Quarterly Energy Dynamics Q4 2019

Market Insights and WA Market Operations

Important notice

PURPOSE

AEMO has prepared this report to provide energy market participants and governments with information on the market dynamics, trends and outcomes during Q4 2019 (1 October to 31 December 2019). This quarterly report compares results for the quarter against other recent quarters, focusing on Q3 2019 and Q4 2018. 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	10 February 2020	

Executive summary

National Electricity Market (NEM) Q4 2019 highlights

Extreme heat and bushfires trigger need for emergency energy reserves

- During December 2019 (and into January 2020), extreme heat, generator and transmission line outages, and bushfires tested the NEM power system and led to price volatility. In Victoria, reserve levels were tight on several days, with Lack of Reserve[1] (LOR) conditions declared:
  - On 20 December 2019, extreme Melbourne heat and a sharp decline in Victorian wind output led to declaration of LOR conditions in the region for almost two hours.
  - On 30 December 2019, high Melbourne temperatures and transmission line outages caused by bushfires resulted in LOR conditions and high Victorian spot prices (up to $6,443/megawatt hour [MWh]). In response to the tight reserve conditions, AEMO activated contracts under the Reliability and Emergency Reserve Trader (RERT) mechanism, resulting in around $3.5 million in costs.

Wholesale electricity and gas prices fall sharply

- NEM electricity spot prices averaged $72/MWh, which was 19% lower than Q4 2018, representing the lowest prices since Q4 2016. A key driver of this outcome was increased supply from wind farms, solar farms, and gas-powered generation (GPG), with combined grid-scale wind and solar output increasing by 39% compared to Q4 2018.
  - Lower prices occurred despite a high number of coal-fired generator outages, increased underlying demand, and record-breaking high temperatures, which resulted in price volatility in some regions.
  - Although South Australia exhibited a significant level of spot price volatility, with high prices (above $300/MWh) increasing the average by $10.43/MWh, these were cancelled out by the impact of negative prices (which cut $8.95/MWh from the quarter's average).
- From November, ASX futures prices for 2020 and 2021 contracts have shown significant declines, with South Australia's calendar year 2020 (Cal20) swaps reducing by $17/MWh (17%), and New South Wales and Victorian Cal20 swaps declining by $13/MWh (13-15%).
- Wholesale prices in gas markets continued their downward trend, falling by an average of 26% compared to Q4 2018, and reaching their lowest level since the end of 2017. This was driven by lower-priced offers coinciding with low international gas prices, decreased electricity prices, and increased Queensland gas production.
  - International gas prices remained comparatively low, with JKM trading at $8.65/metric million British thermal units (MMBtu), despite the quarter leading into the northern hemisphere winter (which typically results in an increase in international gas prices).

Sunny weather lowers demand; dry conditions limits hydro output

- Although maximum demands were generally higher across the NEM, average operational demands were lower, due to sunnier than average Q4 conditions coupled with a record amount of rooftop photovoltaic (PV) capacity installed in 2019.

[1] For further details on LOR conditions, see: https://www.aemo.com.au/news/aemo-market-notifications-explained

- South Australia set a new all-time minimum demand record of 458 megawatts (MW) at 1330 hrs on 10 November 2019, 141 MW lower than 2018's minimum. During this trading interval, rooftop PV provided an estimated 832 MW of output (64% of South Australia's underlying demand)

- Overall, 2019 was Australia's hottest and driest year on record, resulting in the second lowest annual hydro output in a decade.

Other highlights include:

- Total east coast gas demand for Q4 2019 was 9% higher than in Q4 2018, due to increased demand from GPG and record high liquefied natural gas (LNG) exports from Curtis Island.
- Black coal-fired generation decreased by 1,061 MW on average compared to Q4 2018, reaching its lowest quarterly level since Q4 2016. The decline was due to a combination of coal supply issues (notably at Mt Piper, which fell an average 552 MW), unit outages, and displacement by solar output at Eraring, Gladstone, and Stanwell power stations.
- AEMO continued to issue directions to gas-powered generators in South Australia to maintain system security in the region. The cost of these directions steadily increased during 2019, with Q4 2019 direction costs reaching around $13 million, the highest quarterly level on record.
- Frequency control ancillary services (FCAS) costs were $81 million, representing the second highest quarter on record and the highest quarter in more than a decade. Higher FCAS costs were a function of increased NEM-wide FCAS requirements for system security, as well as two high-price events in South Australia in November.

Western Australia Wholesale Electricity Market (WEM) Q4 highlights

- A new all-time record minimum demand was set at 1230 hrs (AWST) on Sunday, 13 October 2019, when operational demand was 1,159 MW, 14 MW below the previous all-time record.
- The WEM also recorded its highest Q4 demand on record, with demand reaching 3,587 MW at 1730 hrs on 12 December 2019. This record was primarily driven by hot conditions experienced in Perth on the day (39°C), with above average temperatures experienced in Perth throughout December 2020.
- Wind and rooftop PV generation increased by an average 87 MW and 63 MW, respectively. This change in generation mix was most pronounced at 1130 hrs on 30 November 2019, when the South West Interconnected System (SWIS) recorded its highest ever level of variable renewable energy (VRE) penetration. At the time, 51% of underlying system demand was supplied by VRE output. This was a result of mild temperatures, clear skies (resulting in high rooftop PV output) and high wind speeds.
- The average Balancing Price increased by 23% compared to Q4 2018, primarily due to an 8% increase in average operational demand and greater GPG output from higher cost open cycle gas turbines, rather than combined cycle gas turbines.
- For the first time since the WEM commenced in 2006, the wholesale electricity price cleared at the Minimum STEM Price, during three Trading Intervals over the weekend of 12-13 October 2019. This outcome was driven by:
  - Record operational demand during this period.
  - High rooftop PV generation, which had an estimated average output of 927 MW during these Trading Intervals.
  - Market Participant bidding behaviour.

Contents

1. NEM market dynamics

1.1 Weather

2019 was Australia's hottest year on record, with annual national mean temperatures 1.52°C above average[2]. Australia also experienced its driest year on record, with national average rainfall levels 40% below average. Globally, 2019 was the second hottest year on record after 2016[3].

In Q4 2019, east coast cities recorded higher than average temperatures compared to both Q4 2018 and the 10-year average, with Brisbane and Sydney leading the increase (Figure 1). December was particularly hot (1.4°C above the 10-year average), with the most days on record above 38°C in east coast capital cities, leading to increased cooling requirements (Figure 2, Figure 3). Compared to Q4 2018:

- In Adelaide, a prolonged heatwave in December increased cooling requirements by 47%.
- On average, Melbourne's weather was not remarkable. However, this conceals a pattern of cooler temperatures in October and November, combined with extreme weather in December when several days of temperatures exceeded 40°C.
- Sydney's cooling requirements reduced by 8%, despite higher maximum temperatures. This was due to the higher than average temperatures occurring during the milder months of the quarter (October and November) rather than December.

Figure 1 Hot Q4 in the capital cities

Average maximum temperature variance by capital city – Q4 2019 vs 10-year Q4 average

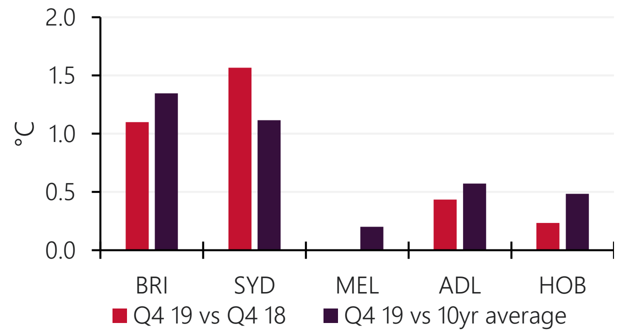
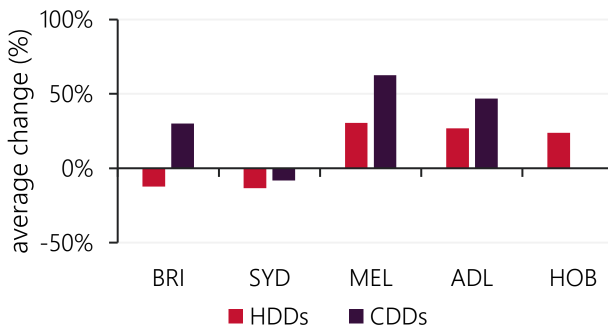


Figure 2 Heating and cooling needs increase

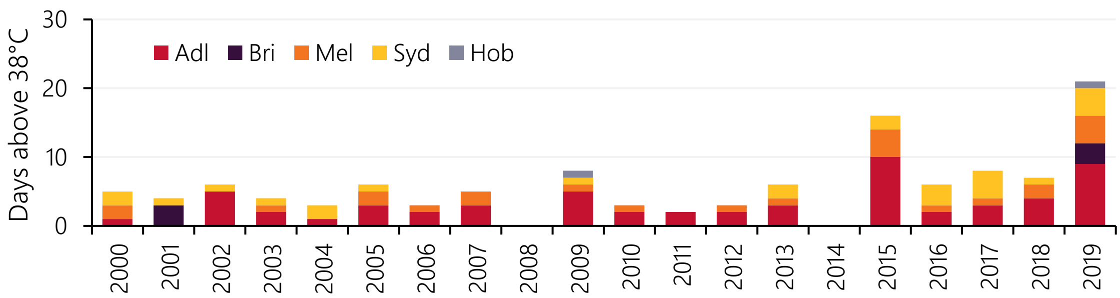
Change in average heating and cooling degree days[4] - Q4 2019 versus Q4 2018



Source: Bureau of Meteorology

Figure 3 Hot weather in December 2019

Number of days above 38°C by capital city – December



[2] Bureau of Meteorology 2019, Annual climate statement 2019

[3] NASA 2020, NASA, NOAA analyses reveal 2019 second warmest year on record

[4] A "heating degree day"(HDD) and "cooling degree day"(CDD) is a measurement used as an indicator of outside temperature levels below and above what is considered a comfortable temperature. HDD value is calculated as max (0, 18 – temperature) whilst CDD value is calculated as max (0, temperature – 24).

1.2 Electricity demand

National Electricity Market (NEM) average operational demand reduced by 90 megawatts (MW) in Q4 2019 compared to Q4 2018, with higher underlying demand more than offset by increased average output from rooftop photovoltaic (PV)[5]. The increase in rooftop PV was a function of new capacity (estimated 1,950 MW in the NEM in 2019[6]) as well as higher solar irradiation (approximately 8% on average in the capitals), which lowered average midday NEM operational demand by almost 1,000 megawatts (MW) (Figure 4).

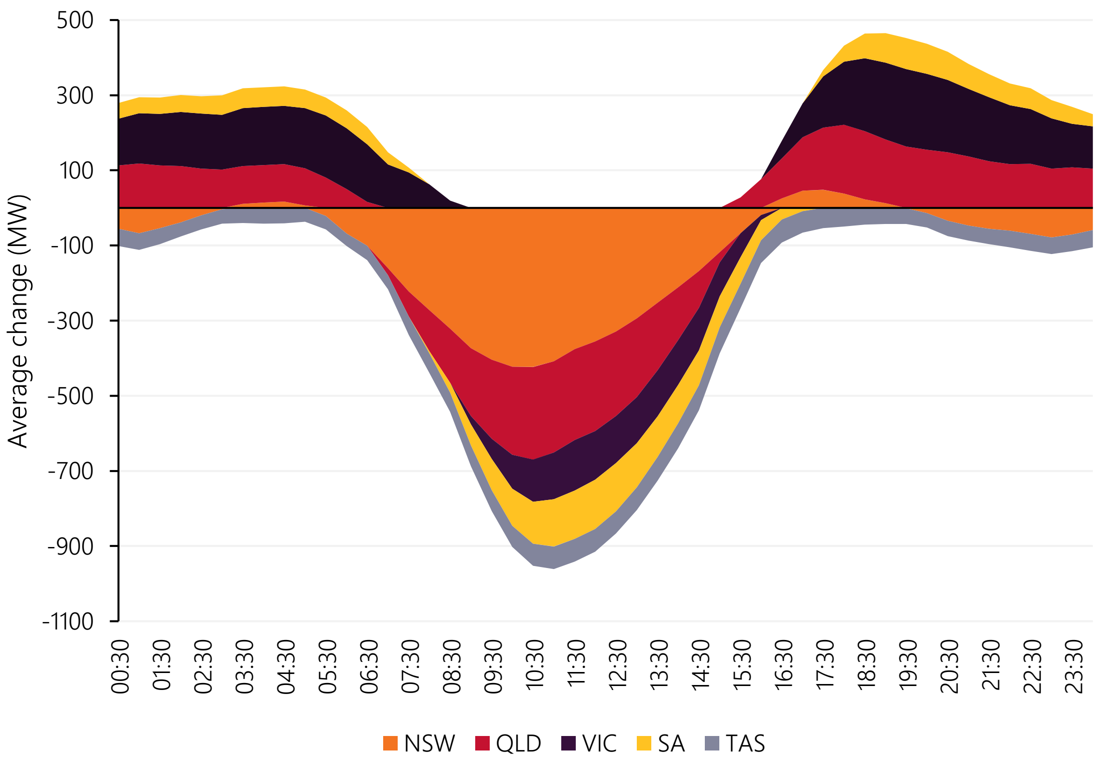
This was, however, offset by higher evening and overnight demand in Queensland, Victoria and South Australia due in part to increased heating and cooling loads, as well as small increases in underlying demand (Figure 4).

Compared to Q4 2018, by region:

- **Queensland and South Australia** – average operational demand remained at similar levels to Q4 2018, as increased overnight demand was offset by reduced daytime demand (due to higher output from rooftop PV).
- **New South Wales** – a slight increase in underlying demand was offset by a significant increase in rooftop PV (+147 MW), partly driven by increased solar irradiation (+8% on average in Sydney despite some smoke affected days), reducing average operational demand by 122 MW.
- **Victoria** – increased heating and cooling requirements were offset by additional rooftop PV output (+111 MW), resulting in increased average operational demand (+68 MW).
- **Tasmania** – average operational demand fell by 49 MW, driven by reduced industrial load.

Figure 4 Rooftop PV reduces daytime demand while heating and cooling loads drives up evening demand

Change in NEM-average operational demand by region and time of day (Q4 2019 versus Q4 2018)



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[5] Note: the estimation methodology for rooftop PV was updated in October 2019, so comparisons between periods should be treated with caution.

[6] Data provided by the Clean Energy Regulator. Total rooftop PV capacity under 100 MW.

Maximum and minimum demand

Table 1 outlines the maximum and minimum demands which occurred in Q4 2019, and the regional records[7].

Table 1 Maximum and minimum operational demand (MW) by region – Q4 2019 vs previous records

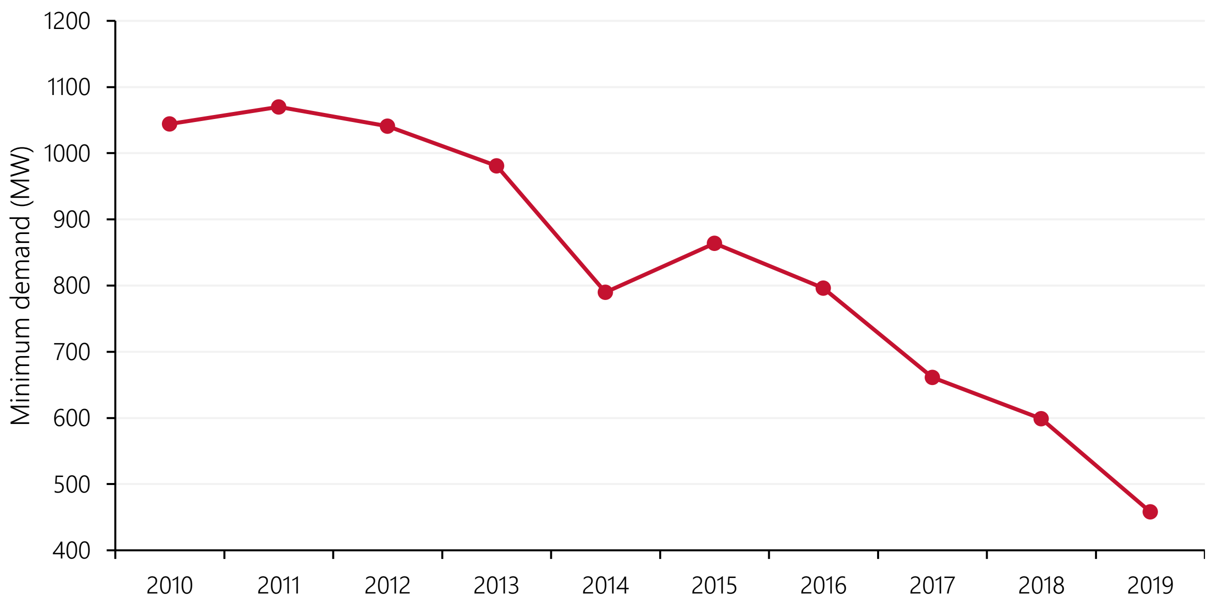
	Queensland		New South Wales		Victoria		South Australia *		Tasmania	
	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min
Q4 2019	9,359	4,520	11,797	5,669	9,249	3,363	3,218	458	1,395	860
All Q4	9,502	2,894	13,620	4,636	9,462	3,217	3,135	599	1,585	552
All-time	10,044	2,894	14,744	4,636	10,576	3,217	3,399	574	1,790	552

* Excluding black system event in South Australia and subsequent market suspension in the region (28 September - 11 October 2016).

The first half of Q4 is typically the lowest demand period in South Australia. In recent years, daytime demand in the region has declined, driven by the rapid uptake of rooftop PV. South Australia's all-time minimum demand record was beaten on three separate days in October and November 2019. On 10 November, a new record of 458 MW was set at 1330 hrs; this was 141 MW lower than 2018's minimum, set on 21 October (Figure 5). During this trading interval, rooftop PV provided an estimated 832 MW of output (64% of underlying demand), and mild conditions meant there was very little heating or cooling load.

Figure 5 New minimum demand records set in South Australia

South Australia minimum demand



South Australia also surpassed its Q4 maximum demand record on 19 December 2019. At 1900 hrs, operational demand reached 3,218 MW, 83 MW higher than Q4 2018. Hot weather across the state was the main driver, with increased cooling requirements boosting demand. On this day, Adelaide's maximum temperature reached 45.2°C, which was the hottest December day on record and led to very high spot prices in the region (Section 1.3.1).

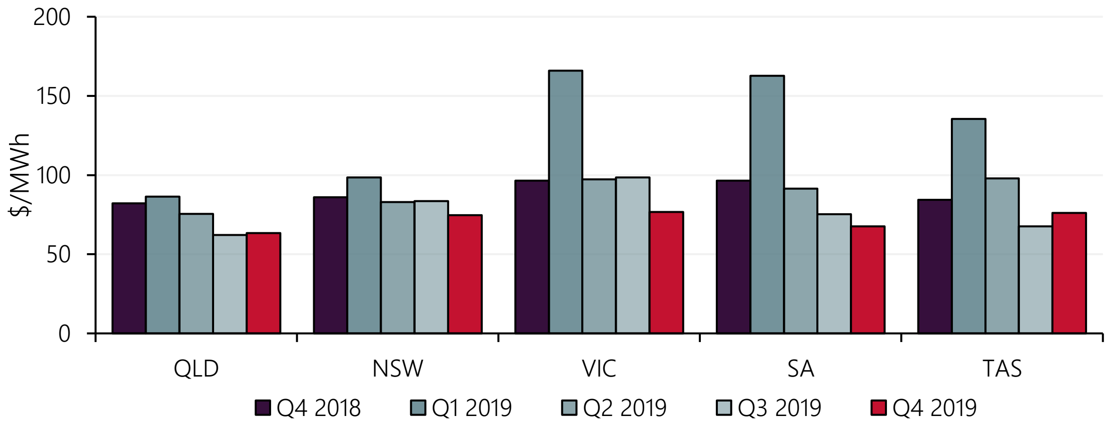
[7] Table records refer to those prior to the commencement of Q4 2019. Instances where the previous record has been broken are shown with red text. The records go back to when the NEM began operation as a wholesale spot market in December 1998. Tasmania joined in May 2005.

1.3 Wholesale electricity prices

NEM spot wholesale electricity prices averaged $72/megawatt hour (MWh), which was 19% lower than Q4 2018, and represented the lowest prices since Q4 2016. Despite price volatility on 19 December (Section 1.3.1), the largest decline occurred in South Australia, averaging $68/MWh in Q4 2019 compared to $96/MWh in Q4 2018, followed by Queensland, at $63/MWh compared to $82/MWh. These overall low Q4 2019 averages occurred despite a high number of coal-fired generator outages, increased underlying demand, and record-breaking high temperatures, which resulted in price volatility in some regions.

Figure 6 Lowest NEM-average wholesale electricity prices since Q4 2016

Average wholesale electricity price by region

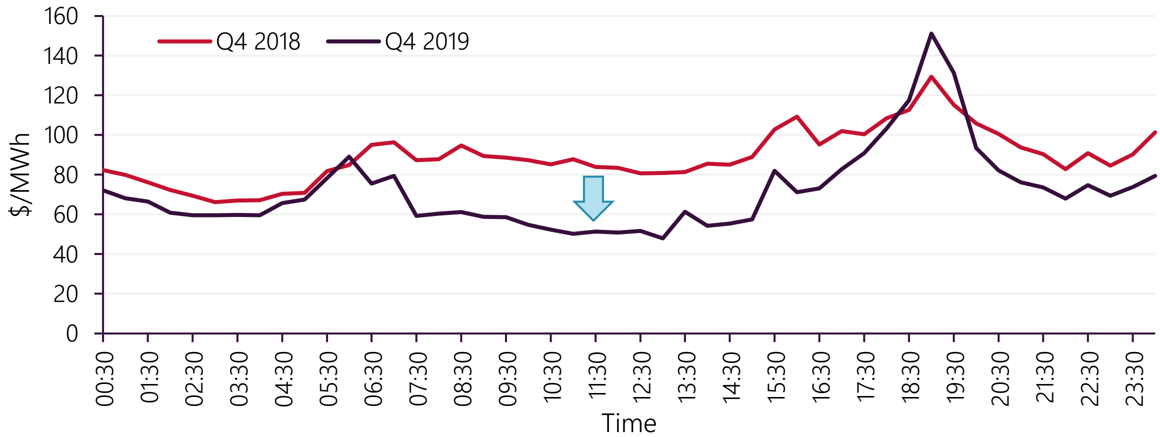


Wholesale electricity price drivers: Q4 2019

Increased wind and solar supply	New wind and grid-scale capacity entering the system in 2019 increased overall output from these generation sources by around 6 TWh (+36%) compared to 2018 (Section 1.4.3).
Elevated GPG output	Participants ran gas-powered generators at elevated levels, largely to cover for outages of coal-fired generators, but also reflecting lower wholesale gas prices (Section 2.2).
Reduced daytime demand	Compared to Q4 2018, increased rooftop PV output substantially reduced average daytime operational demand (see Section 1.2). This, coupled with increased grid-scale solar generation was a key driver of reduced daytime prices across the NEM (Figure 7).

Figure 7 Spot price reductions concentrated in the daytime hours

NEM average spot electricity price by time of day



1.3.1 Wholesale electricity price volatility

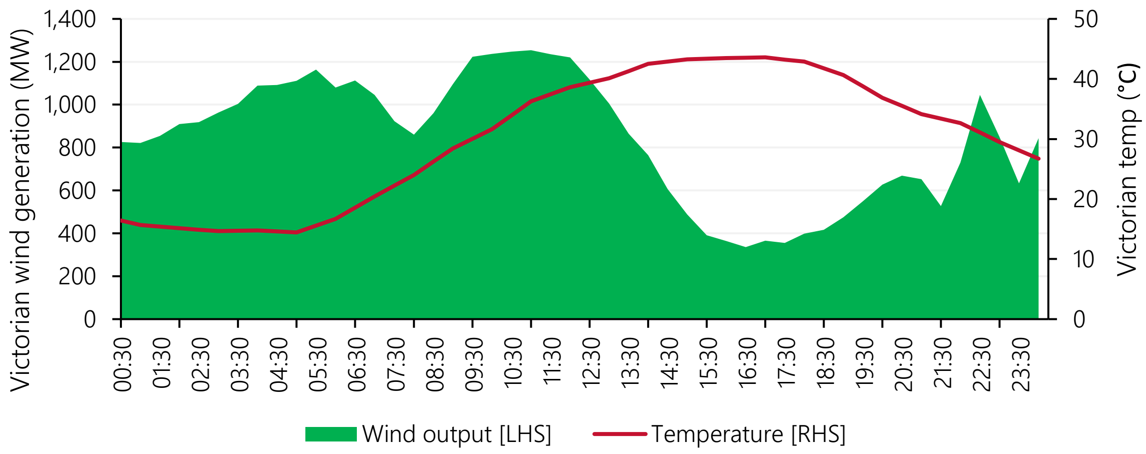
High spot prices

During December (and into January), extreme heat, generator and line outages, and bushfires tested the system and led to high price volatility:

- **19 December 2019** – extreme Adelaide heat (45°C), coupled with low wind output and limits on the Murraylink interconnector, resulted in South Australia's spot price spiking to the market price cap ($14,700/MWh) for one hour.
  - This one event increased South Australia's quarterly-average spot price by $8.10/MWh, cancelling out the quarterly impact of all the negative spot prices in the region.
- **20 December 2019** – extreme heat (45°C in parts of Melbourne) and a sharp decline in Victorian wind output (Figure 8) – some of which was caused by wind farms de-rating due to heat – led to Victorian prices reaching $2,519/MWh and declaration of actual Lack of Reserve 2 (LOR2) conditions in the region for almost two hours.
- **30 December 2019 –** high Melbourne temperatures (maximum of 42.6°C) and line outages caused by bushfires (which reversed flows on the VIC-NSW interconnector) resulted in actual LOR1 conditions, forecast LOR2 conditions, and high Victorian prices (up to $6,443/MWh).
  - In response to the forecast LOR2 conditions, AEMO activated contracts under the RERT mechanism, resulting in around $3.5 million in costs[8].

Figure 8 Loss of Victorian wind output during heat – 20 December 2019

Victorian wind output and temperature – 20 December 2019



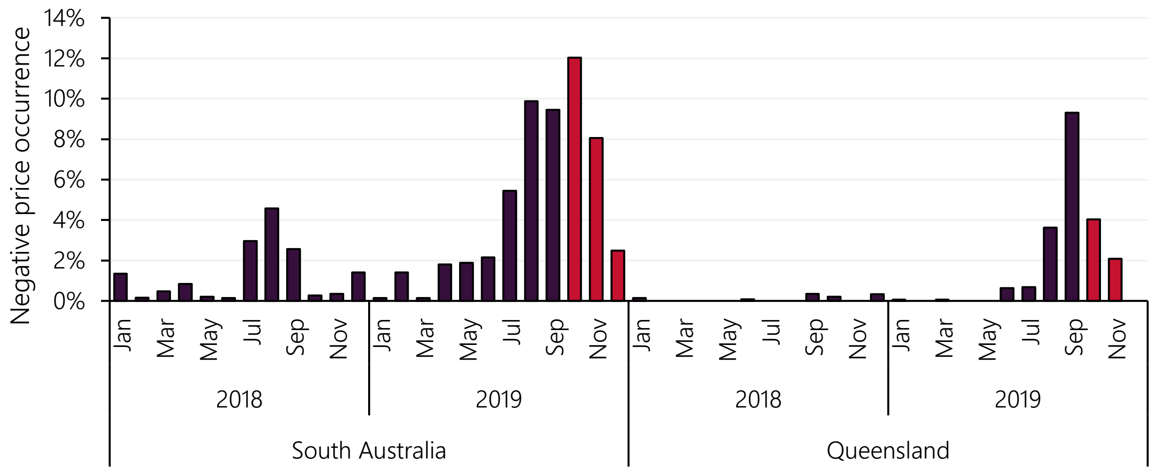
Negative spot prices

During Q4 2019, the occurrence of negative spot prices continued to be confined to South Australia and Queensland. Spot prices were negative 7.5% of the time in South Australia and 2% of the time in Queensland, which was lower than during Q3 2019, but still the second highest quarter on record for both regions (Figure 9). On a monthly basis, there was a declining trend of negative spot prices, as demand in both regions increased due to hot early summer weather.

[8] AEMO 2019, RERT Reporting.

Figure 9 Negative prices remain at near-record levels in South Australia and Queensland

Frequency of negative spot prices in South Australia and Queensland



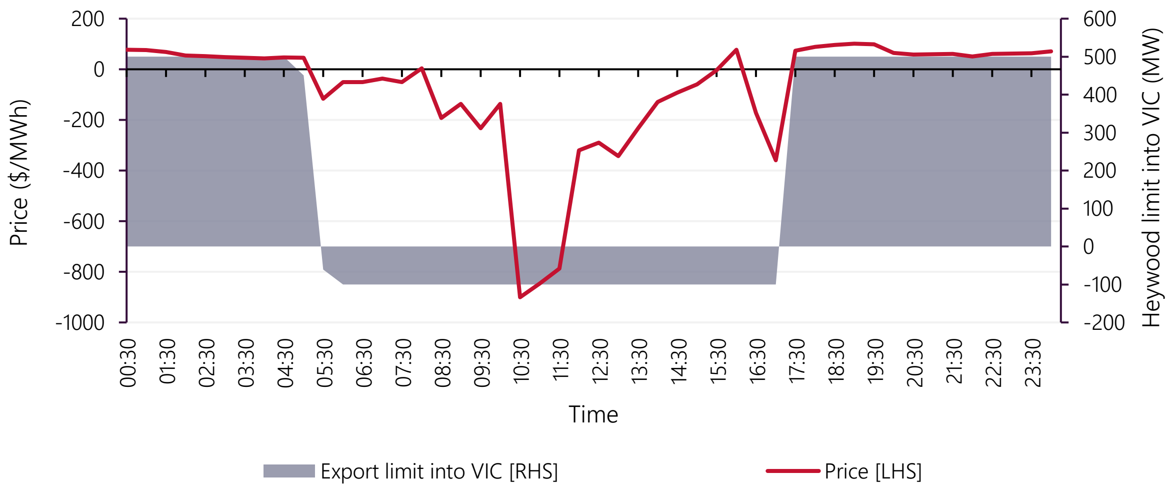
While negative spot prices have been a part of the South Australian market for several years now, typically the highest prevalence of negative spot prices has occurred during Q3 due to seasonal, windy conditions. This year, however, negative spot prices continued into Q4, cutting $9/MWh from South Australia's average price. Drivers of Q4 negative spot prices in South Australia included the coincident occurrence of:

- **Low daytime demand** – rapid uptake of rooftop PV has driven daytime demand reductions in South Australia. In Q4 2019, daytime demand averaged 1,035 MW versus an average of 1,144 MW in Q4 2018.
- **Interconnector constraints** – another factor driving negative spot prices was daytime interconnector constraints. During October and November, South Australia's exports were limited to below 500 MW (down from 700 MW) around 30% of the time, largely due to planned transmission line outages affecting transfers on the Victoria to South Australia interconnectors (Section 1.6).

On 11 November 2019, interconnector constraints coupled with low daytime demand led to 11 hours of negative prices and a daily average price of -$81/MWh, South Australia's third lowest-priced day on record (Figure 10).

Figure 10 Daytime transmission line outages in November contribute to negative daytime pricing

South Australian price outcomes and Heywood Interconnector import limit (into Victoria) – 11 November 2019



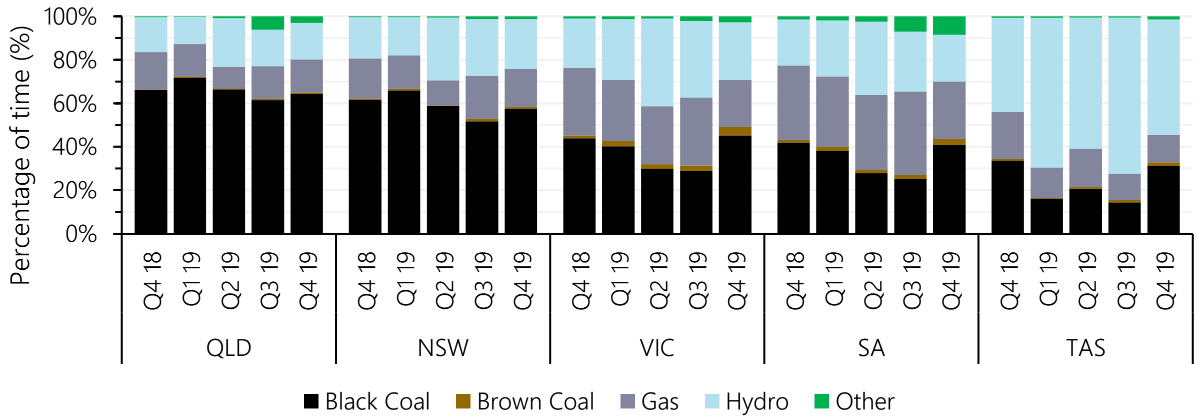
1.3.2 Price-setting dynamics

Figure 11 shows price setting results for Q4 2019 compared to recent quarters. Key outcomes included:

- Increased price setting role for coal, particularly in the southern regions – across the NEM, black coal was the marginal fuel type 48% of the time, up from 36% of the time in Q3 2019.
  - This was due to increased renewable supply (bringing down the price of the marginal price-setting unit), as well as reduced incidence of the VIC-NSW interconnector reaching its capacity limits, which enabled black coal units in New South Wales to set the price in southern regions more frequently (Section 1.6).
- Across the NEM, the three main marginal fuel types (black coal, gas, and hydro) set the price at lower levels than in recent quarters (Figure 12 shows this for Victoria). This was a function of:
  - The large increase in variable renewable energy (VRE) output (Section 1.4.3), which resulted in price setting occurring at a lower-priced point on the supply curve.
  - Some marginal price setting units changing their offers from higher price bands to lower price bands, coinciding with lower domestic gas market prices, and lower international gas and coal prices.
    - For example, between Q4 2018 and Q4 2019, Eraring Power Station (2,880 MW installed capacity) shifted around 500 MW priced at $49-58/MWh to $25-38/MWh, resulting in it setting the price at $46/MWh on average in Q4 2019 (down from $61/MWh in Q4 2018).

Figure 11 Increased price setting role for black coal

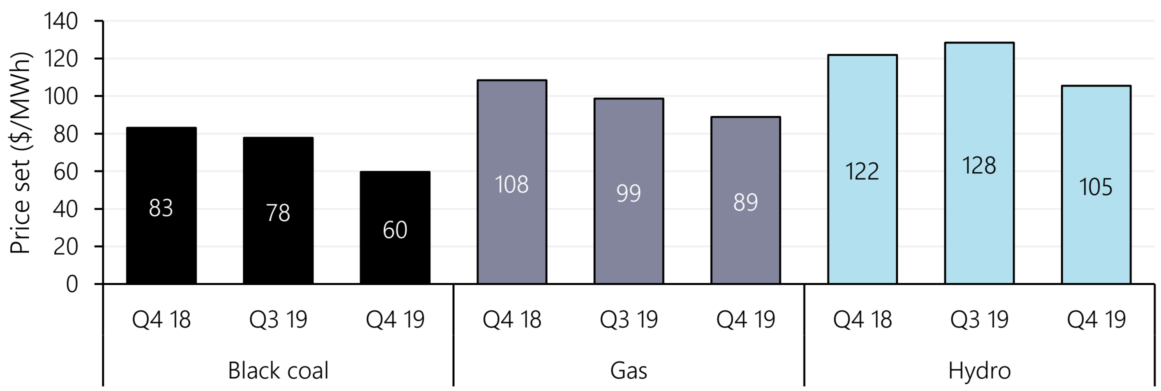
Price-setting by fuel type – Q4 2019 versus prior quarters



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

Figure 12 Coal, gas, and hydro setting Victoria's price at lower levels

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



1.4 Electricity generation

During the quarter, the NEM generation mix was shaped by a combination of thermal coal outages, dry conditions, and high solar irradiation. Figure 13 shows the average change in generation by fuel type compared to Q4 2018, and Figure 14 illustrates the change by time of day.

Quarter highlights include:

- Average black coal-fired generation decreased by 1,061 MW this quarter, reaching its lowest level since Q4 2016. The decline was due to a combination of coal supply issues, unit outages, and displacement by solar output.
- Average grid-scale VRE output continued to rise steadily, with a combined 802 MW increase compared to the same quarter last year, due to continued ramp-up of recently installed capacity, as well as comparatively high solar irradiation.
- Average gas-powered generation (GPG) remained at comparatively high levels, providing cover for coal-fired generator outages.

Figure 13 Large reductions in black coal-fired output

Change in supply – Q4 2019 versus Q4 2018

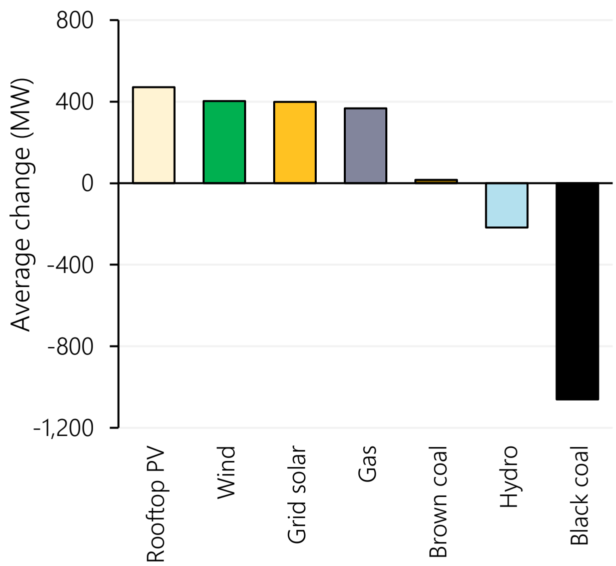
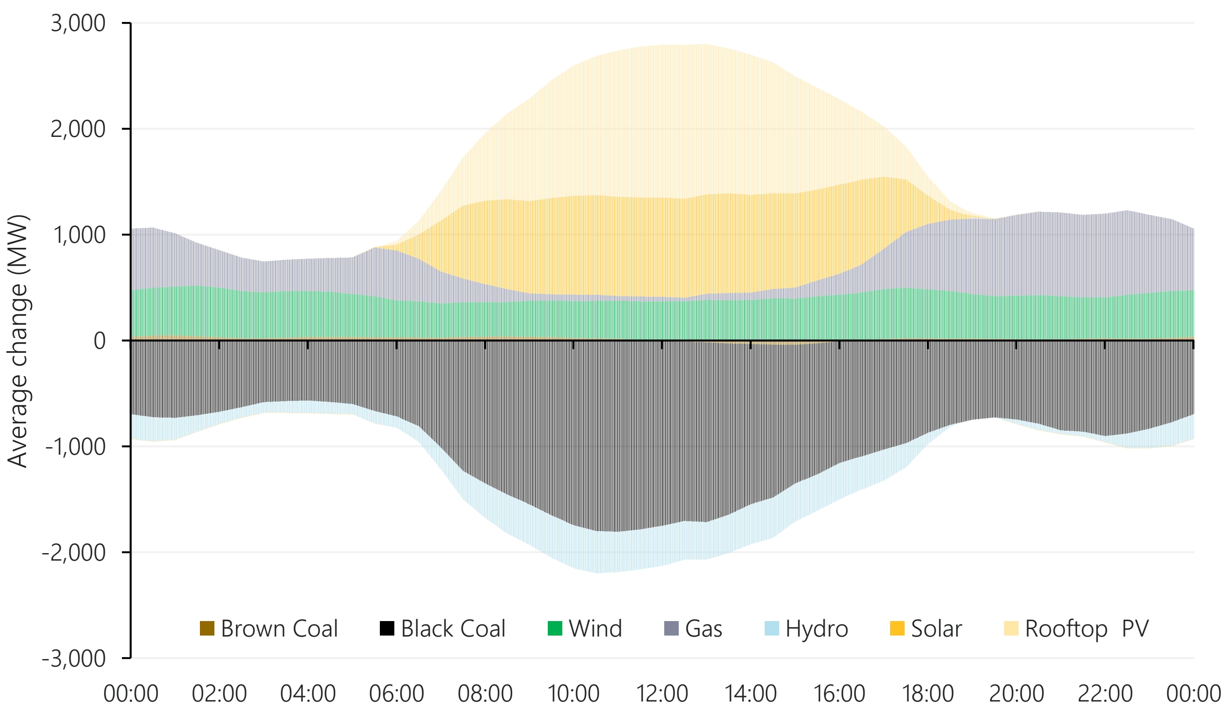


Figure 14 Reduced coal across the day; increased overnight GPG and daytime solar

Change in supply – Q4 2019 versus Q4 2018 by time of day



1.4.1 Coal-fired generation

Black coal fleet

During Q4 2019, average black coal-fired generation was 1,061 MW lower than Q4 2018, with the New South Wales and Queensland fleet decreasing by 692 MW and 369 MW, respectively. Figure 15 shows the average change in black coal-fired generation by power station.

New South Wales' result was driven by decreased output from Mt Piper, Bayswater, and Eraring power stations. By station, compared to Q4 2018:

- Mt Piper continued to be severely affected by coal quality/supply issues. Average output in Q4 2019 was 409 MW, its lowest quarterly generation on record. From mid-November, however, Energy Australia announced an easing of coal supply constraints[9], resulting in higher output in the second half of Q4.
- Reduced generation from AGL's Bayswater (-231 MW on average) was driven mostly by planned outages, with Unit 4 out of service for 71% of the time. The extended outage of Bayswater Unit 4 was part of a major upgrade of the unit, increasing its nameplate capacity from 660 to 685 MW. Lower generation from Bayswater was offset by Liddell, which operated at elevated levels.
- Eraring reduced average output by 231 MW, due to daytime solar displacement (Figure 16) as well as a small increase in outages.

In Queensland, CS Energy's Kogan Creek reduced average output by 280 MW, due to 29 days of unit outage this quarter, a significant increase from none in Q4 2018 (the majority of this was unplanned). At Gladstone and Stanwell power stations, the impact of increased solar penetration was more evident, with average middle of the day output down by 246 MW.

Figure 15 Mt Piper leads black coal output reductions

Change in black coal-fired generation – Q4 2019 versus Q4 2018

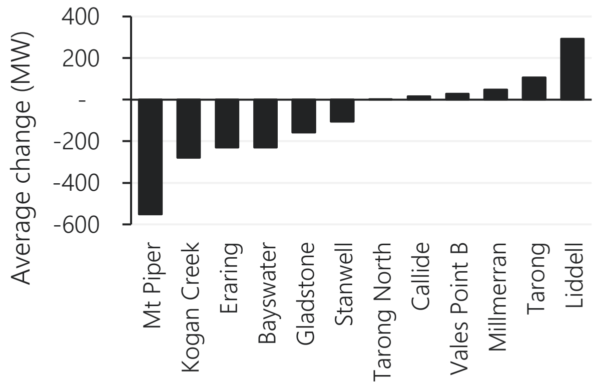
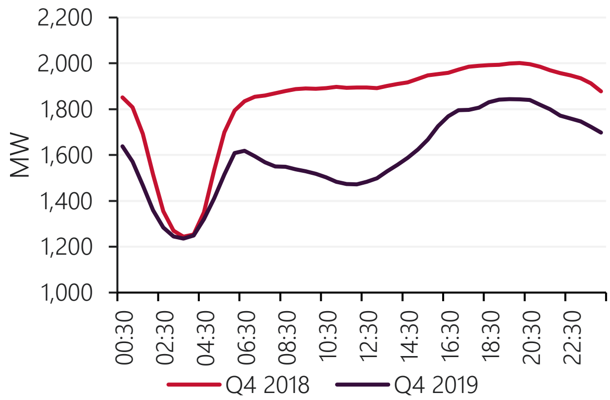


Figure 16 Eraring daytime output displaced by solar

Eraring average generation by time of day – Q4 2019 versus Q4 2018



Brown coal fleet

Average brown coal-fired generation for the quarter was 3,742 MW, a slight increase from Q4 2018 (which also had a high number of outages). AGL's Loy Yang A Unit 2 remained out of service at the end of the year, despite briefly returning to service for four days (24-27 December), resulting in reduced average output of 78 MW (only a small reduction, because LYA4 was on a long outage in Q4 2018). The reduced output from Loy Yang A was, however, offset by increases at Yallourn (+60 MW) and Loy Yang B (+35 MW).

Brown coal-fired generator outages remained high this quarter, with units on outage for 20 days on average, compared to the 10-year average of around 10 days on outage per unit per quarter (LYA2 accounted for 45% of the total).

[9] Energy Australia 2019, Mt Piper establishes coal supplies in time for summer peak

1.4.2 Gas-powered generation

NEM average GPG increased by 367 MW compared to the same quarter last year (Figure 17). This was due to GPG running at elevated levels to cover coal-fired generator outages as well as a reduction in wholesale gas prices. These factors were reflected in GPG market offers – on average, there was around 500 MW more capacity offered at prices below $100/MWh than in Q4 2018. Changes compared to Q4 2018 were:

- Origin Energy's Uranquinty accounted for 50% of the New South Wales increase with its highest Q4 generation since it was commissioned in 2009, while Queensland's Darling Downs accounted for 90% of Queensland's increase. These increases were influenced by outages at Mortlake and Eraring Power Station.
- South Australia's Osborne increased 51 MW mainly due to higher availability than in Q4 2018, while Victoria's Mortlake overall decrease was due to one of its two units (Unit 12) not returning to service until late December after its outage from early July.
  - AGL's new Barker Inlet Power Station 210 MW GPG station commenced generation in Q4 and steadily ramped up over the quarter, averaging 27 MW for the quarter and 64 MW in December.
  - Another factor contributing to higher South Australian GPG was increased prevalence of system strength directions in South Australia (Section 1.7). These directions increased South Australian GPG output by an average of 34 MW (Figure 18).
- Energy Australia's Tallawarra in New South Wales increased average output by 84 MW to cover for reduced output at Mount Piper Power Station, while Newport Power Station in Victoria also increased average output (+92 MW) due to outages at Yallourn Unit 2.

Figure 17 GPG up in the North, mixed in the South

Change in GPG – Q4 2019 versus Q4 2018

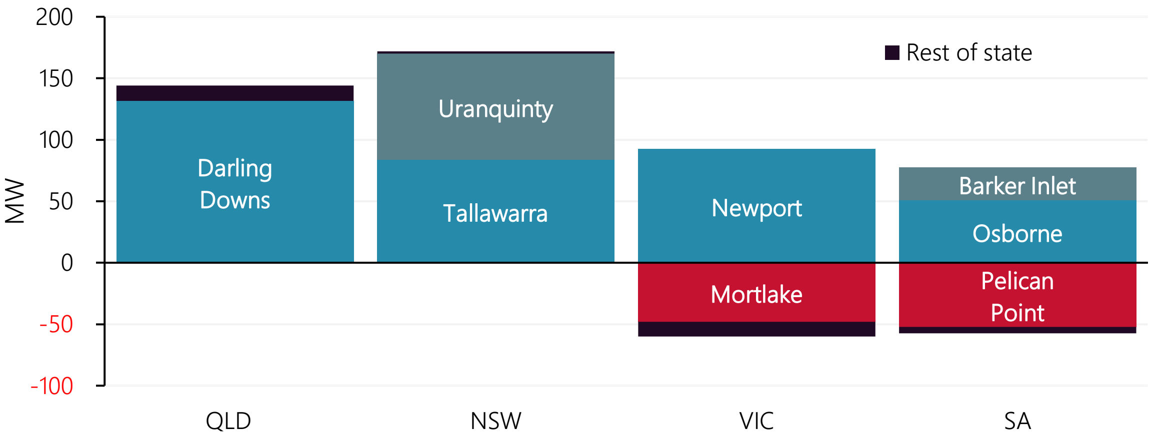
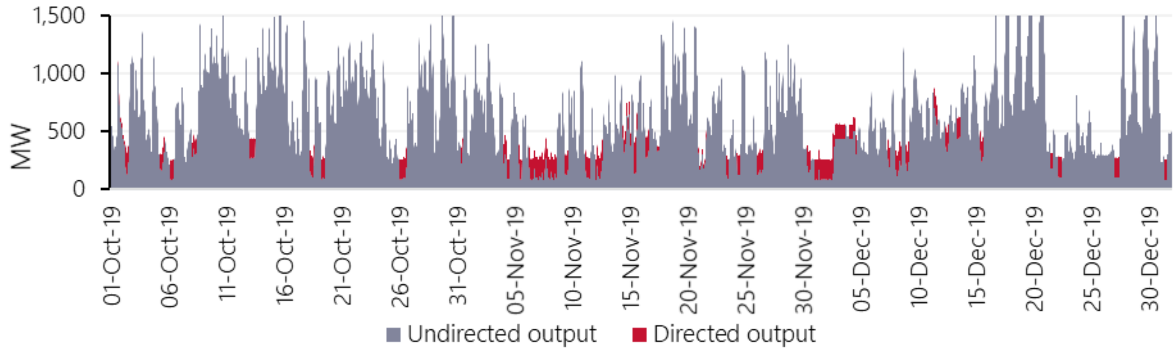


Figure 18 System strength directions contribute to increased GPG

South Australia GPG during Q4 2019 – directed and undirected



1.4.3 Wind and solar

Total VRE output across the NEM has risen steadily across the years, reaching 22 terawatt hours (TWh) by the end of 2019 (Figure 19), representing 11% of the NEM generation mix. Compared to 2018, VRE output increased by 5.9 TWh in 2019, with grid-solar and wind contributing 3.2 TWh and 2.6 TWh respectively. Record VRE generation growth in 2019 is expected to continue into 2020, as the large amount of new capacity currently being accredited is likely to reach full generation by mid-2020[10].

During Q4 2019, average grid-scale VRE generation reached 2,868 MW, representing a 39% increase from last year. VRE generation accounted for 14% of the NEM supply mix compared to 10% in Q4 2018.

Several grid-scale VRE records were once again set in Q4 2019. Trading interval records included:

- Highest grid-scale VRE share of NEM operational demand – NEM VRE output met 32% of NEM operational demand at 1400 hrs on 6 October 2019.
- Highest VRE output on record – NEM VRE output reached 6,396 MW at 1330 hrs on 12 November 2019.
- Highest grid-solar output on record – NEM grid-solar output reached 2,421 MW at 1100 hrs on 4 December 2019.

At 825 MW, average grid-scale solar generation was at a record high this quarter, almost doubling Q4 2018's output. The significant increase was driven by a combination of increased solar irradiation across all states (Figure 20), recently commissioned projects ramping up production, and new capacity additions in New South Wales. Queensland generation accounted for the largest growth, representing 62% of total increase. Growth in grid-scale solar capacity slowed in the second half of 2019: in Q4 2019, only two projects commenced generation (Limondale Solar Farm 2, 29 MW, and Nevertire Solar Farm, 105 MW, both in New South Wales).

Figure 19 Record renewables growth in 2019

Total VRE output by year – 2010 to 2019

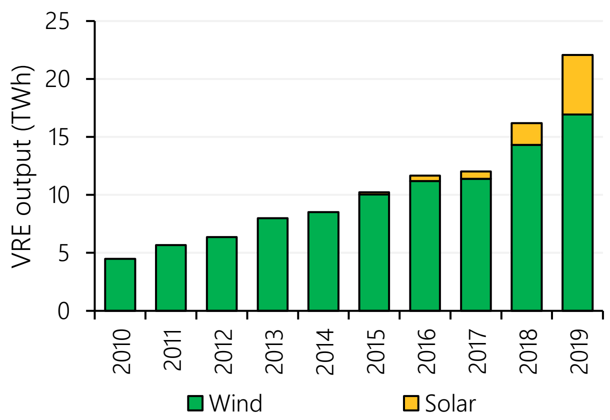
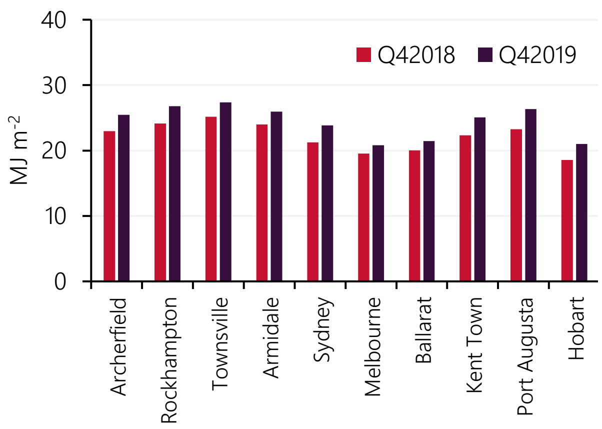


Figure 20 Solar irradiation up across all states

Solar irradiation by weather station – Q4 2019 versus Q4 2018



Wind generation this quarter was up by 403 MW (25%) compared to Q4 2018. This was mostly driven by projects from previous quarter ramping up to full output, as Q4 is not typically a windy quarter.

- Victoria had the largest increase on average (164 MW), with Murra Warra, Yendon, and Crowlands wind farms accounting for 61% of the increase in the state.
- In South Australia, despite newly installed capacity this year, average wind output only increased marginally (41 MW) this quarter, due to increased prevalence of self-curtailment in response to negative spot prices (see Section 1.7).

[10] Clean Energy Regulator 2019, Quarterly Carbon Market Report – September Quarter 2019, at http://www.cleanenergyregulator.gov.au/Infohub/Markets/Pages/Quarterly-Carbon-Market-Reports.aspx.

1.4.4 NEM emissions

In Q4 2019, NEM emissions reached another record low (Figure 21). Total emissions were 33 million tonnes of carbon dioxide equivalent ($MtCO_2$-e), a 5% decrease from Q4 2018, while average emissions intensity was 0.73 tCO_2-e/MWh. Increased renewable output, coupled with lower NEM demand and reduced black-coal generation, continued to drive the downward trend.

Overall NEM emissions in 2019 were also the lowest on record, with absolute emissions at 139 $MtCO_2$-e, representing a 12.5 $MtCO_2$-e reduction from the previous year. Emissions intensity for the year was 0.74 tCO_2-e/MWh, down from 0.80 tCO_2-e/MWh in 2018.

Figure 21 Record low quarterly NEM emissions

Quarterly NEM emissions and emissions intensity (Q4s)

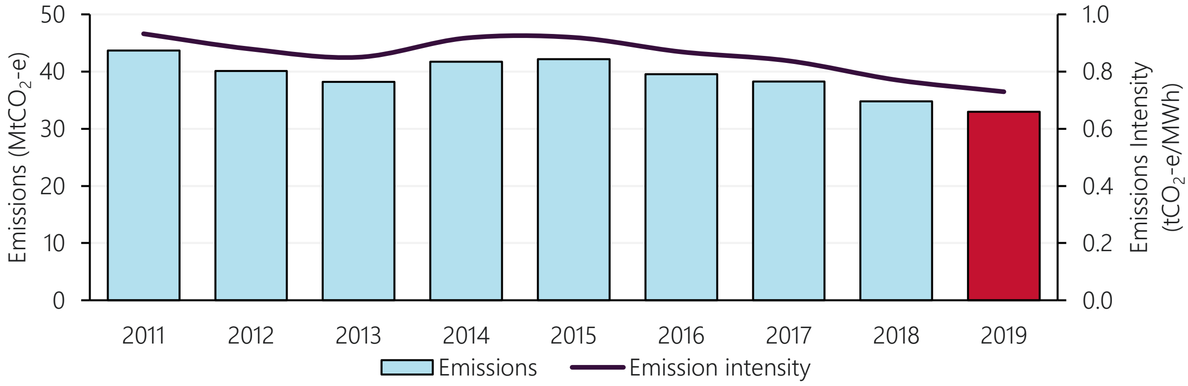
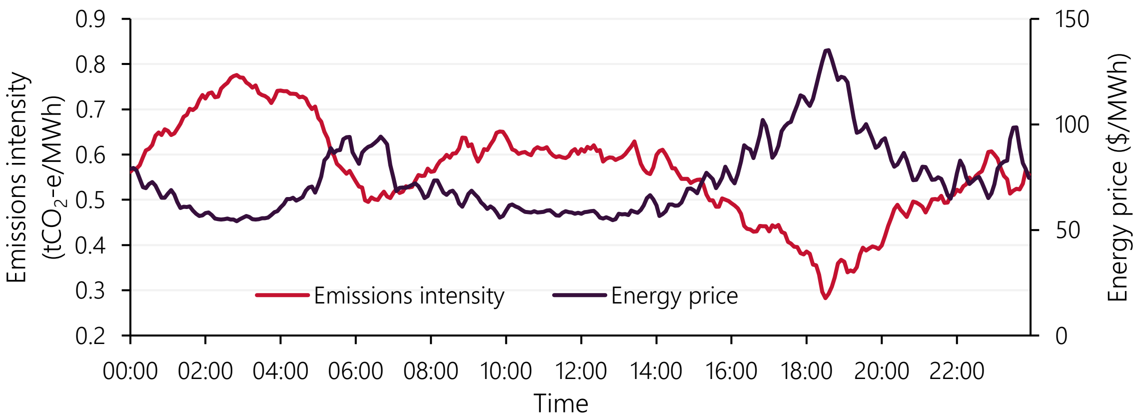


Figure 22 shows the marginal emissions intensity[11] and wholesale electricity price by time of day in Victoria during the quarter, with the two factors inversely correlated. This inverse correlation is currently typical in the NEM and is a function of the different generation types:

- Coal fired-generators typically offer electricity at comparatively lower prices than GPG and hydro, and have a higher emissions intensity. This means when coal-fired generators are marginal, it results in comparatively low spot electricity prices but a high marginal emissions intensity.
- GPG and hydro generators typically offer electricity at comparatively higher prices than other fuel types, and have a lower emissions intensity. This means when these generators are marginal, it typically results in comparatively high spot electricity prices but a low marginal emissions intensity.

Figure 22 Marginal emissions intensity inversely correlated with energy price

Marginal emissions intensity and price by time of day – Q4 2019, Victoria



[11] A marginal emissions intensity is indicative of shifts in supply or load at the margins rather than on average. For example, it demonstrates the impact of changes to emissions that result from storage charging and/or discharging.

1.4.5 Hydro

Dry conditions continued to impact hydro generation across the NEM, with 2019 the driest year on record in Australia[12]. Average hydro generation in Q4 2019 was 218 MW lower than the same period last year (Figure 23). The largest decline occurred in Tasmania (-158 MW), followed by Victoria (-104 MW).

- With Victorian pool prices at their lowest levels since 2017 and continuing dry conditions in Tasmania (Figure 24), Tasmanian hydro generators bid to conserve water rather than to increase exports into Victoria. Between Q4 2018 and Q4 2019, Tasmanian hydro generators shifted marginal capacity from around $60/MWh to around $100/MWh. Hydro Tasmania's water storage levels were steady over the quarter, finishing the year with storage levels at 47%.
- Victoria's quarterly hydro generation fell by 44% compared to Q4 2018, resulting in its fourth lowest Q4 average hydro generation since NEM start. The largest reduction in output was from Dartmouth which has been experiencing low water storage levels[13].
- New South Wales' average hydro generation increased by 61 MW compared to Q4 2018. The increase was predominantly due to increased output from Upper Tumut (from historically low levels in Q4 2018), coinciding with planned black coal-fired generator outages. Comparatively low output from Snowy Hydro over the quarter enabled a slight increase in dam levels ahead of summer (Figure 25).

Figure 23 Low hydro generation in the south

Change in hydro generation by region – Q4 2019 versus Q4 2018

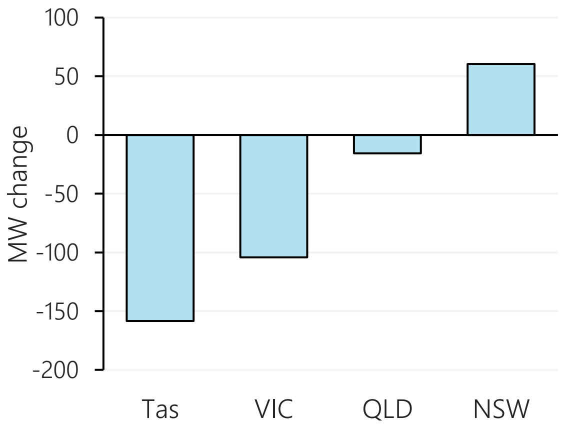


Figure 24 Dry Q4 conditions in Tasmania

Tasmanian rainfall deciles – Q4 2019[14]

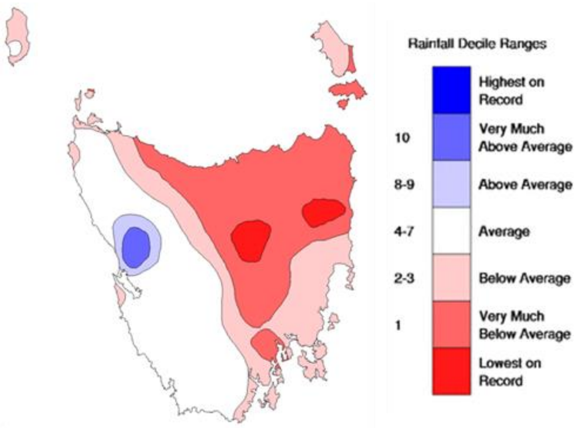
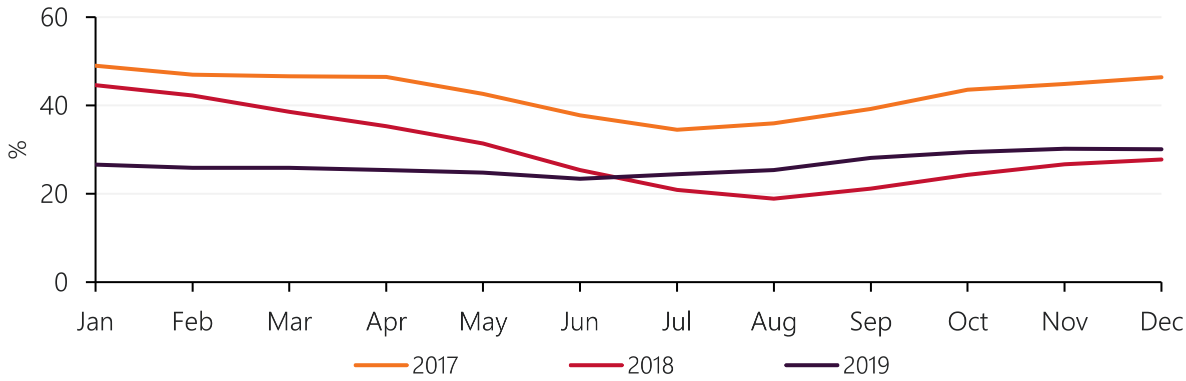


Figure 25 Snowy dam levels increased to 30%

Weekly gross storage levels in percentage



[12] Bureau of Meteorology 2019, Annual climate statement 2019

[13] Goulburn-Murray Water 2019, Storage Levels – Murray storages

[14] Bureau of Meteorology 2019, Tasmanian Rainfall Deciles

1.4.6 Storage

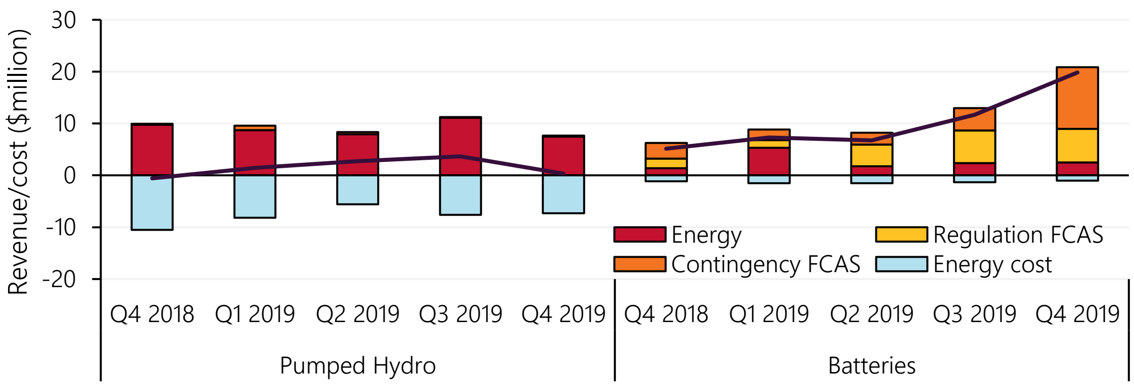
During 2019, market revenue for grid-scale batteries trended upwards, driven by increased returns from Frequency control ancillary services (FCAS) markets (Figure 26). Total Q4 2019 battery revenue of $20 million represents the highest quarter on record and was 70% higher than the previous record. Energy arbitrage revenue increased slightly compared to Q3 2019 (+$0.12 million) but remained a small proportion of battery market revenue (12%).

Drivers of increased FCAS market revenue for batteries included:

- Two very high priced FCAS events in South Australia – islanding of South Australia (or risk of islanding) led to local FCAS requirements and $14 million in FCAS costs. During these events, South Australian batteries provided high levels of FCAS and received an estimated $6.8 million in FCAS revenue.
- Increased market share and higher FCAS prices (see Section 1.5.3). This included Lake Bonney Battery Energy Storage System (BESS) (25 MW/52 MWh), which was active in all eight FCAS markets, commencing operation during the quarter.

Figure 26 Battery revenue reaches record levels in Q4 2019

Revenue sources by storage technology[15]



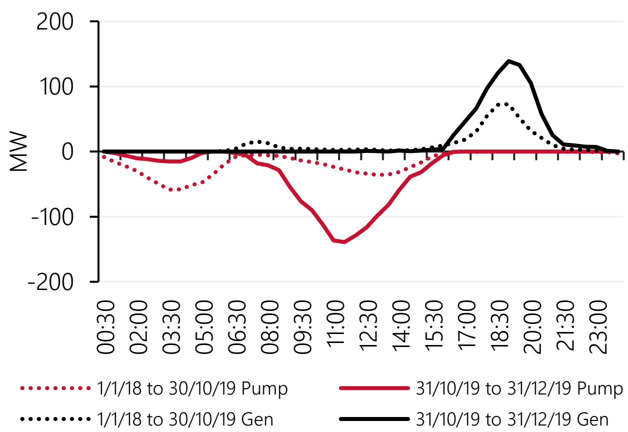
Net revenue for pumped hydro facilities decreased by $3 million compared to Q3 2019. This was driven by a 63% decrease in dispatch of Shoalhaven Pumped Hydro, as well as pumped hydro average energy arbitrage value decreasing from $82/MWh in Q3 2019 to $59/MWh in Q4 2019[16].

On 31 October 2019, ownership of Wivenhoe power station (570 MW) was transferred from CS Energy to CleanCo, a new Queensland state-owned clean energy company. Initial findings since ownership change are:

- Average generation increased from 10 to 18 MW[17].
- Time of pumping has shifted from predominantly overnight to the middle of the day when prices were low (Figure 27).
- Pumping during negative prices increased – in November 2019, Wivenhoe was pumping 83% of the time when Queensland had negative prices, a significant increase from 20% in October 2019.

Figure 27 Shift in timing of operation at Wivenhoe

Wivenhoe pumping and generation by time of day



[15] The calculation of storage arbitrage value for pumped hydro excludes Tumut 3 facility, as its sources of water include both pumped water from Jounama Pondage and inflows from Tumut 1 and Tumut 2 underground power stations and into Talbingo Reservoir.

[16] Storage operating within a portfolio and/or with forward contracts face different incentives for capturing spot electricity revenue than storage operating purely under an energy arbitrage model. The calculation also excludes potential value from the stored water through its sale outside of the energy sector

[17] Average generation utilisation of Wivenhoe was analysed from 1 January 2018 to 31 December 2019.

1.5 Other NEM-related markets

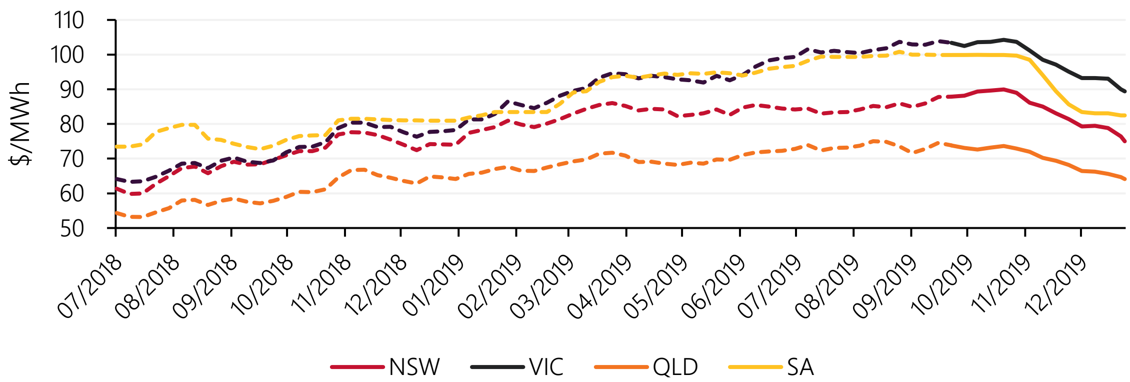
1.5.1 Electricity future markets

ASX electricity futures declined sharply across all regions during Q4 2019 from their record highs during the previous quarter:

- New South Wales' and Victoria's Calendar 2020 (Cal20) swaps declined by $13/MWh over the quarter to finish the year at $75 and $89.50/MWh respectively, while Calendar 2021 swaps decreased $7.50/MWh to $67 and $73.70/MWh.
- South Australia's Cal20 contract reduced by $17/MWh to $82.50/MWh to end the year $7/MWh lower than Victoria, while Queensland fell by $9/MWh to $64/MWh and remained the lowest NEM state future price on the ASX.

Figure 28 ASX Futures decline in Q4 2019

ASX Energy – Cal20 swap prices by region – seven day averages



These price movements have coincided with lower spot electricity and gas prices, increased solar output and expectations of higher generation supply with easing of coal constraints at Mt Piper and the expected return of AGL's Loy Yang A Unit 2.

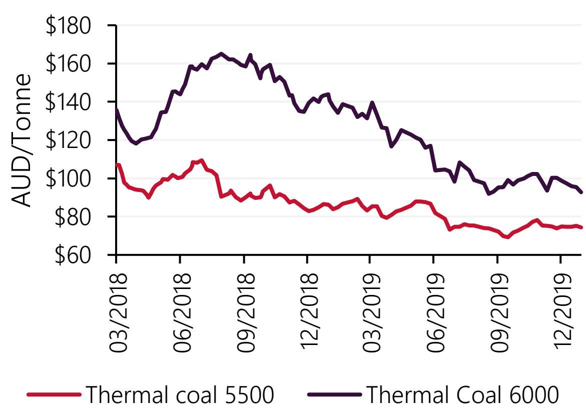
1.5.2 International coal prices

Newcastle thermal coal prices steadied in Q4 2019 at A$98/ton on average, continuing the low-price trend from the previous quarter. Australia maintained its position as the world's second largest exporter of thermal coal after Indonesia in 2019.

China, the world's largest importer of thermal coal increased its own supply with the commissioning in September of the 1,800 kilometre Haoji Railway, which connected the country's coal production provinces in the north with the inland demand centres[18].

Figure 29 Thermal coal prices remain subdued

Newcastle thermal coal prices



[18] Bloomberg New Energy Finance – October 2019.

1.5.3 Frequency control ancillary services

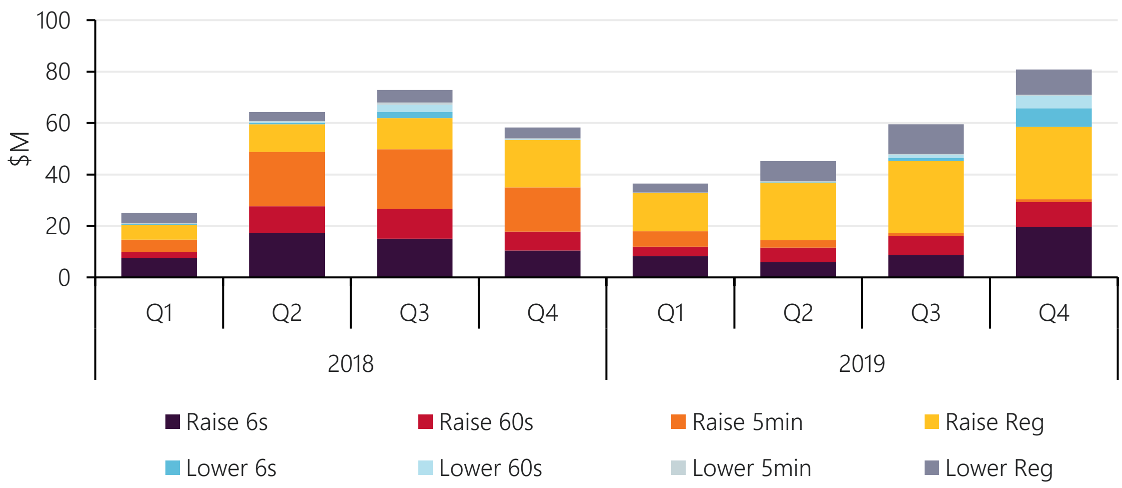
During 2019, FCAS costs rose steadily, mostly driven by increasing FCAS requirements to maintain the system in a stable operating state. In Q4 2019, FCAS costs were $81 million, representing the second highest quarter on record and the highest quarter in more than a decade.

Compared to Q3 2019, Contingency FCAS costs increased by $23 million, while Regulation FCAS costs decreased slightly, but remained at comparatively high levels. Drivers of increased Contingency FCAS costs included:

- Two high priced FCAS events, which contributed $14 million to quarterly costs:
  - On 16 November 2019, a trip of the Heywood Interconnector resulted in South Australia islanding from the rest of the NEM for around five hours. The Heywood trip followed an unexpected trip of the Murraylink Interconnector on the previous day. During the islanding, AEMO invoked local FCAS requirements for South Australia, with scarcity of supply in three FCAS markets resulting in very high FCAS prices.
    - A shortage of Lower 6Sec and Raise6Sec supply led to these markets hitting the price cap ($14,700/MWh) for 100 minutes and 65 minutes, respectively.
    - These high prices resulted in $8 million in South Australian FCAS costs for the day.
  - On 9 November 2019, AEMO invoked local Contingency FCAS requirements for South Australia due to heightened risk of islanding. Similar to the 16 November event, shortage of supply in the Lower 6Sec and Lower 60Sec markets resulted in prices hitting the cap for 85 minutes, and approximately $6 million in FCAS costs for the day.
- Increased FCAS requirements – AEMO recently determined that the changing nature of load means load relief for FCAS should be assumed to be 0.5% (down from 1.5%)[19]. From 12 September 2019 (and into Q4), AEMO began to slowly decrease the assumed level of mainland load relief (reducing by 0.1% per fortnight), which resulted in increased Contingency FCAS requirements in Q4 2019.
- Coal-fired generator outages – planned outages of units at key FCAS-providing coal-fired power stations, including Bayswater and Eraring power stations, reduced lower-priced FCAS supply from these resources.

Figure 30 Second highest quarterly FCAS costs on record

Quarterly FCAS costs by market



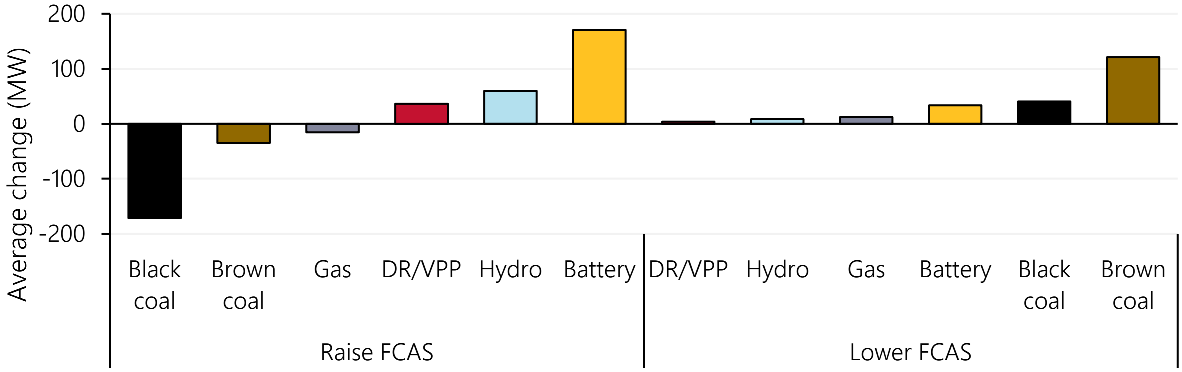
[19] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/2019/Update-on-Contingency-FCAS-Aug-2019.pdf.

During 2019, the price and cost impact of increased FCAS requirements were counterbalanced by increasing supply. Figure 31 shows the change in FCAS supply for Q4 2019 compared to Q4 2018:

- The largest supply increase came from batteries (+204 MW on average), particularly in the higher-priced Raise FCAS markets. In Q4 2019, Lake Bonney BESS commenced operation, providing FCAS supply across all eight FCAS markets. This is in addition to supply from the existing four grid-scale batteries in the NEM which steadily increased during 2019.
- Some hydro generators (in particular, Hydro Tasmania) have provided higher volumes into FCAS markets, increasing average supply by 68 MW, coinciding with rising FCAS prices.

Figure 31 Batteries capture a larger share of FCAS markets

Change in FCAS supply – Q4 2019 versus Q4 2018

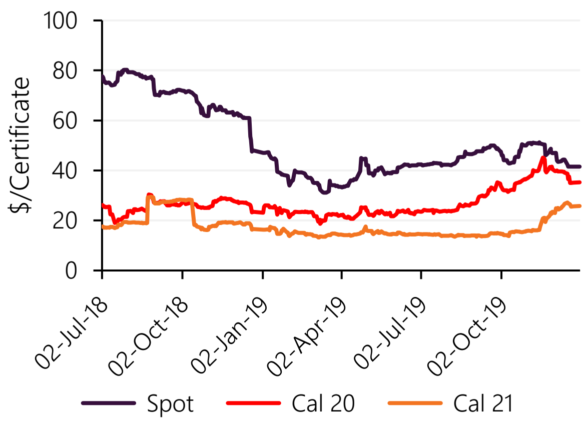


1.5.4 Environmental markets

Spot Large-scale Generation Certificate (LGC) prices increased on average by $1.50/certificate compared to Q3 2019 (Figure 32), reaching a high of $51.1/certificate and exceeding the Q3 high of $50/certificate. Cal20 increased by $11/certificate and peaked at $45/certificate, thereby narrowing the gap to spot LGCs from $19 to $9/certificate compared to Q3 2019.

Figure 32 LGC rally eases end of Q4 2019[20]

LGC spot and forward price over time



The rally from early August to late November for spot LGC and Cal20 prices coincided with:

- The continuation of a low hydro generation year – Calendar 2019 hydro generation was 18% (340 MW) lower than in 2018, which likely resulted in limited LGC creation from hydro generation in 2019.
- Increased curtailment of VRE output associated with negative prices, and network and system security related constraints (see Section 1.7).

The decline from the highs in November towards the end of the year, coincided with:

- Record quarterly VRE output, which will increase LGC supply.
- An announcement by the Clean Energy Regulator in December 2019[21], which clarified that no tax is payable by liable entities who seek a refund of their LGC shortfall charge, including those charges already paid. Other factors being equal, this increases the likelihood of liable entities going into shortfall in 2020 and making up the shortfall in 2021.

[20] Source: Mercari.

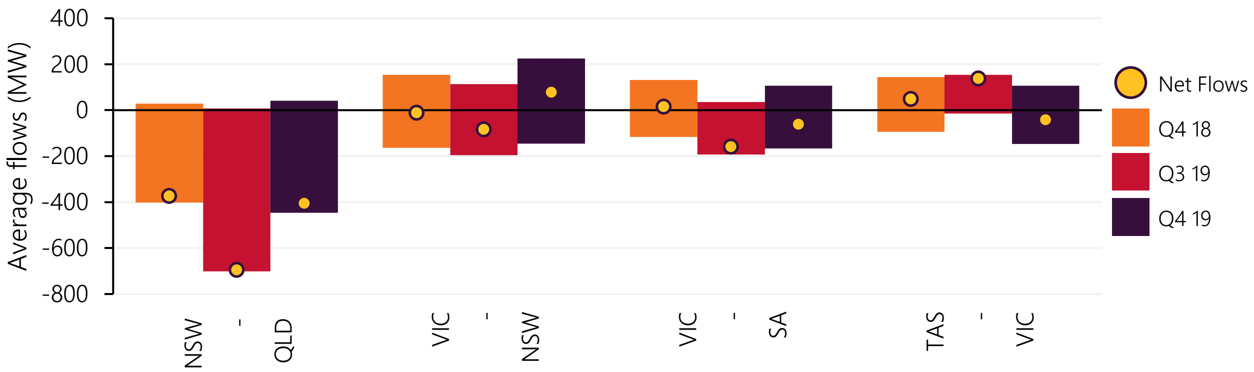
[21] Clean Energy Regulator 2019, Removing the tax on refunds of LGC shortfall charges.

1.6 Inter-regional transfers

In Q4 2019, NEM inter-regional transfers increased on three out of four of the regional interconnectors compared to recent quarters and were 12% higher than in Q4 2018 (Figure 33).

Figure 33 Inter-regional transfers increase across most interconnectors

Quarterly inter-regional transfers



By regional interconnector:

- **Victoria to South Australia** – total transfers increased by 10-15% compared to recent quarters, despite a high amount of planned transmission maintenance, which reduced transfer limits on the interconnectors (in particular, Murraylink). Victoria was a net exporter into South Australia during overnight hours, and a net importer during the daytime hours.
  - The Heywood and Murraylink interconnector were binding at their limits for 19% and 51% of the quarter, respectively, which was four times more frequently than in Q4 2018. This contributed to the comparatively high frequency of negative spot prices in South Australia (Section 1.3.1), as well as increased price separation between Victoria and South Australia.
  - On 18 December 2019, transfer capacity on the Heywood Interconnector for flows from South Australia to Victoria was increased from 500 MW to 550 MW. This was due to commissioning of the over frequency generation scheme, and AEMO completing detailed analysis of power system limits at higher transfers[22].
- **Victoria to New South Wales** – a high number of planned outages of coal-fired generator in New South Wales contributed to a swing in average transfers of 89 MW compared to Q4 2018 (net flow north into New South Wales). Flows north on the VIC-NSW are typically less restricted than flows south[23], so the northerly direction of flows this quarter contributed to:
  - Higher transfers.
  - The interconnector binding at its limits less frequently than in recent quarters (19% of the time in Q4 2019 versus 35%% of the time in Q3 2019), which enabled southern regions' price to be set by units in northern regions more frequently (Section 0).
- **Tasmania to Victoria** – reduced output from Tasmanian hydro generators (influenced by dry conditions and lower Victorian pool prices) reversed flows on the interconnector, with net average transfer of 41 MW into Tasmania.
- **New South Wales to Queensland** – net average transfer of 405 MW into New South Wales was consistent with Q4 2018 results. The impact of a high number of coal-fired generator outages in New South Wales was counterbalance by increased underlying demand in Queensland.

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[22] For further details, see Market Notice 71869.

[23] Average northerly transfer limit of 713 MW compared to southerly transfer limit of 400 MW in 2019.

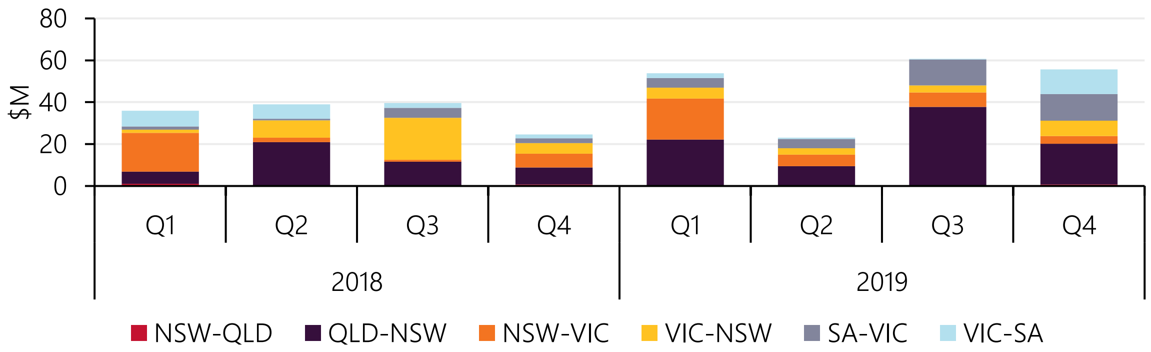
1.6.1 Inter-regional settlement residue

Total inter-regional settlement residue[24] (IRSR) for the quarter increased to $56 million, its highest Q4 value since Q4 2016 and fourth highest quarter since Q1 2016 (Figure 34). The main driver of this result was an increased IRSR value for the Victoria to South Australia compared to the recent quarters, which was due to:

- Increased price separation between Victoria and South Australia – this included extreme price volatility in South Australia on 19 December 2019, which contributed $10 million in IRSR (or 85% of IRSR for Victoria to South Australia flows).
- Negative spot prices in South Australia and Queensland.
  - Negatively priced intervals in South Australia contributed to 68% of the IRSR value for South Australia to Victoria flows.
  - Negatively priced intervals in Queensland contributed to 24% of the IRSR value for Queensland to New South Wales flows.

Figure 34 Highest Q4 IRSR value since 2017

Quarterly positive IRSR value



Prices for units purchased at settlement residue auctions (SRAs) suggest that quarterly inter-regional price separation and/or transfers were higher than expected. In particular, large positive returns occurred for units relating to flows between Victoria and South Australia tranches (Figure 35). The positive returns were a function of increased price separation caused by new renewable supply and declining midday demand in South Australia, high number of outages in Victoria and unexpected price volatility.

Figure 35 Large positive returns for units purchase for exports from Queensland, Victoria and South Australia

SRA tranche analysis – price paid for units versus actual value (Q4 2019)

[24] For further details on IRSR see: AEMO 2018, *Guide to the Settlements Residue Auction.*

1.7 Power system management

Reliability and Emergency Reserve Trader

In December 2019 (and into early January 2020), the combination of extreme heat, generator and transmissions line outages, and bushfires led to several days of LOR conditions, as well as operational challenges. On 30 December 2019, in response to forecast LOR2 conditions (actual or forecast), AEMO activated contracts under the Reliability and Emergency Reserve Trader (RERT) mechanism, resulting in around $3.5 million in costs. Section 1.3.1 provides further details on market and system conditions on these extreme days.

Directions

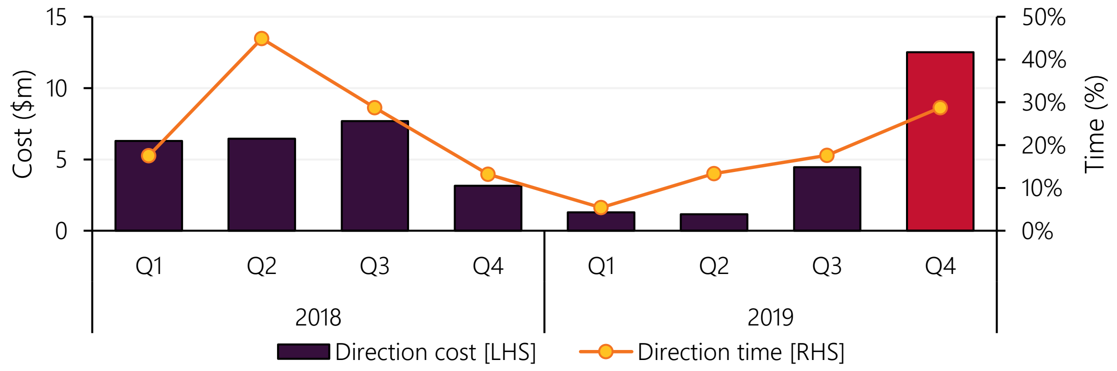
During Q4 2019, AEMO continued to issue directions to gas-powered generators in South Australia to maintain system security in the region. The frequency and cost of these directions steadily increased during 2019, with Q4 2019 direction costs reaching $13 million, the highest quarterly level on record (Figure 36).

The South Australian trend of decreasing daytime demand and low spot prices meant that in October and November, gas-powered generators in the region frequently sought to de-commit from the market for economic reasons and were subsequently directed to remain in the market. Rising direction costs were a function of:

- Increased time on direction – see above.
- The specific unit being directed – a unit with a higher minimum generation level will result in higher direction costs that a unit with a lower minimum generation level.
- Lower spot price during directions – the compensation paid to a directed generator is based on the difference between South Australia's 12-month 90th percentile spot price and the spot price at the time of direction. While the 90th percentile spot price has been relatively flat, spot prices during directions fell to average $16/MWh in Q4 2019 compared to $70/MWh in Q4 2018.

Figure 36 South Australian direction costs reach record quarterly levels

Frequency and cost of system security directions in South Australia



In December 2019, the AEMC introduced a rule change which has the practical effect of removing intervention pricing when units are directed for system security purposes[25]. The requirement to compensate other parties (affected participants and eligible persons) was also removed for intervention events that do not trigger intervention pricing.

[25] AEMC 2019, Application of compensation in relation to AEMO interventions

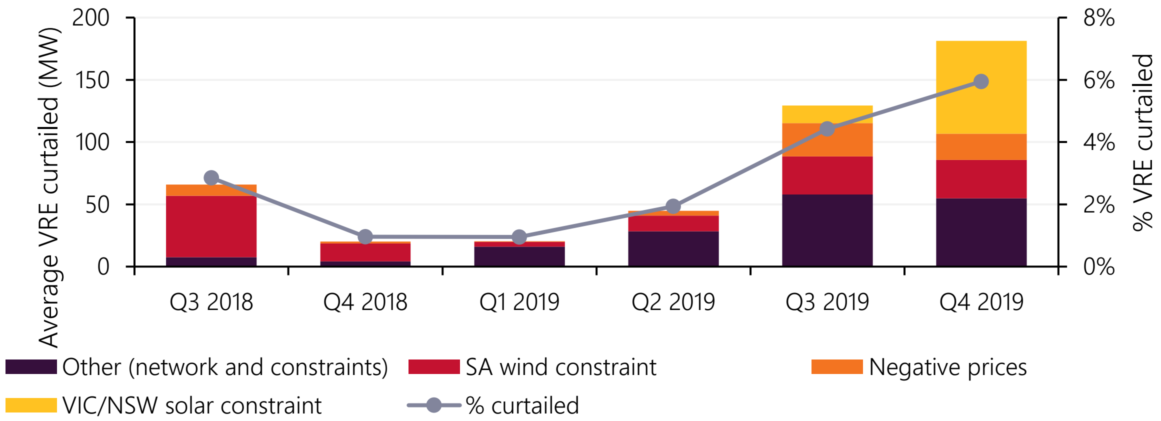
VRE curtailment

During Q4 2019, NEM-wide VRE curtailment increased to 6% of total VRE output, the highest amount on record (Figure 37). Contributors to VRE curtailment included: self-curtailment in response to negative prices, system security constraints on five solar farms (four in Victoria, one in New South Wales), system strength constraints in South Australia, and transmission outages and other network constraints. Most of these factors contributed a similar amount of curtailment as in Q3 2019, but much higher than historical outcomes.

The main increase compared in Q4 2019 to Q3 2019 was the impact of the VIC/NSW solar constraint, with an estimated average curtailment of 75 MW, up from 14 MW in Q3 2019. The increase was due to the constraint being in place for the entire quarter – compared to less than one month in Q3 2019 – as well as sunnier Q4 conditions.

Figure 37 Victoria and New South Wales solar constraint drives increasing VRE curtailment[26]

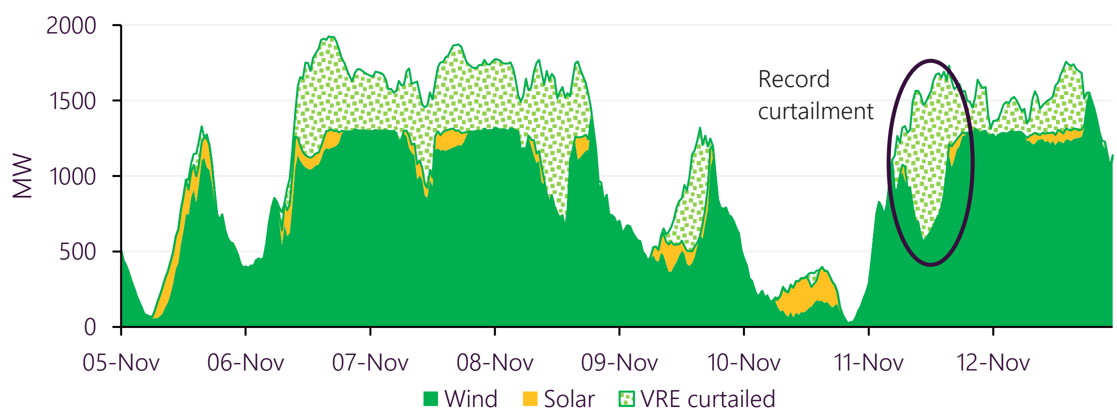
Average NEM VRE curtailed by curtailment type



During the quarter, negative prices contributed to an average 21 MW of curtailment of South Australian VRE output (or average of 313 MW curtailed during negative price events). As previously reported[27], wind and solar farms are increasingly responding to negative spot prices, leading to reduced output over these periods. The self-curtailment from variable renewable energy (VRE) projects during Q4 was largest on days with extended negative spot prices. For example, a record high 968 MW of South Australian VRE output was curtailed at 1300 hrs on 11 November, coinciding with low daytime demand, transmission outages, and a spot price of -$343.33/MWh (Figure 38).

Figure 38 Record amount of South Australian VRE output curtailed on 11 November 2019

South Australian VRE output and curtailment – 5-12 November 2019



[26] Curtailment amount based on combination of market data and AEMO estimates.

[27] For example, AEMO 2019, Quarterly Energy Dynamics – Q2 2019, www.aemo.com.au/-/media/Files/Media_Centre/2019/QED-Q2-2019.pdf.

2. Gas market dynamics

2.1 Gas demand

Total east coast gas demand for Q4 2019 was 9% higher than in Q4 2018 due to increased demand from GPG, higher LNG exports from Curtis Island, and increased residential, commercial and industrial demand (Table 2).

Table 2 Gas demand – quarterly comparison[28]

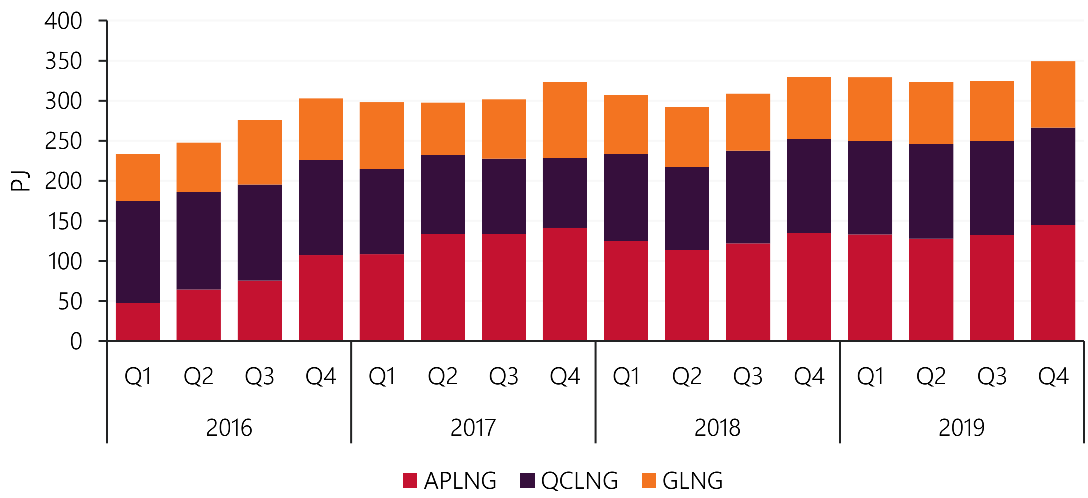
Demand (PJ)	Q4 2019	Q3 2019	Q4 2018	Change from Q4 2018
AEMO Markets *	67.1	112.6	62.7	4.4 (7%)
GPG **	36.1	46.7	23.9	12.2 (51%)
QLD LNG	349.1	324.0	329.6	19.5 (6%)
TOTAL	452.3	483.2	416.2	36.1 (9%)

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

Total pipeline deliveries of 349 PJ flowed to Curtis Island during Q4 2019, an increase of 19.5 PJ compared to Q4 2018, and an increase of 25.1 PJ compared to the previous quarter (Figure 39). This is a new record, surpassing 330 PJ in Q4 2018. A new daily record also occurred on 26 December 2019, with 4,072 TJ flowing to Curtis Island that day. Flows exceeded 4,000 TJ/d on four occasions during Q4 2019; prior to this no day had exceeded 3,935 TJ. Reflecting the record flows, there were 85 LNG cargoes exported during Q4 2019, compared to 78 in Q3 2019.

Figure 39 Record gas flows to Curtis Island for LNG export

Total quarterly pipeline flows to Curtis Island



GPG demand increased significantly in all states except Tasmania, which had minimal changes (Section 1.4.2). Factors for the higher demand included an increase in coal-fired generator outages, low gas market prices and record December temperatures increasing peak NEM demands.

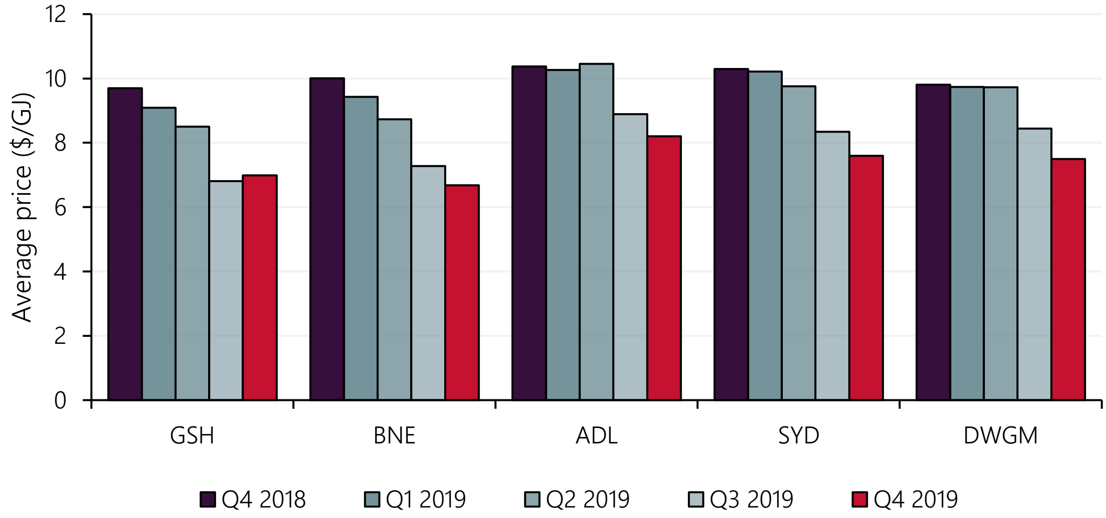
[28] Some entries in this table may have minor variations to numbers published in QED reports, due to changed accounting of several gas-powered generators.

2.2 Wholesale gas prices

Wholesale gas prices continued the downward trend from Q3 2019, falling by an average of 26% compared to Q4 2018 and reaching their lowest levels since the end of 2017 (Figure 40). The largest decreases occurred in Queensland with Brisbane STTM (-33%) and the Gas Supply Hub (GSH, -28%). This was followed by Sydney STTM (-26%), the DWGM (-24%), and Adelaide STTM (-21%).

Figure 40 Gas price decline continues

GSH, DWGM, and STTM quarterly average prices

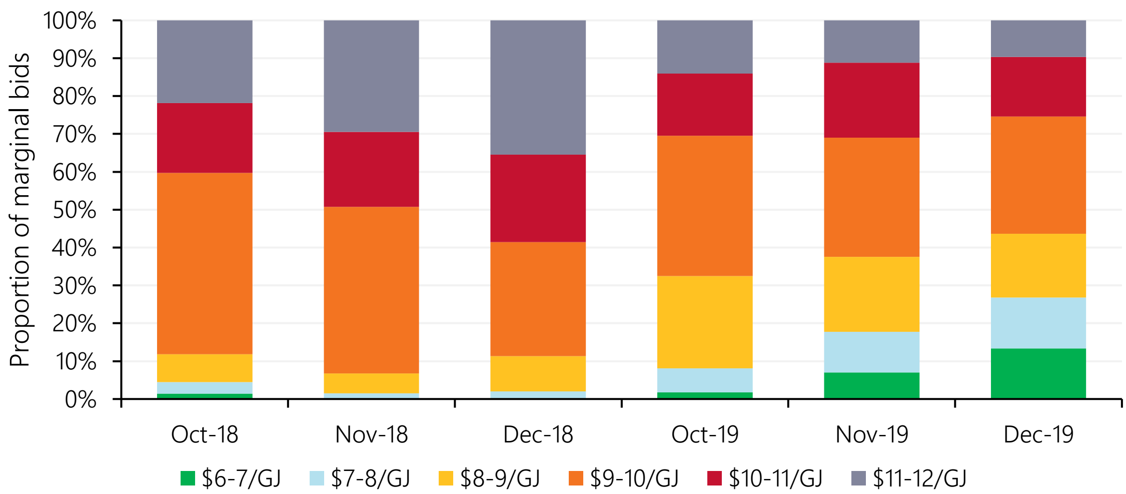


Similar to Q3 2019, price decreases have continued despite a significant increase in demand, with the continuation of more gas being offered at lower prices into the markets (Figure 41). These lower-priced offers have coincided with comparatively low international gas prices (despite approaching the northern hemisphere winter, Section 2.2.1), lower NEM spot and contract prices (Section 1.3) and increased Queensland gas production in 2019 (Section 2.3).

There was also a continuation in competition in bids from Longford producers – during Q4 2019, BHP offered marginally priced gas into the DWGM at $7.90-8.50/GJ, while Esso offers remained at $9.50-$10/GJ.

Figure 41 More marginally-priced gas offered at lower prices

DWGM – proportion of marginal bids by price band



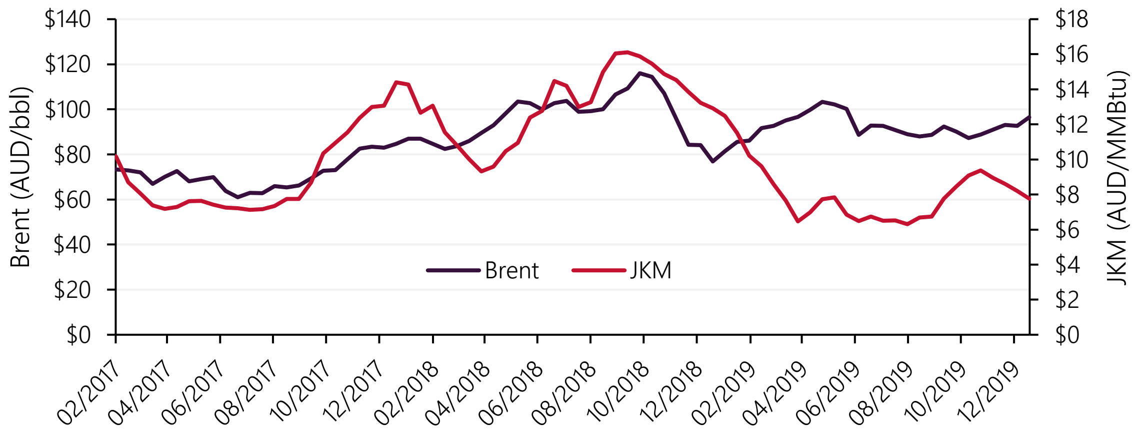
2.2.1 International gas and oil prices

Brent Crude and JKM LNG prices remained relatively flat in Q4 2019 (Figure 42).

Brent Crude oil prices tracked closely to Q3 2019 averages at US$62/barrel (A$91/barrel). Minor price increases occurred towards the end of the quarter with the expected signing of a US-China phase one trade agreement together, with the OPEC+ deal to reduce production by a further 500,000 barrels a day to 1.7 million in 2020[29]. However, futures prices remained comparatively low.

Figure 42 Oil and LNG price separation continues

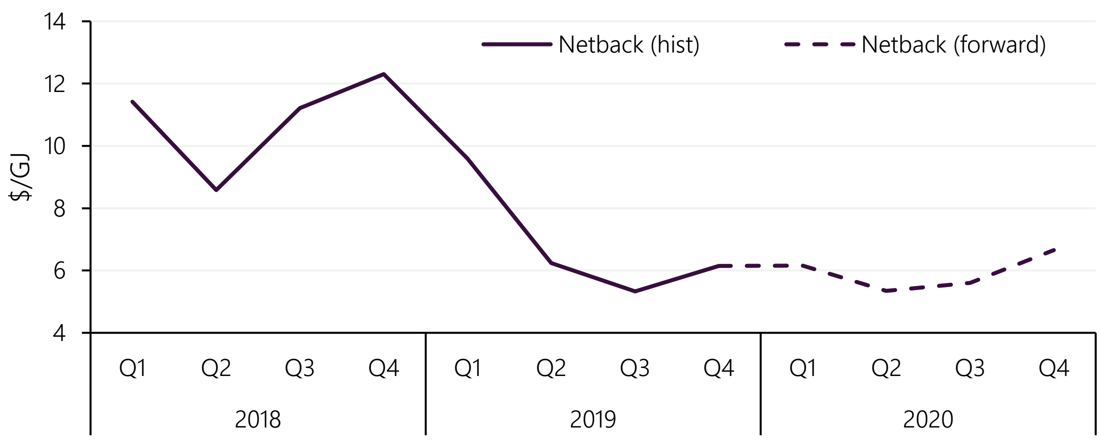
Brent Crude oil and JKM LNG prices in Australian dollars[30]



JKM LNG prices recovered during Q4 2019 as the Northern hemisphere winter approached, averaging A$8.65/MMBtu compared to the low of A$6.90/MMBtu in the previous quarter. However, JKM prices were 39% lower than in Q4 2018, highlighting continued oversupply as new capacity and increased production weigh on prices. These results flowed through to the regularly published ACCC netback price, which has fallen at the same time as domestic prices and is expected to remain low into 2020.

Figure 43 The ACCC netback price has fallen[31]

ACCC netback price historical and forward



[29] https://www.opec.org/opec_web/en/press_room/5797.htm

[30] Source: Bloomberg data in 14 day averages

[31] Source: ACCC 2019, *LNG netback price series*. www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series

2.3 Gas supply

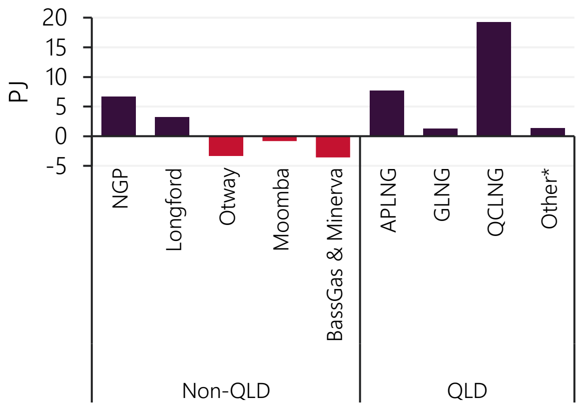
2.3.1 Gas production

Q4 2019 east coast gas production increased by 6% compared to Q4 2018, but decreased compared to Q3 2019 due to seasonality. The reduction compared to Q3 2019 came solely from non-Queensland production, with Queensland production increasing by 5.4 PJ (+1.4%).

As outlined in Table 3, production increases compared to Q4 2018 came mostly from Queensland facilities; Longford was the only facility outside of Queensland to record an increase. In addition, compared to Q4 2018 supply was boosted by 6.6 PJ of production from the Northern Territory, which supplied the Mt Isa region.

Figure 44 Qld production increases to meet demand

Change in east coast gas supply – Q4 2019 versus Q4 2018



* Plant not explicitly stated are grouped as 'Other'

Table 3 Changes in gas production

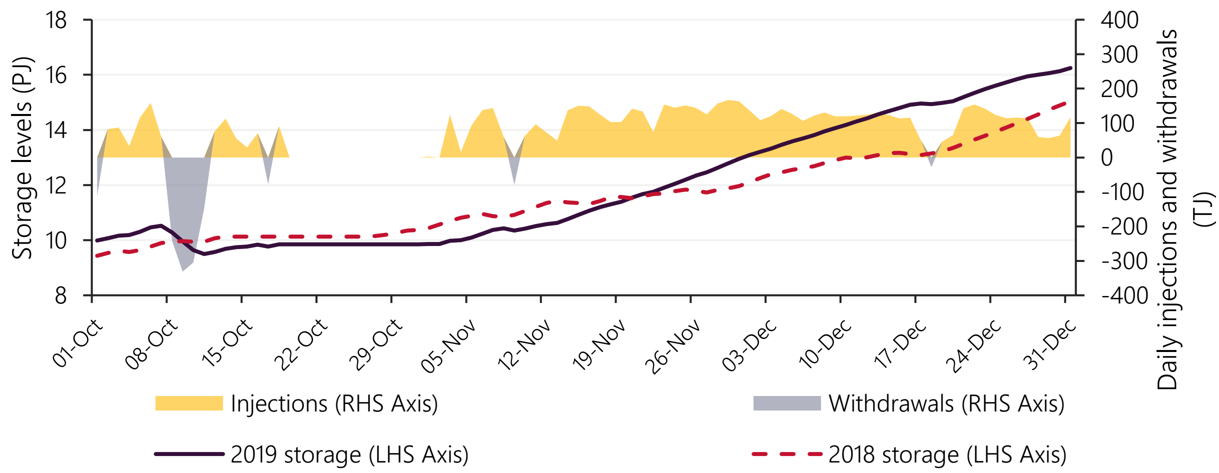
Production increase against Q4 2018	Higher Queensland production (+30.4 PJ), driven by increases at Jordan (+8.5 PJ), Eurombah Creek (+4.2 PJ), Orana (+4 PJ), Bellevue (+3 PJ), Kenya (+2.8 PJ), Windibri (+2 PJ) and Ruby Jo (+1.9 PJ). Higher Longford production in Victoria (+3.2 PJ).
Production decrease against Q4 2018	Reduced production elsewhere outside Queensland; Bass Gas and Minerva production (-3.6 PJ), Otway (-3.3 PJ), Moomba (-0.8 PJ). Minerva ceased production in September 2019.

2.3.2 Gas storage

A gas balance of 16.2 PJ was recorded at the Iona Underground Storage Facility in Victoria at 31 December 2019, 1.2 PJ higher than at the end of 2018 (Figure 45). While storage levels began Q4 2019 lower than in Q4 2018, after 20 November they increased faster than in 2018 due to lower gas exports from Victoria compared to Q4 2018 (Section 2.4). Iona undertook routine seasonal maintenance from 18 to 31 October and was unavailable during that period.

Figure 45 Iona storage levels increase

Iona storage levels



2.4 Pipeline flows

Victorian net gas exports in Q4 2019 reduced by 11.5 PJ compared to Q4 2018, as Victorian production was flat, but more gas was used locally for GPG and to meet cooler weather in the first part of the quarter (Figure 46). During the quarter, Queensland production replaced Victorian exports to the other states, and this saw the continuation of net South West Queensland Pipeline (SWQP) flows to Moomba (Figure 47). This was due to:

- A 6.6 PJ decrease in Carpentaria Gas Pipeline (CGP) flows to the Mt Isa region compared to Q4 2018, displaced by Northern Gas Pipeline (NGP) flows from the Northern Territory.
- Continued higher Queensland production. While LNG demand increased by 19.5 PJ compared to Q4 2018, Queensland production increased by 30.4 PJ, which contributed to:
  - Decreased flows from Victoria to New South Wales compared to Q4 2018, with Victoria importing a net 0.8 PJ via Culcairn, compared to a net export to New South Wales via Culcairn of 5 PJ in Q4 2018. Exports to New South Wales via the Eastern Gas Pipeline decreased by 1.9 PJ.
  - Decreased flows from Victoria to South Australia by 3 PJ compared to Q4 2018, despite a demand increase in that state. Supply was instead met by increased imports into South Australia via the Moomba to Adelaide Pipeline (MAP).
  - Flows from Victoria to Tasmania saw minimal change, increasing slightly (+0.11 PJ).

Figure 46 Victorian gas exports reduce in 2019[32]

Victorian net gas exports to other states

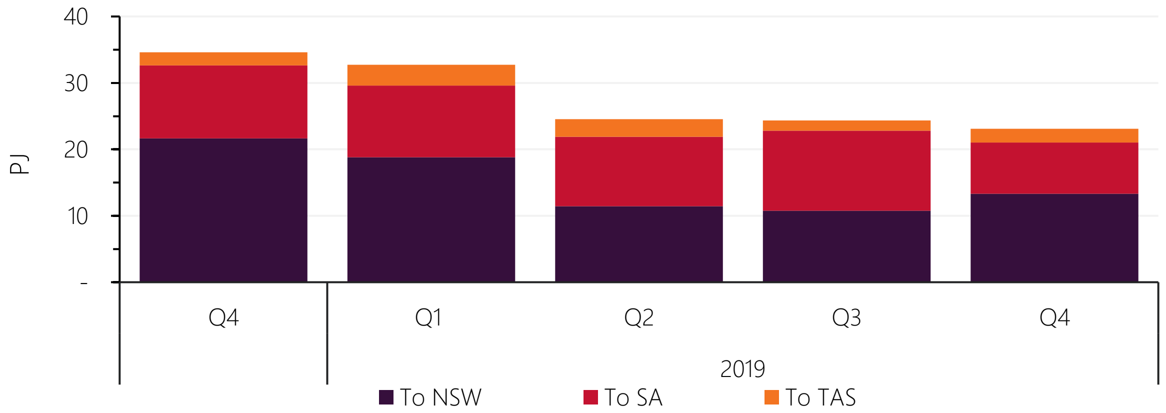
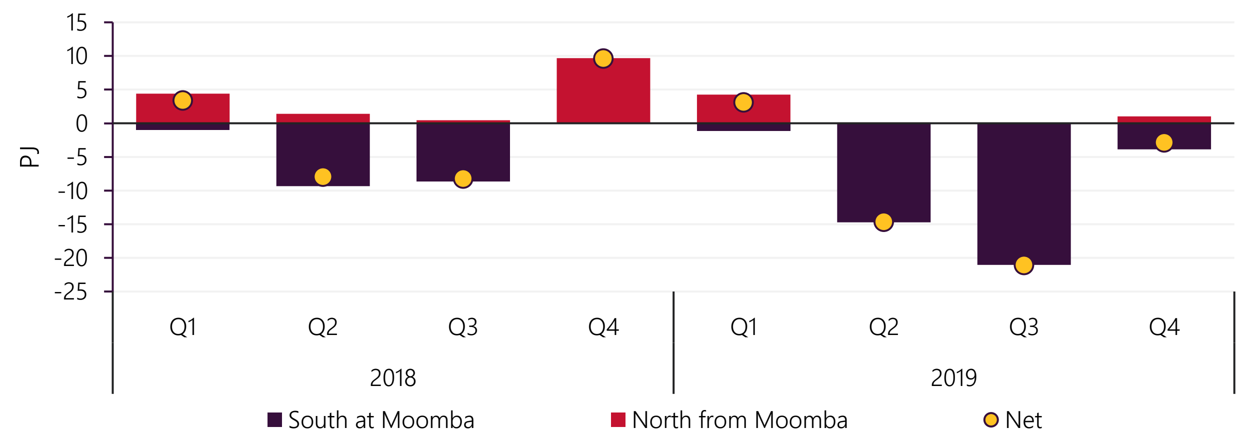


Figure 47 Queensland exporting more gas to other states in 2019

Flows on the South West Queensland Pipeline at Moomba



[32] Chart data may have some minor variations to historical data due to availability of more up-to-date data.

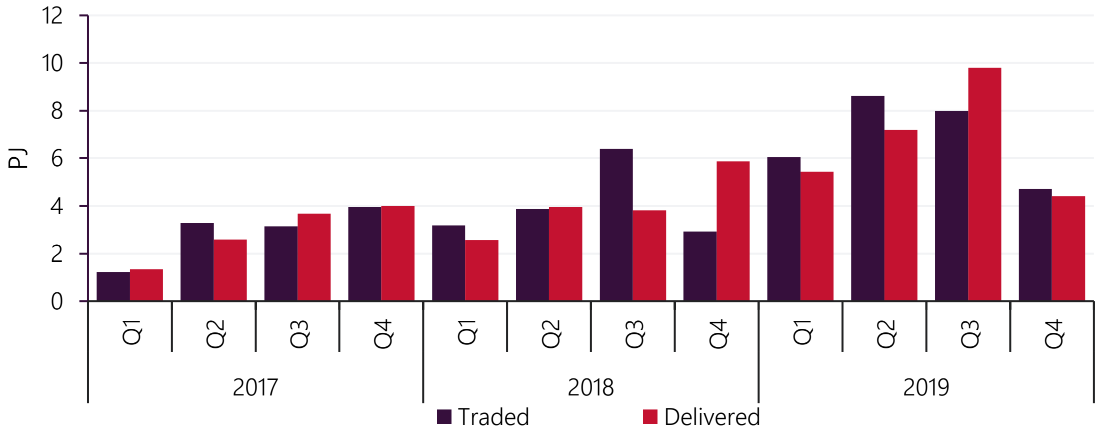
2.5 Gas Supply Hub

In Q4 2019, the GSH experienced its lowest trading volumes for the year for both traded and delivered volume (Figure 48). Compared to Q4 2018, traded volume increased by 1.79 PJ (+61%), however delivered volume decreased by 1.48 PJ (-25%).

2019 was a record volume year for the GSH. Compared to 2018, traded volume increased by 10.97 PJ (+67%), and delivered volume increased by 10.6 PJ (+66%).

Figure 48 Reduction in GSH trades and deliveries[33]

Gas Supply Hub – quarterly trades and deliveries



2.6 Pipeline Capacity Trading and Day Ahead Auction

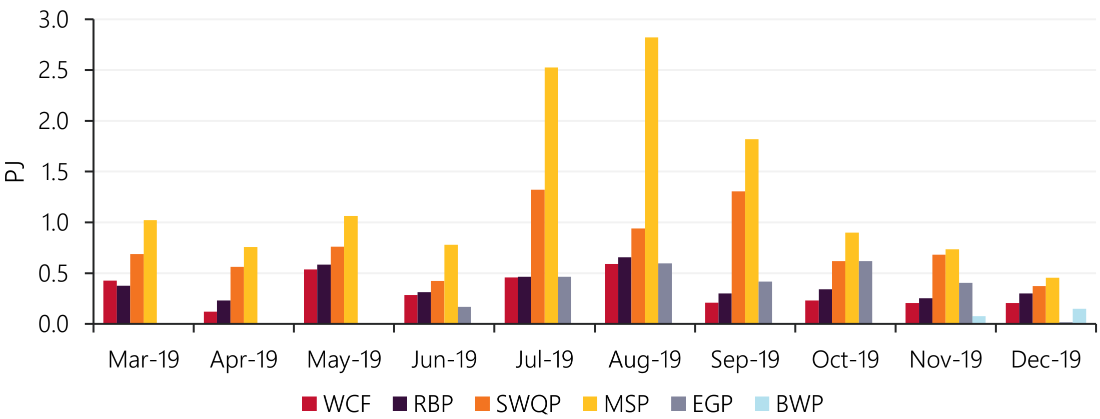
Compared to Q3 2019, in Q4 2019 there was a large decrease in day ahead auction (DAA) utilisation (Figure 49). In particular, the largest decrease in activity occurred on the Moomba to Sydney Pipeline (MSP) and SWQP. This coincided with a decrease in trading volumes on the GSH during Q4 2019.

Average auction clearing prices ranged from $0/GJ on MSP, SWQP, Wallumbilla Compressor (WCF) and Berwyndale to Wallumbilla Pipeline (BWP), $0.02/GJ on EGP and $0.06 on RBP.

While the DAA was utilised every day, no capacity trades have yet occurred on the capacity trading platform (CTP).

Figure 49 Day Ahead Auction volumes reduce in Q4

Day Ahead Auction Results by Month



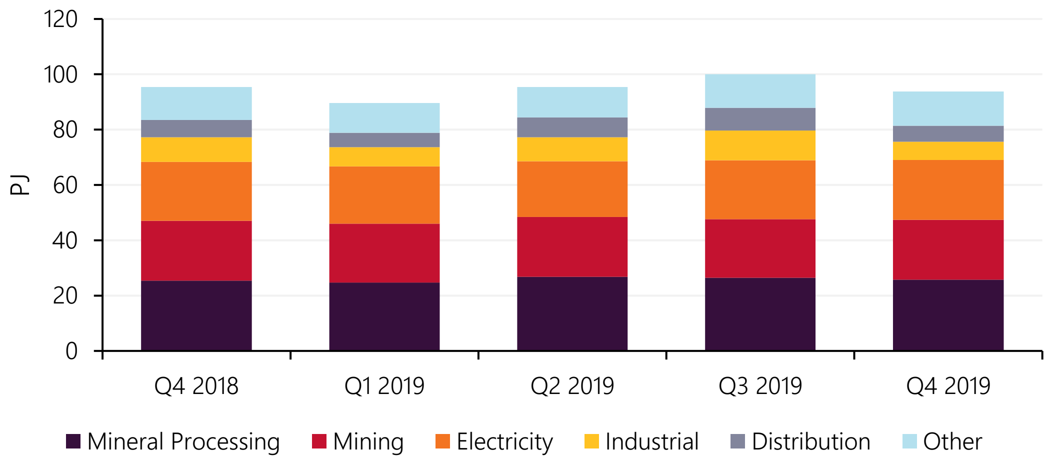
[33] Gas traded on a given day can be for actual physical delivery in future days and months – thus the quantity of trades and deliveries do not always align.

2.7 Gas – Western Australia

In Q4 2019, total Western Australian gas consumption was 94.2 PJ, representing a 6% reduction on Q3 2019 levels (Figure 50). This decrease was largely driven by lower consumption from large industrial users (4 PJ) and reduced gas flows into the distribution network (2.4 PJ). The decrease from large industrial users was largely driven by a 4 PJ reduction at the Yara Pilbara Liquid Ammonia Plant. Compared to Q4 2018, total gas consumption was stable.

Figure 50 Reduced industrial demand leads to lower Western Australia gas consumption

Western Australia quarterly gas consumption by sector

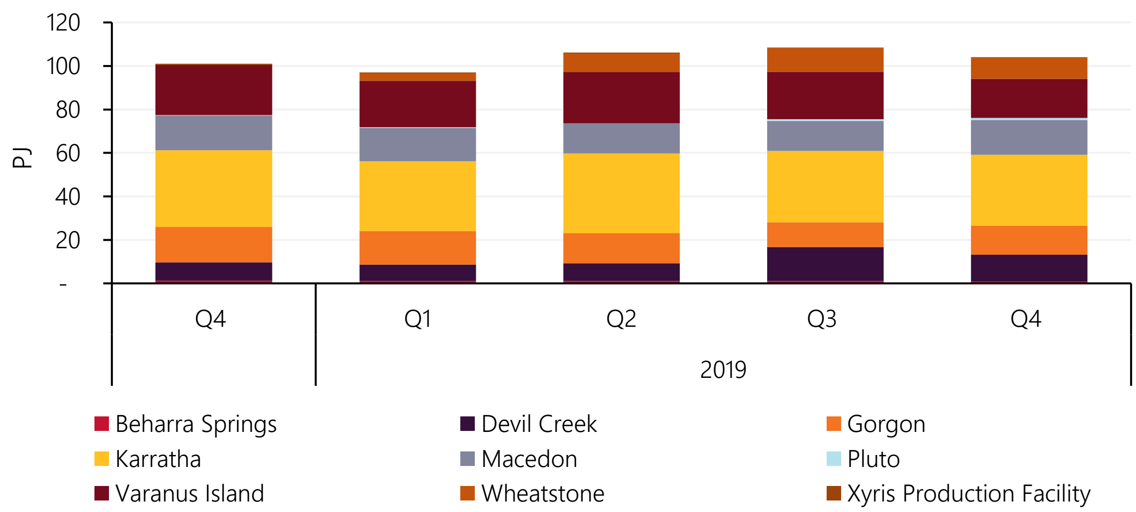


With gas demand reducing, there was a corresponding decrease in supply compared to Q3 2019, with total supply decreasing 4% to 104 PJ. This was largely due to a reduction in production from Devil Creek, Varanus Island and Wheatstone (Figure 51), resulting in Macedon displacing Devil Creek as the third largest gas Production Facility in Western Australia, behind Karratha and Varanus Island (Figure 52).

The slight mismatch between changes in supply and demand during the quarter was partially offset by 1.7 PJ more gas being transferred into Storage Facilities[34] than in Q3 2019.

Figure 51 Western Australia gas supply down 4% compared to Q3 2019

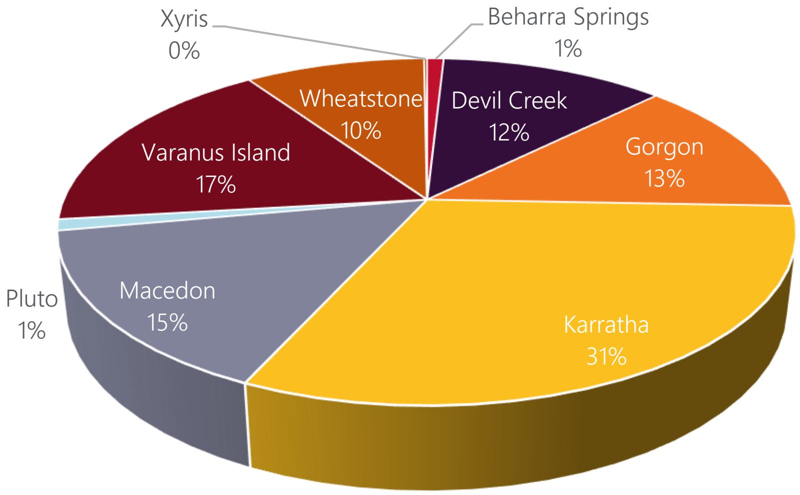
Western Australia quarterly gas production by production facility



[34] Mondarra and Tubridgi Storage Facilities

Figure 52 Macedon overtakes Devil Creek gas production

Western Australia gas supply by production facility – Q4 2019



3. WEM market dynamics

3.1 Electricity demand and weather

Perth temperatures in Q4 2019 were significantly hotter than average, with the average temperature of 28.7°C being 1.4°C higher than the 10-year Q4 average.

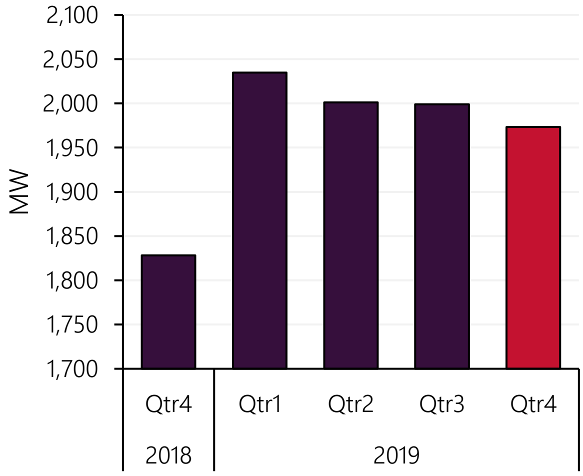
Several notable weather events occurred in Q4 2019:

- November recorded a maximum temperature of 40.4°C, which is the highest November maximum on record[35].
- December 2019 was the hottest December on record, with an average temperature of 25.7°C.
- On 13-15 December 2020, Perth experienced an extended period of high temperatures, with the maximum temperature exceeding 40°C on each day[36].

As a result of increased cooling requirements associated with hot weather, average Wholesale Electricity Market (WEM) operational demand in Q4 2019 increased by 7.9% (145 MW) compared to Q4 2018 (Figure 53).

Figure 53 Hot weather drives WEM demand increase

WEM average operational demand



Maximum and minimum demand

A new all-time record minimum demand[37] was set at 1230 hrs (Australian Western Standard Time [AWST]) on Sunday, 13 October 2019, when operational demand was 1,159 MW, 14 MW below the previous all-time record (which was set at 0330 hrs on Sunday, 15 October 2006, Table 4). At that time, output from rooftop PV was estimated to be 875 MW, meeting 43% of underlying demand.

In addition, the WEM recorded its highest Q4 demand on record, with demand[37] reaching 3,587 MW at 1730 hrs on 12 December 2019. This record was primarily driven by hot conditions experienced in Perth on the day (39°C), with above average temperatures experienced in Perth throughout December 2020.

Table 4 WEM maximum and minimum demand (MW) – Q4 2019 vs records

Maximum demand (MW)			Minimum demand (MW)		
Q4 2019	All-time	All Q4	Q4 2019	All-time	All Q4
3,587	4,006	3,587	1,159	1,159	1,159

[35] http://www.bom.gov.au/climate/current/month/wa/archive/201912.perth.shtml

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

[37] 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.

3.2 Electricity generation

Figure 54 shows the average quarterly change in generation by fuel type compared to Q4 2018; Figure 56 shows the average changes by time of day. These changes highlight the supply-mix transformation occurring in the WEM. Key shifts compared to Q4 2018 included:

- Wind generation increased by 87 MW (47%) on average, largely due to the connection of Badgingarra Wind Farm (130 MW) at the beginning of 2019 and Beros Road Wind Farm (9.9 MW) during Q3 2019.
- Rooftop PV increased by 63 MW on average, with a maximum quarterly output of 994 MW. This trend continues as the installed capacity of rooftop PV in the South West Interconnected System (SWIS) continues to ramp up.
- Coal-fired generation increased by an average of 67 MW (8%), largely driven by higher coal-fired generator availability than in Q4 2018.
- Average GPG slightly decreased (10 MW), however, higher operational demand during the evening peak period (Figure 55) led to higher GPG during these times.

Figure 54 Wind leads the supply increase in the WEM

Average change WEM supply – Q4 2019 versus Q4 2018

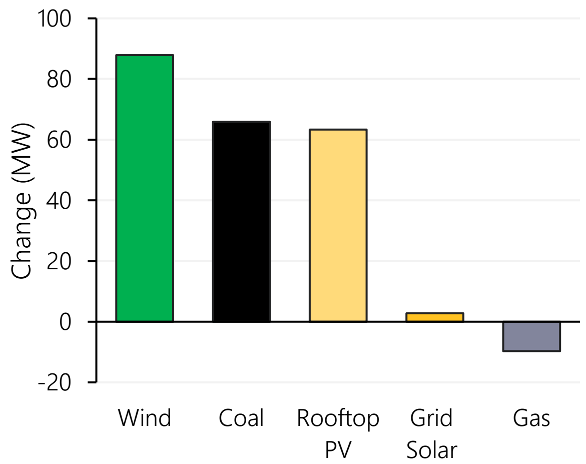


Figure 55 WEM peak demand increases in Q4 2019

WEM average operational demand by time of day

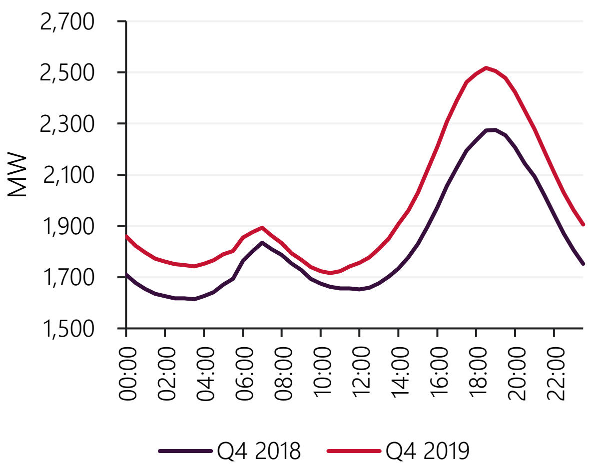
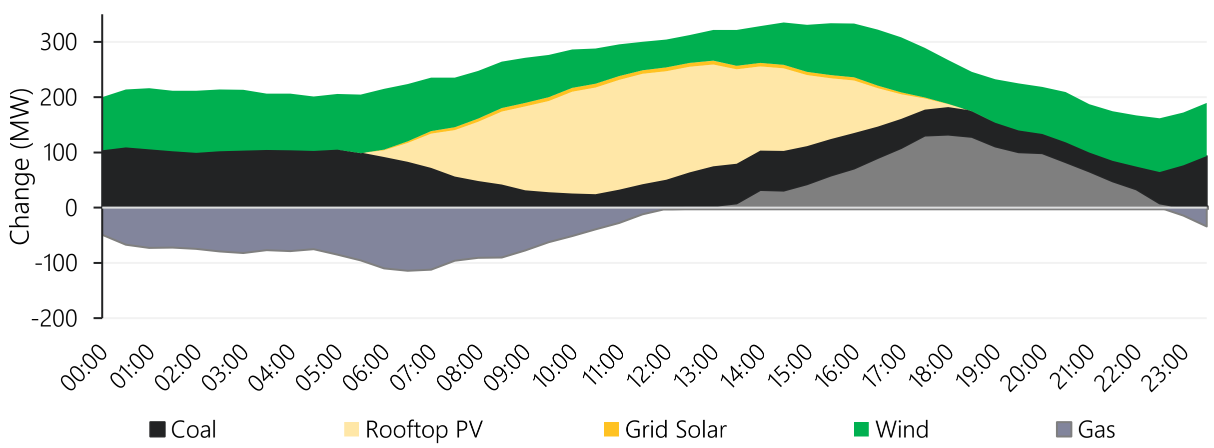


Figure 56 Solar impacts the daytime supply profile; GPG up during the evening peak

Change in WEM supply by time of day and fuel type – Q4 2019 versus Q4 2018



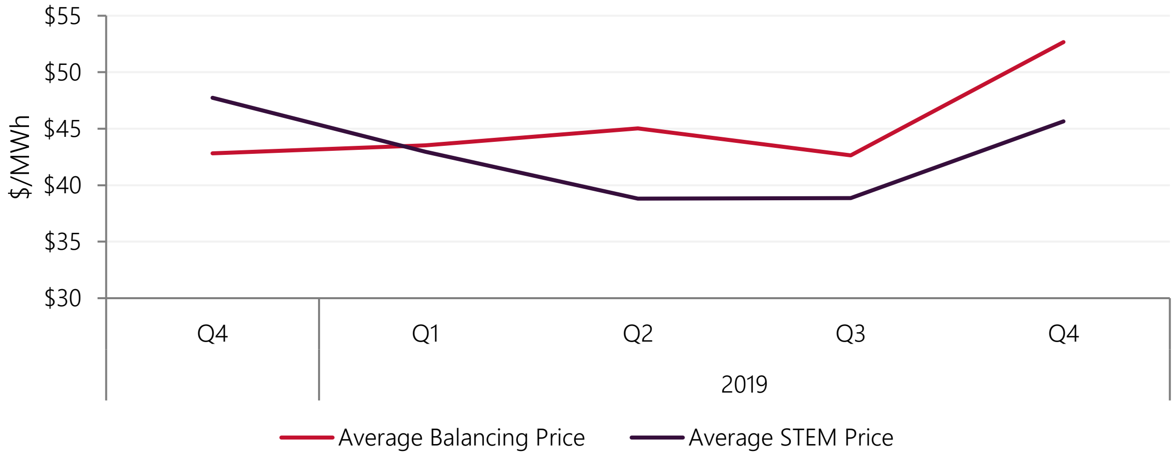
This change in generation mix was most pronounced at 1130 hrs on 30 November 2019, when the SWIS recorded its highest ever level of VRE[38] penetration. At the time, 51% of underlying system demand was supplied by VRE output. This was a result of mild temperatures, clear skies (resulting in high rooftop PV output), and high wind speeds.

3.3 Wholesale electricity pricing

The average Balancing Price in Q4 2019 increased by 23% compared to Q4 2018 (Figure 57), primarily due to an 8% increase in average operational demand and greater GPG output from higher cost open cycle gas turbines, rather than combined cycle gas turbines. The Short Term Energy Market (STEM) prices, however, decreased by 4.3% compared to Q4 2018, partly due to changes in Market Participant bidding and hedging behaviour.

Figure 57 Higher demand leads to higher Balancing Prices

WEM quarterly average wholesale electricity prices



Minimum STEM price

Under the WEM Rules, the Balancing Market has a price floor of -$1,000/MWh; this is defined as the Minimum STEM Price. For the first time since the WEM commenced in 2006, the wholesale electricity price cleared at the Minimum STEM Price, occurring during three Trading Intervals over the weekend of 12-13 October 2019 (Figure 58). This outcome was driven by:

- Record low demand, with operational demand reaching an all-time low of 1,159 MW at 1230 hrs on Sunday, 13 October 2019.
- High rooftop PV generation[39], which had an estimated average output of 927 MW during these Trading Intervals.
- Market Participant bidding behaviour.

The SWIS remained in a Normal Operating State[40] during these intervals and no out-of-merit dispatch was required. Prior to this, the lowest price cleared in the Balancing Market was -$193.86/MWh on 31 March 2013.

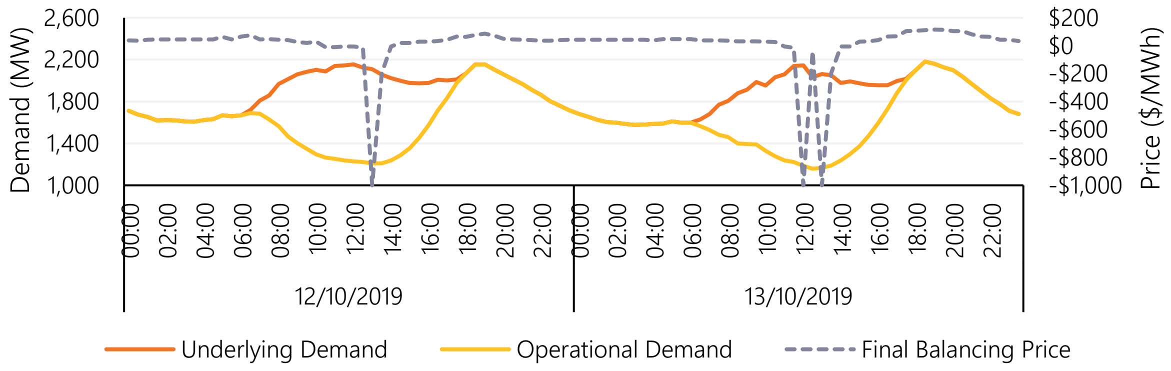
[38] Non-synchronous generation - Rooftop PV, Wind and Grid Solar

[39] The installed capacity of rooftop PV in the SWIS has almost reached 1.2GW

[40] Claire 3.3.1 of the WEM Rules - https://www.erawa.com.au/cproot/20765/2/Wholesale-Electricity-Market-Rules-1-November-2019.pdf

Figure 58 All time minimum operational demand and minimum STEM prices

WEM market outcomes – 12 and 13 October 2019



Approximately 1,200 MW of generation was offered into the Balancing Market at the Minimum STEM Price on both 12 and 13 October. This included 485 MW of coal-fired generation, 571 MW of GPG, and over 100 MW of Intermittent Non-Scheduled Generation[41] (INSG). Within this:

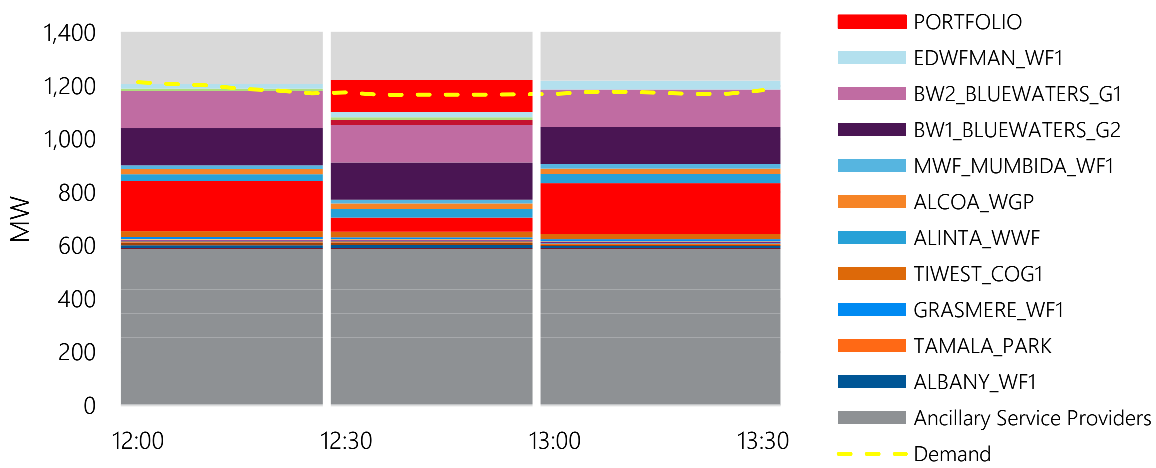
- **Ancillary Services** – 50% was offered for Ancillary Services; Market Participants providing Ancillary Services are obligated to offer these quantities at the Minimum STEM Price.
- **Balancing active facilities** – 46% was provided by Balancing active facilities, which can offer generation at any price, but chose to offer energy at the Minimum STEM Price to ensure they were dispatched and not de-committed.
- **Balancing non-active facilities** – 4% was offered by Balancing non-active facilities[42], which are obligated to offer their generation at the Minimum STEM Price if they would like to be dispatched.

In the three Trading Intervals where the Minimum STEM Price was reached, approximately 50 MW of INSG was dispatched off, as these Facilities were offered into the Balancing Market above the Minimum STEM Price.

A 125 MW change in bidding by Synergy in relation to its Balancing Portfolio contributed to the Balancing Price remaining above the Minimum STEM Price in the 12:30 Trading Interval on 12-13 October (red tranches in Figure 59).

Figure 59 Shift in Synergy Bids during record low demand

Balancing Merit Order at the price floor – 13 October 2019



[41] Intermittent Generator - A Non-Scheduled Generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g. wind).

[42] These are generally smaller facilities, under 10MW, that don't have the communication and control systems in place to automatically respond to dispatch instructions from AEMO.

Generation that is offered at the Minimum STEM Price is ordered in accordance with the tie-break methodology which allocates a random order to all facilities, to apply for the Trading Day. As a result of this methodology the Bluewaters Unit 1, a 229 MW coal generation facility, was the marginal unit on both 12 and 13 October and was dispatched down to accommodate the low operational demand (purple tranches in Figure 59).

If demand had dropped a further 100 MW between the 12:00 and 1:00 Trading Intervals, Bluewaters Unit 1 would have been dispatched below its minimum stable generation level and therefore would have been de-committed. Large synchronous generators, such as Bluewaters Unit 1, inherently provide voltage support and inertia. AEMO must monitor this and may be required to take action in response to the potential de-commitment of a large synchronous generator when demand is low.

Trading behaviour in the STEM and Bilateral markets on these days was not atypical. The net exposure to the Minimum STEM Price (after accounting for energy that was contracted[43] and self-supplied) was 394 MWh, equating to $394,285.

Negative pricing in the Balancing Market is not atypical, however; reaching the Minimum STEM Price for prolonged periods can put pressure on net suppliers into the Balancing Market. The WEM reform[44] will implement several changes to mitigate these market impacts, such as defining a wider suite of essential system services, closer to zero market gate closure, and co-optimisation of energy and essential system services.

3.4 Reserve Capacity Mechanism

The start of Q4 2019 marks the start of the 2019-20 Capacity Year in the Reserve Capacity Mechanism (RCM), with notable changes as follows:

Capacity Credits

The total number of Capacity Credits assigned by AEMO[45] increased from 4,819 MW in Capacity Year 2018–19 to 4,888 MW in Capacity Year 2019–20, mainly due to:

- A new wind facility (Badgingarra Wind Farm) was certified to provide 35 MW of Reserve Capacity.
- A new solar facility (Merredin Solar Farm) was certified to provide 29 MW of Reserve Capacity.

Benchmark Reserve Capacity Price (BRCP)

The Benchmark Reserve Capacity Price (BRCP) is used in the calculation of the maximum price that may be offered in a Reserve Capacity Auction, or as an input in the calculation of the administered Reserve Capacity Price if an auction is not required. The 2020 BRCP value, relevant for the 2022-23 Capacity Year, is $141,900/MW /year. The 2020 BRCP is the lowest calculated since the 2006 BRCP, and has decreased by 8.0% compared to the 2019 BRCP. This decrease can mostly be attributed to the decreasing yield value of the Commonwealth Government bonds (Bonds). Bond yield is an input into the calculation of the Weighted Average Cost of Capital and represents the nominal risk-free rate.

[43] Through Bilateral Contracts and the STEM.

[44] See: https://www.wa.gov.au/organisation/energy-policy-wa/energy-transformation-strategy.

[45] See https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Reserve-capacity-mechanism/Assignment-of-capacity-credits.

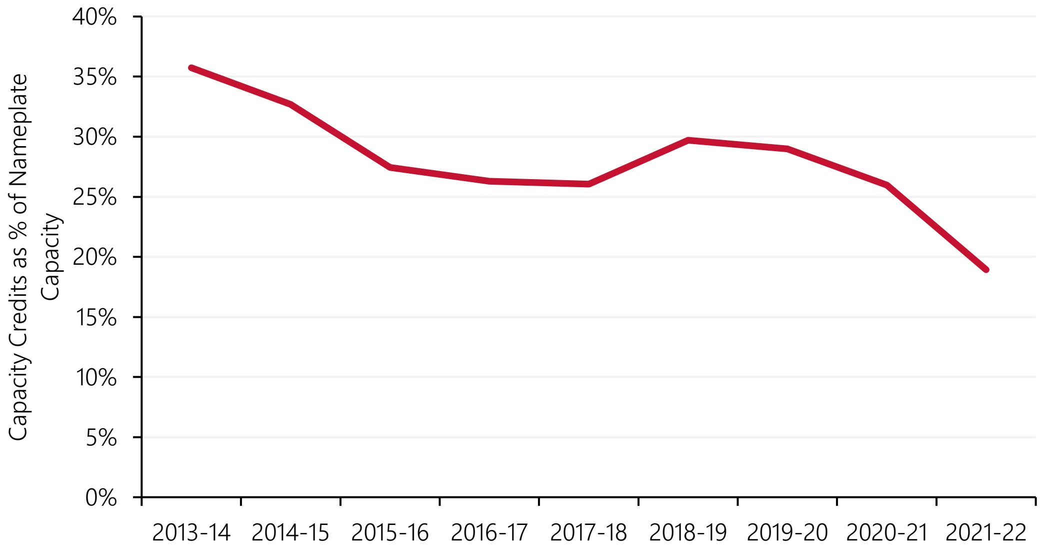
Relevant Level Calculation

The Relevant Level calculation is used to determine the Certified Reserve Capacity level and subsequently the Capacity Credits assigned to INSGs. The Relevant Level calculation assesses the capacity value of INSG's based on their generation during periods with the lowest level of surplus capacity over demand. These periods are more likely to occur when demand in the SWIS is the highest.

The increasing penetration of behind-the-meter PV generation in the SWIS is resulting in periods of highest demand shifting to later in the day, and occurring more in the winter months when, on average, INSG output is lower. This means the level of Capacity Credits assigned to INSGs is reducing (Figure 60).

Figure 60 INSGs to receive fewer capacity credits

Capacity Credits assigned to INSGs



Abbreviations

Abbreviation	Expanded term
AEMO	Australian Energy Market Operator
ASX	Australian Stock Exchange
AUD	Australian dollars
AWST	Australian Western Standard Time
BBL	Barrel
CER	Clean Energy Regulator
CTP	Capacity trading platform
DAA	Day Ahead Auction
DER	Distributed Energy Resource
DWGM	Declared Wholesale Gas Market
EGP	Eastern Gas Pipeline
FCAS	Frequency control ancillary services
FY	Financial year
GJ	Gigajoule
GPG	Gas-powered generation
GSH	Gas Supply Hub
GW	Gigawatt
GWh	Gigawatt hour
HDD	Heating degree day
IRSR	Inter-regional settlement residue
Kcal	kilocalories
LFAS	Load Following Ancillary Services
LGC	Large-scale Generation Certificates
LNG	Liquefied natural gas
MAP	Moomba to Adelaide Pipeline
MMBtu	Metric Million British thermal unit
MSP	Moomba to Sydney Pipeline
$MtCO_2$-e	Million tonnes of carbon dioxide equivalents
MW	Megawatt

Abbreviation	Expanded term
MWh	Megawatt hour
NEM	National Electricity Market
NGP	Northern Gas Pipeline
NSG	Non-scheduled generation
PJ	Petajoule
PV	Photovoltaic
QNI	Queensland to New South Wales Interconnector
RBP	Roma to Brisbane Pipeline
SRA	Settlement Residue Auction
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
SWQP	South West Queensland Pipeline
TJ	Terajoule
TWh	Terawatt hour
VRE	Variable renewable energy