Quarterly Energy Dynamics Q3 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 Q3 2020 (1 July to 30 September 2020). This quarterly report compares results for the quarter against other recent quarters, focusing on Q2 2020 and Q3 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	21 October 2020	

AEMO INSIGHTS

Executive summary

East coast electricity and gas highlights

Wholesale electricity and gas market price decline continues

- Mainland National Electricity Market (NEM) spot electricity prices[1] declined by 45-48% compared to Q3 2019, reaching the lowest Q3 level since 2014.
  - Queensland's quarterly average price of $32 per megawatt hour (MWh) represents its lowest Q3 level since 2014, and the lowest NEM mainland quarterly price since Q2 2015.
  - Drivers included a shift in offers from black coal-fired generators to lower prices, falling gas prices, increased variable renewable energy (VRE) output, and a 1.4% reduction in operational demand.
- Wholesale gas market prices reduced almost 50% compared to Q3 2019, reaching the lowest Q3 level since 2015. The Gas Supply Hub (GSH) price of $3.85 per gigajoule (GJ) was its lowest quarterly average since Q4 2015, while the Victorian price of $4.57/GJ was its lowest since Q1 2016. Drivers included:
  - A continuation of comparatively low international oil and gas prices, which have influenced domestic gas market offers. Low Asian Japan Korea Marker (JKM) gas prices at the end of Q2 and into Q3 2020 are inputs into the Australian Competition and Consumer Commission's (ACCC's) average netback price, which fell to $2.60/GJ, its lowest level since reporting commenced.
  - A 5% reduction in east coast gas demand compared to Q3 2019, due to reduced levels of liquefied natural gas (LNG) export (-11 PJ), as well as lower gas-powered generation (GPG) (-9 PJ). Australia Pacific LNG (APLNG) recorded the main reduction in flows to Curtis Island for LNG export, with both its major customers declaring downward quantity tolerance for 2020[2].

Reduced energy demand in Victoria

- In Victoria, a combination of strict COVID-19 restrictions and mild weather in the second half of the quarter resulted in a 90 MW average reduction in underlying electricity demand[3] in Victoria compared to a 5 MW reduction for the remainder of the NEM. COVID-19 influenced the demand shape, with a significant reduction in the morning peak between 0600 and 0800 hrs, partially offset by small increases in daytime demand and a higher evening peak.
- Victoria's gas demand profile was also affected, most noticeably on cold days with high heating demand. On those days the morning peak occurred two hours later in the day, and remained high during the day, although overnight demand was lower than in previous years.
  - Additional operational and market measures, such as the use of the Dandenong LNG, were required to manage this increased daytime demand.

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[1] 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.

[2] Origin Energy, 2020 Full Year Results: https://www.originenergy.com.au/content/dam/origin/about/investors-media/presentations/200820_FY20_investor_pres_final.pdf.

[3] Underlying demand means all the electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' rooftop photovoltaic (PV) and battery storage.

Other highlights

- New minimum operational demand records were set in South Australia (379 megawatts [MW]) and Victoria (3,073 MW)[4], largely due to increased penetration of distributed photovoltaic (PV), with installations continuing at record levels.
- Hydro generation declined to its lowest Q3 level since 2008, driven by dry Tasmanian conditions which limited hydro output in the region.
- NEM-wide solar and wind curtailment increased to almost 6% of total VRE output. Increases were driven by new North Queensland system strength arrangements (which were subsequently triggered by a series of plant outages), as well as increased economic curtailment in response to negative spot prices (which occurred at the highest quarterly level on record).

Western Australia electricity and gas highlights

- The WEM recorded two new all-time minimum demand records, with operational demand falling to 1,037 MW on Saturday 12 September and falling again to 999 MW the next day (136 MW lower than the previous record set in Q1 2020).
- Growth in VRE output and distributed PV continued to displace coal-fired and gas-powered generation.
  - Compared with Q3 2019, increases in distributed PV generation (+28 MW on average) drove lower average operational demand (-23 MW).
  - Combined increases in average generation from large-scale wind and solar (69 MW and 13 MW respectively) and distributed PV displaced generation from coal (-40 MW) and gas (-64 MW).
- The Balancing Price cleared at the floor price of -$1,000/MWh on two occasions (for six Trading Intervals). The only other occurrence of floor prices was for three Trading Intervals in Q3 2019.
- Between Q3 2019 and Q3 2020, increases in average Balancing Prices largely occurred during evening peaks, with midday Balancing Prices remaining low.
- Gas consumption remained the same as Q3 2019, driven by relatively small changes in temperature, while production decreased by 7% due to facility outages.

[4] These records have since been broken in Q4 2020.

Contents

1. NEM market dynamics

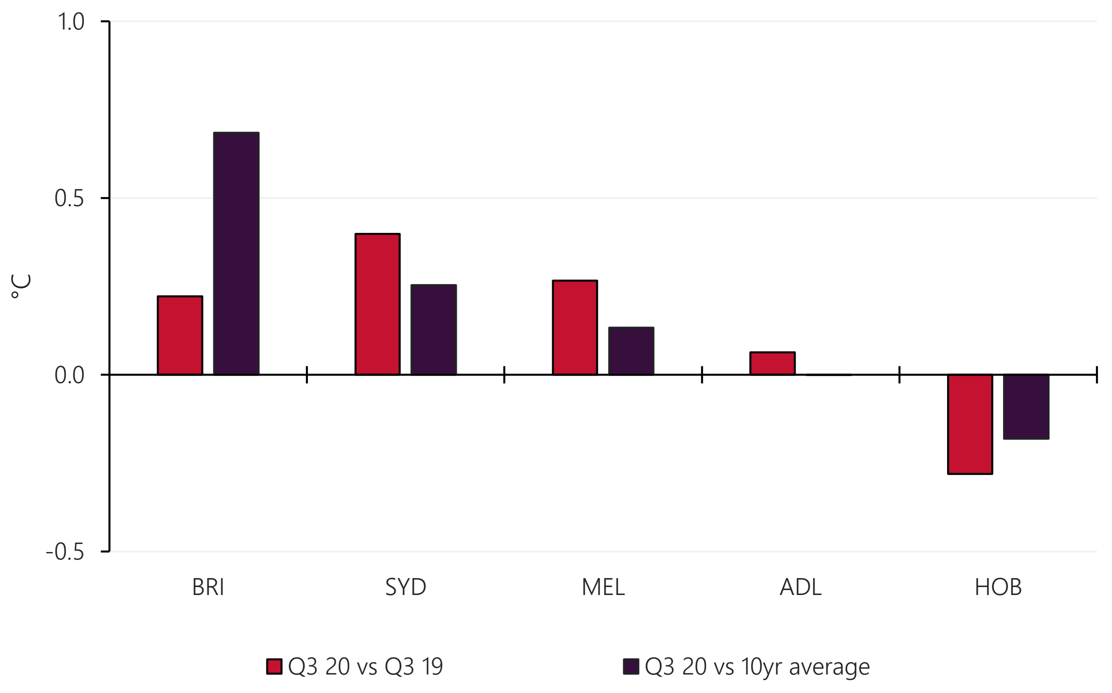
1.1 Weather

The weather over the quarter was warmer than average across all east coast capitals apart from Hobart (Figure 1). Average minimum temperatures in Sydney and Melbourne were around 0.2°C above the 10-year average, resulting in small reductions in heating requirements.

Tasmania experienced very dry conditions during the quarter, largely driven by below average rainfall in July and September[5], while rainfall in Victoria was also below average.

Figure 1 Warmer average mainland temperatures in Q3 2020

Average minimum temperature variance by capital city – Q3 2020 vs 10-year Q3 average



Source: Bureau of Meteorology

1.2 Electricity demand

In Q3 2020, NEM average operational demand decreased by 313 MW (-1.4%) compared to Q3 2019, due to increased distributed PV[6] (+218 MW) and reduced underlying demand (-95 MW, Figure 2).

This year, record uptake of distributed PV during the COVID-19 pandemic[7] has accelerated the declining daytime demand trend. Compared to Q3 2019, New South Wales distributed PV output increased the most on an absolute basis (+75 MW on average), while South Australia increased the most as a proportion of underlying demand (2%, more than double the next highest region).

[5] Bureau of Meteorology 2020, Tasmania in July 2020: http://www.bom.gov.au/climate/current/month/tas/archive/202007.summary.shtml

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

[7] Clean Energy Regulator 2020, Quarterly Carbon Market Report – June Quarter 2020: http://www.cleanenergyregulator.gov.au/DocumentAssets/Documents/QCMR%20June%20Quarter%202020.pdf

With small changes in heating requirements compared to Q3 2019, changes in underlying demand were mostly driven by the continuing impacts of the response to the COVID-19 pandemic:

- Victoria, with the strictest COVID-19 restrictions in place and mild weather in the second half of the quarter, recorded the largest reduction in underlying demand (-90 MW on average), followed by Queensland (-52 MW). Section 1.2.1 provides further details on the COVID-19 related impact on Victorian electricity demand.
- South Australia's underlying demand increased by 52 MW on average, driven by COVID-19 related increases in residential heating, and higher industrial load.
- COVID-19 influenced the demand shape, with a significant reduction in the morning peak between 0600 hrs and 0800 hrs, partially offset by small increases in daytime demand and a higher evening peak.

Figure 2 NEM operational demand down 1.4%

Change in NEM-average operational demand by time of day (Q3 2020 versus Q3 2019)

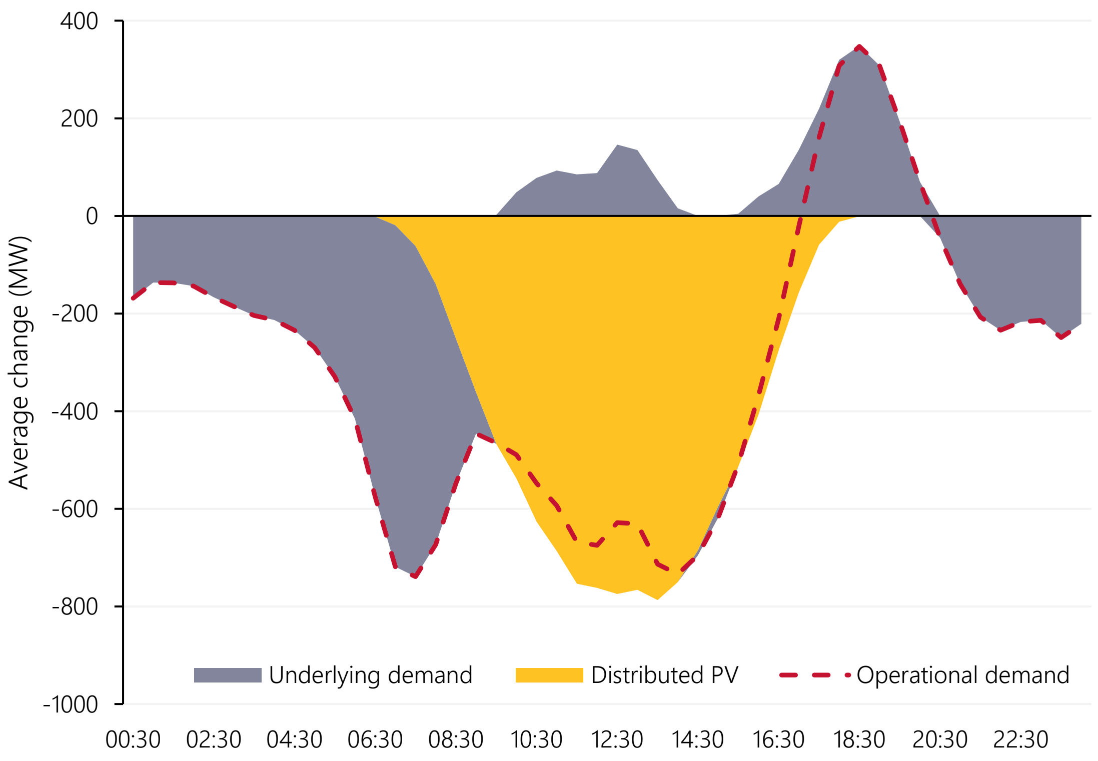


Table 1 Average change in underlying demand, distributed PV, operational demand – Q3 20 vs Q3 19

Average MW	Queensland	New South Wales	Victoria	South Australia	Tasmania
Operational demand	-115	-89	-136	+20	+7
Underlying demand impact	-52	-14	-90	+52	+9
Distributed PV impact	-63	-75	-46	-32	-2

Maximum and minimum demand

Table 2 outlines the maximum and minimum demands which occurred in Q3 2020. During the quarter, new minimum demand records were set in South Australia and Victoria[8]:

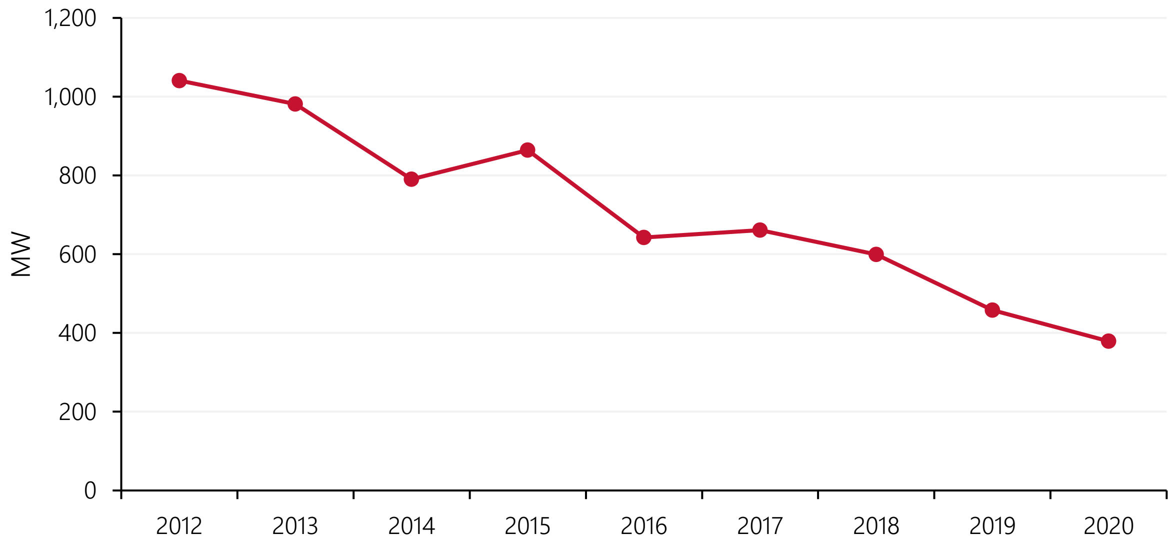
- Victoria's new minimum demand record of 3,073 MW occurred at 1300 hrs on Sunday 6 September 2020, and was 144 MW lower than the previous record set during Q4 2017.
  - During this trading interval, distributed PV provided an estimated 1,408 MW of output (31% of underlying demand), and mild conditions meant there was very little heating load.
  - AEMO's modelling suggests that COVID-19 related measures made a small contribution to setting this new minimum demand record.
- South Australia's new minimum demand record of 379 MW occurred at 1300 hrs on Sunday 13 September 2020[8], and was 79 MW lower than the previous record set during Q4 2019.
  - Drivers were similar to the Victorian record, with distributed PV providing an estimated 923 MW of output (71% of underlying demand).
  - South Australian minimum demands have declined steadily since 2012 (Figure 3).

In addition, a new Q3 maximum demand record of 2,576 MW was set for South Australia at 1900 hrs on 7 August 2020, surpassing the previous record by 46 MW. Drivers of the new record included cold evening conditions, as well a COVID-19 related estimated 83 MW increase in demand (largely residential).

Table 2 Maximum and minimum operational demand (MW) by region – Q3 2020 vs previous records

	Queensland		New South Wales		Victoria		South Australia *		Tasmania	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Q3 2020	8,143	3,985	11,976	5,727	7,844	3,073	2,576	379	1,661	890
All Q3	8,212	2,972	14,289	5,112	8,351	3,601	2,530	574	1,790	792
All-time	10,044	2,894	14,744	4,636	10,576	3,217	3,399	458	1,790	552

Figure 3 South Australian minimum demand record set at 379 MW



[8] These records have since been broken in Q4 2020. As at 20 October 2020, South Australia's record minimum demand is 300 MW, while Victoria's is 3,063 MW.

1.2.1 COVID-19 impact on Victorian electricity demand

During Q3 2020, Victoria was the NEM region most impacted by the COVID-19 pandemic, with stage 4 restrictions that came into effect on 5 August requiring many businesses to close. Key impacts on Victorian demand included:

- **Sectoral impacts** – during Q3, Victorian large industrial demand continued the trend from Q2 and was relatively flat. Commercial demand, however, was significantly reduced due to the stage 4 restrictions (approximately -15%), which more than offset increased residential demand (~10-15%).
- **Seasonality** – as shown in Figure 4, the COVID-19 influenced change in underlying demand varied considerably based on the prevailing season:
  - During July 2020, cold winter conditions meant that increased daytime residential heating load more than offset reduced commercial demand. This resulted in an 1.4% increase in underlying demand compared to July 2019.
  - Moving into September 2020, mild weather meant there was less need for residential heating, so the reduction in commercial demand was the main driver of a 4% fall in underlying demand compared to September 2019.
- **Temperature sensitivity** – during stage 4 restrictions, the increased residential proportion of demand resulted in greater temperature sensitivity. As shown in Figure 5, during cold weather Victoria's underlying demand during the pandemic has been higher than pre-pandemic. Conversely, during mild weather Victorian demand has been at lower levels than pre-pandemic.

Figure 4 COVID-19 reduces Victorian demand; largest impact in September

Change in Victorian-average underlying demand by time of day (Q3 2020 versus Q3 2019)

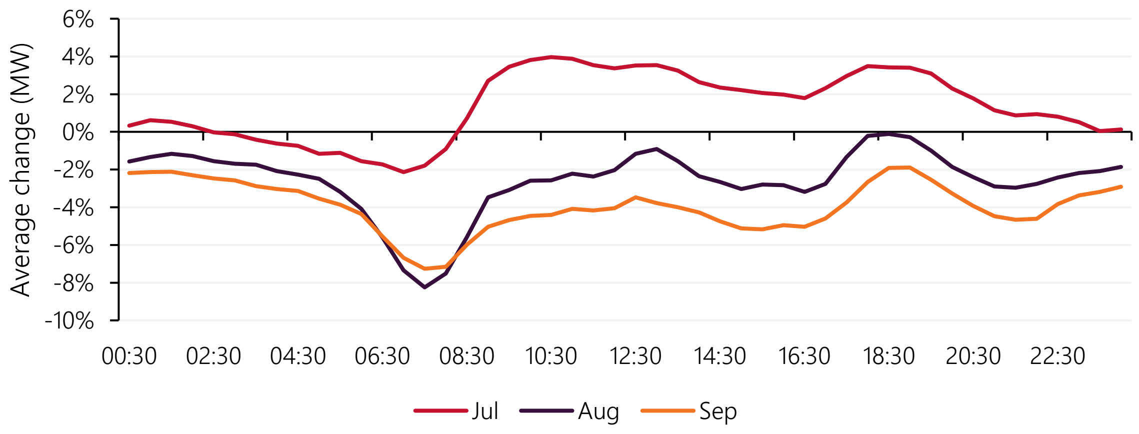
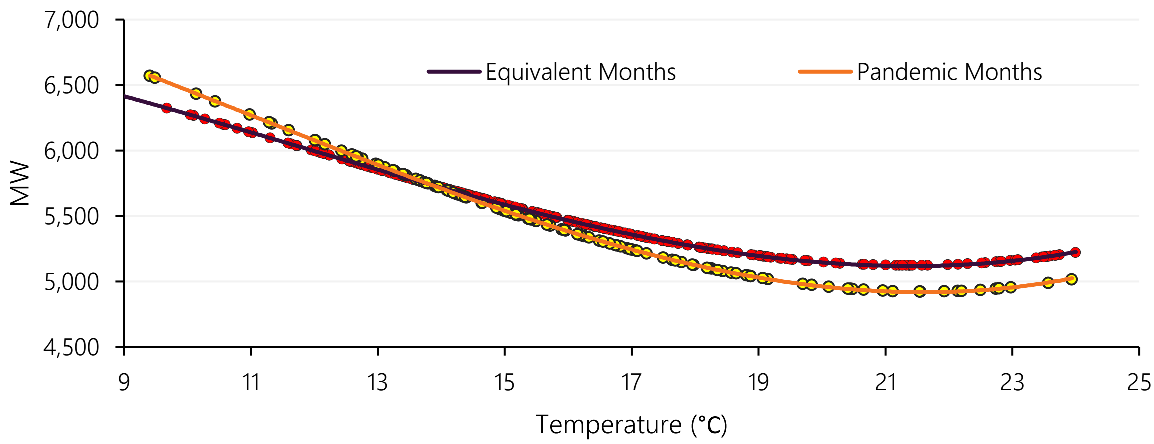


Figure 5 COVID-19 Victorian demand more temperature-sensitive (VIC demand at 1400 hrs)



1.3 Wholesale electricity prices

Mainland NEM average spot electricity prices declined by 45-48% compared to Q3 2019 (Figure 6). Highlights included:

- **South Australia** recorded its lowest Q3 average since 2011 ($40/MWh) while its September average of $15/MWh was its record monthly low.
- **Queensland** remained the lowest-priced NEM region: its quarterly average price of $32/MWh represents its lowest Q3 level since 2014, and the lowest NEM mainland price since Q2 2015.
- **New South Wales** quarterly average ($46/MWh) was the lowest Q3 since 2014.
- The largest reduction in prices by time of day was during the evening peak (down by up to $71/MWh at 1830 hrs) and to a lesser extent the morning peak (Figure 7). Drivers of lower evening peak prices included:
  - Lower-priced offers during the evening peak from GPG, black coal-fired generation, and hydro generation, influenced by falling gas prices.
  - Increased supply from brown coal-fired generation and wind generation during the peak evening period (Section 1.4).

Drivers of the average spot price reductions compared to Q3 2019 included:

- Fewer unplanned outages of coal-fired generators in New South Wales and Victoria, coupled with a shift in offers from black coal-fired generators to lower prices (Section 1.4.1). In particular, Mt Piper and Loy Yang A power stations operated at significantly higher levels than in Q3 2019, with improved coal supply at Mt Piper and the return to full output of unit 2 at Loy Yang A.
- Increased wind and solar generation, with new capacity driving average output increases of 355 MW.
- Reduced operational demand (-1.4%), with continued increases in distributed PV generation reducing daytime demand (Section 1.2).

Figure 6 Lowest Q3 NEM prices since Q3 2014

Q3 average spot electricity prices by NEM region

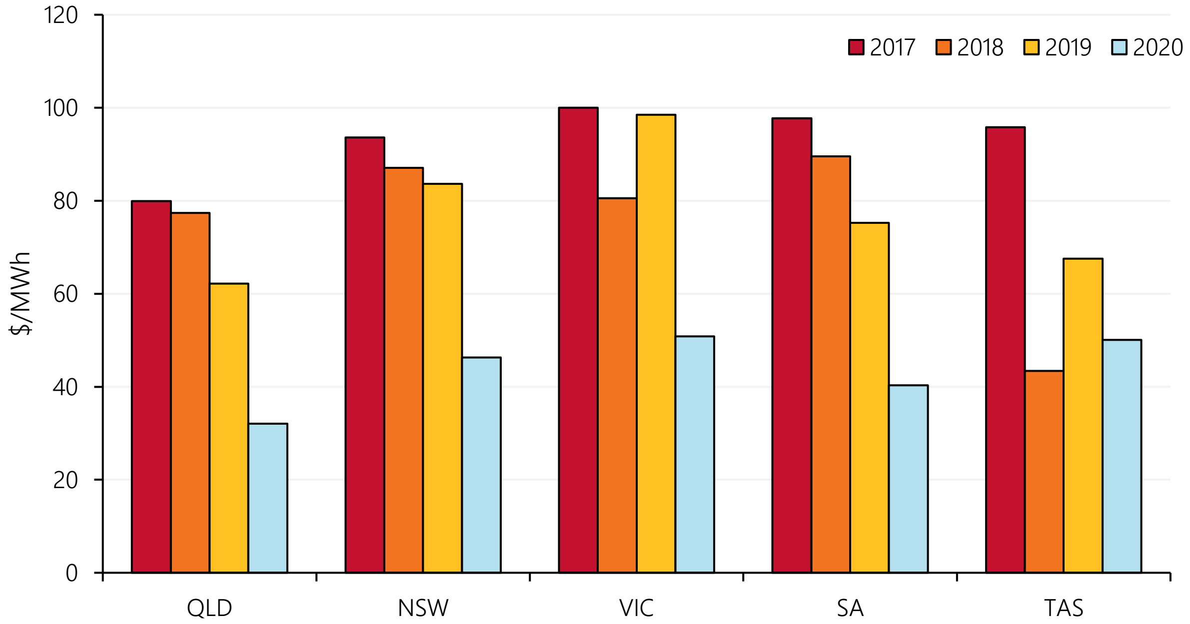
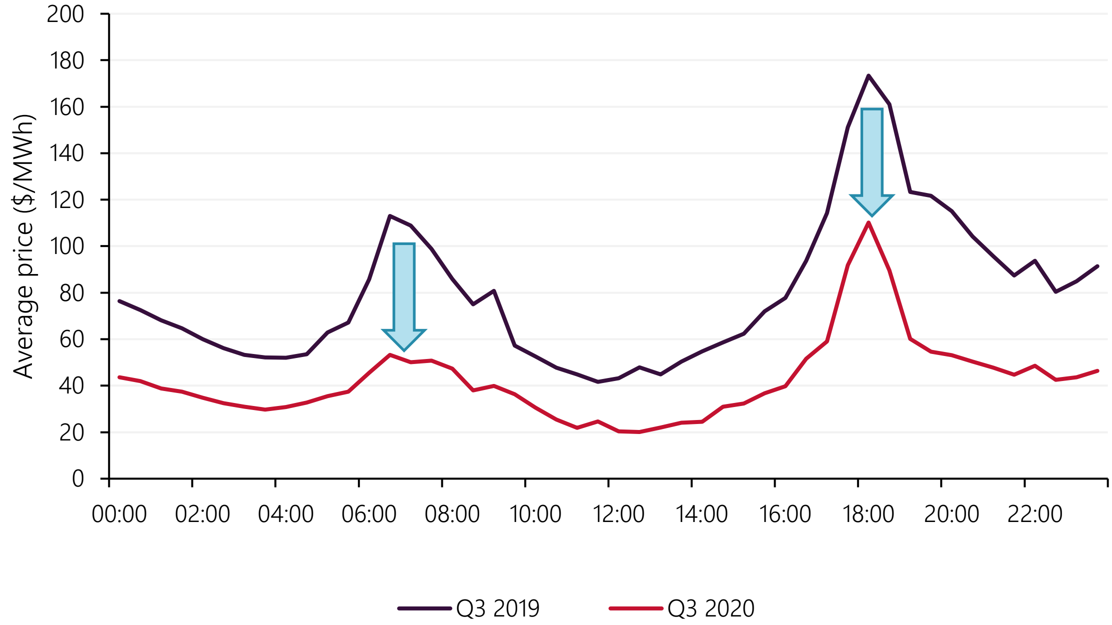


Figure 7 Largest spot price reductions during the evening peak

Mainland NEM average Q3 spot prices by time of day

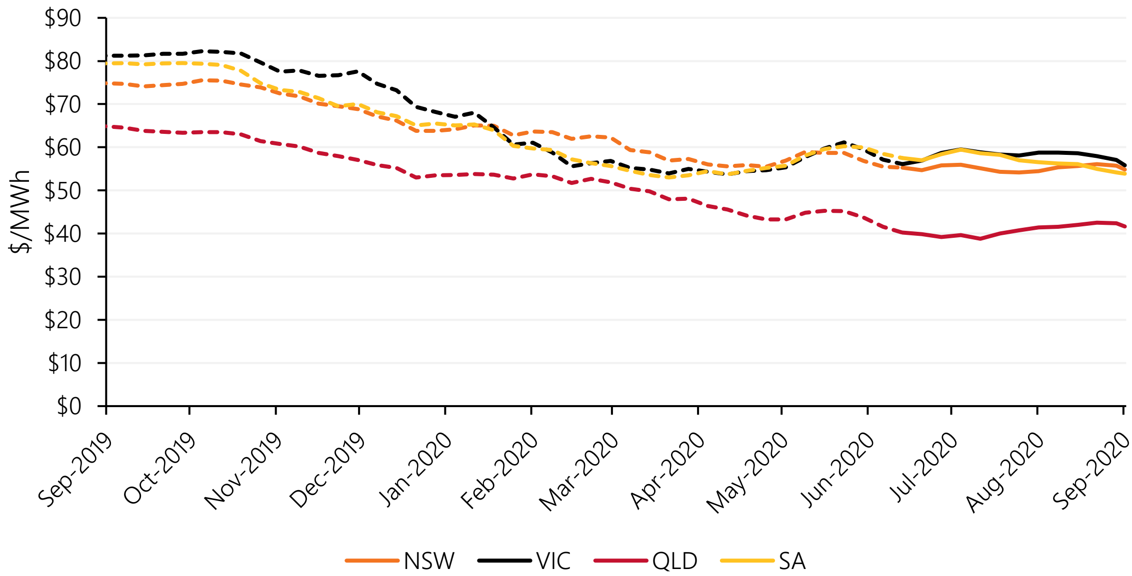


1.3.1 Electricity future markets

During the quarter, NEM electricity futures contract prices traded on the ASX remained at comparatively low levels compared to recent years. At the end of the quarter, calendar year (Cal) 2021 swap contracts averaged $54/MWh across New South Wales and Victoria. South Australia recorded the largest decline, of $8/MWh to finish at $50/MWh, with the decrease coinciding with new constraints on the Heywood interconnector (Section 1.5) and record negative spot electricity prices in the state (Section 1.3.1). Queensland continued to be the lowest priced state and finished the quarter at $40/MWh.

Figure 8 ASX Cal21 futures stabilise

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



1.3.2 Negative wholesale electricity prices

During Q3 2020, negative and zero spot prices[9] occurred in 4.6% of trading intervals, surpassing the previous record set in Q2 2020 (3.6%). The occurrence of negative spot prices was most prominent in South Australia and Queensland, with both states reaching record levels. South Australia's spot prices were negative 10.2% of the time, around 4% higher than the previous record in Q3 2019. In Queensland, spot prices were negative 8.5% of the time compared to 4.5% in Q3 2019.

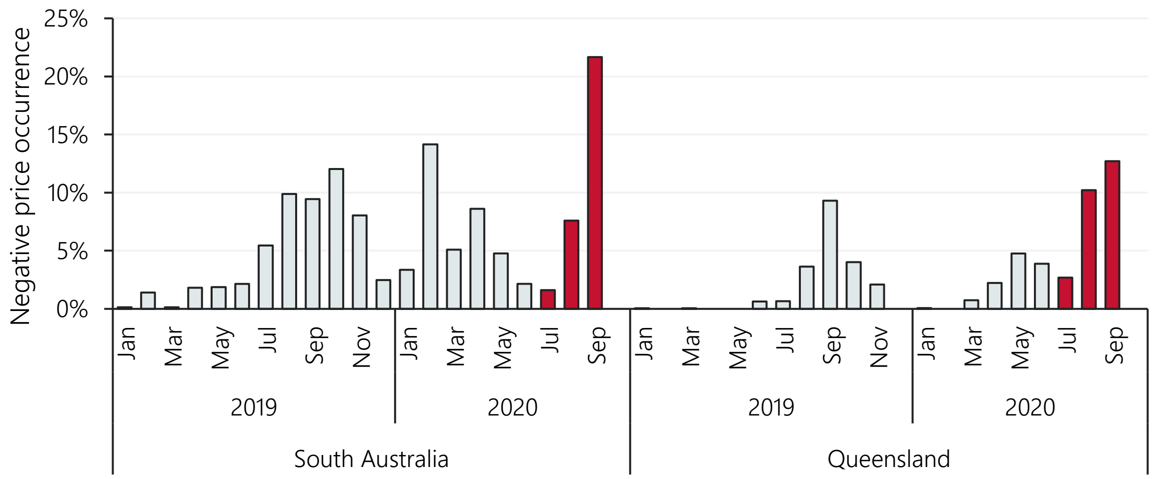
However, the impact of negative prices was less than in Q3 2019. South Australia's quarterly average price was lower by $6/MWh due to negative prices, compared to being lower by $8.2/MWh in Q3 2019. Similarly, Queensland negative spot price impact this quarter was lower, $1.9/MWh compared to $2.7/MWh in Q3 2019. The reduced impact of negative spot prices on the average price was due to the reduced occurrence of highly negative prices (that is, prices below -$100/MWh).

Record quarterly negative spot prices in South Australia were driven by increased occurrences in September, with negative spot prices occurring in 22% of the trading intervals (Figure 9). Drivers included:

- High VRE output – September 2020 was a particularly windy month, as grid-scale VRE exceeded 1,000 MW 47% of the time, compared to 31% in September 2019, and 65% of negative intervals occurring during periods of high VRE output.
- Directed GPG – in December 2019, the Australian Energy Market Commission (AEMC) introduced a rule change which removed intervention pricing when units are directed for system security purposes, with this change (in most circumstances) leading to lower spot prices during directions[10]. On average, 139 MW of GPG was directed during negative spot prices during the quarter.
- Reduced daytime demand – increased distributed PV output reduced daytime demand by 34 MW compared to September 2019 levels, with 76% of negative price intervals occurring during this period.
- Interconnector constraints – Murraylink was binding at its limit more frequently and at lower levels than in Q3 2019, due to a planned outage, as well as constraints which were invoked on 26 August (until its outage) while oscillation issues were being investigated[11]. In addition, a newly introduced reduction in Heywood's import limit into Victoria (Section 1.5) further limited electricity transfers from South Australia to Victoria, contributing to periods of South Australian oversupply.

Figure 9 Record negative price occurrences in South Australia and Queensland

Frequency of negative spot prices in South Australia and Queensland



[9] Hereafter referred to as negative spot prices

[10] When an intervention event brings on additional capacity and counteractions are not implemented, the prices produced by the what-if run will generally be higher than those produced by the dispatch run. This is because the what-if run will continue to signal the price associated with the supply demand balance as it was prior to the intervention, while prices in the dispatch run will generally be lower due to the addition of generation capacity.

[11] See Market Notice 77189.

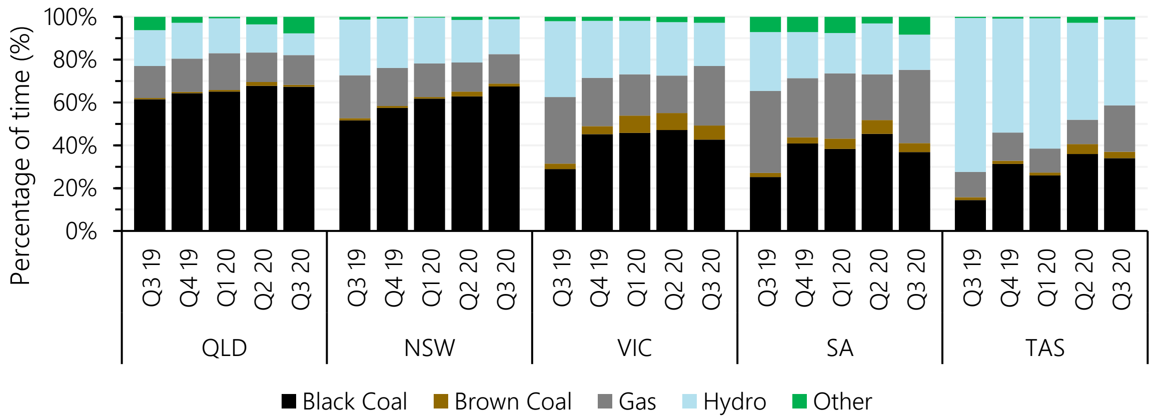
1.3.3 Price-setting dynamics

Figure 10 shows price setting results for Q3 2020 compared to recent quarters. Key outcomes included:

- Hydro's price setting role across the NEM regions declined from an average 35% in Q3 2019 to 21% this quarter, as hydro generation fell to its lowest level since 2008.
- Black and brown coal increased from a combined average of 38% last in Q3 2019 to 53%, mainly as black coal shifted an average of 1,281 MW from higher-priced bands to prices below $40/MWh, and spot prices reduced to levels in which brown coal-fired generation was the marginal unit (typically $0-$20/MWh).
- Grid-scale wind and solar set the spot price 3.3% of the time (combined), the highest level on record.

Figure 10 Hydro's price setting role declined

Price-setting by fuel type – Q3 2020 versus prior quarters



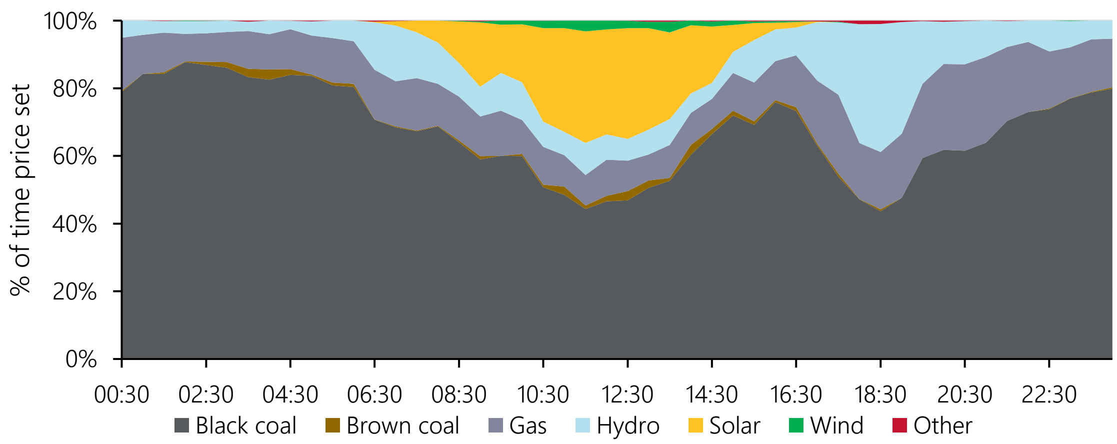
Note: price setting can occur inter-regionally: for example, Victoria's price can be set by generators in other NEM regions.

Figure 11 shows Queensland price setting results for Q3 2020 by time of day. Key outcomes included:

- With the increase in periods of oversupply leading to negative spot prices, grid-scale solar set Queensland's midday price around 30% of the time.
- Black coal set the price on average 67% of the time during the day in Q3 2020, while giving way to grid-scale solar between 1000-1430 hrs (26%), thereafter mainly capturing two blocks 1430-1630 hrs (71%) and 2130-0600 hrs (81%).
- GPG and hydro's price setting roles were highest during the peak evening period at 1830 hrs.

Figure 11 Grid-scale solar sets Queensland's midday price around 30% of the time

Price setting % of time by time of day and fuel type – Queensland Q3 2020



1.4 Electricity generation

During Q3 2020, the NEM generation mix was shaped by a combination of reduced operational demand, dry conditions, and increased supply from lower-priced generation. Figure 12 shows the average change in generation by fuel type compared to Q3 2019, and Figure 13 illustrates the change by time of day.

Compared to Q3 2019:

- Average brown coal-fired generation rebounded from its lowest quarterly average, driven by higher availability from Loy Yang A following the 2019 extended outage of unit 2. In contrast, black coal output declined to its lowest Q3 level since 2014 despite Mt Piper's rebound following its coal supply issues in 2019.
- Despite lower gas prices, average GPG output reduced by 436 MW, as it was less required to cover unit issues at Loy Yang A and Mt Piper, and was displaced by VRE.
- Average hydro generation fell to its lowest Q3 output since 2008. The decline in Tasmanian hydro output was driven by below average rainfall as the state experienced its second driest July on record[12].

Figure 12 Increased output brown coal and VRE

Change in supply – Q3 2020 versus Q3 2019

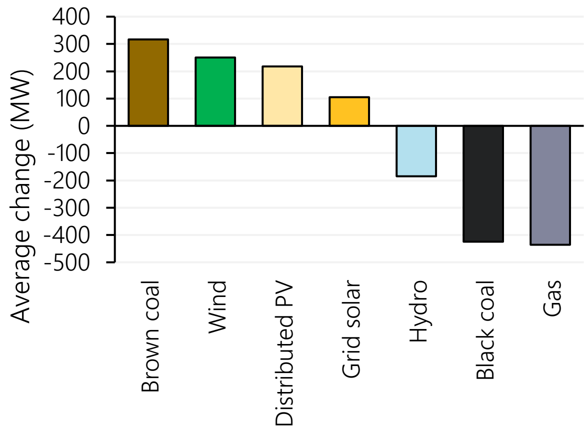
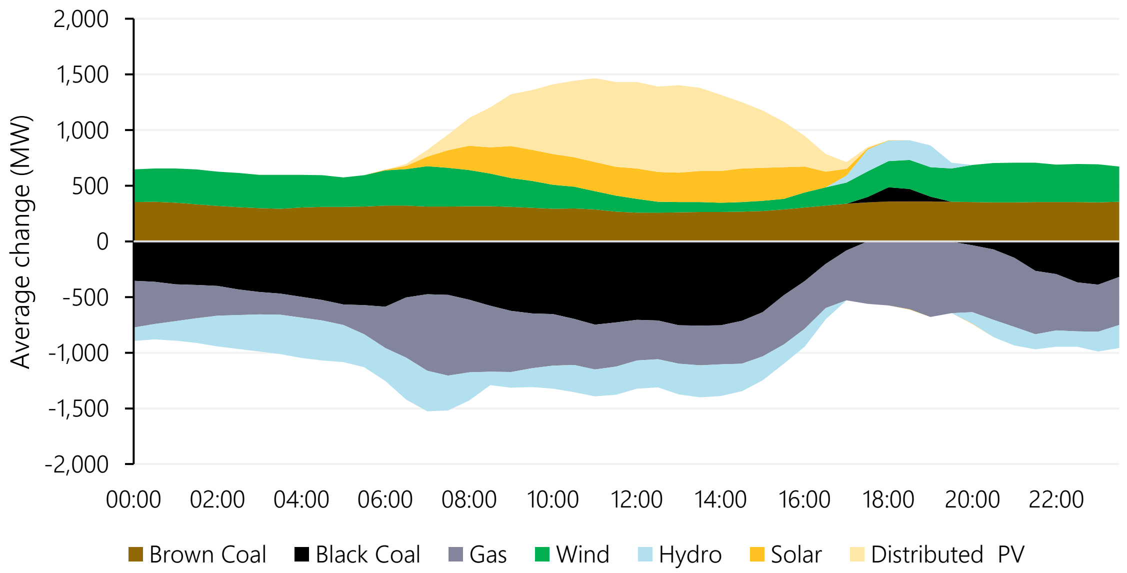


Table 3 NEM supply mix by fuel type

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar
Q3 2019	52.8%	15.6%	10.4%	8.5%	9.8%	2.6%
Q3 2020	51.9%	17.3%	8.6%	7.8%	11.1%	3.1%
Change	-1.0%	+1.7%	-1.8%	-0.7%	+1.3%	+0.5%

Figure 13 Reduced GPG, black coal and hydro across the day, increased VRE and brown coal

Change in supply – Q3 2020 versus Q3 2019 by time of day



12 Bureau of Meteorology 2020, Tasmania in July 2020: http://www.bom.gov.au/climate/current/month/tas/archive/202007.summary.shtml

1.4.1 Coal-fired generation

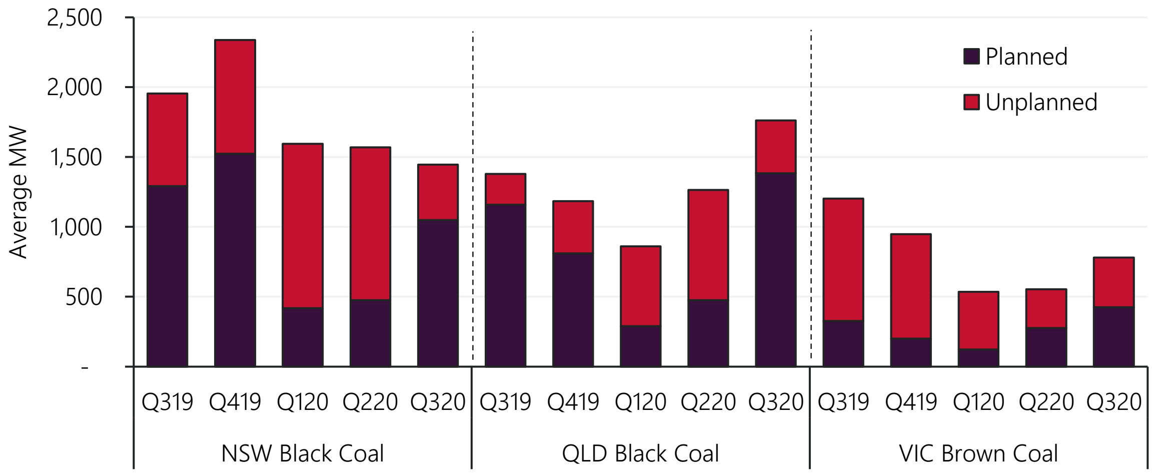
Black coal fleet

During Q3 2020, average black coal generation reduced by 424 MW compared to Q3 2019. Results varied by state, with average output from the New South Wales fleet increasing slightly (+23 MW), while the Queensland fleet fell by 447 MW.

Average black-coal fired generation on outage (mostly planned) was 126 MW lower than Q3 2019, with fewer outages in New South Wales (-509 MW) partially offset by increased outages in Queensland (Figure 14).

Figure 14 Fewer unplanned outages for New South Wales and Victorian coal-fired generators

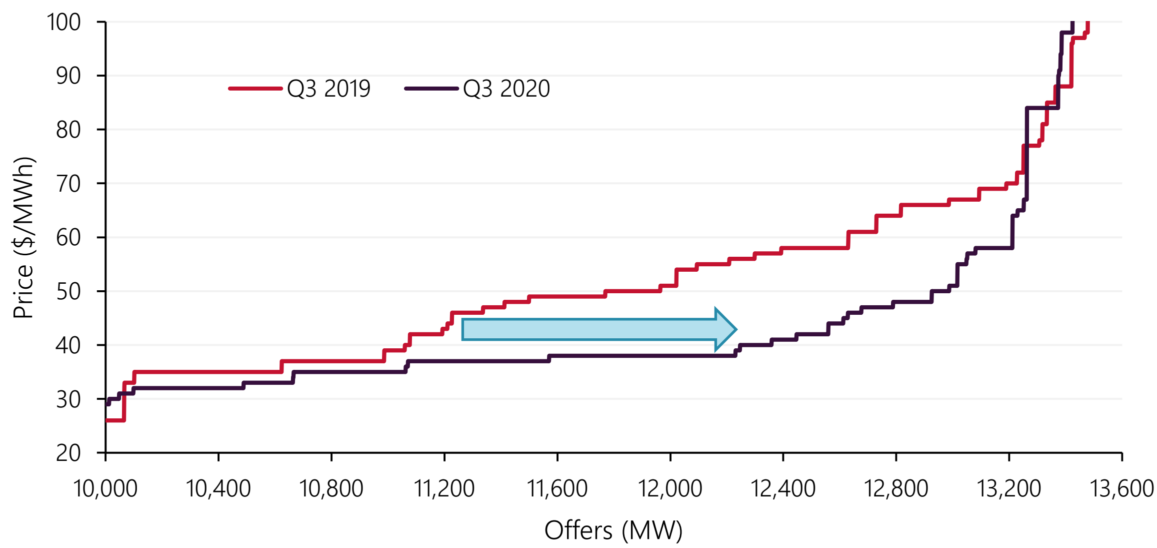
Average black and brown coal-fired generation on outage by classification – Q3 2019 to Q3 2020



The overall reduction in black coal-fired generation occurred despite a significant shift of offers into lower-priced bands. Compared to Q3 2019, an average of 1,281 MW was shifted from higher-priced bands to prices at or below $40/MWh (Figure 15). The AER will explore in more depth in its upcoming reports[13] the drivers of changes in black coal-fired generation bids.

Figure 15 Black coal-fired generation shifting offers to lower prices

NEM black coal-fired generation bid supply curve – Q3 2020 versus Q3 2019



[13] Upcoming Wholesale Markets Quarterly Q3 2020, and Wholesale Electricity Market Performance Report 2020.

In New South Wales, increased generation from Mt Piper (+598 MW) and Bayswater (+62 MW) more than offset lower output from Liddell and Eraring (Figure 16). By station:

- Average output at Mt Piper Power Station increased to 1,032 MW, its highest Q3 generation since 2013. Significantly higher output (+138% on Q3 2019 levels) was predominantly due to the easing of coal supply constraints that severely impacted output in Q3 2019. This was reflected in its availability, with Mt Piper's average days on outage falling from 31 days in Q3 2019 to 3 days in Q3 2020.
- Increased outages (57% planned, 43% unplanned) at Liddell Power Station reduced output by 480 MW on average, its lowest Q3 output since 2014. On average, Liddell units were out of service for 33 days compared to 10 days in Q3 2019.

Average Queensland black coal output this quarter reduced to 5,056 MW, its lowest Q3 generation since 2014. Increased outages across all power stations apart from Kogan Creek and continued displacement by solar and gas were the main drivers for lower output. By station:

- Planned outages at Callide Power Station and displacement by solar reduced coal output by 477 MW.
- Output at Kogan Creek Power Station increased by 575 MW on average, up from historically low levels in Q3 2019. This was mainly due to no repeat of the major outage in Q3 2019.

Brown coal fleet

Average brown coal-fired generation increased by 317 MW compared to Q3 2019, mainly due to higher availability at Loy Yang A, which led to a 447 MW output increase. This was partially offset by decreased output at Loy Yang B (-35 MW) and Yallourn Power Station (-126 MW) due to increased outages – Yallourn also had a high number of unplanned outages in Q3 2019. Yallourn Unit 1 has been on a planned maintenance outage since 3 July 2020 and remained out of service at the end of the quarter.

Figure 16 Mixed results for coal-fired generators

Change in coal-fired generation – Q3 2020 versus Q3 2019

1.4.2 Hydro

Hydro generation declined to 1,726 MW on average, its lowest Q3 output since 2008, and 185 MW lower than Q3 2019 (Figure 17). On a regional basis, compared to Q3 2019:

- Very dry conditions in Tasmania (Figure 18) coupled with low Victorian pool prices reduced Tasmania's hydro generation to its lowest Q3 output since 2008. Compared to Q2 2020, Tasmanian hydro generators bid to conserve water, with generators shifting 258 MW of offers to above $50/MWh. Hydro Tasmania's storage levels remained comparatively low during the quarter, finishing at 41% compared to 48% in Q3 2019, its lowest Q3 finish since 2016 (Figure 19).
- New South Wales hydro generation increased by 22 MW on average, with higher output from Upper Tumut (+24 MW). Above average rainfall at Lake Eucumbene this quarter increased dam levels by 5% to finish the quarter at 33%.
- Average hydro output in Queensland decreased slightly by 12 MW, with reduced output from Barron Gorge and Kareeya (-27 MW combined) partially offset by increased Wivenhoe generation (+15 MW).

Figure 17 Lowest Q3 NEM hydro output since 2008

Average hydro generation by region (Q3s)

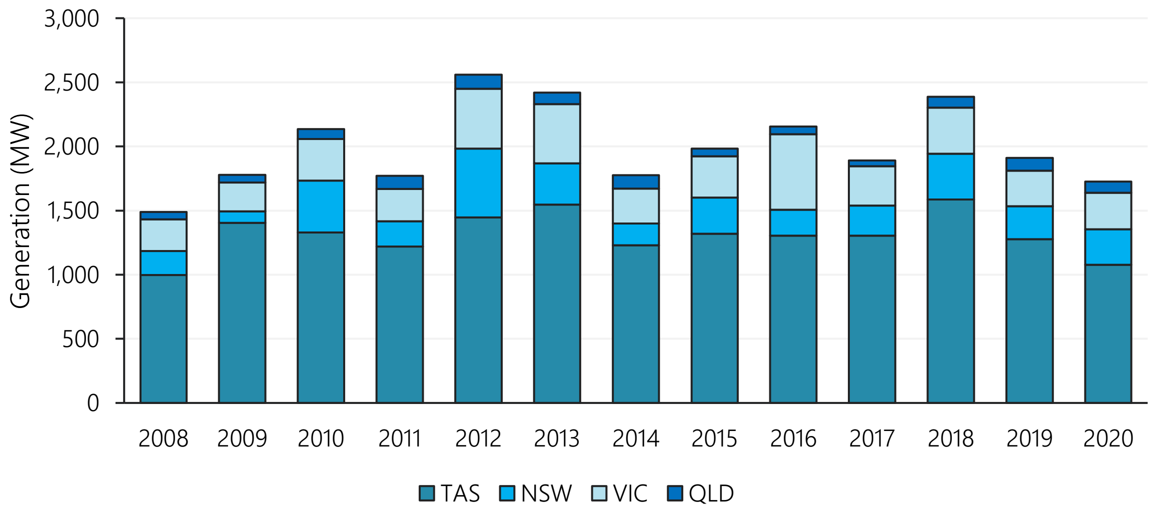


Figure 18 Dry Q3 conditions in Tasmania

Tasmanian rainfall deciles – Q3 2020[14]

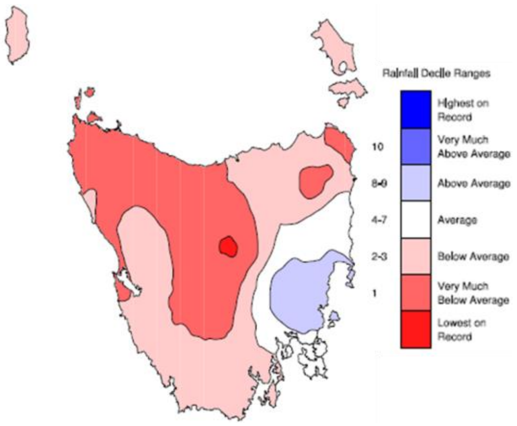
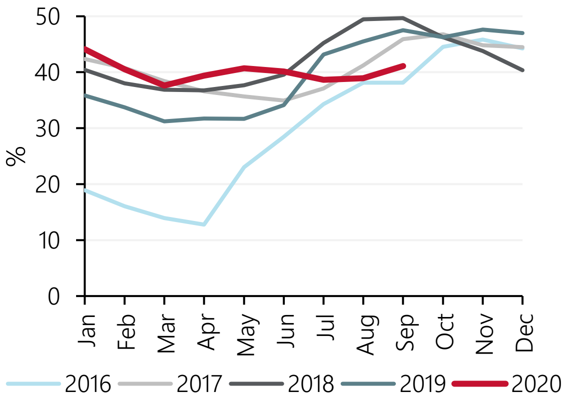


Figure 19 Tasmania storage levels remain low

Monthly Tasmanian water storage levels[15]



[14] Bureau of Meteorology 2020, Tasmanian Rainfall Deciles

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

1.4.3 Gas-powered generation

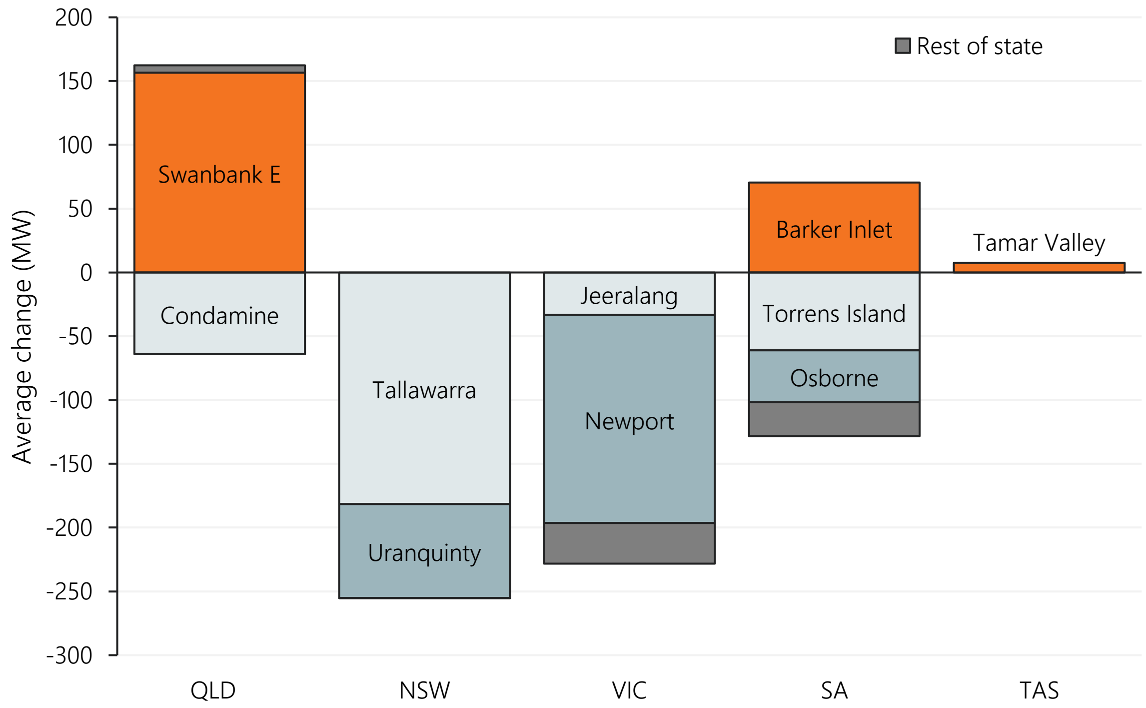
GPG decreased by 436 MW on average compared to Q3 2019 (Figure 20), due to reduced need to cover for coal-fired generator outages (Mt Piper and Loy Yang A), displacement by VRE output, and reduced operational demand. Of note, these GPG reductions occurred despite low spot gas prices (Section 2.2).

On a regional basis:

- New South Wales declined by 255 MW to its lowest Q3 average on record (107 MW). The decline was led by EnergyAustralia's Tallawarra (-182 MW), including a planned 19-day outage, as well as reduced need to cover for Mt Piper outages (Mt Piper had its highest Q3 generation since 2013). Origin Energy's Uranquinty declined 74 MW (despite its Eraring Power Station reducing slightly compared to Q3 2019).
- Queensland GPG continue to generate at higher levels, increasing by 98 MW on average compared to Q3 2019, as gas prices remained low (Section 2.2). Queensland Q3 GPG generation reached its highest Q3 output since 2015, with CleanCo's Swanbank E leading the quarter on quarter increase (+156 MW).
- Victoria declined by 228 MW, led by EnergyAustralia's Newport (163 MW) and Jeeralang (33 MW), mainly due to fewer unplanned brown coal unit outages (Loy Yang A and Yallourn) and increased wind generation.
- South Australia GPG reduced by 58 MW on average, despite increased operational demand and lower local VRE output. Reduced GPG was largely a function of reduced net transfers into Victoria associated with increased Victorian generation (Section 1.5).
  - AGL's Torrens Island reduced by 61 MW on average, which was more than offset by increases from its newer Barker Inlet station (71 MW). Origin Energy's Osborne reduced by 41 MW, with small reductions across the remainder of the GPG fleet.

Figure 20 GPG falls in the southern regions

Change in GPG – Q3 2020 versus Q3 2019



1.4.4 Wind and solar

Compared to Q3 2019, quarterly average VRE output increased by 355 MW, with wind and grid-solar contributing 250 MW and 105 MW, respectively. As new projects continued to ramp up to full output and Q3 typically being the windiest quarter of the year, this resulted in several grid-scale VRE records[16] including:

- **Highest grid-scale VRE share of NEM operational demand** – NEM VRE output met 35% of NEM operational demand at 1130 hrs on 22 September 2020.
- **Highest VRE output on record** – NEM VRE output reached 6,714 MW at 1100 hrs on 21 August 2020.
- **Highest wind output on record** – NEM wind output reached 5,198 MW at 1900 hrs on 22 August 2020.
- **Highest grid-solar output on record** – NEM grid-solar output reached 2,875 MW at 0930 hrs on 27 September 2020.

Wind generation reached a record quarterly high of 2,465 MW on average, surpassing the previous record set in Q3 2019 by 11% (Figure 21). This record was a function of new capacity entering the system in the last year – wind capacity factors were lower than in Q3 2019 due to lower wind speed during the first half of the quarter and increased curtailment (Figure 22). By region:

- Victoria – increased generation (+118 MW) was predominantly due to the continued ramp up of recently commissioned projects offsetting a 6% reduction in average quarterly wind capacity factors due to curtailment and lower wind speeds.
- Queensland – continued ramp up of Coopers Gap wind farm resulted in a 132 MW average increase in output, which more than offset the 25 MW decrease from Mount Emerald wind farm which continued to be affected by Queensland system strength constraints (Section 1.6.2).
- Tasmania – despite two new wind farms since Q3 2019, average Tasmanian wind output only increased marginally by 28 MW, due to a significant drop in wind speed in the region (capacity factors down 13%).

Figure 21 Record quarterly wind generation

Average wind generation by region – Q3 2019 to Q3 2020

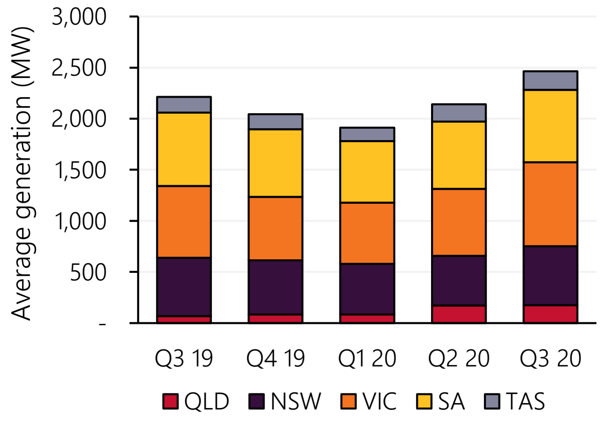
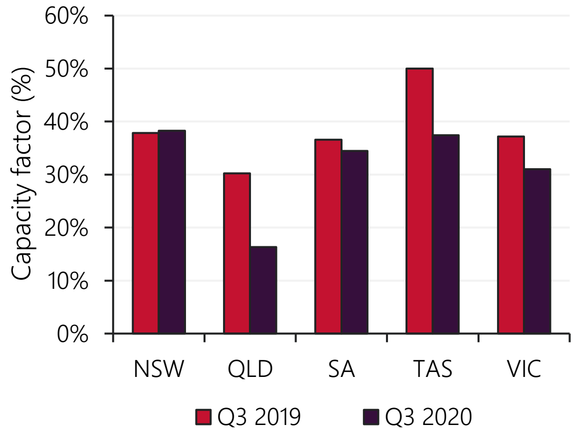


Figure 22 Lower wind capacity factors

Weighted average quarterly wind capacity factors by region (Q3s)[17]



Average grid-scale solar generation was 689 MW this quarter, with the largest increase compared to Q3 2019 occurring in New South Wales (+64 MW). Five new projects commenced generation this quarter:

- New South Wales – Darlington Point Solar Farm (275 MW) and Limondale Solar Farm 1 (220 MW).
- Queensland – Warwick Solar Farm 1 and 2 (64 MW combined).
- Victoria – Kiamal Solar Farm – Stage 1 (200 MW).

[16] Grid-scale VRE records are reported in half hourly time intervals. Some of these records have since been broken in Q4 2020.

[17] Capacity factors of each project are weighted by installed capacity to derive the weighted average by state. Projects that have yet to reach full output by Q3 2019 are excluded from calculation. Note: VWAP capacity factors include self-curtailment from wind farms.

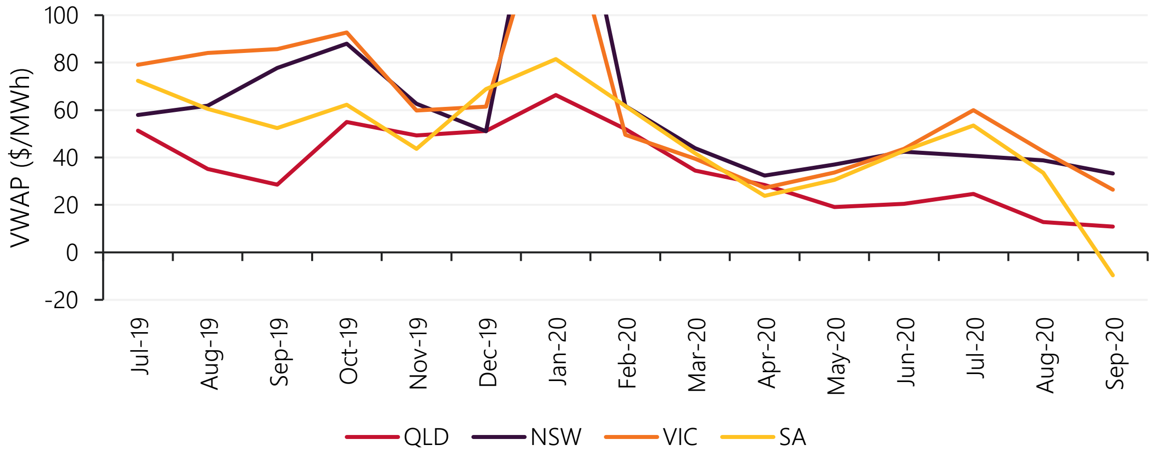
Higher output in New South Wales this quarter was driven by ramping up of installed capacity from previous quarters and to a lesser extent by new capacity additions this quarter. In Queensland, there was a relatively small increase in output (+25 MW) despite new capacity. This was a function of increased curtailment due to negative prices and system strength constraints in North Queensland (Section 1.6.2).

With the declining spot wholesale electricity price (see Section 1.3), the volume weighted price received by both wind and solar generation has fallen significantly in the last year. In Q3 2020, the average NEM volume weighted average price (VWAP) for wind was $38/MWh while solar VWAP was $29/MWh, representing reductions of around 50% from Q3 2019 levels.

Changes in VWAP were more pronounced on a regional basis, with the largest falls occurring in regions with the highest level of negative prices. The South Australian solar VWAP declined to $23/MWh, 62% lower than Q3 2019 levels. Notably, record low wholesale prices in September resulted in South Australian solar farms having to pay $9.7/MWh to generate (Figure 23).

Figure 23 South Australia's solar farms paid to generate in September

Grid-solar monthly volume weighted average price by region – July 2019 to September 2020

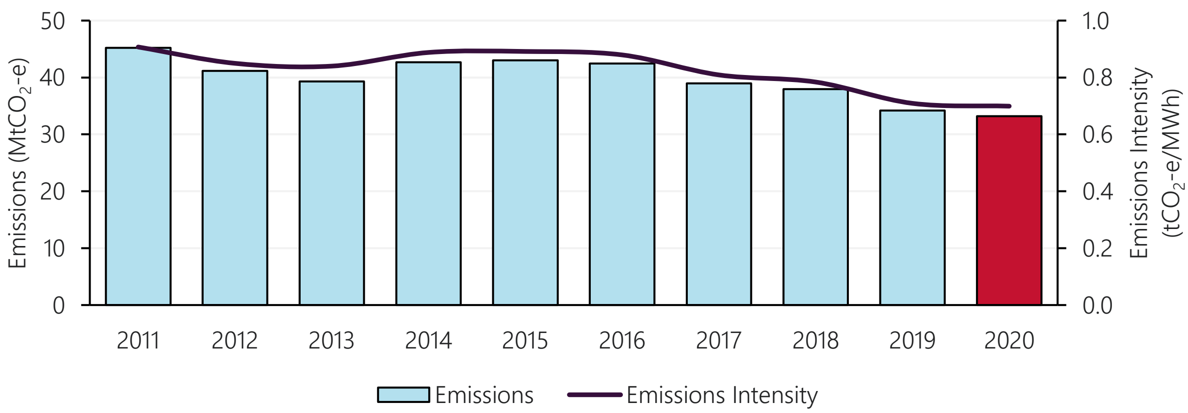


1.4.5 NEM emissions

NEM emissions declined to the lowest Q3 level on record at 33.2 million tonnes of carbon dioxide equivalent ($MtCO_2$-e), while the emissions intensity fell to a new record low of 0.70 tCO_2-e/MWh. Total emissions were 0.7 $MtCO_2$-e higher than the previous quarter record low (32.5 $MtCO_2$-e), although 1 $MtCO_2$-e lower than Q3 2019. Key contributors to the record low emissions intensity – despite increased brown coal-fired generation – included lower black coal-fired generation and increased VRE output.

Figure 24 Lowest NEM emission intensity on record

Quarterly NEM emissions and emissions intensity (Q3s)



1.4.6 Storage

Batteries

NEM battery revenue declined to $6.1 million, its lowest level since Q4 2018 (Figure 25), driven by reduced FCAS prices and outages of Hornsdale Power Reserve during commissioning of its expansion. Continuing recent trends, the primary source of revenue for batteries remained FCAS, with energy arbitrage only contributing 21% of total revenues.

Lower South Australian spot prices contributed to average energy arbitrage value for batteries reducing from $55/MWh in Q3 2019, to $31/MWh in Q3 2020, with charging during negative spot prices unable to completely offset the impact of lower evening peak prices.

Testing and commissioning of the Hornsdale Power reserve expansion was completed in early September, increasing its energy capacity/storage capacity from 100 MW/129 MWh to 150 MW/193.5 MWh, as well as increasing its capacity in the eight FCAS markets. This resulted in a 65% increase in its FCAS enablement for the remainder of the month (Figure 26), and Hornsdale Power Reserve increasing its NEM-wide FCAS market share from an average of 10% to 17% (Figure 27).

Figure 25 Lowest battery market revenue since Q4 2018

Battery revenue sources

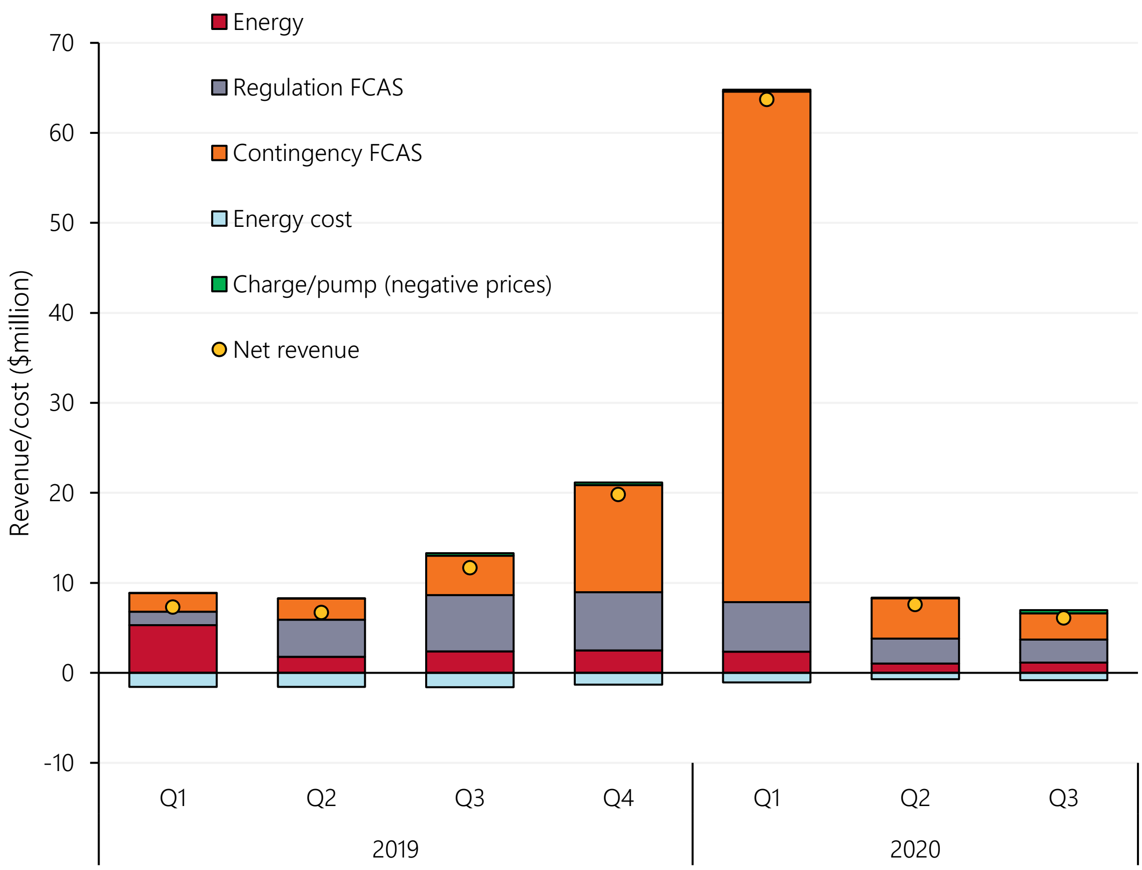


Figure 26 Hornsdale battery expansion increases FCAS supply

HPR daily average FCAS enabled

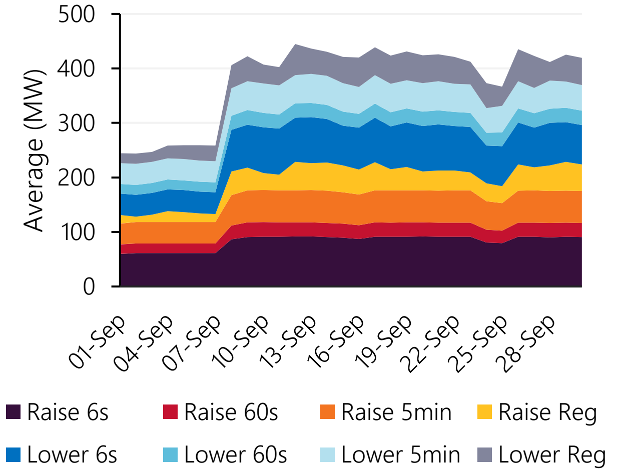
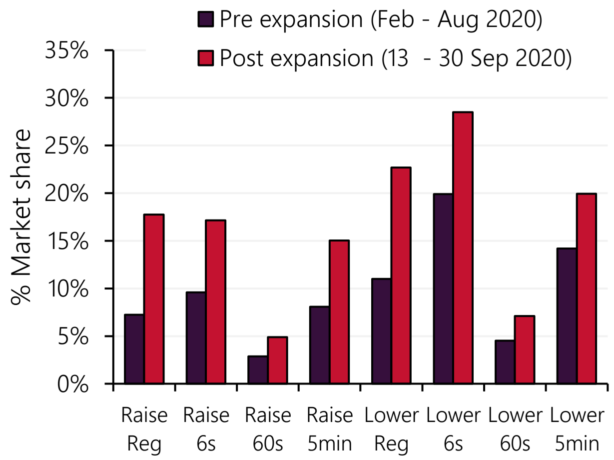


Figure 27 Hornsdale battery captures 17% of NEM-wide FCAS market share following expansion

HPR share of NEM-wide FCAS markets pre- and post-expansion



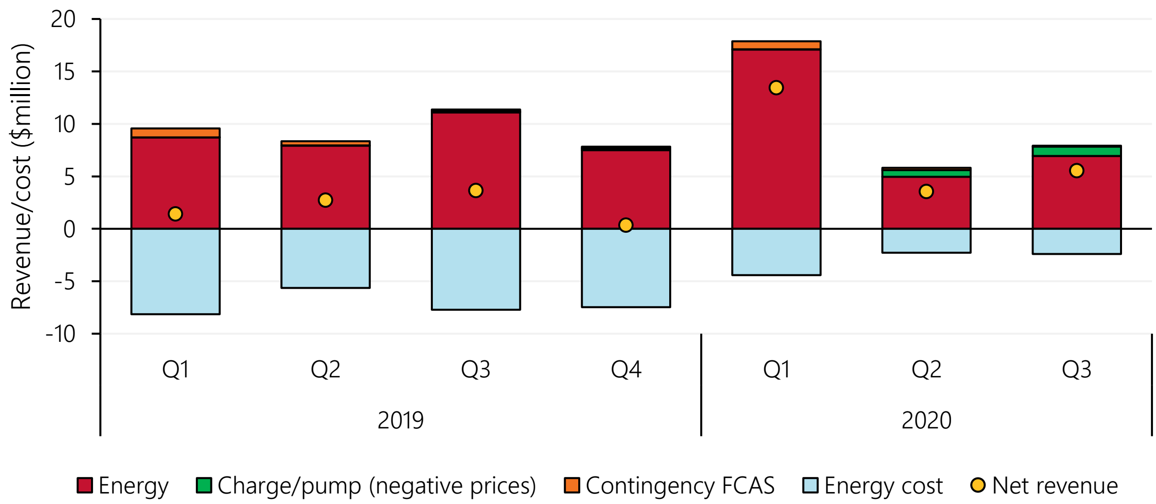
Pumped hydro

Pumped hydro spot market net revenue in Q3 2020 was $5.5 million, 52% higher than Q3 2019. The driver of this increase varied by region:

- **In Queensland**, higher pumped hydro spot revenue was a function of increased utilisation of Wivenhoe, continuing the trend since its transfer into the CleanCo portfolio at the end of October 2019. In Q3 2020, total pumping was 82 GWh, 131% higher than Q3 2019, representing the highest utilisation since Q2 2016. This more than offset the impact of lower average energy arbitrage values, which decreased from $86/MWh to $64/MWh.
- **In New South Wales**, pumped hydro spot market revenue increased despite a 53% reduction in pumping compared to Q3 2019. This was due to average energy arbitrage values increasing from $28/MWh to $42/MWh.

Figure 28 Pumped hydro net revenue higher in 2020 than 2019

Pumped hydro revenue sources



1.5 Inter-regional transfers

In Q3 2020, total inter-regional transfers were 3.2 TWh, a slight increase compared to Q3 2019 (Figure 29).

Figure 29 Total inter-regional transfers increased by 3% compared to Q3 2019

Quarterly inter-regional transfers

Key changes compared to Q3 2019 included:

- **Queensland to New South Wales** – transfers south reduced by 137 MW on average, largely due to outages reducing Queensland black coal-fired generation by 447 MW on average.
  - Planned line works on the Muswellbrook – Tamworth 88 330 kilovolt (kV) lines for 32% of the quarter left the Queensland to New South Wales Interconnector (QNI) on a single contingency, contributing to a 190 MW reduction in average export capacity to New South Wales[18].
  - Despite this reduced export capacity, QNI was binding at its limit less frequently than in Q3 2019, reducing from 28% to 24% of the time. This contributed to a narrowing of the average price spread between the two regions, reducing from $21/MWh to $14/MWh.
- **Tasmania to Victoria** – reduced hydro generation in Tasmania (202 MW) as a result of dry conditions reduced exports to Victoria (by 25 MW) and increased imports (by 136 MW). Net Q3 flows on Basslink swung into the southerly direction for the first time since 2008 (Figure 30).
- **South Australia to Victoria** – increased brown coal generation (317 MW) and reduced Victoria demand (136 MW) resulted in net Victorian imports from South Australia reducing by 54 MW on average.
  - On 17 July 2020, Para No. 1 Static Var Compensator failed due to a transformer fire. A new constraint was introduced to limit flows on Heywood into Victoria from 550 MW to 420 MW and will remain in place until the transformer is replaced (estimated by 1 July 2021).
  - Additionally, Murraylink was constrained from 26 August while oscillations were being investigated[19], followed by a planned outage limiting all flows on Murraylink which commenced on 7 September 2020.
  - Despite these limits, Heywood was binding less frequently than in Q3 2019, reducing from 31% to 16% of the time. This contributed to a narrowing of the average price spread between the two regions, reducing from $23/MWh to $11/MWh.

[18] The AER will provide further analysis on the impact of the lower limits on the QNI and Heywood interconnectors on negative prices and price alignment as part of its upcoming Q3 2020 Wholesale Markets Quarterly

[19] See Market Notice 77189.

- Victoria to New South Wales – increased Victorian generation (Figure 31), and reduced demand in Victoria (-136 MW) contributed to a 129 MW swing in Victoria to New South transfers, resulting in net flows of 47 MW into New South Wales.

Figure 30 Q3 net flows on Basslink swing southerly for the first time since 2008

Q3 flows on The Basslink Interconnector

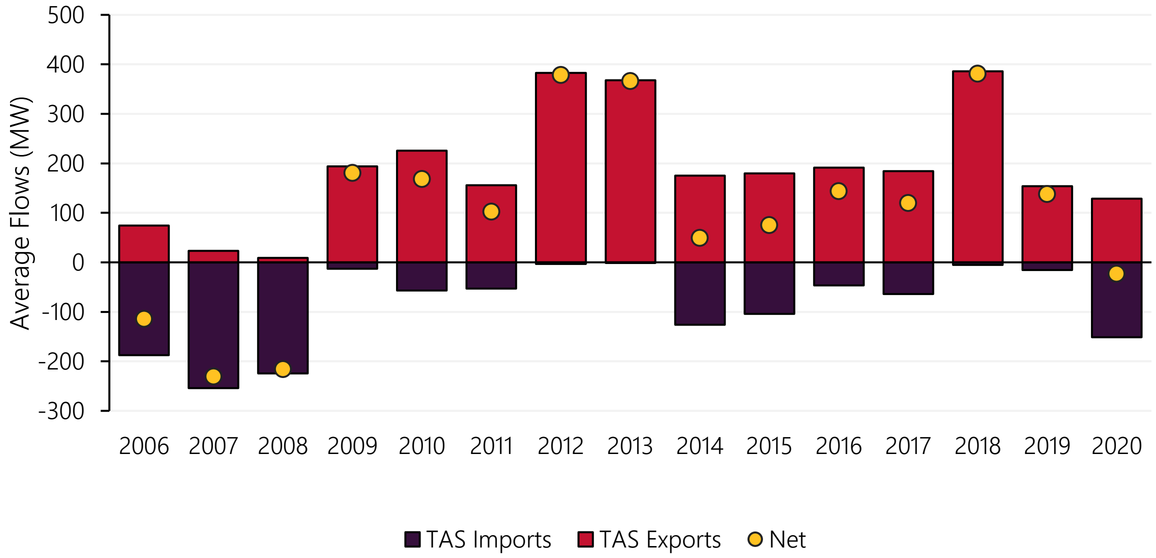
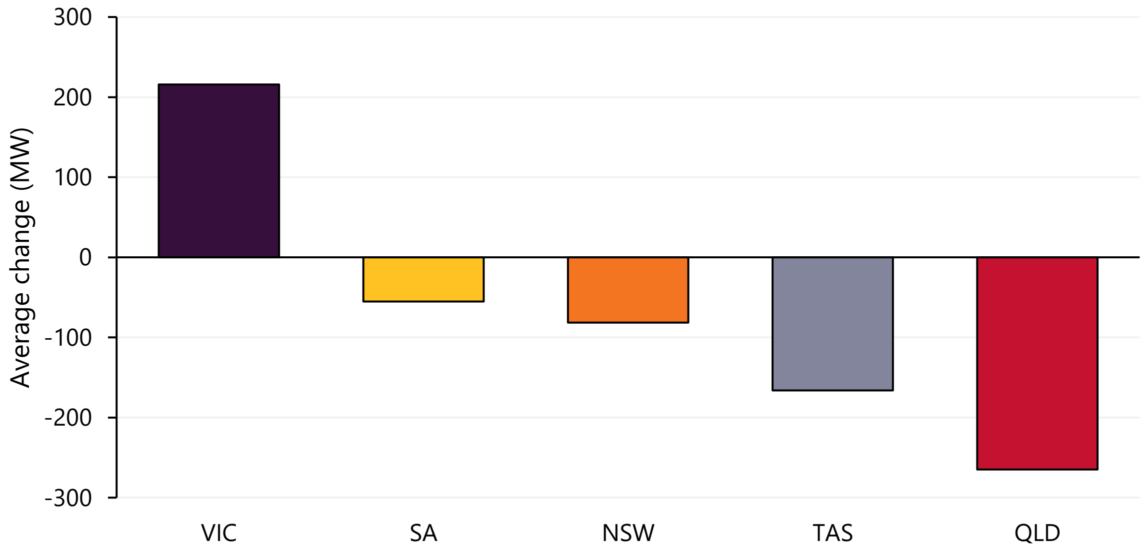


Figure 31 Increased supply in Victoria; decreases in all other regions

Change in regional supply – Q3 2020 versus Q3 2019



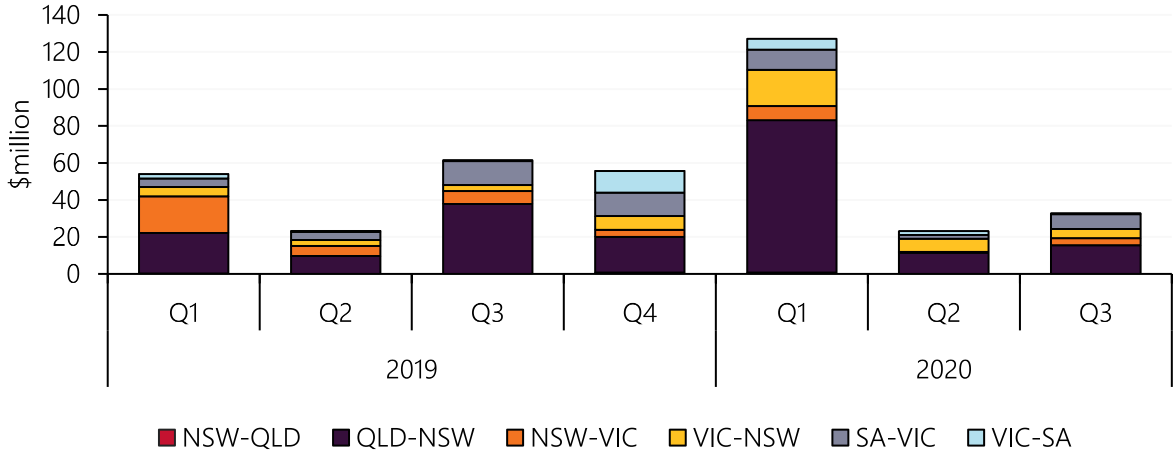
1.5.1 Inter-regional settlement residue

Inter-regional settlement residue (IRSR) was $33 million this quarter (Figure 32), representing a 47% decrease from Q3 2019. IRSR remained low due to NEM-wide low prices and limited price volatility.

These results were driven by reductions in IRSR for Queensland to New South Wales (-$22 million) and South Australia to Victoria (-$5 million). Decreased transfers on these interconnectors, as well as increased price alignment between these regions, drove the IRSR reductions.

Figure 32 IRSR reduced by 47% compared to Q3 2019

Quarterly positive IRSR value



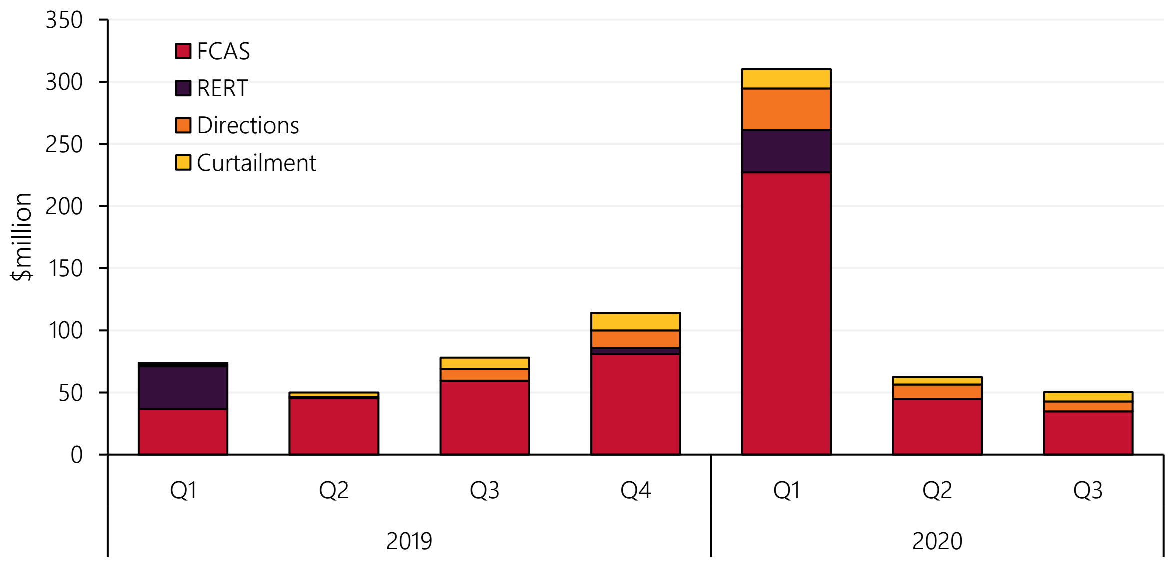
1.6 Power system management

Total NEM system costs[20] continued to trend downwards, decreasing from $62 million in Q2 2020 to $50 million in Q3 2020, $28 million lower than Q3 2019 (Figure 33). By component:

- **FCAS costs** decreased to $35 million this quarter, $25 million lower than Q3 2019 and $10 million lower than Q2 2020. Despite the decline, it remained the main contributor to system costs, accounting for 69% of total costs. Section 1.6.1 provides details on FCAS.
- The cost of **directing units** to maintain system security decreased to $8 million this quarter despite increased time on direction. Section 1.6.3 provides details on system security directions for the quarter.
- Estimated **VRE curtailment costs**[21] increased to $8 million, 28% higher than Q2 2020. Section 1.6.2 provides details on VRE curtailment for the quarter.

Figure 33 System costs continued to decline

Quarterly system costs by category



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

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

1.6.1 Frequency control ancillary services

Quarterly FCAS prices and costs continued to decline, with Q3 2020 costs of $35 million. This was $10 million lower than Q2 2020 and represented the lowest quarter since Q1 2018.

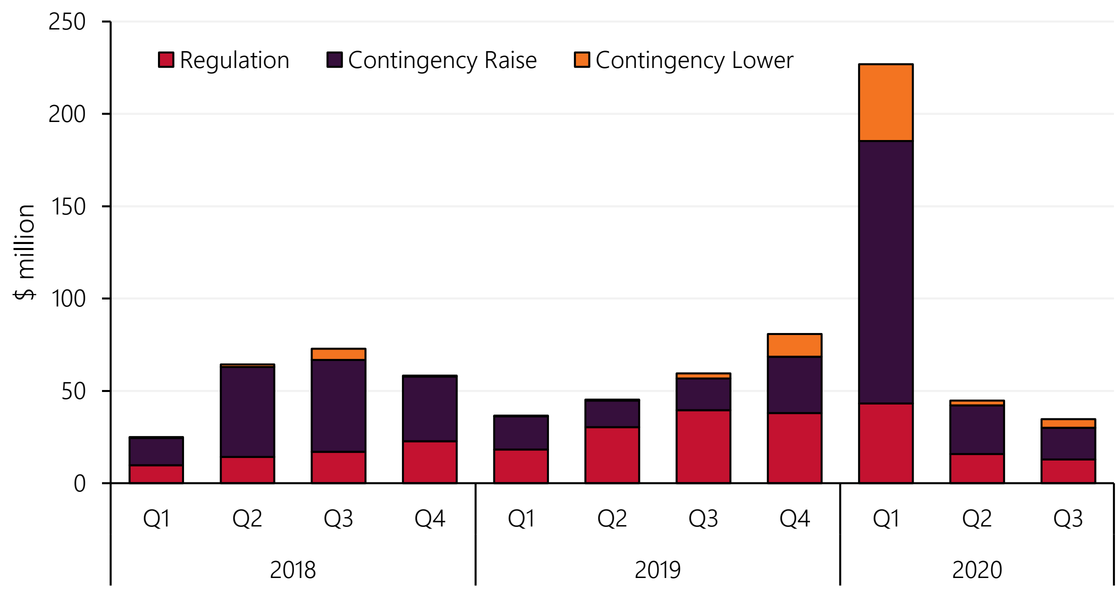
Compared to Q2 2020, average Regulation prices[22] reduced by 22%, Contingency Raise prices reduced by 26%, and Contingency Lower prices increased by 37%. The increase in Contingency Lower prices was largely driven by higher Queensland prices – these were due to local requirements resulting from power line outages which left the QNI on a single contingency.

Contributors to price reductions in the Regulation and Contingency Raise markets included:

- **Reduced market offers**, which were influenced by:
  - Expansions of existing supply – on completion of its 50% expansion in early September, Hornsdale Power Reserve increased FCAS supply across all eight FCAS markets (see Section 1.4.6). In addition, the two existing virtual power plants in South Australia increased their combined capacity from 3 MW to 9 MW in the six Contingency FCAS markets.
  - Return to the market of thermal units – during the quarter, several thermal units – including Bayswater Unit 4, Darling Downs – returned to the FCAS markets after prolonged absences. This coincided with increasing FCAS requirements in 2020 compared to 2019, unit upgrades, and implementation of the Mandatory Primary Frequency Control rule change.
  - A continuation of comparatively low energy prices, particularly in Queensland and South Australia (raise FCAS market prices often move in line with energy prices, due to the opportunity cost of service provision).
- **Reduced Contingency Raise requirements** – AEMO's average Contingency Raise requirements decreased by 6% compared to Q2 2020. This was largely a function of a decrease in the size of the largest credible contingency, due to lower average output from Kogan Creek Power Station (which is typically the largest credible contingency in the NEM).

Figure 34 Lowest FCAS costs since Q1 2018

Quarterly FCAS cost by market[23]



[22] For simplicity, a time-average of the FCAS prices across each of the five regional markets used.

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

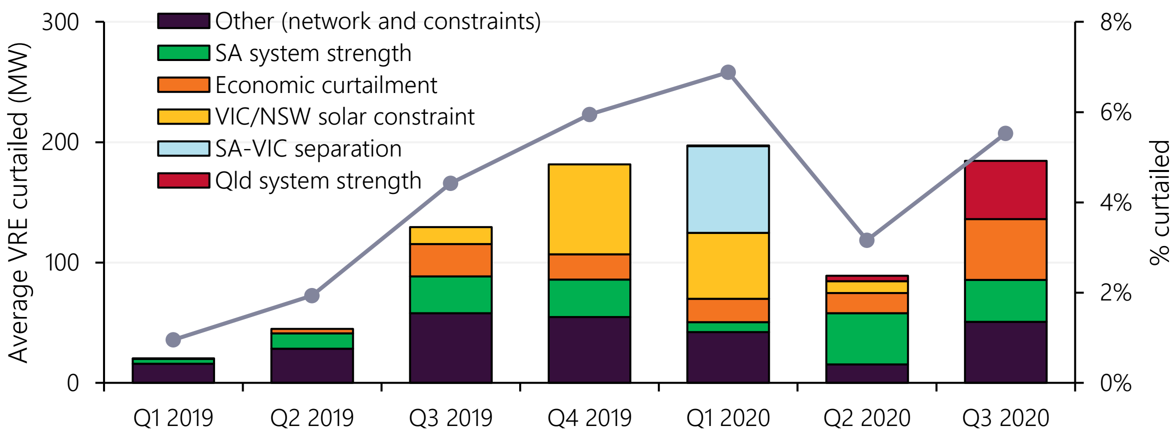
1.6.2 VRE curtailment

During Q3 2020, 5.5% of NEM VRE output was curtailed (Figure 35). Key curtailment drivers included:

- **Queensland system strength arrangements**[24] – in March 2020, system strength limits were introduced in North Queensland which involved constraining the output of three generators[25] in order to maintain power system security. On 27 July 2020, an update to the constraint introduced the potential to limit output from another nine solar farms[26].
  - These constraints were binding more frequently this quarter (55% of the time compared to 16% in Q2 2020), resulting in 49 MW of curtailment on average, up from 5 MW in Q2 2020. Increased outages of relevant Queensland black coal-fired units contributed to the constraints binding more often.
- **Economic curtailment** – the record frequency of negative spot prices contributed to an average of 50 MW of self-curtailment, up from 27 MW in Q3 2019. Increased occurrence of negative spot prices in South Australia and Queensland (Section 1.3.1), particularly during the middle of the day, resulted in higher VRE self-curtailment, with 70% of curtailment occurring between 0700 and 1900 hrs (Figure 36).

Figure 35 Queensland system strength constraint and negative prices drive increased VRE curtailment

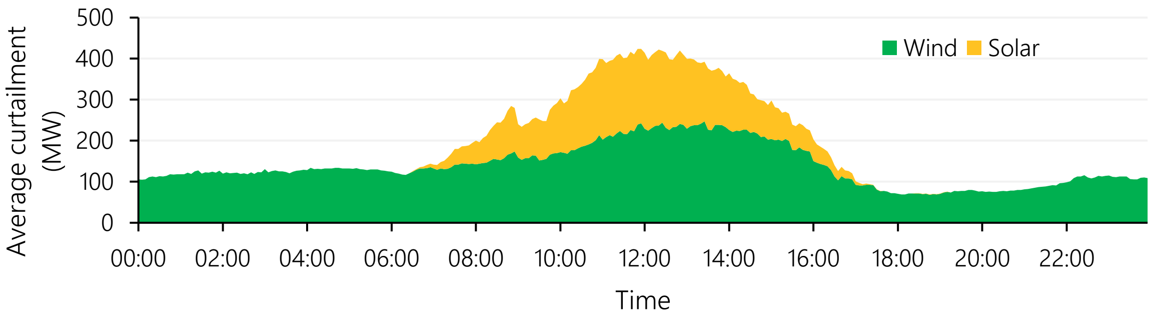
Average NEM VRE curtailed by curtailment type



Note: curtailment amount based on combination of market data and AEMO estimates[27].

Figure 36 Curtailment predominantly occurred during the middle of the day

Average NEM VRE curtailed by fuel type and time of day – Q3 20



[24] Only includes system normal constraints.

[25] Mount Emerald Wind Farm, Haughton Solar Farm and Sun Metals Solar Farm.

[26] For further details, see Market Notice 76455. For latest update, see Market Notice 77646. Updated Qld limit advice can be found here: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/limits-advice.

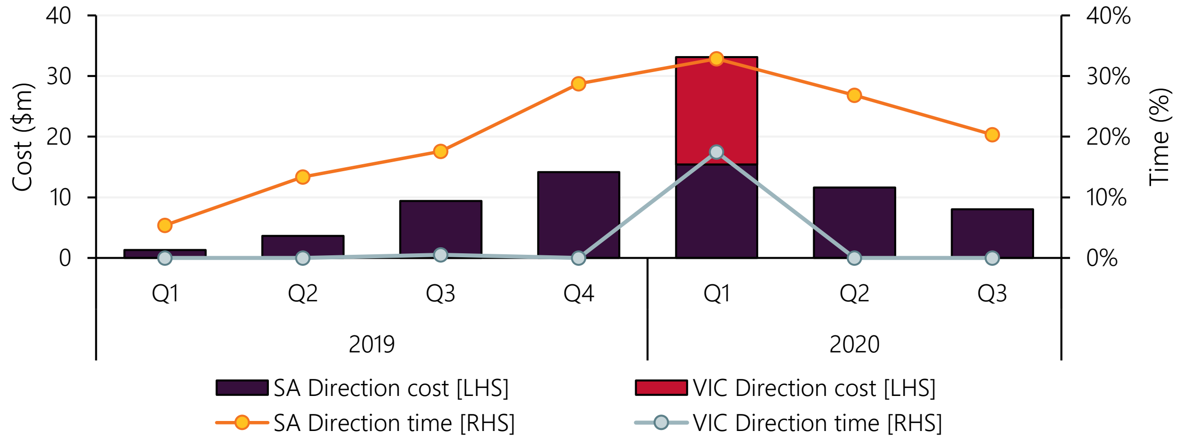
[27] For further information on the curtailment calculation, see: www.wattclarity.com.au/articles/2020/06/not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation/?utm_source=rss&utm_medium=rss&utm_campaign=not-as-simple-as-it-appears-estimating-curtailment-of-renewable-generation.

1.6.3 Directions

During the quarter, AEMO continued to issue directions to GPGs in South Australia to maintain system security in the region. Despite time on direction increasing from 18% in Q3 2019 to 20% in Q3 2020, total directions costs for energy decreased from $9.4 million to $8 million (Figure 37).

Figure 37 Directions costs were slightly lower than Q3 2019 despite more time on direction

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



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

This quarter, approximately 81% of direction costs were incurred in September, as record low South Australian spot prices during the month (Section 1.3) meant GPG in the region frequently sought to de-commit from the market for economic reasons.

Despite an increase in GPG directed this quarter (+5 MW), directions costs declined by $1.4 million compared to Q3 2019. This was mainly due to the significant decrease in the 12-month 90th percentile spot price that is used for compensating participants. On average, the 12-month 90th percentile spot price decreased by $45/MWh to $98/MWh this quarter.

2. Gas market dynamics

2.1 Gas demand

Total east coast gas demand was 5% lower than Q3 2019, due to reduced demand across all three major segments, representing the lowest Q3 gas demand since Q3 2017 (Table 4, Figure 38).

A total of 313 PJ flowed to Curtis Island for LNG export, a decrease of 11 PJ compared to Q3 2019 and a decrease of 3 PJ compared to Q2 2020 (Figure 39). This is the lowest east coast LNG export since Q3 2018, and coincided with low international oil and gas prices (Section 2.2.1). Australia Pacific LNG's (APLNG's) 12.5 PJ reduction in flows to Curtis Island was the largest reduction, with both APLNG's major customers declaring downward quantity tolerance for 2020[28]. There was also extended maintenance on all three LNG facilities during the quarter, further contributing to the decrease.

During Q3 there were 78 LNG cargoes exported, down from 81 in Q3 2019. APLNG reduced from 31 to 29, Queensland Curtis LNG (QCLNG) reduced from 29 to 28, while Gladstone LNG (GLNG) remaining steady at 21 cargoes respectively.

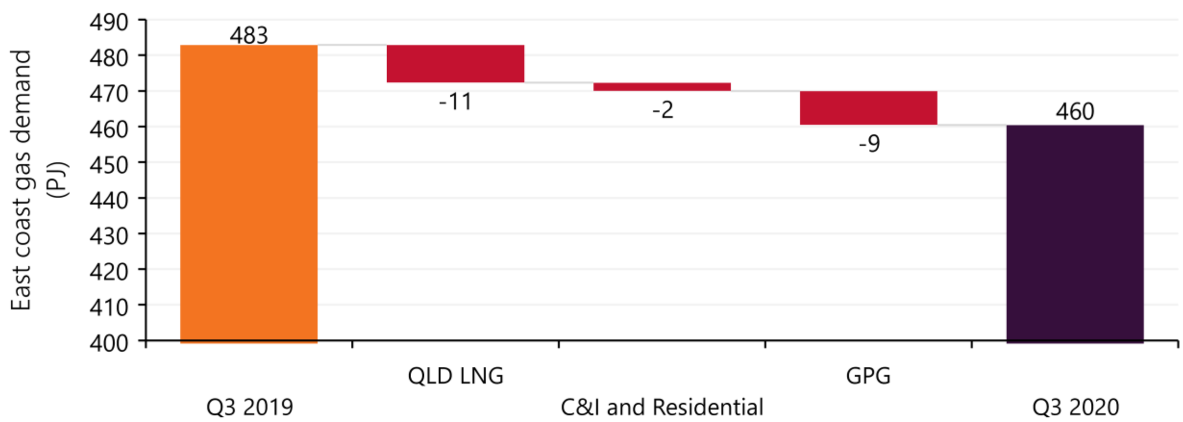
GPG demand decreased by 20% compared to Q3 2019, with reductions in South Australia, Victoria and New South Wales, only partially offset by increases in Queensland and Tasmania. Drivers for reduced GPG are discussed in Section 1.4.3.

Table 4 Gas demand – quarterly comparison

Demand (PJ)	Q3 2020	Q2 2020	Q3 2019	Change from Q3 2019
AEMO Markets *	109.8	97.4	112.1	-2 (-2%)
GPG **	37.2	33.2	46.7	-9 (-20%)
QLD LNG	313.4	316.6	324.0	-11 (-3%)
TOTAL	460.4	447.2	482.9	-22 (-5%)

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

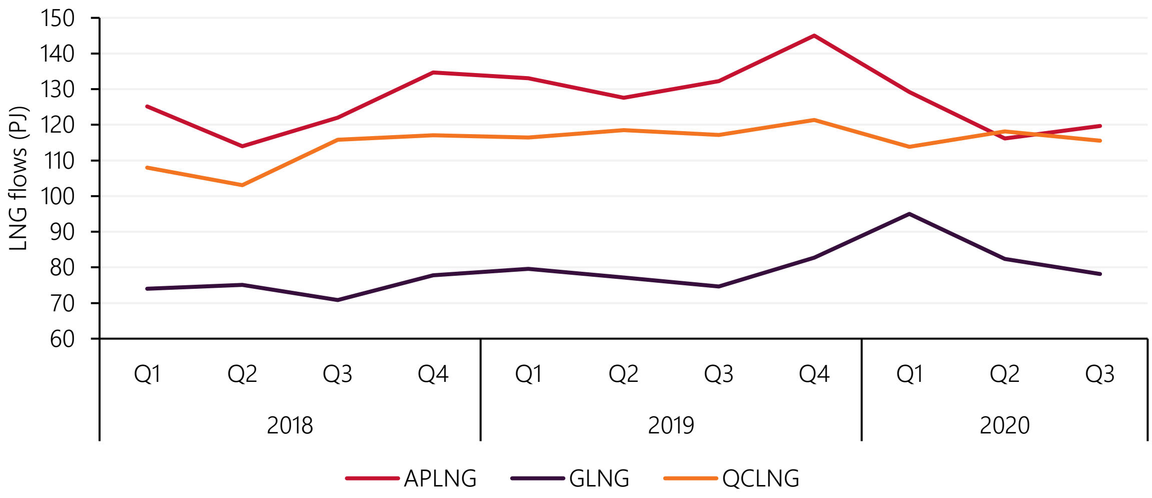
Figure 38 Gas demand falls across all sectors



[28] Origin Energy, 2020 Full Year Results: https://www.originenergy.com.au/content/dam/origin/about/investors-media/presentations/200820_FY20_investor_pres_final.pdf.

Figure 39 Flows to Curtis Island fall to lowest level in 2 years

Total quarterly pipeline flows to Curtis Island



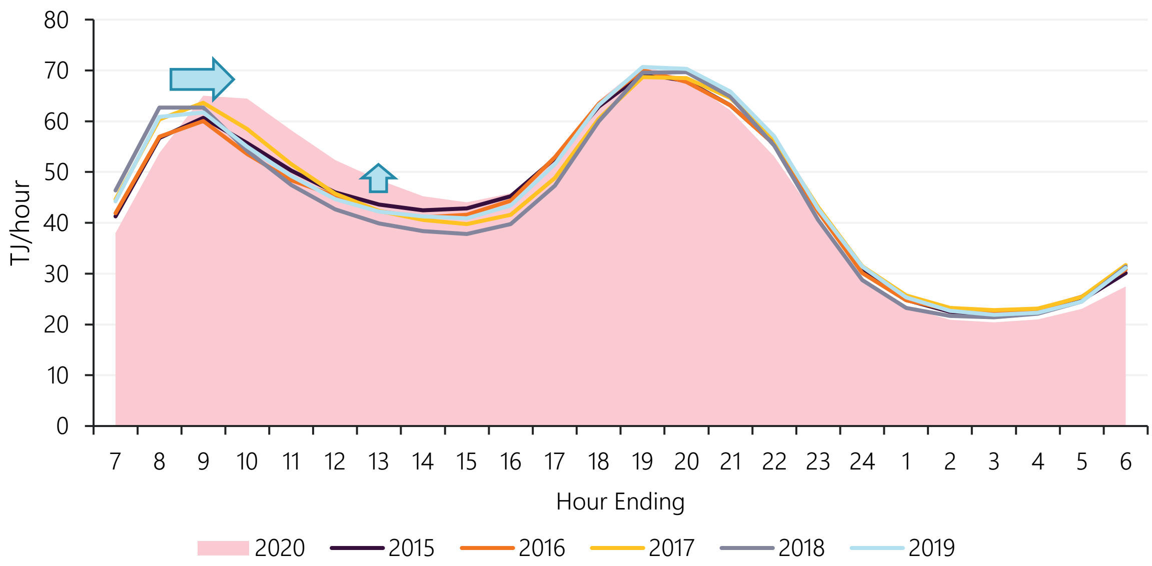
2.1.1 COVID-19 impact on Victorian gas demand

As outlined in Section 1.2.1, in Q3 the COVID-19 pandemic continued to affect economic activity across the east coast of Australia, particularly in Victoria which had COVID restrictions in place for the entire quarter. These measures had a profound effect on the Victorian hourly gas profile, which was most apparent on cold days with high heating demand:

- The morning peak was two hours later with demand 13% lower from 0600 to 0800 hrs, and 13% higher between 0800 and 1400 hrs.
- Demand remained higher until 1900 hrs, with hourly demand tracking lower from 1900 hrs overnight. These changes are shown for high demand days (greater than 1,100 TJ, Figure 40).

Additional operational and market measures, such as the use of the Dandenong LNG, were required to manage this increased daytime demand, particularly on high demand days. AEMO issued notices of threats to system security in the Declared Wholesale Gas Market on 3 July, 4 August, 7 August, and 22 August[29].

Figure 40 Comparison of Victorian gas load shapes for days where demand exceeds 1,100 TJ



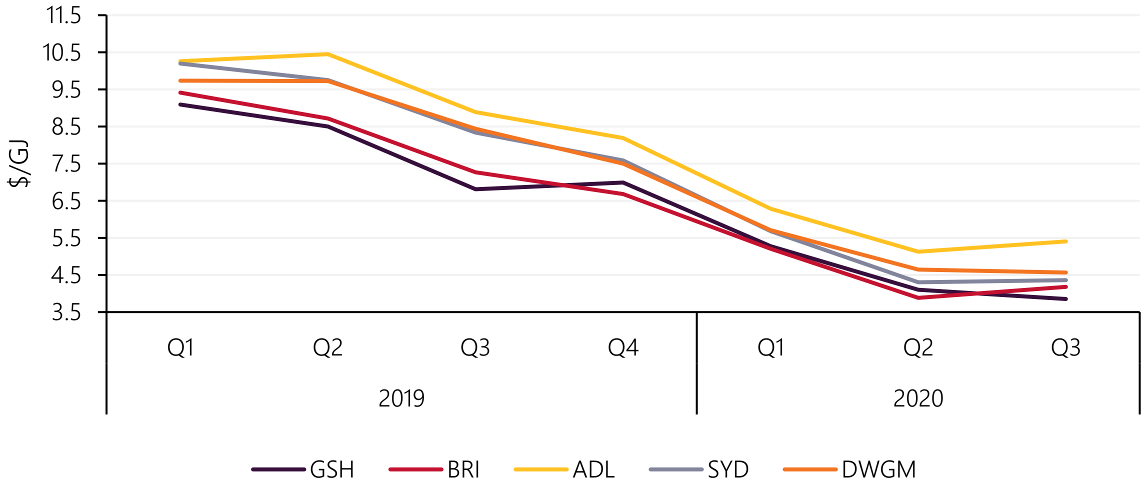
[29] See: https://aemo.com.au/energy-systems/gas/declared-wholesale-gas-market-dwgm/dwgm-events-and-reports.

2.2 Wholesale gas prices

Compared to Q3 2019, prices decreased across all markets, with the largest decreases in Sydney (-47%) and DWGM (-46%). The GSH price of $3.85/GJ was its lowest quarterly average since Q4 2015, while the DWGM price of $4.57/GJ was its lowest since Q1 2016.

Figure 41 Lowest Q3 gas market prices since Q3 2015

East coast quarterly average gas prices by market

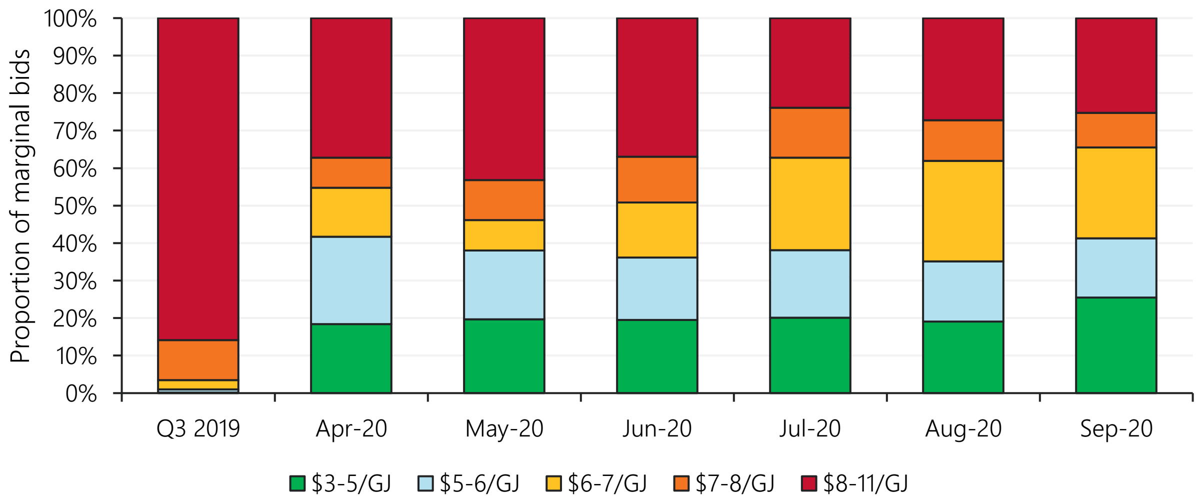


Key contributors to these pricing outcomes included decreased demand across all sectors compared to Q3 2020, and the continuation of more gas being offered at lower prices into the markets. For example, in Q3 2020, 63% of bids in the DWGM were priced under $7/GJ, compared to 3.5% in Q3 2019 (Figure 42). These lower-priced offers coincided with a continuation of low international oil and gas prices. The AER will provide further competition analysis on outcomes in the downstream gas markets as part of its upcoming Q3 2020 Wholesale Markets Quarterly.

Brisbane Short Term Trading Market (STTM) price increases compared to Q2 2020 were due to a pipeline compressor outage in early September which reduced pipeline capacity on the Roma to Brisbane Pipeline (RBP). On four days during the outage the Brisbane ex-ante price reached $10/GJ.

Figure 42 DWGM bids at lower prices than in Q3 2019 and Q2 2020

DWGM – proportion of marginal bids by price band



2.2.1 International commodity prices

During Q3 2020, international energy commodity prices rebounded from the multi-year lows of the previous quarter as the global economy partly recovered from the economic impact of the COVID-19 pandemic.

JKM LNG average prices were A$1.40/GJ higher than in Q2 2020, after reaching a record low during the height of the COVID-19 pandemic (Figure 43). Of note, the JKM price rose steadily during the quarter, increasing from A$3.01/GJ at the start of the quarter to finish at A$6.68/GJ (+121%). Increased demand and spot buying across Asia, coupled with planned and unplanned outages contributed towards the increase[30].

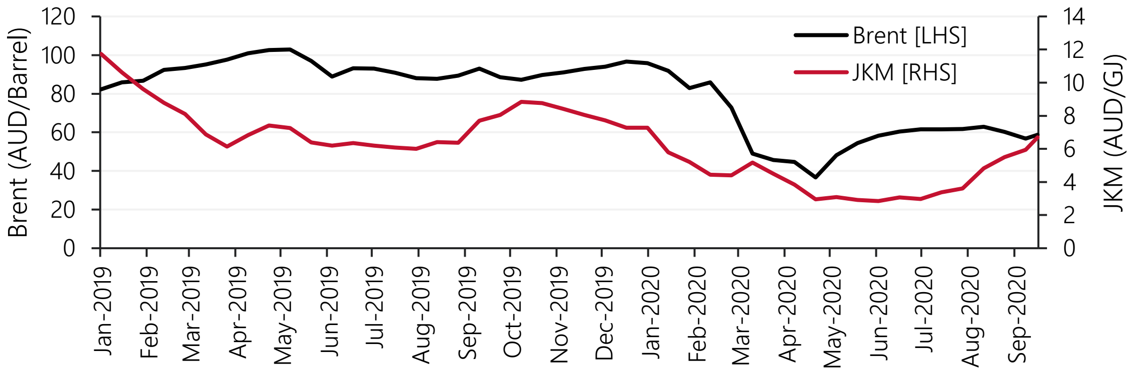
Low JKM prices at the end of Q2 and into Q3 2020 were reflected in the Australian Competition and Consumer Commission's (ACCC's) average netback price, which fell to $2.59/GJ, its lowest level since publication began (Figure 44). However, forward prices for 2021 increased A$0.6/GJ to A$5.89/GJ since Q2.

Brent Crude oil prices increased to A$61/barrel (+$10/barrel on Q2 levels), as the Organisation of the Petroleum Exporting Countries (OPEC) and Russia continued to implement production cuts.

Thermal coal prices recovered from a four-year low (A$66/tonne) to finish the quarter at A$82/tonne, as higher Chinese imports and withdrawal of higher cost producers and cutbacks from other miners stabilised prices[31].

Figure 43 Brent prices stabilise; JKM prices rebound

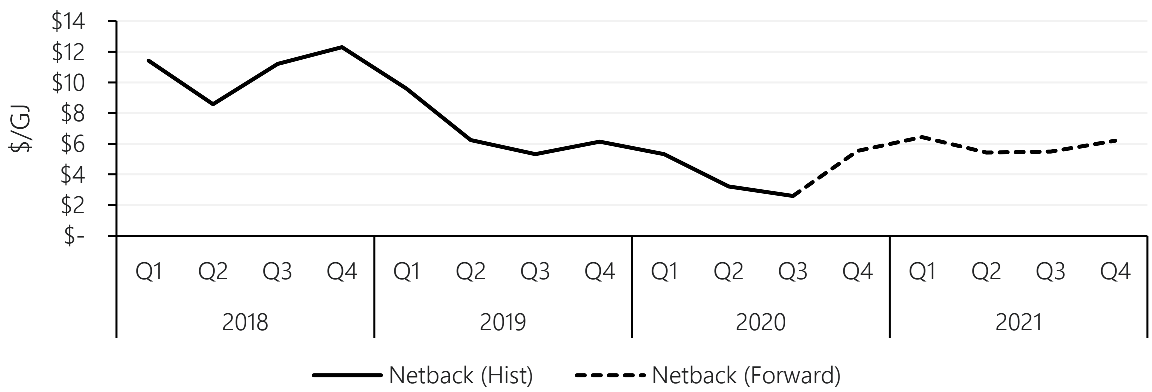
Brent Crude oil and JKM LNG prices in Australian dollars



Source: Bloomberg data in 14-day averages.

Figure 44 ACCC gas netback price at record lows in Q3 2020

ACCC netback price historical and forward[32]



[30] Source: BNEF LNG Monthly, unplanned outages: https://www.afr.com/companies/energy/gorgon-lng-avoids-total-shutdown-20200821-p55o2b.

[31] Resources and energy quarterly – September 2020-page 52.

[32] ACCC 2020, LNG netback 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

Q3 2020 east coast gas production decreased by 12.8 PJ (-2.6%) compared to Q3 2019 (Figure 47) due to:

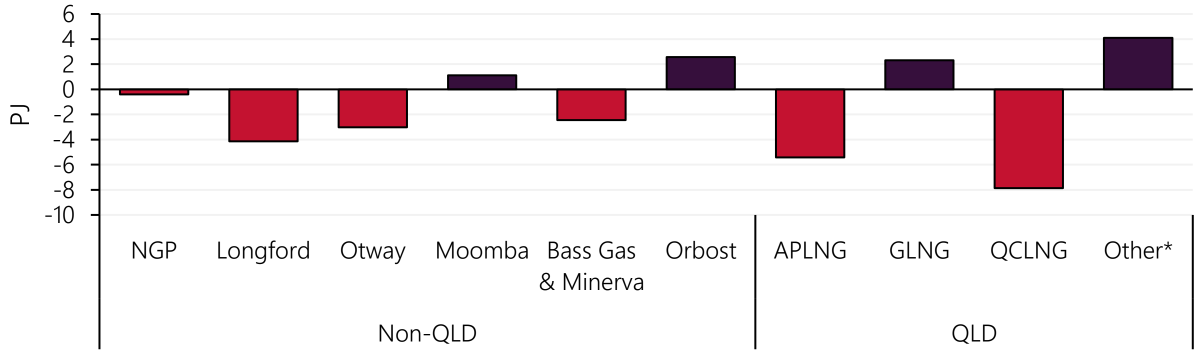
- Reduced Queensland production from QCLNG (-7.9 PJ) and APLNG (-5.4 PJ), partially offset by an increase in GLNG (+2.3 PJ) and other Queensland facilities (+4.1 PJ, including a +1.7 PJ increase from Senex's Atlas facility).
- Reduced Victorian production from Longford (-4.1 PJ), Otway (-3 PJ), and Bass Gas and Minerva (-2.4 PJ).

These decreases were partially offset by:

- Higher Moomba production (+1.1 PJ).
- Orbost production in Victoria, which commenced on 25 March (+2.6 PJ). After achieving a steady daily rate of 45 TJ/d to begin the quarter, it fell to 20-25 TJ/d for much for August.
  - The nameplate rating of the facility is 65 TJ/d, however Cooper Energy reported that foaming in the absorber vessels of the sulphur recovery unit has impaired its processing capacity[33].

Figure 45 East coast gas production down 2.6%

Change in east coast gas supply – Q3 2020 versus Q3 2019



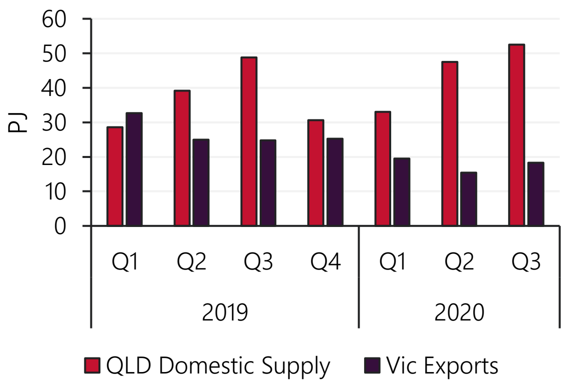
2.3.2 Queensland excess production

Total net domestic supply into Queensland[34] was 53 PJ in Q3 2020, up 4 PJ on Q3 2019 levels (Figure 46). The increase was a function of 11 PJ of reduced LNG exports, with Queensland gas production only reducing by 6.9 PJ resulting in a +6.1 PJ increase in domestic supply.

Southerly flows from Queensland to other states was relatively unchanged (Section 2.4), thus most of this additional gas was used in Queensland for activities such as electricity generation.

In addition, compared to Q3 2019 there were decreased flows from Northern Territory via the Northern Gas Pipeline (NGP) as well as lower Victorian gas transfers to other states (Section 2.3).

Figure 46 Queensland domestic supply increases faster than Victorian transfers



[33] Cooper Energy 2020, ASX announcement 20 August 2020: https://www.cooperenergy.com.au/Upload/APA-and-Cooper-Energy-Unite-for-Orbost-Completion.pdf.

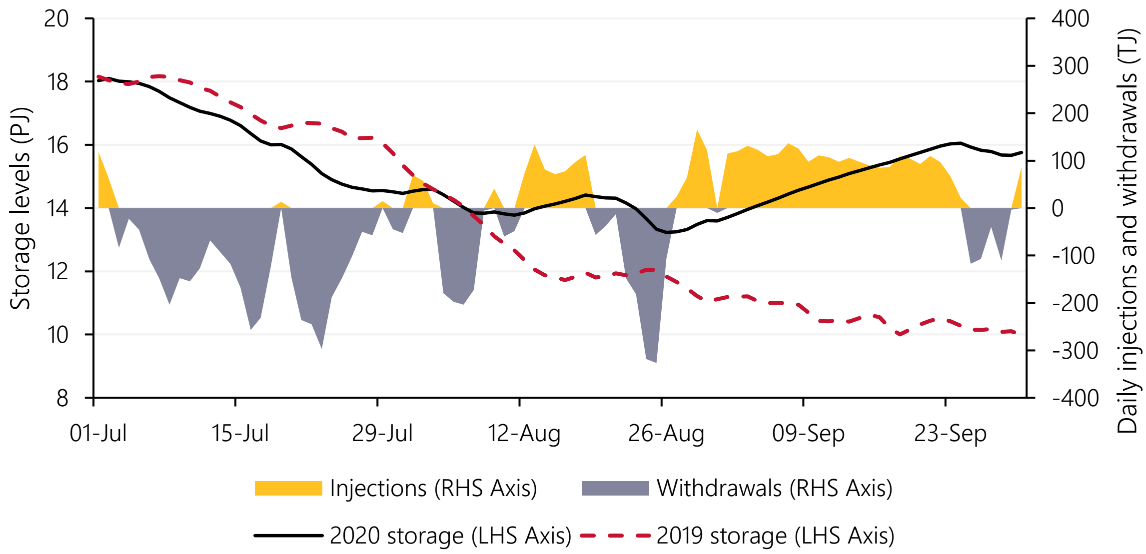
[34] Aggregate Queensland supply minus aggregate demand from Queensland LNG.

2.3.3 Gas storage

A gas balance of 15.7 PJ was recorded at the Iona Underground Storage Facility (UGS) in Victoria at 30 September, 5.6 PJ higher than at the end of Q3 2019 (Figure 47). While Iona was utilised heavily in July, largely to meet South Australian GPG requirements due to low wind output, milder weather in September allowed it to refill. This was the highest storage level for Iona at the end of September since storage levels began being reported in 2016.

Figure 47 Iona Storage finished Q3 at the highest Q3 level since reporting began

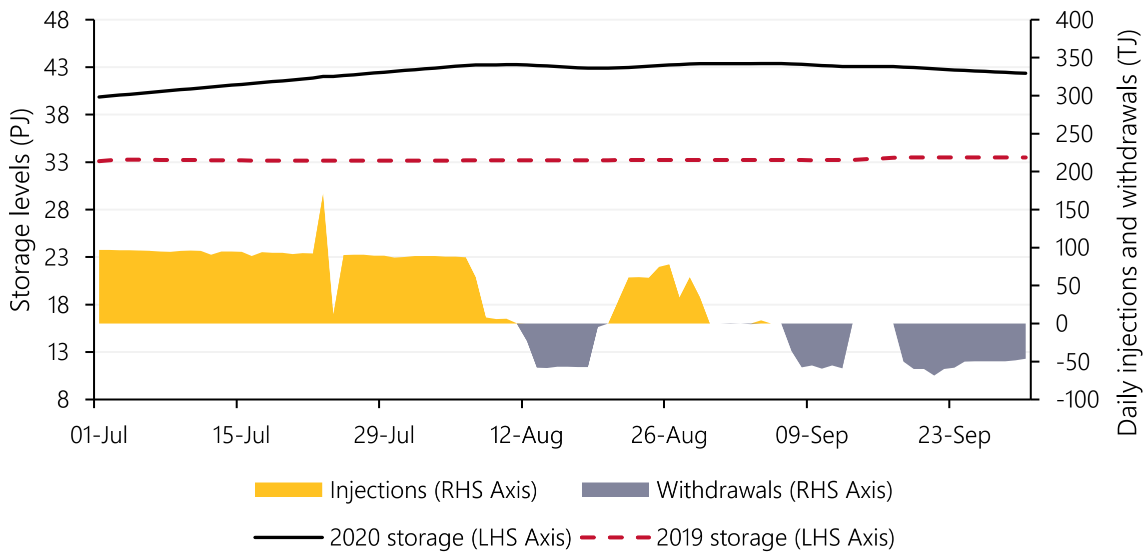
Iona storage levels



GLNG's Roma Underground Gas Storage (RUGS) continued its steady increase through July, before moving to withdrawal mode from September, coinciding with higher GLNG flows to Curtis Island. RUGS recorded a gas balance of 42.4 PJ, 8.9 PJ higher than for the corresponding period in 2019.

Figure 48 Roma Storage finishes the quarter with 8.9 PJ more in storage than Q3 2019

RUGS storage levels

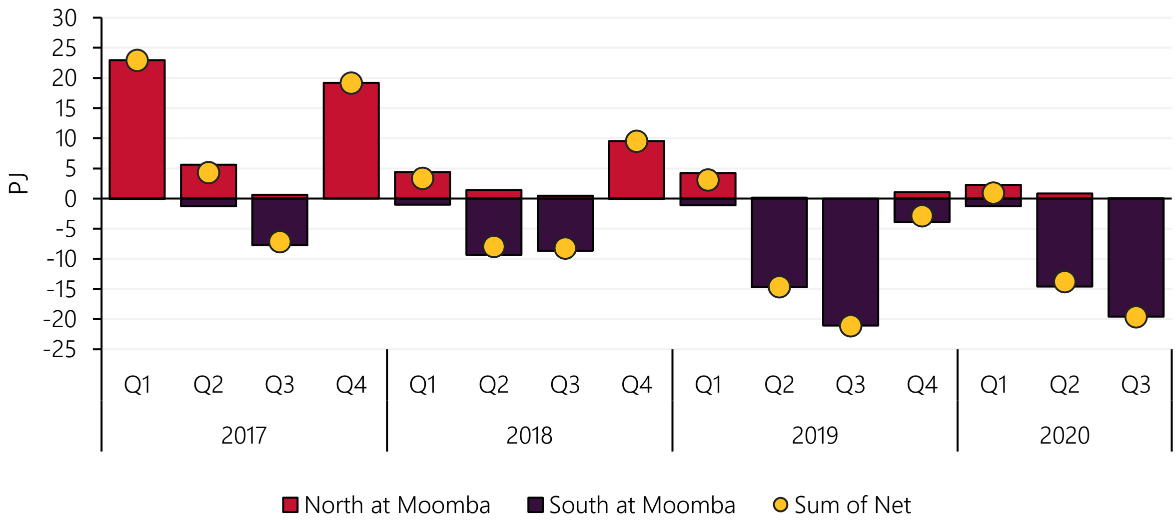


2.4 Pipeline flows

Compared to Q3 2019, there was a 1.5 PJ decrease on net transfers south on the South West Queensland Pipeline (SWQP), driven by lower southern state gas demand.

Figure 49 Small Q3 reduction in gas flows south from Queensland

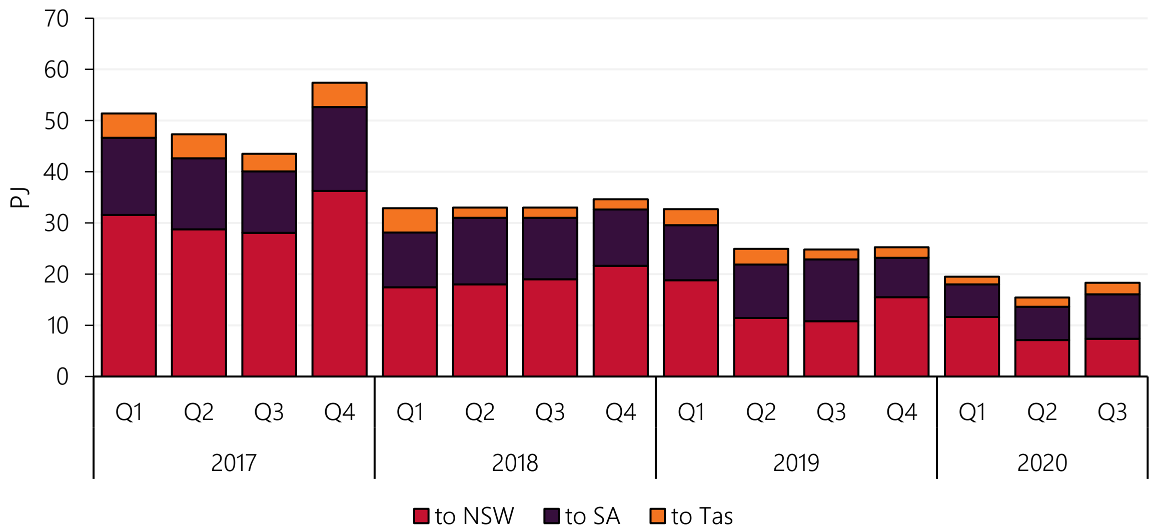
Flows on the South West Queensland Pipeline at Moomba



Victorian net gas transfers to other states reduced by 6.5 PJ compared to Q3 2019 (Figure 52), due to decreased demand in New South Wales and South Australia, and lower Victorian production. Compared to Q3 2019, there was decreased flow from:

- Victoria to New South Wales – Victoria imported a net 8.5 PJ via Culcairn, compared to 7.8 PJ in Q3 2019. Exports to New South Wales via the Eastern Gas Pipeline (EGP) decreased by 3.1 PJ.
- Victoria to South Australia – flows were lower by 3.4 PJ.

Figure 50 Victorian gas transfers to other states lower than 2019

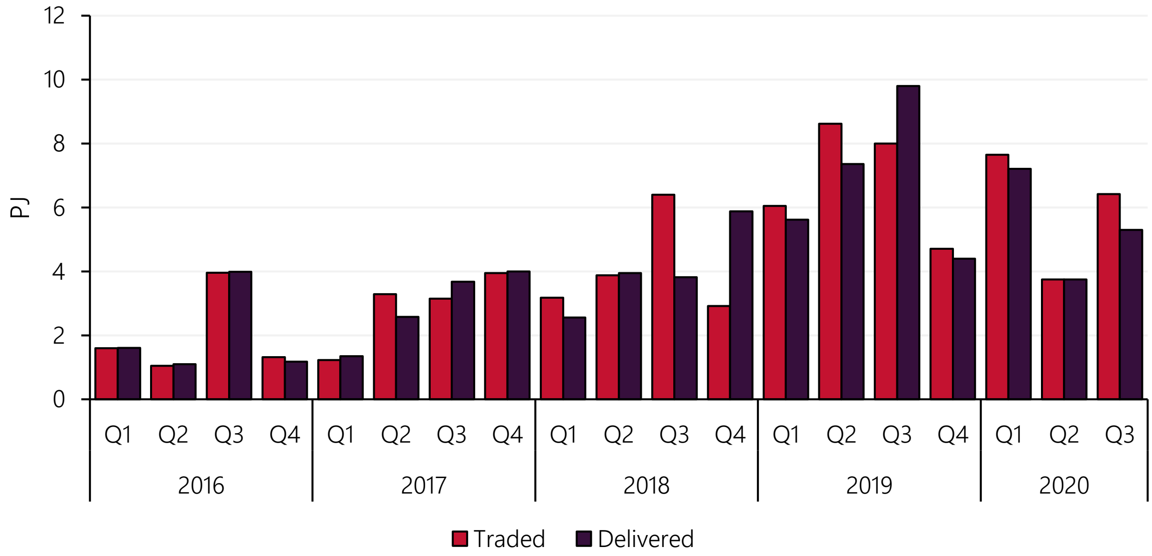


2.5 Gas Supply Hub

In Q3 2020, there were decreased trading and delivered volumes on the GSH compared to Q3 2019 (Figure 51) with traded volume down by 1.6 PJ and delivered volume down by 4.5 PJ. Compared to Q2 2020, traded volume increased by 2.7 PJ and delivered volume increased by 1.6 PJ.

Figure 51 Decreased trading on the Gas Supply Hub compared to 2019

Gas Supply Hub – quarterly trades and deliveries



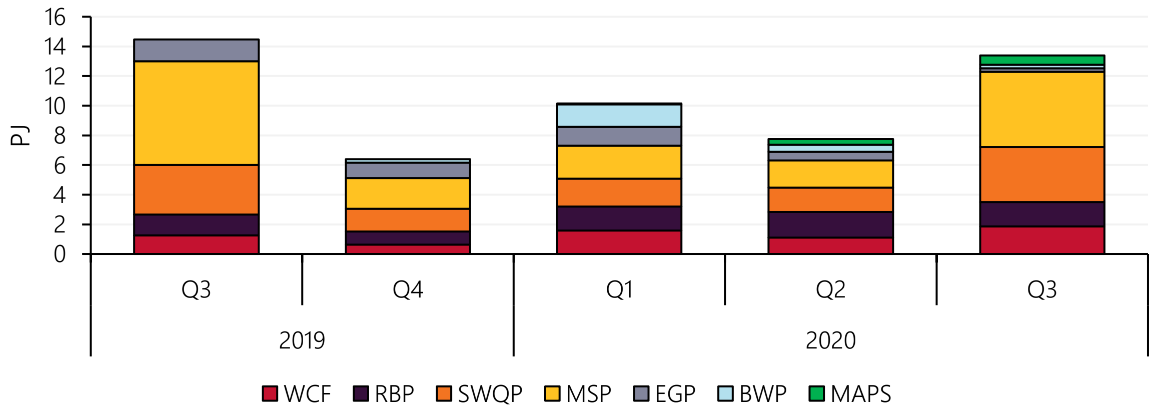
2.6 Pipeline capacity trading and day ahead auction

Compared to Q3 2019, there was a decrease in day ahead auction (DAA) utilisation (Figure 52), despite volume increasing on 5 pipelines and decreasing on 2. The decreases occurred on the Moomba to Sydney Pipeline (MSP) (-1.9 PJ) EGP (-1.2 PJ), with smaller increases occurring on the other pipelines.

Average auction clearing prices remained at close to $0/GJ on most pipelines. The exceptions to this were the RBP, which averaged $0.13/GJ, and the MSP, with the average price to Sydney being $0.31/GJ and $0.23/GJ to Culcairn. The AER will provide further competition analysis on outcomes in the day ahead auction as part of its upcoming Q3 2020 Wholesale Markets Quarterly.

Figure 52 Day Ahead Auction utilisation decreases compared to Q3 2019

Day Ahead Auction Results by quarter



2.7 Gas – Western Australia

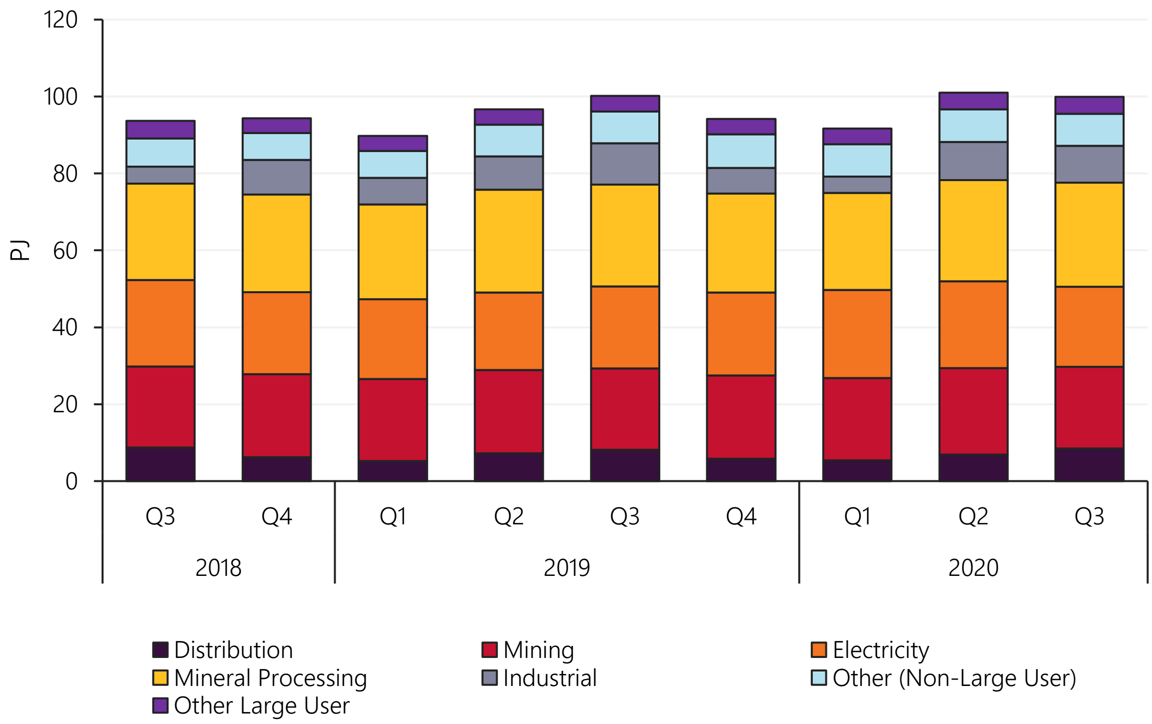
In Q3 2020, total Western Australian gas consumption was 100 PJ, representing a 0.3% decrease on Q3 2019 levels (Figure 53). Key changes by segment included reduced consumption by Large Users overall (-0.8 PJ), and an increased consumption in the distribution network (+0.3 PJ).

Increased distribution network consumption compared to Q3 2019 (+4%) was due to additional heating requirements for residential and commercial buildings, with mean maximum temperatures 0.8°C lower than Q3 2019.

Gas consumption by Large Users reduced for industrial use (-11%) and electricity generation (-3%). However, consumption increased in the Mineral Processing (+2%), Mining (+1%) and Other Large User (+6%) categories. Compared to Q2 2020, the most notable change was an 8% reduction in gas consumption for electricity generation.

Figure 53 Western Australia gas consumption comparable to Q3 2019

WA quarterly gas consumption by industry



Total gas production was 101 PJ, down 7% compared to Q3 2019 (Figure 54). The Karratha Gas Plant accounted for the most significant decrease (-79%), with production volumes down by 26 PJ. In Q3 2019, the Karratha Gas Plant accounted for over 30% of Western Australian production; however, in Q3 2020 the facility's production made up less than 7% of the total due to planned maintenance[35]. There was a corresponding increase in production at Wheatstone (+6 PJ), Macedon (+4 PJ), Gorgon (+3.6 PJ) and Varanus Island (+2.5 PJ), which largely offset Karratha's decrease.

In Q3 2020, Xyris Production Facility produced gas (0.6 PJ) for the first time since Q4 2019, following the completion of the Waitsia Stage 1 Expansion project[36]. As part of this project, the facility upgraded its capacity from approximately 10 TJ/day to 20 TJ/day and added a new connection point to the Metro zone of the

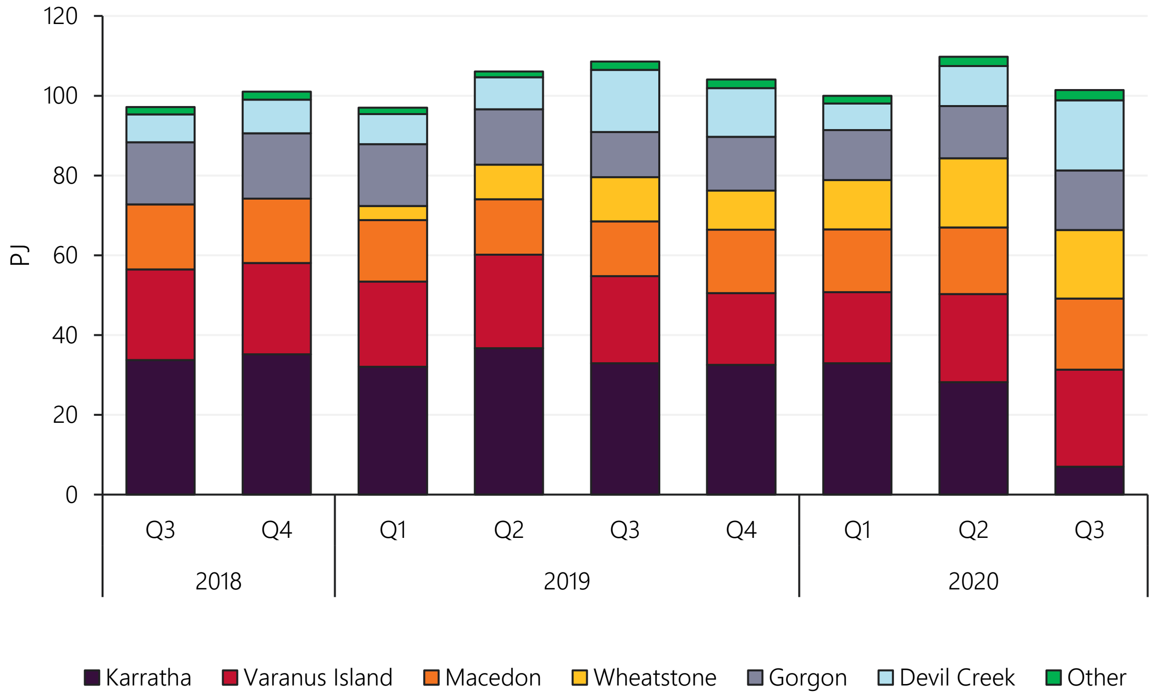
[35] Woodside, Facility Maintenance Information: https://www.woodside.com.au/sustainability/working-openly/facility-maintenance-information.

[36] Mitsui E&P Australia 2020, Waitsia Stage 1 Expansion: https://mitsuiepmidwest.com.au/waitsia-stage-1-expansion-going-into-production-soon/.

Dampier to Bunbury Natural Gas, which is in addition to its existing connection point on the Parmelia Gas Pipeline[37].

Figure 54 Western Australia gas production down 7% compared to Q3 2019

WA quarterly gas production by facility



[37] Mitsui E&P Australia 2019, Waitsia Stage 1 Expansion: https://mitsuiepmidwest.com.au/waitsia-stage-1-expansion-site-works-set-to-commence-end-of-december-2019/

3. WEM market dynamics

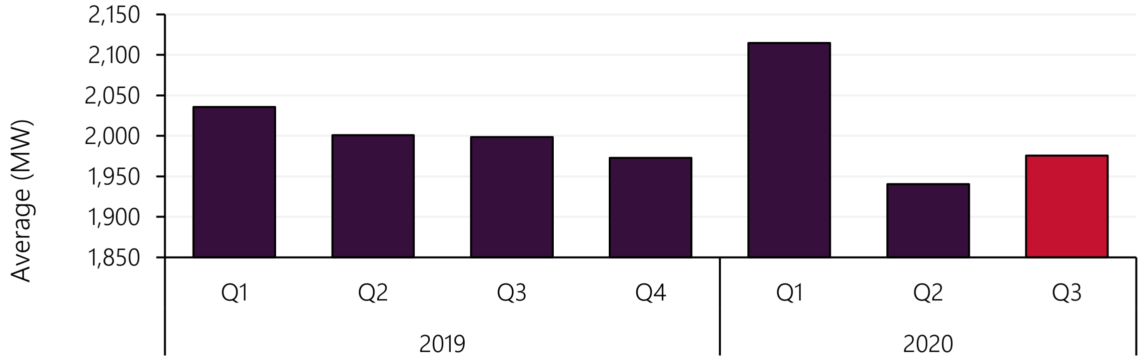
3.1 Weather and electricity demand

Average WEM operational demand[38] in Q3 2020 was 1.1% lower than Q3 2019 (Figure 55).

Perth temperatures in Q3 2020 were in line with historical averages, with a quarterly average maximum of 19.9°C; 0.8°C cooler than Q3 2019 and 0.2°C above the 10-year Q3 average. The average minimum temperature for Q3 2020 was 9.2°C, which is 0.8°C warmer than Q3 2019 and 0.4°C warmer than the 10-year average minimum temperature[39].

Figure 55 WEM Q3 operational demand down 1.1% on Q3 2019

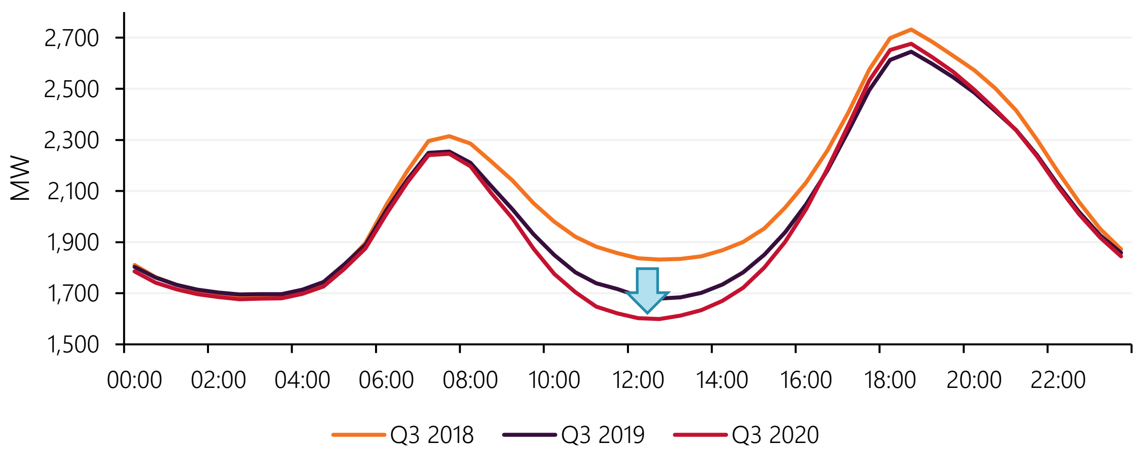
WEM quarterly average operational demand



With weather conditions similar to 2019, the change in operational demand was driven by reducing midday demand (Figure 56). In general, demand in Q3 2020 was lower throughout the middle of the day in line with consistent trends of increasing generation from distributed PV. Demand during morning peaks was similar to Q3 2019, with demand during evening peaks slightly higher than Q3 2019.

Figure 56 Morning and afternoon demand peaks similar to Q3 2019; midday demand continued to reduce

WEM Q3 hourly average operational demand by year



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[38] WEM Operational Demand refers to the average measured total of all wholesale generation in the SWIS and is based on non-loss adjusted sent out SCADA data.

[39] See: http://www.bom.gov.au/climate/current/month/wa/perth.shtml.

3.2 Record demand

In Q3 2020 a new record was set for maximum Q3 demand at 3,437 MW on Monday 3 August 2020 1800 hrs[40], driven by cold temperatures, which reached a daily maximum of 12°C on this day.

In addition, new records for minimum operational demand occurred on Saturday 12 September at 1200 hrs when demand reached 1,037 MW, and again on at 1200 hrs on Sunday 13 September 1200 hrs (Table 5). The new record represents a 136 MW reduction on the previous record which was set in Q1 2020. This is the fifth consecutive quarter in which a new minimum quarterly demand record has been set; three (including this one) were all-time minimum demand records.

This highlights the continuing impact of distributed PV on demand patterns and quantities in the WEM. The estimated output of distributed PV at the time of this minimum demand record was 1,168 MW, representing 54% of the total underlying demand. This is an all-time record for the highest proportion of distributed PV of underlying demand.

Table 5 WEM maximum and minimum demand records

Maximum demand (MW)			Minimum demand (MW)		
Q3 2020	All-time	All Q3	Q3 2020	All-time	All Q3
3,437	4,006	3,418	999	999	999

3.3 Electricity generation

The average change in generation between Q3 2019 and Q3 2020, by fuel type and time of day, is shown in Figure 57. These changes highlight the supply-mix transformation occurring in the WEM which contributed to the record minimum demand observed in section 3.2. Key shifts compared to Q3 2019 included:

- Average GPG decreased by 64 MW, while coal-fired generation decreased by 40 MW. This was despite a slightly higher coal availability of 83.1% in Q3 2020 versus 81.4% in Q3 2019.
- Distributed PV generation increased by 28 MW on average (or +78 MW on average during solar periods)[41], due to increased installed capacity in the SWIS. In Q3 2020 distributed PV reached a new record maximum output of 1,238 MW, surpassing the previous record of 1,006 MW set in Q3 2019.
- Wind generation increased by 69 MW on average, due to the commissioning of new wind farms in the SWIS[42].
- Large-scale solar generation increased by 13 MW on average (or +24 MW during solar periods) due to commissioning of new solar capacity[43].

[40] All times in this section are Australian Western Standard Time (AWST).

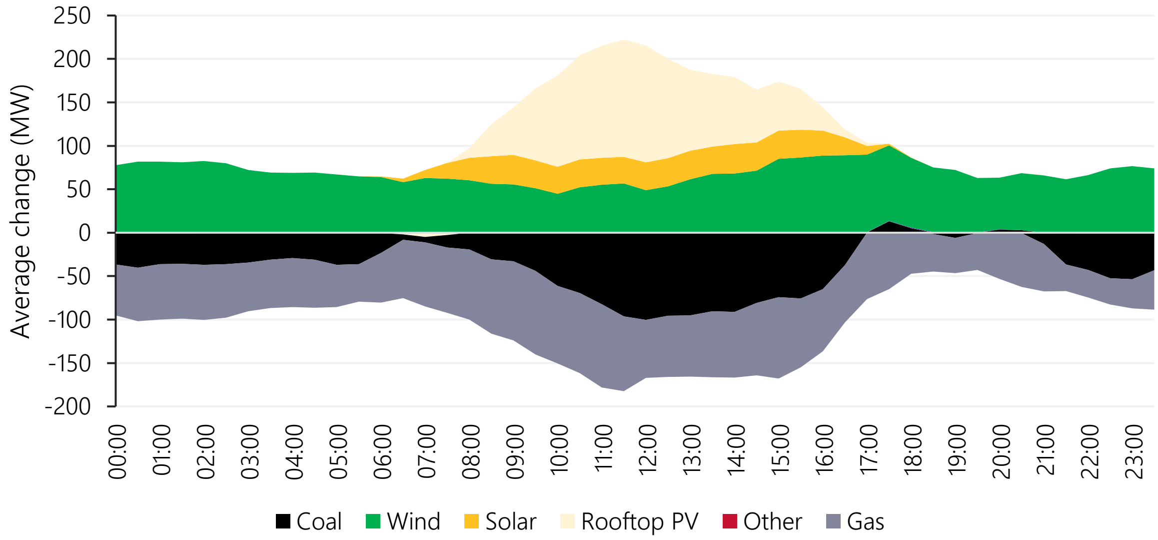
[41] The average increase in distributed PV generation of 29 MW represents the average of all intervals, including night-time intervals when solar generation is nil. The increase of 78 MW is the average increase based on intervals when distributed PV generation is greater than zero, and therefore excludes night-time periods.

[42] Two new wind farms commenced commissioning in Q3 2020 (Yandin and Warradarge wind farms), totalling an increase of 392 MW of installed wind generation capacity.

[43] This includes new 100 MW facility Merredin Solar Farm and the addition of 30 MW solar capacity to the existing Greenough River Solar facility.

Figure 57 Solar and wind generation displace coal and GPG

Average change in WEM supply – Q3 2020 versus Q3 2019



The changing role of coal-fired and gas-powered generation

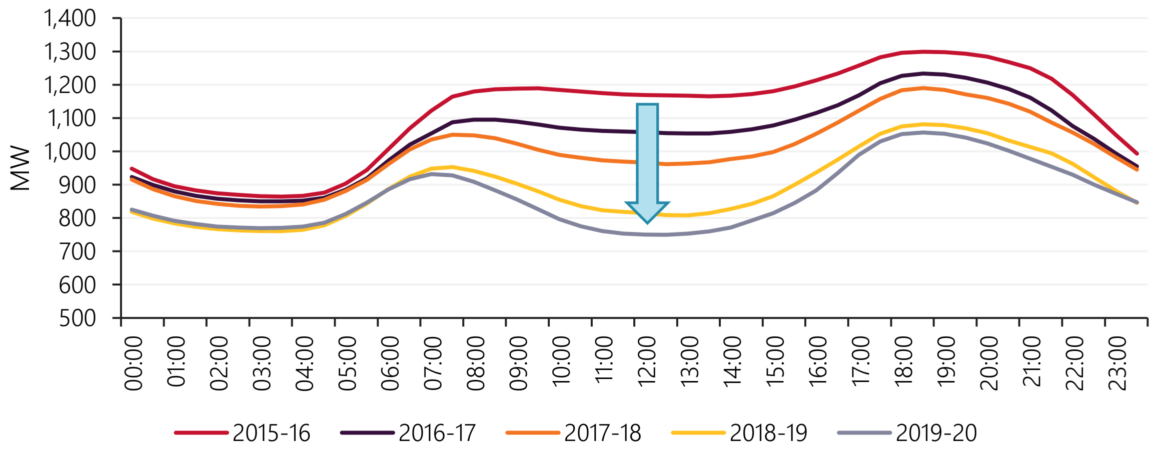
In response to the ongoing quarterly observations on changing generation mix, AEMO has undertaken a longer-term analysis. Increasing amounts of distributed PV, grid-scale wind, and grid-scale solar generation in the WEM are changing the fuel mix and affecting the use of coal-fired and gas-powered generators.

Average daily coal-fired generation profiles for the last five Capacity Years are shown in Figure 58 to illustrate the changing profile over time[44,45].

- Between 2015-16 and 2019-20, coal-fired generation dropped by an average of 248 MW; this reduction has been strongest during the middle of the day when distributed PV is highest.
- Coal profiles are trending from relatively flat generation throughout the day to morning and evening peaks with a midday trough.

Figure 58 WEM average coal generation per day has decreased over the last five years

Average coal generation in the WEM by time of day, Capacity Year 2015-16 to 2019-20



[44] Capacity Year includes the period beginning (Trading Day) 1 October and ending (Trading Day) 30 September and is defined in the WEM Rules.

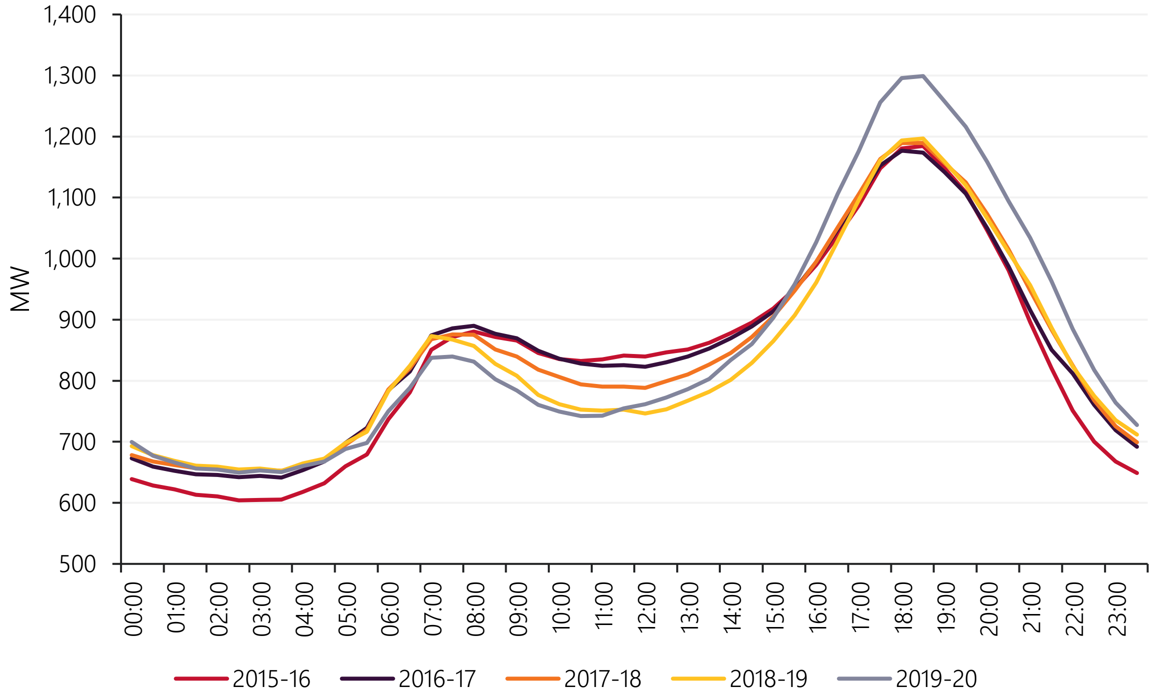
[45] Capacity Years were used for this analysis due to the availability of data for the entire 2019-20 Capacity Year period at the time of Q3 QED publication, allowing for complete year-on-year comparison.

Figure 59 shows the daily GPG generation profile:

- The average level of GPG generation has remained relatively stable, varying between 833 and 858 MW from 2015-16 to 2019-20 respectively.
- Compared to 2015-16, GPG profiles in 2019-20 were characterised by slightly reducing morning peaks, while evening peaks increased.

Figure 59 WEM average GPG per day has remained relatively stable, trending toward reducing morning peaks and strong evening peaks

Average GPG in the WEM by time of day, Capacity Year 2015-16 to 2019-20



The changing profiles of coal-fired and gas-powered generation are largely driven by growing levels of grid-scale wind and solar in the SWIS (Section 3.3) and increasing generation from distributed PV, which is reducing demand in the WEM throughout the middle of the day[46]. This has driven the changing coal generation profiles shown in Figure 58. Further overall decreases in coal generation were due to 220 MW[47] of coal capacity exiting the WEM since Q3 2017. GPG has been comparatively less affected by increases in distributed PV as it typically exhibits the higher ramp rates needed to service the steep transition from midday trough to evening peak.

3.4 Wholesale electricity prices

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

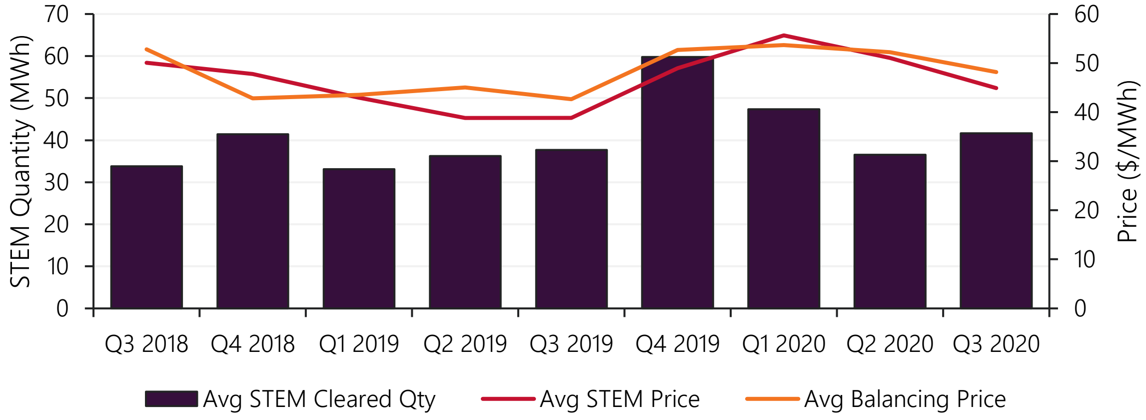
In Q3 2020 the average Balancing Price decreased by $4/MWh from Q2 2020 but increased by $6/MWh compared with Q3 2019 (Figure 60). Similarly, average STEM prices decreased by $6/MWh from last quarter and increased by $6/MWh from Q3 2019. The STEM average quantity during Q3 2020 was 42 MWh, an increase from 38 MWh in Q3 2019 and 37 MWh in Q2 2020.

[46] Increasing generation from distributed PV is driven by growing installation numbers. Installed distributed PV capacity in the SWIS is estimated, based on data from the Clean Energy Regulator, to have increased from 498 MW to 1,489 MW between Q3 2015 and Q3 2020. This includes systems sized under 100 kW and systems sizer over 100 kW and under 10 MW.

[47] 220 MW represents the capacity of retired coal generator Muja AB; retirement took place in a staged approach between October 2017 and April 2018.

Figure 60 Market Prices decreased compared to Q3 2019, but were up on Q2 2020 levels

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



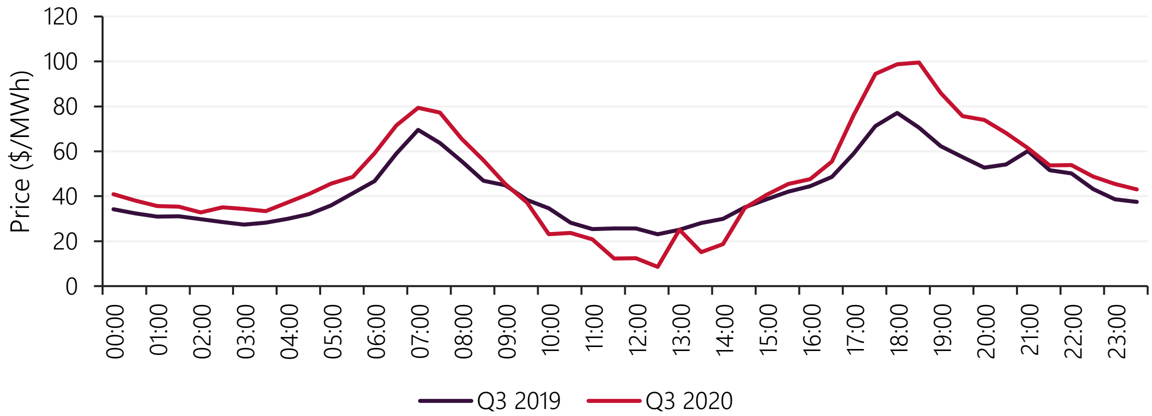
3.4.2 Time of day Balancing Prices

In general, Balancing Prices are influenced by changes in operational demand, Facility availability and participant bidding behaviour. Figure 61 compares Q3 2020 Balancing Prices with Q3 2019 by time of day, with key changes including:

- Q3 2020 average prices were lower in the middle of the day.
  - Lower midday Balancing Prices were largely driven by lower midday demands (Section 3.1), and coincided with the two price floor events in Q3 2020.
  - Increased renewable generation capacity resulted in greater quantities of energy bid at negative prices, leading to a higher proportion of energy being dispatched from wind and solar facilities at lower prices and displacing gas and coal (Section 3.3).
- Changes in participant bidding behaviour resulted in similar operational demand levels having a higher average Balancing Price than in Q3 2019 ($48/MWh Q3 2020 compared with $43/MWh Q3 2019):
  - Overnight prices were slightly higher than in Q3 2019, despite similar levels of operational demand during these periods.
  - Q3 2020 evening peak prices increased significantly, despite marginal differences in operational demand levels during this period (Section 3.1).

Figure 61 Balancing Prices lower during midday but higher during morning and evening peaks

WEM average Balancing Price ($/MWh) by time of day



3.4.3 Negative Balancing Prices

Increasing occurrences of negative energy prices were driven by a combination of growing renewable generation and changing demand profiles. Between Q3 2019 and Q3 2020, negatively priced intervals increased from 4.8% to 6.2% of the time, with 1.8% of all intervals in Q3 2020 occurring at -$30/MWh or lower.

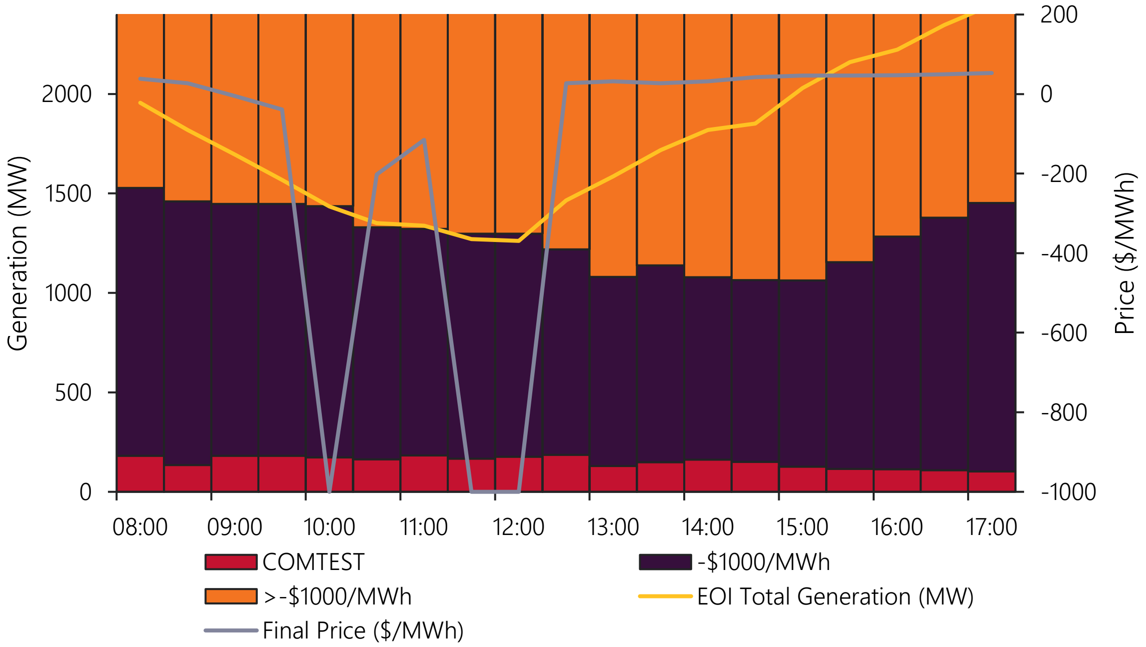
During Q3 2020, the floor price (-$1,000/MWh) was reached on two Trading Days, for three intervals on each day, bringing the total number of floor price intervals in the WEM to nine (with the previous three intervals occurring in Q3 2019). These recent price floor outcomes were driven by a combination of large-scale generator commissioning and record low demands:

- On Saturday 12 September 2020, the floor price was reached at 1230 hrs, 1330 hrs and 1400 hrs.
  - During this event, operational demand fell to record low levels[48] during five Trading Intervals, with the lowest being 1,037 MW (Section 3.2).
- On Saturday 15 August 2020 the price floor was reached at 1000 hrs, 1130 hrs and 1200 hrs:
  - Yandin Wind Farm, Warradarge Wind Farm and Merredin Solar Farm were concurrently commissioning (totalling approximately 170 MW of generation during floor price intervals). All quantities offered from facilities' commissioning activities must be priced at -$1,000/MWh to guarantee dispatch in the Balancing Merit Order (BMO).
  - Low demand (minimum 1,272 MW) was due to mild weekend temperatures (maximum 22°C) and high generation from distributed PV (maximum 1,018 MW).

Figure 62 shows the Balancing Market outcomes for 15 August, with between 1,300 MW and 1,450 MW of generation priced at -$1,000/MWh during the price floor intervals.

Figure 62 Concurrence of low demands and large quantities of generation priced at -$1,000/MWh

Generation price bands during the 15 August 2020 price floor event



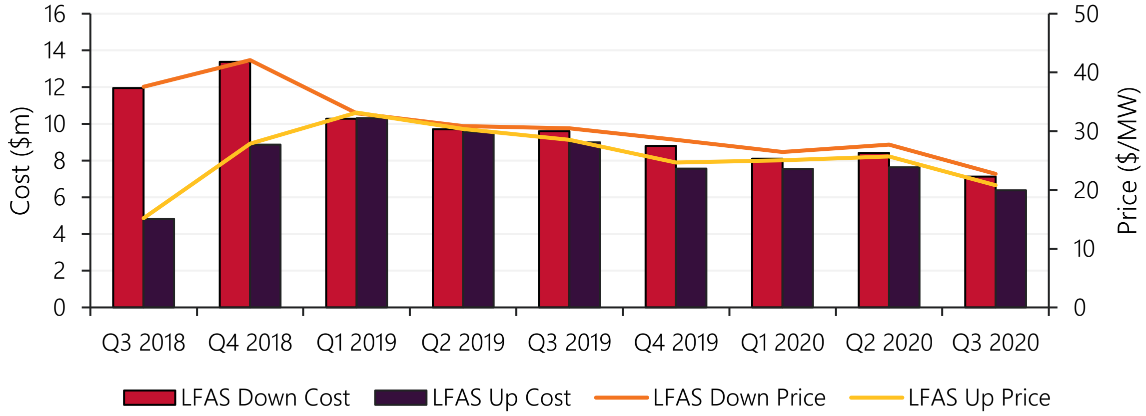
[48] Subsequently surpassed.

3.4.4 Load Following Ancillary Service costs

Load Following Ancillary Service (LFAS) availability costs continued to decline into Q3 2020, with a reduction of $2.6 million compared to Q2 2020 (Figure 63). Factors driving this decrease were similar to previous quarters, including the introduction of a 'sculpted' LFAS requirement in the 2019-20 financial year and the addition of new facilities into the LFAS Market.

Figure 63 LFAS costs continue to decline

Quarterly LFAS Upward and LFAS Downward costs since Q3 2018



Following AEMO's proposal, on 16 September 2020 the Economic Regulation Authority (ERA) approved revised LFAS requirements in response to the increase in Intermittent Non-Scheduled Generation in the SWIS:

- From 85 MW to up to 105 MW of Upwards and Downwards LFAS between 0530 hrs and 1930 hrs.
- From 50 MW to 80 MW of Upwards and Downwards LFAS between 1730 hrs and 0530 hrs.

AEMO has implemented a staged approached to the LFAS requirement increases, with levels increasing to 95 MW and 70 MW from 25 September 2020.

3.5 WEM COVID-19 impacts

In the Q2 2020 QED, AEMO reported on the impact of the response to the COVID-19 pandemic on electricity demand in the WEM. That analysis considered the period of the most significant restrictions and found that while there was no significant change to overall energy consumption, there was a shift in demand from the morning peak to the afternoon and evening peak, a reduction in consumption by large users, and an increase in consumption by small users (particularly in the afternoon, driven by increased working from home arrangements).

Using the same methodology, AEMO has updated the analysis for Q3 to consider the nine-week period beginning 1 July[49]. During this period, key remaining restrictions included interstate and international travel restrictions, the "two square metre rule", and 50% capacity at major sport and entertainment venues[50].

The analysis compares underlying demand[51] quantities and patterns during this period and the equivalent period in 2019 to identify any changes which cannot be accounted for by any other factors, such as weather or the impact of distributed PV.

[49] Roughly corresponding to the beginning of Phase 4 of the lifting of restrictions in WA on 27 June.

[50] See: https://www.wa.gov.au/organisation/department-of-the-premier-and-cabinet/covid-19-coronavirus-wa-roadmap.

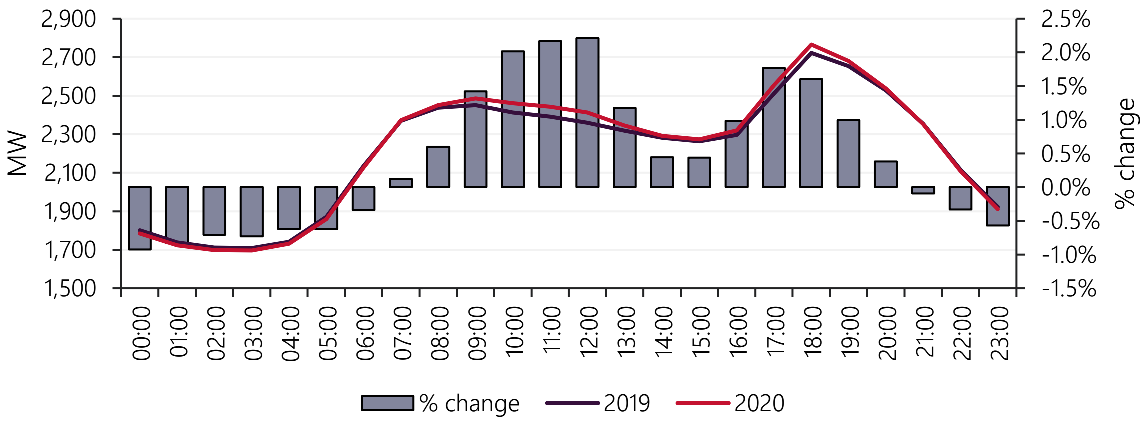
[51] To account for the impact of distributed PV, this analysis considers estimated underlying demand, which is operational demand plus estimated distributed PV output.

Overall Demand Impact

Overall changes in underlying demand from 2019 to 2020 were minor (0.6% increase, Figure 64). There was a very small shift in the demand pattern, with an increase in consumption of 1.2% during the day (0700 hrs to 2200 hrs) peak and a decrease of 0.6% overnight, which is consistent with average hourly temperature profiles. As such, AEMO concluded that during Q3 COVID-19 restrictions had minimal impact on the overall demand quantities and patterns in the WEM.

Figure 64 Limited impact of COVID-19 on WEM underlying demand in Q3 2020

Average WEM underlying demand by time of day



Demand impact by segment

To determine how varying segments were impacted, AEMO also considered the following segments independently:

- Large users – commercial and industrial users with at least 160 MWh[52] in the 12 months prior to implementation of COVID-19 restrictions.
- Small users – with less than 160 MWh in the 12 months prior to implementation of COVID-19 restrictions. This represents smaller commercial and industrial consumers plus all residential consumption.

Total consumption by large users and small users both increased, by 0.4% and 0.7% respectively.

Although flat overall, consumption by small users (Figure 65) increased by 2-6% between 0800 hrs and 1900 hrs, and decreased by 2-4% between 2200 hrs and 0600 hrs. This pattern was largely driven by temperature changes, with increased energy usage for heating during the day and less overnight.

Despite the lifting of most restrictions, continued working from home arrangements may have contributed to the midday increase in small user consumption, as well as the midday decrease in large user consumption that was observed (Figure 66). Consumption from large users followed the opposite pattern to small users, with consumption decreasing by 0.5-1.5% between 0900 hrs and 1800 hrs and increasing by 0.5%-2.5% between 1800 hrs and 0800 hrs.

[52] Section 47 of the Electricity Industry Act 2004 defines the 160 MWh per annum threshold between small and large end user sites.

Figure 65 Underlying consumption by small users in the WEM increased by 0.7%

Change in WEM average small user consumption by time of day, Q3 2019 vs Q3 2020 (total WEM underlying demand less loss-factor adjusted net interval meter consumption)

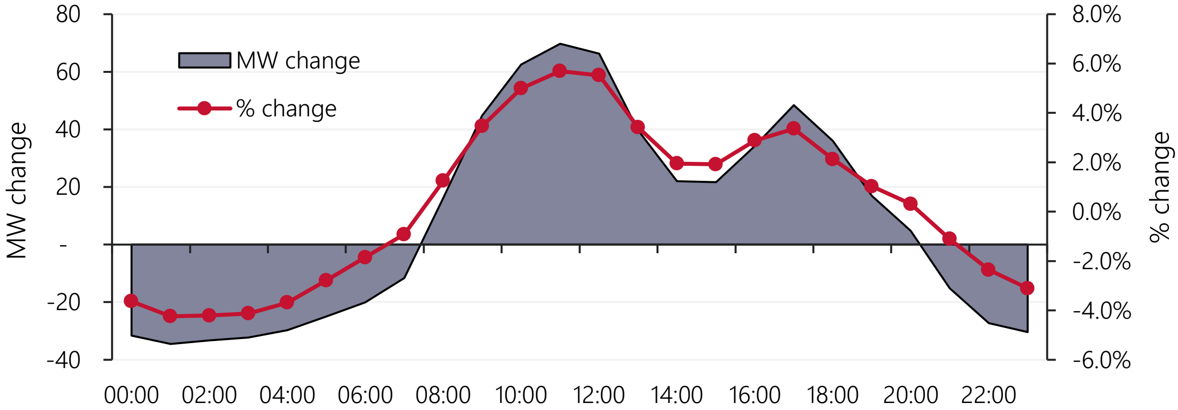
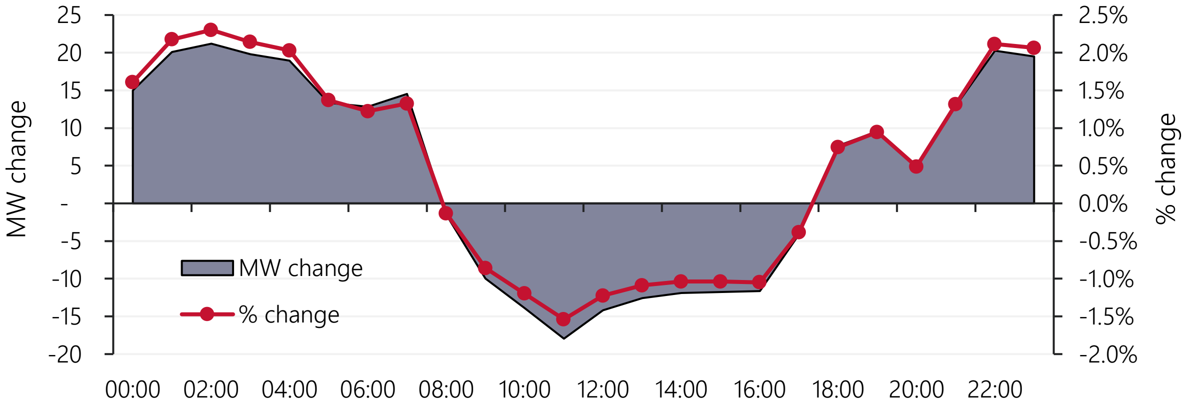


Figure 66 Underlying consumption by large users in the WEM increased by 0.4%

Change in WEM average large user consumption by time of day, Q3 2019 vs Q3 2020 (loss-factor adjusted net interval meter consumption)



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
BBL	Barrel
COVID-19	Coronavirus disease 2019
DAA	Day Ahead Auction
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
FY	Financial year
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

Abbreviation	Expanded term
OPEC	Organisation of Petroleum Exporting Countries
PJ	Petajoule
PV	Photovoltaic
QCLNG	Queensland Curtis LNG
QNI	Queensland to New South Wales Interconnector
RBP	Roma to Brisbane Pipeline
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
VRE	Variable renewable energy
WEM	Wholesale Electricity Market