



Quarterly Energy Dynamics Q1 2021

Market Insights and WA Market Operations

Important notice

PURPOSE

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q1 2021 (1 January to 31 March 2021). This quarterly report compares results for the quarter against other recent quarters, focusing on Q4 2020 and Q1 2020.

Geographically, the report covers:

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

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VERSION CONTROL

Version	Release date	Changes
1	28 April 2021	

Executive summary

East coast electricity and gas highlights

Mild weather cuts energy demand

- East coast average Q1 maximum temperatures were the lowest since 2012, with particularly mild weather in Sydney, Brisbane, and Melbourne. The resulting reduction in cooling load, coupled with record Q1 installation of distributed photovoltaic (PV) capacity, led to National Electricity Market (NEM) average operational demand reducing by 3% on Q1 2020 levels, declining to its lowest Q1 since 2002.
 - Of note, there was record low Q1 average operational demand in three out of the five NEM regions (Victoria, South Australia, and New South Wales).
- Few periods of extreme heat, combined with low NEM price volatility and increased variable renewable energy (VRE) output, resulted in diminished demand for gas-powered generation (GPG), representing its lowest quarter since 2005.

Wholesale electricity prices continue to fall

- Regional spot electricity prices reduced by 21-68% compared to Q1 2020, reaching their lowest average¹ since 2015 (and lowest Q1 since 2012). The largest price reductions occurred in Victoria, falling from \$79 per megawatt hour (MWh) in Q1 2020 to \$25/MWh, and in New South Wales, falling from \$86/MWh to \$38/MWh.
- Drivers of the NEM-wide reduction in prices included the significant reduction in price volatility (that is, prices above \$300/MWh), an increase in lower-priced offers from VRE, hydro, and coal-fired generation, as well as low Q1 operational demand.
 - The lack of Q1 price volatility was primarily due to no repeat of the South Australian separation that occurred in Q1 2020, fewer extreme demand periods, and increased supply from VRE and coal-fired generation during high demand periods.
 - The main exception was a prolonged volatility spike in South Australia following the simultaneous trip of two Torrens Island Power Station busbars, which limited output from Torrens Island and Barker Inlet power stations, and contributed \$14/MWh to South Australia's average quarterly price of \$41/MWh.
- Negative spot prices continued to occur at very high levels in South Australia (16.8% of the time), and Victoria (10.3%). In South Australia, the average spot price during peak solar production (between 1000 hrs and 1530 hrs) was *negative* \$12/MWh.
- AEMO was required to direct South Australian GPGs for system security for a record 70% of the quarter due to persistently low electricity prices below their cost of generation.
- ASX calendar year (Cal) 2022 swap contract prices decreased across all states, finishing the quarter at \$40/MWh on average. The largest reductions occurred in Victoria and in South Australia, which declined by \$8/MWh to \$36/MWh, with South Australia supplanting Queensland as the lowest priced region (on a futures basis).

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

Gas prices and exports driven by northern winter

- A cold winter in the northern hemisphere led to a sustained period of high international gas prices and resulted in an increase in gas flowing to Curtis Island for liquefied natural gas (LNG) export. This represented the second highest quarterly east coast LNG export, just behind the record set the previous quarter.
- International influences saw east coast gas prices increase slightly compared to Q4 2020, despite reduced domestic gas demand. The Brisbane Short Term Trading Market (STTM) remained the highest priced market, averaging \$6.36 per gigajoule (GJ), while the Victorian Declared Wholesale Gas Market (DWGM) remained the lowest priced market at \$5.52/GJ.
- On 29 March 2021, AEMO issued a notice of a threat to system security in Victoria's Declared Transmission System (DTS), due to low levels of contracted Dandenong LNG inventory available for operational and emergency scenarios.

Western Australia electricity and gas highlights

- A new minimum operation demand record was set in the South West Interconnected System (SWIS) on 14 March 2021. Operational demand at this time dropped to 952 megawatts (MW), 33 MW below the previous record, with estimated distributed PV output of 1,026 MW at the time.
- Average Balancing Prices reduced from \$56/MWh in Q1 2020 to \$47/MWh this quarter, due to increased VRE output and reduced daytime demand.
 - Despite lower average prices, there were five intervals clearing at the maximum price of \$267/MWh. Drivers included the largest recorded change in Scheduled Generation within a Trading Day, coupled with higher than forecast demand and lower than forecast Non-Scheduled Generation.
 - There were four times more negatively priced intervals in Q1 2021 than in Q1 2020, with 9% of total intervals being negatively priced.
- There was a significant increase in grid-scale wind and solar output (+259 MW) since Q1 2020, due to newly commissioned wind and solar farms.
- Western Australia's Q1 2021 total domestic gas consumption was 0.75 petajoules (PJ) higher than Q1 2020, due to a 4 PJ increase at Yara Pilbara Liquid Ammonia Plant, which was partially offset by reduced GPG demand.
- In Q1 2021, total Western Australian gas demand remained relatively consistent, while gas production decreased by 8.6% to 91.4 PJ compared to Q1 2020. This represented the lowest quarterly production since Q4 2018. The production decrease was primarily due to lower supply from the Karratha Gas Plant, and resulted in record net withdrawals from Storage Facilities, which increased 12.6 PJ from Q1 2020.

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1. NEM market dynamics

1.1 Weather

During Q1 2021, the weather was much milder than in recent summer quarters, particularly in Brisbane, Sydney, and Melbourne, with maximum temperatures at their lowest Q1 averages since 2012 (Figure 1). Compared to Q1 2020 (when temperatures were also comparatively mild), there was a noticeable reduction in extreme heat days above 38°C (Figure 2). This also contributed to reduced cooling requirements, particularly in Sydney and Brisbane, which decreased by 50% and 44% respectively (Figure 3).

Most National Electricity Market (NEM) regions experienced above average rainfall during the quarter, largely due to the wetter influence of La Niña². Notably, New South Wales had its second-wettest March on record, resulting in extensive flooding throughout the eastern part of the state³.

Figure 1 Very mild Q1 conditions

Average maximum temperature by capital cities (Q1s)

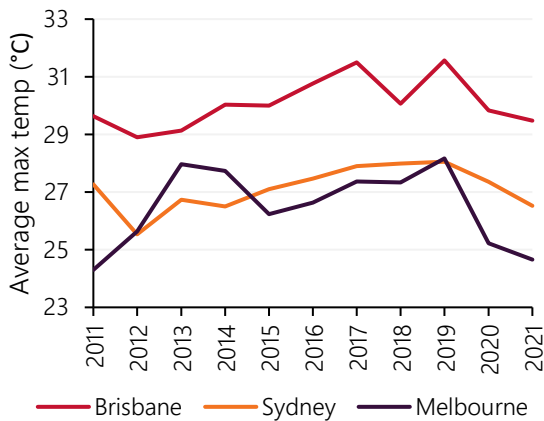
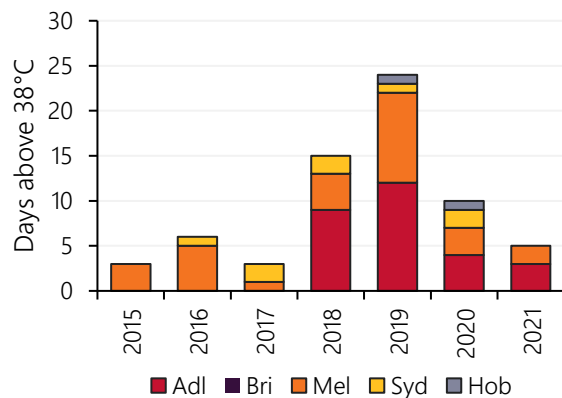


Figure 2 Fewer number of extreme heat days

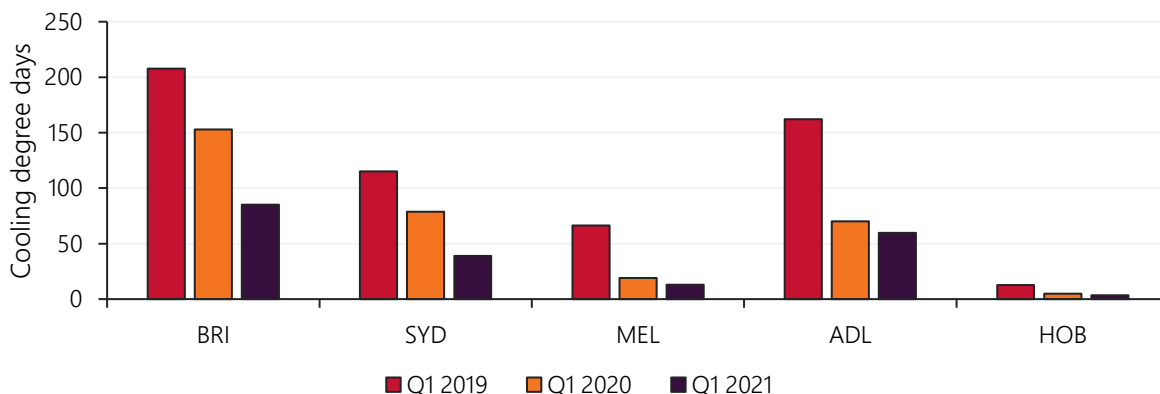
Number of days above 38°C by capital city (Q1s)



Source: Bureau of Meteorology

Figure 3 Reduced cooling requirements across all capital cities

Cooling degree days⁴ (Q1s)



² Bureau of Meteorology 2021, La Niña past peak, but influence expected to continue: http://www.bom.gov.au/climate/enso/wrap-up/archive/20210216_archive.shtml

³ Bureau of Meteorology 2021, Australia in March 2021: http://www.bom.gov.au/climate/current/month/aus/archive/202103_summary.shtml

⁴ 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).

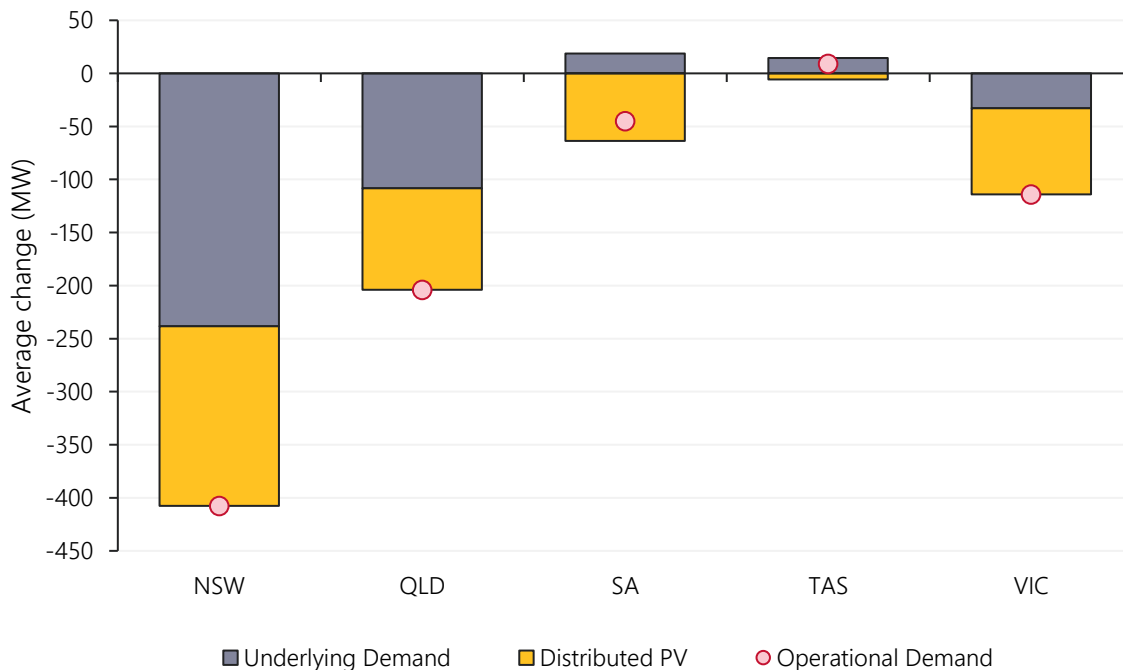
1.2 Electricity demand

NEM quarterly average operational demand fell to 21,192 megawatts (MW), its lowest Q1 average since 2002 and 761 MW (or 3%) lower than Q1 2020. There was record low Q1 average operational demand in three out of the five NEM regions (Victoria, South Australia, and New South Wales). Compared to Q1 2020, reductions occurred across all NEM region, except Tasmania, with the largest decreases occurring in New South Wales (-407 MW) and Queensland (-204 MW, Figure 4). Reduced operational demand was largely a function of:

- **Increased distributed photovoltaic (PV) output**⁵ – the quarter saw a new Q1 record for uptake of distributed PV (~800 MW capacity)⁶ which contributed to substantial daytime demand reductions. Compared to Q1 2020, distributed PV output increased by 415 MW on average, with the largest time of day increase occurring at 1330 hrs (+1,194 MW, Figure 5).
 - By region, the largest increase in average distributed PV output occurred in New South Wales (169 MW on average), in line with the large amount of capacity installed during the last year⁷.
- **Milder weather** – reduced cooling requirements (34% down on average) contributed to lower NEM underlying demand (-346 MW on average).
 - The decline in quarterly underlying demand was most prominent in New South Wales (-238 MW) as average cooling requirements halved, with large reductions occurring between 1330 hrs and 1630 hrs.
 - Despite lower cooling requirements, underlying demand in South Australia and Tasmania increased slightly, partly driven by increased industrial load.

Figure 4 New South Wales leads operational demand reductions

Change in average operational demand by region – Q1 2021 versus Q1 2020



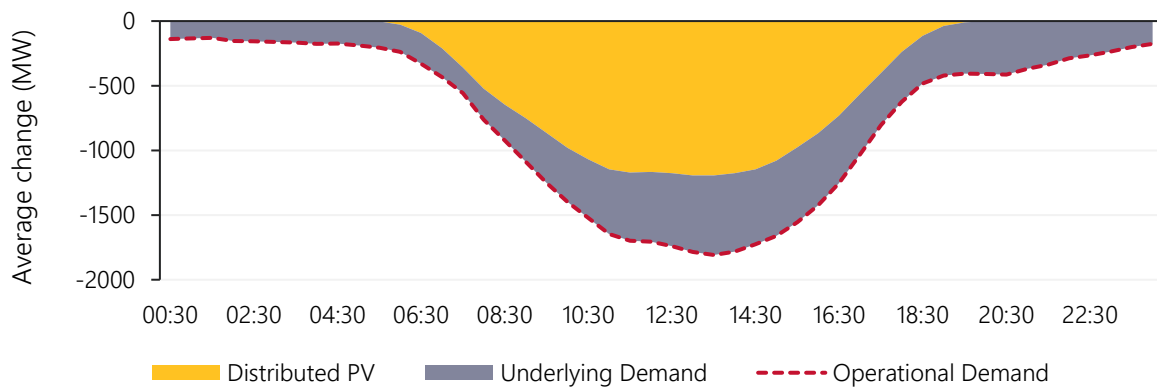
⁵ Increased distributed PV generation results in reduced operational demand because distributed PV is behind the meter, and is based on AEMO estimates using ASEFS2.

⁶ Preliminary data provided by the Clean Energy Regulator.

⁷ Clean Energy Regulator reports quarterly distributed PV ($\leq 100\text{kW}$) capacity by state: <http://www.cleanenergyregulator.gov.au/csf/market-information/Pages/quarterly-Market-report.aspx>

Figure 5 Increased distributed PV dampens midday operational demand

Change in NEM-average operational demand by time of day – Q1 2021 versus Q1 2020



Maximum and minimum demand

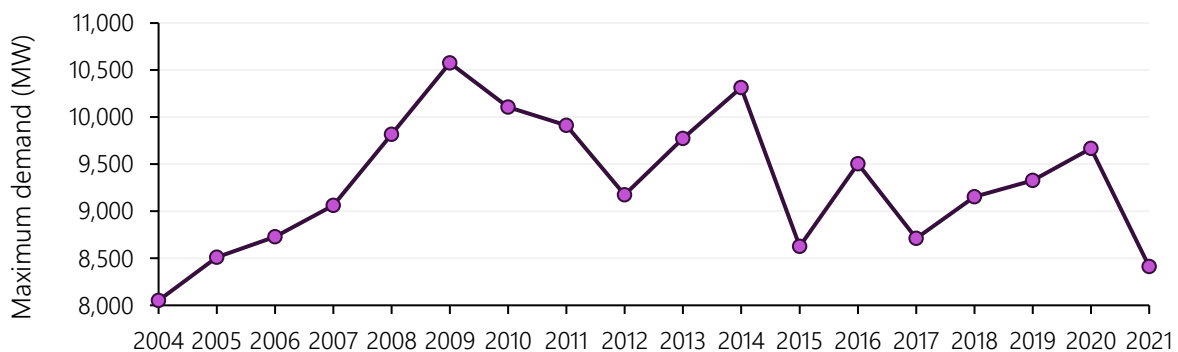
During the quarter, new Q1 operational demand minimums were set in South Australia and Victoria:

- **South Australia’s** new Q1 minimum demand of 358 MW was set on Sunday 14 March 2021 at 1430 hrs, and was only marginally above the 300 MW all-time record set in October 2020. Sunny conditions and mild weather, coupled with low underlying weekend demand, were drivers of the result⁸.
 - As South Australia was at credible risk of separation, and a minimum of 400 MW of scheduled demand is required to maintain system security in this condition⁹, AEMO instructed ElectraNet to take steps to maintain operational demand above 400 MW. This direction resulted in an estimated 71 MW of distributed PV (large distribution-connected and residential solar) output being curtailed, including around 14 MW of residential distributed PV through SA Government’s Smarter Homes’ initiative¹⁰.
- On Sunday 17 January 2021, a new Q1 minimum demand of 2,916 MW occurred in **Victoria**, 384 MW lower than the previous Q1 minimum set in Q1 2020, with similar drivers to those in South Australia.

With mild weather, and increased distributed PV output, quarterly maximum demands were also well down on recent first quarters. In particular, New South Wales’ maximum demand of 12,273 MW was 1,562 MW lower than in Q1 2020, while Victoria’s maximum demand of 8,411 MW was 1,256 MW lower than Q1 2020, and represented its lowest Q1 maximum demand since 2004 (Figure 6).

Figure 6 Mild weather leads to low Victorian maximum demand

Q1 maximum demands – Victoria



⁸ The AER’s Quarter 1 2021 Wholesale Market Quarterly Report will include a focus on this event.

⁹ During this event, South Australia was at credible risk of separation due to the planned outage of the Moorabool – Mortlake (MLTS-MOPS) 500 kilovolt (kV) line in Victoria. AEMO is reviewing the 400 MW secure demand threshold.

¹⁰ For further information, see: <https://aemo.com.au/newsroom/media-release/solar-pv-curtailement-initiative-by-sa-government-supports-the-nem>. Note that the estimated amount curtailed during this event has been revised since this media statement.

1.3 Wholesale electricity prices

NEM quarterly average wholesale electricity prices fell sharply compared to recent first quarters, reaching the lowest Q1 levels since 2012 (Figure 7). Key outcomes included:

- Very low Victorian spot prices** – the largest price reductions occurred in Victoria, falling from \$79/MWh in Q1 2020 to \$25/MWh this quarter, its lowest quarterly average since Q1 2012.
 - This result was a function of a large increase in low-priced brown coal, hydro, wind, and solar supply in the region (+958 MW), coupled with lower operational demand (-114 MW), and no repeat of the price volatility that occurred in 2020.
 - Low average spot prices also occurred in other NEM regions; New South Wales declined from \$86/MWh in Q1 2020 to average \$38/MWh, while Queensland averaged \$43/MWh.
- Negative daytime prices in South Australia** – daytime prices in South Australia between 1000 hrs and 1530 hrs averaged -\$12/MWh (Figure 8). This represents the first quarter – anywhere in the NEM – when the daytime average has fallen below zero on a consistent basis. Section 1.3.3 discusses negative spot prices in more detail.
- Price volatility** – compared to recent Q1s, price volatility dissipated, with the only major price volatility occurring in South Australia on 12 March 2021. Section 1.3.2 provides more details on price volatility.

Figure 7 Wholesale electricity prices continue to fall

Average mainland wholesale electricity price by region (Q1s)¹¹

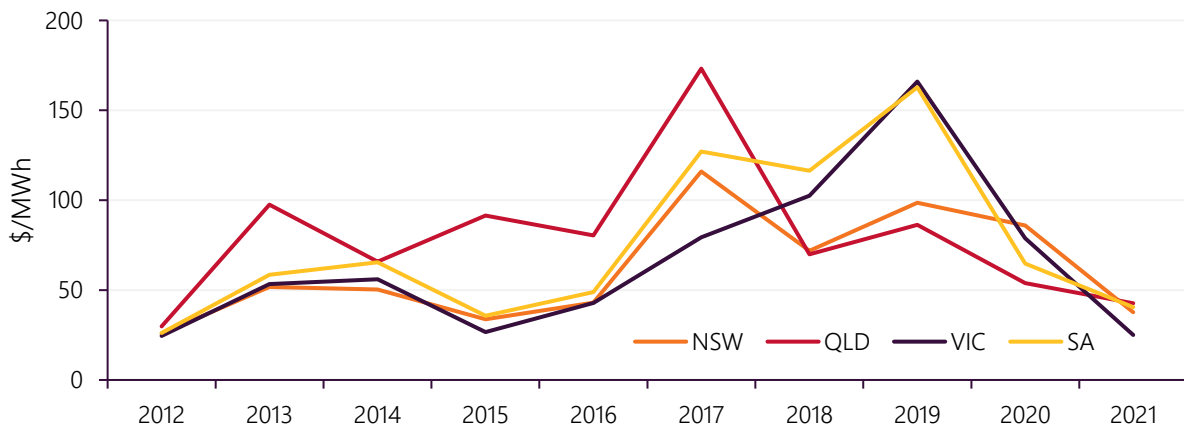
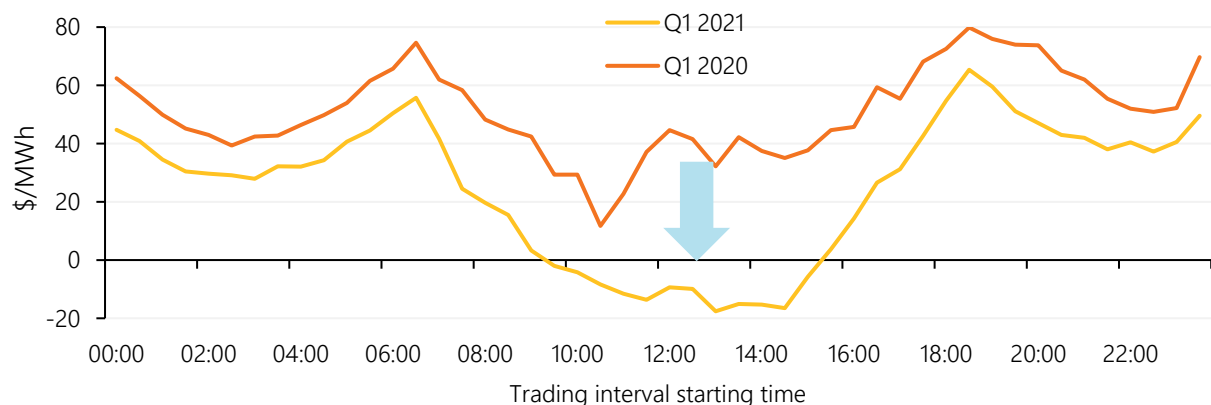


Figure 8 Negative daytime prices in South Australia

South Australian average underlying electricity price¹² by time of day – Q1 2021 and Q1 2020



¹¹ Tasmania averaged \$34/MWh in Q1 2021, down from \$45/MWh in Q1 2020.

¹² Price capped at \$300/MWh.

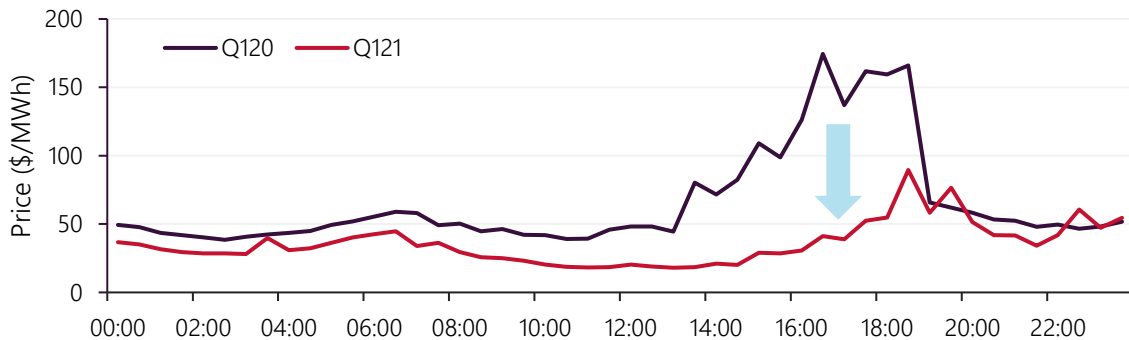
1.3.1 Wholesale electricity price drivers

Drivers of low average NEM spot prices this quarter included:

- **Lack of price volatility** – while Q1 typically exhibits high price volatility (prices above \$300/MWh), volatility this quarter was only confined to South Australia (Section 1.3.2) and there was no repeat of the volatility that occurred in 2020 during the South Australia interconnector separation. As shown in the intra-day pricing profile (Figure 9), the largest reduction in average spot prices occurred during the evening peak (1500 hrs to 1830 hrs) when price volatility was most prominent in Q1 2020.

Figure 9 Largest spot price reduction during the late afternoon/evening peak

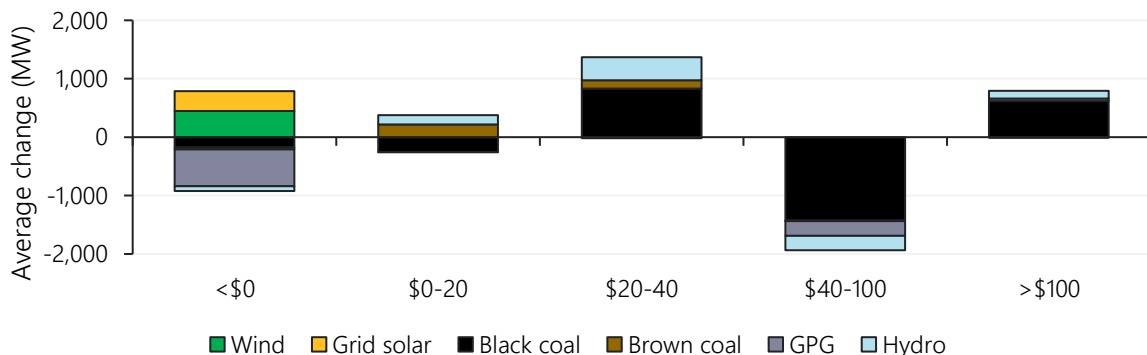
NEM average spot prices by time of day – Q1 2021 versus Q1 2020



- **Significant increase in low-priced supply¹³** – low-priced supply (offers below \$40/MWh) increased by 1,340 MW on average compared to Q1 2020 (Figure 10). Changes by fuel type included:
 - Combined wind and solar provided 786 MW of the increase in low-priced offers. This was primarily driven by new capacity additions and ramping up of existing capacity¹⁴.
 - NEM hydro generation (particularly in Victoria) provided an additional 478 MW of low-priced supply, reflecting increased rainfall and a greater ability to generate.
 - Black coal-fired generation provided an additional 402 MW of low-priced offers, mostly from the New South Wales fleet, as Mount Piper Power Station’s availability increased compared to Q1 2020.
 - Fewer outages from the brown coal-fired fleet led to a 326 MW average increase in low-priced offers.

Figure 10 Significant increase in offers below \$40/MWh

Average change in NEM offers by price band and fuel type – Q1 2021 versus Q1 2020



- **Reduced operational demand** – compared to Q1 2020, the significant increase in distributed PV generation, coupled with mild weather, reduced average operational demand by 761 MW (Section 1.2).

¹³ The AER’s Quarter 1 2021 Wholesale Market Quarterly Report will include a focus change in NEM offers.

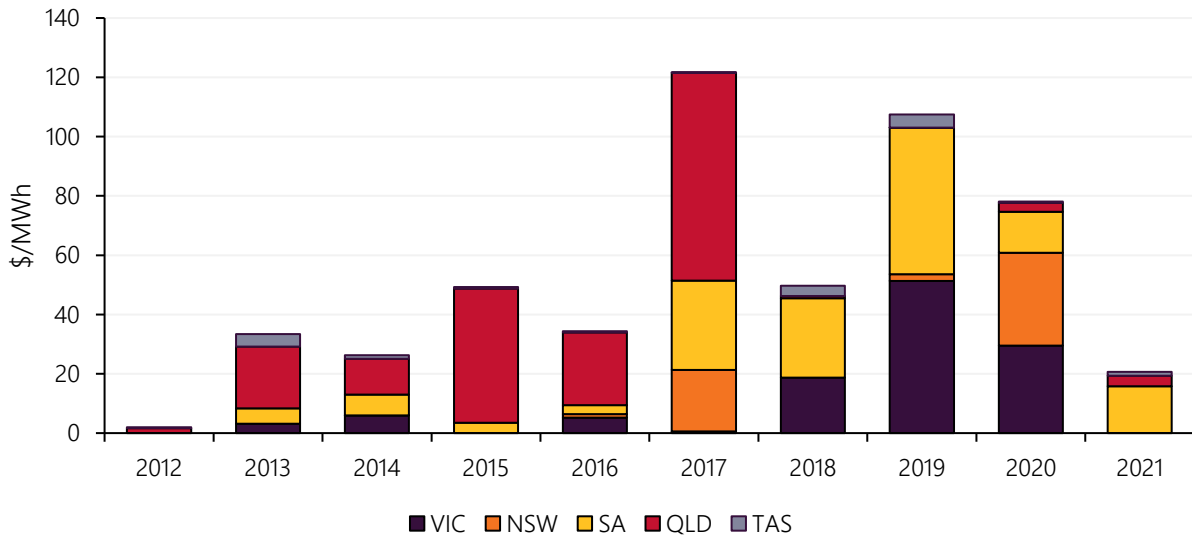
¹⁴ Includes projects which have started generating in quarter(s) earlier than the comparison period (Q1 2020) but have not reached full capacity.

1.3.2 Wholesale electricity price volatility

During Q1 2021, spot price volatility was very low, with cap returns¹⁵ declining to their lowest Q1 average since Q1 2012 (Figure 11). The lack of price volatility was most pronounced in Victoria and New South Wales, which had zero cap returns during the quarter, compared to Q1 2020 when Victoria averaged \$29/MWh, while New South Wales averaged \$31/MWh. The main increase in volatility compared to Q1 2020 occurred in South Australia, with cap returns of \$16/MWh, largely due to price volatility on 12 March 2021¹⁶.

Figure 11 Zero price volatility in New South Wales and Victoria

Quarterly average Q1 cap returns by region - stacked



Wholesale electricity price volatility: Q1 2021 drivers

<p>New South Wales and Victoria</p>	<ul style="list-style-type: none"> • No major power system separation events – in contrast to Q1 2020, which had three major power system separation events, there were none this quarter. • Fewer extreme demands – there was a significant decrease in the top 1% of demand in New South Wales and Victoria due to fewer very hot days as well as increased output from distributed PV. The top 1% of demand in New South Wales fell from 13,008 MW on average in Q1 2020 to 11,576 MW in Q1 2021, while in Victoria it reduced from 8,619 MW Q1 2020 to 7,870 MW in Q1 2021. • Increased supply during high demand periods – in Victoria, combined brown coal, wind, and solar availability during high demand periods (the top 1% of demand) increased by 396 MW on average compared to Q1 2020. In New South Wales, combined wind and solar availability during high demand periods increased by 346 MW on average compared to Q1 2020.
<p>South Australia</p>	<p>The only major price volatility during the quarter occurred in South Australia on 12 March. On that day, a simultaneous trip of the Torrens Island A West 275 kV and Torrens Island B West 275 kV busbars led to the disconnection of Barker Inlet Power Station and restricted output from Torrens Island (Figure 12).</p> <p>This sudden drop in gas-powered generation (GPG) output and availability, coupled with restricted transfers on the Heywood Interconnector (Section 1.5), as well as low wind and solar output, contributed to the trading price spiking above \$5,000/MWh for three hours and a daily average price of \$1,335/MWh¹⁷.</p> <p>This event also contributed to high prices in the 60 Second Lower Contingency Frequency Control Ancillary Service (FCAS) market (Section 1.6.1).</p>

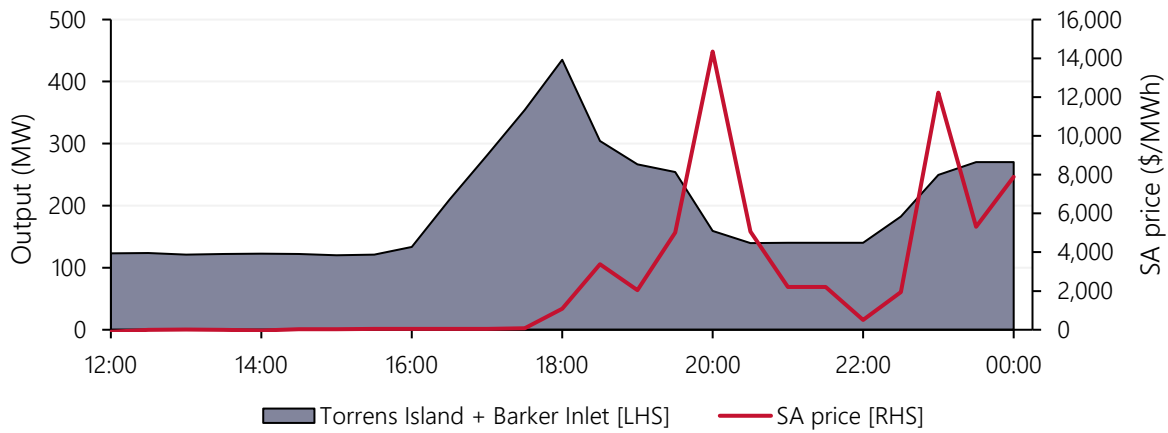
¹⁵ A measure of volatility in electricity prices is the presence of high price events – prices above \$300/MWh. This is often represented as ‘quarterly cap returns’, which is the sum of the NEM pool price minus the \$300 cap price for every half hour in the contract quarter where the pool price exceeds \$300/MWh, divided by the number of half-hours in the quarter.

¹⁶ The AER publishes \$5000/MWh reports which analyse the cause of these events in more details. [AER \\$5000/MWh reports](#).

¹⁷ Details of the event can be found at: AEMO 2021, Preliminary Incident Report – Trip of Torrens Island A and B West 275 kV busbars on 12 March 2021: https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/preliminary-report-torrens-island-275-kv-west-busbar-trip.pdf

Figure 12 Transformer issue at Torrens Island contributes to 12 March price volatility

South Australian trading price and combined Torrens Island and Barker Inlet output – 12 March 2021



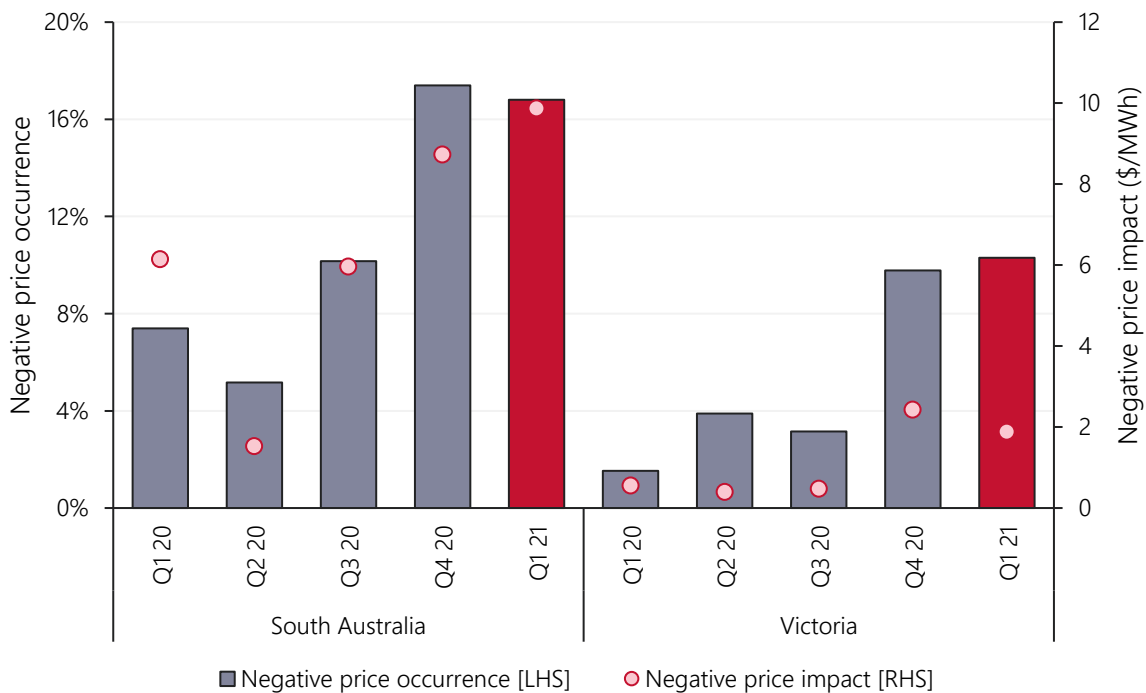
1.3.3 Negative wholesale electricity prices

During Q1 2021, negative and zero spot prices¹⁸ occurred in 5.8% of all trading intervals, up from 2.3% in Q1 2020. Continuing Q4 2020's trend, the occurrence of negative spot prices remained confined to the southern regions, with Victoria reaching record quarterly occurrences (10.3%) and South Australia remaining very high (16.8%, Figure 13). High levels of negative spot prices, particularly during the middle of the day, resulted in the average South Australian spot price between 1000 and 1530 hrs averaging *negative* \$12/MWh.

Negative prices reduced South Australia's average quarterly price by \$10/MWh, but only had a minor impact on Victoria's average (\$1.9/MWh) as there were no trading intervals where Victoria's spot prices were below minus \$100/MWh.

Figure 13 Very high negative spot price occurrence in South Australia and Victoria

Quarterly negative price percentage occurrence – Q1 2020 to Q1 2021



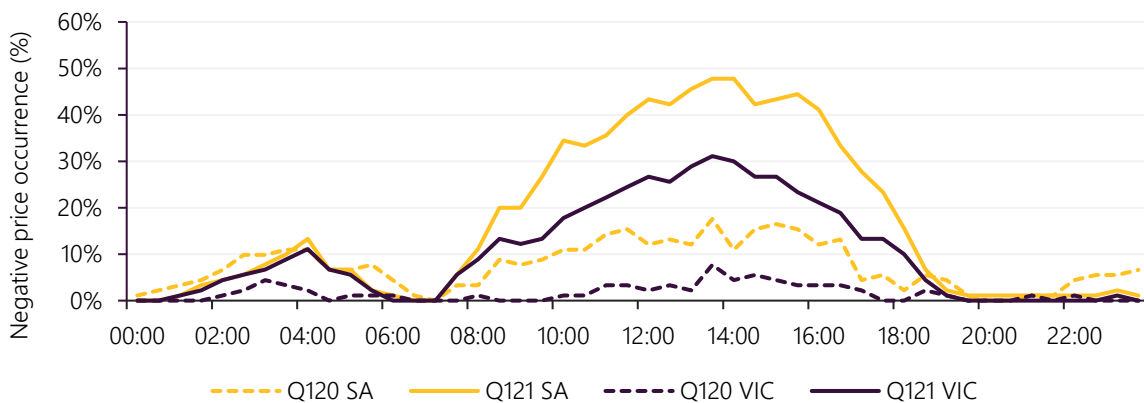
¹⁸ Hereafter referred to as negative spot prices.

Drivers of increased occurrence of negative prices in South Australia and Victoria included:

- **High variable renewable energy (VRE) output** – this quarter, there were increased periods of very high Victorian and South Australia VRE output, mainly due to new renewable capacity installed in Victoria and reduced curtailment of existing capacity. This quarter, combined Victorian and South Australian VRE output was above 2,500 MW 11% of the time compared to 4% in Q1 2020.
- **Low daytime operational demand** – Combined Victorian and South Australian daytime¹⁹ operational demand dropped below 4,500 MW 8.3% of the time compared to 3.8% of the time in Q1 2020, contributing to high negative spot price occurrence during the middle of the day (Figure 14).

Figure 14 Negative spot prices mainly confined to the middle of the day

South Australia and Victoria Q1 negative price percentage occurrence by time of day – Q1 2021 versus Q1 2020

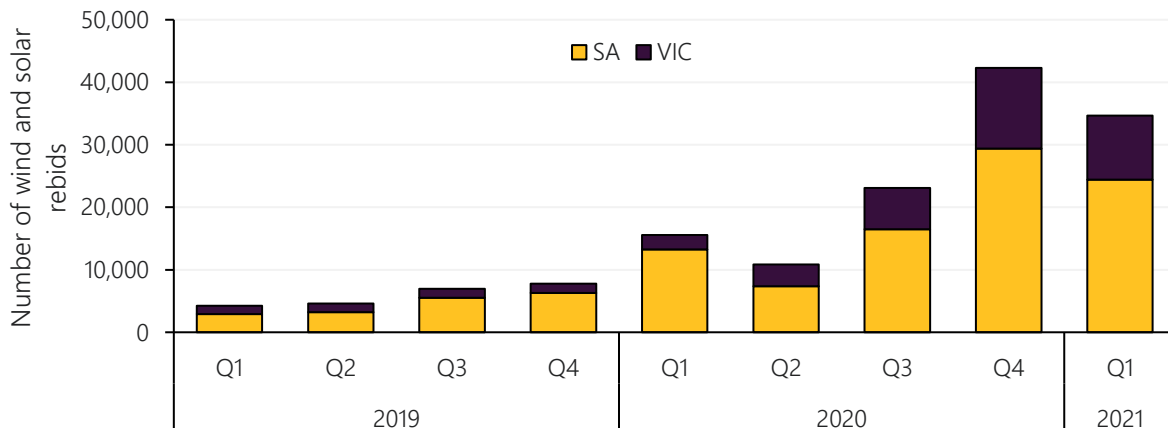


Wind and solar response to negative prices

High levels of negative spot prices during the last two quarters have led to increasing responsiveness from wind and solar farms as they re-bid capacity to higher price bands to reduce the risk of being dispatched at negative prices. The combination of increasing occurrence of negative spot prices, as well as the deployment of automated bidding software during 2020, led to a substantial increase in re-bids. In Q1 2019, South Australian and Victorian wind and solar farms re-bid 4,258 times, increasing to 34,659 re-bids in Q1 2021 (+713%, Figure 15). AEMO estimates that around one-third of South Australian and Queensland VRE capacity has installed automated bidding software, with a slightly smaller amount (around 20%) in Victoria.

Figure 15 Wind and solar re-bidding frequency soars

South Australian and Victorian wind and solar farm number of re-bids by quarter



¹⁹ Between 0730 hrs and 1700 hrs

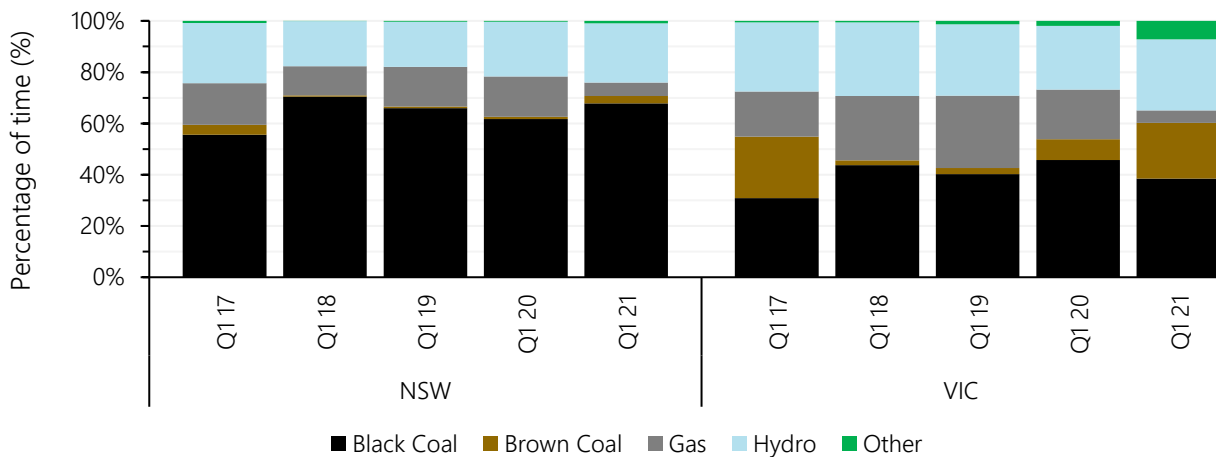
1.3.4 Price-setting dynamics

Price setting outcomes continued recent trends, with coal-fired generation playing a greater price setting role and gas playing a lower role (Figure 16). By fuel type:

- **Coal** increased its NEM average price setting role to 56% of the time, up from 51% in Q1 2020, as spot prices predominantly occurred at levels in which coal-fired generation was the marginal unit (typically \$0-\$40/MWh). The most frequent price setting coal-fired power stations were all located in New South Wales, with Bayswater and Eraring each setting the price 9% of the time, while Vales Point set the price 8% of the time.
- **Gas** price setting declined across the NEM from an average 19% in Q1 2020 to 8% this quarter, its lowest quarterly amount since Q4 2013. Drivers included very low GPG output, and a shift in GPG offers to higher priced bands.
- **Wind and solar** continued to set the spot price more frequently at 3.8% of the time (combined), close to the previous quarter's record. Notably, in Victoria wind and solar generation set the price more often than gas (6.6% versus 4.9%), the first time this has occurred in any NEM region (Figure 17).

Figure 16 Coal price setting role increases

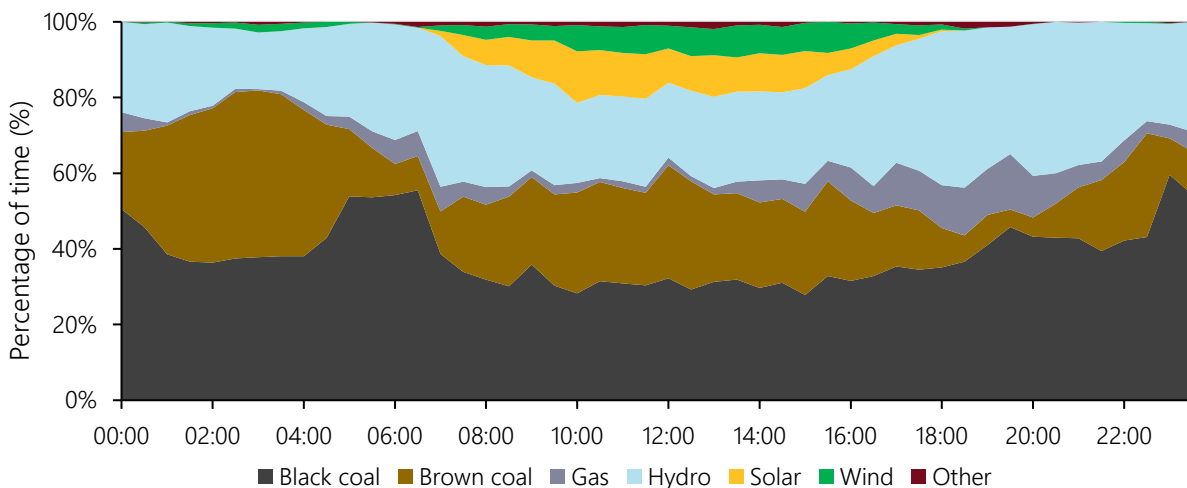
Price-setting by fuel type – Q1s in New South Wales and Victoria



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

Figure 17 Combined wind and solar sets Victoria's price more frequently than gas

Victoria's price-setting by fuel type and time of day – Q1 2021



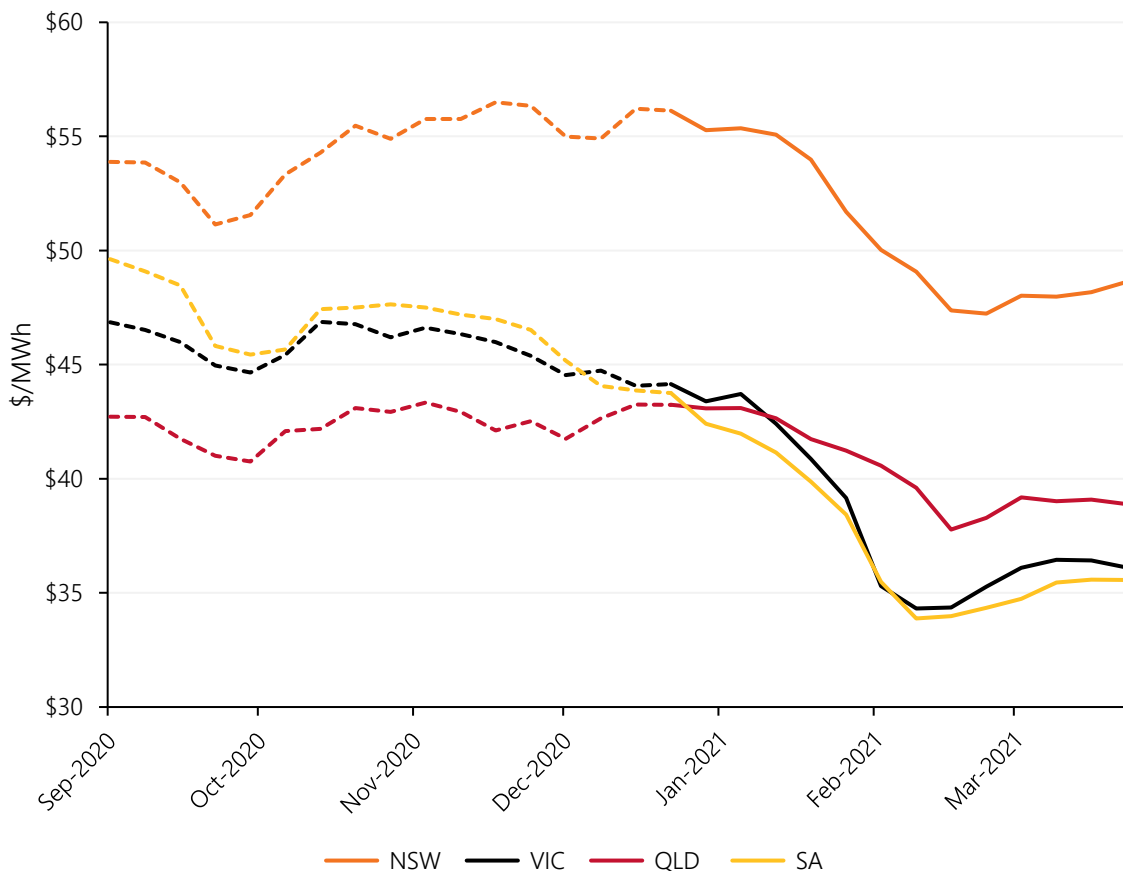
1.3.5 Electricity futures markets

ASX calendar year (Cal) 2022 swap contract prices decreased across all states, from an average of \$46/MWh at the end of 2020 to finish Q1 at \$40/MWh. These price reductions coincided with low mainland spot prices, increased VRE generation, and high occurrence of negative spot prices in the southern regions (Section 1.3).

The largest reductions occurred in Victoria and South Australia, declining \$8/MWh to \$36/MWh, with both regions dropping below Queensland for the first time since 2014²⁰, while New South Wales remained the highest priced state at \$49/MWh (Figure 18). By the end of the quarter, Cal23 swap prices were trading at similar levels to Cal22, indicating an expectation of continued lower prices in the near term.

Figure 18 ASX Futures: South Australia drops \$8/MWh to become lowest priced region

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



At the end of 2020, there was some expectation for Q1 2021 price volatility, with Q1 2021 cap prices averaging \$21/MWh. However, except for South Australia, no significant price volatility eventuated this quarter. Despite the lack of the price volatility, Q1 2022 caps (which began trading on 22 March with the listing of the 5-minute settlement cap product on the ASX) finished the quarter at an average of \$19/MWh, with market sentiment pricing in expectations of a return to some volatility next summer.

²⁰ ASX Cal16: South Australia and Victoria traded below Queensland in short periods during 2014-15.

1.4 Electricity generation

During Q1 2021, decreased thermal and large increases in VRE generation, coupled with multi-year low Q1 operational demand, shaped the NEM supply mix (Figures 19 and 20, Table 1).

Key outcomes included:

- Black coal-fired generation declined to its lowest Q1 average since NEM start at 11,006 MW, 1,018 MW lower than Q1 2020.
- Gas-powered generation (GPG) decreased to its lowest quarterly average since 2005, 787 MW lower than Q1 2020.
- Grid-scale VRE output averaged 3,458 MW, 786 MW higher than Q1 2020.

Figure 19 Black coal and GPG down sharply

Change in supply – Q1 2021 versus Q1 2020

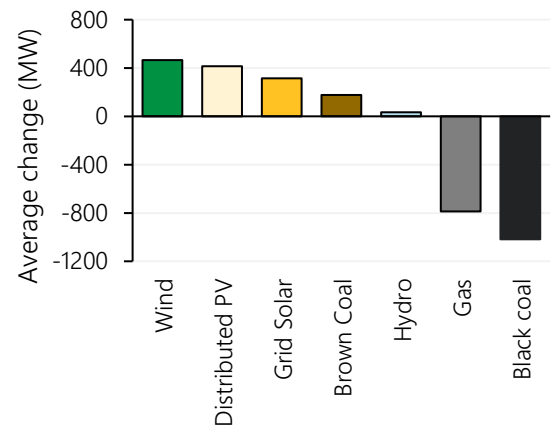
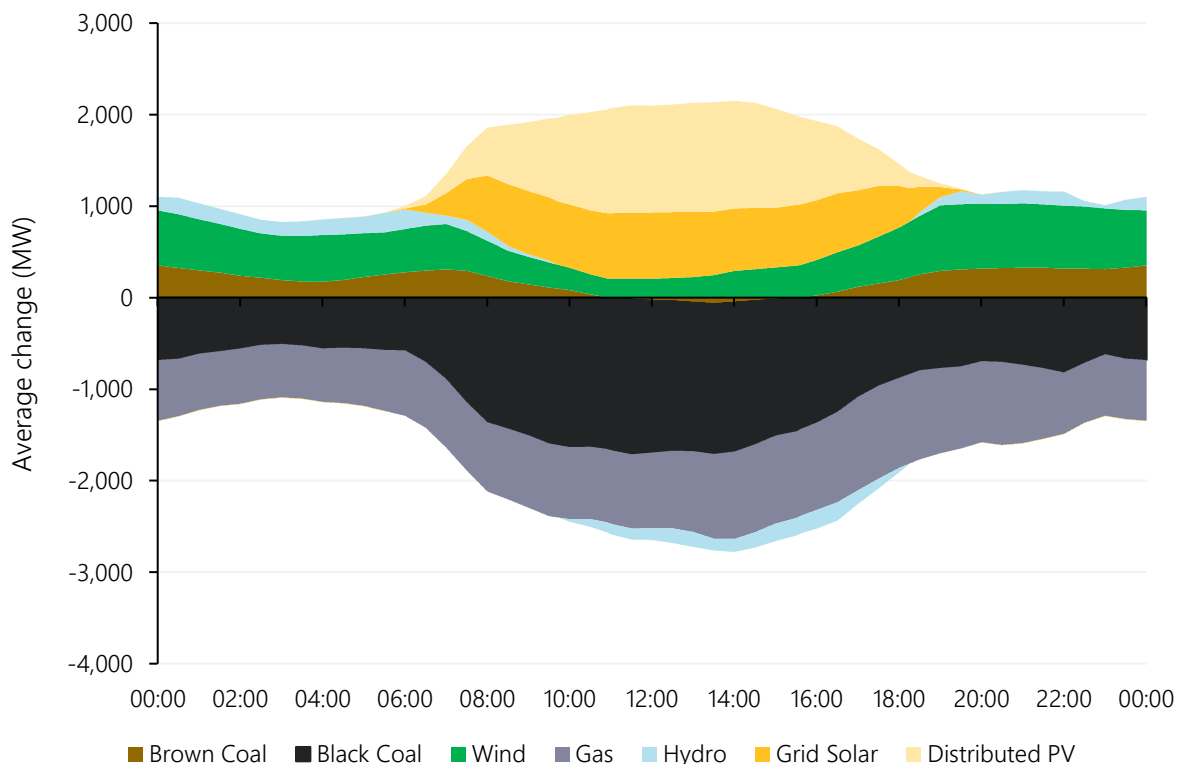


Table 1 NEM supply mix by fuel type

Quarter	Black coal	Brown coal	Gas	Hydro	Wind	Grid solar
Q1 2020	54.3%	18.4%	8.6%	6.6%	8.6%	3.4%
Q1 2021	51.6%	19.9%	5.3%	7.0%	11.2%	5.0%
Change	-2.7%	+1.5%	-3.3%	+0.4%	+2.6%	+1.6%

Figure 20 Solar and wind displace coal and gas, particularly during the daytime

Change in supply – Q1 2021 versus Q1 2020 by time of day



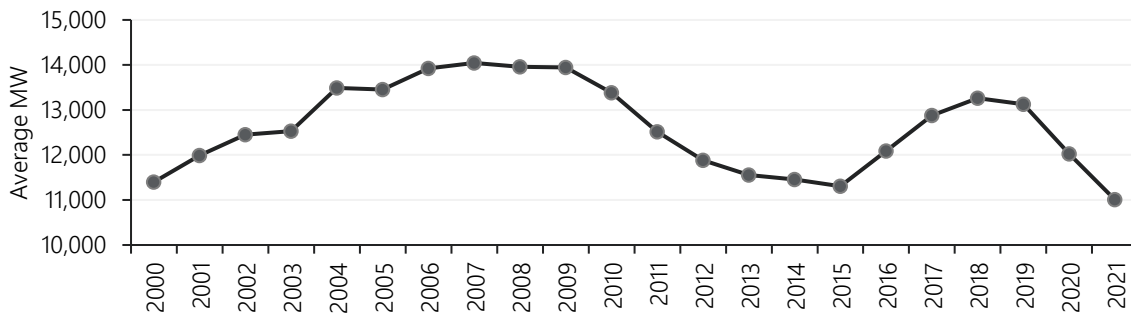
1.4.1 Coal-fired generation

Black coal-fired fleet

During Q1 2021, average black coal-fired generation fell to 11,006 MW, its lowest Q1 output since NEM start and 1,018 MW lower than Q1 2020 (Figure 21). The decline in output occurred despite an increase in lower-priced offers, particularly in New South Wales, where an average of 472 MW of capacity was shifted from higher price bands to below \$40/MWh. Notably, black coal offers remained low despite increasing international coal prices (Section 2.2.1).

Figure 21 Q1 NEM black coal-fired output at new lows

Average NEM black coal-fired generation – Q1s



Average black coal-fired output in **New South Wales** reduced to 5,516 MW this quarter (-667 MW on Q1 2020), its lowest Q1 output since NEM start. The decrease was driven by a combination of reduced operational demand, increased grid-scale solar generation, and unit outages. By station:

- A significant increase in outages (mostly planned), and displacement by daytime solar, reduced Eraring Power Station’s average output by 557 MW, its lowest Q1 output since 2013 (Figure 22). The utilisation rate²¹ at Eraring, one of the most flexible coal-fired generator in the NEM, reduced from 74% in Q1 2020 to 62% this quarter, substantially lower than the rest of the New South Wales fleet (78%, Figure 23).
- Reduced generation at Liddell Power Station (-378 MW) was due to increased outages, as Unit 3 was out of service for the entire quarter following a transformer incident in December 2020.
- Fewer outages at Mount Piper Power Station increased average output by 395 MW, with average availability increasing from 57% in Q1 2020 to 87% this quarter.

Figure 22 Black coal output down, brown coal up

Change in coal-fired generation – Q1 2021 vs Q1 2020

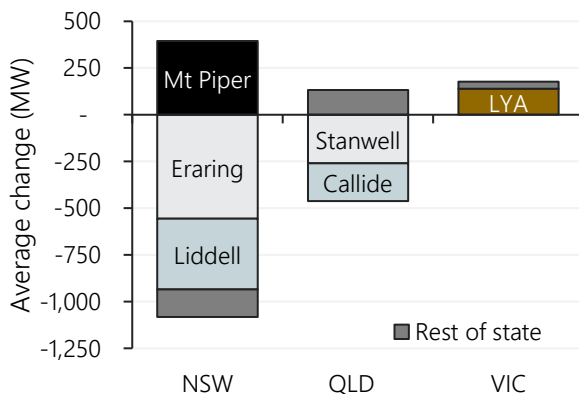
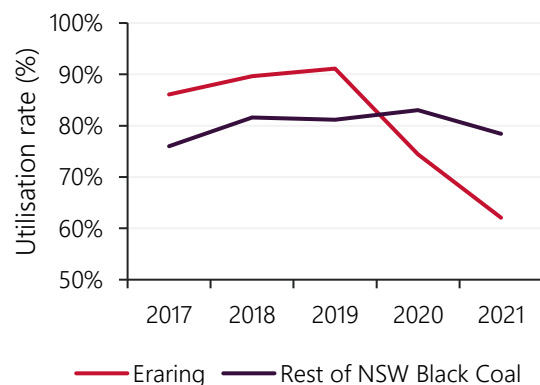


Figure 23 Reduced utilisation of Eraring

Utilisation rate – Eraring versus NSW black coal average (Q1s)



²¹ Ratio of generator’s average output divided by average availability.

Increased outages (mostly unplanned) across most of the **Queensland** fleet, coupled with displacement by distributed PV and lower priced supply from Victoria (Section 1.5), reduced average black coal-fired output in the region to 5,489 MW, 330 MW lower than in Q1 2020.

Brown coal-fired fleet

Average brown coal-fired generation increased by 177 MW compared to Q1 2020, as increased availability more than offset displacement by VRE and lower operational demand. While output from all three brown coal-fired power stations increased, higher output was mainly driven by Loy Yang A (+140 MW). During the quarter, EnergyAustralia announced that Yallourn Power Station will retire in mid-2028 instead of a progressive closure from 2029 to 2032 as previously indicated²². Yallourn’s average annual output has been declining since 2016 (Figure 24), largely driven by increased outages.

With much lower spot prices across the NEM, average dispatch interval output changes from brown coal units has increased significantly (from 8 MW in Q1 2020 to 24 MW). Figure 25 illustrates brown coal units’ ability to progressively ramp down output to around 70% of availability when spot prices were negative. In addition, increased incidence of low or negative spot prices periods in Victoria led to lower brown coal-fired unit utilisation rates this quarter (96%) than in Q1 2020 (98%).

Figure 24 Yallourn output declining since 2016

Yallourn power station average annual output – 2010 to 2020

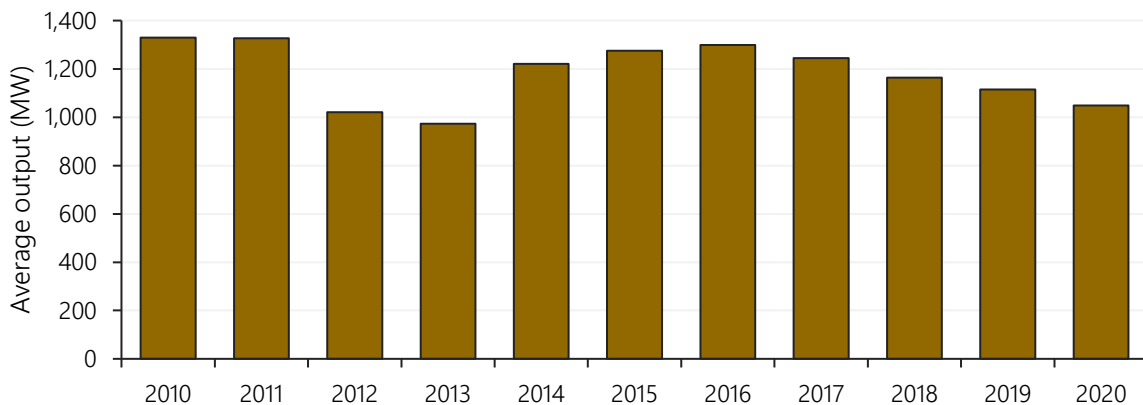
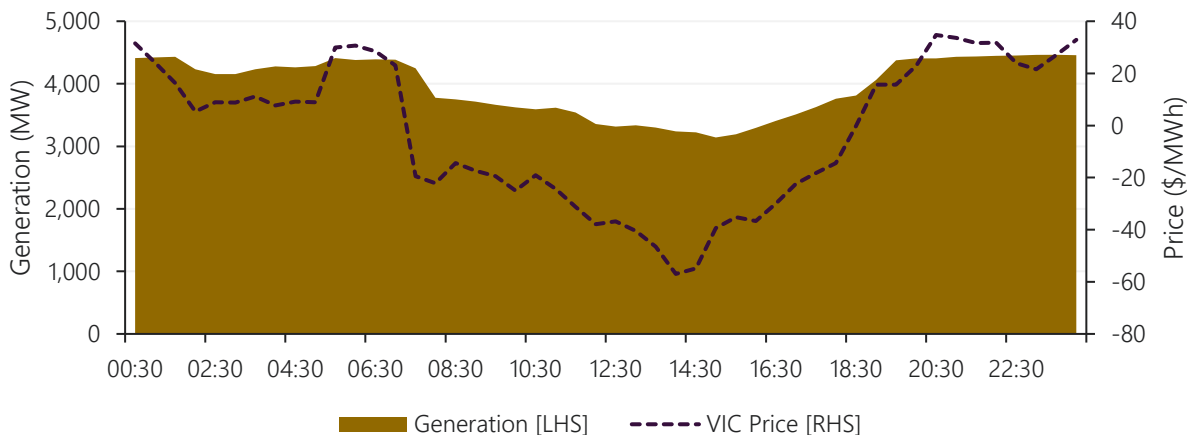


Figure 25 Brown coal responding to negative prices

Brown coal generation and Victoria spot prices – 16 Jan 2021



²² EnergyAustralia 2021, EnergyAustralia powers ahead with energy transition: <https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition>

1.4.2 Hydro

Hydro generation increased by 34 MW on average compared to Q1 2020, with mainland increases offset by Tasmanian reductions (Figure 26). Notably, increased mainland hydro generation occurred despite very low Q1 spot prices and was a function of very heavy rainfall on the east coast (Figure 27) which enabled hydro generators to bid at lower prices to ensure dispatch. Compared to Q1 2020, an average of 478 MW was shifted from higher prices to prices below \$40/MWh (Figure 28).

Regional changes compared to Q1 2020 included:

- In **Victoria**, Murray was the main contributor to the state’s increase of 137 MW, as it produced 343 MW on average, its highest Q1 since 2016. Despite the heavy rainfall in New South Wales and Victoria, hydro dam levels varied; Lake Eucumbene dam storage levels decreased from 37% at the end of 2020 to 30% by the end of Q1 2021, while Lake Jindabyne increased during March to finish at 76%²³.
- CleanCo’s Kareeya was the main contributor to **Queensland’s** 64 MW average increase, as it benefitted from increased run of river flows due to heavy La Nina rainfall in far North Queensland.
- **Tasmania** decreased by 174 MW on average, with low Victorian spot prices and increased imports from Victoria (Section 1.5) resulting in a reduced requirement for Tasmanian hydro generation. Dam levels finished the quarter at 36%, slightly lower than Q1 2020 (38%).

Figure 26 Mainland hydro increase

Change in average hydro generation – Q1 21 vs Q1 20



Figure 27 Heavy east coast rainfall

Australian rainfall deciles, 1 January to 31 March 2021²⁴

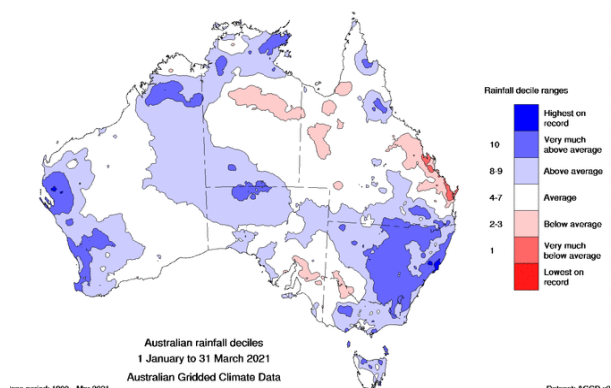
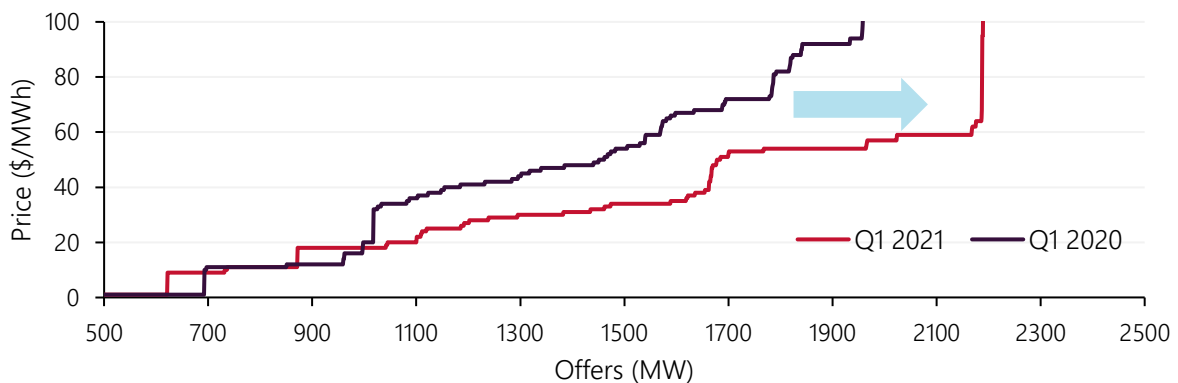


Figure 28 Hydro generation offered at lower prices to ensure dispatch

NEM hydro generation bid supply curve – Q1 2021 and Q1 2020



²³ Snowy Hydro dam levels: <https://www.snowyhydro.com.au/generation/live-data/lake-levels/>

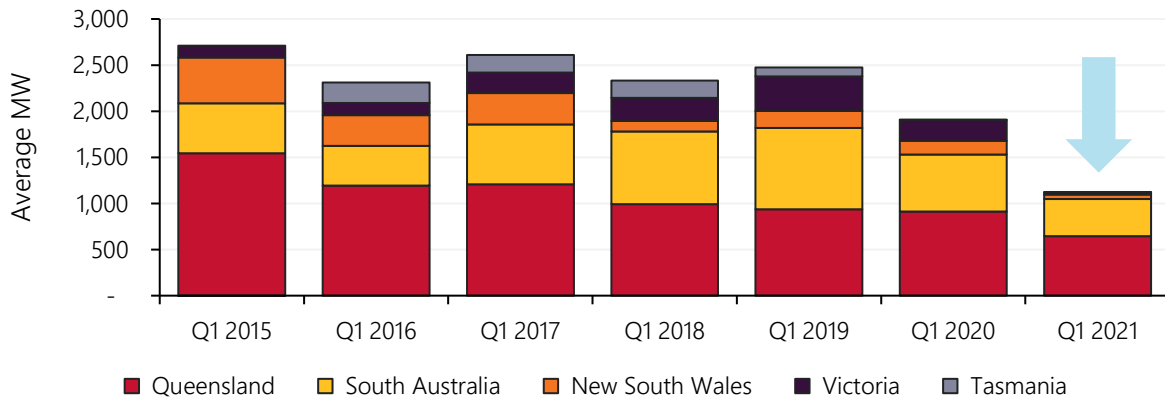
²⁴ Bureau of Meteorology 2021, Recent and historical rainfall maps: <http://www.bom.gov.au/climate/maps/rainfall/?variable=rainfall&map=decile&period=3month®ion=nat&year=2021&month=03&day=31>

1.4.3 Gas-powered generation

NEM quarterly average GPG declined to 1,122 MW (-787 MW on Q1 2020 levels), its lowest quarter since 2005, continuing the recent trend of very low GPG (Figure 29). This trend has been driven by low NEM spot prices (including very low price volatility), coupled with increasing wholesale gas prices (Section 2.2), and reduced thermal unit outages, which has rendered GPG uneconomic in some NEM regions. With higher gas prices, and lower NEM spot prices, there was a 652 MW reduction in GPG offered at prices below \$40/MWh.

Figure 29 Large GPG decline in New South Wales and Victoria

Average GPG generation by state (Q1s)

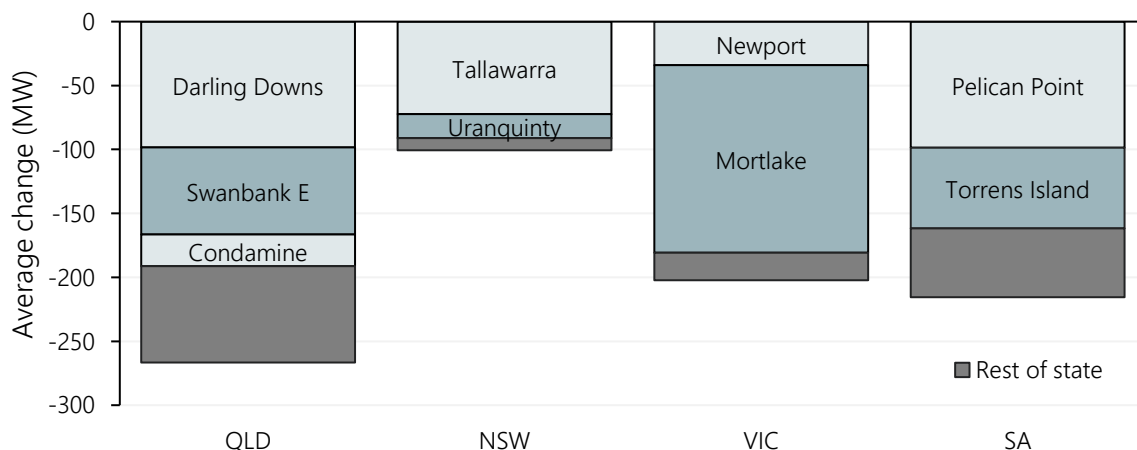


Key regional changes compared to Q1 2020 included:

- **New South Wales** decreased to 47 MW, its lowest GPG since NEM start, with EnergyAustralia’s Tallawarra averaging 35 MW mainly due to substitution from their Mount Piper station (Figure 30).
- **Queensland** declined to 646 MW, with Darling Downs reducing by 98 MW on average and Swanbank E down 68 MW.
- **South Australia’s** GPG reduced by 216 MW on average due to increased imports from Victoria, reduced availability, and higher local distributed PV output.
- **Victoria** decreased to 25 MW on average, its lowest quarterly output since Q1 2003. Mortlake reduced by 147 MW (it was directed for much of Q1 2020 for system security following the separation of the Victorian and South Australian power systems), while Newport was not required for most of the quarter due to increased Yallourn output and very low spot prices.

Figure 30 Large NEM GPG reductions

Change in GPG generation – Q1 2021 versus Q1 2020



1.4.4 Wind and solar

Compared to Q1 2020, average VRE generation increased by 786 MW, with wind and grid-solar contributing 472 MW and 314 MW, respectively (Figure 31). Higher VRE output was predominantly due to new capacity additions and ramping up of projects²⁵, which accounted for 94% of the increase (Figure 32). Another contributor was reduced curtailment due to removal of the West Murray solar constraint in 2020. Higher output this quarter led to two several grid-scale VRE records²⁶:

- **Highest grid-scale VRE output** – NEM grid-scale VRE output reached 6,886 MW at 1000 hrs on 18 February 2021²⁷, 172 MW higher than the previous high set during Q3 2020.
- **Highest grid-solar output** – NEM grid-solar output reached 3,411 MW at 1030 hrs on 5 March 2021, 200 MW higher than the record set in Q4 2020.

Figure 31 Victoria and New South Wales leads VRE output increase

Average change in VRE generation – Q1 2021 versus Q1 2020

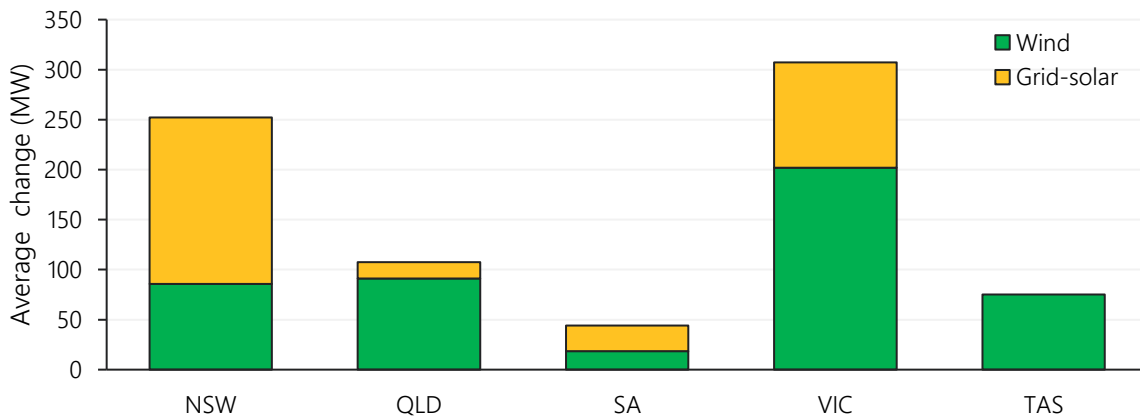
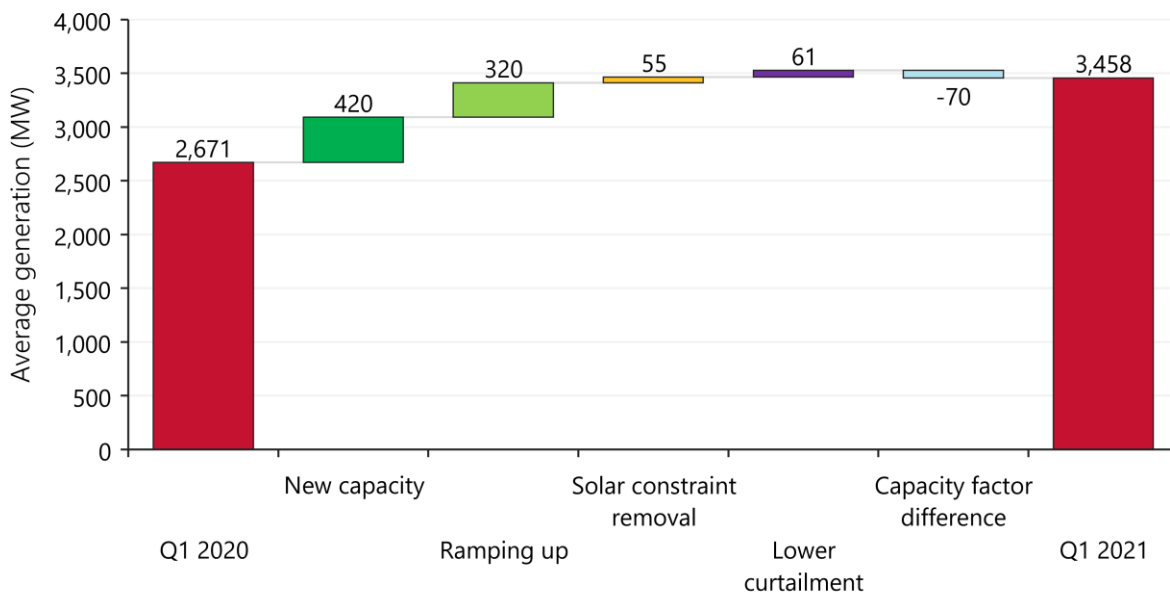


Figure 32 New capacity additions drive VRE output increase

Change in NEM VRE generation – Q1 2021 versus Q1 2020



²⁵ Includes projects which have started generating in quarter(s) earlier than the comparison period (Q1 2020), but have not reached full capacity.

²⁶ Grid-scale VRE records are reported in half-hourly time intervals.

²⁷ This record has since been broken in Q2 2021.

Average grid-scale solar output reached a record quarterly high of 1,070 MW, surpassing Q4 2020 slightly by 48 MW. This outcome was mainly driven by increases in New South Wales (+166 MW) and Victoria (+105 MW), with these regions accounting for 87% of the increase compared to Q1 2020. During the quarter, four new solar farms commenced generation, three in Victoria (Glenrowan West Solar Farm²⁸ 110 MW, Cohuna Solar Farm 27 MW, and Winton Solar Farm 85 MW), and one in New South Wales (Corowa Solar Farm, 30 MW).

- In **New South Wales**, higher solar output was mainly driven by ramping up of recently installed capacity, with Darlington Point, Bomen and Sunraysia Solar Farms accounting for 51% of the increase.
- Increased output in **Victoria** was a function of reduced solar curtailment in relation to the constraint that affected output of four Victorian solar farms in Q1 2020, and ramping up of new capacity additions.

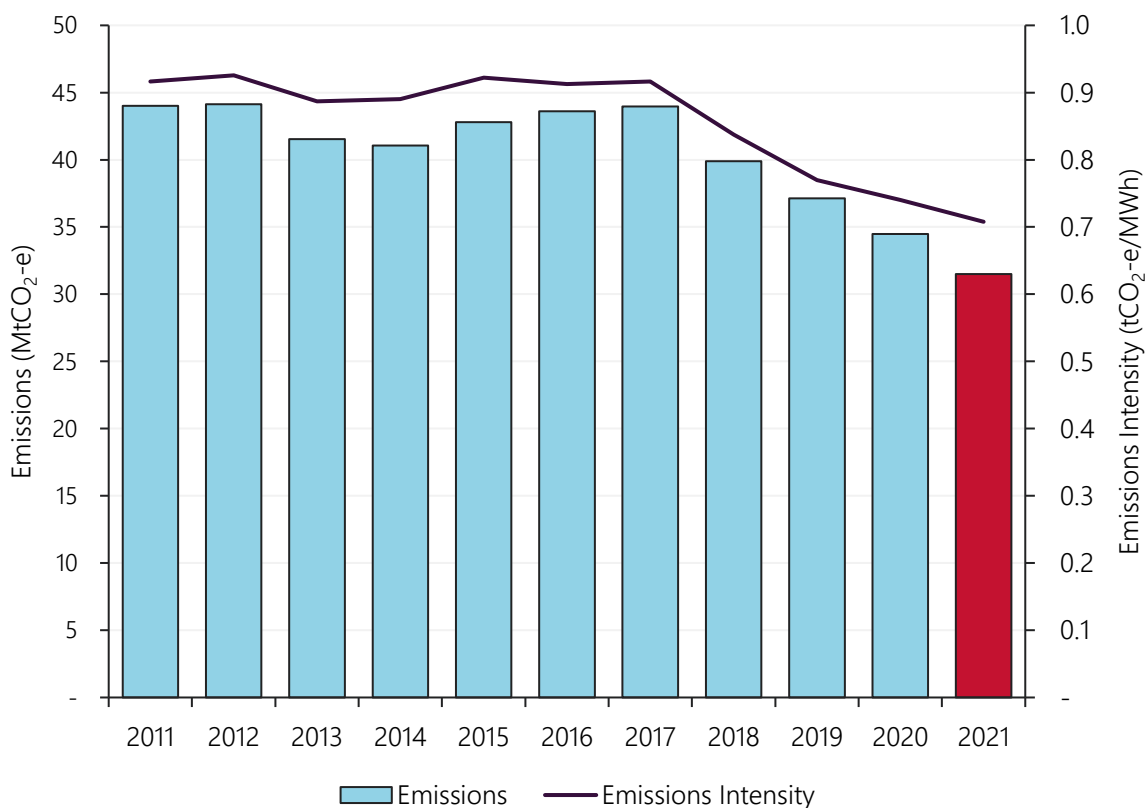
Average wind generation was 2,388 MW, 472 MW higher than Q1 2020, with the largest increase occurring in Victoria (+202 MW). Higher Victorian wind output was mainly due to the continued ramp up of Dundonnell and Bulgana wind farms. One new wind farm commenced generation in Victoria this quarter (Berrybank 1 Wind Farm, 175 MW).

1.4.5 NEM emissions

Quarterly NEM emissions declined to their lowest Q1 total at 31.5 million tonnes carbon dioxide equivalent (MtCO₂-e), 9% lower than Q1 2020, but 3% higher than the previous quarter's record low. Key contributors to reduced emissions included very low Q1 operational demand and significant increases in VRE output, resulting in reduced thermal generation.

Figure 33 Record low Q1 emissions

Quarterly NEM emissions and emissions intensity (Q1s)



²⁸ Glenrowan West Solar Farm commenced generation late Q4 2020.

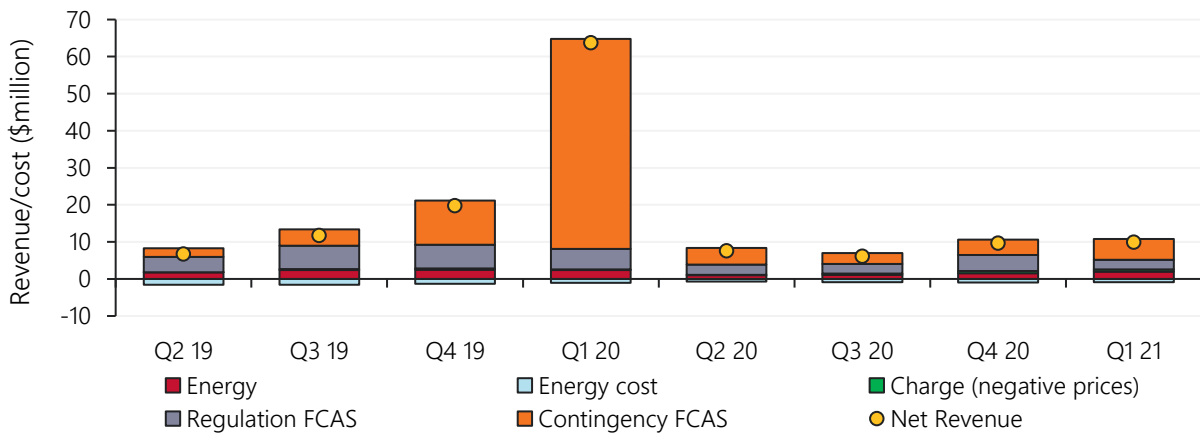
1.4.6 Storage

Batteries

During Q1 2021, net battery market revenue was \$10 million, with frequency control ancillary services (FCAS) continuing to be the largest source of income at 83% of the total. Compared to Q1 2020, there was a significant reduction in market revenues (-\$54 million), largely due to no repeat of the major power system separation events and volatile FCAS market revenues experienced last year.

While quarterly net revenue was comparable to Q4 2020, 60% of the total was derived during March alone. This was largely due to a power system issue at Torrens Island on 12 March which resulted in reduced output from Torrens Island and Barker Inlet power stations, contributing to high energy and FCAS prices²⁹. This event was the largest contributor to total net market revenue for batteries, with contingency FCAS accounting for one-third of March battery revenue of \$4 million. However, South Australian batteries' ability to capture the energy price volatility of 12 March was somewhat limited by their storage capacity, only generating at 18% of their capacity factors on average during the high prices (>\$1,000/MWh).

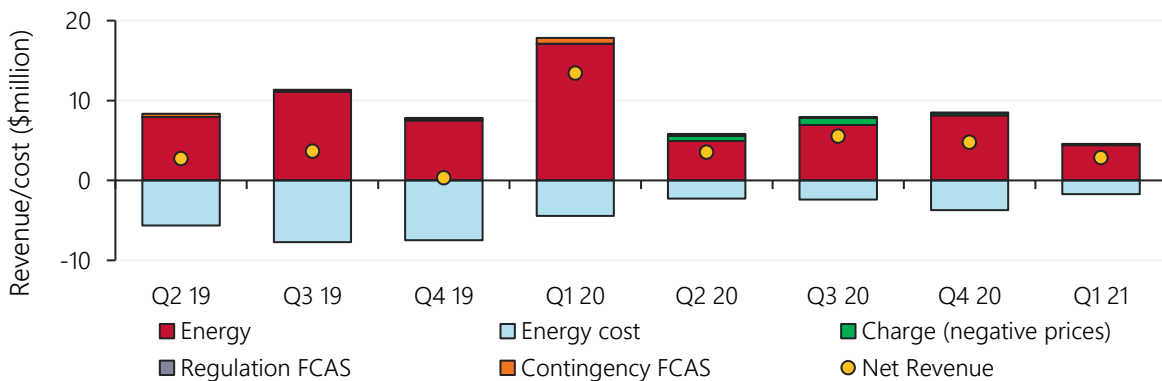
Figure 34 Battery net market revenue down significantly from Q1 2020



Pumped hydro

Pumped hydro spot market revenue declined by 79% compared to Q1 2020. The main contributing factor was declining wholesale electricity prices and volatility in New South Wales and Queensland (Section 1.3), which reduced Shoalhaven's net energy revenue by 93% to \$0.7 million and Wivenhoe's by 36% to \$2.2 million compared to Q1 2020.

Figure 35 Pumped hydro net revenue down on recent results



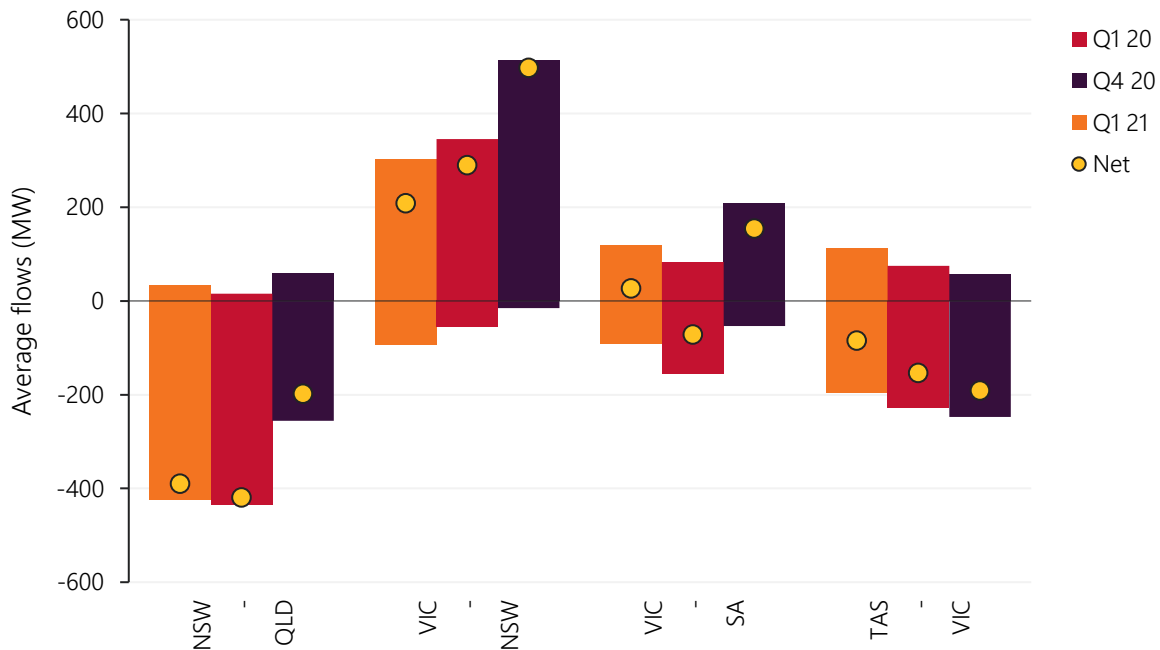
²⁹ AEMO 2021, Preliminary Incident Report – Trip of TIPS A and B West 275 kV busbars on 12 March 2021: https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2021/preliminary-report-torrens-island-275-kv-west-busbar-trip.pdf?la=en

1.5 Inter-regional transfers

Figure 36 shows inter-regional transfers for Q1 2021, with total transfers slightly higher than recent quarters.

Figure 36 Large increase in Victorian electricity exports

Quarterly inter-regional transfers

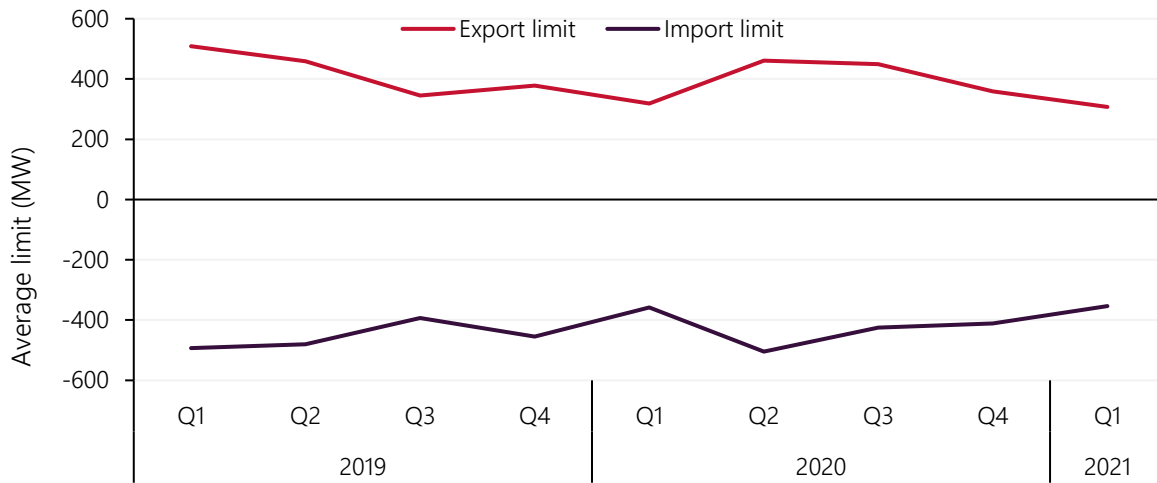


Key outcomes included:

- Restricted Heywood transfers influence market outcomes** – during the quarter, interconnector limits for flows on the Heywood Interconnector (between Victoria and South Australia) averaged 330 MW, which was 95 MW below the two-year average (Figure 37). This result is similar to Q1 2020, when power line damage led to separation of the South Australian and Victorian power systems and restricted interconnector flows for a sustained period. There were two periods of constrained interconnector flow while work was undertaken to reinstate the permanent transmission towers following damage sustained in Q1 2020:
 - Between 25 February and 3 March 2021, a planned outage on the Moorabool – Haunted Gully and Haunted Gully – Tarrone 500 kilovolt (kV) lines in Victoria restricted Heywood interconnector limits to around 30 MW on average.
 - Between 12 and 19 March 2021, a planned outage of the Moorabool – Mortlake 500 kV line in Victoria restricted Heywood interconnector limits to around 10 MW on average.
 - These reduced interconnector limits contributed to increased price separation between Victoria and South Australia (Section 1.3), price volatility in South Australia on 12 March (Section 1.3.2), and elevated Lower 60 Second FCAS costs (Section 1.6.1).
- Victorian electricity exports increased significantly** – net average electricity exports from Victoria increased by 523 MW compared to Q1 2020, reaching their highest level since Q1 2017. Increased Victorian export was a function of higher wind and solar output in the region, and improved performance of the brown coal-fired fleet.
- Tasmanian imports** – continuing recent trends, there were strong transfers from Victoria to Tasmania on Basslink, with net imports increasing from 84 MW in Q1 2020 to 191 MW in Q1 2021. This result was a function of the large increase in low-priced supply in Victoria, as well as Hydro Tasmania bidding to conserve water.

Figure 37 Restricted transfer limits on the Heywood Interconnector

Quarterly average export and import limits on the Heywood Interconnector



1.5.1 Inter-regional settlement residue

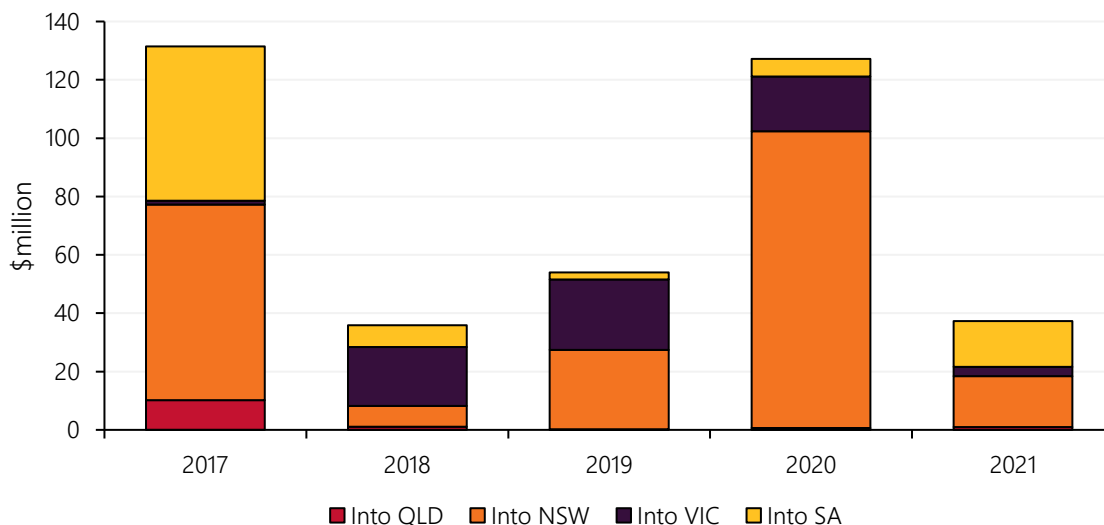
Total inter-regional settlement residue (IRSR) fell from \$127 million in Q1 2020 to \$37 million this quarter. With inter-regional transfers relatively steady, the main driver of reduced IRSR value was the significant reduction in spot price volatility compared to recent first quarters (price volatility is typically a key driver of IRSR value, particularly during first quarters).

The main reduction in IRSR value occurred for transfers into **New South Wales**, which declined \$84 million on Q1 2020 levels due to lack of price volatility in the region, while IRSR value for transfers into **Queensland** and **Victoria** was very low (below \$5 million combined).

The only increase in IRSR value occurred for transfers from Victoria to **South Australia**, totalling \$16 million (+\$10 million on Q1 2020 levels), with 54% of this IRSR value accruing during the South Australian price volatility on 12 March 2021 (Section 1.3.2).

Figure 38 Inter-regional settlement residue falls from Q1 2020

Quarterly positive IRSR value – Q1s



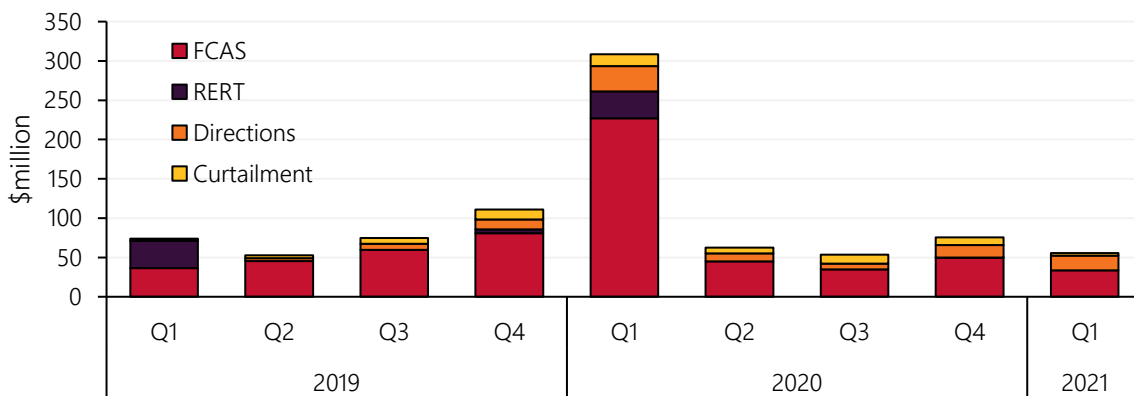
1.6 Power system management

Total NEM system costs³⁰ dropped significantly compared to Q1 2020, largely driven by declining FCAS costs (Figure 39). By component:

- **FCAS costs** decreased to \$33 million this quarter, \$194 million lower than Q1 2020 (a quarter which was significantly affected by major power system separations), accounting for 60% of total system costs. Section 1.6.1 provides details on FCAS.
- The cost of **directing South Australian units** to maintain system security increased slightly compared to Q4 2020, totalling \$19 million, with at least one unit directed online for 70% this quarter. Section 1.6.3 provides details on system security directions.
- Estimated **VRE curtailment costs**³¹ declined to \$3 million, with reduced levels of system strength and other curtailment the main driver. Section 1.6.2 provides details on VRE curtailment for the quarter.

Figure 39 Small reduction in system costs

Quarterly system costs by category



1.6.1 Frequency control ancillary services

Quarterly FCAS costs declined to \$33 million, representing the lowest quarterly cost since Q1 2018 (Figure 40). Compared to Q1 2020 – a quarter which was significantly affected by major power system separations of South Australia from the rest of the NEM – the largest cost reductions occurred in the Contingency Raise (-\$128 million) and Contingency Lower markets (-\$38 million). During the past year, underlying FCAS prices – particularly in the Contingency Raise markets – have been trending down, driven by:

- **Additional supply** – between Q1 2020 and Q1 2021 there was a large increase in Contingency FCAS supply from existing and new providers, particularly from demand response (+137 MW), batteries (+72 MW), and virtual power plants (VPPs, +31 MW, Figure 41). Of note was the increased registered Contingency FCAS supply from Enel X’s demand response (+151 MW), and the progressive increase in VPP-registered Contingency Raise capacity (+63 MW) between Q1 2020 and Q1 2021³².
- **Lower priced offers** – some thermal units provided additional low-priced supply compared to recent quarters, coinciding with lower energy prices, increased competition from new entrants, and the implementation of Mandatory Primary Frequency Control. For example, compared to Q1 2020, Loy Yang B and Gladstone provided additional Contingency Raise FCAS priced below \$5/MWh (88 MW and 33 MW, respectively).

³⁰ In this report, ‘NEM system costs’ refer to the costs associated with FCAS, directions compensation, Reliability and Emergency Reserve Trader (RERT), and VRE curtailment.

³¹ Excludes economic curtailment. The cost of curtailed VRE output is estimated to be \$40/MWh of output curtailed.

³² Between Q1 2020 and Q1 2021, the number of VPPs providing FCAS in the NEM increased from two to eight.

- **Falling energy prices** – as detailed in Section 1.3, NEM spot prices declined to very low averages this quarter. Raise FCAS market prices often move in line with energy prices, due to the opportunity cost of service provision.

Figure 40 Lowest FCAS costs since Q1 2018

Quarterly FCAS cost by market³³

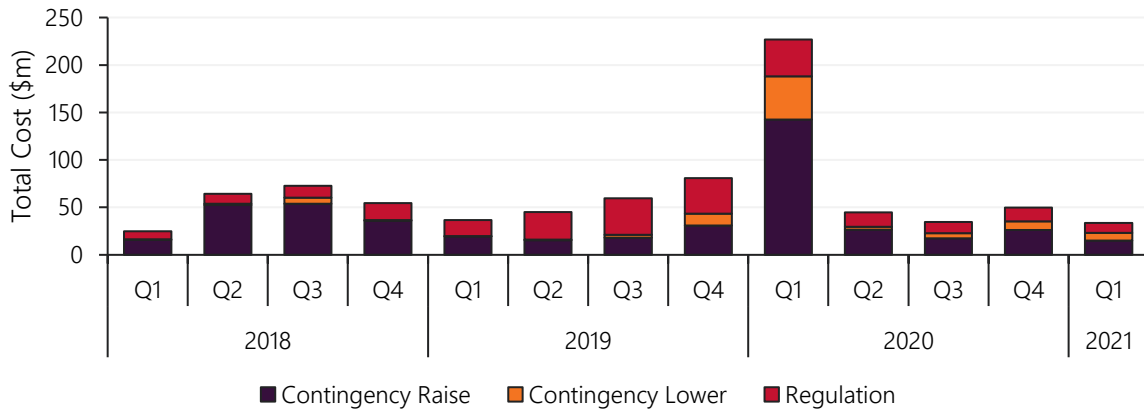
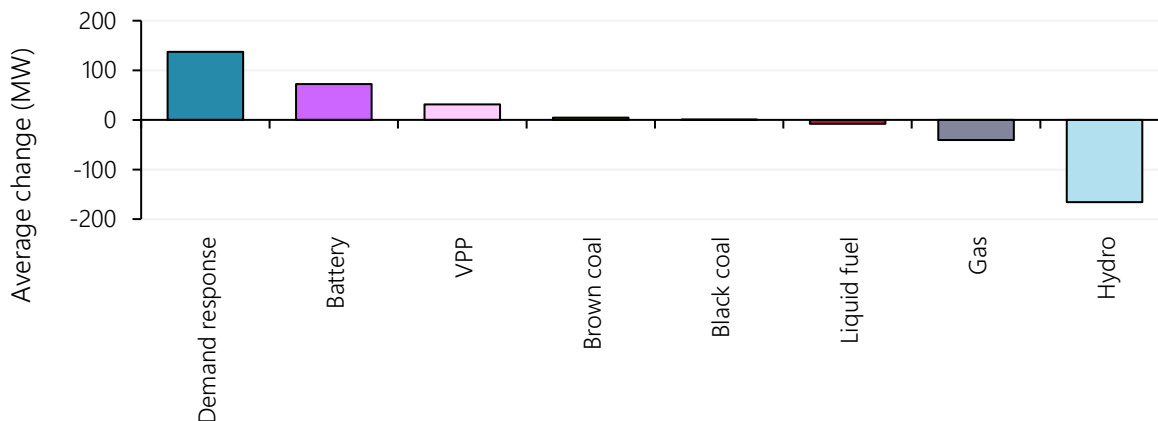


Figure 41 Demand response leads FCAS supply increase

Change in Contingency Raise supply – Q1 2021 versus Q1 2020



FCAS price volatility

Despite total FCAS costs declining, event-based price volatility made a high contribution to total FCAS costs. During the quarter, high-priced periods³⁴ contributed \$9 million (or 27%) of total quarterly FCAS costs. The majority (56%) of these price-volatility related costs occurred in South Australia, mostly occurring during March in the Lower 60 Second FCAS market. Between 12 to 17 March 2021, South Australia’s Lower 60 Second FCAS price was above \$1,000/MWh 20% of the time, due to:

- A planned outage of the Moorabool – Mortlake 500 kV line in Victoria (Section 1.5), which necessitated local South Australian Contingency Lower FCAS requirements during the period.
- Limited Lower 60 Second FCAS supply from Torrens Island Power Station following the 12 March transformer issue.
- Periods of high local Lower 60 Second requirements (greater than 100 MW), largely from 13-17 March to cover for the loss of the Heywood to Tarrone to Haunted Gully to Moorabool 500 kV lines.

³³ Based on AEMO Settlement data and represents preliminary data that will be subject to minor revisions.

³⁴ prices equal to or above \$300/MWh in a given FCAS market

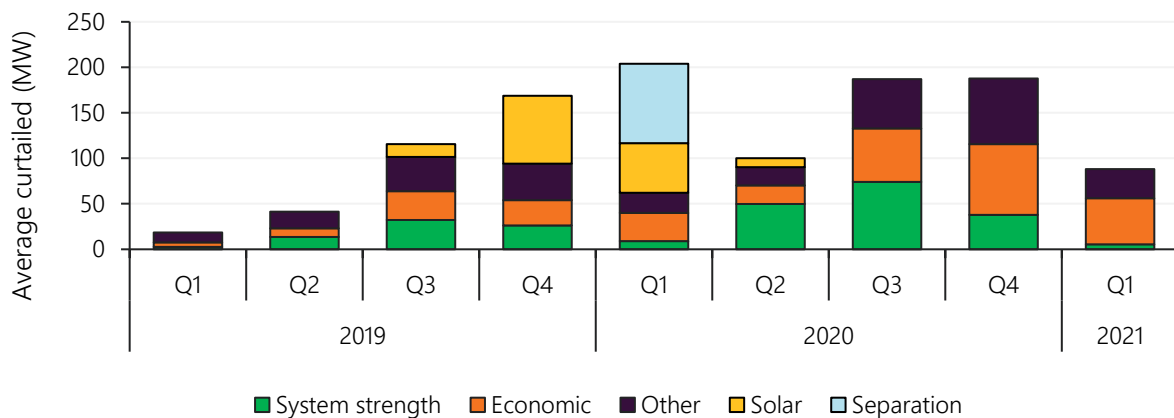
1.6.2 VRE curtailment

VRE curtailment fell to 88 MW on average (or 3% of total semi-scheduled VRE output), lower than recent quarters (Figure 42). By curtailment category:

- **Economic curtailment** – with high occurrence of negative spot prices in South Australia and Victoria, self-curtailment of wind and solar farms in response to market signals became the largest source of VRE curtailment. Economic curtailment accounted for 58% of total curtailment, with the highest levels of economic curtailment occurring at Taillem Bend Solar Farm (7 MW, or 27% of available output), Murra Wurra Wind Farm (7 MW), and Lincoln Gap Wind Farm (4 MW).
- **System strength curtailment** – this fell to 5 MW on average in Q1 2021. In Queensland, changed inverter settings at wind and solar farms in the north of the state, as well as increased demand, resulted in system strength curtailment falling from 15 MW in Q4 2020 to 0 MW in Q1 2021, contributing to Queensland’s curtailment dropping from 14% in Q3 2020 to 1% this quarter (Figure 43).
- **Other curtailment** – ‘other’ curtailment includes unclassified sources of curtailment that can occur due to project specific issues, grid congestion, and other network constraints. In Q1 2021, other curtailment reduced by 40 MW on average compared to Q4 2020, with the largest reductions occurring at Dundonnell Wind Farm (19 MW) and Mount Emerald Wind Farm (6 MW).

Figure 42 VRE curtailment declines³⁵

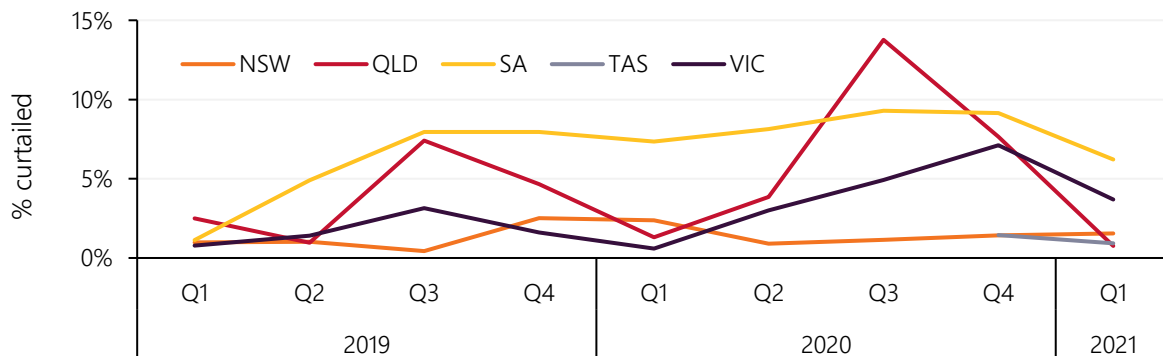
Average NEM VRE curtailed by curtailment type



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

Figure 43 Queensland VRE curtailment drops to near zero in Q1

% of VRE curtailed by region



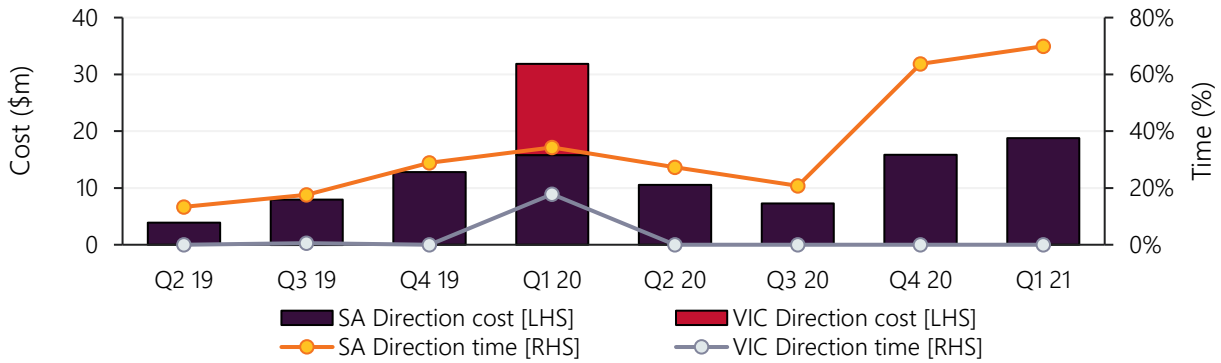
³⁵ Note: some minor updates have been made to historical curtailment categorisation due to updated methodology.

1.6.3 Directions

During the quarter, AEMO continued to issue directions to GPGs in South Australia to maintain system security in the region. Total NEM direction costs of \$18.8 million were \$13 million lower than Q1 2020, as there was no repeat of the major separation event (Figure 44).

Figure 44 South Australian system strength direction costs reach new highs

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



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

In South Australia, system strength directions costs reached new highs, primarily driven by the significant increase in time on directions (70%), which surpassed the previous record set in Q4 2020 (64%). With Adelaide’s spot gas prices averaging \$6 per gigajoule (GJ) and electricity prices below \$40/MWh 68% of the time, GPGs were frequently de-committing from the market for economic reasons.

The average South Australian GPG output under direction increased by 53 MW on Q1 2020 levels, accounting for 30% of average South Australian GPG output this quarter (Figure 45). Also of note was the decreasing average 12-month 90th percentile spot price that is used as the benchmark for compensating participants, which decreased from \$128/MWh in Q1 2020 to \$67/MWh (Figure 46). The falling compensation price led to a significant increase in additional compensation claims³⁶, with AEMO receiving 44 of these claims during the quarter, compared to 36 claims in all of 2020 (largely driven by the separation event in Q1 2020). As these additional compensation claims are processed, final directions costs are likely to be higher than the preliminary costs published in this report³⁷.

Figure 45 Record high SA GPG directed

SA GPG directed

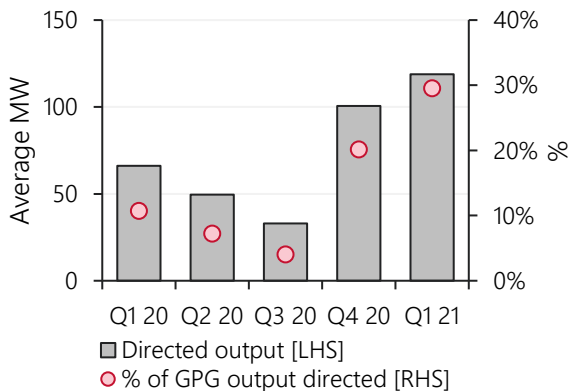
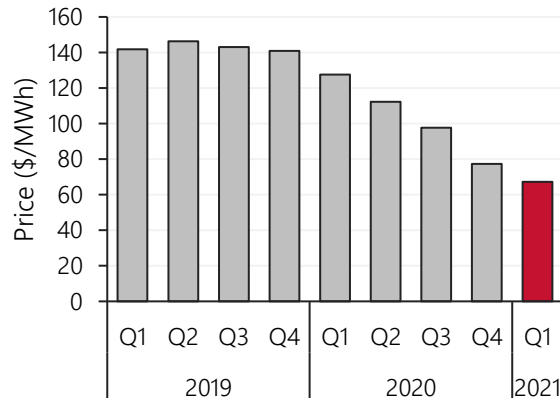


Figure 46 Decline in directions compensation price

SA average quarterly 12-month 90th percentile price



³⁶ Under NER 3.15.7B, a directed participant is entitled to make a written submission to AEMO claiming for additional compensation, equalling the sum of the aggregate of the loss of revenue and additional net direct costs incurred by the directed participant less the amount notified to that directed participant less the aggregate amount the directed participant is entitled receive.

³⁷ Additional claims and additional claims that require independent expert may take up to 30 weeks to finalise

2. Gas market dynamics

2.1 Gas demand

Total east coast gas demand increased slightly compared to Q1 2020 (+1%), largely due to increased Queensland liquefied natural gas (LNG) demand (+19 petajoules [PJ], Figure 47) which was offset by reduced GPG.

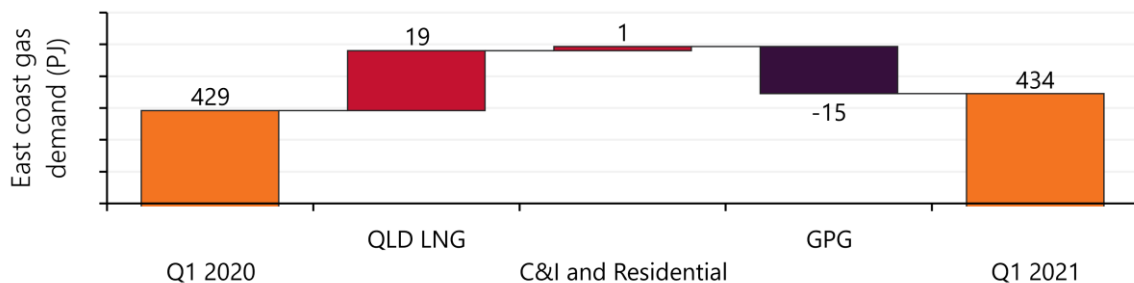
The large increase in Queensland LNG exports was influenced by strong Asian LNG demand and high prices (Section 2.2.1), and was only slightly lower than the record set in the previous quarter (Figure 48). This represents the highest Q1 export quantity and the second highest quarter overall.

By participant, Australia Pacific LNG (APLNG) recorded the largest increase of 11.2 PJ and Queensland Curtis LNG (QCLNG) increased by 7.9 PJ, while Gladstone Liquefied Natural Gas (GLNG) decreased slightly by 0.1 PJ. During the quarter 89 LNG cargoes were exported, an increase from 85 in Q1 2020³⁸, reflecting higher flows to Curtis Island. QCLNG increased from 27 to 30 cargoes, APLNG increased from 31 to 33, and GLNG increased from 26 to 27.

On 17 March, QCLNG experienced an unplanned double train outage, with flows resuming by the end of the following day. This was only the third time a double train outage has occurred at Curtis Island. The outage was mitigated by diverting gas to GLNG, rapid production decreases (particularly at Woleebee Creek, Ruby Jo and Jordan), and reduced pipeline flows from Moomba on the South West Queensland Pipeline (SWQP).

Lower GPG operation, as discussed in Section 1.4.3, resulted in a reduction of 15 PJ which was the lowest quarterly GPG demand since Q1 2005.

Figure 47 LNG exports drives east coast gas demand increase

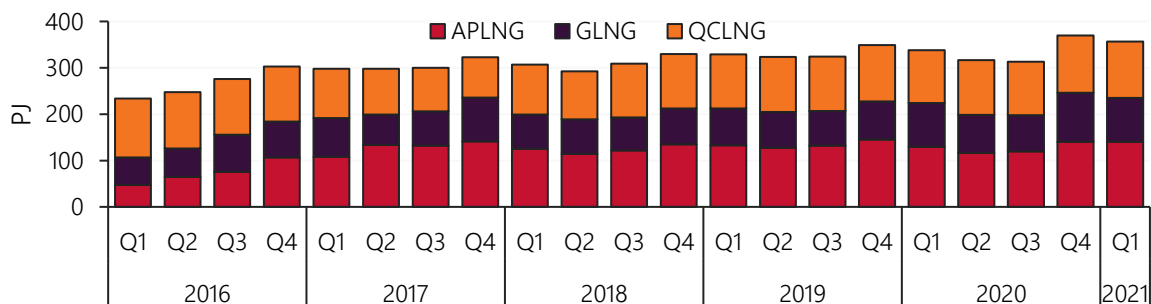


* AEMO Markets demand is the sum of customer demand in each of the Short Term Trading Markets (STTMs) and the Declared Wholesale Gas Market (DWGM) and excludes GPG in these markets.

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

Figure 48 QCLNG and APLNG drive record Q1 flows to Curtis Island for LNG export

Total quarterly pipeline flows to Curtis Island



³⁸ <https://qships.tmr.qld.gov.au/webx/>

2.2 Wholesale gas prices

Compared to Q4 2020, quarterly average gas prices increased slightly in all east coast gas markets except the DWGM in Victoria, which remained steady. This continued recent trends and reflects the influence of higher international prices with the cold northern hemisphere winter (Figure 49). Key outcomes included:

- Gas prices in the **Brisbane Short Term Trading Market (STTM)** averaged \$6.36/GJ, 1% higher than Q4 2020 levels, reflecting higher-priced offers during the quarter. This quarter, 37% of bids into the STTM were below \$7/GJ, down from 64% in Q1 2020 (Figure 50), influenced by high Asian LNG prices.
- **Victoria's Declared Wholesale Gas Market (DWGM)** quarterly average gas price of \$5.52/GJ was the lowest east coast average, 10% lower than other markets. This was strongly influenced by reduced local gas demand, particularly from GPG, and increased Victorian production (Section 2.3.1).

Figure 49 Gas prices increase outside of Victoria from Q4 2020

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

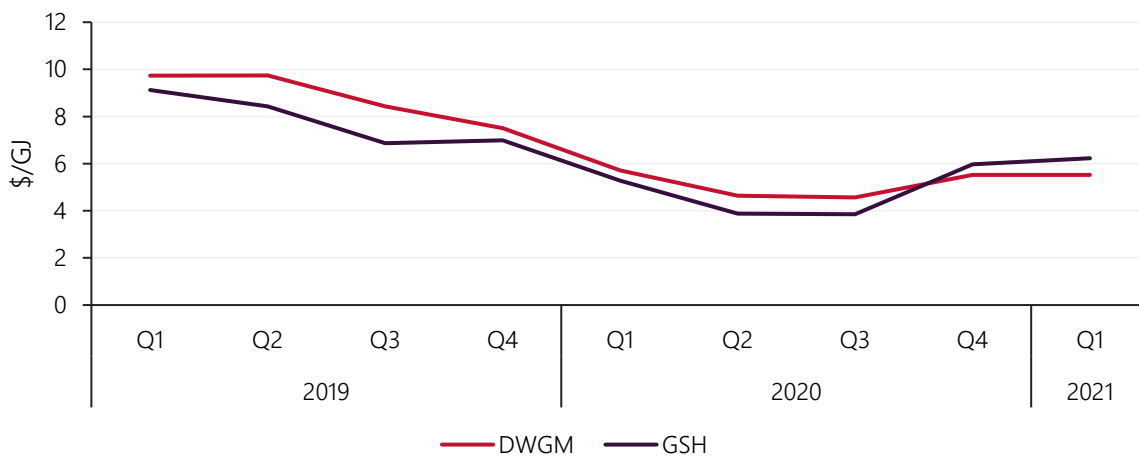
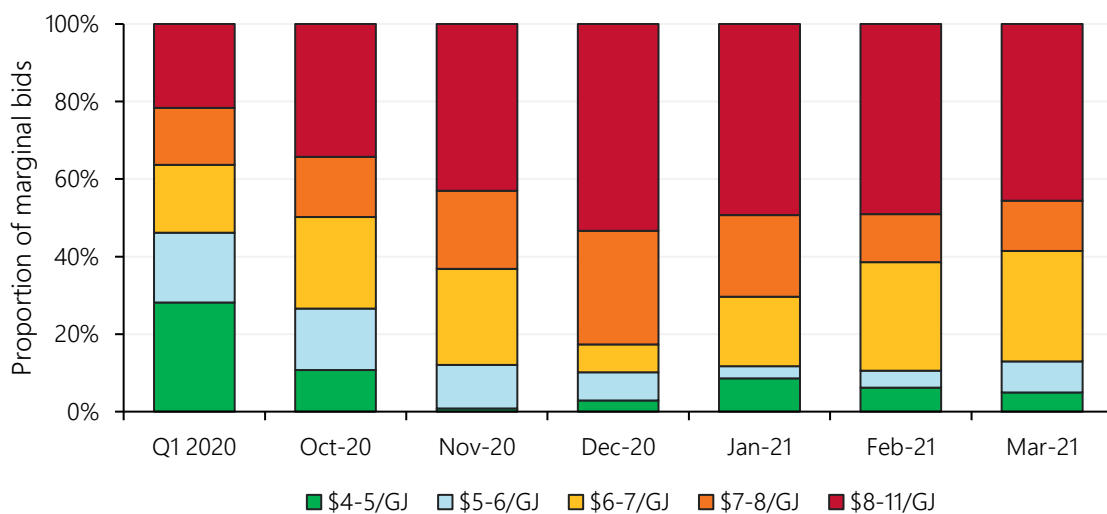


Figure 50 Brisbane STTM bids at higher prices than Q1 2020

Brisbane STTM – proportion of marginal bids by price band



2.2.1 International energy prices

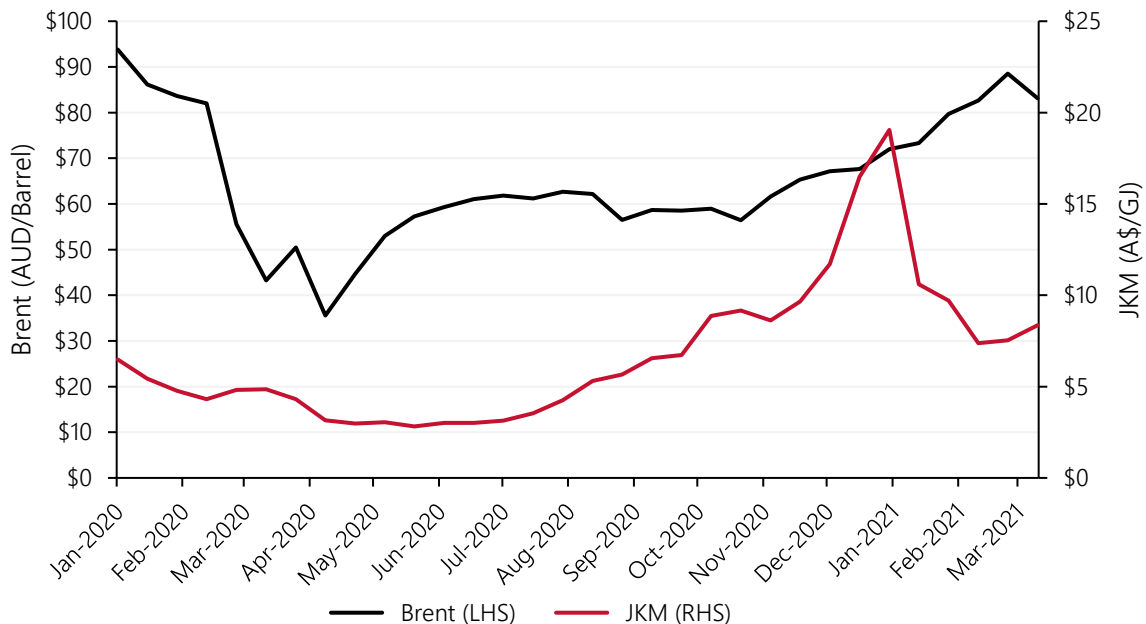
During the quarter, international energy prices continued their high levels from the end of 2020, due to a combination of weather events, demand recovery, and supply disruptions³⁹.

Japan Korea Marker (JKM) LNG prices increased to a multi-year high of A\$24.4/GJ in January but declined to A\$8.4/GJ by the end of the quarter as the cold winter conditions eased (Figure 51). This price volatility resulted in a quarterly average of A\$10.8/GJ, A\$1.2/GJ higher than the previous quarter and A\$5.5/GJ higher than Q1 2020.

High Asian gas prices continued to influence the domestic gas market, resulting in high Queensland LNG exports, and small increases in Queensland gas market prices (Section 2.1). The Australian Competition and Consumer Commission's (ACCC's) average LNG netback price increased from A\$6/GJ in the previous quarter to A\$12.3/GJ in Q1 2021, on par with the previous quarterly record in Q4 2018, and at a significant premium to domestic gas prices.

Figure 51 JKM prices rally to new multi-year high

Brent Crude oil and JKM LNG prices in Australian dollars



Source: Bloomberg data in 14-day averages

Brent Crude oil increased from A\$67/barrel at the end of 2020 to finish the quarter at A\$83/barrel, influenced by the Organisation of the Petroleum Exporting Countries (OPEC) production cuts⁴⁰ and shipping disruptions in March⁴¹.

During the quarter, thermal export coal prices remained at comparable levels to the end of 2020, averaging A\$116/ton, A\$13/ton higher than Q1 2020, mainly due to the northern hemisphere winter coupled with logistical issues in New South Wales late in the quarter from severe floods⁴².

³⁹ The AER's Quarter 1 2021 Wholesale Market Quarterly Report will include a focus on international and domestic gas prices.

⁴⁰ OPEC 2021, The 13th OPEC and Non-OPEC Ministerial Meeting Concludes: https://www.opec.org/opec_web/en/press_room/6310.htm

⁴¹ Bloomberg 2021, What a Long Suez Canal Closure Means for the Oil Price: <https://www.bloomberg.com/opinion/articles/2021-03-25/suez-canal-blocked-what-a-lengthy-closure-will-mean-for-the-oil-price>

⁴² World Energy Org 2021, Severe Storms Disrupt Australian Coal Exports: <https://www.world-energy.org/article/16606.html>

2.3 Gas supply

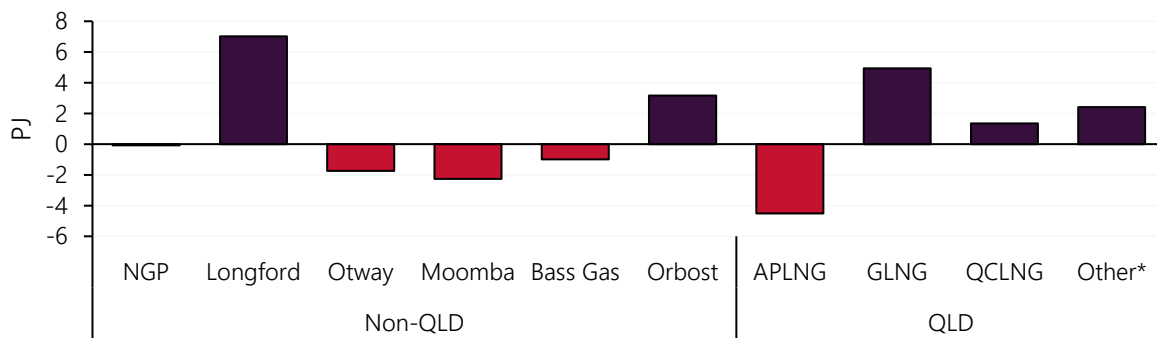
2.3.1 Gas production

East coast gas production increased by 9.4 PJ compared to Q1 2020 (+2%, Figure 52) due to:

- Higher Longford production (+7 PJ), which resulted in an increase in interstate exports from Victoria and higher filling at Iona storage.
- Increased Orbost production, which commenced on 25 March 2020 (+3.2 PJ). Fewer production issues compared to recent quarters resulted in it producing 1.6 PJ more than in Q4 2020.
- Increased Queensland production from GLNG (+4.9 PJ), QCLNG (+1.3 PJ) and other Queensland facilities (+2.4 PJ) to meet increased demand for LNG export (Section 2.1). This was partially offset by a decrease from APLNG (-4.5 PJ), particularly at Combabula (-1.6 PJ), Reedy Creek (-1.6 PJ), and Orana (-1.2 PJ)

Figure 52 Longford production up 15%

Change in east coast gas supply – Q1 2021 versus Q1 2020

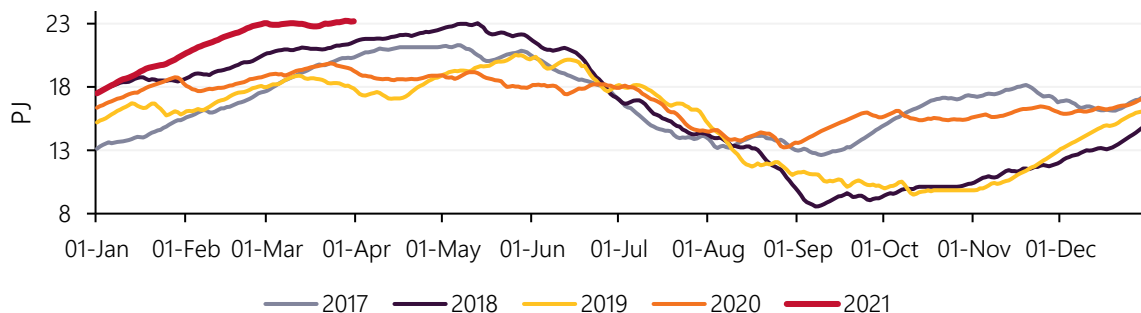


2.3.2 Gas storage

Iona Underground Storage Facility (UGS) finished the quarter with a gas balance of 23.2 PJ, 4.1 PJ higher than at the end of Q1 2020 and near its registered maximum capacity of 24.5 PJ (Figure 53). This represents the highest storage level for Iona for any time of the year since storage levels began being reported in 2016. Iona was filling for most of the quarter, and was only emptying when required to supply Victoria on days where Longford capacity was reduced for maintenance, mostly in March. The high gas balance was a function of increased Longford production (compared to Q1 2020), combined with very low GPG demand.

Figure 53 Iona storage finished Q1 at the highest level since reporting began

Iona storage levels



2.3.3 Dandenong LNG

Dandenong LNG storage levels continued to fall, dropping 51 terajoules (TJ) to finish the quarter at 387 TJ. The lowest point occurred on 12 February, when just 349 TJ was held in storage – a new record minimum from when the DWGM began in 1999 (Figure 54). The decrease was driven by a reduction in contracted capacity, with the Gas Bulletin Board indicating that just 195 TJ is contracted for winter (Figure 55).

On 29 March, AEMO issued a notice of a threat to system security for the Victorian Declared Transmission System (DTS), following publication of the Victorian Gas Planning Report⁴³, which forecast insufficient contracted Dandenong LNG inventory being available for operational and emergency response scenario requirements.

Figure 54 Dandenong LNG stocks fell to their lowest level in DWGM history

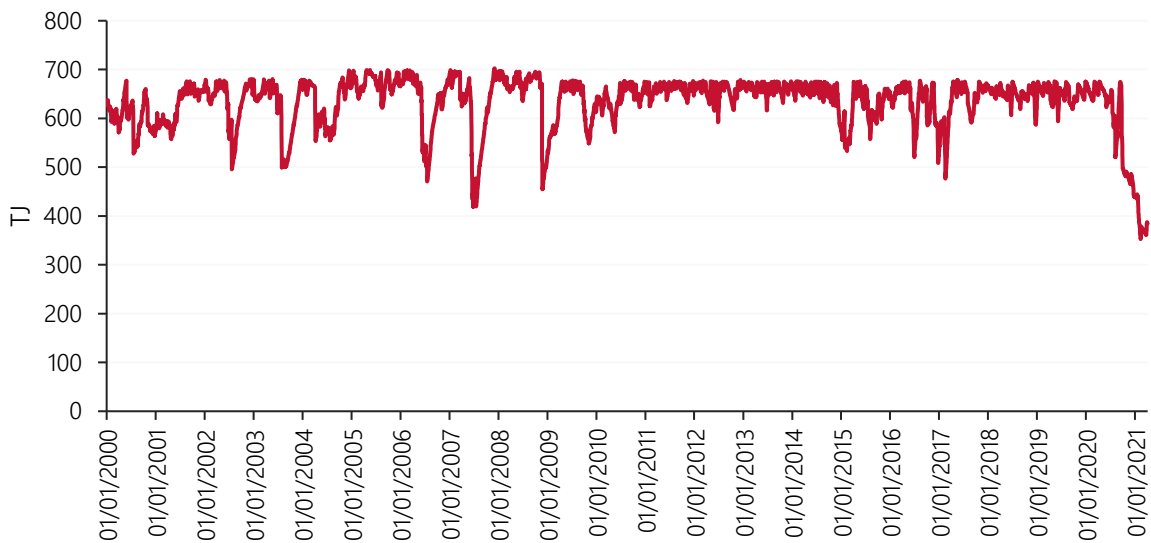
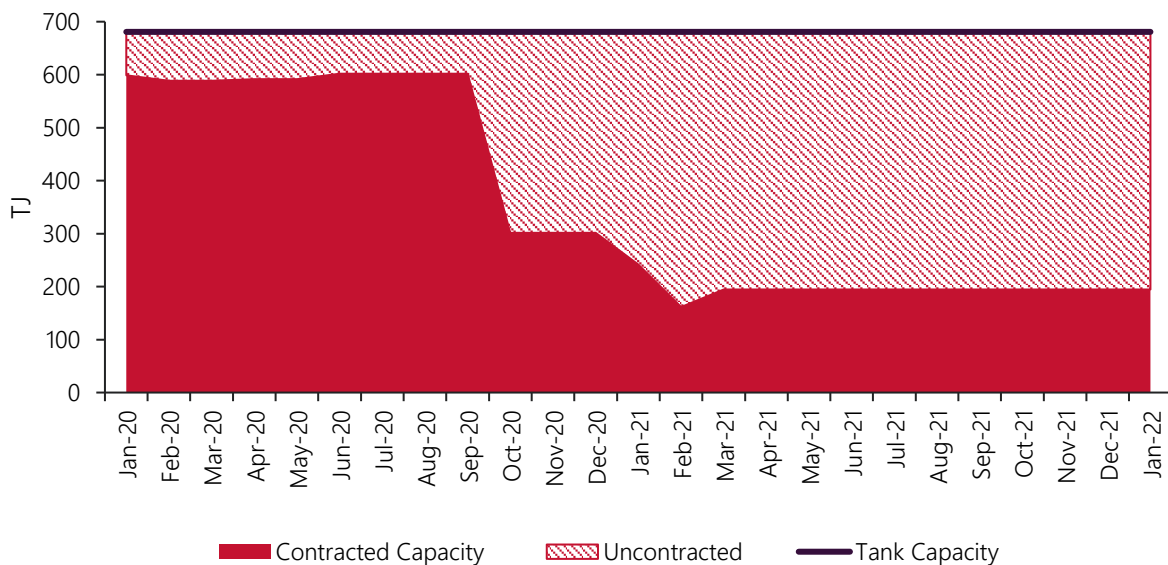


Figure 55 Dandenong LNG remains largely uncontracted in 2021 and beyond



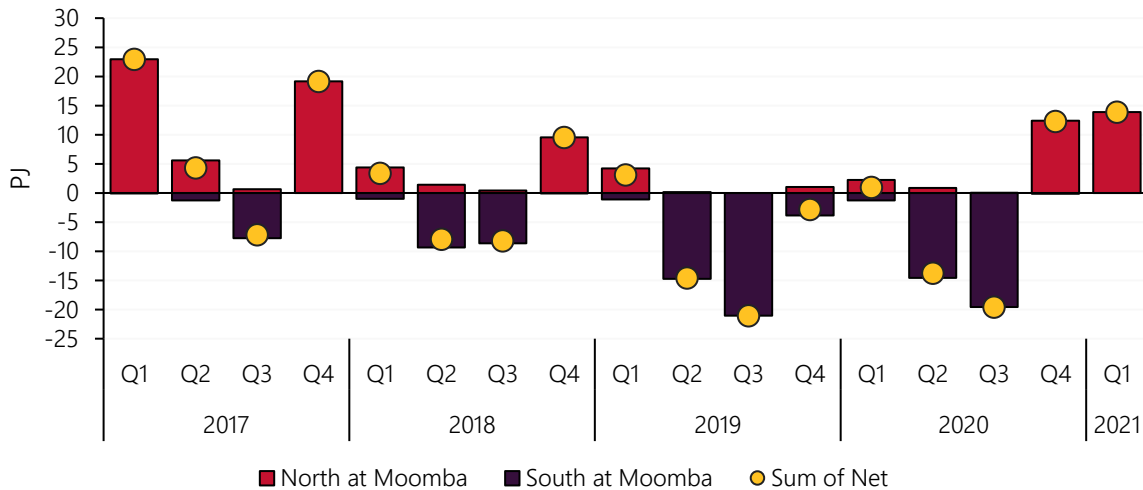
⁴³ <https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/victorian-gas-planning-report>

2.4 Pipeline flows

During the quarter, 13.9 PJ of gas flowed north from Moomba to Queensland, compared to just 1 PJ in Q1 2020, representing the highest flows north since Q1 2017 (Figure 56). The increase in gas flows was a function of high Queensland LNG export demand, coupled with reduced southern GPG demand and a large increase in Longford production.

Figure 56 Highest gas flows to Queensland since 2017

Flows on the South West Queensland Pipeline at Moomba

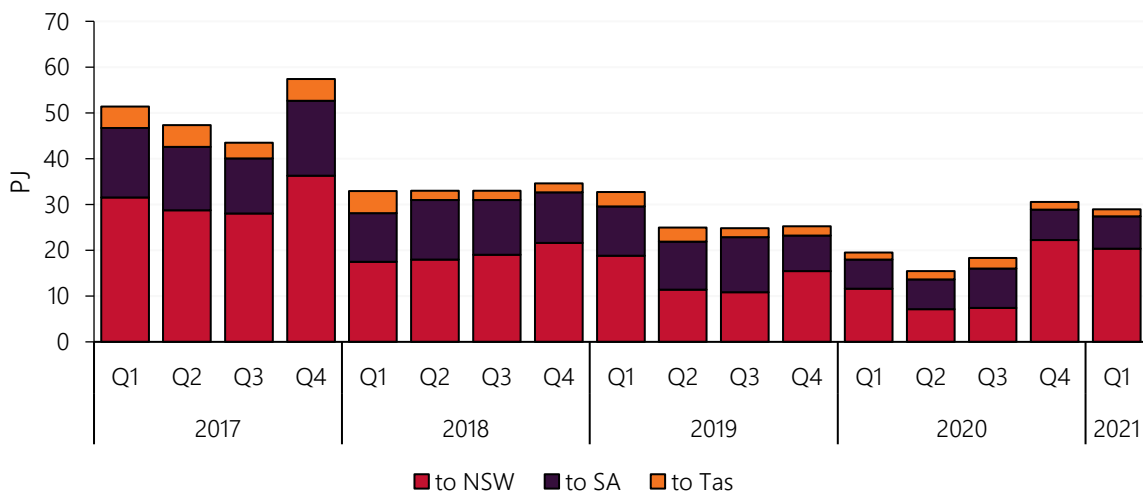


Victorian net gas transfers to other states increased by 9.4 PJ compared to Q1 2020 (Figure 57), reflecting increased Victorian production and very low Victorian GPG demand. Compared to Q1 2020:

- **Victoria to New South Wales** – Victoria exported a net 3.2 PJ of gas via Culcairn, compared to 1 PJ in Q1 2020. Exports to New South Wales via the Eastern Gas Pipeline (EGP) increased by 6.5 PJ.
- **Victoria to South Australia** – transfers increased by 0.7 PJ despite lower South Australian GPG demand, reflecting lower Moomba to Adelaide Pipeline flows. This was due to increased Victorian production, lower Victorian GPG demand, and increased Moomba flows to Queensland.

Figure 57 Victorian gas exports increased compared to Q1 2020

Victorian net gas transfers to other regions



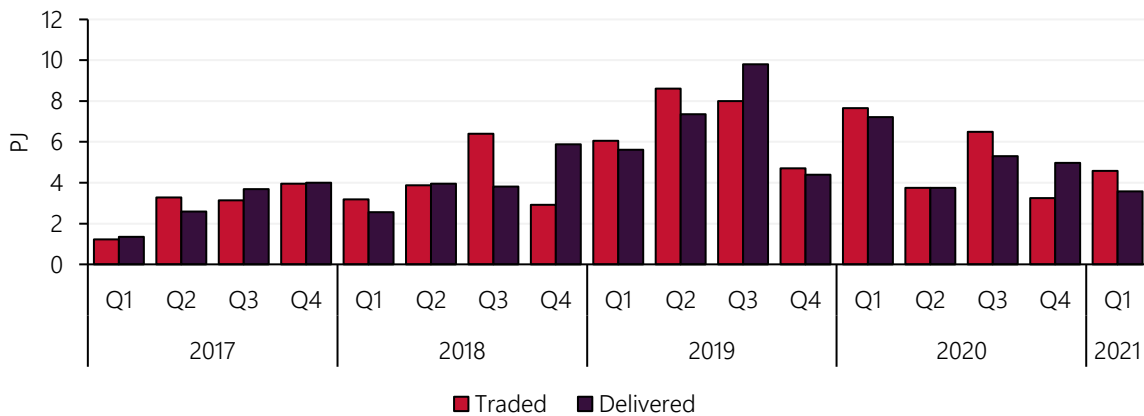
2.5 Gas Supply Hub

In Q1 2021, there were decreased trading volumes and delivered volumes on the Gas Supply Hub (GSH) compared to Q1 2020, with deliveries down by 3.6 PJ, and trades down by 3.1 PJ. This represented the lowest Q1 volume since 2018 (Figure 58).

Despite lower overall GSH trading volumes, on 29 January two new trading points were implemented in New South Wales at Culcairn and Wilton following interest from participants. During the quarter, 70 TJ was traded at Culcairn and 68 TJ at Wilton.

Figure 58 Declining GSH volumes

Gas Supply Hub – quarterly trades and deliveries



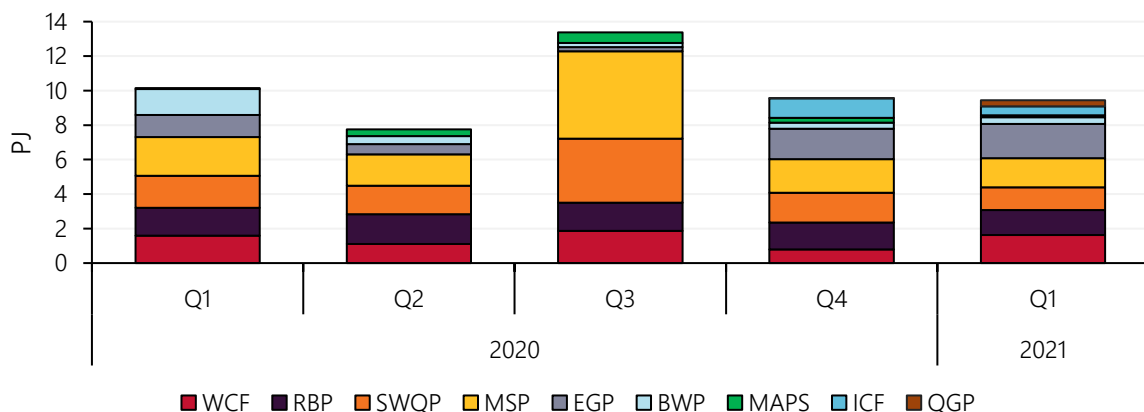
2.6 Pipeline capacity trading and day ahead auction

Day ahead auction (DAA) utilisation remained relatively steady, decreasing slightly on Q1 2020 levels (Figure 59)⁴⁴. Increases occurred on the EGP (+0.7 PJ), Iona Compressor (+0.5 PJ), Queensland Gas Pipeline (+0.4 PJ) and Moomba Compressor (+0.4 PJ) but these were more than offset by decreases on Berwyndale to Wallumbilla Pipeline (BWP) (-1.1 PJ), Moomba to Sydney Pipeline (MSP) (-0.6 PJ) and SWQP (-0.5 PJ).

Average auction clearing prices remained at close to \$0/GJ on most pipelines. The exceptions to this were the SWQP, which averaged \$0.10/GJ, and the EGP, which averaged \$0.02/GJ.

Figure 59 Day Ahead Auction utilisation slightly decreases compared to Q1 2020

Day Ahead Auction results by quarter



⁴⁴ The AER's Quarter 1 2021 Wholesale Market Quarterly Report will additional analysis on the day ahead auction.

2.7 Gas – Western Australia

Western Australia’s Q1 2021 total domestic gas consumption was 92.4 PJ, 0.8% higher than Q1 2020 (Figure 60). The key change compared to Q1 2020 was the 5 PJ (+119%) increase in Large User industrial consumption due to the Yara Pilbara Liquid Ammonia Plant significantly increasing consumption (+4.1 PJ). GPG consumption decreased by 2.6 PJ (-11%), primarily due to decreased consumption at the Wagerup Power Station of 2.25 PJ.

Total Western Australian gas supply was 91.4 PJ this quarter, down 8.6% from 100 PJ in Q1 2020 (Figure 61), representing the lowest quarterly production since Q4 2018; production has been gradually declining since Q2 2020 (Figure 3). The trend of declining gas production has been driven by continued reduction in output by Karratha Gas Plant; its output of 2.8 PJ this quarter was 30 PJ (91%) lower than in Q1 2020⁴⁵. Conversely, all other facilities increased production compared to Q1 2020, with the largest increase at Devil Creek (+7.9 PJ).

Figure 60 Western Australia gas consumption increased 0.8% compared to Q1 2020

WA quarterly gas consumption by industry

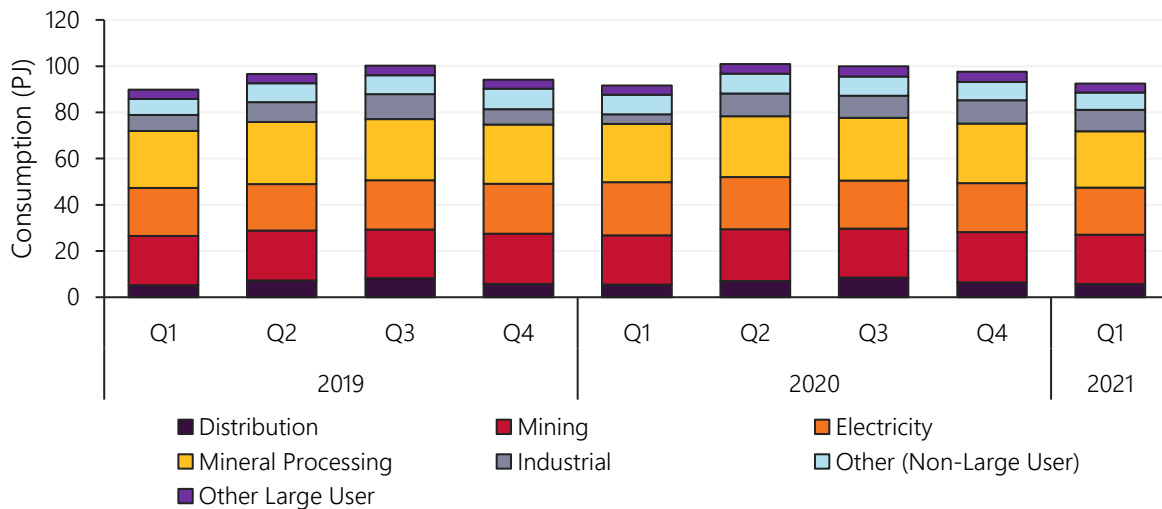
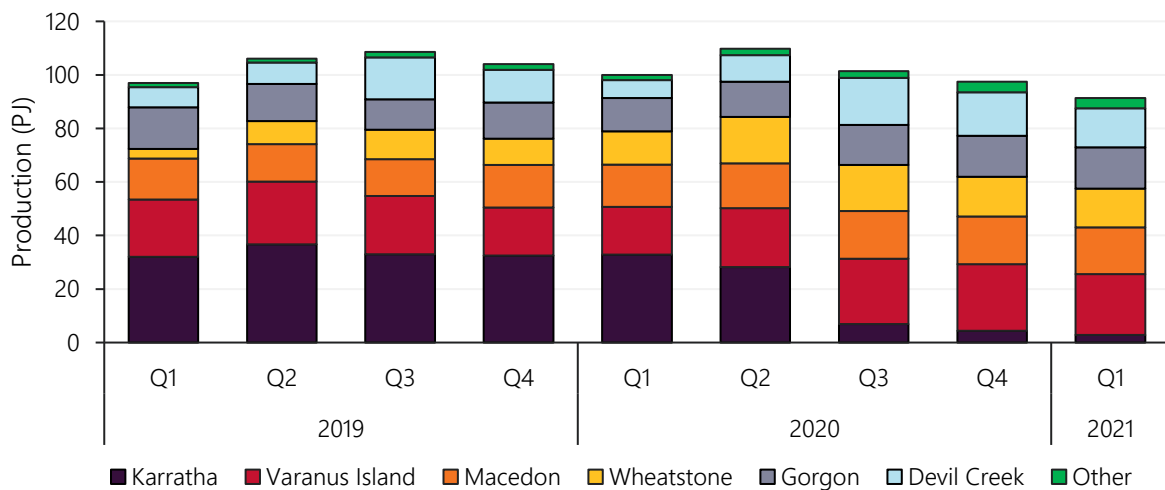


Figure 61 Western Australia gas production down 8.6% compared to Q1 2020

WA gas production by facility



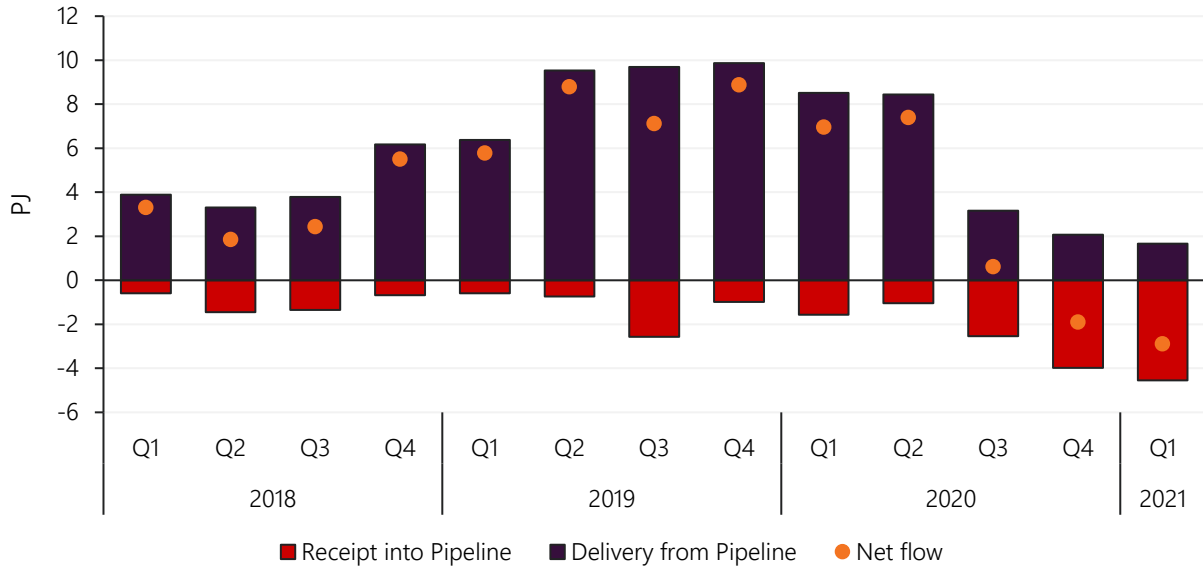
⁴⁵ A comparison of all the Western Australian production facilities revealed that Karratha Gas Plant also recorded the largest decrease in domestic supply between Q1 2020 and Q1 2021, at 30 TJ or 91%.

In line with lower total domestic gas supplied by Production Facilities, there was net withdrawal from Storage Facilities into the pipeline for transport and consumption (Figure 62). This was the second consecutive quarter this has occurred, with a combined net flow from Storage Facilities into the pipeline of 2.9 PJ.

This quarter registered the largest receipt from Storage Facilities since 2017, and the lowest delivery of gas from pipelines to Storage Facilities since 2018 (only 1.7 PJ transferred)⁴⁶.

Figure 62 Net quarterly withdrawal from Western Australia gas storage

Quarterly gas transfer from storage facilities



⁴⁶ The withdrawal of gas from Storage Facilities to meet gas demand may be driven by commercial factors such as spot prices and gas contracts

3. WEM market dynamics

3.1 Weather and electricity demand

Perth’s quarterly average temperature of 24.4°C was its highest in six years, largely driven by high average maximum temperatures during January and March. Compared to Q1 2020, the average maximum temperature was 0.25°C higher (Figure 63), and average minimum 0.21°C lower, highlighting a greater range of temperatures measured⁴⁷.

Figure 64 shows the hourly average operational demand in Q1 2021 and Q1 2020. Demand in the evening peak was 3% higher, primarily due to the warmer weather, while demand in the middle of the day decreased by 6% due to an increase in distributed PV capacity (~100 MW). In terms of overall average demand, the increase in the evening peak directly offset reduced daytime demand, resulting in unchanged average demand compared to Q1 2020.

Figure 63 Hot Perth Q1 weather

Perth Q1 average maximum temperatures 2016 - 2021

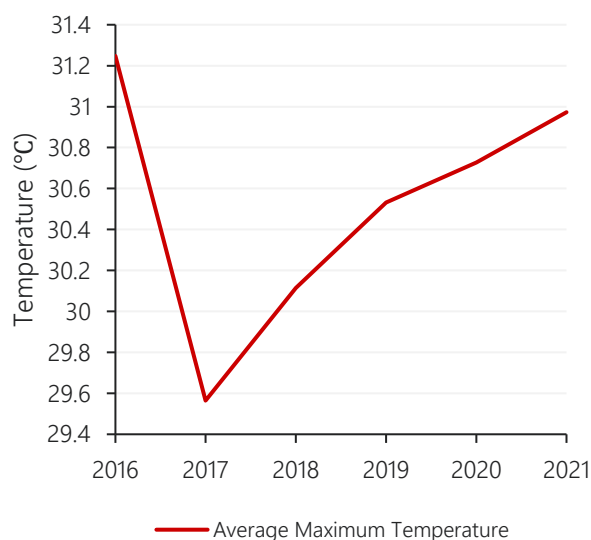
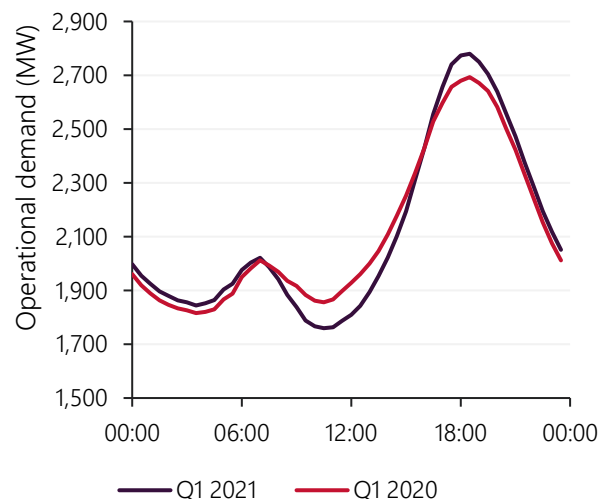


Figure 64 WEM midday demand continued to decrease

WEM operational demand by time of day



Maximum and minimum demand

At 1130 hrs (AWST)⁴⁸ on Sunday 14 March 2021, a new all-time⁴⁸ record minimum operation demand was set in the South West Interconnected System (SWIS) (Figure 65, Table 2). Operational demand⁴⁹ was 952 MW, 33 MW below the previous record which occurred in Q4 2020, with estimated distributed PV output of 1,026 MW.

This continues the trend of record minimum demands, with eight of the last nine quarters sequentially setting new all-time minimum demand records.

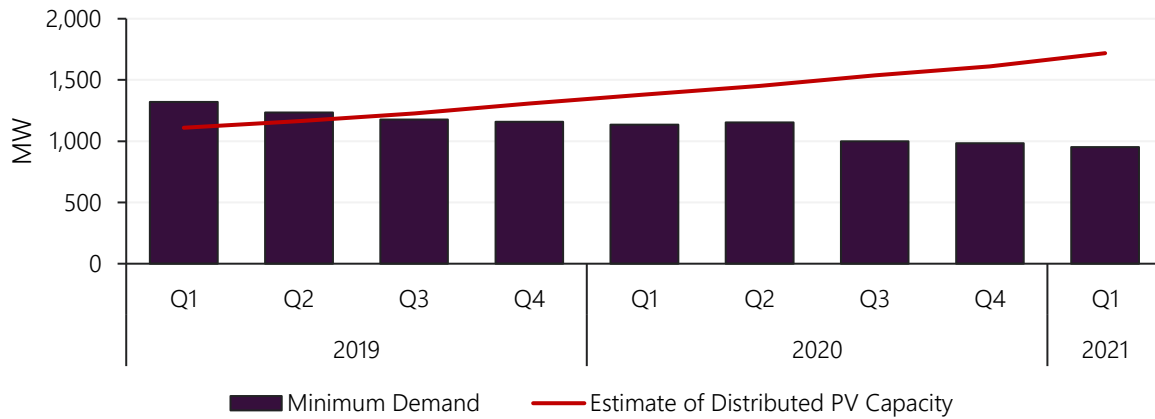
⁴⁷ Bureau of Meteorology 2021, Greater Perth in December 2020: <http://www.bom.gov.au/climate/current/month/wa/perth.html>

⁴⁸ All times in this section are in AWST.

⁴⁹ 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 65 New WEM minimum demand record set

WEM minimum operational demands



On 8 January 2021 at 1800 hrs, the maximum daily demand in the SWIS reached 3,788 MW, representing the second highest daily maximum operational demand since Q1 2016. The high demand was primarily driven by temperature, with the maximum temperature in the Perth metro area on the day reaching 42.2 °C, the hottest day in the quarter and an average temperature over the previous seven days of 34.3°C.

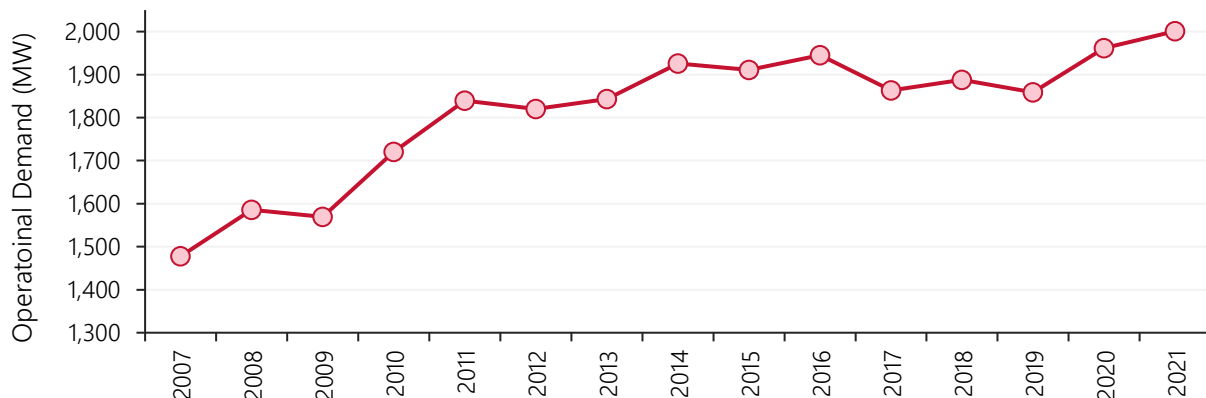
Table 2 WEM maximum and minimum demand records

Maximum demand (MW)			Minimum demand (MW)		
Q1 2021	All-time	All Q1	Q1 2021	All-time	All Q1
3,788	4,006	4,006	952	952	952

This quarter had the highest average midnight operational demand on record at 2,001 MW, which has been trending upwards since 2007 (Figure 66). This is primarily due to an increase in demand from contestable customers⁵⁰.

Figure 66 WEM midnight demand on the rise

WEM average demand at 0000 hrs – Q1s



⁵⁰ Contestable customers must have a load measured by an interval meter that consumes more than 50 MWh in a year.

3.2 Electricity generation

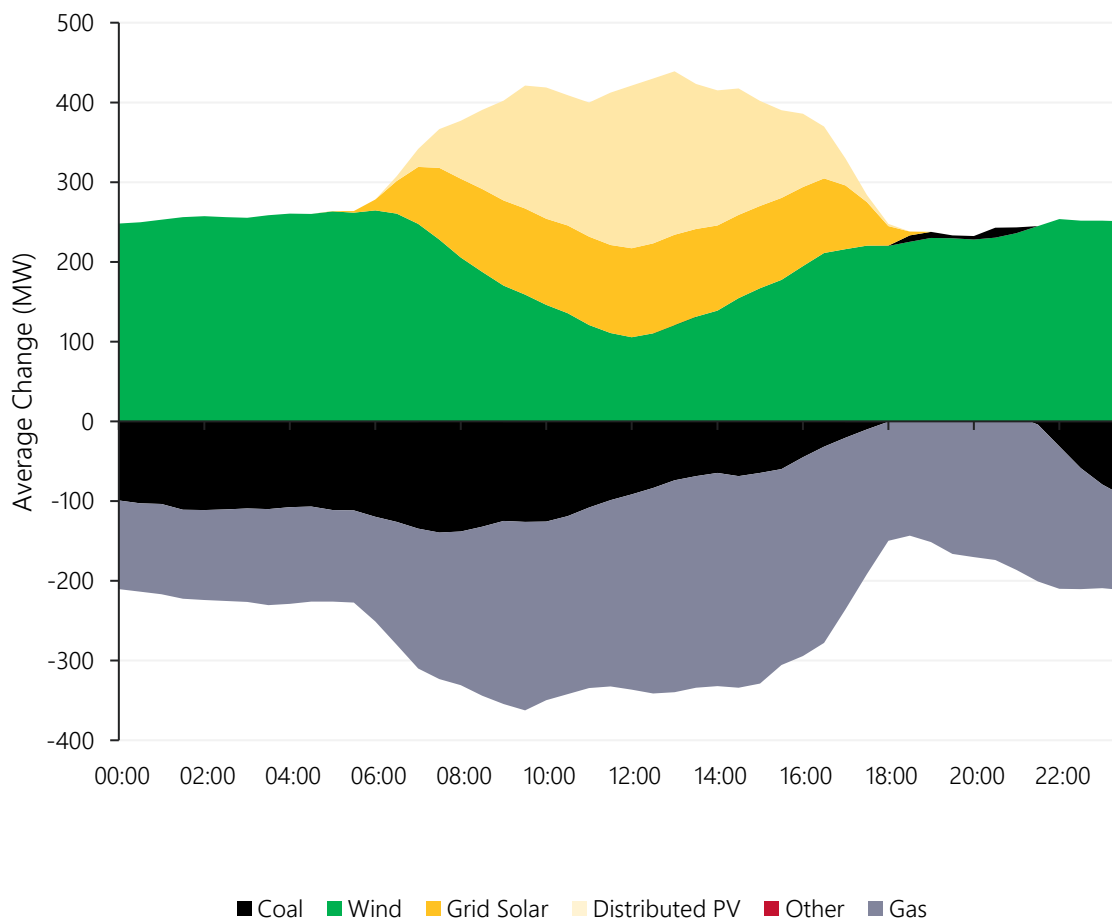
During the quarter, the WEM supply-mix transformation continued to occur, with significant increases in wind and grid solar generation contributing to a high number of negative Balancing Price occurrences (Section 3.3).

Figure 67 shows the average change in generation between Q1 2020 and Q1 2021 by fuel type and time of day. Key shifts included:

- Average GPG decreased by 182 MW and coal-fired generation decreased by 76 MW, due to displacement by VRE output and increased outages. Coal facilities' availability reduced from 100% in Q1 2020 to 88.4%, and gas facilities availability reduced from 100% to 94.5%. There was a small increase in coal-fired generation between 1800 and 2100 hrs, consistent with the 3% increase in demand over this period.
- Wind generation increased by 211 MW on average, due to the addition of two wind farms (Yandin and Warradarge). These wind farms are now fully commissioned, and contribute an additional 392 MW of installed wind capacity to the WEM.
- Distributed PV generation increased by 58 MW on average due to an estimate 24% increase in installed capacity in the SWIS (+7%).
- Large-scale solar generation increased by 48 MW on average due to the addition of 140 MW of new solar capacity, including Merredin Solar Farm, and expansion of the Greenough River Solar facility.

Figure 67 Increased output from wind and solar generation; decline in thermal generation

Average change in WEM supply – Q1 2021 versus Q1 2020



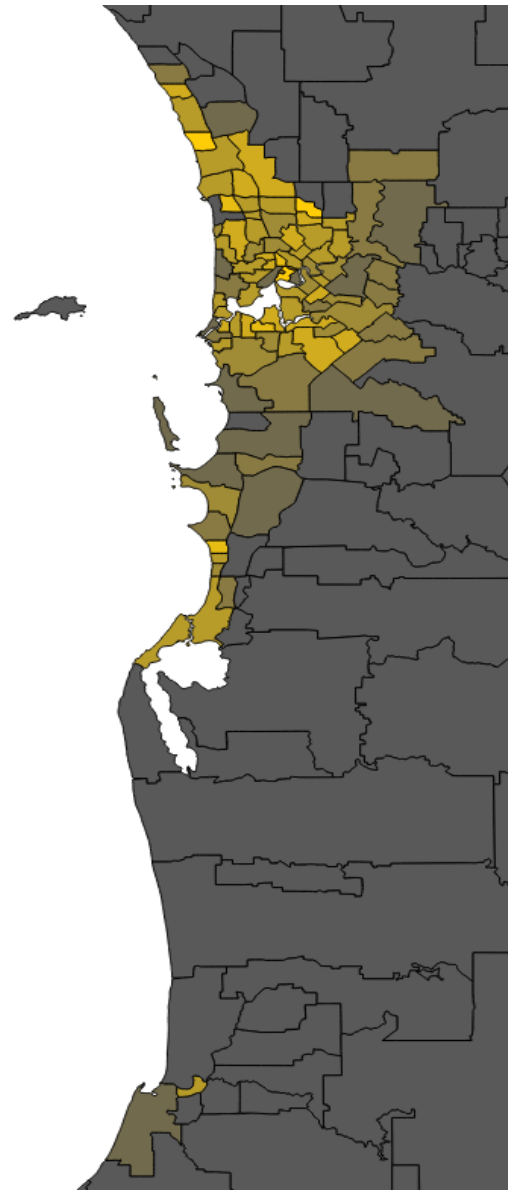
Record generation from distributed PV in the WEM

The growth in distributed PV in this quarter was particularly notable on Saturday 13 March 2021 at 1320 hrs when a new record value of estimated instantaneous non-synchronous generation⁵¹ output compared to total underlying demand was set at 65.2%⁵². Based on analysis of meter data during similar events, AEMO estimates that 35% of the total distributed PV output (over 400 MW) was exported to the SWIS, instead of being used on the premises where the distributed PV is located ('behind the meter').

For the first time, this QED has used data from the Western Australia Distributed Energy Resources (DER) Register to develop insights into the growing capacity of DER such as distributed PV. The DER Register is a requirement of the WEM Rules⁵³ and was launched during Q1 2021 after collaboration between AEMO, Western Power and the Western Australian Government. Under the WEM Rules Western Power is required to provide AEMO with the data for the DER Register. Electrical contractors will be requested to confirm the 'as-installed' DER devices and provide this information to Western Power⁵⁴.

According to the WA DER Register, there was 1.5 GVA⁵⁵ of distributed PV installed in the SWIS as of the 15 March 2021⁵⁶. Figure 68 shows density of installed distributed PV in the SWIS by postcode. This visualises the density of distributed PV in various areas of WA and highlights that 79% of distributed PV is located in the Perth metropolitan area (with postcodes between 6000 and 6199), with particularly high densities (>1200 kVA/km²) of distributed PV in newer suburbs such as Burns Beach and Iluka in north west and Canning Vale in the South East of Perth.

Figure 68 Installed distributed PV by postcode (kVA/km²)



⁵¹ This includes distributed PV and grid scale VRE (solar and wind) Facilities.

⁵² This was an increase compared to the previous record percentage of 61.5% observed in Q4 2020. At the time, distributed PV was estimated to be generating 1,135 MW, non-scheduled generation output was 544 MW, scheduled generation was 569 MW and behind the meter (synchronous) generation output was 325MW.

⁵³ The rule changes to introduce the DER register were an initiative from the WA Government's DER Roadmap.

⁵⁴ Data from the DER Register can be used to provide insight into DER trends, performance, and behaviours to benefit system design, planning and operations in the SWIS. Data on the DER connected in the SWIS by postcode and type from the DER Register is now publicly available on AEMO's [website](#).

⁵⁵ The DER register receives underlying data in VA and not in W.

⁵⁶ The DER data is regularly updated by Western Power and is therefore subject to change. The data is published on the WA DER Register is updated quarterly by AEMO.

3.3 Wholesale electricity prices

Balancing prices decrease compared to Q1 2020

Compared to Q1 2020, the average WEM Balancing Price reduced by 16% (-\$8.5/MWh, Figure 69), due to the large increase in NSG (which generally bid at negative prices), and decreased daytime demand due to continuing uptake of distributed PV (Section 3.1).

The Short Term Energy Market (STEM) cleared quantity increased steadily between Q2 2020 to Q1 2021, with quantities this quarter 11% higher than in Q1 2020 (Figure 70). This demonstrates an increase in participation in the STEM by Market Participants, as they hedge against price outcomes in the Balancing Market.

For the last four quarters, the average STEM Price was lower than the average Balancing Price. This difference between Balancing Price and STEM Price reflects the premium paid Market Generators to secure price certainty a day ahead and minimise exposure to Balancing Prices.

Figure 69 Balancing and STEM prices reduce compared to Q1 2020

WEM quarterly average Balancing Price and STEM price

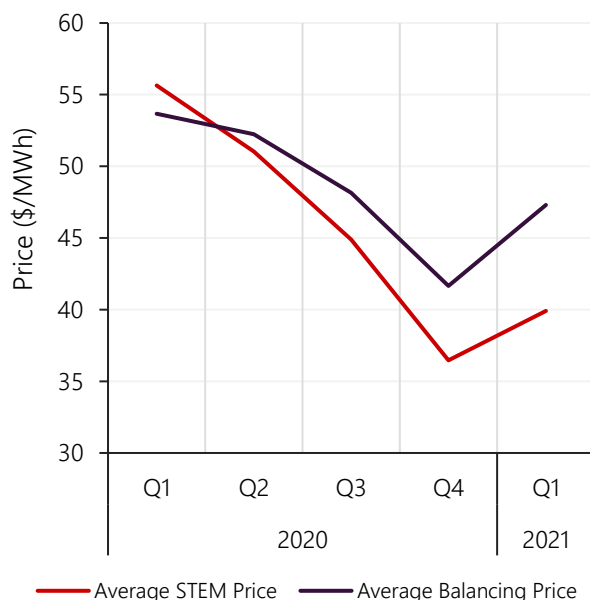
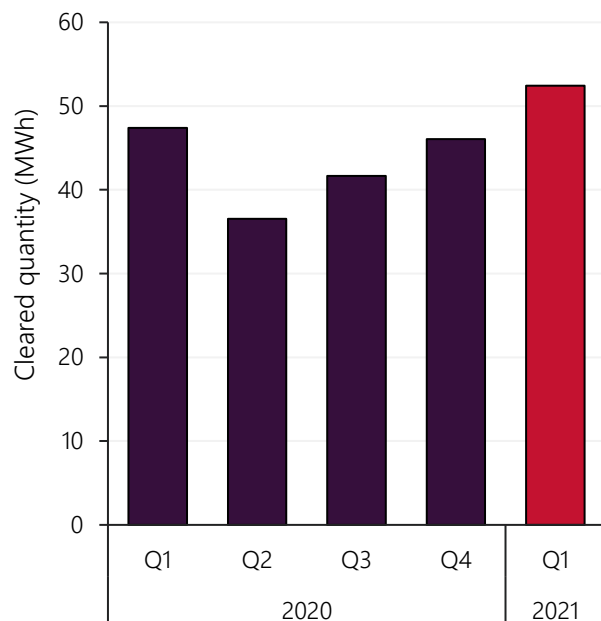


Figure 70 STEM cleared quantity increases

STEM cleared quantity



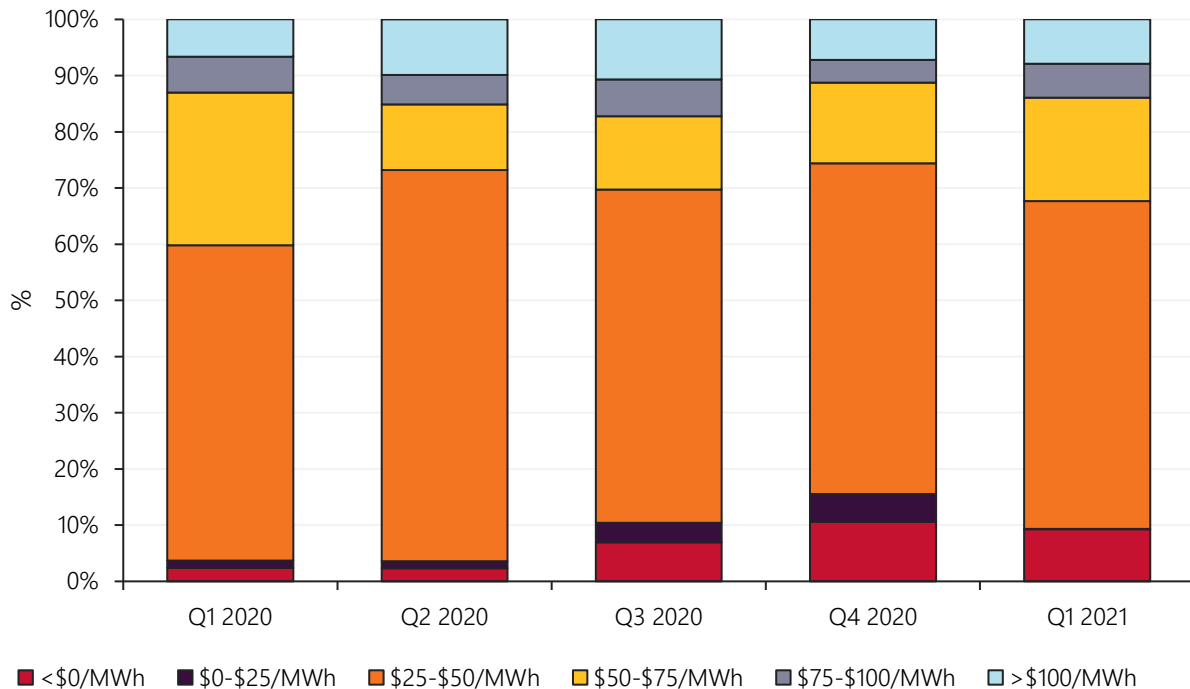
As shown in Figure 71, the most significant changes to the Balancing Price structure included:

- Increased frequency of negative Balancing Prices; there were four times more negatively priced intervals in Q1 2021 than in Q1 2020, with 9% of total intervals being negatively priced.
- Reduced frequency of Balancing Prices in the \$0-25/MWh range, which in Q1 2021 accounted for only 0.15% compared to 1.3% in Q1 2020.
- A corresponding increase in the frequency of higher prices, particularly prices greater than \$100/MWh, which accounted for 8.3% of total intervals in Q1 2021 versus 6.6% in Q1 2020. This was driven by a 6% decrease in availability of GPG, and a 3% increase in operational demand during intervals between 1730 hrs and 1930 hrs.

This growth in occurrence of negative prices and high prices (>\$100/MWh) highlights an increasing spread of Balancing Prices in the WEM.

Figure 71 Increased occurrence of negative priced intervals in Q1 2021

Balancing Price distribution



Maximum price events in Balancing Market

During the quarter, there were five intervals clearing at the maximum price (known as the Maximum STEM Price) of \$267/MWh. Three of these intervals occurred consecutively on Friday 9 March 2021 from 1630 hrs to 1730 hrs (Figure 72). Key factors that led to these maximum prices included:

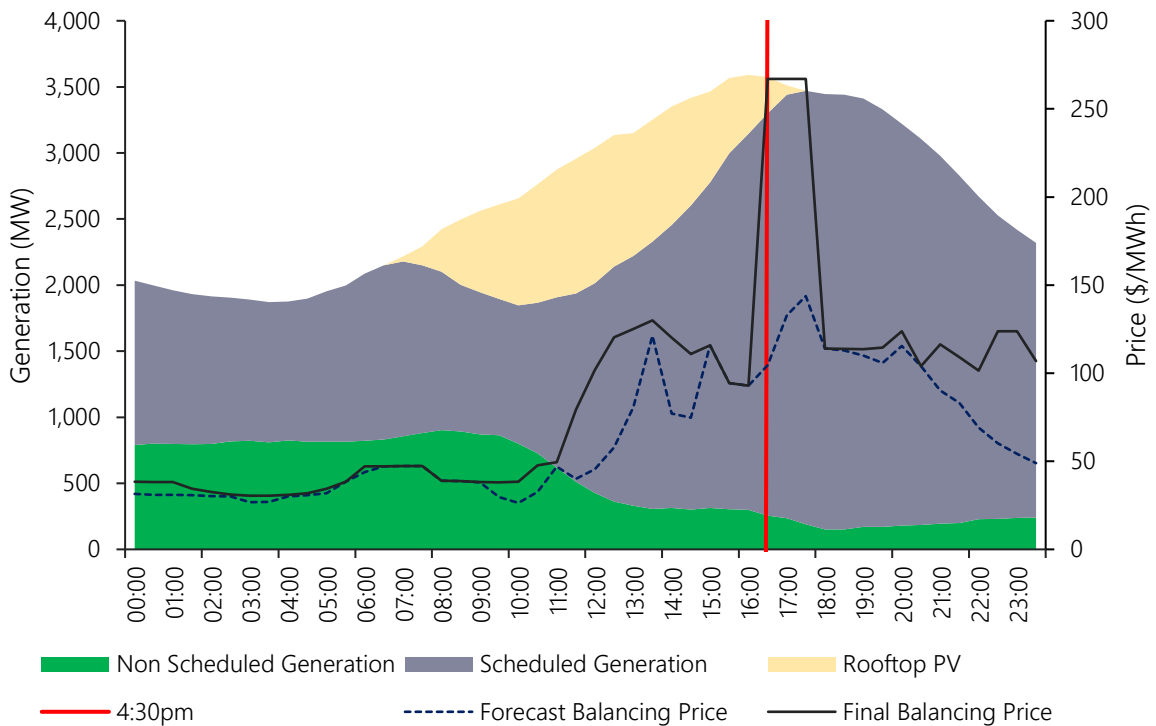
- **Large change in Scheduled Generation across the day** – Scheduled Generation experienced a large change from the morning low to the evening peak. There was a total change of 2,262 MW between 0930 hrs and the maximum demand (3,417 MW), which occurred at 1800 hrs. This was the largest recorded total change in Scheduled Generation output in a calendar day.
- **Inaccuracy in weather forecast and market price** – Weather conditions were warmer (maximum temperature of 35.9°C) and more humid (relative humidity of 42%) compared to the forecast. This resulted in higher demand than forecast, which in turn resulted in the final Balancing Price being higher than forecast.
- **Outages of Scheduled Generation** – 478 MW of Scheduled Generation was on outage; coal-fired generation availability was 85% and GPG availability was 86%, removing some lower-cost and mid-merit generation from the bid stack.
- **Sensitivity of the merit order** – Based on the merit order on the day, small changes in final outcomes compared to forecasts could have a large impact on the price outcome. For example, a small change of 18 MW (or 0.5%) would have resulted in the price clearing at the next lowest price tranche of \$132/MWh.

The above factors can impact market price outcomes. For example, at 1600 hrs there was a difference of \$163/MWh between the forecast and the final Balancing Price of \$267/MWh. Variation between forecast⁵⁷ and final price results in inaccurate price signals and can impact Market Participant trading behaviour and market outcomes.

⁵⁷ AEMO generates a forecast price using a methodology prescribed in the WEM Rules. This relies on Balancing Submissions from generators, including forecast generation from Non-Scheduled Generators, and AEMO's load forecast. AEMO calculates the final Balancing Price using actual end of interval output values for each generator and the actual load.

Figure 72 Price spike on 9 March 2021

Generation by type on 9 March showing the largest ever scheduled generation range in a calendar day. The first max price event at 1630 hrs is highlighted.



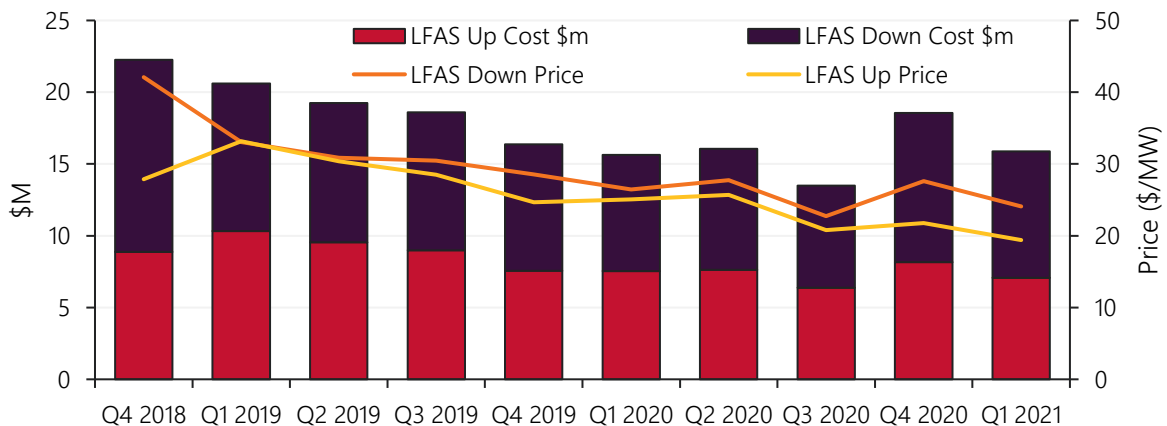
3.3.1 Load Following Ancillary Service costs

The trend of decreasing LFAS Up Prices and LFAS Down Prices since Q4 2018 continued in Q1 2021, decreasing by respectively by \$2.35/MW and \$3.49/MW on average compared to Q4 2020 (Figure 73). Compared to Q4 2020, LFAS costs decreased in both the LFAS Up and LFAS Down markets by \$1.1 million and \$1.6 million respectively.

This cost reduction was despite AEMO needing to increase the sculpted LFAS Requirements in Q4 2020 due to the connection of new wind and solar generators⁵⁸.

Figure 73 Decrease in LFAS Costs in Q1 2021

Quarterly LFAS Upward and LFAS Downward costs since Q4 2018

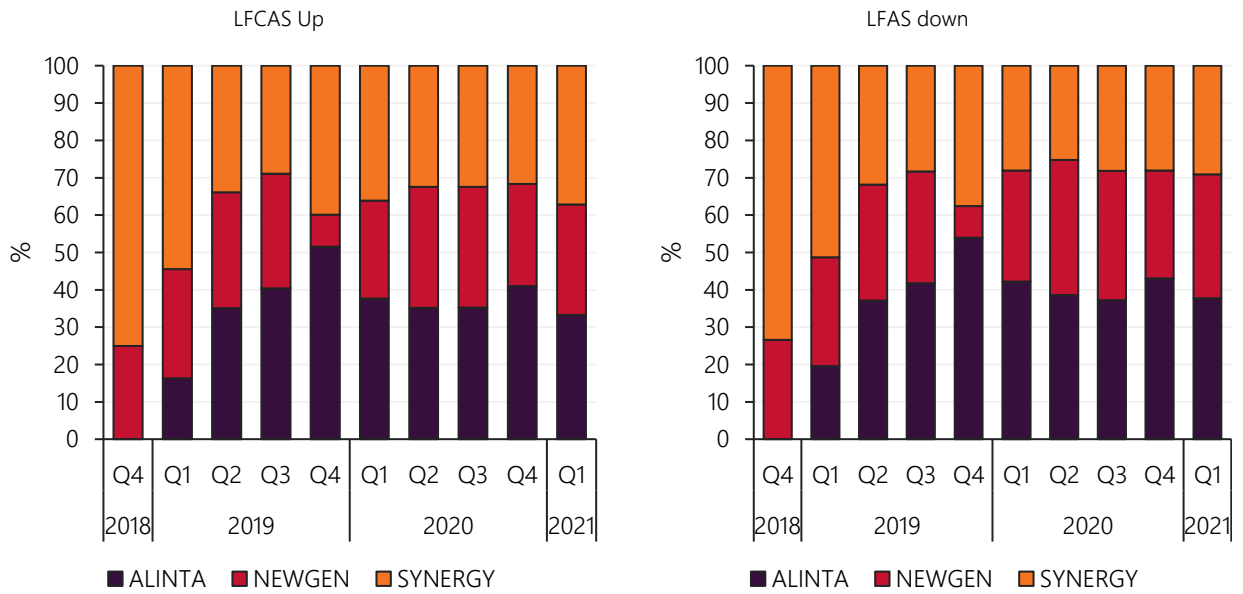


⁵⁸ On 22 September 2020 the LFAS Requirement Upwards and Downwards LFAS changed as follows:

- 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

One aspect that may have contributed to lowering costs over this time period, including Q1 2021, is greater participation in LFAS. Figure 74 shows the increase in participation in the LFAS market as indicated by a growth in cleared quantities for Alinta and Newgen and a reduction in market share for Synergy, which had market share fall from 75% to 37% between 2018 and 2021.

Figure 74 Market share of LFAS Up and LFAS Down stipulated quantities since 2018



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
BWP	Berwyndale to Wallumbilla Pipeline
Cal	Calendar year
DAA	Day Ahead Auction
DTS	Declared Transmission System
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, gas-powered generator
GSH	Gas Supply Hub
GVA	Gigavolt-amperes
IRSR	Inter-regional settlement residue
JKM	Japan Korea Marker
kV	Kilovolts
kVa	Kilovolt-amperes
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	Megawatts

Abbreviation	Expanded term
MWh	Megawatt hours
NEM	National Electricity Market
NSG	Non-Scheduled Generation
OPEC	Organisation of Petroleum Exporting Countries
PJ	Petajoule
PV	Photovoltaic
QCLNG	Queensland Curtis LNG
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
VPP	Virtual power plant
VRE	Variable renewable energy
WEM	Wholesale Electricity Market