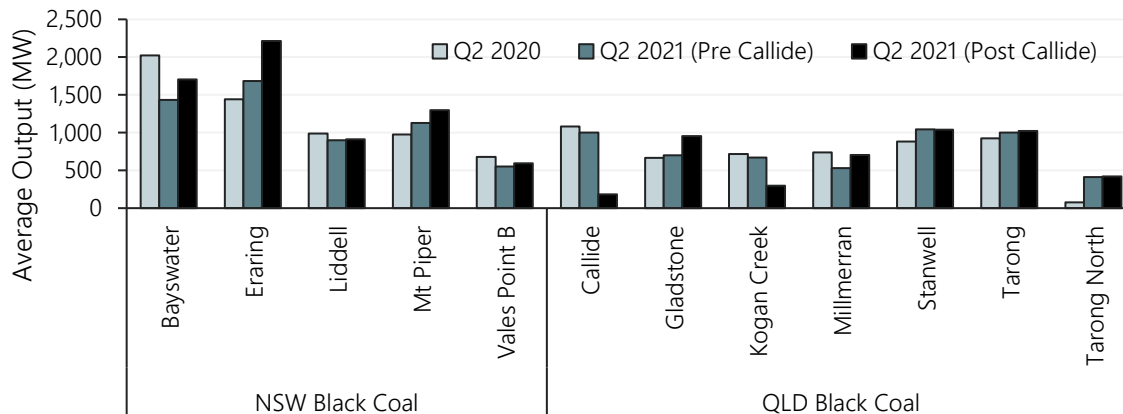
While average output from the New South Wales fleet during April and May was lower than Q2 2020 levels due to high levels of outages, there was a notable increase in output following the Callide incident (Figure 25). Higher output was due to a combination of increased operational demand, higher utilisation across the fleet, and improved availability as units returned to service.

¹⁹ Black coal availability excludes coal-fired generators that have retired

²⁰ Ratio of generator's average generation divided by average availability

Figure 25 New South Wales black coal-fired fleet ran hard after the Callide incident

Average coal-fired generation output by generator – Q2 2021 (Pre and post Callide event²¹) vs Q2 2020



Key changes by power station compared to Q2 2020 were:

- Callide Power Station output reduced by 409 MW due to the incident on 25 May 2021²², which resulted in the loss of three out of four units (one unit was already on outage). By the end of the quarter, two Callide units returned to service (Callide B Unit 1 and 2), with Unit 3 scheduled to return in July and Unit 4 by December 2022²³.
- Tarong North output increased by 341 MW as there was no repeat of the extended outage in Q2 2020.
- Stanwell Power Station output increased by 158 MW, despite increased outages, as 128 MW of offers were shifted from higher price bands to below \$40/MWh. This, coupled with higher spot prices, resulted in Stanwell’s utilisation rate increasing from 65% in Q2 2020 to 93% this quarter.
- Fewer outages, and increased utilisation at Eraring Power Station, increased average output by 456 MW. Eraring’s utilisation rate increased to 82% this quarter, up from 67% in Q2 2020.
- Output at Bayswater Power Station reduced by 484 MW on average, driven by a large increase in time on outage. Unit 2 was out of service for the entire quarter (since early March), undertaking a major maintenance and upgrade program²⁴ to increase its nameplate capacity from 660 MW to 685 MW.
- Vales Point output reduced by 110 MW on average, due to a major planned outage of Unit 6.

Brown coal-fired fleet

Compared to Q2 2020, average brown coal-fired generation decreased by 182 MW, driven by reductions from Yallourn (-146 MW) and Loy Yang B (-64 MW), which more than offset the increase from Loy Yang A (+28 MW).

Yallourn’s quarterly average output declined to 900 MW, its lowest Q2 since NEM start (Figure 26), as heavy rainfall and subsequent mine flood damage severely affected the power station’s operation in mid-June. While repair works were undertaken at the Yallourn mine, three units were taken offline, with only one unit remaining online at minimum generation levels (occasionally increasing to two units to meet evening energy peak). By the end of the quarter, three out of four units returned to service as mining activity resumed, with the fourth unit returning on 2 July (Figure 27)²⁵.

²¹ Post Callide output refers to average output from 1430hrs on 25 May 2021 to end of quarter.

²² More details on this incident, including the market impact, can be found in Section 1.3.2.

²³ Unit 4 was originally expected to return by June 2022.

²⁴ AGL 2021, Largest maintenance works underway at AGL Bayswater: <https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2021/march/largest-maintenance-works-underway-at-agl-bayswater>

²⁵ EnergyAustralia 2021, EnergyAustralia statement on the Yallourn mine – 29 June 2021: <https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-statement-yallourn-mine-29-june-2021>

Figure 26 Yallourn declined to its lowest Q2 output since NEM start

Yallourn average quarterly output (Q2s) – 2000 to 2021

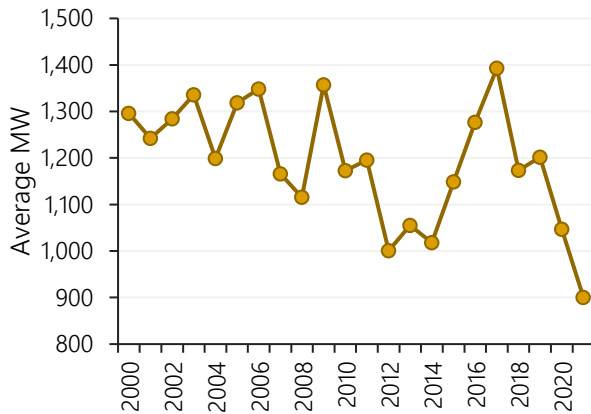
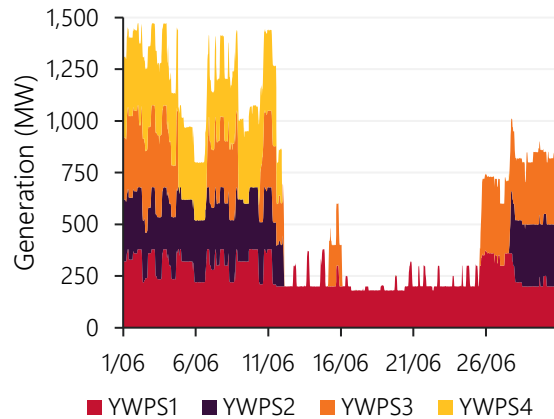


Figure 27 Yallourn’s output impacted by severe floods in June

Yallourn generation by unit – June 2021

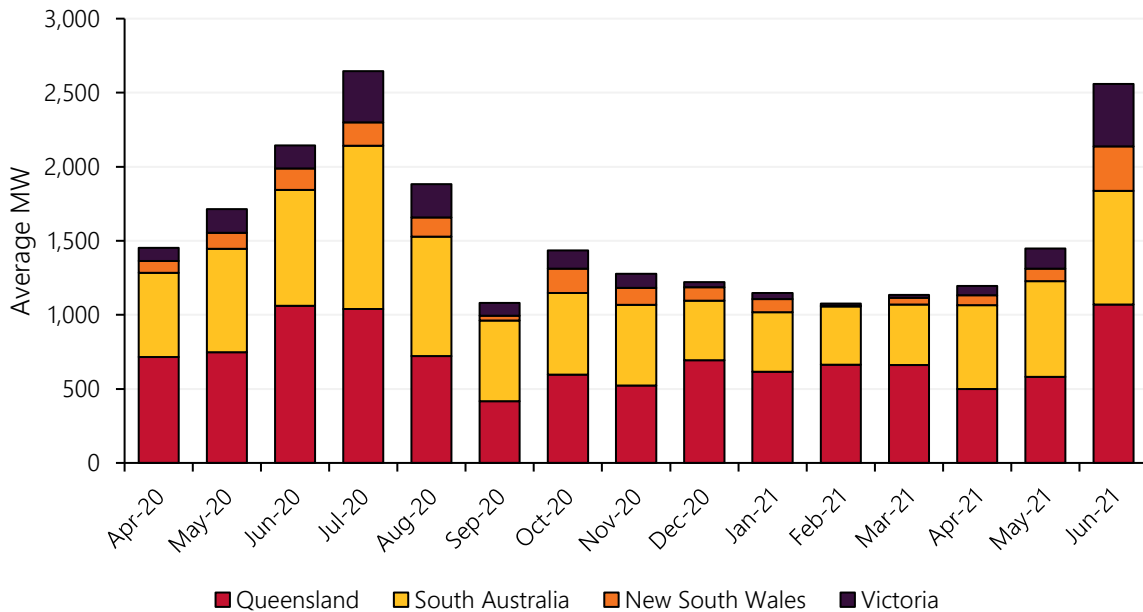


1.3.2 Gas-powered generation

NEM quarterly average GPG rebounded from near-record low output in Q1 2021 but was comparable to Q2 2020. GPG output was particularly high in June, increasing by 1,111 MW compared to May, providing backup capacity following the Callide and Yallourn incidents (Figure 28).

Figure 28 GPG rebounds from near record lows

Average GPG generation by state and month



The return of NEM spot price volatility this quarter (Section 1.2.2), saw peaking GPGs play a greater role, increasing output by 380 MW compared to Q1 2021 (Figure 29). With high morning and evening peak prices, but low daytime prices, GPGs were increasingly ‘two-shifting’: turning on for the morning peak, off during the daytime, and on again for the evening peak. Key examples of a move to ‘two-shifting’ include Jeeralang and Braemar, leading to total GPG quarterly starts increasing to 3,101, the highest level in recent years (Figure 30).

Figure 29 GPG peakers ramp up

Average quarterly NEM GPG generation by classification²⁶

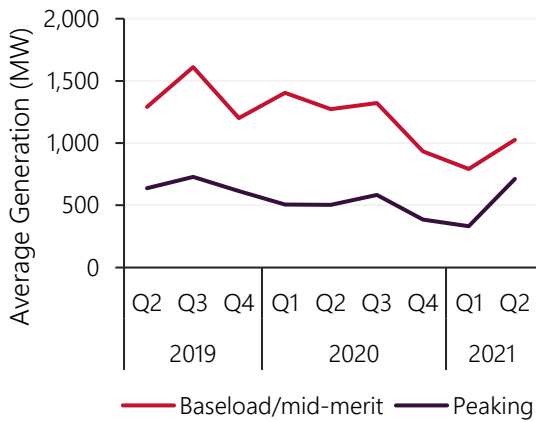
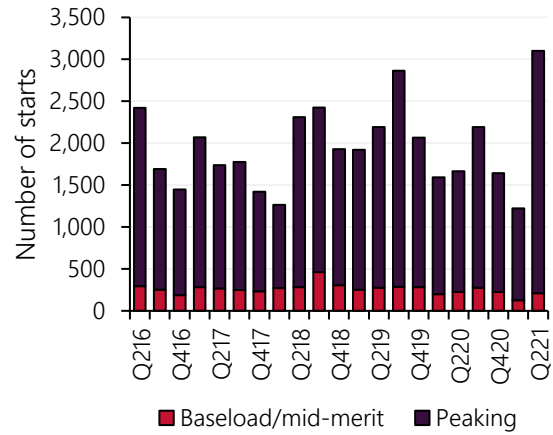


Figure 30 Highest GPG starts in recent years

Number of GPG starts by classification

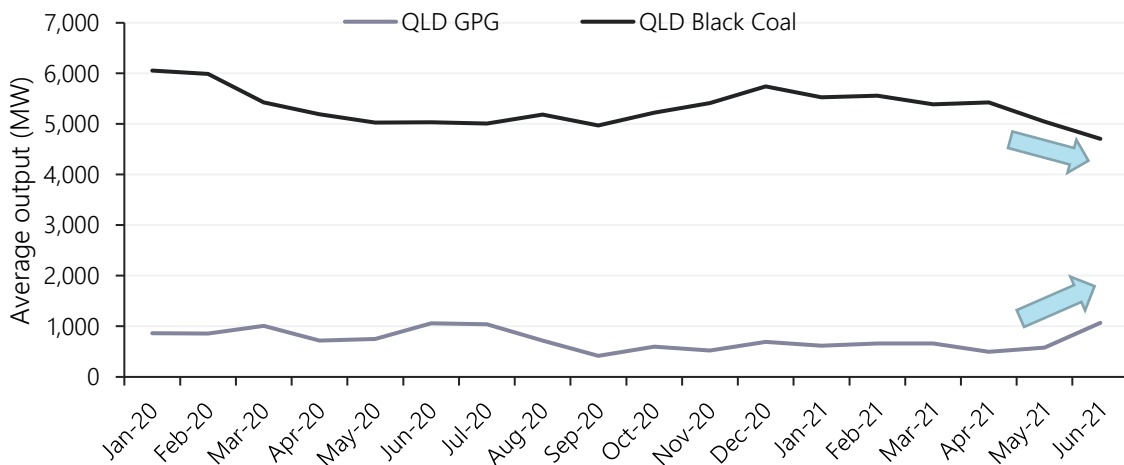


Key regional changes included:

- **Queensland’s** quarterly average GPG decreased by 125 MW compared to Q2 2020, although increased significantly following the Callide incident in May (from 477 MW prior to the incident to 1,072MW on average for the remainder of the quarter, Figure 31).
 - Most of the post-Callide response came from Darling Downs (+193MW), Braemar (+201 MW), and Swanbank E (+107 MW).

Figure 31 Queensland GPG ramps up after the Callide incident

Queensland monthly average GPG and black coal-fired generation – Jan-20 to Jun-21



- Despite significant price volatility (Section 1.2.2), **New South Wales** GPG only increased by 39 MW to a quarterly average of 150 MW. This was due to reduced availability at Tallawarra, as well as a large amount of New South Wales GPG offers remaining at high prices: during the quarter, 84% of its capacity was bidding at prices above \$10,000/MWh.
- **Victorian** GPG output increased by 71 MW compared to Q2 2020, largely due to increased output during June to cover for Yallourn following the flood damage at its mine. Newport led the increase in June compared to May (+188 MW), returning from a two-month planned outage to cover for Yallourn’s reduced generation, while Mortlake (+48 MW) and Laverton (+24 MW) also ramped up output in June.

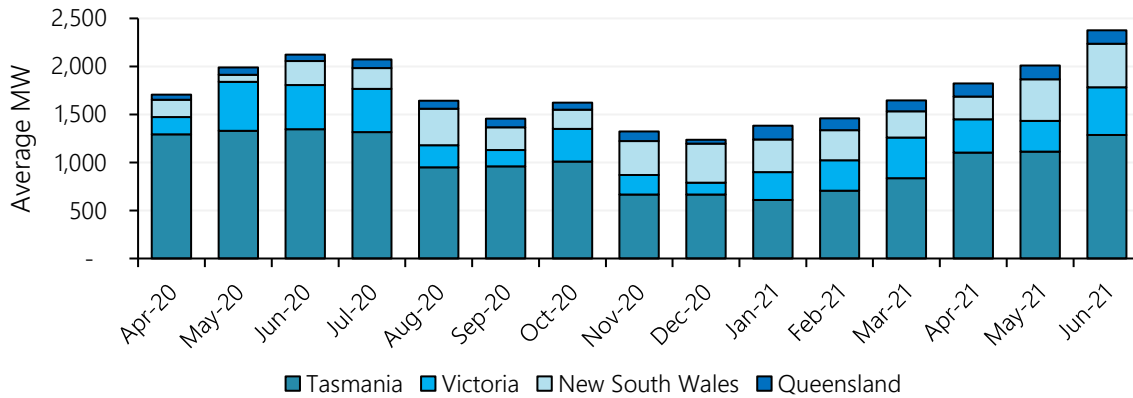
²⁶ Classification Baseload/mid-merit: Darling Downs, Swanbank E, Mortlake, Newport, Osborne, Pelican Point, Tallawarra, Torrens Island, Tamar Valley, remaining are peakers.

1.3.3 Hydro

Hydro generation increased by 130 MW on average compared to Q2 2020, despite dry conditions in some regions, influenced by higher mainland prices and price volatility. Hydro output was particularly high in June, following the Callide incident and Yallourn mine flood damage, increasing by 255 MW on average compared to June 2020 (Figure 32).

Figure 32 Hydro ramps up in June

Average hydro MW generation by state and month



By region compared to Q2 2020:

- **New South Wales** – Snowy’s Upper Tumut was the main contributor to the state’s 208 MW increase compared to Q2 2020 (+124%). Hydro generators in the region were bidding at lower prices during the quarter, with 236 MW more available below \$60/MWh, influenced by coal-fired generator outages, and resulting high spot price volatility. High Snowy output contributed to steadily declining dam storage levels at Lake Eucumbene, reducing to 22% by quarter’s end (Figure 33).
- **Tasmania** – hydro output reduced by 156 MW compared to Q2 2020, as drier than usual conditions reduced output from run of river generators (Figure 34), with Hydro Tasmania shifting offers to higher price bands to conserve water (around 200 MW shifted from below \$20/MWh to around \$30-60/MWh).
- **Queensland** – output increased by 75 MW on average, as heavy north Queensland rainfalls benefitted run of river flows for Kareeya and Barron Gorge.

Figure 33 Snowy dam levels remain low

Monthly Snowy dam levels - Lake Eucumbene²⁷

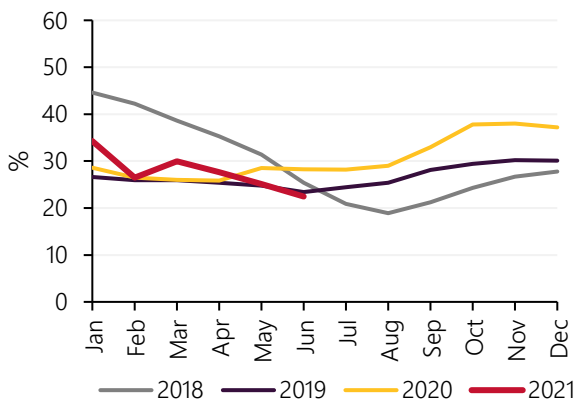
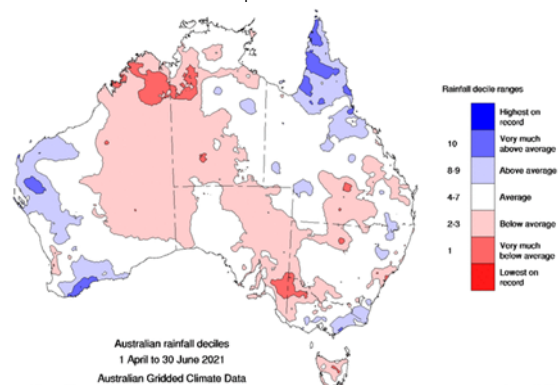


Figure 34 Dry conditions in New South Wales and Tasmania

Australian rainfall deciles 1 April to 30 June 2021²⁸



²⁷Snowy Hydro 2021, Lake levels – Lake Eucumbene: <https://www.snowyhydro.com.au/generation/live-data/lake-levels/>

²⁸Bureau of Meteorology 2021, Recent and historical rainfall maps: <http://www.bom.gov.au/climate/maps/rainfall/?variable=rainfall&map=decile&period=3month®ion=nat&year=2021&month=06&day=30>

1.3.4 Wind and solar

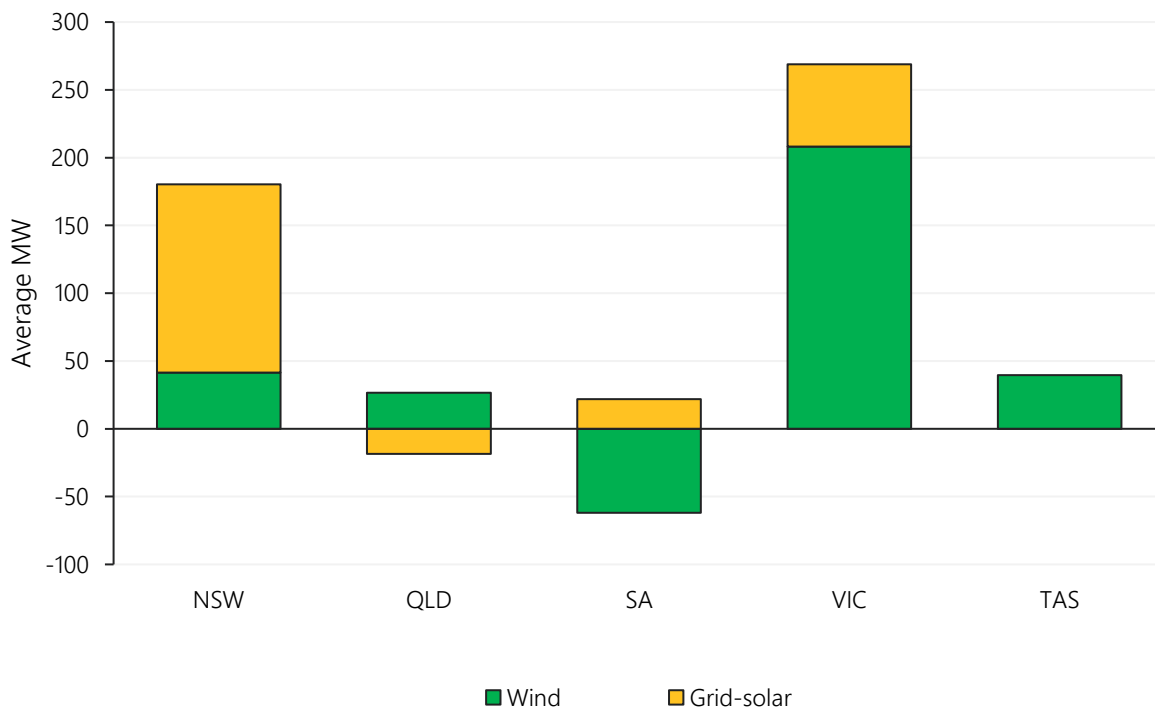
Compared to Q2 2020, average VRE generation increased by 457 MW, with wind and grid-scale solar contributing 254 MW and 203 MW respectively due to new capacity that has connected to the grid in the last year (Figure 35).

During the quarter, several grid-scale VRE trading interval records were set, including:

- **Highest renewable share of NEM operational demand** – on 11 April 2021, renewable penetration, including grid-scale wind and solar, hydro, biomass and rooftop PV, reached a record high 57% of underlying demand in trading interval ending 1130 hrs, up from the previous record of 56% set on 3 October 2020.
- **Highest grid-scale VRE output** – NEM VRE output reached 7,370 MW at 1000 hrs on 11 April 2021, 484 MW higher than the previous record set in Q1 2021.
- **Highest wind output** – NEM wind output reached 5,587 MW at 2100 hrs on 25 May 2021, 389 MW higher than the previous record set in Q3 2020.

Figure 35 VIC leads VRE output increase

Average change in VRE generation – Q2 2021 versus Q2 2020

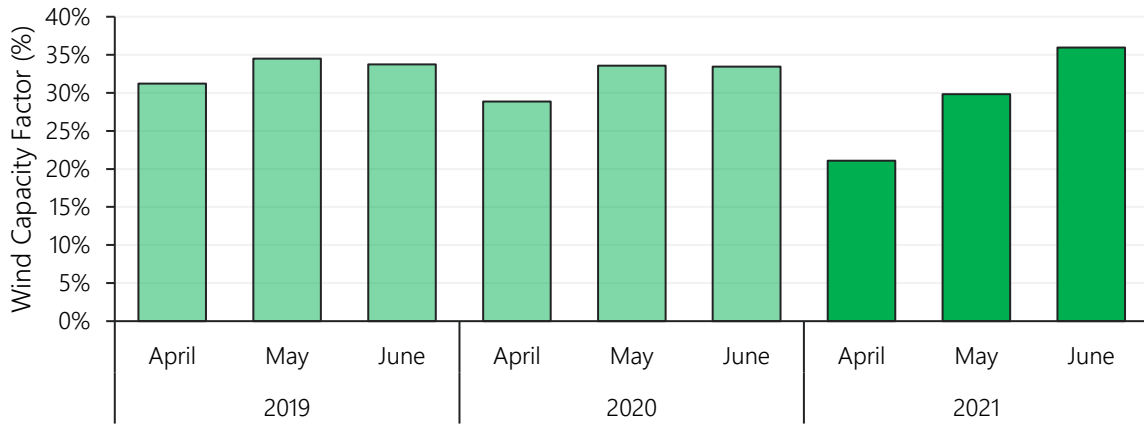


Average wind generation reached 2,398 MW, with increases in Victoria (+208 MW) and Tasmania (+39 MW) more than offsetting reductions in South Australia (-62 MW). One new wind farm commenced generation in New South Wales this quarter (Bango Wind Farm, 155 MW).

- South Australian wind output declined to 594 MW, its lowest quarterly average since Q1 2019, largely due to very low wind speeds in April (Figure 36). South Australia’s wind farm capacity factor during the month was only 21%, substantially lower than April 2020 (29%) and April 2019 (31%), with a prolonged period of low wind output between 23 April to 29 April.
- While Victorian wind farms experienced similarly still conditions to South Australia in April, increased output from ramping up of recently installed capacity (Berrybank and Bulgana wind farms) more than offset the decrease.

Figure 36 Low wind capacity factors in April 2021

South Australian volume weighted wind capacity factors (%)



Grid-scale solar output increased by 203 MW on average, with the largest increase compared to Q2 2020 occurring in New South Wales (+139 MW).

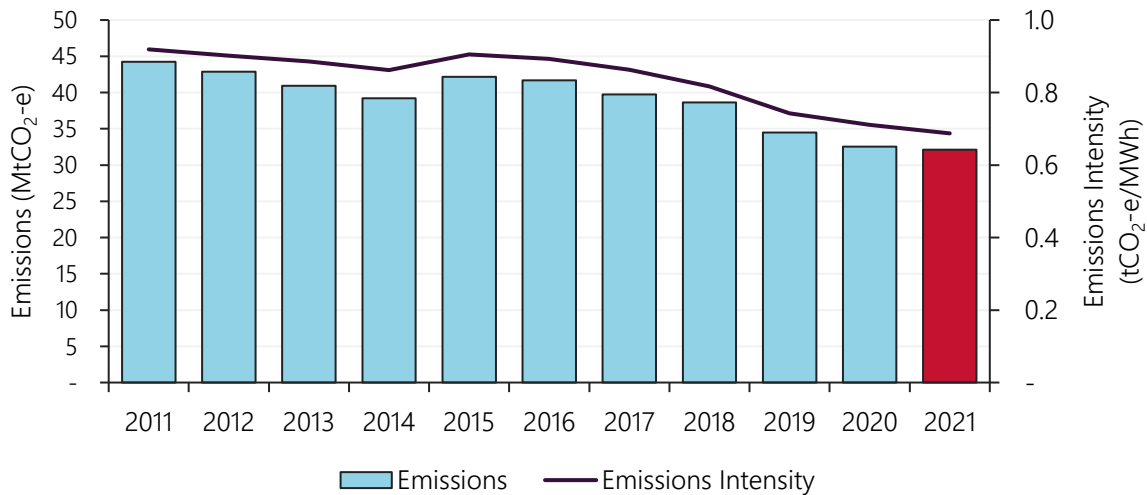
- Increased New South Wales output was driven by ramping up of recently installed capacity, with the three largest solar farms in the region (Darlington Point, Limondale and Sunraysia solar farms) accounting for 52% of the increase.
- Similar to New South Wales, higher Victorian output (+61 MW) was driven by continued ramp up of recently installed capacity (Kiamal and Glenrowan solar farms).
- Despite continued ramp up of recently installed capacity, average Queensland output decreased by 19 MW, mainly due to increased self-curtailment resulting from negative spot prices and high frequency control ancillary service (FCAS) prices (Section 1.5.3).

1.3.5 NEM emissions

Quarterly NEM emissions declined to the lowest Q2 total on record at 32.1 million tonnes carbon dioxide equivalent (MtCO₂-e), 1% lower than Q2 2020 (Figure 37). This occurred despite increased demand and was a function of reduced coal-fired generation and continuing growth in VRE output.

Figure 37 Record low Q2 emissions

Quarterly NEM emissions and emissions intensity (Q2s)



1.3.6 Storage

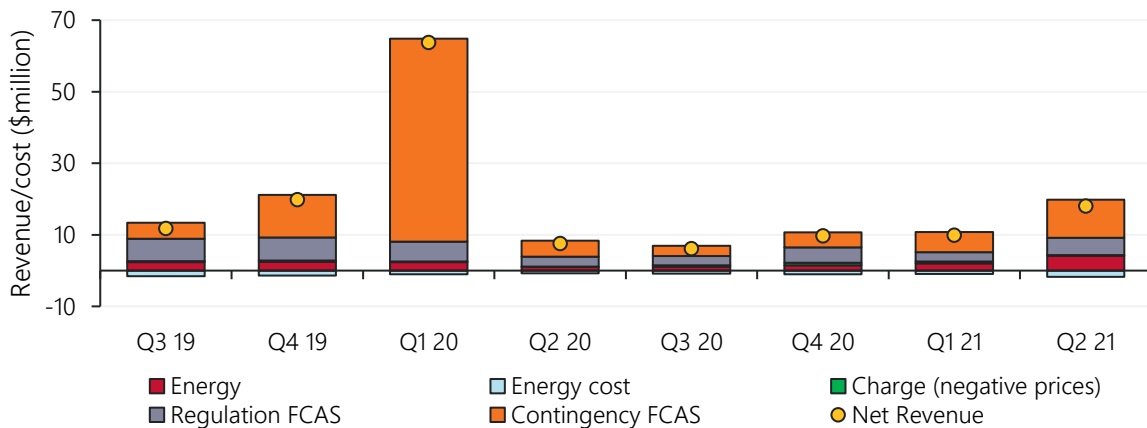
Batteries

During Q2 2021, total net battery market revenue increased to \$18 million, representing the third-highest quarter on record. Net revenue increased compared to Q1 2021 (+\$8.1 million), with contributions from both FCAS and energy arbitrage. FCAS remained the primary source of battery revenue, contributing 78% of the total (Figure 38). By market:

- Higher FCAS revenue (+\$7.2 million) was mainly due to the increase in average South Australia and Victoria Contingency Raise 6 Second (+\$20/MWh) and 60 Second FCAS prices (+\$8/MWh, Section 1.5.1).
- With some energy price volatility in South Australia and Victoria this quarter (particularly in May), grid-batteries benefitted from increased average energy price arbitrage, which resulted in total net energy revenue increasing by \$1 million compared to Q1 2021.
 - While energy revenue was up compared to the previous quarter, it was somewhat limited as batteries were only generating at 44% of their total availability on average during high prices (>\$1,000/MWh). A factor contributing to this was some batteries optimising between FCAS and energy markets (conserving state of energy charge to remain available for FCAS provision).

Figure 38 Highest battery net revenue since Q1 2020

Battery revenue sources



Pumped hydro

Pumped hydro spot market net revenue in Q2 2021 was \$35 million, up from \$3.5 million in Q2 2020 (Figure 39). The marked increase was primarily driven by Wivenhoe Pumped Hydro, which accounted for 99% of net revenue as Shoalhaven was out of service from 18 April and remained offline by the end of the quarter.

Figure 39 Record high pumped hydro revenue

Pumped hydro revenue sources

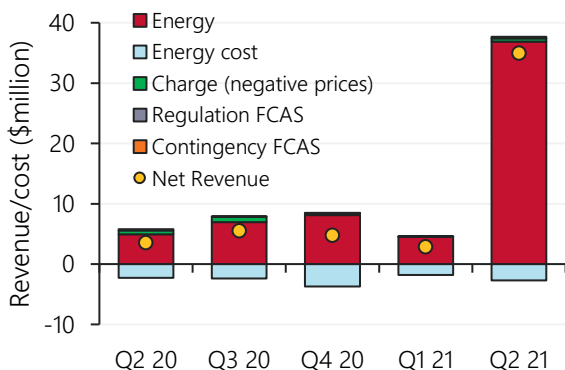
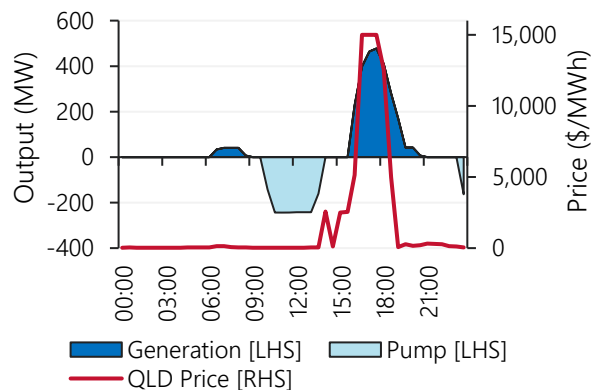


Figure 40 Wivenhoe captured QLD price spikes

Wivenhoe pumped hydro operations on 25 May 2021



Record high spot market revenue from Wivenhoe this quarter was due to high Queensland price volatility, of which 40% was captured on 25 May when Queensland recorded its third highest average daily price since NEM start (Figure 40). Compared to Q2 2020, Wivenhoe’s dispatch increased by 69% as average energy arbitrage values increased to \$582/MWh in Q2 2021.

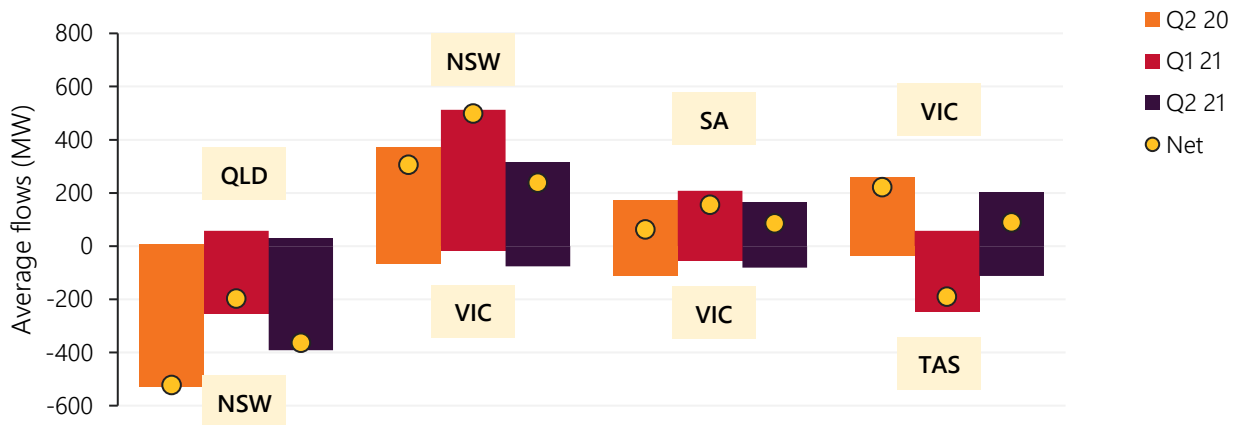
While Wivenhoe was responsive to high prices, generating 77% of the time when prices exceeded \$1,000/MWh, its output was somewhat limited during those trading intervals, only generating 28% of its total availability. This was due to 63% of its available capacity being offered above \$10,000/MWh during high priced events.

1.4 Inter-regional transfers

Figure 41 shows inter-regional transfers for Q2 2021, with total transfers slightly lower than recent quarters. Compared to Q2 2020 transfers were down 11% with reductions on three of the four regional interconnectors.

Figure 41 Electricity transfers across regional interconnectors

Quarterly inter-regional transfers



Key outcomes by regional interconnector included:

- Queensland to New South Wales** – net transfers south reduced by 159 MW on average compared to Q2 2020, largely due to reduced availability of Queensland black coal-fired generation, and increased Queensland operational demand.
 - Continuation of works upgrading QNI lowered the average southerly interconnector limit from 856 MW in Q2 2020 to 728 MW this quarter. This contributed to the interconnector binding at its limits more frequently (27% of the time compared to 21% in Q2 2020), and increased price separation between Queensland and New South Wales (Section 1.2).
- Victoria to New South Wales** – lower interconnector limits led to net flows north into New South Wales reducing by 67 MW compared to Q2 2020.
 - Factors contributing to lower interconnector limits included increased congestion arising from recently commissioned wind and solar farms, and transmission line outages.
 - Lower limits also led to increased time the interconnector was binding at its limits (33% of the time compared to 21% in Q2 2020), contributing to price separation between the two regions.
- Tasmania to Victoria (Basslink)** – net transfer into Victoria reduced by 132 MW compared to Q2 2020, due to reduced Tasmania hydro output (which was influenced by dry conditions). Transfers north were relatively unchanged during the peak morning and evening periods, with the largest reductions occurring overnight (2200 hrs to 0500 hrs) and the middle of the day (0930 to 1500 hrs). These periods coincided with comparatively low Victorian spot prices.

- **Victoria to South Australia** – results were similar to recent quarters, with a small reduction in transfers from South Australia to Victoria compared to Q2 2020. Drivers of this change included reduced South Australian wind output and increased Victorian wind and solar output.

1.4.1 Inter-regional settlement residue

Total inter-regional settlement residue (IRSR) rose significantly from \$23 million in Q2 2020 to \$115 million this quarter, representing the highest Q2 on record (Figure 42).

The main increase occurred for IRSR into New South Wales, driven by periods of high price separation between Victoria and New South Wales (it was the second most volatile quarter on record for New South Wales), coinciding with strong transfers north on the interconnector.

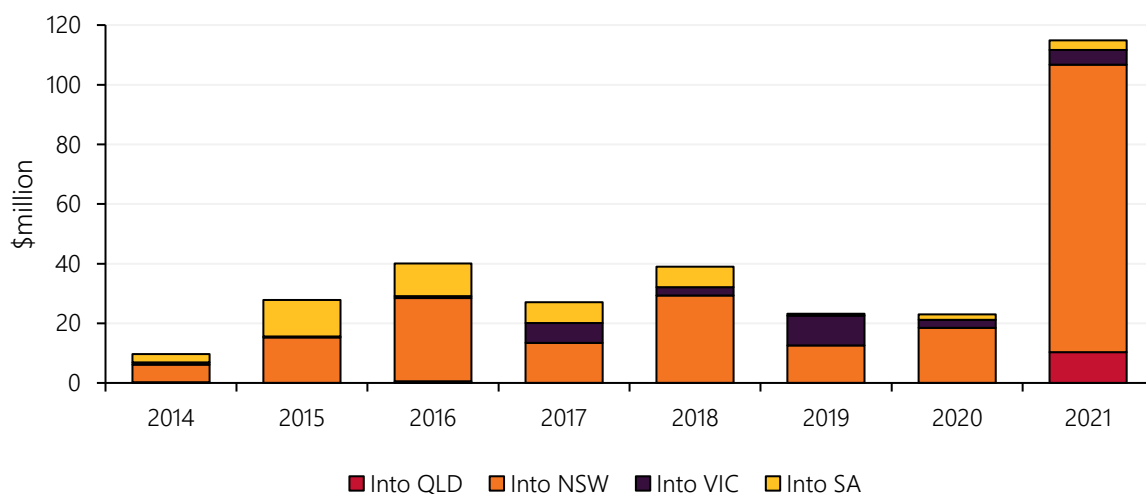
Despite high price volatility in Queensland, IRSR value for transfers into the region did not increase significantly compared to previous Q2s, due to:

- Price volatility occurring in Queensland and New South Wales at the same time, with high trading prices in New South Wales (>\$1,000/MWh) occurring 48% of the time there were high prices in Queensland.
- Counter-price flows arising from network outages, resulting in negative IRSR rather than very high IRSR (see negative residue management section below).

There was comparatively lower IRSR for transfers into Victoria and South Australia due to lower price volatility and low price spread between these regions.

Figure 42 Inter-regional settlement residues increase dramatically into New South Wales

Quarterly positive IRSR value – Q2s



Negative residue management

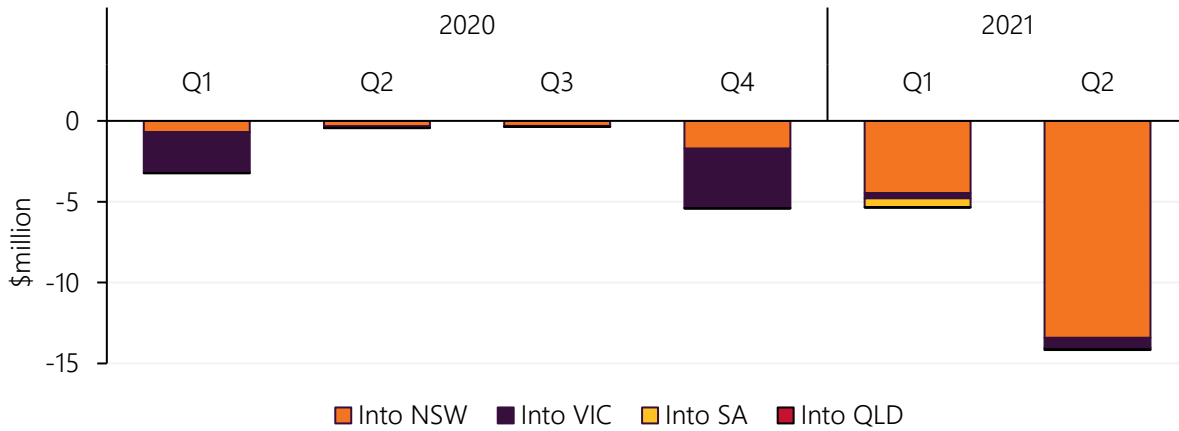
This quarter, negative residues²⁹ occurred at very high levels, increasing to \$14 million, 14 times higher than the two-year average (\$0.9 million average in Q2 2019 and Q2 2020, Figure 43). This was driven by extended periods of counter price flows from Queensland into New South Wales resulting from network outages.

²⁹ Negative residues accumulate from counter-priced flows, that is flows from higher price regions to lower priced regions where the spot market revenue collected on the flow in the receiving region is less than the spot market amount paid in the sending region. Residues are distributed to the importing region's Transmission Network Service Provider (TNSP), either directly or through the Settlement Residue Auction (SRA).

The SRA has a floor of zero on distributions, which means negative residues are passed directly to the TNSP. AEMO has requirements under clauses 3.8.1 and 3.8.10 of the National Electricity Rules to minimise the accumulation of negative residues.

Figure 43 Negative residues rise significantly due to counter priced flows between Queensland and New South Wales

Quarterly negative inter-regional settlement residue

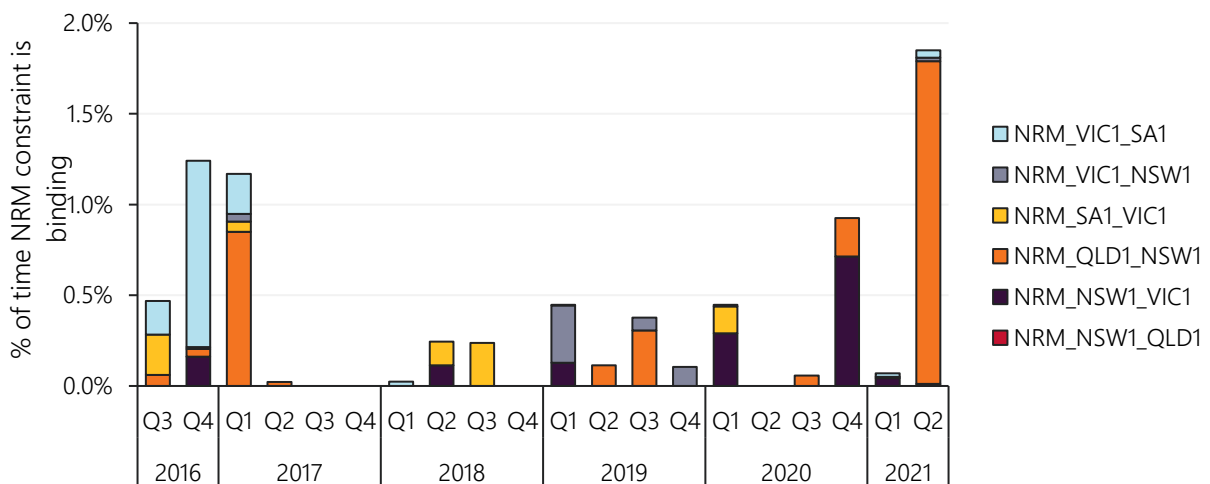


As required by the National Electricity Rules (NER), AEMO automatically triggers negative residue management (NRM) constraints when the accumulation of negative residues on each regulated interconnector reaches or exceeds minus \$100,000 in previous intervals, the current interval, or based on 30 minute pre-dispatch values³⁰. These constraints prevent further accumulation of negative residues by reducing the counter-price flow on the relevant directional interconnector and are designed to violate if security limits are exceeded³¹.

During the quarter, the NRM constraint associated with counter-price flows from Queensland into New South Wales (NRM_QLD1_NSW1) bound for a record 1.8% of the time (Figure 44). The constraint also violated for 35% of the time it was activated, meaning the flow on the interconnector was not able to be reversed to satisfy the NRM requirements. This was due to limited Queensland FCAS supply available to meet local requirements, which contributed to very high Queensland FCAS prices and costs during these periods (Section 1.5.1).

Figure 44 Queensland to New South Wales NRM constraint binding for 1.8% of the quarter

Proportion of time NRM constraints were binding by quarter



³⁰ As a part of AEMO's requirements, it implemented negative residue management (NRM) automated constraints in August 2012.

³¹ The constraints are lifted when the accumulative of residues are greater than the threshold of -\$100,000. Once triggered, the NRM constraints are activated for the current and next trading interval. If the residues are not above the threshold by the end of trading interval, then the NRM period is extended for another trading interval. Brief on Automation of Negative Residue Management, AEMO 2018. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/2018/Brief-on-Automation-of-Negative-Residue-Management.pdf

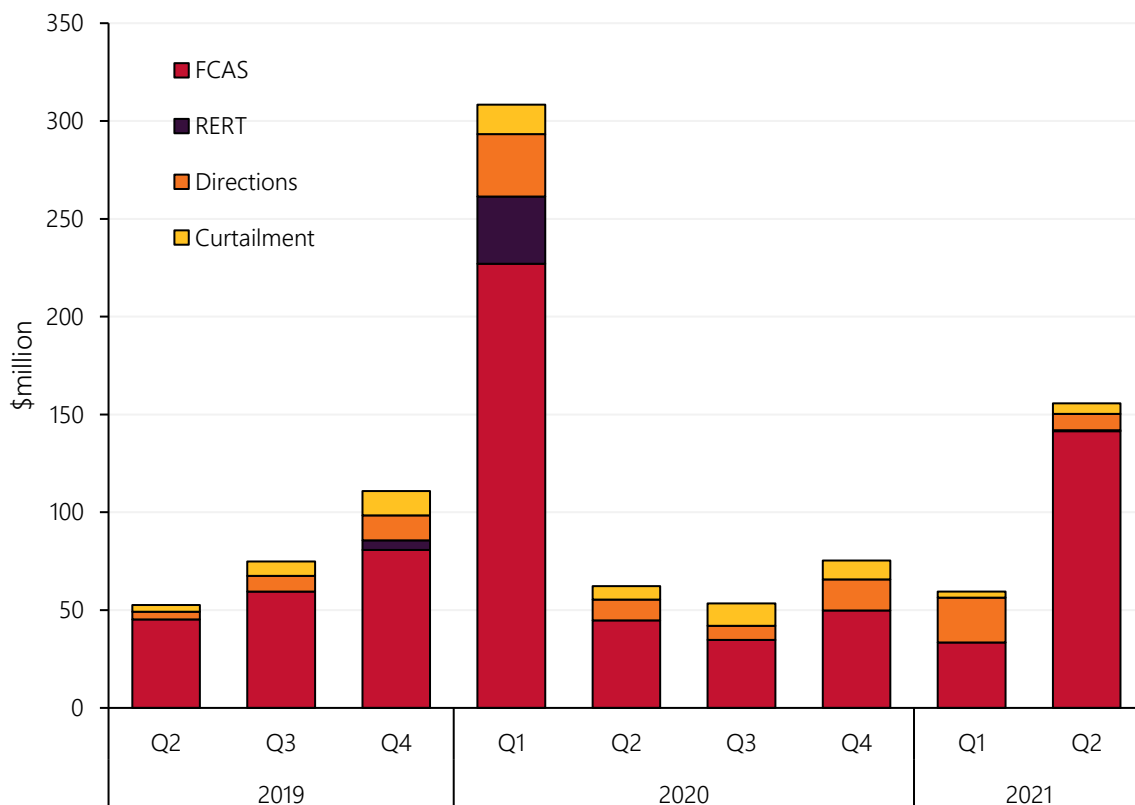
1.5 Power system management

Total NEM system costs³² increased to \$156 million, \$93 million higher than Q2 2020. Higher costs were largely driven by the significant increase in FCAS costs (Figure 45).

- **FCAS costs** increased to \$141 million this quarter, \$97 million higher than Q2 2020, accounting for 91% of total system costs. Section 1.5.1 provides details on FCAS.
- Despite slightly higher time on directions, the cost of **directing South Australian units** to maintain system security was \$2.2 million lower than in Q2 2020 due to lower compensation price. Section 1.5.2 provides details on system security directions.
- Estimated **VRE curtailment costs**³³ decreased to \$5.5 million, mainly due to reduced system strength and other curtailment. Section 1.5.3 provides details on VRE curtailment for the quarter.
- AEMO activated **RERT** in Queensland on 25 May 2021 due to actual LOR2 conditions, and a forecast LOR3 condition, following the major incident at Callide Power Station (Section 1.2.2). The event lasted for 4.5 hours (1700 hrs to 2130 hrs), and an estimated contracted reserve capacity of 15 MW was procured for \$0.45 million³⁴.

Figure 45 NEM system costs increase to \$156 million

Quarterly system costs by category



³² In this report, 'NEM system costs' refer to the costs associated with FCAS, directions compensation, Reliability and Emergency Trader (RERT), and curtailment.

³³ Excludes economic curtailment. The cost of curtailed VRE output is estimated to be \$40/MWh of output curtailed.

³⁴ See AEMO RERT Reporting for more information: https://aemo.com.au/-/media/files/electricity/nem/emergency_management/rert/2021/rert-activation-estimates-25-may-2021.pdf?la=en

1.5.1 Frequency control ancillary services

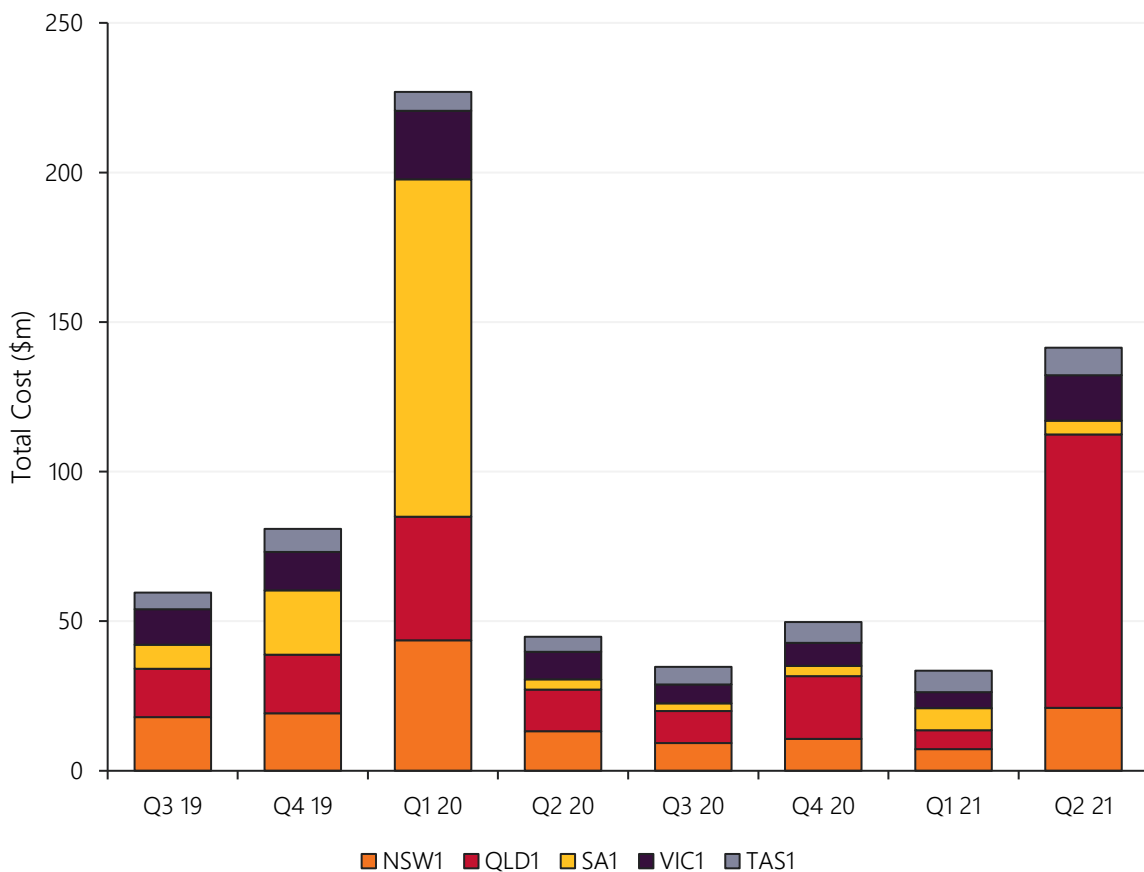
Quarterly FCAS costs rebounded sharply to \$141 million, representing the second highest quarter on record, with most of the cost increases occurring in Queensland (Figure 46)³⁵. By market, 95% of the cost increases compared to Q2 2020 occurred in the Contingency Raise markets (+\$92 million), driven by higher prices (particularly in the Raise 6 Second and Raise 60 Second markets).

Drivers of rebounding Contingency Raise prices included:

- **Localised Queensland requirements and resulting FCAS price volatility** – compared to Q2 2020, Queensland Raise 6 Second and Raise 60 Second prices increased by 840% on average due to significant price volatility (see below for more details).
- **Black coal-fired generator outages** – compared to Q2 2020, supply from black coal-fired generators fell by around 20% in the Raise 6 Second and Raise 60 Second markets due to outages.
- **Higher energy prices volatility** – as detailed in Section 1.2, NEM spot prices increased significantly this quarter. Raise FCAS market prices often move in line with energy prices, due to the opportunity cost of service provision.

Figure 46 FCAS costs rebound to \$142 million

Quarterly FCAS cost by region³⁶



³⁵ The AER Quarter 2 2021 Wholesale Market Quarterly Report will focus on the drivers of high FCAS prices in Queensland.

³⁶ Based on AEMO Settlement data and represents preliminary data that will be subject to minor revisions.

FCAS price volatility

The significant increase in FCAS costs this quarter was largely driven by event-based price volatility, with high-priced periods³⁷ contributing \$87 million (or 62%) of total quarterly FCAS costs. The majority (84%) of these volatility-related costs occurred Queensland, mostly during June in the Raise 6 Second and Raise 60 Second markets. Key days included:

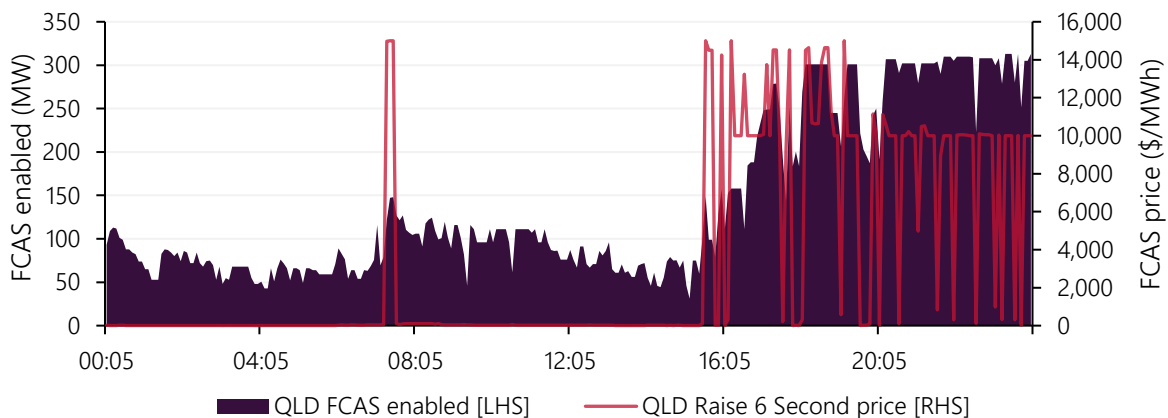
- **3 June 2021** – Raise 6 Second and Raise 60 Second prices spiked above \$10,000/MWh for 215 minutes and 85 minutes, respectively, leading to a daily FCAS cost of \$26 million.
- **4 June 2021** – Raise 6 Second and Raise 60 Second prices spiked above \$10,000/MWh for 30 minutes and 25 minutes, respectively, leading to a daily FCAS cost of \$9 million.
 - On 5 June, following further FCAS price spikes, the Cumulative Price Threshold was exceeded, leading to leading to application of the Administered Price Cap in the region.
- **15 June 2021** – Raise 6 Second and Raise 60 Second prices spiked above \$10,000/MWh for 75 minutes and 35 minutes, respectively, leading to a daily FCAS cost of \$5 million.
- **25 June 2021** – Raise 6 Second and Raise 60 Second prices spiked above \$10,000/MWh for 150 minutes and 120 minutes, respectively, leading to a daily FCAS cost of \$21 million.

Drivers of FCAS costs on these days included:

- **High local Queensland FCAS requirements** – periods of very high localised Queensland FCAS requirements resulting from line outages and subsequent NRM (Section 1.4.1) led to very tight supply-demand conditions in Queensland’s Contingency Raise markets.
 - Figure 47 shows an example of this on 3 June 2021, when transmission line outages led to localised FCAS requirements which rose sharply to very high levels from 1700 hrs following application of NRM on the interconnector. Between 1700 hrs and 2400 hrs, Queensland’s average Raise 6 Second FCAS requirement was 277 MW, around three times its typical enablement level.

Figure 47 Very high localised Queensland FCAS requirements lead to extended price spikes

Queensland Raise 6 Second FCAS enabled and price – 3 June 2021



- **Black coal-fired generation outages** – unit outages at key FCAS providers, including Callide, Stanwell and Tarong power stations, reduced Queensland’s available FCAS supply.
- **Energy price volatility** – extreme energy price volatility in Queensland this quarter (Section 1.2.2) frequently led to very high Queensland Contingency Raise FCAS prices due to the co-optimisation of the markets.

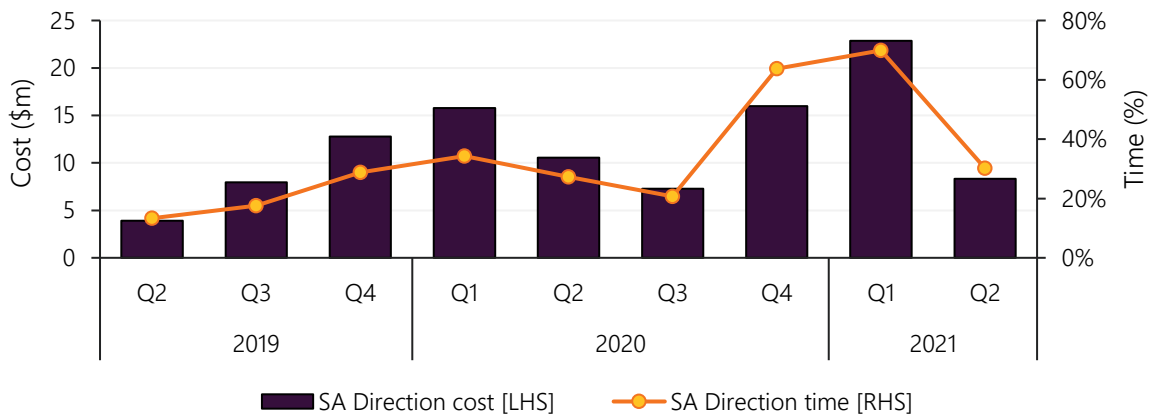
³⁷ Prices equal to or above \$300/MWh in a given FCAS market.

1.5.2 Directions

During Q2 2021, AEMO continued to issue directions to GPGs in South Australia to maintain system security in the region. Total NEM directions costs for energy declined to \$8.3 million, reversing the upward trend in recent quarters (Figure 48). The reduction in South Australian directions costs compared to record highs in Q1 2021 (-\$14.6 million) was largely due to lower time on direction, falling from 70% of the time in Q1 2021 to 30% this quarter. Reduced time on direction also led to lower amounts of directed output, with only 7% of total South Australian GPG output directed this quarter, down from 30% in Q1 2021 (Figure 49).

Figure 48 South Australian direction costs down from record highs in Q1 2021

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



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

The key driver of reduced time on direction was higher spot prices (Section 1.2), influenced by lower local wind output (Section 1.3.4), and thermal unit outages in other NEM regions. With South Australian electricity prices exceeding \$70/MWh 33% of the time compared to only 6% in Q1 2021, it was more economic for GPGs to remain online than in recent quarters.

Figure 49 Directed South Australian GPG falls from recent highs

Proportion of South Australian GPG directed of total South Australian GPG output



While quarterly direction costs were substantially lower due to reduced directions, the proportion of additional compensation claims have increased, accounting for 27% of total this quarter, up from 18% in Q1 2021. With average 12-month 90th percentile spot price (used as a benchmark for compensating participants) averaging at \$71/MWh as well as rising South Australian gas prices (\$8.7/GJ), AEMO received 35 of these additional claims during the quarter³⁸.

³⁸ As these additional compensation claims are processed, final direction costs are likely to be higher than the preliminary costs published in the report. Additional claims and additional claims that require independent expert may take up to 30 weeks to finalise.

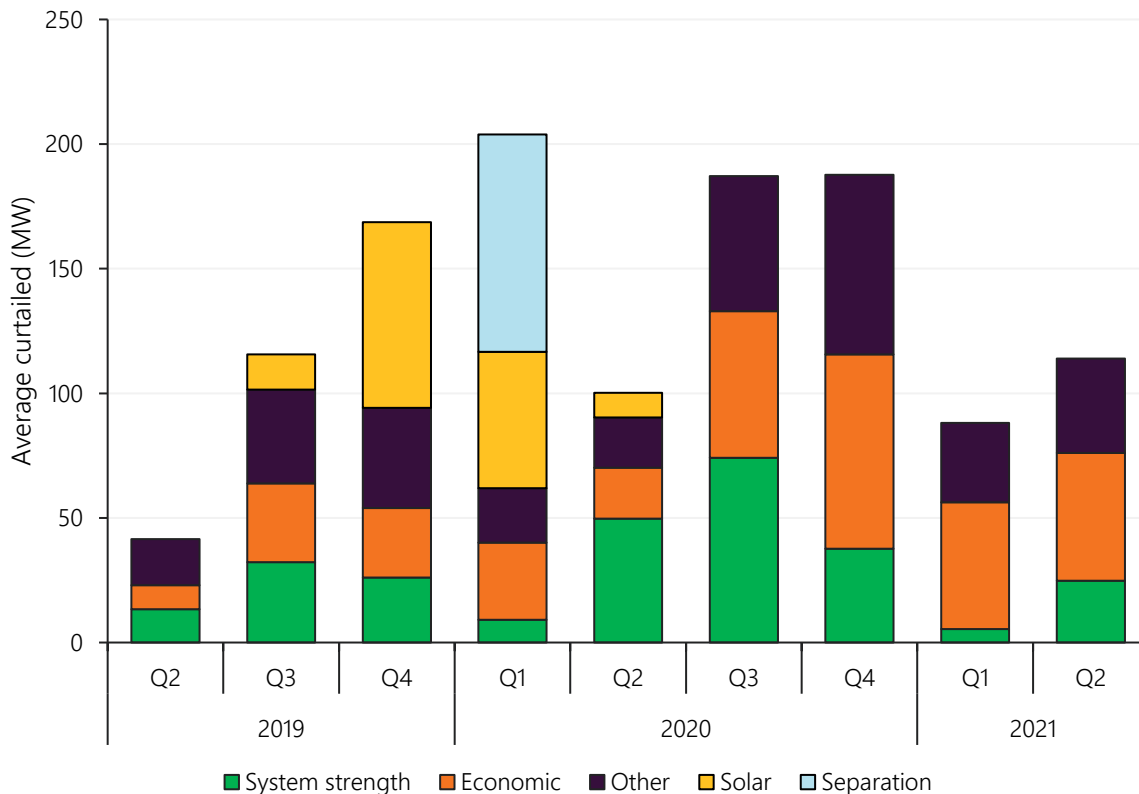
1.5.3 VRE curtailment

VRE curtailment increased to 114 MW on average (or 4% of total semi-scheduled VRE output), slightly higher than Q1 2021 (+26 MW), however lower than in 2020 (Figure 50). By category:

- Curtailment due to **system strength** averaged 25 MW this quarter, up from very low levels in Q1, driven by increased system strength curtailment in South Australia (+18 MW). This was due to an increase in the periods in which semi-scheduled wind farm availability in the region was very high, exceeding 1,200 MW 10% of the time compared to 3% of the time in Q1 2021.
- **Economic curtailment** was relatively flat on Q1 2021 levels as increased self-curtailment from wind and solar farms in Queensland (+24 MW) was mostly offset by reductions in South Australia (-21 MW) and Victoria (-5 MW).
 - With high occurrence of negative spot prices in Queensland, coupled with periods of extremely high Contingency Raise FCAS prices, Queensland VRE generators responded by self-curtailing output to either avoid paying to generate and/or minimise their FCAS costs. For example, on 3 June, around 76% of the Queensland VRE fleet self-curtailed in response to high FCAS prices, with average daily Raise 6 Second price reaching \$3,179/MWh (Figure 51).
 - Increased economic curtailment in Queensland was the main driver of its semi-scheduled curtailment rising from 1% in Q1 2021 to 6% this quarter (Figure 52).
- **Other curtailment** contributed to 38 MW of curtailment this quarter, up slightly on Q1 2021 levels. It includes unclassified sources of curtailment that can occur due to project specific issues, grid congestion, and other network constraints.

Figure 50 VRE curtailment increased slightly from previous quarter

Average NEM VRE curtailed by curtailment type



Note: curtailment amount is based on combination of market data and AEMO estimates. For more information on the calculation, see www.wattclarity.com.au/articles/2020/06/not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation/?utm_source=rss&utm_medium=rss&utm_campaign=not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation.

Figure 51 Queensland VRE responsive to extremely high FCAS prices

Queensland VRE response to high Raise 6 Second FCAS prices – 3 June 2021

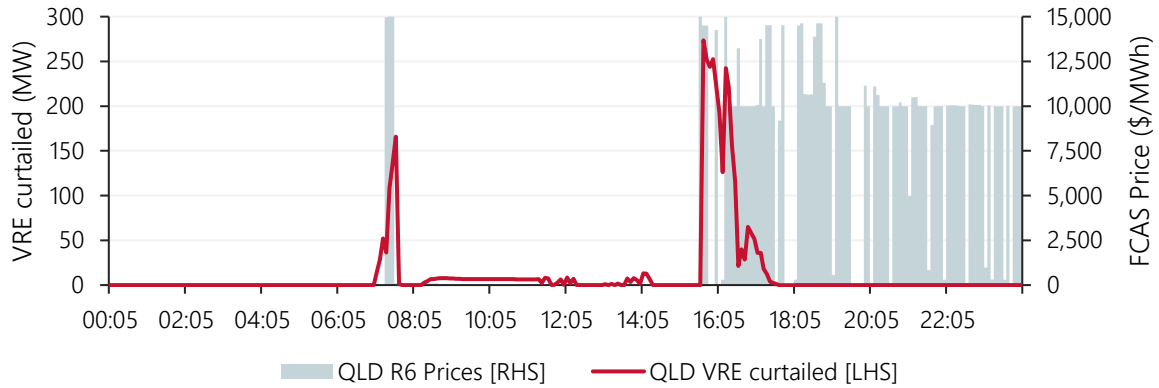
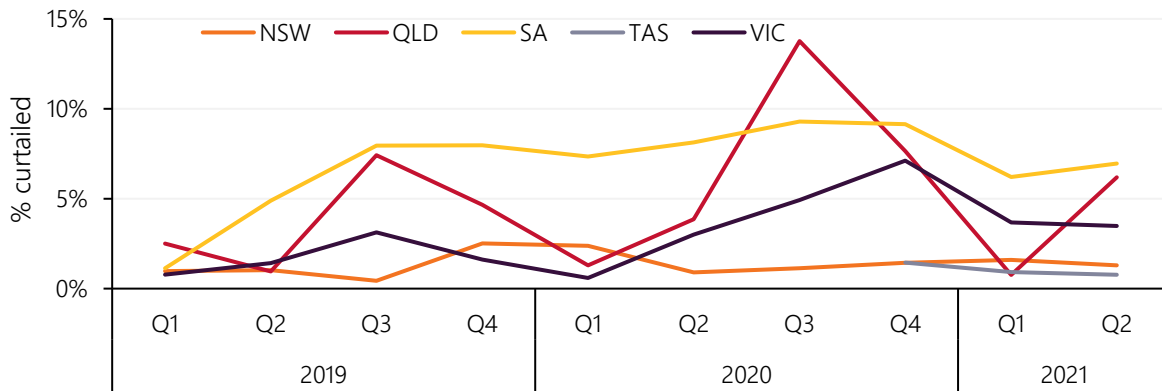


Figure 52 Queensland VRE curtailment increases from Q1 lows

% of VRE curtailed by region



2. Gas market dynamics

2.1 Gas demand

Total east coast gas demand increased by 4% compared to Q2 2020, mostly due to increased Queensland liquefied natural gas (LNG) demand (+19 petajoules [PJ], Table 4). International gas markets were particularly impacted by COVID-19 in Q2 2020 which led to lower gas prices and lower LNG exports. While GPG demand only slightly increased (+2 PJ³⁹), there were significant increases in late May and June as a result of the Callide and Yallourn outages.

Table 4 Gas demand – quarterly comparison

Demand (PJ)	Q2 2021	Q1 2021	Q2 2020	Change from Q2 2020
AEMO Markets *	97.8	57.6	97.5	0.3 (+0.3%)
GPG **	35.4	21.6	33.3	2 (+6%)
QLD LNG	335.8	356.8	316.6	19 (+2%)
TOTAL	469	436	447.4	22 (+5%)

* AEMO Markets demand is the sum of customer demand in each of the Short Term Trading Markets (STTMs) and the Declared Wholesale Gas Market (DWGM) and excludes GPG in these markets.

** Includes demand for GPG usually captured as part of total DWGM and STTM demand. Excludes Yabulu Power Station.

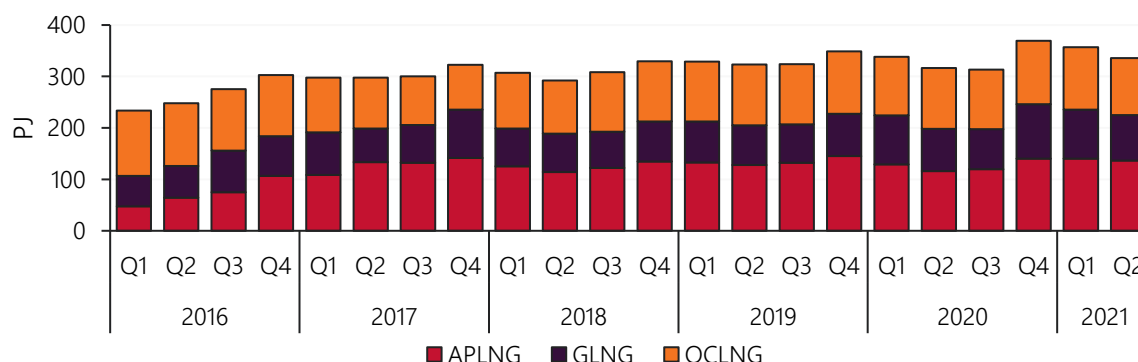
The large increase in Queensland LNG exports continued recent trends, influenced by strong Asian LNG demand and high prices (Section 2.2.1). Despite a 21 PJ decrease from Q1 2021 it was the fourth highest quarter and the highest Q2 export quantity on record (Figure 53).

Compared to Q2 2020 Australia Pacific LNG (APLNG) recorded the largest increase of 20.3 PJ, and Gladstone Liquefied Natural Gas (GLNG) increased by 6.2 PJ, while Queensland Curtis LNG (QCLNG) decreased by 7.3 PJ. During the quarter, 86 LNG cargoes were exported, an increase from 81 in Q2 2020⁴⁰.

On 25 May 2021, QCLNG experienced an unplanned production interruption related to the Callide incident, with its production decreasing from 1,706 TJ to 1,076 TJ, and Curtis Island flows decreasing from 1,368 TJ to 919 TJ. APLNG and GLNG production was also affected but to a lesser extent. While production dropped, flows to Curtis Island also decreased, and no additional gas volumes flowed into the domestic market.

Figure 53 GLNG and QCLNG drive record Q2 flows to Curtis Island for LNG export

Total quarterly pipeline flows to Curtis Island



³⁹High number of gas peaking plant starts this quarter contributed towards increased GPG PJ despite slightly lower average GPG MW compared to Q2 2020.

⁴⁰Queensland Government 2021, Maritime Safety Queensland: <https://qships.tmr.qld.gov.au/webx/>

2.2 Wholesale gas prices

Quarterly average gas prices increased in all east coast gas markets, averaging \$8.20/GJ compared to \$4.37/GJ in Q2 2020 (Table 5). From late May, prices rose sharply, influenced by higher international prices, rebounding GPG demand (Section 1.3.2), and higher QLD LNG demand (Figure 54). Key outcomes included:

- Gas prices in the **Brisbane Short Term Trading Market (STTM)** averaged \$8.48/GJ, 33% higher than Q1 2021 levels and 118% higher than Q2 2020, reflecting higher-priced offers (Figure 55) and increased demand. Prices jumped considerably in June 2021 to an average of \$10.80/GJ, reflecting a substantial shift in marginal bid prices above \$9/GJ.
- **Victoria's Declared Wholesale Gas Market (DWGM)** quarterly average gas price of \$7.22/GJ remained the lowest east coast average, 15% lower than other markets. This was influenced by increased local production, and higher utilisation of Iona Underground Gas Storage (UGS) (Section 2.3.1). Like Brisbane, prices jumped considerably in June to \$9.34/GJ, with higher GPG demand a key driver.

Table 5 Gas prices – quarterly comparison

Price (\$/GJ)	Q2 2021	Q2 2020	Change from Q2 2020
DWGM	7.22	4.65	+55%
Adelaide	8.69	5.13	+70%
Brisbane	8.48	3.89	+118%
Sydney	8.46	4.31	+97%
GSH	8.14	3.88	+110%

Figure 54 DWGM and Brisbane gas prices rise sharply from late May

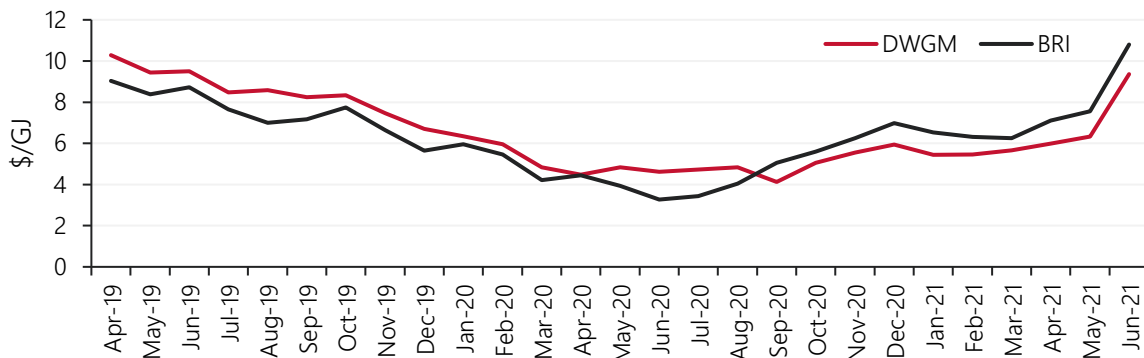
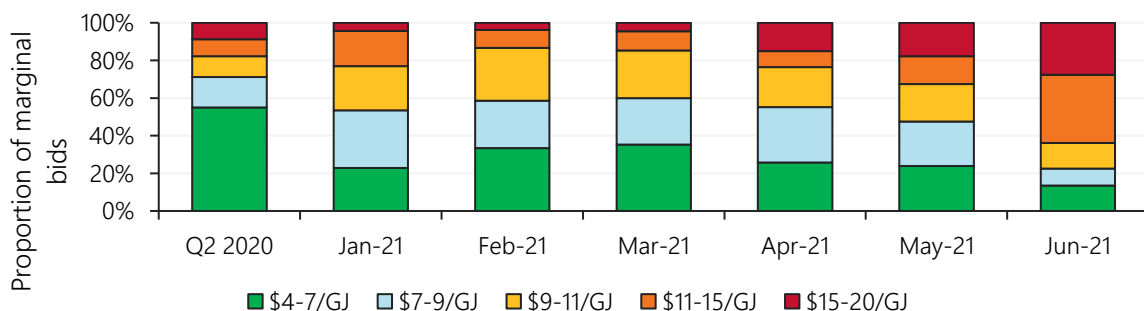


Figure 55 Brisbane STTM bids at higher prices than Q2 2020

Brisbane STTM – proportion of marginal bids by price band



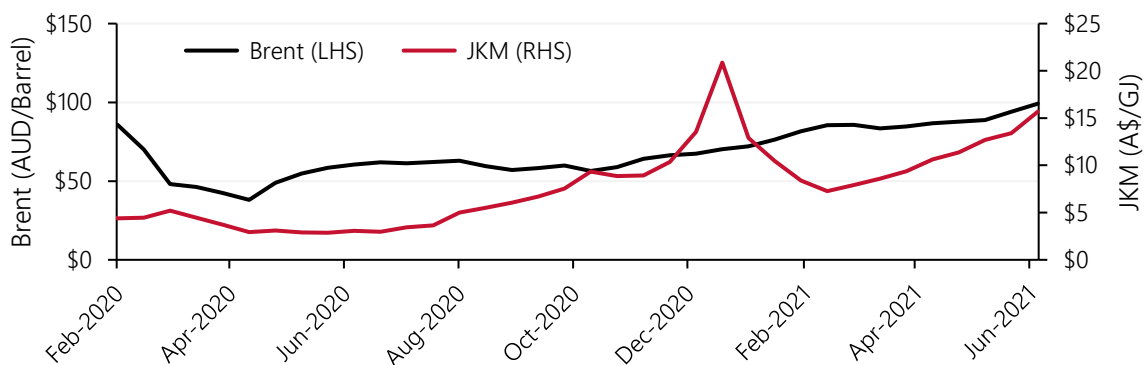
2.2.1 International energy prices

During Q2 2021, international energy prices continued to rise, with drivers including sustained demand recovery, post Northern hemisphere winter LNG storage refilling, and supply disruptions.

Japan Korea Marker (JKM) LNG prices increased steadily from A\$9/GJ at the end of previous quarter to finish Q2 at A\$17/GJ, averaging A\$12/GJ for the quarter (Figure 56). Key drivers included refilling of gas storages, which reached their lowest levels in more than a decade in Europe (and lowest in recent years in Asia), increased Northern hemisphere summer GPG demand due to warmer than average temperatures, and post-winter supply maintenance⁴¹.

Figure 56 Brent and JKM prices continue at high levels

Brent Crude oil and JKM prices in Australian dollars



Source: Bloomberg data in 14-day averages

Brent Crude oil prices continued trending up from A\$83/barrel from the end of Q1 2021 to finish Q2 at pre-COVID levels of A\$100/barrel, influenced by the Organisation of the Petroleum Exporting Countries (OPEC⁴²) ongoing production cuts and drawdowns of global oil stocks due to economic recovery⁴³.

Thermal coal export prices reached a record high of A\$180/ton by the end of Q2, A\$52/ton higher than the end of the previous quarter. Drivers included strong Asian demand, supply disruptions from Indonesia (the world's largest exporter) due to heavy rainfall, and mine safety issues in China⁴⁴.

Figure 57 Record thermal coal export price

Newcastle export thermal coal prices in A\$/ton



Source: Bloomberg

⁴¹ AFR 2021, Not enough natural gas to calm a global price rally: <https://www.afr.com/markets/commodities/not-enough-natural-gas-to-calm-a-global-price-rally-20210626-p584g8>

⁴² OPEC 2021, Ministerial Meeting highlights importance of ongoing rebalancing efforts: https://www.opec.org/opec_web/en/press_room/6429.htm

⁴³ Bloomberg 2021, OPEC sees tight oil market as ministers set for supply talks: <https://www.bloomberg.com/news/articles/2021-05-31/opec-tightens-oil-market-outlook-and-forecasts-sharp-stock-draws?sref=kkhkDP70>

⁴⁴ Bloomberg 2021, It's not over yet for coal as global prices surge on hot demand: <https://www.bloomberg.com/news/articles/2021-06-03/it-s-not-over-for-coal-yet-as-global-prices-surge-on-hot-demand?sref=kkhkDP70>

2.3 Gas supply

2.3.1 Gas production

In line with increased gas demand, east coast gas production increased by 17.2 PJ compared to Q2 2020 (+4%, Figure 58), with key changes including:

- **Higher Longford production** (+8.8 PJ), assisted by the commissioning of the West Barracouta gas field during April, which resulted in an increase in interstate exports from Victoria. Longford’s capacity factor was 92% for the quarter, an increase from 83% in Q2 2020 (Figure 59). However, Longford daily production finished the quarter at lower levels due to a partial outage from 28 June, which reduced Longford’s production from 980 TJ/d to 770 TJ/d⁴⁵.
- **Increased Queensland production** from GLNG (+9.9 PJ), APLNG (+3 PJ) and other Queensland facilities (+0.5 PJ) to meet increased demand for LNG export (Section 2). This was partially offset by a decrease from QCLNG (-2.9 PJ), particularly at Ruby Jo (-9.5 PJ).

Figure 58 Longford and GLNG production increase

Change in east coast gas supply – Q2 2021 versus Q2 2020

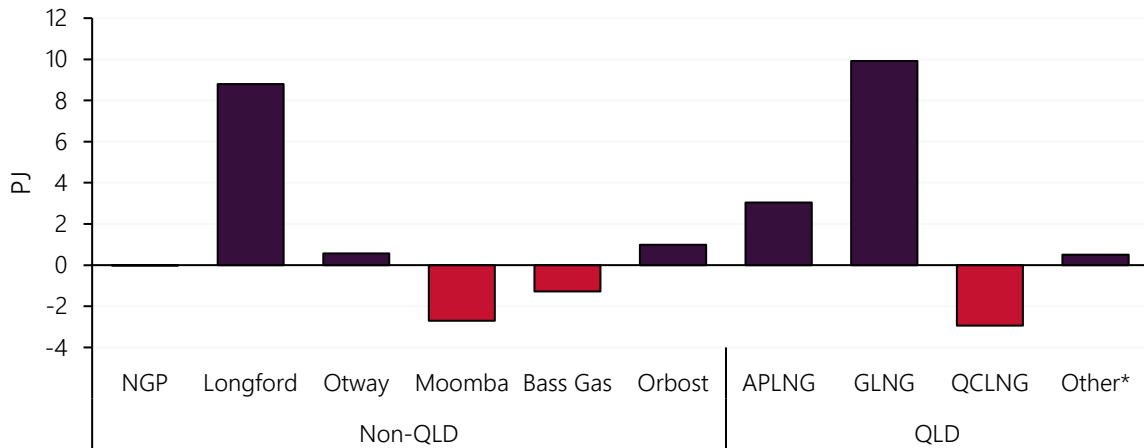
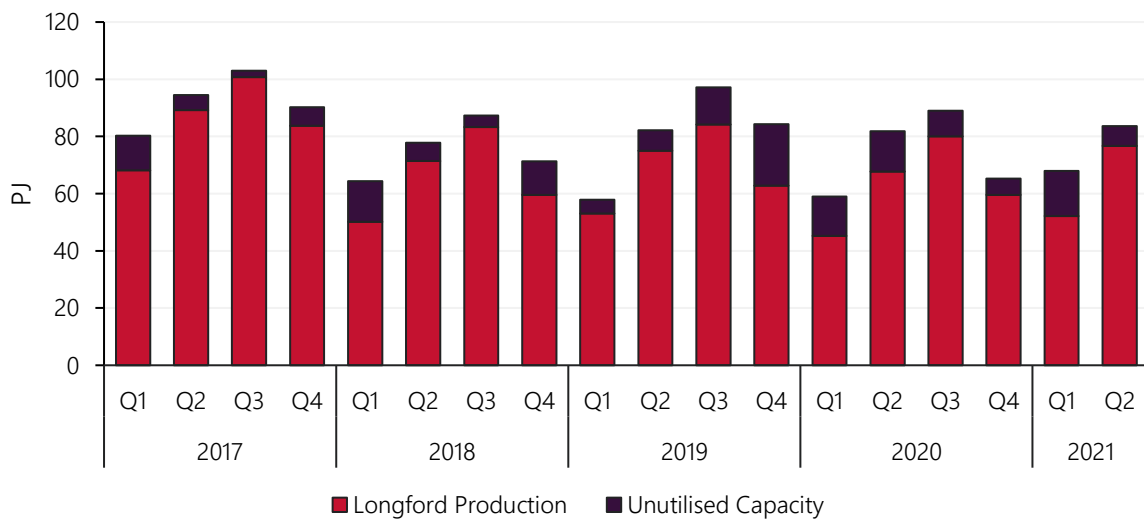


Figure 59 Highest Q2 Longford production since 2017



⁴⁵ This developed into an extended outage, reducing Longford’s capacity during July.

2.3.2 Gas storage

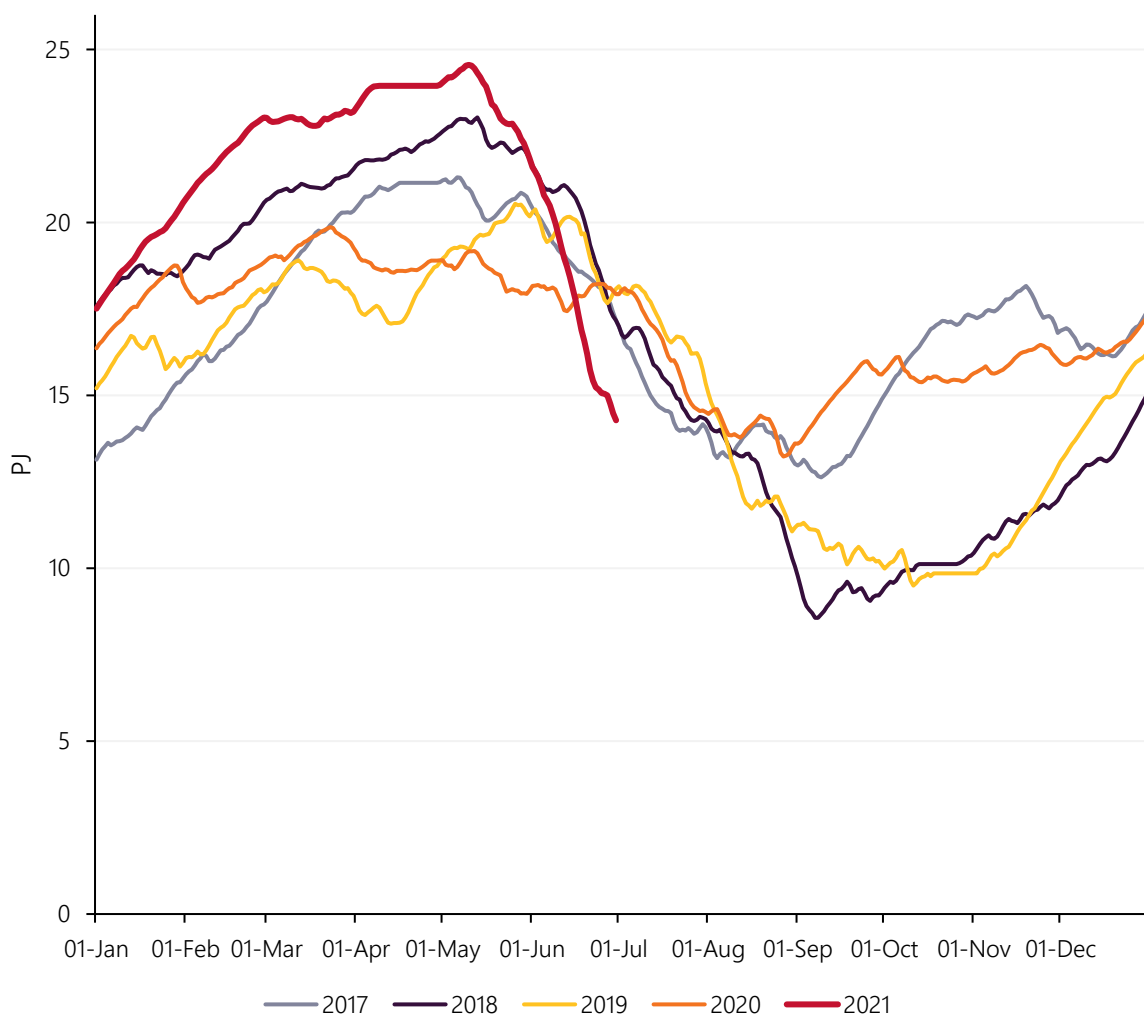
During the quarter, there was rapid emptying of Iona UGS facility. It finished the quarter with a gas balance of 14.3 PJ, 3.6 PJ lower than at the end of Q2 2020 and the lowest level at 30 June since storage levels began being reported in October 2016 (Figure 60).

Of note, this occurred despite Iona storage levels reaching a record high level of 24.5 PJ on 10 May. Iona was heavily utilised from that point on, with high GPG demand in Queensland and Victoria, and a reduction in Queensland gas flows south compared to Q2 2020, contributing factors. Iona also supplied 2.2 PJ from storage from 14 June to 20 June, a weekly record that was mainly driven by higher Victorian GPG demand in response to the Yallourn outage.

On 21 June, Lochard identified a gas leak on a section of piping at the Iona plant. As a result, Iona required an unplanned plant outage for repairs. This went ahead from noon on 24 June and the plant resumed availability from early morning on 25 June, with no material market impact. An additional 24-hour outage will be required before the end of winter to reinstate a section of piping, and it is unable to inject gas into storage until this outage occurs.

Figure 60 Iona storage empties at record rates

Iona storage levels



2.3.3 Dandenong LNG

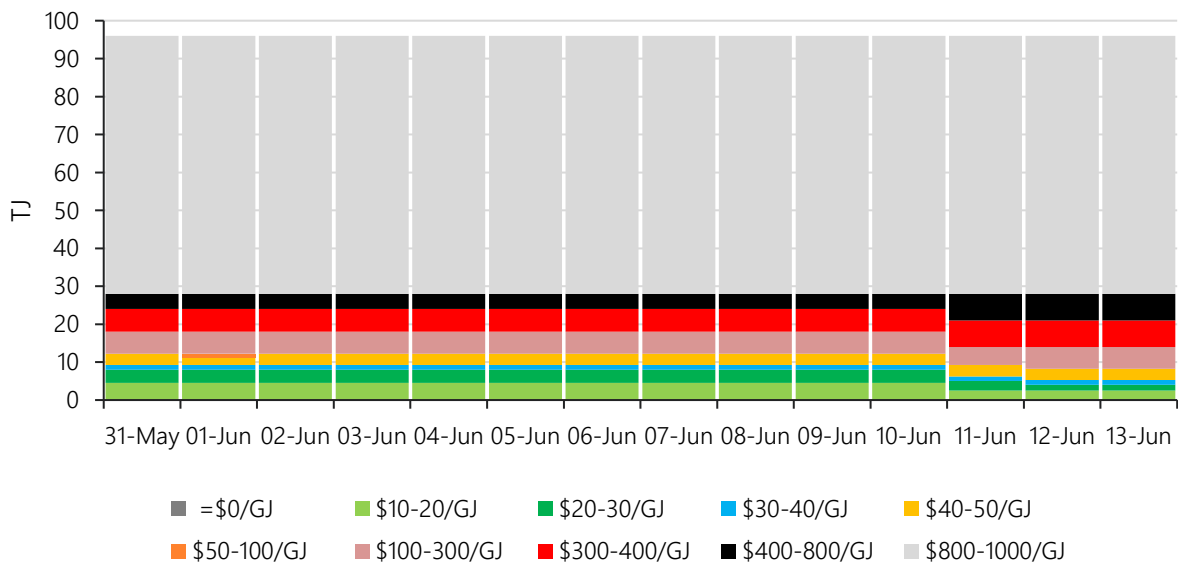
Dandenong LNG storage levels continued to fall⁴⁶, declining by 48 terajoules (TJ) to finish the quarter at 338 TJ, the lowest level since the DWGM began in 1999 (Figure 61). The contracted capacity of 195 TJ did not increase during the quarter.

Of the LNG bid available on the bid stack, less than 5 TJ was bid between \$12-20/GJ, with 83 TJ bid between \$100-\$800, with most volume priced at \$800/GJ (Figure 62).

Figure 61 Dandenong LNG levels continue to fall



Figure 62 Limited volume bid below \$100/GJ on Dandenong LNG bid stack



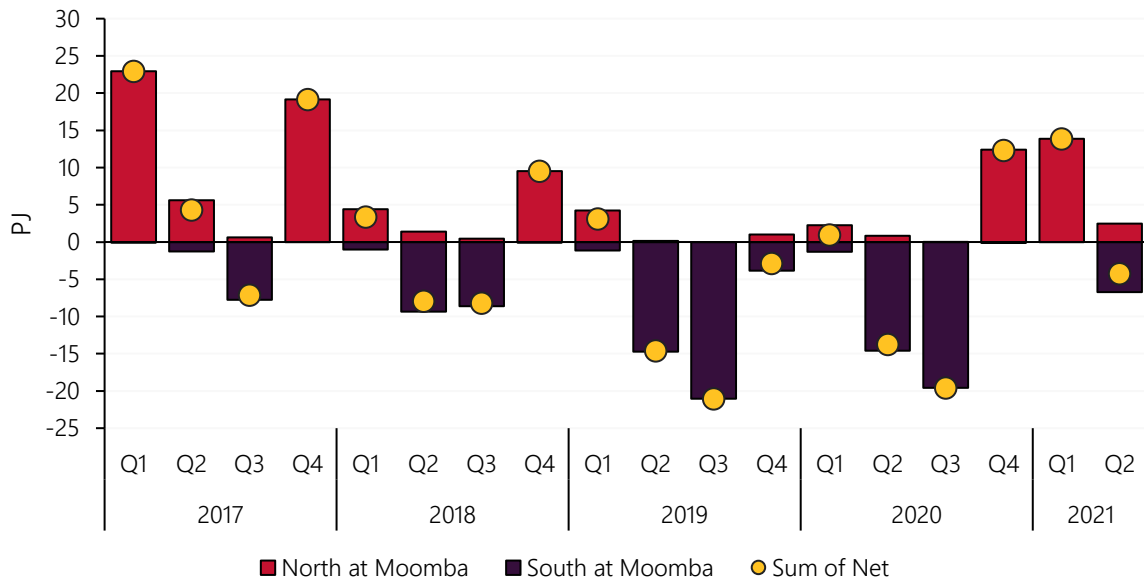
⁴⁶ No gas from Dandenong LNG was scheduled into the DWGM. Reduction assumed to be driven by boil off and/or other uses.

2.4 Pipeline flows

During the quarter, net 4.2 PJ of gas flowed south from Queensland to Moomba, compared to net 13.8 PJ in Q2 2020, representing the lowest Q2 flows south since 2017 (Figure 63). The decrease in gas flows was a function of high Queensland LNG export demand, higher Victorian production, and higher GPG demand.

Figure 63 Lowest Q2 net gas flows from Queensland since 2017

Flows on the South West Queensland Pipeline at Moomba

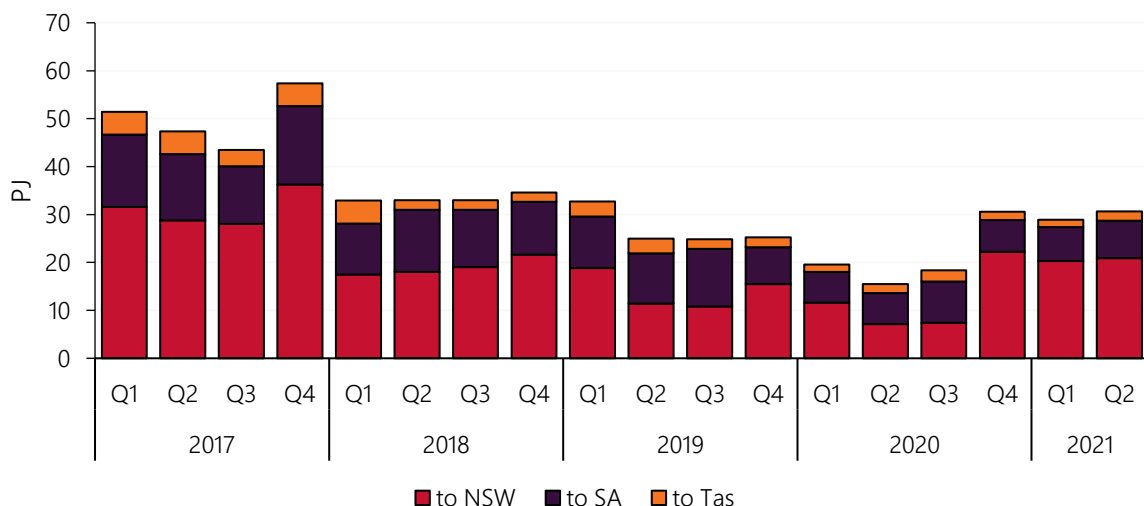


Victorian net gas transfers to other states increased by 15.2 PJ compared to Q2 2020 (Figure 64), reflecting increased Victorian production and a larger drawdown of Iona storage inventory than usual.

- **Victoria to New South Wales** – Victoria exported a net 1.9 PJ of gas via Culcairn, compared to an import of 4.2 PJ in Q2 2020. Exports to New South Wales via the Eastern Gas Pipeline (EGP) increased by 7.8 PJ.
- **Victoria to South Australia** – transfers increased by 1.3 PJ despite stagnant South Australian demand, reflecting lower Moomba to Adelaide Pipeline flows. This was due to increased Victorian production and decreased Queensland flows to Moomba.

Figure 64 Highest Q2 Victorian gas exports since 2017

Victorian net gas transfers to other regions

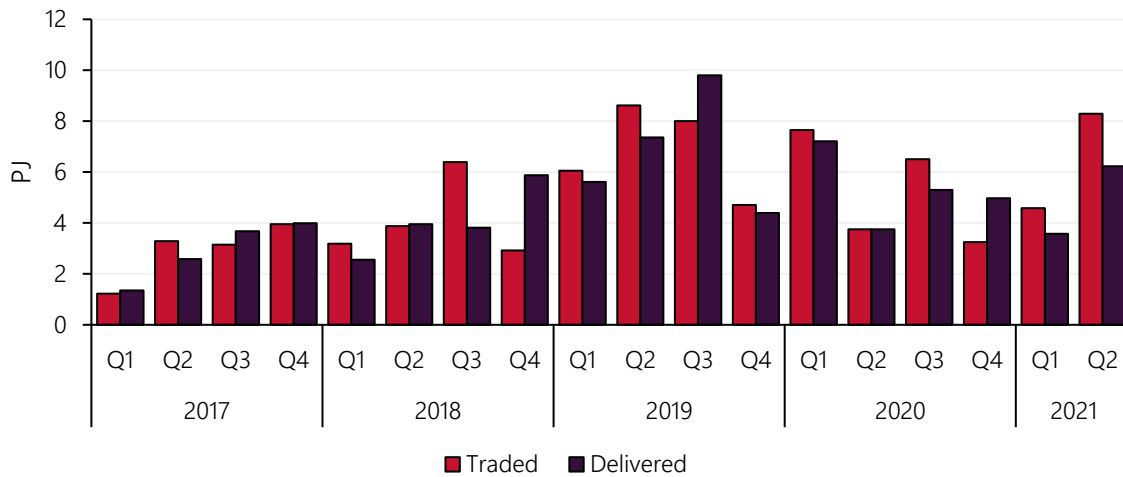


2.5 Gas Supply Hub

In Q2 2021, there were increased trading volumes and delivered volumes on the Gas Supply Hub (GSH) compared to Q2 2020, with deliveries up by 2.5 PJ, and trades up by 4.5 PJ. This represented the highest traded volume for any quarter since Q2 2019 and highest delivered volume since Q1 2020 (Figure 65).

Figure 65 Gas Supply Hub volumes highest since 2019

Gas Supply Hub – quarterly trades and deliveries



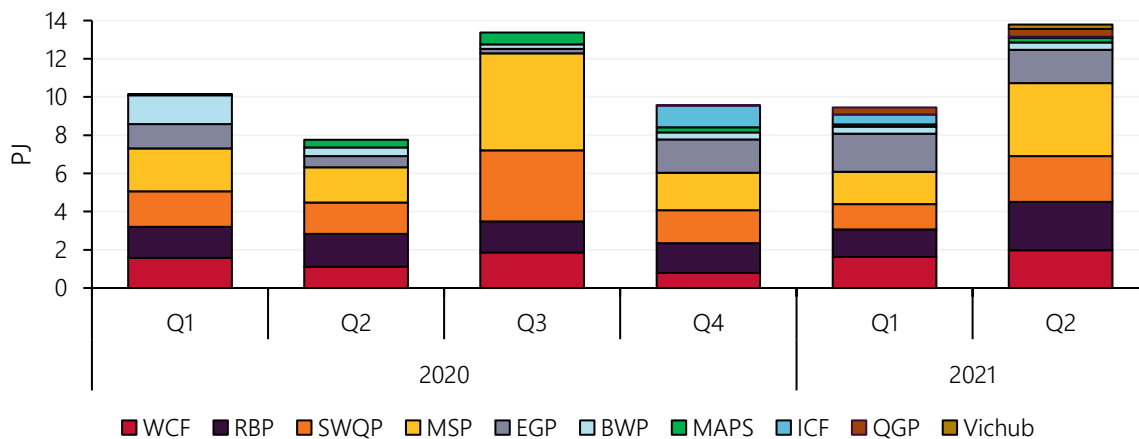
2.6 Pipeline capacity trading and day ahead auction

Day ahead auction (DAA) utilisation was the highest on record, increasing by 6.9 PJ compared to Q2 2020 (+88%). The largest increases occurred on the Moomba to Sydney Pipeline (MSP, +2 PJ), EGP (+1.2 PJ), Wallumbilla Compressor (+0.9 PJ), Moomba Compressor, Roma to Brisbane Pipeline (RBP) and SWQP (+0.8 PJ each). Vic Hub was also used for the first time (+0.2 PJ)⁴⁷.

Average auction clearing prices remained at close to \$0/GJ on most pipelines. The exceptions to this were the EGP, which averaged \$0.20/GJ, the South West Queensland Pipeline (SWQP), which averaged \$0.07/GJ, the RBP which averaged \$0.04/GJ, and the MSP, which averaged \$0.03/GJ.

Figure 66 Highest quarterly Day Ahead Auction utilisation since market start

Day Ahead Auction results by quarter



⁴⁷ The AER's Quarter 2 2021 Wholesale Market Quarterly Report will (include) additional analysis on the day ahead auction highlighting in demand routes.

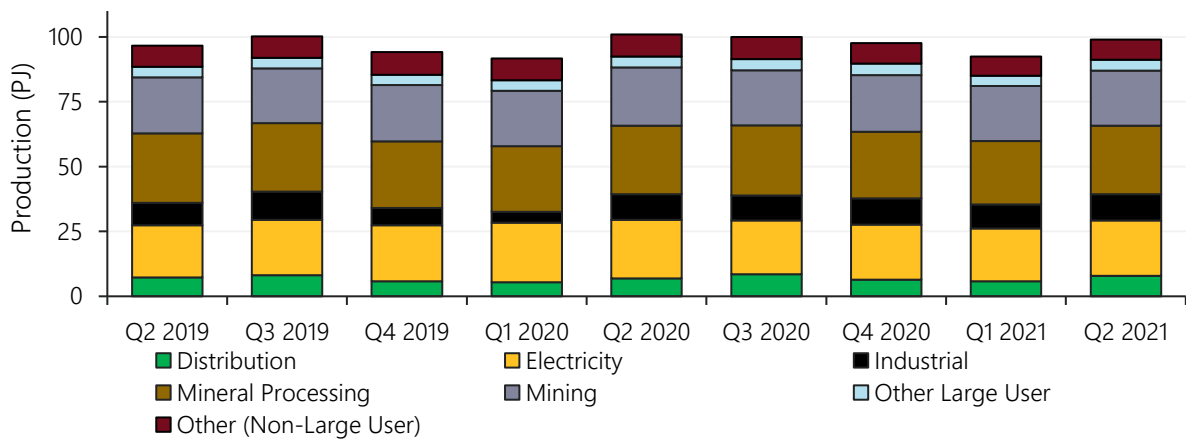
2.7 Gas – Western Australia

Total Western Australian domestic gas consumption in Q2 2021 decreased to 99 PJ, down 1.9% from Q2 2020 (Figure 67). The key drivers for this change were a 1.3 PJ (5.5%) decrease in consumption for electricity generation, as GPG was displaced in the fuel mix by increased wind, solar and coal generation, and a 1.2 PJ (5.2%) decrease for mining.

Consumption by distribution systems increased by 1 PJ (+14%) due to increased heating requirements, as heating degree days increased by 71% from Q2 2020 to Q2 2021 (Section 3.1.1). This was particularly driven by a very cold June, during which gas distribution networks recorded their highest monthly consumption since commencement of the Western Australian Gas Bulletin Board (GBB WA) in August 2013.

Figure 67 Western Australia domestic gas consumption drops 4.6% from Q2 2020

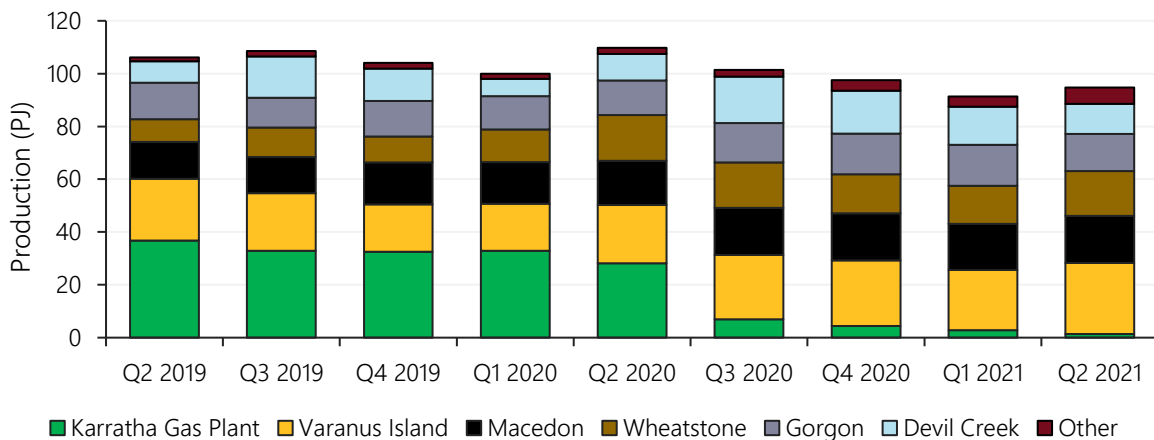
WA quarterly gas consumption by industry – Q2 2019 to Q2 2021



Total Western Australian gas supply was 94.7 PJ in Q2 2021, representing a 15 PJ (14%) decrease from the historic peak in in Q2 2020 (Figure 68). This was driven primarily by the Karratha Gas Plant, which decreased production from 28 PJ to 1.4 PJ over the same period. This reduction has been attributed to the ending of at least one long-term domestic gas supply contract in 2020⁴⁸.

Figure 68 Western Australia domestic gas production drops 14% from Q2 2020

WA quarterly gas production by facility – Q2 2019 to Q2 2021



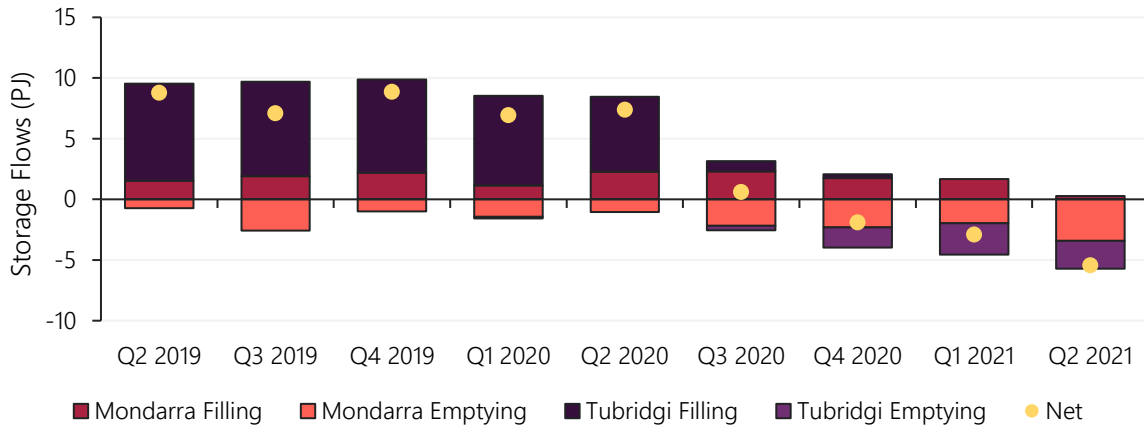
The deficit in production compared to demand was met by a 5.4 PJ net withdrawal from gas storage facilities during the quarter, contrasting a net injection of 7.4 PJ in Q2 2020. Over this period, both Western Australian

⁴⁸AEMO Gas Statement of Opportunities 2020, Section 3.1.3, Domestic Gas Production: https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/wa_gsoo/2020/2020-wa-gsoo-report.pdf?la=en

storage facilities (Mondarra and Tubridgi) shifted from net injection to net withdrawal (Figure 69). This represents a significant change in operation of Tubridgi, which was historically a large importer: between commencement of operations in 2018 and the end of Q2 2020, Tubridgi injected 54.3 PJ and withdrew only 0.2 PJ, nearing its storage capacity of 60 PJ. Since then, Tubridgi has injected 1.2 PJ and withdrawn 6.9 PJ.

Figure 69 Gas storage facilities move from net injection to net withdrawal to meet drop in production

WA gas storage facility injections and withdrawals – Q2 2019 to Q2 2021



3. WEM market dynamics

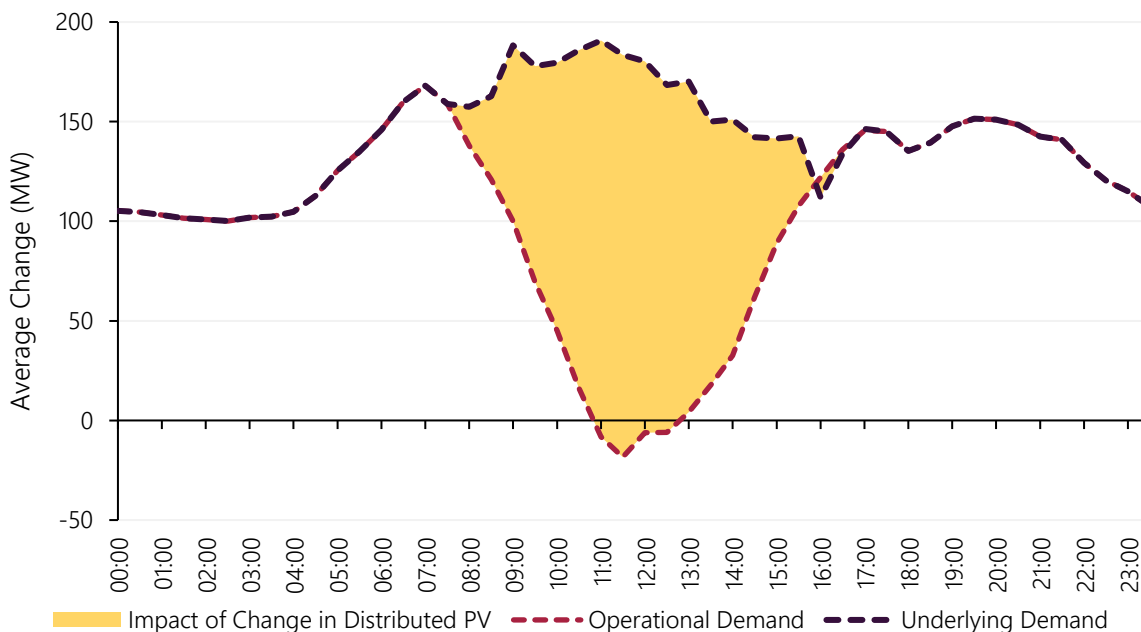
3.1 Electricity demand

3.1.1 Operational and underlying demand

Operational demand⁴⁹ increased from an average of 1,940 MW in Q2 2020, to 2,042 MW this quarter, with increases during most times of day due to increased underlying demand (Figure 70). The only decreases in operational demand occurred between 1100 hrs and 1300 hrs⁵⁰ due to continuing growth in distributed PV output. Average estimated underlying demand increased from an average of 2,066 MW in Q2 2020 to 2,207 MW in Q2 2021 (+7%), largely due to the increased heating load.

Figure 70 Increased underlying demand throughout the day, but higher distributed PV output dampens midday operational demand

Change in Q2 2021 WEM-average operational and underlying demand by time of day compared to Q2 2020



Colder temperatures in Q2 2021 led to increased heating requirements, with HDDs up 71% compared to Q2 2020 (Figure 71). This was predominantly driven by cold weather in June, as Perth experienced its coldest June in 31 years⁵¹. A new record high Q2 operational demand of 3,528 MW was set at 1800 hrs on 22 June 2021, which included Perth’s lowest minimum temperature since 2015.

A new record was also set for the minimum Q2 operational demand, reaching 1,105 MW at 1200 hrs on Sunday 18 April 2021, 50 MW lower than the previous Q2 minimum. The new minimum was a function of low underlying demand (2,130 MW) resulting from mild weather, and high distributed PV output at 1,025 MW (48% of underlying demand).

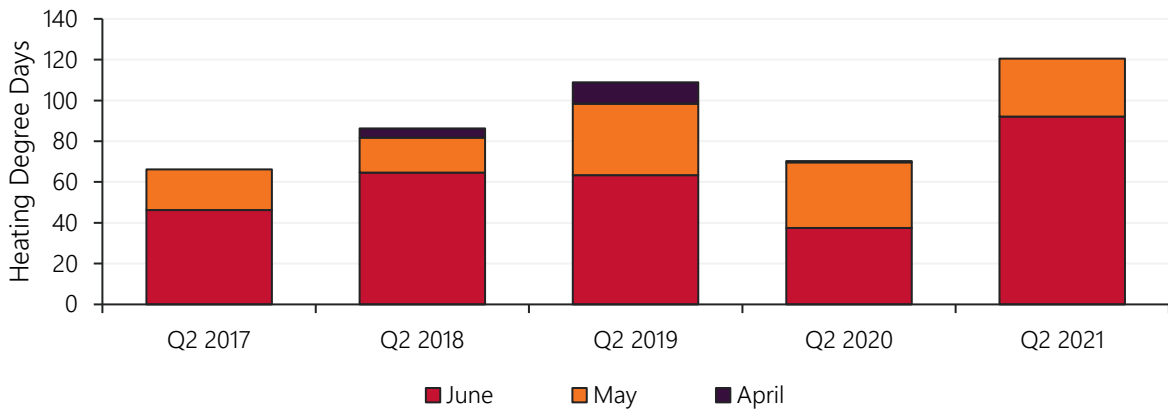
⁴⁹ Operational demand is total wholesale generation from registered Facilities in the SWIS and is based on non-loss adjusted sent out SCADA data, averaged over a 30-minute interval. Underlying demand is operational demand that has been adjusted to remove the impact of distributed PV output.

⁵⁰ In this section, time is in Australian Western Standard Time (AWST).

⁵¹ According to BOM data for Perth Airport: <http://www.bom.gov.au/climate/current/month/wa/archive/202106.summary.shtml#recordsAvgRecentLow>

Figure 71 Increased heating requirements driven by cold June weather

Heating Degree Days compared to previous Q2s by month⁵²



3.2 WEM prices

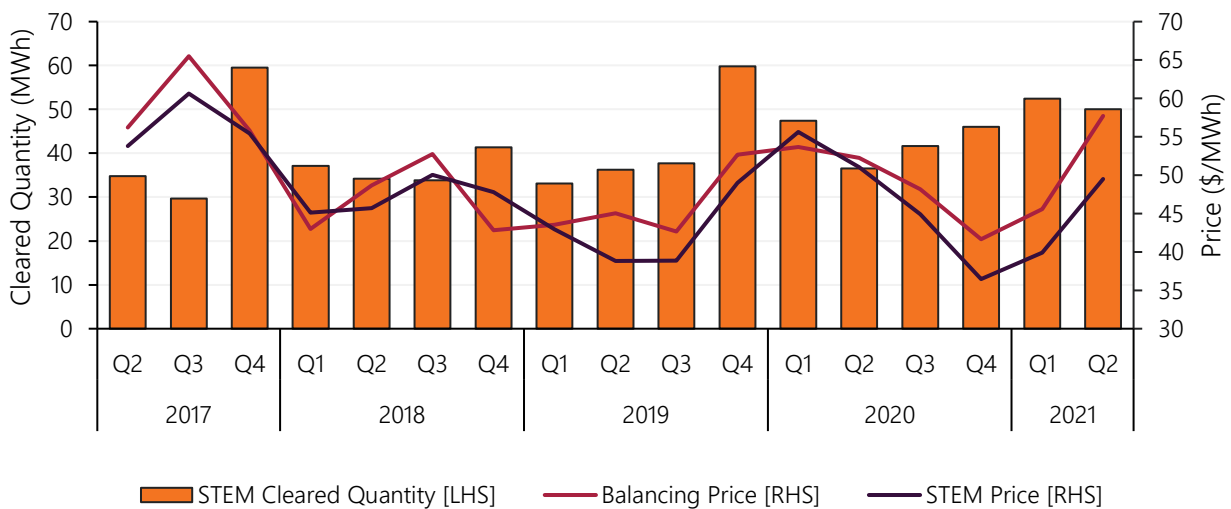
The WEM average Balancing Price increased from \$52/MWh in Q2 2020 to \$58/MWh in Q2 2021, the highest quarterly average since Q3 2017 (Figure 72). There was a greater spread of Balancing Prices compared to Q2 2020, with a higher proportion of negatively priced intervals due to more wind and solar generation (Section 3.2.1), and a high proportion of high-priced intervals due to an increase in operational demand (Section 3.2.2).

The quantity cleared in the Short Term Energy Market (STEM) increased significantly from previous Q2s, rising from an average 36.5 MWh per trading interval in Q2 2020 to 50 MWh in Q2 2021. Over the last five years there has been a gradual increase in the energy traded by Market Participants in the STEM.

The average STEM Price was \$8/MWh below the averaging Balancing Price in Q2 2021, the largest difference since Q3 2016. This difference was driven by dynamic trading and hedging by participants, and indicates the value to energy sellers of securing a day ahead price to minimise exposure to low or negative prices.

Figure 72 WEM Balancing Prices rose to their highest levels since Q3 2017

WEM Average Balancing and STEM Prices, and STEM Cleared Quantity



⁵² A "heating degree day" (HDD) is a measurement used as an indicator of outside temperature below what is considered a comfortable temperature. The HDD value for each day is calculated as max (0, baseline temperature – average [maximum temperature, minimum temperature]). The HDD baseline temperature used for the WEM region is 16°C as per the AEMO Electricity Statement of Opportunities 2021.

3.2.1 Negative prices

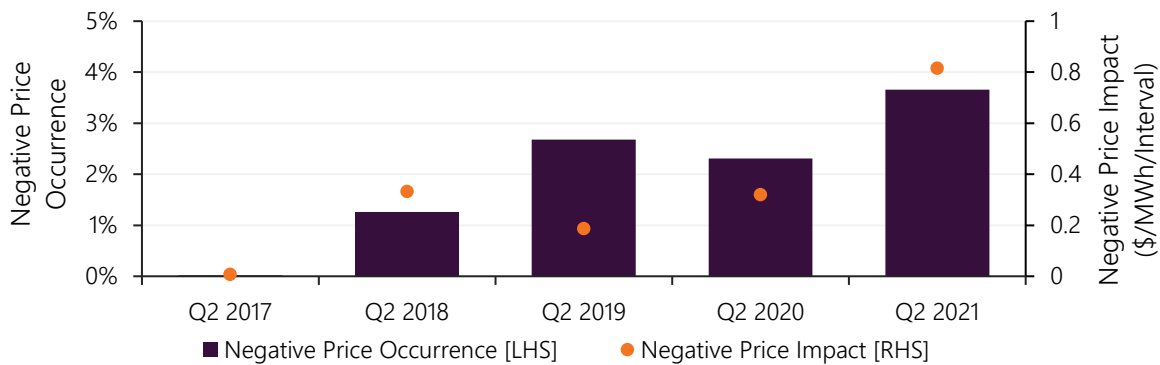
During Q2 2021, negative Balancing Prices (including zero prices) occurred in 3.7% of all intervals, up from 2.3% in Q2 2020, and continuing the trend upwards (Figure 73). Drivers include:

- An increasing quantity of energy was made available in the balancing market at or below \$0/MWh, largely associated with new wind and solar farms that have commenced trading within the last few years. In Q2 2021, there was an additional 60 MW of zero or negatively-priced offers available compared to Q2 2020, primarily from the Yandin and Warradarge facilities which commenced operations in Q3 2020.
- The growth in distributed PV output has led to falling demand during the middle of the day, resulting in more zero or negatively-priced intervals during this period. In Q2 2021, operational demand between 1100 hrs and 1300 hrs decreased by 10 MW compared to Q2 2020 despite an estimated increase in underlying demand of 181 MW during the same period.

The overall impact of negative prices on the quarterly average price⁵³ remained low, at \$0.82/MWh, as most negative intervals cleared between -\$10/MWh and \$0/MWh, and the lowest cleared price was -\$73.83/MWh. However, this represents a material increase from Q2 2020, at \$0.32/MWh.

Figure 73 Frequency and impact of negative price events continues to grow

WEM Q2 average negative price percentage occurrence and impact – 2017 to 2021

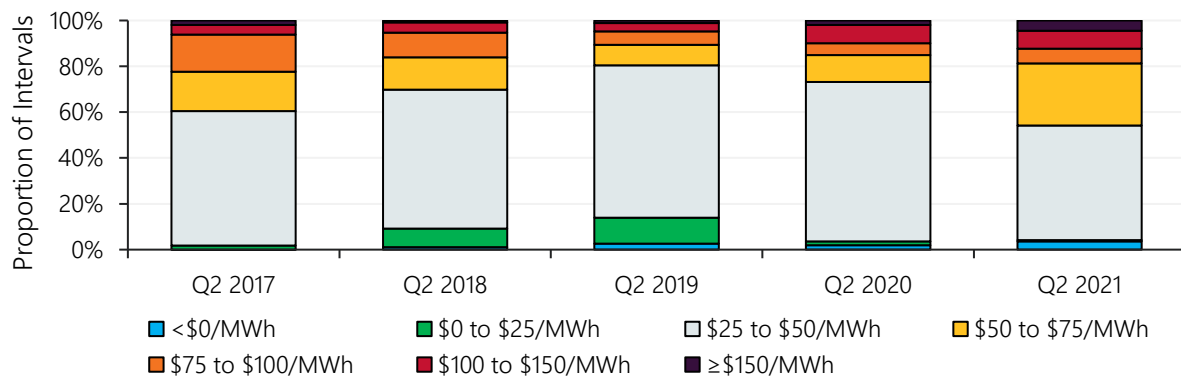


3.2.2 High price events

This quarter, there was an increase in the number of high price events, with 4.4% of all intervals clearing at \$150/MWh or higher, compared to 2.0% in Q2 2020 (Figure 74), driven by increased in operational demand.

Figure 74 Frequency of negative and high price events grows

WEM Q2 cleared Balancing Price distributions – 2017 to 2021



⁵³ Impact of negative prices is a measure of both frequency and magnitude of negative prices. It is defined as the difference in average Balancing Price caused by negative intervals compared to if the Floor Price were \$0/MWh. It is calculated as the absolute sum of the Balancing Price in all negatively priced intervals, divided by the total number of intervals.

Offsetting the impact of increased demand was an increase in average capacity available at or below \$160/MWh, which rose by 209 MW compared to Q2 2020. As a result, most of the high priced intervals cleared between \$150/MWh and \$160/MWh (2.8% of all intervals, compared to 1% in Q2 2020), limiting the impact of high demand on even higher prices.

3.2.3 Price-setting dynamics

Price-setting outcomes changed significantly in Q2 2021 compared to Q1 2021, with the Balancing Portfolio⁵⁴ playing a greater role in setting the price compared to coal, gas, and wind from Independent Power Producers (IPPs) (Figure 75), with higher operational demand contributing to this outcome.

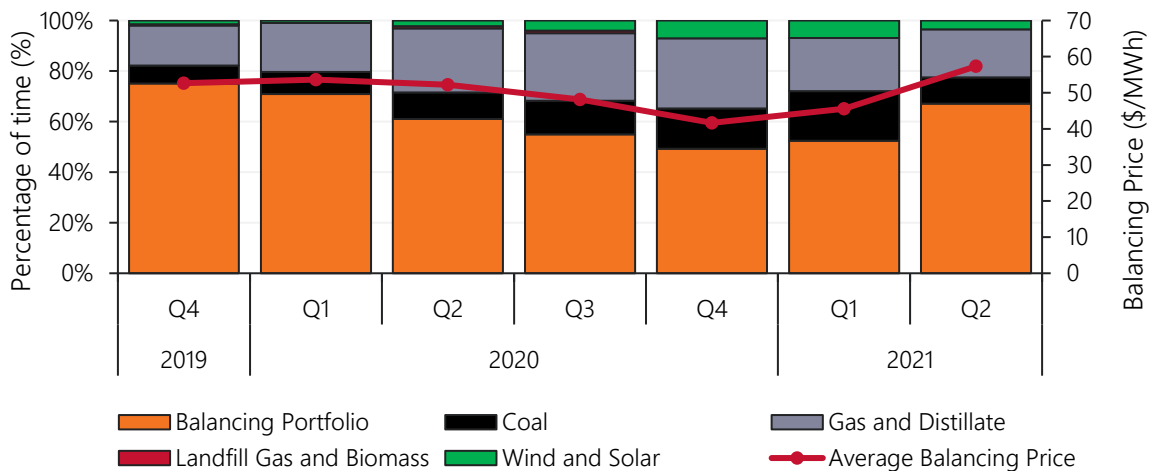
In Q4 2019 the Balancing Portfolio set the price 75% of the time, compared to 67% in Q2 2021. In that time more than 490 MW of Facility nameplate capacity has been connected to the SWIS, leading to the longer-term trend of the Balancing Portfolio setting the price less frequently. This highlights that the WEM is becoming more diversified.

Key price-setting outcomes by type included⁵⁵:

- **Balancing Portfolio** generation set the price 67% of the time in Q2 2021, up from 52% in Q1 2021 and 61% in Q2 2020. The increased price-setting role in Q2 2021 compared to Q1 2021 was the result of higher-priced generation being dispatched. The Balancing Portfolio represents the majority of the bids in the greater than \$100/MWh category. Thus, an increase in demand typically causes increased price-setting from the Balancing Portfolio.
- **Coal-fired** generation set the price 10% of the time in Q2 2021, compared to 20% in Q1 2021. Significant outages of coal-fired generators reduced the average availability⁵⁶ from 94% in Q1 2021 to 88% in Q2 2021, resulting in coal-fired generators setting the price less frequently than in recent quarters.
- With no major changes in availability, **gas and distillate** generation played a relatively similar price-setting role to past quarters, setting the price 19% of the time.
- As **wind and solar** facilities enter the market, their price setting share has increased from 0.6% of the time in Q2 2019 to a high of 7% in Q1 2021.

Figure 75 Higher operational demand contributes to increased price-setting role of the Balancing Portfolio

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



⁵⁴ The Balancing Portfolio has a total Sent Out Capacity of more than 2,700 MW, which represents about 44% of Sent Out Capacity in the WEM.

⁵⁵ Type has been separated by Balancing Portfolio, and fuel-type of non-Balancing Portfolio Facilities.

⁵⁶ Availability is the time averaged proportion of capacity not on outage.

3.3 Electricity generation

3.3.1 Change in fuel mix

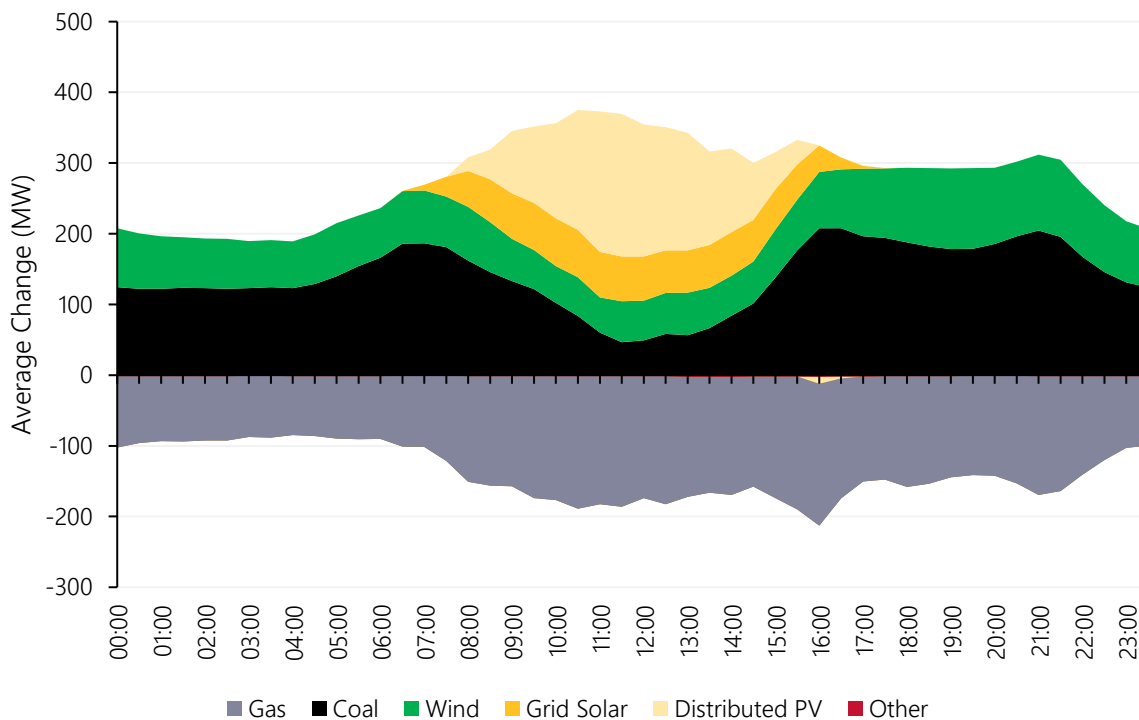
Compared to Q2 2020, a 141 MW rise in underlying demand in Q2 2021 and reduced GPG was met by increased coal, wind, distributed PV, and grid-solar generation (Figure 76).

Key outcomes by fuel type compared to Q2 2020 included:

- **Coal-fired** generation increased by 140 MW (+17%), with the largest increases occurring in the peak morning and evening period. Collie Power Station average output increased by 123 MW, due to reduced outages which increased its availability to 81% (compared to 20% in Q2 2020).
- **Wind** generation increased by 77 MW (+37%) due to the addition of two wind farms – with a combined capacity of 392 MW – in Q3 2020 (Yandin Wind Farm and Warradarge Wind Farm). Cyclone Seroja had a large impact on wind generation (Section 3.3.3) – wind generation was up 91 MW compared to Q2 2020 if ignoring the period when the North Country region was disconnected from the SWIS. Wind generation was particularly high in June 2021 with the top 15 intervals by wind generation since market start. The all-time wind generation record of 945 MW was set between 1300 hrs and 1330 hrs on 27 June 2021.
- **Distributed PV** output increased by 40 MW (+32%) due to the installation of an estimated 351 MW of additional capacity in the last year.
- **Grid solar** generation increased by 22 MW (+662%) due to the addition of 130 MW of capacity in Q3 2020 (Merredin Solar Farm and an upgrade to Greenough River Solar Farm).
- **GPG** decreased by 98 MW (-15%) as it was displaced by lower-priced supply from other fuel types.

Figure 76 Increased output from wind, solar, and coal; decreased output from gas

Average change in WEM generation – Q2 2021 versus Q2 2020



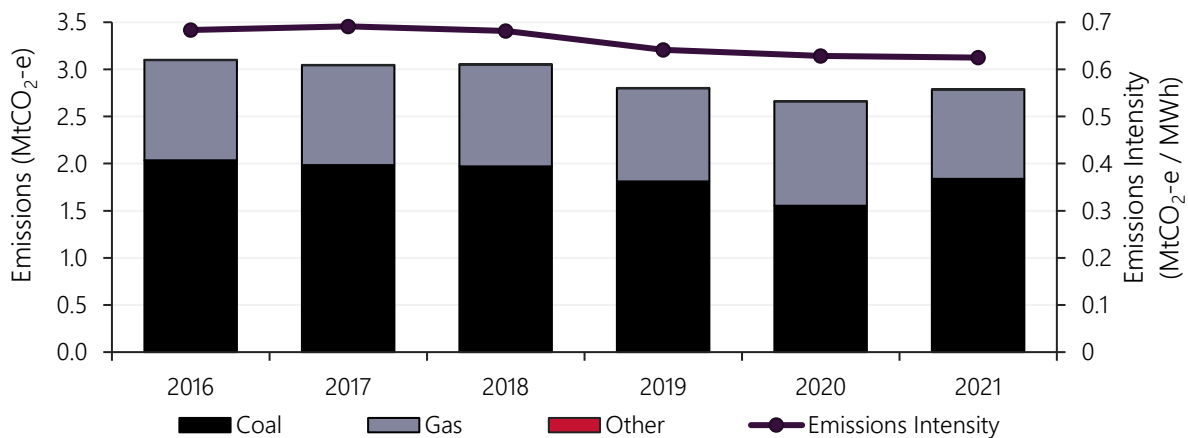
3.3.2 WEM emissions

Quarterly emissions by registered generators in the WEM for Q2 2021 was estimated⁵⁷ at 2.8 MtCO₂-e, down 10.2% from five year ago (Q2 2016, Figure 77). Drivers of this trend include increased grid scale wind and solar generation (+135%) and increased distributed PV generation (+236%). This also led to lower Q2 emissions intensity⁵⁸, which has been declining since Q2 2017.

Compared to Q2 2020, emissions from coal-fired facilities was up 18%, in line with increased coal-fired generation (due to increased demand and higher availability at Collie Power Station). This led to a 0.12 MtCO₂-e increase in emissions between Q2 2020 and Q2 2021.

Figure 77 The Q2 WEM emissions intensity has been declining since 2017

WEM Emissions compared to previous Q2s



3.3.3 Impact of Cyclone Seroja

Cyclone Seroja made landfall on the Western Australian coast near Kalbarri around 2000 hrs on 11 April 2021, resulting in the outage of several transmission lines connecting the North Country region to the rest of the South West Interconnected System (SWIS). The North Country region was islanded from the SWIS from 14 April, and was resynchronised with the SWIS on 21 April, with all damaged transmission lines restored by 25 May⁵⁹.

To maintain system security and electricity supply for customers in North Country during the islanded period, two generation units at the Mungarra Gas Turbine Station were required to run under a Network Control Service contract, and Tesla's Geraldton plant was constrained on during evening peaks.

During this period, wind facilities with a combined capacity of 676 MW, plus a 40 MW solar facility, were affected by the network outages. Figure 78 shows the daily generation of the affected wind farms, which dropped from an average of 500 MW on 11 April to 25 MW on 12 April, before gradually increasing through late April and early May as infrastructure damaged by the cyclone was restored.

⁵⁷ Facility generation data is based on sent-out facility SCADA, as available on the AEMO website. Facility emissions intensities published by the Clean Energy Regulator for FY 2019-20 were used. Emissions due to energy consumed by the power stations themselves are not included, and hence these results is not directly comparable to the CDEI published for the NEM.

⁵⁸ Emissions per sent out MWh of generation.

⁵⁹ Western Power Cyclone Seroja power supply updates: <https://www.westernpower.com.au/community/news-opinion/cyclone-seroja-power-supply-updates/>

Figure 78 Cyclone Seroja affected 767 MW of wind capacity

Daily generation of North Country wind farms during April and May

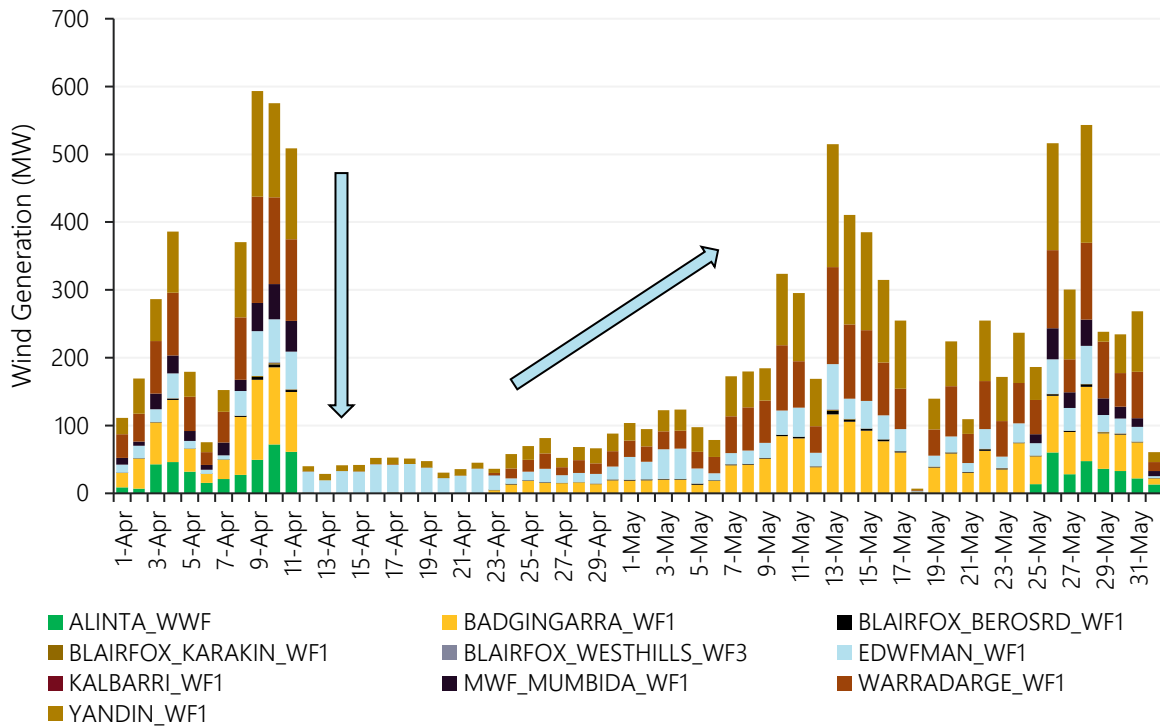
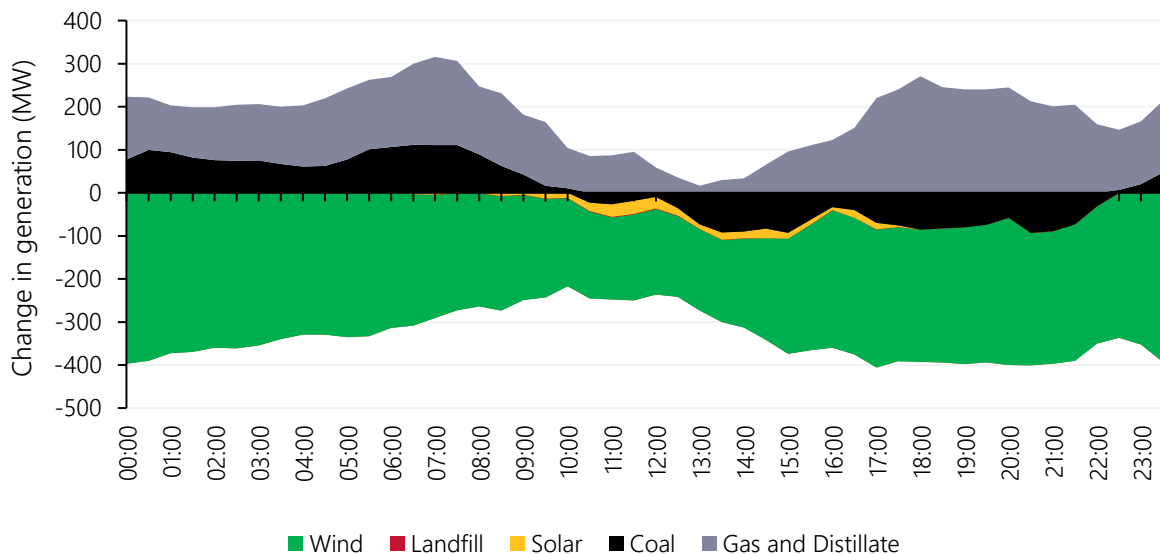


Figure 79 shows the change in fuel mix for the SWIS by time of day from the period in April 2021 before Cyclone Seroja made landfall compared to the rest of April. The islanding in the North Country contributed to a 277 MW reduction in average wind generation, which was offset by a 150 MW increase in GPG and a 19 MW increase in coal-fired generation. The remaining decrease in generation was a result of a seasonal reduction in demand associated with mild temperatures later in April.

Figure 79 Wind generation dropped 277 MW in April following Cyclone Seroja

Change in fuel mix by time of day due to Cyclone Seroja in April 2021 (post-cyclone compared to pre-cyclone)



3.4 Power System Management

3.4.1 Ancillary Services

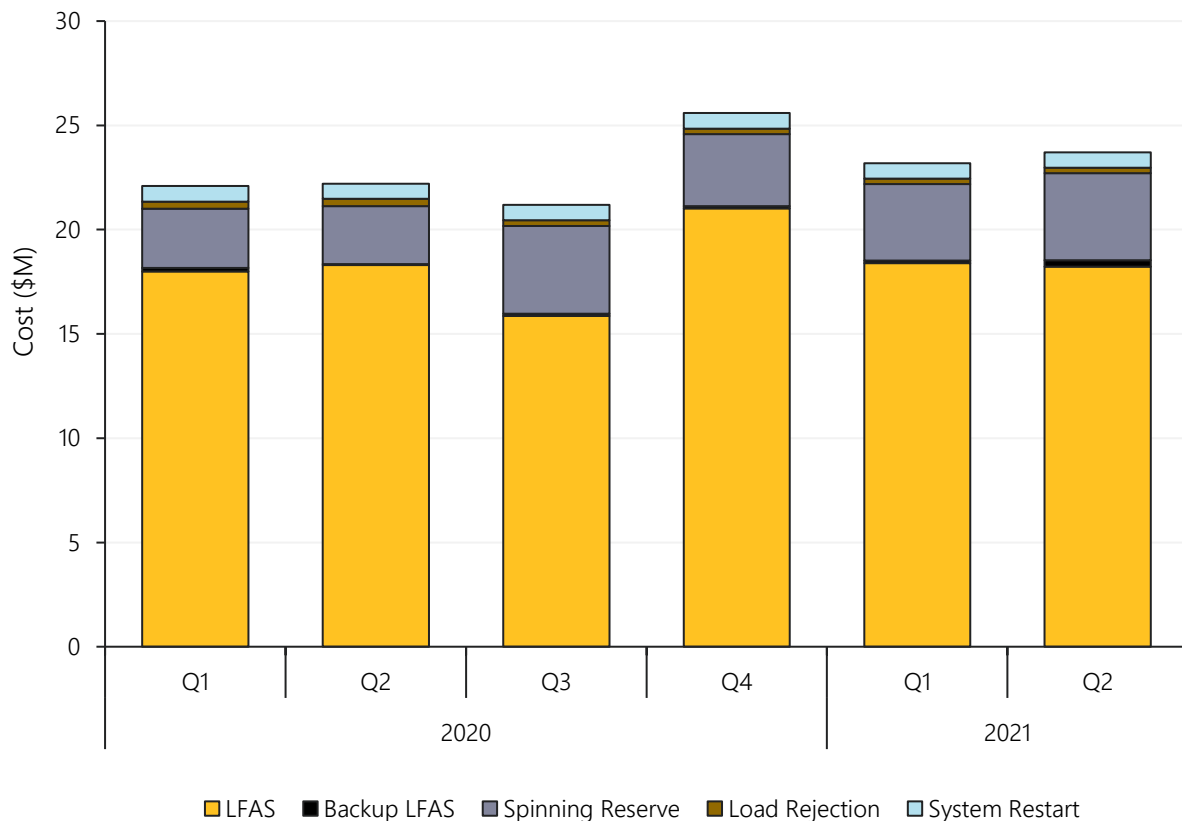
The cost of Ancillary Services⁶⁰ in Q2 2021 was an estimated \$23.7 million, compared to \$22.2 million in Q2 2020 (Figure 80). The main driver for the increase in cost was Spinning Reserve Ancillary Service (SRAS), which increased by \$1.4 million (50%). SRAS costs are primarily driven by the Margin Value review⁶¹, an administrative process that sets the price of SRAS paid to Synergy for the uncontracted portion of the SRAS requirement based on the determined Margin Values and the Balancing Price.

Quarterly Load Following Ancillary Service (LFAS) costs were \$18.2 million, similar to Q2 2020, accounting for 77% of the total Ancillary Service costs. In that time, the average LFAS Up and Down prices dropped by 31% and 14% respectively (Figure 81), counteracting the 20% increase in LFAS requirement effective from 25 September 2020⁶².

The fall in average LFAS prices follows the general trend of decreasing prices since Q2 2020, driven by increased participation in the LFAS market. Market Participants active in the LFAS market offered 13% more LFAS quantity (in MW) in Q2 2021 compared to Q2 2020.

Figure 80 Ancillary Service costs up by 7% compared to Q2 2020

Cost of ancillary services by quarter



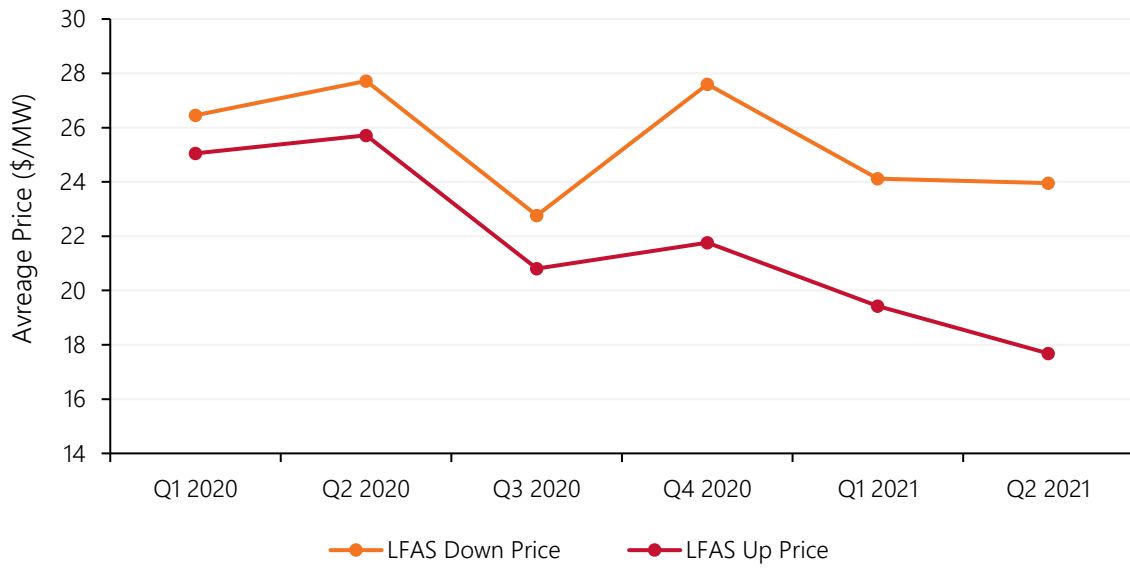
⁶⁰ Ancillary Services cost includes the cost of LFAS, Backup LFAS, Spinning Reserve, Load Rejection, and System Restart Service. The Q2 2021 cost is projected due to June 2021 NSTEM Settlement not occurring until August 2021. The projected value for June 2021 uses the average cost of each component in April and May to estimate the cost for June.

⁶¹ Each year AEMO submits a report with proposed Margin Values to the ERA who makes the final determination as per clause 3.13.3A of the WEM Rules.

⁶² The LFAS requirement was increased from 85 MW to 95 MW between 0530 hrs and 1930 hrs, and from 50 MW to 70 MW between 1930 hrs and 0530 hrs to accommodate the connection of new wind and solar generators. For more information refer to the Ancillary Services Report for the WEM 2021.

Figure 81 LFAS prices decreasing since Q2 2020

Average LFAS Down and LFAS Up Price by quarter



Abbreviations

Abbreviation	Expanded term
AEMO	Australian Energy Market Operator
ASX	Australian Securities Exchange
APLNG	Australia Pacific LNG
AWST	Australian Western Standard Time
Cal	Calendar year
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
ERA	Economic Regulation Authority
FCAS	Frequency control ancillary services
GBB	Gas Bulletin Board
GJ	Gigajoule
GLNG	Gladstone LNG
GPG	Gas-powered generation, gas-powered generator
GSH	Gas Supply Hub
HDD	Heating Degree Day
IPP	Independent Power Producer
IRSR	Inter-regional settlement residue
JKM	Japan Korea Marker
LFAS	Load Following Ancillary Services
LNG	Liquefied natural gas
LOR	Lack of Reserve
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
NEVR	National Electricity Rules

Abbreviation	Expanded term
NRM	Negative residue management
OPEC	Organisation of Petroleum Exporting Countries
PJ	Petajoule
PV	Photovoltaic
QCLNG	Queensland Curtis LNG
QNI	Queensland – New South Wales Interconnector
RBP	Roma Brisbane Pipeline
RERT	Reliability and Emergency Reserve Trader
SRA	Settlement Residue Auction
SRAS	Spinning Reserve Ancillary Service
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TNSP	Transmission Network Service Provider
TJ	Terajoule
UGS	Underground Gas Storage
VRE	Variable renewable energy
WEM	Wholesale Electricity Market