Quarterly Energy Dynamics Q4 2020

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 Q4 2020 (1 October to 31 December 2020). This quarterly report compares results for the quarter against other recent quarters, focusing on Q3 2020 and Q4 2019. 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	29 January 2021	

Executive summary

East coast electricity and gas highlights

Electricity demand falls to a new low in Q4

- Mild Q4 weather and continued strong uptake of distributed photovoltaic (PV) led to falling operational demand across the National Electricity Market (NEM). Quarterly operational demand reduced by 3% on Q4 2019 levels, declining to its lowest quarterly average since 2001.
  - During 2020, approximately 3 gigawatts (GW) of distributed PV capacity was installed Australia wide, up around 50% on the previous record in 2019[1].
- Minimum demands for South Australia and Victoria continued to fall with new minimum demand records set during the quarter.
  - On 25 December 2020, Victoria set a new minimum demand record of 2,529 megawatts (MW), 834 MW lower than 2019's minimum. Sunny, mild conditions, coupled with low Christmas demand were the key drivers of this record.
  - South Australia's new minimum demand record of 300 MW occurred on Sunday 11 October 2020 and was 158 MW lower than 2019's minimum. Notably, during this interval, total solar output in the state was equivalent to 100 per cent of South Australia's underlying demand for the first time on record, a world-first for a jurisdiction of its size[2].

Mixed results for wholesale electricity prices

- There were mixed results for electricity prices, with Queensland and New South Wales rebounding from Q3 2020 lows, while Victoria and South Australia continued to fall. South Australia's quarterly average price fell 57% to $29 per megawatt hour[3] (MWh) (with negative prices accounting for $8.7/MWh of this reduction) resulting in South Australia becoming the lowest priced region for the first time since 2012.
  - While South Australian wholesale electricity costs have fallen, there has been a trend in increasing out-of-market costs to keep the system secure. For example, in 2020 costs associated with directing South Australian gas-powered generators (GPGs) for system strength increased to $49 million (or $4/MWh), 91% higher than in 2019. This trend is expected to be curbed with the commissioning of four synchronous condensers by the middle of this year.
- New South Wales' quarterly average price of $64/MWh was at a significant premium to other regions. This was due to record low New South Wales coal-fired generation (mostly due to planned outages and reduced demand), constraints on imports from other NEM regions, and price volatility (in part resulting from an unplanned trip of a Liddell unit).

Wholesale gas prices increased for first time since beginning of 2019

- Quarterly gas prices increased in all east coast gas markets, averaging $5.90/gigajoule (GJ) compared to $4.50/GJ in Q3, reversing the downward trend which has occurred since the beginning of 2019.

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[1] Preliminary data from the Clean Energy Regulator.

[2] At the time, GPGs were also online in the region, which was necessary for system security, with excess energy exported into Victoria.

[3] Uses the time-weighted average which is the average of spot prices in the quarter and is directly comparable to the swap contract price in the wholesale market. The Australian Energy Regulator (AER) reports the volume-weighted average price which is weighted against demand in each 30 minute trading interval and is an indicator of total market costs in the quarter.

  - Domestic gas prices were influenced by increasing international oil and gas prices. Asian liquefied natural gas (LNG) prices rose steeply to finish the year at multi year highs of A$17.6/GJ, due to a colder than usual northern hemisphere winter, train outages at several key LNG facilities, and shipping disruptions.
- East coast gas demand was 2% higher than Q4 2019, solely due to increased Queensland LNG demand, with quarterly flow to Curtis Island increasing by 20 petajoules (PJ) to reach record quarterly levels.
  - GPG demand decreased by 11 PJ (-29%) compared to Q4 2019, with reductions in all states except Queensland resulting in the lowest Q4 GPG demand since 2005.
- While east coast electricity and gas market outcomes have been highly correlated in recent years, they diverged in the second half of 2020, with gas prices increasing but electricity prices remaining low.

Other highlights include

- Record high wind and solar output, coupled with near record low operational demand, resulted in significant displacement of thermal generation and the lowest NEM emissions on record, with a 7% decline on Q4 2019 levels.
- After reaching capacity on 12 September 2020, Dandenong LNG storage levels fell to 443 terajoules (TJ) on 31 December, its lowest level outside of winter since the beginning of the Declared Wholesale Gas Market (DWGM) in 1999 and the lowest overall since winter 2007. The decrease was driven by lower contracted levels, with the Gas Bulletin Board (GBB) uncontracted capacity outlook indicating that this will continue to fall.
- Unit upgrades were completed at Mount Piper and Loy Yang B power stations, increasing coal-fired capacity by a combined 75 MW.

Western Australia electricity and gas highlights

Record minimum demand in the WEM

- A new record minimum demand was set at 1300 hrs (AWST) on Saturday, 28 November 2020 when operational demand was 985 MW and output from distributed PV was estimated to be 1,189 MW.

Fuel mix transformation continues in the WEM

- Due to the connection of three new wind and solar farms during 2020 (capacity increase: solar +100 MW, wind +392 MW) and increased distributed PV capacity, variable renewable energy (VRE, including distributed PV) contributed 35.3% of total generation in Q4 2020.
  - This led to a decline in average coal-fired generation (186 MW) and GPG (89 MW) compared to Q4 2019. On average, one fewer coal-fired facility was online compared to Q4 2019.
- The quarterly average Balancing Price decreased to $41.66/MWh, a 13% decrease relative to Q3 2020, largely due to increased VRE output. This was the lowest quarterly average Balancing Price since Q2 2015, with a significant increase in negative and low-price intervals.

Stable gas production in WA with a shift in producers

- WA gas production overall was relatively flat, however, there was a shift in production compared to Q4 2019 from Karratha Gas Plant, which reduced output by 87%, to Varanus Island, Devil Creek and Macedon (which increased output by 39%, 4% and 12% respectively).

Contents

1. NEM market dynamics

1.1 Weather

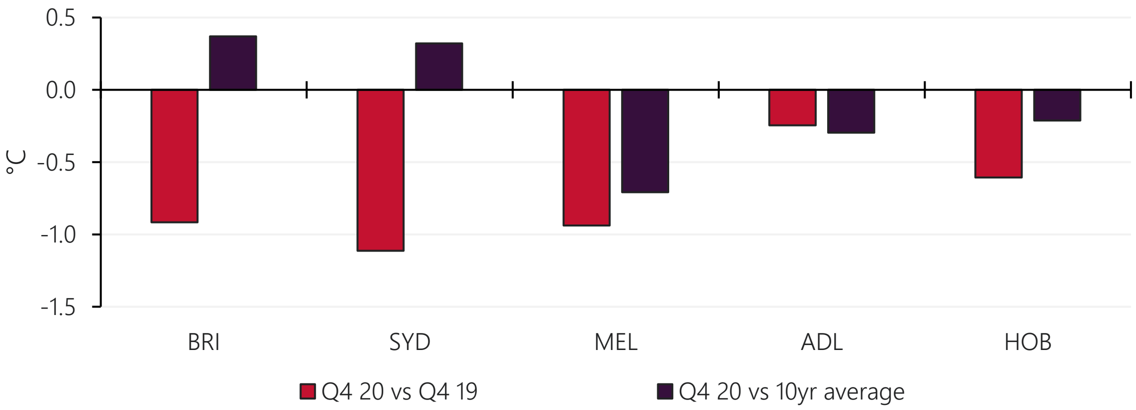
2020 was Australia's fourth-warmest year on record, with annual national mean temperatures 1.15°C above average[4]. Following Australia's driest year on record in 2019, overall rainfall in 2020 was close to the average as La Niña became more established towards the end of the year.

During the quarter, Melbourne and Adelaide's average maximum temperatures were 0.7°C and 0.3°C below the 10-year average (Figure 1), resulting in significant reductions in cooling requirements (Figure 2). There was also no repeat of the heatwave that occurred across several states in December 2019.

During the quarter, all regions apart from south-eastern Queensland and southern Tasmania recorded above average rainfall, largely driven by heavy rainfalls in October and December[5].

Figure 1 Mild Q4 conditions across all capital cities

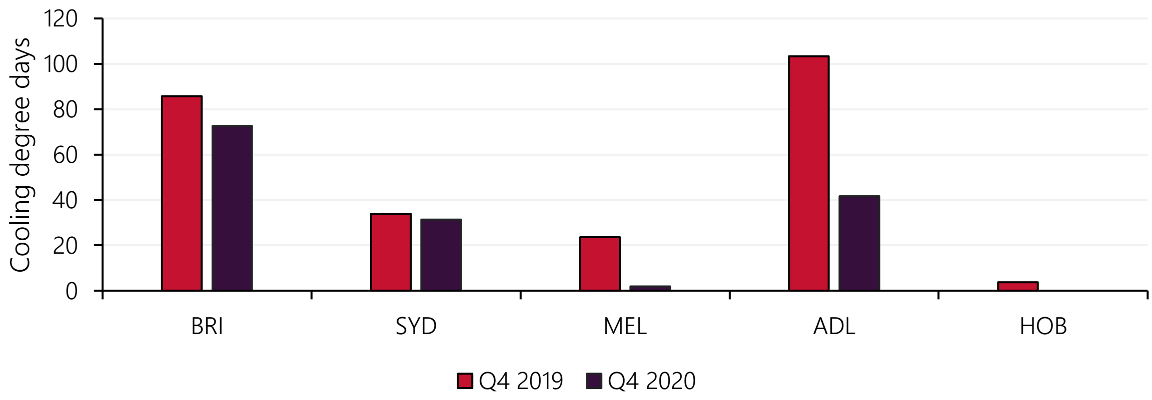
Average maximum temperature variance by capital city – Q4 2020 vs 10-year Q4 average



Source: Bureau of Meteorology

Figure 2 Reduced cooling requirements across all capital cities

Cooling degree days[6] – Q4 2020 versus Q4 2019



[4] Bureau of Meteorology 2020, Annual climate statement 2020: http://www.bom.gov.au/climate/current/annual/aus/2020/

[5] Bureau of Meteorology 2020, Australia in December 2020: http://www.bom.gov.au/climate/current/month/aus/archive/202012.summary.shtml

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

1.2 Electricity demand

NEM quarterly average operational demand was 20,341 megawatts (MW), its lowest quarterly average since 2001 and 620 MW lower than Q4 2019 (-3%, Figure 3). This was a function of:

- **Increased distributed photovoltaic (PV)** – record uptake of distributed PV capacity in 2020 (approximately 3 gigawatts [GW] nationally) drove record high distributed PV[7] output – increasing by an average of 337 MW on Q4 2019 levels – which continued to erode midday demand (Figure 4). The largest increases in distributed PV output occurred in New South Wales (124 MW on average) and Queensland (100 MW on average).
- **Mild weather** – reduced average underlying demand (-283 MW) was mostly driven by lower daytime cooling requirements, particularly in December with a mild start to summer on the east coast (Section 1.1).
  - With Victorian stage 4 COVID-19 restriction lifted on 28 October 2020, COVID-19 did not materially impact demand outcomes this quarter.
  - On a proportional basis, South Australia and Victoria recorded the largest reduction in underlying demand at 3.3% and 2.8%, respectively. South Australia's quarterly average operational demand of 1,213 MW represents its lowest quarterly average since NEM start.
- **Shoulder season** – Q4 is typically the lowest demand quarter of the year spanning the shoulder season months of October and November.

Figure 3 NEM demand reduced to the lowest quarterly average since 2001

Average NEM operational demand (Q4s)[8]

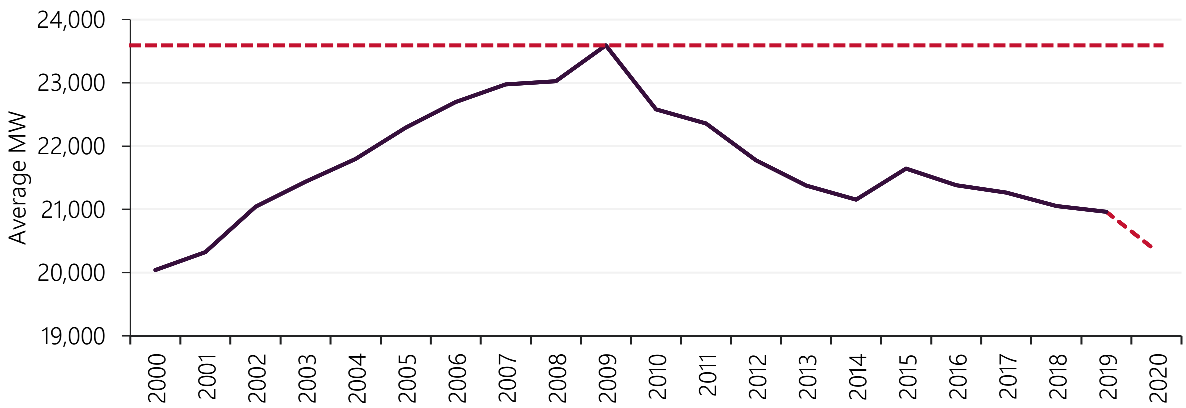
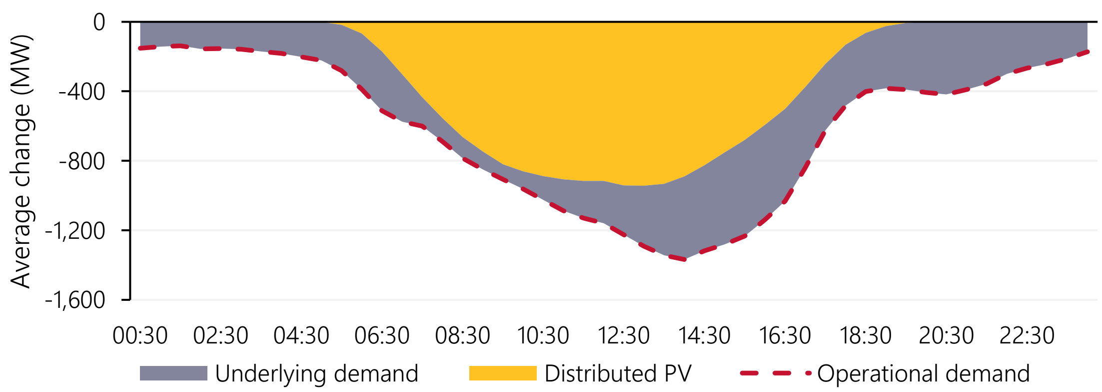


Figure 4 Mild Q4 conditions and increased distributed PV reduced demand across the day

Change in NEM-average operational demand by time of day (Q4 2020 versus Q4 2019)



[7] Increased distributed PV generation results in reduced operational demand because distributed PV is behind the meter.

[8] NEM operational demand for Q4 2000 and 2001 includes estimates for Tasmania.

Maximum and minimum demand

Minimum demands for South Australia and Victoria continued to trend downwards, with new minimum operational demand records set during the quarter (Figure 5 and Figure 6).

Victoria's minimum demand trended downwards rapidly this quarter; its minimum record was beaten on three separate occasions. On Friday 25 December 2020, Victoria set a new minimum demand record of 2,529 MW at 1300 hrs, 834 MW lower than 2019's minimum. Sunny, mild conditions, coupled with low underlying demand associated with Christmas, were the key drivers of the record. During this interval, distributed PV contributed to an estimated 1,653 MW of output (40% of underlying demand).

Figure 5 New minimum record in Victoria

Minimum demand records – 2012 to 2020

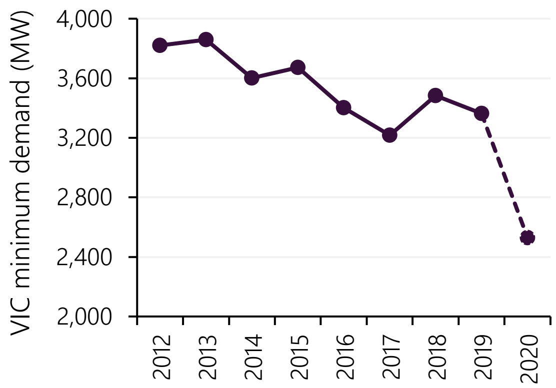
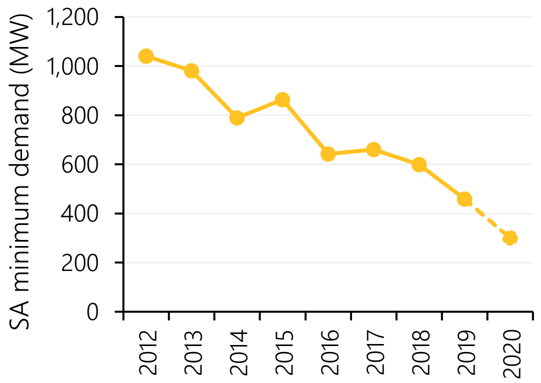


Figure 6 New minimum record in South Australia

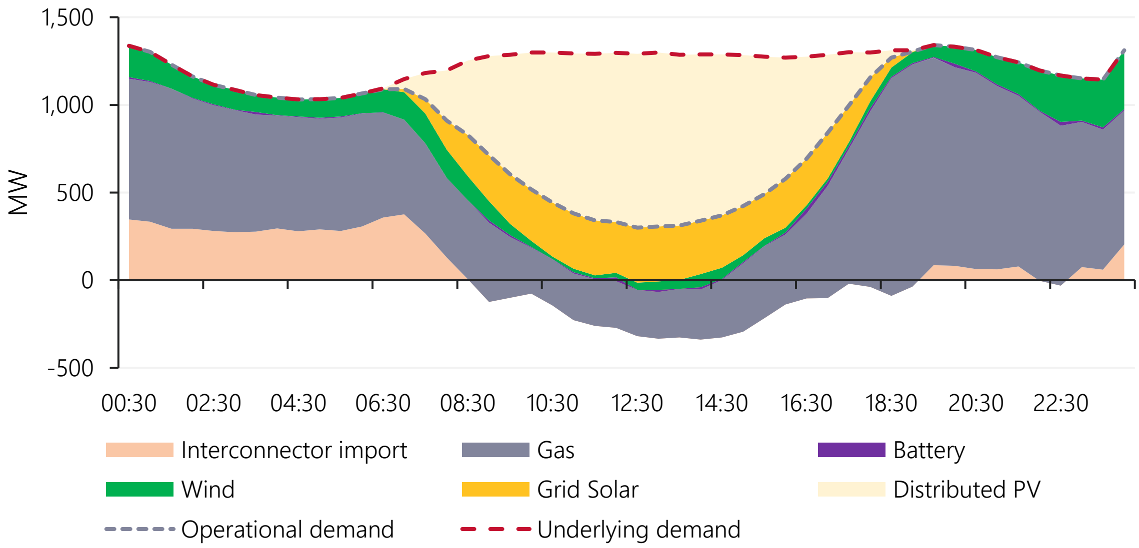
Minimum demand records – 2012 to 2020



South Australia's new minimum demand record of 300 MW occurred at 1230 hrs on Sunday 11 October 2020 and was 158 MW lower than 2019's minimum. Key drivers include low underlying demand associated with the weekend as well as sunny conditions, with distributed PV providing an estimated 992 MW of output (77% of underlying demand). Notably, during this interval, total solar output (distributed PV and grid-solar) in the state was equivalent to 100% of South Australia's underlying demand for the first time on record; this was also a world-first for a jurisdiction of its size (Figure 7)[9]. At the time, gas-powered generators (GPGs) were also online in the region, which was necessary for system security, with excess energy exported into Victoria.

Figure 7 SA solar (grid and distributed) meets 100% of South Australia's demand for the first time

South Australia operational demand by time of day – 11 October 2020



[9] Further details on the event can be found at: https://aemo.com.au/en/newsroom/media-release/solar-power-fuels-south-australias-total-energy-demand.

1.3 Wholesale electricity prices

There were mixed results for wholesale electricity prices compared to recent quarters, with Queensland and New South Wales rebounding from Q3 2020 lows, while Victoria and South Australia continued to fall (Figure 8). Key outcomes included:

- **South Australia supplants Queensland as the lowest-priced region** – compared to Q4 2019, South Australia's quarterly average price fell 57% to $29/MWh, representing its lowest average since Q2 2012. Continued price reductions in the region were largely a function of its lowest quarterly average demand on record, and increased wind and solar output in Victoria and South Australia (328 MW on average).
- **Higher prices in New South Wales** – New South Wales' quarterly average price of $64/MWh was at a significant premium to other regions – 71% higher than Victoria and 42% higher than Queensland. High New South Wales prices were due to record low local coal-fired generation (Section 1.4.1), constraints on imports from other NEM regions (Section 1.5), and price volatility (Section 1.3.1).
- **Wholesale electricity and gas price outcomes** – as shown in Figure 9 (for South Australia) a notable outcome this quarter was the divergence of electricity and gas prices. In recent years there has been a strong correlation between prices in these markets. However, since mid-2020 gas prices have been increasing, while electricity prices have remained low. Drivers of the divergence over this period included:
  - Falling electricity demand and renewables growth, coupled with near record low GPG, resulting in gas prices having reduced prominence in electricity price outcomes.
  - Gas prices being strongly influenced by international LNG and oil markets (Section 2.2).

Figure 8 North-South spot electricity price divergence in Q4

Average spot electricity prices by mainland NEM region

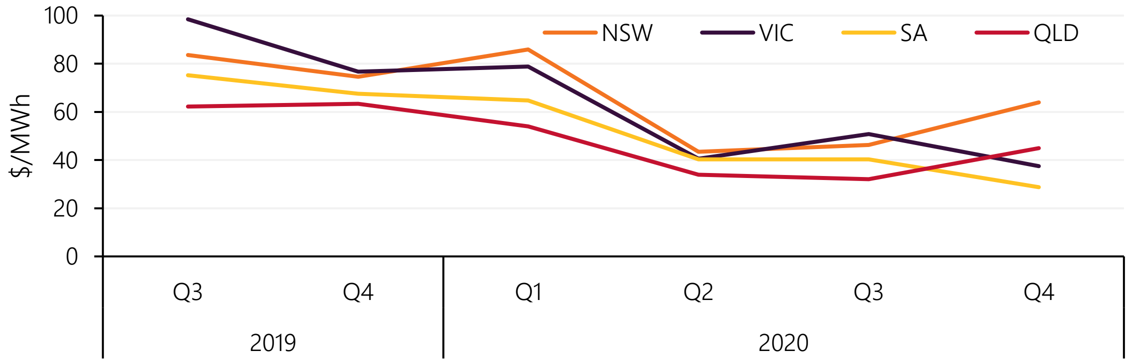
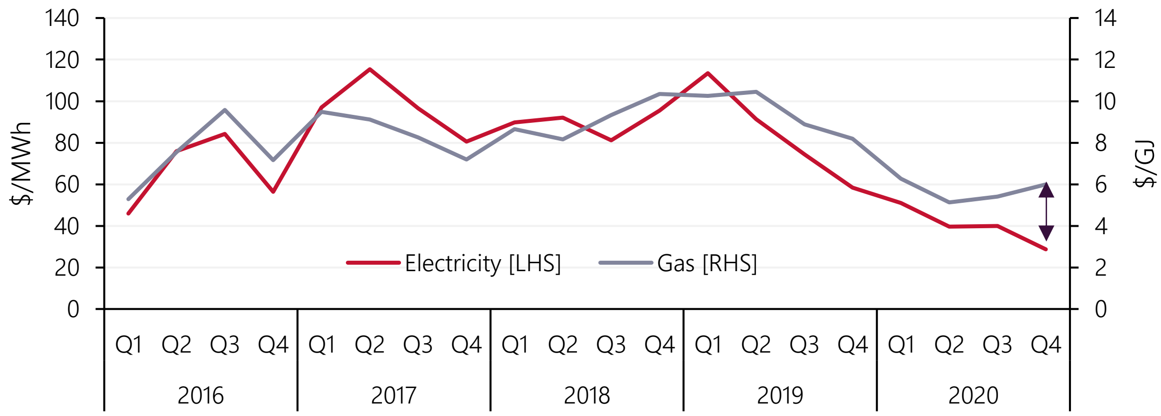


Figure 9 Electricity and gas prices diverge[10]

Average spot electricity and gas prices – South Australia



[10] To remove the impact of electricity price volatility, trading interval prices capped at $300/MWh to prepare this chart.

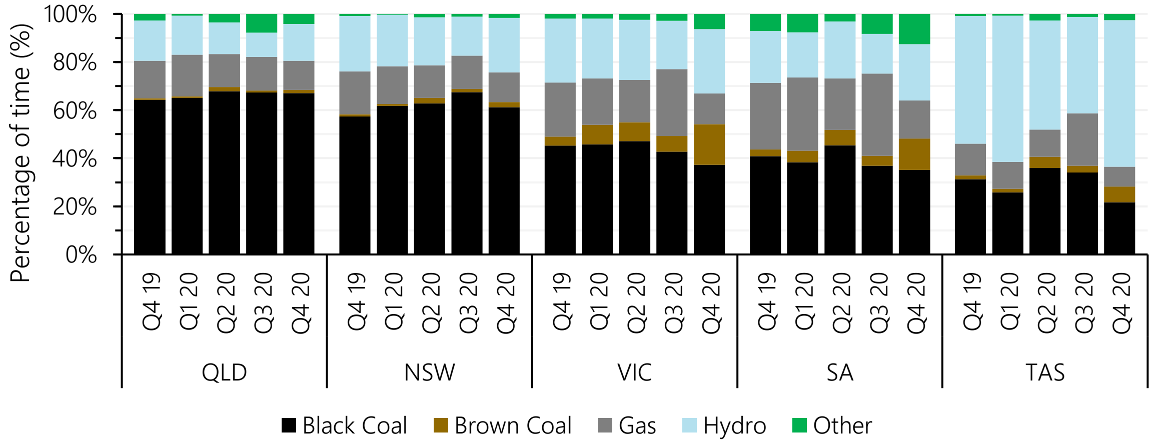
1.3.1 Price-setting dynamics

Figure 10 shows price setting results for Q4 2020 compared to recent quarters. Key outcomes included:

- **GPG's** price setting role across the NEM regions declined from an average 19% in Q4 2019 to 12% this quarter, its lowest quarterly level since Q2 2015. Drivers included low GPG output, and the shift in GPG to higher priced offers. Notably, in South Australia GPG price setting role has declined from 35% of the time in Q4 2017 to 16% of the time this quarter.
- **Brown coal** increased its NEM average price setting role to 8% of the time, up from 2% in Q4 2019, as spot prices reduced to levels in which brown coal-fired generation was the marginal unit (typically $0-$20/MWh).
- **Grid-scale wind and solar** continued to set the spot price more frequently at 4% of the time (combined), the highest level on record. In South Australia, wind set the spot price for 8% of the quarter at an average of minus $75/MWh, predominantly between 0900 and 1500 hrs (Figure 11).
  - Dynamic bidding from wind and solar farms resulted in them setting the spot price at a wider range than they have historically (typically confined to negative or zero). For example, on two separate occasions during the quarter, rebids by Cattle Hill and Musselroe wind farms in response to high Contingency Raise frequency control ancillary service (FCAS) prices led them to set Tasmania's price at the Market Price Cap of $15,000/MWh.

Figure 10 Lowest gas price setting role since Q2 2015

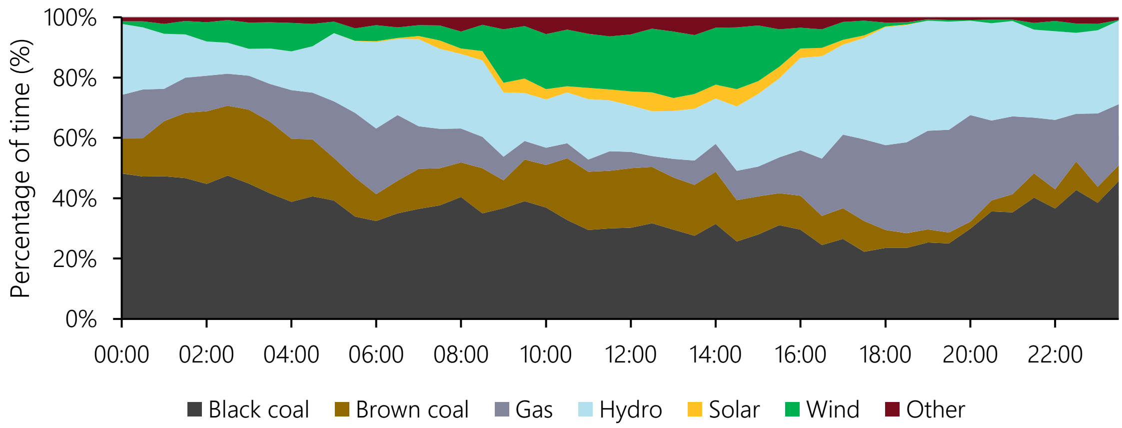
Price-setting by fuel type – Q4 2020 versus prior quarters



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

Figure 11 Wind farms set South Australia's spot price 8% of the time

South Australia price setting by fuel type and time of day – Q4 2020

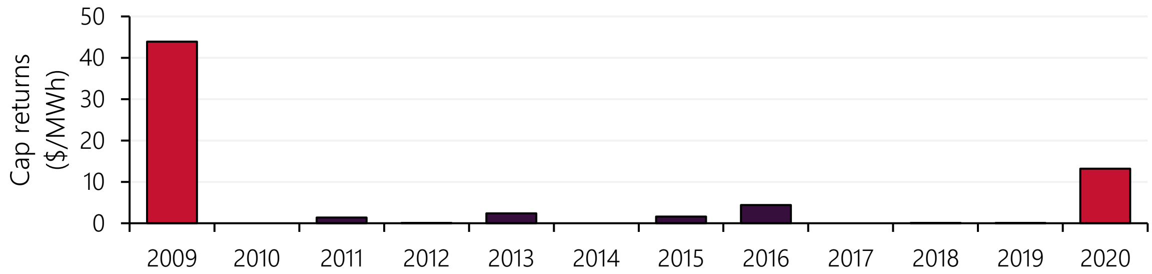


1.3.2 Wholesale electricity price volatility

During Q4 2020, price volatility results were mixed across the NEM regions, with few periods of very high prices in the southern states, but increased volatility in New South Wales and Queensland. In particular, New South Wales' quarterly average cap returns of $13/MWh represents its highest Q4 level since 2009. Queensland cap returns increased from $0.02/MWh in Q4 2019 to $2.4/MWh this quarter.

Figure 12 High levels of price volatility in New South Wales

New South Wales quarterly average cap returns (Q4s)

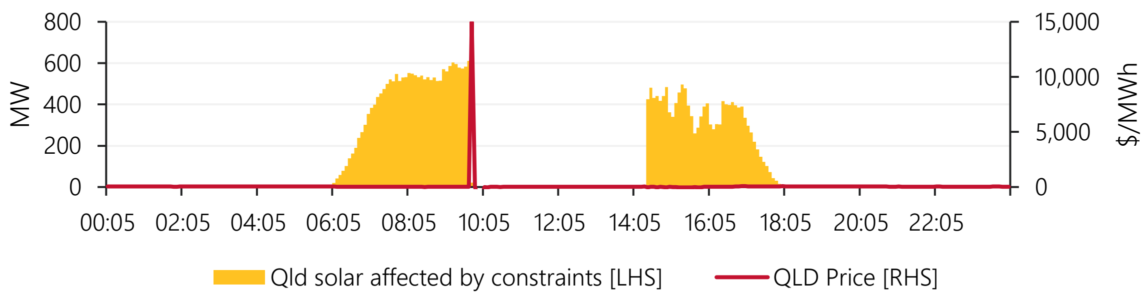


Transmission line outages, generator trips and constraints contributed to the price volatility in New South Wales and Queensland this quarter. Key events included[11]:

- **New South Wales 16 November 2020** – an unplanned outage at Upper Tumut – Stockdill 330 kilovolt (kV) line caused restricted flows into Sydney and led to price volatility, with dispatch prices spiking to $15,000/MWh for 15 minutes.
  - This event also led to price volatility in other regions; Queensland dispatch prices spiked close to market price cap (MPC) for five minutes while Victorian prices fell to market floor price (MFP) due to the line outage forcing excess generation in southern New South Wales into Victoria.
- **New South Wales 17 December 2020** – warm Sydney temperatures, black coal-fired units on outage (3,045 MW – mostly planned outages), an unplanned Liddell unit trip (Section 1.4.1), and restricted imports from Victoria resulted in tight supply/demand conditions:
  - AEMO activated Reliability and Emergency Reserve Trader (RERT) in New South Wales due to forecast lack of reserve 2 (LOR2) conditions (Section 1.6).
  - Dispatch prices in New South Wales spiked above $14,000/MWh for 55 minutes.
- **Queensland 13 October 2020** – North Queensland system strength constraints contributed to price volatility, with the price spiking to $15,000/MWh for one dispatch interval due to a sudden output reduction of 590 MW across nine solar farms when the constraints were invoked (Figure 13)[12].

Figure 13 Queensland spot price spike to $15,000/MWh due in part to system strength constraints

Queensland solar (constrained solar farms only) generation and spot prices – 13 October 2020



[11] The Australian Energy Regulator (AER) published $5000/MWh reports which analyse the cause of these events in more details. AER $5000/MWh reports.

[12] Since this event, the North Queensland System Strength Constraints have changed. See: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/nqld-system-strength-constraints.pdf?la=en.

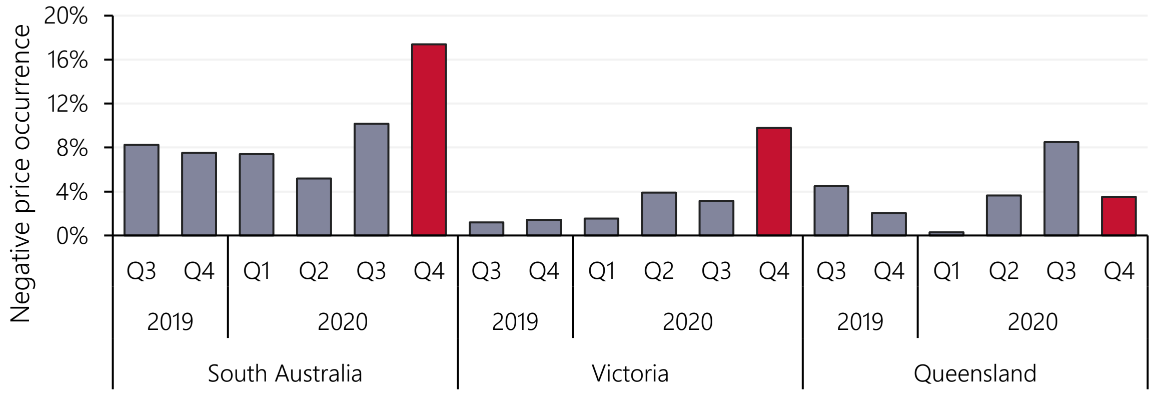
1.3.3 Negative wholesale electricity prices

During Q4 2020, negative and zero spot prices[13] occurred in 7% of all trading intervals, surpassing the previous record set in Q3 2020 (4.6%), with calendar year 2020 averaging 4.4% compared to 1.7% in 2019. Negative spot prices were most prevalent in South Australia and Victoria, with both states reaching record quarterly levels. South Australia's spot prices were negative 17% of the time during Q4 2020, exceeding the previous quarterly of 10%, while Victoria reached a new record of 10%.

Despite the record occurrence of negative spot prices, the impact on the quarterly average prices was limited. Negative prices cut South Australia's average by $8.7/MWh, while the impact was less in Victoria ($2.4/MWh) and Queensland ($0.9/MWh) due to fewer very low prices below minus $100/MWh.

Figure 14 Negative spot prices hit record levels in South Australia and Victoria

Quarterly negative price percentage occurrence



Key drivers of the increase in negative prices in South Australia and Victoria included:

- **Low operational demand** – driven by mild conditions and high distributed PV output. In Q4 2020, combined Victorian and South Australian operational demand dropped below 5,000 MW 16% of the time, compared to 7% of the time in Q4 2019.
- **High variable renewable energy (VRE) output** – largely driven by new capacity installed in Victoria. In Q4 2020, combined Victorian and South Australian VRE output was above 2,500 MW 20% of the time, compared to 9% in Q4 2019.
- **Interconnector constraints** – transmission line outages contributed to reduced interconnector limits, resulting in periods of oversupply and negative prices. The quarterly average export limit for Victoria to New South Wales transfers was 185 MW below its two-year average, while the average export limit from South Australia to Victoria transfers on Heywood was down 33 MW on the two-year average (Section 1.5).

Generators' response to negative prices

The large increase in negative spot prices in South Australia and Victoria led to a variety of bidding responses from generators in those regions:

- **Brown coal** – with the increase of low or negative spot prices, Loy Yang A units responded by shifting marginal capacity to higher price bands (from around $10/MWh to $35/MWh). This resulted in increased operational flexibility, ramping down overnight and in the middle of the day (Figure 15).
- **South Australian GPGs** – as negative spot price occurrences in South Australia continued to trend upwards, GPGs more frequently sought to de-commit from the market for economic reasons, resulting in AEMO needing to direct them to stay on and leading to a record for system strength directions (Section 1.6.3).

[13] Hereafter referred to as negative spot prices.

- **Victorian wind and solar farms** – with Victorian negative spot prices occurring at record levels this quarter, the price responsiveness of wind and solar farms in the region increased, with some participants raising their offer price to ensure they were not dispatched during negative prices (classified as 'economic curtailment', Section 1.6.2). As shown in Figure 16 this behaviour was most prevalent in newly commissioned projects. During the quarter, 8 of 21 semi-scheduled projects in the region demonstrated re-bidding in response to negative prices, with five of those projects being recently commissioned.

Figure 15 Loy Yang A's flexible operation

LYA average generation by time of day – Q4 2020 versus Q4 2019

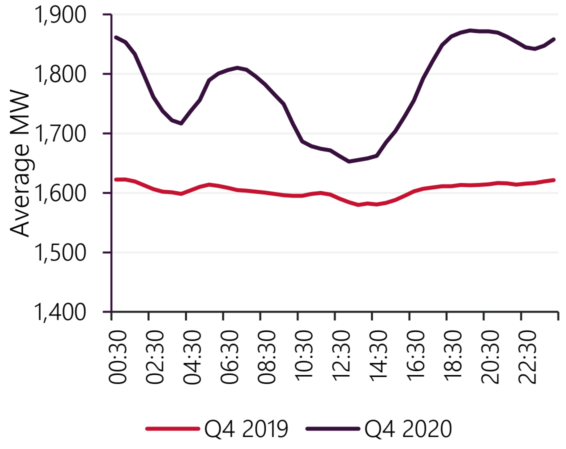
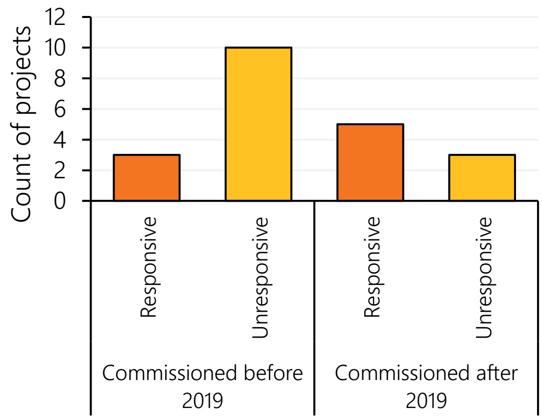


Figure 16 Newer Victorian wind and solar farms more responsive to negative spot prices

Number of Victorian projects responding to negative spot prices in Q4 2020

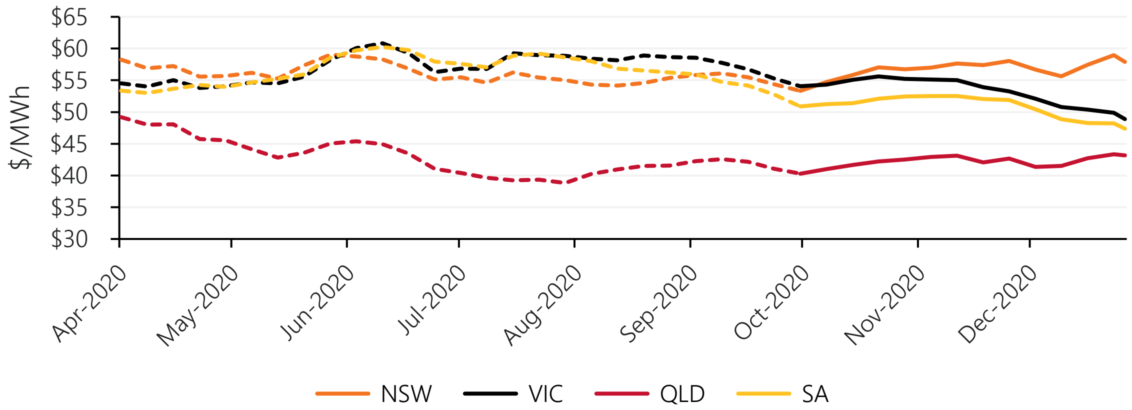


1.3.4 Electricity future markets

During Q4 2020, ASX calendar year (Cal) 2021 swap contracts prices in Victoria and South Australia declined $4.6/MWh from the end of Q3 2020 to finish 2020 at $48/MWh on average. These futures prices reductions coincided with continued spot prices declines and record negative prices in those regions. New South Wales finished 2020 as the highest priced state at $58/MWh, an increase of $4.3/MWh from end of Q3 2020, influenced by Q4 price volatility and the outage at Liddell.

Figure 17 Futures prices up in New South Wales, but down in Victoria and South Australia

ASX Energy – Cal21 swap prices by region – 7-day averages



During the quarter, there were mixed results for prices of Q1 2021 caps:

- Victoria and South Australia declined from an average of $34/MWh in mid-November to end the quarter at $25/MWh, coinciding with low Q4 spot prices.
- New South Wales increased by $4/MWh in late December following an unplanned unit trip at Liddell and resulting price volatility in the region.

1.4 Electricity generation

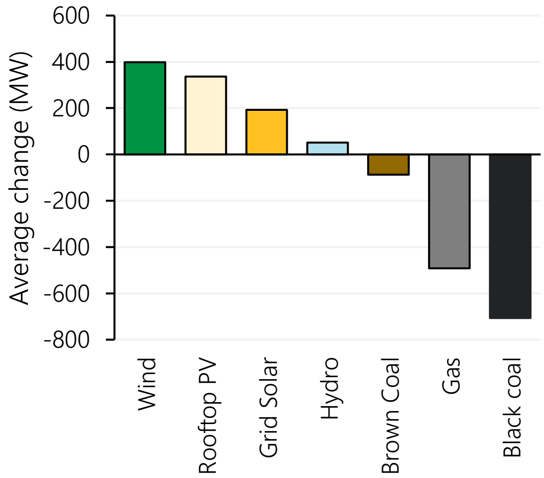
During Q4 2020, increased coal-fired generator outages, coupled with low operational demand, and increased VRE shaped the NEM supply mix. Figure 18 shows the average change in generation by fuel type compared to Q4 2019, and Figure 19 illustrates the change by time of day.

Key outcomes included:

- Average black coal-fired generation decreased by 707 MW on Q4 2019, reaching its lowest level since Q4 2014. The decline in generation occurred mainly in New South Wales which fell to its lowest quarterly average on record; a function of increased outages – including for unit upgrades – low operational demand, and displacement by VRE.
  - Unit upgrades were completed at Mount Piper and Loy Yang B power stations, increasing coal-fired capacity by a combined 75 MW.

Figure 18 Large reductions in thermal generation

Change in supply – Q4 2020 versus Q4 2019



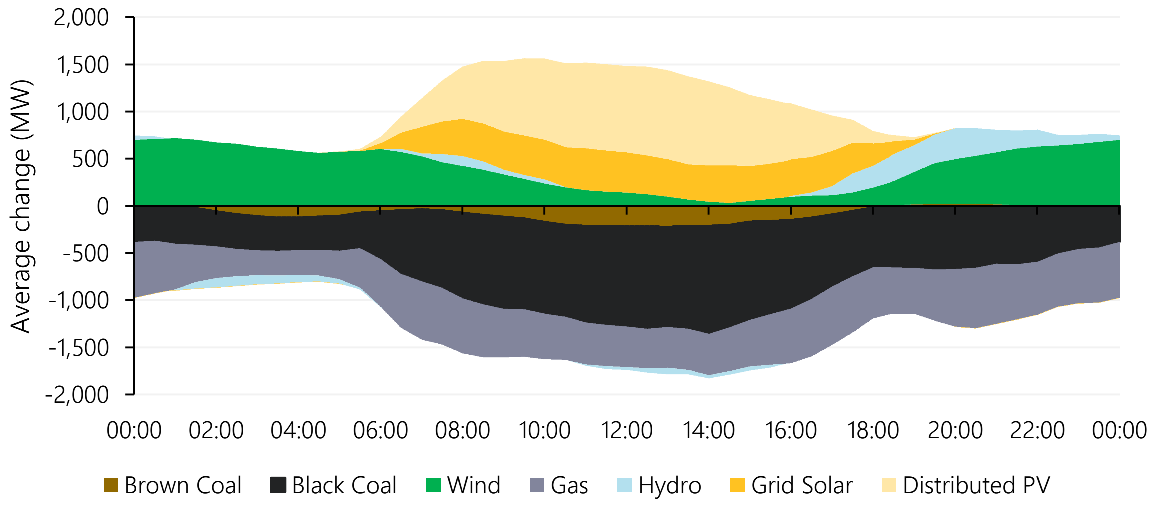
- GPG output decreased to its lowest Q4 output since 2005, mainly due to lower operational demand and displacement by VRE and hydro.
- As recently installed VRE projects continue to ramp up, average quarterly VRE output reached another record high of 3,459 MW, surpassing the previous record set in Q3 2020 by 306 MW. VRE accounted for 17% of the supply mix, up from 13.5% in Q4 2019 (Table 1).

Table 1 NEM supply mix by fuel type

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar
Q4 2019	53.8%	17.6%	8.5%	6.3%	9.6%	3.9%
Q4 2020	52.1%	17.8%	6.4%	6.8%	11.9%	4.9%
Change	-1.7%	0.1%	-2.1%	0.5%	2.2%	1.1%

Figure 19 Thermal generation reduced across the day while VRE output increased

Change in supply – Q4 2020 versus Q4 2019 by time of day



1.4.1 Coal-fired generation

Black coal fleet

During Q4 2020, average black coal-fired generation was 10,710 MW, its lowest quarterly output since Q4 2014 and 707 MW lower than Q4 2019. Average New South Wales black coal-fired output reduced to 5,249 MW, its lowest level since NEM start (Figure 20). Record low output was predominantly driven by a significant increase in outages (mostly planned) (Figure 21), with reduced operational demand and increased grid-scale solar also contributing.

Key changes by station, compared to Q4 2019:

- Increased outages (mostly planned) at Liddell Power Station reduced output by 521 MW, its lowest Q4 output since 2012. Of note, a transformer incident at Unit 3 on 17 December resulted in the unit being taken out of service for the remainder of the quarter. AGL announced that the length of outage may be up to two and half months[14].
- Despite Mount Piper Power Station Unit 1 being out of service for most of the quarter (mostly planned) for a unit upgrade, average output at the power station increased by 116 MW, reflecting higher availability at Unit 2 compared to Q4 2019 which was impacted by coal supply issues. The unit upgrade was completed during the quarter, increasing Unit 1's capacity from 700 MW to 730 MW.

Figure 20 New South Wales black coal-fired generation reduced to lowest quarterly output since NEM start

Average New South Wales black coal-fired generation – Q4s

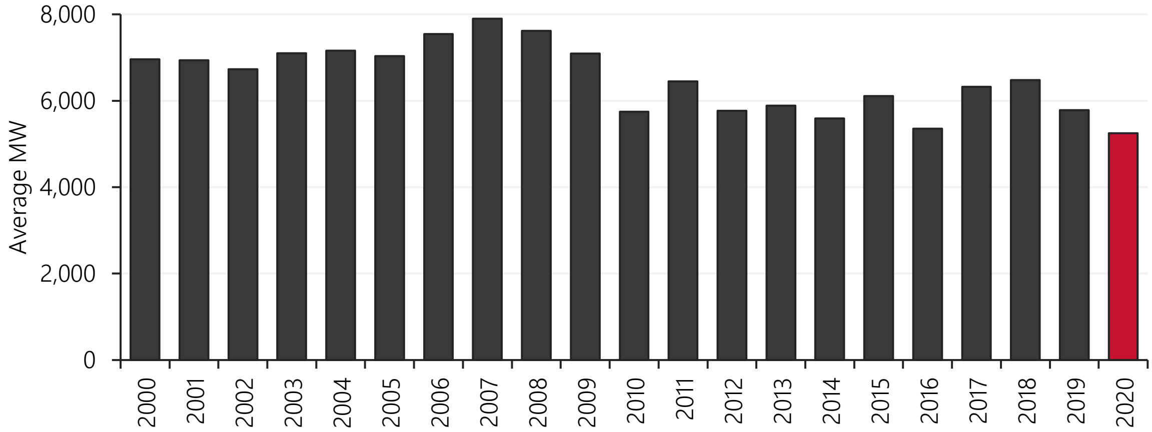
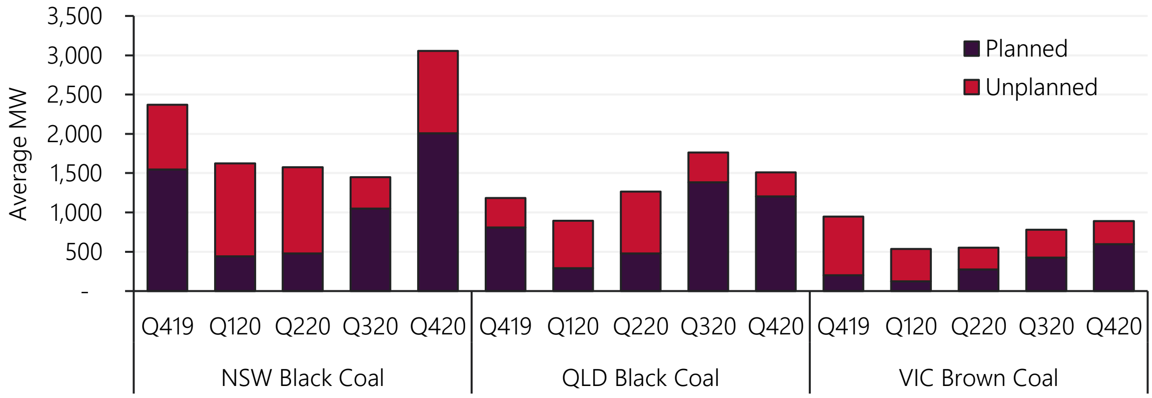


Figure 21 Significant increase in outages from New South Wales fleet

Average black and brown coal-fired generation on outage by classification – Q4 2019 to Q4 2020



[14] AGL 2020, Liddell Incident: https://www.agl.com.au/about-agl/media-centre/asx-and-media-releases/2020/december/liddell-incident.

In Queensland, increased unit outages, coupled with displacement by distributed PV, reduced average black coal-fired generation by 169 MW. By station:

- A planned outage at Tarong North Power Station from late October[15] to replace old economisers reduced average output by 288 MW. The unit returned to service on 3 January 2021.
- Increased outages at Gladstone Power Station reduced average output by 236 MW.

Brown coal fleet

Despite a small increase in availability, average brown coal-fired generation decreased by 87 MW compared to Q4 2019, due to displacement by VRE and lower operational demand, which reduced brown coal-fired unit utilisation[16] from 99% to 95%. Reduced output from Loy Yang B (-182 MW) and Yallourn (-78 MW) was partially offset by increased output at Loy Yang A (+173 MW), which increased due to higher availability (Unit 2 was on an outage for all of Q4 2019). Notably, Loy Yang B Unit 1 was on an extended planned outage as part of a major upgrade which was completed in November 2020. The latest upgrade brings the unit's capacity in line with Unit 2 (which was upgraded in Q2 2019), increasing its capacity from 535 MW to 580 MW.

1.4.2 Hydro

Hydro generation averaged 1,394 MW during the quarter, increasing by 51 MW compared to Q4 2019, with increases in all states except Tasmania (Figure 22). On a regional basis:

- In Victoria, Murray was the main contributor to the state's 89 MW increase compared to Q4 2019, with Snowy bidding Murray to generate at high levels during specific coal-fired generator outages.
- New South Wales reached its highest Q4 average since 2016, as Snowy's Lake Eucumbene dam levels moved to the highest year end level since 2017 (37%), and its hydro assets bid to generate at high levels during specific coal-fired generator outages.
- In Tasmania, hydro generation declined to its lowest Q4 average since 2015, 149 MW lower than Q4 2019, resulting in net imports of 153 MW from Victoria. Drivers of reduced hydro output included dry conditions and low dam levels (Figure 23), as well as lower Victorian wholesale electricity prices (which increases the incentive for Tasmania to import from Victoria).

Figure 22 Tasmanian reduction continues

Change in average hydro generation - Q4 2020 vs Q4 2019

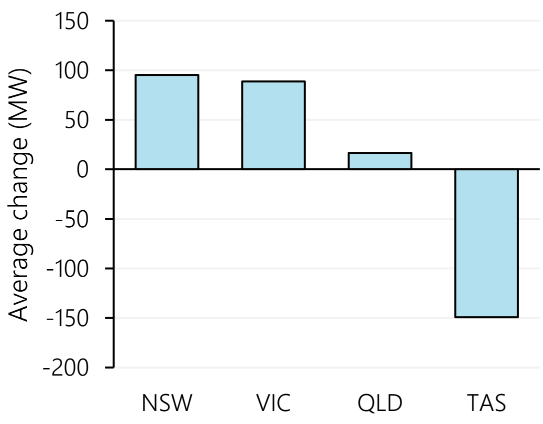
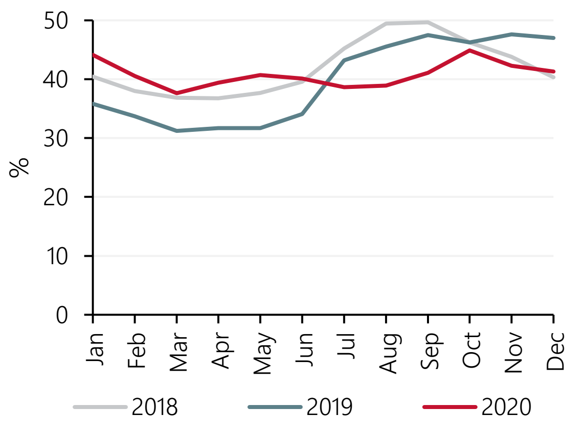


Figure 23 Tasmania storage levels remain low

Monthly Tasmanian water storage levels[17]



[15] Stanwell 2020, Preparations are underway for the Tarong North Power Station outage: https://www.stanwell.com/our-news/news/preparations-are-underway-for-the-tarong-north-power-station-outage/.

[16] Ratio of output divided by availability.

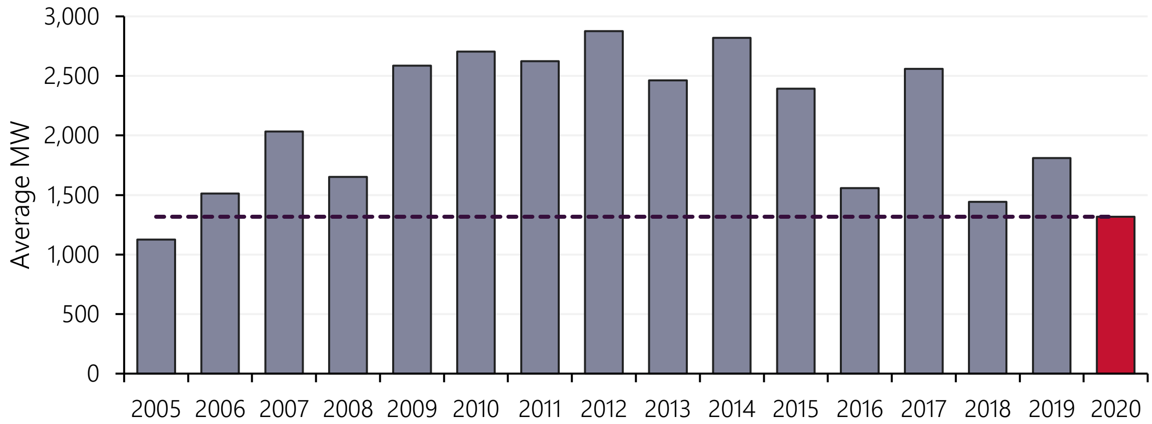
[17] Hydro Tas 2020, Energy Storage Historical Data: https://www.hydro.com.au/water.

1.4.3 Gas-powered generation

Quarterly average NEM GPG decreased to 1,317 MW, representing its lowest Q4 level since 2005 (Figure 24). Key drivers of this reduction included very low operational demand (Section 1.2), record high VRE generation (Section 1.4.4) and reduced requirement to cover for specific coal-fired generator unit outages (Loy Yang A, Eraring, and Mount Piper).

Figure 24 Lowest Q4 GPG average since 2005

Average NEM GPG generation – Q4s

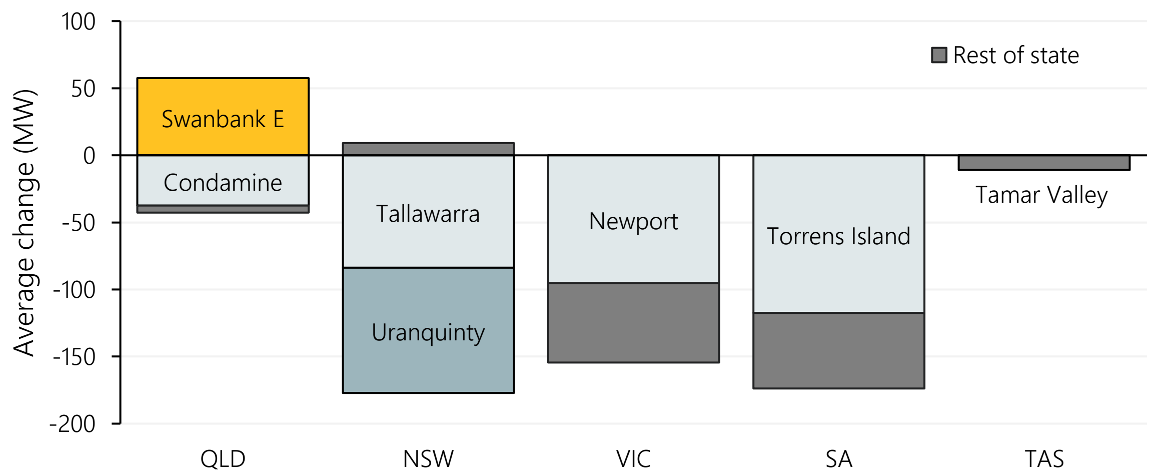


Key regional changes compared to Q4 2019 included (Figure 25):

- New South Wales decreased by 168 MW on average, driven by portfolio dynamics. Increased output at Origin's Eraring Power Station and EnergyAustralia's Mount Piper Power Station meant there was a reduced need for Origin to run Uranquinty (-93 MW) and EnergyAustralia to run Tallawarra (-84 MW).
- Victoria declined 154 MW to an average of 84 MW during the quarter, its lowest state average since Q4 2016, led by Newport's 95 MW decline, with few unplanned outages of brown coal-fired generators.
- South Australia declined 174 MW to an average of 499 MW, its lowest average since Q4 2016. The largest reduction occurred at Torrens Island Power Station (-117 MW), with two Torrens Island A units decommissioned in September 2020[18] and planned outages.

Figure 25 Large GPG reductions in the southern regions

Change in GPG generation – Q4 2020 versus Q4 2019



[18] AGL 2020, AGL Torrens Power Station: https://www.agl.com.au/about-agl/how-we-source-energy/agl-torrens

1.4.4 Wind and solar

Total VRE generation across the NEM reached 26 terawatt hours (TWh) by the end of 2020, representing 14% of the NEM generation mix (Figure 26). Compared to 2019, VRE output increased by 4.3 TWh in 2020, with wind and grid-solar contributing 2.7 TWh and 1.6 TWh, respectively. While VRE output continued to grow in 2020, its annual growth rate (20%) declined compared to 2019 (36%) due to a combination of lower wind capacity factors, increased curtailment, and some delays in project connections and commissioning.

Compared to Q4 2019, average grid-scale VRE output increased by 591 MW, with wind and solar contributing 398 MW and 193 MW, respectively (Figure 27). During the quarter, nine new projects (six solar, three wind) amounting to 1,183 MW of installed capacity commenced generation (Table 2), the highest quarterly addition since Q2 2019. New capacity, coupled with continued ramp up of projects from previous quarter, resulted in several grid-scale VRE records[19] this quarter, including:

- **Highest grid-scale VRE share of NEM operational demand** – NEM VRE output met 36% of NEM operational demand at 0930 hrs on 3 October 2020.
- **Highest grid-solar output on record** – NEM grid-solar output reached 3,210 MW at 1230 hrs on 30 November 2020.

Figure 26 Total NEM VRE output increased by 20%

Total VRE output by year – 2010 to 2020

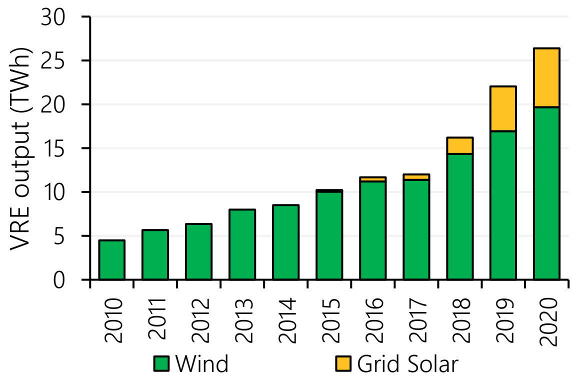


Table 2 New entrants in the NEM in Q4 2020[20]

Tech type	New entrant	Region	Capacity (MW)
Solar	Molong	NSW	30
	Sunraysia		200
	Wellington		170
	Middlemount	QLD	26
	Morgan-Whyalla	SA	7
	Yatpool	VIC	81
Wind	Collector	NSW	219
	Crudine Ridge		138
	Moorabool	VIC	312

Grid solar generation reached a record quarterly high of 1,018 MW on average, surpassing the previous record set in Q4 2019 by 193 MW. This was mainly a result of new capacity entering the system over the last year as solar irradiation during the quarter was lower than Q4 2019.

Average wind generation was 2,441 MW this quarter, with the largest increase compared to Q4 2019 occurring in Victoria (+223 MW) followed by Queensland (+93 MW).

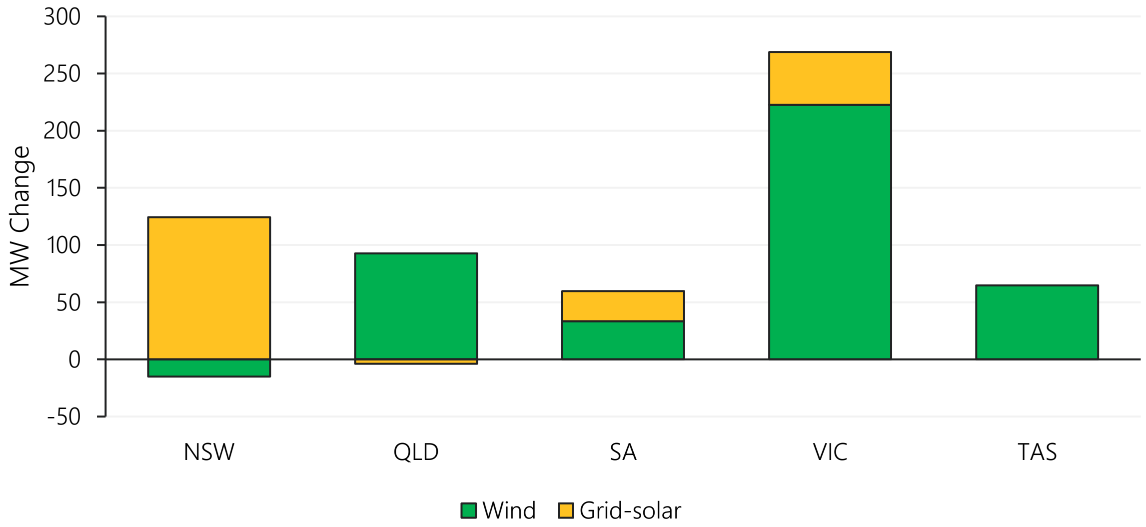
- Higher output in Victoria this quarter was predominantly due to continued ramp up of large amounts of recently installed capacity, including Dundonnell and Bulgana wind farms.
- In New South Wales, despite the commencement of two new wind projects wind generation decreased by 15 MW compared to Q4 2019, due to lower wind speed (-2% on average) for existing wind farms.

[19] Grid-scale VRE records are reported in half hourly time intervals.

[20] Table includes new entrants that began generating during the quarter. Several of these projects are still undergoing testing and have yet to commence generating at full capacity.

Figure 27 Victoria leads VRE output increase

Average change in VRE generation – Q4 2020 versus Q4 2019



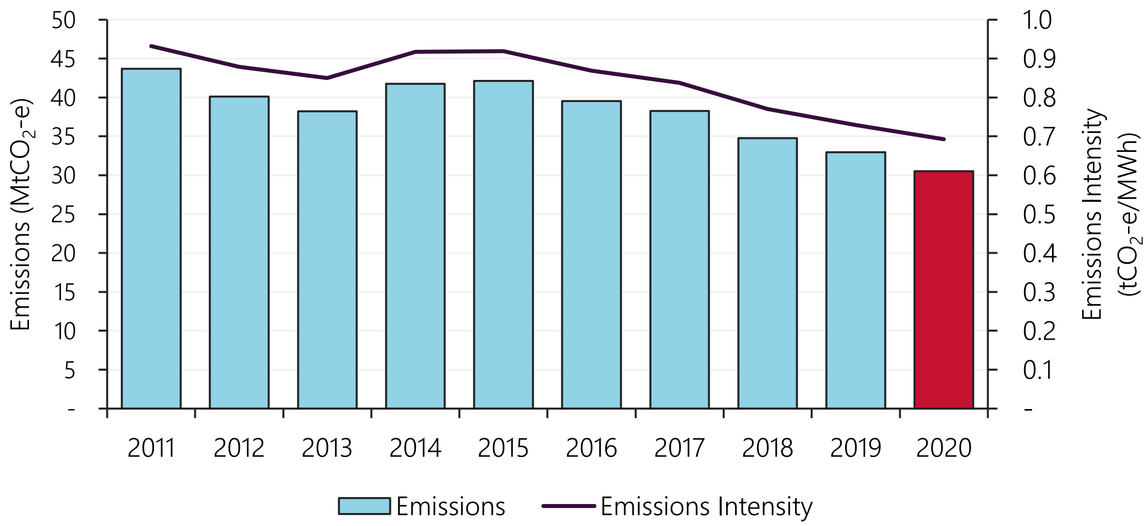
Volume weighted prices (VWAP) received by wind and solar generation in the NEM remained low this quarter, averaging around \$36-\$37/MWh in line with low wholesale spot prices (Section 1.3). On a regional basis compared to Q4 2019, South Australian VRE had the largest decrease of 65%, with its wind farms' VWAP declining to \$21/MWh this quarter, while solar farms' VWAP was \$17/MWh.

1.4.5 NEM emissions

Quarterly NEM emissions declined to the lowest quarterly level on record at 30.5 million tonnes carbon dioxide equivalent ($MtCO_2$-e), while the NEM emissions intensity equalled the previous quarterly record low of 0.7 tCO_2-e/MWh. Total emissions were 7% lower than Q4 2019's record low (33 $MtCO_2$-e) and 8% lower than Q3 2020. Key contributors to the record low emissions included near record low operational demand, coupled with record high VRE output, contributing to declines in high emissions generation (black- and brown coal-fired generation).

Figure 28 Record low emissions in Q4 2020

Quarterly NEM emissions and emissions intensity (Q4s)



1.4.6 Storage

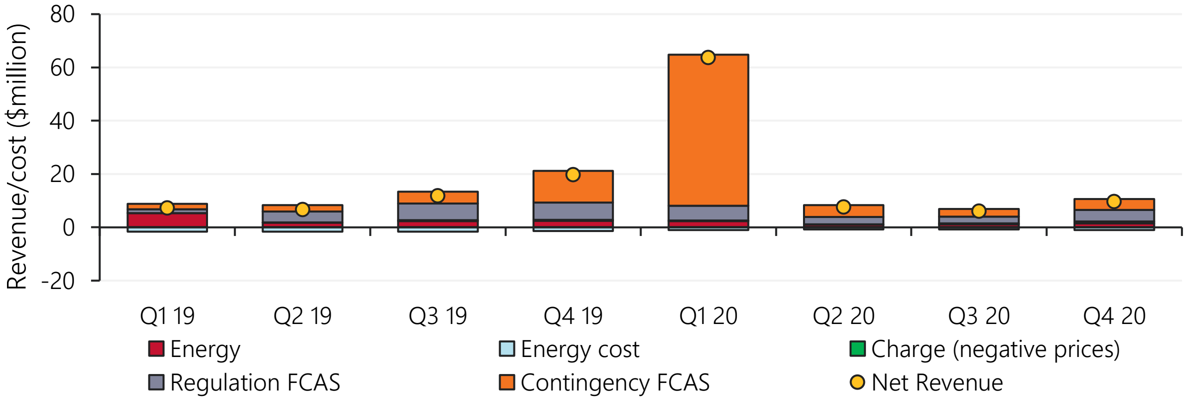
Batteries

During Q4 2020, NEM net battery revenue was $9.7 million, with FCAS markets remaining the largest source contributing 79% of the total (Figure 29). While battery net revenue this quarter was lower than Q4 2019, net revenue increased by $3.5 million compared to Q3 2020. Drivers included:

- Increased FCAS revenue (+$3 million) mainly due to increased average enablement from Hornsdale Power Reserve (HPR) following its expansion last quarter. FCAS revenue at HPR doubled from $2.4 million in Q3 2020 to $4.8 million this quarter, representing 56% of total battery FCAS revenue.
- An increase in energy revenue (+$0.4 million) driven by increased South Australian battery dispatch and volume-weighted average energy arbitrage value (from $30/MWh to $39/MWh). Record high negative price occurrence in South Australia (Section 1.3.3) meant that batteries were able to benefit by charging during those intervals.

Figure 29 Battery net revenue slightly higher than Q3 2020 but lower than Q4 2019

Battery revenue sources



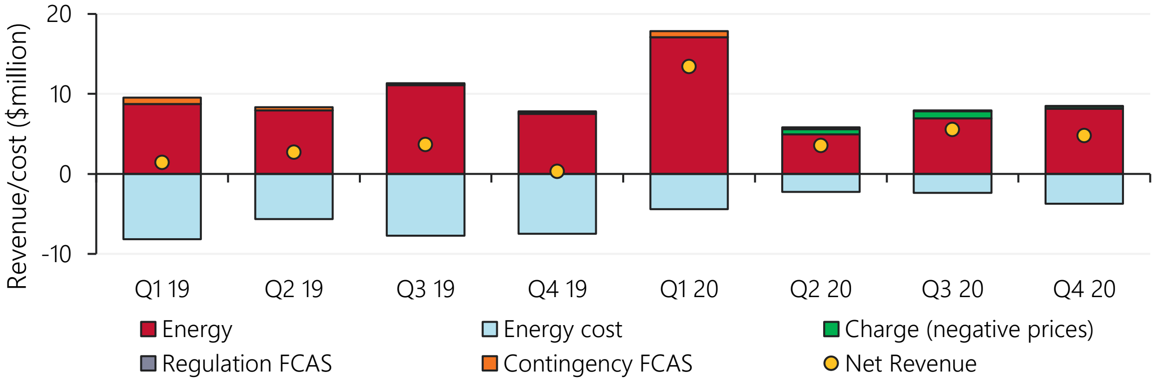
Pumped hydro

Pumped hydro spot market net revenue in Q4 2020 was $4.8 million, up $4.4 million compared to Q4 2019. The increase was mainly driven by a 65% increase in dispatch of Shoalhaven Pumped Hydro as well as the average energy arbitrage for pumped hydro increasing to $50/MWh. One limiting factor regarding Shoalhaven's spot market revenue this quarter was its output during New South Wales price volatility – it generated only 43% of the time when New South Wales trading prices were above $300/MWh.

In Queensland, net revenue at Wivenhoe increased by $0.9 million compared to Q4 2019, a combination of increased dispatch (30%) and average energy arbitrage values increasing from $44/MWh to $52/MWh.

Figure 30 Pumped hydro net revenue higher than Q4 2019

Pumped hydro revenue sources

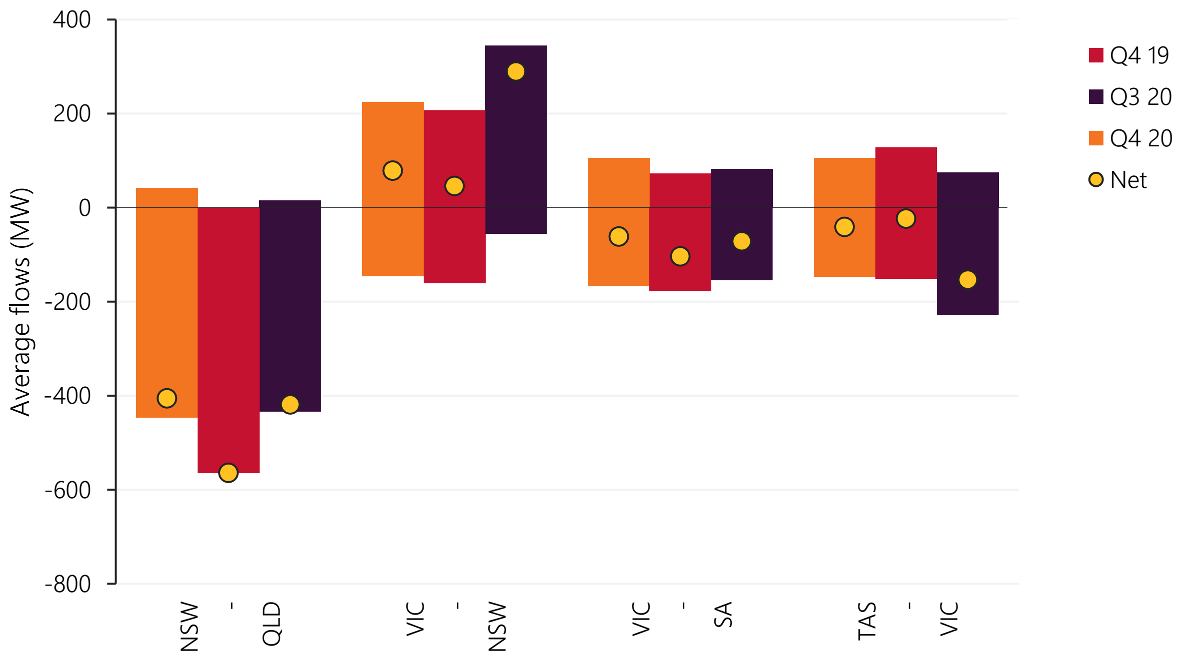


1.5 Inter-regional transfers

Figure 31 shows inter-regional transfers for Q4 2020 compared to recent quarters, with total transfers consistent with recent quarters.

Figure 31 Large increase in Victorian exports to New South Wales

Quarterly inter-regional transfers



Key outcomes by interconnector included:

- **Large increase in Victorian exports to New South Wales** – there was a 211 MW average increase in net transfers north on the Victoria to New South Wales Interconnector compared to Q4 2019 (Figure 31). The main driver of this was New South Wales generation reducing by 502 MW on average – due to record low black coal-fired generation in the region – necessitating increased imports from Victoria.
- **Network limits into New South Wales** – the increase in transfers mentioned above occurred despite reduced interconnector limits for flows into New South Wales. As shown in Figure 32, average interconnector limits for flows from Victoria to New South Wales were 185 MW below the two-year average, while limits for flows from Queensland to New South Wales were 146 MW below the two-year average. These limits contributed to periods of price volatility in New South Wales (Section 1.3.1). Figure 33 shows the modelled changes in generation mix arising from the limits, with increased black coal-fired generation and hydro generation in New South Wales, offsetting reduced black coal-fired generation in Queensland and brown coal-fired generation in Victoria.
  - Victorian drivers – limited export from Victoria to New South was a function of voltage constraints resulting from line outages, as well as recently commissioned wind and solar farms increasing congestion north and south of the interconnector.
  - Queensland drivers – outages of the Muswellbrook to Tamworth (88) line were the main drivers of reduced interconnector limits for flows from Queensland to New South Wales.
- **Increased Tasmanian imports** – a continuation of dry Tasmanian conditions and resulting reduction in local hydro generation led to net imports from Victoria increasing by 112 MW compared to Q4 2019.

Figure 32 Network constrained into New South Wales

Import limits into New South Wales

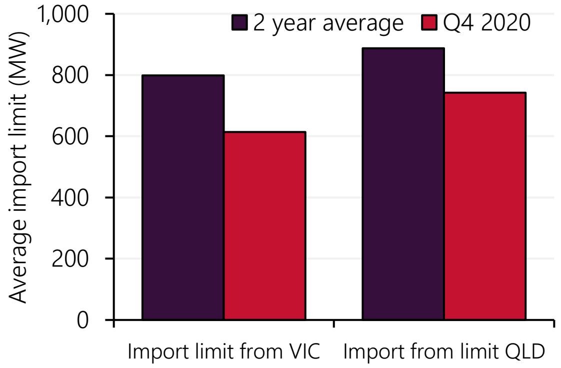
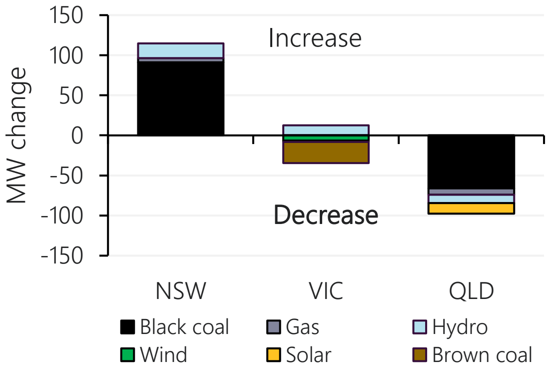


Figure 33 Modelled generation impact of interconnector limits into NSW



1.5.1 Inter-regional settlement residue

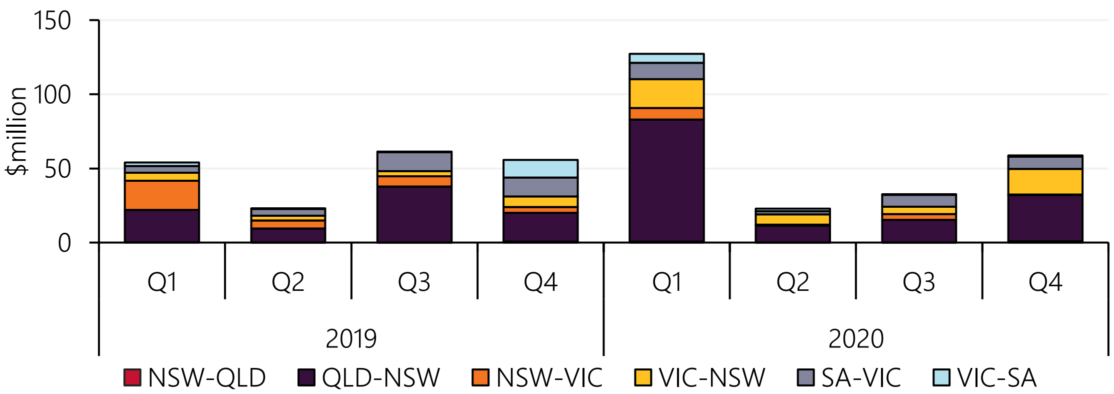
With increased inter-regional price separation, there was a resulting 80% increase in inter-regional settlement residue (IRSR) for the quarter compared to Q3 2020. IRSR value totalled $59 million, the highest Q4 since 2016 and the third highest quarter in the last three years. By region:

- **New South Wales** – IRSR value for transfers into New South Wales dominated IRSR value this quarter, making up 82% of total IRSR value. This represents the highest single region contribution to IRSR (on a proportional basis) since Q2 2013. The main driver of this outcome was New South Wales being significantly higher priced than neighbouring regions (Section 1.3).
- **Queensland and South Australia** – IRSR values for transfers into these regions remained at very low levels, due these regions rarely being higher priced than their neighbouring regions and/or high amount of price alignment with neighbouring regions.
  - Queensland only had higher spot prices than New South Wales for 16% of the quarter.
  - South Australian and Victorian prices were highly aligned, sharing price setting units for 87% of the quarter.

The market impact of counter-price flows[21] increased this quarter, with negative settlement residue increasing to $5.4 million, the highest level since Q1 2017. Most of the negative settlement residue (-$3.4 million) occurred for counter price flows on the Victoria to New South Wales interconnector, when line outages forced interconnector flow south during periods of high New South Wales prices.

Figure 34 Highest Q4 IRSR since 2016

Quarterly positive IRSR value



[21] Counter-price flows occur when electricity is exported from a high price region into a lower priced region in order to manage congestion.

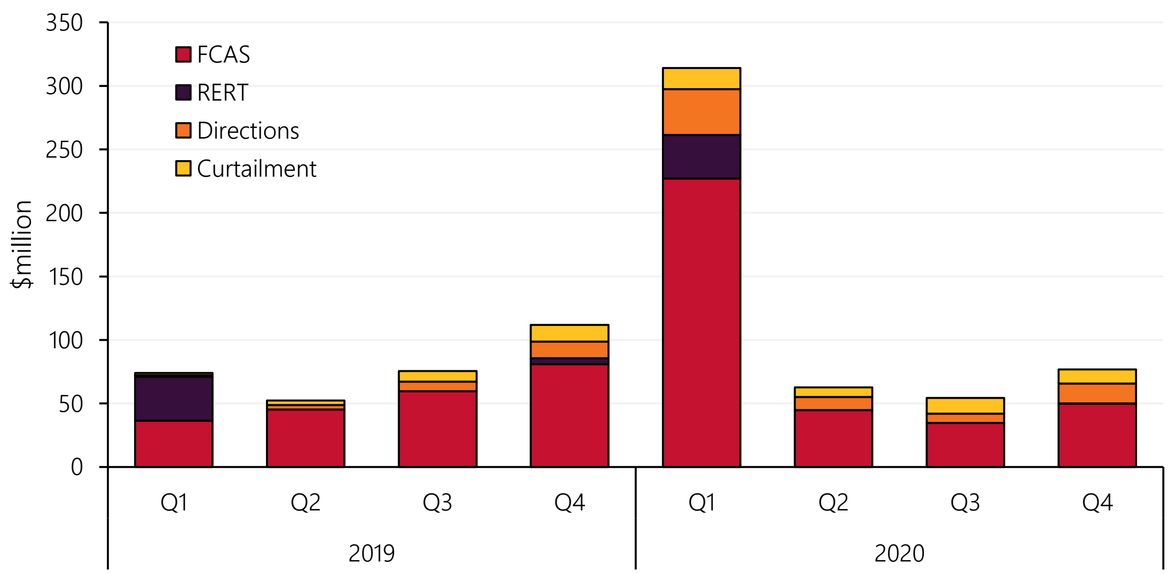
1.6 Power system management

Total NEM system costs[22] increased slightly compared to recent quarters, rising from $55 million in Q3 2020 to $77 million in Q4 2020 (Figure 35). By component:

- **FCAS costs** increased to $50 million this quarter, $15 million higher than Q3 2020, accounting for 65% of total system costs. Section 1.6.1 provides details on FCAS.
- The cost of **directing South Australian units** to maintain system security increased to a near record high of $16 million. Section 1.6.3 provides details on system security directions for the quarter.
- Estimated **VRE curtailment costs**[23] were $11 million, consistent with Q3 2020 results. Section 1.6.2 provides details on VRE curtailment for the quarter.
- AEMO activated **RERT** in New South Wales on 17 December 2020 due to forecast LOR2 conditions. The event lasted for 70 minutes (1720 hrs to 1830 hrs), and an estimated volume of 44.3 MWh of RERT was procured for $0.2 million.

Figure 35 Small increase in system costs compared to recent quarters

Quarterly system costs by category



1.6.1 Frequency control ancillary services

NEM quarterly FCAS costs increased to $50 million, $15 million higher than in Q3 2020, bringing the total cost for 2020 to a record high $356 million (Figure 36).

Compared to Q3 2020, average Regulation prices increased by 15%, Contingency Raise prices by 31%, and Contingency Lower by 30%. The increases in Contingency Lower and Raise prices were largely driven by periods of price volatility resulting from setting local requirements in Queensland and Tasmania. For example, in Queensland on 17 November 2020 local requirements, combined with limited online Queensland FCAS supply, resulted in Raise 60 second prices increasing to the market price cap for 10 dispatch intervals (DIs)[24]. This contributed to Queensland's FCAS cost increasing from $11 million in Q3 2020 to $21 million during the quarter, representing the majority of the NEM-wide cost increase.

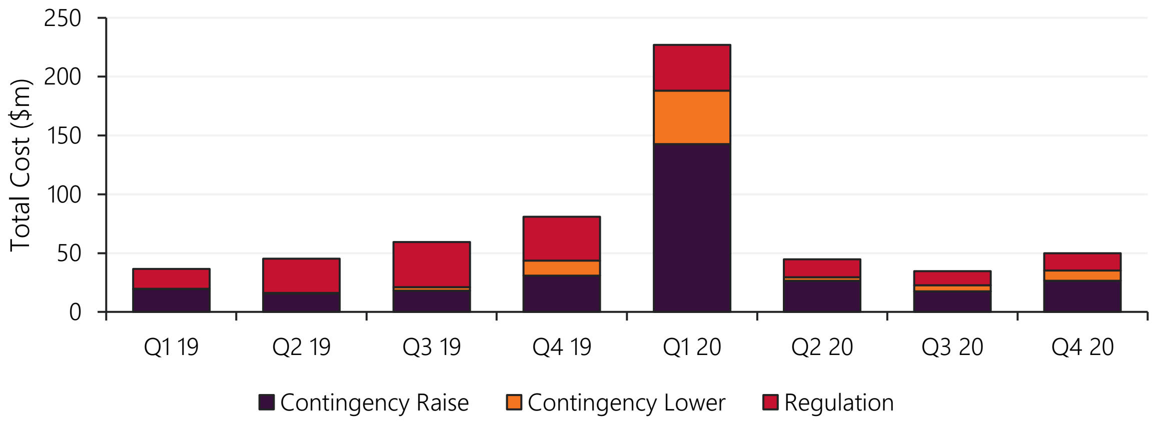
[22] In this report, NEM system costs refer to the costs associated with FCAS, directions compensation, RERT and VRE curtailment.

[23] Excludes economic curtailment. The cost of curtailed VRE output estimated to be $40/MWh of output curtailed.

[24] The AER's Quarter 4 2020 Wholesale Market Quarterly Report will include a focus on the High priced FCAS event in Queensland on 17 November.

Figure 36 Record high FCAS costs in 2020

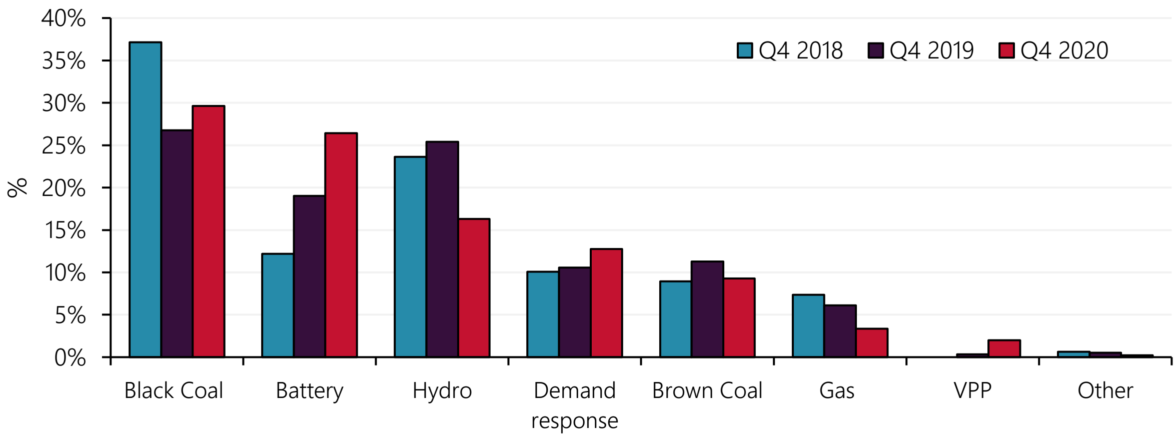
Quarterly FCAS cost by market[25]



On the supply side, batteries and demand response/virtual power plants continued to increase their FCAS market share. Within two years, batteries have increased their market share from 12% in Q4 2018 to 26% percent in Q4 2020, resulting in a reduced market share for coal-fired generation, GPG and hydro. This quarter was the first full quarter of operation for the HPR expansion, which was the main driver of increased battery market share in the last year.

Figure 37 Batteries captures market share

FCAS enabled by fuel type – market share



Mandatory primary frequency response

After completion of the mandatory primary frequency response rule change in March 2020[26], mass implementation began from 30 September 2020[27]. During Q4, a high proportion of the thermal fleet changed unit settings, resulting in improved unit frequency performance. From a market perspective, this resulted in a reduced proportion of causer pays Regulation FCAS costs for these fuel types, with black coal-fired generators' proportions of costs declining from 7% in Q3 2020 to 3% this quarter, with corresponding increases in wind and solar farms' share of these costs.

In addition, compliance with the mandatory primary frequency response rule change may have contributed to some units registering to provide FCAS. For example, during Q4 Darling Downs registered as an FCAS provider in the six Contingency markets (it was already registered to provide Regulation FCAS).

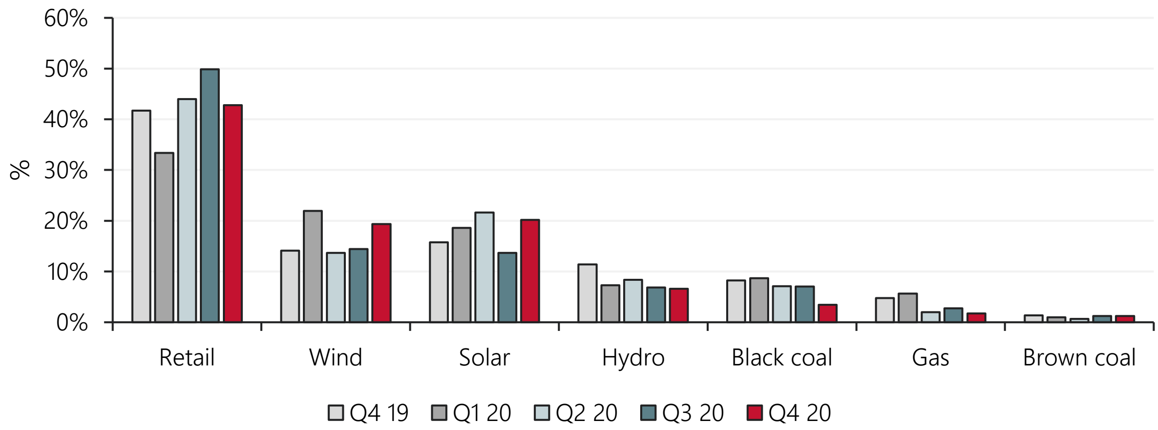
[25] Based on AEMO Settlement data and represents preliminary data that will be subject to minor revisions.

[26] AEMC 2020, *Mandatory primary frequency response*, available at: https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

[27] AEMO 2020, *Implementation of the PFR rule*, available at: https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/pfr-implementation-update.pdf?la=en.

Figure 38 Improved thermal unit frequency performance leads to lower causer pays costs

% share of causer pays FCAS costs by quarter and fuel type



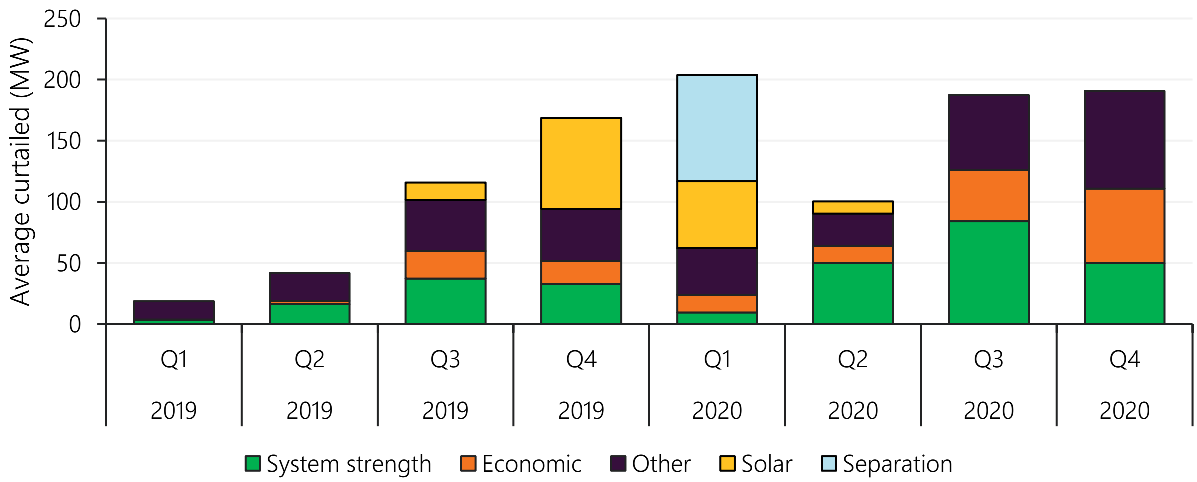
1.6.2 VRE curtailment

VRE curtailment rose to 191 MW on average (5.2% of total NEM VRE output), the second highest level on record (Figure 39). Key curtailment drivers included:

- **Economic curtailment** – negative spot prices contributed to a record amount of self-curtailment, averaging 61 MW, up 42 MW from Q4 2019. The largest regional increases in economic curtailment occurred in Victoria (+21 MW) and South Australia (+21 MW), with eight Victorian VRE projects demonstrating responsiveness to negative prices (Section 1.3.3).
- **System strength curtailment** – quarterly average curtailment due to system strength constraints fell by 34 MW on Q3 2020 levels, largely due to less system strength curtailment in Queensland. This reduction was a function of fewer periods of low demand in north Queensland, as well as changed inverter settings at Mount Emerald Wind Farm that ameliorated system strength issues for that project.
- **Other curtailment** – transmission outages, grid congestion, and other network constraints contributed to 80 MW of curtailment (+37 MW on Q4 2019 levels).

Figure 39 VRE curtailment returns to near record levels

Average NEM VRE curtailed by curtailment type



Note: curtailment amount based on combination of market data and AEMO estimates[28].

[28] For further information on the curtailment 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.

1.6.3 Directions

In 2020, total costs for directing South Australian generators for system strength was $49 million (or $4/MWh), $23 million higher than 2019. During the quarter, AEMO continued to issue directions to GPGs in South Australia and initiated directing hydro generators in Tasmania to maintain system security.

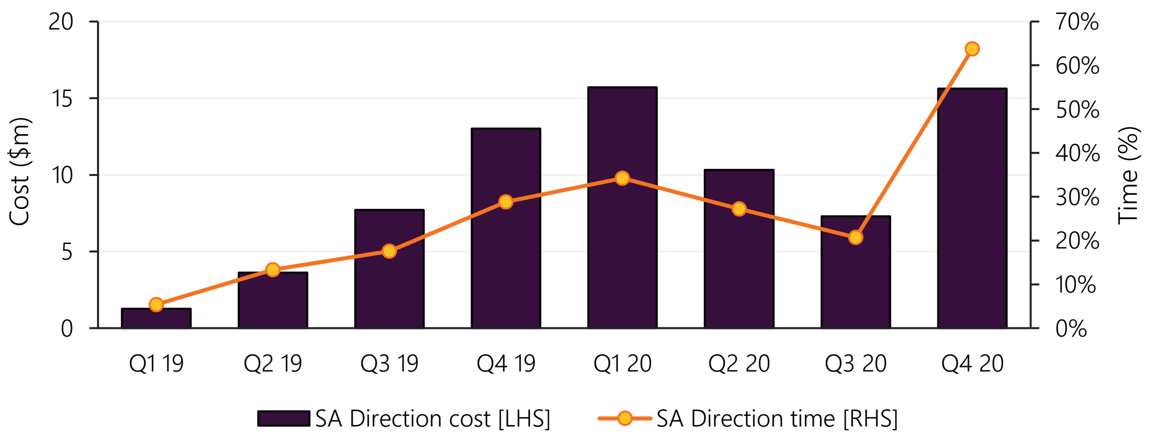
In contrast to falling wholesale electricity prices in South Australia, out-of-market costs in the region have been rising. This quarter, South Australian generators' time on directions reached a record quarterly high of 64%, surpassing the previous record set in Q2 2018 (45%). This resulted in South Australian system strength direction costs reaching near record quarterly levels of $15.6 million (Figure 40).

Increased South Australian time on directions was mainly due to GPGs de-committing for economic reasons as South Australia's electricity demand and spot prices fell. Despite average GPG under direction doubling to 101 MW compared to Q4 2019, representing 20% of total average output (Figure 41), South Australian direction costs only increased by 20%. This was due to the significant decrease in the 12-month 90th percentile spot price that is used for compensating participants, which decreased from $141/MWh in Q4 2019 to $77/MWh this quarter.

In Tasmania, hydro units in the region were directed for system strength for the first time since NEM start. These directions were issued as a result of an unplanned outage of the John Butters – Farrell 220 kV line that led to insufficient fault levels at Burnie, which required units to be online to maintain power system security. However, the overall market impact of these directions was very small, with directions occurring for just 0.9% of the quarter and only $1.4k of compensation cost.

Figure 40 South Australian direction cost and time on directions increased significantly

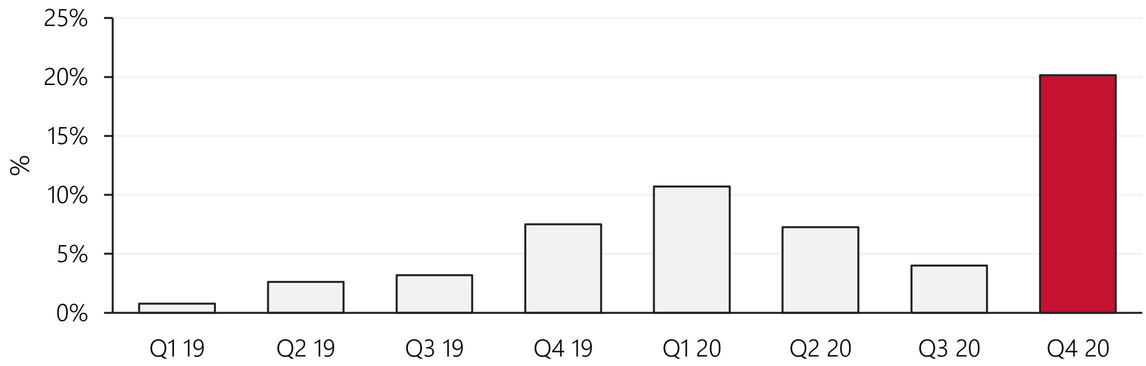
Time and cost of system security directions (energy only) in South Australia



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

Figure 41 Average SA GPG directed reached record highs, accounting for 20% of total average output

% of South Australian GPG directed – Q1 2019 to Q4 2020



2. Gas market dynamics

2.1 Gas demand

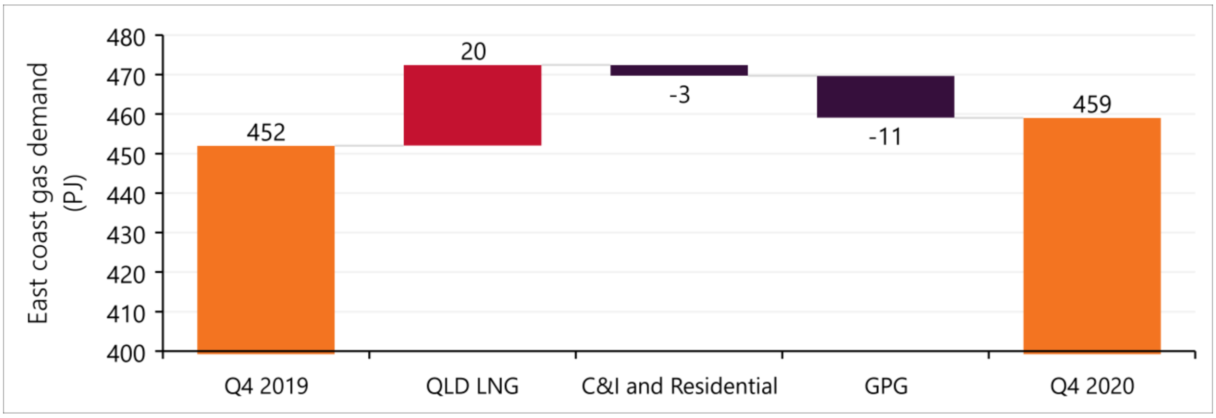
Total east coast gas demand was 2% higher than Q4 2019, driven by increased Queensland LNG demand (Figure 42). AEMO market demand was down 4%, primarily due to a milder Victorian spring than in 2019.

Queensland LNG exports rebounded strongly from the mid-2020 COVID-19 related reductions as Asian LNG demand and prices increased (Section 2.2.1). During the quarter, 370 petajoules (PJ) flowed to Curtis Island for LNG export, an increase of 20 PJ compared to Q4 2019 and an increase of 56 PJ compared to Q3 2020 (Figure 43). This represents a new record, surpassing 349 PJ in Q4 2019. Between 30 October and the end of the quarter, daily flows exceeded 4,000 terajoules (TJ)/day 50 times; prior to this, flows had only exceeded that level on three occasions. GLNG) recorded the largest increase of 23 PJ compared to Q4 2019, Queensland Curtis LNG (QCLNG) increased by 2 PJ, while Australia Pacific LNG (APLNG) decreased by 4.7 PJ.

Reflecting higher flows to Curtis Island, during Q4 there were 96 LNG cargoes exported, up from 78 in Q3 2020. GLNG recorded the largest increase from 21 to 30, with QCLNG increasing from 29 to 31, and APLNG increasing from 29 to 35 cargoes.

East coast GPG demand decreased by 29% compared to Q4 2019, with reductions in all states except Queensland resulting in the lowest Q4 GPG demand since 2005. (Section 1.4.3).

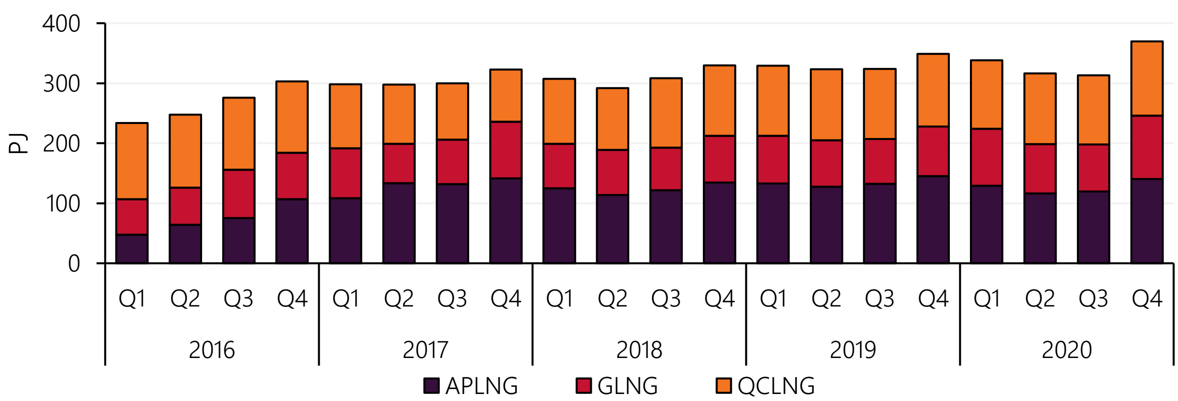
Figure 42 LNG exports drive east coast gas demand increase



* 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.

Figure 43 GLNG increase drives record flows to Curtis Island for LNG export

Total quarterly pipeline flows to Curtis Island



2.2 Wholesale gas prices

Compared to Q3 2020, quarterly average gas prices increased in all east coast gas markets, reversing the downward trend since the beginning of 2019 (Figure 44). Key outcomes included:

- **Brisbane becomes highest-priced market** – gas prices in the Brisbane Short Term Trading Market (STTM) averaged $6.3/gigajoule (GJ), increasing 50% on Q3 2020 levels and making Brisbane the highest-priced east coast gas market for the first time since Q3 2018. This increase coincided with higher Queensland LNG demand.
- **Lower gas prices in Victoria** – Victoria's quarterly average gas price of $5.5/GJ was the lowest east coast average, trading at a 9% discount to other markets, influenced by reduced local gas demand.
- **General gas prices drivers** – compared to Q3, less gas was offered at lower prices into the east coast markets. For example, in Q4 2020, 55% of bids in the Declared Wholesale Gas Market (DWGM) were priced under $7/GJ, compared to 64% in Q3 2020 (Figure 45). This change coincided with an increase in international oil and gas prices, and increased Queensland LNG exports.

Figure 44 Gas prices increase 25% on Q3 levels

DWGM and Gas Supply Hub (GSH) quarterly average gas prices

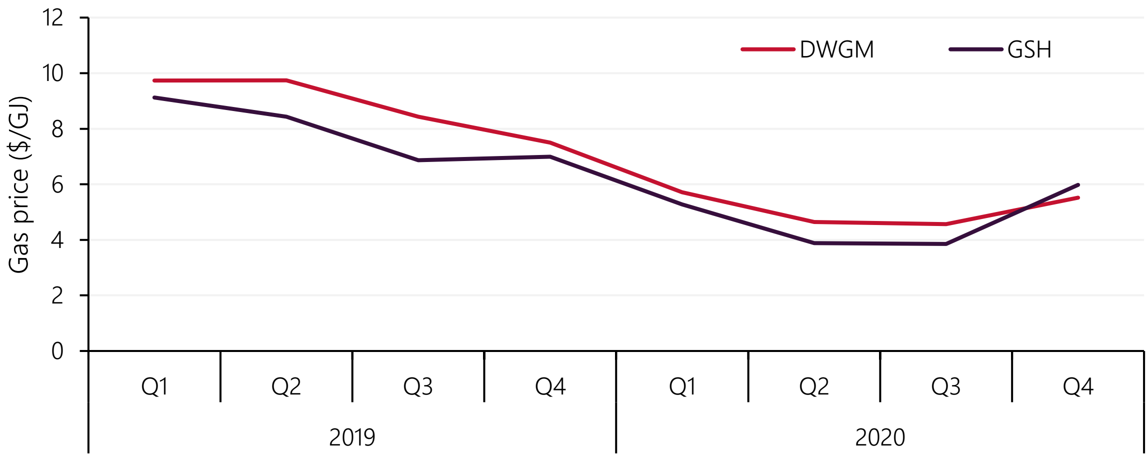


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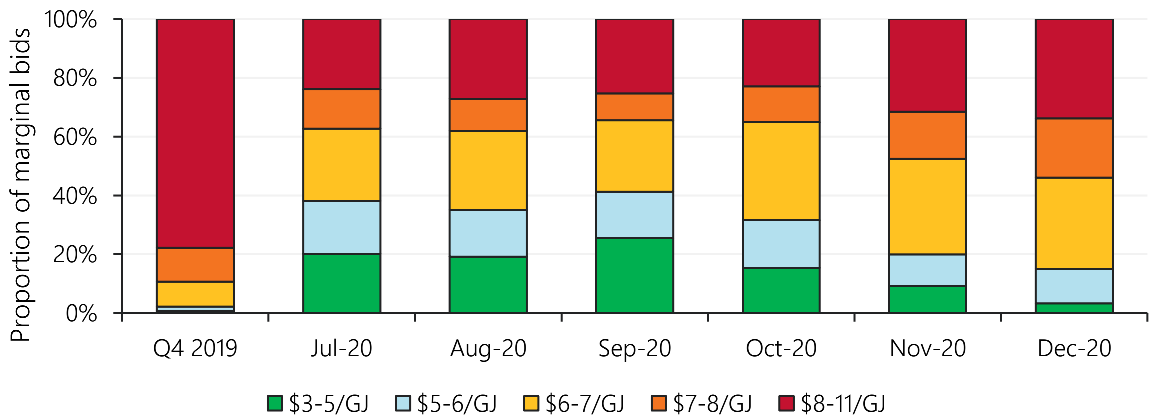
Figure 45 DWGM bids at higher prices than in Q3 2020

DWGM – proportion of marginal bids by price band



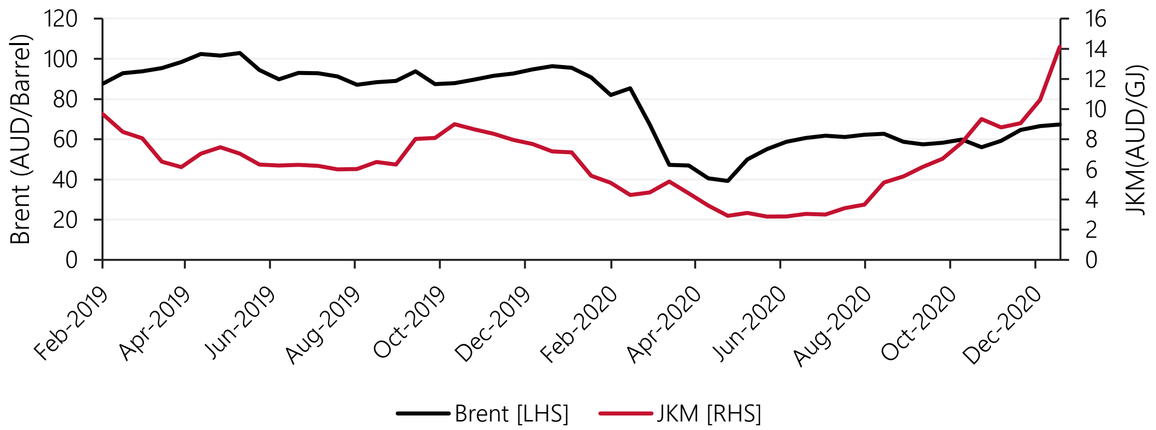
2.2.1 International commodity prices

During the quarter, international commodity prices rebounded from the multi-year lows during mid-2020 caused by the COVID-19 pandemic.

JKM LNG prices rallied during the quarter to an average of A$9.6/GJ, A$1.4/GJ higher than Q4 2019 pre-pandemic levels, mainly due to increased Asian demand driven by a colder than usual northern hemisphere winter coinciding with major supply train outages and shipping transport disruptions[29]. Steep price increases, particularly during December, resulted in JKM prices reaching a multi-year high of A$17.6/GJ at the end of 2020 (Figure 46). Rebounding Asian gas prices affected local market outcomes, contributing to rising east coast gas prices, record Queensland LNG exports, and the Australian Competition and Consumer Commission's (ACCC's) average LNG netback price, which increased from $2.6/GJ in Q3 2020 to an average of $6/GJ in Q4 2020 (Figure 47)[30].

Figure 46 JKM prices rally to multi-year highs

Brent Crude oil and JKM LNG prices in Australian dollars

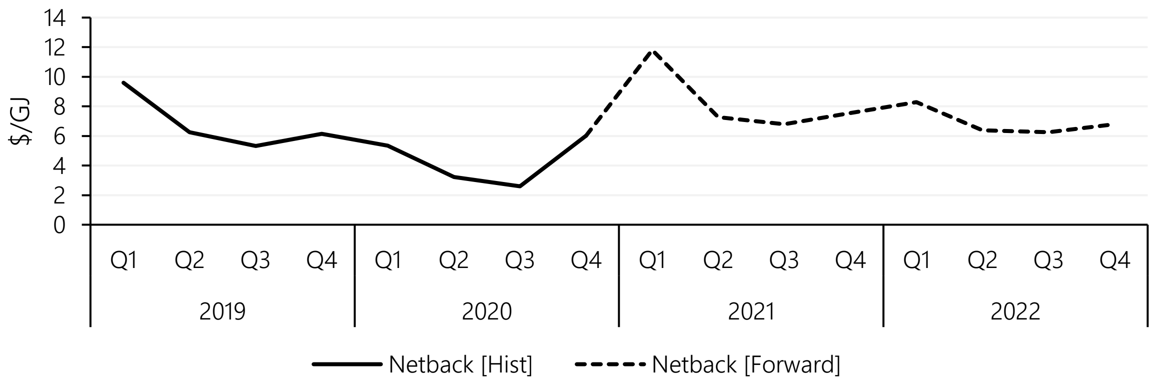


Source: Bloomberg data in 14-day averages

Brent crude oil increased from A$57/barrel at the end of Q3 2020 to finish the year at A$67/barrel, as the Organisation of the Petroleum Exporting Countries (OPEC) maintained production cuts from August to the end of the quarter[31]. Thermal export coal prices continued to recover during the quarter from a low of A$77/tonne and reached A$116/tonne by the end of 2020 due to the colder than usual Asian winter.

Figure 47 ACCC LNG netback rallies to pre pandemic levels

ACCC netback price historical and forward[32]



[29] BNEF LNG monthly report and Bloomberg news.

[30] The AER's Quarter 4 2020 Wholesale Market Quarterly Report analyses factors driving spikes in Asian gas prices over December 2020 and January 2021.

[31] OPEC 2020, The 12th OPEC and non-OPEC Ministerial Meeting concludes: https://www.opec.org/opec_web/en/press_room/6257.htm.

[32] ACCC 2020, LNG netback price series: https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series.

2.3 Gas supply

2.3.1 Gas production

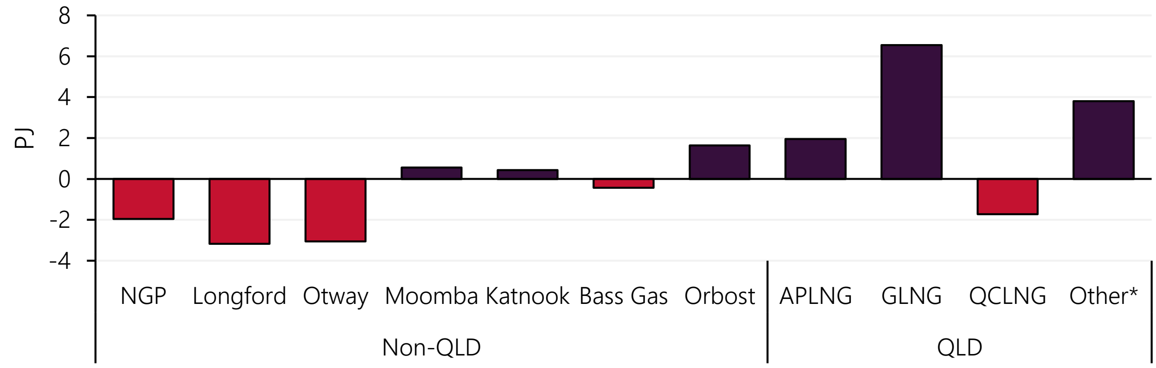
Q4 2020 east coast gas production increased by 4.4 PJ (+1%) compared to Q4 2019 (Figure 48), due to:

- Increased Queensland production from GLNG (+6.5 PJ), APLNG (+2 PJ) and other Queensland facilities (+3.8 PJ) to meet the record demand for LNG export (Section 2.1), which was partially offset by a decrease from QCLNG (-1.7 PJ).
- Increased Orbost production in Victoria, which commenced on 25 March 2020 (+1.6 PJ). However, production issues for much of the quarter resulted in it producing 0.9 PJ less than Q3 2020.
- Higher Moomba production due to increased easterly flows on the South West Queensland Pipeline (SWQP) coinciding with higher Queensland LNG demand (+0.6 PJ).

These increases were partially offset by reduced Victorian production from Longford (-3.2 PJ), Otway (-3.1 PJ), and Bass Gas (-0.4 PJ), reflecting lower demand in the southern markets.

Figure 48 East coast gas production up 1%

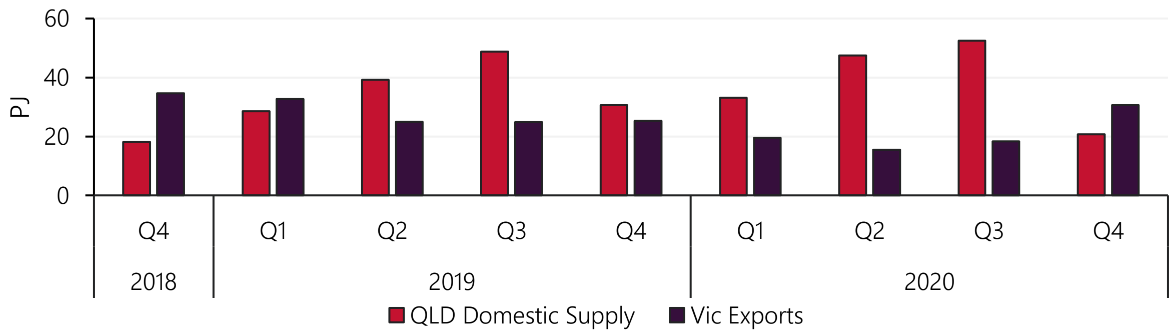
Change in east coast gas supply – Q4 2020 versus Q4 2019[33]



2.3.2 Queensland excess production

Total net domestic supply into Queensland was 21 PJ in Q4 2020, down 10 PJ on Q4 2019 levels (Figure 49) as more gas was exported during the quarter. Queensland gas production increased by 10.4 PJ, while LNG exports increased by 20 PJ. With an increase in Queensland GPG and market demand (+1.2 PJ), this led to northerly flows from the southern markets into Queensland (Section 2.4).

Figure 49 Queensland domestic supply drops sharply



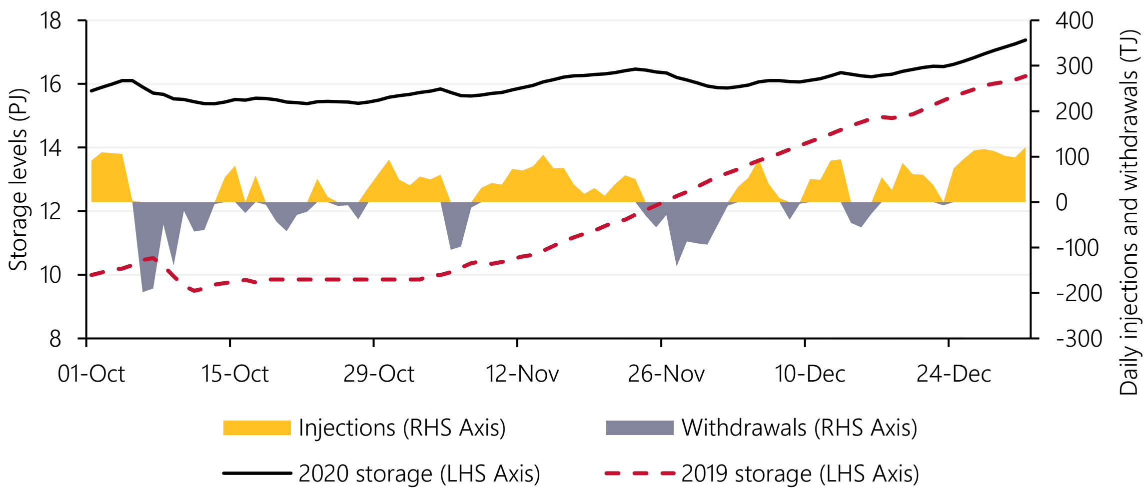
[33] Only includes major production facilities.

2.3.3 Gas storage

A gas balance of 17.4 PJ was recorded at the Iona Underground Storage Facility (UGS) in Victoria at 31 December, 1.1 PJ higher than at the end of 2019 (Figure 50). This was the highest storage level for Iona at the end of December since the end of Q4 2017 which was also 17.4 PJ. Although there were a few occasions where Iona was utilised heavily (in early October during some colder weather and at the end of November coinciding with planned outages at Otway and Longford), Iona was generally refilling for most of the quarter. Lower demand across Victoria, New South Wales and South Australia also contributed to the high gas balance.

Figure 50 Iona storage finished Q4 at the highest Q4 level since 2017

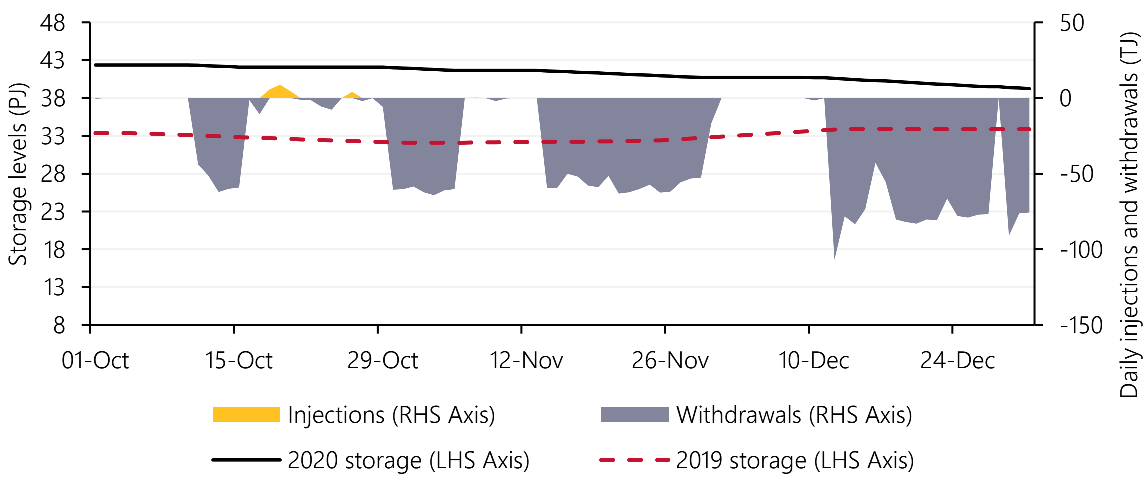
Iona storage levels



GLNG's Roma Underground Gas Storage (RUGS) continued to withdraw for most of the quarter, coinciding with higher GLNG flows to Curtis Island. Despite this, RUGS recorded a gas balance of 39.2 PJ, 5.4 PJ higher than the corresponding period in 2019.

Figure 51 Roma storage finished the quarter 5.4 PJ higher than Q4 2019

RUGS storage levels



2.3.4 Dandenong LNG

Dandenong LNG plays an important role in managing intra-day gas system pressures in Victoria, particularly in winter, and can be scheduled out of merit order if AEMO issues a notice of a threat to system security[34]. If this is required (as it was on several occasions during 2020), market participants must pay uplift charges to compensate holders of LNG who were scheduled out of merit order.

After it reached capacity on 12 September 2020, storage levels fell to 443 TJ on 31 December, its lowest level outside of winter since the beginning of the DWGM and lowest overall since winter 2007 (Figure 52).

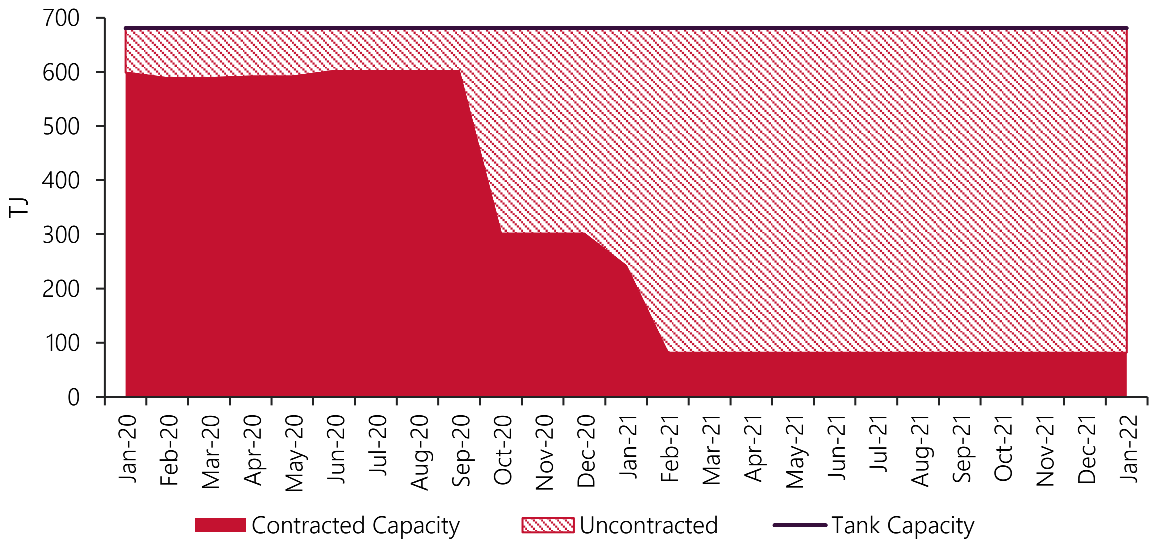
The decrease was driven by lower contracted levels, which are due to further decrease to 81 TJ by February 2021 (Figure 53). If contract levels of LNG are low over winter, there is a risk that some market participants could be exposed to significant uplift charges should AEMO require the injection of LNG due to a threat to system security.

Figure 52 Dandenong LNG stocks have fallen to their lowest levels outside winter in DWGM history.

Dandenong LNG stocks

Figure 53 Dandenong LNG largely uncontracted from February 2021

Dandenong contracted and uncontracted LNG



Source: Gas Bulletin Board

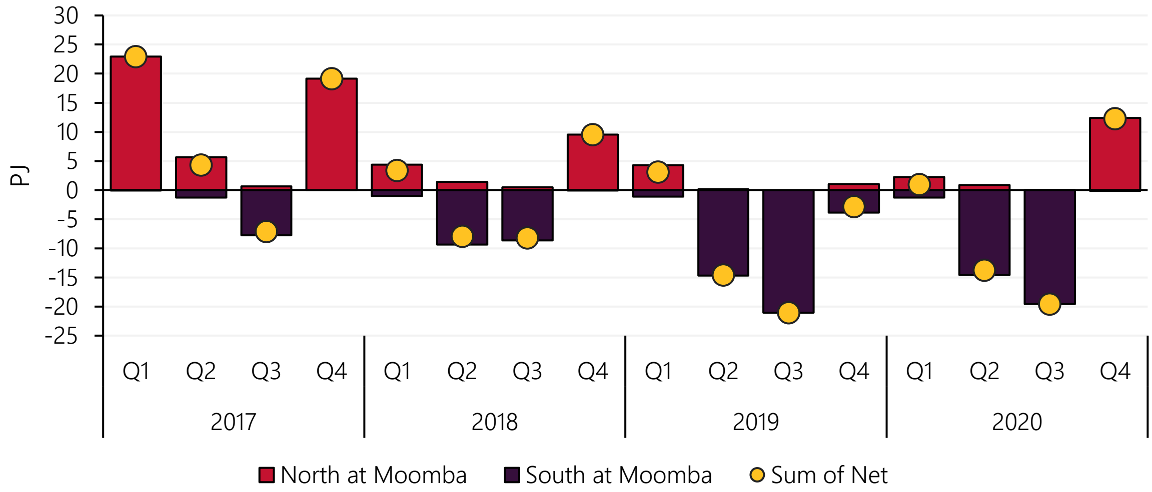
[34] Further information on Dandenong LNG can be found: www.apa.com.au/our-services/gas-transmission/gas-storage/dandenong-lng-gas-storage-facility.

2.4 Pipeline flows

During the quarter 12.3 PJ flowed north from Moomba to Queensland, contrasting with a southerly flow of 2.8 PJ in Q4 2019 and representing the highest flows north since Q4 2017 (Figure 54). The swing in gas flows was a function of record Queensland LNG export demand, coupled with reduced GPG demand in the southern regions. Despite the higher imports to Queensland, flows from the Northern Territory via the Northern Gas Pipeline (NGP) reduced by 2 PJ.

Figure 54 Highest imports to Queensland since Q4 2017

Flows on the SWQP at Moomba



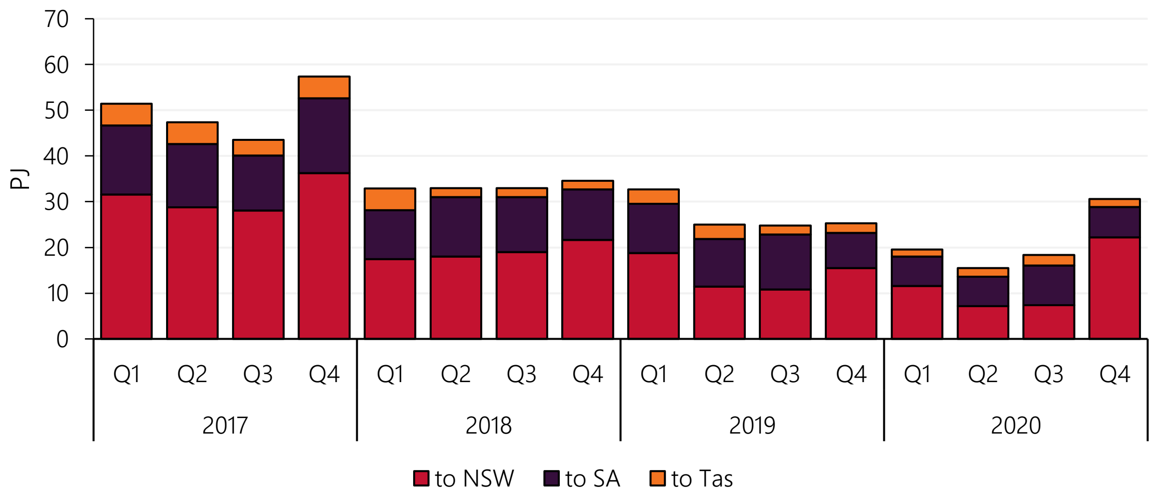
Although Victorian production was lower, Victorian net gas transfers to other states increased by 5.3 PJ compared to Q4 2019 (Figure 56), solely due to an increase in flows to New South Wales which replaced Queensland and Moomba supply.

Compared to Q4 2019:

- Victoria to New South Wales – Victoria exported a net 5.1 PJ via Culcairn, compared to 0.8 PJ in Q4 2019. Exports to New South Wales via the Eastern Gas Pipeline (EGP) increased by 2.2 PJ.
- Victoria to South Australia – transfers reduced by 1.1 PJ due to lower South Australian GPG demand.

Figure 55 Victorian gas exports to New South Wales highest in two years

Victorian net gas transfers to other regions

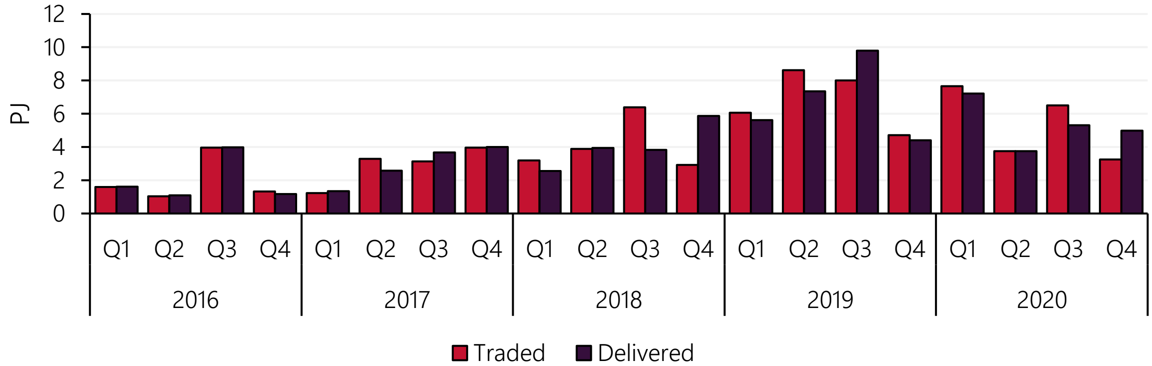


2.5 Gas Supply Hub

In Q4 2020, there were decreased trading volumes but increased delivered volumes on the GSH compared to Q4 2019 (Figure 56) with traded volume down by 1.5 PJ and delivered volume up by 0.6 PJ. This was due to trades occurring in Q3 2020 that were delivered in Q4. Overall, 2020 was the second highest volume year for the GSH, but down from its 2019 record, with traded volume decreasing by 6.2 PJ and delivered volume by 5.9 PJ.

Figure 56 GSH volumes down on 2019 but records its second highest year on record

Gas Supply Hub – quarterly trades and deliveries



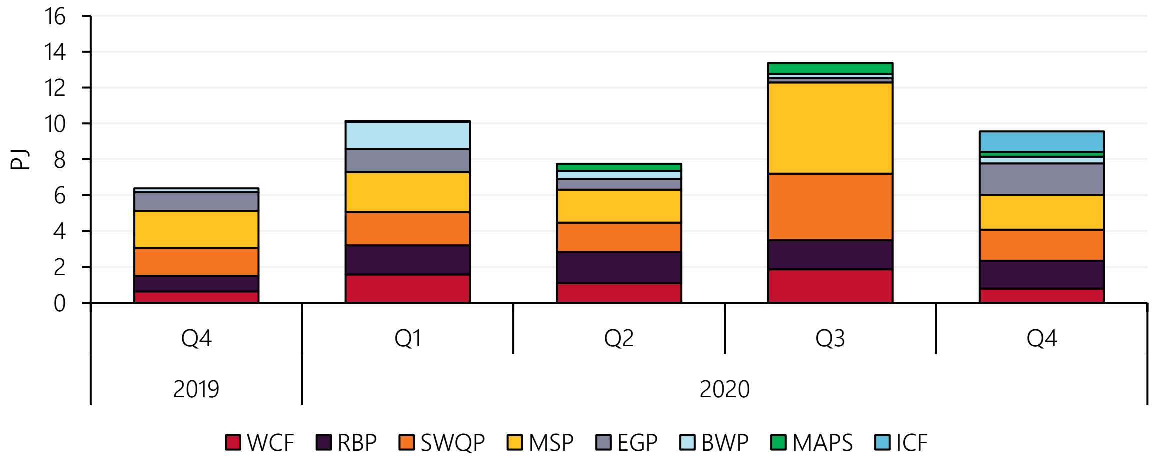
2.6 Pipeline capacity trading and day ahead auction

Compared to Q4 2019, there was an increase in Day Ahead Auction (DAA) utilisation (Figure 57), with volume increases on all previously utilised pipelines except for the Moomba to Sydney Pipeline (MSP) (-0.1 PJ)[35]. The main increases occurred on the Moomba Compressor (MCF) (+1.1 PJ) and Iona Compressor (+1.1 PJ), with smaller increases occurring on the other pipelines. This was the first quarter the Iona Compressor service has been utilised, with only previously very small volumes occurring on Moomba Compressor.

Average auction clearing prices remained at close to $0/GJ on most pipelines. The exceptions to this were the SWQP which averaged $0.18/GJ, and the EGP which averaged $0.02/GJ. SWQP prices increased with competition to transport gas in an easterly direction towards Wallumbilla.

Figure 57 Day Ahead Auction utilisation increases compared to Q4 2019

Day Ahead Auction Results by quarter



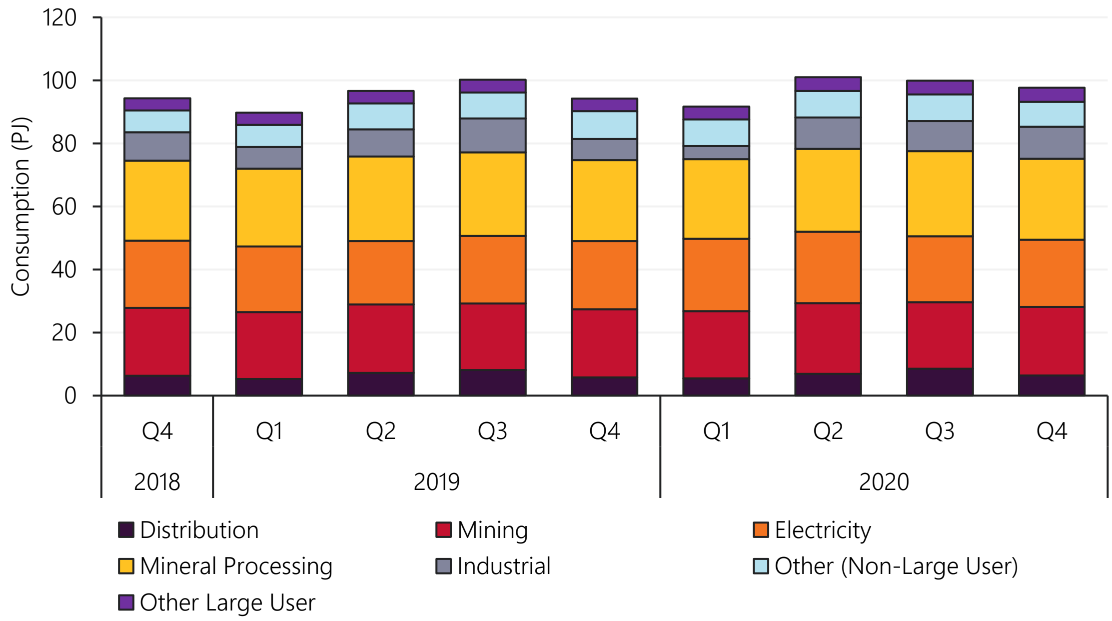
[35] The AER's Quarter 4 2020 Wholesale Market Quarterly Report analyses the auction routes which were most popular between Melbourne, Sydney, Moomba and Wallumbilla on the MSP and SWQP.

2.7 Gas – Western Australia

In Q4 2020, total gas consumption was 97.6 PJ, representing a 3.7% increase on Q4 2019 levels (Figure 58).

Figure 58 Western Australia gas consumption increased 3.7% compared to Q4 2019

WA quarterly gas consumption by industry



This was primarily due to changes in Large User consumption. Compared to Q4 2019:

- **Large User industrial consumption** increased by 52% to 10.2 PJ. This was due to the Yara Pilbara Liquid Ammonia Plant increasing consumption to 7.7 PJ, an 85% increase.
- **Large User electricity consumption** reduced by 1.5% to 21 PJ due to South West Interconnected System (SWIS) GPG reducing by 11% (Section 3.2)[36]. SWIS facilities reduced their consumption by 5.9% to 18.8 PJ; this reduction was partially offset by non-SWIS connected facilities increasing consumption by 5% to 1.7 PJ.
- **Other Large User consumption**, which includes gas processing plants, increased by 12% to 4.4 PJ, its highest level since Q3 2018.
- **Consumption by other connections**[37] was 7.9 PJ in Q4 2020, a 10% reduction, while Distribution-related consumption was 10% higher, due to lower overnight temperatures and in general colder weather compared to Q4 2019.

When grouping by WA Gas Bulletin Board (GBB) Zone, the key change occurred in the Dampier Zone, which increased consumption to 16.2 PJ in Q4 2020, representing a 22.5% increase compared to Q4 2019.

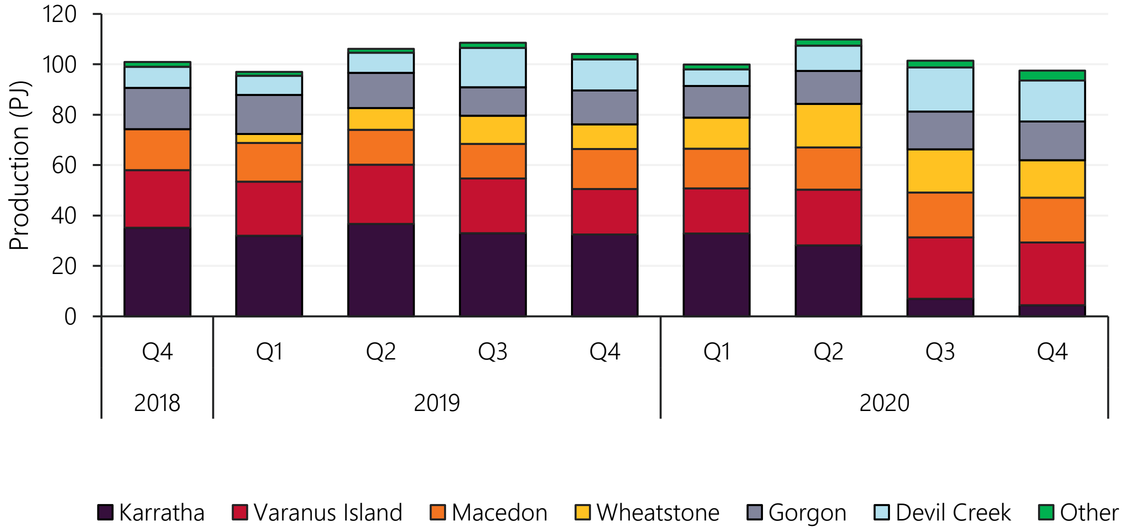
In Q4 2020, total Western Australian gas supply was 98 PJ, a 6% reduction on Q4 2019 levels (Figure 59). The most significant driver behind lower production levels was the output from the Karratha Gas Plant, which continued to decline. During the quarter, Karratha produced 4.4 PJ of gas, down 87% from Q4 2019. This represents a significant change, with Karratha Gas Plant supplying approximately two-thirds of domestic gas in Western Australia 5-10 years ago.

[36] Electricity data on electricity generation in areas outside the SWIS is not publicly available.

[37] Pipeline connected users consuming less than 10TJ of gas per Gas Day. These are referred to as "Other" in the WA GBB.

Figure 59 Western Australia gas production down 6% compared to Q4 2019

WA quarterly gas production by facility

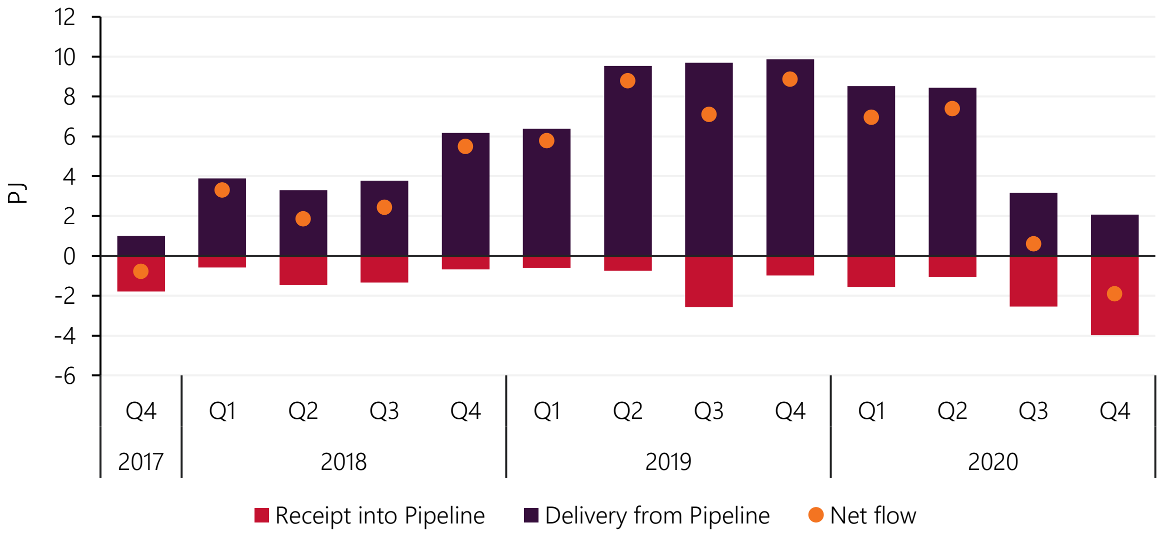


The next three largest facilities by nameplate capacity – Varanus Island, Devil Creek and Macedon – increased their output by 39%, 4% and 12% respectively. Despite shutdowns of the Gorgon Facility earlier in 2020[38], the facility continues to supply the domestic market with pipeline gas, achieving its highest production since Q1 2019. It was observed that for the first time since commencing production, there was a material decrease in Wheatstone's production in Q4 2020, contributing to a decline in total production compared to Q3 2020.

Total production of gas has consistently exceeded total consumption each quarter, indicating increases in stored gas; however, in Q4 2020, production and consumption were closely correlated. Combined net flow from the two Storage facilities, Mondarra and Tubridgi, was negative for the first time, with net injections into the system (Figure 60). This was the first time since Q4 2017 this has occurred, driven by lower production levels.

Figure 60 Net quarterly withdrawal from Western Australia gas storage

Quarterly gas transfer from storage facilities



[38] Chevron 2020, Chevron continues repairs on Gorgon LNG Train 2: https://australia.chevron.com/news/2020/chevron-continues-repairs-on-gorgon-lng-train-2.

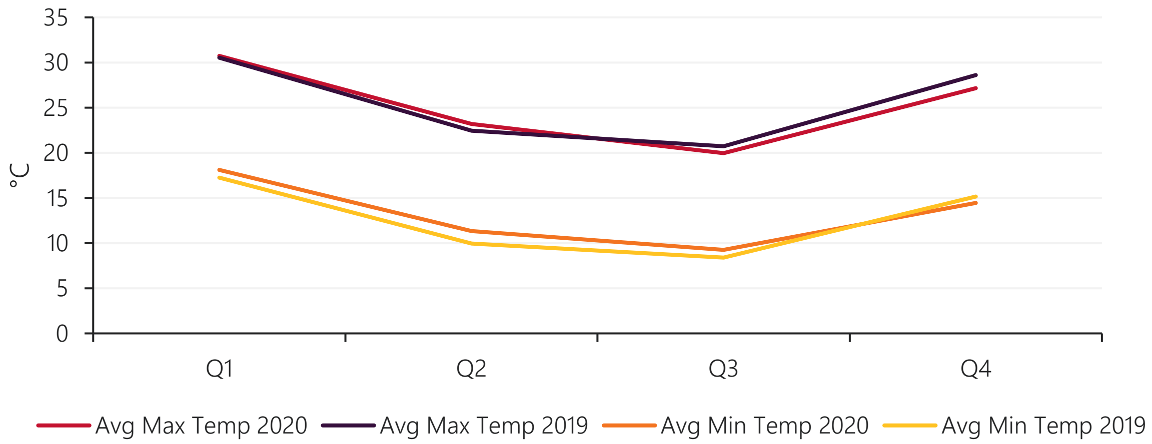
3. WEM market dynamics

3.1 Weather and electricity demand

Perth temperatures in Q4 2020 were in line with the 10-year Q4 average, with the average maximum temperature of 27°C and the average minimum temperature of 14°C. Both average maximum and average minimum temperatures were lower than in Q4 2019 (-1.5°C and -0.7°C respectively) which was a particularly hot quarter (Figure 61)[39]. Although Q4 2020 was average overall, trends indicate a mild November in 2020, with the lowest average maximum and minimum temperature of the past five years, followed by the second hottest December of the past five years.

Figure 61 Mild Q4 Perth weather

Average maximum and minimum temperature - Perth



WEM continues to set minimum demand records through 2020

A new all-time record minimum demand[40] was set at 1300 hrs (AWST) on Saturday, 28 November 2020 (Table 3 and Figure 62), when operational demand was 985 MW, 14 MW below the previous record. At that time, output from distributed PV was estimated to be 1,189 MW. This continues 2020's trend of declining demand, with a new record minimum demand set each quarter.

The average WEM operational demand in Q4 2020 decreased by 6% (-118 MW) compared to Q4 2019. Demand continued to decrease in the middle of the day in line with increasing distributed PV output (Figure 63). Demand in the evening peak was lower than Q4 2019 due to milder weather in November, leading to a reduction in small use customer load across the month.

Table 3 WEM maximum and minimum demand records

Maximum demand (MW)			Minimum demand (MW)		
Q4 2020	All-time	All Q4	Q4 2020	All-time	All Q4
3,618	4,006	3,618	985	985	985

[39] Bureau of Meteorology 2021, Greater Perth in December 2020: http://www.bom.gov.au/climate/current/month/wa/perth.shtml.

[40] All demand measurements use 'Operational Demand' which is the average measured total of all wholesale generation in the SWIS and is based on non-loss adjusted sent out SCADA data.

Figure 62 New WEM minimum demand record set

WEM quarterly minimum demand – Q4 2018 to Q4 2020

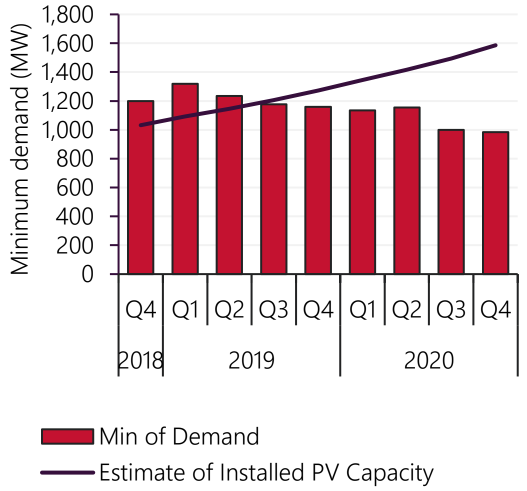
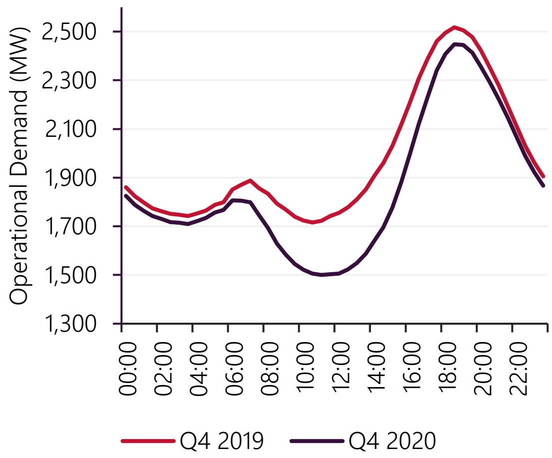


Figure 63 WEM midday demand continued to decrease

WEM operational demand – Q4 2020 versus Q4 2019



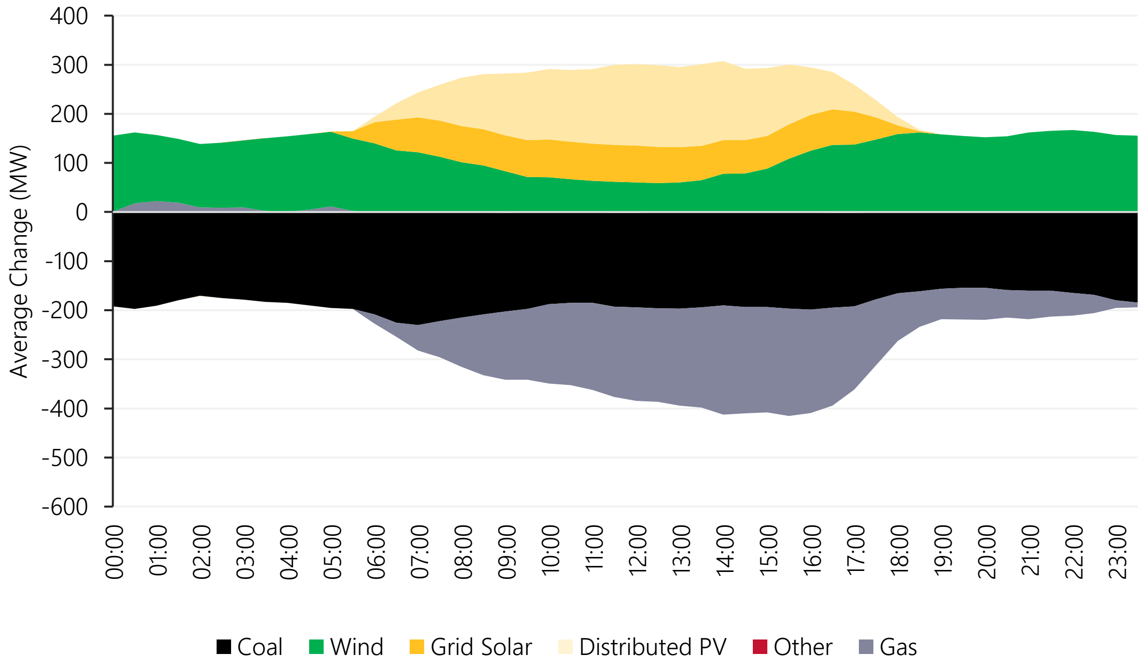
In addition, the WEM reached its highest Q4 demand on record, rising to 3,618 MW at 1630 hrs AWST on 23 December 2020. This record was primarily driven by high temperatures in Perth on 23 December 2020 when the maximum temperature exceeded 40°C.

3.2 Electricity generation

During the quarter, the WEM supply-mix transformation continued to occur. Increases in distributed PV generation contributed to the record minimum demand (Section 3.1) while the increases in wind and grid solar generation contributed to the record negative Balancing Price occurrences (Section 3.3.1). Figure 64 shows the average change in generation between Q4 2019 and Q4 2020, by fuel type and time of day.

Figure 64 Increased output from wind and solar generation; decline in thermal generation

Average change in WEM supply – Q4 2020 versus Q4 2019

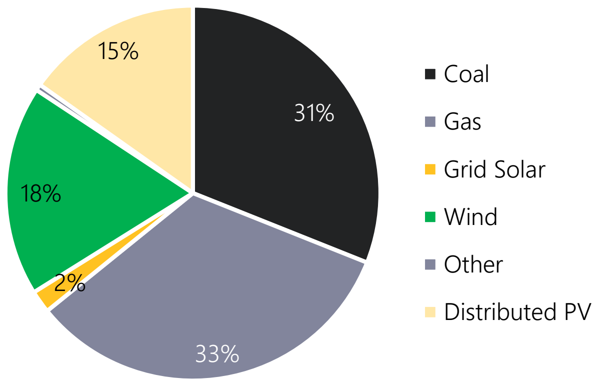


Uptake in Non-Scheduled Generation and distributed PV

Non-Scheduled Generation and distributed PV output continued to trend upward, reaching 35.3% of total generation (Figure 65).

Figure 65 Over 30% of Non-Scheduled Generation and distributed PV generation in Q4 2020

WEM generation fuel mix (%) – Q4 2020



Key shifts compared to Q4 2019 included:

- Grid solar generation increased by 36 MW on average (from 7 MW to 43 MW), due to connection of the 100 MW Merredin Solar Farm. The facility completed commissioning in August 2020, and by December 2020 its generation was close to its nameplate capacity at times of peak generation.
- Wind generation increased by 123 MW on average (+45%) due to connection of Yandin (212 MW) and Warradarge (180 MW) wind farms.
  - Warradarge completed commissioning in November 2020 and for the remainder of the quarter frequently generated close to its nameplate capacity, providing 18% of the total wind generation in Q4.
  - Yandin wind farm has entered the final stage of commissioning and provided 17% of Q4 wind generation, despite being constrained on several occasions.
- Figure 66 shows the increase in output from the three newly connected Non-Scheduled Generators and their contribution to the total wind and grid solar output.
- Estimated distributed PV output increased on average by 58 MW (+21%), with estimated total installed capacity of 1,586 MW at the end of December 2020. Q4 set another distributed PV generation record of 1,238 MW (equal to Q3 record) on 29 October 2020. Figure 67 shows the increasing trend in distributed PV output across Q4s, when this type of generation is typically at the highest point.

Figure 66 Newly connected Non-Scheduled Generators increasing total VRE output

Generation from Non-Scheduled Generators connected in 2020 and total Non-Scheduled Generation

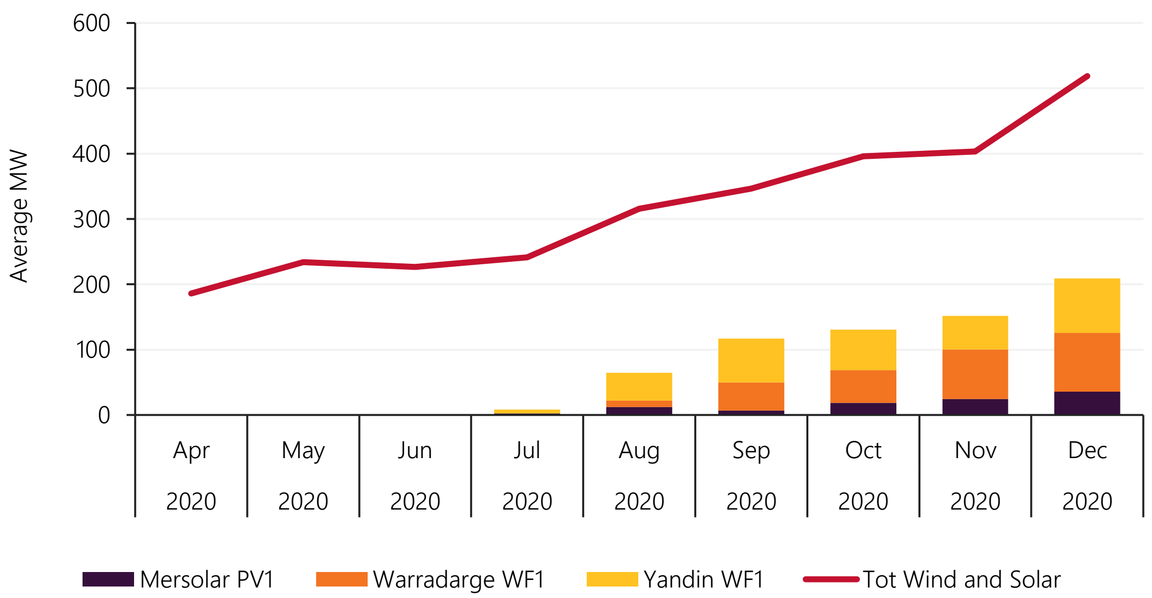
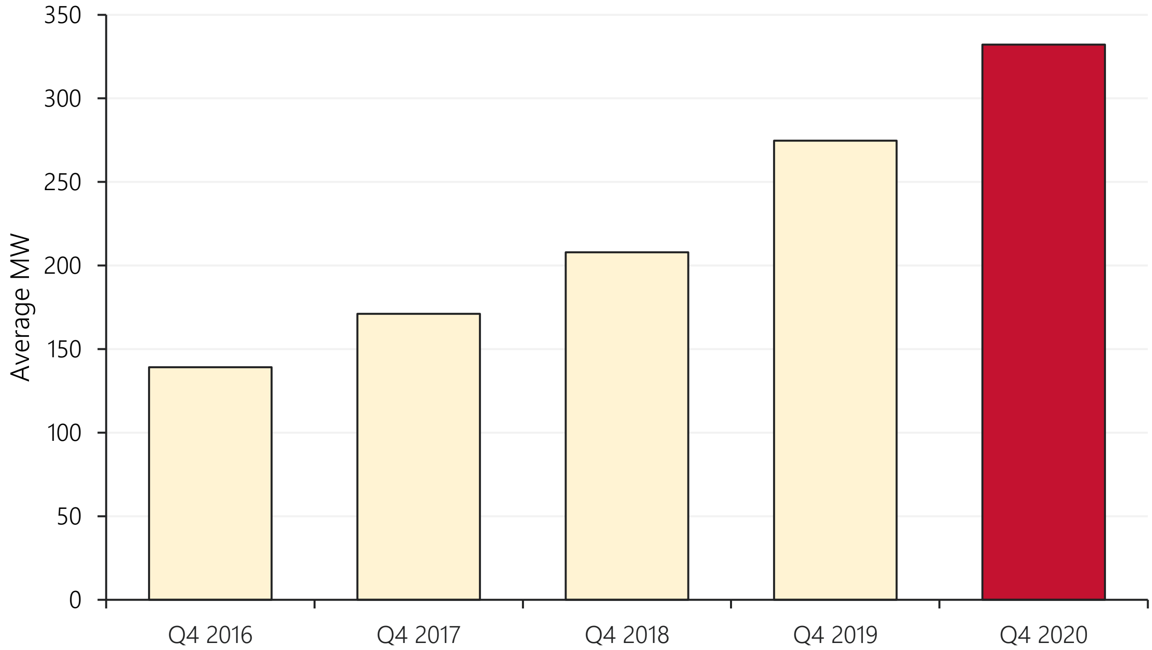


Figure 67 Distributed PV output continued to trend upwards

Distributed PV quarterly output – Q4s



The increase in Non-Scheduled Generation and distributed PV led to a record value of estimated instantaneous percentage of 61.5% of the total underlying demand[41] met from these sources at 1439 hrs AWST on 3 October 2020.

Decline in coal-fired generation and GPG; record minimum generation from Synergy Balancing Portfolio

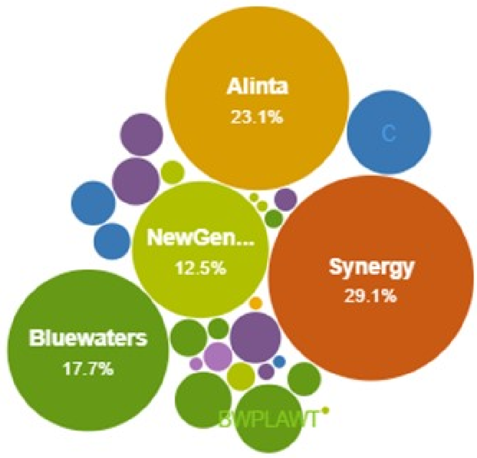
The changes in fuel mix described above led to a decline in coal-fired generation and GPG compared to Q4 2019, with coal-fired generation decreasing by 186 MW and gas generation by 89 MW.

These changes occurred despite increased availability of coal-fired generation (+7%), and similar GPG availability. The average decrease occurred through almost the entire day, except for few intervals overnight for gas generation. Scheduled Generation decreasingly contributed to providing energy at the evening peak in demand.

On average, one less coal facility was operational through Q4 2020 compared to Q4 2019. This contributed to a record minimum quarterly generation percentage from the Synergy Balancing Portfolio (31% of total generation, 10% less compared to Q4 2019). The minimum monthly percentage occurred in October 2020 where the percentage went below 30% (29%), for the first time (Figure 68).

Figure 68 Minimum Synergy generation share

Generation share by Market Participant – October 2020



[41] Underlying demand is equal to operational demand plus estimated demand met by distributed PV.

3.3 Wholesale electricity prices

3.3.1 Short Term Energy Market (STEM) and Balancing Market Summary

The quarterly average Balancing Price decreased by 13% relative to Q3 2020, reaching the lowest average since Q2 2015 at $42/MWh (Figure 69). Changes to pricing since Q4 2019 include:

- **Negative price intervals** – there were 4.5 times more negatively priced intervals in Q4 2020 than in Q4 2019, with over 10% of total intervals being negatively priced (Figure 70).
- **Fewer high-priced intervals** – In addition to this, Q4 2020 had the lowest occurrence (11%) of Trading Intervals priced above $75/MWh of the last five quarters.

Drivers of lower Balancing Prices this quarter included increased generation from the three new Non-Scheduled Generators, that bid at negative prices, and falling demand (Section 3.1).

The STEM followed the same trend, with average prices reducing 19% relative to Q3 2020. This was combined with an average increase in cleared quantity of 4.4 MWh per interval driven by changes in Market Participants' bidding behaviour.

Figure 69 Decrease in Balancing and STEM Prices

WEM Balancing Price, STEM Price, and STEM cleared quantity by quarter

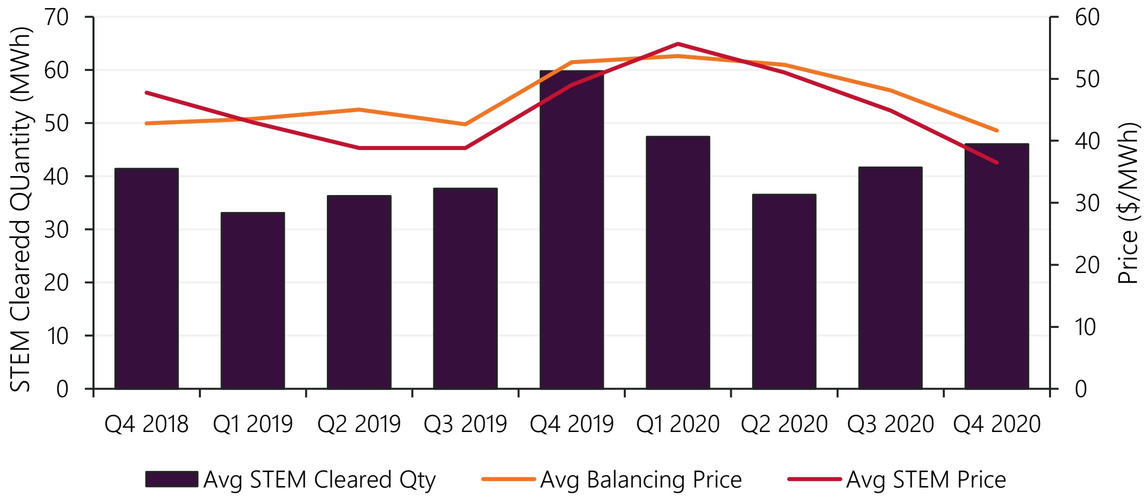
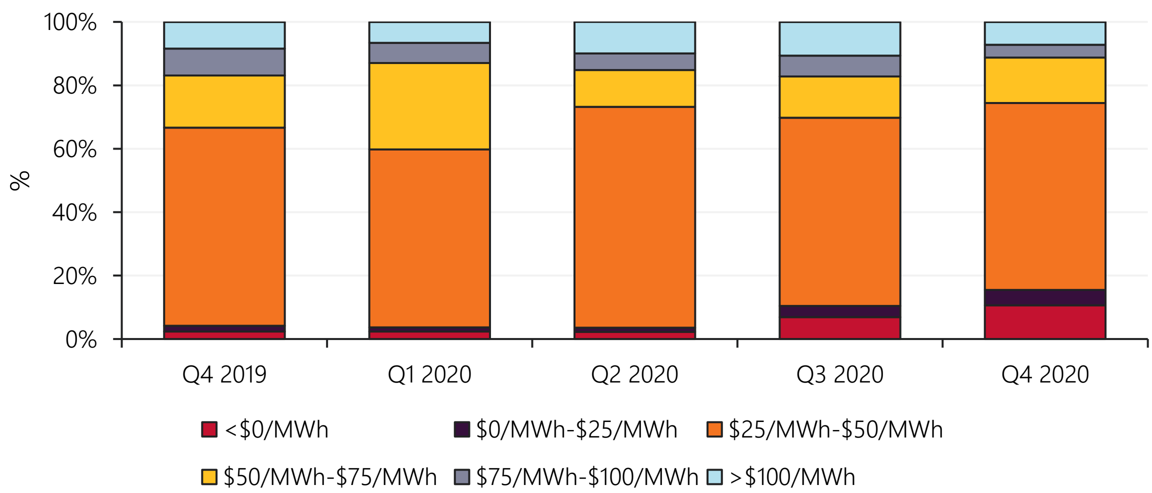


Figure 70 Increased occurrence of negative priced intervals in Q4 2020

Balancing Price Distribution

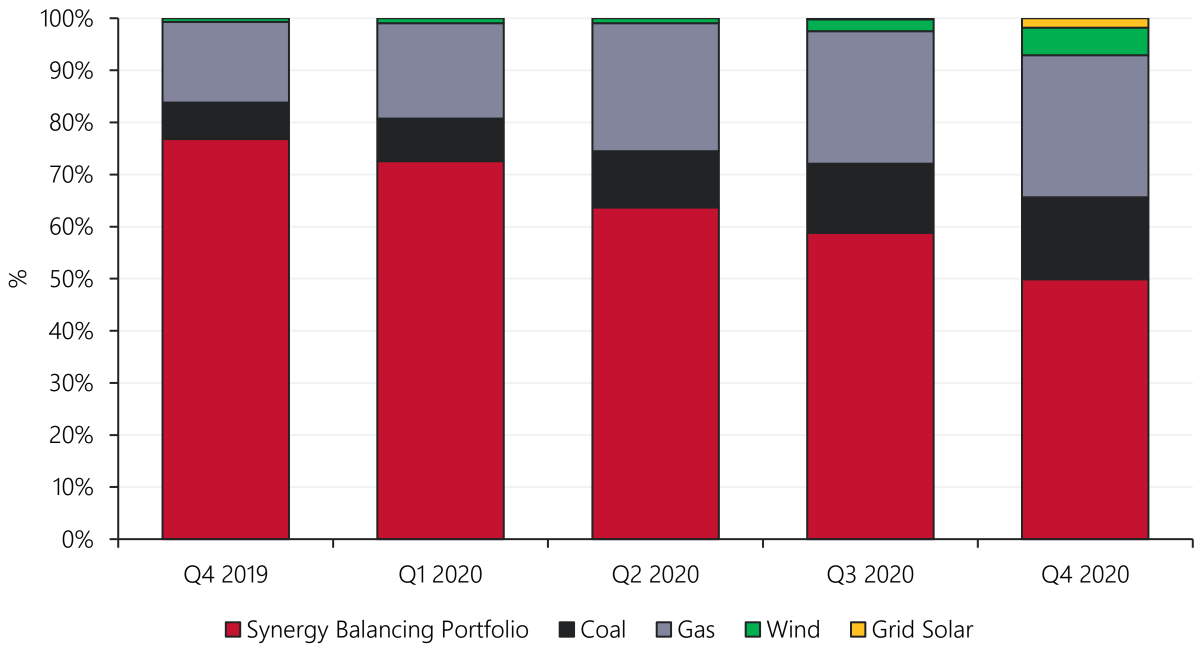


Changing Price Setter Dynamics

The price setter in the WEM Balancing Market has historically been the Synergy Balancing Portfolio the majority of the time. However, this quarter – for the first quarter on record – the price was set by the Synergy Portfolio in fewer than 50% of intervals. The remaining 50% was split, 43% by scheduled generation (coal and gas) and 7% by renewable generation (Figure 71). This change in price setting dyanmics is indicative of increased competition in the WEM.

Figure 71 Price was set by the Synergy Balancing Portfolio less than 50% of time for the first time

Balancing Price Setters



3.3.2 Load Following Ancillary Service costs

AEMO introduced a 'sculpted' approach to LFAS procurement in Q3 2019 to reflect greater variability of distributed PV. The average LFAS quantity was about the same, however the quantity increased during daylight hours and reduced at other times. This improvement, combined with increased competition in the LFAS market (three new facilities were providing LFAS compared to start of 2019), led to more efficient dispatch across energy and LFAS and a downward trend in total LFAS costs over 2019 and 2020.

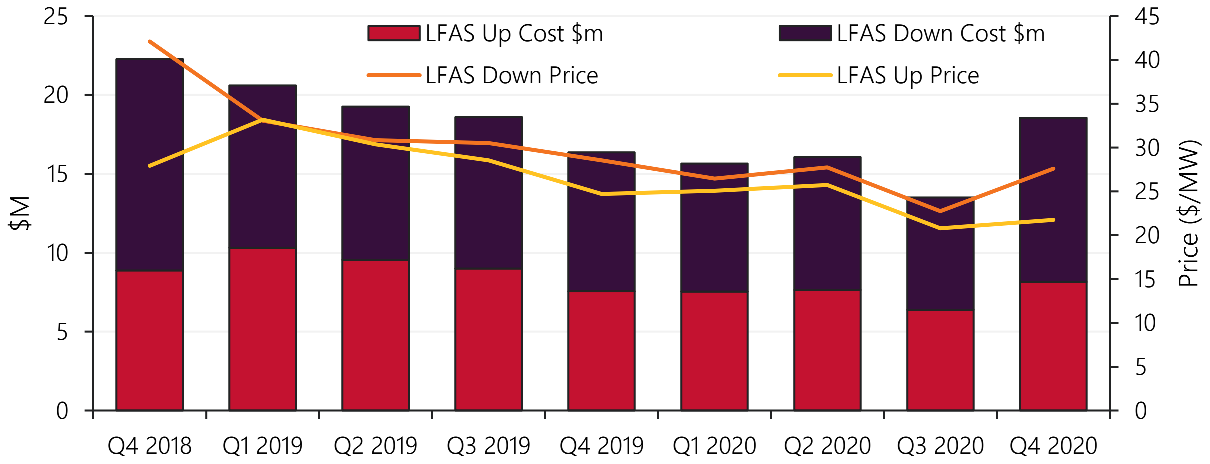
Conversely, total LFAS costs increased in Q4 2020 mainly due to new increased Ancillary Service Requirements, primarily necessary to accommodate the connection of approximately 500 MW of new Non-Scheduled Generation. On 22 September 2020 the LFAS Requirement Upwards and Downwards LFAS changed as follows:

- Increased from 85 MW to 95 MW between 0530 hrs and 1930 hrs.
- Increased from 50 MW to 70 MW between 1930 hrs and 0530 hrs.

Therefore Q4 2020 was the first full quarter of the new requirement in place, resulting in increased costs and prices between Q3 and Q4 2020 (Figure 72). Total costs were similar to costs prior to the introduction of sculpted LFAS, when the LFAS requirement was lower on average. This was likely due to the greater participation in LFAS through 2020.

Figure 72 Increase in LFAS costs in Q4 2020 due to increase in Non-Scheduled Generation Capacity

Quarterly LFAS Upward and LFAS Downward costs since Q4 2018



3.4 Reserve Capacity Mechanism (RCM)

The start of Q4 2020 marks the commencement of the 2020-21 Capacity Year. During the quarter, AEMO also assigned Capacity Credits for the 2022-23 Capacity Year. Key insights from each process are summarised below.

2020-21 Capacity Year commencement

The total quantity of Capacity Credits assigned[42] increased by 77.6 MW compared to the 2019-20 Capacity Year. The increase is mostly due to the assignment of Capacity Credits to the Yandin Wind Farm (212 MW generation capacity) and the Warradarge Wind Farm (180 MW generation capacity), which were assigned a combined total of 77.1 MW of Capacity Credits.

The Yandin Wind Farm is currently being commissioned, while the Warradarge Wind Farm has achieved Commercial Operation status for the purposes of the RCM.

2020 Reserve Capacity Cycle

Assignment of Capacity Credits for the 2022-23 Capacity Year was completed during Q4 2020 as part of the 2020 Reserve Capacity Cycle. In summary:

- The East Rockingham resource recovery facility (the second waste to energy plant in the SWIS after Kwinana waste to energy) was assigned 25.1MW of Capacity Credits. This plant will convert 330,000 tonnes of residual and bio-solid waste from the Perth metropolitan area into electricity and other products[43].
- For the first time, 0.7 MW of Capacity Credits were assigned to energy storage technology as part of an Intermittent Non-Scheduled Generator upgrade[44].

[42] Available at: www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Assignment-of-capacity-credits.

[43] https://arena.gov.au/projects/east-rockingham-waste-to-energy/

[44] Available at: www.aemo.com.au/-/media/files/electricity/wem/reserve_capacity_mechanism/assignment/2020/capacity-credits-assigned-for-the-2022-23-capacity-year.pdf?la=en

Abbreviations

Abbreviation	Expanded term
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
APLNG	Australia Pacific LNG
AWST	Australian Western Standard Time
COVID-19	Coronavirus disease 2019
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
GBB	Gas Bulletin Board
GJ	Gigajoule
GLNG	Gladstone LNG
GPG	Gas-powered generation
GSH	Gas Supply Hub
IRSR	Inter-regional settlement residue
JKM	Japan Korea Marker
LCA	Linepack Capacity Alert
LFAS	Load Following Ancillary Services
LNG	Liquefied natural gas
MSP	Moomba to Sydney Pipeline
$MtCO_2$-e	Million tonnes of carbon dioxide equivalents
MW	Megawatt
MWh	Megawatt hour
NEM	National Electricity Market
NGP	Northern Gas Pipeline
OPEC	Organisation of Petroleum Exporting Countries
PJ	Petajoule

Abbreviation	Expanded term
PV	Photovoltaic
QCLNG	Queensland Curtis LNG
QNI	Queensland to New South Wales Interconnector
RBP	Roma to Brisbane Pipeline
RCM	Reserve Capacity Mechanism
RERT	Reliability and Emergency Reserve Trader
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TJ	Terajoule
TWh	Terawatt hours
VRE	Variable renewable energy
WEM	Wholesale Electricity Market